The State of Natural Gas

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Abstract

As global energy demand rises, natural gas now plays an important strategic role in energy supply. It t is more difficult to transport and store gas than oil and consequently it lagged behind that commodity for a considerable period. Over the last couple of decades this has changed and gas markets continue to expand more rapidly than those of other fossil fuels.

Natural gas is the cleanest and most hydrogen-rich of all the hydrocarbon energy sources and it has high energy conversion efficiencies for power generation. Of more significance is that gas resources discovered but as yet unexploited remain plentiful. The sector is poised for considerable growth over the next two decades and some believe that it may even overtake oil as the prime fuel between 2020 and 2030.

In previous papers we have suggested that the trend towards natural gas becoming the premium fuel of the world economy is not reversible. The key and the challenge for the energy industry is how that transition is to be managed. We examine in this paper sources of natural gas, their limitations and potential. We also identify the technological and commercial challenges to be overcome in taking the world through the transition. There is a fundamental turn towards natural gas which today accounts for about 23% of the world energy demand. Large capital investments in infrastructure to enable increased gas consumption are being made on both demand and supply sides. Several gas-producing countries have embarked upon very ambitious plans for markedly increased gas output. Many new LNG facilities are being built supply chains diversifying and becoming ever more flexible.

Other gas conversion technologies such as GTL and CNG are attracting more serious attention, but energy efficiency, cost and cost inflation remain barriers for these promising alternatives. Natural gas is also competing strongly with other fossil fuels from an efficiency and emissions perspective as the fuel of choice for power generation. However, gas price volatility and security of supply concerns means that some power generators still favor coal and nuclear components in their power generation portfolio. As the cost of carbon emissions have a bigger impact around the world, gas has the potential to increase its share of the power generation market significantly over the coming decade. A rapid growth opportunity exists for natural gas in its potential contribution to transportation either directly or by electrifying the sector. Real and imagined environmental concerns and restricted access for OECD nations to long-term oil reserves are expected to accelerate the emergence of hydrogen fuel cells. Currently available technologies dictate that the most commercially viable source of hydrogen in large quantities is natural gas, particularly methane through the reforming processes that yield synthesis gas (i.e. carbon monoxide and hydrogen). Current technologies, investments and consumption trends suggest that natural gas will be at the center of a worldwide transformation resulting in a greatly expanded market share of gas in the energy mix for power generation, space heating, petrochemical feedstocks and transportation fuels.

(Note: Because of the multi-disciplinary background of the various components of natural gas technology and science, units are quite diverse and at times difficult for practitioners to reconcile.

In the Appendix, a table provides conversions of the most common units used in the various industries, including those addressing volume, weight and energy content.

The Great Energy Dilemma

An adequate energy supply is vital to national economic development and political well-being. Figure 1 shows the unambiguous relationship between per capita oil consumption and wealth. Yet, few issues have degenerated into more ideologically driven misinformation than energy. This situation transcends nations and has become a worldwide conundrum.

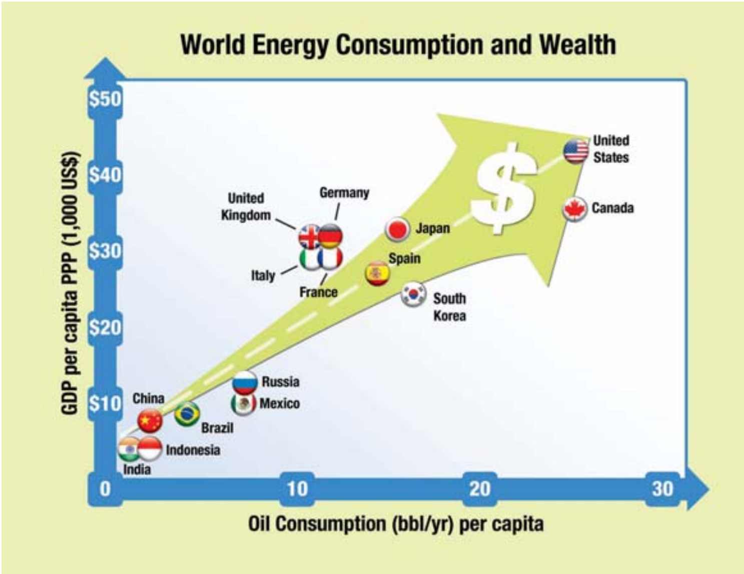

Figure 1The connection between energy supply and wealth (raw data source: US Energy Information Administration, EIA, 2008)

The commercial advantages associated with energy consumption are one reason why governments struggle to limit energy consumption or radically change regional primary energy mixes. The most commercially attractive energy sources usually prevail in most markets, which suggests that current initiatives to promote renewable energy sources around the world on environmental grounds alone remain likely to fail. For such alternatives to be adopted in the longer term they need to demonstrate that they have commercial advantages to consumers, either on a level playing field or through artificially imposed carbon pricing.

Of course, nations want and need to diversify their energy supply so they are less reliant on any one energy provider or source. But it is unacceptable for political leaders, various interest groups and the media to ignore the economic and logistical problems in pursuit of unachievable goals such as “Energy Independence” or a “Fossil Fuel-less” society. More than lip service needs to be given to the huge costs to make the changes proposed and the miniscule odds of achieving such expansive ends no matter how much is spent.

Fossil Fuels Past, Present, Future?

Coal was the fuel of choice in the nineteenth and early twentieth century, but was gradually superseded by oil right after World War II. In the past three decades natural gas has slowly but progressively increased its share of the energy mix. These three fossil fuels account for more 85%

of the world's primary energy. And this has not changed over time (See Figure 2). Other energy sources (nuclear, hydro and renewables) play a far smaller role by comparison.

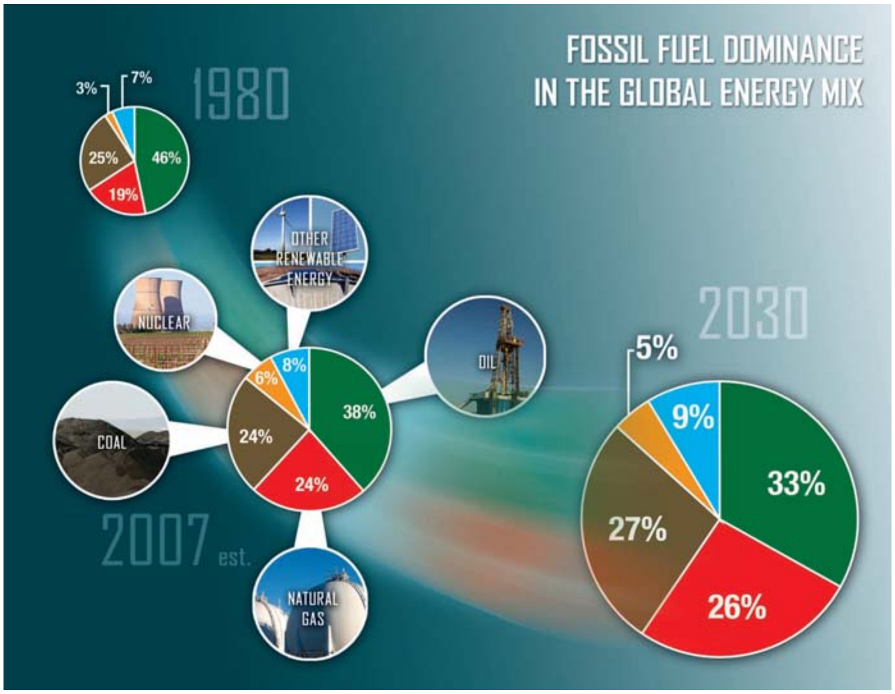

Figure 2 The World energy mix, past, present and future (raw data source: US Energy Information Administration, EIA, 2008)

Thirty years ago, when worldwide energy demand was 60 percent of current levels, fossil fuels were the source of nearly 90 percent of the world's energy supply. Today, the Energy Information Administration of the U.S. Department of Energy (EIA, 2008) forecasts that this is not likely to change in the future, with 86.5 percent of the total energy mix coming from fossil fuels in 2030 despite – or perhaps because of – an expected increase in total energy demand of 62 percent by then. However, many question whether such growth and energy mix is sustainable both in environmental terms and with the remaining fossil fuel reserves much beyond 2030 (Wood et al. 2007).

In spite of programs going back more than 30 years that have subsidized alternative forms of energy at substantial costs to consumers, fossil fuels will still represent more than 85% of the world's primary energy mix. Why is it proving to be so difficult to reduce this dependency, even when energy consumers have to cope with prices of oil, gas and coal exceeding $100/ barrel, $10 / mmbtu and $150 /tonne in many parts of the world in early 2008? One first must consider fossil fuels' advantages.

Fossil Fuels' Advantages

Fossil fuels have advantageous properties enabling them to store and deliver large quantities of energy more effectively and consistently than current alternative energies. (We recognize of course the recent push towards reducing carbon dioxide emissions, a debate which has found many energy experts divided as to its merits.)

One advantage is abundance. Coal is one of the most abundant energy resources, with supplies capable of meeting electricity needs for more than 250 years. And despite current high prices for oil, it is not likely to run out any time soon. Geopolitical factors, including production quotas, civil disturbances and lack of investment among some major petroleum exporting countries and supply bottlenecks in major importing countries, have fed recent price increases alongside sustained demand growth in the developing world.

This abundance produces a second advantage – price. Ethanol, for example, continues to cost significantly more than gasoline on an energy equivalent basis despite large tax credit for its production (Yacobucci, 2006, Herbst, 2007.) Coal remained half as costly as nuclear for electricity generation up to late 2007, the three-fold price increase in coal responding to shortages in China during the cold 2007/2008 winter are expected to be short-term. Wind and solar are too intermittent to serve as base-load power generators, and cost two to five times as much per kilowatt hour of electricity generation when reliability, maintenance and back-up supply costs are factored in.

Fossil fuels, in particular natural gas and oil, have enormous versatility, as Figure 3 illustrates. Byproducts from fossil fuels not only help defray their costs as a fuel but make fossil fuels essential to a wide variety of nonfuel petrochemical industries. Only biofuels can provide similar byproducts.

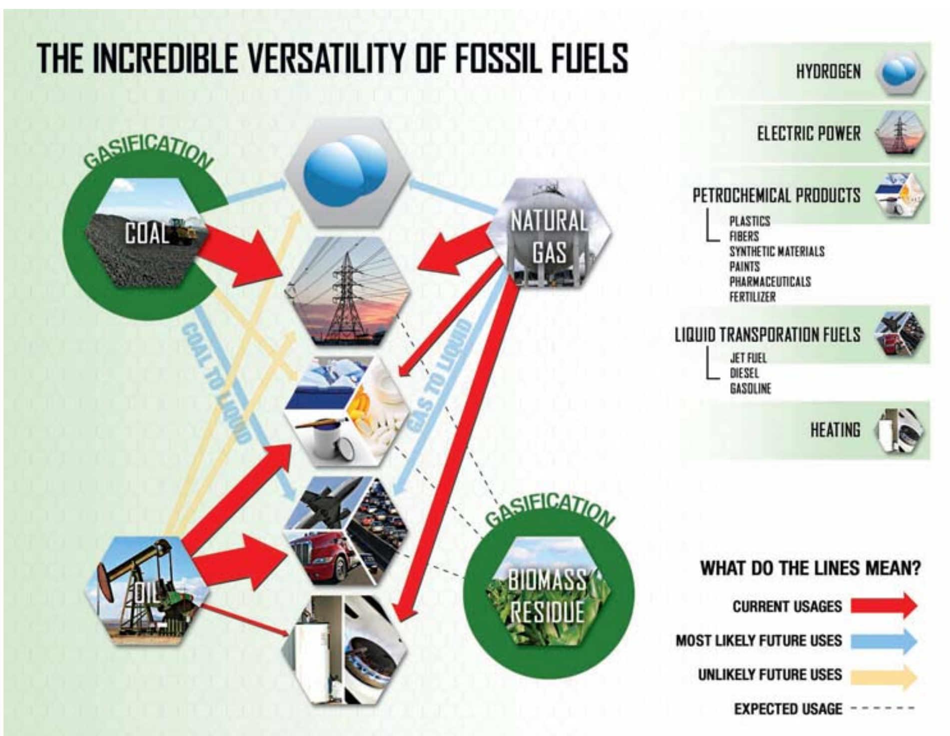

Figure 3 The versatility of fossil fuels

But another factor in the inequality of fuels is that they are not easily interchangeable.

Energy Interchangeability versus Inflexibility

Fossil fuels such as oil, natural gas and coal can be used interchangeably, although with reduced levels of efficiency depending on the use. Coal in the past has been best used for electricity production as it is cheapest, but being the most polluting new coal plants are likely to incur the additional cost burden of carbon capture and sequestration (CCS). But coal can be gasified, at an additional cost, to produce a natural gas to heat homes and through liquefication could, at a high cost and low energy efficiency, provide motor fuel for vehicles whose engines are modified to use it. Natural gas can be fired up to heat a home or to drive turbines for electricity. It can be reformed from a gas to release its hydrogen and to produce longer hydrocarbon liquid fuel molecules through a variety of gas-to-liquid (GTL) conversion process to fuel motor vehicles. Oil can be refined to yield large fractions of gasoline, diesel and aviation fuel and fuel oil for transportation. Crude oil, distillates and fuel oil can also be burned directly to produce electricity, or cracked to produce lighter liquids and gases. In the US and Europe oil and oil products are now mainly used as back-up fuels for power generation plants , since coal and natural gas are both cheaper and more readily available. .However, much distillate and fuel oil are consumed for power generation in other regions of the world as gas supply chains have yet to be extensively developed.

Alternative sources of energy such as solar, wind, geothermal and nuclear can provide electricity, in most cases at considerably higher costs, but they cannot provide liquid fuels for transportation. Their use for transportation would require motor vehicles equipped with battery packs that, in spite of much investment in improved battery technologies, currently lead to increased costs and lower efficiencies. And to replace current road transportation fuels with electricity would require a substantial boost in electricity production, for which the lowest cost and most easily built plants would use coal and natural gas.

It is precisely because of these reasons that many in developed nations interested in achieving energy independence with reduced fossil fuel use are backing the biofuel initiatives, such as ethanol, for transportation.

But in pursuing biofuels, proponents are ignoring the many shortcomings that make them inadequate and potentially economically and environmentally hazardous if used as anything more than a supplement to existing gasoline stocks.

There is an undeniable gap between what is being expected and in some cases claimed for the future role of alternative energies. For example, if the U.S. turned all of its corn into ethanol, it would only supply about 20 percent of the gasoline motorists currently consume (US Department of Agriculture, 2007).

The de-carbonization of fuels is a historical imperative, motivated not only by the real and perceived environmental concerns, but also to improve energy consumption efficiencies. This will require development of new technologies, which initially at least will be costly. This situation is similar to the passing of the steam engine era. There is no doubt that today's technology could build a steam engine far superior to those of the nineteenth century, but on energy efficiency grounds there is no point in doing so.

Natural gas is the only hydrocarbon source of energy that could easily and at manageable cost lead to a further reductions in global carbon intensity through reduction in carbon dioxide emissions. Furthermore, natural gas could provide an ultimate bridge to carbon-free energy sources, particularly in the form of hydrogen extracted from the vast available natural gas and clathrates resources (Mokhatab and Wood, 2007).

Transitions in energy are revolutionary by nature. For example, how does one circumvent trillions of dollars in existing infrastructure designed to handle oil, petroleum products and coal? More prosaic is how to convert transportation currently more than 99% dependent on oil to something different such as natural gas directly (e.g. CNG) or by electrifying the entire sector. While such approaches are plausible, their actual implementation would be costly ($ trillions worldwide), take time to achieve and be commercially difficult for both large and small energy consumers. Certainly nothing will happen overnight. This is a several decades-long process required to achieve such changes even if such policies were to be globally embraced (Economides et al., 2001, Oligney and Economides, 2002).

Regional Gas Supply Potential

Since the early 1970s, world reserves of natural gas have been increasing steadily, at an annual rate of about 5%. Similarly, the number of countries with known reserves has also increased from around 40 in 1960 to about 85 in 2005. The distribution among those regions dominating the global proved reserves of natural gas is identified in Figure 4. Figure 5 illustrates the world's main natural gas producing regions in 2007. As can be seen, the world's ratio of proven natural gas reserves to production at current levels is about 60 years. This represents the time that remaining reserves would last if the present levels of production were maintained. (Note: For petroleum reservoir engineers this statement is easily understood. For others, a clarification is in order because such statements have caused confusion in the past). The term "reserves" does not mean natural gas in place or yet to produce. The concept of reserves as generally adopted refers only to that portion of the global gas resources so far discovered that can be produced with currently available technologies, infrastructure and within the bounds of commercial constraints. In fact, it is conceivable that through further exploration success, changing market conditions, investment in infrastructure and new technology that gas reserves over time could increase even though globally we continue to produce and consume more and more of it. Most explorationists accept that it is easier to find more gas resources than oil resources making a similar claim for oil less credible. It is quite possible therefore that 60 years from today, the reserves-to-production ratio may still be 60 years. Below we present a brief overview of strategically important natural gas reserves holdings on a geographic basis. Space constraints limit our ability to cover all nations with large gas resources, so we select those we consider to be most strategically significant in the coming two decades and consider their potential.

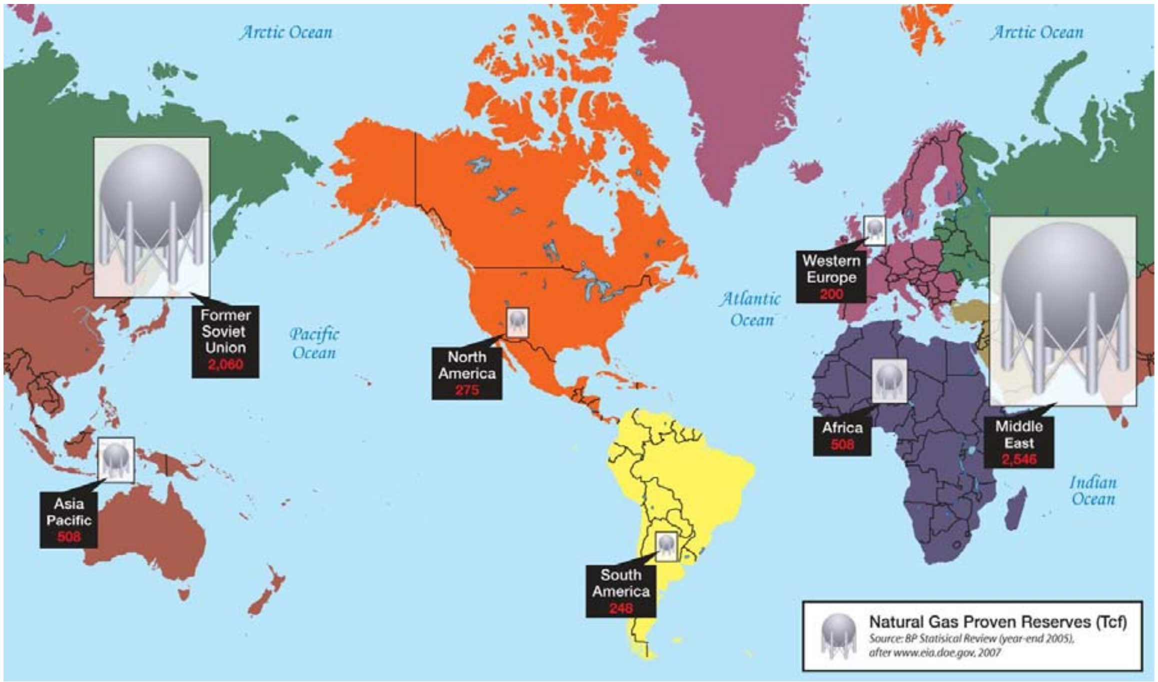

Figure 4 World's main natural gas proven reserves

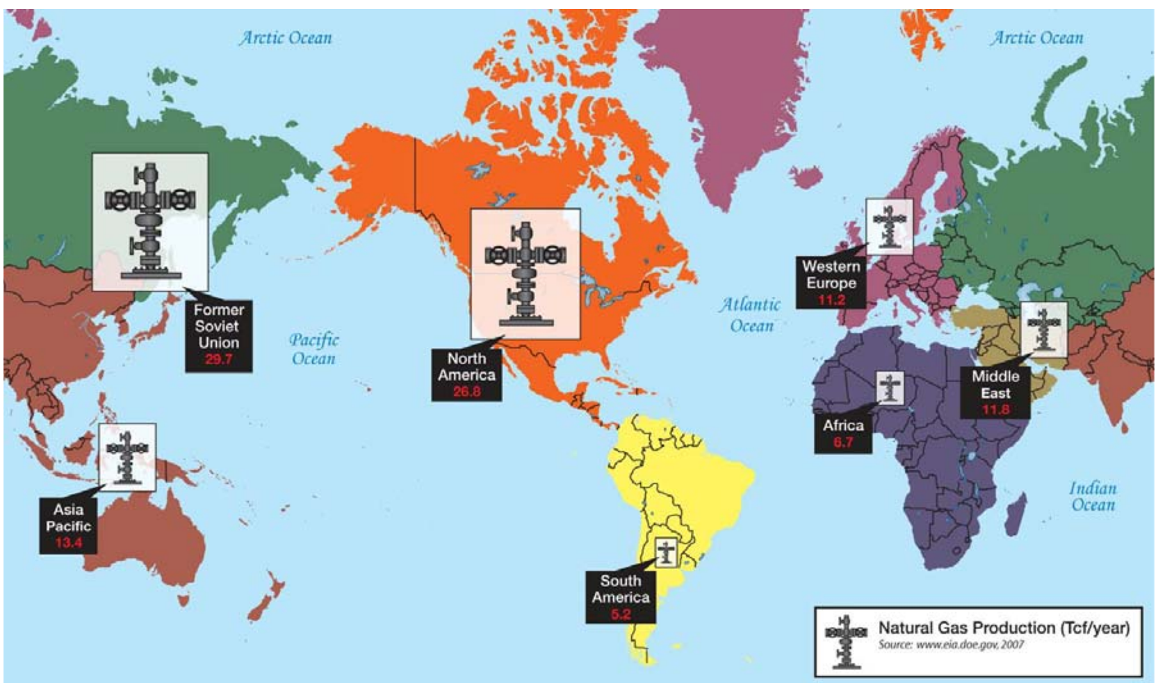

Figure 5 World's main gas producing regions

Russia

Russia has the world's largest proven natural gas reserves, estimated at 1,680 trillion cubic feet (Tcf) (Ndefo et al., 2007). Gazprom, tracing its origins to the Soviet Gas Ministry, is by far Russia's largest gas producer (producing some 95% of the country's natural gas and controlling almost 30% of the world's natural gas reserves). Despite the country's huge reserves, natural gas production has remained essentially flat over the past several years, with a mild production increase (1.3 percent) forecast for 2008 (EIA, 2008). Russia's natural gas production growth has suffered due primarily to aging fields and state regulation, Gazprom's monopolistic control over the industry, and insufficient export pipelines. Three major fields (called the 'Big Three') in Western Siberia--Urengoy, Yamburg, and Medvezh'ye comprise more than 70 percent of Gazprom's total natural gas production, but these fields are now in decline (EIA, 2008). Although the company projects increases in its natural gas output between 2008 and 2030, most of Russia's natural gas production growth under current reserves holdings is likely to come from independent gas companies such as Novatek, Itera, and Northgaz.

The subsequent development of Russia's natural gas industry has been slow and suffered from lack of capital investment in new field developments. This remains a key challenge for the future. Contrary to widely-held beliefs, if current trends continue, Russia will have a severe natural gas shortfall about 100 billion cubic meters by 2010. The main reason for the looming gas shortfall is that over the past several years, Gazprom, Russia's state-owned natural gas monopoly, has not invested sufficiently, and lacks access to the technology to develop new gas fields to replace its rapidly depleting ones without involvement of foreign operators (Ndefo et al., 2007).

Iran

Iran with an estimated almost 1000 Tcf in proven natural gas reserves holds the world's second largest reserves after Russia. More than 60 percent of Iran's gas reserves are located in non-associated undeveloped or partially developed fields. The major non-associated gas fields include South Pars (280-500 Tcf of gas reserves), North Pars (50 Tcf), Kangan (29 Tcf), Nar (13 Tcf), and Khangiran (11 Tcf). There are also several other large gas fields with multi-Tcf reserves. However, most of the gas will come from the offshore South Pars gas field, which is being developed in stages (Omidvar, 2007). The continued development of the offshore South Pars natural gas field, with an estimated 450 Tcf of natural gas reserves or around 47 percent of Iran's total natural gas reserves, is a key part of Iran's energy sector development plan (EIA, 2008)

The South Pars gas field, located 62 miles offshore in the Persian Gulf, was discovered in 1988 and was originally thought to contain just 128 Tcf. Current estimates show at least 280 Tcf (with some estimates going as high as 500 Tcf) as well as over 17 billion barrels of condensate. The South Pars gas field designed in 28 phases; so far only 18 phases have been activated. The first five phases are completed, while the next five are due by the end of 2008. The National Iranian Gas Company (NIGEC) has in the past declared its intention to have the first 16 development phases to be online by 2010, striving to keep pace with Qatar's connected North Field. The development so far achieved falls far short of that plan. The majority of South Pars natural gas development will be allocated to the domestic market for consumption and gas re-injection, with the remainder potentially exported to South Asia or Europe, and LNG production (Omidvar, 2007). Iran's likely medium-term gas export customers are China, India, and Pakistan, but the supply chain infrastructures are unlikely to begin to emerge prior to 2013.

Despite its increased production and booking the second-largest gas reserves in the world, Iran is now a net importer of natural gas.

Qatar

With proven reserves of 910 Tcf, Qatar's natural gas resources rank third in size behind Russia and Iran. Most of its natural gas is in the offshore North Field, the largest known non-associated natural gas field in the world (EIA, 2008). The North Field is a geological extension of Iran's South Pars field, which holds an additional 280 Tcf of recoverable natural gas reserves

Two consortia are already exporting LNG, with many new additions on the way. Qatargas is a joint-venture between Qatar Petroleum (65 percent), Total (10 percent), ExxonMobil (10 percent), Mitsui (7.5 percent) and Marubeni (7.5 percent), and launched its first shipment of LNG to Japan in 1999. Qatargas LNG operates three trains, with a total capacity of 9.2 million metric tons per year (1.3 Bcf/d). Qatar Petroleum and ExxonMobil dominate RasGas, Qatar's second LNG consortium. RasGas has five LNG trains giving the country 30.7 MMt (1.5 Tcf) of annual liquefaction capacity, the most in the world.

Qatar plans to significantly expand natural gas production during the next four years, particularly for export as LNG. Based on existing plans, Qatar is expected to increase its LNG production capacity to 77 MMt/y (3.8 Tcf/year) by 2012 (EIA, 2008), thus becoming the largest natural gas exporter in the world. In five years, Qatar could very likely supply one-third of the world's LNG needs, and once a receiving terminal is completed in the US, Qatar will be the U.S's largest foreign supplier of LNG. The expected increase in natural gas production will fuel the growing natural gas requirements of domestic industry, LNG export commitments, piped natural gas exports through the Dolphin pipeline, and several large-scale gas-to-liquids (GTL) projects.

North America [Canada, Mexico and USA]

The United States has proven natural gas reserves of slightly less than 200 Tcf or about 3 percent of world reserves (6th in the world) (EIA, 2008). The US consumes about 22 Tcf of natural gas, of which 4.3 Tcf is imported. More than 80 percent of U.S natural gas imports come from Canada, mainly from the western provinces of Alberta, British Columbia, and Saskatchewan. Net imports of natural gas from Canada are projected to be 2.5 Tcf in 2009, rise again to 3.0 Tcf in 2015, and then decline to 2.5 Tcf in 2025. Another possibility for future U.S. natural gas supplies lies in northern Canada, which contains around one third of that country's recoverable gas reserves. The Mackenzie Valley pipeline, for instance, could carry as much as 1.2 Bcf/d of gas from Canada's far north to southern Canada and the United States, with a final investment decision possibly coming in 2008 (assuming satisfactory completion of a regulatory and environmental review; currently, the project appears stalled). However, Canada is consuming increasing volumes of gas itself for such activities as oil sands extraction and processing. Accordingly, Canada may export less (or even none at all) natural gas to the United States than has previously been forecast. A competing pipeline would transport natural gas from Alaska's North Slope to the lower -48 states, with possible capacity as high as 4-5 Bcf/d, potentially beginning sometime around 2012. This pipeline discussed repeatedly for decades may also not be built, especially if LNG imports to the United States cover the emerging demand sufficiently and economically.

In the near- to medium -term, the EIA expects increases in natural gas production to come mainly from the lower 48 states. Increased use of new technologies is expected to result in continuing large natural gas finds, including in the deep waters of the Gulf of Mexico but also in onshore fields. In the far longer term, Alaska's North Slope fields represent a large potential natural gas source, with an estimated 30-35 Tcf of natural gas resources, which has remained stranded for several decades, and requires expensive gas pipeline to be built, subject to the constraints described above.

Increased U.S. natural gas consumption will require significant investments in new pipelines and other natural gas infrastructure. New LNG terminals are projected to start coming into operation as early as 2008, and net LNG imports are expected to increase to 6.4 Tcf by 2025 (EIA, 2008).

Canada with 57.9 Tcf of proven natural gas reserves is the second largest producer of natural gas in the Western Hemisphere, after the United States. Canada is an important source of the U.S natural gas supply, where most Canadian natural gas exports enter the U.S through pipelines in Idaho, Montana, North Dakota, and Minnesota. However, analysts now believe that Canadian natural gas production has already peaked at 18 Bcf/d, and that production from the Western Canada Sedimentary Basin (WCSB), which today provides 14 Bcf/d, will decline to 9 Bcf/d by 2020 and to 6 Bcf/d by 2024. This means, Canadian natural gas exports are expected to decline in the coming years, with net exports to the United States forecasted to reach 1.2 Tcf in 2030, or 22 percent of then net U.S natural gas imports (EIA, 2008). One potential source of additional natural gas, assuming a pipeline is built is the Mackenzie Delta which, according to the EIA holds an estimated 5-6 Tcf of recoverable natural gas reserves

To compensate for reduced domestic production, Canadian natural gas companies have begun to explore the construction of LNG receiving terminals. Natural gas companies either could sell re-gasified LNG on the domestic market or re-export it to the US. In total; there are seven LNG regasification projects in Canada at various stages of development, including one in Nova Scotia, one in New Brunswick two in British Columbia, and three in Quebec. These LNG plants, if built, will provide a combined 4.9 Bcf/d of regasification capacity, though the Canaport LNG project is the only to have so far progressed into full-scale construction (EIA, 2008).

There are two potential problems facing Canadian arctic gas projects that may prevent them from replenishing Canadian needs (and, by extension, the needs of the U.S). First, there will be major competition for this gas among the heavy oil producers in Alberta and Saskatchewan. Ironically, production of Canadian oil also requires consumption of natural gas for thermal recovery and processing. Second, the attractiveness of arctic pipelines (including the rival Prudhoe Bay gas pipeline schemes) will clearly be affected by LNG imports.

In 2006, Mexico increased its domestic natural gas production to 4.7 Bcf/d from 2.7 in 1994, a 78% increase. However, consumption has increased by 84%, from 3.2 to 5.9 Bcf/d during the same period.

Mexican natural gas demand is expected to grow by about 6% per year over the next decade. Just for electricity generation, the demand will double (from 2.1 to 4.1 bcf/d) in just 8 years.

This demand for gas is happening while, at the same time, several projects in Mexico have been encouraged to convert conventional electrical power generation to combined cycle turbines. No doubt the policy taxes the domestic demand, which is met today by applying better technologies to mature gas fields and by developing new reserves from the four major natural gas basins situated in the country. However, expected growth in demand brings the very real — and to some surprising — possibility that Mexico will continue importing more than 1.0 Bcf/d of natural gas from today and up to 4 Bcf/d by 2013, when the estimated demand will reach 9.3 Bcf/d and the estimated production will be of 5.5 Bcf/d (Rojas et al., 2004).

Central Asia

Central Asia, in the context of this article includes Turkmenistan, Uzbekistan, Tajikistan, Kyrgyzstan, Kazakhstan, and Afghanistan. Turkmenistan and Uzbekistan have large natural gas deposits yet all of these landlocked countries face challenges in getting those reserves to world markets. Since independence from the Soviet Union, regional natural gas production has been characterized by modest annual increases from Uzbekistan, and by a dramatic collapse (then partial recovery) in production from Turkmenistan. Russia and Gazprom continue, however, to control and direct most gas exports from the region. In addition to field exploration and development, Gazprom is working on projects to increase natural gas exports from the region to Europe through infrastructure under its ownership or control (EIA, 2008). However, these countries are also involved in projects to take the gas east to China and are being wooed by Europe to participate in pipeline projects through Turkey and the Black Sea that avoid Russian control (i.e. Nabucco and White Stream).

Turkmenistan

Turkmenistan has proven natural gas reserves of approximately 101 Tcf – ranking it in the top 15 reserve-holding countries. Turkmenistan contains several of the world's largest gas fields. These fields are in the Amu Darya basin, with half of the country's gas reserve located in the giant Dauletabad-Donmez field alone. In addition to Amu-Darya, Turkmenistan contains large gas reserves in the Murgab basin, particularly the giant Yashlar deposit, which contains an estimated 27 Tcf. All major gas fields in Turkmenistan have been producing for more than a quarter century, and therefore exhibit sign of natural depletion.

Turkmenistan was a substantial natural gas producer under the Soviet Union, but after the country became independent, Turkmen natural gas became a competitor with Gazprom, the Russian state monopoly. Since all of the pipelines connecting the region to world markets were owned by Gazprom and routed through Russia, Turkmen natural gas was squeezed out of the market. As a result, Turkmenistan's incentives for increasing its production of natural gas disappeared. The dispute was temporarily resolved and Turkmenistan exports resumed to both Russia and Ukraine. Turkmenistan and Gazprom agreed to increase gas shipments to 2 Tcf per year with the potential to increase the annual volume to 3.5 Tcf (EIA, 2008). Also, Ukraine signed an agreement with Turkmenistan for gas shipped through Russia. The deals were supposed to last through 2006. Turkmenistan is actively pursuing other options, but most of these deals have fallen apart.

Uzbekistan

Uzbekistan has estimated natural gas reserves of 66.2 trillion cubic feet (Tcf), with the largest reserves in the Ustyurt Region, and ranks among the 15 largest gas-producing countries in the world. Uzbekistan’s natural gas reserves are primarily concentrated in two general areas: the Amu Dar'ya Basin and in the Mubarek area of the southwest part of the country. Most gas production is concentrated in 12 fields, particularly in Shurtan and Kokdumalak, which are being developed rapidly. Now they account for more than 90% of the country's output of gas and condensate.

Uzbekistan is also the only former Soviet republic to have substantially increased its natural gas production since becoming independent with gas production increasing by nearly 50 percent, from 1.51 Tcf in 1992 to 2.1 Tcf in 2005. Uzbek natural gas production remained stable at 5.0 to 5.4 Bcf/day from 1999 to 2006 (EIA, 2008).

Uzbekistan is the third largest natural gas producer in the Commonwealth of Independent States (after Turkmenistan). However, Uzbekistan's natural gas fields were heavily exploited in the 1960's and 1970's by the Soviet Union, and as a result several older fields, such as Uchkyr and Yangikazgan, are beginning to decline in production. In order to offset those declines, Uzbekistan has taken short-term measures to increase gas production by upgrading facilities at existing fields. Longer-term measures involve finding new reserves with foreign help; Uzbekistan has negotiated with Gazprom (Russia) and the now defunct Enron (United States), among others.

Gazprom has invested in recent years in revamping old fields in Uzbekistan and Uzbekneftegaz signed a natural gas supply deal with the company that will supply as much as 350 Bcf per year to Russia by 2006. During 2005, Gazprom started developing in cooperation with Uzbekneftegaz gas condensate fields in Ustyurt region in Uzbekistan and upgrading gas pipelines in Central Asian states to boost natural gas exports from the region. The companies will pump between 280 and 350 Bcf of gas per year from the fields. Lukoil, another Russian energy company, signed a production sharing agreement with Uzbekneftegas in June 2004 to develop the Kandym natural gas deposits, which are estimated to hold roughly 7 Tcf of natural gas. The company expects to begin producing around 210 Bcf per year beginning in 2011.

Where are the big gas importers? And how are their demands growing?

There are three main regional OECD import markets (Europe, East Asia and North America) for natural gas with quite distinct drivers, supply demand fundamentals and pricing mechanisms. China and India are two rapidly growing developing markets set to play more important roles globally as gas importers. Figure 6a and b illustrate how natural imports are set to rise in the regional markets. What is striking is how rapidly imports are set to grow, both in absolute and percentage terms, and replace indigenous production in Europe. Note that the IEA’s definition of OECD Pacific (Figure 6) includes the major gas exporters Australia, Indonesia, Malaysia and Brunei. Within OECD Asia, however, the main consumers (Japan and South Korea) are almost totally dependent on imports for their gas supply.

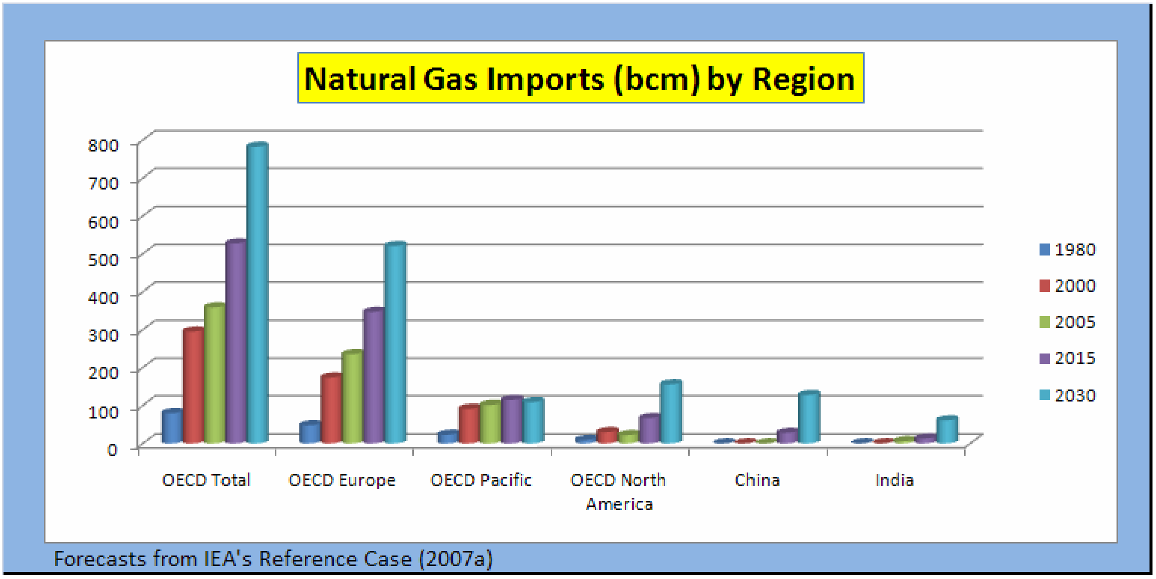

Figure 6a How key gas import markets are forecast to grow in absolute (bcm) terms (IEA, 2007a)

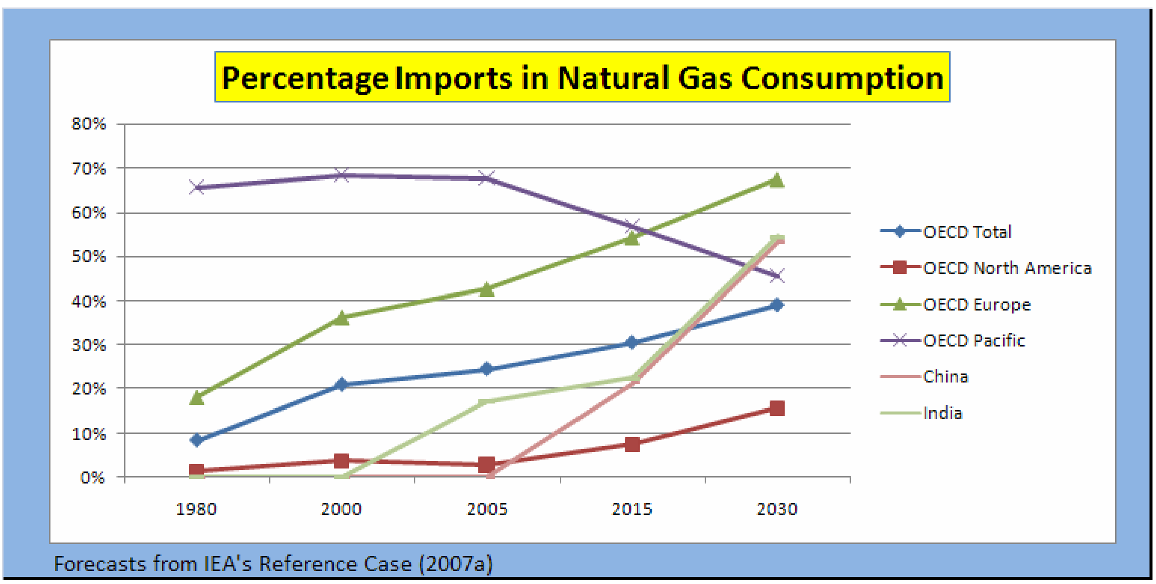

Figure 6b How key gas import markets are forecast to grow in percentage terms (IEA, 2007a) with Europe approaching 70% and total OECD approaching 40% by 2030.

Europe is a rapidly growing gas import market, particularly the European Union (EU). Figures 7, 8 and 9 illustrate by contrasting positions in 2003 and 2006, just how fast that market is changing, in terms of decline of indigenous production and diversification of imports. Many of the large scale infrastructure projects (pipeline and LNG) currently under construction are focused on the EU market. Gas imports grew in absolute terms by some 29% to EU-27 from 2003 to 2006 (compare figures 8 and 9). Gas imports contribution to overall consumption in OECD Europe increased from 36% to 43% between 2000 and 2005 (figure 6b) with LNG's share growing from 14.5% to 16.5% of those imports from a more diversified set of suppliers.

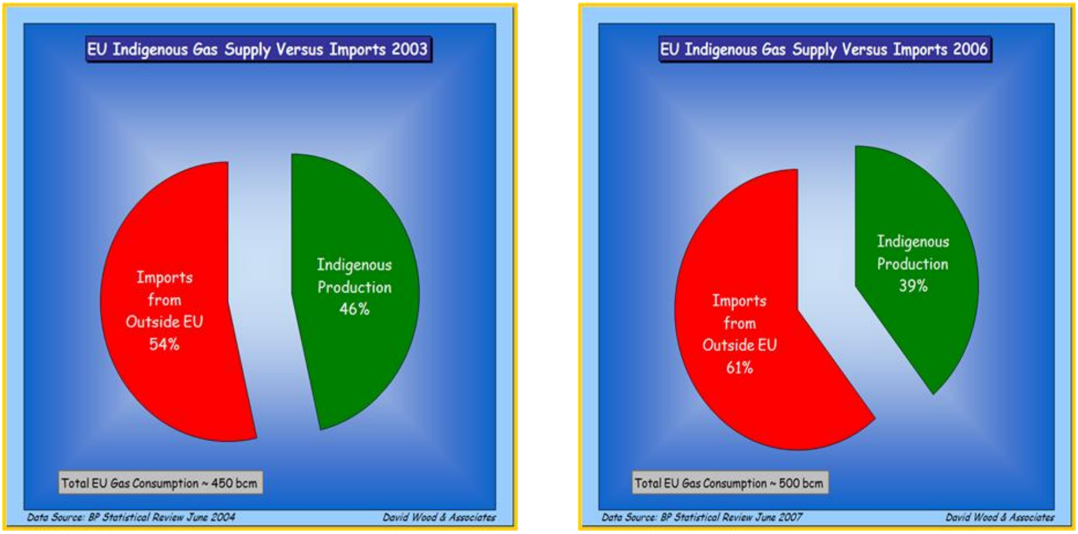

Figure 7 European Union (EU) is becoming rapidly more dependent on imported natural gas. Gas supply to the EU-27 countries is changing more rapidly than is often realised. (Wood and Pyke, 2008). Raw data source: BP Statistical Review of Energy Resources (June 2007).

Gas Imports to EU 27 (2003)

NON-EU Gas Suppliers	Imports bcm	Percentage Share
Russia [Pipeline]	107.56	44.50%
Norway[Pipeline]	68.37	28.29%
Algeria [Pipeline]	30.79	12.74%
Algeria [LNG]	22.40	9.27%
Nigeria [LNG]	9.24	3.82%
Qatar [LNG]	1.87	0.77%
Libya [LNG]	0.75	0.31%
Oman [LNG]	0.32	0.13%
UAE [LNG]	0.24	0.10%
Australia [LNG]	0.08	0.03%
Trinidad [LNG]	0.08	0.03%
Total	**241.70**	**100%**
LNG / Total (%)	**34.98**	**14.5%**

Source: BP Statistical Review June 2004

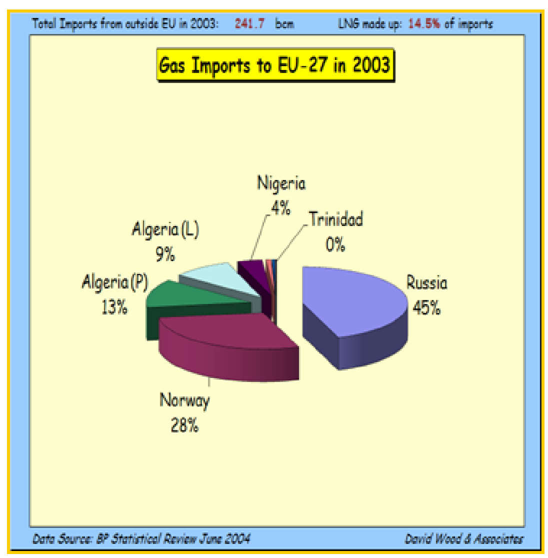

Figure 8 The big three suppliers to EU-27 (Russia, Norway and Algeria) supplied some 95% of gas imports in 2003 including 85% via pipeline (Wood and Pyke, 2008). Raw data source: BP Statistical Review of Energy Resources (June 2007)

Gas Imports to EU 27 (2006)		
NON-EU Gas Suppliers	Imports bcm	Percentage Share
Russia [Pipeline]	127.04	40.61%
Norway[Pipeline]	84.00	26.85%
Algeria [Pipeline]	35.62	11.39%
Libya [Pipeline]	7.70	2.46%
Other {Pipeline]	6.80	2.17%
Algeria [LNG]	23.55	7.53%
Nigeria [LNG]	14.58	4.66%
Egypt [LNG]	8.45	2.70%
Qatar [LNG]	5.36	1.71%
Trinidad [LNG]	3.76	1.20%
Oman [LNG]	1.00	0.32%
Libya [LNG]	0.72	0.23%
Less Turkey [LNG]	-5.72	-1.83%
Total	**312.86**	**100%**
LNG / Total (%)	**51.70**	**16.5%**

Source: BP Statistical Review June 2007

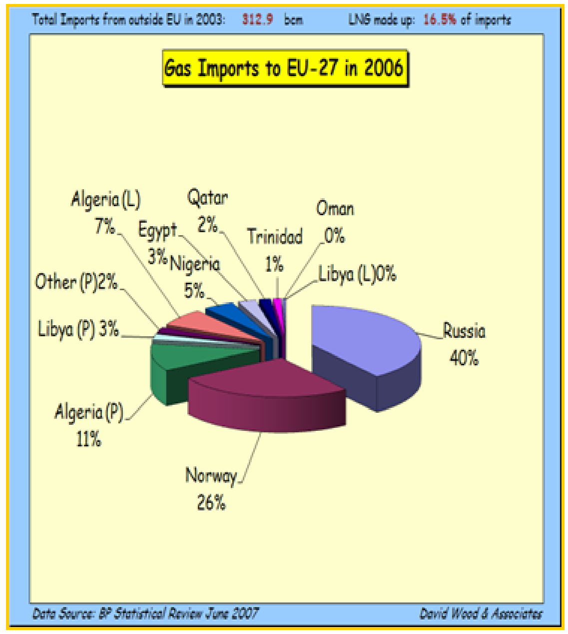

Figure 9 The big three suppliers to EU-27 (Russia, Norway and Algeria) supplied some 84% of gas imports in 2006 including 77% via pipeline. LNG imports were from substantially more diversified sources than in 2003 (Wood and Pyke, 2008). Raw data source: BP Statistical Review of Energy Resources (June 2007).

LNG has the potential to secure some 25% of the EU-27 gas import market by 2025, but that will depend upon crucial investment decisions leading towards more liberalized continental European gas markets, more third-party access to infrastructure and geopolitical maneuvering between EU and its Russian and North African pipeline suppliers (Wood and Pyke, 2008). There is also increased demand for underground gas storage capacity to service the seasonal demand characteristics of the European (and other OECD) markets.

Gas and more gas: the regions and projects that are sustaining global gas supply growth

What are the technologies and resources now available to us?

Tens of billions of dollars are being sunk into capital infrastructure projects focused on expanding and developing new gas supply chains to the three main regional gas import markets of Europe, East Asia, and North America. Both pipeline and LNG projects are attracting substantial investments with LNG capacity growing more rapidly. LNG represents a little less than 30% of the internationally traded gas market and is expected to increase that share to some 35% over the course of the next decade. It is however, the geographic diversity of the LNG projects, the number of new country entrants, both in liquefaction and as LNG importers, and the expanding role of short-term LNG trading that is revolutionizing the international gas business. LNG worldwide production capacity is expected to grow from 240 bcm in 2005 to 360 bcm in 2010 and to 470 bcm (possibly 600 bcm) in 2015 (IEA, 2007b)

Gas-to-liquids (GTL) technologies, both Fischer-Tropsch (already operational in South Africa, Malaysia and Qatar) and oxygenate processes (e.g. methanol and dimethyl ether – DME) remain an emerging gas supply sector. GTL has much future potential, particularly in high oil price markets, but much technological process and efficiency developments required before it becomes more widely exploited. Likewise compressed natural gas (CNG) and small-scale liquefaction technologies clearly have a niche market (Wood and Mokhatab, 2008) in which they can compete on a commercial basis, but have yet to be exploited.

Coal-bed methane, particularly in US and China, is also proving to be a much more significant source of gas in those markets than originally envisaged. Expanding shale gas projects in Canada and US are suggesting that it too, as an unconventional source of gas, may make significant future contributions of gas in the North American market.

More speculatively, the massive reserves of gas hydrates (clathrates) on the continental slope and at high latitudes onshore offer attractive resource volumes for the future, but require innovative technologies to exploit them. These technological and reserves opportunities will ensure the long-term future exploitation of natural gas, but play a minor role in today's natural gas industry. Our focus here is on the pipeline and LNG projects that are destined to impact natural gas supply in the short and medium term.

One of the big challenges for the industry is how to move large volumes of gas from Russia, Central Asia and the Middle East into the main consuming markets. Consequently much ongoing investment, planning and geopolitical maneuvering is focused on infrastructure projects to achieve this. Both nations and companies are competing furiously to gain commercial advantage, no more so than Russia and Gazprom. It is appropriate therefore to highlight some very large scale projects being led by Gazprom that will change the configuration of gas supply chains over the next few years.

Large-Scale Russian Projects Unfolding

The Sakhalin II LNG project is nearing completion and represents a key milestone as it is the first gas liquefaction export project for Russia. Sakhalin Energy, now led by Gazprom with partners Shell, Mitsui and Mitsubishi received its commissioning cargo of LNG in July 2005 at the Prigorodnoye plant in the south of Sakhalin Island. Sakhalin Energy's two-train LNG plant will have a capacity of 9.6 million tones per annum. It has sales contracts in place to export LNG to Japan, South Korea and across the Pacific to USA via Mexico's Costa Azul regasification terminal from 2009. It is optimally located to supply the East Asian market and also expects to secure contracts with China and may be expanded in the future. The strategic importance of the project has come at a price – what was originally an $8 billion project will be delivered at a cost of more than $22 billion.

The huge untapped stranded gas of Eastern Siberia also has potential to supply China's growing demand for gas. This includes the giant Kovykta gas field which Gazprom wrestled from TNK-BP's grasp in mid-2007. However this requires a 4000+km pipeline across difficult terrain and is unlikely to be onstream before 2014.

Looking west into Russia's traditional European gas market there are two major pipelines now sanctioned that will help to consolidate Russia's commanding position in terms of supplying gas to Europe: Nord Stream and South Stream. These are to be conducted as joint ventures with major European utilities much to the dismay of the European Commission which prefers to see a non-Russian pipeline (Nabucco) project completed bringing additional gas sources from Central Asia into Southeast Europe. In 2008 Ukraine are promoting a White Stream alternative to link

Caspian gas through Georgia by pipeline across the Black Sea into either Romania or Ukraine and on into Europe. So far no major gas producing company or European gas utility has joined the project probably due to concern over future relations with Russia and Gazprom. On technical and geographic grounds bringing Middle Eastern and Caspian gas into Europe via Ukraine also has some advantages as Ukraine has substantial underground gas storage capacity.

Nord Stream is to be installed as a 1200-kilometre, submarine trans-Baltic pipeline between Vyborg in Russia and Greifswald in Germany avoiding Eastern European transit countries. Phase one of Nord Stream is scheduled to deliver first gas in 2011 with a capacity of around 27.5 bcma, which will double to some 55 bcma in the second phase due onstream in 2012. The total investment is more than $5 billion and involves Gazprom - 51%, Wintershall - 20%, E.ON Ruhrgas - 20% and Gasunie - 9% (the latter joining in late 2007). Gazprom began production in late 2007 from the South Russkoye field in Western Siberia which will provide some of the gas for this new export route.

The South Stream pipeline, which competes directly with the Nabucco project, is a 50:50 joint venture between Gazprom and Eni (Gazprom's single largest customer). The $10 billion project planned to be onstream by 2013 would run some 900km with a 30bcma capacity under the Black Sea and through Bulgaria, Romania, Serbia and on into Hungary and Austria through the emerging Baumgarten gas hub, in which Gazprom and OMV hold interests. An additional branch is planned to run as an interconnector between Greece and Italy. This route would bypass Ukraine, with which Gazprom has a history of price and payment disputes. Gazprom has also signed gas purchase agreements with Central Asian countries in late 2007, conceding substantial price increases (up to $150 / 1000cm in late 2008) in exchange for control of most of the gas volumes exported from Turkmenistan, which it then sells on to Ukraine and other Eastern European nations, which are struggling to free themselves from dependence on Russian gas supply.

The giant (some 120 tcf) Shtokman field in the high latitudes beneath the Barents Sea has been the focus of negotiations between Gazprom and many IOCs in recent years. Total (25%) and Statoil Hydro (24%) were selected in 2007 by Gazprom (51%) as partners for the project expected to initially produce 23.7 bcma for Europe as additional feed for Nord Stream pipeline gas and LNG exports to other markets from 2013 and 2014 respectively. Both IOCs have experience of high latitude LNG in Norway's Snohvit LNG project (71^{o}N), which came onstream in late 2007 as Europe's first liquefaction plant. Gazprom is also considering a Baltic LNG project at Ust-Luga on the Gulf of Finland, near St Petersburg, testifying how strategically important LNG is becoming in reaching distant markets. Norway on the other hand is also busy expanding its pipeline gas capacity to continental Europe commissioning the Ormen Lange field and Langeled pipeline to UK in late 2006 and offers the only long-term pipeline gas supply competition to Russia in northwest Europe.

In Europe the gas consuming nations are playing their part in enabling competing LNG supplies to be landed. Many new receiving terminals and additional gas storage projects have been and continue to be built and expanded, particularly in Spain and France with major projects under construction in UK, Netherlands and Italy, each planning to expand their roles as gas entry hubs into the wider EU as markets liberalize. The Netherlands although currently a gas exporter is building two substantial regasification terminals in Rotterdam, which together with the BBL pipeline to UK commissioned in 2006, should transform it into a major gas hub. Germany, Poland, Croatia and Slovenia are other European nation eyeing building LNG receiving terminals as a means of providing diversification from Russian gas and long-term security of gas supply.

Other Arctic Gas

Arctic experience in pipeline and LNG gas developments is likely to become even more important in the future as nations and companies contemplate exploitation of potential resources beneath the continental shelf of the whole Arctic Ocean. While gearing up for some tough political negotiations Canada and U.S are finally reconciled to the urgency of developing the vast gas resources stranded for many years beneath the North Slope of Alaska and the Mackenzie delta. These require expensive long-distance pipelines and fiscal agreements between federal and state authorities and the major IOCs have proved elusive in the past. There is little doubt that they will eventually be developed, but Alaskan gas is unlikely to reach the lower 48 states before 2020 with the Mackenzie delta gas in Northern Canada unlikely to contribute to supply before about 2015. It is encouraging for these future export projects that companies in 2008 are once again planning to drill gas exploration wells offshore Alaska.

West African Projects

With six LNG trains now producing at Bonny, Nigeria is set to become the third largest LNG exporter after Qatar and Indonesia with some 37 bcma capacity. Nigeria LNG (NNPC, Shell, ENI, and Total) has a diverse base of customers in Europe, North America and trades short-term cargoes to Asia. Two additional large plants, Brass LNG (NNPC, ConocoPhillips, ENI, Total) and OK LNG(NNPC, Shell, Chevron, BG) are close to final investment decisions, and other LNG projects are in planning along with a more speculative trans-Saharan pipeline project linking Nigerian gas into Algeria’s pipeline export routes. IOCs are motivated to participate in gas utilization projects by penalties due for not complying with no gas flaring rules introduced in 2008. Community unrest in the Niger delta and increasingly disruptive actions by delta militants are causing delays to final investment decisions in several Nigerian gas development projects.

In 2007 Nigeria was joined as an LNG exporter by its neighbor Equatorial Guinea that commissioned the Bioko Island EG LNG Marathon-led project with cargoes being exported mainly to the US. This 4.6 bcma project is now considering expansion with an additional train developing gas from across its offshore borders in Nigeria and potentially Cameroon.

Final investment decision was also taken for Angola’s first 7.0 bcma LNG project after many years of delay from first being proposed by Texaco in 1999. This project is more complex as the gas well come from associated gas reservoirs mainly in deepwater location and will require expensive offshore gas gathering facilities. First LNG from the Project is expected to be delivered by 2012 into the US via a yet to be built regasification terminal near Pascagoula, Mississippi. Offshore liquefaction technologies, yet-to-be deployed, may provide the long-term answer to unlocking deepwater and remote offshore gas resources.

West Africa has potential to supply LNG to all three major markets and is likely to be a key ongoing player in short-term LNG trading once it has its long-term supply chains established.

North Africa

Oil and gas activity has been booming in recent years in Algeria, Libya, Egypt and Tunisia. It is ideally suited to supply gas into southern Europe and several pipeline and LNG projects are operationally with major new export projects being contemplated in Algeria (Gassi Touil, In Salah and In Amenas),Libya and Egypt (offshore Nile Delta). The recent gas licensing round in Libya awarded highly prospective areas to Sonatrach, Gazprom, Shell and others. These, together with large scale upstream investments by international and national oil companies from around the world are focused on proving up enough gas to supply large new liquefaction and pipeline projects. As Egypt has showed since 2004 the location is ideal to trade LNG both to US and to Europe and together with Russia and Norway this region is certain to remain one of their strategically important gas suppliers.

Middle East

Apart from Qatar much in the Middle East remains under-exploited from the point of view of exports. This region will undoubtedly become a major supplier of gas to Pakistan and India by LNG and pipeline and will further expand to fill demand in East Asia, particularly China. Geopolitics has delayed this to some extent, but is unlikely to do so indefinitely. In addition, pipelines linking major gas deposits in Iran with Europe through Turkey (part of the Nabucco project) make commercial, if not current political sense. Some new Middle East gas players are emerging. Yemen LNG (led by Total) is under construction with a 9 bcma liquefaction plant at Balhaf and is due onstream in 2009 to supply Asian, European and US markets.

It is, however, the Qatargas II, III, IV LNG projects, led by QP in partnership with ExxonMobil, ConocoPhillips and Shell, respectively that are destined to bring impressively large new volumes of LNG into world markets between 2008 and 2012. Each phase consisting of one or more large 7.8 mtpa liquefaction trains and with supply chains linked with receiving terminals in Europe (e.g. UK and Italy) and US and utilizing specially commissioned large Q-flex and Q-max ships for delivery. Although the sheer scale of these projects may over-supply some gas markets in the short-term they are set to consolidate and expand LNG's share of globally traded gas.

Southeast Asia and Australasia

This region has been the traditional long-term LNG supplier to the Asian market with Indonesia, Malaysia, Australia and Brunei all having long-term experience in the trade. Gas reserves are to some extent constraining major capacity expansions in Malaysia and Brunei. Aging projects and slow investments in new developments in Indonesia have resulted in it losing some momentum in recent years as supplies from both Arun and Bontang plants have become les reliable. Nevertheless the long-delayed, 9.5 bcma Tangguh LNG project (led by BP) is due onstream within a year and will export to East Asian and west coast of North America via the Costa Azul terminal in Mexico.

Also in late 2007 a final investment decision was taken on the 2.7bcma Donggi LNG project in Central Sulawesi by Indonesia's state-owned oil and gas company Pertamina (21%), local upstream player MedcoEnergi (29%), and Mitsubishi (51%). This project may be small in scale, but is significant in that it does not involve a major European or North American IOC and has a Japanese company with the major shareholding in a liquefaction project for the first time. If successful this suggests that the IOCs may see more competition from independents, NOCs and Asian buyers for equity positions in future liquefaction projects.

In 2007 it is Australia made more progress than any other region in sanctioning gas field developments with further progress associated with Northwest Shelf gas fields (Gorgon, Pluto and Browse) underpinned by LNG sales contracts to all the main Asian buyers at long-term prices in the $8-$10/ mmbtu range. In addition the fifth train of the existing NWS LNG project is due onstream in 2008Several major IOCs are involved but it is Woodside's LNG capacity growth that is most impressive. The Pluto LNG project initial phase involves a 6.5 bcma capacity Liquefaction plant (due onstream late 2010) connected by a 180-km, 36-inch offshore pipeline to a platform supplied by five subsea big bore wells. Meanwhile the Chevron-led Gorgon LNG project expanded its planned capacity to 20 bcma by adding a third liquefaction train now that it has secured planning permission and offtake contracts. However, the project is running several years behind schedule and even with a final investment decision expected in 2008 it will probably not deliver LNG until 2014. The Browse and Sunrise LNG development projects may also be completed in that timeframe.

Other LNG projects under consideration in Australasia are an 8.5 bcma, $10 billion LNG project to develop Papua New Guinea's Hides gas field (final investment decision due 2009) and the world's first coal-bed methane sourced liquefaction project in Queensland in its pre-FEED stage at the moment. Rapid developments and large investment in development of gas for long-distance exports suggest that much gas is to become unstranded over the coming decade. Robust demand for LNG from Japan, South Korea, China and India are fuelling the latest round of liquefaction investment commitments in Asia.

South America

The nature and pace of gas development in South America is more sedate but no less entwined with global geopolitics. Brazil is the only major market for large volumes of gas and is finding it difficult to secure reliable long-term supplies. Expectations are high for recent discoveries in the Santos basin, but large investments are required to prove up and develop those deepwater reserves. Both Brazil and Chile have sanctioned small-scale LNG import facilities to provide security of gas supply. Resource nationalization issues in Bolivia and Venezuela in recent years have led to promising liquefaction export projects being scrapped and most of the continents gas reserves firmly locked in their reservoirs. Nevertheless, Trinidad and Tobago have shown how it can be done over the past decade with 4 liquefaction trains now operational and the largest LNG supplier to US for the last several years. However, long-term sustainability is a cloud on the horizon for Trinidad as it needs to find more gas in order to sustain export at substantial levels beyond 2020.It is therefore promoting gas exploration with some new gas discoveries announced in 2008..

The 5.5bcma Peru LNG project launched in early 2007 is the first liquefaction project on mainland South America, with gas supplied by pipeline across the Andes from the Camisea and surrounding field developments of recent years. The $3.8 billion project is due to commence exports in 2010 to Mexico and possibly the US with RepsolYPF taking a key role in purchasing the LNG. If politics change this facility could in the future be expanded to take gas from Bolivia to export markets, but that seems unlikely in the medium-term. Meanwhile Presidents Chavez and Morales of Venezuela and Bolivia are promoting a trans-continental gas pipeline ("Pipeline of the South") to link their two countries via Brazil. It is unclear yet who is the targeted customer for the gas that would flow through it. In any event by the time it comes onstream, if ever, the world's gas supply will have grown and diversified unrecognizably. Potential LNG projects have been under consideration in Venezuela for many years to develop the large non-associated gas reserves offshore Sucre and more recently Plataforma Deltana. However, there is no sign that foreign investors will in the short-term be prepared to take on the high risks or the tough fiscal terms currently being sought for these projects.

Conclusions

The gas industry has entered an exciting phase of rapid growth from all supply chain and technology perspectives. Natural gas is clearly destined to play a key role in future global energy developments and, specifically, it can help achieve two important energy goals for the 21st century—providing the sustainable energy supplies and services needed for social and economic development and reducing adverse impacts on global climate and the environment in general. For such developments to progress, the construction of large-scale inter-regional natural gas supply networks (pipeline and liquefied natural gas) is required across the globe.

Gas markets are actively competing to secure currently available gas supplies – note Japanese utilities paying up to $20 / MMbtu for some short-term cargoes in January 2008. There is a proliferation of large-scale long-distance pipeline and LNG infrastructure projects under construction in spite of an almost twofold increase in materials and service costs from 2004 to 2008. Expanded gas storage capacity in European markets should help to ease seasonal price volatility as it has historically in North America.. A wide range of alternative technologies, including GTLs, CNG and offshore liquefaction are now being considered more seriously as means of unlocking not just large, but also smaller-scale remote gas reserves. High gas and oil prices are opening up new and challenging high northern latitude and ultra-deep water regions for exploration. Research and development funding is now being spent to develop extraction technologies and strategies to enable the exploitation of the enormous resources of high latitude onshore and offshore gas hydrates.

Many of the supply projects and countries discussed in this article are located in remote regions and involve gas reserves discovered two or three decades ago. Indications are that these will be unlocked in the period to 2025 through a combination of technological development sustained growth in demand from existing and new markets and robust prices caused by existing supply constraints. There is competition from other fuels (mainly from coal and nuclear), but gas is well positioned to offer most attractive commercial, environmental and technological solutions in most regions. However, it will have to demonstrate that it can overcome geopolitical issues associated with long-distance supply chains and provide sustainable supplies at stable competitive prices in order to secure the increased market share now available for the taking.

The authors believe that secure gas supplies will flow around the world in increasing quantities throughout the 21st Century, because:

- there is no shortage of gas reserves;
- demand for it as an energy source is growing rapidly and new markets are opening;
- the industry is capable of providing the technological innovation required to produce, transport and handle it in remote locations;
- the financial sector is ready with investment capital to provide the additional infrastructure needed based upon the industries track record of high performance

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http://fpc.state.gov/documents/organization/76323.pdf

Appendix

Volumetric and energy conversions

(Assuming 1040 Btu/thousand standard cubit feet natural gas)f

	$MMft^3$	Mm^3	Boe	Toe	TLNG	MMBtu	GJ	MWh
$MMft^3$	1	28.34	170	24	20	1040	1097	300
Mm^3	0.035	1	6.1	0.83	0.71	36.7	38.72	11
Boe	5.88 E-3	0.164	1	0.136	0.116	6.0	6.35	1.7
Toe	0.042	1.2	7.4	1	0.8	42.5	45	12.7
TLNG	0.052	1.4	8.9	1.2	1	52	55	14
MMBtu	9.6 E-4	0.027	0.166	0.024	0.019	1	1.06	0.27
GJ	9.1 E-4	0.026	0.157	0.022	0.018	0.94	1	0.25
MWh	3.33 E-3	0.091	0.588	0.079	0.714	3.7	4	1

$MMft^3$	Million standard cubic feet
Mm^3	Thousand standard cubic meters
Boe	Barrles of oil equivalent
Toe	Tonnes of oil equivalent
TLNG	Tonnes of LNG
MMBtu	Million Btu
GJ	Giga Joules
MWh	MW-hr