Full Report

Low Carbon Options and Gas Infrastructure

Chances of efficiency and renewable energies for gas infrastructure planning and security of supply in Europe

This report reflects the views and opinions of the research contractors which may or may not correspond with the opinion of the contracting authority (The Federal Ministry for the Environment, Nature Conservation and Nuclear Safety).

Full report

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List of abbreviations

ACER	Agency for the Cooperation of Energy Regulators
BNetzA	Bundesnetzagentur, German NRA
BMWi	Bundesministerium für Wirtschaft und Energie, German Federal Ministry for Economic Affairs and Energy
CBA	Cost Benefit Analysis
CCGT	Combined-cycle gas turbine
CCS	Carbon Capture and Storage
CEF	Connecting Europe Facility
CNG	Compressed natural gas
CRE	Commission de Régulation de l'Energie (French NRA)
CV	Caloric Value
DE	Germany
DSO	Distribution System Operator
EE	Energy Efficiency
ENTSOE	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EnWG	Energiewirtschaftsgesetz (German Energy Industry Act)
ES	Spain
FID-projects	Final Investment Decision projects
FiT	Feed-in-tariff(s)
FR	France
FYROM	former Yugoslav Republic of Macedonia, a provisional designation (pending resolution of a naming dispute with Greece) used by many international organizations to refer to the Republic of Macedonia
GDP	Gross Domestic Product
GHG	Greenhouse Gas(es)
GRIP	Gas Regional Investment Plans
GTS	Gasunie Transport Services B.V., Dutch TSO
GTYS	Gas Ten Year Statement (UK)
GVA	Gross Value Added
IEA	International Energy Agency
IED	Industrial Emissions Directive
IT	Italy
ITG	Infrastrutture Trasporto Gas, Italian TSO

HVHF	High-volume hydraulic fracturing
LDZ	Local Distribution Zone
LNG	Liquefied Natural Gas
LTECV	loi relative à la transition énergétique pour la croissance verte, French energy transition law
MINETUR	Spanish Ministry of Industry, Tourism and Trade
MiSE	Italian Ministry of Economic Development
Mtoe	Million tonnes of oil equivalent
mtpa	Million tonnes per annum
NDP	Network Development Plan
NL	Netherlands
NOP	Netwerkontwikkelingsplan, Dutch NDP
NRA	National Regulatory Authority
NTS	National Transmission System
PCI	Projects of Common Interest
RE	Renewable Energy
RES	Renewable Energy Sources
RTE	Réseau de Transport d'Électricité, the electricity transmission system operator of France
SEN	Strategia energetica nazionale, Italy's national energy strategy
SGI	Societa Gasdotti Italia, Italian TSO
SJWS	Stakeholders Joint Working Sessions
SNAM	SNAM Rete Gas, Italian TSO
SO&AF	System Outlook and Adequacy Forecast
TEN-E	trans-European energy networks
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UK	United Kingdom

Opening remark

Prognos and Ecologic were assigned to carry out this study commissioned by the German Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety (now: Federal Ministry for the Environment, Nature Conservation and Nuclear Safety) in July 2015. In September 2016 a workshop was carried in order to discuss intermediate findings with stakeholders (see Appendix). In January 2017 an interim report was published. The contents of the interim report are included in this final (full) report.

Most of the information dates back to 2016 or earlier. However, the draft of TYNDP 2017 has also been analysed.

This final ("full") report contains the complete documentation of the results. Additionally, a barrier-free summary of this report has been published both in English and German.

1 Introduction

1.1 Background and assignment

There is broad consensus on the need for a transition from fossil fuels based energy systems towards safe and sustainable low-carbon energy systems. At the same time, recent conflicts in the Ukraine have once more highlighted the need for Europe to improve its energy security and decrease its energy import dependency in particular regarding gas supply security. Clearly, both climate policy and energy security can and need to go hand in hand. The European Council conclusions of 26-27 June 2014 have highlighted the close link between energy security and the 2030 policy framework on climate and energy and have established the framework for an "Energy Union with a forward-looking climate policy". In October 2014, the European Council adopted targets 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 and improving the energy efficiency of the EU by at least 27 % by 2030 compared to a baseline scenario. These targets will contribute to reducing the EU's reliance on gas imports.

In the coming years, important decisions on the development of the European gas infrastructure must be taken. It is important, that these decisions are taken on a solid data basis and reflect the EU's long-term goal of reducing greenhouse gas (GHG) emissions by 80-95 % by 2050, as well as the aim to limit global warming well below **2 °C, if possible to 1.5 °C, in line with the Paris Agreement**. Whilst past planning approaches for energy security and network development assumed an increasing European gas demand, European gas demand was in fact declining between 2010 and 2014. Although natural gas is the fossil fuel with the lowest carbon factor, in the long run, a consequent decarbonisation of the European energy system will lead to a decreased gas demand. A core question of this study is, if demand scenarios and other assumptions that are underlying todays gas infrastructure planning consider this decrease, yet. Is it possible to avoid future infrastructural costs if Europe´s carbon goals are assumed consequently in the plans? And how will the European dependency on imported gas be impacted if more low carbon options are used?

With this study, Prognos AG and Ecologic Institute aim to answer these questions and conclude with recommendations for policy makers, commissioned by the German Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety. This interim report presents in the second chapter results from a status-quo analysis of gas infrastructure plans and their assumptions in the EU and selected focus countries. In the third chapter, a comparison between ambitious energy scenarios and existing network plan scenarios has been carried out. This comparison aims to show the impacts of low carbon options on gas consumption. A risk comparison analysis between energy efficiency measures, the development of renewable energy sources and natural gas has been undertaken in chapter 5. In chapter 5, the possible impacts of low carbon measures on import dependency, gas imports costs, and saving potentials related to gas trade and to gas infrastructure have been assessed.

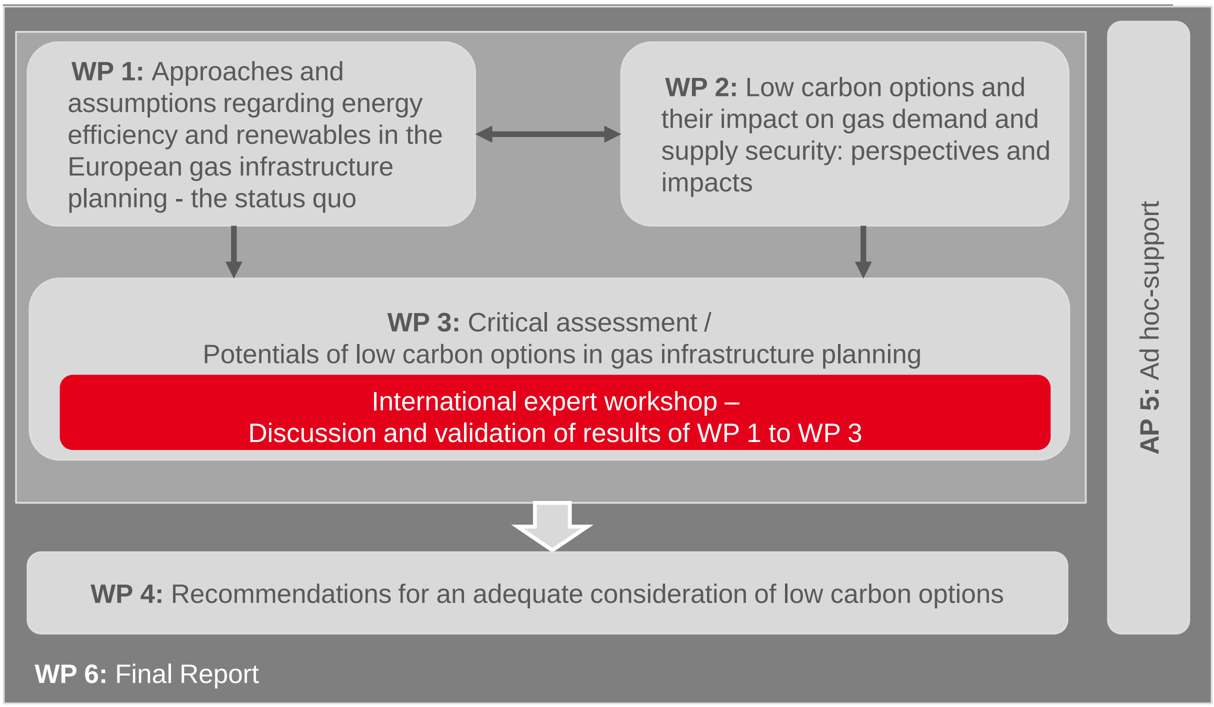
Chapters 1 to 3 and chapter 5 have been published in an interim report on January 19, 2017. In this full report, these chapters underwent only minimal changes, they have not been updated with new documents that have been published since then, except for the TYNDP 2017 scenarios. Neither the impacts of the BREXIT decision nor the measures from the European

Commission's energy "Winter Package" nor the "Clean Energy Package" have been included in this report.

1.2 Study design

The following figure shows the main working packages (WP) of the study.

Figure 1: Study concept



Source: Prognos, Ecologic

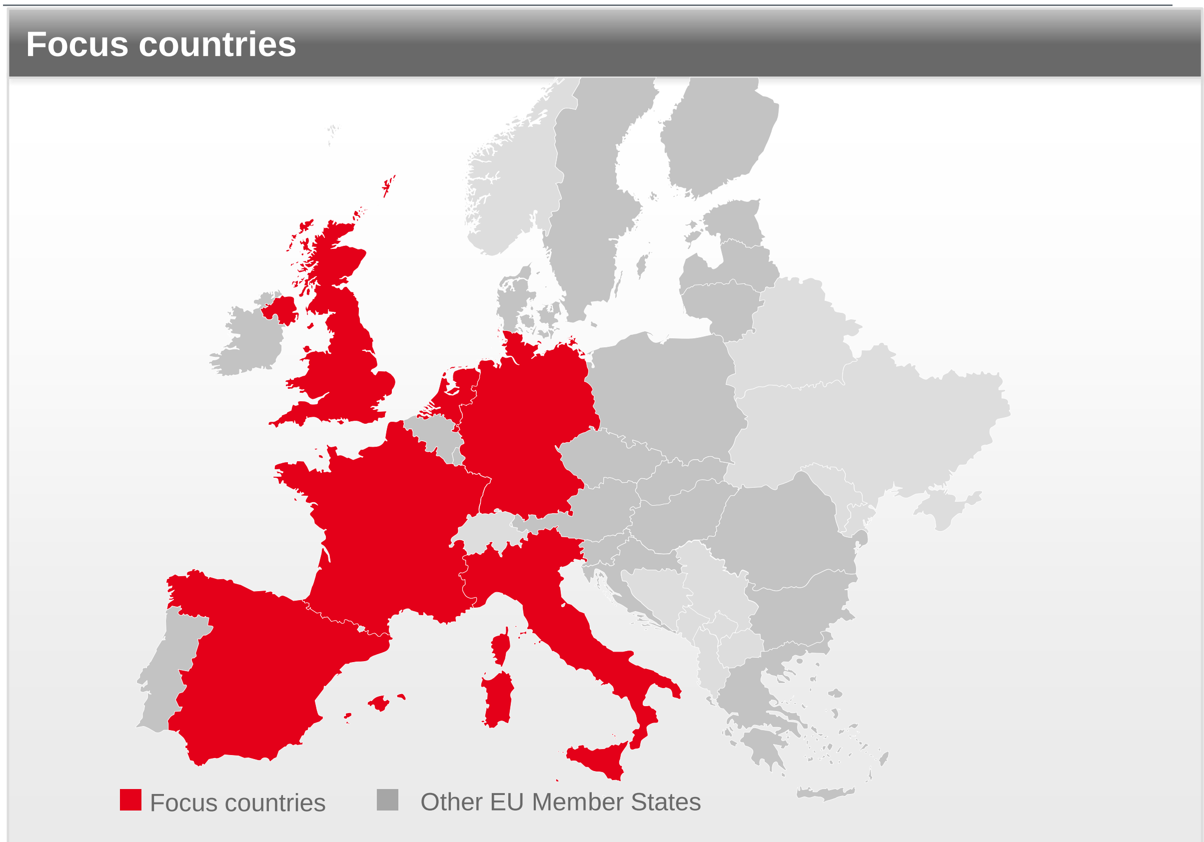
The study opens with an in depth-analysis of planning approaches in Europe and in the focus countries (see Figure 2). The core question of this task is how gas network planning in Europe works today and if underlying assumptions and scenarios do consider national targets for GHG abatement, renewable energies or efficiency development.

In the second step, pathways describing future gas demand are analysed. This analysis is based on existing scenarios which include energy and climate targets and are different to the scenarios used in today´s network plans. The objective of this step is to find out about the impact of low carbon options on gas and capacity demand. To do so we describe the interrelationship between (yearly) gas demand and (hourly) capacity demand. Based on this we discuss if the use of other scenarios would possibly lead to other network plans or a changed capacity demand and, attached with this, to lower costs. Besides, we discuss the target systems which determine network planning and risks that might occur when using low carbon options.

Thirdly, we will assess potentials of a further consideration of low carbon options in demand scenarios underlying network planning. Could they lead to a reduced network development? Has a greater coherence of energy policy targets and network planning therefore potentials for savings?

Based on the results of working packages 1 to 3 we carried out an expert workshop and derived recommendations both from the scientific analysis and its perception from the expert round. The results of this workshop can be found in the annex.

Figure 2: Focus countries



Source: Prognos

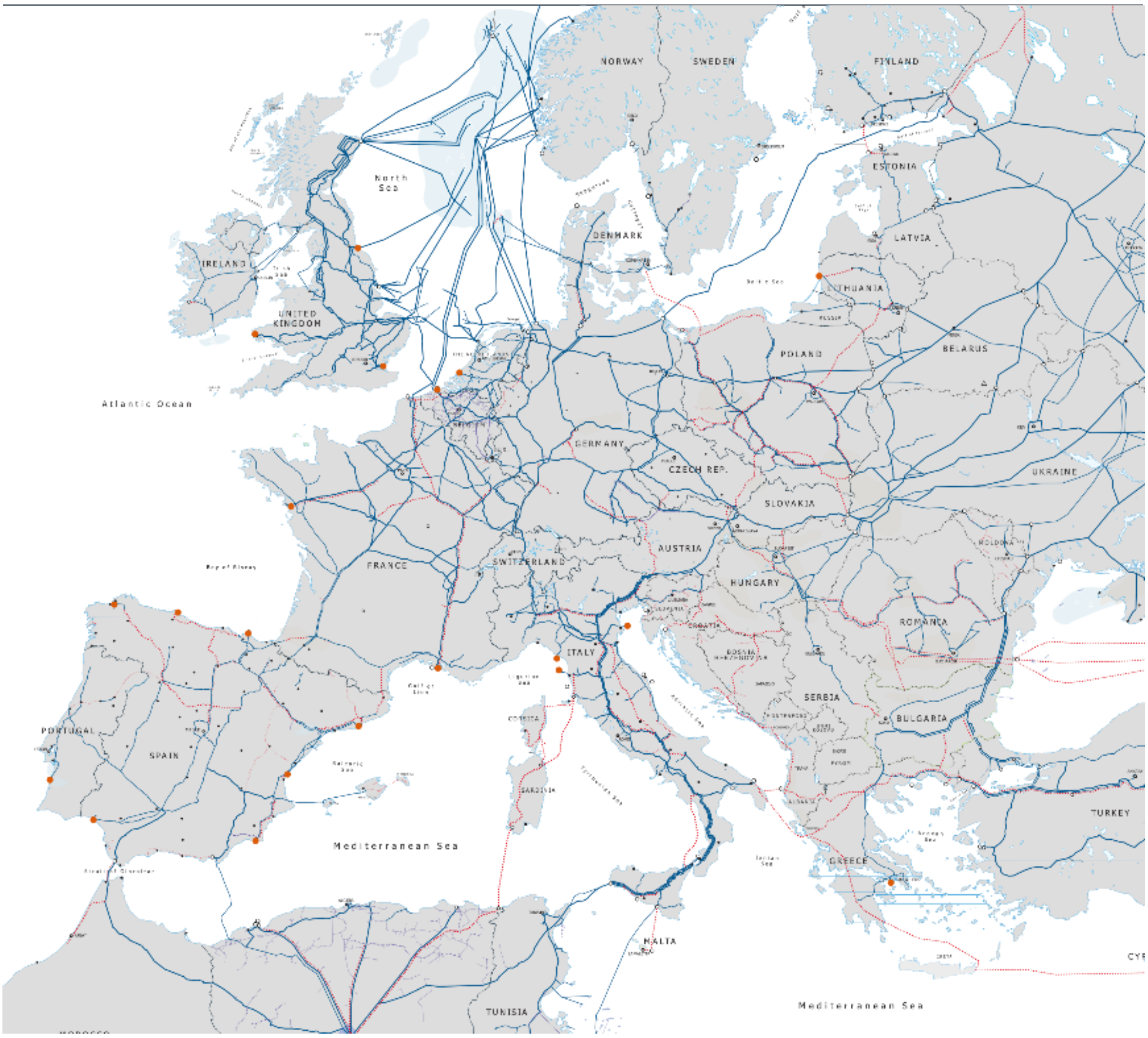
2. Status quo in European gas infrastructure planning

As of 2013, the European gas infrastructure consisted of over 2 million km in pipelines (transmission and distribution networks) and 142 storage facilities serving over 118 million customers. The infrastructure aided to transport supplies of over 5,060 TWh of natural gas in 2013 from both domestic sources and export countries such as Russia, Norway, Algeria and Qatar.

LNG imports to EU-28 countries amounted to 631 TWh in 2013 [Eurogas 2014]. The transmission system is the vital backbone of the whole gas infrastructure and consists of about 247 thousand km in pipelines operated by 51 transmission system operators [ENTSOG 2014]. TSOs have the obligation to present a network development plan considering the projected future developments of gas demand and supply.

In the following the future demand scenarios underlying the most recent development plans of the TSOs in the 6 selected countries will be analysed.

Figure 3: Gas Pipelines and LNG Terminals in Europe, 2014



Source: Based on [ENTSOG 2015]

2.1 Regulatory framework and other determinants for gas infrastructure planning

2.1.1 Regulatory framework in a nutshell

Energy policy in the European Union is a split competence between the individual Member States and the European Union. The 2009 Treaty of Lisbon establishes in Art. 194 that the European Parliament and the Council should establish the measures necessary to achieve the objectives in (a) the functioning of the energy market, (b) security of supply, (c) promote energy efficiency and the development of renewable forms of energy and (d) promote the interconnection of energy networks [European Union 2007]. Member States are competent in establishing policies to influence their energy mix and supply structure and can unilaterally decide on their participation in transnational infrastructure projects [Goldthau 2013].

Within the context of its regulatory role, the European Commission has released three sets of directives in 1998, 2003 and finally 2009. These directives and regulations (labelled "Energy Packages") have aimed at liberalizing the gas and electricity markets and pushing for single market rules [Goldthau 2013]. With respect to natural gas, the "Third Energy Package" of 2009 established the unbundling of production and transmission in order to eliminate potential conflicts of interest and set up provisions to establish a Europe-wide network of transmission system operators (ENTSOG) in order to facilitate cooperation between transmission system operators. The 2009 package also established the Agency for the Cooperation of Energy Regulators (ACER).

Following the Third Energy Package, the European Commission released Regulation 994/2010 concerning the security of gas supply. It contains measures of preventive action for gas supply disruptions and coordinated actions in case of such disruptions. Cross-border interconnections must have reverse-flow capabilities by December 2013 and each national grid must be able to supply total gas demand on an extraordinary cold day despite a potential disruption of the single largest infrastructure within the country [European Union 2010].

Table 1: European legislative acts affecting the natural gas market

Act Type	Reference	Title Topic
Directive	2003/87/EC	Establishing a scheme for greenhouse gas emission allowance trading within the Community
Regulation	715/2009	On conditions for access to the natural gas transmission networks
Regulation	713/2009	Establishing an Agency for the Cooperation of Energy Regulators
Directive	2009/73/EC	Concerning common rules for the internal market in natural gas
Regulation	994/2010	Concerning measures to safeguard security of gas supply
Regulation	347/2013	On guidelines for trans-European energy infrastructure
Regulation	1316/2013	Establishing the Connecting Europe Facility
Communication		"A Framework Strategy For A Resilient Energy Union With A Forward-Looking Climate Change Policy"

Source: Prognos

In April 2013 the European Parliament and Council approved Regulation 347/2013 on the guidelines for trans-European energy infrastructure. The aim of the regulation is the faster development of trans-European infrastructure by means of identifying projects of common interest (PCI), setting up eligibility criteria for future projects and the allocation of financial resources to these out of the "Connecting Europe" Facility (CEF), created by regulation 1316/2013.

2.1.2 Overview of instruments for network planning in Europe

Under the third energy package, different **instruments** have been established for network planning at European, regional and national level. In addition to these planning instruments, the EU has also developed an additional European instrument to support investment in and implementation of infrastructure that helps to support European energy policy goals. Each of these processes is formally required to build on or consider the processes at the other levels, making them formally **interdependent** processes[1].

At **national level**, the TSO in the different Member States develop National Development Plans (NDP), generally on an annual or biannual basis. These national plans identify the main transmission infrastructure needs over a ten-year period and all the investments already decided or to be executed in the next three years. The NDP lay the foundation for network development in each country and provide the building blocks for grid planning at regional and European levels[2]. NDPs of the focus countries are analysed in chapter 2.3.

At **regional level**, a group of TSOs from different countries coordinate together to determine transmission infrastructure needs for a geographically and functionally determined region over a ten-year period. These plans are referred to as Gas Regional Investment Plans, or GRIPs, and are developed every two years[3]. The 2nd edition GRIPs released at various times between November 2013 and August 2015 are the most recent.

At **European level**, ENTSOG uses both the national and the regional plans as the basis to conduct a similar assessment of infrastructure needs, but focussing on the European transmission grid as a whole and transmission infrastructure with a cross-border impact in particular. These plans are referred to as Union-wide Ten-Year Network Development Plans (TYNDP) and are developed every two years. The Union-wide TYNDP is a non-binding document. The TYNDP 2017 is the fifth iteration of the Union-wide TYNDP process and covers the 2017-2037 time horizon[4] (see chapter 2.2.1) TYNDP 2018 is currently being developed.

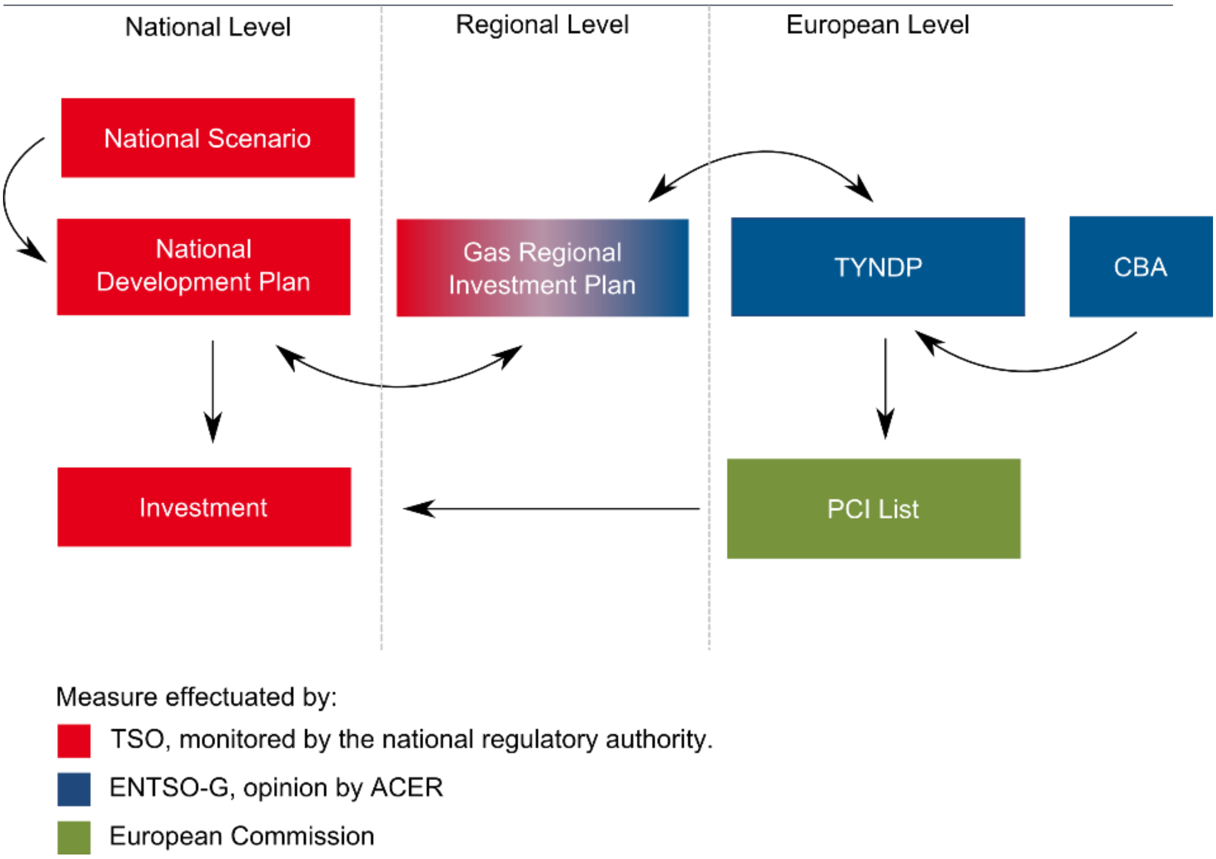
1 Under Article 22(3) of Directive 2009/73/EC the NDP should take into account the Union-wide TYNDP and the GRIPS. Under Article 8.10 of Regulation (EC) 2009/715, the Union-wide TYNDP should build on national investment plans and consider regional investment plans. Moreover, according to Article 3.6 of Regulation (EU) 347/2013, PCI included in the Union list are an integral part of the GRIPs, the Union-wide TYNDP and national infrastructure plans, as appropriate, and to be conferred the highest possible priority under these plans. Annex III 2(4) of the Regulation further specifies that proposed gas infrastructure projects meeting the criteria and falling into the categories of the Regulation must be part of the latest Union-wide TYNDP.

2 Article 22 of Directive 2009/73/EC lays the foundation for network development in each country. TSrequired to submit to the regulatory authority a ten-year network development plan after having consulted all relevant stakeholders and taking into consideration existing and forecasted demand and supply figures.

3 The legal basis for the Gas Regional Investment Plans (GRIPs) is Regulation (EC) 715/2009, which requires TSOs to publish regional investment plans every two years on the basis of which they may voluntarily take investment decisions.

4 The legal basis for the Union-wide TYNDP is Article 8.10 of Regulation (EC) 2009/715. According to Article 8.10 of Regulation (EC) 2009/715, the Union-wide TYNDP should build on the reasonable needs of different network users regarding cross-border interconnections, as well as the long term commitments of investors and identify investment gaps, notably with respect to cross-border capacities.

Figure 4: The Process of network planning in Europe



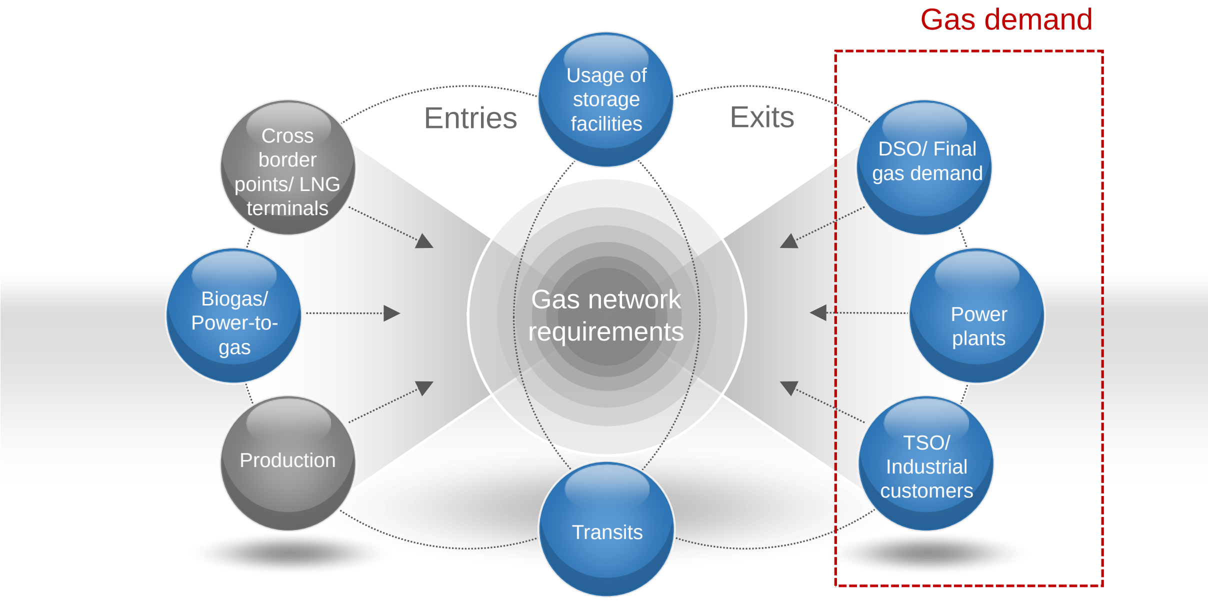
Source: Based on [ENTSO-E]

The primary instrument to support the implementation of gas infrastructure are the **Projects of Common Interest (PCI)** established under the TEN-E regulation. Every two years, the European Commission adopts a new list of PCI projects, which stand to benefit from several measures aimed at supporting investment, including financing for construction works from the CEF (see chapter 2.2.3). Figure 4 shows a simplified depiction of how the processes interact with each other.

Determinants in gas infrastructure planning

Requirements for the gas transmission network result from entries to the system as well as from exits (see Figure 5) and have to be addressed for a stable operation of the network. The change in production sources (conventional/ non-conventional production, biogas, power to gas) or changes at cross border points could change the flow directions or result in a need for new capacities. Commissioning of LNG terminals or cross border points or different usage of storages does also affect the transport flow and the demand for transmission capacities.

Figure 5: Driving forces for the gas network development



Source: Prognos

One motivation for infrastructure expansion is often elevation of security of supply, diversifying supply sources or elevation of market liquidity. These important drivers for changing network requirements will not be assessed in detail in this report.

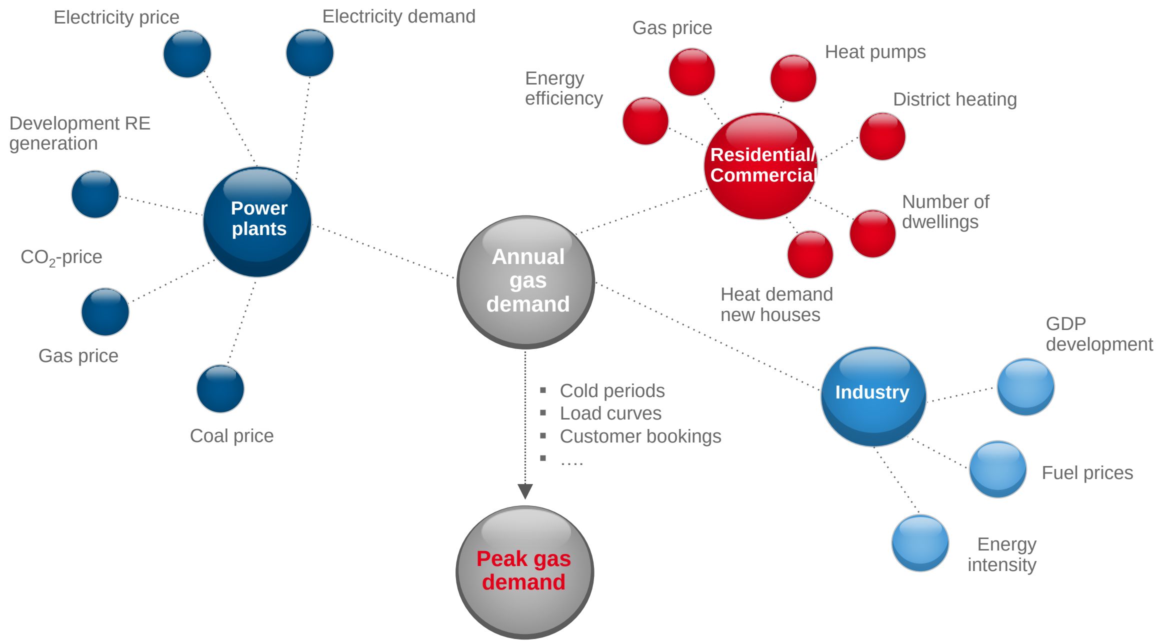
A change in customer requirements and gas consumption also influences the gas network operation. Customers are connected to the gas grid on different levels:

- Residential and small commercial customers are connected to the networks of distribution system operators (DSO),
- Power plants and large industrial facilities are partly directly connected to the transmission network.

The demand of these customers is affected by the driving forces shown in Figure 6.

In all sectors the implementation of policies and regulation can have a strong influence on the gas demand. Environmental and climate policies have thereby a double-edged impact: enhanced energy efficiency and the switch to (nearly) zero-carbon energy sources reduce gas demand, the switch from higher carbon sources (coal, oil) to gas could raise the gas demand.

Figure 6: Driving forces for the annual and the peak gas demand



Source: Prognos

Electricity generation in gas-fired power plants is affected by the development of the electricity demand and the overall installed generation capacity. A higher share of renewable generation will in the mid-term reduce the share of gas. If volatile renewables like wind and solar are deployed they need some backup which could be provided by gas-fired power plants. This development might result in a high capacity demand (peak demand per hour) of gas power plants with low load factors (running times) and thus a limited yearly demand. In competition with other conventional fuels the merit order between gas and coal (hard coal as well as lignite) is determined by the fuel and CO_2-prices. High carbon prices will result in a higher generation from gas-fired plants, low coal and high gas prices in a lower generation in gas-fired plants.

In the residential and most parts of the tertiary sector gas is used for heating purposes. So, the heat demand in these sectors is an important driving factor. Heat demand is mainly influenced by the development of the population and economy, the corresponding number of dwellings and heated space in buildings and energy efficiency measures. A growth of the population could result in a higher gas demand; efficiency measures will lead to a lower demand. The second influencing factor is the substitution of fuels due to changing energy prices or policy interventions. Gas heating could be replaced by e. g. heat pumps or district heating, oil or coal heatings could be replaced by gas heating.

The industrial gas demand is influenced by the development of the economy (mainly the production which is measured by value added) and the development of energy efficiency. Economic growth could result in increasing gas demand, ambitious efficiency in a lower demand. The development of fuel prices along with policy incentives determine the substitutions of gas with other fuels and vice versa.

Determining for gas network planning is not the development of the yearly gas demand but the gas capacity demand (also referred to as peak gas demand). There is no linear relation between annual demand and peak capacity demand. In general, the peak capacity demand seems to follow the trend of the yearly demand but is also subject to influencing technical, meteorological and other factors. This will be an issue of chapter 2.1.3.

2.1.3 Gas demand, temperature, capacity and cost

Only very few scientific publications are available on the interrelation between (yearly) gas demand (measured e.g. in GWh) and (peak) capacity demand (measured in GWh/h or GWh/day). For Germany the following study was published in 2014: "Studie über Einflussfaktoren auf den zukünftigen Leistungsbedarf der Verteilnetzbetreiber" (Study about influencing factors of the capacity demand of distribution system operators, "FfE-Study") [FfE 2014].

Based on actual consumption data, the study analyses the interdependency between gas demand and gas capacity demand, with special focus on the final energy demand of the residential and tertiary sector. The underlying assumption about future gas demand in this study was taken from the scenario "Energiereferenzprognose" ("Reference Scenario", [Prognos 2014]). The main results with reference to the German situation are:

- A decline of gas demand causes a reduction of gas capacity demand but not in a relation of 1:1.
- In the residential sector, the relation between yearly gas demand decline and peak gas capacity demand is roughly 3:1.
- In the tertiary sector the relation is roughly 3:2.
- For the industry sector two situations are distinguished: 1. Capacity demand stays constant, 2. Operating hours stay constant (which results in a nearly constant capacity gas demand because the gas demand of the industrial sector stays nearly constant over the time period).
- The transformation and transport sectors are not analysed in the study.
- The **overall conclusion** for Germany is: The relation of the decline of gas demand and gas capacity demand varies between 1,6:1 and 2,1:1 (depending on the assumptions in the industry sector).

Other generalizable and quantifiable insights about the relation between capacity demand and volume demand in the transport grids are not known to the authors of this study. Therefore, this study uses the FfE-approach as a "**rule of thumb**" for the estimation of the capacity demand across Europe wherever no specific information on the development of capacity demand is available.

Capacity demand of customers – especially in the Residential and Tertiary sectors - is subject to **temperature variation**. A safe infrastructure design will consider cold weather periods and design the capacity in the gas network accordingly. According to Regulation (EU) No 994/2010 member states (or the so called "Competent Authorities") shall ensure that

> "in the event of a disruption of the single largest gas infrastructure, the capacity of the remaining infrastructure, determined according to the N – 1 for-

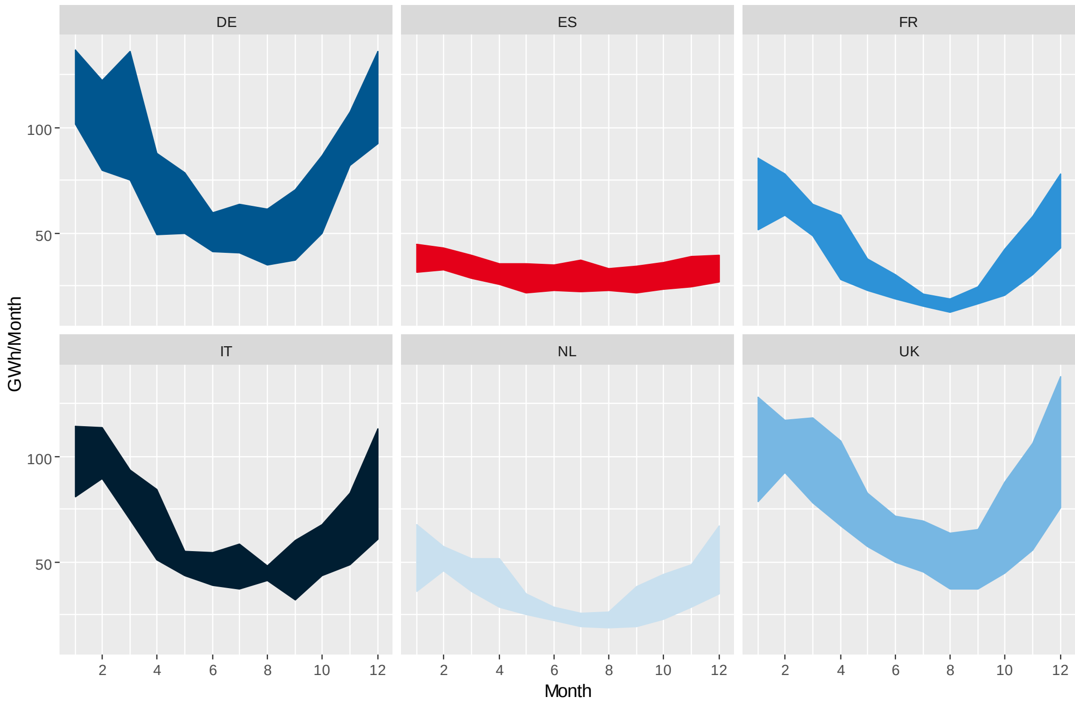
mula (...), is able, (...), to satisfy total gas demand of the calculated area during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years.“

This is a reason why gas networks are often not fully employed – they include a reserve for cold weather. However, most of the reserve capacities are implemented close to the consumers by using flexibility options like storages. Thus, import pipelines do not have to cover the full capacity demand in winter.

In fairly warm countries like Spain, there is no distinctive winter high. Natural gas is used in all sectors and only little more gas is needed for heating in winter. In countries like Germany and the United Kingdom the respective demand in winter is much higher than in summer. Thus, the gas capacity design has to consider the specific temperature variation patterns in the area. An overview of seasonal gas demand patterns in the individual target countries and Europe overall can be seen in figures Figure 7 and Figure 8.

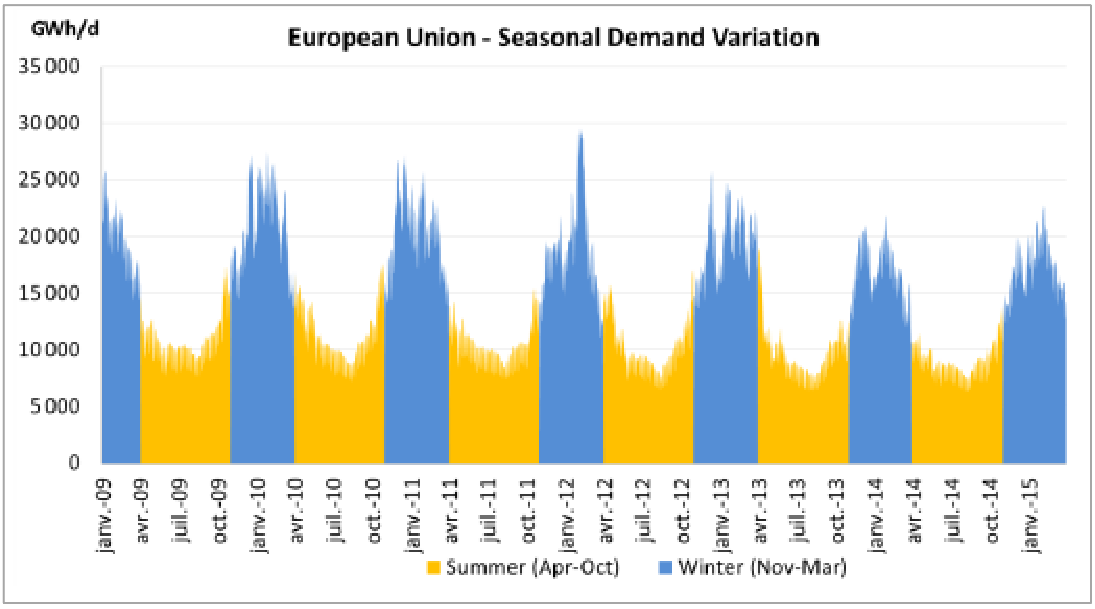
If the gas capacity demand increases due to a growing demand of customers (in a defined area) or due to a shortfall of supply from another source, investments may be needed to maintain the security of supply.

Figure 7: Variation of monthly gas demand in the focus countries 2008 to 2015 (GWh/Month)



Source: Eurostat 2016

Figure 8: Gas capacity demand in the EU 2009 to 2015



Source: ENTSOG, 1st Stakeholder Joint Working Session, 13th January 2016

On the other side, decreasing demand may lead to an abundance of capacity in the gas network compared to customer demand. In this case, new investment may not be needed. In extreme cases a divestment strategy might be followed by the network operator.

After all it remains difficult to answer in a general way what this could mean for (investment) costs of gas supply. This will be discussed in chapters 3 and 4.

2.2 Europe-wide gas infrastructure planning

This section provides a deeper analysis of the key processes for gas infrastructure planning in Europe (Union-wide TYNDP, the GRIPs and the selection of the Union-list of PCI), as well as a closer look at the gas demand scenarios in the Union-wide TYNDP 2017. Each process analysis provides a background for the individual process, as well as an assessment of the relevant stakeholder consultation and decision making processes. A focus of this analysis is the public availability of information, the overall transparency of the process, as well as the sufficiency of stakeholder involvement. The analysis was based on desk-research of available literature. The assessment of the Union-wide TYNDP 2015 and TYNDP 2017 is based on the public report and supporting documents.

2.2.1 Ten Years Network Development Plan (TYNDP)[5]

The TYNDP is an indicative planning document and does not contain binding network development measures. Its purpose is to give a basis for the gas industry and institutions to exchange their knowledge and ideas about the future of European gas markets and networks. In particular, the TYNDP assesses different levels of future infrastructure development[6] under different demand and supply disruption scenarios[7]. According to Article 10(c) of Regulation (EC) 715/2009 a particular focus of this assessment should be on identifying investment gaps, notably with respect to cross-border capacities. The TYNDP also analyses the dependency of EU Member States on various supply sources, including both their physical dependency on supply from Russia and LNG, as well as how strong they are afflicted by the price of one supplier and can benefit from a decrease in import prices.

In the TYNDP 2017 there were 234 network development projects submitted by national TSO´s to ENTSOG. In the former TYNDP 2015 there were 259 network development projects submitted. The difference of submitted projects from 2017 to 2015 is due to the completion of projects (20) as well as renaming and cancellation of projects. The projects cover transmission lines, incl. compressor stations, LNG terminals, storage facilities, production facilities and interconnections with a gas-fired power plant. The by far largest part of the projects, with 79 %, are transmission projects. 13 % are LNG terminals and 8 % gas storage projects. In comparison to 2015, several storage projects were cancelled or not re-submitted. Nearly half of the projects, 101, have a PCI status. 34 of all submitted projects have “FID” status, meaning final investment decision was taken[8].

Table 2: Profile Ten Year Network Development Plan

Rhythm	Biennially
1st NDP Gas	2010
No of TSOs	1 association (ENTSOg)
Current Status	TYNDP 2017
No of Scenarios	4
No of modelling variants	Combination of 3 demand scenarios, 4 infrastructure scenarios, with different climatic cases and with minimum and maximum supply
Considered period	20 years
Number of measures	no legally binding measures
Investment volume	all submitted projects about 86 bn €

5 In this section, the TYNDP 2017 refers to the draft that have been published in 2016, not the final version of 2017.

6 The defined scenarios for infrastructure development for the TYNDP 2017 were: “low infrastructure level”, “advanced infrastructure level”, “PCI 2nd list infrastructure” and ”high infrastructure level”. The “low infrastructure” scenario includes existing infrastructures plus FID projects. The “advanced infrastructure” scenario adds all advanced non FID-projects. The “PCI 2nd list infrastructure” scenario consists of all FID projects and 2nd PCI list non FID projects. The “high infrastructure” finally includes all submitted FID and non FID projects.

7 For the assessment of the infrastructure resilience under the TYNDP 2017, demand disruption is analysed for a normal peak day, under Ukrainian disruption and Belarus disruption. The remaining flexibility is calculated.

8 Not all PCI projects are FID projects and vice versa: only 10 projects have PCI and FID status. There are 109 Non-PCI and Non-FID status projects, which hence make up the majority of projects. The submitted projects are included according to their status in the low, advanced, PCI 2nd list and high infrastructure scenario.

Focus	diversification of supply, infrastructure in eastern regions, completion of internal energy market, bases for 3rd PCI selection process

Source: [ENSTOG 2016e]

The TYNDP is developed by ENTSOG over two years in a “continuous process” with three distinct phases:

1. Concept design and stakeholder engagement,
2. Concept implementation,
3. Formal submission [Lebois 2013b].

A graphic representation of the process for developing the TYNDP-G can be seen below.

Figure 9: Graphic representation of the TYNDP Process

Source: Lebois 2013b

Concept design and stakeholder engagement

ENTSOG begins the process by assessing feedback from the public consultation and the ACER Opinion on the previous TYNDP. On this basis, ENTSOG develops a concept for the upcoming TYNDP within the working structures of ENTSOG. As an association of European TSOs, propositions on the TYNDP are brought forward by the ENTSOG Secretariat, but discussed in a Working Group with the Member TSOs. This Investment Working Group[9] is part of the Systems Development business area of ENTSOG, which covers all ENTSOG activities related to the development of the Pan-European network[10].

In this phase ENTSOG develops demand scenarios for gas demand in the future. Low-carbon and sustainable options for the avoidance of gas consumption (i. e. renewable energies and energy efficiency) are largely considered in terms of their potential impact on future gas demand in the EU. For example, climate policy, development of RES, and ETS certificate price projections are all recognized as factors that could affect the long-term evolution of gas de-

[9] The Investment Working Group platform is supported by four smaller Kernal Groups focusing on specific areas (network modeling, supply and demand data, energy infrastructure priorities and editing) [ENTSOG 2015d]

[10] http://www.entsog.eu/business-areas

mand in the “demand” chapter of the TYNDP 2017. From a process perspective, the consideration of climate policy and low-carbon options within the TYNDP is, therefore, intimately linked with the process of developing the assumptions of how future gas demand will develop.

After adoption by the Investment Working Group, stakeholders review the TYNDP concept. This stakeholder-review consists of an initial workshop and various Stakeholders Joint Working Sessions (SJWSs). Furthermore, bilateral meetings are held with stakeholders upon request. In addition to providing an opportunity for stakeholders to challenge the assumptions of the concept that has been developed by ENTSOG, the process aims at identifying the data required to implement the concept and to internally validate the concept from a methodological standpoint.

According to Article 10(1) of Regulation 715/2009, the consultation process for the TYNDP should take place “at an early stage and in an open and transparent manner”. Article 10(2) of the Regulation also stipulates that “all documents and minutes of meetings” related to the consultations are public, and ENTSOG is obliged to indicate how and why the observations received from stakeholders have been taken into consideration (Article 10(3)). The consultation must involve all relevant market participants, and, in particular the organisations representing different stakeholder groups. Article 10 determines explicitly that the consultations involve the following stakeholder groups:

- National regulatory authorities,
- Other national authorities,
- Supply and production undertakings,
- Network users, including customers,
- Distribution system operators,
- Industry associations,
- Technical bodies and
- Stakeholder platforms.

Environmental organizations are notably absent from this list.

For the TYNDP 2015, the stakeholder engagement process was based on the ACER comments and Opinion received on the TYNDP 2013-2022 and an integrated process of six SJWS and two public workshops. The events were advertised under the events section of the website. Some public documentation of the events is available on the individual event pages as downloads[11]. In particular, slides presented at the workshops have been uploaded. However, minutes of the meetings and participant lists have only been made available for the first two SJWS[12]. The participant list and minutes for the second SJWS on demand and supply scenarios[13] reveals that there were 41 stakeholders officially registered for the event, representing the European Commission, ENTSOE, a national ministry, a national regulator, gas TSOs, gas network users, the electricity industry, a research organisation and a renewable energy industry association. Concerning the demand scenarios, only methodological questions unrelated to the development of final gas demand were discussed.

[11] http://www.entsog.eu/events/tyndp
[12] http://www.entsog.eu/events/2nd-stakeholder-joint-working-session-on-tyndp-and-cba-methodology#downloads
[13] http://www.entsog.eu/public/uploads/files/publications/TYNDP/2014/TYNDP015_140122_SJWS-2_StakeholdersInput%20input.pdf

During a public consultation of the last TYNDP, ENTSOG assessed the views of stakeholders on the TYNDP through a questionnaire[14]. There were eight respondents to the questionnaire covering project promoters, network users, end consumers and institutions. Of this limited number of respondents, most stakeholders believed there were sufficient possibilities for stakeholder engagement [ENTSOG 2015c]. While all respondents to the public consultation questionnaire also said that the demand scenarios at least sufficiently met their expectations [ENTSOG 2015b], both ENTSOG and ACER have suggested that the process for determining the demand and supply scenarios needs improvement due to its central role in the TYNDP. ACER recommends that ENTSOG "consider public workshops involving upstream and downstream industry, research and academia experts, well in advance of the determination of the scenarios in the next TYNDP" [ACER 2015b]. Furthermore, ENTSOG argues "it appears necessary to have an institutional validation of the scenarios to be sure they are consistent with European energy strategy" [ENTSOG 2015c].

Concept Implementation

Following the design of the concept and the stakeholder engagement process, the concept implementation phase is carried out culminating in the release of the draft TYNDP report. In this phase data is collected, processed and used to develop the TYNDP report in accordance with the concept design.

To develop the report, ENTSOG relies largely on data beyond its remit to carry out the assessment [ENTSOG 2015e]. It is, therefore, very reliant on the cooperation of stakeholders and its Member TSOs to carry out the assessment for the TYNDP. In general, three different data types are collected:

- **Project specific data** collected from project promoters. This data is collected through a standard questionnaire in a call for projects carried out for each TYNDP.
- **Country-specific data** provided by the Member TSOs through specific questionnaires.
- **General data** consisting of public data (ex. gas import scenarios by source, scenarios for prices of fuels and emissions) [ENTSOG 2014c].

While the parameters for the demand and supply scenarios are defined in the previously described "top-down" process, the actual data related to future gas demand is provided in a "bottom-up" process by the Member TSOs. For final gas demand in the residential, industrial and commercial sectors, the data collected from the Members TSOs are provided in line with the demand scenario "storylines" developed in the concept design stage. For final sectoral gas demand for power, on the other hand, data on expected future power gas demand is developed in cooperation and consultation with ENTSOE. As a quality control, ENTSOG checks the data and tries to ensure they match the storylines, including by consulting other sources (ex. IEA, Eurogas and the European Commission Reference Scenario). However, there are no explicit requirements for the country-specific data from the Member TSOs to assume an achievement of the EU or national climate and energy targets.

Following data collection, the modelling, analysis and drafting of the report takes place at ENTSOG. This stage requires processing the input data, running simulations using ENTSOGs Network Modelling tool (the "NeMo tool"), analysing the results of the modelling and the drafting the report [ENTSOG 2014d]. After the report has been drafted, the report must gain internal

[14] The respondents were Energy Regulatory Office of the Czech Republic, E-Control, Edison, Elengy, Energy Community Secretariat, Eurogas, Gas Natural Fenosa, TAP and Uprigaz [ENTSOG 2015c].

approval from the ENTSOG Investment Working Group and the ENTSOG decision bodies (the ENTSOG Board and the ENTSOG General Assembly) [ENTSOG 2012]. Following approval, a draft report is published together with a press release and the consultation document.

Formal Submission

After the release of the draft report the responses of stakeholders to the public consultation are evaluated, followed by a potential issuing of a corrigendum to the report and finally submission of the TYNDP to ACER for an opinion. ACER plays an important role in monitoring the Union-wide TYNDP at this stage. According to Article 9(2), ENTSOG submits the draft Union-wide TYNDP to ACER for its opinion. ACER assesses whether the draft TYNDP will "contribute to non-discrimination, effective competition, the efficient functioning of the market or a sufficient level of cross-border interconnection open to third-party access" (Article 9(2)). Within two months of the receipt of the submission, ACER provides its opinion of the draft TYNDP. ACER may make recommendations to ENTSOG and the European Commission.

In its most recent opinion on the TYNDP 2015, ACER identifies significant room for improvement in ENTSOG's approach to stakeholder engagement, in particular the integration of stakeholder feedback and the ACER Opinion into the final TYNDP report. ACER criticizes ENTSOG's approach to the public consultation of the draft," whereby it analyses responses in a separate document without modifying the draft TYNDP itself" [ACER 2015b]. ACER argues that "this approach may also be a reason for the absence of significant interest in providing views during the public consultation, as stakeholders know their views will not be reflected in the current TYNDP" [ACER 2015b]. ACER further emphasizes that the final TYNDP should reflect the views, advice and guidance of ACER and other stakeholders, rather than being treated as a "fait accompli even before the Agency provides an opinion on it" [ACER 2015b].

In light of these perceived weaknesses in the TYNDP process, ACER makes the following non-binding recommendations:

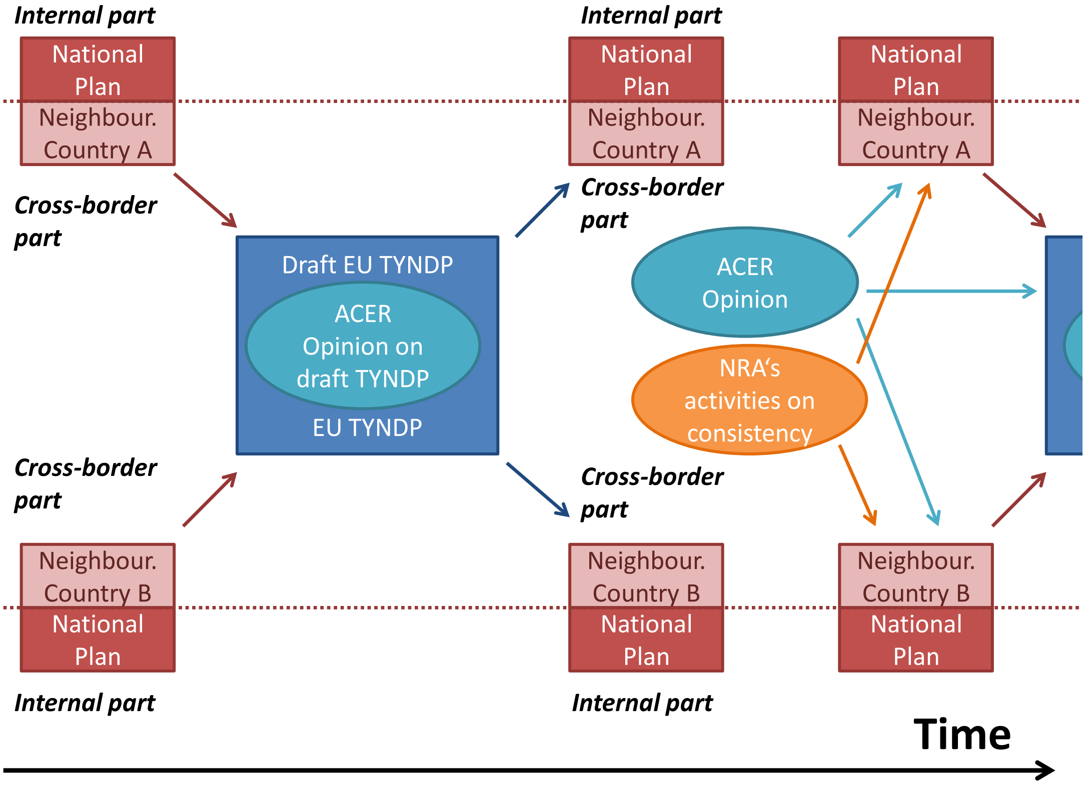
> "The Agency [invites] ENTSOG to properly consider all comments received via all channels, including through workshops, mail, and other means, as well as the public consultation online forms and tools, in order to increase public interest in the development of the TYNDP. In this respect, the Agency suggests that ENTSOG publishes the minutes of the various TYNDP preparation workshops on a regular basis to facilitate a continuous involvement of stake-holders" [ACER 2015b].
>
> "The Agency urges ENTSOG to release the final TYNDP only after duly considering stakeholder feedback and the Agency's Opinion on the TYNDP" [ACER 2015b].

For the TYNDP 2015, the analysis of the public consultation assessed the feedback of stakeholders but did not address how the feedback would be integrated into the TYNDP report. Furthermore, no corrigendum to the TYNDP was issued.

Consistency between the Union-wide TYNDP and the NDPs

If the consistency between NDPs of the TSOs and the Union-wide TYNDP are in doubt, national regulatory authorities may require the TSOs to amend NDPs after consulting with ACER (Article 22.5 of Directive 2009/73/EC). According to Article 8.11 of Regulation 715/2009, ACER also reviews the NDP to assess their consistency with the Union-wide network development plan. If it finds inconsistencies it can recommend amending either one, as appropriate. A simplified representation of the interaction between the national development plans and the EU TYNDP can be seen below.

Figure 10: Interaction between the national plans and the EU TYNDP



Source: Based on [ACER 2014a]

The consistency of the NDP with the TYNDP has been assessed by ACER in opinions adopted in late 2014 and 2016. The most recent opinion [ACER 2016] assesses the consistency between data provided to it by NRAs on the NDPs and the TYNDP 2015 until mid-2016. NDPs were submitted for all reference countries in this report. The main findings of the opinion are as follows:

- **Stakeholder engagement**: ACER highlights that NDPs differ significantly regarding the degree in which stakeholders are proactively engaged and their feedback is considered. While in more than 50 % of the instances NDPs are subject to a public consultation, in some cases NDPs are consulted only with specific stakeholders. The 6 case study countries assessed in this study generally are among the stronger consultation processes. However, even in these countries a number of stakeholder groups are only indirectly consulted via the public nature of publishing the consultation. As such, the ACER Opinion shows clear deficiencies concerning stakeholder consultation in a number of MS and recommends that the NDPs "reflect the interests of market players (shippers), together with the views of stakeholders, about the needs for new infrastructure, during the entire NDP elaboration process."

- **Demand scenarios**: ACER finds that while gas demand scenarios are seen as very important at EU level, they are not given the same importance in the NDPs, where infrastructure capacity demand under peak situations is generally the key parameter.[15] Moreover, both top-down and bottom-up processes are used to develop demand scenarios, leading to some differences between Member States.[16]
- **Regulatory oversight**: ACER finds that regulatory oversight is higher for NDPs than for the EU TYNDP, with NRAs generally being formally empowered to approve or validate NDPs, and sometimes carrying out the consultation of the draft NDP. In contrast, regulatory supervision for the EU TYNDP is mainly in the form of a non-binding ACER Opinion. As such, ACER recommends that it's regulatory oversight be better aligned with the current practice for NDPs and to strengthen the regulatory oversight of NRAs where necessary[17].
- **Identifying investment gaps:** ACER finds that for the NDPs a variety of different approaches are used to identify investment gaps[18]. In contrast, until 2016 the EU TYNDP did not adequately identify investment gaps or assess the degree to which the specific projects address them. ACER underlines the necessity to improve the EU TYNDP methodology.
- **Modelling:** ACER finds that the modelling tools and the network topology used for the elaboration of the EU TYNDP are generally less robust than the much more detailed topology and more robust modelling and simulation tools commonly used for the preparation of NDPs. Consequently, the assessments and the identification of physical capacity bottlenecks, as well as the simulation of gas infrastructure operational conditions, are generally more robust in the NDPs[19] than in the EU TYNDP. ACER recommends ENTSOG "consider improving the modelling for the EU TYNDP".

Concerning the overall consistency of the NDPs with the EU TYNDP, ACER finds that misalignments of cross-border capacities of projects and their construction could be largely avoided with the help of enhanced consultations on draft NDPs with TSOs from neighboring MS and regular exchange of information. ACER also repeatedly recommends enhancing this exchange in order to share information on the various approaches for identifying investment gaps, how scenarios are built, assessed and calibrated, and for modelling to allow ENTSOG to build on the expertise and best practices, models and tools used by TSOs for developing NDPs.

[15] ACER finds that gas supply scenarios receive more attention in the EU TYNDP than in the NDPs. Instead, "gas demand profiles, gas sourcing routes and capacity demand scenarios are the main assumptions used in NDPs, along with the shippers' views on possible gas flow configurations". Regarding the number of scenarios, the Agency also notes that NDPs generally consider a lower number of scenarios compared to the 2015 EU TYNDP.

[16] In some cases, a bottom-up gas demand assessment is calibrated and compared with gas demand scenarios developed under top-down approaches (e.g., policy visions and objectives and econometric models)

[17] According to ACER, regulators play an important role in monitoring the NDPs and the EU TYNDP because TSOs are generally "not in a position to define higher-order gas infrastructure system needs stemming from Member State energy policies (such as, for example primary energy mix policies), upstream developments (particularly those outside the European Union), and other long-term or macroeconomic factors that may fundamentally impact gas supply and demand, and hence the demand for infrastructure services".

[18] 14 NRAs indicated that investment gaps are identified in the NDPs after an in-depth analysis of the infrastructure needs (top-down approach); in 10 cases, the identification of infrastructure gaps is an outcome of gas infrastructure system and/or market modelling; in 11 cases the analysis is performed on a case-by-case basis after an analysis of projects (bottom-up approach); and in 10 cases the identification of the gaps is an outcome of an economic test (capacity auctions, market consultations, shippers' demand for capacity).

[19] In contrast to the EU TYNDP, 71 % of the NDPs use network modelling supported by hydraulic modelling software, and 60 % of the NDPs use market studies.

At the same time, due to the differences between NDPs in terms of their legal nature[20], the number of NDPs per Member State[21], their schedules[22], as well as changes in market fundamentals, ACER recognizes that temporary misalignment between the NDPs and EU TYNDP may be unavoidable even if excellent coordination and regular exchanges take place. As such, ACER finds that while full alignment may be desirable in principle, it only recommends pursuing alignment “to the extent that it is efficient”.

TYNDP 2017

A draft version of the 5th TYNDP for the time period 2017-2037 was released in December 2016, in order to be effectively used in the 3rd PCI list. Following a public consultation, the report will be submitted with the public consultation analysis to ACER for an opinion in 2017 [ENTSOG 2015a].

Structurally, the **stakeholder engagement** process for the TYNDP 2017 was similar to that for the TYNDP 2015. From January 2016 to May 2016, ENTSOG organized a total of seven workshops prior to collecting data from project promoters and member TSOs. Following the stakeholder engagement process, ENTSOG also organized additional stakeholder events to present the underlying data collected for the report (July 2016) and share the preliminary results of the TYNDP assessment with the PCI regional groups (October/November 2016). According to ENTSOG, 40 participants took part in the SJWS and workshops on average [ENTSOG 2016d]. An overview of stakeholder engagement process for the TYNDP 2017 can be seen below[23].

Table 3: Overview of stakeholder engagement for TYNDP 2017

Date	Meeting	Stakeholders	Shared information
Jan 16	Kick-off workshop	Open to public	TYNDP pre-concept
Jan 16	SJWS#1	Open to public	Demand scenario storylines and project data collection
Jan 16	SJWS#2	Open to public	Gas supplies and TYNDP modelling
Feb 16	SJWS#3	Open to public	Project maturity, supply potentials and gas quality
Feb 16	SJWS#4	Open to public	Commodity prices and spreads, TYNDP outputs, project submission
Mar 16	SJWS#5	Open to public	Update on previous topics and wrap-up
Apr 16	Webinar for project promoters	Project promoters	Information for project data collection
May 16	Final concept workshop	Open to public	TYNDP final concept
Jul 16	Early transparency workshop	Open to public	TYNDP input data
Oct 16	Webinar for project promoters	Project promoters	Preliminary TYNDP results

[20] In 8 cases (32%) the projects in the NDPs are mandatory in the short term (i.e., projects expected to be commissioned during the upcoming 3 years must be implemented) and indicative in the longer term and in 2 cases (Great Britain and Germany) the NRAs reported that all projects in the NDPs are mandatory.
[21] 5 NRAs (20%) reported a single consolidated NDP for all TSOs, while in France and Italy each TSO develops its own NDP and consequently there are multiple independent NDPs.
[22] According to the ACER Opinion, NDPs are published annually in 68 % of the cases, bi-annually in 20 % of the cases and “other” situations in 8 % of the cases.
[23] Successes of the process highlighted by ENTSOG include “collecting TSOs’ assumptions for the demand data provided along the different scenarios, adopting a “tomorrow as today” approach for supply flexibility in 2017 and improving the modelling of LNG terminals.”

Oct-Nov 16	Presentation to regional groups	Regional groups	TYNDP analysis of investment needs

Source: Based on [ENTSOG 2016d]

Following the release of the draft TYNDP 2017, the draft report was open for a 6-week public consultation from 20 December 2016 to 3 February 2017 and presented at a TYNDP event on 23 January 2017 [ENTSOG 2016a]. While this feedback together with the accompanying ACER opinion may support ENTSOG in making smaller revisions, ENTSOG has also acknowledged that it will not be able to fully take into account ACER opinion and its previous recommendation in the final TYNDP report. ENTSOG argues that it is unfeasible to make major revisions to the TYNDP 2017 based on the final consultation and ACER opinion due to time constraints linked to the PCI selection process. As such, ENTSOG has proposed instead increasing the transparency of the assessment process in order to enable early involvement by ACER[24] [ENTSOG 2016d].

In terms of **transparency**, it can be positively noted that the dates for all of the workshops were announced prior to the beginning of the process and well in advance of the meetings. The supporting material for each SJWS was published in advance of each meeting and minutes have been provided for meetings in a timely fashion[25]. Furthermore, to encourage the participation of stakeholders in other parts of Europe, two SJWS were held outside of Brussels (Vienna and Ljubljana) and the kick-off meeting and first SJWS were webcast to allow for online participation. Finally, in October 2016, ENTSOG released a map on its website visualizing the projects submitted to the TYNDP 2017, which includes information on the advancement status of projects and their inclusion in the 2nd PCI list. As such, the organizational management of the stakeholder engagement process can be said to have improved both in terms of the availability, timeliness and access to information, the use of webinars/webcasts, as well as the early release of both input data and initial TYNDP 2017 assessments.

Concerning **sustainability**, a number of additions have also been made in regard to the assessment of demand and the coherence of scenarios with the EU climate targets. Most fundamentally, the TYNDP 2017 includes 3 new demand scenarios in line with the 2030 European climate and energy targets[26]. Importantly, these demand scenarios are also based on more detailed storylines providing a better orientation for Member TSOs on the development of energy efficiency, heating technologies, and other low carbon options that could influence demand and aid in meeting the EU's climate and energy targets [ENTSOG 2016].

[24] ENTSOG seems set to continue the process in which stakeholder and regulatory feedback is largely taken into account in the next TYNDP, which is expected in the second half of 2018 (ENTSOG 2016a). ENTSOG argues that it has complied with ACER's recommendation concerning the process in spirit by increasing the transparency of their process in order to allow ACER, NRAs and stakeholders to react at an early stage. As an example, they highlight the organization of a workshop in July 2016 immediately following the collection and validation of TYNDP input data, in which ENTSOG provided an overview of the scenarios, projects and figures on indigenous production that had been submitted to TYNDP and made the data available on its website. ENTSOG argues that releasing TYNDP input data early has encouraged additional stakeholder involvement, allowing stakeholders to review this data and start making use of it at an early stage, and that the presentation of the TYNDP infrastructure needs assessment to the regional group members has helped them get prepared for the PCI selection process (ENTSOG 2016d).

[25] A participant list was only provided for one of the meetings (SJWS#4). However, the publicly available minutes allow for a partial assessment of the active participants at each meeting.

[26] Structurally these changes also include a chapter section describing the achievement of the EU 2030 energy and climate targets under different scenarios in the Demand chapter, as well as a sub-chapter in the Infrastructure chapter on Energy Transition providing insights into how gas infrastructure can support an integrated energy system.

Conclusions

- The development of the Union-wide TYNDP is a highly-structured process, including a significant and formalized stakeholder component. Accompanied by public workshops, stakeholder joint working sessions and public consultations, stakeholders have numerous opportunities to engage in the development of the TYNDP. However, while a relatively high number of stakeholder workshops has taken place, the number of stakeholders actively participating in the process was low, largely limited to TSOs and key institutions. Environmental organisations did not participate in the TYNDP 2015 process and were only involved to a limited extent in the TYNDP 2017 process. As a result, the process could be improved through:
  - Greater and more active participation of environmental organizations or ministries and actively inviting key stakeholder groups to become involved as the European Commission does in the PCI process;
  - Considering the ACER recommendation to factor in the results of the public consultation more strongly into the final TYNDP report;
  - Providing input for stakeholder meetings well in advance of the meetings so that stakeholders have more time to prepare;
  - Making initial TYNDP 2017 analysis publicly available (not just in regional groups)
  - Ensuring greater transparency of the process by providing webcasts, recordings, participant lists and minutes for all stakeholder meetings.
- The consideration of climate policy and low-carbon options within the TYNDP is intimately linked with the process of developing demand scenarios for the TYNDP. To ensure their proper consideration, the process must be developed to ensure broader stakeholder participation and the consistency of demand scenarios with long term European energy strategy. The TYNDP 2017 marked a significant improvement in this regard compared to the TYNDP 2015, as ENTSOG released more detailed storylines for its demand scenarios, and for three of the four scenarios it required TSOs to provide data in line with the EU's medium-term (2030) targets. Nonetheless, the process could be further improved by:
  - More strongly including demand-side expertise (i.e. experts on heating markets) in the stakeholder engagement and data collection process.
  - Requiring TSOs to take into account a long-term perspective beyond the current 10-20 year assessment framework (ex. 2050) when providing data, including coherence with long-term (2050) European climate and energy targets.

ACER opinion on the coherence of the different planning instruments demonstrates that the consistency of the TYNDP and NDPs in terms of implementation timelines and listed projects is relatively low. While some of these inconsistencies may be resolved through process improvements, including the harmonization of timelines under the TYNDP 2017 process, ACER opinion reveals structural issues relating to data collection and low participation of NRAs that should be thoroughly reviewed in the next monitoring process. More fundamentally, however, the monitoring process was largely focused on assessing whether data contained in the plans were aligned, as opposed to whether projects within the NDPs are misaligned with European priorities. This implies that a strengthening of the mandate, resources and tools (ex. additional modelling capabilities) provided to ACER may be desirable to ensure the proper strategic monitoring of gas infrastructure at EU level as suggested by [Bruegel 2016].

2.2.2 GRIPs[27]

The Gas Regional Investment Plans (GRIPs) are developed every two years by Member TSOs of ENTSOG within geographically defined regional groupings. They provide a link between the Union-wide TYNDP and the national TYNDP by providing more detailed understanding of infrastructure needs on the regional level. The content and objective of the GRIPs are less clearly specified in EU Regulation than for the TYNDP. Over time, however, the GRIPs process has become increasingly harmonized with the TYNDP process.

The GRIP Regions

According to Article 12(3) of Reg. 715/2009 the geographical area of TSO regional cooperation for the GRIPs “may be defined by the Commission, taking into account existing regional cooperation structures.” In practice, member TSOs of ENTSOG organized themselves into six regional groupings (see Figure 10):

Figure 11: Map of GRIP regions

Source: [ENTSOG 2015d]

- GRIP North-West,
- GRIP BEMIP,

[27] In this section, the TYNDP 2017 refers to the draft that have been published in 2016, not the final version of 2017.

- GRIP South,
- GRIP South-North Corridor,
- GRIP Central Eastern Europe and
- GROP Southern Corridor.

Membership sometimes overlaps between GRIPS and is based on transmission system interconnections and operation, as well as infrastructure development needs [ENTSOG 2015d][28].

Development of the GRIPs

Like with the TYNDP, Member TSOs use the ENTSOG Investment Working Group platform to coordinate the development of Gas Regional Investment Plans (GRIPs)[29]. The work of developing the GRIPs in each regional grouping and GRIP is led by one or two Member TSOs serving as coordinators. The ENTSOG Secretariat is not formally part of the regional groupings. However, the ENTSOG Secretariat can support the participating TSOs in drafting the GRIPS through a variety of activities, including:

- **Multilateral discussion:** ENTSOG can serve as a facilitator through multilateral discussion between TSOs and ENTSOG staff, helping to contribute to maintain a balance between convergence across regions and the preservation of regional specifics [Lebois 2013c].
- **Single data collection:** The same centralized process as the TYNDP process is used for data collection on demand and national production data and specific data from project promoters [Lebois 2013c].
- **Modelling:** ENTSOG can support the TSOs with the modelling of the European gas system based on the ENTSOG NeMo tool. For the 2nd edition of the GRIPs, 4 out of 6 GRIPs used modelling as an input [Lebois 2013c].
- **Common layout** of the reports.

The process of developing the GRIPs has been described by ENTSOG as a **"learning-by-doing" process**. Due to limited specification in EU Regulation, Member TSOs have had various options for developing the focus of the individual GRIPs. For example, ENTSOG highlighted in the past that it was up to Member TSOs under the GRIPS to determine whether they would like to: [Lebois 2013c]:

- Focus on updating the Union-wide TYNDP results in an environment where vision on the next ten years is always changing,
- Analyse at regional level the Union-wide TYNDP findings,
- Cover specific cases of regional interest not captured in the Union-wide TYNDP.

As a result, in previous iterations the relationship between the GRIPs and the TYNDP has also sometimes been unclear as the six GRIPs have not followed a harmonized process in their development.

[28] ENTSOG (2015), Gas Regional Investment Plans (GRIPs), website available at http://www.entsog.eu/publications/gas-regional-investment-plan-grips, accessed on 25 October 2015.
[29] http://www.entsog.eu/business-areas

Less consistent and transparent public stakeholder engagement activities also make the assessment of the GRIP development process more difficult. Unlike the TYNDP process, public documentation has only been made available on the ENTSOG website for one specially organized GRIP Workshop in November 2013[30]. Presentations on three GRIPs were also delivered at a non-GRIPs specific TYNDP Workshop[31]. Additional opportunities for stakeholder engagement have been possible through the Stakeholder Group meetings of the Gas Regional Initiatives (GRI)[32]. The GRI are a separate process largely driven by National Regulatory Authorities and coordinated by ACER. These GRI bring together regulators, the European Commission, Member States, companies and other relevant parties for cooperation beyond infrastructure planning, including capacity allocation and market integration[33]. In the context of the Stakeholder Group meetings of the GRI, the TSOs of the GRIP NW and the GRIP South have provided updates on the development of the GRIPs at different stages of their development [ENTSOG 2014b, ENTSOG 2013]. However, these discussions seem to generally only be one of several topics on the agenda and attendance at the meetings seems to largely be made up of gas TSOs, utilities and regulators[34]. According to available documentation of the 2nd GRIPs, the main opportunity for formal stakeholder feedback for at least two GRIPs was, therefore, a public consultation at the end of the process [Nienhuis 2013, Kus 2014]. However, the questionnaires used for public consultation of the draft GRIPs under the GRIP NW and the GRIP South received no direct responses [Nienhuis 2013, Kus 2014].

ACER monitoring also provides a reliable commentary on the GRIPs and their relationship to the TYNDP. Under Article 6(9) of Regulation 713/2009, ACER shall monitor the regional cooperation of TSOs and take due account of the coutcome of that cooperation when formulating its opinions, recommendations and decisions. So far, one Opinion has been issued in March 2013 on ACER's own initiative in response to the 1st edition of reports issued between November 2011 and June 2012. This opinion provides recommendations and guidance for future editions. In particular, ACER highlights that "it is not sufficient to simply update project data in the GRIPs in the interim period before the publication of the next TYNDP" [ACER 2013]. In the Opinion, ACER:

- Identifies a need to better define the interrelationship between the Union-wide TYNDP, the GRIPS, and the selection of PCIs, and openly questions the added value of some of the GRIPs for stakeholders compared with the TYNDP 2011-2020;
- Recommends early involvement of stakeholders in the process of preparing the GRIP by organising public events, and encourages allowing "feedback from stakeholders and NRAs [...] to be taken into account before the release of the final version of the GRIP" [ACER 2013];
- Suggests harmonizing the GRIPs methodologies and the use of a regional network modelling tool.

Between the two GRIP reports regions have contributed new content in response to the feedback from ACER and the reports have somewhat converged in terms of content and layout [ENTSOG 2015d].

[30] http://www.entsog.eu/events/grip-workshop
[31] http://www.entsog.eu/events/9th-tyndp-cba-workshop#downloads
[32] http://www.acer.europa.eu/Gas/Regional_%20Intiatives/Pages/Background.aspx
[33] In contrast to the six GRIPs regions, the GRI are split into three gas regions (North-West, South and South-South East), with some EU Member States not covered [ACER Online].
[34] http://www.acer.europa.eu/Gas/Regional_%20Intiatives/South_GRI/21st%20SG%20meeting/Document%20Library/1/I%20-%2021st%20SG%20SGRI%20meeting%20-%20Draft%20minutes.pdf

Outlook

The 3rd edition of the GRIPs will be developed in a joint process with the Union-wide TYNDP for the period 2017-2037 and are to be published in 2017[35]. According to ENTSOG, "this joint process will ensure:

- A common concept;
- A common data set with a single, centralized data collection process;
- Complementary contents;
- Release dates close to each other."

These changes suggest that there will be stronger harmonization of the GRIPs. Moreover, while the ENTSOG Secretariat continues to play no direct formal role in adopting the GRIPs, it will begin to play a greater coordinating role in the GRIPs process [ENTSOG 2015a]. This greater harmonization was decided within the ENTSOG working structures. According to ENTSOG, the members TSOs discussed several options on how to organize the TYNDP and GRIPs processes going forward, taking into account the demands of the PCI selection process, and ultimately came to the conclusion that the most interesting option was that of the joint development process[36].

Conclusions

- The direct relationship between the GRIPS and the TYNDP is not clearly defined in EU law. While the GRIPs have gone into greater detail on regional circumstances compared to the pan-European assessment performed under the Union-wide TYNDP, ACER has expressed doubts as to the added value for stakeholders of the 1st round of GRIPs compared to the TYNDP 2011-2020 as their contents were too similar.
- Opportunities for stakeholders' involvement vary between GRIPs and are generally less structured and transparent than for the TYNDP process. Therefore, in the past there have been limited opportunities for stakeholders to engage in the development of the GRIP, except for post-GRIP consultations. Complementary regional structures in the regulator driven GRI process may, however, support monitoring by NRAs. Therefore, a continued or expanded role for the GRI Stakeholder Groups in the development process could be considered.
- The move towards a joint development process with the TYNDP 2017-2037 for the 3rd edition of the GRIPS will lead to a greater harmonization of the GRIPs reports with the TYNDP and with each other. As the concepts will be commonly developed and the data commonly collected, the role of the TYNDP stakeholder engagement process will, therefore, gain in importance for the GRIPs. In particular, as the treatment of demand scenarios will also be harmonized, the TYNDP process will determine the assumptions made about climate policy and low-carbon options for the GRIPs. This harmonization with the TYNDP provides a new opportunity for more structured stakeholder involvement in the development of the GRIPs, but may also preclude GRIP specific stakeholder engagement.
- The increased harmonization of the GRIPs across regional groupings is welcome as it will increase the comparability of the GRIPs reports, thereby strengthening their value in providing detailed regional analysis that complements the Union-wide TYNDP. However, the growing harmonization of the reports with the TYNDP also risks making them largely

[35] This part of the report has been written in 2016, published in the interim report and has not been updated.
[36] Interview with ENTSOG

indistinguishable from analysis provided in the TYNDP, thereby potentially reducing their added value for stakeholders. Moreover, due to the mutual timing of the reports it is unclear to what extent the Union-wide TYNDP will take into account the GRIPs, as demanded by EU Regulation.

2.2.3 PCI

Gas priority corridors under the TEN-E regulation

TEN-E identifies 9 priority corridors (4 for electricity, 4 for gas and 1 for oil) and 3 thematic areas (smart grids, electricity highways and cross-border CC networks) of trans-European energy infrastructure that require "urgent infrastructure development in order to connect EU countries currently isolated from European energy markets, strengthen existing cross-border interconnections, and help integrate renewable energy[37]". Based on these priority corridors, the EU draws up a list of PCI, which represents specific energy infrastructure projects necessary to implement the corridors. An overview of the four priority gas corridors in the Regulation can be seen in the table below.

Table 4: Overview of Priority Gas Corridors

Name	Purpose	Member States concerned
NSI West Gas' North-South gas interconnections in Western Europe	Gas infrastructure for North-South gas flows in Western Europe to further diversify routes of supply and for increasing short-term gas deliverability	BE, DK, FR, DE, IE, IT, LU, MT, NL, PT, ES, UK
NSI East Gas North-South gas interconnections in Central Eastern and South Eastern Europe	Gas infrastructure for regional connections between and in the Baltic Sea region, the Adriatic and Aegean Seas, the Eastern Mediterranean Sea and the Black Sea, and for enhancing diversification and security of gas supply	AT, BG, HR, CY, CZ, DE, GR, HU, IT, PL, RO, SL, SK
SGC Southern Gas Corridor	Infrastructure for the transmission of gas from the Caspian Basin, Central Asia, the Middle East and the Eastern Mediterranean Basin to the Union to enhance diversification of gas supply	AT, BG, HR, CZ, CY, FR, DE, HU, GR, IT, PL, RO, SL, SK
Baltic Energy Market Interconnection Plan in gas ('BEMIP Gas')	Gas infrastructure to end the isolation of the three Baltic States and Finland and their dependency on a single supplier, to reinforce internal grid infrastructures accordingly, and to increase diversification and security of supplies in the Baltic Sea region	DE, EE, FI, DE, LT, LU, PL, SE

Source: Annex I of Regulation (EU) 347/2013

From the descriptions of the individual gas priority corridors it is clear that the focus is diversification and security of supply. None of them highlights sustainability as a core aim.

Annex II of the Regulation explicitly names the infrastructure categories to be developed to implement the energy infrastructure priorities identified. For natural gas, these are:

- Transmission pipelines,

[37] https://ec.europa.eu/energy/en/topics/infrastructure

- Underground storage facilities (UGS),
- Reception, storage and regasification or decompression facilities for liquefied natural gas (LNG) or compressed natural gas (CNG),
- Equipment needed for system security or to enable bi-directional capacity, including compressor stations.

Regional groups

Under the TEN-E regulation, twelve regional groups are established to select the PCI based on the priority corridors and thematic areas set out in the Regulation, as well as geographical coverage (Article 3.1). Four of these regional groups correspond with the four priority gas corridors of the regulation. These regional groups are responsible for developing and adopting a regional list of proposed gas PCI for the priority gas corridor and are composed of representatives of the Member States, NRAs, TSOs, the European Commission, ACER and ENTSOG[38] (Annex III 1(1)). To ensure consistency between the different groups, the representatives of the regional groups also meet, when necessary, to discuss common issues (Annex III 1(2)).

Decision-making powers in the regional groups are restricted to a decision-making body, consisting of Member States and the Commission (Article 3.1). When drawing up a regional list each individual proposal for a PCI must be approved by the Member States to whose territory the project relates, and the group must take into account advice from the Commission aimed at having a manageable total number of PCI (Article 3.3). If a Member State decides not to give its approval it must present substantiated reasons for doing so to the regional group (Article 3.3), in which case they are examined by the decision-making body at the request of the Member State (Annex III 2(10))[39]. Each group adopts its own rules of procedure (Article 3.2).

Transparency and stakeholder engagement

Under Article 18 of the TEN-E regulation the regional groups are required to provide additional information on a transparency platform, including “the internal rules, an updated list of member organisations, regularly updated information on the progress of work, meeting agendas, as well as final conclusions and decisions of each group” (Annex III 1(6)). As currently implemented, the transparency platform consists of two elements. One element is a PCI map viewer, directly available on the DG Energy website[40]. The other is the CIRCABC information platform, to which a link is available on the DG Energy website[41]. The CIRCABC platform is divided between a non-public section for each regional group, to which only members of the technical-level body of the regional groups (MS, EC, ENTSOG, ACER) have access, and a public section to which all registered stakeholders have access[42]. The conclusions and decisions of regional group meetings are shared only on the non-public section of the platform, while the public section contains more general updates on the process for stakeholders.

[38] According to the ENTSOG AWP 2016, ENTSOG supports the regional groups through technical background and methodologies [ENTSOG 2015a].

[39] According to Preamble 23 of the Regulation, the power to adopt and review the Union list of PCI is delegated to the Commission in accordance with Article 190 of the TFEU, while respecting the right of MS to approve PCI related to their territory.

[40] http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/.

[41] https://circabc.europa.eu

[42] One reason for the distinction between the public and non-public sections is that recipients of project-specific information within the regional groups are required to preserve the confidentiality of commercially sensitive information (Annex III 2(2)).

According to the TEN-E regulation each regional group should invite one group of stakeholders directly to technical-level meetings in view of implementing the priorities of the regulation, include project promoters, representatives of national administrations, NRAs and TSOs, as well as representatives third countries[43] (Annex III 1(4)). Moreover, another group of stakeholders is to be directly consulted in the overall PCI selection process, including producers, distribution system operators, suppliers, consumers and organizations for environmental protection or through the organizations representing them (Annex III 1(5)). For the most recent PCI list, the public consultation mainly consisted of an online questionnaire, available in all EU languages, running from 22 December 2014 to 31 March 2015, as well as a special consultation from 29 July to 22 October for gas related infrastructure projects after the South Stream project was cancelled[44]. In addition to these public consultations there were also special stakeholder workshops on the gas and electricity PCI projects on 15 and 17 of June. These workshops allowed stakeholders to comment on a smaller selection of projects identified as particularly controversial in the public consultation. Finally, cross-regional meetings of the regional groups are also divided into a semi-public and a non-public part. While only members of the regional groups can take part in the non-public parts, the Commission invites representatives of the stakeholder groups to the semi-public parts[45]. According to the European Commission, a number of environmental organizations were invited to the workshops, including the Renewable Grid Initiative, the European Environmental Bureau (EEB), CEE Bank Watch, WWF, Green Peace and Friends of the Supergrid[46]. These invitations are extended to specific (mainly umbrella) organizations.

Past open letters and public statements to the European Commission by civil society stakeholders have been largely critical of the lack of transparency of the PCI selection process and the lack of easily comprehensible information on PCI candidates [Bankwatch 2014, Justice and Environment 2015]. Moreover, criticism of the lack of timely notification of activities and circulation of the necessary information has been echoed by ACER [Acer 2015c]. However, the stakeholders workshop in June 2015 separate from the public consultation were publically commended by the EEB, Birdlife International and CEE Bankwatch Network as a positive step [EEB et. al. 2015].

PCI selection criteria

Article 4(2)(b) of the TEN-E regulation identifies a number of criteria that apply specifically to gas projects. In order to be considered as a PCI, projects must contribute significantly to at least one of the following criteria: market integration, security of supply, competition or sustainability[47]. Therefore, while sustainability criteria do exist in the PCI selection process, it is not mandatory that the project contribute to sustainability as the selection criteria are designed.
Article 4(1) of the regulation also sets the following criteria for being considered as a gas PCI:

- The project must be necessary for one of the four priority gas corridors.
- The potential overall benefits of the project must outweigh its costs.
- The project must meet any of the following criteria:

[43] These include the member countries of the European Economic Area and the European Free Trade Association, the Energy Community institutions and bodies (Annex III 1(4)). Third country-representatives are invited on a consensus basis.
[44] https://ec.europa.eu/energy/sites/ener/files/documents/Report%20final_18_11_2015.pdf
[45] Interview with DG Energy
[46] Interview with DG Energy
[47] In this context sustainability is understood as, inter alia reducing emissions, supporting intermittent renewable generation and enhancing deployment of renewable gas.

- Involve at least two Member States by directly crossing the border of two or more Member States,
- Cross the border of at least one Member State and a European Economic Area country,
- Be located on the territory of one Member State and have a significant cross-border impact[48].

Cost-Benefit Analysis

Under the TEN-E regulation ENTSOG has also developed a cost benefit analysis (CBA) methodology for harmonized energy system wide analysis at Union level and for PCIs. This methodology is used to determine the positive and negative impacts of different levels of infrastructure development and individual PCI applications, including identifying the net-beneficiaries and the net-cost bearers of the PCI among the Member States (Annex V.10, V.11)[49]. This CBA methodology plays an important role in PCI planning, selection, implementation and financing, serving as the basis for:

- A European system-wide CBA of the TYNDPs[50] (Article 11.1),
- The selection of PCI by regional groups (Annex III.2(1)),
- The cross-border cost allocation decisions on PCI by NRA or ACER (Article 12.3),
- The granting of various incentives (Article 13.2) and
- The decision to extend grants for construction works under the Connecting Europe Facility (CEF) (Article 14.2(a)).

In accordance with the TEN-E Regulation, the CBA methodology was submitted by ENTSOG to ACER and the Commission in November 2013. After review by ACER, the Commission and Members States, as well as an extensive stakeholder consultation process that took place parallel to the development of the last Union-wide TYNDP, an adapted version of the methodology was approved by the European Commission in February 2015[51] [ENTSOG 2015d]. This CBA methodology considers some sustainability indicators. However, to be eligible for financial assistance PCIs must only demonstrate an overall net-positive CBA outcome.

According to the ACER Opinion on the 2015 draft regional lists, the CBA methodology as currently implemented focuses on quantifying project benefits and not costs. Accordingly, ACER argues that the TYNDP was "not fit for the purpose of PCI selection" as thorough documentation, consistent modelling and a detailed user guide were lacking [ACER 2015c]. They highlight

48 Annex IV of the regulation defines the conditions that are to be met to be considered a project with a "significant cross-border impact". Concerning gas transmission, projects must concern investment in reverse flow capacities or change the capability to transmit gas across the borders of the Member States concerned by at least 10 % compared to the situation prior to the commissioning of the project (Annex IV (1)(c)). Concerning gas storage or LNG/ CNG, the project must aim at directly or indirectly supplying at least two Member States or at fulfilling the infrastructure standard (n-1 rule) at regional level in accordance with Article 6(3) of Regulation (EU) No 994/2010 (Annex IV (1)(d)).

49 According to Annex V.1, the methodology must be based on a common input data set representing the Union's electricity and gas systems 5, 10, 15 and 20 years after the analysis is performed. This data is to take into account at least "scenarios for demand, imports, fuel prices (including coal, gas and oil), carbon dioxide prices, the composition of the transmission network and its evolution" (Annex V.1(b)). The CBA shall take into account at least the costs of capital expenditure, operational and maintenance expenditure over the technical lifecycle of the project and decommissioning and waste management costs, where relevant (Annex V.5). Moreover, the methodology must cover "all Member States and third countries, on whose territory the project shall be built, all directly neighbouring Member States and all other Member States significantly impacted by the project" (Annex V.10).

50 Article 22 of the Regulation 347/2013 also adapts the Regulation establishing the TYNDP to add that the TYNDP will be subject to a CBA.

51 http://www.entsog.eu/publications/cba-methodology#CBA-METHODOLOGIES.

that ENTSOG has justified the lack of costs data due to the “commercially sensitive” nature of these projects, and call a CBA without cost information a “contradiction in terminis”. As such, ACER recommends that cost information for each project is submitted to ENTSOG and included in the TYNDP [ACER 2015b]. They also highlight that ENTSOE does include cost information in its assessment and makes it a minimum requirement for including the project in the TYNDP. ACER, therefore, recommends that ENTSOG follow the example of ENTSOE to work more closely with stakeholders to get this data. [ACER 2015b]. According to ENTSOG, this recommendation has been followed for the TYNDP 2017, indicating that project costs for the energy system-wide CBA have been collected from promoters and reflected per infrastructure level [ENTSOG 2016e]. However, this cost information is only provided by ENTSOG in aggregate form and is, therefore, not publicly verifiable.

According to the TEN-E Regulation, the methodologies are to be regularly updated and improved (Article 11.5). These updates and improvements can be requested by ACER, on its own initiative or upon the request of NRAs or stakeholders (Article 11.6). As such, ENTSOG describes the CBA methodology as a “living organism”, similar to TYNDP, in that it will undergo regular review [Lebois 2013a]. However, larger changes to the methodology would require going through a full and lengthy public consultation process. Therefore, ENTSOG has clarified that for the current TYNDP process modifications would require staying within the framework of the existing CBA[52].

The PCI selection process

The Union list of PCIs is developed in eight basic steps[53]:

1. Project promoters submit candidate PCIs
2. NRA check the consistent application of the PCI criteria and cost-benefit analysis methodology and evaluate the cross-border relevance of the PCI projects
3. The PCI eligibility criteria are used by the regional group to assess which projects can be included in a regional list and their contribution to the implementation of the priority gas corridors.
4. Stakeholders are consulted on the candidate PCIs.
5. The projects are ranked by the decision-making bodies of the regional groups at technical level, taking into account the assessment of the regulators. Based on this evaluation, draft regional lists together with any opinions by Member States potentially affected by the project are submitted to ACER six months before the adoption of the Union list.
6. ACER assesses the draft regional lists and Member State opinions and provides an opinion focusing “in particular on the consistent application of the criteria and the cost-benefit analysis across regions” (Annex III 2(12)).
7. Following receipt of this ACER Opinion, the decision-making body of each regional group has one month to adopt its final regional list taking into account the ACER Opinion and the assessment of NRAs (ACER III 2(13)).
8. Based on these regional lists adopted by the decision-making bodies of the groups, the Commission establishes a Union list every two years via the delegated acts procedure (Article 3.4). When adopting this Union list, the Commission should ensure cross-regional consistency, ensure that the criteria have been met, take into account the opinion of

[52] Interview with ENTSOG, Public comment by ENTSOG at TYNDP Workshop
[53] Based on the TEN-E Regulation and the description of the 2015 process provided in the delegated act for the 2015 Union list - Commission Delegated Regulation amending Regulation (EU) No 347/2013, C(2015) 8052 Final, https://ec.europa.eu/energy/sites/ener/files/documents/5_2%20PCI%20annex.pdf.

Member States and aim for a manageable total number of PCI (Article 3.5)54. If the number of proposed PCIs on the Union list would exceed a manageable number55, the European Commission is also to consider not including the projects ranked lowest on the regional lists by the regional groups (Annex III 2(14)).

As this description shows, the Commission plays a central role in the PCI selection process, especially in determining the final Union-wide list of PCI. At the same time, in an analysis of electricity PCIs, Antina Sander (2014) points out that the Member States hold the right to nominate PCIs, and the Commission currently does not hold this right. As a result, the choice of projects by MS may not be directly linked to EU objectives and the most important projects from an EU perspective may not be nominated. This is reinforced by a criticism in ACER's Opinion of the lack of more in-depth discussions on the specific infrastructure needs in each priority corridor, indicating that the selection is based less on European priorities and more on specific Member State interests [Acer 2015c].

Financial assistance for PCI

A budget of € 5.35 billion has been allocated to trans-European energy infrastructure under the **Connecting Europe Facility (CEF)** from 2014-20[56]. Projects selected for the Union list of PCI can benefit from EU support for preparatory studies, such as feasibility studies or environmental impact assessments, as well as infrastructure works. Under certain circumstances, gas PCIs can also benefit from CEF grants for building infrastructure. To be eligible to benefit from such support, however, the PCI must demonstrate significant benefits under the project specific CBA, be not commercially viable according to the business plan carried out and have received a cross-border cost allocation (Article 14 of Regulation 347/2013). According to the European Commission, this support should generally not exceed 50 percent of eligible costs for both studies and works, unless exceptional circumstances relating to security of supply and enhanced solidarity merit raising this support to 75 %[57].

Additional sources of EU funding for PCIs include:

- **European Fund for Strategic Investment (EFSI):** The EFSI (aka. The Junker Plan) is a fund set up to support investments through the supply of risk-bearing capacity to the EIB and aiming to help mobilize at least € 315 billion in total public and private sector investments between 2015 and 2017[58]. According to Regulation (EU) 2015/1017 establishing the EFSI, projects should be economically viable, consistent with EU policies, provide additionality, maximize the mobilization of private sector capital, and be technically viable (Article 6.1). The operations of the EFSI will support development of the energy sector in accord-

[54] Moreover, Regulation 1391/2013 amending Regulation 347/2013 has established several principles for clustering PCIs due to their "interdependent, potentially competing or competing nature" (Annex VII.1).

[55] According to the preamble, in order to remain manageable the total number of PCI "should not significantly exceed 220" (Preamble 23).

[56] https://ec.europa.eu/energy/en/news/commission-unveils-list-195-key-energy-infrastructure-projects.

[57] http://europa.eu/rapid/press-release_MEMO-15-6108_en.htm.

[58] See Regulation (EU) 2015/1017 of the European Parliament and of the Council of 25 June 2015 on the European Fund for Strategic Investments, the European Investment Advisory Hub and the European Investment Project Portal and amending Regulations (EU) No 1291/2013 and (EU) No 1316/2013 – the European Fund for Strategic Investments.

ance with Energy Union priorities, including the development and modernization of infrastructure (Article 9.2(c))[59]. According to the European Commission, all energy projects, including PCI are eligible to benefit from the facility[60].

- **CEF Financial instruments:** Financial support provided via financial instruments, not calls for proposals, and decided by the financing institutions (ex. European Investment Bank61).
- **European Structural and Investment Funds:** Member States can also make use of the European Structural and Investment Funds and funds under the European Regional Development Fund (ERDF) to support PCIs.

Initial outcomes of the PCI process

The first overall Union PCI list was drawn up in 2013 and contained 248 PCI. Most the gas projects involved gas transmission infrastructure, but the list also includes gas storage projects and LNG terminals. For the updated Union PCI list adopted in 2015, the number of PCI was reduced to 195[62].This represents 53 fewer PCIs than on the 2013 list[63].

Table 5: No. of PCI by union-wide list

Year	Electricity	Gas	Oil	Smart Grids	Total
2013	132	107	7	2	248
2015	108	77	7	3	195

Source: [Viksne 2014]

So far, roughly € 1.7 billion have been allocated under the CEF to co-finance studies and construction works to implement the PCI in from 2014-2016[64]. While in 2014 € 647 million was allocated to PCIs under one call, nearly € 367 and € 707 million in total were allocated over two calls in 2015 and 2016, respectively. Much of this funding went to proposals addressing energy security and isolation issues in the Baltic regions. In fact, nearly half of the funds allocated went to the BEMIP electricity and gas priority corridor, including more than € 295 million in maximum EU financial assistance for the construction of a gas interconnection between Poland and Lithuania. The numbers in the tables below show that more gas related actions (both studies and works) have been selected for support under the CEF Energy calls and nearly twice the amount of financial support has been made available to gas related actions than for electricity and smart grids.

59 For example, of the projects pre-financed by the Commission prior to the EFSI beginning operations in 2015 is a Spanish project aimed at extending Gas distribution networks. For more information on the project see http://www.eib.org/projects/pipeline/2012/20120132.htm.

60 http://europa.eu/rapid/press-release_MEMO-15-6108_en.htm.

61 http://www.eib.org/projects/priorities/tens/index.htm.

62 http://europa.eu/rapid/press-release_IP-15-6107_en.htm.

63 At the time of the adoption of the updated Union list in 2015, it was expected that 13 projects from the 2013 list will have been completed or commissioned before the end of 2015 and that 62 projects will be completed by the end of 2017 - http://europa.eu/rapid/press-release_IP-15-6107_en.htm.

64 http://europa.eu/rapid/press-release_IP-15-6107_en.htm.

Table 6: No. of actions supported under CEF Energy calls by type

		Studies				Works				Total
		2014	2015	2016	Total	2014	2015	2016	Total	
Electricity	BEMIP Electricity	1	-	1	**2**	2	1	1	**4**	**6**
	NSI East Electric-ity	10	5	1	**16**	-	1	1	**2**	**18**
	NSI West Electric-ity	1	2	2	**5**	-	-	-	**-**	**5**
	NSOG	3	6	4	**13**	-	-	1	**1**	**14**
	Total	**15**	**13**	**8**	**36**	**2**	**2**	**3**	**7**	**43**
Gas	BEMIP Gas	2	2	1	**5**	2	-	2	**4**	**9**
	NSI East Gas	7	6	6	**19**	-	1	2	**3**	**22**
	NSI West Gas	1	6	1	**8**	1	1	-	**2**	**10**
	SGC	3	3	3	**9**	-	1	-	**1**	**10**
	Total	**13**	**17**	**11**	**41**	**3**	**3**	**4**	**10**	**51**
Smart Grids	**Total**	**-**	**-**	**-**	**-**	**1**	**-**	**1**	**2**	**2**
Total		**34**	**35**	**27**	**96**	**6**	**5**	**8**	**19**	**98**

Source: [EC 2014f, EC 2015, EC 2016]

Table 7: Maximum EU financial assistance under CEF Energy 2014/15 calls
according to type of call in million Euro

	Studies				Works				Total
	2014	2015	2016	Total	2014	2015	2016	Total	
Electricity	55.7	23.6	99.0	178.3	167.4	56.4	129.8	353.6	**531.9**
Gas	35.7	36.1	22.8	94.6	356.7	250.6	415.3	1,022.6	**1120.6**
Smart Grids	-	-	-	-	31.7	-	40.5	72.2	**72.2**
Total	**91.4**	**59.8**	**121.8**	**272.9**	**555.9**	**307**	**585.6**	**1,448.5**	**1,721.4**

Note : Rounding errors may apply.

Source: [EC 2014f, EC 2015, EC 2016]

The proportion of gas to electricity financing is surprising considering that the number of gas PCIs on the Union-wide lists has been significantly lower than that for electricity PCI and the combined investment costs of these electricity and gas PCIs is about equal [Gaventa 2014].

Moreover, the 2010 impact assessment that served as the basis for the development of the TEN-E regulation estimated that twice the investment in electricity infrastructure would be needed until 2020 compared to gas infrastructure if Europe is to meet its energy and climate policy objectives (€ 140 billion in electricity vs. € 70 billion in gas[65]) [EC 2010]. Accordingly, the preamble to Regulation 347/2013 establishing the CEF states that "based on the expected preponderance of electricity in Europe's energy system over the next two decades, it is estimated that assistance to electricity projects of common interest will account for the major part of the energy financial envelope under the CEF". Jonathan Gaventa of E3G, among others[66], commented on this potential contradiction in 2014, recommending that the European Commission should implement an explicit earmark for electricity projects under the CEF and regularly report on how funded PCI projects help to contribute to the EU's mid- to long-term decarbonisation objective in order to maximize public value for money [Gaventa 2014].

Conclusions

- Under the TEN-E regulation, none of the descriptions of the priority gas corridors highlight sustainability as a core aim and projects are not required to contribute to sustainability to be considered for PCI status.
- While sustainability is considered in the application of the CBA methodology, a project must only have a net-positive outcome overall to qualify. Moreover, ACER has identified notable weaknesses in the cost-benefit analysis methodology developed by ENTSOG, including the fact that both cost data is often lacking or insufficient for projects submitted to be included on the list of PCI.
- The results of the PCI selection process so far reveal that gas projects have thus far been more strongly supported under the CEF Energy calls than electricity and smart grid projects, despite an arguably higher need for support in the electricity sector to meet the EU's mid- to long-term energy and climate goals. This allocation of CEF funding calls into question whether the current selection process is maximizing public value for money. Furthermore, while the Commission formally play a critical formal role in the PCI selection process, Member State maintain the power to nominate PCIs, potentially undermining the Commission's ability to guarantee projects are directly linked to EU objectives. These potential weaknesses could be addressed by:
  - Earmarking CEF funding for electricity and smart grid projects or setting higher sustainability criteria in their selection;
  - Strengthening the role of the Commission or ACER in ensuring a greater monitoring of the consistency of the proposed PCI projects with EU objectives, including by giving sufficient tools to evaluate their cost effectiveness[67].
- While limited stakeholder consultation processes and a transparency platform are in place, stakeholder engagement could be improved by:
  - giving stakeholders access to more of the documentation provided to members of the regional group, in a readily comprehensible form;
  - informing stakeholders of meetings in a timely manner, by clearly scheduling meetings in advance;

[65] It should also be noted that the estimates of the requirements for investments in gas infrastructure were based on gas demand projections from the PRIMES baseline 2009 and the Reference scenario 2010 for 2020, which have since been revised downwards [EC 2010].

[66] For example, Kuba Gogolewski of CEE Bankwatch Network - http://www.counter-balance.org/wp-content/uploads/2014/10/Presentation-for-the-PCI-Regional-Group-meeting-on-the-29th-of-September.pdf

[67] This point has also been made in [Bruegel 2016]

- opening the public parts of the cross-regional group meetings to all stakeholders;
- holding public stakeholder workshops open to all stakeholders, especially early on the process;
- providing web-streaming of public meetings.

2.2.4 TYNDP scenario analysis and assessment

This section takes a closer look at the data and assumptions underlying the TYNDP 2017, which serves as the primary gas infrastructure planning document at the European level. The central aim of the analysis is to assess the extent to which 2030 national and EU-wide targets relating to low-carbon and sustainable options for the avoidance of gas consumption (i. e. renewable energies and energy efficiency) are integrated into gas infrastructure planning on the EU level. Therefore, it focuses on the demand scenarios of the report, as well as the consideration of EU energy and climate targets.

Gas demand since 1990 and TYNDP scenarios

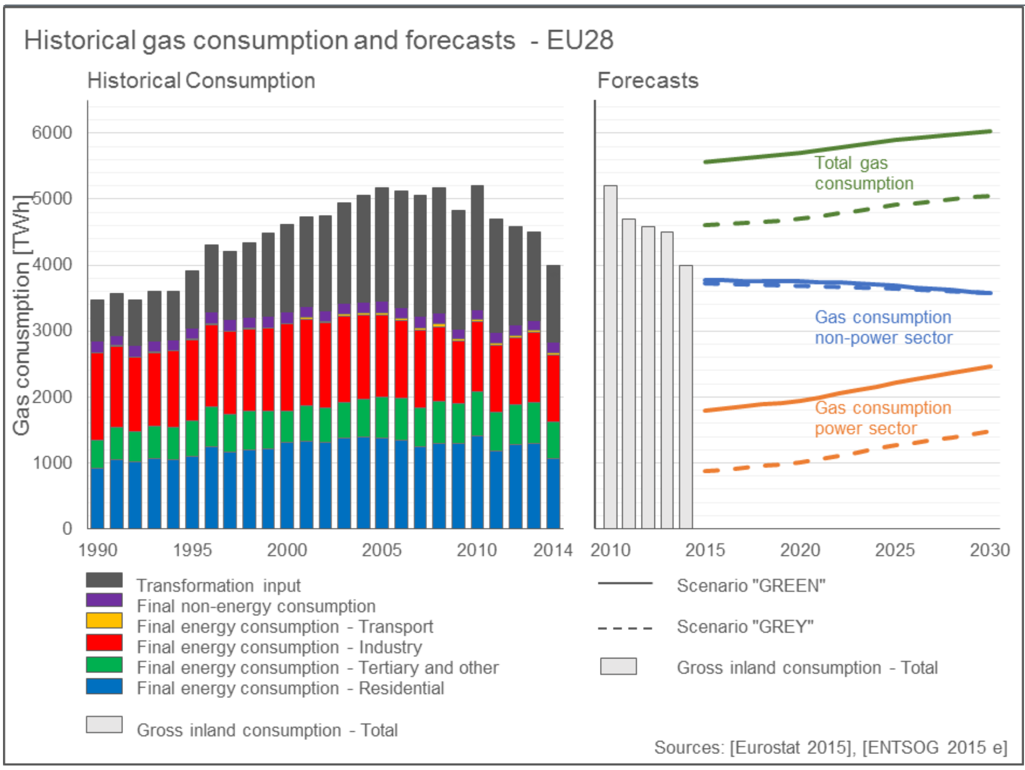
The historical development of the European gas demand is shown in Figure 12. From 1990 to 2005 gas consumption increased continuously and reached 5,180 TWh in 2005. The increase in the residential and the transformation sector was the highest: in the transformation sector gas consumption nearly tripled in comparison to 1990, in the residential sector gas consumption grew about 50 %. This was due to the increasing level of gasification in most European countries and the increasing importance of gas for power generation. From 2005 to 2010 temperature adjusted gas demand[68], which is shown in annex 1 in Figure 57, stayed quite stable with the exemption of 2009 the year of the economic crisis. It shows a drop in gas demand. In the tertiary sector gas demand grew continuously until 2010 (exemption was also a drop in 2009). Gas demand in the industry sector is in contrast slowly decreasing in the observed period.

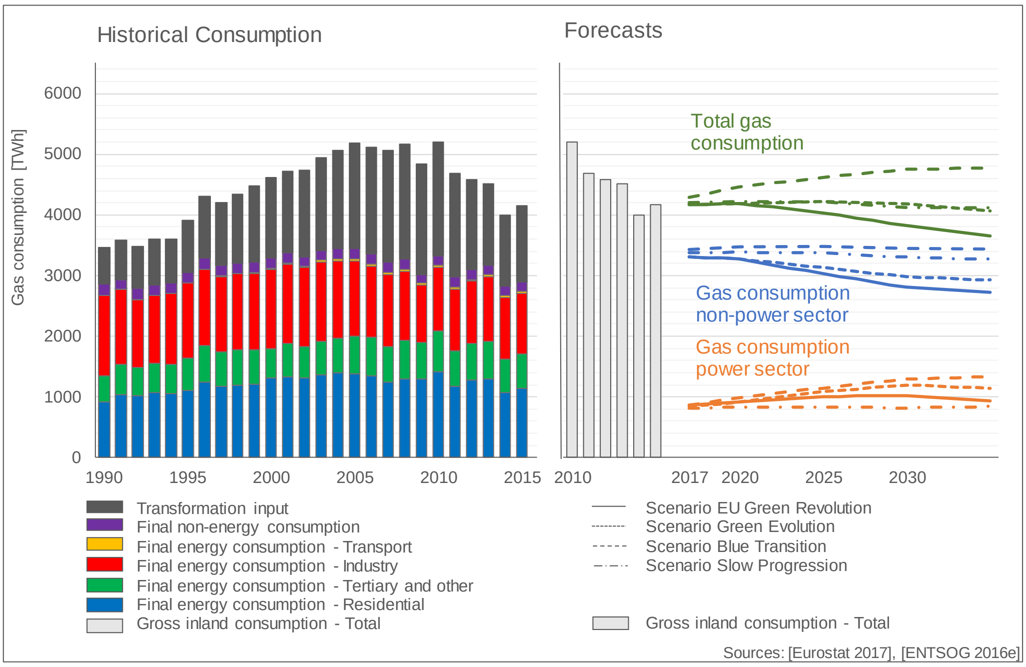
Since 2010 total gas demand in the EU is decreasing especially in the transformation sector. The total consumption was 4,500 TWh in 2013, 4,000 TWh in 2014 and 4160 TWh in 2015. The decrease from 2013 to 2014 was mainly due to a continuing decreasing gas demand in the transformation sector and a decrease in the residential sector as 2014 was a warm year[69]. In 2015 natural gas demand increased due to an increase in the residential and transformation sector. This could be due to lower temperatures and in the transformation sector due to a lower gas price. Still the overall trend since 2010 is a declining gas demand.

[68] Temperature adjusted gas demand is used to get a better comparability with data of previous years. The approach of temperature adjustment is as follows: We use the heating-degree days from 1980 to 2013 (Eurostat data) of each country and calculate the long-term average. This long-term average is compared with the heating-degree days of each year. On the other hand, the demand sectors have a different share of space heating and this share reacts with a higher sensitivity to temperature variations than for example the manufacturing industry. We use data from Odyssee to identify which part in every demand sector needs to be temperature adjusted. In the transformation sector, there is a temperature adjustment only for the gas usage in CHP power plants and (district) heating plants.

[69] Data for temperature adjustment in 2014 was not available in the time of the analysis.

Figure 12: Historical gas consumption 1990-2015 (Eurostat)
and forecast TYNDP 2015 (above) and 2017 (below) for Europe [TWh]





Source: [Eurostat 2017], [ENSTOG 2016e], [ENTSOG 2017a]

For the future evolution of gas demand until 2035 there are four scenarios developed. In contrast to TYNDP 2015 the scenarios represent decreasing, stable and increasing gas demands. The following scenarios are used in the TYNDP 2017:

- **Slow Progression**: limited economic growth and low environmental ambitions
- **Blue Transition**: moderate growth and moderate environmental ambitions
- **Green Evolution**: favourable economic conditions and high environmental ambitions
- **EU Green Revolution** (similar to "Green Evolution" with a higher European cooperation): favourable economic conditions and highest environmental ambitions

The scenarios are all aligned with ENTSOE's scenarios and were developed with input data on gas demand from national TSOs.

The total, power and non-power sector gas demand according to these scenarios are also shown in Figure 12 (on the right side). The starting points in 2017 -around 4,200 TWh- are on the level of 2015´s total gas consumption and in contrast to TYNDP 2015 the scenarios have almost the same starting point. Gas consumption in the non-power sector is nearly stable in "Blue Transition" and "Slow Progression" and notably decreasing in "Green Evolution" and "EU Green Revolution". In the transformation sector, all scenarios show an increasing trend, only a little increase in "Slow Progression" and "EU Green Evolution", a remarkable increase in "Green Evolution" and especially in "Blue Transition". Total gas consumption increases in "Blue Transition", stays nearly stable in "Slow Progression" and "Green Evolution" and decreases slightly in "EU Green Revolution", especially after 2030. In the highest scenario gas demand reaches 4,777 TWh in 2035. Compared with the trend of a decreasing gas demand in the last five years the scenarios seem to cover the upper trend of the future gas demand but do not adequately cover the lower trend of future gas consumption.

Sectoral analysis of scenarios and modelling assumptions.

The economic, price and general assumptions of the four scenarios are shown in Table 8. Three of the scenarios are on track with the 2030/2050 targets, one ("Slow Progression") is not. In contrast to TYNDP 2015 there is more consistency as the fuel and CO_2 prices for the scenarios are all taken from IEAs World Energy Outlook (WEO) 2015. Fuel prices are the highest in the scenario "Slow Progression" (corresponding to WEO Current Policies), still high in "Blue Transition" (corresponding to WEO New Policies) and lower in"(EU) Green (R)Evolution" (corresponding to WEO 450). This results in gas prices in 2040 below 25 €/MWh (in "(EU) Green (R)Evolution") and up to 35 €/MWh (in "Slow Progression").

All scenarios have rising carbon prices. In "Slow Progression and "Blue Transition" CO_2 prices only rise slowly to 30 resp. 40 €/t in 2040. In "(EU) Green (R)Evolution" climate polices are stronger and CO_2 price rises to over 70 €/t in 2030 and over 100 €/t in 2040.

The final gas demand is again assembled from scenarios from the national TSOs. But they seem better elaborated than in the TYNDP 2015 edition. First ENTSOG developed and consulted the storylines of the scenarios, then they shared them with national TSOs to receive data that is in line with the developed scenario storyline. Still there is not one modelled scenario by ENTSOG (no usage of the fuel and CO2 prices), and not enough reflection on the trend of a shrinking gas demand in the recent years. Final gas demand is driven by economic development, energy efficiency, gas in the heating sector and gas and electricity in the transport sector. For these driving forces the general development is provided (see also Table 8) but apart from that there are no more detailed assumptions (as e.g. renovation rate, number of heat pumps, heat networks…) that could be helpful for understanding the scenarios.

Final gas demand stays stable in “Blue Transition” due to increased demand from the industrial and transport sector while residential demand is declining because of efficiency gains. In “Slow Progression” there is a small decline in final gas demand due to some efficiency gains while the economy is weak. In “Green Evolution” and “EU Green Revolution” the deployment of electrification of heating and renewables combined with fast energy efficiency improvements and a modest penetration of gas in transport leads to a shrinking gas demand in 2035 (-12 % resp. -18 % compared to 2017). Still more ambitious energy efficiency could lead to a further decreasing final gas demand as shown e.g. in the assessment of energy efficiency targets (see also chapter 3.2). The scenarios with ambitious environmental policies are still not reflecting a consequent deployment of energy efficiency and renewables and thereby overestimating the lower range of final gas demand.

Table 8: Economic, price and general assumptions TYNDP

Parameters	Scenarios			
	Slow Progression	**Blue Transition**	**Green Evolution**	**EU Green Revolution**
Energy policies	2030/2050 targets not realistically reachable	On track with 2030/2050 targets	On track with 2030/2050 targets	On track with 2030/2050 targets, potential to achieve early
Economic activity	Limited growth	Moderate growth	Strong growth	Strong growth
Energy efficiency	Slowest improvement	Moderate improvement	Fastest improvement	Fastest improvement
Renewables development	Lowest	Moderate	High	Highest
Electrification of heating	Lowest	Moderate	High	Highest
Gas in transport	Lowest penetration	Highest penetration	Moderate penetration	Moderate penetration
Gas vs Coal	Coal before Gas	Gas before Coal (on regulatory basis)	Gas before Coal (on regulatory basis)	Gas before Coal (on regulatory basis)
Gas Prices	expected gas price > coal price	expected gas price > coal price	expected gas price > coal price	expected gas price > coal price
Fuel Prices	Highest (WEO 2015 Current Policies)	Moderate (WEO 2015 New Policies)	Highest (WEO 2015 450)	Highest (WEO 2015 450)
Carbon Prices	Lowest CO_2 price (limited spread of carbon taxes)	Moderate CO2 price (carbon taxes mainly spread)	Highest CO2 price (carbon taxes well spread)	Highest CO2 price (carbon taxes well spread)
Related ENTSOE Visions	Vision 1	Vision 3	Vision 4	Vision 4

Source: [ENSTOG 2016e], [ENTSOG 2017a]

CO_2- und fuel prices are used to assess the share of gas and coal in the power generation mix.

For the projections of installed capacities for power generation three visions from the electricity Ten Year Network Development Plan 2016 from ENTSO-E are used. For “Slow Progression” the ENTSO-E “Vision 1, Slowest Progress” scenario, for “Blue Transition” ENTSO-E “Vision 3, National Green Transition” scenario and for the other two scenarios ENTSO-E “Vision 4, European Green Revolution” scenario is applied. The installed capacities for the different energy sources are shown in Table 9. Renewables include wind, solar, biomass, other renewables and renewable hydro. Non-renewable hydro capacity is part of other conventional. Gas generation capacity in 2030 remains nearly stable in “Vision 1”/“Slow Progression” and increases about 11 % on 220 GW in the other two ENTSO-E Visions used here. Installed gas capacity is in 2030 in all scenarios remarkably lower than it was in the previous TYNDP 2014 (294 and 250 GW in Vision 3 resp. 1)

Installed capacity of renewable energy for electricity generation grows in all scenarios, about 18 % in 2030 in “Vision 1”, about 73 % in “Vison 3” and about 85 % in “Vision 4”. Again, in comparison to the scenarios from the previous year, installed capacity of renewables is lower.

Based on the installed capacity ENTSOG uses a simplified methodology to derive the corresponding power generation: From the net electricity generation the fixed generation (base load nuclear, hydro, wind, solar and others) is subtracted resulting in a “thermal gap”. This gap has to be filled by coal or gas generation. Which share of gas is used depends on prices, technical and other restraints. TSOs could use this methodology or use their own for the yearly gas for power generation as well as peak gas demand for power generation (high demand cases). Gas demand for power generation is increasing notably in all scenarios. A scenario with strong increase of renewable power generation and a decrease of gas power generation is missing.

Table 9: Development of installed capacity electricity generation

	2014	2030			2014-2030		
[GW]		Slow Progression (Vision 1)	Blue Transition (Vision 3)	(EU) Green (R)Evolution (Vision 4)	Change Vision 1	Change Vision 3	Change Vision 4
Coal	175	103	78	61	-41%	-55%	-65%
Gas	199	196	220	220	-1%	11%	11%
Other conventional	242	414	418	424	71%	73%	75%
Renewables *	376	443	652	694	18%	73%	85%
Total	**992**	**1.156**	**1.369**	**1.400**	**17%**	**38%**	**41%**

Source: [ENSTOG 2016e], [ENTSOE 2016], [ENTSOG 2017a]

Impact of scenarios on gas infrastructure

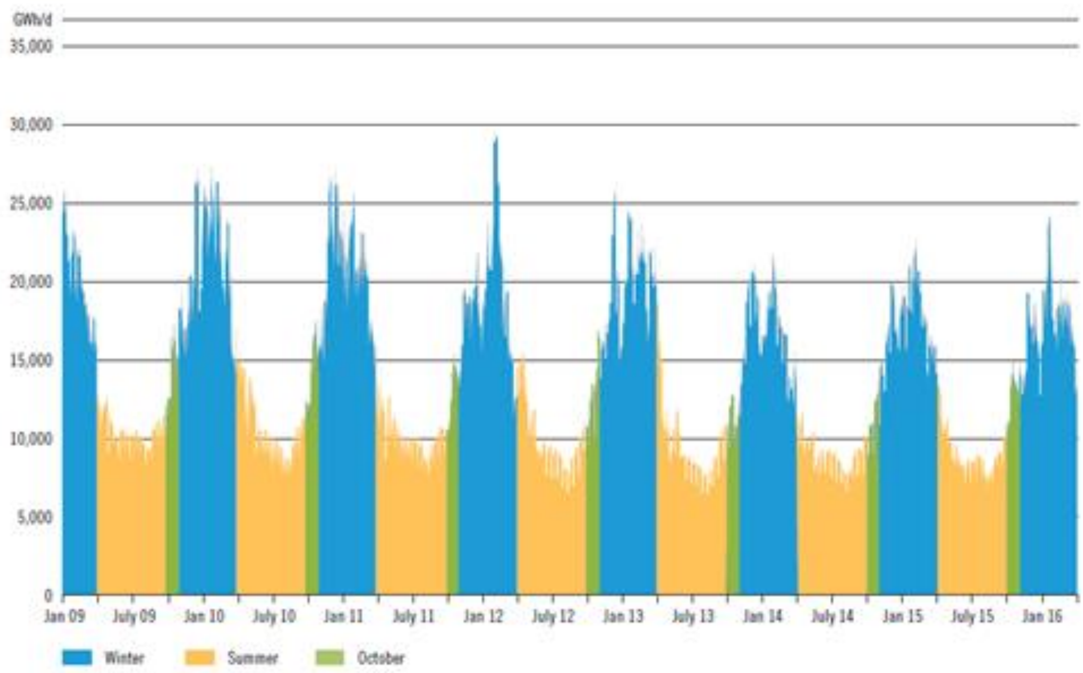
The determining factor for gas infrastructure planning from the demand side is the peak gas demand or gas capacity demand (see also chapter 0 and 2.1.3). In Table 10 the peak demand for each year is shown in detail. The by far highest gas consumption was with 29,452 GWh/d on the 7th of February 2012. Figure 13 shows the development of the gas capacity demand of the European Union from 2009 to the beginning of 2016. The seasonal demand variation is obvious. Besides the day with the highest consumption a 14-day-period with the highest average demand is used in the TYNDP to assess the necessary infrastructure.

Table 10: Historical peak demand EU from winter 2010/11 to winter 2015/16

Gas year	Date	Consumption [GWh/d]	Gas year	Date	Consumption [GWh/d]
2009/10	26.01.2010	27.431	2013/14	29.01.2014	21.769
2010/11	17.12.2010	27.091	2014/15	05.02.2015	22.715
2011/12	07.02.2012	29.452	2015/16	19.01.2016	24.326
2012/13	12.12.2012	25.772			

Source: [ENSTOG 2016e]

Figure 13: Gas capacity demand in the EU 2009 to 2016



Source: [ENSTOG 2016e]

The forecast of final peak demand for the TYNDP network planning is derived from the national TSOs. There is only few information available on these calculations of the national TSOs. Some use standardized calculation methods [Workshop BS]. Peak gas demand for power generation is in most cases calculated by the TSOs or ENTSOG by using again the “thermal gap” method for the installed gas power plant capacities from “Vision 1”, “Vision 3” and “Vision 4” (see also Table 9) which rises in the scenarios “Vision 3” and “Vision 4”. The resulting total peak gas demand for the four ENTSOG scenarios is shown in

Table 11. Total peak gas demand increases a little until 2025 in “Blue Transition” (+2%) and decreases afterwards. In “Slow Progression” there is nearly no change in total peak gas demand until 2020, the following years peak gas demand is declining. Total peak gas demand in “Green Evolution” and “EU Green Revolution” shows the same development: a decreasing trend from 2017 on. In these scenarios decline in peak gas demand is especially strong in final peak demand, peak demand for power generation is still growing, especially between 2017 and 2025. “Blue Transition” shows a similar trend with an even stronger increase in peak demand for power generation. In “Slow Progression” there is only a little decline in final peak demand but also a decline in peak demand for power generation.

In all 2017 scenarios, peak gas demand starts on a lower level than in both TYNDP 2015 scenarios. These numbers seem to be more plausible than in the last edition: peak demand from the starting year 2017 is about 115 % of the highest daily peak demand of the last five years (29,452 GWh/d) which seems to be a reasonable “safety factor”. Still it is questionable if peak demand from power generation will increase as fast as assumed in some of the scenarios.

In short, the only scenario with a temporary increasing peak gas demand is “Blue Transition”. This implicates, there is no strong need for infrastructure measures from the overall European peak gas demand. Even if peak gas demand will intermediately increase, Demand Side Management and enhanced storage usage could secure a higher peak gas demand during the transition period (ca 2025/2030). Some conclusion from TYNDP 2017 on further infrastructure requirements are similar: “*This indicates that the gas infrastructure in the low infrastructure level is capable of enabling the EU 2030 climate targets to be achieved, including in terms of supporting renewable generation, as such fulfilling the TEN-E sustainability pillar.”* [ENTSOG 2016e, p.214] Concerning the accomplishment of the internal market, ENTSOG also states that “*the existing infrastructure is already close to achieving the internal energy market.”* [ENTSOG 2016e, p.214] Still, concerning some areas there are still a lot of improvements through new infrastructure measures identified. These projects lie especially in (South-) East-Europe. Nevertheless, whereas a lot of FID projects are mainly located in North-Western Europe. Probably these may not be not the projects that would be needed to enhance the security of supply. Also, as Eastern Countries show an increasing gas demand in their scenarios, it would be especially interesting to employ more and faster renewables and energy efficiency in these areas to improve security of energy supply [BPIE 2016]. In chapter 4 there are more details on the impacts of low carbon options on infrastructure and costs.

Table 11: Development of peak gas demand (1-Day Design Case) - TYNDP

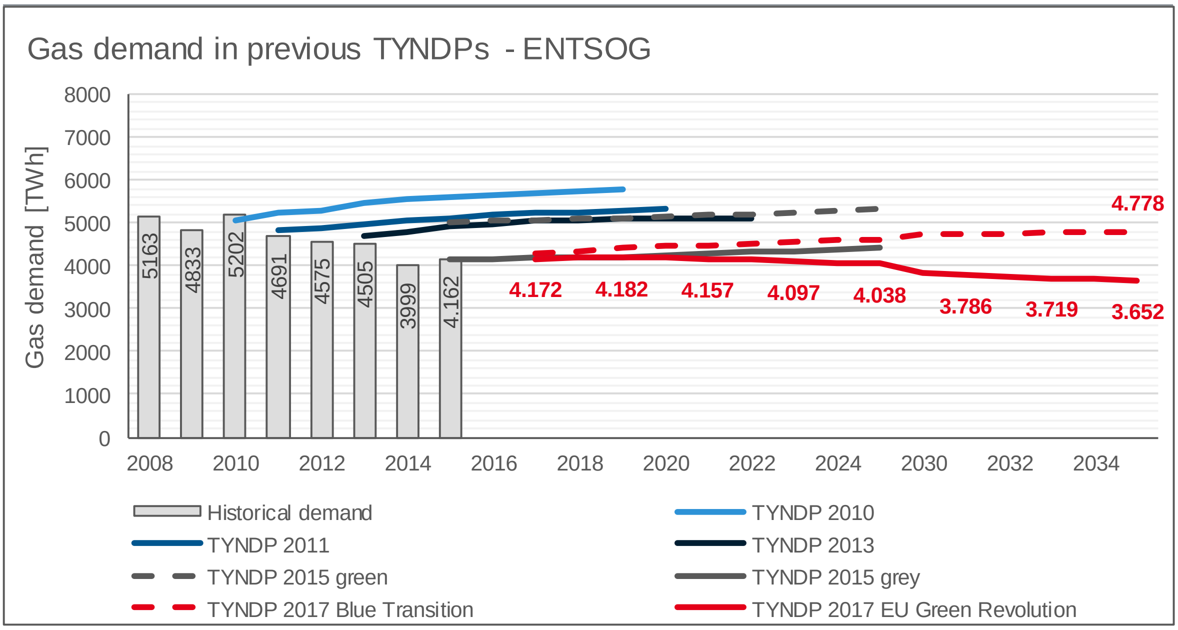
Scenario	Category	2017	2020	2025	2030	2035	Change 2017-25	Change 2025-35
Slow Progression	Final demand	26.973	27.012	26.687	25.608	25.028	-1%	-6%
	Power generation	5.875	5.919	5.744	5.416	5.503	-2%	-6%
	Total	32.848	32.932	32.432	31.024	30.531	-1%	-6%
Blue Transition	Final demand	27.345	27.276	26.914	25.933	25.584	-2%	-5%
	Power generation	6.329	7.021	7.581	8.285	8.339	20%	10%
	Total	33.674	34.297	34.495	34.218	33.923	2%	-2%
Green Evolution	Final demand	26.560	26.073	24.921	23.300	22.588	-6%	-9%
	Power generation	6.238	6.609	7.145	7.721	7.555	15%	6%
	Total	32.797	32.682	32.065	31.021	30.143	-2%	-6%
Green Revolution	Final demand	26.560	26.073	24.921	23.300	22.588	-6%	-9%
	Power generation	6.238	6.609	7.145	7.721	7.555	15%	6%
	Total	32.797	32.682	32.065	31.021	30.143	-2%	-6%

Source: [ENSTOG 2016e]

Critical assessment of scenarios for network development. Figure 14 shows the historical gas demand, gas demand forecasts from the TYNDP 2010, 2011 and 2013 covering a 10 year period, “Green” and “Grey“ from TYNDP 2015 covering a 20 year period compared to the lowest and highest scenario from TYNDP 2017, “EU Green Revolution” and “Blue Transition”. This figure shows that while all of the previous TYNDP gas demand scenarios forecast a growing gas demand for the next 10 to 20 years, these forecasts have been lowered for each of the previous TYNDP in line with developments in EU gas markets. Since 2010 gas demand in the EU fell from over 5,000 TWh to about 4,160 TWh in 2015. The past TYNDP forecasts for European gas demand in 2015 of 6,200 TWh (2010 edition), 5,660 TWh (2011 edition), 5,460 TWh and 5,560 TWh (2015 edition, “Green”) resp. 4,600 TWh (2015 edition “Grey”), thereby overestimate todays demand by far. Even if gas demand from 2014 to 2015 has increased, the trend shows a declining gas demand in Europe with continuing energy efficiency and renewable deployment.

TYNDP 2017 is the first TYNDP with a “decreasing gas” scenario. But in comparison to 2014s gas consumption this scenario shows more a “stable” than a “decreasing” trend. Still, transparency on the detailed assumptions underlying especially the final gas demand is missing as well as an assessment of a consequent deployment of renewables and energy efficiency. It is also notable that all demand scenarios have higher starting points. Gas demand in the starting year should be calibrated on the statistical consumption.

Figure 14: Gas demand in older TYNDP



Source: [ENTSOG 2010], [ENTSOG 2011a], [ENTSOG 2013c], [ENTSOG 2015e], [ENTSOG 2016e], [ENTSOG 2017a]

This discrepancy between forecasts showing an increasing gas demand and the real development of gas consumption over the last 10 to 15 years has led ACER to comment in its opinion that it “sees the need for a ‘reality check’ by comparing past assumptions and projections to actual developments, for the sake of not only improving the quality of the next TYNDPs, but also for enhancing the transparency, robustness and credibility of [ENTSOG]” [ACER 2015b]. A first step to improve TYNDP gas demand scenarios were taken in TYNDP 2017. Furthermore, the trends are assessed in greater detail in a number of reports.

The report “Europe´s declining gas demand” [E3G 2015] describes a declining gas demand throughout the majority of EU member states and sectors between 2010 and 2013 and points to the risk of misevaluating future gas demand by failing to consider structural changes. Evidence is given by analysing historical gas demand forecasts: older projections from the European Commission, ENTSOG, Eurogas as well as projections from Exxon, BP and Shell, which had overestimated todays gas demand by far and still see today an increasing gas demand. [ECA 2015] draws a similar conclusion based on assessments of the gas demand in the Commissions scenarios. The report “The Outlook for Natural Gas Demand in Europe” [OIES 2014] has also analysed European gas demand in detail and presents a scenario to 2030 with a modest growth in gas demand on a 2013 level (which results in a lower 2030 demand than in most of the other projections). But it is emphasized that there is a high degree of uncertainty how gas will develop. These conclusions are in line with other studies, such as “The European gas market looking for its golden age?” [IFRI 2015], which also highlights that European gas demand had decreased since the 2010er years and it is still uncertain how much gas Europe will consume in the near and long-term future. The most important driver for gas demand is the electricity sector which has a difficult surrounding for investment decisions in gas at the moment. The above-mentioned studies focused on the analysis of current trends in gas consumption in the last years. If ENTSOGs gas demand forecasts are compared to scenarios analysing ways to decarbonize Europe, (e.g. "How can renewables and energy efficiency improve gas security in selected Member States" [towards 2030 2014]) the gap between the scenarios is even larger. These scenarios contain strong policies on energy efficiency and renewable energies resulting in noticeably lower future gas demand, as shown in part "3. Potentials of low carbon options" of this report.

Consideration of environmental targets

TYNDP 2017 analyses the first time in a separate chapter the energy transition with the topics sector coupling, gas storage, bio-methane and power-to-gas. This new chapter is a good starting point to discuss further requirements the gas infrastructure will be faced with in the future.

Still the conclusion drawn in TYNDP 2017 are not deep enough: there is no analysis of how much hydrogen could be injected into gas networks and which changes would be required to build hydrogen networks. Further TYNDPs should start these analyses. Furthermore, future TYNDPs could try to assess potential stranded assets if gas demand is declining faster and discuss the fact that non-CO_2-neutral gas will have no future in the long run.

Concerning the scenarios used in TYNDP 2017, 3 of the 4 scenarios and all scenarios used for the assessment of network requirements[70] achieve European energy and climate goals according to ENTSOG. There is information on the development of CO_2 emissions and energy efficiency in the scenarios. But numbers are only provided for emissions and demand of the power sector and final gas demand. So, it is still difficult to verify if 2030 targets are achieved in the scenarios.

Conclusion

- **Gas demand since 1990 and TYNDP scenarios.** European Gas consumption peaked in 2005 and is since then declining. Since 2010 gas demand is decreasing significantly especially due to less gas demand for power generation. 2015 is probably the first year with a slow increase in gas demand. For the future evolution of gas demand four scenarios with decreasing, stable and increasing gas demand are used. Gas demand for power generation is increasing notably in all scenarios. In the non-power sector, the development of gas demand depends on the scenario. Compared with the trend of a decreasing gas demand in the last five years the scenarios seem to cover the upper trend of the future gas demand but do not adequately cover the lower trend of future gas consumption.
- **Modelling assumptions.** The scenarios used are in great part derived from national TSO´s scenarios. There is nearly no transparency on the underlying assumptions. In future for more transparency and consistency the underlying assumptions made by TSOs should be provided by ENTSOG. Gas demand for power generation is not modelled but assessed via the calculation of a "thermal gap".
- **Critical evaluation of scenarios.** Gas demand forecasts in past TYNDP have overestimated todays demand by far. 2017 scenarios include for the first time a "decreasing gas" scenario. Still, there is no assessment of a sharp declining gas demand scenario.

[70] Gas demand in "Slow Progresion", which does not reach 2030/2050 goals, is in between two other scenarios so it does not need to be assessed separately.

Measures should be taken to introduce an appropriate “**reality check**” of future gas demand forecasts, as suggested by ACER.

- **Consideration of environmental targets.** 3 of the 4 scenarios and all scenarios used for the assessment of network requirements achieve European energy and climate goals according to ENTSOG. But there is information on the development of CO_2 emissions and energy efficiency in the scenarios. Future scenarios should show more transparency on the achievement of environmental targets.
- **Impact of scenarios on gas infrastructure.** Peak gas demand is only increasing in one scenario until 2025. All other scenarios show a decreasing peak demand. The TYNDP does not identify single network development projects. A “low” and a “high” infrastructure scenarios are assessed for the demand scenarios and for different supply scenarios. Results show the high infrastructure scenario would reduce price dependency. But it is questionable if the additional infrastructure is needed, especially if gas demand is decreasing faster.

2.3 Gas infrastructure planning in the focus countries

2.3.1 Overview

This chapter sets out to analyse the demand scenarios and assumptions of the proposed Network Development Plans of the focus countries selected for the study. Additionally, the NDP published by ENTSOG for EU-28 (+ Bosnia, FYROM & Switzerland) has been analysed for the Europe wide demand scenarios.

In total, 10 NDPs have been analysed. Most of the TSOs have published a recent version of the NDP in 2015, with two exceptions (Enagás in Spain and TIGF in France). The time horizon of the NDPs usually is 2024 or 2025. The number of scenarios of each NDP ranges from 1 to 4.

Investment volumes of the individual NDP over the time horizon vary greatly from € 0.4 billion to € 3.3 billion by country. The sum of investment in some NDPs is given for FID-projects only, in some countries consist of all proposed projects over the relevant timeframe.

Table 12: Network Development Plans in the focus countries and the EU

Market			Network Development Plans					Investment	
Country	Total gas demand 2013	Number TSO	Organisation	Publication	Time Horizon	Number Scenarios	Network Size	Measures	Volume
	TWh	#		Year	Year	#	t km	#	bn EUR
DE	848	16	FNB Gas	2015	2025	3	40	71	3.3[2]
UK	764	4	National Grid	2015	2025	4	7.6	6	3.3[2]
IT	667	3	SNAM Rete Gas	2015	2024	2	9.4	5	1.2[1]
			Infrastructure Trasporto Gas	2015	2024	1	0.2	0	0
			Società Gasdotti Italia	2015	2024	1	1.4	9	0.4[1]
FR	454	2	GRTgaz	2015	2024	3	32.5	10	3.7[2]
			TIGF	2014	2024	1	5.0		
NL	387	1	Gasunie Transport Services	2015	2025	3	12.5	5	0.4[1]
ES	303	1	Enagás/ Renagas/ Ministerio de Industria, Energía y Turismo	2012	2020	3	9.4	N.A.	7.1[2]
EU+	**4,948**	**51**	**ENTSOG**	**2017**	**2037**	**4**	**247**	**N.A.**	**N.A.**

[1] FID/ [2] FID + Non-FID

Source: Prognos

The following chapters allow in-depth views into the national NDPs, their concepts and planning approaches and their compliance with national climate policy targets.

2.3.2 France

The security of the natural gas supply in France relies primarily on the diversification of imported sources, infrastructure and supply routes, and extensive gas storage facilities. 98 % of France's gas supply is imported: 80 % via gas pipelines and nearly 20 % via LNG [BP 2015]. The country has a diversified portfolio of suppliers, the most important being Norway, Russia, the Netherlands, Algeria, Nigeria and Qatar. France has the third-largest LNG import capacity in Europe, with a regasification capacity of 24 bcm/year spread across its Atlantic and Mediterranean coastlines. Its storage capacity is the third-largest in Europe after Germany and Italy, at over 12 bcm of useful volume. This storage capacity secures gas supplies during peak periods. France has 9 extensive gas interconnections as a result of its borders with five European countries. It is an important transit market thanks to its geographical positioning, especially for transits between south of Europe and northern Europe.

National development plans for gas infrastructure are elaborated by the two TSOs. GRTgaz (75 % subsidiary of GDF Suez, 25 % owned by a public consortium) is the largest TSO in France. It operates around 87 % of the gas transmission grid in France. The second TSO is Total Infrastructures Gaz France (TIGF), which was owned as a subsidiary by Total but was acquired in 2013 by a consortium constituted by SNAM, the Italian gas transport and storage operator (45%), GIC, the Singaporean sovereign fund (35%) and EDF (20%). TIGF operates the gas grid and gas storage facilities in southwest France. It operates about 13 % of the French gas network.

Each of the TSOs discloses an NDP each year taking into account the previous Union-wide TYNDP. The French energy regulator CRE (Commission de régulation de l'énergie) organises a public consultation and decides whether to approve the plans or not. As GRTgaz manages the major part of the country's gas infrastructure, this study will mainly focus on its plan when it comes to details as for instance scenarios and assumptions. Where information is available, both plans will be analysed.

GRTgaz' plan is composed of three sections: the first part deals with the evolution of gas demand in Europe (IEA scenarios until 2030 are used), the second part with the evolution of gas demand in France (three scenarios elaborated by GRTgaz and one elaborated by DGEC[71]) and the third part with the development of gas infrastructure. The following Table 13 shows some historical and topical key facts of the French plans.

Table 13: Profile French network development plans

	GRTgaz	TIGF
Rhythm:	Yearly	Yearly
First NDP Gas:	2005	N.A.
Number of TSOs:	2	
Current status:	Final NDP Gas 2015	Final NDP Gas 2015
Number of scenarios:	4	1
Number of modelling variants:	-	-
Considered period:	9 years, NDP 2015-2024	9 years, NDP 2015-2024
Number of measures:	10	
Investment volume:	€ 814 million (adopted projects), € 3,795 million (projects under way, adopted and not adopted yet)	
Focus:	European demand, national demand, interconnections	Demand, interconnections

Source: [GRTgaz 2015], [TIGF 2015]

Process analysis

[71] Direction générale de l'énergie et du climat - Department of Climate and Energy at the Ministry of Ecology, Energy, Sustainable Development and the Sea.

The legal requirements for developing the NDP in France are described in Article L.431-6 of the French Energy Code. This code establishes that the TSOs shall elaborate a NDP, "after consultation of interested parties". Moreover, the NDP "must take into account the assumptions and needs identified in the report on investment planning in the gas sector drawn up by the Energy Minister"[72].

The TSOs use several mechanisms to collect information from market players about the need for infrastructure, including:

- The consultation platform *Concertation Gaz*[73]*;*
- The work within ENTSOG in preparing the TYNDP;
- The work in preparing the GRIPs;
- The work carried out in the North West and South regional initiatives led by regulators;
- Bilateral meetings.

After consulting stakeholders, the TSOs submit their NDP to CRE in October of each year. On this basis CRE organises a public consultation of the NDPs in November, where questions and explanations can be asked. For the 2015 NDP, a public consultation with five key questions was announced on 4 November and open until 30 November. The public consultation received four responses: three from shippers and one from an association[74].

On the basis of this public consultation and internal deliberations CRE decides in December whether to endorse/approve the NDP and the investments for the next year. CRE can require GRTgaz to change its investments plan or to bring more information concerning a topic for the next NDP.

Finally, in July CRE meets with the TSOs to discuss unclear points, checks the investments for the past year and approves the modified NDP for the current year.

The most recent NDP in France covers the period 2015-2024. While the deliberation for the NDP identifies some differences between the NDP and the Union-wide TYNDP, CRE considers the NDP to be consistent with the Union-wide TYNDP[75]. One of the critics from CRE was that the plans are published relatively late (November each year). This leaves little room to take into account propositions and critics from stakeholders, as the plans have to be endorsed in December.

The most recent NDP are not available in English yet, but the NDP for 2014-2023[76] and all NDP and ten-year system development plans dating back to at least 2006[77] have been provided in English. Moreover, for the NDP 2014-2023 both the public consultation and the deliberation have been made available in English translation[78].

[72] http://www.cre.fr/en/documents/public-consultations/grtgaz-s-and-tigf-s-ten-year-development-plans
[73] The Concertation Gaz platform was created in accordance with the rules established by CRE on September 18, 2008 and serves as a consultation body for issues relating to the gas transmission network. These rules require the platform to establish working groups and provide for good representation of market players. There is not a requirement in the initial rules to include civil society organizations and the platform is not specifically developed for the context of the NDP. – https://www.concertationgaz.com/site/doc?id=15
[74] http://www.cre.fr/documents/deliberations/decision/programme-d-investissements-2016-grtgaz
[75] http://www.cre.fr/documents/deliberations/decision/programme-d-investissements-2016-grtgaz
[76] http://www.grtgaz.com/fileadmin/plaquettes/en/Plan_decennal_2014-2023-EN.pdf
[77] http://www.grtgaz.com/fileadmin/medias/communiques/2006/en/CP01-01082006-en.pdf
[78] http://www.cre.fr/en/documents/deliberations/approval/grtgaz-s-investment-programme-2015

The process is well documented and accessible to interested parties. The yearly basis enables short-term adjustments but leaves just a short period for reactions at the end of each year.

Scenario analysis and assessment

Gas demand since 1990 and NDP scenarios

Historical development of gas consumption

Gas is the third primary energy source in France, after nuclear and oil. Total gas demand represents 15 % of gross inland energy consumption in 2013. The residential sector is the biggest gas consuming sector in France. It represented one third of gross inland gas consumption in 2013.

Gas demand increased during the 1990's. Since 2005, temperature-adjusted gas demand stagnated at around 475 TWh till 2011 and decreased slightly in the last three years. The industry used to be the biggest gas consumer in the 1990's but since 2005, its gas consumption is decreasing. Analogously, the residential and commercial sectors experience a slight but continued reduction of their gas consumption since 2005. The reduced gas consumption in the industry, residential and commercial sectors has been more or less offset by increased gas consumption for power generation. The power sector is traditionally dominated by nuclear power plants, which supply around 70 % of the electricity demand.

Scenarios of the TSOs

GRTgaz has elaborated three gas demand scenarios. All of the scenarios are influenced by the energy transition law ("loi relative à la transition énergétique pour la croissance verte LTECV") which was adopted in July 2015. This law sets targets concerning the development of renewables, a 30 % reduction of primary fossil fuel consumption by 2030, a reduction of nuclear share in electricity production to 50 % by 2025, a 10 % share of biomethane in gas consumption by 2030 and the reduction of GHG emissions. The scenarios also expect a development of power-to-gas. The following scenarios are used in the current NDP:

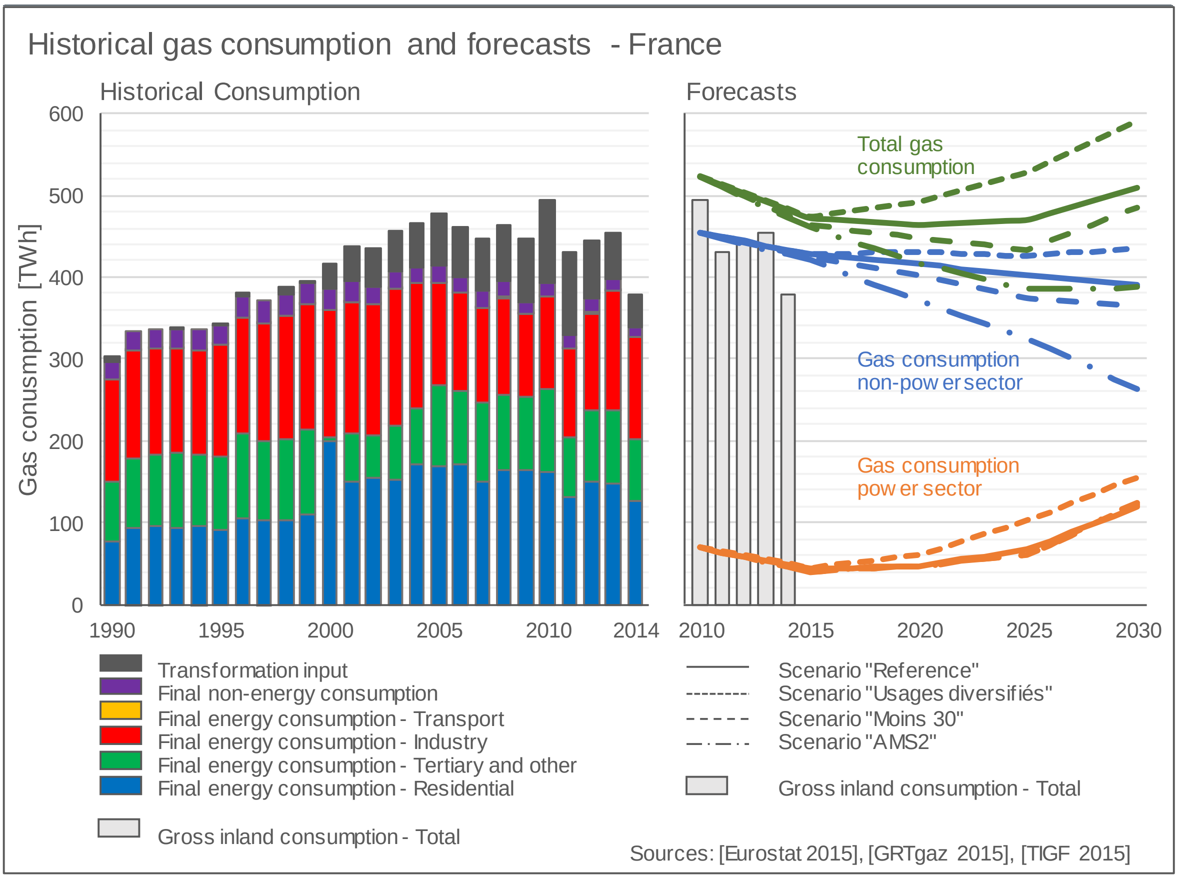
- One reference scenario.
- Scenario "Moins 30" (minus 30) relates to one of the goals of LTECV, a 30 % reduction of total fossil fuels' primary consumption in 2030 compared to 2012. The law indicates that a distinction should be made between fossil fuels according to their relative level of "climate unfriendliness". In this scenario, the 30 % reduction is applied to all fossil fuels, without taking into account their differences regarding CO_2-emissions. In other words, it is assumed that gas consumption should decrease by around 30 % between 2012 and 2030 in this scenario. However, this reduction does not relate to primary gas consumption in GRTgaz plan, but only to the gas consumed in the commercial, residential and industry sectors. Gas for power generation is not taken into account, and biomethane, which is supposed to represent 10 % of consumed gas injected according to the target, would be equivalent to the amount of gas used for mobility. This scenario is also characterized by strong regulatory constraints regarding efficiency measures: technological and economic efforts are maximised to reach the capacity limit of households and other economic stakeholders.
- Scenario "Usages diversifiés" supposes that gas supply becomes more competitive and more available on the market. LNG flows are redirected to Europe. Gas substitutes other

less competitive energy sources and is therefore more consumed and used more broadly: in electricity production (as base load and semi base load as well as back-up for renewables, full load hours of gas plants are higher), the industry, households and the commercial sector (for heat production, where gas substitutes coal and oil products) and transport.

- GRTgaz plan includes one of the scenarios elaborated by DGEC[79] and called "AMS2". It takes into account all the measures of the energy transition law, i.e. in "AMS2", the LTECV objectives for 2020, 2025, 2030 and 2050 are reached.

Figure 15 shows the historical gas consumption in France as well as the projected gas consumption according to the four scenarios. In the graph "forecasts" on the right part of the figure, gas consumption scenarios from both GRTgaz and TIGF have been aggregated. Unlike GRTgaz, TIGF has elaborated only one scenario. The forecast gas consumption in TIGF area has thus been added to each of GRTgaz scenarios.

Figure 15: Historical gas consumption 1990-2014 (Eurostat) and forecast according to the national Network Development Plan – FRANCE [TWh]



Source: Eurostat, [GRTgaz 2015], [TIGF 2015]

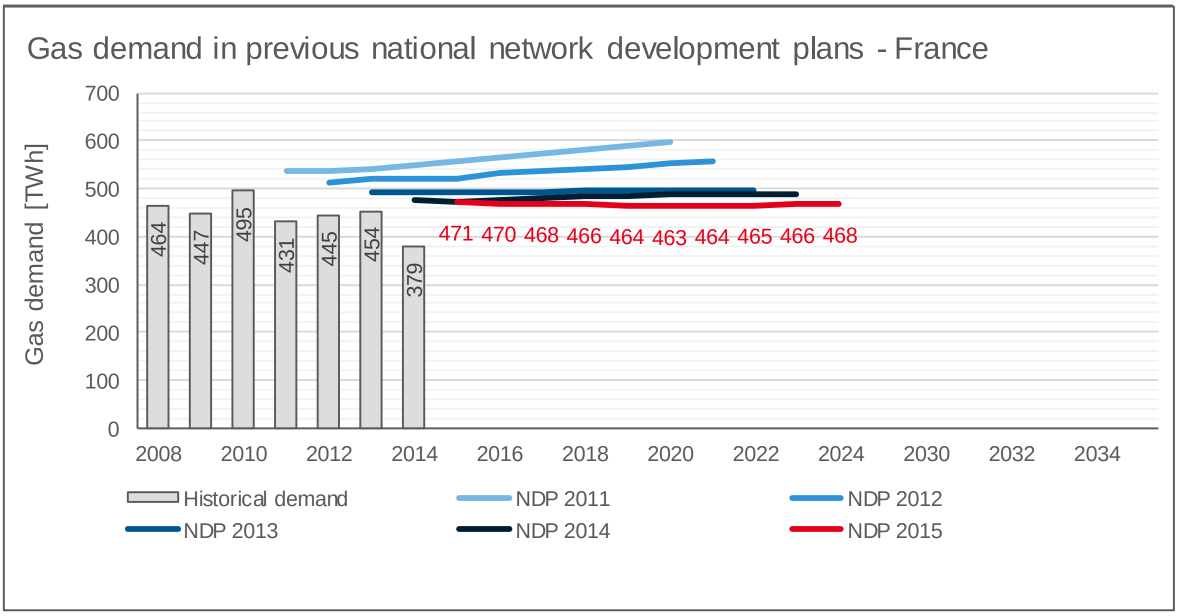
[79] Direction générale de l'énergie et du climat - Department of Climate and Energy at the Ministry of Ecology, Energy, Sustainable Development and the Sea

In all GRTgaz scenarios except “AMS2”, gas consumption is expected to increase sharply from 2025 due to increased power production based on gas and increased use of gas in the transport sector.

All of GRTgaz’ scenarios (“Reference”, “Moins 30” and “Usages diversifiés”), to which TIGF gas consumption forecast has been added, expect an increase of total gas demand between 2015 and 2030 (respectively 8 %, 5 % and 25 %). Only scenario “AMS2” shows a reduction in total gas consumption of 16 %.

The reference scenarios of GRTgaz have been constantly adjusted downwards every year since 2011. As can be seen in the graphic below, global gas consumption was expected to increase in the next decade in every plan from 2011 to 2014. 2015 is the first year when forecast gas consumption shows a slight decrease from 2015 to 2024. Given that historical gas demand from 2005 to 2012 reduced yearly by 1.8%, past reference scenarios have overestimated gas consumption growth.

Figure 16: Gas consumption scenarios in the actual and previous Network Development Plans – FRANCE [TWh]



Source: Eurostat, [GRTgaz 2011], [TIGF 2011], [GRTgaz 2012], [TIGF 2012], [GRTgaz 2013], [TIGF 2013], [GRTgaz 2014], [TIGF 2014], [GRTgaz 2015], [TIGF 2015]

Sectoral analysis of scenarios and modelling assumptions

Between 2005 and 2011, temperature adjusted gas demand in France stagnated at around 470 TWh. Decreasing consumption in the final gas demand was compensated by increasing gas consumption for power generation. Between 2011 and 2013, Eurostat data show an increasing gas demand, which was in fact mainly weather-induced. The temperature adjusted consumption between 2011 and 2013 is decreasing (see also temperature adjusted gas consumption in France in Annex 1 in **Figure 58**). The main reason for this reduction was a reduced gas consumption in gas-fired power plants, from 101 TWh in 2011 to 57 TWh in 2013. Competition with renewables and cheaper coal is one factor. Reduced electricity demand is another factor. Power generation is therefore the main reason why gas consumption remained stable at the level 470 TWh since 2005 (and seems to be the main driver of gas demand increase, together with ambitious gas development goal in the transport sector).

Looking back at the reference scenarios of previous plans, gas consumption was expected to increase after this stagnation period, supported by industrial demand as well as high rates of gas consumption growth in the power sector. These optimistic views abated every year until 2015. In NDP 2015, gas consumption growth rates in the power sector have even been halved compared to NDP 2014, while industrial gas demand decreasing rates worsened. As a result, gas consumption is expected to continue to stagnate in the new NDP between 2015 and 2024.

Table 14: Annual growth rates of sectoral gas consumption
in the actual and previous Network Development Plans as well as historical growth rates in France

	NDP 2015 **2015-2024**	NDP 2014 **2014-2023**	NDP 2013 **2013-2022**	NDP 2012 **2012-2021**	NDP 2011 **2011-2020**	Historical **2005-2012**
Residential and commercial	-0,8%	-1,0%	-1,1%	-0,9%	-0,6%	-1,8%
Industrial	-0,7%	-0,4%	-0,9%	0,7%	0,7%	-2,1%
Power generation	3,1%	7,8%	7,0%	6,7%	6,8%	3,9%
Total gas consumption	-0,3%	0,4%	0,2%	0,9%	1,2%	-0,6%

Source: Eurostat, [GRTgaz 2011], [TIGF 2011], [GRTgaz 2012], [TIGF 2012], [GRTgaz 2013], [TIGF 2013], [GRTgaz 2014], [TIGF 2014], [GRTgaz 2015], [TIGF 2015]

Whether gas consumption will increase, stagnate or decrease depends on various influencing factors, including:

- Residential/commercial sector: population, economic activity, efficiency measures (particularly building renovation)
- Industry: industrial production, structure of industrial branches (energy intensive / less energy intensive), efficiency measures
- Power sector: power demand, competition with renewables and other energy sources, decommissioning of power plants (nuclear, coal).

The analysis of these factors' development is essential to assess their effect on gas consumption and eventually foresee a probable and realistic gas demand path. In the following paragraphs, assumptions from TSOs concerning the evolution of influencing factors of gas demand are described according to available data.

Households and commercial sector: Gas consumption decreases in all scenarios due to building renovation, which offsets increased gas use due to substitution from electricity to gas as well as increased housing stock. This sector stays the most important sector in terms of gas consumption. In scenario “Usages diversifiés”, renovations are less ambitious than in scenario “Référence” (150,000 housings built before 2012 renovated each year, compared to 250,000 in scenario “Référence”, 15 million m² of commercial areas renovated each year, compared to

22 million m² in scenario “Référence”). Substitution from electricity to gas for heat and warm water is higher in scenario “Usages diversifiés”. As a result, gas consumption in this sector is in scenario “Usages diversifiés” almost stable.

Industry: Industrial gas consumption is quite similar in all GRTgaz scenarios, which show a slight decrease of consumption. In scenario “Usages diversifiés”, gas consumption in industry even increases slightly. This is a big difference to scenario “AMS2” (from DGEC), which shows a much bigger decrease of gas consumption. Assumptions concerning efficiency gains are in fact much higher in scenario “AMS2” compared to GRTgaz scenarios while at the same time, the added value of production increases more.

According to the scenarios, gas consumption in final demand will be driven by the development of gas powered vehicles. The scenarios expect that between 12 and 35 TWh of gas will be consumed in the transport sector by 2030. The following table shows the assumptions of the different scenarios. Assumptions on demographic and overall economic developments are not provided in detail in the plan.

Table 15: Assumptions related to the different scenarios and concerning final demand

Parameters	Scenarios			
	I (Reference with mobility)	II (Moins 30)	III (Usages Diversifiés)	IV (AMS2)
Demography	-	-		-
GDP	-	-		-
Economic activity	Industry: added value of production +0,7% per year			Industry: added value of production +1,5% per year
Energy efficiency/ intensity	Residential/ commercial: > 300 000 new dwellings per year > 250 000 dwellings built before 2012 renovated per year > 12 M m2 new tertiary surface per year > 22 M m2 tertiary surface renovated per year > efficiency gains: 35% by dwellings and 15% by commercial buildings Industry's efficieny coefficient: -0,3% to -0,5% per year	Residential/ commercial: > 355 000 new dwellings per year > 400 000 dwellings built before 2012 renovated per year > 13 M m2 new tertiary surface per year > 32 M m2 tertiary surface renovated per year > efficiency gains: 35% by dwellings and 15% by commercial buildings Industry's efficieny coefficient: -0,3% to -0,5% per year	Residential/ commercial: > 300 000 new dwellings per year > 150 000 dwellings built before 2012 renovated per year > 12 M m2 new tertiary surface per year > 15 M m2 tertiary surface renovated per year > efficiency gains: 35% by dwellings and 15% by commercial buildings Industry's efficieny coefficient: -0,3% to -0,5% per year	Residential/ commercial: > 330 000 new dwellings per year during 2015-2016 and 2022-2030, 500 000 during 2017-2021 > all the housing stock should be renovated by 2030 > 8 M m2 new tertiary surface per year > 50 M m2 tertiary surface renovated per year > efficiency gains: 45% by dwellings and 34% by commercial buildings Industry's efficieny coefficient: -1,1% per year per produced ton (GRTgaz estimation)
Renewables	Development of renewable gas: > biomethan: 30 TWh in 2030 (22,5 TWh in GRTgaz area). 2020-2030 ADEME study was used > power to gas: 100 installations in 2030 enable to store 2,5 to 3 TWh of excess renewable electricity ; 1 000 installations in 2050 enable to store 25 to 75 TWh of excess renewable electricity	Development of renewable gas: > biomethan: 30 TWh in 2030 (22,5 TWh in GRTgaz area). 2020-2030 ADEME study was used > power to gas: 100 installations in 2030 enable to store 2,5 to 3 TWh of excess renewable electricity ; 1 000 installations in 2050 enable to store 25 to 75 TWh of excess renewable electricity	Development of renewable gas: > biomethan: 12 TWh in 2030 (9 TWh in GRTgaz area). > power to gas: 100 installations in 2030 enable to store 2,5 to 3 TWh of excess renewable electricity ; 1 000 installations in 2050 enable to store 25 to 75 TWh of excess renewable electricity	Objectives of "loi de transition énergétique pour la croissance verte" are reached
Substitutions	> Gasoil and diesel substituted by gas: 35 TWh in 2030	> Gasoil and diesel substituted by gas: 35 TWh in 2030	> Higher substitution electricity -> gas for heat and warm water > Gasoil and diesel substituted by gas: 12 TWh in 2030	> Gasoil and diesel substituted by gas: 6 TWh in 2030

Source: [GRTgaz 2015]

Power generation and transport: Together with the transport sector, the transformation sector will drive gas demand in France according to the scenarios. Though gas is still a marginal source of power compared to nuclear and renewables, the scenarios expect gas to be developed in parallel with renewables. It is expected to be used not only as a back-up to offset the intermittency of renewables and at peak power demand through gas turbines, but also as base and semi base load through CCGT which would partly substitute coal plants. The scenarios are based on the middle-term forecast of electricity demand for the period 2015-2020 and scenario "Nouveau Mix" for the period 2020-2030 of RTE[80] (Réseau de Transport d'Électricité, the electricity transmission system operator of France) [RTE 2015]. "Nouveau Mix" includes the following targets: increase of renewables in power generation and reduction of nuclear share in electricity production to 50 % by 2025. The following table sums up the main characteristics and assumptions of each scenario.

Table 16: Assumptions related to the different scenarios and concerning power demand

Parameters	Scenarios			
	I (Reference)	II (Moins 30)	III (Usages Diversifiés)	IV (AMS2)
Evolution of electricity generation	> 2015-2020: "consistent" with RTE scenarios for power generation (middle-term forecast) > 2030: scenario Nouveau mix (nuclear is curtailed to 50% of electricity production in 2025 and there is a strong development of renewables)	> 2015-2020: "consistent" with RTE scenarios for power generation (middle-term forecast) > 2030: scenario Nouveau mix (nuclear is curtailed to 50% of electricity production in 2025 and there is a strong development of renewables)		> 2015-2020: "consistent" with RTE scenarios for power generation (middle-term forecast) > 2030: scenario Nouveau mix (nuclear is curtailed to 50% of electricity production in 2025 and there is a strong development of renewables)
Expected role played by gas	> as base load and semi-base load: 7 CCGT to be built between 2025 and 2030 > as peak load, to support fluctuating renewables: 10 gas turbines to be built between 2023 and 2026		> as base load and semi-base load: 8 CCGT to be built between 2025 and 2030 > cogeneration more developed than in other scenarios	
Renewables	> 25% of annual electricity consumption comes from renewables in 2030 (RTE scenario Nouveau mix) > 39% of electricity production in 2030 comes from renewables	> 25% of annual electricity consumption comes from renewables in 2030 (RTE scenario Nouveau mix) > 39% of electricity production in 2030 comes from renewables		> 25% of annual electricity consumption comes from renewables in 2030 (RTE scenario Nouveau mix) > 39% of electricity production in 2030 comes from renewables
Substitutions	> Nouveau mix: CCGT substitute coal fired plants	> Nouveau mix: CCGT substitute coal fired plants		> Nouveau mix: CCGT substitute coal fired plants

Source: [GRTgaz 2015], [RTE 2015]

Table 17 shows the detailed energy mix for power generation according to RTE scenario. Installed capacities of CCGT and renewables are expected to increase while installed capacities of other fossil fuels decrease. The overall installed capacities would increase by 4 % between 2015 and 2020.

[80] While the reference scenario of the middle-term forecast for the period 2015-2020 is used for the electricity network infrastructure development, scenario "Nouveau Mix", together with the other scenarios developed for the period 2020-2030, are only indicative.

Table 17: Development of installed power capacities in France
according to the middle-term forecast of RTE

Reference scenario [GW]	2015	2020	Change 2015-2020
Coal	4	3	-31%
Gas (CCCG)	6	7	18%
Nuclear	63	63	0%
Other conventional	14	10	-29%
Renewables	41	51	25%
Total	127	133	4%

Source: [RTE 2015]

The NDP of GRTgaz and TIGF have been subjected to a consultation process. Participating stakeholders acknowledged the difficulty to assess assumptions made in these plans, as there are great uncertainties concerning gas consumption development. One of the participants estimated the assumptions for industrial and power consumption are too optimistic, given the uncertainties about new tools to overcome peak gas demand. If these hypotheses are effectively too optimistic, it would mean gas demand would decrease even more in the future, which would have consequences on gas infrastructure investments.

Another point of uncertainty is the development of biomethane. The law LTECV sets up the objective of a 10 % share of biomethane in gas consumption by 2030. This goal is quite ambitious. Besides, the consequences of this development on gas infrastructure are unclear. On the one hand, this would require the installation of new equipment to enable reverse flows. On the other hand, it could lead to a reduced use of gas transport networks. The regulator asked the TSOs to provide more information in their next plan concerning the possible impacts of biomethane development on gas infrastructure investments.

The transportation means of biomethane will condition investment decisions. Especially, the central question is: How much biomethane will be transported by pipeline and how much by truck? In the NDP of GRTgaz, scenarios are considering amounts of biomethane equal or close to amounts of gas consumed in the transport sector in 2030 (12 TWh in a trend scenario and 30-35 TWh in a “voluntarist” scenario). This suggests that biomethane could entirely be used for the transport sector. Gas supply options could be similar to those used for oil products, i.e. biomethane could be transported by trucks. In this case, the impacts on gas pipelines investments would be considerable.

Uncertainties over biomethane development and its impacts do not affect gas consumption scenarios until 2024, as a takeoff of the field is expected only around 2022-2023.

The downside factors for gas demand that have been identified during the consultation process might lead to an overestimation of gas consumption.

Consideration of environmental targets

Scenario “AMS2” from DGEC was explicitly modelled in a way that it reaches the national targets set by the LTECV. GRTgaz scenarios take into account the targets of the law. However, it is difficult to assess to which extent the targets are reached.

For instance, scenario “Moins 30” does take into account the target regarding the 30 % reduction of primary fossil fuel consumption, but applies it only to final demand. At this point, no conclusion can be made concerning the LTECV target, which relates to all fossil fuels in primary consumption.

Scenarios “Reference” and “Moins 30” are said to be “consistent” with RTE power scenarios, which reach the target concerning renewables and nuclear in the power sector. However, it is not clear in which way they are consistent, in particular, which elements of RTE scenarios (electricity demand, energy mix, share of gas, assumptions) have been taken into account. It was supposed these GRTgaz scenarios also reach those targets.

Table 18 details the targets as well as the compliance level of scenarios, when information is available.

Table 18: Compliance with energy and climate targets

	Political targets (EU and national)						Have the targets been reached? Scenario			
	2012	2015	2020	2025	2030	Change 2012-2030	I	II	III	IV
Share of renewables in final energy			23%		32%		?	?	?	✓
Share of renewables in power generation					40%		✓	✓	?	✓
Share of nuclear in electricity generation				50%			✓	✓	?	✓
Share of biomethane in gas networks				10%			ambiguous			✓
GHG emissions						-40%*	?	?	?	✓
Final energy consumption						-20%	?	?	?	✓
Fossil fuels (primary energy) - gas	480	456	416	376	336	-30%	?	?	?	✓

* compared to 1990

Source: LTECV, EU Climate and energy package, [GRTgaz 2015]

Impact of scenarios on gas infrastructure

Gas infrastructure development needs are partly assessed on the basis of the peak gas demand. The maximum gas supply capacity of France’s natural gas infrastructure – pipeline imports and liquefied natural gas regasification – would be 3,065 GWh/d, while peak daily natural gas demand would be about 3,960 GWh in 2015, according to GRTgaz scenarios. France has additionally gas storage volumes of 322 GWh/d and by the end of 2015, there should be 520 GWh/d of additional LNG capacity in Dunkirk.

Proposed developments by GRTgaz and TIGF aim to increase gas flows from North to South. The confirmed projects include an improved connection at Dunkirk LNG terminal, increased flows at the interconnection with Spain, creation of an entry point with Switzerland as well as a corridor "Val-de-Saône + Gascogne-Midi" which will improve gas supply from north of France to the south. Proposed projects which have not been decided yet include the creation of an exit point with Germany as well as the Midcat gas pipeline. Midcat aims to increase entry capacity from Spain and give the possibility for Spain to use its large-developed LNG terminals to supply other European countries with gas.

Confirmed measures represent an investment volume of about € 814 million. When all projects are taken into account (under way, confirmed and under consideration), investments reach € 3,795 million.

Conclusions

- **Process.** The process is well documented and accessible to interested parties. The yearly basis enables short-term adjustments but leaves just a short period for reactions at the end of each year.
- **Gas demand since 1990.** Gas consumption stagnated between 2005 and 2011 at around 475 TWh. Gas demand for power generation offset decreasing gas demand in the industrial, commercial and residential sectors. A slight decrease of temperature-adjusted gas demand since 2012 can be noticed.
- **NDP scenarios.** In the reference scenarios, gas consumption is expected to slightly decrease between 2015 and 2024. It is the first time that a decrease is forecasted during the next decade since NDP 2011. From 2025 onward, gas demand is expected to increase due to increased power production based on gas, the development of biomethane production and increased use of gas and in the transport sector.
- **Sectoral analysis of scenarios and modelling assumptions.** The maintained gas consumption until 2025 is explained by the substitution of energy sources by gas in the residential and industrial sector, which would partly offset the decreasing gas consumption in these sectors since 2005. The increase of gas consumption from 2025 is based on the assumption that gas will be chosen for power generation in parallel to the development of fluctuating renewables[81] and compensate the reduction of nuclear power. From 2025 to 2030, gas demand for power generation is expected to double from 60 to 120 TWh. The development of biomethane and power-to-gas would also contribute to increase gas consumption, although their effect on the infrastructures are unclear.
- **Scenarios and climate protection.** There is reference to French climate protection goals (LTECV law). However, it is unclear to which extent they have been taken into account.
- **Scenarios and gas infrastructure.** Proposed developments by GRTgaz and TIGF aim to increase gas flows from North to South.

[81] A number of other options are under study around the world to cover electricity demand with a generation system including intermittent renewable sources, for example demand side management, storage, power imports/exports, use of biomass plants.

2.3.3 Germany

Due to its geographic location Germany plays an important role in development of the European gas infrastructure. This is partly caused by the future development of European gas transits. Today there is a complex gas infrastructure in Germany. Currently, there are 16 transmission system operators (TSO) and over 700 distribution system operators (DSO) spread across the entire country.

There are two major gas qualities and two respective separate networks in Germany: a low calorific value (CV) network and a high CV Network. Due to the expected decline of low CV gas resources in Germany and especially in the Netherlands the change of low CV gas supply to high CV gas supply is an important challenge up to the year 2030. A detailed plan regarding this transformation process is included in the currently valid Network Development Plan 2015. The process of developing the gas Network Development Plan in Germany is described in chapter 2.2.3. The following Table 19 shows some historical and topical key facts of the German Network Development Plan.

Table 19: Profile German Network Development Plan

Rhythm:	Yearly
First NDP Gas:	2012
Number of TSOs:	16 (NDP Gas 2016)
Current status:	Final NDP Gas 2015, (confirmed SF 2016)
Number of scenarios:	3 (SF 2015), 1 (SF 2016)
Number of modelling variants:	2 (NDP Gas 2015)
Considered period:	10 years, NDP 2015-2025
Number of measures:	85 (final NDP Gas 2015)
Investment volume:	3.3 bn € in 2025 (final NDP Gas 2015)
Focus:	Switchover from low to high CV gas, demand of DSO (NDP Gas 2015), international gas sources (NDP gas 2016)

Source: [FNB Gas 2015], Network Development Plan 2015 [NDP 2015], Scenario Framework 2016 [SF 2016]

Process analysis

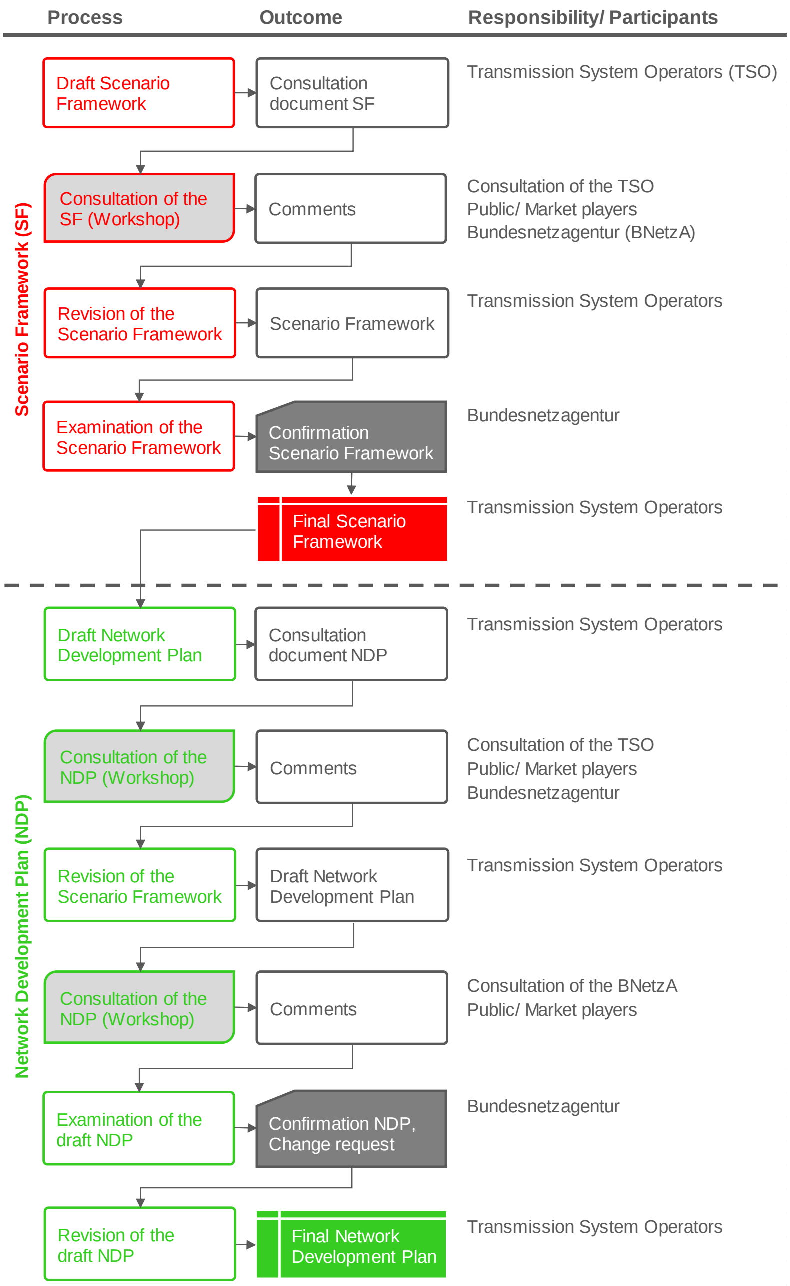
The legal requirements and the general process for the German Network Development Plan (NDP) are described in the German Energy Industry Act (EnWG, Section 15a). The EnWG was modified in June 2011 according to Regulation 715/2009/EC. Figure 17 summarizes the whole process in Germany. There are also regular discussions between the National Regulatory Authority Bundesnetzagentur (BNetzA) and all market players during the whole NDP process in addition to the formal proceedings.

The NDP process can basically be divided into two main parts: Scenario Framework (SF) and Network Development Plan (NDP), whereby the Network Development Plan is based on the confirmed assumptions and results of the Scenario Framework.

The Scenario Framework describes different gas consumption scenarios. There is a coordination with the German electricity transmission system operators and BNetzA regarding the development of the power sector. The gas transmission system operators (TSO) also define assumptions concerning the development of gas production, gas supply, gas storage and gas exports/ imports over the next decade in the Scenario Framework. The Scenario Framework is published for comment in a consultation procedure (duration three weeks), during which the interested public and the market players have the opportunity to comment on the assumptions of the Scenario Framework and state their point of view regarding the future gas infrastructure. The consultation comments regarding the Scenario Framework draft are analysed by the TSO and are taken into account during the revision of the Scenario Framework. The revised Scenario Framework is delivered to the BNetzA who examines the document. This examination phase normally takes about 6-10 weeks and ends with an official confirmation of the Scenario Framework by the BNetzA. With this confirmation the BNetzA can formulate requirements which have to be taken into consideration by the TSO during the development of the Network Development Plan.

The TSO publish the Network Development Plan on the basis of the confirmed Scenario Framework. The first consultation round of the Network Development Plan is similar to the consultation process of the Scenario Framework. After a public consultation organized by the TSO the draft of the Network Development Plan is published by the TSO. This draft is consulted by the BNetzA. Again, the public and all market players have the possibility to comment on the revised Network Development Plan. During this consultation round (duration normally six weeks) the BNetzA addresses key issues by asking consultation questions. After the consultation, the BNetzA has to publish the consultation results of the second consultation round. Within three months after the publication of the consultation results the BNetzA can demand changes to the Network Development Plan which are published in an official change request. This change request has to be implemented into the (final) Network Development Plan by the TSOs within a further period of three months. In case BNetzA does not publish a change request in accordance with the legal guidelines, the published Network Development Plan draft by the TSO would turn automatically into the final Network Development Plan.

Figure 17: Approach, results and responsibilities within the German NDP process



Source: Prognos, based on German Energy Industry Act [EnWG], [FNB Gas 2015]

To sum up, the process of developing the Network Development Plan for gas infrastructure in Germany is complex and challenging, especially considering the timeframe. The EnWG demands a Network Development Plan each year (2012-2016). A modification of the legal situation with a change to a two-year rhythm is in sight. Most market players claimed and support this change. After the 2016 NDP the next Network Development Plan for the gas infrastructure will probably be published in 2018. In addition to the Network Development Plan, an implementation report will have to be published by the TSO concerning the currently valid Network Development Plan in the interim years, beginning in 2017.

In the past, there were simultaneous processes concerning different Network Development Plans due to the legal requirement to publish a topical Network Development Plan every year. Figure 18 shows the chronological sequences of the past years.

Figure 18: Overlapping NDP processes

Year	Process	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	NDP 2012								1				
2012	NDP 2012		2,3		4,5								6
	NDP 2013								1		2		
2013	NDP 2012			7									
	NDP 2013		3		4,5								6
	NDP 2014							1			2		
2014	NDP 2013			7									
	NDP 2014		3		4,5							6	
	NDP 2015							1				2	
2015	NDP 2014	7											
	NDP 2015		3		4,5					6		7	
	NDP 2016							1				(2)	
2016	NDP 2015												
	NDP 2016												

Legend:

1 Start consultation Scenario Framework (TSO, 3 weeks)
2 Confirmation Scenario Framework (BNetzA)
3 Start first Consultation Network Development Plan (TSO, 3 weeks)
4 Draft Network Development Plan (TSO)
5 Start second Consultation Network Development Plan (BNetzA, 6 weeks)
6 Confirmation Network Development Plan, Change request (BNetzA)
7 (Final) Network Development Plan (TSO)

Source: Prognos, based on FNB Gas Website [FNB Gas 2015]

The final Network Development Plan 2015 was published by the TSO on 16 November 2015. It is expected that the BNetzA will confirm the current Scenario Framework 2016 at the end of November or beginning of December 2015.

The NDP is not available in English. Only a brief executive summary is provided in English.[82]

[82] http://www.fnb-gas.de/files/2015_11_16_executive_summary_nep_2015_en_1.pdf

2.3.3.1 Scenario analysis and assessment

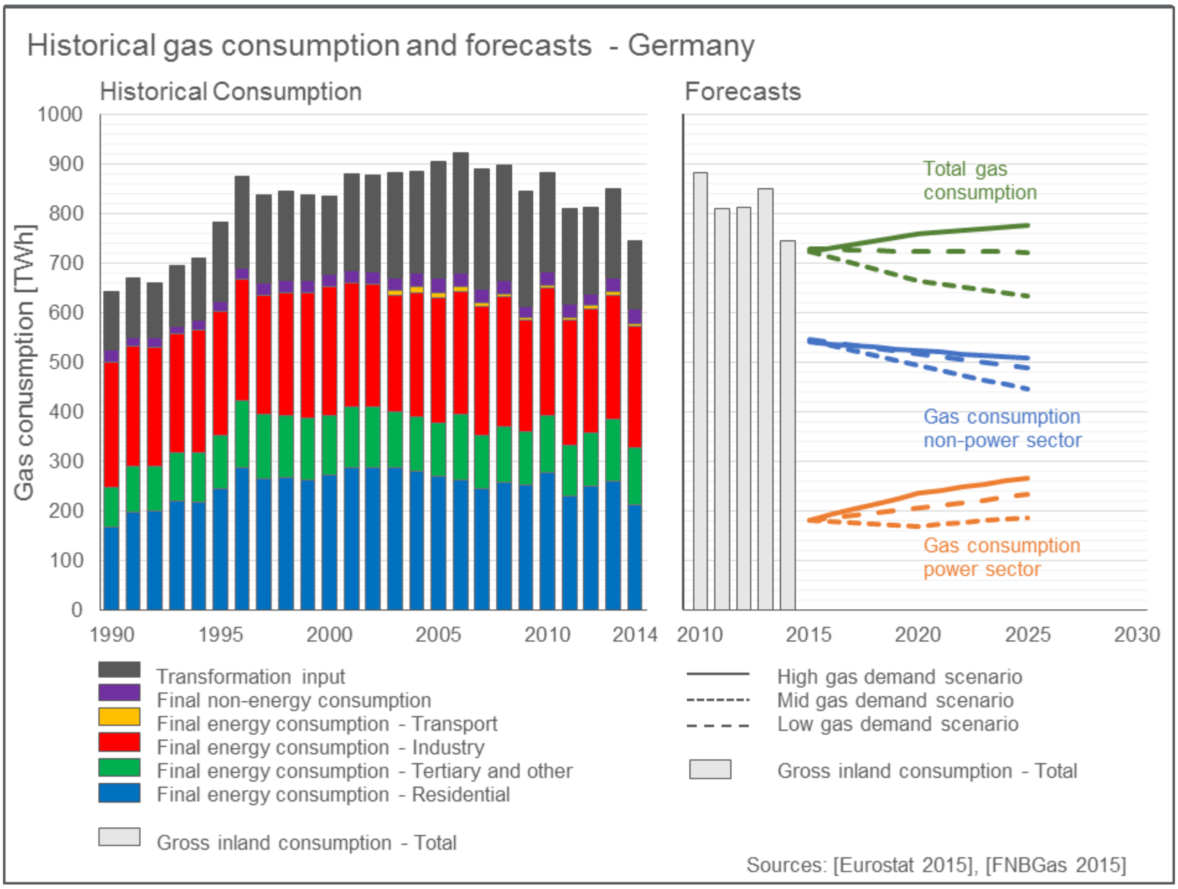
Gas demand since 1990 and NDP scenarios

Gas plays an important role in the German energy supply in all demand sectors, with the exception of transport which is strongly dominated by oil. The German gas demand increased significantly between 1990 and 2000. By comparison, according to Eurostat the gas demand of 2013 is nearly at the same level as it was in 2000. There was a peak gas demand in 2006, since then we see a continuously decreasing total gas demand in Germany. Looking at the temperature adjusted gas demand (annex 1 in **Figure 59**), the figures show the same trend. This decline is due to stronger efficiency measures and a reduced usage of gas in the transformation sector.

There are three gas demand scenarios described in the Scenario Framework (SF) for the Network Development Plan 2015. These scenarios are regarding the final energy demand generally based on the reference projection “Energiereferenzprognose” („Entwicklung der Energiemärkte – Energiereferenzprognose“) [EWI/ Prognos/ GWS 2014], a study which was created by EWI (Institute of Energy Economics at the University of Cologne/ Energiewirtschaftliches Institut an der Universität zu Köln), Prognos and GWS (Institute of Economic Structures Research/ Gesellschaft für Wirtschaftliche Strukturforschung) commissioned by the Federal Ministry for Economic Affairs and Energy (BMWi). The development of the annual gas demand in the Scenario Framework scenarios is shown in the right side of Figure 19.

Scenario II of the Scenario Framework corresponds to the reference scenario of the BMWi study. Scenario III is identical to the target scenario in which the policy objectives are achieved mainly because of additional efficiency measures. Scenario I is based on the reference scenario (like scenario II) with the exception of the household sector. For this sector scenario I relies on the gas demand forecast of the Shell BDH study (Shell BDH Hauswärme-Studie: Klimaschutz im Wohnungssektor – Wie heizen wir morgen? Fakten, Trends und Perspektiven für Heiztechnik bis 2030 - “Hauswärme-Studie“) [Shell BDH 2013]. Based on the above named data sources the Scenario Framework 2015 illustrates a range of annual gas demand scenarios. Scenario I results in an overall slightly increasing gas demand, the gas demand in scenario II remains quite constant and there is a noticeable decline in scenario III.

Figure 19: Historical gas consumption 1990-2014 (Eurostat) and forecast according to the national Network Development Plan – GERMANY [TWh]



Source: [Eurostat 2015], [FNB Gas 2015], Scenario Framework 2015 [SF 2015]

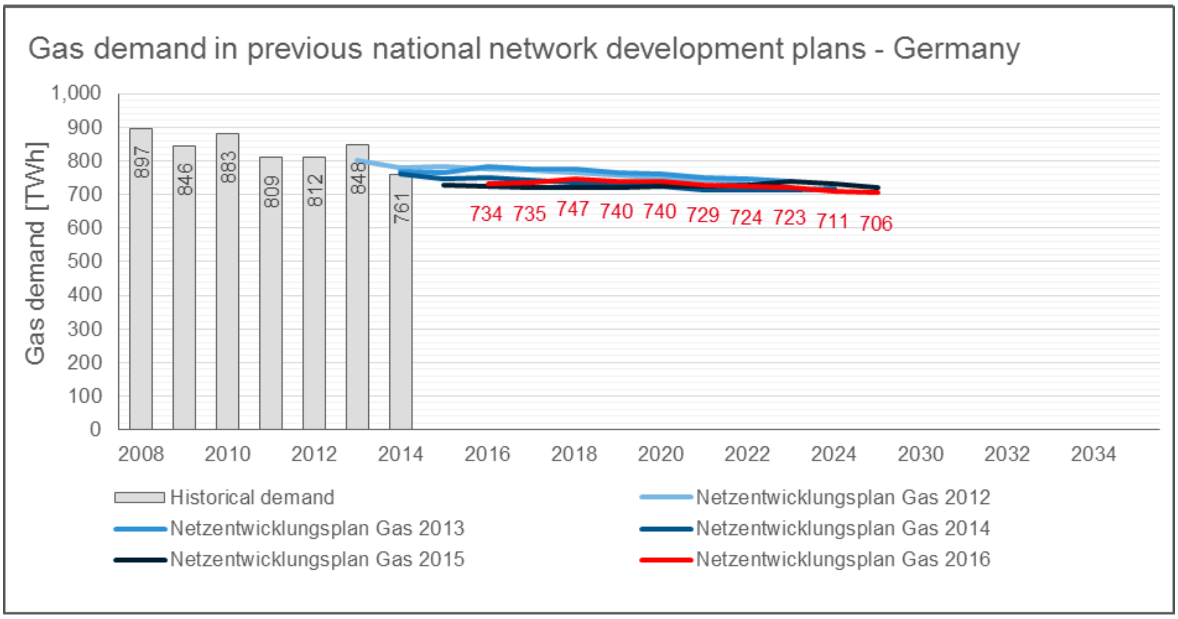
All scenarios expect a decreasing gas demand in the final energy demand sectors. Strongest gas demand decline is expected in the tertiary sector due to a higher renovation rate of the buildings. Decrease in the residential sector is approximately the same as the average of all final gas demand sectors. Gas demand in the industrial sector is expected to remain constant over the next 10-year-period. Gas demand in the transformation/ power sector is expected to increase within the next ten years.

The increase of gas demand in the transformation/ power sector is based on several new gas-fired power plants in the next years. The BNetzA and the German gas and electricity TSO developed criteria for the realisation of new gas power plants. In reality, a lot of gas power plants projects were postponed or cancelled. All in all, the scenario II of the scenario framework 2015 expects a decreasing gas demand which is pretty much in line with the development of the gas demand in Germany in recent years.

The BNetzA recently confirmed the Scenario Framework 2016. The confirmation of this new Scenario Framework was published in December 2015. There is only one gas demand scenario illustrated in the 2016 Scenario Framework which corresponds to the above-mentioned reference scenario of the BMWi study regarding final energy gas demand.

The following figure shows the assumptions regarding the gas demand development in the reference scenarios of the actual and previous German Scenario Frameworks/ Network Development Plans. The figure shows that there are practically no differences in the gas demand assumptions in the last five years. The respective reference gas demand scenario always expected a decreasing future gas demand.

Figure 20: Gas consumption scenarios in the actual and previous Network Development Plans – GERMANY [TWh]



Source: FNB Gas [2016], Scenario Frameworks and Network Development Plans 2012-2016

During the consultation process some participants (especially distribution system operators) criticize the assumptions regarding the decreasing gas demand. They expect an increasing development due to significant rising gas connection points and an increasing gas demand of the industry. The gas demand development according to the target scenario received only very little consent within the consultation process.

The Scenario Framework describes the development of the annual gas demand [TWh] while the modelling variants of the Network Development Plan refer to capacity data [GW]. It is important to keep in mind this difference to understand the relation between annual gas demand and gas capacity.

Sectoral analysis of scenarios and modelling assumptions

The following Table 20 shows crucial assumptions of scenario II regarding demography and economy which significantly determine the future gas demand. These and more details assumptions are published in the reference case of the BMWi study ("Energiereferenzprognose"). The gas demand development of this reference case was confirmed by the BNetzA.

Table 20: Demographic, economic and price assumptions in scenario II

Reference scenario	2015	2020	2025	2030	2035	Change 2015-2025	Change 2025-2035
Population [m.]	79,7	79,4	78,9	78,1	77,1	-1%	-2%
Dwellings [m.]	41,9	42,3	42,6	42,8	42,8	2%	1%
Living space [m. m²]	3.793	3.872	3.931	3.983	4.017	4%	2%
Gas heated living space [%]	51%	52%	52%	52%	52%	2%	-1%
Heat pumps [%]	3%	5%	6%	7%	9%	95%	49%
GDP [bn. €, real 2005]	2.521	2.688	2.863	3.031	3.188	14%	11%
Employees tertiary [m.]	34,6	34,1	33,7	33,2	32,7	-2%	-3%
Employees industry [m.]	5,8	5,6	5,4	5,2	4,9	-7%	-9%
Gas-powered cars [1.000]	100	410	1.050	2.056	3.428	950%	226%
Gas price households [€/MWh, real 2011]	7,1	7,7	8,1	8,5	9,0	14%	10%
Gas price industry [€/MWh, real 2011]	3,7	4,2	4,6	4,9	5,2	24%	14%
Carbon price [€/t, real 2011]	7	10	25	40	53	270%	110%
Renovation rate [%]	1,2%	---	---	1,3%	---	---	---
Gas demand households / population [MWh/p.]	3,0	2,8	2,5	---	---	-15%	---
Gas demand tertiary / employees [MWh/empl.]	2,8	2,4	2,0	---	---	-28%	---
Gas demand industry / GDP [kWh/1.000 €]	82	77	72	---	---	-13%	---

Source: Energiereferenzprognose 2014 [EWI/ Prognos/ GWS 2014]

As described, the gas demand in the Scenario Framework is based on recognized studies. Regarding the transformation sector there is a coordination with the German electricity transmission system operators and the National Regulatory Authority/ Bundesnetzagentur (BNetzA) to match the existing power plant stock and to forecast the development of new (gas) power plants. The decision about a new power plant strongly depends on existing topical requests of connection which were placed to the gas and electricity TSO (requests relating to the Gas Grid Access Ordinance/ Gasnetzzugangsverordnung/ GasNZV and the Regulating Grid Connection of Electricity Generating Installations/ Kraftwerks-Netzanschlussverordnung/ KraftNAV).

Most gas fired power plants will be installed in scenario I of the Scenario Framework. Scenario I includes all requests of connection in accordance with the Gas Grid Access Ordinance (GasNZV). Scenario II illustrates again a kind of reference case where older requests of connection remain unconsidered and there was also a comparison with requests of connections which existed for the electricity transmission grid. Scenario III only includes gas power plants which were already under construction. There are no economic criteria for new construction of power plants in the NDP process. Overall, there is quite a big spread regarding the installed gas power plant capacity in the scenarios which explains the different gas demand developments in the power sector.

Again, in the 2016 Scenario Framework there is also only one power sector scenario illustrated which is similar to scenario II of the Scenario Framework for the Network Development Plan 2015.

Table 21: Development of power sector

Reference scenario [GW]	2012	Scenario I 2025	Scenario II 2025	Scenario III 2025	Change Scenario I 2012-2025	Change Scenario II 2012-2025	Change Scenario III 2012-2025
Hard coal	24,7	24,6	24,6	26,1	0%	0%	6%
Lignite	21,1	14,5	14,5	16,2	-31%	-31%	-23%
Gas	26,8	40,1	29,5	24,0	50%	10%	-10%
Other conventional	26,5	16,7	13,4	13,4	-37%	-49%	-49%
Renewables	80,2	139,2	139,2	128,6	74%	74%	60%
Total	**179,3**	**235,1**	**221,2**	**208,3**	**31%**	**23%**	**16%**

Source: Network Development Plan 2015 [NDP 2015]

Consideration of environmental targets

Within the development of the Network Development Plan there is no controlling of political energy goals. Ultimately, the BNetzA confirms or changes the assumptions of the Scenario Framework but national emission objectives play a minor role in this context compared to the security of gas supply. For example, regarding the final energy demand the Scenario Framework displays as mentioned above the reference and the target scenario of the BMWi study. The German energy and emission objectives are achieved in the target scenario but the BNetzA only confirmed modelling variants which are based on the reference case. This reference case misses the emission objectives. The target scenario which is in line with the existing policy objectives is not relevant for the gas network modelling.

The BNetzA confirmed for the National Development Plan 2016 only one modelling variant for the distribution system operators which is not based on the above described gas demand development of the reference scenario. This modelling variant is based on the long-tern forecasts by the distribution system operators. These forecast shows an overall rising demand capacity. The connection of the gas and the capacity demand is subject of a controversial debate. A study of the FfE (Forschungsstelle für Energiewirtschaft e.V.) expects a decreasing capacity demand based on the decreasing gas demand development of the reference scenario. Other participants of the consultation process support a contrary position.

Regarding the power sector there is a significant increase of renewable electricity generation and as described above there is a coordination between the BNetzA and the gas and electricity Network Development Plans also with regard to future renewable capacities. And there is an examination in the electricity Network Development Plan, whether or not the political energy goals will be achieved.

Impact of scenarios on gas infrastructure

The BNetzA confirmed 85 gas infrastructure measures in the Network Development Plan 2015 which are based on the proposal for network expansion by the TSOs. The differences between the two modelling variants in the Network Development Plan 2015 were very small.

These confirmed measures include pipelines as well as compressor stations and gas pressure regulating and metering stations. It is planned to build 685 km pipeline (with different diameters) and 278 MW compressor capacity with an investment volume of about € 2.7 billion until the year 2020. These data will increase to 810 km pipelines, 393 MW compressor capacity and an investment volume of around € 3.3 billion in 2025.

Driving forces for the new gas infrastructure measures and the capacity increase are the transformation from low CV gas to high CV gas, new power plants and storage capacities as well as the (rising) demand of the DSOs.

Conclusions

- **Process:** The legal requirements and the general process for the German Network Development Plan (NDP) are described in the German Energy Industry Act (EnWG, Section 15a). The NDP process can basically be divided into two main parts: Scenario Framework (SF) and Network Development Plan (NDP), whereby the Network Development Plan is based on the confirmed assumptions and results of the Scenario Framework. The process of developing the Network Development Plan for gas infrastructure in Germany is complex and challenging, especially considering the timeframe until 2016. But there is a modification of the legal situation with a change to a two-year rhythm. In addition to the Network Development Plan, an implementation report will have to be published by the TSO concerning the currently valid Network Development Plan in the interim years.
- **Gas demand since 1990 and NDP scenarios:** Historical gas demand shows a sustained decrease in the last years and the NDP gas demand scenarios continue this trend. A decreasing gas demand in the final energy demand sectors is expected, while gas demand in the transformation/ power sector will slightly increase within the next ten years.
- **Modelling assumptions:** The German NDP 2015 and 2016 are based on the same study regarding the development of final gas demand. The assumptions are published in the study “Energiereferenzprognose” („Entwicklung der Energiemärkte – Energiereferenzprognose“) [EWI/ Prognos/ GWS 2014] commissioned by the Federal Ministry for Economic Affairs and Energy.
- **Consideration of environmental targets:** The BNetzA only confirmed modelling variants which are based on a reference case regarding the gas demand development. This reference case misses the emission objectives. The target scenario which is in line with the existing policy objectives is not relevant for the gas network modelling. Also, the BNetzA only confirmed a modelling variant with a rising capacity demand for the distribution system level.
- **Impact of scenarios on gas infrastructure:** According to the NDP 2015, it is planned to build 810 km pipelines, 393 MW compressor capacity with an investment volume of around € 3.3 billion until 2025.

2.3.4 Italy

The Italian gas transmission network is operated by three TSOs: SNAM Rete Gas (SNAM), Infrastructure Trasporto Gas (ITG) and Societa Gasdotti Italia (SGI). Together, they operate a transmission grid with a cumulative length of 11,143 km. The largest share is operated by SNAM (85 %), followed by SGI (13 %) and ITG currently operating only a single transmission pipeline (2 %).

NDPs are published yearly (starting 2014) by all TSOs as required by national law. The most comprehensive one is published by SNAM, which develops its own demand scenario for the 10 year time period. The other TSOs base their NDPs on the demand scenario developed by SNAM [ITG 2014, p. 37]. The NDPs consider infrastructure projects with and without a final investment decision. Table 22 summarises the key elements of the NDPs (the number of measures and investment volume exclude those that have not been given a final investment decision).

Table 22: Profile Italian Network Development Plan(s)

Rhythm:	Yearly
First NDP Gas:	2014
Number of TSOs:	3 (SNAM, SGI, ITG)
Current status:	3 Final NDP 2015
Number of scenarios (SF):	1 each
Number of modelling variants (NDP):	-
Considered period:	10 years, NDP 2015-2024
Number of measures:	38
Investment volume:	€ 1,9 billion
Focus:	Support to the North-West and Islands Market, implementation of bidirectional border flows, implementation of the Adriatic pipeline

Source: [SNAM 2015], [SGI 2015], [ITG 2015]

Process analysis

The legal basis for the development of the NDPs is Article 16 of Legislative Decree No. 93/11, which requires TSOs to submit an annual NDP and consult stakeholders in the process. The procedures to be followed by TSOs in the development of the NDP are further stipulated in the Decree of the Italian Ministry of Economic Development dated February 27 th 2013 (the "Decree"). In accordance with this Decree, TSOs publish a timetable for the development of the NDP on 1 September of each year along with a formal request for information from stakeholders. Based on the information collected TSOs then develop a draft NDP by March 31st of the next year. These draft NDPs are then published together with the received non-confidential information and data and subject to public consultation and feedback. With the outcome of this consultation taken into account, the NDP is finalized and submitted to the Ministry of Economic Development (MiSE), the Italian Regulatory Authority for Electricity, Gas and Water (AEEGSI) and the Regions by the end of May [SNAM 2015]. Finally, MiSE and AEEGSI evaluate the plan pursuant to their own competencies and ensure consistency with the National Energy Strategy and the Union-wide NDP. No additional public consultation is held.

The timetable for the SNAM NDP covering the period 2015-2024 can be seen below:[83]

Table 23: Timetable SNAM NDP 2015

Year	Date	Task
2014	September 1	Start of information and data collection
	September 30	End of information and data collection
2015	March 31	Public release of NDP / Start of public consultation
	April 30	End of public consultation
	May 31	Delivery of NDP to MiSE, AEEG and Regions

Source: [SNAM 2015]

The most recent NDP of SNAM and ITG cover the period 2015-2024 [SNAM 2015, ITG 2015]. Both of the NDP have been provided in English and are available online.

Although transparency is ensured legally by Italian law, there is little information available about the consultation and possible feedback from stakeholders about the plan. Neither the statement of AEEGSI nor MiSE are available for consultation online.

Scenario analysis and assessment

The most recent NDP published by SNAM contains two forecast scenarios: The gas demand scenario of the SEN and the individual projections of SNAM. The scenarios have a different starting point: The SEN scenario starts in 2010 at a level of 791 TWh and foresees a reduction of 12.5 % to 19.8 % in total gas consumption from 2010 to 2020, resulting in 631-688 TWh total gas consumption in 2020. SNAM projections start in 2014 at a level of 589 TWh and foresee an increase of total gas demand from 2014 to 2020 of 16.0 % to reach 702 TWh in 2020.[84] The large drop from 2010 to 2014 is by SNAM mostly explained by a large economic recession, and it is difficult to assess what percentage of gas consumption reduction is due to energy efficiency measures and renewable energy production, which surely also play a role. After 2020, SNAM predicts a further increase to 729 TWh by 2024. Reasons for the increase of gas demand provided by SNAM are the following [SNAM 2015, p. 33]:

- Expected recovery of macroeconomic and electricity demand
- Additional transport of biomethane
- Progressive increase in the use on natural gas in transport

NDP scenarios and gas demand since 1990. After experiencing a sharp increase from 1990 to 2005, total gas demand has decreased slightly from 2005 to 2010, see also temperature

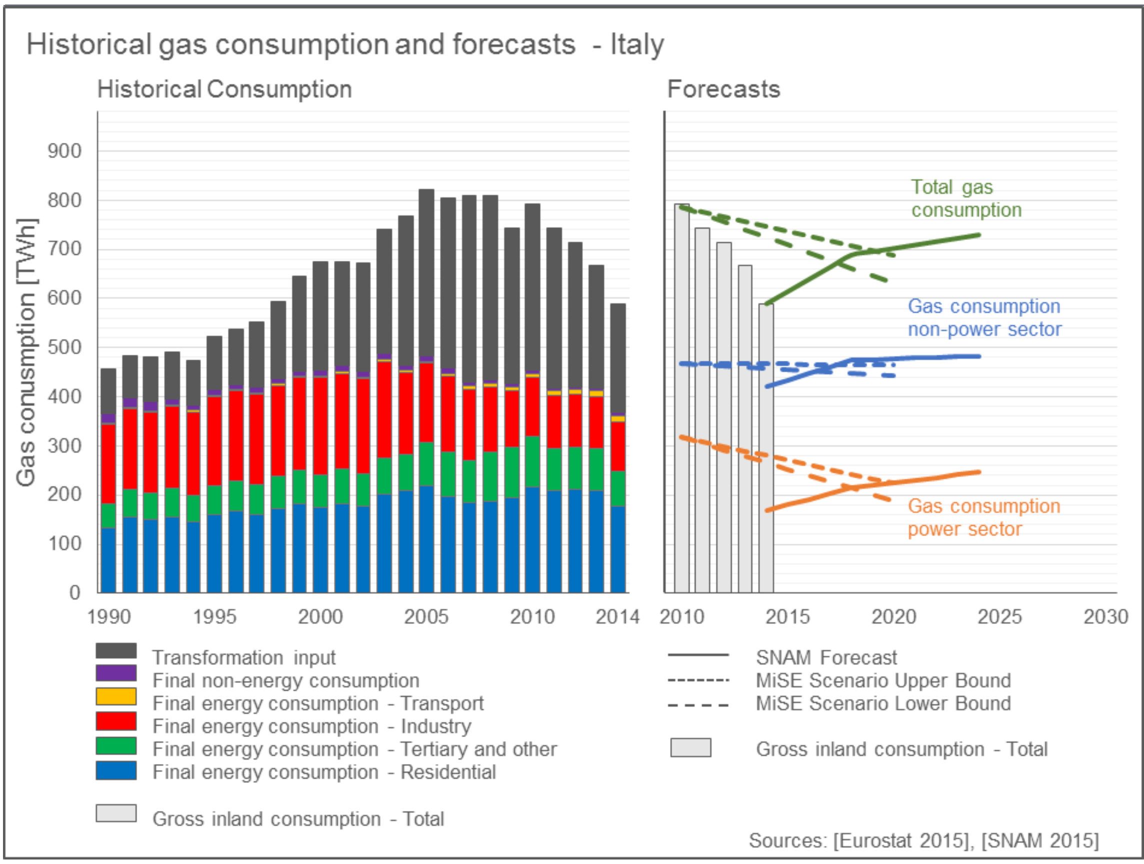
[83] http://www.snamretegas.it/export/sites/snamretegas/repository/file/ENG/Thermal_Year_20142015/ten-year-plan/elaborazione/Timetable.pdf

[84] Since data by SEN and SNAM is not provided for each year missing data have been interpolated linearly to allow for comparison.

adjusted gas demand in annex 1 **Figure 61**. The decrease is more pronounced since 2010. Natural gas demand in the transformation sector has increased strongly up to 2007, but is since then on the decline. It still represents the country's most important source for electricity generation, with a share of natural gas in total electricity generation of 43 % in 2013 [World Bank 2015]. Natural gas demand from industry is experiencing declines since 2001. The tertiary and residential sectors have predominantly seen an increase in natural gas demand. An overview of historical gas demand by sector is shown in Figure 21.

The strong decrease in gas demand since 2008 is often associated with the economic crisis that Italy is experiencing since then. However, a return of industrial production levels to the pre-crisis levels do not necessarily entail a rise in gas demand to pre-crisis levels, as efforts have been undertaken in the meantime to decrease the energy demand overall and to foster electricity production by renewables.

Figure 21: Historical gas consumption 1990-2014 (Eurostat) and forecast
according to the national Network Development Plan – ITALY [TWh]



Source: Eurostat, [MISE 2013], [SNAM 2015]

Sectoral analysis of scenarios and modelling assumptions. There is little transparency about the actual modelling process for SEN and SNAM scenarios.

SNAM scenario is based on the following assumptions:

- A growth of electricity demand of 0.7 % p.a. leading to an increase in gas demand of 3.9 % p.a. (including biogas) for 2014 – 2024. Gas demand from the transformation sector would amount to 246 TWh in 2024.
- A recovery of final energy demand in the residential and commercial sectors from 245 TWh in 2014 up to 289 TWh in 2020. A slight decrease to 280 TWh in 2024 is expected.
- A stable final energy demand from final industry of about 137 TWh, where efficiency gains offset the effects of economic growth.
- An increase of about 20 TWh in private and heavy transport by 2024.

Gas demand from the transformation sector has been reduced by 10 % p.a. since from 2010 to 2014 [Eurostat 2015]. SNAM argues that the decrease is due to the economic recession that has started in Italy since 2008 and predicts an increase from 2015 onwards together with economic recovery. The MiSE has identified the need to lower electricity costs in Italy as one of the four key goals in the energy sector. They are currently above European average due to the high usage of CCGT in the Italian electricity system. SEN scenario hence foresees a decrease of gas in electricity production from 2010 to 2020 [MiSE 2013, p.25]. Electricity production from renewable energy sources is supposed to increase further by 4.3 % per year according to the electricity company ENEL. Additional electricity demand could be met with coal power plants, which are economically competitive due to the low price of coal compared to gas [OIES 2013, p. 93]. The 2020 goals for the energy sector would be met even with a reduction of gas, as SEN shows. An increase of gas demand in the transformation sector after 2020 above the levels predicted by SEN is therefore doubtful.

Table 24: Development of electricity generation in Italy (SEN scenario) [TWh]

	2010	2020		Change 2010-2020	
		min	max	min	max
Oil	10,4	3,5	3,5	-66%	-67%
Coal	55,4	51,8	57,6	4%	-7%
Gas	152,2	120,8	144,0	-5%	-21%
Imports and other conventional	51,9	48,3	18,1	-65%	-7%
Renewables	76,1	120,8	136,8	80%	59%
Total	**346,0**	**345,0**	**360,0**	**4%**	**0%**

Source: [MISE 2013]

SNAM further denotes an increase of gas demand in the residential and tertiary sectors until 2020 by 4.2 % p.a., and thereby to the levels of 2009 – 2013.[85] Italy has a very high usage of gas for ambient heating (70 % of households in 2013 [ISTAT 2013]). As stated in the Energy Efficiency Action Plan (EEAP), energy saving in the building sector is one of the key aspects of the energy efficiency strategy. Energy savings from renovations from 2014 – 2020 could amount in residential and non-residential buildings up to 50 TWh [EEAP 2014]. Due to the large usage of gas for ambient heating, the energy reductions would mostly result in a lower

[85] 2010 having been an exceptionally cold year, 2014 exceptionally warm.

gas demand. SNAM does not present any assumptions on how these foreseen measures could affect gas consumption.

The same holds true for final energy demand in industry, where SNAM projects a stable consumption until 2024. The potential for energy saving is according to EEAP even higher in the industry sector than in the residential and tertiary sectors [EEAP 2014]. Final energy demand from industry has been falling almost continuously since 2000, with an average annual change of -4 % between 2000 and 2005 and -5 % between 2005 and 2010 [Eurostat 2015].

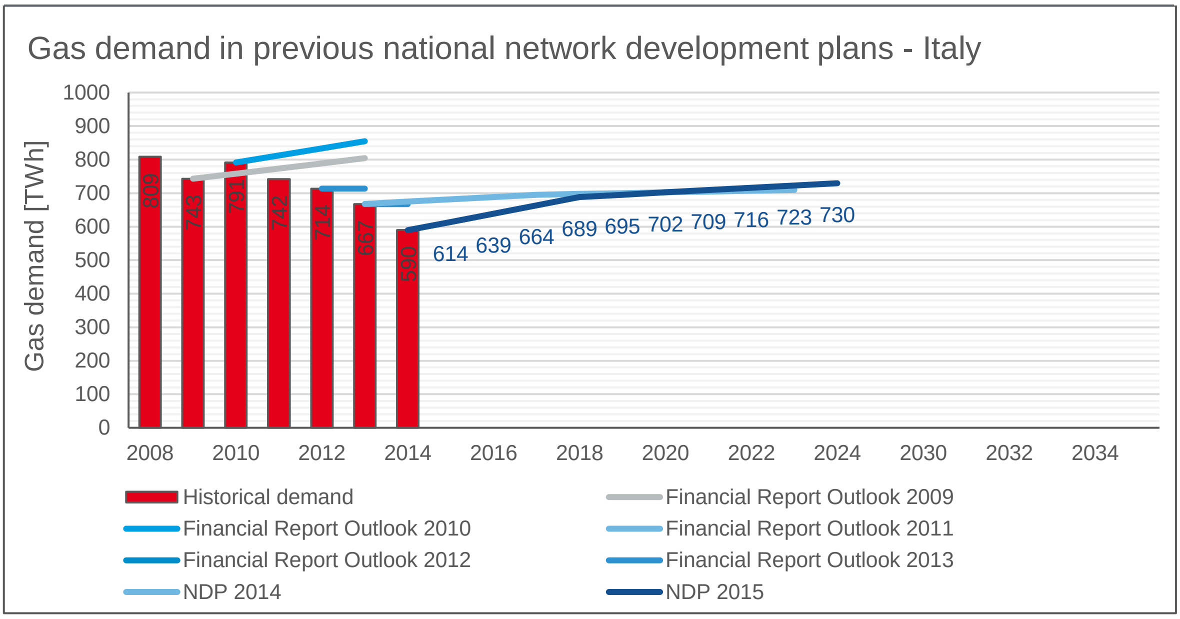
Lastly, Italy is one of the front runners for the use of gas in transport with a share of 75 % of all natural gas vehicles in Europe [OIES 2014]. However, incentives for conversion have been scaled back since 2010. Furthermore, there are increasing efforts to support the electrification of the transport sector as an alternative technology to fuel based transport. Should electric transport become a viable technology, the increase in gas-based transport would not be justified in this range.

For what concerns the assumptions underlying the gas scenario made by SNAM, we can conclude that for one, there is little transparency about the actual figures used in the econometric models (GDP growth, demographics, rate of energy efficiency, etc.). For another, all textual rationales are possibly not in line with SEN. Finally, a range of assumptions and impacts on gas demand could be made available in order to account for the range of future uncertainty.

Empirical evaluation of previous scenarios. SNAM had continuously forecast an increasing or stable gas demand in the years from 2010 to 2015 [SNAM 2010, 2011, 2014, 2015], when actual decreases have taken place. This undermines the validity of the current gas demand scenario.

Furthermore, other studies such as the European Commission also project a change of total gas demand in Italy from 2015-2025 of -9 % and of gas demand from the power sector alone of -21 % [EC 2013]. SEN scenario seems to be more in line with recent developments as well as with other scenario calculations.

Figure 22: Gas consumption scenarios in the actual and previous Network Development Plans – ITALY [TWh]



Source: Eurostat, [SNAM 2015], [SNAM 2014], [SNAM 2013], [SNAM 2012], [SNAM 2011], [SNAM 2010], [SNAM 2009]

Scenarios and climate protection targets. SNAM scenario does not make allusion to the national climate policy targets. Alignment with the energy efficiency targets should have a stronger impact on energy saving than what is seen in the NDP, especially since natural gas is so widely used in space heating. SEN scenario states to be in line with – and even exceeding – national targets concerning the share of renewables in electricity production and CO_2-emissions reduction. The national targets forecast a share of 26 % of final electricity demand produced by renewables and 17 % of final heat demand by 2020. SEN projection estimates the share of renewables in power and heat generation to be at least 35 % and 20 % respectively. The divergence between SNAM scenario and SEN scenario is not commented in the SNAM NDP 2015.

Impact of scenarios on gas infrastructure. SEN and SNAM both recognise the role of Italy as an important transit country for imports from Tunisia and Algeria to Austria, Switzerland and possibly Slovenia. In order to allow for greater security of supply for the region, cross-border connection points will be enlarged in the future. As a result, SNAM has included two main projects with final investment decision up to 2024: Support to the North-Western market and bidirectional cross-border flows, as well as the increase of gas production in Sicily. All investment measures up to 2024 with a final investment decision amount up to € 1.2 billion Investment measures by Società Gasdotti Italia amount to € 0.7 billion ITG does not have any infrastructure projects with a final investment decision.

Conclusions

- **Process.** The Process foresees checks and balances by the AEEGSI, the MISE and general stakeholders. However, none of the decisions or opinions are publicly available, which causes doubt about their effectiveness.
- **Historical context scenario.** Gas consumption peaked in 2005 and is since then declining. The economic crisis in Italy arguably coincides with lowering gas demand and is likely to have an effect. However, a return to pre-crisis levels in gas demand is not necessarily justified, there have been in the meantime substantial efforts to lower the energy and hence gas demand.
- **Modelling assumptions.** Modelling assumptions are only sparsely provided. No ranges are provided, leading to only one scenario. Modelling assumptions could not be in line with the National Energy Strategy provided by MISE and/or unrealistic.
- **Empirical validation past scenarios.** Previous forecasts were mostly too optimistic about the future gas demand, giving the current gas scenario less validity.
- **Scenarios and climate protection.** There is no reference as to whether the econometric forecast models are specified as to meet the climate protection targets in Italy. Efficiency targets should result in reduced gas demand, especially after 2020 where SNAM predicts a gas demand higher than SEN projections.
- **Scenarios and gas infrastructure.** Gas infrastructure projects mainly aim at making of Italy a “Mediterranean Hub” for gas imports from outside of the EU. However, the plan does not take into account the future developments of potential customer regions.

2.3.5 The Netherlands

The Netherlands are among the few European gas producers. The usage for heating and electricity production is high, and the country furthermore supplies the neighbouring countries (Belgium, France, Germany) with low caloric gas, making these regions very dependent on the Dutch export of this specific type of gas. The Dutch transmission system is operated by one TSO, Gasunie Transport Services B.V. (GTS), and eight DSO that distribute natural gas to consumers [CEER 2012].

GTS has published its first Network Development Plan entitled “Netwerkontwikkelingsplan 2015” (NOP) in 2015. Forthcoming changes in national law will make it mandatory for GTS to publish a NDP on a ten year period from 2018 onwards every two years. The current plan published by GTS considers investment necessities over the 2015-2025 period, whilst incorporating a market outlook until 2035. Investment needs for the 2015-2025 period principally arise due to the diminishing domestic production facing stable capacity demand [NOP 2015].

Table 25: Profile of the Dutch Network Development Plan

Rhythm:	Biennially
First NDP Gas:	2015
Number of TSOs:	1 (Gasunie Transport Services)
Current status:	Final NDP Gas 2015

Number of scenarios:	2 (2015)
Number of modelling variants:	---
Considered period:	10-year investments, 20 years outlook
Number of measures:	5 (excl. various medium- & low-scale investments)
Investment volume:	~ 490 m €
Focus:	Respond to diminishing domestic production, Expand quality conversion facilities, Expand transborder capacities

Source: [NOP 2015]

Process analysis

According to GTS the development of the NOP 2015 has been guided by among other things:

- widely reported future trajectories for gas demand made by public bodies such as the IEA and the European Commission,
- public planning documents prepared by the neighbouring country network operators or authorities,
- the Union-wide TYNDP
- the regional work for the GRIP North West
- Bilateral meetings between the GTS and Dutch NRA, shippers, neighbour country TSOs and the Ministry of Economic Affairs.

During the development of the NOP 2015 a public consultation was held. The consultation began with the publishing of a draft version on May 13, 2015 and was closed on 10 June 2015. Moreover, a consultation open to all interested parties was held in Amsterdam on 28 May 2015. GTS received twelve responses during the consultation period from shippers, stakeholder associations, storage operators and the neighbouring network operators from the Netherlands, France, Germany and the UK. All non-confidential responses were provided on the website of GTS[86]. The NOP explicitly highlights where the comments of stakeholders have been taken into account [NOP 2015].

Following this public consultation a 12 week validation phase took place during which the NRA made a procedural, financial and necessity check and the Ministry of Economic Affairs checked the consistency of the draft plan with broader energy market developments.

Following this review and adjustments taking into account the public consultation the final NOP was published on 16 July 2015.

The NOP 2015 is available in English.

Scenario analysis

The NOP 2015 contains three demand scenarios for natural gas over the period 2015-2035. Scenario "Green Focus" is characterized by high economic growth and rapid development of

[86] https://www.gasunietransportservices.nl/en/network-operations/maintenance-of-transmission-system/network-development-plan-nop

sustainability. Efficiency measures are well implemented and capacity in renewable energy sources developed in order to meet the European emissions and renewables targets. Scenario “Cooperative Growth” is also characterized by high economic growth, yet only slow development of sustainability. Energy demand is high but European emissions targets are not met. Scenario “Limited Progress” is characterized by low economic growth and a slow development of sustainability. Energy demand is low due to the economic recession, but renewable energy sources are not developed as planned.

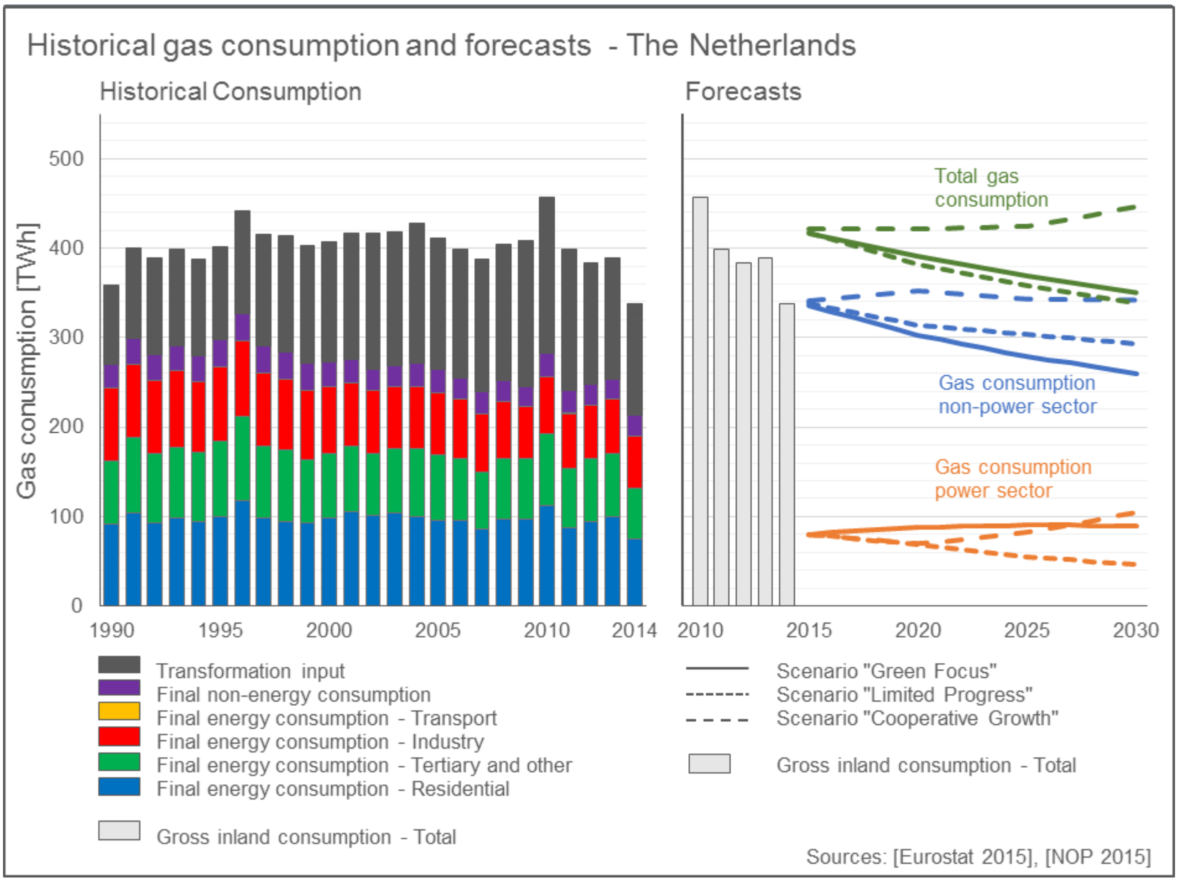
In order to better demonstrate the opposing trends, total gas demand has been split between gas demand for the power sector and the non-power sector. Gas demand of the non-power sector will fall in the long term below the current demand level in all scenarios, mainly due to advancements in energy efficiency. Gas demand in the power sector, however, is the pivotal driving force for future gas demand. In case of high economic growth and a rapid adoption of sustainability (“Green Focus”), natural gas will play a role as a back-up option for intermittent renewable energy sources in power generation. Yearly volume demand will not increase, yet gas demand will be very high in times when renewable energy sources are not available. High economic growth yet slow implementation of sustainability (“Cooperative Growth”) foresees a rapid growth of natural gas demand for power production as renewable energy sources are only little developed and power production from coal eventually becomes more expensive, changing the merit order position compared to natural gas. The only reduction of natural gas demand in the power sector is in the event of economic recession (“Limited Progress”).

NDP scenarios and gas demand since 1990. Total gas demand in 2013 amounted to 386 TWh, with a share of gas demand in final energy demand of 61 %, in the transformation sector of 33 % and in non-energy use of 6 %. With a share of electricity generation from natural gas above 50 % in 2013, the Netherlands make strong usage of natural gas to meet their national electricity demand.

Gas demand in the Netherlands has increased between 1990 and 2000 due to a stronger use of natural gas for power generation. Since 2000 it has diminished slightly due to efficiency measures in industry leading to less demand from this sector. Gas demand for final energy consumption in the household sector has remained stable over the before mentioned period, whilst gas demand in the tertiary sector has risen. The temperature adjusted gas demand is shown in annex 1 in **Figure 60**.

Overall, gas demand in the Netherlands has been more stable than in the other 6 target countries. Gas demand has been slightly reduced from 427 TWh in 2004 to 389 TWh in 2013. Newest figures for 2014 are considerably lower (337 TWh), but have to be considered with care. It has been an exceptionally warm year, thereby reducing the demand of final energy demand for space heating.

Figure 23: Historical gas consumption 1990-2014 (Eurostat) and forecast
according to the national Network Development Plan – THE NETHERLANDS [TWh]



Source: Eurostat, [NOP 2015]

Sectoral analysis and modelling assumptions. The main differences between the scenarios are GDP, investment levels in green technologies, energy efficiency measures, renewable power production, technology substitution and European gasification rates (as summarised in Table 26). No exact numbers for the econometric modelling are given, only rationales.

Table 26: Demographic, economic and price assumptions

Parameters	Scenarios Green Focus	Cooperative Growth	Limited Progress
Demography	-	-	-
GDP	high growth	high growth	low growth
Evolution perspectives/ economic activity	large investments in sustainable technologies	little investment in sustainable technologies	focus on sustainability, but few resources
Energy efficiency/ intensity	rapid adoption of efficient technologies	no adoption of efficient technologies	no adoption of efficient technologies
Renewables	EU emission targets will be met	EU emission targets will not be met	EU emission targets will not be met
Substitutions	insulation of homes, adoption of condensing boilers, micro-CHP and hybrid heat pumps	-	-
Gasification level/ penetration rates	nort-west European gas demand decreases	nort-west European gas demand increases	nort-west European gas demand stable
Prices	-	-	-
Other	-	-	-

Source: [NOP 2015]

Gas demand in the power sector is then again looked at more carefully. It further includes a rationale over a CO_2 price and the evolution of the electricity generation overall (as summarised in Table 27).

Table 27: Assumptions in the power sector

Parameters	Scenarios Green Focus	Cooperative Growth	Limited Progress
Evolution of electricity generation	High	High	Low
Expected role played by gas	Back-up for renewables	More gas demand coal becomes expensive	Remains more expensive then coal
Renewables	High	Low	Low
Substitutions	Heating appliances are partly electrified	-	-
Prices	CO2 High	CO2 Medium	CO2 Low
Other			

Source: [NOP 2015]

Ultimately, GTS uses the “Cooperative Growth” scenario for the capacity balance. The differences between the “Cooperative Growth” and “Green Focus” scenarios are the speed of implementation of energy efficiency and renewable energy policies. For what concerns electricity production from renewable energy sources, the Netherlands are well on track to meet their national targets [NEA 2014]. Investments in energy efficiency have seen difficulties after 2008, which make the argumentation for the “Cooperative Growth” scenario plausible [ECN 2014].

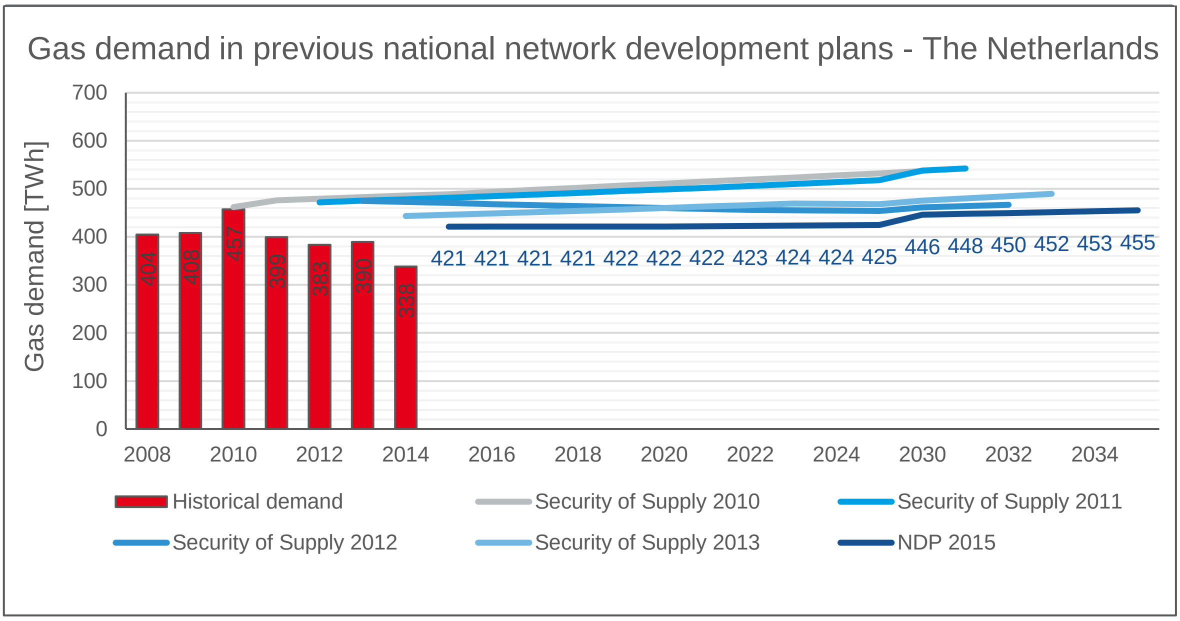
Gas demand in the residential sector has been stable since 2005, despite of the implementation of energy efficiency measures. Only gas demand in industry has fallen by about 10 TWh in the 2005 – 2014 period.

Two stakeholders commented that the gas demand in the "Cooperative Growth" scenario may be too high, and warned the TSO over overinvesting due to the forecasts being too optimistic [GASTERRA 2015, ENGIE 2015]. They did not specify their doubt on a particular assumption.

Empirical evaluation of previous scenarios. The NDP 2015 is the first scenario analysis that GTS undertakes. Previous demand forecasts were published without a range of demand scenarios in a publication entitled "Security of Supply".

Figure 16 shows the projections of gas demand for the security of supply studies since 2010 and the "Cooperative Growth" scenario of the NDP 2015. It is unknown whether figures in the projections are stated as gross or net caloric value (Eurostat figures are net caloric value). But even assuming they would be in gross caloric value and converting them to net caloric value, the projections would historically lie slightly above the actual gas demand.

Figure 24: Gas consumption scenarios in the actual and previous Network Development Plans – THE NETHERLANDS [TWh]



Source: Eurostat, [GTS 2015], [GTS 2013], [GTS 2012], [GTS 2011], [GTS 2010]

Demand forecast and climate policy targets. The demand forecasts presented by GTS contain one scenario that is in line with European climate policy targets (scenario „Green Focus"). Due to the absence of quantitative data, it is difficult to assess whether the modelling is realistic in meeting the climate policy targets. However, it is mentioned that the "Green Focus" scenario accounts for a cumulative installed wind capacity for power generation of 12 GW and a cumulative installed solar capacity for power and heat generation of 8 GW[87]. The Dutch NREAP 2010 foresees a share of renewable energy sources in power generation of 14 % in 2020, the national target lies at 16 % by 2023 [NEA 2014]. The cumulative installed capacity in wind power generation in order to attain this target amounts to 11.2 GW. The cumulative installed solar capacity only amounts up to 0.7 GW [NREAP 2009]. Implementation reports see the cumulative installed wind capacity for 2014 at 3.4 GW and the cumulative installed solar capacity for 2014 at 0.6 GW [NEA 2014].

Impact of scenarios on gas infrastructure. The first Network Development Plan by GTS contains three gas demand scenarios out of which two show a decrease in gas demand. However, the capacity balance is evaluated against the range of gas demand presented in the three scenarios, out of which the "Cooperative Growth" scenario is modelled in a way that "agreed targets for greenhouse gases (GHG) will either not be met or will be revised downward" [NOP 2015, p. 15]. The capacity balance shows that even when compared to the high gas demand scenario, the grid managed by GTS has enough capacity to meet demand until 2030.

It is further clarified that "neither the volume of demand nor the need to enhance demand capacity is identified in this NOP as a primary driver of new investment needs" [NOP 2015, p. 46]. This is somewhat contradictory to the proposed investment necessities.

There are two main results of the Network Development Plan: for one, the NOP 2015 foresees a change in supply sources over the next ten years for North-Western Europe due to the decrease of supply from both the 'Groeningen field' and Norway. As domestic supply decreases, it needs to be substituted with either LNG imports or Russian natural gas. While the interior infrastructure is deemed capable of handling capacity demand in the next years, the entry capacity to the system is not and needs further enhancing. GTS is proposing two investment measures: one at the GATE LNG terminal and one at the Dutch-German interconnector Oude Staatenzijl.

The second result is the need to supply the German, Belgian and French markets with low CV gas, as there is a historical dependency. In order to meet the demand in low CV gas, GTS is planning a further quality conversion plant in order to convert high CV gas to low CV gas.

However, doubt about the benefits of an extension of the GATE Terminal and the H-Gas/L-Gas conversion are mentioned in the stakeholder process [OGE 2015; Gasterra 2015; VGN 2015].

Conclusions

- **Process.** The process foresees checks and balances and information such as comments on the NDP by stakeholders are provided. The technical information on the scenario calculations is sparse.
- **Historical context scenario.** Gas consumption in the Netherlands is more stable than in the other target countries. The peak was in 2004 with around 427 TWh, and has declined to 389 TWh in 2013. Reductions have mainly been achieved in the transformation sector and final energy demand from industry.
- **Modelling assumptions.** Modelling assumptions between the high gas scenario and the low gas scenario mainly differ for what concerns the speed of implementation of renewable energy and energy efficiency policies. Looking at evaluation reports it can be said that

[87] The figure is likely to be erroneous.

renewable energy targets are likely to be met, whereas energy efficiency measures have been implemented somewhat slower after the financial crisis of 2008.

- **Empirical validation past scenarios.** The NDP 2015 provides the first scenario analysis for the Netherlands. Previous projections have however been slightly exceeding realised demand figures.
- **Scenarios and climate protection.** Climate protection targets set out by the Netherlands are only met in the "Green Focus" scenario. In the "Cooperative Growth" scenario that is used to determine the possible maximum capacity needs, climate targets are not met on time.
- **Scenarios and gas infrastructure.** The needs for investment in gas infrastructure do not arise from an increasing demand. They are rather of technical nature and import substitutions. However, there was considerable doubt mentioned in the stakeholder process as to whether the measures were cost-efficient and/or necessary.

2.3.6 Spain

Spain has a well-developed and diversified gas infrastructure. While its storage capacity (4.1 bcm in 2014) is only the 8th biggest in Europe, Spain regasification capacity for LNG is the biggest in Europe. The seven LNG terminals can receive imported liquefied gas (from 11 different countries in 2014) and regasify up to 60 bcm per year of gas (635 TWh). The Spanish system is interconnected with France (via two pipelines), Portugal (via two pipelines), Algeria (via the Medgaz pipeline) and with Morocco (via the Maghreb pipeline). However, its interconnection capacities with Europe, and in particular France are relatively restricted (7.1 bcm or 75 TWh in 2015). About half of imported gas comes as LNG and the other half in pipelines.

According to the IEA, the development of additional cross-border connections will enable Spain to use its large LNG capacity to increase flexibility, diversity and security of supply in the European Union internal market. By re-exporting gas to Asia thanks to its tanks and regasification infrastructure, Spain could even become a kind of "hub" or a trade center for gas in Europe.

The Spanish Network Development Plan is published by the Energy Secretary of State (SEE), from the Ministry of Industry, Tourism and Trade (MINETUR) with the participation of the autonomous regions, the Spanish TSO Enagás and gas users. The NDP is not an NDP for the gas system alone, but rather includes both the electricity and gas sectors.

The last binding plan was released in May 2008 and relates to the period 2008 to 2016. In July 2011, MINETUR published a draft plan for the period 2012-2020 which is the object of the present study, even though the plan is not liable for the cited period. The 2008 and 2011 plans deal not only with gas demand, but also with the development of energy consumption overall. The following Table 28 shows some historical and topical key facts of the Spanish plan.

Table 28: Profile Spanish Network Development Plan

Rhythm:	Unregular
First NDP Gas:	N.A.

Number of TSOs:	1
Current status:	Draft
Number of scenarios:	3
Considered period:	8 years, NDP 2012-2020
Liability of the NDP Gas	No liability
Investment volume:	7.065.bn €
Focus:	Energy consumption: past evolution and projections. Electricity sector: past evolution of demand and projections, infrastructures. Gas sector: past evolution of demand and projections, infrastructures. Strategic reserves of oil products

Source: [PSEG 2011]

Process analysis

For the 2008 NDP, the Spanish TSO Enagas helped elaborate a first draft of the NDP in collaboration with users of the gas network. This draft then underwent an environmental assessment and was consulted by the autonomous regions. Subsequently, a first draft and environmental assessment were published and made subject to a 45-day public consultation beginning 1 August 2007. The outcomes of this public consultation were taken into account in the preparation of a second draft. Finally, this second draft was submitted to the National Energy Commission, which issued a report for adoption by the Spanish government in January 2008.

In July 2011, MINETUR published a draft plan for the period 2012-2020, but the plan is not binding for the cited period. On 16 October 2015 the Spanish government approved a new energy plan for the period 2015 to 2020. However, due to a change in law, this plan now only focuses on the electricity network[88]. The ministry plans to elaborate another plan for the period 2016 to 2024, which will not be released before the end of 2016 or early 2017. This would imply that concerning cross-border infrastructure the Union-wide TYNDP and the GRIP South are the most up to date indicative planning documents for Spain.

The Spanish NDP is not available in English.

Scenario analysis and assessment

Gas demand since 1990 and NDP scenarios

Spain does not have a long tradition of gas consumption. In 1990, gas represented 6 % of gross inland consumption. Coal and oil products were the main energy source in final demand and power generation was dominated by coal, nuclear and hydroelectricity. The increase of gas consumption between 1990 and 2005 was mainly driven by industrial gas demand. This period is characterized by an increase of the activity in the construction sector and an increase of energy intensity (contrary to other neighbouring countries).

2005 was a turning point: both final energy consumption and energy intensity began to decrease. Between 2004 and 2010, energy intensity reduced by 11.3 % due to structural changes, efficiency plans and high energy prices. While final gas demand stagnates since then, gas demand for power generation experienced a sharp increase, especially following the

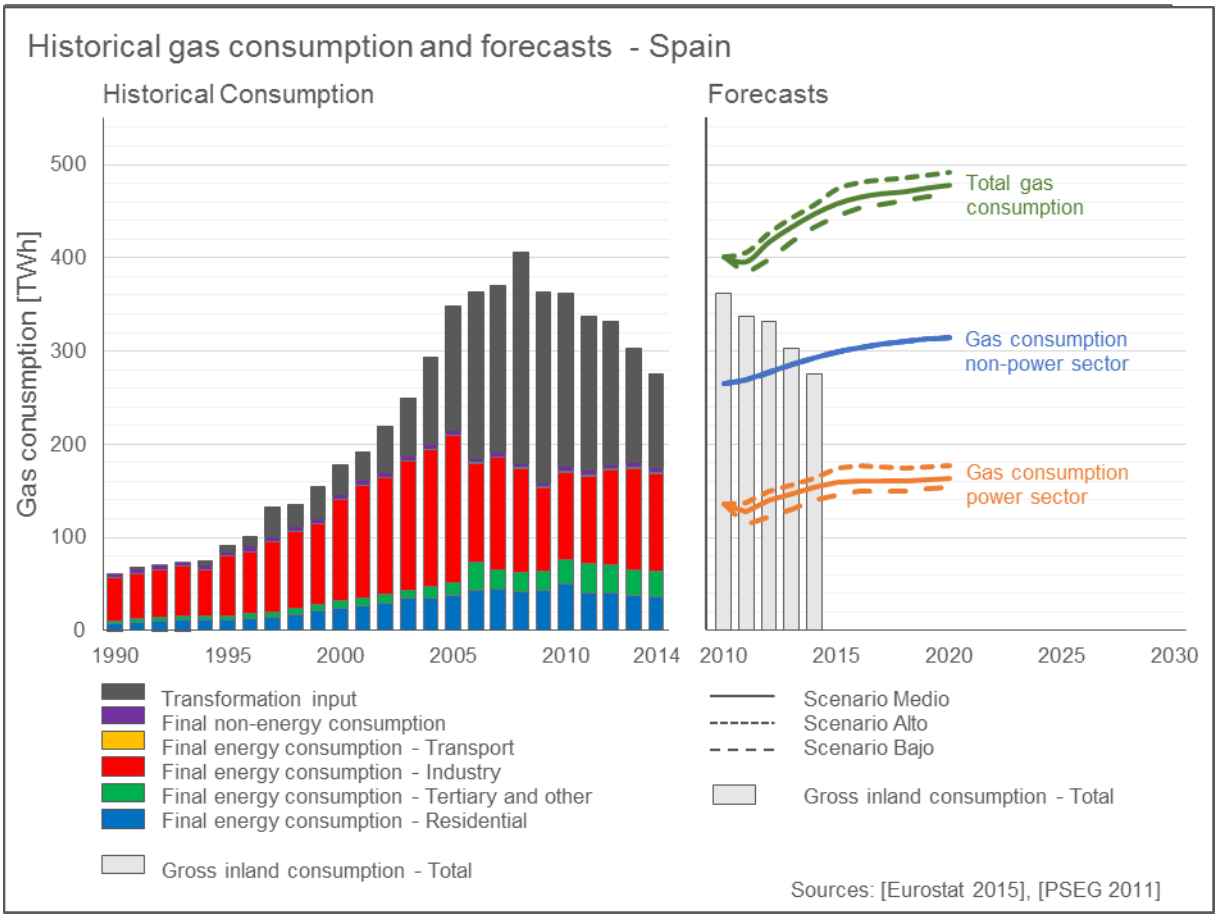
[88] http://www.minetur.gob.es/energia/planificacion/PlanificacionHidrocarburos/Paginas/planificacionHidrocarburos.aspx

introduction of CCGT around 2002. Therefore, primary gas consumption continued to increase and reached a peak in 2008. Since 2008, the use of gas decreased constantly, due to increased power generation from other energy sources, like renewable sources, particularly hydropower and wind. According to data given by Enagás in its annual report 2013, the utilisation rates of CCGTs have been on continuous decline from 52 % in 2008 to 13 % in 2013.

Today, gas represents 22 % of gross inland consumption. It is the 2nd most consumed energy source but its level is barely that from 2004. Still, gas is - together with renewables and nuclear - one of the main energy sources for power generation, despite the sharp decline in CCGTs use since 2008. Hydropower registers large variations from one year to another and impacts the use of gas fired plants. The industrial and power sectors are the largest gas consumers.

The 2011 NDP contains three scenarios for gas demand. Final gas demand remains the same in all the scenarios. Gas demand for power generation, on the other hand, varies according to the competitiveness of gas fired power plants. For this reason, three scenarios have been elaborated, which correspond to different assumptions regarding the competitiveness of gas. Figure 25 shows the development of annual gas demand in the past and in the scenarios, the temperature adjusted gas demand is shown in annex 1 in **Figure 62**.

Figure 25: Historical gas consumption 1990-2014 (Eurostat) and forecast
according to the national Network Development Plan – SPAIN [TWh]



Source: Eurostat, [PSEG 2011]

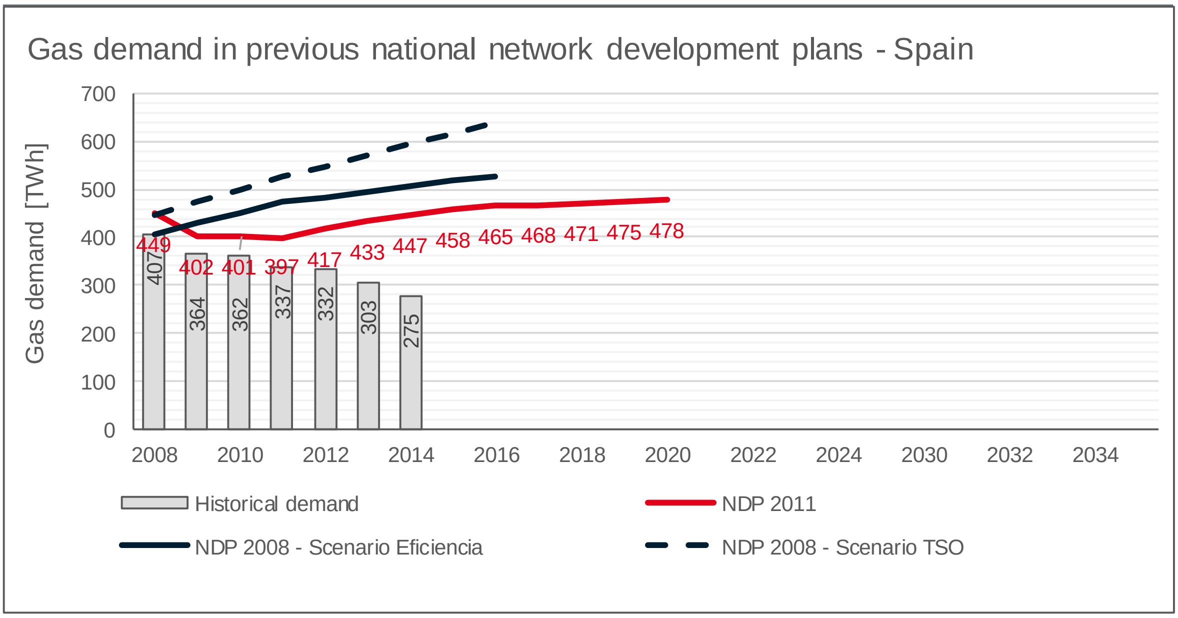
All the scenarios anticipate a slight increase in gas demand between 2010 and 2020 (19 % in scenario Medio, 23 % in scenario Alto, 17 % in scenario Bajo). In the commercial and residential sectors, gas demand is expected to increase slower, until reaching saturation (mature market). Market penetration of gas (number of clients for 100 inhabitants) would then reach 20 % by 2020. The increase of gas demand in the industrial sector should not be significant. Cogeneration is expected to continue its development due to political incentives and the market entry of highly efficient plants. New gas users would contribute to the increase of demand: urban buses, microgeneration plants, back-up for thermal solar plants.

When comparing gas demand scenarios from NDP 2011 with scenarios from NDP 2008 and historical data, it appears that:

- NDP 2011 scenarios were less optimistic than scenarios from 2008. In TSO scenario from 2008, gas demand was expected to cross the 500 TWh mark by 2010 (in the efficiency scenario by 2013), while the 2011 scenario does not expect gas demand to exceed 500 TWh before 2020. The NDP from 2011 dampened the gas consumption growth expectations from 2008.

- All these scenarios expected an increase in gas demand while historical data show a decrease of gas demand between 2008 and 2015. No scenario anticipated a decrease in gas consumption.
- In 2015, gas consumption is about half the amount expected in the TSO scenario of 2008. Given that this scenario is used to decide infrastructure investments for the period 2008-2016, it poses the question whether some investments have been made in this period for useless infrastructures.

Figure 26: Gas consumption scenarios in the actual and previous Network Development Plans – SPAIN [TWh]



Source: Eurostat, [PSEG 2008], [PSEG 2011]

Sectoral analysis of scenarios and modelling assumptions

The sectoral analysis of gas scenarios and historical data enables to understand what the main assumptions were that lead to an overestimation of gas demand.

- A decrease in industrial gas demand was not foreseen. 2000 to 2008, industrial gas demand was rising already very slowly (0.3 % yearly). In NDP 2011, it was nonetheless expected that this demand would recover and increase on average by 1.4 % yearly between 2011 and 2020. Since the start of the economic crisis, industrial gas demand has on the contrary continued to slow down and has even decreased (on average by 0.8 % yearly between 2008 and 2013).
- Neither was the fierce competition for power generation with coal and renewables expected. This not only stopped the installation of new gas fired power plants, but also reduced the rate of utilisation of existing gas fired power plants.

- Industry and power generation are the two main gas consumers in Spain. Their evolution influences greatly the gross domestic gas consumption. Their consumption actually reduced between 2008 and 2013, leading to a reduction of the country's global gas consumption in this period, contrary to what was expected in the scenario from 2011.

Table 29: Growth rates of sectoral gas consumption
in the actual and previous Network Development Plan as well as historical growth rates in Spain

	NDP 2011	NDP 2008	Historical	
	2011-2020	**2008-2016**	**2000-2008**	**2008-2013**
Residential and commercial	2,9%	N.A.	8,6%	1,2%
Industrial	1,4%	N.A.	0,3%	-0,8%
Final demand	1,8%	4,5%	4,3%	0,0%
Power generation	2,8%	4,8%	28,1%	-11,5%
Total gas consumption	**2,1%**	**4,6%**	**10,9%**	**-5,7%**

Source: Eurostat, [PSEG 2008], [PSEG 2011]

The evolution of industrial production as well as gas prices relative to other energy sources are two determining factors that have to be analysed to assess future gas consumption. The following paragraphs deal with the assumptions that have been used in the NDP 2011.

To calculate the projected final gas demand in NDP 2011, a number of assumptions have been made, among others an increase of population of 3 % and of GDP of 25 % between 2010 and 2020. The following table shows some of these assumptions, which are the same for all of the scenarios.

Table 30: Demographic, economic and price assumptions

Reference scenario	2010	2015	2020	Change 2010-2020
Population [m.]	47	48	48	3%
Dwellings [m.]	-	-	-	-
Living space [m. m²]	-	-	-	-
Gas heated living space [%]	-	-	-	-
Heat pumps [%]	-	-	-	-
GDP [bn. €2000]	773	863	969	25%
Employees [m.]	-	-	-	-
Gas-powered cars [1.000]	-	-	-	-
Gas price [€2010/MWh]	-	-	23	-
Oil price [$2008/barrel]	-	-	110	-
Carbon price [€2010/t]	-	-	25	-
Renovation rate [%]	-	-	-	-
Gas demand households / population	-	-	-	-
Gas demand tertiary / employees	-	-	-	-
Gas demand industry / GVA industry	-	-	-	-

Legend: - not available

Source: [PSEG 2011]

Additionally to these assumptions, other factors have been taken into account to build the gas demand models. Of particular importance is energy intensity, which can be split into two components: one part of energy intensity development is driven by structural changes (i.e. share of energy intensive industries, share of services in the economy) and another part is driven by efficiency improvements (intrasectoral intensity). The additional assumptions are summarised in the following table.

Table 31: Additional assumptions for final demand modelling

Parameters	Final demand
Economic activity	Industry: > index of industrial specialisation > net revenues in the industry
Energy efficiency/ intensity	> Final energy intensity (tep/m € 2000): 129.2 (2010), 117.4 (2015), 105.5 (2020) > Change in structural intensity: -0.8 % yearly between 2010 and 2020 > Change in intrasectoral intensity: -1.3 % yearly between 2010 and 2020
Gasification level/ penetration rates	20 % by 2020

Source: [PSEG 2011]

To calculate the gas demand for power generation, one of the scenarios for power demand, developed in the second part of the plan, has been used. This scenario, called „Diseño“, relates to a peak power demand and estimates an averaged 2.3 % annual increase in power demand. Table 32 shows the results of the power demand scenario in terms of installed capacities.

Table 32: Development of installed power generation capacities in GW

Reference scenario [GW]	2010	2012	2014	2016	2020	Change 2010-2020
Coal	11	9	8	8	7	-34%
Gas (CCGT)	25	25	25	25	25	0%
Nuclear	8	8	7	7	7	-6%
Cogeneration	7	8	9	9	10	49%
Other conventional	3	0	0	0	0	-84%
Renewables	44	49	54	59	71	61%
Total	**98**	**99**	**104**	**109**	**122**	**24%**

Source: [PSEG 2011]

This power demand will be covered in priority by renewable energy sources, especially wind and hydropower. Mean production from hydropower is expected to reach 26 TWh with variations of -11 to +10 TWh according to meteorological conditions. The rest of the power demand, which is not covered by renewable sources, is called “thermal gap“, and will have to be met by either coal or gas fired power plants. The relative power generation costs in gas fired power plants (CCGT) compared to coal plants are the determining factor on which the scenarios are based. When costs are higher for coal fired plants, power will be generated in priority by gas plants (scenario Alto) and gas demand for power generation in this scenario will be higher. The following table sums up the para meters used to model gas demand scenarios for power generation.

Table 33: Assumptions for gas demand in the power sector

Parameters	Scenario Medio	Scenario Bajo	Scenario Alto
Evolution of electricity generation	Scenario of peak power demand: +2.3 % per year between 2011 and 2020		
Expected role played by gas	> Meet the demand which is not covered by renewables > In competition with coal power plants		
Generation costs in coal thermal plants and CCGT	Costs in CCGT equal to costs in coal plants	Costs in CCGT superior to costs in coal plants	Costs in CCGT lower than costs in coal plants

Source: [PSEG 2011]

Consideration of environmental targets

The Spanish NDP is not restricted to gas demand analysis and gas infrastructure planning. It encompasses the energy sector entirely and deals with the development of primary and final energy consumption as well as with electricity and gas demand and oil product reserves. Therefore, it offers a consistent view on the different components of the energy system and how they interact. That enables to assess how climate and energy policy goals are taken into account and if they are eventually reached. The Spanish plan offers explicitly an analysis of the compliance of the plan with EU and national targets. The draft plan as it is written complies with all of those targets (see Table 34).

Table 34: Compliance with energy and climate targets

	Political targets (EU and national)			Reached targets
	2005	2020	Change 2005-2020	
non-EU ETS CO_2 emissions (mt)	170	146	-14%	✓
Share of renewables in final energy demand		20%		✓
Share of renewables in transport demand		10%		✓
Share of primary consumption covered by domestic production		Increase		✓
Share of fossil fuels in primary supply		Reduction		✓
CO_2 emissions from power generation		Reduction		✓

Source: [PSEG 2011]

Impact of scenarios on gas infrastructure

To assess whether the present gas infrastructure is adequate for the gas demand and in what way infrastructures have to be adapted, peak gas demand is determined. This peak demand corresponds to the highest gas demand (usually in winter and during a dry hydraulic year) and is composed of demand from:

- Residential and commercial sectors: peak demand is calculated with respect to the number of clients (which is itself a function of population increase and gasification level) and their sensibility to temperature variations,
- Industry: its demand is calculated for a working winter day,
- Power generation: part of the power demand will be met by renewables and nuclear, and the rest by coal plants and CCGT. One of the conditions in the power sector is that the index of electricity coverage (1.1) must be reached.

Gas infrastructure that needs to be developed under this scenario ("CENTRAL") belongs to the category A. Apart from this central scenario, another scenario called "SUPERIOR" is considered to analyse the implications for the gas system of a situation where additional firm capacities are needed to cover a peak power demand. These additional firm capacities are supposed to be gas fired power plants. In this scenario, final demand is the same as in the central scenario but peak gas demand for power generation is higher. Installed gas capacities for power generation increase by 4,500 MW until 2020. Additional gas infrastructure identified in this scenario is incorporated in category B.

In both scenarios, there is no need to invest in additional gas capacities until 2017. In scenario "CENTRAL" 1,800 MW have to be developed until 2020 compared to 4,500 MW in scenario "SUPERIOR". The proposed infrastructures of the category A in the scenario "CENTRAL" include:

- 450,000 m^3 LNG tanker,
- 1 million m^3 regasification capacity,
- 1,635 km of gas pipeline,
- 73.5 MW compressor capacity,
- 3,822 million m^3 underground storage capacity.

Investments for category A infrastructures amount to € 5.122 billion for the period 2012-2020. Category B infrastructures require an additional € 1.9 billion for the same period.

Gas fired power capacities are expected to remain more or less stable until 2020. Only some adaptations would be needed in 2018. However, there is still great uncertainty in Spain concerning the future of nuclear power plants. In 1983 the government enacted a moratorium and Spain stopped the building of new nuclear power plants in 1984. 6 out of 7 nuclear plants will reach their end of life in the 2020's, the 7th and last nuclear plant is expected to be phased out in 2034. Together, Spanish nuclear plants represent 7.4 GW of installed capacity. If the Spanish government maintains the moratorium, new power generation capacities will be needed to compensate the nuclear phase out. CCGT could be among the possible options.

Conclusions

- **Process.** The 8-year time span between NDPs makes it difficult to adjust scenarios to gas demand changes. The next plan is supposed to be released in 2016 or early 2017.
- **Gas demand since 1990**. Gas demand increased sharply from 100 TWh in 1996 to 400 TWh in 2008. Since 2008, it constantly decreased until 300 TWh in 2013. While final gas demand stagnates since 2006, gas demand for power generation experienced a sharp increase, especially following the introduction of CCGT around 2002. The industrial and power sectors are the largest gas consumers today.
- **NDP scenarios.** The NDP from 2011 dampened the gas consumption growth expectations from 2008. Still, all the scenarios expect an increase in gas demand while in reality, gas demand decreased between 2008 and 2015. Especially the scenario from 2008, which is actually used to decide infrastructure investments for the period 2008-2016, strongly diverges from actual gas demand evolution.
- **Sectoral analysis of scenarios and modelling assumptions.** A decrease in industrial gas demand was not foreseen. In NDP 2011, it was expected that this demand would recover. Neither was the fierce competition for power generation with coal and renewables expected. This not only stopped the installation of new gas fired power plants, but also reduced the rate of utilisation of existing gas fired power plants. Gas consumption of the two main consumers in Spain reduced between 2008 and 2013, leading to a reduction of the country's global gas consumption in this period, contrary to what was expected in the scenarios from 2008 and 2011.

- **Scenarios and climate protection.** Scenarios are specifically built to reach national and EU targets.
- **Impact of scenarios on gas infrastructure.** The proposed infrastructures of the category A include: LNG tanker, regasification capacity, 1,635 km of gas pipeline, 73.5 MW compressor capacity and underground storage capacity. Gas fired power capacities are expected to remain more or less stable until 2020. Only some adaptations would be needed in 2018. However, there is still great uncertainty in Spain concerning the future of nuclear power plants.

2.3.7 United Kingdom

The UK NDP is entitled “Gas Ten Year Statement” (GTYS). The GTYS is published annually at the end of the year by “National Grid”, the largest TSO for gas and electricity transmission in the UK. Gas has a 33 % share of gross inland consumption in the UK, making it an important energy source. One of the reasons for this high gas consumption is that the country is a significant gas producer and the gas transmission system is already well established. However, indigenous gas production is declining, dropping from 97,554 ktoe in the year 2000 to 51,468 ktoe in 2010. Projections estimate a production of about 19,580 ktoe in the year 2030 [DG ENER 2013, reference scenario].

The GTYS 2015 deals with customer requirements, especially concerning capability requirements, supply and demand patterns assessed on the basis of future energy scenarios, legislative changes (ex. the implementation of the Industrial Emission Directive (IED)) and asset health in an aging network.

Table 35: Profile United Kingdom Network Development Plan Gas

Rhythm:	Yearly
First NDP Gas:	2000
Number of TSOs:	4 (National Grid is the largest TSO)
Current status:	Final GTYS 2015
Number of scenarios:	4
Number of modelling variants:	1 primary modelling variant + 3 simple calculations
Considered period:	20 years, NDP 2015-2025
Investment volume:	---
Focus:	Customer requirements, Supply and demand patterns, Legislative change (Industrial Emission Directive), Asset health

Source: [National Grid 2014a]

Process Analysis

The GTYS process was established in 2000 and GTYS versions dating back to the year 2011 are available online. The GTYS focuses on the development of the gas network and future challenges. There are no explicit measures resulting from the GTYS assessment and investment volume is not stated. However, projects under construction and under review are shown. National Grid publishes a separate list with planned total expenditure until 2021 and a view of the activities they plan to carry out in the future, but these documents are not part of the GTYS.

Infrastructure planning in the GTYS is carried out on the basis of "Future Energy Scenarios" (FES), which are published by National Grid every year and assess supply and demand across the entire energy sector, as opposed to just gas. The development of the FES involves an extensive stakeholder engagement process. Stakeholder consultation takes place in an annual cycle and consists of a series of workshops, bilateral meetings, questionnaires and an annual conference[89]. The stakeholder engagement process also has a dedicated website and the results of the consultation are published annually in January in a stakeholder feedback document[90]. The information gathered in the consultation is then used to inform the development of the FES scenarios, which are published every July. Since 2015, the proposed scenarios must be submitted to the UK NRA Ofgem by the end of January each year. The stakeholder feedback document is used for this purpose. Feedback from stakeholders in the last year requested inter alia more detail on the assumptions and the modelling behind the FES.

The development of the GTYS also includes an annual cycle of engagement, which mainly consists of an online questionnaire and an email address for feedback on the GTYS[91]. Instead of acting as a time limited public consultation, stakeholders are encouraged to submit their feedback on most recent GTYS anytime in the year. No stakeholder feedback document with statistics has been provided. Therefore, the makeup of the stakeholders providing input using these feedback instruments is not clear. Additional stakeholder engagement related to the GTYS occurs in the context of bilateral meetings and workshops, as well as a dedicated stakeholder engagement website[92]. For example, stakeholder engagement related to the Industrial Emissions Directive and System Flexibility are highlighted in the GTYS 2015. However, according to National Grid[93], these forms of stakeholder involvement largely use existing forums and channels and, therefore, cannot necessarily be seen as stakeholder engagement specifically related to the GTYS.

Scenario analysis and assessment

These following four scenarios from the FES are used to assess the future gas demand:

- **"Slow Progression"** reflects a world with low affordability and high sustainability: the economic recovery is slower. There is a strong focus on policy, regulation and new targets but targets are delayed.
- **"Gone Green"** reflects a world with high affordability and high sustainability: money is available for investments and domestic consumption. A strong policy framework and new environmental enable the country to meet environmental and climate targets on time.

[89] http://www2.nationalgrid.com/uk/industry-information/future-of-energy/fes/Engagement/
[90] http://fes.nationalgrid.com/
[91] https://www.surveymonkey.com/r/GTYS2015
[92] http://www.talkingnetworkstx.com/
[93] https://www.ofgem.gov.uk/sites/default/files/docs/2014/12/ngg_part_2_-_final_for_submission.pdf

- **"No Progression"** reflects a world with low affordability and low sustainability: the economic recovery is slow and no new environmental targets are implemented. Focus is on traditional sources of gas and electricity at the lowest costs.
- **"Consumer Power"** reflects a world with high affordability and low sustainability: the society has more money available. Policies are focused on the decarbonisation in the long run, but no additional targets are implemented. Innovation focuses on improving consumer's quality of life.

Gas demand since 1990 and NDP scenarios.

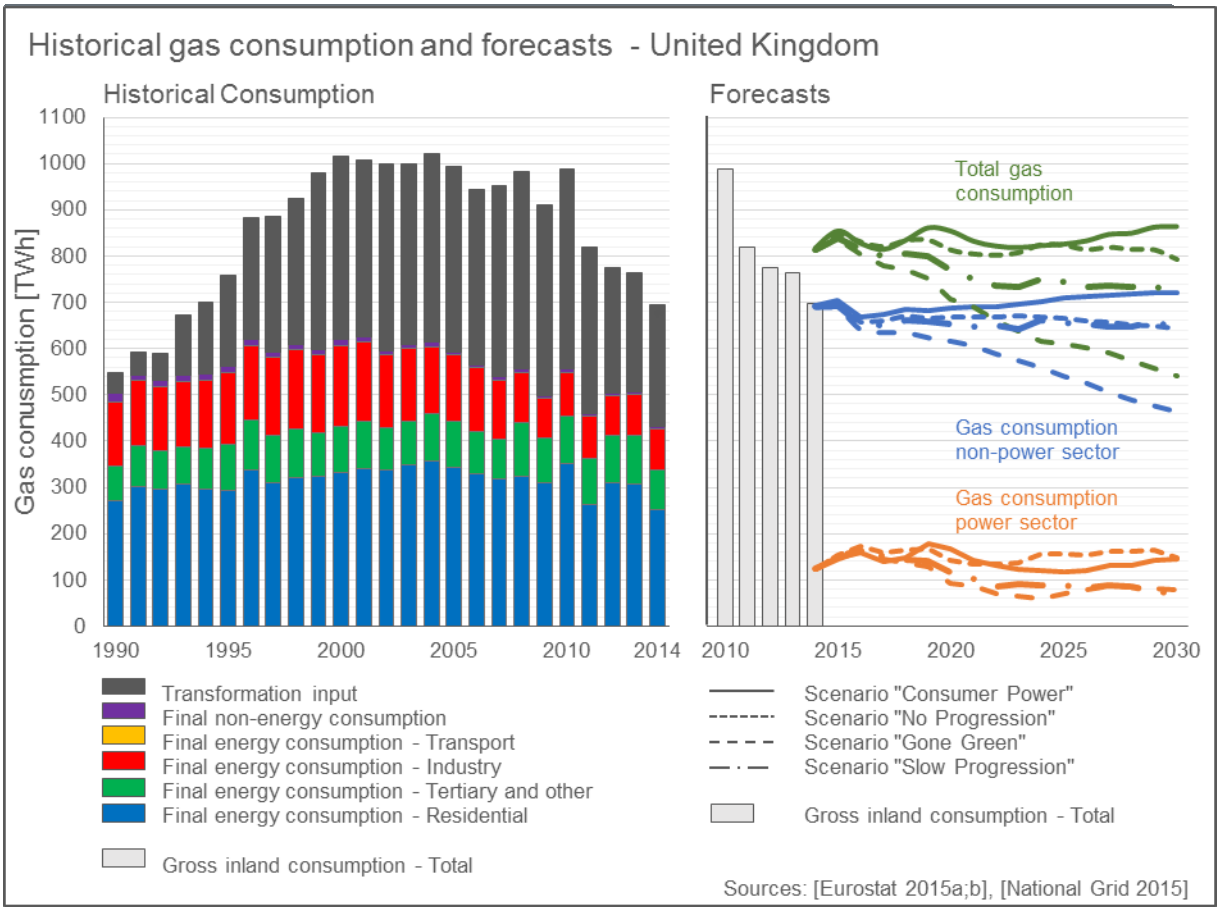
Figure 27 (left side) shows gas consumption in the United Kingdom from 1990 to 2014. In total, 764 TWh of gas were consumed in 2013 and 697 TWh in 2014[94]. From 1990 to 2000 total gas consumption continuously grew and nearly doubled. This strong rise in gas consumption was especially due to increased demand in the transformation sector. From 2000 to 2010 total gas consumption stayed quite stable around 1,100 TWh with a significant drop during the economic crisis in 2009. Since 2011 gas demand has dropped strongly. The biggest reason for this decline is decreasing gas consumption in the transformation sector due to low coal and CO_2 emission prices. Gas consumption in the transformation sector is more volatile than in other sectors as it is directly linked to gas, power, coal and carbon prices.

Gas in the residential sector is primarily consumed for heating purposes. It increased from 1990 to 2000 and stayed nearly stable afterwards. The high consumption in 2010 could be due to the particularly cold winter that year (see also temperature adjusted gas demand in annex 1 in **Figure 63**). The residential sector has the highest share in the final gas demand (about 60 %).

In the industry sector, gas consumption follows the same trend as the transformation sector as a whole, increasing from 1990 to 2000 and decreasing afterwards. Besides changing energy prices, structural changes and stronger energy efficiency are reasons for the shrinking industrial gas demand. After a rising gas demand from 1990 to 1995, gas demand in the tertiary sector has remained stable.

[94] Preliminary number from Eurostat, only natural gas, no sectoral breakdown available yet.

Figure 27: Historical gas consumption 1990-2014 (Eurostat) and forecast
according national Network Development Plan - United Kingdom [TWh]



Source: Eurostat, [National Grid 2015a]

Figure 27 also shows the forecast for gas consumption according to four scenarios used in the GTYS (right side). The gap between the numbers from Eurostat (left) and National Grid can partly be explained by gas exports to Ireland which are included in National Grid´s scenarios. Total gas demand increases from 2015 to 2030 in the “Consumer Power” scenario and remains nearly stable in the “No Progression” scenario. In “Slow Progression” total gas demand decreases a bit and in “Gone Green” total gas consumption is significantly reduced.

Sectoral analysis of scenarios and modelling assumptions. The general assumptions that are underlying the four scenarios are shown in Table 36. Some assumptions are the same for all scenarios. Diverging assumptions are shown individually. The population will increase from 63 million to 71 million in 2035. The occupation rate of households decreases and the corresponding number of households (houses) will increase as well from 27.7 million in 2015 to 31.7 million in 2035. The economic development is stronger in the scenarios “Consumer Power” and “Gone Green”, with the GDP index increasing by about 60 % between 2015 and 2035. In the scenarios “Slow Progression” and “No Progression” the GDP index only increases by about 45 %. Gas prices show the contrary evolution. In ”Consumer Power” and gas prices are low, while in “Slow Progression” and “Gone Green” there is a base case gas price used and in “No Progression” a high price path. The carbon price is the same in all scenarios. A carbon tax is already established in the UK and the carbon price increases steadily to over 50 EUR/t after 2030.

Heating is dominated by gas in the UK. Today over 80 % of the houses use gas heating. The dominance of gas for heating purposes will only decrease slowly. In the “Gone Green” scenario the development of heat pumps and heat networks is strong due to policy incentives and reduces the percentage of gas heating to about 56 % in 2035. In the other three scenarios is development is much slower.

In all scenarios energy demand for heating continues to decline due to loft insulation, cavity wall insulation, solid wall insulation, change of old boilers and reduced heat demand in new houses continues. “Gone Green” achieves the highest energy savings, followed by “Consumer Power and “Slow Progression”. These assumptions lead to a decreasing gas demand in the residential sector in all four scenarios. Apart from “Gone Green” the demand is only slightly decreasing. From 2025 onwards, gas demand in “Gone Green” decreases at a much faster rate due to better insulation and a strong development of low carbon heating.

Energy efficiency in the tertiary and industrial sector is higher in the “Gone Green” and “Slow Progression” scenarios. In “Consumer Power,” gas demand grows slightly due to a higher GVA growth rate and low gas prices. In the other three scenarios gas demand decreases slowly. Only gas demand in the tertiary sector in “Gone Green” decreases at a faster rate due to electrification of the heat supply.

Gas use grows in the transport sector, especially in the “Gone Green” and “Consumer Power” scenarios: with 34 % of the UK transport fleet being gas vehicles in 2035 gas demand for transport sums up to 24 TWh. Achieving this high share of gas in the transport fleet seems rather unlikely to be achieved, however, it should be noted that this level of gas demand for transport would be less than 2-5 % of overall gas demand.

Table 36: Demographic, economic and price assumptions
National Grids Future Energy Scenarios 2015

	2015	2020	2025	2030	2035	Change 2015-2035
Population [m.]	63				71	13%
Houses [m.]	27,7	28,7	29,7	30,5	31,7	14%
Number of houses on heat network [k houses] Gone Green	241	310	672	1017	1419	488%
Slow Progression	238	289	473	576	750	215%
Consumer Power	238	266	401	482	621	161%
No Progression	238	259	391	468	605	154%
Installed heat pumps [m.] Gone Green	0,1	0,9	4,1	7,5	10,1	9212%
Slow Progression	0,1	0,3	0,8	1,5	2,3	2775%
Consumer Power	0,1	0,6	1,4	1,8	2,3	2308%
No Progression	0,1	0,3	0,7	1,2	1,9	2231%
GDP index (2014=100) Consumer Power & Gone Green	102	114	128	145	163	60%
Slow Progression & No Progression	102	111	122	134	147	45%
Gas price [€/MWh]**: Consumer Power	22	20	26	28	29	32%
No Progression & Gone Green	25	25	31	34	35	41%
Slow Progression	30	34	39	44	44	49%
Carbon price [€/t]** all scenarios	29	34	43	50	52	77%
Heat Energy Demand [TWh/a] Gone Green	291	262	244	240	236	-19%
Slow Progression	291	264	248	245	243	-16%
Consumer Power	293	275	266	259	260	-11%
No Progression	294	281	277	275	274	-7%
Natural gas vehicles (% of fleet) Gone Green & Consumer Power	0%	3%	8%	18%	34%	7109%
Slow Progression	0%	2%	6%	11%	19%	5667%
No Progression	0%	1%	3%	5%	8%	4760%

* including gas heat pumps, hybrid heat pumps, air source heat pumps and ground source heat pumps
**Conversion factors:
1 thm: 29,3 kWh, 1 £: 1,35€

Source: [National Grid 2015a], [National Grid 2015b]

Gas demand in the power sector. The electricity demand will decrease in the short term in “Gone Green” and “Slow Progression”. Later in “Gone Green”, “Consumer Power” and “Slow Progression” the electrification of heat and transport are drivers for electricity demand which increases again after 2020.

Gas demand for electricity generation today is about 20 % to 30 % of the total gas demand. Table 37 shows the development of the installed capacity for electricity generation in the four scenarios in 2025. “Consumer Power” and “Slow Progression” show a similar development. In all scenarios gas generation capacities (including gas, gas CCS and gas CHP capacities) increase: in “Gone Green” by only 4 %, in “No Progression” about 33 %. In “No Progression” installed gas capacity is the highest and installed renewable generation the lowest. In “Gone Green” installed renewable generation more than triples to 2025, in “Consumer Power” and “Slow Progression” installed renewable generation grows about 183 % and 150 %, respectively. In comparison to the FES 2014, installed renewable generation in 2025 is remarkably higher throughout all four scenarios. That gives a hint that the future energy scenarios are underestimating the speed of renewable deployment. Installed coal capacity decreases remarkably in all scenarios as a minimum carbon price is underlying all scenarios. CCS is an option in all scenarios except in “No Progression”. In 2035 0.4 GW of Gas CCS plants are installed in “Consumer Power“ and “Slow Progression”, 1.7 GW in “Gone Green” in 2035. But it is doubtful if CCS plants will be commercial available in the near future.

Gas fired power plants replace coal fired power plants, whose installed capacity decreases under all scenarios. Furthermore, they are presented as a balancing tool for variable renewable generation, leading to increasing gas demand after 2020. In 2035 annual gas demand for power generation is the highest in “No Progression” and “Consumer Power”. In “Gone Green” and “Slow Progression” gas demand decreases considerably.

Table 37: Development of installed capacity electricity generation UK

Installed capacity [GW]	2015	Consumer Power 2025	Gone Green 2025	Slow Progression 2025	No Progression 2025	Change Scenario I 2015-2025	Change Scenario II 2015-2025	Change Scenario III 2015-2025	Change Scenario IV 2015-2025
Coal	18,1	4,3	5,6	3,9	5,9	-76%	-69%	-78%	-67%
Gas	32,9	40,4	34,2	38,9	43,6	23%	4%	18%	33%
Other conventional	18,4	21,2	27,1	21,2	15,0	15%	47%	15%	-18%
Renewables	22,1	62,5	71,4	55,2	41,9	183%	223%	150%	90%
Total	**91,5**	**128,4**	**138,3**	**119,2**	**106,4**	**40%**	**51%**	**30%**	**16%**

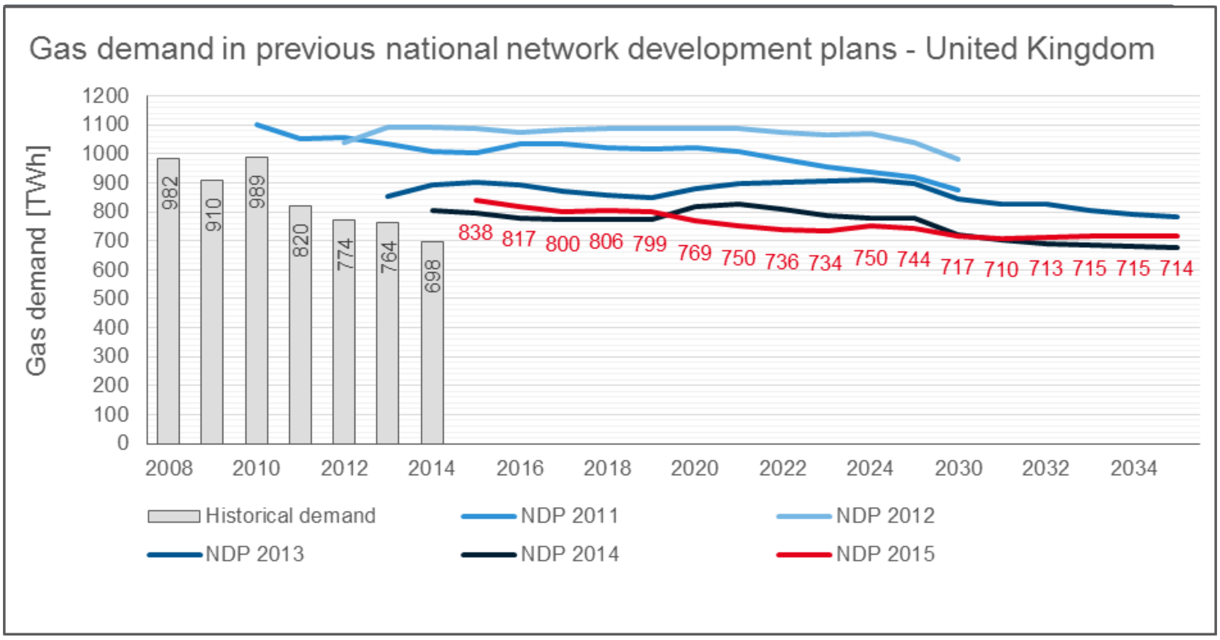
Source: [National Grid 2015b]

Critical assessment of scenarios for network development

Figure 28 compares the forecast of gas demand in previous network development plans since 2011 with the 2015 edition. The scenario shown is always “Slow Progression” which was and is used for the network modelling. The gas demand forecast was highest in the 2012 edition with nearly no decrease in gas demand expected. In 2011 forecasted gas demand was nearly as high as in 2012, but the 2011 scenarios also started from a high overall gas demand in the year 2010. The trend in all scenarios is a stable or slightly decreasing gas demand. However, as gas demand has dropped sharply over the last 5 years the starting point for the forecasts has been lowered every year resulting in a lower gas demand in 2030 and 2035, respectively, for the newer forecasts. As a result, total gas demand in the United Kingdom has been overestimated in the demand scenarios used for network planning in the last years. If the trend of the last years continues and gas demand further decreases due to efficiency gains, the 2014 and 2015 scenarios will have overestimated the demand again.

The scenario used, “Slow Progression” is already one of the lower gas demand scenarios and even in the “high das demand” scenarios gas demand does not grow much in the next 20 years. The strategy of National Grid is therefore not to invest in building up a new infrastructure, but rather focused on dealing with refurbishment of the existing network (e.g. asset health, Industrial Emission Directive). Still it is not unlikely that the decline of gas demand could be faster than currently forecast, such as under the “Gone Green” scenario which shows a continuously strong decrease in gas demand. Moreover, if energy efficiency measures and a faster development of renewable energies are actively pursued, they could result in a faster decrease of gas demand.

Figure 28: Gas demand in older NEP in the United Kingdom



Source: [National Grid 2011], National Grid 2012], National Grid 2013], National Grid 2014],- [National Grid 2015 a]

Consideration of environmental targets. In the scenario „Gone Green” all European and national targets regarding climate policy and renewable energy are met on time: the reduction of greenhouse gases in the UK by about 80 % in 2050 (in comparison to 1990) and a share of 15 % renewable energy in final energy consumption in 2020. For renewable generation, targets are extrapolated to the time after 2020 and are also met in the scenario “Gone Green”. In “Slow Progression” climate and renewable targets are not met on time but achieved later. In “Consumer Power” and “No Progression” the greenhouse gas reduction target and renewable targets are missed.

Impact of scenarios on gas infrastructure. The scenario **Slow Progression** is used by National Grid Gas Transmission for network modelling. According to National Grid it “*matches closely the current UK industry behaviour and represents a reasonable worst case for assessing the future impact on operating the network system*”. [National Grid 2015c] Results are cross checked with sensitivity analysis with sample years from the three other scenarios.

For future years in the long run the "No Progression" scenario is used as it has the highest gas demand and also the highest gas peak demand.

Table 38 shows the peak gas capacity demand for "Slow Progression" divided in smaller consumers connected to lower pressure (LDZ, Local Distribution Zone) and industrial consumers directly connected to the high pressure system (NTS). Including IUK means including the Belgian Interconnector. For the three other scenarios total peak gas demand until 2035 is shown as well in the table. From 2015 to 2025 NTS consumption increases in "Slow Progression", afterwards it decreases slowly. LDZ peak demand increases steadily.

Table 38: Development of (peak) gas capacity (1 in 20 peak day) National Grid

Slow progression [GWh/d]	2015	2020	2025	2030	2035	Change 2015-2025	Change 2025-2035
Total LDZ	3.756	3.625	3.489	3.398	3.292	-7%	-6%
NTS consumption	1.857	2.017	2.305	2.059	2.170	24%	-6%
NTS shrinkage	9	9	10	10	10	9%	0%
Total including IUK	4.812	4.807	4.824	4.609	4.559	0,2%	-5%
Consumer Power [GWh/d] Total	5.115	5.483	5.502	5.375	5.227	8%	-5%
Gone Green [GWh/d] Total	4.971	4.914	4.556	4.037	3.661	-8%	-20%
No Progression [GWh/d] Total	5.051	5.443	5.719	5.690	5.634	13%	-1%

Source: [National Grid 2015a]

In the GTYS the existing construction projects are shown. All are compressor stations that need to be modified for emission reduction demanded by the Industrial Emissions Directive (IED). As mentioned before, the IED is one of the focus topics of the GTYS 2015. All gas-driven compressors must be within the new limits by the end of 2023. Therefore, new units are installed in the affected compressor stations. Another topic is the liquefied natural gas storage facility at Avonmouth. This station was built in the 1970s. It will likely be closed in 2018 as reinforcement would not be economically viable. The risks resulting from the closure of Avonmouth are assessed in the GTYS. As planning processes have improved, no new investment is needed at the moment and further investments are deferred

The transmission network is aging, so asset health is a topic of the GTYS as well. To address this issue, National Grid will review if assets are still needed or if a better alternative solution is available.

System flexibility is a future topic and project. The system has to be capable to deal with varying within day demand and supply, changing geographic supply and change in the direction of gas flows. To address the topic for within-day flexibility the profiling of demand is modelled.

The FES scenarios are used to assess the geographic distribution of supply and demand and the adaptability of the system.

There are no figures about investment costs in the GTYS. But National Grid publishes separately their planned expenditure.[95] The planned expenditure of National Grid Gas Transmission from 2014 to 2021 lies between GBP 217 million and GBP 441 million, summing up to a total of GBP 2,348 million.

Overview of scenarios

The following table gives an overview of scenarios, their compliance with national climate target systems and the use of scenarios in gas network planning. It shows the consideration of EU 2020 Targets like the reduction of GHG-emissions or the share of renewable energies.

Table 39: Scenarios in European network plans
and their compliance with climate target systems

		EU 2020 Targets						
Country	**Scenario**	**Reduction GHG-emissions**	**Share RES in energy consumption**	**Increase energy efficiency**	**Further national targets**	**Partial compliance, not further specified**	**Δ% Total gas demand**	**Used for network planning**
NL	"Green Focus"	x	x	x	-		- 19.6	
	"Limited Progress"				-		- 21.8	
	"Cooperative Growth"				-	x	8.1	x
IT	SEN	x	x	x	x		- 19.6	
	SNAM					x	- 19.6	x
UK	"Consumer Power"	x					7.7	
	"Gone Green"	x	x	x	x		- 10.9	
	"No Progression"						7.2	(x)
	"Slow Progression"	x			x		- 15.3	x
FR	"Reference"				(x)		12.9	x
	"Moins 30"				(x)		4.7	
	"Usages diversifies"						24.9	
	"AMS2"	x	x	x	x		-15.9	
ES	Medio	x	x		x		19.2	*
	Alto						17.0	

95 http://www.talkingnetworkstx.com/our-performance.aspx.

	Bajo					22.7	
DE	“High gas demand” (I)	-	(x)	-	-	7.3	
	“Mid gas demand” (II)	-	(x)	-	-	-1.0	x
	“Low gas demand” (III)	x	x	x	(x)	-12.6	
EU	“Slow Progression”	-		-			
	“Blue Transition”	(x)**		-			x
	“Green Evolution”	(x)**		x			x
	“EU Green Revolution”	(x)**		x			x

x: objective achieved // -: objective not achieved // (x): objective partially achieved/ partially used for network planning // blank: no data available
* The Spanish NDP from 2011 is not liable for the period 2012-2020. Another NDP should be published by the end of 2016 or beginning of 2017 for the period 2017-2024. ** On track with 2030/2050 targets

The **conclusions** concerning the individual aspects are as follows:

- **Process:** The process for the development of the “Future Energy Scenarios” and “Gas Ten Year Statement” is well established and harmonized. National Grid has a significant stakeholder engagement process related to the scenario development used for the GTYS and sufficient opportunities for stakeholders to provide feedback on the most recent GTYS through an online ex-post questionnaire. In person stakeholder engagement processes (including for the FES) are, however, not specific to the GTYS making assessment of stakeholder involvement in the development of the GTYS difficult to assess.
- **Gas demand since 1990 and NDP scenarios:** Gas consumption grew steadily from 1990 to 2000 and remained nearly stable from 2000 to 2010 with a total gas consumption **around** 1,100 TWh. Since 2011 gas demand has decreased strongly especially in the transformation sector resulting in a total gas consumption around 700 TWh in 2014. For the GTYS four scenarios are used representing different environmental and economic developments. Gas demand grows slightly in one scenario, remains stable in the second and decreases slightly in the third. Gas demand only decreases considerably in one scenario.
- **Modelling assumptions:** The four scenarios are part of the “Future Energy Scenarios” from the TSO National Grid. Most of the underlying assumptions of the four scenarios are published. However, the assumptions are less transparent on energy efficiency development and the development of renewable energies could still be underestimated throughout all scenarios. E.g. installed capacity of renewable power generation has been adjusted upwards significantly from 2014 to 2015.
- **Critical evaluation of scenarios:** The scenarios do not show an increasing gas demand: in the highest gas demand scenario demand stays nearly stable, in the three other scenarios there is a slow to faster decrease of gas demand. Past scenarios have clearly overestimated historical demand. They are indications that the trend of a faster **decreasing** gas demand is not adequately considered in the 2015 scenarios and future gas demand is overestimated again.
- **Consideration of environmental targets:** One scenario in which European and national targets regarding climate policy and renewable energy are met on time and gas demand is

decreasing considerably is considered, but this scenario is not used for network modelling in the GTYS.

- **Impact on Gas Infrastructure:** Focus of the GTYS is on the implementation of the Industrial Emissions Directive and system flexibility. Deferring investments (e.g. replacement of LNG storage in Avonmouth) and monitoring of asset **health** are signs that National Grid is already responding to the reality of a decreasing gas demand. Nonetheless, if gas demand decreases more strongly than anticipated, some investments, especially for diversifying the gas supply, would probably not be needed.

2.4 Conclusions on European gas infrastructure planning

The present study analyses existing instruments, processes and scenarios for gas infrastructure planning in Europe with focus on six countries. It aims to find out whether scenarios that are used for gas network planning in Europe consider climate policy goals and low carbon options in an adequate way. Besides, processes and instruments are critically assessed.

Gas infrastructure planning on a **European level** is largely based on the instruments TYNDP, GRIPs and PCI. Therefore, we base our conclusion on the critical assessment of these instruments:

TYNDP

- The **TYNDP** is an indicative document with the purpose to give a basis for planning of European gas markets and networks. In particular, the TYNDP assesses different levels of future infrastructure development under different demand and supply disruption scenarios.
- The development of the Union-wide TYNDP gives stakeholders many opportunities to engage. The number of stakeholders actively participating in the process is low, largely limited to TSOs and key institutions. Environmental organisations have generally not participated. ACER recommended factoring the results of the public consultation more strongly into the final TYNDP report.
- Consideration of climate policy and low-carbon options within the TYNDP is intimately linked with the process of developing demand scenarios for the TYNDP. In order to ensure proper consideration of climate policy and low-carbon options, the planning process should ensure broader stakeholder participation and consistency of demand scenarios with long term European energy strategy. ACER suggests holding public workshops with key stakeholders, including experts from industry and academia, well in advance of the TYNDP stakeholder process.
- Based on ACER monitoring, the consistency of the TYNDP and the NDP in terms of implementation timelines and listed projects is relatively low. Data on projects is often lacking. (ex. due to jurisdictional issues). Participation of NRAs in the ACER monitoring process was low. Moreover, the focus of the monitoring process was largely on an assessment of whether the incomplete data in the plans were aligned, as opposed to whether projects within the NDPs are misaligned with European priorities. As such, the more strategic monitoring of the consistency of the NDPs and the TYNDP is left solely in the hands of NRA. This implies that a strengthening of the mandate, resources and tools (ex. additional modelling capabilities) provided to ACER may be desirable to ensure the proper coordination of gas infrastructure at EU level, as suggested by [Bruegel 2016] and [ECA 2015].

GRIPS

- **Gas Regional Investment Plans** are plans on a regional level in which a group of TSOs from different countries coordinate transmission infrastructure needs for a geographically and functionally determined region over a ten-year period.
- Opportunities for stakeholders' involvement vary between GRIPs and are generally less structured and transparent than for the TYNDP process. There have been limited opportunities for stakeholders to engage, with the exception of post-GRIP consultations.
- The joint development of the TYNDP 2017-2037 and the 3rd GRIPS will help aligning these two processes. As both processes will be jointly developed and data commonly collected, TYNDP stakeholder engagement process will gain in importance for the GRIPs. As the treatment of demand scenarios will also be harmonized, the TYNDP process will also determine the assumptions made about climate policy and low-carbon options for the GRIPs.
- The harmonization of the GRIPs will increase the comparability of the GRIPs reports. The growing harmonization, however, risks making them largely indistinguishable from analysis provided in the TYNDP, thereby reducing their added value for stakeholders. Moreover, due to the mutual timing of the reports it is unclear to what extent the Union-wide TYNDP will take into account the GRIPs, as demanded by EU Regulation.

PCIs

- **Projects of Common Interest** are an important instrument for the implementation of gas infrastructure under the TEN-E regulation. The projects on the PCI list are supported among others with financing from the CEF.
- None of the PCI priority gas corridors highlight sustainability as a core aim. Projects are not required to contribute to sustainability to receive PCI status. While sustainability is considered in the application of the CBA methodology, a project must only have a net-positive outcome overall in order to qualify.
- The results of the PCI selection process so far reveal that gas projects have thus far been more strongly supported under the CEF Energy calls than electricity and smart grid projects, despite an arguably higher need for support in the electricity sector in order to meet the EU's mid- to long-term energy and climate goals.
- While the Commission formally plays a critical role in the PCI selection process, Member States maintain the power to nominate PCIs, potentially undermining the Commission's ability to guarantee projects are directly linked to EU objectives. The role of the Commission or ACER in the selection and monitoring of PCI projects could be strengthened and stakeholder engagement improved.

Critical assessment of Europe-wide scenarios

- The four scenarios in the TYNDP 2017 are in great part derived from national TSO's scenarios. There is sparse transparency on the underlying assumptions. Gas demand forecasts in past TYNDPs have overestimated todays demand by far. TYNDPs 2017 scenarios are the first with increasing, stable was well as decreasing gas demand. According to ENTSOG 3 of the 4 scenarios achieve European energy and climate goals but there is no transparency on the development of GHG emissions. Compared with the trend of a decreasing gas demand in the last years the scenarios still seem to overestimate the future gas demand.

- The TYNDP does not identify single network development projects. A “low” and “high” infrastructure scenario is assessed for the demand scenarios and for different supply scenarios. The need for new investments if gas demand is decreasing and the danger of stranded investments are not assessed.

Conclusions for the national level

Besides the European level this report analyses **six focus countries** and takes a close look at NDPs and the underlying scenarios for gas infrastructure planning.

- NDPs have widely different timings for the preparation and significant differences in the frequencies in preparing national development plans. While Germany, France, the UK, and Italy have a yearly cycle, the Netherlands’ NDP appears in a biennial frequency and a Spanish NDP has not been published since 2008. Germany is changing to a two-year cycle with an intermediate evaluation.
- Stakeholder engagement varies strongly. While stakeholder engagement for the Italian NDP consisted largely of a public consultation in written form on a draft NDP (ex. IT), the processes in the Netherlands and Germany also include workshops. The UK and Germany both have stakeholder engagement during the scenario development process. The Netherlands strongly involved neighbouring TSO, receiving input from France, Germany and the UK.
- The NRA play a clear role in the NDP process in France, Germany and the UK, while the exact involvement of the NRAs is less clear in Italy and the Netherlands. The Spanish NDP was directly managed by the government. These differences matter since varying levels of involvement in the NDP process may impact the ability of the NRA to monitor the process, including for consistency with the TYNDP and coherence with energy and climate goals.
- Some of the NDP are available in national languages only. Some NDP (DE) offer executive summaries in English. The French, Italian and Dutch NDP are available in their full length in English.

Critical assessment of scenarios at the national level

- All network plans are based on one or more future scenarios. The dominating time horizon is 10 years. Only one scenario per country is binding for the definition of measures.
- In the past, gas demand scenarios that were used for network planning have frequently overestimated the gas demand in most of the focus countries. Looking on the trend of gas demand in the last years it seems that UK and Germany have used the most reliable scenarios. More recently, all of the NDPs reacted to a reduced demand with respective (lower) scenarios. However, a greater validity of gas demand forecasts seems necessary.
- None of the scenarios that are used for the infrastructure planning and definition of measures is completely coherent with governmental goals for GHG emissions reduction targets or low carbon options. Two of the national scenarios (NL, IT) are partially coherent, the others are not.
- Network planning is subject to European law and regulation. Energy policy aims at the functioning of the energy market, security of supply, promoting energy efficiency and the development of renewable forms of energy and promoting the interconnection of energy networks.
- The regulatory authorities are required to discuss the adequacy of network plans with the stakeholders and the consistency with TYNDP of ENTSOG. Adequacy in this context means

that the capacity demand in the market can be met safely. Compliance with long term government climate policy goals is not a primary obligation for TSO. However, it can be assumed that realistic demand scenarios would help to avoid an overestimation of infrastructural needs in network plans.

- Thus, network plans in Europe and their underlying demand scenarios are not based on the implementation of all necessary low carbon options to fulfil climate policy goals. Security of supply and functioning of the markets are still the main considerations for infrastructure planning. A discussion about what an adequate level of consideration of climate targets is should be initiated.

3. Potentials of low carbon options

3.1 Objectives and methods

This chapter aims to provide answers to the central question: to what extent can low carbon options, especially renewable energy sources (RES) and energy efficiency (EE), reduce investments in gas infrastructure?

To this end, we have compared the scenarios used for gas network planning (see chapter 2) with other available scenarios – among them scenarios with different assumptions regarding CO_2-prices. The scenarios include trend (or business-as-usual) scenarios as well as scenarios with high RES and EE development rates. For each of the focus countries as well as for the EU as a whole, several steps and analysis have been carried out, in order to answer these questions:

1. How high is the realisation of EE and RES potentials in the analysed scenarios? Is there a relationship between the extent to which EE and RES are deployed and gas demand?
2. Comparison of NDP scenarios to the other available scenarios: Are there major differences in the evolution of gas demand in the NDP and the other scenarios? If yes, what are the reasons?
3. Using the two previous steps, what can be said about potentials of low carbon options, especially EE and RES, for lowering the gas demand?
4. What are the consequences for gas capacity demand, infrastructure and associated costs? For countries in which no further information on capacity demand has been available the consequences on capacities have been assessed on the basis of the results of the FfE-study (see chapter 2.1.4).

3.2 Europe-wide analysis of low carbon options

3.2.1 Analysed European scenarios

In Europe, energy policy and planning are based – among others – on the Reference scenarios from the European Commission which have been updated biennially between 2003 and 2009. The latest updates are from 2013 and 2016. These scenarios are projections of current policies but do not assume that (all) energy-related climate targets are reached.

> "Moreover, REF2016 does not include the politically agreed but not yet legally adopted 2030 climate and energy targets."[96]

These scenarios can indicate if policies are missing to reach the European energy and climate targets and which further policies are needed. We included these scenarios as they are important in the European energy policy debate. They show which gas demand Europe would require in case that the targets are not reached.

[96] EU Reference Scenario 2016, Main results p.5

Besides, we analyse a scenario that reaches the European energy and climate targets for 2030: a reduction of greenhouse gas emissions in comparison to 1990 of at least 40%, and a share of 27 % of renewables in gross final energy consumption and at least 27 % energy efficiency (EE 27) and the scenario that represents the likely future proposal of the European Commission of 30 % energy efficiency (EE 30). Furthermore, we assessed one target scenario from the European Commission with a high deployment of renewable energies from the decarbonisation scenarios in 2011 and one target scenario from the European Commission with energy efficiency of 40 % representing the proposal of the European parliament (EE 40). Additionally, a scenario with an even more ambitious climate policy from the IEA ("450 ppm scenario"), and two very ambitious scenarios from the Greenpeace energy [r]evolution report are analysed.

All scenarios except those from Greenpeace analyse the energy system for the EU-28 countries[97]. The Greenpeace energy [r]evolutions scenarios examine OECD Europe, which does not include some Eastern European countries but Turkey and Norway among others. Hence, the following numbers from these scenarios cannot be compared directly. We include the scenarios nevertheless to show the trend of gas consumption in a scenario with 100 % GHG reduction and 100 % renewable generation[98]. The scenario from the IEA is only available until the year 2040, all other scenarios examine the time until 2050. The following table describes the analysed studies and scenarios and indicate if and which targets are reached.

Table 40: Overview of analysed scenarios for Europe

Study	Scenario	Scenario description	Target compliance
Reference Scenarios			
European Commission, EU Reference scenario, 2016	Reference 2016	Reference scenario of the European Commission 2016; Projection of trends up to 2050 assuming that policies adopted until end of 2014 are implemented	Only 2020 targets of GHG emissions, RES are reached
European Commission, Trends to 2050, 2013	Reference 2013	Reference Scenario of the European Commission 2013; Projection of trends up to 2050 assuming that policies adopted until spring of 2012 are implemented	Only 2020 targets of GHG emissions, RES are reached
Scenarios with measures and targets			
EU Comission, Impact Assessment, 2014	EE27	Part of the impact assesment for the energy efficiency directive; Modelling with a binding energy efficiency target of -27% in 2030 in the Member States	Nearly all 2020/ 2030 targets are reached
ICCS, E3M Lab, PRIMES modelling for the Impact Assessment, 2014	EE30EC_a	Part of the impact assesment for the energy efficiency directive; Modelling with a binding energy efficiency target of -30% in 2030 in the Member States	Nearly all 2020/ 2030 targets are reached
ICCS, E3M Lab, PRIMES modelling for	EE40EC_a	Part of the impact assesment for the energy efficiency directive; Modelling with a binding energy	Nearly all 2020/ 2030 targets are reached

97 The scenarios from the impact assessment of the "Energy roadmap to 2050" only include EU 27. But the difference is very small: Croatia, the 28th member stands for less than 0.5 % of the European primary energy demand. In contrast to the EU COM, ENTSOG additionally assesses the countries Bosnia Herzegovina, Macedonia, Serbia and Switzerland, which account in total for 1 % of the European demand.

98 There is still some fossil fuel consumption in the "advanced energy [r]evolution" scenario for non-energy use.

the Impact Assessment, 2014		efficiency target of -40% in 2030 in the Member States	
European Comission, Energy Roadmap 2050, Impact assessment, 2011	High RES	Decarbonisatoin scenarios (80% GHG reductions by 2050) from the European Commission; HIGH RES is a scenario with a very high overall RES share and very high RES penetration in power generation	Nearly all 2020/ 2030 targets are reached
IEA, Word Energy Outlook 2015	450 Scenario	Scenario from the World Energy Outlook of the IEA that reaches a pathway consistent to the 2° climate goal	All targets except 2020 RES, EE targets are reached
Ambitious scenarios with measures and targets			
Greenpeace, Energy [r]evolution - a sustainable world energy outlook, 2015	energy [r]evolution	Very ambitous target scenarios, this scenario reaches about 90% GHG emission reduction in 2050 without CCS and nuclear	All targets except 2020 RES, EE targets are reached or exceeded
	advanced energy [r]evolution	Scenario that reaches 100% GHG emission reduction in 2050 and 100 % renewable energy supply	All targets except 2020 RES, EE targets are reached or exceeded

Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015]

Table 41 compares in detail the compliance of the analysed scenarios with the European targets. Not for all scenarios data on GHG emissions were available (marked with a * in the table). For these scenarios we use the CO_2-emissions to indicate if GHG reduction targets are reached. The reference scenarios reach the 2020 targets of GHG reductions and renewables share but miss all other targets. The scenarios with measures and targets reach or nearly reach all targets except the 2020 efficiency target. Ambitious scenarios also nearly reach all targets (exception is again the 2020 energy efficiency target) and achieve a higher share of renewables and a higher reduction of GHG emission, especially in the long run.

Table 41: Comparison between scenarios and European energy and climate targets

	Reduction GHG emissions (compared to 1990)			Renewable energy		Energy efficiency	
	2020	**2030**	**2050**	**2020**	**2030**	**2020**	**2030**
Targets EU Commission	-20%	-40%	-80-95%	20%	27%	20%	27%
EU Reference 2016	-24%	-34%	-46%	21%	24%	-18%	-24%
EU Reference 2013	-24%	-32%	-43%	21%	24%	-17%	-21%
EU EE27 2014		-40%	-78%		28%		-27%
EU EE30 2014	-25%	-40%	-78%	21%	28%	-18%	-31%
EU EE40 2014	-25%	-44%	-80%	21%	27%	-18%	40%
EU High RES 2011 *	-23%	-40%	-83%	21%	31%	-16%	-26%
IEA 450 *	-30%	-54%		17%	27%	-18%	-28%

Greenpeace e. [r]evolution *	-21%	-52%	-92%	19%	37%	-14%	-31%
Greenpeace advanced e. [r]evolution	-22%	-56%	-100%	19%	40%	-14%	-31%

Note: Red colour means the targets will not be reached.
* Given as reduction of CO_2 emissions as no further information on GHG emissions were provided

Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015]

3.2.2 Potentials of low carbon options and influence on gas demand

The analysed scenarios have similar assumptions regarding population: a slow increase until 2030 and a very slow increase until 2040 followed by stagnation. The economy shows an average growth of around 1,5 %. So, population and economy are slight drivers for the development of the gas demand, but other factors are a lot more important.

The concept of focusing on the demand side and investing in energy efficiency before new energy supply sources or new grid infrastructure are considered (termed “Efficiency First”) is gaining importance. It is a principle of the Energy Union Strategy of the European Union and it is also deployed in the focus countries: E.g. “Efficiency First” is one of the cornerstones of the consultation document on energy efficiency policy (“Grünbuch Energieeffizienz”) of the German Federal Ministry of Economic Affairs and Energy. A consequent deployment of “Efficiency First” might make an achievement or over-achievement of the European efficiency targets more likely.

Table 42 shows the development of the primary energy demand in the analysed scenarios to demonstrate the development of **energy efficiency** and the comparison to the 2007 reference projections. The current reference scenario (2016) shows a continuous decline in the primary energy demand up to 2050. Target scenarios have a stronger focus on energy efficiency leading to primary energy demand decreasing faster than in the reference scenarios: The scenarios EE27, EE 30 and EE40 have a focus on reducing primary energy demand in 2030 so the decrease in primary energy demand in these scenarios especially high between 2015 and 2030. In the long run, no additional energy efficiency measures are implemented and energy efficiency increases slower after 2030. The two scenarios with strict decarbonisation, energy [r]evolution and advanced energy [r]evolution have high energy efficiency gains throughout the observed timeframe resulting in notably lower primary energy demand in 2050.

The concept of focusing on the demand side and investing in energy efficiency before new energy supply sources or new grid infrastructure are considered (termed “Efficiency First”) is gaining importance. It is a principle of the Energy Union Strategy of the European Union and it is also deployed in the focus countries: E.g. “Efficiency First” is one of the cornerstones of the consultation document on energy efficiency policy (“Grünbuch Energieeffizienz”) of the German Federal Ministry of Economic Affairs and Energy. A consequent deployment of “Efficiency First” might make an achievement or over-achievement of the European efficiency targets more likely.

Table 42: Energy efficiency EU 28: Development of primary energy demand in the analysed demand scenarios in TWh

	Primary energy demand [TWh]				Change compared to EU reference 2007 projection		
	2015	2020	2030	2050	2015	2020	2030
Targets EU		*17.250*	*15.921*			-20%	-27%
EU Reference 2016	18.142	17.758	16.701	15.904	-14%	-18%	-24%
EU Reference 2013	18.923	17.938	17.328	17.562	-11%	-17%	-21%
EU EE27 2014	18.916	17.700	15.921	15.340	-11%		-27%
EU EE30 2014	18.916	17.665	15.222	13.813	-11%	-18%	-31%
EU EE40 2014	18.917	17.649	13.198	11.987	-11%	-18%	-40%
EU High RES 2011	19.606	18.155	16.147	11.970	-7%	-16%	-26%
IEA 450	18.568	17.771	15.782		-12%	-18%	-28%
Greenpeace e. [r]evolution	19.634	18.581	15.045	11.391	-7%	-14%	-31%
Greenpeace advanced e. [r]evolution	19.632	18.576	15.103	11.776	-7%	-14%	-31%

Note: Greenpeace energy [r]evolution and advanced energy [r]evolution data are for OECD Europe

Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015]

The scenarios also have a different development of **renewable energies.** In Table 43 the share of renewables in the final energy demand is shown. Starting with about 16 % in 2015 the share of renewables in final energy demand reaches between nearly 30 and 100 % in 2050. In the two reference scenarios, this share is nearly doubling between 2015 and 2050, in the target scenarios the share is growing even faster, especially after 2030. In the very ambitious scenario, advanced energy [r]evolution, energy demand is met by renewables in 2050. The only fossil fuels that are used are for non-energy use. In the very ambitious scenarios the 2030 target is exceeded clearly. This shows the important role of renewable generation in most of the target scenarios. Please note: Some scenarios include the gross final energy demand but most studies don´t.

Table 43: Renewables: Share of RES in energy demand in the analysed demand scenarios -EU 28

Scenario	2015	2020	2030	2050
Targets EU		**20%**	**27%**	
EU Reference 2016	16%	21%	24%	31%
EU Reference 2013	16%	21%	24%	29%
EU EE27 2014	16%		28%	50%
EU EE30 2014	16%	21%	28%	51%
EU EE40 2014	16%	21%	27%	52%

EU High RES 2011	15%	21%	31%	75%
IEA 450	14%	17%	27%	
Greenpeace e. [r]evolution	15%	20%	40%	86%
Greenpeace advanced e. [r]evolution	15%	21%	44%	100%

Note: Greenpeace energy [r]evolution and advanced energy [r]evolution data are for OECD Europe

Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015]

Some scenarios set a **CO_2 price** (IEA 450), in some scenarios the CO_2 price is one of the results (European Commission scenarios) or they are calculated without CO_2 price (Greenpeace scenarios). Regarding gas demand CO_2 prices are especially important for the coal-to-gas-fuel-switching in power generation. In the scenarios with a CO_2-price the price varies between 25 and 100 €/ t in 2030 and between 100 and 285 €/t in 2050 (all in real terms). CO_2 prices in ENTSOG´s "EU Green Revolution" scenario (around 80 €/t in 2030) ranges on the upper margin similar to IEA´s 450 scenario. ENTSOG´s "Blue Transition" scenario (CO_2-price of around 30 €/t in 2030) on the other hand assumes moderate CO_2 prices similar to IEA´s New Policy Scenario. There are differences between target and reference scenarios. Scenarios without ambitious climate policy and strengthened emission trading schemes result mostly in lower carbon prices but at times target scenarios with already amplified measures in place could result in lower carbon prices than in reference scenarios.

CO_2 emissions decrease in all analysed scenarios continuously. In comparison to 4,030 Mt CO_2 in 1990 emissions decrease in 2050 by about 40 to 45 % in the reference scenarios. In all target scenarios the 80 % target in 2050 is reached[99], in the Greenpeace scenarios it is exceeded with over 90 % resp. 100 % reduction. (IEA 450 only has data until 2040). Table 44 shows the CO_2 prices from the analysed scenarios and the development of CO_2-emissions.

Table 44: Development of CO_2-emissions (energy related) and CO_2 -price in the analysed European scenarios

	Price CO_2 [Euro/t]				**CO_2 -emissions [Mt CO_2]**			
	2015	2020	2030	2050	2015	2020	2030	2050
EU Reference 2016		15	27	87	3.524	3.281	2.844	2.175
EU Reference 2013		10	35	100	3.593	3.265	2.876	2.364
EU EE27 2014		10	39	243	3.590		2.467	846
EU EE30 2014		10	25	180	3.590	3.205	2.465	826
EU EE40 2014		8	6	165	3.590	3.207	2.231	727
EU High RES 2011		25	35	285	3.673	3.087	2.395	670
IEA 450		22	100		3.154	2.811	1.835	
Greenpeace e. [r]evolution		-	-	-	3.498	3.124	1.906	328
Greenpeace advanced e. [r]evolution		-	-	-	3.492	3.107	1.731	0

Note: Greenpeace energy [r]evolution and advanced energy [r]evolution data are for OECD Europe

99 As some scenario show no data on GHG emissions we analyze here energy related CO_2 emissions.

Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015]

Figure 29 shows the correlation between energy efficiency, renewable energies and the corresponding gas demand represented by the size of the circle. It becomes visible that target scenarios with a high employment of energy efficiency and renewable energies result in a lower gas demand. This becomes even clearer over time. In 2030 gas demand is not differing very much whereas in 2050 the changes in gas demand between reference and target scenarios become clearer.

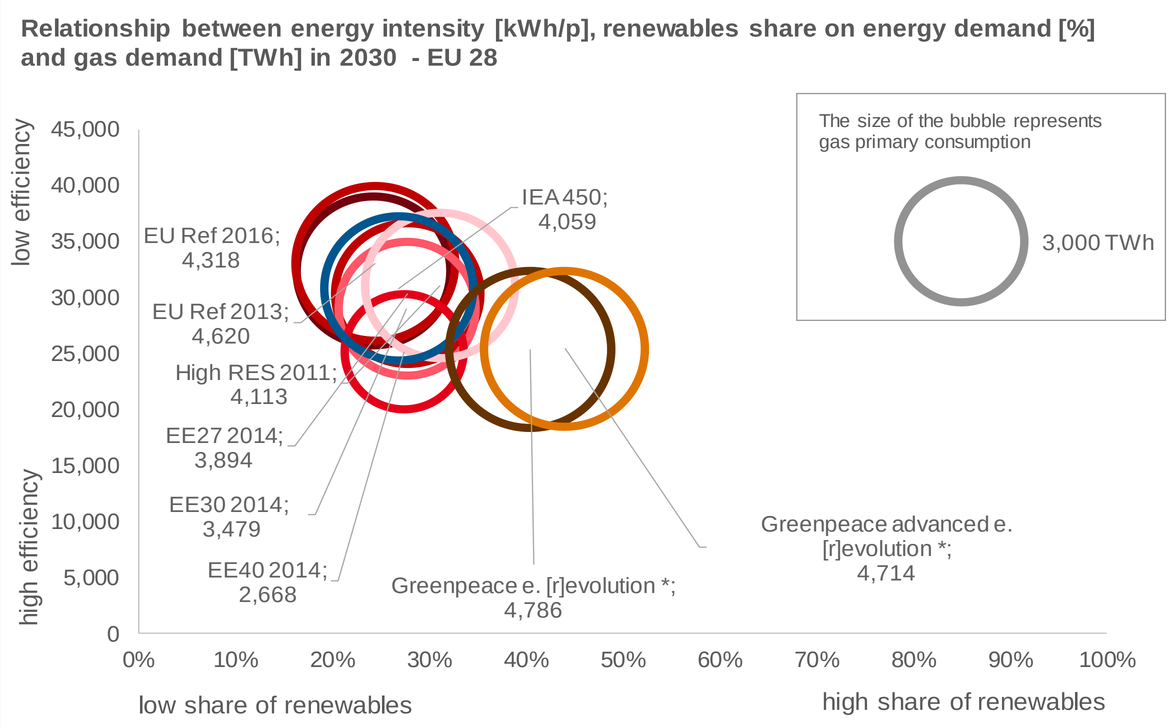
The **influence of energy efficiency** on gas demand is shown distinctly in the scenario "EE 40" which has the lowest gas consumption in 2030.

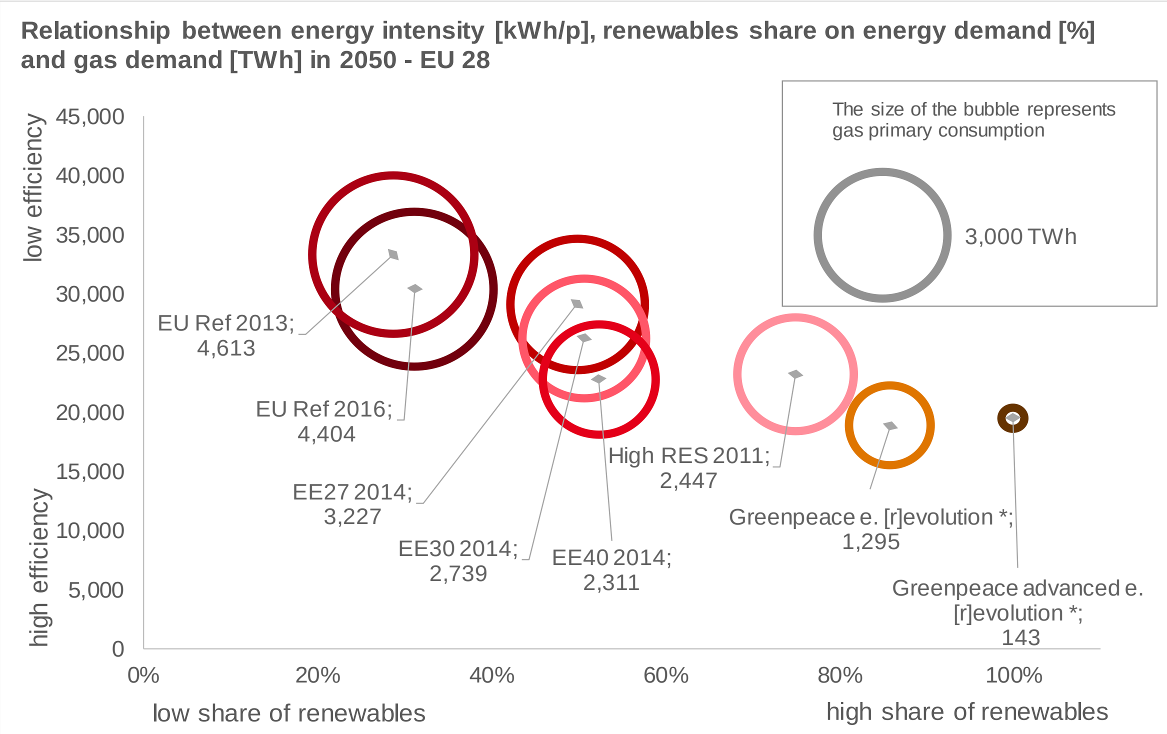
In the Greenpeace scenarios, primary energy demand per person declines fast but gas demand only starts declining from 2025 onwards. In these scenarios, fuel switches from nuclear to gas and from coal to gas compensate the gas demand reduction due to energy efficiency gains. In the long run, gas demand in the Greenpeace scenarios declines steeper than in all other scenarios: the correlation between energy efficiency and less gas demand becomes visible once the additional gas power generation due to the nuclear and coal phase outs is substitute by renewables generation.

The same applies for **renewable energy**: with a share of 100 % renewable energy, there is no gas demand left (Greenpeace advanced energy [r]evolution scenario in 2050). The trend shows that gas demand is declining with a higher share of renewables. ("High RES 2011" /2050). In the medium term (2030) however, in some scenarios gas demand and the share of renewables grow at the same time (Greenpeace). So probably other fuels, e.g. coal, are phased out earlier than gas in these scenarios. Final gas demand is also declining faster than primary gas demand which could mean that more gas is used for power production.

Taken together the analysed scenarios provide **evidence** that **gas demand is declining** when RES und EE targets and policies are in place.

Figure 29: Relationship between energy intensity, renewable share and primary gas demand in 2030 and 2050 -EU





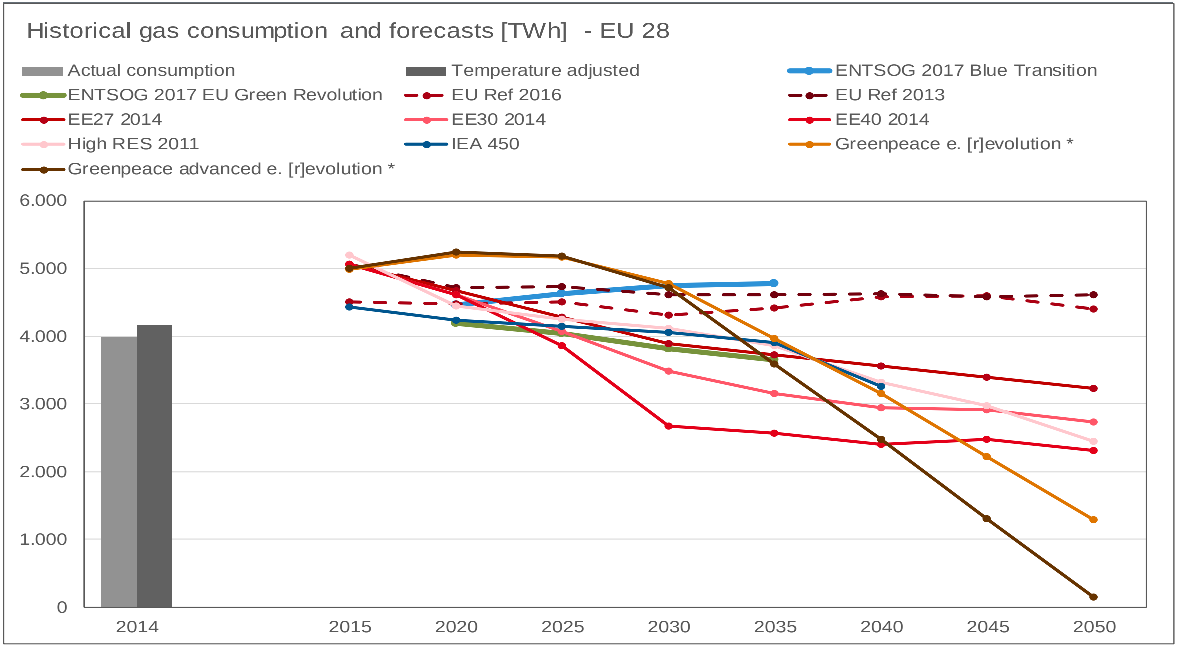
* Gas demand for OECD Europe

Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015]

3.2.3 Gas demand in these scenarios

The primary gas demand of the analysed scenarios in comparison to the **primary gas demand** forecasts from the TYNDP 2017 is shown in Figure 30. The numbers for 2015 are not historical values but already scenario outcomes. The actual consumption for 2014 as well as the temperature adjusted value is shown on the left. European gas consumption has declined strongly since 2010 (see also chapter 2.2, Figure 12). Some older scenarios from 2011 or 2014 have not foreseen this development and have higher levels of gas demand in 2015. Other scenarios assess a slightly different region (OECD Europe in the Greenpeace scenarios, EU 28 all other scenarios). The gas demand in 2014 was also remarkably low. The temperature adjusted gas demand is on the level of the more recent scenarios (reference 2016, IEA 450). **The ENTSOG scenario "Blue Transition" and the EU Ref 2016 are the only ones with an increasing gas demand after 2020**. **All the other analysed scenarios show a declining gas demand.** In the reference scenarios the gas demand is only slowly declining or nearly stagnating. In the target scenarios gas demand is declining and nearly halving from 2015 to 2050 in the European Commission scenarios (High RES 2011 and EE30 2014, EE 40 2014. In the very ambitious scenarios, gas demand diminishes strongly until 2050 (about -75 resp. -97 %). It is noticeably that older scenarios before 2015 (such as High RES 2011, reference 2013 and scenarios from 2014) have overestimated gas demand for 2015. So, it seems likely that future gas demand is overestimated in the reference scenarios. Gas demand is declining strongly in scenarios that reach the targets and further efficiency leads clearly to less gas demand (EE 40 2014). After 2030 gas demand is nearly stable in the scenarios EE 27, EE 30 and EE 40. These target scenarios focus on the 2030 target. If further efficiency measures are deployed after 2030 gas demand could decline further.

Figure 30: Primary gas demand in the analysed scenarios in Europe in TWh



* Gas demand for OECD Europe Note: 2014 was an exceptional warm year

Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015], [ENTSOG 2016e]

Even without further RES and EE targets and policies in Europe gas demand will probably not grow as shown in the reference scenarios. The development of gas consumption over the last five years was declining and this trend is likely to continue. If additional and ambitious measures are applied gas demand could diminish faster. Taken together the analysed scenarios provide **evidence** that **gas demand is declining** when RES und EE targets and policies are in place. The difference of gas consumption between the TYNDP scenarios "EU Energy Revolution" and "Blue Transition" and gas consumption in the analysed scenarios is shown in Table 45 in TWh and bcm. This shows the great potential for gas savings in scenarios with strong energy efficiency and high deployment of renewables. **The ENTSOG scenario "Blue Transition" seems to overestimate future gas demand.**

For gas network planning this means, today's RES and EE targets and policies will lead to a shrinking gas demand. Higher RES and EE targets could in the long run lead to an even further reduced gas demand and gas network planning needs to be based on more realistic demand scenarios.

Table 45: Gas saving in the analyzed scenarios compared to the TYNDP 2017 in TWh and bcm[100]

	Blue Transition				Green Revolution			
	in TWh		in bcm		in TWh		in bcm	
	2020	2030	2020	2030	2020	2030	2020	2030
Gas demand in ENTSOG Scenario	**4.456**	**4.745**	**423**	**451**	**4.187**	**3.819**	**397**	**363**
EU Reference 2016	-20	427	-2	41	-290	-499	-27	-47
EU Reference 2013	-268	126	-25	12	-538	-800	-51	-76
EU EE27 2014	-215	852	-20	81	-485	-74	-46	-7
EU EE30 2014	-163	1.266	-15	120	-433	340	-41	32
EU EE40 2014	-161	2.077	-15	197	-430	1.151	-41	109
EU High RES 2011	12	632	1	60	-258	-294	-24	-28
IEA 450	211	687	20	65	-58	-240	-6	-23
Greenpeace e. [r]evolution	-747	-40	-71	-4	-1.017	-966	-97	-92
Greenpeace advanced e. [r]evolution	-788	32	-75	3	-1.058	-895	-100	-85

Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015], [ENTSOG 2016e]

A lower gas demand could also lead to a higher energy security in Europe. Table 46 shows the **import dependency** for gas resulting from analysed scenarios based on European gas production in the EU reference scenario 2016[101]. Norwegian gas is not included in European production. The import dependency is today at about 70 % and will increase in nearly all scenarios. As

[100] Calculated with 1 TWh = 0.09494 bcm according to EU Com 2014/ IEA

[101] In different scenarios indigenous production will develop differently due to less/ more investment in production capacities as well as less/ more consumption. For a first approach this was not considered. Details can be found in the following chapter.

European production declines severely, the import dependency remains high also in most of the ambitious target scenarios. Still the overall amount of gas consumption will be very small in these scenarios (see also Figure 30).

Table 46: Import dependency gas in Europe based on European gas production according to EU reference 2016

Import dependency	2015	2020	2030	2050
Gas production in the EU according to EU Reference 2016 [TWh]	1377	1239	913	620
Resulting gas import dependency in the analysed scenarios				
EU Reference 2016	69%	72%	79%	86%
EU Reference 2013	73%	74%	80%	87%
EU EE27 2014	73%	73%	77%	81%
EU EE30 2014	73%	73%	74%	77%
EU EE40 2014	73%	73%	66%	73%
EU High RES 2011	74%	72%	78%	75%
IEA 450	69%	71%	78%	
Greenpeace e. [r]evolution	72%	76%	81%	52%
Greenpeace advanced e. [r]evolution	72%	76%	81%	0%

Note: Greenpeace energy [r]evolution and advanced energy [r]evolution data are for OECD Europe

Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015

Capacity

The correlation between declining yearly gas demand and gas capacity demand is explained in chapter 2.1.3 in detail. It is difficult to draw precise conclusions on capacity demand based only on the development of the yearly demand, especially on an aggregated level for Europe. In general, capacity demand will certainly decline less rapidly than the yearly demand due to situations with a high gas peak demand (cold winter days). On the other hand, average peak gas demand is declining faster than yearly demand in some regions due to changing gas use (more use for transport and power generation). Therefore, the assessment of peak capacity development for network planning should be made on a regional perspective [Workshop BS]. To have a first estimation of the development of the corresponding peak demand, we use the method from [FFE 2014]. It does not seem reasonable to use this method until 2050. Table 47 compares the development of the capacity demand in the final use of gas for the analysed scenarios using a factor of 2:1 (decline of gas demand to decline of gas capacity demand) with the index development of peak gas demand in the two scenarios from TYNDP 2017. The index – corresponding to gas consumption – is declining in all analysed scenarios. The development in the EU reference scenarios (index of 0,95 in 2030) is similar to the development of ENTSOG´s "Blue Transition" scenario. In the scenario "EU Green Revolution" the index capacity is declining a bit faster. By contrast, in scenarios with ambitious renewable and efficiency deployment final peak gas demand will decline notably, especially in a scenario with high efficiency gains

(EU EE 40). TYNDP 2017 foresees a total final peak gas demand of 23,300 (EU Green Revolution) and 25,933 (Blue Transition) GWh/d in 2030. A more realistic peak demand in the starting year together with an ambitious scenario would therefore lead to a considerably reduced peak demand in 2030. Future network planning should assess the corresponding network situation.

The effect of reduced peak demand could be even stronger if additionally gas demand response is introduced. Gas demand response is already discussed detailed in the US due to their increase of gas fired power plants and the simultaneity of gas and electricity peak in winter. There are still practical, legal and regulatory hurdles but a Canadian demonstration project found up to 20 % saving potential if thermostat settings are changed [Manning et al 2007 cited by Brattle 2014]. Further potential for gas demand response could be provided by industrial consumers, power plants or district heating operators [Workshop BS].

There need to be further research with a regional perspective on the evolution of peak gas demand for decreasing yearly gas demand and on the potentials of gas demand response to examine further potential savings in gas infrastructure [Workshop BS].

Table 47: Estimated gas capacity demand for final energy sectors, index development - Europe

Capacity demand for final gas demand [Index 2015 = 1,00]	2015/ (2017)	2020	2030	2050	Change 2015 (2017) - 2030
ENTSOG EU Green Revolution [index 2017 =1,00]	1,00	0,98	0,88	-	-12%
ENTSOG Blue Transition [index 2017 =1,00]	1,00	1,00	0,95	-	-5%
EU Reference 2016	1,00	1,00	0,95	-	-5%
EU Reference 2013	1,00	0,96	0,95	-	-5%
EU EE27 2014	1,00		0,89	-	-11%
EU EE30 2014	1,00	0,95	0,85	-	-15%
EU EE40 2014	1,00	0,95	0,78	-	-22%
EU High RES 2011	1,00	0,91	0,88	-	-12%
IEA 450	1,00	0,98	0,93	-	-7%
Greenpeace e. [r]evolution	1,00	0,99	0,91	-	-9%
Greenpeace advanced e. [r]evolution	1,00	0,99	0,90	-	-10%

Note: Greenpeace energy [r]evolution and advanced energy [r]evolution data are for OECD Europe;
ENTSOG scenarios calculated from TYNDP 2017 data, all others using the method explained in 2.1.4

Source: Prognos based on [ENTSOG 2015c]; [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015]

Table 48 shows the development of the installed capacity for gas power generation. Until 2030 installed capacity for gas power generation is decreasing in the European reference scenario 2016 as well as in more ambitious scenarios (EU EE30, EE 40 and High RES). In the scenario IEA 450 and in the Greenpeace scenarios (that cover OECD Europe) the capacity is increasing up to 27 %. In the TYNDP scenarios installed gas capacity increases by 11 % ("EU

Green Revolution" as well as "Blue Transition"). These grow rates seem optimistic in today´s surrounding. Peak gas demand for power generation will probably more likely stagnate. Here also further analysis is needed.

Table 48: Installed power plant gas capacity [GW] - Europe

Installed capacity of gas power plants [GW]	2015	2020	2030	2050	Change 2015-2030	Change 2015-2050	Change 2030-2050
EU Reference 2016	220	210	208	269	-5%	23%	29%
EU Reference 2013	253	259	281	302	11%	19%	8%
EU EE27 2014	253	259	258	212	2%	-16%	-18%
EU EE30 2014	253	259	254	190	0%	-25%	-25%
EU EE40 2014	253	258	240	158	-5%	-38%	-34%
EU High RES 2011	241	231	227	182	-6%	-25%	-20%
IEA 450	222	241	281		27%		
Greenpeace e. [r]evolution	267	313	309	162	16%	-39%	-48%
Greenpeace advanced e. [r]evolution	257	286	287	0	12%	-100%	-100%

Note: Greenpeace energy [r]evolution and advanced energy [r]evolution data are for OECD Europe

Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015]

Both demand for power production and the demand of final gas customers must be secured during the coldest day and over a cold period. This must be assessed simultaneously. In scenarios with RES and EE targets and policies yearly gas demand as well as peak capacity demand is declining quicker. Especially peak capacity for power generation seems to be very high in the TYNDP scenarios. Future analysis for security of supply in peak conditions should include an analysis of the whole energy system with integrated approaches. A proposal can be found at [Energy Union Choices 2016].

3.2.4 Impacts on infrastructure and costs

As discussed above and in previous chapters, gas and capacity demand in ENTSOG scenarios has been overestimated in the past. In contrast to the ENTSOG scenarios gas demand declined between 2010 and 2015 and will continue to decline in most other scenarios, especially in those that have ambitious RES and EE targets. With **more ambitious efficiency** targets gas demand would nearly be **halved** in comparison to the ENTSOG "Blue Transition" projections.

Impacts of a reduced future gas demand on infrastructure and costs are analysed in detail in chapter 4. According to the concept "Efficiency First" it should be investigated if gas demand could be reduced by energy savings or efficiency improvements. Infrastructure projects with regard to a finalisation of the internal market should be checked against "Efficiency First" as well. Besides, lower gas demand would also lead to a higher share of domestic gas production and therefore increase security of supply from a geopolitical perspective. For gas network planning this means, low carbon options, especially renewables and energy efficiency, do reduce the demand for new gas infrastructure. Future TYNDPs should therefore also consider target scenarios.

Costs

If less infrastructure needs to be built costs could be saved. The study "A perspective on Infrastructure and Energy Security in Transition" [Energy Union Choices 2016] compares the costs for infrastructure to ensure security of supply for a high gas demand scenario with a scenario that reaches climate targets. It found potential savings of € 11.4 billion between the high and the low case that could arise if gas demand is lower due to low carbon options. These savings could be realised when security of gas supply is assessed in an integrated way including an inspection of the power sector. However, the study did not analyse if or which projects of the TYNDP would become redundant. So, this number needs some validation but shows that there are potentials for significant cost savings in the gas infrastructure. Chapter 4 of this study assesses potential cost savings due to a faster deployment of EE and RES in detail. Besides infrastructure costs less gas demand would also save gas import costs.

3.2.5 Conclusion

- **Efficiency and RES potentials and gas demand**: There is clear evidence from the analysed scenarios that a high deployment of renewables and efficiency would lead to a shrinking gas demand and in the last consequence to a complete phase out of natural gas as a fuel. If the already agreed EU RES and EE targets were achieved, 852 TWh gas demand could be saved in 2030 as compared to the ENTSOG Blue Transition scenario. More ambitious targets, like the EE 40-target, as agreed by the European Parliament (EE 40), could even save up to 2,000 TWh (compared to the Blue Transition scenario) and still over 1,000 TWh (compared to the EU Green Revolution scenario). The development of final gas capacity demand would decrease at least by about 11 % (EE 27) or 22 % (EE 40) compared to 2015.
- **Comparison of NDP and other scenarios**: The ENTSOG Blue Transition scenario is the only scenarios with an increasing gas demand after 2025. Other analysed reference as well as target scenarios expect a stagnation or even a fast decline of gas demand. TYNDP scenarios 2017 include at least scenarios with decreasing gas demand (EU Green Revolution). Still, the potential of low carbon options for reducing the gas demand has not fully been assumed therein. Infrastructure planning should consider consistent demand projections that assume energy and climate targets.
- **Consequences on gas capacity demand**: A lower gas demand leads to a reduced gas capacity demand. However, the decline rates of capacity demand are expected to be smaller than those of gas demand. Nevertheless, a first estimation found that in ambitious scenarios final peak gas demand will decline notably in the future. There need to be further research with a regional perspective on the evolution of peak gas demand for decreasing yearly gas demand and on the potentials of gas demand response. The analysed scenarios show a high uncertainty about the development of the installed capacities of gas fired power plants both in the reference as well as in the target scenarios.
- **Infrastructure demand**: A reduced gas capacity demand might make a lot of infrastructure investments superfluous. Some investments could still be needed whatsoever. But before

investing in new infrastructure projects potential efficiency improvements and investments should be examined and applied.

- Synoptically, infrastructure measures need to be assessed under a "**on track" perspective**. To avoid stranded investments, infrastructure measures should consider both reference and target scenarios as well as more ambitious scenarios.

3.3 Potentials of low carbon options in the focus countries

3.3.1 France

3.3.1.1 Analysed scenarios

Several studies were selected in order to analyse the development of gas demand in France under different assumptions concerning efficiency and renewable development:

The following table summarizes the characteristics of the scenarios that have been analysed in this study. They are divided in three groups: reference scenarios, which assume a business-as-usual (BAU) development of energy consumption, target scenarios or/and explorative scenarios, which reach climate goals or answer the question "what happens if…?" and explore different assumptions like electrification, diversified energy mix or increased efficiency, and one ambitious scenarios, which models a decarbonisation pathway.

Table 49: Characterisation of the analysed demand scenarios - France[102]

Study	Scenario	Scenario description	Target compliance
Reference Scenarios			
Alliance Nationale de Coordination de la Recherche pour l'Energie (ANCRE), Scénarios de l'ANCRE pour la transition énergétique, 2013	ANCRE - TEND	Trend scenario	None of the targets are reached.
Direction générale de l'énergie et du climat (DGEC), Scénarios prospectifs Energie - Climat - Air pour la France à l'horizon 2035, 2015	DGEC - AME	This scenario models the energy demand when all the existing measures that have effectively been adopted or implemented up to 1st january 2014 are taken into account.	None of the targets are reached.
EU Commission, EU Reference scenario 2016, 2016	EU-REF2016	This report focuses on trend projections. It does not predict how the EU energy landscape will actually change in the future, but provides one of its possible future states given certain conditions. Legally binding GHG and RES targets for 2020 will be achieved. Policies agreed at EU and Member State level until December 2014 will be implemented.	Some of the targets are reached.
Scenarios with measures and targets or explorative scenarios			

102 "Factor 4" refers to the objective of reducing GHG emissions by a factor 4 by 2050.

Alliance Nationale de Coordination de la Recherche pour l'Energie (ANCRE), Scénarios de l'ANCRE pour la transition énergétique, 2013	ANCRE - SOB	Reinforced sufficiency (efficiency scenario): this scenario focuses on sobriety, efficiency and RES development, while reaching the target "Factor 4" and reducing the share of nuclear energy in electricity mix by 50 % by 2025	Some of the targets are reached.
	ANCRE - ELE	Decarbonisation through electricity: this scenario focuses on efficiency and expansion of the use of electricity, which is based on nuclear energy and RES, while reaching the target "Factor 4"	None of the targets are reached.
	ANCRE - DIV	Diversified vectors: this scenario focuses on efficiency, expansion of the use of electricity and use of the wide range of energy sources such as waste heat, bioenergies and integrated energy systems, while reaching the target "Factor 4"	None of the targets are reached.
IDDRI, CIRED, SDSN, EDDEN, Pathways to deep decarbonization in France, 2015	DDP - DIV	This diversification scenario focuses on decarbonization through diversification of alternatives to efficiency. In particular, measures such as new nuclear plants, expansion of CCS and very high amounts of bioenergy are implemented in this scenario.	Some of the targets are reached.
	DDP- EFF	This efficiency scenario is consistent with the LTECV target of reducing final energy demand by 50 % by 2050. In this scenario, RES represent 50 % of power generation. Its main feature is ambitious efficiency savings in all sectors.	Some of the targets are reached.
Agence de l'environnement et de la maîtrise de l'énergie (ADEME), L'exercice de prospective de l'ADEME, Vision 2030-2050, 2013	ADEME	This study uses two different methodologies for the two time scales: until 2030, the scenario contemplates the maximum potentials for efficiency gains and renewable expansion that can be reached realistically. For the period until 2050, the scenario reaches the target "Factor 4".	Some of the targets are reached.
Direction générale de l'énergie et du climat (DGEC), Scénarios prospectifs Energie - Climat - Air pour la France à l'horizon 2035, 2015	DGEC - AMS2	This target scenario models the energy demand when, in addition to the measures taken into account in AME, additional measures adopted after the 1.01.2014 are integrated, esp. LTECV objectives. In this scenario, the targets of reducing by 40 % GHG emissions by 2030 compared to 1990 and of increasing the share of renewables in final energy to 32 % by 2030 are met.	Some of the targets are reached.
Ambitious scenarios with measures and targets			
negaWatt and Institute Caisse des Dépôts pour la Recherche, Scénario négaWatt 2011-2050, 2014	negawatt	This target scenario aims to show how ambitious climate goals as well as a sustainable future can be reached with realistic options.	Most of the targets are reached.

Note: LTECV refers to the law "Loi relative à la transition énergétique pour la croissance verte » (see chapter 2.3.2.2) and NEEAP refers to the 2014 National Energy Efficiency Action Plan (see chapter 3.3.1.2).

Source: Prognos, based on [negawatt 2014], [DGEC 2015], [ANCRE 2013], [ANCRE 2015], [ADEME 2013], [DDP 2015], [EU Ref 2016]

3.3.1.2 Potentials of low carbon options and influence on gas demand

In order to reduce its GHG emissions, France aims in its legislative package LTECV (see chapter 0) to:

- Reduce its overall energy consumption (increase its energy efficiency):

- primary energy consumption should decrease to 219.9 Mtoe in 2020 as indicated in the national energy efficiency plan.
- final energy consumption should reach 131.4 Mtoe in 2020 as indicated in the national energy efficiency action plan, decrease by 20 % by 2030 and be halved by 2050 compared to 2012.

- Develop its renewable energy sources (RES), which should reach 23 % of final energy by 2020 and 32 % by 2030, with the following distribution in 2030: 40 % of power generation, 38 % of final heat consumption, 15 % of final fuel consumption and 10 % of gas consumption. At the same time, primary fossil fuel consumption should be reduced by 30 % in 2030 compared to 2012.

The following table gives an overview of the extent to which the analysed scenarios reach these national and EU targets concerning efficiency and RES. Target scenarios (negawatt, ADEME and DGEC-AMS2) mostly reach the targets. Scenario PDD-EFF seems to fare worse than other target scenarios, but biogas is not incorporated in final renewables consumption, which distorts this comparison. It must be noticed that LTECV targets have been adopted only in July 2015, so that many scenarios have not integrated these targets. The other scenarios miss the targets.

Table 50: Comparison between scenarios and EU and national targets - France

	Primary fossil fuel consumption [TWh]	**Primary energy demand [TWh]**	**Final energy demand [TWh]**			**% renewables in final energy**		**% renewables in power generation**
	2030	**2020**	**2020**	**2030**	**2050**	**2020**	**2030**	**2030**
LTECV and Article 3 EED targets	*1.058*	*2.557*	*1.528*	*1.377*	*861*	*23%*	*32%*	*40%*
negawatt	819	2.460	1.727	1.320	848			62%
ANCRE - SOB	1.132	2.745		1.309	1.018		13%	30%
ANCRE - ELE	1.210	2.919		1.543	1.284		13%	29%
ANCRE - DIV	1.171	2.826		1.527	1.306		17%	28%
ANCRE - TEND	1.423	2.987		1.747	1.767		11%	25%
EU-REF2016	1.262	2.723	1.820	1.715	1.690	24%	26%	39%
ADEME	826			1.433	956			46%
PDD - DIV	1.011	1.992	1.717	1.586	1.368	15%	26%	37%
PDD - EFF	850	1.839	1.630	1.328	886	8%	12%	30%
DGEC - AME	1.342		1.779	1.791		18%	21%	

DGEC - AMS2	837			1.640	1.407		22%	34%

Note: Red colour means the targets have not been reached.

Source: Prognos, based on [negawatt 2014], [DGEC 2015], [ANCRE 2013], [ANCRE 2015], [ADEME 2013], [DDP 2015], [EU Ref 2016]

Concerning energy efficiency, all of the scenarios expect a decrease of energy intensity (defined as primary energy consumption per person), even though many of the scenarios miss the 2020 target as defined in the National Energy Efficiency Action Plan 2014 (NEEAP 2014). By 2030, the reduction in energy intensity ranges from 9 % (PDD-DIV) to 49 % (negawatt) and by 2050 from 13 % (ANCRE-TEND) to 71 % (negawatt) compared to 2010.

Table 51: Energy efficiency: Development of primary energy demand and primary energy demand per person in the analysed demand scenarios - France

Primary energy demand [TWh]	2010	2020	2030	2040	2050	Change 2010-2020	Change 2020-2030	Change 2030-2050	Change 2010-2050
NEEAP 2014 targets		*2.557*							
negawatt	3.009	2.460	1.662	1.133	1.010	-18%	-32%	-39%	-66%
ANCRE - SOB	3.097	2.745	2.443	2.219	2.088	-11%	-11%	-15%	-33%
ANCRE - ELE	3.097	2.919	2.763	2.610	2.537	-6%	-5%	-8%	-18%
ANCRE - DIV	3.097	2.826	2.627	2.518	2.428	-9%	-7%	-8%	-22%
ANCRE - TEND	3.097	2.987	2.962	3.009	3.096	-4%	-1%	5%	0%
ADEME			2.105		1.422			-32%	
EU - REF2016	2.945	2.723	2.576	2.374	2.242	-8%	-5%	-13%	-24%
PDD - DIV	2.033	1.992	1.953	1.997	1.889	-2%	-2%	-3%	-7%
PDD - EFF	2.033	1.839	1.539	1.372	1.114	-10%	-16%	-28%	-45%
DGEC - AME									
DGEC - AMS2									
Primary energy demand/ person [kWh/p]	**2010**	**2020**	**2030**	**2040**	**2050**	**Change 2010-2020**	**Change 2020-2030**	**Change 2010-2030**	**Change 2010-2050**
negawatt	47.852	37.294	24.251	16.018	13.974	-22%	-35%	-49%	-71%
ANCRE - SOB	49.317	41.808	35.671	31.520	28.874	-15%	-15%	-28%	-41%
ANCRE - ELE	49.317	44.465	40.340	37.071	35.083	-10%	-9%	-18%	-29%
ANCRE - DIV	49.317	43.048	38.354	35.766	33.587	-13%	-11%	-22%	-32%
ANCRE - TEND	49.317	45.493	43.243	42.737	42.820	-8%	-5%	-12%	-13%
ADEME			30.275		19.221				
EU - REF2016	47.931	42.267	38.437	34.290	31.728	-12%	-9%	-20%	-34%
PDD - DIV	31.246	30.194	28.494	28.236	26.135	-3%	-6%	-9%	-16%
PDD - EFF	31.246	27.878	22.455	19.400	15.412	-11%	-19%	-28%	-51%
DGEC - AME									
DGEC - AMS2									

Note: Red colour means the target has not been reached.

Source: Prognos, based on [negawatt 2014], [DGEC 2015], [ANCRE 2013], [ANCRE 2015], [ADEME 2013], [DDP 2015], [EU Ref 2016]

Concerning renewable energy sources, their share in primary energy demand is expected to increase in all of the scenarios. However, the share varies greatly according to the scenarios: it ranges from 16 % to 34 % in 2030 and from 24 % to 89 % in 2050.

Table 52: Renewables: Share of RES in primary energy demand in the analysed demand scenarios – France

RES demand/ primary energy demand [%]	2010	2020	2030	2040	2050
negawatt	8%	14%	34%	70%	89%
ANCRE - SOB	8%	11%	17%	22%	27%
ANCRE - ELE	8%	11%	16%	22%	27%
ANCRE - DIV	8%	13%	19%	25%	31%
ANCRE - TEND	8%	13%	18%	21%	24%
ADEME			29%		57%
EU - REF2016	9%	16%	18%	21%	27%
PDD - DIV	14%	22%	33%	43%	50%
PDD - EFF	14%	22%	29%	39%	50%
DGEC - AME					
DGEC - AMS2					

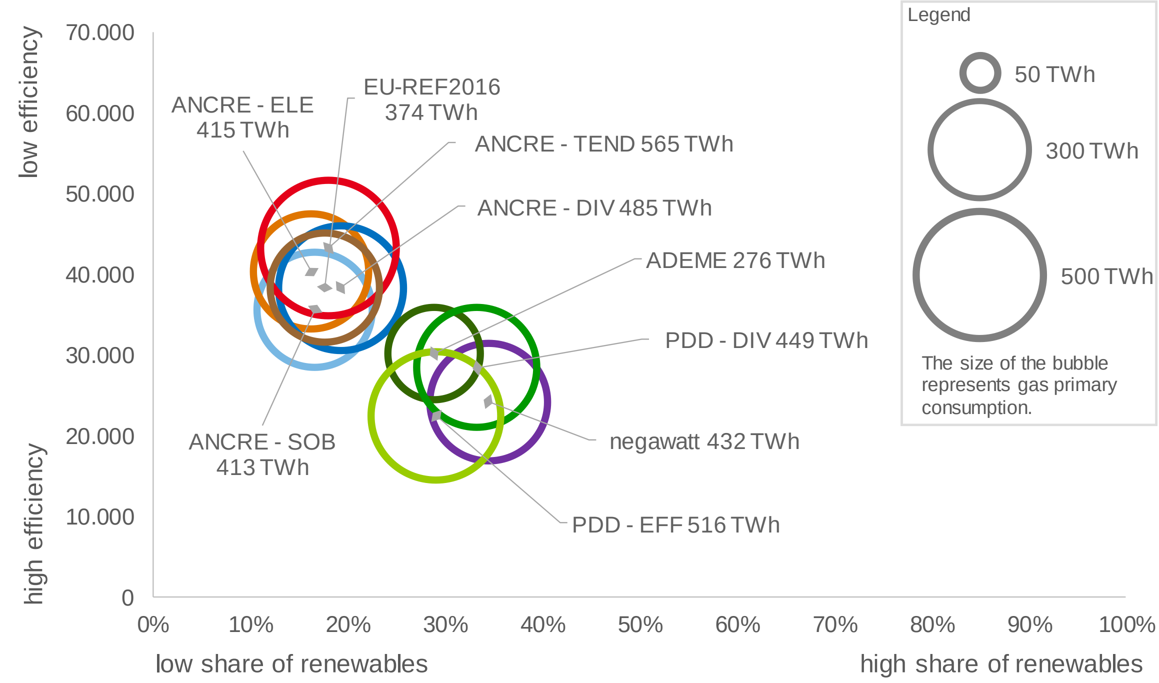
Source: Prognos, based on [negawatt 2014], [DGEC 2015], [ANCRE 2013], [ANCRE 2015], [ADEME 2013], [DDP 2015], [EU Ref 2016].

All of the scenarios show an increase in energy efficiency as well as a substitution of fossil/nuclear energy sources by renewables. The range of these efficiency and RES developments is nonetheless quite wide. Moreover, a great part of the scenarios misses national and EU targets. The adoption of LTECV in 2015 denotes a sharpened political stance on efficiency and RES issues which could help to better exploit efficiency and RES potentials.

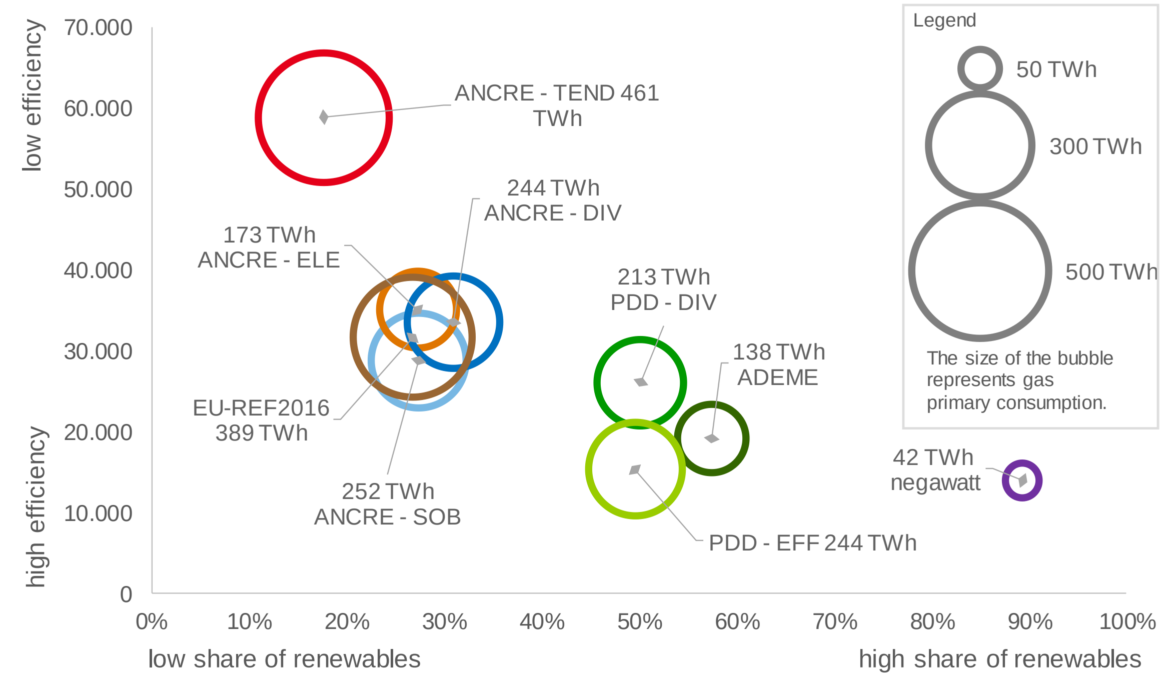
The impact of RES development and efficiency measures on gas consumption is represented in the following graphs. In 2030, relationships between the two factors and gas consumption is not to be seen: in spite of efficiency measures and RES development, gas consumption continues to increase to replace nuclear and other fossil fuel plants for power generation. In 2050 on the other hand, the power generation sector is expected to be largely composed of renewables and natural gas is not playing a major role. The 2050 graph illustrates that the more efficient the energy system and the greater the share of renewables in primary energy, the smaller is the gas demand.

Table 53: Relationship between energy intensity, share of renewables in primary energy consumption and primary gas consumption - France

Relationship between energy intensity [kWh/p], share of renewables in primary energy consumption [%] and primary gas consumption [TWh] in 2030 - FRANCE



Relationship between energy intensity [kWh/p], share of renewables in primary energy consumption [%] and primary gas consumption [TWh] in 2050 - FRANCE



Source: Prognos, based on [negawatt 2014], [DGEC 2015], [ANCRE 2013], [ANCRE 2015], [ADEME 2013], [DDP 2015], [EU Ref 2016]

The scenarios use similar assumptions regarding CO_2 prices, except DGEC. Most of them do not model CO_2 prices of the EU exchange trading scheme, but introduce a CO_2 tax on fossil fuels (see Table 54). DGEC scenarios incorporate both CO_2 taxes and a CO_2 price for sectors under the EU ETS (not represented here). The scenarios were elaborated before the adoption of LTECV in 2015, which sets the following evolution for the CO_2 tax: 7 EUR/tCO_2 in 2014, 14.5 EUR/tCO_2 in 2015, 22 EUR/tCO_2 in 2016, 56 EUR/tCO_2 in 2020 and 100 EUR/tCO_2 in 2030.

Table 54: CO_2 tax in the analysed scenarios -France

Price CO_2 [Euro/t]	2010	2015	2020	2025	2030	2040	2050
negawatt							
ANCRE - SOB	42				100		300
ANCRE - ELE	42				100		240
ANCRE - DIV	42				100		240
ANCRE - TEND	42				100		240
ADEME							
EU - REF2016							
PDD - DIV			58		90	183	280
PDD - EFF			75		120	236	360
DGEC - AME		15	22	22	22		
DGEC - AMS2		15	22	22	22		

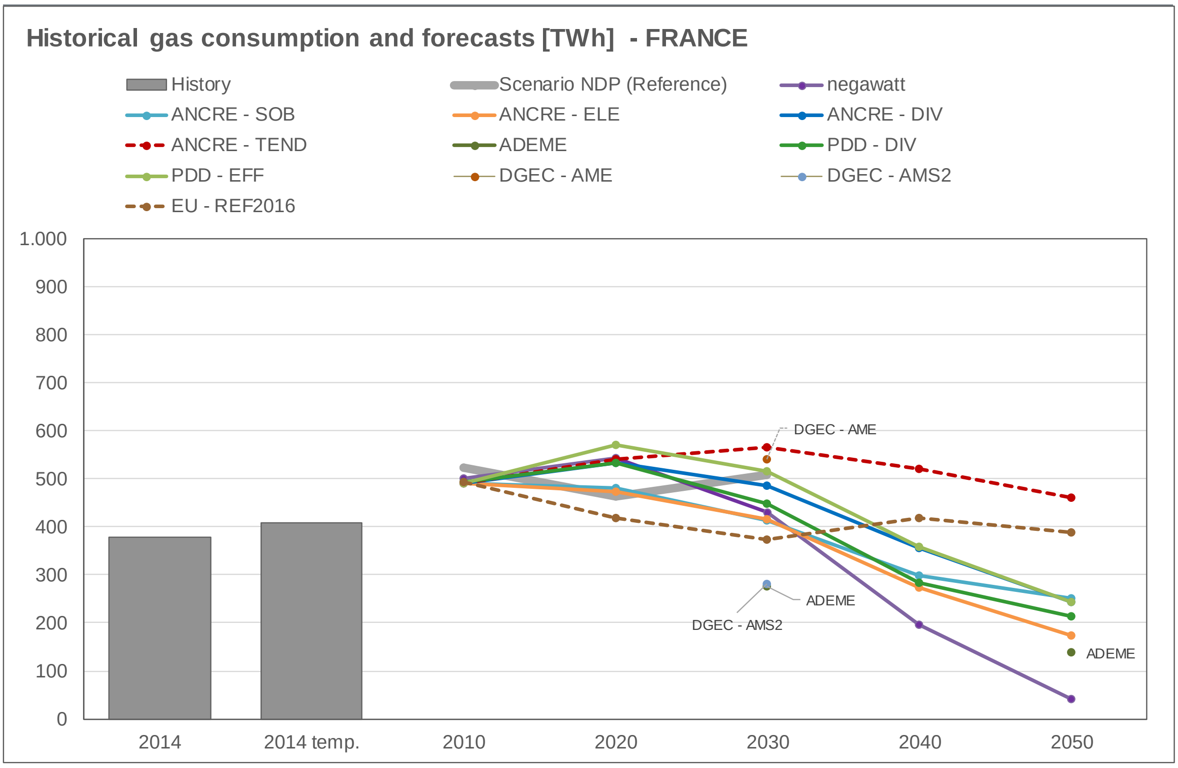
Source: Prognos, based on [negawatt 2014], [DGEC 2015], [ANCRE 2013], [ANCRE 2015], [ADEME 2013], [DDP 2015], [EU Ref 2016]

Overall, the scenarios include a CO_2 tax and are in line with the new law. Therefore, a high CO_2 tax (above 100 EUR/t CO_2) seems to be needed by 2030 to achieve positive effects on efficiency increase and RES development. However, assumptions regarding CO_2 prices are not expected to explain the differences between the scenarios, as they are quite similar. The effects of CO_2 prices in the EU ETS, however, are unknown and their evolution quite uncertain.

3.3.1.3 Gas demand in these scenarios

Between 2010 and 2020, most of the scenarios for which data is available display an increase in gas demand. Exceptions are on the one hand ANCRE scenarios ELE and SOB (which are focused on electrification and efficiency respectively, explaining the reason why gas demand in these scenarios decreases earlier than in the other scenarios) and on the other hand the NDP reference and EU REF2016 scenarios, which for the first time have taken into account the decreasing trend in gas consumption since 2010 (see Figure 16). The other scenarios seem to have overlooked this recent decreasing trend. In the NDP, this trend is expected to be short-term and postpones the increase of gas consumption to the time after 2020. In the EU-REF2016 scenario, the decreasing trend in longer-term: gas consumption is expected to continue to reduce in the next two decades and will increase only from 2035, to offset a sharp decrease in nuclear generation capacities. This increase is however short term: from 2045, gas consumption for power generation as well as gross gas demand will decrease (see Figure 31).

Figure 31: Development of gas demand in analysed scenarios -France



Note: 1. Each analysed study is pictured in a different colour. 2. 2014 was an exceptionally warm year. It was the warmest year since 1990. Therefore, the temperature-adjusted gas consumption has been added. 3. Trend / reference / business as usual scenarios are indicated with a spotted line.

Source: Prognos, based on [negawatt 2014], [DGEC 2015], [ANCRE 2013], [ANCRE 2015], [ADEME 2013], [DDP 2015], [EU Ref 2016], [GRTgaz 2015], [TIGF 2015]

The reason for an increase in gas consumption between 2010 and 2020/2030/2035 is similar in the different scenarios:

- Final gas demand decreases (except in the scenario DDP-EFF, because of ambitious gas use in the transport sector: 117 TWh in 2020, 150 TWh in 2030[103]). Gas demand in the residential (biggest gas consumer in France) and tertiary sectors as well as in the industry decreases because of:
  - Efficiency measures, which reduce the overall energy use, especially for heating purposes and electricity (more efficient appliances);
  - The development of district heating using waste heat from industries and power plants. Moreover, one of the LTECV objectives is to multiply by 5 the energy transported by heating and cooling networks and coming from renewable and waste sources by 2030;
  - The development of heat pumps and biomass (incl. biogas) for heating purposes.

[103] In comparison, ADEME (in the report « Vision pour le biométhane en France pour 2030 ») calculates 30 TWh of biomethane production by 2030 in its scenario “Business as usual” and 60 TWh by 2030 in its “pro-active” scenario.

- On the other hand, gas use in the power sector increases, partly to offset closure of nuclear and oil plants, and in parallel to the development of renewable energy sources. New gas turbines and CCGT are expected to be built. The increase in gas consumption for power generation is expected to exceed the decrease in final gas demand.
- In the 2015 NDP, the use of biogas and the development of gas in the transport sector (around 30-35 TWh in each case) play a major role in the gas consumption increase.

The highest gas consumption over the period 2010-2050 is reached in 2020 in the scenario PDD-EFF. It must be noticed that even in this most bullish case in terms of gas consumption, gas demand is only 15 % above the peak reached in 2010 of 495 TWh. In the EU-REF2016 scenario, gas demand reaches the highest amount in 2040, which stays far below the 2010 peak. By 2030, gas consumption in the NDP decreases and is smaller than all the other scenarios except EU-REF2016 (where the decreasing trend last longer). By 2030, gas demand in the NDP increases to 509 TWh and is higher than gas consumption in almost all of the target/explorative scenarios. Even the gas consumption of the EU-REF2016 scenario is lower. When comparing gas demand in the scenarios, gas saving potential in 2030 ranges from 24 TWh to 233 TWh (see Table 55).

Table 55: Gas saving potential: differences between alternative scenarios and the NDP for 2020 and 2030 in TWh - France

Saving potential [TWh]	2020	2030
NDP 2015	463	509
Savings (delta NDP 2015 - gas demand in the scenario):		
negawatt	-80	77
ANCRE - SOB	-18	96
ANCRE - ELE	-12	94
ANCRE - DIV	-70	24
ANCRE - TEND	-79	-56
ADEME		233
EU - REF2016	45	135
PDD - DIV	-71	60
PDD - EFF	-108	-7
DGEC - AME		-33
DGEC - AMS2		228

Source: Prognos, based on [negawatt 2014], [DGEC 2015], [ANCRE 2013], [ANCRE 2015], [ADEME 2013], [DDP 2015], [EU Ref 2016], [GRTgaz 2015], [TIGF 2015]
Note: Saving potential is indicated in green.

The 2015 NDP does not go beyond 2030. Around 2035, the EU-REF2016 scenario expects a slight increase in gas consumption due to an increased use of gas for power generation (which would take place a decade later than the increase expected in the NDP scenario). Primary gas demand only reaches a maximum of 419 TWh and decreases afterwards. Except the EU-REF2016 scenario, all other scenarios expect a reduction in gas consumption after 2030. As efficiency measures continue to reduce energy demand and renewable energies continue to replace fossil fuels and decarbonize sectors, gas is used less and less. Between 2030 and 2050, gas demand decreases between 19 % and 90 % (except in the EU-REF2016). As a consequence, the share of gas in primary energy demand also decreases from 2020 or 2030 onward and reaches a wide range of shares in 2050, from 4 % in negawatt to 35 % in PDD-EFF. Compared to 2010, share of gas is smaller in 2050 except in PDD and EU-REF2016 scenarios (see Table 56).

Table 56: Share of primary gas demand in the analysed demand scenarios - France

Gas demand/ primary energy demand [%]	2010	2020	2030	2040	2050	Change 2010-2020	Change 2020-2030	Change 2030-2050	Change 2010-2050
negawatt	17%	22%	26%	17%	4%	33%	18%	-84%	-75%
ANCRE - SOB	16%	18%	17%	13%	12%	11%	-3%	-28%	-24%
ANCRE - ELE	16%	16%	15%	10%	7%	3%	-8%	-55%	-57%
ANCRE - DIV	16%	19%	18%	14%	10%	19%	-2%	-46%	-36%
ANCRE - TEND	16%	18%	19%	17%	15%	15%	5%	-22%	-6%
ADEME			13%		10%			-26%	
EU - REF2016	17%	15%	15%	18%	17%	-9%	-5%	19%	3%
PDD - DIV	24%	28%	28%	26%	27%	14%	1%	-2%	13%
PDD - EFF	24%	31%	36%	34%	35%	30%	14%	-3%	43%
DGEC - AME									
DGEC - AMS2									

Note: The columns entitled “Change year X- year Y” represent the increase of the gas share in primary energy demand in the given period, not the gas share itself.

Source: Prognos, based on [negawatt 2014], [DGEC 2015], [ANCRE 2013], [ANCRE 2015], [ADEME 2013], [DDP 2015], [EU Ref 2016]

As already mentioned in chapter 0, the development of biogas can have significant impacts on gas demand and its transport infrastructures. The primary gas demand (that was analysed above) does not incorporate biogas/ biomethane. The table below illustrates the importance of assumptions concerning biogas development. In some scenarios, biogas consumption in 2050 represents a major part of overall gas consumption. In negawatt, 79 % of gas consumption is biogas. In PDD-DIV, the share of biogas in gas consumption reaches 59 %. LTECV targets a 10 % share of renewable sources in final gas consumption. ADEME mentioned the following figures in a previous report (« Vision pour le biométhane en France pour 2030 »): 30 TWh of biomethane production by 2030 in its scenario “Business as usual” (40 % being injected in the gas network and 60 % in cogeneration) and 60 TWh by 2030 in its “pro-active” scenario (50 % being injected in the gas network and 50 % in cogeneration). These are ambitious goals and some stakeholders expressed caution concerning the amount of biogas that would be actually produced in the future[104].

[104] Source: Délibération de la Commission de régulation de l’énergie du 17 décembre 2015 à l’examen du plan décennal de développement et portant décision d’approbation du programme d’investissements pour l’année 2016 de GRTgaz.

Table 57: Biogas demand in the analysed scenarios

Biogas [TWh]	2010	2020	2030	2040	2050
negawatt	4	27	73	123	157
ANCRE - SOB					
ANCRE - ELE					
ANCRE - DIV	0		10		33
ANCRE - TEND					
ADEME			67		102
EU - REF2016					
PDD - DIV	6	19	98	241	303
PDD - EFF	6	7	34	107	142
DGEC - AME					
DGEC - AMS2					

Source: Prognos, based on [negawatt 2014], [DGEC 2015], [ANCRE 2013], [ANCRE 2015], [ADEME 2013], [DDP 2015], [EU Ref 2016]

There tends to be a relationship between efficiency, renewables and gas consumption after 2030. With increasing efforts on efficiency and RES development, a gas reduction after 2030 can be expected. This means that investments in infrastructure have to be carefully analysed. Especially, the timeframe for the return on investment can be relatively narrow and not be enough to make the infrastructure profitable.

3.3.1.4 Impacts on infrastructure and costs

2 proposed projects are linked to increased gas imports which would be needed in case of an increase in gas consumption:

- Expansion of LNG terminal in Montoir from 370 to 550 GWh/d
- Expansion of LNG regasification capacity in the south of France with the construction of Fos Cavaou (270 GWh/d).

Both of the projects are expected to start operating in 2021, but neither the costs nor the necessity of those capacities are known or justified. They are not decided yet. There is great uncertainty concerning the actual expansion of the terminals, as France already has enough import capacities and could use available and under-utilized LNG terminals in Spain. Some stakeholders urge investors to find long-term purchase commitments before starting the projects, as well as to provide detailed and public cost-benefit analyses of the projects.

A number of proposed projects are indirectly linked to increased import capacities and concern increased transport capacities to reduce congestion at some entry points. This is the case of the 2015 extension of LNG terminal capacities in Dunkirk. This generates the need to:

- create exit capacities towards Belgium (Alveringem)
- create a corridor called *Arc de Dierrey* in order to improve the traffic flow in the northern zone.

Additional investments would also be necessary in the case of the expansion of:

- LNG Montoir: the corridor *artère du Maine* would need to be doubled and a new pipeline would need to be built between Chémery and Dierrey (costs are unknown)
- Import capacities from the south with the Midcat and/or Fos Cavaou projects. A strengthening of the flows from south to north would be needed, for example by doubling the corridor *artère du Rhone* (projects Eridan and Arc Lyonnais).

Other projects aim to improve the distribution of gas on the territory. Gas imports are concentrated in the North of France (Dunkirk, Obergailbach and PIR Norway) so that the TSO aims to improve transport capacities from north to south of France and in the Iberian Peninsula. Moreover, since 2015, the two market zones have combined to create a unique market zone for gas in France. The traffic from north to south also needs to be improved and the infrastructure needs to be adapted. Projects linked to these developments are: Val-de-Saone, Gascogne-Midi and Eridan.

Table 58 summarises existing and proposed projects from the NDP.

Table 58: Existing and proposed projects in the NDP 2015

Category	GWh/d	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Costs mEUR
Entry (Belgium)	Taisnières B - Conversion zone low CV in high CV (2029)	230	230	230	230	230	230	230	230	230	230	
Entry (Belgium)	Taisnières H	640	640	640	640	640	640	640	640	640	640	
Exit (Switzerland, Italy)	Oltingue (PIR)	223	223	223	223	223	223	223	223	223	223	
Exit (Switzerland)	Jura (PIR)	37	37	37	37	37	37	37	37	37	37	
Entry (Germany)	Obergailbach (PIR)	620	620	620	620	620	620	620	620	620	620	
Entry	LNG Montoir (PITTM)	370	370	370	370	370	370	550	550	550	550	?
Entry	LNG Fos (PITTM): Fos Tonkin + Fos Cavaou	410	410	410	410	410	410	680	680	680	680	?
Entry (Norway)	Gasco (PIR)	570	570	570	570	570	570	570	570	570	570	
Entry (northern zone, Belgium)	Haut de France II/Arc de Dierrey - LNG Dunkerque (PITTM)		520	520	520	520	520	520	520	520	520	1185
Exit (Belgium)	PIR Alveringem		270	270	270	270	270	270	270	270	270	86
Exit (Spain)	PIR Pirineos (Biriatou) - firm	165	165	165	165	165	165	165	165	165	165	99
Entry (Spain)	PIR Pirineos (2 interconnexions: Biriatou + Larrau): Artères de l'Adour, du Béarn, Girland	165	225	225	225	225	225	225	225	225	225	200
Entry (Switzerland, Italy)	Oltingue (PIR)				100	100	100	100	100	100	100	15
Exit (Germany)	Obergailbach (PIR)								100	100	100	600
	Val-de-Saone (Creation of a single zone)				x							740
	Gascogne-Midi (Creation of a single zone)				x							173
	Eridan (2021-2022)								x			620
Entry	Midcat (Midi-Catalogne) - 2022								230	230	230	400
Exit	Midcat (Midi-Catalogne) - 2022								80	80	80	
Total		**3430**	**4280**	**4280**	**4380**	**4380**	**4380**	**4830**	**5240**	**5240**	**5240**	**4118**

Legend

existing
under way
decided
project (not decided)

Source: Prognos, based on [GRTgaz 2015] and [TIGF 2015]

Key findings

Investments in gas infrastructure have to be carefully analysed as a gas reduction after 2030 can be expected. Especially, the timeframe for the return on investment can be relatively narrow and not enough to make the infrastructure profitable.

Nevertheless, the effects of gas consumption development on infrastructures and associated costs cannot be estimated in detail because:

- There is little or no information on the costs of LNG projects, or on the reasons why they should be realised
- It is difficult to distinguish between projects linked to gas imports and those linked to the improvement of the connection between regions or countries (especially improvement of traffic flows along the axis north-south in both directions).

The most bullish scenario of gas demand indicates an increase of 75 TWh. This additional amount can theoretically be covered by existing capacities. For example, LNG regasification terminals in 2014 have not even reached 40 % of utilisation rate. Moreover, in 2016, 10 mtpa of LNG import capacities have already been added in Dunkirk, which represents 125 TWh or 20 % of both French and Belgian gas demand.

Some inconsistencies can also be noted:

- Spain LNG capacities are largely underused while among the NDP proposed projects, there are LNG expansion projects in the south of France;
- Some projects aim to develop flows from north to (under-supplied) south while at the same time, there are available import capacities in the south. More should be done to take the existing infrastructure into account[105].

Overall, more transparency is needed for stakeholders to be able to better assess the usefulness of proposed investments: assumptions that are made for demand projections, extra costs for consumers and users of transport networks, coherence of the projects with adjacent TSO projects.

3.3.1.5 Conclusion

- **Efficiency and RES potentials and relationship with gas**: There tends to be a relationship between efficiency, renewables and gas consumption after 2030. With increasing pressure on efficiency and RES development, a reduction of gas consumption after 2030 can be expected.
- **Situation of NDP scenarios compared to other scenarios**: The 2015 NDP scenario seems to be in line with other non-target scenarios (increase of gas consumption in the power sector that would surpass a decreasing consumption in final energy in the short term), but not in line with target scenarios, which are the scenarios that best achieve EU and national climate and energy targets. The EU-REF2016 scenario expects a short term increase in

[105] These inconsistencies can partly be explained by the different views concerning cross-border interconnections. Especially, the Midcat project would not be, according the CRE (http://www.cre.fr/documents/presse/dossiers-de-presse/dossier-de-presse-les-interconnexions-electriques-et-gazieres-en-france#), of interest for France and its taxpayers (costly infrastructure development and reinforcement, more expansive gas). On the other hand, the European Commission says it would help reduce Europe's dependence on Russian gas. It would also enable Spain to use its under-utilized LNG capacities and get cheaper pipeline gas. This highlights the conflicting national and EU interests when it comes to optimize national infrastructure for European use. As a consequence, some infrastructures are used inefficiently at the EU level.

gas consumption between 2035 and 2045 (corresponding to the decrease in nuclear generation capacities) but even in this case, gas demand stays below the 2010 peak.

- **Assumptions about possible reduction of gas demand**: With the adoption of LTECV in 2015, French government sharpened its stance on efficiency and renewable targets. Energy transition is therefore likely to be accelerated. This means that investments in infrastructure have to be carefully analysed. Especially, the timeframe for the return on investment can be relatively narrow and not be enough to make the infrastructure profitable. The effect of biogas development on overall gas consumption and gas infrastructures are uncertain and has yet to be investigated. However, two facts seem to show the effects are likely to be limited: first, in the “pro-active” scenario of ADEME, biogas production does not go beyond 60 TWh in 2030 (and only 50 % of this amount is supposed to be injected in networks), which can be compared with 281 TWh, which is the gas demand in the lowest scenario. Second, the use of plant and animal resources to produce biogas may come in competition with other uses (i.e. land use, food supply). The extent of possible methane or hydrogen production with power to gas technologies is highly speculative.
- **Consequences on infrastructure and costs**: The increase in gas consumption amounts to 15 % of the 2010 peak consumption (or 75 TWh) in the most bullish scenario. In this extreme scenario, it should be verified if the increase in demand could eventually be met by increased use of under-utilized (French and Spanish) capacities or if there are other more cost efficient alternatives. Better cooperation between countries and coherence with adjacent TSO projects are needed to avoid inconsistent and inefficient projects. In particular, more efficient distribution of gas imports across regions would improve the profitability of existing and under-used import infrastructures, while avoiding costly and redundant projects that are at risk of being mothballed. Overall, more transparency is needed for stakeholders to be able to better assess the usefulness of proposed investments.

3.3.2 Germany

3.3.2.1 Analysed scenarios

We analysed five different studies with a total of ten demand scenarios (Table 59). The considered scenarios can be divided in reference and (ambitious) target scenarios. Our analysis includes four reference and six target scenarios which are especially analysed regarding their assumptions and results about gas demand, energy efficiency and renewable energies.

Table 59: Characterisation of the analysed demand scenarios – Germany

Study	Scenario	Scenario description
Reference Scenarios		
Öko-Institut/ Fraunhofer ISI, “Klimaschutzszenario 2050 (2nd edition)”, 2015	AMS	This scenario takes all measures into account which have been implemented by 2012, these measures were extrapolated until 2050. That means, this scenario shows the current status of energy and climate policy.
EWI/ Prognos/ GWS, „Entwicklung der Energiemärkte – Energiereferenzprognose“, 2014	Referenz	This reference scenario displays a likely development of the energy markets and expects further climate policy actions. Climate protection will play an important role in the future.

European Commission, EU Reference scenario, 2016	EU Reference Sce-nario 2016	New reference scenario of the European Commission
Dr. Joachim Nitsch, „Die Energiewende nach COP 21 – Aktuelle Szenarien der deutschen Energieversorgung (Kurzstudie)“, 2016	SZEN-16 - TREND	This scenario takes all measures into account which have been implemented by 2015, these measures were extrapolated until 2050. That means, this scenario shows the current status of energy and climate policy.
Target Scenarios		
Öko-Institut/ Fraunhofer ISI, “Klimaschutzszenario 2050 (2nd edition)”, 2015	KS 80	The defined objectives regarding GHG emissions, renewables and energy efficiency of the German energy concept will be achieved in this scenario. The 80 percent reduction of GHG emissions until 2050 compared with 1990 shows a development which is at the bottom end of the target corridor.
	KS 95	The defined objectives regarding GHG emissions, renewables and eneryg efficiency of the German energy concept will be achieved in this scenario. The 95 percent reduction of GHG emissions until 2050 compared with 1990 shows a development which is at the upper end of the target corridor.
EWI/ Prognos/ GWS, „Entwicklung der Energiemärkte – Energiereferenzprognose“, 2014	Ziel 80	The defined objectives regarding GHG emissions, renewables and energy efficiency of the German energy concept will be achieved in this scenario. The 80 percent reduction of GHG emissions until 2050 compared with 1990 shows a development which is at the bottom end of the target corridor. This target scenario requires additional measures compared with the reference case.
Fraunhofer ISE, „WAS KOSTET DIE ENERGIEWENDE? – Wege zur Transformation des deutschen Energiesystems bis 2050“, 2015	ISE 85 (incl. Biogas, hydrgen, biomethane)	The defined objectives regarding GHG emissions, renewables and energy efficiency of the German energy concept will be achieved in this scenario. The 85 percent reduction of GHG emissions until 2050 compared with 1990 shows a development which is in the middle of the target corridor.
Dr. Joachim Nitsch, „Die Energiewende nach COP 21 – Aktuelle Szenarien der deutschen Energieversorgung (Kurzstudie)“, 2016	SZEN-16 - KLIMA 2050	The defined objectives regarding GHG emissions, renewables and energy efficiency of the German energy concept will be achieved in this scenario. The 95 percent reduction of GHG emissions until 2050 compared with 1990 shows a development which is at the upper end of the target corridor.
Ambitious Target Scenarios		
Dr. Joachim Nitsch, „Die Energiewende nach COP 21 – Aktuelle Szenarien der deutschen Energieversorgung (Kurzstudie)“, 2016	SZEN-16 - KLIMA 2040	This scenario shows a development with strengthened climate protection to reach the 2 °C-objective. That means for Germany that the decarbonisation of the energy system has to be achieved already until 2040 and that there are negative emissions necessary between 2040 and 2050.

Source: Prognos, based on [Öko-Institut/ Fraunhofer ISI 2015], [EWI/ Prognos/ GWS 2014], [EU Reference Scenario 2016], [Fraunhofer ISE 2015], [Nitsch 2016]

The following table shows the objectives of the German policy (“Energiekonzept der Bundesregierung”).

Table 60: Characterisation of the analysed demand scenarios – Germany

Goals of the German government	2020	2030	2040	2050
Greenhouse gas emissions (compared to 1990)	-40%	-55%	-70%	-80-95%
Primary energy demand (compared to 2008)	-20%	---	---	-50%

Share of renewables of gross electricity consumption	35%	50%	65%	80%

Source: Prognos, based on „Energiekonzept der Bundesregierung“

3.3.2.2 Potentials of low carbon options and influence on gas demand

In this chapter, assumptions and results of the different scenarios regarding efficiency, renewables and CO_2-prices are analysed.

Table 61 shows the development of the efficiency indicator primary energy demand per person in the analysed scenarios. There is a range of the decline of this indicator from 2020 to 2050 in the considered reference scenarios (Klimaschutzszenarien 2050 – AMS, Energiereferenzprognose Referenz, EU Reference Scenario 2016, SZEN-16 – TREND) between -10 % and -23 %. Especially the EU Reference Scenario 2016 shows a relatively small reduction with regard to the considered efficiency indicator. There is only a small range between the considered target scenarios (Klimaschutzszenarien 2050 – KS 80 and KS 95, Energiereferenzprognose Ziel, ISE 85, SZEN-16 – KLIMA 2050 and 2040) regarding this indicator. The reduction ranges from
-34 % to -39 % between 2020 and 2050. It becomes clear that there is a huge difference between the reference and target scenarios.

Table 61: Energy efficiency: Development of primary energy demand and primary energy demand per person in the analysed scenarios

Primary energy demand [TWh]	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
Klimaschutzszenarien 2050 - AMS	3.375	2.923	2.646	2.446	-13%	-28%	-16%
Klimaschutzszenarien 2050 - KS 80	3.119	2.456	2.058	1.815	-21%	-42%	-26%
Klimaschutzszenarien 2050 - KS 95	2.894	2.164	1.858	1.649	-25%	-43%	-24%
Energiereferenzprognose Referenz	3.287	2.908	2.595	2.321	-12%	-29%	-20%
Energiereferenzprognose Ziel 80	3.150	2.623	2.222	1.914	-17%	-39%	-27%
EU Reference Scenario 2016	3.586	3.238	3.032	2.975	-10%	-17%	-8%
ISE 85 (incl. Biogas, hydrgen, biomethane)	-	-	-	2.044	-	-	-
SZEN-16 - TREND	3.545	3.182	2.944	2.771	-10%	-22%	-13%
SZEN-16 - KLIMA 2050	3.382	2.751	2.315	1.992	-19%	-41%	-28%
SZEN-16 - KLIMA 2040	3.346	2.607	2.104	1.967	-22%	-41%	-25%
Primary energy demand/ person [kWh/p]	**2020**	**2030**	**2040**	**2050**	**Change 2020-2030**	**Change 2020-2050**	**Change 2030-2050**
Klimaschutzszenarien 2050 - AMS	42.821	37.596	34.714	33.059	-12%	-23%	-12%
Klimaschutzszenarien 2050 - KS 80	39.575	31.583	27.001	24.527	-20%	-38%	-22%
Klimaschutzszenarien 2050 - KS 95	36.720	27.839	24.381	22.282	-24%	-39%	-20%
Energiereferenzprognose Referenz	41.421	37.236	34.165	31.806	-10%	-23%	-15%
Energiereferenzprognose Ziel 80	39.692	33.590	29.250	26.230	-15%	-34%	-22%
EU Reference Scenario 2016	44.478	40.637	39.035	39.914	-9%	-10%	-2%
ISE 85 (incl. Biogas, hydrgen, biomethane)	-	-	-	-	-	-	-
SZEN-16 - TREND	44.039	40.233	38.993	37.547	-9%	-15%	-7%
SZEN-16 - KLIMA 2050	42.012	34.785	30.665	26.997	-17%	-36%	-22%
SZEN-16 - KLIMA 2040	41.566	32.963	27.861	26.653	-21%	-36%	-19%

Source: Prognos, based on [Öko-Institut/ Fraunhofer ISI 2015], [EWI/ Prognos/ GWS 2014], [EU Reference Scenario 2016], [Fraunhofer ISE 2015], [Nitsch 2016]

Table 62 shows the share of renewable energy sources in primary energy demand. It becomes clear that renewables play a more significant role in the target scenarios. The share of the renewables is between 27 % and 38 % in 2050 in the reference scenarios. This range is higher in the target scenarios and ranges from 51 % to 85 %.

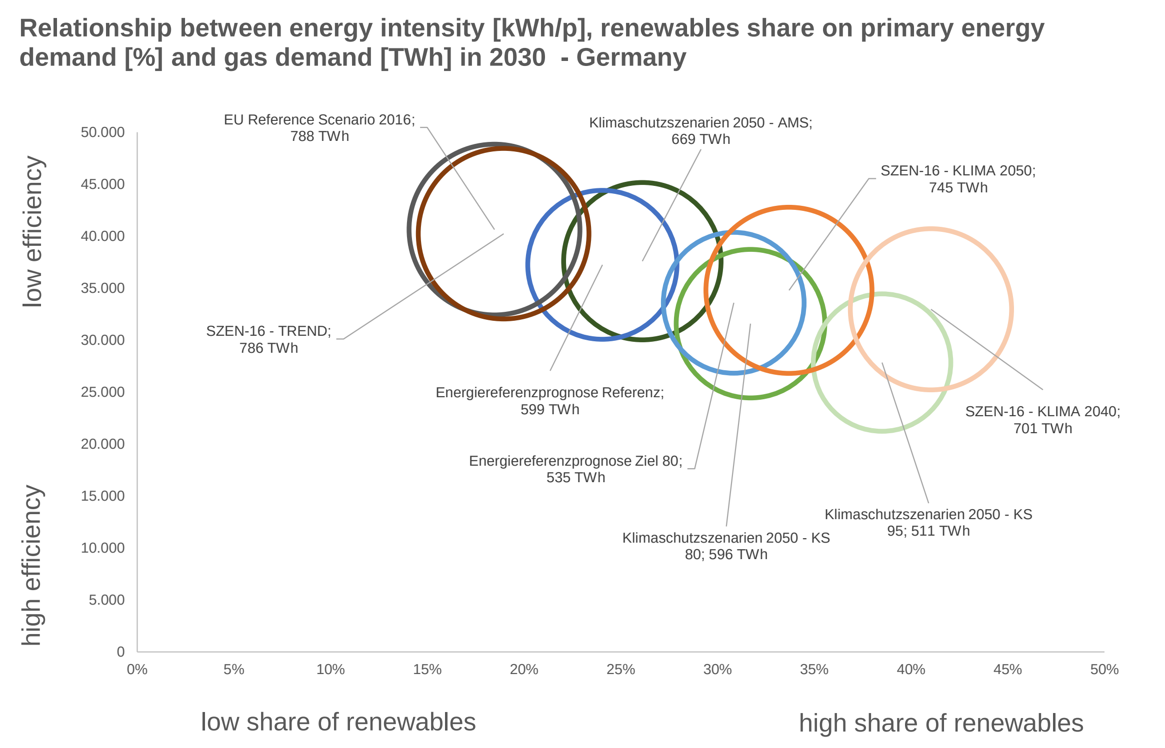
Table 62: Renewables: Share of RES in primary energy demand in the analysed demand scenarios

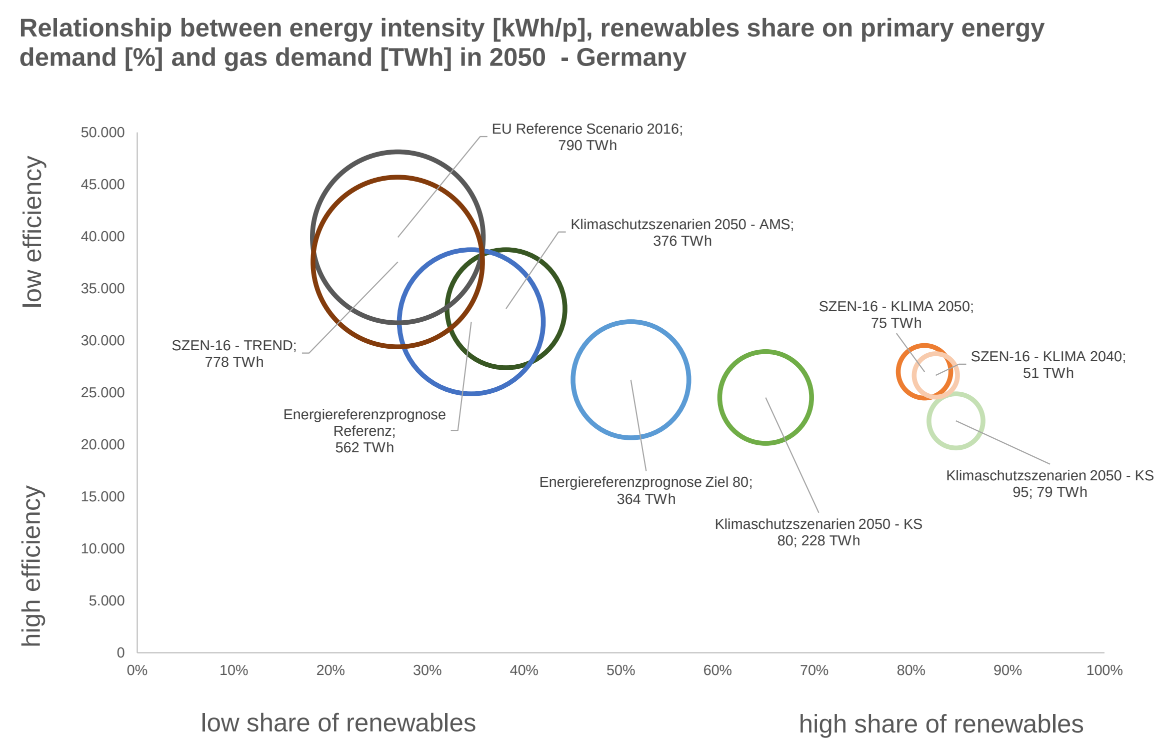
Primary RES demand/ primary energy demand [%]	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
Klimaschutzszenarien 2050 - AMS	21,2%	26,1%	30,2%	38,1%	23%	80%	46%
Klimaschutzszenarien 2050 - KS 80	22,3%	31,7%	46,0%	65,0%	42%	191%	105%
Klimaschutzszenarien 2050 - KS 95	21,8%	38,5%	59,6%	84,6%	76%	288%	120%
Energiereferenzprognose Referenz	18,4%	24,0%	28,2%	34,5%	30%	87%	44%
Energiereferenzprognose Ziel 80	20,7%	30,8%	39,9%	51,0%	49%	146%	66%
EU Reference Scenario 2016	16,3%	18,5%	22,5%	27,0%	13%	65%	46%
ISE 85 (incl. Biogas, hydrog., biometh.)	-	-	-	67,2%	-	-	-
SZEN-16 - TREND	15,0%	18,9%	22,2%	26,9%	26%	79%	42%
SZEN-16 - KLIMA 2050	16,9%	33,7%	57,2%	81,4%	99%	382%	142%
SZEN-16 - KLIMA 2040	17,3%	41,0%	75,0%	82,6%	138%	378%	101%

Source: Prognos, based on [Öko-Institut/ Fraunhofer ISI 2015], [EWI/ Prognos/ GWS 2014], [EU Reference Scenario 2016], [Fraunhofer ISE 2015], [Nitsch 2016]

The relationship between energy intensity, share of renewables in primary energy consumption and primary gas consumption in the considered scenarios is represented in the following figures for the years 2030 and 2050. The last tables and the following pictures illustrate that there is a huge potential regarding enhanced energy efficiency and more renewables. To realise these potentials, advanced (political) measures are necessary.

Table 63: Relationship between energy intensity, share of renewables in primary energy consumption and primary gas consumption – Germany 2030 and 2050





Source: Prognos, based on [Öko-Institut/ Fraunhofer ISI 2015], [EWI/ Prognos/ GWS 2014], [EU Reference Scenario 2016], [Fraunhofer ISE 2015], [Nitsch 2016]

The following table shows the published CO_2-prices in the analysed scenarios. The target scenarios require a much higher CO_2-price than the reference scenarios, up to 200 Euro/t in the "Klimaschutzszenario 2050 – KS 95" in 2050. It is remarkable that all analysed scenarios expect a much higher CO_2-price than today. That means a functioning pricing system is necessary in all scenarios.

Table 64: Price for CO_2 in the analysed scenarios and greenhouse gas emissions

Price CO_2 [Euro/t]	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
Klimaschutzszenarien 2050 - AMS	14	30	40	50	114%	257%	67%
Klimaschutzszenarien 2050 - KS 80	23	50	90	130	117%	465%	160%
Klimaschutzszenarien 2050 - KS 95	30	87	143	200	190%	567%	130%
Energiereferenzprognose Referenz	10	40	58	76	300%	660%	90%
Energiereferenzprognose Ziel 80	10	40	58	76	300%	660%	90%
EU Reference Scenario 2016	15	27	62	87	77%	480%	228%
Greenhouse gas emissions [mio. t]	**2020**	**2030**	**2040**	**2050**	**Change 2020-2030**	**Change 2020-2050**	**Change 2030-2050**
Klimaschutzszenarien 2050 - AMS (total)	877	776	678	568	-11%	-35%	-27%
Klimaschutzszenarien 2050 - KS 80 (total)	775	578	395	252	-25%	-67%	-56%
Klimaschutzszenarien 2050 - KS 95 (total)	692	408	208	59	-41%	-91%	-86%
Energiereferenzprognose Referenz (energy-related)	633	564	452	346	-11%	-45%	-39%
Energiereferenzprognose Ziel 80 (energy-related)	568	434	297	196	-24%	-65%	-55%
EU Reference Scenario 2016 (total)	893	780	666	532	-13%	-40%	-32%
EU Reference Scenario 2016 (energy-related)	734	644	536	419	-12%	-43%	-35%

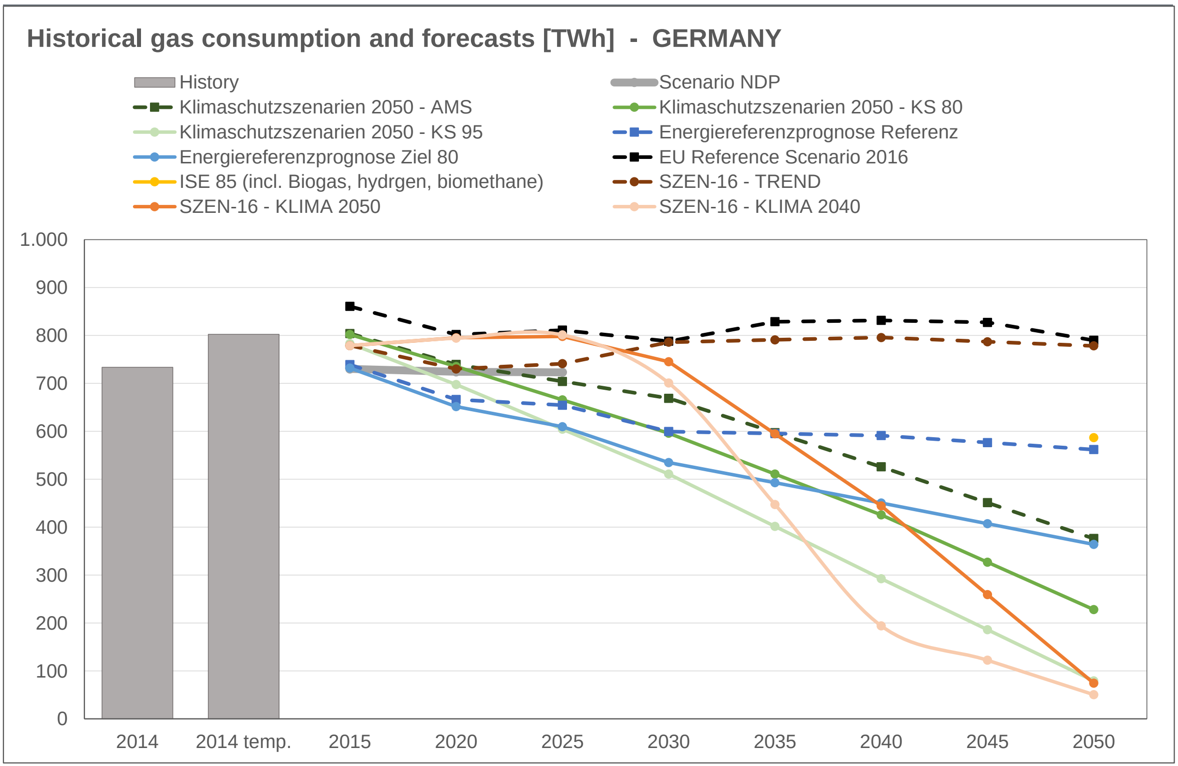
Source: Prognos, based on [Öko-Institut/ Fraunhofer ISI 2015], [EWI/ Prognos/ GWS 2014], [EU Reference Scenario 2016], [Fraunhofer ISE 2015], [Nitsch 2016]

In summary, it can be stated that all target scenarios – these are normally climate protection scenarios – assume a stronger reduction of primary energy demand, a higher share of renewables and a higher CO_2-price than the reference scenarios. To realise the potentials presented in the target scenarios, more significant political and social changes as well as changes in the energy system will be necessary. From today's perspective, there are existing barriers against such changes. A political change towards an "efficiency first-policy" could help to reduce these existing barriers.

3.3.2.3 Gas demand in these scenarios

The following figure shows the yearly gas demand in the analysed scenarios compared to the expected gas demand in the topical Network Development Plan gas 2015.

Figure 32: Development of gas demand in analysed scenarios – Germany



Note:
1. Each analysed study is pictured in a different colour (“Klimaschutzszenarien 2015” in green, “Energiereferenzprognose” in blue, “EU Reference Scenario 2016” in black, “ISE” in yellow, “SZEN-16” in brown/orange).
2. Additionally there are synthetic gases produced with electricity in the scenario “Klimaschutzszenarien 2010 – KS 95”.

Source: Prognos, based on [Öko-Institut/ Fraunhofer ISI 2015], [EWI/ Prognos/ GWS 2014], [EU Reference Scenario 2016], [Fraunhofer ISE 2015], [Nitsch 2016]

Figure 32 shows that there is already a spread at the beginning of the observed period. This depends on the different time in which the studies were conducted. The development of gas demand in the NDP gas 2015 is based on the scenario “Energiereferenzprognose Referenz” for final energy demand and a special defined scenario for power plants and the transformation sector.

The NDP gas demand scenario considers the next ten years, the other analysed scenarios build a future until 2050. Looking to 2025 a nearly stable gas demand is expected in the NDP gas 2015. Compared with the other scenarios there are reference scenarios as well as target scenarios with a constant gas demand over this time period.

Figure 32 also shows the wide spread of the expected gas demand in the future. Scenarios with the same target (“Klimaschutzszenarien 2050 – KS 95” and “SZEN-16 – KLIMA 2050”) can be very different regarding the gas demand during the time period. For example, target scenarios “SZEN-16 – KLIMA 2050 and 2040” see quite a stable gas demand over the next ten years, according to these scenarios the gas demand will decrease much stronger after 2025 and until 2050.

As written above for efficiency and renewables, the same applies for gas demand: there is a huge potential regarding the development of the gas demand but to realise these potentials, advanced (political) measures are necessary.

Primary gas demand remains quite stable in the German NDP gas 2015 until 2025. The following table shows the differences regarding gas demand of the analysed scenarios compared to the gas demand in the NDP 2015 for 2020 and 2025. (Note: a reason for differences is a different base year of the studies.) Table 55 shows that there are gas saving potentials especially through energy efficiency and renewable sources in the target scenarios of the studies "Klimaschutzszenarien 2050" and "Energiereferenzprognose". Other analysed scenarios show an enhanced decreasing gas demand after 2025/2030. These developments cannot be displayed in this table because the NDP has an observation period of only ten years according to German law.

Table 65: Gas saving potential: differences between alternative scenarios and the NDP gas for 2020 and 2025 in TWh - Germany

Gas savings potential [TWh]	2020	2025	2030	2050
NDP gas 2015	724	723		
Savings (delta NDP gas 2015 - scenario gas demand)				
Klimaschutzszenarien 2050 - AMS	-15	19	---	---
Klimaschutzszenarien 2050 - KS 80	-11	57	---	---
Klimaschutzszenarien 2050 - KS 95	26	119	---	---
Energiereferenzprognose Referenz	58	69	---	---
Energiereferenzprognose Ziel 80	72	114	---	---
EU Reference Scenario 2016	-78	-88	---	---
ISE 85 (incl. Biogas, hydrgen, biomethane)	---	---	---	---
SZEN-16 - TREND	-6	-18	---	---
SZEN-16 - KLIMA 2050	-71	-75	---	---
SZEN-16 - KLIMA 2040	-70	-78	---	---

Source: Prognos, based on [Öko-Institut/ Fraunhofer ISI 2015], [EWI/ Prognos/ GWS 2014], [EU Reference Scenario 2016], [Fraunhofer ISE 2015], [Nitsch 2016], NEP Gas 2015

The following table shows the primary gas demand and the share of gas in the primary energy demand. Primary gas demand will decline in all scenarios between 2020 and 2050 with the exception of the scenario "SZEN-16 – TREND". There is a wide spread of gas demand in 2050 between 793 TWh and 51 TWh. The share of gas in primary energy demand is expected to rise in three reference scenarios between 2020 and 2050 ("Energiereferenzprognose Referenz", "EU Reference Scenario 2016", "SZEN-16 – TREND"). The share of gas in primary energy demand is between 28 % and 3 % in 2050.

Table 66: Share of primary gas demand in the analysed demand scenarios - Germany

Primäry gas demand/ primary energy demand [%]	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
Klimaschutzszenarien 2050 - AMS	21,9%	22,9%	19,9%	15,4%	4%	-30%	-33%
Klimaschutzszenarien 2050 - KS 80	23,6%	24,3%	20,7%	12,6%	3%	-47%	-48%
Klimaschutzszenarien 2050 - KS 95	24,1%	23,6%	15,7%	4,8%	-2%	-80%	-80%
Energiereferenzprognose Referenz	20,3%	20,6%	22,8%	24,2%	2%	19%	17%
Energiereferenzprognose Ziel 80	20,7%	20,4%	20,3%	19,0%	-1%	-8%	-7%
EU Reference Scenario 2016	22,4%	24,3%	27,4%	26,6%	9%	19%	9%
ISE 85 (incl. Biogas, hydrgen, biomethane)	-	-	-	-	-	-	-
SZEN-16 - TREND	20,6%	24,7%	27,0%	28,1%	20%	36%	14%
SZEN-16 - KLIMA 2050	23,5%	27,1%	19,2%	3,7%	15%	-84%	-86%
SZEN-16 - KLIMA 2040	23,7%	26,9%	9,2%	2,6%	13%	-89%	-90%

Source: Prognos, based on [Öko-Institut/ Fraunhofer ISI 2015], [EWI/ Prognos/ GWS 2014], [EU Reference Scenario 2016], [Fraunhofer ISE 2015], [Nitsch 2016]

Capacity

The following data regarding the development of the gas capacity are based on the results of [FfE 2014]. Table 67 shows gas capacity development according to the estimation on the basis of [FfE 2014] and the installed power plant capacities according to the analysed scenarios.

Table 67: Estimation: Development of gas capacity demand for final energy sectors (estimation) and installed power plant gas capacity - Germany

Capacity demand for final gas demand [Index 2020 = 1,00]	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
Klimaschutzszenarien 2050 - AMS	1,00	0,95	0,86	0,75	-5%	-25%	-21%
Klimaschutzszenarien 2050 - KS 80	1,00	0,91	0,79	0,66	-9%	-34%	-28%
Klimaschutzszenarien 2050 - KS 95	1,00	0,87	0,71	0,56	-13%	-44%	-36%
Energiereferenzprognose Referenz	1,00	0,92	0,88	0,85	-8%	-15%	-8%
Energiereferenzprognose Ziel 80	1,00	0,90	0,82	0,76	-10%	-24%	-15%
EU Reference Scenario 2016	1,00	0,94	0,93	0,94	-6%	-6%	-1%
ISE 85 (incl. Biogas, hydrogen, biomethane)	-	-	-	-	-	-	-
SZEN-16 - TREND	1,00	1,00	1,00	0,98	0%	-2%	-2%
SZEN-16 - KLIMA 2050	1,00	0,88	0,70	0,53	-12%	-47%	-40%
SZEN-16 - KLIMA 2040	1,00	0,86	0,63	0,52	-14%	-48%	-40%

Installed Capacity of gas power plants [GW]	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
Klimaschutzszenarien 2050 - AMS	23	21	11	4	-7%	-81%	-79%
Klimaschutzszenarien 2050 - KS 80	24	28	16	4	15%	-83%	-86%
Klimaschutzszenarien 2050 - KS 95	20	28	16	4	40%	-81%	-86%
Energiereferenzprognose Referenz	17	30	36	48	76%	182%	60%
Energiereferenzprognose Ziel 80	17	25	26	35	47%	106%	40%
EU Reference Scenario 2016	22	27	42	41	23%	89%	54%
ISE 85 (incl. Biogas, hydrogen, biomethane)	-	-	-	75	-	-	-
SZEN-16 - TREND	22	30	33	35	40%	63%	17%
SZEN-16 - KLIMA 2050	29	40	39	29	40%	2%	-28%
SZEN-16 - KLIMA 2040	-	-	-	-	-	-	-

Source: Prognos, based on [FfE 2014], [Öko-Institut/ Fraunhofer ISI 2015], [EWI/ Prognos/ GWS 2014], [EU Reference Scenario 2016], [Fraunhofer ISE 2015], [Nitsch 2016]

Capacity demand for the supply of final customers will decrease in all scenarios between 2020 and 2050. The relation of gas demand and gas capacity especially in strong climate protection scenarios is questionable and was discussed on the expert workshop.

The capacity of gas power plants varies widely between the different scenarios. The study "Klimaschutzszenarien 2050" expects by far the strongest decline of installed gas power plants. Other scenarios anticipate an increased capacity of gas power plants (e.g. back up-capacities for renewables, compensation for coal and lignite power plants).

3.3.2.4 Impacts on infrastructure and costs

As network development planning is a complex matter, it is difficult to associate individual infrastructure projects with specific requirement categories, such as higher final gas demand, as these indications are not uniquely defined. However, the following table shows an allocation of the NDP gas 2015 measures to different demand factors as a best guess.

Table 68: Effects of NDP gas 2015 measures on different grid requirements - Germany

NDP gas 2015 measures for…	Number of measures	Investment volume [Mio. Euro]
Power plants/ industry	7	551
Cross-border interconnection points	9	729
Grid reinforcement	25	1.370
Storage facilities	18	1.213
Distribution sytem operators	15	554
Switchover of low CV gas networks to high CV gas	51	1.625

Note: A lot of measures have an effect on several grid requirements. Therefore, this table contains multiple entries. The NDP gas 2015 includes overall 85 measures with an investment volume of about 3,3 bn. Euro.

Source: Prognos, based on FNB Gas, NDP gas 2015

It becomes clear that a lot of measures are in principle independent of the future gas demand (e.g. measures for the switchover of low CV gas networks to high CV gas). However, there are measures for the satisfaction of a rising gas capacity demand. These are often associated with regional differences regarding gas demand development and insufficient firm capacities in different regions.

Overall it is hard to say which measures will become superfluous and at which time. In the past there were different capacity demand scenarios analysed in the German gas NDP. For the next ten years the differences between these modelling scenarios are negligible. But it must be mentioned that there is so far no analysis about which measures would be necessary in a strong climate protection (target) scenario. A lot of scenarios (including the capacity demand scenario for distribution system operator in the NDP gas 2016) assume an overall increasing gas capacity demand at the DSO level because, in accordance with the decision of the BNetzA, the internal orders of the DSO are used for the modelling in the NDP. As written above the German NDP gas considers a time period of ten years. As previously shown there are even target scenarios which expect a stable gas demand over this period which is in line with the current gas demand assumptions in the NDP gas. Perhaps it is necessary to adjust the considered time period in the NDP gas to include existing long-term political goals in the network planning.

3.3.2.5 Conclusion

- **Efficiency and RES potentials and relationship with gas:** With increasing pressure on efficiency and RES development, a reduction of gas consumption can be expected - especially after 2030. There is a huge potential regarding enhanced energy efficiency and more renewables. To realise these potentials advanced (political) measures are necessary.
- **Situation of NDP scenarios compared to other scenarios**: The 2015 and 2016 NDP scenarios (with a 10 year time horizon) are based on a reference scenario and they are in line not only with other reference, but also with some target scenarios. The observation period of the NDP compared to the other studies is quite short.

- **Assumptions about possible reduction of gas demand**: Increases in energy efficiency and renewable energy production would lead to a lower gas demand. However, additional political measures are necessary to reach the energy efficiency and RES targets of the considered scenarios.
- **Consequences on infrastructures and costs**: There are many different impacts on infrastructure planning; most of the infrastructure investment projects are not caused by market demand (e.g. measures for the switchover from low CV gas to high CV gas). The German NDP gas considers a time period of ten years. As shown above there are even target scenarios which expect a stable gas demand over this period which is in line with the current gas demand assumptions in the NDP gas. However, in the long run a significant decrease of gas demand is expected in the target scenarios with higher efficiency and more renewables. But overall it is hard to say which of the projects will become superfluous and at what time. An additional gas network calculation with a clearly reduced gas demand (according to a target scenario) is necessary to identify such projects.

3.3.3 Italy

3.3.3.1 Analysed scenarios

Five different studies with overall ten demand scenarios were selected for the comparison of gas demand with the gas demand projected in the NDP scenario. The considered scenarios can be divided in reference and target scenarios. Our analysis includes four reference and six target scenarios which are especially analysed regarding their assumptions and results of gas demand, energy efficiency and renewables. The following Table 69 describes the characteristics of each analysed demand scenario.

Table 69: Characterisation of the analysed demand scenarios - Italy

Study	Scenario	Scenario description
Reference Scenarios		
ENEA, Rapporto Energia ed Ambiente: Scenarie e Strategie, 2013	Scenario di Riferimento	The scenario takes into account the European environmental targets for 2020 and thereby measures of the national renewable and energy efficiency action plans. Only those policies in action are considered.
Greenpeace / GWEC / EREC / DLR, Energy [r]evolution: Uno scenario sostenible per l'Italia	Scenario di Riferimento	Reference scenario depicting a continuation of current trends and policies. The scenario is based on the Current Policies Scenario published in the WEO 2011 by the IEA.
European Commission, European Energy Trends: Update 2016, 2016.	Reference scenario	Reference scenario of the European Commission
Target Scenarios		
ENEA, Rapporto Energia ed Ambiente: Scenarie e Strategie, 2013	Scenario Roadmap 2050	The scenario takes into account the Roadmap 2050 of the European Commission, which aims to reduce GHG emissions in 2050 by 80 % compared to 1990.
Greenpeace / GWEC / EREC / DLR, Energy [r]evolution: Uno scenario sostenible per l'Italia	Energy [R]evolution scenario	The scenario has as a key target the reduction of worldwide GHG emissions to below 4 Gt / year by 2050 in order to hold the increase in average global temperature below +2 °C. A second objective is the global phasing out of nuclear energy.

IDDRI / SDSN / ENEA / FEEM, Deep decarbonisation pathways: Pathways to deep decarbonisation in Italy, 2015	RES + CC	Target scenario showing a pathway to a low carbon economy in Italy in line with the +2°C - goal of the UN COP 21. Characteristics are extensive useage of renewable energy and carbon capture leading to a high electrification of energy use.
	EE	Target scenario showing a pathway to a low carbon economy in Italy in line with the +2°C - goal of the UN COP 21. The scenario focusses on high levels of energy efficiency as renewable energy sources are not as widely available
	Demand reduction	Target scenario showing a pathway to a low carbon economy in Italy in line with the +2°C - goal of the UN COP 21. The scenario focusses on high costs of decarbonisation and associated demand reductions for energy consumption.

Source: [ENEA 2013]; [EU Ref 2016]; [DDPP IT 2015]; [Greenpeace IT 2013]

Italy has the following climate targets relating to its energy system:

- 17 % of renewable energy in gross final energy consumption by 2020 (Directive 2009/28/EC Art. 3)
- 1.5 % annual savings to be achieved over the period 2014-2020 compared to the average of 2010 – 2012 (Directive 2012/27/EU Art. 7).

Target / Explorative scenarios are modelled in a way as to reach the European climate goals or even go beyond. However, even reference scenarios are in line with the renewable energy target as set by the Renewable Energy Directive Art. 3. As for energy efficiency defined by the Energy Efficiency Directive Art. 7, reference scenarios are likely not in line.

3.3.3.2 Potentials of low carbon options and influence on gas demand

In the following, energy efficiency and share of renewables in energy consumption are considered in the different scenarios for Italy.

Table 70 resumes the development of primary energy demand in the analysed scenarios. Energy efficiency is higher in target than reference scenarios: From 2020 to 2030, primary energy demand in some reference scenarios is still increasing. Target scenarios expect a decrease of 9 % to 22 %. The Energy [R]evolution scenario foresees possibilities for energy saving especially in heat demand and transport, but also electrical and electronical appliances [Greenpeace 2013]. ENEA sees vast possibilities in final demand reduction of around 40 % by 2050 in a target scenario versus the reference scenario. Savings would come by 50 % from the ‘civil’ sectors (households, services and agriculture), 35 % from transport, and 15 % from industry. For the civil sector, it is especially the demand for heating that could be reduced by better isolation of buildings and substitution of gas and petrol fired heating systems by electrical ones [ENEA 2013].

Table 70: Energy efficiency: Development of primary energy demand in the analysed demand scenarios - Italy

Primary energy demand [TWh]	2015	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
Indicative Target EED Art. 3		*1,838*						
ENEA - Ref	1,884	1,915	1,927	1,988	2,038	1%	6%	6%
Greenpeace - Ref	1,892	1,869	1,889	1,918	1,960	1%	5%	4%
Euoprean Commission - Ref 2016	1,768	1,790	1,656	1,615	1,592	-6%	-10%	-4%
ENEA - Target	1,861	1,694	1,571	1,411	1,423	-7%	-16%	-9%
Greenpeace - Energy [R]evolution scenario	1,797	1,683	1,537	1,415	1,312	-9%	-22%	-15%
DDPP - CCS + RES	1,653	1,425	1,182	1,105	1,172	-17%	-18%	-1%
DDPP - EE	1,644	1,407	1,147	1,047	1,078	-22%	-28%	-8%
DDPP - Demand Reduction	1,605	1,329	1,037	926	956	-22%	-28%	-8%

Source: [ENEA 2013]; [European Commission 2013]; [DDPP IT 2015]; [Greenpeace IT 2013]

Table 71 shows the share of renewables in primary energy demand from 2020 to 2050 for Italy. According to the reference scenario of the Primes Ver.4 Energy Model Italy is in line with the renewable energy targets laid out in Art. 3 of the Renewable Energy Directive [EU Ref 2016]. However, there is a strong divide in the development of the energy system, with reference scenarios maintaining a share of renewables at around 20-25 % of primary energy demand up to 2050, while target scenarios foresee a strong increase to 60-80 % for the same time frame. The increase in RES comes from final energy demand as well as from electricity generation. As noted earlier, space heating is mostly supplied by natural gas and to a lesser extent by petrol heating. A change to electrical heating systems would allow for an energy system supplied largely by RES in 2050 but would require a transformation of the electrical system.

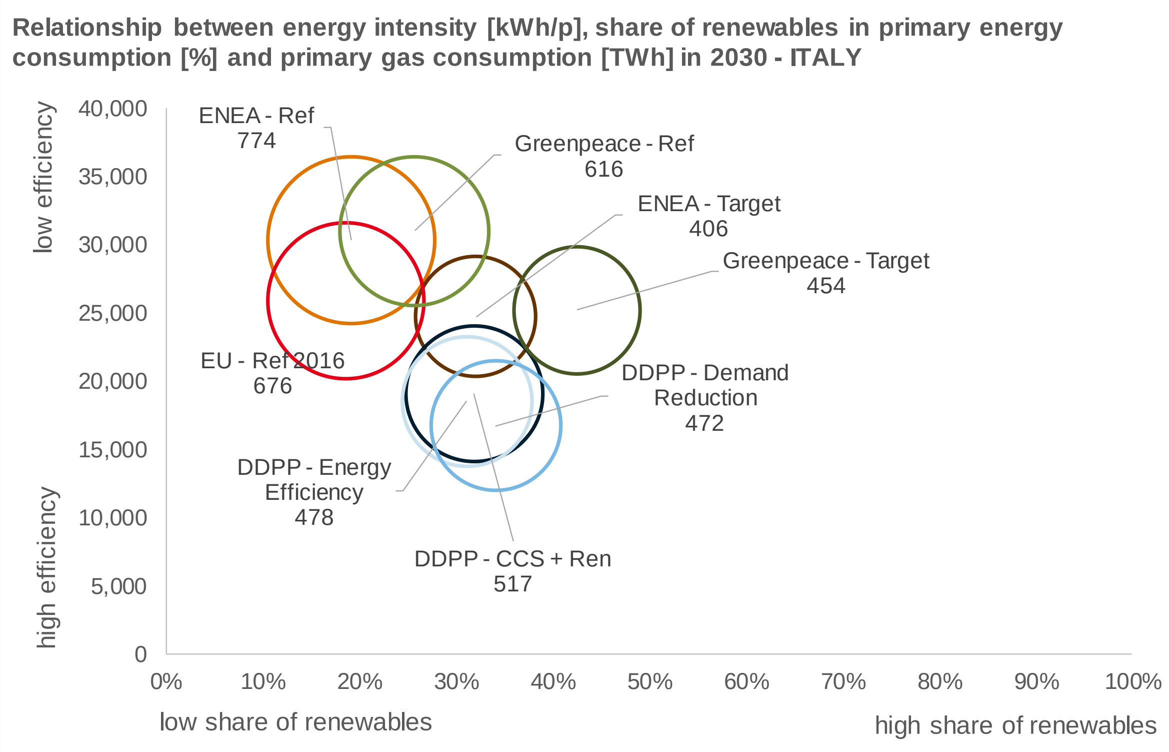
Table 71: Renewables: Share of RES in primary energy demand in the analysed demand scenarios - Italy

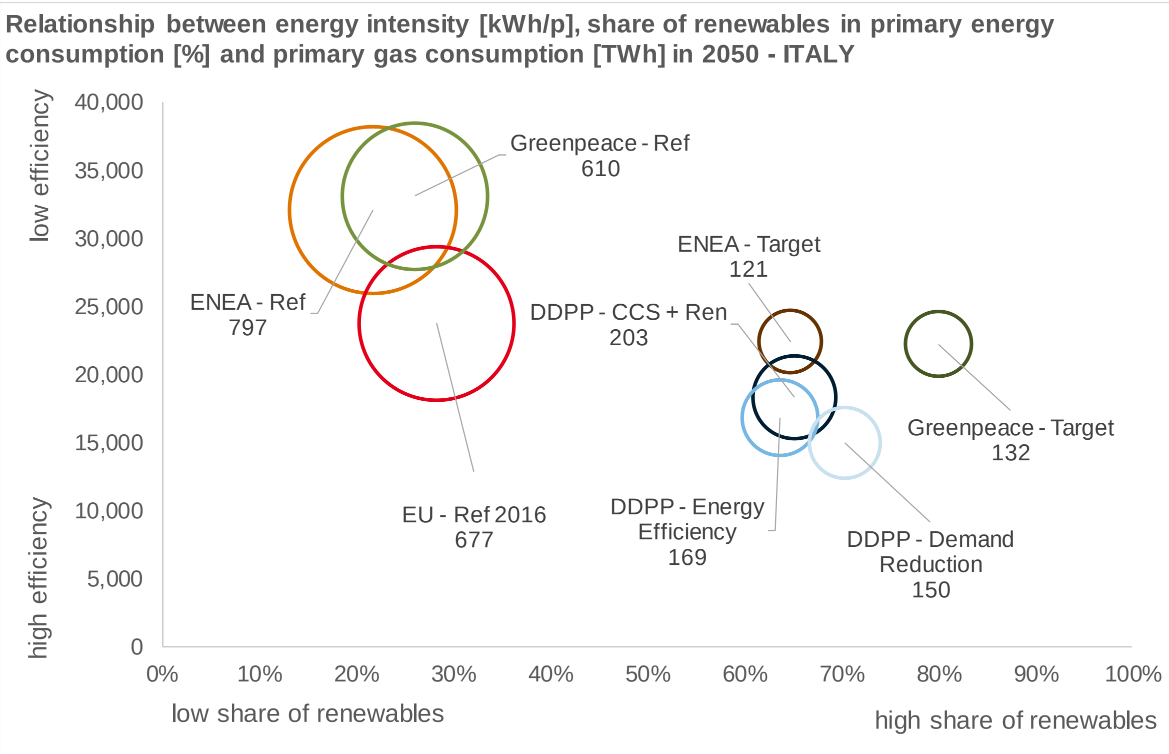
Primary RES demand/ primary energy demand [%]	2015	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
ENEA - Ref	16.3%	17.3%	19.1%	21.6%	21.7%	10%	25%	13%
Greenpeace - Ref	17.3%	21.3%	25.7%	26.4%	26.1%	21%	23%	1%
Euoprean Commission - Ref 2016	14.2%	15.2%	18.6%	23.3%	28.3%	22%	86%	52%
ENEA - Target	15.8%	23.2%	32.1%	46.2%	64.7%	38%	179%	102%
Greenpeace - Energy [R]evolution scenario	19.3%	25.5%	42.5%	61.4%	80.0%	67%	214%	88%
DDPP - CCS + RES	13.4%	18.6%	31.9%	48.6%	65.2%	72%	251%	104%
DDPP - EE	13.3%	18.3%	31.1%	47.3%	63.7%	70%	247%	104%
DDPP - Demand Reduction	13.6%	19.3%	34.1%	52.7%	70.3%	77%	264%	106%

Source: [ENEA 2013]; [EU Ref 2016]; [DDPP IT 2015]; [Greenpeace IT 2013]

In reference scenarios all three variables, energy intensity, share of renewables and gas consumption stay mostly on the same levels during time, in 2050 and also in 2030. Target scenarios show a decrease in energy intensity and an increase in renewable energy production while natural gas consumption reduces significantly, especially in 2050. This effect can be seen in Figure 33.

Figure 33: Relationship between energy intensity, share of renewables in primary energy consumption and primary gas consumption in 2030 and 2050 – Italy





Source: [ENEA 2013]; [EU Ref 2016]; [DDPP IT 2015]; [Greenpeace IT 2013]

3.3.3.3 Gas demand in these scenarios

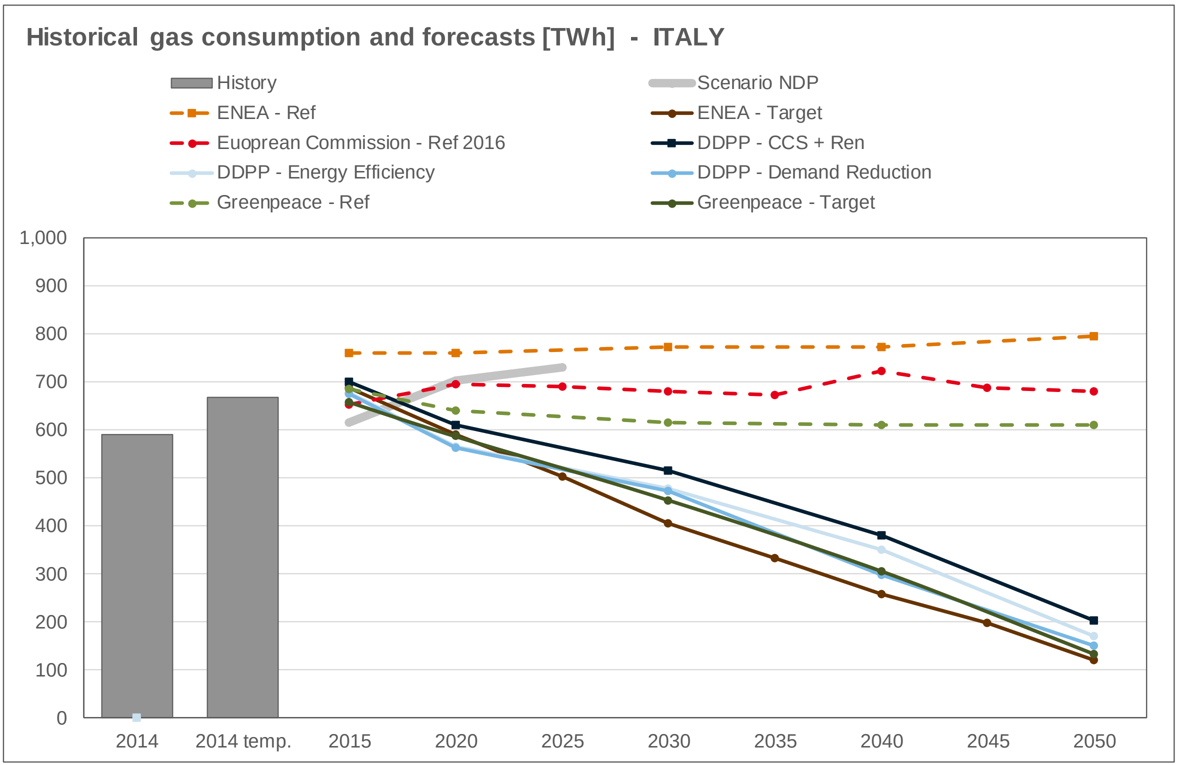
There is a strong divide on the future role of gas in the Italian energy system, depending on the type of scenario (see Figure 34). Reference scenarios predict a stable role of gas to supply the Italian energy demand up to 2050, while target scenarios expect a strong decline of gas. The scenario of the Italian NDP is the only scenario that shows an increase from 2015 to 2024. According to the SNAM, the increase is due to the economic recovery following a recession of the Italian economy in the last years. Most depicted target scenarios have been calculated prior to the recession and hence start at a higher level than the NDP scenario. However, the assumption made in the NDP does not seem very realistic, as during the recession period renewables have largely increased, demand from industry lowered long-term due to relocation and demand from heating has lowered due to better insulation.

According to the power grid operator Terna [Terna 2015], the electricity generated from wind and solar energy increased from 5 TWh in 2008 to 37,5 TWh in 2014, which corresponds to almost half of the decrease in gas power generation, the other half being mainly due to the decrease in power demand and party to a switch from gas to coal. Regardless of yearly temperature variations, gas demand in the residential sector has remained roughly stable over the last decade. New buildings are subject to strict energy efficiency requirements and thus should add less consumption than the savings from the dismissing of old, often very inefficient buildings [ENEA 2015].

In order to compensate the gas demand reduction caused by the improved efficiency of buildings and by the increased renewable capacities, one should assume that the gas demand from the industrial sector would increase well above the pre-crisis level.

It is often argued that gas demand would remain at high levels in order to come into play as a back-up technology for intermittent renewable energy sources [MISE 2013]. However, given the high share of gas in the Italian power mix, additional renewable capacities are actually likely to replace at least partly gas generation. ENEA argues in its scenario development, that in order to achieve a low carbon energy system in Italy, gas demand will be reduced. In case of a roll-out of CCS technologies, the price effect of carbon will outweigh the flexibility that gas turbines could offer to an energy system, further diminishing the role of gas after 2030 [ENEA 2013].

Figure 34: Development of gas demand in analysed scenarios - Italy



Source: [ENEA 2013]; [EU Ref 2016]; [DDPP IT 2015]; [Greenpeace IT 2013]; [SNAM 2015]

As can be seen in Table 72, the gas saving potential of the alternative scenarios compared to the scenario used in the NDP over 100 TWh for some target / explorative scenarios. The possibility to save natural gas is clearly given when switching to a low-carbon energy system with the help of renewable energy sources and energy efficiency. Gas demand in the NDP scenario seems to overestimate future gas demand by far.

Table 72: Gas saving potential: differences between alternative scenarios and the NDP gas in TWh - Italy

Gas savings potential [TWh]	2020	2030	2040	2050
Gas Demand NDP 2015	702	-	-	-
Savings (delta Gas Demand NDP 2015 - scenario gas demand)				
ENEA - Ref	-59	-	-	-
Greenpeace - Ref	62	-	-	-
Euoprean Commission - Ref 2016	7	-	-	-
ENEA - Target	113	-	-	-
Greenpeace - Energy [R]evolution scenario	115	-	-	-
DDPP - CCS + RES	91	-	-	-
DDPP - EE	136	-	-	-
DDPP - Demand Reduction	138	-	-	-

Source: Prognos

3.3.3.4 Impacts on infrastructure and costs

The proposed measures in the Italian NDPs are not precisely attributed to final demand or gas demand for electricity generation. The impact on infrastructure projects is difficult to estimate. Infrastructure investments having received a final investment decision status for the period 2015 – 2024 are of a magnitude of € 1.2 billion overall.

There are projects (such as the proposed GALSI pipeline) that are argued for against the background of import diversification for Italy and other European countries downstream. The expansion of import capacities in Italy would secure Italy's position as a 'gas hub' for Europe. Obtaining competitive gas prices through import diversification could outweigh the costs of these import projects. However, import capacity from Tunisia has been roughly over 20 % in the last two years [IEA 2016], leaving doubts as to whether additional import quantity from this region is needed, or whether a strategy of full capacity utilisation should be ensured beforehand.

3.3.3.5 Conclusion

- **Efficiency and RES potentials and relationship with gas:** There is a relationship between efficiency, renewables and gas consumption after 2030 in target scenarios. With increasing pressure on efficiency and RES development, a reduction of gas consumption after 2030 can be expected.
- **Situation of NDP scenarios compared to other scenarios**: In contrast to all other scenarios, the NDP scenario assumes a steep growth of gas demand in the period 2015-2025. This does not seem credible. Reference scenarios would likely meet European targets by 2020 for renewable energy, but not for energy efficiency. Target / explorative scenarios go beyond these targets.

- **Assumptions about possible reduction of gas demand**: Increases in energy efficiency and renewable energy production would lead to a lower gas demand. However, current political efforts for renewables development and energy efficiency are more in line with levels of reference scenarios.
- **Consequences on infrastructures and costs**: Further import routes through Italy against the background of under-utilised import capacity are difficult to argue for. They should be assessed for scenarios with a declining gas demand and achievement of energy and climate targets as well. The argument for further import capacity on the ground of import diversification is not within the scope of this study.

3.3.4 The Netherlands

3.3.4.1 Analysed scenarios

Table 73 describes the characteristics of each analysed demand scenario. We analysed five different studies with overall 13 demand scenarios. The considered scenarios can be divided in reference and target scenarios. Our analysis includes five reference and eight target scenarios which are especially analysed regarding their assumptions and results of gas demand, energy efficiency and renewables.

Table 73: Characterisation of the analysed demand scenarios –The Netherlands

Study	Scenario	Scenario description
Reference Scenarios		
ECN / PBL, Nationale Energieverkenning 2015, 2015	Vastgestelde beleid	Scenario of the "Nationale Energie Verkenning" describing the state of the Dutch energy system up until 2030. Reference scenarrio taking into account only concrete, officially published measures and binding agreements
Greenpeace / GWEC / EREC / DLR, Energy [R]evolution: A sustainable netherlands energy outlook, 2013	Reference scenario	Reference scenario reflecting a continuation of current trends and policies. The scenario is based on the Current Policies Scenario published in the WEO 2011 by the IEA.
European Commission, European Energy Trends, Update 2016	Reference Scenario	Reference Scenario of the European Commission
CE Delft, Scenario-ontwikkeling energievoorziening 2030. 2013	BAU	Reference scenario containing all measures of the Aggreement on Energy for Sustainable Growth (2013) by the Dutch parliament.
Target / Explorative Scenarios		
CE Delft, Scenario-ontwikkeling energievoorziening 2030. 2013	A	Target scenario with 40% CO2 - Emission reduction compared to 1990, 25% of final demand met by renewable energy sources, maximum usage of decentralised potential for power and heat.
	B	Target scenario with 40% CO2 - Emission reduction compared to 1990, 25% of final demand met by renewable energy sources, low usage of decentralised potential for power and heat.
	C	Target scenario with 55% CO2 - Emission reduction compared to 1990, 25% of final demand met by renewable energy sources, maximum usage of decentralised potential for power and heat.

	D	Target scenario with 100% CO2 - Emission reduction compared to 1990, 25% of final demand met by renewable energy sources, low usage of decentralised potential for power and heat.
	E	Target scenario with 100% CO2 - Emission reduction compared to 1990, 100% of final demand met by renewable energy sources, maximum usage of decentralised potential for power and heat.
PBL / CBP, Nederland in 2030-2050, 2015	Hoog	Scenario assuming that all pledges made by the parties of the Copenhaguen Accord come into force. The EU meets its goal of a 40% CO2 Emission reduction by 2030. Global emissions of GHG lead to an increase of 2.5°-3°C by the 2100.
	2° C Decentraal	Target scenario aimining to reduce national GHG emissions in order to maintain global warming below 2°C. Focus on energy efficiency, strong electrification and low usage of fossil fuels
	2°C Centraal	Target scenario aimining to reduce national GHG emissions in order to maintain global warming below 2°C. Focus on CCS, heat grids and usage of biomass.

Source: [ECN 2015]; [Greenpeace NL 2013]; [CE Delft 2013]; [PBL / CBP 2015]

3.3.4.2 Potentials of low carbon options and influence on gas demand

The Netherlands have formulated national targets for renewable energy use and energy efficiency in the “Energieakkoord voor duurzame groei” of September 2013 (SER 2013). The agreement follows the European targets formulated for the Netherlands in the Energy Efficiency Directive of 2012 and the Renewable Energy Directive of 2009. The Dutch targets are as follows:

- 14 % of primary energy consumption to be met by renewable energy sources in 2020
- 16 % of primary energy consumption to be met by renewable energy sources in 2023
- 1.5 % p.a. efficiency improvement of final energy demand for the period from 2014-2020 compared to 2010-2012.[106]
- An indicative target of 607 TWh final energy demand in 2020 according to Art. 3 EED (Directive 2012/27/EU)

In the following, energy efficiency and share of renewables in primary energy consumption are considered in the different scenarios for the Netherlands.

Table 74 shows the development of primary energy demand / person from 2020 to 2050 in the Netherlands. All scenarios foresee a decline in consumed primary energy. Compared to other countries, the divide between reference and target scenarios is not as pronounced. Especially the WLO – scenarios in line with a 2°C global warming target exhibit only a 5-6 % decline between 2020 and 2030, and only 8-11 % between 2030 and 2050. Target scenarios by Greenpeace and CE Delft foresee a much more pronounced decline already during the 2020 – 2030 period.

[106] The efficiency gains as defined by the Energy Efficiency Directive (Directive 2012/27/EU) relate to the sum of efficiency gains by individual measures. They do not relate to the primary energy consumption overall. As an example, a country can finance measures that save up to 50 TWh of Energy from 2014-2020, and yet have a rising primary energy consumption.

Table 74: Energy efficiency: Final energy demand in the analysed demand scenarios – The Netherlands

Primary energy demand [TWh]	2015	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
ECN - Vastgestelde Beleid	883	873	868	-	-	-1%	-	-
Greenpeace NL - Reference	974	957	926	896	864	-3%	-10%	-7%
European Commission -Reference 2016	813	797	742	700	692	-7%	-13%	-7%
CE Delft - BAU	813	799	720	-	-	-10%	-	-
Greenpeace NL - Target	923	835	730	651	584	-13%	-30%	-20%
CE Delft - A	813	750	626	-	-	-17%	-	-
CE Delft - B	813	789	741	-	-	-6%	-	-
CE Delft - C	813	750	624	-	-	-17%	-	-
CE Delft - D	813	702	481	-	-	-31%	-	-
CE Delft - E	813	722	540	-	-	-25%	-	-
WLO - Hoog	883	889	899	894	890	1%	0%	-1%
WLO - 2° Decentraal	875	859	829	785	743	-4%	-14%	-10%
WLO - 2° Centraal	878	869	853	823	795	-2%	-9%	-7%

Source: [ECN 2015]; [Greenpeace NL 2013]; [CE Delft 2013]; [PBL / CBP 2015]

Table 75 shows the share of renewables in primary energy demand from 2020 to 2050 in the Netherlands. According to the ECN which publishes an annual energy outlook, the Efficiency target as laid out in the European Efficiency Directive Art. 7 will not be reached.

By 2050, RES demand is set to be much higher in Target / explorative scenarios than in reference scenarios.

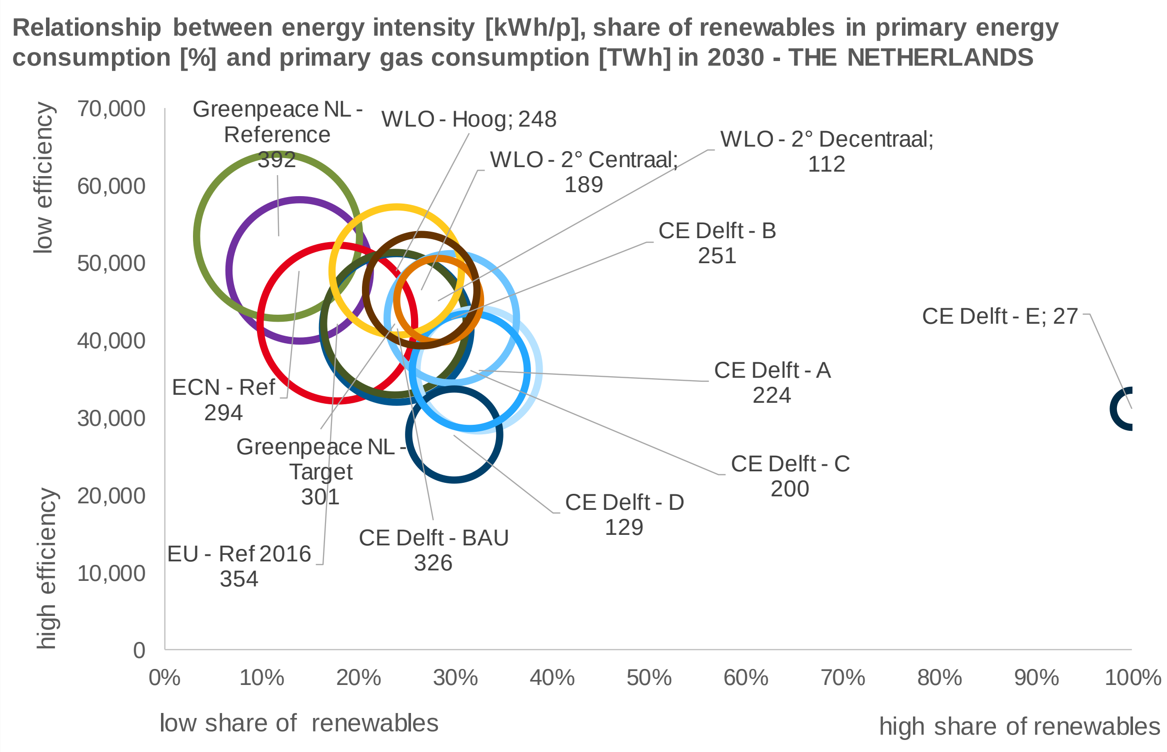
Table 75: Renewables: Share of RES in primary energy demand in the analysed demand scenarios – The Netherlands

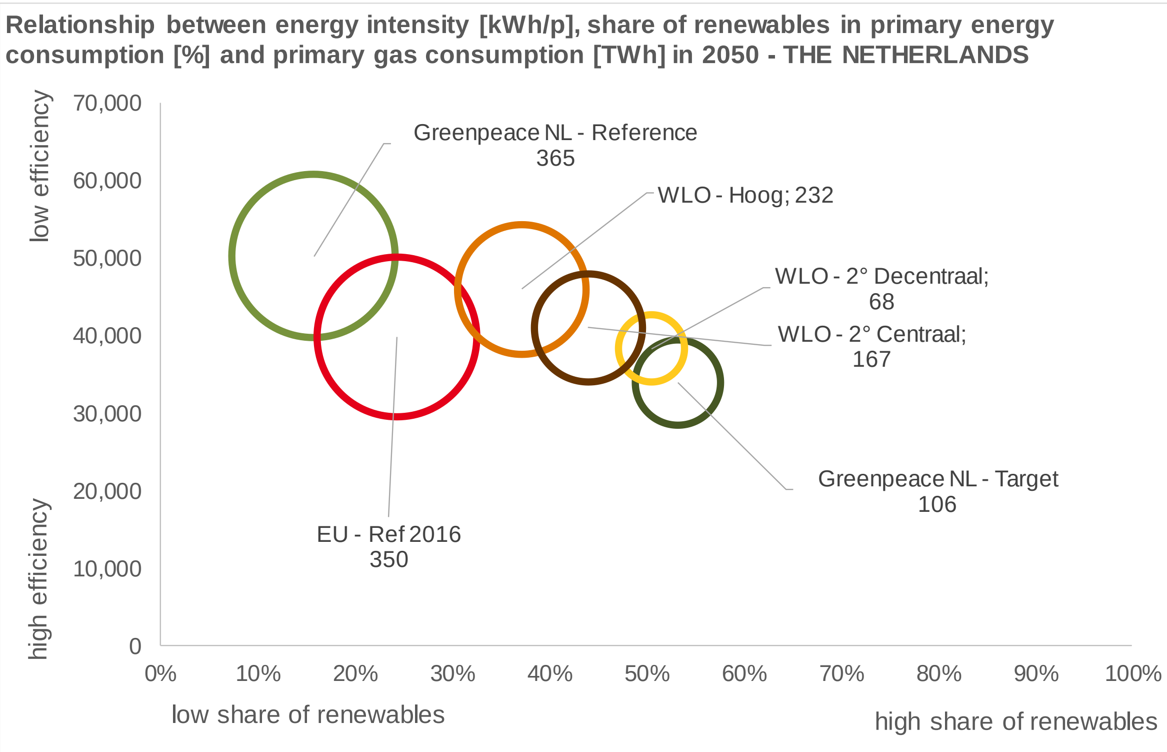
RES demand/ primary energy demand [%]	2015	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
ECN - Vastgestelde Beleid	5%	9%	14%	-	-	51%	-	-
Greenpeace NL - Reference	6%	9%	12%	14%	16%	32%	77%	34%
European Commission -Reference 2016	7%	14%	18%	21%	24%	23%	68%	36%
CE Delft - BAU	5%	10%	26%	-	-	144%	-	-
Greenpeace NL - Target	7%	14%	24%	38%	53%	67%	275%	124%
CE Delft - A	5%	14%	32%	-	-	129%	-	-
CE Delft - B	5%	13%	30%	-	-	124%	-	-
CE Delft - C	5%	14%	32%	-	-	128%	-	-
CE Delft - D	5%	13%	30%	-	-	125%	-	-
CE Delft - E	5%	37%	100%	-	-	173%	-	-
WLO - Hoog	6%	9%	24.0%	30%	37%	162%	306%	55%
WLO - 2° Decentraal	6%	10%	28.3%	38%	50%	189%	415%	78%
WLO - 2° Centraal	6%	10%	26.5%	34%	44%	178%	361%	66%

Source: [ECN 2015]; [Greenpeace NL 2013]; [CE Delft 2013]; [PBL / CBP 2015]

As a general remark, target scenarios have a considerably lower gas demand than reference scenarios. This tendency is more pronounced by 2050 than in 2030, despite the fact that target scenarios move in this direction already by 2030 (see Figure 35).

Figure 35: Relationship between energy intensity, share of renewables in primary energy consumption and primary gas consumption in 2030 and 2050 – The Netherlands





Source: [ECN 2015]; [Greenpeace NL 2013]; [CE Delft 2013]; [PBL / CBP 2015]

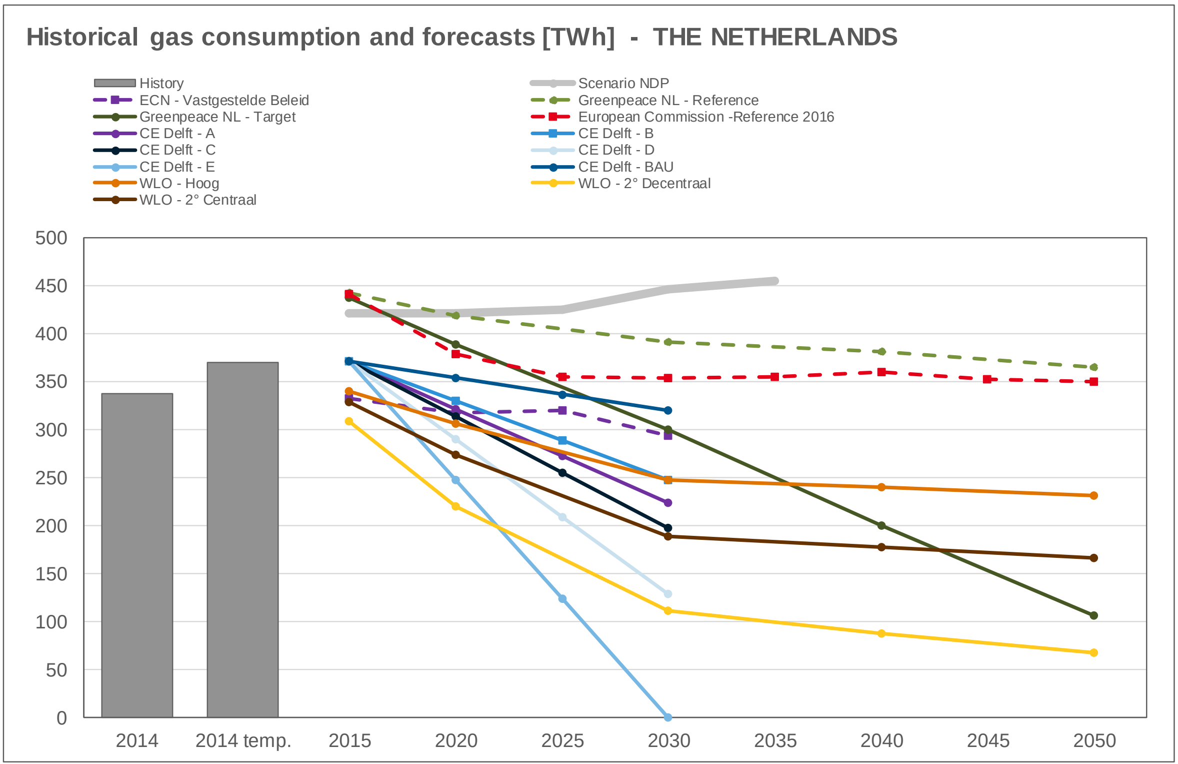
3.3.4.3 Gas demand in these scenarios

Trajectories for future gas demand are depicted in Figure 36. All scenarios foresee a falling gas demand compared to 2015, yet at differing rates. The lowest rates of change appear in the reference scenarios. Target scenarios exhibit a much faster rate of change.

The authors of the Dutch NDP presented a range of possibilities concerning the future Dutch gas demand. However, the present capacity is evaluated against the maximum future gas demand scenario. This scenario is not in line with most scenarios listed above

Natural gas has been used widely in electricity production and in order to meet final energy demand as the resource was readily available after the discovery of the 'Groeningen field'. Since production of the field is declining and slowly phasing out, there is an incentive to substitute to other primary energy forms, which is acknowledged in all scenarios. Additionally, target scenarios aim at decarbonising Dutch economy and hence reducing the amount of gas utilised in all sectors, mostly by large scale electrification and electricity production by renewables. Some target scenarios, as CE Delft C, make stronger usage of CCS technologies. However, the introduction of CCS technologies enables a preferential utilisation of coal over natural gas. First, the price of coal is projected to be lower than that of natural gas. Second, the capture of CO_2 is less cost intensive for coal [CE Delft 2013].

Figure 36: Development of gas demand in analysed scenarios – The Netherlands



Source: [ECN 2015]; [Greenpeace NL 2013]; [CE Delft 2013]; [PBL / CBP 2015]

As can be seen from Figure 36 and Table 76 below, all alternative scenarios predict a low gas demand for the Netherlands than the gas demand scenario used for the capacity balance in the NOP 2015. The scenarios are much more in line with the “Green Focus” scenario of the NOP.

Table 76: Gas saving potential: differences between alternative scenarios and the NDP gas in TWh – The Netherlands

Gas savings potential [TWh]	2020	2030	2040	2050
Gas Demand NDP 2015	422	425	-	-
Savings (delta Gas Demand NDP 2015 - scenario gas demand)				
ECN - Vastgestelde Beleid	104	131	-	-
Greenpeace NL - Reference	3	33	-	-
European Commission -Reference 2016	43	71	-	-
CE Delft - BAU	68	105	-	-
Greenpeace NL - Target	32	124	-	-
CE Delft - A	100	201	-	-
CE Delft - B	92	177	-	-
CE Delft - C	108	227	-	-
CE Delft - D	131	296	-	-
CE Delft - E	174	425	-	-
WLO - Hoog	116	177	-	-
WLO - 2° Decentraal	201	313	-	-
WLO - 2° Centraal	148	236	-	-

Source: Prognos

Capacity

The Netherlands have a similar structure of gas demand as Germany, with a pronounced demand for gas during the heating period. Against this background, we will use the empirical findings on the relation of gas demand and capacity established by [FfE 2014].

Capacity demand for final gas demand is set to reduce by 10 % at most in target scenarios for the period of 2020 – 2050 and 37 % at least in target scenarios, considering the same time frame (see Table 77). The large reduction of gas demand for space heating is one of the pivotal driving forces in target scenarios.

Capacity demand for gas power plants is set to decline over target and reference scenarios. The driving factor is the development of renewable energy sources for electricity production that can substitute electricity production by gas and other fossil fuel power plants. The production of electricity by intermittent renewable energy sources will require a large increase in flexibility of the energy sector overall. Whereas reference scenarios (and the Dutch NDP) foresee gas power plants as an integral part of the power sector flexibility, target scenarios such as the Energy [R]evolution foresee a combination of different flexibility measures, especially electrical storage and demand side management [Greenpeace 2013].

Table 77: Estimation: Development of gas capacity demand for final energy sectors (estimation) and installed power plant gas capacity – The Netherlands

Capacity demand for final gas demand [Index 2020 = 1,00]	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
ECN - Vastgestelde Beleid	1.0	1.0	-	-	-4%	-	-
Greenpeace NL - Reference	1.0	1.0	1.0	0.9	-3%	-8%	-4%
European Commission -Reference 2016	1.0	0.9	0.9	0.9	-6%	-13%	-8%
CE Delft - BAU	1.0	1.0	-	-	-3%	-	-
Greenpeace NL - Target	1.0	0.9	0.7	0.6	-13%	-39%	-30%
CE Delft - A	1.0	0.9	-	-	-14%	-	-
CE Delft - B	1.0	0.9	-	-	-12%	-	-
CE Delft - C	1.0	0.8	-	-	-18%	-	-
CE Delft - D	1.0	0.7	-	-	-26%	-	-
CE Delft - E	1.0	0.5	-	-	-50%	-	-
WLO - Hoog	1.0	1.0	0.9	0.8	-3%	-21%	-18%
WLO - 2° Decentraal	1.0	0.9	0.7	0.6	-11%	-37%	-29%
WLO - 2° Centraal	1.0	0.9	0.8	0.7	-7%	-32%	-27%

Installed Capacity of Gas Power Plants [GW]	2015	2020	2030	2040	2050	Change 2020-2030	Change 2020-2050	Change 2030-2050
ECN - Vastgestelde Beleid	17	16	15	-	-	-6%	-	-
Greenpeace NL - Reference	20	17	16	16	15	-6%	-12%	-6%
European Commission -Reference 2016	17	14	12	15	18	-15%	23%	45%
CE Delft - BAU	-	-	-	-	-	-	-	-
Greenpeace NL - Target	20	17	14	11	8	-18%	-53%	-43%
CE Delft - A	-	-	-	-	-	-	-	-
CE Delft - B	-	-	-	-	-	-	-	-
CE Delft - C	-	-	-	-	-	-	-	-
CE Delft - D	-	-	-	-	-	-	-	-
CE Delft - E	-	-	-	-	-	-	-	-
WLO - Hoog	-	-	-	-	-	-	-	-
WLO - 2° Decentraal	-	-	-	-	-	-	-	-
WLO - 2° Centraal	-	-	-	-	-	-	-	-

Source: [ECN 2015]; [Greenpeace NL 2013]; [CE Delft 2013]; [PBL / CBP 2015]

3.3.4.4 Impacts on infrastructure and costs

According to the Dutch NDP 2015, investments in the Dutch transmission system are necessary due to three reasons:

- Quality conversion due to the falling gas supply from the Groeningen field
- Access to the gas roundabout
- Specific investment proposals from neighbouring network operators

In sum, the proposed measure with FID-Status have an investment volume of € 400 million for the period 2015-2025. However, measures such as quality conversion or additional access to the gas roundabout do assume a stable gas demand in the north-west European region. However, measures proposed by the NDP in order to achieve an import substitution may not be needed altogether considering a falling gas demand in the Netherlands and North-West Europe as a whole. This applies particularly to the extension of the LNG Terminal in Rotterdam and the capacity increase of the Oude Statenzijl border point (see also GTS 2015, p. 44 for a capacity balance with a low gas demand scenario).

The authors of [CE Delft 2013] notice that the large distribution system in the Netherlands that supplies G-, L- and H-Gas to consumers domestically and abroad would not be necessary anymore as soon as the Groeningen field stops supplying G-gas.

Furthermore, the authors of [CE Delft 2013] assume that biogas will be introduced into the gas network. In areas of low and medium pressure, there should be no requirement for further investments. Only in regions where there is a high imbalance between supply and demand (e.g. regions with extensive agricultural activity), further high pressure grids could be required. Furthermore, the gas network could play a larger role in a system with power-to-gas plants.

3.3.4.5 Conclusion

- **Efficiency and RES potentials and relationship with gas**: There is a relationship between efficiency, renewables and gas consumption after 2030. With increasing pressure on efficiency and RES development, a reduction of gas consumption after 2030 can be expected.
- **Situation of NDP scenarios compared to other scenarios**: All scenarios analysed in this section predict a falling future gas demand. The scenario used to evaluate the capacity needs in the NDP show an increasing gas future gas demand. It is not in line with the target scenarios that reach EU and national targets.
- **Assumptions about possible reduction of gas demand**: Natural gas has played a large role in the Dutch economy as a fuel for heating and electricity due to its large domestic availability. In order to decarbonise the economy and reduce a future import dependency, switching to renewable forms of electricity and heat generation is largely advocated in the analysed scenarios.
- **Consequences on infrastructures and costs**: Measures proposed by the Dutch NDP are mostly for technical **substitution** purposes and their amount is the lowest of all six countries. However, a falling gas demand in the region would allow further reductions in gas infrastructure expenditure, especially for what concerns the LNG terminal in Rotterdam.

3.3.5 Spain

3.3.5.1 Analysed scenarios

Relatively few studies are available regarding gas demand consumption scenarios in Spain. The following three studies were selected: [EU Ref 2016], [OIES 2014], [IDAE 2011]. Moreover, other studies deal with energy consumption in general or with specific parts of the energy system such as power generation, efficiency and renewable potential. Therefore, the following studies have been additionally analysed in order to have more insight on these specific topics: [Deloitte 2016], [EfE/ Bloomberg 2011], [CEE 2014], [Greenpeace 2011], [PwC 2010]. The characteristics of the scenarios are presented in Table 79.

The following table gives an overview of the extent to which the analysed scenarios reach national and EU targets concerning efficiency and RES. It should be noted that the scenario EU-REF2016 reaches both of the targets.

Table 78: Comparison between scenarios and EU and national targets - Spain

	Primary energy demand [TWh]	% renewables in final energy
	2020	2020
national and EU targets	*1.393*	*20%*
Scenario NDP (Reference)	1.654	21%
IDAE - REF	1.930	N.A.
IDAE - EFF	1.659	N.A.
EU-REF2016	1.381	21%

Note: Red colour means the targets have not been reached.

Source: Prognos, based on [EU Ref 2016], [IDAE 2011], [PSEG 2011]

Table 79: Characterisation of the analysed demand scenarios - Spain

Study	Scenario	Scenario description
Reference Scenarios		
Instituto para la Diversificación y Ahorro de la Energía (IDAE), Plan de energías renovables (PER) 2011-2020, 2011	IDAE - REF	This scenario takes into account efficiency measures that have been adopted until 2010, especially the plan for energy savings and efficiency 2004 - 2012.
EU Commission, EU Reference scenario 2016, 2016	EU-REF2016	This report focuses on trend projections. It does not predict how the EU energy landscape will actually change in the future, but provides one of its possible future states given certain conditions. Legally binding GHG and RES targets for 2020 will be achieved. Policies agreed at EU and Member State level until December 2014 will be implemented.
Oxford Institute for Energy Studies (OIES), The outlook for natural gas demand in Europe, 2014	Oxford Energy	The author analyses likely trends for gas demand development until 2030.
Club español de la Energía (CEE), Instituto español de la energía, Factores clave para la energía en España : una visión de futuro, 2014	CEE - Base	In this scenario, current trends are assumed to continue in the future, particularly the evolution of energy intensity and political measures.
Greenpeace, Energía 3.0: Un sistema energético basado en inteligencia, eficiencia y renovables 100 %, 2011	Greenpeace BAU	This scenario reflects actual trends in energy demand.
Target / Explorative Scenarios		
Instituto para la Diversificación y Ahorro de la Energía (IDAE), Plan de energías renovables	IDAE - EFF	This scenario takes into account additional efficiency measures compared to scenario REF (especially measures from the plan for energy savings and efficiency 2011-2020), that would enable to reduce primary energy demand by 14 % compared to the reference scenario.

(PER) 2011-2020, 2011		
Deloitte, Un modelo energético sostenible para España en 2050, 2016	Deloitte	The scenario aims to show the path of the energy mix, should Spain reach its 2050 objectives, and details the required economic, regulatory and technological conditions.
economics for energy and Bloomberg, Potencial económico de reducción de la demanda de energía en España, 2011	EforE / Bloomberg	This study assesses the potential for energy savings in each sector until 2030, using marginal cost curves and for 3 scenarios (trend, technological and political).
Club español de la Energía (CEE), Instituto español de la energía, Factores clave para la energía en España : una visión de futuro, 2014	CEE - Eficiente	This scenario includes specific measures that would enable to change the trajectory of GHG emissions so as to reach the 2030 targets.
Greenpeace, Energía 3.0: Un sistema energético basado en inteligencia, eficiencia y renovables 100 %, 2011	Greenpeace 3.0	In this scenario, efficiency measures reduce energy demand and renewables make 100 % of power generation in 2050.
PricewaterhouseCoopers, El modelo eléctrico español en 2030, Escenarios y alternativas, 2010	PwC	This study analyses four scenarios depicting various power generation capacity mixes in 2030. The scenarios apply various assumptions concerning the share of renewables and the phase out of nuclear plants.
Ambitious scenario		
Greenpeace, Energía 3.0: Un sistema energético basado en inteligencia, eficiencia y renovables 100 %, 2011	Greenpeace 3.0	In this scenario, efficiency measures reduce energy demand and renewables make 100 % of power generation in 2050.

Source: Prognos, based on [EU Ref 2016], [OIES 2014], [IDAE 2011], [Deloitte 2016], [EfE / Bloomberg 2011], [CEE 2014], [Greenpeace 2011], [PwC 2010]

3.3.5.2 Potentials of low carbon options and influence on gas demand

Available scenarios dating back before 2013 expect an increase in primary energy demand until 2050. The increase rate depends on efficiency measures. In a scenario with pro-active implementation of efficiency measures (IDAE-EFF), the increase per decade stays below 10 %. However, it must be borne in mind that IDAE study from 2011 did not fully take into account the long term aspect of the economic crisis that began in 2007 or was more optimistic on future economic growth. For example, the GDP was expected to grow by 2.3 % in 2012 and 2.4 % in 2013, while it actually declined by 2.6 % in 2012 and 1.7 % in 2013 (World Bank). Moreover, it was assumed that GDP would grow by an average of 2.4 % in the period 2014 to 2020, while the new National Energy Efficiency Action Plan 2014 (NEEAP) now expects the GDP to reach a growth of 2.4 % only in 2020. The same applies to the 2011 NDP and EU Reference scenarios 2013 (not represented here). In 2014, primary energy consumption in Spain amounted to 1,357 TWh, after a continuous decline since the beginning of the economic crisis in 2007. The projections given by the studies older than 2013 seem therefore to overestimate energy consumption. On the contrary, the new EU projections expect a continuous decrease in energy consumption (Table 80). While EU Ref 2013 expected a 2 % increase in primary energy consumption, the EU REF 2016 sees a 19 % decrease between 2015 and 2050. The new EU projections for Spain expect an annual GDP growth of 1.5 % between 2015 and 2050.

Table 80: Energy efficiency: Development of primary energy demand and primary energy demand per person in the analysed demand scenarios - Spain

Primary energy demand [TWh]	2010	2015	2020	2030	2050	Change 2010-2020	Change 2020-2030	Change 2030-2050
NEEAP 2014 targets			*1.393*					
IDAE - REF	1.534	1.743	1.930			26%		
IDAE - EFF	1.534	1.604	1.659			8%		
EU-REF2016	1.428	1.382	1.381	1.260	1.129	-3%	-9%	-10%
Primary energy demand/ person [kWh/p]	**2010**	**2015**	**2020**	**2030**	**2050**	**Change 2010-2020**	**Change 2020-2030**	**Change 2030-2050**
IDAE - REF	32.855	36.815	40.201			22%		
IDAE - EFF	32.855	33.878	34.553			5%		
EU-REF2016	30.728	29.821	30.216	28.320	24.772	-2%	-6%	-13%

Source: Prognos, based on [EU Ref 2016], [IDAE 2011]

If an economic recovery takes place, as the World Bank expects, energy consumption could rapidly increase. In 2014, GDP increased by 1.4 % and in 2015 by 3.2 %. Depending on the strength of the recovery, energy demand could be impacted. Energy consumption in the industry should be the driver of final energy demand growth, if economic growth improves. Moreover, efficiency gains in the industry are more limited than in the residential sector.

[Economics for Energy / Bloomberg] assessed energy saving potential in three scenarios. According to the study, 178 TWh to 423 TWh could be saved by 2030, especially in the generation, transport and residential sectors.

Spain has implemented a program to develop renewable energy sources (RES) since 2004. Guaranteed feed in tariffs supported a fast RES development, but represented a growing financial burden. In 2012, RES represented 14 % of final energy consumption and 31 % of electricity generation. However, from 2010, the government introduced legislation reducing or phasing out RES incentives in order to reduce the tariff deficit. As a result, RES investments and deployment have significantly slowed down. Among the data below, only EU REF 2016 takes into account the new legislation reducing RES incentives.

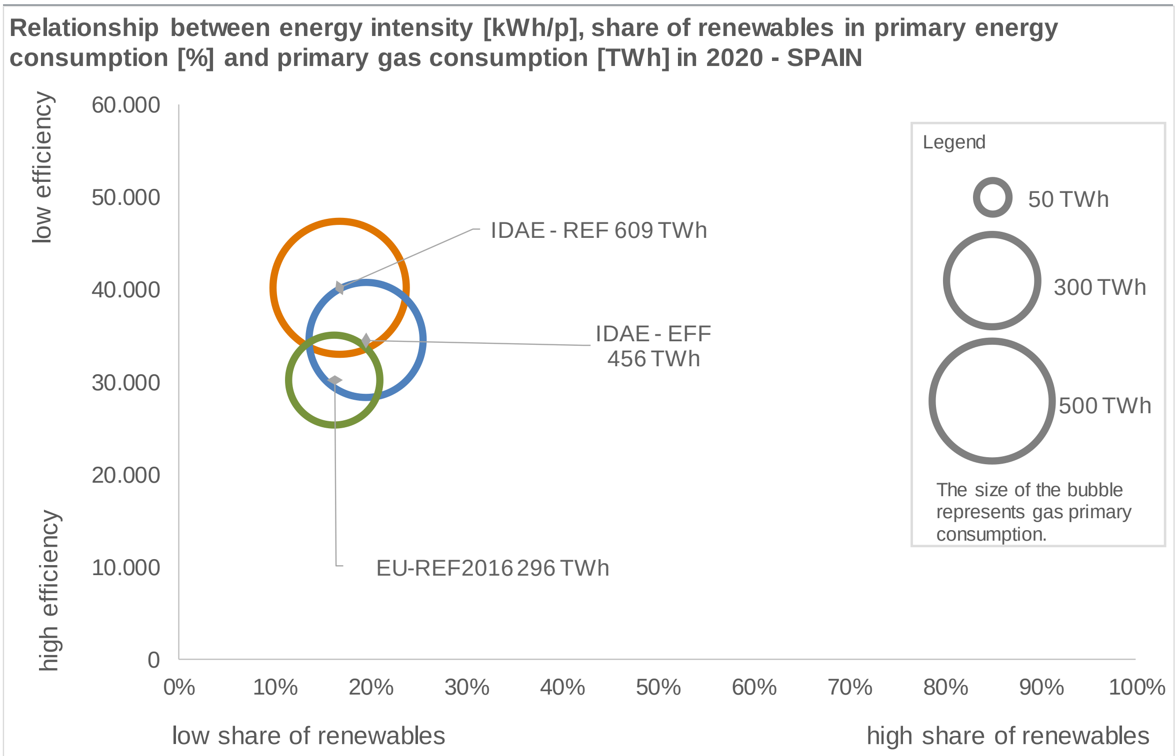
Table 81: Renewables: Share of RES in primary energy demand in the analysed demand scenarios - Spain

RES demand/ primary energy demand [%]	2010	2015	2020	2030	2050
IDAE - REF	11%	14%	17%		
IDAE - EFF	11%	15%	20%		
EU-REF2016	12%	13%	16%	22%	36%

Source: Prognos, based on [EU Ref 2016], [IDAE 2011]

When considering the available data on efficiency, renewables and gas consumption in 2020 (Figure 37), the following relation can be seen: gas demand reduces when efficiency increases.

Figure 37: Relationship between energy intensity, share of renewables in primary energy consumption and primary gas consumption - Spain



Source: Prognos, based on [EU Ref 2016], [IDAE 2011]

IDAE took into account CO_2 prices in the EU ETS sectors of 14 EUR/tCO_2 in 2010, 18 EUR/tCO_2 in 2015, 24 EUR/tCO_2 in 2020 and 30 EUR/tCO_2 in 2030. They were used for both of the scenarios (REF and EFF), so that energy consumption change was driven in those scenarios primarily by efficiency measures. Moreover, as the economic crisis reduced significantly energy demand, GHG emissions reduced and CO_2 prices currently do not play a role.

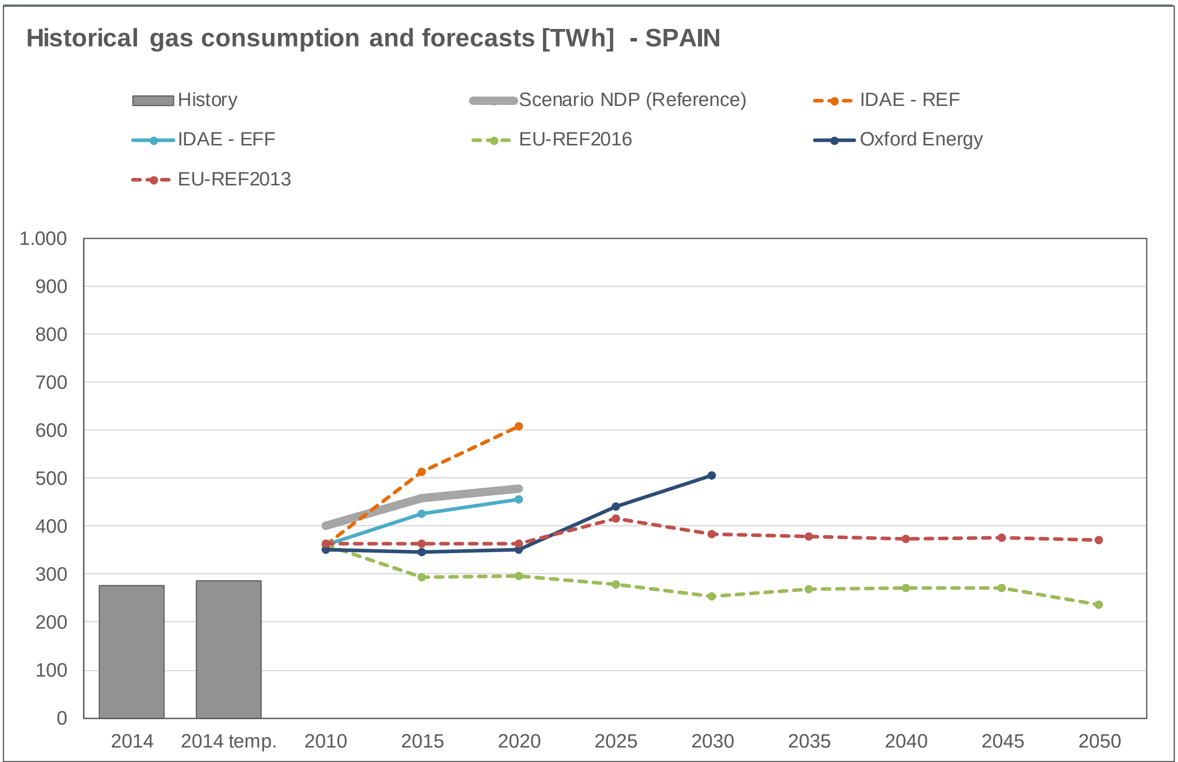
Key findings

- In the last years, Spain's energy consumption was largely influenced by the economic crisis which began in 2007. Since then, primary energy consumption reduced continuously. Energy demand projections that have been made during that time depend on GDP projections and are therefore very uncertain. Spain showed first signs of economic recovery in 2014.
- Future energy demand growth will depend on the intensity of the economic recovery. Therefore, there is little visibility for the moment.
- Political measures to foster energy efficiency have been slowed down by the urgency to cope with macroeconomic consequences of the crisis, especially the unemployment. Regarding RES development, the phasing out of incentives has created distrust and uncertainty and dampened RES deployment. Investments for efficiency measures and RES deployment are likely to be reduced to low levels at the moment when energy demand will be pushed up by economic growth. In the mid-term, economic growth is a prerequisite of efficiency due to a quicker turnaround rate of the building and machinery stock.

3.3.5.3 Gas demand in these scenarios

Gas demand projections vary among the scenarios. While older scenarios like [IDAE 2011] and [PSEG 2011] expected an increase in gas consumption (from 19 % to 69 %) until 2020, [EU Ref 2013] and [OIES 2014] indicate a stagnation of gas demand until 2020, taking into account the prolonged effects of the economic crisis, followed by an increase in gas demand after 2020. The most recent study [EU REF 2016] is even more cautious and do not expect any substantial increase in gas demand, even with a GDP growth of 1.5 % per year. Moreover, scenario EU REF 2016 is in line with 2020 EU targets for Spain (see 3.3.5.1).

Figure 38: Development of gas demand in analysed scenarios - Spain



Note:
1. Each analysed study is pictured in a different colour.
2. 2014 was an exceptionally warm year. It was the warmest year since 1990. Therefore, the temperature-adjusted gas consumption has been added.
3. Trend / reference / business as usual scenarios are indicated with a spotted line.

Source: Prognos, based on [EU Ref 2016], [OIES 2014], [IDAE 2011], [EU Ref 2013], [PSEG 2011]

When comparing gas demand in the scenarios, gas saving potential in 2020 ranges from 22 TWh to 182 TWh (see Table 55). The biggest saving potential would be reached in the EU REF 2016 scenario.

Table 82: Gas saving potential: differences between alternative scenarios and the NDP for 2015 and 2020 in TWh - Spain

Saving potential [TWh]	2015	2020
NDP 2015	458	478
Savings (delta NDP 2015 - gas demand in the scenario):		
IDAE - REF	-56	-131
IDAE - EFF	**32**	**22**
EU-REF2016	**165**	**182**
Oxford Energy	**113**	**128**

Note: Saving potential is indicated in green.

Source: Prognos, based on [EU Ref 2016], [IDAE 2011], [PSEG 2011]

Electrification and gasification of all sectors is often seen as the way to reach GHG targets in 2030 and 2050. In the transport sector, the use of electric and CNG vehicles is expected to expand. Market penetration of gas is expected to increase in some studies and gas could replace coal and oil in some industrial processes. As a result, electricity and gas could increase their role in final energy. Electricity demand increases accordingly. In parallel, efficiency measures dampen the increase of gas demand in the final demand. Moreover, the increased use of CHP and district heating reduces the share of gas for heat production. Overall, the development of final gas demand will depend greatly on the pace of GDP growth, as industry is the biggest gas user when considering final energy, and on the substitution level of other fossil sources by gas. In the EU REF 2016, final gas consumption is even expected to decrease by around 20 % until 2030 and stabilize at around 140 TWh.

Since the economic crisis reduced electricity demand, there are overcapacities by electricity generation. While RES generate 40 % of the electricity, gas-fired power plants have quite low load factors. Moreover, following the US shale gas surge, excess coal became cheaper than gas and partly replaced gas for electricity generation. It is uncertain how gas demand for electricity production will develop in the future. While some scenarios expect a moderate reduction in gas use until 2020/2030 and then an increase following the nuclear and coal phase out [OIES 2014], others give different assumptions concerning nuclear phase out ([Greenpeace 2011], BAU) or contemplate the possibility to replace the 7,5 GW nuclear capacities by more renewables combined with various alternatives like DSM, more interconnections and gas-fired plants. In [EU REF 2016], gas consumption for electricity generation is expected to increase in some periods after 2015, while capacities of gas fired power plants reduce by 54 % between 2015 and 2050. The degree of gas use therefore can vary a lot according to hypothesis of nuclear and coal phase out and use of various alternatives, but most of the time, there is a gas component in the energy mix.

In February 2016, Enagas announced that gas demand increased by 4.5 % in 2015, reaching 314 TWh. Half of the increase was due to the increased GDP (and therefore increased industrial activity and gas use in industrial processes). The other half relates to increased gas use in the electricity production (due to a lower electricity output from hydraulic power plants) and increased number of clients using gas. It should be noted that even in the case of an increase in gas demand, it will take place from relatively low levels, so that it will take some time before they reach the previous peak of 2008 (407 TWh).

Key findings

- Many components influence gas consumption in Spain: GDP growth plays a big role, because industry is a big gas consumer. Measures fostering energy savings and the deployment of renewables influence the role of gas and the degree to which it would substitute other fossil fuels, and therefore the level of its consumption. Finally, the schedule of the nuclear and coal phase out will also determine the role of gas in the power generation mix.
- A number of events make it difficult to analyse the effects of these components on gas consumption:

  - The economic crisis blurred the visibility concerning the relationships between consumption, efficiency, renewables and GHG emissions. It was largely responsible for the decline in primary gas consumption since 2007.
  - Changing politics and legislations, particularly concerning RES deployment, created uncertainty over the extent and the speed to which low carbon options will be enforced in the future.
- However, a few assertions can be made from the analysed studies. First, early studies, including the NDP, assumed rather optimistic trends regarding GDP growth, power demand development and consequently gas demand growth. Second, given the high share of electricity produced by hydropower plants and wind turbines, back-up capacities are and will be necessary for dry hydraulic year when nuclear plants or coal plants will be phased out. Third, even if there is an increase in gas demand in the future (due to increasing GDP and electricity demand), it will take some time before consumption reaches 2008 levels. In the meantime, the priority will be to use under-utilized infrastructure and progressively increase their operating time. In case gas demand develops according to the EU REF 2016 scenario, only 38 % of the projected gas demand in the NDP 2011 would effectively materialize.

3.3.5.4 Impacts on infrastructure and costs

In the 2011 NDP, investment projects for gas infrastructures are based on the assessment of peak final gas demand as well as peak electricity demand, which are themselves based on demand scenarios for gas demand and electricity demand. As already stated in chapter 0, gas demand was largely overestimated: the NDP expected gas demand to increase by 20 % between 2011 and 2020, while it actually continued to reduce. In 2014, primary gas demand reached 275 TWh, 38 % below the projected demand.

Similarly, electricity demand was overestimated in the NDP 2011: final electricity demand was expected to increase by 14 % from 2005 to 2015 and continue to grow until reaching 351 TWh in 2020. Actually in 2014, final electricity demand reached 227 TWh, that is 6 % below 2005 levels. This makes it unlikely that electricity demand recovers fully before 2020.

Moreover, the two most recent studies [EU REF 2016] and [OIES 2014] points to a stagnation or even a reduction of primary gas demand at least until 2020.

The NDP assumes that an extra electricity generation capacity of 1,800 MW would be needed by 2020. This is the main driver of gas demand increase. Even in the case that this additional capacity would be provided by additional plants other than gas-fired turbines, the NDP suggests an increase in regasification capacities, as well as the adaptation of other infrastructures in order to deliver the additional gas imports at the right places (gas pipelines, compressions stations, distribution network, LNG tanks). The needed investment until 2020 amounts to € 5,122 million. Even in case of an increase in electricity and gas levels before 2020, there are idle LNG capacities as well as CCGT that are actually operating 2,000 hours a year instead of the 5,000-6,000 hours a year that were assumed when those plants were built. In 2015 for instance, only 20 % of LNG capacities in Spain were actually used. Those excess and underused capacities are likely to be sufficient to meet the demand.

As a conclusion, € 5,122 million could be saved until 2020. An update of the situation should be realized so as to check if the proposed infrastructure investments are still needed in the future (after 2020) and would only be translated to a later period, or if the situation changes so that gas would be needed less (as expected in [EU REF 2016]).

It is important to remind that the 2011 NDP is not binding due to political and legislative changes. The previous NDP (2008-2016) runs out at the end of 2016 at which time a new NDP is supposed to be drafted and adopted.

3.3.5.5 Conclusion

- **Efficiency and RES potentials and relationship with gas**: A number of events make it difficult to analyse the effects of these components on gas consumption: first, the economic crisis blurred the visibility concerning the relationships between consumption, efficiency, renewables and GHG emissions. It was largely responsible for the decline in primary gas consumption since 2007. Second, changing politics and legislations, particularly concerning RES deployment, created uncertainty over the extent and the speed to which low carbon options will be enforced in the future.
- **Situation of NDP scenario compared to other scenarios**: In the last years, Spain's energy consumption was largely influenced by the economic crisis which began in 2007. Since then, primary energy consumption reduced continuously. Energy demand projections that have been made during that time (**including** the 2011 NDP) were optimistic about GDP recovery, and have overestimated gas demand growth. The NDP expected gas demand to increase by 20 % between 2011 and 2020, while actually it continued to reduce. In 2014, primary gas demand reached 275 TWh, 38 % below the projected demand. More recent studies indicate a stagnating or even decreasing gas demand until at least 2020. Spain showed first signs of economic recovery in 2014.
- **Assumptions about possible reduction of gas demand**: Future energy demand growth will depend on the intensity of the economic recovery. GDP growth plays a big role, because industry is a big gas consumer. Measures fostering energy savings and the deployment of renewables influence the role of gas and therefore the level of its consumption. The schedule of the nuclear and coal phase out will also determine the role of gas in the power generation mix. In spite of these uncertainties, a few assertions can be made from the analysed studies. First, given the high share of electricity produced by hydropower plants and wind turbines, back-up capacities are and will be necessary for dry hydraulic year when nuclear plants or coal plants will be phased out. Second, if there is an increase in gas demand in the future (due to increasing GDP and electricity demand), it will take some time before consumption reaches 2008 levels.
- **Consequences on infrastructures and costs**: In the 2011 NDP, gas demand was largely overestimated, with an increasing electricity demand seen as the main driver of gas demand increase. Even in case of an increase in electricity and gas levels before 2020, idle LNG capacities as well as CCGT (that are actually operating 2,000 hours a year instead of the 5,000-6,000 hours a year that were assumed when those plants were built) are likely to be sufficient to meet the increase. Therefore, the proposed € 5,122 million investments could at least be postponed until after 2020. An update of the situation should be realized so as to check if the proposed infrastructure investments are still needed in the future. It is important to remind that the 2011 NDP is not binding due to political and legislative changes. The biggest challenge for Spain is not the access and distribution of gas to cover its demand, but rather the optimal use of its import infrastructure and especially better gas exchanges with the rest of continental Europe (see footnote 105).

3.3.6 United Kingdom

3.3.6.1 Analysed scenarios

There are varies analysis on decarbonising energy systems in the United Kingdom, e.g. "Pathways to 2050" [AEE 2011] or meta-analyses on these studies, e.g. "The UK energy system in 2050: Comparing Low-Carbon, resilient Scenarios" [UKERC 2014] or "Pathways for Heat: Low Carbon Heat for Buildings" [Carbon Connect 2014]. In this analysis, we concentrated on very recent studies and the reference scenario from the European Commission. Table 83 gives an overview of the analysed scenarios and their characteristics. Scenarios with targets and measures reach or over exceed the long-term decarbonisation targets. But none of the scenarios achieves a more ambitious renewable share so the analysed scenarios are only classified as "reference" or "with targets and measures" Almost all of the scenarios rely on the official UK population projection with 71 million in 2030 and 77 million people in 2050. GDP growth is assumed to be between 2 and 2.3 %. Only the EU Reference scenario 2013 has a lower population assumption with 70 million people in 2030 and 76 million in 2050 and an average GDP growth of 1.9 %.

Table 83: Overview of analysed scenarios in the United Kingdom

Study	Scenario	Scenario description	Target compliance
Reference Scenarios			
European Commission, Trends to 2050, 2016	EU Reference	Reference Scenario of the European Commission	2020 targets are met, long term decarbonisation target is not met
Scenarios with measures and targets or explorative scenarios			
Committee on Climate Change, Sectoral scenarios for the Fifth Carbon Budget, Technical report, 2015	Central	Scenarios that are the foundation for 5th carbon budget (2028-2032) in the UK. Scenario "Central" represents the best assessment of the technologies and behaviours to meet 2050 targets cost-effectively	all climate targets including carbon budgets are met
Institute for Sustainable Development and International Relations (IDDRI), Sustainable Development Solutions Network (SDSN), UCL Energy Institute (UCL-Energy), Pathways to deep decarbonization in the United Kingdom, 2015	D-EXP	Scenario from the Deep Decarbonization Pathways Project (DDPP) in which pathways to deeply reducing greenhouse gas emissions in different countries are researched; D-EXP is a scenario with a strong focus on near-term power sector decarbonisation, a strong role of CCS and high level of end-use sector electrification, 2050 targets are reached	long term decarbonisation target is met
	M-VEC	Also from DDPP, scenario with less nuclear and CCS, less electricfication, stronger role of hydrogen and bioenergy, 2050 targets are reached	long term decarbonisation target is met
	R-DEM	Also from DDPP, scenario with strong reduced demand in buildings and transportation, 2050 targets are reached	long term decarbonisation target is met
UK Energy Research Centre (UKERC), The future role of natural gas in the UK, 2016	Maintain	Scenarios that focus on the role of gas, the Maintain scenario reaches the 2050 targets with a high roleout of CCS and other low-carbon options	long term decarbonisation target is met
	Maintain (tech-fail)	Scenario similiar to Maintain, but without CCS, 2050 targets are reached	long term decarbonisation target is met

Source: Prognos based on [EC 2016], [CCC 2015], [DDPP UK 2015], [UKERC 2016]

The Climate Change Act 2008 sets the legally binding target for the United Kingdom to reduce carbon emissions by at least 80 per cent from 1990 levels by 2050. It also defines carbon budgets for time periods of five years to achieve this target. The first carbon budget (2008-2012) was met and the second carbon budget (2013-2017) is very likely to be met. The third carbon budget requires a reduction of carbon emissions of 35 % in 2020. This year the 5th carbon budget was passed with a reduction of 57 % in 2030.

There is only one national target on renewable generation in the UK which is linked to the European Renewable Energy Directive and requires at least 15 per cent of its energy consumption from renewable sources by 2020. There is no binding national target for energy efficiency[107].

Table 84 compares UKs energy and climate targets with the results of the analysed scenarios. All scenarios except the European reference scenario 2016 reach the long term decarbonisation targets. One decarbonisation scenario (UKERC Maintain 2016) misses the short term carbon targets, but reaches the long term target.

Table 84: UK energy and climate targets and compliance in the analyzed scenarios

	Reduction GHG emissions (compared to 1990)				Renewable energy		Energy efficiency	
	2020	2025	2030	2050	2020	2030	2020	2030
Targets UK	**-35%**	**-50%**	**-57%**	**-80%**	**15%**			
CCC Central 2015	-46%	-53%	-61%	-84%				
DDPP D-EXP 2015				-92%	7%			
DDPP M-VEC 2015				-94%	6%			
DDPP R-DEM 2015				-90%	6%			
UKERC Maintain 2016	-32%		-54%	-81%				
UKERC Maintain (techfail) 20	-32%		-54%	-81%				
EU Reference 2016	-41%		-52%	-56%	15%			

Source: Prognos based on [EC 2013], [CCC 2015], [DDPP UK 2015], [UKERC 2016]

3.3.6.2 Potentials of low carbon options and influence on gas demand

Assumptions on population and GDP growth do not vary much between the analysed scenarios but the underlying policies and technologies used are different. One major difference is the **appliance of CCS** which is used as a low carbon option in most of the analysed scenarios. "Maintain (techfail)" is the only scenario where no CCS is deployed[108]. Besides, hydrogen generation becomes an important part of the energy economy. It is used to decarbonise transportation and industry in the first place. In most scenarios hydrogen is produced from natural gas via steam methane reforming in combination with CCS. Nuclear energy as a low carbon option is

[107] The Energy Efficiency Directive has only bonding measures for 2020.
[108] In the EU Reference Scenario 2013 CCS is employed from 2020 on.

deployed throughout all analysed scenarios but is not analysed further as the focus point of this study lies on energy efficiency and renewable energies[109].

Energy efficiency plays an important role in the scenarios as well. Table 85 shows the development of energy efficiency as primary energy demand for the analysed scenarios[110]. In nearly all scenarios primary energy demand decreases between 2010 and 2050. It is remarkable that also in the reference scenario energy intensity decreases about 33 %. In all scenarios most of the decrease happens between 2010 and 2030. Energy efficiency includes better buildings standards as well as efficiency improvements in industry and transport. In one scenario, D-EXP 2015 increases in 2050 due to the amplified hydrogen generation in these scenarios.

Table 85: Energy efficiency: Development of primary energy demand in the analysed demand scenarios- United Kingdom

Primary energy demand [TWh]	2010	2020	2030	2050	Change 2010-2030	Change 2020-2050	Change 2030-2050
CCC Central 2015							
DDPP D-EXP 2015	2,629	2,327	2,154	2,630	-18%	13%	22%
DDPP M-VEC 2015	2,629	2,306	2,065	2,156	-21%	-7%	4%
DDPP R-DEM 2015	2,629	2,288	2,096	2,324	-20%	2%	11%
UKERC Maintain 2016	2,639		1,944	1,972	-26%		1%
UKERC Maintain (techfail) 2016	2,639		1,806	1,722	-32%		-5%
EU Reference 2016	2,468	2,157	2,059	2,082	-17%	-3%	1%

Source: Prognos based on [EC 2013], [CCC 2015], [DDPP UK 2015], [UKERC 2016]

Besides energy efficiency the **heating structure** is changing profoundly in the target scenarios: in the DDPP scenarios it is changing from 80 % natural gas to heat pumps (about 60 % in 2050) and district heating (about 15 %) in D-EXP and R-DEM or to solar heating in great parts (about 40 %, M-VEC). Also, in CCC Central 2015 heat pumps (2.5 million in 2030) and district heating begin to play an important role resulting in less gas use in buildings.

Another important low carbon option in most of the analysed scenarios is the deployment of **renewable energies**, especially for electricity generation.

Table 86 shows the share of renewable energy in the gross final energy demand. It is noticeable that scenarios with a strong role of CCS as DDPP D-EXP and UKERC Maintain have a relative slow growth of renewable share with 17 % in 2050. This share is even lower than the renewables share in the reference scenario (19 % in 2050, Reference 2013). Scenarios without or with less CCS by contrast have a share of over 50 % renewables on primary energy demand in 2050 (DDPP M-VEC).

109 For this analysis it is not important if gas is replaced by nuclear or renewable energies, this would only result in small differences.

110 For the CCC Central scenario primary energy demand was not available.

Table 86: Renewables: Share of RES in energy demand in the analysed demand scenarios – United Kingdom

RES/ energy demand [%]	2010	2020	2030	2050
Target UK		15%		
CCC Central 2015				
DDPP D-EXP 2015	3%	7%	18%	30%
DDPP M-VEC 2015	3%	6%	26%	56%
DDPP R-DEM 2015	3%	6%	16%	35%
UKERC Maintain 2016	3%		12%	17%
UKERC Maintain (techfail) 2016	3%		14%	35%
EU Reference 2016	3%	15%	17%	20%

Source: Prognos based on [EC 2013], [CCC 2015], [DDPP UK 2015], [UKERC 2016]

To achieve the climate targets a **carbon price** is included in most of the scenarios. Table 64 shows the carbon price in the analysed scenarios. The price is a result of the modelling and is growing sharply in the target scenarios. The DDPP study even indicate a very high price over 1000 £/t as the residual emissions are very difficult to mitigate. In the CCC Central scenario the necessary carbon price is also high, but with 222 £/t clearly lower. Table 64 also shows the resulting CO_2 emissions in the analysed scenarios. In the target scenarios emissions are reduced by about 80 to 90 % in comparison to 2010, thereby exceeding the climate target of 80 % reduction of 1990 energy related emission of 653 Mt CO_2.

Table 87: Price for CO_2 and development of energy related* CO_2 emissions in the analysed scenarios – United Kingdom

Price CO_2 [£/t]*	2010	2020	2030	2050
CCC Central 2015		30	78	222
DDPP D-EXP 2015			150	>1000
DDPP M-VEC 2015			330	>1000
DDPP R-DEM 2015			150	>1000
UKERC Maintain 2016				
UKERC Maintain (techfail) 2016				
EU Reference 2016		15	27	87

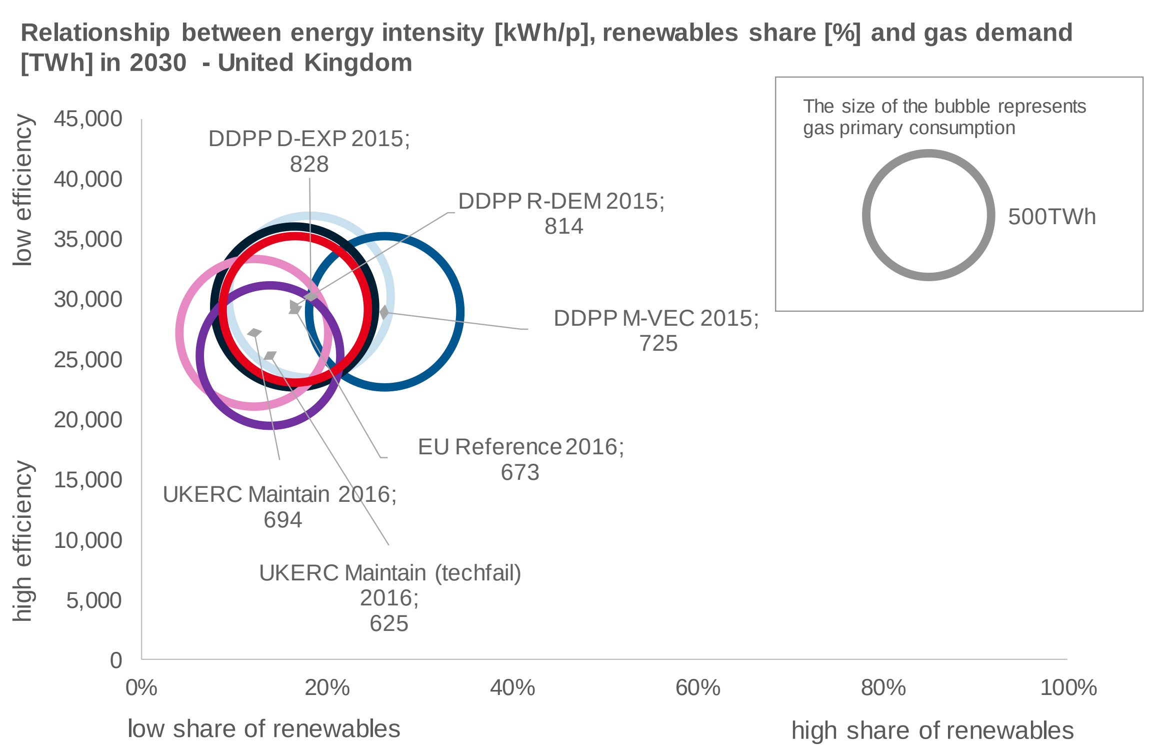
GHG emissions [Mt CO_2eq]	2010	2020	2030	2050
CCC Central 2015	613	436	314	126
DDPP D-EXP 2015	456			63
DDPP M-VEC 2015	456			48
DDPP R-DEM 2015	456			80
UKERC Maintain 2016	670	550	370	150
UKERC Maintain (techfail) 2016	670	550	370	150
EU Reference 2016	636	473	388	357

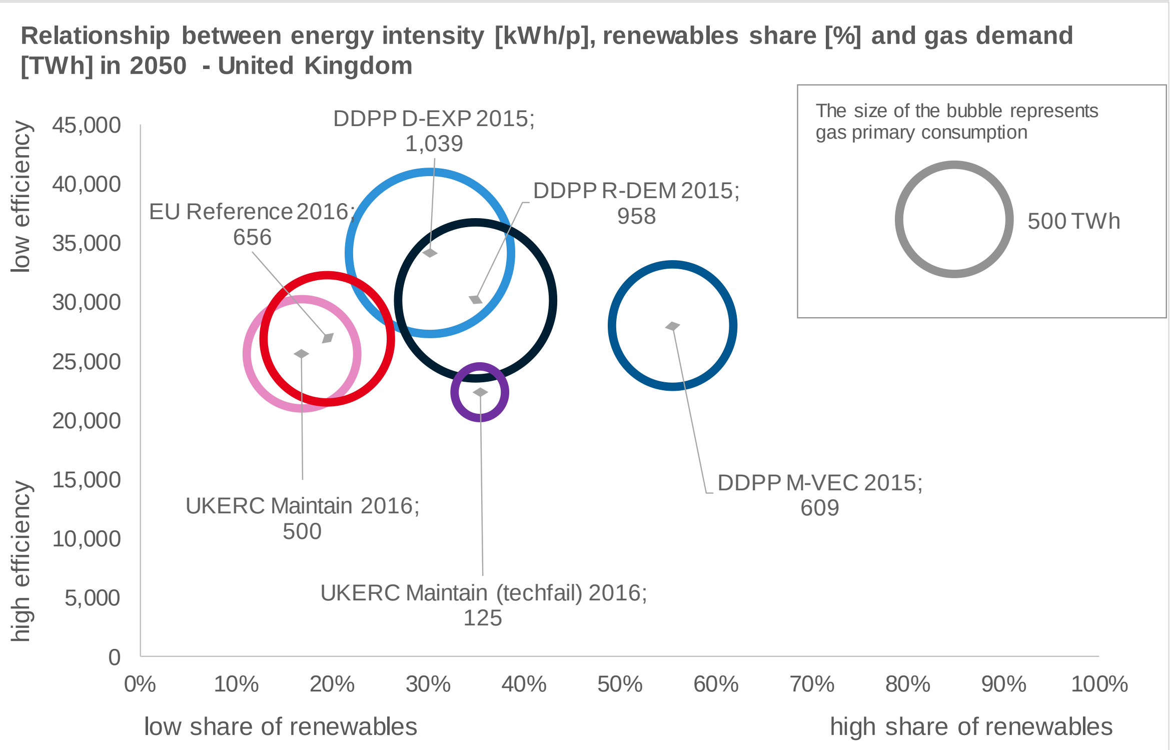
* Note: EU Reference Scenario: Price in EUR/t
UKERC scenario all GHG emissions

Source: Prognos based on [EC 2013], [CCC 2015], [DDPP UK 2015], [UKERC 2016]

To assess the **impact of energy efficiency and renewable energies** the analysed scenarios are shown with their development of energy efficiency, renewables shares and gas demand in Figure 39. It is remarkable that the analysed scenarios in the United Kingdom – no matter if target or reference scenario – do not achieve very high shares of renewables in 2030 nor 2050. But there are efficiency gains achieved. The resulting gas demand remains quite high throughout nearly all of the analysed scenarios but one: In UKERC Maintain (techfail) gas demand in 2050 has decreased sharply while energy efficiency is ambitious. So, for these analysed scenarios in the United Kingdom it cannot be concluded that only efficiency and renewables lead to a lower gas demand. These scenarios employ **other low carbon options** to reach the climate targets. If these options include CCS gas demand is not decreasing much. Still, a high gas demand in a world with low emissions only works with a massive use of CCS technologies which is not economically feasible today.

Figure 39: Relationship between energy intensity, share of renewables in primary energy and gas demand in the scenarios in 2030 and 2050 – United Kingdom





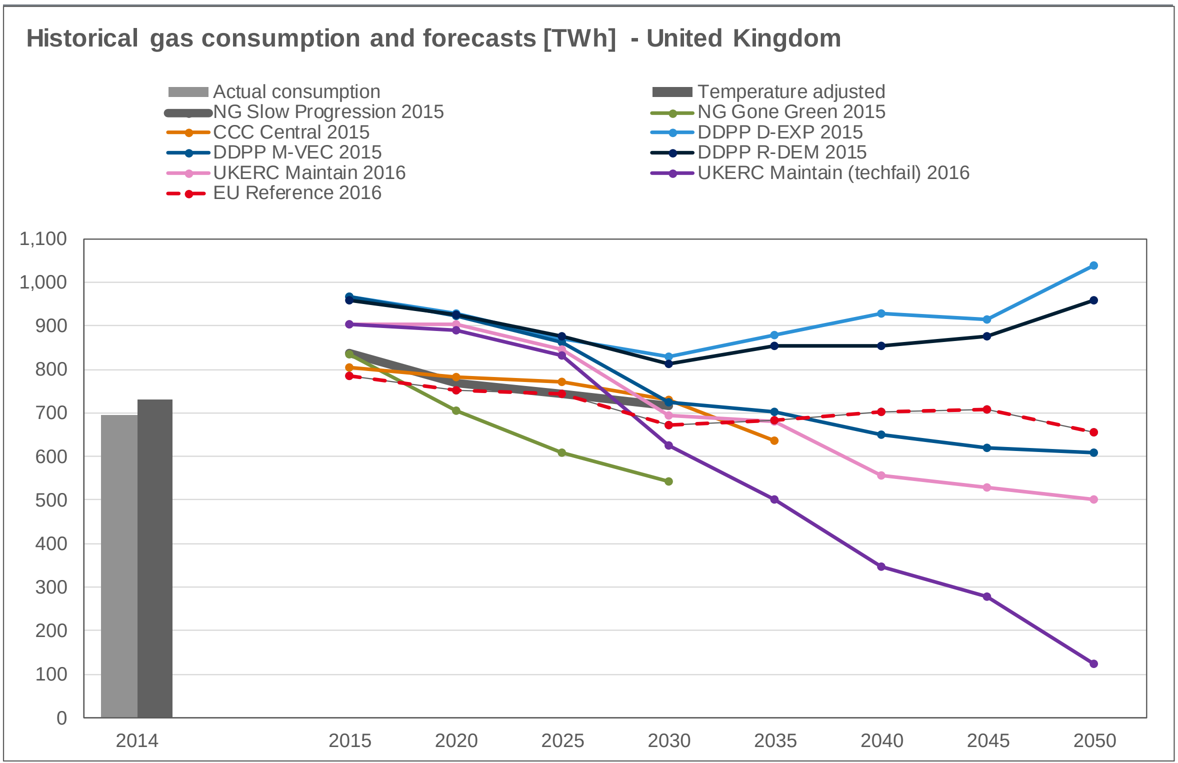
Source: Prognos based on [EC 2013], [CCC 2015], [DDPP UK 2015], [UKERC 2016]

3.3.6.3 Gas demand in these scenarios

The different low carbon options described above result in a different development of the yearly gas demand which is shown in Figure 40. The figure also shows in comparison two gas demand scenarios from National Grids Future energy scenarios 2015 (see also chapter 2.3.7), the “Slow Progression” scenario, that is used for network planning, in grey, and the “Gone Green” scenario in green. In two scenarios gas demand rises over 2015 levels and the scenario with the highest gas demand in 2050 is surprisingly a target scenario, DDPP D-EXP. In this scenario as well as in DDPP R-DEM gas demand rises from 2030 onwards. Also, in the scenarios DDPP M-VEC and UKERC Maintain gas continuous to have an important role. The reason for the continuing **high gas demand** is the wide deployment of **CCS**. In the DDPP scenarios and the UKERC Maintain scenario natural gas is also used for hydrogen production in combination with CCS. These scenarios still have a share of natural gas on primary energy demand between 25 % to nearly 40 % in 2050. The only target scenario with a drastic reduction of gas consumption is UKERC Maintain (techfail) with gas consumption decreasing by 88 % between 2050 and 2010. Most of the reduction is happening after 2025.

In comparison to these scenarios the **scenario used for gas network planning** shows little differences in the development for the next 10 to 15 years. “Slow Progression” is even nearly in line with the CCC Central scenario (in orange) from the 5th carbon budget. Remarkably, National Grid´s target scenario, “Gone Green”, shows the lowest gas demand until 2030. But this scenario is not used for the network planning in the first place. For the near to midterm perspective the scenario used in UK´s Gas Ten Year Statement seems to be a **good estimate**. The important question about the role of gas will rise after 2025 or 2030 when gas demand for heating could be decreasing due to energy efficiency and alternative heating options (as it does in UKERC Maintain or UKERC Maintain (techfail)). If the climate targets are to be reached, emissions from gas have to be abated afterwards (CCS) or gas cannot be used further. But severe questions remain, whether CCS is economically feasible in large scale in the near future.

Figure 40: Development of gas demand in the analysed scenarios - United Kingdom



Source: Prognos based on [EC 2013], [CCC 2015], [DDPP UK 2015], [UKERC 2016]

Capacity

For the United Kingdom a development of the final peak gas demand was estimated from the development of the yearly final gas demand according to the method explained in 2.1.3.2.1.3. The development is shown in Table 88Table 88, again this is a rough estimation and the development of peak gas demand should be analysed more in detail. Especially in 2050, when final gas demand becomes very small in some scenarios, the applied formula would not work. Peak gas demand in the scenario used for network planning ("Slow Progression", GTYS) declined by 10 % between 2015 and 2030. This development seems to be in line with the development of capacity demand from the analysed alternative scenarios.[111]

[111] Estimated decrease in alternative scenarios is between 4 and 11 %, starting from 2010 (GTYS starting point is 2015)

Table 88: Estimated gas capacity demand for final energy sectors, index development – United Kingdom

Capacity demand for final gas demand [Index 2010 = 1,00]	2010	2020	2030	2050	Change 2010-2030	Change 2010-2050	Change 2030-2050
CCC Central 2015	1.00	0.98	0.92	0.50	-8%	-50%	-46%
DDPP D-EXP 2015	1.00	1.01	0.96	0.79	-4%	-21%	-18%
DDPP M-VEC 2015	1.00	1.01	0.96	0.67	-4%	-33%	-31%
DDPP R-DEM 2015	1.00	0.99	0.92	0.84	-8%	-16%	-9%
UKERC Maintain 2016	1.00		0.90	0.67	-10%	-33%	-26%
UKERC Maintain (techfail) 2016	1.00		0.89	0.56	-11%	-44%	-38%
EU Reference 2013	1.00	0.94	0.92	0.90	-8%	-10%	-2%

Source: Prognos based on [EC 2013], [CCC 2015], [DDPP UK 2015], [UKERC 2016]

There were not enough detailed data on installed capacity of gas power plants available. Probably in future gas power plants will mostly be used as back-ups with a very low load factor [UKERC 2016]. Nevertheless, peak gas capacity demand from gas power plants could remain high as back-up is mostly needed in cold winter situations.

3.3.6.4 Impacts on infrastructure and costs

The future gas demand varies broadly throughout the analysed alternative scenarios. Therefore, it is not easy to draw direct conclusions from the development of gas demand in the alternative scenarios to the development of gas infrastructure. If CCS is employed and gas demand stays on a similar level, the gas infrastructure needs to be maintained and probably new gas supply sources with the corresponding infrastructure need to be build. When CCS cannot be employed in large scale and climate targets shall be reached, gas consumption needs to decrease nearly completely. This is in line with the recent study on the future role of gas in in the United Kingdom: "*Unless CCS technologies are widely deployed, its future role will be more a diminishing one of filling an ever smaller gap between energy demand and other sources of low or zero carbon supply.*" (UKERC 2016, p.32). This will have impacts on the network system as well: DDPP 2015 state it is important to maintain the existing gas and distribution systems but "a *key question therefore remains on how the distribution system will be maintained during the transition to a low-carbon energy system, particularly since any new investments in maintaining the grid will likely be used for a maximum of around 20 years compared with the usual technical lifetime of such pipelines of around 80 years*." In general, in spite of target scenarios with a still increasing gas demand, the **uncertainties** on the future role of gas are discussed and have to be further examined. This is also important for future investments in gas network infrastructure and possible cost savings. In the Gas Ten Year Statement there is no list of planned investments, but the total amount National Grid is planning to spend is published. There is still a high amount of the yearly expenditure linked to asset replacement, which could not be needed, if gas demand was decreasing faster. On the other hand, the GTYS already deals with a changing gas use and most of the measures National Grid planned in the Gas Ten Year Statement concern compressor stations due to the fulfilment of the Industrial Emission Directive or the enhancement of system flexibility which is also needed for the transition to a low-carbon energy system. Nevertheless, there are a lot of questions concerning the future of the gas network system in the UK (e.g. demolition, modification for hydrogen transport…) that should be examined and included in future GTYSs.

3.3.6.5 Conclusion

- **Efficiency and RES potentials and relationship with gas**: The analysed scenarios use in the first place other low carbon options than renewables and energy efficiency. Still there is a strong relationship between a low carbon energy system and a strong decrease in gas demand, the only exemption is a high deployment of CCS.
- **Situation of NDP scenarios compared to other scenarios**: The scenario “Slow Progression” which is used for network planning is in line with most of the analysed scenarios in the next ten years. Only very ambitious target scenarios show a faster decrease of gas demand.
- **Assumptions about possible development of gas demand**: There are some greater uncertainties on the development of gas demand: One is the development of CCS which could result in a continuing high gas demand when deployed for power or hydrogen generation with natural gas or lead to a decreasing gas demand if not deployed. The other uncertainty refers to the development of heating systems which today rely predominantly on natural gas.
- **Consequences on infrastructures and costs**: The future of the gas network in UK is highly insecure and relies on the development of other technologies. UKs GTYS already deals with the changing requirements. Project decisions are taken on a site-by-site assessment. So, there are only few possibilities for cost savings. More attention needs to be given to the future of distribution systems as well as on alternative use of the gas network, especially if a hydrogen economy is build.

3.4 Conclusion on potentials of low carbon options on gas demand

This chapter analyses the potential of energy efficiency (EE) and renewable energy sources (RES) to reduce gas demand and infrastructural needs and thus avoid investment cost. To do this, we compared scenarios underlying existing Network Development Plans with reference and target scenarios as well as more ambitious scenarios regarding GHG abatement. These are our findings:

- **EE and RES potentials and gas demand**: Both at European level and in the focus countries there is clear evidence from the analysed scenarios that a high deployment of EE and RES would lead to a **shrinking gas** demand. In all analysed countries except Spain scenarios are available in which the use of natural gas would be reduced to a fraction of its current levels (approx. 10 %) or even phased out completely when energy and climate targets are reached or overachieved (e.g. Greenpeace Advanced energy [r]evolution) **until 2050**. In the medium term until 2030 gas demand stagnates in most reference and also in some of the target scenarios with high RES and efficiency gains. However, in scenarios with high efficiency gains (e.g. EE 40) gas demand could already decrease remarkably before 2030.
- **Comparison of NDP and other scenarios**: None of the scenarios underlying gas network plans in the focus countries and Europe as a whole assumes that GHG abatement targets are fully reached. In Europe as well as in most of the focus countries scenarios for gas network planning are the only scenarios that assume an increasing gas demand. Compared to these scenarios, policies already in use (reference scenarios) would lead to a stagnating or shrinking gas demand. Scenarios that reach energy and climate goals by deploying EE and RES have a great potential to further reduce gas demand. This is especially valid for the time after 2030. In very ambitious scenarios there is nearly no (fossil) gas consumption left in 2050 so wide parts of the infrastructure designed to transport conventional gas

would be superfluous in 2050. However, it has not been examined how much of the infrastructure might be needed to transport low-carbon gases like biogas or hydrogen.

- **Consequences on gas capacity demand**: A lower (yearly) gas demand leads to a reduced (hourly) gas capacity demand of customers, especially in the long run (after 2030). However, the decline rates of capacity demand are expected to be smaller than those of the (yearly) gas demand. The interrelationship between yearly and hourly demand needs to be examined further. Most of the analysed studies expect a reduction of gas demand in the heat markets. A much broader variety of results can be found, however, for gas used in power generation. There is a high diversity in the reference as well as the targets scenarios about the installed capacities of gas fired power plants – especially in 2050. This makes clear conclusions about the capacity demand more difficult.
- **Infrastructure demand**: A reduced gas capacity demand could make some gas infrastructure investments superfluous, especially projects with the purpose to cover market demand. Other projects might nonetheless be needed. This depends on the main driver of the projects (e.g. market demand, security of supply or others). But before investing in new infrastructure projects potential efficiency improvements and investments should be examined and applied ("Efficiency First"). An integrated view on security of supply and demand forecasts could furthermore reduce the demand for infrastructure and costs, according to a recent study. [Energy Union Choices 2016]
- Therefore, infrastructure measures should not only be assessed under high gas demand conditions but also from an "**on track" perspective.** Furthermore, more ambitious scenarios should be considered to reflect possible changes in line with the Paris agreement.

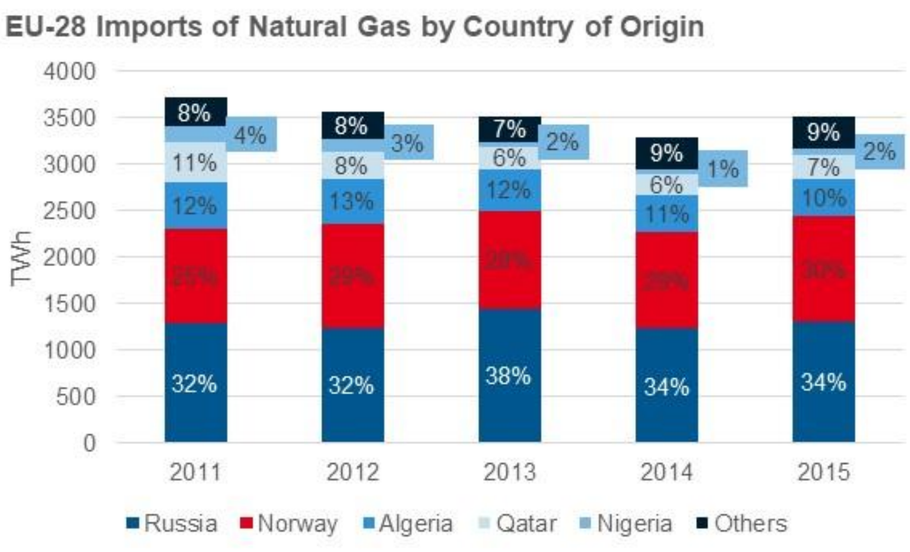
4. Impact of low carbon options on import dependency, infrastructure demand and costs

The objective of this chapter is to assess the possible impacts of low carbon measures on import dependency (chapter 4.1) and on gas import costs. Saving potentials related to gas trade are calculated in chapter 4.2, and saving potentials related to gas infrastructure are analysed in chapter 4.3.

4.1 Import dependency: origin of imported gas in reference and low carbon scenarios for Europe (and focus countries)

In 2015, the European Union imported about 3,500 TWh of natural gas. As shown in Figure 41, the main trading partners were Russia (34 %), Norway (30 %) and Algeria (10 %). Smaller trading partners were Qatar, Nigeria, Trinidad and Tobago and Egypt, among others. Out of total imports, 89 % were transported by pipeline, and 11 % were imported as LNG. The largest LNG trading partner is Qatar, with imports to the EU-28 in 2015 of about 270 TWh.

Figure 41: Imports of natural gas to the European Union by country of origin



Source: [Eurostat]

A measure to calculate the concentration of market power widely applied in economics is the Herfindahl Index (or Herfindahl-Hirschmann-Index; HHI). The HHI is the sum of all squared market shares[112], and measures the size of market players in relation to the considered market. It

[112] $HHI = \sum_{i=1}^{N} a_i^2$, where $a_i = \frac{x_i}{\sum_{j=1}^{N} x_j}$, N being the total number of stakeholders i in the market

is an indicator of the amount of competition between them. The HHI generally lies anywhere between $^{1}/_{N}$ and 1 (*N* being the total number of stakeholders *i* in the market). A HHI of 1 describes a completely monopolistic market situation. The concentration of market power is considered to be detrimental to economic welfare, as prices for consumers are higher in oligopolistic or monopolistic markets.

When applied to the gas market, the HHI can be calculated in terms of access concentration using transmission capacities or in terms of market share concentration using actual trade volumes. Both methods have advantages: access concentration is easier to calculate for the future as (technical) infrastructure capacities are well documented, whereas the actual utilization of transmission capacity depends on further factors such as prices, production levels available for export and others. An HHI based on actual flows takes all effects into account. For this forecast analysis, the transmission capacity method was chosen.

Within the European Union, the concentration of market power is diverse, depending on the country and region under focus. Countries such as Germany, France, the Netherlands and Italy exhibit a high import route diversification and the possibility to trade with several gas exporting countries. Countries in Eastern Europe mostly depend on a sole supplier and have no diversified import routes. The positive effect of competition and a lower concentration of market shares can be seen in Lithuania, where the construction of an LNG terminal has led to a considerable decrease in gas prices. Overall, the proposed projects lead to a greater diversification of import routes.

Looking at the individual countries that are the core focus of this study, the future concentration of market share is lowest for Italy/ Germany and highest for Spain. It should be noted that in our analysis LNG has been treated as a single source. However, LNG can be purchased from various supplier countries. The development of the Herfindahl Index for target countries for the next 20 years under consideration of the infrastructure investment level can be seen in the following table.

Table 89: Development of the Herfindahl Index by infrastructure investment level, 2016-2037

		All Projects		Only FID	
	2016	**2025**	**2037**	**2025**	**2037**
Germany	0,17	0,21	0,22	0,16	0,16
Spain	0,51	0,48	0,49	0,53	0,55
France	0,25	0,26	0,26	0,25	0,25
Italy	0,23	0,16	0,15	0,20	0,20
The Netherlands	0,29	0,29	0,29	0,29	0,29
United Kingdom	0,30	0,30	0,30	0,30	0,30

Source: Prognos

Despite the fact that import routes are diversified in terms of infrastructure, the HHI by actual flow is likely to increase in the future. European production of natural gas is on the decline and the European Union will be more and more dependent on imports. Most trading partners that have pipeline connections to the EU will see their export flows decline: Norway, as their stocks will slowly deplete, and Algeria, as the increasing domestic demand for natural gas could cause exports to the European Union to drop. Russia on the other hand still has vast reserves and is looking to increase its pipeline capacities. Other possible sources of import would be the world-wide LNG market, and the Caspian region. In 2017, LNG terminals in Europe were widely underused, as there are bottlenecks in the network connecting LNG-terminals and pipelines and as prices for LNG still exceed those of pipeline gas. Pipeline projects from the Caspian region are, apart from the TAP/ TANAP project, not yet very advanced in their planning process.

On the other hand, higher energy efficiency and more renewables could generally help to reduce the gas import dependency of the European Union. As shown in the previous sections, scenarios with higher renewables and energy efficiency reduce the overall dependency on gas in all scenarios in the long term, and mostly in the medium term. Whereas gas is used in the power sector in the short to medium term, these increases are offset by gas savings in final energy demand. Energy efficiency and renewables provide, next to a low carbon provision of energy, also a possibility to reduce the energy import dependency of European countries.

4.2 Savings of gas import costs in low carbon scenarios

In this chapter, we analysed possible savings between 2020 and 2030 on the basis of reduced gas import needs in different scenarios. Other economic aspects and effects were not taken into account. The following table summarises the above-mentioned potential gas savings in different scenarios compared to the scenario EU Reference 2016.

Table 90: EU 28 gas savings between 2020 and 2030 in different scenarios compared to EU Reference 2016[113]

	Unit	2020	2025	2030
EUCO30	TWh	-7	215	635
EUCO+40	TWh	30	241	1.620
IEA 450	TWh	231	353	259
TYNDP 2018 Sustainable Transition	TWh	73	-509	-653
TYNDP 2018 Distributed Generation	TWh	73	-509	35

Negative values indicate a higher gas demand compared to the EU Reference 2016 scenario

Source: Prognos

113 Note: Gas savings represented in this table are not comparable with gas savings given in Table 45, because the baseline scenarios used to calculate the savings are different (TYNDP scenarios in Table 45 and EU Reference 2016 in Table 90). Please note that the target scenarios are also different (EU EE30 and EU EE40 in Table 45 are different from EUCO30 and EUCO+40).

These gas savings potentials are multiplied with a gas import price (in real terms, 2016 Euro) based on the World Energy Outlook 2017 (scenario “Sustainable Development”). The gas price is about 16,4 Euro/MWh in 2020 and increases to 22,8 Euro/MWh in 2030. The following table shows possible annual and cumulated savings in the analysed scenarios compared to the scenario EU Reference 2016. Future cash flows have not been discounted.

In total, the annual savings potential reaches around € 37 billion in 2030 (scenario EUCO+40), and the cumulated amount reaches about € 133 billion between 2020 and 2030 (scenario EUCO+40).

Table 91: EU 28 yearly and cumulated savings potentials in different scenarios compared to TYNDP scenarios

Annual savings from less gas imports compared to the scenario EU Reference 2016	Unit	2020	2025	2030
EUCO30	billion € [2016]	-0,1	4,3	14,5
EUCO+40	billion € [2016]	0,5	4,9	36,9
IEA 450	billion € [2016]	3,8	7,1	5,9
TYNDP 2018 Sustainable Transition	billion € [2016]	1,2	-10,2	-14,9
TYNDP 2018 Distributed Generation	billion € [2016]	1,2	-10,2	0,8
Cumulated savings from less gas imports compared to the scenario EU Reference 2016	**Unit**	**2020**	**2020-2025**	**2020-2030**
EUCO30	billion € [2016]	-0,1	12,0	63,1
EUCO+40	billion € [2016]	0,5	15,4	132,9
IEA 450	billion € [2016]	3,8	32,3	64,5
TYNDP 2018 Sustainable Transition	billion € [2016]	1,2	-25,4	-90,2
TYNDP 2018 Distributed Generation	billion € [2016]	1,2	-25,4	-44,6

Source: Prognos

4.3 Infrastructure requirements and associated costs

The objective of this chapter is to categorize TYNDP infrastructure projects according to their purpose and assess the corresponding costs. At first, the main type and purpose of infrastructure projects from TYNDP 2015 and 2017 have been assessed in an overview. Projects of TYNDP 2017 have then been examined in detail and the costs of these projects have been estimated.

4.3.1 Comparison of infrastructure projects in TYNDP 2015 and 2017

From TYNDP 2015 to TYNDP 2017 the submitted infrastructure projects changed slightly.

Table 92 shows the evolution of submitted projects from TYNDP 2015. 20 projects were completed and are now part of the existing infrastructure. 80 were cancelled or not re-submitted[114]. So, it is likely that TYNDP 2017 also contains projects that will not be built in the end. The remaining projects, 175 in total, are again included in TYNDP 2017.

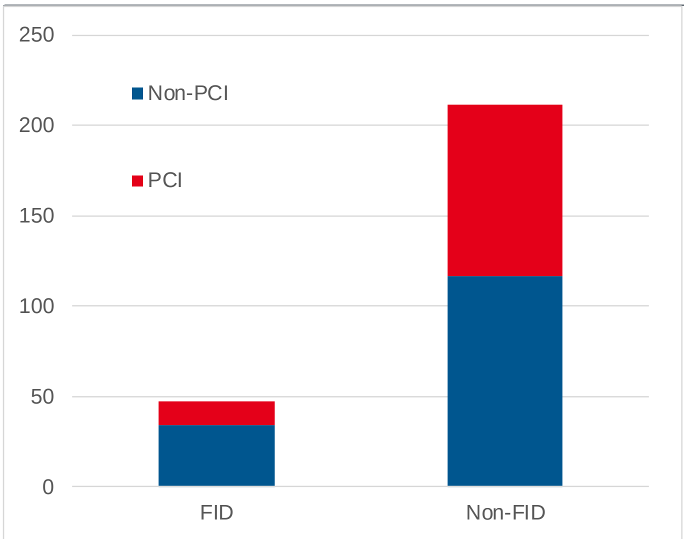
Table 92: Projects from TYNDP 2015 in TYNDP 2017[115]

	Pipeline	LNG	UGS	Total
Completed	15	3	2	20
Still planned	134	26	15	175
Not re-submitted	7	5	14	26
Cancelled	40	5	13	58
Total	**196**	**39**	**44**	**279**

Source: [ENTSOG 2017a]

Figure 42 shows the status of infrastructure projects from TYNDP 2015 for PCI and non-PCI projects. In Table 93 these projects are categorized by type. Most of the PCI projects have a non-FID status, only 13 PCI projects have a FID status. Most projects with PCI label are pipelines. Less than 20 % of the PCI projects are LNG terminals or underground storage projects (UGS).

Figure 42: Number of infrastructure projects TYNDP 2015 per status



Source: [ENTSOG 2015e]

114 Projects in TYNDP 2017 needed to be actively resubmitted, so inactive projects could be identified and left out.
115 Note: in TYNDP 2015 there are only 259 infrastructure projects. TYNDP 2017 lists however 279 projects from TYNDP 2015.

Table 93: Overview of projects by type and main driver (TYNDP 2015)

		PCI	Non-PCI	Total
Type	Pipeline	88	88	**176**
	LNG	13	26	**39**
	UGS	7	37	**44**
Main Drivers	Market Demand	61	75	**136**
	Regulation SoS	14	29	**43**
	Regulation-Interoperability	3	7	**10**
	Others	30	40	**70**
	Total	**108**	**151**	**259**

Source: [ENTSOG 2015e]

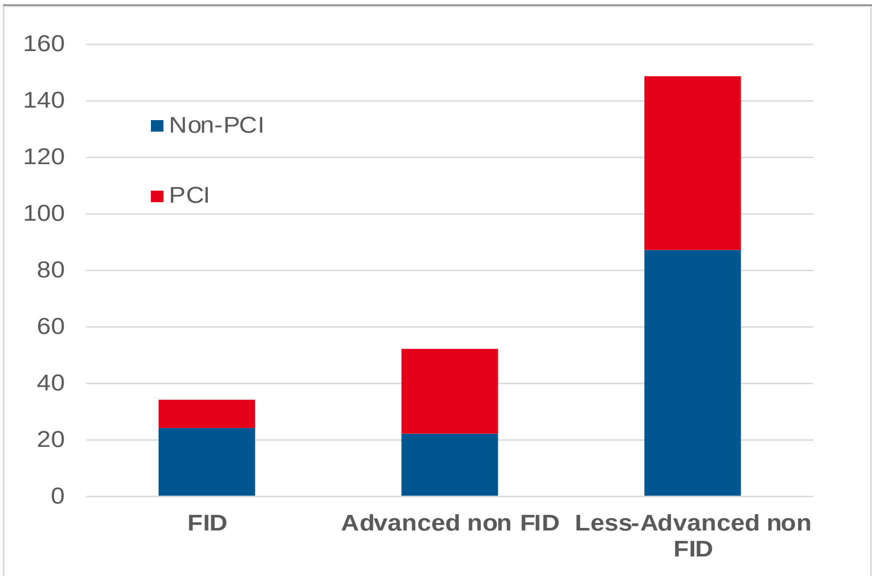
Table 93 lists the main drivers for PCI and non-PCI projects according to the project overview from the TYNDP (TYNDP 2015 Annex A). The main driver for over half of the projects, PCI as well as non-PCI projects, is "Market Demand". In further explanations and project details, "Market Demand" is partially defined as security of supply or diversification of sources, so it would be premature to assume that all projects with the main driver "Market demand" would not be needed in a strong climate scenario with a fast decreasing gas demand. Still, the main driver "Market Demand" could be an indication that a lot of projects were planned based on the expectation of a raising gas demand. Without modelling of the gas network, it is not possible to validate the need for a project. The projects from TYNDP 2015 will not be assessed here further.

TYNDP 2017

In the TYNDP 2017 there are three levels of projects status: FID, advanced non-FID and non-advanced non-FID. Figure 43 gives an overview of the PCI and non-PCI projects and their status. In total, 234 infrastructure projects were submitted.

Table 94 shows the type of projects for PCI and non-PCI projects. As in 2015, most of the projects (80 %) are pipeline projects. 13 % are LNG terminals and 8 % underground storage facilities. In comparison to 2015, there are even less PCI LNG terminals and underground storage projects. In the following, all PCI projects – as they may benefit from accelerated planning and permit granting, and have the right to apply for funding from the Connecting Europe Facility – and all FID projects – as they are very likely to be completed in the short- to medium term – will be examined in detail. These projects correspond to the "2nd PCI list" infrastructure level from the TYNDP 2017.

Figure 43: Number of infrastructure projects TYNDP 2017 per status



Source: [ENTSOG 2017a]

Table 94: Overview of projects by type (TYNDP 2017)

Type	PCI	Non-PCI	Total
Pipeline	87	99	**186**
LNG	8	22	**30**
UGS	6	12	**18**
Total PCI	**101**	**133**	**234**

LNG = LNG Terminal; UGS = Underground storage/ Storage Facility

Source: [ENTSOG 2017a]

4.3.2 Classification of infrastructure measures

Methodology

A precise segregation of TYNDP projects according to their necessity in a scenario with ambitious efficiency and renewable development measures would require a modelling of gas flows, which has not been undertaken in this study. Instead, gas infrastructure projects in the TYNDP have been classified according to their main benefits, purpose or aim. It will be the responsibility of the decision maker to decide which category fits with the political agenda and with corresponding (political, social, economic) requirements, and which infrastructure can be seen as “unnecessary”. The methodology used for this segregation is described below.

The TYNDP contains a vast number of infrastructure projects, some of them being highly uncertain or in early stages. Therefore, the analysis focused on projects which are in the advanced development stage of FID and on PCI projects. The vast majority of gas infrastructure projects could be seen as aiming to increase the security of gas supply in Europe. In fact, most of the projects aim to store or transport gas from a place to another, thus increasing the flexibility of the gas network. For the purpose of this study, a new categorisation of projects has been elaborated so as to better highlight their added-value and above all, enable a more detailed differentiation between them.

Overall, infrastructure projects could be grouped in the following categories: storage and reverse flow projects, gas import projects, domestic gas production projects, projects aiming to increase the interconnection between EU countries, rehabilitation/upgrading projects. Moreover, some projects have been identified as aiming specifically to increase gas consumption through improved penetration. Projects that are expected to go into operation in 2018[116] have been grouped, because they are likely to be already under construction. Some projects relate to other projects, so the probability of their commissioning depends highly on the commissioning of these other projects, and they have been grouped into one category. Finally, projects have been identified that are redundant with/ parallel to existing or planned infrastructure. They run parallel to other infrastructure or compete with it. Projects that could not be categorised in these groups form a category on their own.

Concerning import and interconnectivity projects, a further differentiation step has been undertaken. In fact, some countries are more vulnerable to gas supply shortages than others. This geographical factor has been taken into account. Member states have thus been classified according to their dependence on supply sources. Countries dependent on one supplier for more than 75 % of their energy supplies are Baltic States (Finland, Estonia, Latvia) and East European States (Poland, the Czech Republic, Slovakia, Austria, Slovenia, Romania, Bulgaria). Germany, Greece and Hungary are to a lesser extent partly dependent on Russian gas. This differentiation is also important because infrastructure projects that aim at increasing gas flows towards and between member states with a limited access to gas supplies or a dependence on one supplier are less dependent on gas demand growth. Their aim is to open up countries and improve their access to various gas suppliers.

Table 95: Classification of countries according to their dependence on Russian gas imports

% of Russian gas imports	List of countries
Over 75 %	Bulgaria, Czech Republic, Estonia, Latvia, Austria, Poland, Romania, Slovenia, Slovakia, Finland
Between 50 % and 75 %	Germany, Greece, Hungary
Less than 50 %	All the other countries

Source: [Eurostat]

116 The first full year of operation used in the assessment is the first full calendar year following the commissioning date. For each project, the commissioning year relates to when the first capacity increment of the project is commissioned in the case where there is more than one increment. It is not unusual for projects that the commissioning year indicated in the TYNDP does not correspond to the actual start-up of the infrastructure because of delays in the administrative process or in the construction.

This classification is essential to distinguish between on the one hand infrastructure that depends on the increase of gas demand, and on the other hand infrastructure that aims to balance gas flows between regions, improves the distribution of gas among EU member states and enables cross-border capacity development. The following table details the categories that have been used to classify the TYNDP 2017 selected projects.

Table 96: Categorisation of selected projects from TYNDP 2017

Category	Aim of projects
A.	Diversification of gas supply sources for supplier-dependent countries (LNG, pipelines)
B.	Increasing the degree of interconnectivity between the gas transmission systems of EU countries, especially for countries with limited gas infrastructure/ import sources
C.	Storage/ reverse flow (increase flexibility and resilience to demand increase or disruptions)
D.	Development of domestic gas production
E.	Upgrading due to new norms, to comply with environmental norms; rehabilitation
F.	Diversification of gas supply sources for non-supplier-dependent countries (LNG, pipelines)
G.	Flexibilisation of markets in non-supplier-dependent countries
H.	Big import infrastructure projects (> 5 bcm/a or 138 GWh/d)
I.	Increase gas consumption/ penetration
J.	Subsequent projects that are enabled by other projects
K.	FID projects shortly under construction or will be built before 2019 (commissioning year)
R.	Redundant/ parallel infrastructure
?	No categorisation is possible

Source: Prognos

The classification of infrastructure projects has been conducted according to the described methodology above, and required a detailed analysis of the characteristics of the projects. For some specific projects, further assumptions must have been made. The following paragraphs illustrate with a few examples the difficulties encountered and assumptions made.

Project Musel LNG (Spain): this project aims at increasing gas imports in a country that already has excess gas import capacities and low utilisation rates. It has been classified under category F. and could be seen as an unnecessary project. If not built, the costs of gas infrastructure could be reduced. However, the construction on the LNG terminal was completed in October 2012. The terminal was immediately mothballed and has not been placed in operation. It is highly uncertain if conditions will be in place in the future for the terminal to be operated economically.

Projects that relate to Balkan states (countries outside of the EU): some projects like ALKOGAP or the interconnector Bulgaria-Serbia aim to increase cross-border connexions in south-east Europe. These projects contribute to increased flexibility and opening-up of this region, thereby improving security of supply in East Europe. Therefore, those projects have been considered and analysed in this study.

Redundant/ parallel projects: they are projects that would be built along other existing or planned infrastructure, or that could fulfil the same function as other existing or planned infrastructure. Many EU countries in the East are among the most vulnerable to gas supply shortages because they depend on few suppliers or infrastructure or because they are isolated from neighbouring countries. Therefore, many of the planned projects are located in Eastern Europe. However, some of the projects are actually competing with others:

- Existing infrastructure: this group includes pipeline projects planned along existing pipelines that aim to increase gas flows. Various reasons explain such a move. For example, additional gas sources are hoped for, or the existence of multiple infrastructure is expected to trigger the creation of a gas hub. It includes also projects aiming to short-cut existing pipelines.
- Infrastructure connecting Cyprus to the rest of Europe: new gas reserves have been discovered in the Levantine Basin off the coast of East Mediterranean countries (including Israel, Lebanon and Turkey). These new gas supplies could be transported to mainland Europe through proposed infrastructure. At least two expensive competing projects exist: EastMed, an underwater pipeline which would bring gas to Greece, and CyprusGas2EU, an LNG terminal. Then, Poseidon and IGI pipelines projects are expected to transport the gas from EastMed towards Italy and Eastern Europe respectively. However, little is known about the overall reserves that could be sent to continental Europe and whether their amount would be sufficient to make any transport infrastructure profitable. Apart from this major uncertainty, it is considered in this study that at least one of these projects will not be realised because they compete with each other.
- LNG terminals and import pipelines in Eastern Europe: there are numerous projects aiming at opening up supplier-dependent countries in the East of Europe. Sometimes these projects compete with each other. In Estonia, three projects aim to import gas from suppliers other than Russia: Tallinn LNG, Paldiski LNG and the Baltic interconnector. Moreover, they are all situated within a 50 km range. At least one of them is therefore considered redundant. In Southern Europe, there are also numerous planned import projects which involve Greece. The projects TANAP/ TAP (Trans Anatolian Natural Gas Pipeline/Trans Adriatic Pipeline), approved by the EU, are under construction and will supply gas from the Caspian Sea to Greece via the two consecutive pipelines TANAP and TAP. Meanwhile, Poseidon will connect EastMed pipeline to Italy and IGI is supposed to connect EastMed to TAP pipeline. In addition, two projects plan the construction of LNG terminals in Greece, Revythoussa LNG (near Athens) and Alexandroupolis LNG (near the Turkish border). Here, it has also been considered that only part of those infrastructure projects would be built and profitable in the future.
- Interconnections in Eastern Europe: many infrastructure projects in eastern Europe aim to allow gas flows from one country to the other, mainly along the north-south axis. In that respect, one route involving many projects have been identified: the EastRing route, allowing gas flows from Bulgaria, to Romania, Slovakia, Poland, with the possibility to continue to the Baltic states with GIPL projects. Other projects seem to run parallel to EastRing or to reinforce existing infrastructure that already run parallel to EastRing. One of the projects called TESLA aims to transport natural gas from Greece to Central and Eastern Europe via Macedonia, Serbia, Hungary and Austria. However, a whole part of TESLA is not even in project, especially the part through Serbia, making it unlikely to be fully built in the medium term.
- Connection of Malta: today, there is no gas consumption in Malta. The main source is oil, including to produce electricity. Projects aiming to connect Malta to continental Europe in order to replace oil with gas in Malta have been proposed. One option is to connect Malta

with the European Gas Network through an underwater pipeline, the other is to build an LNG terminal. The two projects are competing with each other and one of them will probably not be built. Another option for Malta would be to use alternative energy sources. Renewables potential seems limited, but one possibility is to directly import electricity from other EU-areas via the interconnector. Anyway, there is much uncertainty over the most efficient way to develop low-carbon solutions in Malta.

No categorisation possible: Some projects could not be categorized. Some of them could not be visualised on a map and/ or there is no indication on their location (for example GCA Mosonmagyaróvár, Mirror Baltic Pipe). Sometimes, redundancy is difficult to identify with certainty, especially when two infrastructure projects seem to run parallel to each other but then diverge in the end to deliver gas in two different countries. In this case, projects have been classified in this group.

Naturally, some projects can be classified in more than one category. For example, big import infrastructure projects could also be categorised in projects aiming for the diversification of gas supply sources for supplier-dependent countries. In such cases, the category "big import infrastructure projects" takes precedence over the other categories.

4.3.3 Estimation of the costs of selected TYNDP projects

Main results

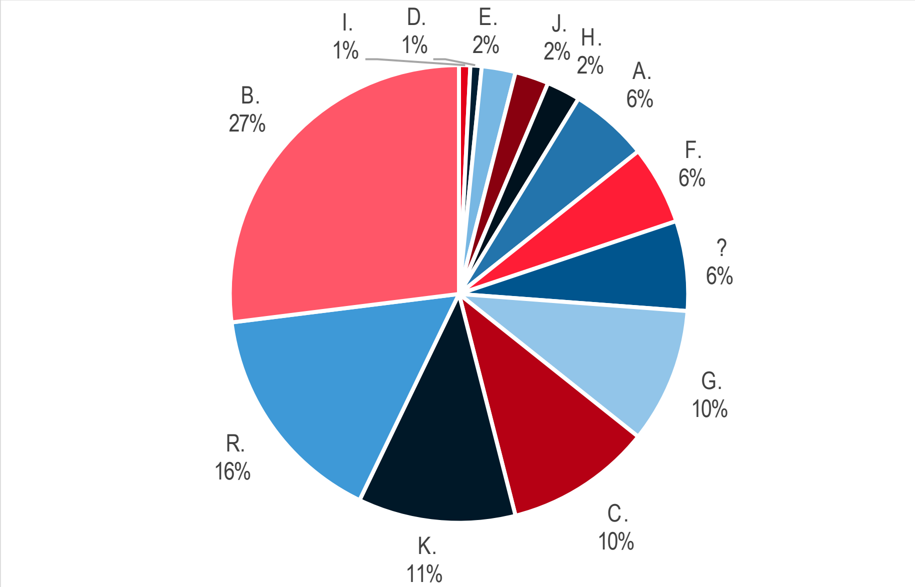
Infrastructure costs of selected TYNDP projects have been assessed and classified. The amount of needed investment for their construction has been estimated using various sources of information:

- project-specific information from news, articles, EU fact sheets for projects with an EU loan grant, or national development plans of involved countries;
- project specific technical information in TYNDP (length and diameter of pipeline, storage and send-out capacities). Financial data are available only in an aggregated form according to project status categories;
- ACER average infrastructure costs (e.g. average and median costs of pipeline construction in €/km according to the diameter of the pipeline). ACER data usually underestimate the costs for underwater pipeline projects, which are much more expensive than underground pipelines. In these cases, project-specific data from articles have been prioritised over the estimation with ACER data.

For some projects, it was not possible to assess investment needs, especially when technical data are missing or confidential. This was the case for a small number of projects, among them GCA Mosonmagyaróvár (category "?"), a project for the construction of a gas pipeline between Romania and Bulgaria and system enhancement measures. However, these missing estimations are not expected to distort the results significantly.

A total of 126 projects have been analysed. Most of the projects (27 %) belong to the category B and aim to connect gas transmission systems, especially in Eastern Europe. 11 % of the projects are supposed to be in an advanced state and commissioned shortly (in 2018). 10 % of the projects involve the construction of a storage installation or enable reverse flow of gas. 10 % of the projects relate to the flexibilization of gas markets in non-supplier-dependent countries (mainly Western Europe). 16 % of projects are estimated to be redundant with or run parallel to existing infrastructure or with other projects. 6 % of the projects could not be categorized (Figure 44).

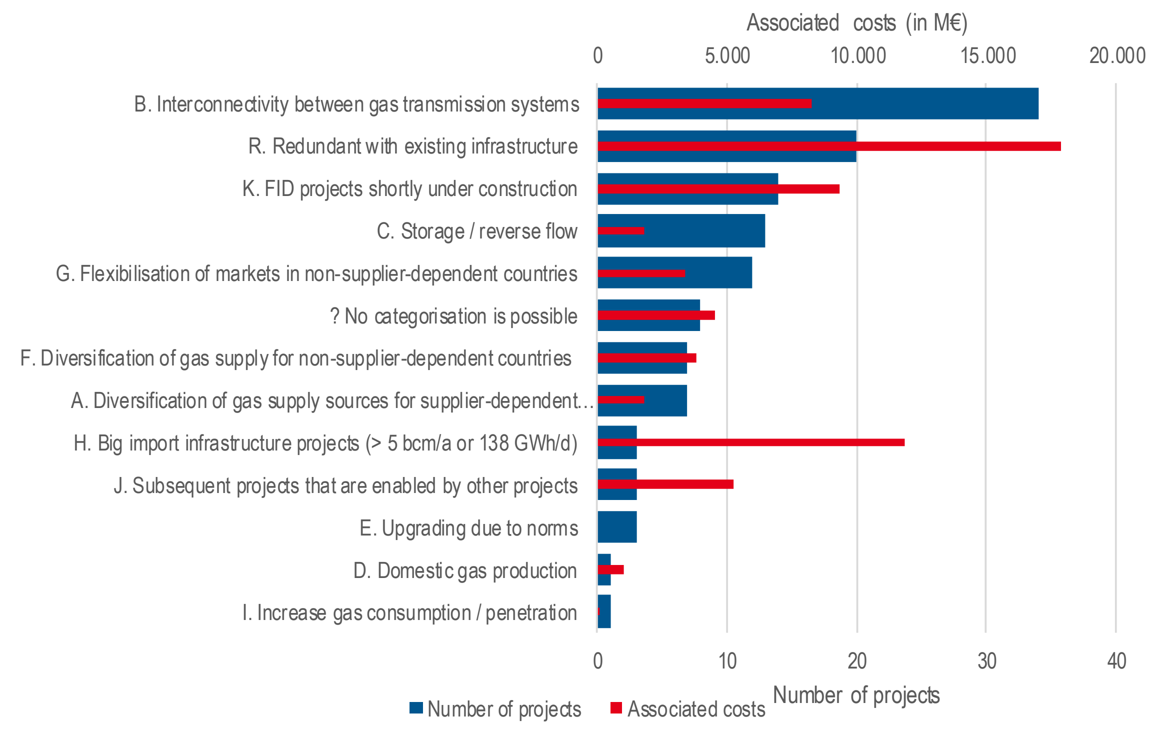
Figure 44: Distribution of the selected TYNDP projects according to the identified categories



Source: Prognos AG based on [ENTSOG 2017b]

Looking at the investments needed to build these projects, it has been estimated that redundant/ parallel infrastructure projects represent a major part of the costs (26 %). They are followed by big import infrastructure projects (17 % of the estimated costs), FID projects (shortly) under construction (14 %) and interconnectivity projects (12 %). Among FID projects under construction, the TANAP pipeline is by far the most expensive project (€ 6,95 billion or 74 % of total investment needs in this category). The category E. ("Upgrading due to norms") contains three projects. Their investment costs could not have been estimated because of unavailable data. However, they are expected to be relatively low.

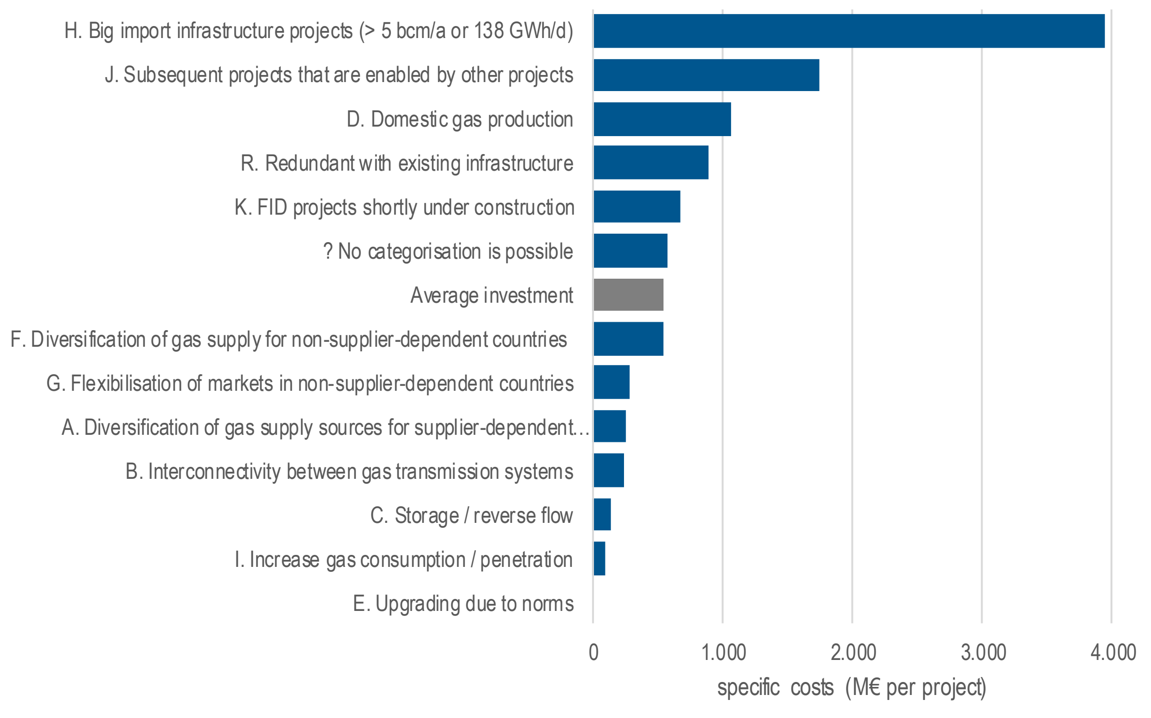
Figure 45: Number and investment costs associated to the project categories



Source: Prognos AG based on [ENTSOG 2017b]

The specific investment needs of projects have been calculated for each category. On average, the investment needed for a TYNDP project is € 0.55 billion. Big infrastructure projects are by far the most expensive category, requiring on average € 4 billion investment. They are followed by projects that are proposed because of other infrastructure projects. One project in this category requires on average € 1.75 billion. However, TAP project stands out from the others because of its high costs (around € 4.5 billion), which distorts the average costs per project in this category. Projects aiming at developing domestic gas production, redundant/ parallel infrastructure projects as well as advanced FID projects have also an above average cost. The cheapest categories comprise upgrading projects, projects aiming at increasing gas consumption, storage / reverse flow projects, projects aiming to connect gas transmission grids and diversify gas supply.

Figure 46: Specific costs of projects according to their category



Note: No investment costs for the category E. ("Upgrading due to norms") could have been estimated because of unavailable data.

Source: Prognos AG based on [ENTSOG 2017b]

Contextualisation and discussion of results

The estimated costs are consistent with the aggregated data given in the TYNDP 2017. Especially, the estimations for the category "FID projects" are close to the data given in the TYNDP report. The differences are bigger for the categories "Advanced Non-FID" and "Less-Advanced Non-FID" because non-PCI projects at early stage of development have been excluded from this study. Therefore, the estimations of these two categories should not be compared with TYNDP costs data.

Table 97: Comparison with TYNDP expected costs (in € billion)

	FID Projects	Advanced Non-FID	Less-Advanced Non-FID	Total
TYNDP (190 projects)	27,5	16,0	42,5	86,0
Estimated costs for the 126 selected projects	26,9	9,1	33,2	69,2

Source: Prognos AG, [ENTSOG 2017a]

The costs for the analysed projects sum up to € 69 billion. These estimated costs are much higher than estimations in other studies. [Energy Union Choices 2016] analysed the need for gas infrastructure investments for different scenarios and identifies investment needs between € 2.8 billion (scenario that reaches climate goals with integrated approach) and € 14.1 billion (scenario with high demand and no integrated approach). According to this study, it should be possible to secure the European security of gas supply without investing a high amount of money in new infrastructure.

The investments needed in the gas infrastructure are likely to be much lower than € 69 billion because of several restrictions. First, some projects are still being regularly delayed and facing barriers (lack of market support, lack of political support); so, it is likely that some of these infrastructures will not be built. Second, it is essential to consider infrastructure projects in the case of a "climate change" or “target” scenario. In such a scenario, efficiency measures will be implemented, and renewable energy sources will be developed, so that gas demand is likely to decrease (see chapter 3). In the case of ambitious target scenarios, peak gas demand is also expected to decline substantially. In less ambitious target scenarios, short-term gas demand might increase occasionally before 2030. In this case, the additional (peak) demand could be covered for example by the use of underground storage facilities or through solidarity between member states. Additional infrastructure projects that aim to substantially increase extra-EU gas imports (including cross-border pipelines and LNG import terminals) could be unprofitable in this context and become stranded assets. In fact, these infrastructures are directly linked to gas demand. If efficiency measures are implemented, gas demand could be too weak to ensure an economic utilisation of import capacities, as is currently the case for some Spanish LNG import terminals. In addition, in a “target” scenario, investments will in priority be directed towards the switch to renewables and energy efficiency to achieve environmental and climate targets. Measures for finalisation of internal market would be comparatively of minor importance. Some categories of infrastructure projects should therefore be examined very cautiously, and their profitability calculated considering less economically advantageous hypothesis like weaker gas demand.

Investment opportunities in gas infrastructure could be even more restricted if the Paris targets of “holding the increase in the global average temperature to well below 2°C above pre-industrial levels” (UNFCCC, 2015), no fossil fuel must be consumed around the second half of the 21st century worldwide. In Europe, fossil fuel consumption needs to be marginal probably around 2040 (see also chapter on scenario analysis) to reach these goals. In this case, not only coal and oil but also fossil gas consumption needs to be drastically reduced. With reducing gas consumption, even present gas infrastructure will be used less and less, except if a green gas infrastructure is established. Considering the relatively long lifetime of 40-50 years or even longer of gas pipelines that are supposed to be commissioned in the next five years, today’s investments are likely to become stranded assets. Furthermore, there could be additional costs to remove the gas infrastructure. Costs for decommissioning e.g. pipelines reach around 1 million €/km [FNB Gas 2017].

Overall, there will probably be a trade-off between a totally flexible European gas network guaranteeing a zero loss of load in any situation, and the need to rationalize and diversify investments into other energy carriers (electricity, renewables) and energy efficiency. Therefore, some of the projects categories are likely to be preferred over others, according to their added value and relative costs. Also, to the extend projects receive public funding (e.g. PCI), public money will probably be spent in a way that is consistent with political targets, especially in infrastructure projects with a long lifetime. Some projects that seem adequate for today’s situation might actually undermine targets in the long term, financial means invested in it could be wasted or diverted from alternatives projects that would be more in line with European interests. In early 2018 the European Investment Bank approved a € 1.5 billion loan for the TAP pipeline, which interconnects with TANAP and is a part of the Southern Gas Corridor. TAP would transport gas from Greece (at the Turkish border) to Italy. Together with TANAP, the total investments needed to transport gas from Azerbaijan to Italy would amount to € 11.45 billion (including an EU public backing of € 3.5 billion). It remains to be seen in which way this infrastructure would fit into the long-term EU climate strategy and whether it will be profitable.

4.4 Conclusions: Import dependency, diversity and costs

Gas infrastructure plays a key role for the European energy system. The development of the energy infrastructure is a much-debated issue regarding the future transformation of the energy system. There are a lot of different aspects to take into consideration concerning future requirements of gas infrastructure, such as the development of capacity demand, flexibility or diversification of import sources. These aspects have been analyzed in this chapter.

The evolution of market power concentration has been assessed in chapter 4.1, using access to transmission capacities and actual trade volumes, and taking planned infrastructure into account. Planned infrastructure projects lead to a greater diversification of import routes but changing gas production trends might increase market concentration and hence lead to respective (possibly more concentrated) gas flows over time. The picture for Europe in terms of import dependence and market concentration is diverse, with the case study countries for this report (Germany, France, the Netherlands, Italy, Spain, the United Kingdom) largely exhibiting high import route diversification, while several, largely Central and Eastern European Member States have a high level of concentration due to being reliant on a sole supplier.

As shown in chapter 4.1, a significant increase in domestic renewable energy production and the adoption of ambitious energy efficiency measures could help to the reduce import dependency of the European Union by delivering significantly reduced gas consumption and lowering the demand for gas imports. These gas savings are particularly high under scenarios with ambitious energy efficiency measures (e.g. the Commission's EUCO+40 achieving a -40 % energy efficiency target for the EU28).

Gas demand is not the only aspect determining the construction of infrastructure projects. Other requirements like flexibilization or diversification of import routes have to be considered. In chapter 4.3, a new categorization of projects in the EU TYNDP has been used to assess their added-value and achieve a greater differentiation between the types of projects being developed. Infrastructure costs of selected TYNDP projects have also been assessed, classified and estimated using various sources of information. This assessment shows that a large share of projects is aimed at connecting gas transmission systems (especially in Eastern Europe) (27 %), installing storage or enabling reverse flow of gas (10 %), or induce market flexibility in non-supplier dominated markets (mainly in Western Europe) (10 %). These projects generally have moderate to low specific costs and are therefore estimated to make up a moderate share of the overall estimate investment costs but must also be carefully assessed on a case-by-case basis in terms of their medium- to long-term business case. At the same time, a significant number of projects are estimated to be redundant with or run parallel to existing infrastructure (16 %), while making up the largest individual category of overall investment costs. Furthermore, the category 'big infrastructure projects' consists of only a handful of large import pipeline projects that risk becoming stranded assets under ambitious climate scenarios compatible with the Paris Agreement, but make up the second highest share of overall investment costs due to particularly high specific project costs. This categorization must be interpreted carefully: without a detailed modelling of the gas network, it is not possible to validate the need for a given project.

These results underline the need to carefully assess the economic viability of investment projects, in particular where scarce public resources are being invested. The assessment also shows that the investment needed in the gas infrastructure is likely to be much lower than the estimated cumulative cost of the proposed projects. Besides technical requirements, political priorities and economic support/market interests play an important role for the realization of gas infrastructure projects. Overall, there will probably be a frequent trade-off between the goal of achieving a totally flexible European gas network guaranteeing a zero loss of load in any situation, and the need to more efficiently rationalize and diversify investments into other energy carriers (electricity, renewables) and energy efficiency to ensure an appropriate return of value for money invested.

Table 98: Overview of the main quantitative results from chapter 4 gives an overview of the main quantitative results obtained in this chapter. The estimated investments that would be needed to reach 2030 EU climate targets have been added for comparison purposes. The total investment needed to build all the infrastructure projects selected in this study amounts to € 69 billion. 43 % of investments relate to projects belonging to the categories "Big import infrastructure projects" and "Redundant with / parallel to existing infrastructure". Potential savings from reduced gas import needs vary according to the level of ambition set in target scenarios, as well as to the scenario used as baseline/reference. Taking the scenario EU Reference 2016 as reference and comparing it to EUCO30 scenario, cumulated savings over the period 2020-2030 amount to € 63 billion Taking the scenario TYNDP 2018 Sustainable Transition as reference and comparing it to EUCO+40 scenario, cumulated savings over the period 2020-2030 reach to € 223 billion This represents 31 % of the total estimated cumulated investments that would be needed to reach 2030 EU climate targets.

Forward looking gas demand scenarios build the basis for network development plans, which in turn are a prerequisite for infrastructure investment. Consequently, it is essential that gas demand scenarios depict the correct gas demand to induce adequate investment and prevent overspending, especially when projects receive public financing. Furthermore, the different network development plans to should show the effects of different scenarios on gas infrastructure needs and take uncertainties into account. The possibility of a long-term decreasing gas demand (e.g. target scenarios) should be considered, to be prepared for different possible developments.

Table 98: Overview of the main quantitative results from chapter 4

	billion EUR	Share of cumulated investments needed to reach EU 2030 climate goals
Costs of infrastructure projects selected in this study	69	
H. Big import infrastructure projects (> 5 bcm/a or 138 GWh/d)	12	2%
R. Redundant with / parallel to existing infrastructure	18	2%
Other infrastructure projects	39	5%
Savings from reduced gas imports compared to the scenario EU Reference 2016 (2020-2030)		
EUCO30	63	9%
EUCO+40	133	19%
Savings from reduced gas imports compared to the scenario TYNDP 2018 Sustainable Transition (2020-2030)		
EUCO30	153	21%
EUCO+40	223	31%
Investments needed to reach EU 2030 climate goals over the period 2011-30		
Annual	38	
Cumulated (2011 - 30)	722	

Please note that the comparison with the 2030 EU climate goals just aims to give an order of magnitude. Investments to reach the EU climate goals cover all the energy carriers (not only gas) as well as efficiency measures.

Source: Prognos AG, 2030 climate & energy framework (https://ec.europa.eu/clima/policies/strategies/2030_en)

5. Comparing risks for EE, RES and natural gas

This section compares key risks associated with scenarios that foresee stable or rising natural gas consumption with those in scenarios that foresee an ambitious deployment of energy efficiency and renewable energy. This assessment provides insights for anticipatory risk management in regard to strategies that promote gas security and decarbonisation through high-RES and EE pathways. While a comprehensive review of all risks related to EE, RES and natural gas is beyond the scope of this report, the assessment provides a broad overview of the most critical risk factors in order to identify key issues that should be further explored and frame a broader discussion about the comparative risks of EE, RES, natural gas. After identifying key risks for EE, RES and natural gas, a qualitative assessment is made of their potential impact in the short- (2015-2025), medium- (2025-2035) and long-term (2035-2050), including risk level and potential risk mitigation options[117].

For the risk assessment, we look at the following five risk categories[118]:

Policy and regulatory risks: Inadequate political ambition or regulatory barriers preventing the achievement of the EU's climate and energy goals

Technological risks: "Disruption" that can occur when an energy source or related infrastructure is exhausted or production is stopped, especially factors linked to the physical characteristics of the technology itself.

Geopolitical risks: "Disruption" arising from the competition around scarce and valuable resources, and the risk of the owner of a strategic resource using it as a tool for achieving political and economic advantage.

Economic and social risks: Economic and social "disruptions" caused by the overall cost of the energy system, erratic fluctuations in the price of energy products or distributional effects linked to the energy system.

Environmental and health risks: Damage to the environment & health caused by energy production, whether accidentally, during operations or as a result of polluting emissions.

5.1 Policy and regulatory risks

Energy efficiency

Upscaling energy efficiency to meet the EU's long-term decarbonisation goals poses a great investment challenge. It is estimated that EUR60-100 billion will be needed to be invested annually in the buildings sector alone to meet cost-effective potentials [EC 2012]. Furthermore, the

[117] The temporal dimension is key to the analysis of energy security, as it can lead to considerably different areas of emphasis and outcomes. Short-term energy security "focuses on the ability of the energy system to react promptly to sudden changes within the supply-demand balance," such as in the case of supply disruption due to weather, accidents or political events (IEA Online). Long-term energy security, on the other hand, "deals with timely investments to supply energy in line with economic developments and sustainable environmental needs" [IEA Online].

[118] Based on [EC 2010, DOE 2015 and Johansson 2013]

IEA estimates that energy efficiency investments will need to be increased eightfold from current levels to keep the EU on track to staying well below 2 degrees celsius [IEA 2014b]. However, while many energy efficiency investments can be made with proven, cost-effective technologies, high up-front costs and long pay-back periods are frequently barriers to investment. In the buildings sector, the sector with the highest potential for reducing gas consumption, additional market failures such as split incentives, lack of financing, and imperfect knowledge have been a significant impediment to growth. Due to these and other barriers, energy efficiency investments have repeatedly underperformed the expectations of models assuming the deployment of all cost-effective investments. Meeting ambitious energy efficiency goals is, therefore, likely to require targeted policies to improve the business case for energy efficiency investments that go beyond the largely voluntary approaches that exist at EU level today. This need for further efforts on energy efficiency is highlighted by the 2016 European Commission Reference Scenario (BAU), which expects a decrease in primary energy consumption by 18.4 % by 2020, and 23.9 % by 2030, falling short of both the 2020 and 2030 indicative EE target of 20 % of 27 % (relative to 2007 baseline projections). As the reference scenario does not include the politically agreed, but not yet legally adopted 2030 climate and energy targets, further efforts to increase ambition in the medium-term are to be expected, but not yet adopted.

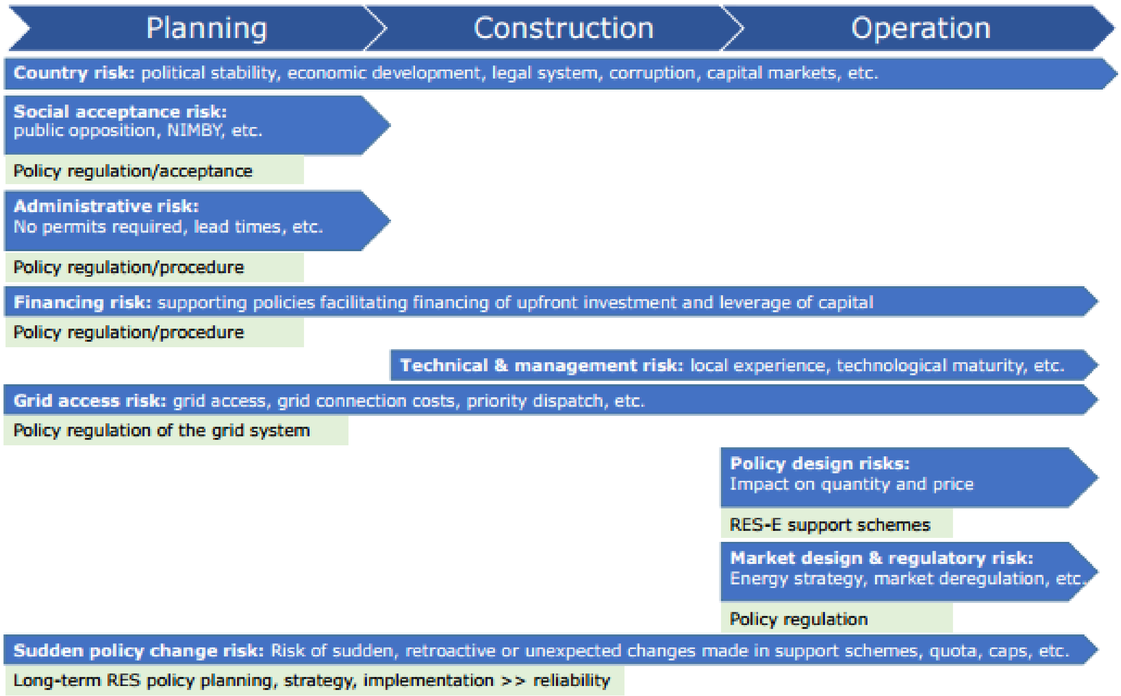
Renewable energy

Progressive technology cost reduction, relatively stable investment conditions, favourable financing conditions and increasing RES sector maturity have dramatically decreased RES costs over the last decades, in particular for wind onshore and solar PV. Furthermore, technology costs for several renewable energy technologies are set to continue to decline, steadily improving the competitiveness of renewable energy sources [Fraunhofer et al. 2014; IRENA 2016]. Nonetheless, technology specific and structural market design challenges often continue to present a barrier to renewable energy technologies competing with conventional ones under current political and regulatory conditions. These challenges pose a risk to the successful deployment of renewable energy technologies required for medium- to long-term decarbonisation of the energy sector and a significant displacement of gas imports.

While renewable energy technologies generally have low operating costs, much of the investment has to be made upfront by the investor. Furthermore, a number of policy relevant factors can influence the risks associated with a renewable energy project. As Figure 47 shows, this array of risks covers the full project development process and can impact renewable energy projects at various points in a project cycle, from planning to operation. When left unmitigated by renewable energy support policies these high upfront-costs and project risks can lead to both difficulties in attracting investors, as well as higher financing costs due to the necessary risk premium required to incentivize investment. For example, a recent study looking at the impact of risks in renewable energy investments finds that the cost of capital can vary considerably between EU Member States based on varying risk factors[119]. Among stakeholders interviewed for the study, policy design risks were on average perceived as the most pressing risk, followed by administrative issues, market design and grid access.

[119] Assessing the weighted average cost of capital (WACC) for onshore wind the study found financing costs varying from 3.5 % for Germany to 12 % for Greece in 2014, providing an indication of varying levels of project risk. Among stakeholders, policy design risks were on average perceived as the most pressing risk, followed by administrative issues, market design and grid access [*Noothout et. al. 2016].*

Figure 47: Risks related to RES projects



Source: [Noothout et. al. 2016]

In order to address the investment risks faced by renewables, RES policies have often been used to provide more investor certainty, including in the form of fixed remuneration that largely shields the investor from competitive forces (ex. Feed-in-Tariffs). However, increased market penetration for certain RES technologies (ex. wind and solar pv) has put pressure on policy-makers and regulators to reduce support schemes and increasingly expose these technologies to further competition on electricity markets. At the same time, the current electricity market design poses a number of challenges for renewable energy projects to recoup their investments without these support schemes. These challenges include the decreasing market value of wind and solar electricity at high levels of penetration, limited flexibility of power systems and subsidies for conventional technologies. While a reduction of RES support may be necessary to avoid higher system costs in the medium- to long-term, reducing RES support schemes too quickly without an appropriate market design may also significantly slow-down investment in renewable energy sources due to higher revenue risks for investors [Janeiro 2016].

The 2016 European Commission Reference Scenario (BAU) projects that the EU will reach its 2020 RES target of 20 % of final energy consumption, but will only achieve a 24 % share by 2030 without further measures. As such, additional efforts, including strong implementing measures to achieve the EU-binding target of 27 % renewables by 2030 will be required to keep the EU on a track to meet its ambitious long-term climate and energy goals.

Natural gas

Due to its lower CO_2 emissions factor than coal and oil, and flexible ramping capability, natural gas is frequently hailed as a potential “bridge fuel” to be used to replace coal fired generation and complement variable renewable energy sources by providing back-up power generation. This potential role in support of climate policy has been given further credence by the considerable expansion of unconventional gas production, most notably exemplified by the US "shale gas revolution"[120]. However, use of natural gas as a bridge fuel entails a number of significant climate policy risks.

Most critically, natural gas remains a fossil fuel whose impact must be severely limited in the long-term for the most ambitious global long-term climate policy goals to be reached. Compared to the 2 degree Celsius target, the remaining carbon budget in the 1.5 Celsius degree target is significantly reduced, requiring stringent early emissions reductions and potentially significant negative emissions reductions by mid-century for this target to be technically feasible. Continued expansion or stable use of natural gas in large volumes in the medium term is, therefore, incompatible with global efforts to restrict a global temperature rise to within 1.5 degrees by the end of the century. Furthermore, target scenarios assuming a larger role for natural gas in the medium- to long-term (ex. IEA 450 scenario[121]) frequently assume a significant carbon price, as well as a considerable build out of both CCS and/or nuclear power in the medium- to long-term. These abatement strategies defer much of the heavy lifting of GHG mitigation to the medium- to long-term and bet on costly, risky technologies with uncertain growth potential.

Scenarios with significant natural gas consumption in the medium- to long-term also pose more general risks to the decarbonisation of the energy system. In particular significant investment in gas in the form of long-term contracts or built-infrastructure with long periods of cost recovery risk *'locking-in'* the use of gas. These economic incentives or legal requirements for the continued use of natural gas threaten to decrease the flexibility of policy-makers or substantially raise the cost of decarbonisation in the medium- to long-term due to path-dependency. Investments in gas also risk *'locking-out'* energy efficiency and renewable energy investments and yielding a net-negative climate policy balance if they compete for financing or policy support, or are substituted instead of coal.

Conclusion:

- Energy efficiency investments will need to be substantially increased in the coming decades to meet the EU's long-term decarbonisation goals, especially in the building sector. However, a number of barriers are impeding efforts to scale up these investments. Meeting the EU's energy efficiency goals will require targeted policies to improve the business case for energy efficiency investments that go beyond the largely voluntary approaches that exist at EU level today, especially in case the political ambition is increased for the medium- to long-term. The expected strengthening of EE policies will be critical in shaping the future deployment of these investments. An insufficiently strong outcome in the upcoming revision of the EED poses a political and regulatory risk in the short- to medium-term.
- Increasing the deployment of RES in line with EU's ambitious 2050 targets will require a strong policy investment framework that will likely need to include continued technological support in the short run at least until new business models and improved market rules

[120] The discovery and exploitation of previously unreachable gas reserves combined with the prospect of a favourable climate policy framework famously led the IEA to herald (or at least suggest) the beginning of a 'golden age of gas' in 2011 [IEA 2011]

[121] The IEA 450 target scenario reviewed in the previous chapter sees a significant long-term rise in gas consumption (globally), while remaining in line with a 50 % chance of meeting the global 2 degrees target. It is important to note, however, that the IEA 450 target scenario assumes a decrease in gas consumption in the long-term similar to the European Commission's High RES Scenario from the 2011 Energy Roadmap.

can improve the bankability of these investments without policy intervention. As such, pressures to weaken existing support measures and insufficiently strong implementing measures for reaching the EU's binding 27 % target pose a policy & regulatory risk towards renewable deployment in the medium- to long-term.

- Natural gas can help supporting the transition to a low-carbon energy system in the short- to medium-term, in particular by displacing coal and providing back-up power generation to support a significant ramp-up of variable renewable energy sources. However, it remains a fossil fuel that must be limited to achieve the EU's goal of reducing greenhouse gas emissions by 80-95 % by 2050, as well as the goal to limit global warming well below 2 °C, if possible to 1.5 °C, in line with the Paris Agreement. As such, it can only be a limited tool for achieving decarbonisation. Policy-makers should take measures to avoid locking-in the use of gas through an expensive overbuilding of capacity, as well as a locking-out of renewable energy sources.

5.2 Technical risks

Energy efficiency

No significant technical risks for energy efficiency could be identified[122]. On the contrary, by reducing gas and electricity demand energy efficiency can help to create an additional margin of security by increasing the flexibility of the whole energy chain, in particular through demand response. Extreme cold spells in the winter or heat waves in the summer can result in higher demand for gas and electricity that puts severe stress on electricity and natural gas systems, threatening outages. Reducing demand at peak hours can help to reduce electricity and gas system stresses by freeing up capacity, thereby lowering the risks of power and gas interruptions. Other energy efficiency benefits linked to reducing technical risk include [COMBI 2015a, RAP 2015]:

- Deferral or avoidance of unnecessary investments in generation, transmission and distribution systems,
- Avoidance of the need to expand natural gas supply, including investments in gas import infrastructure,
- Increased reliability through reduced congestion in transmission and distribution systems,
- Reduction of technical risks linked to ambitious deployment of renewable energy sources.

Renewable energy

Intermittency is a key feature of the energy production profiles of a number of renewable energy sources, including wind, solar PV, wave and tidal power that require them to be complemented by additional measures for generation adequacy to be guaranteed. As a result, increased penetration of these technologies in the electricity sector has required grid operators to learn to become more flexible and adapt their operations to variable generation in order to

[122] While not constituting a significant energy security risk, one technical challenge with energy efficiency measures that should be noted in this context is the phenomenon known as the "rebound effect" in which the expected energy efficiency gains of a technology are partly negated by a behavioural or systemic response (ex. price reduction) [Maxwell et. al. 2011]. While there is little agreement on the magnitude of the rebound effect, studies find that the direct rebound effects can range from 0%-65 % and most estimates tend to converge between 10 % and 30 % [IEA 2014a]. However, these rebound effects can be taken into account when designing policy interventions in order to leave room to adjust for ambition and hedge against potential failures to deliver on promised demand reduction [Maxwell et. al. 2011].

better balance supply and demand. Existing flexibility measures include grid expansion, the geographic and technological spreading of renewable energy technologies, the flexibilisation of thermal power plants, curtailment of renewables at times of surplus, expansion of demand response measures, as well as the use of pumped storage power plants. While providing a steep learning curve, advances in grid operation and new investments have allowed grid operators to become increasingly adept at handling high shares of variable renewable generations, demonstrating that it will be technically feasible to integrate high shares of RES in the short- to medium term with existing, proven technology.

On the other hand, research indicates that in the long run higher levels of integration (80+%) can pose technical challenges for the integration of renewables and may require significant infrastructure investments in unproven or costly technologies. Moreover, considerable uncertainties remain as to which technologies or approaches will be most cost-effective. For example, while an energy system with very high shares of wind and solar electricity will be difficult to operate without significant investments in energy storage, the potential for new pumped storage is limited and future costs of next-generation energy storage such as battery storage and power-to-liquids are still uncertain. Furthermore, the value that storage provides depends strongly on a variety of other factors, including the ambition level regarding greenhouse gas reductions, as well as the availability of other low-carbon technologies and flexibility measures [Agora Energiewende 2014; de Sisternes et. al. 2016].

These concerns and uncertainties also apply to the future potential and cost-effectiveness of using bioenergy and hydrogen to replace fossil fuels in the energy system. Bioenergy in the form of woody biomass, biogas or biofuels and hydrogen generated through electrolysis from renewable electricity represent a controllable and storable form of renewable energy that can help to integrate large shares of wind and solar pv, or replace natural gas in heating and oil in transport. However, there are limits to the sustainable supply of biomass that set clear boundaries to their potential application in the energy system (see environmental risks). Moreover, the wide-spread transition to hydrogen faces both technical and economic hurdles, including the explosive nature of hydrogen, technical limits to the share of hydrogen that can be injected into the gas grid, potential costs of adapting grid infrastructure and appliances to hydrogen, the general inefficiency of electrolysis (especially when combined with methanation) and competition from CCS and other grid integration technologies[123]. Therefore, while the existing gas grid can play a role in integrating these “renewable gases” the costs and limits of large scale conversion of the infrastructure and devices must be further explored.

Natural gas

The key technical risks linked to the use of natural gas are technical failure or disruption of critical infrastructure impacting gas flows in the short-term, and under-investment in infrastructure in the medium- to long-term. These technical risks can occur across the entire natural gas supply chain and, therefore, originate both from the gas exporting or transit country (external risk), as well as the gas importing country (internal risk). Technical risks are mitigated in the short-term by appropriate risk contingency and network development planning, as well as appropriate infrastructure investments in the short- to medium-term that help to ensure the continued operation and maintenance of the grid.

Concerning external technical risks, significant technical security margins have developed in the EU over time due to past expectations of strongly growing gas demand. Existing pipeline

[123] See [Dodds et al. 2013; Götz et al 2016; and Ueckerdt et al 2013].

capacity (422 bcm) alone would be sufficient to satisfy 2015 import requirements (255bcm), and LNG (183 bcm) and storage (92bcm) provide additional flexibility[124] [Bruegel 2015]. However, internal EU infrastructure bottlenecks prevent these import capacities from being utilized equally across the EU leading to regionally specific vulnerabilities[125]. In particular, a number of Member States (especially in the Baltic region and South Eastern Europe) are reliant on Russia as their sole or dominant supplier of natural gas and have until recently had limited flexibility options at their disposal[126]. European Commission, ENTSOG and other[127] stress tests have revealed that those Member States most dependent on Russian gas would be disproportionately impacted by a technical failure that significantly reduces Russian gas supplies, both through involuntary demand curtailment and higher prices. Past supply side measures[128] have helped to reduce the potential impact of a significant short-term technical disruption, and additional demand side measure would help to further reduce these risks in the medium- to long-term. However, additional targeted supply-side infrastructure investments may be needed to ensure the security of supply to these regions, in particular South Eastern Europe.

Conclusion:

- Energy efficiency has a very low technical-risk profile and serves as a powerful risk mitigation option. While no technical risks could be identified, energy efficiency provides numerous technical benefits, in particular by increasing the margin of security in peak hours.
- Uncertainties about the future technologies and cost of infrastructure investment needed to integrate high shares of renewable energy (ex. grid expansion, battery storage, demand response, etc.) pose a low risk to the development of renewable energy sources in the short- to medium-term. However, high shares of renewable energy (80+%) increase these risks in the long-term. Uncertainties concerning technologies supporting high penetration of renewable energy must be taken into account when considering their potential role in the future energy system. By reducing the demand for infrastructure investments, strong energy efficiency policies can help to minimize these risks.
- Natural gas was found to have a relatively low technical risk profile for most of Europe. External technical risks may rise with increased import volumes, but past measures have helped reduce the impact of technical disruptions and current technical risks are largely mitigated by significant overcapacities. Internal infrastructure bottlenecks, however, prevent gas from being effectively distributed across Europe. Additional targeted investments may, therefore, be needed to ensure security of supply for those regions most vulnerable to technical supply disruptions from Russia, especially South Eastern Europe.

[124] These overcapacities also help to explain the low rates of utilization for pipelines (58%), LNG terminals (32%) and storage (18%) [Bruegel 2015].

[125] Examples of external risk highlighted in the literature include both under-investment in Russian natural gas production infrastructure, which could affect long-term gas production in Russia, as well as the significant need for modernizing the aging Ukrainian transit system [Checchi et al 2009].

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[127] For independent stress tests see Toth et. al. 2015, Climate Strategies 2015, European Union Choices 2016.

[128] These measures include reduced gas demand through energy efficiency and renewable energy, as well as supply side investments such as LNG-terminals (ex the Klaipeda and Świnoujście terminals in Lithuania and Poland), storage facilities,'reverse-flow' pipelines and alternative pipeline routes (ex. Nord Stream I)

5.3 Geopolitical risks

Energy efficiency

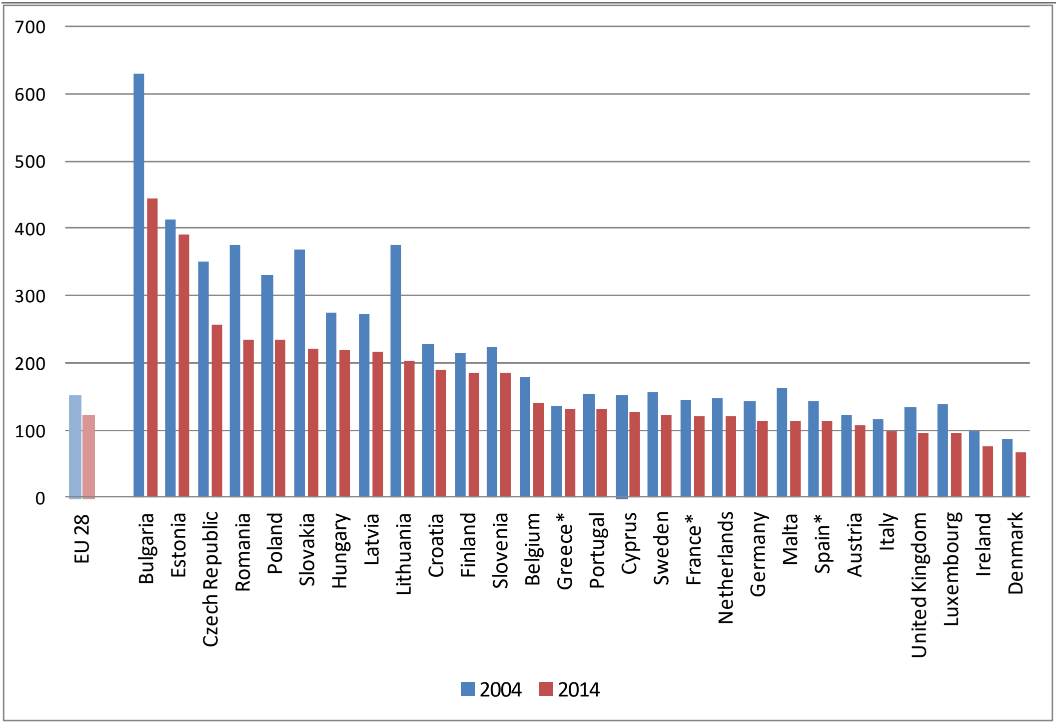
No significant geopolitical risks for energy efficiency could be identified. To the contrary, energy efficiency in the form of energy savings and demand response can play a substantial role in reducing the cost of geopolitical risk mitigation. Failure to take energy efficiency into account, on the other hand, can [RAP 2015]:

- Lead to oversized pipes and infrastructure that could have been avoided, such as pipelines and LNG ports
- Lock-in additional long-term contracts for natural gas at higher volumes than needed in the future.
- Lead to stranded assets and higher costs for ratepayers/taxpayers.

Furthermore, while energy efficiency has greatly improved in Central and Eastern Europe over the last decades, some of the EU Member States most vulnerable to gas supply disruptions from Russia are also among the EU's most energy intensive economies (see Figure 48). These figures imply energy efficiency measures may provide particular energy security benefits in these Member States and should be prioritized [129].

[129] It should also be noted that significant energy efficiency potentials have been identified for the Ukraine, the EU's most important transit country for Russian pipeline delivery of gas [Rozwalka et. al. 2016; IEA 2015A]. Tapping into these EE potentials has the potential to help reduce the Ukraine's dependence on gas imports via EU, thereby strengthening the EU's security of supply. EU external support measures to help advance implementation of EE measures in the Ukraine have been announced, but are contingent upon energy sector reforms being implemented that guarantee the independence of the Ukrainian energy regulator.

Figure 48: Energy intensity of the EU economy, 2004 and 2014



Note: Unit of measure kg of oil equivalent per € 1 000 of GDP, * 2014 provisional

Source: Eurostat (online data code: tsdec360)

Renewable energy

Some ambitious energy scenarios assume substantial imports of electricity from the EU's regional neighbours playing an important role in a transition to an energy system with 100 % renewable energy in the long term (ex. energy [r]evolution, [Greenpeace 2015]). This centralized model has raised security concerns due to the potential risk of strategic interruption of energy flows by North African energy producing countries [Lilliestam and Ellenbeck 2011] or the risk of disruption of energy flows due to physical or cyber attacks on renewable electricity production and transmission infrastructure [Lacher and Kumetat 2011]. Some authors have concluded that the risk of attacks on infrastructure would remain rare and limited and that the risk of strategic interruption is largely contingent upon coordinated political action by several states. However, reliance on mega-projects to supply the EU with additional low carbon energy raises the prospect of shifting geopolitical dependencies into new hands and towards new delivery infrastructure (Milesecure 2014)[130].

Another potential source of dependence is the trade of biomass as a fuel stock. Biomass fuels differ from variable wind and solar in that they are both exhaustible if harvested unsustainably and the energy content is storable. Currently, biomass remains mostly supplied domestically.

[130] A widely discussed case study of the geopolitical risk these import relationships may pose is that of the Desertec . This unsuccessful project envisioned the development of large-scale centralized solar plants in North Africa to export significant quantities of electricity via HVDC cables under the Mediterranean Sea to Europe to meet future EU demand.

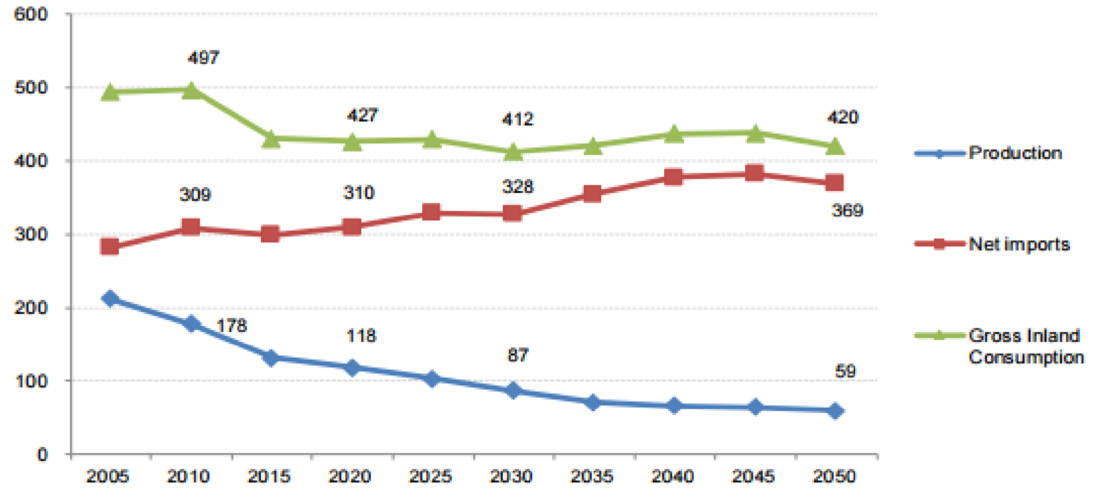
However, according to the most recent 2016 European Commission Reference Scenario increased demand and limited supply potential could lead to increases in biomass imports post-2020 from 11 % of biomass demand in 2020 to 15 % in 2030 and beyond. Therefore, while current quantities of biomass trade do not suggest trade vulnerabilities to be generated in the near future, future transportation routes could expose new vulnerabilities if the EU grows to increasingly rely on imported biomass in power, heating and transport from unstable suppliers [Hansson et al 2006]. This long-term vulnerability to biomass imports is directly influenced by technological developments in advanced biofuels and substitute transport technologies (ex. electric vehicles, fuel cell vehicles) and can be mitigated by the diversification of import portfolios [Johannson 2013; IEA 2007].

Finally, the increasing reliance on scarce materials for application in low carbon technologies, such as tellurium, ruthenium and indium for solar energy, neodymium for wind power and lithium for electric vehicle batteries poses another potential risk [Johannson 2013; Angerer et. al. 2016]. The production of several rare earth metals is concentrated in a limited number of producers, in particular China. These concentrations of raw material production clearly limit the potential for risk mitigation through diversification of suppliers. Large scale deployment of low carbon technologies, therefore, has the potential to significantly raise demand for these raw materials and create a critical trade vulnerability [Sathaye et al. 2011]. Risk mitigation measures include the development of substitutes, effective recycling systems (resource efficiency) and reduced capacity deployment through energy efficiency.

Natural Gas

Import dependency is a function of both net imports and total demand [EC 2014g]. As the previous review of target scenarios highlights, higher shares of energy efficiency and renewable energy could lead to significant declines in gas demand in the long-term, especially under highly ambitious EE and RES pathways. In parallel, domestic gas production and resource discovery is set to undergo a steady decline (see Figure 49).

Figure 49: Gas production, net imports and demand (in bcm)



Source: PRIMES, EU Reference Scenario 2016

The resulting risk of natural gas import dependency developing over the medium- to long-term can be evaluated by assessing the projected absolute volumes of gas imports across various scenarios[131] (see Table 99).

Table 99: Net gas import under various EU scenarios

Gas imports EU	2015	2020	2030	2050
Gas production in the EU according to EU Reference 2016 [TWh]	1377	1239	913	620
Resulting gas imports [TWh]				
EU Reference 2016	3132	3237	3405	3784
EU Reference 2013	3684	3486	3707	3993
EU EE27 2014	3683	3433	2981	2607
EU EE30 2014	3683	3380	2566	2119
EU EE40 2014	3683	3378	1755	1692
EU High RES 2011	3821	3206	3200	1828
IEA 450	3050	3006	3146	
Greenpeace e. [r]evolution	3605	3964	3873	675
Greenpeace advanced e. [r]evolution	3621	4006	3801	-476

Note: Uses domestic gas production from EU Reference Scenario 2016 as a baseline

Source: Prognos based on [EC 2016A], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015B], [Greenpeace 2015]

Table 99, which looks at the scenarios assessed in chapter 3, shows that volumes of imported gas are likely to increase or remain relatively stable across most scenarios in the short-term (2020), whereas projections diverge in the medium- (2030) to long-term (2050). Of particular note are the EE 27, 30 and 40 target scenarios of the European Commission, which project a considerable drop in gas imports in the medium-term due to early implementation of ambitious energy efficiency measures, as well as the Green e. [r]evolution target scenarios, which project a strong reduction in gas imports in the long-run. The BAU EU Reference Scenario from 2016, on the other hand, projects a considerable increase in gas imports across all time frames. Among these scenarios, EE40 projects the strongest reduction in net gas imports in the medium-term and can, therefore, be assumed to best mitigate import dependency risks, while also taking early action on climate change.

131 A relative assessment of import dependency is problematic over the medium- to long-term, as both the denominator (primary energy consumption) as well as the numerator (imported fuels) of the indicator can decline over time under ambitious decarbonisation scenarios. As such, it is better use absolute numbers to assess the risks of long-term energy import dependency.

Figure 50: Extra-EU supply needs in the TYNDP 2017 Scenarios

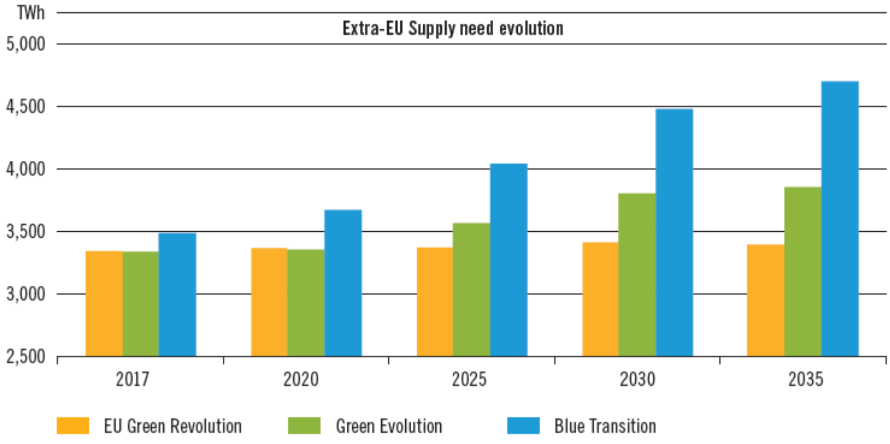


Figure 6.2: Evolution of extra-EU supply needs in the different scenarios

Source: [TYNDP 2017]

By comparison, it is notable that gas imports remain stable (EU Green Revolution) or rise over time (Green Evolution/Blue Transition) for the scenarios assessed in the TYNDP 2017. A particularly dramatic increase is seen for the Blue Transition scenario, in which projected gas imports far exceed those of any other scenario.

Increased import dependency does not by itself need to imply increased vulnerability[132]. Import vulnerability can be said to be low despite high levels of imports if suppliers are reliable, there is sufficient diversification, no supplier is dominant and prices are low. However, a number of characteristics set natural gas apart from oil and hard coal in terms of its import vulnerabilities. Key among are that gas is largely transported by pipeline[133], historically limited to regional markets and has a significant concentration among suppliers[134]. Furthermore, the present market structure for many of the EU Member States most dependent on gas supplies from Russia is frozen with long term (take-or-pay) contracts, making it difficult to diversify gas supplies by shifting suppliers in the short-run. While these contracts can be renegotiated, they do not adapt quickly to changing market conditions[135].

[132] Next to the previously mentioned demand side measures, importing countries can increase domestic production (ex. unconventional gas resources), strengthen interconnection of European gas grids, fix long-term supply contracts, invest in strengthening bilateral energy partnerships, as well as diversify supply countries and routes.

[133] 80-85 % of EU gas imports are delivered by pipeline, while 15-20 % are delivered by LNG [EPRS 2015]

[134] Security of supply can be threatened if a high proportion of imports is concentrated among few, or a single provider. In 2015, more than 77 % of the EU's total extra-EU gas supplies came from Russia (40%) and Norway (37 %), up from 69.1 % in 2014 and 59.6 % in 2010 [EC 2016b; EC 2014e].

[135] Tóth et. al 2015 used a gas flow model to assess more drastic measures by looking at the impact of ambitious renewable and energy efficiency deployment combined with a complete break up of all long-term contracts in the EU with Russia. The study found that gas purchase related expenditures would rise significantly in the short-term (2020) if these measures were adopted, but also finds that in the medium term (2030) this scenario would result in net benefits for the EU. Moreover, they conclude that it would be possible to reduce dependence on Russian natural gas supplies to as low as 79 TWh/year in this timeframe (6.5 % of 2015 levels) without any country experiencing skyrocketing natural gas prices. However, the authors make an effort to point out that these supply security benefits cannot be achieved through demand reduction policies alone, as they assume that improvements in gas and power infrastructure, including the implementation of PCI projects and reverse flow upgrades, are also realized.

These characteristics make gas importing and supplying countries highly interdependent (security of supply vs. security of demand[136]), but leave gas importing countries exposed to potential risks from both source countries, as well as transit countries through which the pipeline flows [Stern 2002]. These risks include potential disruption in the source and transit countries linked to internal instability (ex. terrorism, strikes, riots or political downturn) as well as nationalistic policies (ex. nationalisation of production facilities), which can impact gas supplies in both the short- to medium-term. A particular concern is the use of control over natural gas pipelines as a geopolitical weapon by the source or transit country to extract political or economic concessions, in particular in the case of Russia.

An additional indirect geopolitical risk of natural gas is the problem of resource rents generated by imports. Due to the significant volumes of natural gas imported by the European Union, large financial sums flow into the resource producing countries. As such, the resource rent created by European demand for oil and natural gas can produce negative externalities regarding internal stability, economic diversification and governance in oil and gas producing countries (the 'resource curse'), as well as wider negative geopolitical externalities, such as indirect support for autocratic regimes. While these rents are likely to decline significantly for oil and coal in the medium- to long-term, they could increase for gas in the medium- to long-term (see next section), especially in scenarios with large scale deployment of gas with CCS [Casier 2015]. As a result, a reduction of EU import volumes through demand-side measures may reduce the flows of these rents, which in turn could force autocratic governments to introduce economic restructuring measures and potentially implement social and political reforms [ECN 2016]. Decreased oil & gas revenues in resource provider countries may, however, also pose risks if the EU's leverage provided through its interdependent energy relations is reduced, or the resulting structural change leads to political instability [Dupont 2015]. A forward thinking engagement with the EU's energy partners is needed that helps to orient their economies to new markets and ensures a stable energy transition. A particular opportunity in the EU's neighborhood lies in the expansion of new energy trading relationships in renewable energy.

Conclusion:

- Energy efficiency is in the unique position of helping to reduce geopolitical risks for both renewable energy and gas, while posing no readily identifiable risks of its own. Some of the countries most vulnerable to gas supply disruptions from Russia have among the highest potentials for energy efficiency measures.
- Geographically varying availability of land and potential for renewable energy development raise the prospect of new trade dependencies developing in the medium- to long-term in a system dominated by renewable energy sources. Large scale centralized renewable energy projects are also likely to play an increasing role in the energy system in the long term, due to advantages of economies of scale and a changing regulatory environment. As a result, the external dimension of low carbon energy security, in particular energy partnerships with new suppliers of electricity and raw materials and the development of new international governance structures should be dealt with pro-actively and at an early stage. Import vulnerabilities linked to imports of biomass and raw materials can be mitigated through diversification of supply, the development of substitutes and resource efficiency measures, including recycling and energy efficiency. Potential vulnerabilities linked to the increased centralization of renewable energy development should be carefully monitored.

[136] Exports to Europe account for ¾ of Russia's total gas export revenues.

- Due to declining domestic gas production and resource discovery the EU is at risk of increasing its gas import dependency under BAU over the medium- to long-term, while potentially increasing resource rents for autocratic regimes in oil and gas producing countries. Furthermore, the characteristics of typical natural gas transport and supply contracts in the EU frequently leave gas importing countries exposed to significant risks from unreliable source and transit countries, especially when a supplier is dominant and diversification is low. Scenarios projecting large increases in gas imports over the medium- to long-term can be assumed to bear the highest geopolitical risk (ex. the TYNDP 2017 Scenario 'Blue Transition'). By contrast, early implementation of ambitious demand side measures (ex. EE40 scenario) combined with forward thinking engagement with the EU's energy partners can mitigate import dependency risks, while taking early action on climate change. Member States or national regulators should also monitor long-term contracts to ensure that in aggregate they are in line with medium- and long-term EU and national climate and energy goals.

5.4 Economic and social risks

Energy efficiency and renewable energy

An economic assessment of developing high shares of energy efficiency and renewables must take into account system-related costs (ex. additional generation costs), distributional costs (ex. costs that accrue for selected groups in society), and macro-economic costs (ex. gross and net impact on employment) [DiaCore 2015]. The development of these costs over time relative to other energy sources is one way to determine the economic risk (affordability) & social risk (acceptability) that a high ambition strategy would entail. The impact assessments from the EU's 2030 climate and energy package, the EU energy efficiency strategy and the revised Energy Efficiency Directive provide some important conclusions on how these costs can be expected to develop in the EU over time [EC 2014b, 2014c, 2016b]. In these impact assessments the European Commission estimates that ambitious energy efficiency and renewable energy policies would not result in significantly higher overall costs to the energy system compared to business as usual, while they would help to reduce energy imports and may have a net positive impact on GDP and employment[137].

At the same time, while Commission modelling indicates that real incomes would increase under these policies across all household groups and in most countries [EC 2016b], these policies also risk producing distributional effects on the household and service sectors, as well as lower income Member States compared to BAU by significantly increasing the need for investments and shifting expenditures from operational costs (fuel) to capital costs (investments) [EC 2014b]. Furthermore, shifts in employment will disadvantage workers in certain sectors and likely require a higher skilled workforce. As a result, ambitious energy efficiency and re-

[137] Models used by the European Commission impact assessment for the revision of the Energy Efficiency Directive come to different conclusions on the impact of EE and RES on employment depending on assumptions about financing conditions and whether labour resources can be absorbed in the sectors expecting to benefit from EE investments, However, EE and RES investments are generally considered to be beneficial for employment compared with other energy investment alternatives, as they are labour intensive. For example, one study cited in the impact assessment concludes that employment creation compared to oil and gas sector investments is 2.5 to 4 time larger for EE and 2.5 to 3 times larger for RES [Pollin et. al. 2009].

newable energy policies may require targeted social and labour policies to ensure that households (especially vulnerable consumers[138]) are able to cope with the burden of increased expenditures and that workers are able to be retrained to avoid unemployment and labour shortages.

The diversification benefits of renewable energy sources may also decrease or become negative over the long-term. In the short term, renewable energy sources help to diversify the European energy supply by having a different risk profile than fossil fuels and reducing the variability of generation costs [IEA 2007]. Over the long term, however, these diversification advantages may be reduced when systems have become dominated by renewable energy sources, as competing technologies will be forced out of the market [Johansson 2013]. The same may hold true for the diversification of energy use across sectors if growing electrification for heat and power increases reliance on the power grid, as opposed to other infrastructure (ex. gas grid). Therefore, in high RES scenarios with limited use of nuclear power and CCS and a high degree of electrification, the balance between the various RES technologies and applications will play an important role in ensuring continued resilience of the system.

However, the risks associated with new investments in renewable energy technologies are relativized when assessed against a full range of options and future investment risks. For example, a 2012 study by CERES compares the levelized cost of electricity (LCOE) against the relative risk of new generation resources using a multi-criteria composite risk index[139]. While assessed in the US context, this more nuanced cost analysis draws attention to the fact that the price for any resource may not take into account the relative risk of acquiring it. Importantly they find a clear difference in risk between renewable resources and non-renewable resources and determine that energy efficiency ranks lowest in both cost and risk when a broader range of risk factors is taken into consideration (see Figure 51).

[138] Member States concerned about distributional effects can address these by designing schemes, including financial instruments, that reach energy poor households as a priority [EC 2016b]. Studies on the multiple benefits of energy efficiency show that improving the efficiency of buildings lived in by people who face fuel poverty can have a particularly positive impact on reducing energy poverty and associated effects on well-being [COMBI 2015b].

[139] The risks reviewed were construction cost risk (unplanned cost increases, delays and imprudent utility action); fuel and operating cost risk (fuel cost and availability, as well as O&M costs); new regulation risk (air and water quality rules, waste disposal, land use, and zoning); carbon price risk (state or federal limits on greenhouse gas emissions); water constraint risk (availability and cost of cooling and process water); capital shock risk (availability and cost of capital, and risk due to project size); and planning risk (risk of inaccurate load forecasts, competitive pressure) [CERES 2012]

Figure 51: Relative risk of new generation resources

Source: CERES 2014

Natural Gas

The key economic risks linked to natural gas are the cost of gas imports and price volatility, as well as the risk of new investments in gas infrastructure becoming stranded. The European Commission estimates the cost of gas imports at EUR72 billion in the year 2015[140] [EC 2016d]. While importing raw materials can be economically rational, as European Union companies also benefit from the sale of goods and services to oil and gas exporting countries [Bardt et. al. 2016], declining domestic gas production high gas demand could increase the volumes and prices of gas needing to be imported leading to current account deficits and reduced economic competitiveness among other negative externalities (see previous section).. Reducing gas demand through substitution (ex. through renewable energy sources) and energy efficiency, on the other hand, serves to mitigate fuel import costs[141], providing savings that can be reinvested into the EU domestic economy.

As gas prices have historically been linked to the price of oil (oil-indexation), they have also suffered similar price volatility risks on international markets. Extreme oil and gas price volatility can lead to negative macroeconomic and energy security impacts. In addition to posing a risk to volatility in headline inflation and real disposable income (macroeconomic impacts), it can

[140] This is down from € 87 billion in the year 2013, largely due to low gas prices.

[141] In addition to lower import volumes, energy efficiency can lower gas commodity prices, as well as gas capacity and storage costs due to reduced natural gas demand [RAP 2015]. It should be noted, however, that reduced gas prices may also provide an incentive for increased gas consumption, or make it more difficult to convince stakeholders to support the phasing out of fossil fuels. In fact, a recent risk assessment of the German Energiewende found it to be robust and resilience to a wide range of future unpredictable, high impact ('Black Swan') events with the exception of a persistent lowering of fossil fuel and consumer energy prices [Prognos et.al. 2016].

also lead to higher cost of capital, hinder the financing of necessary investments and create the risk of misallocating resources that cease to be economical after a sudden change in relative pricing [IEA et al 2011]. Long-term contracts have traditionally been used as a financial instrument for hedging against some forms of price risk. Following liberalization of EU gas markets, however, trading on open liquid hubs, as well as hedging through financial derivatives are additional strategies for managing gas price risk.

Finally, climate science is clear on the fact that if catastrophic climate change is to be avoided, the vast majority of carbon fuels must remain unexploited. Leaving these assets untapped will, however, lead to a significant loss of revenues for fossil fuel companies, which could have significant financial knock-on effects for those invested in domestic and foreign fossil fuel producers as well as the financial returns on domestic gas transmission infrastructure. As such, the transition to a low carbon energy system must be managed in such a way as to reduce the risk of assets becoming 'stranded', in particular through early action on climate change[142].

For example, one approach to geopolitical risk mitigation that circumvents the constraints of pipeline supplies is the import of LNG. LNG transported by cargo ship provides access to alternatives to Russian and Norwegian gas, thereby helping to diversify the EU's gas supplies[143]. New LNG terminals can also be more easily realized than import pipeline projects[144], which generally involve complex and politically charged negotiations between multiple export, transit and import countries. As such, LNG can play a significant role in providing 'back-up' access to gas supplies in the case of supply disruption and diversifying import sources, especially for those Member States reliant on a single gas supplier. However, existing LNG capacity in Europe remains considerably underutilised[145], and the combination of long-term declines in gas demand and nationally oriented security of supply planning[146] risks new investments in LNG becoming stranded assets in the medium- to long-term. As LNG terminals are highly capital intensive investments, their support through EU funds also risks competing with funds for energy efficiency, renewable energy and electricity infrastructure that could help the EU to reach its medium- to long-term climate goals (see Section 2.2.3)

Conclusion:

- Multiple European Commission assessments conclude that ambitious energy efficiency and renewable energy policies are unlikely to result in significantly higher overall costs to the energy system compared to BAU, while potentially having a positive impact on GDP and import costs. However, distributional impacts may require targeted social and labour

[142] A recently published study by the European Systemic Risk Board (2016) juxtaposed a "benign scenario" in which the increased cost of a transition to a low-carbon economy occurs gradually with an "adverse scenario" in which this transition occurs late and abruptly. The study finds that while the adjustment costs under the benign scenario remain manageable and there is limited systemic risk, under the adverse scenario the costs are significantly higher due to late implementation of climate policies. As a result, the adverse scenario potentially results in a "hard landing" implying higher costs to the economy and "effects equivalent to a large and persistent negative macroeconomic shock " (ESRB 2016). These findings echo the main conclusions of the Stern Review from 2007, which finds that early action on climate change far outweigh the costs of inaction or late action (Stern Review 2007).

[143] Qatar, Algeria and Nigeria provided a combined 89 % of LNG supplies to Europe in 2015 [EC 2016b]

[144] It should also be noted that the Asian premium of LNG prices over European hub prices that existed over the last several years have almost disappeared [EC 2016b]. In fact, while piped natural gas has historically had a competitive pricing advantage, LNG has also become even cheaper in some Member States than pipeline gas, including in Italy and Spain [EPRS 2015].

[145] According to Bruegel 2015, LNG terminals had a 32 % utilization rate in 2015.

[146] As Bruegel 2015 points out, "nationally-administered approaches regularly fail to select the most efficient portfolio of options". By contrast, addressing gas supply security at the EU level can reduce costs through join solutions, avoid undermining the internal energy market through unilateral SoS policies, and increase solidarity between Member States.

policies and distributional measures to ensure public acceptance for low carbon technologies and infrastructure, in particular financial support for vulnerable consumers and job training measures for workers in disadvantaged sectors.

- When it comes to investment in new generation capacity, renewable energy sources and especially energy efficiency are among the lowest-risk investments when a broad range of risk factors is taken into account. However, diversification benefits of renewable energy sources may decrease over the long-term.
- An increase in net gas imports in the medium- to long-term risks raising the EU's energy import bill and gas prices, as well as potentially increasing the price volatility of gas supplies. Large increases in import costs and extreme gas price volatility could lead to current account deficits and reduced economic competitiveness. Financial instruments can help to mitigate the impact of price volatility. However, demand-side measures provide a more effective method of mitigating import cost risk and reducing the impact of sudden price hikes or supply disruptions on individual investors and the economy.
- Access to LNG can help to mitigate import dependency risks, especially for those Member States reliant on a single gas supplier. However, misguided investments into LNG and other new import infrastructure also risk generating stranded assets and competing with low carbon options for scarce public resources. As such, LNG remains a risky and expensive option for reducing geopolitical risks, in particular relative to energy efficiency.

5.5 Environmental and health risks

Energy efficiency

The environmental and health impacts from the manufacturing, installation and operation of new materials and equipment for energy efficiency investments differ significantly between substances and technologies. For example, petroleum based building insulation materials have less favourable values concerning climate, ozone, health and ecotoxicological impacts compared with renewable raw materials [IÖW 2016]. Energy efficient compact fluorescent lightbulbs contain toxic mercury, requiring extra precautions to be taken for their safe disposal. These environmental risks must be taken into account and can be partially mitigated through the use of substitutes (ex. insulation materials from natural fibres) and by carefully assessing a full range of energy efficiency investment options using a life-cycle approach.

However, while these environmental impacts of energy efficiency investments must be carefully managed, they are small compared to the environmental benefits of energy savings. By decreasing energy-use and the associated material consumption, energy savings can reduce the environmental impact of avoided energy throughout its entire life-cycle ("from well-to-wheel"). Furthermore, by reducing energy demand they can contribute to reduced system requirements, thereby helping to avoid additional environmental impacts associated with built infrastructure throughout the energy system. As such, next to the clear climate benefits of reducing demand for fossil fuels, energy efficiency is associated with a variety of environmental and health co-benefits [EC 2014d], including:

- Improved health conditions by lowering the emission of air pollutants and reducing the cost of air pollution control[147]

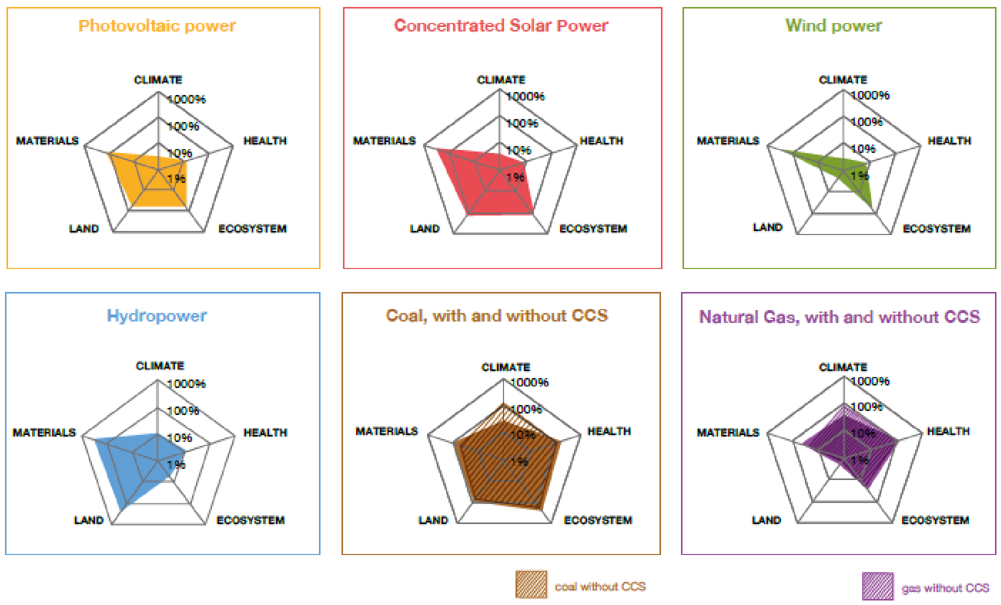
[147] According to the EC Impact Assessment for the 2014 Energy Efficiency, the health benefits of energy efficiency are "disproportionately larger in lower income Member States expressed as a percentage of GPD and much larger in scenarios with ambitious energy efficiency policies and a renewables target".

- Reduced pollution and resource consumption from energy extraction, transformation, transportation and use.

Renewable energy

A recent UNEP review [UNEP 2015] of most of the commercially available renewable and non-renewable power generation technologies (excluding nuclear energy and biomass) allows for a nearly comprehensive comparison of the full life cycle costs of a range of technologies. The study assessed these technologies both in terms of their GHG emissions, as well as their trade-offs in terms of environmental, health and resource use impacts (see figure below). Comparing the technologies over a range of indicators, the study concludes that replacing conventional fossil fuel-fired power plants (including natural gas) with renewable energy technologies offer substantial reductions in the emissions of greenhouse gases and other pollutants, helping to reduce such environmental and health impacts as eutrophication, acidification, particulate matter, smog and other forms of toxicity. In direct comparison, carbon capture and storage technologies utilized with natural gas were also found to lead to substantial reductions in greenhouse gas emissions, but without reducing dependence on finite fossil fuel resources and resulting in a moderate increase in resource use and the release of other emissions. As a result, the replacement of fossil fuels with renewable energy sources was considered to offer “a clear opportunity to reduce environmental pollution from electricity generation” [UNEP 2015]. Conversely, using natural gas instead of renewable energy sources to substitute coal leads to a net increase in environmental pollution.

Figure 52: Overview of life cycle costs by technology group



Source: [UNEP 2015]

However, assessed renewable energy technologies (Solar PV, Concentrated Solar Power, Wind, Hydro and Geothermal) also led to ecological impacts associated with land use, water use, and increased material consumption of iron, cement and copper. For example, wind and solar are associated with similar land use impacts as with coal mining, and geothermal and concentrated solar power use slightly more water for production than typical fossil fuel power plants without air cooling. Furthermore, while the material consumption linked to renewable technologies is not seen as a concern in the short term, the use of copper and functionally important metals is considered a long-term risk depending on the availability of substitutes. The resource dependency issue reinforces the conclusions on scarce materials discussed in the geopolitical risks section.

Due to the variability of intermittent generation technologies (mainly wind and solar), the environmental impacts of grid integration measures such as grid expansion, flexible operation of fossil fuel generation and energy storage also need to be taken into account. The study finds that depending on the expected design of the electricity network, its required stability and the strategy used to balance supply and demand, GHG emissions for these integration measures may be "in the same range or even higher than the life cycle emissions of the investigated renewable generation sources[148] [UNEP 2015]. While grid integration is not expected to substantially compromise environmental benefits in the short run, in the medium term growing requirements for grid and storage investments could lead to additional environmental impacts that must be carefully assessed. The study, therefore, concludes that additional research is need to fully assess the life cycle costs of these technologies and to develop integrated electricity systems with minimal impact.

The renewable energy source widely considered to carry the highest environmental risk is bioenergy. The firing of woody biomass for heating or power generation can be a source of air pollution comparable or worse than coal[149], and can pose environmental risks for forest ecosystems if sourced from unsustainably managed forests (threat of deforestation). Furthermore, the production of first generation biofuels based on food crops (in particular sugar-cane and corn-based ethanol) can reduce the land available for food production, lead to air pollution from agricultural burning[150], increase greenhouse gas emissions through indirect land-use change, as well as put significant stress on biodiversity and ecosystems through increased water consumption for irrigation. Additional impacts associated with bioenergy are the planting of crop monocultures, and increased use of fertilizers and pesticides[151].

These numerous challenges indicate that the role that bioenergy, including biogas, can play in a future sustainable energy system has clear environmental limits. Focusing biofuel production on degraded or abandoned land, setting clear sustainability criteria for the harvesting of woody biomass, the electrification of transport and developing next-generation biofuels can help to mitigate some of these environmental risks. More importantly, energy savings can help reduce the overall biomass feedstock being consumed, especially in the short- to medium-term. However, the challenge of meeting the EU's long-term 80-95 % GHG reduction target may increase bioenergy demand substantially in the long-term relative to the EU reference scenario [Forsell, N. et al. 2016].

148 According to the study, some evidence shows that grid extension may have a lower environmental impact than energy storage technologies.

149 See [PFPI 2014]

150 It should be noted that certain biodiesel fuel mixes can lead to a reduction in particulate matter and sulphur dioxide compared with traditional diesel - http://www.unep.org/climatechange/mitigation/Bioenergy/Issues/WaterSoilAir/tabid/29468/Default.aspx

151 See [Webb et al 2012]

Natural Gas

Natural gas is frequently promoted as a “bridge technology” in the energy transition due both to its environmental performance relative to other fossil fuels[152] and the complementarity of some gas power plants with intermittent renewable energy sources (ex. wind and solar). However, next to the climate and economic policy risks discussed previously, in particular indirect substitution of renewable energy sources and the potential lock-in of fossil fuel infrastructure, the use of natural gas is also associated with significant environmental and health risks along each step of the supply chain, including production, transport and combustion[153].

Conventional gas production in the EU is set to decline in the coming years, in particular in the Netherlands where the depletion of the Groningen field is under close monitoring by authorities [ENTSOG 2016e]. However, new technological developments in hydrocarbon resource extraction techniques, in particular hydraulic fracturing, raises the possibility of exploiting newly recoverable “unconventional” gas resources. While a universally recognized distinction between conventional and unconventional fossil fuels is not available, the term "unconventional" refers primarily to the geological characteristics of the hydrocarbons [AMEC 2015]. Unconventional formations often stretch over very large areas, are characterized by low energy content per rock volume and by low or very low permeability. The main types of unconventional fossil fuels are: tight gas, shale gas, coal bed methane, methane hydrates, tight oil, shale oil, oil shales and oil sands.

Current estimates for technically recoverable unconventional gas in Europe place these at about 16 trillion cubic meters (tcm) for shale gas, 3 tcm for tight gas and 2 tcm for coal bed methane, which compares with about 0.4 tcm gas consumption in Europe in 2015 [JRC 2012; EC 2016c]. Accordingly, studies have found that unconventional gas resources could represent 10 % of EU gas demand (i.e. 2-3 % of the overall energy mix) by 2035, with shale gas estimated to have the greatest potential for development, particularly in France and Poland[154]. While these volumes are not enough for the EU to become self-sufficient in gas production and are unlikely to have the impact of the shale gas revolution in the US, supporters of increased domestic production have argued that exploiting these resources could help to partially compensate the decline in the EU’s conventional gas production, thereby contributing to supply diversification, price moderation and import reduction[155][JRC 2012].

[152] While technology specific, natural gas can broadly be said to have about half of the life-cycle GHG emissions compared to most common coal technologies, due to the lower carbon intensity of natural gas as a fuel and the higher efficiency of natural gas power plants (especially combined-cycle gas turbines). The environmental impact of natural gas on the local level in terms of air pollution is also generally lower than coal and petroleum, as it releases less NOx, SO_2 and particulate matter.

[153] While the external costs of safety accidents are insignificant when compared to the climate change and air pollution effects resulting from the normal operation of the natural gas supply chain and natural gas has the lowest expected fatality rates of all fossil fuel chains, in comparative perspective with renewable energy sources natural gas performs more poorly. While the maximum consequences of low frequency accidents in natural gas chains are considered lower than those for nuclear power and hydro, comparative studies find that they have distinctly higher fatality rates and are more prone to severe accidents than all renewable energy sources [Burgherr et al 2014]. The majority of accidents and fatalities in the natural gas chain take place in the transport & storage stage, but a substantial share also occurs in power plant and home heating applications (ex. gas boiler explosions) [Burgherr et al 2014, Burgherr et al 2005].

[154] At present, there is no commercial production of shale gas using high-volume hydraulic fracturing in the EU, however, the IEA estimates that 73 % of EU shale gas technically recoverable resources are split between France (5.1 tcm) and Poland (5.3 tcm). Remaining reserves would be mostly shared by Germany, the Netherlands, the United Kingdom, Denmark and Sweden. At present, only tight gas is commercially produced in Europe, notably in Germany, but the number of coalbed methane projects is increasing and oil shales are produced in Estonia, where it is the dominant electricity feedstock [EC 2014e].

[155] In a study JRS estimates that in the best-case scenario of EU shale gas development, shale gas could replace declining conventional gas capacities, reducing Europe’s dependence on gas imports by an average of 6 % in 2020 to more than 20 % in 2040, allowing the EU to maintain gas import dependency at a stable 60 %. However, the study is also premised on gas demand in Europe increasing [JRC 2012].

The environmental risks of gas production can differ in a number of ways, in particular in regard to the extraction site (onshore vs. offshore) and extraction technique (conventional vs. unconventional). Offshore operations face unique challenges concerning the containment and storage of substances, the movement of goods and the disturbance of the marine environment through noise pollution, whereas issues of land-take, built environment and management of water resources can play a more important role in onshore operations [AMEC et al 2016]. Moreover, while both conventional and unconventional gas production entails environmental risk, they can differ significantly in the scale of impacts [AMEC et al 2016]. For example, for shale gas production, a more intensive stimulation technique (high-volume hydraulic fracturing) is required than in most conventional production, and more and less productive wells are drilled over a wider area, generally increasing the environmental footprint of operations. Natural gas production using hydraulic fracturing is, therefore, associated with a variety of significant environmental impacts (see Table 100).

Table 100: Environmental impacts linked to high-volume hydraulic fracturing (HVHF)

Surface and groundwater contamination: Contamination of groundwater can occur due to the chemicals used in hydraulic fracturing process in case of leaks (e.g. improper well design or casing), whereas surface water contamination can occur when wastewater is not properly managed and treated. Mitigation options include careful site selection based on underground risk characterization, as well as proper well insulation and management of waste water.

Air pollution and greenhouse gas (GHG) emissions: Venting, flaring and fugitive methane emissions can occur during shale gas exploration or production, which have a negative impact on local air quality (including ozone formation) and the climate. Air emissions can also result from on-site equipment and increased transport in production areas. Good practices can help to prevent and mitigate some emissions.

Water resource depletion and pressure on water dependent ecosystems: Shale gas resource extraction requires significantly higher volumes of water than conventional gas production, part of which is not recovered. As such, HVHF and other techniques risk significantly increasing water demand, which can put additional stress on aquifers in water scarce regions and compete with other uses, as well as potentially impacting local ecosystems. Water management plans and best practices (ex. re-use of flow-back water) can contribute to reducing demand by making efficient use of water.

Seismicity: hydraulic fracturing has been linked to minor earthquakes through induced seismicity linked to the injection of large volumes of waste water in the underground, a phenomenon also reported for geothermal activity. The size of this risk is currently unclear and requires further research.

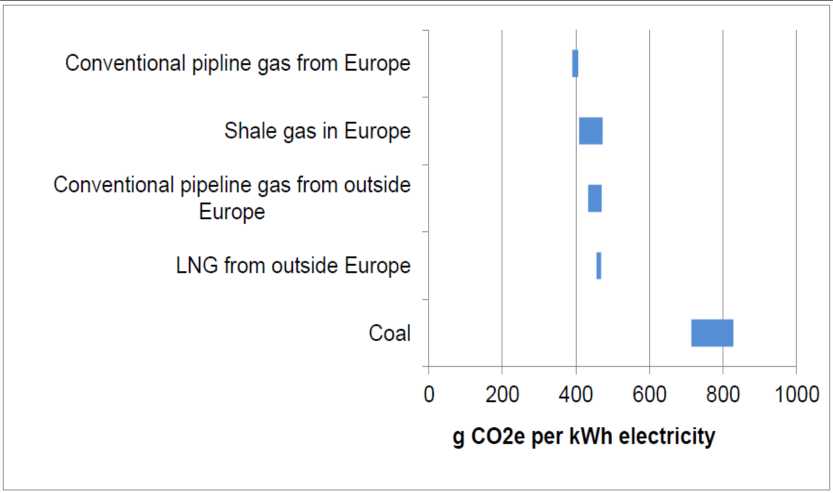
Land use and cumulative effects: The large number of wells and related infrastructure needed for shale gas extraction can compete with other land uses and result in land fragmentation impacting local communities and biodiversity. Moreover, the resulting increase in local road traffic can result in higher cumulative effects, such as increased air, noise and soil pollution and road accidents.

Health: Health impacts from unconventional and conventional gas production may include toxicological effects of substances at both the local extraction sites (ex. Silica) and related activities/facilities in the region (ex. compressor stations and waste operations), but are highly contested. While some studies have concluded that hydraulic fracturing is safe provided it is properly regulated, others have called for caution due to lack of conclusive scientific evidence. Mitigation options include active monitoring of gas production activities, as well as further epidemiological studies (EC 2016e).

Source: Based on [EC 2014e]

Concerning climate impacts, while some studies have concluded that the lifecycle GHG emissions from shale gas may be larger than conventional natural gas, oil or coal [Howarth et al, 2011][156], a large number of studies also indicate that they are lower than coal[157], but comparable or slightly higher than conventional gas systems. A Commission study assessing the climate impact of shale gas concludes that if emissions are properly controlled, power generation emissions from domestically produced shale gas may be 2-10 % lower than electricity generated from some imported conventional pipeline gas (ex. Russian and Algeria), and 7-10 % lower than in the case of LNG imports[158] (see Figure 53).

Figure 53: Life-cycle emissions from coal and gas powered electricity generation



Source: [AEA 2012]

These environmental impacts and risks require careful management, both to safeguard the public interest and enable the public acceptance of potential operations, i.e. in order to maintain a "social license to operate". In January 2014, the Commission adopted a Communication and a Recommendation on the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing (HVHF), which laid down minimum principles for such activities, but are legally non-binding. The Recommendation invites Member States to ensure that:

- A strategic environmental assessment is carried out prior to granting licenses
- A site-specific underground and above-surface risk characterization is carried out
- Baseline reporting takes place (e.g. water, air, seismicity)
- The public is informed of the composition of the fluid used on a well by well basis
- The well is properly insulated from surrounding geological formations

156 [Howarth et al 2011] assumes higher levels of methane emission during well completion and pipelines transmission and a higher GWP factor for methane.

157 [AEA 2012] concludes that emissions from shale gas generation are 41 % to 49 % lower than emissions from electricity generated from coal on the basis of methane having a 100 year GWP of 25.

158 The study finds that GHG emissions per unit of electricity generated from shale gas may be around 4-8 % higher than for electricity generated by conventional pipeline gas from within Europe, largely due to additional emissions in the pre-combustion stage, but can be reduced to 1-5 % using mitigation measures [AEA 2012].

- Venting is limited, flaring is minimized and gas is captured for subsequent use[159]
- Best available techniques (BAT) and good industry practices are used [EC 2014g].

A recent review of these recommendations[160] concluded that if applied thoroughly they can be a useful tool for managing risks from HVHF in a transparent manner [EC 2016c]. At the same time, the Commission found that the recommendations have been applied unevenly across Member States and unsatisfactorily in some[161]. Moreover, feedback from a stakeholder event in June 2015 revealed that while the oil and gas industry considers the recommendation sufficient, water-producing associations and environmental NGOs have asked for further measures. In fact, due to concerns about residual health and environmental risks, a number of EU Member States or regions have adopted temporary moratoria on hydraulic fracturing practices and two Member States (France and Bulgaria) have enacted legal bans [EC 2014e]. In the coming years, the Commission plans to carry out activities that will increase transparency and monitoring, foster correct and uniform application of the recommendations and best practices in waste management, as well as support further research on health impacts and risks of hydrocarbon extraction [EC 2016c].

Further supply chain emissions linked to gas transmission and distribution can also have a non-negligible impact on the GHG performance of natural gas. Important factors impacting performance include the efficiency of liquefaction and regasification processes for LNG, the performance of LNG tanker engines (old/new technology, motor size, used fuel), the performance of pipelines (pressure, diameter, natural gas leakages), as well as the CO_2 concentration in the raw gas [Taglia et al 2009]. The reduced climate performance of liquefied natural gas (LNG) is due to the substantial energy requirements to liquefy and transport gas (typically for longer distances), whereas for pipeline transport, reduced performance is largely a factor of losses when travelling over longer distances[162] (see Figure 54).

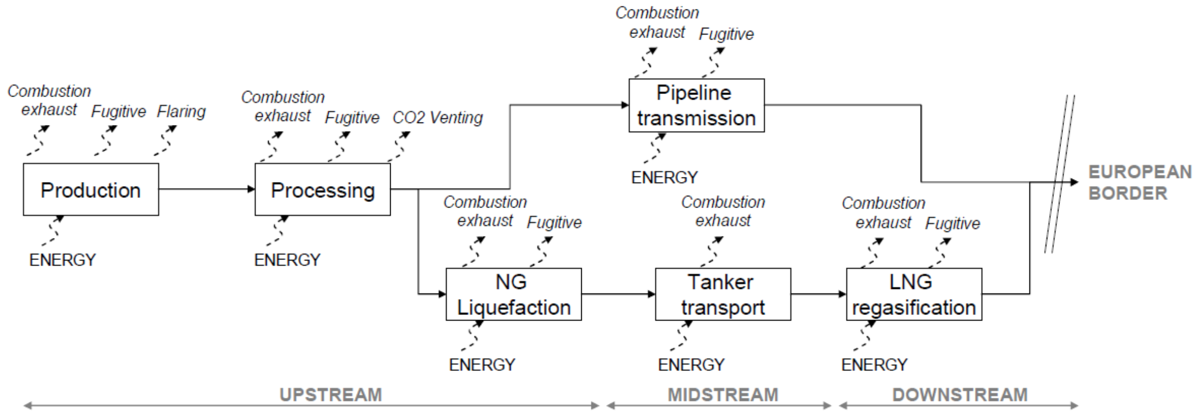
[159] "Venting" refers to the release of gases directly into the atmosphere, while "Flaring" is controlled burning of natural gas, a process typically used as an alternative to venting.

[160] The review found that 11 Member States (Austria, Denmark, Germany, Hungary, Lithuania, the Netherlands, Poland, Portugal, Romania, Spain, and the UK) have thus far granted, or plan to grant authorizations for the development of hydrocarbons that may require the use of HVHF. A total of 80 exploratory wells have been drilled, 16 of which used HVHF.

[161] For example, following its adoption Poland simplified environmental legislation to such an extent that the Commission had to launch an infringement procedure due to failure to fulfil obligations under the EIA directive and some Member States have not enshrined the recommendations in national legislation.

[162] The differences in GHG emissions between supply chains are mostly due to differences in transmission distance. For example, one study found the supply chain emissions of Russian gas from Siberia imported in Germany, which travelled a distance of more than 5000 km, to be 45 % more GHG intensive than the European average and therefore more GHG intensive than LNG gas [Taglia et al 2009]. By comparison, the distance covered from the European production fields is 500 km in average (Eurogas & Mercogaz 2009).

Figure 54: Main emissions from gas supply chain



Source: [Taglia et al 2009]

Therefore, while pipelines are generally preferable from an economic point of view for onshore transmission, from an environmental point of view the distance of the gas source can make a significant difference. On the one hand, gas sources closer to the point of consumption will generally have a lower environmental footprint. On the other, where gas must be transported over long distances, pipeline transmission will generally only be preferable to LNG up until a certain distance[163].

A wide range of mitigation options exist to improve the climate performance of the natural gas chain, including the use of CCS in natural gas plants and industrial applications, the substitution of natural gas with climate-neutral renewable gas, the development of high efficiency gas utilisations (ex. heat pumps, micro-CHP, combined cycle), efficiency improvements for liquefaction units on LNG chains, the improvement of compressor efficiencies during long distance pipeline transmission and the reduction of flaring during gas production on associated gas fields. Perhaps the most crucial measure in the short-term, however, is taking steps to address methane leakage [Eurogas & Marcogaz 2009]. In terms of climate change effects, burning natural gas (methane) is better than releasing it into the atmosphere, as it has a much higher global warming potential (GWP) (28-34 times the rate of CO_2 over 100 years) and a shorter lifespan in the atmosphere[164]. Due to the different approaches used to quantify methane leakage rates, studies indicate leakage rates ranging from as low as 1 % to as high as 9 %, a margin of error that can have significant consequences[165] [Ricardo-AEA 2016]. As such, a precau-

[163] One study places this distance at 3000 km for land and 1800 km for below sea pipelines [Taglia et al 2009]. To demonstrate the impact, one scenario-based study finds that mean emissions for electricity generation in Europe using US exported LNG are 11 % higher than in the US, but could save GHG emissions relative to Russian pipeline natural gas as long as US fugitive emissions remain below an estimated 5-7 % rate for Russian gas [Abrahams et al 2015].

[164] The GWP increases to 84-86 the rate of CO2 over a 20 year time period [IPCC 2013]

[165] Critics argue that studies looking at methane in the atmosphere (“top-down” studies) give evidence that estimates based on wells, pipelines and refineries (“bottom-up” reviews) dramatically underestimate total methane leaks; for example, one recent study using new techniques revises methane emissions from fossil fuel development upward by 20-60 % [Schwietzke et al 2016]. While studies on this issue are not conclusive, the consequences are potentially large. For example, based on more pessimistic assumptions on methane leakage rates and the GWP of methane some studies conclude that use of natural gas in the power and heating sector can have a larger GHG footprint than coal if methane leakage is not controlled [Howarth 2014; Taraska et al 2014]. Furthermore, a recent Ricardo-AEA [2016] study found that while there is some potential for reducing GHG emissions from the transport sector through the use of natural gas and biomethane, reductions achieved are very

tionary approach that takes into account the upper bounds of estimates for the GWP of methane[166] and actively manages methane leakage is crucial to reducing the environmental risks associated with natural gas.

Methane leakage in the natural gas life-cycle can include fugitive emissions (ex. small leaks from equipment), vented emissions (ex. intended vents for maintenance or operational reasons), incomplete combustion emissions from gas engines, and pneumatic emissions from gas operating valves and devices [Vorgang 2009]. Whereas fugitive emissions are unintended releases, pneumatic emissions and venting are caused by operation and equipment. According to one study, fugitive emissions, vents, and pneumatic emissions each make up roughly one-third of methane emissions in the EU natural gas supply chain [Vorgang 2009]. Mitigating methane leakage is a function of changing practices that lead to these emissions wherever they occur (i.e. drilling, extraction, processing and transport), which can include both identifying the responsible leaks (ex. fugitive emissions), as well as modifying technology and operations. Best practices include flaring, optimization of operations and maintenance[167], and proper monitoring programmes [Vorgang 2009].

It should be noted that due to high shares of natural gas imports in Europe, much of the methane leakage linked to production and 65 % of the transport GHG emissions take place outside of Europe [Eurogas-Marcogaz 2009]. As such, while the potential to reduce losses in gas grids can still be significant in individual Member States (see Figure 55), efforts to address the problem of methane leakage must also include cooperation with gas producers and transit countries outside the EU and reflect the varying emissions in different source countries. Furthermore, scale effects must be taken into account as growing consumption of natural gas can also serve to offset gains made in addressing methane leakage[168].

sensitive to assumptions on methane leakage during production/distribution and methane slip that occur when the fuel is used in road transport or shipping.

166 Environmental groups in the US have consistently criticized the impact assessments of the Department of Energy and the Environmental Protection Agency concerning their use of outdated global warming potential (GWP) figures.

167 For example, according to [Tractabel Engineering 2016] an 80 % reduction of gas losses in transmission can be achieved when gas is recompressed instead of vented before maintenance, and the UK has been able to reduce losses in its distribution network tenfold by replacing old grey cast iron pipes with yarn/lead joints.

168 For example, one recent study found that while improvements in industry practices in the US have reduced leaks from oil and gas facilities from about 8 percent of production to about 2 percent over the past three decades, dramatic production increases have canceled out efficiency gains keeping the overall contribution from fossil fuel activities constant [Schwietzke et al 2016].

Figure 55: Level of losses in gas grids in EU Member States

Source: [Tractabel Engineering 2016]

Conclusion:

- Energy extraction, transformation, transport and use are not possible without environmental impacts. However, energy efficiency measures can play a crucial role in reducing the environmental impacts of all energy generating technologies, including renewable energy technologies and natural gas. In particular, energy savings can reduce the environmental impact of avoided energy throughout its entire life-cycle and contribute to reduced system requirements, generating substantial environmental and health benefits.
- A comparison of energy generation technologies over a range of indicators reveals that replacing fossil fuels (including natural gas) with renewable energy technologies offers substantial reductions in the emissions of greenhouse gases and other pollutants, helping to reduce such environmental and health impacts as eutrophication, acidification, particulate matter, smog and other forms of toxicity. Like other energy generation technologies, however, renewable energy sources and their associated infrastructure (ex. transmission grid, storage) produce technology- and site-specific environmental effects that pose environmental risks and trade-offs, including raw material use, water consumption, damage to biodiversity and increased land use. Policy-makers must take these risks and trade-offs into account when planning the policy design for a future low-carbon energy mix. In particular, the use of bioenergy for power generation, transport and heating will have to be carefully

weighed against the deployment of alternative technologies, such as electric vehicles and heat pumps. While energy savings and other risk mitigation strategies can help mitigate the environmental impacts in the short- to medium-term, the environmental risks of bioenergy are significantly higher in the medium- to long-term under European Commission target scenarios and thus require careful policy monitoring.

- While generally considered less carbon intensive than other fossil fuels when combusted, natural gas is still associated with significant environmental risks along each step of the supply chain. In the European context, particular challenges include environmental risks associated with a potential increase in the domestic production of unconventional gas reserves (ex. water contamination and depletion, air pollution, seismicity, land-use change, health impacts) and the leakage of methane, a GHG far more potent than CO_2. As a result, a precautionary approach to environmental risk management becomes particularly important in the application of gas production techniques with uncertain environmental impacts (ex. high-volume hydraulic fracturing) and for supply chains that entail high energy losses and methane emissions (ex. LNG transport, long-distance pipelines). Since the EU imports much of its natural gas, the majority of GHG emissions linked to production and transmission take place outside of Europe. As such, efforts to address the problem of methane leakage must include cooperation with gas producers and transit countries outside of the EU and should furthermore reflect both the scientific uncertainty about methane leakage rates from various source countries, as well as the potentially more harmful global warming potential of methane. CCS technologies could play an important role in mitigating the GHG emissions of natural gas combustion, but would likely increase gas consumption and therefore potentially worsen gas import dependence and the environmental impacts in earlier parts of the supply chain (ex. methane leakage).
- As a result, the replacement of fossil fuels with renewable energy sources (including electrification and the substitution with renewable gases within environmental constraints), the reduction of fossil and renewable gas consumption through energy efficiency measures, and the reduction of methane leakage through the application of industry best practices offer the clearest opportunity to reduce the environmental risks associated with natural gas, as well as the energy system as a whole.

5.6 Risk categorization and conclusion

The previous sections provided a broad overview of the most critical risk factors identified in the academic and policy literature linked to EE, RES and natural gas. A summary of these risk factors is provided in the tables below (see Table 101 and Figure 56). Where possible an assessment is made as to the **time horizon** applicable to the individual risk category, distinguishing between short (2015-2025), medium (2025-2035) and long-term time horizons (2035-2050)[169]. Furthermore, a qualitative assessment of the overall **risk level**, is provided for each identified risk category, distinguishing between low, low-moderate, moderate, moderate-high and high-level risks, and various **risk mitigation options** are presented for each risk category. Following these overview tables, a comparative assessment is made for each energy resource

[169] The temporal dimension is key to the analysis of energy security, as it can lead to considerably different areas of emphasis and outcomes. Short-term energy security "focuses on the ability of the energy system to react promptly to sudden changes within the supply-demand balance," such as in the case of supply disruption due to weather, accidents or political events (IEA Online). Long-term energy security, on the other hand, "deals with timely investments to supply energy in line with economic developments and sustainable environmental needs" (IEA Online).

Table 101: Overview of risks linked to EE, RES and Gas

Energy Efficiency							
Risk Categories			Description	Potential Impact	Time Horizon	Risk Level	Mitigation Options
Policy & Regulatory	**E.1**	**Policy Design**	Inadequate political ambition	Inadequate/Reduced investment	M, L	Low-Moderate	Ambitious revision of the EED
Economic & social	**E.2**	**Distributional effects**	Shifts in employment and increased burden on the residential & tertiary sectors, as well as lower income Member States.	Reduced societal acceptance	M, L	Moderate	Targeted social and labour policies, distributional measures between Member States
Environmental & health	**E.3**	**EE materials and technologies**	Environmental impact of EE materials and technologies	Reduced societal acceptance	S, M, L	Low	Life-cycle assessment, Substitutes, R&D

Renewable Energy							
Risk Categories			Description	Impact	Time Horizon	Risk Level	Mitigation Options
Policy & regulatory	**R.1**	**Policy, market design & grid access**	Inadequate political ambition and/or lack of predictable policy framework	Inadequate investment	M, L	Moderate	EE, RES-support policies, Reform of electricity market design
Technical	**R.2**	**Grid integration**	Concerns and uncertainties linked to grid integration under high levels of RES penetration	Reduced development	L	Moderate	EE, R&D
	R.3	**Technical potential**	Concerns and uncertainties linked to potential and cost-effectiveness of using high shares of bioenergy and hydrogen to replace natural gas	Lower cost reductions; Reduced development	M, L	Moderate - High	EE, R&D

Geopolitical	**R.4**	**Import dependence**	Dependence on imports of electricity, biomass and scarce materials, such as rare earths	Lower reduction of import costs; Price volatility	M, L	Low - Moderate	EE, diversification of supply, substitutes and resource efficiency
Economic & social	**R.5**	**Distributional effects**	Shifts in employment and increased burden on the residential & tertiary sectors, as well lower income Member States.	Reduced societal acceptance	M, L	Moderate	EE, Targeted social and labour policies, distributional measures between Member States
	R.6	**Diversification**	Lower diversification in the energy system due to dominance of low carbon options	Reduced resilience	L	Low - Moderate	Energy mix (Balance RES technologies and their applications)
Environmental & health	**R.7**	**Renewable energy technologies**	Technology specific environmental and health impacts associated with land use, water use, and increased material consumption	Reduced societal acceptance	S, M, L	Low - Moderate	EE, Resource efficiency, Life-cycle assessment, R&D
	R.8	**Grid integration**	Environmental impact of grid integration measures	Reduced societal acceptance	S, M, L	Moderate	EE, Resource efficiency, Life-cycle assessment, R&D

Natural Gas							
Risk Categories			Description	Potential Impact	Time Horizon	Risk Level	Mitigation Options
Policy & Regulatory	**G.1**	**BAU / "Bridge fuel" Scenarios**	Gas 'locked-in' or RES/EE 'locked - out'	Long-term climate goals undermined	L	Moderate - High	EE, RES (including renewable gas), CCS
Technical	**G.2**	**Failure / disruption of supplies**	Technical failure or disruption of critical infrastructure impacting gas flows in the short-term	Supply-disruption, Higher costs/prices	S	Low - Moderate	EE, RES substitution, Targeted supply-side measures
	G.3	**Under-investment**	Infrastructure under-investment in exporting or transit country	Supply shortfalls, Higher costs/prices	M, L	Low	EE, RES substitution, Targeted supply-side measures
	G.4	**Incomplete IEM**	Infrastructure bottlenecks prevent gas from being effectively distributed across EU	Increased SoS vulnerability to Russia in certain regions of the EU	S, M	Moderate	EE, RES substitution, Targeted supply-side measures
Geopolitical	**G.5**	**Import Dependence**	Risks from both source and transit countries, including supply disruption and use of natural gas pipelines to extract concessions	Supply shortfalls, Higher costs/prices, Increased vulnerability to Russia in certain regions of the EU	M, L	High	EE, RES substitution, Targeted supply-side measures
	G.6	**Long term contracts**	Long term (take-or-pay) contracts lock-in supplies from Russia and do not adapt quickly to changing market conditions	More difficult to diversify supplies	S, M	Low-Moderate	Monitoring by regulators for alignment with EU energy goals
	G.7	**Resource rents**	Higher imports of gas lead to larger financial flows and resource rents to producing countries	Negative externalities in gas producing countries, Support for autocratic regimes	M, L	Moderate-High	EE, RES substitution

Economic & social	G.8	**Import costs**	Declining domestic production and increased imports lead to substantial rise in import bill and potentially also gas prices	Current account deficits, reduced economic competitiveness	M, L	Moderate	EE, RES substitution, Increase in domestic production (ex. Shale gas)
	G.9	**Price volatility**	Price volatility of gas on international and regional markets	Volatile inflation and real disposable income, Higher cost of capital, Risk of misallocating resources	S, M, L	Moderate	EE, Financial instruments
	G.10	**Stranded assets**	Lower gas demand and nationally-administered SoS planning risk new LNG terminals and other import infrastructure becoming stranded assets	Higher costs for tax/rate-payers; Inefficient use of public funds to detriment of EE/RES	M, L	Low-Moderate	EE, RES substitution, Restricting use of public funds for LNG projects
Environmental & health	G.11	**Gas production**	Environmental & health risks linked to the extraction of gas resources, including seismicity, chemicals usage, water depletion, surface water quality, air quality, methane leakage, waste, landtake	Reduced societal acceptance	S, M, L	Moderate	EE, RES substitution, Further scientific study, Application of industry best practice and COM Recommendations
	G.12	**Supply chain losses**	Losses in supply chain due to energy consumption or leakage resulting in GHG emissions, including flaring (CO_2) and venting/fugitive emissisons (CH_4)	Long-term climate goals undermined; Increased environmental & economic cost	S, M, L	Moderate	EE, Application of industry best practice, Targeted measures to reduce methane leakage

Note: The time horizon categories refer to short-term (S) (2015-2025), medium-term (M) (2025-2035), and long-term (L) (2035-2050).

Figure 56: Risk categories by risk level and time horizon

Risk Level	Time Horizon: Short	Time Horizon: Medium	Time Horizon: Long
1 - Low	E.3	E.3 G.3	E.3 G.3
2 - Low-Moderate	R.7 G.2, G.6	E.1 R.4, R.7 G.6, G.10	E.1 R.4, R.6, R.7 G.10
3 - Moderate	R.8 G.4, G.5, G.9, G.11, G.12	E.2 R.1, R.5, R.8 G.4, G.5, G.8, G.9, G.11, G.12	E.2 R.1, R.2, R.5, R.8 G.8, G.9, G.11, G.12
4 - Moderate-High		R.3 G.7	R.3 G.7
5 - High		G.5	G.1, G.5

Note: Risk categories identified in Table 101. Blue = energy efficiency, Green = renewable energy, Orange = natural gas.

Source: Ecologic Institute

In comparing the risks across categories, a number of key observations can be made:

Energy efficiency

- In comparative perspective, energy efficiency is by far the lowest risk energy resource of the three. While distributional effects linked to the cost and impact of EE investments present a moderate risk in the medium- to long-term, only few risk categories with a low or moderate risk level were identified for EE. Furthermore, no significant risks could be identified for the technical and geopolitical risk categories. Overall, the risks associated with ambitious EE scenarios can be considered highly manageable when existing risk mitigation measures are applied.
- EE investments and ambitious EE scenarios as a whole produce a range of co-benefits that allow it to play an important role in mitigating risks for both RES and natural gas development across the full risk spectrum. EE measures, including both energy savings and demand response, should be strongly prioritized in mitigating risks for these energy resources through the application of the “efficiency first” principle in energy system planning and investment decision-making.

Renewable energy

- Eight risk categories were identified for ambitious RES scenarios, of which most were assessed at a low-moderate or moderate risk level and one at a moderate-high risk level. However, these risks must be viewed against the risk of late action in the context of climate change and carbon assets becoming "stranded" (i.e. unusable) in a decarbonized energy system. Furthermore, a comparison of risks across a broad range of risk factors reveals a lower cumulative risk level for ambitious RES scenarios than for BAU or high gas scenarios, especially for the categories policy and regulatory risks, geopolitical risks and environmental risks.
- The **temporal dimension** plays an important role in assessing risks linked to high RES scenarios, as the extent and nature of the risks depends strongly on the time horizon considered. For example, while some risks represent barriers to getting to high shares of RES and EE (ex. lack of an appropriate policy framework) and require risk mitigation in the short to medium term, others represent risks that appear once higher levels of RES penetration have been achieved (ex. grid integration) and largely emerge in the medium- to long-term. Others yet will see risk decline in the short-run, but increase in the long-run (ex. diversification). Overall, high RES scenarios are associated with greater cumulative risk in the long-term than in the short- to medium-term.
- The risk profile of ambitious RES scenarios is highly dependent on the overall **energy mix** and the mix of **RES technologies** in the energy system. A system with significant shares of CCS and nuclear will face other risks and challenges than one largely reliant on RES and EE and each renewable energy source has risks that are inherent to its specific technology (ex. environmental impacts). For example, the risk assessment indicates that scenarios with a high share of bioenergy have significantly more risks associated with them.
- While some RES risks are associated with traditional risk management strategies (ex. diversification and the development of substitutes to mitigate import dependence), others will require innovative solutions with uncertain outcomes (ex. market design). In this context, energy efficiency (including both energy savings and demand response) and resource efficiency measures represent low risk strategies that should be prioritized to guarantee risk mitigation at the lowest cost.

Natural Gas

- Twelve risk categories were identified for high natural gas, scenarios spanning across all risk levels and time horizons, with a particularly high concentration at the moderate risk level. Thus, it can be said that high natural gas scenarios have a comparatively higher cumulative risk level compared with high RES scenarios and a significantly higher cumulative risk level compared with ambitious EE scenarios.
- Demand-side measures, such as a high deployment of EE and RES can make a significant contribution to mitigating natural gas risks across the full spectrum of risk categories and should be strongly prioritized in EU and national infrastructure and risk mitigation planning. The European Commission scenario EE40 projecting a strong reduction in net gas imports in the medium-term could make a particular contribution to mitigating risks linked to gas, while also taking early action on climate change.
- Numerous studies highlight that the risk mitigation benefits of EE and RES are in part contingent upon the successful completion of supply side measures. For example, while Tóth (2015) assumes the implementation of a significant number of gas PCI projects, Energy Union Choices (2016) assumes varying degrees of gas and power infrastructure investments. As such, these low carbon options do not represent a risk mitigation strategy for natural gas on

their own. Mitigation of the full range of risks associated with natural gas will require additional measures, including new gas infrastructure investments. Nonetheless, prioritizing demand-side measures, taking into account long-term climate targets in system planning and targeting supply-side investments can ensure that the costs of risk mitigation are minimized, in particular in the medium- to long-term.

6. Conclusions and recommendations

In October 2014, the European Council adopted targets for reducing EU domestic green-house gas emissions by at least 40 % compared to 1990, increasing the share of renewable energy to at least 27 % of final energy consumption and improving the energy efficiency of the EU by at least 27 % by 2030 compared to a baseline scenario. As a consequence to these targets, European fossil fuel consumption is to decrease substantially. Particularly interesting is the role of natural gas: Although it has the lowest carbon factor of all fossil fuels and from a climate perspective preferable to other fossil fuels, a consequent decarbonisation of the European energy system will in the long run lead to a decreased gas demand.

Providing the European economy with natural gas to ensure energy security requires widespread and intertwined infrastructure consisting of pipelines, compressor stations, LNG terminals and many other components. Investments to the infrastructure are high and long-term. Some infrastructure investments receive public financing to promote energy security. At national, regional and European level network development plans look ten years into the future to estimate future gas demand, the need for infrastructure investments and identifying possibilities for public financing.

Analysing gas infrastructure planning at European level and for six focus countries (France, Germany, Italy, The Netherlands, Spain and the UK), **Section 2** of this study shows that none of the scenarios that are used for infrastructure planning is completely coherent with governmental goals for GHG emission reduction targets or low carbon options. Instead of basing infrastructure requirements on target scenarios that portray a pathway to reaching climate goals, gas development plans are based on reference scenarios that are not in line with climate and energy targets. Security of supply and functioning of markets are still the main considerations for infrastructure planning.

Gas demand scenarios that were used for network planning have frequently overestimated the gas demand in most of the focus countries. Looking on the trend of gas demand in the last years it seems that UK and Germany have used the most reliable scenarios. More recently, all the NDPs reacted to a reduced demand expectation with respective (lower) scenarios. However, a greater validity of gas demand forecasts seems necessary.

Section 3 of this study analyses **scenarios** incorporating a strong deployment of energy efficiency and renewable energy sources. While some of these scenarios estimate a stagnating gas demand in the medium term, all of them expect a shrinking natural gas demand to reach energy and climate goals in the long run. In all countries except Spain scenarios are available in which the use of natural gas would be reduced to a fraction of its current levels (approx. 10 %) or even phased out completely when energy and climate targets are reached or overachieved. At European level, estimated gas demand in 8 target scenarios is lower in 2030 compared to gas demand estimated in the TYNDP 2017 “Blue Transition”, with estimated savings ranging from 1 % to 43 % compared to TYNDP levels. However, the decline rates of capacity demand are expected to be smaller than those of (yearly) gas demand, depending on the usage of natural gas (e.g. power generation, heating, etc). The interrelationship between yearly and hourly demand needs to be examined further.

Assessing **import dependency, diversity and costs, Section 4** of this study shows that planned infrastructure projects lead to a greater diversification of import routes. However, changing gas production trends might increase market concentration and hence lead to respective (possibly more concentrated) gas flows over time. Import diversification is high for the countries analysed in this study, but low for Central and Eastern European member states that are often reliant on a single supplier. Some of the countries have high potentials for energy efficiency measures. Significantly increasing energy efficiency, especially in the building sector, and renewable energy sources can reduce the import dependency by reducing gas imports.

Linking yearly gas demand to capacity demand and ultimately natural gas infrastructure costs is complex. A detailed modelling of the gas network is necessary to ultimately decide over infrastructure investments. To understand the order of magnitude of monetary savings related to lower gas demand, a rough estimation has been made concerning savings in infrastructure expenditure and natural gas imports. The **sum of infrastructure expenditures** for advanced FID and PCI projects amounts to €69 bn, only a minor share of this is public money. Out of this sum, €30 bn (43 %) relate to expenditures categories “Big import infrastructure projects” and “Redundant with / parallel to existing infrastructure” which might be superfluous if target scenario were used for network planning. More importantly, **fuel import savings** associated with lower gas demand are ranging from €63 bn to €223 bn for the time period from 2020 to 2030. In comparison, investments needed to reach European climate and energy goals in 2030 are estimated to be €38 bn annually over a time period from 2011 until 2030 by the European Commission, translating to €722 bn of cumulated investments over the time period from 2011 to 2030. To sum up, significant infrastructure investment savings are possible when relying on target scenarios. Even higher fuel cost savings can be expected when gas demand is reduced in line with target scenarios.

Finally, **Section 5** of this study compares **key risks** associated with renewable energies, energy efficiency and natural gas usage in terms of different risk categories. Risks associated with energy efficiency are regulatory risks resulting from inadequate political ambition, economic and social risks associated with distributional effects and health and environmental risks stemming from a deployment of new materials. Renewable energies are associated with, among others, regulatory risks resulting from inadequate political ambition, technical risks concerning uncertainties in technical potential and grid integration, geopolitical risks in terms of electricity import dependence, economic and societal risks resulting from distributional effects and environmental risk resulting from higher land use. Natural gas is associated with the largest quantity of risks in all risk categories, varying from a regulatory risk such as a gas lock-in, technical risks in terms of supply disruptions, geopolitical risks such as import dependence and long term (take or pay) contracts, economic risks associated import costs and stranded assets and environmental risks linked to the extraction of gas. Member States or national regulators should monitor long-term contracts to ensure that in aggregate they are in line with medium- and long-term EU and national climate and energy goals.

Replacing fossil fuels (including natural gas) with renewable energies offers substantial reductions in the emissions of greenhouse gases and other pollutants, helping to reduce such environmental and health impacts as eutrophication, acidification, particulate matter, smog and other forms of toxicity. However, renewables also produce technology- and site-specific environmental effects that pose environmental risks and trade-offs, including raw material use, water consumption, damage to biodiversity and increased land use, which need to be addressed. Energy efficiency measures can play a crucial role in reducing the environmental impacts of all energy generating technologies, including renewable energy technologies and natural gas. In particular, energy savings increase the margin of security in peak hours and reduce the environmental impact of energy use throughout its entire life-cycle and contribute to reduced system requirements, generating substantial environmental and health benefits. Meeting the EU's energy efficiency goals will require targeted policies to improve the business case for energy efficiency investments that go beyond the largely voluntary approaches that exist on EU level.

Distributional impacts may require targeted social and labour policies and distributional measures to ensure public acceptance for low carbon technologies and infrastructure, in particular financial support for vulnerable consumers and job training measures for workers in disadvantaged sectors.

As a **general conclusion** gas network development processes need to take target scenarios into consideration if climate and energy targets are to be taken seriously. Current scenarios used in network plans do not reflect gas demand savings associated with renewable energy and energy efficiency measures appropriately. Natural gas can help supporting the transition to a low-carbon energy system in the short- to medium-term by displacing coal and providing back-up power generation to support a significant ramp-up of variable renewable energy sources. However, it remains a fossil fuel which use needs to be reduced to achieve the EU's goal of reducing greenhouse gas emissions. Monetary savings associated with lower gas demand result from avoided infrastructure investments and gas import savings. It is highly recommended to assess the risk of stranded investments, in particular where infrastructure projects receive public financing.

To achieve this, the following **recommendations** are given to policy makers and stakeholders:

- Network development plans should **show the effects of different scenarios** on gas infrastructure needs, and better consider the possibility of a decreasing gas demand, to be prepared for different possible developments. NDPs and their underlying demand scenarios are, in their current state, not based on the implementation of all necessary low carbon options to fulfil climate policy goals. Security of supply and functioning of the markets are still the main considerations for infrastructure planning.
- None of the **PCI** priority gas corridors highlight sustainability as a core aim. Projects are not required to contribute to sustainability to receive PCI status. In order to improve the adequate level of public spending stakeholder engagement in the selection and monitoring of PCI projects should be improved, especially for what concerns redundant or big import infrastructure projects in order to avoid stranded-investments.
- A strengthening of the mandate, resources and tools provided to **ACER** may be desirable to ensure the proper coordination of gas infrastructure at EU level. To ensure proper consideration of low-carbon options, the planning process should ensure earlier and broader stakeholder participation, and consistency of demand scenarios with long term European energy strategy.
- **Uncertainties and risks** associated with scenarios need to be considered in network development planning. Even though a high usage of natural gas is termed as a reference case, it is associated with large environmental, societal and geopolitical risks. Policy-makers should take measures to avoid locking-in the use of gas through an expensive overbuilding of capacity, as well as a locking-out of renewable energy sources. Uncertainties concerning technologies supporting high penetration of renewable energy must be considered when considering their potential role in the future energy system. By reducing the demand for infrastructure investments, strong energy efficiency policies can help to minimize these risks

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8. Annex

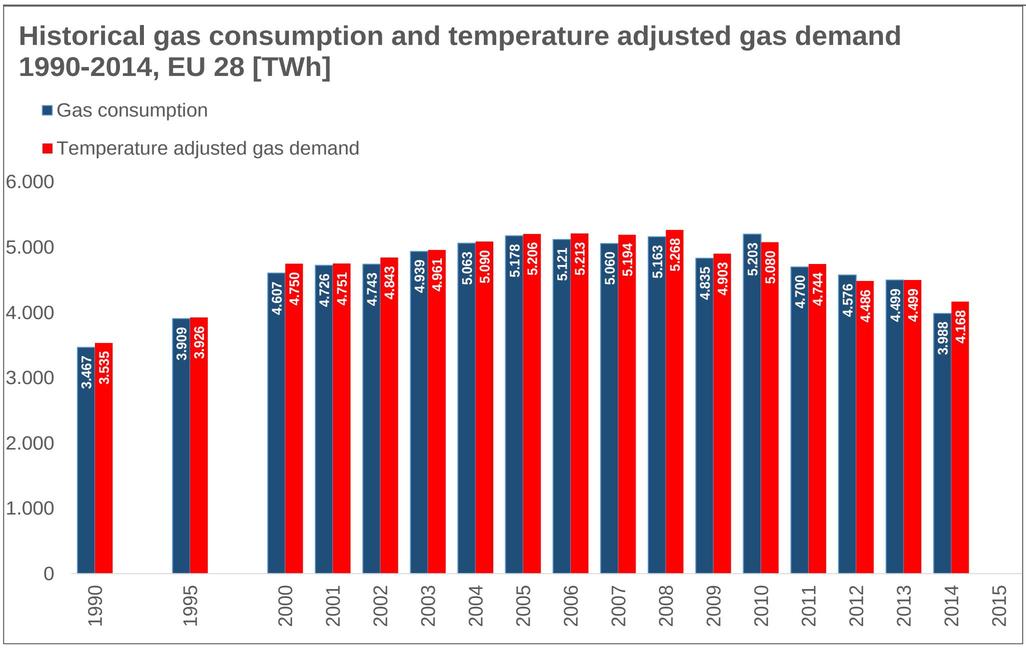
Table 102: Characterisation of the analysed demand scenarios – Europe

Study	Scenario	Scenario description	Target compliance
Reference Scenarios			
European Commission, EU Reference scenario, 2016	Reference 2016	Reference scenario of the European Commission 2016; Projection of trends up to 2050 assuming that policies adopted until end of 2014 are implemented	Only 2020 targets of GHG emissions, RES are reached
European Commission, Trends to 2050, 2013	Reference 2013	Reference Scenario of the European Commission 2013; Projection of trends up to 2050 assuming that policies adopted until spring of 2012 are implemented	Only 2020 targets of GHG emissions, RES are reached
Scenarios with measures and targets			
EU Comission, Impact Assessment, 2014	EE27	Part of the impact assesment for the energy efficiency directive; Modelling with a binding energy efficiency target of -27% in 2030 in the Member States	Nearly all 2020/ 2030 targets are reached
ICCS, E3M Lab, PRIMES modelling for the Impact Assessment, 2014	EE30EC_a	Part of the impact assesment for the energy efficiency directive; Modelling with a binding energy efficiency target of -30% in 2030 in the Member States	Nearly all 2020/ 2030 targets are reached
ICCS, E3M Lab, PRIMES modelling for the Impact Assessment, 2014	EE40EC_a	Part of the impact assesment for the energy efficiency directive; Modelling with a binding energy efficiency target of -40% in 2030 in the Member States	Nearly all 2020/ 2030 targets are reached
European Comission, Energy Roadmap 2050, Impact assessment, 2011	High RES	Decarbonisatoin scenarios (80% GHG reductions by 2050) from the European Commission; HIGH RES is a scenario with a very high overall RES share and very high RES penetration in power generation	Nearly all 2020/ 2030 targets are reached
IEA, Word Energy Outlook 2015	450 Scenario	Scenario from the World Energy Outlook of the IEA that reaches a pathway consistent to the 2° climate goal	All targets except 2020 RES, EE targets are reached
Ambitious scenarios with measures and targets			
Greenpeace, Energy [r]evolution - a sustainable world energy outlook, 2015	energy [r]evolution	Very ambitous target scenarios, this scenario reaches about 90% GHG emission reduction in 2050 without CCS and nuclear	All targets except 2020 RES, EE targets are reached or exceeded
	advanced energy [r]evolution	Scenario that reaches 100% GHG emission reduction in 2050 and 100 % renewable energy supply	All targets except 2020 RES, EE targets are reached or exceeded

Source: Prognos based on [EC 2016], [EC 2013], [E3M 2014], [EC 2011], [IEA 2015], [Greenpeace 2015]

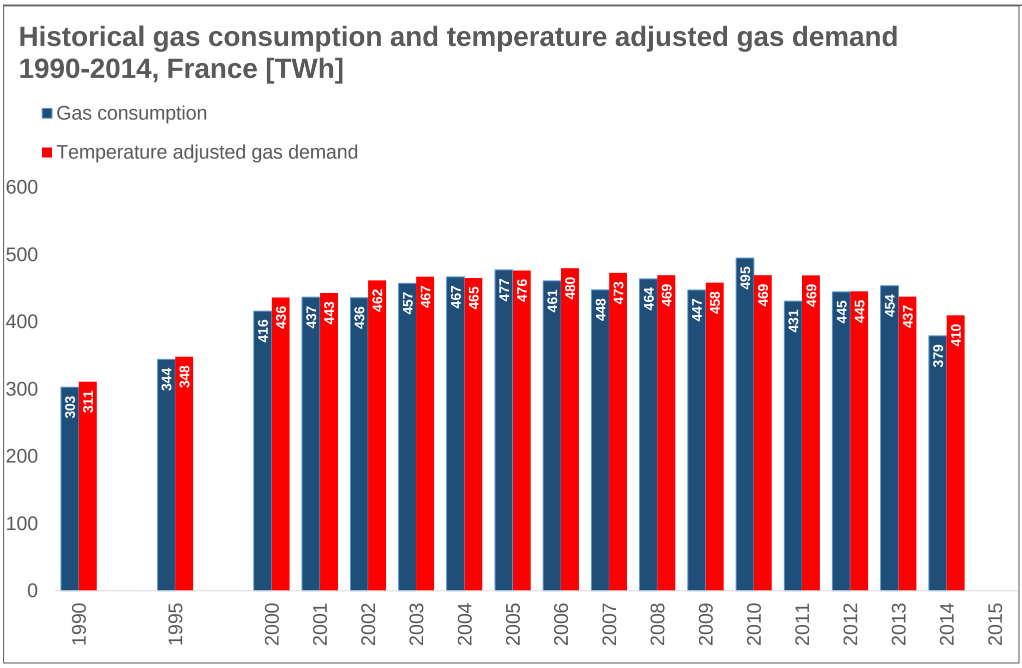
8.1 Additional Graphs

Figure 57: Temperature adjusted gas demand 1990-2014 – EU 28



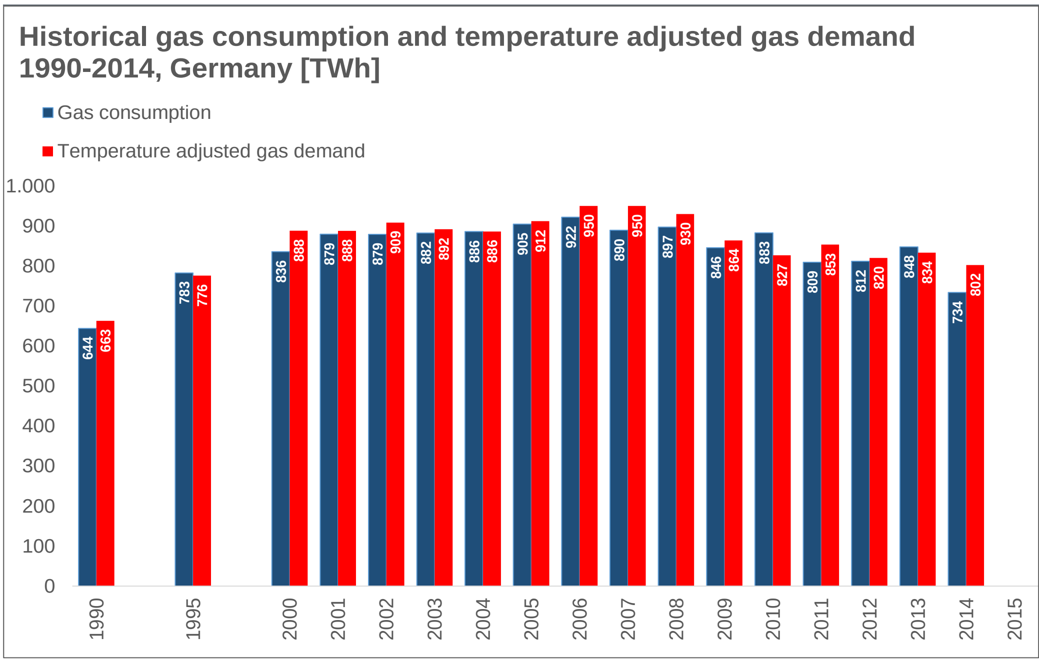
Source: [Eurostat 2015]

Figure 58: Temperature adjusted gas demand 1990-2014 – France



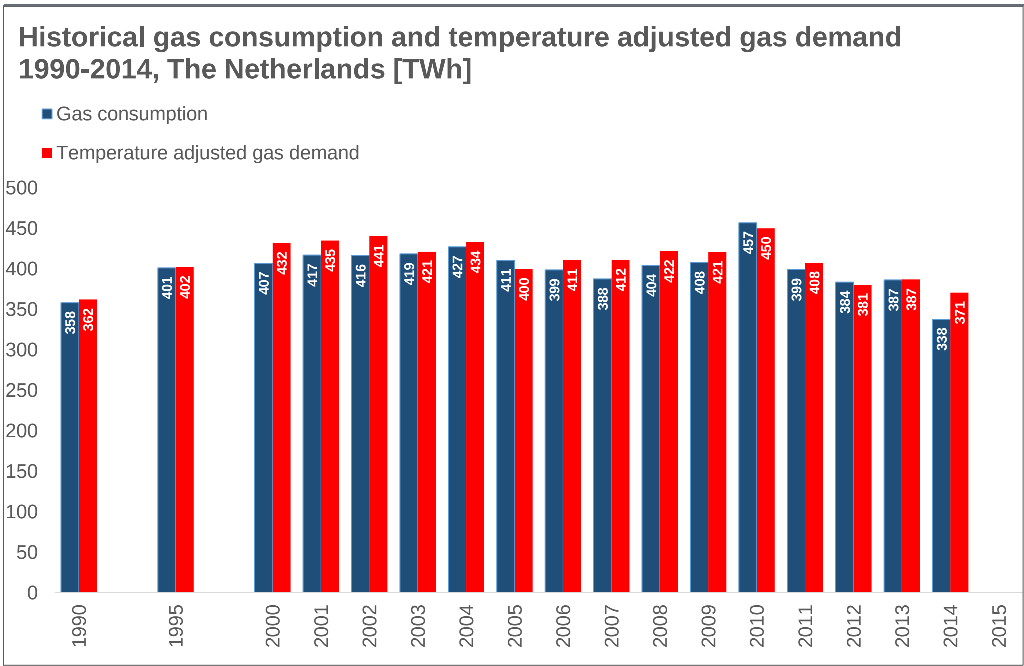
Source: [Eurostat 2015]

Figure 59: Temperature adjusted gas demand 1990-2014 – Germany



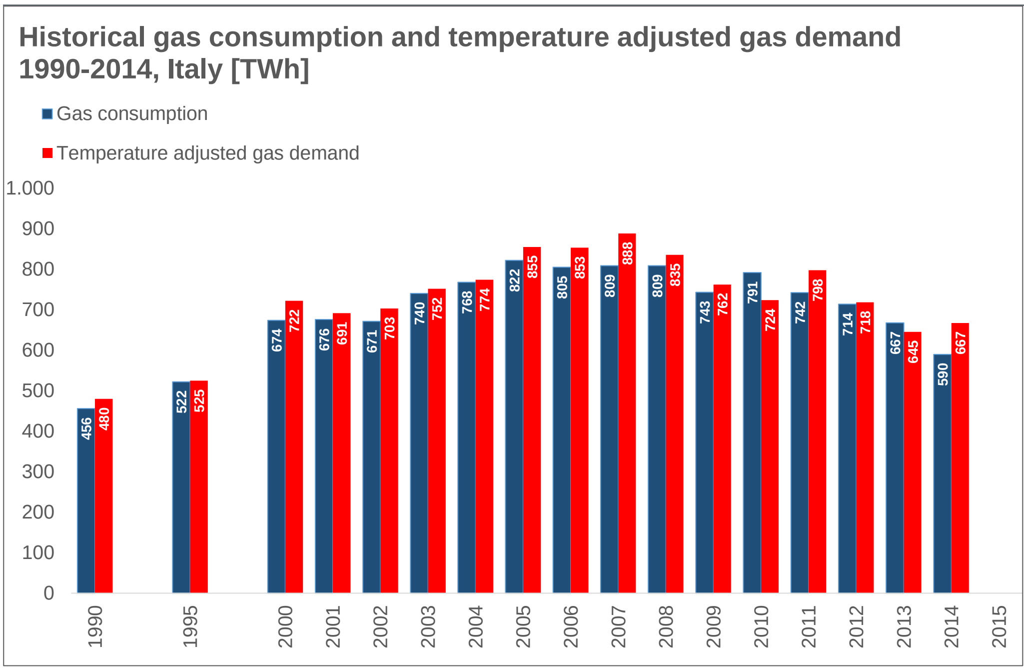
Source: [Eurostat 2015]

Figure 60: Temperature adjusted gas demand 1990-2014 – The Netherlands



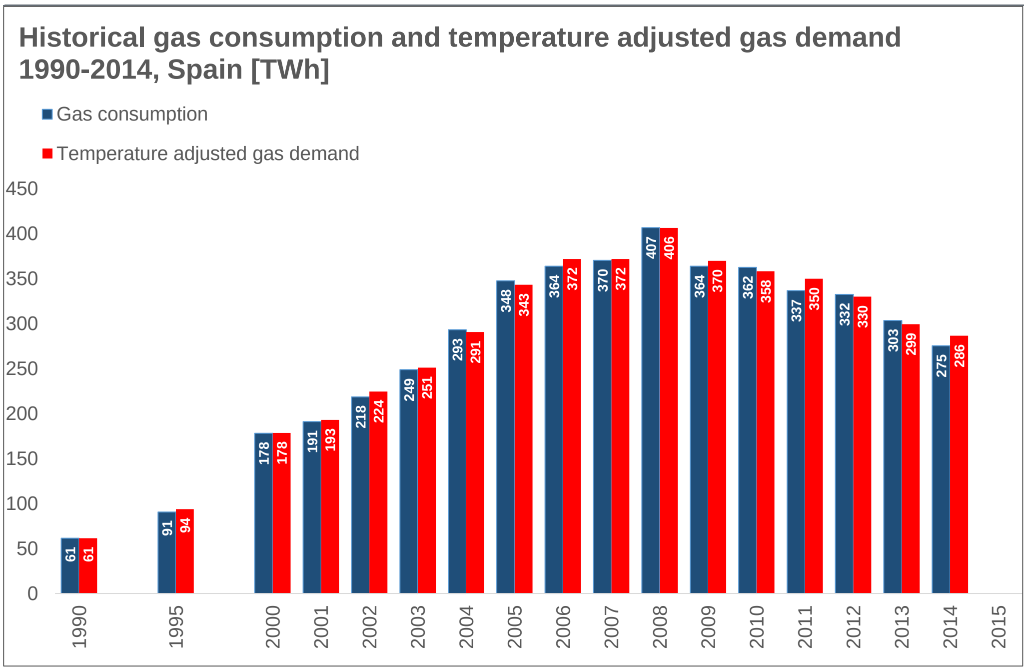
Source: [Eurostat 2015]

Figure 61: Temperature adjusted gas demand 1990-2014 – Italy



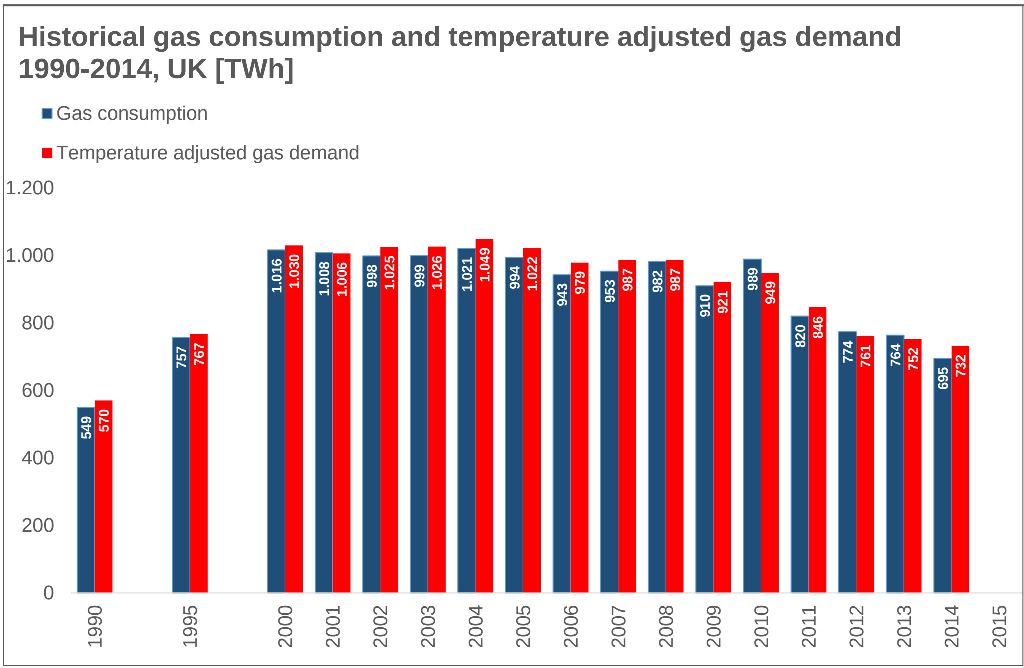
Source: [Eurostat 2015]

Figure 62: Temperature adjusted gas demand 1990-2014 – Spain



Source: [Eurostat 2015]

Figure 63: Temperature adjusted gas demand 1990-2014 – United Kingdom



Source: [Eurostat 2015]

8.2 Workshop documentation

Low carbon options and gas infrastructure: The impact of energy efficiency and renewables on EU gas demand and infrastructure planning

When: Thursday, September 15, 2016 from 10:00 a.m. to 4:00 p.m.

Where: Representation of the State of North Rhine-Westphalia to the EU in Brussels

Who: Participants from National Administrations, Regulatory Bodies, Gas Transmission System Operators, KOM, NGO, Civil Society, Scientists

The upcoming decisions on the development of the European gas infrastructure must be based on solid data and reflect the EU's long-term climate & energy policy objectives. Among others, they should take into account the growing impact of energy efficiency and renewables deployment on gas demand, the EU's goal of reducing greenhouse gas emissions by 80-95 % by 2050 compared to 1990 levels, as well as the goal to limit global warming well below 2 °C, if possible to 1.5 °C, in line with the Paris Agreement. Although natural gas is the fossil fuel with the lowest carbon factor, in the long run a consequent decarbonisation of the European energy system will lead to a decreased gas demand. Deployment of renewables and energy efficiency improvements have contributed to the significant decline of gas demand in recent years in the EU.

- Do the demand scenarios underlying today's gas infrastructure planning take these trends adequately into account?

- To what extent can a consistent implementation of the EU's climate and energy targets contribute to reduce the EU's gas import dependency and future gas infrastructure costs?

These are the core questions of a study that Prognos AG and Ecologic Institute are undertaking on behalf of the German Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety with the aim of providing recommendations to policy-makers.

This expert workshop was held to present the intermediate results of the study and featured a discussion of the key questions of the study among relevant stakeholders, including gas TSOs, regulators, government, civil society and academia. The discussion was held in English under the Chatham House rule and was moderated by *Jens Hobohm, Partner and Deputy Director of Prognos AG*.

Introduction

The workshop began with an introduction to the project by *Jens Hobohm*. A focus was placed on framing the context for the discussion, in particular highlighting the significant decline in gas demand in the EU since 2010 against the backdrop of a changing gas supply picture. This changing demand and supply landscape makes it crucial that the EU make the right investment decisions to achieve a successful transformation of the energy system.

Session 1: Gas infrastructure planning at EU and regional level: process analysis, review of shortcomings and recommendations

This session featured a presentation by *Andreas Graf (Ecologic Institute)* on the key findings of an analysis of the key processes for gas infrastructure planning in Europe (TYNDP, GRIPs, PCI selection, NDPs) based on interviews and desk-research. A key focus of this analysis is a review of shortcomings concerning the public availability of information, the overall transparency of the process and the sufficiency of stakeholder involvement. The presentation focused mainly on the findings and recommendations concerning the EU TYNDP 2015, the consistency of the NDPs with European goals and the PCI selection process. Core questions guiding the discussion included:

- What role has process played in the overestimation of gas demand in previous TYNDP and NDP scenarios?
- Does the EU need stronger sustainability criteria in network planning, PCI selection and public funding decisions (ex. energy efficiency first?)
- Do we need to strengthen the mandate, resources and tools (ex. additional modelling capabilities) provided to ACER to ensure the proper coordination of gas infrastructure planning at EU level?

Conclusions/Recommendations from Discussion:

- Gas infrastructure planning processes should:
  - Proactively engage NGOs in the stakeholder processes for gas infrastructure due to its perceived complexity
  - Improve transparency of the consultation processes.
  - More strongly include demand side expertise (i.e. experts on heating markets)
  - Take into account a long-term perspective beyond the current 10-20 year assessment framework (ex. 2050) when making infrastructure planning decisions to assess lock-in.

  - Increase the transparency of the modeling done for the TYNDP, GRIP and NPD processes in terms of both input/ output data in order to make it easier to verify and check results.
  - More strongly integrate environmental considerations in the PCI selection process (i.e. “Efficiency First”), for example, by opening the projects eligible for funding under the gas PCI priority corridors to demand side projects, better taking into account sector coupling (electricity and gas) or integrating demand response into the CBA of gas infrastructure planning, as is already happening in the US.
- The study should:
  - Provide a more detailed assessment of why the overestimation took place.
  - Take into account institutional factors, such as how do different market designs require different infrastructure.
  - Update the findings of the report on TYNDP 2015 to take into account the stakeholder process of the TYNDP 2017, which sees various improvements.

One participant suggested to move away from a strict focus on gas infrastructure vs. EE + RES to highlight the big picture, including coal and nuclear, the role of renewable gas, as well as the cost of increased electricity infrastructure as a result of renewable energy deployment.

Remark by Prognos/Ecologic: This was not the task of the study.

Session 2: Gas infrastructure planning in selected Member States: scenario analysis, review of shortcomings and recommendations

This session featured a presentation by *Hanno Falkenberg (Prognos AG)* on scenarios used for gas infrastructure planning in the EU TYNDP and the NDPs of the six target countries of the study (France, Germany, Italy, the Netherlands, Spain, the United Kingdom). In particular, the presentation provided a historical analysis of gas demand in each of the selected countries and compared these to scenarios used for National Development Plans. The analysis reveals that while there was a large increase in gas consumption in much of Europe between 1990-2000, gas demand was stagnant or slowly increased from 2000-2010 and has mostly decreased since 2010 (esp. transformation and residential sectors). At least since 2010, forecasts have consistently over-estimated actual gas consumption. The assessment also reveals that there is generally little consistency between the scenarios used for network planning and the renewable energy and energy savings targets for the individual countries, i.e. these targets have not or not to their full extent been considered in the network planning processes. Core questions guiding the discussion included:

- **Historical trend:** Can we expect the historical reduction of natural gas demand to be long-lasting? What effect will electrification, energy savings and renewable energy use have on gas consumption?
- **Scenarios used:** What type of scenario should be used for network planning: A most likely scenario or one reflecting current policies?
- **Validation NPD scenarios:** What validation measures do we have in NDP processes and should they be strengthened?

Summary of discussion:

- ENTSOG does not see its scenarios as forecast, but rather as possible development pathways.
- Some participants argued that the main variables influencing a gas demand underperformance have been framework variables such as the clean spark spread, low ETS prices and other economic factors unrelated to RES and EE. Moreover, the development of gas demand, especially in power generation, is very volatile. For example, in France gas demand increased in 2015 by 15 % in the transformation sector. Other participants, however, argued that process is a key reason for the overestimation, as the current TYNDP are focused on the short- to medium-term, while only a long-term perspective allows to assess lock-in effects.
- The TYNDP 2015 has a stronger focus on the power sector and transport sector and was weaker on the heating sector. However, for the TYNDP 17 and 18, ENTSOG is digging more deeply into the heating sector, especially on the role of heat pumps.
- The need for an adequate plausibility analysis was raised in regard to pricing. In particular, the assumption in the TYNDP 2015 that gas prices will go down by 20 % from 2015-2020 and that hard coal prices would increase by 80 % until 2030 were questioned. CO_2 prices projections were also considered too high.
- It was highlighted that there is a clear difference between the number of pipelines planned and the number realized, i.e. there are many more projects in the TYNDPs than are built. How large should this ratio be?
- Some stakeholders highlighted that infrastructure is not only necessary for gas demand but also for competition and security of supply. Therefore, an integrated view on the wealth gains from energy security is also needed to fully assess infrastructure needs. However, one stakeholder highlighted that the value of oversized infrastructure for energy security should by calculated at the European, not the national level, as it is a shared competence.
- The role of gas storage - especially to cover peak gas demand - was discussed. It was stated that Europe is already well supplied with storages. One participant argued that TSOs are private operators and one should not limit investments they wish to make with their private money when a need has been identified by market actors. Therefore, there is no need for a “top down” process to determine infrastructure needs. Another participant, however, questioned whether it can be assumed that companies will truly only build pipelines that are needed. Currently, market players help determine whether a pipeline is built, but are only obligated to order capacity for a period of a few years. Further it should be borne in mind that the costs for their investments are passed on to customers in the form of grid charges.
- One participant suggested, that the money for projects should first be collected before the project is included in the plan, not the other way around. This might ensure the viability of the project.
- It was highlighted that the type of scenarios used for infrastructure are different between NDP and need to be distinguished (indicative vs. normative scenarios). It was questioned if network planning shall anticipate the outcome of political decisions?

Recommendations

- A top-down infrastructure needs assessment may be necessary. Scenarios with long-term target achievement should be reviewed to see which projects are still viable under these assumptions.
- Storylines for the TYNDP process should be translated into targets, both on the national level, as well as for the aggregate level in the long-term (ex. 2050).
- The historical overprediction of gas demand raises questions about the need for the regulator to be more strongly included in demand scenario validation.

Session 3: Further scenario analysis with a special focus on the impact of EE and RES on gas demand and initial thoughts on infrastructure cost implications

This session featured a presentation by *Eva-Maria Klotz (Prognos AG)* on analysis of reference and target scenarios for the six target countries and the EU TYNDP. In particular, the assessment highlighted the expected development of EE and RES in the scenarios over time, the relationship between the deployment of EE and RES and gas demand, as well as the relationship between overall gas demand and peak gas capacity demand. Core questions guiding the discussion included:

- What is the relationship between gas demand and peak capacity demand for final energy
- How high is the potential to decrease peak gas demand even further (e.g. integrated approaches)?
- What is the interrelationship between peak gas demand and cost?

Summary of discussion:

- In some regions average peak gas demand is declining faster than yearly demand due to changing gas use
- Today's peak gas demand in TYNDP and the winter outlook/review is calculated based on expertise from national TSOs.
- Currently the factor between the average and peak gas demand is 1:7-10 mainly due to temperature variations between summer and winter. For some member TSOs this calculation is derived from a standardized calculation based on yearly demand. For the EU level, ENTSOG takes the peak demand from the Member TSOs and sums it up.
- Large regional variations in the development of infrastructure needs exist making it difficult to make broader statements about developments for the EU as a whole or even for regions within a country. Some regions may still have this growing demand, while other areas might have a decline. A regional perspective is needed on peak demand.
- If there are investments that might not be needed in the medium to long-term, is there a way to model the system in a way that allows certain pipelines/projects to be deleted from the list?

Recommendations:

- A regional perspective is needed on peak demand.
- The study should include analysis and an explanation of the specific factors leading to a movement from high gas (capacity) demand in the medium-term to low gas (capacity) demand in the long-term for the Greenpeace scenarios.
- The study should take a closer look at the potential to decrease peak demand through integrated approaches/sector coupling (ex. Energy Union Choices), while also bearing in mind the investment costs of electrification of the heating system. Overall system costs of alternative scenarios should be included.
- The study should take a closer look at the impact of energy efficiency on peak demand/infrastructure costs – what impact does demand response have on peak loads?

Session 4: Promoting energy security through high EE and RES pathways: a comparative discussion of risks for EE, RES and natural gas

This session featured a presentation by *Andreas Graf (Ecologic Institute)* on the results of a draft comparative risk assessment of risks associated with high EE, high RES and high natural gas scenarios. The assessment reviews a wide variety of risks, including policy & regulatory risks, technological risks, geopolitical risks, economic & social risks and environmental risks. Key preliminary conclusions highlight the low comparative risk profile and clear risk mitigating benefits of energy efficiency. The risks for ambitious RES scenarios are more substantial than those for EE, but have a lower cumulative risk level than for BAU or high gas scenarios. Mitigation of the full range of risks associated with natural gas will require additional measures, including new gas infrastructure investments. However, these investments must be targeted and demand-side measures clearly prioritized. Core questions guiding the discussion included:

- How and where can energy efficiency be best integrated into EU gas infrastructure planning processes to make best use of its risk mitigating properties?
- What/where are the limits to demand side measures in reducing risks for RES and natural gas?

Summary of discussion:

- A risk assessment should not only look at energy dependency, but rather also energy independence. Increased energy independence could have important foreign policy benefits in terms of flexibility in dealing with difficult resource exporting countries.
- In order to better incorporate EE as a resource we need to begin by assessing where there is a significant cost-effective potential that is not being delivered and to start thinking about EE as infrastructure. Such assessments are already being performed in integrated planning in the US. While TSOs in Europe are unbundled, the EU could use other instruments such as Energy Efficiency Obligations to ensure the value of EE is incorporated into investment decision-making. Moreover, instruments such as geotargeting (identifying specific areas of congestion and growth through GIS supported tools) could allow for a more targeted approach in CBA for new investments supported by European funds.

Recommendations:

- Risks linked to biomass need to be separated from hydrogen in the assessment
- Health & Safety Risks should be added in the assessment.

Table 103: Workshop Agenda

9.30 –10.00	**Registration**
10.00 –10.05	**Welcome** Susann Schwarze, Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety, Germany
10.05 – 10.20	**Opening remarks and introduction of the project "Low carbon options and gas infrastructure: Chances of efficiencies and renewable energies for gas infrastructure planning and security of supply in Europe"** Jens Hobohm (Prognos AG)
10.20 – 11.20	**Gas infrastructure planning on the EU and regional level: process analysis, review of shortcomings and recommendations** Presentation by Andreas Graf (Ecologic Institute) followed by discussion
11:20 – 11:30	**Coffee Break**
11:30 – 12:30	**Gas infrastructure planning in selected Member States: scenario analysis, review of shortcomings and recommendations** Presentation by Hanno Falkenberg (Prognos AG) followed by discussion
12.30 – 13.30	**Lunch Break**
13.30 – 14.40	**Further scenario analysis with a special focus on the impact of EE and RES on gas demand and initial thoughts on infrastructure cost implications** Presentation by Eva-Maria Klotz (Prognos AG) followed by discussion
14:40 – 14:50	**Coffee Break**
14:50 – 15:50	**Promoting energy security through high EE and RES pathways: a comparative discussion of risks for EE, RES and natural gas** Presentation by Andreas Graf (Ecologic Institute) followed by discussion
15.50 – 16.00	**Closure and next steps** Jens Hobohm (Prognos AG)

Table 104: List of participants of the international workshop
held September 15, 2016 in Brussels

1	Anagnostopoulos	Filippos	Buildings Performance Institute Europe (BPIE)
2	Bayer	Edith	Regulatory Assistance Project (RAP)
3	Bryan	Katharina	European Court of Auditors
4	Castro Agra	Maria	Enagás
5	Dufour	Manon	E3G
6	Enriquez	Abel	Enagás
7	Falkenberg	Hanno	Prognos AG
8	Garcia	Delphine	GRTgaz Deutschland
9	Gareis	Nina	European Commission DG ENERGY
10	Giuli	Marco	European Policy Centre (EPC)
11	Graf	Andreas	Ecologic Institute
12	Gras	Sebastian	European Commission DG ENERGY
13	Greulich	Stefan	European Network of Transmission System Operators for Gas (ENTSOG)
14	Groschoff	Jan	Federal Ministry for Economic Affairs and Energy (BMWI)
15	Heidrecheid	Céline	European Network of Transmission System Operators for Gas (ENTSOG)
16	Hobohm	Jens	Prognos AG
17	Klotz	Eva-Maria	Prognos AG
18	Luebbeke	Imke	WWF
19	Maes	Tom	Commission de Régulation de l'Electricité et du Gaz (CREG)
20	Muhlke	Robert	GRTgaz
21	Piria	Raffaele	Adelphi
22	Roche	Colin	Friends of the Earth Europe (FoEE)
23	Rososinska	Barbara	Regulatory Assistance Project (RAP)
24	Purontaus	Eero	Coalition for Energy Savings
25	Schwarze	Susann	Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety (BMUB)
26	von Hirschhausen	Christian	TU Berlin and DIW

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Imprint

Low Carbon Options and
Gas Infrastructure

Chances of efficiency and renewable energies for gas infrastructure planning and security of supply in Europe

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