SENATE RURAL AND REGIONAL AFFAIRS
AND TRANSPORT COMMITTEE

INQUIRY INTO AUSTRALIA'S FUTURE OIL SUPPLY AND ALTERNATIVE TRANSPORT FUELS

SUPPLEMENTARY SUBMISSION 2 ON EUROPEAN NATURAL GAS IN A GLOBAL CONTEXT

5 MAY 2006

BRIAN J FLEAY B.ENG, M.ENG SC., MIEAUST, MAWA
59 View Street North
Perth 6006
Western Australia
08 9328 7065
bfleay@iinet.net.au

Brian J Fleay B. Eng, M. Eng Sc.
Associate, Institute of Sustainability & Technology Policy
Murdoch University W.A.

PERSONAL BACKGROUND

Brian is an executive member of the Australian Association for the Study of Peak Oil.

He is a member of the Board of International Advisers to the Oil Depletion Analysis Centre (ODAC), a branch of the London-based Association for the Study of Peak Oil and Gas (ASPO).

He was a member of the WA Minister for Planning and Infrastructure's Transport Energy Strategy Committee in 2003-04.

He is a member of the Sustainable Transport Coalition of W.A. that has a major focus on oil supply futures, transport and land use planning.

He worked for the Water Authority of W.A. and its predecessors from 1959, retiring in 1993.

He completed his career managing the operation and maintenance of Perth's water sources, both surface and groundwater.

During the 1980s he represented the Water Authority on national committees on water quality issues and for 8 years was a member of the National Health and Medical Research Council's Water Quality Committee.

His family has been farming in the Avon Valley east of Perth since the early 1830s.

In the late 1970s he was inspired by the work of Nicholas Georgescu-Roegen and Howard T. Odum on economics, environment and energy, with a focus on petroleum issues. Thereafter he widened his understanding of ecological economics and related issues, complemented by his employment in the water industry that was confronting conditions where water resource and environmental constraints to its operations became its central focus.

On retirement he took these issues up publicly and in 1995 wrote a book, *The Decline of the Age of Oil.* He has campaigned on these issues ever since.

RATIONALE FOR THIS LATE SUBMISSION

My main submission (6 April) made brief mention of the imminent decline of European natural gas production in the context of North American gas production decline—my Appendix 3 discusses the latter issue. The issue surfaced for Europe over the New Year when there was a supply crisis involving Russian gas exports to Europe and the Ukraine. The February and March issues of the UK-based Petroleum Review and Petroleum Economist had very informative articles that prompted me to make this submission.

In essence North American gas, with 29 per cent of world consumption, commenced decline early this decade. Europe and the former Soviet Union (FSU) has also commenced decline, starting with the UK in 2004, and will extend to Europe as a whole about 2010 and the FSU by 2020. Europe consumes 17 per cent and the FSU 26 per cent of world gas consumption. The two continents consumed 70 per cent of world gas in 2004.

This natural gas decline coincides with the emerging decline of oil and is deeply involved with electric power as well. The Committee needs to be aware of this in making its report.

TABLE OF CONTENTS

	Page
1. Abstract and Recommendations	3
2. Introduction	5
3. Europe and the Former Soviet Union.	5
3.1 Gas supply and consumption in 2004.	5
3.2 Western Europe	7
3.3 United Kingdom gas.	8
4. Industry Responses.	9
4.1 UK: LNG and gas pipelines.	9
4.2 North European Gas Pipeline.	10
4.3 Nabucco	10
4.4 Other options.	10
4.5 Summary	10
5. Gazprom	10
6. Gas and electric power.	11
6.1 UK electric power.	11
6.2 Russian electric power.	12
7. World natural gas.	12
7.1 The world	13
7.2 Former Soviet Union	14
7.3 Liquid natural gas.	15
8. Nuclear power	16
9. Net energy implications	17
10. Conclusions	18
10. References	19

****

EUROPEAN NATURAL GAS
THE GLOBAL CONTEXT

BRIAN FLEAY

5 MAY 2006

1. ABSTRACT AND RECOMMENDATIONS

The high cost of transporting natural gas leads to plateau-like production profiles. Decline begins late in the production cycle and can be steep. *Consequently gas markets are confined to continents with limited global trade, mostly as LNG.*

Europe and the former Soviet Union (FSU) is such a continent. Decline has commenced in the UK and will extend to Europe by 2010 and then to the FSU. The FSU's reserves for natural gas are significantly over-stated, the real figure uncertain. Europe is not well prepared for the supply crisis.

The world database for natural gas is poor due to inconsistent and inadequate reporting of flared gas and that re-injected into oil fields, and other factors. Public auditing of data is needed. The most unreliable data is from the FSU and Middle East countries. World gas reserves could be overstated by as much as 25 per cent.

> **Recommendation:** The deficiencies in reporting of natural gas reserves, for the FSU and Middle East in particular, make it even more imperative for public auditing of reserves data on a field-by-field basis. The present deficiencies have serious economic consequences.

Europe imports piped gas from the FSU and Algeria and LNG from North Africa, with increased imports proposed. Europe and the FSU consume 41 per cent of world gas. North America, also on

the threshold of decline, consumes 29 per cent with growing imports of LNG. China and India will soon be significant importers of natural gas.

> **Recommendation:** Natural gas production in the continents of North America and Europe/FSU are on the threshold of decline, starting with North America and with the UK in Europe/FSU followed by the rest of Europe, then the FSU. This is as important as the world equivalent for oil. The Committee's report should draw stress its importance.

New pipelines are proposed to bring more gas to Europe from the FSU and Norwegian gas fields. Russia's Gazprom dominates FSU gas production and transport. Gazprom is lifting its gas prices within FSU countries to match its charges to European customers.

UK electric power generation is fueled by natural gas, coal and nuclear. The UK is rapidly becoming an importer of all fossil fuels. Magnox nuclear plants will be decommissioned in 2010. *The UK faces a major energy supply crisis with rising prices and adverse economic consequences.*

Europe is installing 100 MW of new gas turbines for electric power generation. The FSU is a significant user of natural gas for electric power generation and plans to double its nuclear power capacity and decommission many ageing nuclear power plants by 2020.

> **Recommendation:** The Committee's report should draw attention to the rapid growth in gas-fired electric generators in the USA and Europe that has been based on unrealistic expectations of future natural gas supply to fuel them. This reinforces the need for a long-term strategic plan for natural gas as gas turbines have lives of at least 30-35 years.

Declining natural gas production in North America and Europe and anticipated imports from China and India has triggered a doubling of world LNG export/import capacity by 2010. Commitments to post 2008 projects may be constrained by rising costs for raw materials and the inability of the specialist companies to handle the volume of work. The rising costs extend to upstream petroleum exploration and development as well. *Higher natural gas and electricity prices are inevitable.*

> **Recommendation:** The Committee should draw attention to the severe specialist manpower and industry resource constraints limiting the pace of LNG development and deepwater offshore exploration and development—costs are escalating. Half of Australia's discovered but undeveloped natural gas is in deepwater offshore. Geoscience Australia considers deepwater offshore to be the frontier region for exploration in Australia.

The commercial energy input to exploration, development and operation in the oil and gas industry must be increasing more rapidly than the energy content of its output. All the signs are that the net energy yield per unit of gross output must be declining. Some 60 per cent of world commercial energy comes from petroleum products. This reinforces the prime necessity for energy conservation and demand management; to restructure to a less energy intensive civilisation.

> **Recommendation:** There is an urgent need for more and better information on the embodied energy content of key goods and services, and of the net energy yield of energy sources. This information is essential to develop reform strategies and priorities.

The first major decommissioning of nuclear power plants will occur in the UK by 2010 followed by the FSU. Both countries plan to expand their nuclear power capacity. Very large investments will be required to decommission and quarantine these plants, and secure long-term disposal of radioactive wastes. *The rising costs of oil and gas will inflate all these costs.*

Expansion of the nuclear power industry is being advocated in the USA and Europe where similar constraints to its development also exist. It is the most capital-intensive source of electric power.

Like the petroleum industry, the nuclear industry has an ageing technical work force approaching retirement with limited numbers of young experienced professionals emerging to replace them.

Finally, the nuclear power industry has been consuming large uranium stocks from the 1970s and from dismantled nuclear weapons. These stocks are running out leading to shortages. Supplies from mines are limited and prices rising. Deposits of high-grade uranium ore are limited. A significant petroleum input is used in mining and processing uranium. *The realism of these visions for growth in nuclear power must be questioned.*

The nuclear power industry is thoroughly embedded in the fossil fuel industry and dependent on it.

> **Recommendation:** The Committee should recommend investigation of the viability of the nuclear power industry as an energy intensive industry in the context of the impending decline of high quality oil and gas production

2. INTRODUCTION

Last winter natural gas was in short supply in Europe. Cold weather from November stretched supply and a dispute between Russia and the Ukraine over gas pricing led to delivery constraints. A less well-known cause is the decline of UK gas production, also imminent for other North Sea gas fields. This paper explains the background and its implications for Europe and the world.

The cost of transporting natural gas any distance is six to ten times greater than the equivalent for oil. Natural gas must be compressed for transport. Compressors consume one per cent of the gas in a pipeline for every 500 km. The pipes are larger than for the equivalent in oil. About 15 per cent of the gas input to a liquefied natural gas (LNG) plant is used to liquefy the gas and is used at the receiving terminal to convert it back to gas. The LNG infrastructure and LNG tankers required are more expensive than their oil equivalents.

This high capital and operating cost of transporting natural gas flattens the production profile of life-cycle gas production from a petroleum province compared to the equivalent for oil. These gas production profiles tend to be extended plateaus compared to the usual more sharply defined peaks for oil. Also the more free-flowing gas usually enables more of the gas-in-place to be extracted (70-80 per cent) compared to oil where the figure is usually 30-40 per cent. Consequently gas production decline is often delayed until about 70 per cent of the extractable gas has been produced. The decline rate can be steep. Gas production and consumption tends to be confined to the continents, there is less international trade than with oil.

3. EUROPE AND THE FORMER SOVIET UNION

3.1 Gas supply and consumption in 2004

The FSU produces 70 per cent of the gas in this region and Europe 30 per cent, the latter mostly from the North Sea (90 per cent). Russia exports gas to Turkey and Turkmenistan exports gas to Iran. Iran also exports gas to Turkey. Turkey in this paper is regarded as a part of the Middle East. New facilities for oil and gas production in eastern Siberia to supply Japan and China are planned and some are under construction, but not yet producing. Additional natural gas is piped into Italy and Spain from Algeria. LNG is imported into Western Europe, mainly from Algeria and Nigeria.

Table 1 shows the production, consumption, imports and exports of natural gas in 2004 for the FSU, Western and Eastern Europe. Table 2 gives data for the FSU, Table 3 for Eastern Europe and Table 4 for Western Europe. The data is from BP Statistical Review of World Energy 2005.

In Table 1, line 1 European imports from the FSU are 7 bcm lower than the difference between FSU production and consumption, after allowing for FSU exports to Iran and Turkey. Some countries, e.g. Germany and France, store gas in depleted oil and gas fields for withdrawal at peak demand periods. Gas is consumed in its transport to Europe and leakage occurs from pipelines. There are rounding and metering errors as well. These factors probably account for the discrepancy. It is not clear if the BP Statistical Review of World Energy accounts for these factors. This could explain the imbalances in the Tables.

The exchanges of gas between European nations and with the FSU are influenced by the locations of gas fields and pipelines. Most European gas imports from the FSU come from Russia through pipelines that cross the Ukraine, with a lesser portion via Belarus. A minor amount comes from Azerbajan, Uzbekistan and Kazakhstan—they are not in the Russian Federation.

TABLE 1
EUROPE & FORMER SOVIET UNION GAS 2004—SUMMARY
Billion cubic metres per year

Region	Production	Consumption	External Imports Pipe	LNG	Total	Exports to Europe
Former Soviet Union	744	583			NIL	134
Eastern Europe	18	72	53		53	---
Western Europe	290	421	114	36	150	---
Total	**1,052**	**1,076**	**167**	**36**	**203**	**134**
Imports Algeria/LNG			**34**	**36**	**70**	
Minus Algeria/LNG			**133**		**133**	**134**

The FSU exported 20 bcm to Turkey and Iran, total exports 154 bcm. Europe imported 41 per cent of its gas consumption, 28 per cent from the FSU and 13 per cent from Algeria and Nigeria.

TABLE 2
FORMER SOVIET UNION & TURKEY GAS 2004
Billion cubic metres per year

Country	Production	Consumption	Imports	Exports
Azerbajan	4.6	8.5	3.9	
Kazakhstan	18.5	15.2		3.3
Russian Federation	589.1	402.1		187
Turkmenistan	54.6	15.5		39.1
Ukraine	18.3	70.7	52.4	
Uzbekistan	55.8	49.3		6.5
Belarus		18.5	18.5	
Other est.	3.3	2.7	0.6	
TOTAL FSU	**744.4**	**582.5**	**75.4**	**236**
All FSU exports	**162**		**161**	
Turkey		22.1	17.9	

Turkmenistan exported 5.2 bcm to Iran. Turkey imported 14.4 bcm from Russia and 3.6 bcm from Iran. FSU exports *received* in Europe were about 133 bcm. FSU imports are from within the FSU.

TABLE 3
EASTERN EUROPEAN GAS 2004
Billion cubic metres per year

Country	Production	Consumption	Imports	Exports
Bulgaria		3.1	2.9	
Czech Rep.		8.8	9.8	
Finland		4.4	4.6	
Hungary		13.0	11.0	
Lithuania		3.1	2.6	
Poland	4.4	13.2	9.1	
Romania	13.2	18.8	5.9	
Slovakia		6.8	7.3	
Other est.		1.0		
TOTAL	**17.6**	**72.2**	**53.2**	

Eastern Europe imports nearly all of its natural gas from the FSU. A minor amount is imported from West European countries.

TABLE 4
WESTERN EUROPEAN GAS 2004
Billion cubic metres per year

Country	Production	Consumption	Imports Pipe	Imports LNG	Imports Total	Internal export West Europe
Austria		9.5	7.8		7.8	0.7
Belgium-Luxemburg		16.3	17.7	2.8	20.5	
Denmark	9.4	5.4		---		3.8
France		44.7	37.0	7.6	44.6	
Germany	16.4	85.9	91.8		91.8	12.2
Greece		2.4	2.2	0.5	2.7	
Ireland, Rep.of		4.1	3.7		3.7	
Italy	13.0	73.3	61.4	5.9	67.3	0.1
Netherlands	68.8	43.5	13.6		13.6	49.2
Norway	78.5	4.6		---		74.4
Spain		27.3	9.7	17.5	27.2	
Portugal		3.1	2.3	1.3	3.6	
Sweden		0.8	1.0		1.0	
United Kingdom	95.9	98.0	11.4		11.4	9.8
Other est.	7.6	12.0	4.5		4.5	
Total	**290**	**421**	**264**	**36**	**300**	**150**
Less Internal W.Eur.			**114**	**36**	**150**	
Less Algeria/LNG	**290**	**421**	**80**		**** 80**	

**** Represents net FSU exports to Western Europe.** LNG imports came mostly from Algeria (22 bcm/yr.) and Nigeria (12 bcm/yr.). Natural gas is piped from Algeria (34 bcm) into Spain and Italy. Ireland imports its gas from the United Kingdom—combined consumption was 102 bcm, 24 per cent of West European consumption and 8 bcm more than UK production.

3.2 Western Europe

Table 5 shows West European cumulative natural gas production and reserves as at end 2004 and production for 2004. Sources: BP Statistical Review of World Energy reports from 1992 and BP Statistical Review of World Gas 1992. All except Italy would be from North Sea gas fields. At this stage I do not have access to pre 1981 production data for the individual countries.

TABLE 5
WESTERN EUROPE
CUMULATIVE PRODUCTION & RESERVES TO 2004

Country	Cumulative from 1981 Bill. cub. metres	Reserves 2004 Bill. cub.metres	Production in 2004 Bill. cub. metres
Denmark	?	90	9.4
France	106	---	---
Germany	424	200	16.4
Italy	374	170	13.0
Netherlands	1,510	1,490	68.8
Norway	929	2,390	78.5
United Kingdom	1,486	590	95.9
Total	**5,032**	**4,930**	**282.0**
Production to 1981	**1,600+**		
Cumulative to 2004	**6,630+**		

Adding cumulative production to reserves gives an ultimate of about 11,600 bcm, excluding any new discoveries, of which 57 per cent had been produced. By 2010 this could reach 70 per cent, with the Netherlands approaching 70 per cent and Norway about 50 per cent of discovered gas produced. **About 2010 European gas production will commence its decline**.

Oil and gas exploration and development has been winding down in the North Sea for some time as the prospects for finding giant oil and gas fields in accessible locations diminishes. The UK and Norway dominate European oil production.

UK oil production peaked in 1999 and by 2004 had declined by nearly one-third. Norway's oil production peaked in 2001 and has since declined by 7 per cent. European oil production peaked in 2000 and has since declined by 16 per cent, and the decline rate is increasing (BP 2005). Preliminary data shows a 16 per cent production decline for 2005 at which level the UK would be an oil importer (Petroleum Review 2006). However, the government did not expect the UK would be importing oil until 2007. The current rises in oil and gas prices may lead to some marginal new development, but in the main only small oil and gas fields are left to find and these are unlikely to come into limited production until after 2010.

3.3 United Kingdom gas

UK gas consumption increased by 80 per cent in the 1990s following deregulation of the gas industry. UK gas production began around 1970, reached 36 bcm in 1981, 51 bcm in 1992, and peaked at 108.4 bcm in 2000. Cumulative production up to 1981 would be about 200 bcm for a cumulative production of 1,690 bcm to 2004 (Table 5). Adding this to reserves gives an ultimate production of nearly 2,300 bcm of which 71 per cent has been produced. By the end of 2005 this would be about 75 per cent. Gas production peaked at 108.4 bcm in 2000 and declined by 6.7 per cent in 2004. For a brief period to 2003 the UK exported gas to Europe.

Preliminary data for 2005 show that UK gas production fell from a rate of 96.3 bcm/yr In November 2004 to 82.6 bcm in November 2005, averaging about 8 per cent below 2004 for the year and was 12 per cent less than consumption, including Ireland (Petroleum Review 2006a). The UK began importing gas in 2004. However, significant gas import infrastructure has been timed to become operational in 2007/8 when the need to import gas was expected.

However, oil and gas production is falling faster than the government anticipated. *Has a steep decline in gas production commenced?* Retail gas prices increased by 22 per cent in 2005 while the day-ahead wholesale price doubled on the 2003 price and in November 2005 spiked at eight times higher (Petroleum Review 2006b).

There was a view that the Netherlands had withheld gas exports to the UK at the most critical time when capacity in the interchange pipeline was available. Skebrowski (2006) says the mass media in the UK blamed lack of competition markets in Europe for the shortfalls and high prices. The reality he said is more prosaic, quoting Jonathan Stern—the Director of Gas Research at the Oxford Institute of Energy Studies. The UK operates a fully liberalised gas market. In the face of excess supply, this delivers low prices and reliable supply—which is exactly what happened over the last few years, with UK customers enjoying the lowest gas prices in Europe. For historical reasons, the continental markets of Europe have been suspicious of free markets, preferring a degree of cartelisation, longer-term contracts and assured supply. For a continental supplier to have diverted gas to the UK this winter in pursuit of possibly temporary price gain would have been very eccentric as it would have risked failure to supply its own consistently higher paying customers.

He says; for the moment both the UK and the EU Commission are keen to decontrol and marketise continental gas markets. However, as security of supply looms larger, the attractions of a fully marketised approach may wane and the existing system come to look more attractive. Free markets only work well in the face of excess or potentially excess supply. If supply is likely to be constrained—or felt likely to be constrained—a continental-style approach may seem preferable.

4. INDUSTRY RESPONSES

- Landia et al. (2006) claim that Europe faces a decline of indigenous gas production of 95 bcm/yr to 163 bcm/yr by 2015 while consumption will rise by 150 bcm to 700 bcm, a supply gap of some 240-250 bcm[1]. This estimate assumes a halving of the consumption growth rate to 2.4 per cent per year. A range of pipeline and LNG projects are proposed or under construction. Landia et al. also observe that continental hubs are developing and market liberalisation growing with a shift away from long term contracts to spot gas pricing. Three key projects are underway that can change market dynamics:
- Full scale entry of the UK into the LNG market—already happening.
- North European Gas Pipeline (NEGP).
- Nabucco projects for shipping Caspian gas to Europe—the most unlikely options.

4.1 UK: LNG and gas pipelines

The UK may need to import some 60 bcm by 2010 (Nicholls 2004). Three new LNG terminals are planned that will link the UK into the global gas market. The UK has a more developed gas market than in Europe.

- A terminal at the Isle of Grain on the Thames estuary is receiving LNG and has a capacity of 5 bcm that will rise to 17 bcm annually from about 2009—this date may be advanced.
- Two terminals approved for Milford Haven in Wales with an eventual combined capacity of 26 bcm/year, in operation from 2009. Earlier dates could be possible.

The UK spot market hit new highs in November 2005 when the Isle of Grain terminal only received four cargoes. *Other scheduled cargoes were diverted to the higher priced US market.*

North American gas production has also begun to decline—gas field depletion has already begun. A steep decline has been delayed so far by frantic drilling, expansion of coal bed methane, substitution of other fuels, reduced industrial use and mild winters and summers that have limited gas consumption for winter heating and summer electric power generation. US capacity to import LNG is being expanded. *US wholesale gas prices are three and four times the levels in the 1990s and often spike to five time these levels, and occasionally even higher.*

These UK LNG terminal projects have a combined ultimate capacity of 43 bcm/yr and depend on the development of sufficient LNG supply capacity around the world—see later discussion below. New European pipeline projects could delay this LNG agenda.

A pipeline already connects Netherlands gas fields to the UK, via Zeegrugge in Belgium. Additional compressor capacity at Zeebrugge increased its capacity from 8 bcm to 16.5 bcm/yr in early 2005, with a further expansion by 8.5 bcm/yr planned for 2007/08 for a total addition of 17 bcm/yr (Nicholls 2004). Additional supply from the FSU to Europe would be required to meet these UK commitments from 2010—see below. Russia's Gazprom is a partner in the project (Gorst 2006). An additional pipeline of 16 bcm capacity from the Netherlands is scheduled for 2007/8.

Among the new projects proposed is a 1,200 km pipeline from Norway's Ormen Lang gas field (gas reserves of 397 bcm) to the UK. Treaty principles between the countries were agreed in 2004 with contract negotiations proceeding for a scheduled start-up date for late 2007. The project could supply up to 25 bcm/yr by 2010, if it is built (Nicholls 2004).

All these new projects add up to over 100 bcm/yr by 2010. However, Nicholls 2004 estimate of a shortfall of 60 bcm by 2010 may now prove to be on the low side. All the projects depend on substantial upstream development. See footnote 1 below.

[1] Landia et al. are not clear on whether Europe includes Eastern Europe. Their 2005 figure for indigenous production in 2005 is some 33 bcm less than the BP (2005) figure for Western Europe in 2004. See Table 1. The reasons for the discrepancy are not clear. The shortfall may be less than Landia et al. expect.

4.2 North European Gas Pipeline

The NEGP proposal will deliver Russian gas from the Russian Baltic coast to a terminal in Germany via a new 1,200 km $5-6 billion pipeline *under* the Baltic Sea. This will avoid the problem of transit payments that plague the existing pipeline through the Ukraine, as happened early in 2006. The gas will come from a western Siberia field with additional pipeline capacity already under construction by Gazprom. The Baltic pipeline, to be completed in 2010, will deliver 27.5 bcm/yr and be built by a consortium of Russia's Gazprom and two German companies. There are plans to eventually double the capacity to 55 bcm/yr (Gorst 2006).

The NEGP may leave capacities available in the Ukranian route to Europe. Such unused capacity may attract gas from the Caspian—either via Turkey, which has considerable oversupply, or from Turkmenistan, which currently supplies gas to the Ukraine.

4.3 Nabucco

A consortium of five companies (Nabucco) have proposed a pipeline to transport gas from Iran and the Caspian region through Bulgaria, Romania and Hungary and terminating in Austria. It is expected to start operations in 2011 with a capacity of up to 32 bcm. It would open a fifth supply corridor to Europe after Russia, Norway, Algeria and LNG. As such it poses potentially significant competition to Russian supply, Gazprom and the NEGP project. Gazprom competition poses a significant obstacle to these projects (Landia et al. 2006). Gazprom has been negotiating contracts to buy Turkmenstan gas to circumvent this potential competition. Kazakhstan also has ambitions to become a gas exporter (Gorst 2006).

4.4 Other options

Expansion of LNG terminal capacity at Barcelonia in Spain (12.3 bcm) is near completion. There appear to be a number of other LNG terminal projects proposed to 2012 in Europe on which little detail is available, but possibly with as much 50 bcm/yr capacity (Landia et al. 2006).

4.5 Summary

Norway's Ormen Lang, NEGP and Nabucco pipeline projects propose 112 bcm of new capacity by 2010. The possible LNG projects amount to about another 108 bcm to 2012, giving a total of 220 bcm of new import capacity to Europe by 2012 against Landia et al's possibly high estimate of 240-250 bcm/yr by 2015. Up to 20 bcm/yr more natural gas would be required as feedstock to LNG plants around the world. The investment required is massive. Higher gas prices are inevitable for these targets to be achieved. In the short-term supply shortfalls in Western Europe, especially in the UK, will drive higher gas prices. *Is Landia et al's projected 2.4 per cent production growth too high in these circumstances?*

But before addressing the global natural gas supply position we will discuss the roles of Russia's Gazprom and of natural gas consumption by the electric power industry.

5. GAZPROM

Gazprom is majority owned by the Russian State. The company owns and operates Russia's entire 50,000 km natural gas trunk line network, controls the bulk of gas reserves and 86 per cent of production, and is the world's biggest gas exporter (Hill 2006). Control over transport helps the company fend of competitors seeking to erode its domestic monopoly over production and marketing. Export pipelines to 21 countries are for Gazprom's use only. Gazprom has global aspirations in gas markets.

But control comes at a cost. Projects to expand and maintain the gas network account for 45 per cent of Gazprom's annual capital investment. The gas giant is planning a major expansion of its export system and expects pipeline projects will account for the bulk of its spending until 2010.

Early this decade Gazprom built Blue Stream, a 1,210 km pipeline under the Black Sea to Turkey. Blue Stream was built in a hurry in an effort to capture the Turkey market before its competitors from Caspian countries and elsewhere arrived on the scene, some with US backing (Gorst 2006).

Gazprom announced plans early in 2005 to start applying “market principles” in its gas dealings with the states of the Commonwealth of Independent States (those arising from the collapse of the Soviet Union). Buyers would have to pay European prices for gas and settle all the bills in cash rather than by barter. Gazprom also pledged to increase and monetise its payments for use of gas-transit pipelines crossing various CIS states, including the Ukraine and Belarus.

But the implementation of the reform late in 2005 was heavy handed. Gazprom demanded that the Ukraine pay up to $230/’000 c. metre in 2006 compared with $50/’000 c. metre in 2005. The old rate was a legacy of the Soviet era. The dispute was perceived to interfere with gas supply in the middle of a cold winter and had repercussions throughout Europe. A complicated truce was rapidly reached. The prices of expensive Russian gas and cheaper Turkmenstan supplies were blended to bring Turkmenistan gas to the Ukraine frontier for five years at a more affordable price through a pipeline owned by Gazprom and assistance from a bank in Austria. The gas will be delivered to the Ukraine at $95/’000 c. metre. Gazprom has agreed to pay the Ukraine higher gas transit fees.

The deal is contingent on co-operation from Turkmenistan. Gazprom’s gas purchases will rise to 80 bcm/yr over 20 years, absorbing almost all the Central Asian republic’s export surplus. Gazprom’s customers in the Caucasus have agreed to pay Gazprom more for Russian gas in 2006, but still far behind European levels.

Russia’s image has been badly damaged by the dispute. Buyers in Gazprom’s most profitable market were shaken by the first serious threat of a supply cut in over 25 years of Russian gas trading. The wisdom of relying on one source for such a large proportion of supply is being questioned (Gorst 2006a).

Gazprom desires to exert more influence through the supply chain, including into LNG and the European retail markets (Hill 2006).

6. GAS AND ELECTRIC POWER

Over 100 gigawatts (GW) of new gas-fired power stations are being planned or are being built across Europe, according to Platts global energy service (Petroleum Review 2006c):

- 20,300 MW of combined cycle gas turbine (CCGT) is under construction in Western Europe.
- A further 20,000 MW are approved to proceed.
- 70,000 MW are proposed or applying for permits.
- In the UK over 15,000 MW of new gas plant is being planned. A similar amount is also being planned for Eastern Europe.

Over the last two years nearly 24,000 MW of CCGT plant has come on line across Western Europe. CCGT capital costs are roughly half the cost of clean coal and less than a third of new nuclear. The risk for gas plant is in the fuel cost, but it does seem that developers are more relaxed than politicians on the future price and availability of gas. Perhaps the events of the last year may lead to a change of thinking.

6.1 UK electric power

About 40 per cent of UK generation capacity is coal-fired, 40 per cent gas fired and 20 per cent is mostly ageing nuclear plants. About 35 per cent of the UK’s electricity is generated through gas-fired plant (Petroleum Review 2006c). The UK was self-sufficient in coal in 1987 (BP 1992), but production had halved by 1995, when 25 per cent of coal consumption was imported. In 2004 coal consumption of coal had fallen slightly on 1995 but production was only one-quarter of the 1987 level and imports had grown to 72 per cent of consumption (BP 2005). This fall was an outcome of the Thatcher government's confrontation with the coal miners in the mid 1980s. Coal is almost exclusively used for electric power generation and for iron and steel production.

The electric power industry must now consume a large portion of UK gas consumption.

The UK's old Magnox nuclear power stations are due for decommissioning in 2010 (Price 2006). Nuclear power is discussed in a wider context below.

6.2 Russian electric power

Following the fall of the Soviet Union in 1991, the Russian economy slumped and the demand for gas and electricity fell. Economic recovery since the late 1990s has led a steady growth in demand. However, years of neglect have affected the infrastructure of the Russian electricity industry to the point that without private investment, a lack of capacity may effectively place a cap on further economic growth. Power stations are reaching the end of their useful lives on a significant scale.

One company in the Russian Federation, RAO UES (Unified Energy System), accounted in 2004 for 72 per cent of installed generation capacity, 69 per cent of power production and 71 per cent of end-user sales. The Russian state owns 52.7 per cent of RAO UES while Gazprom owns 10.3 per cent. A subsidiary owns the high-voltage grid. The Ministry of Nuclear Energy owns the nuclear power stations. The main network is in Russia with lesser independent systems in Siberia and the Far East. Plans to privatise many of these assets, except nuclear power plants and the high-voltage network, are on the agenda for this decade. This includes breaking up RAO UES into separate generation, transmission and distribution companies and increasing competition in generation.

Almost half of the country's nuclear reactors are within five to 10 years of completing their useful lives and will need to be replaced—presumably this applies also to the Ukraine's nuclear power plants. *Russia plans to double its nuclear output by 2020 in order to decrease its dependence on natural gas (Hill 2006).*

FSU coal consumption halved between 1987 and 1998 with only a minor increase since then. The decline of natural gas consumption to 1998 was proportionately less and is now almost back to its 1987 level (BP 2005). *This suggests there has been a significant shift to natural gas for electric power generation since 1987*.

Hydro is also a priority with RAO UES earmarking $14 billion for new plants in Siberia and the Far East, which are currently energy-deficient (Hill 2006). FSU nuclear power is discussed in a wider context below.

7. WORLD NATURAL GAS

The discussion above reveals a rapidly emerging natural gas supply crisis in Europe as consumption there continues to rise and production to fall. The prime solutions, discussed above, are for increased imports from Russia followed by more LNG from other continents. The shortfall could be circa 150 bcm/yr in 2010, depending on how fast production declines and the consumption growth rate. A similar situation has been emerging this decade for natural gas in North America where production is poised for a steep decline. These two regions between them consume over 70 per cent of the world's natural gas.

Natural gas comes from both stand-alone gas fields and from associated gas in oil fields. Marketing of gas began in the USA during World War II after the invention of welded steel pipelines made long-distance transport of gas possible. Before that natural gas was regarded as a nuisance and flared at oil well sites with few records kept. Flaring is now kept to a minimum.

But historical gas production and discovery records are still poor. Some gas is re-injected into oil wells to assist in oil production—some may be extracted again for sale. Some "wet" gas may have light liquid hydrocarbons removed for separate sale and the remaining smaller volume sold as "dry" gas. Often raw natural gas will contain nitrogen or carbon dioxide. Some published data accounts for some of these factors (e.g. the USA), but a lot do not so that the statistics are not consistent or reliable, especially for reserves. Many countries lack transparent reporting regimes and very few qualify their statistics to account for these variations. Some gas discoveries included in reserves may be "stranded"—too far from pipelines to be marketed at an affordable price.

Finally, estimates of the *most probable* volume of extractable gas (and oil) are not made on a consistent basis. Some countries under report, some over report reserves. This is probably the case for FSU oil and gas where published reserves may be overstated by as much as 30 per cent. The BP Statistical Review of World Energy publishes the high figure for the FSU. The Middle East reserves figure may also be overstated. These issues are discussed below. *It is often politically convenient for countries and companies to maintain this lack of transparency.*

A paper by Jean Laherrére (2004) to the Association for the Study of Peak Oil's conference in Berlin, May 2004, discusses these issues at length for world gas and the principal producing regions. www.peakoil.net/iwood2004/pptBerlin/Proceeding.html

7.1 The World

Table 6 lists gas reserves, production and consumption in 2004 for the major regions of the world (BP 2005). Note the concentration of reserves in the FSU and Middle East. North America and Europe consume 47 per cent of world gas but only have seven per cent of notional reserves.

TABLE 6
WORLD GAS RESERVES, PRODUCTION & CONSUMPTION 2004
Billion cubic metres

Region	Reserves		Production		Consumption	
			Volume	Per cent	Volume	Per cent
North America	7,300	4.1	763	28	784	29
Central & Sth America	7,100	4.0	129	5	118	4.4
Former Soviet Union	58,100	32.5	733	27	625	23
Europe	5,400	3.0	318	12	483	18
Middle East	72,800	40.6	280	10	242	9
Africa	14,100	7.8	145	5	69	2.6
Asia Pacific	14,200	7.9	323	12	368	14
World Total	**179,000**		**2,692**		**2,689**	

North American reserves data are more transparent and reliable than most and are for "dry" gas. "Wet" gas production would be higher. All supply is from production internal to North America except for a small but growing quantity of LNG imports. The region has consumed over 70 per cent of its discovered gas and is on the threshold of a steep fall in gas production, like Europe. This paper will not discuss natural gas for the Americas any further, except where it relates to LNG imports.

Africa supplies gas to Europe and the USA and will be discussed below in that context. Iran and Qatar allegedly contain about 60 per cent of Middle East gas reserves *in one gas field straddling the Persian Gulf.* The reserve estimate for this field is based on very sparse information and could be overstated. The Middle East could become involved in supplying the Europe/FSU region post 2010. The Asia/Pacific region is too far away from Europe to be of relevance.

Gas statistics for Europe are reasonably transparent and reserves data is reliable compared to many other parts of the world and has been discussed above. *The major data uncertainty for Europe is for the FSU.* World gas reserves could be significantly less than shown in Table 6.

7.2 Former Soviet Union

Russia produces 80 per cent of FSU gas and has 83 per cent of the reserves (BP 2005). We will concentrate on Russia and my comments will be based on Laherrére (2004), figures 52 to 63.

At the 1979 World Petroleum Congress Khalimov described the method of reserve classification under Soviet rules. A correlation with western methods could not be found. The main fault is that Russian reserves are based on the maximum theoretical recovery factor, viz what reserves would be if there were no economic, environmental or technology constraints. These are considerable as the major Russian gas fields are located in the sub-Arctic reaches of the Ob River basin, east of the Ural Mountains. These countries still use this method.

Laherrére (2004) plotted annual production against cumulative production for the four largest Russian fields[2]. He showed that ultimate production could be about 70 per cent of that forecast by the Russian method (Figures 56-60). These four had peaked at various times some years ago at a total of 590 bcm/yr. In 2004 they only produced 380 bcm, but together comprised 65 per cent of Russian production. Clearly these fields are at a mature stage. He shows in figure 63 a similar forecast for Russia by Zittel. This plot shows profiles of individual producing and discovered fields with the four super giant gas fields in decline and a growing number of smaller ones not yet producing (Figure 63). These suggest a Russian gas peak around 2015 at a slightly higher level than in 2004.

Equivalent data by field for other FSU countries could show similar patterns. However, the performance of Russian gas fields will dominate the outcome of FSU gas production and the onset of decline. Long gas pipelines require substantial field reserves and lives of 20 or more years to justify the investment.

Laherrére (2004) also found that delays until this decade in posting past data obtained during the chaotic 1990s economic environment and that were not backdated gave an exaggerated reserve figure for 2004 (Figure 52). He backdated reserve revisions to the years of initial discovery *and* applied the 70 per cent reduction to the exaggerated figures (see the last paragraph) He found the FSU's most likely reserves in 2004 were reduced from 54,000 bcm to 30,000 bcm (Figure 53). This is about half the figure in Table 6 from BP Statistical Review of World Energy 2005.

Cumulative FSU consumption to 2004 was 22,000 bcm (Figure 61), giving an ultimate production of about 53,000 bcm without additional gas discoveries. Cumulative production could reach about 30,000 bcm by the middle of the next decade, close to 60 per cent of ultimate. Decline would be imminent. *There is an implied need for accelerated investment in an increasing number of smaller gas fields to maintain and expand production.*

Is this the compelling reason for Gazprom pursuing an aggressive agenda to raise gas prices for exports to countries like the Ukraine and Belarus? Is this why Russia plans to double its nuclear power plant capacity by 2020 to reduce its dependence on electricity from gas turbines? Taxes on oil and gas production provide over half the Russian government's revenue.

Some Russian gas in East Asia is being developed for export to China and Japan. This is probably the least explored part of the country. A pipeline from Russia's Central Siberian gas fields to East Asia is also being explored. This would increase Russian bargaining power with its gas customers.

We have not heard the last word on Russian gas reserves. The few original super giant fields are now in decline. Russia's government uses its natural gas as a political asset when dealing with its neighbours and shows no inclination to be more transparent regarding reserves and gas field performance.

---

[2] After production decline begins this plot is a downward trending straight line. Its intersection with the horizontal axis gives an indication of the likely ultimate gas extraction (or oil as the case may be).

Beyond 2020 there may be natural gas development from offshore in the Arctic Ocean. Work would have to begin about 2010. But this means extreme and costly technical challenges in developing and operating gas platforms in ice-bound seas. Gas will no longer be cheap. Pipelines to central Europe are 4,000 km long.

7.3 Liquid natural gas

Table 7 shows the status of projected LNG capacity for 2004-2010. Sales of 178 bcm were made in 2004, seven per cent of all gas. Over 60 per cent was traded in the Asia Pacific region, mostly to Japan and South Korea from Indonesia, Malaysia, Australia, Brunei and the Middle East (Qatar, Oman and the UAE). Algeria and Nigeria supply LNG to Europe and the USA. Carribean countries and Algeria were the main LNG suppliers to the USA (BP 2005).

About 15 per cent additional gas is needed as fuel in these LNG plants and the final marketable gas in the receiving countries will be 12-15 per cent less as some of the gas will be burnt for re-gasification of LNG at the terminals.

TABLE 7
LNG EXPORT CAPACITY 2005-2010
Billion cubic metres per year

Country	2004 actual	2006 est.	2008 est.	2010 est.
Algeria	26	26	26	30
Nigeria	13	18.5	29.5	44
Egypt	---	2	8	15
Indonesia	33	33	43.5	53
Malaysia	28	28	28	37
Brunei	10	10	10	10
Australia	12	16	16	28
Qatar	24	29	52	95
Oman	9	14	14	14
United Arab Emirates	7	7	7	7
Yemen	---	---	9.5	9.5
Russia – Far East	---	---	13	13
Trinidad & Tobago	14	14	14	14
Others	2	2	4	6
Total	**178**	**200**	**274**	**365**

Generally companies do not commit to LNG projects until sufficient long-term contracts for sales have been negotiated. Estimates in Table 7 for 2006 are for plant already commissioned or under construction. Estimates for 2008 are mostly for plant now under construction, and where tenders are let or about to be called. Estimates for 2010 are for projects still in the planning and sales contract negotiating stages and are more speculative (Quinlan 2002, Gavin 2005, Gorst 2005, Quinlan 2005, Clark 2006, Daya 2006, Petroleum Economist 2006). A corresponding increase in LNG receiving terminal capacity, LNG tankers and new gas field development is needed as well. All these projects are very capital intensive.

This is a doubling of LNG capacity to 2010. The principal markets for this *new* LNG capacity are in Europe and the USA where natural gas production is declining. The USA can import LNG from all these major suppliers, but with long trans-Pacific/Atlantic Ocean hauls. The US also faces strong opposition to the building of new LNG terminals that will restrain its LNG import potential. New markets are developing in China and India, the scale of which is as yet unclear, but potentially significant. *Before discussing the realism of these aspirations we need to discuss other constraints.*

Matthew Simmons[3] has doubt about the potential of the field shared by Iran and Qatar, which holds the world's largest gas reserves[4]. "They've drilled only 25 holes in a tiny section in Qatar's North Field, and one has come up dry. That's why they announced a moratorium on further gas projects last April." Reservoirs on the Iranian side are complicated, which is why development of South Pars has stalled (Petroleum Economist 2006a).

US-based consultants Poten & Partners say the cost of constructing LNG units has been rising—partly as a consequence of higher prices for raw materials and partly because the world's LNG construction specialists are overwhelmed with orders (Petroleum Economist 2006b).

A driver of the worldwide boom in LNG projects from the late 1990s has been falling construction costs. Larger train capacities (economies of scale) and other engineering developments had made LNG more competitive with pipelines with some project costs at less than US$200 per tonne a year capacity. However, more recent contracts have been in the US$250-350t/yr range. Also the price of steel has doubled since early 2003 and nickel has nearly doubled. *These material prices also impact upon the cost of new pipelines and tankers.* There are only three big contractors for LNG units who typically completed only one or two trains until 2003. Completions are due to peak at 10 trains in 2009.

A substantial increase in construction capacity is needed to meet demand. *This suggests the LNG capacity targets for later in the decade may not be achievable.*

Likewise there is a massive increase in LNG shipping under way. The number of active LNG carriers increased from 154 in January 2004 to 175 two years later. Last year the world order book increased from 56 to 107 (~US$200 million each) and the size of tankers is increasing. There is a similar rise in demand for offshore drilling rigs with steeply rising hire charges for some, such as deepwater rigs.

On gas fields, Matthew Simmons says: "Every deep-water rig is at work, but it takes two or three years to test a block. If we had 300 rigs we could do it. But we only have 50 and the next ten will cost US$0.6-0.9 billion apiece—because shipyards are busy building container ships, LNG vessels and VLCC's …". He does not envisage new rigs being built before 2015, by which time rig hire charges will have soared from US$300,000 a day to close to US$1,000,000 a day (Petroleum Economist 2006a).

The petroleum industry has an acute shortage of experienced professional exploration and production staff, and many are approaching retirement age. A new generation of young professionals is not emerging in the numbers required. The fall in oil and gas prices from the mid 1980s led to companies shedding staff and a slump in new graduates from universities (Nicholls 2006). Shortages of key staff may limit the expansion plans of the industry.

The sale price of new natural gas is going to rise—and already is in Europe and the USA. Add in rising oil prices and we have a climate for "demand destruction". For Europe this *may* shift the balance to new gas pipelines from FSU countries. But the geopolitical risks cannot be ignored. Diversity of sources of gas supply sources is important, a dilemma that European countries now face following the events with gas supply from the FSU last winter.

8. NUCLEAR POWER

Both the UK and the FSU face decommissioning a significant proportion of their nuclear power plants from 2010—see the paragraphs under Gas and Electric Power above. Both propose

[3] Matthew Simons is the founder and chairman of Simmons & Company, an energy investment company in Houston Texas servicing the energy industry, particularly for upstream oil and gas.
[4] Reputedly half of the Middle East's gas reserves, or 15-20 per cent of world reserves.

building new nuclear power plants to replace these, and more. Combined cycle gas turbine capital costs are roughly half the cost of clean coal and less than a third of new nuclear (Petroleum Review 2006c). There will be the additional costs of cleaning up and isolating these old plants. This would be the first significant decommissioning of nuclear power plants in the world.

Britain's Nuclear Decommissioning Authority says in a report published last year that the cost of decommissioning and site clean-up, including for the Sellafield nuclear fuel processing site, had risen to A$136 billion over 25 years, a rise of A$29 billion (West Australian 2006). Russia and the Ukraine produce nearly three times the electricity from nuclear plants than does the UK (BP 2005). In the FSU clean up costs could be at least A$300 billion if properly carried out.

In March, Britain's Sustainable Development Commission suggested in a report that uranium supplies could struggle to meet even a modest projected increase in global demand from 65.000 tonnes now to 76,000 tonnes in 2025. The report suggests supply will not fully meet demand over the next decade and the annual shortfall may reach 10,000 tonnes by 2015 (Price 2006).

The problem is partly that 40 per cent of uranium supply comes from secondary stocks—1970s stockpiles, fuel from decommissioned weapons and tailings. The stockpiles are starting to run out and the report suggests their exhaustion by 2010. In the 1990s, the market price fell below $US20 a kilogram. Since 2004, prices have risen to above $US70. While this price should stimulate the exploration, location and production of new supplies, that process could take more than a decade.

Without new supplies, the report suggests that supplies of uranium recoverable at below $US40 per kilogram will be exhausted by 2025 and supplies recoverable at less than $US80 a kilogram by 2035. Uranium exploration is a high-cost, high-risk business. What might happen to the economics of nuclear power if the price of uranium were driven into the $US70 to US$130 range, due to factors such as supply interruptions or higher average extraction costs?

One could also add; what will happen to uranium prices from the emerging higher costs of oil and gas as inputs to its extraction and processing into nuclear fuels? And to the costs of building new plants, decommissioning nuclear power plants, clean up of their sites and disposal of radioactive wastes? *The nuclear power industry is firmly embedded in the fossil fuel industry, in particular the oil and gas industries.*

9. NET ENERGY IMPLICATIONS

In my first submission, in Sections 3 and 7 and in Appendices 1 and 4, I discussed economics from an energy quality viewpoint and the economics of energy projects from a net energy yield viewpoint, viz. the direct and indirect energy input required to produce a gross energy output. The difference, the net energy yield is what matters. The outlook for world oil supply suggests increasing energy inputs relative to the gross energy output.

The same outlook is emerging for natural gas in North America and Europe/FSU, if anything with greater intensity due to the more capital-intensive nature of natural gas infrastructure, the faster decline rates that can be expected and the high cost of gas transport. There are additional implications for gas-fired turbines for the electric power industry as well.

Oil comprises 36 per cent of world commercial energy consumption and natural gas 23 per cent (BP 2005). This suggests the urgent necessity for energy demand management and a general reduction in the intensity of energy use in a structured way. *Is the net energy yield of high quality petroleum fuels now declining even though the gross energy output may still be increasing?*

The majority of nuclear power plants are in North America and Europe/FSU with the older plants now facing decommissioning, site clean up and quarantining of nuclear reactors for decades. These are ongoing energy intensive tasks and are a call on future high quality commercial energy.

And the problem of disposal of nuclear wastes is not yet resolved. The construction of new nuclear power stations and expanding the nuclear fuel supply are also very energy intensive industries, the latter certain to increase as high-grade uranium ores are depleted.

Will expanding of the nuclear power industry now be a liability?

10. CONCLUSIONS

The cost of transporting natural gas any distance is six to 10 times greater than for oil and constrains its production profiles to extended plateaus, in contrast to oil. Decline usually sets in late in the cycle of production of extractable gas, and can be steep. Consequently production and consumption is mainly confined to continental markets with limited global trade.

Europe and the former Soviet Union (FSU) is one such continent. Rapid decline has commenced in the UK and should extend to the rest of Europe by the end of the decade and possibly to the FSU by 2020. The FSU's official reserves for natural gas are significantly over-stated because of a too optimistic definition of reserves and deficiencies and delays in reporting data during the economic confusion of the 1990s. There is a lack of transparency. Europe is not well prepared for the supply crisis.

The world database for natural gas is poor through inconsistent and inadequate reporting. Some gas is flared and past reporting of this is poor, some is re-injected into oil fields and may be extracted for sale at a later date, some has liquid hydrocarbons removed and may contain other inert gases. There is a lack of transparency and public auditing of data in many countries. The most unreliable are the FSU and Middle East countries who have 65-75 per cent of world gas reserves. The most reliable statistics are from the OECD countries. World gas reserves could be overstated by as much as 25 per cent, principally in the FSU and Middle East.

Europe imports piped gas from the FSU and Algeria and as LNG from North Africa. Projects are planned and underway to increase these imports. In 2004 Europe consumed 17 per cent of world gas production and the FSU 24 per cent. North America is another continent on the threshold of rapid production decline. It consumes 29 per cent of world gas production, with minor but growing imports of LNG. North American natural gas is not discussed in detail in this paper. China and India are on the threshold of becoming significant importers of natural gas.

Significant pipeline projects are underway or proposed to bring more gas to Europe from the FSU and to better connect Europe to Norwegian gas fields in the North Sea. Russia's Gazprom, majority owned by the government, dominates FSU gas production and transport both internally and externally. Gazprom has a strategy to progressively lift its gas prices to FSU countries towards the levels it charges its European customers.

UK electric power generation is fueled by natural gas (35 per cent), coal (45 per cent) and nuclear (20 per cent). The UK has ceased to be an exporter of oil and gas will become a significant importer of both by the end of the decade. The UK also imports 72 per cent of its coal consumption. Old Magnox nuclear plants will be decommissioned in 2010. *The UK faces a major energy supply crisis with escalating gas, oil and electric power prices leading to adverse economic consequences.*

Europe is at the beginning of a 100 MW expansion of gas turbines for electric power generation. The FSU is also a significant user of natural gas for electric power generation and plans to double its nuclear power capacity by 2020 as well as decommission many ageing nuclear power plants.

The declines of natural gas production in North America and Europe together with anticipated imports from China and India has triggered a projected doubling of LNG export capacity from 2004 to 2010, including LNG plants, receival terminals and LNG shipping. Company commitments to post 2008 projects may be constrained by rising costs for raw materials, e.g. steel and nickel, and the inability of the limited number of specialist design and construction companies to handle the volume of work. The same rising cost problem extends to upstream petroleum exploration and development and to gas pipelines. *The sale prices of natural gas are rising.*

Decommissioning of nuclear power plants is about to take place in the UK and the FSU. Both countries plan to expand their nuclear power capacity *at the same time.* Large investments will be required in decommissioning, cleaning up of hazardous wastes and their safe disposal. *The rising costs of oil and gas will inflate all these costs, including for new nuclear plant.* Expansion of the nuclear power industry is being advocated in the USA where similar constraints exist.

Like the petroleum industry, the nuclear industry has an ageing technical work force approaching retirement with few experienced professional staff emerging to replace them.

Finally, the nuclear power industry has been feeding on uranium stocks from the 1970s and from dismantled nuclear weapons, with limited supply from mines. These stocks are running out, leading to escalating prices high-grade uranium ores are limited. A significant petroleum input is used in mining and processing uranium ores, waste disposal and management. *The cost of uranium is also going to rise in real terms.*

The net energy yield per unit output of petroleum fuels is almost certainly contracting. The industry is starting to run faster to stand still.

The realism of the visions for growth in nuclear power capacity must be questioned, given its dependence on high quality fossil fuels. *The nuclear power industry is thoroughly embedded in the fossil fuel industry and dependent on it.*

11. REFERENCES

BP Statistical Review of World Energy: 1992, 1997 and 2005.

BP 1992, *BP Review of World Gas*.

Clark, Martin 2005, *Destination Pluto,* Petroleum Economist, September, p. 23.

Daya, Ajeslia 2006, *Positive outlook—for now,* Petroleum Economist, March, p. 13.

Gavin, James 2005, *Doha takes a breather,* Petroleum Economist, November, p. 18.

Gorst, Isabel 2005, *Gazprom targets the US,* November, p. 21.

Gorst, Isabel 2006, *Ringing Europe with gas lines,* Petroleum Economist, February, p. 11.

Gorst, Isabel 2006a, *Gas-price spat alarms Europe,* Petroleum Economist, February, p. 10.

Hill, Andrew 2006, *Changes afoot in Russian electricity and gas markets,* Petroleum Review, February, p. 20.

Laherrére, Jean 2004, *Future of natural gas supply,* Association for the Study of Peak Oil 3rd Annual Conference, Berlin 2004. http://www.peakoil.net/iwood2004/pptBerlin/Proceeding.html

Landia, Alexander, Adams, Julie, Doerler, Joerg 2006, *Replacing indigenous supplies in European gas markets,* Petroleum Review, February, p. 36.

Nicholls, Tom 2004, *Gas import plans take shape,* Petroleum Economist, February, p. 12.

Nicholls, Tom 2006, *The big crew change*, Petroleum Economist, March, p. 3.

Petroleum Economist 2006, *Liquefied natural gas*, March, p. 36.

Petroleum Economist 2006a, *The Back Page: Matthew Simmons. Cassandra of the energy industry, March p. 48.*

Petroleum Economist 2006b, *Construction costs move upwards,* March, p. 36.

Petroleum Review 2006a, *Latest UK production figures,* March, p. 5.

Petroleum Review 2006b, *Gas spikes mark 2005,* March, p. 9.

Petroleum Review 2006c, *New gas-fired power plans in Europe,* March, p. 11.

Price, Greg 2006, *Lies & statistics,* Australian Financial Review, 1-2 April, p. 63.

Quinlan, Martin 2002, *Growing gas-import market,* Petroleum Economist, November, p. 25.

Quinlan, Martin 2005, *Warnings on limits to growth,* Petroleum Economist, November, p. 8.

Skrebowski, Chris 2006, *Squaring up to industry challenges,* Petroleum Review, March, p. 2.

West Australian 2006, *Britain's N-plant clean up costs rise*, 1 April, p. 37.