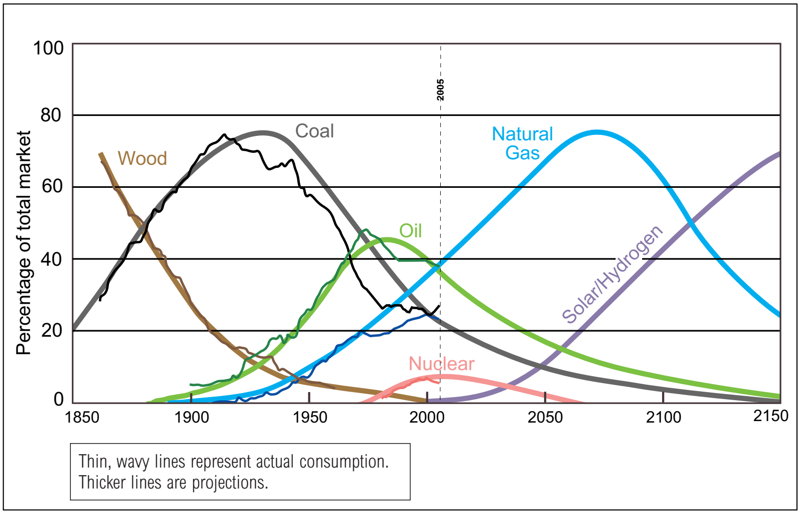
The Global Outlook

Natural gas has its own resource base, which differs from oil, but oil reservoirs also contain natural gas and natural gas liquids. Natural gas is lighter than air while oil is a viscous liquid. Natural gas is compressible; oil is not. Natural gas fields produce 70 to 80 percent of their reserves, while oil fields produce from 30 to 50 percent depending upon the kind of recovery used. Natural gas can be produced from very low permeable formations such as shales, tight sands and coals while most sources of oil cannot. Natural gas is found in both shallow formation and at great depths down to 20,000 to 30,000 feet, while oil is usually found no lower than 15,000 feet (the U.S. Gulf of Mexico is an exception). Because it is relatively plentiful, cleaner than oil or coal and requires the lowest capital cost if used to produce electrical power, natural gas has become the fuel of choice for all but the transportation sector where oil still reigns.

World Primary Energy Substitution



Source: Robert A. Hefner III
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(After C. Marchetti and N. Nakicenovic)

According to one projection, natural gas will surpass coal and oil and become the principal global source of primary energy in the 21st century.

Most observers are confident that the world will not run out of natural gas any time soon. Natural gas reserves and remaining recoverable resources are much larger than oil reserves and resources (for comparison, U.S. gas reserves are approximately 200 TCF) with about 20,000 trillion cubic feet (tcf) of discovered, undiscovered and produced resources. Only about 10% has been produced to date. If only proven and probable reserves are considered, there are about 7,300 tcf of natural gas, most located in the Middle East (2984 tcf) and Russia (2014 tcf). ("Proven reserves" are economic to produce today, while "probable reserves" are likely to be produced in the near future).

While resources appear sufficient, a closer examination of demand and supply for the next twenty-five years provides a less optimistic picture of future production capacity. One estimate indicates that gas demand will grow at about 1.8% per annum until 2030, faster than any other fuel, while overall energy demand grows at 1.4% per year.

This growth will be faster in the emerging economies than in the developed ones. Asia and the Middle East/Africa will lead the way, growing 3.2% and 3.0% per year, respectively. In contrast, North American demand is expected to grow by only 0.9% and European demand by 1.2% per year. The power sector will lead the way, growing by 2.0% per year, followed by industrial demand at 1.7% and residential and commercial at 1.6%.

Where will this gas come from? One estimate indicates that through 2030 most of it will continue to come from local production, that is, from within the region where it is consumed. Additionally, about 10 percent will come from imports outside the consumption region that are already under contract. But by 2030, about 90 billion cubic feet (bcf), or about 20% of all consumption, will have to come from new supplies from outside the consumption region, with about 50 bcf delivered by pipeline and 40 bcf delivered through LNG trade. Regionally, there will be wide variations in supply. In North America, local production and new pipeline supplies from Canada, which are slowly diminishing, will provide the overwhelming majority of gas while LNG will fill the remainder. In contrast, in Europe, local production will have dwindled to less than one third of current production, with new supplies coming from outside the region mostly through pipeline deliveries and a significant portion through LNG trade. In Asia, local production will continue to provide about 50 percent of supplies, while LNG trade will provide most of the new supplies and a small portion will come from new pipelines.

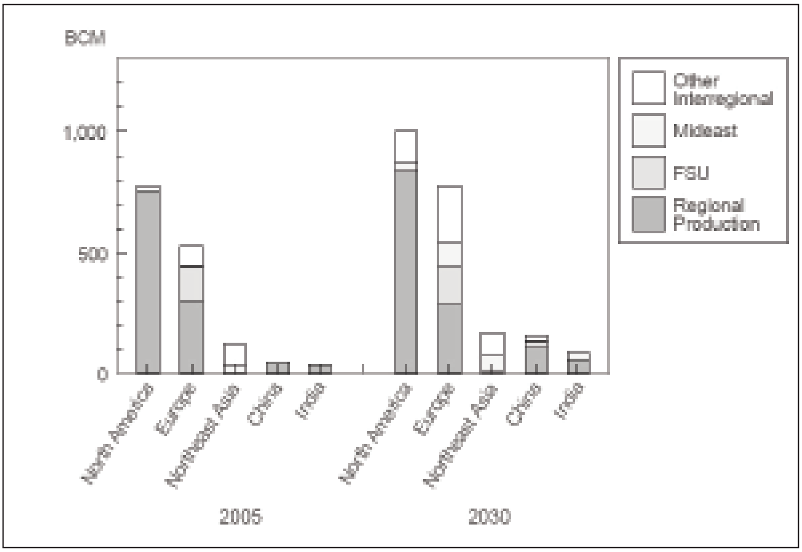
A strong caveat to these overall projections is that many of the potential supplies of natural gas are likely to be constrained by economic, technical and political issues. In addition, some participants were concerned that not enough supply-demand interaction was considered in these estimates, so it is possible that the demand estimates were overstated. Their point is that often demand is projected, and supply is then assumed to be forthcoming to meet future demand. Such estimates ignore national policies and geopolitics and the willingness of producing countries to produce at expected levels.

Cross-border and Global Trade

A closer examination of markets brought the group to the conclusion that major shifts in natural gas trade are slowly beginning to convert regional markets into a global natural gas market. Until the late 1990s, natural gas markets were regional with little global trade. North America was self-contained. Europe relied on its own production supplemented by gas from North Africa and the Former Soviet Union (FSU). Asia relied on regional LNG production and LNG imported from the Middle East. These patterns started to change in the late 1990s.

As demand for natural gas in Europe, Asia and North America continued to grow and major new LNG projects were developed in the Middle East, Australia and West Africa, cross-border and global trade increased and linked markets together. Europe and North America outgrew their traditional pipeline sources as they turned more and more to gas-fired electric generation, with LNG as the marginal source of supply. New markets in China and India added to trade in LNG. This surging demand brought forth new LNG supplies from the Atlantic Basin and the Middle East. The FSU (primarily Russia) began looking eastward for new markets and developing LNG facilities to supply them. By the early 2000s, gas markets became more global, linked by cross-border pipelines and global LNG tanker trade, with LNG sending price signals across all markets. These interregional markets are expected to continue their growth. For example, the International Energy Agency projects that by 2030, 41% of gas supplies will come from interregional trade, up from 11% in 2005.

The Growing Reliance on Interregional Gas Supply



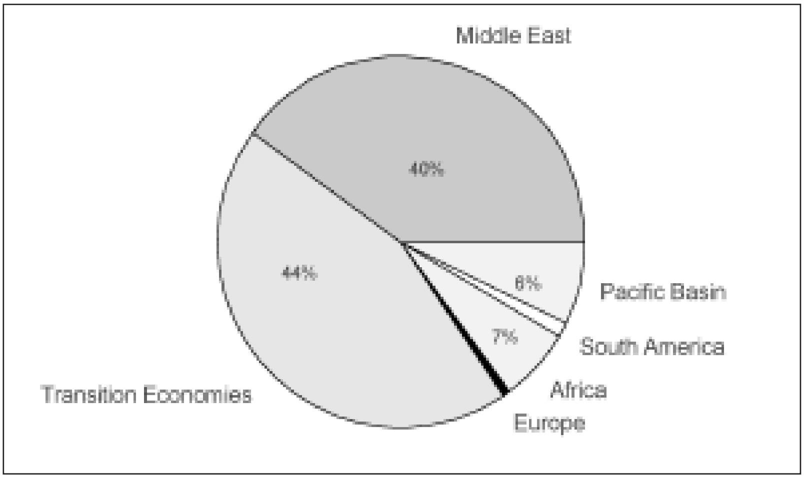
Source: James T. Jensen, Jensen Associates

The five major gas importing regions relied on interregional imports for only 11% of demand in 2005 but will be 41% reliant by 2030, with Europe and Northeast Asia the principal interregional importers.

With greater reliance on LNG, its supply outlook has become more uncertain. As recently as 2005 five countries accounted for more than 75% of the growth in the past five years in LNG trade – Qatar, Australia, Nigeria, Trinidad, and Egypt. In the next twenty years, 75% of new supplies are expected to come from Atlantic Russia, Australia, Venezuela, Iran and Nigeria. As will be discussed later, several of these new suppliers have significant national policy and geopolitical issues to resolve before new supplies will be forthcoming. Moreover, new supplies of LNG have been slow to develop due to long lead times in constructing facilities. These construction delays have developed and costs have escalated due to strong demand for supplies and contractors coming not only from the LNG industry but from petrochemicals, refineries, and oil and gas exploration and development. Past projections of $500-600 per ton of installed liquefaction capacity have been overtaken by more recent projections of $1,000 to $1,200 per ton. Thus, larger investments will be required to meet future demand. Many participants indicated, however, that these cost levels were not permanent and would diminish over time, though not back to former levels.

While most of the participants were confident that global supplies were sufficient to meet future needs, some related facts raised the question of whether market fundamentals, national policies or geopolitics will be more influential in the future. For example, by one estimate, more than half of the future potential for natural gas production will come from reserves that are not yet committed to long-term contracts. Overwhelmingly, these uncommitted natural gas reserves are located in the Middle East and the Former Soviet Union. Will sufficient funds be invested in each region to bring forth supplies in a timely fashion? Will countries permit investments from outside? Will internal political or economic considerations prevent resource-rich countries from expanding exports? These questions will be explored in detail later in this report but are summarized here.

Regional Share of the World's Uncommitted Gas



Source: James T. Jensen, Jensen Associates

84% of the world's uncommitted gas reserves are in the Middle East and the transition economies of the Former Soviet Union.

Based on market fundamentals, most new LNG supplies out to 2020 would come from the Middle East, with about 60 percent of the supply coming from one field—the jointly owned field known as the North Field in Qatar and South Pars in Iran. If additional Iranian gas is considered, then 90 percent of all uncommitted gas in the Middle East will come from these two countries—a questionable assumption, as will be discussed below. Outside Qatar and Iran, Saudi Arabia has significant natural gas reserves, but the Saudis so far have shown little interest in developing their gas for the LNG trade. Moreover, most of the Saudi natural gas is associated with oil, and production depends on the level of oil production in the Kingdom.

Russia, the largest holder of natural gas resources and reserves, traditionally has been linked to Europe via pipelines, but is now seeking to diversify its markets through pipelines to the Far East and possibly through developing its own LNG trade. Russia, however, is undergoing a major change in its approach to energy policy and, as discussed later, there is great uncertainty about future levels of gas production.

Outside the Middle East and Russia, there are substantial natural gas reserves that could be available for export. The areas with the largest uncommitted reserves include Algeria, Australia, Indonesia, and Nigeria. Other potential export areas include Angola, Egypt, Equatorial Guinea, Norway, Peru, and Yemen. Also, not to be overlooked is future natural gas development in Libya. While market fundamentals will have a profound impact in each of these areas, national policies also will be significant in countries such as Nigeria, Venezuela, Bolivia, and Indonesia.

LNG Value Chain

The outlook for LNG will depend upon many factors including the demand for LNG, the supply and availability of reserves, access to reserves, capital for investment, and the cost and availability of supplies, human resources and contractors. In discussing how various factors would impact the future of natural gas and LNG trade, the participants focused on some parts of the LNG value chain and found that some facilities were less costly and easier to build than others. For example, liquefaction facilities were high cost and depended upon the location of natural gas supplies. Transportation costs are still high and, while per unit costs are diminishing, there are long lead times associated with the ordering and construction of LNG tankers. The least expensive part of the value chain is facilities to re-gasify the LNG.

New companies are entering this trade in Europe and the U.S., perceiving opportunities to take advantage of both long-term relationships and spot markets. A change in business psychology is occurring, with many market participants wanting extra available capacity to take advantage of short-term changes in trading patterns and prices. These companies are introducing flexibility to the LNG trade that did not exist previously and are making it a more dynamic industry, similar to the trade in oil. It is interesting to note that due to the lack of such flexibility, recent large price disparities between the U.S. and Europe did not shift substantial supplies from one region to the other. As more flexibility is introduced, more price arbitrage is likely to occur, making for a more robust global market.

Regional Issues in Demand

In the discussion of regional demand for natural gas, the Forum focused on the three largest consuming regions: North America, Europe, and Asia, with a detailed look at Singapore and Korea.

North America

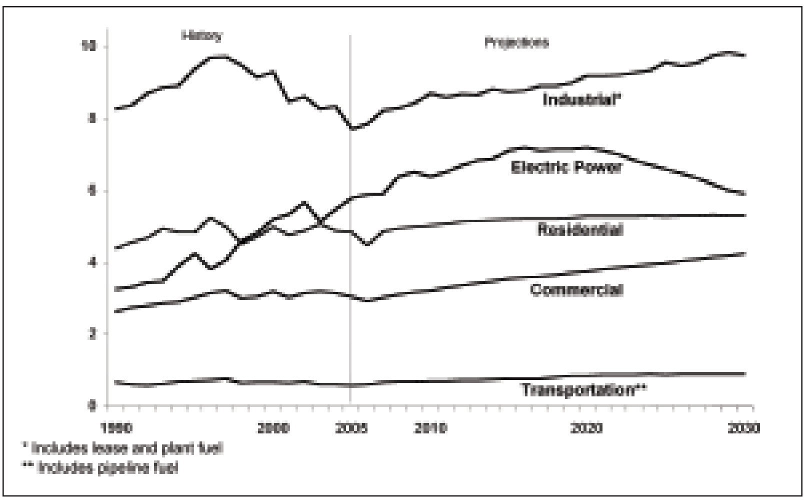
The North American regional discussion centered on the United States. The outlook to 2030 is drawn from the Energy Information Administration's (EIA) Annual Energy Outlook for 2007. A key element of the natural gas outlook is the real price of oil, since natural gas prices are linked to oil prices. In the reference case scenario, the average real price of oil to 2030 is projected at about $55 per barrel – with oil prices projected to decline from 2006 through 2015 and then steadily increase to $59 (about $95 in nominal terms) by 2030.

In EIA's projection of fuel consumption out to 2030, hydrocarbons continue to dominate, with liquids the leading source of consumption. Demand for these liquids will increase by 1.1% per year, while demand for natural gas will increase by 0.7% per year, from 22 tcf to a little over 26 tcf, with the largest growth in the industrial sector. Natural gas prices to 2030 are expected to average between $5 and $6 per thousand cubic feet (mcf), with prices falling in the early part of the projection period and then steadily increasing from 2015 to 2030. In nominal dollars, prices in 2030 are projected to be about

$9.60 per mcf. Not surprisingly, gas prices generally follow the pattern for oil prices.

It is in the consumption projections that some interesting and perhaps startling facts appear. In the early 2000's natural gas use for electric power generation was the fastest growing sector. This trend changes dramatically over the projection period due to the increasing cost of natural gas relative to coal. By 2020, gas demand in the electric power sector peaks at 7.2 tcf and then declines as new coal-fired generation displaces natural gas-fired generation. (It should be noted that EIA does not assume any policy changes in its projections, including such changes as constraints on carbon emissions that could reduce the cost advantage of coal.) Industrial use remains the largest consuming sector for natural gas throughout the period.

U.S. Natural Gas Consumption by Sector



Source: Annual Energy Outlook 2007, Energy Information Administration

The electric power sector is currently the fastest growing source of gas demand in the United States, with the growth rates in the industrial and commercial sectors set to outpace it in the middle of the next decade. These projections assume no major policy changes, such as imposing constraints on carbon emissions.

On the supply side, total domestic production is projected to increase from 18.3 tcf to 20.6 tcf in 2030, slower than the growth in consumption. As a result, net imports grow from 3.6 tcf to 5.5 tcf. Currently a substantial portion of U.S. imports come from Canada by pipeline. Canadian gas pipelined to the U.S. continues at a fairly constant level, between 2.6 and 3 tcf, through 2013 when resource depletion in Alberta and growing Canadian domestic consumption reduce U.S. imports from Canada to about 1 tcf. As these pipeline imports decline, the deficiency will be made up by increasing levels of LNG imports. By 2030, total U.S. LNG imports are projected to increase from 0.6 tcf today to 4.5 tcf or about 17% of U.S. natural gas consumption. A more disaggregated look at projections for U.S. natural gas supply to 2030 provides some important points. First, unconventional natural gas production will continue to grow and is expected to account for about 50 percent of U.S. domestic production by 2030. Second, natural gas via pipeline from Alaska's North Slope is assumed to enter the U.S. domestic market by 2018, increasing domestic production by 1.7 tcf. There was some skepticism within the group regarding the timing and likelihood that an Alaska natural gas pipeline will be developed. Many indicated more federal government leadership was required before progress could be made on the development of this pipeline.

The following conversions are used in this report:

1 billion cubic meters (bcm) =
35.3 billion cubic feet (bcf) =
0.73 million tonnes of LNG =
6.29 million barrels oil equivalent =
0.9 million tonnes oil equivalent =
36 trillion British thermal units (btu)

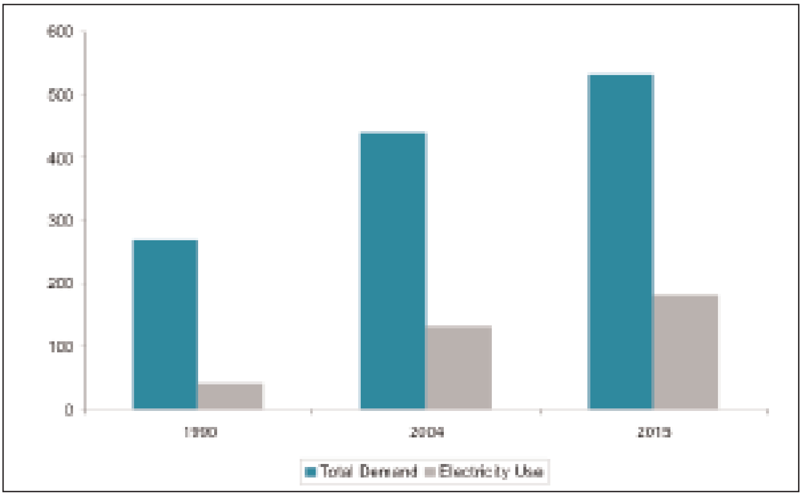
Looking at future LNG imports to the U.S., in addition to the current five U.S. re-gasification terminals, four more are under construction, and an additional twenty have been approved by the Federal Energy Regulatory Commission or Coast Guard. Proposals for fourteen others have been filed. Two terminals have been approved in Canada and three in Mexico. It is likely that some of these re-gasification terminals will not be built. Based on this activity, EIA projects that the total capacity of U.S. LNG receiving terminals will increase from 1.4 tcf in 2005 to 6.5 tcf in 2030. Of course there could be substantial variation in the actual level of LNG imports depending upon the price of natural gas.

In sum, the United States natural gas market confronts increasing demand, decreasing domestic supply, and stable to declining Canadian supplies, leading to a growing shortfall in total North American supplies. The shortfall increasingly will be filled by LNG. There are large uncertainties in the level of LNG imports due to how quickly U.S. unconventional natural gas supplies will be developed, whether natural gas from Alaska will enter the U.S. market, and the accuracy of future demand projections.

Europe

European natural gas demand is projected to increase by over 20 percent from 2004 to 2015. About one third of European demand for natural gas in 2015 will be for gas-fired electricity generation. This continues a trend that started in the late 1980s and early 1990s as European countries sought cleaner sources of fuel for electricity generation. Natural gas was the obvious choice, especially as climate change became an important part of European energy and environmental policy. Demand, however, is uneven across Europe. Italy, the United Kingdom and Turkey lead in the absolute demand for natural gas-fired electricity generation, while Germany is far behind and France relies on nuclear power rather than natural gas.

OECD Europe Evolution of Gas Demand



Source: World Energy Outlook 2006, International Energy Agency

Gas demand in the electricity sector will grow at almost twice the rate of total gas demand in Europe to 2015.

European gas supply is dependent upon production within Europe and imports. The UK, for example, has moved from self-sufficiency in natural gas to being a net importer. Other countries largely rely on imports of natural gas from North Africa and Russia. Italy, Spain and Portugal, for example, get most of their imports from North Africa. East and Central Europe, Germany and increasingly Italy get their imports from Russia. The question for the future is the capability of these exporting regions or countries to meet future demand growth from Europe.

An important issue for Europe is the availability of future supplies for export from Russia. By one estimate, it is projected that Russian domestic natural gas demand may increase by more than 20 percent by 2015. This increase will be faster in the electric power sector, where it is projected to grow by 30 percent despite a concerted effort to use more coal. One of the questions looming over domestic Russian demand is whether the low, subsidized prices charged for industrial use of gas will continue. Prices are currently projected to increase from about $40 per thousand cubic meters (mcm) in 2006 to $110 per mcm in 2010. While President Putin has approved these price increases, past efforts to increase domestic prices have run into political opposition and have been delayed or abandoned. If these increases do take place, Gazprom may be more willing to sell into the domestic market and not export additional gas to Europe. This potential change in Gazprom's policies could have a very significant impact on future gas supplies for Europe. However, Gazprom exports less than one third of its gas production to Europe but receives more than half of its revenues from these sales, and it is unlikely to reduce exports to its most profitable buyers.

Overall one third of Gazprom's production is exported today, but two thirds of its revenues come from these exports. If domestic prices increase to a level significantly above today's breakeven level, then Gazprom and other producers may find it just as lucrative to serve the domestic market without the necessity of building additional very expensive long-distance pipelines to Europe or Asia.

Gazprom has been engaged in a policy of increasing gas prices to former members of the Soviet Union by eliminating domestic subsidies and bringing cross-border prices closer to market levels. This policy has had varying degrees of success. But it also has led to accusations that Gazprom and Russia have been using energy as a political weapon, especially against countries that have tended to institute political regimes that are more western looking. Examples in recent years include Ukraine, Georgia, Estonia, Latvia, Lithuania, Poland, and Belarus. Europe, too, has raised its level of concern as interruptions in gas supplies from Russia, always considered extremely reliable, have occurred more frequently. This has led to calls from within Europe to seek alternative sources of supplies from the Middle East, Caucasus and Central Asia. This potential shift away from Russian imports can affect not only energy relations between Europe and Russia, but also global natural gas balances as Europe seeks supplies in more distant countries.

In the future Europe will need a more diverse electricity sector with less reliance on natural gas and more efficiency in both gas and electricity use to counter gas demand growth. It will need more diverse sources of natural gas supply and the infrastructure to support it, including more intraregional connections in both gas and electric power.

Asia

LNG plays a major role in supplying natural gas to Asian markets, with Japan and Korea by far the largest importers. Regional LNG supplies come from Indonesia, Malaysia, Australia and Brunei, while supplies from the Middle East come from Qatar, Oman and the UAE. One of the most important factors affecting LNG supplies to Asia is the gradual shift of sources from regional production to Middle East production.

Asian demand growth is due to the rapid economic and population growth and to the growth in income in many of the Asian economies. With increasing wealth among the population there is a growing demand for energy services, especially electricity. As Asia becomes more urban there also is growing demand for natural gas, since it is easy to use and is clean. There also are challenges. These include the development of infrastructure to deliver gas, the price of gas supplies and the ability of consumers to pay. Moreover, there is competition among the electricity and industrial sectors for new gas supplies.

Finally, most Asian economies are importers of natural gas. At the present time there is hesitancy among some buyers to sign long-term contracts for new supplies. The attitude is wait-and-see to find out how fast demand is growing and whether new economic supplies are forthcoming. Korea is a good example because of the growing gap between its committed supplies of LNG and its demand. Korean companies remain cautious about signing more long-term contracts and instead are relying more and more on short-term contracts and the spot market.

In the overall supply and demand balance for Asia out to 2030, coal remains the dominant fuel, followed by oil. Natural gas, however, is the fastest growing fuel, increasing at an annual rate of 4.0%. Power generation will drive coal demand and transportation will drive oil demand. The combination of power generation, residential, commercial and industrial demand will drive natural gas demand.

China leads all Asian economies with a 7.4% projected annual average growth of natural gas demand from 2002 to 2030, and it will consume the largest total amount of natural gas by 2030. Japan and Korea are the next largest consumers, but their annual average growth rate in consumption is relatively low at 1.3% and 2.9%. Indonesia is next in line after these three in total consumption in 2030, but also with a low growth rate of only 2.8%. Countries with very low consumption today but large projected growth include Vietnam (7.3% per year), Philippines (6.9%), and Singapore (5.7%).

Singapore's small size makes it a relatively small factor in regional gas demand, but it is dependent upon natural gas for 80 percent of its energy consumption. It is therefore developing LNG terminals to supplement the pipeline gas it now receives primarily from Indonesia and expects LNG to increase from a current 3% to over one third of gas imports. (India was not represented at the Forum; but it is a very important market for natural gas, has growing domestic production, is actively pursuing a gas pipeline from Iran, has several LNG terminals, and shows significant growth in LNG consumption.)

Overall, power and heat generation, followed by industrial demand, will consume most of the new gas supplies in Asia. Coal will show the biggest growth in the power and heat sector, followed by natural gas. All other fuels, including oil, nuclear, and hydro, will not increase their market share in the power sector out to 2030. Korea is an exception in demand growth for natural gas, since the residential, commercial and industrial sectors that are supplied by the city gas pipeline system are growing faster than the electric power sector.

Most of the new demand will be in the form of LNG. For Japan, Korea and Taiwan virtually all new gas will arrive as LNG. While there are uncertainties for China, a little more than half of its new supplies are likely to be in the form of LNG. Most of this new LNG will come from the Middle East rather than from within the region. Many future gas supplies to the largest consumers in Asia are not committed under long-term contracts. In Japan, for example, about 25% of its natural gas demand for 2015 is not under long-term contracts as its present long-term contracts with Indonesia, Malaysia and Brunei expire. About 90% of Japan's expected 2030 natural gas imports are not yet covered by long-term contracts. Korea is looking at a similar growing gap between committed supplies and future needs—about 11 million tons per year in 2013 widening to almost 23 million tons per year in 2020.

A principle reason for the lack of future supply commitments is the dearth of timely projects, not the inadequacy of reserves. No new projects in Asia will be on line in the next four to five years. Some of the problems confronting Asian producers include significant cost increases in all stages of the LNG chain; severe bottlenecks in the fabrication of equipment for ongoing projects; major shortages in skilled workers for these projects; and unique internal problems in Indonesia (including exhaustion of some large gas fields) resulting in new LNG projects being extended well into the future. While these shortages and cost increases are likely to abate, they are creating tightness in the LNG market through 2012.

While there is some attempt to introduce price flexibility into new contracts, for the most part LNG pricing in Asia continues to rely heavily on the JCC (Japanese Crude Cocktail) formula—a basket of oil imported into Japan from various oil exporting countries. Pricing was linked to oil early in the development of LNG contracts reflecting greater substitutability in power generation between natural gas and oil. As this substitutability lessened, tradition has maintained the pricing linkage. As a result, as oil prices increased over the last five years, the landed LNG prices into Asia have increased as well.

Recent energy trends in China indicate a dramatic increase in demand. From 2002 to 2004 primary energy demand increased by 38 percent, with coal use responsible for 89 percent of this increase. Natural gas consumption increased by 36 percent and electricity by 35 percent. Electric power capacity is increasing dramatically, with 101 gigawatts of capacity added in 2006 alone. China increasingly is seeking natural gas supplies to diversify its energy mix. It has twenty LNG terminals in the planning stage, with a terminal at Guandong now operating and one at Fujian opening in the near future. Moreover, China has signed an agreement with Turkmenistan to buy gas via pipeline, and another with Russia for the purchase of gas from the Kovykta deposit in Eastern Siberia is being delayed by pricing disputes.

Singapore

Even though the Singapore market is small, it presents an interesting case study. A variety of global and domestic forces are putting energy high on Singapore's domestic agenda. Growth, especially in China, is creating opportunities and pressures throughout Asia. Tightening energy markets are forcing Singapore to refocus on its energy security concerns. Finally, growing environmentalism is calling for another look at how energy is used within Singapore.

The domestic focus is on the appropriate fuel mix given Singapore's urban population and limited land. Consideration is being given to where to find new supplies and how to sustain secure energy for the future. Natural gas supplies are at the top of the agenda due to availability and environmental cleanliness. Coal also is being considered; however, technology is important in order to use coal in the cleanest way possible in Singapore's urban environment. While neighboring economies are discussing nuclear power, this is not a consideration for Singapore with its limited land area. Presently, Singapore's electric power supply comes primarily from natural gas, at 80 percent of consumption, followed by incineration of waste at 17 percent and oil at 3 percent.

In May 2007, Singapore passed a Gas Act that altered its industry structure by opening the natural gas market. Open access is now required for LNG terminals and procurement. Singapore currently consumes about 6.6 billion cubic meters (bcm) or 4.8 million tons of LNG. A new LNG project is underway that will result in a new terminal by 2012. In global terms, Singapore's requirements are modest, and planners expect that it should be able to gain access to the market relatively easily. Singapore also is seeking a future role as an LNG trader, similar to its role in oil, and thus it is seeking sufficient capacity for trading purposes without undermining its energy security needs. The requirement of open access for LNG terminals, that is, permitting many shippers to use the terminal, is expected to permit Singapore to add three million tons of capacity from 2012 to 2018 to meet increasing domestic demand and to allow for trading. In addition Singapore and its neighbors are exploring the possibility of a trans-ASEAN pipeline grid in the near term and a trans-ASEAN power grid for the long term.

Korea

Korea is the second largest importer of LNG in Asia, after Japan. It is also a substantial oil importer – fifth largest globally and third largest in Asia behind China and Japan. Korea's energy mix relies most on oil, with 50 percent of consumption, followed by coal at 24 percent, nuclear at 14 percent, natural gas at 12 percent, and renewables at 2 percent.

Korean natural gas consumption is divided between electricity and city gas segments. City gas includes residential, commercial and industrial segments. It comprises about three fifths of all natural gas demand and is expected to increase to 79% by 2020, with the highly seasonal residential consumption being the fastest growing sector. All gas comes into Korea in the form of LNG and is distributed through pipeline networks concentrated in the largest population centers surrounding Seoul and Pusan. The LNG is imported from within Asia—Indonesia, Malaysia, Australia and Brunei—and from the Middle East—Qatar, Oman, Egypt and UAE. Qatar is its largest supplier, followed closely by Indonesia.

Korea is looking at a growing gap between committed supplies and future needs and increasingly is looking outside of Asia for future supplies. This gap will be about 11 million tons per year in 2013 and will widen to almost 23 million tons per year in 2020. Korea is examining various supply options including gas from the Caspian, Russia and Trinidad. While LNG will continue to dominate the future supply picture, Korea is also looking at pipeline options from Eastern Siberia. Shorter-term contracts and the spot market are also being used to increase supply flexibility. But Korea's energy security concerns are increasing as it shifts away from long-term contracts and it makes contingency plans for the decline in natural gas supplies from Indonesia, now about 25 percent of its supply. These concerns may lead Korea to liberalize its license policy for LNG terminals and to reform its natural gas industry.

Asia will continue to rely on LNG for most of its natural gas supplies. Pipeline gas currently plays a relatively small role but may increase substantially with the development of new pipelines from East Siberia and Central Asia. But regional supplies will not be able to meet Asia's voracious appetite for natural gas, and increasingly the additional supplies will come from the Middle East, providing additional evidence of the emergence of a global natural gas market.

Regional Issues in Supply

The Forum discussion of regional supply issues focused largely on the three largest natural gas reserves owners—Russia, Iran and Qatar. Each country presents different economic, national policy and geopolitical issues that create uncertainties in the development of future supplies and make increased exports in the long term unlikely.

Russia

While Russia has huge natural gas reserves—about 26% of world reserves—it is difficult to determine the rate of development. Gazprom dominates the industry. Its investment practices are highly questionable, being more politically motivated than economically based, and its production figures are met with much skepticism. In 2006, Gazprom produced about 550 bcm, 90% of Russia's 2006 production. Gazprom's own estimates of its production in 2020 vary widely, with a range from 550 to 670 bcm. Other Russian analysts have tried to develop projections of future production but have had difficulty in arriving at accurate estimates.

While there are independent natural gas producers in Russia, increasingly Gazprom is exerting full control over the development of all natural gas reserves in Russia. Independent producers increasingly are coming under Gazprom's influence, including independents such as Novatek, Rospan and TNK-BP. It is likely that Gazprom's control will be complete by the end of 2007 or by the Presidential election in March 2008.

Gazprom, however, is evolving. In the 1990s while the oil industry was going through the divestiture of state-owned assets, a similar goal was set for Gazprom. The oligarchs who bought other state-owned industries in the 1990s, however, were not interested in Gazprom assets. Consumer subsidies in the form of low domestic natural gas prices and long-term contracts dominated the industry. This was very different from the oil industry. The oligarchs found the natural gas business less susceptible of quick profits and thus they avoided it. There was some divestiture of assets and the development of small independent natural gas companies, but Gazprom was able to retain its core businesses through the Putin era, when the government moved to strengthen the dominant role of Gazprom. The appointment of Alexei Miller as Gazprom's President put Putin's man in charge. Putin controls many of the top level appointments and monitors the company's activities daily, and decision making within Gazprom is totally opaque.

As previously mentioned, Gazprom has been increasing natural gas prices to Former Soviet Union states such as Azerbaijan, Georgia and Ukraine. The increases have been substantial and in some cases have brought them to levels equal to those in Western Europe. There was a widespread perception in Russia that increasing these prices, in particular to Ukraine, would throw these economies into recession or worse. While there was a temporary economic slowdown in Ukraine after the initial introduction of higher natural prices in 2006, since then economic growth has been quite robust. This has given Gazprom a strong argument that increasing prices within Russia will not lead to an economic slowdown. As a result, domestic industrial gas prices are now scheduled to increase through 2011 to levels that should make them equal to Western European prices, unless political factors intervene.

Since the future of Russian production is so dependent upon Gazprom, Gazprom's future is critical to the European and global gas supply picture. Gazprom is becoming a more commercial company. Gazprom asserts that it intends to establish a more predictable investment program. After the election in March 2008, it is likely that there will more internal management changes, possibly leading to increasing transparency in the decision making process. Some Forum participants expressed doubt about these changes occurring in such a short time frame.

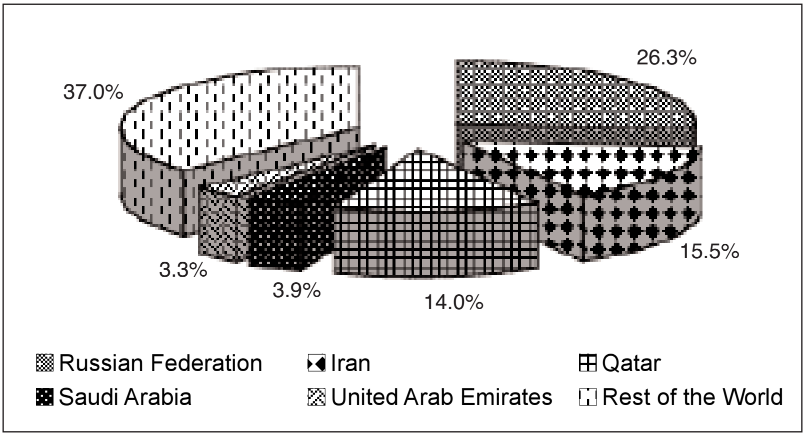
As stated above, Gazprom's natural gas production is more politically motivated than economically based. Its national policy is not to develop new fields until export markets are developed and long-term contracts are in place. Based on this policy the next large natural gas fields to be developed, in the Yamal Peninsula, will be delayed until there are firm markets in Europe or China. Without them, Yamal development keeps slipping. Putin's goal is to secure the role of Russian companies in global markets. Foreign investors in Russia are expected to provide access to foreign markets so that Russian companies can continue to expand and become global players. Companies either comply or are excluded or squeezed out of the market. Moreover, those in power now control huge financial flows and are able to enrich themselves without taking ownership positions.

The Russian government is pursuing its own interests and, as a result, no new fields will be developed until there is greater certainty in the export markets and long-term contracts are in place. Even then, Russia may not be willing to invest to satisfy this external demand. Thus, future natural gas exports from Russia are highly uncertain. Production is declining from existing fields; delays exist in developing new fields; domestic consumption is increasing, although this may be tempered if price increases occur; and therefore less future production is likely to be available for export.

Iran

The second largest holder of natural gas reserves is Iran, with about 993 tcf or 16 percent of global reserves, behind Russia at 26 percent and ahead of Qatar at 14 percent. Iran's production in 2006 was about 16 billion cubic feet per day (bcf/d). Iran claims that this will increase in 2010 to 24.8 bcf/d and then fall back to 20.7 bcf/d in 2020. However, only 20 to 30 million tons of LNG may be developed and even smaller volumes in pipeline gas for export. (20 million tons of LNG = 974 bcf)

Total Gas Reserves Worldwide



Source: FACTS Global Energy Group

Russia has 26% of the world's gas reserves, with Iran possessing over 15% and Qatar 14%.

Presently, Iran is a relatively small exporter of natural gas with total annual exports of 200.9 bcf, with most going to Turkey and very small amounts to Armenia and Azerbaijan. This places it 15th among the world's natural gas exporters. The reasons for these limited exports include a very large gas re-injection program to sustain crude oil production, a massive expansion of the domestic natural gas pipeline grid selling gas at very low prices, a large program to develop the petrochemical industry, a shift towards CNG to reduce gasoline demand, a lack of external funds for investment in production, and major political opposition to natural gas exports.

Most of Iran's natural gas production is used for re-injection in producing fields in order to maintain its crude oil production. Re-injection accounted for about 56 percent of its gas production in 2000, rose to 64.7 percent in 2005, and is expected in increase to 72.2 percent by 2020. The Iranian government is projecting an increase in crude oil production from today's 4 million barrels per day (mbpd) to 5.4 mbpd. This means an increase in production capacity of three million barrels per day to account for the natural decline in production as well as for new capacity. The Forum discussion indicated that this level of investment and capacity building was impossible given today's political environment. It is more likely that oil production will remain at the current level or fall. But even for production to remain level, there will have to be a massive natural gas re-injection program of 10 to 11 bcf/d, which is about the same level as Qatar's LNG exports.

Historically, a significant percentage of Iran's natural gas production has been lost to shrinkage (dry gas without liquids that is 8-13% less than produced wet gas), loss (gas that escapes from pipelines) and flaring (burning of associated gas). This percentage is declining, however, and is expected to continue declining, from 19.4 percent in 2000 to 3.0 percent in 2020. This will approximately offset the increased re-injection of gas.

The remainder of Iran's natural gas production, averaging about 25 percent between today and 2020, is for domestic consumption and exports. Iran's domestic gas market in the last five years has been growing at an annual average rate of over 10 percent and is expected to continue its robust growth at over 7 percent out to 2020. The primary uses for natural gas in the domestic market are power generation and residential and commercial demand. The latter two areas will comprise the largest domestic uses by 2020. With very low domestic natural gas prices there has been rapid growth in all domestic sectors. Price hikes have been put on hold, especially for power and industry, in order to promote development of these sectors. In the industrial sector, Iran is putting in place more than 27 million tons of new petrochemical capacity by 2010. Almost all of these plants rely on natural gas for their supply. In the transport sector, compressed natural gas will be used to displace gasoline in order to reduce the level of gasoline imports. There are several domestic gas pipeline projects under construction or scheduled for construction in the near future. The goal of these projects is to increase use of natural gas and reduce the use of oil. One of the projects, however, will create capacity for export to India and Pakistan, since its line is larger than can be used just for domestic purposes.

In addition, many of Iran's projects have been delayed due to the lack of outside investment resulting from sanctions affecting international financial markets. At least as important is the mismanagement of the energy sector stemming from divided authorities and internal disorientation in the government. Internal subsidies also have contributed to an unwillingness to invest, since the prospect of an adequate return on investment is poor, and growing domestic opposition to natural gas exports has slowed project implementation. Moreover, Iran has a habit of announcing various agreements with no intention of implementing them. They often are announced for external consumption to illustrate its continuing role in oil and natural gas markets. Despite these problems, there will be some exports due to pressure from China and India, both of which need large infusions of natural gas to sustain their economic growth.

In sum, Iran is not likely to have sufficient capacity to meet all its export commitments. Domestic consumption will be its highest priority. Increasing domestic demand means less gas available for export. No increased gas exports are foreseen given the current economic and political environment, and disruptions to export customers can be expected in the future if domestic needs require even more natural gas.

Qatar

The pessimistic view of future Russian and Iranian exports is mirrored in Qatar and the rest of the Middle East, where there is a growing shortage of future LNG capacity. Yemen, Oman and Abu Dhabi have insufficient reserves for new capacity. Qatar, owner of the world's third largest natural gas reserves and the single largest natural gas field—the North Field, has abundant reserves, but a significant percentage already is committed. No additional sales are contemplated.

Qatar has been aggressive in developing its fields. It created two state-owned companies, Qatargas and Rasgas, to develop and market its natural gas in conjunction with international oil companies. Partners with Qatargas include ExxonMobil, Total, ConocoPhillips, Mitsui and Shell. Rasgas' partner is ExxonMobil. Since Qatar is so far from the countries seeking its natural gas, all of its exports have been in the form of LNG. Deliveries to Asia (Japan, Korea and Taiwan) began in 1997, have grown significantly to over 2 bcf per day in 2007, and will remain flat through 2012. Deliveries to Europe began in 2003 and are expected to reach about 4.5 becf/d by 2012, more than deliveries to Asia. Lastly, LNG deliveries to North America have started on a spot basis and will continue to grow on a committed basis from 2008 through 2012, to about 3 bcf/d. Increasingly, LNG is moving in the direction of Atlantic markets rather than Asian markets.

Qatar represents about 14 percent of global LNG trade. Given that spot cargos now comprise about 13 percent of global LNG shipments and given Qatar's substantial role in the spot market, Qatar (and the Middle East) plays the role of swing producer between the growing Asian and Atlantic markets.

Qatar is now approaching a self-imposed limit to further development. LNG exports will grow from 30 million tons per year currently to 77 million tons per year by 2012. While there still seem to be substantial reserves to be developed, a more conservative wait-and-see approach rather than additional development of production and export capacity apparently is now Qatar's policy. Part of the reason is the growing uncertainty over the size of the North Field. Recently, ConocoPhillips hit a dry hole. Speculation has increased that the level of natural gas reserves may not be as high as the generally accepted number of 900 tcf or more. Pipeline and gas-to-liquids (GTL) projects have been reduced substantially while domestic consumption has skyrocketed. If reserves are lower, then Qatar must be careful not to over commit its reserves for future development. It has said openly that it will not consider any more LNG development until 2010, and even then its domestic needs for power generation, desalination and industrial growth will take top priority over its exports.

Qatar dominates the addition of LNG capacity through 2012. Four other countries—Nigeria, Australia, Russia and Iran—are planning substantial increases that will total two thirds of new liquefaction capacity or a combined 178 million tons per year. Given the discussion about Russia and Iran, the participants at the Forum doubted whether these plans will play out fully. Russia could possibly reach its planned 20 million tons of LNG capacity per year, but at substantially higher prices. It is unlikely that Iran will reach its planned 39 million tons per year. Nigeria is going through increasing domestic turmoil, and the likelihood of it achieving its 60 million tons of planned capacity is doubtful. One participant thought that Nigeria could reach a total of only 43 million tons per year. Australia, with plans for 59 millions tons of new capacity, alone among the four has a strong likelihood of achieving its goals, but at a later date than now projected. Other countries such as Malaysia are essentially played out. Indonesia with large resources may get back into the exporting business but at a much lower level. This puts greater importance on Qatar, which is today's largest LNG exporter and will be the largest by far in 2012.

Qatar's success rests on several factors including its large known gas reserves, its willingness to develop these reserves in concert with a small number of highly regarded international oil companies, its foresight in developing world class export facilities, and strong government support and rapid decision making. Can other countries – Nigeria, Russia, Iran, and Australia – offer the same key success factors?

Technology Issues

The discussion of supply and demand issues in the global market consistently indicated that technological developments will have a major impact on market fundamentals. Technology will also have an impact on geopolitics, since its use can affect how countries produce their resources.

The group discussed the highly technical nature of the industry and the complexity of developing, producing, and transporting natural gas. In LNG, the highly complex nature of liquefaction facilities requires cutting edge technologies not only to produce the LNG, but additional technological advances to bring costs down. Recent developments include cryogenic pipelines, mega trains and floating liquefaction facilities. Technology has brought innovations to the transportation of LNG where tanker size and other technological developments have helped transform the economics of the industry. At the delivery end, on-board regasification and storage is helping to reshape the industry by finding ways to deliver LNG to areas where onshore re-gasification facilities cannot be built.

Similar technological developments are expanding the potential use of natural gas for gas-to-liquids (GTL). Rather than liquefying the natural gas, new processes are transforming the gas into a clean liquid that has similar characteristics to diesel. Stranded gas can be converted to a liquid that is highly marketable and easier to transport than pipeline or liquefied natural gas. Oryx, the first of the big GTL plants, is being developed with Sasol in Qatar and is costing $35,000 per barrel per day of capacity, with a total cost of about $1 billion. Shell's Pearl GTL facility, now under construction in Qatar, is costing about $100,000 per daily barrel of capacity and the total cost is likely to be in excess of $18 billion. This facility needs crude oil prices in the range of $60-70 to be economic. The dramatic cost increases have lessened the enthusiasm for GTL technology substantially.

Unconventional gas

Unconventional natural gas resources are very large—more than 30,000 tcf—and producing these reservoirs requires a different mindset from normal production. As the quality of new natural gas reservoirs deteriorates relative to earlier discoveries, enhanced technology is required to produce them, "to produce gas from lousy rocks," in the words of one participant. These reservoirs include tight gas sands, gas shales, coal bed methane, and gas hydrates. All of these deposits have similar characteristics. They have dense permeability and therefore require significant hydraulic fracturing in order to sustain the gas flow. They also require different drilling strategies.

The largest reserves of tight gas sands and gas shales are in North and South America. Substantial gas shales also are found in the Middle East and China. The worldwide resource for gas shales exceeds 15,000 tcf, or almost twice the level of total natural gas reserves. Tight sands are found throughout the globe in relatively small amounts. North and South America have the largest estimated reserves of tight gas sands at over 7,000 tcf—the largest unconventional producing resource in the U.S. It requires multiple hydraulic fracturing treatments from many wells which account for the largest cost of production. In one example given, on a 40-acre area with 48 wells drilled, the recovery rate was about 55 percent; on a 20-acre area with 82 wells, the recovery rate increased to 75 percent; while on a 10-acre area, 165 wells produced an 80 percent recovery factor. More wells clearly improve recovery. New technology is improving recovery and reducing the environmental impact. For example, a single well pad can permit drilling 16 wells that can access more discontinuous sands, and allow a higher level of fracturing while minimizing the environmental footprint.

The gas shale industry began in the U.S. in 1821 in Fredonia, New York, where gas was found seeping naturally from a gas shale deposit. A small well was drilled and gas piped to nearby buildings. Since then the number of wells drilled into gas shale deposits has increased to over 40,000 today. Production from these wells is over 1 tcf annually—about 5% of total U.S. gas production—with a potential resource base of 500 to more than 1000 tcf in gas shale resources alone. Gas shales are located in basins in many parts of the US, including the Appalachia, Michigan, Illinois, Arkoma (Arkansas-Oklahoma), Fort Worth, and San Juan (New Mexico). The shales are found in thick layers (up to 1,900 feet thick) ranging from 600 to 11,000 feet deep depending upon the location.

In Texas most conventional gas fields are in decline, while the Barnett shale is rapidly expanding. With a 310 percent increase in production in the last five years, it is now one of the largest producing fields in the state. This rapid change is due in part to the increase in horizontal drilling, which is reducing the cost of production. Multiple fractures are required to maximize gas flow to overcome poor reservoir quality, and one horizontal well can utilize multiple fractures rather than having to drill many wells to achieve the same results. Another technology used in conjunction with horizontal drilling is microseismic—the use of many small explosions to characterize the formation in a way to maximize gas flow.

With a significant range in drilling costs, from $0.93 to $2.44 per thousand cubic feet, unconventional gas can be quite attractive in today's high priced natural gas market. The Barnett shale basin needs natural gas prices in the range of $4.50 to $5.00 per mcf for development. Some areas may need prices as high as $6.00 to $7.00 for development. (Recall that the EIA projected real average gas prices of $5.50 mcf out to 2030).

Some participants questioned why there is such a strong push for LNG capacity in the U.S. when unconventional gas development is moving forward in such an aggressive manner. One possible answer is the "dream" of $4.00 gas in the U.S. with LNG imports. Based on the discussion of circumstances in many potential exporting countries, many participants thought that $4.00 gas was indeed just a dream. Another possible answer is that U.S. energy models have not adapted fast enough to the fast pace of shale development and are overestimating the need for LNG and underestimating new supplies from unconventional resources. If this is true, the U.S. companies may be planning too much LNG capacity and future reliance on LNG is significantly overstated.

Gas Hydrates

A final discussion on evolving natural gas technologies focused on natural gas hydrates, a source not yet competitive but of interest because of the huge resources to be found globally. Gas hydrates are crystalline solids consisting of gas molecules, primarily methane, surrounded by a cage of water molecules. Gas hydrates form when gas and water combine under the appropriate conditions of pressure and temperature. When gas hydrates are warmed or depressurized they turn back to gas and water. The hydrates concentrate natural gas.

There are several types of gas hydrate deposits. They can be dispersed in shale, or filling the veins and fractures of shales, or located on the sea floor in mounds around vents, or filling the pore space of subsurface sands and gravels. They are found onshore in Arctic areas and in water along the continental shelf. Estimates of gas hydrates in the U.S. exceed hundreds of thousands of tcf, more than all other natural gas resources combined.

Producing gas hydrates is expensive and complicated, and much of the resource base will not be produced in the foreseeable future. A hydrate stability zone has to be found, a gas source has to be found and there has to be a method of gas migration – usually through a well drilled into the gas source within the hydrate stability zone. Many believe that a "bottom simulating reflector" or BSR has to exist in order to find gas hydrate deposits using seismic data. But recent research leads other experts to the conclusion that a BSR is not required to find a gas hydrate deposit. What is required are appropriate pressure and temperature conditions, reservoir quality sand, and adequate gas flux.

From the perspective of those working with gas hydrates, many of the pieces of a commercial industry are coming together. Companies applying existing technology are making strides while new technology is being developed. While past and present test wells have led to gas hydrate recovery, none of the wells is commercial. By one estimate, commercial wells are five to ten years away, although this estimate engendered quite a bit of skepticism among some of the participants.

The Geopolitics of Natural Gas

In addition to market fundamentals and technology, national policies and geopolitical factors can have a significant impact on the supply and price of gas. Geopolitics in the context of this report focuses on countries using energy issues to achieve external political objectives and diverging from free market principles. The Forum looked in particular at two aspects of this global questions—Europe and its suppliers, and the Middle East and Asia.

Russian supply to Europe

As imports become more important to Europe, so do the political relationships between Europe and its external suppliers, Russia, Algeria, Libya, Egypt, and Nigeria, and new potential supply sources in the Caspian region and the Middle East. In examining the relationship between Russia and Europe, it was noted that Russian gas comes from three major sources – Gazprom production, independent production, and Central Asia. These sources supply the Russian domestic market, Commonwealth of Independent States (CIS) countries and European countries. Each of these supply sources and markets is subject to complex economics and politics that are rapidly changing.

Gazprom's production from its existing fields has been declining for several years. By 2020 there will be a decline from today's annual production of 550 bcm to about 350 bcm, not enough to meet demand from the three markets indicated. If the potentially enormous Yamal fields in the very far north of Eastern Siberia come on line by 2011, then Gazprom production actually will increase for a period of time before declining again by 2020. With Yamal on line, production would stay above 500 bcm for most of the period out to 2020. If first Yamal production slips to 2015, then production will sink below 500 bcm by about 2012 or 2013 and stay below 500 bcm out to 2020. Gazprom must make massive investments to bring Yamal online and it has not done so. To date, its investment level has been barely sufficient to maintain its licenses. It certainly has not made the investments necessary to bring first gas on line by 2011, and there is skepticism about whether it has made or will make the necessary investments to bring first gas on line by 2015.

Some European political leaders have come to the conclusion that there is a pressing need to reduce the reliance on imports from Russia. In part this reflects the view that President Putin does not share the same democratic values as the Europeans, in light of Putin's attitude towards free elections and an open and free media and ownership of strategic resources by the west. There is a widespread perception that Russia does not respect the rule of law or legal contracts; that corporate governance is unimportant; and that corruption is endemic in the business environment. There is growing centralization and state control of energy and other industries. Some Europeans fear from all this that Russia will use oil and gas as a weapon against European and other countries in order to achieve economic and political objectives. In addition, some Europeans perceive that Russia supports a gas cartel to attack the European Union's interests. Moreover, Russia has not ratified the Energy Charter that would provide for third party access to Russian gas pipelines and which the Europeans see as providing protections for foreign investors in Russia. There is also cause for concern over Gazprom's desire to buy downstream assets in Europe while European countries are not given the same reciprocal opportunities in Russia.

Of course, Russians have a different viewpoint. They consider European governments as hypocritical. They see one set of rules for

Russia and its friends and another set for all others. They perceive that western countries were happy when it was weak in the 1990s but now are unhappy with Russia's reassertion of its legitimate interests. They see the EU dominated by anti-Russian new members and say that EU regulators have undermined long-term natural gas contracts and the security that they bring. Russia also sees the EU as a gas importers' cartel. The Russian government concludes from all this that it will not allow the Europeans or the U.S. to dictate Russia's national interests—domestic and international.

There is widespread belief in Europe that Gazprom is not a reliable partner, due in part to recent disruptions in the flow of natural gas through Ukraine and Belarus. One participant argued that the evidence does not support this belief. Gazprom receives more than $40 billion per year from its exports to Europe and Eastern Europe and therefore has the incentive to maintain its reliability. Gazprom has extended all of its 20-30 year contracts with western European buyers well before their expiration dates. All are legally binding agreements with international arbitration and liquidated damage provisions. Gazprom Marketing and Trading has been a long-term presence in Europe trading natural gas from many countries, not just Russia. Russia's biggest problem is reliable transit through Ukraine and increasingly through Belarus. As a result, Russia is taking steps to limit its exposure to Ukraine and Belarus by building pipeline bypasses that are under its control. These include the Nord Stream pipelines under the Baltic Sea to Germany and the newly announced South Stream pipeline in the Black Sea. From Gazprom's perspective, it has consolidated its position in Europe and is taking steps to provide secure, reliable transit.

The first of the Nord Stream pipelines is due to open in 2010 and the second may open by 2013 or 2014. These pipelines would provide capacity directly from Russia to Germany, bypassing both Ukraine and Belarus. They are intended to replace existing capacity in the latter two countries rather than adding substantial new capacity. The source of the natural gas could be the Shtokman natural gas field in the Barents Sea or Yamal. Both have been the subject of delays. Recently Gazprom has announced that it intends to partner with Total in the development of Shtokman. A new company will be formed to develop and operate Shtokman. Gazprom will retain 51 percent, while foreign investors will be offered significant shares in the company; Total was offered 25 percent. These announcements may augur an acceleration of the development of Shtokman, which now is slated to come on line somewhere around 2017. But Shtokman is not a substitute for Yamal, since Shtokman has about 90 tcm of reserves while Yamal has 280 tcm.

The South Stream pipeline is a very recent development. Gazprom already operates the Blue Stream natural gas pipeline under the Black Sea to Turkey. This has been a success. There have been discussions aimed at expanding this system. But Turkey has been selling Russian gas to other countries in violation of the long-term contracts. Rather than expanding Blue Stream and letting Turkey continue with its violations, Russia is now looking at another bypass. With the announcement of a feasibility study for South Stream, a new strategy may be to build a pipeline directly to Bulgaria under the Black Sea. Gas going this way could supply markets throughout Europe without having to transit Ukraine or Turkey. The message is that if you mess with Russian natural gas, Russia will bypass you. But Russia cannot bypass every country. Once a pipeline has been built, it is difficult to avoid problems in the country or countries where it transits. Russia's policy is to diversify its pipeline options, and with sufficient spare capacity it can avoid problems and perhaps punish countries that create problems.

Gazprom views these pipelines as transit-avoidance systems, increasing the reliability of natural gas supply to Europe. As mentioned, they are intended to replace existing transit routes through Ukraine and Belarus, rather than add substantial new capacity for new supplies to Europe. They suggest that Russia is concerned about the reliability of European supply rather than the opposite. Both systems are very expensive and if built will raise the transportation cost to Gazprom unless European customers are willing to pay for the enhanced reliability.

What about the future of Russian natural gas supplies to Europe? Because supplies will be tight until at least 2015 when Yamal is scheduled to come on line, it is likely that supplies to Europe will peak at 180 to 200 bcm per year by 2010 or shortly thereafter and not increase further. The impact may be felt in the Russian domestic market rather than the export market. Moreover, internal prices for natural gas are moving towards parity with European levels (at least in the industrial market, which makes up most of the domestic market) diminishing the incentive for Gazprom to export its gas. In the past, Gazprom was content to leave the domestic market to independent companies since profits, if any, were small. As this market becomes more profitable, Gazprom will be less likely to leave it to others and will move to assert its control over the independents in order to maximize its control.

African supply to Europe

Two pipelines now connect North Africa to Spain and Italy, with additional pipelines planned. Algerian pipeline supplies will peak in the mid 2010s, or possibly sooner if domestic demand continues to grow rapidly. There is no likelihood of pipeline supplies from Egypt and limited additional LNG capacity. Nigeria will continue to supply Europe through LNG capacity; however, new capacity is threatened by political turmoil and is likely to be delayed and not at the levels planned. Equatorial Guinea and Angola are new sources with large uncertainties in their potential supply. Libya is the great hope for substantial new supplies but is more likely to provide LNG than pipeline supply. Economics and national issues, not geopolitics, appear to be the major factors in Africa.

Caspian-Central Asian supply to Europe

The Caspian-Central Asia region presently supplies Europe through the Gazprom system. This gas comes mostly from Turkmenistan and is used internally or is sold to Ukraine; however, it frees up Russian gas that can be exported. Could the Caspian-Central Asia region supply Europe more directly? Azerbaijan is developing its natural gas reserves and will not have large exports available until the mid 2010s. For both Kazakhstan and Turkmenistan, Europe is likely to be the third choice after Russia/CIS and China. Turkmenistan, for example, just announced an agreement for new sales of natural gas to China through a pipeline yet to be developed. Iran is a highly unreliable source of supply. Thus, even though Europe, with U.S. support, is looking to the Caspian-Central Asia region for additional natural gas supplies, little is likely to be forthcoming.

What does this mean for Europe? Politically, many in Europe increasingly view Russia as unreliable and potentially threatening, and Russia sees Europe as hostile. The concern over natural gas is reinforcing a worsening political climate. Economically, possibly after 2015, most likely after 2020, there will be no increased availability of natural gas in Europe. This means that large scale gas-fired electricity generation cannot be built. Europeans will have to look elsewhere for sources of incremental power generation. In addition, from a policy viewpoint Europe will not be able to achieve its carbon reduction ambitions using more natural gas. While this outcome is not set in stone, the supply realities of natural gas will have to change quickly and substantially to produce a different outcome. Europe has a little breathing space until this reality occurs. The question is whether Europe will take the opportunity to make some sensible investments in storage to cope with short-term volatility or take steps to lessen its future natural gas demand. One participant concluded that faced with a false sense of security resulting from adequate current supplies, it is unlikely that European policy makers will react effectively and in a timely fashion.

Middle East supply to Asia

The discussion of Asian imports of Middle East gas led to the conclusion that geopolitical factors tend to gain importance as the mismatch between supply and demand becomes larger. The natural gas trade is based upon a strong interdependence between buyers and sellers due to the reliance on long-term contracts. Despite this interdependence, both LNG and pipeline transport face significant security problems. For LNG, these include sea-lane chokepoints and the consequences that would arise from the temporary shutdown of these sealanes. For cross-border pipelines, security can be a significant problem as pipelines cover long stretches where they can be vulnerable to natural or manmade disasters or political interruptions.

As natural gas markets evolve into global markets, there will be an increasing need for long-haul supply. The Middle East is evolving into the swing supplier, capable of moving LNG supplies to the Asian or Atlantic markets. Long distance natural gas pipelines crossing several borders also are being developed that will move regional markets more towards global markets.

The Forum considered the political and security experience of the increasing trade between the Middle East and Asia. Japan has been the leader in developing the LNG trade, with its first shipment of LNG in 1969. Since then it has developed many LNG regasification terminals with almost half of the world's total of these terminals by 2005. It has diversified its LNG imports from several sources within Asia—Brunei, Indonesia, Malaysia, Australia—and increasingly from the Middle East—Qatar, Oman and UAE. Future sources include LNG from Sakhalin Island (Russia) and the Gorgon field in Australia.

One of the major sea chokepoints in the delivery of LNG from the Middle East to Asian markets is the Strait of Malacca between Indonesia (Sumatra) and Malaysia and Singapore. The Strait is about 900 km long, with the narrowest point near Singapore where it is about 500 meters wide. Traffic through the Strait continues to climb, with more than 65,000 vessels of all types transiting in 2006.

These included more than 21,000 tankers (VLCC crude tankers, smaller crude and product tankers, and LPG/LNG tankers) of which almost 3300 were LNG/LPG tankers. Piracy and armed robbery at sea in the Strait remains a serious threat, although the total number of attacks in declining. In the period 2001 through 2006, more than 1900 people were taken hostage, about 260 injured, about 140 went missing, and 97 were killed. Coordination among Indonesia, Malaysia and Singapore in preventing terrorism takes place on an ongoing basis; however, cooperation from the international community is needed, including sharing of the financial burden. Alternatives to the Strait of Malacca are available; but these sea lanes add four to five days to the trip in each direction, and there is an urgent need for navigational upgrades. Pipelines across the Malaysian peninsula have been under discussion for years with the most serious proposal set forth in May 2007, when Malaysian, Indonesian and Saudi Arabian firms signed an agreement to build the Trans-Peninsula Oil Pipeline.

The Trans-ASEAN Gas Pipeline (TAGP) has been an excellent example of regional cooperation in building a pipeline that connects the Philippines, Brunei, Malaysia, Singapore, Indonesia, Thailand, and Vietnam. Additions to this pipeline grid are underway or under discussion. The next step in development among the ASEAN nations is an interregional power grid to complement the natural gas grid.

In the East China Sea, an era of confrontation between China and Japan appears to be coming to end with the signing this year of an agreement on the joint development of natural gas resources. This agreement marks a departure from the past period of confrontation and may lead to a "business-first" rather than "politics-first" principle.

In another area with strong geopolitical overtones, a gas pipeline from Iran to Pakistan to India has been in the development stage for over ten years. Some progress was made as the countries appear to have reached agreement recently on the pricing of the natural gas from Iran. Future meetings this year are planned to finalize the agreement on pricing and on the transit fees through Pakistan. Continued progress is in question, however, due to U.S. opposition in light of their heightened concern about Iran's nuclear activities, support for terrorism, and human rights violations.

As natural gas markets evolve globally and more long distance transport of natural gas occurs, security concerns increase. Ways to ameliorate these concerns include: supply diversity for importing countries, market diversity for exporting countries, diversity in the means of transportation (LNG and pipelines), inter-regional cooperation including cross-investment among regions, intra-regional cooperation such as the Trans-ASEAN Gas Pipeline, and enhanced transport security. Geopolitical risks can be lessened with a growing sense and recognition that the Middle East and Asia are becoming inextricably linked.