Monitoring report on the security of supply on the Belgian natural gas market

Year 2014

(based on article 5 of the directive 2009/73/EC)

Member States are asked under article 5 of the Directive 2009/73/EC of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC to provide each year a monitoring report on the natural gas security of supply issues. This report should contain at least the following aspects:

1. the balance of supply and demand on the national market,
2. the level of expected future demand and available supplies,
3. envisaged additional capacity being planned or under construction,
4. the quality and level of maintenance of the networks,
5. measures to cover peak demand and to deal with shortfalls of one or more suppliers.

The information in the report below gives an overview of the required information. The report is based on 2014 data and was established in cooperation with the Federal Planning Bureau and in consultation with the Commission for Regulation of Electricity and Gas (CREG) and Fluxys Belgium.

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1. The balance of supply and demand on the national natural gas market

1.1. Natural gas demand in 2014

The natural gas demand needs to be looked at on a yearly, monthly or daily basis as those three options provide a different insight in the needed volumes to cover the total demand in one year, in a specific month, but also on the flexibility needs of the network to cope with fluctuations of the natural gas demand during a day.

Belgium consumes two different types of natural gas, namely H-gas (with high calorific value) and L-gas (with low calorific value). L-gas was mainly originating from the Dutch Groningen field (Groningen gas) but now more and more L-gas is obtained by ballasting H-gas in the Netherlands (adding nitrogen to obtain L-gas). Those two different types of natural gas request a separate network. A distinction will be made between the figures for L-gas and H-gas in order to give a reliable overview of the Belgian natural gas market.

1.1.1. Evolution of the total natural gas demand

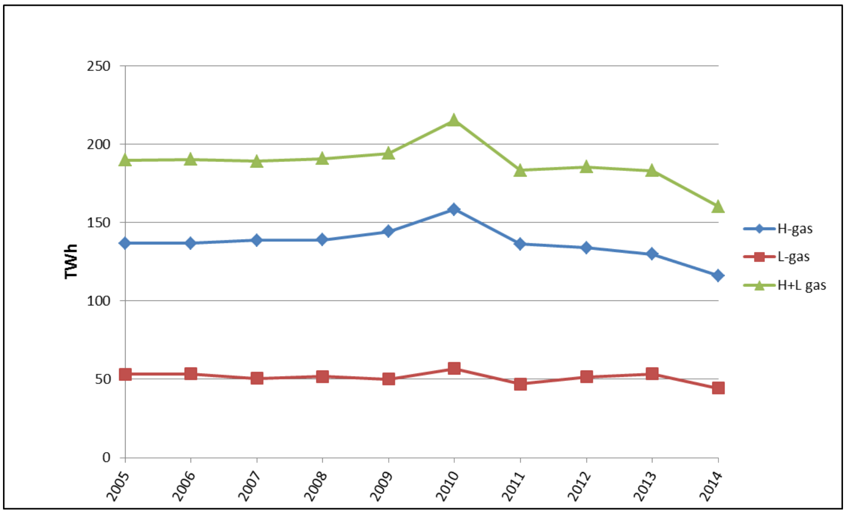
The natural gas demand can be expressed in the actually measured consumption on the transmission network and the consumption normalised to correct for the dependency of the consumption with the weather conditions[1]. The normalised consumption sets out the amount of natural gas that would be consumed in a specific year provided standard winter condition occur. These standard conditions are calculated as an average of the temperatures over a moving period of 30 years. The demand figures are normalised for the entire distribution network to get a better indication of the structural annual growth rates of the natural gas demand in the distribution network as the consumption is very dependent on the outside equivalent temperature and to be able to extract the demand for a winter with peak conditions.

The graphs below show the evolution of the total measured Belgian natural gas consumption (L-gas, H-gas and combined) for the period 2005-2014 (in GWh/year) (figure 1). Figure 2 gives the evolution of the total Belgian consumption after correction based on normalised temperature profile. In 2014, total measured natural gas demand of the Belgian consumers amounted to 160,4 TWh of which 116,1 TWh for H-gas (72% of total demand) and 44,3 TWh for L-gas (28% of total demand). Total measured gas consumption in 2014 was the lowest of the last 10 years. 2014 was, according to the equivalent degree days, an exceptionally warm year (1829 Degree Days which is the lowest value since 1961[2]) and therefore there was a large decrease in consumption on the distribution networks (e.g. households and small to medium sized enterprises). The natural gas consumption of this network has decreased by 18,8% compared to 2013. The natural gas consumption from the large industrial consumers and the electric utilities are also decreased by 3,9% and 6,7% compared to 2013. The consumption from the large industrial consumers is the second lowest consumption of the last 10 years. Only the year 2009 was lower. That year was characterized by the financial crisis which

[1] Weather normalization is the process by which the energy use from one year is adjusted to account for specific weather conditions. Through this procedure, the energy in a given year is adjusted to express the energy that would have been consumed under 30-year average weather conditions.
[2] Source: http://www.aardgas.be/consumenten/de-aardgasfederatie/nieuws-en-publicaties/graaddagen

caused the natural gas demand of the large industrial consumers to decrease very sharply (see fig. 7 page 11). In figure 1, we also note the spike in consumption in the year 2010, which was due to the exceptionally cold winter (Degree Days amounted to 2703 for 2010).

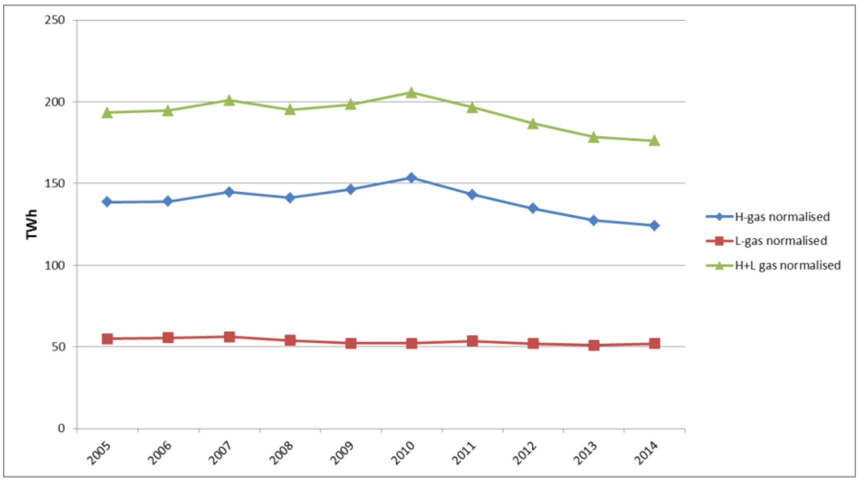
Figure 1: Evolution of the total annually measured natural gas consumption 2005-2014 (TWh/year)



Source: Based on electronic data platform Fluxys Be

Figure 2 shows the total natural gas consumption corrected with a normalised temperature profile. Under normalised average winter conditions, the demand for L-gas was 52 TWh in 2014 and H-gas decreased to the lowest level of the last 10 years. (H-gas = 124,2 TWh in 2014). The reason for this decrease is the decline in the consumption of the natural gas by the large industrial consumers and the electric utilities.

FIGURE 2: EVOLUTION OF THE TOTAL ANNUALLY NORMALISED NATURAL GAS CONSUMPTION 2005-2014 (TWH/YEAR)



Source: Based on electronic data platform Fluxys Be and own calculation

1.1.2. Breakdown of natural gas consumption per consumer category

Total natural gas consumption can be attributed to three categories of consumers: the consumers connected to the distribution network (e.g. households, small to mediumsized enterprises (TD)), the large industrial consumers connected to the gas transport network (TI) and the electric utilities (TE). The chapters below provide a more detailed overview of the evolution per consumer category with a focus on the evolution of the natural gas demand over the last ten years, and on the shares of the three consumer categories in the total natural gas consumption.

1.1.2.1. Evolution of the yearly natural gas consumption on the distribution network

1.1.2.1.1. Link between Degree Days and distribution network consumption

A large part of the natural gas consumption on the distribution network (TD) stems from households that use natural gas mainly for space heating. Below 16,5°C, the natural gas consumption is mainly influenced by the outside equivalent temperature, which can be converted into a certain number of "Degree Days" (DD)[3]. For temperatures above 16,5°C, we assume that the consumption is independent from the outside temperature. This is referred to as the "base consumption" that corresponds to the natural gas needs for hot water boilers and cooking, and the natural gas demand stemming from small and medium enterprises connected to the distribution grid.

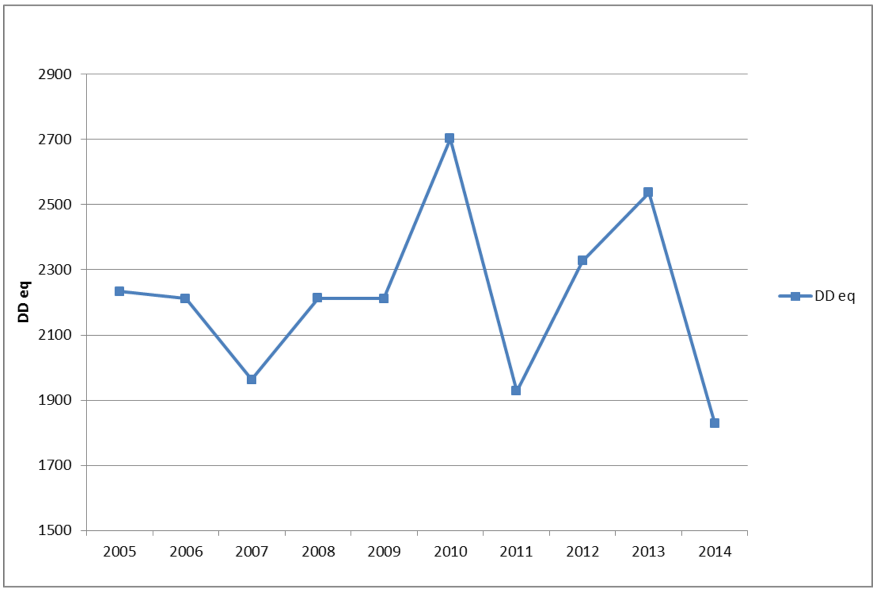
1.1.2.1.2. Annual evolution of the DD.

In order to understand the evolution of the natural gas consumption on the distribution network, the evolution of the equivalent Degree Days (DDeq)[4] in the period 2005-2014 needs to be analysed. From the data, it is clear that the years 2007 (1963 DDeq) and 2011 (1928 DDeq) noted a lower number of DD, which means that those were relatively warmer years. The year 2010 on the other hand counted a very high number of DD (2703 DDeq), meaning it was an exceptionally cold year. Year 2014 (1829 DDeq) was, according to the equivalent degree days, an exceptionally warm year.

[3] The equivalent Degree Days (DDeq) gives an overview of the average profile of the need for heating of a dwelling in Belgium. For a given day, the DD are calculated through the difference between 16,5°C and the equivalent temperature that day. The equivalent temperature is defined as: Teq(n)= 60%*Taverg(n)+30%*Taverg(n-1)+10%*Taverg(n-2) where Taverg(n),Taverg(n-1) and Taverg(n-2) are the average day temperatures measured by the Royal Meteorological Institute in Uccle on resp day n, n-1 and n-2. If the average daily temperature is higher than 16,5°C during 3 consecutive days, the DD is equal to 0.

[4] To take into account the thermic inertia of buildings in order to better estimate the real heating needs, the equivalent DDeq are calculated by taking into account the DD of the 2 previous days as explained in footnote 3.

Figure 3: Evolution of the equivalent Degree Days (DDeq)



Source: http://www.aardgas.be/consumenten/de-aardgasfederatie/nieuws-en-publicaties/graaddagen

1.1.2.1.3. DD normalisation of the yearly consumption.

The measured consumption on the distribution network is fairly volatile and in close correlation with the number of DDeq. The normalised consumption profile is more stable and gives a better indication of the market penetration rate of natural gas in the last ten years. We obtain the normalised natural gas consumption by calculating the yearly natural gas consumption that correlates to a normalised temperature profile that is identical for each year. The variations in the yearly natural gas consumption that we record then are no longer influenced by the meteorological conditions in those years, but by other variables that influence the natural gas consumption, like the growth rate of the amount of connections by the consumer categories on the distribution network.

1.1.2.1.4. Teq. and daily consumption under winter peak conditions.

We also use the notion of equivalent temperature in order to estimate the capacity needs of the distribution network to ensure the security of supply under winter peak conditions. The infrastructure has to be able to transport all the natural gas that could be consumed at a winter peak day that occurs with a statistical probability of once in 20 years. In Belgium, the reference value for the winter peak occurring once in 20 years was set at -11°Ceq or 27,5 equivalent Degree Days in the risk assessment. Based on the daily measured consumptions for a given winter period, we can deduce the existing linear relation between the equivalent temperature and the daily consumption. Based on this correlation, we can extrapolate the consumption to -11°Ceq in order to deduce the amount of natural gas that the distribution network will consume at -11°Ceq with a risk of 50%/50%. This method is used in point *"2.1. Evolution of the peak demand on the distribution network"* to determine the natural gas imports and the transmission capacity needed to satisfy the consumption on the distribution network at -11°Ceq.

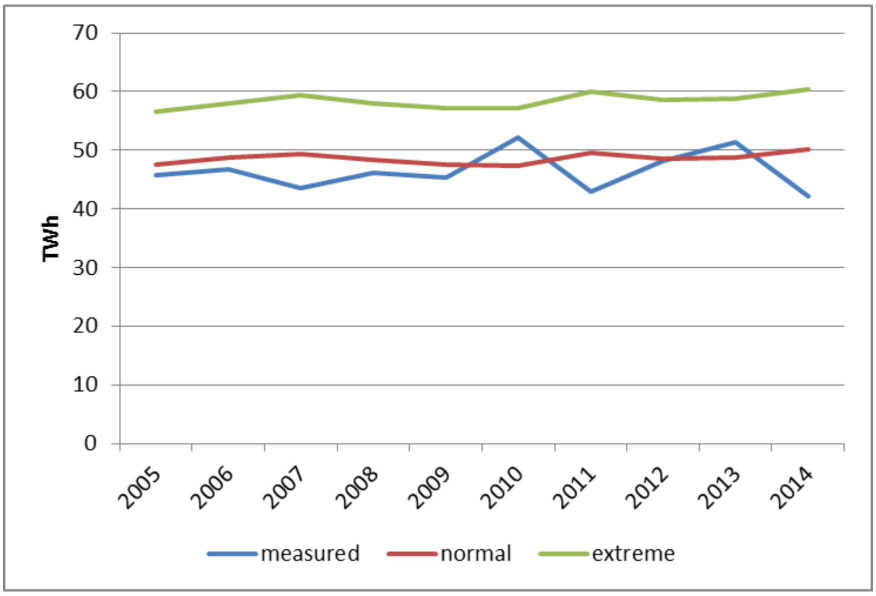
Note that the maximum hourly consumption during a peak day could be about 20% higher than the average hourly peak consumption that day. This implies that a certain amount of daily flexibility in the natural gas network is necessary to be able to balance this swing in peak demand during the day. This flexibility should be either imported, covered by the linepack within the network or provided through intraday gas trading.

The figures below split out the consumption on the distribution network for L-gas and for H-gas. The consumption on the L-gas distribution network lies in the same order of magnitude as for H-gas and follows the same trend. This is normal given that the customers on the H- and L-gas network have the same behaviour (i.e. consume more the cold years and less the warmer years).

In 2013, the measured consumption on the H-gas distribution network was 51363 GWh and 46545 GWh on the L-gas distribution network. In 2014, the measured consumption on the distribution network reached 42177 GWh for H-gas and 37371 GWh for L-gas, this means an decrease of the natural gas consumption on the distribution network of respectively 17,9 % for H-gas and 19,7 % for L-gas. This strong decrease is mainly due to the different temperature conditions in those years.

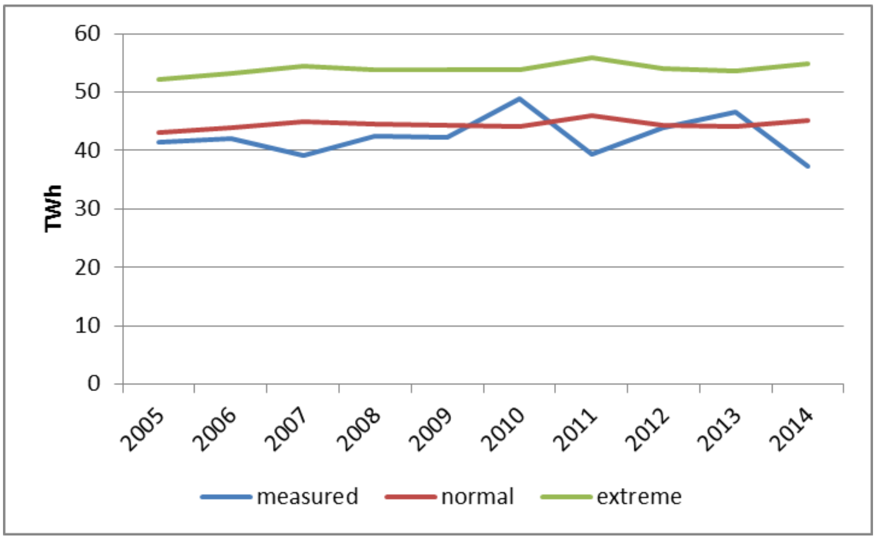
In 2014, the normalised natural gas consumption on the H-gas distribution network reached 50.238 GWh and 45072 GWh on the L-gas distribution network. In 2013, the normalised natural gas consumption on the distribution network was 48856 GWh for H-gas and 44113 GWh for L-gas.

Figure 4: Evolution of the Yearly H-gas consumption on the distribution network (2005-2014) (TWh/year)



Source:Based on electronic data platform Fluxys Be and own calculation

FIGURE 5: EVOLUTION OF THE YEARLY L-GAS CONSUMPTION ON THE DISTRIBUTION NETWORK (2005-2014) (TWH/YEAR)

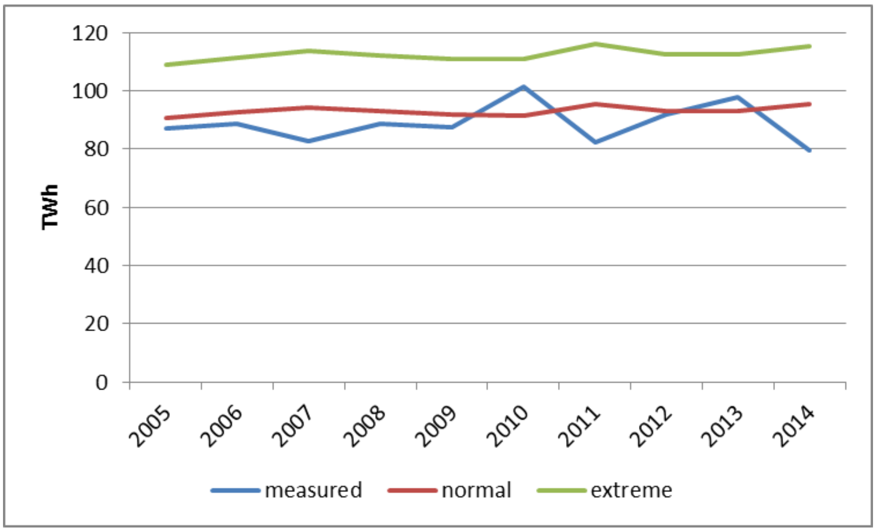


Source: Based on electronic data platform Fluxys Be and own calculation

The extreme curve in the figures above shows the calculated annual natural gas consumption for an extreme temperature profile as obtained in the gas year 1962-63 with 3040 DD. This curve gives an estimation of the maximum natural gas volume that would be consumed on the distribution network in a given year. The extreme natural gas volume follows the same evolution as the normalised temperature profile and is about 20% higher than the normalised temperature profile. We can therefore assume that in an extreme winter condition, the suppliers on the distribution network would have to be able to increase the energy volumes significantly in order to cover the swing in the demand.

The evolution over the last ten years of the total natural gas consumption on the distribution network for L-gas and H-gas combined is displayed in figure 6. The total measured consumption on the distribution network in total amounted to 97908 GWh in 2013 and decreased to 79548 GWh in 2014. For a normalised temperature profile, the total figure is 92969 GWh in 2013 and 95310 GWh in 2014.

Figure 6: Evolution of the Yearly natural gas consumption on the distribution network (L+H combined) (2005-2014) (TWh/year)



Source:Based on electronic data platform Fluxys Be and own calculation

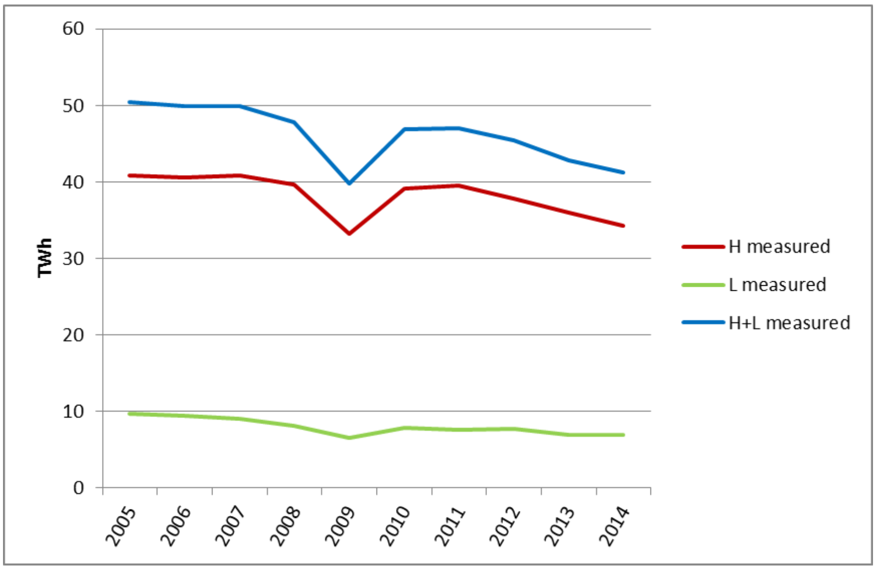
1.1.2.2. Evolution of the yearly natural gas consumption by the large industrial consumers connected to the transmission network

Natural gas consumption by large industrial consumers connected to the transmission network is less influenced by the outside temperature, so it is sufficient to only look at the measured consumption to assess the trend of the past years. In the year 2009, we see a sharp drop for the natural gas consumption by the large industrial consumers. That year was characterized by the financial crisis which caused the natural gas demand of the large industrial consumers to decrease very sharply. This sharp decrease is noticeable in both the H-gas and L-gas network.

After the 2009 crisis, the total natural gas consumption by the large industrial consumers started to pick up again in 2010 and 2011. After 2011 the total natural gas consumption by the large industrial consumers is declining. In 2014 the total natural gas consumption was 41162 GWh. This is a decrease of 12,4 % compared to 2011 (47023 GWh). On the L-gas network, the natural gas consumption by the large industrial consumers which has risen again since 2010 after the dip in 2009 decreased in 2014 to a value of 6902 GWh. This is almost the same as in 2013 (6907 GWh).

The consumption on the H-gas network increased from the strong decline to 33234 GWh in the crisis year 2009 back to previous levels (39046 GWh) in 2010 and reached 39489 GWh in 2011 before coming down again to 34260 GWh in 2014. This is the second lowest consumption level of the last 10 year.

Figure 7: Total yearly natural gas consumption of the large industrial consumers (2005-2014) (TWh/year)



Source: Based on Electronic data platform Fluxys Be

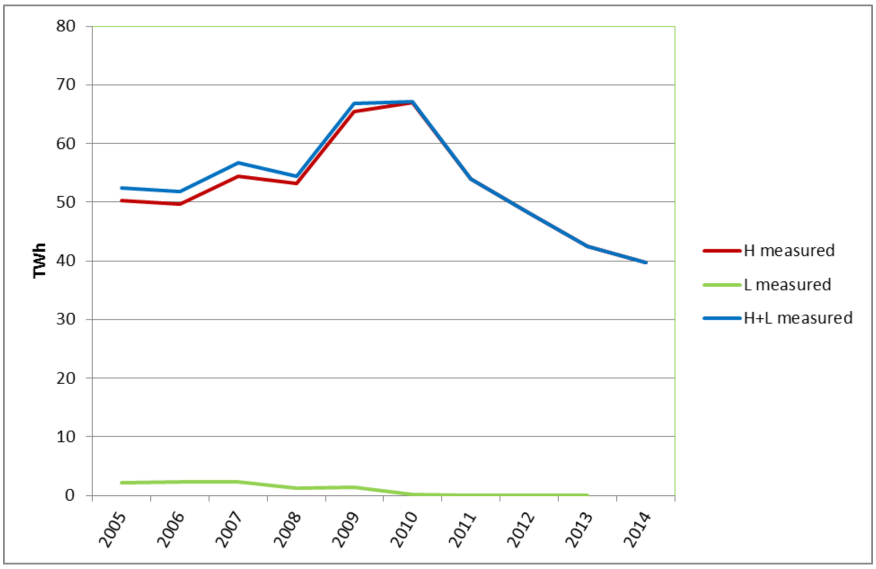
1.1.2.3. Evolution of the yearly natural gas consumption by the electric utilities

In the L-gas network, natural gas consumption by electric utilities was fairly limited in the last 10 years and quasi disappeared since 2010. Since 2014 no more power plants are connected to the L-gas transport network. The reason for this is that there is no longer an interest from the larger market players (power plants and large industrial consumers) to be connected to the L-gas transport network and that the TSO always tries to connect similar clients to the H-gas transport network.

On the H-gas network, natural gas demand stemming from the electric utilities indicates an increasing trend over the period 2001-2010. The electricity production from natural gas in the years 2009 (66836 GWh) and 2010 (67215 GWh) was exceptionally high. One of the explanations of the large increase by the electric utilities in 2009 and continuing is the shift from the surplus of natural gas that had not been taken up by the large industrial consumers to the electricity production. Because there was less production of the nuclear power plants in France during this period, a large part of that electricity production was exported to France. In 2011 the natural gas consumption by electric utilities fell back to previous levels of 53936 GWh and decreased further in 2013 to 42518 GWh and 39661 GWh in 2014 which is the lowest value of the last 10 years. The decline compared to 2013 is due, on the one hand, to the decrease in the residual load[5], and on the other hand, to a higher share of electricity imports in the total power supply.

[5] The residual load is the load that remains to be covered by dispatchable electricity generation units (thermal, reservoir hydro) after the contribution of variable renewable energy is subtracted.

Figure 8: Total yearly natural gas consumption by the electric utilities (2005-2014) (TWh / year)

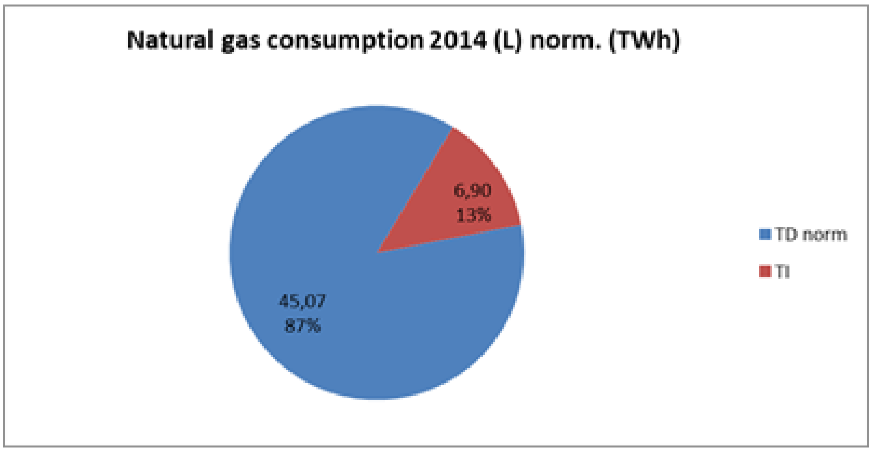


Source: Based on electronic data platform Fluxys Be

1.1.3. Relative share of the natural gas consumption per consumer category

The breakdown of the total natural gas consumption for H-gas and L-gas emphasizes the relative importance of the natural gas demand per consumer category (for normalised temperatures). It is clear that the main source of demand on the L-gas network stems from the consumers connected to the distribution network (TD) (About 87%). This makes the consumption on the L-gas network particularly sensitive to changes in the outside temperature.

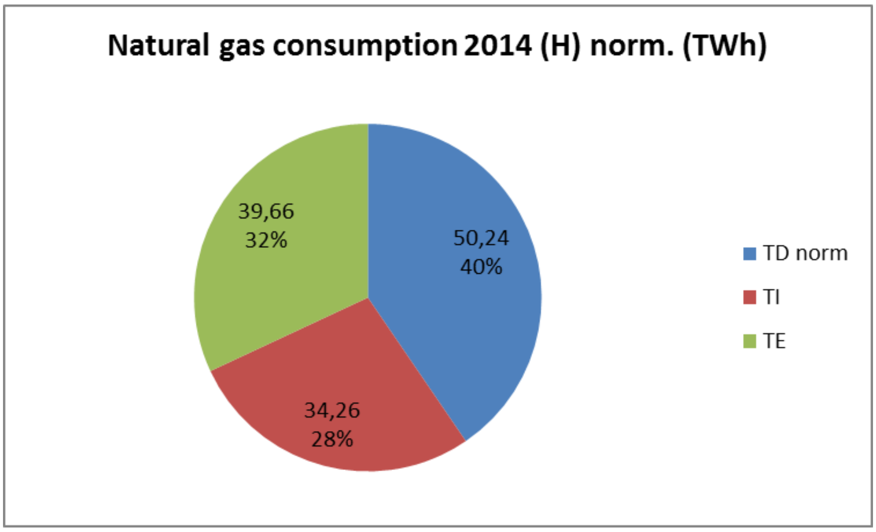
Figure 9: Natural gas consumption (norm.) per consumer category on the L-gas network in 2014(TWh)



Source: Based on electronic data platform Fluxys Be and own calculation

On the H-gas network, in 2014 the consumers connected to the distribution network (TD) account for about 40% of the natural gas demand after temperature normalisation, while the large industrial consumers(TI) and the electric utilities (TE) take up respectively 28% and 32%.

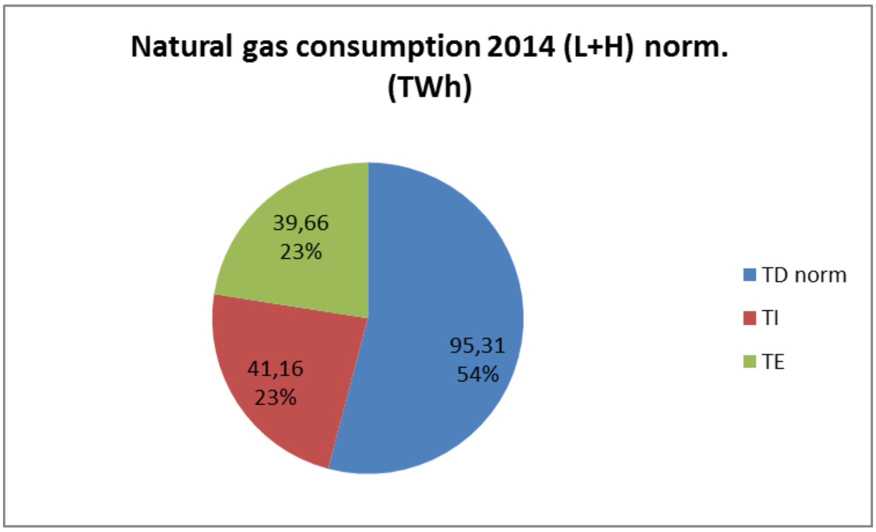
Figure 10: Natural gas consumption (norm.) per consumer category on the H-gas network in 2014(TWh)



Source: Based on Electronic data platform Fluxys Be and own calculation

The figures below demonstrate the relative importance of the distribution network in the total natural gas consumption. In 2014, the distribution sector takes up more than half (54%) of the total yearly normalised natural gas consumption. The large industrial consumers account for 23% of the total natural gas consumption while the remaining 23% are consumed by the electric utilities.

Figure 11: Natural gas consumption (norm.) per consumer category in total in 2014 (GWh)

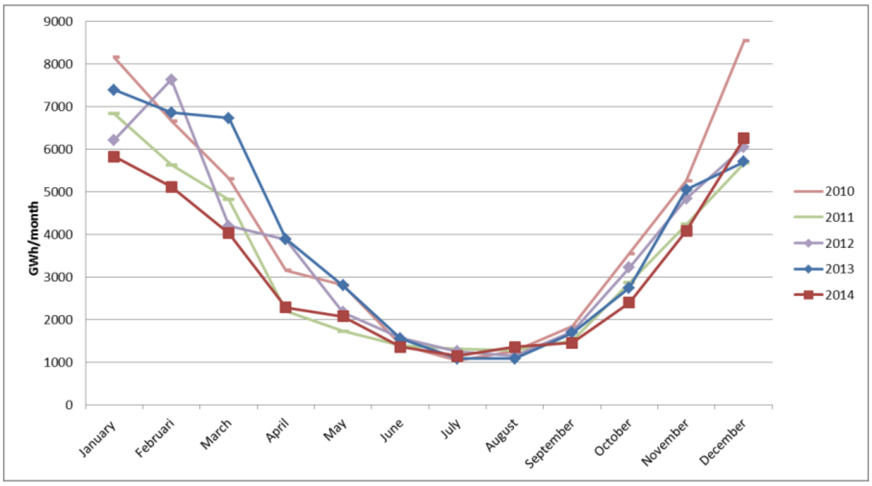


Source: Based on electronic data platform Fluxys Be and own calculation

1.1.4. Seasonality in the natural gas demand

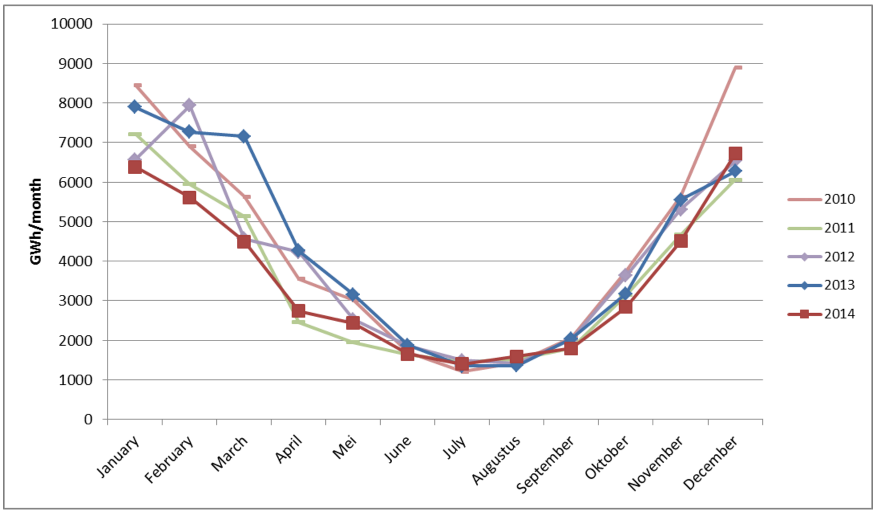
As the distribution network takes up more than half (norm) of the total natural gas demand, and as the natural gas demand on the distribution network is linked to the outside temperature, a high degree of seasonality can be noticed in the natural gas consumption. Natural gas consumption on the distribution network for H-gas as well as for L-gas may increase by approximately a factor seven depending on the summer or winter conditions. The monthly demand pattern is quite stable over the different years.

Figure 12: Monthly natural L-gas demand on the distribution network (2010-2014) in GWh/month



Source: Based on electronic data platform Fluxys Be

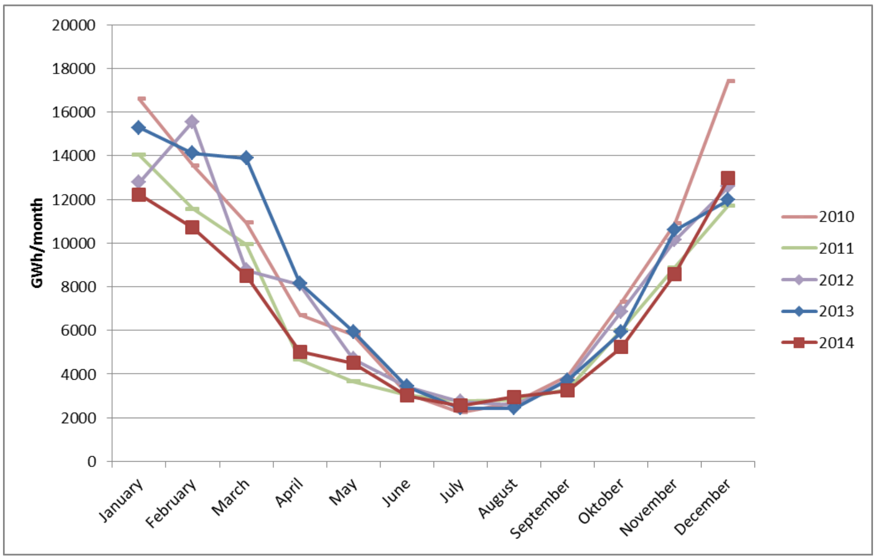
Figure 13: Monthly natural H-gas demand on the distribution network (2010-2014) in GWh/month



Source: Based on Electronic data platform Fluxys Be

The total natural gas consumption (H+L gas) on the distribution network (figure 14) in the months July and August fluctuates in general around 2,2 TWh and increases to about 14 TWh in the months December to January/February. This strong seasonal swing indicates again that not only the natural gas volumes are important to secure the supply, but also the seasonal flexibility of the supply sources and in the network to be able to cope with the strongly fluctuating demand.

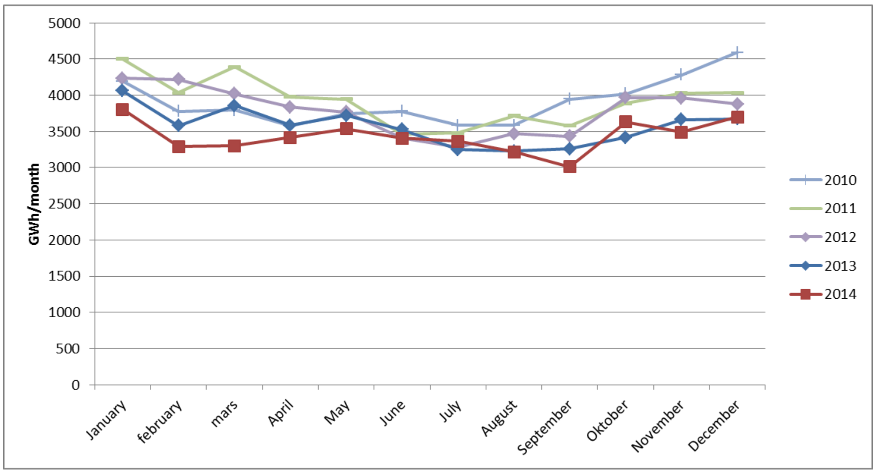
Figure 14: Total (L+H) monthly natural gas demand by the distribution Network (2010-2014) (GWh/month)



Source: Based on electronic data platform Fluxys Be

For the large industrial consumers, there is hardly a seasonal swing noticeable in the monthly natural gas demand. This is because the industrial processes are not strongly dependent on the outside temperature. There is only a very minor correlation with the outside temperature which is caused by the heating of the industrial buildings. We also note that the consumption in 2014 was in most months lower than 2013.

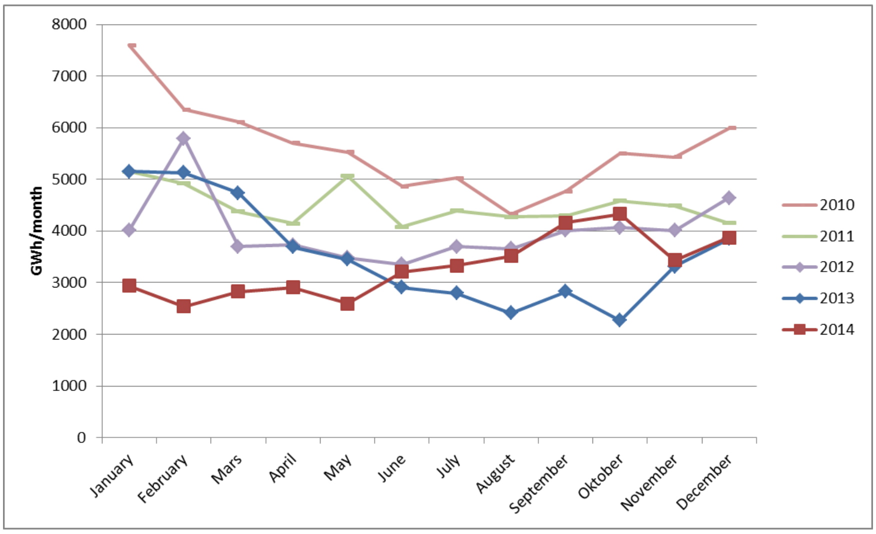
Figure 15: Evolution of monthly natural gas consumption by large industrial consumers (2010-2014) (GWh/month)



Source: Based on Electronic data platform Fluxys Be

The natural gas demand of the electric utilities is hardly linked with the outside temperature either. The significantly higher consumption by the electric utilities at the beginning of 2010 can be noticed in the monthly data. A large part of this additional electricity production was exported to France because a considerable part of French households use electricity for heating. As the flexibility in the power production in France is more limited due to the composition of the production park (mainly nuclear), part of the flexibility of the Belgian electricity production was exported to France. Therefore we can state that the gas demand from the electric utilities in Belgium is to a limited extend correlated to the outside temperature. This is again visible in 2012 during the cold spell in February 2012 when a sharp rise was observed in the natural gas consumption by the electric utilities. However the rise of the natural gas consumption by the electric utilities in the second half of 2014 is probably due to the shut down of the nuclear power plants Doel 3, Tihange 2 and Doel 4.

Figure 16: Evolution of monthly natural gas consumption of the electric utilities (2009-2014) (GWh/month)



Source: Based on electronic data platform Fluxys Be

1.2. Natural gas supply in 2014

1.2.1. Natural gas imports

Belgium has a well-diversified natural gas supply portfolio and network for H-gas that allows sourcing from alternative supplies in case of a supply disruption. This is also shown in figure 17 below. It is however necessary to keep in mind that supplies can only be re-routed if the suppliers have access to upstream transmission capacity to inject the gas in Belgium through another entry point or are able to book capacity on the secondary capacity market for this purpose.

The supplies of L-gas depend on L-gas production in the Netherlands. Since 2009, the Dutch market does not differentiate in the gas quality as the transmission system operator converts H-gas into L-gas by ballasting it (if necessary) which increased the accessibility to the L-gas market. Due to a higher magnitude of earthquakes in the Groningen region in the beginning of 2013, the Dutch Administration have taken a decision to limit the total gas production from the Groningen field to 42,5 billion $m^3(n)$/year in 2014 and 30 billion $m^3(n)$/year in 2015.(exclusive 2 billion $m^3(n)$/year for technical problems). There will be a new decision concerning the production limit for 2016 and beyond at the end of 2015.[6]. As long as the production limit has no impact on the export of L-gas to Belgium, it will have no impact on the future of the conversion planning from L-gas to H-gas.

Because a significant part of the Belgian consumers depends on L-gas , which comes to an end in the future, the conversion of the L-gas system to a H-gas system will be necessary in order to compensate the decline of L-gas exports from the Netherlands.

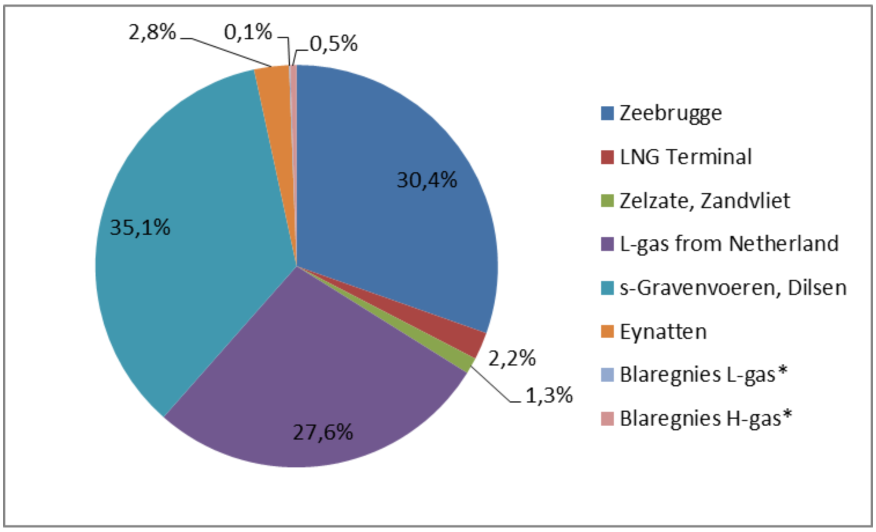
As this is a very specific item , Belgium has set up a task force on L-gas who deals with the security of supply of the L-gas market.

However, as indigenous gas production in the Netherlands starts declining, the Netherlands prepares to the shift from a net-exporter to a net-importer of gas.

Natural gas (H-gas) can enter the country through a series of entry points on the natural gas transmission network. LNG supplies, mainly from Qatar via the Zeebrugge terminal, accounted for a share of 2,2 % of Belgian natural gas consumption in 2014. That is less than in 2013 when LNG imports accounted for still 4,6%. One of the reasons for this decrease is that more LNG is diverted to the Asian markets due to the price difference. Zeebrugge is no longer the main gateway to the Belgian market with a total market share of 30,4% (37% in 2013). There is a shift toward ‘s Gravenvoeren / Dilsen that has now 35,1% of the imports of natural gas for the Belgian market (19,4% in 2013). The Zelzate entry point represents for 1,3% of Belgian supplies coming from 0,9% in 2013. Through the interconnection point of Eynatten (Germany) Belgium received 2,8% of its natural gas.

Natural gas customers who use L-gas are supplied directly from the Netherlands (27,6%), or indirectly, in backhaul, via the Blaregnies interconnection (0,1%) point with France. H-gas form the Netherlands is mainly supplied through ‘s-Gravenvoeren and Dilsen.

FIGURE 17. NATURAL GAS IMPORTS PER ENTRY POINT IN 2014



Source: CREG: jaarverslag 2014

* The entry points of Blaregnies are used in “reverse flow” of the physical flows by making use on those points of the dominant natural gas flow.

[6] More information is available on the website of www.rijksoverheid.nl/ez

In the risk assessment, we have already mentioned that the suppliers (H-gas) no longer base their portfolios on the demand of the consumers in a specific country, but they rather keep EU-wide portfolios. At least the major players on the natural gas market do so. On the one hand, this makes it very difficult to isolate the supply portfolio destined for the Belgian market. On the other hand, it increases the flexibility of the suppliers to deal with an emergency somewhere in the European market. Mostly they have storage available in other countries and access to flexible contracts and more diversified supply routes. This means that renominations should also be easier to handle in case of an emergency.

The entry-exit model that was introduced by the transmission system operator on 1 October 2012 shows positive results as it increases flexibility.

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.

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.

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 (daily market based balancing). 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.

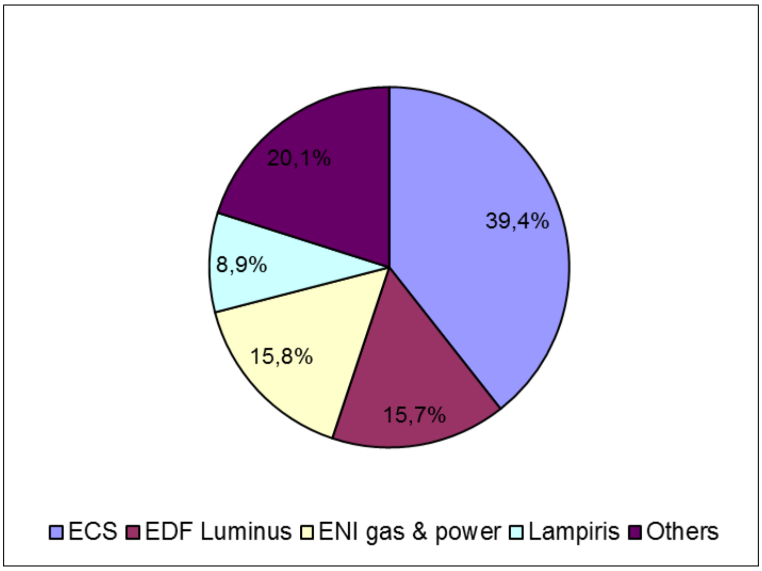
1.2.2. Wholesale and retail market

As mentioned before, total natural gas consumption in Belgium in 2014 amounted to 160,4 TWh. Based on the energy deliveries on the transmission network, we can set out the relative market shares of all the 22 suppliers that were active on the Belgian natural gas market in 2014.

1.2.2.1. The retail market in 2014

We have to keep in mind that the retail market consumes two different types of natural gas: H-gas (with high calorific value) and L-gas (with low calorific value). Most of the customers connected to the L-gas grid are households. There are currently 20 L-gas suppliers active on the Belgian L-gas market.[7]

Figure 18. Market Shares of the Natural Gas Companies who occupy +/-80% of the retail market on the distribution network, 2014.



Source: Persbericht Ontwikkeling van de elektriciteits – en aardgasmarkten in België jaar 2014 (Creg, CWAPE, Brugel, Vreg) and own calculation

1.2.2.2. The wholesale market in 2014

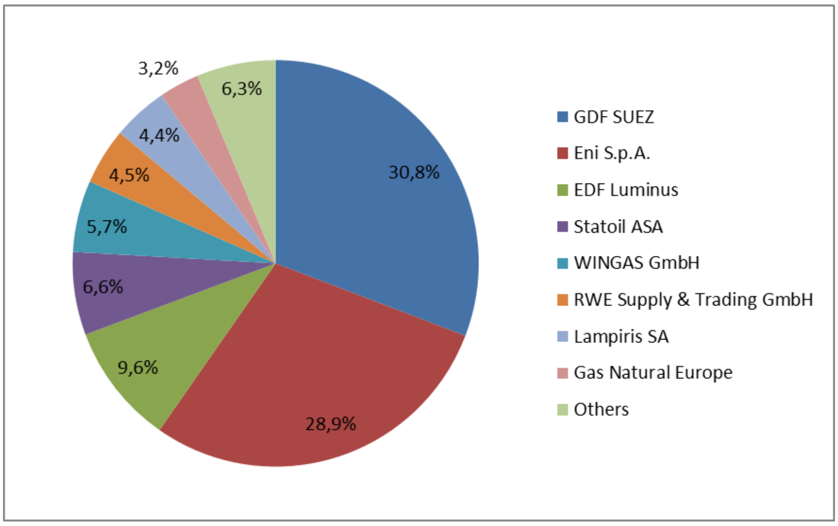
The wholesale market players sell natural gas to the suppliers on the distribution network and to about 250 large industrial end-users, power plants and cogeneration plant connected directly to the transmission grid.

In 2014, 35 suppliers are holder of a transport licence delivered by the federal authority among which 22 were active and have used the licence to supply natural gas to the Belgian market.

This year GDF Suez is the largest player on the wholesale market with a market share of 30,8%, which is a small decrease compared to previous year (32,7%). Eni S.p.A. is the second largest player with a decreased market share of 28,9 % (2013 = 31,4%). In third place we have EDF Luminus with a decreased market share of 9,6 % (2013 = 11%). Statoil ASA was able to increase its market share to 6,6%. In fifth place we have Wingas GmbH with a market share of 5,7%. Those five companies together represent 81,6% of the total wholesale market. Players like RWE Supply & Trading GmbH, Lampiris SA and Gas Natural Europe have a market share in Belgium between 3 and 5% each.

[7] There are 22 suppliers active on the Belgian H-gas market of which 20 do also supply to L-gas customers.

Figure 19: Market Shares of Natural Gas Supply Companies on the transmission network, 2014

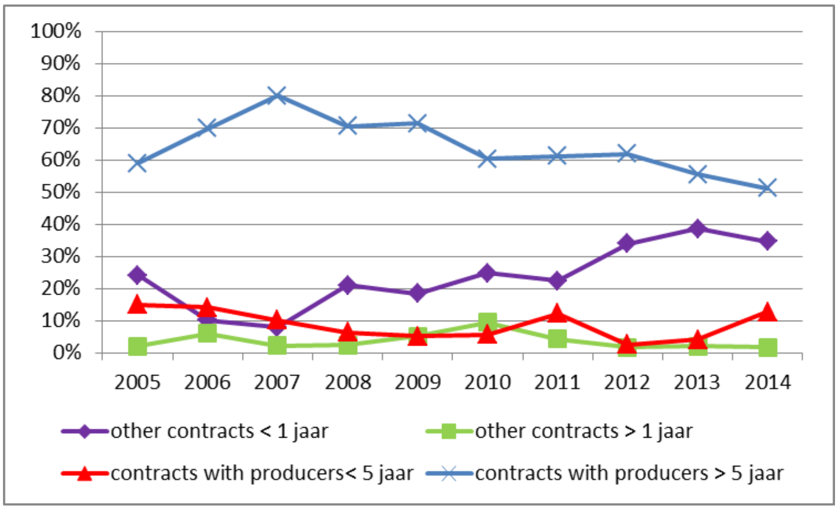


Source: CREG jaarverslag 2014

Historically, natural gas was (and for a large part still is) imported through long term contracts between producers and suppliers. The market liquidity can be increased by trading on the gas hub. In the national gas trade, the ZTP for notional trading as well as over the counter (OTC) trading services for H-gas and ZPTL for L-gas, and the Zeebrugge Beach for physical trading services have a key commercial role as part of Europe's major spot markets for natural gas. Huberator facilitates OTC trading of natural gas through bilateral agreements with third parties, while exchange-based trading is anonymously operated by ICE-Endex. Both provide a spot market for trading of within-day and day-ahead natural gas contracts.

The figure below gives an overview of the composition of the supply portfolios of the suppliers active on the Belgian gas market of the last 10 years. In 2014 the long term (duration of more than five years) and shorter term contracts (duration ≤ 5 years) with the producers still make up the majority (63,7%) of the existing gas contracts (measured in supply volume). The sourcing on the wholesale market is more volatile and has a light decline in 2014(36,3% of the total gas contracts, in 2013 was this 39,5%). The reason for this volatility is that the gas sourcing on short term basis is highly dependent on the gas demand and prices in the short run and on the other hand the dominance of the long term contracts in the portfolios of largest gas suppliers on the Belgian gas market.

Figure 20: Composition of the average supply portfolios for the the Belgian natural gas market between 2005 and 2014 (%)



Source: CREG jaarverslag 2014

1.2.3 Natural gas in storage

Belgium has only one underground gas storage installation operated by Fluxys Belgium (used for commercial storage), which is the aquifer storage in Loenhout, with a useful storage capacity of 725 million m^3(n). Only high calorific gas (H-gas) is stored in this facility. Short term LNG storage is also available at the Zeebrugge LNG terminal. Part of the stored natural gas is reserved by Fluxys Belgium for operational balancing of the network. The rest of the storage capacity is sold to the market for dealing with seasonal swings and situations of peak demand.

If the storage is filled up to its full capacity, the stored natural gas represent theorically about 45 days send out at the peak output. In reality, the effective peak output duration is depending on the realized send out profile. In general natural gas injection in the storage normally starts in April and ends in October while withdrawal lasts from November until March. The storage capacity in Loenhout allows third party access on the basis of which storage capacity can be booked for the long (from 2 to 10 years), short term (one year or less). The short term capacity is sold through auctions or on a first committed first served basis during the storage year.

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

The law of 11 June 2011 also foresees that the competent authority can oblige the natural gas undertakings to liberate the natural gas in storage if an emergency situation as specified in the regulation 994/2010 occurs. This natural gas should be used in first instance to supply the protected customers connected to the distribution network.

Table 1: Natural Gas storage capacity in Belgium (H-gas, June 2013):

Location	**Type**	**Working capacity**[8] **(10^6 m³(n))**	**Peak output**[9] **(10^6 m³(n)/day)**
Loenhout	Underground	725	15 (625 k*m³(n)/h)

The Zeebrugge LNG terminal also has storage capacity available (a working capacity of 228 mcm in gas and a peak send out of 45,6 mcm/day), but 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 into the pipelines.

TABLE 2: GAS IN UNDERGROUND STORAGE WINTER PERIOD 2014 - 2015

	UNDERGROUND GAS STORAGE											
	2014	*2014*	*2014*	*2014*	*2014*	*2014*	*2015*	*2015*	*2015*	*2015*	*2015*	*2015*
	July	*August*	*September*	*October*	*November*	*December*	*January*	*February*	*March*	*April*	*May*	*June*
Gas storage capacity (MCM)	725	750	750	750	750	750	750	750	750	700	700	700
Gas amount in storage first day of the month (MCM)	576,165	651,435	747,588	745,242	735,668	704,039	610,941	425,061	232,544	133,909	125,002	189,128
Gas stocks change (MCM)												
- withdrawal			-2,346	-9,574	-31,629	-93,098	-185,880	-192,517	-98,635	-8,907		not available
+ injection	75,270	96,153									64,126	not available
Maximum withdrawal capacity (MCM/day)	6,00	6,00	6,00	6,00	15,00	15,00	15,00	15,00	6,00	6,00	6,00	6,00
Remaining days for using the stored gas (1)	96	109	125	124	49	47	41	28	39	22	21	32

Source: Fluxys Belgium

(1) The remaining days for using the stored gas are now calculated as gas in storage divided by the Maximum withdrawal Capacity. This maximum withdrawal capacity can be sustained for maximum 3 days at full send-out regime, afterwards technical storage constraints appear and the actual withdrawal capacity

[8] Working gas capacity = total natural gas storage minus cushion gas
[9] Peak output = the maximum rate at which gas can be withdrawn from storage

2. Level of expected future peak demand and available supplies

This chapter gives some insights in the calculation of the future natural gas peak demand and checks whether the available entry capacity on the Belgian network is sufficient to fulfil the winter peak demand for the Belgian consumers and how much of the capacity is available for border-to-border transmission to other countries. Therefore an assumption has to be made of the expected gas peak demand growth on the distribution network, of the large industrial consumers and of the electric utilities. The growth of the peak demand for the distribution network is the most crucial to calculate. For the large industrial consumers and the electric utilities, we use default values based on the statistical peak consumption.

2.1. Evolution of the peak demand on the distribution network

In order to estimate the future consumption levels of the peak demand on the distribution network, we make an estimation of the natural gas demand during the winter peak period. We assume that the peak consumption is obtained at a winter peak day. The winter peak day is considered as one day with an extreme temperature occurring with a statistical probability of once in 20 years. Belgium considers the use of -11°Ceq or 27,5 Equivalent Degree Days as the reference value for the winter peak occurring once in 20 years.

The evolution of the natural gas demand on the distribution network at -11°Ceq (27,5 DDeq) is estimated based on a linear regression model. According to the determined parameters for this regression, we can compute:

- the average value of the natural gas consumption level at -11°Ceq, this is a 50% chance that the actual natural gas demand will be higher than the calculated demand;
- the natural gas consumption level at -11°Ceq with a 1% risk of exceeding the calculated natural gas demand[10];
- the average growth rate in an analysed period;
- an estimation of the peak natural gas consumption in the coming winters.

The calculations are based on the average demand on a peak day. We do have to keep in mind that this differs from the maximum hourly consumption during a peak day which can be up to 20% higher than the average peak day demand. This difference will have to be absorbed by the flexibility in the system (e.g. through the linepack or imported through the interconnection points).

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

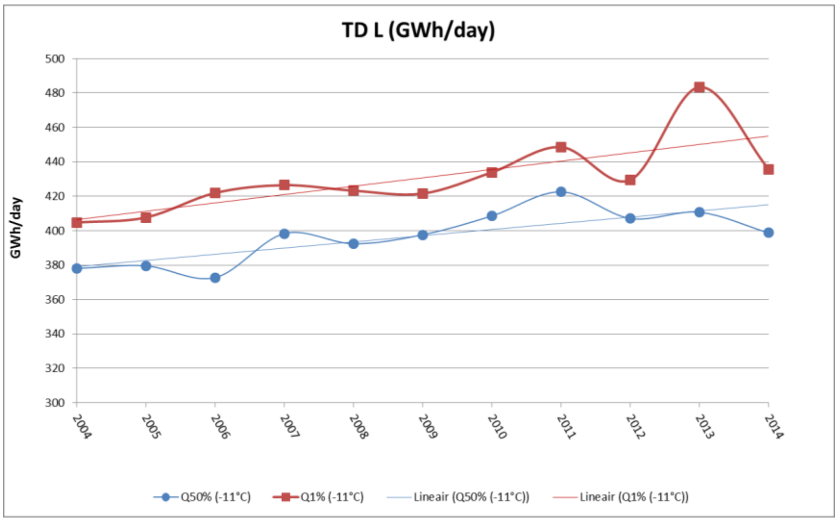
2.1.1. Evolution of the daily average peak demand on the L-gas distribution network (TDL)

Based on the daily average consumption data on the L-gas network during the winter period , we can calculate the parameters for the regression curves. The curve Q50% represents the calculated natural L-gas demand (in GWh/day) by the distribution network for the winter peak period at -11°Ceq at a 50% risk of obtaining lower temperatures and therefore a higher natural gas consumption. We also calculate the consumption at a 1% risk of exceeding the calculated natural gas demand due to lower temperatures.

Based on those curves, we can compute the linear regression curve that provides us with the growth rate of natural gas demand from the L-gas distribution network in the past 11 years. The growth rate at a 1% risk based on the linear regression of the natural gas consumption over the period 2004/2005 and 2014/2015 (red curve) gives us a growth rate of 1,1%. The growth rate at a 50% risk based on the linear regression of the natural gas consumption over the period 2004/2005 and 2014/2015 (blue curve) is calculated at 0,9 %. Given the phasing- out scenario on the future of the L-gas market and that the L-gas market area is already more saturated than the H-gas market area, we will take the lower percentage and use the 50% risk growth rate of 0,9% for the growth estimations.

This will be our basis hypothesis to start from to calculate the future winter peak natural gas demand by the L-gas distribution network. One aspect to take into account by using a linear regression model is that it might overestimate the peak natural gas demand for the coming years. This is because possible smoothening effects that might occur in the years to come for example due to saturation and efficiency gains are not taken into account in a linear model.

FIGURE 21: DAILY AVERAGE WINTER PEAK DEMAND FOR L-GAS (2004-2014)



Source: DG Energy – FPS Economy

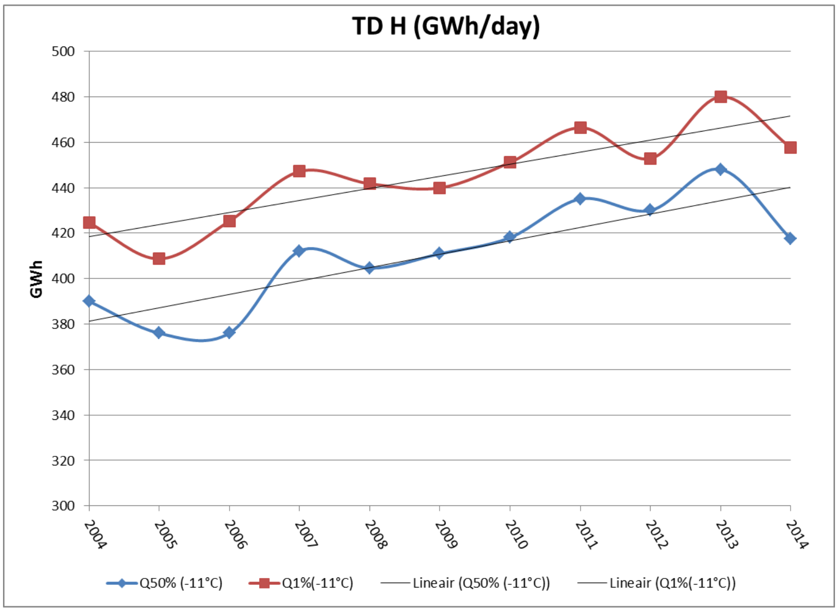
2.1.2. Evolution of the daily average peak demand of the H-gas distribution network (TDH)

The same method as for L-gas described above is used to obtain the linear regression curves for the H-gas growth rates. The H-gas consumption on the distribution network at -11°Ceq is calculated in a

50% and a 99% range. Based on those curves the growth rate for H-gas demand can be calculated through a linear regression curve. The use of the linear regression model to calculate the future peak natural gas demand on the H-gas distribution network might (as for L-gas) overestimate the peak demand for the coming years. This is because it does not take into account new evolutions in the network, efficiency gains that might have a smoothing effect on the future natural gas demand.

We obtain a growth rate for peak natural gas demand of H-gas over the years 2004-2014 of 1,1% per year at a 1% risk and 1,4% at a 50% risk. For further calculations, we will use the calculated growth rate of 1,1% based on the 1% risk.

FIGURE 22 : DAILY AVERAGE WINTER PEAK DEMAND FOR H-GAS (2004-2014)



Source: DG Energy – FPS Economy

In order to interpret the consequences of these assumptions, it is necessary to keep in mind that this is a static assumption that does not take into account possible changes in the natural gas consumption due to a higher connectivity to the gas network, demographic changes, switching behaviour of heating sources, energy efficiency, ….

2.2. Natural peak gas demand projections up to 2025

Based on the calculated growth rates of the peak natural gas demand for L-gas and H-gas on the distribution network, it is possible to evaluate the future total peak natural gas demand for the coming 10 years. Therefore we will have to add the estimated consumption of the distribution network to the estimated consumption of the large industrial consumers and the electric utilities.

For the distribution network, we combine, as hypothesis, a growth rate of 0,9 %/year for L-gas and of 1,1 % for H-gas. Those growth rates are obtained through a regression analysis as explained in the chapter above. The estimations of the natural gas demand by the large industrial consumers and the electric utilities come from the Transmission System Operator (TSO). For each large industrial consumer, power plant or cogeneration unit, the TSO determines a peak capacity perspective of the hourly consumption (default value) that represents the realistic natural gas needs. The calculation of the default value is based on a statistical analysis of the highest thirty hourly consumption over the three previous years. Non-representative data can be excluded. Therefore, weekends, official holidays, abnormal peaks (test phase, incident, …) will not be taken into account.

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

Information available about the future expansion, construction or closure of new industries or power plants that will be connected or taken off the network for the next five years allow to build peak demand scenario for the future. New or expanding industries or electric power plants give an estimation of the capacity they would need for natural gas supply within a certain time delay. Based on the provided figures, a low case, medium (or reference) case and high case scenario can be drafted for the large industrial consumers and the electric utilities. In the low case scenario, we assume hardly any new power plants or large industrial clients coming online. The medium or reference case takes up new or expansions of large industrial clients or power plants for which a final investment decision could be expected. The high case scenario takes up all the projects that have been introduced and for which no final investment decision has been taken.

2.2.1. Projections of the hourly daily average L-gas demand and entry capacity

2.2.1.1 Future of L-gas in Belgium

Production of the Groningen field is expected to significantly and steadily decline. The Administration is well aware of this issue. Gas quality conversion of H-gas into L-gas is costly and energy-intensive, as it would require large amounts of relatively pure nitrogen. Therefore, the Administration considers a conversion of the L-gas network to H-gas to be the only viable long-term scenario. Due to a higher magnitude of earthquakes in the Groningen region in the beginning of 2013, the Dutch government has taken a decision to limit the total gas production from the Groningen field to 42,5 billion $m^3(n)$/year in 2014, 30 billion $m^3(n)$/year in 2015.(exclusive 2 billion $m^3(n)$/year for technical problems). There will be a new decision concerning the production limit for 2016 and beyond at the end of 2015[11].

It is certain that the entire replacement of L-gas by H-gas will have considerable consequences for the Belgian gas market. Most importantly, the current long term L-gas contracts will not be renewed or prolonged beyond 2028/2030. Consequently, as from then, an entire conversion of all the Belgian L-gas consumers to H-gas should be realized. In Belgium, the discussions with regard to the possible technical stages in order to successfully manage this conversion project have started. A working group within Synergrid (federation of the DSO’s and TSO) has been created. The results of this working group should consist of concrete and technically feasible proposals to convert the L-gas market.

[11] More information is available on the website of www.rijksoverheid.nl/ez

2.2.1.2 Projections of the average L-gas peak demand

Figure 23 below gives an overview of the projected total natural gas peak demand on the L-gas network in 2 scenarios. We consider it important to provide a simulation of the impact of a total conversion on both the L-gas and H-gas demand.

The first scenario describes the estimation of the evolution of the L-gas peak demand without taking into account the total conversion of the L-gas network (no conv.) due to the depletion of gas reserves in the Groningen field in the Netherlands. This scenario provides an estimation of the evolution of the L-gas demand as long as the conversion process of the L-gas market has not been started. Nevertheless this scenario takes into account the previous decision regarding the conversion to H-gas of several industrial consumers that are located in the Limburg province (Albert channel). This conversion process should be finalized in 2015 and will reduce the peak consumption of the industrial sector with 50 k*m^3(n)/h.

The second scenario illustrates the estimated evolution of L-gas, taking into account the total conversion of the L-gas network (conv.) due to the depletion of gas reserves in the Groningen field in the Netherlands. The current hypothesis considers the possibility to convert the total L-gas market over a period of 14 years (starting in 2016). The first 4 years a small conversion is foreseen, after these period the convertion goes further in almost a lineair manner. Consequently, in 2030, no more L-gas imports from the Netherlands would be needed for the Belgian market.

Apart from this conclusion with regard to the volume that should be converted, there is another striking figure that better allows to measure the extent and magnitude of the conversion operation, namely the number of active L-gas connections that should be converted. At present, there are an estimated 1.500.000 L-gas connections in Belgium that should be converted in a time span of 14 years (2016-2030).

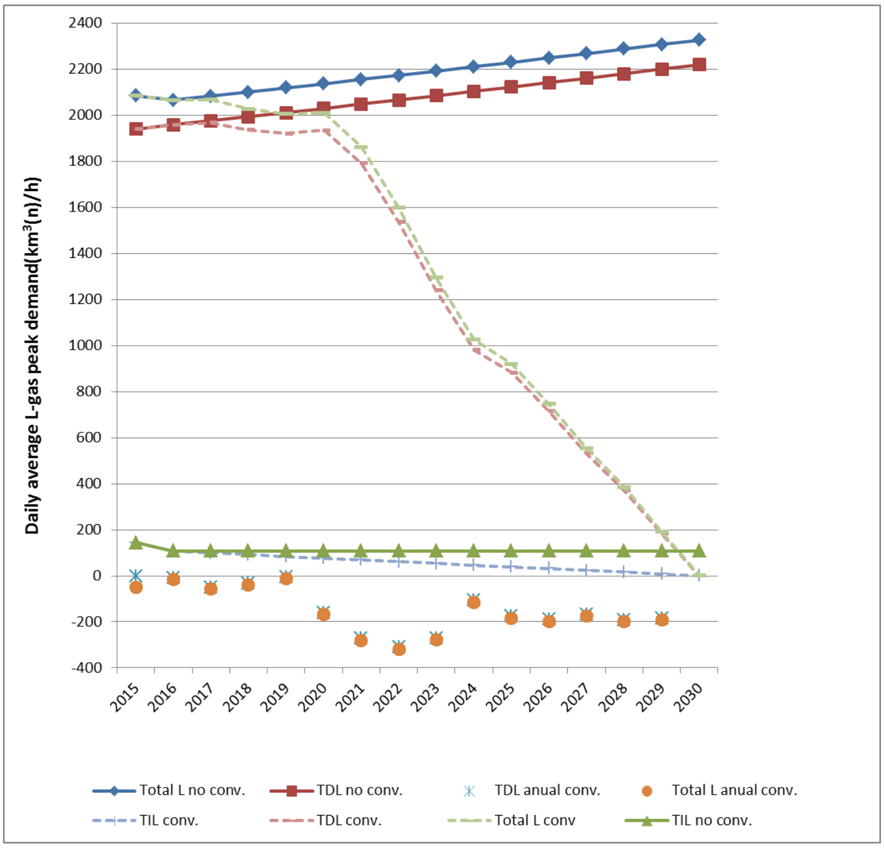
The following hypotheses apply to the two scenario's.

- The yearly rate obtained from the calculation regarding the peak demand growth of the distribution network is 0,9%, on the basis of the last winter analysis.
- the above same growth rate will be applied to the natural gas peak demand from the distribution network to estimate the demand over the coming years

Based on the assumptions explained above and in the non L-gas conversion scenario, the total average peak demand (see figure 23) would increase from 2085 k*m^3(n)/h in the 2014-2015 winter to 2230 k*m^3(n)/h by 2025. The increase in the peak demand is mainly due to the increase of the peak consumption by the distribution network. It is to note that the L-gas market is already more saturated than the H-gas market. It should result in a lower growth rate of L-gas market in comparison to the H-gas market.

The growth of the large industrial consumers will be very limited. After the conversion in Limburg (e.g. Albert channel), the peak consumption will reach 107 k*m^3(n)/h.

Figure 23 : L-gas peak demand from 2015-2030 (k*m³(n)/h)



The dotted lines in figure 23 illustrates the evolution of the L-gas peak demand in the context of the total conversion of the L-gas market by 2030. In the corresponding H-gas scenario (related to the conversion of the L-gas network), the quantity of L-gas that will be converted to H-gas, will contribute to a rise of the yearly peak H-gas consumption. The difference in the consumed volumes of L- and H-gas is due to the fact that high calorific gas is richer than the low calorific gas[12]. The estimated TDL peak volumes (x) annually converted are based on the indicative planning for conversion of the end users on the distribution network communicated by Synergrid in june 2015.

2.2.1.3 Projections on BE-interconnections points of the entry and exit capacity for L-gas

We compare the expected peak demand with the available entry capacity to evaluate the remaining capacity in the network to get an estimation of the available capacity for natural gas transmission from border to border to the neighbouring countries.

Table 3: estimation of the available entry[13] and exit capacity for the L-gas border points (k*m³(n)/h).

Evolution (min(Flx.Adj TSO))									
L gas entry			1/01/2014	1/01/2015	1/01/2016	1/01/2017	1/01/2018	1/01/2019	1/01/2020
North border	Poppel/Hilvarenbeek	NL (GTS)	2730	2730	2730	2730	2730	2730	2730
Total NB			2730	2730	2730	2730	2730	2730	2730

[12] In order to transport the same energy, the capacity or allocated volume will be 15,7% less.

[13] The information on the available capacity is for the years 2015-2017 based on information from Gasunie transport services (network ontwikkelingsplan 2015). For the years after 2017, we have taken the hypothesis that this value of 2017 will remain unchanged.

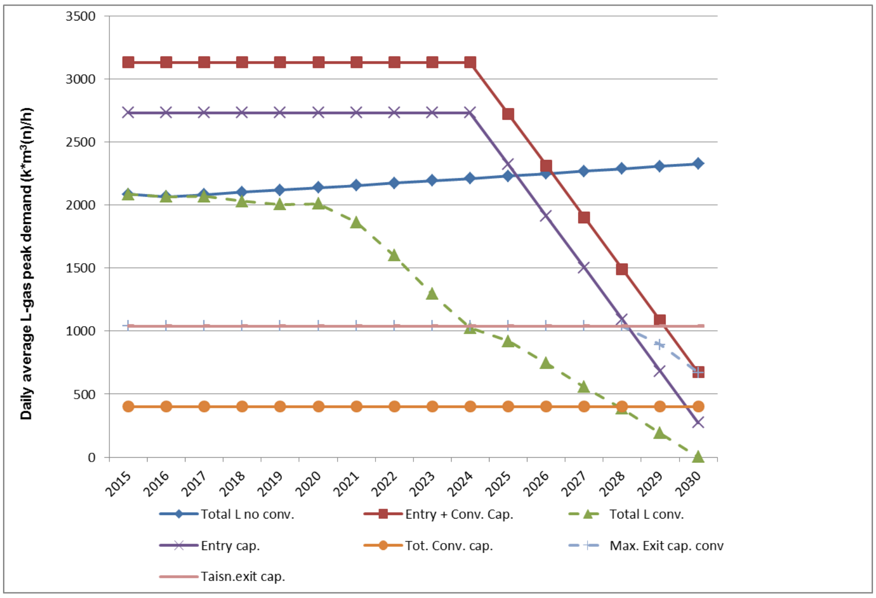
Evolution (min(Flx.Adj TSO))									
L gas exit			1/01/2014	1/01/2015	1/01/2016	1/01/2017	1/01/2018	1/01/2019	1/01/2020
South border	Blaregnies/Taisnières	FR (GRT gaz)	1040	1040	1040	1040	1040	1040	1040
Total SB			1040	1040	1040	1040	1040	1040	1040

Till 2020 this offered firm capacity stays the same. As we have no insight in the results of the future open seasons for the next winter periods, we assume that no other changes will occur in the available capacity. The physical firm exit capacity available on the Dutch side of the border plays a crucial role in the security of L-gas supply in Belgium (and France). Therefore it would be useful to have an clear insight of the future developments of the physical firm exit capacity on the Dutch side of the border in order to move towards a match with the capacity available at the Belgian side which is sized according the expected needs of the Belgian L-gas market (and transmission needs to supply France with L-gas).

On top of the L-gas imports from the Netherlands, Belgium is able to convert H-gas into L-gas thanks to the conversion units in Lillo (production capacity of L-gas: 300 k*m³(n)/h) and in Loenhout[14] (production capacity of L-gas: 100 k*m³(n)/h). Those conversion units from H-gas to L-gas may increase the entry capacity by 400 k*m^3(n)/h as long as nitrogen supplies (for the Lillo because the Loenhout unit extracts nitrogen directly from the ambient air) are guaranteed[15]. The conversion plant allows conversion of H-gas into L-gas if there is a shortage for L-gas.

Total entry capacity for L-gas is about 3130 k*m^3(n)/h (e.g. in winter 2015/2016, entry capacity : 2730 k*m³(n)/h and conversion capacity 400 k*m³(n)/h).

Figure 24: L-gas peak demand and entry capacity projections from 2015-2030 (k*m^3(n)/h)



Source: DG Energy – FPS Economy

[14] Till 2017 this facility is mothballed with a restart delay of maximum 2 weeks.
[15] The scenario considers that a sufficient amount of nitrogen and the associated capacity has been reserved by Fluxys Belgium.

The dotted line in figure 24 shows the scenario taking into account the total conversion whereas the solid line illustrates the scenario which doesn't take into account such a conversion process. Beyond 2024, the yearly volume that is exported to Belgium and France could be linearly reduced by 15%. In order to keep this in mind, we assumed an artificially reduction in exit capacity of the Netherlands by 15% every year. Indeed, this constraint affects the yearly production volume from the Groningen gas field available for the Belgian and French market. However, this does not necessarily imply that the daily volume or available capacity during a peak day with extreme winter conditions has the same profile with a linear reduction.

In conclusion, it should be noted that the planning of the conversion process should take into account the (reduced) volume available from the Netherlands to the Belgian and French market from 2025 onwards and that the French-Belgian consumption should certainly not exceed this reduced quantity.

2.2.2 Projections of the daily average H-gas demand and entry capacity

2.2.2.1 Projections of the hourly daily average peak H-gas demand

First of all we will establish the base demand. The natural gas base peak demand is based on the natural gas demand from the distribution network to which the calculated growth rate for the peak demand was applied up to 2030, the actual consumption from the large industrial consumers and the electric utilities. The growth of the consumption at the winter peak demand on the H-gas distribution network was set at 1,1 %/year.

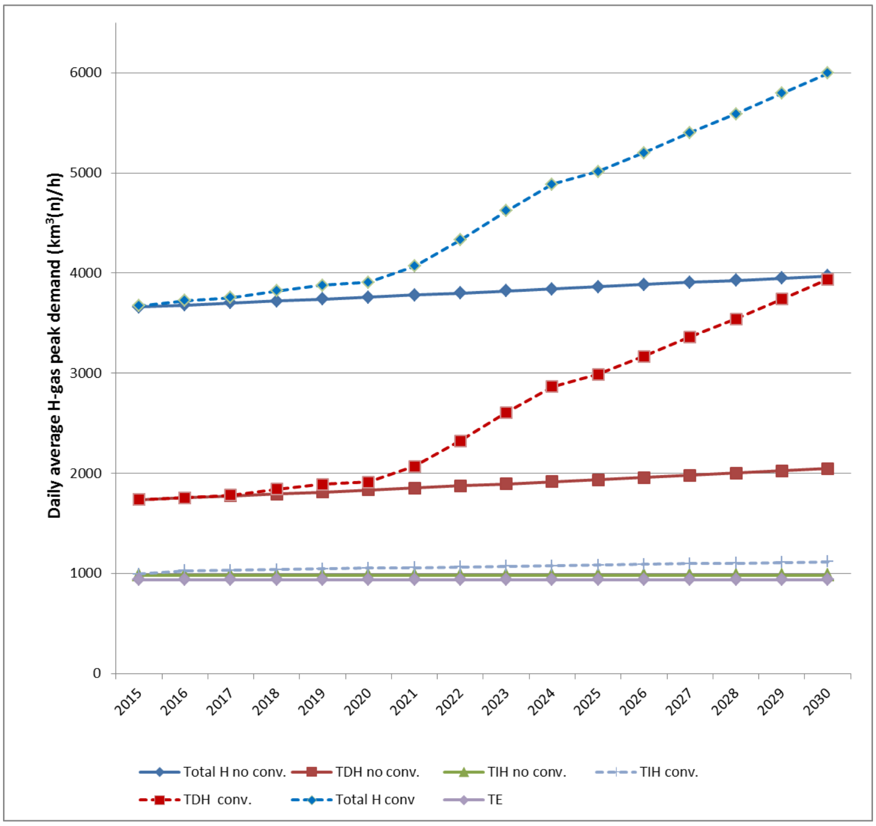
In 2015, the calculated peak demand for the consumers of the distribution network, the industrial consumers and the electric utilities amount to respectively 1737 k*m³(n)/h (TD), 986 k*m³(n)/h (TI) and 939 k*m³(n)/h (TE). The consumption of the gas cogeneration facilities is integrated in the industrial consumption and amounts approximately to an estimated 263 k*m³(n)/h (TCog). The total calculated peak demand is equal to 3662 k*m³(n)/h (TH).

In 2025, the calculated peak demand for the consumers of the distribution network, the industrial consumers and the electric utilities will equal respectively 1938 k*m³(n)/h (TDH), 986 k*m³(n)/h (TIH) et 939 k*m³(n)/h (TEH). The peak base demand will amount to 3863 k*m³(n)/h (TH).

Taking into account the future but inevitable conversion of the L-gas market (end of the conversion probably around 2029/2030), at this stage, it is important in our view to give a estimation of the impact of such an operation on the H-gas consumption. The dotted curves show the evolution of the H-gas consumption in the scenario of a total & progressive conversion of the L-gas market by 2030. As a consequence, the industrial consumption will rise slightly and linearly at a capacity growth of 6,4 k*m³(n)/h per year. Moreover it should be noted that a unique rise of 42 k*m³(n)/h will take place in 2015. This value takes into account the conversion of some industrial consumers in the Limburg province.(Albert channel)

In 2025, in the L-gas conversion scenario, the calculated peak demand for the consumers of the distribution network, the industrial consumers and the electric utilities will equal respectively 2989 k*m³(n)/h (TDHconv), 1086 k*m³(n)/h (TIHconv), 939 k*m³(n)/h (TEH). The calculated peak demand will amount to 5014 k*m³(n)/h (THconv).

Figure 25: H-gas peak demand (k*m^3(n)/h)



Source: DG Energy – FPS Economy

The next step is to complete this "base peak demand data" with the growth perspectives (as a result of new installations or the growth of existing units) or the decline (as a result of the closure of installations or the reduction of activities of existing facilities) for the industry sector and for the electricity production.

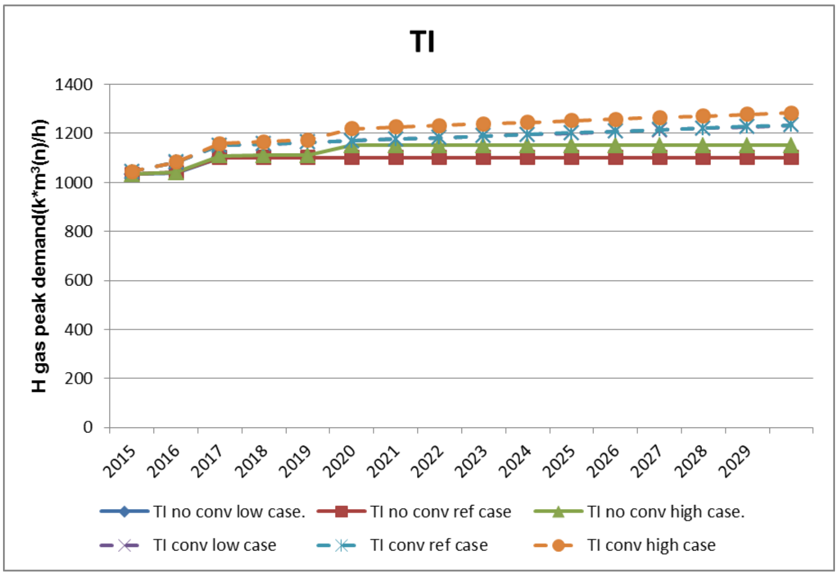
The increased/decreased consumption from the large industrial consumers and the electric utilities are analysed according three scenarios: the low, medium and high case scenario. The results are presented in figure 26. The results of the low, medium and high scenario are represented by three different colours (e.g. for REF case, red).

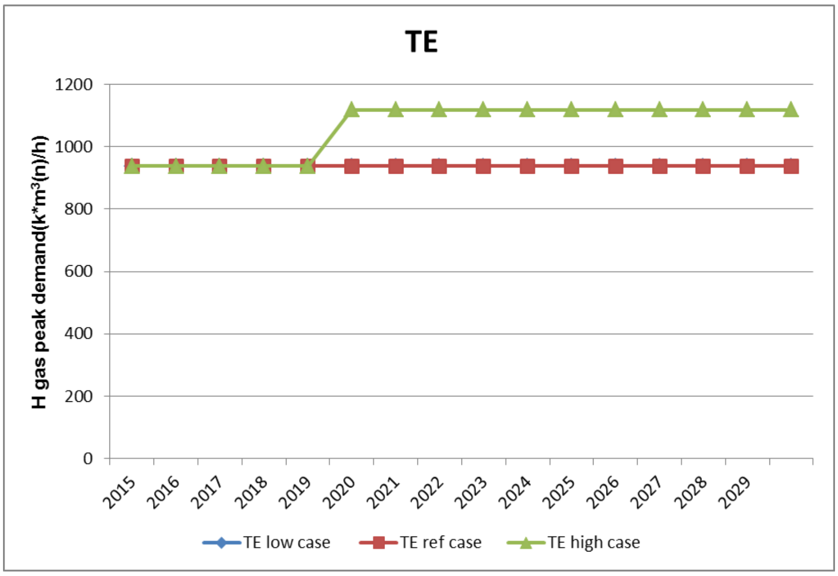
In the low case scenario, the weight of shut-downs or demand reductions is more important than the increase of new or the reinforcement of existing installations.

In the reference case scenario, the weight of new units or the reinforcement of existing ones for both the industry sector and electricity generation sector is more important than the closure or reductions. This scenario is most close to our current perception of the economic climate.

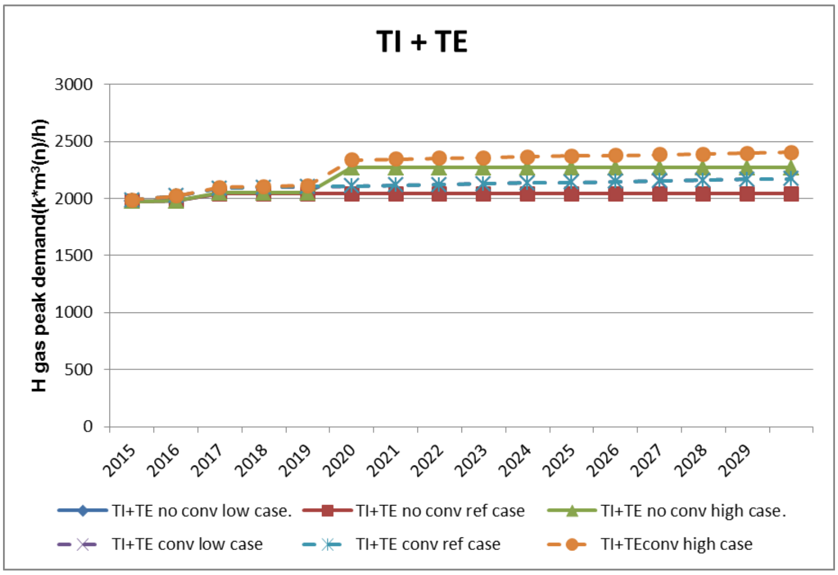
In the high case scenario, for the industry sector, we take the assumption that the majority of the industry activities will take up again their activity and -moreover- that the principal industrial projects will be able to get realized. As for the electricity generation sector, we start from the assumption that the majority of the growth potential will be realized. Just as in the reference case scenario, in this case, the weight of new units or the reinforcement of existing ones for both the industry sector and electricity generation sector is more important than the closure or reductions.

Figure 26: H-gas peak demand (in k*m³(n)/h) by industry, electric utilities and both sectors according to low, ref and high case scenarios[16]





[16] The data received from the TSO for the preparation of the scenarios, try to give a forecast for the next five years. The value obtained after five years will be extended to 2030.



For the industry sector and the electricity production sector, we assumed a same evolution for the low and the ref. case . This means that the weight of shut-downs or demand reductions is limited. In this case, we observe in 2025 an increase of the peak consumption of 116 k*m³(n)/h for the industry sector and no changes for the electricity production sector. In this scenario, the total demand of these two sectors will increase by 116 k*m³(n)/h.

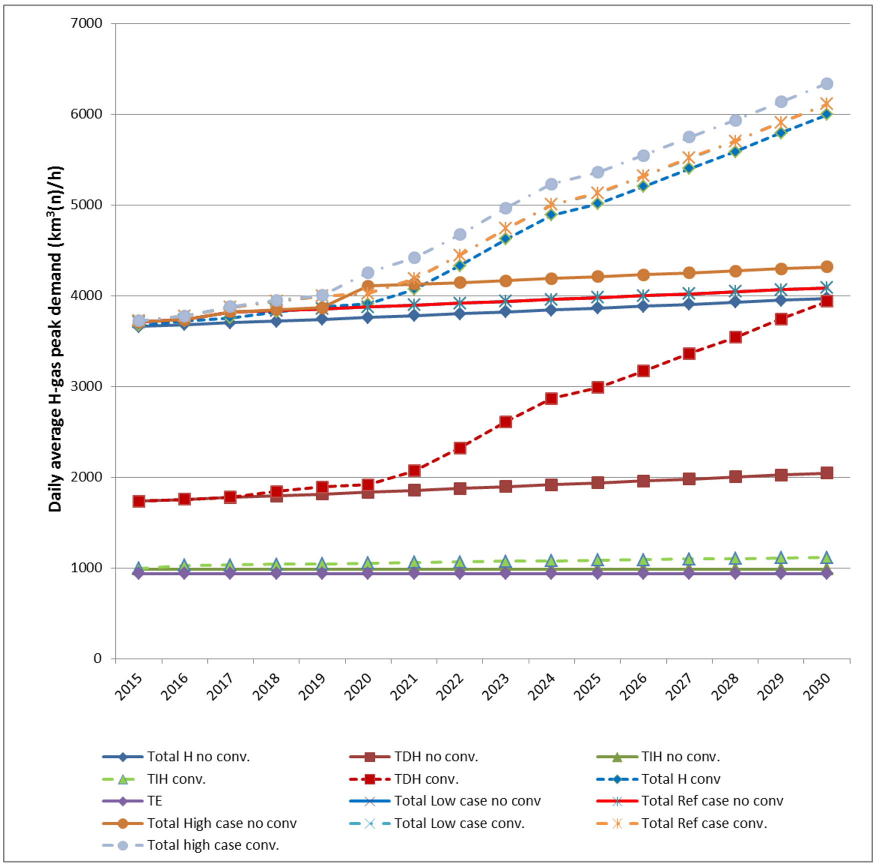
In the high case scenario, we observe in 2025 an increase in the peak consumption of 166 k*m³(n)/h for the industry sector and 180 k*m³(n)/h for the electricity sector. In this scenario, the total demand of these two sectors will increase by 346 k*m³(n)/h. Currently all new projects are still in study phase; the realisation of the project will only start after the written notice and capacity booking send by the customer to Fluxys Belgium.

In addition, it is to be noted that the lead time to construct a gas fired power plant is about three years and the lead time for connecting a possible new power plant on the Fluxys Belgium network will depend on the location of this potential power plant (near or far from an existing high pressure pipeline). In some cases, location of a possible power plant is close to an existing pipeline or an existing site and the connection can be performed rather quickly; in some other cases, if there are no pipelines near the chosen location, it may take five years to connect the power plant to the Fluxys Belgium network.

The projections for the total demand in the low, medium and high case scenario are represented in figure 27 by three different colours.

The total average peak demand would increase in the low and ref case scenario from 3711k*m³(n)/h in the 2015 to 3979 k*m³(n)/h by 2025 without an L-market conversion (increase of 7,2%) and to 5130 k*m³(n)/h with a L-market conversion (increase of 38,2%). In the high case scenario, we would see an increase in 2025 by 13,4 % from 3711 k*m³(n)/h in 2015 to 4209 k*m³(n)/h without an L-market conversion and by 44,4% to 5360 k*m³(n)/h with a L-market conversion.

Figure 27: H-gas total peak demand in the low, reference and high case scenarios.



Source: DG Energy – FPS Economy

2.2.2.2 Projections on BE-interconnections points of the entry and exit capacity (physical flows) for H-gas

The only new entry capacity is to attribute to new pipeline connecting Dunkirk to Zeebrugge (new entry in Alveringem at the French-Belgian border). It will increase in 2016 the entry capacity with 1000 $k^*m^3(n)/h$[17].

The two following tables illustrate the evolution of the physical entry or exit flows at the interconnection points with the neighboring transmission grids. These values have been tested through simulations carried out by Fluxys Belgium, which doesn't imply any problem with regard to the technical feasibility for the network. This doesn't regard necessarily the maximal technical possible physical flow at the interconnection point for the Belgian TSO. Indeed, for certain interconnection points, the below table shows a value well below of the technical limit of the interconnection point, given the current needs or interest of the market to send the flows via this interconnection point.

In any case, the indicated value in the below table will not exceed the maximal available value at the neighboring transmission operator. Apart from some exceptions, for most of the interconnection points, the physical flows in the tables are close to the maximal technical flows that are possible on

17 The capacity of the new pipeline has been calculated and the value is 1.000 k*m3(n)/h.

the Belgian or neighboring transmission grid. The values didn't have to be limited artificially by lack of market interest.

In the following tables, every capacity increase is indicated in green and all capacity decrease is indicated in red. As above mentioned, capacity decrease means a reduction of the simulated capacity, not an infrastructure modification.

As can be seen in the table below, the theoretical entry and exit capacity are relatively stable during the period 2014-2015 and equal respectively 12105 k*m³(n)/h (entry) and 8855 k*m³(n)/h (exit). As from 2016-2017, the entry capacity will increase by +990 k*m³(n)/h following the start of exploitation of the canalization Dunkerque/Zeebrugge (+1000 k*m³(n)/h) and the decrease of entry capacity between the Netherland and Belgium (Zandvliet -10 k*m³(n)/h). Also the exit capacity will increase by +750 k*m³(n)/h as a result of the increase of the exit capacity between Belgium and the Netherlands (ZZ (Zelzate) +300 k*m³(n)/h) and between Belgium and Germany (Eynatten 1&2 +450 k*m³(n)/h).

Table 4A: Firm entry capacity projections from 2014-2020 (in k*m³(n)/h)[18]

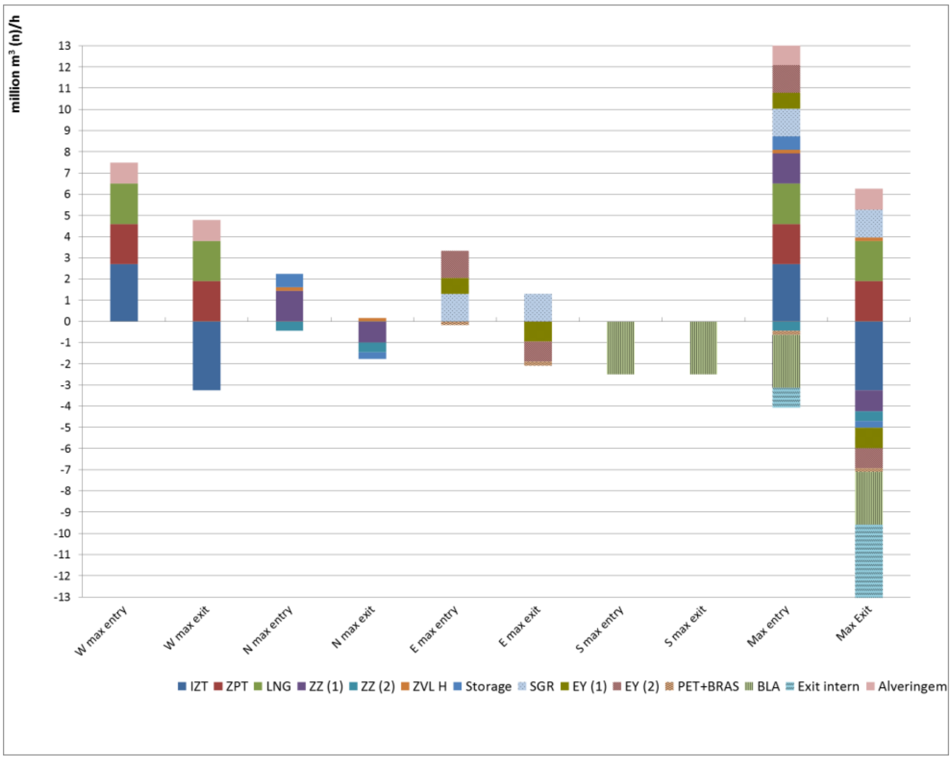
Evolution (min(Flx.Adj TSO))		*New investment							
H gas entry			1/01/2014	1/01/2015	1/01/2016	1/01/2017	1/01/2018	1/01/2019	1/01/2020
West border	IZT (Interconnector)	UK (Nat.grid gas)	2700	2700	2700	2700	2700	2700	2700
	ZPT (Gassled)	No (Gassco)	1900	1900	1900	1900	1900	1900	1900
	LNG Terminal		1900	1900	1900	1900	1900	1900	1900
	Alveringem*	FR (GRT gaz)	0	0	1000	1000	1000	1000	1000
Total WB			6500	6500	7500	7500	7500	7500	7500
North border	ZZ(1) GTS	NL (GTS)	1450	1450	1450	1450	1450	1450	1450
	ZZ(2) GTS	NL (GTS)							
	Zandvliet H	NL (GTS)	180	180	170	170	170	170	170
	Loenhout		625	625	625	625	625	625	625
Total NB			2255	2255	2245	2245	2245	2245	2245
East border	s Gravenvoeren	NL (GTS)	1300	1300	1300	1300	1300	1300	1300
	Eynatten (1)	D (Wingas Transport)	750	750	750	750	750	750	750
	Eynatten (2)	D (Open Grid Europe)	1300	1300	1300	1300	1300	1300	1300
	Pétange + Bras	Lux (Creos)							
Total EB			3350	3350	3350	3350	3350	3350	3350
South border	Blaregnies	FR (GRT gaz)							
Total SB			0	0	0	0	0	0	0
Total			12105	12105	13095	13095	13095	13095	13095

[18] The information on the technical capacity is based on the information provided by Fluxys BE (scenario's simulations) and could be subject to changes over the coming years. Although individually available, the capacities on the IP's IZT, ZPT, LNG Terminal and Alveringem are limited in aggregate (the value 'Total West' is not always available)

Table 4B: Firm exit capacity projections from 2014-2020 (in k*m^3(n)/h)[19][20]

Evolution (min(Flx.Adj TSO))		*New investment							
H gas exit			1/01/2014	1/01/2015	1/01/2016	1/01/2017	1/01/2018	1/01/2019	1/01/2020
West border	IZT (Interconnector)	UK (Nat.grid gas)	3250	3250	3250	3250	3250	3250	3250
	ZPT (Gassled)	No (Gassco)							
	LNG Terminal								
	Alveringem*	FR (GRT gaz)							
Total WB			3250	3250	3250	3250	3250	3250	3250
North border	ZZ(1) GTS	NL (GTS)	700	700	1000	1000	1000	1000	1000
	ZZ(2) ZEBRA	NL (GTS)	450	450	450	450	450	450	450
	Zandvliet H	NL (GTS)							
	Loenhout		325	325	325	325	325	325	325
Total NB			1475	1475	1775	1775	1775	1775	1775
East border	s Gravenvoeren	NL (GTS)							
	Eynatten (1)	D (Wingas Transport)	700	700	950	950	950	950	950
	Eynatten (2)	D (Open Grid Europe)	750	750	950	950	950	950	950
	Pétange + Bras	Lux (Creos)	180	180	180	180	180	180	180
Total EB			1630	1630	2080	2080	2080	2080	2080
South border	Blaregnies	FR (GRT gaz)	2500	2500	2500	2500	2500	2500	2500
Total SB			2500	2500	2500	2500	2500	2500	2500
Total			8855	8855	9605	9605	9605	9605	9605

The following figure illustrates graphically the data of the previous two tables. By convention, the exit capacities have a negative value and the entry capacities have a positive value.



[19] The information on the technical capacity is based on the information provided by Fluxys BE (scenarios simulations) and could be subject to changes over the coming years

[20] For Pétange + Bras see point 3.3: Market Integration Belux.

2.2.2.3 Entry capacity needs for the domestic Belgian market and border-to-border transmission through Belgium

Here below, we will develop several scenarios that will take into account:

- extreme climate conditions with a maximal Belgian consumption or climate conditions comparable to summer months with minimal needs in terms of heating
- the storage in Loenhout that can be full or empty
- send-out or no send-out of LNG from the LNG terminal in Zeebrugge
- the existence of maximal physical flows at certain entry or exit interconnection points

We assume as well that certain events are correlated with the climate:

- During a cold spell in which the equivalent temperature in Belgium would be -11°Ceq, we assume that the consumption of the Belgian market is at its maximum and the gas exports to Luxemburg via the interconnection points Bras and Pétange are maximal (since they are very much correlated with the climate conditions in Belgium). In the event that this cold spell occurs in the beginning or in the middle of a winter period (from December until the first half of March), we will assume that the storage in Loenhout is in its sending-out phase at nominal throughput. On the contrary, in the case that this cold spell occurs even later than mid-March, we make the assumption that the storage in Loenhout might not send-out any gas anymore.
- During the summer months when the demand for heating is minimal, we make the assumption that the consumption of the Belgian market will be minimal as well as the exports to Luxemburg. We consider that the storage of Loenhout - on the contrary - will be in the phase of injection at maximal throughput.

In the different scenarios, the transport network will be brought in its equilibrium state, namely the sum of the entries will be equilibrated by the sum of the exit flows. In order to obtain this equilibrium, the flows from an interconnection point of the Belgian network will be modified and will serve as a an equilibrium variable. Only the hourly average of a peak day will be used in these scenarios. This means that the gas stocks in the transmission network (also known as linepack) is sufficient to compensate for the hourly disequilibria.

Certain interconnection points with adjacent networks are unidirectional, either at the entry side (Zeepipe, ‘s Gravenvoeren, Zandvliet H), or at the exit side (Zelzate 2, Blaregnies, Pétange/Bras). It should be noted that there will be a new interconnection point (entry) available in 2016, namely in Alveringem, following to the new transport pipeline between Dunkerque and Zeebrugge. The Zeebrugge terminal is considered as an inland interconnection point (solely entry). The L-gas production facilities (conversion from H-gas) and the consumption of the Belgian internal market are considered as inland exit points.

Some interconnection points are bi-directional, namely Zelzate 1, Eynatten 1 and 2, and the Interconnector. The H-gas storage in Loenhout is considered as an inland (and bi-directional) interconnection point (injection (IN) / withdrawal (OUT)).

The first three scenarios (1a, 1b, 1c) take into account interconnection capacities & domestic demand forecasts of 2015, whereas the two following scenarios (2a, 2b) take the values of 2025.

The first scenario 1a will simulate the winter conditions with maximal entry flows from Norway, Germany and the Netherlands and exit to France. The storage at Loenhout and the LNG terminal is able to withdraw at its nominal capacity. The chosen amount for the domestic consumption is the value obtained from the medium case scenario of 2015.

In this case, the network can be brought to an equilibrium if the sum of the border exit flows do not exceed 5334 k*m³(n)/h. In the simulation hereafter, we have taken the Interconnector and the interconnection point Zelzate 2 as equilibrium variables.

In these conditions, we notice that the average border-to-border gas flows can attain 131 % of the average physical flows destined to cover the consumption of the domestic market.

Scenario 1a	max.IN:	No, Ger, NL
capacity 2015	max.OUT	Fr, LNG
Winter period	period linked	Max. internal BE (H) + Max. Lux.
		Max. conversion H => L
		Storage max. send out
	balancing var.:	UK (interconnector) -2654 (max. flow 3250)
		ZZ(2) min flow

Interconnection points	Entry	Exit
ZPT	1900	
SGR	1300	
ZVL H	180	
ZZ (1)	1450	0
ZZ (2)		0
EY (1)	750	0
EY (2)	1300	0
IZT	0	-2654
BLA		-2500
PET+BRAS		-180
LNG	1900	
Storage	625	0
Exit Intern BE H (internal IP)		-3711
Exit conv. H=> L		-360
Total	9405	-9405
Saldo	0	

Network in balance	Entry	Exit	Transit / intern use
Exit intern BE		-4071	
Entry / Transit	9405	-5334	1,31

The second scenario 1b takes the same assumptions as scenario 1a, but assumes that there is no withdrawal from the LNG terminal and that the Loenhout storage is empty. In this case, the network can be in equilibrium if the sum of the exit flows is lower or equal than 2809 k*m³(n)/h. We arbitrarily used the Interconnector as equilibrium variable in the simulation.

In these conditions, we notice that the average border-to-border flow can attain 69% of the average physical flows destined to cover the consumption of the domestic market. This scenario can be used to simulate a cold snap at the end of an extreme cold winter, with as consequence that the Loenhout gas storage would be nearly empty.

Scenario 1b	max.IN:	No, Ger, NL
capacity 2015	min.IN	LNG (min.flow 0)
	Max out.	FR
Winter period	period linked	Max. internal BE (H) + Max. Lux.
		Max. conversion H => L
		Storage min. send out
	balancing var.:	UK (interconnector) - 129 (max. 3250))

Interconnection points	Entry	Exit
ZPT	1900	
SGR	1300	
ZVL H	180	
ZZ (1)	1450	0
ZZ (2)		0
EY (1)	750	0
EY (2)	1300	0
IZT	0	-129
BLA		-2500
PET+BRAS		-180
LNG	0	
Storage	0	0
Exit Intern BE H (internal IP)		-3711
Exit conv. H=> L		-360
Total	6880	-6880
Saldo	0	

Network in balance	Entry	Exit	Transit / intern use
Exit intern BE		-4071	
Entry / Transit	6880	-2809	0,69

The third scenario 1c uses the same assumptions as scenario 1a but considers that the Loenhout storage is in a “injection phase” and that the domestic gas demand is at a very low level (for example during summer). In this case, the network can be in equilibrium when the sum of the exit flows of Blaregnies, Zelzate and the interconnector is lower or equal than 5971 k*m³(n)/h.

We notice that the average border-to-border flows can be up to 6,32 higher than the physical flows destined to cover the domestic demand.

Scenario 1c	max.IN:	No, Ger, NL (except ZZ(1) and ZZ(2))
capacity 2015	max.OUT	Fr, UK , LUX
	period linked	Min. internal BE (H) + Min. Lux.
		No conversion H => L
		Storage max. send in
	balancing var.:	NL (ZZ 1&2)

Interconnection points	Entry	Exit
ZPT	1900	
SGR	1300	
ZVL H	180	
ZZ (1)	0	-127
ZZ (2)		-94
EY (1)	750	0
EY (2)	1300	0
IZT	0	-3250
BLA		-2500
PET+BRAS		-32
LNG	1900	
Storage	0	-325
Exit Intern BE H (internal IP)		-1002
Exit conv. H=> L		0
Total	7330	-7330
Saldo	0	

Network in balance	Entry	Exit	Transit / intern use
Exit intern BE		-1002	
Entry / Transit	7330	-6328	6,32

The scenarios 2a and 2b use the same assumptions as scenarios 1a and 1b, but taking into account the estimations of the domestic demand (medium case scenario) for 2025, in a scenario of the conversion of the L-gas market (see chapter 2.2.2.1).

In these two circumstances, we notice that the average border-to-border flows can represent respectively up to 89% and 49 % of the average physical flows destined to cover the domestic H-gas consumption.

Scenario 2a	max.IN:	No, Ger, NL, FR (ALV)
capacity 2025	max.OUT	Fr (BLA), LNG
Winter period	period linked	Max. internal BE (H) + Max. Lux.
		Max. conversion H => L
		Storage max. send out
	balancing var.:	UK (interconnector) out = -2225
		ZZ(2) no exit flow

Interconnection points	Entry	Exit
ZPT	1900	
SGR	1300	
ZVL H	170	
Alveringem	1000	
ZZ (1)	1450	0
ZZ (2)		0
EY (1)	750	0
EY (2)	1300	0
IZT	0	-2225
BLA		-2500
PET+BRAS		-180
LNG	1900	
Storage	625	0
Exit Intern BE H (internal IP)		-5130
Exit conv. H=> L		-360
Total	10395	-10395
Saldo	0	

Network in balance	Entry	Exit	Transit / intern use
Exit intern BE		-5490	
Entry / Transit	10395	-4905	0,89

Scenario 2b	max.IN:	No, Ger, NL, FR (ALV)
capacity 2025	min.IN	LNG (no flow 0)
	Max out.	FR (BLA), UK
Winter period	period linked	Max. internal BE (H) + Max. Lux.
		Max. conversion H => L
		Storage min. send out
	balancing var.:	UK (interconnector) IN = 300
		ZZ(2) no exit flow

Interconnection points	Entry	Exit
ZPT	1900	
SGR	1300	
ZVL H	170	
Alveringem	1000	
ZZ (1)	1450	0
ZZ (2)		0
EY (1)	750	0
EY (2)	1300	0
IZT	300	0
BLA		-2500
PET+BRAS		-180
LNG	0	
Storage	0	0
Exit Intern BE H (internal IP)		-5130
Exit conv. H=> L		-360
Total	8170	-8170
Saldo	0	

Network in balance	Entry	Exit	Transit / intern use
Exit intern BE		-5490	
Entry / Transit	8170	-2680	0,49

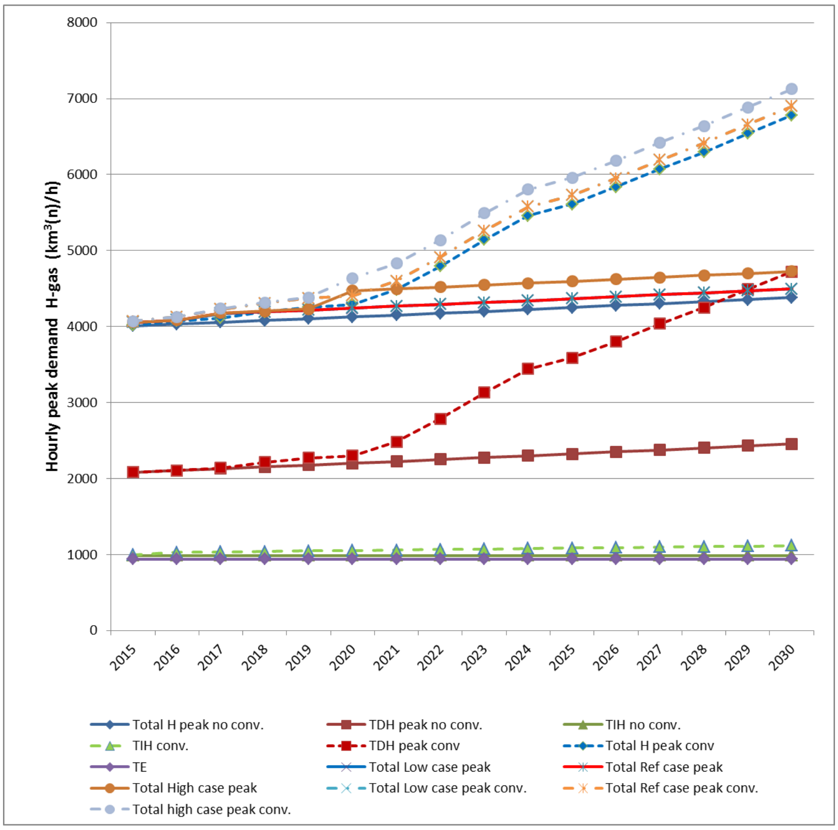
For the H-gas network, we can assume that at the moment, there is sufficient capacity to meet the needs of the domestic Belgian market.

2.3. Projections of the H-gas demand at the hourly peak

In addition of the calculations made on a daily average basis, the same is made for the hourly peak value as this will have its implications on the flexibility in the network. We assume that the hourly peak equals the average peak increased with 20%. The data for the increase in the natural gas consumption in the three scenario's (low, medium and high case) remain the same, so the main conclusion is that the remaining capacity available for exports during the hourly winter peak will be 20% lower during the peak than in the scenario described above.

With an L-market conversion, the total H-gas demand on the hourly winter peak will reach in 2025 in the low case and medium case scenario 5728 k*m^3(n)/h and 5958 k*m^3(n)/h in the high case scenario. Without an L-market conversion, the total H-gas demand on the hourly winter peak will reach in the low case and medium case scenario 4367 k*m^3(n)/h and 4597 k*m^3(n)/h in the high case scenario.

Figure 29: H-gas hourly peak demand projections from 2015-2030 (k*m^3(n)/h)



Source: DG Energy – FPS Economy

3. Natural gas infrastructure

3.1. Existing infrastructure

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

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

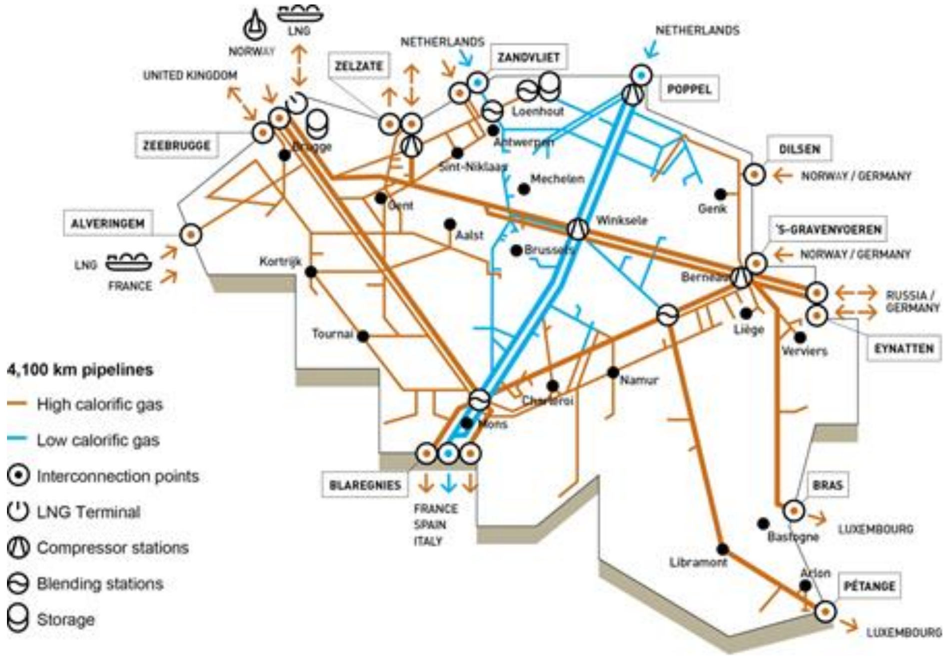
Winksele. The compressor station at Winksele lies at the crossroads of major North/South (L-gas) and East/West (H-gas) transmission axes. The existing compression facility for L-gas serves to maintain pressure levels in the North/South pipeline. Due to increasing demand for capacity for both the domestic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

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

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

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

Figure 30 The Belgian transmission network (2014)



Source: Fluxys Belgium

3.2. New infrastructure development

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

Main infrastructure investments identified in the Fluxys Belgium TYNDP 2015-2024 are underway or will start in the coming year(s) under investment decision:

➔ **Enhancement of the Zeebrugge LNG terminal:** The project of a second capacity enhancement of the Zeebrugge LNG terminal includes the construction of a second berthing jetty allowing ships from 2000 m³ LNG up to a capacity of 217000 m³ LNG and the construction of a 5th tank. This second capacity enhancement gives rise to additional berthing rights offered to the market for the purpose of loading ships. The investment decision of the project was already taken in 2011 for the construction of the second jetty. The commissioning of this second jetty is expected by end 2015.
In order to enable to provide transshipment services following the signature of a 20 years-contract with the Yamal LNG consortium, Fluxys Belgium also took the investment decision for the construction of a fifth tank with a capacity of 180000m³ and additional process

facilities. The construction will start before the end of 2015 and commissioning of the 5th tank and process facilities is planned for end of 2018.

➔ **Firm entry France**: In the context of the construction of the LNG-terminal in Dunkirk (FR) which will be commissioned late 2015, Fluxys Belgium and GRTgaz have decided to construct a new pipeline (DN900) from Dunkirk via Pitgam to the Belgian border at Alveringem and from Alveringem to Maldegem, connecting the new pipeline to the VTN pipeline. The Alveringem interconnection will connect non-odorized gas coming from France with the Belgian grid, allowing an expected 8 bcm of imports as from late 2015. Fluxys Belgium will make available about 1000000 m3(n)/h from the Dunkirk facility to the Belgian network, either to Zeebrugge Beach or to the ZTP(virtual trading point).

➔ **Reinforcement of the Ypers area:** Gaselwest, a DSO active in West Flanders, asked Fluxys Belgium to provide a new injection point in the Ypers area, since its backbone network reaches saturation. By the fact that the most western part of this region is not yet supplied by a high pressure gas pipeline, the project includes the construction of a 7 km long pipeline from the new section Alveringem-Maldegem to the Ypers area between Houthulst and Poelkapelle. The pipeline will feed a new reduction station (city gate) to feed the Ypers area in low pressure gas. The commissioning of these two investments is planned for 2016.

➔ **Reinforcement Hageland (Tessenderlo-Diest):** The distribution networks in the region between Leuven and Diest (Iverlek) and between Tessenderlo and Halen (Interenerga) reach saturation. In order to create an injection point in these networks, it is necessary to strengthen the Fluxys Belgium grid which results in a pipeline project (DN 250 over 1,5 km and DN 600 over 14,5 km) between Tessenderlo and Diest (L-gas pipe) and the construction of a new injection point for both concerned DSO's at Diest. The works are planned to start beginning 2016 and to be achieved in August 2016. The commutation to the H-gas system of large industrial customers will free the necessary upstream capacity for this project.

➔ **Pressure increase Oupeye-Lanaken:** A project is started to adapt the pipeline between Lixhe and Lanaken in order to flow at a higher working pressure and obtain an increase in transport capacity for the Limburg H transport system. Through this eastern route, Fluxys Belgium will be able to provide the necessary capacity to switch consumers from L-gas to H-gas in the Limburg's region (see also reinforcement Hageland). The project is scheduled for 2018.

➔ **Enhancement of the Brussels area:** Sibelga, Brussels' DSO, has asked Fluxys Belgium to provide a new injection point in the southern area of Brussels. This needs Fluxys Belgium to build a new 7,7 km long pipeline between Overijse and Jesus-Eik and a new pressure reduction station (city gate). The project will be implemented in 2017 to be available for commissioning end 2017.

➔ **Connections for new power plants:** Several projects connecting new CCGT power plants are still being studied. These gas power plants require capacity at an operating pressure that cannot be provided by the DSO's, which is why they must be directly connected to the TSO network. Connection requests have been asked to Fluxys Belgium for different sites but have not yet resulted in a firm demand from customers.

3.3. Market-Integration: Belux

Luxembourg gas transmission system operator (TSO) Creos Luxembourg and Belgian TSO Fluxys Belgium and their respective regulators, ILR (Institut Luxembourgeois de Régulation) and the Commission for Electricity and Gas Regulation (CREG), are closely working together to integrate their national gas markets in a sole BeLux market area from October 1st. This initiative constitutes the first market integration project between two European Member States. With the creation of an integrated Belgian/Luxembourg market, the entry-exit access fees between Belgium and Luxembourg will fall away and the Zeebrugge Trading Point (ZTP) will become the gas trading point for the integrated market. In addition, the same balancing rules will apply and a new joint entity (Balansys) is set up to manage the balancing of the integrated market. However, since the balancing company was not yet established at the time of approval of the integrated model by the respective NRAs, balancing activities will be covered during an interim period by Fluxys Belgium, who will act as a Single Point of Contact for the network users regarding these activities. At the same time, both TSOs will keep their distinct identities and organizational structures. The FPS Economy DG energy has done an adjustment to the Belgium gas law such that these market integration has no any negative impact on the security of supply. With the removal of the Bras/Pétange interconnection point from the commercial offer, grid users will no longer have to reserve capacity at that point to transmit gas between Belgium and Luxembourg. Meanwhile, the interconnection point at Remich will be dedicated to the trading and operation of a conditioned capacity product.[21]

3.4. The PCI selection process

European Commission objectives

One of the Commission's priorities is to complete the construction of an internal energy market by putting in place missing interconnections, opening up certain Member States and eliminating internal bottlenecks.

The criteria for obtaining PCI status are as follows: the project must generate significant benefits for at least two Member States, contribute to market integration and further competition, enhance security of supply and reduce CO_2 emissions.

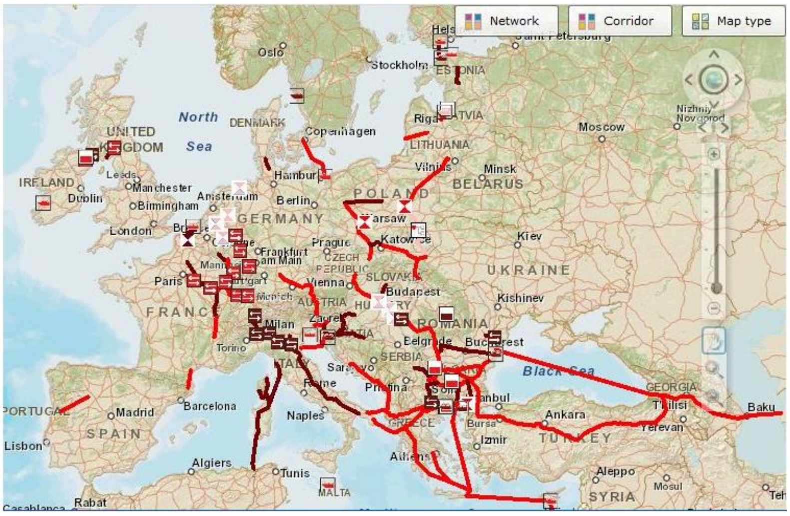
Projects with the PCI label (which is valid for two years) will benefit from faster and more efficient permit granting procedures and improved regulatory treatment and may also have access to financial support from the Connecting Europe Facility (CEF).

1st PCI selection round 2013

[21] More information is available on the website of Fluxys Be (http://www.fluxys.com/Belgium) and Balansys (http://www.balansys.eu/)

The Commission adopted in 2013 the first Union list of Projects of Common Interest (PCIs), which comprises some 250 projects in the fields of gas and electricity transmission, storage and LNG, as well as smart grids and oil.

The following map gives a graphical overview of the gas infrastructure projects in Europe that received PCI status during the first selection round in 2013.



PCI interactive map (EU website)[22]

PCI selection round 2015

In 2014 a new process through the Regional Groups has been launched in order to have a 2nd list of PCI projects adopted by November 2015 by the European Commission. Fluxys Belgium has submitted a PCI candidature for the L/H conversion project in Belgium, which will be evaluated together with the conversion project in France proposed by GRTgaz & GrDF.

[22] http://ec.europa.eu/energy/infrastructure/pci/pci_en.htm

4. Quality and level of maintenance of the networks

Fluxys Belgium, the TSO, is responsible for the quality and the maintenance (incl. replacement investments) of the network.

One of the main concerns of Fluxys Belgium is the service life and reliability of its network, actively promoting a safety culture within its organization. Fluxys Belgium actively contributes to the security of supply of the country by taking measures to ensure the maximum availability of its services.

The choice of materials can be important in this regard. The high-pressure pipelines used by Fluxys Belgium are made of high quality steel and meet all applicable European and international standards. The pipes undergo quality-control procedures at the factory and these procedures are overseen by a recognised independent inspection body. The pipes also have a synthetic coating and are fitted with a cathodic protection system to prevent external corrosion.

In accordance with Article 133 of the Code of Conduct, Fluxys Belgium has also developed a tracking system that monitors the quality and reliability of operation of its transportation network and transportation services. The report of this tracking system takes into account the situations in which subscribed transportation services were interrupted or reduced by Fluxys Belgium. During 2014 there were no (non customer agreed) reductions and interruptions of firm services..

Each year, Fluxys Belgium monitors commercial parameters and plans the maintenance periods of its network in consultation with adjacent TSO's and its customers. The work and intervention overview published on the Fluxys Belgium website lists the works and interventions planned for the current year that could affect the execution of the transmission contracts. The overview is updated each month for the current calendar year.

Fluxys Belgium has been performing Internal Line Inspections ('ILI' also called I-pigging) for several years. The first ILI of a pipeline takes place after 20 years of operation, afterwards the targeted inspection frequency is between 7 to 15 years. Pigging results, when validated, can lead to requests to further physically inspect the condition of the pipeline. These examination works are performed with a priority depending on the type of issue discovered during the I-pigging run.

All pipelines are not accessible for Internal Line Inspections for various reasons (geometry of the line, gas flow, absence of pig traps…). At the moment, we increased the ratio to 80 % of the Fluxys Belgium high pressure network being "piggable" and Fluxys Belgium continues to conduct a program to improve this ratio. At the same time research and development is going on to develop other methodologies of inspection in order to cover 100 % of the network.

Fluxys Belgium also plans replacement investments of the aging gas infrastructure where needed. E.g. Fluxys Belgium is currently (period 2015-2016) replacing part of the pipelines between Poppel and Blaregnies downstream of Weelde.

The maintenance of the network is supported by a centralized management system (SAP Plant Maintenance) and is based on Work Orders generated by this system. Different tasks are performed to ensure the maintenance and the monitoring (preventive & predictive maintenance) of the network.

Patrols by helicopter flights are performed on the main sections on a regular basis (5 to 6 days per week for main pipelines to twice a week or once every two weeks for other parts of the high pressure network). Moreover, this air surveillance is supplemented by patrols by car (minimum once per month for main pipelines to once per week for portal areas) and foot patrols throughout the network (once per year).

Gas detection is performed yearly on the entire grid using an helicopter equipped with the CHARM-system (CH4 Airborne Remote Monitoring). Point measurements are executed during vehicle and pedestrian inspection on pipeline zones which can not be covered during the CHARM- flights.

Finally, third-party works (work sites nearby Fluxys Belgium’s pipelines) are actively followed up. New technologies such as Threatscan (detection of shocks) are used and Fluxys Belgium participates in a project of detection of works through optical fibres.

5. Measures to cover peak demand and to deal with shortfalls of one or more suppliers

5.1. Market functioning

Reforms of the organisation of the Belgian gas market in recent years (move to a full entry-exit model, notional trading point, market-based balancing regime, etc.) aimed at increasing market access, market liquidity and market integration with adjacent trading places. These initiatives are beneficial for competition as well as for security of supply. Suppliers have a large flexibility in choosing routes and sources within a highly interconnected network that does not face congestion. Monitoring of the market during peak circumstances, e.g. cold waves, has shown that the Belgian market is able to attract additional gas flows to cope with peak demand at reasonable wholesale prices. The current market functioning in Belgium has a significant potential to deliver gas supplies to cover peak demands. This situation holds in particular for H-gas. The supply of L-gas mainly depends on the Dutch wholesale market which is also very liquid but suppliers depend on the capacity availability at the Dutch side of the cross-border interconnection at Poppel.

5.2. Legal supply requirements

The suppliers active on the Belgian natural gas market that dispose of a federal supply licence for both H-gas and L-gas will need to prove that they have contracted enough natural gas to meet the supply criteria for the 7 day peak demand, the 30 day peak demand and sufficient supplies through alternatives routes in case of a disruption of the largest natural gas infrastructure. This in reference to the stipulations in regulation n° 994/2010 of the European parliament and the council concerning measures to safeguard security of gas supply. The supply standard applies to the protected customers, it is to say the customers connected to the distribution network.

Since the liberalisation of the natural gas market in Belgium, there was no longer a clear legal basis for dimensioning a security of supply standard. Before the market liberalisation, some criteria did exist in the Belgian natural gas market[23]. Even though it is currently not obliged by law, some of the market participants still apply those criteria to frame their portfolio:

1. A transport capacity covering the daily peak demand at -11°Ceq (assumed statistical risk of 1 in 20 years)
2. The natural gas volumes need to be able to cover the natural gas demand linked to the winter peak of 1962/1963, the coldest year in the century (statistical risk of 1 in 95 years)
3. A gas volume covering natural gas demand for a 5 day peak period between -10°Ceq and -11°Ceq (average temperature during the day measured at Uccle with a statistical risk of 1 in 95 years)

[23] Those criteria were only applied for the natural gas demand stemming from heating needs but did not stipulate any security of supply provisions for the supply to large industrial consumers or power plants.

A similar obligation will be applied. The above criteria fall into two parts. The first part is the infrastructure obligation and the second part is the molecule (commodity) obligation which refers to the temperature parameter and thus the natural gas demand for heating purposes.

For the infrastructure calculations, the TSO bases its calculations in the investment plan on the -11°Ceq hourly peak criterion. By introducing the same criteria for the network users, both the molecule standards will be in line with the infrastructure standard. An improvement is already made through the introduction of the new entry-exit model since October 2012. In this new model, the TSO calculate the needed capacity per aggregated receiving station (ARS) of each distribution grid to cover the full demand distribution network behind that specific ARS at -11°Ceq. The network users are forced to book the capacity calculated by the TSO in order to cover the winter peak demand and to avoid free riding. This way, at least the capacity is already in place to cover the peak demand.

Regarding the supply standards foreseen in the Regulation 994/2010, suppliers have the responsibility to respect them. Furthermore, in order to limit the interpretation margin at the implementation level of the Regulation, the Belgian authority responsible for the security of supply has tried to prepare a document setting the value of the number of degree days to associate respectively to each climatic risk with a probability of 1 in 20 years as stipulated in Article 8 a) and b) regarding supply standards of regulation 994/2010. Indeed, suppliers being free to use the methodology and climate data they consider to be appropriate, the results obtained in the framework of the implementation of supply standards may be different. In other words, depending on the chosen methodological approach, the volumes of gas to ensure are different. In order to reduce the margin of interpretation, the project aimed at setting the number of degree days for each scenario foreseen in the procurement standards. A proposal was prepared and several meetings were organized with an association representing suppliers. To date, this consultation with the sector failed to reach an agreement. With the upcoming revision of the Regulation 994/2010 the discussion is momentarily on hold in order to start the discussion again with the revised Regulation.

We would like to note that it is sometimes difficult to obtain data that can be aggregated consistently. Furthermore, the allocation of an (international) supply-demand portfolio of a supplier to Belgian customers is rather artificial since each supplier manages its portfolio as a whole. Suppliers hold information in different formats and it has been difficult for some suppliers to provide the requested information in the required format. Given that contractual positions can change rapidly, there is also a question about the usefulness of such information. Furthermore, we will need to look at the consequences that can be imposed on network users that cannot fulfil the supply standard.

In any case, the natural gas suppliers remain responsible of any shortage of natural gas (for identified consumers).

Conclusion

The Belgian gas network is highly connected with the neighboring countries that benefits to the security of supply of Belgium. This makes also Belgium an important transit country for gas in the Northwest region. Belgium also benefits from sufficient reverse flow capacity on the following axes: BE-UK, BE-DE, BE-NL.

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 distinctive and operated separately.

In 2014, 72% of the Belgian gas demand is H-gas, 28% is L-gas. L-gas is mainly used in the distribution network and a small part by large industrial consumers directly connected on the transport network. H-gas is delivered to the distribution network, large industrial consumers and power-plants directly connected on the transport network. In 2014, 49,6% of the total natural gas consumption in Belgium was on the public distribution network, 25,7% was used by large industrial consumers and another 24,7% 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.

With the findings in this report, we may conclude that at the moment the Belgian gas transport network provides sufficient capacity to meet the needs of the domestic Belgian market.
Due the decline of the Groningen field, a conversion (shift) from L-gas to H-gas in the next 14 years is necessary for Belgium.