Natural gas supply for the EU in the short to medium term

Clingendael International Energy Programme

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Abbreviations

BBL	Balgzand-Bacton pipeline (between the Netherlands and the UK)
BCG	Boston Consulting Group
bcm	billion cubic metres
bcm/a	billion cubic metres per annum
DB	Deutsche Bank
DTI	Department of Trade and Energy (UK)
EU-15	European Union – Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, UK
LNG	liquefied natural gas
NAM	*Nederlandse Aardolie Maatschappij*, Shell/Exxon joint venture for oil and gas exploration and production in the Netherlands
NPD	Norwegian Petroleum Directorate
NWCE	North West Continental Europe
OGP	International Association of Oil and Gas Producers
OME	Observatoire Méditerranéen de l'Énergie
tcm	trillion cubic metres
TPA	third party access (to a pipeline network owned and operated by another company)
UKOOA	UK Offshore Operators Association

Preface

The European gas market is undergoing substantial changes which are partly due to increasing imports from countries outside of the EU and partly due to the liberalisation process. The guiding theme for Clingendael Energy Papers on the European gas market is to examine whether the proposed changes to the market structure, i.e. the completion of the internal gas market, will generate an outcome which meets the fundamental energy policy requirements. These fundamentals of energy policy are: price, security of supply and protection of the environment. To realise all three fundamentals a certain degree of stress, or rivalry, and imperfections must be overcome. In a well-balanced policy environment, however, the market can produce these three elements of energy policy. Policy changes aimed at only one of these fundamentals can easily upset the balance. Liberalisation of the market essentially addresses pricing issues and if imperfections exist, the market cannot be expected to generate an optimal balance among the three energy policy fundamentals. Market imperfections can be of a technical-economic nature, inherent to the type of market or can be government induced. The energy market typically also involves the production of public goods such as security of supply. During the past decades, many governments secured these public goods in state or semi-state enterprises within, for example, the electricity generation and gas sectors. In the new market structure, public goods are secured by regulation, both at the European and national levels. The transition to a new market structure will be fraught with market imperfections, thought to be temporary, because the various member states have different points of departure in the national market structure and move at various speeds of liberalisation. These temporary imperfections could be considered an acceptable trade-off for evolving to a more efficient system of allocation, if the other two fundamentals of energy policy are not too much nor for too long in jeopardy. The end result should be a market structure that allows for a balanced energy policy and that can efficiently and effectively deal with the stresses between the three fundamentals.

This paper addresses an essential issue for European gas markets: the physical availability of supplies in the short and medium term. Declining domestic natural gas production makes it necessary to critically examine current assessments of potential external supply sources for the European gas market. After all, diverging views with respect to resource availability can lead to very different ideas about the setting in which the reorganisation of the market can take place.

These papers are the product of an in progress research project on the development of the European gas market at the Clingendael International Energy Programme (CIEP) and feature insights from extensive discussion with both industry and government officials. The responsibility for the content of this paper lies entirely with the Clingendael International Energy Programme.

Coby van der Linde
March 2004

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0. Introduction

European gas consumption will increase considerably over the next few decades. It is predicted that gas will become the fastest growing source of energy, increasing in share of total EU energy consumption from 21% in 2001 to 27% in 2020. Reasons for this are primarily related to the environmental attractiveness of gas compared with its alternatives coal and nuclear energy, as well as to the relatively low construction cost of gas-fired power plants. Such a share increase, in fact, is a continuation of the trend that began in the late 1970s.

A key question is whether there will be enough gas supply to satisfy this increased demand, and it is generally assumed that there will. After all, although domestic production may decrease, gas resources external to the EU are abundant, and can be expected to find their way to the EU market. This is the gist of most publications addressing the question of EU gas supply. However, despite the fact that indeed there are ample resources, we will argue that near the end of this decade the supply capacity for North Western Europe may not meet demand, whereas the Mediterranean countries will enjoy sufficient import capacity. This paper provides an inventory of the potential supply sources that are relevant in this decade for the EU-15, the current and potential transmission capacities and the critical factors for supply sources to meet increasing demand for gas[1]. As such, it provides information for further discussions such as the effects of liberalisation, cost and price levels, as well as longer-term views to be examined in subsequent papers in this series.

1. Public reports on potential supply estimates

There are a number of reports dedicated to providing an outlook for the gas supply potential for the EU:

- The International Association of Oil and Gas Producers (OGP 2003) presents an overview of proved, probable and possible reserves as published by relevant authorities, but places less emphasis on the scope and timeframe as to how and when these reserves can be developed and brought to market.
- A comprehensive summary of future gas supply potential is provided by a Observatoire Méditerranéen de l'Énergie (OME) report, published by the European Commission (OME 2001). The report concludes that the EU can look to the future of its gas supplies with great confidence and calculates an oversupply situation for 2010. The report also provides cost estimates for gas from various supply sources.
- Extensive data can also be found in the reports published by Global Insight (Global Insight 2003 – formerly DRI-WEFA), providing forecasted supply and demand developments by country and by sector, for both natural gas

[1] In this paper, volumes of natural gas are expressed in bcm (billion cubic meters), as the majority of references quote using this unit. It must be realised that the energy content of the various gas supply sources can vary slightly, leading to inaccuracies in supply and demand calculations. However, these should be well within error bands associated with other uncertainties and do not affect the conclusions of this paper. The largest effect is the overestimating of Dutch supply contributions by up to 10% due to the relatively low calorific value of Groningen gas. Other variations should be within a few percent.

and electricity, as well as itemised details of infrastructure, contractual and gas storage developments. These reports are updated on a regular basis.

- A recent publication 'Keeping the Lights On' (BCG 2003), discusses choices for European power generation and voices concerns regarding the huge investments needed in the gas import infrastructure.
- 'Playing on the short side' published by Deutsche Bank in partnership with Wood Mackenzie also touches on the European supply outlook (Cook & Griffin 2003).

This is not an exhaustive list of publications addressing EU supply potential, but it is indicative of research, perspectives and projections for this area.

Merely reviewing reserve figures is an insufficient means to properly assess supply potential. The classification of reserve categories is often inconsistent across countries, and numbers indicating 'potential' should be treated with caution. Further, it is essential to base supply outlook figures on planned activities (such as field production forecasts, development projects, infrastructure projects and exploration activity levels) and in context of historic trends and track records. The 'European Gas Supply and Demand Service' report (Global Insight 2003) distinguishes actual contracted supplies from assumed prolongations, which adds yet another dimension. For this analysis, however, focus will be upon physical production and transmission capacity (existing and planned).

2. EU-15 domestic supply

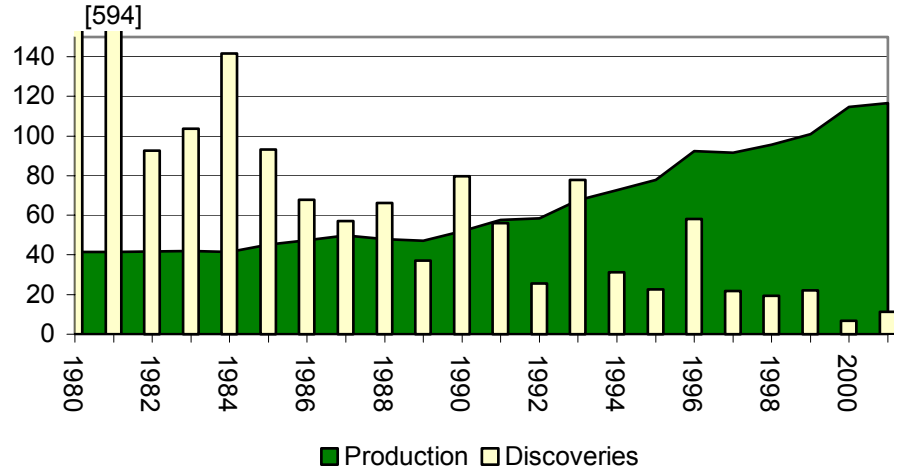
Natural gas only started to make inroads in European energy consumption following the discovery of major domestic resources. The introduction of gas, for example, in the Netherlands and the UK rapidly revolutionised their energy systems, and engendered a major spin-off to other Western European countries. However, this was solely driven by the availability of 'own' gas; otherwise these developments would have been much slower. What is the outlook for the EU domestic resources? And what are the implications? In the EU, there are two major gas producers: the United Kingdom and the Netherlands. Not part of the EU, but a major near-by supplier is Norway. Other producer countries include Germany, Denmark, Italy and to a lesser extent Austria and Ireland. This paper examines the expected future domestic supply by referring to forecasts provided by various institutes and agencies, and by considering the production levels in previous years and reserve development.

2.1 The United Kingdom

Oil and gas were discovered in the UK in the 1960s, and the UK has since become an important player in the oil and gas market. At present it is the largest gas producer within Europe and exports are transported to the continent through the Interconnector pipeline. The UK reserves are solely located offshore, in the various basins of the North Sea, and as from 2002 production also stems from the so-called Atlantic Margin, north of Scotland. The North Sea basins are mature areas, where few or no significant discoveries can be expected in the future. The Atlantic Margin is still under-explored and may still yield some positive surprises.

During the 1980s, sizeable gas discoveries were made, primarily in the southern and central North Sea. Production has steadily increased and is currently at its peak level of 115 bcm per annum (bcm/a). However, over the course of the past few years, the rate of addition to reserves through new discoveries has continuously declined and is at a level of 10 – 20 bcm of added reserves per annum (figure 1). The past and planned exploration activity levels as published by the Department of Trade and Industry (DTI) show a drop from around 150 exploration and appraisal wells (both targeting oil and gas) in the early 1990s to 20 – 30 wells for more recent years (DTI 2003a). This is a clear sign that the UK is entering the 'end game'. Also in the less explored areas, such as the Atlantic Margin, the anticipated level of exploration for new fields is modest (less than a handful of wells per year). The current proved remaining reserves are estimated at some 735 bcm. Although reserve additions through exploration successes can never be completely excluded, for this decade a sharp decline in production is expected.

Figure 1 – UK production and reserves added through discoveries



Source: IHS.

So what will be the actual level of decline? Wood Mackenzie estimates the base case production to range between 50 and 70 bcm/a for 2010, with a possible upside if major discoveries are made e.g. West of Shetlands. The OME report is more optimistic for the UK indigenous production outlook, but this perception might be based on aged data.

The UK Offshore Operators Association (UKOOA) report 'Competing in a global industry' (the 2002 industry survey) forecasts production for 2010 at approximately 60 bcm. It should be noted that in the preceding 2001 UKOOA survey the projected output for 2010 was still in excess of 70 bcm! The forecast recently published by the DTI (2003b) indicates a production level of 70-80 bcm for 2008. Given this and the most recent UKOOA projection, with demand rising to 110-120 bcm/a by 2010, the supply gap will be around 50-60 bcm/a.

The UK will become a net importer around 2005 and the production decline appears to be accelerating leading to a substantial supply gap in 2010.

2.1.1 Infrastructure

The UK is connected to continental Europe (Belgium) by the Interconnector pipeline, which has a capacity of 20 bcm per year (but of only 8.5 bcm/a in the opposite direction from Belgium to the UK, with an capacity upgrade to 16.5 bcm/a planned for 2006). Another export pipeline runs to Ireland with an export capacity of some 7 bcm/a. These are the only transmission lines that have been used by the UK to export gas. From Norway, the Vesterled pipeline (previously known as the Norwegian Frigg pipeline) runs from Frigg to St. Fergus and has a capacity of 13 bcm/a.

The Balgzand-Bacton interconnector (BBL) is an import pipeline project that will link the Netherlands and the UK. It could be operational by 2006, providing that all regulatory issues (e.g., such as exemption from third party access (TPA) provisions) are resolved in a timely manner. The BBL will have a minimum capacity of 8 bcm/a and will be used initially for importing Dutch gas, and no doubt later for Russian gas. In addition, plans exist to build a 1200 km pipeline from the Norwegian Ormen Lange field to the UK (Easington). This pipeline will have a capacity of 20 bcm/a and may be ready by 2007. Also planned is the Symphony line from Sleipner/Heimdal to Bacton.

LNG terminals are planned for the Isle of Grain (National Grid Transco) and at Milford Haven, Wales (Exxon/Mobil and Petroplus). In 2010, LNG receiving capacity in the UK may be between 10 and 30 bcm/a, depending on which projects have been realised by that time, and whether satisfactory arrangements with regards to TPA issues have been achieved. Consequently, LNG may fill a substantial part of the UK supply gap.

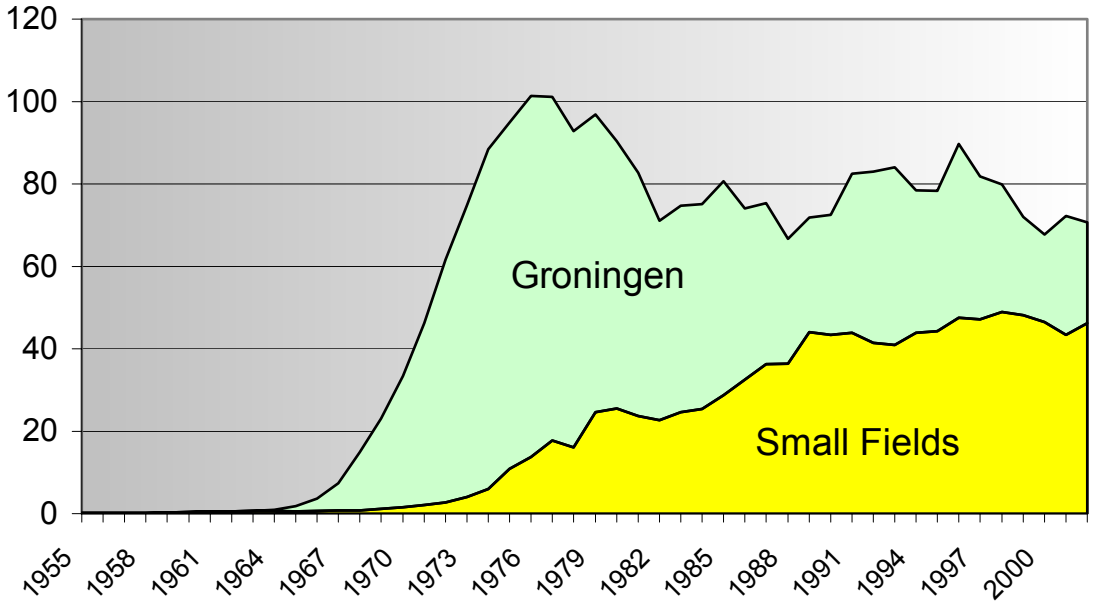
2.2 The Netherlands

The advance of natural gas in the Netherlands, and within Western Europe for that matter, began with the discovery of the Groningen field in 1959. This giant field, with original reserves at some 2700 bcm, has enabled the Netherlands and surrounding countries to base a considerable part of their energy supply on gas. Indeed, since the early 1970s, gas has provided for half of Dutch energy requirements. Groningen reserves are currently down to 1100 bcm. Compressors are being installed to ensure sufficient production capacity for the remainder of the field's life.

Following the 1973 oil crisis, Western Europe became aware of its vulnerability with regards to hydrocarbon supplies. This realisation, coupled with a re-consideration of nuclear policies, increased recognition of the tremendous value of the Groningen asset. To preserve the field with its unique swing capacity, the so-called 'small fields policy' was introduced. This policy encourages operators to explore and exploit smaller fields, which are taken into production at the cost of the Groningen production. This policy has been very successful. To-date, some 1500 bcm of additional gas resources have been discovered both onshore and on the Dutch part of the continental shelf. For the last few years the majority of Dutch production has been supplied from the small fields. This is illustrated in figure 2, showing production subdivided into 'Groningen' and 'small fields' contributions. During the last two decades, exploration has steadily added reserves at a level varying between 30 and 50 bcm/a. This approach has considerably prolonged the life of the Groningen field and will enable the Netherlands to continue to play a role in the gas production over in the next two decades. In other words, if not for the small fields production, at historic production levels the Groningen

field would now be depleted. In figure 2 the relative importance of the small fields is clearly illustrated.

Figure 2 – Groningen and small fields production history (bcm/a)



Source: TNO-NITG, EZ.

The level of Dutch production over the next years will likely continue to be governed by the above policy considerations, also in a liberalised world. The Dutch government has committed itself to the small fields policy, however the details of the necessarily revised arrangements to this effect are not yet available. This means that for a number of years to come Dutch gas production will likely continue to be capped at similar levels as for the previous decade (70-80 bcm).

Nevertheless there are some uncertainties regarding the mix of 'small fields' and 'Groningen' production that may at some point affect the total production level. It should be noted that the Dutch small fields are more or less in a similar situation as the existing fields in the UK. The production of the combined small fields has currently reached a maximum and will very likely decline during the remainder of this decade and beyond. The severity of this decline will depend on the small fields reserve replenishment which can still be realised during the remainder of the decade (see also NITG-TNO 2002). In this respect, some recent policy developments have been counterproductive. Taxation issues and environmental restrictions play significant roles and feed uncertainties around future small fields production levels. Groningen, however, still has substantial reserves and can make up the difference for a while to come, but whether this happens is also a matter of policy.

The OME report (2001) assumes that current Dutch production levels will continue for two decades while other reports even anticipate an increase in production. These projections are overly optimistic, but an assessment of the medium term outlook for the small fields production will require close monitoring of field development plans and reserve additions over the next few years.

Although it can be assumed that in 2010 the Dutch small fields production level will be in decline, the total production and export level is likely to be similar to recent years (70 bcm), depending on the Groningen depletion policy.

2.3 Other EU producers

Three other producers of some significance within the EU are Germany, Italy and Denmark. The following table characterises their contribution to the EU indigenous production.

Table 1 – Natural gas in Germany, Italy and Denmark (bcm)

Country	Remaining reserves at end of 2002[1]	Average annual production 1991-2000[2]	Production in 2000[2]	Expected production in 2010[3]
Germany	320	21	22	15
Italy	230	19	16	13
Denmark	80	6	8	7

Sources: [1] BP 2003; [2] IEA 2002a; [3] Global Insight, 2003.

Germany has a long production history. Exploration and appraisal activity is currently limited to a few wells per year. A gradual decline in production is to be expected in the next decades.

Italy's production comes from the Po valley and the Adriatic Sea. There may still be some limited offshore potential for additional supplies, but this will likely not offset the decline in production.

Denmark's production only started in the mid 1980s, but given its limited resources it will never reach high levels.

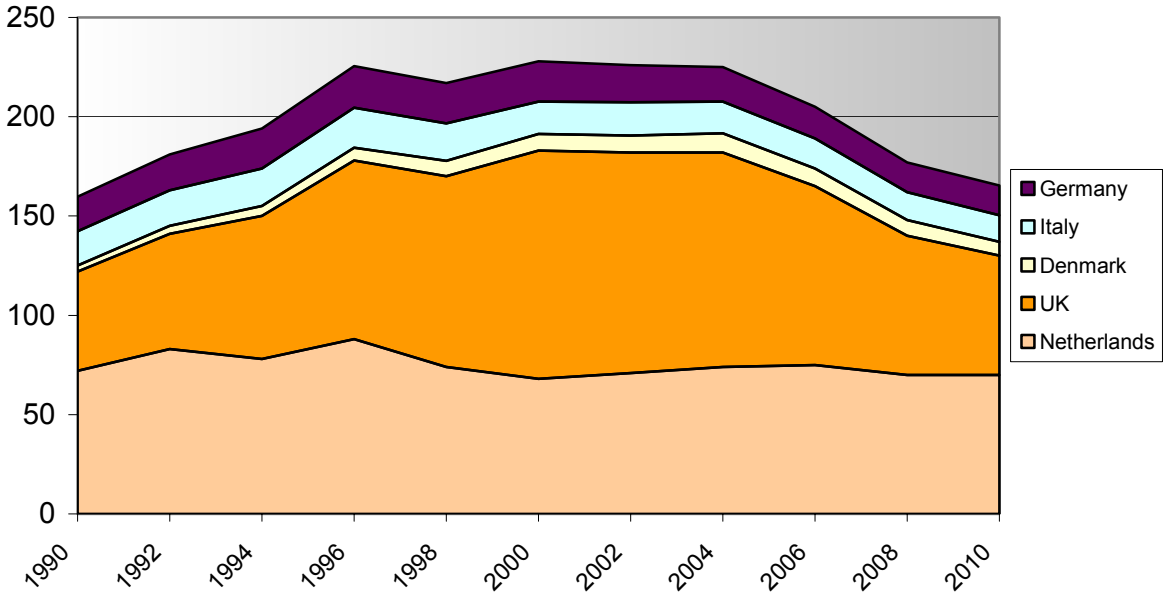
Other EU-15 producers of some significance include Germany, Italy and Denmark. Production in these countries will gradually decline in this decade.

2.4 EU indigenous aggregate production

The total EU-15 indigenous production (from the UK, Netherlands, Germany, Italy and Denmark) in 2010 will be in the range of 160 to 190 bcm per annum, with the upside only being realised in the event of significant exploration successes during the next few years. In figure 3, the actual and predicted indigenous production levels are shown as a 'best estimate', using reconciled data from Global Insight, IHS, UKOOA and NAM.

The publications reviewed generally quote higher forecasts. In 'Keeping the Lights On' (BCG 2003) a level of 200 bcm of indigenous production is still assumed. In the OME report (OME 2001), the EU-15 production level is estimated at around 225 bcm for 2010, and hardly declining thereafter. The EU production level in 2010 as provided by Global Insight also indicates a level of 200 bcm. It would appear that the published forecasts for the UK and the Netherlands are often too high, and are most likely based on aged data. This is not insignificant and it should be noted that a supply gap of 20-30 bcm requires a major infrastructure project to fill it. For example, the much-discussed North Transgas pipeline through the Baltic Sea will *only* add 30 bcm per annum.

Figure 3 – Indigenous EU-15 production (bcm)



In the past, common wisdom has held that industry production forecasts are always conservative and that in reality the remaining reserves to annual production ratios are under-estimated. The question is whether this assumption is currently still valid. In the US there are signs that domestic gas production is falling more rapidly than anticipated. In Europe, a similar trend may well emerge. There is no doubt that for markets with conditions of increasing demand and declining production it is much more important to get the forecasts right than for developing markets.

The EU-15 indigenous production levels in 2010 will most likely be in the range of 160 to 190 bcm which is considerably less than assumed in most gas supply outlook publications.

3. Norway

Norway will clearly be a stable supplier to Europe. It has a vast, though high cost, resource base. Development of this resource base is primarily constrained by the sales and transmission outlook (to Europe). Resources consist of 1200 bcm connected reserves, 1400 bcm reserves for which development is planned and another 1200 bcm of discoveries for which development projects still have to be approved. This means that production during the next two decades can be drawn from existing fields.

The production initially maintained a plateau of 25 bcm/a for a long time, but has been steadily increasing since 1996, up to 62 bcm/a in 2002. The largest field is Troll, discovered in 1979, which started producing in 1996 and will provide a major contribution to the production increase that will take place during the next years from 70 bcm in 2005 up to a level in excess of 100 bcm/a by 2010. Norway's exploration potential is illustrated by the 1997 discovery of Ormen Lange (400 bcm), now the second largest field in the country. Whilst the exploration in the North Sea is moving into the 'near field – lower volume' category, the Norwegian Sea and the Barents Sea probably still have exploration potential, although exploration results during the past few

years were somewhat disappointing. Also, environmental issues may further delay exploration in the Barents Sea. An environmental impact assessment for exploration is ongoing. The only project that is in an execution phase in this area is the construction of an LNG plant to export gas from the Snohvit field.

OME (2001) is still predicting a modest estimated 100 bcm production and export level by then. The Norwegian Petroleum Directorate (June 2003) foresees a production level of 110 bcm/a in 2010, based on operator's production forecasts. Being the most recent, for this paper it will be assumed to be the most likely estimate.

3.1.1 Pipelines

The total export capacity to continental Europe is 79 bcm per annum; in addition a line to the UK (St. Fergus) with 13 bcm/a capacity is in place. Export lines to Scandinavian countries are planned. Planning for an export line to Poland has been cancelled due to the sluggish growth of Polish gas demand. In particular, however, increased export capacity to Britain must be established in order to accommodate the looming UK supply gap. In part, this could be accommodated by so-called wetgas connections (for partly treated gas) between the Norwegian and British upstream pipeline networks. A major new development is the planned pipeline from Ormen Lange to Easington which will add 20 bcm of export capacity.

Much is expected of Norway to fill the looming supply gaps in Europe. To reach a supply level of 110 bcm/a in 2010, exports must double in less than eight year's time.

4. Algeria

To the south, Algeria is a major natural gas producer and exporter to the EU. Commercial production began in 1961, some five years following the start of the country's oil exports. Algeria's natural gas production currently exceeds its oil production in barrels of oil equivalent.

The largest field is Hassi R'Mel, which initially held proven reserves of about 2400 bcm. Other fields taken in production during the 1980s include Alrar and Rhoude Nouss. Estimates of total remaining reserves range from 3900 bcm to 4500 bcm. Other fields will be taken into production during 2003-05, and will be operated by western oil companies.

Exploration activity during the past decade appears to have been modest, even though Algeria has been open to foreign investors for more than a decade. Indeed, the country is considered to be under-explored. From 1991-2000, on average, 19 exploration wells were drilled annually but most of these were targeting oil. Total added natural gas reserves amounted to 279 bcm, which have hence not increased reserves considerably and have replaced production by just a bit more than a third. However, with the availability of significant existing undeveloped fields, the need to intensify the exploration effort is low.

Annual production has steadily increased during 1991-2000 from 66 bcm to around 80 bcm. With new fields coming on-stream in the next few years, total production will increase to 85 bcm per annum. Given Algeria's reserve base, it may be expected that this or a higher production level can be maintained in the medium to long term. Planned export capacity will most likely be sufficient to accommodate even higher exports (see below).

4.1.1 Pipelines and LNG

Algeria's pipeline exports are run through two major lines. The Enrico Mattei (formerly Transmed) pipeline (1067 km) runs from Hassi R'Mel via Tunisia and Sicily to mainland Italy. It has an annual capacity of some 24 bcm, which is fully utilised. Expansion of the line to 27 bcm is scheduled to be ready by late 2004. The second export line, 'Pedro Duran Farell' (formerly MEG), runs through Morocco to Cordoba and connects to the Spanish and Portuguese transmission networks. It has a capacity of 8.5 bcm per year, which is set to increase in two steps to 13 bcm also by late 2004.

With the start-up of the Arzew GL4Z plant in 1964, Algeria became world's first LNG producer. The LNG liquefaction capacity is currently some 30 bcm per annum. These LNG exports go to France, Belgium, Spain, and Turkey.

New export capacity[2]

A new pipeline on the drawing board is Medgaz, which is in an advanced planning stage. It will connect the Hassi R'Mel area directly with Spain. Operation will begin in 2006 and will have an initial capacity of 7 bcm/a, which is planned to be increased gradually to 16 bcm/a (EIA 2003). Another pipeline may be laid to Italy via Sicily, extending up to southern France. Its capacity would be 8 – 10 bcm.

In addition, Algeria plans to further increase its LNG export capacity from the current 30 bcm/a to 36 bcm/a. Algeria's total annual production is currently around 80 bcm per annum, of which around 20 bcm is domestically consumed, around 30 bcm is exported by pipeline and a little less than 30 bcm as LNG[3].

Supplies from Algeria to the EU could hence increase from the current 50 - 55 bcm to 75 – 80 bcm by the end of this decade if a reasonable share of the projects is executed as proposed. However, some delays in the execution of the projects might appear.

Algeria can remain a stable and low cost supply source for the Mediterranean with an export level at some 75 – 80 bcm/a in 2010 if a reasonable share of the projects planned is executed, which is likely.

5. Russia

Russia has vast gas resources. Giant fields in Western Siberia were discovered in the 1960s. Russia's production peaked at 643 bcm in 1991, declined to 571 bcm in 1997, and recovered to 590 bcm in 1999. Some 80-85% of the gas production comes from the Nadym-pur-Taz fields, primarily Yamburg, Urengoy and Medvezh'ye. These fields have been in production since 1986, 1978 and 1974 respectively and have now been in decline for several years. There are some uncertainties concerning the projected further rate of decline, but it is certain that a great deal of new production capacity must be brought on-stream during the next two decades to maintain or increase current production levels. The following options to this effect are being pursued:

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[2] At the time of writing (January 2004), a major accident took place in the Skikda LNG facility, destroying three of the six liquefaction trains with a capacity of around 3 – 4 bcm/a. How this will affect Algeria's LNG export position in the medium run is still unclear, depending on whether and how fast the installations will be rebuilt and how that will influence future projects.

[3] Domestic consumption includes some losses and flaring.

a) Other fields in the same Yamal-Nenets region. For example, in 2001 the Zapolyarnoye field (3.4 tcm reserves, discovered in 1965) was taken into production and will have a production plateau of 100 – 150 bcm per year. However, this is the last large field that is relatively easy to develop. Other smaller fields in the vicinity of Yamburg (150 – 300 km outstep) are planned to be developed during 2007-10, yielding a total production increase of some 120 – 130 bcm per year.

b) The Shtokmanskoye field in the Barents Sea, about 550 km offshore from Murmansk, situated in water depths of 300 – 340 meters and discovered in 1988. Gazprom and Rosneft have set up a joint venture to develop the field, which will require huge capital investments (some 15 billion USD). Development is planned towards a production start in 2010. However, this is likely a very optimistic estimate. Reserves in this field are 1.8 tcm and peak production will be around 250 million cubic metres per day, some 90 bcm per year.

c) Super giant fields have been discovered on the Yamal Peninsula, but these are at least 1.5 times as expensive to develop as Shtokmanskoye. These fields are located in environmentally fragile areas which poses additional challenges. It is highly unlikely that the Yamal fields will be developed before 2020.

d) It is expected that gas producers other than Gazprom can contribute by developing smaller fields which are of no interest to Gazprom. Obstacles for this process are the low domestic gas prices and issues regarding access to (Gazprom) pipeline systems.

e) A serious option to counter the imminent Gazprom production decline is the purchase of gas from Turkmenistan and Kazakhstan, which may in fact provide Russia with cheaper gas than by developing, for example, the high cost Yamal fields. In this way Russia would become a conduit for exports from the Stans to Europe.

The decline of the 'big three' is expected by Gazprom to fall from nearly 400 bcm per annum in 1999 to some 110 – 120 bcm by 2015 (IEA 2002c), but this may be overly pessimistic. Such a decline might possibly be (and only just) compensated by the currently envisaged developments this decade in the Nadim-pur-Taz area (220 – 270 bcm). At best, production from this region will remain stable during the next two decades. Any additional production must come from new large developments, such as Shtokmanskoye, possibly the small fields and imports from the Stans.

5.1.1 Pipelines

The main trunk lines that are used for export of Russian gas to Western Europe run through the Ukraine. The capacity of this transmission system is 135 bcm per year, of which 80 bcm is destined for the EU-15. Due to problems with the Ukrainian pipelines and supplies during the 1990s (illegal siphoning and money issues), Gazprom has been considering establishing additional routes to bypass the Ukraine. A settlement on the issue was reached in 2001. The only gas pipeline currently not traversing the Ukraine is the Yamal-Europe line, commissioned in 1996. This pipeline actually does not start in Yamal as was originally planned, but connects the Western Siberian fields via the Northern Lights route to Belarus, then through Poland to Germany. The pipeline is expected to transport 33 bcm per year from 2003. A second line

(Yamal II) is planned, but is currently on hold. It would increase throughput from 33 bcm to 59 bcm per year

Another pipeline still on the drawing board is the North TransGas Pipeline, involving an investment of some three billion USD. It would be well located to transport gas from the Barents Sea (Shtokmanskoye) to the European market, running from the Barents Sea to the area north of St. Petersburg, and then through the Baltic Sea to Germany, with possibly a connection to Sweden. The section through the Baltic Sea would have a capacity of 30 bcm. The section from the Barents Sea to St. Petersburg would have a higher capacity, as part of the Shtokmanskoye gas would also be destined for the Russian domestic market.

It may well be that only one of these two northern pipelines (Yamal II or North TransGas) will be realised, primarily due to Gazprom's capital constraints, although both projects are being discussed at political levels. The total transmission capacity to Europe is thus likely to be close to 200 bcm per annum sometime during the next decade. Indeed Russian export projections assume that supplies to Europe can increase from 130 bcm per year to 200 bcm per year in 2020 (CEC 2004: 50)[4]. This would require that:

- developments in the Nadim-pur-Taz area, as well as Shtokmanskoye, take place as planned;
- the production decline of the 'big three' is not as dramatic as assumed by Gazprom;
- as a minimum, either the North TransGas or the Yamal II pipeline is constructed.

Russian supply potential for the next two decades remains difficult to assess because of the many different factors influencing its gas sector. These are beyond the scope of this paper and warrant a separate detailed discussion. For the purposes of this paper, it suffices to provide an indication of the main issues that could affect the Russian supply potential:

1) It is uncertain whether Russia will be able to attract sufficient capital to finance the huge investments required to add production and transmission capacity. The 1998 crisis is indicative of this, with foreign banks subsequently shying away from investment in the country for a few years. By way of a current example, Gazprom is postponing investments in the development of the Shtokmanskoye field due to capital constraints.

2) Far East gas markets are also developing, in particular China. These markets will be calling upon Russian supplies. Although the gas will be provided from other fields in East Siberia, the associated development projects will be competing for capital with developments in the West.

3) National energy policies and the structure of the domestic market, with regulated (low) prices and the problem of non-payments also have an impact on the export potential. At some point these problems will be resolved and the Russian economy will likely develop into a more open market economy. If domestic gas prices indeed become more realistic, Russian producers may prefer to sell locally rather than to export. On the other hand, Russia will still need hard currency and in this vein, a more healthy economy

[4] The export figure is derived from reported projections for Russian exports of 275 – 280 bcm, accounting for other exports to e.g. Belarus and Ukraine.

will attract more capital to accelerate investments in undeveloped fields and exploration.

4) Another policy issue impacting the availability of natural gas for export is the desired fuel mix for power generation in Russia. The current share of gas in the electricity fuel mix is 42%. Russian strategy experts are concerned about the energy security risks that an over-reliance on gas could imply. In response, there could be a drive to increase the share of coal and nuclear energy in the power sector, which would make more gas available for export. There are a number of factors that could prohibit the implementation of such policies, one of which is the environmental and safety angle, precisely the reason why Europe is opting for more gas in the power sector (IEA 2002c: chapter 3).

Russia's export potential hence is not limited by resources but by availability of capital and impacted by a range of interrelated and complex policy issues. Gazprom projects a 50 bcm increase in exports to OECD Europe from 2000 to 2005 and a 20 bcm increase from 2005 to 2020 (IEA 2002c: 140). Wood Mackenzie forecasts an increase in supply potential from Russia to Europe of no less than 200 bcm from 2005 to 2015 (Cook & Griffin 2003: 14). The latter projection, however, is not supported by an adequate account of planned extensions to transmission capacity that would be required, and is in severe conflict with the IEA projection.

Although Russia has vast natural gas resources, the outlook for medium term supply capacity to Europe is fraught with uncertainties. These relate to domestic consumption developments, declining production of existing fields, capital availability and investment climate, national energy policies and (geo)political developments.

6. LNG sources

Although the vast majority of gas supplies reach and will continue to reach Europe by pipeline, LNG has acquired a niche position of significance and it is certain that its role will increase in importance. A separate paper in this series has been published that analyses the potential of LNG for Europe (CIEP 2003). The following table gives an overview of the LNG imports in 2002.

Table 2 – LNG imports for 2002 (bcm)

	Algeria	Libya	Nigeria	Qatar	Trinidad	Oman	U.A.E.	Others
Belgium	3.2						0.1	
France	10.2		0.8			0.54		
Greece	0.5							
Italy	2.2		3.5					
Spain	5.95	0.63	1.61	2.2	0.46	0.76	0.5	0.15

Source: BP 2003.

The total amount of LNG supplies to the EU in 2002 was about 39 bcm, i.e. 10% of total EU consumption. During this decade the share will increase. Liquefaction capacity of LNG exporters will be expanded, and there will be new entrants into the LNG market. Newcomers relevant to the European LNG market for this decade will be Egypt and Norway. The total combined liquefaction capacity of the countries exporting to Europe will more than

double between 2000 and 2010. However, these exporters also serve American and Asian markets. If we assume that the European share of the supplies from the LNG exporters will more or less remain the same, then the liquefaction capacity increase would potentially make available additional supplies in excess of 40 bcm per year, i.e. a substantial increase compared to the actual supplies in 2002.

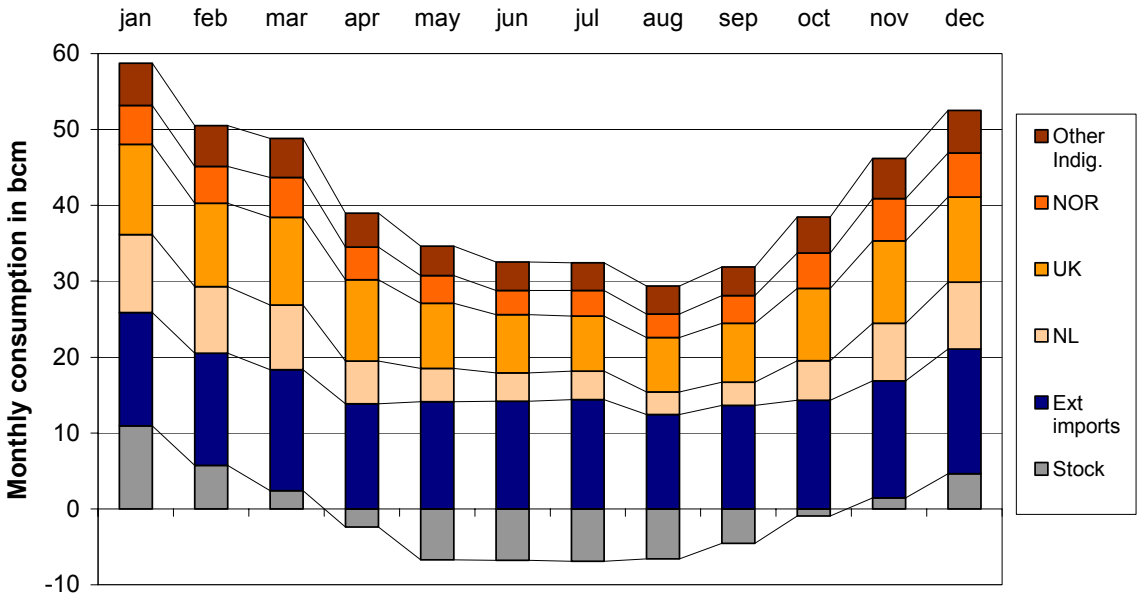
However, receiving LNG terminals must be expanded, and indeed additional capacity is being planned or built in Italy, Greece, Spain and France. LNG receiving capacity is also proposed for the UK. Total additional receiving capacity by 2010 would be in excess of 40 bcm, which is in line with the increased export potential to the EU of the LNG suppliers. As a consequence, LNG imports by the EU can more double from 2002 to 2010.

LNG will play an increasing role in the supply of gas to the EU, in particular for the Mediterranean region.

7. Another dimension: swing capacity

A particular feature of the gas market is the need for available swing capacity in order to meet both daily and seasonal variations in demand which are caused by the patterns in the use of gas for heating and electricity generation (as opposed to industrial use). If future electricity generation becomes more gas-based, the need for swing capacity could further increase.

Figure 4 – Gas consumption in IEA Europe in 2000



Source: IEA

This aspect is not referred to by most publications addressing supply potential, but has been extensively treated in the report 'Flexibility in natural gas supply and demand' (IEA 2002a).

In figure 4, gas production in 2000 for IEA Europe is shown (EU-15 plus the Czech Republic, Hungary, Norway, Switzerland, and Turkey). Note that the total consumption for the summer months equals the indigenous production plus imports less the stock additions. The highest consumption was in

January (58.6 bcm), the lowest in August (23.2 bcm). This large seasonal variation in the use of gas is in part accommodated by the (summer-) injection in and (winter-) production from storage facilities (depleted reservoirs, aquifers, salt caverns etc.). For IEA Europe, in excess of 90 such facilities are available. In 2000, the maximum production from these facilities was 11 bcm (January). The rest of the additional capacity needed to satisfy January consumption derives from indigenous resources, as the imports from Russia and Algeria are provided at more or less a constant level throughout the year. The following table 3 shows the swing in 2000 provided by the various production and import sources (supply in January divided by the supply in August).

Table 3 – Swing sources

Source	Ratio January/August Output
Imports	1.3
UK	1.7
Norway	1.6
Netherlands	3.5
Other indigenous	1.5

Figures based on IEA.

From this overview it is clear that indigenous production can have a significant role in accommodating seasonal swing. This is also illustrated by the situation that for countries with major indigenous resources (the UK and the Netherlands), relatively little storage capacity can be found. From the data it is clear that Norway has a considerable level of swing in its deliveries, as is also concluded in the report 'Flexibility in natural gas supply and demand' (IEA 2002a: 62). This may be somewhat surprising given the high cost levels of Norwegian development and export, but the Troll field provides about half of the Norwegian production and offers high flexibility. The question is whether this will continue to be the case. Norway will be stepping up its exports substantially and will need much more of the pipeline capacity that is currently available (the current combined pipeline capacity to continental Europe is 79 bcm compared with the export level of 54 bcm).

High cost imports, especially from Russia, will continue to be delivered at high load factors. In 2000, the swing provided by the combined 94 storage facilities in the IEA with a total working volume of 58.8 bcm (IEA 2002a: 66) was at roughly the same level as the swing delivered by the indigenous production flexibility. Assuming that by 2010 the swing from UK and Norwegian production will be minimal, the seasonal flexibility from indigenous production will primarily rely on the Netherlands alone with its 42% share in the 'indigenous swing' in 2000. UK and Norwegian production flexibility provided for about 25% of the total IEA swing in 2000, which in the future must be delivered by different means. Additionally, in 2010 the overall consumption level will also be higher in absolute terms. Estimating the amount of additional storage needed as a result of these developments is not straightforward, as there may be other means to cope with seasonal demand variations (e.g. interruptible contracts). Nevertheless there is no doubt that significant storage capacity must be added to cope with the transition to higher imports. Swing by Dutch indigenous (Groningen) production will continue to be delivered for a

number of years beyond 2010, but its relative significance will gradually diminish.

The shift from indigenous production to imports implies a need for additional storage capacity to be built.

8. Matching supply and demand

Analysis of the match between supply and demand requires the subdivision of Europe into a number of sub-markets. The potential for consumption growth varies considerably between mature markets such as the UK and the Netherlands on the one hand, and emerging markets in eastern and southern Europe on the other. Further, there is a strong geographic component. Different areas are not yet fully connected through pipeline systems and distance from source to market generally plays an overriding role both for pipeline gas and LNG. European sub-markets are distinguished as follows:

- UK/Ireland
- North West Continental Europe (NWCE – the Netherlands, Belgium, Luxembourg, France, Germany, Austria)
- Iberia (Spain, Portugal)
- Scandinavia (Sweden, Finland, Denmark – not an integrated market)
- Italy
- Greece

This subdivision reflects the current situation and that for a few years to come. Connectivity between markets will increase and in due course there will be less reason to distinguish sub-markets in terms of a connectivity perspective. This is illustrated by the recent EU decision laying down a series of guidelines for trans-European energy networks (EU 2003).

8.1 Supply and demand in 2000

The following table 4 provides an overview of the EU supply situation in 2002. The data is derived from 'Natural Gas Information' (IEA 2003).

Table 4 – EU-15 Supply and Demand 2002 (bcm)

	Consumption	NL	Norway	UK	Algeria	Russia	Other*	LNG**
UK/Ireland	100	-	1	99	-	-	-	-
NWCE	206	66	46	9	14	50	16	5
Italy	73	8	4	-	23	19	15	4
Iberia	23	-	3	-	15	-	-	6
Greece	2	-	-	-	0.5	1.5	-	-
Scandinavia	11	-	-	-	-	5	6	-
Total***	416	74	54	108	53	76	37	15

Source: IEA 2003.
* German, Italian and Danish production
** excluding Algeria
*** Minor discrepancies in *Total* amounts are due to rounding of figures

8.2 Supply and demand in 2010

By 2010, a number of pipeline projects, as discussed above in the producer sections, will have been completed, providing additional supply capacity. However, simultaneously, European demand for gas is expect to rise on average by up to 2.9% per year (IEA 2002d), with significant regional variations in demand development. The demand and supply situation in 2010 will be reviewed for the regions UK/Ireland, NWCE, Iberia and Italy.

8.2.1 UK/Ireland

An analysis of UK energy demand developments in can be found in 'Energy projections for the UK' (DTI 2002). Gas demand increase will depend on the developments in the power sector and the extent to which further switching to gas will take place, in addition to GDP growth and energy prices. Global Insight estimates the demand of combined UK/Ireland will have risen to 120 bcm per annum by 2010. This is in line with Wood Mackenzie projections and corresponds more or less with the high price scenario of the DTI (2002: 46). For a low price scenario demand could be considerably higher. UK production will have substantially decreased to a level of around 60 bcm. The supply gap for UK/Ireland will be in the order of 50 – 60 bcm. Only in the event of substantial exploration successes in the Atlantic Margin over the next few years will the supply gap be less. This gap must be closed by Norwegian, Dutch, Russian and LNG imports.

A key issue for the UK in the next few years will also be to replace the swing capacity currently provided by its own producing fields.

8.2.2 North West Continental Europe

Demand in NWCE will increase to 250 – 260 bcm per annum (Global Insight, 2003), implying a yearly growth of 2.5%. Apart from the demand increase, the gap is widened by a decrease in German production and the cessation of UK supplies. Assuming Dutch production remains at the same level or slightly less, some 70 – 80 bcm of increased supplies will be required. These are expected to come from Norway, Russia and some LNG.

8.2.3 Iberia

Spain has experienced a very rapid increase in the use of gas over the past decade (from 5.4 bcm in 1990 to 15.6 bcm in 2000). Some estimates predict natural gas consumption growing at a 10% annual rate during this decade. Portugal has only recently started to consume gas (2.3 bcm in 2000). Global Insight assumes a total Iberian consumption by 2010 of some 38 bcm.

Lacking any indigenous resources, supply options for Iberia are restricted to piped gas from Algeria and LNG. Given the projects for pipelines (both new and extensions) and LNG regasification terminals, Spain and Portugal will have more than adequate import capacity by 2010.

Considering potential over-supply for Iberia and a possible tight supply for North West Europe, additional transmission capacity between Spain and France would allow relatively low cost Algerian gas to become available for the northern markets as well. Such infrastructure is indeed being planned.

8.2.4 Italy

Italy's demand for gas will increase to around 96 bcm per annum by 2010 (Global Insight 2003). Additional imports from Algeria, Russia, Norway, Libya and LNG will allow Italy to cover its requirements.

Figure 5 – Possible supply development 2002-10 for North West Europe (NWCE – including the UK), implying much increased Norwegian and Russian exports (bcm)

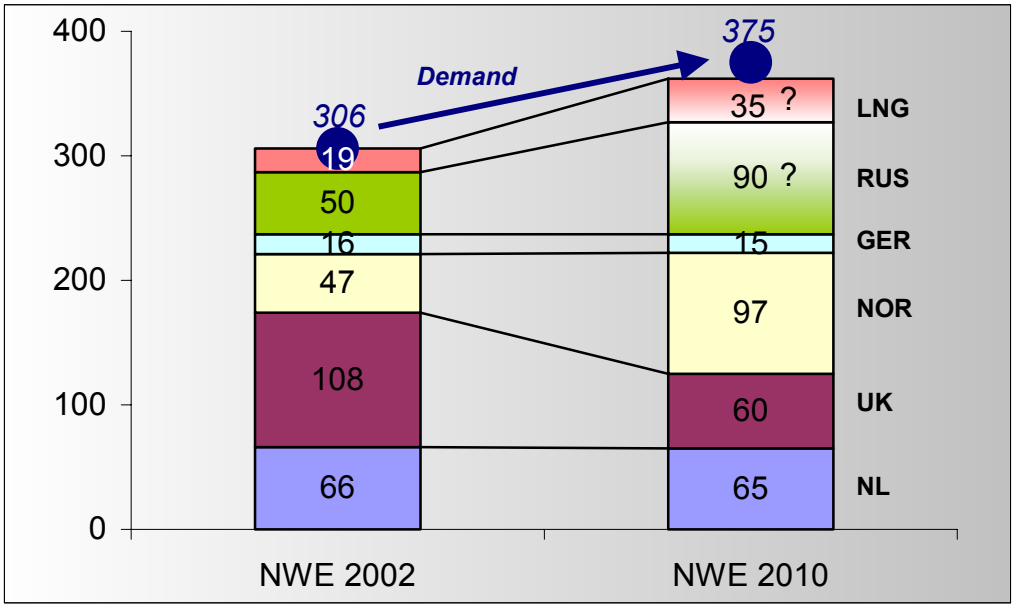
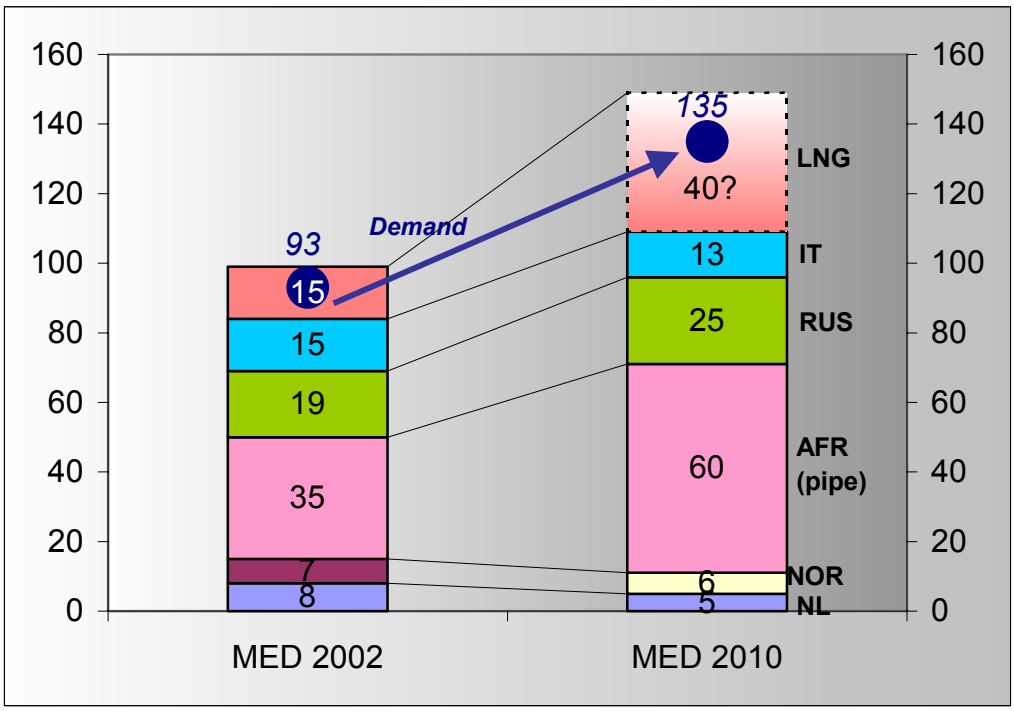


Figure 6 – Possible supply development 2002-10 for Iberia and Italy combined, with increased LNG potential and more piped gas from Algeria and Libya (bcm)



Figures 5 and 6 illustrate possible developments in the supply potential situation from 2002 to 2010 for the main EU-15 regions. Expected demand is indicated with a marker. Volumes quoted are indicative only and are based on the data available in the public domain. Whereas the Mediterranean, and especially Iberia, may expect an overcapacity in 2010, for northern Europe there are some serious risks that supply capacity will be insufficient to meet demand.

Combined with the UK/Ireland, North West Europe in 2010 might need additional supplies close to 120 bcm, if not more. This gap will need to be filled by increased imports from Norway, Russia and some LNG sources. Although not impossible, it is likely that the supply situation in 2010 for North West Europe will be tight. To fill the gap, both Norway and Russia will have to dramatically increase their exports. Norwegian production and exports are expected to increase to some 110 bcm (from 50 bcm in 2000), of which around 85-90% would be destined for North West Europe. This is not an implausible scenario. With exports at 56 bcm in 2002, Norway has set out to accomplish this. Secondly, Russia must increase exports to North West Europe from 50 bcm in 2000 to a level of some 90 bcm in 2010. For Russia to achieve this share increase, additional transmission capacity must be in place (the North Transgas line alone will likely not be enough), but also production will need to increase. Neither Global Insight (2003) nor OME (2001) foresee Russian exports to North West Europe reaching this level. Russia's own export projections show a considerable overall increase over the next few years (50 bcm/a), and a slower increase beyond 2005 (IEA 2002c). If true, it then remains to be seen what portion is allocated to North West Europe. In 2002, Russian exports to North West European countries combined stood at 50 bcm, and hence not yet on the way up compared to 2000. In fact, there are risks that Russia may even be developing a shortage of gas in the medium term. Conversely, the LNG projects could have a larger share than shown above, but then more projects will be needed than are currently planned.

Although this analysis should be considered rudimentary (as the 2010 projections are notional), it can be concluded that the supply gap in 2010 will easily be a reality. In particular there are questions regarding Russia's ability to deliver a substantial increase in exports. If indigenous, Norwegian or Russian contributions are less than expected, the supply gap becomes a fact. If, on the other hand, demand growth is less than the predicted 2.5% or LNG projects take off in the coming years, the situation will be more relaxed. A particular solution for mitigating some of the risk could be the connection of the potentially oversupplied Mediterranean markets with the northern markets, as already recognised in e.g., 'Playing on the short side' (Cook & Griffin 2003).

9. Conclusions

For gas to continue as the fastest growing source of energy for Europe in the next decades, adequate supplies must be brought to the market. Although there are vast natural gas resources within economical distance from the EU, it is not a given that they will become available in a timely manner. Whereas over the course of the previous two decades gas market growth was primarily driven by indigenous EU production capacity, for the next two decades imported gas will take up the largest share. For a number of reasons it will nevertheless be important to maximise the utilisation of indigenous resources. Apart from security of supply considerations, indigenous resources will

continue to play a key role in accommodating seasonal swing capacity and absorbing volume discontinuities, e.g., in the form of high volume supply increments as a result of the completion of major infrastructure projects, or in the form of long term supply disruptions.

Many projects are planned or are in the execution phase to accommodate the changing supply situation. A key development will be the transformation of the UK from a net exporter to a major gas importer. In the UK, gas demand growth (driven by developments in the power sector), may be affected by the uncertainties with respect to the supply developments. At the same time investments in the supply infrastructure (which are less incremental than is the case for indigenous production systems!) require clear signals of firm demand. Although initially projects can more or less be based on the need to replace the rapidly declining UK production, the task ahead is formidable. There will be a need for Norway to double its export level in less than ten years. Europe will also need considerable additional supplies from Russia. Russian supplies from the current sources have particular uncertainties. Projects may suffer from lack of capital, and export levels are – both positively and negatively – affected by various national policy issues. In addition it should be emphasised that current Russian production largely comes from fields in decline. For these reasons the supply situation for Northern Europe could be tight in 2010, if not running short. A steeper decline in indigenous production or less than expected exports from either Norway or Russia could lead to such a situation. Concerted attention will need to be focussed on the element of swing capacity. If exports require full pipeline capacity just to meet volume requirements, swing must come from (remaining) indigenous production and storage.

Conversely, for southern Europe there should be less concern. Pipeline and LNG projects in execution and on the drawing board appear to be more than adequate to satisfy the rapidly increasing demand. Of course, the total demand for the Mediterranean EU is much less than northern Europe and moreover Algeria is a nearby and relatively low cost supply source. Given the planned LNG projects, southern Europe and in particular Iberia may find itself in an over-capacity situation if these projects are all to proceed as planned. Increased connectivity with northern markets may alleviate some of the disparities in the supply outlook for the EU-15.

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