The supply of natural gas in the context of the CE2030 scenarios

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1. Impact of the alternative CE2030 scenarios on natural gas demand

As natural gas is potentially used for electricity generation and as its combustion generates CO2 emissions, all alternative scenarios (with/without nuclear electricity generation and with/without CCS technology) have an incidence on natural gas demand and hence gas imports.

The next figures give the profile of natural gas demand for each scenario. Each profile should be appreciated against the baseline scenario as it expresses the sensibility of the model to the different hypotheses.

Original data expressed in ktoe have been conversed in Bcm (billion cubic meter) using the following conversion :

1 Bcm = 0.8859 Mtoe or 885.9 ktoe

1.1. Final gas demand

Remember that in the baseline scenario and high price scenario, no hypothesis has been made concerning a reinforcement of the Kyoto commitment and only the relative price evolution of fuels influences the trade off between their uses. This is of importance for the generation sector where substitution of gas is possible with coal but does not influence so much the final gas consuming sectors which have less substitution alternatives than in the electricity sector and the unfavourable gas price evolution does not reduce much the final gas consumption.

In the alternative scenarios, the implicit cost of adapting to the CO2 objectives (-15 % and -30 % constraint) is incorporated in the cost of using one of another fuel and thus incorporated in the decision process ("internalisation" of this external cost).

More stringent CO2 emissions constraint affects final gas demand whose reduction is even more sensitive when no CCS is available (Bpk30s & Bpk30ns) which is reflected through higher CO2 costs. Consequently there is a decrease in final gas consumption and more renewables are put into place. When nuclear electricity generation is maintained (Bpk30ns), even less gas is consumed, while on the other hand the share of renewables is increased.

The Bpk30s scenario (no nuclear and no CCS are available) has the most impact on final gas demand.

However, final gas consumption reduces in all scenarios due to a modified energy mix but also mainly due to the fact that internalising higher carbon values gives a very strong incentive to final consumers to adopt energy savings measures. Strong (and high) price signals are needed to induce final consumers to adopt energy saving behaviours. [1]

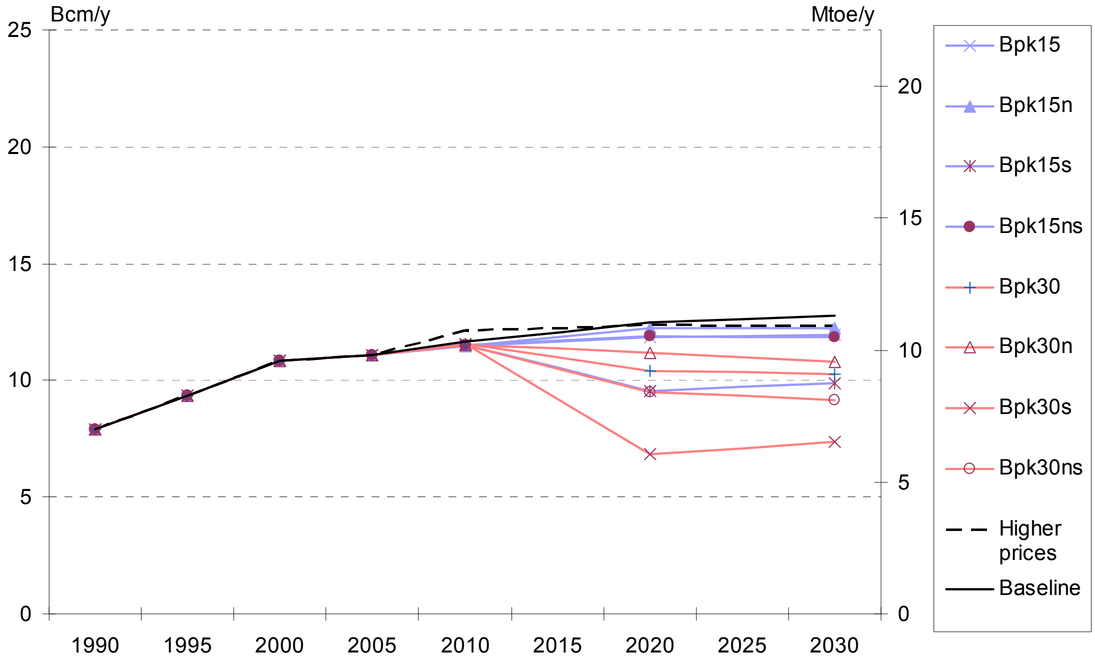
[1] Further considerations on these matters are developed in : Gusbin D., Henry A. (2007), "Eclairage sur des enjeux de la politique énergétique belge confrontée au défi climatique", FPB Working paper 1-07, p. 26.

Indeed, the final demand sectors decrease their final gas consumption sometimes (from 2020 on) by more or less 0,5-1 Bcm/y in the most favourable scenarios relative to the baseline. When scenario assumptions are more stringent and/or less favourable to gas, the final consumption is reduced by 2,5-3 Bcm/y and up to 5,5 Bcm/y (the same magnitude as the actual industrial gas consumption). As no change in value added is assumed against the baseline scenario, this means that the "gas" intensity of the gas consuming industries and of the tertiary sector has to decrease sensitively compared to the baseline.

Two main factors may contribute to the decrease in the final gas consumption of industry : a partial switch from integrated steelworks to electric arc furnaces in the iron and steel sector (which will affect final gas consumption for a maximum actual consumption of about 1 Bcm/y), and a further increase in the energy efficiency.

In the tertiary and residential sectors a decline is recorded following a decrease in the demand for energy services and further improvements in the efficiency of heating devices. [2]

Figure 1 : Final gas demand (industry, residential, tertiary, transport)



1.2. Gas demand for electricity generation

1.2.1. Comment on the PRIMES results

In the generation sector gas demand reflects the trade off that has to be done between gas, coal, nuclear energy and renewables knowing that the availability or not of CCS and/or nuclear capacity affects the relative cost of these primary fuels for electricity generation (whose costs include the CO2 costs).

2 To reach this increased efficiency it should be worth to underline the necessity to conduct extensive R&D work for ALL kind of consumers (energy intensive consumers have already a high incentive to limit their consumption only by the fact that fuel cost are high relative to their total costs).

Higher gas prices reduces gas demand mainly in the electricity generation sector : the gas cost within global generation cost represents a high share and electricity producers will rely more on coal as the relative price evolution favours this fuel which is not affected by stringent CO2 constraints in the baseline scenario and in the high oil and gas scenario.

For the alternative scenarios, the main trend is that gas demand globally increases through 2030 when there is a nuclear phase-out, an increase in gas demand that is emphasized when moreover no CCS is available which then disadvantages coal (no use of coal for thermal power generation).

The availability of nuclear generation reduces the requirements for gas as the availability of CCS (Bpk15n & Bpk30n).

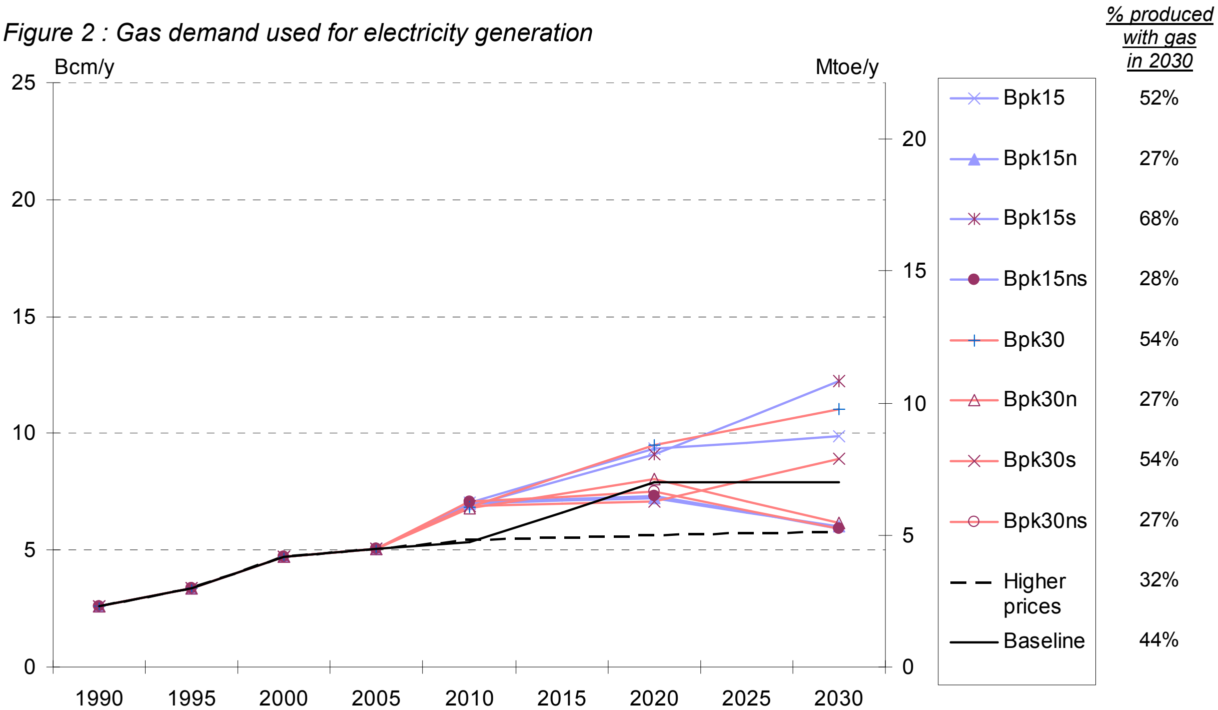
In the most constrained scenario where no CCS and no nuclear are available (Bpk30s), hydrogen fuel cells come into play ensuring 13,1% of electricity production, next to renewable energy sources and the rest of the generation being provided by natural gas. However the use of the hydrogen channel justifies why in this scenario (where the CCS constraint is the strongest and no nuclear available), the gas demand for electricity is not higher than in the Bpk15s scenario. [3]

The share of electricity generated from gas varies considerably from one scenario to another the highest share being observed when there is no nuclear and no CCS available. Under these hypotheses electricity production is the lowest and relies first on gas. However these percentages are based on yearly average electricity production figures and could become much higher under certain circumstances as for instance should there be no wind in a cold evening restraining the alternatives to gas : the combination of no wind, no PV (evening), no nuclear, no coal (CCS not available) could lead to a situation where more than 90 % of electricity production relies on gas in a winter period when final demand for gas (due to heating needs) is also very strong.

This hypothetical example emphasises the need to have sufficient flexibility on gas deliveries along the whole year. This can be achieved within the (negotiated) terms of the supplying (long term) contracts, flexibility agreements with consumers (firm *vs* interruptible), available storage management and/or through gas acquisitions on the spot market. The question then remains at which spot price as climate conditions are very similar on the European markets and when all these gas requirements are brought together, they will support higher spot prices.

[3] The rationale behind the PRIMES model results are as follow (see FPB (2006), Long term energy and emissions' projections for Belgium with the PRIMES model. Addressed to the Commission Energy 2030). Without CCS and nuclear, the CO2 -30 % constraint induces the highest "cost" for CO2 emissions (2150 €/t CO2 - see FPB (2006), p. 37) which makes in the absence of coal and nuclear energy, hydrogen fuel cells competitive for electricity and steam generation even against gas. In this scenario gas is used for direct electricity generation and also "indirect" electricity generation through the hydrogen fuel cell channel. The underlying hypothesis is that efficiency improvement expected in the hydrogen fuel cell (combined heat and power) will be strong enough against the efficiency of combined cycle gas turbine, even if there is a dual transformation process from natural gas to hydrogen and then to electricity.

Figure 2 : Gas demand used for electricity generation



1.2.2. Additional comments on the consequences of phasing out power stations

The PRIMES model estimates gas requirements by economically optimizing the cost of the energy system under different scenarios as represented in Figure 2. For instance, in the CE2030 Baseline scenario with nuclear phase-out, PRIMES replaces the decommissioned nuclear power-plants from 2020 on with a production mix which also includes coal and gas. In a similar approach on nuclear decommissioning, the CREG published in its indicative plan for natural gas supply 2004-2014 (CREG 2004) a forecast of the consequence of a complete switch from nuclear energy to gas (execution of the nuclear phase out law, to be achieved between 2015 and 2025). This switch induces an increase of gas consumption by the electricity generation sector of 5,1 Bcm/y at the end of the period (for a production of 43 888 GWh - see Table 1). [4]

If in parallel the phase-out of the actual coal-fired power stations (1573 MW) would entirely be compensated by a switch to natural gas combined cycles ensuring the same production (4800 hours/year with 38 % efficiency for coal-fired plants), this would represent an additional gas consumption of some 1,2 Bcm/y (assuming 60 % efficiency for the combined cycle).

Based on the present production park (and thus not taking into account the increasing electricity demand), a complete swap from coal-fired and nuclear power plants to natural gas combined cycles would thus require some 6,3 Bcm/y of supplementary gas supplies in 2025-2030 which is more or less an equivalent volume to the current gas consumption of the electricity generating sector.

[4] This has to be compared to the CE2030 Baseline scenario where the replacing power plants use mixed energy sources including natural gas of which consumption increases with some 2,8 Bcm/y between 2005 and 2030 in the electricity generation sector.

Table 1 : Switch from nuclear to gas based electricity generation according to the nuclear phase-out law over the period 2015-2025. [CREG, 2004]

Nuclear power plants				Swith to CCGT *	
Nuclear power plant	Closing date	Capacity MWe	Electricity generation GWh	Annual gas consumption ** M.m³(n)/y	Peak flow natural gas k.m³(n)/h
Doel 1	12/02/2015	392,5	2980	346	48
Tihange 1	01/10/2015	962,0	7304	847	118
Doel 2	01/12/2015	434,5	3299	383	53
Doel 3	01/10/2022	1006,0	7639	885	124
Tihange 2	01/02/2023	985,0	7479	867	121
Doel 4	01/07/2025	985,0	7479	867	121
Tihange 3	01/09/2025	1015,0	7707	893	125
Total		5780,0	43888	5088	710

* Annually 90,3 % of electricity generated using nuclear power is covered by natural gas. Bearing in mind the back-up, a peak flow must be provided for the use of combined cycle gas turbine (CCGT) power plants amounting to 96,2 % at peak times.

** Account is taken of a forecast increase in capacity of 42 MWe in 2005.

Concerning the influence of this switch on the peak load requirements of gas, the estimation made by the CREG (see Table 1) can be used as a reference. Indeed, the CREG has estimated that the required additional peak flow capacity reaches 710000 m³/h in 2025 under the assumption that all nuclear power plants are exclusively replaced by gas-fired generation plants. “This additional capacity can be compared to the capacity of the Zomergem-Lillo supply axis to Antwerpen and Loenhout.”

However, as underlined by the CREG if substantial investment is needed, this is manageable as far as plans are initiated in due time.

1.3. Total gas demand

The total natural gas demand sketched in Figure 3 results from the summing up of :

the final gas demand (Figure 1) ;

\+ gas used as fuel input for electricity and steam generation (Figure 2) ;

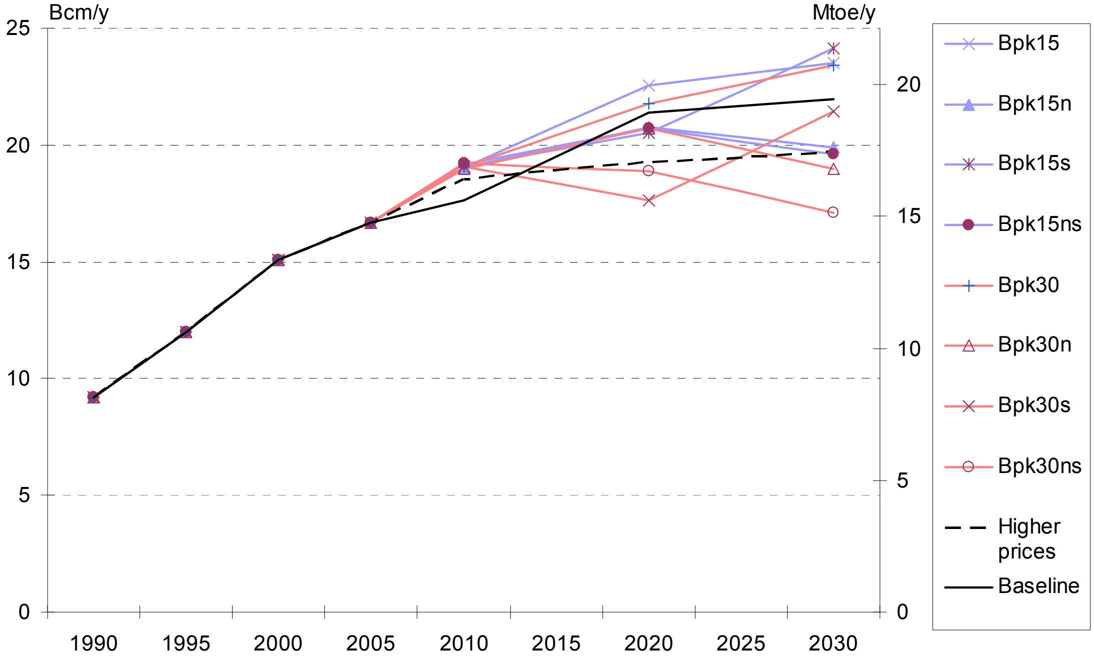
\+ gas use by the energy branch (own use by the gas sector including losses, and use by other energy branches of the energy transformation sector) ;

\+ non-energy use of gas ;

\- volumes of gas issued of gas works (as we consider here the natural gas demand).

Total gas demand fluctuates at the horizon 2030 between some 17 to 24 Bcm/y which is about -22 % and +10 % around the baseline gas demand (22 Bcm/y). With the higher gas and oil price scenario, the need for gas declines as a result of the less competitive prices for the electricity generation sector : by 2030 gas demand decreases by more than 10 % compared to the baseline (black line against stippled line in Figure 3).

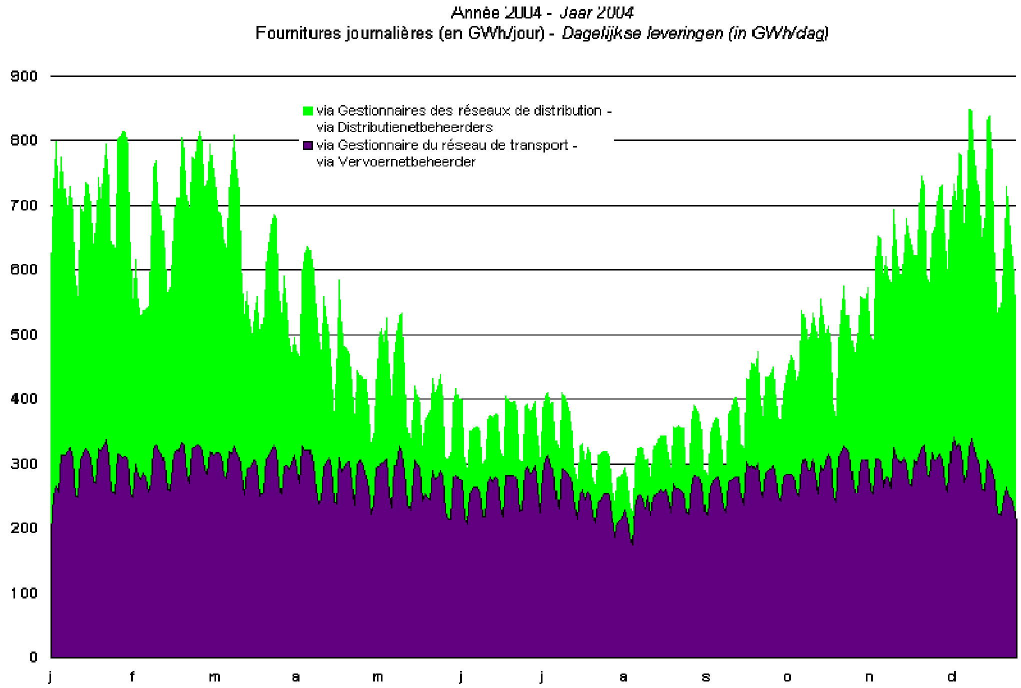
Figure 3 : Total gas demand



1.4. Average gas demand versus peak gas demand

It has to be kept in mind that the results given by the PRIMES model refer to yearly average consumptions. Figure 4 illustrates the daily deliveries to all consumers made through the Belgian transmission and distribution networks during the year 2004. Indeed gas consumption varies during the year mainly due to fluctuating consumption by the residential and tertiary sectors where gas is mainly used for heating and delivered through the distribution network. Direct deliveries to large industrial consumers and to electricity producers through the transmission network fluctuate mainly on a weekly basis reflecting the industrial use. It also seasonally slightly decreases from February to August and increases within the winter season, a seasonal fluctuation partially induced by the electricity generation sector.

Figure 4 : Daily gas deliveries to final consumers



Deliveries to	**GWh/year (cumul. on the year**	**GWh/day (average per day)**	**GWh/day Daily minimum in 2004**	**% against day average**	**GWh/day Daily maximum in 2004**	**% against day average**
Residential, tertiary & small industries	85484	234,2	52	22,2 %	542	231,4 %
Large industries & electricity producers	101960	279,3	174	62,3 %	337	120,7 %
Total deliveries *	187444	513,5	226	44,0 %	830	161,6 %

* Maximum and minimum total deliveries may differ from the sum of its two components as minimum and maximum consumption are reached on different days.

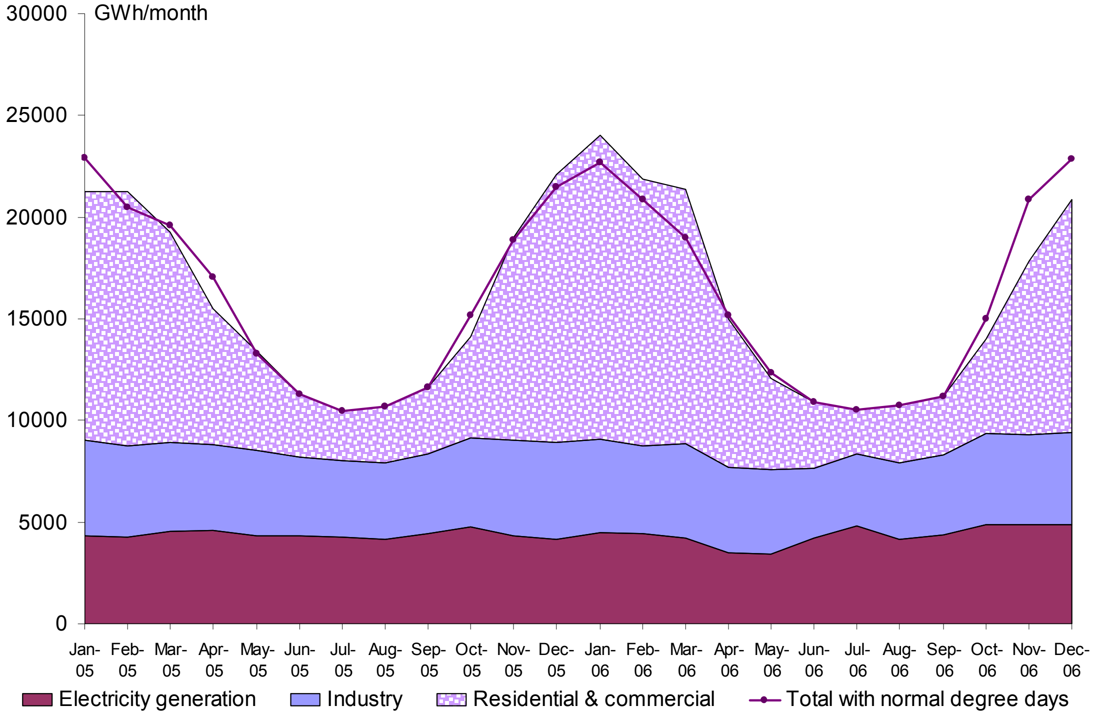
The range of variation is quite high on a daily basis and certainly for the deliveries through the distribution network to small consumers which are the most sensitive to temperature changes.

To extrapolate the incidence of this variability on gas demand two influences have to be "eradicated" :

- indeed daily fluctuations are partially managed through linepack management which refers to the volume of gas contained in the network at any given time and which can be "managed" by modulating compression in the network within certain tolerated limits. Monthly consumption data are not so volatile ;
- more generally the range of variation is also influenced by weather conditions which influence can be reduced by using a correction coefficient based on what is called the "degree days".

These two influences have been illustrated in the next figure based on monthly data and after correction for normal weather conditions on the gas consumption of the residential sector, tertiary sector and small industries and which are the most sensitive to weather conditions.

Figure 5 : Monthly gas deliveries to final consumers



Sources : Synergrid, ARGB and own calculations.

These corrections have been adapted to the monthly data's for the years 2001 to 2006. Minimum and maximum monthly consumption has been identified for each year and related to the average consumption calculated for each year. Gas consumption varies between 63,0 % and 143,4 % around the average gas consumption which when extrapolated to the Baseline scenario at the horizon 2030 gives a range from a minimum of 13,8 Bcm/y to a peak of 31,5 Bcm/y.

Notice that this range of variation may become greater as important climate changes become more concrete and influence gas consumption for heating purposes. On the other hand, gas consumption from the (large energy consuming) industries may reduce as the economy evolves to more services supplies, an evolution which simultaneously increases electricity requirements. The further incidence on gas consumption depends from the electricity production plants used and how far gas-fired plants are used for base load or for peak supply.

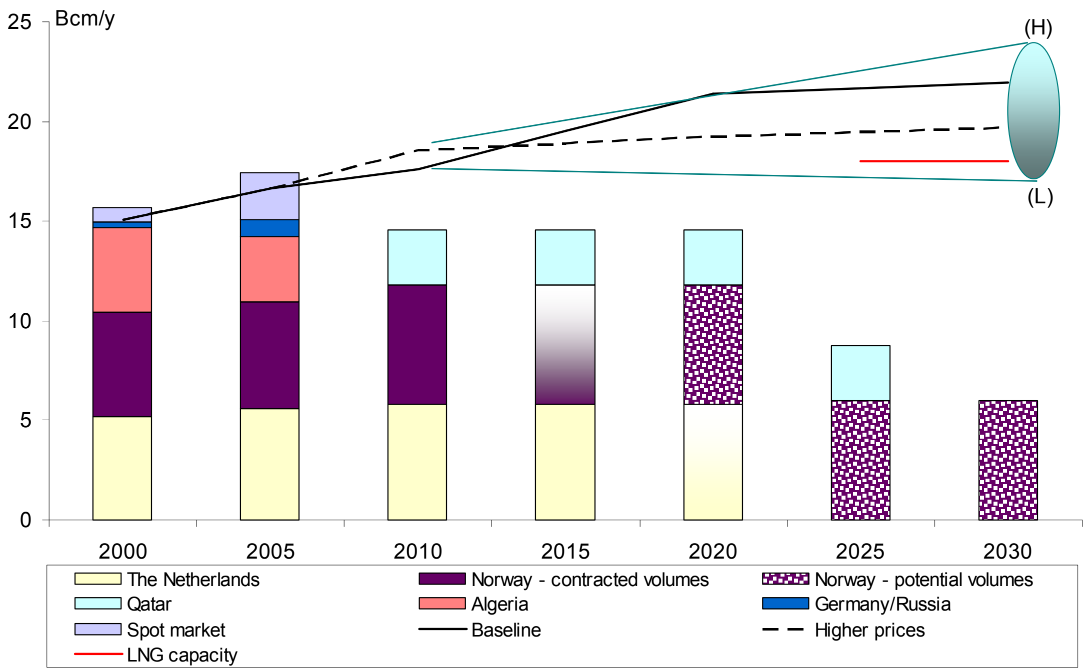
2. Potential gas supplies

As before, all this gas demand has to be imported. The Belgian gas market has in the past been supplied through long term "take or pay" contracts concluded by its historical gas operator Distrigas, which had contracted supplies from different sources, mainly the Netherlands, Norway and Algeria. Some supplies have also been provided through the spot market with LNG imports stemming from time to time from Abu Dhabi, Nigeria and recently from Qatar, and with gas from the United Kingdom delivered via the Interconnector. However the flow of imports from the United Kingdom will more and more reverse in the other direction, due to the changing status of this gas producer from net gas exporter to net gas importer. In recent years Russian gas has also been delivered through the German entry point.

In 2005, 20 operators hold an authorisation right to access the natural gas transmission network. However only 3 operators effectively supplied the Belgian market : Distrigas (85,4 %), GDF Négoce (10,4 %) and Wingas GmbH (4,2 %).[5]

Figure 6 represents the potential gas demand and how so far it is covered by contracted supplies. Global gas demand is given in the baseline scenario and the higher fuel prices scenario as well as the magnitude in 2030 of total gas demand generated by the different alternative scenarios is represented by the oval disk. On the supply side, the origins of past imports (2000 & 2005) are represented in stacked columns. The expected capacity of the Zeebrugge terminal is also given : its capacity has been risen from 4,5 Bcm/y to 9 Bcm/y and Fluxys has already announced the project to bring this capacity to 18 Bcm/y (Pétrostratégies n°994 - 12/2006).

Figure 6 : Potential gas balance and its supplies



Sources : SPF Economie - Evolution du marché de l'énergie en 2005 (origins of imports), SYNERGRID - Flux de gaz naturel en Belgique (total imports) & own estimates.

Total imports for 2000 and 2005 include volumes which are re-exported to Luxemburg. Spot markets include volumes from UK (in 2005 0,4 Bcm/y) and other hubs which origins cannot be clearly identified.

In 2005, about 59 % of the aggregated supply portfolio gas volume of the active suppliers on the Belgian market was still contracted through long term contracts with producers (> 5 years), 15 % mainly under contracts with producers expiring within 5 years, 2 % under contract of more than 1 year and the remaining 24 % were delivered under short term contracts (CREG - Annual report 2005).

5 These figures only refer to the transmission market and not the distribution market as the 3 operators partially sold these volumes also to other suppliers of the distribution market. In : CREG - Annual report 2005.

Future supplies rely on several assumptions, the main one being that Distrigas the historical supplier of the Belgian market, will still dedicate the volumes of the contracts subscribed to the Belgian market. However it should be kept in mind that within a liberalised market, there is no guarantee that all these volumes will effectively be delivered to the Belgian market, the relevant market for this operator (as for all operators) being enlarged to the European market. As commercial operator, Distrigas designs a portfolio of gas acquisitions which suits to its gas sales in Belgium and outside Belgium. The same remark has to be applied to other operators which will supply the Belgian market (nowadays it concerns Gaz de France Négoce and Wingas GwbH).

Potential gas supplies could still come from :

- the Netherlands : the long term contract concluded with the Netherlands still represents 6,89 Bcm/y of (L) gas (or 5,8 Bcm/y in (H) gas eq)[6] until 2016 when the contract with Gasunie ends. Distrigas has the possibility to extend its duration till 2020. Beyond, the probability of extending this contract for a longer period is thin, the Dutch authorities having expressed their concern to preserve their declining gas reserves ;
- Norway provides some 6 Bcm/y to the Belgian markets and has still sufficient gas reserves to continue to do it for the next two decades. Actually Norwegian gas deliveries have been contracted with Distrigas respectively until 2010, 2011 and 2018. However it is worth mentioning that with the United Kingdom becoming a net gas importer, Norwegian gas has there a new outlet market ;
- Algeria : the long term contracts being concluded with Algeria (4,5 Bcm/y) have reached an end in 2006 and have not been renewed. However Sonatrach has already expressed its interest in having access to the Zeebrugge terminal for the further deployment of its LNG exports (In : Pétrostratégies n°995 - 12/2006) ;
- a first contract has been concluded between Rasgas (Qatar) and Distrigas for import at the LNG Zeebrugge terminal of 2,75 Bcm/y for 20 years beyond 2007. Nevertheless, it is not guaranteed that this volume will end in the Belgian market.

Until 2015, all these contracts are more or less sufficient to satisfy the expected gas demand (including some spot transactions). Behind this time framework, more than 50 % of the demand as to be covered with new gas contracts. Indeed, behind these contracts concluded by the historical supplier, gas is and will also be provided by other gas suppliers as Wingas or Gaz de France. Consequently, it is even more complicated to make some guess of which volumes could reach the Belgian market.

More and more the supply portfolios of the commercial operators are managed on an integrated basis and it is more and more complicated (or even impossible) to link a specific supply contract to a specific delivery contract. At the most, the relevancy of such an approach at the Belgian level is questionable as with the liberalisation of the European gas markets, the relevant market for (formerly "national") operators has been extended to the European market.

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[6] CREG (2004) - Proposition de plan indicatif d'approvisionnement en gaz naturel, p. 62.

3. Several stakes behind an adequate gas supply

Besides the conclusion of supply arrangements, security of supply has also to do with transmission capacities (LNG reception and network infrastructure) and flexibility measures as available storage.

3.1. LNG import infrastructure

The capacity of import infrastructure has been extended at the Zeebrugge terminal. However concerning the security of supply of the Belgian market, it should be underlined that :

- increased capacity does not guarantee increased supply : the infrastructure is there but has to be supplied by gas which relies on the initiative of buyers and also sellers. Indeed, LNG gives flexibility and increases the opportunities for its owner to sell gas in many places. In a context where gas demand increases worldwide and many new LNG re-gasification terminals are projected and/or installed some competition could appear for this gas supply. In this respect having some LNG supplies benefiting from the frame of long term contracts is also interesting to secure some volumes ;
- the LNG Zeebrugge terminal is an entry point to a well functioning hub which can be used for arbitrages operations between several markets by operators who manage their gas acquisition portfolio in parallel with their sales which are <u>not necessarily</u> into the Belgian market ;
- in view of a further important increase of the import capacity of the LNG Zeebrugge terminal, an appropriate adjustment of security measures should be envisaged (e.g. technical incidents, terrorism, ..) ;
- the LNGRV (LNG regasification vessel technology) as developed by e.g. Exmar and which gives the opportunity to directly deliver natural gas from the vessel on (after regasification on board) increases also the reception capacity of the place where such a vessel unloads. Another stake is relative to the capacity of the local transmission system and to the capacity of the consumer market to absorb almost instantaneously the delivered gas volumes (138 000 m³ of LNG unloaded in 7 days would represent a send out of some 493 000 cm/h or about 20 % of the average Belgian gas demand in winter period). The presence of the Zeebrugge hub is therefore very important in order to manage in an optimal way these supplementary gas volumes. Another offshore LNGRV project in front of Rotterdam handles the question of almost instantaneously absorption in a different way as gas will be stored there in depleted offshore gas fields.

3.2. Storage requirements

Gas has the advantage that it can be stored which is quite interesting regarding the seasonality of demand in the mid term and also the variability of gas demand in the short run [7]. To have a storage infrastructure at disposal gives some flexibility to supply to adequately respond to demand variation, and this more and more in a context where gas supplies will be imported from more distant suppliers (the nearby British and Dutch productions are rather on a declining trend - moreover, their proximity gave the opportunity to benefit from very flexible conditions in delivered gas volumes, the Groningen gas field being used as "back-up" storage).

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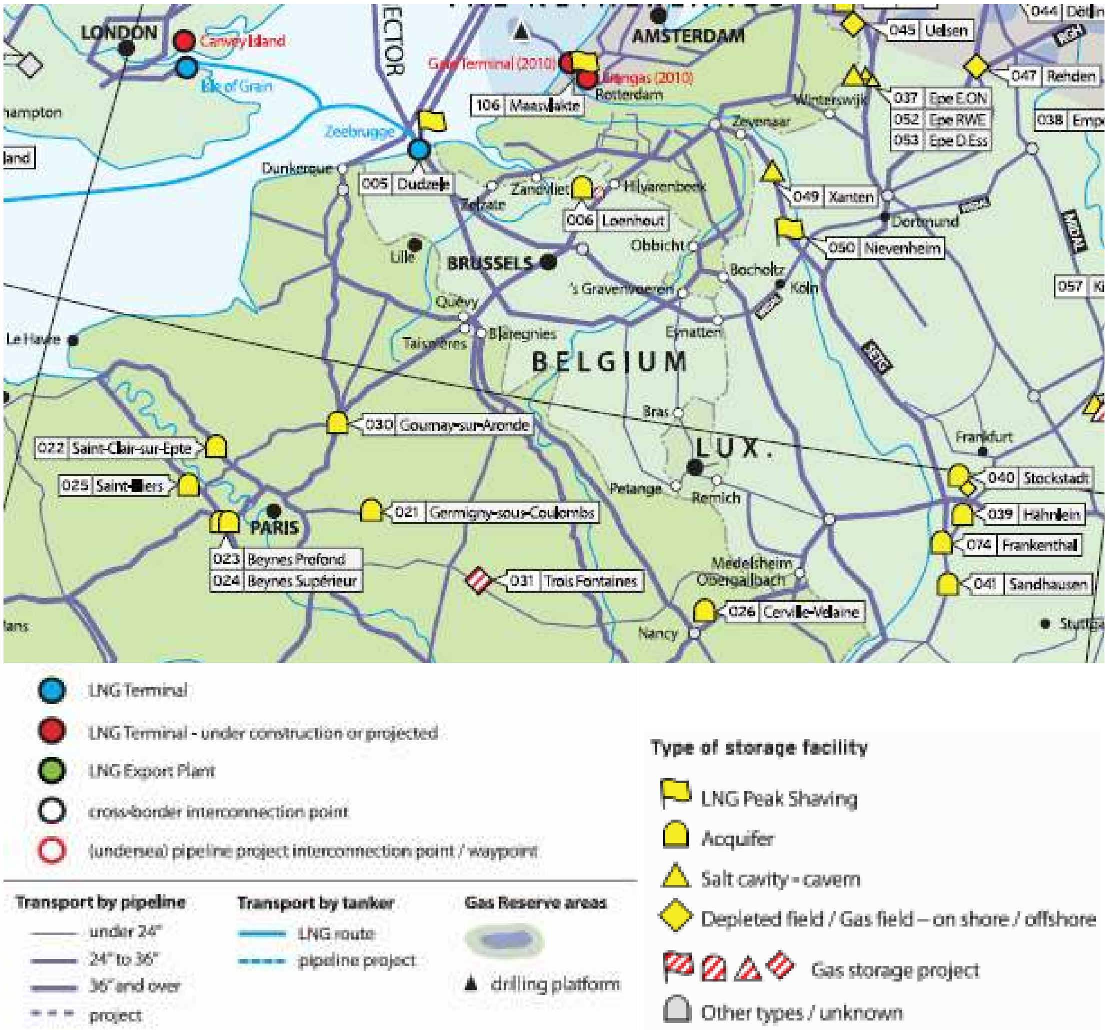
7 Similarly to an electricity network a gas network has also to be balanced on short delays to ensure a good working of the gas transmission within the network.

Relying on more LNG means also that you have to adapt a discontinued flow of gas supply to a continued flow of gas injection into the network/market where a LNG storage capacity plays the role of a buffer between incoming / sent gas. The capacity of the LNG storage is also important for the good working of the reception terminal (actually 261 000 m³ of LNG stored in three tanks at Zeebrugge). Subsequently to the decision to increase the capacity of the Zeebrugge terminal to 9 Bcm/y a fourth tank is currently being built increasing the (buffer) storage capacity with 57 %.

In the Belgian case, storage capacity is limited to LNG storage in Dudzele (55 Mcm of working gas for peak shaving) and to underground storage in the region of Loenhout (580 Mcm of working gas increased to 700 Mcm around 2009-10). Some prospects have been engaged by a joint initiative of Fluxys and Gazexport (100 % subsidiary of Gazprom) to develop another underground storage in the region of Poederlee which shares the same geological underground structure with Loenhout. The storage of an expected capacity of 300 Mcm should be operational in 2012. Nevertheless, when benchmarking storage capacities in Belgium with those in neighbouring countries, it appears that the Belgian storage possibilities are rather limited (limited available sites). On this matter, it could be useful to prospect in neighbouring countries (France, the Netherlands, Germany and even United Kingdom) for seasonal storage capacity [8] and to reinforce collaboration.

8 The storage question has been considered as an important stake for the supply of the United Kingdom (now becoming gas importer). However, the United Kingdom benefits from depleted offshore gas/oil fields which can be converted to "storage centres". This is not the case for Belgium.

Figure 7 : Localisation of storage sites in Belgium and neighbouring countries

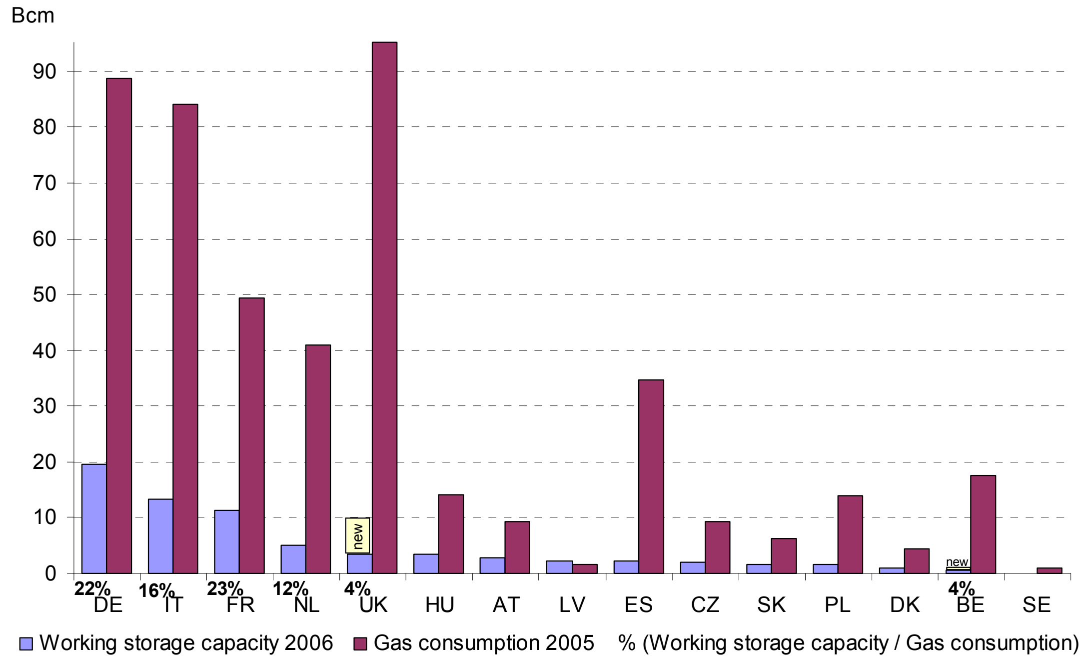


Source : GSE Storage map - 09/2006.

However, considering these neighbouring countries, their capacity to make some gas storage available is limited (see Figure 8) : Germany and France have the highest storage capacity compare to their consumption (22-23 %) but concerning available capacity the declared available capacity is actually about 0,3-0,4 % of technical capacity in France (0,35 Bcm) and Germany (0,73 Bcm) [9]. The Netherlands have a quite high ratio of storage compare to their consumption but it is also reserved for public service operation and for production, and the two major Dutch sites are located in the North, in the region of Groningen. The British market has a very thin capacity and has first to adapt to its new status of gas importer and to develop some gas storage for the balancing of its own market. New storage projects are announced to be put in service during the next five years increasing the British working gas capacity to 10 Bcm (Pétrostratégies n°989 - 11/2006).

9 ... without any respect to the localisation of these storages. In : ERGEG Interim 2006 Report on Monitoring the Implementation of the Guidelines for Good TPA Practice for Storage System Operators (GGPSSO) 10 May 2006.

Figure 8 : Gas storage capacity in Belgium and neighbouring countries against their respective gas consumption (working storage capacity excluding LNG)



Sources : European Regulators' Group for Electricity and Gas - ERGEG Interim 2006 Report on Monitoring the Implementation of the Guidelines for Good TPA Practice for Storage System Operators (GGPSSO) 10 May 2006, Eurogas for consumption data, Pétrostratégies n°989 (2006) and own calculations.

3.3. Gas supply and liberalised markets

Even if some sources state that the reduction of the share of long term contracts is a good thing for competition, flexibility and hence security of supply [10], this position has to be put into perspective and relying significantly on spot transactions is not always convenient. The availability of long term contracts has also certain advantages :

- it reduces uncertainty for the parties engaged in the contract but also for instance for the TSO which has to adapt/design the network infrastructure. Indeed, gas transmission needs a specific (and heavy) infrastructure that cannot be improvised : compliance with permission procedures and regulations is required and takes time ;
- it secures the volumes concerned by the contract (eventually with some flexibility in the volumes delivered during the year) ;
- upstream producers faced with huge investments are also seeking to subscribe long term contracts in order to reduce financial uncertainty.

The European Council has expressed its position on this matter in its Council directive 2004/67/EC of 26 April 2004 concerning measures to safeguard security of natural gas supply :
"Long-term contracts have played a very important role in securing gas supplies for Europe and will continue to do so. The current level of long term contracts is adequate on the Community level, and

[10] In : CREG - Plan indicatif d'approvisionnement en gaz naturel 2004 (English version of the indicative guidelines pp. 4-5).

it is believed that such contracts will continue to make a significant contribution to overall gas supplies as companies continue to include such contracts in their overall supply portfolio." and explicitly asks to report long term contracts.

By "long-term gas supply contract" the Council means a gas supply contract with a duration of more than 10 years. Member States have to establish a report pursuant to Article 5 of Directive 2003/55/EC, in which the extent of long-term gas supply contracts concluded by companies established and registered on their territory and their remaining duration have to be reported. Indeed gas supply contracts are explicitly taken into account in the non-exhaustive list of instruments to enhance the security of gas supply.

It is expected that long term contracts will continue to drive the gas supply at the horizon of this report.

3.4. The developing role of Russian gas

Some fear has been expressed about Russia as a trusty gas and energy supplier for the European market. Today it is still a marginal gas supplier to Belgium (4,9 % through Germany) whereas on average 24 % of European gas consumption is already imported from Russia. However the interest of the Russian counterpart for the Belgian "gas place" is noticeable :

- Gazprom has concluded in June 2006 through its subsidiary Gazexport a Memorandum of Agreement with Fluxys to develop joint explorations for underground natural gas storage possibilities in Poederlee, the objective being to establish a joint venture between Fluxys and Gazexport for the project ;
- in December 2004 Distrigas & Co and Gazexport have concluded a contract for the transit of Russian gas from Eynatten at the German border to Zeebrugge and its hub, for a volume of 2,5 Bcm/y until 2018 ;
- since 1995 Gazprom has a 10 % shareholding in the sub-sea Interconnector pipeline linking the Zeebrugge terminal to the British Bacton terminal and as a shipper holds long term capacity rights in both flow directions.

Even if these projects are probably first to be attributed to the position of Belgium as transit country on the route to the British gas market, it could also be considered as a first step to a further presence of the Russian supplier. On the contrary to other European countries, relying on more Russian gas would lead to a more diversified gas supply for the Belgian market as Russia is still a marginal supplier. In the context of some long term contracts coming to an end, there is a potential future for Russian gas that could be placed on the Belgian market. This is an option which should not be left behind regarding the gas volumes needed to balance the market, certainly when considering the CE2030 scenarios with the highest gas demand. The question then remains if the perceived "risk" of the Russian supplier is acceptable considering what happened with Russian gas supply begin 2006.

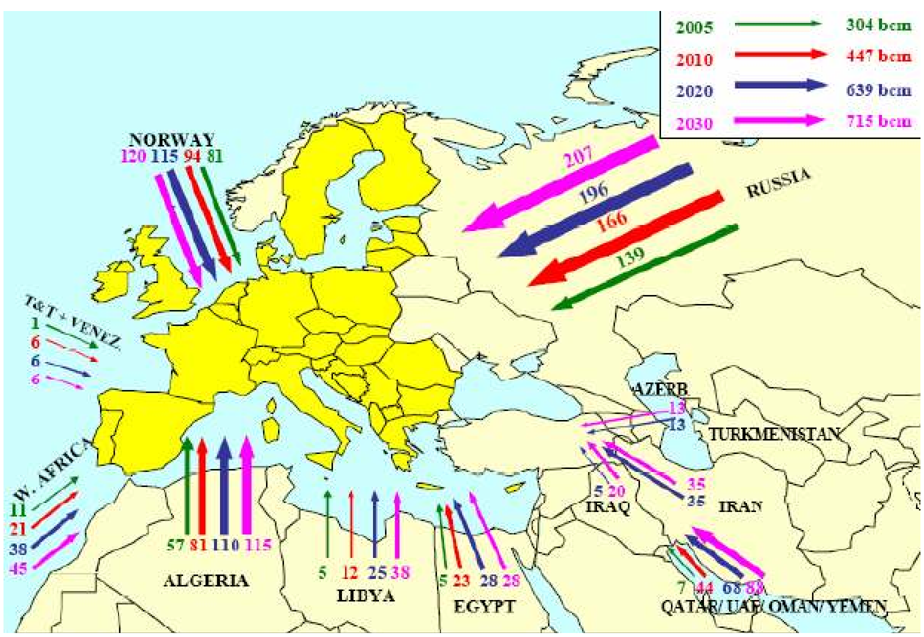
Several professional observers underline that one should not extrapolate what they consider to be a punctual incident in the frame of Russia's policy to obtain market-conform prices from certain former Soviet Union member states. It is also crucial for Russia to be able to deliver huge quantities of gas to the European Union. Presently 90 % of the Russian gas (126 Bcm/y) is destined for Europe (the Baltic states excluded). The long term energy plan of the Russian Ministry of Fuel and Energy (Mintopenergo) has foreseen that Europe will remain the most important export destination for Russian gas at the horizon 2020 (74 % of the total gas exports).

Russia will remain a key player for the European gas market as the greatest holder of world gas reserves, moreover located at the border of Europe. Figure 9 summarizes the results of the contribution of the "Observatoire Méditerranéen de l'Energie" (OME) to the ENCOURAGED project [11] which deals with gas, electricity and hydrogen corridors to Europe. The OME has made an assessment of the external long term gas supply potential to Europe. This assessment is based on several elements as the geological potential of producers/suppliers, country and company strategies and planning, political and geopolitical considerations as well as market developments, including the increasing competition that has to be taken into account against non European gas consumers for attracting future gas supplies.

The total gas supply potential available to Europe is expected to increase to 715 Bcm/y by 2030 (of which 227 Bcm/y of LNG) with Russia still being the main potential supplier (207 Bcm/y) followed by Norway (120 Bcm/y) and Algeria (115 Bcm/y). Simultaneously, new supply potentials emerge from the Middle East (Qatar), the Caspian countries, Nigeria, Egypt and Libya. All this will require new pipeline and LNG infrastructure, including re-gasification capacities.

To balance the still increasing European gas demand against a declining European production, OME expects European import requirements to increase from 304 Bcm/y in 2005 to 470 (low demand scenario) to 650 Bcm/y (high demand scenario) in 2030. According to the demand scenario, Russian gas deliveries would at the utmost represent a share of 32 to 44 % of imports in 2030 assuming that all the potential Russian gas exports are delivered to the European market.

Figure 9 : Future gas export potential to Europe



Source : Observatoire Méditerranéen de l'Energie, OME News Letter n°33 - February 2007 - p.4.

[11] EC financed project by the DG-Research.

In view of the high rise of import requirements it is obvious that particular and continuous attention should be given to timely investments in the upstream gas industry. This is particularly the case for Russia with three of their super-grant fields declining at a rate of 20 Bcm/y (IEA, 2006b). The fourth field, Zapolyarnoye, which come on stream in 2001, has already peaked at 100 Bcm/y. Enormous investments are required to bring new fields on stream (IEA estimate: 17 billion $/y).

In parallel, the possible establishment of an OPEC for gas around Russia and other important producers is clearly evoked from time to time. However to counterbalance the strong negotiation power of such potential grouping (and even against the Russian supplier on its own) the European Commission has strongly supported the idea that if it wants to achieve its energy and climate change objectives developed in its latest "Energy policy for Europe" (January 2007) it has to develop "effective energy relations with all its international partners, based on mutual trust, cooperation and interdependence. This means relations broadened in geographical scope, and deepened in nature on the basis of agreements with substantial energy provisions." [12] The only advice which can be given is that Belgium should subscribe to a strong global European positioning on this matter.

3.5. Belgium as transit country

As gas needs a specific infrastructure for its transportation it is also essential to have the sufficient capacity to transport the gas to the final country of destination. In this respect, Belgium is also an important country for the transit of gas mainly from the north to the south (from Norway to France, Spain, Italy and from the Netherlands to France) and increasingly from the east to the west, transporting Russian gas to the British gas market through the Interconnector which is now increasingly used in reverse flow. Indeed, with the United Kingdom becoming a net importer the capacity in reverse flow from Zeebrugge to Bacton has been increased to 23,5 Bcm/y even if this gas pipe was originally installed to transport gas from the UK to the Netherlands and Germany.

Presently long term contracted transit capacity on the Belgian territory is about 50 Bcm/y which almost represents three times the domestic gas consumption. This capacity has been subscribed by about 25 operators.

All investments done on the Belgian gas transmission infrastructure have also to take into account the specific needs and further developments of the European gas markets. An appropriate and timely investment policy on the Belgian gas infrastructure can favour transit of gas through Belgium instead of other transit channels, reinforcing also the security of supply issue.

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[12] Communication from the Commission to the European Council and the European Parliament : An energy policy for Europe. Brussels, 10.1.2007 - COM(2007) 1 final, p. 18-20.

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