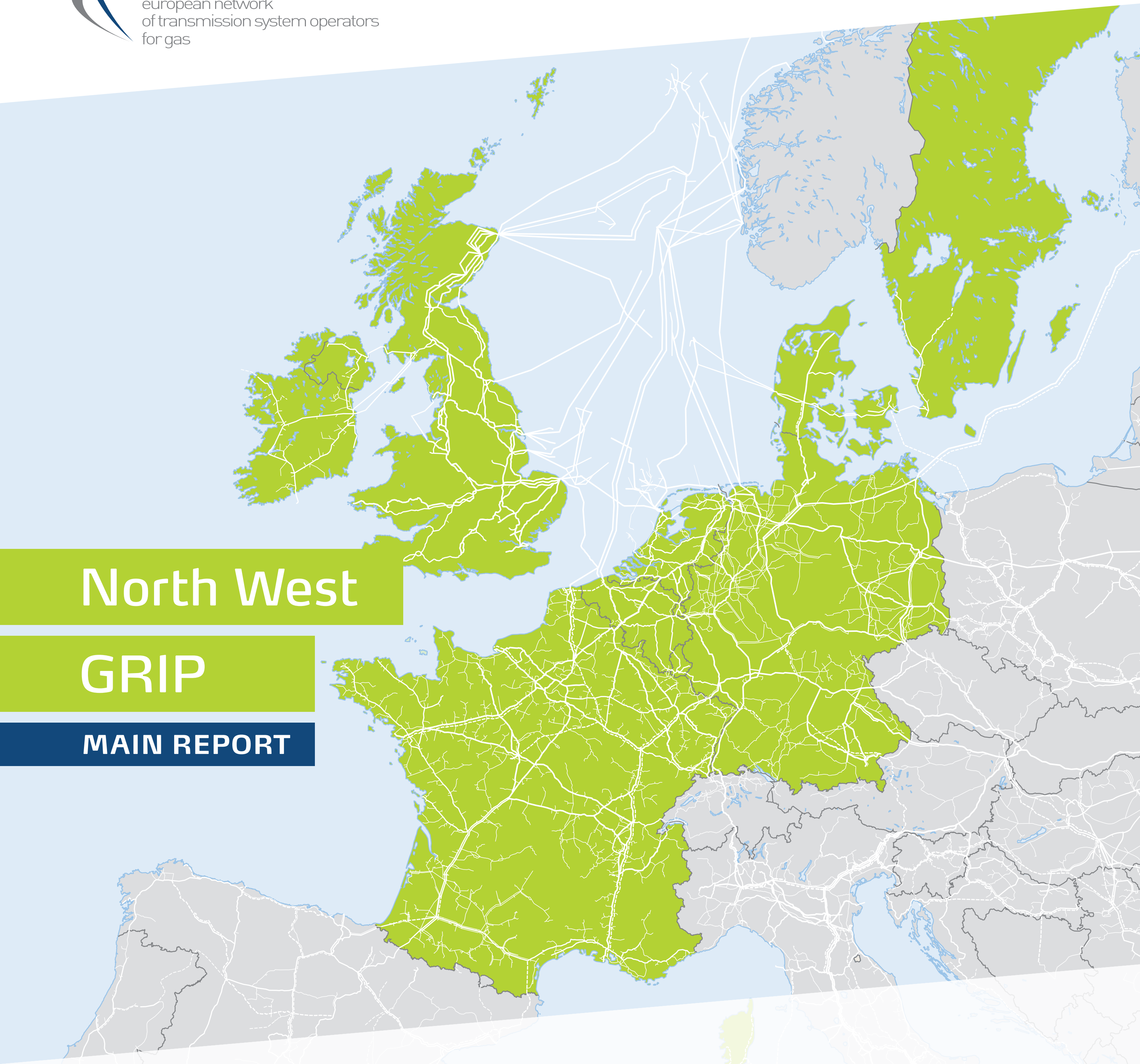
entsog
european network
of transmission system operators
for gas

GAS REGIONAL INVESTMENT PLAN 2017



North West

GRIP

MAIN REPORT

Table of Content

Foreword

It is our pleasure to welcome you to the third edition of the North West Gas Regional Investment Plan (NW GRIP).

The NW GRIP is the result of close cooperation between the Transmission System Operators (TSOs) in the nine countries which are covered in the North West GRIP Region (NW Region). This continued cooperation between the TSOs has spanned the past few decades, and is evident in the day-to-day operations of the gas network and in the well-functioning gas market in the NW Region.

The 2017 edition of the NW GRIP builds on the previous editions of the NW GRIP and also complements the ENTSOG Ten-Year Network Development Plan 2017 (ENTSOG TYNDP 2017) published in December 2016. Specific attention is paid to energy transition and the role of gas in a sustainable society, and to low calorific gas in the NW Region in order to support a PCI (Project of Common Interest) application for associated L-gas to H-gas conversion infrastructure projects.

The coordination of this document was facilitated by Fluxys and Gasunie Transport Services (GTS).

The NW GRIP working group will be launching a post publication consultation on the NW GRIP and welcomes further comments from stakeholders, which could improve future editions of the document.

We hope that you will find the document useful and enjoy reading it.

Pascal De Buck

Managing Director & CEO,
Fluxys

René Oudejans

Interim CEO,
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Executive summary and conclusions

The 3rd Gas Regional Investment Plan for North West Europe (NW GRIP) contributes to the fulfilment of tasks listed in the European Directive 2009/73/EC Article 7 and Regulation 715/2009 Article 12. Special attention is paid to energy transition with potential pathways for the gas markets and gas infrastructure in the NW Region towards a sustainable future. Starting from recent political developments like the Paris COP21, the role of gas and the related transmission infrastructure is developed for the energy transition required to achieve the targeted greenhouse gas (GHG) emission reductions.

The report starts with a general overview of the role of gas and gas infrastructure in the NW Region in chapter 2, highlighting the different characteristics of energy transport via gas and electricity.

In chapter 3 an overview is presented of policies and targets for the energy transition on an EU level and for the different Member States of the NW Region. Additionally, a selection of key projects and initiatives undertaken by the NW Region TSOs, together with other stakeholders in the energy sector, are highlighted which are designed to pave the way for a sustainable future. An important role is foreseen for the development of new technologies that enable a physical and virtual coupling and integration of the EU energy systems for electricity, gas, heating and mobility infrastructure. The use of the existing gas infrastructure allows for an intelligent sector coupling and helping the envisaged decarbonisation in an economically efficient and technically achievable way which a single energy infrastructure will not be capable of. Specific topics covered in this chapter relate to sector coupling on the basis of green mobility, gas fired combined heat & power and hybrid heating, but also to the development of green gases and energy efficiency measures in gas transmission.

As can be seen in chapter 4, the Northwest European gas market is functioning well and includes the most liquid hubs in Europe. Market integration has further evolved with the successful mergers of hubs between Belgium and Luxembourg, and in the South of France. Interconnections are well developed between hubs and prices are converging, with the notable exception of the TRS hub in the South of France where prices can reflect current physical bottlenecks.

The NW GRIP is based on the same dataset as the ENTSOG Ten-Year Network Development Plan 2017 (ENTSOG TYNDP 2017) and the scenario storylines identified therein. Chapter 5 identifies how demand for gas could develop in the NW Region according to these storylines. All scenarios show a stable to decreasing evolution for total gas demand, although an increase in the power generation sector is expected in some of the scenarios, especially in terms of peak demand. Due to the pronounced decrease anticipated for the NW Region's indigenous production, the dependence on imports from outside the NW Region and Europe as a whole will continue to grow, indicating the need for additional infrastructure. A potential major supply increase to the NW Region could be implemented through the Nord Stream 2 project.

Chapter 6 takes a deep dive in the ENTSOG TYNDP 2017 network assessment, highlighting specific results for the NW Region.

The anticipated decline of L-gas production provides the most pressing investment requirement for the NW Region. As the only region where L-gas is produced and consumed, the announced phasing out of the Groningen field and the decline of the German L-gas production will require considerable infrastructure investments to allow the L-gas to H-gas market conversion in large parts of Belgium, France and Germany. In chapter 7 a dedicated overview is presented of these markets, which are soon to be converted and the specific infrastructure adaptations required to achieve this.

For the first time, a specific regional analysis on the conversion of L-gas markets to H-gas has been implemented as an add-on to the European-wide assessment in the ENTSOG TYNDP 2017.

Based on the same data set, completed with specific L-gas data collected by the NW GRIP TSOs, and a comparable methodology to the ENTSOG TYNDP 2017, a supply adequacy analysis has been performed for the current L-gas regions. This includes the development of specific CBA indicators that can form the basis for potential future PCI applications regarding L-gas to H-gas conversion projects. The results of chapter 8 underpin the need for an L-gas to H-gas conversion of the concerned markets in a coordinated way according to the announced decrease of the L-gas production in the NW Region.

Finally, chapter 9 of the NW GRIP is dedicated to planned country-specific infrastructure development over the coming years. This includes descriptions of recent developments and the progress of major market and network development projects presented in the last NW GRIP edition.

Image courtesy of Fluxys

1 Introduction

Image courtesy of ONTRAS

This is the 3rd Gas Regional Investment Plan produced by gas Transmission System Operators (TSOs) of North West Europe. This NW GRIP covers gas infrastructure projects and analysis from the following countries: Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Sweden and the United Kingdom.

It is a legal obligation for TSOs, based on the European Directive 2009/73/EC Article 7 and further detailed by the European Regulation 715/2009 in Article 12, to publish a Gas Regional Investment Plan. This NW GRIP will contribute to the fulfilment of tasks listed in the Gas Directive and Gas Regulation. TSOs will publish a GRIP based on regional cooperation every two years.

This NW GRIP builds on the Ten-Year Network Development Plan 2017 produced by the European Network of Transmission System Operators for Gas (ENTSOG TYNDP 2017) and existing National Plans within the NW Region.

The NW GRIP covers in detail two topics of high relevance for infrastructure development in the NW Region. These are:

- Energy transition towards a sustainable future
- Low-calorific gas

Furthermore, the underlying NW GRIP focuses at regional level on:

- Market developments in the NW Region
- Supply and demand evolution
- The results identified in the ENTSOG TYNDP 2017
- North West European Infrastructure developments

The NW GRIP TSOs hope that this document will help to assess the need for gas infrastructure in the NW Region and provide useful information to all stakeholders.

2 The role of gas and gas infrastructure in the NW Region

Image courtesy of Terranets

The share of gas in the gross energy consumption varies considerably per country, as illustrated in the figure below. Despite a slight reduction, averaging at 2.5 percentage points, in the total gas share compared to the previous edition of the NW GRIP, the figure nevertheless highlights the important role gas still plays within the NW Region.

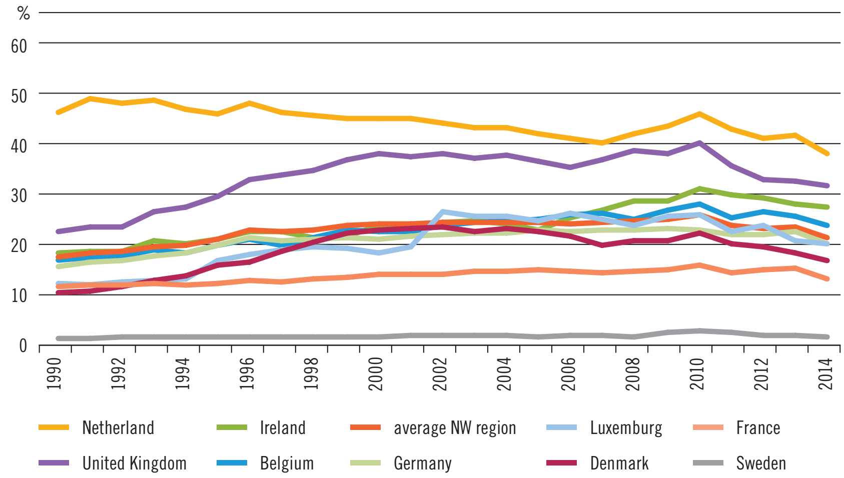


Figure 2.1: Gas share in Gross Energy Consumption (Source: Eurostat)[1)]

The European energy system is changing as politicians have agreed on climate and energy goals in order to achieve a low-carbon energy system. In spite of having the most climate friendly profile of the fossils fuels, emitting 50 to 60 % less CO_2 when combusted in a new, efficient natural gas power plant compared with a new typical coal plant[2)], the figure below illustrates that natural gas has not been able to displace coal consumption significantly. The explanation is to be found in low coal prices combined with little incentive to reduce carbon emissions, i. e. low CO_2 prices, resulting in coal remaining ahead of gas in the merit order.

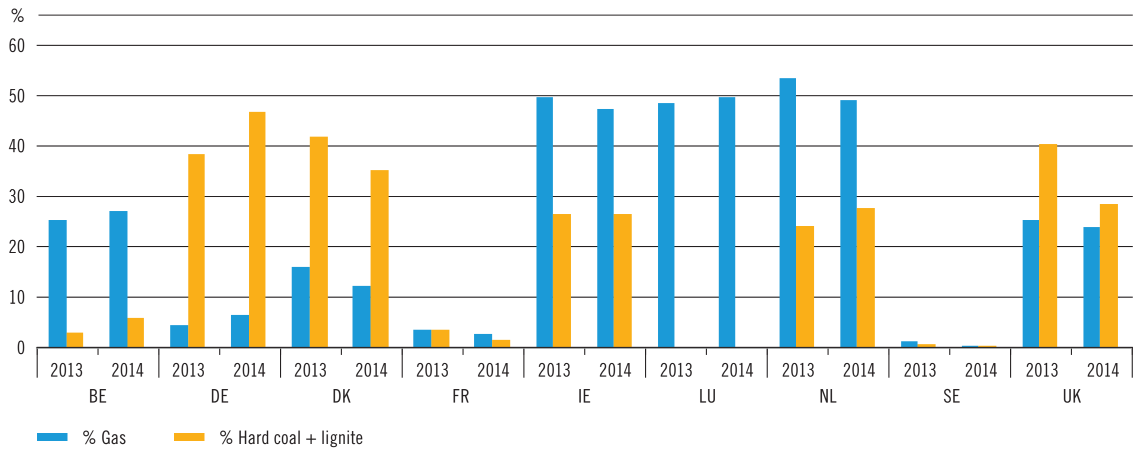


Figure 2.2: Share of Gas and Coal in Power Generation Fuel Mix in 2013 and 2014
(Source: Yearly Statistics & Adequacy Retrospect 2014, ENTSO-E and StatLine[3)])

1) It must be noted that the low gas demand from 2011 to 2014 in the EU is recovering following a rise of around 4 % in 2015 and an expected increase of 6 % in 2016 according to Eurogas.

2) Source: National Energy Technology Laboratory (NETL). 2010. Cost and performance baseline for fossil energy plants, Volume 1: Bituminous coal and natural gas to electricity. Revision 2. November. DOE/NETL-2010/1397. United States Department of Energy.

3) Electronic databank of Statistics Netherlands.

Nevertheless, the figure shows that even with external factors such as low coal and carbon prices, together with more renewable energy sources coming on line, gas still plays a significant role in the NW Region power generation mix. There are however significant differences between individual countries in the NW Region.

Shifting the focus to the location of production and consumption of electricity and gas, there is a notable divergence. While electricity production and consumption is more localised (consumed in the same country where it is generated), gas is much more internationally traded and transported, as shown in the figures below.

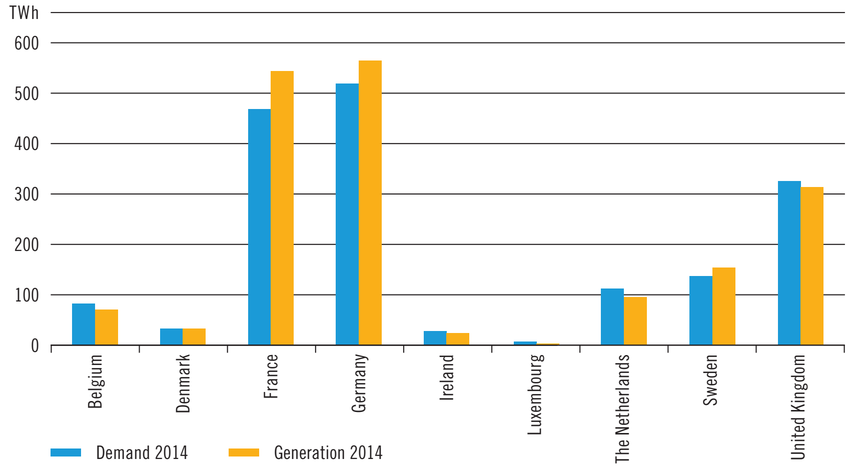


Figure 2.3: Electricity generation and consumption 2014
(Source: Yearly Statistics & Adequacy Retrospect 2014, ENTSO-E)

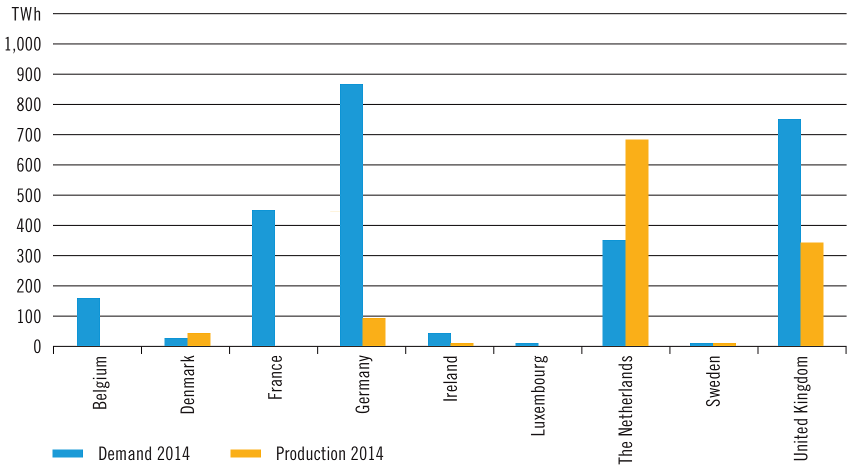


Figure 2.4: Gas production and consumption 2014
(Source: Historic country level production and demand, ENTSOG)

This difference between location of production and consumption has consequences for the cross-border interconnection capacity when gas is compared with electricity on a country to country basis. Figure 2.5 shows the cross-border interconnection capacity within the NW Region for both gas and electricity on country by country basis.

Though the illustration is from the previous edition of the NW GRIP, the same conclusion can still be drawn i. e. the gas system has considerably higher interconnection capacity in comparison to the electricity system. The difference is in part explained by the difference in market size, the difference of peak demand compared to an average demand, and the fact that most of the gas consumed is not produced in the same country. As the electricity infrastructure is set to expand significantly in the years to come with an interconnection target of 10 % of installed capacity by 2020

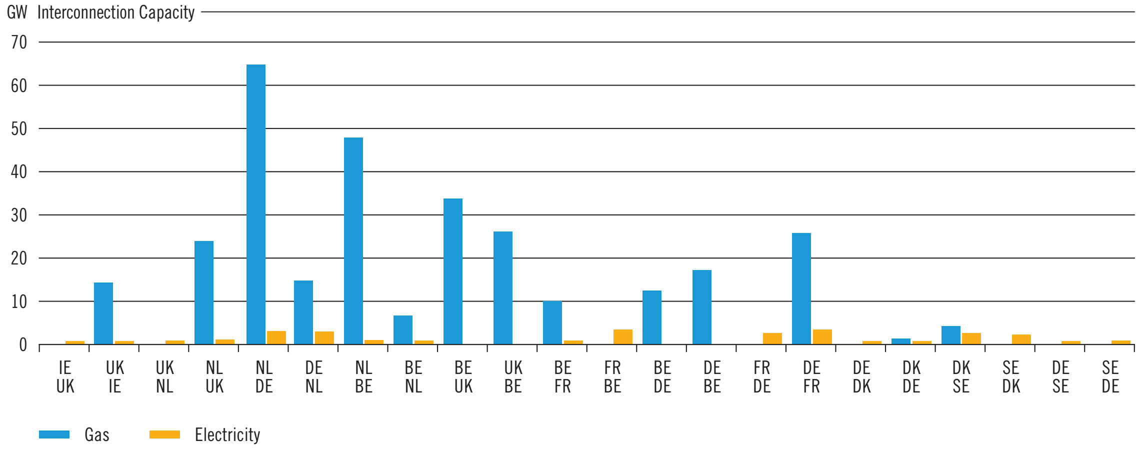


Figure 2.5: Cross border interconnection capacities for gas & electricity in 2013 (Source: NW GRIP 2013)

and 15 % by 2030, it highlights the need for moving large quantities of energy across EU. With more than 2 million kilometres of gas pipelines already in place in the NW Region and an average transportation unit cost of around 11 €/kW/100 km for gas, as opposed to 230 €/kW/100 km for electricity[4)], the gas infrastructure constitutes a cost-effective and affordable way to transport energy. It is also energy efficient since transmission of natural gas via pipelines only uses 0.5 % of the transmitted energy, where line losses through electricity networks are at least twice as high as for gas.

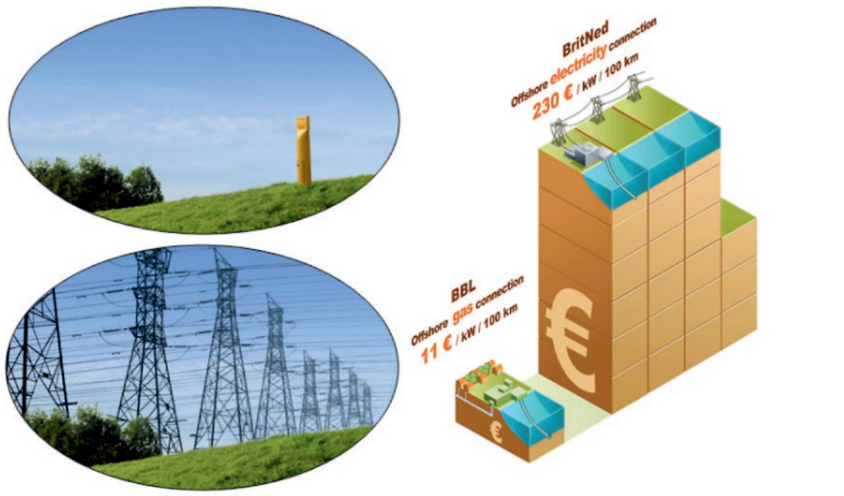


Figure 2.6: Comparison of gas and electricity transmission infrastructure with regard to cost and landscape impact (Source: ENTSOG)

Finally, achieving a low-carbon society will lead to an increasing proportion of renewables in the energy mix. Due to the nature of clean energy sources like solar and wind – solar fluctuates with weather and the daily cycle and wind is also intermittend – there have to be some means of providing electricity when the sun is not shining and the wind is not blowing. Gas functions as an instantly available back-up in case of shortages as gas turbines can be turned on and off quickly to meet variable power demands. Furthermore gas also offers an efficient storage medium potential in case of surplus of renewable electricity. By converting excess electricity into hydrogen or synthetic natural gas, electricity can actually be stored in gas networks and storage installations. In this way, gas infrastructure can support the electricity networks by transporting and storing energy at low costs while accommodating future large volumes of excess sustainable energy, thus preventing suboptimal use of costly sustainable energy.

4) Source: www.britned.com, www.bblcompany.com/about-bbl/technical-information, https://en.wikipedia.org/wiki/BBL_Pipeline

3 Energy transition towards a sustainable future

Image courtesy of Open Grid Europe

3.1 Introduction

The 2017 edition of the NW GRIP for the first time aims to highlight the contribution of its member TSOs towards a sustainable energy transition and decarbonisation in the NW Region.

The main features that have been observed as a result of the NW GRIP TSO energy transition survey carried out in autumn 2016 are the following:

1. Gas infrastructure and natural or renewable gas with a key role in a low-carbon society

Natural gas is the cleanest, most efficient and versatile of fossil fuels and can reduce carbon emissions immediately as e.g. a new natural gas power plant has substantial lower CO_2 emissions than a new coal fired power plant. Combining these inherent properties with the increasing production of renewable gases, most notably biomethane, its wide range of application possibilities and its competitive cost of supply, gas must be considered as an important energy source to reach greenhouse gas (GHG) emission reduction targets whilst ensuring Europe's competitiveness on a global level. Furthermore with an already well developed and integrated transmission grid in the NW Region the gas infrastructure offers a very cost-efficient way to transport energy and in time an efficient storage medium for surplus renewable electricity. Ensuring that all sorts of gaseous sources can flow in the European transmission grid must therefore be seen as vital element in the decarbonisation of traditional gas consuming sectors as well as new ones such as Compressed Natural Gas (CNG) and/or Liquefied Natural Gas (LNG) in the transportation sector.

2. Different roads towards a low-carbon society

In the countries comprising the NW Region, national energy policies and climate programmes have been in place for years, in line with the EU energy targets for the reduction of GHG, energy efficiency and the share of renewable energy in EU. Assessing the different countries' approaches, it is clear that the focus, and thus the number and types of energy transition activities, vary from country to country as national policies go together with different strengths in their respectable technology progress. National legal and regulatory frameworks support these efforts in some ways, albeit to differing extents in the Member States.

3. Gas transmission systems as support to the energy transition

National energy policies and climate programmes have seen steady and sometimes even harsh revisions challenging the traditional fossil based Energy Company's way of doing business. Based on the number and types of gas activities, for instance renewable gases or modes of clean transportation and energy efficiency, that TSOs in the NW GRIP countries are engaged in, it is evident that evolving their business in order to become part of the solution rather than part of the problem is a clear imperative. Though the differentiated pace of change of national systems and priorities, inevitably results in different approaches and strengths in the technological progress and transition.

4. Sector coupling as a key in a low-carbon society

In order to achieve a cost-efficient way of decarbonising the energy system it is required that a physical coupling of gas, power, heat and mobility infrastructures are designed in a way which ensures optimal use of each of the sector's strengths. Combining at least two energy carriers in hybrid appliances, enables consumers to instantaneously use the energy carrier of their choice, thus offering flexibility to avoid network congestion and potentially minimising costs. By providing consumers with a choice of energy based on e.g. price signals, hybrid systems can act as an economic and optimal way of connecting various energy carrier infrastructures through end-user appliances.

5. More research, innovation and exchange needed

New technologies contributing to decarbonisation involving gas infrastructure show varying levels of development. For instance, Power to Gas (P2G) projects are, wherever in place, still more or less pilots and the technology has not yet reached commercial status. Hybrid heating has made remarkable progress in a number of countries, e.g. the Netherlands, and these systems are expected to achieve the necessary economies of scale. To initiate further innovation and help incentivise investments a closer cooperation is necessary between gas & electricity TSOs as well as district heating operators and investors in mobility infrastructure (fuelling stations). This is key for the systems analysis underpinning National Development Plans.


Image courtesy of Gascade

3.2 Policies and targets for energy transition

On the 4th of November 2016, decarbonisation of the economy got a new impetus, as the COP21 Paris Agreement came into force aiming at keeping the global temperature rise below 2 degrees Celsius above pre-industrial levels and to pursue efforts that will limit it to 1.5 degrees.

Though, years before COP21, the EU Energy Union Strategy identified decarbonising the economy as one of the five dimensions to be covered by EU energy policies, thus opening up a perspective towards energy transition on the European level.

In the following paragraphs the EU as well as the NW GRIP Member State's energy transition policies and targets will be outlined.

3.2.1 EU PERSPECTIVE

As mentioned decarbonising the economy is a central dimension in EU Energy Union Strategy which consists of climate actions such as:

- turning the EU Emissions Trading System (EU ETS) into a driver of CO_2 reduction
- the identification of strong but fair national targets for sectors outside the Emissions Trading Scheme (ETS) to cut GHG emissions
- developing and implementing a roadmap towards low-emission mobility
- an energy policy making the EU a world leader in renewables.

Since its publication in 2015, EU institutions have strongly supported a quick ratification of the Paris Agreement. This was followed by the EU low-carbon economy roadmap in 2016 suggesting a cut in GHG emissions to 80 % below 1990 levels by 2050. The European Commission (EC) has set milestones to achieve 40 % emissions cuts by 2030 and 60 % by 2040 and wants all sectors to contribute. The EC imperative that a low-carbon transition should be both feasible and affordable must be considered as an invitation for natural gas and gas infrastructure to play a proactive role. However, the role of gas has not yet been specified according to sectors, regions and countries. Climate targets of Member States and ways to achieve them are still under discussion both on EU and national levels.

The Directive 2009/28/EC of 23 April 2009 on the promotion of the use of energy from renewable sources, referred to as the Renewable Energy Directive (RED), as amended by the Indirect Land Use Change (ILUC) Directive[5)], aims to ensure that all Member States will contribute to reaching 20 % renewables at EU-level by 2020. The RED also includes a 10 % target for each Member State for the share of renewable energy in transport by 2020. The implementation of the RED, including the design of the support schemes promoting the development of renewable energy, is the responsibility of Member States.

5) Source: https://ec.europa.eu/energy/en/topics/renewable-energy/biofuels/land-use-change

Early 2016 the EC published a legislative proposal on a new Renewable Energy Directive post-2020. After public stakeholder consultation, the proposal became part of the comprehensive 'Energy Winter Package' comprising initiatives focusing on energy efficiency, energy performance of buildings, bio-energy sustainability and energy market design and energy governance.

The EC's proposal aims at promoting renewable energy through a comprehensive approach to speed up the replacement of obsolete fossil fuel boilers with efficient renewable heating and increasing the deployment of renewable energy in district heating and CHP. It also supports local authorities in preparing strategies for the promotion of renewable energy and heating and incentivises the uptake of renewable energy in heat production, including CHP.

The EC initiative foresees proper market conditions for the cost-effective development and deployment of renewable energy. In particular, it would aim at:

- Establishing an accountable and reliable system for the achievement of the 27 % target
- Creating market conditions allowing for the cost-efficient financing and integration of renewable energy into the market
- Addressing remaining challenges related to the uptake and integration of renewable energy in the EU energy markets and grids
- Promoting cooperation between Member States in regional approaches to renewable energy and market integration and grid operation. In addition the initiative would aim to compensate for market failures, such as inadequate inclusions of externalities in the cost of energy sources, as well as to avoid the creation of new market failures.

3.2.2 MEMBER STATE PERSPECTIVES

In line with the EU energy targets for the reduction of GHG, energy efficiency and the share of renewable energy in EU consumption, national energy policies and climate programmes have been in place in the countries of the NW Region for decades, and have seen a steady amount of regulatory and legislative instruments been put in place.

In the following paragraph these efforts are described on a country to country basis.

Belgium

Currently the federal government and the 3 Regions are developing within their competencies an Energy Vision/Energy Pact defining the legal framework for the energy transition. The Energy Pact is foreseen for 2017.

The General Belgian Energy Policy & Priorities for 2017, as prepared by the Federal Public Services of Economy, lie in the preparation of the energy transition in Belgium (based on security of supply and the nuclear phase-out) and the finalization of the energy pact.

In its 2016 review for Belgium, IEA acknowledged Belgium's recent progress in several areas of energy policy, but stressed the need for a national long-term energy strategy without delay, in order to respond to the challenge of decarbonising the economy while ensuring security of supply and affordability of energy. A major issue to be addressed is the country's nuclear phase-out policy and its consistency with its objectives regarding electricity security and climate change mitigation.

In November 2016, the Flanders region was the first Belgian entity to ratify the Paris climate agreement, shortly followed by the Walloon parliament. The federal minister of energy, environment and sustainable transition confirmed at the 22nd UN climate conference in Marrakesh the ambition of a Belgian ratification of the Paris agreement in the first half of 2017.

Denmark

The Danish government has a long-term objective that Denmark must be independent of fossil fuels by the year 2050 and that while pursuing this objective Denmark must continue to be one of the leading countries in the green transition.

The basis for this is a broad parliamentarian agreement (2012–2020) focusing on increased energy efficiency, more renewable energy, smart grid strategy and a better framework for biogas and electricity/biomass in the transport sector.

Recently the Danish government has established an Energy Commission that will analyse and assess trends in the energy sector and make recommendations for a cost-effective Danish energy policy for the period 2020–2030. The Energy Commission is expected to publish recommendations for the Danish energy policy in early 2017.

The national energy policy is also reflecting the commitments with regard to the international climate agreements and EU targets. International cooperation is seen as vital for handling the climate issue and ensuring a more cost effective energy transition.

Most recently Denmark has undertaken an initiative to host the annual EU Energy Infrastructure Forum which aims to facilitate the development of the European gas and electricity infrastructure. It has been estimated that European gas and electricity infrastructure is in need of significant investments, estimated at up to 200 billion Euros towards 2020.

The current energy policy has on the one hand resulted in an increasing production of biogas, but on the other hand it has also resulted in a reduced consumption of natural gas. This is due to increased energy efficiency and increased use of tax exempted biomass for CHP. The current government has no coherent strategy for the use of natural gas in the transport sector.

France

In France the framework is set by a 2015 law on 'Energy transition towards a sustainable growth'. This text defines binding targets such as reducing the share of nuclear production down to 50 % by 2025 and having biogas covering 10 % of the total gas consumption by 2030.

It comes with two associated tools:

- The low-carbon national strategy describing processes and tools
- The multi-annual program for energy defining intermediate targets

The latter replaces all former energy-specific programs in order to ensure a cross-energy consistency and it tackles each sector (production, consumption, and network) and dimension (security of supply, emission reduction, competitiveness). The first program covers the 2016–2018 and 2019–2023 periods with binding targets for 2023.

Considering the overall uncertainty about the future energy mix, 2023 targets take the form of ranges compared to the situation in 2012:

- A final energy consumption decreasing by 3.1 % to 12.6 % through further energy efficiency
- An accelerated decrease of fossil fuel consumption based on their emission factor as a result from the willingness to move away from them:

REDUCTION TARGETS FOR FOSSIL FUEL CONSUMPTION BY 2023, COMPARED TO 2012		
	2023 REFERENCE CASE	2023 OPTIONAL SCENARIO
COAL	–37.0 %	–30.0 %
OIL	–23.0 %	–9.5 %
NATURAL GAS[6)]	–16.0 %	–9.0 %

Table 3.1: Reduction targets for fossil fuel consumption by 2023, compared to 2012 (Source: Decree n° 2016-1442, 27 October 2016 on Multiannual Programme for energy)

- A further development of Renewable Energy Sources (RES) amounting for 24.9 % of the primary energy mix
- The production of 8 TWh of biogas facilitated by national tenders and an easier access to grid injection for biomethane
- A biomethane production for natural gas vehicles (NGVs) reaching 2 TWh (20 % of NGV consumption) through a supporting scheme aiming at complementing electrical vehicles.

Beyond these quantitative targets, there will be no development of new coal powerplants (except if equipped with carbon capture and storage [CCS]) while the running hours of existing ones will decrease in anticipation the coal phasing-out around 2023.

Regarding natural gas, the program focuses on security of supply with the possible revision of existing standards after 2018 while an underground gas storage strategy and demand-side management (200 GWh/d) will be developed. It also maintains the ban on hydraulic fracking and describes supplier's responsibilities with regard to transparency on natural gas origin.

From a financing perspective the plan anticipates around € 10 billion of public spending throughout the 2016–2023 period. It also calls for scrutiny of the cost-benefit ratio of any new interconnection project in gas.

6) These targets do not include biomethane

Germany

On 14 November 2016 the German government adopted the Climate Action Plan 2050, laying down the principles and goals of the German government's climate policy[7]. The Climate Action Plan 2050 provides guidance on all areas of action in the process of achieving the German domestic climate targets in line with the Paris Agreement. The long-term targets are based on the guiding principle of extensive GHG neutrality in Germany by the middle of the century.

The areas of action defined in the Climate Action Plan 2050 are energy, buildings, transport, trade and industry, agriculture and forestry. Based on the climate targets for 2050 the Climate Action Plan formulates milestones and measures for all areas of action. The 2030 emission reduction targets for the areas of action are given in the table below.

2030 EMISSION REDUCTION TARGETS FOR THE AREAS OF ACTION

	1990 (in million tonnes of CO_2 equivalent)	2014 (in million tonnes of CO_2 equivalent)	2030 (in million tonnes of CO_2 equivalent)	2030 (reduction in % compared to 1990)
ENERGY SECTOR	466	358	175–183	60–61 %
BUILDINGS	209	160	70–72	67–66 %
TRANSPORT	163	160	95–98	42–40 %
INDUSTRY	283	181	140–143	51–49 %
AGRICULTURE	88	72	58–61	34–31 %
SUBTOTAL	1,209	890	538–557	58–54 %
OTHER	39	12	5	87 %
TOTAL	1,248	902	543–562	56–55 %

Table 3.2: 2030 emission reduction targets for the areas of action (Source: German Climate Action Plan 2050, BMUB)

The German gas transmission and distribution systems provide an ideal basis for supporting the German energy policy. In this context the following main legislative measures are currently in place and are expected to be further developed:

1) Renewable energy sources act (EEG) and the gas network access regulation (GasNZV) covering among others the integration of biogas into gas transmission and distribution networks[8].

2) Combined heat-and-power act (KWKG) covering among others the support of gas-fired combined heat-and-power systems[9].

3) Energy tax act (EnergieStG) covering among others a mineral oil tax reduction on CNG use in the transport sector[10].

4) Federal Immission Control Act (BImSchG) and 13th Federal Immission Control Regulation (13. BImSchV) under which the German TSOs implement technical measures to reduce immissions of the gas transmission facilities, e.g. compressor stations[11].

7) Source: www.bmub.bund.de/fileadmin/Daten_BMU/Download_PDF/Klimaschutz/klimaschutzplan_2050_kurzf_en_bf.pdf

8) Source: www.gesetze-im-internet.de/gasnzv_2010

9) Source: www.bmwi.de/DE/Service/gesetze,did=22130.html

10) Source: www.gesetze-im-internet.de/energiestg/BJNR153410006.html

11) Source: www.gesetze-im-internet.de/bimschg

Ireland

The Irish Government's White Paper, 'Ireland's Transition to a Low Carbon Energy Future' published in December 2015 in terms of energy security identifies that *'the development of indigenous biogas resources for heating and transport will likely play a part in gas diversification in the future.'*

Energy from biomethane or renewable gas has the potential to contribute significantly to Ireland's renewable energy targets. Ireland has a legally binding target to achieve 16 % of gross final energy demand from renewable sources by 2020 under the EU Renewable Energy Directive (2009/28/EC). In order to achieve this target the Irish government introduced a 12 % target for renewable heat by 2020.

Utilising mature technologies, with the right investment, renewable gas has the potential to satisfy over 20 % of Ireland's gas demand by 2030. Capitalising on this opportunity would reduce the country's reliance on imported fuels and provide Ireland with a renewable indigenous fuel source.

The White Paper also identifies developing *'a national policy framework to underpin and support the deployment of infrastructure for the use of alternative transport fuels, including compressed natural gas'* as a key renewable energy action.

The White Paper has included CNG as a viable renewable technology option to contribute to the Renewable Transport sector stating that *'technologies are likely to become more cost effective and widely adopted over time. These include electric vehicles, renewable fuels such as biogas and advanced liquid biofuels, as well as less carbon-intensive fossil fuels, including compressed natural gas (CNG) and liquefied petroleum gas (LPG).'*

Another notable undertaking within the White Paper is the establishment of a Green Bus Fund to promote sustainable public transport. This initiative intends '*to support energy efficient and renewable transport'*, by establishing a *'green bus fund to support the purchase of cleaner and greener public transport vehicles in the period to 2020'*.

Luxembourg

Luxembourg is firmly embedded in Central West Europe. An analysis of Luxembourg's energy future can therefore not be made without understanding the key drivers changing Europe's energy landscape and its direct neighbours.

Luxembourg has a highly developed economy, with the 2nd world's highest GDP per capita [12]. Despite the fact that Luxembourg's population is expected to almost double by 2050, from currently 560,000 to almost 1,100,000 in 2050, the total final energy consumption in electricity and gas is expected not to further grow by 2050.

Energy transition in Luxembourg towards 2050 horizon is driven by energy efficiency and integration of renewables in the distribution networks. Drivers such as the COP21 Paris Agreement and the various European Union energy targets and directives, as well as global trends in energy sector transformation and technology deployment, especially digitalisation will have a significant impact on the final energy consumption, mainly driven by electricity. Nevertheless, natural gas will play an important role in the energy transition until 2050 and gas demand even shows moderate growth for 2025. Industrial gas consumption is projected to be stable, but the consumption in the residential heating sector is projected to further increase mainly due to the switch from heating oil to gas of the customers still awaiting this switch.

Since 2008, Luxembourg's energy policy has also been focused on reducing CO_2 emissions in transport, as a large labour-work force is coming from the neighbouring countries (France, Belgium, Germany), generating a high energy consumption and CO_2 emissions related to the transport sector.

12) Source: www.imf.org/external/pubs/ft/weo/2016/02/weodata/index.aspx


Image courtesy of Gasunie

The Netherlands

The Dutch government aims to achieve a carbon neutral energy mix by 2050 that is safe, reliable and affordable. This implies an energy mix consisting entirely of renewables or fossil fuels combined with CCS.

The political discussion on energy transition is generally based on a distinction of four energy functions: the power sector, industry, mobility, and buildings. This distinction is also used in most recent policy documents.

Several agreements have been made during the past years that should stimulate the energy transition, often by focusing on energy efficiency and renewable energy production, the most important one being the Energy Agreement from 2013. This agreement involved employers, unions, and NGOs committing to targets that run until 2023. Among these is a target of 16 % renewable energy production in 2023. The agreement aims to create 15,000 additional jobs and € 900 million in tax cuts.

In Q1 2016, the government published the Energy Report 2016 that formulated the policy priorities post 2020. Most notably, this includes a focus on CO_2 emission reduction. Following this report, a comprehensive stakeholder dialogue was organised to translate the Energy Report into a concrete policy agenda. This agenda was published in December 2016. It contains additional measures to realise the targets set in the Energy Agreement from 2013, as well as a more long-term policy overview.

An issue that attracts particular political debate involves the closing of the remaining coal fired power plants.

Sweden

The Swedish government has declared that Sweden shall have zero net emissions of GHG to the atmosphere by the year 2050, and will thereafter have negative emissions. The Swedish energy policy is based on the same three cornerstones as assessed within the framework of the EU energy cooperation. The policy thus seeks to accommodate:

- Ecological sustainability
- Competitiveness
- Security of supply

In a broad parliamentary energy policy agreement, published on 10 June 2016, it was decreed that Sweden shall have a robust electricity system with high reliability, low environmental impact and with access to electricity at competitive prices. The goal for 2040 is 100 % renewable electricity production. This is a goal, not an end date prohibiting nuclear power and it does not mean the closure of nuclear power through political decisions. A goal for energy efficiency for the time period 2020–2030 shall be developed and be approved no later than 2017.

Swedish nuclear power, which together with hydropower accounts for the larger part of Sweden's energy supply, is facing major investment needs to meet the new safety requirements. The Swedish Radiation Safety Authority has decided that these new requirements must be met by 2020, otherwise the reactors may not continue operation. Nuclear power must bear its own costs, and the principle that nuclear power should not be subsidised remains. New reactors are allowed to be built at existing sites, up to a maximum of ten reactors.

Hydropower has a central role in Sweden's renewable electricity supply. The continued high levels of hydropower production is an important part of the efforts to achieve an increased share of electricity from renewable energy sources. No large expansion of hydropower is planned but an upgrade of existing plants with modern environmental permits will take place.

The renewable energy will continue to be expanded and Sweden has a significant potential for renewable electricity production. It is also reasonable to assume that Sweden will continue as a net exporter of electricity in the long term. Through the efficient use of existing hydro power and bio-energy power sector output can be increased. The power issue is important to consider when it comes to expansion of renewable electricity production.

Image courtesy of Swedegas

United Kingdom

The UK has a target to produce at least 15 per cent of its energy consumption from renewable sources by 2020. Over recent years the volume of renewable electricity sources has increased substantially. While the electricity sources generation sector is on the required trajectory to meet its unofficial sub-target, significant progress is still needed in the heating and transport sectors if the UK is to meet the target on time. The biggest challenge is decarbonising the heating sector.

The Climate Change Act 2008 established a target for the UK to reduce its carbon emissions by at least 80 per cent from 1990 levels by 2050. This target represents the UK's contribution to global efforts to limit the temperature rise to 2 °C from 1990 levels. To ensure that regular progress is made towards this long-term target, the act also established a system of legally binding five-yearly carbon budgets, as shown below:

DETAILS OF THE UK CARBON BUDGETS

BUDGET	PERIOD	FIVE-YEAR CARBON BUDGET / FINAL TARGET ($MtCO_2e$)	REDUCTION BELOW BASE YEAR
FIRST CARBON BUDGET	2008–2012	3,018	23 %
SECOND CARBON BUDGET	2013–2017	2,782	29 %
THIRD CARBON BUDGET	2018–2022	2,544	35 %
FOURTH CARBON BUDGET	2023–2027	1,950	50 %
FIFTH CARBON BUDGET RECOMMENDATION	2028–2032	1,765	57 %
2050 TARGET	2050	160	80 %

Table 3.3: Details of the UK Carbon Budgets (Source: Committee on Climate Change)[1)]

The UK has made significant progress in reducing carbon emissions. The first carbon budget (2008–2012) was achieved on time. The last official UK Government statistics show a decrease of 35 % in total GHG emissions between 1990 and 2014. This suggests that the second carbon budget (2013–2017) will also be met.

In November 2015 the Secretary of State for Energy and Climate Change announced a new direction for energy policy. One announcement within this was that unabated coal-fired electricity generation would be restricted from 2023 and cease by 2025. Additionally the government recognised that gas-fired electricity generation will play an important role in facilitating decarbonisation as it can support low carbon electricity generation. The Secretary of State also reiterated support for nuclear generation as a low carbon source of electricity. The announcement also stated that offshore wind support will continue via contracts for difference (CfD) auctions, provided cost reduction targets can be met. Auctions for offshore wind projects will continue to 2019 when an evaluation of cost-effectiveness will be undertaken. The Government is consulting on whether onshore wind will be eligible for future CfD auctions. Planning decisions for onshore wind have also been moved to local authorities in England and Wales.

The annual Autumn Statement was announced in November 2015. The decision was made not to support phase two of the CCS pilot project scheme. Both proposed projects have now halted. This is expected to delay CCS development in the UK.

Another significant change has been reductions in solar photovoltaic (PV) panel costs over the last few years. Costs have reduced by around two thirds since 2010, and solar subsidies from February 2016 have been reduced by a similar proportion to reflect lower installation costs.

13) Source: www.theccc.org.uk/tackling-climate-change/reducing-carbon-emissions/carbon-budgets-and-targets

3.3 Sector coupling

In a decarbonised energy system fluctuating renewable energy sources such as wind and solar account for a large part of the electricity generation. As often neither time nor location of renewable electricity production and electricity demand correspond, the envisaged increase of renewable electricity production is expected to lead to a large increase in transport and storage requirements of electrical energy.

Therefore it is required to develop new technologies that enable a physical and virtual coupling and integration of the EU energy systems for electricity, gas, heating and mobility infrastructure. By combining these infrastructures, an optimal use of the potentials and strengths of each other can be utilised whilst ensuring security of supply. This will enable the EU energy systems for electricity, gas, heating and mobility to decarbonise in an economically efficient and technically achievable way which a single energy infrastructure will not be capable of.

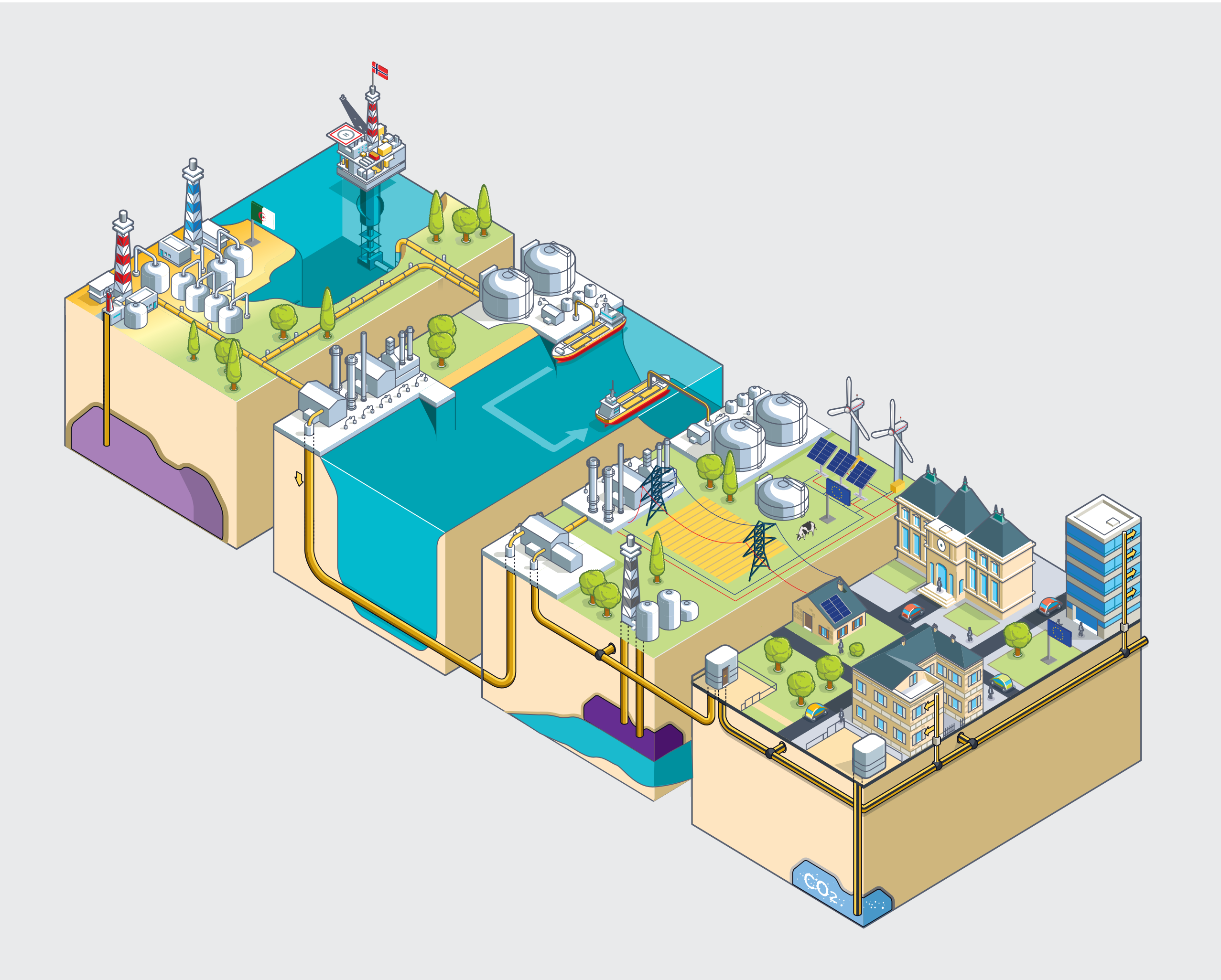


Figure 3.1: Sector coupling and role of gas infrastructure (Source: GIE, 2016)

As described in the previous paragraphs research of various gas technologies has been conducted for many years, already prompting a reduction of GHG's through an increasing usage of renewable gases and in a mid to long term perspective how to utilise the advantages that the gas infrastructure holds in regards to extensive storage capacity for renewable electricity and long-distance energy transmission. The gas infrastructure therefore provides the possibilities in order to allow for an intelligent sector coupling. In this way sector coupling allows the use of existing infrastructure instead of investing into additional new infrastructure. Thereby affordable renewable energy can be provided while achieving the European climate targets.

In the following sections major developments in this context are presented.

Example 1: Sector coupling in Northern Germany

Currently, Open Grid Europe (OGE) is in the course of replacing several obsolete gas-turbine-driven compressor units in a transport facility located close to the North Sea shore. This region features a considerable number of wind turbines and also plenty of photovoltaic power generation. Thus, power supply in that area is currently already close to 100 % renewable and further development of renewable power generation is to be expected.

To be able to provide congestion relief to the local medium-voltage-grid, OGE decided to replace one of the gas-turbine-driven units with a new electrically driven device. Together with the operator of the electricity grid OGE will develop a concept to optimally employ the electric compressor unit and particularly operate it, when the grid is heavily loaded with surplus renewable power.

3.3.1 GREEN MOBILITY

As communicated by the EC in the 'Clean Power for Transport: A European alternative fuels strategy', alternative fuels are urgently needed to break the over-dependence of European transport on oil. Furthermore the transport sector is contributing around 25 % of total CO_2 emissions in the EU[14], while simultaneously being the only sector that has experienced almost continuous growth over the last 20 years. Alternative fuels to oil must be seen as indispensable in decarbonising the transport sector and thus a key element in achieving the target of a 60 % reduction of CO_2 emissions from transport by 2050, as set out in the 'Roadmap to a Single European Transport Area – Towards a Competitive and Resource Efficient Transport System'[15].

With an abundance of natural gas sources and an uptake in the production of renewable biomethane, gas as a fuel offers a long-term security of supply and considerable potential to contribute to the diversification of transport fuels. Natural gas, even though a fossil fuel, offers environmental benefits with lower GHG emissions than any hydrocarbon fuel (up to 25 %). When natural gas is blended with biomethane or bio-synthetic natural gas (bio-SNG), further CO_2 emission reductions can be reached with a potential of up to 95 % compared to traditional fuels[16]. Furthermore gas, natural as well as renewable, has very low emissions of harmful pollutants such as NO_X, particulate matter, etc., and is therefore key in terms of improving air quality substantially in areas with dense traffic.

3.3.1.1 Compressed natural gas and compressed biomethane (CNG/CBM)

CNG or CBM is a proven, reliable and mature technology for the broad market and is the most widely used technique for gas driven vehicles with close to 200,000 vehicles on the road in the NW Region and more than 1,300 refuelling stations servicing them in 2015. Due to low GHG and harmful pollutant emissions and a comparable range and refuelling time to traditional fuels, CNG vehicles are gaining grounds within urban fleets of buses and utility trucks and increasingly receiving attention by commercial fleets.

CNG DEVELOPMENT IN TRANSPORT IN THE NW REGION (2015)

	BE	DE	DK	FR	IE	LU	NL	SE	UK	TOTAL
LIGHT DUTY VEHICLES	2,600	81,423	114	3,098	5	443	10,000	49,945	N/A	147,628
HEAVY DUTY VEHICLES	10	18,169	88	11,145	3	47	150	3,177	N/A	32,789
FUELLING STATIONS	45	921	13	44	2	7	150	221	N/A	1,358

Table 3.4: Number of CNG vehicles and fuelling stations (Source: NW GRIP TSOs)

14) When including maritime transportation.

15) Source: COM (2011) 144

16) Source: The Natural & bio Gas Vehicle Association 2017

Example 2: CNG network in Ireland

In order to facilitate and encourage the uptake of CNG by commercial fleet operators Gas Networks Ireland intends to provide full national coverage of public CNG fast-fill compressor stations. Gas Networks Ireland is proposing to develop a 70-station CNG fuelling network, co-located in existing forecourts, on major routes and/or close to urban centres. This will help satisfy the requirements of the EU's Alternative Fuels Directive which aims to establish CNG refuelling facilities along key routes at every 150 km by 2025.

Gas Networks Ireland is currently targeting at least 5 % penetration of CNG or renewable gas for commercial transport and 10 % of the bus market in Ireland by 2025.

3.3.1.2 Liquefied natural gas and liquefied biomethane (LNG/LBM)

The EC underlines in its LNG and Storage Strategy how LNG can foster security and resilience of gas supply, enhance competitiveness and, by reducing environmental impacts, offers valuable contributions to a greater sustainability of energy systems especially if blended with LBM. The Strategy has identified transport as a key sector, where *'LNG will increasingly be used as an alternative to marine fuels in shipping and to diesel in heavy duty vehicles such as lorries as alternatives currently are limited. Small scale LNG may also play a role in reducing environmental impacts in the supply of heat and power, for example to industry or other consumers in remote and/or off-grid areas currently dependent on more polluting fossil fuels'*.

The Strategy has described the full implementation of Directive 2014/94/EU on alternative fuels, including the establishment of LNG refuelling points across the TEN-T corridors and at maritime and inland ports as a main action point.

LNG or LBM offers a cost-efficient alternative to diesel for waterborne activities (transport, offshore services, and fisheries), trucks and rail, with lower pollutant and CO_2 emissions and higher energy efficiency. LNG/LBM is particularly suited for long-distance road freight transport for which alternatives to diesel are extremely limited.

For waterborne transportation more stringent standards came into effect on 1 January 2015, creating Sulphur Emission Control Areas (SECAs) for shipping in the Baltic Sea, North Sea and English Channel as set by the International Maritime Organisation (IMO), the regulatory authority for international shipping. Thanks to its low emission values, LNG or LBM is a particularly good alternative fuel for ships to meet these standards. In October 2016, the IMO decided to impose a global sulphur cap of 0.5 %[17)] on marine emissions from January 2020.

The North Sea, the Channel and the Baltic Sea shall also become a Nitrogen-Oxide Emission Control Area (NECA) area in 2021, with LNG as the only fuel which inherently complies with the NECA without after-treatment.

As shown in the table below the LNG market development for heavy-duty as well as

17) Ships will have to use fuel oil on board with a sulphur content of no more than 0.5 % m/m, against the current limit of 3.5 %. The interpretation of 'fuel oil used on board' includes use in main and auxiliary engines and boilers.

waterborne transportation in the NW Region is still emerging, as only a limited number of operational LNG/LBG trucks and ships currently are in operation.

LNG DEVELOPMENT IN TRANSPORT IN THE NW REGION (2015)										
	BE	DE	DK	FR	IE	LU	NL	SE	UK	TOTAL
HEAVY DUTY VEHICLES	35	0	0	26	0	0	17	68	N/A	146
SHIPS	3	2	2	0	0	0	1	7	N/A	15
ROAD FUELLING STATIONS	2	0	0	2	0	0	17	6	N/A	27
BUNKERING OPTIONS	0	2	2	0	0	0	1	2	N/A	7

Table 3.5: Number of LNG road and maritime vehicles and fuelling stations (Source: NW GRIP TSOs)

Example 3: Small-scale LNG in Belgium

The market for small-scale LNG is growing in Belgium. The challenge consists of developing the appropriate infrastructure so that LNG powered trucks and ships can refuel:

- With the newly constructed second jetty in 2016, bunker vessels are able to load LNG in order to supply other ships (ship-to-ship bunkering). As such the Zeebrugge LNG terminal is further developing into a hub for small-scale LNG as an essential link in the logistical chain for the supply of LNG as a fuel for shipping, inland waterways and road transport.
- In the first half of 2017, the 5,100 cubic meters LNG bunker vessel built jointly by Fluxys, Engie, NYK and Mitsubishi will come in operation in Zeebrugge to serve the bunkering market.
- At the LNG terminal in Zeebrugge trailers can load LNG which they then use to supply filling/bunkering stations and ships. The current capacity of 4,000 truck loadings per year is about to be doubled in 2017.
- Currently, two filling stations for LNG-fuelled trucks are in use in Belgium (in Veurne and in the port of Antwerp), and opportunities to build additional stations are currently studied.
- Five LNG-powered inland navigation vessels are currently supplied via tanker trucks that take on LNG at the LNG terminal in Zeebrugge (truck-to-ship bunkering), and expected to increase in the near future to 13. Truck-to-ship bunkering is also possible in the port of Antwerp, and the port authority wishes to further increase the availability of LNG by setting up a permanent station.


Image courtesy of Fluxys

3.3.2 GAS-FIRED COMBINED HEAT AND POWER

In order to ensure uninterrupted power supply, variable renewable energy sources need a reliable back-up, which is flexible enough to absorb sudden and substantial variations in demand. As hydropower installations are limited by geography and increasingly being subject for environmental concerns, fast-reacting thermal plant technologies must be seen as highly complementary and should be jointly installed in order to ensure a stable supply.

Fast-reacting fossil technologies should be understood as gas-fired CHPs, as the technology is extremely efficient, rapidly deployable and affordable, making gas ideally versatile, whilst having a significantly better climate and environmental profile than coal, emitting as much as 50 to 60 % less CO_2, a number which will rise concurrently with the production of renewable gases, and negligible emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_X) and particulate matter compared with other fuels [18].

Combined production of heat and power is more efficient than separate production of heat and power. When electricity is produced separately, measures need to be taken to remove excess heat from the process, for instance by using cooling water from rivers, lakes or the sea. This cooling process in itself already consumes energy besides the obvious waste of heat into the open waters. In a combined heat and power production process, the heat that used to be waste is now a product. Obviously this is an efficiency gain as it increases the output of the process while the units of input stay the same. Keeping in mind that electricity is often used for (industrial) heating purposes, it will be clear that combined heat and power production can provide a significant contribution to the reduction in primary energy demand (without reducing final consumption).

Both heat and power are sold on markets with their own characteristics. Heat is a very local market used in Industrial applications or for local district heating, which is of course very seasonal. Power is a national or European market which is getting much more volatile through intermittent renewable energy sources with a zero or very low marginal price. If the heat market needs supplies from a CHP plant, then this plant will also generate electricity with a risk that it has to compete with very low electricity prices. This puts the financial return of the CHP plant at risk. On the other hand, with high energy prices there is a risk that the demand for heat is low (more likely for district heating than for industrial processes), also putting the financial return at risk. This drawback is getting more and more substantial, to a point that some operators of CHP plants are forced to mothball these highly efficient installations.

In future, these risks may be mitigated with energy storage like storing heat. In this way situations can be avoided where at low electricity prices the CHP plant must run because of heat demand in the market: the required heat from the market can be extracted from storage. Also situations can be avoided that at high electricity prices the CHP plant cannot run because there is no heat demand in the market: the produced heat can be stored instead.

18) Source: www.igu.org/natural-gas-cleanest-fossil-fuel

3.3.3 HYBRID HEATING

Sector coupling can be realised by the use of hybrid appliances. The term hybrid means that at least two energy carriers are involved. An example of a hybrid application is the hybrid heat pump, which can run on both gas and electricity. It is a combination of a condensing boiler and an air-sourced heat pump. This offers a wide variety of opportunities: the hybrid heat pump can use electricity at times that electricity is cheap and abundantly available, thereby avoiding curtailment and lowering the energy bill for the owner. On the other hand, the hybrid heat pump can use gas instead of electricity at times that electricity is expensive and scarce, thus also contributing to a lower energy bill for the consumer. The choice of whether gas or electricity is used also depends on the efficiency of the condensing boiler and the air-sourced heat pump. The efficiency of the condensing boiler does not depend very much on the outside air temperature. In contrast, the efficiency of the air-sourced heat pump, measured by the coefficient of performance (COP), is very sensitive to the outside air temperature as can be seen in the figures below. The figure on the left hand shows the COP for space heating (only for low temperature radiators) and the figure on the right shows the efficiency for the production of domestic hot water (DHW).

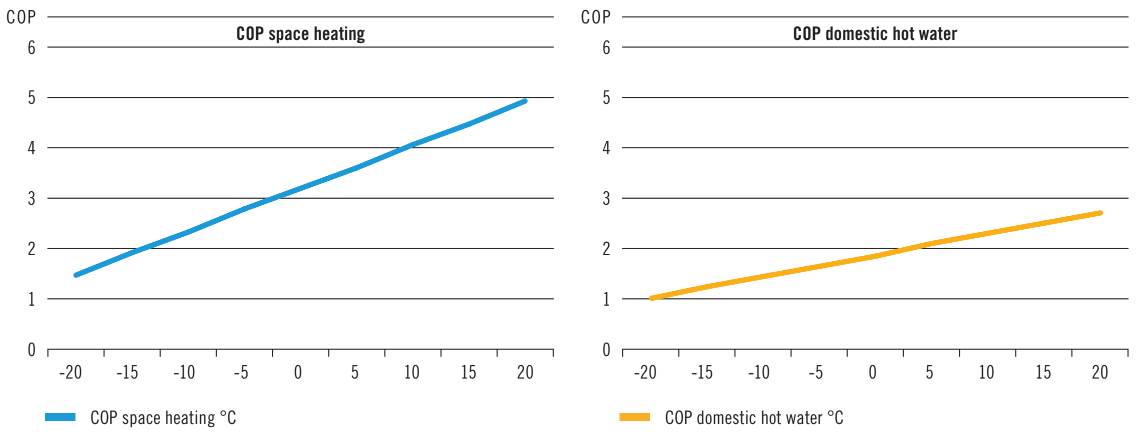


Figure 3.2: Air-source heat pump efficiency (Source: Ecofys[19])

Under circumstances that the efficiency for generating electricity is 50 % or less, the COP of a heat pump must be higher than 200 % in order to still achieve a lower primary energy consumption.

Instant switchable hybrid appliances enable consumers to instantaneously use the energy carrier of their choice thus minimizing cost and network congestion.

Hybrid appliances offer flexibility to avoid network congestion and increase security of supply. Flexibility in energy carrier choice at consumer level should be utilised before turning to conversion between energy carriers.

Therefore, hybrid systems can act as a very economically attractive way to connect gas and electricity infrastructure through end-user appliances.

Of course, hybrid heat pumps can only be installed in homes which are connected to both electricity and gas infrastructure. As an example, figure 3.3 shows a scenario how hybrid heat pumps could develop in the Netherlands.

19) Source: www.ecofys.com/nl/publications/hoe-beinvloeden-technologiekeuzes-in-woningen-de-toekomstige-kosten

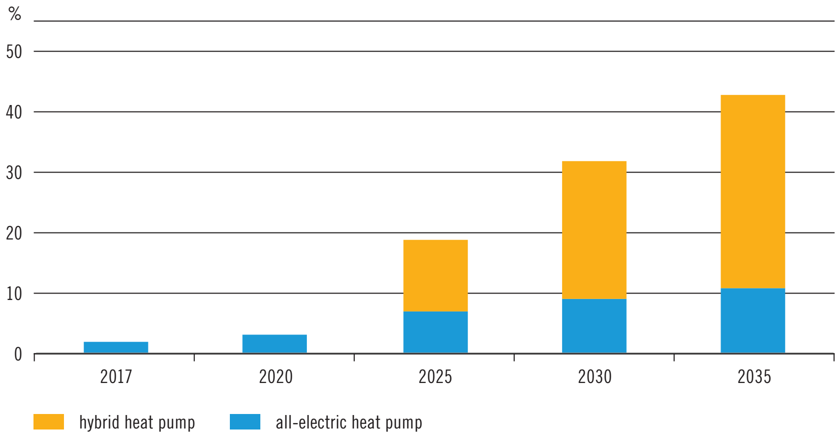


Figure 3.3: Outlook for hybrid heat pumps in the Netherlands (Source: GTS)

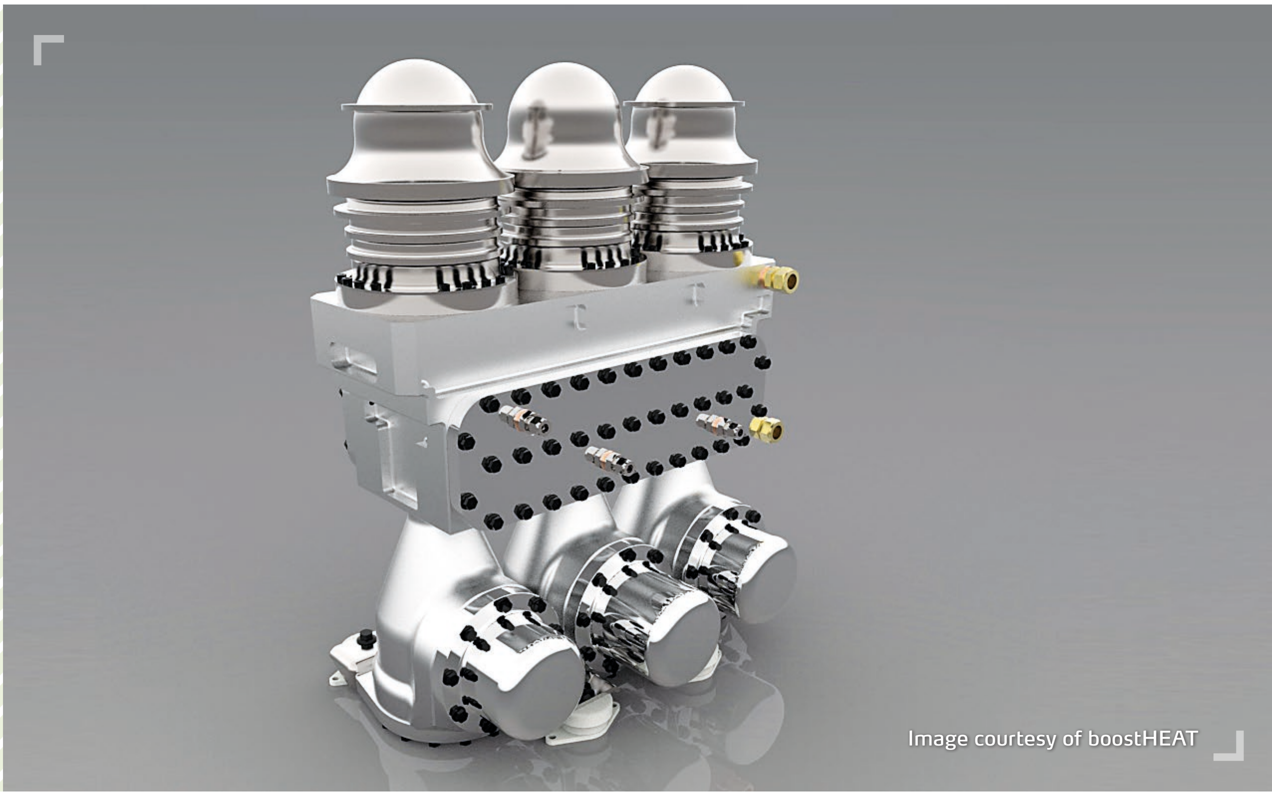
Example 4: Thermodynamic boilers

Fluxys has taken a minority participation in boostHEAT[20], a French energy efficiency company, with the goal of financing the industrial production of a new generation of thermodynamic boilers for the residential and services sector.

The international patented technology of boostHEAT, based on research started in 2004, combines a condensation boiler operating on natural gas and a heat pump containing a new type of thermal compressor that utilises the burner's heat to efficiently compress a natural coolant.

The thermodynamic boiler is an innovative technology allowing for an unprecedented efficiency and an optimum complementarity between renewable energy and natural gas.

20) Source: www.boostheat.com/en



3.4 Energy transition perspectives and initiatives involving TSOs

In the NW Region the gas transmission grid and gas already play an important role in the drive to achieve a low-carbon society and must be considered an important contributor to curtailing climate change and achieving a low-carbon society.

By the nature of their tripartite and regulated business, TSOs of the NW Region are naturally aware of their responsibility to offer a safe, economic and sustainable energy transport. Furthermore in a region where energy transition is a wide-spread and rapidly progressing process, the gas TSOs are also gradually changing and adapting to this new pathway, increasingly taking a more active and integrated part in reducing GHG emissions.

In the following paragraphs perspectives on the role of gas in the transition to a low-carbon society in the NW Region are presented and how the TSOs are supporting this progress through individual initiatives/actions as well as multilateral collaborations such as the Green Gas Initiative[21)].

3.4.1 RENEWABLE GASES

In a low-carbon energy system in which fluctuating solar and wind power accounts for a large part of the electricity generation, the development of a coherent energy system is required. This entails the development of new gas technologies that can bridge the gap between gas and other energy sources. With an extensive European gas grid totalling at approximately 2.2 million kilometres and 255 renewable gas injection points already in place[22)], renewable gases ensure an optimised and cost-efficient way to transport and distribute 'clean' energy.

For a number of years, research has been conducted into a broad range of areas, resulting in the development of renewable gas production technologies and appliances. Particularly in recent years, increasing attention has been focused on the possibility of utilising the gas infrastructure to transport and store renewable gases.

Renewable gases can be produced through several different processes and can be created using many different sources of energy. Typical examples include biogas made from anaerobic digestion and synthetic natural gas (SNG) produced by thermal gasification or hydrogen by means of electrolysis which can be turned into methane also known as methanisation. The advantage of producing methane rather than hydrogen is that the gas can then be used directly and in unlimited volumes in the natural gas network.

21) The Green Gas Initiative is a commitment where seven independent gas infrastructure companies have agreed to achieve a 100% carbon-neutral gas supply in their transport infrastructure by 2050. Source: www.greengasinitiative.eu

22) Source: The European Federation of Local Energy Companies (CEDEC).

Example 5: Renewable Gas in Ireland

Ireland has a legally binding target to achieve 16 % of gross final energy demand from renewable sources by 2020 under the EU Renewable Energy Directive (2009/28/EC). In order to achieve this target the Irish government introduced a 12 % target for renewable heat by 2020. Renewable gas is one of the most cost effective and versatile renewable energy sources available in Ireland and can help meet renewable energy targets for 2020. The Irish Government's White Paper, 'Ireland's Transition to a Low Carbon Energy Future' published in December 2015 in terms of energy security identifies that 'the development of indigenous biogas resources for heating and transport will likely play a part in gas diversification in the future'.[1]

3.4.1.1 Biomethane

Biomethane is upgraded biogas from anaerobic digestion or bio-sng from thermal gasification or methanisation (see section 3.4.1.2 and 3.4.1.3 for more details). This process ensures that the biogas and/or bio SNG are upgraded to the same standard as natural gas, allowing it to be injected into the gas grid providing the same wide range of applications as natural gas.[23]

Example 6: Biomethane in German TSO grids

In Germany two pipelines of ONTRAS Gastransport GmbH regularly carry almost 100 % biomethane. One pipeline the FGL 28 (DN 500, DP 16) is approximately 20 km long runs west of Leipzig and is fed by the Thronitz biomethane injection plant. The second one, FGL 88 (DN 400, DP 25) of also 20 km is fed by the biogas plant in Güstrow, Germany, with up to 5,000 m³/h of biomethane.

Biomethane is a renewable fuel with strong inherent benefits. It can be produced with a nearly constant output and quality. It can be stored, it can be traded, it can be transported efficiently over long distances at a low cost, and it can provide flexibility to intermittent energy resources. Production of biomethane also provides societal benefits such as production of energy from waste streams. Lastly by-products of biomethane can be used as fertilizer, thus ensuring a recirculation of phosphor and reduction of GHG emissions in the agricultural sector.

Both the production and the subsequent upgrading of biogas to biomethane is a proven technology with a widespread utilisation in almost all countries of the NW Region. Between 2013 and 2015 approximately 27,000 GWh of biomethane was injected into TSO and DSO grids – enough to heat approximately 1.5 million[24] homes. This upward trend is already having an effect on the operation of the transmission grids. For example in Germany, the Netherlands and Denmark the increasing volumes of biomethane injected into the distribution grid have resulted in saturation of these systems over some months. Projects are therefore currently ongoing in order to facilitate the reverse flow of excess biomethane from the distribution network to the transmission grid. The DSOs and TSOs involved have identified technical solutions in order to pressurise biomethane flowing from distribution to transmission grids and de-odorise where necessary. Furthermore, regulatory principles were agreed between them to make biomethane available beyond local levels. This effort has contributed to upgrade i. e. the 'greening' of natural gas at a larger scale and shows how transmission systems can be used in a decarbonised future.

23) http://irishsolarenergy.org/wp-content/uploads/2015/12/Energy-White-Paper-Dec-2015.pdf

24) Based on an yearly consumption of 1,500 m³ which is more or less the average in the Netherlands

Image courtesy of Sønderjysk Biogas Bevtoft A/S

Example 7: Bevtoft biomethane facility in Denmark

In July 2016 the Bevtoft biomethane facility (with a capacity of up to 21 million m³/year) was connected directly to the Danish transmission grid. Due to difference in gas quality specifications in Denmark (5,000 ppm oxygen) and Germany (10 ppm for sensitive assets) this resulted in a reduction in available capacity at Ellund towards Germany. In September the capacity was re-established, though the risk of flow reduction towards Germany still exists.

A so-called 'Oxygen Task Force' has therefore been established in order to assess all possible sustainable solutions whereby market distortions are avoided e.g. by exploring the possibility of removing the oxygen directly at the production site, at the border point, at the sensitive assets etc., and in a long-term perspective how oxygen level at an European level can be determined without distorting the growth of biomethane production.

As countries such as France and Ireland are expecting to increase the biomethane production from less than 100 GWh combined to over 20,000 GWh by 2026 and with all the other NW GRIP countries following suit to various degrees, biomethane is set to play a bigger role in the gas supply of the NW Region in the future.

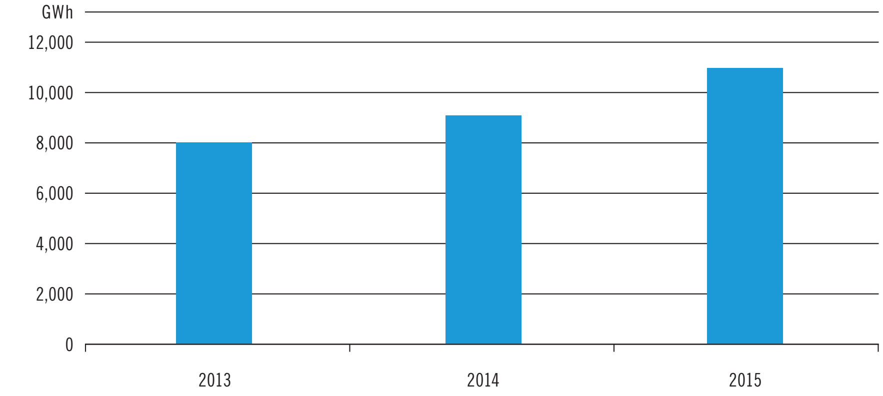


Figure 3.4: Biomethane injected into TSO and DSO grid (Source: NW GRIP TSOs)

With an outlook of increasing injection of biomethane into the NW Region gas grids in the years to come, the climate and environmental profile for gas consumption will also improve gradually as fossil natural gas is replaced by renewable gas. For example, as illustrated in the figure below, the increasing share of biomethane injected into to the grids in the NW Region has cut CO_2 emissions of approximately 5.5 million tonnes[25)] or the equivalent yearly CO_2 emissions from 2.7 million passenger cars[26)]. Biomethane must therefore be considered as a potential and important alternative energy source in the effort to achieving European and national climate emissions targets by reducing CO_2 emissions while simultaneously improving air quality[27)], by replacing fossil natural gas with renewable gases.

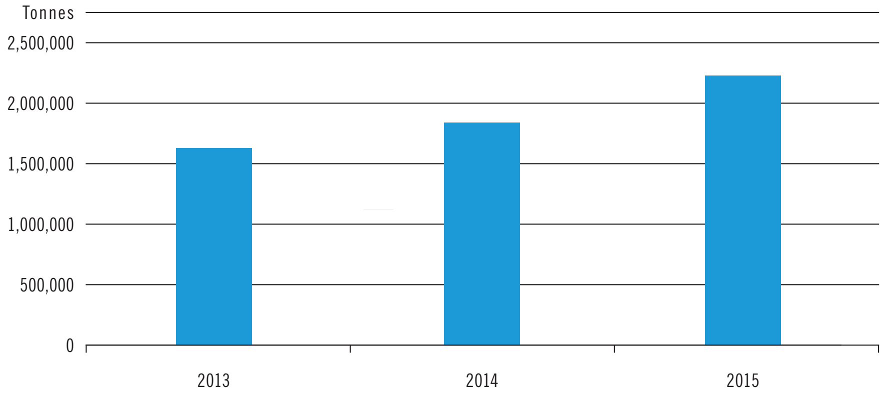


Figure 3.5: CO_2 savings from the displacement of natural gas in the NW Region (Source: NW GRIP TSOs)

25) CO_2 savings are calculated based on net calorific values in accordance with the IPCC Guidelines for National Green House Gas Inventories.

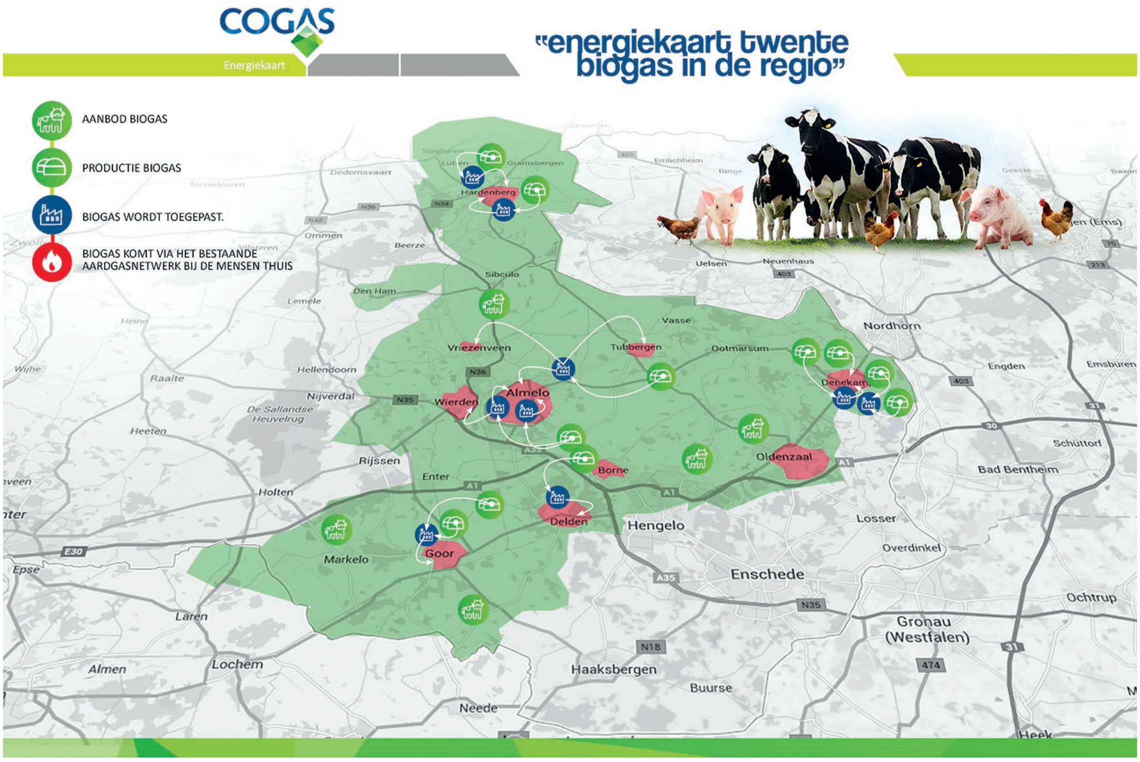
26) In 2014 an average passenger car in UK emitted 2 metric tons of CO_2. This is based on an average of CO_2 156.6 g/km and yearly mileage of 12,800 km. Source: New Car CO_2 Report 2015 (Society of Motor Manufacturers and Traders) & National Travel Survey: England 2014 (Department for Transport).

27) Reduction of particulate matter and NO_X emissions.

Example 8: Biogas Network in Twente

As of 26 January 2017 the Biogas Network Twente transports 'rough' biogas from the production site to a reprocessing plant, where it is converted into green gas. Cogas and Gasunie New Energy have developed the biogas network in Twente as a joint venture. The first producer connected to Biogas Network Twente is Oude Lenferink, a pig farm in Fleringen. Oude Lenferink will produce around 6 million m³ of biogas a year. From the production location in Fleringen, a 7,5 km long pipeline has been built to the Almelo reprocessing plant. In this reprocessing plant, the biogas is converted into approximately 4 million m³ of green gas. This green gas has the same quality as natural gas and can be injected directly into the natural gas network.

The pipeline from Fleringen to Almelo is the beginning of the Biogas Network Twente. There are plans to expand the network in the long term with a Gasunie pipeline to create a network connecting several producers and consumers of biogas. The advantage of this set-up is that multiple biogas producers can make use of one single central reprocessing plant. This minimises the pre-processing cost and encourages the production of green gas further. The Biogas Network Twente is designed to process and transport around 40 million m³ of green gas a year, the equivalent of 25,000 Dutch households thereby creating a saving in CO_2 emission of 6,000 tons every year.



3.4.1.2 Bio Synthetic Natural Gas (Bio-SNG)

In many of the present energy utilisation applications renewable biomass and biomass derived fuels could already replace fossil fuels with associated environmental benefits. For example, thermal gasification is where biomass is converted into a fuel e.g. SNG, which can substitute fossil fuels in high efficiency power generation and CHP applications. Considering biomass is a renewable resource this may very well become a significant component in the drive to achieve a higher degree of renewable sources in the energy mix. In addition, biomass is considered CO_2 neutral as it removes from the atmosphere via photosynthesis the same amount as it releases via the gasification process.

Example 9: Bio-SNG in UK

A project to build a demonstration bio-SNG plant near Swindon that will use organic waste and biomass has been awarded funding by Ofgem as part of the Network Innovation Competition (NIC). The demonstration plant is planned to be operational in 2018 producing up to 2 mcm per year of bio-SNG. This will either be used as compressed biomethane (CBM) for road transport or injected into the gas network. If the technology can be developed successfully the developers anticipate that there could be production of around 3 bcm by 2030, rising to 9 bcm by 2050.

Whereas biomethane contained in biogas is produced via anaerobic digestion of organic materials (e.g. manure, organic waste etc.), thermal gasification is where biomass (e.g. forestry residues) is transformed in a process using less oxygen than normal combustion (gasification). The technique requires that the raw materials are controlled under high pressure, to derive methane gas. When heated, the fuel's hydrocarbons are broken down to form a SNG. The SNG is then upgraded to methane gas. However due to the high levels of carbon monoxide in the bio-SNG, it is not expected to be possible to transport it in the gas system without conversion to methane.

Besides being able to be injected into the existing natural gas grid, biomass derived SNG can, with minor equipment modifications, also be used in most of the current natural gas energy conversion devices[28]:

- Air-blown gasification produces a clean burning fuel gas that could be used for direct combustion in boilers to produce heat and steam, or in gas and Stirling engines to produce electricity in the 20–30 % efficiency range.
- Pressurised gasification with close-coupled gas turbines offers the capability to produce electricity at 40 % or higher efficiency.
- Enriched-air or oxygen blown gasification produces a SNG, suitable for conversion to hydrogen, chemicals, fertilizers, or substitute liquid fuels.

Example 10: GoBiGas in Sweden

GoBiGas (Gothenburg Biomass Gasification Project) in Sweden is the world's first demonstration plant for large scale production of bio-SNG through the gasification of forest residues. The site is dimensioned to produce 20 MWth product gas from 32 MW fuel input. The 20 MW demonstration plant with a capacity of supplying bio-fuels to approximately 15,000 cars or 400 buses a year was initiated in March 2014 and became fully operational in December 2014.

28) Source: IEA Bioenergy Taskforce 2013: Thermal Gasification of Biomass.

3.4.1.3 Hydrogen and methane from Power to Gas

Power to Gas converts renewable electrical power into a gaseous energy carrier. This means that renewable electricity can be converted into hydrogen which can be directly injected in the gas grid and transported and stored in the gas system. As hydrogen changes the quality and heating value of natural gas, intense research, aimed at defining optimum injection rates and identifying measures to make current gas infrastructure fit for hydrogen, is currently being undertaken. Hydrogen can be utilised directly as a transport fuel or in the chemical industry or undergo a process of methanisation by the synthesis of hydrogen and carbon dioxide to become a bio-SNG which can be injected into the natural gas grid. In a future electrical energy system powered by intermittent renewable energy sources such as solar and wind, this technology must be considered as an important element in turning system and sector coupling into reality[29)].

In the 2030 Framework for climate and energy, EU countries have among others set a target of at least a 27 % share of renewable energy consumption by 2030[30)]. With an increasing proportion of renewables in the energy mix, with strong preferences to fluctuating wind and solar energy, the match between renewable power supply and demand is becoming more challenging. An example of this can be found in Germany where strong winds in 2009 caused a 71 hours of wind curtailment resulting in an economic damage of approximately 100 million Euros. By converting excess renewable electricity to hydrogen or SNG, the gas infrastructure can function both as a storage medium as well as an instantly available back-up in case of shortages. Furthermore valuable synergies can be found when integrated with the chemical industry and mobility sector. When imbalance issues in the power infrastructure are solved by applying power to gas, the chemical industry and mobility sector can be fed by renewable hydrogen. In this way a win-win situation is created between the intermittent effects of renewables and that need for decarbonisation in the industrial or mobility sectors.

29) Source: Henning & Palzer 2015: THE ROLE OF POWER-TO-GAS IN ACHIEVING GERMANY'S CLIMATE POLICY TARGETS WITH A SPECIAL FOCUS ON CONCEPTS FOR ROAD BASED MOBILITY, Fraunhofer ISE.

30) Source: https://ec.europa.eu/clima/policies/strategies/2030_en


Image: iStockphoto.com

This perspective has in recent years fostered an increasing interest in R&D activities related to Power to Gas in Europe. Out of the around 50 pilot and demonstration projects launched worldwide, most of them being announced in the past three years, 37 are located in the NW Region with another 11 planned in the near future[31].

Example 11: GRTgaz's initiative for Power to Gas[32]

'Jupiter 1000' is the first Power to Gas project connected to the gas transmission network in France and the first experiment at a MW scale. The project will recycle CO_2 from stack emissions by integrating a CO_2 capture unit on the chimneys of a local industrialist. The project is carried out in close cooperation with industrialists which will consume the gas produced by the Power to Gas demonstration plant.

Coordinated by GRTgaz and carried out in collaboration with the Marseille Port Authority, 'Jupiter 1000' calls upon various French partners with complementary skills, involving, injection of hydrogen, production of synthesized methane, recovering of CO_2 from industrial smoke and two electrolysis technologies.

The cost of the project amounts to €30 million, almost two thirds of which are financed by industrial partners and a third by subsidies. The French Regulatory Commission of Energy (CRE) is also backing the project which enters into the framework of the energy transition, and which aims to expand use of natural gas networks in the long-term.

The development of Power to Gas is promising to further integrate the existing power and gas networks via the intermediate step of hydrogen. Also in that step, gas grids can play a role. Besides biomethane produced out of hydrogen, gas grids can also be used to transmit the hydrogen directly. With some adaptations, existing infrastructure can be converted to carry hydrogen instead of natural gas. This has been proven in several locations in NW Europe and can be of value in places where hydrogen use as an energy stock or carrier is expected to increase. The benefits of transmitting hydrogen via the grid instead of converting it back and forth in to methane or electricity are obvious in terms of efficiency, economics and emissions. An example of such synergies is given below.[32]

Example 12: Hydrogen symbiosis in Zeeland

Chemical companies Dow Chemical, Yara and ICL-IP Terneuzen are planning to exchange hydrogen via the gas transmission grid of Gasunie Transport Services in the most South Western part of the Netherlands. Dow Benelux produces hydrogen as a by-product, while fertilizer producer Yara and bromine producer ICL-IP need hydrogen as feedstock for their production processes. By exchanging hydrogen, these companies can significantly reduce their combined CO_2 emissions. The hydrogen is planned to be exchanged via an existing gas pipeline of Gasunie Transport Services. The usage of the underground gas transport grid provides a durable, efficient and safe way of transporting of hydrogen, eliminating the need for transport via road, railway or water. On the 14 March 2016 a so called Green Deal was signed by the Minister of Economic Affairs and the companies involved, paving the way for realizing this initiative. This Green Deal shows that the national gas transmission network provides a solution to achieve sustainability in sectors which are typically more difficult to decarbonise.

31) Source: European Power to Gas Platform.

32) www.jupiter1000.com/en/accueil.html

3.4.1.4 Renewable gases guarantees of origin

The market for renewable gases, notably biomethane, injected into the natural gas grid is at very variable rates and based on a range of different support schemes, at various stages of development within the NW Region Member States. Registering quantities and characteristics of renewable gases injected into the natural gas grid in national biogas registers for mass balance purposes is a key function for enabling renewable gas trading.

At the moment certification systems of the guarantee of origin (GoO) are mostly focused on biomethane[33)]. Registering biomethane when it is injected into the natural gas grid serves to document the origin of the gas and prevents double counting. Registers are already established in almost every country of the NW Region.

CERTIFICATION SYSTEM THAT GUARANTEES THE ORIGIN OF RENEWABLE GASES									
	BE	DE	DK	FR	IE	LU	NL	SE	UK
YES		×	×	×	×		×		×
NO	×					×		×	

Table 3.6: Overview of certification systems in NW Region (Source: NW GRIP TSOs)

An important factor in terms of maximising the potential of renewable gases to contribute to security of supply and carbon reduction targets is the ability to trade it across national borders. This will enable transfer of biomethane to areas where the demand exceeds production and vice versa, thus increasing the producer's opportunities to reach significantly larger markets and enhancing the incentive to introduce large scale production plants of biomethane in the NW Region.

A big step in realising this vision was taken on the 28 September 2016 as the European Renewable Gas Registry (ERGaR) was established in order to ensure an independent, transparent and trustworthy documentation scheme for mass balancing of biomethane distributed along the European natural gas network.[34)]

At the time of writing ERGaR constitutes of 11 members whereas 8 are to be found in the NW Region.

3.4.2 ENERGY EFFICIENCY IN GAS TRANSMISSION

Energy efficiency has been an overall target within the European Union for years. The 2012 Energy Efficiency Directive (2012/27/EU) foresees binding measures which shall contribute to reaching the 20% energy efficiency target of the EU by 2020. According to Recital (1) of the 2012 Energy Efficiency Directive, *'Energy efficiency […] improves the Union's security of supply by reducing primary energy consumption and decreasing energy imports. It helps to reduce GHG emissions in a cost-effective way and thereby to mitigate climate change. Shifting to a more energy-efficient economy should also accelerate the spread of innovative technological solutions and improve the competitiveness of industry in the Union, boosting economic growth and creating high quality jobs in several sectors related to energy efficiency.'* Member states were required to transpose the Directive's provisions into national laws by 5 June 2014 and by implementing these laws stimulate a more efficient use of energy at all stages of the energy chain from its production to its final consumption.

33) A GoO certification scheme for premium hydrogen is currently being developed by the CertifHy Consortium.

34) See press release: http://www.biosurf.eu/wordpress/wp-content/uploads/2016/10/ERGaR-press-release-final.pdf

In line with the IEA[35] definition of energy efficiency as 'a way of managing and restraining the growth in energy consumption' it has also been the understanding of the members of the NW Region that before discussing ways of generating, transporting or storing energy the question needs to be raised how to save energy and, by doing this, reduce energy demand. The objective to find ways to use energy more efficiently in gas transmission has not only been requested by the Directive, but was addressed in Regulation (EC) No 715/2009 which in Article 8(6) lit. f foresees ENTSOG to define rules for 'energy efficiency regarding gas networks'.

NW GRIP members have taken high energy efficiency as a challenge and this subchapter shows examples of how this challenge is met by TSOs. Their activities, projects and initiatives to improve energy efficiency can be divided into two categories:

1. **Technological/operational measures directly related to the transmission systems and gas transport; i.e. to the core business of the TSOs**

2. **Technological, administrative and organizational measures related to non-transmission activities; i.e. the auxiliary daily business.**

In both respects, the NW GRIP members have worked towards achieving compliance with the Directive. By tackling energy efficiency issues from different angles and establishing tailored strategies to find the most efficient ways to improve energy efficiency, each of the NW GRIP TSOs have developed special know-how and expertise. On top of the EU Energy Efficiency Directive, national legal and regulatory frameworks that were already in place from the past and the National Energy Efficiency Action Plans that were developed following the Directive in the NW GRIP countries recently have backed-up and motivated TSOs to give energy efficiency a high priority.

A recent example of how TSOs increase energy efficiency in gas transport are mobile gas compressors that have been implemented for instance in France, Germany and the Netherlands. These solutions help to avoid venting of gas under repair/maintenance works on the network and thus reduce methane emissions and energy loss.

In common with other industries, TSOs in the NW Region feel responsible for their environment and try to save and/or efficiently use energy. Also, a bigger awareness towards the use of low carbon energy – wherever possible in daily non-gas transmission business – has been developed. For example, several TSOs deploy CNG cars and either purchase or generate renewable power, e.g. from solar panels on company buildings, for system operation and office use.

Though these are only snapshots of a whole series of activities which NW GRIP TSOs undertake to improve their energy efficiency, the above examples have proven their worth already in the course of decarbonising the economy. The TSOs are aware of the fact that in particular the technological/operational measures are of interest and importance in cases where the 'well-to-wheel' carbon footprint of natural gas and its applications are considered. With this approach of evaluating the contribution of a fuel/technology to CO_2 emission reduction or the even more comprehensive 'lifecycle' assessment, energy efficiency measures can be tested and compared to alternative fuels and technologies. By further improving energy efficiency, NW GRIP TSOs aim at an important contribution towards making gas and gas-based technologies competitive in the NW Region's future energy mix and offering benefits to their economies, environments and societies.

35) Source: www.iea.org/topics/energyefficiency

4 Market development in North West Europe

Image courtesy of National Grid

4.1 Introduction

The NW Region has pioneered liberalised gas markets. Access to several supply sources, including substantial indigenous production, and high gas demand have favoured the formation of the most liquid hubs in Europe with further improvements in recent years confirming the leading position of the NW Region. The early implementation of Network Codes (CAM and Balancing) has created easier access for market players, while the successful mergers of hubs have been milestones for market integration between Belgium and Luxembourg, and in the South of France.

Strong interconnections between countries help ensure price convergence between wholesale markets. A key task for any TSO is to ensure that there is enough capacity available efficiently to market participants. By ensuring enough capacity, TSOs allow the flow of gas to where it is most valued based on price signals. The evolution of prices in the North West European Gas Hubs demonstrate a high level of convergence, with the exception of TRS, in the south of France, where continuous spreads with PEG Nord have led to investments to increase capacity and create a single market.

4.2 North West European Gas Hubs

The gas hubs in the NW GRIP are the largest and most liquid hubs in Europe. They have continued to grow in recent years, many of them experiencing record levels of traded volumes in 2015[36)].

The TTF hub in the Netherlands and the NBP hub in the United Kingdom are the two largest, most mature, and most liquid hubs in Europe. Together, they represent over 80 % of European traded volumes, and have churn ratios three times higher than any other European hub. So far, they are also the only two hubs that meet all of the targets for hub liquidity as defined by ACER in the January 2015 revision of the Gas Target Model. As of 2014, TTF has taken first place in terms of traded volumes in Europe, overtaking the NBP. This has been partly attributed to increased liquidity at the TTF hub due to a change in balancing regime implemented in June 2014. TTF also remains a preferred benchmark for traders managing their gas portfolios.

36) Parts of the following analysis are based on the July 2015 IHS 'European Gas Hub Tracker' report.

The physical hub Zeebrugge Beach in Belgium is also one of the most mature hubs on the continent. It serves as a gateway to Europe for gas coming in from Norway, the UK, and LNG from the Zeebrugge LNG Terminal. As of the end of 2015, it has also been connected to the Dunkirk LNG terminal, commissioned in 2016 in France. The ZTP (the virtual Zeebrugge Trading Point) has continued to grow since its inception in October 2012. In October 2015, ZTP became the gas trading point for the new BeLux balancing zone, the integrated gas market for Belgium and Luxembourg.

The two German hubs, NetConnect Germany (NCG) and GASPOOL, continue to experience growth in traded volumes and number of transactions. The NCG is the more liquid of the two German hubs.

The PEG Nord hub ('Point d'Echange de Gaz') is the largest of the two trading regions in France. The TRS hub (Trading Region South) was launched on 1 April 2015. It is the product of the merger between the PEG Sud and the TIGF trading regions in the South of France, and is one of the first cases of successful market integration between gas hubs. The TRS was established with the aim of increasing the liquidity and depth of the southern French market. It is also part of a comprehensive plan overseen by the French National Regulator CRE to establish a unified trading zone for France in 2018.

The Gaspoint Nordic (GPN) hub in Denmark was created in 2008, and, though very small, accounts for approximately 70 % of the present Danish gas consumption.


Image courtesy of Fluxys

4.3 Hub Liquidity

Traded volumes in the North West hubs have grown steadily, with a 23% yearly increase in 2014 and a 12% increase in 2015. The TTF hub has overtaken the NBP hub in 2014 as the hub with the highest traded volume. NBP and TTF account for 85% of the volume traded on hubs in the NW Region.

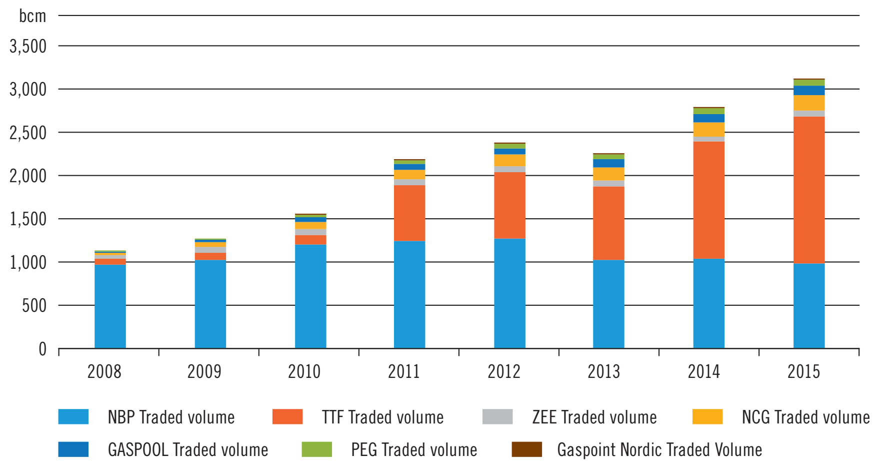


Figure 4.1: Traded volumes at North West gas hubs, 2008 to 2015 (Source: IHS, Gaspoint Nordic)

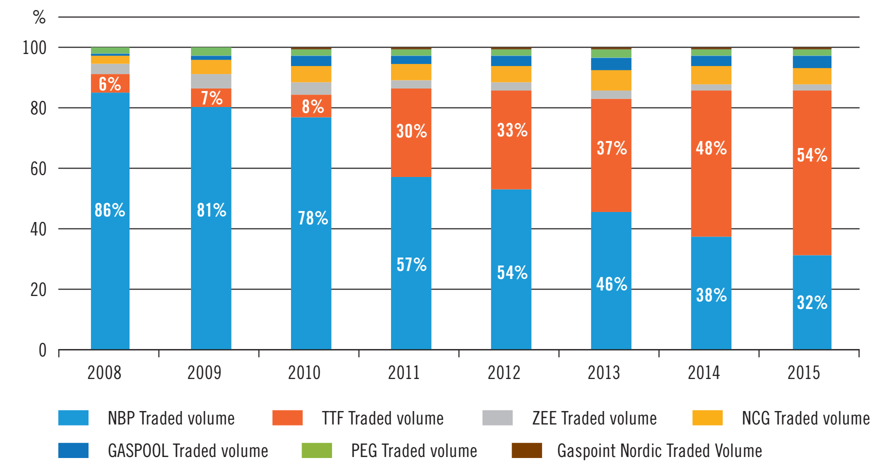


Figure 4.2: Breakdown of traded volumes at North West gas hubs, 2008 to 2015 (Source: IHS, Gaspoint Nordic)

Liquidity has continued to increase as well. The churn ratio represents how many times a volume of gas is traded on average on a hub before consumption. As shown below, the TTF hub has by far the highest churn ratio of the NW Region, in part due to the implementation of a new balancing regime in June 2014 in accordance with the European Union's Balancing Network Code.

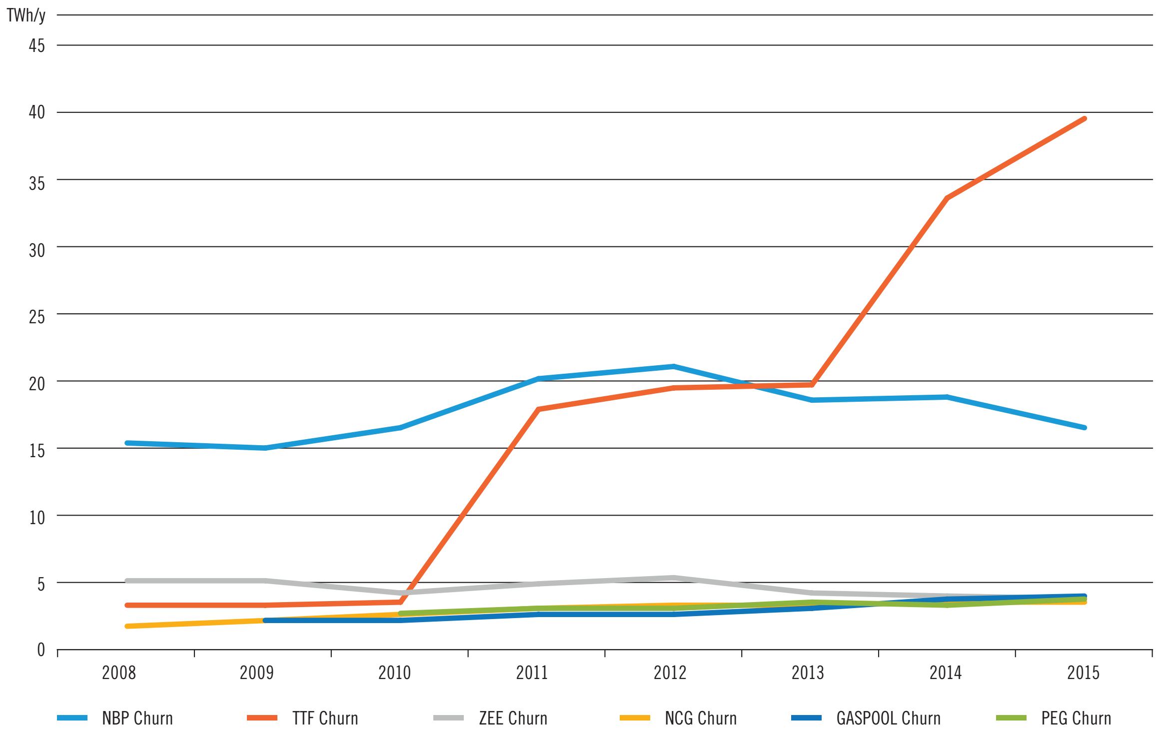


Figure 4.3: Evolution of churn ratio between 2008 and 2015 (Source: IHS)

4.4 Hub Prices

Price correlation between gas hubs is a good way to measure market integration, as strong interconnections between hubs and reduced physical, regulatory, and contractual barriers tend to decrease price volatility.

As such, the close price correlation illustrated by the two figures presented here is evidence of the high level of market integration, liquidity, and competitiveness between North West hubs.

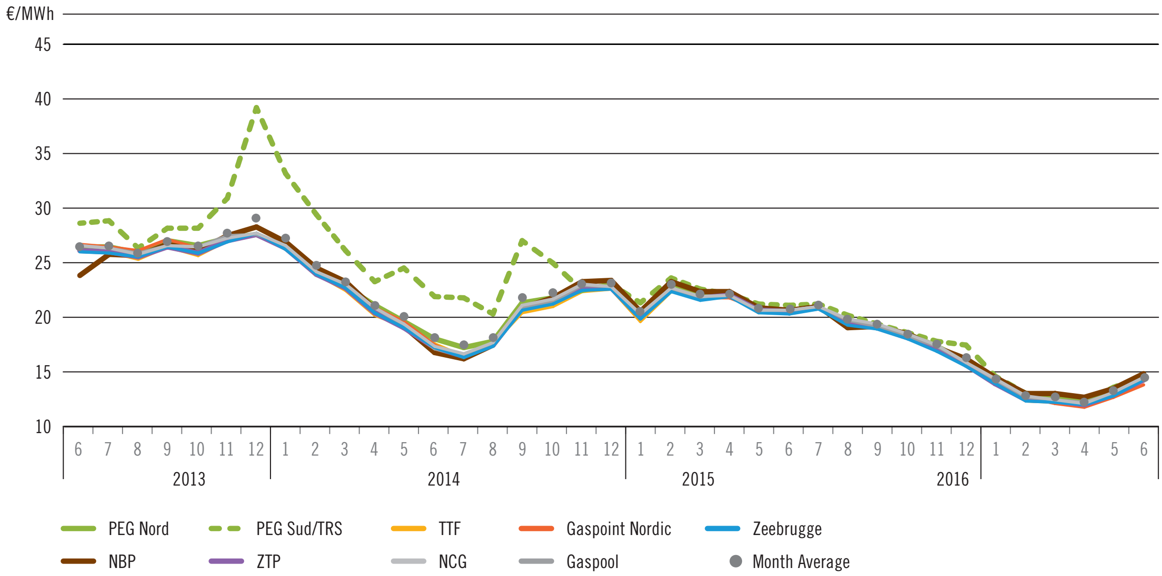


Figure 4.4: Day-Ahead Gas Price Evolution at European Hubs (2013–2016 monthly averages) (Source: Bloomberg, Powernext, Gaspoint Nordic)

The overall decrease in gas prices can be attributed primarily to a reduction in demand for gas (especially after the mild 2013–2014 winter), a decrease in world-wide fuel prices, particularly petrol, and an increase of LNG exports to Europe after LNG prices fell in Asia. The gas price hike during the third and fourth quarters of 2014 is mainly due to worries about the supply of Russian gas at a time of geopolitical tensions with Ukraine.

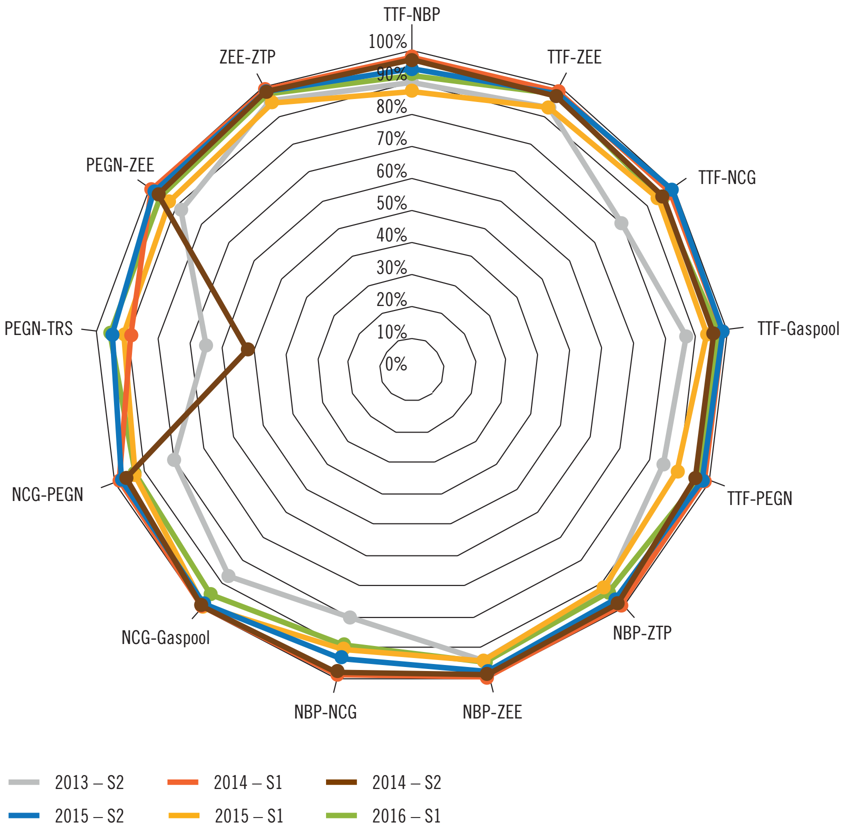


Figure 4.5: European Hub Price Correlation 2013–2016 (Source: Bloomberg, Powernext)

The graph above illustrates the high degree of integration in NW Region hubs. The very high price correlation is the result of scarce commercial barriers, and is only improving with time. The only disconnected hub is the TRS, where prices are influenced by the region's LNG dependence and the existence of a physical bottleneck in the French network between the PEG Nord and the TRS trading zones (see case study 4.4.1). In the end, a well-connected region with an integrated market benefits the end-user consumers who can reach the most competitive suppliers.

4.4.1 CASE STUDY: BOTTLENECK LINK NORTH-SOUTH

Despite continued efforts and investments to increase integration between gas hubs, bottlenecks remain at some interconnection points.

One example is that of the TRS, where an important price spread occurred between 2012 and 2015 due to a physical congestion at the North-South link in France.

While marginal in 2011, the price spreads between North and South zones has deepened under the impact of low LNG deliveries in Europe, and rose from 1.6€/MWh in 2012 to 3.5€/MWh in 2014, even reaching 17€/MWh in December 2013.

Pressure on this point has been eased since early 2015, thanks to lower LNG prices in Asia, higher LNG deliveries in Spain and an increased use of storages in the area.

This situation is expected to be resolved with the planned merger between the PEG Nord and TRS trading regions and the establishment of a unified trading zone for France in 2018. Indeed, investments such as the Val de Saône project are ongoing in order to solve the physical congestion.

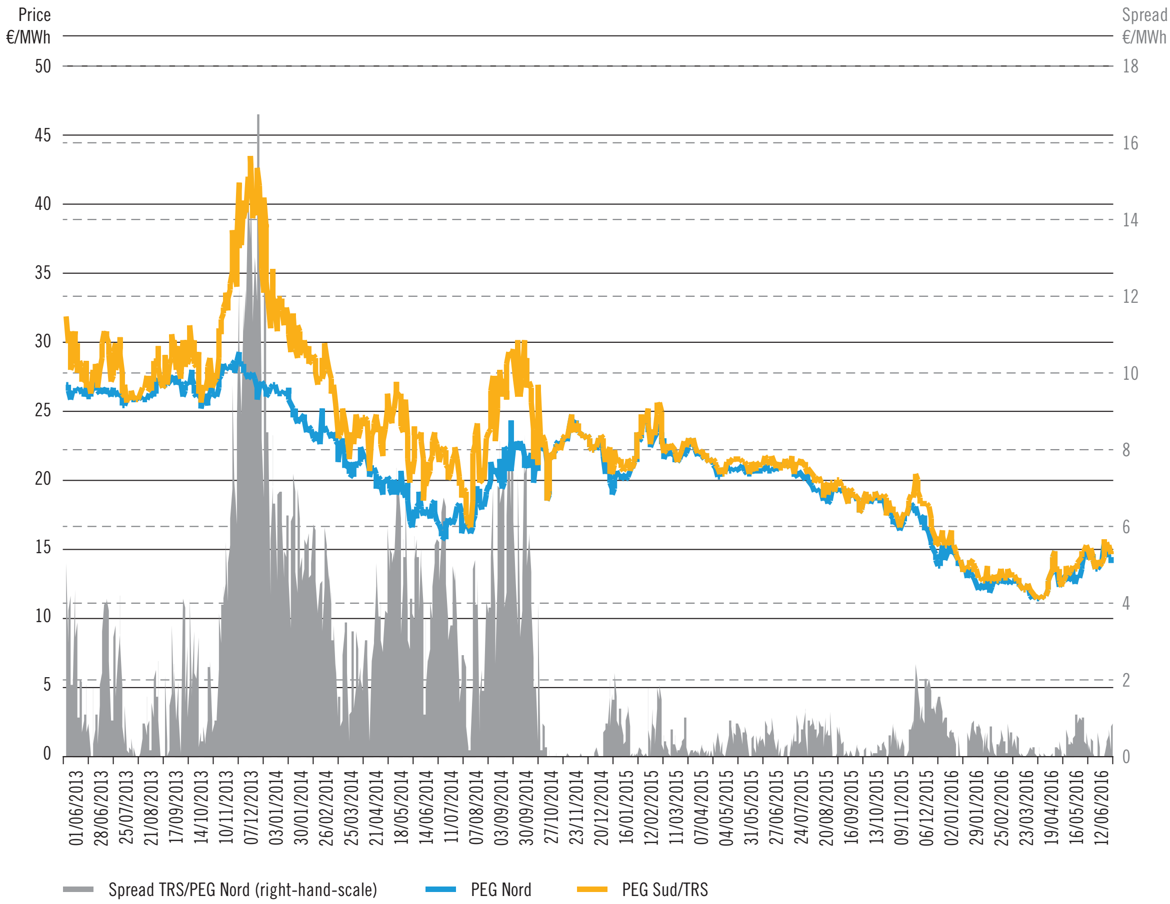


Figure 4.6: Evolution of price spread between TRS and PEG Nord (Source: Powernext)

5 Supply & Demand

Image courtesy of Fluxys

5.1 Introduction

In this chapter an overview is given of gas supply and demand in the NW Region. A comparison is made between the NW Region and the EU as a whole. The demand for gas (on an annual basis and on a peak day) is presented according to four scenario storylines. In all scenarios, gas demand is stable to decreasing, but indigenous production is decreasing faster.

Import dependency is therefore increasing. Although current direct import infrastructure is capable of importing additional gas, extra infrastructure will have to be evaluated to make sure that these additional import volumes can be transported up to where the gas is needed. Unlike total gas demand, the power generation sector is expected to increase in most scenarios.

The scenarios used in describing the development of gas demand have been defined in the ENTSOG TYNDP 2017. These define the basis of the analysis performed for the NW Region.

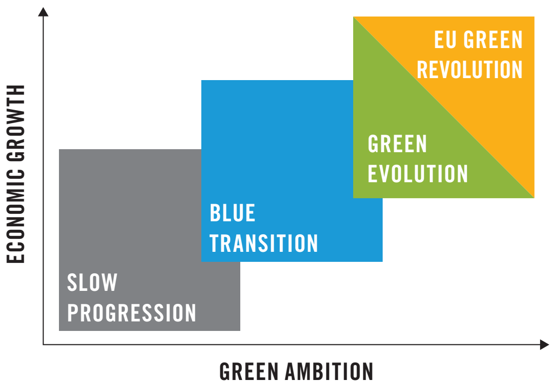


Figure 5.1: ENTSOG TYNDP 2017 scenario storylines (Source: ENTSOG TYNDP 2017)

Slow Progression
The economic growth is limited in this scenario. Green ambitions are the lowest and so the energy generation mix stays generally the same as today.

Blue Transition
This scenario shows efficient achievement in terms of green ambitions under a context of moderate economic growth.

Green Evolution
This scenario is characterised by favourable economic conditions and high green ambitions with high RES development.

EU Green Revolution
The storyline for the Green Revolution scenario is largely based on the same assumptions as Green Evolution, however the EU 2050 climate targets are reached earlier.

A further explanation of the scenarios can be found in the ENTSOG TYNDP 2017[37].

37) Source: www.entsog.eu/publications/tyndp#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2017

5.2 Annual Demand

When comparing the development of annual demand in the NW Region and in the EU as a whole similar patterns are observed. The final demand (public distribution, industrial customers and transport sector) in the NW Region is expected to be stable to decreasing in all scenarios, due to further efficiency measures both in homes and in industry.

On the other hand, gas demand for power generation is increasing, except for the slow progression scenario, both in the NW Region and the whole EU. In none of the scenarios is it envisaged that total demand in the NW Region will increase while for the whole of the EU we observe a small increase in the blue transition scenario only.

Figure 5.2 shows the expected development based on TSO estimations, linking it to actual figures from the recent past. It must be noted that the winters were fairly mild and the historical values are not temperature corrected, while the future figures assume an average annual temperature.

The NW Region represents around 60 % of total EU gas demand, but this share is slowly decreasing towards 50 % in 2036. The reason for this is that the gas market in the NW Region is mature with a high penetration of gas in the fuel mix. Improved energy efficiencies, for example ongoing insulation of homes, are important factors for the decreasing gas demand and the decreasing share relative to the EU as a whole.

A further observation is the steep decline in gas demand for power generation in the past few years. There are two underlying reasons that explain this drop. The first reason is the competition between gas and coal. The lower coal prices in the world market make the spark spread for coal fired power generation more attractive than for gas fired power generation, putting coal ahead of gas in the merit order for power generation. Another reason is the increasing share of renewable generation, mainly solar and wind. When available, these have near zero marginal cost and thus are placed before gas in the merit order thereby reducing gas volumes. In the future, depending on the scenario, gas will remain stable or regain market share in power generation if climate protection measures and CO_2 prices in the ETS increase, which would make coal less attractive compared to gas.

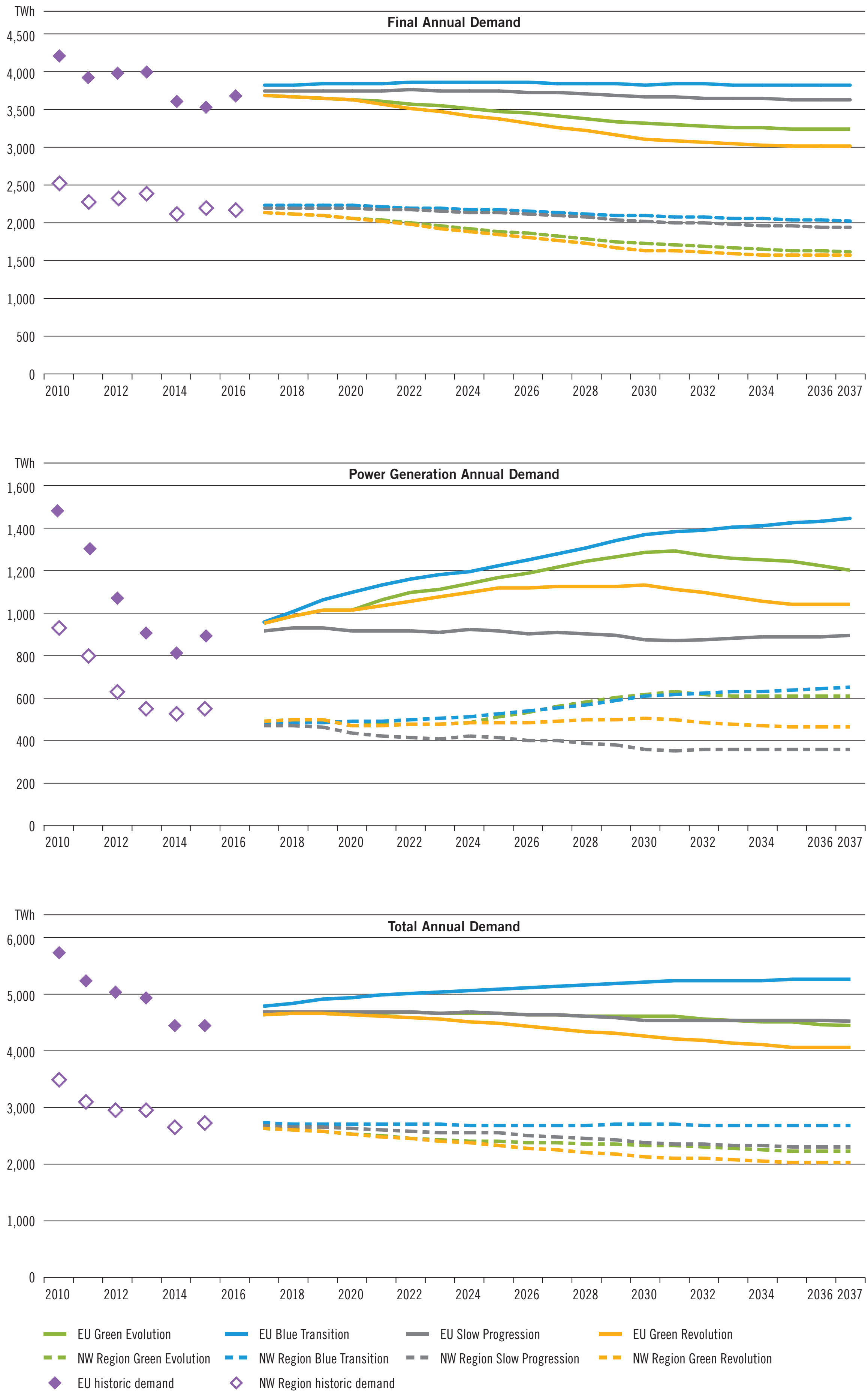


Figure 5.2: Final Annual Demand, Power Generation Annual Demand and Total Annual Demand (Source: ENTSOG TYNDP 2017)

5.3 Peak Demand

The final gas demand on a peak day in the countries of the NW Region shows a gradual decrease in all countries.

The peak gas demand for power generation shows a more diverse picture. All scenarios, except the slow progression scenario, show a modest increase in peak demand.

The combination leads to a steady to slow expected decrease in overall gas peak demand

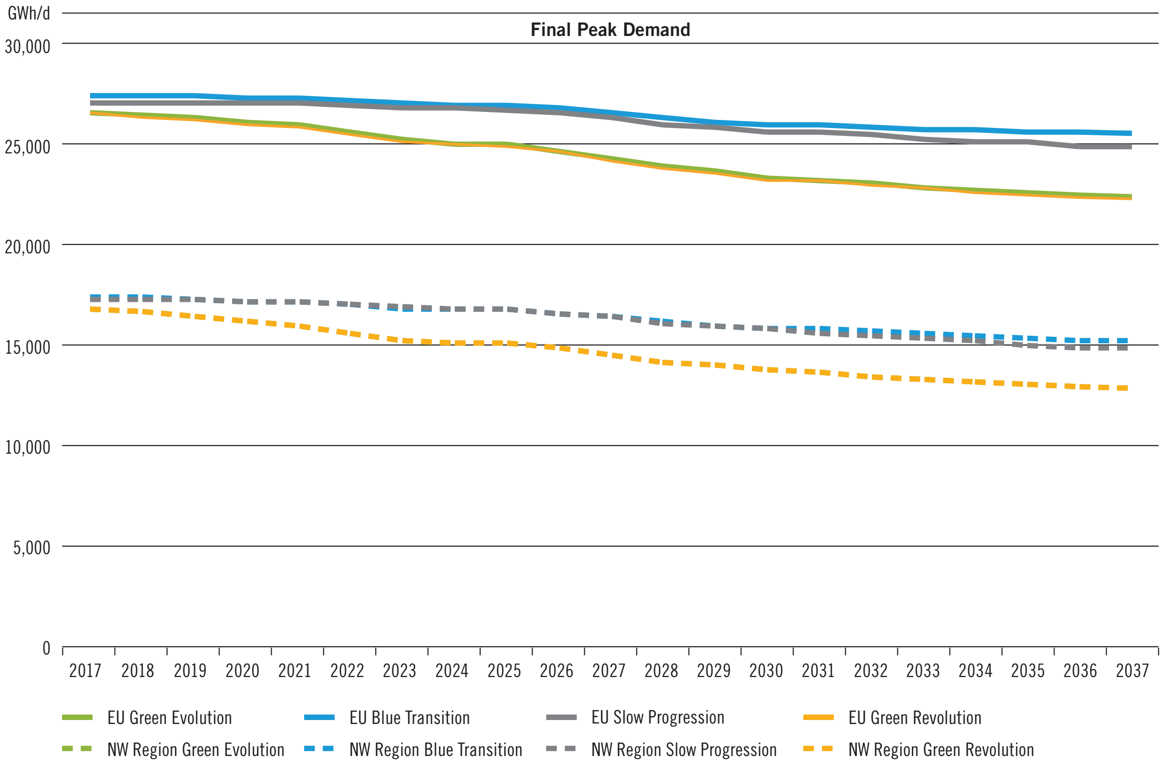


Figure 5.3: Final Peak Demand (Source: ENTSOG TYNDP 2017)

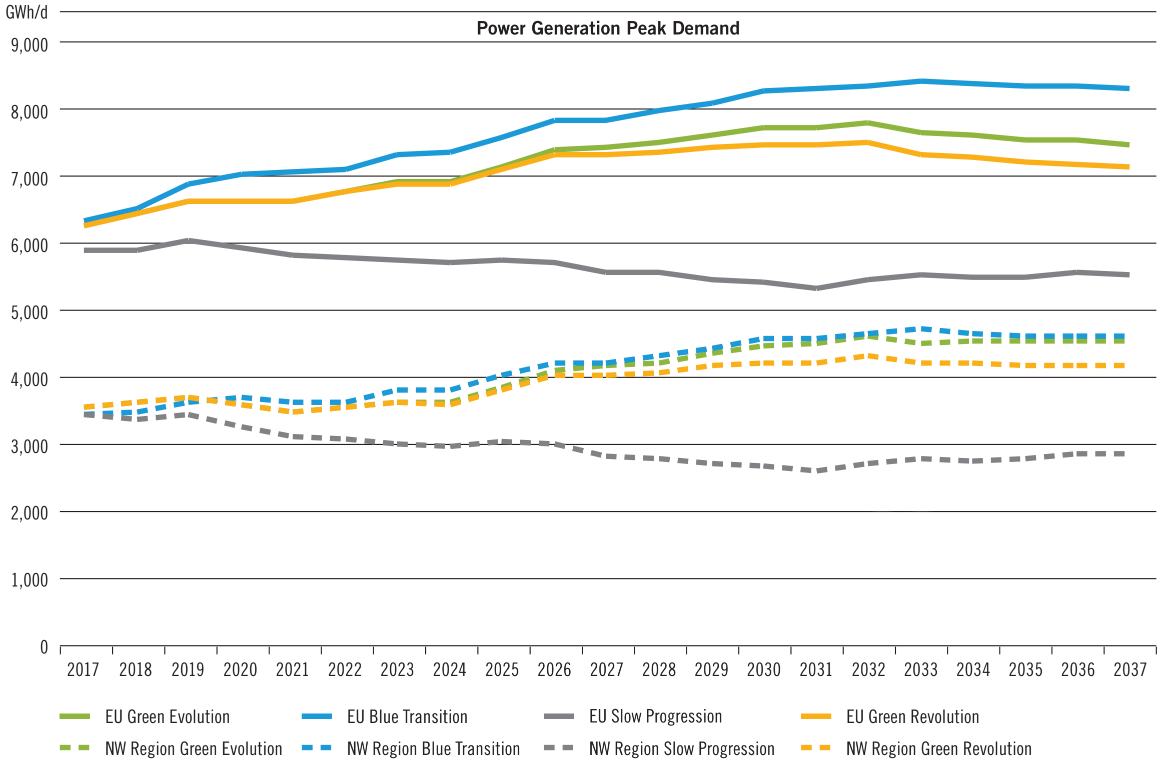


Figure 5.4: Power Generation Peak Demand (Source: ENTSOG TYNDP 2017)

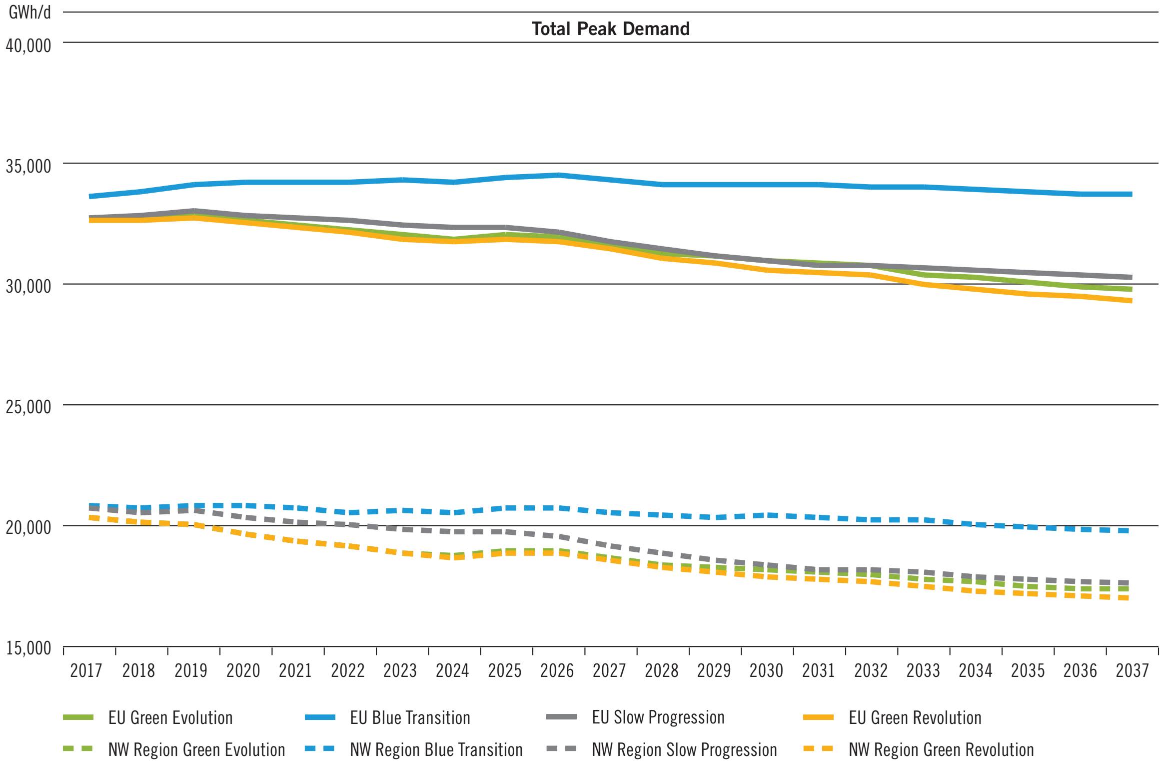


Figure 5.5: Total Peak Demand (Source: ENTSOG TYNDP 2017)

5.4 Load Factors

The load factors of final demand, gas for power generation and total demand are presented in the graphs below. A load factor can be defined as the average load divided by the peak load in a specified time period.

It can be observed that the load factors in the EU as a whole are always higher than in the NW Region, for all market segments. The development of the load factors is different depending on the scenarios. In the Green Revolution scenario in particular, a decrease can be seen, which suggests that gas demand is tending to show more extremes. This can be explained by an increasing role for gas as a back-up fuel and a decreasing role for gas as bulk energy supplier.

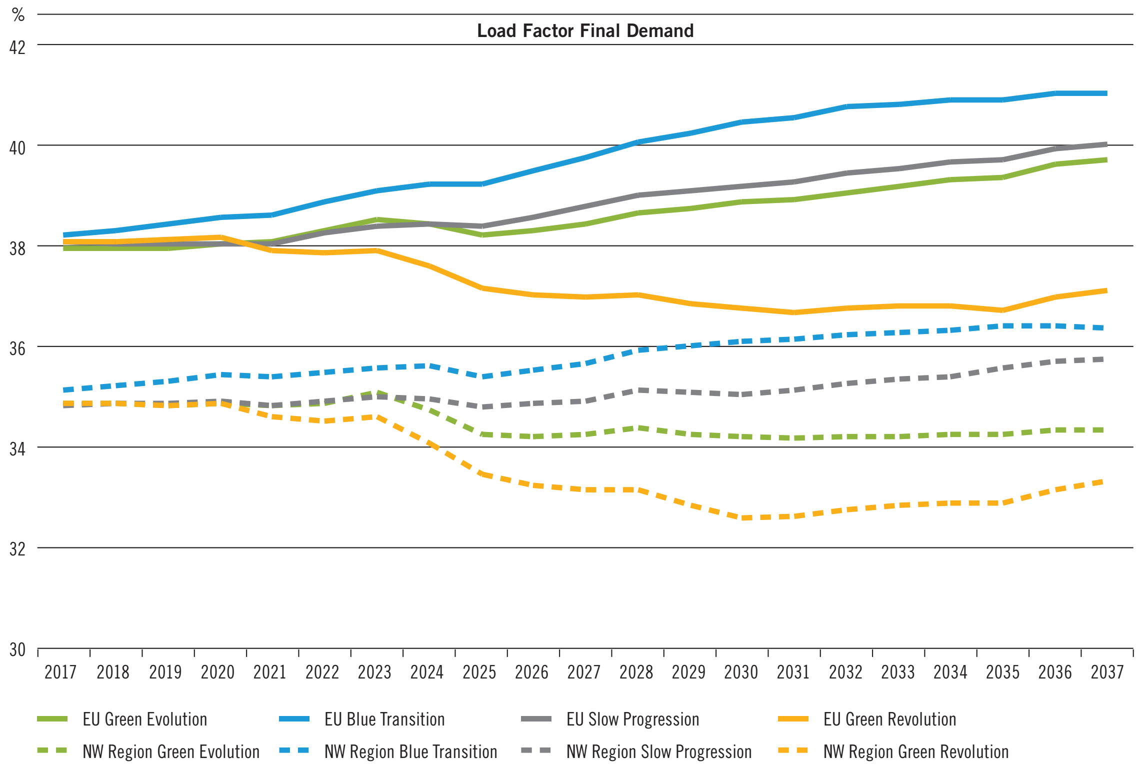


Figure 5.6: Load Factor Final Demand (Source: ENTSOG TYNDP 2017)

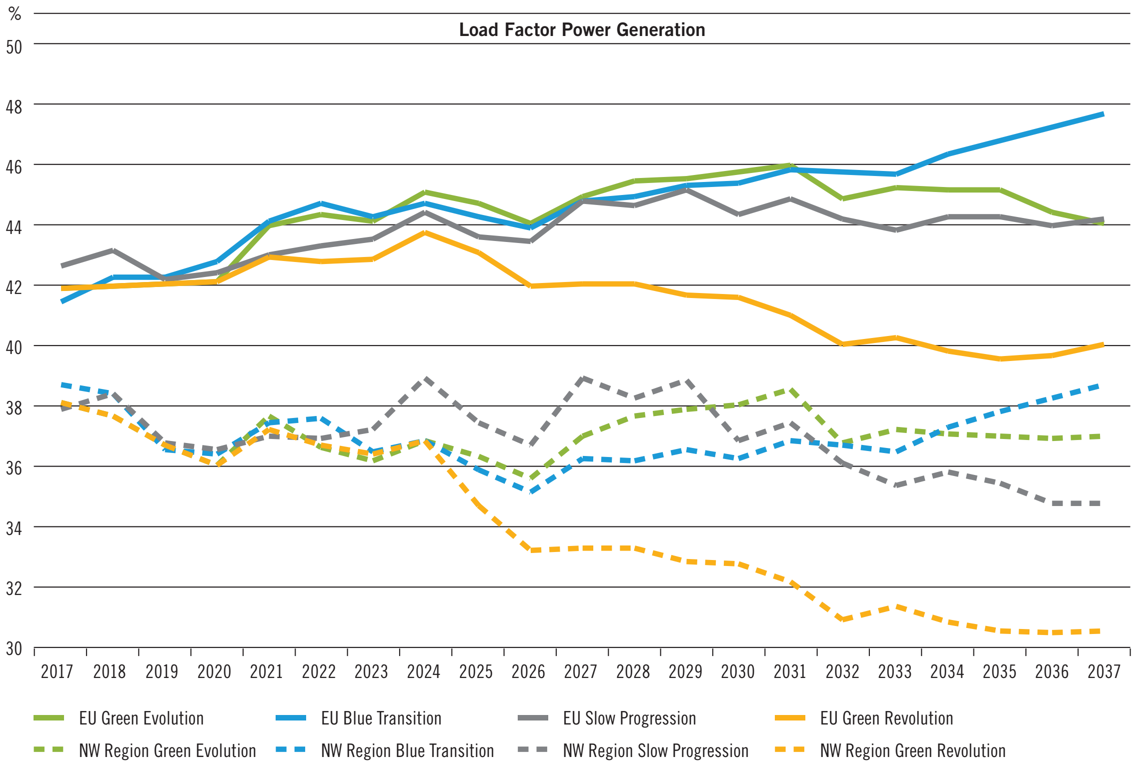


Figure 5.7: Load Factor Power Generation (Source: ENTSOG TYNDP 2017)

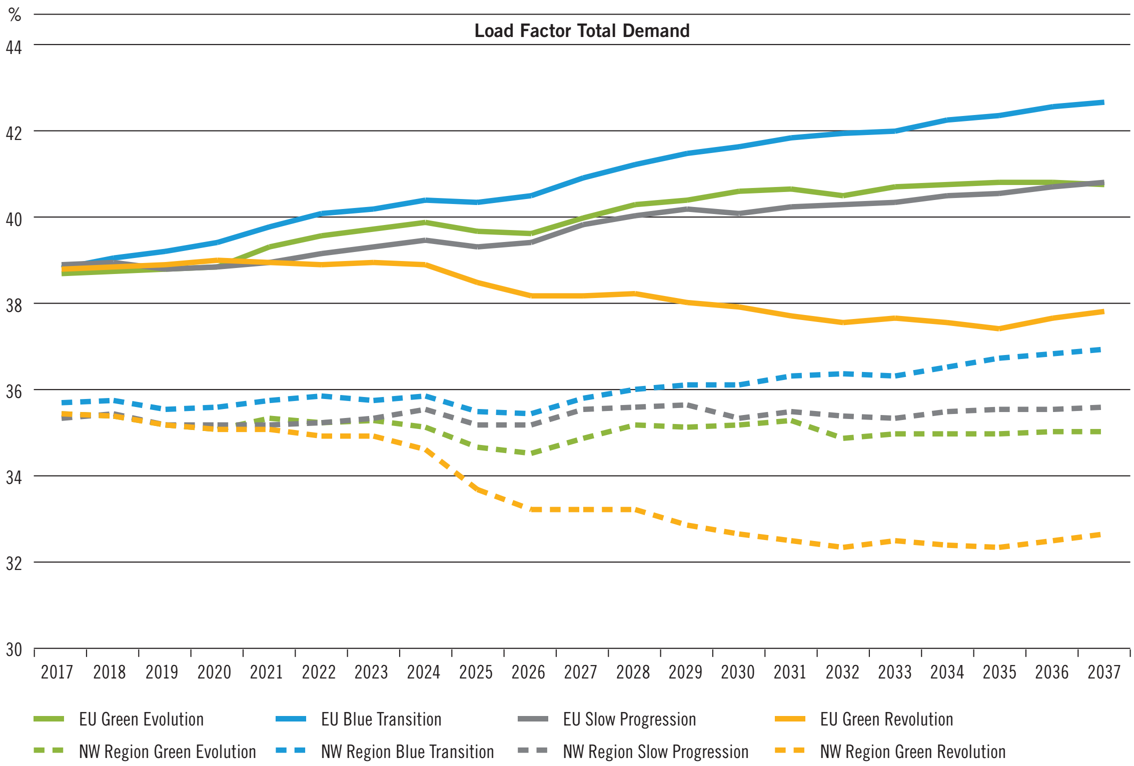


Figure 5.8: Load Factor Total Demand (Source: ENTSOG TYNDP 2017)

5.5 Direct Supply to the NW Region and Import Dependency

The NW Region has many interconnections with other European regions and has also direct access to several supply sources (information from the ENTSOG TYNDP 2017 Annex C and D) including:

- National Production
- Imports from Norway[38)]
- Imports from Russia via Nord Stream and potentially Nord Stream 2[39)]
- Imports from LNG[40)]

National production and the volumes that can be imported from a direct linked supply source are shown in figure 5.9, not taking into account the flows to or from interconnections with other European regions.

A comparison between the directly linked annual supply capability to the NW Region and demand described in the four scenarios in the NW Region shows that there is ample import infrastructure to supply gas at the borders of the NW Region (not taking into account internal transport requirements). It must be noted that utilization of this import infrastructure will have to increase above levels observed in the past (see figure 5.9).

Due to the decreasing indigenous production (mainly the UK and the Netherlands), dependency on imported gas will increase from a current level of about 60 % to almost 90 % for all scenarios (see figure 5.10).

As was noted in the previous paragraph, current import infrastructure (providing direct access to the NW Region) is capable of providing the required annual volumes. On the contrary, the current internal infrastructure in the NW Region needs adaptation to be able to cope with these changed supply patterns related to the decreasing indigenous production. The latter is especially true in order to integrate the current L-gas markets into the H-gas networks and provide the necessary H-gas volumes.

At a regional level, supply adequacy must take into account gas quality; gas production in the NW Region consists mostly in low calorific gas, which cannot be directly substituted to high calorific gas. Chapters 7 and 8 will provide readers with a dedicated analysis on the impacts of the declining L-gas production in the concerned countries.

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38) Minimum and maximum scenario according to the ENTSOG TYNDP 2017.

39) The supply via Nord Stream 2 to the NW Region is included in the Advanced infrastructure level of the ENTSOG TYNDP 2017 and does not refer to the Low infrastructure level.

40) In order to show the LNG import capability, LNG terminal capacities have been used with operating hours of 1,000 (minimum scenario) and 8,000 (maximum scenario) per year.

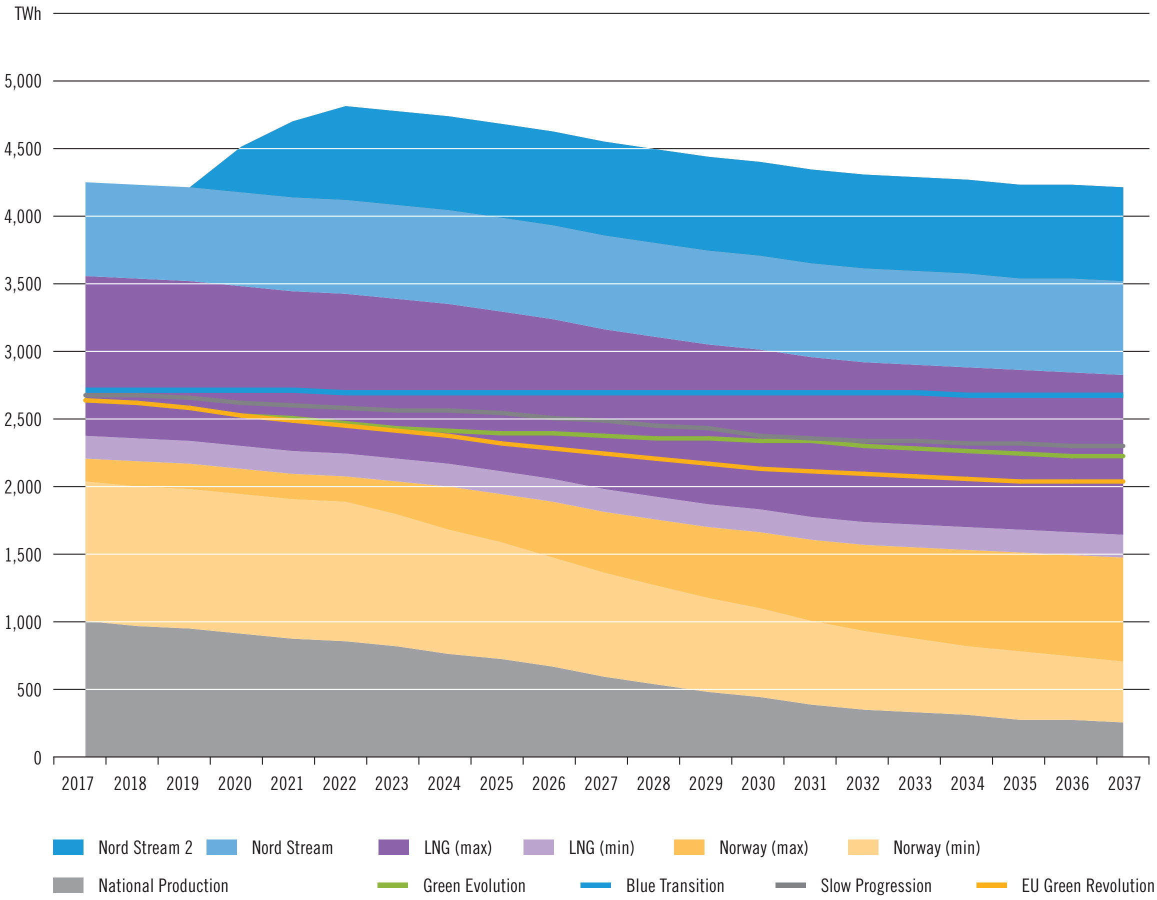


Figure 5.9: Annual direct supply capacities to the NW Region & Annual demand (Source: ENTSOG TYNDP 2017)

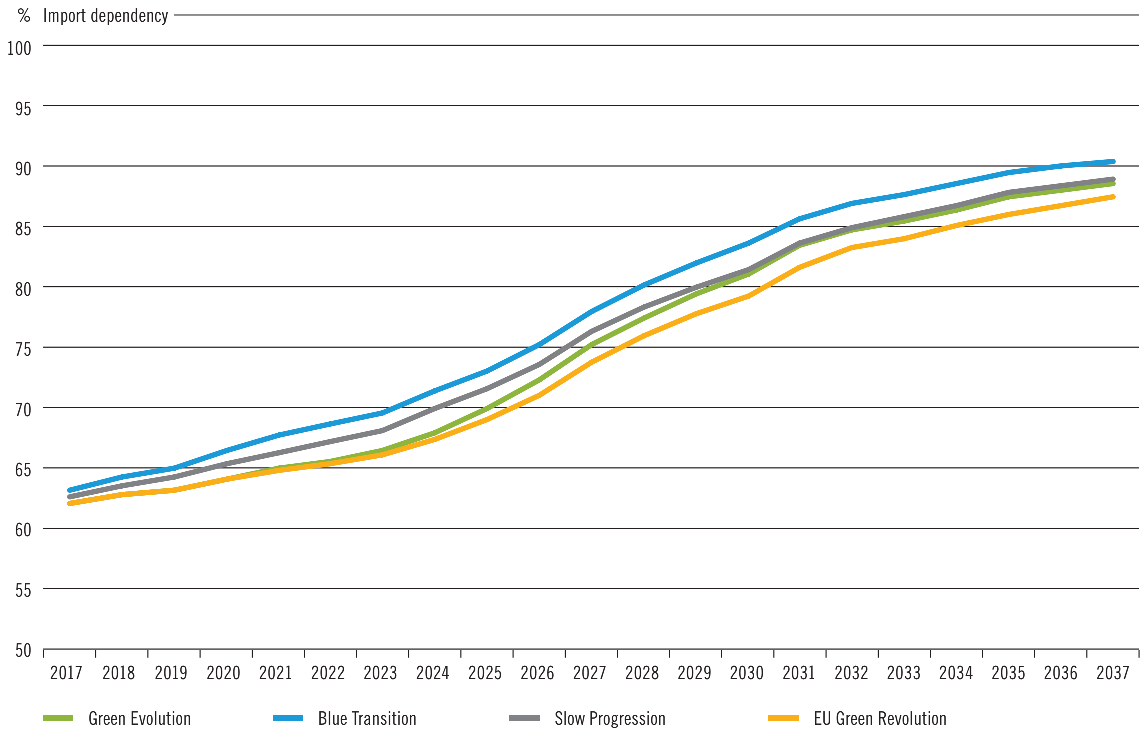


Figure 5.10: Import Dependency (Source: ENTSOG TYNDP 2017)

6 ENTSOG TYNDP 2017 findings from a regional perspective

Image courtesy of Gascade

6.1 Introduction

The ENTSOG TYNDP 2017 provides an extensive assessment of the European gas system in order to identify potential investment needs across a 20-year range. It also shows how projects submitted to the ENTSOG TYNDP 2017 could help to mitigate these needs.

The NW GRIP is consistent with the ENTSOG TYNDP 2017 process and data set. This chapter aims to highlight the findings from the ENTSOG TYNDP 2017 from a regional perspective, while an in-depth analysis of the L-gas issue in the NW Region will be provided in chapters 7 and 8.

The ENTSOG TYNDP 2017 was developed applying the Cost Benefit Analysis (CBA) methodology as approved by the EC in February 2015. In this CBA methodology, a number of development levels of the European gas system are assessed against the priorities of the European energy policy: sustainability, security of supply, competition and market integration. The assessment is carried out for a 20 year period, for different potential evolutions for gas demand and gas infrastructure, with three demand scenarios (Blue Transition, Green Evolution and EU Green Revolution) and four infrastructure levels (Low, Advanced, High and 2nd PCI list).

In this chapter, relevant indicators for the NW Region are analysed with regard to the impact of advanced projects or PCI projects on these indicators.

While the ENTSOG TYNDP 2017 model provides a thorough assessment of the European gas system, it does not take into account gas quality. Since L-gas plays an important role in the NW Region, with certain specific requirements, members of the NW GRIP have decided to provide stakeholders with additional assessments on this matter through a set of relevant indicators such as Supply Adequacy Outlook, Disrupted Demand and Remaining Flexibility, N-1, and Supply Source Dependence.

The main findings for the NW Region show:

- Overall supply and demand adequacy for the NW Region.
- Important remaining flexibility even in case of peak demand, and import route disruption.
- Luxembourg, Sweden and Ireland do not completely fulfil the N-1 criteria and may face demand disruption in cases where their largest infrastructure is not available at a peak demand situation. Luxembourg and Sweden are however not bound by, but shall endeavour to meet, the obligation under the current Regulation 994, as long as some specific conditions are met. Even though Luxembourg disposes of a conditional exception for the N-1 criterion pursuant to Article 6 of the Regulation 994/2010 for its entire national consumption, currently the demand scenarios are covered by contracts that enable suppliers to guarantee the security of supply for the protected customers.

6.2 Remaining Flexibility

The resilience on a balancing zone level can be measured through the Remaining Flexibility indicator, defined as the possible increase in demand of the zone before an infrastructure or supply limitation is reached somewhere in the European gas system.

The results of the ENTSOG TYNDP 2017 show that the NW Region gas transmission system can cope with the highest demand scenarios, such as the Blue Transition, even under disruption of the Belarus or Ukrainian transit. The current infrastructure between Germany and Denmark is however just sufficient for Denmark and Sweden to face their high demand situations with a Remaining Flexibility close to 0%, even though the situation will be improved in Sweden thanks to a LNG PCI project in Gothenburg.

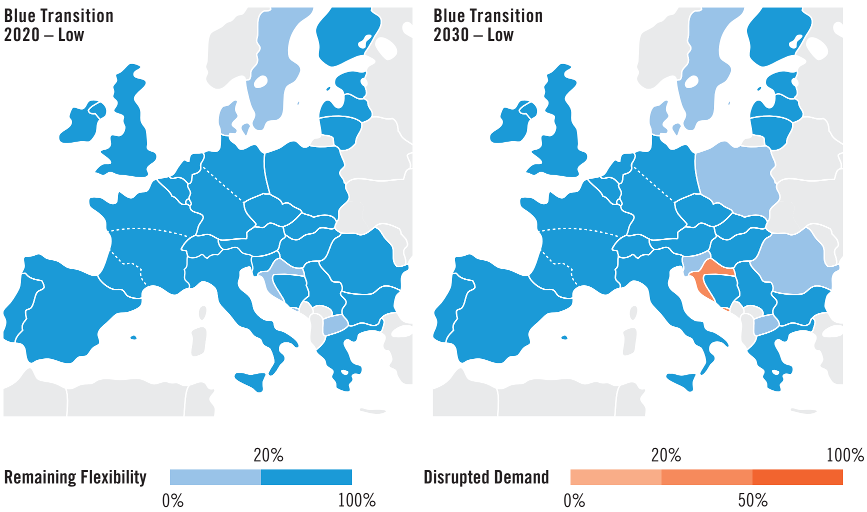


Figure 6.1: Remaining Flexibility and Disrupted Rate, Low infrastructure level (Source: ENTSOG TYNDP 2017)

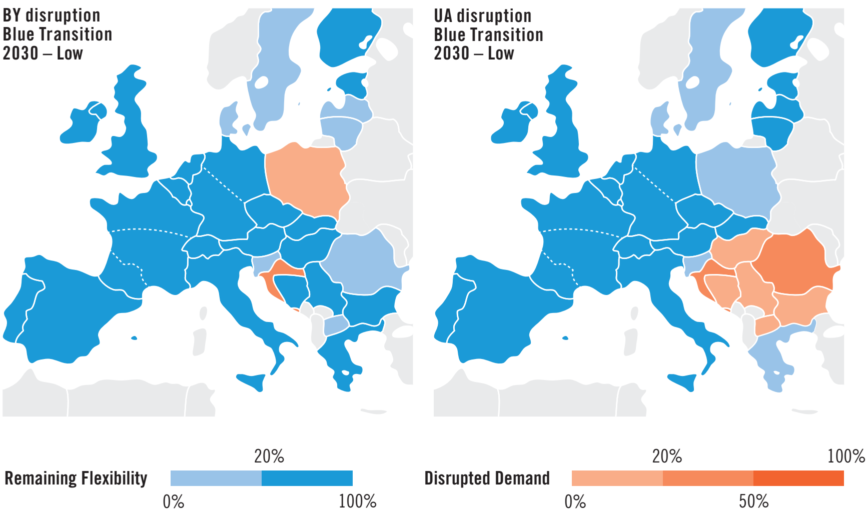


Figure 6.2: Remaining Flexibility and Disrupted Rate under Belarus and Ukrainian disruption, Low infrastructure level (Source: ENTSOG TYNDP 2017)

6.3 N-1 infrastructure assessment

The N-1 indicator is a capacity-based indicator. It is calculated for each country and derives from the Regulation (EC) 994/2010 on Security of Supply. It measures the ability of a country to cope with a peak demand situation in case its largest border infrastructure is unavailable.

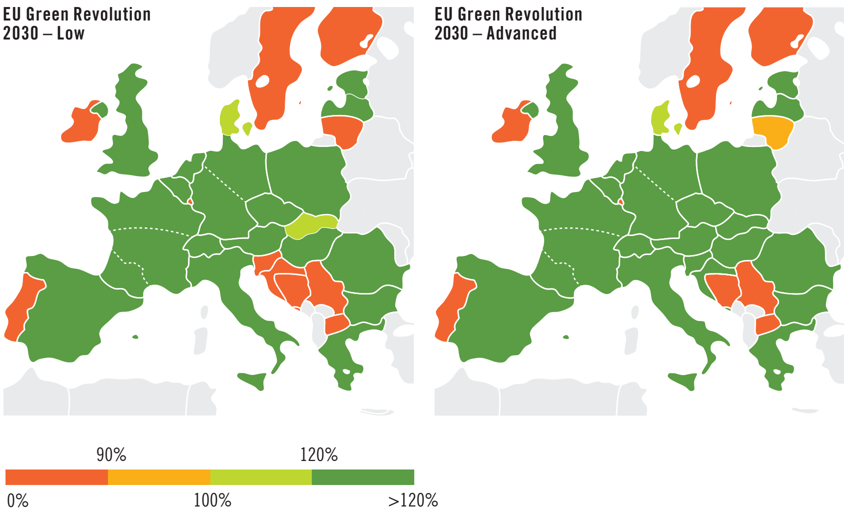


Figure 6.3: N-1 indicator, Low and Advanced infrastructure level (Source: ENTSOG TYNDP 2017)

This indicator highlights countries which rely on a limited number of interconnections, such as Sweden, Ireland and Luxembourg, even in the lowest demand scenarios such as the EU Green Revolution. Luxembourg and Sweden are exempted of the N-1 rule, considering the low gas consumption in Sweden and the limitation of having only two interconnections in Luxembourg[41)].

This picture will not change for these countries with advanced projects or PCI projects, even though the situation will be improved in Sweden thanks to a LNG PCI project in Gothenburg.

41) Technically Luxembourg has 3 interconnection points (Bras, Pétange and Remich), but the first two were commercialised together before the BeLux market integration (starting from the 1 October 2015 the Bras/Pétange interconnection point was removed from the commercial offer).

7 Low calorific gas in the NW Region

Image courtesy of GRTgaz

7.1 Introduction

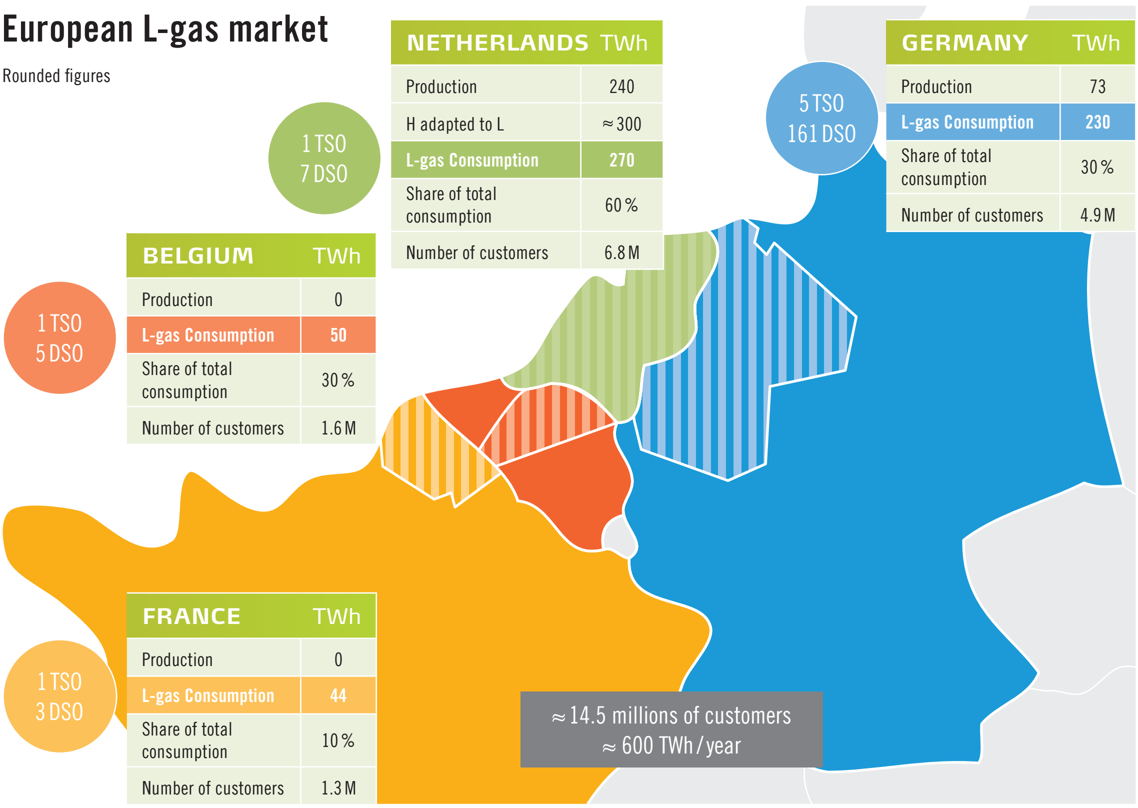
L-gas supply in Germany and the Netherlands is in decline. Due to its different gas composition, L-gas markets will have to be converted. This conversion process has started in Germany and Belgium with France soon to follow.

Due to its different gas composition, the L-gas markets in Germany, Belgium and France are physically separated from the H-gas markets in Europe. Not all countries appliance's which are suitable for operating on H-gas are suitable for L-gas and vice versa. However, although physically separated, these markets are commercially integrated.

The L-gas market today serves more than 14 million customers and has a considerable share in the gas markets of the Netherlands, Germany, Belgium and France, as indicated in the map below.

European L-gas market

Rounded figures



NETHERLANDS	TWh
Production	240
H adapted to L	≈ 300
L-gas Consumption	270
Share of total consumption	60 %
Number of customers	6.8 M

GERMANY	TWh
Production	73
L-gas Consumption	230
Share of total consumption	30 %
Number of customers	4.9 M

BELGIUM	TWh
Production	0
L-gas Consumption	50
Share of total consumption	30 %
Number of customers	1.6 M

FRANCE	TWh
Production	0
L-gas Consumption	44
Share of total consumption	10 %
Number of customers	1.3 M

Figure 7.1: The European L-gas market (Source: NW GRIP TSOs)

7.2 L-gas supply from the Netherlands

About 90 % of L-gas is supplied from the Netherlands, of which some 40 % is direct production from the Groningen gas field with the balance a blend from various H-gas sources.

Historically the main supplier of L-gas is the Groningen gas field in the Netherlands as can be seen in the graph below which shows the record of gas production from the Groningen gas field.

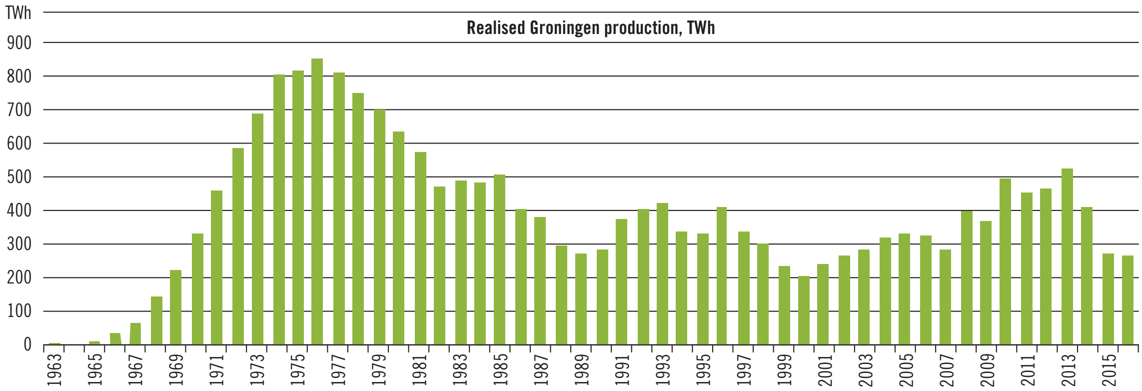


Figure 7.2: Realised Groningen production (Source: ECN[42])

These reserves are however in decline which makes conversion of the infrastructure and appliances in the L-gas markets necessary. Furthermore, future Groningen production has been the topic of extensive analyses and discussions, on geological, technical and political levels. The background to this is the increased level of tremors in Groningen. Figure 7.3 shows these recent occurrences.

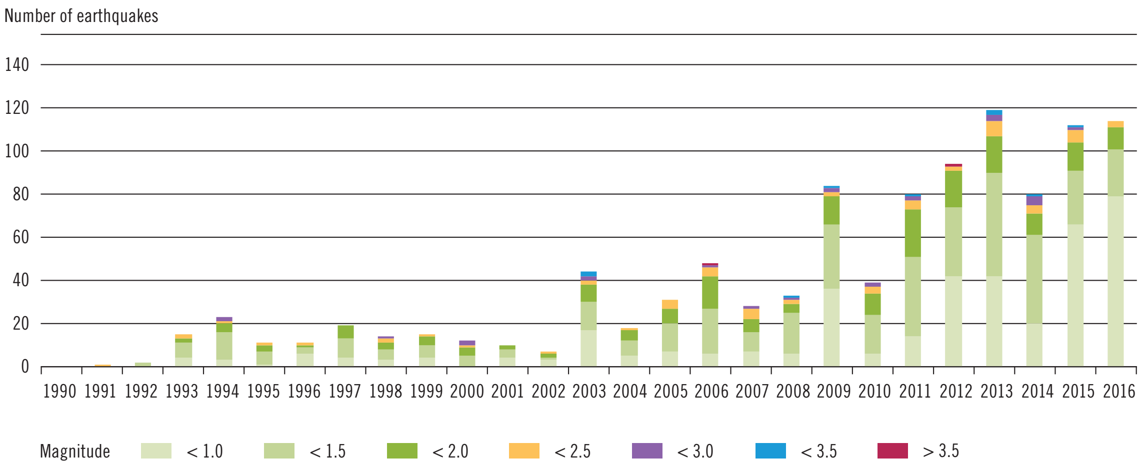


Figure 7.3: Number of earthquakes and their magnitude in the Groningen gas field – from 1990 to 2016 (Source: NAM)

42) www.ecn.nl/nl/energieverkenning

This has resulted in a governmental decision to reduce the level of Groningen production bearing in mind the safety and security of people living in the Groningen area while maintaining security of gas supply to the markets that depend on L-gas.

In figure 7.4 the recent decision taken in September 2016 (which is still open for appeal) to limit production to 24 bcm for average winters is shown. In cold winters the production may be increased to 30 bcm[43] (not shown in the graph).[44]

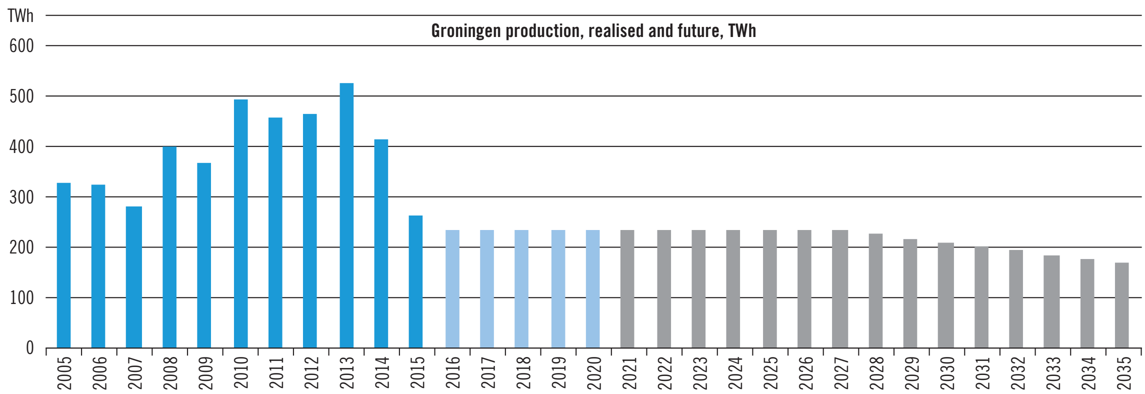


Figure 7.4: Groningen production, realised and future (Source: NAM[2])

Due to the decline of the Groningen field, it was decided that the export of L-gas from the Netherlands to Germany, Belgium and France will be reduced, whilst however honouring contractual obligations and safeguarding security of supply.

43) Source: www.rijksoverheid.nl/actueel/nieuws/2016/09/23/instemmingsbesluit-groningen-vergroten-veiligheid-en-verminderen-schade

44) www.nam.nl/feiten-en-cijfers/gaswinning.html

7.3 L-gas market in Germany

The L-gas market historically developed in the north-western part of Germany, in proximity to the indigenous production and the Dutch border. It consists of approximately 4.9 million customers, supplied via the networks of 5 TSOs and 161 DSOs. Several underground storage facilities are also connected to the TSOs' networks.

Figure 7.5: L-gas transmission network Germany (Source: TSOs Germany)

Similar to the situation in the Netherlands, the German indigenous production is also declining. Figure 7.6 shows the historical yearly production volumes for the years 2006 to 2014 as well as the producers' outlooks up to 2026.

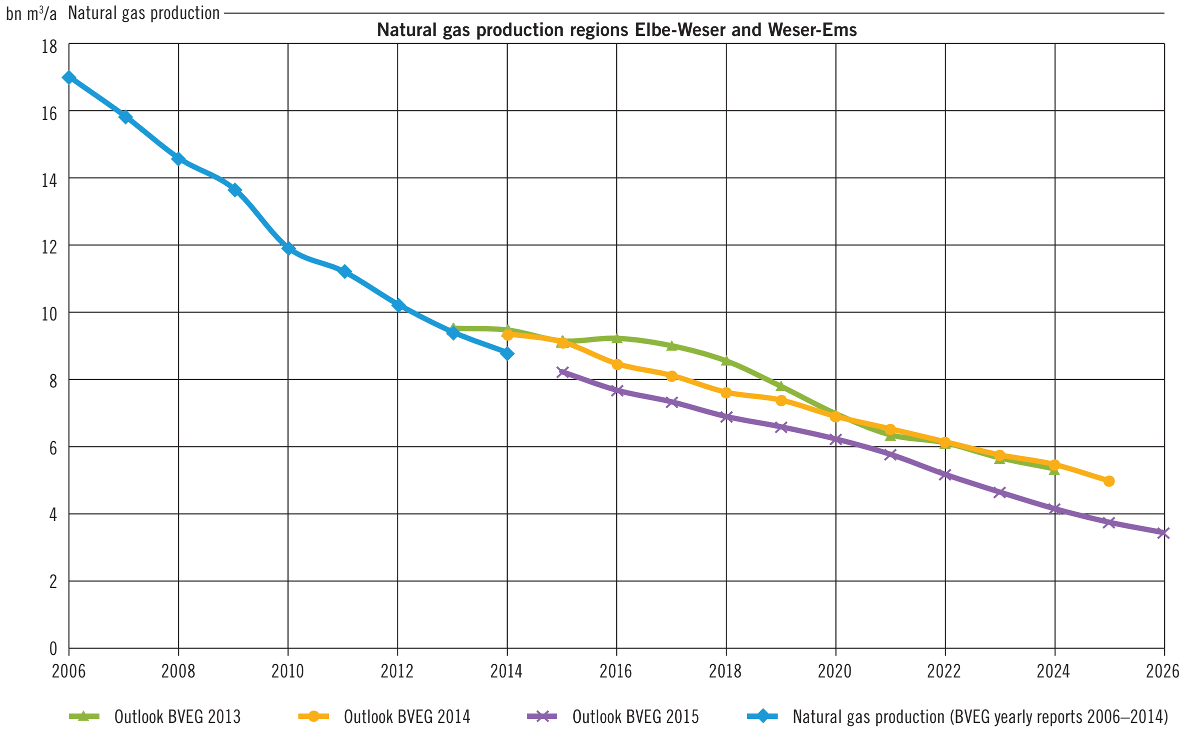


Figure 7.6: Natural gas production Germany, regions Elbe-Weser and Weser-Ems
(Source: Outlook BVEG 2013, 2014 and 2015, TSOs Germany)

In order to meet the challenges of declining supply, the German TSOs, in close cooperation with market participants and national authorities, have started a process for market conversion from L-gas to H-gas, which is scheduled to take place between 2015 and 2030. After 2030, a small L-gas market will remain which will be supplied by the residual domestic production.

The conversion is planned on a phased basis across 108 local areas, according to the national network development plan 2016. By the end of 2016, three local areas, with approximately 20,000 appliances, have already been converted to the supply of H-gas.

Conversion of markets will take several years, not only due to required adaptation of infrastructure, but also due to the number of customers and the fact that all appliances will have to checked and adapted to a different gas quality range.

On the transport system, adaptation of the infrastructure is needed not only in order to connect the (former) L-gas system to the H-gas grid but also to enhance the system capacity for the additional volumes that are needed to supply the converted market.

The national network development plan 2016 identifies more than 70 projects related to the market conversion from L-gas to H-gas. The complexity ranges from single valves and metering stations to new pipelines and compressor stations. About 357 km of new pipelines and about 283 MW of additional compression are needed in order to enhance the transport system for the market conversion by 2026.

7.4 L-gas market in Belgium

The Fluxys Belgium network receives L-gas at the Dutch border through the Poppel interconnection point. The gas is transported towards the current L-gas market in Belgium and to the French border at the Blaregnies interconnection point. The latter represents the only supply of L-gas to the French market.

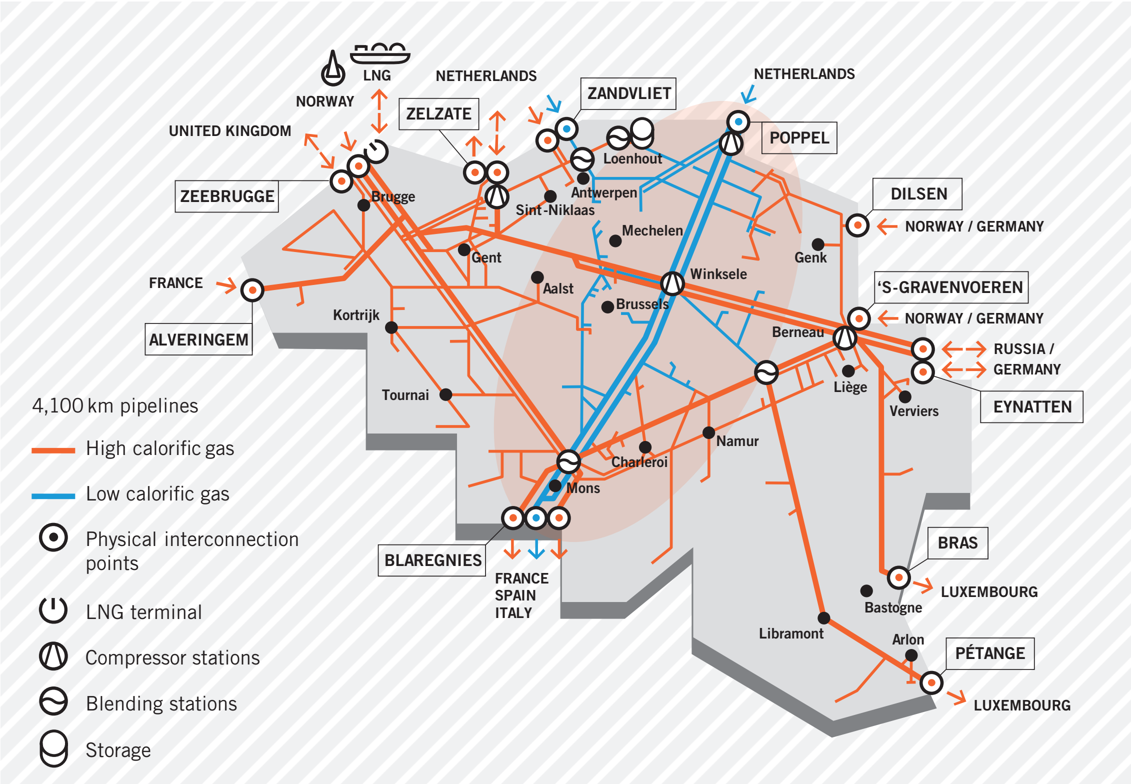


Figure 7.7: Integration zone for the L and H transmission networks (Source: Fluxys Belgium)

The Dutch authorities have announced that exports of L-gas to Belgium and France will cease by 2030. As such, Fluxys Belgium must in principle guarantee the continuity of services, transmitting L-gas at the Hilvarenbeek entry point to customers in Belgium and to France until both of these markets have been converted (i.e. at the latest in 2030).

The DSOs and TSOs within Synergrid[45)] have drawn up an indicative schedule of the conversion of the Belgian L-gas market. This indicative schedule is predominantly based on the maximum re-use of existing infrastructure and maintenance of transmission and distribution capacity for those (Belgian and French) L-gas markets not yet converted as well as for the 'new' H-gas markets.

The recent evolutions of the Groningen earthquakes and resultant impact on L-gas production requires the conversion to be initiated as soon as possible. The sequence proposed by Synergrid allows from a transport infrastructure point of view to start with significant conversion steps as from 2018.

The number of end-user connections to be converted before 2030 will be around 1.6 million.

45) Synergrid represents the Belgian federation of gas and electricity TSOs and DSOs (www.synergrid.be)

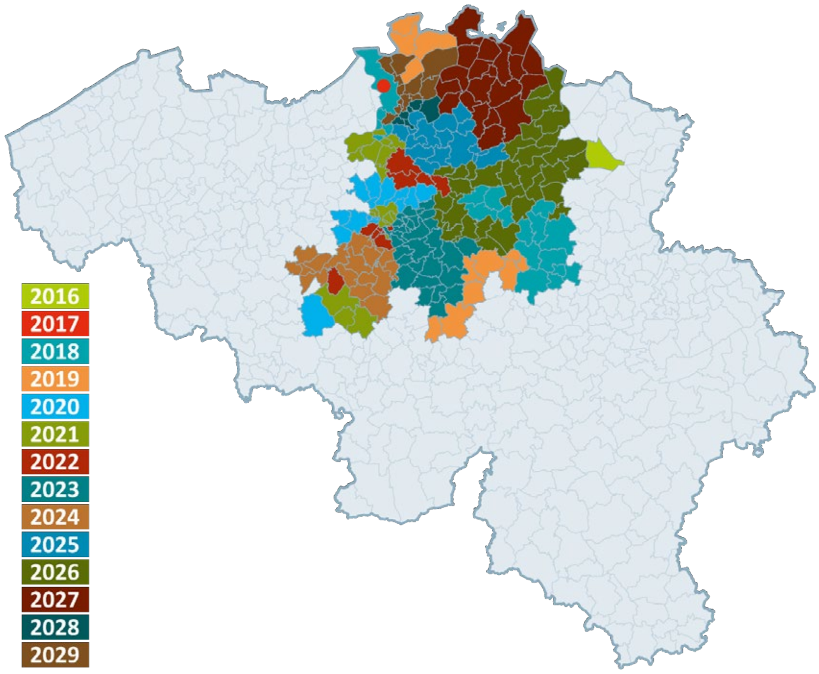


Figure 7.8: Indicative schedule for the conversion of the L-gas market (Source: Synergrid)

The main changes to be made to the Fluxys Belgium network involve gradually integrating L-gas transmission infrastructure into the H-gas transmission network. Existing connections (currently closed) between the two networks will be progressively modified if necessary, and then re-opened to supply the new public distribution clusters and industrial customers with H-gas. The transmission capacity of existing connections will not be sufficient to supply certain clusters with H-gas, meaning that new infrastructure will have to be built.

The suitable design of these changes or new infrastructure must make it possible to supply the newly converted H-gas market while also maintaining transmission capacity to that market still being supplied with L-gas. The L-gas transmission capacity to France must also be maintained in light of contractual provisions and schedule of the conversion of the French market.

The investments expected to cover modifications to the Fluxys Belgium network in connection with the L/H conversion are mainly for:

- Interconnections between the West-East H-gas backbone and the North-South L-gas backbone, mainly planned for 2018–19 so as to start converting the zone to the south of Winksele in 2020;
- Shoring up certain pressure-reducing stations to secure the optimum operation of the H-gas market following the conversion;
- Additional temporary separators between the parts of the network with different gas qualities during the various phases of the conversion, or different pressures during or after conversion.

These modifications are still being studied. The scope and schedule, especially for the second and third bullet points above, still need to be set out. The TSO investment does not take into account inspections of gas appliances at customer sites or changes to public distribution networks.

7.5 L-gas market in France

The L-gas network is supplying the Northern region of France, representing around 10% of national gas demand, and 1.3 million customers.

It is supplied by one entry point from Groningen through Belgium at Blaregnies/Taisnières L. The L-gas network also includes a peak-conversion facility from H-gas to L-gas at Loon Plage, and an underground storage (UGS) facility at Gournay. The H-gas and L-gas balancing zone have been merged into PEG Nord since April 2013.

Figure 7.9: L-gas and H-gas networks in France (Source: GRTgaz)

Considering the cessation of the Dutch L-gas exports by 2030 and the recent decisions to limit the Groningen production, the continuity of transmission to consumers must be ensured by converting the L-gas network into H-gas, which already supplies most of French consumers. In addition to the modifications of the network, an intervention at each consumer will be necessary to take an inventory of appliances using natural gas, and potentially apply new settings, or even replace them.

To prepare for the planning of conversion activities, a decree was issued 23 March 2016 (n°2016-348). This decree specifies the regulatory framework and the general organization of the conversion operation. It introduces a pilot phase between 2016 and 2020, a coordination committee led by national authorities, and requests infrastructure operators to submit a joint conversion plan within six months.

This plan has been submitted for approval to the concerned ministries by GRDF, Gazélec Peronne, SICAE Somme and Cambraisis, Storengy and GRTgaz. An economic and technical evaluation will be carried out in 2017 by the NRA.

This conversion plan is based on a breakdown of the current L-gas consumption into 20 geographical sectors. Each sector will be converted independently and successively, from Dunkerque to Taisnières, enabling a gradual conversion until 2029, with a conversion rate compatible with the interventions required for each of the 1.3 million customers.

The first sectors to be converted during the pilot phase are the areas around Dunkerque, Grande Synthe, Doullens and Gravelines, which are close to the H-gas network. To prepare for conversion of these sectors between 2018 and 2020, GRTgaz is preparing the required modifications on the transmission network by 2018, which include connections between the L-gas network (67.7 bar) and the H-gas network (85 bar), a 2 km pipeline between Brouckerque and Spycker.

These investments should be confirmed by GRTgaz by the end of 2016.

Other modifications will be required for the second phase of the conversion plan, from 2021 to 2029. They will be set according the plan approved by national authorities.

Figure 7.10: Clustering of L-gas conversion process (Source: GRTgaz)

8 L-gas assessment

Image courtesy of Fluxys Belgium

8.1 Introduction

On the basis of the ENTSOG TYNDP 2017 process and related data set, the NW GRIP 2017 aims to provide a focus on the NW Region. While the ENTSOG TYNDP 2017 model provides a thorough assessment of the European gas system, it does not take account of gas quality. Since L-gas plays an important role in the NW Region with certain specific requirements, members of the NW GRIP have decided to provide stakeholders with an additional assessment on this matter.

When considering gas quality, and the L-gas specifics, the mains findings of this outlook are:

- Beyond 2020 the declining supplies are no longer sufficient to balance L-gas demand in Belgium, France and Germany without the implementation of conversion projects.
- Available L-gas supplies are sufficient to balance yearly L-gas demand in Belgium, France and Germany, on the condition that L-H conversion projects are implemented as planned.
- In order to face the anticipated L-gas decline after 2020 conversion projects will have to be started well in advance.

8.2 Methodology

The ENTSOG TYNDP 2017 assessment already tackles the impact of the decreasing indigenous production at European level. A specific analysis is nevertheless necessary to measure its impact on the L-gas supply-demand balance and related infrastructures.

For this purpose, the NW GRIP follows an approach which is consistent with the applied methodology and the basic data used in the ENTSOG TYNDP 2017 process assessed by ENTSOG. Specific assessments have been carried out on the following basis:

- From a physical perspective; L-gas and H-gas are two separate networks with dedicated infrastructures. They are only connected with limited conversion capacities from H-gas to L-gas and from L-gas to H-gas for peak situations.
- From a market perspective; L-gas and H-gas are traded through an integrated market in France, Germany and the Netherlands, whereas in Belgium, trading is done on two separate markets for L-gas and H-gas.

Due to existing commercial arrangements, gas quality has no impact on end-user prices if trading is done in an integrated market. Therefore, the ENTSOG TYNDP 2017 (giving one indicator value for the integrated markets and a value for each of the two separate Belgian L-gas and H-gas zones) accurately reflects the situation with respect to the following indicators and their evolution: Monetization, Gas Price

Indicator, Marginal Price, Supply Source Price Dependence and Diversification. In addition, national conversion plans and NW GRIP findings have enabled the definition of minimum L-Gas flows from the Netherlands to Belgium and Germany and from Belgium to France to cover L-gas demand. Such constraints have been used in the ENTSOG TYNDP 2017 in order to maximise consistency between regional and European assessments.

Hence the NW GRIP only focuses on physical indicators, capturing the impacts of the declining L-gas production:

- Supply and Demand adequacy
- Disrupted Demand
- Remaining Flexibility
- Supply Source Dependence on L-gas imports from the Netherlands
- N-1 analysis

L-gas specific indicators have been collected by ENTSOG as part of the ENTSOG TYNDP 2017 process for the concerned countries: Belgium, France and Germany. These indicators are:

- L-gas demand for an Average Day and a Peak Day (Design Case) for all the ENTSOG TYNDP 2017 demand scenarios (Blue Transition, Slow Progression, Green Evolution, and European Green Revolution). For Germany, the demand is based on the data published in the draft of the national network development plan 2016, and does not differentiate between the different scenarios.
- L-gas production
- L-gas interconnection capacity
- Conversion facility capacity from H-gas to L-gas
- UGS capacity linked to the L-gas networks

Indicators have been calculated under two infrastructure levels to illustrate the evolution of supply resilience with and without the L-H conversion projects:

- Low: current L-gas infrastructure, without considering L-H conversion projects, as described in chapter 7
- High: current L-gas infrastructure, L-H conversion projects considered (including related PCI candidates)

The high infrastructure level takes into account the consumer conversion from L-gas to H-gas supply and the infrastructure projects required to integrate the L-gas network with the H-gas network. Therefore, the L-gas demand is decreasing over time in the high infrastructure level, to be replaced by H-gas, while it is stable in the low infrastructure level.

Indicators are shown from the perspective of both the remaining L-gas consumers and the L-gas consumers that have already been converted to H-gas. The indicator values for the latter customers are taken from the ENTSOG TYNDP 2017.

In this NW GRIP only results for one demand scenario are shown, while the indicator results for all scenarios can be found in the annex. All scenarios lead to the same conclusion.

The Supply Adequacy Outlook assesses to what extent L-H conversion projects are crucial to ensure supply continuity to existing L-gas consumers.

The indicators focus on the security of supply and dependence on Dutch L-gas exports for remaining L-gas areas until the end of the conversion process in 2030.

8.3 Supply Adequacy Outlook

This section compares the outlook of L-gas demand and supply evolution until 2030 when conversion processes are supposed to be finalised in Belgium, France and Germany.

On a yearly basis, the available supply sources to balance L-gas demand are Dutch exports and German L-gas production (the availability of H–L conversion facilities is designed for extreme climatic conditions).

The supply adequacy outlook states that available supplies are sufficient to balance yearly demand in Belgium, France and Germany, on the condition that conversion projects are implemented as planned.

On a peak basis, the available supply capacities to balance L-gas demand are Dutch exports, German L-gas production, UGS and H–L gas conversion facilities.

Along with the declining production, production capacities (and therefore export capacities from the Netherlands) are also getting lower. Available UGS capacities also depend on the deliverability in the L-gas grids which is reduced due to the customer conversion.

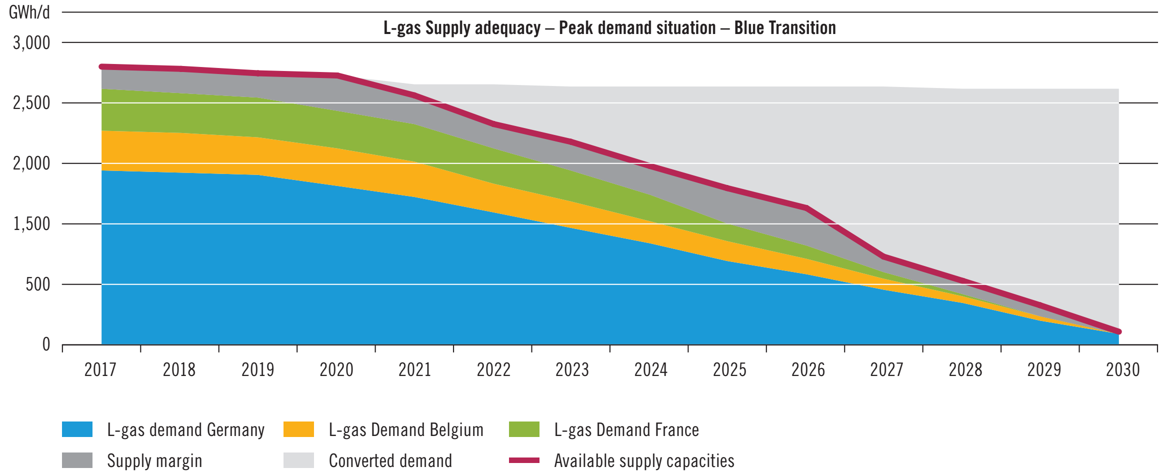


Figure 8.1: L-gas supply adequacy in Belgium, France and Germany in the Blue Transition Scenario (Source: NW GRIP TSOs)

The supply adequacy outlook in figure 8.1 shows that the available supply capacities for the Design Case are sufficient to balance peak demand in Belgium, France and Germany, if L-H conversion projects progress as planned. A limited supply margin exists to face possible unexpected events, including a delay in the conversion process in one of the three countries.

In conclusion, the conversion projects, that is the continuous adaptation of system operators' infrastructures (transmission, storage and distribution), are consistent with current L-gas demand and supply projections. In the short term specific measures are in place to face a potential cold year. In the medium term, any deviation from present projections would endanger the coordinated national conversion plans put in place to ensure the supply of millions of consumers across four Member States.

8.4 Disrupted Rate and Remaining Flexibility

The Remaining Flexibility indicator has been adjusted to take account of the conversion process in order to measure the resilience at the level of individual L-gas areas. The indicator is calculated for the Design Case as the additional share of demand each national L-gas area is able to cover before an infrastructure or supply limitation is reached somewhere in Belgium, France or Germany.

This calculation is made independently for each country, as restrictions on the interconnection capacities do not allow the sharing of Remaining Flexibility and Disrupted Demand between Germany and Belgium/France. The higher the indicator value is, the better the resilience. In the case the Remaining Flexibility is zero, this indicates that the country will experience Disrupted Demand at a peak demand situation.

The Disrupted Rate represents the share of the peak gas demand that cannot be satisfied. It is calculated for a daily volume. The level of disruption is assessed and assumes a cooperative approach between countries in order to mitigate its relative impact. This means that countries try to reduce the disrupted rate of other countries by mutual burden sharing. Non-alignment of Disrupted Rate between countries may occur in the case of an infrastructure bottleneck between countries or in the absence of interconnections (e.g. between Germany and Belgium from an L-gas perspective).

The results show that until 2020, peak supplies (Dutch exports, German production, UGS and H–L gas conversion facilities) are sufficient to maintain current flexibility for the remaining L-gas consumers. Beyond 2020 the declining supplies are no longer sufficient to balance L-gas demand in Belgium, France and Germany without the implementation of L–H conversion projects. These projects are necessary to maintain the current flexibility for the remaining L-gas consumers while improving it further for consumers converted to H-gas (especially in Germany).

Image courtesy of GRTgaz

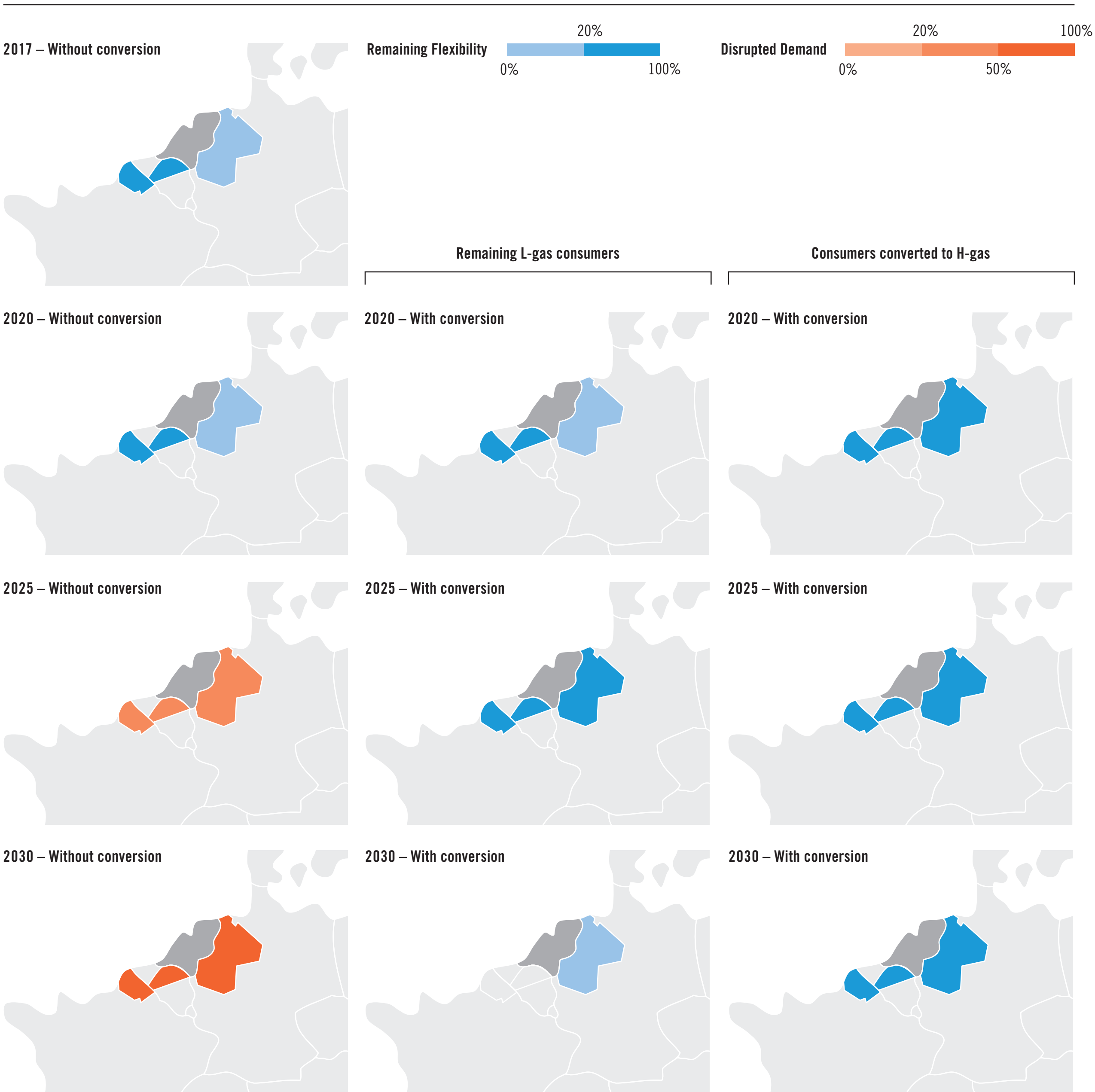


Figure 8.2: Disrupted Rate and Remaining Flexibility with and without conversion projects (Source: NW GRIP TSOs)

For the situation '2030 with conversion', the indicator for remaining L-gas consumers in Belgium and France is not specified as in this case there would be no L-gas market anymore.

8.5 N-1 infrastructure assessment

The N-1 indicator is a capacity-based indicator. It is calculated for the L-gas area of each country and derives from Regulation (EC) 994/2010 on Security of Supply. It is intended to measure if countries would have the necessary capacities to cover their peak demand, even in the case where the single largest infrastructure would be unavailable[46]. The indicator is expressed as the percentage of the peak demand that remaining capacities can cover.

The single largest infrastructures are:

- For Germany: Zevenaar interconnection point in 2017 and 2020, Winterswijk IP in 2025, a share of German L-gas production in 2030
- For Belgium: Poppel/Hilvarenbeek entry point from 2017 to 2030
- For France: Blaregnies/Taisnières L entry point from 2017 to 2030

The following maps show the assessment results for the N-1 indicator. The low infrastructure level illustrates the strong dependency of L-gas consumers on export lines of L-gas from the Netherlands in a peak demand situation. Depending on the year, the conversion projects will improve the situation in France and Germany for remaining L-gas consumers. In 2030 the dependence of the last German L-gas consumers on the largest infrastructure is back at today's level. As was explained in chapter 7.3, for the period after 2030 a small share of the original L-gas market is intended to absorb the remaining national production. As national production is the only source (apart from conversion facilities and storages), a high relative dependence is to be expected.

Consumers of the three countries converted to H-gas during the process will benefit from the high level of diversification in the NW Region.

46) It differs from the original indicator calculated by the Competent Authorities as it has to be:
– computed up to 2030,
– consistent with the capacity used in the NW GRIP (application of the lesser of rule to the capacity level on each side of a flange).

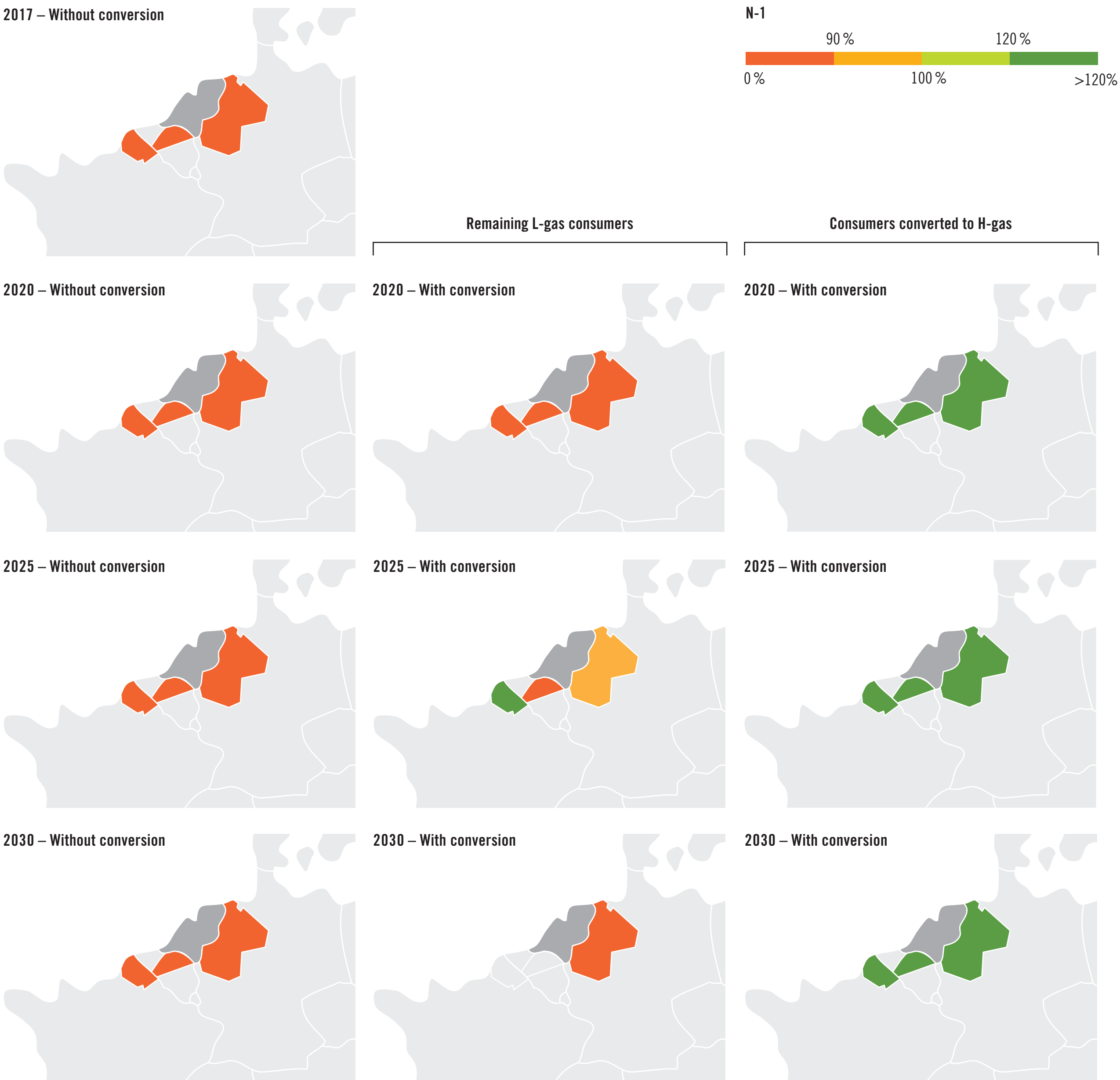


Figure 8.3: N-1 Indicator with and without conversion projects (Source: NW GRIP TSOs)

For the situation '2030 with conversion', the indicator for remaining L-gas consumers in Belgium and France is not specified as in this case there would be no L-gas market anymore.

8.6 Supply Source Dependence

This indicator represents the minimum share of a given supply in a countries overall supply mix. It is not intended to represent a disruption and the analysis is done over the whole year.

In the NW GRIP the supply source dependence is assessed on Dutch L-gas exports under the assumption that countries interact in a cooperative way, meaning that they try to share the level of dependence with other countries. Nevertheless the absence of L-gas interconnection between Germany on one hand and Belgium and France on the other hand prevents the sharing of German L-gas production.

The maps show that all throughout the planned L-H conversion process the relative dependence of remaining L-gas consumers on Dutch exports remains high as the supply potential of the other sources is decreasing as well. However, due to the declining demand during the conversion process, the absolute value of dependence is also reducing. Such dependence will only disappear once the conversion projects are fully commissioned, in 2029 for France and 2030 for Belgium. Dependence on Dutch exports will also disappear for Germany, since the remaining German L-gas market will rely on national production from 2030. Consumers converted to H-gas during the process will obviously no longer be dependent on Dutch L-gas exports.


Image courtesy of Fluxys

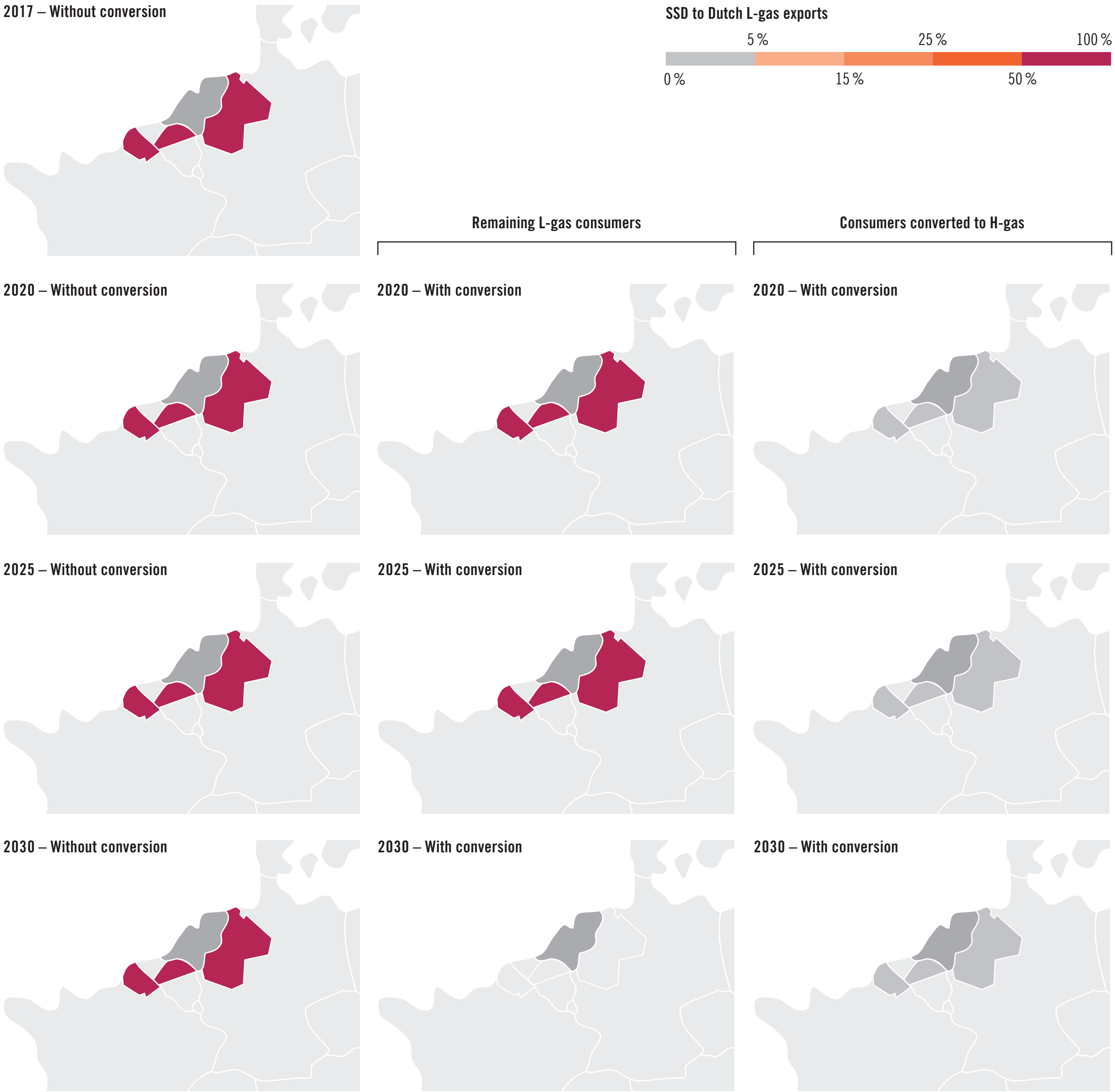


Figure 8.4: Supply Source Dependence to Dutch L-gas exports in Belgium, France and Germany, with and without conversion projects (Source: NW GRIP TSOs)

For the situation '2030 with conversion', the indicator for remaining L-gas consumers in Germany, Belgium and France is not specified as in this case there would be no Dutch L-gas exports anymore.

9 Country-specific infrastructure developments

Image courtesy of Fluxys

9.1 Introduction

This chapter aims at identifying the major market and infrastructure developments going on in the NW Region. A national perspective is presented with a focus on recently achieved milestones as well as planned or ongoing projects and initiatives. In this respect the country specific infrastructure development chapter can be seen as a summary of the respective national development plans.

9.2 Belgium

9.2.1 MARKET AND NETWORK OVERVIEW

Natural gas will remain a core component of the energy mix in tomorrow's low-carbon economy. As a natural gas infrastructure company, Fluxys aims to build bridges between markets so that suppliers can transport natural gas flexibly to their customers or between European gas trading places.

Fluxys Belgium is the independent operator of both the natural gas transmission grid and storage infrastructure in Belgium. The company also operates the Zeebrugge LNG terminal. Fluxys Belgium is active in the transmission, storage and LNG businesses and intends to play a pioneering role in developing the gas infrastructure required to diversify Europe's natural gas supply sources and in developing the solutions needed to connect and integrate European gas markets.

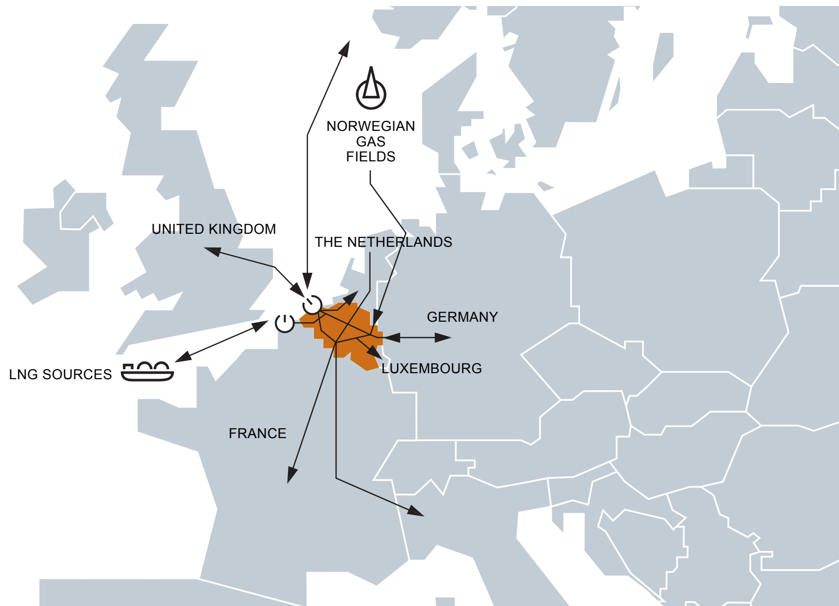


Figure 9.1: Fluxys Belgium network in NW Europe (Source: Fluxys)

The Belgian natural gas grid is one of the best interconnected infrastructures in North West Europe. The 18 interconnection points on the Belgian grid are opening the network to natural gas flows from the United Kingdom, Norway, the Netherlands, Russia and all LNG producing countries. The Belgian grid also serves as the crossroads for transmission flows of natural gas to the Netherlands, Germany, Luxembourg, France, the United Kingdom and Southern Europe.

9.2.2 MILESTONES

BeLux market integration, a first in Europe

On 1 October 2015, Fluxys Belgium and Creos Luxembourg successfully launched the first ever gas market integration between two European Union Member States, namely Luxembourg and Belgium. This market integration is fully in line with the European Union's blueprint that aims at building an internal gas market without borders, where gas can flow freely from one country to another. The successful merging of the Luxembourg and Belgian gas markets is the result of around two years of close collaboration between Creos Luxembourg, Fluxys Belgium and their respective regulators, the Luxembourg Regulatory Authority (ILR) and Belgium's Regulatory Commission for Electricity and Gas (CREG).

The merging of the markets opens up more opportunities for competition for the two countries and boosts security of supply for Luxembourg. The integrated market is beneficial for suppliers too, as there is now only one balancing zone for the two countries and liquidity on the ZTP gas trading point is boosted. With the removal of the Bras/Pétange interconnection point from the commercial offer, grid users no longer have to reserve capacity at that point to transmit gas between Belgium and Luxembourg.

Alveringem-Maldegem, the Dunkirk – Zeebrugge link

In parallel with the construction of the LNG terminal at Dunkirk, a pipeline has been laid to link this new installation to the Zeebrugge area. The pipeline connects three infrastructures: the Dunkirk LNG terminal as a new gas entry point for Europe, the grid of French system operator GRTgaz and the Fluxys grid in Belgium. GRTgaz has laid a 26-km long pipeline from the compressor station in Pitgam to the French-Belgian border. Fluxys Belgium has built a new interconnection point in Alveringem near Veurne, and a 72-km long pipeline between Alveringem and Maldegem.

The new installations of the two system operators were commissioned in late 2015. This combination allows the transport of up to an additional 8 billion m³ of natural gas to Belgium and elsewhere in Europe from the Dunkirk LNG terminal, strengthening security of supply, market integration and diversification of sources while offering a wider basis for natural gas trading in the NW Region. The project gives system users maximum flexibility in choosing the destination for their natural gas flows, as by using the Belgian system they can move their gas flows to a wide range of destinations. Besides, it renders the Belgian grid completely bidirectional.

9.2.3 INVESTMENT PLAN FLUXYS BELGIUM: THE PROGRAM IN A NUTSHELL

Every year, Fluxys Belgium updates its ten-year indicative investment program for its three core activities, namely natural gas transmission and storage, and LNG terminalling. The four main pillars of the program are constituted by,

- Investments triggered by commercial initiatives and external cooperation
- Investments required to cover anticipated trends in peak demand in Belgium
- Investments aiming to guarantee the integrity of the natural gas transmission infrastructure and ensure that said infrastructure is in good condition
- Investments in equipment, ICT applications and buildings

The indicative investment plan for the period 2017–2026 shows that beyond the significant ongoing and future development of the LNG infrastructure in the Zeebrugge area, the transmission capacity of the Fluxys Belgium network is considered sufficient to meet market demand with regard to domestic and border-to-border activities. Major investments sanctioned over the past four years made it possible to develop a Belgian network of an adequate size with considerable entry capacities, bidirectional flows without congestion and optimum connections with other gas networks in Northwest Europe. The drop in future investments is therefore a logical development.

While investments are still anticipated in the short term to support the development of certain public distribution networks and to make the modifications needed to convert L-gas networks, a significant part of the indicative investment plan 2017–2026 is therefore devoted to the maintenance, modification and modernisation of the network.


Image courtesy of Fluxys

9.2.4 ZEEBRUGGE LNG TERMINAL, YOUR LNG GATEWAY INTO NORTHWESTERN EUROPE

The Zeebrugge LNG terminal serves as a gateway to supply LNG into North West Europe. Any LNG unloaded at the terminal can be redelivered for consumption on the Belgian market, or traded on the Zeebrugge Hub for onward transmission to supply other end consumer markets in any direction such as, the United Kingdom, the Netherlands, Germany, Luxembourg, France and Southern Europe. Almost 40% of investments planned in Belgium over the next decade are linked to the two projects aiming to further develop the Zeebrugge LNG terminal, that is the construction of a fifth storage tank and a third jetty.

Yamal LNG

In March 2015 Fluxys LNG concluded a 20-year contract with Yamal Trade for the transshipment of up to 8 million tonnes of LNG per year (approximately 11 billion cubic metres of natural gas). The transshipment services will form a key link in the logistics chain from Russia's Yamal peninsula to supply Asian markets, among others, year-round. This agreement will promote LNG activity in Zeebrugge in the long term and will also significantly bolster traffic at the port.

In order to facilitate these transshipment services, Fluxys LNG is building a fifth storage tank capable of holding some 180,000 m³ LNG. Additional compression capacity is being developed too. The new storage tank will primarily be used during winter for the transshipment of LNG from LNG icebreaker vessels from the Yamal production site to traditional LNG carriers. Preparatory works began in mid-2015 and the new storage tank is set to be commissioned early 2019, according to the current schedule.

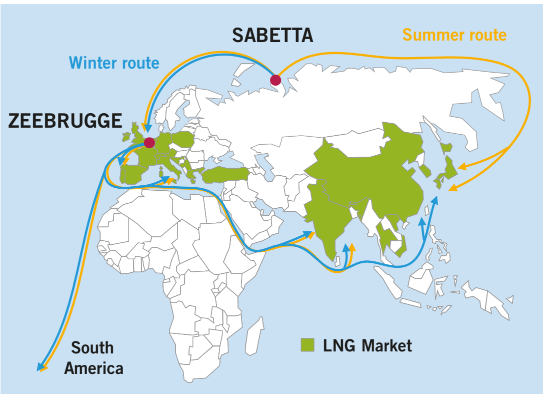


Figure 9.2: Yamal LNG project in Zeebrugge (Source: Fluxys)

Small scale development

A second jetty for the loading and unloading of LNG carriers has recently been commissioned at the Zeebrugge LNG terminal. It will be the site of the loading and unloading of vessels both large and small carrying between 2,000 m³ and 217,000 m³ of LNG. Small bunker vessels will thus be able to load LNG to then resupply other vessels powered by LNG or small bunker terminals. With the construction of the second jetty and the new capacities which have already been reserved, the Zeebrugge LNG terminal is continuing to evolve into a hub for the small-scale use of LNG, i.e. as a fuel for shipping and long-distance haulage trucks.

In 2015, Fluxys LNG conducted a market survey for the LNG terminal to ascertain interest in small-scale LNG services, such as the loading of small bunkering and supply vessels, or even services loading LNG trucks. The survey recorded sufficient interest to warrant the launch of a preliminary study to identify which infrastructure extensions would be needed.

In October 2015, Fluxys signed an agreement with ENGIE, Mitsubishi and NYK Line to acquire 25% in a vessel that will offer LNG bunkering services from its home port of Zeebrugge, Belgium. This liquefied natural gas (LNG) bunkering vessel, with a capacity of 5,100 cubic metres LNG, is currently under construction in South Korea and delivery is planned for the first half of 2017. Becoming a partner in the ownership of this LNG bunkering vessel fits Fluxys' strategy to support the development of the small-scale LNG market.

In March 2016, Gazprom and Fluxys signed a Framework Agreement on small-scale LNG cooperation in the European market. The agreement reflects the intention of the parties to collaborate on joint projects in the construction and operation of LNG receiving terminals, LNG filling stations and LNG bunkering infrastructure in Europe.

Third Jetty (PCI candidate)

Another project through which Fluxys LNG wishes to actively contribute to the development of LNG is the construction of a third jetty at the Zeebrugge LNG terminal. This jetty will be used by small LNG vessels (capacity of approximately 2,000 m^3 to 30,000 m^3), which should encourage the development of smaller scale LNG activities, such as the bunkering of commercial vessels. The project still needs to undergo a market consultation, but feasibility studies are currently being conducted for a range of technical solutions.

9.2.5 L/H CONVERSION

The gradual depletion of the Groningen natural gas field (which produces low-calorific natural gas, or L-gas) has prompted the Dutch government to completely phase out L-gas exports to Belgium and France between 2024 and 2030 and to Germany between 2020 and 2030. Moreover, extracting natural gas from the dwindling field triggers earthquakes, so production capacity has been limited since 2014.

L/H conversion in Belgium (PCI candidate)

For more information and background regarding the planned L/H conversion in Belgium, please refer to chapter 7.4.

The investments expected to cover modifications to the Fluxys Belgium network in connection with the L/H conversion are mainly for;

- Interconnections between the VTN and the Dorsales (at Winksele) mainly planned for 2018–19 so as to start converting the zone to the south of Winksele in 2020;
- Shoring up certain pressure-reducing stations to secure the optimum operation of the H-gas market following the conversion;
- Additional temporary separators between the parts of the network with different gas qualities during the various phases of the conversion, or different pressures during or after conversion.

These modifications are still being studied. The scope and schedule, especially for the second and third bullet points above, still need to be set out. This does not take into account inspections of gas appliances at customer sites or changes to public distribution networks.

Transmission to Germany

Germany also needs to convert from L-gas to H-gas (approximately 30 bcm/year). This change in import needs is analysed extensively in the national Network Development Plan drawn up by the German TSOs (NDP 2016). This plan comprises two supply scenarios:

- Q1: Extra supply from the south/south-east
- Q2: Extra supply from the north-east
  (linked to the expansion of the Nord Stream)

Both scenarios also include increased supplies from the west/south-west (LNG from Belgium, the Netherlands, the UK and France).

Fluxys Belgium supports the vision of the German development plan and supports the principle of capacity development at the Eynatten interconnection point on the Belgian-German border as part of the ZEELINK project, which intends to lay a new dual pipe in Germany on the border between Belgium and North Rhine-Westphalia. The direct link with the Zeebrugge zone, which is itself directly connected to the new Dunkirk terminal by the new Alveringem–Maldegem pipeline and with the Dutch network via the Zelzate border station, can provide the German market with the required capacity and flexibility as well as access to diversified supply sources.

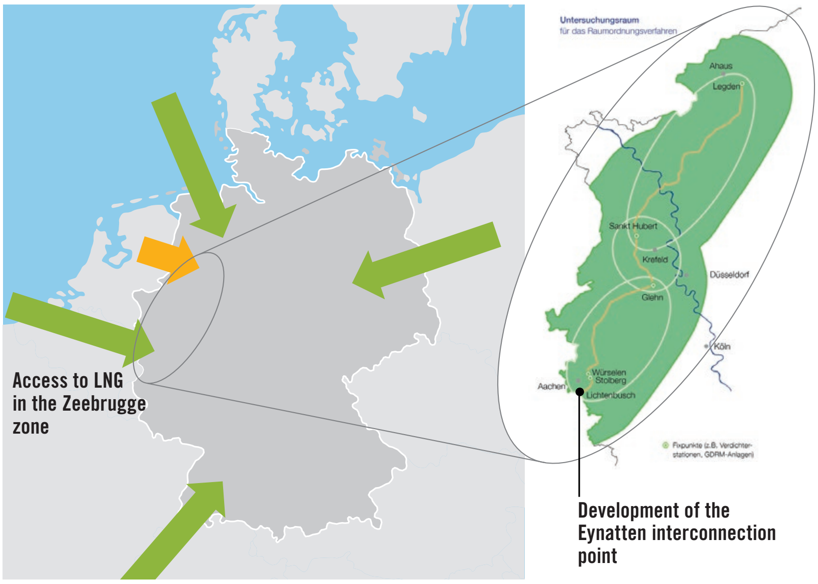


Figure 9.3: Development of the Eynatten IP in the context of L/H conversion in Germany (Source: Fluxys)

9.3 Denmark

9.3.1 GAS TRANSMISSION AND STORAGE DEVELOPMENT

The natural gas transmission network covers most of Denmark and totals around 950 km in length. The oldest parts were built in the 1980s and the most recent part in 2013, when a project co-financed by the EU resulted in a doubling of the connection capacity to Germany and the wider European gas market. The Danish infrastructure also provides natural gas to the Swedish market.

A maintenance program ensures that the system will be able to remain safe and operational for decades to come. The central control room is located by the compressor station in Egtved (see figure below) and is continuously staffed. The control centre facilitates the supply of gas from the Danish part of the North Sea and from Germany as well as exports to Germany and Sweden. Furthermore the system is linked to two storage facilities.

Figure 9.4: The Danish gas production, storage and transmission system (Source: Energinet.dk)

9.3.2 CONSOLIDATION OF THE DANISH GAS INFRASTRUCTURE

Currently a consolidation of the Danish gas infrastructure is taking place. This has included Energinet.dk acquiring the Stenlille gas storage facility in 2014, making Energinet.dk the owner of both storage facilities in Denmark. Following the purchase the storage facilities were consolidated into an independent commercial company Gas Storage Denmark. Furthermore in September 2016, Energinet.dk took ownership of one of the three gas distribution companies in Denmark renaming it to Dansk Gas Distribution.

Moreover, Energinet.dk is obliged to acquire the Dansk Olie og Naturgas (DONG) offshore gas pipeline from the North Sea Platforms to the mainland (and the corresponding oil pipeline in the North Sea). At the time of writing, negotiations are still on-going.

9.3.3 BIOGAS INFRASTRUCTURE DEVELOPMENT

It is expected that 2016 is going to be the year with the greatest increase of biogas production to date with production expected to exceed 2,500 GWh of which more than 1/3 will be upgraded to biomethane and injected to the natural gas network. In comparison the total production in 2012 was 1,200 GWh, which almost all went exclusively to the production of electricity and heat. This trend is expected to continue with an estimated total production of approximately 4,200 GWh in 2020[47)], where more than 2,000 GWh is expected to be upgraded and injected to the natural gas network.

Since 2014, 18 plants have been commissioned, with a number of plants expected to follow in the coming years. Out of the 18 plants, one plant is connected directly to the transmission grid, while the rest are connected to the distribution network.

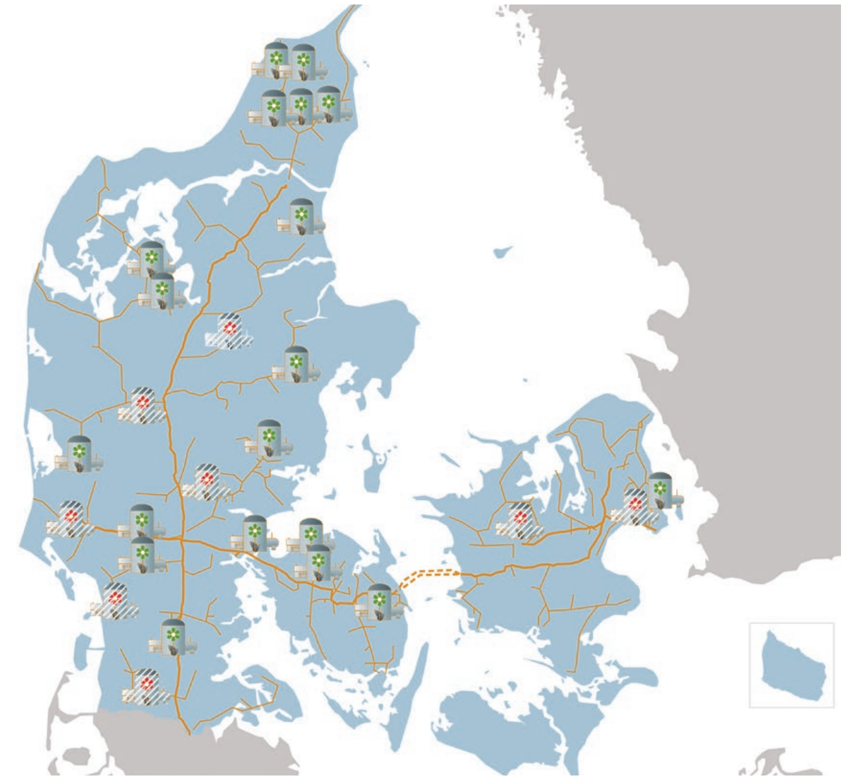


Figure 9.5: Biogas upgrading plants connected to the natural gas grid in Denmark (Source: Energinet.dk)

In periods of low demand, it is expected that the quantity of injected biomethane in some distribution network will exceed the local gas consumption if current trends continue. Energinet.dk is therefore engaged in six projects with the overall objective of ensuring that excess biomethane can be reversed into the transmission grid safely.

Lastly, due to a difference in gas quality specifications in Denmark (5,000 ppm oxygen) and Germany (10 ppm for sensitive assets) there was a reduction in the available capacity at Ellund towards Germany in the summer of 2016. In September the capacity was re-established, though the risk of flow reduction towards Germany still exists, if the oxygen level in the exported gas at a later point does comply with the German specification. Energinet.dk has therefore started a so-called 'Oxygen Task Force' with the aim of assessing all possible sustainable solutions whereby market distortions are avoided e. g. by exploring the possibility of removing the oxygen directly at the production site, at the border point, at the sensitive assets etc., and developing a long-term view of how oxygen levels at a European level can be determined without distorting the growth of biomethane production.

47) With an uncertainty spread ranging between 3,600–5,800 GWh in 2020.

9.3.4 DEVELOPMENT OF GAS IN THE MOBILITY SECTOR

Energinet.dk supports market actors in establishing alternative fuel structures by providing access to analyses, data etc. but is not investing in either CNG or LNG infrastructure, as opposed to the DSOs which are very active.

So far no LNG driven vehicles are used or promoted, while the market for CNG can be characterised as a first mover market, mainly driven by municipalities with climate targets and used in their local fleets of buses and waste disposal trucks. At the moment 16 CNG refuelling stations are in operation in 15 cities, while another four are expected to be commissioned in 2017.

Figure 9.6: Existing and planned gas filling stations in Denmark (Source: Energinet.dk)

Given national authorities hold the greatest expectations for electrification of Light Duty Vehicles, gas is only expected to play a role in Heavy Duty Vehicles and as Denmark currently has the highest taxes on NGVs in Europe, only a modest expansion of CNG infrastructure and fleets are expected in the coming years.

In terms of maritime transportation a limited LNG infrastructure is currently being developed, as two LNG vessels[48)] (Samsø and Hirtshals) had their maiden voyage in 2015, with another 9 vessels ordered. Furthermore a liquefaction plant is planned[49)] at one port while small scale bunker facilities are under consideration in a few ports.

48) Ferries

49) Expected capacity is 150–300 tonnes/day

9.4.5 ONE BALANCING ZONE FOR DENMARK AND SWEDEN

In order to let the gas flow more easily, thus reducing transaction costs making the Danish-Swedish gas market more liquid and attractive, Energinet.dk and Swedegas (Swedish TSO) are currently assessing the possibility of establishing a unified balancing zone.

9.3.6 NO–DK–PL PIPELINE (BALTIC PIPE)

A new pipeline connecting Poland, Denmark and Norway is now under consideration in order to achieve the following;

- Integrating the Danish-Swedish and Polish gas markets by means of supply competition and bidirectional trading with the aim of ensuring increased price convergence.
- Strengthening regional security of supply by providing access to Norwegian gas for the Danish-Swedish and Polish gas markets and additionally for the markets in the wider Central and Eastern Europe.
- Further increase the load-factor of existing infrastructure in order to reduce tariffs to the benefit of users of the infrastructure.

The Baltic Pipe Project (DK–PL interconnection) has been included on the PCI list compiled by the EC.

The Danish and the Polish TSOs, Energinet.dk and GAZ-SYSTEM S.A. as project promoters have initiated a feasibility study (partly financed by the EU) which will consider interconnecting the national gas markets through a bidirectional subsea pipeline and expanding the national transmission systems. In the direction from Denmark to Poland, several technical capacity scenarios of the pipeline, up to 10 bcm/y, are being considered. It is expected that the feasibility study will be finalised by the end of 2016 with the aim to ensure that the pipeline is fully operational no later than 2022.

It is a prerequisite for the DK-PL interconnection that a Norwegian-Danish offshore tie-in is established. In cooperation with the Norwegian ISO, GASSCO, a pre-feasibility study has been performed, identifying four feasible solutions for a tie-in to Norwegian offshore pipelines crossing the Danish sector for the import of gas from Norway.

The project is dependent on sufficient market demand for capacity as well as various government approvals that could lead to an FID in 2018.

9.4 France

The transmission network in France covers more than 37,000 km. It is connected to 4 countries (Belgium, Germany, Switzerland and Spain) through 7 on-shore interconnection points. It is also supplied by one import point from Norway and 4 LNG terminals, including the new Dunkirk LNG terminal, which should be operational by the end of 2016. There are also large UGS facilities, covering roughly 30% of national gas demand.

9.4.1 DEVELOPING INTERCONNECTIONS

Since 2005, investments made by TSOs in France have led to a 50% increase of entry capacity and to a doubling of exit capacity. All developments of cross border capacities have been conducted through market consultations, organised with each neighbouring TSO, including;

- With Germany: an open season in 2005, led to the creation of new entry capacities from Germany, 120 GWh/d in 2008 and 70 GWh/d in 2009 to reach a total of 620 GWh/d.
- With Spain: After two consultations organised in 2009 and 2010, cross border capacities with Spain have been enhanced in 2013 and in 2015 in both directions, 195 GWh/d have been added from Spain to France and 65 GWh/d from France to Spain.
- With Belgium: Fluxys Belgium and GRTgaz have completed two consultations together, one in 2010 and the other in 2011 in order to consolidate the integration of the French, Belgian and North European markets. These consultations led to an increase of capacity by 50 GWh/d in 2013 from Belgium to France at Blaregnies/Taisnières, and to a new interconnection point created in 2015 at Alveringem to provide non-odorised gas from the new Dunkirk LNG Terminal to the Belgian border up to 270 GWh/d.
- With Switzerland/Italy: The open season conducted jointly by GRTgaz and FluxSwiss in 2012 to create a new entry point from Switzerland to France by 2016-2018 could not lead to investments, although stakeholders confirmed their interest. GRTgaz proposed in 2014 a new product associated with fewer investments. After a consultation phase, and the following approval of the investment by the NRA, GRTgaz took a FID in 2015. The corresponding infrastructure will be commissioned in 2018, enabling a reverse flow at Oltingue from Switzerland up to 200 GWh/d, 100 GWh/d being interruptible. This new entry point will give access to new supply sources from Italy and will enable further arbitrage for shippers between hubs.

With a 13 bcm capacity, the new Dunkirk LNG terminal should be operational by the end of 2016. In order to connect it to the transmission network, GRTgaz has performed a major work program with a total budget of € 1,185 million, including a 17 km non-odorised pipeline, the pipeline 'Hauts de France II', 123 km in length and the pipeline 'Arc de Dierrey' at 300 km, all commissioned between 2015 and 2016. These investments are also significantly improving the flexibility of the gas system.

The expansion of the LNG terminals in Montoir and Fos is being considered. The LNG terminal in Montoir could be expanded from 10 to 12.5 bcm by 2020/2022, requiring notably the reinforcement of the Maine pipeline and the reinforcement of compressor stations.

Image courtesy of Fosmax LNG

The expansion of the LNG terminal Fos Cavaou from 8 to 16 bcm would involve the reinforcement of the Rhône pipeline from South to North, including Eridan (220 km), Arc Lyonnais (200 km), the Beauce pipeline (63 km) and additional compressor power.

Further developments of interconnection are being considered with both Germany and Spain. These projects have been identified as PCI projects for the 2015–2017 period.

With Spain: the PCI 5.5 Midcat aims to reinforce the interconnections with Spain by creating a new interconnection point, east of the Pyrenees, in order to mitigate the dependence of the Iberian Peninsula on LNG and enhance market integration. Enagás, GRTgaz and TIGF have performed a joint technical study to identify the investments required to create firm capacities. To add 230 GWh/d firm capacity from Spain to France and 160 GWh/d from France to Spain, several developments of French and Spanish networks have been identified amounting to roughly € 3 billion. In order to enable these capacities and remove congestions that would result from South to North flows, the project would require, in addition to new compressor power, the following items:

- The looping of the Rhône pipeline (220 km), PCI project 5.8.2, Eridan
- The looping of the East Lyonnais pipeline (150 km), PCI project 5.8.1, East Lyonnais
- The looping of the Midi pipeline (240 km)
- The looping of the Beauce pipeline (63 km)
- The connection to the border (120 km)

A smaller set of investments, the STEP project (South Transit East Pyrénées), is also being considered. It is limited to investments on the Enágas and TIGF networks and would create interruptible capacities, up to 180 GWh/d from France to Spain and 230 GWh/d in the other direction.

With Germany: Beyond commercial backhaul capacity already existing from France to Germany, physical reverse flow from France to Germany is under consideration. The PCI creating a reverse flow from France to Germany would improve access to LNG for the German market and contribute to the need for additional supplies in western Germany as a replacement for L-gas. The creation of this reverse flow (100 GWh/d) will necessitate the reinforcement of the network on the North East pipeline between Morelmaison and Voisines, additional compressor stations and adaptation of some interconnections to enable a reverse flow. It would also require

Figure 9.7: Development of interconnections in France (Source: ENTSOG TYNDP 2017 Map)

solutions to harmonise odorization practises in France and Germany, since gas is odorised upon entry on the transmission system in France and Spain, whereas it is done upon entry on the distribution system in Germany. GRTgaz is currently conducting feasibility studies on two types of solutions. The first solution consists in adopting non-centralised odorization practices. It is currently being assessed technically and economically on two small scale units. An alternative solution is also being considered, with a de-odorization plant, more suitable for intermittent flows. The results from these two feasibility studies are expected in 2017.

9.4.2 THE CREATION OF A SINGLE TRADING ZONE IN FRANCE IN 2018

In addition to the development of interconnections, the simplification of the gas market has been a constant priority for CRE (French NRA). The NRA has set a target in 2012 to finalise market integration in France and create a single market place by 2018. To this end, GRTgaz and TIGF have decided in 2014 and 2015 to invest €880 million. The PCI projects Val de Saône (5.7.1) and Gascogne Midi (5.7.2) from the second PCI list will enable the merger of balancing zones by creating additional flows from North to South, thus removing the current bottleneck between North and South and reducing the LNG dependency in the South of France. These projects have been approved by CRE and supported by stakeholders after a Cost Benefit Analysis in 2013 and a cross border cost allocation between France and Spain in 2014.

The Val de Saône project consists in the looping of the Burgundy pipeline (189 km), a third compressor adding 9 MW to the compressor station in Etrez, and adjusting the interconnections at Palleau, Etrez and Voisines. The permitting phase is completed and works will begin in 2017 with commissioning in 2018.

The Gascogne Midi project aims to create a physical flow from TIGF to GRTgaz through the Midi pipeline. It consists in the looping of the Gascogne pipeline (60 km), and consolidation of the Barbaira compressor station and the adaptation of interconnections in Cruzy and Saint Martin de Crau. Permitting is ongoing and commissioning is also expected in 2018.

9.4.3 ENSURING THE L-GAS CONVERSION PROCESS

The decrease of L-gas supply by 2029 will require converting L-gas consumers in France. In 2016, French infrastructure operators have submitted a plan to convert the L-gas customers to H-gas in the North of France to the relevant ministries. GRTgaz will start works to prepare the transmission network to enable the first conversions of L-gas customers in selected cities as a testing phase between 2016 and 2020. The conversion will then be extended and performed from 2021 to 2029. More details can be found in the dedicated L-gas chapter 7.5.

9.4.4 PREPARING THE ENERGY TRANSITION

The energy transition supposes a more holistic approach to energy challenges. Convergence between energy systems and links between centralised and decentralised levels come to the forefront of the process. The geographical coverage and the flexibility of existing gas infrastructures are decisive assets that can benefit the whole energy system. Therefore gas TSOs are well-placed to support an efficient energy transition which is sympathetic to economic perspectives. A special attention is given to projects supporting a more flexible and less carbon intensive system while avoiding the stranding of assets and the associated cost and societal implications.

In addition, GRTgaz is already looking at tomorrow's technologies and has launched the first Power to Gas industrial demonstration in France. By 2018, the 'Jupiter 1000' project will commission an innovative solution to produce hydrogen through electrolysis, along with a methanisation and CO_2 capture process.

TSOs can also help the development of more sustainable use and sourcing of gas even when they are not directly responsible for it. With this purpose in mind GRTgaz supports

- gas-fired power production through a flexible commercial offer and the development of hub liquidity in order to help the market to capture every spark-spread opportunity (a dedicated consultation platform pilots the topic under NRA chairmanship),
- gas mobility as team leader for the development of the sector in France (GRTgaz is recognised as both a neutral and industry player with a long term vision for the sector),
- oil and coal conversion to gas in the industrial sector through economic and technical studies,
- the drafting of new piece of legislation related to electricity and/or heat production (capacity mechanism, feed-in tariff …).

9.4.5 DEVELOPING THE PRODUCTION OF BIOMETHANE

In light of the objective defined in the Law on Energy Transition for Green Growth - 10% renewable gas in the mix by 2030 – the network will acquire new production tools (for biomethane or synthetic gas). Close to 600 biomethane injection units will be required by 2025 to achieve this goal, mainly on the distribution network. Biomethane producers can benefit from a feed-in tariff, guaranteed by law over 15 years. In 2015, 17 facilities were able to inject 82 GWh of biomethane into French grid. The biomethane sector is expected to take off by 2022/2023. Connecting these facilities to the gas grid may have some impacts on the gas infrastructure. In particular, biomethane production could be higher than local consumption, especially in rural areas. To maximise biomethane injection, infrastructure operators are considering several solutions, including peak-shaving, development of local consumption, and linking distribution grids. On the transmission system, some backhaul facilities could be envisaged to move up gas upstream from distribution to transmission grid.

9.5 Germany

On 1 April 2016 the German TSOs submitted the draft German Network Development Plan (NDP) 2016 to the German national regulatory authority Bundesnetzagentur (BNetzA). In the draft German NDP 2016 the German TSOs propose investments into the German gas transmission system of € 4.4 billion by 2026. These investments include 802 km of new pipelines and 551 MW of additional compressor power.

The major drivers for the investments are the requirements to adapt the German gas transmission system for the entry of additional H-gas replacing the declining indigenous L-gas production and the L-gas imports from the Netherlands (see also chapter 7.3).

The draft German NDP 2016 is based on a scenario framework which was consulted on in mid-2015 and formally acknowledged by BNetzA on 11 December 2015. In December 2016 BNetzA revised the scenario framework. Based on the revised scenario framework, the German TSOs are developing and consulting on a revised draft German NDP 2016 in Q1 2017.

The scenario framework for the NDP 2016 describes two supply scenarios for additional H-gas quantities required due to the declining Dutch and German L-gas production under consideration of – among others – projects described in the ENTSOG TYNDP 2015. Based on the shares defined in the scenario framework for the two supply scenarios, the following peak flow assumptions were applied in the modelling of the draft German NDP 2016:

ASSUMPTIONS ON ADDITIONAL ENTRY PEAK FLOW (GWh/h)		
Supply scenario	**Q.1**	**Q.2**
NORTH EAST	2.7	17.9
WEST/SOUTH WEST	13.1	13.6
SOUTH/SOUTH EAST	22.7	11.1

Table 9.1: Peak flow assumptions depending for the two supply scenarios Q.1 and Q.2 (Source: draft German NDP 2016)

The supply scenario Q.2 was derived by taking a limited share of additional capacities from Nord Stream 2 into account, while the supply scenario Q.1 did not include this assumed additional capacity.

9.5.1 MARKET CONVERSION PROJECTS L- TO H-GAS IN THE GASPOOL MARKET AREA

The complete conversion of the German gas transmission system from L-gas to H-gas is planned for 2030 as set out in the draft German NDP 2016. For this reason Gasunie Deutschland developed a project called 'GUD: Complete conversion to H-gas (TRA-N-955)' to show in several steps the implementation of the GUD L-gas transmission system in H-gas until 2030. The project is linked to the GTS project 'H-Gas conversion of L-Gas export border point (TRA-N-882)'. On the German side no investments are required, the pre-existing infrastructure will be used. The project is only a capacity modification, which does not require actual investment or construction works.

The project 'Embedding CS Folmhusen in H-Gas (TRA-N-951)', which is also related to the conversion of the German gas transmission system from L-gas to H-gas, ensures the operability of the Compressor Station Folmhusen in the H-gas system (so far this can only accommodate L-gas).

9.5.2 MARKET CONVERSION PROJECTS L-GAS TO H-GAS IN THE NCG MARKET AREA INCLUDING THE ZEELINK PROJECT

In order to handle the declining L-gas production of the Groningen field, the German TSOs Open Grid Europe and Thyssengas are planning the development of several new metering and regulating stations connecting H-gas transmission system with the current L-gas transmission systems in line with the draft German NDP 2016.

In addition, Open Grid Europe and Thyssengas are currently developing the 227 km ZEELINK project from the Belgian-German cross-border interconnection point Lichtenbusch via Sankt Hubert to Legden (North Rhine-Westphalia). The ZEELINK project includes a new 39 MW compressor station near Aachen.

The ZEELINK project represents the largest single project in the German Network Development Plan 2016. It connects new H-gas sources to the German gas transmission system (e.g. the LNG-terminal Zeebrugge in Belgium), reinforces the North-South transmission capacity in the NCG market area and thereby contributes to the security of supply in the NCG market area including the regions affected by the L-gas production decline.

9.5.3 NCG MARKET AREA TSO PROJECTS –

technical capacities from/to gas storages and to DSO systems

The following system enhancement projects aimed at increasing the technical capacities between the TSO and DSO systems as well as between the TSO systems and gas storages in the NCG market area are included in the draft German NDP 2016 and the TYNDP 2017.

- New 33 MW Wertingen compressor station by bayernets and Open Grid Europe (TRA-N-340)
- New 39 MW Rimpar compressor station project by GRTgaz Deutschland and Open Grid Europe (TRA-N-755)
- New 45 MW Rothenstadt compressor station by GRTgaz Deutschland and Open Grid Europe (TRA-F-337)
- New 39 MW Herbstein compressor station by Open Grid Europe (TRA-F-344)
- 49 MW upgrade of the Werne compressor station by Open Grid Europe (TRA-F-345)
- Schwandorf to Finsing pipeline (141 km) project by Open Grid Europe (TRA-F-343)

9.5.4 PROJECTS TO ENABLE PHYSICAL CAPACITY TO TRANSPORT GAS IN BOTH DIRECTIONS BETWEEN MEMBER STATES

The following project is included in the draft German NDP 2016 and the TYNDP 2017: West to East operation of the Waidhaus interconnection point by GRTgaz Deutschland and Open Grid Europe (TRA-F-753)

9.5.5 TENP REVERSE FLOW PROJECT

The Reverse Flow project on TENP[50] consists in the reversal of the compressor station in Hügelheim, improving the flow patterns in the compressor station of Mittelbrunn and building a new deodorization plant near the German-Swiss border. The works in the compressor stations in Hügelheim and Mittelbrunn are necessary to allow the transportation of gas quantities from Italy to Germany in the South/Southwest Region at the cross-border point Wallbach. The construction of the deodorisation plant is necessary to remove THT from the gas coming from France via Switzerland for it to be compliant with the German market.

9.5.6 MONACO (PHASE I)

German TSO bayernets will build a new pipeline called 'MONACO' (phase I) from Haiming/Burghausen to Finsing (near Munich). Because of the resulting increase in cross-border-capacity for gas exchange, the importance of the project was identified at European level and was therefore awarded PCI-status (October 2013). The construction permit was granted in early 2016 and initial preparation measures towards construction took place in autumn 2016.

MONACO (phase II) was planned to connect MONACO (phase I) further westwards from Finsing to Amerdingen. However, the draft German NDP 2016 did not confirm the necessity for additional transport capacity. Therefore the current position is that this project will not be pursued.

9.5.7 MORE CAPACITY

The German TSOs GASCADE, NEL, Gasunie Deutschland, ONTRAS and Fluxys Deutschland have launched a non-binding market survey in 2015 to determine the future need for additional transport capacities at the borders of the H-Gas market area GASPOOL.

The non-binding enquiries submitted for the purposes of the survey are used to determine whether there is sufficient cross-border demand for the further planning of new development projects (demand analysis).

The survey identified further needs of new gas infrastructure related to higher cross-border capacity demand. The respective TSOs are therefore developing infrastructure projects which depend on a binding capacity auction to be held in 2017.

50) Source: www.fluxys.com/tenp/en/TenpSystemInfo/SouthNorthProject/ReverseFlow

The outcome for the GRIP NW region relates to the market area transmission of gas volumes from Russia to GASPOOL and further from GASPOOL to the Netherlands. The enquired capacities at the border from Russia to GASPOOL and from GASPOOL to the Netherlands are higher than the current available technical capacities. The TSOs agreed to carry out a technical study to identify further developments on the borders of the corresponding market areas.[51)]

The following projects are partly considered in the 'more capacity' market survey.

9.5.7.1 EUGAL

Additional capacity needs were identified as a result of the market survey. To ensure the transport of the requested new gas volumes and to further improve the security of supply for the market areas of Poland, the Czech Republic, GASPOOL and NCG, the EUGAL (European Gas Pipeline Link) Project (TRA-N-763) has been developed by GASCADE Gastransport GmbH.[52)]

9.5.7.2 Expansion NEL

Based on the supply scenario Q.2 of the German NDP 2016 a new Compressor Station in the south of Hamburg for the import of gas volumes from Russia via Nord Stream to Germany (GASPOOL) is required. The project 'Expansion NEL' (TRA-N-807), developed by Gasunie Deutschland, NEL Gastransport and Fluxys Deutschland is a prerequisite for the transport of new capacities into the market area to cover the growing German demand for high-calorific gas, caused among others by the necessity of the conversion from L-gas to H-gas. The project is part of 'more capacity', which includes e.g. the extension of the Receiving Terminal Greifswald.

9.5.7.3 Transport of gas volumes to the Netherlands

The project 'Transport of gas volumes to the Netherlands (TRA-N-808)' was developed by Gasunie Deutschland to cover the demand at the German-Dutch border as the result of the non-binding market survey 'more capacity'. The project is including the evacuation of gas volumes from Russia via Nord Stream and Germany to the Netherlands.

9.5.7.4 Upgrade IP Deutschneudorf and Lasów

Linked to the 'more capacity' project, the German TSO ONTRAS intends to increase its cross-border capacities at the Deutschneudorf and Lasów interconnection points. These two capacity extension projects aim to support the exchange of gas between the Czech Republic and Germany as well as Poland and Germany. A final investment decision has not been taken yet.

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51) Further information can be found on www.more-capacity.eu

52) Further information can be found on www.eugal.de

9.5.8 PROJECT OVERVIEW

The projects of the draft German NDP 2016 included in the TYNDP 2017 are shown in the figure below.

Figure 9.8: TYNDP 2017 project map Germany (Source: Draft German NDP 2016)

9.6 Ireland & Northern Ireland

9.6.1 OVERVIEW OF MARKET AND TRANSMISSION SYSTEM

The onshore natural gas transmission network in Ireland & Northern Ireland is 2,104 km in length and supplies gas to over 840,000 homes and 35,000 businesses on the island of Ireland. Gas accounts for approximately 28% of Ireland's Total Primary Energy Requirement (TPER), reflecting its role in electricity generation, process and heating use.

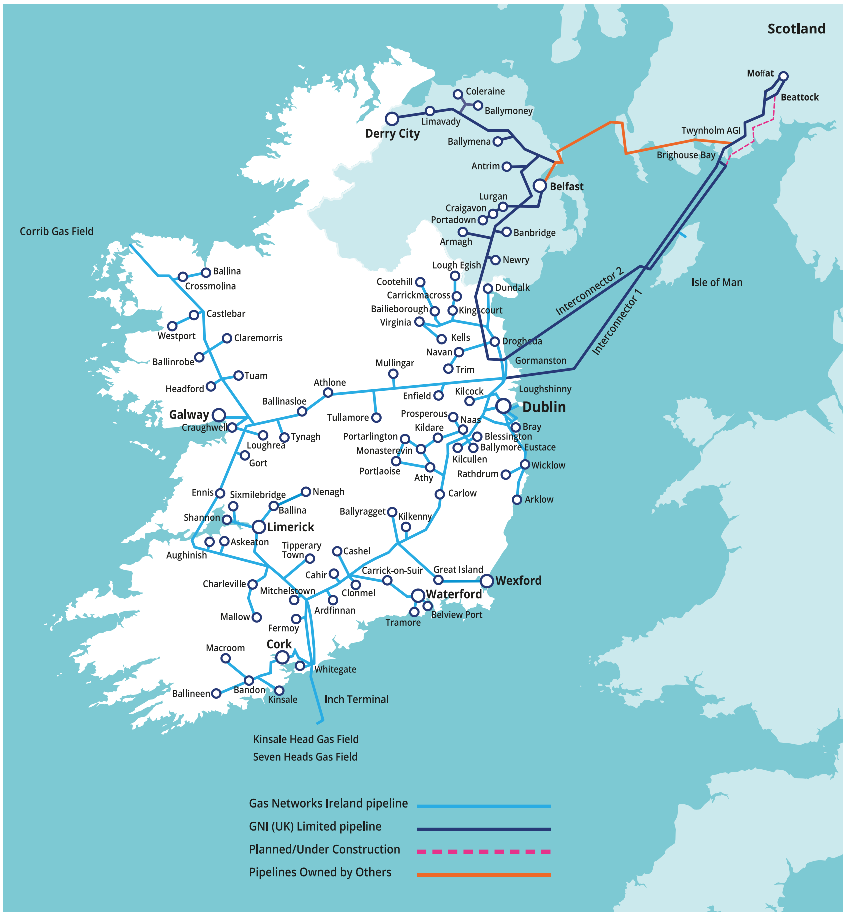

Figure 9.9: Ireland & Northern Ireland Transmission pipelines
(Source: Gas Network Ireland Network Development Plan 2016)

The Moffat Interconnection Point (IP) is the connection point between the National Grid (UK) and the GNI (UK) Limited onshore pipeline in Southwest Scotland which connects into the Gas Networks Ireland transmission system in Ireland via two subsea interconnectors. Twynholm connects the GNI (UK) Limited onshore pipeline in Southwest Scotland supplying gas to transmission system in Northern Ireland via the Scotland to Northern Ireland gas pipeline (SNIP), owned by Premier Transmission Limited.

Historically the Moffat Interconnection Point was the largest source of gas supply to the Gas Networks Ireland transmission system and the single utilised supply point for the NI gas transmission network. As recently as 2015 the Moffat Entry Point supplied circa 95 % of the annual Ireland's gas demand and still meets 100 % of Northern Ireland demand. This connection to the GB National Transmission System (NTS) facilitates Ireland and Northern Ireland's participation in an integrated European energy market.

The Kinsale storage facility which is connected to the Gas Networks Ireland transmission system at the Inch Entry point is operated by PSE Kinsale Energy Limited (KEL) using the depleted Southwest Kinsale gas field. KEL has advised that it plans to cease full storage operations in 2016/17 and commence blowdown of Southwest Kinsale. There will be no further injections into Southwest Kinsale, with production gas only to be supplied from the Inch Entry Point from summer 2017 onwards, ceasing in 2020/2021.

The Corrib gas field commenced production on the 31 December 2015 and is expected to meet up to 55% of annual Gas Networks Ireland system in 2016/17, with the Inch and Moffat Entry Points providing the balance. By 2024/25 Corrib gas supplies will have declined to approximately 50 % of peak production levels which will re-establish the Moffat Entry Point as the dominant supply point for Ireland.

In Northern Ireland, the Utility Regulator has recently issued conveyance licences to extend the natural gas transmission network to the west of Northern Ireland and develop distribution networks in towns in this area which until now had no access to piped natural gas. It is estimated that this transmission extension project would connect up to 40,000 new businesses and domestic consumers to natural gas in the West and North West. The Strabane leg of the network extension was commissioned in January 2017 and the main transmission pipeline will be commissioned in 2018.

9.6.2 RENEWABLE GAS

Energy from biomethane or renewable gas has the potential to contribute significantly to Ireland's renewable energy targets. Ireland has a legally binding target to achieve 16 % of gross final energy demand from renewable sources by 2020 under the EU Renewable Energy Directive (2009/28/EC). In order to achieve this target the Irish government introduced a 12% target for renewable heat by 2020.

Utilising mature technologies, with the right investment, renewable gas has the potential to satisfy over 20 % of Ireland's gas demand by 2030. Capitalising on this opportunity would reduce the country's reliance on imported fuels and provide Ireland with a renewable indigenous fuel source. Gas Networks Ireland is proposing a target to achieve 20 % renewable gas on the gas network by 2030. With emerging technologies such as Power to Gas with methanisation, algae, and gasification, far more ambitious targets are possible for 2050.

9.6.3 COMPRESSED NATURAL GAS (CNG) FOR TRANSPORT

In order to encourage the uptake of CNG by commercial fleet operators Gas Networks Ireland intends to provide full national coverage of public CNG fast-fill compressor stations. Gas Networks Ireland is proposing to develop a 70-station CNG fuelling network, co-located in existing forecourts, on major routes and/or close to urban centres. This will help satisfy the requirements of the EU's Alternative Fuels Directive which aims to establish CNG refuelling facilities along key routes at every 150 km by 2025. This comprehensive refuelling station network, will allow a transition to both natural gas and renewable gas as alternative fuels.

Gas Networks Ireland is currently targeting at least 5 % penetration of CNG or renewable gas for commercial transport and 10 % of the bus market in Ireland by 2025.

Figure 9.10: CNG Transport in Ireland (Source: Gas Network Ireland Network Development Plan 2016)

9.6.4 COMPRESSED AIR ENERGY STORAGE

Gaelectric CAES NI Ltd. is currently developing a Compressed Air Energy Storage ('CAES') project in Larne, Co. Antrim. The project has been granted a mineral prospecting licence from Department for the Economy (DfE) and is a Project of Common Interest (PCI) since October 2013. In December 2015, a planning application and Environmental Impact Assessment (EIA) was submitted to the Department for Infrastructure (DfI) Strategic Planning Division.

The facility will generate up to 330 MW of power and will create demand of up to 250 MW during its compression cycle, both for periods of up to 6 hours. The project involves the creation of two storage caverns within salt deposits which are a feature of the east Antrim coastal areas of Northern Ireland.

9.6.5 INFRASTRUCTURE DEVELOPMENT

The Twinning of the South West Scotland Onshore system (PCI 5.2), which was previously approved, will enhance security of supply to the island of Ireland. This project involves the twinning of a previously unparalleled 50 km section of pipeline and will result in an entire dual interconnector sub-system between Great Britain and Ireland and remains on schedule for completion in the 2017/18 gas year.

Currently physical flows at the Moffat interconnection point are uni-directional i.e. Great Britain to Ireland. System modifications would be required to accommodate bi-directional flows at Moffat. Following the submission of a cost benefit analysis to the EC in May 2015, three projects allowing bidirectional physical flows at Moffat were successfully placed on the second European Union PCI list published in November 2015. The individual PCIs in Cluster 5.1 to allow bidirectional flows from Northern Ireland to Great Britain and Ireland and also from Ireland to United Kingdom, are described in the following sections.

Physical Reverse Flow at Moffat Interconnection Point (PCI 5.1.1)

This project will look at physical reverse flow from Republic of Ireland to Great Britain (UK), providing security of supply benefits on a regional basis, in addition to increased market integration and increased competition. GNI (UK) submitted an application under the Connecting Europe Facility (CEF), for feasibility studies in October 2015. This application was not successful. However at the time of writing GNI (UK) Limited has submitted an updated application for CEF funding in relation to these studies in the second CEF call for funding.

The supply position in Ireland has changed dramatically since the previous submission, with the Corrib gas field coming on stream. This could result in up to 100 days where there is excess supply on the system. The 50 km twinning project in South West Scotland, a key prerequisite for physical reverse flow at Moffat is also nearing completion. This greatly enhances the viability of the project.

Upgrade of the SNIP (Scotland to Northern Ireland) pipeline to accommodate physical reverse flow between Ballylumford and Twynholm (PCI 5.1.2)

This project comprises an installation of bi-directional compression on the Scotland to Northern Ireland pipeline (SNIP); pipework modifications at 2 above ground installations (AGIs) to allow bi-directional metering and flow control and moving gas odorization point to a new point(s) downstream of the bi-directional transmission system.

Development of the Islandmagee Underground Gas Storage (UGS) facility at Larne (Northern Ireland) (PCI 5.1.3)

Islandmagee Storage Limited (IMSL) plans to create eight caverns, capable of storing up to a total of 420 million cubic metres of gas. This facility will safeguard Northern Ireland's ability to meet the increasing peak of demand whilst also providing security of supply to Ireland and Great Britain.

In June 2016 IMSL finalised a 2nd grant agreement with the EC under the Connecting Europe Facility (CEF), towards the costs associated with the Front End Engineering & Design (FEED) for the project. The Company is working with Mutual Energy Limited, and advisers, to secure the new investors who will take this strategically important project through to a Final Investment Decision, targeted for 2017.


Image courtesy of Bord Gáis Ireland

9.7 Luxembourg

On 1st October 2015, the Luxembourg gas transmission system operator, Creos Luxembourg and the Belgian gas transmission system operator, Fluxys Belgium launched the very first integrated gas market involving two EU Member States.

This merger, which received broad media coverage is the result of extensive cooperation dating back to 2013 between Creos Luxembourg, Fluxys Belgium and their respective regulators, the Institut Luxembourgeois de Régulation (ILR) and Belgium's Commission de Régulation de l'Electricité et du Gaz (CREG).

It is very much in line with the main objectives of the Gas Target Model updated on the 16 January 2015, that is, to improve liquidity and accessibility as key features for an efficient gas market design, and the EU's goal to create an internal, borderless gas market where gas supplies can circulate freely between all Member States. Combining the two markets enhances market competitiveness for both countries, and also strengthens Luxembourg's security of supply.

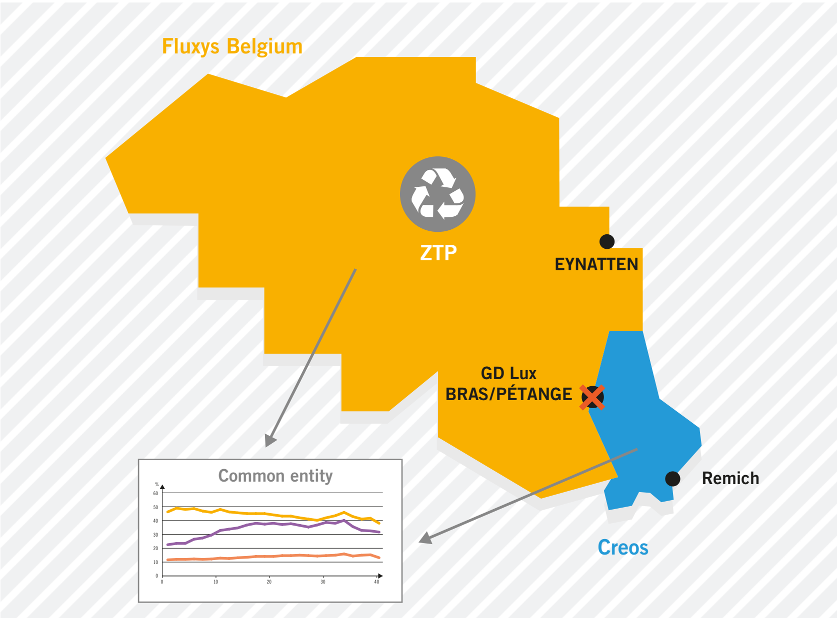

Figure 9.11: A single integrated gas market for Belgium and Luxembourg (Source: Fluxys Belgium & Creos Luxembourg)

In common with Europe's other gas markets, the Belgian and Luxembourg markets makes use of national entry/exit systems, with access fees applying between the two countries. In other words, to be able to transmit gas from Belgium to Luxembourg, suppliers had to pay an exit fee for gas to leave Belgium and an entry fee to enter Luxembourg. With the creation of the integrated Belgian/Luxembourg market, these entry-exit access fees between Belgium and Luxembourg were removed and the Zeebrugge Trading Point (ZTP) became the gas trading point for the integrated market.

The merger has created a single balancing market in the two countries, offering further opportunities for suppliers and shippers to be active in both countries. In order to manage the rules and mechanisms for commercial balancing in the new integrated market area, Creos Luxembourg and Fluxys Belgium have established a new jointly owned (50/50) company called Balansys.

9.8 The Netherlands

The Dutch gas transmission network capacity is continually adapted in order to ensure that the network is organised in such a way that all transmission requirements can be met. The requirements for transmission capacity are laid down every two years in the Dutch network operators' Network Development Plan (in Dutch: Netwerk Ontwikkelingsplan, abbreviated as NOP), last published in 2015.

This document is prepared by GTS in order to propose investment measures that will ensure the required capacity for the gas transmission system in the Netherlands in order to meet gas demand. The NOP has a horizon of twenty years, contains in-depth analyses on transmission requirements and capacity scenarios and is easy to access as it written in English.

In the NOP, GTS uses capacity demand scenarios which describe a range of credible futures regarding gas transmission for the GTS network. These scenarios show a decrease in capacity demand.

On the supply side, the main driving force for future planning is that gas produced in the Netherlands is in decline. The NOP incorporates the most recent known figures known at the time of publication. Gas produced in other, nearby parts of North West Europe, notably the UK and Germany, is also declining and Norway's production is not expected to increase.

Comparing the demand situations with the trend in local production, and with the existing entry capacity, there is a clear need for additional gas from outside North West Europe. The amount of additional gas needed will differ according to the scenarios, and the direction from which it may come will differ over time. The sources of additional supply will be predominantly liquefied natural gas (LNG), delivered to terminals in North West Europe, and Russian gas delivered by pipe. Longer term options may include larger volumes of both pipeline gas and LNG from new infrastructure in Europe.

Analyses of the scenarios show that the main gas transmission system, as well as the gas distribution networks in the Netherlands are robust enough to absorb expected changes in the level of market demand for gas over the next ten years. However the additional supply needs exceed the total entry capacity of the system, which needs to be expanded.

9.8.1 DEVELOPMENTS RELATED TO QUALITY CONVERSION

The increased need to convert high calorific gas into a quality suitable for the low calorific market, due to the decline of the Groningen field, may lead to a need for investment in additional gas quality conversion facilities. In 2014 GTS started preparation for the expansion of this quality conversion facility to ensure that, following on from a ministerial decision, this project can be realised in accordance with the L-gas conversion timetable, see Section 7. The Minister of Economic Affairs in September 2016 decided to postpone a final investment decision by one year and to re-assess in 2017. This evaluation will consider whether an expansion of the nitrogen blending facility at Zuidbroek is necessary. Before taking a final decision in 2017, the Ministry will have to assess how the latest developments which influence the need to use quality conversion, compared to other means of (future) flexibility. It has become clear that as a result of lowering the annual production from the Groningen field, its peak production capacity will decline slower than previously assumed. Another development that should be assessed is that the neighbouring countries, Germany, Belgium and France, have indicated that they could start earlier than agreed with the conversion of their markets, which would lead to lower demand for L-gas flexibility than originally expected.

9.8.2 DEVELOPMENTS RELATED EXIT CAPACITIES

An important development is the adjustment of exit capacity on the Dutch - German border. The conversion of L-gas markets in Germany to H-gas as a result of declining German production and lower availability of Dutch L-gas, is expected to gain pace around 2020. The GTS grid has sufficient capacity to transmission the amounts of H-gas to Germany that are needed for this market conversion. However adjustments will need to be made at the exit points. This also requires investments on the German side of the border. An example of this is the new H-gas interconnection to GTG Nord at Oude Statenzijl which is in the engineering phase at this moment.


Image courtesy of Gasunie

9.8.3 DEVELOPMENTS ENTRY CAPACITIES

Due to the relocation of entry capacity from the gas production fields to interconnection points on the borders and gas storage facilities the transmission lines between these entry points and the rest of the grid need reinforcement. The exact location of entry determines where investments are needed. Several parties are developing plans that will lead to an increase in demand for entry capacity for which GTS will need to progress reinforcement investments. This primarily concerns the Oude Statenzijl interconnection point on the Dutch -German Border (see also the “more capacity” topic in chapter 9.5) and the connection to the GATE LNG-terminal.

Initiatives at OSZ and at GATE generate additional flows on entry- and exitpoints, as shown in the graph below.

Figure 9.12: Possible flows from projects at OSZ and GATE (Source: GTS)

9.8.4 DEVELOPMENTS RELATED TO LNG

Gate LNG terminal (see picture below) has been expanded to include a third berth and special infrastructure for the loading of small LNG vessels. These small LNG vessels will enable distribution to LNG terminals in other North Sea and Baltic ports where large LNG tankers are prohibited to deliver directly due to their draught.

Figure 9.13: Overview of the GATE terminal in the port of Rotterdam (Source: GTS)

In conjunction with LNG bunker vessels, the new berth will in future also make it easier for ocean-going vessels to fill up with LNG in Rotterdam. As with other kinds of maritime fuel LNG can be pumped on board large ocean-going vessels using bunker vessels. These can now be loaded at Gate terminal which receives LNG from large LNG tankers arriving from several global countries of origin. The use of LNG as a maritime fuel is being encouraged by the European Union, the Dutch government and the Port of Rotterdam because of its more environmentally friendly properties.

The third berth is intended especially for small vessels. Gate terminal has two jetties where mainly large LNG tankers berth to unload their LNG cargo into the three 180,000 m³ storage tanks. The cold LNG (minus 160 °C) is pumped from these storage tanks along insulated pipelines to the new berth and, with the aid of two or three special loading arms, is loaded into the small seagoing vessels and bunker vessels. The system is fully enclosed, with vapor being collected and fed back to the terminal. At the new third berth small volumes of LNG, from 1,000 m³ up to 20,000 m³, can be loaded, increasing to 40,000 m³ in the longer term. The LNG is loaded at a maximum speed of 1,000 m³ per hour and each year around 280 ships (including smaller ones) can be loaded.

Adjacent to Gate terminal, the Port of Rotterdam has developed the new, 255-meter long, 150-meter wide and 7.5-metre deep Yukon Harbour. The third berth of Gate terminal is built on this new quay wall and it can handle vessels of up to 180 meters in length.

9.9 Sweden

9.9.1 GAS TRANSMISSION

The construction of the Swedish transmission grid began in 1985 and three years later the grid reached Gothenburg. In 2004, the latest major expansion was made which led to today's transmission grid.

The transmission grid consists of 601 km pipelines, 41 measuring and regulator stations and 6 gas metering stations located in southwestern Sweden. The grid is connected to about 26,000 km of distribution pipelines. The system has a pipeline interconnection with the Danish gas system with a maximum cross border capacity of 88 GWh/day. This pipeline interconnection is from Dragör in Denmark to Klagshamn in Sweden and due to Swedish legislation the gas is odorised on the Swedish side in Klagshamn.

Sweden has a vulnerable supply position due to the single cross-border entry point onto the gas system. This weakness has been mitigated primarily by the Ellund project which involves increasing the capacity between Germany and Denmark, which has led to a better supply situation in Denmark and therefore also Sweden. The upcoming LNG terminal in Gothenburg and increasing biogas production will also strengthen the security of supply position.

9.9.2 STORAGE

The transmission system is connected to the Skallen UGS facility. This rock cavern storage facility, characterised by high input and withdrawal capacity, has a capacity of 10 mcm and can handle pressures in excess of 200 bar. The size of the storage does not allow seasonal storage but is limited to peak shaving services.

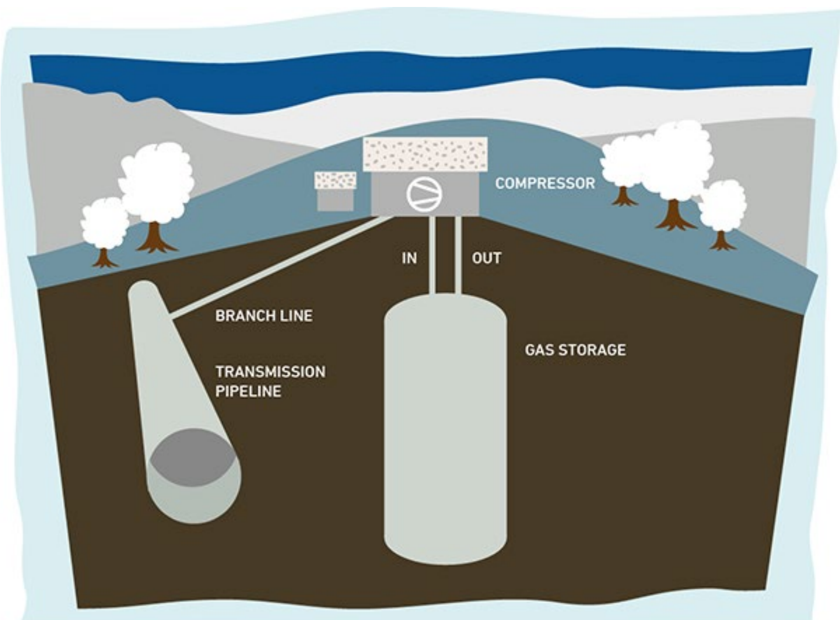

Figure 9.14: Skallen Storage – Owned and operated by Swedegas (Source: Swedegas)

9.9.3 LNG INFRASTRUCTURE DEVELOPMENT

In Sweden, there are two LNG terminals in operation. The Nynäshamn LNG terminal, south of Stockholm, has a storage volume of 9,300 tons and is in operation since 2011. In this area only the local refineries are connected to the terminal. Other customers (industries and the city of Stockholm) are supplied with gas by truck. The Lysekil LNG terminal on the Swedish west coast is in operation since 2014. In common with the Nynäshamn LNG terminal, a small local distribution grid connects to refineries and the other customers are supplies by truck.

In Gothenburg, an LNG terminal is planned to be built and this terminal, in contrast to the two mentioned above, will be connected to the transmission grid. The project has PCI status, environmental permit granted and a concession application pending. An open access terminal to promote competition is at a planning stage at the port of Gothenburg, where anyone who wishes to supply LNG to the Swedish market can contract capacity. As well as connecting to the transmission system, the terminal will support railcar loading, truck loading, storage and bunkering. The market segments will consist of regional grids, heavy trucks, off-grid industry, marine and the transmission grid.

9.9.4 BIOGAS INFRASTRUCTURE DEVELOPMENT

Production of biogas is increasing every year and in 2015 there were 282 facilities in Sweden producing almost 2 TWh. Of these facilities 10 are connected to the gas grid and they injected around 0.5 TWh. More than 1.1 TWh was used as fuel for vehicles.

The two largest sites are GoBiGas and Jordberga and they are both connected to the gas grid. GoBiGas produces biogas through thermal gasification of biofuel and forest residue. It is one of the largest sites of its kind and is in operation since 2014. Jordberga, also commissioned in 2014, is an anaerobic digestion plant which mainly uses locally produced energy crops as raw material.

Swedegas is a member of the Green Gas Commitment and has therefore committed to a CO_2 neutral gas supply by 2050.

Figure 9.15: Jordberga biogas facility (Source: Swedegas)

9.9.5 DEVELOPMENT OF GAS FOR ROAD TRANSPORT

The CNG market has grown considerably in Sweden until recent years when it has slowed down. In 2015, almost 1.6 TWh was used as CNG and over 70 % of this share was from biogas. The number of public filling stations stands at 161.

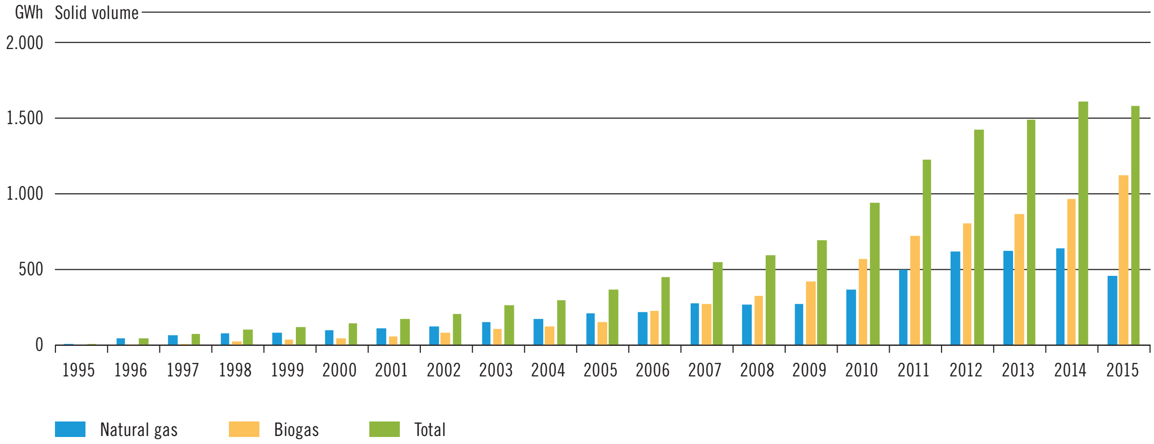

Figure 9.16: Development of CNG (divided into natural gas and biogas) (Source: SCB)

9.9.6 ONE BALANCING ZONE FOR DENMARK AND SWEDEN

Swedegas and Energinet.dk (Danish TSO) are investigating if a joint balancing zone can have net positive effects on the development of the Swedish and Danish gas markets. A project will analyse the expected cost and benefits and recommend a decision (go/no go) to the respective decision making bodies of Swedegas and Energinet.dk in 2017.

9.9.7 REGIONAL GAS GRIDS

Since the transmission grid covers a rather small part of Sweden, Swedegas is looking at the possibility of building regional grids, which are not connected to the transmission system. Two projects have started and these regional grids will be supplied with gas from LNG and biogas facilities.

9.10 United Kingdom

9.10.1 OUR NETWORK

The National Transmission System (NTS) plays a vital part in the secure transportation of gas and facilitation of the competitive gas market in the UK. We have a network of 7,600 km pipelines, presently operated at pressures of up to 94 bar, which transports gas from coastal terminals and storage facilities to exit offtake points from the system. At the exit offtake points, gas is transferred to eight Distribution Networks (DNs) for onward transportation to domestic and industrial customers, or to directly connected customers including storage sites, power stations, large industrial consumers and interconnectors (pipelines linking Great Britain with Ireland, Belgium and Holland).

9.10.2 CHANGING GB GAS DEMAND

Between 2005 and 2010, gas demand was relatively stable at around 1,080 TWh/year. During this period, declining demand in manufacturing was counteracted by an increase in demand for gas-fired power generation. In 2010, gas demand fell sharply as lower coal prices meant that coal was favoured over gas for power generation. Gas remained marginal within the UK power generation sector until 2015 when a rise in the price of coal led to gas returning as the preferred thermal generation fuel. This led to a sharp increase in the usage of gas.

Residential gas demand hit a peak of 400 TWh/year in 2004 and has fallen steadily at an average of 2 % per year. Since 2004, Government incentives and heightened consumer awareness have led to homeowners improving levels of insulation and replacing old gas boilers with new, more efficient, A-rated boilers.

9.10.3 THE ROLE OF CCGTS

In the last year we have seen an increase in annual gas demand for Combined Cycle Gas Turbines (CCGTs). The cost of gas relative to coal has fallen significantly, making gas the more favourable fuel for electricity generation. Furthermore, as a result of EU environmental directives, coal power stations are being retired with the last site expected to close in 2025. Predicting gas demand based on the price differential between coal and gas is therefore no longer a suitable technique.

We are seeing increasing levels of solar and wind capacity connecting to onshore and offshore electricity grids. This means that gas-fired generation is likely to decline from its present high. It will become a more marginal fuel (i.e. operating with low load factors) up to 2020 and beyond.

The behaviour of CCGTs is expected to become more unpredictable as their requirement to generate will correlate with renewable generation output and the interaction with other balancing tools.


Image courtesy of National Grid

9.10.4 EXPORTS

Exports account for around a sixth of total GB gas demand. We currently have two export interconnectors, one to Ireland and one to Continental Europe. In 2016, the Corrib gas field started injecting into the Irish system, resulting in lower levels of exports to Ireland.

We expect that while Corrib is running there will be a reduction in exports from Great Britain. However, it is anticipated that the gas field production will be relatively short lived, with rates reducing over time and the reliance on GB exports gradually returning.

Exports to Europe via the Interconnector UK (IUK) are highly sensitive to both the overall UK supply/demand balance and continental gas markets. The import and export levels flowing through IUK interconnector are subject to uncertainty.

9.10.5 CHANGING GB GAS SUPPLY

From the mid-1990s to 2000s, supply patterns were dominated by the UK Continental Shelf (UKCS). Gas mainly entered the system at terminals on the east coast and travelled in a north to south pattern.

From the mid-2000s onwards, as the UKCS declined, new imports were connected:

- Norwegian gas at Easington.
- Continental gas (BBL) at Bacton.
- LNG at Isle of Grain and Milford Haven.

In addition, a number of new medium-range storage sites were added. At the same time as the range of supplies has increased, demand has decreased, giving a larger surplus of capacity over peak demand.

As a result of these changes, the credible range of supply patterns needed to meet demand has increased considerably. This affects future system planning as we have to develop a sufficiently adaptable system to be able to deal with multiple supply pattern possibilities.

9.10.6 STORAGE

Many new storage sites have been proposed over the last ten years and there are currently plans for nearly 9 bcm of space, both for medium-range fast-cycle facilities and for long-range seasonal storage. However, none of these projects is at the stage of requiring investment in the NTS.

9.10.7 IMPORTS

The UK has a diverse set of import options with pipelines from Norway, the Netherlands and Belgium, and from other international sources in the form of LNG. There are currently no firm plans for increased pipeline interconnection.

9.10.8 THE FUTURE OF GAS PROJECT

As the owner and operator of Great Britain's gas transmission network, we ensure that gas flows to supply our businesses, heat our homes and drive our industry. In order to be ready for a changing energy future, we want and need to evolve the transmission system to ensure we are reducing the cost of our energy solutions, delivering what our customers want and contributing to a sustainable future.

There is a growing consensus that gas can continue to play a key role in the UK's energy mix out to 2050 and beyond, enabling us to meet our carbon emissions target in an affordable way. Policy decisions are needed in the short term to keep overall energy system costs low and ensure that consumers get the best deal possible, but we recognise the complexity around the wide range of options. There is no simple whole energy system solution. Our Future of Gas engagement programme will develop insights on the future of gas from a transmission system perspective. We will pull together the wealth of information that already exists on this topic, including analysis by the GB gas distribution networks; our latest Future Energy Scenarios (FES 2016); and additional scenarios and reports produced by the energy industry and academics.

Combining this with our system operator expertise and input from our customers and stakeholders, we believe we are well-placed to facilitate this debate and to provide an overall view of how gas can be a partner to electricity in a low-carbon future.

Through our Future of Gas engagement programme, we will set out options for the role that gas can play out to 2050, supporting the achievement of the UK's 2050 carbon emissions target.

We want to understand future market requirements and what they could mean for our transmission system. We will engage with stakeholders to understand what customers and end consumers' value. This will allow us to identify optimal levels of future investment in the system and innovative ways to adapt our commercial arrangements. As our insights develop we will set out recommendations for no regrets actions that government, industry and National Grid may take, over the coming years, to ensure that the needs of GB consumers are met. Our aim is to identify options that ensure the optimum mix of security, affordability and sustainability.

Over the next year we will publish further insights and recommendations as a result of this engagement and our developing analysis. It is essential that we get customer and stakeholder input, views and feedback to provide we make optimal decisions around the future of the transmission system, how we operate it and how the market framework needs to evolve.

Definitions

Advanced Non-FID Project

In line with the rule defined in the ENTSOG TYNDP 2017, a project will be considered as an Advanced Non-FID Project if, and only if:

- The project is commissioned by the 31st of December 2022 at the latest.
  - In case such a project also includes increments commissioned after 2022, such increments will not be included in the Advanced infrastructure level.

AND

- Permitting phase of the project has started before the 1st of April 2016 close-of-business.

OR

- FEED has started or the project has been selected for receiving CEF grants for FEED before the 1st of April 2016 close-of-business.

Biomass

The biodegradable fraction of products, waste and residues of biological origin from agriculture (including vegetal and animal substances) forestry and related industries including fisheries and aquaculture and the biodegradable fraction from industrial- and municipal waste in accordance with the sustainability criteria stipulated in Article 17 of Directive 2009/28/EC.

Biomethane

In line with the definition in the ENTSOG TYNDP 2017, Biomethane is defined as Biogas produced from biomass and waste which has been upgraded to natural gas quality for the purpose of grid injection and Power-to-Gas volumes.

Capacity-based Indicator

In line with the definition in the ENTSOG TYNDP 2017, Capacity-based indicators concern indicators which reflect the direct impact of infrastructures on a given country as their formulas are limited to capacity and demand of a country or a Zone.

Cooperative Supply Source Dependence indicator (CSSD)

In line with the definition in the ENTSOG TYNDP 2017, the Cooperative Supply Source Dependence is defined as an indicator that identifies Zones where the physical supply and demand balance depends strongly on a single supply source, when all Zones together try to minimise the shared relative impact (the flow pattern resulting from modelling will spread the dependence as wide as possible in order to mitigate as far as possible the dependence of the most dependent Zones) and as defined in the ENTSOG TYNDP 2017 section 4.2.4 in Annex F.

Cost-Benefit-Analysis (CBA)

In line with the definition in the ENTSOG TYNDP 2017, the Cost-Benefit-Analysis in an analysis carried out to define to what extent a project is worthwhile from a social perspective.

Deliverability

In line with the definition in the ENTSOG TYNDP 2017, the Deliverability is defined as the rate at which the storage facility user is entitled to withdraw gas from the storage facility

ESW-CBA Methodology

In line with the definition in the ENTSOG TYNDP 2017, the ESW-CBA Methodology is defined as the integrated methodology (Energy System Wide) under Regulation (EC) 347/2013 supporting the selection of Projects of Common Interest (PCIs) composed of two steps:

- TYNDP-CBA step, providing an overall assessment of the European gas system under different levels of infrastructure development
- Project Specific-CBA step, providing an individual assessment of each project's impact on the European gas system based on a common data set.

FID project In line with the definition in the ENTSOG TYNDP 2017, the FID project is defined as a project where the respective project promoter(s) has (have) taken the Final Investment Decision.

Final Demand Final demand is the sum of the sectors R&C, industrial and transport.

Final Investment Decision (FID) In line with the definition in the ENTSOG TYNDP 2017, the Final Investment Decision is defined as the decision to commit funds towards the investment phase of a project. The investment phase is the phase during which construction or decommissioning takes place and capital costs are incurred (EU No 256/2014).

Firm capacity In line with the definition in the ENTSOG TYNDP 2017, the Firm capacity is defined as the gas transmission capacity contractually guaranteed as uninterruptible by the transmission system operator

Gas Quality In line with the definition in the ENTSOG TYNDP 2017, natural gas is made up of several component gases and is therefore subject to natural variation. This inconsistency affects the energy contained within a given volume of gas; the measure used is the Calorific Value (CV) of the gas. The Wobbe Number or Wobbe Index, is another important characteristic which describes the way in which the gas burns and is calculated as a factored ratio of CV and Specific Gravity (SG otherwise known as Relative Density).

Gas Regional Investment Plan (GRIP) An investment plan to be published every two years by TSOs in line with Article 12(1) of EU Gas Regulation (EC) 715/2009.

Guarantee of origin (GoO) An electronic document which has the sole function of providing proof to a final customer that a given share or quantity of energy was produced from renewable sources (Directive 2009/25/EC , Article 2 pc. j.).

H-Gas H-gas is gas complying with the gas quality definition in Commission Regulation (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules.

Infrastructure Level In line with the definition in the ENTSOG TYNDP 2017, The project status is used to define three infrastructure levels. A fourth infrastructure level is considered in relation to the previous PCI list. These infrastructure levels are used in the TYNDP for the assessment of the European gas system.

- Low Infrastructure Level: existing Infrastructures + Infrastructure projects having a FID status (whatever their PCI status is)
- Advanced Infrastructure Level: existing infrastructures + Infrastructure projects having a FID status + Advanced non-FID projects
- PCI 2nd list Infrastructure Level: existing Infrastructures + Infrastructure projects having a FID status (whatever their PCI status is) + Infrastructure projects labelled PCIs according to the previous selection (not having their FID taken). This Infrastructure Level is handled in line with the CBA methodology in force, and consistently with what has been done in the previous edition, to build a bridge between two sequential PCI selection rounds and to enable the assessment of the cumulative effects of the 2nd list of PCI projects.
- High Infrastructure Level: existing Infrastructures + Infrastructure projects having a FID status (whatever their PCI status is) + Infrastructure projects not having a FID status (whatever their PCI status is)

Interconnection Point In line with the definition in the ENTSOG TYNDP 2017, Interconnection Points mean physical or virtual points connecting adjacent entry-exit systems or connecting entry-exit systems with an interconnector.

Interconnector In line with the definition in the ENTSOG TYNDP 2017, an Interconnector is a transmission pipeline which crosses or spans a border between Member States for the sole purpose of connecting the national transmission systems of those Member States.

Import Route Diversification indicator (IRD) Indicator which measures the diversification of paths that gas can flow through to reach a zone as defined in the ENTSOG TYNDP 2017 under section 4.1.1. in Annex F.

L-Gas As described in Chapter 6.2 of the ENTSOG TYNDP 2017, most of North West Europe is supplied with high-calorific gas (H-gas), apart from specific areas covering parts of the Netherlands, Germany, Belgium and France. These areas are supplied with low-calorific gas (L-gas) coming from the Groningen field (Netherlands), German fields and H-gas conversion facilities (e.g. by injection of nitrogen) through specific infrastructures with limited connections to the respective neighboring H-gas network.

LNG Terminal In line with the definition in the ENTSOG TYNDP 2017, a LNG Terminal is a facility at which liquefied natural gas is received, stored and 'regasified' (turned back into a gaseous state) after shipment by sea from the area of production.

Load Factor Load Factor is the average load divided by the peak load in a specified time period.

Methanisation Hydrogen from electrolysis can be used together with CO_2 to produce methane. This is called methanisation.

The CO_2 source may, for example, be biogas, which contains approximately 35 % CO_2, but the CO_2 may also come from other sources, e.g. breweries, bioethanol factories or possibly power stations.

Methanisation of CO_2 can take place:

- Chemically, using catalysts
- Biologically, by means of microorganisms

The gas produced through thermal gasification of biomass and consisting of hydrogen (H_2), carbon monoxide (CO) and methane (CH_4), can also be methanised. In this case, hydrogen and CO react by means of catalysts to form methane.

N-1 The indicator measuring the impact of the loss of the single largest infrastructure of a given country adapted to the context to the ENTSOG TYNDP 2017 and the CBA.

National Production In line with the definition in the ENTSOG TYNDP 2017, National Production is defined as indigenous production coming either from off- or onshore gas sources in a country and covered in the ENTSOG TYNDP 2017. An allocation per zone in a country has been carried out where relevant.

Peak Day The highest demand for gas, or electricity, on any day in a given year

Physical Congestion Physical Congestion means a situation where the level of demand for actual deliveries exceeds the technical capacity at some point in time as defined under Article 2(1)(23) of Regulation (EC) 715/2009.

Power to Gas In line with the definition in the ENTSOG TYNDP 2017, Power to Gas is defined as the process of converting surplus renewable energy into hydrogen gas by rapid response electrolysis.

Project

In line with the definition in the ENTSOG TYNDP 2017, a Project designates any initiative, event or development that:

- creates new capacities
- or modifies existing capacities
- or aims at creating the necessary infrastructure for enabling such capacity changes.

At points of the following types:

- Cross-Border Points between Transmission Systems
- Cross-Balancing Zone Points between Transmission Systems
- LNG Entry Points
- Storage Entry-Exit points

Such Projects do have to be submitted to ENTSOG in order for ENTSOG to take into account the induced changes to the existing capacities. All Projects submitted to ENTSOG are listed in the Annex A of the TYNDP. A Project is submitted by one Project Promoter.

A Project can fall into two specific categories :

- Project with Associated Investment is a Project which requires financial investment and actual construction works will take place
- Capacity Modification is a 'Project-like' data submission within the Data Portal by a Promoter. Capacity Modification is any capacity change (positive or negative) on a modelled Operational Point, whereby no actual physical work or financial investment is necessary to carry out the capacity modification. Due to this, it is not considered as an actual Project but as a Capacity Modification and will be labelled accordingly in ENTSOG publications, including TYNDP Annexes. Capacity Modifications can be the result of the following actions:
  - Change in future demand assumptions, leading to capacity recalculations
  - Dynamic storage behaviour
  - Shifting of capacity between IPs
  - Decrease of capacity due to degradation of the transmission system
  - Decrease of capacity due to gas depletion
  - Technical Agreements between TSOs
  - Etc.

Project of Common Interest (PCI)

In line with the definition in the ENTSOG TYNDP 2017, a Project of Common Interest is a project which meets the general and at least one of the specific criteria defined in Art. 4 of the TEN-E Regulation and which has been granted the label of PCI Project according to the provisions of the TEN-E Regulation.

Project Promoter

In line with the definition in the ENTSOG TYNDP 2017, a Project promoter is a registered legal entity, which has the capacity to undertake legal obligations and assume financial liability in order to realise the Project it promotes and submits during the course of the ENTSOG data collection procedure.

Reference Case

In line with the definition in the ENTSOG TYNDP 2017, Reference Case means the reference price configuration for which the supply curve for each import source varies between the same price assumptions.

Remaining Flexibility indicator (RF)

Remaining Flexibility indicator which measures the resilience of a zone as defined in the ENTSOG TYNDP 2017 section 4.2.1. in Annex F. The value of the indicator is set as the possible increase in demand of the Zone before an infrastructure or supply limitation is reached somewhere in the European gas system.

Renewable gas Gaseous fuels which are made from Biomass, hydrogen made from renewable sources or methane made from renewable hydrogen (methanisation) serve as a renewable alternative to fossil fuels in order to reduce GHG emissions without adversely affecting the environment or social sustainability.

Scenario In line with the definition in the ENTSOG TYNDP 2017, a Scenario is defined as a set of assumptions for modeling purposes related to a specific future situation in which certain conditions regarding gas demand, fuel prices and biomethane.

Supply Potential In line with the definition in the ENTSOG TYNDP 2017, the Supply Potential is defined as the capability of a supply source to supply the European gas system in terms of volume availability. A Supply Potential is the range defined through Maximum and Minimum. Supply Potentials for a supply source have been developed independently with no assessment on the likelihood of their occurrence.

Supply Source Price Dependence indicator (SSPDe) Is an indicator which measures the price exposure of each Zone to the alternative increase of the price of each supply source and as defined in the ENTSOG TYNDP 2017 section 4.2.6. in Annex F.

Supply Source Price Diversification indicator (SSPDi) Is an indicator which measures the ability of each Zone to take benefits from an alternative decrease of the price of each supply source and as defined in the ENTSOG TYNDP 2017 section 4.2.5. in Annex F.

Synthesis gas Is a mixture of carbon monoxide, carbon dioxide and hydrogen and is produced by gasification of a carbon containing fuel including natural gas, coal, biomass, or virtually any hydrocarbon feedstock.

Technical capacity In line with the definition in the ENTSOG TYNDP 2017, the Technical capacity is defined as the maximum firm capacity that the Transmission System Operator can offer to the network users, taking account of system integrity and the operational requirements of the transmission network (Art. 2(1)(18), REG-715).

Ten-Year Network Development Plan (TYNDP) In line with the definition in the ENTSOG TYNDP 2017, the Ten-Year Network Development Plan is the Union-wide report carried out by ENTSOG every other year as (TYNDP) part of its regulatory obligation as defined under Article 8 para 10 of Regulation (EC) 715/2009.

Total demand Total demand is defined as sum of the Final demand and the gas demand for power generation.

Transmission In line with the definition in the ENTSOG TYNDP 2017, Transmission is defined as the transport of natural gas through a network, which mainly contains high-pressure pipelines, other than an upstream pipeline network and other than the part of high-pressure pipelines primarily used in the context of local distribution of natural gas, with a view to its delivery to customers, but not including supply (Art. 2(1)(1), REG-715).

Transmission System In line with the definition in the ENTSOG TYNDP 2017, a Transmission System is defined as any transmission network operated by one Transmission System Operator (based on Article 2(13), DIR-73).

Transmission System Operator (TSO) In line with the definition in the ENTSOG TYNDP 2017, a Transmission System Operator is defined as a natural or legal person who carries out the function of transmission and is responsible for operating, ensuring the maintenance of, and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transport of gas (Article 2(4), DIR-73).

Wobbe Index In line with the definition in the ENTSOG TYNDP 2017, the Wobbe Index is defined as a measure of the interchangeability of fuel gases and their relative ability to deliver energy.

Zone In line with the definition in the ENTSOG TYNDP 2017, a Zone is defined as a country or balancing zone at which level the market shall balance gas demand and supply.

Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
BBL	Balgzand Bacton Line
BeLux	Integrated Market for Belgium and Luxembourg
bcm	Billion cubic meters
BNetzA	Bundesnetzagentur
CAM	Capacity Allocation Mechanisms
CBA	Cost Benefit Analysis
CBM	Compressed Biomethane
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CEER	Council of European Energy Regulator
CEF	Connecting Europe Facility
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
COP21	21st Conference of Parties
CRE	Commission de Régulation de l'Energie
CREG	Commission for Electricity and Gas Regulation
DSO	Distribution System Operator
EC	European Commission
ENTSOG	European Network of Transmission System Operators for Gas
ERGaR	European Renewable Gas Registry
ETS	Emissions Trading Scheme
EU	European Union
FID	Final Investment Decision
GB	Great Britain
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GIE	Gas Infrastructure Europe
GNI	Gas Networks Ireland
GoO	Guarantee of Origin
GPN	Gaspoint Nordic
GRIP	Gas Regional Investment Plan
GTS	Gasunie Transport Services
GUD	Gasunie Deutschland
GWh	Giga Watt hours
GWh/d	Giga Watt hours per day
H-gas (H)	High Calorific Gas
HDV	Heavy Duty Vehicle
IHS	Information Handling Services
IEA	International Energy Agency
ILR	Institut Luxembourgeois de Régulation
ILUC	Indirect Land Use Change
IMO	International Maritime Organization

IP	Interconnection Point
IRD	Import Route Diversification
IUK	Interconnector UK
km	Kilometers
kW	kilowatt
L-gas (L)	Low Calorific Gas
LBM	Liquefied Biomethane
LDV	Light Duty Vehicle
LNG	Liquefied Natural Gas
mcm	million cubic metres
MWh	Mega Watt hour
NAM	Nederlandse Aardolie Maatschappij
NBP	National Balancing Point
NCG	NetConnect Germany
NECA	Nitrogen Emission Control Area
NGO	Non-Governmental Organization
NGV	Natural Gas Vehicle
NEP	Netzentwicklungsplan
NOP	Netwerk Ontwikkelingsplan
NO_x	Nitrogen Oxides
NRA	National Regulatory Authority
NTS	National Transmission System
NW	North West
OGE	Open Grid Europe
P2G	Power to Gas
PCI	Project of Common Interest
PEG	Point d'Echange de Gaz
ppm	Parts per million
PV	Photovoltaics
R&D	Research and Development
RED	Renewable Energy Directive
RES	Renewable Energy Source
SECA	Sulphur Emission Control Area
SNG	Synthetic Natural Gas
SoS	Security of Supply
SSD	Supply Source Dependence
TIGF	Transport Infrastructures Gaz France
TRS	Trading Region South
TTF	Title Transfer Facility
TSO	Transmission System Operator
TWh	Tera Watt hours
TYNDP	Ten-Year Network Development Plan
UGS	Underground Gas Storage
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
ZTP	Zeebrugge Trading Point

Country Codes (ISO)

AL	Albania
AT	Austria
AZ	Azerbaijan
BA	Bosnia and Herzegovina
BE	Belgium
BG	Bulgaria
BY	Belarus
CH	Switzerland
CY	Cyprus
CZ	Czech Republic
DE	Germany
DK	Denmark
DZ	Algeria
EE	Estonia
ES	Spain
FI	Finland
FR	France
GR	Greece
HR	Croatia
HU	Hungary
IE	Ireland
IT	Italy
LT	Lithuania
LU	Luxembourg
LV	Latvia
LY	Libya
MA	Morocco
ME	Montenegro
MK	FYROM
MT	Malta
NL	Netherlands, the
NO	Norway
PL	Poland
PT	Portugal
RO	Romania
RS	Serbia
RU	Russia
SE	Sweden
SI	Slovenia
SK	Slovakia
TM	Turkmenistan
TN	Tunisia
TR	Turkey
UA	Ukraine
UK	United Kingdom

List of Tables

List of Figures

4 MARKET DEVELOPMENT IN NORTH WEST EUROPE

5 SUPPLY & DEMAND

6 ENTSOG TYNDP 2017 FINDINGS FROM A REGIONAL PERSPECTIVE

7 LOW CALORIFIC GAS IN THE NW REGION

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