international comparison, Australia looks well placed to reap the rewards of Asia's love affair with coal. Indonesia, which will benefit most from Queensland's current supply problems, will also increase exports in coming years, but these increases are expected to peak as domestic demand for coal rises. The country is in the process of building a large number of new coal-fired power plants to meet rapidly rising domestic electricity demand.

South Africa, too, looks likely to see domestic demand encroach on its ability to raise export volumes, and much earlier than Indonesia. While South Africa has expanded its port capacity, it does not have the other parts of the jig-saw in place - namely new mines and internal transportation. Australia may find that its strongest competition in fact comes from relative newcomers to the coal market, such as Mozambique, Botswana and Mongolia, while that northern energy giant Russia is also expanding its ability to export coal to eastern markets.

However, in the short term, recovering from the floods will be the main priority, setting back other plans. The extent of the damage to mines and transport infrastructure has yet to be determined, but is likely to be counted in billions of dollars. According to Australia's Commonwealth Bank, Queensland's export coal industry will take six months to recover fully from the floods, which it estimates had by mid-January held back 14 million tons of coal exports over the previous eight weeks, of which 10.3 million tons was coking coal. This represents 9% of Queensland's annual coking coal exports and 4% of globally-traded coking coal volumes in 2010, the bank said.

The loss of 3.6 million tons of thermal coal represents 1% of world traded thermal coal market tonnage in 2010, the bank said. However, it added that coal producers in NSW will start to prioritize coking coal output at the expense of thermal coal, leading to more thermal coal shortages. The bank said that the supply deficit in the seaborne global coking coal market will rise to 13 million tons in 2011 from 8 million tons in 2010. Growth in Queensland's coking coal exports in 2011 is now expected to be 3% this year, compared with pre-flood estimates of 10%.

GECF agenda

The Gas Exporting Countries Forum needs to overcome its internal conflicts of interest if it is to become an effective and credible organization. The insistence on oil parity is outmoded. The Forum should work on changing the nature of competition in European markets from that of gas-to-gas to gas versus its alternatives, in the process forging a consensus on the long-run marginal cost of gas as a benchmark for both prices and investment. **Andrey Konoplyanik**

Although the Gas Exporting Countries Forum has not been welcomed by gas consuming countries, which view it essentially as an emergent gas OPEC, it could play an important and constructive role in today's gas markets. However, first the GECF needs to address its own internal conflicts of interest. Key members of the GECF, such as Algeria, Iran and Russia, as well as its senior political officers, have made statements in support of gas price increases at a time when the organization's own members are competing with each other for market share.

GECF members face two immediate problems: price competition in European markets, and the direction of major new export pipelines, which will potentially bring them into even greater competition in both old and new markets. Both of these issues are influenced by estimates of future demand in key markets, such as Europe, where demand trends are unclear. Some forecasts assume a rapidly expanding role for natural gas, led by the power generation sector, others reflect "de-methanisation" or "methane-phobia" led essentially by an environmental agenda and/or the intention of escaping too high a dependence on Russian gas.

The lack of clear signals relating to future gas demand provides scope for the GECF to play a leading role in research and market analysis, similar to the research activities undertaken by OPEC for oil. This would have the aim of narrowing the gaps in methodology employed by different bodies that produce such widely varying results.

European gas glut

The current glut of gas makes life difficult for the GECF, but also creates a reason for its existence. The glut is a combination of three factors. First, the global economic crisis, which has diminished gas demand worldwide. Second, the continuous increase in supplies of both pipeline gas and LNG to the European market. These were already being developed prior to the financial crisis. And third, the re-direction to the EU of LNG flows in the Atlantic basin primarily destined for the US market. This was the result of the increase in domestic US

unconventional gas production, which virtually closed the US gas market to imported gas.

Most of these redirected LNG flows in the Atlantic basin are from Qatar, which has been using its competitive advantage in terms of low production and delivery costs to leverage its LNG into European markets at delivery prices below the levels of its main competitors, Algeria, Norway and Russia. In addition, Qatar has delivered much of its LNG to Europe on a spot basis, which has proved competitive to Long-Term Gas Export Contracts indexed to oil, which is the dominant contractual basis for pipeline deliveries to Europe.

Compared to spot prices, LTGEC prices are less flexible in adapting to new market conditions. LTGEC pricing formulas reflect mostly oil price fluctuations in the previous two to three quarters and are recalculated usually on a quarterly basis. The composition of the formulas themselves are subject to negotiation between the contractual parties usually only once in three years. So when the market is oversupplied, which was the case for Europe in 2009-2010, all prices tend to trend down, but spot prices fall first and faster than LTGEC prices.

As a result, exporters using spot pricing expanded their market share at the expense of pipeline exporters. Pipeline gas buyers reduced their purchases as far as Take and/or Pay (TOP) contractual obligations allowed, but after reaching the minimum level they then faced a dilemma. Either stick to the contract and buy more gas at contract levels above the spot market. Or violate their contractual obligations and reduce their TOP off-take below minimum levels and buy more on the spot market, at the same time trying to persuade or force exporters to downgrade their contract prices in line with spot prices and withdraw penalties for violating the contractual terms. Some importers of pipeline gas even filed lawsuits against exporters in an attempt to protect what they called the 'right' of buyers to buy at lower spot prices, despite their LTGEC contract obligations.

This process clearly sets GECF members against each other. In fact, Qatar has little choice but to sell its newly-produced LNG at any marketable price. The country has made huge investments in its LNG facilities on the expectation of gas demand growth worldwide, especially in the US, and on the wave of t he gas price rises in the mid-2000s, which were stimulated by oil price increases. Qatar invested in its LNG on a project financing basis, which means that at least 70-80% of the investment was raised by project sponsors as debt financing on international capital markets.

These huge loans need to be repaid on time or the companies face huge penalties from financial institutions. As a result, Qatar's dumping of gas is not so much a marketing strategy as a necessity. It also means that if a different means of paying off investments can be found, dumping by individual GECF members might be avoided. This could be a major focus of the GECF's activities.

Competition or cooperation?

Gas prices that are too low are not in the interests of producers or consumers. Low gas prices increase demand but do not stimulate investment, leading eventually to a deficit and rising prices. High prices reduce demand, as consumers switch to alternatives, again reducing the incentive to invest.

The best price is not a short-term equilibrium price, reflecting the near-term supply-demand balance, but a price which covers the Long-Run Marginal Costs of gas, on the one hand, and is below the LRMC of the next cheapest alternative. Finding a mutually acceptable pricing mechanism that achieves such a price could be spearheaded by the GECF.

This means maximizing the resource rent of gas in competition with different energy sources in the end-user market of the importing state. This would require a mechanism that addresses the investment environment, reflecting the realities of the physical rather than the paper energy markets. A fair price would not mean a 'fair price level', but a 'fair pricing mechanism', leading to a dynamic and competitive export price that reflects changing market conditions.

GECF members face a dilemma: whether to engage in competitive or cooperative behavior. For example, the LRMC of Russian gas is higher than that of Qatari gas. So Qatar has a competitive advantage and can discount its selling price below Russian prices to expand its market share and repay its project financing debt. However, both countries are losers from this competition; Russia will lose market share, while Qatar will fail to maximize its long-run resource-rent collection.

Participation in the GECF opens for all major gas exporters an opportunity to move from competition with mutually negative results to cooperation with hopefully mutually positive results for both gas exporters and consumers. The latter should receive a predictable price below the level of the LRMC of the cheapest gas alternative, which would be to their long-term advantage, compared with the short-term price benefits generated by the gas glut.

The GECF thus needs to work on changing the character of competition in the gas market from one between major gas exporters - mainly pipeline gas versus LNG -- to competition between gas and alternative energies. This requires a fair assessment of the LRMC of gas worldwide, which could be another core area of GECF activities. The GECF should be involved in the 'Gas JODI project' - the extension of the

multinational Joint Oil Development Initiative to gas, by helping to collect data from its members and by developing a global LRMC supply curve for gas.

Pricing preferences

Producers, exporters and hedgers are interested in minimizing the price risk to their physical deliveries through the use of financial instruments. They act first in the physical market; the paper market is secondary. LTGEC pricing provides the lowest level of volatility and the highest predictability and transparency of future price behavior as a result of indexation formulas based mostly, but not solely, on oil prices from previous quarters. Price volatility is detrimental to producers' long-term investment and trading decisions, regardless of the actual price level. For project investors, it is not the price level that matters so much as the predictability of price behavior and its transparency. Both directly influence the pay-back of their capital-intensive and long-term investments.

The preferences of buyers are naturally different. At any given time, they want the lowest price possible, which means they would like to switch from spot pricing to LTGEC pricing and vice versa, depending on whichever offers the lowest price. This makes it very difficult to create a contractual structure that is stable and transparent that reflects buyers interests in full.

If the 'Anglo-Saxon model' of gas market architecture was developed in continental Europe, it would mean the appearance of a third group of players in the paper market, which, as with oil, would include financial speculators not engaged in the physical market. Financial traders prefer increases in price volatility because they make money not via physical deliveries, but through trade in energy-related financial instruments. This model may generate new price risks for both consumers and producers, and, as such, security of supply issues. The GECF could thus play a role in leading the difficult debate on developing market structures and pricing mechanisms that will minimize price volatility in the emerging global gas market.

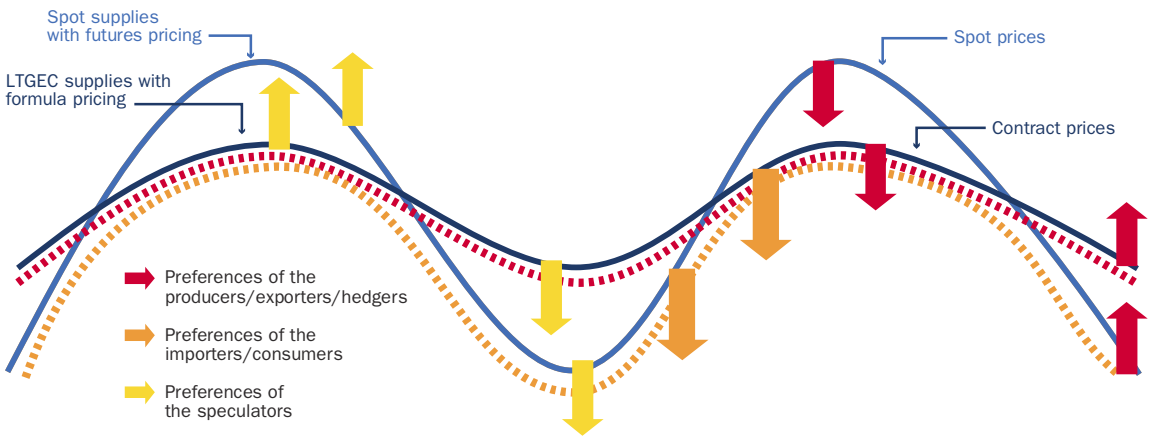
Gas pricing directions

It is possible to identify five major routes for possible changes to LTGECs indexed to oil. First would be a move to overall spot/futures pricing. This is the preferred option of the European Commission, and is incorporated into the vision of the future architecture of the EU internal gas market in the form of regional zones with liquid trading hubs. This is the Anglo-Saxon model designed for continental Europe by the EU's Third Energy package.

However, for the moment, European gas hubs are not liquid at all. All continental European gas hubs are characterized by a 'churn level' measured in single digits, at best from three to five and lower. The churn of the UK's National Balancing Point has been fluctuating around the marginal level of 15, mostly approaching this level from below. This means that no European hub is ready today to become the European equivalent of the US market's Henry Hub. And the lower the liquidity, the greater the possibility of price manipulation.

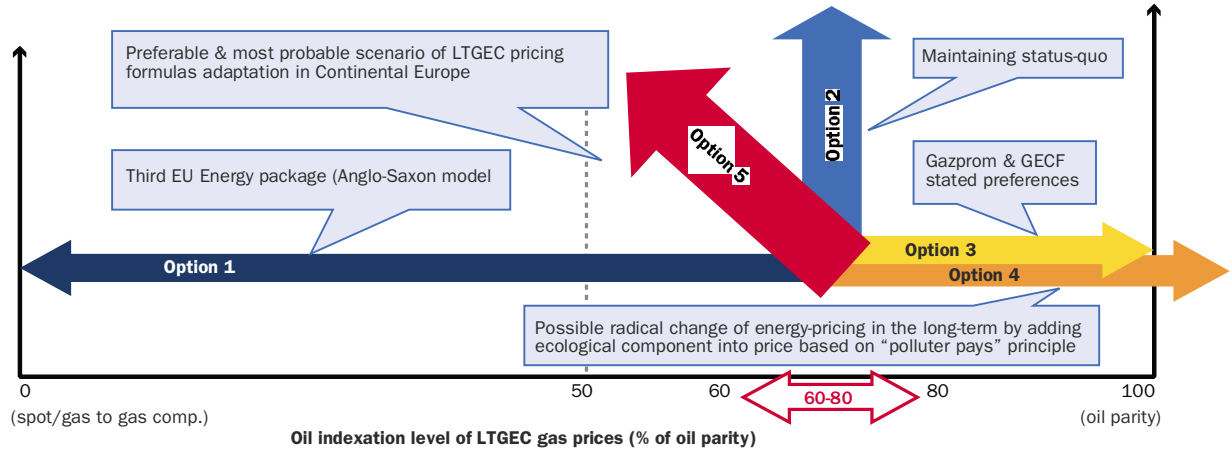
The current level of liquidity at Henry Hub exceeds the most liquid European hub, the NBP, by a factor of more than 20, while all gas hubs are less liquid that key oil markets such as NYMEX or ICE. These latter have churn rates that exceed 2000. There is no knowing what time scale is required for Europe's gas hubs to reach the requisite level of liquidity, nor indeed if they will ever reach such a level. And, as argued, even if they did, there is no clear case for then moving all contractual structures in Continental Europe to spot pricing because this would allow non-energy speculators to dominate the paper markets, which in turn would increase price volatility to the detriment of all actors in the physical energy value chain.

Pricing preferences



Source: Dr A. Konoplyanik

Evolution of gas pricing mechanisms in Europe: main options



Source: Dr A. Konoplyanik

The second option would be to maintain the status-quo, which would largely mean retaining current LTGEC with oil-indexation formulas. Three quarters of the price basket in these formulas in the EU are based on two petroleum products: Light Fuel Oil and Residual Fuel Oil. For major gas exporters to the EU – Russia, Norway and the Netherlands - the oil component is even higher, around 90%. However, since 1962, when the original Groningen contract was established, the spectrum of replacement fuels for gas in different sectors has expanded. The gap has increased between the economic substance of the replacement value formulae and its contractual embodiment. To maintain the status quo would mean further deviation from the economic substance of the replacement value concept.

The third option would be to retain oil indexation and reach oil parity. Moving from the current gas-to-oil price ratio of about 0.6-0.8 to parity is the stated preference of both the GECF and Russia's state-owned gas company Gazprom. However, the only way this could be achieved within the framework of oil-indexed formulae would be to increase the LFO component (typically 15% above the crude price) and minimize the RFO component (typically 30% below the crude price). This would further undermine the replacement value concept of gas pricing.

Moreover, it would be next to impossible to persuade buyers to switch to such a pricing formula as it would mean price increases at a time when they are fighting with Gazprom and other gas exporters for price discounts. This option appears wholly impractical. Yet two consecutive GECF ministerial declarations in April and December 2010 were made in support of oil parity. The GECF's attachment to the concept of oil parity prevents its from initiating a broader debate on mutually acceptable gas pricing options, which can be more flexible and adaptable to the changing state of the market.

A fourth option would be to deviate from oil indexation and to exceed oil parity. This is not as crazy as it first sounds, but would require a radical change in energy pricing over the long term. It could be achieved by adding an environmental component to the pricing formulae based on the 'polluter pays' principle. Since gas is the cleanest fossil fuel, it would obtain the lowest pre-tax price among its competitor fossil fuel replacements. In this case the number of ingredients within the pricing formulae would increase. The indexation character would be preserved, but the oil element would fall. The final result could even exceed the GECF and Gazprom's goal of gas prices reaching oil parity. However, achieving such a large and coordinated change in energy pricing is unlikely given the lack of progress in UN talks to agree a replacement framework for the Kyoto Protocol. For the time being the idea remains largely theoretical.

The final option would be to adapt LTGECs in line with the historical evolution of replacement values. This evolution suggests formulae develop from simple to more complex structures and that the oil indexation component is gradually reduced. The more liberalized the importer's market is, the more sophisticated the pricing basket within the LTGEC and the smaller the oil-indexation component. The general trend is quite clear, moving away from oil parity in an evolutionary rather than revolutionary manner, but retaining the net-back replacement value principle.

The structure of supplies would be two-fold. First, long-term gas supplies to meet baseload demand, with more flexible and shorter-term LTGECs. These would feature modified gas replacement value formulas with price indexation not limited to oil. And second, short-term supplementary gas supplies priced on a spot basis at regional European hubs. Support for such an approach might at least start to break down perceptions of the GECF as a gas OPEC and eventually deliver pricing mechanisms that meet the interests of both producer and consumer.