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FPS Economy, S.M.E.s, Self-employed and Energy

Risk assessment Belgium

After regulation No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply

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Executive Summary

The updated risk-analysis Belgium 2014 does not reveal particular concerns or risks to meet Belgian natural gas demand under normal and usual circumstances. The reasons for Belgium's robust natural gas system are various:

- Belgium is a crossroad for important gas flows from diverse sources and routes;
- Belgium's gas infrastructure does not face congestion to meet national gas demand nor to transport gas from border to border to supply neighboring countries;
- Several international supply companies with various types of supply contracts are active in Belgium together with a list of newcomers competing with each other;
- Belgium has achieved a well-functioning gas market with wholesale gas prices correlated and converged with gas prices in the neighboring markets;
- Belgium has a high level of market liquidity and intensive cross-border trades.

All these positive characteristics of the Belgian natural gas system provide confidence in secure gas supplies. However, there are some issues and concerns which require proper attention.

National Risks

Infrastructure

From the infrastructure point of view, incidents on major pipelines or interconnection points in Belgium can be handled by the transmission system operator for a limited period without significant impact on other sectors or end consumers. The remaining flexibility in the H-gas system is sufficient to cope with incidents for a certain period of time. Of all the risks listed under point 2.3., the risks most likely to occur for the Belgian gas supply are technical incidents on the pipelines, or IT problems or (local) loss of electric power supply which can cause very short interruptions on some of the installations. Issues with gas quality do also occur. This could be mainly an issue for the gas transmission to the UK as the gas from Qatar could fall slightly above the upper end of the Wobbe index for the UK, but also the industrial clients on the Belgian gas network face sometimes technical difficulties if the gas quality (in the Belgian Wobbe range) changes too rapidly.

At this moment, there is no physical congestion on the interconnections so shippers could (in theory) be able to renominate gas flows if an incident occurs on one of the other border points. As the Belgian TSO is not a supplier of last resort, the ability for the TSO to react to an incident depends a lot on the market behaviour of the shippers and suppliers. For the market players, it is not always evident to reallocate the flows. First of all the decisions are linked to the existing contracts, and secondly, they need time to analyse the situation on the available capacities (in Belgium and abroad). For L-gas the situation would be much more complicated. As there is hardly any flexibility left in the capacity, possible incidents are much harder to cope with during peak demand. However, as Belgium has never had only one incident on the L-gas network since the beginning of the gas flows from the Netherlands and measures are implemented to prevent a same incident in the future, we assume that the probability of disruptions from the Netherlands is rather low, but we will follow the current situation of the Groningen field very closely.

Molecules

On the molecule side, most of the larger gas suppliers can react swiftly to an incident by reallocating gas via other border points. Most of them have flexibility options with the gas producers or are active on the gas hubs. However, because of the market liberalisation, the EU wide portfolios of most of the shippers, and through the trades on the gas hubs, it is much harder to get a comprehensive overview of the gas flows for the Belgian end consumers. This will be important to see if the companies comply with the supply standard. In the preventive action plan, we will look more deeply into the supply standard and decide if it needs to be fulfilled by each shipper separately or by all shippers for Belgium as a whole[1]. Furthermore, Belgium deems it necessary to upgrade the supply standard so it achieves the same level as the infrastructure standard for the consistency of the approach.

As Belgium is an important transit country, it might be useful to take up a more regional approach for the N-1 calculations as now there is an abstraction of transit flows. Those might however be important for the protected customers in other countries.

Phase-out of low calorific gas (L-gas) and earthquakes in the Groningen region

Belgium is for 30% supplied by L-gas from the Netherlands. The announced production decline of the Groningen gas field and the impacts (and remaining risks) of earthquakes in the Groningen region, strongly impacts the Belgian L-gas market. Belgium faces challenges to organize a transition to a fully H-gas market. Especially the transition period in which L-gas consumers should progressively been switched to H-gas requires specific attention to security of supply (as well as safety) issues. This transition requires a coordinated approach between the Netherlands, Belgium and France. The threat of earthquakes provides an additional risk component which requires a high degree of flexibility in order to cope with any accelerated reduction of L-gas production, and consequently drop in L-gas exports, dependent on what the Dutch government may decide.

European risks

It has to be taken into account that not only national risks have to be taken into account. In case of possible risks in other countries of the European Union or abroad Belgium can still be affected. It is therefore important that such risks need to be investigated and that possible measures have to be taken into account by the European Union to avoid these risks.

EU gas market – new challenges for security of supply monitoring

The level of security of gas supply basically results from the commercial contracts between producers, wholesalers, retailers and final consumers. Gas trading within the EU is more and more international in which national borders disappear. The move to an internal energy market in Europe has replaced the nations by the European market places (hubs) where gas demand meets gas supply at a certain price level. Certainly in NW Europe (more than 55% of the EU consumption) where market integration, price convergence and correlation are almost perfect, are the markets the places where gas flows are attracted and sourced from diverse routes to meet demand. Furthermore, these markets and supply/demand portfolio are internationally organized. In this environment it is not possible anymore to discuss in a straightforward manner

[1] The last option might create free riding amongst the suppliers.

supply/demand on a national level in terms of gas sources used or the role of "national" UGS facilities. Market liquidity is no pure matter anymore of local supplies or local UGS or local LNG terminals etc. but depends largely on cross-border trading and swapping between markets. Commercial mechanisms which are made possible thanks to mitigating any congestion or market access obstacles. In this environment a well-functioning of gas market is the starting point for delivering security of gas supply at reasonable prices. Any interventions may be needed once the capabilities of the market to supply customers are exhausted.

Indirect threats from shocks elsewhere in Europe

Belgium's security of supply is sensitive to events elsewhere in Europe since gas flows to Belgium are for more than 50% cross-border traded to other EU-countries. Any shortage of gas in the EU will have an impact on the wholesale gas prices. Natural gas prices may increase and impact the economy. Market integration contributes to security of gas supply within the EU but at the same time makes markets more sensitive to shocks elsewhere in the EU, events which are primarily reflected in the gas wholesale prices to pay.

Current market mechanisms within Europe imply that e.g. Belgium - only marginally depending on gas flows from Russia - will feel the impacts of any cut in Russian gas supply to Europe. Wholesale prices will increase according to the drop of Russian gas volumes to Europe. Since the high level of market integration and cross-border price convergence, Belgium will also face higher wholesale gas prices. Depending on the alternative (more expensive) sources (e.g. LNG) and the nature of the cut in Russian gas exports (level and duration), higher price levels may have a structural impact without endangering the supply of gas to Belgium as such. Obviously, security of gas supply does not only mean the safeguarding of natural gas availability but includes also the requirement of gas supplies at reasonable prices. In a market environment, any gas shortage will primarily be reflected in an increase of gas prices and an adaptation of supply as well as demand. A well-functioning natural market is crucial in which price signals have the capability to attract new gas volumes from new sources. This market mechanism requires sufficient transmission capacity and easy access to networks, as is the case in Belgium for cross-border trading.

Risks related to electricity black-outs

It should be recognized that there is an important link between gas and electricity. For example gas-fired power plants but also compressor station on the gas network which are more and more electricity-driven. So it is important to stay alert for possible treats and to investigate how the dependency of the electricity and gas sector can have an impact on one another. The mutual dependency between gas and electricity is a topic that should deserve more attention from us in the future. But also the EU also should encourage to investigation of the possible dependency, not only on national levels but also on regional levels.

Risks related to less commercial viability of UGS and LNG terminals in the EU

The current gas economics provide often more competitive alternatives to physical storage and LNG supplies. A prerequisite for security of gas supply in the EU is the access to various infrastructure facilities including UGS and LNG terminals. As long as no (contractual) congestion is observed on cross-border interconnection points and cross-border trade is facilitated, it is not a prerequisite that the required UGS (nor LNG facilities) is located in each country.

Introduction

The intention of the Regulation 994/2010 of the European Parliament and of the Council Concerning Measures to Safeguard Security of Gas Supply is to prevent the kind of gas crisis situations EU-27 experienced in January 2009. One of the means considered in the Regulation to achieve this target is performing a full risk assessment. Article 9[2] of the regulation on "Risk Assessment" is of great importance in this regard:

Each Member State shall make a full risk assessment of the risks affecting its security of gas supply by:

(a) ***using the standards specified in Articles 6 and 8*** *(infrastructure standard and supply standard)*
(b) ***taking into account all relevant national and regional circumstances****,*
(c) ***running various scenarios*** *of exceptionally high gas demand and supply disruption, such as failure of the main transmission infrastructures, storages or LNG terminals, and disruption of supplies from third country suppliers, taking into account the history, probability, season, frequency and duration of their occurrence as well as, where appropriate, geopolitical risks, and assessing the likely consequences of these scenarios;*
(d) ***identifying the interaction and correlation of risks with other Member States****,*

The first risk assessments are due by 3 December 2011. The Federal Public Service of Economy, S.M.E.s, Self-employed and Energy (DG Energy) has been officially appointed as the provisional Competent Authority for Belgium and has prepared a Risk Assessment on the security of gas supply as required by the Regulation 994/2010. Roughly, the timeframe of the Belgian actions was the following:

27 Dec 2010	Designation of 'temporary' competent authority (FPS Economy)
26 Jan 2011	Kick-off meeting with largest gas companies and TSO
Feb-April 2011	Discussion with individual gas companies and TSO
30 May 2011	Workshop risk assessment GCG
End June 2011	Gas questionnaire for all gas shippers and suppliers
27 June 2011	Round table discussion on risk identification & risk analysis
26 August 2011	Bilateral consultation FR on risk assessment
13 Oct 2011	Gas platform: discussion on risk assessment
End Oct 2011	Draft document on the risk assessment
Nov 2011	Final consultation with stakeholders
3 Dec 2011	Submission final version to the Commission
3 June 2012	Submission Preventive Action Plan
3 June 2012	Submission Emergency Plan

[2] Regulation no 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply.

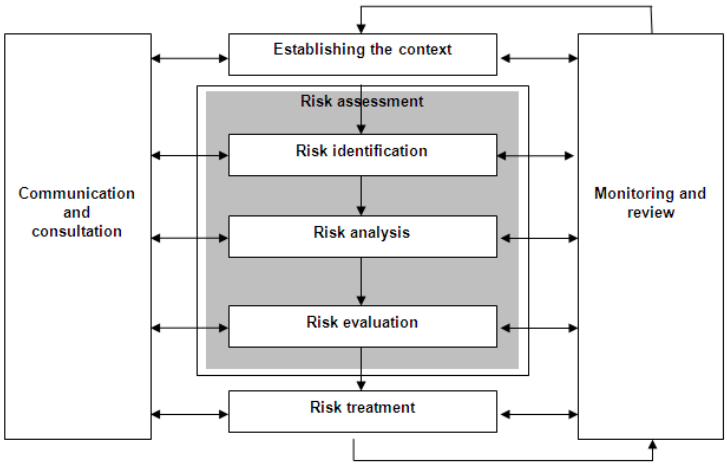
3 June 2014	1st Update Risk assessment

The Competent Authority is responsible for ensuring the implementation of the measures set out in the regulation. However, there is also an important role in the establishment of the risk assessment for the TSO Fluxys Belgium (N-1 calculation, reverse flow study, risk scenario's,…), the NRA CREG (market based measures, risk identification & analysis,…) and the shippers & suppliers (supply standard,…). Natural gas undertakings, the transmission system operator, industrial gas consumers, organisations representing interests of households and the NRA shall cooperate and provide the Competent Authority upon request with all necessary information.

The risk assessment gives a first indication of the main risk for Belgium's gas security of supply. The actions taken to prevent and mitigate the risks were taken up in the preventive action plan and in the emergency plan that was established by the end of 2012. An update of this preventive action plan and emergency plan will be made by the end of 2014.

Structure of the risk assessment

The International Standard on risk management ISO 31000 was suggested by the Joint Research Centre (JRC) of the European Commission. Belgium decided to make use of this international and commonly accepted ISO 31000 standard for its risk assessment.



The methodology is structured in five steps:

- Step 1: Establishing the context of the Belgian gas sector
- Step 2: Risk identification
- Step 3: Risk analysis
- Step 4: Risk evaluation
- Step 5: Risk treatment

1. Establishing the context: Components of the Belgian gas system

1.1. Introduction

The context of the Belgian gas system will be described according to the following five parameters:

- Institutional context
- Regional context
- Supply and demand - context
- Gas infrastructure (capacity) context
- Gas infrastructure utilization & contracts

1.2. Institutional context

1.2.1. The competences on federal and regional level

Competences on energy in Belgium are divided over the federal state and the regions. There are three regions in Belgium, the Flemish region, the Walloon region and the Brussels region with each their own regulator and their own competences.

The federal government is responsible for the following:

- the national equipment program for the electricity sector
- de nuclear fuel cycle
- large infrastructure for storage, transmission, LNG terminal and production of energy
- tariffs

The regions are competent for:

- distribution and local transport of electricity on the network with a voltage inferior to 70.000 volt
- public gas distribution
- use of mine gas and blast-furnace gas
- district heating
- valorisation of stone piles
- renewables with the exception of those on the Belgian Continental Platform
- energy recovery by the industry and other users
- rational energy use

The federal government is competent for all subjects of the general interest that were not explicitly taken up in the competences of the regions, so security of energy supply remains one of the competences of the federal government.

There are four regulators in Belgium – one federal and three regional ones. The CREG, the federal regulator, monitors the natural gas market and approves transportation and distribution tariffs and other regulated assets. It also has a general advisory role on gas markets. Regional regulators (VREG of Flanders, CWaPE of Wallonia and Brugel of Brussels-Capital) also have legal powers to monitor the distribution of natural gas and ensure compliance with regional public service obligations. The table below gives an overview of the competences of the regulators.

Table 1 : the competences of the regulators on federal and regional level

Federal CREG	**Flanders** VREG	**Wallonia** CWaPE	**Brussels-Capital** Brugel
• Control TPA; approve conditions of TPA into transmission networks • Control execution of plans regarding development of the natural gas transmission network and continuity of supply • Ensure that public service obligations are fulfilled by suppliers and the network operator • Work with the competition authority • Verify the absence of cross-subsidies between categories of clients • Approve the tariffs charged for using the transmission and distribution network	• Distribution of natural gas • Appoint DSOs • Grant delivery licenses to suppliers • Technical regulations for the management and expansion of the distribution network • Provide mediation regarding disputes • Ensure compliance with legal and statutory functions • Advise the Flemish government on operation of the Flemish energy market • Ensure that public service obligations are fulfilled	• Distribution of natural gas • Technical regulations for the management and expansion of the natural gas distribution network • Ensure compliance with legal and statutory functions • Advise the Walloon government on operation of the Walloon energy market • Ensure that public service obligations are fulfilled • Control the eligibility of clients for the competitive market	• Distribution of natural gas • Ensure compliance with legal and statutory functions

1.2.2. Legal arrangements for security of gas supply

1.2.2.1. Main legal framework

Two main legal acts cover the global framework for the security of gas supply. The first one is the law of 22 January 1945 on the economic regulation and prices (modified by the law of 30/07/1971) which states in article 3 that:

- Ministers having the Economic affairs, the Agriculture or the Supply in their attributions can, each one in what relates to it, prohibit, regulate or control

    - the following activities : import, production, manufacture, preparation, detention, transformation, use, distribution, purchase, sale, exposure, presentation, offer on sale, delivery and transport
    - the following items : products, matters, food products, goods and animals that they indicate.
- Possibility for the concerned Minister to reduce or suspend, temporarily or definitively, the supply of all people or companies devoting itself to one of the above mentioned activities
- Possibility to proceed or to make proceed to the requisition of products and goods

The second is the gas Act of 12 April 1965 (with several modifications):

> "The King can […] take any necessary safeguarding measure in the following cases:
> threat of crisis or sudden crisis in the energy market;
> the security of supply in the country is threatened;
> threat on the physical security or the safety of people, equipment or installations;
> threat on the integrity of transport networks.

1.2.2.2. Specific legislation related to public service obligations (PSOs)

Furthermore, there is some specific legislation related to public service obligations (PSOs). As required by the security of gas supply regulation, the legislation related to PSOs was communicated in February 2011 to the European Commission. Hereafter those PSOs are described.

National legislation

- Article 15/1 of the Gas Act (12/04/1965), modified by article 20 from the law of 01/06/2005: general obligation related to the responsibility of the exploitation and development of the gas installations
- Article 15/11,§1 of the Gas Act (12/04/1965), modified by article 109 (law of 22/12/2008) and article 5 (law of 27/02/2003) = PSO on the necessary investments (al.1°) and on both the regularity and quality of supplies (al. 2°)
- Royal Decree of 16/12/1999 giving a list of priority consumers in case of supply disruption
- Ministerial Decree of 23/10/2002 related to PSOs in the gas market = implementing decree for already mentioned article 15/11, §1, al.1° (Gas Act of 12/04/1965) and indicating specific cases where supply disruption is authorized
- Article 1 of the Gas Act (12/04/1965), modified by article 2 from the law of 11/6/2011: Law to amend the Act of 12 April 1965 on the transport of gaseous and other products by pipeline
- Article 1,2 ,15/13 of the Gas Act (12/04/1965), respectively modified by article 55, 56, 86 from the law of 08/01/2012: Law to amend the Act of 29 April 1999 on the organization of the electricity market and the Act of 12 April 1965 on the transport of gaseous and other products by pipeline
- Ministerial Decree of 18/12/2013 establishing the federal emergency plan for natural gas supply

Regional legislation: (distribution network)[3]

- The Flemish « Energy Decree » on energy policy (08/05/2009) concerning i.a. the DSO's responsibilities (art. 4.1.6) and Public Service Obligations imposed to DSO's & suppliers (art. 4.1.16, 4.1.19, 4.1.20, 4.1.22, 6.1.1, 6.1.2., 7.5.1)
- The Flemish « Act » on energy policy (19/11/2010) concerning the organisation of the gas market including Public Service Obligations (several articles under title III)
- The Flemish «Technical Regulation Gas Distribution» by Ministerial Decree (21/01/2010) concerning Planning Code (Chapter II)
- The Walloon « Decree » on gas market (19/12/2002) concerning i.a. the DSO's responsibilities (art. 12) and the Public Service Obligations imposed to DSO's & suppliers (art. 32-33)
- The Walloon « Decree » on gas market (19/12/2002) concerning i.a. the DSO 's Investments Plan called Adaptation Plan (art.16) aiming to ensure the continuity of supply, the safety, the development and the extension of the network
- The Brussels « Ordonnance » on gas market (01/04/2004, modified by Ord. 14-12-2006 and by Ord. 20-07-2011) concerning i.a. the DSO's responsibilities and tasks (art. 5) and the Public Service Obligations imposed to DSO's & suppliers (art. 18)
- The Brussels « Ordonnance » on gas market (01/04/2004, modified by Ord. 14/12/2006 and by Ord. 20-07-2011) concerning i.a. the DSO 's Investments Plan (art. 10) aiming to the continuity and the security of supply

1.2.2.3. Other legislations related to security of gas supply

a. Prospective studies and the TSO's investment plans

The article 34 of the Gas Act (12/04/1965, modified by the law of 01/06/2005) foresees the framework of carrying out a prospective study on security of gas supply. This study aims to help the government to formulate a policy on the matter and to take the necessary measures in time. It analyses the possibilities of carrying out the adequacy between the gas supply and demand in the medium and long term. They have a horizon of at least 10 years.

The prospective studies analyse also the network capacity and more precisely whether the required investments to guarantee the security of supply can be realized (in the event of engineering problems or insufficient dimensioning of the network). Besides those studies, there are two other reference documents on the investments to be realized by the market: the TSO's (Fluxys Belgium) ten-year indicative investment programme (updated each year) and the Transmission program (catalogue of transmission services marketed by Fluxys Belgium).

b. Social dispute

The Regent's Decree of 29/01/1949 foresees the situation of gas shortage in case of social dispute in the gas sector. Amongst the Ministers concerned, the Minister in charge of Economic Affairs and Self-employed is responsible for implementing this decree.

[3] Annex I describes some regional technical legislation related to security of supply

c. Specific aspects related to security and safety requirements

=> TSO's responsibility (Fluxys Belgium)

- The TSO is responsible for crisis mechanisms (see royal decree on public service obligations on gas of 23 October 2002).
- The TSO has to set up an plan for incident management and a back-up plan. A 2-yearly update is mandatory.
- The TSO has to respect the Code of conduct (range of operational and administrative guidelines for the users of the gas network) which indicates i.e.
- Plan for incident management and shut-off plan (see royal decree of 23/12/2010)

=> KLIM (Kabel en Leidingen Informatie Meldpunt)

Following to the Ghilenghien disaster, a Cable and Pipeline Information Point (the KLIM) was set up. It collects and monitors the location of all cables and pipelines in Belgium in order to prevent accident with pipelines.

=> Coordination between regional and national emergency planning

The general crisis policy is supervised by the Coordination and Crisis Centre of the Government (CCCG) linked to the Federal Public Service "Home Affairs" (see royal decree of 31/01/2003 related to the emergency plan). The CCCG's action covers the following cases:

- vital interests or essential needs (production and distribution of energy are parts of them) of the population are threatened;
- urgent decisions are needed to be taken;
- coordinated effort of various departments and organizations are needed.

The Federal Public Service "Economy" has set up 2 coordination units for this general crisis policy: the Crisis Cell and the Bureau of Civil Plans for Defense.

1.2.3. Intergovernmental agreements

Belgium signed the following intergovernmental agreements with non-EU countries:

1. Agreement signed with **Norway**
   Date of signature : 14/04/1988
   - Subject : transmission by gas pipeline coming from the Norwegian continental Shelf and from other areas by Pipeline to the Kingdom of Belgium (it concerns in particular the pipeline called « **Zeepipe** » starting in Norway and ending at Zeebrugge)
   - Agreement legally approved under the law of 19/09/1991 (published on 20/09/1993 in the official journal for publication of Belgian legislation)

2. Agreement with **Norway** (based on the above mentioned agreement)
   - Date of signature : 19/11/1993
   - Subject : Agreed procedures for safety supervision of the gas pipeline from the Norwegian Continental Shelf to Belgium (**Zeepipe**)

- The signing parties are the Norwegian Authorities represented by the Norwegian Petroleum Directorate (NPD) and the Belgian counterpart represented by the Ministry of Economic Affairs
- This agreement replaces the precedent agreement signed by NPD in December 1989 and by the Ministry of Economic Affairs in January 1990.

3. Agreement signed with **Norway**
   Date of signature : 20/12/1996
   - Subject : Laying of the gas pipeline called « **Norfra** » on the Belgian continental Shelf (it concerns in particular the definitive delineation of the course of the pipeline)
   - Agreement legally approved under the law of 13/05/2003 (published on 05/11/2003 in the official journal for publication of Belgian legislation)

1.2.4. Market liberalisation in Belgium

Liberalisation of energy markets in Belgium has taken place in gradual steps and the pace of reforms has varied among the regions. Flanders fully legally opened its gas market on 1st July 2003. Wallonia and Brussels-Capital opened the market to industrial consumers in 2004 and to residential ones in 2007. The overall Belgian gas market has been fully liberalised since 1st January 2007 when supplier choice was granted to all consumers in all the regions.

Gas transmission and distribution have been legally unbundled from import and supply activities. On 1 December 2001, the activities of Distrigas, the incumbent player on the Belgian gas market, were split through which the supplier activities remained by Distrigas and the transmission activities went to Fluxys. The Belgian municipalities (through Publigas) held a participation in both the activities. In 2006 Suez and Publigas were to sign an agreement about the conveyance of transit activities of Distrigas to Fluxys. In March 2006 Fluxys was appointed by law as the only operator of the natural gas transmission grid and the underground gas storage facility and Fluxys LNG as the operator of the LNG terminal.

Historically, the Suez group and its subsidiaries had the dominant position on the Belgian distribution market. After the merger of Suez with GDF, the GDF Suez group became the most important player on the Belgian gas market. Because of the fusion of Suez with Gaz de France, Suez was forced by European legislation to sell all its shares in Distrigas. Also, because of her dominant position in the Belgian gas market, Suez had to reduce her participation in Fluxys from 57,25% to 44,75%. In November 2008, the Italian company ENI bought shares in Distrigas, the largest supplier, from GDF Suez (57,24%) and municipalities (31,25%). At the same time, Distrigas sold the transit activities it held (through its affiliate Distrigas & Co) to Fluxys, the latter also acquiring GDF's share of their common Belgian transit subsidiary (SEGEO).

In this way, Publigas could increase its shares in Fluxys by 12,5% to 45,22%. In 2007 and 2008 several other regulatory reforms took place: the gas transmission and distribution tariff system was amended and the powers of the regulator were reinforced.

The table below gives an overview of the market structure as it exists today with the key players on the Belgian gas market and the status of different activities.

Table 2: Structure of the Belgian gas market

Unbundled activities	Players	Status
Import	ENI, GDF Suez, Wingas, EDF, …	Free competition
Transmission network	Fluxys Belgium	Regulation (CREG)
Distribution network	17 DNO's	Regulation (CREG/regional regulators)
Supply	ENI, ECS, Luminus, Nuon, SPE, GDF,….	Free competition
Taxes	Governments: federal and regional	Laws and decrees (through TSO, DSO, supplier)

Thanks to those developments, all Belgian border-to-border transmissions are now controlled by Fluxys Belgium. These developments have decreased the predominance of the GDF Suez group, although its affiliates Electrabel Custromer Solutions (ECS) and GDF jointly still own significant market shares. Until May 2010, GDF Suez also still has an important stake in the transmission system operator, Fluxys. On 8 December 2009 the gas law was amended to impose strict corporate governance rules and an independent functioning of the TSO. Therefore, gas companies were no longer allowed to have more than 24,99% of the shares of the TSO. Because of this law, Suez was obliged to sell another part of its shares. In March 2010, Suez had an agreement to sell all its remaining shares in Fluxys to Publigas. After this, Publigas and Fluxys carry out a reorganisation of the company to comply with the gas law of 10 September 2009 that prohibits the TSO to have participations in supply companies or their affiliates. Therefore, the Fluxys Holding, now Fluxys, was created to take over the shares that were held by Fluxys Fluxys Europe in the BBL company (exploiting the pipeline between Balgzand and Bacton) and in Interconnector The Fluxys group now consists out of three building blocks:

- Fluxys Belgium: the TSO responsible for all regulated activities (transmission and storage of gas and terminalling of LNG) in Belgium
- Fluxys Finance: responsible for treasury and management of the financial risks
- Fluxys Europe: responsible for all non-regulated activities outside Belgium

End March 2011, Publigas sold 10% of the shares in Fluxys G[4] to the Canadian fund company "La Caisse de depot et placement du Québec". This was increased to 20% on 22 September 2011 This capital increase is intended to support Fluxys G's investment program, including the acquisition of interests of Eni, an Italian company active in the energy sector, in TENP (Germany) and Transitgas (Switzerland) pipelines, instrumental in supplying gas to the German, Swiss and Italian markets.

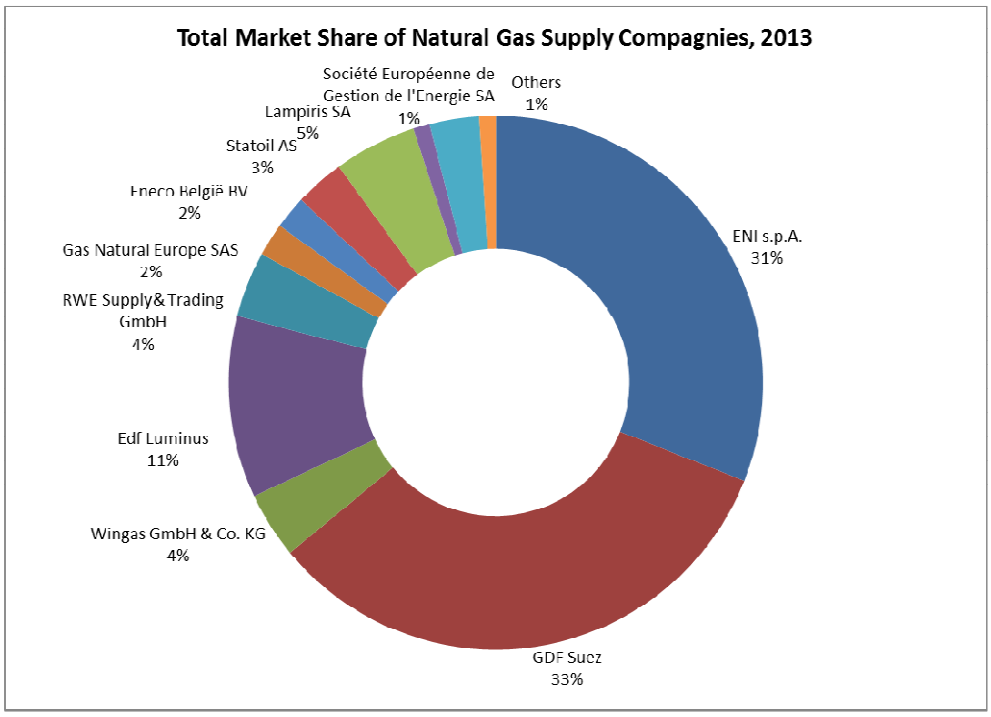
The Belgian government has no ownership in the upstream/downstream but still has a golden share in Fluxys and ENI.

[4] Fluxys G: the old name of Fluxys

1.2.5. The Belgian wholesale and retail market

Wholesale market players in Belgium provide natural gas to 17 distribution companies and to about 250 large industrial end-users and power plants connected directly to the transmission grid.
The graphs show the total market shares of all the suppliers active on the Belgian gas market.

Figure 1: Market Shares of Natural Gas Supply Companies, 2013



Source: CREG

The market liberalisation has created the possibility to establish a wholesale market in which gas can be sold to other suppliers with their own portfolio. Historically, gas was (and for a large part still is) imported through long term contracts between the producers and suppliers. The creation of a wholesale and a retail market makes the decoupling possible between the gas producer and the final gas supplier. In order to have a good functioning of the gas market with a high security of supply, it is important to have a liquid market. This liquidity can be increased by the development of the gas hub. In the national gas trade, Zeebrugge has a key commercial role as one of Europe's major spot markets for natural gas. Huberator, the operator of the Zeebrugge Hub, facilitates over the counter trading of natural gas, while exchange-based trading is operated by APX Gas ZEE, established in 2005. It provides a spot market for trading of within-day and day-ahead gas contracts.

For the retail market, it is important to know that Belgium has two different types of gas: H-gas (with high caloric value) and L-gas (with low caloric value). The L-gas market serves a quarter of the Belgian consumption and supplies certain regions exclusively, including the Brussels region. Most of the customers connected to the L-gas grid are households.

1.3. Regional context

1.3.1. Belgium in the North-West gas region

Belgium serves as an important transit country for gas either coming through pipelines or LNG. Being located in the middle of the largest gas consumer markets in the EU (UK, DE, FR and NL), Belgium is very well placed with its highly interconnected transmission network. The Zeebrugge area is one of the most important natural gas landing points in the EU28. Connecting to a variety of pipeline gas and LNG sources, the Zeebrugge area has an overall throughput capacity of about 48 bcm/y. This corresponds with roughly 10% of the border capacity needed to supply the EU28. As for pipeline gas flows, the Zeebrugge area gives access to natural gas from Norwegian and British offshore production fields in the North Sea as well as from Germany. Worldwide LNG supply is accessible through the Zeebrugge LNG terminal. The terminal has three primary shippers and standard provisions are in place to facilitate spot LNG deliveries. Any LNG or pipe gas brought into the Zeebrugge area can be traded at the Zeebrugge Hub or shipped through the Fluxys Belgium grid for delivery into the Belgian market or redelivery at one of the borders for onward transmission to the United Kingdom, the Netherlands, Germany, the Grand Duchy of Luxembourg, France and Southern Europe.

1.3.2. Gas regional initiative

The development of regional gas markets is an important and practical intermediate step towards the eventual goal of a competitive, single-European gas market. On 25 April 2006, ERGEG launched the Gas Regional Initiative (GRI) to speed up the integration of Europe's national gas markets. The GRI created three regional gas markets in Europe (North-West; South South-East; and South regions) as an interim step to creating a single-EU gas market. Belgium is part of the North-West regional initiative in which also The Netherlands, France, Ireland, Great Britain, Germany, Denmark, Sweden, Northern Ireland and Norway (observer) are involved. The goal of the regional initiative is to tackle barriers to competition, such as the lack of market integration, transparency and balancing issues.

In 2008, the Secondary Market pilot project was initiated as to establish online platform(s) for the trading of firm secondary gas transport capacity rights on a day-ahead basis. Belgium and France have established a platform named Capsquare to buy or sell secondary market capacity in the Fluxys network (Belgium), and in the GRTgaz network (France). It also proposes primary capacity for both networks at once through the Bundled Fluxys-GRTgaz product Zeebrugge Hub to PEG North. Companies that hold capacity they do not intend to use can valorise it at market price by selling it through the Capsquare platform. It also provides an alternative source for the standard primary market as single capacity can be booked on the secondary market and bundled capacity on the primary market.

1.3.3. Gas platform

Belgium is part of the regional Gas Platform that brings together energy ministers from Belgium, Germany, France, Luxembourg and the Netherlands. Two working groups operate in the framework of this Platform: 1) on market and competitiveness issues, and 2) on security of supply. The objective of the first working group is to facilitate cross-border trade. Its priorities include regional view on allocation mechanisms; more compatible balancing

regimes; market alignment/integration, transport procedures in different countries. The priority of working group two will be the implementation of the regulation 994/2010 on security of gas supply. The Member states of the Penta region currently do not foresee a joint regional risk assessment or the establishment of regional plans. However, close cooperation on regional level will be organised for the following items: methodology of the risk assessment, change of views on the preventive action plan and the emergency plan, discussions about the reverse flow projects, the interaction on the simulation of disruption scenarios and one item that is very specific for the North-West region, namely the Dutch planned phase-out of L-gas.

1.3.4. L-gas market

Belgium has two different types of gas: H-gas (with high caloric value) and L-gas (with low caloric value). L-gas is mainly originating from the Groningen field in the Netherlands (Groningen gas). To be able to import or inject the L-gas into the Belgian L-gas network, the gas needs to fulfil certain quality specifications, amongst others, the gas needs to have a Wobbe index between 43,9 MJ/m³(n) et 46,89 MJ/m³(n). For H-gas, the Wobbe index is situated between 49,13 MJ/m³(n) et 56,81 MJ/m³(n). This lower Wobbe index is compensated through a higher pressure in the public distribution network. The average pressure for non-industrial clients in the distribution network is about 25mbar, while for the H-gas the average pressure is 20 mbar.

Those different characteristics for L and H gas end in having two different infrastructure networks and two separate commercial markets in Belgium, one for L-gas and another for H-gas.

Dutch supplies are reliable and the L-gas is of good quality. Having a reliable gas producer so close to the Belgian gas market surely increases the security of gas supply. However, the current situation will not be sustainable in the very long term: a large part of the Belgian consumers depend on one single source of gas, which may come to an end in the future. Following the official communication of the Dutch Ministry of Economic Affairs mentioning the reduction of the L-gas export towards the Belgian market as form 2024, a conversion project will be necessary to replace the L-gas by H-gas.

As this is a very specific item for our region, Belgium has set up a task force on L-gas who deals with the security of supply of the L-gas market. In this task force experts form the energy administration work together with the regulators, TSO's and suppliers from Belgium, the Netherlands and France. Some the challenges in the near future due to the L-gas conversion are: what to do with the Poppel connection, will there be enough storage, winter and summer analysis, possible regional effects…. It is therefore necessary to make a simulation exercise together with Fluxys Belgium to see what possible effects are as well as to see what possible investments will be.

1.4. Supply and demand

1.4.1. Supply

1.4.1.1. Current and projected gas supply

Gas represents roughly 26% of the total primary energy supply. Belgium's TPES grew steadily in the period from 1983 to 2003, with an annual average growth rate of 2%, reaching a peak of nearly 59 million tonnes of oil equivalent (Mtoe) in 2003. TPES has slowly decreased since 2003, and is expected to continue to decline, totalling some 55,5 Mtoe in 2020.

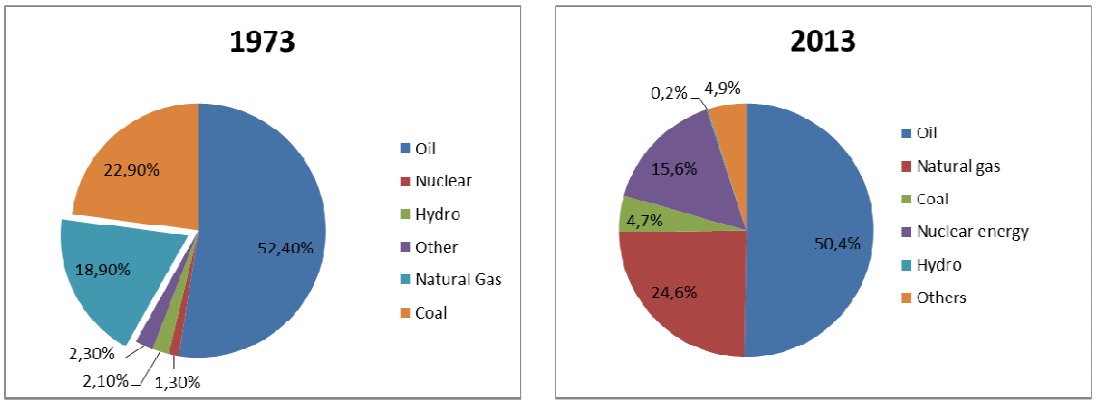


Figure 2: Natural gas imports as part of the total primary energy supply in 1973 and 2013

Source: IEA, BP Statistical world Review

Nevertheless, natural gas demand is expected to rise sharply, as new power generation to replace ageing power facilities by 2020 is mainly gas-fired. But at the moment the economic conditions for gas-fired power plants are not favourable.

The foreseen nuclear phase out will probably have a considerable impact on the Belgian gas sector. All seven nuclear reactors are planned to be shut down in the future. The table below lists these seven reactors, with their installed capacity, start and probable end date. Currently the nuclear reactors of Doel 3 and Tihange 2 are temporarily closed. If these reactors stay closed for the coming months (especially during the winter period) this could have an effect on the gas consumption in Belgium.

Table 3: Nucleair power plants in Belgium (2008 figures)

Nuclear installation	Installed capacity (MW)	Start date	End date
Doel 1	392,5	15 February 1975	2015
Tihange 1	962	1 October 1975	2025
Doel 2	433	1 December 1975	2015
Doel 3	1.006	1 October 1982	2025
Tihange 2	1.008	1 February 1983	2023
Doel 4	1.008	1 July 1985	2025
Tihange 3	1.015	1 September 1985	2025

In November 2008, a group of experts was asked by the Minister of Energy, to produce a report (GEMIX) on the ideal energy mix for Belgium in 2020 and 2030. On the basis of this report, the Belgian government declared in October 2009 that the lifetime of the three oldest nuclear reactors (Doel 1 & 2 en Tihange 1) will be prolonged by 10 years. In total, more than 5.800MW of installed (nuclear) capacity will have to be replaced in the coming decades. Obviously, this could have a huge impact on the gas needs of Belgium in the decades to come. One of the risk scenario's described below will focus on the possible impact of a nuclear phase out. In 2012, the Belgium government decided to prolong the lifetime of Tihange 1 with 10 years, from 2015 to 2025.

1.4.1.2. Gas imports

Belgium has no indigenous gas production; so we rely entirely on imports for our gas consumption. 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. The majority of gas imports are still based on long-term contracts. This is thanks to the presence of large shippers on the Belgian market. 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.

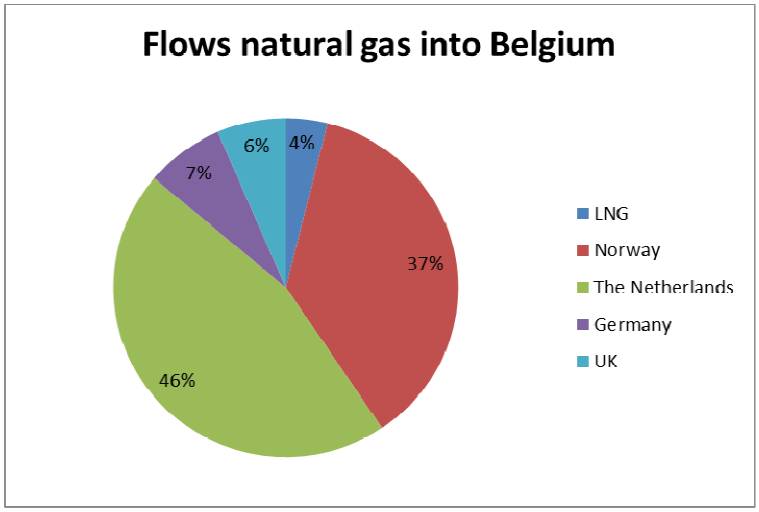


Figure 3: Physical flows of natural gas into Belgium in 2013

Source: Fluxys, FOD

As most European countries, we do note a decrease in the diversification of our import portfolio. Still Belgium has a good score on the HHI- index. HHI means the Herfindahl-Hirschman Index, a commonly accepted measure of 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. Belgium has an average score compared to other member states (based on the figures of the EC report on the energy market).

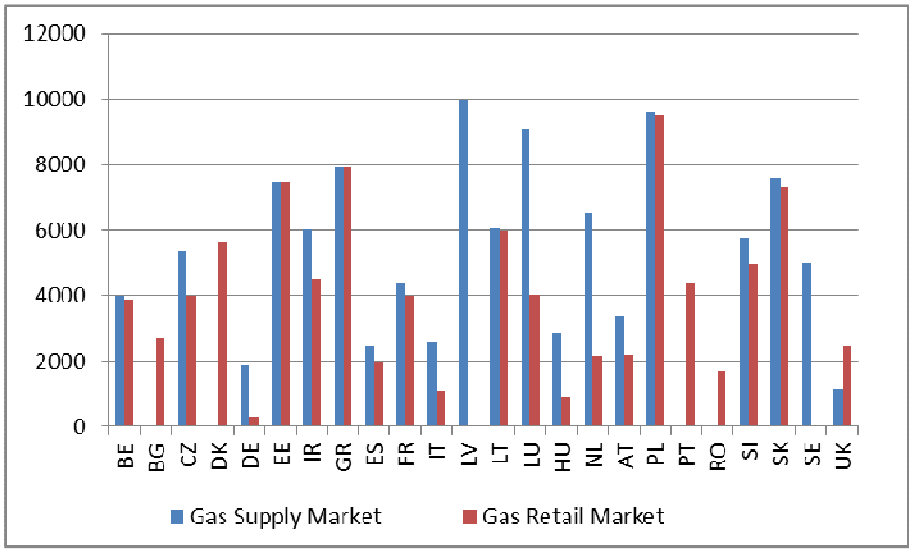


Figure 4: HHI in national gas supply and retail markets according to the report of the energy markets in 2011

Source: EC report on the energy markets in 2011

As we look at the European gas reserves and production rates for conventional gas, we see that most of them will only last for about one production decennium. The table below gives an overview of the reserves, production and the lifespan of the gas reserves in Europe in 2012. According to the BP statistical review of world energy 2013, 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 long 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 ratio with the ones of 2009 (for the Netherlands 17,3 and Norway 19,8), it is noticeable that the new ratio are smaller than those of 2009, this because the production in those countries increased.

Table 4: Natural gas reserves and production in 2009

	Production		reserves	
	2009	Change 2009 over 2008	trillion cubic meters	R/P ratio*
Denmark	**8,4**	-16,3%	**0,06**	7,6
Germany	**12,2**	-6,3%	**0,08**	6,4
Italy	**7,4**	-12%	**0,06**	8,6
Netherlands	**62,7**	-5,6%	**1,09**	17,3
Norway	**103,5**	4,5%	**2,05**	19,8
Poland	**4,1**	0,3%	**0,11**	26,6
Romania	**10,9**	-4,2%	**0,63**	57,9
United Kingdom	**59,6**	-14,1%	**0,29**	4,9

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

Source: BP Statistical review of World Energy 2010

Table 5: Natural gas reserves and production in 2012

	Production (in billion m³)		reserves	
	2012	Change 2011 over 2012	trillion cubic meters	R/P ratio*
Denmark	**6,4**	-9,4%	**0,04**	5,9
Germany	**9,0**	-9,8%	**0,06**	6,1
Italy	**7,8**	1,7%	**0,06**	7,0
Netherlands	**63,9**	-0,8%	**1,04**	16,3
Norway	**114,9**	12,6%	**2,09**	18,2
Poland	**4,2**	-1,1%	**0,12**	28,3
Romania	**10,9**	<0,05%	**0,10**	9,3
United Kingdom	**41,0**	-14,1%	**0,25**	6,0

*R/P = lifespan of the reserves at the current production rate
Source: BP Statistical review of World Energy 2013

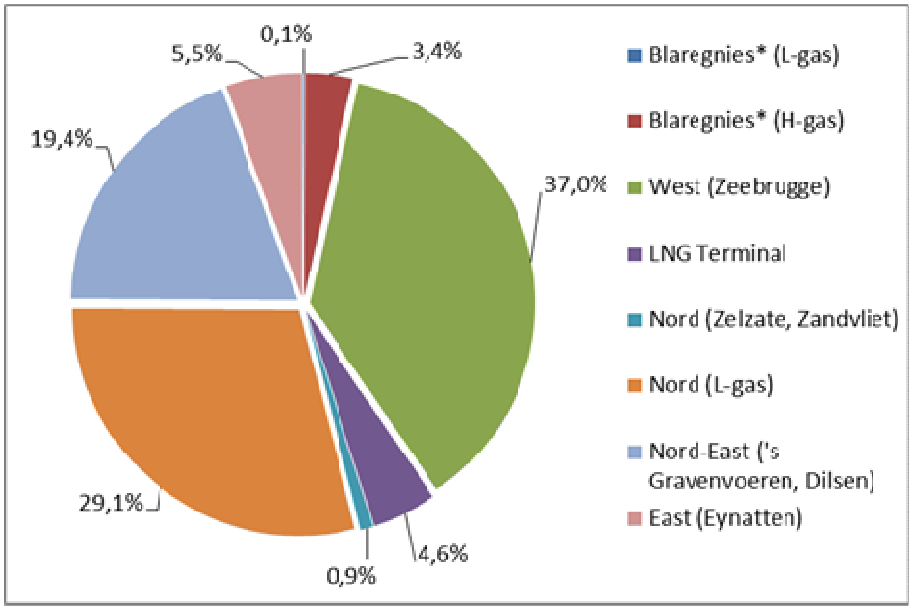
Since The Netherlands and Norway represent together 70% of the natural gas imports of Belgium, substantial alternative supplies will need to be available to replace the declining gas supplies from the Netherlands and Norway in due time. In the long run, these developments will most likely cause an increased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

1.4.1.3. 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 5). 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**

Figure 5: Distribution of the entry volumes in 2013

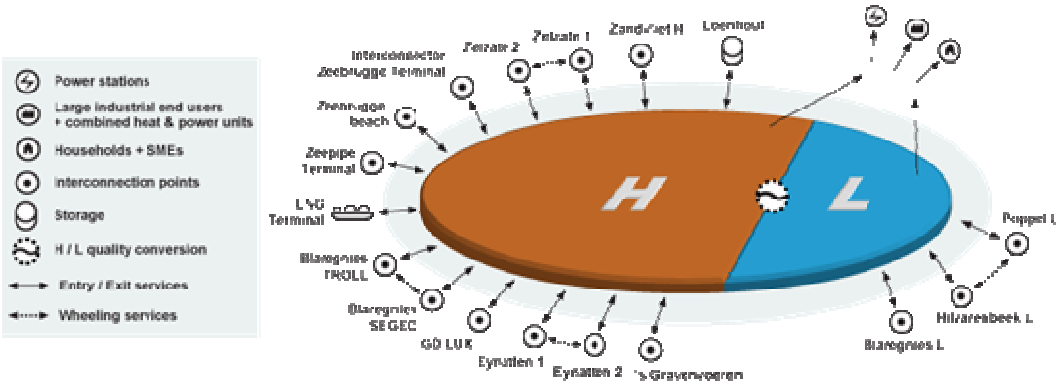


Source: CREG; *The entry points of Blaregnies are opposite to the physical flows (reverse flows) by making use of the dominant transits on these points

Figure 5 illustrates that most gas comes to Belgium via pipelines. 4,6% 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 onward transmission 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].

1.4.1.4. Entry-exit model

Figure 6: Entry-exit model Belgium, 2012



Source: Fluxys

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 14 interconnection points with neighboring 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 the Grand Duchy of Luxembourg
- natural gas is also passed on to other end-user markets from the LNG terminal in Zeebrugge.

The system by which Fluxys 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 the public distribution exit point via a distribution system operator.

[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.

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 6).

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 position 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.

1.4.2. Demand

In 2013, the total measured gas demand of the Belgian end consumers amounted to 183,2 TWh, of which 129,8 TWh is H-gas (71% of total demand) and 53,5 TWh is L-gas (29% of total demand). This results in about ± 17 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.

1.4.2.1. Evolution of the yearly gas demand

Table 6: Ranking of the coldest gas years according to the Degree Days (DD)

Ranking	GasYear	DDeq	DDeq corr.
18	1969	2.670	2.517
17	1952	2.751	2.535
16	1983	2.643	2.542
15	1961	2.729	2.547
14	1916	2.906	2.556
13	1984	2.661	2.564
12	1923	2.894	2.570
11	1964	2.746	2.575
10	1939	2.847	2.583
9	1986	2.678	2.589
8	1940	2.882	2.622
7	1928	2.944	2.638
6	1995	2.696	2.641
5	1941	2.915	2.658
4	1955	2.893	2.688
3	1978	2.807	2.688
2	1985	2.901	2.808
1	1962	3.040	2.861

Most of the gas consumption on the distribution network is used for heating, it is very sensitive to the outside temperature. Therefore the number of degree days 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.

The graphs below show the evolution of the total gas consumption in Belgium for the period 2003-2013 (in GWh/year) for the measured (T meas) and a normalised temperature profile (T norm). We see that the consumption in 2010 had increased in 2010 due to the cold winter, but in 2011 and 2012 the consumption came back to the same level as before 2010, this level can be set as the normal temperature profile.

Figure 7: Total measured yearly consumption from 2004-2013 (in TWh)

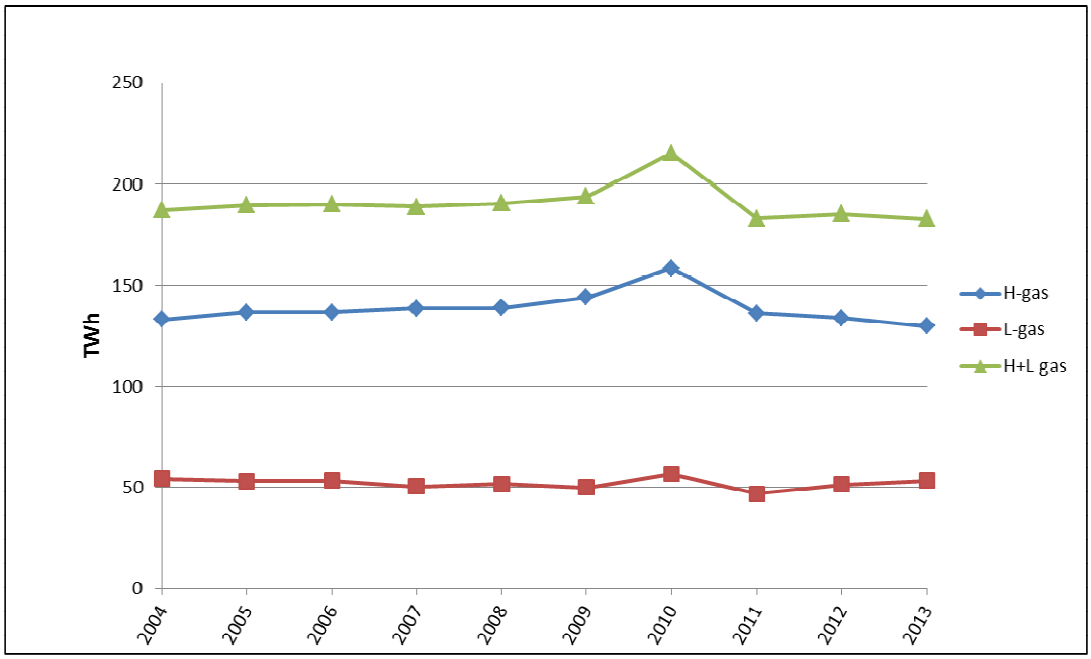
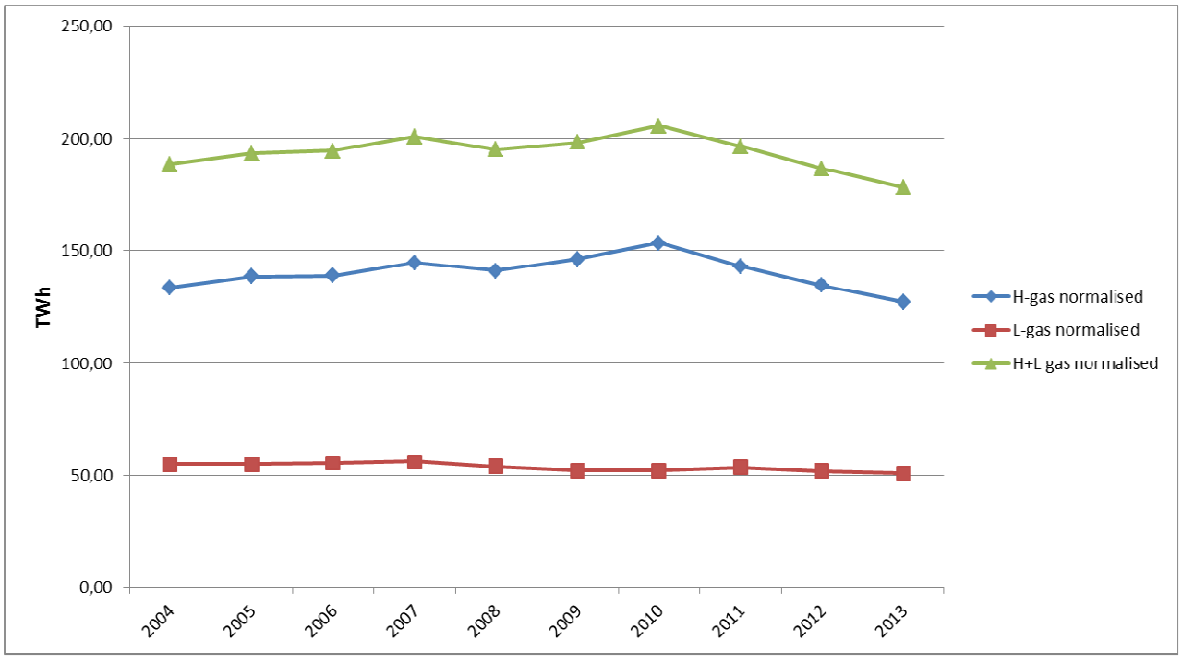


Figure 8: Total yearly consumption 2004-2013 in TWh (normalised)



The yearly L-gas consumption in 2013 amounted to 53,47 TWh. This equals 29% of the total yearly consumption of L- and H-gas (183,23 TWh). The public distribution sector takes up about 87% of the total L-gas consumption (46,54 TWh). The industry sector takes up the remaining part (6,9 TWh or 13% of the L-gas consumption). In 2013, the L-gas consumption by the electricity generating sector was negligible (0,014 TWh).

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 still continues in 2013 where as the consumption level is lower than the level of 2004 and will continue to decline because of the conversion of all industrial clients on the L-gas network to the H-gas network.

Figure 9 : Yearly L-gas consumption on the distribution network in GWh (2004-2013)

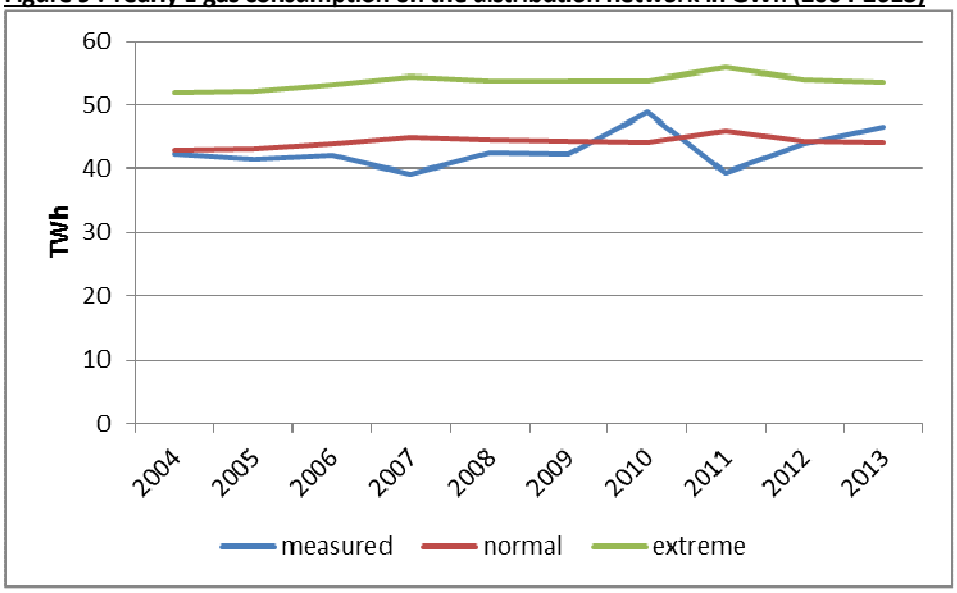
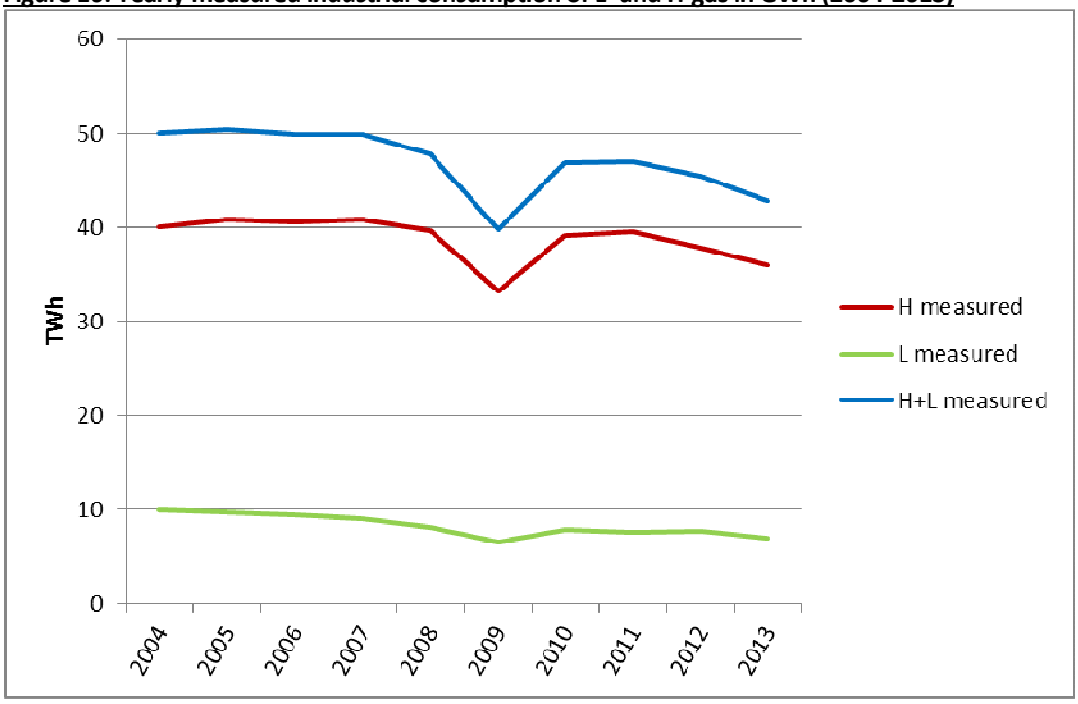


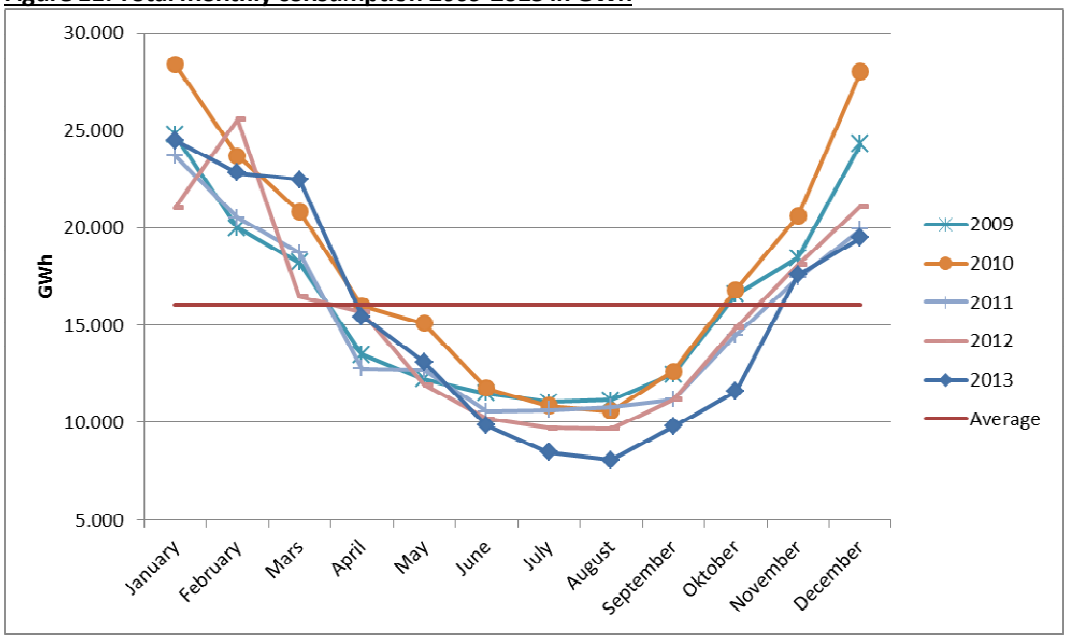
Figure 10: Yearly measured industrial consumption of L- and H-gas in GWh (2004-2013)



1.4.2.2. Monthly gas demand & seasonality

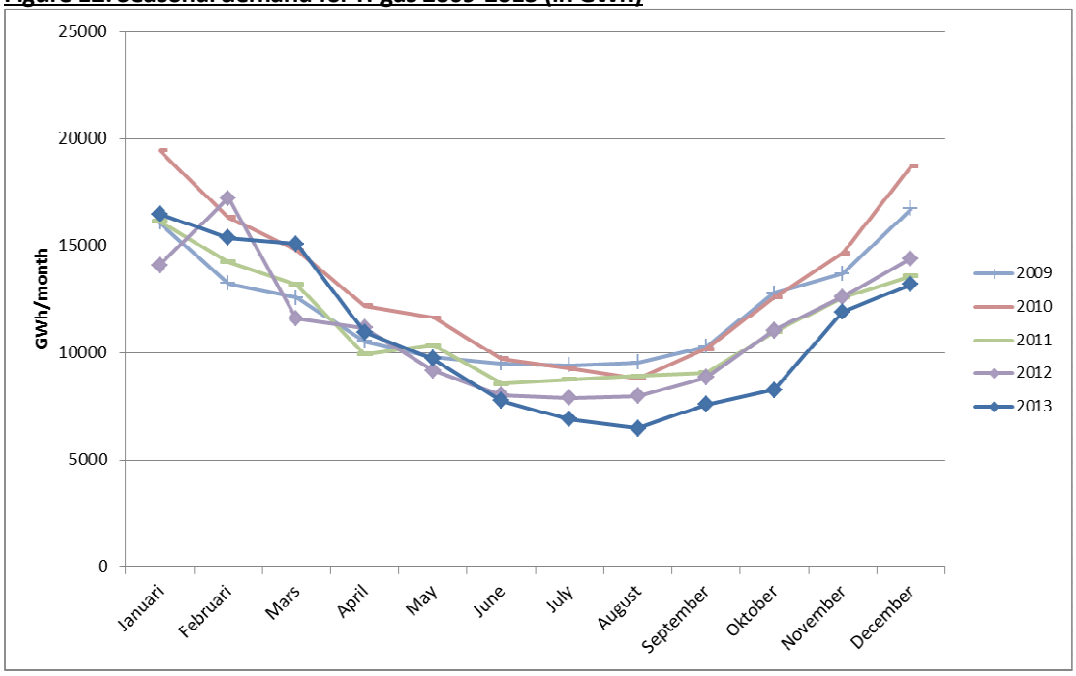
The monthly demand pattern is quite stable across the different years. We also see that the global gas demand is strongly linked to the outside temperature. Belgian gas consumption shows a strong seasonal pattern (figure 11). The average gas use per month is 15.269 GWh/month, while the average use in the months of July and August is around 8.274 GWh/month, or 54,18% of the average gas consumption. The average gas demand in those months is independent on the outside temperature and represents mainly the gas demand from the Industry users (TI) and electricity production (TE). The gas use in the winter months can amount to more than 23.000 GWh/month.

Figure 11: Total monthly consumption 2009-2013 in GWh



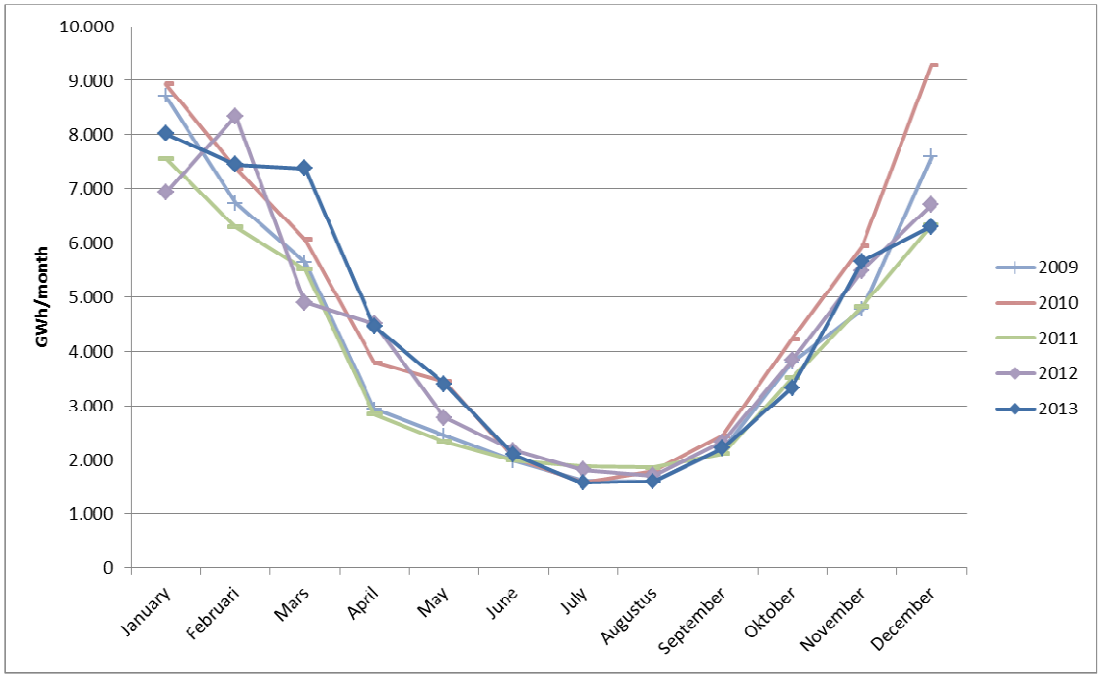
Figures 12 and 13 illustrate the seasonal swings for H gas and for L gas. We can see that the seasonal swing for L-gas is much more pronounced than for H-gas. This is because of the L-gas network mainly exists out of households who use gas mostly for heating.

Figure 12: Seasonal demand for H-gas 2009-2013 (in GWh)



As for the period 2009-2013, the average monthly consumption of H-gas is 11.712 GWh. The baseline monthly consumption that is not dependent on temperature represents 8.398 GWh, or 72% of the monthly consumption.

Figure 13: Seasonal demand for L-gas 2009-2013 (in GWh)



As for L-gas, in the same period, the average monthly consumption is 4.315 GWh. The threshold of the baseline monthly consumption (quantity that is independent of temperature) is 1.702 GWh, which equals approximately 39% of the average monthly L-gas consumption.

It can be concluded that L-gas consumption is relatively more volatile during the year, compared to H-gas. The fact that 87% of all the L-gas is consumed by the public distribution sector can explain this higher volatility.

1.4.2.3. Peak day demand vs. average day demand

Table 7 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 three times (300%) as high as an average day. Compared to other NW-European countries, Belgium has the third highest ratio. 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. Obviously, this ratio has an impact on the needed infrastructure capacity.

Table 7: Average demand vs. peak demand in NW EU (in GWh/day)

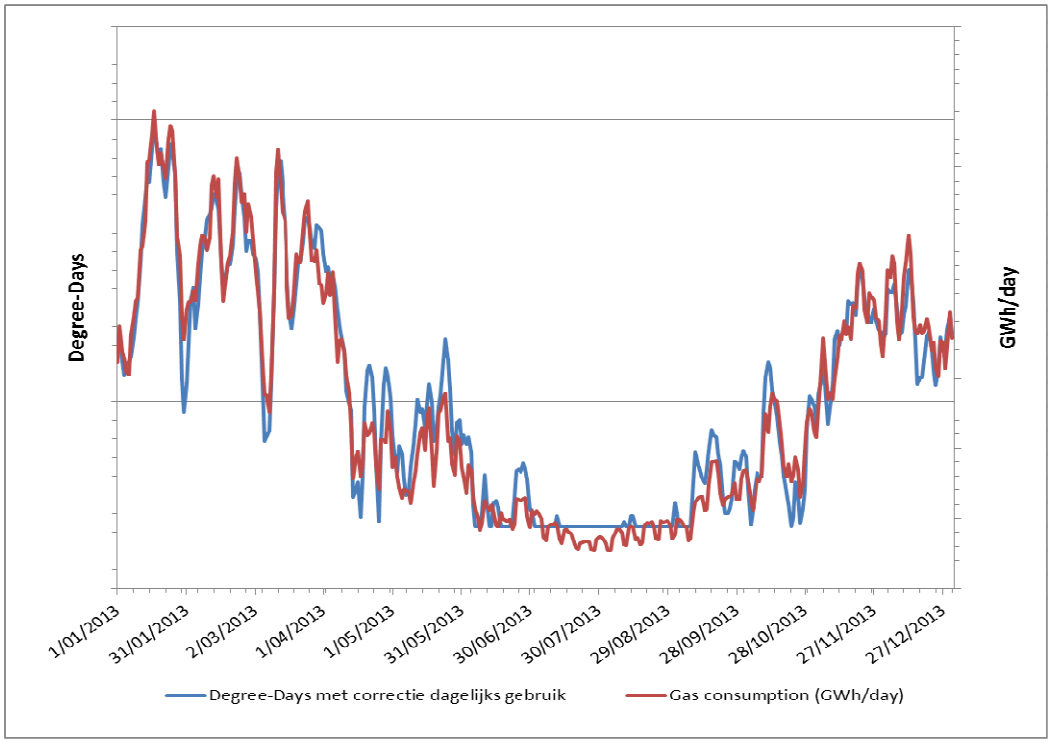
Capacity (in GWh/day)		IRL	UK	F	D	NL	BE	LU	Nw-EU
Demand (Peak Day)	2013	264	5.334	4.512	5.215	4.468	1.500	72	21.365
	2018	298	4.993	4.551	4.969	4.590	1.814	78	21.292
	2022	313	4.659	4.537	4.793	4.666	1.878	82	20.928
Demand (Average day)	2013	152	2.258	1.416	2.436	1.208	552	39	8.060
	2018	172	2.409	1.499	2.321	1.182	603	40	8.226
	2022	184	2.201	1.522	2.238	1.160	619	41	7.965
Ratio Peak Day/Average Day	2013	174%	236%	319%	214%	370%	272%	183%	265%
	2018	173%	207%	304%	214%	388%	301%	194%	259%
	2022	170%	212%	298%	214%	402%	303%	202%	263%

Source: ENTSOG TYNDP

Below 16,5°C, the gas consumption is mainly influenced by the outside temperature, or more exactly by the number of degree days (DD). As shown in figure 14, peak consumption corresponds generally with a day that registered a high number of DD. Some days note a lower consumption than would be expected by the DD. This can be explained either by the consumption on weekends or holidays, and because the consumption on a peak day is also dependant on the conditions before and after the peak day.

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 8 of the regulation 994/2010 EC for the infrastructure criteria.

Figure 14 : Correlation between DD and gas consumption



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 January, statistically the coldest month of the year. We look for the 15 days representing the coldest day temperatures in the last 100 years. The table below shows us that the fifth value registered in the last 100 years gives us 27,4 DD or an equivalent temperature of -10,9°C. It is worth noting that of those 15 values, 10 were recorded in the last 30 years.

Table 8: Climatic conditions in the last 100 years in January

Climatic conditions last 100 years in January				
Ranking	Date	Year	DD	Teq
15	16/jan	1987	26,3	-9,8
14	22/jan	1940	26,5	-10
13	15/jan	1985	26,5	-10
12	23/jan	1942	26,6	-10,1
11	16/jan	1985	26,8	-10,3
10	18/jan	1963	26,9	-10,4
9	1/jan	1997	26,9	-10,4
8	12/jan	1987	27,1	-10,6
7	13/jan	1987	27,4	-10,9
6	14/jan	1987	27,4	-10,9
5	2/jan	1997	27,4	-10,9
4	15/jan	1987	27,6	-11,1
3	8/jan	1985	27,7	-11,2
2	21/jan	1942	28,4	-11,9
1	22/jan	1942	29,6	-13,1

If we take into account 20 values for the coldest temperature in the winter period (December to February), we obtain the following results:

Table 9: 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

The fifth value gives us an equivalent temperature of -11,9°C and the sixth value -11,4°C.
If we make a correction for the global warming, we receive the results below. The fifth value gives us an equivalent temperature of -11,4°C.

Table 10: Corrected climatic peak values in winter during last 100 years

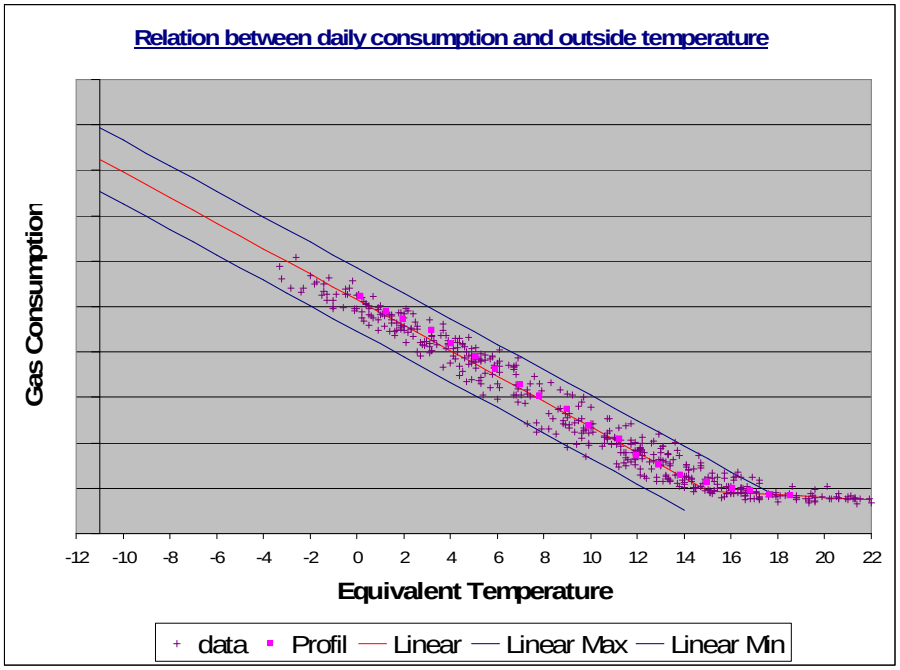
Corrected climatic peak values in winter during last 100 years			
Ranking	Date	DD	Teq
20	18/01/1963	26,6	-10,1
19	2/02/1954	26,6	-10,1
18	16/01/1985	26,6	-10,1
17	19/12/1938	26,7	-10,2
16	23/02/1956	26,7	-10,2
15	12/02/1929	26,7	-10,2
14	1/01/1997	26,8	-10,3
13	12/01/1987	26,9	-10,4
12	21/12/1938	27,0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

Estimation of the average hourly consumption at a winter peak day

Based on the yearly consumption data, we can determine the evolution of the parameters that influence the correlation between the consumption and the outside temperature. We have opted for a linear regression model. Some models use a saturation factor at a certain temperature, but as we have no data showing saturation at extreme temperatures. Therefore we prefer to use the linear model.

Figure 15: Relation between daily consumption and outside temperature



At a given equivalent temperature, we ascertain a dispersion of the consumption values. For lower temperatures, for example when the equivalent temperature is below 8°C, we try to estimate the regression curve that correlates to the 1% risk to obtain a higher consumption value. This exercise is performed based on the daily flows that supply the distribution network, because those are heavily influenced by the outside temperature (main use for heating). As shown in the graph above, there are two zones with a linear behavior, with a transition zone at approximately 16,5°C.

For equivalent temperatures above 16,5°C, we assume that the consumption is independent of the outside temperature. This "baseline consumption" corresponds to the recurrent energy needs independent of the outside temperature, for example, the needs for sanitary hot water, cooking or the energy needs of the small and medium enterprises connected to the distribution network.

The consumption on the distribution network, can be up to 9 times the baseline consumption. As the average yearly degree days amounts to 6,38 DD (which corresponds to an equivalent temperature of 10,12°C), the daily peak consumption at the distribution network can be 3,5 to 4,2 times as high as the average consumption.
We also consider, as first approximation, that the consumption of the industrial clients and the power plants directly connected to the Fluxys Belgium grid is not influenced by the outside temperature. Below we will explain how we obtain the reference value for the industrial clients and power plants directly connected to the transmission grid.

Determination of the average hourly consumption on a peak day

The average hourly consumption on a peak day is defined in function of the simultaneous occurrence of the following conditions:

- the gas needs of the public distribution are fulfilled up to an equivalent temperature of -11°C ;
- the peak of the maximal industrial consumption, estimated on a daily basis, is fulfilled;
- the power plants operate at full capacity;
- maximum booked exit capacity at the borders may be fully nominated.

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. According to the determined parameters for 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 analyzed period;
- an estimation of the peak consumption in the coming winters.

Reference value for the public distribution

The data for the winters 2003/2004 till 2013/2014 allow to determine the values of the linear regression.

Table 11 : Reference value for the public distribution

	Energy			Volume	
TD 2013/2014	Risk 50/50 GWh/day	Delta 1% GWh/day	Risk 99/1 GWh/day	Risk 50/50 k*m³(n)/h	Risk 99/1 k*m³(n)/h
Gaz H	443	28	471	11,50	1.605
Gaz L	420	27	447	9,77	1.791

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 of the three previous years. Non-representative data can be excluded. Therefore, weekends, official holidays, abnormal peaks (test phase, incident, …) or abnormally low consumption will not be taken into account.

The statistical analyses identifies 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 analyze 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.

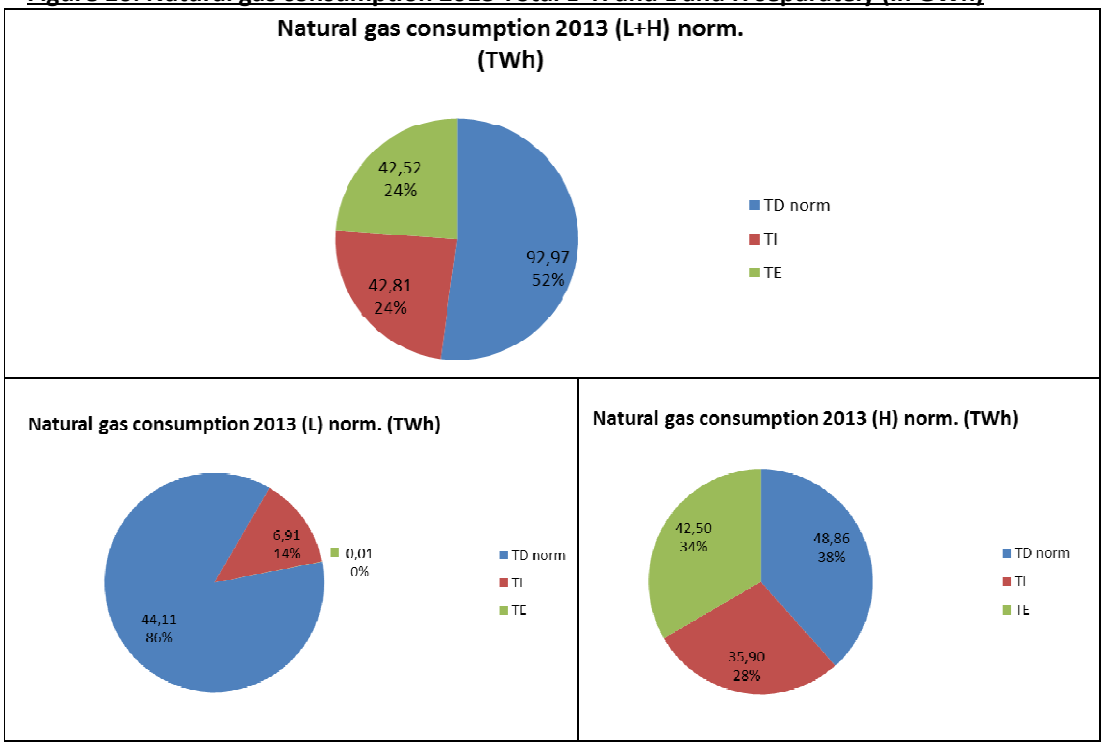
Demand for Border-to-border transmission

For the L-gas network, the reserved border-to-border transmission capacity on the Belgian network has to 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).

Gas demand by sector

The graphs below shows the breakdown of the total consumption for H-gas and for L-gas in 2012 of the public distribution (TD) (= 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.

Figure 16: Natural gas consumption 2013 Total L+H and L and H separately (in GWh)

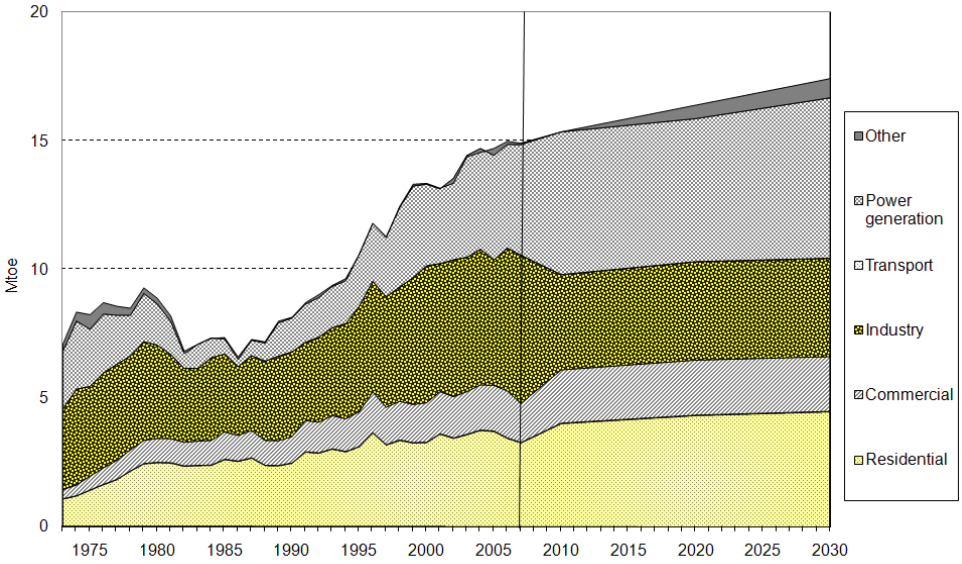


Above figures demonstrate the importance of the public distribution TD (i.e. households, SME's, hospitals and schools) in Belgium. In 2013 52% of the natural gas consumption in Belgium is used by the public distribution sector, 24% by the large industrial players and 24%

by the power plants. The L gas is only used by the distribution sector (86%) and the industry (14%). H-gas is used by all three sectors, namely public distribution (38%), industry (28%) and by the power generation sector which accounted for 34%.

The share of the electricity sector in the total yearly natural gas consumption increased from 24% in 2000 to 32% in 2010 and decreased to 24% in 2013. In absolute terms, this equals an decrease from 67,22 TWh in 2010 to 42,81 TWh in 2013.

Figure 17: Gas consumption per sector 1973-2030 (in Mtoe)



Sources*: Energy Balances of OECD Countries*, IEA/OECD Paris, 2009

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 between 2015 and 2025) 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.

1.4.2.4. Interruptible & protected customers

Energy end-users include residential and commercial customers as well as industrial firms 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 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 if all the firm capacity is booked by the shippers.

The definition of protected customers in the regulation states that protected customers include all household customers connected to a gas distribution network and can also include small and medium sized enterprises and essential social services connected to the gas distribution network provided that these additional customers do not represent more than 20% of the final gas use.

The regulation defines the protected customers as all household customers connected to a gas distribution network and may also include:

- small and medium-sized enterprises connected to the distribution network and essential social services connected to the gas distribution or transmission network if they do not represent more than 20% of the final gas use
- district heating installations to the extent that they deliver heating to household customers and to customers mentioned above provided that these installations are not able to switch to other fuels and that they are connected to the distribution or transmission network.

For 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. Protected customers represent about 50% of the total gas demand. Most of this demand stems from household consumers. It might be useful to study (in consultation with the distribution network operators) if it could be possible for the telemeasured clients to reduce their consumption in case of an emergency.

Table 12 gives a detailed overview of the consumption profiles on the distribution network during the winter peak.

Table 12: Consumption profiles and their representation on the distribution network

2012-2013	S30	S31	S32	S41	S31+S32+S41
H	10,13%	12,63%	19,90%	57,34%	89,87%
L	13,34%	12,14%	19,62%	54,91%	86,67%

There are 4 consumption profiles on the distribution network: S30, S31, S32 and S41. The household customers are represented under category S41. Their consumption is heavily reliable on the outside temperature. The other three profiles dispose of a VAT number and correspond to the tertiary, commercial and industrial sector.

The profiles S31 and S32 are the non-telemeasured clients. S31 are the commercial clients that consume less than 150.000 KWh/year, S32 clients consume more than 150.000 KWh/year. The gas consumption of those clients is dependent on the outside temperature so they are close to household consumers.

The profile S30 represents the telemeasured clients. Those are the larger (industrial) clients with an hourly counting of the gas consumption (hospitals, administrative buildings, large supermarkets,…) connected to the distribution grid. We can see that the gas consumption of these consumers (except for the hospitals) is less dependent on the outside temperature. The consumption of those clients represents less than 20% of the total gas demand.

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 on 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 are willing to have supply interrupted at some point, according to the reasons in the contract (mostly meteorological circumstances) and for a maximum amount 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 only offers interruptible capacity to the market if there is no firm capacity left. Even if Fluxys would offer interruptible capacity, the price difference between interruptible and firm capacity has become too small to be an incentive. 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 unlikely 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.

1.4.2.5. Fuel switching

Fuel switching capability is the short-term capability of a manufacturing establishment to have used substitute energy sources in place of those actually 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 transformation sector and for a very small part in the industry sector.

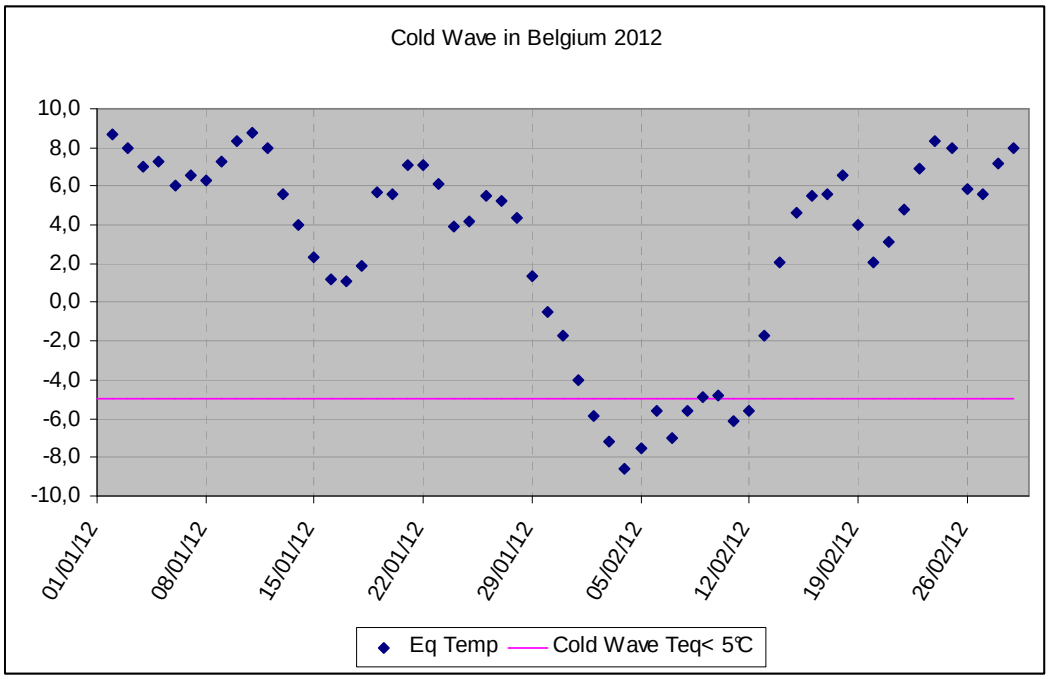
In Belgium there is no program in place in order to encourage or otherwise require users of gas to switch to another fuel source in case of a disruption of natural gas supply. Also the new power plants that are constructed do not have the build-in capability to switch fuel.

1.4.3. Case: Cold wave 2012

1.4.3.1. The event

Late January and early February 2012, we experienced a period of climatic hazard of 7 consecutive days during which the equivalent temperature was below -5 °C (-5,9 °C; -7,2 °C; -8,6 °C; -7,5 °C; -5,6 ° C; -7 °C; -5,6 °C) from 2 until 8 February 2012. The coldest day was recorded Saturday, February 4 with an equivalent temperature of -8,6 °C. The day of the week where the lowest temperature was observed is Monday, February 6th with -7,5°C.

Figure 18: Cold wave in Belgium 2012



NB. Dates re-taken in the graph above correspond to Sundays

1.4.3.2. Highlights of the event

Records

During this period, the previous record of physical flows transported for domestic demand were beaten during 8 days almost continuously learn from February 2 to February 10 (except Sunday, February 5). The two most important values recorded were measured Friday the 3rd February with 1,165 GWh and Tuesday, February 7th with 1,181 GWh (old record: January 8, 2010 with 1,073 GWh).

Physical flows to domestic demand and transportation from border to border (B2B) were on the 8 of February a little over 2 TWh.

Management of physical flows

At the network transport capacity at the borders were allocated North, East and West side entrance and used to supply the domestic market as well as France (Exit border Blaregnies/ Taisnières L-gas and H-gas). In the view of transportation from border to border (B2B), the flows were North-South and not so much East-West (usually natural gas flows from D to UK in winter).

a)At entry side

More concretely during the two peak days of 7 and 8 February, the needs were provided as followed on the entry points:

- 25% of the flows came from Norway via the Zeepipe
- 25% of the flow came from the Netherlands via the Poppel / Hilvarenbeek entrance and was intended to serve the French and Belgian L-gas market.
- 13% of flows had been provided by the LNG terminal in Zeebrugge
- Between 10 and 11% flowed through the entry point of the Netherlands s'Gravenvoeren.
- -6% of flows had been imported from Germany via the interconnection point Eynatten (of which 3% were immediately exported to Germany by the same point (see point b))
- Having regard to the possibilities of underground storage located in Belgium are limited, the natural H-gas storage of Loenhout provided 7% of the needed gas
- In particularly 8% of flow came from the United Kingdom via the interconnector. In other (more normal) winter circumstances the Interconnector is used as an exit point of the Belgian network rather than as an entry point to serve the Belgian market.

b) at output side

Also during this same period of 2 days, the imported feeds have been allocated to the following uses :

- between 60% and 63% was transported to the domestic market (national use)
- between 28% and 32% was exported to France
- 3% was exported respectively to the Netherlands and Germany and 2% to the Grand Duchy of Luxembourg.

The level of domestic demand

Necessary to ensure home heating, energy needs had reached 90% of estimated needs in climate scenario with a peak at -11°C.

Another point, the evolution of the consumption of gas for power generation was unusually correlated to the outside temperature. If this electrical production was destined for the Belgian market, this dependence would be relatively low. To fix ideas, the increase in electricity consumption compared to the temperature is generally estimated in Belgium to 50 MW per degree less consumption for one day peak of between 12.000 MW and 14.500 MW.

The explanation may be found in the fact that an important part of this electricity was exported to countries with a strong dependence of the power consumption compared to the outside temperature (e.g. France). This point was confirmed by the Belgian electricity network operator Elia.

Management Belgian TSO + cooperation between the TSO and the adjacent networks

At the Belgian TSO, there was nothing significant to report this period and was managed without incident (considered " as usual " at this time of year).

At the level of cooperation, a continuous exchange of information took place between Fluxys and the adjacent TSOs.

Operation of the Hubs

The wholesale price of gas on its various hub followed the same trend and has little delayed, which attempts to show that the markets remained highly interconnected.

1.5. Infrastructure

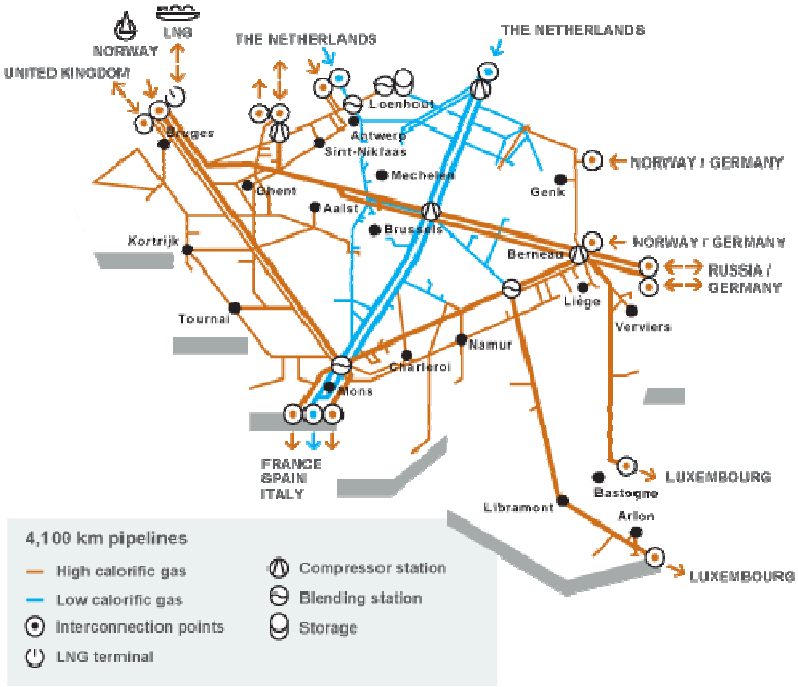
1.5.1. Pipelines

1.5.1.1. Overview of the pipeline network

Fluxys, Belgium's transmission system operator, has a network of about 4.100 kilometres of pipelines with 14 interconnection points and four compression stations. The 8 cross border pipelines connects the Belgian gas market directly to Norway, UK, Germany, the Netherlands, France and Luxembourg. The five 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. In 2010 the upgrade of compression station was started to include four new compression units to increase pressure on the East/West axis (VTN/ RTR1 and 2). Currently not yet in use.
- **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 19: Belgian transmission network operated by Fluxys Belgium



Source: Fluxys

In 2013, the Belgian gas network transported ± 17bcm of natural gas for consumption in Belgium and for the border-to-border transmission (long term booked capacity) of about 23 bcm of gas to other end-user markets in the Netherlands, Germany, Luxembourg, France and UK. The Fluxys network delivers gas directly to about 250 large industrial end-users and power stations, and supplies the grids of 17 distribution system operators which deliver gas to residential and small- to medium-sized industrial users.

Since October 2012 Fluxys 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.

1.5.1.2. 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.

Table 13: Firm entry and exit capacity offered on the connection points (in mcm/d)

	Connection point	Type	Firm capacity offered 2014 (mcm/d)		Firm capacity offered 2017 (mcm/d)	
			Entry	Exit	Entry	Exit
H	IZT	EP	64,800	78,000	74,400	78,000
	LNG terminal 1		22,800	0,000	**22,800**	**0,000**
	LNG terminal 2	LNG	22,800	0,000	**22,800**	**0,000**
	ZPT	EP	45,600	0,000	45,600	0,000
	Alveringem	EP	0,000	0,000	24,000	0,000
	Zandvliet H	EP	4,320	0,000	4,320	0,000
	Zelzate 1	EP	34,800	16,800	**34,800**	**16,800**
	Zelzate 2	EP	0,000	10,800	0,000	10,800
	Eynatten 1	EP	18,000	16,800	18,000	16,800
	Eynatten 2	EP	31,200	18,000	31,200	**18,000**
	S Gravenvoeren + Obbicht	EP	31,200	0,000	31,200	0,000
	Blaregnies H	EP	0,000	60,000	0,000	**60,000**
	Loenhout Storage	S	15,000	7,800	15,000	7,800
	Pétange & Bras (GD Lux)	EP	0,000	4,320	0,000	4,320
	L-inject	EP	0,000	0,000	0,000	0,000
L	Poppel/Zandlviet L	EP	65,520	0,000	65,520	0,000
	Blaregnies L	EP	0,000	27,360	0,000	27,360
	Transfo H → L	EP	9,600	8,640	9,600	8,640

∗ Alveringem will be online from 2016. Transfo H→ L is the entry capacity at the L-gas side and exit at the H-gas side Source: Data compiled based on information of Fluxys

The VTN-RTR pipeline (H-gas) is bi-directional linking 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 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 European markets. 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 grid via the subsear Zeepipe pipeline.

The need for new infrastructure is evaluated every year by Fluxys 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 (January at -11°Ceq) and border to border transmission requirements are being set up to calculate the effects on the network.

Current investments planned/underway:

- Second jetty for LNG terminal in Zeebrugge: by the end of 2015 a second jetty will be constructed so LNG ships with a capacity of 3.500 to 217.000 cubic meters can dock in Zeebrugge. Early 2013 the Zeebrugge Port Authority completed construction of the underwater structure. Meanwhile, an agreement was reached with an EPC contractor. Fluxys started in 2013 with the construction of the superstructure, everything would be ready by 2015.

The entry capacity from France could increase thanks to the future LNG-terminal in Dunkirk (FR) that will come on line in 2016. The terminal with a capacity of 13 bcm, in which EDF has a share of 65,01%, will be located near to the Belgian-France border. The other project partners are Total (9,99 %) and Fluxys G (25%). A new pipeline from Dunkirk via Pitgam to Alveringem (BE) and from Alveringem to Maldegem will be constructed, connecting the pipeline to the VTN/RTR pipeline. This will increase entry capacity to the Belgian gas market.

The Alveringem interconnection will connect non-odorized gas coming from France with the Belgian grid. Fluxys will make available at least 800 000 m3(n)/h from the Dunkirk facility to the Belgian network, either to the Zeebrugge Beach or to the Zeebrugge Trading Point. Capacity will be first assigned to companies committing for over 20 years. Second, up to 100 GWh/day will be jointly proposed by Fluxys and GRTgaz from PEG Nord Zeebrugge Trading Point. Priority will be given to shippers committing for more than 10 years. In the non-binding phase which took place last year, six companies requested 420GWh/day mostly over 20 years.

The pipeline project will be constructed in such a way that physical reverse flow will be technically feasible.

1.5.1.3. Infrastructure in the L-gas market

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

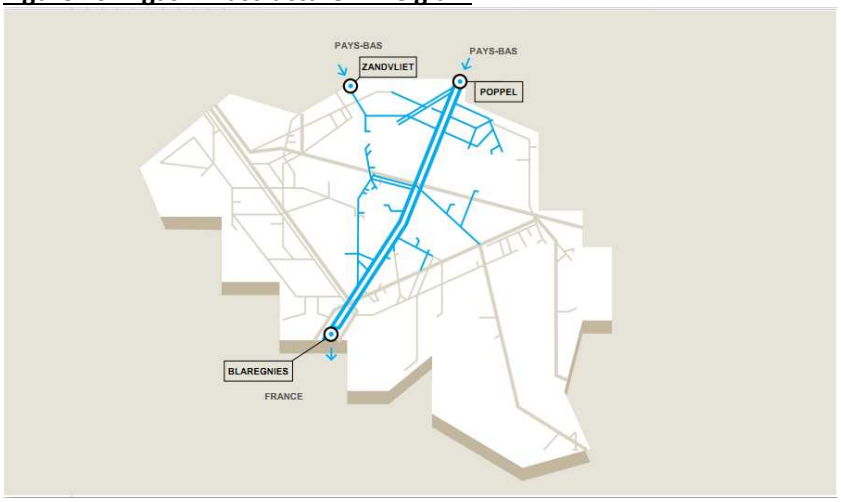
- an physical entry point at Poppel/Zandvliet L:
  The corresponding point at the Dutch side of the border (exploited by GTS) is Hilvarenbeek and Zandvliet L. The available capacity at Poppel is 2.734 k*m³(n)/h.
- an exit point at Blaregnies :
  The corresponding entry point in the French network (exploited by GRTgaz) is Taisnières. The entry capacity at Blaregnies is 981 k*m³(n)/h.
- a conversion unit for H-gas to L-gas at Lillo:
  The capacity of the conversion unit at Lillo can produce up to 288 k*m³(n)/h of L-gas.
- a conversion unit for H-gas to L-gas at Loenhout:
  The capacity of the converter at Loenhout can produce up to 96 k*m³(n)/h of L-gas.

Belgium has no storage facilities for L-gas.

Coming from Poppel, the L-gas is transported over a couple of kilometers to a first compression station. From there, it is transported to a second compression station 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 have to be considered

as a cluster. We have to note that in extreme winter conditions, the pressure in the Belgian network at Zandvliet L is systematically higher than the pressure in the corresponding exit point at the Dutch grid, which is used to supply the province of Zeeland. The interconnection point of Zandvliet L can therefore not be considered as a commercial and firm entry point.

Figure 20: L-gas infrastructure in Belgium



Source : Fluxys

1.5.1.3.1. The L-gas supply in Belgium

About 183,2 TWh (+/- 17 bcm in 2013) of natural gas is consumed annually by the Belgian market (data 2013), a little more than ¼ of the total consumed amount is L-gas, about 53,5 TWh. 85% of this gas is intended for public distribution (ie 46,5 TWh) and the remaining 15% (or 6,9TWh) 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.

1.5.1.3.2. The future of L-gas

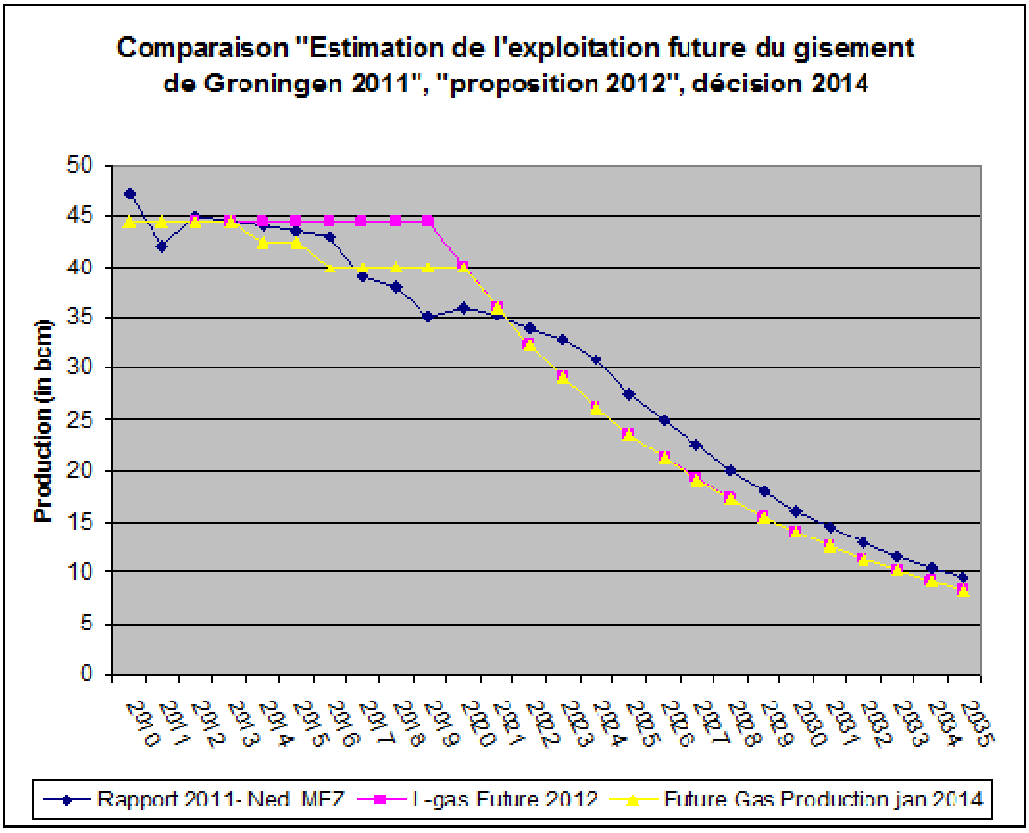
There was a small study conducted based on the decision by the Netherlands of January 2014. In January 2014 the Dutch government decided to set a maximum on the production of the Groningen gas field for the next 3 years to:

- 42,5 bcm for 2014 and 2015
- 40 bcm for 2016

The annual volume of 42,5 bcm for the years 2014 and 2015 is the volume roughly corresponding to the average annual volume calculated based on 425 billion over 10 years in 2010 decided not to involve the amounts earned prior to 2010.
In 2016, the volume of 42,5 bcm is reduced by 6% (40 bcm).

This decision could possibly be taken by the authorities of the Netherlands based on the fact that the operator of the transportation network GTS has a sufficient margin in terms of infrastructure for the conversion of H gas into pseudo- L-gas when the production of L-gas from the Groningen field is reduced with 4,5 bcm.

Figure 21: Estimation of the future exploitation of the Groningen Gas Field



The table below shows our estimates on the changes in the reserves of Groningen-gas in the coming years (these results are not binding values, and are just used to give a hypostasis). Pending the decision should be taken by the Dutch authorities in 2017 , the ceiling set in 2016 42,5 bcm has been artificially maintained until 2021. This is a hypothetical calculation that currently rests on any official information.

Year	Annual Prod. Groningen fields	% of 2010	Avail. Volume on 1st of January (bcm)	% initial vol i.e. 2800 (bcm)
2010	44,5	100%	918	32,8%
2011	44,5	95%	874	31,2%
2012	44,5	90%	829	29,6%
2013	44,5	85%	780	27,9%
2014	42,5	80%	736	26,3%
2015	42,5	75%	693	24,8%
2016	40,0	71%	651	23,2%
2017	40,0	67%	611	21,8%
2018	40,0	62%	571	20,4%
2019	40,0	58%	531	18,9%
2020	40,0	53%	491	17,5%
2021	40,0	49%	451	16,1%

2022	36,0	45%	411	14,7%
2023	32,4	41%	375	13,4%
2024	29,2	37%	342	12,2%
2025	26,2	34%	313	11,2%
2026	23,6	31%	287	10,2%
2027	21,3	29%	263	9,4%
2028	19,1	26%	242	8,6%
2029	17,2	24%	223	8,0%
2030	15,5	22%	205	7,3%
2031	13,9	21%	190	6,8%
2032	12,6	19%	176	6,3%
2033	11,3	18%	163	5,8%
2034	10,2	17%	152	5,4%
2035	9,2	15%	142	5,1%

1.5.1.3.3. Future of L-gas in Belgium

Future supply of low-calorific natural gas in Belgium is dependent, among other things, on changes in suppliers' purchase contracts and the remaining lifetime of the L-gas field in the Netherlands. Against this backdrop, the Federal Public Service Economy has set up a Task Force comprising the Belgian TSO Fluxys, distribution system operators, natural gas suppliers and the authorities. The Task Force's role is to take stock in the medium term of security of supply with regard to low-calorific natural gas in Belgium. Based on the conclusions drawn, various paths will then be examined. One of the first points noted by the Task Force is that the shift from low-calorific to high-calorific natural gas is already under way in the province of Limburg/ Antwerp (Albertkanaal). This shift will require multilayered investment and action involving the Belgian TSO Fluxys as well as the distribution system operators, suppliers, grid users, regulators and system operators in neighboring countries.

1.5.2. 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 EU Europe. In 2015 a second jetty will be taken into use, this will increase 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.

In July 2008 Fluxys LNG also launched new LNG loading services in response to requests from terminal users willing to better exploit commercial opportunities on the LNG market.

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 contracts with three terminal users which started in 2007: Qatar Petroleum/Exxon Mobil, ENI Gas&Power and GDF Suez. In June 2007, Qatar Petroleum/ExxonMobil transferred its contract to EDF Trading for the entire duration, while GDF Suez announced in February 2008 that it had subleased part of its capacity to ConocoPhillips. Besides these long-term contracts, tankers from almost every LNG production site can deliver spot LNG. However since 2011 most spot LNG is unloaded in Asia or South America, because LNG prices are a lot higher there.

Table 21: Terminal capacity booked through long term contracts

Shippers	Years	Quantity (bcm)	Slots	Start
Qatar Petroleum/Exxon Mobil (Rasgas*)	20	4,5	55	01/04/2008
ENI Gas&Power	20	2,7	33	01/04/2007
GDF Suez**	15	1,8	22	01/10/2008
Total	-	+/- 9 BCM	110	-

* Full assignment from QP/ExxonMobil to EDFT

** Partial sublease from GDF Suez to ConocoPhilips

Source: Fluxys

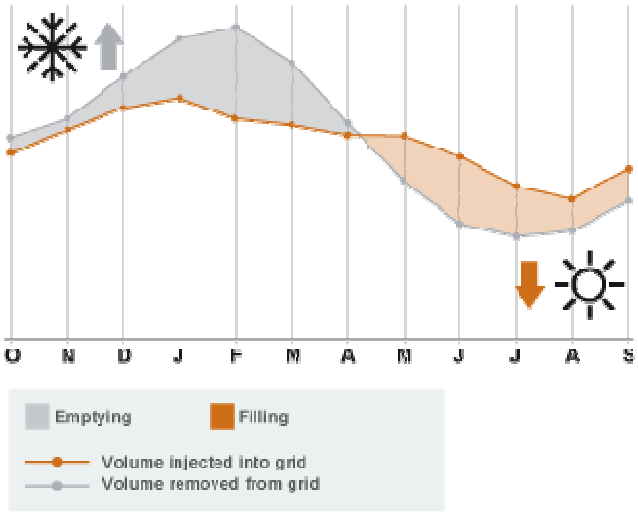
In 2008 Fluxys LNG launched LNG loading services in response to requests from terminal users willing to better exploit commercial opportunities on the LNG market. Loading of LNG ships has been a great success from the start. Especially since 2011 almost half the unloaded quantity of LNG is later loaded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

1.5.3. Storage facilities

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. It's 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.

Figure 22: Example of gas storage to balance seasonal gas swings



Source: Fluxys

1.5.4. N-1 infrastructure standard

The N-1 formula describes the ability of the technical capacity of the gas infrastructure to satisfy 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 taken into account for the calculation of the N-1 standard. The impact of N-1 has to be carefully evaluated therefore because this does not mean that all imports are destined for the Belgian domestic market. Therefore it could be useful in the future 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 formula, as calculated below, should at least equal 100 %.

The calculation of the N-1 formula, presented in this document, is based on the investment plan 2013 - 2023. Investment planning for the 10 years to come is done by Fluxys on a yearly basis. Every year, by the end of May, the investment plan is updated taking the evolutions on the market, the planning of adjacent TSO's and specific grid calculations into account.

1.5.4.1. Definitions and assumptions

All the definitions and assumptions for calculating the N-1 formula are described in this paragraph and are consistent with the assumptions and definitions used in the investment plan.

- **Technical Capacity**

According to Article 2(1)(18) of Regulation (EC) No 715/2009, 'technical capacity' means the maximum firm capacity that the transmission system operator can offer to the network users, taking account of system integrity and the operational requirements of the transmission network.

The methodology used for defining the maximum firm capacity that Fluxys can offer is the default target capacity applied for capacity simulations and is based on the up- and/or downstream bottlenecks. This results in a realistic value of the capacity that can be offered on a firm basis under all simulated scenarios according to the commercial model and takes into account the reality of the adjacent TSO as defined by:

- Asset reality i.e. current assets and likely future investments
- Commercial behaviour (e.g. interruptible management,…)
- Flow planning assumptions (e.g. measured maximum flow,…)
- End user demand

The technical capacities appearing in the investment plan are also provided by Fluxys to ENTSOG for the Ten Year Network Development Statement.

- **Definition Entry point, production and storage facilities**

Entry points, storage and LNG facilities are considered as interconnection points with adjacent network systems on which firm capacity is offered to the network users. So the technical capacity is stated per contractual interconnection point. This means that the physical interconnection points such as Dilsen and 's Gravenvoeren are considered to be the contractual interconnection point 's Gravenvoeren.

Since entry points, storage and LNG facilities are considered to be contractual points, the calculation of the N-1 formula is first presented considering the single largest gas infrastructure as a contractual point.

However, for calculated areas where this calculation methodology of the N-1 formula indicates non-compliancy, alternative calculations are given taking the following aspect of the definition of single largest infrastructure into account: When several gas infrastructures are connected to a common upstream or downstream gas infrastructure and cannot be separately operated, they shall be considered as one single gas infrastructure.

- **Calculated area**

The 'Calculated area' means a geographical area for which the N – 1 formula is calculated, as determined by the Competent Authority. Since the recital of the Regulation 994/2010 states that the specificities of low calorific gas should be considered at national and regional level, Fluxys provides in this document the calculation of the low and high calorific gas as separate calculated areas.

Exceptionally high gas demand with a statistical probability of once in 20 years

Since public distributions are temperature dependent, exceptionally high gas demand occurring with a statistical probability of once in 20 years for the public distributions is considered to be the demand (expressed in mcm/d) at an equivalent daily temperature of -11°C. This temperature is the result of a statistical approach and corresponds with a statistical probability of once in 20 years. This probability is calculated based on data of the last 100 years.

For the Power Plants and Industrial Clients a default value is used.

1.5.4.2. Calculation: supply side

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

Table 22: Capacities on the Connection points

	Connection point	Type	2014 (mcm/d)	2017 (mcm/d)
H	IZT	EP	64,800	74,400
	LNG terminal 1	LNG	22,800	22,800
	LNG terminal 2	LNG	22,800	22,800
	ZPT	EP	45,600	45,600
	Alveringem	EP	0,000	24,000
	Zandvliet H	EP	4,320	4,320
	Zelzate 1	EP	34,800	34,800
	Zelzate 2	EP	0,000	0,000
	Eynatten 1	EP	18,000	18,000
	Eynatten 2	EP	31,200	31,200
	S Gravenvoeren + Obbicht	EP	31,200	31,200
	Blaregnies H	EP	0,000	0,000
	Loenhout Storage	S	15,000	15,000
	Pétange & Bras (GD Lux)	EP	0,000	0,000
	L-inject	EP	0,000	0,000
L	Poppel/Zandlviet L*	EP	65,520	65,520
	Blaregnies L	EP	0,000	0,000
	Transfo H -> L	EP	9,600	9,600

* Exit capacity at the interconnection point Hilvarenbeek

For the High calorific calculated area, this comes down to the following parameters (in mcm/d):

EP_H = IZT + ZPT + Alveringem + Zandvliet H + Zelzate 1 + Zelzate 2 + Eynatten 1 + Eynatten 2 + 's Gravenvoeren + Blaregnies H + GD Lux + L-inject

EP_H (2014) = 64,8 + 45,6 + 0 + 4,32 + 34,8 + 0 + 18 + 31,2 + 31,2 + 0 + 0 + 0 = 229,92

EP_H (2017) = 74,4 + 45,6 + 24 + 4,32 + 34,8 + 0 + 18 + 31,2 + 31,2 + 0 + 0 + 0 = 263,72

P_H = -8,64

P_H (2014) = -8,64

P_H (2017) = -8,64

* H gas used to produce L gas

S_H = Loenhout Storage

S_H (2011) = 15,0

S_H (2015) = 15,0

LNG_H = LNG Terminal1 + LNG Terminal 2

LNG_H (2014) = 22,8 + 22,8 = 45,6

LNG_H (2017) = 22,8 + 22,8 = 45,6

I_H = IZT

I_H (2014) = 64,8

I_H (2017) = 74,4

For the Low calorific calculated area, this comes down to the following parameters (in mcm/d):

EP_L = Poppel/Zandvliet L + Blaregnies L
EP_L (2014) = 65,520 + 0 = 65,52
EP_L (2017) = 65,520 + 0 = 65,52
*

P_L = 9,6 (Transfo H ->L)
P_L (2014) = 9,6
P_L (2017) = 9,6
** L gas production based on conversion of H gas

S_L = none
S_L (2014) = 0
S_L (2017) = 0

LNG_L = none
LNG_L (2014) = 0
LNG_L (2017) = 0

I_L = 65,52
I_L (2014) = 65,52
I_L (2017) = 65,52

1.5.4.3. Calculation: demand side

With respect to the demand side, market-based demand-side measures to compensate for a supply disruption are offered to the market in the form of interruptible contracts, but are not subscribed by the network users at this moment.
For the high calorific calculated area, the Transfo H/L demand is taken into account at the demand side.

Table 23: Maximum gas demand and market based demand side measures

		2014 (mcm/d)	2017 (mcm/d)
Dmax	H-net	88,01	89,30
	L-net	48,77	48,79
Deff	H-net	0,00	0,00
	L-net	0,00	0,00

1.5.4.4. Basic N-1 calculation

The N-1 calculation shows that in the High Calorific 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.

For the low calorific calculated area a regional approach might be recommended since the single largest infrastructure of the Low Calorific Regional Calculated area is of common interest. However some considerations concerning the definitions and assumptions used are described in the following paragraph.

Table 24: N-1 calculation based on border with highest max. capacity: IZT

	N-1 (%)	
	2014	**2017**
H-net	246,7%	270,0%
L-net	19,7%	19,7%

Table 25: N-1 calculation based on ZTP

	N-1 (%)	
	2014	**2017**
H-net	278,3%	311,9%
L-net	19,7%	19,7%

1.5.4.5. Alternative calculations

The previous N-1 calculation for the Low Calorific Calculated Area shows that the Belgian L network infrastructure would not to be able to satisfy the gas demand of the corresponding calculated area for Belgium during a day of exceptionally high gas demand in the event of a disruption of the single largest gas infrastructure.

However, this needs further analysis. Indeed, in the previous calculations 65,5 mcm/d are considered for the largest entry where this results in a potentially too stringent interpretation of the definition that states that when several gas infrastructures are connected to a common upstream or downstream gas infrastructure and cannot be separately operated, they shall be considered as one single gas infrastructure. Since the contractual point of Poppel already consists of the physical interconnection points Zandvliet L and Poppel, which are connected to separate gas infrastructures upstream and can be operated separately, defining them together as the single largest infrastructure needs some caution.

In addition, 3 pipelines enter the physical interconnection point of Poppel, from which one supplies the same area as Zandvliet L. The rest of the low calorific area is supplied by the remaining 2 pipelines.

Depending on whether the contractual point Poppel/Zandvliet L can be considered to be 2 different gas infrastructures and the 2 remaining pipelines can also be considered to be back-up for each other, dividing the technical capacity of the single largest infrastructure.

The alternative calculation of the shut-down of one of the main pipelines to Poppel, which will divide the technical capacity of the single largest infrastructure by 2, is given in table 26:

Table 26: Alternative N-1 calculation

	N-1 (%)	
	2014	2017
L-net	19,7%	19,7%
L-net – Disruption 1 upstream Line	86,9%	86,8%

1.6. Gas infrastructure utilizations & contracts

In June 2011, the Belgian Energy Administration sent questionnaires to all gas undertakings that currently possess a federal supply licence. As the administration wanted to gain as much insight as possible, the questionnaire was quite comprehensive.

Many of the gas undertakings stressed their will to cooperate on a subject that they confirmed as being important and/or necessary. Due to the sensitive nature, a few legal remarks were made and several partners stressed the confidential nature of the data provided. The administration anticipated and duly recognised these concerns. The technical obstacles were harder to anticipate. Some questions were open for interpretation, others were simply impossible for some companies to answer. For the future, the level of clarity of the questions will need to increase, with more definitions. Another difficulty was the structure of the gas market. The free market has spawned a large network of cross ownership and arrangements. Any study on the gas market should make sure that each amount of gas is only counted once. Nevertheless, the questionnaires provided a very valuable insight into the Belgian gas market and allowed the competent authority to make this Risk Assessment.

1.6.1. Results questionnaire shippers

1.6.1.1. Contracts

Shippers and suppliers active on the Belgian market tend to integrate their sourcing contracts for Belgium into the European-wide market. More and more, the contracts are diversified to the extent that a direct link between sourcing contract and supply contract disappears. Listing the exact source of the gas molecules on the Belgian market is therefore hard.

Management on a European scale is also demonstrated in the use of storage facilities, with suppliers citing foreign storage as a source of flexibility or peak capacity for the Belgian market. In general, the integrated approach seems to provide advantages for the security and for the flexibility of the gas market.

The big supply companies lean towards a conservative attitude on their contracts. The sourcing contracts are divers and long term contracts with producers are preferred. Some companies indicated that in their quest for a secure supply, they opt to use the least amount of separate infrastructure between producer and end user. In general, most companies claim to cover all bases in the event of a crisis.

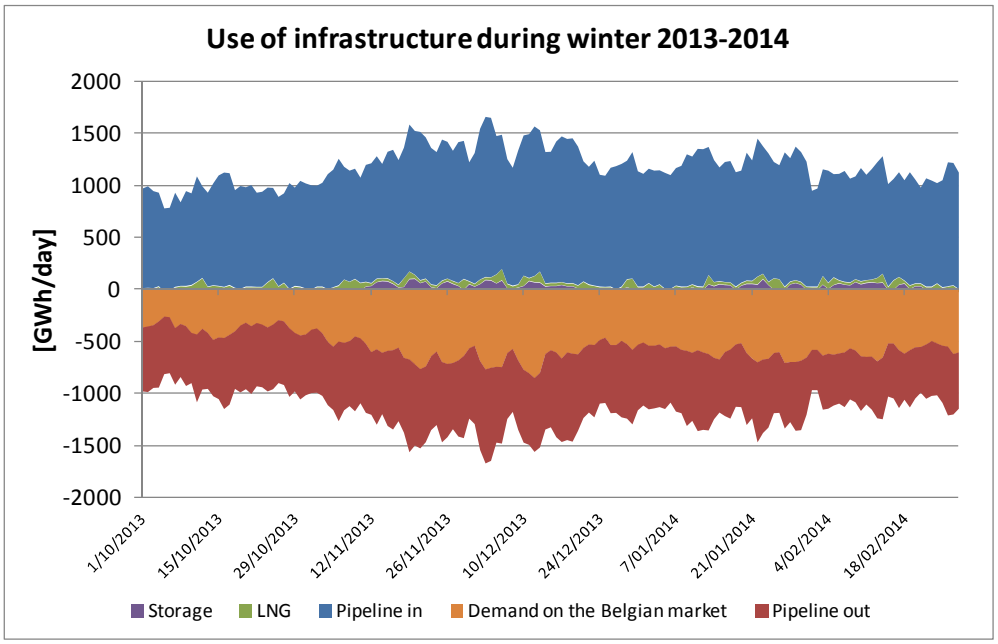
The long term contracts with the Netherlands will last until 2029. The current contracts (and acquisitions on the spot market) are sufficient to cover the expected demand until 2016. After

2016, it depends on the transition and the ratio of the current long-term contracts if the demand will be covered.

1.6.1.2. Infrastructure utilization

With most natural gas originating from Norwegian and Dutch gas fields, the ZPT and Poppel injection points are listed by the shippers.
The Zeebrugge Hub is often cited as an alternative delivery point, demonstrating the alternative routes that arrive at the point.
Shippers citing LNG terminals in Spain, France, Portugal and Italy as possible alternative delivery points if there were a disruption in supply on the Zeebrugge LNG Terminal.
The Zeebrugge LNG terminal provides a significant part, with the Loenhout storage facility providing some capacity during high-demand periods.
The Loenhout site is cited many times as a way of providing flexibility in the case of an incident.

Figure 23: Use of infrastructure during winter period 2013-2014



Source: based on data provided by Fluxys

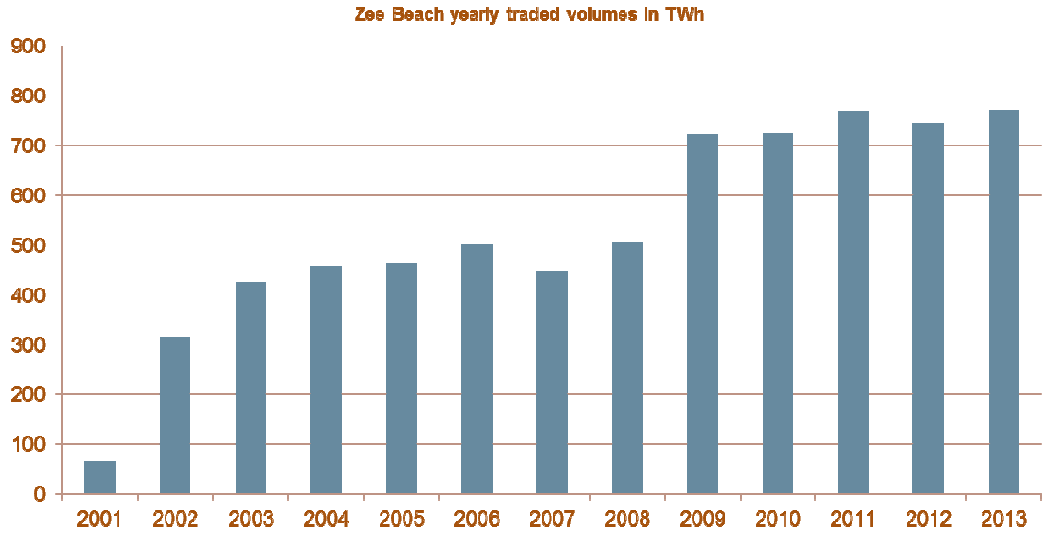
More detailed figures about the entry and exit volumes (for the years 2012 and 2013) as well as the winter period of 2013-2014 can be found in Annex IV and Annex V.

1.6.2. Zeebrugge Trading platform

The Zeebrugge Trading Platform is a notional trading point like TTF in the Netherlands.
Huberator, the operator of the Zeebrugge Beach and ZTP is a subsidiary of Fluxys. Zeebrugge Beach is a physical (with gas molecules made available from delivery borders in the Zeebrugge area, the LNG terminal or the Belgian market) as well as a virtual hub. Currently (February 2014) there are 82 traders at Zeebrugge Beach. In 2010, net traded volumes were up 0,4% on 2009. In 2011 the growth of the net traded volumes was 6% to drop to -3% in 2012. Bilateral trading is also a possibility.

Huberator was created in the wake of the first UK-continent gas link between Bacton and Zeebrugge coming on stream in late 1998. As price differentials between both markets presented arbitrage opportunities the market expressed the need for an actor to facilitate trading in Zeebrugge. Huberator developed the spot gas market, which was the first one in continental Europe.

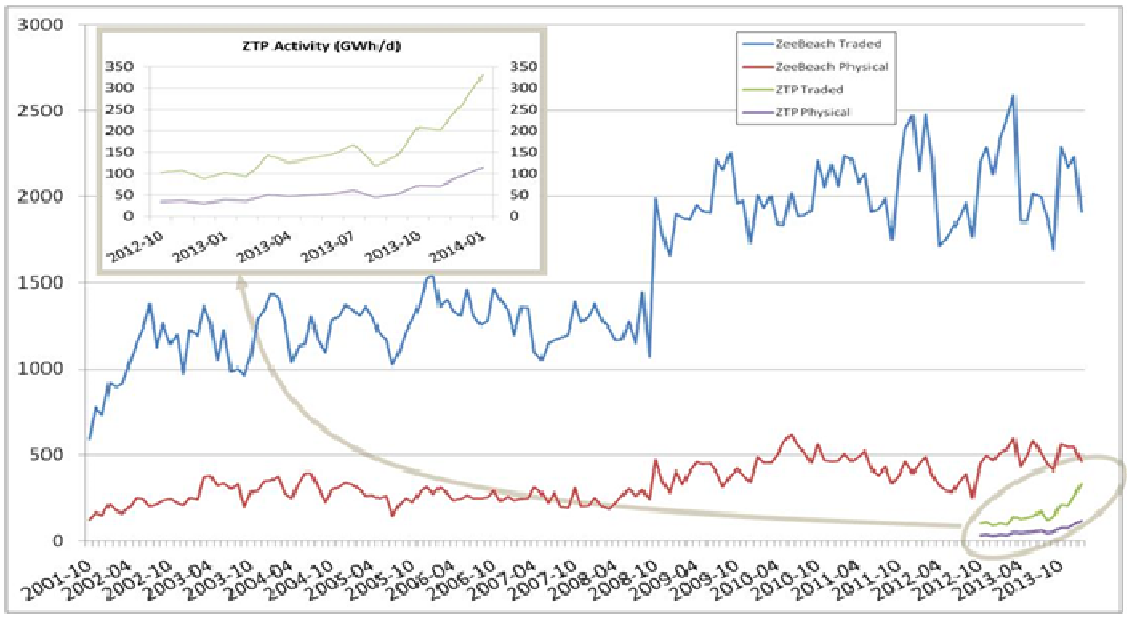
Figure 24: Evolution of traded volume on the Huberator



Source: Fluxys

Since 2001 the figure above shows that the traded volume on the Huberator was growing until 2011, after 2011 the traded volume stays is almost equal every year.
The graph below shows the traded and physical throughput since 2001 (in GWh/day).

Figure 25: Traded quantities and physical throughput (in GWh/day)



Source: Fluxys

2. Risk identification

2.1. Context & objective

In the previous chapter, the context of the Belgian gas system was described. As mentioned in the general introduction of this document, the actual risk assessment part consists of three blocks, the risk identification, the risk analysis and the risk evaluation. This chapter will focus on the first, namely the risk identification.

Risk identification is the process of finding, recognizing and describing risks. It is a **screening exercise** and serves as a preliminary step for the subsequent risk analysis stage. Risk analysis is the process to comprehend the nature of risk and to determine the level of risk. Risk evaluation is the process of comparing the results of risk analysis with risk criteria to determine whether the risk and/or its magnitude is acceptable or tolerable[6].

The objective of this exercise is to identify and list the threats and hazards that may lead to the main undesired consequence: a loss of gas supply. The final objective is to develop a comprehensive list of potential threats and hazards that can cause a loss of gas supply in Belgium.

2.2. Key parameters of risks

According to ISO31000, risks are the combination of the consequences of an event or hazard and the associated likelihood of its occurrence. Consequences are the negative effects of a disaster expressed in terms of human impacts, economic and environmental impacts, and political/social impacts.

Risk = hazard impact * probability of occurrence

Assessing risks means answering the following three fundamental questions:

- What can happen and why?
- What are the consequences?
- What is the probability of its future occurrence?

2.3. Question 1: "What can happen?"

The key of this step is to make an exhaustive identification of threats and hazards. Not being exhaustive in this step may end up in important risk underestimation. Obviously, not all hazards/threats are of equivalent importance to the Belgian case.

Moreover, the list is structured per category of risk. Five categories of risks were identified in this exercise: technical, (geo)political, economic, environmental, and geological risks.

[6] SEC (2010) 1626 final, risk assessment and mapping guidelines for disaster management

2.3.1. Technical risks

a. Hazards	b. Threats
• unintentional technical failure of infrastructure • pipeline burst • explosion • fire • leakage • problems with utilities necessary to operate the pipelines such as the compressor stations or SCADA • ICT breakdown (control rooms) • failure of infrastructure due to impact (for example plane, train crash) • failure of infrastructure due to extreme weather • flood/ingress of water • technical failure due to human error • technical neglect • accidents • maintenance of infrastructure (scraping/pigging/…) • outdated technology • loss, unavailability of personnel (due to for example a pandemic (flu)) • loss of power supply/utilities/services • gas quality • loss of telecom	• intentional sabotage & attack of critical infrastructure • acts of vandalism • theft of equipment or critical materials • targeted cyber attack • virus/trojans

2.3.2. (Geo) Political risks

a. Hazards	b. Threats
• civil unrest or war in supplier countries • civil unrest or war in transit countries • involuntary output reduction	• voluntary output reductions (by gas suppliers) • diplomatic incident • political turmoil • supply cut-off • terrorism (e.g. targeted attacks on gas infrastructure) • strikes in transport, energy,… sector • intentional blockades • sea-lane bottlenecks • Piracy • Policy changes in supply countries by rogue regime prioritizing domestic supplies over export

2.3.3. Economic risks

a. Hazards	b. Threats

• gas price volatility • sudden loss of supply (imports, production) • Sudden peak gas demand,… • supply-demand imbalance • regulatory failure/shortcoming	• commercial dispute • monopolization of market • underinvestment • public opinion opposition

2.3.4. Environmental risks (e.g. natural hazards)

a. Hazards
• hurricane • thunderstorm (& lightning) • earthquake • flood • landslide • extreme cold wave • extreme heat wave • increasing greenhouse gas emissions • marine pollution

2.3.5. Geological risks (producer countries)

• Resource depletion/shortage • Extraction difficulties • Political constraints for extraction

2.4. Question 2: "What are the consequences?"

The first question gives us a comprehensive overview of possible hazards/threats. A second fundamental question assesses the consequences of above events. First of all, there are different types of impact. As described in an EC working staff document[7], several types of impact are defined, namely:

- Human impacts: number of affected people
- Economic impact
- Environmental impact
- Political impact
- Social impact

If we apply this to Ghislenghien event, namely the explosion of the high pressure gas pipeline explosion at Ghislenghien in 2004. Several types of impact can be identified.

- Human impact: death toll
- Economic impact: cost of restoration of infrastructure, buildings,…; loss of gas
- Environnemental impact: air pollution etc.
- Political impact: impact on public order and safety
- Social impact: social & psychological impact

[7] SEC (2010) 1626 final, risk assessment and mapping guidelines for disaster management

In this document, solely the impact in terms of "**loss of gas supply**" will be analysed. The other types of impact will not be discussed in detail.

Moreover, the actual assessment of the gas supply-related consequences (impact) is difficult. There is again a choice between a qualitative and a quantitative approach. In the qualitative approach, consequences can be determined by creating a (standardized) scale of impact, such as for example the scales 1) Minor impact, 2) Noticeable impact and 3) Severe impact.

In the quantitative approach, consequences (impact) of risks can be quantitatively expressed in different ways:

- Quantity of not delivered gas to the protected customers (mcm/d)
- Quantity of not delivered gas to all customers (mcm/d)
- Duration of the shortage of gas (hour)
- Impact on the economy (euro)
- …

In the risk analysis of the Belgian gas system, the impact will be estimated **in a qualitative way**.

2.5. Question 3: "What is the probability of its future occurrence?"

The assessment of probability can be very subjective and difficult. Moreover, the assessment may be quantitative or qualitative, in function of the available data to assess the likelihood of a risk. When the option selected is the qualitative one, a likelihood scale should be defined, with for example 5 scales: 1) very low probability, 2) low, 3) medium, 4) high and 5) very high.

Although such scale could be considered as too coarse, and other more precise ones could be defined. As an example, in the EURACOM project, the following scale is suggested:

- 1 Very low probability (It is extremely unlikely that the incident will occur – no experience in the Belgian gas sector)
- 2 low probability (It is unlikely to occur – very limited experience in the Belgian gas sector, happened only once in ten years)
- 3 Medium probability (It is a likely event – similar accidents have been reported once in three years in the Belgian gas sector)
- 4 High probability (It is very likely to occur – it has been experienced once a year in the Belgian gas system)
- 5 Very high (It will happen in the close future)

In the risk analysis of the Belgian gas system, the probability of certain events will be estimated in a qualitative manner.

2.6. Other variables

- **Timeframe**: probability and consequences of risk change in different timeframes. Therefore, it is necessary to categorize and distinguish between:

- short-term: existing risks and risks appearing within the coming 5 years
- medium-term: risks appearing within the coming 5-10 years
- long-term: risks appearing in more than 10 years

A technical failure of gas infrastructure is mostly a short term event whereas the shortage of interconnection capacity in 2025 concerns more a LT event.

- **Intentionality**: Threats imply intentional acts (acts of terrorism, vandalism, theft, …). Hazards are non-intentional (extreme weather, accidents,…).
- **Provenance:** The risks can both occur in supplier, transit (external risks) and/or consumer states (internal). Not all hazards and threats listed above, are taking place in Belgium. A lot of hazards/threats are likely to occur abroad, in supplier and transit states that are of importance to Belgium
- **Duration:** Short duration (events/shocks) versus long duration (processes/stresses)
- **Timing:** winter versus summer (seasonal elements), peak versus normal situation, …
- **Frequency**
- **Severity of disruption**

2.7. Overview possible scenarios & variables

Ideally, risk identification would consider all possible hazards, their probabilities of occurrence and their possible impacts. However, this is not feasible. In this Belgian risk Assessment, the most probable risks will be assessed.

Building further on the results of step 1 (i.e. establishing the context), step 2 (i.e. risk identification) and taking into account historical data and past incidents, numerous scenarios of the identified risks can be developed. The objective for this scenario building is to identify certain events that could have a large impact on the Belgian gas sector. As it is not possible to simulate all possible scenarios, a selection of the risks with a high probability or a large impact on the Belgian gas supply might be made. We suggest five scenarios that could be presented in the risk analysis (next chapter):

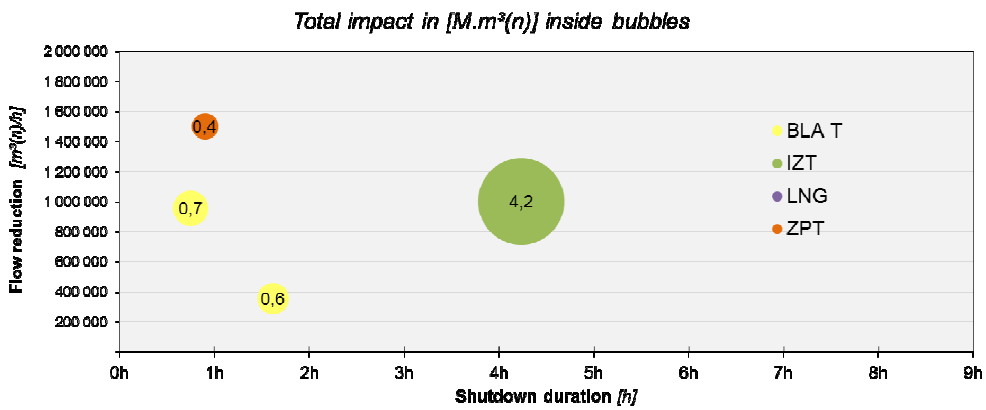
1. Political unrest in Middle East: LNG disruption scenario (Qatar)
2. Hurricane in North Sea: major outage of supplies from Norway
3. Technical failure major pipeline: outage of supplies from the Netherlands
4. Nuclear phase out Belgium
5. Terroristic attack on Loenhout storage facility

These five important scenarios for the Belgian gas system are presented in table under section 3.2.

2.8. Risk evaluation based on historical incidents

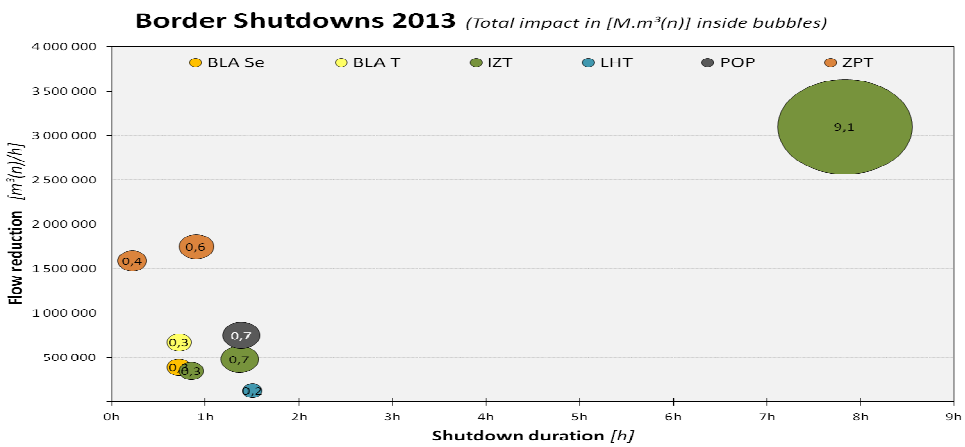
Figures 26 and 27 below give an overview of the incidents happened in 2012 and 2013 on the interconnection points.

Figure 26: Events 2012



Source: Fluxys

Figure 27: Events 2013



Source: Fluxys

It is visible that the most incidents had a limited impact on the system and most incidents lasted generally less than 2 hours. In 2012 and 2013 the incidents with the largest impact were caused by problems on the IZT.

3 Risk analysis

3.1. Objectives

The objective of the risk analysis is to:

1. **define scenarios** as combinations of previously identified events (hazards and threats) that may jeopardize the correct gas system performance.
2. **assess the likelihoods** of the hazards/threats identified above.
3. **assess the consequences/impact** under the conditions of each scenario.
4. Assess the elements that may influence the likelihoods and impact of certain threats and/or hazards.

3.2. Scenario analysis

Scenarios	Category risk	Impact	Likelihood	Timeframe	Threat/ hazard	Provenance	Duration	Timing	Severity
Political unrest in Middle East: LNG disruption scenario on 15/01 (Qatar)	Political risk	Severe	Low	Short term	Hazard	External	30 days	Winter	295 GWh/d
Hurricane in North Sea: major outage of supplies from Norway on 15/01	Environmental risk	Severe	Very low	Short term	Hazard	External	1 month	Winter	411 GWh/day
Technical failure major pipeline: outage of supplies from the Netherlands on 5/02	Technical risk	Severe	Low	Short term	Hazard	External	7 days	Winter	77 GWh/day
Nuclear phase out Belgium and impact of increased gas supplies from Russia	Political risk	Noticeable	High	Long term	Threat	Internal & external	/	/	n/a
Failure of Loenhout storage facility - all storage capacity out (15/7)	Geo-political risk	Noticeable	Low	Short term	Threat	Internal	2 months	Summer	625 mcm/day

3.2.1. Scenario 1: LNG disruption scenario

LNG represents about 15% of the import capacity in Belgium and about 10% of the total yearly gas supplies entering the Belgian network (average 2006-2013). Send out capacity from Zeebrugge is 1,7 mcm/h (about 9 bcm/y) with a storage capacity of 380.000 m³ LNG. The Zeebrugge LNG facility has about 5,5 days of autonomy (storage capacity/ daily regasification capacity).

It is interesting to look at the main threats and hazards in the LNG value chain. Those can either occur upstream in the production or liquefaction (natural disasters, technical accidents, fires, terrorist attacks, political unrest, ….), midstream in the shipping (due to weather conditions, terrorist attacks, wars, pirates, chokepoints, …) or downstream in the regasification (natural disasters, technical accidents, fires, terrorist attacks, …). Each of those occurrences can have an impact either on the LNG supply or the gas supply.

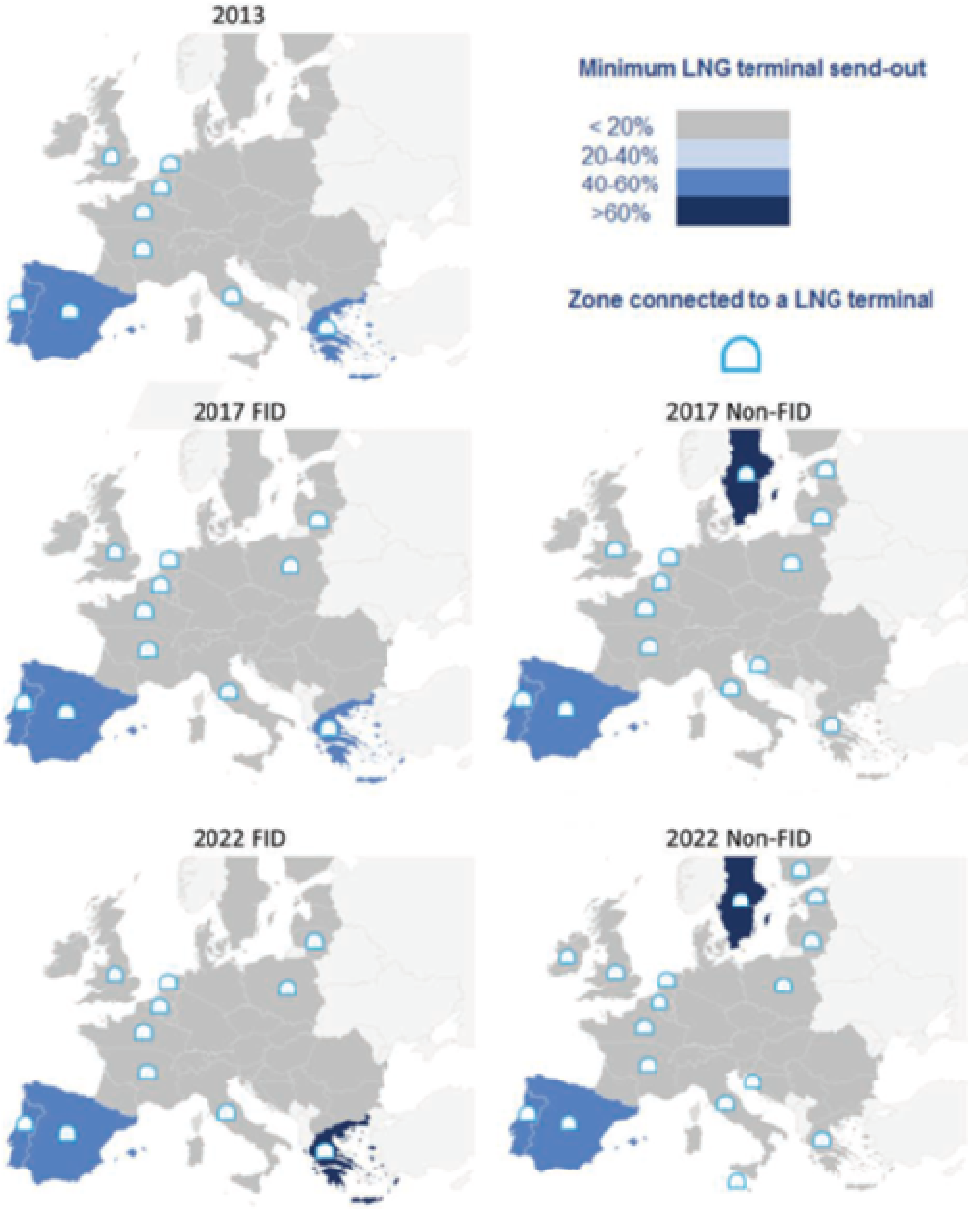
In the EU system wide Ten Year Network Development Plan 2013-2022 (TYNDP), ENTSOG has considered in its network modeling several different disruptions of supply sources and/or routes. For LNG an alternative approach has been chosen[8]. It is difficult to define a realistic LNG disruption of European impact because globalization and flexibility of the LNG chain allow for the rerouting of LNG ships, including between terminals, in response to price signals. This opens the possibility to replace a specific LNG source by another one. Due to the fact that it is impossible to determine what the reaction of the market will be in the long term and to determine how many cargoes would be replaced in an emergency event, ENTSOG investigates how far the LNG deliverability can be reduced towards Europe without the occurrence of network congestion. This approach, for long term assessment under the infrastructure perspective, helps picture the level of dependence on this source for each country and/or how Europe could be impacted by a major move of global LNG supply to another region. It also pictures the impact of a technical disruption of an LNG terminal in a Zone having a single facility (e.g. Greece in 2013) or maritime conditions impacting all facilities of a given Zone (e.g. Fos Cavaou and Fos Tonkin located in GRTgaz South Zone).

In a reference case (no source disruptions or reduced LNG supply), when considering peak demand situations at EU level, imports from pipeline sources are capped at the daily maximum achieved in the period 2009-2011. For LNG a dual approach is followed. LNG is first used as a regular import source at average daily supply level, based on the years 2009-2010-2011, which is increased by 10% to consider the winter swing. Total EU demand is balanced using the remaining LNG send-out capacity (on top of import source use) and UGS deliverability. This is referred to as supply of last resort.

The higher described LNG "incident" scenario can show what the impact would be if LNG were not to reach Europe. LNG supply availability for Europe as a whole is lowered and being replaced by remaining supply sources (up to technical maximum) and additional UGS send-out. Modeling results show the minimum percentage of LNG send-out needed for the different terminals to avoid local or regional network congestion. Countries needing more than 20% of technical LNG send-out capacity (considered as a lower technical limit), are considered to be more vulnerable to a major distortion to LNG deliveries. The map below illustrates the minimum send-out of LNG terminals under daily peak demand situations.

[8] Source: ENTSOG TYNDP 2013-2022

Figure 28: LNG terminals minimum send-out under daily peak demand



Source: ENTSOG

Only four regions require an LNG send-out above 20% utilization under daily peak demand situation:

- Iberian Peninsula; in order to supplement the maximum use of Algerian pipe supplies and interconnection with TIGF Zone
- Sweden; as capacity from Denmark and limited biogas production cannot match the demand
- Greece; in order to supplement the maximum use of Turkish pipe supplies and interconnection with Bulgaria
- Malta; as LNG is the only supply source

It can be concluded that the resilience of the European gas system, and North West Europe in particular, to low delivery of LNG is excellent and some transmission and UGS Non-FID projects should help improve it.

More specific for Belgium, enough interconnection capacities are available to replace lacking LNG supply with gas from other sources with shippers using alternative routes available to them.

Development of LNG terminals in Europe should not be considered as an increase in its dependency to this supply but rather offer alternative supply to face high daily demand situations. It should also be noted that LNG is by nature already diversified in its potential origins. When considering a sustained period of high demand during 14 days, comparable results are achieved.

Table 26: Overview of possible risks in the LNG value chain

Risk description		**Natural disasters**	**Technical accidents**	**Terrorist attacks**	**Political unrest**	
Initial consequences		Lack of LNG	Lack of LNG	Lack of LNG	Lack of LNG	**Liquefaction**
Impacted	countries	EU countries supplied by the affected region of the producing countries	EU countries supplied by the affected liquefaction facility	EU countries supplied by the affected liquefaction facility	EU countries supplied by the affected region of the producing countries	
	quantity	EU part of the production of the affected region of the producing countries	The capacity of the affected production facility	The capacity of the affected production facility	EU part of the production of the affected region of the producing countries	
	duration	Time needed to repair damaged infrastructure	Time needed to repair damaged infrastructure	Time needed to repair damaged infrastructure	Duration of the conflict	
Mitigation measures		Regasification terminals can be supplied by LNG from other sources or spot LNG	Regasification terminals can be supplied by LNG from other sources or spot LNG	Regasification terminals can be supplied by LNG from other sources or spot LNG	Regasification terminals can be supplied by LNG from other sources or spot LNG	
		storage	storage	storage	storage	
		Gas by pipelines	Gas by pipelines	Gas by pipelines	Gas by pipelines	

Risk description		**Weather conditions**	**Terrorist attacks**	**Political unrest**	**piracy**	**Chokepoints**	
Initial consequences		Delay in LNG delivery	Lack of LNG from one or several shippers	Disruption of LNG route	Disruption of LNG route	LNG of a few ships up to disruption of part of LNG route	**Shipping**
Impacted	countries	EU countries supplied by the LNG ships affected by bad weather conditions	EU countries supplied by the LNG ships attacked by terrorists	EU countries supplied by the LNG route passing through region in unrest	EU countries supplied by the LNG route made unsure by piracy attacks	EU countries supplied by the LNG route affected by chokepoints	
	quantity	Some LNG ships	Several LNG ships	Capacity of LNG route	Capacity of LNG route	A few LNG ships or part of the capacity of LNG supply route	
	duration	A few days	days	Duration of the conflict	Duration of piracy	A few days to permanent	

Mitigation measures	LNG storage	LNG storage	Rerouting LNG	Secure LNG routes	LNG storage at regasifiaction terminals + spot LNG unaffected by chokepoints	
	Spot LNG	Spot LNG	Regassification terminals can be supplied by LNG from other sources	Regassification terminals can be supplied by LNG from other sources	Rerouting supply	
	storage	storage	storage	storage	storage	
	Gas by pipelines	Gas by pipelines	Gas by pipelines	Gas by pipelines	Gas by pipelines	

Risk description		**Natural disasters**	**Technical accidents**	**Terrorist attacks**	
Initial consequences		Lack of gas	Lack of gas	Lack of gas	**Regasification/storage**
Impacted	countries	Country of regasification terminal	Country of regasification terminal	Country of regasification terminal	
	quantity	Capacity of regasification terminal	Capacity of regasification terminal	Capacity of regasification terminal	
	duration	Time needed to repair damaged infrastructure	Time needed to repair damaged infrastructure	Time needed to repair damaged infrastructure	
Mitigation measures		Reroute LNG ships to other terminals	Reroute LNG ships to other terminals	Reroute LNG ships to other terminals	
		storage	storage	storage	
		Gas by pipelines	Gas by pipelines	Gas by pipelines	

Source: GLE

3.2.2. Scenario 2: Technical incident on Zeepipe

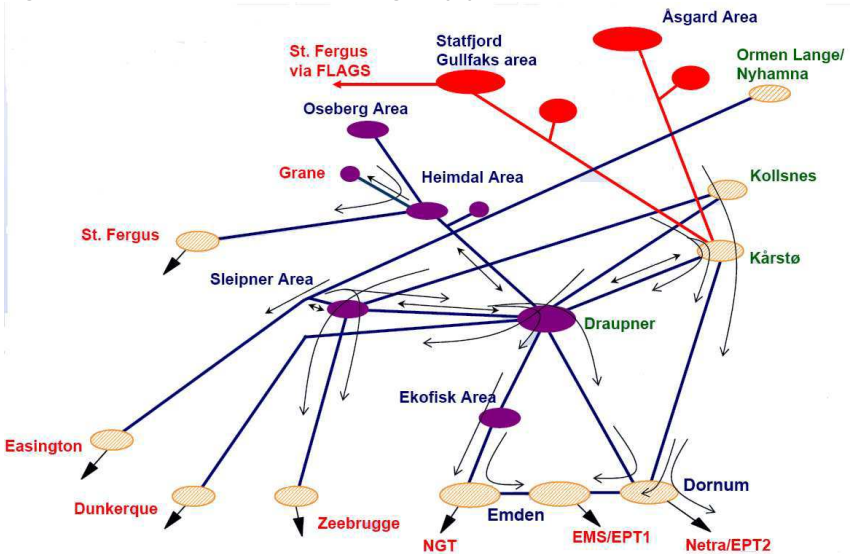
Norway is the largest gas supplier to the Belgian Market and represents about 35% of the gas supplies. Most of the gas coming from Norway to Belgium is imported via the Zeepipe (ZPT). Norwegian gas is not only exported to Belgium, but also towards France, United Kingdom, Germany, and the Netherlands through different undersea pipelines. Norwegian supplies accounted for about 20% of the total yearly European supplies during the last years, and this is expected to remain stable in the coming years. For the North West region of Europe this percentage lies even higher as the landing points of the Norwegian pipelines are situated here.

Zeepipe I comprises a 40-inch pipeline running for about 813 km from Sleipner (SLR) to the receiving terminal in Zeebrugge. Zeepipe I became operational in 1993 and has a capacity of roughly 15 bcm per year (or 42 million scm per day). Zeepipe I also includes a 30-inch pipeline between Sleipner (SLR) and Draupner S. A part form the Zeepipe I coming directly into Belgium, Zeepipe consists of two other pipelines, Zeepipe II A and Zeepipe II B. Zeepipe II A starts at the Kollsnes gas processing plant and ends at the Sleipner riser facility. This pipeline became operational in 1996. Zeepipe II A is a 40-inch pipeline which is 299 km long and has a capacity of 26,3 bcm per year (or 72 million scm per day). Zeepipe II B starts at the Kollsnes gas processing plant and ends at Draupner E. The pipeline became operational in 1997. Zeepipe II B has a 40-inch diameter, runs for about 301 km and has a capacity of 25,9 bcm per

year (or 71 million scm per day). The Zeepipe system has been built for an operating life of 50 years.

The Norwegian gas network is developed in a way that it is possible to redirect flows from almost either gas field to most of the receiving terminals in our neighboring countries. Forms of potential supply interruption can be divided into short term or long term failures. Short term failures could happen regular and can easily be managed on a day to day basis by using built in redundancy and system flexibility. Long term failures could be due to design, fabrication or installation errors, corrosion, third party intervention, natural hazards, incorrect operation and structural issues.

Figure 29: Overview of the Norwegian pipeline network



Source: Gassco

In the EU system wide Ten Year Network Development Plan 2013-2022 (TYNDP) from ENTSOG two different Norwegian disruption scenarios were considered, complete disruption of Norwegian supply to France (failure of Franpipe) on one hand, and partial disruption of Norwegian supply to United Kingdom (failure of Langeled) on the other hand. Although these are no disruptions on a Belgian border point, the impact could possibly be as high due to the high degree of interconnectivity in the North West region, and the change in flow patterns these kinds of disruptions can introduce.

The Norwegian disruption scenarios have been tested (by means of the ENTSOG network simulation tool NEMO) for different years, being 2013, 2017, and 2022. With regards to infrastructure, the three years represent different gas infrastructure configurations which always cover the existing infrastructure and the planned infrastructure projects in accordance with their FID status. The considered demand in Europe corresponds to two short periods of high daily demand conditions. A single day with peak demand in order to capture the situation of highest transported gas quantity (national peak demand per day as calculated by TSOs and laid down in National Development Plans), and a 14-day period of high demand (based on an occurrence of climatic conditions 1-in-20 years), especially with regard to UGS and LNG terminals in order to capture the impact on supply availability especially with regard to UGS and LNG terminals. Capacity at internal EU cross-border interconnection points is considered

technically available, although not always fully exploitable, taking into consideration the proximity of the interconnection points to the disrupted source and the underlying infrastructure.

The disruption scenarios comprise a variation on the reference case scenarios where all pipeline imports are available at the maximum reached on one day during the last 3 years or at the highest average of 14 consecutive days during the last 3 years. The missing gas supply derived from the unavailability of Franpipe or Langeled is managed by rerouting supply of Norway through alternative routes if possible and, finally, as a last resort, by additional gas from UGS and LNG. This assessment results in the identification of the Remaining Flexibility of each Balancing Zone and of the different types of infrastructure located in the Zone. This indicator is defined according the below formulae:
Infrastructure level (percentage of technical capacity not used):

$$Remaining\ Flexibility = 1 - \frac{Flow}{Capacity}$$

Zone level (percentage of aggregated entry capacities not used):

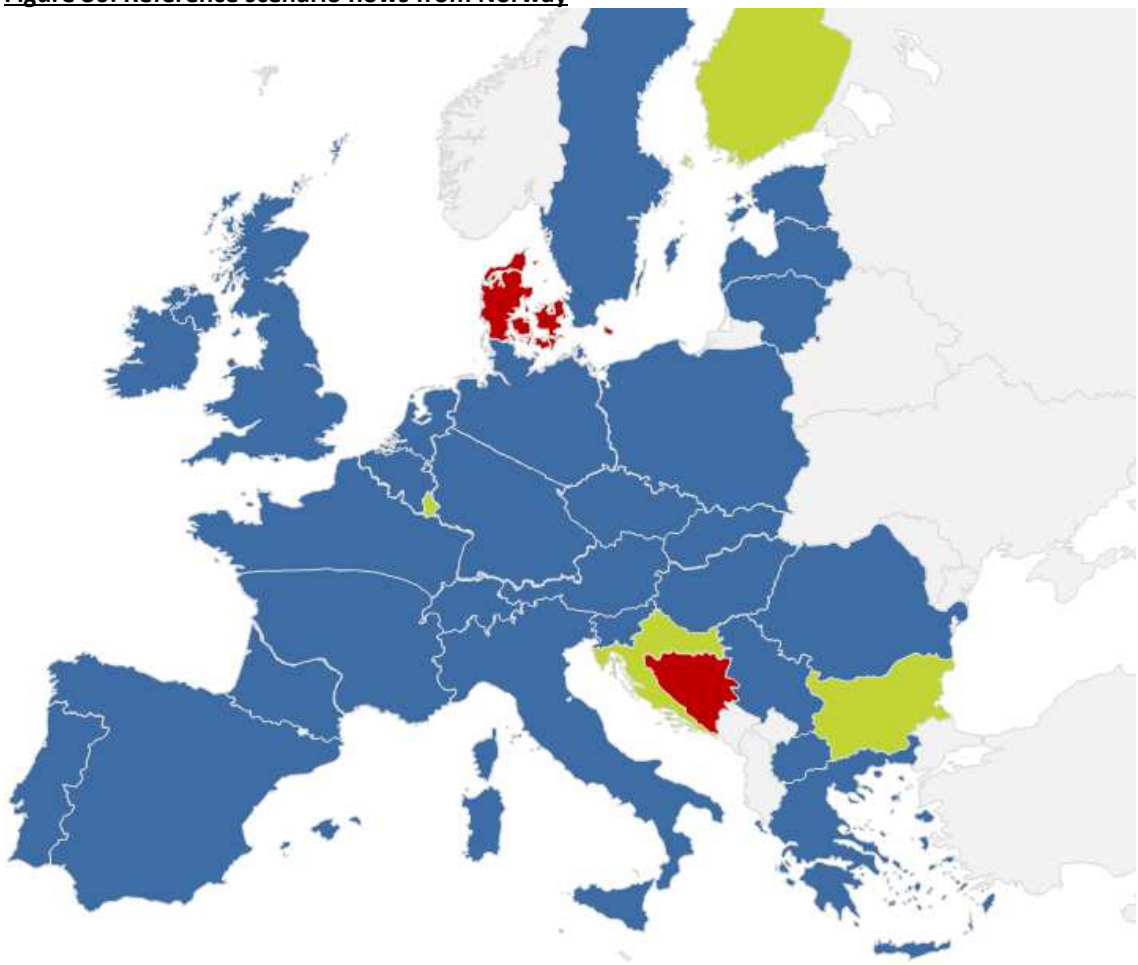
$$Remaining\ Flexibility = 1 - \frac{\sum Entering\ Flow}{\sum Entry\ Capacity}$$

Should the concerned disruption occur in reality, flows actually transmitted at the concerned EU cross-border interconnection points could result in different Remaining Flexibility levels than those resulting from ENTSOG simulations due to, among other reasons, the prevailing flow sources at those interconnection points, market dynamics or other SoS measures possibly undertaken under crisis conditions.

The main results off all ENTSOG scenarios marked with a Norwegian disruption of Langeled or Franpipe is that the Remaining Flexibility in all European market areas doesn't decrease significantly compared to the respective reference cases without disruption, with the exception of France. The considered disruptions don't result in any additional countries facing a shortage of gas supplies, or additional infrastructures becoming congested. This result can be explained by the fact that the interrupted gas supply can be partly diverted to some spare capacity on other Norwegian routes with landing points not far from the interrupted route, while the rest of the missing gas will be compensated by increased LNG or UGS deliveries. The high degree of interconnectivity in the North West region of Europe provides the opportunity to deliver the shifted supply volumes to the European market areas facing high demand conditions.

As an example, the results for one Norwegian disruption scenario are shown hereunder together with the associated reference case without disruption. It concerns a 2013 scenario where Europe is facing a peak daily demand situation and all pipeline supply sources are at their respective maximum, while LNG and UGS are applied to match the demand supply balance. The different colors represent the Remaining Flexibility at zone level as described above (red less than 1%, yellow 1 to 5%, green 5 to 20%, blue more than 20%)

Figure 30: Reference scenario flows from Norway

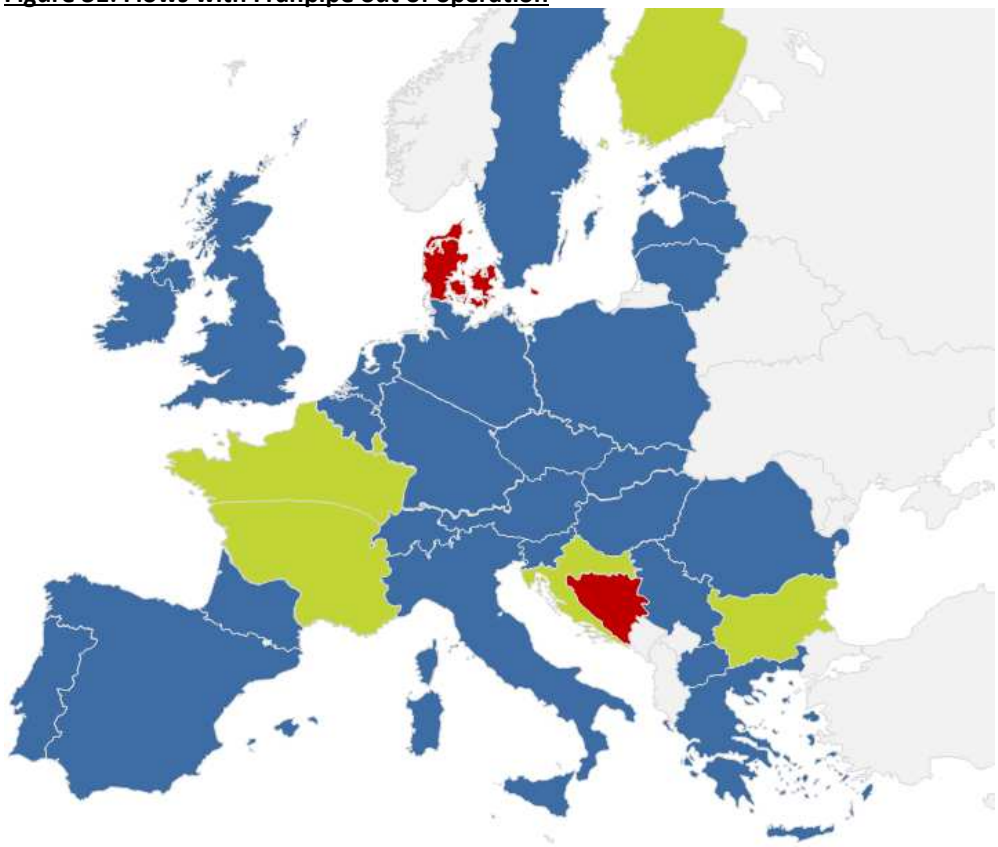


Source: ENTSOG

For Belgium demand is considered around 1.500 GWh/day. In the reference scenario entry flows (for one of possibly many acceptable flow patterns) are mainly coming from the Netherlands, Norway, Germany, Zeebrugge LNG Terminal, and Loenhout Storage Facility, while some gas is transited towards France and Luxembourg. In this particular example, no flow is necessary between Belgium and the UK because there is sufficient storage, production, LNG and flows from Norway and BBL to foresee in the gas demand for the UK region as a whole.

When Franpipe would be disrupted, the loss of supplies from Norway amounts to 585 GWh/d compared to the reference case where the technical capacity of Franpipe was fully used. This loss of supply can be compensated through increased supplies from Norway to the UK and increased send-out from LNG terminals or underground storages. The increased Norwegian supply causes an increased flow through the Interconnector towards Belgium. In addition an increased transit from Belgium towards France is helping the incident situation in France.

Figure 31: Flows with Franpipe out of operation



Source: ENTSOG

The flow situations shown above are one of many conceivable flow situations and do not necessarily mean that in reality the flow distribution will be the same in case of such events. The simulations show only that disruptions can be managed by using the technical capacity and the usual flow schemes. The considered technical capacities of installations and interconnection points in the ENTSOG simulation tool are the result of input from the concerned TSOs. In this way all resulting EU wide flow patterns are implicitly checked on a national level through entry-exit hydraulic simulations.

3.2.3. Scenario 3: Loss of supply from the Netherlands

In this scenario we look at the two possibilities of loss of supply from the Netherlands. The first possibility is short term loss (during a short period of time), the other possibility is long term loss of supply (e.g. the reduction of L-gas coming from the Groningen Field).

3.2.3.1. Short term loss of supply

Analog of the analysis described under paragraph 1.5.4. (N-1 calculation), in case of loss of supply on the L-gas network during a period of exceptionally high gas demand, the Belgian L-gas network will probably not be able to satisfy the gas needs on the L-gas network.

The N-1 results are given in the table below:

	N-1 (%)	
	2014	**2017**
L-net	19,7%	19,7%
L-net – Disruption 1 upstream Line	86,9%	86,8%

The use of L-gas in Belgium is very temperature dependent, this because most L-gas is used on the distribution network. Belgium is also a transit country of L-gas to France. So in case a short term loss of supply there is a chance that less L-gas can be delivered to France if this loss of supply is during a period of exceptional high gas demand (extreme conditions).

The Belgian L-gas network will not be upgraded because in the not so far future the L-gas network will be gradually be transformed in a H-gas network due to the reduction in the production of L-gas of the Groningen field.

3.2.3.2. Long term loss of supply

Like already discussed in paragraph 1.5.1.3. in due time the L-gas production in the Groningen field will be reduced and over time the L-gas network of Belgium will be transformed in a H-gas network.

The future supply of low-calorific natural gas in Belgium is dependent, among other things, on changes in suppliers' purchase contracts and the remaining lifetime of the L-gas field in the Netherlands. Against this backdrop, the Federal Public Service Economy has set up a Task Force comprising the Belgian TSO Fluxys, distribution system operators, natural gas suppliers and the authorities. The Task Force's role is to take stock in the medium term of security of supply with regard to low-calorific natural gas in Belgium. Based on the conclusions drawn, various paths will then be examined. One of the first points noted by the Task Force is that the shift from low-calorific to high-calorific natural gas is already under way in the province of Limburg. This shift will require multilayered investment and action involving the Belgian TSO Fluxys as well as the distribution system operators, suppliers, grid users, regulators and system operators in neighboring countries.

3.2.3.3. Conclusion

Because one of the possible solutions to deal with the future depletion of L-gas reserves in the Netherlands is a total conversion from L-gas to H-gas network, there are no plans to reinforce the existing L-gas infrastructure on the Belgian territory. However, as long as L-gas is sufficiently available and remains flexible, reliable and sustainable, and furthermore this option remains technical and economical optimal, there is no need to anticipate the conversion of the total L-gas network. Nevertheless, we will not exclude the possibility to convert certain zones connected to the L-gas network to be able to absorb the growth for L-gas.

Concerning the incident management on the L-gas market, it will be sufficient to use the mechanisms for mutual assistance. Therefore, the regional cooperation with France, for whom Belgium is the transit country, and the Netherlands, the L-gas producer, should be stimulated.

3.2.4. Scenario 4: Nuclear phase out Belgium

In January 2003, the Belgian parliament passed a law codifying the national policy of Belgium to phase out nuclear energy for commercial electricity production. The law prohibited the construction of new nuclear power plants and set a 40 years limit on the operational period of existing plants.

Several studies have assessed the impact of the nuclear phase-out on the electricity sector and on the general Belgian energy and environmental policies. In particular, a comprehensive study by the Commission for the Analysis of the Belgian Energy Policy towards 2030 (Commission Energy 2030) came to the conclusion that the government should reconsider its 2003 law because the nuclear phase-out would lead to higher electricity prices and endanger Belgium's energy security and ability to meet its climate change targets. On the other hand, some other studies concluded that it was possible for Belgium to reach its EU targets even if the nuclear phase-out policy continued.

In November 2008, the government commissioned the so-called GEMIX study to an expert group consisting of four Belgian and four international experts. The mission of the GEMIX expert group was to elaborate different scenarios and to provide the Belgian government with recommendations on the ideal energy mix for Belgium in the medium and long term. The recommendations were based on the three fundamental principles: security of supply, competitiveness of the Belgian economy and sustainable development. Based on the GEMIX findings, the Belgian government declared in October 2009 that the lifetime of the three oldest nuclear reactors (Doel 1 & 2 and Tihange 1) will be prolonged by 10 year.

In 2013 the Belgian government decided that the lifetime of the Tihange 1 nuclear reactor will be prolonged until 2025.

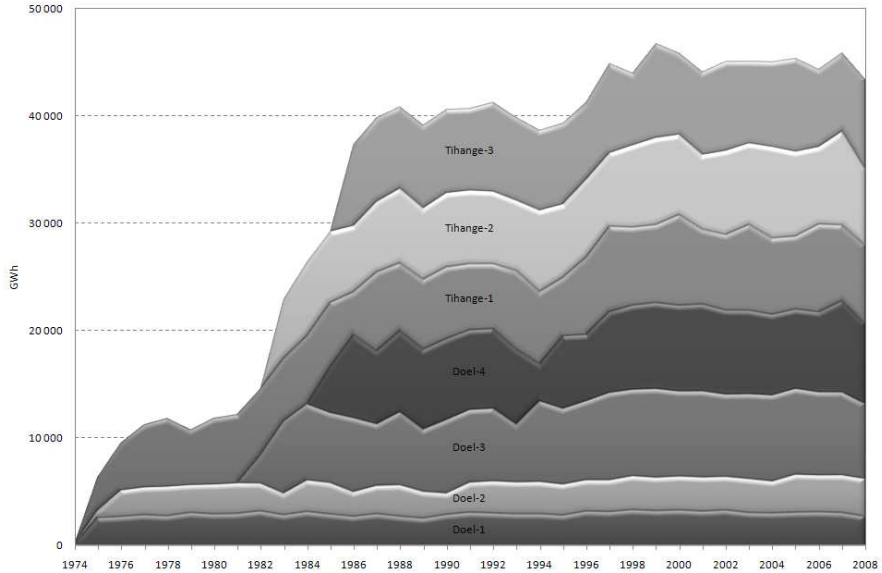
Belgium has seven operating nuclear power reactors – all pressurised water reactors – that have a total generating capacity of 5.824,5 MWe net.

Table 35: Installed nuclear capacity in 2008 (MW)

Nuclear installation	Installed capacity (MW)[9]	Start date	End date
Doel 1	392,5	15 February 1975	15 February 2015
Tihange 1	962	1 October 1975	1 October 2025
Doel 2	433	1 December 1975	1 December 2015
Doel 3	1.006	1 October 1982	1 October 2022
Tihange 2	1.008	1 February 1983	1 February 2023
Doel 4	1.008	1 July 1985	1 July 2025
Tihange 3	1.015	1 September 1985	1 September 2025

In 2007, the Belgian reactors produced 45,9 TWh, more than 55% of the country's electricity generation and more than 20% of total primary energy supply.

Figure 32: Electricity production per nuclear plant 1974-2008



Source: International Atomic Energy Agency, Power Reactor Information System database

It is clear that a nuclear phase out will have a considerable impact on the Belgian economy and the Belgian energy sector in general. The seven operating nuclear power reactors have an installed capacity of more than 5.800 MW. This capacity needs to be replaced by alternative capacity, probably by gas-fired capacity and renewables. Also the use of natural gas in electricity production of Belgium will probably become more and more important.

In the prospective study on electricity three basic scenarios were investigated to describe the impact of a nuclear phase-out:

- Nuc-1800 is based on the gradual dismantling of the nuclear power plants after 40 years of operation, in accordance with the law on the gradual phasing out of nuclear energy for industrial electricity, issued on January 31, 2003. The name of the scenario refers to the loss of 1.800 MW of nuclear capacity (Doel 1 & 2 and Tihange 1) in the electricity system in 2020.

[9] In 2008.

- Nuc-900 is inspired by the decision of the Council of Ministers on July 4, 2012 which provides for an extension of ten years of operational duration of the Tihange 1. For other nuclear power plants, the 2003 Act continues to apply. The name of the scenario refers to the loss of around 900 MW of nuclear capacity (Doel 1 & 2) in the electricity system in 2020.
- Nuc-3000 is based on the assumption that 3.000 MW will be no longer available in 2020 due to the early closure of a number of plants and the application of the law of 2003, except for the Tihange 1 power plant, as in the scenario of available nuclear capacity nuc-900, continues its activities until 2025. In other words, 3.000 MW will disappear from electricity system by 2020.

The table below gives the evolution of the nuclear capacity in Belgium according to the three basic scenarios.

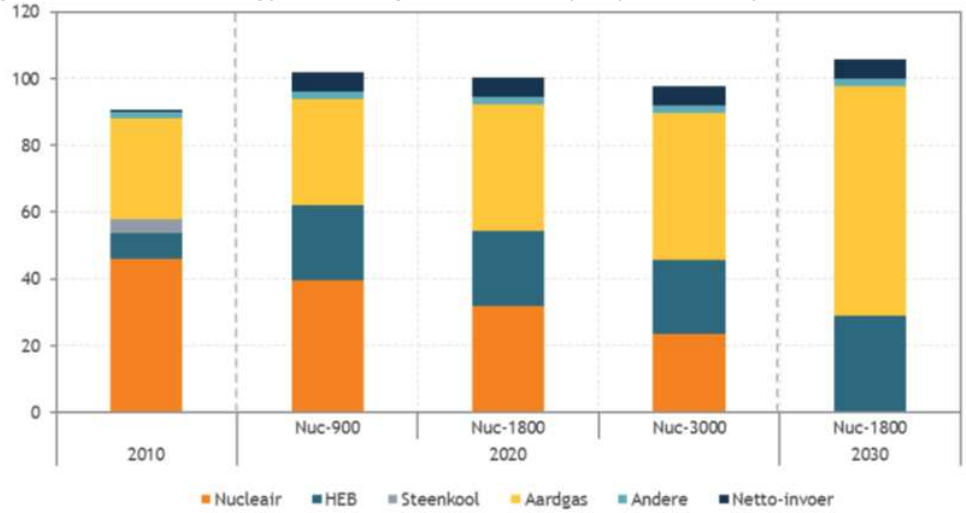
MW	2010	end 2015	2020	end 2022	end 2023	end 2025	2030
Nuc-900	5.825	4.999	**4.999**	3.993	2.985	0	**0**
Nuc-1800	5.825	4.037	**4.037**	3.031	2.023	0	**0**
Nuc-3000	5.825	2.985	**2.985**	2.985	2.985	0	**0**

The electricity supply

There are two ways to meet electricity demand : production electricity in Belgium or electricity import from neighboring countries .

In figure 33 an overview of the energy mix in Belgium is given for the year 2010. A prospective analysis of the energy mix is given for the three basic scenarios in 2020.

Figure 33: Overview energy mix in Belgium (2010 and prospective analysis)



It is assumed that the net electricity imports will remain constant over the projection period, and is equal to 5,8 TWh. The selected level corresponds to the average during the period 2003-2010 and is higher than during the last two years, at 0,6 TWh in 2010 to 2,5 TWh in 2011. The imported electricity corresponds to 6 % of the demand for electric energy in 2020 and 5 % in 2030 . Because the import does not change during the projection period, it can be assumed that the Belgian electricity production adapts to changes in electricity demand.

First of all there is a decline of nuclear power as a result of the elimination of the nuclear capacity given by the 3 basic scenarios:

- In Nuc-900, which simulate the closing of Doel 1 and 2 in 2015 and the prolonging of the lifetime by 10 years of Tihange 1, the share in nuclear power will decreases by 51% in 2010 to 41% in 2020.
- In Nuc-1800, which respect the timing of the nuclear phase out according to the Act of 2003, the share of nuclear power will decrease to 26%.
- In Nuc-3000, taking in account 3.000 MW of nuclear capacity will no longer be available, the share of nuclear power will decrease to 26%.

There is the rise of renewable energy sources (RES) as their share in the total net production increased from 8 % in 2010 to 24 % in 2020, regardless of the baseline scenario. This important evolution is independent of the hypothesis about nuclear energy and is mainly explained by obligation for Belgium to cover 20% of the energy requirement in 2020 by RES, as stipulated in the legislative Climate and Energy Package , but also by the increase in fossil fuel and carbon price that the RES development work in hand.

The share of natural gas increases in the scenarios Nuc-1800 and Nuc-3000 with respectively 40 % and 48 % of total net production in 2020, compared to 34 % net production in 2010. However, this share drops slightly in scenario Nuc-900 where it still amounts to only 33 %. These results show in contrast with the renewable energy that the usage of natural gas in the electricity production is strongly linked to the phase-out of nuclear power plants.

Figure 34 shows a more detailed view of the evolution of the power produced by renewable energy sources corresponding to scenario Nuc-1800 (in GWh).

Figure 34: Evolution electricity production by renewable energy sources

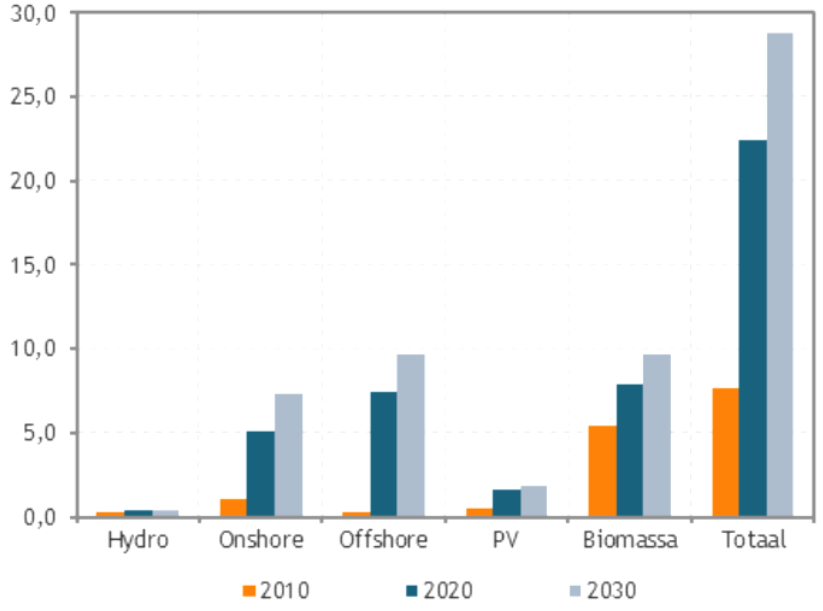
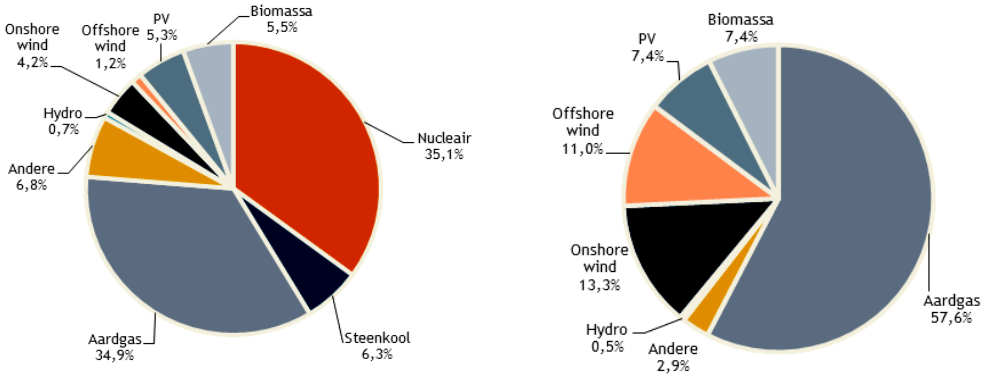


Figure 35: Distribution of the generating capacity of each form of energy (2010 left , 2030 right) , scenario Nuc -1800



In 2030, the projections of the three basic scenarios join together and rises net production to 100 TWh. By then all nuclear power plants are closed , regardless of the scenario. Between 2010 and 2030 the Belgian electricity increases by an average of 0,5 % per year. The structure of the electricity production is almost bipolar, since natural gas and RES together ensure 98 % of the total net production. The remaining 2 % is consistent with the derived gas and oil products . The oil products will only be used to meet peak demand. Coal will disappear from the energy mix of electricity by the assumption that up to 2030 no investments will be made in new coal power stations. The share of natural gas in 2030 is estimated at 57,6 % and RES at 39,6%.

Conclusion

In conclusion, the phase out of the Doel 1 and 2 in 2015 and Tihange 1 in 2025, could have a manageable impact on the gas sector. The main (basic) consequences for the Belgian energy sector would be:

- more electricity imports from neighbouring countries if this is possible.
- more renewable electricity
- a slightly less diversified Belgian energy mix
- more gas import from non-EU countries (i.e. Russia, Middle East)

As the power sector also has an important impact on the gas sector (compression stations, gas burners, …) the impact of an electrical black out or local electricity power cut also needs to be looked at, probably even on a European level.

3.2.5. Scenario 5: Disruption on the Loenhout storage facility

3.2.5.1. Global context

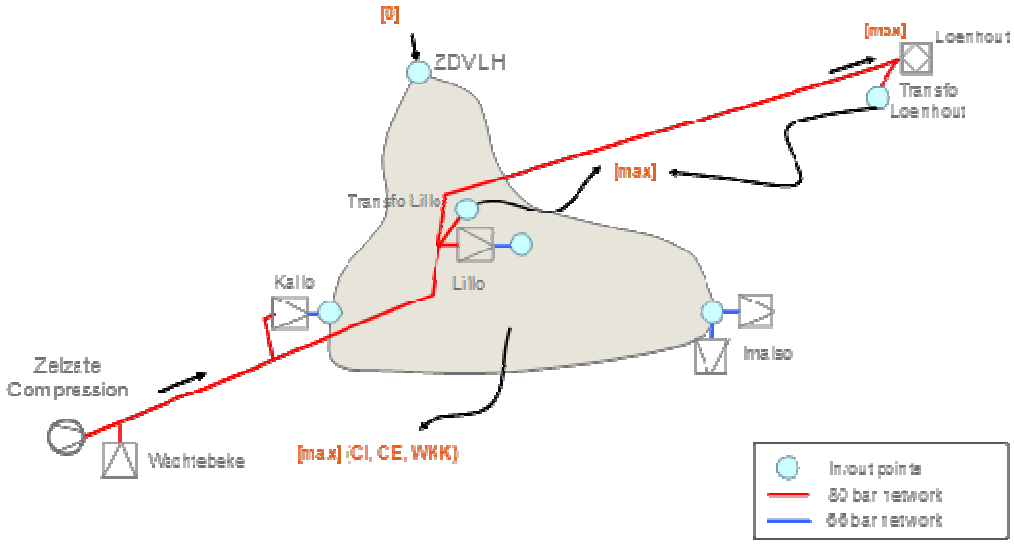
In case of a disruption of the Loenhout storage, there is enough capacity at other borders to fulfill a balance with an exceptionally high gas demand. The result of the N – 1 formula is more that 100% (cfr. chapter 1.5.4: even a disruption of the single largest gas infrastructure gives a result of more than 100 %).

3.2.5.2. Local issues

What means a shutdown of Loenhout for the regional network? Loenhout directly feeds the Antwerp region, together with gas coming from the border Zandvliet (H) and gas coming from the Zelzate compressor station. For this regional network two extreme cases can be considered :

- Maximum transfer to Antwerp (maximum consumption (transfo included, but related to temperature), maximum storage and no entry in Zandvliet)

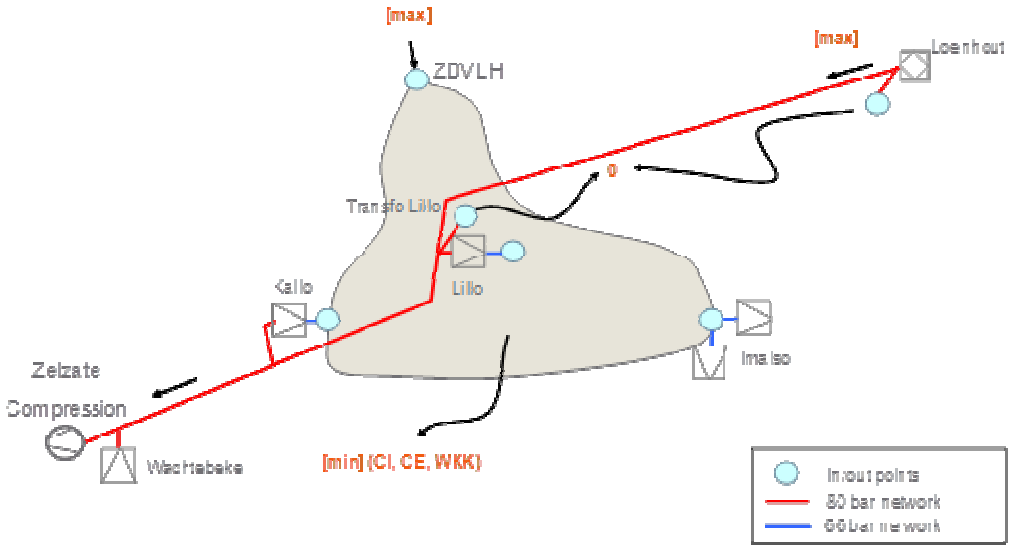
Figure 36: Maximum transfer to Antwerp (schematic overview)



This situation will create a high flow to the Antwerp region, which is limited by the minimum necessary pressure to feed certain clients and the storage facility. This situation is covered by the network simulations, so no emission of Loenhout is necessary. A shut down of Loenhout will reduce the maximum flow to Antwerp and decrease the network load.

- <u>Maximum transfer from Antwerp</u> (minimum consumption (no transfer), maximum emission and maximum entry in Zandvliet)

<u>Figure 37: Maximum transfer from Antwerp (schematic overview)</u>



In this situation the entry flow from Loenhout and Zandvliet will not completely be consumed in the Antwerp region, which will lead to a net transfer of gas to the Zelzate compression. The pressure drop in the pipelines will reduce the pressure at the entrance of the compression of Zelzate, which results in a lower outlet pressure and possible issues in the rest of the network. A shut-down of Loenhout will reduce the maximum transfer to Zelzate and decrease the network load.

3.3. Supply standard

Analysis of the application of supply criteria given by Article 8 of Regulation 994/2010 in Belgium

When comparing the criteria of Regulation 994/2010 with those applied previously in Belgium, there are significant differences. It is therefore appropriate to ask whether these new criteria are adequate or not, to ensure security of supply at a reasonable and prudent level. The following paragraphs show the first two criteria, and compare the consequences of their application.

Criteria "molecules" of Regulation 994 /2010

Article 8 of Regulation 994 /2010 provides that Member States require gas companies to take measures to ensure the supply of natural gas to protected customers of the Member State in the following cases:

a) extreme temperatures for a period of seven days peak , occurring with a statistical probability of once in twenty years;
b) a period of at least thirty days of exceptionally high gas demand occurring with a statistical probability of once in twenty years;
c) a period of at least thirty days in case of failure of the largest gas infrastructure under average winter conditions.

Historical national criteria[10]

The criteria used by the industry and once endorsed by the Monitoring Committee of the Gas and Electricity before the liberalization of the gas and electricity were as follows:

1. the volume of the winter was to cover the consumption of winter 1962/1963 , the coldest winter of the century (Statistical risk of 1 in 95 years);
2. a peak volume for 5 consecutive days between -10°C and -11°C should be assured (statistical risk of 1 in 95 years);
3. transport capacity of hourly peak at -11°C must be guaranteed (statistical risk of 1 in 20 years).

The third national standard is to be compared with Article 6 of Regulation 994/2010, which sets more stringent standards for the infrastructure TSO. This article provides that gas infrastructure must be able to satisfy total gas demand of the calculated area during a day of exceptionally high gas demand occurring with a statistical probability of once in twenty years and this, even in the case of failure of the largest infrastructure. The italicized phrase of the previous sentence is an additional constraint, requiring the TSO to introduce redundancy to cope with a failure of the largest infrastructure.

[10] NB. The listed temperatures are equivalent to average daily temperatures Uccle.

The first two criteria are national criteria "molecules" that apply to suppliers of the Belgian market. It is incumbent upon them to ensure market supply even in the following extreme conditions:
- a long, cold winter;
- An extreme cold peak limited in time.

They are to be linked respectively with the criteria b) and a) of Article 8 of Regulation 994/2010.

Long and harsh winter

NB.

a) Before discussing what follows, it should be borne in mind that:
   - The consumption of the public distribution can be decomposed into two parts:
     i. a fixed part, called "basis consumption", which hardly depends on the outside temperature and takes into consideration the other needs than heating (health, cooking ...)
     ii. a variable part representing the needs for heating, which are zero when the equivalent temperature is above 16,5°Ceq and increase linearly (in first approximation) proportional to the equivalent temperature below 16,5°Ceq (see Schedule : concept of equivalent temperature);
   - It follows that changes in consumption of public distribution are mainly influenced by changes in degree days obtained for the supplied area (see appendix: the concept of degree days);

b) In the following text, we note "winter (3)" or "meteorological winter" period comprising the months of December, January and February (slightly offset from the astronomical winter, which runs from December 22 to one year to 20 or 21 March the following year). We note "winter (5)" the period comprising the months of November, December, January, February and March (corresponding to the period when heating needs are the most important). We also note "DDcorr." the value of estimated equivalent degree-days in 2012, after correction induced by global warming.

The gas year 1962/1963 is the coldest year of the century with 3.040 DD (or 2.861 DDcorr.).

Table 36 : Ranking of the coldest gas year according to the Degree Days

Ranking	GasYear	DDeq	DD corr.
18	1969	2.670	2.504
17	1952	2.751	2.518
16	1983	2.643	2.530
15	1961	2.729	2.532
14	1916	2.906	2.535
13	1984	2.661	2.553
12	1923	2.894	2.570
11	1964	2.746	2.561
10	1939	2.847	2.564

9	1986	2.678	2.578
8	1940	2.882	2.603
7	1928	2.944	2.619
6	1995	2.696	2.631
5	1941	2.915	2.641
4	1955	2.893	2.672
3	1978	2.807	2.676
2	1985	2.901	2.797
1	1962	3.040	2.846

It was also during the gas year 1962/1963 that winter(3) winter(5) were the coldest of the century respectively with 1.657 DD (or 1.621 DDcorr.) and 2.335 DD (or 2.246 DDcorr.). For the Audit Committee, the winter notion corresponded to the volume necessary to ensure the supply of winter(5). The implementation of these criteria therefore required that the market has to have a large amount of molecules to face a long and harsh winter.

Table 37 : Ranking of the winter periods (Dec-Feb) according to degree days

Degree days -> Dec - Feb					
Ranking	GasYear	DD	DD Corr.	DD GY	DD/(DD GY)
29	2010	1.233	1.231	2.253	54,72%
28	2012	1.237	1.222	2.326	53,17%
27	1981	1.258	1.235	2.505	50,20%
26	1964	1.274	1.240	2.746	46,41%
25	2005	1.258	1.253	2.380	52,84%
24	1967	1.287	1.255	2.597	49,56%
23	1990	1.273	1.257	2.475	51,42%
22	1968	1.292	1.260	2.620	49,31%
21	2008	1.279	1.276	2.328	54,95%
20	1996	1.289	1.277	2.494	51,66%
19	1952	1.336	1.293	2.751	48,57%
18	1985	1.314	1.295	2.901	45,30%
17	1923	1.363	1.298	2.894	47,09%
16	1969	1.342	1.311	2.670	50,26%
15	1963	1.349	1.314	2.571	52,49%
14	2009	1.323	1.321	2.457	53,85%
13	1986	1.358	1.339	2.678	50,70%
12	1933	1.409	1.352	2.726	51,69%
11	1995	1.374	1.362	2.696	50,96%
10	1955	1.430	1.389	2.893	49,45%
9	1940	1.447	1.395	2.882	50,19%
8	1916	1.466	1.397	2.906	50,45%
7	1984	1.421	1.401	2.661	53,40%
6	1978	1.449	1.424	2.807	51,60%
5	1928	1.534	1.474	2.944	52,13%
4	1939	1.548	1.495	2.847	54,37%
3	1941	1.560	1.508	2.915	53,50%
2	1946	1.562	1.514	2.735	57,11%
1	1962	1.657	1.621	3.040	54,51%
				Mean	51,38%

Table 38 : Ranking of the winter periods (Nov-Mar) according to degree days

Degree days -> Nov-March					
Ranking	GasYear	DD	DD corr.	GasYear DD	DD/(GYDD)
36	2010	1.814	1.810	2253	80,5%
35	1981	1.868	1.814	2505	74,6%
34	2009	1.827	1.821	2457	74,4%
33	1964	1.902	1.818	2746	69,3%
32	1950	1.934	1.825	2671	72,4%
31	1996	1.864	1.835	2494	74,7%
29	1954	1.938	1.836	2600	74,6%
28	1975	1.915	1.849	2584	74,1%
27	2008	1.870	1.863	2328	80,3%
26	1967	1.945	1.866	2597	74,9%
25	1961	1.956	1.866	2729	71,7%
23	1963	1.971	1.885	2571	76,7%
22	1943	2.008	1.887	2660	75,5%
21	1921	2.045	1.885	2815	72,7%
20	1968	1.991	1.913	2620	76,0%
19	1940	2.041	1.914	2882	70,8%
18	2005	1.938	1.926	2380	81,4%
16	1952	2.051	1.946	2751	74,6%
15	1955	2.049	1.949	2893	70,8%
14	1984	2.016	1.967	2661	75,8%
13	1969	2.048	1.972	2670	76,7%
12	1986	2.024	1.979	2678	75,6%
11	1923	2.132	1.976	2894	73,7%
10	1939	2.117	1.988	2847	74,4%
9	1928	2.140	1.992	2944	72,7%
8	1933	2.132	1.993	2726	78,2%
7	1995	2.047	2.017	2696	75,9%
6	1985	2.093	2.045	2901	72,2%
5	1978	2.105	2.046	2807	75,0%
4	1916	2.213	2.044	2906	76,1%
3	1946	2.210	2.094	2735	80,8%
2	1941	2.240	2.116	2915	76,9%
1	1962	2.335	2.247	3040	76,8%
				Average	75,2%

As an illustration, given that on average, the number of degree days the last 30 years gas amounted to 2.353, the winter of 1962/1963 had 29% more degree days. It is also noted that the 5 months of winter (5) represent approximately 75% of the heating needs, while the 3 months of winter (3) the heating needs were 51%.

Extreme cold peak limited in time

A cold peak limited in time corresponds to an average daily temperature equivalent in Uccle between -10°C and -11°C for 5 consecutive days.

This reference has its origin in the cold peak of January 1987.

begin	end	Equivalent temperatures					Average
12/01/1987	16/01/1987	-10,6	-10,9	-10,9	-11,1	-9,8	-10,66

The temperature range was obtained by rounding down and up, respectively the 4th and 5th values (-11,1°C and -9,8°C).

It should be noted that this cold peak occurs ones every 25 years.

Comparison of historical national criteria with the criteria of Article 8 of Regulation 994/2010

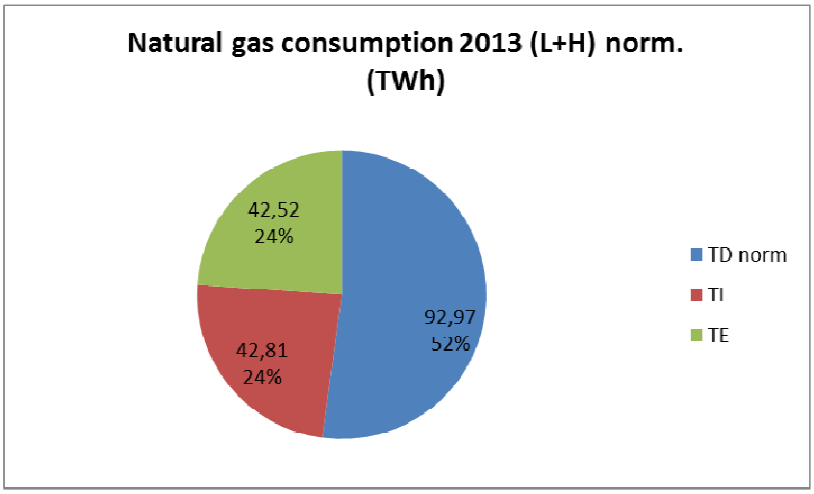
a) National Market and protected customers

The most pragmatic approach adopted by the Audit Committee, on the proposal of market participants, is to consider that the suppliers of the gas market are able to supply their customers even in extreme weather conditions.

In general, national criteria were applicable to the entire market, that is to say that the market should ensure gas supply to both public supply, industry and electricity producer, even under conditions of severe winter (1962/1963) or an extreme cold peak.

Regulation 994/2010 reduced this requirement to protected customers. If the concept of "protected client" is equated to that of "public distribution", the criteria of Article 8 of the 994/2010 Regulation is only applicable on 52 % of the national market (based on consumption standardized annual temperature of 2013) (see graph below).

Figure 38: Natural gas consumption of L and H-gas per sector (2013)



b) Result of the application of the criteria a) of Article 8 of Regulation 994/2010

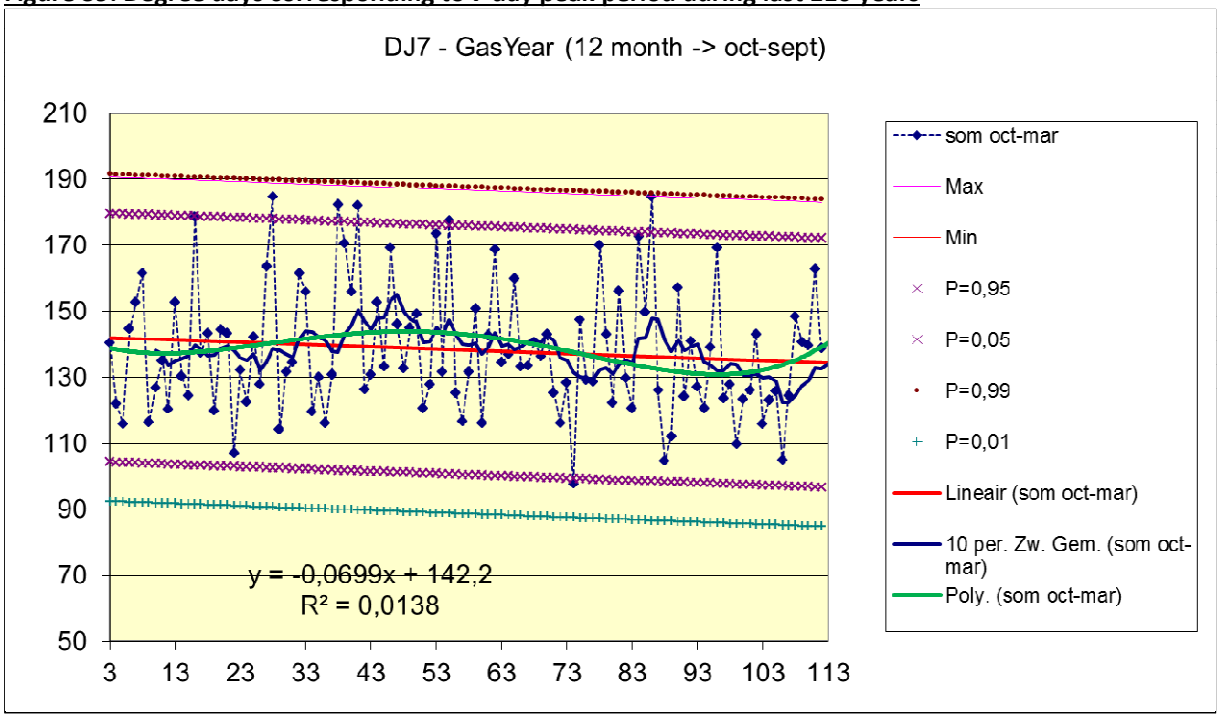
As a reminder, this criteria says that the gas companies need to take the necessary measures to ensure supplies to protected customers of the Member State in the case of extreme

temperatures for a period of seven days peak, occurring with probability statistical once in twenty years.

The following graph shows, in blue diamonds, the search result for the last 110 gas years (that is to say from October of year n to September of year n + 1), the number of degree-days for the period of seven coldest days of each gas year. The rose crosses indicates the limit beyond which the number of degree days 95 % chance of finding (5% risk).

NB. In this graph and similar graphs that follow, the abscissa represents the year 3 corresponding to 1903 and 113 in 2013.

Figure 39: Degree days corresponding to 7 day peak period during last 110 years



In the table below are listed the five periods of seven consecutive cold days which were the coldest of the past 100. To facilitate interpretation, degree days in this table are converted into equivalent temperature in the following table.

Table 38 : Degree days for the 7 day peak period occurring once in 20 years

begin	end	Degree Days							
1/02/1917	7/02/1917	24,8	25,5	27,2	26,9	25,6	25	23,7	178,7
12/02/1929	18/02/1929	27,3	27,9	28,9	26,8	25,5	24,8	23	184,2
19/12/1938	25/12/1938	27,2	29,1	27,5	25,8	25,7	23,8	23,2	182,3
17/01/1942	23/01/1942	23,9	23,8	23,8	26	28,4	29,6	26,6	182,1
11/01/1987	17/01/1987	24,7	27,1	27,4	27,4	27,6	26,3	24,3	184,8
		25,6	26,7	27,0	26,6	26,6	25,9	24,2	

During the past 100 years, the most important cold peak of seven consecutive days was recorded during winter 1986/1987, with 184,8DD.

Table 39 : Conversion of 7 day peak period degree days to equivalent temperature

begin	end	Equivalent temperature							Average
1/02/1917	7/02/1917	-8,3	-9	-10,7	-10,4	-9,1	-8,5	-7,2	-9,0
12/02/1929	18/02/1929	-10,8	-11,4	-12,4	-10,3	-9	-8,3	-6,5	-9,8
19/12/1938	25/12/1938	-10,7	-12,6	-11	-9,3	-9,2	-7,3	-6,7	-9,5
17/01/1942	23/01/1942	-7,4	-7,3	-7,3	-9,5	-11,9	-13,1	-10,1	-9,5
11/01/1987	17/01/1987	-8,2	-10,6	-10,9	-10,9	-11,1	-9,8	-7,8	-9,9
	Mean	-9,08	-10,18	-10,46	-10,08	-10,06	-9,4	-7,66	

Of the five coldest periods in the last 100 years, totaling on average (mean) four days between -10°C and -11°C, on the one hand, and two days between -9°C and -10°C, on the other hand.

By applying criteria a) of Article 8 of Regulation 994 /2010 to look for extreme temperatures for a seven consecutive days peak period we assume, occurring with a statistical probability of once in twenty years. We interpret "seek extreme temperatures for a period of seven peak days" as "seek for each gas year, the maximum number of degree days obtained by accounting for seven consecutive days associated with these degree days." Then, we seek the value corresponding to 5% risk.

This value is 169,6 DD. It is 8% lower than in the winter of 1966/1987 (184,8 DD).

The regulation doesn't say anything about the differences between degree-days within the period of seven days. However, the degree days may change significantly during this period. For proof just check the following table, which shows some examples of changes in degree days for periods of seven days having recorded a maximum of ±170 DD.

Table 40 : Evolution of the degree days within a 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

These five periods totaling 169,5 degree-days each have an average of -7,7°Ceq. But three of them include a temperature between -10°C and -11°C , two in count one temperature value between -10°C and -11°C and another counts two. In the latest case, it is found that as the amount of degree-days of the period is constant, recorded for two days less than -10°C, it is necessary that the remaining days are much warmer than the average period (-7,7°Ceq). In other words, this period knows the most evolution regarding contrast (-4,1, +3,2).

The variability of the equivalent temperature is not defined in a regulatory manner, one could simply apply a zero variability. This would provide a period of seven consecutive days where

the temperature is -7,7°C and deduce that the limits of daily peak flow conditions to be fulfilled are limited to -7,7°C. If this approach is adopted - and nothing seems to oppose the regulation - the market may no longer have to provide an equivalent temperature below -7,7 °C. However, no less than 17 gas winters show a similar temperature below -7,7°C at least one day during the past 100 years (after correction due to global warming), or about one in six winter. In the context of security of supply, this result is not acceptable, because it is simply not prudent.

Conclusion

Criteria a) of Article 8 does not seem sufficient to ensure security of supply, for two main reasons:

1. it does not take into consideration the wintry conditions of the winter of 1986/1987 (which occurs ones in 30 years), during which the temperature was below -10°C during almost five consecutive days;
2. within the period of seven days, no criteria of evolution of the equivalent temperature was defined, which, depending on the chosen profile and its variance, will have a significant impact on the daily peak flow to be provided by the market.

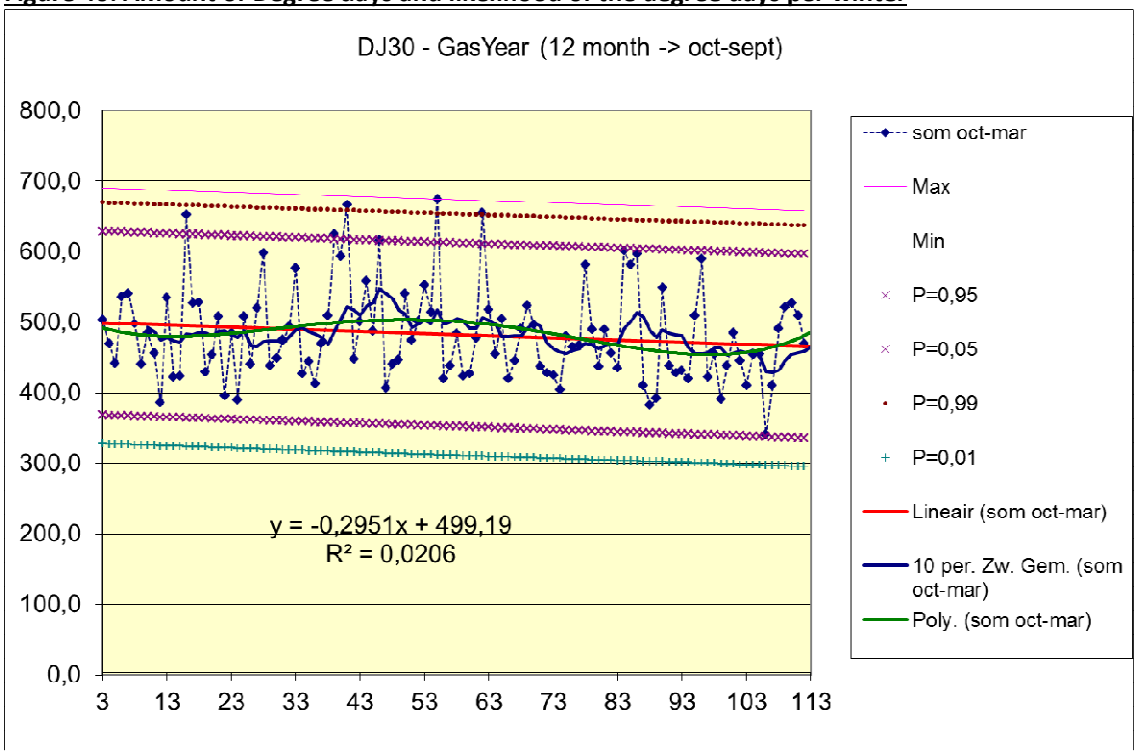
c) Result of applying criteria b) of Article 8 of Regulation 994/2010

As a reminder, this criteria says that the gas companies need to take the necessary measures to ensure the supply of natural gas to protected customers of the Member State in the case of a period of at least thirty days of gas demand exceptionally high, occurring with a statistical probability of once in twenty years.

Following that it is assumed that a period of at least thirty days of exceptionally high gas demand is equivalent to the protected customers, a period of at least thirty days exceptionally cold.

The following graph shows, indicated with blue diamonds, the evolution for the last 110 years gas (that is to say from October of year n to September of year n +1), the number of degree - days obtained by taking , for each gas year , the period of 30 consecutive cold days. The rose crosses indicate the limit beyond which the number of degree days 95 % chance of finding (5% risk).

Figure 40: Amount of Degree days and likelihood of the degree days per winter



During the past 110 years, the period of the 30 consecutive coldest days was recorded during winter 1955/1956, with 675DD.

The number of degree days obtained with a 5% risk of 593,9 DD (taking in account the climate change). This value is 12% lower than in winter 1955/1956.

But is that the gas volume of an extreme month with a risk of 5 % or a gas volume during a winter period with an average of five months?

As stated above, the natural gas consumption related to the needs for heating increase almost linearly with the number of degree- days. A multiplicative coefficient close to this consumption is proportional to the number of degree- days recorded over a given period . At this consumption must be added a part that is almost independent of the degree days, this is due to the use of other applications running on natural gas (cooking, hot water production ...). We can translate that the consumption is almost constant by an artificial increase in the number of degree days, a fixed amount proportional to the number of days in the period. For protected network H-gas customers (i.e. customers on the public distribution network of H-gas), this amounts to 3,25 per day increase the number of degree-days because of the weather conditions. Thus, if the study period is seven days , the number of degree-days due to the weather will be increased by 22,75 DD (7 x 3,25 DD). The sum of degree-days given by both sources is a first approximation, proportional to the gas consumption.

The following table shows a day, seven days, 30 days , one month, five months , six months and one year:

- The average maximum degree-days for each gas year (salmon color);
- The number of degree- days with a 5% risk (blue);
- The number of degree-days equivalent to the consumption of applications other than heating (yellow);
- The result of the addition of the third value to each of the 1st.

Table 41 : Average DD per peak period and amount of DD with 5% risk

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)	Linearly 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

The comparison of the peak values with a risk of 5% a month (691 DD) and one year (3.836 DD) shows that the consumption of one month represents only 18.02% of that of a year. Even if we limit the comparison to the winter period (five months – 2.525 DD), peak demand with a 5% risk represents only 27 % of requirements.

By comparison, the national criteria of supply (ensure the volume of the winter 1962/1963, the coldest year of the last century) provided that the market has a gas volume equivalent to 2713 DD on 3836 DD needed to face an extremely cold year with a risk of 5 % or more than 71 % of the annual volume.

The table below gives the percentage that represents a consumption in a peak month with a risk of 5 % relative to the total consumption of one year, six months and five months on one hand with respect to the average and, secondly the peak with a risk of 5 %.

Table 42 : Percentage of the consumption in peak scenario and 5% risk scenario

		1 day	7 days	1 month 30 days	5 month 150 days	6 month 180 days	1 year 365 days
Percentage of the total 1 Year	Average 100 years	0,70%	4,44%	16,05%	63,27%	71,14%	100,00%
	Peak 5% 100 years	0,78%	5,01%	18,02%	65,81%	75,86%	100,00%
Percentage of the total 6 month	Average 100 years	0,98%	6,23%	22,56%	88,93%	100,00%	140,56%
	Peak 5% 100 years	1,03%	6,61%	23,76%	86,75%	100,00%	131,83%
Percentage of the total 5 month	Average 100 years	1,10%	7,01%	25,37%	100,00%	112,45%	158,06%
	Peak 5% 100 years	1,19%	7,62%	27,39%	100,00%	115,27%	151,96%

Conclusion

Criteria b) of Article 8 of the 994/2010 Regulation can be considered as a sufficient criteria to ensure security of supply in peak conditions of a long and harsh winter. Indeed, this criteria requires that the market is able to prove that it has a volume of natural gas equivalent to ¼ of winter needs within a period of five months in peak conditions with a risk of 5 %, this is, in our opinion, insufficient.

General conclusion

Although the criteria of Article 8 of Regulation 994 /2010 are the minimum requirements from which a European consensus has been reached and solidarity mechanisms were, among others, to be developed. It nonetheless results that not only these criteria are sufficient, even prudent, to ensure security of supply in the country.

4 Risk evaluation

In the risk evaluation, all risks (with its 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, has to 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 only 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 43: 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 44: Assessment of the probability of accidents

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

	Probability				
Impact	Very low	Low	Medium	High	Very High
Minor			Environmental risks	ICT breakdown Scenario 4	
Low	Scenario 5	Scenario 1			
Noticeable	Failure of infrastructure due to extreme weather	Pipeline burst Loss of power supply	issues with gas quality Unintentional failure of infrastructure Scenario 2		
Severe	intentional sabotage	Cyber attack Scenario 3			
Very Severe					

4.1. Conclusion

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 completely separate. Belgium also benefits from sufficient 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.

At 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 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 4% (in 2013) of the gas that physically enters the Belgian network is LNG, this part can be replaced by pipeline gas in case of a disruption.

- 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 is 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.

Annexe I : Degrés-jours et degrés-jour équivalents

Pour plus d'explications sur les degrés-jours, l'on consultera le site www.synergrid.be.

Pour un jour donné, les degrés sont égaux à la différence entre 16,5 °C et la température moyenne mesurée par l'IRM à Uccle.

Par exemple, si la température moyenne d'un jour a été de -2°C, le nombre de degrés-jours pour cette journée est de 18,5°C (DJ = 16,5 - (-2)). Si la température moyenne d'une journée est supérieure à 16,5°C, on prend la valeur 0.

Dans la présente étude, les « degrés-jours équivalents » (DJéq), tels que définis par Synergrid, sont utilisés comme référence pour les besoins en gaz naturel réels pour le chauffage. On tient donc compte du tampon thermique des bâtiments via l'enregistrement des besoins en chauffage des deux jours précédents.

Deux exemples de calcul :

jour 1 : température moyenne en journée de 18°C jour 2 : température moyenne en journée de 14°C jour 3 : température moyenne en journée de 12°C alors DJ (jour 1) = 0 DJ (jour 2) = 2,5 DJ (jour 3) = 4,5 **DJéq (jour 3) = 3,45**	jour 1 : température moyenne en journée de -2°C jour 2 : température moyenne en journée de +3°C jour 3 : température moyenne en journée de -4°C alors DJ (jour 1) = 18,5 DJ (jour 2) = 13,5 DJ (jour 3) = 20,5 **DJéq (jour 3) = 18,2**

Dans l'étude, la demande de gaz naturel estimée pour le chauffage sur les réseaux de distribution est corrigée pour la température.

Pour la correction des consommations annuelles et mensuelles d'après un « profil de température normal » (t° norm.), les degrés-jours équivalents moyens sont pris pour la période 1976-2005. Le nombre moyen de DJéq sur une base annuelle pendant ces 30 ans s'élève à 2.415 DJéq.

Pour la correction des consommations annuelles et mensuelles d'après un « profil de température extrême » (t° extrême), les degrés-jours équivalents sont pris pour la période 1962/63, caractérisée par un hiver extrêmement froid. Le DJéq annuel pour le profil de température extrême s'élève à 3.040 DJéq. Les besoins en chauffage pour ce profil de température sont par conséquent supérieurs de 26 % au profil moyen pendant la période 1976-2005.

Les deux profils de température sont représentés au tableau ci-dessous.

	DJéq (t° norm.)	DJéq (t° extrême)
J	417	648
F	367	520
M	306	329
A	219	208
M	110	161
J	48	32
J	17	13
A	16	47
S	65	68
O	166	175
N	298	349
D	386	490
Total	**2.415**	**3.040**

Annex II : Regional technical legislation related to security of supply

1. Region of Brussels-Capital: Technical regulation (Decree of 13.07.2006)

***Section 2.4.* — Garanties à donner par le détenteur d'accès**

Art. 119. Le détenteur d'accès garantit au gestionnaire du réseau de distribution qu'à dater de l'entrée en vigueur et pendant toute la durée du contrat d'accès, les prélèvements effectués aux points d'accès relevant de son portefeuille seront couverts par des contrats de fourniture.

Le détenteur d'accès garantit également qu'il fera injecter, via le réseau de transport et les stations de réception, autant de gaz qu'il en fournit aux utilisateurs du réseau de distribution avec lesquels il a conclu un contrat de fourniture. Le détenteur d'accès déclare et garantit à cette fin au gestionnaire du réseau de distribution que tous les contrats nécessaires à l'obtention de l'accès au réseau de transport et aux autres réseaux de distribution ont été conclus.

Art. 120. Le détenteur d'accès s'engage à informer immédiatement le gestionnaire du réseau de distribution en cas de modification d'un des éléments repris au contrat d'accès ou de l'identité et des coordonnées de l'utilisateur du réseau de distribution présent sur un point d'accès relevant de son portefeuille.

2. Walloon Region: Technical regulation (Decree of 12.07.2007)

***Section 2.3.* - Déclarations et garanties du fournisseur**

Art. 125.

§1er. Afin de maintenir l'équilibre du réseau de distribution, chaque fournisseur doit injecter durant la période élémentaire définie à l'article 136, via le réseau de transport, le ou les réseaux de distribution interconnectés (s'il échet) et les stations de réception, autant de gaz qu'il en est fourni aux URD pour lesquels il a conclu des contrats d'accès. A cette fin, le fournisseur souscrit les quantités de gaz nécessaires **pour faire face aux conditions extrêmes correspondant à une température équivalente à Uccle de -11°C durant une journée**.

§2. Si le fournisseur collabore avec un affréteur, il conclut avec ce dernier un contrat de collaboration où les responsabilités mutuelles sont clairement délimitées et décrites avec précision.

Art. 126. Le fournisseur déclare et garantit au GRD qu'à partir de la date d'entrée en vigueur du contrat d'accès et pour la durée totale de celui-ci, **tous les prélèvements ou injections prévus par lui sont ou seront couverts par un contrat de fourniture, y compris aux conditions extrêmes précisées à l'article 125.**

Art. 127. Le fournisseur déclare et garantit au GRD, pour ce qui concerne l'accès à d'autres réseaux de distribution et au réseau de transport, qu'il conclura tous les contrats nécessaires à couvrir l'accès pour toutes ses injections et tous ses prélèvements. Ce faisant, le fournisseur relève le GRD de toute responsabilité à ce sujet.

Art. 128. Le fournisseur avertit immédiatement le GRD si une ou plusieurs déclarations ou garanties susdites viennent à expiration.

3. Flanders Region: Technical regulation on distribution (Decree of 04.04.2007)

Afdeling IV.2.5 Verklaringen en garanties van de leverancier

Artikel IV.2.5.1 De leverancier verklaart en garandeert ten opzichte van de distributienetbeheerder dat vanaf de datum van het verkrijgen van toegang onder de voorwaarden van het toegangsreglement en voor de hele duurtijd ervan, alle door hem geplande afnamen en injecties gedekt zijn of gedekt zullen zijn door een leverings- of aankoopcontract.

Artikel IV.2.5.2

§1 De leverancier draagt bij tot het evenwicht op het distributienet door ervoor te zorgen dat er evenveel gas ingebracht wordt via het vervoernet en de ontvangstations als er geleverd wordt bij de distributienetgebruikers waarvoor hij toegang heeft.

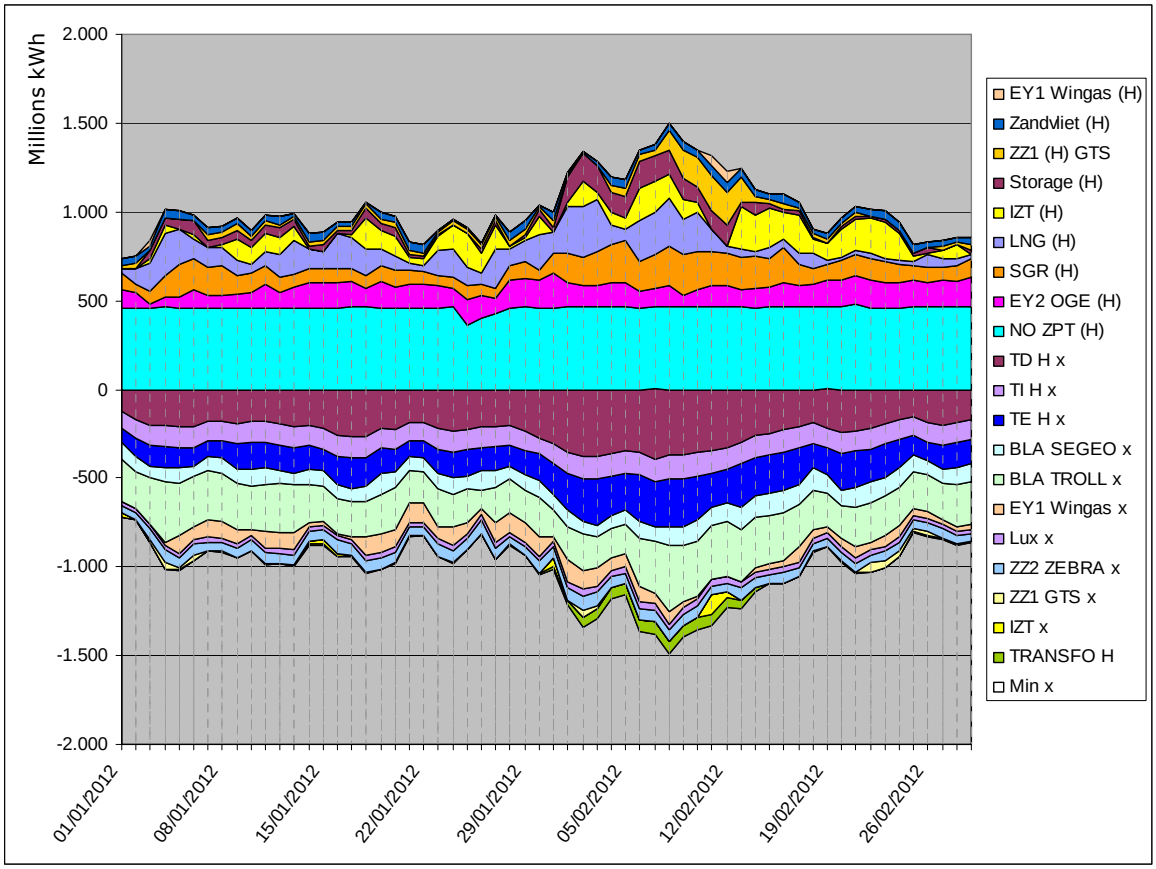
§2 Als de leverancier voor de toegang naar het vervoernet opteert voor samenwerking met een bevrachter, moet voor elke bevrachter een verklaring die de leverancier en de bevrachter hebben ondertekend, aan de distributienetbeheerder bezorgd Technisch Reglement Distributie Gas 04-04-2007 VREGDM-#5720-v10-Technisch_Reglement_Distributie_Gas_v04- 04-2007.DOC Pagina 39 van 67 worden. In die verklaring wordt de samenwerking van de beide partijen bevestigd met betrekking tot (een deel van) de toegangspunten waarop de leverancier toegang tot het distributienet heeft. De distributienetbeheerder stelt daarvoor een modelformulier op.

Artikel IV.2.5.3 De leverancier verklaart en garandeert, voor wat de toegang tot andere distributienetten en tot het vervoernet betreft, ten opzichte van de distributienetbeheerder dat hij de nodige contracten zal afsluiten zodat de toegang voor alle injecties en afnamen gedekt is.

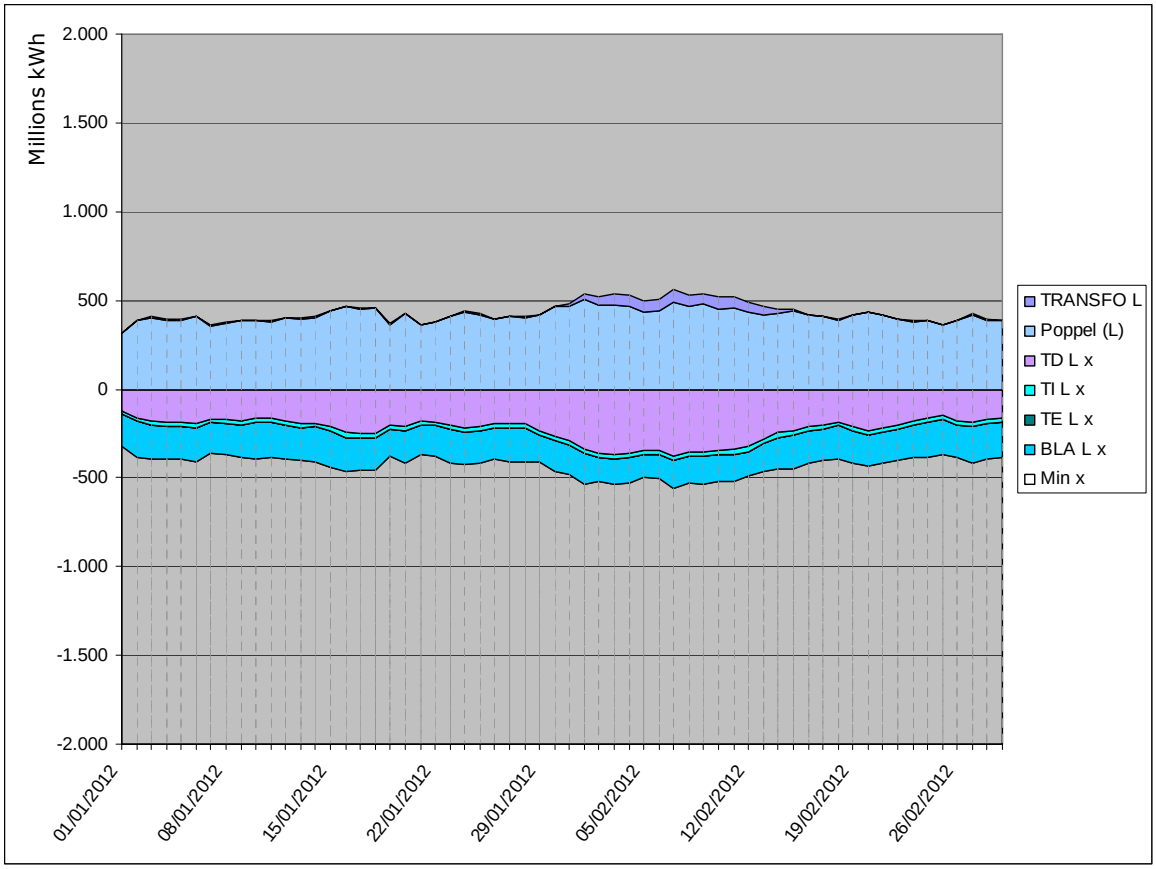
Artikel IV.2.5.4 De leverancier of de bevrachter waarschuwt de distributienetbeheerder onmiddellijk als een of meer van de hierboven beschreven verklaringen en garanties vervallen.

Annex III: Cold wave: Entries and exits volumes Belgian grid

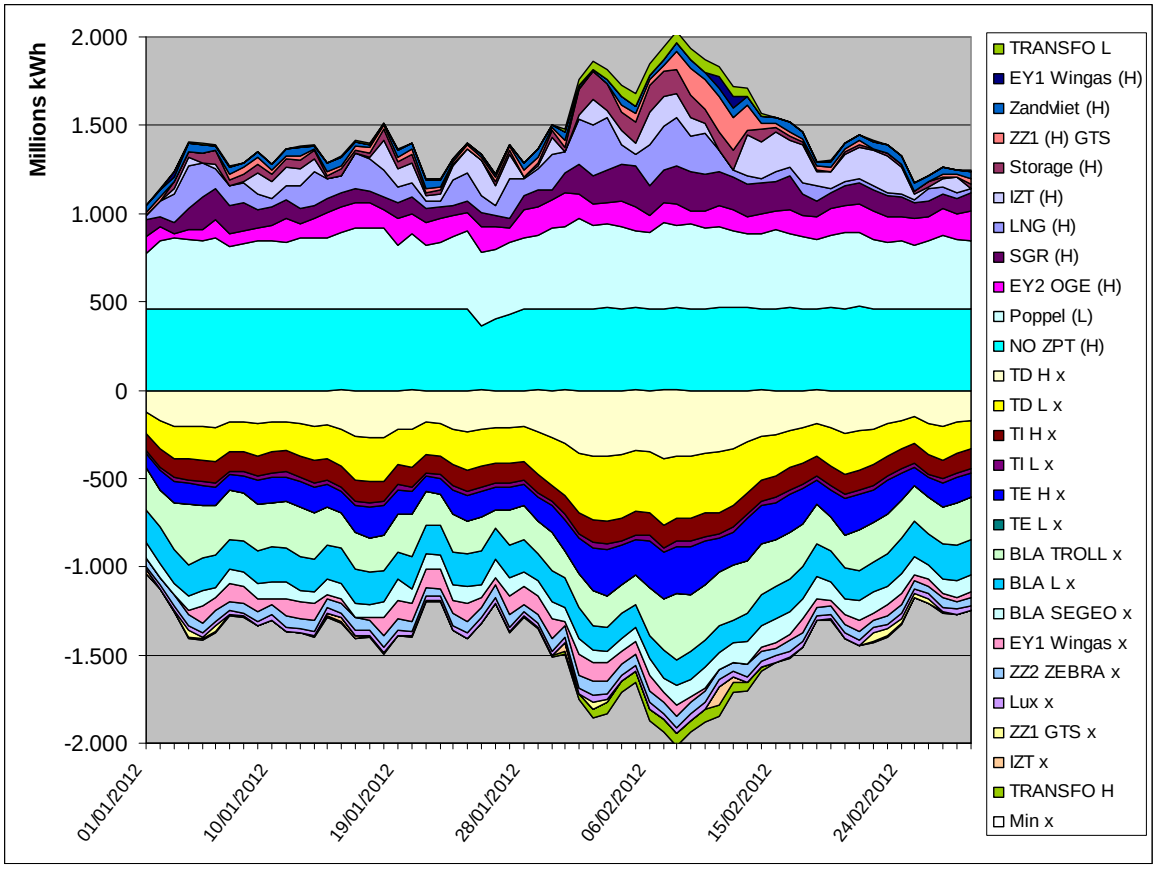
Annex A: H-gas network entries and exits during cold wave period



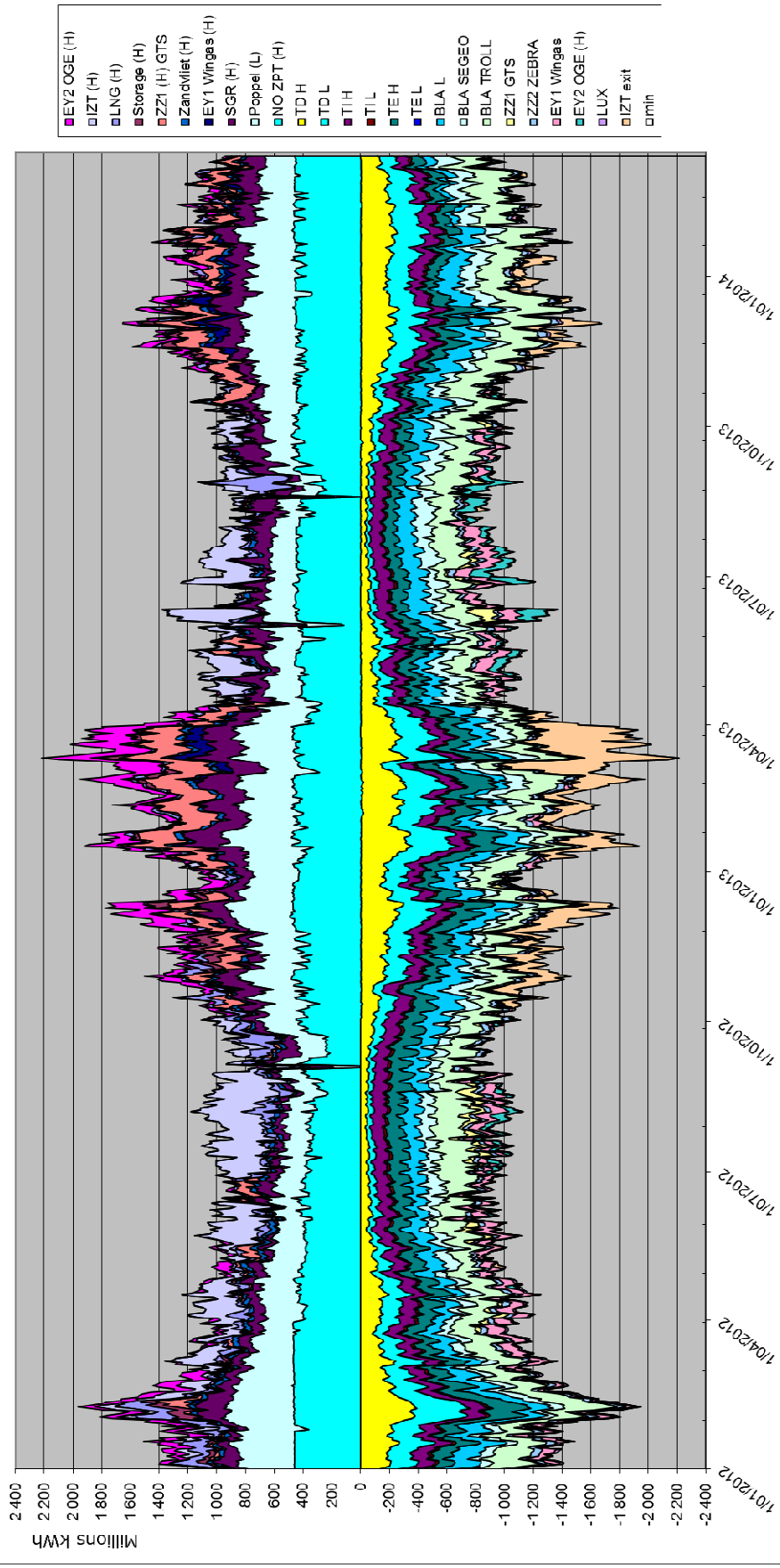
Annex B: L-gas network entries and exits during cold wave period



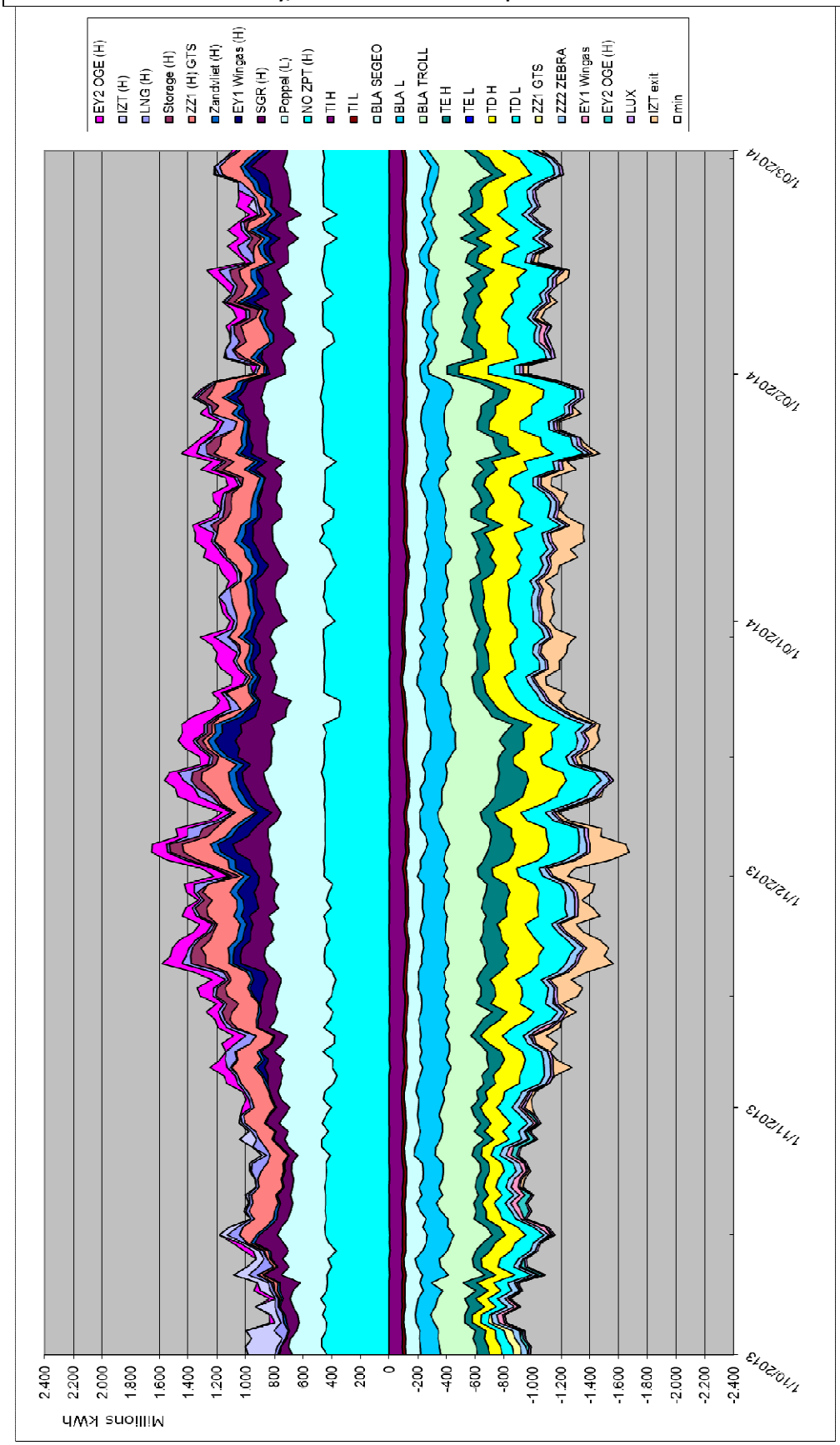
Annex B: Total Belgian gas network entries and exits during cold wave period



Annex IV: The commercial entry/exit flows for the years 2012-2013.



Annex V: The commercial entry/exit flows for the winterperiod of 2013-2014.



Annex VI: N-1 calculations

Calculations based on the following formula:

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

Results N-1 H-gas network

Scenario 1 : Based on Fluxys capacity and loss of Interconnector pipeline

N-1 Calculation (mcm/day)	Date	2014	2017
D_{max}	H	88,01	89,3
D_{eff}	H	0	0
EP_m	H	229,92	263,72
P_m	H	-9,6	-9,6
S_m	H	15	15
LNG_m	H	45,6	45,6
I_m	Interconnector	64,8	74,4
N-1[%]		246,7%	270,0%

Scenario 1: Based on min(Flxys, adjacent TSO) capacity and loss of Interconnector pipeline

N-1 Calculation (mcm/day)	Date	2014	2017
Dmax	H	88,01	89,3
Deff	H	0	0
Epm	H	229,92	263,52
Pm	H	-8,64	-8,64
Sm	H	15	15
LNGm	H	45,6	45,6
Im	Interconnector	63	63
N-1[%]		248,7%	282,7%

Scenario 2: Based on Fluxys capacity and loss of Zeepipe pipeline

N-1 Calculation (mcm/day)	Date	2014	2017
D_{max}	H	88,01	89,3
D_{eff}	H	0	0
EP_m	H	229,92	263,72
P_m	H	-9,6	-9,6
S_m	H	15	15
LNG_m	H	45,6	45,6
I_m	Zeepipe	45,6	45,8
N-1[%]		268,5%	302,2%

Scenario 2: based on min(Fluxys, adjacent TSO) capacity and loss of Zeepipe pipeline

N-1 Calculation (mcm/day)	Date	2014	2017
Dmax	H	88,01	89,3
Deff	H	0	0
Epm	H	229,92	263,72
Pm	H	-9,6	-9,6
Sm	H	15	15
LNGm	H	45,6	45,6
Im	Zeepipe	43,2	43,2
N-1[%]		271,2%	304,9%

Scenario 3: Based on Fluxys capacity and loss of Loenhout storage facility

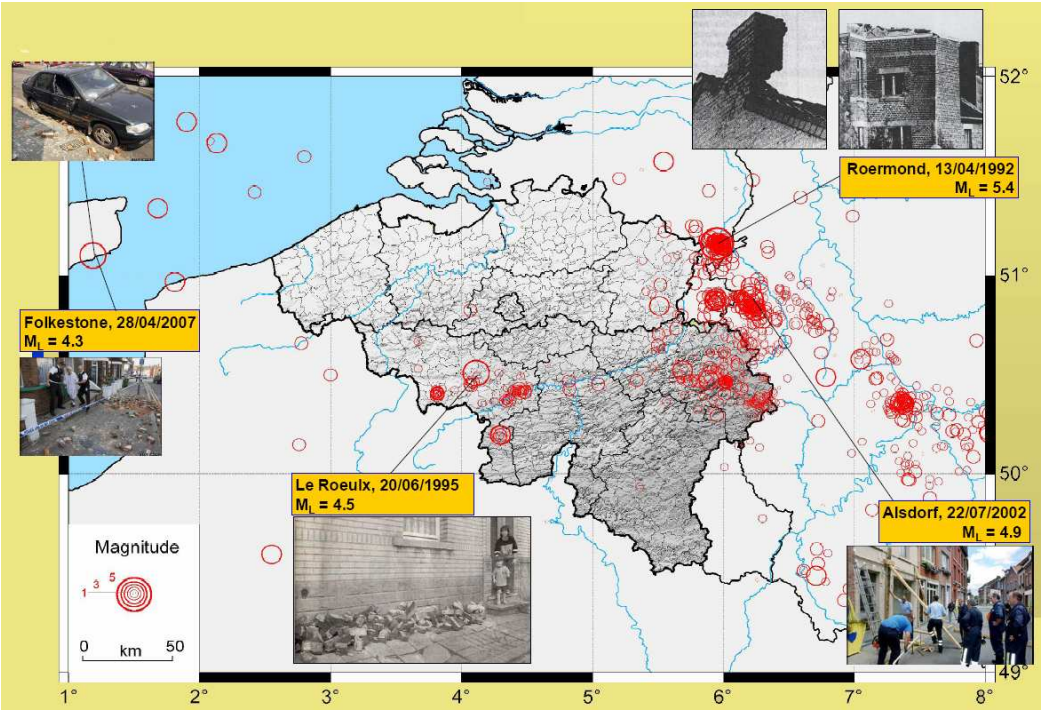
N-1 Calculation (mcm/day)	Date	2014	2017
D_{max}	H	88,01	89,3
D_{eff}	H	0	0
EP_m	H	229,92	263,72
P_m	H	-9,6	-9,6
S_m	H	15	15
LNG_m	H	45,6	45,6
I_m	Loenhout	15	15
N-1[%]		303,2%	336,5%

Annex VII: Earthquakes in and around Belgium since 1985

De recente seismische activiteit in België is verre van verwaarloosbaar. In antwoord op de aardbeving van **Luik** op 8 november 1983 werd het Belgisch seismisch netwerk stelselmatig uitgebouwd **vanaf 1985**. Sedert dat jaar werden er **1106 aardbevingen** geregistreerd, gedetecteerd en gelokaliseerd, waarvan **40 aardbevingen** met **een kracht van meer dan 3.0** op de schaal van Richter.

Onderstaande kaart toont de epicentra van de aardbevingen in en rond België sedert 1985. Het valt op dat de seismische activiteit **geconcentreerd** is **in een aantal zones**:

- Het **grensgebied België, Nederland en Duitsland**: de aardbevingen van Roermond in 1992 en Alsdorf in 2002 situeren zich in deze zone
- De omgeving van **Luik** en de **Hoge Venen**;
- Het Bekken van **Mons** ;
- Het **Brabantmassief** dat zich onder de Noordzee verderzet. De aardbeving van Le Roeulx in 1995 hoort wellicht ook tot deze zone.



Source: Afdeling Seismologie Koninklijke Sterrenwacht van België