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LONG-TERM GAS SUPPLY SECURITY IN AN ENLARGED EUROPE

Final Report ENGAGED Project

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Abstract

The final report contains the results of the SYNERGY project 'Long-term Gas Supply Security in an Enlarged Europe', ENGAGED. The project concerned a study on the long-term gas supply security in Europe with a focus on the developments, risks and policies in the candidate countries in Eastern Europe. For that reason the report not only includes a European and EU-30 wide scenario analysis but also chapters on specific topics. One study and thus chapter concerns the gas market and regulation developments in a number of relevant candidate countries. Another chapter presents a Russian vision on gas demand, production and supplies from Russia and also includes a paragraph on the supplies from other neighbours and the transit issues in the Ukraine. Finally the report contains a chapter discussing the required network infrastructure for bringing the gas from external gas suppliers to the EU-30 markets. Hereby it analysis and tests the network flexibility to cope with some unlikely and unexpected supply interruptions in main pipelines to EU markets. The background information of the studies underlying the chapters can be partly found in the annexes and in the individual task reports. During the project the results of the study were discussed at several seminars in candidate countries and particularly on the final seminar in Prague, in June 2003, with different and important stakeholders and market actors. The partner organisations and principal researchers involved in the study are mentioned below.

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LIST OF ABBREVIATIONS

Bcm	Billion cubic metres
CEECs	Central Eastern European Countries
CR	Czech Republic
DSO	Distribution System Operator
ERA	Energy Regulatory Authority
EU	European Union
GHG	Greenhouse gas
HP	Heat only plant
CHP	Combine heat and power
LNG	Liquefied natural gas
Mcm	Million cubic metres
MJ	Mega-joule
NAS	New Accession States
NG	Natural gas
NPP	Nuclear power plant
PJ	Peta-joule
PL	Poland
POGC	Polish oil and gas company
RES	Renewable energy sources
RO	Romania
SK	Slovakia
SoS	Security of supply
Tcm	Trillion cubic metres
TJ	Terra-joule
TPA	Third party access
TPES	Total primary energy supply
TSO	Transmission System Operator
USSR	Union of Soviet Socialist Republics
CIS	Commonwealth of Independent States
UGSS	Unified Gas Supply System
FSU	Former Soviet Union

EXECUTIVE SUMMARY

S.1 Background

The development of the European gas market in relation to a number of structural changes, led to great concern that in the long term (2010-2030) the gas security of supply is declining to unacceptable levels for EU-30 consumers. Particularly those living in accession countries in Central and East Europe, expect a strongly growing gas demand and import dependency. The driving factors that push for these structural changes in the gas market in Europe and creating concern for supply security are:

- The progressive creation of an integrated European internal gas market, which results in increasing uncertainty for investors in production and infrastructure, necessary to connect these remote production locations outside the EU-30 with main consumer markets.
- EU membership of ten candidate countries in 2004 (and five other counties thereafter).
- Growing gas demand in EU-30 and thereby a strongly increasing gas import dependency in the next decades from currently 40 till around 70% in 2030.

Recently the Commission expresses its concern also in a Communication (COM(2003) 262 final) entitled 'The development of Energy policy for Enlarged European Union, its neighbours and partner countries'. The goal of the study, therefore, was to analyse the gas supply security situation in Europe in the long term with a focus on the candidate countries. And also formulate policy measures at the EU and national level for the candidate and transit countries that enhance the overall gas supply security situation in Europe.

S.2 Objectives of study

The study did seek to assess the outlook for the gas supply security situation in the medium and long term. It provides the EU and particularly the candidate countries with recommendations for enhancing their gas supply security situation, conditional on the development towards the enlargement of the EU and the liberalisation of the internal energy market. This is put in the light of an increasing import dependency of gas supplies from outside the EU and remote regions.

The study focused on the following objectives:

- To analyse and *evaluate the long term and strategic gas supply security situation* in Europe with support of scenarios that analyse and illustrate the different perspectives and consequences for gas markets and to evaluate measures to reduce perceived supply risks.
- To analyse gas supply and transit network capacity requirements in the long term, by giving an overview of *alternative gas supply routes* and potential gas reserves and resources and the possibility for the EU to use these in the long run. To provide the EU and particularly the candidate countries with recommendations regarding enhancement of specific transit routes and interconnections.
- To identify *candidate countries* 'at risk' by analysing the long-term development of their gas market (demand, supply and import). Analysed were the Czech Republic, Slovakia, Poland and Romania. To provide the EU and particularly the candidate countries with recommendations regarding the implementation of gas supply security policies.
- To review the progress in candidate countries in *the implementation of the EU Gas Directive*. This in order to improve the natural gas supply security position of these countries and the realisation of an integrated internal EU gas market in the next decade. Attention was paid to the Czech Republic, Slovakia, Poland, Romania, Hungary and Turkey.
- To provide input for a *dialogue* between the EU and the candidate, transit and producing/exporting countries such as Russia and Ukraine, e.g. by preparing an inventory of bot-

tlenecks in gas network capacities and solutions. This for the timely development of interconnections and a reliable gas infrastructure in the long run.

S.3 What is gas supply security?

Security of gas supply for consumers is basically an issue of risk. All energy supply systems inherently contain a certain level of risk for consumers, but the question is what level and type of risks are acceptable. This depends on the context in which the question is posed. The scope in this study is the medium and long-term gas market in Europe wherein the EU consumer is largely and increasingly depending on natural gas import. Moreover, he is mainly depending on a relative small number of key gas exporters with remote production locations. Furthermore, gas supply security is generally more important for political and economical reasons than supply security in other industries, because of the essential nature of gas. It is difficult to get alternatives and its supply depends mostly on monopoly controlled pipeline networks. Consequently there are high costs involved in gas supply interruptions. Adequate security levels for consumers depend very much on the perception of the consumers' willingness to pay for higher security levels, which tend to fall if risks are reduced and the 'costs of providing extra security' that tend to rise if risks are reduced.

Unfortunately optimal levels of security are difficult to assess due to uncertainties and subjective and different perceptions of risks in this context by the different stakeholders. What policy makers can do, however, is trying to assess if security levels are within a certain and acceptable margin for a majority of consumers'.

S.4 Approach

The study was split up in a number of different studies. Each focussing on an important part of the earlier formulated overall objectives of the study. The following studies have been undertaken:
- An analysis of the long-term development of gas markets and the adequacy of gas supply in Europe.
- Development of gas scenarios for the EU candidate countries, Czech Republic, Poland, Slovakia and Romania and an analysis of their Security of Supply (SoS) policies.
- A review of the implementation progress of the EU Gas Directive in these countries and in Hungary and Turkey.
- An analysis of the capacity of and investment requirements in the gas infrastructure, including considerations of resilience and supply security of the network.
- An analysis of the developments in and outlook for the Russian gas sector and Ukraine's transit capabilities.

Combined, the results of these studies give a fairly comprehensive overview of long-term development of the gas markets in Europe and particularly in the accession countries with respect to levels of supply security, the key drivers and bottlenecks. Possible solutions to improve these levels and reduce the risks for the EU-30 are addressed. Some of the studies show different outcomes, e.g. regarding potential gas resources and supplies available to the EU-30 in the longer run, because of differences in assumptions and background. The chapter on Russian gas sector and Ukraine's transit issues furthermore gives the Russian and respectively Ukraine's vision on these issues. In the next sections the main results and conclusions from our study are summarised. For a more complete presentation of results one should read the full final report.

S.5 Long term adequacy of gas supply in Europe

An enlarged European Union faces the prospect of a substantial increase in gas imports in the next three decades in the absence of rigorous new government policies at EU and national levels. In a *Reference Scenario*, natural gas demand in EU-30 is projected to grow by an average 2.1% per year over the projection period-the most rapid growth rate of any fuel other than non-hydro renewables. The share of gas in total primary demand will continue to grow, from 22% at present to 33% in 2030. The power sector will be the main driver of gas demand, especially in the first half of the projection period.

With indigenous production projected to stagnate, all of EU-30's projected increase in demand will have to be met by increased imports. *Net imports are projected to surge from 200 Bcm in 2001 to almost 650 Bcm in 2030.* The share of imports in the region's total gas demand will rise from 38% to just under 70% over the same period. The bulk of imports are expected to come from EU-30 two main current suppliers, Russia and Algeria, and a mixture of piped gas and LNG from other African and Former Soviet Union countries, the Middle East and Latin America.

Under an alternative *Low Gas Imports Scenario*, a combination of sharply lower gas demand, due to higher gas prices and policies that reduce gas demand, and slightly higher indigenous gas production results in a significantly lower rate of growth in gas imports into EU-30. By the end of the projection period, imports in this scenario are little more than 60% of their level in the Reference Scenario. Most of this difference is due to lower gas consumption in the power sector which will use more coal and nuclear instead of gas. Gas imports nonetheless virtually double over the projection period. Imports are somewhat higher in a *High Gas Import Scenario*, mainly due to even more rapid growth in power-generation demand than in the Reference Scenario.

The enlargement of the European Union to twenty-five countries will temporarily increase the degree of gas-import dependence, as eight new accession countries are net gas importers. But the enlargement to thirty countries would reduce the degree of gas-import dependence because of the inclusion of Norway. Both short- and long-term supply security concerns are likely to be exacerbated. The high degree of dependence of the candidate accession countries in Central and Eastern Europe and their unusually heavy dependence on imports from a single country, Russia, will have an impact on supply-security risks in the EU. Reliance on a single supply route in some accession countries adds to the short-term risks.

The projected increases in gas demand and imports in the Reference Scenario imply a need for substantial investment in gas production, transportation and storage capacity both within EU-30 borders as well as in those countries that will supply gas to Europe. *Just under $ 500 billion will need to be invested in gas-supply infrastructure in EU-30 countries and a further $ 190 billion in external supplier countries over the period 2001-2030.* The sheer scale of the capital needs as well as a number of developments, including longer supply chains, geo-political factors and energy-market liberalisation, raise question marks about whether this investment will be forthcoming in a timely manner. There is a risk that supply bottlenecks could emerge and persist for long periods due to the physical inflexibility of gas-supply infrastructure and the long lead times in developing gas projects.

EU and national policy makers will clearly need to tread very carefully in reforming their gas and electricity markets to ensure that the new rules and emerging market structures do not impede or delay investments that are economically viable. EU policymakers will also need to take account of the increased risks facing both upstream producers and merchant gas companies as a result of energy liberalisation in setting rules for long-term supply contracts and joint marketing arrangements. An intensified political dialogue between EU and gas companies and with the governments of supplier countries could support investment in certain high-risk, large-scale gas projects by lowering country and project risks. The development banks, including the European

Investment Bank, as well as national and multilateral export credit agencies, will continue to play an important role in backing major cross-border pipeline projects in the future. The restructuring and privatisation of gas companies in major gas producing and transit countries may contribute to reducing future investment risks, but if European market continues to be fragmented investment risks might even increase.

S.6 Potential of Russian gas supply

Gas export and import outlook

Russian's view is that their gas export policy regarding Western and Eastern European markets depends on the gas market developments in neighbouring regions and the restructuring of the Russian gas industry. The export policy in the 'optimistic economic growth scenario' (if crude oil prices are high in world markets) is based on the assumption that Russia revenues for Russia support the economic growth and Russia will keep its share in the supplies to foreign markets and even continue to expand its market share if import demand rises. Russian gas export in this scenario is expected to grow from 139 Bcm in 2001 to 181 Bcm in 2020. At the same time gas reserves of East Siberia and the Far East will be mobilised to enter Asian-Pacific markets, first of all in China, Korea, and Japan.

In the pessimistic economic growth outlook for Russia, the so called 'Constrained scenario', (if crude oil prices are low in world markets) for internal reasons the gas export volumes to Europe will be constrained slightly in the short and medium term. However, if gas prices as a reaction to this development rise again to a relatively high level in Europe in the period 2010-2020, it might be possible to exploit the Shtockman gas fields and export these volumes to Western Europe or USA. As a result gas export volumes might reach the levels of the 'optimistic scenario' again in 2020. At the same time, if gas prices in Asian-Pacific countries stay tightly linked to the low world crude prices, export projects in the Far East continue to be unattractive for investors. Gas deliveries to CIS and Baltic countries are expected to rise to about 62-69 Bcm, while the main demand comes from Ukraine and Belarus.

West Siberia will remain the main resource base of the Russian gas industry. Its resources will dominate supply to all regions in Europe, the Ural and the industrial areas in the south of West Siberia. Gas from Tyumen will remain the main export resource.

However, gas production volumes will drop due to the fact that Senomanian reserves of the Nadym-Purtaz area in Tyumen region are gradually exhausted. The unique resource base of the Yamal peninsula will probably be put in operation by 2020. The Yamal and Gydan reserves, the Karsk Sea shelves, unique in their technical complexity and required investments, will probably be put in operation after 2020.

To satisfy the consumers in the Volga region, the Urals, and the Central and North Caucasus regions, it is reasonable to expand gas import from Central Asia and Kazakhstan. Gas import can be carried out either as purchases of gas at the border of the exporting country, either through Russian participation in Turkmen and Kazakh gas production by product sharing or else by barter trade between Russian gas companies and Northern and Northeastern provinces in Kazakhstan. Consequently Russian gas imports might rise to 55-58 Bcm in 2020.

Investment needs in the Russian gas sector
Gazprom's strategy to further develop the gas resource base, production, the reconstruction and extension of gas transport and distribution system, gas processing plants, and the construction of more underground gas storage facilities, requires large investments in the next decades. In the first five years (2001-2005), investments in gas production and transport are estimated around $ 16-17 billion, for the last five years (2016-2020) around $ 32-35 bln. Throughout the whole period investments in the operation and further development of the industry are crudely estimated to be about $ 90-100 bln. Compared with investments by *Gazprom* PLC in 1999 of only $ 3.1 bln. and in 2000 of $ 3.2 bln. In order to mobilise these large investments for the exploration and production of gas, foreign investors must be attracted. Some examples of large projects in Russia are development of Shtockman gas condensate deposits in the long term.

But also the pipeline constructions require huge investments of around $ 1-1.5 bln., which is mainly connected with the implementation of export projects based on long term take-or-pay contracts. Among these projects is the 'Blue-Stream' pipeline implemented by *Gazprom* PLC together with *ENI*, which enables to deliver gas to Turkey irrespective of countries of transit. Investments in the project are $ 2.2 bln. To develop Shtockman deposit it is required to construct a pipeline for which investments are estimated at $ 5.5-6 bln and will probably start before 2010. The cost of the pipeline Korykta-China is estimated at $ 7.6 bln.

The potential of gas production and exports of Turkmenistan and Kazakhstan to the EU via Russia, Ukraine or other transit routes is large. The production and export volumes in Turkmenistan might rise from 45-56 Bcm in 2005 towards around 85-100 Bcm in 2020 and in Kazakhstan from 16-20 Bcm in 2005 to 40-50 Bcm in 2020.

Ukraine's transit issues
Currently, the Ukraine is clearly the most important gas transit country for Europe with an extensive gas network of pipelines and storage facilities in order to transport large volumes of gas mainly from Russia to Europe through Slovakia, Poland and Romania. It is therefore important that the Ukraine meets EU standards for safe and reliable transport of natural gas. Russian gas transit to Europe takes place in volumes of around 110-120 Bcm a year, while gas supply to Ukrainian consumers is currently around 65-70 Bcm per year.

Insufficient actions and financing of maintenance of Ukraine's gas transport system might in the future lead to a deterioration of gas network conditions. This could creates doubts about reliability of gas supply to Europe via Ukraine in the next decade. It is one of the key reasons for the Russians to develop alternative routes for gas transit from Russia to the European Union. Urgent and adequate measures are needed for keeping Ukraine's pipeline system effective for gas transit to Western Europe.

S.7 Resilience of the European gas transport network

In order to identify potential bottlenecks in the gas transmission system, sudden and prolonged 'gas supply disruption cases' are simulated for the year 2020. Four disruption cases are analysed. Without assuming any probability for these cases to happen, they merely are used as a tool to analyse the resilience of the European gas transport network.

The four disruption cases are:
- Disruption of Russian supply through the Ukraine, in which the complete transmissions pipeline capacity across the Russian-Ukrainian border, becomes unavailable (Russian Case) for exports to EU.
- Disruption of Algerian supplies to EU altogether (Algerian Case).

- Disruption of gas transits through Turkey, *i.e.* transit pipelines from Turkey to Greece and Bulgaria become unavailable (Turkish Case).
- Disruption of Norwegian supplies to EU altogether (Norwegian Case).

Results of these gas disruption cases are evaluated with respect to a reference case in which there are no disruptions in gas supply in 2020.

Russian case impacts
In the reference case it is expected that about 50% of Russian exports pass the Ukrainian border in 2020. Russian supplies decline by 97 Bcm in case of a disruption. Alternative routes, particularly Blue-Stream and Russian LNG, absorb about 12 Bcm of gas diverted from the Ukraine route. The Baltic pipeline to Germany cannot be used as an alternative, since it is already fully used in the reference case. EU-30 demand is falling sharply due to the sharp price increases, caused by strongly rising costs of alternative supplies. But several CEEC's are hit most severely.

Algerian case impacts
In the reference case Algerian exports are at their maximum level, as pipeline and LNG exporting capacities are fully used. However if interrupted there is no alternative for transport of Algerian gas to Europe, consequently countries currently directly supplied by Algeria (Spain, France and Italy) are severely hit, because alternatives are lacking. The reserve capacity for alternative supplies is very small and Spain and Italy will have to rely on additional LNG from more remote and expensive sources. About two-third of interrupted supplies is replaced by those expensive LNG alternatives. Therefore, gas price levels increase substantially. The CEEC's are, however hardly affected by a complete interruption of gas exports from Algeria.

Turkish case impacts
The impact of the interruption of gas transit through Turkey, which mainly consists of Iranian gas exports to Italy, are relatively small, since transit volumes in 2020 are assumed to be rather small (about 10 Bcm). Since Iran can only supply the EU via Turkey, Caspian supplies are 'pushed out' of Turkey (and into the Ukrainian route). On the other hand the 'lost supplies' from Iran to Italy are partly substituted by additional Caspian supplies via Ukraine.

Norwegian case impacts
Norway supplies at almost full production capacity to the EU in the reference case in 2020. However, alternatives for disrupted Norwegian supplies are hardly available. Russia and Algeria are already exporting at full capacity to Europe. Therefore, LNG from remote regions is the most important alternative supply available. The CEEC's are hardly affected, except Czech Republic and Hungary, but other EU 30 countries are severely hit by a disruption in Norwegian gas supply.

General conclusions on European gas network
Existing and planned gas supply and transmission infrastructure (both LNG and pipeline) seems sufficient to meet expected gas demand in 2020. In case of disruption in one of the key supplies, the transmission network capacity is a constraining factor leading to price rises. In the Russian and Algerian cases, EU 15 gas consumption would be reduced by some 6%. Prices in eight selected Member States would increase between 10-40% in the Russian case and between 2-60% in the Algerian case. In the Norwegian case, EU 15 gas consumption would be reduced by some 13%. Prices in the eight Member States would rise between 5 and 60%.

Caspian gas supplies become increasingly important for CEECs and Turkey, assuming that pipeline capacity is expanded accordingly.

In the next decades LNG supplies from remote sources play an increasingly important role in filling the supply gap in any of the disruption cases. Consequently, investment in expanding LNG regasification capacity will be very important for ensuring security of gas supply to EU-30 in the medium and longer term. The following bottlenecks are identified in the European pipeline transmission network:

- Iran into Turkey and further into Europe.
- Bulgaria and Romania into Europe.
- Cross-links between CEECs that are important for mutual assistance in case of emergencies.
- From the west and south into CEECs. Trade flows and pipelines are currently dimensioned for deliveries from East to Western Europe.
- Spain, however addressing this by developing its LNG facilities.
- Belarus and Ukraine into EU-30.

Turkey's role as transit country for gas from the Caspian Region and Iran to Europe depends critically on:

- Development of domestic gas demand in Turkey.
- Expansion of pipeline capacities from Turkey to Greece and Italy.
- Expansion of pipeline capacities from Turkey to Bulgaria and further to Romania, Hungary and Austria.
- Availability of gas supplies from the Caspian Region and Iran.

S.8 Gas scenarios and policies in candidate countries

Despite the large differences in economic structure, availability of domestic energy resources and the current share of gas in the supply mix across the candidate countries, the share of gas is strongly growing and consequently also the import requirements in the next decades. In the Czech Republic and Slovakia the gas import dependency is around 90%, Romania rises from 20 till 60-70% and will be in Poland 75-85% in 2030. The gas demand development depends on the pace of restructuring of coalmines (Poland and Czech Republic) and economic growth, particularly in Romania and Slovakia.

In all four NAS of concern there are limited domestic energy resources available and therefore a substantial growth of energy import is expected that will result in a strong growth in import dependency. Thus these countries should take measures to mitigate the consequences of this growth of dependency. Dependency can be reduced through diversification of gas import suppliers and diversification of terms of contracts, and through further implementation of policies to promote energy efficiency and local and renewable energy sources. Keeping sufficient gas storage capacity and stocks in accordance with the EU Directive amendment requirements can also substantially enhance security of energy supply.

In a reference scenario, the total gas demand in the Czech Republic, Poland, Romania and Slovakia will rise from 45 Bcm in 2000 to 85 Bcm in 2030. In the Czech Republic, the total gas storage capacity today amounts to one third of the annual gas consumption. The Polish government has issued an ordinance on the maximum level of gas that can be imported from a single country. For 2020, it is set at 49%.

The four NAS are becoming important transit countries for gas supplies from East to West. Therefore, it is of the utmost importance that measures are taken in time in these countries that secure sufficient transit capacities and interconnections and other facilities, including the required maintenance of these capacities to provide sufficient security of supply to the consumer markets in EU. For creating a genuine integrated EU-30 internal gas market and secure the role as transit countries towards EU-15 markets, candidate countries should timely invest in pipeline connections of the gas network relevant for CEECs.

1. INTRODUCTION

1.1 Background

In November 2000, the European Commission launched a Green Paper on European energy supply security[1]. The Green Paper identifies two main priorities 1) controlling the growth of demand and 2) managing energy supply dependency in Europe. The final conclusion was that the import dependency from oil and gas supplies from outside the EU will rapidly increase. Enlargement of the EU, even with a gas-rich country like Norway, will not change the situation. More likely, the situation will get worse, since Central and East European (CEE) accession countries depend almost entirely on Russian gas supply, while at the same time demand for gas in those countries is growing. See Table 1.1 below. Apart from the 'traditional' gas sources in Norway, Algeria and especially Russia, 'new' gas countries enter the picture as potentially important supplier for the EU-30 market.

Table 1.1 *Current import dependence of relevant EU-30 countries, 2001*

Country	Net imports [Bcm]	Net imports as percentage of primary supply: From non-EU-30 countries [%]	From all countries [%]
Austria	5.63	60	72
Belgium	15.40	17	99
Bulgaria	3.12	94	94
Czech Republic	9.52	72	96
Finland	4.57	100	100
France	38.53	54	92
Germany	72.05	35	76
Greece	2.02	100	100
Hungary	9.58	63	72
Italy	54.71	65	77
Luxembourg	0.87	n.a.	100
Poland	8.74	53	63
Romania	2.97	17	18
Slovak Republic	7.20	91	91
Slovenia	1.04	100	100
Spain	17.26	77	96
Sweden	0.97	0	102
Switzerland	3.09	12	100
Turkey	15.75	99	99

Source: IEA databases.

Security of supply is a widely used notion, which covers a range of issues spread over different time frames. For the gas market it can most simply be characterised in the following ways:

- Short term or operational, which is the ability to maintain continuity of supply on a daily basis under extreme conditions, e.g. exceptional demand during cold weather or short term supply difficulties caused by a local compressor failure. These issues are typically 'intra Member States'. The demand mix is a very important variable in this regard, particularly factors such as the proportion of seasonal residential demand and the volume of interruptible load.

[1] Towards a European strategy for the security of energy supply-COM(2000) 769 final, 29.11.2000.

- Medium or strategic, which is the ability to withstand a major unexpected disruption caused e.g. by the political or technical interruption of a major source. Strategic security risks highly depend on the supply position. Countries that are heavily dependent on one source or physical link employ strategic measures to protect themselves against such eventualities.
- Long term, which is defined as the ability to meet the future demand for gas with a combination of indigenous and imported gas supplies. There is inevitably uncertainty about the precise availability of future gas supplies in terms of their source and costs.

Given the expected strongly growing energy dependency of the EU on resources outside the EU, the medium and long-term assumption will become more important than previously. Therefore, the project will mainly focus on security of natural gas supply in the medium to long term. As the Green Paper correctly indicates, security of supply does not mean to maximise energy self-sufficiency or to minimise dependency, but aims to reduce the risks linked to such dependence at reasonable costs. Balancing these efforts against perceived risks will take an important position in this report.

Several measures can be taken to prevent medium and long term interruption in gas supply. Without pretending to be complete, the following options are available:

- Completing the Internal Market. This in the context of progressive creation of an integrated European internal market not only in the EU Member States (MS), but also creates a level playing field, market opening, fair competition etc in the Candidate Members and in the neighbouring third countries surrounding the EU. This with a focus on main gas suppliers and transit countries. Basically this means implementing the EU gas Directive and other Security of supply (SoS) measures and creating the gas infrastructure necessary for well functioning of the gas market Europe-wide.[2]
- Improving production and exploration of existing and new gas fields and opening up new fields in Siberia, Iran and Caspian region. For the long run, non-conventional gas resources, such as gas hydrates and coal bed methane etc. might prove to be important.
- Promoting the diversification of gas supply and transport routes, including extending connections to main (European) transport pipelines. More efficient use and upgrading of existing pipelines and investing in new export/transport capacity and interconnections. Opening-up or expanding supplies from new supplying countries, such as Turkmenistan, Iran and improving interconnections for gas supplies to candidate countries.[3]
- Enhancing the trade volume covered by long-term (take-or-pay) contracts, interruptible contracts and backup contracts with other suppliers were usually viewed as essential to supply security in the past. Under these contracts, the buyer is obliged to pay for a certain percentage of the annual off-take volume specified in the contract, even if he is not able to use or resell the gas. Hence buyers take (most of) the volume risk, whereas sellers take the price risk. Probably the balance of market power in the liberalised European gas markets will gradually shift from sellers to buyers in the next decades. Currently liberalisation of gas markets and enhancing supply security are often seen as conflicting objectives.
- For enhancing reciprocal regional assistance and co-operation between gas market parties in countries along the supply chain from producer of gas to consumer it is necessary to identify and analyse the issues and solutions to tackle these. This is also a prerequisite for improving the dialogue between the EU and producing and transit countries.

Note that the focus in this study and consequently this report is on long-term gas supply security and its policies to mitigate unacceptable levels of supply risks to main consumer markets in EU-30. This with an emphasis on the position of the candidate countries.

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[2] COM(2001)125,13.3.2001,COM(2001)775, 20.12.2001.
[3] COM(2003)262, 13.5.2003)

1.2 Key role accession and producer countries

The European Commission (EC) has already finished negotiations with eight candidate countries in Central and East Europe to join the EU in 2004. Clearly, the majority of accession countries are important gas transit countries between key suppliers like Russia and EU-15 and are therefore important factors in securing adequate import for their growing domestic gas markets and trade volumes flowing from producing to consuming countries in EU-15. Consequently, the implementation of the Gas Directive for creating competitive markets and policies regarding gas supply security in these accession countries are of eminent importance for both consumer and producing countries and thus the gas supply security in Europe. By August 2000 the EU Gas Directive had to be implemented in most of the MS. Since gas policy is the competence of individual countries, this meant that national legislation/regulation, complying with the principles set out in the Directive, had to be in place. This proved (and still proves) to be a difficult process, since some countries failed to meet the deadline, while other MS complied in time. Also with the 15 different countries, just as many different interpretations of the Directive exist. Moreover, different countries emphasise different components, depending on their priorities and preferences. With the envisioned timing of the enlargement of the EU, the candidate countries are now faced with implementation of recently adopted Gas Directive amendments. Main elements of these amendments concern a framework of measures enhancing gas supply security of Member states.

Next, the importance of candidate countries as gas transit countries, requires the timely investments in new interconnections and other facilities that are needed for securing uninterrupted trade flows from key suppliers, Russia, Norway, Caspian region etc to EU-15. Since these are high risk and high capital investments a careful scrutiny of the investment requirements and priorities for interconnections etc in accession countries is needed. In particular when candidate countries are expected to have a fast growing gas demand in the next decades and are expected to rely on one single supplier in the future. In fact, the restructuring of the energy sector in the past enhanced already the share of natural gas, which resulted in substantial changes in the gas market structures in several CEE candidate countries. Some candidate countries already took action in order to guard their supply security, because of the dependence on a single gas supplier. Some countries have found new suppliers (e.g. since 1997, the Czech Republic purchases Norwegian gas) or entered into swap contracts (e.g. the Hungarian gas industry with Ruhrgas and Gaz de France). Others have expanded gas grids and interconnections (e.g. between Austria and Hungary), or are planning to do so (e.g. between Hungary and Romania). Detailed interconnections between all the EU countries and particularly the New Associated States (NAS), seem essential for the appropriate functioning of a liberalised internal gas market, as well as for security of gas supply. Several candidate countries, most notably Hungary, Poland, Czech Republic and Slovenia have already started to reform their gas industry, in anticipation of joining the EU and its internal liberalised market. While technical opportunities have grown, candidate countries now have started the implementation of regulations in order to comply with the EU Gas Directive in the coming years.

In this report we explicitly pay attention to the gas market developments in some key accession countries that are also relevant transit countries. Particularly the current and future situation regarding their level of supply security for gas and policies to improve these are addressed.

Regarding the major producing and exporting countries of importance for the EU-30, many specific gas studies have been conducted so far. Dialogues have been set up e.g. the recent Prodi/Putin dialogue between Russia and the EU. In the long term, gas exploration, production and transport of gas from Russia, Algeria, the Caspian region and Middle East to the EU-30 is of imminent importance. However, uncertainties and (economic) risks for investors, traders etc. are also high due to continuously changing economic circumstances in these regions, the EU and in the world energy markets. EU policies and particularly comprehensive measures directed to facilitate the production and export of gas (technical, legal as well as economic) from producing countries are limited, but of the utmost importance for the supply security of the EU now. Especially in support and preparation of a fruitful dialogue between the EU-30 and the key supply regions it is necessary to analyse the long-term gas supply security, developments in demand and supply and assess the key investments in the gas infrastructure in the next decades.

After the enlargement of the EU, security of the gas supply will be of increasing concern, because of the expected growing gas consumption, restructuring and liberalisation of emerging gas market infrastructure, new energy market conditions. As the Commission recently expressed its concern in a Communication (COM(2003) 262 final) entitled 'The development of Energy policy for Enlarged European Union, its neighbours and partner countries'. Therefore the goal of the study, which is the basis of the report, was to analyse the gas supply security situation in Europe in the long term with a focus on the candidate countries. Policy measures at the EU and national level for the candidate and transit countries that enhance the overall gas supply security situation in Europe are recommended.

1.3 Objectives of the study

The study did seek to provide the EU and particularly the candidate accession countries with recommendations for enhancing their gas supply security situation, conditional on the development towards the enlargement of the EU and the liberalisation of the internal energy market. The focus was on analysing the long term and strategic natural gas (including LNG) supply security situation up till 2030 in the light of and increasing import dependency of gas supplies from outside the EU and remote regions.

The study particularly focused on the following objectives:

- Analyse and *evaluate the long term and strategic gas supply security situation* in Europe with support of scenarios that analyse and illustrate the different perspectives, consequences for gas markets and evaluate measures to reduce perceived supply risks.
- Analyse gas supply and transit network capacity requirements in the long term. Give an overview *of alternative gas supply routes* and potential gas reserves and resources and the possibility for the EU to use these in the long run.
- Provide specified *candidate countries* 'at risk' with recommendations regarding their respective new and/or revised energy policy on supply security, which becomes valid starting from the date of membership of the EU. Special attention is paid to four key candidate accession countries the Czech Republic, Slovakia, Poland and Romania
- Review the progress of six selected candidate countries, Czech Republic, Slovakia, Poland, Romania, Hungary and Turkey on the implementation of the EU *Gas Directive*, and provide recommendations on the attainment of the target for this process. This with specific attention to the measures on gas supply security and regarding *TPA to transmission* and transit pipelines, and LNG facilities in candidate countries.
- Provide the EU and particularly the candidate countries with recommendations regarding the *implementation of gas supply security policies* such as enhancement of specific transit routes and interconnection, to improve the natural gas supply security position of these countries in the internal EU gas market in the next decades.
- Provide background inputs for a *dialogue* between the EU, transit and the producing/exporting countries such as Russia, Algeria and Ukraine, i.e. by preparing an inventory of bottlenecks and solutions for the long-term development of a reliable gas production/export/transit infrastructure.

1.4 Scope of study

According to the European Commission (2000) the purpose of an EU energy supply security policy is to secure the immediate and longer-term availability of a diverse range of energy products at a price that is affordable to all consumers while respecting environmental requirements. Supply security refers to the state of being safe against a disruption to, or non-availability of, supply (IEA, 1995). When considering gas supply security, the particularities of the gas market, such as the rigid nature of the transport network, the relative difficulty of storage and the regional nature of markets, should be taken into account (IEA, 1995). IEA identified broadly two classes of long-term gas supply security risk. *First type of risks* concerns the long-term risk that new gas supplies cannot be brought on stream to meet growing demand for either economic or political reasons. The failure to mobilise long-term supply to ensure the customer's gas against stable prices is regarded as the most important class of risks so far. This issue now in the EU has an increased attention in the face of the liberalisation and creation of competitive gas markets in the EU-30. In fact it assumes a situation of non-availability of supply against 'reasonable costs or affordable prices' for consumers thus where gas demand or economic gas-consuming investments outpaces the for gas supply required production and transport necessary investment (IEA, 1995). This leads to analysis such as conducted by OME (2001) for the EC, estimating the gap between projected demand and contracted supply and identifying the costs of gas from projects to reduce this gap. The size of the gap then gives an indication of the potential security problem and the impact on investments in gas infrastructure, costs of delivery from long distances to the consumer markets and the final gas prices for consumers.

Note however, that these absolute measures tend to ignore the underlying market and economic factors that influence the gas markets. The purpose of the EC as given in the beginning already indicates the importance of affordable prices (i.e. economic factors). Essentially, 'there is no such thing as a long-term supply-demand gap in terms of volumes', because supply and demand always meet at a certain price, albeit at exceptionally high price levels (IEA, 1995) or is leading to relative high 'substitution/switching cost' by the consumer. Lead times related to bringing new supplies on stream or purchasing new supplies on the market prove an important determinant in covering expected demand. In markets dominated by long-term contracts, lead times may be long and strategies looking forward a number of years affect purchasing behaviour. Similarly with reserve-production ratios, 'the relevant question in a security context is not whether the resource exists but whether the conditions are right for the resource to be mobilised' (IEA, 1995). Recent observations show that over the last decades reserves and reserves-to-production ratios seem rather constant 8-12 years due to 'just in time' management by the liberalised industry.

The so-called long term dependency 'gap' will, under normal conditions through relying on efficiently functioning liberalised gas markets in Europe (through trading and financial instruments, which allow for efficient allocation and in time investing in gas supplies and transportation capacity) be 'automatically' closed. Of course it is assumed that specific standards and/or obligations superimposed by regulators and governments on market players are in place for addressing short and medium term supply security risks. This issue is namely not addressed in this project as mentioned earlier. Clearly the long run perspectives regarding the gas supply security situation and possible risks stemming from an increasing and large dependency on external supplies of the EU-30, can best be evaluated on the basis of energy scenarios up till 2030, with an emphasis on gas sector and market developments. This of course means also including the relevant and important gas supply and production countries and regions outside the EU-30 in the analysis. Furthermore the focus of the analysis will be on supply security risks for the EU-30 as a whole and the selected candidate countries.

A second type of risk identified by IEA concerns the effects of disruptions to existing and normally functioning gas trade and supplies caused by a political or an accidental event. Although this class of risks at that time (1995) were considered almost negligible, it is certainly more relevant for nowadays perceptions of Europe's energy dependency and the geopolitical situation. Europe's dependency on gas supplies from remote areas will in the next decades become so large that this class of risk needs again scrutiny on its relevance and consequences for the supply security of Europe for the following reasons. In fact what is at stake is the resilience of the gas transport network connecting suppliers and consumers in Europe.

In the past, the long-term gas supply security situation in Europe for EU-30 was always analysed within the context of a political, economic stable climate. However politically and socially motivated interruptions in the decades ahead cannot completely be ignored in a world as we face it today. Most arguments in favour of excluding such politically motivated disruptions are based on expectations of economic rational behaviour of the principal actors. This is based on the assumption and optimistic view regarding the expected restructuring of monopoly companies and liberalisation of large government controlled gas supply sectors in some of the key supplying countries. Nevertheless, observing history it can tell us afterwards, that in the past the most unexpected interruptions in oil supply were not of a technical and economic nature but mainly motivated by political arguments. Therefore we also analysed what we call the 'security of supply risks of a strategic nature' by evaluating the impacts of unexpected interruptions of gas supply from the key suppliers to the EU. Note that these events might have a low probability but perhaps a high and costly impact to the gas markets and society if they occur. So both type of risks, the long-term (adequacy of) supply security analysis and strategic risk of an unexpected interruption of gas supply (let's say in 2020) were analysed in the framework of the gas supply security study.

1.5 The structure of the report

In Chapter 2 follows a presentation of results of an analysis of the long-term adequacy of gas supply in Europe. This analysis of the gas supply security situation of the EU, including the candidate countries in the long run is based on a scenario analysis consisting of a reference scenario and two variants illustrating the uncertainty of gas demand, supply and prices in the long run. Analysed are among other things the gas demand/import developments, the key import sources and the 'costs' of gas supplied to the EU-30 and candidate countries up till 2030. Next in Chapter 3 the focus is on the potential development and availability of gas resources and supply from Russia, Turkmenistan and Kazakhstan and transit through Ukraine. From the analysis in Chapter 2 the great relevance of Russian gas supply in the overall supply becomes very clear. Addressed are Russian gas sector developments, potential gas supplies from Turkmenistan and Kazakhstan and finally follows in the chapter an overview of the current situation and issues in Ukraine, a key transit country with respect to supplies from Russia and Turkmenistan. Thereafter Chapter 4 presents the results of the analysis of the resilience of the European gas transport network in the framework of assessment of strategic gas supply risks for EU-30 consumer markets. The impacts of interruptions in four important gas supply routes/sources to the EU-30 are analysed. It concerns projected supplies in 2020 from Norway, Russia and Algeria and via Turkey to EU-30. On this basis also bottlenecks in interconnections and the transport capacity required in the future are evaluated.

In Chapter 5 the long-term development of the gas markets in four relevant accession countries, Czech Republic, Poland, Slovakia and Romania is analysed and presented. Particularly the development of gas demand and import dependency will be discussed with support of newly developed comprehensive gas (energy) scenarios for these countries. Furthermore policy measures for improving the gas supply security situation are assessed and recommended where relevant. The new gas scenarios are compatible with the EU energy strategy for the security of supply[4]. The scenarios will provide a policy framework for the respective national governments for their

[4] Towards a European strategy for the security of energy supply-COM(2000) 769 final, 29.11.2000.

decisions and activities promoting a sustainable development of the gas sector. Next in this chapter follows a brief overview of the current (December 2002) progress and status of implementation of the EU Gas Directive, with an emphasis on Security of Supply (SoS) measures, is presented for these four countries, the Czech Republic, the Slovak Republic, Poland and Romania and also Hungary and Turkey. Finally in Chapter 6 a summary of conclusions and recommendations in the different chapters is reported.

2. LONG TERM GAS SCENARIOS FOR EUROPE

2.1 Introduction

2.1.1 Objectives and scope

The objective of the study[5], which forms the basis for this chapter, is to formulate different scenarios of natural gas supply in Europe for the period 2000-2030 and analyse their implications for supply security and policy. This study seeks to provide the European Union and particularly the candidate accession countries with recommendations for enhancing their gas-supply security, taking account of the enlargement of the EU and the liberalisation of the EU energy market. In the next chapter the risks and consequences of unexpected gas supply interruptions are presented. The focus of this chapter is on the long term and strategic natural gas supply security situation through to 2030 in the light of the implementation of EU Directives and proposed supply security policies in the EU-30 and specifically those implemented in the candidate accession countries.

Scenarios were prepared for the European Union in aggregate in two different configurations:

- The current membership of states (EU-15).
- An enlarged Union of 30 member states (EU-30). The additional members include the ten accession countries that are expected to join the Union in 2004 (Cyprus, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Malta, Poland, Slovakia and Slovenia) and five other countries that might join at some time in the future (Bulgaria, Norway, Romania, Turkey and Switzerland).

The scenarios consider the balance of energy demand and supply under various assumptions concerning macroeconomic trends, population growth, energy prices, technology and government policies. Each scenario determines the gap between indigenous production of natural gas and demand for each configuration and the breakdown of net imports by region of origin.

2.1.2 Methodology and approach

The Economic Analysis Division of the IEA made available data and its in-house World Energy Model to assist with the preparation of the scenarios and related analysis. The IEA uses this model to produce the projections contained in the *World Energy Outlook*, an authoritative assessment of the prospects for global energy markets published every two years and most recently in late 2002. The IEA also made available the results of its analysis of gas-supply costs carried out in 2001 and the preliminary results of its ongoing work on energy investment needs.

The IEA World Energy Model is a mathematical model made up of five main modules: final energy demand, power generation, refinery and other transformation, fossil-fuel supply and emissions trading. The main exogenous variables are GDP, population, household size, international fossil-fuel prices and technological developments. Different scenarios can be modelled by modifying one or more of the exogenous assumptions. The model was revised substantially in 2002, especially with regard to the treatment of technological developments, renewable energy

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[5] Task 5A: Analysis of Long Term Adequacy of Gas Supply in Europe (Menecon Consulting).

sources and supply-side factors. A global refinery model was added and regional disaggregation has been increased.[6]

In line with the approach adopted in the *World Energy Outlook 2002*, baseline or core projections for this study were derived from a Reference Scenario. The projection period is 2001 to 2030. The last year for which complete energy demand and supply data are available is 2000, although some preliminary data is available for natural gas for 2001.

Modifying assumptions concerning energy prices and government policies on nuclear power, renewables and energy efficiency and conservation generated two variants of the Reference Scenario. Basic assumptions on macroeconomic conditions and populations are the same as for the Reference Scenario. These variants correspond to higher and lower gas imports into the European Union compared to the Reference Scenario. These alternative scenarios were designed so as to capture key uncertainties with respect to the evolution of European energy markets. These include the pace of liberalisation and the impact on energy prices and government strategies for dealing both with rising energy-related emissions of greenhouse gases and the prospect of increased dependence on imports of natural gas.

2.2 Reference scenario projections

2.2.1 Key assumptions

The Reference Scenario incorporates a set of explicit assumptions about underlying macroeconomic and demographic conditions, energy prices and supply costs, technological developments and government policies. It takes into account many new policies and measures in European countries and in other parts of the world designed to combat climate change. Many of these policies have not yet been fully implemented; as a result, their impact on energy demand and supply does not show up in the historical data, which are available in most cases up to 2000. These initiatives cover a wide array of sectors and a variety of policy instruments.

The Reference Scenario does not include possible, potential or even likely future policy initiatives. Major new energy policy initiatives will inevitably be implemented during the projection period (2001 to 2030), but it is impossible to predict precisely which measures among those that have been proposed will eventually be adopted and in what form. For that reason, the Reference Scenario projections should not be seen as forecasts, but rather as a baseline vision of how energy markets might evolve if governments individually or collectively do nothing more than they have already committed themselves to do.

The rate of technological innovation and deployment affects supply costs and the efficiency of energy use. The sensitivity of the projections to these assumptions varies by fuel and sector. Since much of the energy-using capital stock in use today will have been replaced by 2030, technological developments that improve energy efficiency will have their greatest impact on market trends towards the end of the projection period. Most heating and cooling systems and industrial boilers will be replaced in the next 30 years. But most existing buildings, many power stations and most of the current transport infrastructure will still be in use. The high cost of building these facilities makes early retirement extremely costly. They will not be replaced unless governments provide strong financial incentives. The very long life of energy-capital stock will limit the extent to which technological progress can alter the amount of energy needed to provide a particular energy service. In general, it is assumed that current technologies become more efficient, but that no new breakthrough technologies beyond those known today will be

[6] A description of the structure of the World Energy Model can be found in IEA (2002), *World Energy Outlook* (Annex D).

will be used on a large scale with any significant impact on energy use before 2030. Hydrogen fuel cells, fuelled by natural gas, are assumed to begin to play a small, but growing role in power generation towards the end of the projection period.

Electricity and gas market reforms aimed at promoting competition in supply are assumed to proceed, although the emergence of effective competition is expected to be gradual. Energy taxes are assumed to remain unchanged. Likewise, it is assumed that there will be no changes in national policies on nuclear power. As a result, nuclear energy will remain an option for power generation solely in those countries that already have a nuclear industry and that have not yet officially abandoned it, namely Bulgaria, the Czech Republic, Finland, France, Hungary, Lithuania, Romania, Slovenia, Spain and the United Kingdom. Nuclear power is assumed to be phased-out progressively in Belgium, Germany, the Netherlands, Sweden and Switzerland. The key underlying assumptions about macroeconomic trends, population growth and energy prices are summarised below.

Macroeconomic and demographic prospects

Economic growth is the most important determinant of energy demand. In the past, European energy demand has risen broadly in line with gross domestic product. Since 1971, each 1% growth in GDP has yielded a 0.47% increase in EU-30 primary energy consumption. Only the oil price shocks of 1973-1974 and 1979-1980 affected this relationship to any significant degree (Figure 2.1). Energy demand is expected to continue to follow economic activity over the next three decades. Consequently, all the energy demand projections, including natural gas, in this study are sensitive to underlying assumptions about economic growth.

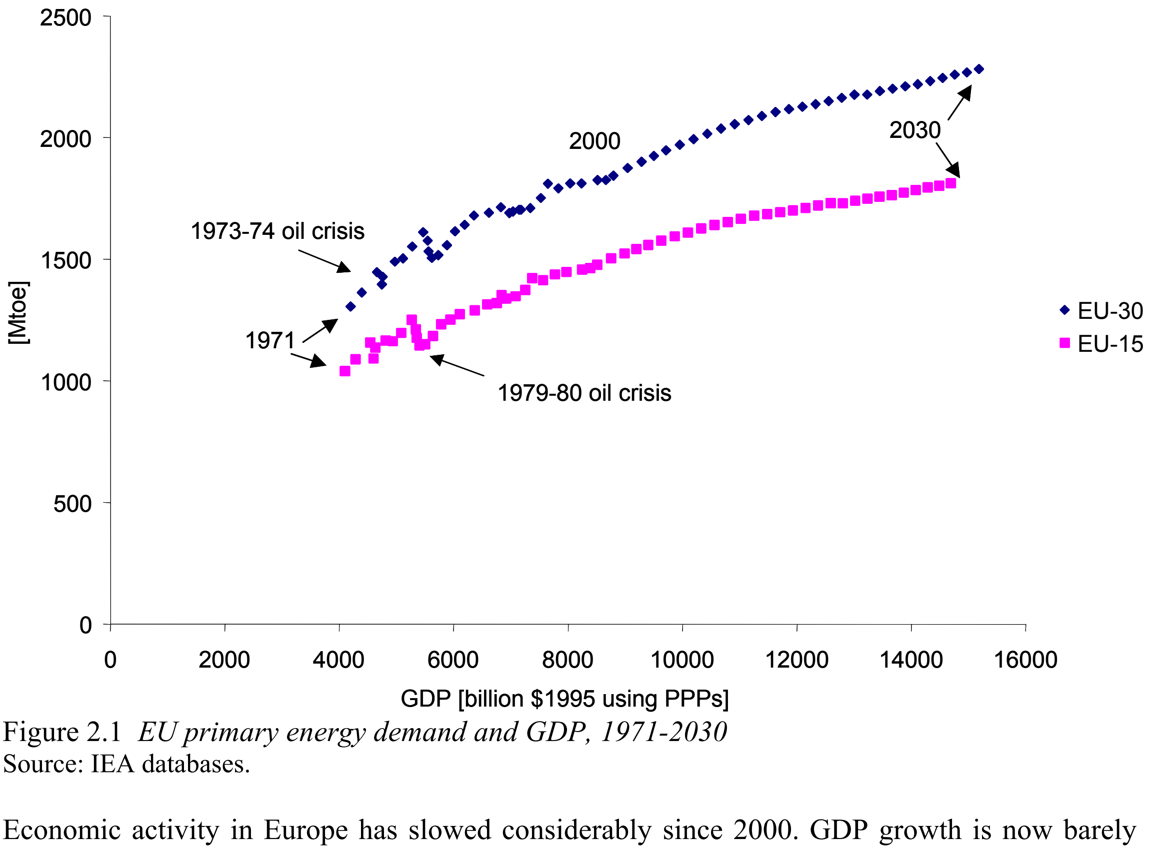

Figure 2.1 *EU primary energy demand and GDP, 1971-2030*
Source: IEA databases.

Economic activity in Europe has slowed considerably since 2000. GDP growth is now barely positive in many European countries, with overall growth of less than 1% expected in EU-30 in 2003. The Reference Scenario assumes that macroeconomic prospects in European countries will improve in the coming years: GDP growth is assumed to average 2.3% during the period 2000-2010 in both EU-15 and EU-30, see Table 2.1. In the longer term, however, GDP growth is assumed to trend down, averaging only 1.9% per year in the last decade of the projection period in both groupings.

Table 2.1 *Average annual real GDP growth in Europe*

[%]	1971-2000	1990-2000	2000-2010	2010-2020	2020-2030	1971-2030
EU-30	2.5	2.0	2.3	2.0	1.6	1.9
EU-15	2.4	2.0	2.3	2.0	1.6	1.9

Source: IEA analysis.

Population growth affects the size and pattern of energy demand. The rates of population growth assumed for the European Union are based on the most recent United Nations projections.[7] EU-30 population is assumed to hold steady in the current decade and decline by around 0.1% per year on average over the period 2000-2030, compared with growth of around 0.5% over the past three decades. Declining fertility rates are expected to more than offset immigration. Total EU-30 population reaches 407 million compared with 417 million in 2000.

2.2.2 Energy prices

Energy prices, exogenous variables in the IEA World Energy Model, are important drivers of total energy demand and supply and the fuel mix. Average end-user prices are derived from assumed fossil fuel prices on wholesale or bulk markets. They take into account current tax rates, which are assumed to remain unchanged. Final electricity prices are derived from marginal electricity-generation costs.

The price trends assumed in the Reference Scenario reflect judgements about the prices needed to ensure sufficient supply to meet projected demand in Europe and in other regions. The smooth price trends assumed should not be interpreted as a prediction of stable prices, but rather as long-term paths around which prices could fluctuate. Indeed, oil and gas prices will probably remain highly volatile.

The underlying assumptions for EU import prices for oil, natural gas and steam coal are summarised in Table 2.2 (in fuel-specific units) and in Figure 2.2 (in comparable heat-equivalent units). The average IEA crude oil import price, used as a proxy for international oil prices, is assumed in the Reference Scenario to average $ 21 per barrel up to 2010 in real year 2000 dollars. That price is roughly equal to the average for the period 1986-2001. Prices are assumed to rise in a linear fashion after 2010, reaching $ 25 in 2020 and $ 29 in 2030. This rising trend reflects the expectation of a gradual increase in marginal production costs and shifts in supply patterns. Because of rising production costs in high-cost producing regions, such as the North Sea, the oil-importing costs will have to rely increasingly on imports from a few countries, mainly in the Middle East and the former Soviet Union. The increasing market dominance of the biggest Middle East producers could lead to a shift in OPEC production and pricing policies in pursuit of higher crude oil prices in the longer term.

Table 2.2 *EU fossil fuel import price assumptions*

[$ 2000]	Units	1990	2000	2001	2010	2020	2030
Crude oil	Per barrel	27.30	28.00	23.39	21.12	25.00	29.00
Natural gas	Per Mbtu	3.27	3.00	3.63	2.76	3.29	3.80
Steam coal	Per tonne	62.62	34.61	37.28	38.84	41.21	43.60

Source: IEA (2002), *World Energy Outlook.*

7 United Nations Populations Division (2001), *World Population Prospects: The 2000 Revision.*

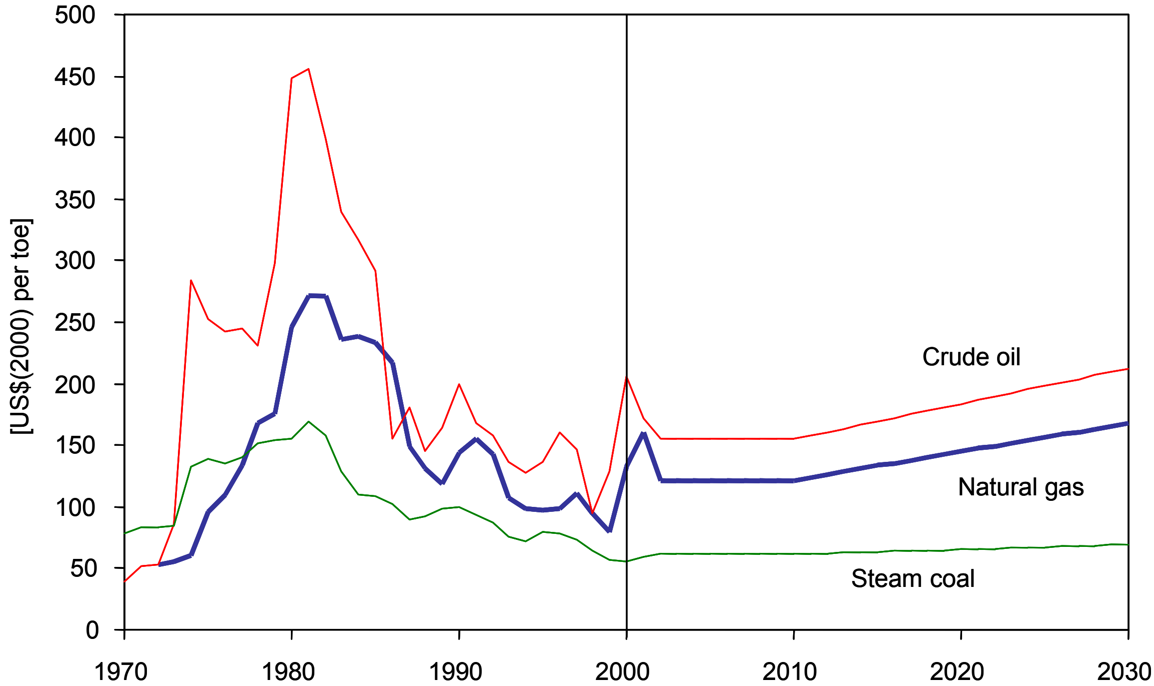

Figure 2.2 *Assumed EU fossil fuel import prices*
Source: IEA (2002), *World Energy Outlook*.

The assumed trend in European gas import prices to 2030 reflects the underlying trend in oil prices together with costs and market factors specific to the region. Oil and gas prices remain linked through price indexation clauses in long-term supply contracts as well as through inter-fuel competition between gas and oil products at the burner tip. Gas prices are assumed to remain flat at around $ 2.80/Mbtu in year 2000 dollars. Gas-to-gas competition is expected to put some downward pressure on border prices as spot trade develops. Lower downstream margins and efforts by national regulators to reduce access charges could further depress end-user prices. But the cost of bringing new gas supplies to Europe is expected to increase as the distances over which the gas has be transported lengthen and project costs rise. This factor is assumed to offset the impact of growing competition. Prices are assumed to rise after 2010 in line with oil prices. As a result, the ratio of gas to oil prices remains flat throughout the projection period at around 80%, which is close to the average for the last decade.

International steam-coal prices are assumed to remain flat in real terms over the period 2002 to 2010 at $ 39/metric tonne, the average for the preceding five years. Thereafter, prices are assumed to increase very slowly in a linear way, reaching $ 44/tonne by 2030. Declines in the cost of mining and increasingly stringent environmental regulations that restrict the use of coal in many countries are expected to offset to a large extent the impact of higher oil prices on the value of coal and therefore its price from 2010.

2.2.3 Results

Primary energy demand

Total primary energy demand in EU-30 is projected to rise by an average 0.7% per year over the projection period well below the rate of 1.2% for the period 1971-2000. The fuel mix is expected to change markedly, with demand for some fuels growing rapidly and others falling (Figure 2.3).

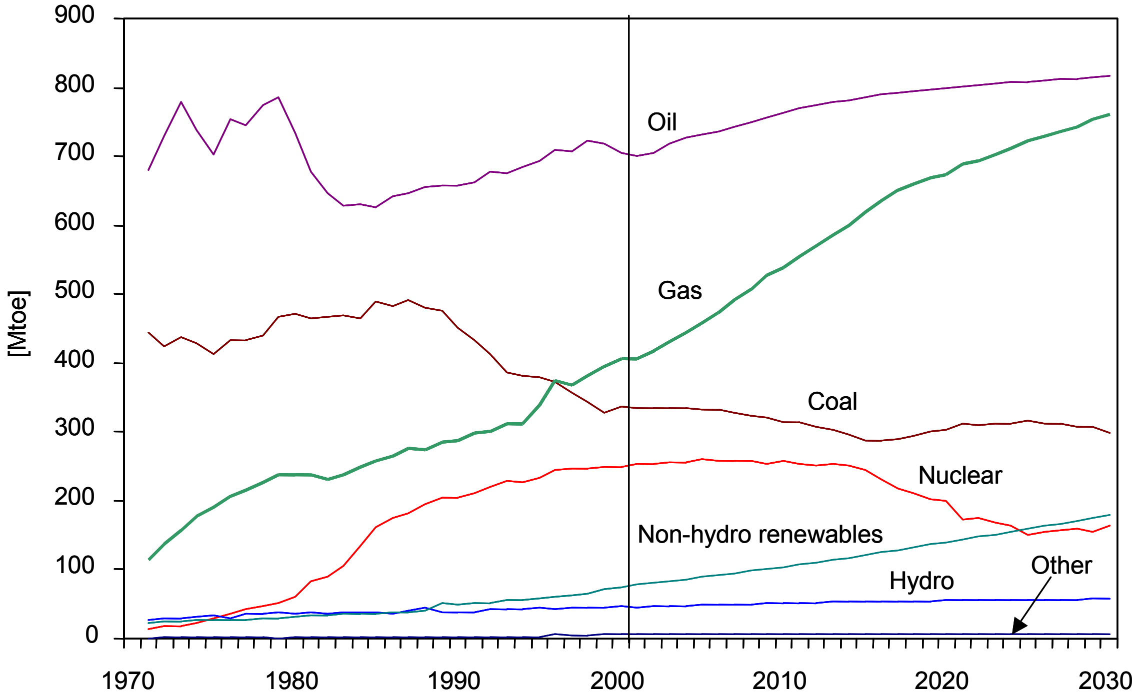

Figure 2.3 *EU-30 primary energy demand*
Source: IEA analysis.

Gas grows faster than any other energy source in absolute terms (Figure 2.4). The shares of coal and oil in the primary fuel mix continue to decline while those of gas and non-hydro renewables increase significantly. Oil remains the largest single source of energy in 2030, even though its share falls slightly, from 39% now to 36% in 2030 (Figure 2.5). The share of gas climbs from 22% to 33% over the same period. Nuclear production is projected to decline progressively after 2010, falling from 14% of primary energy demand in 2000 to 8% in 2030. Non-hydro renewables grow at the fastest rate and their share in total demand reaches 8% in 2030.

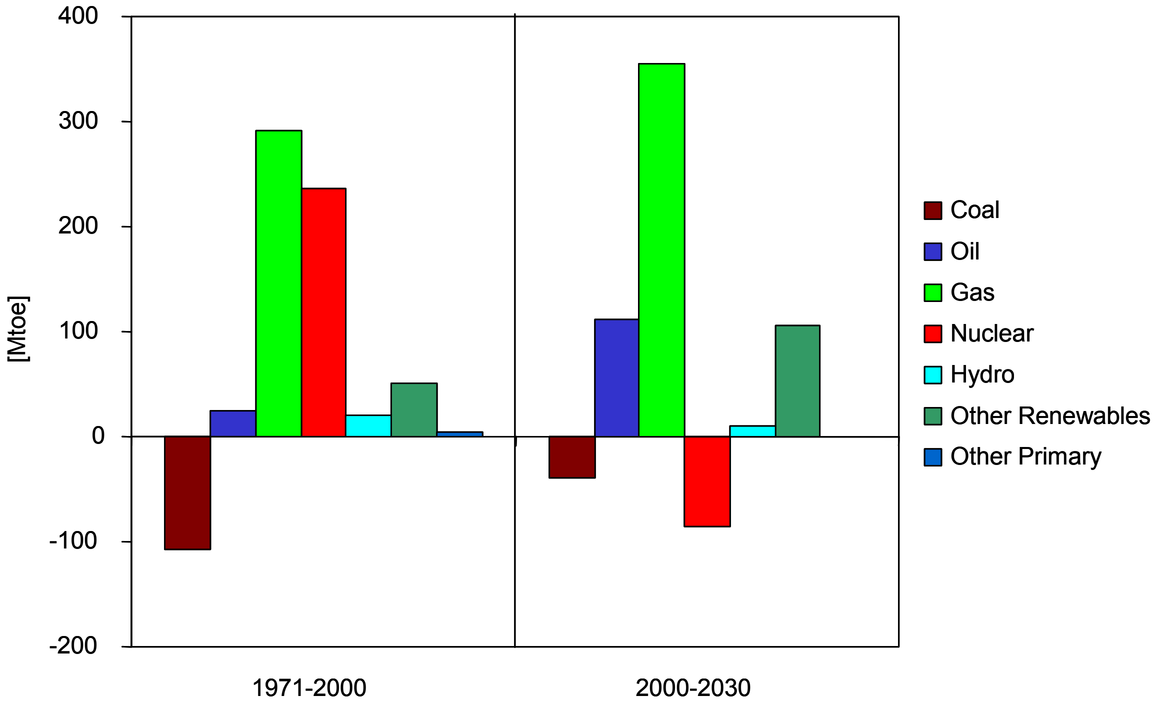

Figure 2.4 *Change in EU-30 primary energy demand*
Source: IEA analysis.

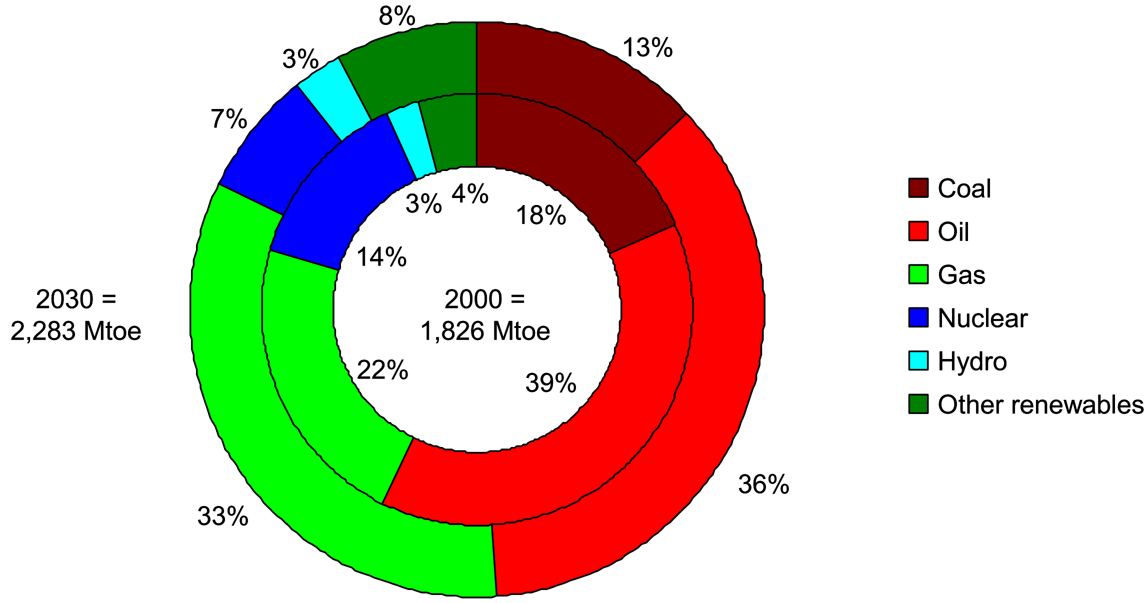

Figure 2.5 *Fuel mix in EU-30 primary energy demand*
Source: IEA analysis.

Primary energy intensity is projected to continue to fall in line with past trends, at an average annual rate of 1.2% between 2000 and 2030. Energy demand trends are similar for EU-15, with total demand rising at the same average rate (see Appendix D for detailed results).

Natural gas demand
Natural gas demand in EU-30 is projected to grow by an average 2.1% per year over the projection period the most rapid growth rate of any fuel other than non-hydro renewables, though well below the 4.5% rate of growth in gas demand over the past three decades. Demand is projected to continue to slow progressively throughout the projection period, from 2.9% in 2000-2010 to 1.2% in 2020-2030. The share of gas in total primary demand continues to rise, from 22% at present to 33% in 2030, although the pace of gas penetration slows in the second half of the projection period (Figure 2.6).

The power sector will be the main driver of gas demand, especially in the first half of the projection period (Figure 2.7). Demand in all other end-use sectors also increases steadily: by around 1% per year in the residential and services sectors and 0.8% per year in industry.

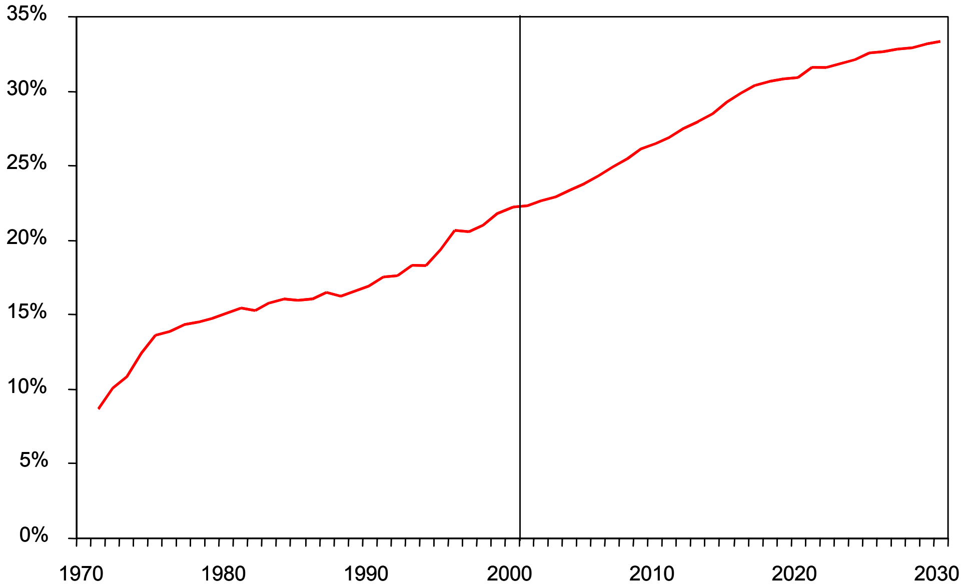

Figure 2.6 *Share of natural gas in EU-30 primary energy demand*
Source: IEA analysis.

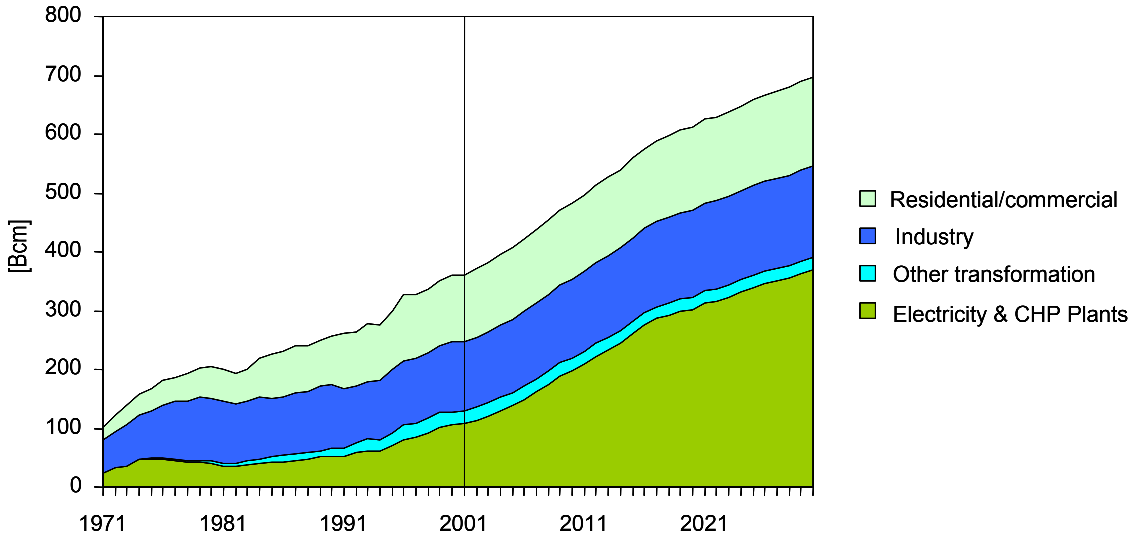

Figure 2.7 *Natural gas demand in EU-30 by sector*
Source: IEA analysis.

Gas is expected to account for the bulk of incremental generation in Europe (Figure 2.8). Further improvements in the thermal efficiency of combined-cycle gas-turbine (CCGT) plants together with the inherent environmental advantages of gas over other fossil fuels mean that gas will be the preferred option in new power stations in most EU countries assuming gas remains competitively priced. Hydrogen-powered fuels cells, based on reformed natural gas, are also projected to make a small but growing contribution to meeting electricity needs towards the end of the projection period. Public resistance to new nuclear reactors and the higher cost of nuclear generation in most countries lead to a decline in nuclear power capacity as old plants are retired. Most of this capacity is replaced by gas-fired CCGTs, although some new coal plants using advanced clean coal technology are expected to be built towards the end of the projection period. As a result, the pace of construction of new CCGTs slows.

The share of gas in total power production is projected to surge from under 16% in 2000 to over 41% in 2030, including hydrogen fuel cells. The power sector's use of gas rises on average by around 4.3% per year.

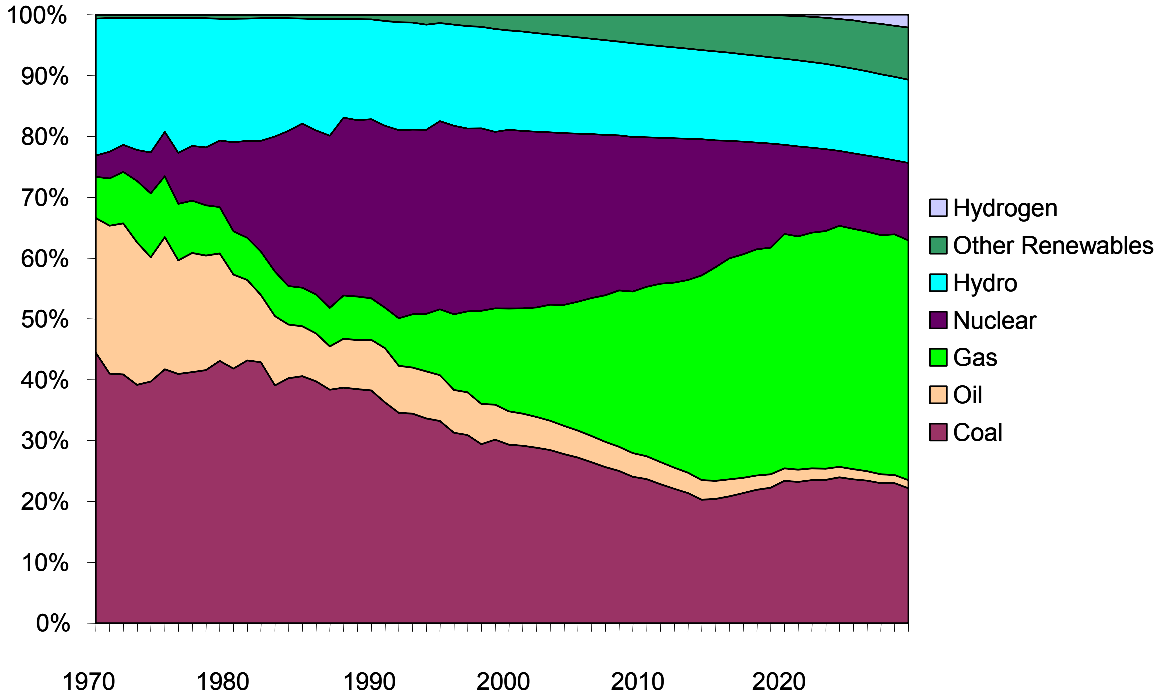

Figure 2.8 *Fuel shares in power generation in EU-30*
Source: IEA analysis.

Natural gas production

Natural gas production in EU-30 amounted to around 320 Bcm in 2001. Three producers the United Kingdom (113 Bcm), the Netherlands (78 Bcm) and Norway (57 Bcm) accounted for 77% of the total. Most of these countries' output is from offshore fields in the North Sea a mature producing region. Germany, Italy and Denmark are the only other significant producers. Gas resources in Europe are limited: proven reserves now stand at a little over 8 Tcm, or 5% of the world's total. In its most recent survey in 2000, the US Geological Survey estimated undiscovered resources at around 11 Tcm, equal to only 2% of global resources.

There is limited potential for any significant increase in gas production in the region. Production from the North Sea is expected to peak in the next few years and gradually decline, although higher output from the Norwegian Sea and the Norwegian sector of the Barents Seas is expected to offset this trend to some extent (Figure 2.9). Overall, Norwegian output is projected to rise throughout the projection period. Currently contracted supplies will plateau at around 75 Bcm/year by 2005 or soon after. But there is scope for further increasing sales, even without adding capacity to the network of offshore pipelines. With additional compression, current pipeline capacity of 86 Bcm/year could probably be increased to 100 Bcm/year. Production is expected to reach this level by 2010 and continue to increase with the development of more northerly offshore fields and the construction of new export pipeline and LNG facilities, reaching 155 Bcm by 2030. UK output is expected to decline steadily over the next three decades, and the country will become a major net importer of gas before the end of the current decade. Total EU gas production is projected to peak at around 330 Bcm around the middle of the current decade and then stagnates gradually, reaching 290 Bcm in 2030.

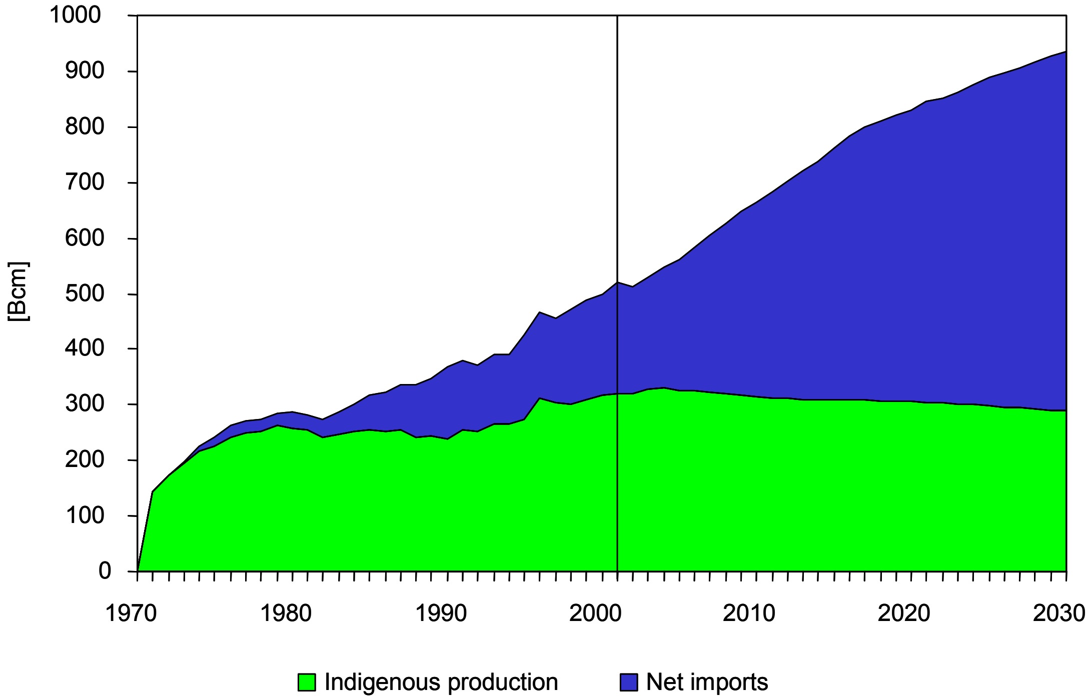

Figure 2.9 *Natural gas supply in EU-30*
Source: IEA analysis.

Natural gas imports

With falling indigenous production, all of EU-30's projected increase in demand will have to be met by increased imports. Net imports are projected to surge from 200 Bcm in 2001 to almost 650 Bcm in 2030. The share of imports in the region's total gas demand will rise from 38% to just under 70% over the same period (Figure 2.10). Import dependence follows the same trend for EU-15, increasing from 191 Bcm (44% of total supply) to 633 Bcm (81%).

Figure 2.11 illustrates the breakdown of EU-30 gas imports by region of origin. Imports into EU-30 and EU-15 by region are projected on the basis of the availability of gas for export in net gas-exporting countries (derived from production and demand projections in those regions) and a bottom-up analysis of supply costs (see below). The bulk of imports are expected to come from Europe's two main current suppliers, Russia and Algeria, and a mixture of piped gas and LNG from other African and Former Soviet Union countries and from the Middle East and Latin America. An overview by BEICIP/Franlab of natural gas reserves, supply and export potentials from countries outside the EU is presented in Appendix A.

Russia is projected to remain the largest single supplier in 2030, exporting over 210 Bcm to EU-30 of which 60 Bcm will go to the accession countries (mainly Bulgaria, the Czech Republic, Poland, Romania and Turkey). But the biggest increase in supplies will be from the Middle East, mostly in the form of LNG, although increasing quantities of gas are expected to be transported to Europe by pipeline from Iran and possibly Iraq towards the end of the projection period. Imports of LNG from Trinidad and Tobago and Nigeria are set to rise. Other new sources of gas are expected to include Libya (via under-sea pipeline), Egypt and Qatar (both LNG). Venezuela could also emerge as an LNG supplier in the long term. Spot shipments from other LNG exporters in the Middle East and Latin America and possibly further a field could play an increasingly important role if a global short-term market in LNG develops.

The role of accession countries in transit of gas from Former Soviet Union and Middle East to current EU-15 Member states will increase significantly. Transit volumes across Bulgaria, Poland, Romania and Turkey are projected to grow from 75 Bcm to 151 Bcm in 2030.

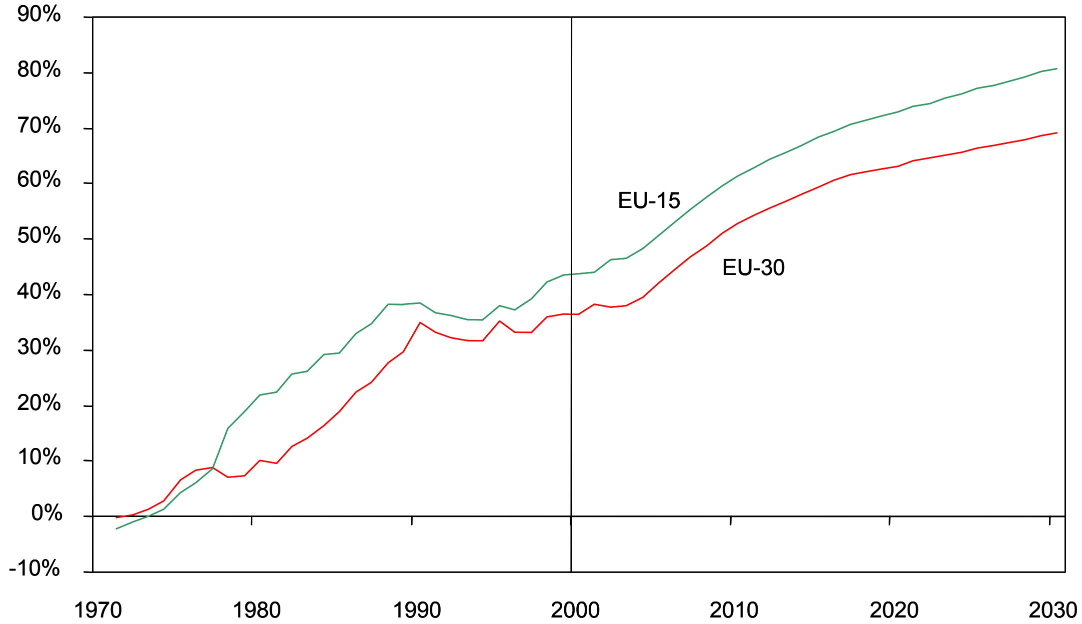

Figure 2.10 *Share of net imports in total gas supply*
Source: IEA analysis.

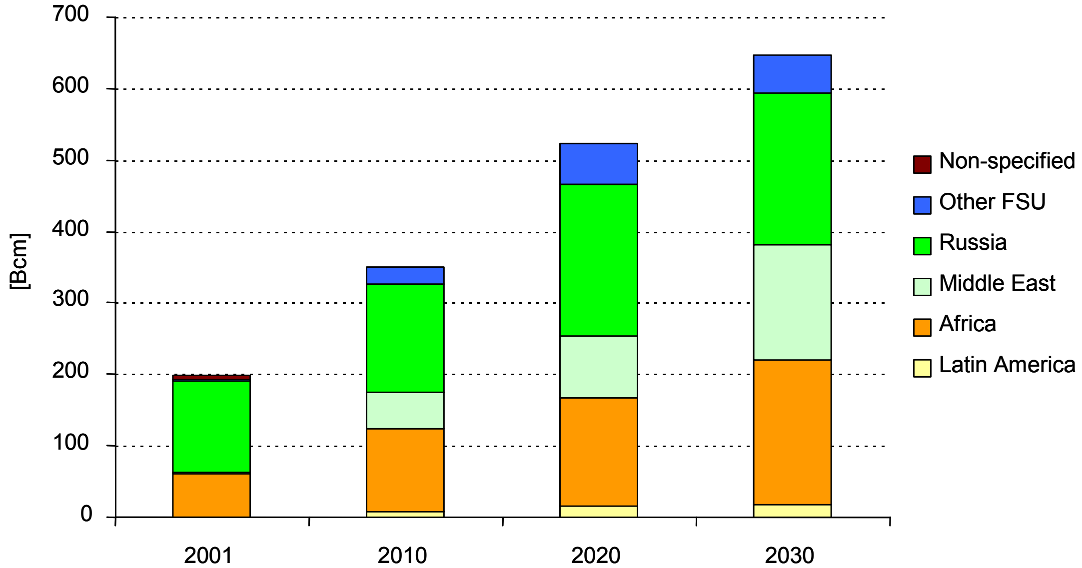

Figure 2.11 *Net gas imports in EU-30 by region of origin*
Source: IEA analysis.

That there is enough gas in the ground in these countries to meet Europe's gas needs until 2030 is not in doubt. Proven Reserves in the Former Soviet Union, Africa and the Middle East alone amount to 126 Tcm-equal to more than 240 years of current EU-30 consumption (Table 2.3). But the unit costs of producing and transporting these reserves to EU markets will most likely be higher than for the current sources of gas used by EU-30 countries as they are more distant and, in some cases, more costly to produce. Indicative costs of incremental gas supplies for a range of potential sources for delivery beginning 2010-2015 are shown in Figure 2.12 and Table 2.3.

Table 2.3 *Natural gas proven reserves and undiscovered resources*

Country	Reserves [Bcm] (at 1.1.02)	Undiscovered resources [Bcm] (at 1.1.96)	Total
Azerbaijan	1,370	1,909	3,279
Kazakhstan	1,900	2,045	3,945
Russia	46,475	33,075	79,550
Turkmenistan	2,900	5,878	8,778
Uzbekistan	1,850	0,426	2,276
Other Former Soviet Union	1,386	0,779	2,165
Total FSU	*55,881*	*44,112*	99,993
Algeria	4,523	1,386	5,909
Egypt	1,557	0,578	2,135
Libya	1,325	0,597	1,922
Nigeria	4,500	3,487	7,987
Other Africa	1,213	4,125	5,338
Total Africa	*13,118*	*10,173*	23,291
Iran	26,500	8,902	35,402
Iraq	3,109	3,396	6,505
Qatar	25,768	1,163	26,931
Other Middle East	15,761	22,955	38,716
Total Middle East	*71,138*	*36,416*	107,554
Trinidad & Tobago	0,558	0,900	0,1,458
Venezuela	4,163	2,865	7,028
Other Latin America	3,350	11,417	14,767
Total Latin America	*8,071*	*15,182*	23,253

Source: Reserves-Cedigaz (2002), Natural Gas in the World; resources-United States Geological Survey (2000), *World Petroleum Assessment 2000.*

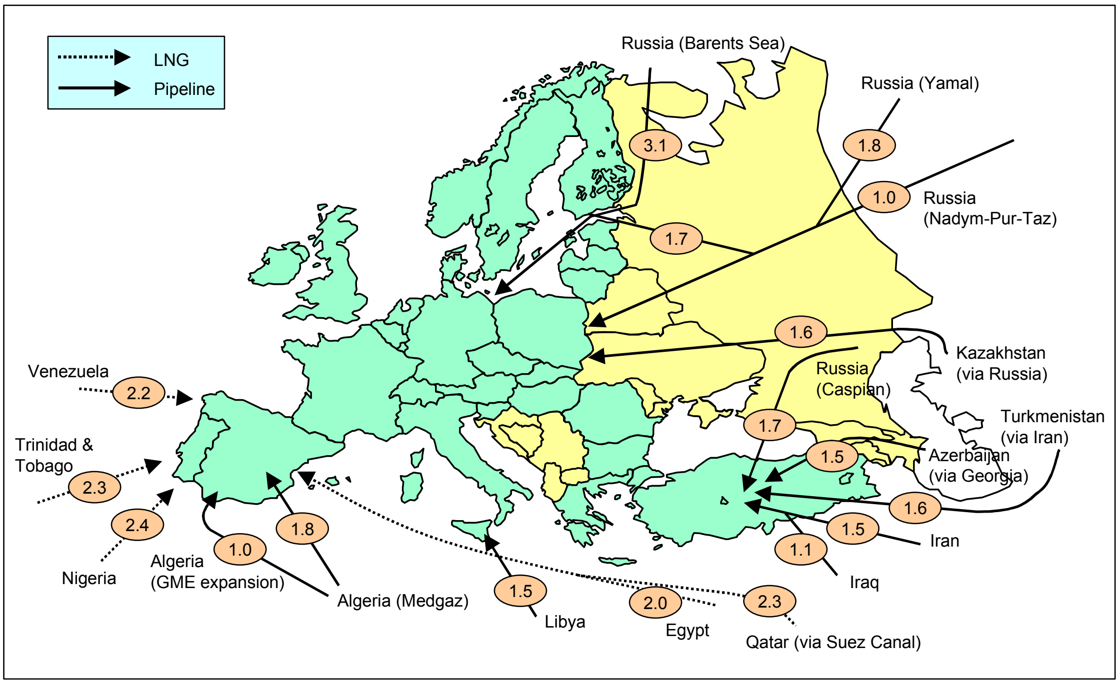

Figure 2.12 *Indicative supply costs for new sources of gas to EU-30 borders in 2020-2015 [$/Mbtu]*

Turkey has access to the cheapest gas supplies in EU-30 thanks to its proximity to low-cost Middle East reserves. Piped gas from Algeria (with additional compression on the Mahgreb-Europe line), from Libya (via a new sub-sea line) and from the Russian Nadym-Pur-Taz region in Western Siberia is probably the cheapest near-term option for supplying southern and northern Europe. But these sources will not be sufficient to meet rising demand after 2015. A new sub-sea line direct from Algeria to Spain is likely to be a competitive medium-term option to supply southern Europe, followed by LNG from Egypt, Latin America and the Middle East. New green-field projects to bring gas from the Yamal Peninsula in Russia and from the Caspian region will be much more expensive, unless they are able to make use of existing pipeline capacity. The ranking of each supply source according to total costs is shown for delivery to East/North Europe, South Europe and Turkey in Figure 2.13.

Table 2.4 *Indicative supply costs for new sources of gas to EU-30 Borders in 2010-2015 [$/Mbtu]*

Country/source	Mode	Delivery point	Production[1]	Transport[2]	Total
Russia-Nadym-Pur-Taz (via Belarus)[3]	Pipe	Polish border	0.5	0.5	1.0
Russia-Nadym-Pur-Taz (via Baltic S.)[4]	Pipe	German coast	0.5	1.2	1.7
Russia-Yamal (via Belarus)[5]	Pipe	Polish border	1.0	0.8	1.8
Russia-Barents Sea (via Baltic Sea)[6]	Pipe	German coast	1.0	2.1	3.1
Russia-Caspian (via Black Sea)[7]	Pipe	Turkey-Ankara	0.8	0.9	1.7
Kazakhstan (via Russia/Ukraine)[8]	Pipe	Slovak border	0.5	1.1	1.6
Turkmenistan (via Iran)[9]	Pipe	Turkey-Ankara	0.4	1.2	1.6
Azerbaijan (via Georgia)[10]	Pipe	Turkey-Ankara	0.6	0.9	1.5
Iran (South Pars)[11]	Pipe	Turkey-Ankara	0.5	1.0	1.5
Iraq (North)[12]	Pipe	Turkey-Ankara	0.5	0.6	1.1
Libya (direct)[13]	Pipe	Italy-Sicily	0.6	0.9	1.5
Algeria (via Morocco)[14]	Pipe	Spanish coast	0.6	0.4	1.0
Algeria (direct)[15]	Pipe	Spanish coast	0.6	1.2	1.8
Egypt[16]	LNG	Spain	0.6	1.4	2.0
Nigeria[16]	LNG	Spain	0.6	1.8	2.4
Qatar[17]	LNG	Italy	0.4	1.9	2.3
Trinidad & Tobago[16]	LNG	Spain	0.6	1.7	2.3
Venezuela[16]	LNG	Spain	0.5	1.7	2.2

Source: Menecon Consulting analysis based on IEA databases.

Notes:

1. Production costs, which do not include taxes or royalties, are notional.
2. Includes transit charges, which are assumed to be a function of the number of countries crossed and distance. Pipeline and LNG costs are based on generic capital and operating cost estimates that take no action of project-specific factors, a 10% discount rate and 30-year asset lives. Utilisation rate of 90% for LNG liquefaction and 85% for pipelines are assumed.
3. New 25-Bcm/year line from Torzhok compressor station to Polish border.
4. New 25-Bcm/year sub-sea line from Torzhok to St. Petersburg and across Baltic Sea to German coast.
5. New 25-Bcm/year line from Yamal Peninsula to existing trunklines and from Torzhok to Polish border.
6. New 25-Bcm/year line from offshore Shtokman field via Russia mainland and Baltic Sea.
7. Bluestream system expansion involving supply from Astrakhan field and new 16-Bcm/year parallel line across Black Sea to Ankara.
8. New 25-Bcm/year overland line from Kashagan field across Russia and Ukraine.
9. New 25-Bcm/year overland line across Iran to Ankara, Turkey.
10. New onshore and offshore 15-Bcm/year line from Shah-Deniz field via Georgia to Ankara.
11. New 25-Bcm/year overland line to Ankara.
12. New 25-Bcm/year line from the Kashim Al Ahmar/Gilbat fields to Ankara.
13. New 11-Bcm/year sub-sea line.
14. 9 Bcm/year of additional capacity on Maghreb-Europe line with increased compression.
15. New 12-Bcm/year sub-sea line direct to Spanish coast.
16. Greenfield 7-million tonnes/year two-train projects.
17. Shipped through the Suez Canal.

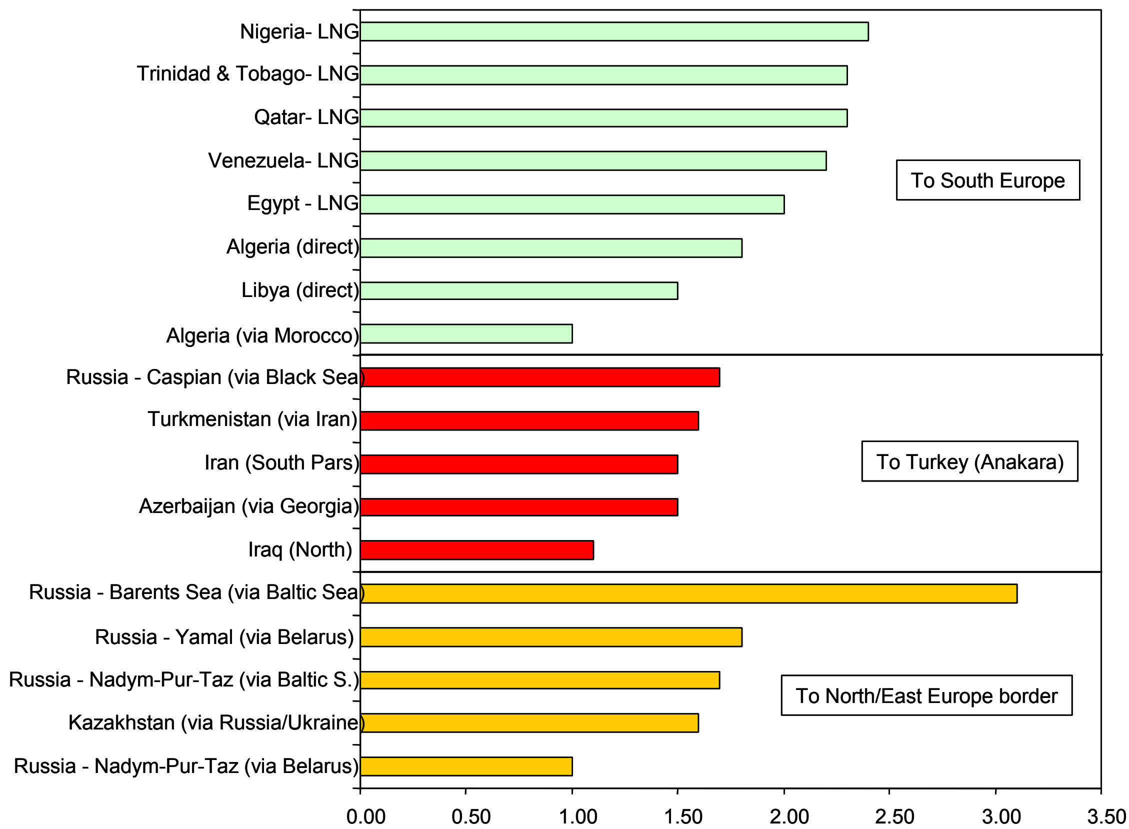

Figure 2.13 *Ranking of supply costs for new sources of gas to EU-30 Borders in 2010-2015 [$/Mbtu]*

Source: Menecon Consulting analysis based on IEA databases.

In practice, supplies are unlikely to be developed in strict cost-order because of other factors that influence buyers' choices of upstream projects, including the following:

- Political risk is a major consideration for many of the more distant supplies, particularly those whose gas must transit through several countries deemed to be politically unstable. In recent years, occasional disruptions to Russian gas supplies through Ukraine to Western Europe and Turkey because of non-payment by Ukrainian gas buyers have highlighted these risks. Such country risks are a major obstacle to developing projects for high-capacity pipelines to bring gas from the Middle East and the Caspian region.
- Potential or actual government limitations on the proportion of imports from a single supplier may significantly alter supply patterns. In Spain, for example, imports from a single country are legally capped at 60% of total imports. This means that LNG is likely to be favoured over increased piped supplies from Algeria, which currently supplies most of Spain's gas.

2.3 Alternative scenarios

2.3.1 Approach and assumptions

The Reference Scenario projections of gas demand, indigenous production and imports are subject to a range of uncertainties. The reliability of those projections depends not just on how well the model represents reality, but also on the validity of the assumptions that underpin them. European gas markets could evolve in ways that are much different from the Reference Scenario.

The main sources of uncertainty, which are all inter-related, are:

- *Macroeconomic conditions*
  If GDP growth in Europe is slower than assumed, demand will grow less rapidly, other things being equal.
- *Fossil-fuel prices*
  Gas prices will remain strongly linked, through contractual arrangements and inter-fuel competition, to oil prices. But liberalisation and gas supply/demand fundamentals could cause prices to de-couple to some degree, if only temporarily. The ratio of gas prices to coal prices will largely depend on the economics of power generation.
- *Energy resources*
  While good information is available about proven gas reserves, there is considerable uncertainty about the prospects for new discoveries in EU countries and neighbouring regions, as well as the cost of extracting those reserves and transporting them to market.
- *Energy technology*
  The rate of technological advances in the use and supply of energy is a key factor. For example, hydrogen fuels cells fuelled with natural gas could alter energy market trends after 2020 depending on the pace of cost-reductions and technological improvements.
- *Investment climate*
  The Reference Scenario projections imply a need for massive investment in gas supply infrastructure and demand-side equipment to use gas, including power stations. Various factors, such as political instability, regulatory uncertainty and price volatility, might impede the timely mobilisation of this investment.
- *Government policies*
  Changes in the government policies of gas-consuming countries, including those aimed at combating climate change, at curbing pollution and at promoting competition in gas and electricity markets, could have a major impact on market trends. The production and pricing policies of major oil and gas producers are also critically important to gas-price trends.

Two alternative scenarios corresponding to higher and lower gas imports to provide a contrasting picture of how EU gas markets could evolve given different sets of circumstances were developed. Specifically, these scenarios analyse the sensitivity of the results for gas supply and imports for an enlarged Europe to different trends in oil and gas prices and the availability of nuclear power than assumed in the Reference Scenario. The potential impact of new government policies to promote the use of renewables and to save energy whether for energy security or environmental reasons was considered in the Low Gas Imports Scenario. Table 2.5 summarises the changes in underlying assumptions in the two scenarios compared to the Reference Scenario.

In the *Low Gas Imports Scenario*, oil and gas prices are assumed to follow a higher trajectory than in the Reference Scenario. The dominant OPEC oil producers are assumed to pursue a policy of raising prices in response to domestic budgetary pressures and/or a sharper decline in non-OPEC production than assumed in the Reference Scenario. Natural gas prices are assumed to rise even faster than oil prices, because of higher production and transportation costs. EU gas liberalisation is assumed to proceed more slowly than assumed in the Reference Scenario, so that gas-to-gas competition fails to temper the upward pressure of costs on prices. The ratio of gas prices to oil prices rises gradually throughout the projection period, reaching 0.85 in 2030, compared with 0.79 in the Reference Scenario.

Table 2.5 *Assumptions under alternative scenarios*

		Reference	Low gas imports	High gas imports
Crude oil price [$ 2000/barrel]	2010	21	25	17
	2020	25	30	20
	2030	29	36	22
Natural gas price [$ 2000/toe]	2010	110	135	85
	2020	130	165	95
	2030	151	201	101
Government energy policies		No changes	• New nuclear plants built and lifes of existing plants extended • New energy savings and renewables measures currently under consideration adopted (see Table 3.2 for details). • Slower pace gas-market liberalisation	• More rapid phase-out of nuclear (earlier retirement) • Faster liberalisation and development of gas-to-gas competition

Source: IEA analysis.

It is further assumed that as a result of higher fossil-fuel prices, it is more economically attractive to invest in extending the lifes of existing nuclear reactors. Some new nuclear capacity is also built, as it becomes a cheaper alternative to gas-fired CCGTs. The improvement in the competitiveness of nuclear power and higher energy prices generally are assumed to increase the public acceptability of nuclear plants.

In addition, this scenario takes into account a number of government policies and measures that are currently being considered by EU-15 countries aimed at either saving energy or promoting renewables. These measures are summarised in Table 2.6. The effects of many of these measures were estimated using detailed bottom-up sub-models of the energy system, including capital-stock turnover models, which were incorporated into the IEA World Energy Model.

In the *High Gas Imports Scenario*, oil and gas prices are assumed to be lower than in the Reference Scenario. This might happen because the dominant OPEC oil producers decide to pursue a more aggressive market-share policy or because non-OPEC producers are able to raise their production faster than expected, putting downward pressure on oil prices. Natural gas prices are assumed to be proportionately weaker than oil prices, possibly because of more intense gas-to-gas competition as liberalisation of EU gas markets proceeds more rapidly and because of technology-driven reductions in production and transportation costs. The ratio of gas prices to oil prices falls from 0.93 in 2001 to 0.70 in 2030, compared with 0.79 in the Reference Scenario.

Lower energy prices would undermine the competitiveness and public acceptability of nuclear power. It is therefore assumed that existing plants are retired earlier than in the Reference Scenario and that no new plants are built anywhere in EU-30.

The basic assumptions about macroeconomic conditions and population in both alternative scenarios are the same as in the Reference Scenario.

Table 2.6 *New policies and measures considered in the low gas imports scenario*

Sector	Programme/measure	Impact
Industry	Regulations/standards for new motor systems.	Improved efficiency of new motors.
	Voluntary programmes including information/technical assistance, energy auditing and target setting.	Improved efficiency of new technologies and accelerated deployment; lower energy needs in buildings and for appliances.
	Tax incentives and low-interest loans for investment in new technologies.	Accelerated deployment of new boilers, machines and process-heat equipment.
	Increased funding for R&D programmes.	Improved efficiency of new equipment after 2010-2015.
Residential/commercial	Framework Directive on equipment standards.	Increased efficiency of new appliances.
	Buildings Directive.	Increased thermal efficiency of buildings.
Power generation	Full implementation of the Renewables Energy Directive (including guaranteed prices, mandatory portfolio shares and investment tax credits).	Increased share of renewables in the fuel mix in generation.
	Policies to promote combined heat and power production.	Increased share of CHP in generation.
	Various policies including R&D and deployment to accelerate the penetration of highly efficient coal and gas plants.	Higher thermal efficiencies in new plants.

Source: IEA analysis.

2.3.2 Results

The scenario analysis yields significantly different trends in and patterns of natural gas demand and supply (Figure 2.14). The deviations from the Reference Scenario are most marked for the Low Gas Import Scenario, largely because of the substantially lower demand resulting both from higher energy prices, from less need for new gas-fired generation capacity and from new government policies. Net imports still increase in that scenario, but much less rapidly than in the Reference Scenario. Imports are somewhat higher in the High Gas Import Scenario, mainly due to more rapid growth in power-generation demand.

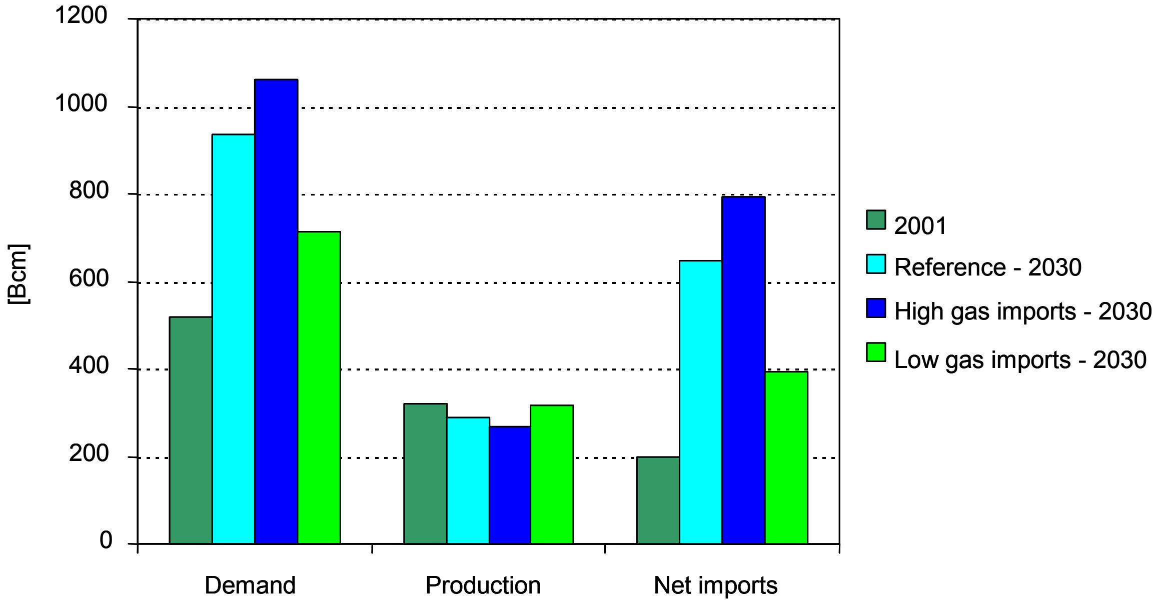

Figure 2.14 *Natural gas demand and supply under alternative scenarios*
Source: IEA analysis.

Natural Gas Demand
Gas demand deviates significantly under the alternative scenarios, as a result of changes in overall demand for energy as well as fuel switching. In the *Low Gas Imports Scenario*, higher energy prices, increased nuclear power capacity and government policies to increase energy efficiency and boost renewables result in slower growth in demand for natural gas throughout the projection period (Figure 2.15). Primary demand for gas still increases by close to 90%, from just under 500 Bcm in 2000 to 936 Bcm in 2030. The share of gas in the primary fuel mix is also lower in 2030, at 27% compared with 33% in the Reference Scenario. In the *High Gas Imports Scenario*, gas demand increases more rapidly, reaching 1,061 Bcm in 2030, while its share in the primary fuel mix reaches 33%.

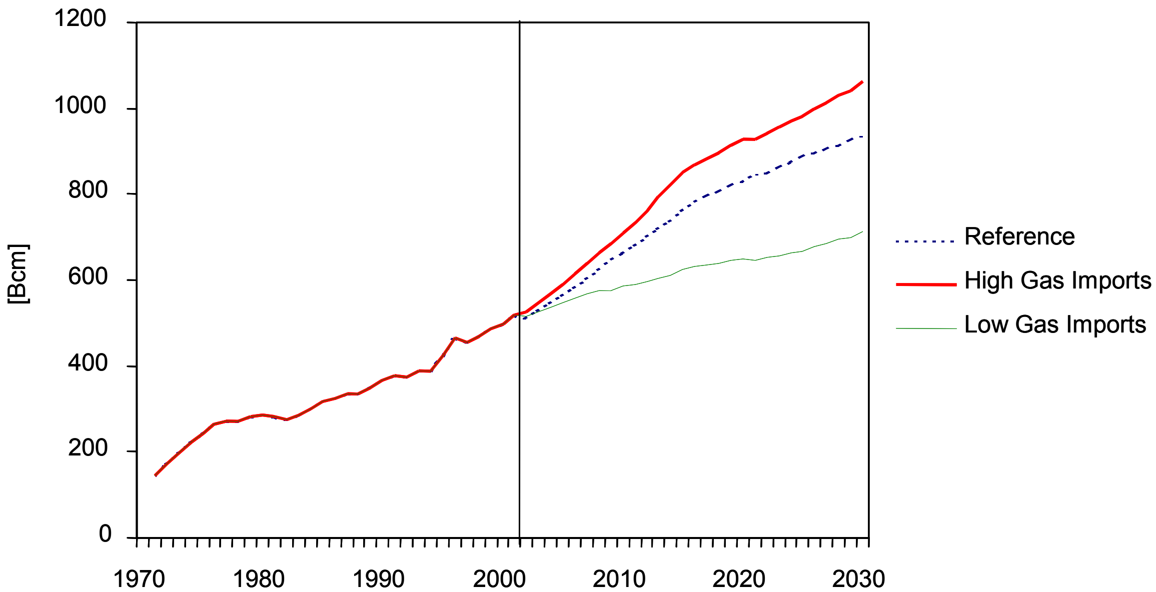

Figure 2.15 *Primary natural gas demand under alternative scenarios*
Source: IEA analysis.

The deviations in gas demand from the Reference Scenario in both alternative scenarios are driven largely by changes in the fuel mix in the power sector (Figure 2.16). Gas use for power generation, including hydrogen production for fuel cells, increases by only 2.2% per year on average in the Low Gas Import Scenario, compared to almost 4.5% per year in the Reference Scenario. The share of nuclear power in total electricity production declines slightly while the share of non-hydro renewables increases rapidly, reaching 17% in 2030. The shares of coal and oil fall sharply (Figure 2.17). In the High Gas Imports Scenario, the share of gas in the fuel mix increases moderately at the expense of nuclear power compared with the Reference Scenario, with little change in the shares of the other fuels.

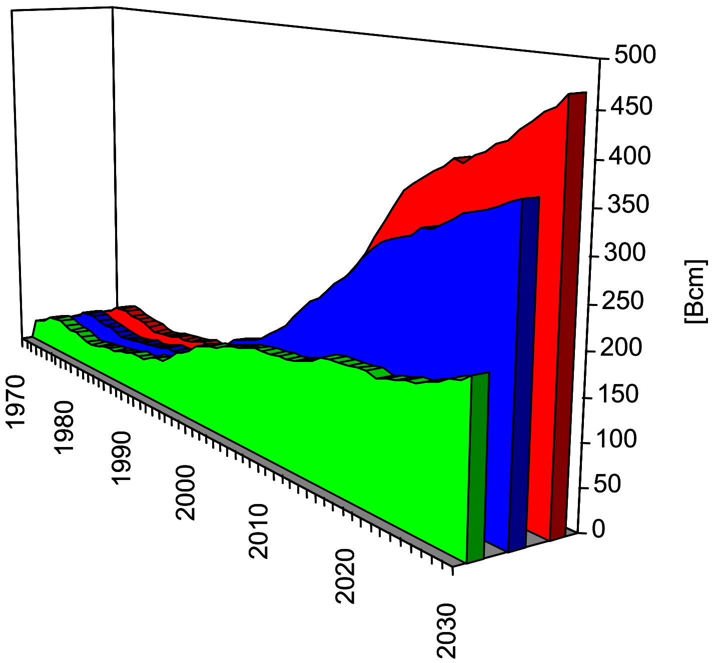

Figure 2.16 *Natural gas consumption for power generation under alternative scenarios*
Note: Includes gas used for hydrogen production for fuel cells.
Source: IEA analysis.

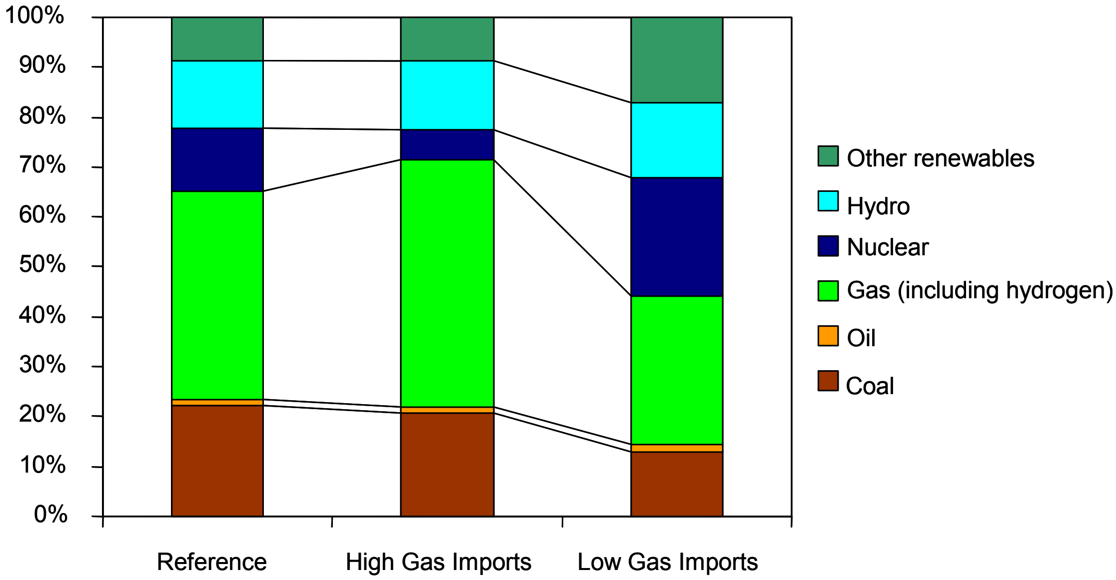

Figure 2.17 *Natural gas consumption for power generation under alternative scenarios*
Source: IEA analysis.

Natural gas production

Indigenous gas production in EU-30 is relatively insensitive to the assumed changes in prices in both alternative scenarios. Although higher prices can encourage governments to open more acreage for exploration and development drilling, gas production in Europe tends to be driven more by the success of exploration drilling and fiscal policies than by short term price movements. In 2030, production is 28 Bcm higher in the Low Gas Imports Scenario and 20 Bcm lower in the High Gas Imports Scenario (Figure 2.18).

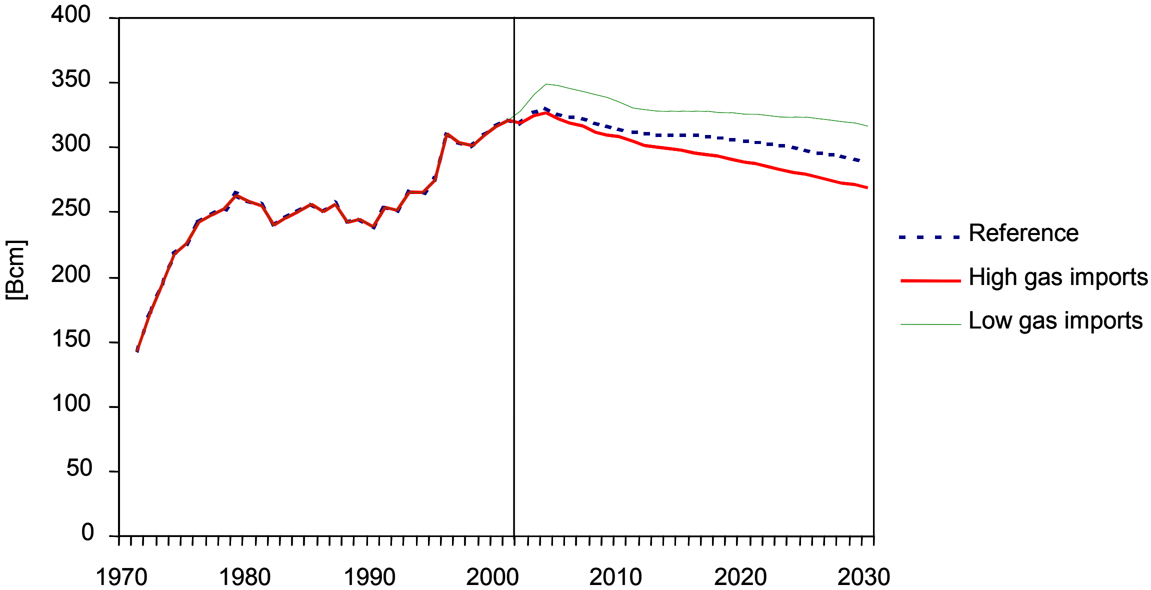

Figure 2.18 *Natural gas production under alternative scenarios*
Source: IEA analysis.

Natural gas imports

The combination of lower demand and higher production results in significantly lower rate of growth in gas imports into EU-30 over the projection period under the *Low Gas Imports Scenario* (Figure 2.19). Imports rise from 200 Bcm in 2001 to 250 Bcm in 2010 and 390 Bcm in 2030. By the end of the projection period, imports in this scenario are little more than 60% of their level in the Reference Scenario. Most of this difference is due to lower gas consumption in the power sector. Although it was modelled separately, Germany would account for a large proportion of the reduction in gas imports vis-à-vis the Reference Scenario, on the assumption that its nuclear reactors are not phased out as currently planned and new coal-fired plants are built. The shares of the main supplier regions to EU-30 also differ markedly from the Reference Scenario (Figure 2.19). Imports from the Middle East are considerably lower in 2030. Imports from Africa and Russia are also lower, but less so than for the Middle East and other Former Soviet Union countries where long-run marginal supply costs are generally highest. Transit gas across the accession countries accounts for most of the reduction in imports from the Former Soviet Union and Middle East.

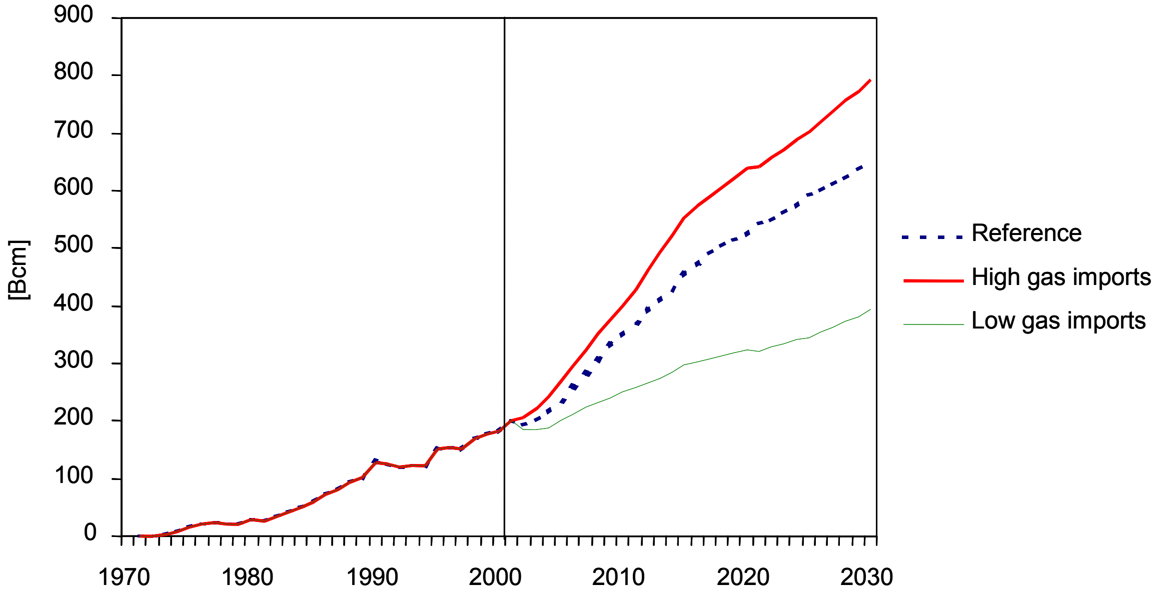

Figure 2.19 *Natural gas net imports under alternative scenarios*
Source: IEA analysis.

Imports are somewhat higher in the *High Gas Imports Scenario*, mainly due to stronger demand. Imports reach 400 Bcm in 2010 and 790 Bcm in 2030. The Middle East and Russia would account for most of the additional gas imports under this scenario compared to the Reference Scenario as most of the low-cost sources of supply in North Africa would have been committed by then. Such a large increase in dependence of supply in North Africa would raise enormous concerns about security of supply (see Section 4). Transit volumes across the accession countries would also be substantially higher.

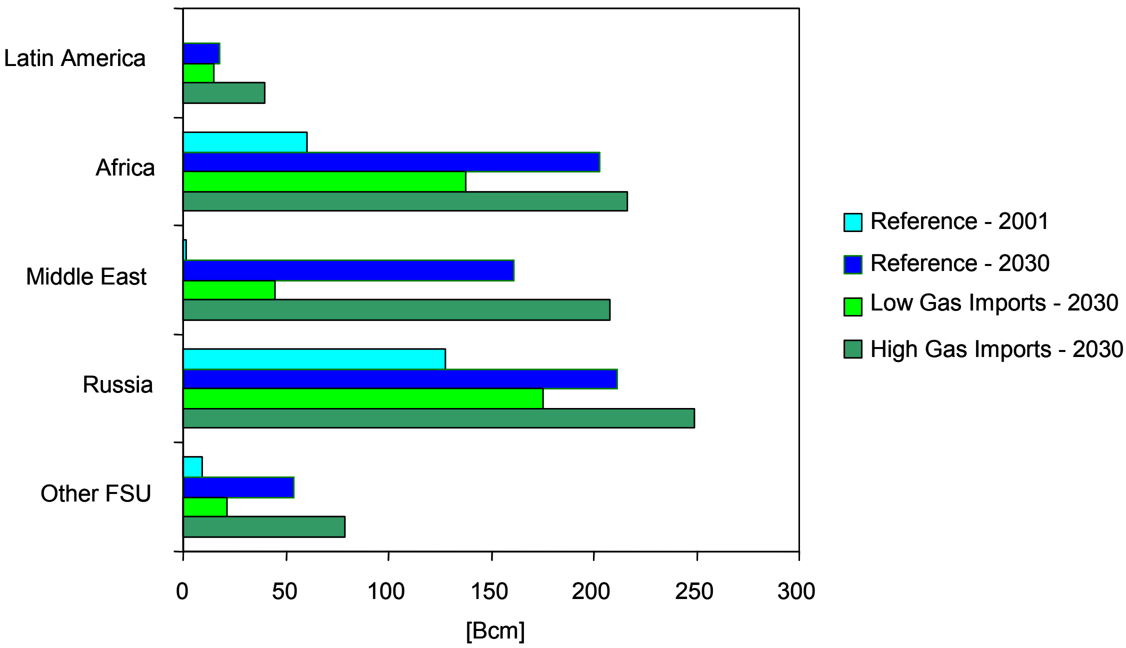

Figure 2.20 *Natural gas imports by origin under alternative scenarios*
Source: Menecon Consulting analysis based on IEA projections.

2.4 Implications for supply security and policy

The potential enlargement of the European Union would reinforce concerns about gas-supply security. Security risks fall into two broad categories:

- The short-term risk of disruptions to existing supplies caused by political events, strikes, accidents or technical failures.
- The long-term risk that new supplies cannot be brought on-stream quickly enough to meet growing demand for either political or economic reasons.

In its 2000 Green Paper on energy security[8], the European Commission identified the purpose of an EU gas supply security policy as securing the immediate and longer-term availability of a diverse range of gas supplies at a price that is affordable to all consumers while respecting the environment. In practice, this involves reducing to an acceptable level the risks and consequences of gas supplies not being available. The risks of disruption in key supplies are analysed and discussed in the next chapter. Below some key points of the long-term risks are elaborated.

2.4.1 Impact of enlargement on supply security

Although the enlargement of the European Union to thirty countries would *reduce* the degree of gas-import dependence because of the inclusion of Norway, the main gas-producing country by the end of the projection period, both short- and long-term supply security concerns are likely to be exacerbated. In the Reference Scenario, imports rise from 38% of total gas supply in 2001 to 69% in 2030 for EU-30. For EU-15, the share of imports increases from 44% to 81%. However, there is no reason to think that Norway's accession to the European Union would enhance the security of gas supply, as it is already a well established, reliable and politically stable supplier to EU countries in close proximity to Western European markets. On the other hand, the high degree of dependence of the candidate accession countries in Central and Eastern Europe and their unusually heavy dependence on imports from a single country Russia will affect supply-security risks for the Union as a whole. Reliance on a single supply route in some accession countries adds to the short-term risks. Enlargement would nonetheless be expected to reduce the risk associated with transit of gas across the accession countries to existing EU-15 Member states.

We have not modelled the import dependence of individual EU member states. However, it is reasonable to suppose that the Central and Eastern European countries will remain heavily dependent on imports from Russia since they lie along the principal supply routes into Western Europe. Developing alternative supply options, such as LNG or pipeline connections to enable imports of gas from Norway or North Africa, would be extremely expensive.

Turkey, by contrast, is diversifying its sources of gas imports significantly. At present, it imports gas only from Russia, directly via the Blue-stream system and overland via Romania and Bulgaria. It also imports LNG from Algeria and Nigeria. Imports by pipeline from Iran are expected to grow substantially: a 10-Bcm/year pipeline from Iran was completed in 2001 although only small volumes have so far been delivered on an intermittent basis. In addition, first gas from the Shah-Deniz field in Azerbaijan through a 15-Bcm/year pipeline that will transit Georgia is expected in 2007. Iraq and Turkmenistan could emerge as major additional suppliers to the Turkish market in the longer term. Turkey is expected to become a major transit route for Middle East and Caspian gas supplies to Central and Western Europe in the longer term. The national gas companies of Austria, Bulgaria, Hungary, Romania and Turkey are investigating the feasibility of building a pipeline from Turkey to Austria.

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[8] European Commission (2000), *A Green Paper: Towards a European Strategy for the Security of Energy Supply.*

2.4.2 Long-term investment needs

The scale of the projected expansion of the EU-30 gas market raises question marks about whether investment will be forthcoming in a timely manner. The projected increases in gas demand and imports in the Reference Scenario imply a need for substantial additions to gas production, transportation and storage capacity both within EU-30 borders as well as in those countries that will supply gas to Europe. Just over half of the total 450 Bcm increase in import capacity that will be needed by 2030 is expected to be met by new pipelines. More than 200 Bcm/year of additional LNG regasification capacity will also be needed (Figure 2.21). There will be also be a need to expand distribution networks and downstream storage capacity, although the rate of expansion will be proportionately less than for high-pressure transmission since the average load factor is expected to rise as the share of base-load power plants in total demand increases.[9]

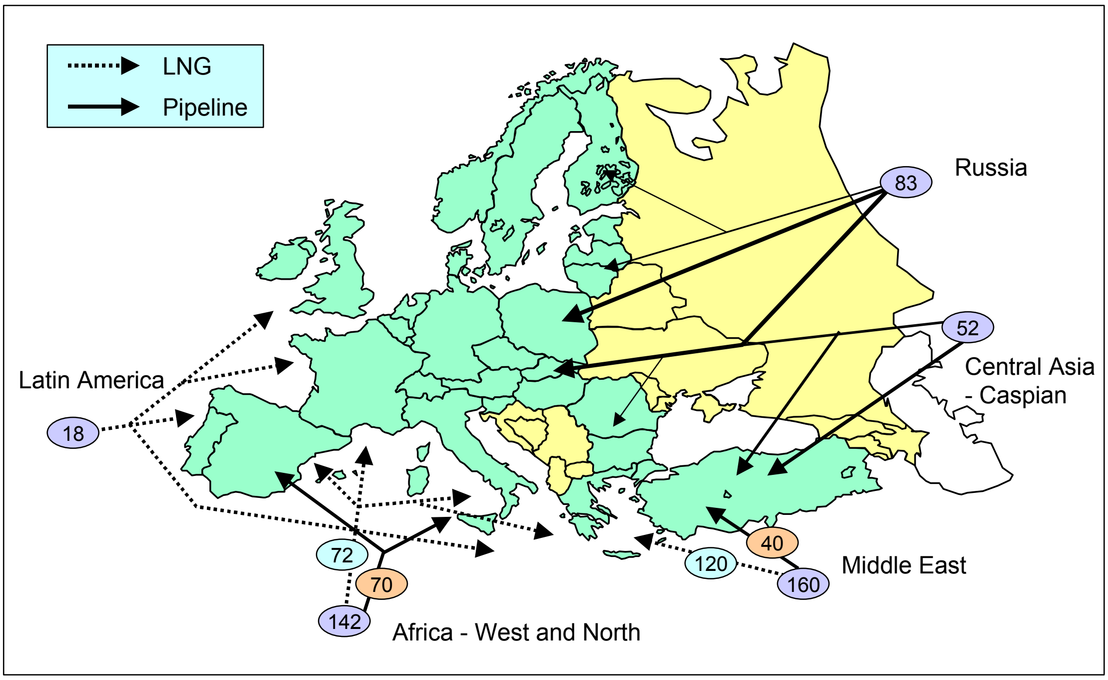

Figure 2.21 *Incremental gas import flows to eu-30 in reference scenario, 2000-2030 [Bcm]*
Source: IEA analysis.

The financing requirements for these capacity expansions will be enormous. We estimate that just under $ 500 billion will need to be invested in gas-supply infrastructure in EU-30 countries and a further $ 190 billion in external supplier countries over the period 2001-2030 (Figure 2.22). In total, this amounts to almost $ 23 billion per year (Table 2.7). Although most of the increase in supplies will come from imports, exploration and development in EU-30 almost entirely in the Northwest Europe Continental Shelf are expected to account for more than a third of total capital expenditure. This is mainly because development costs will rise steeply as UK, Danish and Dutch gas reserves in the North Sea are depleted. Upstream spending in both EU-30 and external supplier countries accounts for about half the total projected investment in EU-30 gas-supply infrastructure. Transmission and distribution within EU-30 border makes up most of the rest. Investment per Bcm of new production capacity will be significantly higher for EU-30 than for external suppliers. Faster production decline rates in EU-30 make the cost of *net* capacity additions even higher.

Average annual investment requirements are projected to remain broadly flat over the period 2001-2030, as rising spending in the upstream sector in external suppliers and in LNG chains offset declining transmission investment. Unit capital costs for LNG liquefaction, shipping and

[9] An increase in the average load factor means that less pipeline capacity is needed relative to overall gas demand.

regasification are nonetheless expected to continue to fall. Total investment in national transmission networks in EU-30 and in trunklines from external suppliers is projected to decline progressively throughout the projection period. However, the estimates presented here do not include spending on refurbishing transmission lines, because of the lack of reliable data on the state of old lines. Some high-pressure lines in Russia are already more than thirty years old and many are in poor condition because of extreme operating conditions and low construction standards. Our analysis suggests that the cost of refurbishing obsolete transmission lines in Europe and Russia could exceed $ 50 billion over 2001-2030, assuming operating lives of around 35 years in FSU countries and 50 years in Europe.

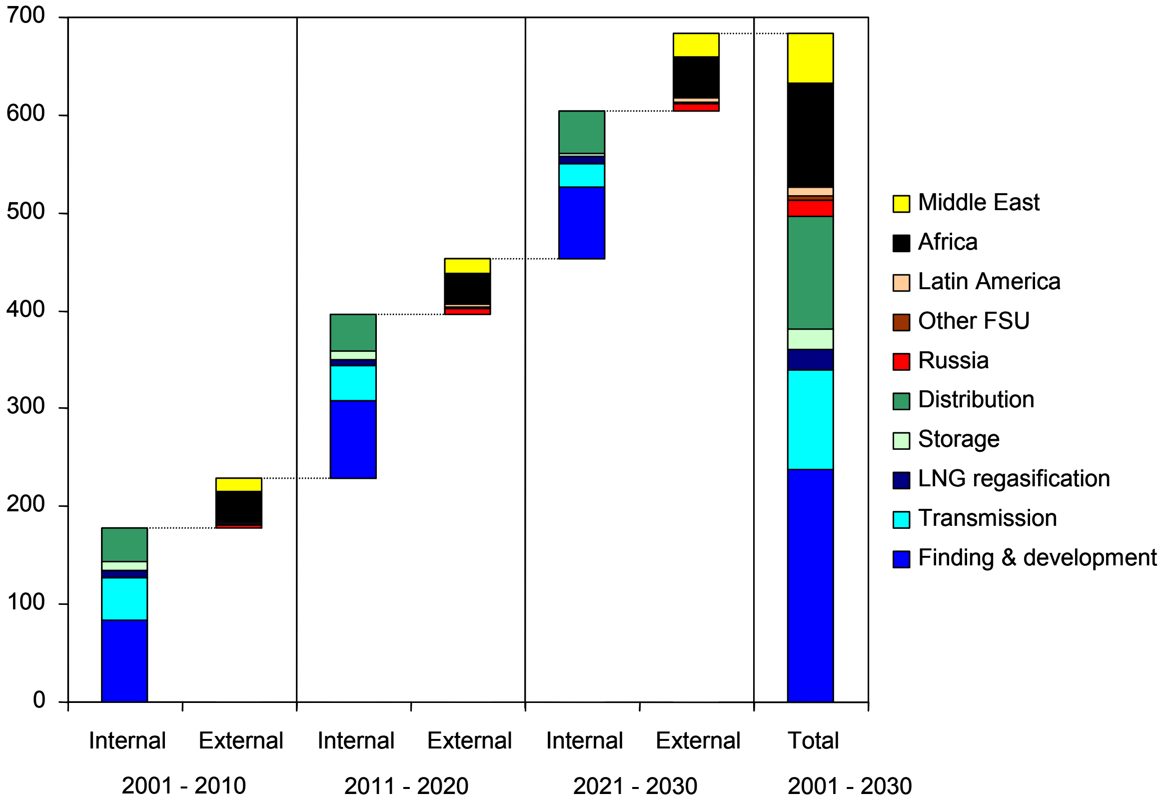

Figure 2.22 *Cumulative investment in gas-supply infrastructure for EU-30, in [$ billion]*
Source: IEA analysis based on IEA (203), World Investment Outlook (forthcoming).
Note: Based on Reference Scenario projections. Internal investments cover infrastructure built within EU-30 borders. External investments include finding, development and transportation outside EU-30.

Table 2.7 *Average annual investment needs for gas-supply infrastructure in EU-30 [$ billion]*

Sector	2001-2010	2011-2020	2021-2030	Total 2001-2030
Finding and development	8.45	7.87	7.39	7.90
Transmission	4.19	3.70	2.30	3.39
LNG regasification	0.83	0.49	0.84	0.72
Storage	0.91	0.99	0.23	0.71
Distribution	3.39	3.75	4.36	3.83
Total internal investment	*17.76*	*16.79*	*15.11*	*16.55*
Russia	0.39	0.58	0.74	0.57
Other FSU	0.04	0.13	0.18	0.12
Latin America	0.23	0.27	0.39	0.30
Africa	3.12	3.22	4.29	3.54
Middle East	1.34	1.43	2.39	1.72
Total external investment	*5.12*	*5.63*	*7.99*	*6.25*
Total investment	*22.88*	*22.42*	*23.10*	*22.80*

Note: Based on Reference Scenario projections.
Source: IEA analysis.

Financing expansions of local distribution and national transmission networks as well as interconnectors is not expected to be a major hurdle to investment in most EU countries. Existing operators will most likely continue to finance most new investment, mainly out of operating cash flows. Tariffs for the use of transmission and distribution systems are generally regulated on a cost-of-service basis, effectively providing a high level of assurance to the investor that he will be able to recover his capital and operating costs. Consequently, debt financing where necessary is unlikely to be a problem in most cases. Although the sums of money required are large, there is no shortage of capital available for downstream or upstream projects that can demonstrate an adequate return on investment taking account of the associated risks. In addition, the Union provides financial and other forms of assistance for new gas-infrastructure projects in member states as well as transit countries in Central and Eastern Europe under the Trans-European networks (TEN) programme.

There is considerably less certainty about how much investment will be needed in projects in external supplier countries and whether that investment will be forthcoming, especially beyond the current decade. A number of developments, including longer supply chains and the growing importance of LNG in European gas supply, will give rise to profound shifts in gas-supply investment risks, required returns and financing costs. As a result, there is a growing danger that investment might not occur quickly enough. In this case, supply bottlenecks could emerge and persist for long periods due to the physical inflexibility of gas-supply infrastructure and the long lead times in developing gas projects: investment decisions have to be taken well in advance of when demand is expected to materialise. Such investment shortfalls would drive up prices and accentuate short-term price volatility. The main investment uncertainties are the costs of supplying gas to EU borders, issues relating to the financing of large-scale projects, geo-political factors and the impact of liberalisation on contracting practices and financing.

Supply Costs

The cost of supplying gas to EU-30 markets is expected to rise significantly throughout the projection period, as the region has to turn to new, more distant sources to replace existing supplies that will be depleted and to meet rising demand. New supplies from the as-yet-undeveloped Yamal Peninsula in Russia, for example, are expected to cost at least twice as much as fields in the Nadym-Pur-Taz region. Transportation is becoming the most expensive component in an increasing number of new projects. While technological advances are expected to lower the per kilometre unit cost of high-pressure offshore transmission and LNG liquefaction, shipping and regasification, the pace of cost reductions and their impact on the relative economics of pipeline and LNG projects are highly uncertain.

Higher costs than expected will drive up required rates of return, either rendering some major projects uneconomic or raising the amount of capital needed.

Financing Large-scale Projects
New projects to supply Europe are becoming increasingly 'lumpy', involving extremely large initial investments, often amounting to several billions of dollars. For example, the capital cost of the proposed Northern European Pipeline from Russia to Germany, including a connecting onshore pipeline from the existing Trans-Siberian transmission system, is estimated at close to $ 7 billion ($ 5.7 billion for the offshore alone). Similarly, greater distances and larger capacities are pushing up the total capital cost of LNG chains, despite significant reductions in unit costs in recent years. See also Appendix B on LNG technology prospects.

Greenfield projects are the most costly and challenging of all types of gas investment, since the infrastructure for the full supply chain gas-field production facilities, high-pressure pipelines and/or LNG chains and local distribution networks needs to be brought into operation simultaneously. The profitability of such projects depend heavily on how quickly all the supply capacity is put to use, because upfront capital expenditures account for the overwhelming bulk of total supply costs. The technical risks of some projects, such as the Russian Yamal and Shtokhman projects, will also be higher because of extreme climatic and geographic conditions. Obtaining financing for large, technically challenging investments is more difficult, time consuming, costly and, therefore, uncertain.

Geo-political Factors
These will become increasingly important as attention shifts to potential projects in the Caspian region and the Middle East. A more stable political environment in those regions and enhanced relations with Europe would lower investment risk and the cost of capital, making it more likely that investments will be made and reducing the need for higher gas prices. Pipeline projects are particularly vulnerable to perceptions of political risk where they involve transit.

The Impact of Liberalisation
There is considerable uncertainty about the pace of liberalisation of EU gas markets and its structural and market implications. But it is clear that long-term take-or-pay contracts in some form will remain necessary for investors to obtain financing for large scale projects in Europe, at least until the transition to a truly competitive downstream gas market has been completed. However, as has already been observed in North America, there is likely to be a tendency for the gas merchants to seek contracts of somewhat shorter duration than the 20 to 25 year terms that are typical in Europe at present, because of the increased risks they face. And they will push for less onerous take-or-pay conditions and more flexible pricing terms, in recognition of the uncertainties about their future market share and the risk of being stranded with surplus gas that they might have to sell on at a loss. At the same time, the merchant companies may have to take a bigger financial involvement in pipeline systems to spread risk and secure adequate financing at reasonable cost. Once gas-to-gas competition and liquid spot markets are well established, the need for long-term contracts to secure financing may disappear, since spot markets could then take any volumes that a gas merchant contracts for but is unable to sell directly.

For now, the uncertainties relating to the evolution of the regulatory framework at national and EU levels, together with the additional price volatility that will inevitably result from the emergence of gas-to-gas competition, is leading to a perception of greater overall project risk on the part of investors and financiers. Uncertainties about how quickly spot markets and market centres develop, as well as the possibility of significantly lower wellhead prices in the future, are also increasing risk. These factors might raise the cost of capital, skew investment towards smaller, closer-to-market projects and form a barrier to investment in technically riskier, multi-billion dollar projects.

Liberalisation of electricity markets is also contributing to the risks faced by developers of gas-supply projects, because of the importance of power-generation load. Major new gas-supply projects will need to be underpinned by firm long-term contracts between gas merchants and power companies, involving fairly rigid off-take commitments and pricing terms. But uncertainty about how the future structure of the power-generation industry and changes in regulation, as well as the impact of government policies on electricity demand prospects, may make it harder for power generators to make those kinds of commitments.

2.4.3 Policy implications

The long-term gas supply scenarios described in this report demonstrate the enormous impact that energy and environmental policies could have on gas demand and, therefore, the need to import more gas. Policies to promote the more efficient use of energy and the deployment of renewables in power generation could play an important role in reducing gas needs. But their impact would be limited in the next decade or so because of the slow rate of replacement of energy equipment and power plants. Such policies could also carry a high economic cost. Policies that boost the role of nuclear power could have a larger impact on gas imports, especially in the short term. They might also be less costly, especially if oil and gas prices were to rise. However, political considerations and public acceptability will remain the primary determinants of the future role of nuclear power.

The impact of liberalisation on investment and long-term supply security is a particular concern. EU and national policymakers will clearly need to tread very carefully in reforming their gas and electricity markets to ensure that the new rules and emerging market structures do not impede or delay investments that are economically viable. This is especially important with regard to cross-border pipelines and LNG regasification terminals. The management of the transition to competitive gas markets is especially critical to industry perceptions of uncertainty, the cost of capital and willingness to invest. Establishing a long-term policy and regulatory framework which sets clear and stable rules for gas and electricity markets is a critical condition to attract investment in gas-supply infrastructure and power plants. Although it is impossible to completely remove uncertainty about future changes in the regulatory environment, investors will at least require reassurances about the long-term evolution of market rules.

The public authorities can also provide special treatment for very large projects, by exempting them from specific regulatory requirements that would otherwise jeopardise financing or increase costs. For example, removing the requirement on LNG terminals to make available their capacity to third parties at regulated rates may be expected to encourage investment. The second EU gas Directive permits national regulators to exempt LNG regasification capacity from third-party access requirements under certain conditions. And several national regulators, including Ofgem in Britain, have signalled that they will consider favourable applications for exemptions from LNG terminal developers. For their part, several companies considering investments in new terminals have indicated that they would be more likely to proceed if third-party access obligations were lifted. To the extent that such a move results in the building of more terminals and a more diversified supply mix, it would contribute to a more competitive EU gas market.

Similarly, policymakers will need to take account of the increased risks facing both upstream producers and merchant gas companies as a result of energy liberalisation in setting rules for long-term supply contracts and joint marketing arrangements. Downstream European gas companies are responding to the increased challenge of mobilising investment in large-scale gas-import projects by seeking a greater degree of co-operation and partnership with upstream operators. This approach can help to mitigate risk and create a more reassuring climate for large investments. These partnerships involve joint investment in infrastructure projects and gas marketing ventures. For example, several European gas companies, notably Ruhrgas, are strengthening their commercial ties with Gazprom, while Gaz de France and Sontatrach have negotiated partnership agreements.

EU and national policymakers may also need to play a more proactive role in promoting investment in certain high-risk, large-scale gas projects especially strategically important cross-border pipelines. The European Commission is already seeking to reduce country risk by intensifying a political dialogue with the governments of supplier countries, such as the EU-Russia energy dialogue, a formal process launched in 2000.[10] This should contribute to a more stable investment climate and support closer collaboration between upstream and downstream companies. National-level initiatives and policies will also play a major role. The German Government's support for the E.On and Ruhrgas merger was motivated partly by the strengthened financing capability that the merger would give to Ruhrgas for investments in Russian and other gas-supply projects. And the UK Government is giving strong political backing to the proposed Northern European Gas Pipeline project, which may ultimately bring Russian gas to the British market.

The arguments for explicit subsidies to selected gas projects are less compelling, because of the market distortions they can result in and the financial cost. Nonetheless, there may also be a case for some form of public support for cross-border projects where there are significant strategic benefits to the country or region, such as diversity of supply or increased scope for competition between suppliers. A number of multilateral and regional lending institutions, including the European Investment Bank and the European Bank for Reconstruction and Development, have successfully provided financial and other types of assistance to such projects in the past. A notable success was the Maghreb-Europe Pipeline, to which the EIB lent €1 billion. The development banks, as well as national and multilateral export credit agencies, will continue to play an important role in backing major pipeline projects in the future.

2.4.4 Conclusions

An enlarged European Union faces the prospect of a substantial increase in gas imports in the next three decades in the absence of rigorous new government policies at EU and national levels. In a Reference Scenario, natural gas demand in EU-30 is projected to grow by an average 2.1% per year over the projection period the most rapid growth rate of any fuel other than non-hydro renewables. The share of gas in total primary demand will continue to grow, from 22% at present to 33% in 2030. The power sector will be the main driver of gas demand, especially in the first half of the projection period.

With indigenous production projected to stagnate, all of EU-30's projected increase in demand will have to be met by increased imports. Net imports are projected to surge from 200 Bcm in 2001 to almost 650 Bcm in 2030. The share of imports in the region's total gas demand will rise from 38% to just below 70% over the same period. The bulk of imports are expected to come from Europe's two main current suppliers, Russia and Algeria, and a mixture of piped gas and LNG from other African and Former Soviet Union countries and from the Middle East and Latin America.

Under an alternative Low Gas Imports Scenario, a combination of sharply lower demand and slightly higher production due to higher prices and policies that reduce demand results in a significantly lower rate of growth in gas imports into EU-30. By the end of the projection period, imports in this scenario are little more than 60% of their level in the Reference Scenario. Most of this difference is due to lower gas consumption in the power sector. Gas imports nonetheless virtually double over the projection period. Imports are somewhat higher in a High Gas Import Scenario, mainly due to even more rapid growth in power-generation demand than in the Reference Scenario.

[10] COM(2003) 262, 13.5.2003.

Although the enlargement of the European Union to thirty countries would reduce the degree of gas import dependence because of the inclusion of Norway, the main gas-producing country by the end of the projection period, both short and long-term supply security concerns are likely to be exacerbated. The high degree of dependence of the candidate accession countries in Central and Eastern Europe and their unusually heavy dependence on imports from a single country Russia will accentuate supply security risks for the Union as a whole. Reliance on a single supply route in some accession countries adds to the short-term risks.

The projected increases in gas demand and imports in the Reference Scenario imply a need for substantial investment in gas production, transportation and storage capacity both within EU-30 borders as well as in those countries that will supply gas to Europe. Just under $ 500 billion will need to be invested in gas-supply infrastructure in EU-30 countries and a further $ 190 billion in external supplier countries over the period 2001-2030. The sheer scale of the capital needs as well as a number of developments, including longer supply chains, geo-political factors and energy market liberalisation, raise question marks about whether this investment will be forthcoming in a timely manner. There is a risk that supply bottlenecks could emerge and persist for long periods due to the physical inflexibility of gas-supply infrastructure and the long lead times in developing gas projects.

EU and national policymakers will clearly need to tread very carefully in reforming their gas and electricity markets to ensure that the new rules and emerging market structures do not impede or delay investments that are economically viable. Policymakers will also need to take account of the increased risks facing both upstream producers and merchant gas companies as a result of energy liberalisation in setting rules for long-term supply contracts and joint marketing arrangements. An intensified political dialogue with the governments of supplier countries could support investment in certain high-risk, large-scale gas projects by lowering country and project risks. The development banks, including the European Investment Bank, as well as national and multilateral export credit agencies, will continue to play an important role in backing major cross-border pipeline projects in the future.

3. POTENTIAL GAS SUPPLY FROM RUSSIA AND TRANSIT IN UKRAINE

3.1 Russian gas sector

3.1.1 Introduction

During the last quarter of 20th century the development of the oil and gas sector created the structure of the energy industry in the USSR and in Russia after the collapse of the USSR. The sectors provided about 75-80% of the total production of primary energy resources, 70-75% of the domestic energy consumption and up to 95% of the energy exports. Therefore also the location of the findings of oil and gas greatly influenced the spatial pattern of supply network to consuming areas. More importantly, in the last century the role of oil for the Russian economy was reduced due to the increasing importance of natural gas to supply domestic markets and later on the export markets.

Consequently, the oil and gas export plays a vital role in the economy of Russia and also of some other FSU countries. Gas export provides 54% of total energy exports revenue and 17.2% of total income of the Russian State budget. It is especially important with a view on the dramatic situation on the domestic market with extremely low gas prices and low payment discipline.

Nowadays the major market for Russian gas export is Western Europe, which consumes about 70% of gas exported from Russia. Introduction of the European Gas Directive and instability of gas prices, as well as attempts to limit the Russian gas exports to the European gas markets (the EU gas supply diversification policy) resulted in an increasing interest and concern of Russian officials and authorities in the energy market developments in the EU. Below follows a Russian vision on the developments and current situation in Russia.

3.1.2 Russia's energy production potential

Russia has one of the largest energy reserves in the world. With 2.8% of the world's population and 12.8% of the world's territory, Russia has 12-13% of probable and about 12% of proven oil reserves, 42% of probable and 34% of proven natural gas reserves, about 20% of the proven hard coal reserves and 32% of brown coal reserves. Currently the total extraction volume throughout the whole period of exploration makes up: for oil-17% of probable reserves, for gas-5%, see Table 3.1. The proven fuel reserves in 1999 enable gas production for 81 years.

Table 3.1 *Mineral fuel reserves in Russia, in 2000*

	Probable reserves			Proven reserves			
	Volume	[%] of World	[%] Extraction	Volume	[%] of World	Share in Russian energy reserves	Share in production
Oil, incl. condensate	…	12-13	17	…	12	7.8	31.6
Natural gas, Tcm	236	42.3	5	46.9	32	24.1	49.8

In 2000 about 12 Tcm of natural gas had been explored out of the 236 Tcm of probable reserves, and 22 Tcm had been put into operation. In 2005, depending on the gas production rate, 37-38 Tcm out of the total reserve will be extracted, the exploration costs being $ 10/1000 cm, and the selling price-$ 30/1000 cm. In 2010, with an annual production of 630 Bcm, 45-46 Tcm will be put into operation. This figure will rise up to 50 Tcm, if the annual production will rise up to 700 Bcm. Stabilisation of annual gas production, however, won't stop the increase in gas prices (up to $ 40-48 /1000 cm), and production growth to 700 Bcm will rise the prices to $ 48-58/1000 cm.

Around the year 2020 about 54 Tcm will have to be put into operation on top of the annual production of 650 Bcm, with a selling price of gas being $ 52-70 /1000 cm. So reserves of the Yamal peninsula will have been put into operation for realising a sufficient production volume up to 700 Bcm in 2020. This will also require the additional production of 57 Tcm of reserve with the selling price being near $ 60-73/1000 cm.

3.1.3 Current status of Russian gas industry

During the transition period the Russian gas industry turned out to be the most effective and stable industry in the national energy sector. It provided 50% of the domestic consumption and 40% of foreign currency revenue of the total State energy export revenues and also about 25% of tax revenues of the Federal budget.

The so-called 'Unified Gas Supply System (UGSS) of Russia' was maintained and gradually reconstructed (facilities and entities, not related to the production, were singled out and separated). This enabled continuation of production of energy throughout the time of economic reforms in the last ten years. In 1990-2000 gas production dropped by 9.1%, due to the decrease in gas demand in Russia and insolvent (or non-payment of) consumers in CIS countries.

The stable and effective performance of the industry was based on the unique, highly effective deposit base and gas transportation systems, constructed in the 70s-80s. The UGSS includes 'main pipelines' with a total length of 149 thousand km. If including their bends (taking into account isolated gas companies) the total length of Russian gas pipelines is 151 thousand km. Furthermore it includes about 689 of compressor houses with the total capacity of 42.6 mln kW and 22 underground gas storage facilities. Russian gas is not only stored in Russian gas storage caves, but is also stored in Latvia, Ukraine, Germany and France (Redaine). The length of gas distribution networks is about 359 thousand km, which is twice as much as that of main pipelines. This disproportional ratio results from the fact that deposits are located far from main consumer areas and that the natural gas supply share is rather low (in urban areas it is 53%, in rural areas 19%).

In 2000, gas production volume in Russia was 584 Bcm, of which 91% was produced in West Siberia. Three deposits (Yamburg, Urengoy, Medvezhie) produce 68% of gas in Russia. *Gazprom* PLC exploits 69 deposits with total reserves of 17.3 Bcm. Ten of these deposits are located in West Siberia, their reserves are up to 13.5 Bcm, which is around 78%. The industry's transition towards a situation of self-financing, low prices of gas in the national market and huge expenses for credit redemption eroded the financial basis of the gas industry. Consequently also the creditworthiness and scope of funding investments by companies through self-financing dropped substantially. Foreign bank loans reached amounts of $ 14 bln, of which $ 7 bln are long-term loans.

Currently, the main gas deposits in West Siberia have been reduced substantially, Medvezhie by 78%, Urengoy (Cenomanian stage) by 67%, Yamburg (Cenomanian) by 46%. Production increases at the deposits currently operating, led to their earlier exhaustion than expected. However in 2000 such deposits produce still 72% of the total gas output in Russia and probably in 2020 about 50%.

At present, more than 30% of all the pipelines have been in operation for 10-15 years, the rest of the other pipelines are also approaching this operation time or have exceeded this lifetime. The reduction in the volume of pipeline reconstructions in general, the shortage of financial resources, and focus only on problematic segments will lead to a decreasing reliability and economic efficiency and environmental safety of the UGSS. Note that more than 19 thousand of gas distribution systems have exceeded their initial technical lifetime and need replacement being obsolete.

3.1.4 Current pricing and taxation in gas industry

Taxation

In 1995 the excise on natural gas was introduced, with its rate of 15% at the beginning of the year, then -25%, and in September-30% of the sales price. At that very time two laws (No. 63 of 25.04.1995, and No. 25 of 23.02) imposed the 20% VAT of controlled prices and a special tax of 1.5% (later 3%) of the price, aimed at supporting the most imported industries in Russia. At the beginning of 1996 indirect taxes made up 51.5% (and more than 65% including other taxes) of the gas supply price.

Prices and tariffs

Initial wholesale prices of gas for industrial RF consumers have been shaped, taking into account transportation and production costs of gas producers (*Gazprom* PLC, *NorilskGazprom* PLC, *YakutGazprom* PLC). Note that in accordance with the Government's Bill of July 13 1993, called 'To the state regulation of price of gas and other energy resources ', in July 20, 1993 the average wholesale price of gas was 7900 Rubles (before denomination) for 1000 m^3, and the value added by gas distributors was 1100 Rubles for 1000 m^3. This price was corrected every month taking into account the average consumer price index of the previous month.

Since 1st of January 1996, the wholesale gas prices (fixed on October 1, 1995) could not be raised until the end of 2000 in accordance with the Government's Decree of October 13, 1995. Furthermore, household consumers enjoyed substantially lower prices than industry. Since 1997 FOREM power plants have also been getting special benefits. The main reason was that the Russian Government tried to curb inflation.

At the same time prices of equipment and other inputs, used in the gas industry, increased more than 2.5 times. The growing dollar exchange rate that resulted increased the expenses for foreign equipment; pipes, spare parts and consequently foreign bank loans were used and had to be reimbursed in the Russian currency. So the transit fees for the export of the Russian gas melted away quickly.

There was a system of federal and regional bodies for regulating gas prices. However, in fact these regulated wholesale prices were not introduced locally, often for the sake of political preferences of regional authorities, especially just before elections. It led to a constant decrease in the revenues from the gas supplies.

The Government's pricing policy (with deregulated prices of residual oil and coal and regulated artificially low gas prices) an enormous price disparity emerged. The ratio of prices of coal, gas and residual oil became around 1: 0.5:2.8 in 1999. In 2000 it changed only slightly due to the gas price increases, i.e. ratios 1:0.65:2.6. In advanced western European countries this ratio is 1:1.6:1.7. The pricing policy in Russia couldn't serve as a basis for the well functioning energy market. It led to an increase in the gas consumption (its share rose to 47.8% in the total fuel consumption), and to the lower efficiency in gas use.

The situation was aggravated by bad paying and consumption discipline among consumers. Advance payments for gas and the right to cut off debtors were not allowed by law (unlike in the situation with coal and residual oil). Metallurgy, the chemical industry and the power industry were the largest debtors together with well-off regions, such as Tatarstan, Bashkortostan, Nizhny Novgorog and Sverdlovsk regions, Moscow and St. Petersburg. Even when the respective laws were adopted, regional authorities opposed gas cuts.

Due to technological peculiarities gas suppliers are limited in their means in order to influence gas debtors (unlike coal and residual oil suppliers).

Belarus, Ukraine, Moldova were large debtors, too. Ukraine owed Russia (including penalties and contractual fines) about $ 2.1 bln. in 2000, Belarus and Moldova-$ 900 mln.

The Government settled its foreign policy, using gas supply as a lever, paying no attention to the losses *Gazprom* PLC bore. Thus, CIS countries' debts to *Gazprom* PLC were considered as debts to Russia. Agreements between the Governments of the RF, Belarus, Ukraine, Moldova presupposed deliveries of food and technological resources to Russia (incl. weapons) for more than $ 1 mln. *Gazprom* PLC was compensated for this barter late and not completely.

In February 2001, the negotiations between the Presidents of the RF and Ukraine resulted in the deferral of debt payments for gas, granted to Ukraine for 10 years. Besides, Ukraine received a technological loan of 2 Bcm without interest payments, and 5 Bcm as an insurance loan from the emergency fund. Low gas prices on the national markets, non-payments and ersatz payments for gas resulted in losses, *Gazprom* PLC bore on the national and CIS markets in 1996-1998.

3.1.5 Current gas demand

The artificial curbing of natural gas prices together with the restructuring of the industry, led to a decrease in oil and gas production, shifted the mix of fuels in the energy balance of the country, with gas becoming a dominant fuel. The share of gas in energy resource production rose from 40.1% in 1990 to 47.4% in 2000, whereas the share of oil dropped to 32.4%, and the share of coal-to 13.2%. In advanced countries the share of gas varies from 12.5% in Japan to 35% in the UK. Large energy consumers such as the USA and Germany maintain the gas share at 21 till 26% of energy demand, and did not let the coal share drop below 25%.

The main consumers of gas in Russia are not households or industry, where it is sometimes difficult to substitute gas for other energy carriers due to technological and economic considerations. So households and industry use up only 40% of gas. The remaining 60% is used by power plants and large-scale DH boilers, which can also use other types of fuel.

Perhaps an excessive high gas share in the domestic energy consumption is also unwise, because gas supply cannot be secured in the long-term. Currently already 85% of gas deliveries come from a remote region (north part of Western Siberia) through the pipelines of long distances to the European part of the country, where the share of gas in the total energy consumption is 58% of the total demand. And for power plants and boilers it is 74% and 78% respectively.

3.1.6 Current Russian gas export and Gazprom's activities in Europe

The delivery of Russian gas to Europe started first to Poland in 1966, then to Czechoslovakia in 1967, to Austria in 1968, to Italy, Germany, France-at the beginning of the 70s. At the end of the 70s a contract 'gas-pipes' was signed with the Federative Republic of Germany. Gas was delivered to the countries members of the Council for the Mutual Economic Aid in accordance with the Government agreements, at low prices.

Gazprom's independence revived the company's activity on foreign markets despite rigid competition. Nowadays gas is no longer delivered to the border, but directly to 19 European countries. The traders are European gas merchant ventures, established by *Gazprom* PLC in the importing countries together with these countries. *Gazexport* PLC has 17 offices in 14 European countries.

Gazexport's greatest achievement was the launching of a company in Germany, 'Wingas', the construction of three gas pipelines and an underground gas storage facility, which enabled Russian suppliers to find and supply the West-European consumers. Taking into consideration possible deliveries of the Russian gas to the UK market, *Gazexport* purchased 10% of the shares of the gas transporting system Inter-Connector (from the UK to Europe).

In 2000 *Gazprom* PLC exported 129 Bcm to 19 European countries. 70% of this volume was exported to Western Europe, including Germany, Italy, France (76%). In 1992 gas was exported to 13 European countries, 99.2 Bcm, 62% of this volume was exported to Western Europe, the rest to the former members of the Council for the Mutual Economic Aid. In 1992-2000 exports to Western Europe substantially increased, *Gazexport* sells gas there at higher prices and the payment was complete.

In the coming period, significant changes are expected in the Russian policy concerning gas exports. This concerns a transition from being solely exporter to the European markets and diversifying supplies to other neighbouring regions. Russia's involvement in Asia Pacific markets will become more and more important. Next to a growth in oil, coal and refined product export sales, this will imply building up a transport network for natural gas markets and perhaps also with a wide-scale export of electricity and therefore, a further integration of both energy systems. In the future exports of energy, notably natural gas, to nearby (FSU) and remote markets will also increase.

It is noteworthy that great opportunities exist for natural gas LNG shipments to foreign markets. Having presently captured 35% of world exports, Russia can, and should, remain active on foreign gas markets in particular, seriously impacting fundamentals of the European market and building new networked gas market in the North West Asia. It is also worthwhile to consider the possibility for Russia to enter the world LNG market. At the same time, according to New Russian Energy Strategy two other new developments are foreseen:
- Russia will become a big gas importer from Central Asia countries.
- Russia's role of oil exporter will gradually override its role as gas exporter.

3.1.7 Outlook for economic development of expected growth of gas demand

'The Program of the Social and Economic Development of the Russian Federation up to 2010' served as a basis for the elaboration of the Energy Strategy of the Russian Federation up to 2020, approved by the RF Government in November, 2000. However, the performance of the national economy and the fuel and energy sector in 2000 turned out to be much better than expected. Besides, in May 2001 the RF Government approved of 'The Basic Directions of the RF Social and Economic Development in the Long Run'. Taking the new information into consideration, the basic parameters of the optimistic economic development are shown in Table 3.2.

Table 3.2 *The 'optimistic scenario' of the economic development*

	1999	2000	2001- 2005	2006- 2010	2011- 2015	2016- 2020	2021-2025	2026-2030
Growth annual rate [%]								
- GDP	5.4	8.3	5	5.5	5.5	5.2	4.5	3.2
- industry	8.1	9	7	7.5	7	6.5	5.4	4.6
- agriculture	4.1	5	3.7	4	4	3	2	1

The 'optimistic scenario' can only be realised if efficiency of economy and energy sector is stimulated, i.e. decreasing energy intensity of GDP of around 30%, or ca 3% p.a. However it is only attainable if oil world market price remains sufficiently high, namely around or higher than 23/25 $ per barrel. If not, the 'constrained or pessimistic' economic growth scenario becomes more relevant, see Table 3.3.

Table 3.3 *The 'constrained scenario' of the economic development*

	2000	2001-2005	2006-2010	2011-2015	2016-2020	2021-2025	2026-2030
Growth annual rate [%]							
-GDP	8.3	3.5	3.5	3.5	3.4	3.2	3
-Industry	9	4-5	4-4.5	4-5	4-4.5	3.5-4	3-3.5
-Agriculture	5	2.7-3	3	3	2.8-3	2-2.2	1.7-2

Furthermore, in Table 3.4 the expected gas demand in Russia for the two different economic growth scenarios is displayed.

Table 3.4 *Russian gas consumption in the 'optimistic and constrained' scenario, 2000-2030*

[Bcm]		*2000*	*2001*	*2002*	*2005*	*2010*	*2015*	*2020*
Total gas demand, incl. exports	*low*				615	665	697	724
	high	596	585	597	626	709	750	780
Domestic gas demand	*low*				414	444	462	478
	high	399.0	406.9	410.1	428	475	504	525
As [%] to the 2000 volume	*low*	100			104	111	116	120
	high	100	102.0	102.8	107	119	126	132
Share in total energy consumption [%]	*low*				*49.3*	*48.7*	*47.0*	*45.9*
		49.8	*50.2*	*50.6*	*49.3*	*48.6*	*47.2*	*45.6*
Demand of gas is made up by:								
- Pipeline losses	*low*				50	54	55	55
	high	47.7	45.7	47.6	51	56	58	59
- And other demand	*low*				364	390	407	422
	high	351.3	361.2	362.5	377	420	446	466
Of which by power plants	*low*				159	167	165	167
	high	151.0	155.7	157.7	156	163	167	172
In share [%]	*low*				*43.6*	*42.8*	*40.5*	*39.6*
	high	*43.0*	*43.1*	*43.5*	*41.4*	*38.8*	*37.5*	*36.9*
Of which by centralised heating	*low*				73	79	82	83
	high	70.3	73.7	71.8	75	82	86	86
In share [%]	*low*				*20.0*	*20.2*	*20.1*	*19.6*
	high	*20.0*	*20.4*	*19.8*	*19.9*	*19.6*	*19.3*	*18.5*
Of which by industry and construction	*low*				65	69	72	74
	high	64.9	69.5	68.9	74	85	89	96
In share [%]	*low*				*17.9*	*17.8*	*17.6*	*17.5*
	high	*18.5*	*19.2*	*19.0*	*19.5*	*20.3*	*20.0*	*20.6*
Of which by households and services	*low*				57	62	68	71
	high	54.8	52.5	54.9	60	75	80	82
In share [%]	*low*				*15.6*	*15.8*	*16.6*	*16.8*
	high	*15.6*	*14.5*	*15.2*	*16.0*	*17.8*	*17.9*	*17.6*
Total Volume Export	*low*				*199*	*217*	*231*	*236*
	high	*193.6*	*180.5*	*184.5*	*197*	*230*	*242*	*245*
Of which to CIS	*low*				45	45	44	43
	high	60.1	47.8	48.3	46	45	45	45
To Europe	*low*				155	158	159	158
	high	133.5	132.7	136.2	151	160	163	162
To Asian countries	*low*					14	28	35
	high					24	35	38
Other demand and stocks changes	*low*				2	5	4	10
	high	3.9	-2.4	2.0	1	4	4	10

Note however that the Russian Institute apparently foresees an increase of the exports to Europe of only 30 Bcm per year. This is in great contrast with the foreseen needs and other expectations for the year 2020, see Chapter 2 Figure 2.20, with increase of about 83 Bcm per annum.

3.1.8 Outlook for natural gas production

The projection of the Russian gas production is depending on many factors, i.e. the development of the Russian industry's resource base (exploration and findings), and on the development of gas demand in the domestic and foreign markets, and of course on the gas price levels in these markets. Gas production was considered in various gas-producing regions and at various deposits. The development is included and substitute deposits were taken into account and also the technical and economic parameters of the deposits and possible producer's prices. Optimisation of the gas industry development took place in accordance with the production and financial model of *Gazprom* PLC and other companies. This enabled to assess the gas-producing areas and deposits, requiring immediate development, based on conventional prices in the national and foreign markets and by the financial state of main gas producing companies.

Based on the gas demand outlook for Russian gas demand and EU scenarios published last years the following gas production figures are projected for the next decades, see Table 3.5, below. West Siberia will remain the main gas-producing region in Russia, though its role will drop from 91% to 76% in period 2000-2020. Also production in Nadym-Purtaz will drop. Furthermore, Yamal reserves are expected to be developed after 2015. Gas production in the European zone will rise up to 128 Bcm when Shtockman deposit is launched. The costs of the gas export to the Asian-Pacific countries and willingness for these consumer countries to pay these gas prices will determine gas production volumes in East Siberia and the Far East. If the demand for Russian gas in these countries is relatively high, and taxation and loan conditions for constructing the gas pipelines etc. are beneficial to investors, the gas production in these areas can grow up to 38-58 Bcm. Cenomanian reserves at the operating deposits of Nadym-Purtaz region are being exhausted. Gas production in this part of West Siberia will decrease in 2020 to volumes that are 25% of the current volumes.

The future gas production in 2020 will for about 24% come from current production deposits. More than 76% of the gas production is to be extracted from new deposits at Nadym-Purtaz region, the Barents Sea shelf, the Yamal Peninsula, Nepsko-Botuobinsk region in the Republic of Sakha. Irkutsk region and the shelves of the Sakhalin island. The program of developing small, low-flow deposits and reserves is of local importance, especially in the further to be developed European production regions.

Production (production and transportation) costs of development of new gas-producing sites (the investment component included) and the introduction on the market of reserves from the Yamal and Gydan peninsulas and North Seas shelves might push the consumer prices from \$ 50 to \$ 95/ 1000 m^3. This if consumers are willing to pay and no cheaper alternatives are available at that time.

Table 3.5 *Projection Russian gas production under two scenarios, period 2000-2020*

[Bcm]		2000	2001	2002	2005	2010	2015	2020
Total Gas Production	*low*				*606*	*635*	*660*	*682*
	high	*584.0*	*581.2*	*594.8*	*609*	*665*	*705*	*730*
Including Tyumen region	*low*				552	557	517	511
	high	526.2	522.9	536.5	553	563	549	531
by provinces:-Nadym-Pur-Taz	*low*				552	527	487	408
	high	526.2	522.9	536.5	553	533	477	394
- Obsko-Tazovskaya guba	*low*					30	30	30
	high					30	30	30
- Yamal	*low*						0	73
	high						42	107
- Tomsk region	*low*				5	7	9	9
	high	3.3	4.1	4.4	6	9	9	10
- RF European region	*low*				41	40	48	67
	high	47.1	46.8	46.4	42	41	50	83
Including South Federal District	*low*				16	19	28	29
	high	14.4	15.4	16.8	16	20	30	32
- Shtockman	*low*							23
	high							36
- East & West Siberia	*low*				4	12	52	52
	high	4.0	3.7	4.0	4	20	52	52
- Far East	*low*				4	19	34	43
	high	3.4	3.7	3.5	4	32	45	54
Of which from Sakhalin	*low*				2	9	24	24
	high	1.8	2.1	2.5	2	20	24	30
Import	*low*				9	30	37	42
	high	12.5	3.7	1.7	17	44	45	50
Total gas supply	*low*				615	665	697	724
	high	596	585	597	626	709	750	780

The potentially available gas supply for Russian domestic needs is not limited to the RF territory. Russia co-operates with Turkmenistan, Kazakhstan and Uzbekistan concerning the exploration and production of gas, which will enable to peak-load the Russia gas transportation systems, Orenburg and Astrakhan gas processing plants. Besides, *Gazprom* PLC can be actively involved in the Asian and Pacific markets by geological exploration and gas production in South Parse (Iran), Vietnam and India shelves, carried out by Russian companies.

The development of deposits will require technological innovations in construction of wells and other gas-producing facilities on frozen soil, especially regarding horizontally-branched wells. This would greatly enhance productivity of processing and preparation of valuable gas components. The improvement of well flows during the last stages of production will be made through hydraulic in-situ disruptions, application of chemicals etc.

Launching exploration of new deposits on the Northern seas shelves, located far away from mainland in extremely difficult conditions, will require advanced drilling equipment such as rigs and deck gear; high pressure pipe-lines on the sea bottoms, construction of coastal infrastructure, including units to process and liquefy gas, too.

3.1.9 Development of gas transport, storage and high value products

UGSS Gas transportation systems in East Siberia and Far East require significant reconstruction and modernisation in order to improve their safety, ecological and economic effectiveness. In the period 2001-2020 about 23 thousand km of main pipeline segments and bends will have to be replaced as well as 25 thousand MW gas compressor units will have to be modernised or/and replaced too, see Table 3.6.

Table 3.6 *Gas network modernisation requirements 2000-2020*

Replacements		2001-2010	2011-2020	2001-2020
Pipeline segments	[1000 km]	10	13	23
Gas compressor unit	[1000 MW]	12	13	25

The program of gas supply expansion in Russia and of export deliveries; of the construction of new gas outlets and connectors supposes that by 2020 about 27 thousand km of main pipelines with the diameter of 1420 mm and the pressure of 7.5-10 Mpa will have been built. Both programs that of construction and that of modernisation are worked out in parallel, which will enable to increase the UGSS efficiency.

The UGSS's expansion involves increasing the amount of gas distribution systems up to 25 thousand km within 5 years, which covers 84% of the rural areas. Rapid construction rates within depend on the usage of PE pipes, which will enable to decrease the costs around 1.5-2 times and the construction period three times, which will enable to supply 800 thousand households with gas. Note that 50% of these consumers can be found in rural areas. Liquefied gas has a very important place in the rural gas supply. Its consumption will grow probably 1.2-1.3 times, which is the result of additional investment in the liquefied gas supply systems.

One of the core elements of gas supply reliability is the construction of new underground gas storage (UGS) facilities and modernisation of existing ones. In 2000-2020 the further development of UGS is planned, incl. in salt in-situ deposits. This might double annual production (UGS in Perm, Volgograd, Kaliningrad regions). The ratio of the UGS capacity to national gas consumption will increase to 12-13%, and if export deliveries are taken into account even to 17-19%. In the future, *Gazprom* PLC will take part in UGS construction in Europe and use UGS capacity in the whole CIS. As a result also the volume of gas pumped in UGS in Europe, mainly in Germany, will rise to around 13-15%.

The most pressing problem of gas processing in *Gazprom* PLC is re-equipment and reconstruction of operating plants. This in order to increase the production of valuable products (components) from the natural gas, economic efficiency and ecological safety of processing enterprises (Sosnogorsk, Orenburg, Astrakhan gas processing plants, Surgut and Urengoy condensate processing plants). If conditions in foreign markets (stable prices and increasing export volumes) are favourable, this could enable (finance) the construction of methanol production plant in Arkhangelsk, ethane-processing plants in Novy Urengoy and Tcherepovets. This policy of producing from natural gas more valuable end products (a deeper carbohydrate processing) could also lead to the increasing production of motor fuels, perhaps up to 3-4.5 thousand tons, sulphur, methanol and PE-production.

The disposal and processing of associated gas has been decreasing in recent years, gas-processing plants (GPP) are loaded at less than 30%. Such a situation is a result of losses in production and sale of associated gas (costs are twice as much as its price). About 80% of GPP capacity is not controlled by oil companies, but the final sales do not reduce losses of gas production enterprises. However, it is expected that waste disposal and processing problems in market economy of Russia will require legislative measures like those already adopted and implemented in the USA and other EU countries and thereby hampering sales from Russia.

3.1.10 Gas export and import outlook

Russian gas export policy on Western and Eastern European markets depends on the gas export market outlets , its restructuring and diversification policies of suppliers and customers. The export policy in the 'optimistic scenario' is based on the assumption that Russia will keep its share in the total gas deliveries and continue to expand its number of clients. The gas export in this variant will grow from 139 Bcm in 2001 to 181 Bcm in 2020. At the same time new production will emerge from gas reserves of East Siberia and the Far East. So, Russia will enter Asian- pacific markets, first of all in China, Korea, and Japan.

In the 'constrained scenario' variant (low oil prices on western markets) in the period 2002-2005, the gas export volumes to Europe will probably be constrained. If prices of gas again grow in the period 2010-2020, exports of gas (especially Shtockman gas to Western Europe) will grow again and by 2020 the gas export volumes will reach also the level of the 'optimistic scenario' variant. At the same time under this 'constrained scenario' variant the gas exports to Asian-Pacific countries will probably not rise due to low prices of gas contracts on these markets which are strongly linked to the than low crude oil world market prices. This will make investing in export projects unattractive for investors. Gas deliveries to CIS and Baltic countries are expected to be in the range of 62-69 Bcm, the main demand is expected in 2020 from Ukraine and Belarus.

West Siberia will remain the main resource base of the RF gas industry and determine supply to all regions of the European zone of Russia, Urals, the industrial areas in the south of West Siberia. Furthermore, gas from Tyumen will remain the main export resource.

Gas production volumes will drop in the next decades due to the fact that Senomanian reserves of Nadym -Purtaz area in the Tyumen region are exhausted in that period of two decades. Therefore the important resource base of the Yamal peninsula will probably have to be put in operation around 2020. The Yamal and Gydan reserves, the Karsk Sea shelves, unique in their complexity and thus require huge investment volumes, are being considered to be reserves, which will be put in operation only some time after 2020.

To satisfy the demand of 'solvent consumers' in the Volga region, the Urals, the Central and North Caucasus regions it is sensible to expand gas imports from Central Asia and Kazakhstan in the next decade. Gas import can be carried out either as purchases of gas on the border of the exporting country through Russian participation in Turkmen and Kazakh gas production and further product sharing, or by barter trade deliveries to northern and north-eastern areas of Kazakhstan in return for gas imports. It is expected that Russian gas imports in both variants will rise up to 55-58 Bcm per year by 2020.

Table 3.7 *Russian gas pipeline capacity requirements for export to Europe*

Gas pipeline system	Year	Capacity [Bcm/year]	Costs [Bln. US$]	Length [km]
Increase of Balkan pipeline	2004-2005	Up to 38	0,6-0,8	400
Yamal-Europe	2002	28 (up to 33)		5100
	2010	56 (full 63)	36 (full-76)	
Blue Stream	2007-2008	Full 16	3.3	370 (land) + 390 (sea), full 1213
Russia-Finland	2003	Up to 12,5		
North European Gas Pipeline	2007	19.7	Up to 8-10	586 (land) + 1183 (sea)
	2009	30		
Poland-Slovakia (bypass)	Postponed	Up to 60	1	

3.1.11 Investment needs in the gas sector

Gazprom's strategy of the development of the resources, gas production, reconstruction and further development of gas transport and distributing systems, gas processing and the construction of more underground gas storage, require large investments. In the first five years (2001-2005) needs for investments in gas production and transformation will be \$ 16-17 bln. But in the last five years (2016-2020) even \$ 32-35 bln. Throughout the whole period, investments in the maintenance and development of the industry will totally amount to about \$ 90-100 bln. Note that in 1999 *Gazprom* PLC spend only \$ 3.1 bln. of investment and in 2000-\$ 3.2 bln., see Table 3.7. Gas production in Russia in 2001-2010 will require large investment in exploration and production itself. These investment volumes can only be realised if foreign investors are attracted.

Some examples of ongoing investments are : To develop Shtockman gas condensate deposit a consortium was set up. Its participants are: *Gazprom* PLC and *Rosshelf* (together they hold the controlling stock), *Total, Norsk Hydro, Conaco, Fortum*. Investments in the production facilities are estimated at \$ 8-9 bln. A new large project in Nadym-Purtaz is the development of the first group of on-land deposits and the deposits near the coastal line of Tazovsk and Ob' Bays. Investments in these projects are estimated at \$ 4-5 bln. In 2005 Koryktinsk gas condensate deposit will be started and the production license will give the right to supply Irkutsk and Angarsk industrial regions with gas. The first stage of the project will require \$ 1-1.5 bln. of investment. The largest investor of the project is *BP- Amoco*.

Furthermore, the annual need for investment in pipeline reconstruction is estimated around \$ 1-1.5 bln. New construction is mainly connected with the contracting and the implementation of export projects. Among these projects the 'Blue Stream' pipeline is constructed by *Gazprom* PLC together with an Italian company, ENI, which enables to deliver gas to Turkey irrespective of any transit country. Investments in the project are around \$ 2.2 bln. With tax benefits, and more than 80% of the investments being covered by loans from a bank consortiums and guaranteed by export revenues. To develop Shtockman deposit it is required to construct exporting main pipelines. Investments in the gas pipeline system are estimated at \$ 5.5-6 bln before 2010. The cost of the pipeline Korykta-China is estimated at \$ 7.6 bln. In fact investments should start to flow 5-7 years ahead of the start of production of gas. These slow speeds of the implementation of production programs are mainly caused by a lack of financial resources. This in turn will lead to a further decrease in gas production, which will influence gas production in a negative way in the next five years.

3.1.12 Proposed reforms

Currently the following reforms of the Russian gas market are proposed:

- Creation of a competitive environment, mainly in gas production, its transportation and other services to supply customers with gas.
- Improved taxation and pricing policies aimed at financial stability of gas companies and their attractiveness for investors. But the economic interests of the state and consumers should be preserved.
- Improved organisation and regulation of the gas companies to promote the development of an efficient gas market. Implement improved mechanisms of the state regulation on the industry.
- Establish a sound legal basis that will ensure sound economic decisions by all gas market parties during and after the reform.

There are two strategies of creating a competitive environment:

- Proposed by liberal wing of Russian government: *Gazprom* is split up into independent production, transportation and distribution companies.

- Backed by *Gazprom: Gazprom* remains integrated company, whereby the gas market is divided into regulated part and competitive part.

In the next years, significant changes are expected in the Russian policy concerning energy exports, with its transition from only supplying the European market to wider diversification of Russian energy export to other Russian markets. Russia's involvement in Asia Pacific markets will become more and more important. Rather than only growth in oil, coal and refined product export sales, this implies building up an extended network and volume for supplying natural gas and electricity to new foreign markets. In the future period, also significant exports of energy, notably natural gas, to nearby (FSU) and more remote consumer markets will continue to take place and their volumes will rise. Also noteworthy are the great opportunities for LNG shipments to foreign markets. Having presently captured 35% of world exports, Russia will remain active on foreign gas markets, in particular the West-European markets and therefore will building up a new network of gas markets in the North-West Asia. The scope for Russia to enter the world LNG market is also on the agenda.

3.2 Gas sector Turkmenistan and Kazakhstan

3.2.1 Gas industry in Turkmenistan

The resource base of the gas industry development

Turkmenistan is after Russia the second largest fossil fuel resource base among CIS members. The main explored reserves and gas production are in the Amu-Darya province, i.e. in Eastern Turkmenistan. These gas deposits originated from Mesozoic sediments, which are divided into two productive groups, per-salt and sub-salt. The gas of the first group is sulphur-free methane, that of the second hydrogen sulphide containing ethane. 90% of 3,000 Bcm of proven reserves are accumulated in Amu-Darya province. The further exploration of new deposits is planned on the basis of sub-salt Jurassic complex.

New deposits are scheduled to be explored in the South Caspian province. As far as their potential is concerned, these two provinces are alike, but the South Caspian province is mostly oil-bearing (73% of the whole oil reserve in the country), whereas Amu-Darya province is gas-bearing (more than 64% of gas reserves). More than 80% of the explored gas reserves is found in Dauletabad-Donmez gas deposit.

Turkmen geologists consider 85% of the country's territory, including the Caspian shelf, to be prospective oil- and gas-bearing areas. However, the estimate of hydrocarbon reserves in these areas varies substantially, see Table 3.8.

Table 3.8 *Estimates of hydrocarbon reserves in prospective areas of Turkmenistan*

Areas	[1000 sq. km.]	Oil reserves [mln. t.]	Gas reserves [Bcm]
Caspian shelves			
- Southern	40	2000	2000
- Middle	30	1000	2800
Kapetdag	20	570	2800
W. Kapetdag	20	800	29
Right bank of the Amu-Darya	16	1075	1765
N. Karabogaz	14	-	600
Repetek-Kelif	5	30	470
Daryalyk-Dovgan	40	-	750
Total		*5475*	*11214*

Gas production

Proven gas reserves of all the 24 deposits of the country make up more than 3 Tcm, with 1.3 Tcm found in the Dauletabad-Domez deposits. On-land deposits have been depleted for more than 50%, with some deposits reaching a 90% depletion rate.

The State company *Turkmengas* exploits 21 deposits out of 33, mainly in Eastern Turkmenistan. The State company *Turkmenneft* exploits 12 deposits in Western Turkmenistan and on the Caspian shelf. Note that these shelf deposits have been depleted only for 30%. *Turkmengas* is the leading gas exporter, for more than 85% of the total production volume.

The country's gas production is restricted by the remote position of deposits, far from sales markets. The transport infrastructure is very poor, the access to foreign markets is provided through the system *Central Asia-Center (CAC)* and through the gas pipeline Korpedze-Kurt-Kouie. So, the gas production volume is not determined by the demand for Turkmen gas, but mainly by demand from foreign markets, because domestic consumption does not exceed 12-13 Bcm per year. Future demand is expected to increase only up to 16-18 Bcm . In 1991 the production volume reached a peak of 84.5 Bcm due to export (90% of the production). As a result the gas production in the country in period 1997-2001 more than trebled, see Table 3.9.

Table 3.9 *Turkmen gas production and export in 1991-2001*

Years	Production [Bcm]	Export [Bcm]	Export share in production [%]
1991	84.5	75.8	89.7
1995	31.3	22.6	72.2
1996	34.3	24.3	70.8
1997	17.2	6.5	37.8
1998	13.2	1.8	13.6
1999	22.4	13.2	46.9
2000	43.0	30.7	66.0
2001	64.8	46.8	72.2

Taking into consideration the current situation in the country's gas industry, future development requires large investments in gas exploration, production, processing and transportation. Turkmen program of licensing exploration and production of gas and oil, apart from *Turkmengas* and *Turkmenneft,* focuses on foreign investors, who are interested in gas exports to European and Asian markets. In 1991-1998 the volume of foreign investments in the oil and gas industry was around $ 1-1.2 bln. (country's own estimate).

Forecasts of reserves than can be produced effectively in the country are around 65 Bcm and 85-90 Bcm in 2010-2020. This if exploration in the Amu-Darya province takes place, large investments in gas production and its sweetening are possible and access to new markets is secured. Turkmen geologists estimate that gas production can rise to 100-120 Bcm in 2010-2020, according to the probable resource estimation.

Further development of gas production in operated deposits requires large investments in drilling and the major reconstruction of operating wells (the well reserve decreased till 20% in the period of 1990-2001) and gas condense production increases. This needs also reconstruction of preparation and gas-cleaning units with the application of new equipment and technologies that enable to improve gas filtering. Turkmen gas that is entering the CAC pipeline is namely not dry and sweetened enough.

Gas transportation

Turkmenistan exports gas to Russia and other CIS members (via Russia) and to Iran through the pipeline Korpedze-Kurt-Kouie. China, Pakistan and Turkey will buy Turkmen gas. The USA is also interested in the construction of the exporting pipelines. As a result, they have launched consortiums for the construction of this exporting pipeline.

Central Asia Gas Pipeline consortium, headed by a US company *Unicoil* (54% of shares) also includes *Delta Oil Company* (Saudi Arabia), *Kresent* (Pakistan), *Hyndai* (South Korea), *Hochu Corporation* (Japan). The consortium participates in the construction of the pipeline Turkmenistan - Afghanistan - Pakistan (the length is 1464 km, the diameter is 1220 mm, the pressure is 10 Mpa, the capacity is 20 Bcm and the costs are about $ 2 bln.) The resource base of this pipeline is Dauletabad-Donmez deposits and Balhyz-Garabil gas area.

Royal-Dutch-Shell participates in the construction of the pipeline Turkmenistan-Iran-Turkey. The resource base is Naip and Kerpichli areas in Eastern Turkmenistan, deposits of Ouchiadzi group (sites in Yashlar-Yelote, Gourrukbil-Garabil, Malay, Garafiovlan- Yelshansk), as well as the Caspian shelf deposits. The length of the line is 3.5 thousand km, the diameter is 1420 mm, the capacity is 20 Bcm. The first run of the line from Turkmenistan was launched in 1997 from the deposit in Korpedze to the settlement of Kurt-Kouie. If Turkey's demand for gas is decreasing, Iran faces Turkmenistan as a competitor and might not be interested in Turkmen gas transportation through its territory.

The Transcaspian pipeline for Turkmen and Azerbayjan gas export to Turkey (to the city of Erzerum) was constructed together with a US company *PSG* . The resource base was the Caspian shelf, the length of the pipeline is about 2000 km, the diameter is 1220 mm, the pressure is 15 Mpa, the capacity is up to 30 Bcm, the costs are about $ 2.3 bln.

Exxon (USA), *Mitsubishi* (Japan), *CNNC* (China) consider the construction of the pipeline Turkmenistan - Uzbekistan - Kazakhstan - China with the total length of 5730 km, China - South Korea - 650 km, South Korea -Japan - 1660 km. The capacity is 30 Bcm a year. The total investment exceeds $ 11 bln. Taking into accounts the high capital needs of the project the project has been cancelled.

The delivery of Russian gas to Turkey through the gas pipeline 'Blue Stream', of Azerbayjan and Iranian gas to Turkey (in Iran the production has started since 2001 and the export volume is expected to reach 10 Bcm in 2003-2004, which will deprive Turkmenistan of an easy opportunity to export to Turkey. However, none of the projects mentioned above has found financing so far, all of them are very risky, political and financial. Therefore Turkmenistan is more and more interested in using Russian pipelines for gas transportation to foreign markets.

The main pipelines of the country, especially of CAC are worn out for more than 80%. After acquiring independence the country has never reconstructed the lines nor renewed the equipment. The peak load has never exceeded 50%. The reconstruction of the Kazakh section of the system will enable to raise the capacity to 60-65 Bcm per year. Turkmen, Uzbek and Kazakh gas can load the system to its full capacity. But investments for the reconstruction of the pipelines on the territories of Kazakhstan, Uzbekistan and Turkmenistan are estimated at more than $ 3.5 bln.

Russia has suggested launching a joint gas transportation company that will reconstruct CAC and deliver Turkmen, Uzbek and Kazakh gas to Russia and CIS countries. With gas production increasing to 85-95 Bcm, Turkmenistan will be able to export about 61-77 Bcm. If export to Iran through the current pipelines increases to 8-12 Bcm, the total potential export is estimated at 50-65 Bcm.

The Governments of Russia and Turkmenistan aim at expanding integration in the gas industry and establishing the Euro-Asian Union of Gas Producers. Russian participation in gas resource exploration and gas transportation through Russian transportation systems will provide control of gas delivery volumes, gas pricing and the overall situation in the Central Asia region. See Table 3.10 for a final balance of gas production demand and export.

Table 3.10 *Forecast of the gas balance in Turkmenistan*

[Bcm]	2005	2010	2015	2020
Production of gas*	55.0-58.0	75.0-80.0	83.0-90.0	90.0-110.0
Demand for gas	11.0-12.0	13.0-15.0	14.0-16.0	16.0-19.0
Gas import	0	0	0	0
Gas export	44.0-46.0	62.0-65.0	69.0-74.0	74.0-91.0

*Without the gas spent on cycling and without the losses of associated gas.

3.2.2 Gas industry in Kazakhstan

The resource base of the gas industry

In Kazakhstan there are the following oil- and gas- bearing provinces: Akhtyrsk, West Kazakhstan, Mangystau, Zhiambyl.

Akhtyrsk oil- and gas province is the oldest oil and gas producing area, where the resources of the subsalt layer are exploited. The province's deposits are highly worn out. New large gas reserves are highly unlikely to be found there. Seventy-five hydrocarbon deposits have been explored, 39 of which are operating.

Mangystau province has 66 explored oil and oil- and gas deposits, 27 of which are in operation, their reserves make up 172 Bcm. The largest oil- and gas deposits are Ouzen, Zhetybay, Kalamkas, Karazhanbas.

In the West Kazakhstan province there are 7 explored oil-, gas- and condensed gas deposits, the largest of which is Karchaganak with the reserves of residue gas of 1.35 Tcm.

Zhambyl province in the Southwest of the country includes Amangeldin group of deposits, found in the 60s. These deposits are small, the total reserve is about 750 Bcm, their gas is rich in helium (about 5%). The largest Amangeldin deposit has the gas reserves of 25 Bcm. The deposits are not explored, because the exploration, production and processing require large investments.

The explored gas reserves in Kazakhstan are about 1.84 Tcm, but probable reserves exceed 3 Tcm. The estimations of Kazakhstan gas reserves and of large explored deposits are based on the estimation of hydrocarbon deposits in the Caspian Coastal oil- and gas province. But about 90% of the explored gas reserves and 85% of the potential reserves are already found.

Table 3.11 *Forecast of the gas balance in Kazakhstan*

[Bcm]	2005	2010	2015	2020
Production of sales gas*	20	30-37	32-42	35-60
Demand for gas	8-10	12-17	15-20	17-25
Gas import	4-6	5-7	8-9	7-10
Gas export	16	23-27	25-31	25-45

*Without the gas spent on cycling and without the losses of associated gas.

Kazakh gas export is most effective through Russian gas transportation systems. Gas from Karachanagak can be processed at Orenburg gas processing plant or a new Kazakh plant and can be transported to Russian or foreign markets through the pipelines 'Soyuz' and Orenburg-Novopskov. Gas from the reserves in West Kazakhstan can be directed through the CAC system. Before 2010 the system can be loaded with Turkmen gas, because with all the deliveries to Orenburg, the gas processing plant, Kazakh exporting potential can load CAC up to 20-25%

only. In 2010-2020, though, Kazakh exporting potential will perhaps increase twice, thereby competing with Turkmen to Western markets.

The current conditions of the Kazakhstan's main gas pipelines
Gas transportation systems in Kazakhstan were constructed in the 60s-80s, about 20-40 years ago. They have been worn out for more than 70% and the gas compressor unit for 60-90%. Transport of Turkmen gas of low quality, full of contaminating impurities, not dry and sweetened enough, erodes the pipelines fast. Thus, it is necessary to raise gas quality requirements substantially in the future. The list of the pipelines is given in Table 3.12.

Table 3.12 *Concessioned main pipelines*

Pipeline name	Length [km]	Diameter [mm]	Planned capacity [Bcm]
1. Central Asia-Centre (CAC)			67
CAC-2	974	1220	
CAC-3	745	1220	
CAC-4	1337	1420	
CAC-5	823	1220	
2. Makat- N. Caucasus	370	1420	25.5
3. Orenburg-Novopskov	382	1220	
4. Orenburg-W. Border (Soyuz)	382	1420	54.8
5. Bukhara-Urals (1st and 2nd runs)	1175	1020	14
6. Okarem-Beyneu	546	1220-1020	10
7. Kartaly-Rybnyi-Kustanai	278	820-530	7
8. Bukhara-Tashkent-Almaty	792	1020-530	13.4
9. Gazli-Shimkent	314	1220	13.4

In 1997, Kazakhstan gas transportation system was leased concession to the Belgian company *Tractabel* for 15 years. Besides the pipelines and 23 compressor houses, three underground gas storage systems (Bazoy, Poltoratsk, Akyrtobinsk) were leased to concession. The concessionaire was required to reconstruct, modernise and expand gas transportation systems with the total investment volume exceeding $ 450 mln. However, for three years the concessionaire did not perform its obligations, i.e. direct exchange and transportation links with *Gasprom* PLC and *Uztransgas* were not built and therefore the contract was terminated.

Nowadays, Kazakhstan is trying to establish links with *Gasprom.* These links are defined by the parties' interest in long-term cooperation in using Russian gas transportation systems for gas transportation from Kazakhstan. Taking into account the price of gas in W. Kazakhstan and Karachagalak gas producing plants ($ 10-18 for 1000 m^3), *Gasprom* can use Kazakhstan resources to supply consumers in Russia, CIS and Baltic states with gas through the operating pipelines in Russia. Kazakhstan aims at expanding CAC's capacity up to 65 Bcm, which will enable to transport gas from Kazakhstan, Turkmenistan and Uzbekistan through Russian gas transportation systems. In the framework of the Russian-Kazakh joint project of Karachaganak gas transportation, *Gasprom* can market their gas in Russia, CIS and, possibly also Europe. The two countries carry out the same pricing policy and have the fixed schedule of Kazakh gas deliveries. This co-operation is a good foundation for the Euro-Asian Union of Gas Producers.

In 2001, Kazakhstan signed an agreement with Russia for co-operation in the gas industry for 10 years. The agreement concerns the joint project of gas transportation through Kazakhstan and Russia to western markets; the discovery, exploration and exploitation of gas deposits; the terms of product sharing; the processing of this gas at Russian plants until ready for export; sales of the final product. The project involves starting a joint venture, maintaining parity of both sides. Its members are going to be *Gazprom* and the close joints stock company *National Company 'Oil and Gas Transportation'*.

The joint venture will deal with:

- Purchases and marketing of natural gas on mutually beneficial and profitable terms, incl. natural gas of Karachaganak deposit. This is especially acute, as the production and transportation of gas condenses from Karachaganak stopped due to double taxation and lack of customers.
- Transport and processing of gas from Kazakhstan in Russian processing plants, including the gas to be consumed by Kazakhstan.
- Optimisation of transportation routes and effective gas exchange to supply Kazakh customers with gas.
- Management of joint projects of natural gas transportation through Russia and Kazakhstan to third parties.
- Construction of new competitive transportation facilities and their infrastructure.

3.3 Ukrainian gas transport system

3.3.1 General

Ukraine is a main gas transit country in Europe and has an extensive network of gas pipelines, storage facilities necessary to transport large volumes of gas mainly from Russia to Europe through Slovakia, Poland and Romania. It is therefore important that Ukraine meets more and more EU standards for safe and reliable transport of natural gas.

The Ukrainian gas-transport system (GTS) has a total length of 36,000 km and serves two basic functions, namely that of Russian gas transit to Europe in volumes of around 110-120 Bcm a year and that of gas supply to Ukrainian consumers in volumes of 65-70 Bcm per year.

The insufficient funding of maintenance of the GTS has led to a deterioration of network conditions and did create great concern over the reliability of gas supply to Europe through the territory of Ukraine. It is one of the reasons for a Russian search for alternative ways of natural gas transit from Russia to the European Union countries. Russia and Ukrainian authorities are aware and will take adequate measures for keeping Ukraine the status of a key transit country of Eurasian natural gas to the EU countries.

Ukrainian's gas transport system is closely connected to gas transport systems of other countries in Central Europe, such as Poland, Romania, Hungary and via Slovakia the network of Ukraine is connected to the general EU gas network. Ukrainian GTS is able to supply the growing demand for natural gas in the EU up till 140 Bcm. Russia is and will be in future one of the main natural gas suppliers to the EU. Therefore, it depends very much on the developments of the gas system in Ukraine. So Ukrainian's GTS may become also an excellent entry point of Kazakhstan, Turkmenistan and Uzbekistan exports to the EU markets.

3.3.2 General characteristics of Ukrainian gas transport system

Ukraine has a developed gas-transport system. At the beginning of 2003 the gas-pipelines total length was about 37,000 km including around 23,000 km of gas-main pipelines and 14,000 km of the branch gas-pipelines and there existed around 1,380 gas distribution stations (GDS). Also there are 71 compressor plants. Ukrainian GTS includes also 13 underground gas-storage systems with an active capacity of 32.6 Bcm. GTS accomplishes gas transit through Ukraine territory in the following directions:

- In western direction to Western European countries, and
- In southern direction to Romania, Turkey and Balkan Region countries.

Besides, gas transit to some regions of Russia is accomplished through a gas-main pipeline Novopskov-Aksaj-Mozdok, and gas transit to Moldova is also accomplished in Southern direction. Total capacity of cross-border capacity on entry to Ukraine is 290 Bmc a year. Total exit capacity is 175 Bcm per year including gas transport capacity to European countries of 140 Bcm per year.

Although during the last ten years gas transit to Europe (western and southern directions) didn't exceed 120 Bcm (1999). In 2001 the design capacity of gas-main pipelines was used only at 60% for entry and 71% for exit. Consequently there is a potential for extension of gas transit but this requires more intensive maintenance of the network.

According to expert assessment, the Ukrainian GTS needs investments in amount of 420 millions of Euro per year. However, having recently analysed the Ukrainian GTS technical conditions and its functioning it is still possible to conclude that GTS is still satisfactorily operating. During 30 years of its operation the gas supply to Europe was never cut off. Furthermore, starting from 1993 the investigations of the World Bank and the International Energy Agency have shown that the Ukrainian system current status is better then it was expected. But nevertheless sufficient investments are needed to keep it that way functioning in the longer term.

3.3.3 Tariffs for gas transit

In the 1990s a tariff on Russian gas transit through a territory of Ukraine was $ 1.75 per 1,000 m^3 and 100 km. It is also used now for construction and exploitation of new gas mains (for example, Close Joint-Stock Company 'Gaztranzit' provides services to 'Gazprom' in sphere of gas transit with this tariff). However, taking into account the fact that until recently all gas transit was not paid in monetary terms but by gas with a cost fee of $ 80 per 1,000 m^3, at the end of 90s Russia and Ukraine have agreed on:

- A reduction of price of the gas supplied for transit with a factor of 1.6, to $ 50 per 1,000 m^3.
- A reduction of transit service cost with a factor of 1.6, to $ 1.09375 per 1000 m^3 and 100 km.

3.3.4 Options to improve GTS management

Possible variants of Ukrainian GTS operation and development

For mobilising the required investments to maintain and extend the capacities of the GTS it is necessary to create an institutional framework to support that. The following options are under discussion currently:

- Ukrainian GTS transfer to concession.
- Emission of 'Ukrtransgaz' stocks and privatisation of Ukrainian GTS by selling these stocks to industrial investors.
- Foundation of joint venture with Russian 'Gazprom' and Western industrial investors.
- Creation of International Consortium for Ukrainian GTS management and development.

Guidelines for Consortium's activities

In case of establishment, the International Consortium will be a legal entity that will execute gas transit through the territory of Ukraine for export to European countries in accordance with intergovernmental treaties being concluded. In accordance with outlined tasks the subjects of Consortium's activities could be:

- Construction and maintenance of gas-pipeline systems.
- Gas transport through newly constructed gas mains.
- Expansion and reconstruction of GTS.
- Organisation of investing projects, including supervision; and

- Design and building of linear parts of gas-main pipelines and compressor stations, underground gas storages and other technological objects to ensure safe and continual supply of additional gas volumes to consumers in Ukraine and its export to European countries.

International Consortium's activities will have to be subject to state control in Ukraine in accordance with Law of Ukraine 'On Natural Monopolies' and other regulations on control over activities of natural monopolists, namely:
- Rates on natural gas transport and other statutory rates are to be regulated by the National Commission on Regulation of Energy Sector.
- Consortium doesn't have the right to control the activities on gas market's subjects in Ukraine.
- Neither state functions nor gas-trader status could be delegated to Consortium.
- Consortium will provide guarantees of third entities' rights for access to pipeline.
- An independent audit (control) over GTS operations is necessary, and
- Consortium has to get a license for transport of natural gas by pipelines.

A state body Operator of GTS of Ukraine will conduct all activities on GTS maintenance on the base of agreement with the Consortium.

Conclusions

Based on the analysis of various questions concerning possible establishment and operation of the International Consortium on management and development of Ukrainian gas transport system it proves that International Consortium, in case of its establishment can create beneficial terms and take into account the interests of Ukraine and European Union countries. It is the opinion of the Ukrainian's authorities that this could furthermore enable:
- To create conditions for extending economic co-operation between Ukraine and European Union in all fields, namely gas sector, which will definitely promote Ukraine economic development.
- To accelerate the integration of Ukraine into European and world economy through participation in and balancing fairly the interests of natural gas providers, consumers and traders.
- To assist in more efficient use of gas-main pipelines in Ukraine
- To improve international position and political image of Ukraine as a key part of European system of energy supply security.
- To promote Ukraine's introduction into European system of energy supply security as an equal partner.
- To ensure continuous gas transit through the territory of Ukraine to European countries and safe gas supply to consumers.
- To be the next step in establishing legal basis and obligatory rules of conduction for every participant in accordance with European Energy Charter's requirements.
- To stimulate the European Energy Charter's Treaty ratification by Russia as an obligatory condition of the International Consortium establishment.
- To provide Ukraine with indirect (for trade) access to gas transport systems of Russia and European Union and thereby permit Ukraine to enter European market with its own natural gas or with gas bought from other third countries.

4. RESILIENCE OF THE GAS TRANSPORT NETWORK

4.1 Introduction

Strategic supply security, or the 'ability to withstand a major unexpected disruption, caused, for example, by the political or technical interruption of a major source', is the prime focus in this chapter. Here, the supply position of a country is of particular importance. Countries that heavily depend on one source or physical link face higher risks than others in this respect.

To analyse strategic gas supply risks, consideration is given to gas supply disruptions that are by nature unexpected, *i.e.* they are difficult to predict and have a very low probability, but may have a high impact. These include disruptions in supplies along vital long-distance gas transmission corridors or at major pipeline interconnections. The key question then is, are additional security of supply measures, *e.g.* provisions and standards, obligations, pipeline investments, necessary to protect against high and costly impacts, particularly in candidate countries? In order to assess 'acceptable costs' of taking such measures (or the willingness to pay for such higher security levels), there is a need to have at least a crude idea about the costs of sudden disruptions. Here it will be evaluated in terms of price pikes and the extent to which production and transport routes need to be replaced at short notice. These disruption effects can be partly offset by storage, as outlined in the proposed EU Directive on gas security, and by commercial arrangements between suppliers and consumers or extra investments in (over) capacity of pipelines, interconnections and LNG terminals.

The main objective of study[11] on which this chapter is based is to identify potential bottlenecks in the gas transmission system by simulating sudden and prolonged 'gas supply disruption cases'. Four cases will be analysed against the background of a reference case, which is based on input from the project partners from candidate countries and from the IEA (which forms the basis of Chapter 2: Long Term Gas Scenarios for Europe). Without assuming any probability for these cases to happen, they merely are used as a tool to analyse the resilience of the European gas transport network.

The following disruption cases are selected:

- Case I: Disruption of Russian gas transported through the Ukraine, *i.e.* a breakdown of Ukrainian transit lines for Russian gas only, which means that Ukrainian transit of Caspian gas is still considered possible (although in real life this type of discrimination is unlikely in the case of a disruption). Transit capacity through the Ukraine currently is about 130 Bcm/year and although the transport pipelines are in bad condition we assume that this capacity, and even a bit more, will also be available for the transit of Russian and Caspian gas in 2020 (148 Bcm in the reference case). As a result of the disrupted Ukraine corridor, Russian gas supply would have to find alternative and more costly routes into Europe.
- Case II: Disruption of all Algerian gas supply to Europe due to a complete halt in production. In 2000, supplies were about 60 Bcm for Europe, but higher export volumes are expected for 2020 (in the reference case).
- Case III: Disruption of all gas supplies through Turkey's territory. It is expected that in 2020 the overall import capacity will be about 70 Bcm/year, while export capacity to the rest of the EU is assumed to be 20 Bcm (in the reference case). In this disruption case the export capacity is assumed zero.

[12] Gas Market Equilibrium Model for an Enlarged Europe.

- Case IV: Disruption of all Norwegian gas supplies. Currently Norway supplies about 53 Bcm, but production capacity is much larger. For the reference case for 2020 we assume a maximum of 110 Bcm.

These cases are considered as most relevant for getting a better understanding of the possible impacts of disruptions in gas supply and consequently the strategic risks for gas supplies to the EU30 as a whole and the selected accession countries in particular.

For the year 2020, the changes in gas prices, trade patterns and supply and demand effects (with respect to the reference case) are discussed. Results are presented for individual countries and especially for a number of selected accession and candidate countries.

An important element in retaining and enhancing a secure gas supply to Europe is the capability of the transmission network to deal with sudden unexpected interruptions of key supplies to EU-30. In this study, we 'track' gas trade flows to the point of consumption. Also it is assessed which firm or region produces the gas and which route (*i.e.*, via which other countries) is used to arrive at the point of consumption. The objective is to analyse the effects of disruption of certain transmission supply routes and which alternative routes will take over to transport gas to their consumer destination and at what price. A distinction is made between pipeline and LNG transport options, because the costs are substantially different between the two options. Thus we assume two types of gas transmitted-pipeline gas and LNG.

4.2 Scope, assumptions and data inputs

For analysing and estimating the impacts of sudden and unexpected gas supply disruptions in the traditional routes to the EU-30, the model GASTALE[12] (version 2003) of ECN is used. A detailed description of assumptions used for GASTALE-2003 is given in the Appendix C. GASTALE is a market equilibrium model and defines a market equilibrium as a set of prices, producer input and output decisions, transmission flows, and consumption that simultaneously satisfy each market participant's first-order conditions for maximisation of their net benefits (known as Karush-Kuhn-Tucker conditions) while the market is cleared (i.e. supply equals demand).[13]

The static model uses production cost curves, linear demand curves, transmission and distribution costs and transmission capacity as the main inputs. The main gas pipelines and LNG infrastructure and production capacities, as projected for 2020, are used as model input, with an emphasis in this model version on the long distance supply transmission routes going into the EU-30. For analysing the different cases, expected gas demand for 2020, as specified by the IEA and in studies conducted by different project partners, is used.

4.3 Results of the reference case

In this section we present the results for the reference case, which represents a competitive gas market equilibrium, given the expected production and transmission capacities for the year 2020. The reference case represents a competitive European gas market with a maximum social welfare (producer and TSO profits plus consumer surplus), see also Figure 4.7. In Section 4.4 the results of the four disruption cases are discussed.

[13] This is known as a mixed complementarity problem. Because the first-order optimality conditions for mathematical programs are a special case of complementarity conditions, complementarity is a natural way to cast equilibrium problems. Further, as it is practical to solve very large complementarity problems, much realistic detail can be captured. Finally, there is a rich body of theory that allows one to analyse such models for properties such as solution existence and uniqueness.

4.3.1 Gas demand and prices

Demand figures in the reference case are (of course) not the same as the numbers we used to calibrate the demand functions (see Appendix C). In general, demand in the reference case is somewhat higher (10 to 15%) than the initially expected demand used for calibration. Table 4.1 shows the relative differences for all countries.

The United Kingdom faces a 12% lower demand than initially expected. This may be explained by the fact that the United Kingdom has to import about half of its gas demand, whereas it has no cheap nearby supply options. Norwegian supply is relatively expensive with limited available capacity, and distances to cheaper options are large.

Reference demand in Hungary and the Czech Republic is similar to initial demand, which is possibly caused by the fact that CEEC countries demand functions are calibrated on relatively low prices. In the model they have to compete for gas with the current EU Member States which are able to pay higher gas prices as a starting point.

Turkish reference demand is 42% higher than expected demand used for calibration. The proximity to cheap supply options in the Caspian Region and Iran, and its initially high gas prices may explain the relatively high reference demand.

Table 4.1 *Gas demand and border prices*

	Demand [Bcm]			Price [€/1000 m^3]
Country	Reference	Initial	Difference [%]	Reference
Austria	14.40	12.45	16	89.36
Belgium	27.54	24.47	13	104.84
Czech Rep	13.29	13.10	1	80.32
France	72.26	66.32	9	108.76
Germany	141.74	123.47	15	83.39
Hungary	18.72	19.64	-5	85.08
Italy	119.90	109.95	9	105.35
Netherlands	70.02	63.37	10	100.53
Poland	20.50	19.00	8	60.55
Romania	31.83	29.02	10	39.51
Slovakia	14.08	12.07	17	64.31
Spain	44.85	40.64	10	104.35
Turkey	41.49	29.25	42	30.86
United Kingdom	126.45	143.89	-12	116.05
Total	757.08	706.64		

Because of the assumed linear demand functions, the change in prices is opposite to the change in demand. Thus, gas prices in Hungary and the UK are higher in the reference case than initial prices in those countries. In the other countries equilibrium reference prices are lower than initially assumed. The last column of Table 4.1 shows border prices, i.e. the end-use price net of within-country distribution costs.

4.3.2 Gas supply, sales and flows

Figure 4.1 and Table 4.2 give an overview of the main gas flows to Europe in the reference case in 2020. It shows production volumes in each region, as well as the LNG and pipeline flows to the countries considered. The darker countries in the figure are the consuming countries we distinguish (eight EU15 countries, five CEECs and Turkey). Note that production volumes in the EU and CEEC include exogenous production (see Appendix C for further explanation).

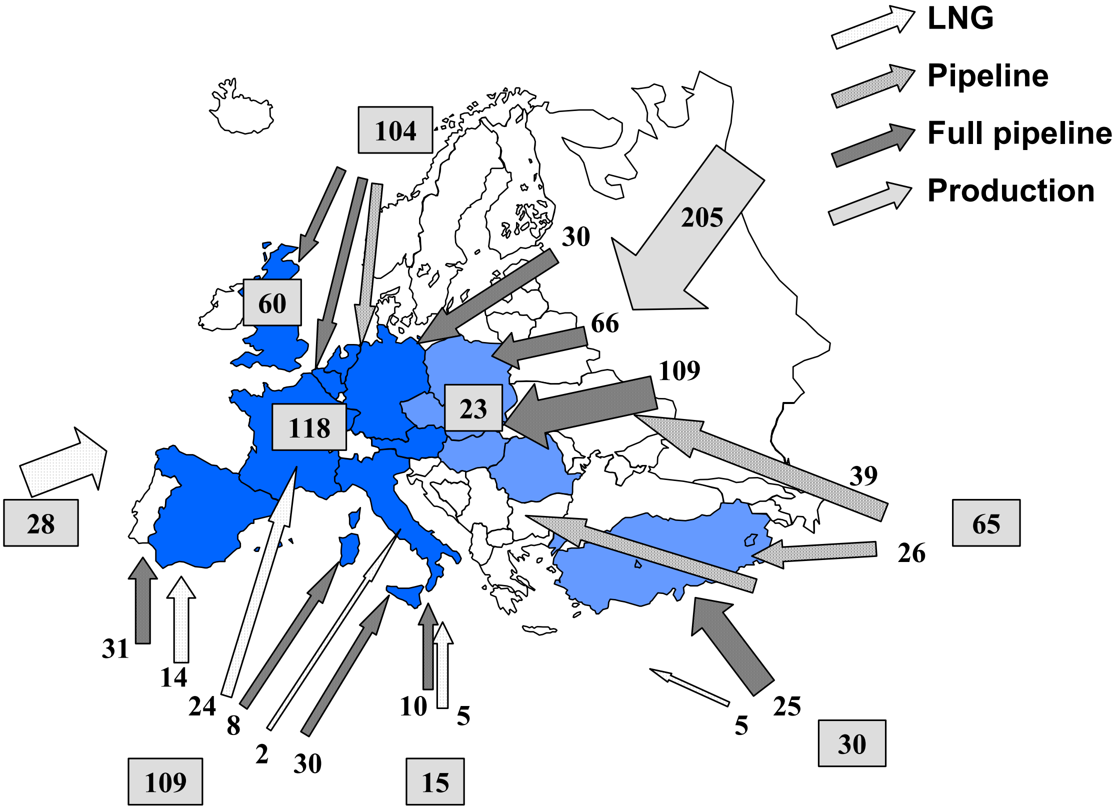

Figure 4.1 *Gas production and major gas flows to EU, CEEC and Turkey, reference case [Bcm]*

The within each region capacity usage, shown in Teble 4.2, must be interpreted carefully. For example, EU15 internal flows only use 39% of available capacity. However, the capacity of 354 Bcm is a result of two-way counting; pipelines like the UK-Belgium Inter-Connector are counted for both directions.

Table 4.2 *Gas flows and pipeline capacities in the reference case in 2020 (capacities in parentheses) [Bcm]*

To From	Belarus	Ukraine	EU15	CEEC	Turkey
Russia	66 (66)	109 (255)	30 (30)	-	0 (16)
North Africa	-	-	79 (79)	-	-
Norway	-	-	104 (147)	-	-
Caspian	-	39 (50)	-	-	26 (30)
Iran	-	-	-	-	25 (25)
Belarus	-	0 (29)	-	66 (66)	-
Ukraine	-	-	-	148 (148)	-
EU15	-	-	143 (354)	0 (8)	-
CEEC	-	-	138 (171)	73 (127)	0 (14)
Turkey	-	-	10 (10)	0 (10)	-

Table 4.3 and Table 4.4 give a more detailed overview of gas and LNG supply and demand in the reference case. In the Caspian Region and Russia, there are no restrictions in direct connections to the neighbouring countries such as the Ukraine. However, flows from the Ukraine and Belarus in the direction of European markets are constrained by capacity. Moreover, the Caspian Region competes with Russia for transit capacity through the Ukraine. In the reference case, Russian gas via Blue-Stream pipeline is too expensive to compete with Caspian and Iranian gas for supply to Turkey. And Russian LNG is too expensive to compete with other LNG

supplies. It is clear that export capacity is the restrictive factor in Iran, Algeria and Libya, consequently these countries cannot increase their export to substitute other more expensive export supplies in case of any disruption. But capacities are not a binding constraint in Norway, although it is approaching its production ceiling, so the extra upward supply potential is very limited. LNG supplies from remote areas ('LNG other') is in general the most expensive supply option and capacity is consequently not a binding constraint in the reference case.

Table 4.3 *Gas supply options and sales in the reference case [Bcm]*

Country	Production and export	Export capacity	Production capacity	EU	CEEC	Turkey
Algeria	109	109	170	109		
Caspian Region	65	80	100	7.38	31.91	25.85
EU	174	-	188	174.43		
Iran	30	30	60	15		15
Libya	15	15	30	15		
Norway	104	153	110	104.11		
Russia	205	380	250	160.81	43.89	
LNG other	28	61	90	27.59		
Exogenous prod.	27			3.83	22.63	0.64
Total demand	757			617.15	98.43	41.49

Note: Export capacity of LNG other is determined as total import capacity of EU, CEEC and Turkey (130 Bcm) minus export capacities of LNG supplying countries (except LNG other).

Table 4.4 *LNG exports and imports in reference case [Bcm]*

Country	LNG exports	LNG sending capacity	France	Italy	Spain	United Kingdom
Algeria	40	40	24	2.31	13.69	
Iran	5	5				5
Libya	5	5		5		
Norway	0	5.7				
Russia	0	13				
LNG other	27.6	61.3		6.59		21
Total	77.6	130	24	13.9	13.69	26

Belgium, Romania and Turkey do not use their LNG receiving capacities in the reference case, whereas in France and the United Kingdom LNG receiving capacity is fully utilised. The only possibility for France to increase its gas imports is to use LNG capacity in Belgium and Spain and transport the gas via pipelines to France (as pipelines into Belgium and Spain are fully used). But our results show that this option is too expensive. For the United Kingdom a similar argument applies, with only Belgian LNG reception as a supply option.

Spain and Italy partly use their LNG receiving capacities. Pipelines are fully used, and LNG capacity is fully utilised to meet demand. For Spain, current (2000) LNG capacities suffice, while planned LNG capacity investments in Italy are needed to meet reference demand.

4.3.3 Main conclusions of reference case

In the reference case, the only supply option with significant unused capacity is 'LNG other', which is in general also the most expensive supply option. Other options with some unused supply potential are:

- Russia to Turkey (Blue-Stream pipeline), however other bottlenecks in Turkey (see below) prevent onward transit to Europe.
- Pipeline gas from Norway to Germany and France, as well as Norwegian LNG supplies.

It is striking that even the ‘expensive’ Baltic pipeline from Russia to Germany is ‘fully’ utilised in the reference case. The annual transmission capacities of Belarus (66 Bcm), the Ukraine (148 Bcm), Algeria (109 Bcm), Libya (15 Bcm) and Iran (30 Bcm) are also fully utilised. Extension of transmission capacity is necessary to enable increasing gas supplies from the cheapest supply options in North Africa, the Caspian Region, Russia and Iran to European markets. It is also noteworthy that transmission capacity from EU15 countries into CEEC countries is also limited, consequently there is hardly any scope for supplies from Western Europe to candidate countries, to serve as effective backup option in case of emergencies.

Transit of gas through Turkey into the EU (via Greece 10 Bcm) is restrictive, whereas transit possibilities of gas flowing through Turkey into CEECs (via Bulgaria another 10 Bcm) are not used. The latter is caused by bottlenecks in the transit route into the EU at Romanian-Hungarian border.

4.4 Results of disruption cases

Four disruption cases are analysed:
- Disruption of Russian supply through the Ukraine, in which the complete transmissions pipeline capacity across the Russian-Ukrainian border, becomes unavailable (Russian Case).
- Disruption of Algerian supplies altogether (Algerian Case).
- Disruption of transits through Turkey, *i.e.* transit pipelines from Turkey to Greece and Bulgaria become unavailable (Turkish Case).
- Disruption of Norwegian supplies altogether (Norwegian Case).

4.4.1 Summary of qualitative results

Russian case

In the reference case, over 50% of Russian exports pass the Ukrainian border. When this route becomes unavailable, Russian gas export flows will ‘search’ alternative routes. The only alternative routes are Turkey (Blue-Stream) and Russian LNG; the Baltic pipe to Germany is already fully used in the reference case. Markets that were supplied by Russia via the Ukraine in the reference case will ‘search’ for alternative supply options. As Norway and ‘LNG other’ have unused supply potential, their exports increase. And because the Caspian Region does not have to compete with Russia for transit capacity through the Ukraine anymore, the Caspian supplies will probably increase, maybe even at the expense of supplies to Turkey.

Algerian case

In the reference case Algerian exports are at their maximum level, as pipeline and LNG exporting capacities are fully used. Contrary to the Russian Case as defined, there is no alternative for Algerian gas to Europe, as we assume that production falls to zero. The countries currently directly supplied by Algeria (Spain, France and Italy) are severely effected. The upward potential of other supply sources is very small. Spain and Italy use much more LNG than in the reference case. ‘LNG other’ will probably supply more than in the reference case. However, in this study our focus is on impacts of the Algerian Case on the countries not directly supplied by Algeria, and particularly on the CEEC countries.

Turkish case

The impact of the Turkish Case is relatively small, since transit volumes in the reference case are small. Italy is affected, because it receives Iranian supplies via Turkey and Greece in the reference case. As Iran can only deliver to Turkey, Caspian deliveries are pushed out of Turkey (and onto the Ukrainian route). Therefore, the Caspian Region competes harder for Ukrainians transit capacity, pushing out some of the Russian transits. Nevertheless, the impact of this disruption is dissipated throughout the network. Therefore, only small impacts in southeast Europe, and hardly any in northwest Europe are noted.

Norwegian case

Norway supplies at almost full production capacity to the EU in the reference case. However, alternatives for disrupted Norwegian supplies are hardly available. Russia and Algeria are exporting at full capacity to Europe. Therefore, 'LNG other' is the most important alternative and supplies much more than in the reference case.

4.4.2 Effects on gas demand and prices

Table 4.5, Figure 4.2 and Figure 4.3 give an overview of the consumption and price effects as a result of the different gas disruption cases.

Table 4.5 *Consumption and consumption change for all disruption cases*

	Ref.	Russian Case			Algerian Case			Turkish Case			Norwegian Case		
Country	[Bcm]	[Bcm]	[Δ]	[%]	[Bcm]	[Δ]	[%]	[Bcm]	[Δ]	[%]	[Bcm]	[Δ]	[%]
Czech Rep.	13.3	11.93	-1.4	2	13.2	-0.1	0	13.3	0.0	0	11.7	-1.6	2
Hungary	18.7	16.13	-2.6	4	18.6	-0.2	0	18.7	0.0	0	17.5	-1.2	1
Poland	20.5	18.35	-2.1	4	20.5	0.0	0	20.5	0.0	0	20.4	0.0	0
Romania	31.8	24.71	-7.1	12	31.8	0.0	0	28.4	-3.4	84	31.8	0.0	0
Slovakia	14.1	11.87	-2.2	4	14.1	0.0	0	14.1	0.0	0	14.0	-0.1	0
Turkey	41.5	36.95	-4.5	8	41.4	-0.1	0	41.6	0.1	+3	41.5	0.0	0
EU15	617.2	579.1	-38.1	66	581	-36.2	99	616.4	-0.8	19	537.5	-79.7	96
Demand effect	757.1	699.0	-58.0		720.5	-36.6		753.0	-4.0		674.5	-82.6	

% = Fraction of total demand decrease.

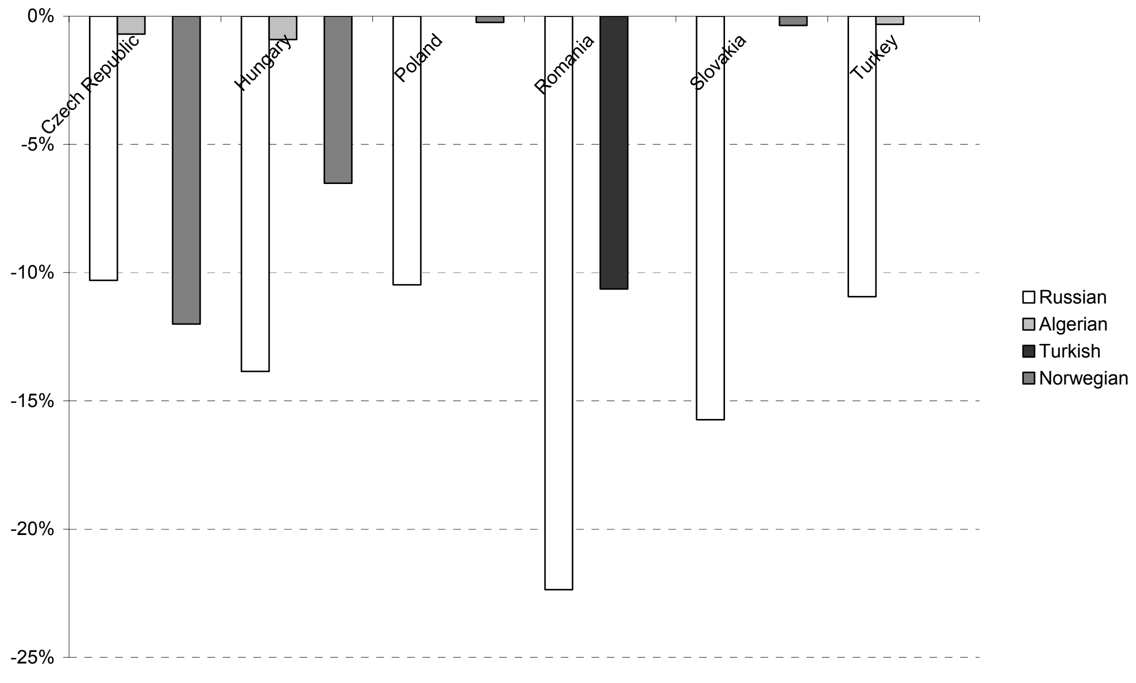

Figure 4.2 *Demand changes in CEECs and Turkey compared to the reference case*

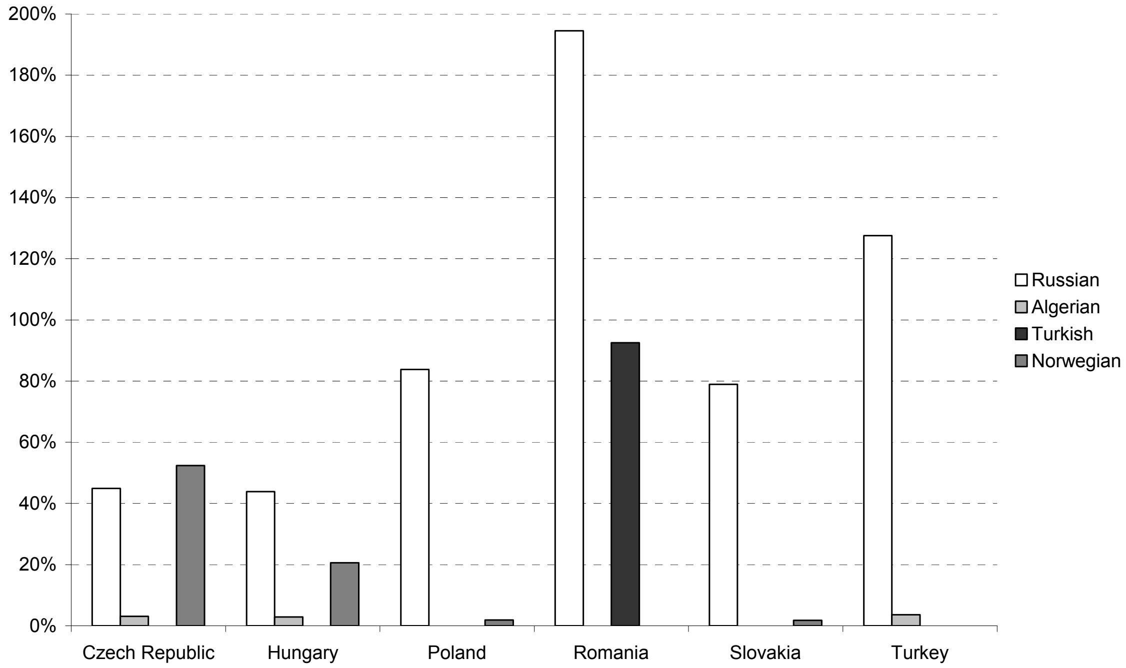

Figure 4.3 *Price changes in CEECs and Turkey compared to the reference case*

Russian case
It is clear that disruption of the Russian-Ukraine supply affects all consuming countries considered, and not surprisingly, the impacts for CEEC are most severe. Although Romania does not import Russian gas in the reference case, its gas market is highly affected by the disruption of Russian supply. This is mainly due to the substantial and fixed volume of domestic gas production, resulting in relative small volumes for trading and thus more sharp market changes. This is illustrated in Figure 4.4, where the difference between total demand and the effective demand curve for imports (the latter is used in the model) is caused by domestic production. Because of disrupted supplies, prices rise and are causing a major shift along the Romanian demand curve.

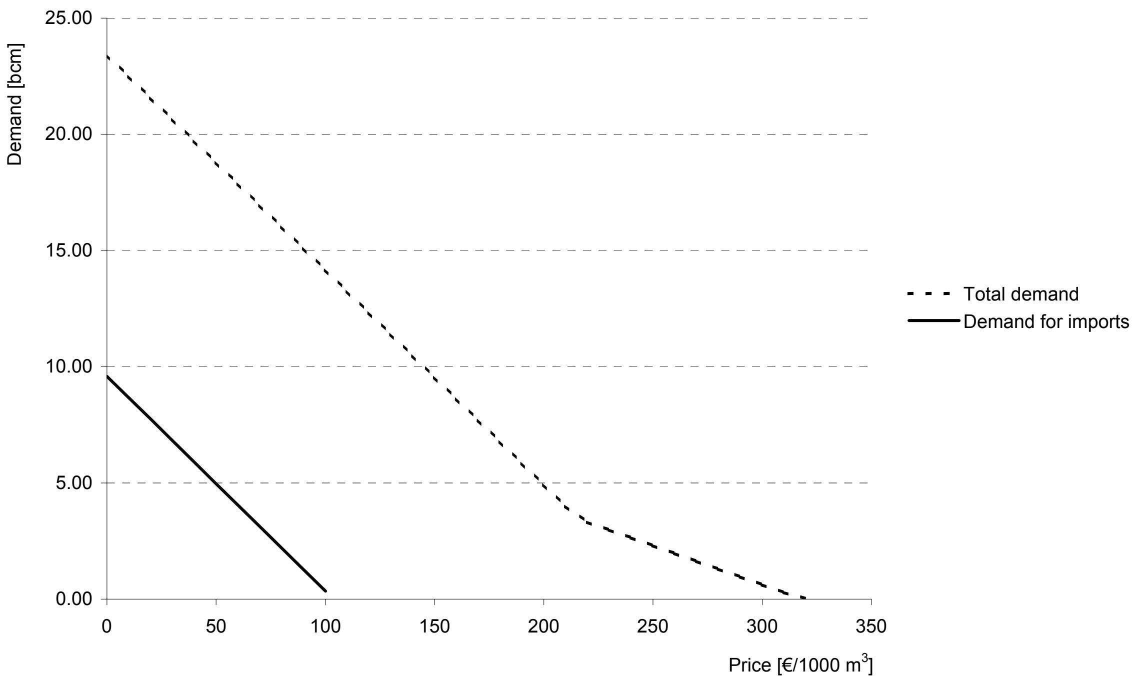

Figure 4.4 *Romanian gas demand-price relationship*

Algerian case
Disruption of Algerian supply hardly affects CEECs and Turkey, but Italy and Spain are hit hard (see figure 4.5 and 4.6). Spain is fully dependent on Algerian supply, see the reference case (including for its LNG supplies which count for about one-third of total supplies) and has no real other importing possibilities. Italy, on the other hand, only relied for about one-third of its imports on Algeria in the reference case. Nevertheless, disruption of Algerian supply has still a substantial impact on Italian gas prices by increasing these.

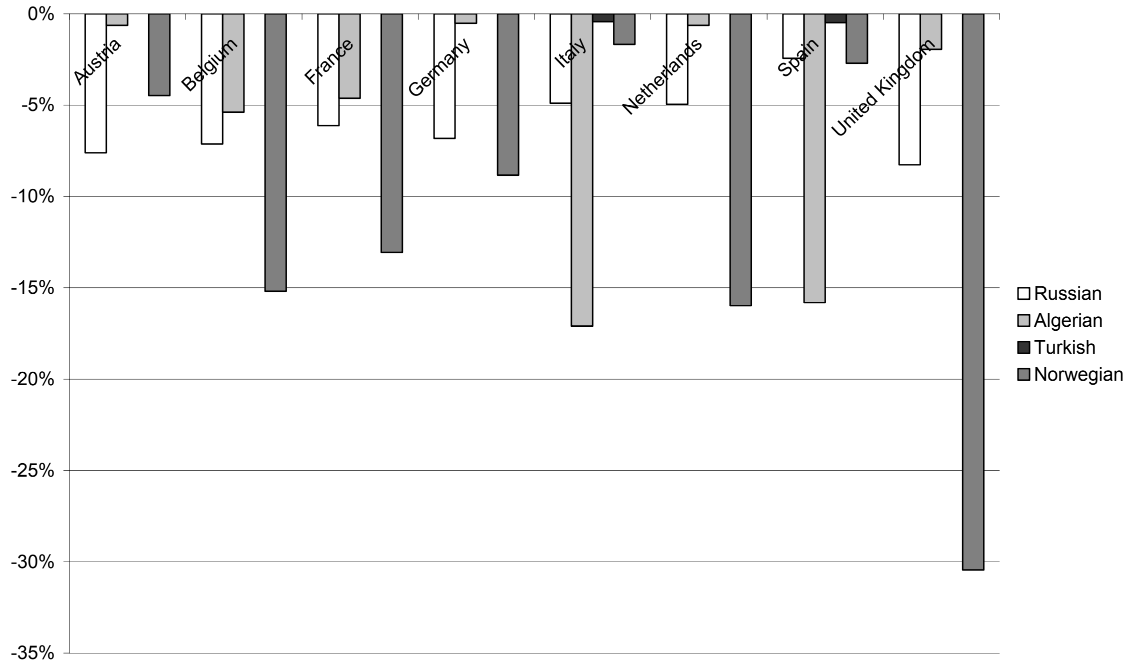

Figure 4.5 *Demand changes in selected Member States compared to the reference case*

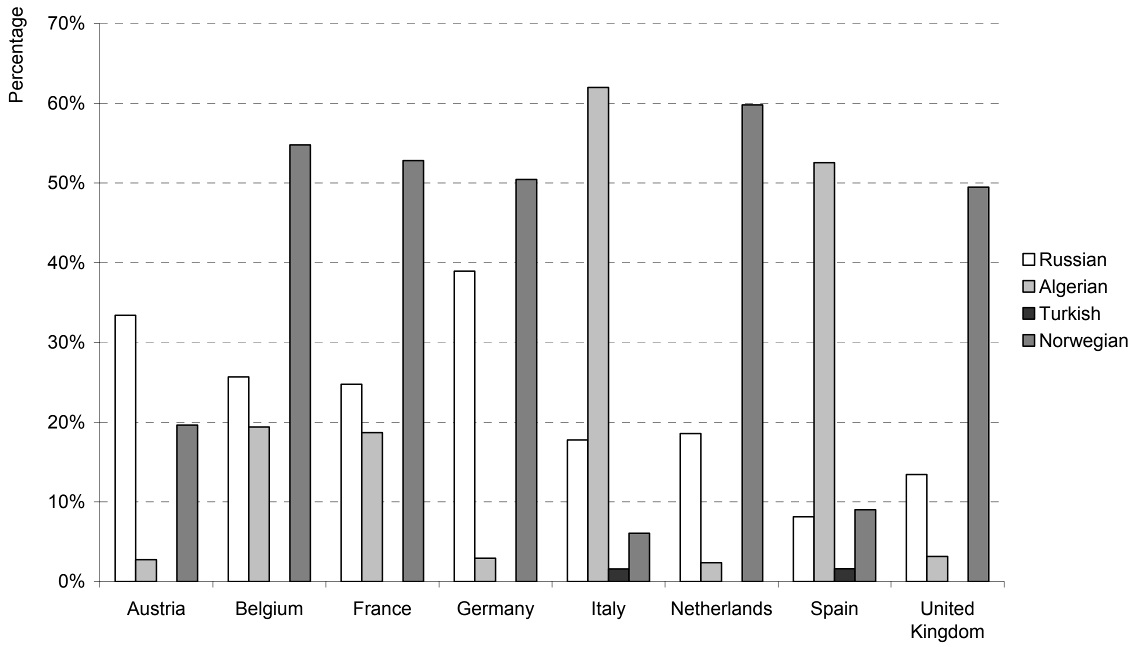

Figure 4.6 *Price changes in selected Member States compared to the reference case*

Turkish case
The disruption of Turkish gas transit only has a substantive impact on Romania. Again, the Romanian demand curve is to 'blame' for the large impact. Gas demand in Turkey profits from disrupted transit, because Iran has no alternative gas outlets and the Caspian region prefers sales to Turkey (at relatively low prices) over long-distance transportation that would incur high transmission costs.

Norwegian case
Disruption of Norwegian gas supplies has little effect on CEECs. Only the Czech Republic and Hungary are affected. However, it has a major impact on gas markets in current EU Member States (see Figures 4.5 and 4.6).

4.4.3 Gas supply, sales and flows

Table 4.6, Figure 4.7 and Figure 4.8 give a summary of the main production and supply effects of the different disruption cases.

Table 4.6 *Production, production change, substituted supply and demand effect for all disruption cases*

Country	Ref. [Bcm]	Russian Case [Bcm]	[Δ]	[%]	Algerian Case [Bcm]	[Δ]	[%]	Turkish Case [Bcm]	[Δ]	[%]	Norwegian Case [Bcm]	[Δ]	[%]
Algeria	109.0	109.0	0.0	0	0.0	-109.0	-100	109.0	0.0	0	109.0	0.0	0
Caspian Region	65.1	80.0	14.9	15	68.9	3.8	3	62.5	-2.6	-27	65.1	0.0	0
Norway	104.1	109.6	5.5	6	105.3	1.2	1	104.1	0.0	0	0.0	-104.1	-100
Russia	204.7	107.8	-96.9	-100	213.9	9.2	8	197.5	-7.2	-73	204.7	0.0	0
LNG other	27.6	46.1	18.5	19	86.0	58.4	54	33.4	5.8	59	49.0	21.4	21
Supply effect	510.5	452.5	-58.0		474.1	-36.4		506.5	-4.0		427.8	-82.7	
Replaced supply			38.9	40		72.6	67		5.8	59		21.4	21

Note: Iran and Libya keep on supplying there full loads, 30 and 15 Bcm respectively.
% = Fraction of disrupted supply.

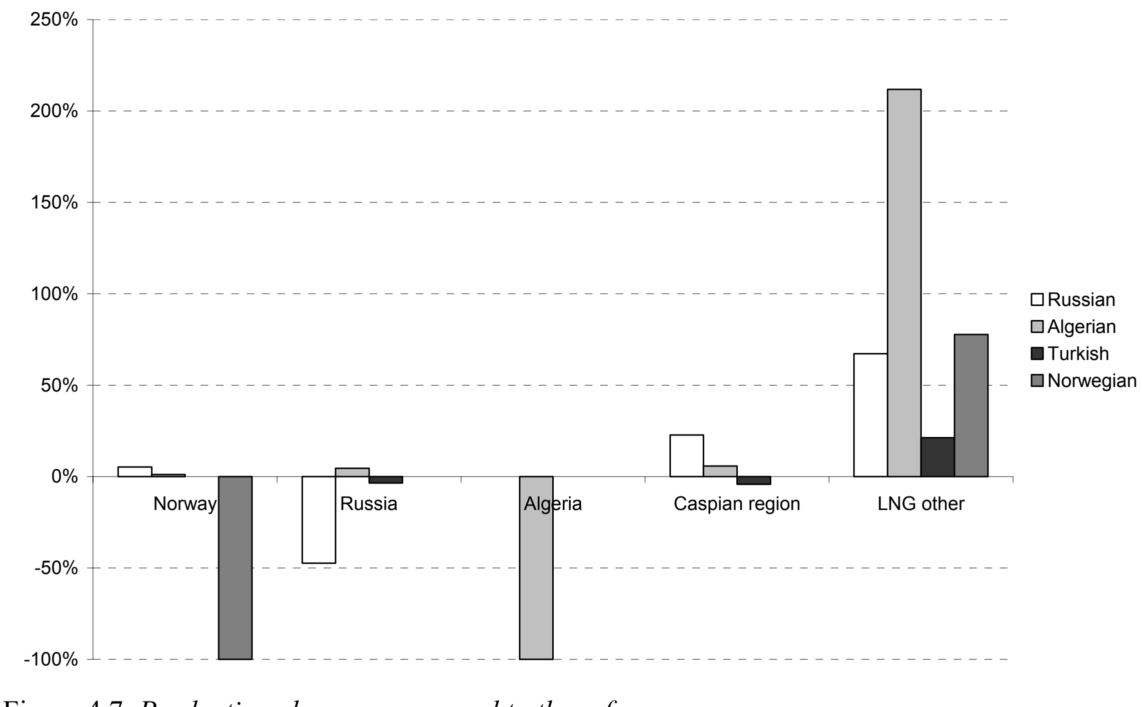

Figure 4.7 *Production changes compared to the reference case*

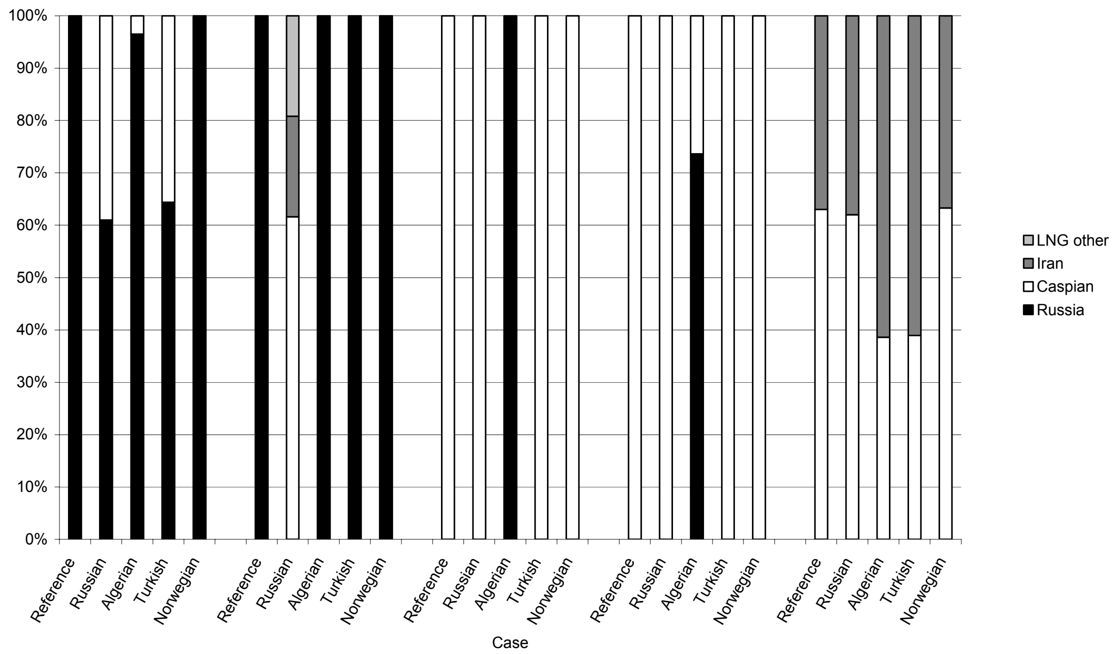

Figure 4.8 *Origin of imports for selected CEECs and Turkey for all cases*
Note: Poland is 100% dependent on Russian supply in all cases.

Russian case

In the Russian Case, all pipeline capacities into Europe are fully utilised and LNG supplies make up the shortfall under normal conditions. The export capacity of the Caspian Region and Norway is fully utilised. 'LNG other' supplies about 20 Bcm more than in the reference case. Russian supplies fall about 97 Bcm. Alternative routes absorb about 12 Bcm of gas diverted from the Ukraine route. There is some small supply through Bluestream route and via the Russian LNG export option now, totalling 10.5 Bcm.

The main impact of the disruption in Russian supplies is a drop in total EU-15 *(in fact 8 of 15 EU countries in model)* demand volumes of 58 Bcm (7.7% of total consumption in the reference case). In other words, about 60% of the Russian drop in supply is not replaced by other sources. From the results of the reference case was already learned that LNG was the only alternative supply option with significant unused capacity. As a result, consuming countries without (additional) LNG import capacity see their consumption fall sharply, because LNG is just too expensive to replace the Russian supplies.

Algerian case

Algeria is the biggest single LNG supplier in the reference case. When Algeria is disrupted, we see that LNG deliveries are taken over by 'LNG other' and Russian LNG. 'LNG other' supplies are close to maximum capacity, and Russia even is at full LNG capacity. Norwegian LNG is still too expensive, because of the high Norwegian production costs, which are not outweighed by the lower transmission costs compared to Russia.

As Russian supplies shift partly to LNG, its transits through Ukraine drop somewhat, favouring Caspian supplies. Finally, Norwegian supplies to France increase to fill up the spare capacity in the reference case, partly offset by smaller deliveries to Germany.

Compared to the Russian Case, where only 40% of disrupted supplies is replaced, we see that in the Algerian Case about two-thirds of disrupted supplies are replaced by other supply options. The total drop in demand is about 36 Bcm.

Turkish case
In the reference case, transit through Turkey is10 Bcm This is made up entirely by Iranian supplies to Italy. When Turkish outlets are disrupted, Iran has just one delivery option: Turkey. Caspian supplies are partly pushed out, encouraging competition between Caspian and Russian (in ref. Case 108.7 Bcm and here 101.5 Bcm) gas for Ukrainian transit capacity. Table 4.7 shows that transmission prices of transport through the Ukraine (that is fully utilised already in the reference case) to Europe increase significantly as a result of this increased competition. Part of Russian supplies is pushed out by Caspian supplies. Combined production levels of the Caspian Region and Russia nonetheless drop by almost 10 Bcm. The lost Iranian supplies to Italy are partly substituted by supplies from 'LNG other' and by additional Caspian supplies (in ref. case 39.3 and here 46.5 Bcm) via the Ukraine.

Table 4.7 *Transmission prices*

		Gas flows	Transmission price[€/1000 m^3]		
From	To	[Bcm]	Reference case	Turkish case	Increase
Ukraine	Hungary	10	52.71	53.45	0.74
Ukraine	Poland	5	28.19	28.93	0.74
Ukraine	Romania	28	7.15	44.45	37.30
Ukraine	Slovakia	105	31.95	32.69	0.74

Norwegian Case
Unexpectedly a disruption of Norwegian supplies has the biggest impact on consumed volumes in EU-15. Contrary to the Russian Case as defined, there are no other suppliers that can use the idle pipeline capacities. And also contrary to the Algerian Case, there are no 'profitable' LNG supplies that can be taken over by other LNG suppliers. Since all pipeline capacity into the here analysed eight of the EU countries is restrictive in the reference case, there is no possibility to increase supplies via pipelines when Norwegian supply is disrupted. The only additional supplies are from 'LNG other' (an increase of 21 Bcm), which leads to increased LNG imports in Belgium, Italy and Spain. Moreover, we see a reshuffle of the existing LNG deliveries (see Table 4.8).

Table 4.8 *LNG sales [Bcm]*

Supplier	Importing Country	Reference Case	Norwegian Case	Difference
Algeria	Belgium	0.00	7.50	7.50
Algeria	France	24.00	10.02	-13.98
LNG Other	France	0.00	13.98	13.98
Algeria	Italy	2.31	0.00	-2.31
Libya	Italy	5.00	5.00	0.00
LNG Other	Italy	6.59	14.05	7.46
Algeria	Spain	13.69	22.48	8.79
Iran	United Kingdom	5.00	5.00	0.00
LNG Other	United Kingdom	21.00	21.00	0.00

4.4.4 Discussion of other impacts

Welfare effects
The welfare effects for the gas consuming countries, considered in this study, as a result of the disruption cases when compared to the reference case are shown in Figure 4.9. Producer and TSO profits are generally higher when gas supply is disrupted, because they are able to get higher prices for their gas, while production costs are lower per unit (since volumes are lower) and increased transport prices only partly offset the higher end-user prices. Consumer surplus and overall social welfare are lower in case of supply disruptions. Disruption of Norwegian gas

supply has the most severe effects, followed by disruption of Russian supplies via the Ukraine and Algerian supply. Disruption of gas transit through Turkey hardly has any welfare effects.

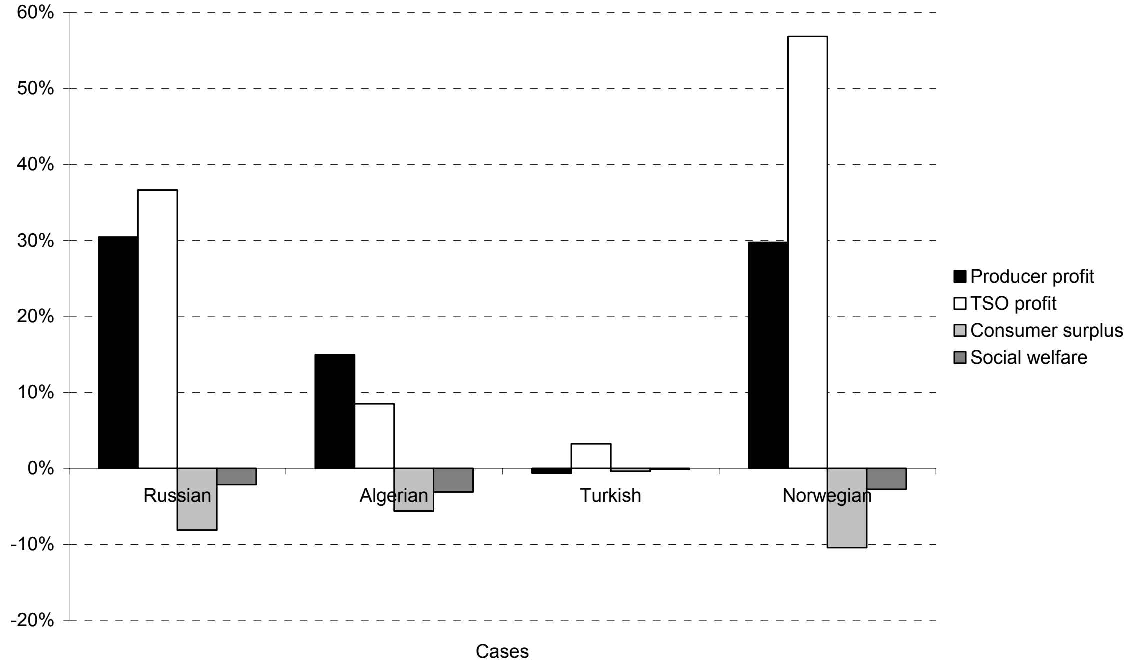

Figure 4.9 *Welfare effects of interruption cases compared with reference case*

Measuring dependency

Earlier studies (e.g. Wood MacKenzie, 1998 and IEA, 1995) have calculated 'survival periods' in case of gas supply interruptions, based on storage capacities in each country. Like storage, interruptability of demand, i.e. the fraction of demand that contractually can be interrupted, LNG import capacity and domestic production capacity increase the flexibility to meet supply disruptions. Table 4.9 gives an overview of which part of total demand in each country is 'covered' by other sources than imports by pipelines.

The recommended storage is two months of average demand, i.e. about 17% of yearly consumption (EC 2002). In Belgium, Spain, the United Kingdom, the Netherlands, Turkey, Romania, Poland and Italy current storage capacities are insufficient to meet 2020 demand for two months. However, these countries have either significant LNG import capacities, or significant own production capacity making the need for storage less pressing. It should be noted that the different flexibility options usually have different purposes, i.e. they will and cannot be used in the same way whenever a gas supply interruption occurs.

Table 4.9 *Coverage of gas demand in pipeline disruption situation [%]*

Country	Interruptability	Storage	LNG	Own production
Austria	33	22	0	14
Belgium	32	3	31	0
Czech Republic	<1	16	0	2
France	18	16	36	3
Germany	20	15	0	20
Hungary	29	17	0	16
Italy	33	12	22	14
Netherlands	11	4	0	110
Poland	22	7	0	27
Romania	n.a.	6	9	48
Slovakia	0	22	0	1
Spain	23	3	84	0
Turkey	23	5	41	2
United Kingdom	26	3	19	51

Sources: IEA, 2003 (Interruptability percentages) and IEA, 2002 (Storage capacities). Turkish storage is based on a planned storage facility of 1.6 Bcm in Marmara Sea for 2005. Project partner EnergSys gave the Polish interruptability fraction, July 2003. Energetické Centrum Bratislava provided the Slovakian fraction (0%), July 2003.
Note: The percentages in the table below relate to the expected 2020 demand figures, see Table C.1.

4.5 Discussion of infrastructure projects

At project meetings and in the media several options for infrastructure investments have been discussed. Based on our reference case we have assessed the added value of these investment opportunities if realised. Without even suggesting to present a complete list and overview, below the relevance of some optional pipeline projects is discussed.

Norway-Poland, 8 Bcm

Russia is the main supplier to Poland. A few years ago, Poland contracted gas supplies from Norway. When last years growth in gas demand slowed down, contract terms with Russia have been renegotiated. The explicit need for a new pipeline via Denmark for Norwegian supplies has therefore disappeared, as there is some spare Norwegian capacity to Germany. Increasing the Germany-Poland transit capacity seems a more cost-effective investment than building a pipeline from Norway to Poland. This would also increase EU15-CEEC transit capacity relevant for effective backup agreements.

Turkey-Bulgaria-Romania-Hungary-Austria, extension from 10 to 20 Bcm

The only bottleneck in the route from Turkey to Austria in the reference case is the Romania-Hungary cross-border capacity. Looking one step further, also capacity Austria-Italy is restrictive. Current supplies to Austria via Romania come from Ukraine. So increased supplies to Turkey are necessary to use the transit route Turkey to Austria anyway. Extra supplies to Turkey might come from Iran, Iraq, the Caspian region and North Africa. We may conclude that investment in the Turkey-to-Austria transit route is only useful in combination with major upstream investments in the aforementioned regions. Also the future development of gas markets in the Balkan region can benefit enormously of diversifying supplies to Southeast Europe.

Algeria-Spain-France (MEDGAZ), extension from 12 to 16 Bcm
This is an option to secure cheap Algerian supplies to Spain in a business-as-usual situation. In the model, France only receives LNG from Algeria, as Spain uses all pipeline supplies from Algeria itself. As LNG costs are expected to fall relative to pipeline costs, and taking account of the security of supply risks, more pipelines from Algeria to Spain/France do not seem a top priority. France might better invest in more LNG regasification terminals for enhancing their supply flexibility.

Libya-Italy (GreenStream), extension from 8 to 20 Bcm
For diversification of South European supply options this seems a beneficial option, namely because of security of supply as well as having access to cheap business as usual gas supplies. But increased reliance on Libyan gas carries geo-political risks at the moment.

Netherlands-United Kingdom (BBL), extension from 8 to 12 Bcm
United Kingdom leans heavily on Norwegian and LNG supplies. LNG capacity is projected to be 26 Bcm in 2020. Capacities from Belgium and from the Netherlands into the United Kingdom are not fully utilised in 2020. Spare capacity from Belgium to United Kingdom is about 21 Bcm, however the spare capacity in BBL is only about 0.5 Bcm in the reference case. As there is no spare capacity into the Netherlands and into Belgium, extending BBL (compared to the planned capacity of 8 Bcm) seems only useful in combination with other investments (capacity into the Netherlands). See also the recent developments facilitating Russian supplies to the United Kingdom. So evaluating the investments in BBL should be conducted through including simultaneously an evaluation of investments in LNG facilities for securing supplies to the United Kingdom in the long run.

LNG terminal Germany Wilhelmshaven (assumed to exist in 2020)
Germany seems to have sufficient inward interconnections with surrounding countries. Therefore Germany benefits directly from investments to secure supply in surrounding countries. Germany could however become a major transit country for Russian gas to the Northwest European countries beyond 2020. German capacity into the Netherlands should be increased. (As already mentioned before discussing the Russian supplies to the United Kingdom.) For the diversification of German supplies a LNG terminal could be an interesting option. However, from a European perspective there are also other more optimal locations available to build LNG import terminals or increase LNG import capacities than in Germany.

Intra CEEC pipeline capacities
In the gas scenario and policy study, see Chapter 5, it is suggested that pipeline capacity between some of the CEEC countries is lacking. Table 4.10 shows the assumed capacities and trade flows for 2020 in the reference case. The table shows that Czech Republic has only significant import gas transport capacity from Slovakia. Diversification of entrance points seems a good suggestion. For example Poland should increase import capacity from Germany (or Denmark/Norway). Other CEEC countries seem to have sufficient supply diversification to reach a minimum level of flexibility needed to deal with unexpected disruptions. Of course, instead of extra pipeline capacities an alternative for short-term interruptions one should also consider increasing the storage capacity locally.

Table 4.10 *Intra-CEEC connections [Bcm]*

From	To	Flow	Capacity
Poland	Czech Rep	0.00	0.10
Slovakia	Czech Rep	56.90	56.90
Austria	Hungary	0.00	5.30
Romania	Hungary	10.00	10.00
Ukraine	Hungary	10.00	10.00
Belarus	Poland	66.00	66.00
Germany	Poland	0.00	2.30
Ukraine	Poland	5.00	5.00
Bulgaria	Romania	0.00	10.00
Hungary	Romania	0.00	2.00
LNG	Romania	0.00	2.50
Ukraine	Romania	28.00	28.00
Poland	Slovakia	5.71	29.70
Ukraine	Slovakia	105.00	105.00

4.6 Conclusions

Based on our model analysis, while noting its limitations and assumptions, the following conclusions can be drawn:

- Existing and planned gas supply and transmission infrastructure (both LNG and pipeline) seem sufficient to meet expected gas demand in 2020. In case of a disruption in one of the key supplies, the transmission network capacity is a constraining factor leading to price rises, need for reallocate trade flows etc.
- Some countries hardly (or not at all) use their LNG regasification facilities. Moreover, Blue-Stream pipeline from Russia to Turkey is hardly used in any of the disruption cases, nor in the reference case. Thereby illustrating their expensive nature.
- Expected gas consumption for 2020 can be met in most of the cases.
- Disruption of Norwegian gas supply in EU-30 has the biggest overall impact. The current EU Member States are most severely affected, while a disruption of Russian supplies via the Ukraine has a major impact on the Accession CEECs and Turkey as well as on the EU-15 Member States,
- Caspian gas supplies become increasingly important for CEECs and Turkey, assuming that pipeline capacity is expanded accordingly.
- LNG supplies from remote sources play an increasingly important role in filling the supply gap in any of the disruption cases. LNG regasification capacity will become very important in ensuring a flexible and thus a secure gas supply to EU-30 in the medium term.
- Investments in transmission pipelines from Russia, Iran and North Africa to Europe are important. This includes investments in terms of planned and unplanned new capacity, but critically is also the maintenance of existing capacity and improving access (e.g. reducing costs of access).
- Identified are the following bottlenecks in pipeline transmission of gas:
    - Iran into Turkey and further into Europe.
    - Bulgaria and Romania into Europe.
    - Cross-links between CEECs, which are important for mutual assistance in case of emergencies.
    - From West and South into CEECs. Flows and pipelines are currently dimensioned from east to west.
    - Spain, however addressing this by developing its LNG facilities.
    - Belarus and Ukraine into EU-30.

- Turkey’s role as transit country for gas from the Caspian Region and Iran to Europe depends critically on following factors:
  - Development of the domestic gas demand in Turkey,
  - Expansion of pipeline capacities from Turkey to Greece and Italy,
  - Expansion of pipeline capacities from Turkey to Bulgaria and further to Romania-Hungary-Austria,
  - Availability of gas supplies for export (i.e. capacity export interconnections) from the Caspian Region and Iran.

5. GAS SCENARIOS AND POLICIES FOR CANDIDATE COUNTRIES

5.1 Introduction

Due to the great restructuring of the energy sector that will take place in the next decades in the accession countries it is expected that the drive for cleaner and more efficient electricity production will result in increasing demand for gas in the long run. This would enhance the dependency of these countries on imports of energy carriers and particularly increase the dependency of EU in the next decades. Consequently, it is important to analyse the possible developments in the long term (until 2030) of gas demand, supply and the resulting import requirements and to assess the 'gas supply security situation' and policy measures (that should be) taken in these for gas import most relevant candidate countries. In this chapter three different gas demand scenarios (a reference scenario and two variants, a low and high import demand) are developed for four key accession countries with respect to gas consumption. This to cope with the uncertainty in long term gas demand projections and see how urgent and what type of SoS measures are required. Additionally, most of these for the gas consumption relevant countries are also important transit countries for transporting gas from the big supplying countries to the main consumer markets in the EU-15. These countries are the Czech Republic, Poland, Romania and Slovakia later on called as the New Accession States (NAS). Furthermore one should note that the obligation of candidate countries to implement the Gas Directive in their market regulations and create a really competitive gas market is also part of supply security measures in their country. So recommendations in the field of national energy policy and security of gas supply should be in compliance with the EU Gas Directives too.

5.2 Gas scenarios and policies of four candidate countries

In the next three paragraphs of this section, first the key assumptions for developing the gas scenarios are presented. Next followed by a presentation of the resulting long-term developments of gas consumption, supply and import. Three scenarios are developed to anticipate the great uncertainty surrounding long-term developments of economy, energy prices and other factors influencing gas demand and supply. To assure a consistent and reliable analysis the partner institutes each used there well established modelling tools, such as EFOM-ENV[14] or ENPEP[15].

5.2.1 Economic developments in long term

Although it is very difficult and almost impossible to project the economic developments in the candidate countries for the next thirty years we need these for estimating developments in the energy sector and gas demand in long run.

Based on earlier estimates made in studies on EU scenarios by PRIMES model and using detailed analysis carried out by NAS project teams the GDP growth rates per country as the basis for our reference scenario were developed.

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[14] Energy Flows Optimisation Model incl. environmental impact (EFOM-ENV).

[15] ENergy and Power Evaluation Program (ENPEP) was developed by ANL with support from the US Department of Energy (DOE). ENPEP is a set of nine integrated technical analysis module, four of which were employed for this study. These modules include the Model for the Analysis of Energy Demand (MAED), BALANCE, ELECTRIC and IMPACTS.

Average GDP growth rate in the period 2000-2030 by country is as follows:

- Czech Republic 3.6%
- Poland 3.8%
- Romania 5.6%
- Slovakia 3.3%

For an estimate of energy demand more detailed assumptions are necessary, see other data on GDP growth rates presented in the following table.

Table 5.1 *GDP growth rates by country in 2000-2030*

Country	2000-2005	2005-2010	2010-2015	2015-2020	2020-2025	2025-2030
Czech Republic	3.6	4.0	3.7	3.6	3.2	3.3
Poland	3.0	3.2	5.6		3.0	
Romania	5.0	5.4	5.6		6	
Slovakia	3.3	3.3	3.3	3.3	3.3	3.3

Assumed is a 'Step-by-step convergence' of NAS economies (structure) to those of the current EU15 countries average structure. This means further decrease in the share of industry and agriculture and growth of the share of services in the total GDP. (See Table 5.2.)

Table 5.2 *Structure of economies of NAS in 2030*

Country	Agriculture	Industry and construction	Transport	Services
Czech Republic	3.3	29.9	7.3	59.5
Poland	1.9	23.9	4.5	69.7
Romania	9.9	34.2	55.9	
Slovakia	3.3	29.9	7.4	59.4

5.2.2 Energy prices

The international fuel price outlook is based on the important assumption that global energy markets will remain well supplied at a relative modest price throughout the projection period and they are based on the output of the analysis carried out with the POLES model. Thus, in comparison to the *'ups and downs'* of the past 30 years, the primary energy prices assumed here reflect the current consensus view that no supply constraints are likely to be felt, at least in the period to 2020. These assumptions on primary energy prices follow an optimistic view on future discoveries of new oil and gas fields and on further advances in extraction technologies.

Table 5.3 *International fuel price assumptions*

	Average border price in EU [US$/barrel of oil equivalent)]					Annual growth rate [%]			
	1990	2000	2010	2020	2030	90-00	00-10	10-20	20-30
Crude oil	27.92	28.00	20.08	23.84	27.91	0.03	-3.27	1.73	1.59
Natural gas	15.60	15.51	16.98	20.47	22.92	-0.06	0.91	1.89	1.14
Hard coal	13.09	7.35	7.17	7.02	6.96	-5.60	-0.25	-0.22	-0.08

Note: Average boarder prices in the EU [$00/boe].
Source: POLES.

All NAS project teams applied international energy price assumptions to imported energy carriers. Transport prices and taxes/duties were added to get local prices. Domestic energy carriers (coal, oil, gas, renewables) were priced using local costs. Assumptions on import price of hard coal to Europe are extremely low which results in limited competitiveness of domestic coal in all analysed NAS. Due to that sensitivity analysis to hard coal import price was carried out in countries with high importance of domestic coal (Poland, Czech Republic, Romania) to assess the impact on future demand.

5.2.3 Definition of different gas scenarios

In order to stress and deal with the great uncertainties in developing long term gas demand projections the partners first developed a so called reference scenario reflecting more or less continuation of currently known and accepted energy and environmental policies relevant for gas demand in the country. Next, two deviating gas scenarios per country were developed reflecting the possibility that key policies can be changed or key external conditions are changed in the next decade. As a result each country has formulated its own energy strategy depending on policy priorities. This is described for example as follows:

- *Reference scenario*-continuation of current trends in energy supply patterns with no specific policies for promotion of energy efficiency, RES and penetration of gas.
- *High gas scenario*-further reduction of GHG emissions will be required and thus coal could play lower role in future energy supply and nuclear energy will not mature enough to replace coal in power and heat production.
- *Low gas scenario*-growth of gas demand could be regulated though diversification of energy sources (reasonable share of coal, oil and nuclear energy), active policy for promotion of energy efficiency and RES.

Key assumptions used for developing the three different gas scenarios are described below in Table 5.4.

Table 5.4 *Key assumptions used for developing three gas scenarios by country*

Country	Reference scenario	Gas scenarios
Czech Republic	Free energy import, restrictions on availability of domestic coal and nuclear	*LG*-Limited availability of imported energy sources domestic coal and nuclear *HG*-Stricter GHG emissions target (-50% in 2030) gas, renewables, savings
Poland	No restrictions on use of energy resources, no nuclear	*LG*-Active policy for promotion of renewables, savings *HG*-Switch from coal to gas, more gas in chemical industry
Romania	No restrictions on import, one new nuclear unit	*LG*-Expanded nuclear programme to reduce import dependency (4 new units) *HG*-switch from coal to gas, limited nuclear programme (1 new nuclear unit)
Slovakia	No restrictions on use of energy resources, decommissioning of one NPP but no new NPP	*LG*-Energy efficiency and expanded nuclear program *HG*-Stricter emissions target, switch from coal to gas in electricity and heat production

5.2.4 Country gas scenarios

CZECH REPUBLIC

Brief presentation of reference and gas scenarios

The Czech Republic has very limited domestic resources of natural gas and thus the economy is very sensitive to changes in import prices. Gas must compete on the market with domestic brown coal and nuclear energy in power generation and also in heat production in large district heating networks. In these cases gas is currently not competitive. Nevertheless, gas has recently penetrated to end use market where to a large extent gas replaced coal and partly also electricity for space heating.

The reference scenario shows that in case of a low international price on coal, the future power and heat production would be mainly based on coal but more on imported hard than domestic coal. The demand for gas would increase by 20% till 2010 and the demand would be saturated on the level of about 11-12 Bcm. Higher penetration of natural gas would be possible in case when substantial strengthening of current targets on reduction of major pollutants would take place and also in case of higher coal prices on the world market as compared to the assumption in the reference scenario. In this case the demand for gas would be by 4 Bcm higher and this additional gas would be mostly used for power and heat production in CHP plants. Nevertheless all gas demand variants show a fast growth of dependency of the Czech economy on import of energy sources, either coal or gas. The import dependency can increase from current 30% to 60% or even 70% depending on scenario. A so-called Low demand scenario was developed showing effects of possible reductions in the gas import dependency though a wider use of domestic resources coal and renewables! In this Low demand scenario the gas import could be lowered by 1 Bcm as compared to the reference scenario and by 4 Bcm as compare to the high gas demand scenario in the year 2030.

Table 5.5 *Gas supply by scenario-Czech Republic*

[PJ]	2000	2005	2010	2015	2020	2025	2030
Reference scenario	316	379	385	376	378	393	401
Low gas demand scenario	316	335	354	353	355	355	355
High gas demand scenario	316	379	383	382	422	523	541
[Mcm]	2000	2005	2010	2015	2020	2025	2030
Reference scenario	9,294	11,059	11,234	10,971	11,030	11,468	11,701
Low gas demand scenario	9,294	9,853	10,412	10,382	10,441	10,441	10,441
High gas demand scenario	9,294	11,118	11,235	11,206	12,379	15,342	15,870

Most of gas will be imported as domestic gas sources can provide only about 1 Bcm per year. Thus the import dependency will grow in all scenarios but it will be the highest in case of the high gas demand scenario.

Table 5.6 *Energy import dependency-Czech Republic [%]*

Scenario/year	2000	2005	2010	2015	2020	2025	2030
Reference scenario	32.1	41.5	43.8	47.9	53.5	59.5	63.5
Low gas demand scenario	32.1	43.0	45.6	48.7	52.0	54.3	60.4
High gas demand scenario	32.1	43.2	46.1	49.8	55.9	68.0	70.8

Conclusions and recommendations

Based on results of the thorough analysis of three different scenarios, the following recommendations for the national energy policy could be drawn:

- The growing dependency on energy import, mainly natural gas import, will require a more serious analysis of security of energy supply concerning both the structure of energy sources of the energy carriers as well as the lack of diversity in energy suppliers.
- The future needs for gas storage capacities to comply with the EU Directive requirements should be secured in the next years to increase security of supply in the country.
- The future impact of growing import of energy carriers should be analysed from the trade balance point of view.

- The long run strategic role of different domestic energy resources should be analysed, both regarding fossil fuels and renewables, and more concise policy should be designed for their wider use in the future.
- The future potential of the use of nuclear energy as an alternative to electricity generation based on fossil fuels such as coal and gas should be analysed from a greater variety of view points, i.e. regarding security of supply risks, fuel supply availability, waste management, costs, stability of power grid. etc.
- The energy efficiency should play an important role in the future energy policy objectives, because it can substantially contribute to the improvement of security of energy supply through reduction of energy consumption. Note that in all scenarios is assumed a large penetration of energy saving measures up to the level of economic potential. Nevertheless, an implementation of all measures in the category of economic energy saving potential will require a more intensive promotion policy of the government, which is not in place yet.

POLAND

Brief presentation of reference and gas scenarios

In the Reference scenario, it has been assumed to prolong the development tendency and legal regulations valid at the end of the year 2000. In case of Poland, it means observing stringent, domestic environmental standards as well as domestic legislative rules concerning diversification of the imported natural gas supplies (Council of Ministers Ordinance on diversification of natural gas supply).

In order to analyse possible changes in natural gas demand two sub-scenarios have been created, so-called Low Gas (LG) and High Gas (HG) scenario. Major differences between the Reference scenario and the LG and HG scenarios include:

- Introduction of new, very stringent limits in pollution emissions-according to the Directive 2001/80/EC.
- Reducing in a much greater scale emissions from local heat sources throughout faster and more complex withdrawing coal burning in urban areas substituted mainly by gas (in HG) or RES (in LG).
- Implementing solutions preferring RES strategy development (in LG-scenario implementation of the national renewable energy strategy).
- Implementing legal obligation for diversification of natural gas import supplies (LG and HG).
- Growing nitric fertilisers' production based on natural gas (only in HG-scenario).

Total primary energy demand rises only by about 8-9% up to the year 2030 despite an increase of electricity share (in final energy) from around 13% in 2000 to more than 17% in 2030. This is possible due to significant change in electricity production structure with the use of new systems and especially rises in CHP co-generation including significant part based on natural gas. Natural gas demand growth in High gas scenario is almost 2.5 times higher than in the year 2000. In the Low gas scenario, which due to development of the renewables (four times higher than in 2000) shows a much more moderated gas demand growth. A question may be raised on possibility of such an increase in renewables as well as in the feasibility of the economic and institutional conditions that must be created successfully such fast increase of renewables.

The calculations made show significant changes in the structure of the consumed natural gas. In the current Polish consumption structure industry and residential sectors are the largest consumer sectors (totally over 85% of consumption). In the year 2030 it may be expected that those two sectors will use totally around 56-60% of gas and the highest growth in fuel demand will probably be observed in the power and DH sectors, from the current 2% up to 24-29%. In other sectors the increase in gas demand will be moderate, yet noticeable mostly in the distributed and industrial CHP. Most of the units will substitute currently used, old-fashioned industrial and municipal CHP. The computations in all the three scenarios have shown a very possible 2-2,5 times increase in natural gas demand. At such a growth level there is space for using hard coal in the amount of about 35-40% of the balance and lignite of around 7.5-10%.

Table 5.7 *Gas supply by scenario-Poland*

Specification	2000		2005	2010	2020	2030	
	[PJ]	*[%]*		[PJ]			*[%]*
Reference scenario	394	*10.3*	419	518	682	891	*21.4*
Low gas scenario	394	*10.3*	410	480	594	738	*17.9*
High gas scenario	394	*10.3*	421	524	732	951	*22.9*
	[Mcm]	*[%]*		[Mcm]			*[%]*
Reference scenario	10,914	*10.3*	11,607	14,349	18,892	24,681	*21.4*
Low gas scenario	10,914	*10.3*	11,357	13,296	16,454	20,443	*17.9*
High gas scenario	10,914	*10.3*	11,662	14,515	20,277	26,343	*22.9*

Conclusions and recommendations

The findings in the scenario study led to the following suggestions for gas market and supply security policies in the future. Review of the Polish gas market scenarios shows that in Poland up to the year 2010 some growth in the natural gas demand is expected. Basically there are currently two consumer market segments: power plants and large CHP plants as well as residential and tertiary sectors that may cause an increase in the total natural gas demand by about 2.5 Bcm (in 2010).

Both for the gas market actors and the state administration it means no necessity for developing a great gas pipelines investment programme up to that time (2010). The same period ought to be used instead for modernising activities mainly changing gas network configuration and for expanding natural gas storage more and more necessary in case of gas consumption increase by power and CHP sectors. Quite indispensable are also investments in control- and measuring systems as well as computer-based management tools to create a better functioning of the gas market. Significant investment level may become necessary only after the year 2015.

Main uncertainty factors of the future natural gas demand, next to the international gas prices, consist of:

- state policy in the field of energy strategy and the implementation of renewables,
- cost-effectiveness of the domestic hard coal sectors,
- a possible stronger restructuring policy that is in place before the year 2010.

Sensitivity calculations for the imported coal prices have namely shown that even a domestic coal price increase of about 5-8% may cause a significant shift towards the imported coal from the year 2015 on. However, only simultaneous rise in domestic coal costs and imported coal prices of about 15-20% will improve the competitive position of natural gas used (versus coal) as a favourable fuel in the power and CHP generation sectors.

Over twofold growth of natural gas demand causes in effect very serious import increase. An import dependency amounting in 2000 to around 67% holds on stable level about 60-70% up to the year 2010 (60% in the Low gas scenario-favouring renewables) and thereafter quickly increases up to around 75-82% in 2030. However, it must be noted that such great dependency on imported gas doesn’t fulfil the diversification conditions on “supply from one single exporter”. This very important energy security issue is particularly relevant in the case of Poland, which imports of natural gas from Russia in 2001 of around 85%, but aiming at no more than 49% in 2019. This is according to the provisions from the Council of Ministers Ordinance. Assuring diversification of the natural gas supplies requires additional capital investments to secure gas to be imported from other new directions. One can assume this might lead to a bit more expensive import contract of gas than in current supplies contracts. On one hand gas might become also slightly less competitive to hard coal and lignite from the domestic mines, but this could also lead better functioning of a competitive gas market in general and thus lower gas prices for consumers.

Based on the results of the sensitivity calculations it is recommended that the Polish gas sector should lower its operation and maintenance costs soon. This because the current ratio of the gas prices in comparison to the steam coal used in the power and CHP plants is strongly in favour of coal burning. This recommendation is valid for the current market conditions determined by environmental rules and obligations as well as for the fuels and energy tax/pricing policy. International Polish commitments (mainly environmental ones) will not disturb the rational use of both the steam coal and lignite in power and CHP sectors up to the year 2015. Beyond the year 2015 quite significant influence from more stringent emission standards for individual plants (Directive 2001/80/EC) will be felt that will probably push the growth of the natural gas demand.

ROMANIA

Brief presentation of reference and gas scenarios

Besides the reference scenario, two other gas import demand scenarios were elaborated.. Subsequently, in the low gas demand scenario, a gas quantity needed for electricity generation is substituted with an equivalent nuclear source for generation of the same electricity quantity. In the high gas demand scenario, natural gas substitutes an equivalent quantity of nuclear fuel and lignite for production of electricity, respectively heat and electricity. In both alternative scenarios, it's expected that the final energy consumption would undergo only a small modification in comparison with the reference scenario.

The following table presents the changes in the natural gas supply by scenario in the period 2000-2030. There is a very big difference in gas supply among the three scenarios.

A fast growth of gas demand is recorded in the whole period in the Reference scenario - the demand is doubled till 2030 but taking into account the drop in gas consumption in 1990s the level of consumption in the year 1990 would be reached only after the year 2025. The difference in gas demand between the Low and High scenario is 70% in the year 2030.

Table 5.8 *Gas supply by scenario-Romania*

[PJ]	2000	2005	2010	2015	2020	2025	2030
Reference scenario	572	627	733	898	1049	1159	1273
Low gas scenario	572	627	636	750	804	816	832
High gas scenario	572	627	887	1041	1183	1288	1396
[Mcm]	2000	2005	2010	2015	2020	2025	2030
Reference scenario	17,120	18,752	21,932	26,877	31,388	34,685	38,084
Low gas scenario	17,120	18,752	19,026	22,442	24,048	24,400	24,907
High gas scenario	17,120	18,752	26,537	31,145	35,382	38,531	41,776

In the reference scenario, the share of the primary energy import in the total energy resources is assumed to increase to about 65.4% in 2030 in comparison with 30.4% in the year 2000, of which the natural gas import will represent about 45% from total import value.

In the low gas demand scenario, the share of the primary energy import in the total energy resources is assumed to increase to about 66.1% in 2030 in comparison with 30.4% in 2000, of which the natural gas import will represent 25.4% from total import value.

In the high gas demand scenario, the share of the primary energy import in the total energy resources is assumed to increase to about 67.8% in 2030 in comparison with 30.4% in 2000, of which the natural gas import will represent 54.5% from total import value.

Conclusions and recommendations

Gas has been a very important energy carrier in Romania despite the drop in demand in the 1990s due to drop in general economic performance of the country. According to results of all 3 scenarios, the demand for gas will significantly grow and both in Reference and High gas demand scenarios will be more than doubled. This expected growth of demand would be mostly covered by gas import resulting in very fast gas import dependency. To reduce potential risk of high import dependency and also high economic burden of the gas import, it is highly recommended to deal with the following issues:

- Development and implementation of an energy policy that focuses on the application of available high-performance technologies to increase the efficiency of energy production and utilisation, to increase energy conservation, to utilise renewable energy sources, and to reduce pollution of the environment.
- Energy management that provides for long-term continuous energy supply, diversification of energy supply sources, and establishment of adequate domestic fuel stocks;
- Diversification of natural gas import sources.
- Promotion of reduction of environmental pollution.
- Implementation of the whole Community acquis in the field of energy up to the year 2007, the date from which Romania could become a full member of EU.

SLOVAKIA

Brief presentation of reference and gas scenarios

The current situation on the domestic energy market in Slovakia from the point of view of natural gas demand and supply can be described as follows:

- Slovakia represents one of the most important east-west natural gas transit countries in the Central European region.
- The import dependency is high, domestic energy demand is covered predominately (more than 90%) by imports of energy carriers, i.e. oil, gas, nuclear fuel and hard coal, mainly from Russia and via Ukraine.
- The diversification policy of gas imports is not applied yet as policy because there is not a direct pipeline from an other gas export sources than Russia via Ukraine;
- The privatisation of gas utilities is finalised in Slovakia and future policy of gas supply will be influenced by the new foreign investors (Gas de France, Ruhrgas and also Gazprom).
- The only important domestic primary energy source is brown coal from underground mines with a very poor quality from environmental point of view and high costs.
- The applied environmental legislation, focused on emission of basic pollutants is harmonised with EU policy regulations, legislation and emission standards.
- This tightening of legislation stimulates use of gas as the fuel in industrial CHP and heat production as well as in the local sources for district heat supply. In the last few years many of these sources went for a fuel switch from coal to gas. The sources with two auxiliary fuel sources gas and oil will be forced to use gas only.
- The critical issue represents the nuclear share in the electricity generation. At present, there are 6 units operation with installed capacity of 440 MW_e each. According to the government decision, two old units will be decommissioned in 2006 and 2008. As substitution, combined cycles are considered, what will cause an additional gas demand. On the other side, the finalisation of the additional two nuclear units with the same capacity is still an open discussion. The decision depends on the new owner after privatisation of the public electricity sector.

On the basis of key assumptions of final energy demand, environmental policy and nuclear electricity share, the three scenarios (reference, low and high) were designed, what indicates the possible range of natural gas demand. The following table illustrates the possible increase of natural demand in selected years.

Table 5.9 *Gas supply by scenario-Slovakia*

[PJ]	2000	2005	2010	2015	2020	2025	2030
Reference scenario	244	271	308	320	364	369	376
Low gas scenario	244	270	301	308	349	352	357
High gas scenario	244	270	326	361	422	446	464
[Mcm]	2000	2005	2010	2015	2020	2025	2030
Reference scenario	7,176	7,971	9,059	9,412	10,706	10,853	11,059
Low gas scenario	7,185	7,935	8,839	9,054	10,257	10,359	10,487
High gas scenario	7,185	7,947	9,576	10,613	12,409	13,128	13,646

Conclusions and recommendations

Considering the issues mentioned above and summarising the gas demand scenarios the following conclusions and recommendations may be derived:

- An increase of gas demand indicated in all scenarios shows that the consideration of a policy of gas import and diversification is necessary, both by the new management of privatised gas utilities and government.
- The retirement of current nuclear power units will bring an additional gas demand of approximately 1,020-1,060 Tcm (million of standard cubic meters) that will be allocated in electricity supply system preferably. The import of coal should be alternative but this would harm Slovakia's environmental conditions. Such a decision would face the SO_2, NO_X and CO_2 caps, resulting from international agreements and therefore pose a barrier for this policy.
- The existing environmental policy stimulates the fuel switch from coal and oil to gas and will lead to an additional gas import demand in the long run.
- The implementation of national energy policy focused on the use of renewable energy sources can partly compensate above increase in gas demand, but simultaneous support of combined cycle implementation in industrial sector, which is a part of the current energy policy framework too, has a conflicting impact.
- The energy saving policy in industry and residential sector will lead to an additional reduction of gas demand.
- The above results stress the importance of national policy focused on energy conservation and increase of the share of renewables in the national energy balance.

5.2.5 General conclusions and recommendations

General conclusions

The long-term gas demand and supply developments are analysed in four EU accession countries, namely the Czech Republic, Poland, Romania and Slovakia. These countries widely differ in terms of their economic performance, availability of their own gas resources, the level of penetration of gas, and regarding the speed of the energy transformation processes as well great difference in demand structure. However, these four countries represent a large part of the gas market in all NAS. On top they also play now or they will play soon a very important role in transit of gas from remote production locations outside the EU to large consumer markets in EU. Therefore, the analyses of the gas scenarios and security of supply situation is very important for a more accurate assessment of the long-term development of the whole European gas market.

More specific the following conclusions can be drawn:
Gas plays an important and growing role in all four NAS. Nevertheless there are important differences in the level of energy market penetration of gas and the future growth of the gas demand.

In the reference scenario, both the Czech Republic and Slovakia show saturation of gas demand by the end of the analysed period (2030) after an increase of demand by reaching a share of gas in TPES of about 30% or 50%, respectively.

Concerning Poland and Romania a fast growth of gas demand is recorded in the whole period in the Reference scenario. In case of Poland, an increase of gas consumption is by about two and half times. This can be explained by energy market penetration of gas as a relatively new fuel. In case of Romania the big gas producing country, the demand is doubled till 2030 but taking into account the drop in gas consumption in 1990s the level of consumption in the year 1990 would be reached only after the year 2025.

Table 5.10 *Reference gas supply scenario by country*

[Mcm]	2000	2005	2010	2015	2020	2025	2030
Czech Republic	9,294	11,059	11,234	10,971	11,030	11,468	11,701
Poland	10,914	11,607	14,349		18,892		24,681
Romania	17,120	18,752	21,932	26,877	31,388	34,685	38,084
Slovakia	7,176	7,971	9,059	9,412	10,706	10,853	11,059

Gas will have to compete on the energy market in all four NAS with domestic energy sources such as domestic coal (in all four countries, but mainly in Poland and the Czech Republic) and with nuclear energy (all except Poland). In addition, import of hard coal can play an important role in future energy supply in all countries in concern. There exists however a large uncertainty regarding financial viability of further domestic coal production and future changes in import prices of coal from the world markets.

To evaluate impact of competitive fuels, additional scenarios to Reference scenario were calculated. They are generally called 'Low gas scenario' and 'High gas scenario'. While in case of Poland and Slovakia the difference in gas demand between the Low and High scenario is only about 30% in the year 2030, in case of the Czech Republic it is 50% and in case of Romania even 70% (see the following tables).

The most of natural gas scenarios have been obtained without stronger environmental constraints (except the Czech Republic) going significantly beyond the Kyoto Protocol commitments, and other international obligations (e.g. sulphur and nitric Protocols).

Table 5.11 *Low gas demand scenario per country*

[Mcm]	2000	2005	2010	2015	2020	2025	2030
Czech Republic	9,294	9,853	10,412	10,382	10,441	10,441	10,441
Poland	10,914	11,357	13,296		16,454		20,443
Romania	17,120	18,752	19,026	22,442	24,048	24,400	24,907
Slovakia	7,185	7,935	8,839	9,054	10,257	10,359	10,487

Table 5.12 *High gas demand scenario per country*

[Mcm]	2000	2005	2010	2015	2020	2025	2030
Czech Republic	9,294	11,118	11,235	11,206	12,379	15,342	15,870
Poland	10,914	11,662	14,515		20,277		26,343
Romania	17,120	18,752	26,537	31,145	35,382	38,531	41,776
Slovakia	7,185	7,947	9,576	10,613	12,409	13,128	13,646

The comparison of gas demand by country and scenario in the year 2000 and 2030 is given in the following figure. The highest gas consumption both in the year 2000 and 2030 can be seen in Romania followed by Poland.

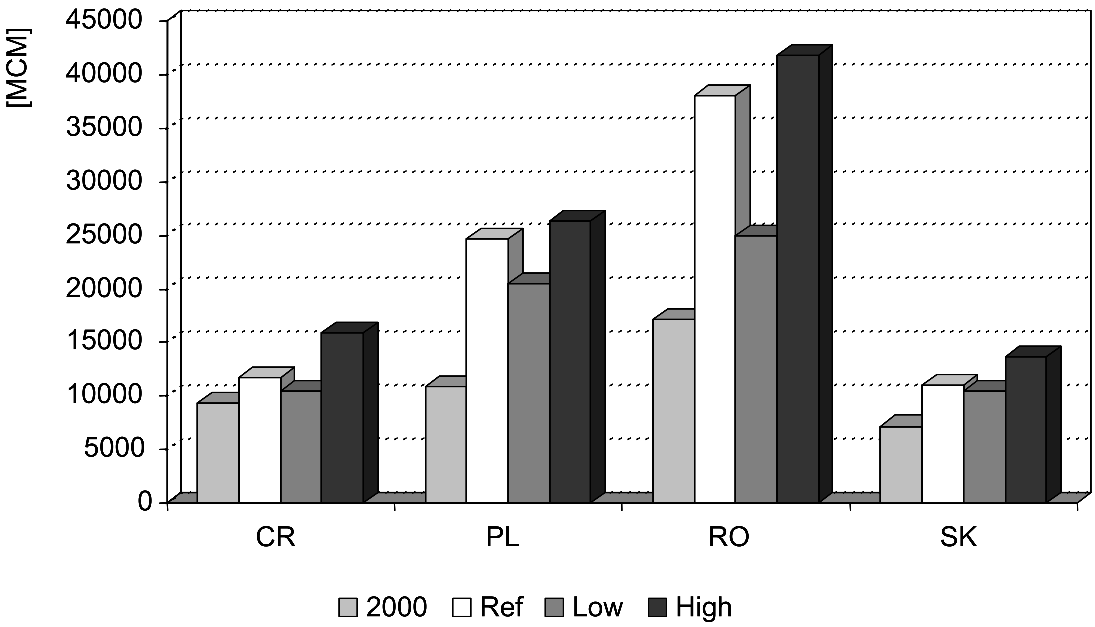

Figure 5.1 *Gas consumption per country and scenario in 2000 and 2030*

- If we add the demand in all four NAS, than the result shows clearly an increase of gas demand by 50% (Low gas scenario) and by 120% (High gas demand scenario) between the years 2000 and 2030. In case of the Reference scenario the increase is by about 95%.

Table 5.13 *Comparison of gas supply scenarios*

[Mcm]	2000	2005	2010	2020	2030
Reference scenarios	44,513	49,419	56,574	72,016	85,525
Low gas scenarios	44,513	47,897	51,573	61,200	66,278
High gas scenarios	44,513	49,479	61,863	80,447	97,635

- In 2000, Poland shows the lowest energy import dependency (25%) and the highest is in Slovakia (about 90%). In all four countries energy import dependency will grow and will become an important issue to be dealt with irrespective of the specific scenario. In 2030 the lowest energy import dependency shows again Poland (40%) and the highest-Slovakia (about 90%); the Czech Republic and Romania are in between (about 65%). Different picture shows gas import dependency currently the Czech Republic and Slovakia are more than 90% dependent on gas import, while Romania covers 80% of its needs from domestic resources and Poland 23%. The picture will change in 2030 - gas import dependency will grow to 60-75% in Romania and to 75-85% in Poland.

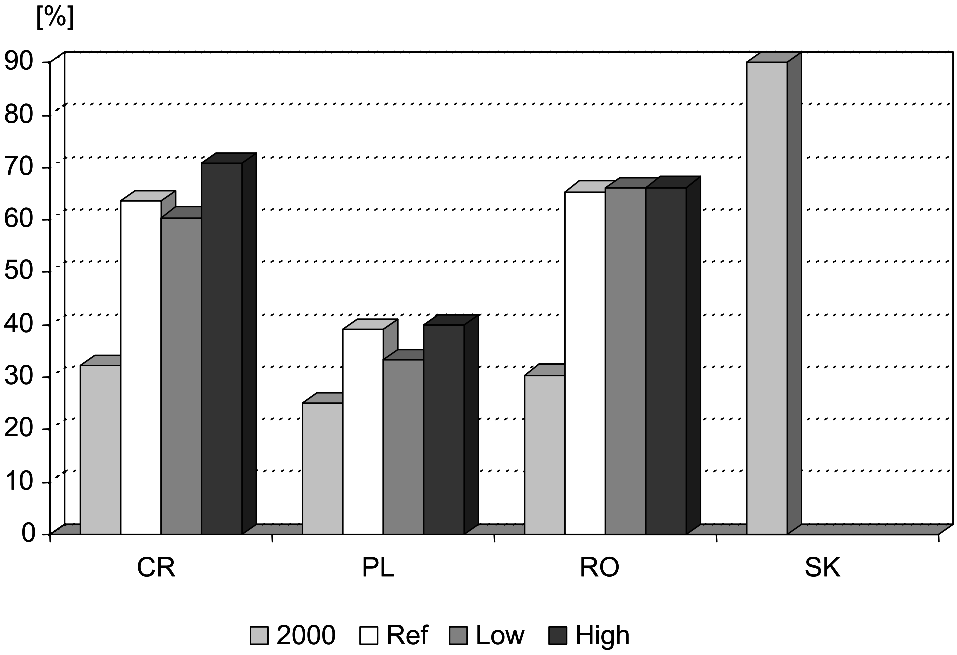

Figure 5.2 *Energy import dependency per country and scenario in 2000 and 2030*

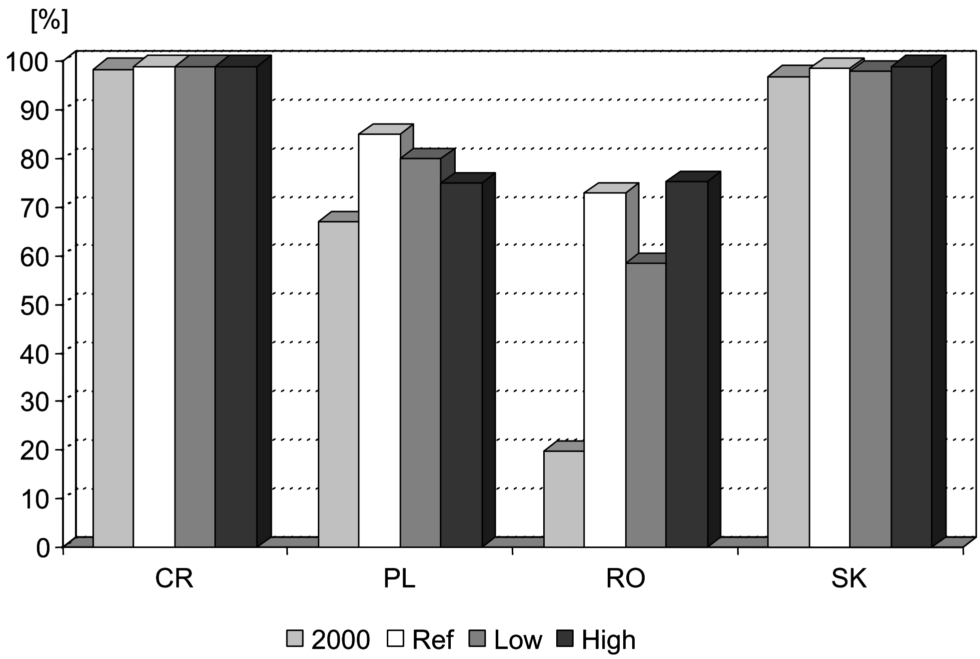

Figure 5.3 *Gas import dependency per country and scenario in 2000 and 2030*

General recommendations

- *Import dependency*-In all four NAS of concern there are limited domestic energy resources available and therefore a substantial growth of energy import is expected that will result in a strong growth in import dependency. Thus all 4 NAS should take measures to mitigate the consequences of this growth of dependency. The way in which import dependency can be reduced is both through diversification of gas import suppliers and terms of contracts, and through further wider implementation of policies to promote energy efficiency and mainly local and renewable energy sources.
- *Security of energy supply* should be enhanced through diversification of gas import by origin, also diversification of contracts and keeping sufficient gas storage capacity and stocks in accordance with the EU Directive amendment requirements.

- *Transit network capacity* - all four NAS are increasingly becoming very important transit countries of gas supplies from East to West. Therefore it is of the utmost importance that measures are taken in time in these countries that secure sufficient transit capacities and interconnections and other facilities, including the required maintenance of these capacities to provide sufficient security of supply to the consumer markets in EU.

5.3 Implementation Gas Directives in six candidate countries

5.3.1 Introduction

Regulatory issues in the EU accession countries play a significant role in the area of transport and production of natural gas within an enlarging Europe. In the study, which is for six candidate countries, Czech Republic, Poland, Romania, Poland, Hungary and Turkey conducted an analysis of the implementation of Gas Directive and the proposed amendments thereto. Thereby focusing on six main regulatory topics that are related to security of supply issues. These six topics are:

- monitoring of security of supply,
- public service obligations,
- cross-border trade,
- access to pipelines, storage and LNG facilities,
- security stocks, and
- authorisation procedures.

It should be noted that these six main regulatory topics and their related inquiries were originally formulated in March 2002. This was prior to the publication of two recently proposed EC directives: (1) the amended proposal for a directive to amend the Electricity and Gas Directives of 7 June 2002, [16] and (2) the proposed directive on safeguarding security of gas supply of 11 September 2002.[17] In addition, a new (unofficial) version of the draft Gas Directive was made available in October 2002.[18] The conclusions reached in our study, which was conducted as of September/October 2002 should therefore be seen as preliminary given that there is a moving target at both EU and national levels. In addition to the recent proposals from the European Commission, several of the accession countries being examined are in the process of amending their primary legislation relating to the gas sector and translations of this draft legislation have not yet been made available in every case.

The next sections in this chapter present the results of the survey and analysis of the national regulatory regimes, for the two most important of the six main topics addressed by the study on the implementation of EU Gas Directive in the six candidate countries. For a complete report of this part of the study, see the specific report of this study. Consequently this overview concerns three sections, namely two on the topics of 'monitoring of security of supply' and 'security stocks in natural gas' and a section concerning a brief summary of conclusion per country thereby addressing all six topics in very general terms.

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[16] Amended Proposal for a Directive of the European Parliament and of the Council amending Directive 96/92/EC and 98/30/EC concerning rules for the internal markets in electricity and gas, COM(2002) 304 final (7 June 2002).

[17] Proposal for a Directive of the European Parliament and the Council concerning measures to safeguard security of natural gas supply, COM(2002) 488 final (11 September 2002).

[18] Inter-institutional file 2001/0077 (COD), doc. 12766/02 (10 October 2002).

5.3.2 Monitoring of security of gas supply

EC legislation

The European Commission's amended proposal of June 2002 to amend the Gas Directive (COM(2002) 304 final) would require Member States or the designated regulatory authority to 'ensure the monitoring of security of supply issues' (ex Article 4a, now Article 5). It is proposed that the competent authorities should issue an annual report on the security situation and any related measures. In particular, this monitoring would be required to cover the supply/demand balance on the national market, the level of expected future demand and available supplies, envisaged additional capacity under planning or construction, and the quality and level of maintenance of the networks.

The proposed directive on measures to safeguard security of gas supply (of 11 September 2002) represents a more comprehensive vision of a Community framework for addressing security of supply policies. It further elaborates the reporting requirements that would have to be met by the competent authorities in the Member States under the monitoring requirement of the proposed Article 5 of the Gas Directive. Thus, there is a cross-reference between the two draft directives. In addition, the proposed directive on security of gas supply would require Member States to define their general policies for security of gas supply (Article 3(1)), which should be implemented in a non-discriminatory manner, without hampering market entry, and which should contribute to the completion of a fully operational internal market for gas.

The rationale and justification for the Commission's proposal for a directive on safeguarding security of gas supply, in general terms, is set forth in the explanatory memorandum and has recently been restated in its second benchmarking report,[19] as follows:

> *"Organising security of supply cannot be left to the industry alone and Member States have an obligation to ensure that all market players take minimum measures with regard to security of supply. Moreover, security measures can be costly and it is perfectly feasible that certain operators could neglect these measures to reduce costs if no minimum standards apply. Thus, the adoption by Member States of measures requiring the industry to meet minimum standards is therefore an integral part of market opening. In so doing, it is important that security of supply has a European dimension, that there is a degree of convergence in the approach of Member States to this issue including certain minimum standards."*

National measures

The accession countries appear to have developed two main approaches for monitoring the security of supply issues in the gas sector.

The first approach, identified thus far in the Czech and Slovak Republics, Romania, and Turkey, is to define specifically the monitoring and disclosure obligations of the various existing market participants and, moreover, to create new market participants with clear responsibilities over monitoring functions. One good example of this approach is in Romania, which established a gas market operator in 2001. Another example is found in the Czech Republic, which has required the formulation of annually-updated contingency plans from the gas generating plants, transmission system operator, distribution system operator and the underground gas storage facilities operator.

By way of example, the focal point of the monitoring process in the Czech Republic is the Gas Dispatching Centre, which provides the monitoring of the planning of gas supplies and consumption and the preparation of solutions for emergency situations. On the basis of the balances

[19] European Commission Staff Working Paper, Second benchmarking report on the implementation of the internal electricity and gas market, SEC (2002) 1038 (1 October 2002), at 25.

provided by the other market participants, the Centre prepares an annual gas balance, and an assessment and interpretation thereof, and submits this to Ministry and the regulator. Moreover, the Centre is required to submit a monthly report on the gas system balances to the Ministry, and to provide any other information requested by the Ministry or regulator in the exercise of their duties. Additional legal obligations apply to the dispatching centres of the gas undertakings, which are obliged to maintain 'safe and reliable operation' and 'equilibrium between gas resources and gas consumption'. In addition, the Czech Republic is currently considering the transformation of the Main Gas Dispatching Centre into a distinct legal entity, as well as the creation of a gas market operator to be modelled on its electricity market operator.

In Poland, the various monitoring functions relating to security of gas supply are not assigned to a single entity, but rather appear to take place pursuant to the Energy Law on four levels: the central government, the local authorities, energy enterprises, and system operators. In addition, the regulatory authority, the President of ERA, plays a general role in the process of monitoring security of energy supply at all four levels. For example, the 'development plans' required of the energy enterprises are obligatory (Article 16 of the Energy Law), are subject to regulatory approval, and factor into the approval of tariffs by the President of ERA, as they constitute one of the major cost components.

The second approach used in the accession countries is to institutionalise the policy-making process in a systematic manner, for example, by regulating the formulation and evaluation of national energy policy guidelines. This demonstrates how energy policy and energy law can interact: whereas energy policy can provide the objectives for the legal and regulatory framework, energy laws can, in turn, be used to institute a systematic, dynamic, open and responsive policy-making process on an ongoing basis.

The best example of this from the accession countries under review, is the 1997 Polish energy act, which makes the Minister of Economy (MoE) responsible for periodically presenting guidelines of the state energy policy accompanied by long-term energy forecast (at least 15-year period). This must be submitted to the Council of Ministers for its approval. These state energy policy guidelines are required to determine, *inter alia*, an assessment of the energy security of the state, and forecast of domestic demand for fuels and energy, and forecast of fuels and energy imports and exports and a forecast of production capacity for fuels and energy and an obligatory fuel reserves policy (Art. 15) as well. Every two years, the Council of Ministers is obliged to assess the implementation of the guidelines, make proposals for their correction, if necessary, and prepare a short-term forecast (up to the 5-year period) and submit it to the lower house of the Parliament (*Sejm*) (Art. 13).

Other examples of provisions on systematic policy-making which covers the topic of security of gas supply can be found in Romania, in Government Ordinance 60/2000 and the Czech Republic's Act on Energy Management of October 2000. These various policy-making processes found in the accession countries may provide models to the European Commission and to certain Member States for further elaboration of, and possible means of compliance with, Article 3(1) of the proposed directive on measures to safeguard security of gas supply (of 11 September 2002).

Not all of the accession countries appear to have adopted provisions requiring a systematic elaboration of natural gas policy. The notable exception is Turkey, which has adopted a forward-looking Gas Market Law in 2001 that sets the stage for unbundling, privatisation and restructuring of the key national Turkey's gas supplier, named Botas. But it does not elaborate regulation for the future governmental policy-making processes for the gas sector.

5.3.3 Security stocks in natural gas

EC legislation

The European Commission's recent proposals for a new Community framework on security of gas supply would introduce quantitative requirements (i.e., 60 days) that it characterises as the '*de facto* equivalent [of] the obligation to maintain oil stocks'. In particular, the proposed directive would require Member States to publish the manner in which they guarantee that non-interruptible customers (i.e., customers who cannot immediately switch to alternative back-up fuels) would be ensured continued supplies for at least a 60-day period in the event of a disruption of the largest supply source to the national market in question. But this proposed Community regime does not dictate a definition of a minimum level of gas stocks to be held in storage facilities, given that the capacities and geological conditions for gas storage vary considerably among the Member States.

National measures

Poland has made a recent change to its rules on natural gas stocks. According to certain provisions of the Energy Law now only temporarily in force, compulsory gas fuels stocks were to reach up to 2010 the level of 90-days average annual natural gas consumption in Poland. However, the amendment to the Energy Law from July 24th, 2002 has cancelled this obligation as of January 1st, 2003. The amended Article 10 of the Energy Law requires gathering and stocking of fuel reserves only by the electricity and district heat producers. The present conditions mean that such obligation concerns mainly compulsory stocks of hard coal, lignite and liquid fuels, and only to a small extent natural gas. In addition, Poland has a separate Act on State Reserves and Compulsory Fuel Stocks, which will regulate this issue.

In countries such as the Czech Republic and Slovakia, there is no explicit obligation on the transmission company or other entities to maintain security stocks in gas. Rather, the project partners have characterised the requirements as being implicit in various legislative provisions, such as certain obligations on the operator of the underground gas storage facilities and the monitoring obligations and emergency planning obligations of gas dispatching centres.

The Turkish Gas Law establishes various obligations on gas undertakings to contract for gas storage capacities, some of which are stated in specific quantitative terms. Thus, applicants for gas import licences are required to have pre-contracted rights to storage: within five years, an import company will be obliged to hold a storage capability of at least 10% of its imported volume. Moreover, all gas wholesalers are subject to obligations to contract for adequate storage capacity, verifiable by the regulator who is entitled to receive the executed lease contracts for such storage capacity. In addition, the regulator is authorised 'to determine the storage quantities to be maintained with a view to balance the intensive seasonal demand of the following year for each city and to take necessary measures.'

In Romania, general rules on natural gas storage are included in Government Ordinance No. 60/2000. This does set forth general obligations to maintain stocks of natural gas, but this is not precisely quantified in the ordinance in terms of days.

5.3.4 Summary and conclusions per country

Czech Republic

The Czech monitoring mechanisms for security of gas supply include both systematic formulation of energy policy pursuant to the Act of Energy Management, as well as specific monitoring functions assigned to the gas market participants and the governmental authorities. The focal point is the main Gas Dispatching Centre. On the basis of the balances provided by the other market participants, the Centre prepares an overall annual gas balance, and an assessment and interpretation thereof, which it submits to Ministry and the regulator. Moreover, it is required to submit a monthly report on the gas system balances to the Ministry, and to provide any other information requested by the Ministry or regulator in the exercise of their duties. The Centre also prepares the contingency plan of the gas system and distributes it to gas undertakings.

Proposed amendments to the Czech Energy Act being considered during the summer of 2002 include changing the access regime under Article 55 from 'agreed access' to 'regulated access' and to accelerate the gas market opening to 28% as of 1 July 2003 (instead of 1 January 2005) and 33% as of 1 January 2005 (instead of 10 August 2008). Final decisions on this speed-up will be agreed during the accession negotiations. There is also a proposal to create a gas market operator modelled upon the electricity market operator that currently functions in the Czech electricity sector.

The Czech Republic does not appear to have a compulsory regime for third party access to underground storage facilities. Moreover, the unbundling of Transgas's transmission and storage functions will be done through account separation. Certain commentators have expressed concerns that Transgas may retain its monopoly position on the market and effectively limit its competitors' access to gas transmission, storage and distribution, unless ERO rigorously enforces the regulations. The privatisation of Transgas was approved by the Czech Competition Authority on 17 May 2002.

Total gas storage capacity in 2002 is reported to be 2.5 Bcm in eight underground storage facilities. Six of these facilities are owned and operated by Transgas and have a capacity of 1.9 Bcm. These are supplemented by long-term lease agreements with companies in Slovakia and Germany for storage of an additional 1.1 Bcm. In total, the storage capacity amounts to about one-third of annual consumption. The Czech Energy Act does not state a direct obligation to require Transgas or other entities to maintain security stocks of natural gas. However, the obligations in this respect are implicit in various provisions of the Act, such as the obligations on the operator of the underground gas storage facilities and the monitoring obligations and emergency planning of the Gas Dispatching Centre.

Hungary

The Hungarian regime for the gas sector is in transition as the preparation of a new gas law and has begun and should be completed by end 2002 or early 2003. MOL has predicted that implementing decrees should be ready by 1 April 2003 and that the new Gas law will be in place by 1 July 2003. Real market opening is predicted to not take place until 2004.

MOL has reported that it is undergoing a process of legal unbundling into three independent legal companies, MOL Gas Storage Co., MOL Gas Transmission Co., and MOL Gas Supply Co. The system operator and the gas transmision business will not be separated, however, but will instead remain under MOL Gas Transmission Co.

The precise rules on monitoring and dispatching functions, public service obligations relating to security of supply, access and connection to gas networks and storage facilities, crisis measures and security stocks are therefore under discussion and likely to be adapted in the near future. The draft rules are not yet available, and therefore this report should be viewed as preliminary in nature.

Poland

In Poland, the various monitoring functions relating to security of gas supply are not assigned to a single entity, but rather appear to take place pursuant to the Energy Law at various governmental levels and within the energy undertakings in consultation with the regulator, the President of ERA, who also has general powers to regulate in this area. The Government has also retained the power to introduce crisis measures by way of an ordinance defining limitations on the sales or supply of fuels in case of energy security of the state. The Government has also issued an ordinance on the maximum level of gas that can be imported from a single country.

This supply diversification order establishes specific limits in terms of graduated percentages for the period 2001-2020, at which time the maximum is set at 49% in 2020.

Various and numerous public service obligations apply to energy enterprises in Poland, and the regulator appears to have some general powers to define and elaborate these further. There is an obligation to offer transmission services to eligible customers, but this TPA rule appears to be severely limited in scope in the case of natural gas in Poland since the Energy Act limits the application of this rule to transmission of natural gas produced in EU Member States. This would appear to make the TPA rule inapplicable to natural gas extracted outside the EU. Given that Poland imports most of its natural gas from or through the Russian Federation, this effectively means that within Poland, this imported gas is not subject to the TPA regime. There is also no regulation on access to storage facilities or to LNG facilities.
However, Poland is the only candidate country under review that has set a schedule for 100% market opening At present, and until a new MoE ordinance is issued, the previous MoE ordinance (issued on 6 August 1998) requires that the gas market should be opened gradually for customers who have a free access to the transmission network, and who buy annually:

- Not less than 25 Mcm of natural gas (high methane content)-shall obtain the right to TPA services from July 1st, 2000.
- Not less than 15 Mcm of natural gas-shall obtain the right to TPA services from January 1st, 2004.
- Others-purchasing annually less than 15 Mcm of natural gas-shall obtain the right to TPA services on December 5th, 2005.

According to certain provisions of the Energy Law now only temporarily in force, compulsory gas stocks are to be increased by 2010 to the level of 90-days of average annual natural gas consumption in Poland. However, the amendment to the Energy Law from July 24th, 2002 has cancelled this obligation as of January 1st, 2003. The amended Article 10 of the Energy Law requires gathering and stocking of fuel reserves only by the electricity and district heat producers, but this has very limited application to natural gas (which constitutes about 2.3% of the total fuel input to thermal power and CHP plants).

The fuels reserves policy in Poland is generally regulated by the Act from 30th May 1996 'On State Reserves and Compulsory Fuel Stocks', as amended. According to this Act, the Council of Ministers may determine by the ordinance, targeted quantity and schedule for stock building as well as the procedures for maintaining and managing fuels' compulsory stocks (the same as in case of compulsory oil stocks).

Under Article 32 of the Polish Energy Law, a licence is required for gas storage with minor exceptions (capacity less than 1 MJ/s) and storage of liquid fuels in retail trade. However, there does not appear to be an authorisation procedure for constructing storage and LNG facilities. The technical conditions and licensing requirements for construction of storage facilities are strictly regulated under the Geological and Mining Law, as well as the Building Law and accompanying secondary legislation.

Romania

In general, it appears that the drafters of Romania's gas legislation have given some attention to including legal provisions addressing certain monitoring functions as well as general obligations relating to gas transit and gas storage. Market opening is currently set at 15%, comprising approximately 41 eligible customers, who may benefit from a regime designated by law as a form of regulated network access.

Table 5.14 *Liberalisation of domestic gas market (including first nine months of 2002 as reported by ANGRN)*

Year	Degree of market opening [%]	Effective degree/ consumption	Number of companies	Switching of suppliers [%]
2001	10	6.5%/ 1.03 Bcm	17	70
2002	25	15,75%/ 1,71 Bcm	41	70

ANGRN reports further that market opening as of January 2003 is scheduled at 30%. It has also stated recently that the maximum opening scheduled for 2006 is only 35%.

A gas market operator has been established and charged with the load management tasks including the monthly determinations of the required balance between imports and domestic gas production, based on detailed reports that it should receive from the licensed gas distributors and gas producers. At present, the market operator is a department of the national gas transport company, S.N.T.G.N. Transgas, but there may be plans to separate this function in the future based on a financing mechanism that would require service contracts with the various market participants.

The National Transportation System (SNT) for natural gas in Romania is solely operated by S.N.T.G.N. Transgas, although it has an obligation to publish tariffs and other conditions concerning regulated access to the system. The SNT and has been designated by law as part of the public property of the state and as carrying 'strategic importance'. This designation and the accompanying special or exclusive rights may give rise to questions as to compatibility with Article 86(2) of the EC Treaty. In practice, there are other firms besides S.N.T.G.N. Transgas who are technically responsible for imports of natural gas.

Gas transporters are obliged to provide 'equal, non-discriminatory access'' to the national transport system (with respect to eligible producers, suppliers and users) and distribution companies are similarly obliged with respect to their distribution systems, but of course they have the right to deny access for various reasons set forth by law. The general rule seems to have been changed in 2001 from a system of negotiated access to one of regulated access, such that transporters and distributors are now obliged to publish the 'tariffs and/or other conditions and obligations concerning regulated access to the system'. Government Ordinance No. 60/2000 also provides a role for the regulator, ANGRN, in that 'available capacities shall be allocated in compliance with conditions established by ANGRN'.

Natural gas storage service providers are required to ensure equal, non-discriminatory access to producers and/or suppliers to storage facilities within the limits of their capacity. The regulator has approved a standard contract to be used for underground gas storage facilities and has set different tariffs for each facility. The company S.N.G.N. ROMGAZ, as operator of the seven UGS facilities, is required under Government Ordinance No. 60/2000, in general terms, to 'reserve a minimum storage capacity for the transporters so that the latter may keep the whole natural gas supply system in balance at any time of the year and ensure minimal SNT operational variables.' However, this obligation to keep security stocks is not clarified in more quantitative terms such as a specific number of days of average gas consumption or in terms of a percentage of annual supply.

Slovakia

The basic legislative framework for Slovakia's accession in the energy field has been adopted, except for the pending draft laws on energy efficiency and on natural monopolies. Some of the relevant secondary regulations needed for implementation of basic legislation are still to be developed. This includes measures relating to the monitoring of the demand/supply balance, collecting and reporting statistical data, and development of rules of third party access to networks.

At present, the energy act obliges the holder of a licence covering gas transit to provide access to third parties for purposes of transit into a third country.

Market opening as of January 2002 applied to consumers with an annual consumption exceeding 25 million m^3 and as of January 2003 will apply to consumers with an annual consumption of 15 million m^3. As of January 2004, the limit is 5 Mcm.

Table 5.15 *Time schedule of liberalisation of domestic electricity and gas market*

To liberalise domestic gas market for consumers with annual consumption exceeding	
25 mln m^3	January 2002 (27 customers)
15 mln m^3	January 2003
5 mln m^3	January 2004

There does not appear to be an explicit obligation in the energy act on the gas dispatching centre or other entities to maintain security stocks of natural gas. However, the obligations in this respect are implicit in various provisions of the energy act, given that the role of the gas dispatching centres is to ensure the ‘balance between sources and consumption’ and ‘the reliability of energy supplies’ (Art. 12(1)).

Unlike some countries, natural gas storage does not appear to be an activity subject to licensing in Slovakia. Moreover, there does not appear to be a compulsory regime for third party access to underground gas storage facilities.

Under the energy act, gas distributors and electricity and/or heat producers using solid or liquid fuels are obliged to keep emergency stocks of such fuels up to a level determined by a decision of the Regulatory Office.

Turkey

Turkey has established a progressive regulatory regime designed to promote a competitive market structure in line with EU requirements. Jurisdiction over regulatory activities has been shifted from the relevant Ministry to the Energy Market Regulatory Authority (EMRA), which oversees both the electricity and gas markets. One of its first tasks of the new regulator is to draft the secondary legislation required under the Gas Law, which is scheduled to be completed no later than 1 November 2002. EMRA is designated as an ‘independent administrative and financially autonomous public institution’, located in Ankara and related to Ministry of Energy and Natural Resources.

With respect to the gas sector, EMRA is responsible for regulation of activities relating to import, transmission, distribution, storage, trade and export of natural gas, including licensing, monitoring, price regulation, and dispute settlement functions. It has significant powers, *inter alia*: to monitor market performance; to determine the substantive terms and conditions of the licenses and certificates that it issues to the market participants; to draft and enforce the performance standards and distribution and customer services codes; to define eligible customers; and to lay down pricing principles in accordance with the Gas Law.

The Gas Law contains detailed and complex rules on restructuring and privatisation of the gas sector designed with a view towards the long-term development of a competitive gas market. Some of these rules are currently applicable to the market participants, while other provisions set forth a schedule that entails the long-term (i.e., until 2009) restructuring of Turkish Petroleum Pipeline Corporation, called Botas. This within the framework of market opening.

The Turkish Gas Law does not appear to require the government to engage in systematic elaboration and assessment of a natural gas policy or strategy at present or in the future. If none currently exists in Turkey, a legal requirement on the government to engage in systematic formulation and assessment of natural gas policy is therefore to be recommended. The topics required to be addressed could, for example, include consideration of the long-term development and particularly providing natural gas security, forecasting demand, forecasting imports and exports, investment programmes, and development of gas storage capacity.

The drafters of Turkey's gas legislation have instead sought to define the respective roles and responsibilities of the market participants and of the regulator. Several provisions relating to reporting and disclosure obligations of the market participants indicate the basis for a coordinated system of monitoring of security of gas supply under conditions of market liberalization, although certain regulations on the required disclosure by gas transmission necessary for secure operation are yet to be adopted.

Gas import and gas wholesale companies are regulated extensively in ways related to safeguarding of security of supply, including reporting obligations to the regulator. Thus, gas wholesalers (selling to the distribution companies) 'must draw up supply schedules as necessary and take measures for adequate storage in order to meet maximum seasonal natural gas demand of the customers', and they must present to the regulator the lease contracts executed with the storage companies. The import companies must inform the regulator of the stated terms of the import contracts, any extension of the terms, envisaged annual and seasonal import amounts, and the changes in such amounts and the obligations related to the security of the system, which are stated in the contracts or in any extension thereof.

The Turkish 'Transit Law' is wholly dedicated to petroleum pipeline projects and is designed to ensure the enforcement of international agreements to which Turkey is signatory. During and after the completion of transit projects covered by the law, Turkey guarantees the security of the pipeline, land and facilities by committing state security forces to their protection. Insurance coverage is mandatory against any likely threats, unless international agreements provide otherwise. Other provisions relate to environmental protection rules, expropriation, costs, taxes, and arbitration.

Other provisions in the Gas Law imply further that transmission companies may carry transit gas and that there are no exclusive rights to engage in such activity. The Gas Law states that the 'national transmission network investment programmes developed by taking into consideration the transit natural gas transmission' shall be subject to examination and approval by the regulator. It also implies that the regulator, EMRA, will be involved in approving transit agreements, given that it has the power to determine transmission tariffs (including prices, terms and tariff conditions).

Competition will be promoted under the gas release programme now applicable to Botas company: it cannot execute a new natural gas purchase contract until its imports are reduced to an amount equal to twenty percent of the national consumption. Botas will carry out a series of tender procedures for this purpose.

The Turkish Gas Law establishes various obligations on gas undertakings to contract for gas storage capacities, some of which are stated in specific quantitative terms. However, these obligations to secure storage capacity and take other obligations to safeguard supply are not as specific as that set forth in the European Commission's recent proposals for a new Community Framework on safeguarding security of gas supply.

6. CONCLUSIONS AND RECOMMENDATIONS

6.1 Europe-wide

An enlarged European Union faces the prospect of a substantial increase in gas imports in the next three decades in the absence of rigorous new government policies at EU and national levels. Natural gas demand in EU-30 is projected to grow by an average 2.1% per year over the projection period-the most rapid growth rate of any fuel other than non-hydro renewables. The share of gas in total primary demand will continue to grow, from 22% at present to 33% in 2030. The power sector will be the main driver of gas demand, especially in the first half of the projection period.

With indigenous production in the EU-30, except for Norway, projected to stagnate, all of EU-30's projected increase in demand will have to be met by increased imports. Net imports are projected to surge from 200 Bcm in 2001 to almost 650 Bcm in 2030. The share of imports in the region's total gas demand will rise from 38% to just fewer than 70% over the same period. The bulk of imports are expected to come from Europe's two main current suppliers, Russia and Algeria, and a mixture of piped gas and LNG from other African and Former Soviet Union countries and from the Middle-East and Latin America.

However a combination of sharply lower demand and slightly higher production due to higher prices and policies that reduce demand could result in a significantly lower rate of growth in gas imports into EU-30. By the end of the projection period, imports in this scenario are little more than 60% of their level in the Reference Scenario. Most of this difference is due to lower gas consumption in the power sector which will use more coal and nuclear instead of gas. Gas imports nonetheless virtually double over the projection period.

The enlargement of the European Union to twenty five countries will temporarily increase the degree of gas-import dependence as ten new accession countries are net gas importers. Both short- and long-term supply security concerns are likely to be exacerbated. The high degree of dependence of the candidate accession countries in Central and Eastern Europe and their unusually heavy dependence on imports (currently 90%) from a single country Russia will accentuate supply security risks for the EU as a whole. Reliance on a single supply route in some accession countries adds also to the short-term risks.

The projected increases in gas demand and imports in the Reference Scenario imply a need for substantial investment in gas production, transportation and storage capacity both within EU-30 borders as well as in those countries that will supply gas to Europe. Just under \$ 500 billion will need to be invested in gas-supply infrastructure in EU-30 countries and a further \$ 190 billion in external supplier countries over the period 2001-2030. The sheer scale of the capital needs as well as a number of developments, including longer supply chains, geo-political factors and energy-market liberalisation, raise question marks about whether this investment will be forthcoming in a timely manner. There is a risk that supply bottlenecks could emerge and persist for long periods due to the physical inflexibility of gas-supply infrastructure and the long lead times in developing gas projects.

EU and national policy makers will clearly need to tread very carefully in reforming their gas and electricity markets to ensure that the new rules and emerging market structures do not impede or delay investments that are economically viable. Policymakers in the EU will also need to take account of the increased risks facing both upstream producers and merchant gas companies as a result of energy liberalisation in setting rules for long-term supply contracts and joint marketing arrangements. An intensified political dialogue between EU with the gas companies and the governments of supplier countries could support investments in certain high-risk, large-scale gas projects by lowering country and project risks. The development banks, including the European Investment Bank, as well as national and multilateral export credit agencies, will continue to play an important role in backing major cross-border pipeline projects in the future if the EU market regulations and policies are in line with commercial conditions. The restructuring and privatisation of gas companies in major gas producing and transit countries may contribute to reducing future investment risks.

6.2 Gas export and import outlook from Russia and Caspian region

Russian gas export policy regarding Western and Eastern European markets depends on the gas market developments in neighbouring regions and the restructuring of the Russian gas industry. The export policy in the 'optimistic economic growth scenario' is based on the assumption that Russia will keep its share in the supplies to foreign markets and even continues to expand its market share if import demand rises. Russian gas export in this scenario is expected to grow from 139 Bcm in 2001 to 181 Bcm in 2020. At the same time gas reserves of East Siberia and the Far East will be mobilised to enter Asian-Pacific markets, first of all in China, Korea, and Japan.

In the 'pessimistic economic growth scenario' (if crude oil prices are relative low in world markets) the gas export volumes to Europe will be constrained slightly in the short run. However if gas prices continue to be relatively high in Europe in the period 2010-2020, it will be possible to exploit the Russian gas fields and export the required volumes to Western Europe. As a result gas export volumes will reach the levels of the 'optimistic scenario' again in 2020. At the same time, if gas prices in Asian-Pacific countries stay tightly linked to the low crude prices, export projects in the Far East continue to be unattractive for investors. Gas deliveries to CIS and Baltic countries are expected to become about 62-69 Bcm, while the main demand comes via Ukraine and Belarus.

To satisfy the consumers in the Volga region, the Urals, and the Central and North Caucasus regions, it is reasonable to expand gas import from Central Asia and Kazakhstan. Gas import can be carried out either as purchases of gas at the border of the exporting country, either through Russian participation in Turkmen and Kazakh gas production by product sharing or else by barter trade between Russian gas companies and Northern and Northeastern provinces in Kazakhstan. Consequently Russian gas imports might rise to 55-58 Bcm in 2020.

Gazprom's strategy to further develop the gas resource base, production, the reconstruction and extension of gas transport and distribution system, gas processing plants, and the construction of more underground gas storage facilities, requires large investments in the next decades. Throughout the whole period investments in the operation and further development of the industry are crudely estimated to be about \$ 90-100 bln. Compared with investments by *Gazprom* PLC in 1999 of only \$ 3.1 bln. and in 2000 of \$ 3.2 bln. The potential of gas production and exports of Turkmenistan and Kazakhstan to the EU via Russia, Ukraine or other transit routes is large. The production and export volumes in Turkmenistan might rise from 56/45 Bcm in 2005 towards around 100/85 Bcm in 2020 and in Kazakhstan from 20/16 Bcm in 2005 to 50/40 Bcm in 2020.

6.3 Ukraine's transit issues

Currently the Ukraine is clearly the most important gas transit country for Europe with an extensive gas network of pipelines and storage facilities (30 Bcm) in order to transport large volumes of gas mainly from Russia to Europe through Slovakia, Poland and Romania. It is therefore important that the Ukraine meets EU standards for safe and reliable transport of natural gas. Russian gas transit to Europe takes place in volumes of around 110-120 Bcm per year, while gas supply to Ukrainian consumers is around 65-70 Bcm per year. Potentially transit capacity can grow to 160 Bcm.

6.4 Resilience of the European gas transport network

In order to identify potential bottlenecks in the gas transmission system, sudden and prolonged 'gas supply disruption cases' are simulated for the year 2020. Four disruption cases are analysed. Without assuming any probability for these cases to happen, they merely are used as a tool to analyse the resilience of the European gas transport network.

The four disruption cases are:
- Disruption of Russian supply through the Ukraine, in which the complete transmissions pipeline capacity across the Russian-Ukrainian border, becomes unavailable (Russian Case).
- Disruption of Algerian supplies altogether (Algerian Case).
- Disruption of transits through Turkey, *i.e.* transit pipelines from Turkey to Greece and Bulgaria become unavailable (Turkish Case).
- Disruption of Norwegian supplies altogether (Norwegian Case).

Results of these four 'disruption cases' are evaluated with respect to a reference case in which there are no disruptions in gas supply. General conclusions were that existing and planned gas supply and transmission infrastructure (both LNG and pipeline) seems sufficient to meet expected gas demand in 2020. In case of disruption in one of the key supplies, the transmission network capacity is a constraining factor leading to price rises. Expected EU-30 gas consumption projected for 2020 can still be met in most of the disruption cases, through a reallocation of trade routes and demand responses. Note that consumer demand is declining as a consequence of gas price rises for the consumers. These prices rises and demand reactions are based on the assumptions on demand flexibility per country and sector.

Caspian gas supplies become increasingly important for CEECs and Turkey, assuming that pipeline capacity is expanded accordingly.

LNG supplies from remote sources play an increasingly important role in filling the supply gap in any of the disruption cases. Consequently, investment in expanding LNG regasification capacity will be very important for ensuring security of gas supply to EU-30 in the medium and longer term.

We can identify the following bottlenecks in the European pipeline transmission network:
- Iran into Turkey and further into Europe.
- Bulgaria and Romania into Europe.
- Cross-links between CEECs, which are important for mutual assistance in case of emergencies.
- From the west and south into CEECs. Flows and pipelines are currently dimensioned from east to west.
- Spain, however addressing this by developing its LNG facilities.
- Belarus and Ukraine into EU-30.

Turkey's role as transit country for gas from the Caspian Region and Iran to Europe depends critically on:
- Development of domestic gas demand in Turkey,
- Expansion of pipeline capacities from Turkey to Greece and Italy,
- Expansion of pipeline capacities from Turkey to Bulgaria and further to Romania, Hungary and Austria,
- Availability of gas supplies from the Caspian Region and Iran.

6.5 Gas scenarios and policies in candidate countries

Despite the large differences in economic structure, availability of domestic energy resources and the current share of gas in the supply mix across the candidate countries, the share of gas is strongly growing and consequently also the import requirements in the next decades. In the Czech Republic and Slovakia the gas import dependency is around 90%, Romania rises from 20 till 60/70% and Poland will be 75-85% in 2030. The gas demand development depends on the pace of restructuring of coal mines (Poland and Czech Republic) and economic growth, particularly in Romania and Slovakia.

- In all four NAS of concern there are limited domestic energy resources available and therefore a substantial growth of energy import is expected that will result in a strong growth in import dependency. Thus these countries should take measures to mitigate the consequences of this growth of dependency. Dependency can be reduced through diversification of gas import suppliers and diversification of terms of contracts, and through further implementation of policies to promote energy efficiency and local and renewable energy sources. Security of energy supply can also substantially be enhanced by keeping sufficient gas storage capacity and stocks in accordance with the EU Directive amendment requirements.
- The four NAS are becoming important transit countries for gas supplies from East to West. Therefore it is of the utmost importance that measures are taken in time in these countries that secure sufficient transit capacities and interconnections and other facilities, including the required maintenance of these capacities to provide sufficient security of supply to the consumer markets in EU. For creating a genuine integrated EU-30 internal gas market and secure the role as transit countries towards EU-15 markets, candidate countries should timely invest in pipeline connections of the gas network relevant for CEECs.

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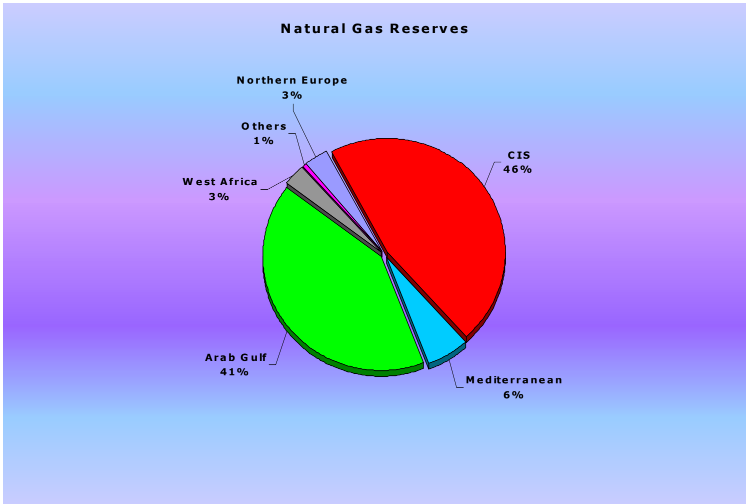
APPENDIX A POTENTIAL RESERVES, SUPPLIES AND SUPPLY GAP FOR EU

A thorough analysis conducted by company Beicip in the framework of the Engaged project concerned a preliminary review of potential gas reserves, supplies, and the demand gap to the EU. Below in this appendix follows a summary of the result of this analysis.

A.1 Potential gas supply options outside EU

Gas reserves outside EU
Faced with increasing import needs, Europe has to seek supply sources in increasingly remote areas. As shown in the chart and table below, the world natural gas reserves are very congregated. There are 46% in the CIS and 41% in the Arab Gulf. There are also significant volumes of natural gas reserves, which are situated in the Mediterranean area (6%), Northern Europe (3%) and West Africa (3%). The remaining gas reserves are rather scattered.



Gm3	
Northern Europe	3 808
CIS	51 950
Mediterranean	6 642
Arab Gulf	46 344
West Africa	3 515
Others	602
Total	112 861

Figure A.1 *Gas reserves outside Europe*

CIS's region
With 47,730 Bcm of proven natural gas reserves, the Russian Federation is the first and foremost holder of natural gas resources in the world. It thus has a prominent role in the future of the natural gas industry.

Among the countries of the former Soviet Union, Turkmenistan is also an outstanding player. Indeed, the country holds 2,850 Bcm of proven natural gas reserves. Since its relation with the Russian federation improved, the country is counting on these large reserves to increase its production and exports in order to finance its growth recovery. However, significant investments in pipeline infrastructure remain necessary to reach such goals.

Finally, Azerbaijan has 1,370 Bcm of proven natural gas reserves and very significant potential reserves. However, here again, there are major infrastructure developments, which are required in order to process such potential.

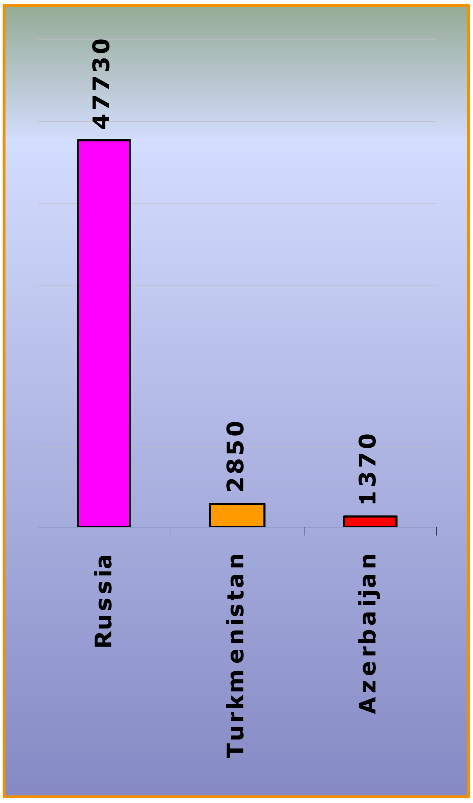


Figure A.2 *CIS's region*

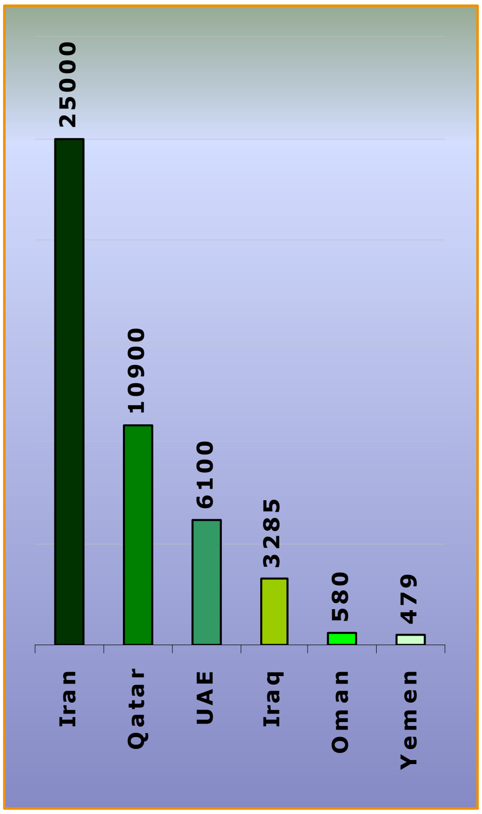


Figure A.3 *Arabic Gulf region*

Arabic Gulf region
A tremendous amount of natural gas reserves is also located in the Arabic Gulf.

With its 25,000 Bcm of proven natural gas reserves, Iran has is the second more influential player, in the future development of the world wide natural gas market.

As for Qatar, with its 10,900 Bcm of proven natural gas, it appears as being the third largest source of natural gas in the world.

With 5,992 Bcm of proven natural gas reserves, the United Arab Emirates are considered as being the fifth largest holders of natural gas resources worldwide.

Iraq has 3,285 Bcm of proven natural gas reserves and some potential for enlarging them in the ten coming years. Almost two-third of the resources are associated to oil production.

Eventually, Oman has 580 Bcm of proven natural gas reserves, with significant potential of betterment and with proven natural gas reserves of about 479 Bcm, Yemen has also considerable potential as a natural gas producer and exporter.

Mediterranean region
Algeria has 4,077 Bcm of proven natural gas reserves. As such, the country is ranked in the top 10 worldwide. The state owned company, Sonatrach, estimates that the ultimate potential of the country gas is much bigger (+25%).

Large discoveries have been made in recent years in Libya, where proven natural gas reserves have already reached the amount of 1,315 Bcm.

Egypt's proven reserves were about 1020 Bcm until 2000 but major recent discoveries has led Egypt's government to ask for a reassessment of the figures. As a result, the figures are now 50% higher.

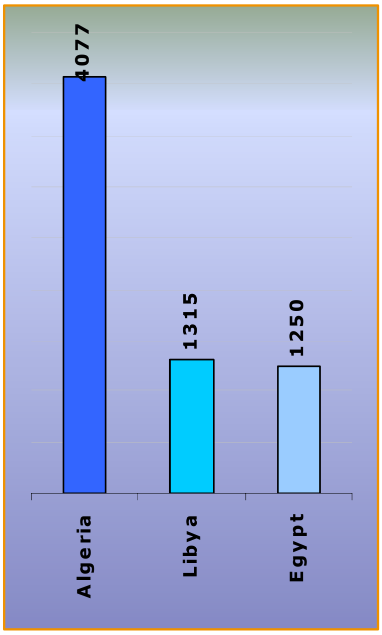


Figure A.4 *Mediterranean region*

Export potential for EU from outside Europe

A crude assessment of potential supply from producing countries outside EU 30 has been made on the basis of a specific survey and analysis performed by Beicip Franlab. The latest projections of gas production profiles in potential supplier countries have been considered.

The estimated export potential of selected producing countries for EU 30 is presented in the following table, based on the analysis made by Beicip Franlab.

Table A.1 *Potential gas exports suppliers to EU 30 , excluding Norway, in year 2020*

Billion m3		EU 30	Far East South Asia	USA	Other		Total Export
Russia		**220**	20		60	Ukraine/Belarus	**300**
Norway		**100**	-	5	-		105
Algeria		**90**	-	5	5	Maroc /Tunisia	100
Libya		**15**	-	-	-		15
Iran	LNG + pipe Turkey	**20**	35	5	-		60
Azerbaidjan	Pipe Turkey	**10**	-	-	-		10
Turkmenistan	Pipe Turkey	**5**	-	-	55	Russia	60
Egypt		**12**	-	-	3	Jordan /Syria	15
Irak	Pipe Syria + Turkey	**5**	-	-	5	Syria	10
Nigeria		**30**	-	15	5		50
Qatar		**10**	35	5	20	UAE Dolphin/Kuw/Bahr	70
UAE	LNG Adgas	**1**	12	-			13
Other Middle East	LNG Yemen /Oman	**5**	25	-			30
Angola		**5**	-	5			10
Trinidad		**15**	-	15			30
Venezuela		**5**	-	10			15
Total		**548**	**127**	**65**	**153**		**893**
Total excl. Norway		448	127	60	153		788

Table A.2 *Gas exports expected from Russia till 2020*

Billion m3	2000	2010	2020
Production	585	630	690
Import	13	50	100
Total Gas Supply	598	680	790
Internal consumption	396	445	490
Other uses (cycling, reserves)	8		
Exports	194	235	300
To Europe EU 15	80	90	100
To Europe EU 30	130	170	220
To ex CIS excl. EU 30	64	60	60
To Asia		5	20

The estimated projected balance of Russia production, import and export to various areas is provided in the above table. A major role is clearly given to additional supplies from Russia. However it should be noted that projections are uncertain figures, i.e. in a recent projection provided by the Russian Institute ERI, see next section, lower figures for gas export potential to EU 30 are projected, namely in 2020 about181 Bcm instead of 220 Bcm.

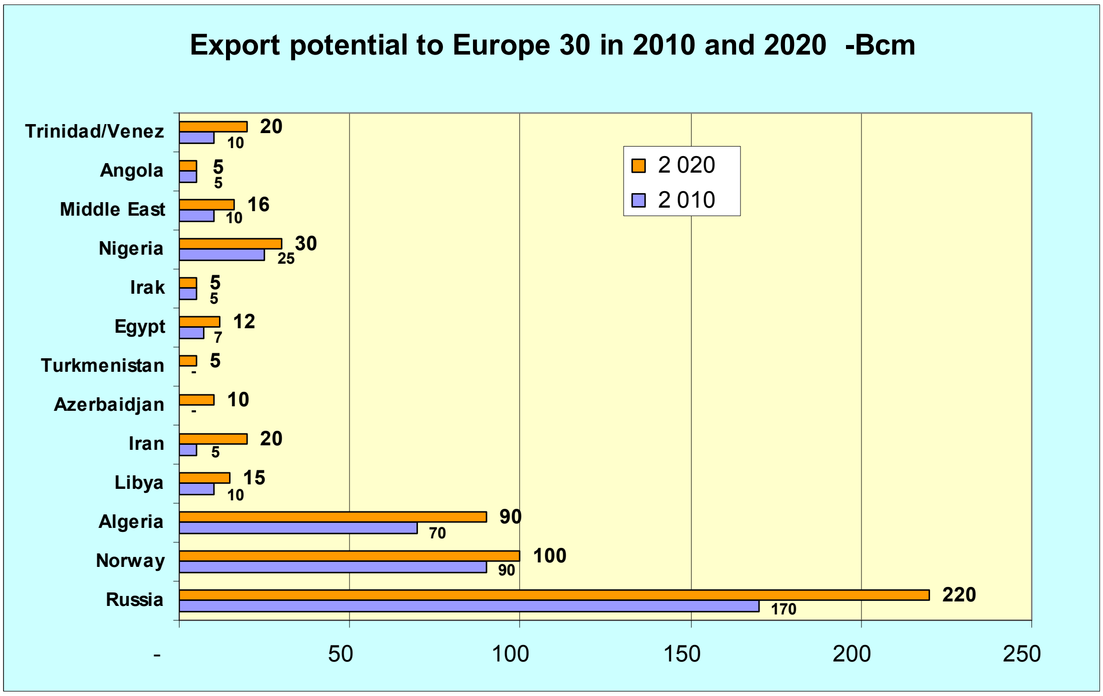


Table A.3 *Export potential to Europe 20 in 2010 and 2020*

From these figures it becomes clear that potential supply from Russia and some other former USSR countries is of crucial importance to the EU-30 and consequently needs a specific analysis of the current and long term developments of the gas sector in Russia, Turkmenistan and Kazakhstan.

A.2 Potential Gas Supply EU-15 and Accession countries

The following tables show the gas import requirements by difference between gas demand and domestic gas supply:

Table A.4 *Natural gas domestic supply for EU-15*

Natural Gas domestic supply for EU 15			BF			
Bcm	**1 999**	**2 000**	**2 005**	**2 010**	**2 015**	**2 020**
Austria		1.63	1.39	1.16	1.16	1.16
Belgium						
Denmark		8.64	6.67	4.71	4.71	4.71
Finland		-	-	-	-	-
France		1.73	1.22	0.72	0.64	0.56
Germany		18.66	16.11	13.55	13.18	12.81
Greece		0.03	0.01	-	-	-
Ireland		1.15	2.99	4.83	4.11	3.38
Italy		17.43	17.43	17.43	17.43	17.43
Luxembourg		-	-	-	-	-
Netherlands		75.52	75.52	75.52	72.62	69.71
Portugal						
Spain		0.45	0.29	0.13	0.10	0.06
Sweden						
United Kingdom		115.60	109.74	103.87	83.25	62.62
TOTAL EU15	**-**	**240.8**	**231.4**	**221.9**	**197.2**	**172.4**
Average annual growth			-0.7%	-0.8%	-2.3%	-2.6%

Table A.5 *Gas domestic supply in Accession Countries*

Gas Domestic supply in Accession Countries

Billion M3	**1 999**	**2 000**	**2 005**	**2 010**	**2 015**	**2 020**
Norway	4.4	***4.5***	***5.2***	***6.1***	***7.0***	***8.2***
Switzerland	-	-	-	-	-	-
Turkey	0.3	***0.5***	***0.4***	***0.1***	***0.1***	***0.1***
Subtotal 1	**4.7**	**5.0**	**5.6**	**6.2**	**7.1**	**8.3**
Romania	14.2	***14.3***	***12.9***	***11.5***	***11.4***	***11.2***
Hungary	3.4	***3.7***	***3.5***	***3.3***	***3.2***	***3.1***
Poland	3.7	***4.8***	***4.6***	***4.4***	***4.4***	***4.3***
Czek Rep.	0.1	***0.2***	***0.2***	***0.2***	***0.2***	***0.2***
Slovakia	0.2	***0.3***	***0.2***	***0.2***	***0.2***	***0.2***
Bulgaria	-	***0.0***	***0.1***	***0.1***	***0.1***	***0.1***
Slovenia	-	***-***	***-***	***-***	***-***	***-***
Central Europe	***21.5***	***23.4***	***21.5***	***19.6***	***19.3***	***19.0***
Total	**26.2**	**28.4**	**27.1**	**25.8**	**26.5**	**27.3**

Table A.6 *Gas consumption and imports in EU-15 and in Accession Countries*

Gas consumption and imports in EU 15						
Billion M3	**1 999**	**2 000**	**2 005**	**2 010**	**2 015**	**2 020**
Consumption	361.2	378.8	429.1	481.3	535.4	586.5
Domestic supply		240.8	231.4	221.9	197.2	172.4
Imports	54.3	138.0	197.7	259.3	338.2	414.0
Gas consumption and imports in Accession Countries						
Billion M3	**1 999**	**2 000**	**2 005**	**2 010**	**2 015**	**2 020**
Consumption	80.5	90.9	100.0	128.4	163.6	207.7
Domestic supply	26.2	28.4	27.1	25.8	26.5	27.3
Imports	54.3	62.5	72.8	102.6	137.1	180.4

A.3 Projected Gas Demand Supply gap EU

Before analysing the gas resource and supply potential available in the long term for EU-30 we briefly summarise the mainstream figure available that are the background and incentive of our study. In this section Figure A.5 shows the increasing import needs up till 2020.

According to Beicip gas demand projections and required imports (in Bcm) would be as illustrated in the following graph. It appears that total import needs for EU 30 would approximately reach in 2020 the total consumption of EU15, around 590 Bcm.

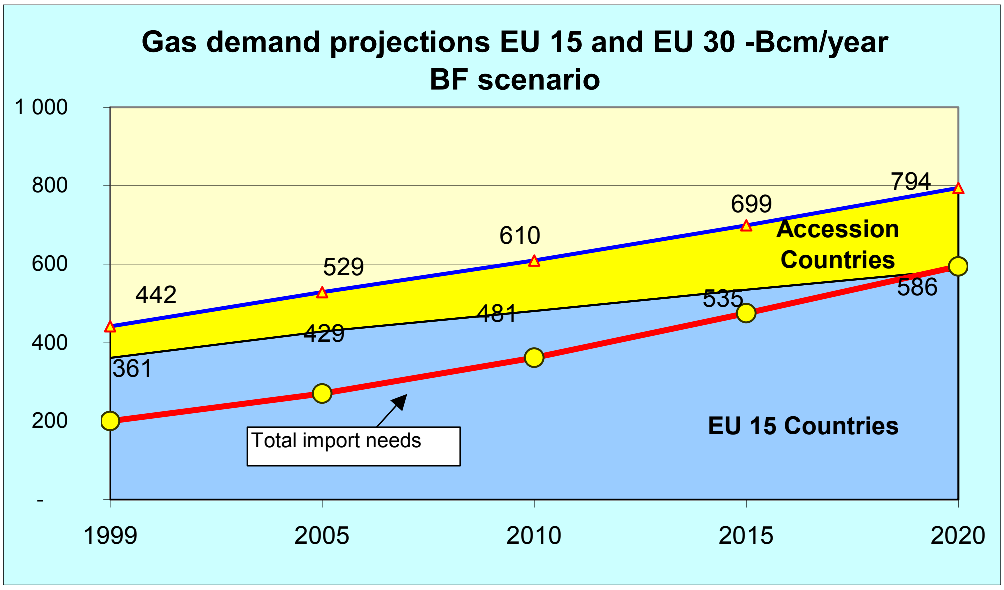


Figure A.5 *Gas demand projections EU 15 and EU 30 [Bcm/year]*

The comparison of gas import needs and potential supply from outside Europe is presented in the following table and graph, considering incremental needs for both import and potential supply starting from 2000 as reference year.

Table A.7 *Gas import needs*

Gas import needs					
Billion M3	**2 000**	**2 005**	**2 010**	**2 015**	**2 020**
Europe 15	138	198	259	338	414
Accession countries	62	73	103	137	180
Europe 30	200	270	362	475	594
Europe 15 balance -incremental from 2000					
Imports required			121		276
Potential supply			114		191
Supply gap			**7**		**85**
Europe 30 balance -incremental from 2000					
Imports required			161		394
Potential supply			154		284
Supply gap			**7**		**110**

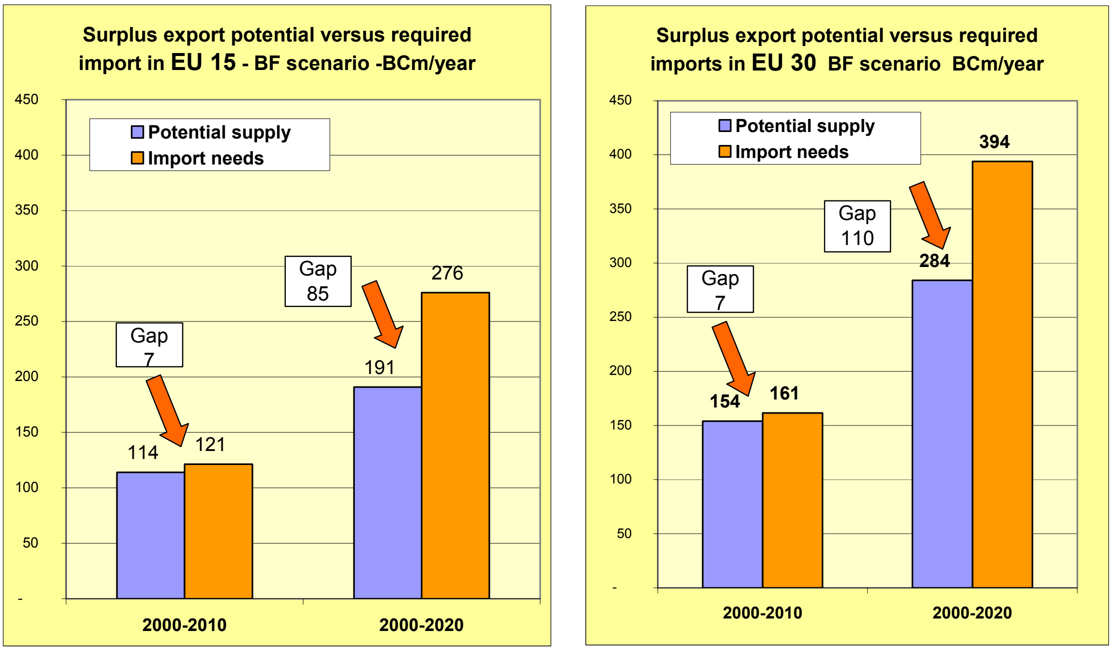


Figure A.6 *Surplus export potential versus required import in EU 15/EU 30 BF scenario [Bcm/year]*

It appears that there would be no difficulty in meeting the gap between demand and supply in the year 2010, both for EU 15 and for EU 30. The gap is only of 7 Bcm and could be easily resolved either on the demand side or on the supply side.

However the gap would become substantial in 2020, both for EU15 (85 Bcm) and for EU 30 (110 Bcm). This would mean that either gas demand would have to be restrained compared to expected growth rate, or gas supply from more remote sources would have to be found, probably at a higher price. The balance would be found between the value of gas as an attractive energy source compared to alternative fuels and the willingness to pay at end use level.

These first conclusions point to the critical aspect of gas demand projections for EU-30 countries, which are strongly depending on the particular role of natural gas for meeting increasingly severe environmental constraints, in particular the Kyoto protocol commitments.

APPENDIX B ECONOMICS OF LNG VERSUS PIPELINE CONNECTIONS

In the framework of Engaged Beicip analysed also briefly the role of LNG. In this appendix follows a summary of observations.

B.1 World market LNG

With a total world LNG consumption of 143 Bcm in 2001, Asia was accounting for 97% and Europe only for 8% of total market. The Asian market is dominated by the high demand of Japan, followed by South Korea and Taiwan, with Indonesia as the largest LNG producer, followed by Middle East (Qatar), Malaysia and Australia. European LNG demand is still limited with Algeria as main supplier, Libya and Egypt as a newcomer. The US market is very limited on account of the still high production level of domestic fields, but this situation is changing and USA will inevitably become a large LNG importer due to decline of domestic production. Until now these three markets were practically separated with some occasional spot deliveries from Middle East and Algeria to USA and Japan, but contracts between markets are more and more frequent, subject to limitations of transport cost.

The two following schemes show our view on the most likely development of LNG connections: the current situation is relatively simple, but things will probably become more and more complex.

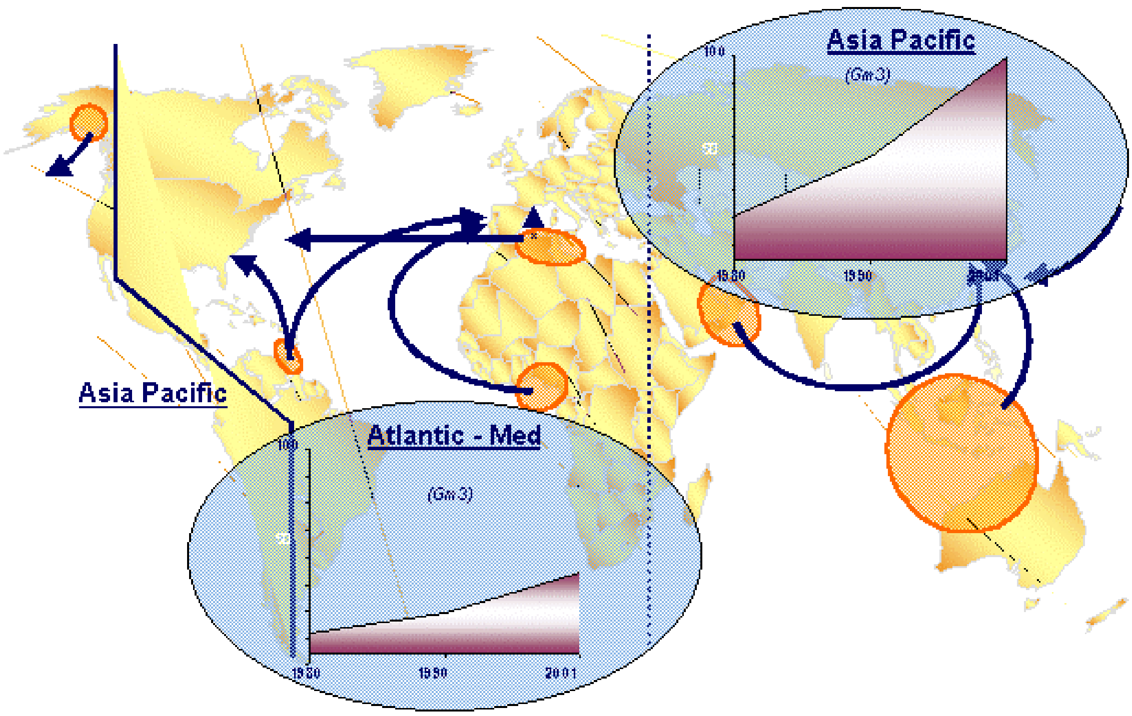


Figure B.1 *The initial scheme*

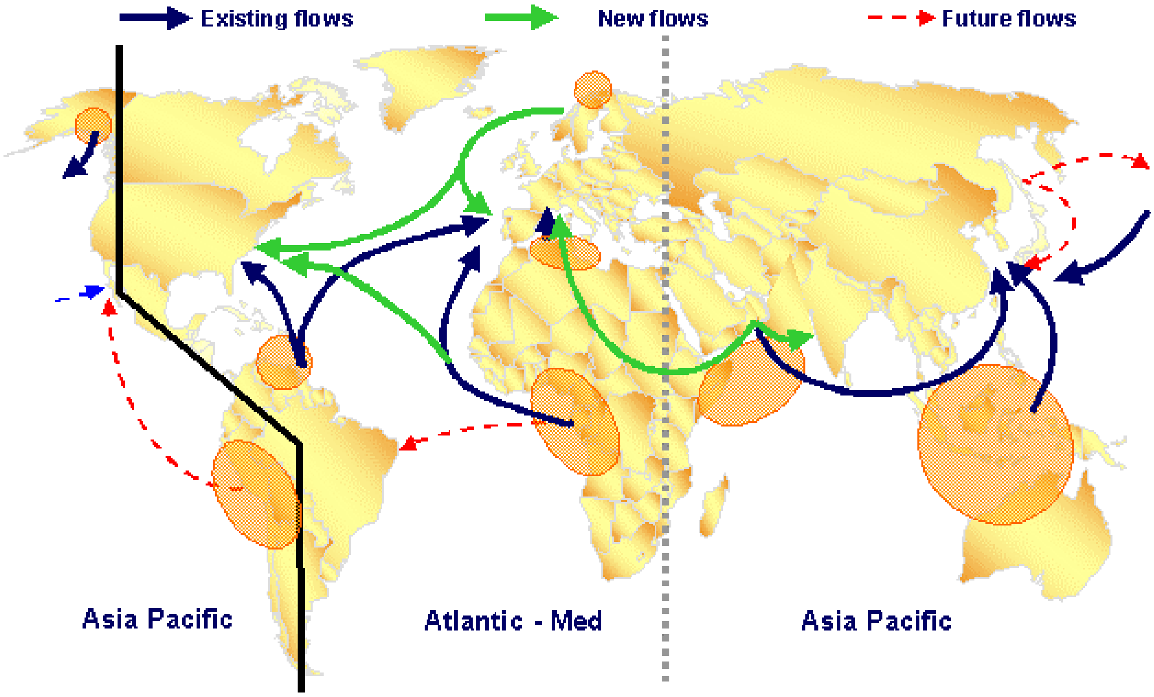


Figure B.2 *LNG trade is becoming more and more complex*

Looking only at the horizon 2010 we have estimated that there will be a substantial development of LNG import infrastructure in Europe, from 42 Bcm in 2000 to 65 Bcm in 2010. During the same period import capacity in the US area (Atlantic basin) would more than double, from 27 Bcm in 2000 to 60 Bcm in 2010 but not exactly for the same reasons:

- It has been indicated above that Europe was requiring more than 500 Bcm of imported gas around 2020, and this gas has to come from more and more remote sources, involving distances where LNG is fully competitive with pipelines (Middle East, South America). But LNG could also be preferred for security of supply reasons as far as it is not required in this case to cross several countries involving political risks. This is reflected by current LNG projects under study for gas from Stokhman and Yamal fields in Russia. There would be in this case to accept an additional cost for security of supply.
- The question in USA is different as far as this country is starting a process in which it becomes progressively a massive importer of gas as a result of exhaustion of reserves and thus declining production. Most operators in the US think that the best strategy to deal with gas decline is to import gas (mostly in the form of LNG). As power generation is a very large potential consumer of gas, the alternative of clean coal technology is seriously considered and substantial progress is made. This alternative provides emissions profiles close to those of gas, but it is now admitted that this technology will not be fully commercial before 2010 at least.

B.2 Impact of technological progress on pipeline and LNG costs

Capital investment required for gas transport infrastructure will be substantially affected within the next decade by technological progress, both for pipelines and LNG facilities. This will mainly result in reductions in future gas transport costs particularly sensitive on long distance connections, and will favour the connections between more remote production and consumption centres, with an obvious impact on security of supply.

The magnitude of cost reductions presented below are based on a recent study carried out by IFP /ENI for the European Commission 'GATE 2020' (Gas Advanced Technology for Europe).

Concerning pipelines, current high capacity onshore connections use steel grades up to X70 and operating pressures under 75 bar. Recent studies have concluded that by using higher steel grades (X80 and even X100) pressure levels could be increased to 140 bar, allowing for the same pipe diameter:

- To transport a higher gas volume
- And to make savings in compression needs.

Europipe II has been the first pipeline using X-80 steel. Using higher grade X-100 steel allows a pressure of 140 bar without requiring a higher wall thickness as is used in traditional pipes.

The combination of above advantages implies that the unit transport cost using X-100 steel can be reduced by 20% compared to current X-70 pipes. The following graph shows the reduction in transport cost for a pipeline connection of 1,000 Km, which can reach not far from 0.10 US$/MMBtu.

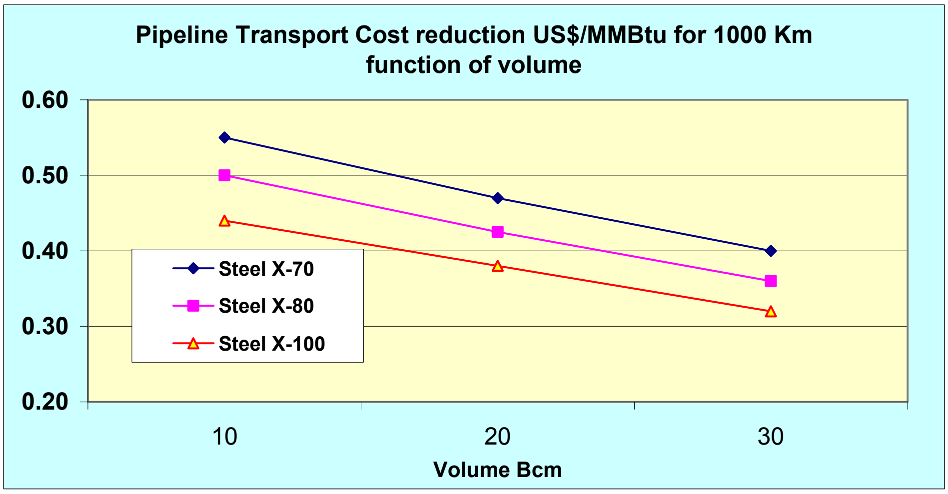


Figure B.3 *Pipeline transport cost reduction*

B.3 Conclusions

With respect to LNG chain, technological developments and cost reduction are expected in 2010 and 2020, mainly in liquefaction plants design and tanker capital costs.

Looking directly at the 2020 horizon, the following developments are expected:

- Reduction of 20% in liquefaction plant capital cost, and maximum train sizes of 6 Million Tons/year (presently 3 Mt/y).
- Shorter plant construction period: 4years instead of 5.
- Faster operation build up profile.
- Reduction of 10% on tankers capital costs with higher tanker size (200,000 m^3 instead of presently 130,000 m^3).

The following graphs illustrate the reduction in liquefaction costs as a function of volume, and in total LNG chain cost for a 10 Bcm capacity (7.5 Million tons/year) as a function of distance.

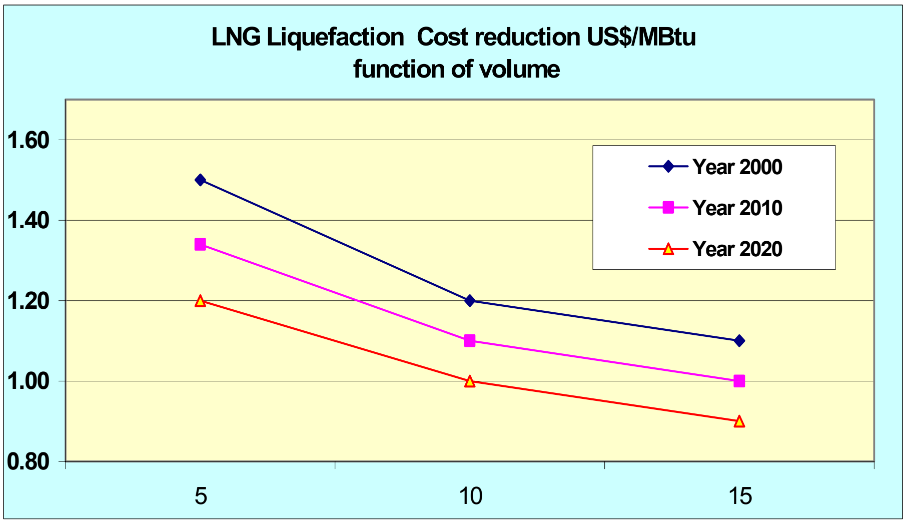


Figure B.4 *LNG liquefaction cost reduction*

APPENDIX C DATA INPUT AND ASSUMPTIONS FOR GAME ANALYSIS

C.1 Demand side

C.1.1 Consumption, prices and elasticities

Expected gas consumption (2020), end-use prices (in terms of 2000 prices) and elasticities are used to calibrate the linear demand curves for each consuming country. Necessary input data for consumption and prices is given in Table C.1. The countries specified in this table are included in GASTALE-2003 as the relevant gas consuming countries. Other countries are disregarded. Modelled consuming countries represents 95% of total EU15 consumption and 94% of EU30 consumption in 2000.

Expected consumption in 2020 for the total group of modelled consuming countries is a factor 1.5 higher than actual consumption in 2000 (1.3, 1.3 and 2.2 respectively for households, industry and power generation). This growth is mainly due to increased gas demand in power generation. Consumption by power generators in Poland (438%), Spain (437%) and France (929%) is expected to grow substantially over the considered period of twenty years.

Price elasticities are always a controversial subject. We assume average elasticities of -0.25 for households, -0.4 for industry and -0.75 for power generation, which are equal between all consuming countries. In the 1999 WEO (IEA, 1999) there is some discussion of price elasticities.

Table C.1 *Natural gas prices and expected consumption in 2020*

	Price [a] [€/1000 m^3]			Consumption [b] [Bcm]		
Country	Households	Industry	Power generation	Househol ds	Industry	Power generation
Austria	225.65	170.74	139.41	2.81	3.96	5.68
Belgium	370.39	152.44	152.44	7.11	7.56	9.80
France	322.09	152.44	152.44	26.42	20.76	19.14
Germany	339.26	170.74	139.41	54.06	38.05	31.36
Italy	339.26	170.74	139.41	36.63	35.45	37.87
Netherlands	326.50	151.30	135.00	21.34	21.92	20.11
Spain	446.44	159.34	149.91	5.96	18.88	15.80
United Kingdom	266.03	95.07	94.47	51.37	30.16	56.63
Czech Republic	194.52	134.12	132.85	4.63	5.70	2.77
Slovak Republic	194.52	134.12	132.85	3.54	3.15	5.38
Hungary	151.08	113.45	90.73	9.37	3.67	6.60
Poland	224.86	120.86	120.86	7.10	8.10	3.80
Romania	64.42	90.67	92.40	4.54	10.62	13.86
Turkey	234.26	159.21	153.33	4.72	3.01	21.52
Average/Total						

[a] Source: IEA (2002), prices in grey cells are not available from IEA and therefore based on known prices in other countries and/or sectors (*e.g.* the price for French power generation is assumed to equal the price for French industry). Prices in Romania are from ISPE.

[b] Source: IEA (2003), for Hungary, Romania and Slovakia based on average growth factors for accession countries (1.5, 1.3 and 2.3 respectively for households, industry and power generation) and for Austria, Belgium, France and Germany based on growth factors for EU15 countries (1.3, 1.2 and 2.6 respectively for households, industry and power generation) compared with 2000 data. French power generation based on IEA (2000). Assumed is the German power generation growth factor is 2. Czech Republic and Poland based on project country reports.

Source: IEA (2002). Italy, Netherlands, UK and Czech power generation growth factors based on 2020 projections. Growth factors for Spain and Turkey based on 2010 projections.

C.1.2 Exogenous production

For relevant consuming countries not denoted as relevant producing countries, domestic production in 2000 is treated as exogenous, *i.e.* deducted from expected consumption (in 2020) before the demand function is calibrated. Producing countries, *i.e.* with endogenous production, are indicated by-in Table C.2, whereas a 0 denotes that there is no production at all.

Table C.2 *Exogenous production [Bcm]*

Country	Exogenous production
Austria	1.805
Belgium	0
France	1.863
Germany	-
Italy	-
Netherlands	-
Spain	0.162
United Kingdom	-
Czech Republic	0.219
Slovak Republic	0.173
Hungary	3.194
Poland	5.209
Romania	13.83
Turkey	0.639
Total	27.094

C.2 Supply side

C.2.1 Production

We assume that gas is simultaneously extracted from several fields that may have different unit costs. Yfi gives the yearly capacity of the fields that are exploited. A profit-maximising producer who extracts from two or more fields extracts gas from a particular field until its marginal cost equals the marginal cost of the other fields (net of transmission costs). Thus, the marginal cost of producer *fi* equals the highest marginal cost among active fields. The marginal cost functions have to satisfy our assumptions of being increasing and convex in production.

Table C.3 shows the major gas producing (and exporting) countries[20] relevant for Europe's gas supply. Actual production in 2000 is given as well as assumed annual production capacity in 2000 and 2020. For countries like Algeria, Caspian region, Iran and Russia, assumed production capacity is smaller than actual production because we are only interested in the capacity available for supply (export) to Europe. For example, Algerian gas supply to Europe was 58.4 Bcm in 2000 whereas its total (marketed) production was 84.4 Bcm. Data in the four latter columns of Table C.3 are used to construct the production cost curves for each producer. Assume the following form for the marginal cost function (see Golombek et al., 1995):

$$CY'_{fi}\ (y_{fi}) = A_{fi} + B_{fi} \cdot y_{fi} + C_{fi} \cdot \ln(1 - y_{fi} / Y_{fi}) \qquad A_{fi}, B_{fi} > 0,\ C_{fi} < 0,\ 0 < y_{fi} < Y_{fi}$$

The parameters of the marginal cost function, *A*, *B* and *C*, are selected consistent with available information (Golombek *et al.*, 1995; Drewry, 1999; Beicip, 2003). The intercept, A_{fi}, is interpreted as the marginal cost of the first unit of production.

[20] In this study firms are equal to producing countries, thus any combination *fi* refers to a one producing country.

Table C.3 *Assumed production capacity [Bcm] in 2020 and parameters of production cost curve*

Producing country	Production capacity	Parameters A	Parameters B	Parameters C
Algeria	170	10	0	-5
Caspian Region [a]	100	12	0	-10
Denmark	18	15	0.75	-22
Germany	25	5	0	-12
Iran	60	10	0	-5
Italy	15	12	0.75	-10
LNG other [b]	90	90	0.1	-5
Libya	30	12	0	-5
Netherlands	70	5	0	-12
Norway	110	12	0.2	-10
Russia	250	12	0	-5
United Kingdom	60	15	0	-10
Total	998			

[a] Azerbaijan, Kazakhstan, Turkmenistan and Uzbekistan.
[b] A combination of several LNG exporting countries.

C.2.2 Distribution costs

Costs of distributing gas to final customers within consuming countries are based on Arthur D Little (2003) for EU15 Member States and on input of the project partners for the candidate countries (Czech Republic, Poland, Romania). For power generation in EU15 Member States, we assume high load factors of 8000 hours per year and 50 km transport on high-pressure transmission lines (HTL). For industry we assume 5000 hours load, 200 km transport on HTL and 30 km on regional transmission lines (RTL). Arthur D Little (2003) does not provide distribution costs for small gas users, therefore, a proxy for households is based on the difference in 2000 end-use prices between industry and households plus the distribution costs of industry. Other countries' distribution costs are our guess.

Table C.4 *Distribution costs [€/1000 m^3]*

	Power generation[a]	Industry[b]	Households[c]
Austria	2.18	15.71	70.61
Belgium	3.66	8.94	226.90
France[d]	3.66	12.46	182.11
Germany[d]	1.64	16.81	185.33
Italy[d]	8.89	21.62	190.14
Spain	13.51	21.55	308.65
United Kingdom[d]	3.37	8.08	179.04
Netherlands[d]	3.67	7.52	182.72
Czech Republic[e]	47	61	75
Slovak Republic[e]	15	45	90
Hungary[e]	15	45	90
Poland[e]	15	45	90
Romania[e]	15	20	45
Turkey[e]	15	45	90

[a] For EU15 Member States, adapted from Arthur D Little (2003). Assuming 50 km transport on high-pressure transmission line (HTL), 0 km on regional transmission line (RTL) and 8000 hours load.
[b] For EU15 Member States, adapted from Arthur D Little (2003). Assuming 200 km transport on HTL, 30 km on RTL and 5000 hours load.
[c] For EU15 Member States, estimation based on the difference in 2000 end-use prices between industry and households plus the distribution costs of industry.
[d] Averages are taken from low and high tariffs in those countries.
[e] For non-EU15 countries, data are according to input of the project partners (Czech Rep. , Poland, Romania) or our own assessment.

C.2.3 Transmission cost and capacity

Long-distance transport costs of gas are based on unit costs per kilometre and differing for on-shore and offshore transport. Sources (Hartley & Brito 2001, Favennec 2002, Beicip 2003) indicate on-shore cost per kilometre between 0.010 and 0.016 €/1000m^3/km, offshore between 0.014 and 0.070 €/1000m^3/km and a ratio between onshore and offshore cost between 2.5 and 5.0. Regarding pipeline transmissions we have used the following cost figures as the starting point in our calculations.

Table C.5 *Gas transmission costs*

		Distance dependant [€/1000m^3/km]
Pipeline	Onshore	0.012
Pipeline	Offshore	0.048

Since there are economies of scale involved in pipeline investments and therefore also in related transmission costs, a correction factor for pipeline transmission costs is incorporated. The correction factor adjusts the cost per kilometre numbers. Assuming a standard capacity of 10 Bcm, we define the following correction factor:

$$3\sqrt{10 / TransmissionCapacity}$$

which is multiplied with the initial costs per kilometre in Table C.4. For example, for an annual transmission capacity of 4 Bcm, the correction factor is 1.357, which results in onshore pipeline transmission costs of 0.016 €/1000m^3/km. For annual capacity of 92 Bcm the correction factor is 0.477, resulting in 0.006 €/1000m^3/km.

Transmission capacity is restricted. Table C.6 shows, on an aggregate level, the pipeline capacities assumed for 2020. For North Africa (Algeria and Libya), the EU and CEEC the data is aggregated in order to limit the size of the table. (For calculations we used the disaggregated data). LNG receiving and sending capacities are shown in Table C.7 and Table C.8. The assumptions are based on existing and planned capacities.

Table C.6 *Aggregated pipeline transmission capacities in 2020*

From To	Belarus	Ukraine	EU15	CEEC	Turkey
Russia	66	255	30	-	16
North Africa	-	-	79	-	-
Norway	-	-	147.4	-	-
Caspian	-	50	-	-	30
Iran	-	-	-	-	25
Belarus	-	29	-	66	-
Ukraine	-	-	-	148	-
EU15	-	-	354.1	7.6	-
CEEC	-	-	171.3	126.7	14
Turkey	-	-	10	10	-

Table C.7 *LNG imports and receiving capacity*

LNG importing country	LNG imports [Bcm] in 2000	LNG receiving capacity [Bcm] in 2000	2020[a]
Belgium	4.4	4.4	7.5
France	12.0	13.0	24.0
Italy	4.7	4.8	24.0
Romania	0	0	2.5
Spain	8.0	22.0	34.0
Turkey	4.3	4.3	12.0
United Kingdom	0	0	26.0
Total	33.4	48.5	130.0

[a] Based on planned capacities.

Algeria, Libya, Iran, Norway, Russia, Trinidad & Tobago, Qatar, Nigeria, Egypt, Venezuela, UAE, Yemen, Oman, Angola are expected to be (come) LNG exporting countries to Europe, where the latter nine are LNG-only exporters. LNG export capacities of the countries that are not explicitly modelled as gas producing countries are represented by one LNG producer (LNG other) in our model.

Table C.8 *LNG exports and sending capacity*

LNG exporting country	LNG exports [Bcm] in 2000	LNG sending capacity [Bcm] in 2000	2020[a]
Algeria	25	28	40
Libya	1	2	5
Iran	0	0	5
Norway	0	0	5.7
Russia	0	0	13
LNG other	43	45	90
Total	69	75	168.7

[a] Based on planned capacities.

LNG transport costs contain a fixed component and a distance dependent component. The fixed component is mainly built up from liquefaction and regasification and vessel loading and unloading. The distance related component is mainly fuel related cost for the vessels. Sources (Hartley & Brito 2001, Drewry 1999, Favennec 2002, Beicip 2003) indicate distance related LNG costs to be in the range of 0.0025-0.0033 €/1000 m^3 /km and a fixed cost between 45 and 60 € / 1000 m^3. Knowing this and tuning our numbers on OME 2001 supply cost numbers and all relevant distances, the following are the numbers we have used as transport costs for LNG from the incorporated LNG exporting countries and the LNG importing countries.

Table C.9 *LNG transport costs [€ /1000 m^3]*

Country	Fixed Cost	Belgium	France	Italy	Romania	Spain	Turkey	United Kingdom
Algeria	55	8	4	4	9	3	7	8
Iran	80	21	12	9	10	12	8	21
Libya	61	16	7	3	6	7	4	16
Norway	80	8	10	17	24	12	23	8
Russia	90	9	9	13	18	22	24	25
LNG other	0	20	11	8	9	11	7	22

Fixed cost component of LNG other is incorporated in its production cost function.

For example, to determine the total supply costs of Algerian LNG to Turkey we add the fixed cost component of 55, the distance related term of 7 and the production costs (that differ per unit, see the production cost function parameters in Table C.3).

APPENDIX D IEA REFERENCE SCENARIO RESULTS

Table D.1 *EU-30-reference scenario results*

	Level						Growth rates per annum [%]					
	1971	1990	2000	2010	2020	2030	1971-2000	1990-2000	2000-2010	2010-2020	2020-2030	2000-2030
Assumptions												
GDP [US$1995, PPP]	4197	6973	8517	10671	13006	15180	2.5	2.0	2.3	2.0	1.6	1.9
Population [millions]	372	398	417	419	415	407	0.4	0.5	0.0	-0.1	-0.2	-0.1
Energy Prices [$2000]												
Coal [per tonne]	53	63	35	39	41	44	-1.4	-5.8	1.2	0.6	0.6	0.8
Oil [per barrel)]	7	27	28	21	25	29	4.8	0.3	-2.8	1.7	1.5	0.1
Gas [per toe GCV)]	-	130	119	110	130	151	-	-0.9	-0.8	1.8	1.5	0.8
Total Energy [Mtoe]												
Total Primary Energy Supply	1306	1691	1826	2037	2176	2283	1.2	0.8	1.1	0.7	0.5	0.7
Coal	445	451	337	315	303	299	-0.9	-2.9	-0.7	-0.4	-0.2	-0.4
Oil	681	657	705	763	799	816	0.1	0.7	0.8	0.5	0.2	0.5
Gas	114	287	406	539	674	760	4.5	3.5	2.9	2.3	1.2	2.1
Nuclear	13	205	249	259	200	163	10.6	2.0	0.4	-2.6	-2.0	-1.4
Hydro	28	39	48	52	55	58	1.8	2.1	0.8	0.6	0.6	0.6
Other Renewables	23	50	75	104	140	180	4.1	4.0	3.4	3.0	2.5	3.0
Other Primary	1	2	6	6	6	6	-	-	0.0	0.0	0.0	0.0
Electricity & CHP Plants	346	648	713	817	871	918	2.5	1.0	1.4	0.6	0.5	0.8
Coal	197	284	244	233	228	228	0.7	-1.5	-0.5	-0.2	0.0	-0.2
Oil	76	58	44	35	22	14	-1.8	-2.7	-2.3	-4.4	-4.5	-3.7
Gas	28	51	105	197	302	369	4.7	7.5	6.5	4.3	2.0	4.3
Nuclear	13	205	249	259	200	163	10.6	2.0	0.4	-2.6	-2.0	-1.4
Hydro	28	39	48	52	55	58	1.8	2.1	0.8	0.6	0.6	0.6
Other Renewables	4	11	23	41	64	87	6.7	7.5	5.9	4.5	3.1	4.5
Total Final Consumption	972	1190	1302	1465	1601	1700	1.0	1.0	1.2	0.9	0.6	0.9
Coal	193	127	64	56	51	47	-3.7	-6.6	-1.3	-1.0	-0.7	-1.0
Oil	543	559	626	695	742	767	0.5	1.1	1.0	0.7	0.3	0.7
Gas	90	222	280	320	351	371	4.0	2.3	1.4	0.9	0.6	0.9
Electricity	103	196	237	283	328	364	2.9	1.9	1.8	1.5	1.0	1.4
Heat	21	46	38	41	45	47	2.0	-1.9	0.8	0.7	0.6	0.7

	Level						Growth rates per annum [%]					
	1971	1990	2000	2010	2020	2030	1971-2000	1990-2000	2000-2010	2010-2020	2020-2030	2000-2030
Renewables	21	40	57	70	84	104	3.4	3.7	2.0	2.0	2.1	2.0
Electricity Output [TWh]	1451	2710	3292	3902	4487	4929	2.9	2.0	1.7	1.4	0.9	1.4
Coal	645	1040	992	938	997	1090	1.5	-0.5	-0.6	0.6	0.9	0.3
Oil	322	220	188	151	99	66	-1.8	-1.5	-2.2	-4.2	-4.0	-3.5
Gas	98	195	522	1036	1673	1944	5.9	10.4	7.1	4.9	1.5	4.5
Nuclear	51	785	955	992	766	627	10.6	2.0	0.4	-2.6	-2.0	-1.4
Hydro	327	450	556	601	637	674	1.8	2.1	0.8	0.6	0.6	0.6
Other Renewables	9	20	78	183	311	423	7.7	14.5	8.9	5.4	3.1	5.8
Hydrogen	0	0	0	0	5	105	-	-	-	53.0	36.6	-
Gas Consumption [Mtoe]												
Total Primary Demand	114	287	406	539	674	760	4.5	3.5	2.9	2.3	1.2	2.1
Electricity & CHP Plants	28	51	105	197	302	369	4.7	7.5	6.5	4.3	2.0	4.3
Other Transformation	-4	14	21	22	21	21	-	4.4	0.3	-0.5	-0.2	-0.1
Total Final Consumption	90	222	280	320	351	371	4.0	2.3	1.4	0.9	0.6	0.9
Industry	55	109	121	134	147	156	2.8	1.1	1.0	0.9	0.5	0.8
Residential/commercial	35	113	158	185	203	216	5.4	3.4	1.6	0.9	0.6	1.0
Gas Supply [Bcm]												
Demand inc. Stock Change	143	367	499	663	829	936	4.4	3.1	2.9	2.3	1.2	2.1
Indigenous Production	143	239	317	314	305	289	2.8	2.9	-0.1	-0.3	-0.6	-0.3
Net Imports	0	129	182	350	524	647	-	3.5	6.7	4.1	2.1	4.3
Indicators												
TPES/GDP	0.31	0.24	0.21	0.19	0.17	0.15	-1.3	-1.2	-1.2	-1.3	-1.1	-1.2
TFC/GDP	0.23	0.17	0.15	0.14	0.12	0.11	-1.4	-1.1	-1.1	-1.1	-0.9	-1.0
Gas demand/TPES [%]	9%	17%	22%	26%	31%	33%	3.3%	2.7%	1.8%	1.6%	0.7%	1.4%
Gas production/Demand [%]	100%	65%	63%	47%	37%	31%	-1.6%	-0.2%	-2.9%	-2.5%	-1.8%	-2.4%
Gas Imports/Demand [%]	0.0	35%	37%	53%	63%	70%	-	0.4%	3.7%	1.8%	0.9%	2.1%

Table D.2 *EU-15-reference scenario results*

	Level						Growth rates per annum [%]					
	1971	1990	2000	2010	2020	2030	1971-2000	1990-2000	2000-2010	2010-2020	2020-2030	2000-2030
Assumptions												
GDP [US$1995, PPP]	4096	6749	8241	10326	12585	14689	2.4	2.0	2.3	2.0	1.6	1.9
Population [millions]	343	365	377	378	374	367	0.3	0.3	0.0	-0.1	-0.2	-0.1
Energy Prices [$2000]												
Coal [per tonne]	53	63	35	39	41	44	-1.4	-5.8	1.2	0.6	0.6	0.8
Oil [per barrel]	7	27	28	21	25	29	4.8	0.3	-2.8	1.7	1.5	0.1
Gas [per toe GCV]	-	130	119	110	130	151	-	-0.9	-0.8	1.8	1.5	0.8
Total Energy [Mtoe]												
Total Primary Energy Supply	1041	1320	1458	1627	1731	1813	1.2	1.0	1.1	0.6	0.5	0.7
Coal	307	299	212	191	186	180	-1.3	-3.4	-1.0	-0.3	-0.3	-0.6
Oil	606	549	593	635	659	670	-0.1	0.8	0.7	0.4	0.2	0.4
Gas	82	223	339	453	556	620	5.0	4.3	2.9	2.1	1.1	2.0
Nuclear	13	188	225	232	179	153	10.4	1.8	0.3	-2.6	-1.5	-1.3
Hydro	19	22	27	28	30	31	1.2	2.1	0.3	0.4	0.5	0.4
Other Renewables	16	39	60	87	120	157	4.8	4.5	3.8	3.3	2.7	3.3
Other Primary	0	0	2	2	2	2	-	-	0.0	0.0	0.0	0.0
Electricity & CHP Plants	263	493	555	638	677	714	2.6	1.2	1.4	0.6	0.5	0.8
Coal	142	196	162	147	147	144	0.5	-1.9	-1.0	0.0	-0.2	-0.4
Oil	69	43	35	27	16	10	-2.3	-2.1	-2.6	-5.0	-4.3	-4.0
Gas	16	33	84	165	244	292	5.8	9.8	7.0	4.0	1.8	4.2
Nuclear	13	188	225	232	179	153	10.4	1.8	0.3	-2.6	-1.5	-1.3
Hydro	19	22	27	28	30	31	1.2	2.1	0.3	0.4	0.5	0.4
Other Renewables	3	10	21	39	61	83	6.6	7.5	6.2	4.7	3.1	4.7
Total Final Consumption	772	931	1052	1181	1286	1359	1.1	1.2	1.2	0.9	0.6	0.9
Coal	127	76	32	28	24	21	-4.7	-8.4	-1.3	-1.4	-1.3	-1.3
Oil	478	474	529	581	617	633	0.4	1.1	0.9	0.6	0.3	0.6
Gas	68	179	240	272	296	312	4.5	3.0	1.2	0.9	0.5	0.9
Electricity	83	157	192	228	263	289	2.9	2.1	1.7	1.4	1.0	1.4
Heat	5	17	20	24	27	30	5.1	2.1	1.6	1.3	1.0	1.3
Renewables	12	28	38	48	59	74	4.0	3.1	2.2	2.1	2.2	2.2
Electricity Output [kWh]	1165	2142	2572	3064	3511	3834	2.8	1.8	1.8	1.4	0.9	1.3
Coal	509	801	704	640	687	724	1.1	-1.3	-1.0	0.7	0.5	0.1
Oil	300	194	161	126	77	51	-2.1	-1.8	-2.4	-4.8	-4.0	-3.8
Gas	72	148	450	905	1414	1598	6.5	11.8	7.2	4.6	1.2	4.3
Nuclear	49	720	864	889	685	588	10.4	1.8	0.3	-2.6	-1.5	-1.3

	Level						Growth rates per annum [%]					
	1971	1990	2000	2010	2020	2030	1971-2000	1990-2000	2000-2010	2010-2020	2020-2030	2000-2030
Hydro	225	260	319	328	343	360	1.2	2.1	0.3	0.4	0.5	0.4
Other Renewables	9	19	74	176	300	409	7.7	14.5	9.1	5.5	3.1	5.9
Hydrogen	0	0	0	0	5	105	-	-	-	53.0	36.6	-
Gas Consumption [Mtoe]												
Total Primary Demand	82	223	339	453	556	620	5.0	4.3	2.9	2.1	1.1	2.0
Electricity & CHP Plants	16	33	84	165	244	292	5.8	9.8	7.0	4.0	1.8	4.2
Other Transformation	-2	11	15	15	16	16	-	2.8	0.6	0.2	-0.1	0.2
Total Final Consumption	68	179	240	272	296	312	4.5	3.0	1.2	0.9	0.5	0.9
Industry	36	78	102	111	122	129	3.6	2.7	0.9	0.9	0.6	0.8
Residential/commercial												
Gas Supply [Bcm]												
Demand inc. Stock Change	103	282	428	571	701	783	5.0	4.3	2.9	2.1	1.1	2.0
Indigenous Production	105	173	241	221	191	150	2.9	3.3	-0.9	-1.5	-2.4	-1.6
Net Imports	-2	109	187	350	511	633	-	5.6	6.5	3.8	2.2	4.1
Indicators												
TPES/GDP	0.25	0.20	0.18	0.16	0.14	0.12	-1.2	-1.0	-1.2	-1.4	-1.1	-1.2
TFC/GDP	0.19	0.14	0.13	0.11	0.10	0.09	-1.3	-0.8	-1.1	-1.1	-1.0	-1.1
Gas demand/TPES [%]	8%	17%	23%	28%	32%	34%	3.8%	3.2%	1.8%	1.4%	0.6%	1.3%
Gas production/Demand [%]	102%	61%	56%	39%	27%	19%	-2.0%	-0.9%	-3.7%	-3.5%	-3.4%	-3.5%
Gas Imports/Demand [%]	-2%	39%	44%	61%	73%	81%	-	1.3%	3.4%	1.7%	1.1%	2.1%

APPENDIX E IEA HIGH GAS IMPORTS SCENARIO RESULTS

Table E.1 *EU-30-high gas imports scenario results*

	Level						Growth rates per annum					
	1971	1990	2000	2010	2020	2030	1971-2000	1990-2000	2000-2010	2010-2020	2020-2030	2000-2030
Assumptions												
GDP [US$1995, PPP]	4197	6973	8517	10671	13006	15180	2.5	2.0	2.3	2.0	1.6	1.9
Population [millions]	372	398	417	419	415	407	0.4	0.5	0.0	-0.1	-0.2	-0.1
Energy Prices [$2000]												
Coal [per tonne]	53	63	35	39	41	44	-1.4	-5.8	1.2	0.6	0.6	0.8
Oil [per barrel]	7	27	28	17	20	22	4.8	0.3	-4.9	1.6	1.0	-0.8
Gas [per toe GCV]	-	130	119	85	95	101	-	-0.9	-3.4	1.2	0.6	-0.5
Total Energy [Mtoe]												
Total Primary Energy Supply	1306	1691	1826	2044	2195	2306	1.2	0.8	1.1	0.7	0.5	0.8
Coal	445	451	337	315	297	282	-0.9	-2.9	-0.7	-0.6	-0.5	-0.6
Oil	681	657	705	768	817	838	0.1	0.7	0.9	0.6	0.3	0.6
Gas	114	287	406	575	754	862	4.5	3.5	3.6	2.7	1.3	2.5
Nuclear	13	205	249	225	126	80	10.6	2.0	-1.0	-5.6	-4.5	-3.7
Hydro	28	39	48	52	55	58	1.8	2.1	0.8	0.6	0.6	0.6
Other Renewables	23	50	75	104	140	180	4.1	4.0	3.4	3.0	2.5	3.0
Other Primary	1	2	6	6	6	6	-	-	0.0	0.0	0.0	0.0
Electricity & CHP Plants	346	648	713	817	871	918	2.5	1.0	1.4	0.6	0.5	0.8
Coal	197	284	244	233	222	212	0.7	-1.5	-0.5	-0.5	-0.5	-0.5
Oil	76	58	44	35	23	14	-1.8	-2.7	-2.2	-4.4	-4.6	-3.7
Gas	28	51	105	231	381	468	4.7	7.5	8.2	5.1	2.1	5.1
Nuclear	13	205	249	225	126	80	10.6	2.0	-1.0	-5.6	-4.5	-3.7
Hydro	28	39	48	52	55	58	1.8	2.1	0.8	0.6	0.6	0.6
Other Renewables	4	11	23	41	64	87	6.7	7.5	5.9	4.5	3.1	4.5
Total Final Consumption	972	1190	1302	1472	1621	1725	1.0	0.9	1.2	1.0	0.6	0.9
Coal	193	127	64	56	50	47	-3.7	-6.6	-1.4	-1.0	-0.7	-1.0
Oil	543	559	626	699	760	789	0.5	1.1	1.1	0.8	0.4	0.8
Gas	90	222	280	323	355	377	4.0	2.3	1.5	0.9	0.6	1.0
Electricity	103	196	237	283	327	362	2.9	1.9	1.8	1.5	1.0	1.4
Heat	21	46	38	41	44	47	2.0	-1.9	0.8	0.7	0.5	0.7
Renewables	21	40	57	69	84	103	3.4	3.7	2.0	1.9	2.0	2.0

	Level						Growth rates per annum					
	1971	1990	2000	2010	2020	2030	1971-2000	1990-2000	2000-2010	2010-2020	2020-2030	2000-2030
Electricity Output [TWh]	1451	2710	3292	3894	4467	4903	2.9	2.0	1.7	1.4	0.9	1.3
Coal	645	1040	992	938	972	1015	1.5	-0.5	-0.6	0.4	0.4	0.1
Oil	322	220	188	153	100	65	-1.8	-1.5	-2.1	-4.2	-4.1	-3.5
Gas	98	195	522	1157	1959	2315	5.9	10.4	8.3	5.4	1.7	5.1
Nuclear	51	785	955	863	485	306	10.6	2.0	-1.0	-5.6	-4.5	-3.7
Hydro	327	450	556	601	637	674	1.8	2.1	0.8	0.6	0.6	0.6
Other Renewables	9	20	78	183	311	423	7.7	14.5	8.9	5.4	3.1	5.8
Hydrogen	0	0	0	0	5	105	-	-	-	53.0	36.6	-
Gas Consumption [Mtoe]												
Total Primary Demand	114	287	406	575	754	862	4.5	3.5	3.6	2.7	1.3	2.5
Electricity & CHP Plants	28	51	105	231	381	468	4.7	7.5	8.2	5.1	2.1	5.1
Other Transformation	-4	14	21	21	19	18	-	4.4	-0.1	-1.1	-0.5	-0.6
Total Final Consumption	90	222	280	323	355	377	4.0	2.3	1.5	0.9	0.6	1.0
Industry	55	109	121	139	151	159	2.8	1.1	1.4	0.8	0.5	0.9
Residential/commercial	35	113	158	184	204	218	5.4	3.4	1.5	1.0	0.7	1.1
Gas Supply [Bcm]												
Demand inc. Stock Change	143	367	499	708	928	1061	4.4	3.1	3.6	2.7	1.3	2.5
Indigenous Production	143	239	317	308	289	269	2.8	2.9	-0.3	-0.6	-0.7	-0.5
Net Imports	0	129	182	399	638	792	-	3.5	8.2	4.8	2.2	5.0
Indicators												
TPES/GDP	0.311	0.243	0.214	0.192	0.169	0.152	-1.3	-1.2	-1.1	-1.3	-1.0	-1.1
TFC/GDP	0.232	0.171	0.153	0.138	0.125	0.114	-1.4	-1.1	-1.0	-1.0	-0.9	-1.0
Gas demand/TPES [%]	9%	17%	22%	28%	34%	37%	3.3%	2.7%	2.4%	2.0%	0.8%	1.7%
Gas production/Demand [%]	100%	65%	63%	44%	31%	25%	-1.6%	-0.2%	-3.7%	-3.3%	-2.1%	-3.0%
Gas Imports/Demand [%]	0%	35%	37%	56%	69%	75%	-	0.4%	4.4%	2.0%	0.8%	2.4%

APPENDIX F IEA LOW GAS IMPORTS SCENARIO RESULTS

Table F.1 *EU-30-low gas imports scenario results*

	Level						Growth rates per annum					
	1971	1990	2000	2010	2020	2030	1971-2000	1990-2000	2000-2010	2010-2020	2020-2030	2000-2030
Assumptions												
GDP [US$1995, PPP]	4197	6973	8517	10671	13006	15180	2.5	2.0	2.3	2.0	1.6	1.9
Population [millions]	372	398	417	419	415	407	0.4	0.5	0.0	-0.1	-0.2	-0.1
Energy Prices [$2000]												
Coal [per tonne]	53	63	35	39	41	44	-1.4	-5.8	1.2	0.6	0.6	0.8
Oil [per barrel]	7	27	28	25	30	36	4.8	0.3	-1.1	1.8	1.8	0.8
Gas [per toe GCV]		130	119	135	165	201		-0.9	1.2	2.1	2.0	1.8
Total Energy [Mtoe]												
Total Primary Energy Supply	1306	1691	1826	1975	2045	2087	1.2	0.8	0.8	0.3	0.2	0.4
Coal	445	451	337	311	252	197	-0.9	-2.9	-0.8	-2.1	-2.4	-1.8
Oil	681	657	705	721	722	699	0.1	0.7	0.2	0.0	-0.3	0.0
Gas	114	287	406	475	528	579	4.5	3.5	1.6	1.1	0.9	1.2
Nuclear	13	205	249	272	280	280	10.6	2.0	0.9	0.3	0.0	0.4
Hydro	28	39	48	52	55	58	1.8	2.1	0.8	0.6	0.6	0.6
Other Renewables	23	50	75	138	203	269	4.1	4.0	6.3	3.9	2.8	4.4
Other Primary	1	2	6	6	6	6			0.0	0.0	0.0	0.0
Electricity & CHP Plants	346	648	713	796	812	836	2.5	1.0	1.1	0.2	0.3	0.5
Coal	197	284	244	230	178	128	0.7	-1.5	-0.6	-2.5	-3.2	-2.1
Oil	76	58	44	36	22	14	-1.8	-2.7	-2.0	-4.6	-4.9	-3.9
Gas	28	51	105	135	160	197	4.7	7.5	2.6	1.7	2.1	2.1
Nuclear	13	205	249	272	280	280	10.6	2.0	0.9	0.3	0.0	0.4
Hydro	28	39	48	52	55	58	1.8	2.1	0.8	0.6	0.6	0.6
Other Renewables	4	11	23	71	117	159	6.7	7.5	11.8	5.1	3.1	6.6
Total Final Consumption	972	1190	1302	1417	1507	1556	1.0	0.9	0.8	0.6	0.3	0.6
Coal	193	127	64	55	50	45	-3.7	-6.6	-1.4	-1.1	-0.9	-1.2
Oil	543	559	626	652	666	651	0.5	1.1	0.4	0.2	-0.2	0.1
Gas	90	222	280	317	344	358	4.0	2.3	1.3	0.8	0.4	0.8
Electricity	103	196	237	277	308	333	2.9	1.9	1.5	1.1	0.8	1.1
Heat	21	46	38	42	45	47	2.0	-1.9	0.8	0.7	0.5	0.7
Renewables	21	40	57	74	95	122	3.4	3.7	2.6	2.6	2.5	2.6

	Level						Growth rates per annum					
	1971	1990	2000	2010	2020	2030	1971-2000	1990-2000	2000-2010	2010-2020	2020-2030	2000-2030
Electricity Output [TWh]	1451	2710	3292	3810	4205	4513	2.9	2.0	1.5	1.0	0.7	1.1
Coal	645	1040	992	920	749	587	1.5	-0.5	-0.7	-2.0	-2.4	-1.7
Oil	322	220	188	156	99	63	-1.8	-1.5	-1.9	-4.5	-4.4	-3.6
Gas	98	195	522	764	1067	1238	5.9	10.4	3.9	3.4	1.5	2.9
Nuclear	51	785	955	1045	1074	1074	10.6	2.0	0.9	0.3	0.0	0.4
Hydro	327	450	556	601	637	674	1.8	2.1	0.8	0.6	0.6	0.6
Other Renewables	9	20	78	323	575	772	7.7	14.5	15.3	5.9	3.0	7.9
Hydrogen	0	0	0	0	5	105				53.0	36.6	
Gas Consumption [Mtoe]												
Total Primary Demand	114	287	406	475	528	579	4.5	3.5	1.6	1.1	0.9	1.2
Electricity & CHP Plants	28	51	105	135	160	197	4.7	7.5	2.6	1.7	2.1	2.1
Other Transformation	-4	14	21	23	23	23		4.4	0.7	0.2	-0.1	0.3
Total Final Consumption	90	222	280	317	344	358	4.0	2.3	1.3	0.8	0.4	0.8
Industry	55	109	121	137	147	151	2.8	1.1	1.2	0.7	0.3	0.7
Residential/commercial	35	113	158	181	198	207	5.4	3.4	1.4	0.9	0.5	0.9
Gas Supply [Bcm]												
Demand inc. Stock Change	143	367	499	585	650	712	4.4	3.1	1.6	1.1	0.9	1.2
Indigenous Production	143	239	317	335	326	317	2.8	2.9	0.6	-0.2	-0.3	0.0
Net Imports	0	129	182	250	324	394		3.5	3.2	2.6	2.0	2.6
Indicators												
TPES/GDP	0.311	0.243	0.214	0.185	0.157	0.138	-1.3	-1.2	-1.5	-1.6	-1.3	-1.5
TFC/GDP	0.232	0.171	0.153	0.133	0.116	0.102	-1.4	-1.1	-1.4	-1.4	-1.2	-1.3
Gas demand/TPES [%]	9%	17%	22%	24%	26%	28%	3.3%	2.7%	0.8%	0.7%	0.7%	0.7%
Gas production/Demand [%]	100%	65%	63%	57%	50%	45%	-1.6%	-0.2%	-1.0%	-1.3%	-1.2%	-1.2%
Gas Imports/Demand [%]	0%	35%	37%	43%	50%	55%		0.4%	1.6%	1.5%	1.1%	1.4%