Preventive Action Plan Belgium

After Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard security of gas supply

July 2019

FPS Economy, S.M.E.s, Self-Employed and Energy
North Gate III, Koning Albert II-laan 16

1000 Brussels

Table of Contents

Executive summary

The Security of Gas Supply Regulation

EU Regulation 2017/1938 ("The Regulation") mandates that EU Member States are required to implement measures to safeguard gas security of supply. To assess Member States' ability to supply gas, under predefined Standards (i.e. Infrastructure Standard and Supply Standard), Regulation 2017/1938 requires each Member State to prepare a National Risk Assessment. The National Risk Assessment identifies possible risks and hazards to Member States security of gas supply. In addition, Member States are required to prepare a Preventive Action Plan which outlines measures to either remove or mitigate the risks and hazards identified in the Risk Assessment.

Preventive Action Plan

Pursuant to the Regulation, Member States are required to implement measures to safeguard security of gas supply including, inter-alia, the development of this Preventive Action Plan. The purpose of this preventive action plan is to identify the possible measures the Belgian government and the stakeholders in the gas industry can take in order to reduce risks that could occur in the gas supply chain.

This Preventive Action Plan is developed by the Directorate General for Energy in concertation with the National Regulatory Authority (CREG) and the Transport System Operator (Fluxys Belgium). This plan shall be notified to the European Commission and made public and will be updated every 4 years.

The first sections of this Preventive Action Plan consists of information already present in the Risk Assessment that was notified to the Commission in February 2019, which is not made public. This information covers mainly the description of the gas system in Belgium and its compliance with the infrastructure standard, including in the regional context, and a summary of the scenarios examined in the Risk Assessment upon which the preventive measures are based.

The second part presents all the measures put in place in Belgium that can have a positive impact on the security of gas supply, including voluntary measures available to the market actors, other obligations or measures related to the security of supply and regional cooperation either between the TSOs (operational level) or directly between the Members States.

Belgium's Risk Assessment

<u>The Infrastructure Standard</u>: is assessed by performing the N-1 calculation. The N-1 calculation removes the technical capacity of the single largest piece of gas infrastructure on a peak day with a view to determining whether the remaining gas infrastructure can meet 100% of peak day gas demand. To comply with the standard, the calculation must equate to 100% or more. Taking into account the fact that Belgium's gas system is separated into 2 distinct network (for High- or Low-calorific gas), this calculation is performed for each gas quality. The result for H-gas is well above 100% due to the many interconnection points with various supply routes. This means that the Belgian H-gas network is still able to supply the Belgian market during a day of peak consumption without the largest import infrastructure (Interconnection point with UK). For L-gas however, due to the Netherlands being the only exporting country, the strict application of the N-1 formula gives a result below 100% but the risk is managed by taking into consideration that the only interconnection point for importing

L-gas to Belgium is actually constituted of several distinct pipelines. The result of this N-1 calculation is also going to improve in the coming years due to the ongoing conversion of the L-gas network to H-gas, thus giving access to a broader selection of supply sources.

Disruption of the LNG terminal (Zeebrugge) or the Underground Gas Storage (Loenhout): while both these installations contribute to the diversification of gas sources and provide the market with alternatives in case of a crisis, neither of them is found strictly essential on its own to supply the Belgian end-consumers during a peak day.

Disruption on the L-gas entry point from the Netherlands: while the results of the N-1 calculation for the L-gas network suggest a high risk in case of a total disruption on this point, a further analysis taking into account the actual configuration of the infrastructure and more plausible scenarios allow for a non-negligible mitigation of the impacts of this risk. There is however a lot less flexibility available than on the H-gas network and this, in association with the expected end of exports from the Netherlands in 2030, calls for preventive measures to be taken (conversion of the L-gas network).

Blackout or local power outage: a joint study of Elia (electricity TSO) and Fluxys Belgium has shown that, in the scenario of a large scale blackout, the interconnections points of the Zeepipe (from Norway) and 's Gravenvoeren (from the Netherlands), as well as the LNG terminal of Zeebrugge and the underground storage of Loenhout, should still be operational. These would be enough to supply the 5 "black-start" power plants in Belgium and allow Elia to conduct the recovery phase and rebuild their network. The gas consumption of other end-consumers in Belgium would be greatly reduced by the blackout and would gradually rise during the recovery phase, while at the same time more power plants would come back online until a full return to normal of both the electricity and gas systems.

A local power outage could impact one of the electricity-driven compression installations in Belgium, but those are only needed in situations with a high transit from border to border, so there would be no impact on the Belgian market.

Nuclear phase out and L/H conversion: in the coming years, two events are going to have a noticeable impact on the H-gas consumption in Belgium: the conversion of the L-gas network that will gradually shift the consumption of a large part of the public distribution from L-gas to H-gas; and the phasing-out of nuclear power plant, that will likely be replaced by gas-fired power plants for a large part. These two events will have the effect of increasing the consumption of H-gas in Belgium. A first evaluation using the N-1 method with the existing H-gas entry capacities and predictions for the gas consumption in the coming years has shown no problem for the Belgian transmission network to cover this increasing demand.

Preventive Measures

Increased import flexibility: most companies have access to flexible contracts, both for the gas (molecules) and capacities on the transmission network. This allows them to react to events or evolutions of the situation by adjusting the level of utilization of the different supply routes according to the demand.

Commercial gas storage: there is one underground gas storage in Loenhout. At European level, storage generally contributes to the security of supply during the winter months. While it is not strictly essential on its own to supply the Belgian end-consumers during a peak day, it contributes to the diversification of gas sources and provide the market with alternatives in case of a crisis and provides the shippers and suppliers with one more arbitrage possibility. Under normal winter circumstances and if the storage is filled up to its full capacity, the stored gas can be used during about 60 days.

LNG terminal: in addition to the many supply sources available to the Belgian market by pipelines, the Zeebrugge LNG re-gasification terminal offers even more sources diversification by giving access to LNG producers all over the world. The availability of LNG on the global market is also expected to increase in the coming years following the discoveries of new gas reserves.

Diversification of gas supply sources and routes: most suppliers have multiple contracts with different suppliers and import gas via a variety of supply routes. The higher the diversification, the lower the impact of an incident on one supply source or route.

Bi-directionality and reverse flow: capacity in both directions is offered at every interconnection point, either by physical bi-directionality or by reverse flow when the physical flows are consistently unidirectional. According to the network code on capacity allocation mechanisms, auctions are continuously organized giving the market the opportunity to signal capacity requirements. New investments in infrastructure to respond to market interests are analysed yearly by the TSO in the investment plan for the coming 10 years.

Interruptible contracts: as a form of demand-side management, suppliers may conclude interruptible contracts with their clients. In this case, they have the right to interrupt the customer, normally in return for a discount on price and with some notice. This type of contract is however seldom used, because many cheaper supply side measures are available to the suppliers in Belgium.

The TSO may also offer interruptible capacity at interconnection points, but only after all firm capacity is booked. Firm capacity being widely available, interruptible capacity is not often used either.

Regional cooperation

According to Annex I - Regional Cooperation of Regulation No 2018/1937, Member States' risk groups are the basis for risk-based cooperation. In accordance with Article 7 (2), significant transnational risks to the security of gas supply in the Union are identified and risk groups should be identified on this basis. These risk groups serve as a basis for enhanced regional cooperation with the aim to increase the security of gas supply and allow all Member States concerned to agree on appropriate and effective cross-border measures within or outside these groups alongside emergency corridors.

Belgium is a member of five risk groups that are dependent on supplies from the North Sea or from the East.

L-gas risk group

Member States: Belgium, France, Germany, the Netherlands

Norway risk group

Member States: Belgium, Denmark, Germany, Ireland, Spain, France, Italy, Luxembourg, the Netherlands, Portugal, Sweden, the United Kingdom

UK risk group

Member States: Belgium, Germany, Ireland, Luxembourg, the Netherlands, the United Kingdom

Baltic Sea Risk Group

Member States: Germany, Czech Republic, Austria, Belgium, Denmark, France, Luxembourg, the Netherlands, Slovakia, Sweden

Belarus Risk group

Member states: Belgium, Czech Republic, Germany, Estonia, Latvia, Lithuania, Luxembourg, the Netherlands, Poland, Slovakia.

1 Introduction

This Preventive Action Plan is developed pursuant to Regulation EU 2017/1938 concerning measures to safeguard the security of gas supply ("the Regulation") by the Directorate General for Energy of the Federal Public Service Economy, SMEs, Self-Employed and Energy, acting as the competent authority as defined in Article 2 of the Regulation. This Preventive Action Plan is developed in concertation with the National Regulatory Authority (CREG) and the Transport System Operator (Fluxys Belgium). This plan shall be notified to the European Commission and made public and will be updated every 4 years unless circumstances require a more frequent update.

The purpose of this preventive action plan is to identify the possible measures the Belgian government and the stakeholders in the gas industry can take in order to reduce risks that could occur in the gas supply chain. It gives an overview of the actions that already exist and makes an analysis of new actions that could be introduced. The primary focus will be on the risk for the entire gas system. Risks that only have a local impact are part of the emergency planning of the transmission system operator and/or the distribution system operators.

In the risk assessment a series of risks were identified. The risk assessment gives a first indication of the main risk for our gas security of supply. The actions to take to reduce the risks and mitigate their impact are now taken up in this Preventive Action Plan.

As prescribed in the template given in Annex VI of the Regulation, this plain contains:

- A description of the gas system in Belgium, also in the regional context by giving overviews of the gas systems in the 5 risk groups;
- A summary of the Risk Assessment conducted pursuant to the Regulation, in order to identify the risks that will need to be addressed in this Plan;
- An explanation on how the Belgian gas system complies with the infrastructure standard, both at national and regional (risk group) level;
- An explanation on how the Belgian gas system complies with the supply standard, and the associated volumes consumed by the protected customers;
- A description of the market based preventive measures available to the gas sector to reduce the risks and mitigate their impact;
- A description of other measures and obligations imposed on the gas sector;
- A description of the recent and future gas infrastructure projects having a positive impact on the security of supply;
- A description of the public service obligations imposed on suppliers and system operator with a link to the security of supply; and
- A description of the cooperation put in place at regional level.

2 Description of the gas system

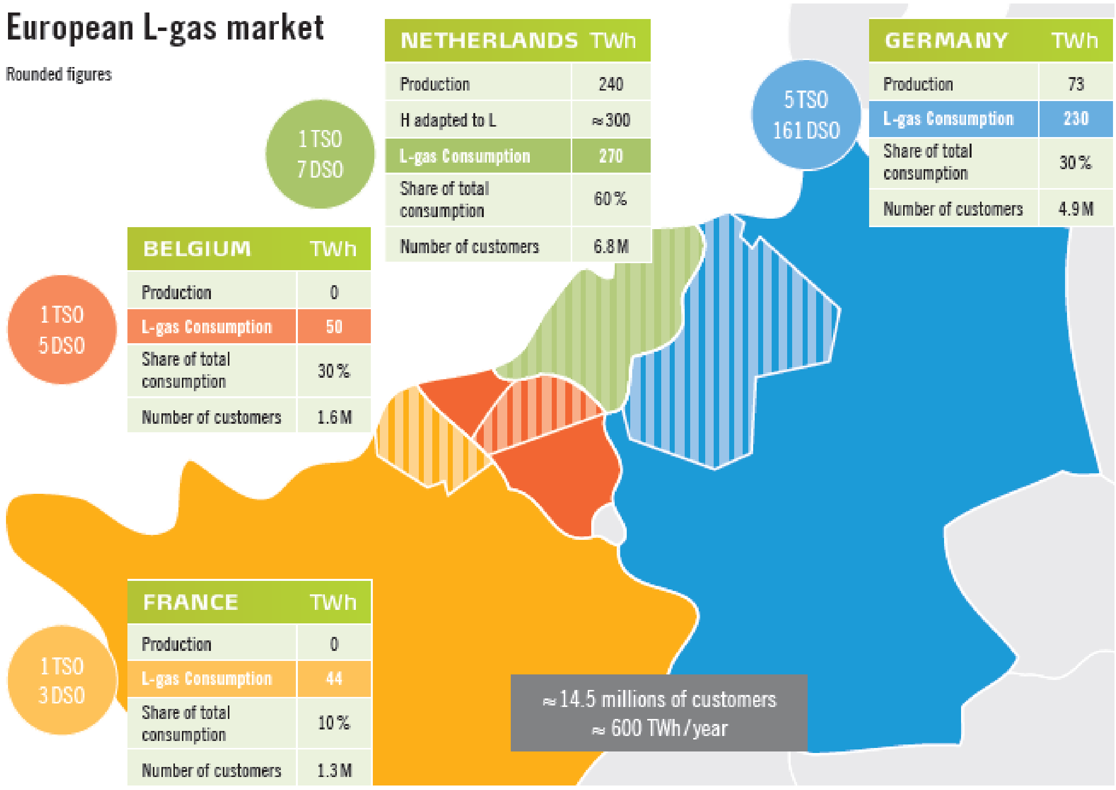
2.1 Regional systems in risk groups

2.1.1 L-gas risk group

Gas produced from the Dutch Groningen field is called G-gas. Low calorific gas (L-gas) is a combination of gas originating from the Groningen field, blended with high calorific gas (H-gas) or H-gas blended with nitrogen. L-gas is consumed in the Netherlands and exported to Germany, Belgium and France.

The current market demand for all these L-gas consuming countries is shown in the overview below (Figure 1, based on 2017 data). The Netherlands is the largest consumer and main supplier of L-gas in the region. Germany, the second largest market, does also have L-gas production but this is insufficient to meet all domestic demand. Demand in Belgium and France is entirely supplied by imports from the Netherlands. L-gas is exclusively supplied from within the L-gas region. Therefore, there is no import from or export to other regions.

Figure 1: Overview of the L-gas market



Source: Gas Regional Investment Plan North West 2017

Table 1 gives an overview of the L-gas consumption observed in the last three years. The build environment accounts for more than half of total L-gas consumption, making the demand sensitive to climatic conditions.

Table 1: Historic L-gas demand

Year (unit=TWh)	2015	2016	2017
Public distribution	288	306	297
Industry and power generation	263	276	272
Total	551	583	569

Source: data supplied by member states

Total L-gas production in the region over the last three years is shown in Table 1. These figures further illustrate the role of the Netherlands as main supplier of L-gas. Belgium and France only have quality conversion capacity to produce L-gas out of H-gas.

Table 2: L-gas production in the region

Year	2015		2016		2017	
Country	Volume produced (TWh)	Maximal daily production capacity (GWh/d)	Volume produced (TWh)	Maximal daily production capacity (GWh/d)	Volume produced (TWh)	Maximal daily production capacity (GWh/d)
NL	495	2.407	528	2.551	519	2.700
DE	149	220	139	220	125	220
FR	0	57	0	57	0	57
BE	0	3	1	3	0	3
Total	645	2.686	668	2.831	644	2.980

Source: data supplied by member states

Table 3 provides an overview of all the underground gas storage facilities in the L-gas gas region. Most of the storage capacity is situated in the Netherlands and Germany. The storages at Epe are located on Germany territory, but these facilities are also connected to the Dutch gas transmission network. Belgium does not have L-gas storage capacity.

Table 3: L-gas underground gas storage facilities

Facility	Country	Storage capacity (TWh)	Maximum withdrawal (GWh/d)	
			100% full	30% full
EnergyStock	NL	3	252	252
Norg (Langelo)	NL	47	742	698
Alkmaar	NL	5	357	357
Epe Nuon	NL	3	117	117
Epe Eneco	NL	1	95	41
Epe Innogy	NL	3	119	119
Peakshaver	NL	1	312	312
Epe L-Gas (innogy)	DE	2	98	98
Epe L-Gas (UES)	DE	4	238	0
Lesum	DE	2	52	52
Nüttermoor L-Gas	DE	0	24	24
Speicherzone L-Gas (EWE)	DE	10	306	306
Empelde	DE	2	73	73
Gournay	FR	13	248	248
Total		96	3.032	2.696

Physically, the L-gas networks are separated from the H-gas networks, as L-gas and H-gas differ in gas quality. The two separated networks are connected through blending stations in the Netherlands and in France. These can blend the different gasses and/or use nitrogen to produce the required Wobbe-index for low calorific gas.

2.1.2 Norway risk group

The Norwegian production may decline progressively in the future. Norwegian National Petroleum directorate foresee a reduction from a current level around 120 Bcm/year to a level of 90 bcm/year in 2030-2035.

The Norwegian pipeline system is well-connected to the United Kingdom and to the Continent. Based on the production level forecast, the limiting factor will be the overall production.

For the N-1 calculation the disruption of the largest pieces of infrastructure which supply Norwegian gas has been considered:

- Disruption of Emden station (from Norway to the continent);
- Disruption of Langeled pipeline (from Norway to the United Kingdom).

N-1 results are well above 100% meaning in case of disruption of a major infrastructure supplying Norwegian gas the other entry capacities shall be sufficient to cover peak demand as it may occur 1 in 20 years.

Regarding the issue of transit trough Switzerland, both N-1 calculations for Italy on one side and the other member states in the risk group on the other side are above 100%.

ENTSOG has conducted simulations of potential disruption of Norwegian gas supply and assessed the impact it may have on the possibility to satisfy demand The following scenarios have been considered:

- Disruption of the largest offshore infrastructure to the United Kingdom (Langeled pipeline) during 2 months (from January 1st to February 28th);
- Disruption of the largest offshore infrastructure to continental Europe (EUROPIPE II) during 2 months (from January 1st to February 28th);
- Disruption of the largest onshore infrastructure from Norway (Emden station) during 2 weeks (from February 15th to February 28th).

In the simulations conducted the infrastructure is resilient enough to find other means of supply that can compensate for the disruption. Those other means are:

- Reorganization of flows from Norway;
- Additional withdrawal from storages;
- Additional send-out from LNG terminals.

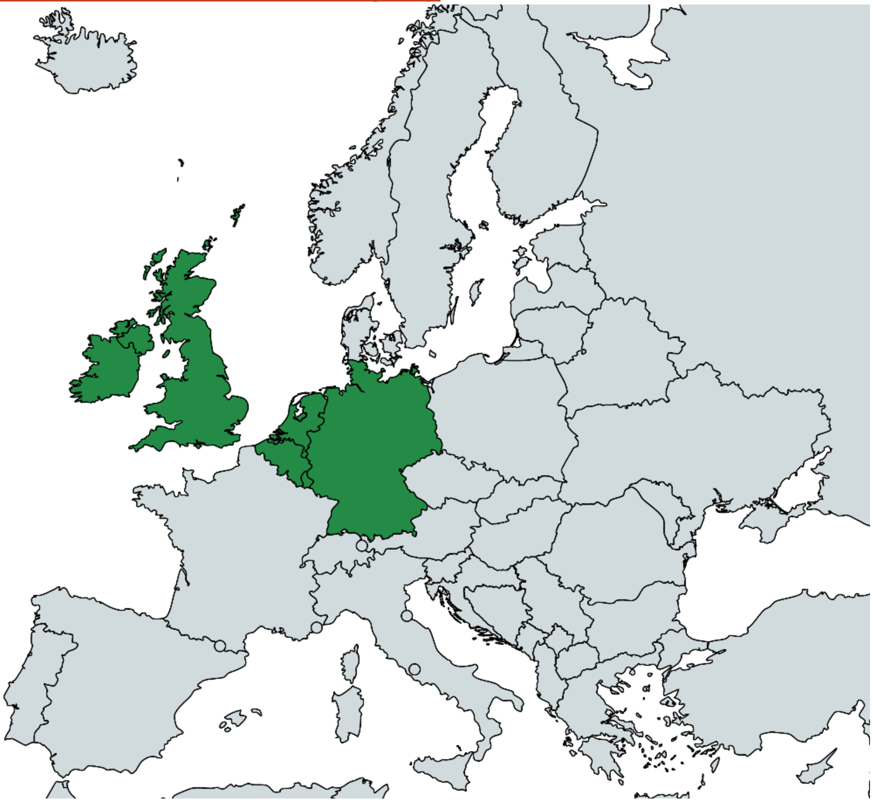
The use of these other means prevents demand curtailment. Nevertheless, an increase in the price of gas may be necessary in order to allow the use of those other means.

The analysis presented in the Risk Assessment demonstrates that gas supply infrastructure is resilient to all but the most unlikely combinations of supply shocks. The upper ends of supply ranges are enough to maintain supplies to protected consumers in all scenarios.

2.1.3 UK risk group

The United Kingdom risk group is made up of the following countries: Belgium, Germany, Ireland, Luxembourg, the Netherlands and the United Kingdom.

Figure 2: Members of the UK risk group



The natural gas systems of the members of the United Kingdom Risk Group are characterised by significant levels of interconnection, liquid markets and sufficient infrastructure that more than meets the region's needs. Further detail of the individual gas systems of the Member States of the United Kingdom risk group can be found in the Common Risk Assessment for the United Kingdom Risk Group.

The countries in the United Kingdom Risk Group represent a significant proportion of total European gas demand. In 2016, their combined annual consumption accounted for about 50% of total consumption in the EU-28. Germany and the UK were the countries with respectively the highest and the second highest natural gas demand in Europe in 2016.

Except for Belgium and Luxembourg, all Member States of the United Kingdom Risk Group have some level of domestic production, underpinning the resilience of the north-west European gas system. The United Kingdom and the Netherlands are the two largest natural gas producers in the European Union, producing approximately 416TWh (38 bcm) and 430TWh (44 bcm) respectively in 2017.

Although production from the United Kingdom Continental Shelf has, since 2014, increased year-on-year due to the development of new fields, increased production at some of the existing fields and production of cushion gas from the Rough storage facility as it is prepared for closure[1], production

[1] Without the contribution made by the extraction of cushion gas from the Rough storage facility, overall UKCS production would have fallen by 1.5%.

from the UKCS has generally been falling since the turn of the century, with production declining by around 8% a year between 2000 and 2013[2].

Natural gas production in the Netherlands will decline rapidly over the next decade, due to the decision taken in 2018 to terminate production from the Groningen gas field by 2030. The shutdown in Groningen production is expected to reduce national Dutch production by an average of 19% per year in the period 2018-2021. Further detail regarding the planned shutdown of Groningen is set out in Chapter 4 of the UK Risk Group Common Risk Assessment.

Projected data for 2018-2020 indicates that the total storage deliverability in the United Kingdom Risk Group is 10,212 GWh/day. The breakdown of this figure can be found in the Annex to the UK Risk Group Common Risk Assessment, alongside a breakdown of total production capacity (projected to be 3,538 GWh/day in 2020) and the maximum technical LNG facility capacity (projected to be 2,405 GWh/day from 2018-2020)

2.1.4 Baltic Sea risk group

The Baltic Sea risk group is chaired by Germany and made up of the following countries: Austria, Belgium, Czech Republic, Denmark, France, Germany, Luxembourg, the Netherlands, Slovakia, Sweden.

The description of the gas infrastructures in the various Member States reveals a tightly meshed gas infrastructure in this region. This risk group has a variety of supply sources and routes at its disposal.

The risk group possesses considerable storage capacity. Germany alone has more than 40 gas storage facilities and the second highest storage capacities in Europe (if Ukraine is included). In combination with the storage capacities in the other countries in this area, this region is capable of ensuring a very high level of security of supply.

Further to this, a considerable amount of investment is currently planned in the region. The majority of the investment in Germany will have a direct and positive impact on the interconnection capacities with neighbouring Member States. Additional transport capacities have a positive effect on the trading markets, since different transport routes and supply sources can be used.

The trading markets in this region are also characterised by a high level of liquidity, which also has a positive impact on security of supply. The Title Transfer Facility (TTF) in the Netherlands and the two German market areas, Gaspool and Net Connect Germany (NCG), are trading places with some of the highest liquidity in Europe.

The region meets the N-1 standard. The calculation of the N-1 standard has been undertaken for the two leading entry points into the region, Greifswald and Velke Kapusany. Both calculations show that the N-1 standard is well above 100%. This will improve further in future as a host of infrastructure measures will be realised which will further increase the import capacities.

[2] Digest of UK Energy Statistics 2017, Chapter 4, p.91

The risk group has not identified a risk to which it feels particularly exposed. Risks do of course exist, particularly technical ones which cannot be entirely excluded, as was shown in 2017 by the Baumgarten incident. But at the same time, one has to say that the gas infrastructure in this region displays a high level of resilience due to significant redundancies. The scenarios defined in this risk group cover the widest possible range of disruption, irrespective of the risk event triggering the disruption.

The analysis has shown that all the Member States in this risk group are capable of coping with the defined disruption to supply and interruption scenarios without external support, i.e. using the infrastructure available to them and alternative sources of gas, such as liquefied natural gas (LNG), without any impact on supply being expected. Furthermore, the Member States in this risk group are not reliant on support from neighbouring countries, and no cross-border effects or repercussions have been identified.

The resilience of this risk group to exogenous supply shocks is bolstered by domestic production, alternative gas imports, existing storage capacities and liquid and developed gas markets. Supply can be maintained even in the case of extreme scenarios.

2.1.5 Belarus risk group

The Belarus Risk Group serves as the basis to analyse risks related with gas supply disruptions via Belarus, one of the pivotal gas supply corridors from the Russian Federation to the European Union. The Belarus Risk Group includes the EU Member States that are supplied with natural gas shipped via Belarus, or adjacent EU Member States that are affected by gas imports via Belarus.

Due to the fact that dedicated to Low-calorific gas risk group was established and cooperation to increase the security of gas supply shall be managed at regional (L-gas) level, the common risk assessment for the Belarus Group focuses on risk assessment for high-methane gas systems.

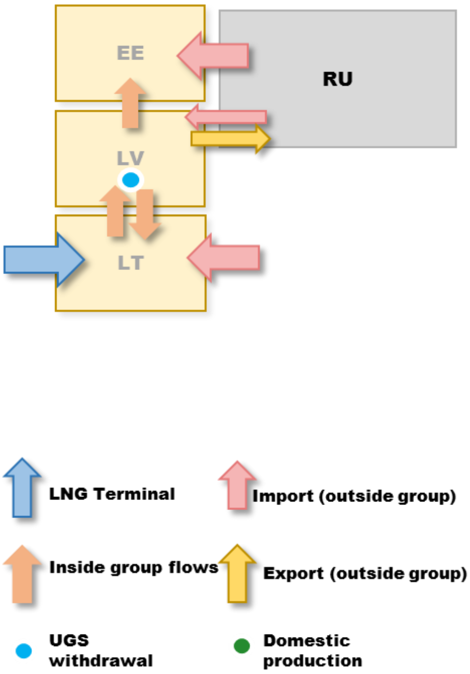
Taking into consideration the geographical position of the countries of the region and infrastructure limitations, the Belarus Risk Group is divided into two sub groups:

- East-Baltic subregion and
- Middle-west countries sub region.

Creation of a separate East-Baltic subregion for the working purpose of the report follows from the fact that the Baltic States (together with Finland) remain isolated from the wider EU gas system. This means that for the time being there is no possibility to transport gas between both sub regions in normal and emergency conditions. These circumstances are set to radically change once the Gas Interconnection Poland – Lithuania (GIPL) is put into commercial operation.

East-Baltic subregion:Estonia, Latvia, Lithuania

Figure 3: East - Baltic sub region: Estonia, Latvia, Lithuania schema

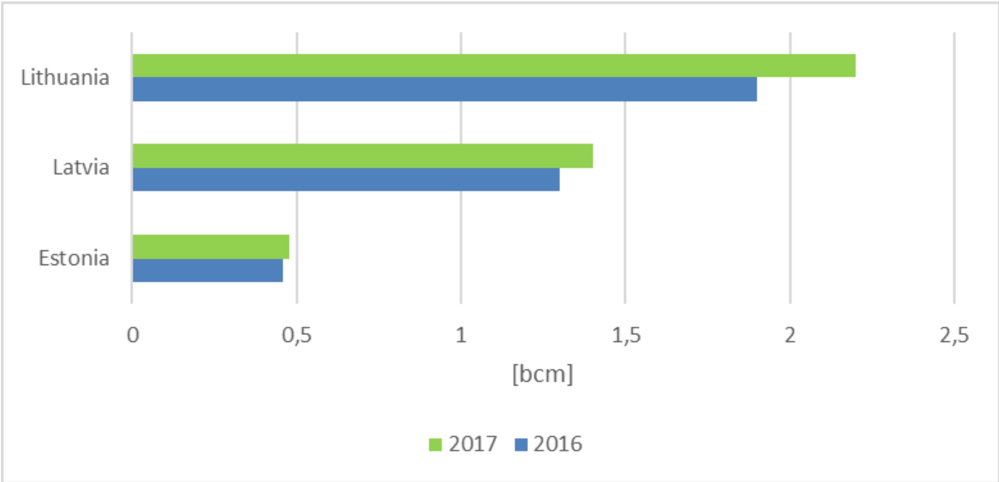


The East-Baltic subregion constitutes the so called “energy island” that has been supplied entirely with gas coming via the Belarus corridor to Lithuania and directly from Russia to Estonia and Latvia. The commissioning of FSRU in Klaipeda provided the first source of diversification for the region. Latvia’s Inčukalns UGS is the only storage facility in the East-Baltic sub region. It provides seasonal storage that supports the functioning of the gas infrastructure in the whole region. It is also noted, that natural gas transit from Belarus to Kaliningrad Region of Russian Federation cross Lithuanian territory.

The three Baltic States together consumed in 2017 just about 4 bcm of natural gas. The biggest consumption of all three countries of East-Baltic sub region in 2017 was in Lithuania and it was almost 2,2 bcm.

Figure 4 shows a range of gas consumption in three countries in 2016 and 2017.

Figure 4: Annual gas consumption in East-Baltic sub region

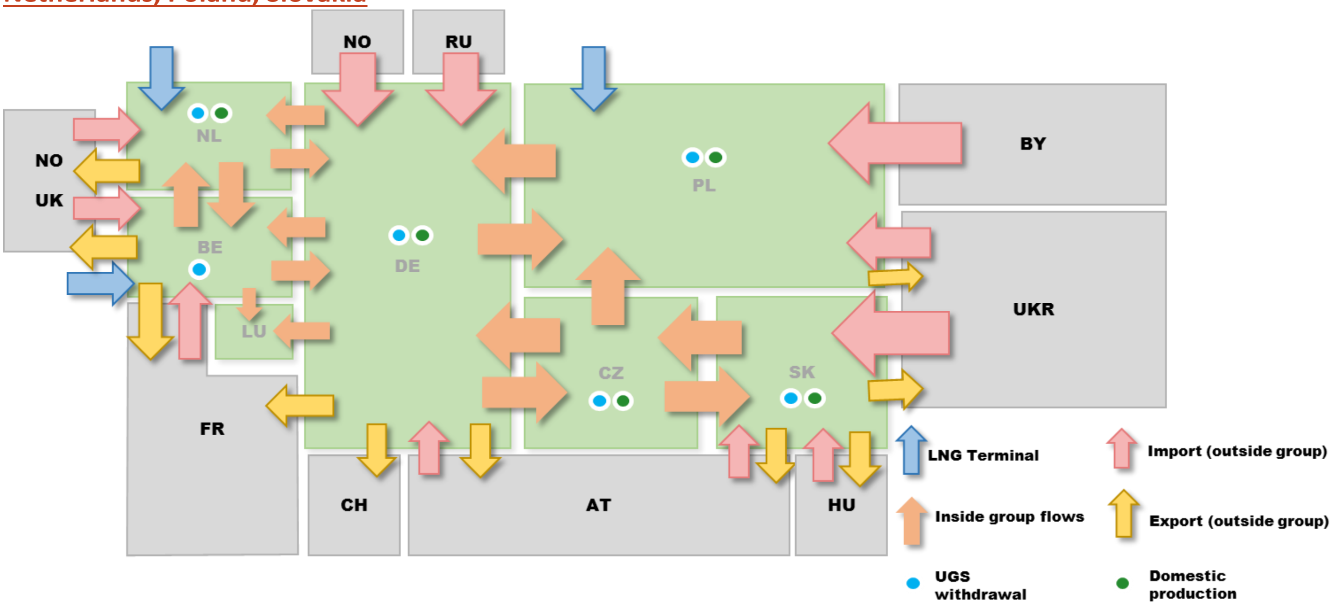


Subregion's underground gas storage working capacity reaches 2,13 bcm. There is one UGS in the East-Baltic sub region: Inčukalns UGS in Latvia. Maximal daily withdrawal capacity when the storage is full (1st of October 2017) reached 21,70 mcm/d and maximal daily withdrawal capacity in the end of the season (30th of March 2017) reached 9,30 mcm/d.

The technical capacity of LNG facilities in 2016/2017 was 3,74 bcm/y in the East- Baltic sub region. The only LNG terminal in Baltic Region is in Lithuania.

Middle-west countries subregion: Belgium, Czech Republic, Germany, Luxembourg, Netherlands, Poland, Slovakia

Figure 5: Middle-west countries sub region: Belgium, Czech Republic, Germany, Luxembourg, Netherlands, Poland, Slovakia



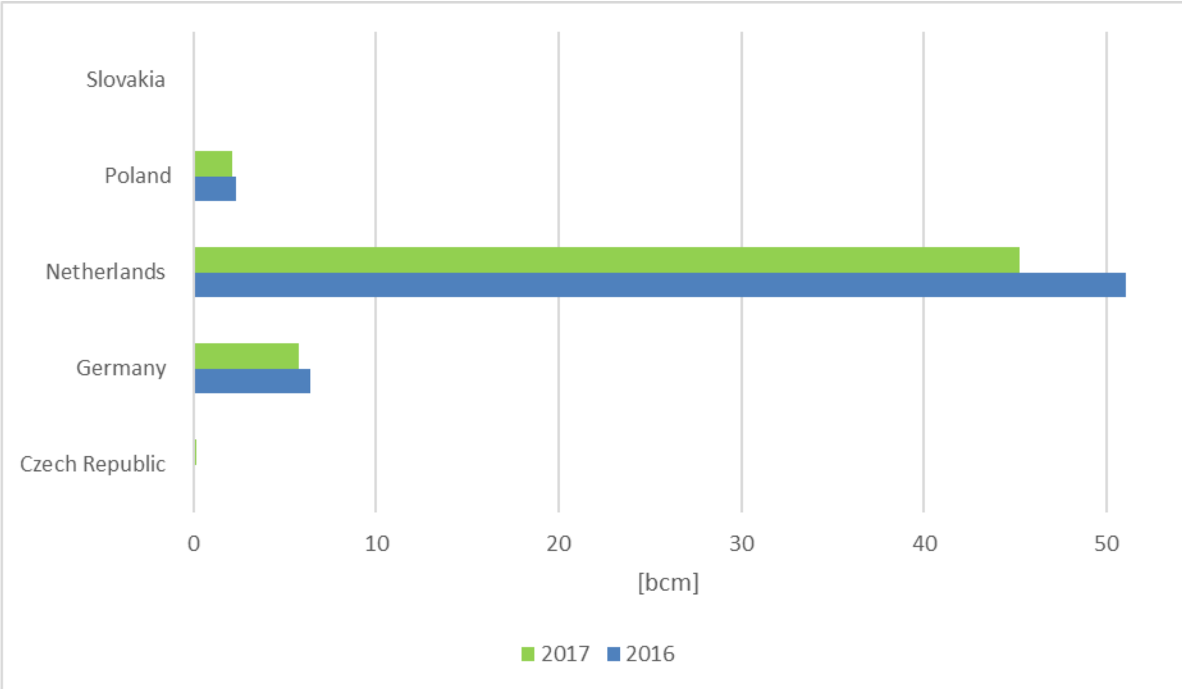
The countries in the Middle-west subregion comprise most of the gas supply corridors of Russian sources to the European Union. Therefore, the transmission systems in the region were largely built and optimised for the transit of gas from East to West. The Belarus supply corridor constitutes one of the key delivery import routes from Russia to the European Union by providing approx. 44 bcm/y of technical entry capacity to the European Union. The Middle-west subregion is also supplied with Russian gas that is shipped via the Ukraine corridor and across the Baltic Sea.

The sub region may also benefit from gas imports from Norway that are directed to Belgium, Germany and the Netherlands, and LNG supplies to the terminals located in Belgium, Poland and the Netherlands. Furthermore, domestic production of natural gas provides another source of supply predominantly in the Netherlands, Germany and Poland.

The biggest producer of gas in this sub region is the Netherlands, with total gas production approx. 45,24 bcm in 2017.

Figure 6 shows the biggest gas producers in Middle-west subregion.

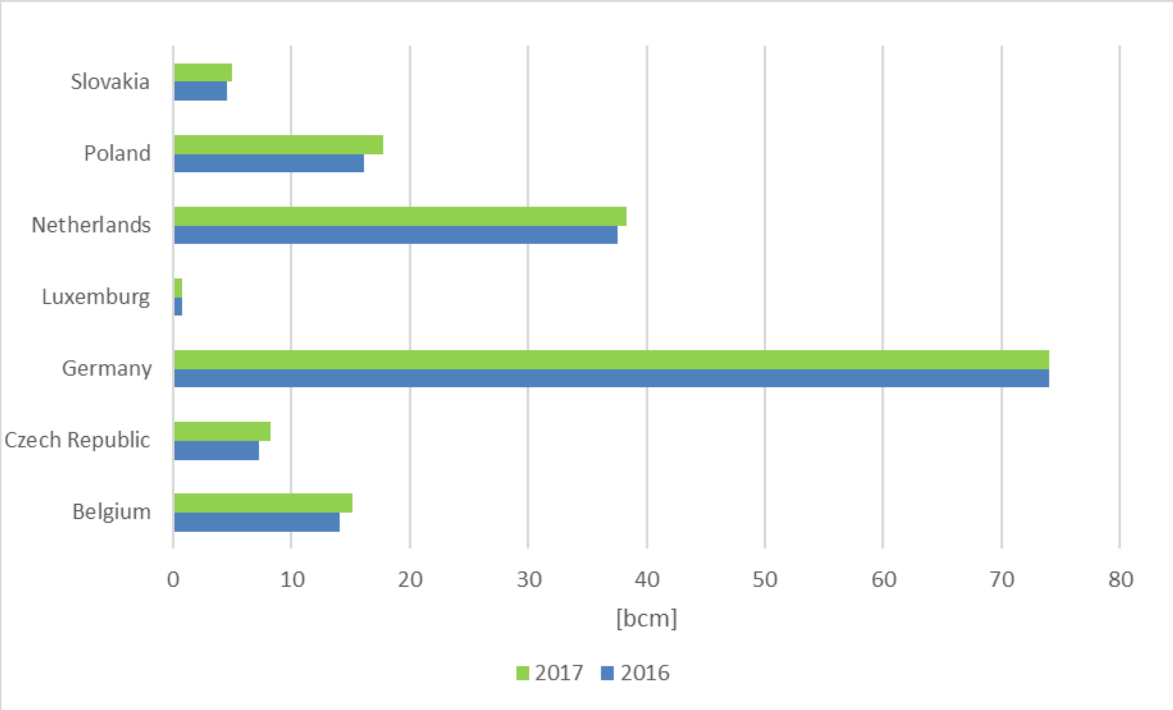
Figure 6: Gas production in Middle-west countries sub region



Countries of Middle-west subregion consumed in 2017 just under 160 bcm of natural gas in total. The biggest consumer in the subregion was Germany with the consumption reaching approx. 74 bcm.

Figure 7 shows gas consumption in countries of Middle-west subregion in 2016 and 2017.

Figure 7: Annual gas consumption in Middle-west countries sub region



Subregion's underground gas storage working capacity is approx. 45 bcm. The maximum usable working gas volume of underground gas storages in Germany is approx. 25,3 bcm, giving Germany the largest storage capacity in the European Union. In Germany maximal daily withdrawal capacity when the storages are full (1st of October 2017) reached 658,90 mcm/d and maximal daily withdrawal capacity in the end of the season (30th of March 2017) reached 515,56 mcm/d.

The technical capacity of LNG facilities in 2016/2017 was almost 26 bcm/y in the Middle-west subregion.

2.2 National system

2.2.1 Demand

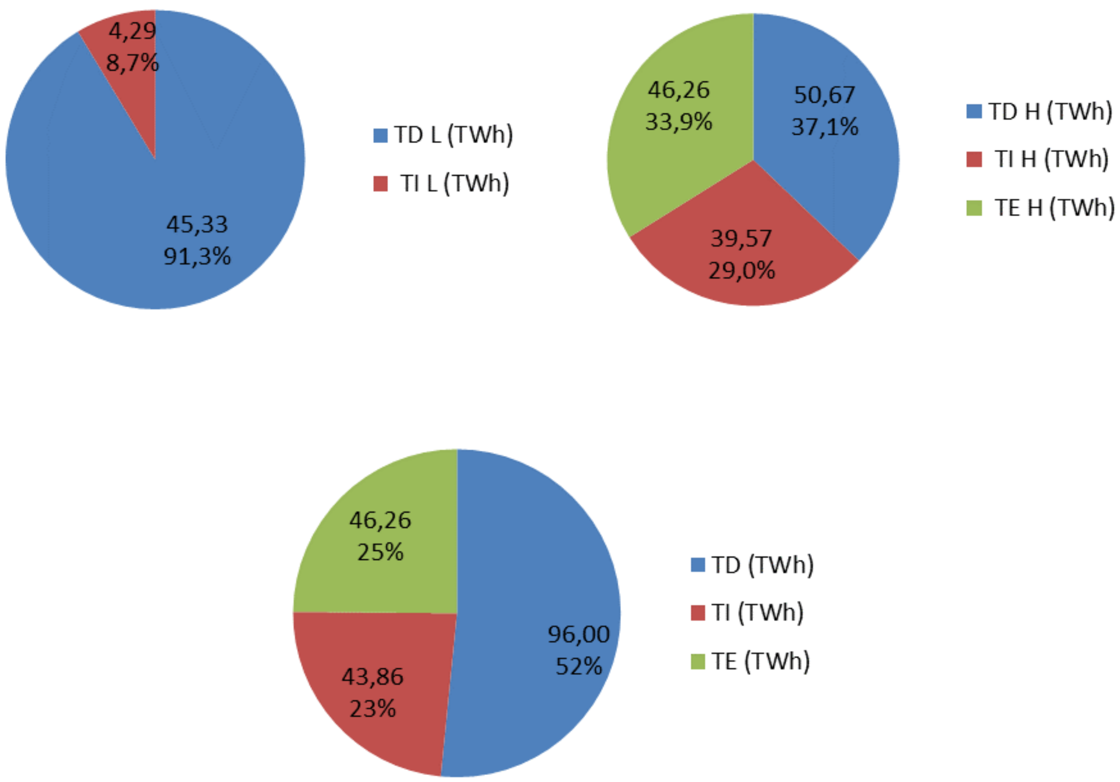
In 2017, the total measured gas demand of the Belgian end consumers amounted to 182.0 TWh, of which 134.4 TWh is H-gas (74% of total demand) and 47.6 TWh is L-gas (26% of total demand). This results in about 16.4 bcm/year of total gas demand in Belgium. The Belgian gas consumption is divided over H-gas or high calorific gas and L-gas or low calorific gas, which we will treat separately.

The L-gas demand in Belgium also has a different behaviour than the H-gas demand due to the different consumers that are connected to the two networks. A large majority of the L-gas consumption (91%) is attributed to the public distribution and the remaining 9% goes to industrial consumers (large consumers) directly connected to the transmission network of Fluxys. There are no power plants on the L-gas transport network.

Gas demand by sector

Figure 8 shows the breakdown of the total consumption for H-gas and for L-gas in 2017 of the public distribution (TD, normalized) (= households, small and medium enterprises, hospitals and schools), the large industrial players that are directly connected to the transmission network (TI), and for the electricity plants that are directly connected to the transmission network (TE). The protected customers are defined as TD (See p. 62).

Figure 8: Natural gas consumption 2017 Total L+H and L and H separately (in GWh)



Source: FPS Economy based on data available on gasdata.fluxys.com and own calculations

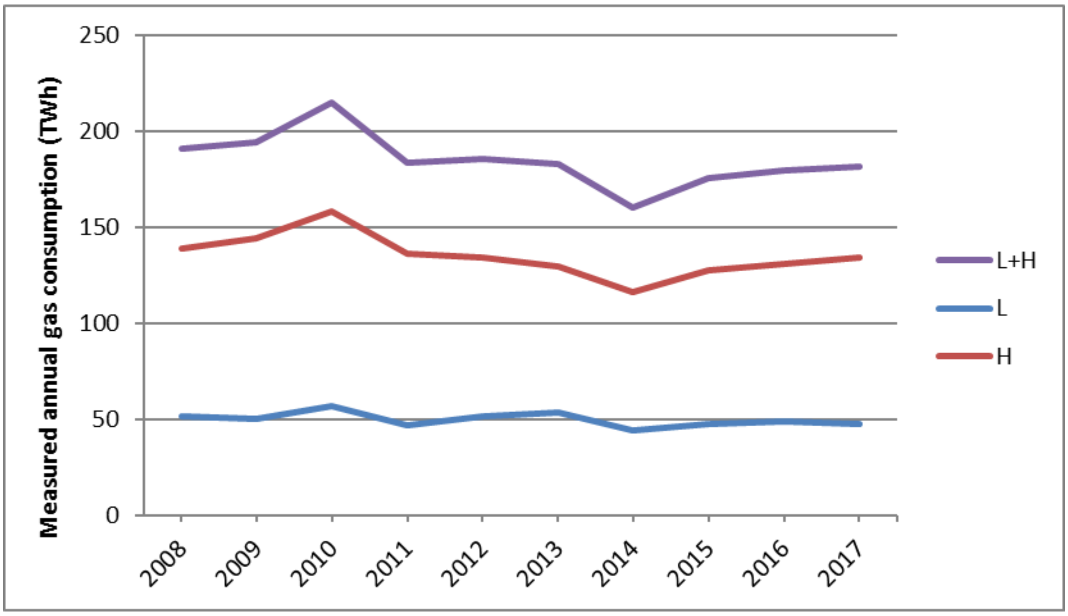
Above figures demonstrate the importance of the public distribution TD (i.e. households, SME's, hospitals and schools) in Belgium. In 2017 52% of the natural gas consumption in Belgium is used by the public distribution sector, 23% by the large industrial players and 25% by the power plants. The L gas is only used by the distribution sector (91%) and the industry (9%). H-gas is used by all three sectors, namely public distribution (37%), industry (29%) and by the power generation sector which accounted for 34%.

Evolution of the yearly gas demand

As most of the gas consumption on the distribution network is used for space heating, it is very sensitive to the outside temperature. Therefore, the number of equivalent degree-days[3] will have a significant influence on the consumption. Also, the pattern of the degree days over the year will have an influence on the consumption. The consumption of the industry is to a lesser extent influenced by the outside temperature.

Figure 9 and Figure 10 show the evolution of the total gas consumption in Belgium for the period 2008-2017 (in GWh/year) for the measured and a normalised[4] temperature profiles. In Figure 9, we see that the consumption in 2010 had increased due to the cold winter, and in a hotter year (2014) it decreased. These variations are still noticeable, but to a lower extent, after a normalization of the consumption of the public distribution (Figure 10). This can be explained by the remaining temperature dependence of the consumption of industrial consumers (For office heating, etc.) and power plants (Correlation between electricity demand and temperature). It is however more difficult to normalize these consumptions against temperature due to the other factors having an important effect on them. (Economic context, availability of other sources of electricity, etc.)

Figure 9: Total measured yearly consumption (2008-2017)

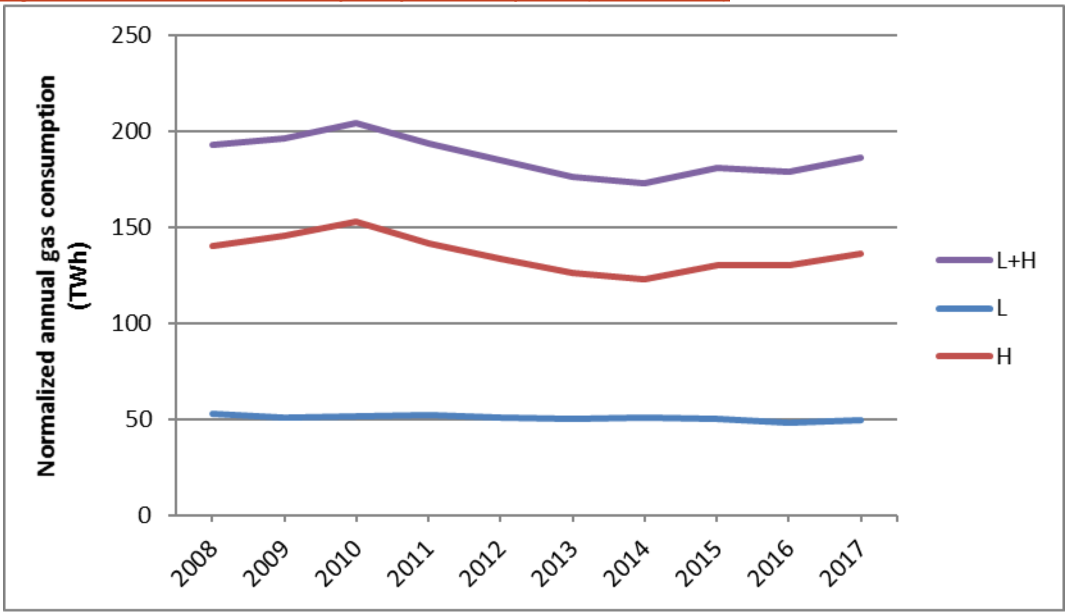


Source: FPS Economy based on data available on gasdata.fluxys.com and own calculations

[3] See Annex 1a: Degree-days and equivalent temperatures, p. 95

[4] See Annex 1b: Normalisation of the consumption, p. 98

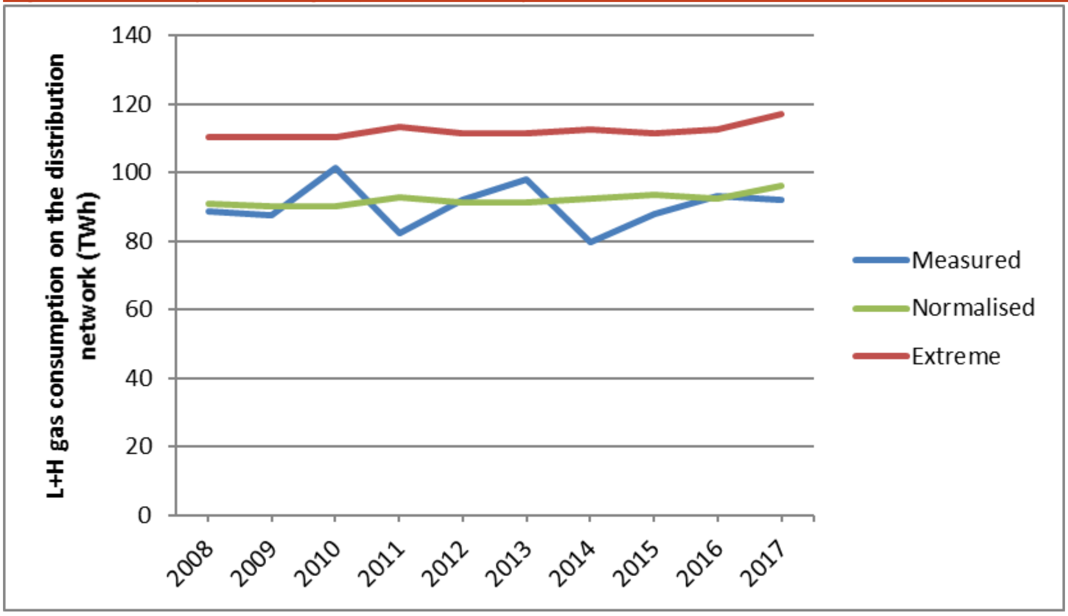
Figure 10: Total normalized yearly consumption (2008-2017)



Source: FPS Economy based on data available on gasdata.fluxys.com and own calculations

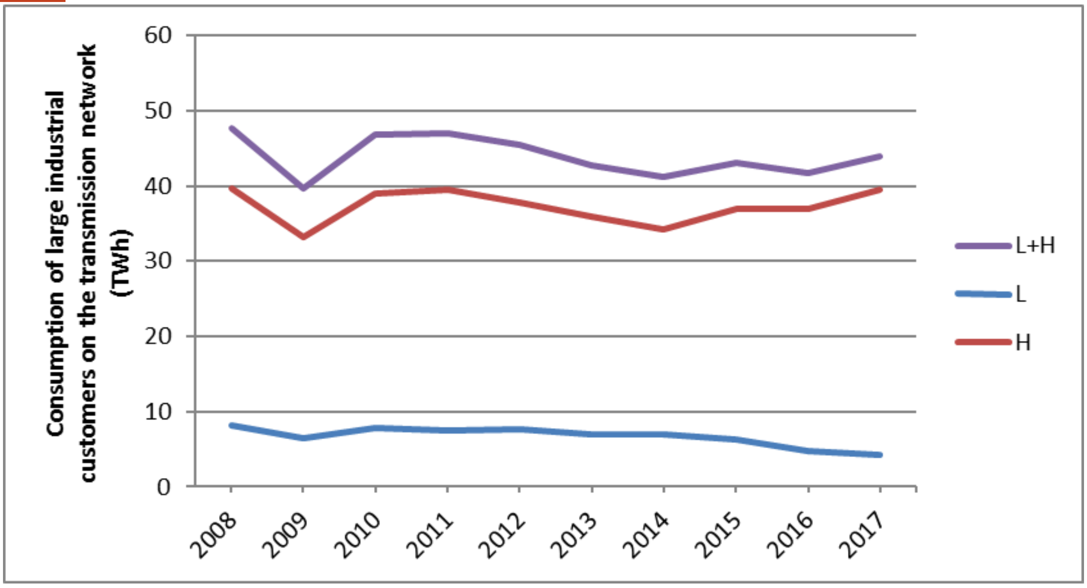
The consumption of the industrial clients directly connected to the Fluxys L-gas grid was relatively stable in the period of 2004-2007, with an average consumption of 9,5 TWh/year. At the start of the financial and economic crisis of 2008-2009, the consumption decreased sharply in 2009 to 6,5 TWh. In 2010, the consumption was again close to 2008 levels (see figure 10). In 2012 there is a decline in consumption after 2 stable years (2010 and 2011), this decline continues in 2015 and further onwards because of the conversion of all industrial clients on the L-gas network to the H-gas network.

Figure 11: Yearly natural gas (L+H) consumption on the distribution network (2008-2017)



Source: FPS Economy based on data available on gasdata.fluxys.com and own calculations

Figure 12: Yearly measured natural gas (L and H) consumption from industrial consumers (2008-2017)



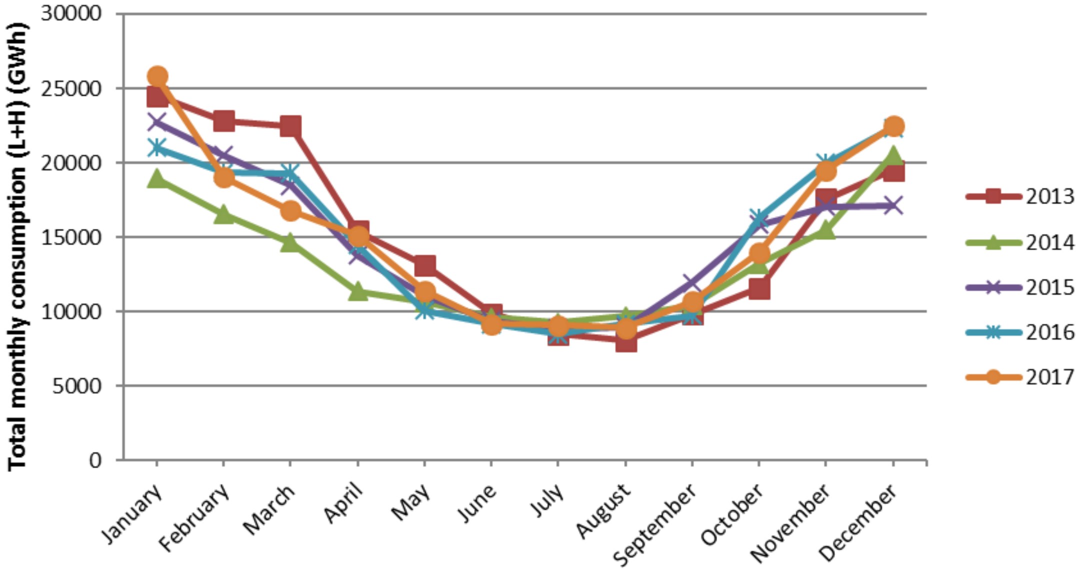
Source: FPS Economy based on data available on gasdata.fluxys.com and own calculations

As already mentioned, primary gas demand is also expected to grow in medium and long term. The government's forecasts project a strong growth of gas consumption in power generation because the new capacities that need to be built (particularly to replace a large portion of the nuclear generation capacity to be phased-out) will probably be mainly gas-fired. An increase in intermittent renewables-based power generation could also increase demand for gas to fuel back-up facilities. Growth in gas demand is also expected in the residential sector because households continue to move away from gasoil towards natural gas for heating.

Monthly gas demand & seasonality

The monthly demand pattern is quite stable across the different years. We also see that the global gas demand is strongly linked to the outside temperature. Belgian gas consumption shows a strong seasonal pattern (Figure 13). The average gas demand in July and August is mostly independent on the outside temperature and consists mainly of the gas demand from the industrial consumers (TI) and electricity production (TE). The gas use in the winter months can amount to more than 25.000 GWh/month.

Figure 13: Total monthly consumption 2013-2017



Source: FPS Economy based on data available on gasdata.fluxys.com and own calculations

The consumption in a cold month (January is typically the coldest month of the year) can be more than 200% higher than in a summer month. This leads to widely different possible demand situations in any given incident scenario that must be evaluated in the context of this Risk Assessment. The preferable and more conservative approach is of course to consider the worst-case scenarios, with a peak consumption over the specified period. The shorter this period is, the greater the difference between the associated peak consumption and the average consumption is. Peak days are widely used, even if hourly consumption can be roughly 20% higher on that day. This is because the gas system gives some time to react to increasing demand, mostly by the use of linepack as a temporary storage to momentarily bridge the gap between supply and demand. Suppliers can afterwards adjust their purchases of gas to balance their portfolios by the end of the gas day.

Peak day demand vs. average day demand

Table 5 illustrates the considerable difference between the gas demand on an average day and the peak demand day. This difference results in a very high peak day/average day ratio. In Belgium, peak day demand can be 276% as high as an average day. Belgium has a similar ratio to the average in the North-Western region. This high ratio can be explained by the high share of household demand, which can be very volatile in function of the temperature. Other countries have a lower share of the residential sector, but higher share of industry demand. This industry demand is mostly quite stable throughout the year and consequently results in a lower ratio peak day/average day demand. The peak day demand is the most representative of the needed infrastructure capacity.

Table 4: Average demand vs. peak demand in NW EU (in GWh/day)

	Year	BE	DE	FR	IE	LU	NL	UK	NW-EU
Peak day demand (GWh/d)	2017	1207	5906	4018	258	46	3969	4584	19988
	2020	1185	5783	3885	281	46	3843	4340	19362
	2025	1464	5563	3859	302	45	3727	3660	18620
Average day demand (GWh/d)	2017	437	2183	1260	136	23	1112	1921	7072
	2020	437	2172	1214	147	22	1074	1729	6795
	2025	561	2127	1172	162	20	1011	1497	6552
Ratio peak / average day	2017	276%	271%	319%	190%	199%	357%	239%	283%
	2020	271%	266%	320%	190%	207%	358%	251%	285%
	2025	261%	261%	329%	187%	221%	368%	245%	284%

Source: ENTSOG TYNDP 2017 (Green evolution scenario)

Demand for Border-to-border transmission

For the L-gas network, the reserved border-to-border transmission capacity on the Belgian network must be in line with the entry capacity of the French network at Taisnières. Each reservation above this entry capacity will lead to a reduction in the available capacity to guarantee the security of supply for the Belgian L-gas customers. Further in this analysis, we assume that the reserved capacity on the Belgian network to guarantee the gas transmission to France is equal to 1040 k*m³(n)/h (or 243,85 GWh/day).

Interruptible & protected customers

Energy end-users include residential and commercial customers as well as industries and electric utilities. These customer groups have different energy requirements and thus quite different service needs. In the natural gas market, consumers can contract for either firm or interruptible service. Residential and small commercial customers such as households, schools, and hospitals use natural gas primarily for space and water heating and need reliable supply. Such customers require on demand service with no predetermined quantity restrictions, known as firm service. In contrast, larger commercial, industrial, and electric utility customers could have fuel switching or dual-fuel capabilities (which is however rarely the case in Belgium) and could receive natural gas through a lower priority service known as interruptible service. In theory, energy supply reliability could be effectively handled at the customer level ability to switch quickly to an alternative fuel. Therefore, some countries distinguish between protected customers for whom most of the capacity offered is firm capacity. In Belgium, interruptible capacity is only offered after all the available firm capacity is booked by the shippers.

End-users on the transport network

Contrary to the protected customers, the gas supply to industrial consumers connected to the Fluxys transport network could be interrupted. Historically, the infrastructure for transporting and delivering natural gas is designed and operated primarily to meet the need for firm service. Because the peak demand for natural gas tends to be seasonal, interruptible service contracts allow pipeline and distribution system operators to increase one of their fixed assets and better manage costs of service on average. These arrangements allow operators to maximize economic efficiency by meeting the needs of their committed firm service customers while providing delivery during off peak periods to interruptible and seasonal customers. In the past, these arrangements provided opportunities for large-volume energy consumers such as industrial firms and electric generators to attain lower-cost energy supplies.

There are two kinds of interruptible contracts:

1. Supplier interruption:

   Suppliers have the right to interrupt the customer, normally in return for a discount on price and with some notice in advance. The notice period will be specified in the energy contract. Most interruptible contracts specify that there will only be a few hours' notice, unless it is specified otherwise in the contract. Customers with an interruptible contract have agreed to receive gas but also to have supply interrupted at some point, according to the reasons in the contract (mostly meteorological circumstances) and for a maximum number of hours or days.

   Interruptible contracts are more and more disappearing from the stage. This is due to the fact that the attributed discounts are no longer a sufficient incentive on the longer term. In the industrial sector, interruptible contracts account for less than 5% of the total contracted volumes between end users and suppliers. Interruptions are also limited to force majeure events. For the power plants, we also see a tendency towards more firm contracts (depends a lot on the supplier).

2. Transporter or border-to-border interruption:

   The TSO has the right to interrupt supply (this is to interruptible contracted customers) in the network for operational reasons under normal circumstances. Again, this will be covered in the transmission contract signed by the network user. Interruptible capacity is hardly booked by the shippers because Fluxys Belgium only offers interruptible capacity to the market if all the available firm capacity has already been booked. Even if Fluxys Belgium would offer interruptible capacity, the price difference between interruptible and firm capacity has become too small to be an incentive. Therefore, we can consider that interruptible capacity for the shippers is negligible in Belgium.

We must be clear however that the above-mentioned interruptions are separate to other interruption rights, which can only be called upon in potential or actual emergency situations. In emergency situations, some companies can reduce demand considerably when prices are high or maintain production by switching to back-up fuels. However, some still need to maintain a certain level of gas to keep systems going and to let their plant safely shut down.

Some gas users have back-up systems and fuels to switch to in the event of an emergency or if commercial incentives make using an alternative fuel source preferable. Not every gas user has back up fuels (most of the end consumers in Belgium do not), so the gas system and the procedures that exist within it are designed to minimize the risk of gas being switched off from those who don't expect it to be (those not on interruptible contracts). Appliances for commercial premises generally incorporate flame out safety devices. These allow for supplies to be quickly and safely reinstated following a cessation in gas supplies.

In case of an emergency, the safe provision of gas to domestic users and other low volume users (all connected to the distribution network) is the top priority. Before firm customers are interrupted, emergency plans provide for the suspension of the normal market for gas. After the suspension, it will depend on how quickly gas supply and demand are balanced, before firm customers start to be interrupted. Before firm customers are interrupted, firm border-to-border transmission will be interrupted. Calls on the general public may take place asking the citizens to restrain gas usage, but this would depend on the type of emergency.

Role of gas for power generation

In 2018, gas-fired power plants and cogenerations (CHP) accounted for 27.6% of the total installed production capacity (See Table 11). This is nearly as much as the nuclear power plants (28.7%) and rises when considering only production capacities that are independent from the weather conditions. Natural gas then accounts for 40% of the production capacities that could theoretically be available all year round.

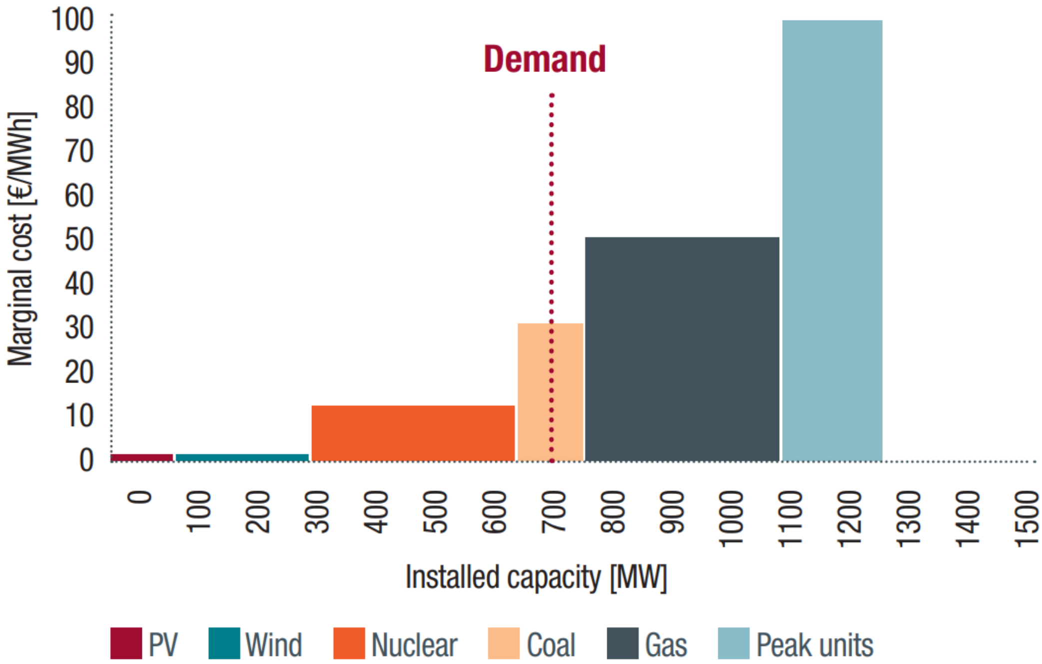
Another advantage of gas-fired power plants is their flexibility, which cannot be offered by other climate-independent sources like nuclear and CHP. These gas-fired power plants represent nearly 60% of the flexible production capacity, which is essential for the balancing of the electricity grid.

Table 5: Installed electricity production capacity (2018)

	Installed production capacity	% of total production capacity	Flexible	Climate in-dependent
	MWe			
Nonrenewable thermal production	**11758**	**57.1%**		
Nuclear	5919	28.7%	NO	YES
Gas-fired	3846	18.7%	YES	YES
CHP	1835	8.9%	NO	YES
Turbojet (oil)	158	0.8%	YES	YES
Renewable, climate independent production	**1125**	**5.5%**		
Biomass	794	3.9%	YES	YES
Waste	331	1.6%	YES	YES
Renewable, climate dependent production	**6414**	**31.1%**		
Wind	2774	13.5%	NO	NO
Solar	3526	17.1%	NO	NO
Hydro	114	0.6%	NO	NO
Storage	**1308**	**6.3%**		
Pumped hydro	1308	6.3%	YES	YES
Total	**20605**	**100%**		

To determine which production units must be used, a detailed modelling of the power plants' economic dispatch is performed. The assessment takes into account the power plants' marginal costs (see Figure 14) and also enables the pumped-storage power plants and hydroelectric reservoirs to be appropriately modelled. Economic availability depends on the generation capacity available for the hour in question. The price in any given hour is determined by the intersection between the curve for supply (ranking of the power plants) and demand. Demand is considered inelastic in this context. The market response to high prices is also taken into consideration.

Figure 14: Example of an economic stack for a given time and a given production park



Source : Elia

Overproductions are due to certain types of production considered as priority ('must-run'), most of them non-flexible and can occur in a context of low consumption. This so-called "must run" production will generate an excess of production in any situation where consumption is lower than this non-flexible production, even though the vast majority of flexible production has been shut down.

Fuel switching

Fuel switching capability is the short-term capability of a manufacturing establishment to have used substitute energy sources in place of those currently consumed. Capability to use substitute energy sources means that the establishment's combustors (for example, boilers, furnaces, ovens, and blast furnaces) had the machinery or equipment either in place or available for installation so that substitutions could actually have been introduced within 30 days without extensive modifications. Fuel-switching capability does not depend on the relative prices of energy sources; it depends only on the characteristics of the equipment and certain legal constraints.

Fuel switching possibilities, short term switching away from the use of natural gas to another fuel, are limited in Belgium. Fuel switching is only possible in the industry sector.

In Belgium there is no program to encourage or otherwise require users of gas to switch to another fuel source in case of a disruption of natural gas supply. Also, the new power plants do not have the built-in capability to switch fuel.

Border to border transmission

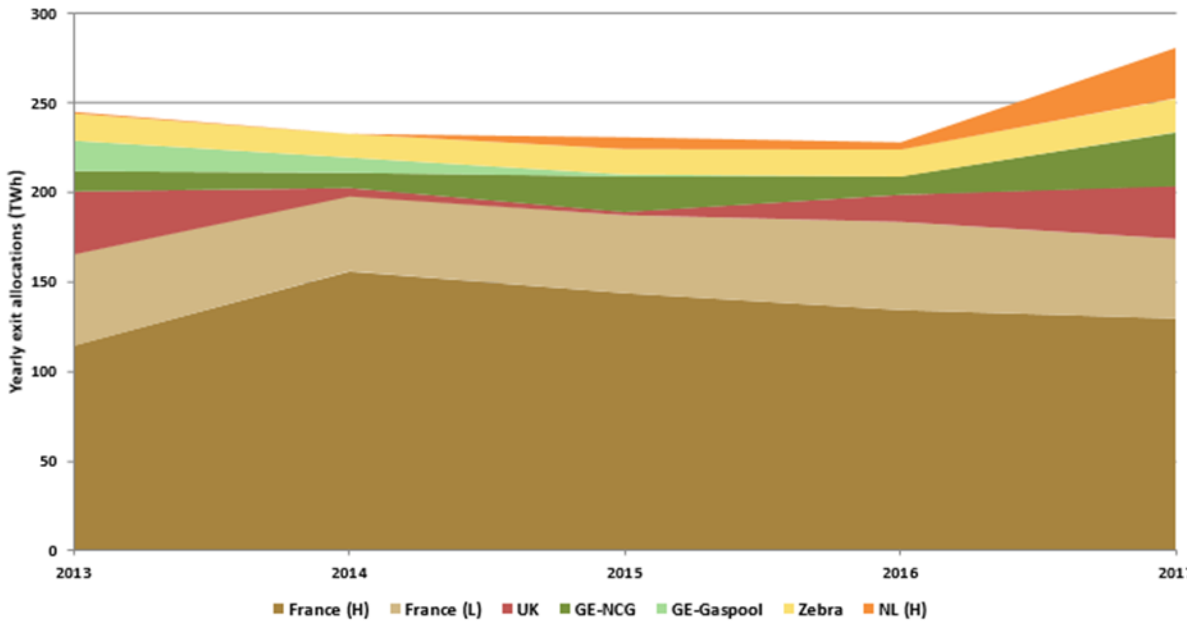
The total (allocated) volume of gas (H and L) transported from the Fluxys Belgium exit border points towards adjacent markets is increasing in 2017 up to around 275 TWh (see Figure 15).

A significant part of this volume (around 50% in 2017) is destined for the French market (L and H-gas), although in slight decrease since 2014.

Volumes heading to the United Kingdom (via IUK) have been characterized by continued growth since 2015, most probably as a result of the closure of significant storage capacity in UK and therefore compensated by volumes stored on the continent during the winter.

On the other hand, to store those volumes during the summer period, more volumes are transported from UK to NL and Germany via Fluxys Belgium and therefore increasing the respective exits as reflected on the graph.

Figure 15: Yearly exit allocations (2013-2017)



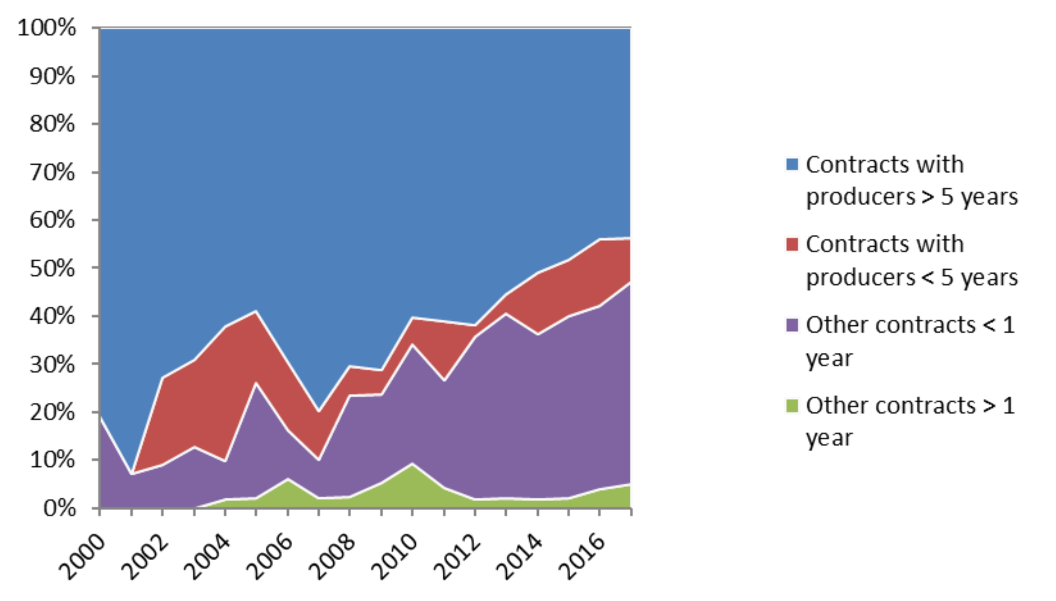
Source: Fluxys Belgium

2.2.2 Supply

Imports

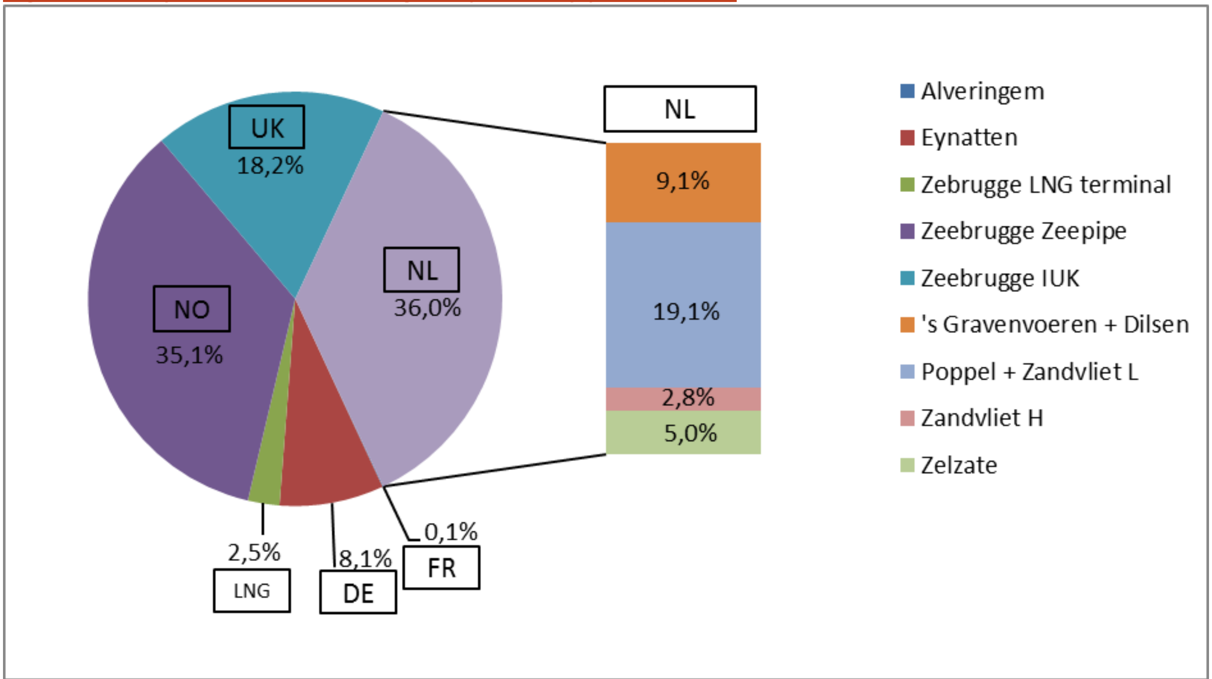
Belgium has no indigenous gas production and thus relies entirely on imports. The current import portfolio is well diversified by origin and type of supply: the Netherlands and Norway are the principal pipeline suppliers, while Qatar is the main source of LNG imports. Long-term contracts with natural gas producers remain the backbone of the portfolio of the most important suppliers on the Belgian market, but suppliers increasingly rely on the wholesale markets (hubs). In 2002, contracts with duration of less than 5 years made their entry into the Belgian market and from 2004 we had the first one-year contracts. The provisioning via the spot market (Zeebrugge Hub) has evolved a lot since 2001. Most suppliers use spot market deliveries to optimize their portfolio.

Figure 16: Evolution of the composition of the average supply portfolio 2000-2017



Source: CREG annual reports

Figure 17: Physical flows into Belgium per entry point (2017)



Source: FPS Economy based on data available on gasdata.fluxys.com and own calculations

Figure 17 illustrates that most gas comes to Belgium via pipelines. Only 2.5% is imported via the LNG-terminal of Zeebrugge. The Zeebrugge LNG terminal serves as a gateway to supply LNG into North-western Europe. Any LNG unloaded at the terminal can be redelivered for consumption on the Belgian market, traded on the Zeebrugge Hub, or shipped to supply other end-consumer markets in the UK, the Netherland, Germany, Luxemburg, France and Southern Europe. However, we want to note that not all LNG can be traded at the Zeebrugge Hub, nor shipped to the UK due to quality restrictions[5].

The total (allocated) annual volume entering the Fluxys Belgium network is increasing in 2017 and amounts to nearly 460 TWh.

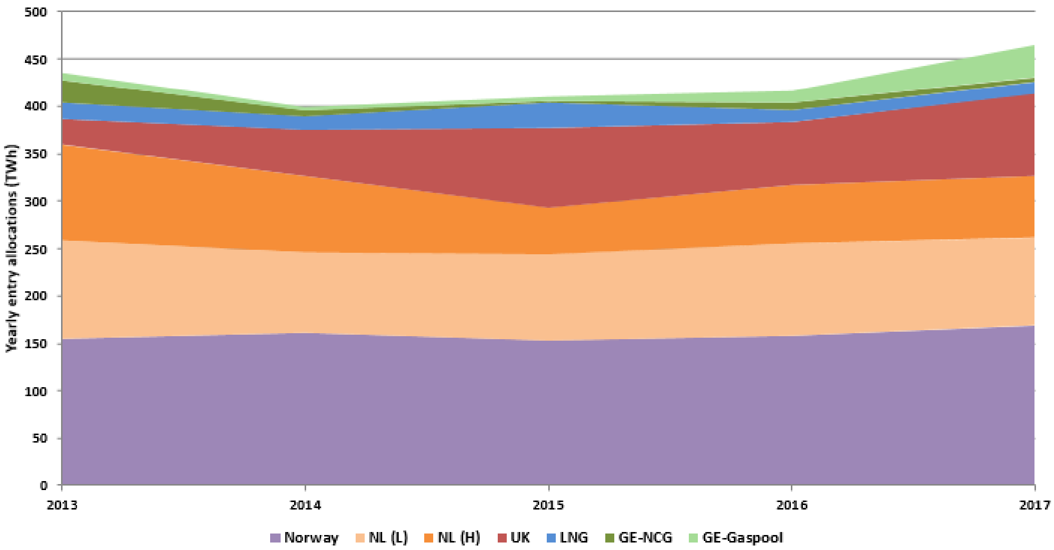
Two main routes supply more than half of the incoming volumes: Norwegian H-gas delivered via the Zeepipe pipeline (about 150 TWh / year) and L-gas from the Netherlands via the Hilvarenbeek Interconnection point (about 100 TWh / year).

Volumes from the UK are increasing in 2017 (cf. exit analysis referring to more storage on the continent for UK, entering the Fluxys Belgium system via IUK).

Volumes from Germany remain relatively limited, although showing a significant increase in 2017 probably also related to stored gas in Germany for UK entering the Fluxys Belgium system and heading towards UK.

Quantities of imported LNG remained stable in 2017.

Figure 18: Yearly entry allocations (2013-2017)



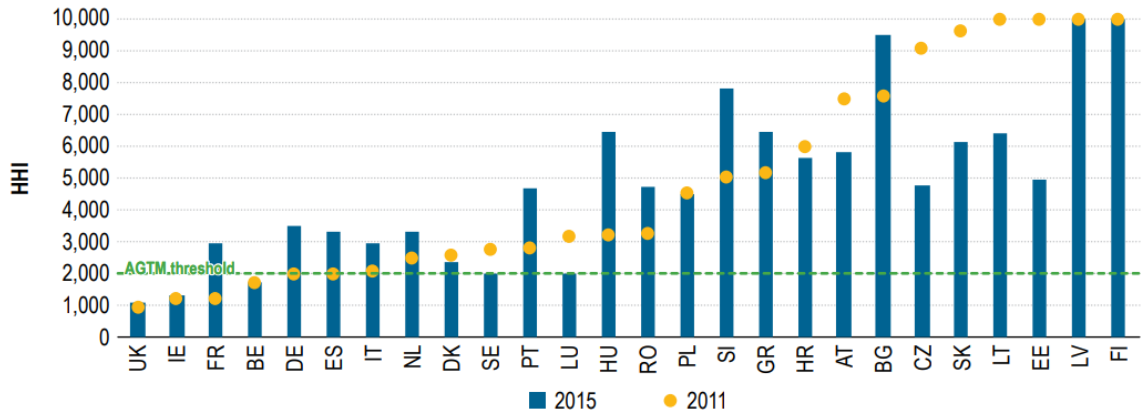
Source: Fluxys Belgium

As most European countries, we do note a decrease in the diversification of our import portfolio. Still Belgium has a good score on the Herfindahl-Hirschman Index (HHI), a commonly accepted measure of

[5] The debate focuses on the Wobbe Index, which is much narrower in the UK than in the rest of Europe, between 47.20-51.41 megajoules/cubic metre (MJ/m3). The Belgian gas law foresees a wobbe index for H-gas between 49,132 MJ/m^3(n) and 56,815 MJ/m^3(n). Norwegian and Qatari gas can have specifications at the upper end or slightly above the UK level.

market concentration. It is calculated by squaring the market share of each country we import from and then summing the resulting numbers, the higher the index, the more concentrated the market. Figure 19 shows the estimated HHI values at MS level for 2015 and their evolution with respect to 2011. The HHI threshold for a well-functioning market is a value of 2000, and Belgium is one of the Member states meeting this criterion.

Figure 19: Estimated HHI index per Member State 2011–2015



Source: ACER Market Monitoring Report 2015

As we look at the European gas reserves and production rates for conventional gas, we see that, at the current production rates, none of them will last more than 18 years. Table 12 gives an overview of the reserves, production and the lifespan of the gas reserves in Europe in 2017. According to the BP statistical review of world energy 2018, the reserves of our two most important supply countries (Netherlands and Norway) are quickly declining. We expect the imports of those countries to fall - from the Netherlands in the middle term and from Norway in a more distant future. The reserves-to-production ratio (R/P ratio) for both countries is respectively 16,3 and 18,2 years. When comparing these new R/P ratios with the ones of 2009 (for the Netherlands 17,3 and Norway 19,8), it is noticeable that the new ratios are smaller than those of 2009, this because the production in those countries increased.

Table 6: Natural gas reserves and production in 2017

	2017 Production (bcm/year)	Growth rate per annum		Reserves (trillion cubic meters)	R/P ratio (years)
Denmark	**5,1**	7,7%	-8,0%	**<0.05**	2,7
Germany	**6,4**	-7,6%	-8,2%	**<0.05**	5,1
Italy	**5,3**	-4,0%	-6,2%	**<0.05**	8,1
Netherlands	**36,6**	-12,6%	-4,2%	**0,7**	17,9
Norway	**123,2**	+6,7%	+2,8%	**1,7**	13,9
Poland	**4,0**	-2,0%	-0,9%	**0,1**	16,6
Romania	**10,3**	+14,2%	-2,0%	**0,1**	9,9
United Kingdom	**41,9**	+0,6%	-6,7%	**0,2**	4,4
Other Europe	**9,1**	+5,0%	-2,1%	**0,1**	16,0

*R/P = lifespan of the reserves at the current production rate

Source: BP Statistical review of World Energy 2018

Since the Netherlands and Norway represent together 70% of the natural gas imports of Belgium, substantial alternative supplies will need to be available to replace the declining gas supplies from the Netherlands and Norway in due time. In the long run, these developments will most likely cause an increased dependence on gas imports from Russia and the Middle East.

Supply routes

Belgium is directly connected to four upstream pipelines for H-gas and two for L-gas feeding directly into the Belgian gas system (see also Figure 21). Those are:

- **The Interconnector (bi-directional)** connecting Belgium and the UK,
- **Zeepipe** providing a direct link to the Norwegian gas fields,
- **WEDAL** and **TENP** connecting Belgium to Germany and thereby giving access to Russian gas.
- **Dorsales connecting the Netherlands to Belgium and France**

Storage

A valuable tool for dealing with demand swings is storage. Belgium has only one underground storage installation operated by Fluxys Belgium (used for commercial storage), which is the aquifer in Loenhout. Its useful storage capacity is 700 mcm. Only high calorific gas is stored at this facility. Short term LNG storage is also available at the Zeebrugge LNG terminal. Part of the stored gas is reserved by Fluxys Belgium for normal balancing of the network. The rest of the storage capacity is commercialized under a regulated regime on the market for dealing with seasonal swings and situations of peak demand.

Storage users with subscribed storage capacity in Loenhout are obliged to achieve a gas filling level of at least 90% on the 1st of November according to the booked storage capacity and must still have a level of 30% of gas in storage on the 15th of February.

Table 7 Natural Gas storage capacity in Belgium (H-gas)

Location	Type	Working capacity	Peak output
		GWh	GWh/day
Loenhout	Underground	8192,5	169,5

The Zeebrugge LNG terminal also has storage capacity available (a working capacity of 2576 GWh and a peak send out of 515 GWh/day), but because of the high number of slots that are allocated, the LNG storage must send out almost immediately after the LNG cargos have been unloaded. Therefore, the LNG storage tanks do not operate as storage as such but more as a very temporary buffer before sending out into the pipelines.

Table 8 Gas in underground storage, winter period 2016-2017

	2016						2017					
	jul	aug	sep	oct	nov	dec	jan	feb	mar	apr	may	june
Gas storage capacity (GWh)	7910	7910	7910	7910	7910	7910	7910	7910	7910	7910	7910	7910
Gas amount in storage[6] (GWh)	3477	5032	6857	7558	7627	7548	7084	4240	2438	1403	1892	2770
Gas stocks change (GWh)												
- withdrawal					-79	-464	-2844	-1802	-1035			
+ injection	1555	1824	702	69						489	878	368
Maximum withdrawal capacity (GWh/d)	68	68	68	68	170	170	170	170	68	68	68	68
Remaining days for using the stored gas	51	74	101	111	45	45	42	25	36	21	28	41

The future of L-gas

Production of the Groningen field is expected to significantly and steadily decline. The Belgian competent authority is aware of this issue. Gas quality conversion of H-gas into L-gas is costly and energy-intensive, as it would require large amounts of relatively pure nitrogen. Therefore, the Administration considers a conversion of the L-gas network to H-gas to be the only viable long-term scenario. Due to a higher magnitude of earthquakes in the Groningen region, the volume allowed to be produced has been restricted in the past years. In March 2018, the Dutch energy Minister announced his intention to reduce the Groningen volume to max 12 bcm by October 2022 at the latest. To compensate for this reduction and maintain Security of Supply for the own domestic market and for the adjacent countries, GTS is asked to build a new quality conversion unit in Zuidbroek and to convert about 200 industrial clients to H-gas.

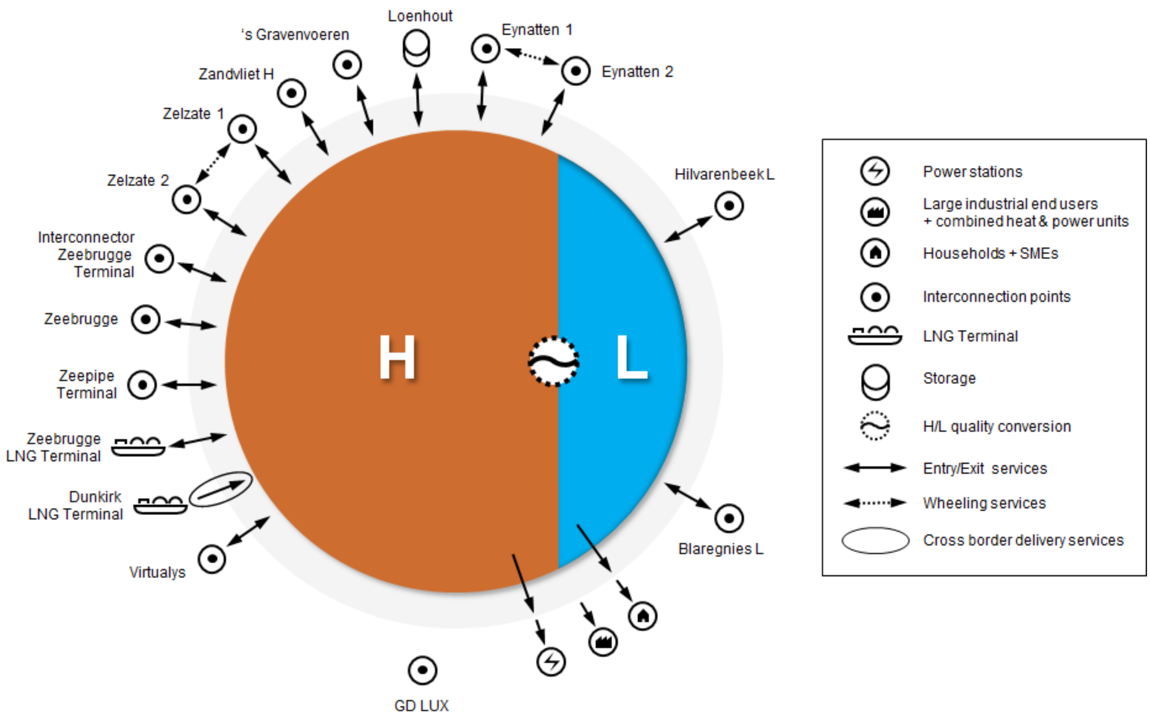
In Belgium, the decision to proceed with the conversion has been taken and the planning has been confirmed for the years 2018, 2019 and 2020. For the years 2021-2029, the planning is currently indicative.

[6] On the first day of the month

2.2.3 Infrastructure

Entry-exit model

Figure 20: Entry-exit model Belgium (2018)



Source: Fluxys Belgium

The Fluxys Belgium transmission grid has a high level of interconnectivity with adjacent transmission grids, offering extensive access to Northwest European market areas and production facilities.

With 17 physical interconnection points with neighbouring natural gas transmission systems, the Belgian grid is a central crossroads for gas flows in North-Western Europe:

- transmission of Dutch and Norwegian natural gas to France, Spain and Italy
- transmission of British natural gas to continental Europe
- transmission of Russian natural gas to countries including the United Kingdom
- transmission of natural gas to Luxembourg
- natural gas is also passed on to other end-user markets from the LNG terminal in Zeebrugge.

The system by which Fluxys Belgium offers the transmission services to the Grid Users is an entry/exit model. Through this entry/exit model, natural gas enters the Fluxys grid at an interconnection point and can either leave the grid at another interconnection point or be consumed by a Belgian final customer at a domestic exit point or at a public distribution exit point via a distribution system operator.

Transmission services can be subscribed and used independently at interconnection points (entry & exit services) and at domestic exit points (exit services). The model enables parties to freely exchange quantities of gas within the Belgian system. This natural gas can, by consequence, be delivered from any interconnection point and taken off towards any interconnection point or any domestic exit point.

The transmission grid is divided into two entry/exit zones: The H-zone and the L-zone.

The H-zone corresponds to the physical H-calorific subgrid and the L-zone to the physical L-calorific subgrid (see Figure 20).

In addition, daily market-based balancing will be applied. In order to reliably and efficiently operate the Fluxys grid, the total quantities of natural gas entering the Fluxys grid must be, on a daily basis, equal to the total quantities of natural gas leaving the Fluxys grid or consumed by Final Customers. Any remaining residual differences at the end of the day will be settled by Fluxys Belgium (market short: Fluxys Belgium buys gas at ZTP; market long: Fluxys Belgium sells gas to ZTP) for the account of the causing shipper(s).

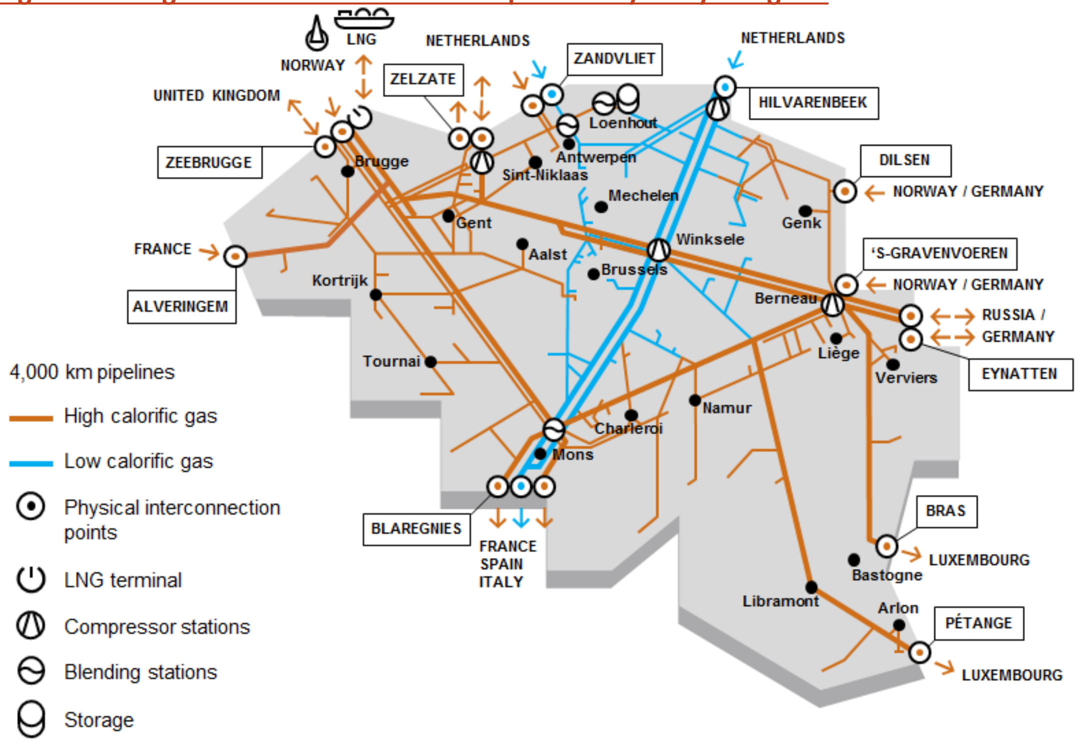
Within the day, the market balancing position, being the sum of the respective individual balancing positions of each Grid User, is assumed to remain within a predefined upper and lower market threshold, corresponding to the commercially offered flexibility within the system. This market balancing position is updated on an hourly basis, together with the individual balancing position of each Grid User, representing the cumulated delta so far within the day. As long as the market balancing position remains within the predefined market threshold, there is no residual intervention by Fluxys Belgium. When the market position goes beyond the market threshold, also within a day, Fluxys Belgium intervenes on the market in order to settle the residual excess or shortfall beyond market threshold, by a sale or purchase transaction. Such intervention is reported by Fluxys to Grid User(s) identified as contributing to the residual imbalance by a proportional settlement in cash of their individual balancing position.

Overview of the pipeline network

Fluxys Belgium, Belgium's transmission system operator, has a network of about 4000 kilometres of pipelines with 17 physical interconnection points and four compression stations. The 8 cross border pipelines connect the Belgian gas market directly to Norway, UK, Germany, the Netherlands, France and Luxembourg. The four compressor stations are located in:

- **Weelde**: The compression station in Weelde was upgraded in 2010 to increase the pressure of low-calorific natural gas in the pipeline from Poppel on the Dutch border to Blaregnies on the French border.
- **Winksele**: to increase pressure on the North/South axis. The compression station has been upgraded with four new compression units in order to increase pressure on the East/West axis (VTN/ RTR1 and 2).
- **Berneau**: in 2010-2011 additional compression stations were built on the high calorific gas pipeline from 's Gravenvoeren on the Dutch border to Blaregnies on the French border and to export further on the VTN/RTR pipeline (Zeebrugge-Zelzate/Eynatten.
- **Zelzate**: The Zelzate compressor station came on line at the end of 2008 to create additional capacity for the overall rise in demand of the Belgian domestic market and enables larger volumes to be transported to and from the underground storage facility in Loenhout.

Figure 21: Belgian transmission network operated by Fluxys Belgium



Source: Fluxys Belgium

In 2017, the Belgian gas network transported ± 16.5 bcm of natural gas for consumption in Belgium and about 25 bcm of gas to other markets in the Netherlands, Germany, Luxembourg, France and UK. The Fluxys Belgium network delivers gas directly to about 220 large industrial end-users and power stations and supplies the grids of 13 distribution system operators which deliver gas to residential and small- to medium-sized industrial users.

Since October 2012 Fluxys Belgium has a new entry-exit model. The border-to-border transmission of gas through Belgium is assured via the major two-way high-pressure pipeline systems connecting Belgium to its neighbours. The line from Zeebrugge to Blaregnies linking the North Sea and the UK to France (H-gas) is still used mainly for B2B transaction transit. There is a separate pipeline, parallel to the Zeebrugge-Blaregnies pipeline, for domestic transmission in the western part of the country. Presently, all pipelines are meshed in one network and lined up to be used for border-to-border transmission as well as for domestic supply.

Fluxys Belgium and the Luxembourg TSO Creos Luxembourg have worked on the integration of their respective H markets. Since 1 October 2015, the BeLux zone consists of an entry/exit system with Zeebrugge Trading Point (ZTP) as its virtual trading point. No capacity subscription is needed to have natural gas transported between Belgium and Luxembourg (and vice versa).

On 1 December 2017 Fluxys Belgium and GRTgaz have introduced Virtualys, a single virtual interconnection point between the Belgian ZTP and French PEG Nord gas trading places with a view to facilitate cross-border trading.

Interconnections and reverse flow capacity

The table below gives an overview of the technical capacities in forward and reverse flow on each of the interconnection points in Belgium. These capacities only give an overview of the capacity (either in reverse or forward flow) on each interconnection point on the Belgian borders. Capacities are also dependent on capacities offered by adjacent TSO and could change over time. Belgium benefits from sufficient reverse flow capacity on the following axes: BE-UK, BE-DE, BE-NL.

Remarks:

- The technical capacity is not a fixed invariable value. An increase of the technical capacity can be allowed by reducing the technical capacity of other interconnection points (resulting in the same network load), by optimizing the steering possibilities or by modifying the network flow scenario's.
- Published firm capacity can be temporarily higher, based on temperature effect, network load and booked 'restricted' transmission services (wheeling, operational capacity usage commitments (OCUC)).
- Although individually available, the capacities on the interconnection points IZT, ZPT, LNG Terminal and ALV are limited in aggregate (as indicated on the Fluxys Belgium data platform).

Table 9: Firm entry and exit capacity offered on the connection points (in mcm/d)

	Connection point	Type	Firm capacity offered 2018 (mcm/d)		Firm capacity offered 2022 (mcm/d)	
H			Entry	Exit	Entry	Exit
	IZT	EP	64.80	78.00	64.80	78.00
	LNG terminal 1		22.80	0.00	22.80	0.00
	LNG terminal 2	LNG	22.80	0.00	22.80	0.00
	ZPT	EP	43.20	0.00	43.20	0.00
	Virtualys	EP	4.62	66.00	4.62	66.00
	Dunkerque	EP	19.38	0.00	19.38	0.00
	Zandvliet H	EP	4.20	0.00	4.20	0.00
	Zelzate 1	EP	36.00	24.00	36.00	24.00
	Zelzate 2	EP	0.00	10.80	0.00	10.80
	Eynatten 1	EP	18.00	24.00	18.00	24.00
	Eynatten 2	EP	31.20	24.00	31.20	24.00
	S Gravenvoeren + Obbicht	EP	31.20	0.00	31.20	0.00
	Loenhout Storage	S	15.00	7.80	15.00	7.80
L	Poppel/Zandvliet L	EP	65.52	0.00	65.52	0.00
	Blaregnies L	EP	0.00	24.96	0.00	24.96
	Transfo H → L	EP	9.60	8.64	9.60	8.64

Source: Data compiled based on information of Fluxys

Notes:

- Virtualys is the new virtual interconnection point (VIP) comprising of the two physical interconnection points in Blaregnies (H-gas) and Alveringem. Some of the available capacity in Alveringem is used for transborder access to the Dunkerque LNG terminal
- Transfo H→ L: the entry capacity is on the L-gas side and the exit on the H-gas side. The capacities shown in the table also consider the unit in Loenhout, which is currently mothballed.
- Fluxys Belgium's network still has an interconnection point at Pétange & Bras (connection point Belgium-Luxemburg) but it not commercialized anymore

The VTN-RTR pipeline (H-gas) is bi-directional linking the UK and the Zeebrugge hub with Germany and the Netherlands, the Segeo pipeline (H-gas) runs from the Dutch border in 's Gravenvoeren to France and the Poppel-Blaregnies pipeline runs from north to south, linking the Netherlands with France (L-gas). In 2010, the Zelzate entry point (physical bi-directional) came into operation following investments in the Dutch grid through which the capacity on the East-West axis increased. This also shored up the supply into the Belgian market and enabled greater volumes of natural gas to be traded on the Zeebrugge hub. The Interconnector Zeebrugge Terminal (IZT) connects the Fluxys Belgium grid to the subsea Interconnector pipeline which runs to Bacton in the United Kingdom and is so far the only physical bi-directional link between the UK and continental Europe. IZT allows natural gas from the Continent to be shipped to the United Kingdom. The Interconnector also serves as the only gas export route from the United Kingdom. Gassco's Zeepipe Terminal (ZPT) connects Norway's Troll and Sleipner offshore gas fields to the Fluxys Belgium grid via the subsea Zeepipe pipeline.

The need for new infrastructure is evaluated every year by Fluxys Belgium in the updated investment programme for the next 10 years. These updates take into account the changes in requirements in terms of natural gas supply, request for new connections and the changing needs of grid users identified through subscription periods and international market consultations among other things. Several simulations based on the winter peak (at -11°Ceq) and border to border transmission requirements are being set up to calculate the effects on the network.

LNG terminal

The Zeebrugge port has an LNG re-gasification terminal (in operation since 1987) with a capacity of 9 bcm per year. The various facilities at Zeebrugge together have an annual throughput capacity of 50 bcm of natural gas, which represents about 10% of gas consumption in Europe. In 2016 a second jetty has been taken into use, this has increased the capacity and flexibility of the LNG terminal.

The LNG terminal in Zeebrugge is operated by Fluxys LNG, which is 100% owned by Fluxys. In 2008, the terminal's throughput capacity was doubled to 9 bcm per year by building a fourth storage tank and additional send-out capacity. Currently the terminal has a send-out capacity of up to 12.000 m³ LNG per hour (or 1,7 mcm/h in gas) and can unload 110 LNG cargos per year (previously only 66 ships per year). The four storage tanks can hold 380.000 cubic metres of LNG, the equivalent of about three shiploads of LNG. Noteworthy is that LNG storage accounts for about 25% of the total national storage capacity. From the storage tanks, the gas can be pumped into the regasification unit and then injected into the grid. Because of the high number of slots that are allocated, the LNG storage has to send out almost immediately after the LNG cargos have been unloaded. Therefore, the LNG storage tanks do not operate as storage as such but more as a very temporary buffer before sending out in the pipelines.

The capacities of the LNG terminal are allocated through an open season procedure and are subscribed through long term contracts (15-20 years) on the primary market. Any remaining unused capacity is allocated, until a new open season procedure is launched, according to the rule 'first come, first served'. Fluxys LNG signed long-term unloading and regasification contracts with three terminal users which started in 2007: Qatar Petroleum/Exxon Mobil, ENI and Engie. In June 2007, Qatar Petroleum/ExxonMobil transferred its contract to EDF Trading for the entire duration. Engie announced that its contract will be transferred to Total in the course of 2018. Tankers from almost every LNG production site can deliver spot LNG.

Table 13: Terminal capacity booked through long term contracts

Shippers	Years	Quantity (bcm)	Slots	Start
EDFT (*)	20	4,5	55	01/04/2008
ENI	20	2,7	33	01/04/2007
Engie (**)	15	1,8	22	01/10/2008
Total	-	+/- 9 BCM	110	-

* Full assignment from QP/ExxonMobil to EDFT since 2008

** Full assignment announced from Engie to Total in 2018

Source: Fluxys

In 2008 Fluxys LNG launched LNG loading services in response to requests from terminal users willing to better exploit commercial opportunities on the LNG market. Loading of LNG ships has been a great success from the start. Especially since 2011 almost half the unloaded quantity of LNG is later reloaded and shipped to markets which offer a higher price.

In 2012, Fluxys LNG launched a subscription window to assess the level of demand for additional loading capacity at the Zeebrugge LNG terminal. In the end of 2012, Fluxys LNG allocated almost 200 additional Berthing Rights spread over a 10 years period which provide the opportunity to load an LNG ship.

In 2015, Fluxys LNG signed a 20-year contract with Yamal Trade to tranship up to 107 cargoes per year as from 2019 in Zeebrugge. Under the transhipment contract, 107 ships of 172.000 cubic meters LNG can berth at one jetty, simultaneously with another LNG ship at the second jetty. This will allow the transfer of LNG from one ship to the other via the LNG pipeline of the Zeebrugge terminal. Also, a fifth storage tank of 180.000 cubic meter of LNG is being constructed, which will allow cargoes to be transhipped from one ship to another even when both ships are not simultaneously at berth in Zeebrugge.

Infrastructure in the L-gas market

The existing infrastructure in the L-gas network consists of:

- a physical entry point at Poppel/Zandvliet L:
  The corresponding point at the Dutch side of the border (exploited by GTS) is Hilvarenbeek and Zandvliet L. The available capacity at Poppel is 65.52 mcm/d.
- an exit point at Blaregnies:
  The corresponding entry point in the French network (exploited by GRTgaz) is Taisnières. The entry capacity at Taisnières is 24.96 mcm/d.
- two quality conversion units for H-gas to L-gas in Lillo and Loenhout[7]:

[7] The Loenhout conversion unit is currently mothballed due to lack of interest from the market, with a maximum of 2 week notice for restarting.

Their maximum total production capacity is up to 9 600 mcm/d of L-gas, depending on outside temperatures and other operational constraints.
Belgium has no storage facilities for L-gas.

Coming from Poppel, the L-gas is transported over a couple of kilometres to a first compression station, Weelde. From there, it is transported to a second compression station (Winksele) halfway between Poppel and Blaregnies. A second entry point is situated at Zandvliet L. L-gas can be imported through this entry point as long as the pressure in the Dutch gas grid is higher than the pressure in the Belgian network. The quantities taken up at Zandvliet L are derived from the quantities available at Poppel. The entries at Poppel and Zandvliet L must be considered as a cluster.

3 Summary of the risk assessment

In the risk evaluation, all risks (with their likelihoods and impacts) identified and analysed during the risk identification & risk analysis, are evaluated.

- Risk is acceptable => OK
- Risk is not acceptable => risk treatment/risk avoidance/risk transfer is needed.

Risk treatment is not part of the risk assessment as such. Risk treatment will be addressed in the preventive action plans and emergency plans.

As for the risk evaluation, it is not feasible to guarantee a total protection of the entire Belgian gas supply. A reasonable risk threshold, that determines a realistic protection level, must be defined.

The level of the threshold will depend on several matters, most of all on:

- the quantities of gas lost
- the probability of the risks considered
- the duration to cover

The guarantee of a secure gas supply in Belgium comes at a cost. The higher the risk that needs to be covered, the higher the price tag.

We can try to classify the risks according to the probability levels and the impact. The classification only gives a broad indication of the risks, as the impact of the same risk may vary according to the timing and the location of the incident. We have tried to take into account the most likely outcome of the incidents based on historical experiences.

Table 10: Severity levels of consequences criteria

Impact	Description
Minor	Short-term disturbance of sector activity. No direct consequences to other sectors.
Low	Temporary disturbance of national gas supply. Consequences are eliminated by efforts of Fluxys Belgium alone. Impact of consequences of disturbance of gas supply on other sectors (heat supply) are negligible.
Noticeable	Gas supply disruption to the area and necessity of back-up systems or alternative measures.
Severe	The impact of the disruption of gas supply to other sectors is severe. (Load shedding)
Very severe	Long-term efforts required for restoration of gas supply. Impact on other sectors and protected customers.

Table 11: Probability levels of incidents

Probability level	Probability	Average frequency of occurrence
1	Very low	Less than once in 20 years
2	Low	Once in 10 years
3	Medium	Once in 3 years
4	High	Once a year
5	Very high	More often than once a year

Table 12: National scenarios overview

Scenario	Impact	Likelihood	Timeframe	Threat/ hazard	Provenance	Duration	Severity
Loss of capacity at the interconnection point Hilvarenbeek	Severe	Low	Short term	Hazard	Internal & external	14 days	341 GWh/d unavailable
LNG disruption	Noticeable	Low	Short term	Hazard	External	30 days	461 GWh/d unavailable
Local power outage, blackout	Severe	Low	Short term	Hazard	External	1 day	n/a
Failure of Loenhout storage facility	Noticeable	Low	Short term	Threat	Internal	2 months	169 GWh/d unavailable
Nuclear phase out and L/H conversion	Noticeable	High	Long term	Threat	Internal & external	/	n/a

	Probability				
Impact	Very low	Low	Medium	High	Very High
Minor	-For Belgium, the scenarios considered within the risk groups fall into these categories				
Low					
Noticeable		-LNG disruption -Failure of Loenhout storage facility		-Nuclear phase out and L/H conversion	
Severe		-Loss of capacity at the interconnection point Hilvarenbeek -Local power outage, blackout			
Very Severe					

The Belgian gas network is highly connected to the neighbouring gas markets. This makes Belgium an important transit country for gas in the Northwest region. About 50% of all gas entering Belgium is for Belgian end-users, the other half is transported to other markets.

The Belgian gas transmission grid is divided into two entry/exit zones: the H-zone (high-calorific gas) and the L-zone (low calorific gas). The two zones are physically separate. Belgium also benefits from enough reverse flow capacity on the following axes: BE-UK, BE-DE, BE-NL.

71% of the Belgian gas demand is H-gas, 29% is L-gas. The L-gas demand is mostly for the distribution network and a smaller part for the industry network. The H-gas is delivered to the distribution network, industry and power-plants. In 2013 52% of the total natural gas consumption in Belgium was on the public distribution network, 24% was used by large industrial players and another 24% by power-plants.

In Belgium the protected customers are defined as all customers connected to the distribution network. One of the reasons is that a selective shut off is not possible on the distribution network. Most consumers on the distribution network are households.

The result from the N-1 analysis (246.7% for the H-gas network) indicates that in case of an interruption of the largest entry point in Belgium this would not give problems for the gas supply. This can be explained by the large connectivity of the Belgian gas infrastructure to other gas markets.

On the L-gas network, the N-1 analysis was below 100%. This result still depends on how the analysis was made (look at the infrastructure as one or divide it in multiple pipelines like the entry pipeline really is constructed from. However historically only one incident happened on this network for which measures are implemented to prevent this in the future. It also needs to be taken into account that because of the decline of the Groningen gas field a conversion of the L-gas network to the H-gas network will be a next step in the future. Because of these prospects there are no more extension plans for the L-gas network for the future.

For the Risk assessment 5 different scenarios were analysed and described. These scenarios were chosen because they could have a potentially high impact in Belgium when they occur. These scenarios were:

- Political unrest in the Middle East: Disruption of LNG from Qatar
- Hurricane in North Sea: Disruption of supplies from Norway by Zeepipe
- Technical Failure of major pipeline: Loss of supply L-gas from the Netherlands
- Nuclear phase-out in Belgium
- Terroristic attack on Loenhout storage facility

The different scenarios which were analysed did not show any large risk for the Belgian gas supply:

- The Zeepipe is part of a large pipeline infrastructure coming from Norway to West-Europe. In case of a disruption of the Zeepipe it is possible to reroute the gas which normally goes by the Zeepipe to Belgium to one of our neighbouring countries. Also due to the high interconnectivity of Belgium gas coming from other entry points can fill in the gap created by a disruption of the Zeepipe.
- When no LNG is delivered to Belgium it will not cause an insurmountable problem for Belgium. Only 8.1% (in 2015) of the gas that physically enters the Belgian network is LNG, this part can be replaced by pipeline gas in case of a disruption and would represent an increase of 8.8% on the capacity utilization of the pipeline network.
- The nuclear phase-out in Belgium is coming and would probably have a manageable impact on the gas sector because the energy production by gas power plants could become an important part of the energy-mix in Belgium, but it has to be taken into account that at the moment the economic conditions, for natural gas, are not favourable.
- A disruption of the Loenhout storage facility will not have a large effect on the Belgian network because of the high interconnectivity of the Belgian network as well the N-1 analysis is above 100%.

These updated risk assessment for Belgium does not reveal particular concerns but this does not mean that possible risks could not occur in the future and so it stays important to investigate and analyse the Belgian gas network on a regular basis for possible new as well as known risk scenarios. This to make sure that possible measures can be investigated and implemented.

4 Infrastructure standard

The N-1 formula describes the ability of the technical capacity of the gas infrastructure to meet total gas demand in the calculated area in the event of disruption of the single largest gas infrastructure during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years. Gas infrastructure includes the gas transmission network including interconnectors as well as production, LNG and storage facilities connected to the calculated area. We do note that the transit flows are not considered for the calculation of the N-1 standard. Therefore, it is useful to calculate the N-1 standard also at regional level.

The technical capacity of all remaining available gas infrastructure in the event of disruption of the single largest gas infrastructure should be at least equal to the sum of the total daily gas demand of the calculated area during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years. The results of the N-1 calculation, should at least equal 100 %.

The N-1 formula is defined in Annex II of the Regulation as follows:

$$N-1[\%]=\frac{EP_m+P_m+S_m+LNG_m-I_m}{D_{max}}\cdot 100, N-1\geq 100\%$$

Where

EP_m: technical capacity of entry points, other than production

P_m: maximal technical production capacity

S_m: maximal technical storage deliverability

LNG_m: maximal technical LNG facility capacity

I_m: technical capacity of the single largest gas infrastructure

D_{max}: total daily gas demand

D_{eff}: demand-side measures

4.1 N-1 calculation: national level

The calculation of the N-1 formula, presented in this document, is based on the Fluxys Belgium indicative investment plan 2018-2027. Investment planning for the 10 years to come is updated by Fluxys Belgium on a yearly basis, taking the evolutions on the market, the planning of adjacent TSOs and specific grid calculations into account.

4.1.1 Supply side

At the supply side the Technical Capacity of the Entry points, Storage, LNG and Production facilities is presented hereunder.

Table 13: Capacities on the entry points (2018)

H	Connection point	Type	Entry capacity (GWh/d)
	IZT	EP	732.24
	LNG terminal 1	LNG	230.52
	LNG terminal 2	LNG	230.52
	ZPT	EP	515.28
	Virtualys	EP	52.21
	Dunkerque	EP	218.99
	Zandvliet H	EP	48.82
	Zelzate 1	EP	393.24
	Eynatten 1	EP	203.40
	Eynatten 2	EP	352.56
	's Gravenvoeren + Obbicht	EP	352.56
	Loenhout Storage	S	169.50
L	Poppel/Zandvliet L	EP	642.10

Notes:

- Virtualys is the new virtual interconnection point (VIP) comprised of the two physical interconnection points in Blaregnies (H-gas) and Alveringem. Some of the available capacity in Alveringem is used for transborder access to the Dunkerque LNG terminal.
- Quality conversion units are considered as production for the N-1 calculations, with a negative value on the H-gas side. The mothballed unit in Loenhout is not taken into account.
- Fluxys Belgium's network still has an interconnection point at Pétange & Bras (connection point Belgium-Luxemburg) but it not commercialized anymore and has no entry capacity to Belgium.
- No fundamental modification of the infrastructure is foreseen for the coming years

For the High calorific calculated area, this results in the following parameters (in GWh/d):

EP_H = IZT + ZPT + Virtualys + Dunkerque + Zandvliet H + Zelzate 1 + Eynatten 1 + Eynatten 2 + 's Gravenvoeren

EP_H = 732.24 + 515.28 + 52.21 + 218.99 + 48.82 + 393.24 + 203.40 + 352.56 + 352.56
= 2869.30

P_H = H gas used to produce L gas
P_H = -65.20

S_H = Loenhout Storage
S_H = 169.50

LNG_H = LNG Terminal1 + LNG Terminal 2
LNG_H = 461.04

I_H = IZT
I_H = 732.24

For the Low calorific calculated area, this results in the following parameters (in GWh/d):

EP_L = Hilvarenbeek/Zandvliet L
EP_L = 642.10

P_L = Transfo H ->L (L gas production based on conversion of H gas)
P_L = 65.20

S_L = none
S_L = 0

LNG_L = none
LNG_L = 0

I_L = Hilvarenbeek/Zandvliet L
I_L = 642.10

4.1.2 Demand side

The demand on a peak day is characterized by the simultaneous occurrence of a peak consumption by the 3 sectors: public distribution, industry, and electricity generation.

Public distribution

The evolution of the gas needs of the public distribution at -11°Ceq (27,5 DD) is estimated based on a linear regression using the data (Consumption and degree-days) from the previous winter[8]. According to the parameters obtained with this regression, we can compute:

- the consumption level at -11°C with a 50% risk of exceeding it (50/50), notably the average value;
- the consumption level at -11°C with a 1% risk of exceeding it (99/1);
- the average growth rate in an analysed period;
- an estimation of the peak consumption in the coming winters.

Table 14 shows the consumption levels for both H- and L-gas calculated based on the data from the winter 2017-2018.

Gas demand of the industrial clients and the power pants connected directly to the Fluxys grid.

For each industrial client, electrical power plant or cogeneration unit, the transmission system operator (TSO) determines a default value of the hourly consumption that represents the real gas needs. The calculation of the default value is based on a statistical analysis of the hourly consumptions

[8] See Annex 2b: Winter analysis, peak day consumption, p. 93

of the three previous years. Non-representative data such as weekends, official holidays, abnormal peaks (test phase, incident, etc.) or abnormally low consumption can be excluded.

The statistical analyses identify also, as a sort of warning mechanism, each drastic change in the consumption profile of the consumer over a certain period. Based on those alerts, the TSO, in cooperation with the customer, can analyse the underlying reasons for such alerts and determine whether future investments in the network will be necessary.

This evaluation process is carried out on a regular basis starting from the default values set out on their previous analyses, meaning:

- every year, if the default value is larger or equal to 20 k*m³(n)/h;
- every two years for each default value smaller than 20 k*m³(n)/h.

For the high calorific calculated area, the quality conversion units' demand is taken into account at the production side, with a negative value.

Table 14: Peak day consumption by sector and gas quality

	2018			2022		
1-in-20 consumption (GWh/d)	L	H	Total	L	H	Total
Public distribution	455	486	941	351	636	988
Industry	22	161	183	18	165	182
Electricity production	0	343	343	0	342	342
Total	**477**	**990**	**1466**	**369**	**1144**	**1513**

4.1.3 Results

This calculation has been made for the years 2018 and 2022 with the consumption and capacity values presented in table 16 and table 17. Given that no fundamental modification of the infrastructure are foreseen in the coming years, the same capacity values have been considered for both 2018 and 2022.

Table 15: N-1 calculation based on border with highest max. capacity: IZT

	N-1 (%)	
	2018	**2022**
H-gas	273%	236%
L-gas	14%	18%

The N-1 calculation shows that, in the H-gas calculated area, the gas demand is satisfied during a day of exceptionally high gas demand in the event of a disruption of the single largest gas infrastructure.

In 2022, we also see the shift of the consumption from L-gas to H-gas following the conversion of the market. This change in the consumption and the fact that the capacity at entry points remain the same explain how the N-1 results decrease over time for H-gas while they increase for L-gas. Since the N-1 formula shows that gas demand for the H-gas is more than satisfied in the event of a disruption of the single largest gas infrastructure, some additional transit flow to exit interconnection points would be possible.

For the L-gas calculated area, this first approach shows that a complete failure of the entry point Hilvarenbeek would have major repercussions on the security of supply for L-gas customers in Belgium. However, a further analysis shows that the contractual interconnection point of Hilvarenbeek consists of the two physical points of Zandvliet L and Poppel, with the latter being supplied by two distinct pipelines. The failure of one of those pipelines is not likely to prevent the operation of the second one. Subsequently, when considering the contractual point of Hilvarenbeek as two separate physical interconnection points, the technical capacity of the single largest infrastructure on the L-gas transport network in Belgium can be divided by 2 (321.05 GWh/d instead of 642.1 GWh/d). The alternative calculation of the shut-down of one of the pipelines to Poppel, is given in Table 16. A regional approach has also been taken in the L-gas risk group.

Table 16: Alternative N-1 calculation

	N-1 (%)	
	2017	**2021**
Hilvarenbeek 100% disruption	14%	18%
Hilvarenbeek 50% disruption (1 pipeline)	81%	105%

4.2 N-1 calculation: regional level

4.2.1 L-gas risk group

The calculation set out below shows that the N-1 score for the entire L-gas region is 114% for 2018, which lies above 100%.

The following input parameters are used for the N-1 calculation:

GWh/d	Historical Data			Projected Data			
	2015	2016	2017	2018	2019	2020	2021
Technical capacity of entry points (EPm)*	0	0	0	0	0	0	0
Maximal technical production capacity (Pm)	5,241	5,146	5,016	4,425	4,350	4,186	4,024
Maximal technical storage deliverability (Sm)	2,197	2,176	2,289	2,289	2,289	2,289	2,289
Maximal technical LNG facility capacity (LNGm)	0	0	0	0	0	0	0
Technical capacity largest gas infrastructure (Im)	759	759	742	742	742	742	742
1 in 20 gas demand (Dmax)	5,325	5,270	5,278	5,264	5,221	5,181	5,099
Market-based demand side response (Deff)	2	2	2	2	2	2	2

There are no L-gas entry points in the L-gas area as all the L-gas comes from locations that are qualified as production locations. The capacity of the blending stations is together with the domestic production of L-gas included in the production capacity. UGS Norg (in the Netherlands) is currently the largest single infrastructure in the L-gas region (the "-1").

In the Dutch system the average daily demand at effective temperature of -17^{0}C, which corresponds with a 1 in 50 peak demand, is used in the calculations (in accordance with the Dutch Gas Act) and therefore is the basis for Dutch gas demand in the scenarios. Gas demand of protected customers is included in the numbers for peak gas demand. For Germany, Belgium and France the average daily demand for 1 in 20 is used in the scenarios. For Belgium this corresponds to a temperature of -11^{0}C

Example N-1 calculation for the entire L-gas risk group for 2018:

$$114\% = \frac{0 + 4{,}425 + 2{,}289 + 0 - 742}{5{,}264 - 2}$$

The table below shows the outcome of the N-1 formula for the period 2015-2021. In all years, the N-1 criterion is met. However the percentage is decreasing slightly each year, due to declining production from the Groningen field.

	Historical Data			Projected Data			
	2015	2016	2017	2018	2019	2020	2021
Reference scenario (Norg unavailable)	125%	125%	124%	114%	113%	111%	109%

4.2.2 Norway risk group

For EP_m, interconnection between members states within the risk group and interconnection with Switzerland have not been considered.

Indeed, those calculations do not take into account the possible limitation of flow within the risk group due to limited available capacity of TENP[9] pipeline and related southbound flow to Italy trough Switzerland. Additional calculations have also been conducted considering only those members states directly connected.

For the calculation it has been considered the disruption of the largest pieces of infrastructure which supply Norwegian gas:

- Disruption of Emden station (from Norway to the continent);
- Disruption of Langeled pipeline (from Norway to the United Kingdom).

				Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
Technical capacity of entry points (EPm)*	**11 696**	**11 637**	**11 372**	**11 445**	**11 445**	**11 445**
Maximal technical production capacity (Pm)	**4 845**	**4 153**	**4 168**	**4 198**	**3 942**	**3 593**
Maximal technical storage deliverability (Sm)	**16 096**	**16 096**	**15 848**	**16 046**	**16 090**	**16 108**
Maximal technical LNG facility capacity (LNGm)	**5 978**	**6 497**	**6 508**	**6 447**	**6 447**	**6 447**
1 in 20 gas demand (Dmax)	**26 709**	**26 637**	**27 127**	**27 198**	**27 208**	**27 362**
Market-based demand side response (Deff)	**5**	**5**	**5**	**35**	**35**	**35**

* only entry point from outside the risk group

Technical capacity largest gas infrastructures (Im)			2015	2016	2017	2018	2019	2020
DE/NL	Norway	Emden EPT	989	989	989	989	989	989
UK	Norway	Langeled	770	770	770	836	836	836

N-1 for region		Historical Data		Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
Emden EPT	141%	140%	136%	137%	136%	134%
Langeled	142%	141%	137%	137%	136%	135%

N-1 results are well above 100% meaning in case of disruption of a major infrastructure supplying Norwegian gas the other entry capacities shall be sufficient to cover peak demand as it may occur 1 in 20 years.

Regarding the issue of transit trough Switzerland, both N-1 calculations for Italy on one side and the others member states in the risk group on the other side are above 100%.

[9] Fluxys SA, controller of TENP pipeline, disposed the unavailability, for surveys and inspections, of 60% of the same transport infra-structure capacity at least until March 2019.

Projected data are included, in order to some indication regarding the evolution of N-1 in the future. In order to reduce the uncertainties projected data are limited to the period 2018-2020.

Some infrastructures development not included in the data are in progress such as Trans Adriatic Pipeline or Baltic Pipeline and may be commissioned in the next years. Those development may lead to an increase N-1 for Norway risk group.

4.2.3 UK risk group

The North-West European gas system, comprising the six countries of the United Kingdom Risk Group, namely Belgium, Germany, Ireland, Luxembourg, the Netherlands and the United Kingdom, has a strong gas security of supply position characterised by extensive and resilient infrastructure, and significant levels of interconnection coupled with indigenous gas production. This strength of infrastructure is enhanced by a mature and liquid gas market which has demonstrated an ability to deliver even during the most extreme combination of infrastructure failure and increased demand.

The N-1 standard has been calculated for the entire United Kingdom Risk Group, using the formula prescribed in Annex II of the Regulation:

$$N - 1\,[\%] = \frac{EP_m + P_m + S_m + LNG_m - I_m}{D_{max} - D_{eff}} \times 100,\ N - 1 \geq 100\ \%$$

Where: N-1 Formula

- EP_m - technical capacity of entry points, other than production
- P_m - maximal technical production capacity
- S_m - maximal technical storage deliverability
- LNG_m - maximal technical LNG facility capacity
- I_m - technical capacity of the single largest gas infrastructure
- D_{max} - total daily gas demand
- D_{eff} - demand-side measures

For EP_m, interconnection between Member States within the United Kingdom Risk Group has not been assessed. The annex to this report outlines the parameters used in the calculation of the N-1 standard. For the purposes of calculation, disruption of the largest infrastructure of the group has been assessed:

- Disruption of Felindre pipeline connecting the South Hook and Dragon LNG terminals to the UK National Transmission System with a capacity of 892GWh/d;
- Disruption of Mallnow interconnection point between Germany and Poland with a capacity of 932GWh/d;
- Disruption of Emden EPT entry point from Norway to the continent with a capacity of 989 GWh/d.

Technical capacity largest gas infrastructure (I_m)			Historical Data			Projected Data		
			2015	2016	2017	2018	2019	2020
			GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
UK	LNG Terminals	Felindre	946	946	957	892	892	892
DE	Poland IP	Mallnow	931	932	932	932	932	932
DE/NL	Norway Pipeline	Emden EPT	989	989	989	989	989	989

N-1 for region	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
Felindre	149%	148%	141%	144%	143%	142%
Emden	149%	147%	141%	143%	142%	141%
Mallnow	149%	148%	141%	143%	142%	141%

N-2	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
Felindre + Emden	143%	141%	135%	137%	136%	135%
Felindre + Mallnow	143%	142%	135%	138%	137%	136%
Emden + Mallnow	143%	141%	135%	137%	136%	135%

N-3	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
Felindre + Emden + Mallnow	137%	135%	129%	132%	130%	130%

As demonstrated above, the region's N-1 result is well in excess of 100%. The region is capable of achieving up to an N-3 result under the formula. For the UK Risk Group region to fail the N-1 test, around a third of existing gas infrastructure capacity would have to be lost.

Given its role in supporting security of supply across the Northwest Europe Gas System, the bi-directional flow capacity of interconnectors is shown in the table below:

[See next page for table]

Interconnection points with bi-directional capacity		**Capacity (GWh/d)**	**Description of arrangements**
Eynatten	BE > DE	542	
Eynatten	DE > BE	556	
IUK	BE > UK	814	
IUK	UK > BE	605	
Cluster Emden-Oude Statenzijl H	NL > DE	504	
Cluster Emden-Oude Statenzijl H	DE > NL	1847	
Zelzate	NL > BE	393	
Zelzate	BE > NL	393	
Oude Statenzijl H Gasunie	NL > DE	64	
Oude Statenzijl H Gasunie	DE > NL	36	
Oude Statenzijl H OGE	NL > DE	71	
Oude Statenzijl H OGE	DE > NL	162	
Interconnection points with reverse flow capacity (e.g. interruptible capacity) and bidirectional flow exemptions			**Description of arrangements**
Hilvarenbeek / Poppel	NL > BE	642	
Hilvarenbeek / Poppel	BE > NL		Backhaul Capacity and Backhaul Level 1
Oude Statenzijl L (GTG-Nord, GUD)	NL > DE	252	
Oude Statenzijl L (GTG-Nord, GUD)	DE > NL		Backhaul Capacity and Backhaul Level 1
Zevenaar	NL > DE	456	
Zevenaar	DE > NL		Backhaul Capacity and Backhaul Level 1
Winterswijk	NL > DE	179	
Winterswijk	DE > NL		Backhaul Capacity and Backhaul Level 1
Tegelen	NL > DE	5	
Tegelen	DE > NL		Backhaul Capacity and Backhaul Level 1
Cluster Limburg (‘s Gravenvoeren, Bocholtz Tenp, Bocholtz Vetschau)	NL > DE	858	
Cluster Limburg (‘s Gravenvoeren, Bocholtz Tenp, Bocholtz Vetschau)	DE > NL		Backhaul Capacity and Backhaul Level 1
Zandvliet H (Fluxys)	NL > BE	47	
Zandvliet H (Fluxys)	BE > NL		Backhaul Capacity and Backhaul Level 1

Vlieghuis-Kalle	NL > DE	72	
Vlieghuis-Kalle	DE > NL		Backhaul Capacity and Backhaul Level 1
Moffat IC1/IC2	UK > IE	330	
Moffat IC1/IC2	IE > IE		Virtual reverse flow. Physical Flow Exemption
BBL	NL > UK	494	
BBL	UK > NL		Virtual reverse flow. Physical Flow Exemption
Remich	DE > LU	39	
Remich	LU > DE		Exemption
Bras/Pétange	BE > LU	48.8	
Bras/Pétange	LU > BE		Exemption
South North Pipeline	IE > UK	66	
South North Pipeline	UK > IE		Exemption

The methodology for the N-1 calculation concerning the disruption of Felindre pipeline may be found in the tables of Annex 3

4.2.4 Baltic sea risk group

For the calculation of the n-1 standard it is assumed that the entire region is seen as one “calculated area”. That means that only the entry points connecting the region with countries outside the region are taken into account. Cross-border capacity points inside the region are not included.

The single largest infrastructure of this region is the Slovakian entry point Velke Kapusany. The analysis conducted in the common risk assessment by the Baltic Sea risk group was somewhat different, because it focused on the entry point Greifswald which is slightly smaller than Velke Kapusany.

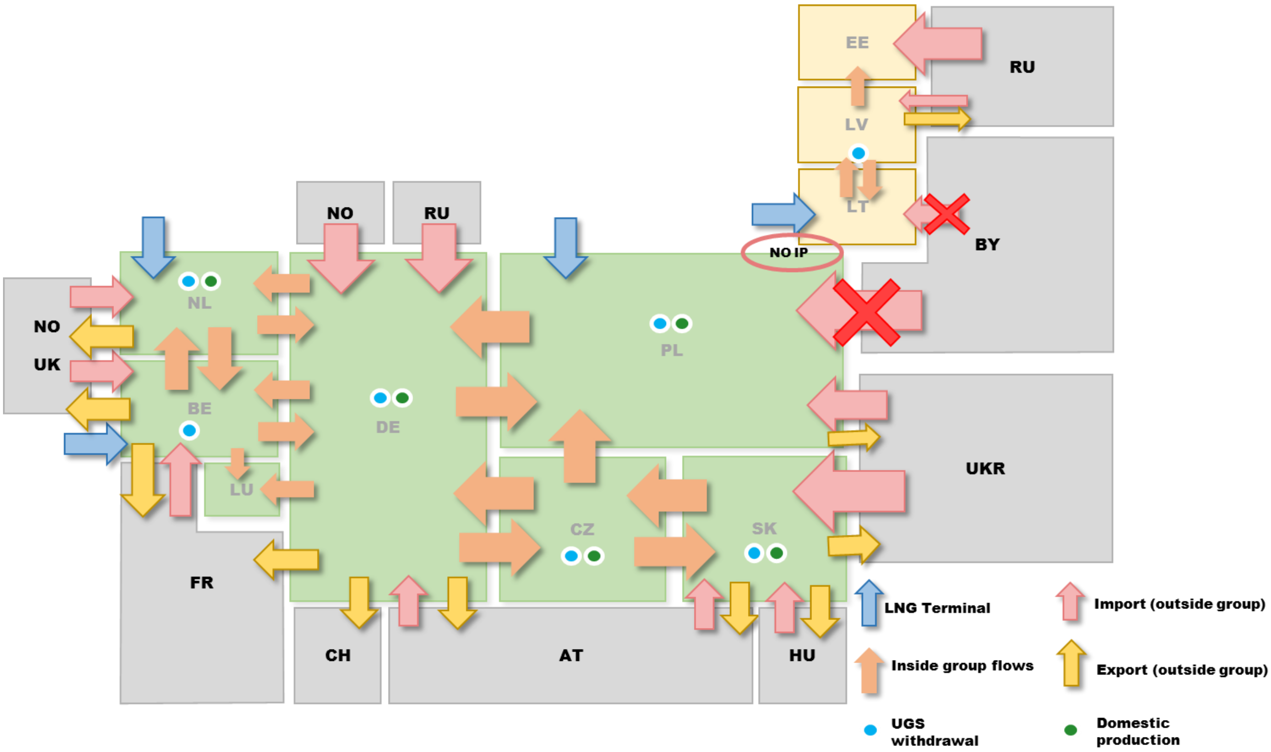
Table 17: Entries for the N - 1 formula by each member state

Entry capacity	EP_m	[GWh/d]	11.372,9	
Production capacity	P_m	[GWh/d]	2.478,2	
Storage capacity	S_m	[GWh/d]	15.245,4	
LNG capacity	LNG_m	[GWh/d]	2.190,6	
Largest infrastructure	I_m	[GWh/d]	2.028,0	Velke Kapusany (SK)
Peak demand	D_{max}	[GWh/d]	16.187,8	
Demand side managment	D_{eff}	[GWh/d]	0,5	Denmark

$$N-1\,[\%] = \frac{11.372{,}9+2.478{,}2+15.245{,}4+2.190{,}6-2.028{,}0}{16.187{,}8-0{,}5} * 100 = 203\%$$

4.2.5 Belarus risk group

Figure 22: N-1 approach – disruption of supply routes through Belarus



Creation of two separate subregions: East-Baltic and Middle-west countries, for the working purpose of the report, follows from the fact that the Baltic States remain isolated from the wider EU gas system. This means that N-1 formula should be applied separately for each subregion. Two levels of the maximum working volume is taken into consideration – 100% and 30 %.

Table 19: Demand-side figures, Dmax/Deff

	DMAX	DEFF
	[GWh/d]	[GWh/d]
East-Baltic	**333,7**	**0,0**
Midlle - west	**11 872**	**0,0**

Table 18: Supply-side figures, Em

	EPm [GWh/d]
EAST-BALTIC SUM	**454,0**
MIDDLE - WEST SUM	**10 104,42**

Table 19: Supply-side figures, LNGm/Pm/Sm-100%/Sm-30%

	LNG_M	P_M	S_M/LEVEL OF STORAGES AT 30 %	S_M/LEVEL OF STORAGES AT 100 %
	[GWh/d]	***[GWh/d]***	***[GWh/d]***	***[GWh/d]***
East-Baltic	***122,4***	***0,0***	***241,6***	***315,6***
Midlle - west	***1 018,0***	***2 513,8***	***8 405,3***	***12 916,3***

Since the Belarus Risk Group was established to analyse risks associated with gas supply disruptions via Belarus, the single largest infrastructure to be taken into account for regional N-1 formula, with the highest capacity to supply the region through Belarus, is an entry point to Poland – Kondratki, which is where the Polish part of Transit Gas Pipeline Yamal – Europe starts. The Transit Gas Pipeline System in Poland represents a part of the gas pipeline system measuring an estimated 4 000 km, running from Russia through Belarus and Poland to Western Europe. Since the Baltic States remain isolated from the EU gas system (until Poland – Lithuania Interconnection is put into operation), N-1 for the East-Baltic sub region is calculated separately, taking into account UGS Inčukalns/Kotlovka an entry point to the Lithuania as the single largest infrastructure to supply the East-Baltic sub region.

Table 20: Single largest gas infrastructure of common interest for the risk group

	I_M	
	[GWh/d]	**-**
EAST - BALTIC	**315,6**	
LATVIA	315,6	*UGS Inčukalns*
MIDDLE - WEST	**1 024,3**	
POLAND	1 024,3	Entry point to Yamal gas pipeline - Kon-dratki

Table 21: N – 1 formula results

	SM-100%	SM-30%
	D_{MAX}	D_{MAX}
EAST - BALTIC SUB REGION: ESTONIA, LATVIA, LITHUANIA	173%	151%
MIDDLE - WEST COUNTRIES SUB REGION: BELGIUM, CZECH REPUBLIC, GERMANY, LUXEMBOURG, NETHERLANDS, POLAND, SLOVAKIA	215%	177%

The Belarus Risk Group countries do not specify the market-based demand-side measures (D_{eff}). It is impossible to determine the part of D_{max} that in the case of a disruption of gas supply can be sufficiently and timely covered with market-based demand-side measures in accordance with point (c) of

Article 9(1) and Article 5(2). There is no such market-based demand-side relevant measures. Therefore no N-1 results with D_{eff} were obtained.

4.3 Bi-directionality

As required under Article 5(4) of the regulation, the following tables indicate bi-directional capacities or exemptions for all the interconnection point in Belgium.

Table 22: Interconnection points not subject to the obligation

IP	Connection with	Description of the arrangements
LNG Terminal	n.a.	The interconnection point LNG Terminal of Zeebrugge is a connection to an LNG facility, which falls under the exceptions defined in Article 5(4) (a).
ZPT	Norway	The cross-border interconnection Zeepipe Terminal with Norway is a connection to a production facility, which falls under the exceptions defined in Article 5(4) (a).
Hilvarenbeek	Netherlands	The interconnection point Hilvarenbeek is a connection to a production facility, which falls under the exceptions defined in Article 5(4) (a).

Table 23: Interconnection points equipped with permanent bidirectional capacity

IP	Connection with	Description of the arrangements
IZT	UK	Bi-directional firm capacity is offered at the interconnection point. Currently, the interconnection point IZT is not fully booked on the Belgian side, which indicates no request for further enhancements of either entry or exit capacity.
Zelzate 1	Netherlands	Bi-directional firm capacity is offered at this interconnection point, but is not fully booked on the Belgian side, which indicates no request for further enhancements of either entry or exit capacity.
Eynatten 1	Germany	Bi-directional firm capacity is offered at this interconnection point, but is not fully booked on the Belgian side, which indicates no request for further enhancements of either entry or exit capacity.
Eynatten 2	Germany	Bi-directional firm capacity is offered at this interconnection point, but is not fully booked on the Belgian side, which indicates no request for further enhancements of either entry or exit capacity.
Blaregnies H	France	Bi-directional firm capacity is offered at this interconnection point. However, physical reverse flow will only be accepted for non-odorised gas, except in case of emergency. The market consultation with a view to developing firm transmission capacity from France to Belgium indicated that the scenario for creating a new capacity at the interconnection point Blaregnies H through

		the construction of a deodorization facility was not requested by the market

Table 24: Exempted interconnection points

IP	Connection with	Description of the arrangements
Zandvliet H	Netherlands	Firm entry capacity is offered on this interconnection point to serve a local area in Belgium. A bilateral meeting between Fluxys Belgium and GTS led to the conclusion that firm reverse capacity is not requested by and is not useful to the Dutch market because there is no source of gas available for firm reverse capacity to be useful. (Backhaul Capacity and Backhaul Level 1)
's Gravenvoeren	Netherlands	Firm entry capacity is offered at this interconnection point. Results of recent market consultation by GTS have shown no need for additional reverse firm capacity. In emergency however, physical reverse flow is possible.
Zelzate 2	Netherlands	Firm exit capacity is offered on this interconnection point to serve a local area in the Netherlands. Firm entry capacity is not requested by and not useful for the Belgian market because there is no source of gas directly available on the upstream network. Fluxys Belgium never received a request for entry capacity from Zelzate 2. In case of emergency the interconnection points Zelzate 1 and 's Gravenvoeren are the main sources for physical flow towards Belgium.
Bras/Pétange	Luxembourg	Not used commercially: single market, balancing zone and entry/exit model with Luxembourg
Alveringem[10]	France	Firm entry capacity is offered at this interconnection point since this connection is not odorized.
Blaregnies L	France	Backhaul capacity is already offered to the market. In case of emergency, physical reverse flow is possible although this gas is odorized and, as such, cannot be offered to the Belgian market.

[10] Alveringem and Blaregnies (H-gas) are now aggregated as a bi-directional virtual IP (Virtualys) plus a cross-border access to the Dunkirk LNG terminal in France

5 Compliance with the supply standard

5.1 Definition of protected customers

In the regulation EU 2017/1938 regarding measures to safeguard the security of gas supply ("the Regulation"), the eligibility of clients to be considered as protected customers is defined depending on their profile as end users (households, SMEs, social services, district heating, etc.) and also depending on their level of consumption (threshold of 20% of the annual gas consumption for SMEs and essential social services). In order to rigorously follow this definition, it would be necessary to have precise data about the consumption of each category of end users as defined in the Regulation. Such data is not readily available as such for the Belgian distribution network because the clients are categorized according to their consumption as follows:

a. **Purely residential customers** (S41). This category can be fully included in the protected customers following the Regulation.
b. **Commercial customers consuming less than 150.000 KWh/year** (S31). This category typically contains district heating, small enterprises and social services, but it cannot be excluded that it also contains larger enterprises (not eligible as protected customers) and combined residential and business users (such as home offices) that might be assimilated to the residential customers and not considered when calculating the threshold of 20%
c. **Commercial customers consuming more than 150.000 KWh/year** (S32). This category typically contains district heating, medium sized enterprises and social services with a residential-like behaviour such as hospitals and nursing homes, but also larger industrial clients that are not tele-measured.
d. **Tele-measured customers** (S30) whose consumption is monitored hourly. These customers can be large hospitals, administration buildings, large supermarkets, etc. some of which are eligible as protected customers but should be considered when calculating the threshold of 20%.

These categories rarely correspond to the ones defined in the Regulation but are rather a mix of several types of end-users as defined in the Regulation.

Furthermore, there is little or no technical possibility to selectively reduce the consumption of a specific category of end-users connected to the distribution network or to stop their gas supply altogether, although this specific category is defined following the type of users or their consumption.

Given the fact that eligible protected customers are present in each of the above categories, the pragmatic solution that has been chosen is to consider every customer connected to the distribution network in Belgium as a protected customer. This is a prudent measure to avoid any error in the estimation of the actual volumes of gas needed by the eligible customers as defined in the Regulation and to ensure their supply regardless of the consumption category they are in.

As part of the Preventive Action Plan and Emergency Plan, measures are considered in order to limit the consumption of customers non-eligible under the Regulation in a crisis situation. However, given the complex situation, both technically and institutionally (public distribution is a Regional competence in Belgium), the efficiency and impact of such measures are difficult to identify accurately.

Consumption of the non-residential protected customers

While taking into account the previous statement, an estimation of the consumption of the categories of customers defined in the Regulation can however be useful for two purposes: evaluate the share of consumption by SMEs and essential social services to verify that it represents less than 20% of the annual consumption in Belgium, and evaluate the share of consumption by non-eligible customers and the impact they have when considered as protected customers.

The first table below shows the breakdown of the total consumption on the distribution network, with both H-gas and L-gas. When taken separately, the relative share of each category is similar for both types of gas, so it is not necessary to make the two calculations individually.

Table 25: Consumption by client categories on the distribution network

Public distribution		Total	S41	S31	S32	S30
Consumption	TWh	**92.97**	42.54	10.35	18.03	22.06
	%	***100%***	*45.8%*	*11.1%*	*19.4%*	*23.7%*

Most of the eligible customers are in the S41, S31 and S32 categories, but the latter two also contain non-eligible customers. After consulting the sector, we make the assumption that the consumption of those non-eligible customers represents roughly 5% of the total consumption on the distribution, or 4.65 TWH.

Table 26: Eligibility of client categories on the distribution network

Public distribution		Total	S41	S31 + S32	S31 + S32	S30
Eligibility			Protected	Eligible	Non-eligible	Partially eligible
Consumption	TWh	**92.97**	42.54	23.73	4.65	22.06
	%	***100%***	*45.8%*	*25.5%*	*5.0%*	*23.7%*

This data can be more easily linked to the customer categories as defined in the Regulation, but there remain two unknowns: the share of residential customers (District heating or other) in the “eligible S31 + S32” customers, and the share of essential social services in the “S30 customers”.

Table 27: Consumption by client categories on the transport network

<table>
<tr><td>Total transmission network</td><td>Electricity generation</td><td>Industrial customers</td><td colspan="4">Public distribution</td></tr>
<tr><td rowspan="3">179.43 TWh
100%</td><td rowspan="3">44.72 TWh
24.9%</td><td rowspan="3">41.73 TWh
23.3%</td><td colspan="4">92.98 TWh
51.8%</td></tr>
<tr><td>S41</td><td>S31 + S32 (Eligible)</td><td>S31 + S32 (Non-eligible)</td><td>S30</td></tr>
<tr><td>42.54 TWh
23.7%</td><td>23.73 TWh
13.2%</td><td>4.65 TWh
2.6%</td><td>22.06 TWh
12.3%</td></tr>
</table>

In 2016, the total Belgian gas consumption was 179.4 TWh, so the combined consumption of protected SMEs and essential social services must be under 35.9 TWh to comply with the Regulation. The majority of these customers are in the “eligible S31 + S32” category, and represent at most 23.73 TWh, given that this category also contains an unknown number of district heating installations. The remaining margin (12,16 TWh) represents more than half of the consumption by S30 customers (tele-measured). This leaves ample room for the SMEs and essential social services in this category to be included in the protected customers without going beyond the 20% threshold.

Table 28: Consumption by eligible consumers

	Total BE	20% threshold	S31 + S32 (Eligible)	Remaining margin
TWh	**179.43**	35.89	23.73	12.16
%	***100%***	*20%*	*13.2%*	*6.8%*

There remains the question of the share of consumption by non-eligible customers on the distribution network. These customers are present in the S31, S32 and S30 categories. We have already estimated the share in the first two categories to 5% of the public distribution consumption (4.65 TWh). At least half of the S30 customers also fall into this category. Depending on the actual share of eligible customer in S30, the total consumption of non-eligible customers represents between 8.7% and 14.9% of the total annual consumption. The actual value for this potential demand reduction in case of a crisis situation should however not be overestimated because shortages are more likely to be linked with a cold spell and a high demand from residential customers and essential social services such as hospitals and nursing homes. The relative impact of measures to reduce the demand from non-eligible customers on the distribution network will therefore be limited in a high demand scenario. In the case of a shortage of gas where the supply of the distribution network would be at risk, the focus would be to introduce a ban on consumption for the non-eligible customers identified above.

Table 29: Summary of the yearly consumption

<table>
<tr><th>Total transmission network</th><th>Electricity generation</th><th>Industrial customers</th><th colspan="2">Public distribution</th></tr>
<tr><td rowspan="3">179.43 TWh
100%</td><td rowspan="3">44.72 TWh
24.9%</td><td rowspan="3">41.73 TWh
23.3%</td><td colspan="2">92.98 TWh
51.8%</td></tr>
<tr><td>Eligible</td><td>Non-eligible</td></tr>
<tr><td>71.77 – 77.30 TWh
36.9 – 43.1%</td><td>21.21 – 26.74 TWh
8.7 – 14.9%</td></tr>
</table>

Given the technical difficulties to differentiate between the consumer categories defined in the Regulation and the relatively low estimated consumption of the non-eligible consumers connected to the distribution networks, it has been decided to consider all the clients connected to the public distribution as protected customers.

5.2 Volumes and capacities associated with the supply standards

According to article 8 of the regulation, the gas undertakings have to be able to supply the protected customers of the Member State in the following cases:

1. Extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years
2. Any period of at least 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years
3. For a period of at least 30 days in case of the disruption of the single largest gas infrastructure under average winter conditions

The gas undertakings that will need to live up to those standards are all gas undertakings that deliver gas to the distribution network.

In our risk analysis, we already tried to convert the above standards in more concrete criteria that can be applied and checked on a transparent basis. First of all we had to check what temperature profile corresponds to the 7 day peak period occurring with a statistical probability of once in 20 years. For this period, we had identified the number of degree days and the equivalent temperature, based on historical data of the last 100 years. This way we can establish a profile that can be used to simulate gas demand.

For the 7 day peak period statistically occurring once in 20 years, we obtained the following result:

Table 30: Degree days and equivalent temperatures for the 7 day peak period

begin	end	Degree Day/Equivalent temperatures							Sum/mean
28/12/1996	3/01/1997	23,1	23,3	20,1	23,1	26,9	27,4	25,3	169,2
		-6,6	-6,8	-3,6	-6,6	-10,4	-10,9	-8,8	-7,7
1/01/1979	7/01/1979	25,6	24,6	23,7	22,9	24,6	25,7	22,9	170,0
		-9,1	-8,1	-7,2	-6,4	-8,1	-9,2	-6,4	-7,8
17/01/1963	23/01/1963	23,6	26,9	26,2	22,8	22,9	23,9	22,3	168,6
		-7,1	-10,4	-9,7	-6,3	-6,4	-7,4	-5,8	-7,6
17/12/1946	23/12/1946	23,4	23,5	24	25,8	25,6	23,6	23,4	169,3
		-6,9	-7	-7,5	-9,3	-9,1	-7,1	-6,9	-7,7
19/01/1940	25/01/1940	24,5	25,6	23,5	26,5	24,6	23,6	22,2	170,5
		-8	-9,1	-7	-10	-8,1	-7,1	-5,7	-7,9
	Average	24,0	24,8	23,5	24,2	24,9	24,8	23,2	169,5
		-7,5	-8,3	-7,0	-7,7	-8,4	-8,3	-6,7	-7,7

Source: FPS Economy

For the 30 day period of peak demand, we obtained the following results for the degree days based on the historic data of the last 100 years:

Table 31: Average and peak degree days (DD) per peak period

Consumption due to	Slope		1 day	7 days	1 month 30 days	5 month 150 days	6 month 180 days	1 year 365 days
Central Heating (CH)	Linear Varying in function of DD	Average 100 years	21,2	133,0	466	1.734	1.913	2.325
		Peak 5% 100 years	26,8	169,6	594	2.037	2.325	2.650
Others than CH	Constant		3,3	22,8	98	488	585	1.186
	Total	Average 100 years	24,5	155,8	564	2.222	2.498	3.511
		Peak 5% 100 years	30,1	192,4	691	2.525	2.910	3.836

Source: FPS Economy

The volumes (energy in kWh) and the transport capacities (in $m^3(n)/h$) corresponding to the supply standards are given in the following Table 32 and Table 33. The fact that in Belgium, two types of gas are distributed, leads to two values, one for the protected customers in the low calorific gas zone and one for the protected customers in the high calorific gas zone. These values were based on the gas year 2011-2012 and can be re-actualized with the last data available (transfer of customers from the low calorific gas market to the high calorific gas market, growth on the distribution network…). Due to the cold spell in gas year 2011-2012 these values however are quite representative for a winter colder than average.

For H and L gas we will apply respectively the conversion factor energy/volume of 11,3 KWh/m^3 and 9,77 kWh/m^3.

Table 32: Volumes (in TWh) corresponding to the supply standard

	H (TWh)	L (TWh)
7 days (5% climatic Risk)	2,95	2,83
30 days (5% climatic Risk)	10,87	10,30
30 days (50/50 climatic Risk)	9,14	8,56

Table 33: Capacities (in $m^3(n)/h$) corresponding to the supply standard

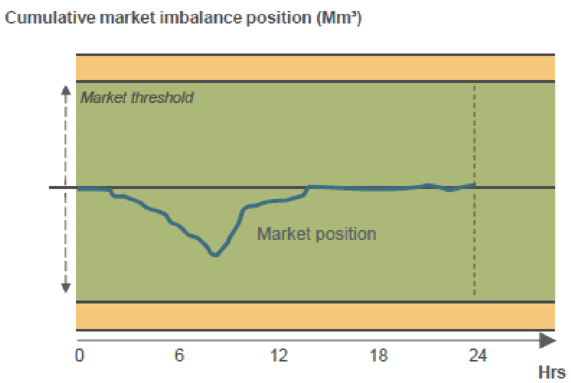
	H ($m^3(n)/h$)	L ($m^3(n)/h$)
7 days (5% climatic Risk)	1.866.921	2.067.237
30 days (5% climatic Risk)	1.602.603	1.757.885
30 days (50/50 climatic Risk)	1.347.949	1.459.843

5.3 Measures in place to comply with the supply standards

As discussed in previous section, the peak winter peak value occurring once in 20 years is -11°C_{eq}. The above criteria fall into two parts. The first part is the infrastructure obligations and the second part is the molecule obligation.

For the infrastructure calculations, the TSO still bases its investment plan on the -11°Ceq hourly peak criterion. By introducing the same criteria for the shippers, both the molecule standards will be in line with our infrastructure standard. An improvement is already made through the introduction of the new entry-exit model. The TSO will calculate the needed capacity per aggregated receiving station (ARS) to cover the full demand distribution network behind that specific ARS at -11°Ceq. The shippers and suppliers will then be forced to book the capacity calculated by the TSO in order to cover the winter peak demand and to avoid free riding. This way, at least the capacity is already in place to cover the peak demand.

Another measure that is already in place to make sure suppliers deliver gas to Belgian end-users, is the daily market balancing regime. The Belgian TSO monitors the balance between entry and exit on a cumulative basis for all hours of a given day and intervenes in order to keep the system balanced at all times.



Two kinds of interventions are possible:

- Within day interventions
- End of day interventions

Within day interventions:

In case the market balancing position goes beyond the upper (or lower) market threshold during a gas day, the Belgian TSO intervenes through a sale (or purchase) transaction on the commodity market.

- The considered volume is then settled in cash with the grid user (s) contributing to such imbalance in proportion of their individual contribution.
- Grid users which are causers are penalized by 3% of the Belgian TSO price for the settled volumes, and grid users helping the system are settled at the Belgian TSO price (no penalty).

During the gas year 2017-2018 (from 1st October 2017 until 30 September 2018), there were 159 TSO interventions (buying or selling gas) during a gas day (39 days out of 365) for about 279 GWh on the H-gas market and 94 interventions during a gas day (27 days out of 365) for about 84 GWh on the L-gas market.

End of day interventions:

At the end of the gas day, each grid user is returned to zero individually by a settlement in cash:

- Grid users helping the system pay (or get paid) the Belgian TSO price (no penalty).
- Imbalance causing grid users pay (or get paid) the Belgian TSO price with an additional penalty of 3%.

To settle the balancing position of all the grid users to zero at the end of the gas day, the TSO has bought about 1,390 GWh of gas for the H-gas market and 465 GWh for the L-gas market. We can therefore conclude that grid users trust the balancing system and rely on the TSO to establish their equilibrium position at the end of the day and that the balancing system makes it possible to avoid cases of tension and crisis through adequate flexibility and a well-functioning information system to all market players in this area. During the “Beast of the East” event in February-March 2018, there was no declared crisis on the gas market in Belgium, which proves once again the robustness of the system in place.

To conclude, in case of an imbalance of the market caused by suppliers that don’t fulfil their contractual engagements related to their clients, there are mechanisms in place that allow to reduce this imbalance to a level acceptable for the network. The Belgian TSO will take care of the purchase of gas and charge it to the causing grid user that they identify, thus ensuring the gas supply to the end consumers.

6 Preventive measures

In this chapter, we will make an evaluation of the possible market-based measures (supply side & demand side) and attempt to assess the most efficient means that can be used to reduce the impact of an incident. We will discuss each measure separately. For each of the measures we will check if they are already applied in Belgium, what the potential impact is of the measure, what the potential costs are to apply it, if the measure could be carried out and supported by the gas sector and what actions would be necessary to execute the measure in Belgium.

6.1 Increased import flexibility

Most companies have access to flexible contracts. This either included in their long-term contracts (mostly a provision is foreseen of 85%-115% or 90%-110% of the contracted gas that can be taken up), or they dispose of forward contracts on the European Hubs. Companies can either buy all their gas to cover the winter demand at -11°C with forward contracts, or they can foresee gas to cover the average winter demand, and if necessary, buy additional gas on a short-term basis. There is no obligation in Belgium to dispose of flexibility in the supply contracts. This is solely done on a company basis.

A total picture of the costs of the flexible contracts is very hard to obtain as the costs for flexibility differ according to the contracts. Every single company can have multiple contracts and prices which may vary substantially, so it is impossible to give an estimate for Belgium as a whole.

The import flexibility is monitored by an obligation on the gas companies to report on their gas contracts. This monitoring is done by the CREG, the Belgian Energy regulator and the Energy Administration. The Energy Administration has asked the CREG to provide a detailed study on the flexibility of the gas contracts. This study will serve as a starting point for future evaluations.

6.2 Facilitating the integration of gas from renewable energy sources into the gas network infrastructure

Integrating gas from renewable (e.g. Biogas) is only economically viable if injected in the distribution network in Belgium. This also falls under the competence of the regional governments, so a federal policy option here is not possible. As the production of biogas remains limited, the potential for biogas to serve as a preventive measure for incidents is negligible.

Depending on the prospective for the production of biogas in the future, we can reassess the situation to see whether this could serve as a preventive measure and if government action needs to be taken at that point.

6.3 Commercial gas storage – withdrawal capacity and volume of gas in storage

The aquifer in Loenhout is the only underground storage installation (for H-gas) in Belgium and is used for commercial storage. The useful storage capacity at Loenhout is 700 mcm, with a send out capacity of 625.000 cubic metres per hour and injection capacity of 325.000 cubic metres per hour. Under normal winter circumstances and if the storage is filled up to its full capacity, the stored gas can be used during about 60 days.

All companies can subscribe (a part of) storage capacity at Loenhout on a short term basis (within the storage year) on a yearly term basis (service period for one year) or on long term basis (service period between two and ten storage years). During a storage year in function of optimisation of the Storage Installation, the storage operator could offer additional services for injection, storage volume, and for withdrawal, on a short-term basis (e.g. daily, weekly, monthly, or yearly or another term). The Yearly Term and Long-Term Storage Services on the Primary Market can be subscribed and allocated through a Subscription Window or an Auction window organised by Storage Operator, after which the principle of First Committed First Served is applied. Participation to such allocation process is open to all Storage Users having registered as Participants and signed a Storage Agreement, according to the Terms and Conditions of a particular Subscription Window. The priority is given to Participants who commit to subscribe the longest service duration for their Storage Services. Services on a short-term basis can be subscribed and allocated on a First Committed Fist Served Basis within the applicable storage year between the 15/04/(year) and 14/04/(year+1)

As gas storage possibilities remain limited in Belgium, Fluxys Belgium looked in 2010 for other potential sites for underground gas storage in the Limburg province in collaboration with the Flemish Institute for Technological Research (VITO) and the Limburg Investment Company (LRM). This was without much success. However, as Belgium is surrounded by countries that have enough gas storage possibilities (e.g. Germany, France, UK, and The Netherlands) and most gas undertakings active in Belgium are also active in the neighbouring countries, gas operators can make use of the storage flexibility in several countries over the different gas markets. Furthermore, as LNG capacity (and the possibility for fast storage) is increasing in the neighbouring countries, this will also provide a source of short-term storage on site at the terminal.

There is no storage for L-gas. Currently Belgium uses, for the L-gas grid in particular, the ability of the Dutch L-gas fields as swing supplier and flexibility provided in the supply contracts. With shrinking Dutch gas production, maintaining the flexibility of this gas supply could be more difficult or more costly (depending on contractual arrangements) in the future.

As most companies operate at a European level, most of them have contracted storage capacity outside of Belgium. In case of an emergency, gas companies can exercise a swap of gas from storage abroad and gas transmission in Belgium.

6.4 LNG terminal capacity and maximal send-out capacity

The Zeebrugge LNG re-gasification terminal (in operation since 1987) has a yearly throughput capacity of 9 bcm per year. Currently the terminal has a send-out capacity of up to 2 800 m³ LNG per hour (or 1,7 mcm/h in gas) and can unload 110 LNG cargos per year. The four storage tanks can hold 380.000 cubic metres of LNG, the equivalent of about three shiploads of LNG. Because of the high number of slots that are allocated, the LNG storage must send out almost immediately after the LNG cargos have been unloaded. Therefore, the LNG storage tanks do not operate as storage as such but more as a very temporary buffer (3-4 days) before sending out in the pipelines. It is therefore useful to increase the send out capacity of the LNG terminal and to increase the storage capacity. With the disappearance of the peak shaving plant in Dudzele, new mechanisms should be sought to cover the peak demand.

Fluxys launched an open season for a second capacity enhancement of the Zeebrugge LNG terminal. The project has been approved and includes the construction of a second berthing jetty allowing ships from app. 1 000 m³ LNG up to a capacity of 217 000 m³ LNG and the construction of a 5th tank.

The second berthing jetty gives rise to additional berthing rights offered to the market for the purpose of loading ships and allows a second ship to dock at the same time. The investment decision of the project was already taken in 2011 and was commissioned by end December 2016.

In order to enable to provide transhipment services following the signature of a 20 years-contract with the Yamal LNG consortium, Fluxys Belgium also took the investment decision for the construction of a fifth tank with a capacity of 180,000m³ and additional process facilities. The construction has started end 2015 and commissioning of the 5th tank and process facilities is planned for the second half of 2019.

The capacities of the LNG terminal are allocated through an open season procedure and are subscribed through long term contracts (15-20 years) on the primary market. Any remaining unused capacity is allocated, until a new open season procedure is launched, according to the rule 'first come, first served'. Currently, four shippers have slots reserved in the LNG terminal. Besides these long-term contracts, tankers from Egypt, Nigeria, Trinidad, Malaysia and Qatar deliver spot LNG.

6.5 Diversification of gas supplies and gas routes

As already mentioned above, gas supplies are well diversified. There is no legal obligation in Belgium for portfolio diversification or for entry point diversification. We do however note that most gas undertakings have a very well diversified portfolio and use at least two entry points to bring the gas into Belgium. The suppliers have multiple contracts with different suppliers and bring the gas in via a variety of supply routes. The higher the diversification, the lower the impact of an incident on one supply source or route.

The costs of diversification depend more on the contract type and conditions and cannot really be seen as costs as such, but as a proper procedure for due diligence (?) in the gas business. Certainly, the larger companies with many long-term contracts dispose of a very well diversified portfolio. We have noted that smaller companies depend more on contracts on the gas hubs than contracts directly with producers.

6.6 Reverse flow and investments in infrastructure

Reverse flow exists already on all borders with the neighbouring countries. Open seasons were conducted on most borders in the period 2006-2011. In the meantime, the CAM network code has been implemented and auctions are continuously organized giving the market the opportunity to signal capacity requirements. Reverse flows and investments in infrastructure are analysed yearly by the TSO in the investment plan for the coming 10 years. This investment plan is revised by the NRA and the Competent Authority to analyse if the infrastructure expansions are in line with the predicted gas demand.

Capacity on the Belgian side of the interconnection points is mostly higher than on the adjacent networks. There is enough flexibility left in the network to deal with a cold wave, as the Belgian network is designed on an -11°C standard. This was also proven during the February 2012 cold wave. The gas consumption on the distribution network had reached peak level on 3 February 2012 (1.165 GWh) and 7 February 2012 (1.181 GWh). The gas flows on the transmission network (entry) to assure the total domestic consumption and the border-to-border transmission reached their peak level of a little bit over 80 GWh/h on 14 February 2017. About 40% of the 80 GWh/h was destined for the Belgian gas consumption, the rest being destined for export, mainly to France, UK, Netherlands and Germany. There was enough flexibility remaining in the network. In the H-gas network, about 50% of the available demand capacity was used and about 70% of the demand capacity on the L-gas network (L-gas demand almost exclusively for distribution networks).

6.7 Coordinated dispatching by transmission system operators

Fluxys has several Operating Balancing Agreements (OBA) with the TSOs in neighbouring countries, namely GRTGas (FR), GTS (NL), OGE (DE), Gassco (NO), IUK (UK), Zebra en Gascade. This agreement between countries can contribute to reduce the impact of an incident.

6.8 Use of interruptible contracts

Suppliers have the right to interrupt the customer, normally in return for a discount on price and with some notice. The notice period will be specified in the energy contract. Most interruptible contracts specify that there will only be a few hours' notice, unless it is specified otherwise in the contract. Customers with an interruptible contract have agreed to receive gas but are willing to have supply interrupted at some point, according to the reasons in the contract (mostly meteorological circumstances) and for a maximum number of hours or days per year.

Interruptible contracts are hardly offered anymore to end consumers in Belgium. This is because the attributed discounts are no longer a sufficient incentive on the longer term. In the industrial sector, interruptible contracts account for less than 5% of the total contracted volumes between end users and suppliers. Interruptions are also limited to force majeure events. For the electricity plants, we also see a tendency towards more firm contracts.

The TSO must interrupt supply (this is to interruptible contracted customers) in the event of technical difficulties with the transportation system or in the event of congestion. Again, this will be covered in the customer's contract. Interruptible capacity is hardly booked by the shippers because Fluxys Belgium only offers interruptible capacity to the market if there is no firm capacity left. Therefore, we can say that interruptible capacity for the shippers is negligible in Belgium.

We have to be clear however that the above-mentioned interruptions are separate to other interruption rights, which exist for use only in potential or actual emergency situations. In emergency situations, some companies can reduce demand considerably when prices are high or maintain production by switching to back up fuels. However, they still need to maintain a certain level of gas to keep systems going and to let their plant safely shut down.

At any point an accident could damage a major part of the gas infrastructure and cut off supply. Some gas users have back-up systems and fuels to switch to in the event of an emergency or if commercial incentives make using an alternative fuel source preferable. Not every gas user has back up fuels (most of the end consumers in Belgium do not have back up fuels), so the gas system and the procedures that exist within it are designed to minimise the risk of gas being switched off from those who don't expect it to be (those not on interruptible contracts). Appliances for commercial premises generally incorporate flame out safety devices. These allow for supplies to be quickly and safely reinstated following a cessation in gas supplies.

In the event of an emergency, the safe provision of gas to domestic users and other low volume users (all connected to the distribution network) is the top priority. Before firm customers are interrupted, emergency plans provide for the suspension of the normal market for gas. After the suspension, it will depend on how quickly gas supply and demand is balanced, before firm customers start to be interrupted. Before firm customers are interrupted, firm border-to-border transmission will be interrupted. Public appeals may take place asking the public to restrain gas usage but this would depend on the type of emergency.

6.9 Fuel switch possibilities including use of alternative back-up fuels in industrial and power generation plants

Fuel switching from gas to fuel oil or diesel is no longer applied in Belgium. The remaining capacity is only used for black-start and not for fuel switching purposes. Also the environmental limitations do not allow fuel switching from gas to fuel oil or diesel. Therefore, we do not take into account any fuel switching capacity in the natural gas sector.

6.10 Voluntary firm load shedding

The impact of voluntary firm load shedding is very limited in Belgium and is an option the government cannot control as it is highly dependent on price signals. It will mainly be used by companies that contract their own gas, like for example power plants. Only companies with real time measuring will be able to adjust their gas consumption. Of course, also the type of contract the companies have with their gas supplier is determining whether it will be possible to see how the price fluctuates on a real time basis, and how the consumption can be adjusted to it. A study is being conducted on possible measures that can be taken to reduce demand, within this study voluntary firm load shedding is one of the topics which will be investigated.

7 Other measures and obligations

Different policies are put in place to reduce the probability of occurrence of the causes that may lead to an incident.

The causes covered by the policies put in place are the following:

- Intrinsic safety of pipelines
- Safety vis-à-vis third parties working near pipelines
- Critical Infrastructure Security (EPCIP)
- Cybersecurity (NIS)

7.1 Intrinsic safety of pipelines

The Belgian State has recently adopted a new regulation concerning the safety of transport pipelines.

A new decree of 19 March 2017 prescribes the general and fundamental safety measures to be taken in the context of the establishment and operation of pipelines intended for the transport of gaseous products and others.

This Royal Decree is part of the regulatory framework relating to the safety of pipeline transport installations, which includes rules, ranging from the most general to the most detailed, whose completeness, precision and consistency ensure a high level of safety. This regulatory system is composed of three levels:

1. The Royal Decree of 19 March 2017 on safety measures for the establishment and operation of installations for the transport of gaseous and other products by pipeline, incorporating general safety requirements;
2. Technical Codes specifying the detailed technical requirements applicable in 4 particular areas (Design and Construction, Exploitation, Risk Analysis and Safety Management System). These Technical Codes are intended to reflect industry best practices and European and international standards. These must therefore be reviewed regularly to maintain, where appropriate, a match between the technical measures described therein and the evolution of these best practices and standards;
3. Transport authorizations including any individual requirements.

This regulation takes into account technological developments, current best practices in the safety of pipeline transportation and some elements highlighted during incidents. It takes into account the rules of good industry practice as well as the functional standards established at European and international level, among others by the "gas infrastructure" Technical Committees of European and international standardization institutes.

In terms of safety management, this regulation notably requires the transmission system operator to have a safety management system. This system must include:

- the role, responsibilities and training of staff. This involves defining the organization of the personnel (and any subcontractors) associated with accident risk management, identifying training needs and establishing training plans;
- the identification and evaluation of accident risks. The aim is to define and implement procedures for this purpose, covering all the phases of life of transport installations: design, construction, operation, maintenance and decommissioning;
- the control of exploitation; it involves the adoption and implementation of procedures and instructions for the safe operation of transport facilities;
- procedures for managing changes to existing transmission facilities;

- the emergency plan. This involves adopting and implementing procedures to identify foreseeable emergencies and develop an emergency plan to deal with them;
- the prevention and analysis of accidents as well as the follow-up of corrective actions: The aim is to define and implement the procedures, in particular feedback procedures, to analyse accidents and thus identify corrective actions in relation to these.

The transport authorization holder shall submit an external safety audit to his safety management system within one year of the start of operation of his first transport facility and every five years thereafter.

7.2 Safety vis-à-vis third parties working near pipelines

All works planned in an area containing such installations, must imperatively be the subject of information and consultation between the client and the carrier, in accordance with the Royal Decree.

In addition, the Royal Decree of 19 March 2017 creates a reserved area inside the protected area. This is of smaller width and depends on the operating pressure of the pipe. No intervention is allowed in this zone, except in special cases listed in the annexes of the Royal Decree of 19 March 2017, without prior contact with the carrier responsible.

An electronic platform, the Federal Cable and Conduct Information Contact Point (CICC), is a website on which anyone wishing to carry out work can check whether facilities for the transport of dangerous products by pipeline or underground or overhead high-voltage links are present nearby. This site automatically reports planned work to the relevant transport operators with infrastructure nearby.

7.3 Security of Critical Infrastructures (EPCIP)

The European Program for Critical Infrastructure Protection (EPCIP) sets the overall framework for activities aimed at improving the protection of critical infrastructure in Europe - across all EU States and in all relevant sectors of economic activity. It is implemented in a European directive (2008/114/EC) on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection.

On 1 July 2011 the Belgian Government has implemented the European directive on Critical infrastructure in Belgian Law with the possibility to not only identify European critical infrastructure but also national critical infrastructure. The Belgian law aims at covering not only terrorism, but also criminal activities, natural disasters and other causes of accidents. In short, it seeks to provide an all-hazards cross-sectoral approach. The energy sector with its subsectors: gas, electricity and petroleum is one of the key subjects within this law, next to transport, telecom and the banking sector. A Royal Decree specifically for the energy sector was published on 11 March 2013. The Belgian Law was updated on 15 July 2018 with a law laying down various provisions.

The Critical infrastructure Law is composed around:

1. Identification of critical infrastructures (National and European)
2. Security Analysis

3. Inspection
4. Exercises

In order to implement the Belgian Law on critical infrastructure the sectoral government for Energy has so far taken the following actions:

(1) the identification of national and European infrastructures in accordance with the procedure of the EPCIP Directive and Law,

(2) the designation of the critical infrastructures, national and European, (total 37) within the electricity and natural gas sub-sectors and

(3) after receiving a positive recommendation from the Crisis Center General Management on, service of the designation as critical infrastructures with respect to the respective operators. The identification process within the petroleum sector is ongoing.

7.4 Networks and Infrastructure Systems (NIS)

The Network and information System Directive was adopted by the European Parliament on 6 July 2016 and entered into force in August 2016. Member States have to transpose the Directive into their national laws by 9 May 2018 and identify operators of essential services by 9 November 2018.

The NIS directive is the security to the security services for the impact of the security or impact services to prevent. In the same spirit, the notification requirement of incidents in the directive relates to incidents that have an impact on the services provided.

The obligations contained in the NIS Directive apply mainly to entities that, in the event of an incident that affects the security of their network and information systems, can significantly disrupt the provision of essential services for the maintenance of critical social or economic activities. The NIS Directive also stipulates that when assessing the importance of the disruptive effect of an incident, particular account must be taken of its consequences for economic or social activities or for public safety.

The disruption of the digital services referred to by law (the digital service providers) may also prevent the same essential services from being provided. This bill develops a common approach to the security measures applied by the various types of providers, extends the target group of the security obligations, revises the definitions and introduces obligations for reporting security incidents in network and information systems.

The transposition of the directive in Belgian law is still ongoing (January 2019). A similar approach as in the Belgian Law on critical infrastructure is foreseen and the same entity will be designated as sectoral government . Also the process of identification and inspection will be quite similar to the law on critical infrastructure. One difference : there will be the possibility that the different regions are consulted when providers of essential services (public law or private law persons) or digital service providers for other aspects of their activities would be subject to regional or community rules.

8 Infrastructure projects

8.1 Existing and new infrastructure

Fluxys Belgium, Belgium's transmission system operator, has a network of more than 4100 kilometres of pipelines with 18 interconnection points and four compressor sites. Different cross border pipeline systems connect the Belgian natural gas market directly to Norway, UK, Germany, the Netherlands, France and Luxembourg. The most recent compression facilities at Zelzate, Winksele and Berneau are electrically driven (like elsewhere in the EU: more and more compressor stations are electrically instead of natural gas driven), which again confirms the growing convergence between electricity and natural gas security of supply which deserves particular attention. The four compressor sites are located in:

- **Weelde:** The compression station in Weelde was renewed in 2010 to maintain the capacity of low-calorific natural gas in the pipeline from Poppel on the Dutch border to the French border at Blaregnies.

- **Winksele:** The compressor site at Winksele lies at the crossroads of major North/South and East/West transmission axes. The existing compression facility for L-gas serves to maintain pressure levels in the North/South pipeline. Due to increasing demand for capacity for both the domestic market and border-to-border, it was decided to build new compressor facilities in Winksele for the East/West H-gas transmission axis as well. In this way, capacity can be enhanced on both the East/West and North/South transmission axes. This new facility is operational since end 2012.

- **Berneau:** Since 2010, work has been done to build additional compressor facilities at the compressor station in Berneau. These upgrade works has extend the options for combining natural gas flows on the East/West and North/South axes and also fit in with, inter alia, the transition to an entry/exit system and the introduction of a virtual trading point.

- **Zelzate:** The Zelzate compressor station came on line at the end of 2008 to create additional capacity for the overall rise in demand of the Belgian domestic market and enables larger volumes to be transported to and from the underground storage facility in Loenhout. Since 2010 it is also used to recompress the cross border natural gas delivery at Zelzate from the Dutch GTS grid.

The Fluxys Belgium transmission grid is also connected to other facilities operated by Fluxys Belgium or its subsidiaries: the Loenhout underground storage facility and the LNG terminal located in Zeebrugge. The Loenhout underground storage facility is aquifer storage for high calorific natural gas that combines mainly seasonal storage with high flexibility of usage. The Zeebrugge LNG terminal is used to load and unload ships carrying liquefied natural gas (LNG). LNG is temporarily kept in storage tanks at the facility as a buffer before re-gasifying the LNG and injecting it into the grid for transmission or loading the LNG back onto LNG ships or LNG trucks.

8.2 New infrastructure development

The need for new infrastructure is evaluated every year by Fluxys Belgium in the **ten-year indicative network development**[11]. These updates take into account the changes in requirements in terms of natural gas supply, request for new connections and the changing needs of grid users identified through subscription periods and international market consultations among other things. Several simulations based on the winter peak (January at -11°Ceq) are being set up to calculate the effects on the network. In the latest investment plan, the calculations are based on the Entry-Exit model.

Main infrastructure investments identified in the Fluxys Belgium TYNDP 2019-2028 are underway or will start in the coming years(s) under investment decision:

- **Finalisation of the enhancement of the Zeebrugge LNG terminal:** The project of a second capacity enhancement of the Zeebrugge LNG terminal included the construction of a second berthing jetty allowing ships from 2,000 m³ LNG up to a capacity of 217,000 m³ LNG and the construction of a 5th tank. This second capacity enhancement gives rise to additional berthing rights offered to the market for the purpose of loading ships. This second jetty has been commissioned in December 2016 and its first commercial operation took place on January 9 2017.

  In order to enable to provide transhipment services following the signature of a 20 years-contract with the Yamal LNG consortium, Fluxys Belgium also took the investment decision for the construction of a fifth tank with a capacity of 180,000m³ and additional process facilities. The construction has started end 2015 and commissioning of the 5th tank and process facilities is planned for Q2 2019.

- **LH Conversion :** At the request of the Belgian authorities, Synergrid[12] produced an indicative conversion timetable. The indicative timetable is based on re-using as much as possible the existing infrastructure with a view to avoid investments that are only necessary for the transition period. To realize the conversion, Fluxys Belgium will gradually have to adapt its grid to ensure the continuity of transmission services for both converted and non-converted markets. The required adjustments are assessed, costed and included in the yearly indicative investment plan. One of the main adaptation is to build new connections between the L-gas backbone and the H-gas backbone in the existing Winksele station.

- **Replacement policy :** Fluxys Belgium continuously evaluates his transport network infrastructure in order to evaluate his fitness for purpose. Amongst others, Fluxys Belgium decided to modify the network configuration at the east side of Brussels by building a new pipe line between Kraainem and Haren. The project includes also the construction of a pressure reducing station at Kraainem which will allow to lower the pressure in the pipe line that is situated in a high population dense area between Kraainem and Woluwé-Saint-Lambert (planned 2019).

[11] https://www.fluxys.com/en/company/fluxys-belgium/infrastructure

[12] http://www.synergrid.be/: the Federation of Electricity and Gas System Operators in Belgium.

Similar restructuration projects are planned in other regions such as (not limited to) Brakel-Ath (2019) and Tertre-Thieulain (2020).

- **Adapting the network for third party needs :** Fluxys Belgium needs to modify/divert some pipeline routes in order to allow new, generally public, constructions. Projects (not limited to) like Oosterweelverbinding in Antwerp (as from 2019) or enlargement of the Albert canal in Genk (2019) require network adaptations.
- **Connections for new power plants**: For several years, several projects connecting new CCGT power plants are being studied. These gas power plants require capacity at an operating pressure that cannot be provided by the DSO's, which is why they must be directly connected to the TSO network. Connection requests have been asked to Fluxys Belgium for different sites but have not yet resulted in a firm demand from customers because the stakeholders and the market are currently preparing for the Capacity Remuneration Mechanism auctions (CRM) to be started early 2021.
- **New city gates for DSO :** New injection points enhancing capacity on the distribution networks have been recently built in Zele, Kalmthout and Zonhoven. Several city gates are projected to be adapted/upgraded over the coming years
- **Reinforcement Limburg**: To further develop the available capacity in Limburg, a project study has been started to adapt the pipeline between Lixhe and Lanaken in order to flow at a higher working pressure and obtain an increase in transport capacity for the Limburg H transport system. Through this eastern route, Fluxys Belgium will be able to provide the necessary capacity to switch consumers from L-gas to H-gas in the Limburg's region (see also reinforcement Hageland). The project is scheduled for 2020 but investment decision will be depending of the regional demand growth (Public Distribution, industry and/or new power plants). Further development of the H capacity is currently analysed via a new connection between the VTN pipeline and the recently built Tessenderlo/Diest pipeline. This capacity would be required in case of significant new demand for Power Plants (cf. CRM auctions)

Summary of main infrastructure projects and estimated commissioning date:

Project	Estimated commissioning date
5th tank Zeebrugge LNG Terminal (FID)	Q2 2019
LH Conversion (Winksele project, FID)	Q1 2020 (phase1&2)
Reinforcement Limburg (Non FID)	Depending of CRM outcome

9 Public service obligations related to the security of supply

Public Service Obligations (PSOs) are part of the criteria to grant natural gas supply and transport authorizations, which are established by royal decree following the recommendations of the Regulator (CREG).

The royal decree of 23 October 2002 regarding public service obligations in the natural gas market imposes on the gas undertakings that were granted a supply authorization to ensure the continuity of gas supply to the distribution networks and their end-consumers according to the contracts concluded with these parties. The supply of gas may, however, be reduced or interrupted in the following cases, provided that the reduction or interruption is necessary :

- in case of force majeure;
- in case of connection of new transport or distribution facilities or for the maintenance of existing installations.

This royal decree also imposes on gas undertakings that were granted a transport authorization to build and/or operate additional transport facilities under economically justified conditions allowing end-customers to either increase the maximum hourly rates provided at the supply points already connected or to supply new supply points.

These PSOs are subject to a compensation covered by the tariffs to the end-consumers, which are approved by the Regulator who also controls the executions of those obligations.

PSOs are also imposed on the Distribution System Operators (DSOs) and suppliers by the 3 regions. Their execution and compensation in the tariffs are controlled by the respective regional regulator. These PSOs impose on the DSOs and suppliers to ensure the regularity and quality of the gas supply to their end-customers (or only for the households customers in the Brussels-Capital Region).

10 Regional dimension

10.1 Operational cooperation between TSOs

Cooperation in North West Europe

TSOs are tasked to run their networks as efficiently as possible either through incentives or other mechanisms, and as such solving constraints on cross-border points is part of the day-to-day operational business of TSOs. Neighbouring dispatching centres work closely together, where required, optimising gas flows and operation of the network in the region.

The dispatching centres of the region have various means to deal with such cross-border issues. For example:

- to swap gas (re-routing), not only bilaterally but also tri-laterally;
- operational Balancing Agreements (OBAs);

- mutual assistance, for instance to reduce fuel gas;
- exchange of personnel, knowledge and knowhow.

All these years of cooperation and experience have resulted in intensive contacts between the neighbouring TSO's in North West Europe. Working with Neighbouring Network Operators (NNOs) is for GTS a common practise as is working nationally with Distribution System Operators.

In case of a constraint at an interconnection point (whether this is due to maintenance, climatic conditions or interruption of supply) NNOs inform each other and relevant shippers immediately through bilateral contacts and through publication on the respective websites. Various actions can be taken to overcome or minimize the constraint. Either through the balancing regimes, or by re-routing gas via other entry/exit points in case the preferred route is constrained.

Regional cooperation within ENTSOG

With the 3rd Energy Package the European Network Transmission System Operators (ENTSOG) was founded. The Netherlands has been an active member from the start.

The bi-annual publication of the Ten Year Network Development Plan (TYNDP) and the Gas Regional Investment Plan (GRIP NW) are examples of these new ways of cooperation in North West European.

10.2 Regional cooperation between Member States

10.2.1 L-gas risk group

Regional issues related to security of supply are addressed and discussed in the Pentalateral Gas Platform. In this platform the following Ministries responsible for energy policy participate: Belgium, France, Germany, Luxembourg and the Netherlands, while the Commission is sometimes invited as an observer. The Benelux Secretariat provides logistic support. National Regulatory Authorities and TSOs are also sometimes invited, just as the European Commission.

The L-gas risk group activities have been and are conducted within the framework of the Pentalateral Gas Platform under the chairmanship of the Netherlands who currently acts as the group's coordinator.

If necessary, these arrangements make it possible to scale up rapidly to the political level if needed. The earthquake in Zeerijp in 2018 illustrates this. Directly after this earthquake there has been a meeting of the responsible directors-general of the L-gas countries to discuss the situation, followed by bilateral phone calls between the Dutch Minister of Economic Affairs and Climate Policy and his colleagues.

Preventive measures

The preventive measures to enhance the security of supply of L-gas supply and to diminish the dependence on the Groningen field are the following:

- The building of a new nitrogen plant by GTS. The plant is expected to be operational by Q2 2022 and will be able to produce around 68 TWh (7 bcm) of pseudo L-gas (in a cold year).
- Additional nitrogen purchases by GTS for one of the existing blending stations to further increase the production of pseudo L-gas. This would lead to an estimated amount of gas saved from the Groningen field of 10 to 15 TWh (1 to 1.5 bcm).

- Converting nine large-scale users of L-gas in the Netherlands to H-gas or other sources of energy. This would lead to an estimated amount of gas saved from the Groningen field of approximately 20 TWh (2 bcm) by 2022.
- Conversion of the Belgian, French and German L-gas markets to adapt all gas appliances and net-works to H-gas supply.

The objective of these measures is to decrease as soon as possible the need for production from the Groningen field to a level lower than 12 bcm/year.

Next to this in the Netherlands also some possible future measures have been identified:

- Filling UGS Norg with pseudo L-gas.
- Decreasing gas demand by enhanced energy transition measures (switch to renewable energy sources instead of H-gas).

The feasibility of these future measures will be assessed in the forthcoming period.

Conversion of the Belgian L-gas network

After the Dutch authorities announced the deadlines for a reduction in production, Belgium has developed a conversion plan. Although the date announced by the Netherlands for the beginning of the decrease in exports was 2024, a pilot phase of conversion was carried out in 2016 and 2017. Moreover, as of 2015, the last major industrial zone fueled by L-gas has been converted. No power station is supplied with L- gas anymore.

A notable difference between the conversion process in Belgium and in the other concerned Member States is that all appliances installed in Belgium should be fit for both gas qualities since 1978. In most cases, no replacement of the appliance is therefore necessary, but a verification by a qualified technician is strongly recommended.

In 2017, there were about 1.6 million clients connected to the Belgian L-gas network. Synergrid (Belgian federation of transport and distribution networks) has put into place an indicative planning for the conversion of these connections, the details of which are presented in Table 34. In June 2018, approximately 50,000 connections have been converted as the first phase of the conversion plan.

A public information campaign was set up in 2017 and was launched at a press conference of the Belgian Energy Ministers (federal and regional). The indicative conversion schedule was communicated to the population at that time.

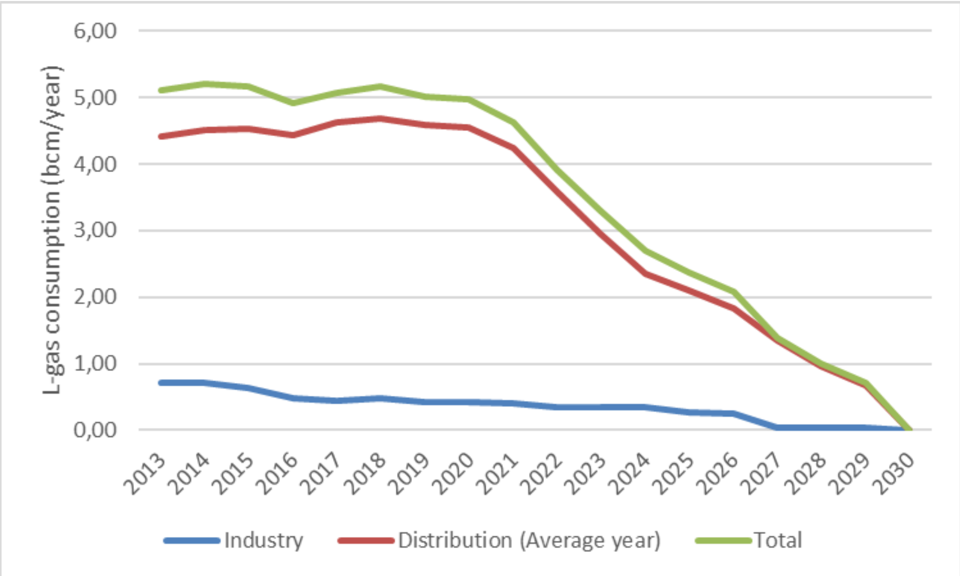
Some growth is still observed in the peak consumption by the public distribution, mostly due to new clients being connected to the networks. To take this into account in the future consumption previsions, we adjusted the initial planning by Synergrid with an annual growth of 1.5% (see Figure 23).

Table 34: Indicative conversion planning Belgium, with growth

	Connections to be converted	
Year	Based on 2017	Growth adjusted
2018	53.217	54.015
2019	30.787	31.718
2020	127.663	133.494
2021	238.789	253.442
2022	221.278	238.379
2023	208.077	227.520
2024	91.698	101.771
2025	94.695	106.673
2026	162.419	185.708
2027	126.540	146.855
2028	90.740	106.887
2029	209.141	250.053
TOTAL	**1.655.044**	**1.836.515**

In order to translate the decreasing number of connections into a decreasing L-gas consumption, the assumption has been made that the consumption is proportional to the number of connections on the public distribution (i.e. that each client, apart from the industrial consumers, has roughly the same peak consumption). Based on this assumption and the previous years' winter analyses, shows the decrease in consumption by the public distribution (TD) and the industrial customers connected to the transport network (TI).

Figure 23: Yearly consumption on Belgian L-gas network (2013-2031)



Conversion of the German L-gas network

Specific preventive measures concerning the L-gas situation for Germany are:

- Continuous planning of market conversion in the German Network Development Plan (adaption every two years).
- Early conversion of industrial customers where feasible.
- Blending facility next to Oude Statenzijl will be ready winter 2019/20.
- Amendment of German energy law, that industrial customers do not get access to the L-gas grid if there is a reasonable access to the H-gas grid.

10.2.2 Norway risk group

Place holder for the regional chapter of the Norway risk group (To be developed by France)

10.2.3 Baltic sea risk group

A cooperation mechanism has been drawn up pursuant to Art.8(4) SOS Regulation. It basically provides for all forms of communication to be used for the cooperation within the risk group. Conference calls have proved to be an efficient method. Prior to a conference, the chair presents a proposal for discussion during the conference. Objections and requests for changes which affect all Member States equally are resolved if possible in consensus. In terms of crisis prevention, it is important to have expert contacts in order to avert harm by engaging in an early and transparent exchange of information. It has proved worthwhile also to use these forms of cooperation for the drafting of the preventive action and emergency plans in order to facilitate contacts in a crisis.

Crisis prevention is in principle a national responsibility; consultations take account of cross-border issues. In order to be able to take measures to maintain security of supply in neighbouring member states on a cross-border basis in the case of a crisis, it is urgently necessary to engage in advance in **cross-border coordination between the relevant German and neighbouring TSOs at the respective international IPs**, if necessary with the backing of the competent authorities. In particular, a common understanding of the handling of crisis levels and resulting measures should be reached, so that crisis management can be undertaken in line with the SoS Regulation in the case of a bottleneck, particularly where there is a shortage on both sides, and the burden of the measures can be distributed equally (i.e. on a nondiscriminatory basis).

The TSOs also involve neighbouring cross-border system operators in their considerations about the expansion of infrastructure in the context of the consultations on the Network Development Plan.

Preventive measures

The risk analysis has shown that the risk of a disruption to supply in the Baltic Sea risk group – caused by technical failure – is calculable. Nevertheless, it is important to continue to ensure that the system is reliably maintained and secure.

The Network Development Plan Gas plays an important role in the ensuring of an orderly gas supply – including in the international context. It must contain all the effective measures which are technically required in the coming ten years for a secure and reliable operation of the system. These include:

- the needs-based optimisation and strengthening of the grid
- the needs-based expansion of the grid
- the maintaining of security of supply.

It thus makes a major contribution towards ensuring security of supply throughout the Baltic Sea region.

In particular, the Network Development Plan contains all the grid expansion measures which must be undertaken in the coming three years, including the timetables necessary for the implementation. The NDP is a key element for Germany, as a central transit country for gas flows. All the members of the Baltic Sea risk group – like other neighbours of Germany – benefit from Germany's security of supply and benefit from a high standard of planning. The ever-broader updating of the NDP is an indispensable element of this.

In order to enable TSOs to continue to fulfil their responsibility for a secure and reliable operation of the grid in future, they are required to produce a joint Network Development Plan in every even calendar year and to present it to the Bundesnetzagentur, the competent regulatory authority, by 1 April (Section 15a Energy Industry Act). This Network Development Plan is based on the scenario framework, and the TSOs must use this framework as they draw up the Plan (Section 15a subsection 1 sentence 4 Energy Industry Act).

The scenario framework must include appropriate assumptions about the development of gas production, supply, consumption and exchange with other countries. Also, the TSOs must take account of planned investment projects in the regional and EU grid infrastructure, in storage facilities and in LNG regasification facilities. Finally, they must include the effects of possible disruption to supply.

In order to identify these measures, the Energy Industry Act requires that the TSOs model the German long-distance gas grids when they draw up the Network Development Plan.

The draft Gas Network Development Plan is presented to the Bundesnetzagentur for scrutiny.

There is a legal requirement that the Bundesnetzagentur confirms the scenario framework, taking account of the results of the public consultation carried out by the TSOs.

10.2.4 UK risk group

The United Kingdom Risk Group comprises the United Kingdom, Belgium, Germany, Ireland, Luxembourg, the Netherlands. The group operates on a consultative basis: the UK holds the pen on drafting the implementation of regional aspects of the Regulation, with all decisions made in consultation with members of the Risk Group. Regular group meetings held via teleconference and in person at the Gas Coordination Group are supported by email discussions and, where appropriate, bilateral communication.

In the event of a national gas system emergency, the emergency measures set out in National Emergency Plans (NEPs) demonstrate how the Risk Group has adopted a collaborative approach to handling NGSE, where applicable.

The UK National Preventive Action Plan (PAP) for gas has been developed alongside this revision of the NEP and the regional cooperation mechanisms and agreements relating to managing emergencies across Northern Ireland and the Republic of Ireland.

The United Kingdom and Ireland have carried out a Joint Risk Assessment identify and assessing regional risks. This is contained at Chapter 6 of the UKRG Common Risk Assessment and provides details on the mechanisms developed for communication, including intergovernmental agreements, transportation arrangements and load shedding protocols.

The primary vehicle for regional co-operation on the Emergency Plan is through the UK and Ireland Gas Emergency Group. This group comprises representatives from governments, regulators and TSOs of GB, Ireland and Northern Ireland. The group meets twice a year and has developed a regional approach to emergency planning to ensure that the gas emergency operational plans of all jurisdictions work together. This is achieved through the development of protocols between the TSOs and modifications to emergency plans identified following joint emergency exercises. These are fundamental to the management of a stage 3 crisis level (i.e. emergency). Much of the work of this group has to-date focussed on this aspect of regulatory co-operation.

In addition, the group supports government and regulatory co-operation through the adoption and development of emergency planning procedures and communication protocols for emergency management. These measures have a primary role in the early warning and alert crisis levels and seek to ensure consistency of emergency response and preparedness.

Preventative Action Measures

Political risks associated with the UKRG

UKCS offshore production infrastructure is directly connected to the United Kingdom and Netherlands transmission networks. The Netherlands' production infrastructure is directly connected to the Netherlands transmission network. There are no third countries through which gas transits within the UKRG; there is, therefore, no need for preventative measures concerning transit of third countries.

UK risks associated with the UKRG

The production of natural gas from the United Kingdom Continental Shelf has declined since the turn of the millennium, although a small increase due to new fields was seen in 2015 and 2016. Despite this, the UK, along with the Netherlands, remains one of the two major gas producing nations within the EU.

UK oil and gas production is expected to start to fall again in the years ahead, though production estimates are subject to uncertainty. There are a wide range of possible outcomes because the future rate of production is dependent on a number of different factors including the level of investment and the success of further exploration. Operators continue to find it difficult to accurately predict additional production from investing in older fields as they mature. The projections are therefore the best estimates rather than a definitive prediction of future production of oil and gas from the UKCS.

For the United Kingdom's Continental Shelf (UKCS), the Oil and Gas Authority (OGA) has set out the Maximising Economic Recovery (MER) Review which allows the OGA to consider a regional element of security with the objective of maximising the economic recovery of the UK's oil and gas resources in the North Sea.

In the South of the North Sea (SNS) UKCS area, there is a risk of decline in the production of oil and gas based on a lack of investment. The lack of investment in SNS infrastructure puts at risk the production life of current assets in the SNS that retrieve 'stranded reserves' of oil and gas. At current the SNS is not being heavily invested in as it is a mature site of exploration, having been exploited since 1967. By leaving oil and gas reserves 'stranded' in the SNS from lack of coordinated investment; fiscal opportunities are being lost to the market and assets of gas security in the UKRG are also lost.

The OGA is working to maximise the economic recovery of hydrocarbons from the UKCS by creating an environment that stimulates exploration activity leading to the discovery of new oil and gas reserves. The OGA has made available large amounts of exploration data, including new government-funded seismic data, data on wells, prospects, geological mapping and lessons learned. This has helped generate new interest in UKCS oil and gas acreage.

Most issues are addressed and resolved through the stewardship process. Asset stewardship is crucial to maximising economic recovery from the UKCS and to delivering greater value overall. Effective stewardship means that asset owners consistently do the right things to identify and then exploit opportunities and that assets are in the hands of those with the right behaviours and capabilities to achieve MER UK.

The OGA has worked closely with operators, licence holders and other interested parties to develop Area Plans across the oil and gas life cycle that integrate exploration, development, production, operations and decommissioning to maximise economic recovery – for example, through the optimum use of infrastructure to extend the life of hubs. The OGA has reaffirmed its focus on the importance of collaboration and urged industry to increase the pace at which licensees develop a culture of collaboration internally and externally within existing joint venture (JV) partnerships and beyond.

Working with industry, government, and the research community, the OGA is committed to overcome current constraints on technology innovation and commercialisation. The OGA works closely with industry and government, including BEIS, HM Treasury and other key government departments, providing expertise and evidence where appropriate. The OGA works with a range of stakeholders including the Scottish Government to Over the last two years, we have seen many positive examples of collaboration between companies leading to solutions to long-running issues. The MER UK Strategy requires licence holders to ensure that optimal technologies are used for MER UK. As part of its Asset Stewardship Strategy, the OGA expects that licence operators have technology plans which identify actions and timelines to access and/or develop the critical technologies needed for their assets.

The MER Review is an example of how non-market-based Government actions can create positive impacts on the private market and a positive outcome for the UKRG security

Netherlands risks associated with the UKRG

For many years, total annual production in the Netherlands was about 80bcm. This has already decreased in the past year and will continue to decrease in the coming years due to production limitations set on the Groningen field and lower production levels of the small fields.

As a result of earthquakes related to gas production in Groningen, the volume allowed to be produced has been restricted in the past few years. In 2018, the Netherlands decided to reduce production from Groningen as fast as possible to 12bcm and then continue to 0bcm, i.e. to terminate production from the Groningen field. Since 2013, gas production from Groningen has fallen 54bcm to 23.98bcm in 2017 and will continue to fall. In addition, reduced production from Dutch small fields will further constrain natural gas production in the Netherlands.

On the 8th of January 2018, a gas production-induced earthquake occurred at Zeerijp. Following the advice of the State Supervision of the Mines, the Dutch Minister has decided to reduce production from Groningen as fast as possible to 12bcm and then continue to 0bcm, i.e. to terminate production from the Groningen field.

To achieve this, GTS will invest in a new nitrogen plant at Zuidbroek which can, starting gas year 2022-2023, produce up to 7bcm of pseudo L-gas in a cold year. In addition, GTS will purchase additional nitrogen which can produce 1 to 1.5bcm of pseudo L-gas from gas year 2020-2021. Furthermore, industrial clients will be converted between gas year 2019-2020 and gas year 2022-2023 from L-gas to H-gas. Possibilities to accelerate the market conversion in Germany, Belgium and France will also be investigated.

In the meantime, production from the Groningen field will never be more than is required from a security of supply perspective. This means that the blending stations of GTS will produce baseload (on average, 85% of blending stations Ommen and Wieringermeer); the Groningen field combined with other sources (storage facilities) will cover the rest of the market.

In addition to these volume-reducing measures, the Minister also decided to close the production clusters in the Loppersum region. This decision will reduce the capacity of the Groningen field by approximately 25%.

Germany

In 2017, Germany produced 7.9bcm of natural gas with a calorific value of 9.77kWh/m^3 which is classified as L-Gas. Production in 2017 decreased by 8.6% compared to 2016, with the forecast production continuing to decline due to the depletion of existing reserves.

Despite this, there are many import routes to supply the German market known as "diversification of supply routes" and the German gas infrastructure network is well suited to meeting the demands for transportation of gas within Germany.

In addition, the relevant companies are already acting to prevent the decline in the availability of L-gas negatively affecting security of supply. German L-gas producers, who are the affected network operators and storage system operators have set up a joint working group to develop a plan for the coordinated conversion from L-gas to H-gas. This conversion plan is included in the national network development plan as an input parameter.

Ireland

The Kinsale Heads storage facility is now in blowdown mode and is therefore classed as production until its expected final closure in 2020. The gas security of Ireland is however ensured by the new Corrib gas field which commenced production during the 2015/16 gas year and supplied 62% of gas demand in Ireland in 2016/17. The Moffat Entry Point accounted for 31% of the overall requirement with the remaining 5% supplied from production gas from an off-shore gas field at the Inch entry point.

The Corrib gas field would be expected to supply approximately 27.7% of ROI peak day gas demand in 2018/19 in the event of a 1-in-50 winter peak day, with Inch accounting for around 2.3%. The Moffat Entry Point would be expected to meet nearly 69.9% and 78% of ROI demand and Gas Networks Ireland system demands respectively in 2018/19, in such circumstances. Moffat is anticipated to meet 89.5% and 92.2% of ROI and Gas Networks Ireland system peak day demands respectively in 2026/27.

Connection with Member States outside of the risk group

Germany

Germany has an extensive transmission system. The network of the transmission system operators is connected to the systems of neighbouring countries via a large number (>25) of cross-border interconnection points. This transport infrastructure is essential for Germany's natural gas market, situated as it is in the centre of Europe and functioning as an important trading hub for the continent. In the southern part there are significant import points on the borders of the Czech Republic and Austria. The major export points are on the borders to France, Switzerland and Austria. The transmission system is thus used for both transit and supply services.

In the past, gas consumed in the northern part of the supply area in Schleswig-Holstein and Hamburg largely came from Danish reserves. For some years now, Denmark has been stepping up preparations for supply from German imports via the Ellund station. The Nord Stream and Baltic Sea Pipeline Link (OPAL) pipelines were put into operation at the end of 2011. The OPAL can transport up to 35 bcm of natural gas a year from Nord Stream. This means that Nord Stream and the OPAL, together with pipelines in the Czech Republic (Gazelle), ensure supply volumes for the Waidhaus import point and strengthen the security of supply for Germany, France and the Czech Republic.

Netherlands

In the Netherlands there is a total of 135,000 km of gas pipelines. There are 8 Local Distribution Companies for gas in the Netherlands, of which there are 7 operating gas transmission grids for L-gas and 1 for H-gas.

On the Maasvlakte in Rotterdam, Gate terminal has built the first LNG import terminal in the Netherlands. The terminal currently has a throughput capacity of 12bcm per annum and consists of three storage tanks, two jetties and a process area where LNG will be re-gassified. Annual throughput capacity can be increased to 16bcm in the future. The terminal dovetails with Dutch and European energy policies, built on the pillars of strategic diversification of LNG supplies, sustainability, safety and environmental awareness.

Non-Market Preventative Measures

The countries within the United Kingdom Risk Group adopt a market-based approach to guaranteeing security of supply, although a number of countries do adopt measures which they consider to be necessary to guarantee security of supply. The Preventative Action Plan focuses on those measures which proceed the declaration of an NGSE in Member States; as such, no measures relating to stages of an emergency are discussed here.

10.2.5 Belarus risk group

Placeholder for the regional chapter of the Belarus risk group (To be developed by Poland)

11 Conclusions

This Preventive Action Plan was established according to the SoS Regulation.

It describes on the one hand all the tools available to the market (market based measures) to ensure the security of supply to the end consumers in Belgium and to cope with unforeseen incidents. While these market based measures are an essential part of the normal functioning of the market, they can still be used in crisis situations, as is detailed in the Emergency Plan.

These market based measures are mostly based on and take advantage of the facts that the Belgian gas infrastructure is well developed and that the gas supply sources are well diversified. Most of the preventive measures consist in giving the market participant an optimal access to the gas infrastructure.

On the other hand, this plan describes the legal obligations that apply to the market, either the suppliers or the system operators, in order to ensure that they use the tools available to them to ensure the supply of gas to end-consumers and especially to the Protected Customers.

Annex 1a: Degree-days and equivalent temperatures

The public distribution sector uses gas primarily for space heating. This results in a strong correlation between gas consumption levels and exterior temperatures when they drop below 16.5°C.

Above this temperature, consumption remains relatively stable because gas is barely used for space heating anymore and the other uses (such as cooking and domestic hot water) are not temperature dependant.

Below 16.5°C, we can observe a direct proportionality between the gas consumption on a given day and the difference between the average outside temperature and this threshold temperature of 16.5°C on the same day. This difference, or number of degree-days (DD), is therefore best suited to represent the influence of outside temperatures on gas consumption on the public distribution networks. For example, if the average temperature for a day was -2°C, the number of degree-days for that day is 18.5 (DD = 16.5 - (-2)).

The correlation between the consumption of natural gas and degree-days gets even better if you replace the average temperature of the day by an equivalent temperature (T_{eq}) calculated as 60% of the temperature of the same day, 30% of the temperature of the previous day and 10% of the temperature of the day preceding yet. This improvement reflects notably better thermal inertia of the buildings.

This methodology is applied in Belgium since 1993. In order to not cause confusion, it was decided to talk about equivalent degree-days (DDeq) which differ from the ordinary degree-days.

Where $DD_{eq} = 16,5 – T_{eq}$

and $T_{eq} = 0,6\ T_m + 0,3\ T_{m-1} + 0,1\ T_{m-2}$,

with T_m the real average temperature i.e. the arithmetic average on day m of 13 surveys measured by RMI (Royal meteorological Institute) every two hours in Uccle (place of reference currently used for all of the country).

Table 35: Examples of equivalent degree-days calculations

day 1 : mean temperature of 18°C	day 1 : mean temperature of -2°C
day 2 : mean temperature of 14°C	day 2 : mean temperature of +3°C
day 3 : mean temperature of 12°C	day 3 : mean temperature of -4°C
then	then
DD (day 1) = 0	DD (day 1) = 18,5
DD (day 2) = 2,5	DD (day 2) = 13,5
DD (day 3) = 4,5	DD (day 3) = 20,5
DDeq (day 3) = 3,45	**DDeq (day 3) = 18,2**

Equivalent degree days can also be added over a given period (week, month, year, etc.) while maintaining the link with the total consumption of gas in the same period. When for a given month, there is no equivalent degree days found in Uccle (i.e. when the equivalent temperature does not fall below 16.5 ° C), the number of degree-days monthly is taken as equal to 1 for this month.

This property is used to define normal conditions for a month or year as the average number of degree days observed for this period over the reference period of 30 years, updated every 5 years.

Since January 1, 2016, the reference period is 1986-2015 and includes 2301 normal degree days.

For the correction of annual and monthly consumption linked to an "extreme temperature profile" (extreme temperatures), DDeq are taken for the period 1962 to 1963, characterized by an extremely cold winter. The annual DDeq for extreme temperature profile totalled 3.040 DDeq.

Table 36: Monthly degree-days in normal and extreme conditions

	DDeq (t° norm.)	DDeq (t° extreme)
J	401	648
F	357	520
M	298	329
A	196	208
M	99	161
J	42	32
J	13	13
A	14	47
S	62	68
O	159	175
N	281	349
D	379	490
Total	**2.301**	**3.040**

Table 37: Ranking of the coldest gas years according to the Degree Days (DD)

Ranking	Year	DD_{eq}
18	1969	2.670
17	1952	2.751
16	1983	2.643
15	1961	2.729
14	1916	2.906
13	1984	2.661
12	1923	2.894
11	1964	2.746
10	1939	2.847
9	1986	2.678
8	1940	2.882
7	1928	2.944
6	1995	2.696
5	1941	2.915
4	1955	2.893
3	1978	2.807
2	1985	2.901
1	1962	3.040

Annex 1b: Normalisation of the consumption

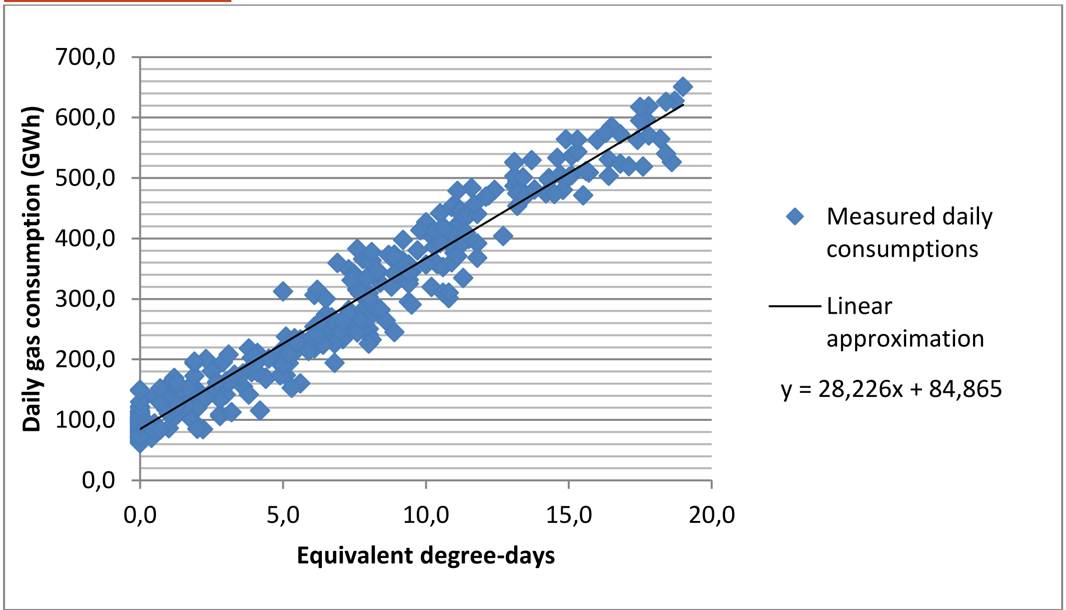
As stated in annex 1a, the gas consumption by consumers connected to the public distribution is strongly linked to the weather conditions. When comparing the market shares of the three sectors (public distribution, large industries and power generation), this can lead to a relatively higher share of the public distribution in case of a colder year, or a lower share in case of a warmer year. This effect is particularly unwanted when comparing consumptions or market shares between different years.

For this reason, total yearly consumptions on the public distribution are usually normalised to correspond to an average year, with DD_{norm}= 2301.

To proceed with this normalisation, a link must first be established between daily gas consumption on the public distribution and the number of equivalent degree-days on the same day. This can be done by a linear approximation based on the measured daily consumptions and equivalent degree days over the year. Such an analysis is shown on Figure 24 for the year 2017. The resulting theoretical relation between the daily gas consumption (TD) and equivalent degree-days (DD_{eq}) is as follows:

$TD[GWh] = 28.226 * DD_{eq} + 84.865$

Figure 24: Correlation between equivalent degree-days and daily gas consumption on the public distribution (2017)



For the purpose of normalising the yearly consumption, the previous relation can be adapted by multiplying the offset parameter by 365 (or 366 for a leap year):

$TD_{norm}[GWh] = 28.226 * DD_{norm} + 365 * 84.865$

Annex 2a: Extreme weather conditions (1 in 20 years)

We start from the basic principle that the peak consumption is obtained at a winter peak day. A winter peak day is considered as one day with extreme temperature occurring with a statistical probability of once in 20 years conform the provisions of article 5 of Regulation (EU) 2017/1938 for the infrastructure standards.

To be able to find the number of DD corresponding to the equivalent temperature occurring with a statistical probability of once in 20 years, we have to observe values in the winter months (December to February). We look for the 20 days representing the coldest day temperatures in the last 100 years. Table 38 shows us that the fifth value registered in the last 100 years gives us 28,4 DD or an equivalent temperature of -11,9°C. This 5th value (5th percentile) can be considered as a temperature occurring statistically once in 20 years.

Table 38: Climatic peak values in winter during last 100 years

Climatic peak values in winter during last 100 years			
Ranking	Date	DD	Teq
20	18/01/1963	26,9	-10,4
19	1/01/1997	26,9	-10,4
18	2/02/1954	27	-10,5
17	23/02/1956	27,1	-10,6
16	12/01/1987	27,1	-10,6
15	3/02/1917	27,2	-10,7
14	19/12/1938	27,2	-10,7
13	12/02/1929	27,3	-10,8
12	13/01/1987	27,4	-10,9
11	14/01/1987	27,4	-10,9
10	2/01/1997	27,4	-10,9
9	21/12/1938	27,5	-11
8	15/01/1987	27,6	-11,1
7	8/01/1985	27,7	-11,2
6	13/02/1929	27,9	-11,4
5	21/01/1942	28,4	-11,9
4	2/02/1956	28,4	-11,9
3	14/02/1929	28,9	-12,4
2	20/12/1938	29,1	-12,6
1	22/01/1942	29,6	-13,1

This value can be further refined by takin global warming into account. If we make a correction for the global warming, we receive the results shown in Table 39. The fifth value gives us an equivalent temperature of -11,4°C.

Table 39: Corrected climatic peak values in winter during last 100 years

Corrected climatic peak values in winter during last 100 years			
Ranking	Date	DD	Teq
20	18/01/1963	26,6	-10,1
19	2/02/1954	26,6	-10,1
18	16/01/1985	26,6	-10,1
17	19/12/1938	26,7	-10,2
16	23/02/1956	26,7	-10,2
15	12/02/1929	26,7	-10,2
14	1/01/1997	26,8	-10,3
13	12/01/1987	26,9	-10,4
12	21/12/1938	27,0	-10,5
11	13/01/1987	27,2	-10,7
10	14/01/1987	27,2	-10,7
9	2/01/1997	27,3	-10,8
8	13/02/1929	27,3	-10,8
7	15/01/1987	27,4	-10,9
6	8/01/1985	27,5	-11,0
5	21/01/1942	27,9	-11,4
4	2/02/1956	28,0	-11,5
3	14/02/1929	28,3	-11,8
2	20/12/1938	28,6	-12,1
1	22/01/1942	29,1	-12,6

Based on the results obtained above, we can set the reference value for the winter peak occurring once in 20 years at rounded -11°C, corresponding to 27,5 DD.

Annex 2b: Winter analysis, peak day consumption

In order to estimate the consumption levels of the peak demand on the distribution network, we make an estimation of the natural gas demand during the winter peak period. We assume that the peak consumption is obtained at a winter peak day. As explained in annex 2a, the winter peak day is considered as one day with an extreme temperature occurring with a statistical probability of once in 20 years. Belgium considers the use of -11°C_{eq} or 27.5 DD_{eq} as the reference value for the winter peak occurring once in 20 years.

The evolution of the natural gas demand on the distribution network at -11°Ceq (27.5 DDeq) is estimated based on a linear regression model. According to the determined parameters for this regression, we can compute:

- the average value of the natural gas consumption level at -11°Ceq, this is a 50% chance that the actual natural gas demand will be higher than the calculated demand;
- the natural gas consumption level at -11°Ceq with a 1% risk of exceeding the calculated natural gas demand[13];
- an estimation of the peak natural gas consumption in the coming winter.

The calculations are based on the average demand on a peak day. We do have to keep in mind that this differs from the maximum hourly consumption during a peak day which can be up to 20% higher than the average peak day demand. This difference will have to be absorbed by the flexibility in the system (This flexibility should be either imported by cross border gas trading, covered by the linepack within the network or provided by the underground natural gas storage (H-gas) in Loenhout or additional gas send out from the LNG terminal in Zeebrugge).

Peak demand on the L-gas distribution network (TDL)

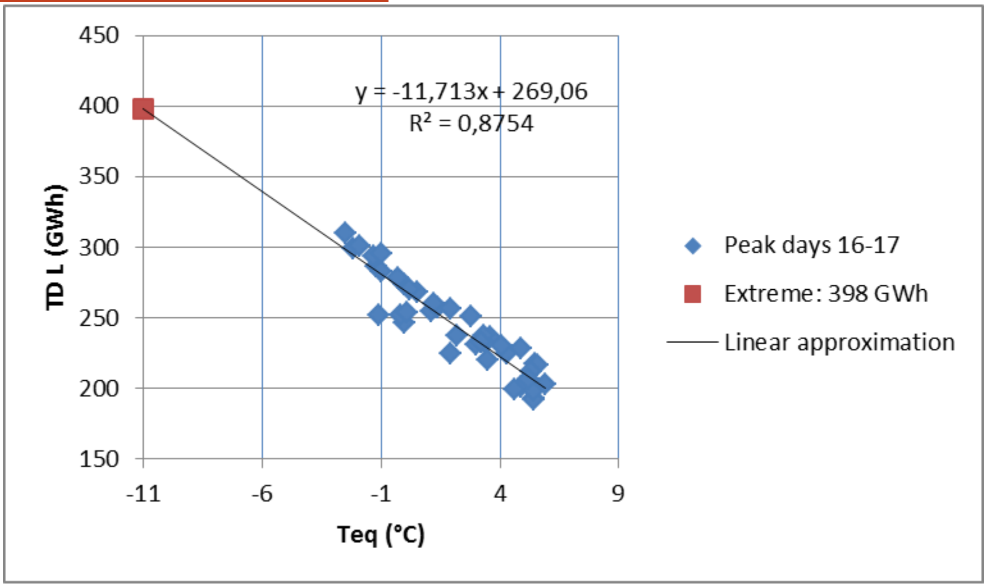
Based on the daily measured consumptions of the distribution network for a given winter period, we can deduce the linear relation between the daily equivalent temperature and the daily consumption. Based on this correlation, we can extrapolate the consumption to -11°C_{eq} in order to deduce the amount of natural gas that the distribution network will need at -11°C_{eq}.

This process is similar to the one used for the normalisation of yearly consumption, but in this case we limit the considered data to days more representative of a peak day. Only the days corresponding to all of the following criteria are taken into account:

- Between 5th November and 5th March
- Teq < 6°C
- Weekdays (no weekends)
- No holidays

[13] A correction factor is applied to the linear regression to cover 99% of the measured data (so called 1% risks).

Figure 25 Correlation between equivalent temperatures and consumption levels on the L-gas distribution network (Winter 2016-2017)



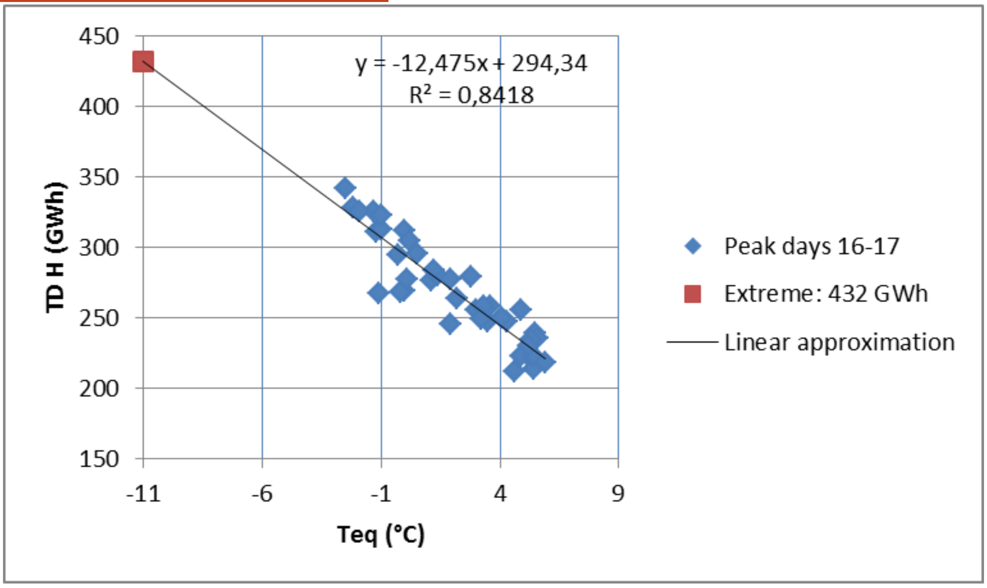
Source: FPS Economy calculation based on data available on gasdata.fluxys.com

This estimation is at the centre of the confidence interval, so there is a 50% probability that, on a cold day with -11°C_{eq}, the actual measured consumption would be higher. In order to better represent a maximum daily consumption, we also calculate a level of consumption with a 1% probability of being exceeded. (Upper limit of the 99% confidence interval)

Peak demand of the H-gas distribution network (TDH)

The same method as for L-gas described above is now used to obtain the linear regression curve for the H-gas growth rate. For the 2016-2017 winter period, the estimated consumption at -11°C_{eq} was 431,56 GWh, and 445,81GWh for the upper limit of the 99% confidence interval.

Figure 26 Correlation between equivalent temperatures and consumption levels on the H-gas distribution network (Winter 2016-2017)



Source: FPS Economy calculation based on data available on gasdata.fluxys.com

Annex 3: UKRG N-1 parameters

This annex reports the breakdown of the parameters used to compute the N-1 score for the United Kingdom Risk Group.

EP_m: Technical capacity of entry points

Technical capacity of entry points (EP_m)			Historical Data			Projected Data		
			2015	2016	2017	2018	2019	2020
			GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	Norway	ZPT (Zeepipe)	515	515	515	515	515	515
BE	France	Alveringem	0	271	271	271	271	271
DE	Denmark	Ellund	37	91	33	33	33	33
DE	Austria	Oberkappel	133	160	160	160	160	160
DE	Austria	Überackern 2	230	230	230	230	230	230
DE	Austria	Überackern	54	61	61	61	61	61
DE	Czech Republic	Deutschneudorf	198	198	198	198	198	198
DE	Czech Republic	Brandov-Stegal (Olbernhau)	9	5	0	0	0	0
DE	Czech Republic	Waidhaus	904	907	907	907	907	907
DE	Norway	Dornum	774	721	721	721	721	721
DE/NL	Norway	Emden EPT	989	989	989	989	989	989
DE	Poland	Mallnow	931	932	932	932	932	932
DE	Poland	Kamminke/Gubin/Lasow	0.0	0.1	0.1	0.1	0.1	0.1
DE	Russia	Greifswald	618	618	618	618	618	618
UK	Norway	Langeled	770	770	770	836	836	836
UK	Norway	Vesterled	396	396	396	451	451	451
UK	Norway	FLAGS	275	275	275	330	330	330
Total			**6,833**	**7,140**	**7,076**	**7,252**	**7,252**	**7,252**

P_m: Maximum technical production capacity

Maximum technical production capacity (P_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	0	0	0	0	0	0
DE	301	301	301	301	301	301
IE	0	104	104	110	94	92
LU	0	0	0	0	0	0
NL	2,994	2,218	2,156	2,144	1,959	1,818
UK	1,111	1,232	1,319	1,355	1,349	1,327
Total	**4,406**	**3,854**	**3,879**	**3,910**	**3,702**	**3,538**

S_m: Maximum technical storage deliverability

Maximum technical storage availability (S_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	170	170	170	170	170	170
DE	4,600	4,600	4,600	4,600	4,600	4,600
IE	33	33	33	0	0	0
LU	0	0	0	0	0	0
NL	4,180	4,180	4,163	4,163	4,163	4,163
UK	1,650	1,606	1,231	1,279	1,279	1,279
Total	**10,632**	**10,588**	**10,197**	**10,212**	**10,212**	**10,212**

LNG_m: Maximum technical LNG facility capacity

Maximum technical LNG facility capacity (LNG_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE: Zeebrugge LNG Terminal	461	461	461	461	461	461
NL: Gate	399	399	399	399	399	399
UK: South Hook	649	649	660	663	663	663
UK: Dragon	297	297	297	229	229	229
UK: Isle of Grain	649	649	649	653	653	653
Total	**2,455**	**2,455**	**2,466**	**2,405**	**2,405**	**2,405**

D_{max}: 1-in-20 gas demand

1 in 20 gas demand (D_{max})	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	1,307	1,303	1,357	1,466	1,478	1,490
DE	5,460	5,460	5,460	5,460	5,460	5,460
IE	207	221	206	277	281	288
LU	6	6	5	5	5	5
NL (1-in-50 demand)	3,729	3,648	3,678	3,692	3,678	3,664
UK	4,970	5,013	5,343	5,039	5,008	4991
Total	**15,680**	**15,651**	**16,048**	**15,940**	**15,910**	**15,898**

This annex reports the breakdown of the parameters used to compute the N-1 score for the United Kingdom Risk Group.

EP_m: Technical capacity of entry points

Technical capacity of entry points (EP_m)			Historical Data			Projected Data		
			2015	2016	2017	2018	2019	2020
			GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	Norway	ZPT (Zeepipe)	515	515	515	515	515	515
BE	France	Alveringem	0	271	271	271	271	271
DE	Denmark	Ellund	37	91	33	33	33	33
DE	Austria	Oberkappel	133	160	160	160	160	160
DE	Austria	Überackern 2	230	230	230	230	230	230
DE	Austria	Überackern	54	61	61	61	61	61
DE	Czech Republic	Deutschneudorf	198	198	198	198	198	198
DE	Czech Republic	Brandov-Stegal (Olbernhau)	9	5	0	0	0	0
DE	Czech Republic	Waidhaus	904	907	907	907	907	907
DE	Norway	Dornum	774	721	721	721	721	721
DE/NL	Norway	Emden EPT	989	989	989	989	989	989
DE	Poland	Mallnow	931	932	932	932	932	932
DE	Poland	Kamminke/Gubin/Lasow	0.0	0.1	0.1	0.1	0.1	0.1
DE	Russia	Greifswald	618	618	618	618	618	618
UK	Norway	Langeled	770	770	770	836	836	836
UK	Norway	Vesterled	396	396	396	451	451	451
UK	Norway	FLAGS	275	275	275	330	330	330
Total			**6,833**	**7,140**	**7,076**	**7,252**	**7,252**	**7,252**

P_m: Maximum technical production capacity

Maximum technical production capacity (P_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	0	0	0	0	0	0
DE	301	301	301	301	301	301
IE	0	104	104	110	94	92
LU	0	0	0	0	0	0
NL	2,994	2,218	2,156	2,144	1,959	1,818
UK	1,111	1,232	1,319	1,355	1,349	1,327
Total	**4,406**	**3,854**	**3,879**	**3,910**	**3,702**	**3,538**

S_m: Maximum technical storage deliverability

Maximum technical storage availability (S_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	170	170	170	170	170	170
DE	4,600	4,600	4,600	4,600	4,600	4,600
IE	33	33	33	0	0	0
LU	0	0	0	0	0	0
NL	4,180	4,180	4,163	4,163	4,163	4,163
UK	1,650	1,606	1,231	1,279	1,279	1,279
Total	**10,632**	**10,588**	**10,197**	**10,212**	**10,212**	**10,212**

LNG_m: Maximum technical LNG facility capacity

Maximum technical LNG facility capacity (LNG_m)	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE: Zeebrugge LNG Terminal	461	461	461	461	461	461
NL: Gate	399	399	399	399	399	399
UK: South Hook	649	649	660	663	663	663
UK: Dragon	297	297	297	229	229	229
UK: Isle of Grain	649	649	649	653	653	653
Total	**2,455**	**2,455**	**2,466**	**2,405**	**2,405**	**2,405**

D_{max}: 1-in-20 gas demand

1 in 20 gas demand (D_{max})	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
BE	1,307	1,303	1,357	1,466	1,478	1,490
DE	5,460	5,460	5,460	5,460	5,460	5,460
IE	207	221	206	277	281	288
LU	6	6	5	5	5	5
NL (1-in-50 demand)	3,729	3,648	3,678	3,692	3,678	3,664
UK	4,970	5,013	5,343	5,039	5,008	4991
Total	**15,680**	**15,651**	**16,048**	**15,940**	**15,910**	**15,898**

Assessed Margin	Historical Data			Projected Data		
	2015	2016	2017	2018	2019	2020
	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d	GWh/d
Technical capacity of entry points (EP_m)	6,833	7,410	7,076	7,252	7,252	7,252
Maximal technical production capacity (P_m)	4,406	3,854	3,879	3,910	3,702	3,538
Maximal technical storage deliverability (S_m)	10,632	10,588	10,197	10,212	10,212	10,212
Maximal technical LNG facility capacity (LNG_m)	2,455	2,455	2,466	2,405	2,405	2,405
Total peak supply	24,326	24,037	23,618	23,779	23,571	23,407
1 in 20 gas demand (D_{max})	15,680	15,651	16,048	15,940	15,910	15,898
Margin	8,646	8,386	7,570	7,839	7,662	7,509
Margin (%)	36%	35%	32%	33%	33%	32%