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Decoupling the Oil and Gas Prices

Natural Gas Pricing in the Post-Financial Crisis Market

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Gouvernance européenne et géopolitique de l'énergie

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This paper looks into natural gas pricing in the post-financial crisis market and, in particular, examines the question whether the oil-linked gas pricing system has outlived its utility as global gas markets mature and converge more rapidly than expected and as large new resources of unconventional gas shift the gas terms-of-trade.

Two opposing natural gas pricing systems have coexisted for the last two decades. On the one hand, there is traditional oil-linked pricing, used in pipeline gas imports by Continental European countries and in LNG imports by the countries in Far East. The other is the system led by futures exchanges in deregulated, competitive markets largely in the UK and the US.

In the first half of 2009, natural gas prices set by oil-linked formulas in Continental Europe were twice as high as market prices at the Henry Hub or the NBP (National Balancing Point). Because of this, oil-indexed Russian imports fell sharply to their contract limits and discussions on de-linking gas pricing started once again. This time, the most vocal were major European gas companies which had to buy expensive oil-indexed natural gas. The same situation is developing in Asia between oil-indexed LNG and the one based on market gas prices. Even traditional oil-indexed LNG buyers in the Far East are insisting on a partial linkage to Henry Hub prices.

Gas pricing formulas in Continental Europe are typically indexed to light and heavy fuel oil. In the 1970s when oil was used to fuel many power stations and large-scale industrial plants, the logic of natural gas directly replacing oil products made sense, but markets have changed significantly over the past two decades. Crude and oil products have been increasingly forced out of power generation and other stationary uses both by price and by policy. Instead, oil is overwhelmingly used as transportation fuel. Therefore, the logic of oil as the replacement comparator for gas is no longer supported by reality.

The financial crisis and economic downturn starting in September 2008 had a profound impact on economic activities including natural gas demand. Global gas demand fell sharply between 2008 and 2009 and for the first time in decades, electricity demand also decreased. With weak electricity markets, fuel competition between spot priced natural gas and coal took place at many power plants.

There have been developments on the supply side of the natural gas market as well. Unconventional gas has completely changed the landscape of the US gas market in the last few years and is already being felt across global gas markets. As a result of increasing production from unconventional gas resources, the prospects for US LNG imports are scaled down significantly at the time when Qatar is starting up six of its 7.8-million-tonne-per-year trains. This has softened the LNG market worldwide, although the reduction in nuclear power in the wake of Fukushima may mitigate this somewhat.

Natural gas pricing based on the market will not happen on its own as the institutions of market pricing need to be built. Experiences in the UK and the US show that a mature gas sector needs to be appropriately regulated with gas-on-gas competition and transparent trading exchanges. Spot transactions at hubs and futures trading at financial centres are essential to developing market-based pricing but they don't happen overnight. In the US, gas reform legislation preceded viable gas trading by more than ten years. Nonetheless, after the financial crisis of 2008, spot trading volumes at an increasing number of Continental European hubs have been rising phenomenally.

In addition, a number of new futures exchanges are starting trading. Since futures markets attract a wide range of investors including financial institutions. They have large trading volumes and their price formation influence is much larger than that of spot markets. Historically speaking, it was a futures market, the NYMEX, which changed oil pricing from OPEC's official sales price system to the market-based price in the 1980s.

As criticism of oil-linked pricing emerged, Gazprom announced that it had agreed to link 15% of the volume to spot gas prices over the period of 2010-2012 in February 2010. But this came only after Norway was already allowing up to 25% based on spot prices and the Netherlands' GasTerra was giving concessions.

The IEA calls the issue of decoupling oil and gas prices as "Arguably, the most important question faced by the gas industry over the coming three years."[1] Whether the partial spot price indexation will continue beyond the three years and will be extended to other contracts depends on the global supply-demand balance and on the evolution of spot and oil-linked prices. It might also depend on whether European regulators are going to continue acquiescing in passing through oil-indexed prices to consumers. The consensus is that the relatively soft market will continue for the next few years, and, if so, there will be more pressure to move away from oil indexation.

However, such a change will not take place uniformly and universally. There will be in all likelihood many variations. Western Europe is closer to adopting market pricing. Expansions and

[1] IEA "Medium-Term Oil and Gas Markets 2010", P195.

establishments of futures markets are a particularly good sign. Even a country like Germany, without an LNG terminal and traditionally heavily dependent on Russian imports, wants to have lower priced supplies through interconnections to other countries and by way of spot and futures trading.

Meanwhile in Eastern Europe, due to the legacy of the Soviet Union, one supplier, Gazprom, dominates the gas market. So long as this situation continues, there is no competition and no market prices. The deals given by Gazprom to the major Western European buyers were not generally available to smaller buyers in East and Central Europe. The region is beginning to diversify its gas supplies through interconnection with other European countries and via LNG imports.

In Japan, Korea and Chinese Taipei, conditions are more difficult for introducing gas-to-gas competition and we will more likely see LNG prices discounted under the same or a similar scheme as in Europe rather than a full move to market pricing. However, these countries know they will lose competitive edge in their economies if they continue to pay higher energy prices. In all probability, China will seek gas prices both from Russia and LNG suppliers that reflect market forces rather than linkages to oil. This will force the hands of traditional Far East LNG buyers to abandon the JCC for greater market-based pricing.

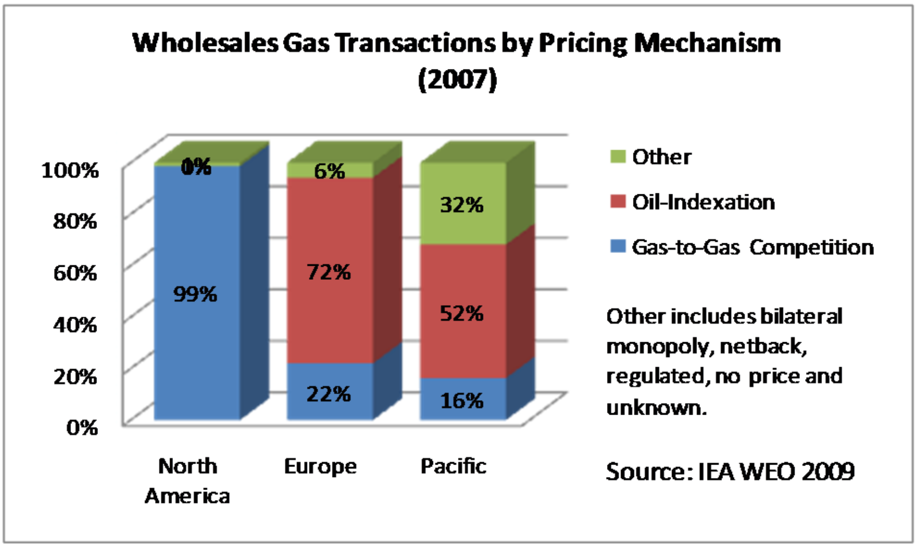
Adopting market-based pricing does not necessarily mean the end of long-term contracts. Long-term contracts have proven to be an effective tool for long-term and large-scale investment. If there is a change, it would be limited to the price provisions of long-term contracts. The Netherlands and Norway already use these kinds of long-term contracts, with prices tied to the NBP market. In the case of the Russians, the rationale behind long term contracts was to provide an incentive to make the huge investments needed in hostile frontier gas provinces. The Russians have not upheld their end of the bargain and should be increasingly held to account for the lack of investment in incremental capacity. Gazprom production is still 8% off 2008 and is lower than April 2010.

A gas price formula based on the replacement value had its own rationale at one point in time. However, as global gas markets mature, suppliers and consumers are identifying better ways to price natural gas. When economies, society and people have the perception that prices emerging in competitive markets are the real prices, industry will have to adapt. Europe, the Pacific and many other countries and regions are ready for such a change.

Introduction

Two opposing natural gas pricing systems have coexisted for the last two decades. On one hand, there is traditional oil-linked pricing, used in pipeline gas imports by Continental European countries and in LNG imports by the countries in Far East (Japan, Korea, Chinese Taipei and China). The other is the one led by futures exchanges in deregulated, competitive markets largely in the UK and the US. There is a third gas pricing system in developing countries and oil/gas producing countries where natural gas prices are basically set by political authorities.

Figure 1



According to the IEA's World Energy Outlook 2009, almost one-third of wholesale gas worldwide is priced on the basis of gas-to-gas competition, while one-fifth is indexed to crude or oil products. Some 40% of gas consumed worldwide is subject to direct price regulations, and about one-quarter is subsidized or sold below the production cost. The composition for the three OECD regions is shown below (Figure 1). Gas-to-gas competition determines almost all wholesale prices in North America, whereas oil-price indexation is the dominant pricing mechanism in Continental Europe, and also prevalent in the Pacific.

While economists and regulators have long argued in favor of competitive pricing in a deregulated market, this has not been fully realized in Continental Europe or the Far East. This is in spite of continuing measures, policies and efforts to deregulate the gas sector and open it to competition, particularly in Europe. Long term contracts and oil indexation have their origins in the nascent European gas market of the 1970s. Since that time, sources of gas have multiplied; gas markets and infrastructure are much denser. European gas markets are nearly mature enough for full gas-on-gas competition and pressure from consumers is building.

Change is accelerating as a consequence of weak natural gas markets after the financial crisis starting in summer of 2008. Natural gas consumption in the OECD countries fell sharply in 2009, and continued to fall in 2010. It is expected to take a few years for the gas demand to return to 2008 levels. Coincident with this weak gas demand, a divergence in prices has emerged. Market-based spot prices (for both natural gas and LNG) remain low while oil-linked prices of long-term contract volumes are much higher. Particularly in Continental Europe and the Far East, this has become a serious issue for the gas industry and consumers as the gap between the two has widened to unprecedented levels.

The graph below (Figure 2) shows oil and natural gas prices from 2009 to 2011.[2] In the graph, natural gas is priced between "crude oil parity" (shown as calorie conversions for Brent and JCC), which was historically the goal of gas-producing countries in the price negotiations, and "market prices" (shown as UK NBP and US Henry Hub), proving the point advocated by economists and regulators that during periods of gas-to-gas competition, lower gas prices should benefit consumers and the economy as a whole. The second point in the graph is that oil-indexed gas prices follow crude prices with a time lag of a few months. In the first half of 2009, this put oil-linked natural gas prices far above Henry Hub and NBP prices (even above the crude parity prices), reflecting rising crude oil prices in the second half of 2008.

Global natural gas trade fell as the demand decreased. But some gas exporters lost out over others because of the price differentials. In Europe, for example, gas imports from Russia, which has oil-linked natural gas prices, fell sharply while Norwegian gas imports partially based on market prices increased. As a result, Russia's Gazprom had to follow suit by including spot natural gas prices in its export pricing formula to European customers in early 2010.

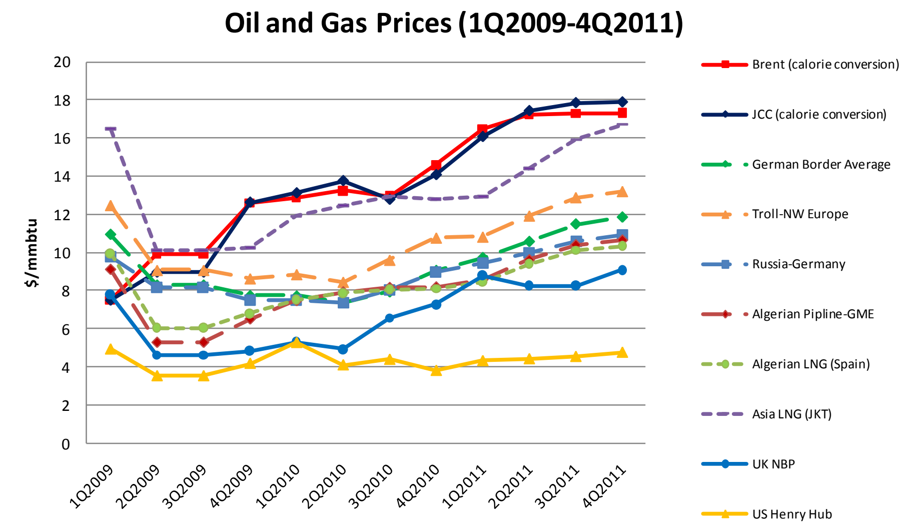
Meanwhile, global spot LNG trading volumes have been increasing. Qatar is starting production from newly built LNG liquefaction trains. But the US will not take the LNG as anticipated, because unconventional gas production is rising fast in that country.

[2] Based on data in Gas Matters (March 2011). Forecast prices for 1Q2011 and onwards are shown in the graph because some of the natural gas prices are set by a formula based on other energy prices a few months earlier.

This situation will create large spot LNG volumes in the coming years, adding further price pressure on oil-linked LNG volumes under long-term contracts as well as similarly priced pipeline gas imports.

Will the oil-linked gas pricing system survive weak gas markets after the financial crisis? How is economic recovery going to shape gas price formation? Will the shale gas phenomenon continue to distort markets? Are gas markets inevitably linked to oil prices by the market for NGLs? Is Gazprom's pricing compromise temporary or permanent? Will the European Commission's third package finally bring gas-to-gas competitions in Continental Europe? Will there be changes in the Pacific market in light of the changes in Continental Europe? This paper looks into natural gas pricing in the post-financial crisis market.

Figure 2



Source: Gas Matters (March 2011)
Numbers for 2011 are forecast
Brent and JCC calculated at 5.929 mmbtu per barrel

Oil-Indexed Gas Prices

Pricing Formula

A typical oil-index pricing formula is expressed as follows.[3]

Pm = Po + 0.60 x 0.80 x 0.0078 x (LFOm - LFOo)

+ 0.40 x 0.90 x 0.0076 x (HFOm - HFOo)

In the formula, the natural gas price **Pm** applicable during the month of **m** is a function of the starting natural gas price **Po**, adjusted by price developments in the competing fuel markets.

Po is normally a price based on the concept of netback value. Given high transportation costs and large infrastructure expenses of natural gas, the price is designed to reflect the netback value at the border of the buyer's country and is calculated by deducting the buyer's costs between the border and its customers (e.g. transmission, storage and distribution costs) out of the market value. In some cases, marketing incentives are incorporated in **Po**, setting the gas price marginally lower than those of competing fuels.

LFOo and **HFOo** are the starting prices of light fuel oil and heavy fuel oil. **LFOm** and **HFOm** represent the prices for the month **m**, which typically take the average value of the previous six to nine months with a time lag. The prices are quoted from markets and include or exclude taxes, depending on the agreement.

In this example, 0.60 and 0.40 represent the natural gas market segments which compete with light fuel oil and heavy fuel oil respectively. (Note that these are not ones for light fuel oil and heavy fuel oil in the total energy market.)

Meanwhile, 0.80 and 0.90 are called the pass through factor. Assume ratios of 0.8 and 0.9 and that the prices for light fuel oil and heavy fuel oil are rising, buyers will benefit from this price setting. Conversely, sellers will benefit from it when the prices are falling. This factor serves to share risks and rewards between sellers and buyers in the changing price conditions.

[3] "Putting a Price on Energy" (Energy Charter Secretariat, 2007), P154.

The figures 0.0078 and 0.0076 are technical factors to convert fuel oil prices per unit (e.g. $/tonne) into natural gas prices per unit (e.g. euro/kWh).

In addition, long-term contracts usually have some form of price review clause allowing parties, at regular intervals (typically three years) or when the market undergoes major changes, to review the price formula in order to adjust it to changing market conditions.

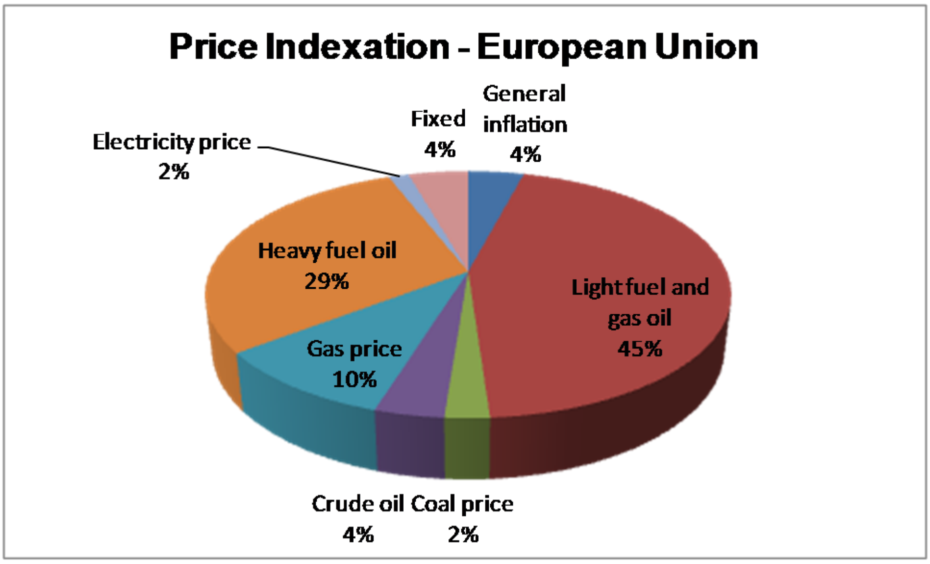
While light fuel oil and heavy fuel oil are the two factors most commonly quoted in the price formula, other energy prices are also quoted. According to the European Commission's "Energy Sector Inquiry"[4], natural gas prices are also indexed in varying degrees to inflation, crude oil, coal, electricity, spot gas and others, in addition to light fuel oil and heavy fuel oil. The first graph (Figure 3) shows price indexation under long-term gas supply contracts in the European Union as a whole. It is based on the data for 2004 and indicates the average volume-weighted indexation in the sample of contracts. Due to confidentiality surrounding price formulas, "Energy Sector Inquiry" still remains an important publicly accessible document a few years after its publication.

There are large variations of indexation by supply source and by purchasing region. The second and third groups of graphs (Figure 4 and 5) show the differences. The Netherlands, Norway and Russia place emphasis on light and heavy fuel oils in their price formulas among the producers. Meanwhile, Algeria's heavy indexation to crude oil can be traced back to price negotiations on its LNG and Transmed pipeline exports taking place during the country's turbulent period in the late 1970s and early 1980s. Interestingly in the UK where the NBP market price is dominant, there are various other price quotations (including not only light and heavy fuel oils but also general inflation, electricity price, coal price, crude oil and other) in the price formulas on both selling and purchasing sides. This suggests the complexity of gas pricing and that price formulas are used to make adjustment to NBP prices in individual deals.

In addition, "Energy Sector Inquiry" points out that "Since the continuing practice of linking gas to oil and oil-derivatives' prices is widespread in Europe, contract prices paid by different producers to different suppliers move in an almost identical manner through time. As a result, prices paid by purchasers under long-term contracts do not react smoothly (or at all) to changes in the supply and demand of gas markets. This effect is exacerbated by the fact that the indexation in long-term contracts is usually linked to variables calculated with trailing averages, further reducing response to price signals."

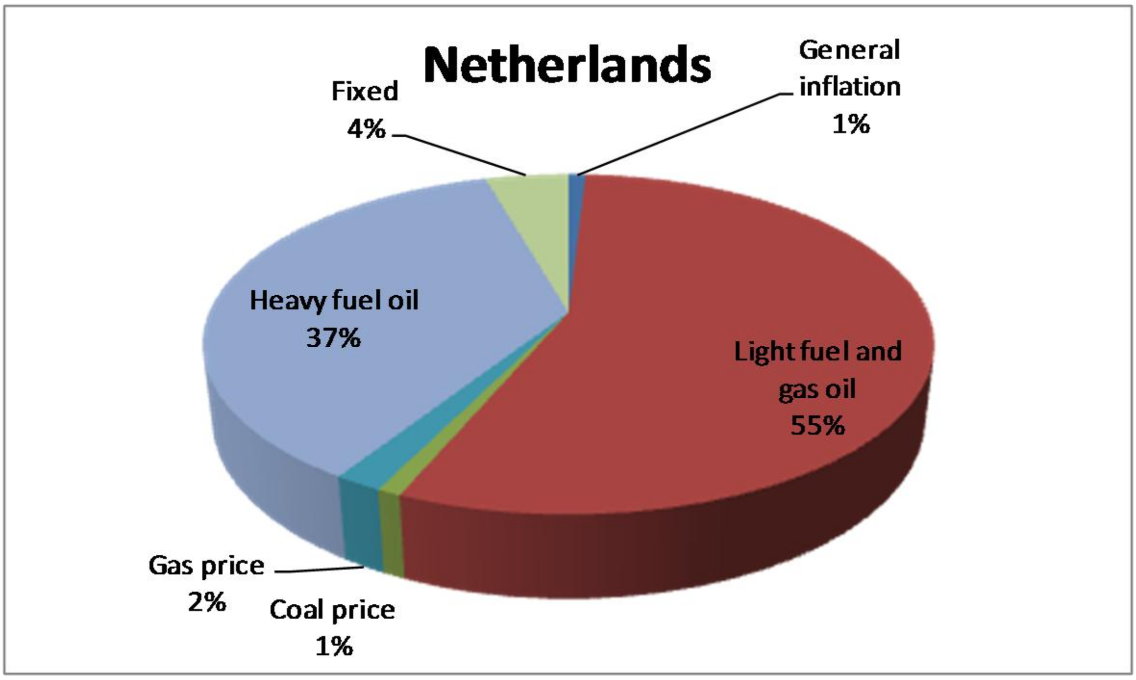
[4] "DG Competition Report on Energy Sector Inquiry" (European Commission, January 2007), P101.

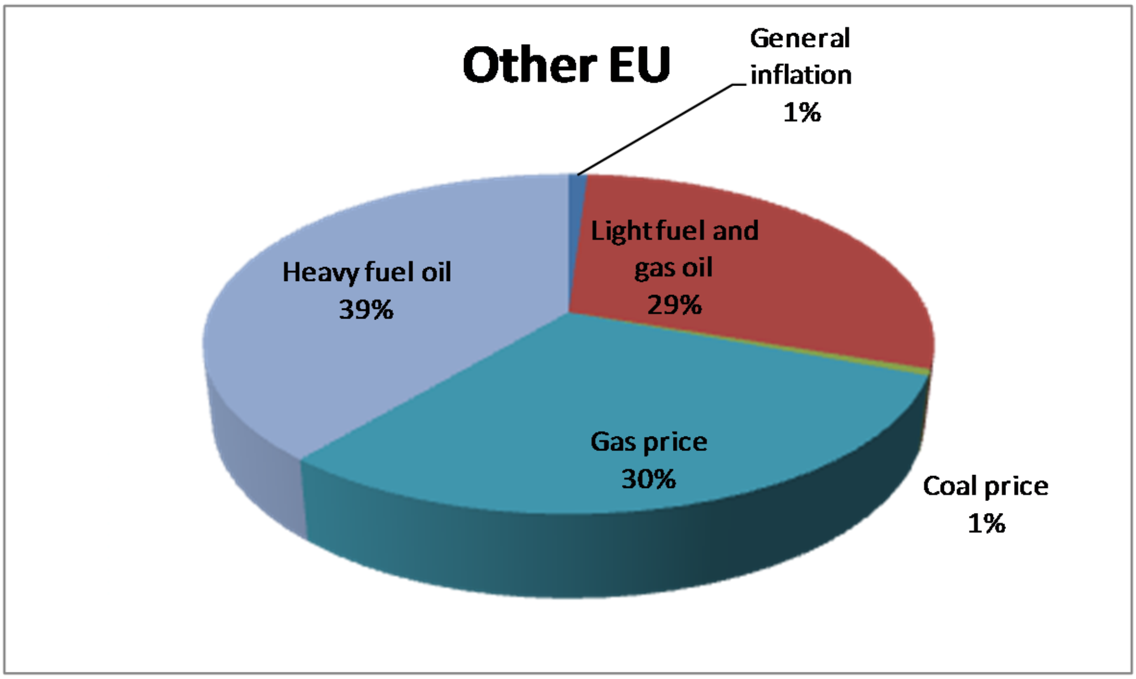
Figure 3

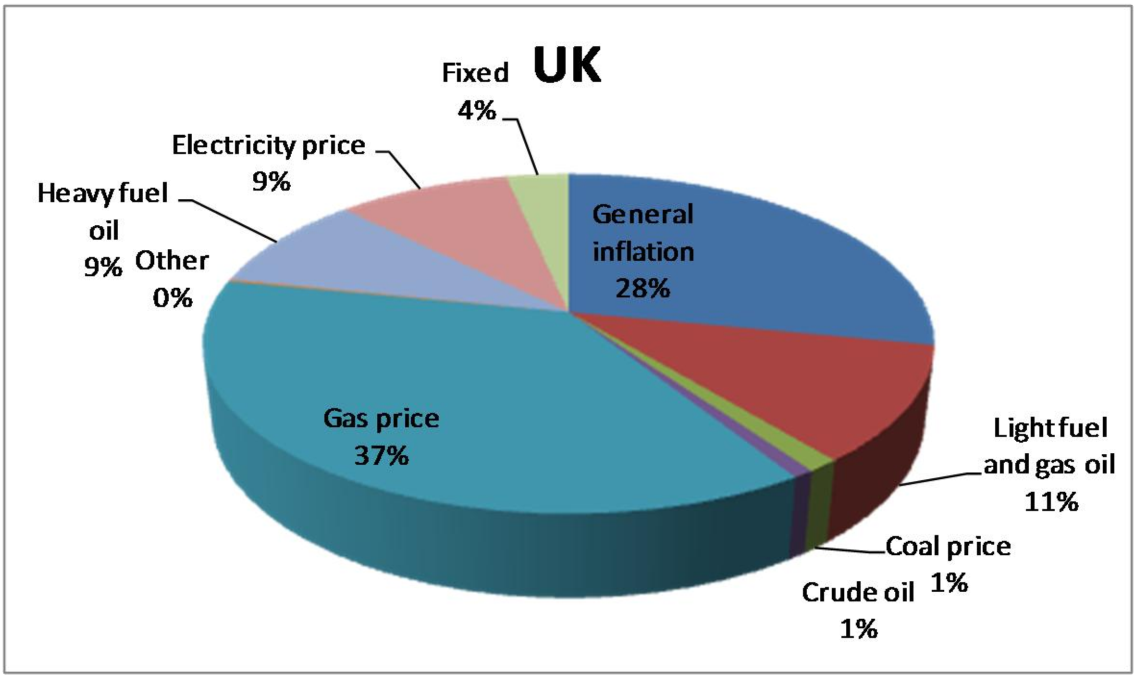


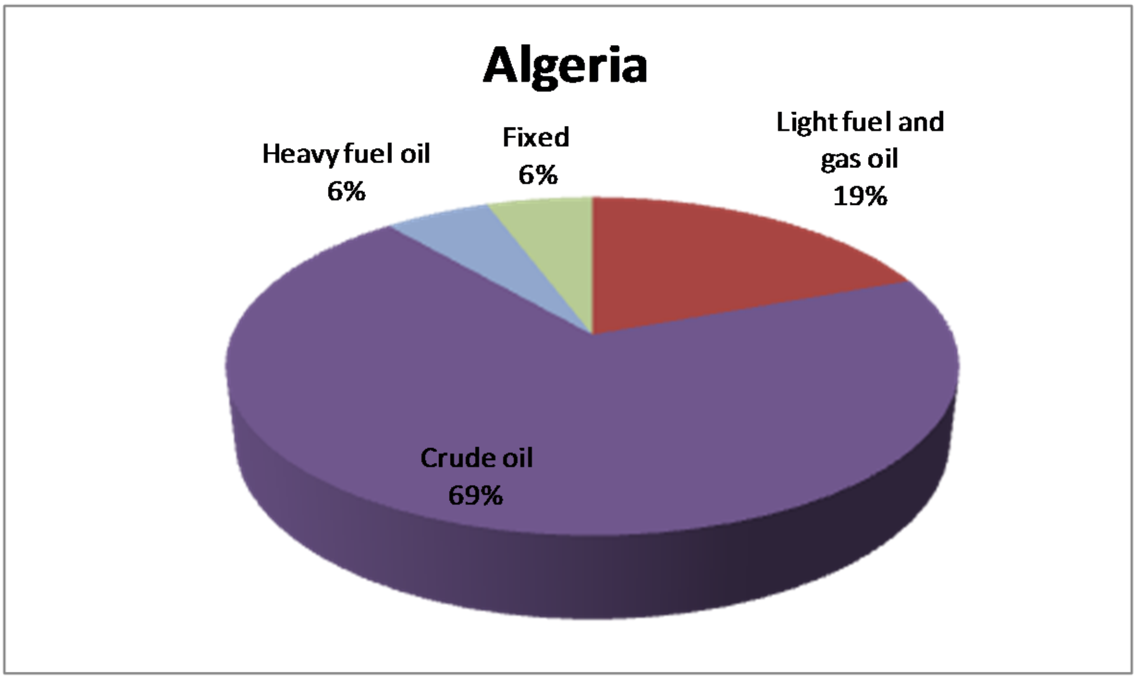
Source: Energy Sector Inquiry 2007

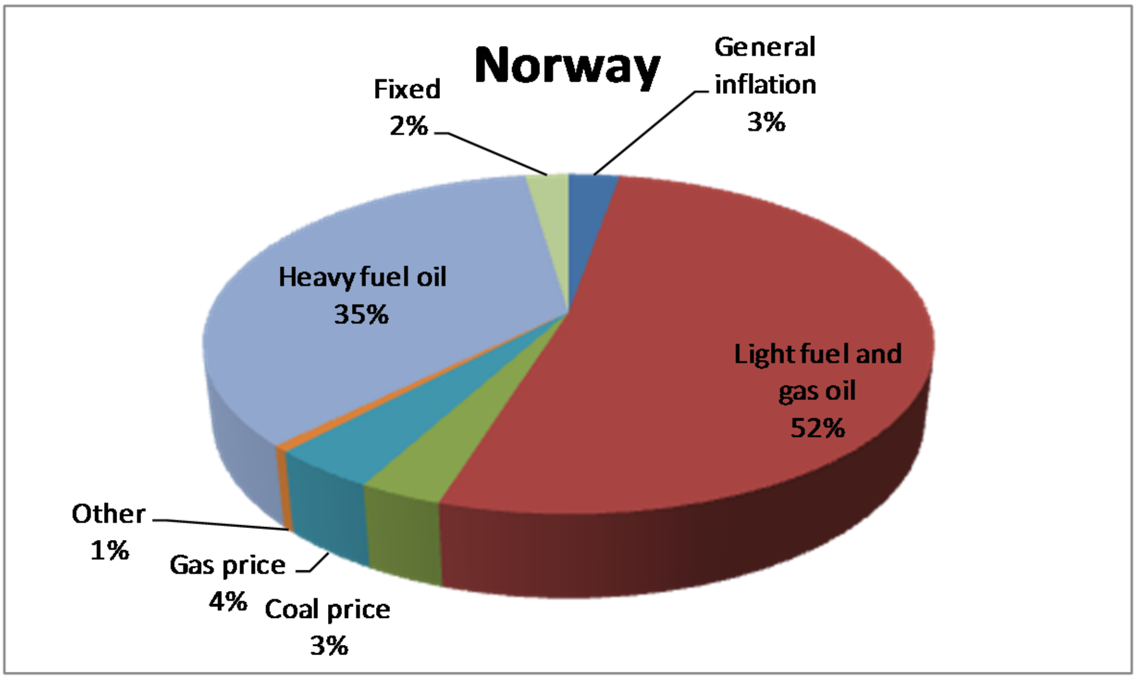
Figure 4 Price Indexation by Producing Region

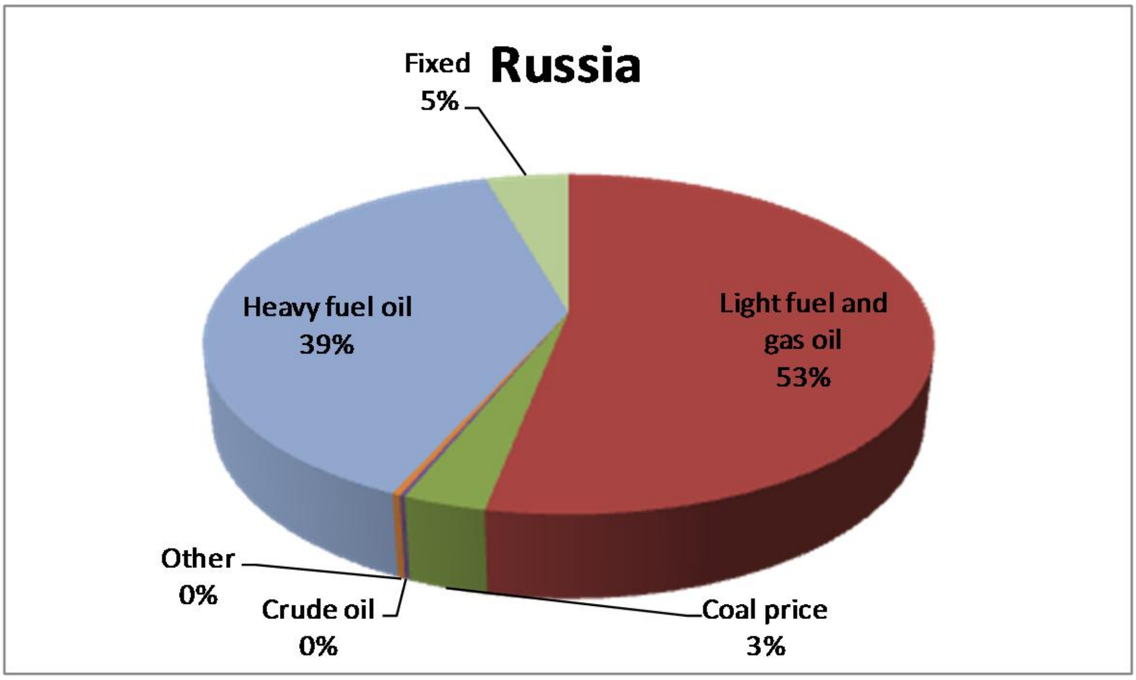



Other EU
General
inflation
1%
Light fuel and
gas oil
29%
Heavy fuel oil
39%
Gas price
30%
Coal price
1%


UK
Fixed
4%
Electricity price
9%
Heavy fuel
oil
9%
Other
0%
General
inflation
28%
Gas price
37%
Light fuel
and gas oil
11%
Coal price
1%
Crude oil
1%

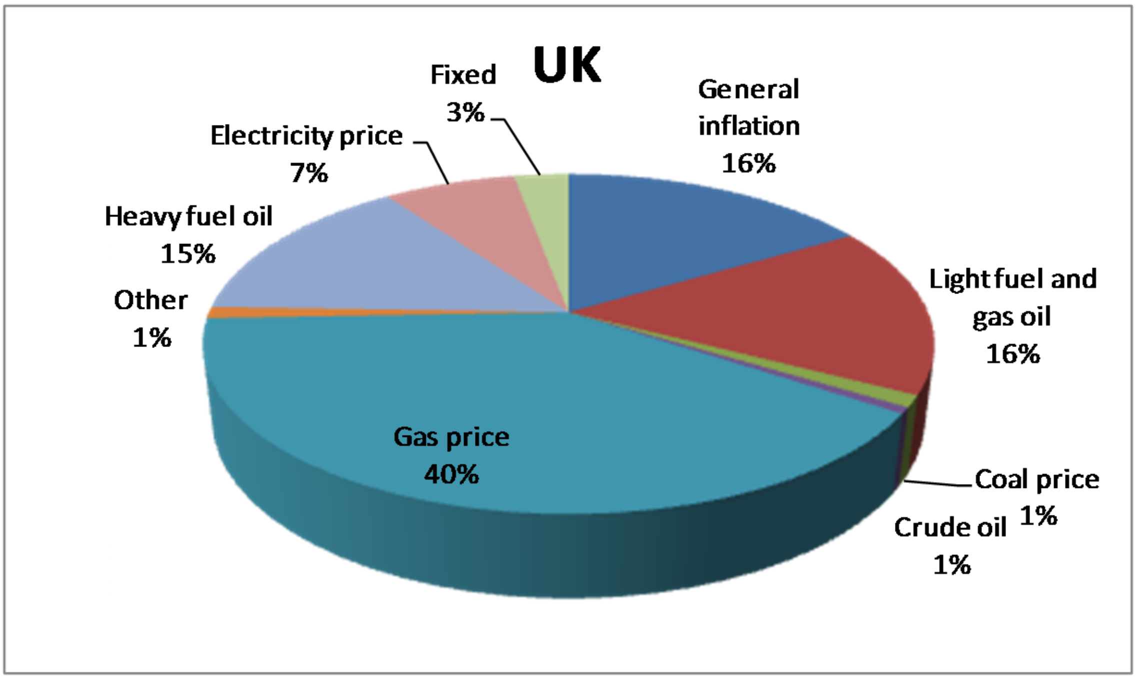

Algeria
Heavy fuel oil
6%
Fixed
6%
Light fuel and
gas oil
19%
Crude oil
69%

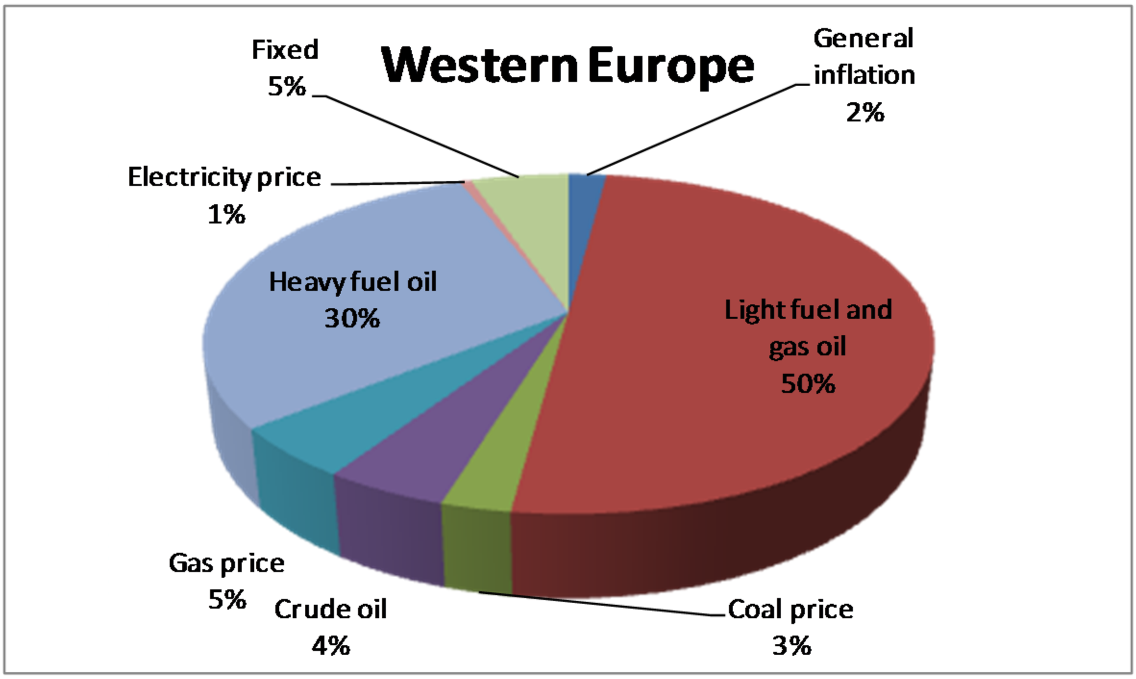

Norway
Fixed
2%
General
inflation
3%
Heavy fuel oil
35%
Light fuel and
gas oil
52%
Other
1%
Gas price
4%
Coal price
3%

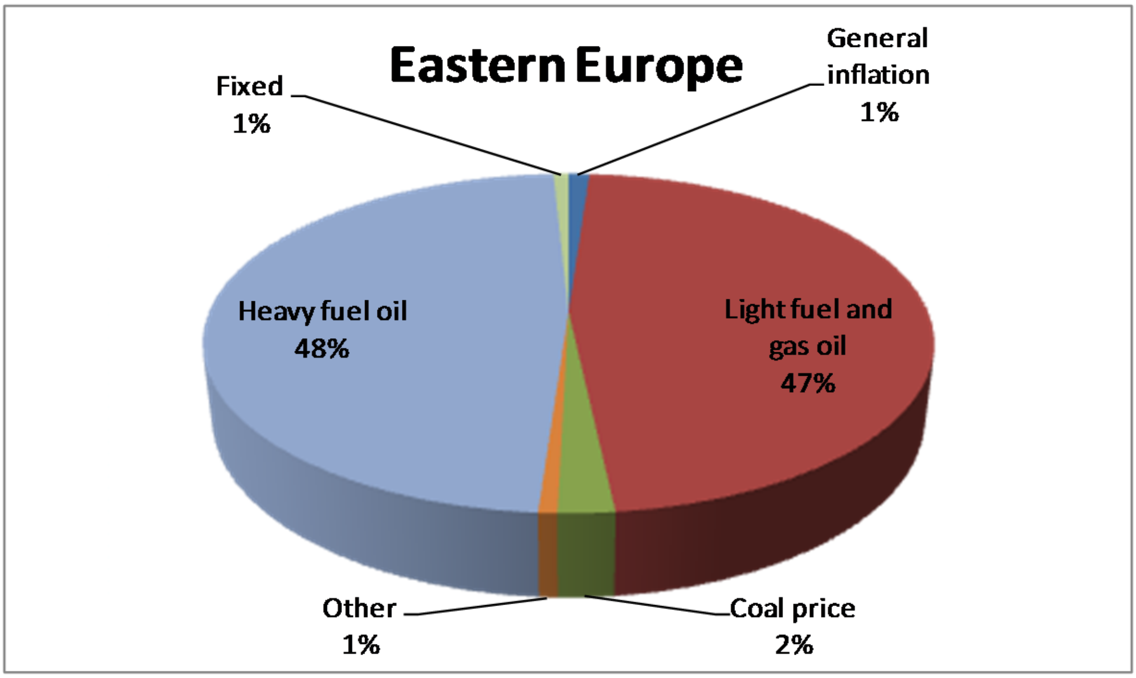


Source: Energy Sector Inquiry 2007

Figure 5 Price Indexation by Consuming Region







Source: Energy Sector Inquiry 2007

Disappearing Rationale for Oil-Indexation

In the first half of 2009, natural gas prices set by oil-linked formulas in Continental Europe were twice as high as market prices at the Henry

Hub or the UK/NBP. Because of this, oil-indexed Russian imports fell sharply to their contract limits and discussions on de-linking gas pricing started once again. This time, the most vocal were European gas companies which had to buy expensive oil-indexed natural gas.

In the 1970s, when oil was used to fuel many power stations and large-scale industrial plants, the logic of natural gas replacing oil products made sense, but markets have changed significantly over the past two decades. Crude and oil products have been increasingly forced out of power generation and other stationary uses by both price and policy. Instead, oil is now overwhelmingly used as a transportation fuel. Therefore, the logic of oil as the replacement comparator for gas is no longer supported by reality.

Jonathan Stern of the Oxford Institute for Energy Studies says oil-indexation pricing has already been outdated.[5] Stern wrote a paper in 2007,[6] which he supplemented with a follow-up paper after the financial crisis in 2009.[7] He argued that "the logic of linking gas prices to those of (mainly) oil products had largely disappeared in the major European gas markets."[8]

According to Stern,[9] the original rationale for oil-linked gas prices was that end-users had a real choice between burning gas and oil products, and would switch to gas if there was a price incentive to do so. This was justified when oil product indexation was established in the late 1970s and early 1980s. However, the interest of existing gas users to switch to oil products appeared to be limited and declining in the 2000s, because of:

- the cost and inconvenience of maintaining oil-burning equipment and substantial stocks of oil products
- The continuing insecurity of oil suppliers
- the emergence of modern gas-burning equipment in which the use of oil products means a substantial loss of efficiency
- tightening environmental standards in relation to power sector emissions

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[5] Stern wrote that "[the 2007 paper] probably created more debate and controversy than anything else I have ever written". Stern (2009), Acknowledgements.
[6] Stern "Is There A Rationale for the Continuing Link to Oil Product Prices in Continental European Long-Term Gas Contracts?" (Oxford Institute for Energy Studies, 2007).
[7] Stern "Continental European Long-Term Gas Contracts: is a transition away from oil product-linked pricing inevitable and imminent?" (Oxford Institute for Energy Studies, 2009).

[8] Ster (2009), P2.
[9] Stern (2007), P33.

He continued that "the original rationale [becomes] increasingly dubious in the majority of countries, particularly in North West Europe. There is no likely scenario in which European energy users installing new fuel-burning equipment will choose to use oil products rather than gas in stationary uses, unless they have no access to a gas supply".

Stern also questioned the price transparency of fuel oil markets. He wrote that, although gasoil prices were quoted at a number of locations in Europe in a range of widely accepted industry publications (such as Platts and Argus) and gasoil markets were verifiably liquid, fuel oil had neither of these attributes.

He concluded that "a transition away from formal contractual oil product price linkage is inevitable and arguably has already begun with a great degree of spot gas pricing indexation in some long term contracts".[10]

[10] Stern "Continental European Long-Term Gas Contracts: is a transition away from oil product-linked pricing inevitable and imminent?" (Oxford Institute for Energy Studies, 2009), P13.

Natural Gas Market after the Financial Crisis of 2008

Natural Gas Demand

The financial crisis and economic downturn starting in September 2008 had a profound impact on economic activities including natural gas demand. Global gas demand fell sharply by 3% between 2008 and 2009. Previously, global gas demand had fallen only twice – first in 1975 following the oil crisis and, then, in 1992 in the aftermath of the collapse of the Soviet Union. But the drop this time was larger than on those occasions in both percentage and volume terms.

In addition, electricity demand decreased by 4% in OECD countries in 2009 for the first time ever. With weak electricity markets and lower gas prices, fuel competition, mainly between spot priced natural gas and coal, took place at many power plants. But the situation varied from one country to another. The US, for instance, saw gas demand increasing at power generation plants, thanks to low gas prices resulting from rising unconventional production (Figure 6). The share of natural gas in power generation rose from 21% in 2008 to 23% in 2009, while coal's share fell from 48% to 45%. In absolute terms, there was a loss of 230 million Megawatthours in coal-based generation between 2008 and 2009, and 38 million Megawatthours of that gap was filled with gas. Conversely in the European and Pacific power generation sector, high oil-linked gas prices exacerbated the decline in gas demand.

According to IEA statistics, OECD gas demand fell by 50 BCM or 3.2% to 1,495 BCM in 2009. Within the OECD, Europe suffered the most as demand dropped by 5.4%. Demand in the OECD Pacific decreased by 3.4%, while North American demand fared relatively well with a fall of just 1.7% (Figure 7). As mentioned above, displacement of coal by gas took place in the US.

Looking into the OECD gas demand by sector, the industrial and power sectors largely accounted for the fall (Figure 8). Many factories and plants were closed or reduced their output due to the economic downturn, while reduced economic activity caused a fall in electricity demand across the board.

Figure 6

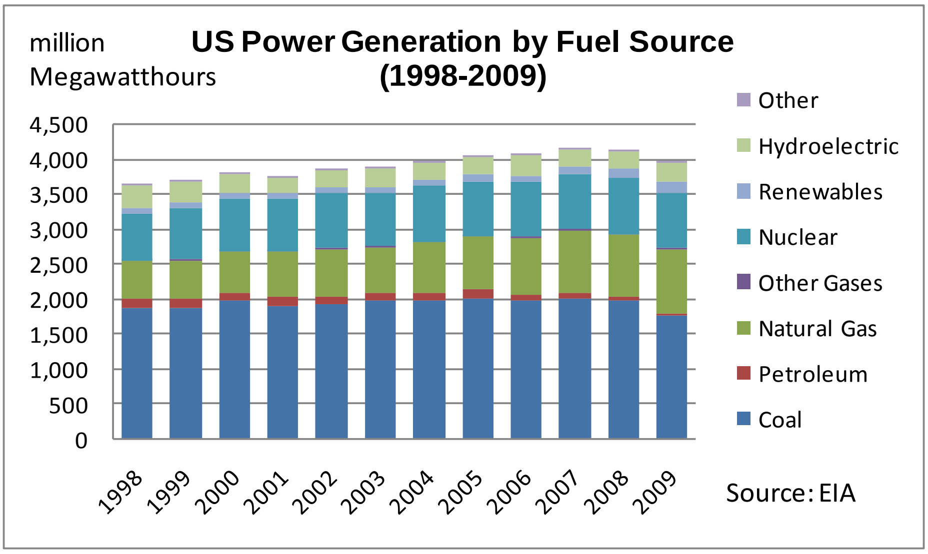
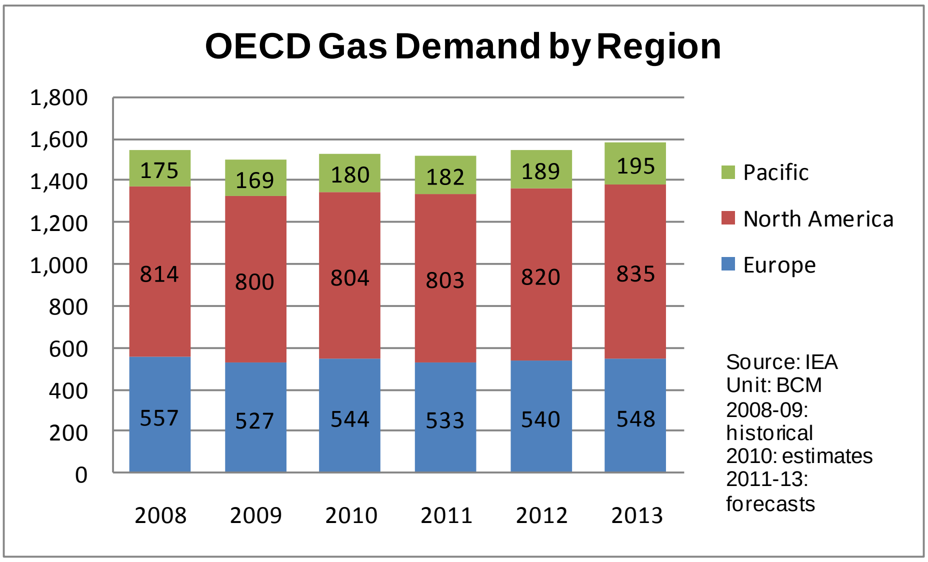


Figure 7

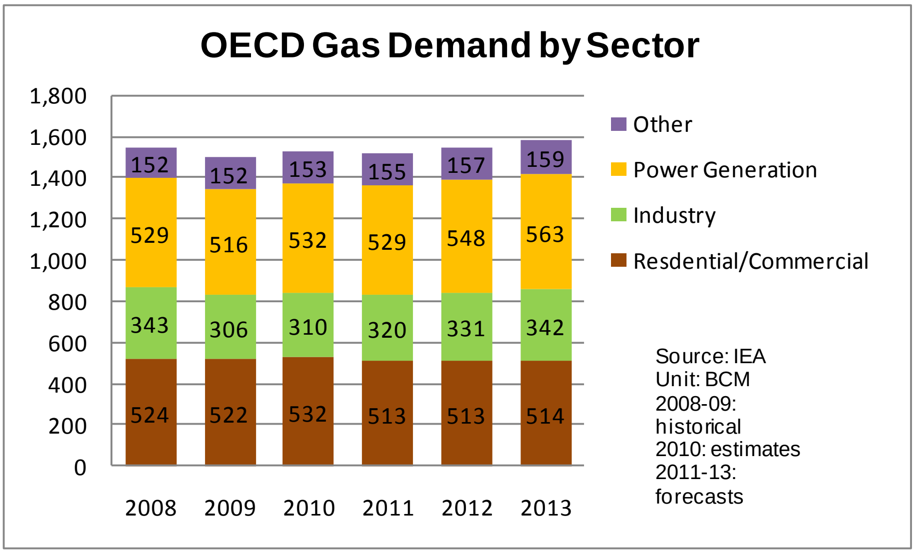


Source: IEA, Medium-Term Oil and Gas Markets, 2010

In late 2009 and early 2010 OECD economies started showing some improvement and gas demand started rising. Increasing gas demand was also supported by the cold winter of 2009/2010. In the second half of 2010, however, gas demand for industrial use and power generation slowed down. It was thought that fiscal stimulus packages provided by the governments were phasing out in the second half and that economic recovery was not strong enough to continue the growth.

The IEA forecast that OECD gas demand would recover slowly with consumption returning to the 2008 levels by 2012 or 2013, depending on the region.[11] Meanwhile, the main drivers of gas demand - the economies in North America and the Pacific - are expected to show strong economic recoveries while Europe's recovery is anticipated to be more sluggish. Sector-wise, the residential and commercial sectors will be relatively stable, while the industrial sector will recover only slowly and not return to the 2008 level until 2013.

Figure 8



Source: IEA, Medium-Term Oil and Gas Markets, 2010

Outside the OECD, demand fell in the former Soviet Union but rose in China, India, the Middle East and North Africa, whose economies were largely unaffected by the financial crisis and economic downturns. Most significant developments in natural gas demand are taking place in Asia.

In 2009 Chinese gas demand grew by 11% to 90 bcm.[12] But natural gas accounted for only 3.7% in the country's primary energy mix.[13] More than 70% of China's energy need is met by coal but the country needs cleaner energy. Therefore, China's gas demand is expected to increase faster than any other country/region. China began to receive LNG imports in 2006. The country has three operating terminals with a capacity of 17 bcm per year, and three more are under construction. China has long-term contracts with

[11] IEA, "Medium-Term Oil and Gas Markets" (2010), P141.

[12] Cedigaz

[13] BP Statistical Review of World Energy 2010

Australia, Indonesia, Malaysia and Qatar. It imported 7.6 bcm of LNG both under long-term contracts and on a spot basis in 2009, an increase of 72% from the previous year. Moreover, in January 2010 China started importing Turkmen gas through the newly-built Turkmenistan-China pipeline transiting Uzbekistan and Kazakhstan. The import volume currently stands at 20 bcm per year but is set to increase to 40 bcm per year with the opening of the second pipeline in 2011-12. Gas pricing in this pipeline is reported to be oil-linked.

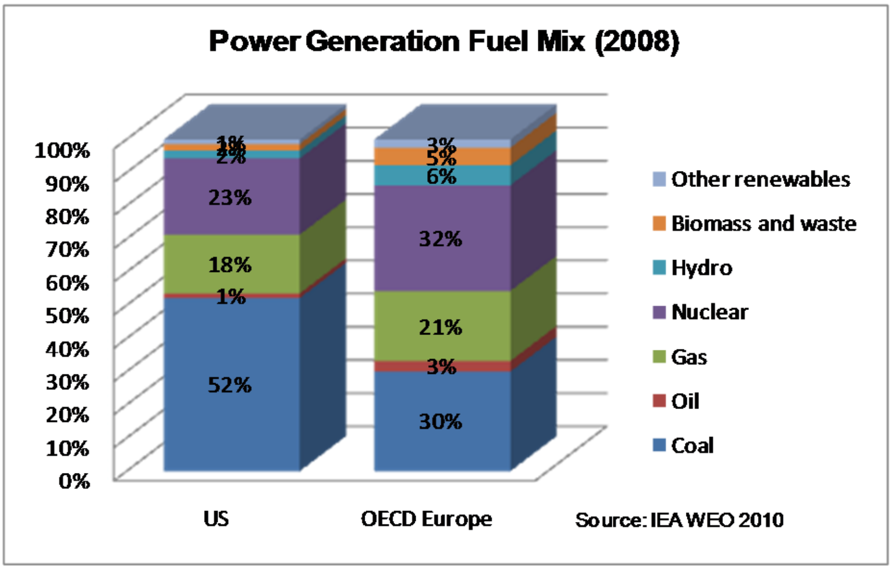
Indian gas demand grew even faster than Chinese demand in 2009, rising by 23% to 53 bcm.[14] This large increase was because of the exploitation of the offshore giant Krishna-Godavari KG-D6 field near the city of Kakinada on the eastern shore. The field started production in April 2009, supplying gas to the domestic market. Output from the field is expected to reach a plateau of 30 bcm per year in 2011. As in China, coal dominates India's primary energy mix (52%) and natural gas accounted for only 10% in 2009.[15] Therefore, there is room for further gas demand increases. India started importing LNG in 2004, rising to 13 bcm in 2009, a 17% increase from the previous year. India has two operating LNG terminals and one is under construction. In addition, there are three planned gas pipeline projects (Iran-Pakistan-India, Turkmenistan-Afghanistan-Pakistan-India and Myanmar-India) to import gas – none of which appear to be on the near horizon.

As pointed out earlier, power sector demand can vary due to competition among fuels. The US uses much more coal (52%) than OECD Europe (30%). Meanwhile, OECD Europe relies more on nuclear (32%) than the US (23%), due mainly to contributions from France. Natural gas accounted for 18% of power in the US and 21% in OECD Europe in 2008 (Figure 9). The OECD power generation demand should be returning to the 2008 levels in 2010, thanks to increases in North America. The future power generation demand also depends on energy and environmental policies on renewable, nuclear and CO2 among other things. Because European electricity grids are poorly integrated, the aggressive installation of wind and solar power in certain countries is accelerating the expansion of gas capacity to provide stability to national grids where intermittent power is prevalent.

[14] Cedigaz

[15] BP Statistical Review of World Energy 2010

Figure 9



The IEA's forecast in the autumn of 2010 did not incorporate political upheavals in the MENA region or Japan's earthquake/ tsunami/nuclear disaster, all of which are unfolding as of writing.

In recent years, gas demand in Egypt and Libya as well as other gas-producing countries in North Africa and Middle East has been expanding rapidly, supported by government policy to promote domestic gas use in order to maximize oil exports. Social and economic turmoil in North Africa and Middle East will bring down domestic natural gas demand at least in the short term, as happened in the FSU in the 1990s. Furthermore, long term natural gas production and exports from these countries could be affected by the turmoil if things go wrong.

Meanwhile, Japan is likely to need more natural gas (i.e. more LNG imports) to meet its electricity demand, in the absence of affected nuclear reactors at Tokai, Fukushima and Onagawa. This could in turn tighten the global LNG market. In the medium- to long-term, should many countries reduce their nuclear ambitions, the fuel of choice to compensate for lower nuclear will be gas. But the situation is still fluid at Fukushima as of writing and it is too early to assess the larger picture.

Unconventional Gas

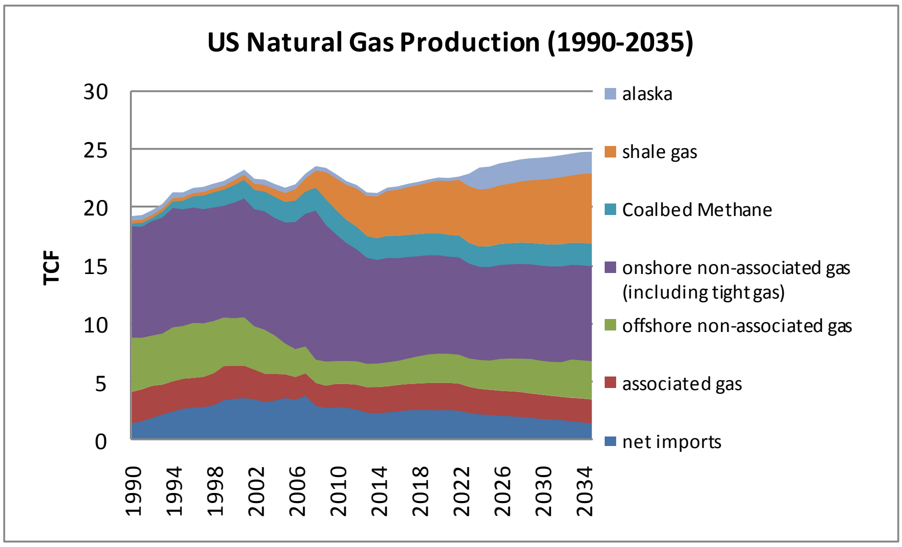
Unconventional gas is the most popular topic in the natural gas sector right now. It has completely changed the landscape of the US gas market in the last few years, and is already being felt across global gas markets. Unconventional gas production began in the US on a commercial basis in the 1980s. During the 1990s output volumes rose with the vastly expanded application of new technologies – more powerful seismic, hydraulic fracturing and horizontal drilling.[16] With the high gas prices of the mid 2000s, increasing production from unconventional gas resources grew rapidly, offsetting a decline in conventional gas production, drastically reversing the downward trend of total US domestic natural gas output, and having a large impact on the world LNG market. US net gas imports peaked at 108 bcm (including 21 bcm of LNG imports) in 2007. Two years later in 2009, the net imports fell to 79 bcm (including 12 bcm of LNG imports), which can be attributable to growing unconventional gas production. Due to earlier expectations of higher LNG imports, the US proceeded with expansions and construction of LNG terminals. There are 11 operating LNG terminals, with a capacity of 172 bcm per year, and three terminals under construction, with a capacity of 31 bcm per year, in the US.[17] US LNG terminals are destined to suffer low utilization rates – and some are even exploring options to reverse their activities by taking up liquefaction of US gas for export. Three terminals on the Gulf coast have been authorized to re-export delivered LNG.

There are four types of unconventional gas: tight gas,[18] coalbed methane (seam gas),[19] shale gas[20] and gas hydrates.[21] There is no commercial production of hydrates yet. But the others (tight gas, coalbed methane and shale gas) are all produced commercially today. In the US, shale gas production is already larger

16 Advanced 3D micro-seismic technology has been employed to monitor hydraulic fractures and subsurface water circulations in recent years.
17 The Federal Energy Regulatory Commission
http://www.ferc.gov/industries/gas/indus-act/lng.asp
18 Tight gas is natural gas produced from a low-permeability formation (mainly sandstone and limestone) which cannot be developed economically with conventional vertical wells.
19 Coalbed methane is natural gas contained in coal beds. The gas has an affinity to coal and is held by pressure from groundwater.
20 Shale gas is natural gas produced from hydrocarbon-rich shale formations. Shale gas originates from organic matter trapped during the formation of sedimentary shale rocks.
21 Gas hydrates are naturally occurring crystalline water-based solids, physically resembling ice. In hydrates, non-polar gas molecules are trapped inside a cage-like structure of hydrogen-bonded water molecules (known as a clathrate). Many gases form hydrates in nature. But methane hydrates are by far the most common, because methane is the most abundant natural gas.

than that of coal-bed methane. Unconventional gas is defined as natural gas extracted from the source rock as opposed to conventional gas produced from a sealed reservoir to which gas has migrated from the source rock. In this sense, shale gas is truly "unconventional".[22]

Figure 10



Source: US EIA, AEO 2010

Unconventional gas production wells decline faster than conventional ones and the total production is smaller requiring more drilling and fracturing. In addition to the use of the latest technologies like hydraulic fracturing, horizontal drilling and micro-seismic, these wells require close quality control over well integrity, water management and well retirement to ensure no negative impact on the environment.

In 2009[23] unconventional gas output (including coalbed methane and shale gas but excluding tight gas) accounted for 22% (or 129 bcm) of the total US natural gas production of 583 bcm. Unconventional gas output is expected to increase to 227 bcm in 2035, accounting for 34% of the total (Figure 10).

According to the EIA, US well-head natural gas prices averaged $3.67 per mmbtu for 2009 and $4.16 per mmbtu for 2010. One can say that unconventional gas - in part produced to profit from high NGL (Natural Gas Liquids) prices - has brought down the natural gas price to these levels. As a consequence, the US enjoys the lowest natural gas prices among OECD countries.

[22] See "Les perspectives du Shale Gas dans le monde" Bruno WEYMULLER (Note de l'Ifri, January 2011)
[23] Data for 2010 is not available as of writing.

In fact, one factor helping unconventional gas production is the considerable financial contribution from liquids sales. Setting aside the debate whether gas shale contains more NGLs than conventional reservoirs or not, NGL production has always been an integral part of the development plan in the Barnett shale play in northern Texas. As the shale gas production grows there, NGL output increases correspondingly. NGL sales bring financial benefits especially when oil prices (NGL prices track oil prices) are higher than natural gas prices on a btu-equivalent basis. Therefore, gas is produced as much for the value of its associated liquids as for the sale of the gas itself.

In Europe, Austria, France, Germany, Hungary, Poland, Sweden and the UK are starting to explore and develop unconventional gas resources. Europe imports more than 45% of the natural gas it consumes, and recently suffered from disruptions of natural gas supply from Russia. Therefore, many countries are examining unconventional gas as a mean to reduce their import dependency and to enhance the supply security. The focus is Poland where some 60 exploration permits have been issued and drilling campaigns are currently under way.

Europeans will need to identify a new set of regulations, environmental standards and revenue sharing mechanisms to convince their publics to accept gas production from shale. Subsoil ownership and fiscal regimes for minerals differ a great deal from the US. In France, a harsh public debate results from a lack of public consultation on shale gas permitting and the arrival of “Gasland” in local theaters. As 2012 is a presidential election year in France, both oil and gas work in shale is effectively stalled.

At this time, it still remains uncertain whether unconventional gas will repeat the same success in Europe as it has in the US. The development of unconventional gas is still in an early stage in Europe where the resource base is being evaluated. In addition, there are issues of water use/disposal and the environmental impacts of fracturing operations, which worry local communities and governments. Europe does not have the same experience with oil and gas production as most American states. Nonetheless, unconventional gas production has the potential to change not only Europe’s security of supply but also the basic fabric of European gas markets.

China is in the early stage of exploring and exploiting unconventional gas resources. The government is keen to promote policies to develop its unconventional gas resources, as the country’s natural gas import dependency is expected to rise. There is tight gas production in China. But, because China categorizes tight gas into conventional gas, the size of tight gas production is unknown. Traditionally, the focus is on coalbed methane. China as the world’s largest coal producer has some 130 bcm of proved coalbed methane reserves, and is estimated to have produced 3 bcm mainly from the

Ordos basin in 2010. Although there is no shale gas production in the country, China is looking to the success of shale gas in the US. PetroChina has drilled a few wells recently, while foreign firms such as Shell and Fortune Oil are studying the shale gas resources.

Needless to say, all of the potential new gas arising from unconventional plays puts greater pressure on the linkage between gas prices and crude oil or oil products.

LNG Market

LNG is an increasingly important factor in shaping the global natural gas market after the financial crisis of 2008. Between April 2009 and December 2010 Qatar started up six 7.8-million-tonne-per-year trains, bringing its ambitious liquefaction capacity expansion programme into reality (Figure 11).[24] Thanks to these new trains, Qatar's total liquefaction capacity has increased by 50% to 77 million tonnes per year.[25] Supported by this supply side development, world LNG trade volumes increased by 7.3 % in 2009 and by 22% in 2010.

With six trains fully operating, LNG supply from Qatar is expected to grow even further in 2011. The US was originally the intended market for much of this production. But prospects for exports to the US have been sharply curtailed because of increasing unconventional gas production there. As Qatar looks for alternative markets, it has concluded a number of long-term contracts with China in 2008-2010. But LNG cargoes without a predetermined customer are serving as a tool for transmitting price signals between previously separate markets, as Qatar offers the European and Asia Pacific buyers with short-term and spot LNG cargoes. In 2010 Qatar became the largest LNG supplier to Korea and Chinese Taipei. Meanwhile in Europe, it supplies LNG both at the market price, mainly to Belgium and the UK, and at the oil-index price under long-term contracts. While Qatar has developed large LNG tankers called "Q-flex" and "Q-max" to reduce transportation costs, it is reportedly mulling over the use of normal tankers to sell its LNG to other markets which do not have port facilities for "Q-flex" and "Q-max".

On the import (demand) side of the world LNG trade, the Asia Pacific market continued to account for more than one half. The Asia Pacific market's LNG imports actually fell by 2.0% in 2009 but rose by 17% in 2010. Meanwhile, European LNG imports are rising fast. As explained above, market-priced LNG imports are increasing, eating into shares of expensive pipeline gas imports indexed to oil. The

[24] With the start-up of six new liquefaction trains, Qatar has completed its capacity expansion program, and currently does not have further expansion programmes.
25 Qatar now has by far the largest liquefaction capacity in the world, more than double that of the second largest, Indonesia, or the third largest, Malaysia.

European import volume has increased by 24% or 13 BCM in 2009 and by another 26% or 18 BCM in 2010. This has been helped by the opening of a number of LNG terminals – Dragon and South Hook in the UK, Fos Cavaou in France, and Adriatic (Rovigo) in Italy. Russia's pipeline exports to Europe fell by 20 BCM from 2008 to 2009.[26] Therefore, LNG can be thought to have caused 13 BCM of the 20-BCM decline in 2009.

Figure 11

Qatar's New Liquefaction Trains				
Project	**Partners**	**Capacity**	**# of trains**	**Start-Up**
Qatargas 2	Qatar Petroleum, ExxonMobil, Total	7.8 mt/y	2	Apr 2009
Qatargas 3	Qatar Petroleum, ConocoPhillips, Mitsui	7.8 mt/y	1	Sep 2010
Qatargas 4	Qatar Petroleum, Shell	7.8 mt/y	1	Dec 2010
RasGas 3	Qatar Petroleum, ExxonMobil	7.8 mt/y	2	Sep 2009 Feb 2010

Source: various

There are two pricing systems co-existing in the global LNG trade. One is famously called the "S-curve" linked to oil, commonly used in the Asia-Pacific basin, and the other is based on the competitive market prices of natural gas, used in more flexible LNG trading in the Atlantic basin.

Typically S-curve pricing formula is expressed as:[27]

P=A*JCC+B

A is a coefficient linking the JCC (Japanese Crude Cocktail) quotation in \$/bbl with the LNG price in \$/mmbtu. Long-term LNG contracts commonly use the average monthly JCC prices over a certain period, to dilute the volatility of oil prices. The coefficient **A** is a heating conversion factor from oil to gas and the heat parity value is typically 0.172. But actual coefficients used in the contracts are somewhat smaller (the slope is gentler). **B** is a constant in \$/mmbtu.

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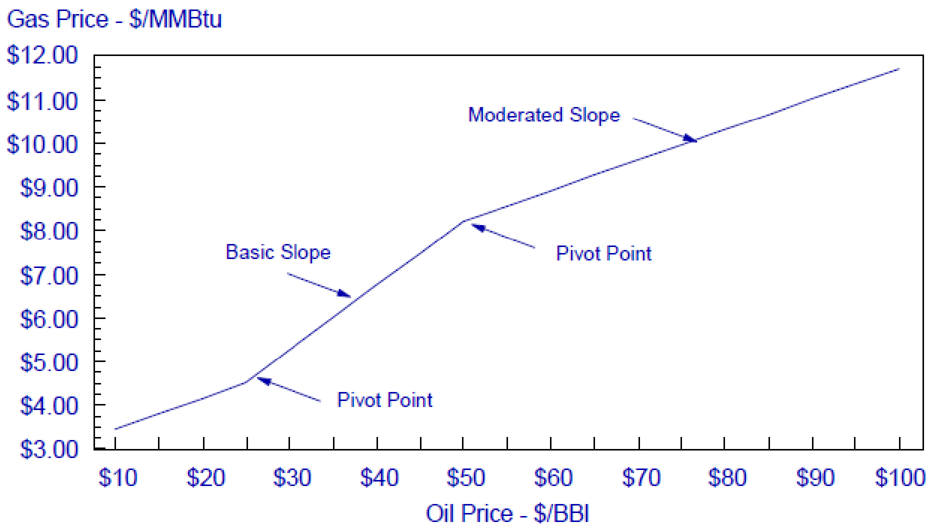
[26] Cedigaz. Pipeline trade volumes for 2010 are not available as of writing.

[27] "Putting a Price on Energy" (Energy Charter Secretariat, 2007), P190.

Figure 12: S-Curve

(Basic Slope – 0.1485, Pivot Points at USD25 and USD50)



Source: Jensen Associates

S-curves are intended to reduce price risks by mitigating the impact of either rapidly rising or falling oil prices. The sellers need to have some form of price floor, protecting their liquefaction projects from oil price collapse. As a trade-off, buyers want upside protection. Floor and ceiling prices can be set to offset such risks. In actual contracts it is more common to change the slope, which represents the oil-gas price relationship, above and below certain price levels. The graph below is a typical S-curve from the early 2000s.

The increase in oil prices starting 2005 put upward pressure on LNG pricing. In the contracts signed in this period (such as Australian North West Shelf or Indonesian Tangguh), the slopes became steeper and there were no ceiling prices or upside protections. Then, oil prices collapsed in 2008 and the gas market became over-supplied in 2009 and onwards. These oil-indexed LNG volumes have to compete with market-priced spot LNG volumes in the market. Now traditional oil-indexed LNG buyers, such as Tokyo Gas, are insisting on gentler slopes and a partial linkage to Henry Hub or other market prices.[28]

The other LNG pricing system is based on natural gas market prices. During the 2000s LNG trade expanded rapidly in the Atlantic market. International oil companies (IOCs),[29] which had liquefaction plants in Trinidad and Tobago, Nigeria and other countries as well as terminals in Europe and North America, started flexible LNG trading

[28] "Gas Matters" (December-January 2011), P11.
[29] Including BG, BP, Repsol, Shell, Statoil and Total.

based on schemes called “arbitrage” and “self-contracting”. These IOCs took marketing risks and started selling the re-gasified gas from LNG (in many cases, via pipeline) directly to the final consumers in North America and Europe. Since LNG cargos going into the UK and the US had to compete with other pipeline gas, they were priced based on Henry Hub and NBP prices. Belgium’s Zeebrugge terminal also played an important role in expanding this flexible LNG trading to Continental Europe.

A situation similar to Continental Europe is developing between the Asian S-curve LNG pricing and the one based on the UK/US gas markets. In the fourth quarter of 2010, oil-linked Asian LNG price averaged $12.90/mmbtu. Meanwhile, LNG cargos going into the US were priced so that they could compete with the Henry Hub price of $3.80/mmbtu. The differential ran as high as $9/mmbtu, as abundant shale gas supplies in the US lowered natural gas prices at Henry Hub. Furthermore, LNG cargos destined for the UK market faced competition from the NPB price of $7.28/mmbtu. Even for the cargos entering into Continental Europe, the threshold is the Russian-German pipeline gas price of $8.84/mmbtu for the same quarter (see Figure 2). There is a desire to change the indexation from crude oil to gas market price among buyers in the Asia Pacific market. However, the discussion is not making progress, because there are no major competitive gas markets in the region and the Henry Hub and NBP markets are geographically far away.

LNG can move between markets so long as the price spreads allow. Increasingly, these differentials drive the trading community's interest in LNG. The spot LNG market[30] has been growing steadily since its inception in the early 1990s (Figure 13). Spot trading jumped to 19% of the total LNG trading volume in 2007, owning to stoppage of operation at Japan’s Kashiwazaki-Kariwa nuclear power plant and Korea’s delay in signing long-term contracts, and then fell in 2008. Figure 14 shows that spot LNG trading (Asian spot, European spot and UK/US combined) accounted for 17% of the total in 2009. Spot LNG trading is expected to increase again in the next few years, because of extra demand from Japan, resulting from its nuclear problem. LNG trading today is buying and selling the physical only and there are no financial or “paper” markets – LNG is not a global commodity yet. Nonetheless, LNG spot trading is increasingly playing an important role in cross-border gas price formation. But the gas bubble that the IEA was projecting for the next few years is already being absorbed by the huge increases in Chinese consumption and this may slow the growth of spot LNG.

[30] Including trading on a spot basis and under short-term contracts.

Figure 13

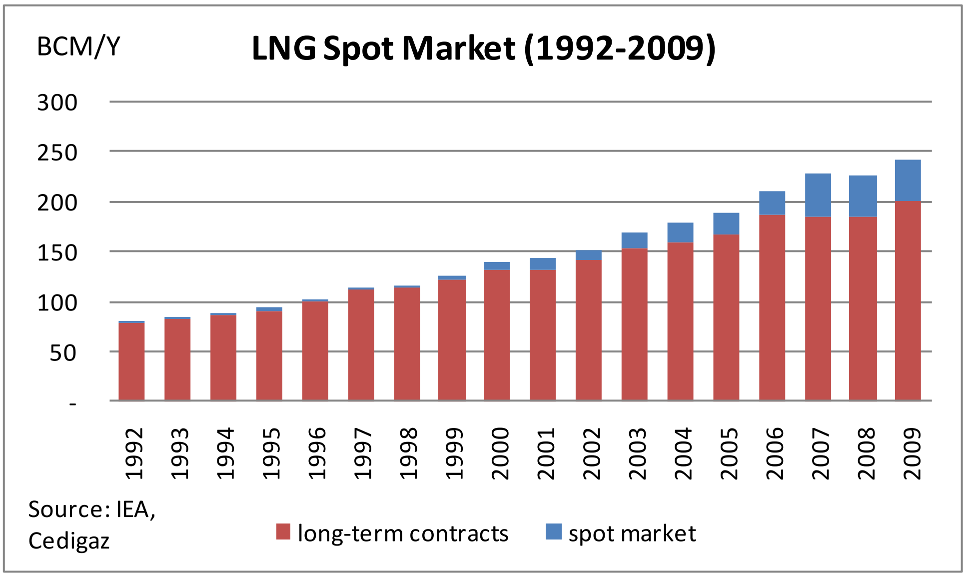
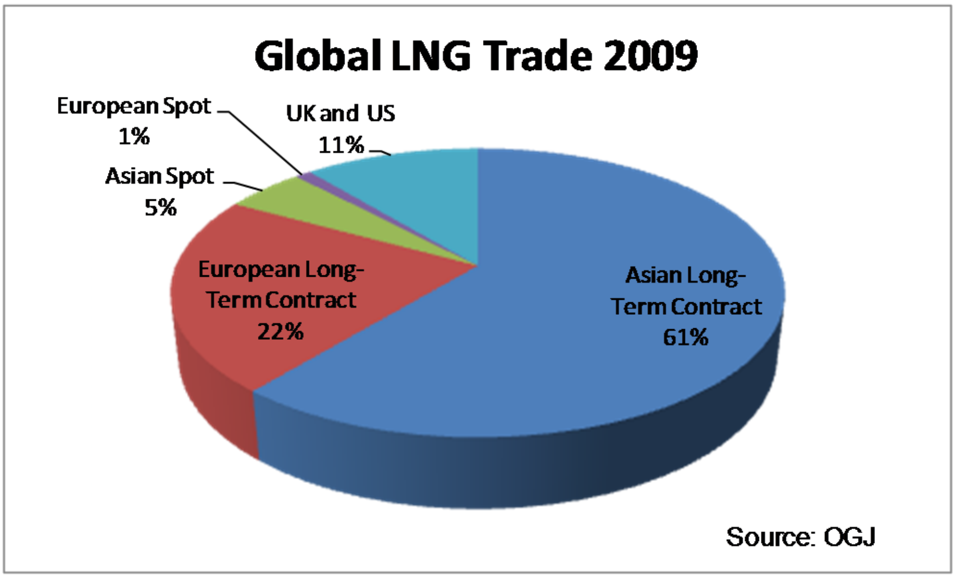


Figure 14



Outlook for Natural Gas Pricing

The EU's Third Package

Natural gas pricing based on the market will not happen on its own. Experiences in the UK and the US show that a mature gas sector needs to be appropriately regulated to promote gas-on-gas competition and transparent trading exchanges. The experience in North America took over 10 years from the National Gas Act in 1978 to begin to rationalize US gas markets, but 23 years later, markets are still maturing. Spot transactions at hubs and futures trading at financial centers are essential to developing market-based pricing. At the same time, it should be noted that long-term deals still have their utility as European gas market is relatively immature. Long-term deals help investors with expensive infrastructure in upstream and mid-stream.

In Europe, the European Union's third energy package came into force on March 3, 2011. The third package consists of (in terms of gas):

Gas regulation – regulation of conditions for access to the natural gas transmission networks.

Regulation establishing ACER (Agency for the Cooperation of Energy Regulators).

Gas directive concerning common rules for the internal market in natural gas (2009/73/EC).

The third package focuses on unbundling – separation between transmission and production/supply of vertically integrated companies. It aims at enhancing non-discriminatory access to networks to create competition between producers/suppliers. The gas directive provides the EU member states with three policy options for unbundling:

Ownership unbundling (OU) – There is no control of the supplier over TSO (Transmission System Operator) who owns and manages the network. Although minority shareholding is allowed, the supplier does not have voting rights and cannot appoint administrators.

Independent System Operator (ISO) – The ownership of network is vertically integrated into the supplier. But the network is operated by a separate entity, ISO. The ISO will make investment decisions. The regulator will have strict monitoring in this case.

Independent Transmission System Operator (ITSO) – The ownership as well as the operatorship of network are vertically integrated into the supplier. TSO (Transmission System Operator) is created within the supplier. The TSO has independent management, supervisory body and compliance officer. The TSO will be placed under heavy regulations and monitoring.

In February 2011, the European Union's heads of state and the governments confirmed that a "fully functional, interconnected and integrated internal market" should be fully implemented by 2014[31] and that "no European state should remain isolated from the European gas and electricity networks after 2015".

Through the first and second packages (1998, 2003), the European Commission has sought to create a competitive European gas market. So far, the Commission has most effectively challenged the destination clauses in LNG and pipeline gas supply contracts. It has successfully had Algeria, Nigeria and Russia agree to remove the destination clauses from existing or future contracts. This issue came up again in a recent deal between Poland and Russia. An intergovernmental agreement was signed in October 2010, stipulating Russian gas supply to Poland for 2010 to 2022, preferential gas prices and establishment of pipeline operator in the Polish section of the Yamal pipeline. The agreement also included abolition of the destination clause which had prevented Poland from re-exporting gas to third parties, where once again the Commission had to force destination restrictions out of the deal.[32]

Furthermore, the European Commission has viewed it as a competition issue that particular importers have similar pricing formulas in their contracts with particular exporters. Meanwhile, the Commission shows understanding for the need for long-term contracts on the grounds that they are a necessary tool to secure investment in large-scale energy projects. With the third package, the European Commission is determined to bring full competition into the gas sector.[33]

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[31] This is taken as the deadline for the third package.

[32] "Gas Matters" (December-January 2011), P18

[33] "Gas Matters" (March 2011), P19.

Spot and Futures Markets in Continental Europe

Spot trading volumes at Continental European hubs have been rising fast in the last few years. There are now seven major gas trading hubs in Continental Europe. In addition there is the UK's NBP, started in 1996 with by far the largest trading volume. The seven continental hubs are: Zeebrugge in Belgium (starting in 2000), TTF in the Netherlands (2003), Italy's Punto di Scambio Virtuale (PSV) (2003), France's Point d'Exchange Gaz (PEG) (2004), Germany's Gaspool (2004) and NetConnect Germany (NCG) (2006) and Central European Gas Hub (CEBH) in Austria (2005).

Since their inception, trading volumes at European hubs have been expanding rapidly. In particular, aggregating the trading volumes of the seven hubs shows a phenomenal growth of 57% in 2008 and 56% in 2009. As mentioned above, the main reason is a shift from supplies under long-term contracts with oil-indexed prices to spot volumes. Technical improvements (pipeline and LNG terminal capacities, balancing rules, access to pipeline and storage facility, gas qualities) also helped the growth. The combined trading volume of the seven hubs stood at 293 BCM in 2009, accounting for 65% of Continental Europe's gas consumption in volume terms (Figure 15).

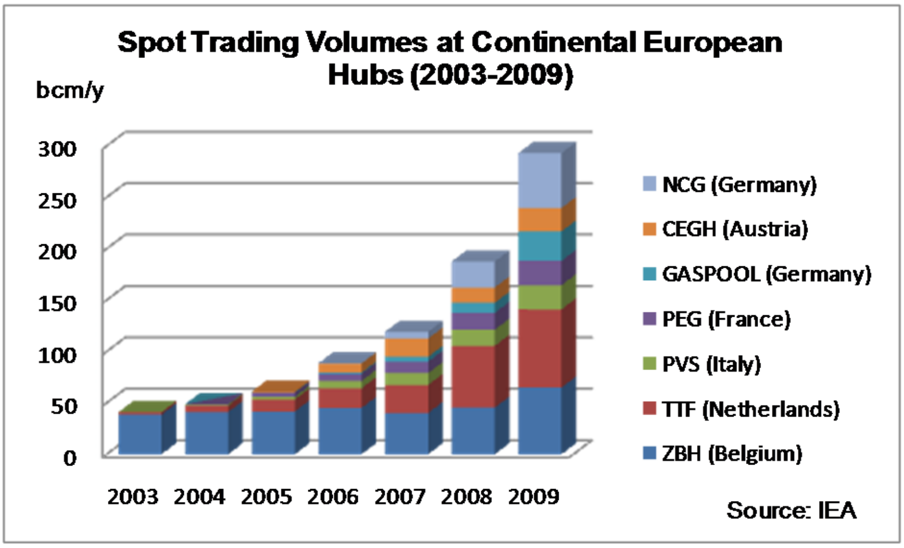
Belgium's **Zeebrugge** is the first trading hub (i.e. spot market) in Continental Europe where the Interconnector links Zeebrugge to the Bacton terminal in the UK. Trading started at Zeebrugge in 2000, after start-up of the Interconnector operation in 1998. In addition, it is an LNG terminal, receiving LNG mostly from Qatar, as well as a landing point for the North Sea gas carried by pipeline from Norway and the UK. Gas also comes from Germany and the Netherlands via the onshore pipeline network. Zeebrugge's trading volumes have increased by 43% between 2008 and 2009, to 65 BCM. But Netherlands' TTF is growing even faster and has taken over the position as the largest gas trading hub in Continental Europe.

TTF (Title Transfer Facility), established in 2003, is a virtual market place for gas trading on Netherlands' national gas transmission grid operated by GTS (Gas Transport Services), a wholly owned subsidiary of Gasunie. APX-ENDEX, an energy exchange for electricity and gas in Belgium, Netherlands and the UK, launched trading of TTF gas in 2005. TTF trading volumes have been increasing rapidly, and in 2009 TTF became the largest gas hub in Continental Europe, with a trading volume of 76 BCM per year (compared to Netherlands' gas production of 74 BCM for the same year).

Italy is Europe's third largest gas consumer (77 BCM in 2009), and ENI dominates the natural gas market. In the face of falling demand and expensive oil-indexed gas imports, spot trading volume at **PSV** rose by a phenomenal 51% to 24 BCM in 2009. Similarly in France where the gas market is dominated by GDF Suez, trading at **PEG** increased by 44% to 24 BCM in the same year. This volume accounted for 48% of the country's consumption 49 BCM.

In 2009, two newly organized German hubs, **Gaspool** and **NCG**, started operating. The two hubs are expanding fast. Their combined trading (82 BCM in 2009) is already larger than that of Netherlands' TTF, and equates to 90% of Germany's consumption volume. Gaspool covers H-gas markets in northern Germany, while NCG includes the former E.ON Gastransport area. The Gaspool and NCG markets are operated by pipeline/service companies under the same names. Now, the European Energy Exchange (EEX) trades both spot and futures contracts of Gaspool and NCG.

Figure 15



Austria's **CEGH** started trading in 2005 and its trading volume increased to 23 BCM in 2009. The CEGH market is an important one to watch, as it will play a role in introducing gas-to-gas competition and market pricing in Central and Eastern Europe. Its delivery point is Baumgarten, where pipelines originating in Russia diverge to supply gas to Austria as well as to Germany, Italy and Hungary through transit pipelines. Currently all physical gas supply to CEGH comes from Russia's Gazprom. Shares of the CEGH Gas Exchange are owned 80% by OMV and 20% by the Vienna Stock Exchange. Following a cooperation agreement between OMV and Gazprom signed in January 2008, there is a proposed 50% share transfer from OMV to Gazprom and its subsidiary Centrex European Energy & Gas, which is subject to prior approval of the European Commission.[34] In addition, Baumgarten is the European destination for the planned Nabucco and South Stream pipelines. These

[34] IEA "Medium-Term Oil and Gas Markets 2010", P212.

pipelines intend to connect to Baumgarten in the coming years.

As to futures trading, the two major natural gas futures exchanges have been NYMEX's Henry Hub (starting in 1990) and ICE's NBP (1997). In the last few years, however, a number of exchanges have started trading new gas futures in Continental Europe. Now, most Continental European hubs have futures exchanges. There is Powernext gas futures (2008) in France, and Germany has GASPOOL futures and NCG futures (2007) at the European Energy Exchange (EEX). APX-ENDEX trades both Zeebrugge and TTF gas futures. In addition, the UK's ICE started listing Dutch TTF futures in March 2010 as well as Germany's Gaspool and NCG futures in November 2010. Meanwhile in December 2010, CEGH Gas Exchange launched CEGH gas futures in Vienna. Since futures markets attract a wide range of investors including financial institutions. They have large trading volumes and their price formation influence is much larger than that of spot markets. Historically speaking, it was a futures market, the NYMEX, which changed oil pricing from OPEC's official sales price system to the market-base price in the 1980s. These new futures exchanges show that there is considerable interest in trading natural gas as a commodity in the market.

Relation between Oil and Gas Prices

There are arguments by those who support contractual linkage of gas price with oil that gas prices tend to follow oil prices in competitive markets. There are even longer standing arguments that, because oil and gas are often produced together, prices of their products will respond to the same market phenomena. The arguments no doubt had some merit when the difficult gas projects of the late 70s were being launched in Russia and Norway. Similar arguments can be also found that, since NGL and GTL – products from natural gas – are linked to oil prices, the price of natural gas should be linked to oil prices as well. But these are liquids and are priced in oil markets – yet their value in the gas stream does play a role in gas production decisions as discussed earlier.

It is true that substantial volumes of gas are produced in association with oil and therefore are driven by oil price dynamics. However, there are giant and super-giant non-associated gas fields producing large volumes as well. As touched upon earlier, oil and gas are already two different commodities consumed in different markets. It is up to these markets to determine the value of products in the deregulated, competitive industry environment.

Abolishing contractual linkages between oil and gas prices would not necessarily mean the end of a relationship between the two. Jensen wrote about the relationship of oil and gas prices in the fully liberalized market.[35] In the graph below (Figure 16), he compared the NYMEX Henry hub strip prices[36] with WTI crude oil prices in $/MMbtu from 1991 to 2008. Jensen called the period between deregulation of the natural gas sector in the early 1990s and the winter of 2000/2001 "gas bubble". He found that "the early price behavior of both North American and UK markets appeared to confirm early expectations that gas-to-gas competition would decouple gas pricing from oil pricing. …Since both North America and the UK liberalised when they had substantial supply surpluses, they experienced severe producer price competition and their gas prices were indeed well below those of oil". Gas has thus become a separate commodity from oil in terms of both supply and demand.

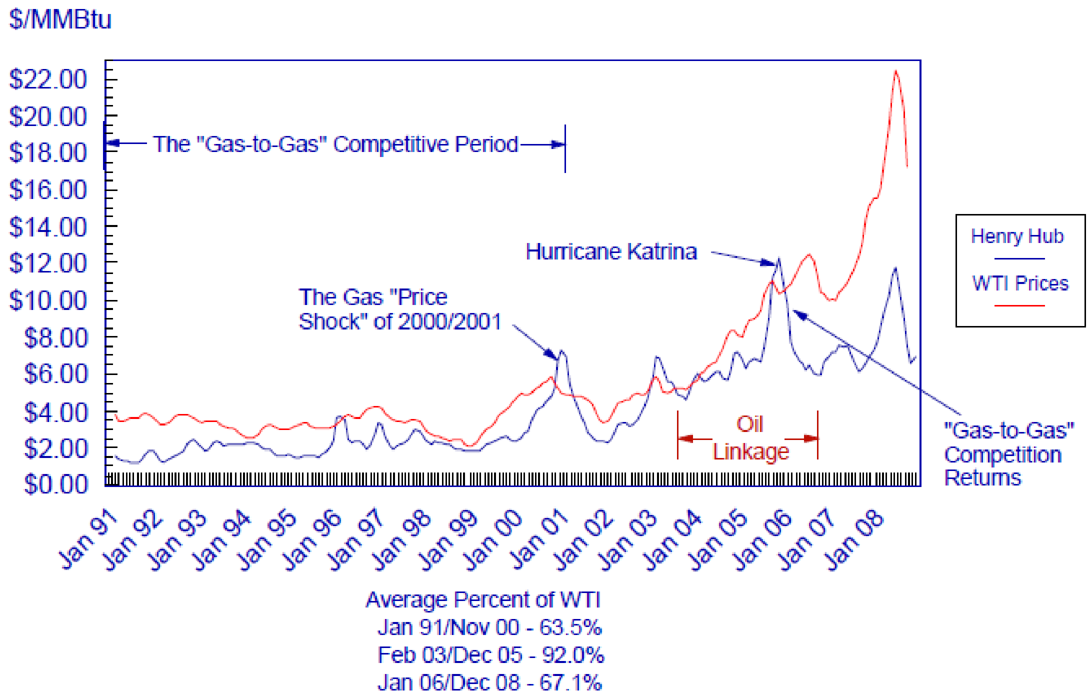
Extremely cold weather, coupled with strong economic growth on the demand side and low storage levels on the supply side, hit the US in the winter of 2000/2001. This resulted in a severe price increase. As gas prices rose, power and industrial plants started fuel switching and the linkage between oil and gas prices was re-established. Then, starting around 2004, rising oil prices strongly influenced natural gas prices. Jensen noted that "…both regional commoditized markets (the US and the UK) have shown that, in times of shortage, inter-fuel competition can set prices that may be indirectly linked to oil after all." This linkage weakens as gas drives oil out of heating markets in places like the US northeast and German households.

In 2006 the gas-to-gas competition returned, as a result of demand response to higher gas prices, and in around 2007 supplies from unconventional gas resources started growing. This glut market has basically continued to date in the US and gas prices are low and separated from oil.

[35] "Recent Developments in LNG Trade and Pricing" (Energy Charter Secretariat, 2009), P25.

[36] The NYMEX Henry Hub strip price is the average forward price of the next 12 months of the futures contracts. The strip price tends to adjust seasonal changes in gas price.

Figure 16 Relation between Oil and Gas prices



Source: Jensen Associates

Gas Exporting Countries Forum

From its first meeting in Teheran, Iran, in May 2001, the Gas Exporting Countries Forum (GECF) now has a ten-year history (Figure 17). According to its website,[37] GECF has 14 member countries.[38] GECF countries control 40% of the world gas production and 67% of the world gas reserves, compared to OPEC's shares of 41% in production and 77% in reserves.[39] This calculation was made before the arrival of shale gas on markets.

From its inception, observers have seen GECF as an aspiration by some gas exporters to create a "Gas OPEC" – a forum/organization which could set/coordinate gas export prices/volumes. But it is also widely perceived that GECF would face difficulties in attaining such a goal due mainly to the fact that these gas exporting countries already have their respective captive markets. Some gas exporters, such as Canada and Australia, do not take part in the Forum while others like Brunei, Indonesia, Malaysia

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[37] http://www.gecforum.org
[38] Algeria, Bolivia, Egypt, Equatorial Guinea, Islamic Republic of Iran, Kazakhstan (observer), Libya, Netherlands (observer), Nigeria, Norway (observer), Qatar, Russian Federation, Trinidad & Tobago and Venezuela.
[39] BP Statistics 2010.

and the UAE are non-active. Not surprisingly the world's biggest producer and consumer of gas – the USA – has not been invited to sit at the GECF table.

In 2007 and 2008 Russia launched the initiative to establish the GECF. Russia was already smarting from the European rebuke for its conduct in Ukraine and President Putin saw a gas club as another way to extend his sphere of international influence. Iranian interest in a GECF must surely have been based on a longer term vision as Iran (with 16% of the world's reserves) cannot expect to play significantly in world gas markets for several years. The Qataris probably see no option but to be present in any gas producer forum, but as a neighbor to Saudi Arabia, they know that any production restraint by gas producers would invariably fall on the biggest net gas exporter – them. In the background of the initiative, there were rising oil and gas prices and growing confidence on the part of natural resource owning countries at the time – but motivations varied. GECF agreed to adopt its charter and to establish a secretariat in Doha, Qatar. Since these moves, however, GECF has once again became low-profile, attracting very little attention (see the recent media report in the Appendix).

Figure 17

GECF Ministerial Meetings		
1	May 2001	Tehran, Iran
2	February 2002	Algiers, Algeria
3	February 2003	Doha, Qatar
4	March 2004	Cairo, Egypt
5	April 2005	Port of Spain, Trinidad & Tobago
6	April 2007	Doha, Qatar
7	December 2008	Moscow, Russia
8	June 2009	Doha, Qatar
9	December 2009	Doha, Qatar
10	April 2010	Oran, Algeria
11	December 2010	Doha, Qatar

Source: GECF website, other

Nevertheless it is important to be aware of the potential posed by GECF. If low gas prices and declining gas demand continue and the gas sector moves to a competitive one based more on the market, these developments would provide an opportunity for gas exporters to consider the role of GECF once again. It will be sufficient for the GECF to schedule a meeting for the increasingly relevant spot markets to react to the news. GECF may only generate noise, but in markets it will be news.

Way Forward

Contractual decoupling of gas prices from oil prices is not a new issue. In the natural gas market only a limited number of large institutions are involved, and they only move slowly. But it looks as if times are changing: the issue is reaching a new stage at least in Europe. The IEA calls the issue of decoupling oil and gas prices "Arguably, the most important question faced by the gas industry over the coming three years."[40]

Related to gas pricing is the use of long-term contracts to secure financial viability of gas projects. Gas projects normally have a long project life and require large-scale investment with a large portion invested up front. Moreover, a number of segments (from gas fields through pipeline and distribution network to power plants or factories) form a "gas chain", where the success of a gas project depends on developments in the other parts of the chain as well as on its own. A failure in one part affects the entire chain. Traditionally, project finance on a non- or limited-recourse basis is chosen to finance these large-scale gas projects. Long-term contracts play a key role in it and financial institutions have become accustomed to them. Long-term contracts between the seller and the buyers of gas are used to minimize uncertainties over project revenues, prices and marketing.

However, such a traditional financing model is changing, due to changes in and outside the gas sector. The financial crisis had a major impact on banks and other financial institutions, which are the lenders in project finance. As a result, project finance has become more costly and hard to obtain. In addition, lenders are aware of the changes taking place in natural gas markets and do not rely solely on long-term contracts any more. Furthermore, gas companies with their relatively good financial backgrounds are increasingly using corporate loans, bonds, or internal cash flows in combination with project finance. National gas companies may even enjoy government guarantees. Therefore, continuing insistence on the traditional long-term contracts raises questions.

Just after the start of the financial crisis in autumn 2008, European gas companies began voicing concern that they might not be able to take the minimum obligation volumes in the face of falling demand. With it, criticism over oil-linked pricing emerged. Negotiations took place between Russia's Gazprom and European buyers such as ENI, E.ON Ruhrgas, and, in February 2010, Gazprom announced that it had agreed to link 15% of the volume to spot gas prices over the period of 2010-2012. But this came only after Norway was already allowing up to 25% based on spot prices. GasTerra of the Netherlands is understood to have given concessions in the 2009

[40] IEA "Medium-Term Oil and Gas Markets 2010", P195.

negotiation of the extension of log-term contracts with GDF Suez, Distrigas and Swissgas. These changes were intended to narrow the gap between spot and long-term contract prices in Europe. Take-or-pay clauses have also been eased, giving more flexibility to buyers as to the timing of their lifting of the volumes. But at a minimum, the inviolate nature of oil price indexation has been challenged.

Whether the spot price indexation will become a common feature depends on global supply-demand balances and on the evolution of spot and oil-linked prices. It might also depend on whether European regulators are going to continue acquiescing in passing through oil-indexed prices to consumers. The consensus is that a relatively soft market will continue for the next few years, and, if this is indeed the case, there will be more pressure to move away from oil indexation.

However, such a change will not take place uniformly and universally. There will in all likelihood be many variations. There are also possibilities that the change will take place in the form of lowering prices under the same oil-indexed formula, or, introducing spot market indexation for a certain part of the volume (e.g. above the minimum obligatory level). Unlike the UK and the US, European and Asia Pacific countries have to import natural gas or LNG from suppliers which stand on different economic conditions and philosophies. US gas deregulation was enacted by Congress in the 1978 Natural Gas Policy Act. The Act established multiple categories of gas and their specific prices, but set them on a path to converge finally in 1987. The same Act established a uniform regulatory for all gas at the Federal level. This will not be easy for producers to accept, as they do not want to compromise the core concept of existing contracts or abandon crude parity pricing.

Looking into each region, Western Europe is moving slowly toward market pricing. Establishing new futures markets, and expanding existing ones, are particularly good signs. It is also encouraging to see European gas companies moving gradually away from oil indexation to market-based pricing. Even Germany, without an LNG terminal and traditionally heavily dependent on Russian imports, wants to obtain lower-priced supplies through interconnections to other countries and through spot and futures trading. Furthermore, as electricity, coal and CO2 emissions move toward market pricing, oil-linked gas volumes would constitute another mismatch in the market, similar to what happened in 2009.

Meanwhile in Eastern Europe, due to the legacy of the former Soviet Union, one supplier, Gazprom, dominates the gas market. So long as this situation continues, there can be little or no competition and no market prices. Russia's own internal market for 400 BCM/year is an example of a price regime administered by the state and clearly out of touch with global markets. The deals given by Gazprom to the major Western European buyers were not generally available to smaller buyers in East and Central Europe. As the EU puts this on its policy priority list, the region first needs to diversify its gas supplies through interconnection with other European countries and via LNG imports.

Pacific LNG importers, Japan, Korea and Chinese Taipei, have almost no indigenous gas production and rely almost entirely on LNG imports to meet their gas demand. Although there is competition from other fuels, it is difficult to imagine that gas-to-gas competition will take place in the countries in the near future unless Asian gas consumers begin to fear loss of competitive edge because of higher energy prices – and make it a political issue. In this region, it is more likely to see prices discounted under the same or a similar scheme as being practiced in Europe rather than an effort to move to full market pricing.

It should be emphasized that adopting market-based pricing does not mean the end of long-term contracts. But the exclusive use of long-term contracts could eliminate liquidity of the market and be a barrier to new entrants. Lack of transparency is another weakness of long-term contracts. The confidentiality of long-term contracts makes it difficult for regulators or the public to get a better view of volumes and prices. Nonetheless, long-term contracts are still an essential tool for long-term and large-scale investment. If there is a change, it would be limited to the price provisions of long-term contracts. The Netherlands and Norway already use these kinds of long-term contracts, with prices tied to the NBP market.

Conclusion

World gas markets are changing and the basis and mechanisms of price formation are changing with them. There is no reason to expect a revolution in gas pricing, but formulas designed to address the challenges of the 1970s will need to adjust to the realities of the present and expectations for the 21st century.

Because such changes will imply a redistribution of costs and benefits, vested shareholders will defend the status quo. But hopefully and ultimately, appropriately regulated markets will assert themselves and shareholders along the entire value chain will have their interests served.

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Appendix

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Doha to host 11th GECF ministerial meeting

Tehran Times Economic Desk

TEHRAN -- The 11th Gas Exporting Countries Forum (GECF) ministerial meeting will kick off in Doha, Qatar on Thursday.

Ratifying the 2011 budget, officially opening of the forum's secretariat, studying the global market and developing a 5-year strategic plan will be discussed in the meeting, SHANA news agency reported.

The Gas Exporting Countries Forum, which has been called the 'gas OPEC', groups together some of the world's leading gas producers.

The energy ministers of the member countries approved the charter of the organization in the 7th GECF ministerial meeting in Moscow on December 23, 2008.

The GECF was established in Tehran in 2001. Until the seventh ministerial meeting in Moscow, it operated without a charter or fixed membership structure.

The GECF has agreed to establish its headquarters in Doha, Qatar, the world's biggest producer and exporter of liquefied natural gas.

The forum's current members are Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Kazakhstan (observer), Libya, Netherlands (observer), Nigeria, Norway (observer), Qatar, Russia, Trinidad & Tobago, and Venezuela.

Gas producers face the challenge of shaping a market, as 70% of gas is sent by pipeline to regional consumers and no global benchmark price exists on an exchange.

Russia, Qatar, and Iran combined own 53.2% of the world's gas reserves. Russia has the world's largest reserves, followed by Iran, Qatar, Turkmenistan and Saudi Arabia