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CONTENTS

Six articles published here are grouped under two different headings: the EU Energy Policy and Features of Recent Oil Developments. Both are highly topical. The financial crisis which risks to push the environmental objective toward the back burner, the election of President Obama which on the contrary involves a greater concern with that objective, and the Russian–Ukrainian gas supply crisis, all call for an appraisal of the EU ambitious energy policy. The current state of the world petroleum market characterised by relatively low prices, falling oil demand, a reluctance to invest, distorted futures prices, and considerable uncertainties also calls for an analysis of some of its aspects.

David Buchan and Giacomo Luciani who are among the best independent observers of EU policies cover the first theme. Buchan gives marks to the different policies comparing the EU potential for success on every item with actual performance. While the environmental and the internal market policies score high marks, supply security, nuclear, R&D, efficiency and renewable energies leave much to be desired. He tells us why. Among the many reasons, an important one is the failure of the EU to organise gas sharing agreements between members, and to build interconnections.

The internal market policy, which seeks to create an integrated, open and competitive gas (and electricity) market in Europe, does not sit comfortably with the supply security objective. Luciani focuses on this issue, detailing the dilemma and the contradictions involved. The solutions faced serious obstacles. The private sector will not willingly build interconnections where the return on investment is low or negative. To develop LNG regasification plants is a more promising option.

Luciani is puzzled by the EU Commission's decision to establish regulatory institutions with the power to mandate investments in gas inter-connectors. There are better ways to improve supply security without abandoning the need for even-handed approaches and transparent rules when supporting certain projects necessary for the diversification and a better distribution of supplies.

The fall in oil demand, particularly

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but not exclusively in the USA, is widely believed to be a major factor in the recent collapse of oil prices. Paul Horsnell and Costanza Jacazio's article is about the crucial role played by US oil demand behaviour in determining price movements. This is in contrast with the great crisis of 1986 where supply policies were critical. US oil demand has proved to be very sensitive to changes in economic conditions. There are big swings that defeated forecasters; errors in demand forecasts are very significant for the USA, the country that can be labeled 'the swing consumer'. Horsnell and Jacazio spell out the conditions required to change market sentiments later in 2009, and induce a price increase. One of these conditions is 'that the extreme sensitivity of US demand to the economic cycle is not echoed in future data for other OECD areas'.

The current oil situation challenges oil and gas corporations, both private and national. What are their worries and what should be their strategies? Ivan Sandrea who explores these issues is however more optimistic than many contemporary observers about the opportunities for investment in the long run and the ability of corporations to soldier on in a difficult economic environment.

Bassam Fattouh delves in the very difficult issues posed by the term structure of futures oil prices. In current oil market jargon, rather barbarisms, these issues relate to backwardation and contango, that is the signs of the spreads (or differentials) between the prices of futures contracts of different maturities. He observes that these spreads have been recently very volatile and subject to 'reinforcing dynamics'. This would have only been a curiosity if it didn't have significant impacts on 'the international pricing system, financial investment, inventories and OPEC's behaviour'.

The current oil price collapse crisis is the third significant one to have occurred in the past 22 years. The preceding ones, labeled counter shocks, marked oil history in 1986 and 1998. Horsnell and Jacazio made some comparisons between the 1986 and the 2008–9 events with reference to the different roles played by demand in these two episodes. Incidentally, they revealed that the current crisis has already lasted three months longer than the traumatic 1986 instance. One is entitled to ask: and how much longer will it continue to prevail? A comparison of the 2008–9 oil price collapse and the crisis of 1998–9 will have to wait for the next issue of Forum.

The article by Axel Wietfeld and Niels Fenzl on LNG trading is not directly part of any of the two previous groups of papers. There are, however, some interesting relationships. LNG offers a part solution to the supply security problem of Europe addressed by Luciani; and the current oil and economic crisis cannot be without impact on gas developments. Looking at the long term the authors are reasonably optimistic about demand increases, greater price competiveness, increasing significance of the spot market, and therefore diversification of markets and supplies.

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The European Union Energy Policy

David Buchan assesses Europe's collective 'inaction'

Collective measures are supposed to carry greater weight and speak louder than individual action. That is largely why countries join the European Union. But in the crisis over Russian gas shipments across Ukraine, the joint pleadings of the final customer, the EU, fell on deaf ears in Moscow and Kiev. Of course, if Russia and Ukraine were determined to quarrel, an outsider could not force them to agree – not even an EU of 500 million people that is both disputing countries' main market. Yet inside Europe too the EU has also done precious little, in terms of organising gas sharing arrangements or creating gas interconnections, to help its gas-bereft member states. What gas sharing has taken place has been organised bilaterally between Czechs and Slovaks, and between Austrians and Slovenes.

In fulfilling its potential to add value to member states' energy and climate policies, the EU has a very mixed record. This is one of the themes of my forthcoming book for the Oxford Institute for Energy Studies. Table 1 suggests how performance measures up against potential in EU energy policy. It does not attempt to be scientific, but rather a spur to thinking about the EU's relevance to energy policy (or the gap between potential and performance). Potential is obviously harder to judge than performance, because it is what might have happened rather than what has. Assessment of potential must also pay some regard to past history and present necessity, because these factors shape what is legally and politically possible today.

Of the three policy areas topping Table 1 and also topping the EU agenda, climate change gets the highest potential rating. This is because where EU-level action is considered essential – and in the case of climate change even action on an EU scale is too geographically limited – necessity tends to override politics and legalities. That said, the December 2008 reforms to EU climate change policies showed the clear political imprint of the current recession, even though the reforms themselves chiefly relate to the period 2012–2020. A combination of poorer EU states in central and east Europe and of major exporters led by Germany lobbied successfully to continue getting free carbon emission allowances (for an analysis of the December 2008 climate change agreements, see my comment on OIES website). The reason for the somewhat lower potential rating of EU internal market policy (A-) in Table 1 is that there is still some national resistance to EU designing energy market blueprints, although EU legislators expect to reach final agreement in spring 2009 on further liberalisation rules for gas and power markets.

Table 1: Buchan's Benchmark

EU policy	*EU potential*	*EU performance*
Climate change	A+	A–
Internal market	A–	B+
Security of supply	B+	D
Nuclear power	A–	D
Renewable energy	A–	C
Energy R & D	B+	C
Energy efficiency	B	C

Source: author

In energy security, however, to talk of national resistance to EU involvement is an understatement. Rather, it has been national insistence (from most member states) that the EU stay out of this area. This is why I rate EU energy security potential at B+, despite the theoretical market power of 500 million consumers over outside suppliers. To the extent that member states have in the past been ready to make international arrangements to handle energy security, they have preferred to do it outside the EU – through the International Energy Agency to which 19 of the 27 EU states belong. For the IEA deals only with emergency oil stock level and sharing. IEA membership never posed any conceivable supranational threat to national sovereignty over energy resources or control of national energy mixes in the way that many EU states imagined might arise if energy security were written into EU treaties as a clear EU competence. For instance, the UK, long content with its oil stock commitments to the IEA, bridled until very recently at the prospect of a clear EU treaty competence on energy, out of fear that 'Brussels' might force it to share North Sea oil and gas reserve, as it has had to do with fish stocks. This will change with the Treaty of Lisbon, if ratified in a second Irish referendum later this year. The Lisbon treaty carries language, for the first time, tasking the EU with 'ensuring security of energy supply in the Union', and, again for the first time, put this and other energy references currently scattered around EU treaties into a separate treaty article.

You might have thought that this dry business of treaty-writing might have been driven faster by events on the ground, such as EU enlargements and Russian energy cut-offs. The eight central European and Baltic states entered the EU in 2004, and Romania and Bulgaria in 2007, bringing with them their fears of over-dependence on Russia for energy, and for gas in particular. Lending substance to these fears were the brief interruptions of Russian energy through Ukraine in early 2006 and through Belarus in early 2007. Yet by the time of the first total and prolonged cut-off of Russian gas flow through Ukraine in January 2009, precious little provision had been made at the EU level for any serious disruption.

The best measure of this has been the foot-dragging in revising the EU's astoundingly complacent Gas Security Directive of 2004. This is still the basis of EU action in this area, and even with the present gas crisis is unlikely to be changed before 2010–11. In 2002 the European Commission proposed that every member state take measures to protect gas consumers, mainly households with no possibility of fuel switching, if the country's largest single source of supply were cut off for 60 days. The Commission left to member states how to ensure this – through storage, or flexible production or gas sharing with neighbours. The proposal was not too prescriptive; it did not call for minimum storage levels.

> "The January 2009 crisis … requires fresh thinking about, and maybe fresh money for, alternative gas sources"

Yet lobbied by the gas industry, the European Parliament effectively neutered the draft directive in 2003, questioning the very need for it. The German MEP who was the parliament rapporteur on the directive, said at the time 'no difficulties in the field of gas supplies have ever arisen which would be comparable to the oil crises' of the 1970s (that had led to the IEA's creation). This was a true statement in 2003. Nor was the rapporteur out of line with conventional wisdom of the time (and even now) in saying gas supply should be more secure than oil supply because there was competition between gas exporters and not a cartel, and because of mutual dependence between buyers and sellers of gas cemented in long-term contracts. Yet everyone knew in 2003 that the east Europeans would join in 2004 and everyone knew the new arrivals had particular energy security anxieties. So the European Parliament and the Council of Ministers (which in 2003 was only too delighted to agree with MEPs that the Commission leave gas security to member states) should have catered for the special energy concerns of their east European partners about to join them.

However, even after the 2006 and 2007 interruptions set off alarm bells, many member states dozed on. In April 2008 the Commission asked member states about revising the 2004 directive to improve national gas security measures across the EU. But the only one of the 27 governments to show any real interest was Poland (which incidentally has also tried to involve Nato in energy security); most others, and especially Germany, reiterated that gas security was more a matter for industry and governments than for the EU. In January 2009 of course they all speak differently. EU energy ministers have now asked the Commission to 'speed up' revision of the 2004 directive.

Although there are no quick fixes to energy security, EU governments and legislators are now likely to go along with Commission proposals on alternative energy infrastructure and sourcing inside and outside the EU. Though the EU got some responsibility for encouraging trans-European energy networks in the 1992 Maastricht treaty, Brussels has never had money to do this, beyond paying for the odd feasibility study. Now there is talk that energy infrastructure should figure high in a Euros 5bn EU contribution to the general fiscal stimulus to the European economy. Up to now the EU has had no role in the sensitive matter of siting energy pipelines and pylons, which is entirely a national responsibility. But the Commission has appointed 'coordinators' as go-betweens to help governments resolve impasses over cross-border interconnectors. And even before the 2009 gas crisis, the Council had asked the Commission to examine ways of 'streamlining' planning of EU-wide energy systems.

The January 2009 crisis not only calls for measures to improve Europe's internal resilience to external energy shocks. It also requires fresh thinking about, and maybe fresh money for, alternative gas sources. The case for Gazprom's proposed direct routes to the EU via Nord Stream and South Stream may be strengthened, though this will depend on final evaluation of Russia's and Ukraine's respective roles in their quarrel. The previously weak case for the Nabucco project to bring non-Russian gas to Europe has clearly improved.

There is also the wider question of whether Europe can improve its bargaining position with outside suppliers by pooling its demand with collective purchases of gas. The Commission has suggested the creation of a 'Caspian Development Corporation' to pool enough demand for Nabucco to make that pipeline worth building. Such an idea would have to be squared with EU competition rules and energy liberalisation goals. But it could be part of a package of measures that might at last help the EU to make up for lost time – and to close that gap between potential and performance.

Giacomo Luciani focuses on the gas supply security issue

The Russian–Ukrainian gas crisis of 2009 will have far reaching consequences in several directions, but surely it has served to highlight the contradictions and pitfalls of EU gas supply policy. The Commission seems intent to move swiftly to promote a selected group of projects, which are expected to address the issue. Gazprom too is expressing the intention of moving with similar boldness to promote its own strategic projects. We are moving into uncharted territory, and decision makers may not be fully aware of the implications of decisions they might soon be making.

The EU approach to the gas market has been dominated by the objective of establishing an integrated, competitive and transparent European gas market. A corollary of the wider objective of establishing a single

European market for energy – itself a corollary of the overarching objective of establishing a Single European Market, which is the very raison d'être of the European Union – the integrated gas market, together with the parallel electricity market, has been the cornerstone of European energy policy for the past 15 years at least.

Born out of the wish to promote European competitiveness (part of the perennial competition with the USA) and of the perception that Reagan and Thatcher-style gas deregulation and market liberalisation could make a significant cost difference to industry as well as families, the objective of the integrated, competitive, transparent European gas market has been elevated to the status of solution to all gas supply problems.

> "The expectation that private investors would be keen to promote new interconnections proved entirely ill founded"

Specifically, with respect to security of supply, it was felt that the creation of the European gas market would offer a superior solution to the old web of bilateral relations between gas-exporting and gas-importing companies, based on long-term take or pay contracts with destination clauses (restrictions) and exclusive use of dedicated transmission facilities.

The reasoning has been that an integrated European gas market would have such huge dimension and such extraordinary liquidity – because of the very large number of final clients and competing suppliers – that any producer outside of the EU would be attracted to exporting towards Europe. Consequently, Europe would no longer need a procurement policy, because the market would automatically attract the most competitive supplies, and suppliers would be ready to bear the cost of investment required to reach the market and the price and volume risk involved (both substantially mitigated by the liquidity of the market).

Whether this vision is sound or not we shall probably never know, because the integrated gas market is not there and in all probability never will be. After all, not even the USA has a truly integrated gas market, as domestic interconnections serving some states are notoriously insufficient.

The integration of the European market has been hindered by the lack of investment in essential interconnections and the limited capacity of existing ones – combined with the non-cooperation of gas industry incumbents, occasionally supported by the hostility of environmental groups to new pipelines. The expectation that private investors would be keen to promote new interconnections proved entirely ill founded.

In fact, when consideration is taken of the crucial characteristics of the gas industry, the outcome is hardly surprising. Gas transmission requires very substantial up front investment, and is only attractive if a guarantee exists that capacity utilisation will soon reach a very high level. Interconnecting two gas markets, each of which has supplies from the same sources and at comparable conditions (hence with little or no price differential) is unlikely ever to be attractive, because the risk of insufficient utilisation is very high. The UK Interconnector attracted private investment exactly because the rules of the game were so strikingly different in the UK and the Continent – opening the door to the possibility of arbitraging prices and volumes. But within the Continent, conditions are widely similar: in addition, incumbent companies have no appetite for competing with each other (in fact experience has shown that they would not export to the UK even in the presence of a significant price differential, simply because that is not their way to go about business…). Interconnections which might come to be used only at times of crisis, or in any case rarely, have no chance of attracting private investment.

As this became increasingly clear, the Commission has moved in the direction of strengthening regulators, and establishing a European regulating body by enhancing cooperation between national regulators. In addition, it promoted ownership separation of the gas grids from other gas industry's activities, or, as second best, separation of management of the gas grids from ownership of the same. The regulators, in this approach, would be empowered to mandate the realisation of interconnections which gas companies would not spontaneously promote.

This approach finds an obvious obstacle in the fact that the importance of gas in the national energy balances of individual EU member countries varies widely. In some countries gas is an important fuel for power generation, in others it is not at all. In some countries gas is an important source of home heating in winter, in other countries (and climates) this may be just a marginal consideration. In addition, it is generally accepted that gas is not a necessary component of energy supply, and several regions are not linked to their country's respective national grid at all. Just to name one example, Sardinia is not connected to the Italian gas grid, and has no supply of methane. Consequently, the exposure to the risk of gas supply interruptions is far from uniform, and for certain countries or regions within countries this might not be a concern at all. How are the Commission or the European regulator going to decide which interconnections truly are needed?

Furthermore, who will be asked to foot the bill of interconnections primarily motivated by security rather than commercial considerations? If the market and private initiative decide, the question does not arise at all. But if regulators mandate an outlay which the market does not fully justify, a decision must be made on how this is going to be recouped. Security might be improved only for one of the two countries to be interconnected: will that country pay the whole cost?

As for external supplies, new projects have been implemented which were supported by strong economics. At least three new suppliers (Qatar, Egypt and Libya) have established export projects to European markets. Algeria has inaugurated a new pipeline across the Mediterranean, expanded the capacity of older pipelines, and is expected to launch a further new pipeline to Italy (the GALSI project). This proves that new supply projects will attract investment when they are sound.

In December 2008, the European Council endorsed the European Economic Recovery Plan, within which €3.5 bn. is allocated to energy investment. As I am writing these lines, the Commission just announced that it 'proposes to use Euro 1.750 billion of the stimulus set out in the recovery plan to inject the necessary resources into key strategic interconnections. The Commission has used the second Strategic Energy Review (SER 2) to guide the choice of projects. The SER 2 has already identified a number of projects to address shortcomings and exploit opportunities, highlighting Baltic Interconnection, a Southern Gas Corridor, liquefied natural gas (LNG), the Mediterranean, Central and South-East Europe, and a North Sea offshore grid. The proposal of a Regulation establishing a programme to aid economic recovery by granting Community financial assistance to projects in the field of energy includes the list of about 20 projects that address the objectives of security and diversification of supply, both for gas and electricity, as well as maturity that allows works to begin quickly.' (Press release of Jan 28, 2009 MEMO/09/36) In this context, it appears that the Commission might invest €250 million in the Nabucco pipeline project in order to speed up its implementation. In addition, the European Investment Bank has said that it is ready to finance up to 25 per cent of the cost of the project. (Financial Times, 28.01.09)

On the one hand, this new, more aggressive approach may well succeed in getting some of the projects out of the doldrums in which they have been bogged down for years. On the other, offering public funding to some projects and not others clearly constitutes interference with the level functioning of the market, and is bound to discourage new projects down the road. The approach consisting in selecting specific projects as being strategic and extending special support is incompatible with a transparent and competitive market.

> "the importance of gas in the national energy balances of individual EU member countries varies widely"

Support from public funding, in the shape of equity or credit, is very much welcome, but should be extended on the basis of transparent criteria applied to all. It may be acceptable to give greater support to projects that connect new suppliers, or improve security by opening alternative routes with reduced dependence on transit countries, or simply constitute a diversification of transit countries. However, differential treatment of projects should be in any case rooted in clear and quantitative criteria.

This discussion is of direct relevance to Gazprom and the two strategic projects that it is pursuing in association with European partners: the North and the South Streams. Neither project serves the purpose of linking a new supplier to the European market: indeed both are tools for Gazprom to defend its market position in Europe. Yet, both projects constitute a significant form of diversification from excessive dependence on transit across the Ukraine, and reduce the number of transit countries (the North Stream can supply Germany with no transit country at all; the South Stream can supply Italy with two – new – transit countries rather than three).

The Nabucco project promises to link new exporting countries to the European market, but the actual availability of gas from these countries is in doubt. Given that it would be politically incorrect to acknowledge that Nabucco is about importing Iranian gas, we are left with uncertain supplies of gas from Azerbaijan, Turkmenistan, Egypt or Iraq. Lack of reliable gas supplies is a main reason why Nabucco has been unable to make much progress so far.

The emphasis on expanding LNG regas capacity is rather more coherent with the ideal of creating an integrated and competitive market. Greater reliance on LNG supplies with multiple entry points would provide the European network with a source of flexibility alternative to greatly expanding interconnections. Uniform facilitation of regasification terminals still constitutes interference with the free functioning of the market, but is more justified than supporting a specific pipeline.

Financial support to LNG regasification terminals might be extended in exchange for control of a share of capacity, which might then be auctioned off on a short-term basis in order to encourage new entrants and flexibility. In order to promote private investment in terminals, extensive exceptions to TPA obligations have been offered to new projects. This is indeed necessary to avoid free riding on the part of some importers, but limits flexibility of supply and access of new entrants. Public support in exchange for capacity, later to be made available to the highest bidder, seems a preferable alternative.

If the ideological approach is set aside, and pragmatism prevails, we may still see value in the concept of a less regulated European gas market. It would be paradoxical that in order to achieve competition and integration, we would end up resorting to massive regulation, administrative imposition of investment and preferential funding to politically selected strategic projects. A more sensible approach must be found, combining public funding and support to investment on the basis of transparent and universally applied criteria in order to achieve the required degree of supply diversification and flexibility.

Features of Recent Oil Developments

Paul Horsnell and Costanza Jacazio focus on the critical role of US oil demand

The latest sharp crash in the oil price cycle might seem to bear some strong parallels with 1986. In our view the key feature that makes the 2008/9 cycle different is that its cause lay primarily in demand conditions. In particular, as we detail below, the sharp swings in US demand played a particularly central role in the evolution of market perceptions as to the health of the market. However, in terms of straightforward price behaviour and market sentiment, the comparison with 1986 works better. In oil market mythology, 1986 swiftly gained a totemic status. Say, for example, '1992' to an oilman and you will probably get a blank look, as that year carries no clear association with any particular market environment. But say '1986' and you are using an oil shorthand that is fraught with meaning. To invoke 1986 is to call on the representation of those circumstances that are thought of as the worst of all possible times for producers, a yardstick against which all other periods of upheaval and misery in the industry can be measured. As in any mythology, the reality of the 1986 price crash may not always match up perfectly with the elements in the myth, but that probably matters little. Over time 1986 has become a form of code for an extremely challenging market environment, complete with a price crash and a severe and lasting bust in the investment cycle.

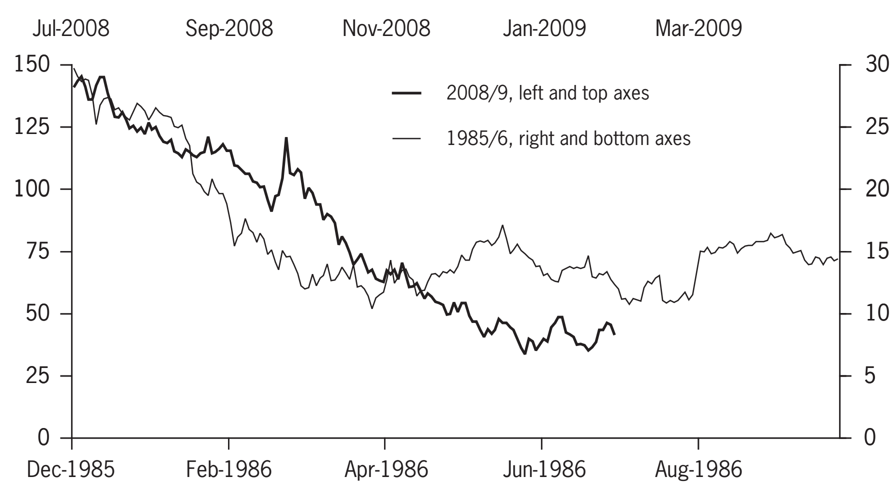
Given the usefulness of the concept of 1986 as a general state of mind, it may be difficult for 2008 to take over seamlessly as the oil market code for the foreboding associated with nasty things coming out of the dark forest. However, in terms of both the extent and duration of the price fall, recent market moves have now gone beyond 1986.

The depth of the current reversal is illustrated in Figure 1, which overlays the course of the market during the respective periods of the most rapid fall, i.e. from December 1985 onwards and from July 2008 onwards. The associated price axes are shown in the ratio of five 2008/9 dollars to each 1985/6 dollar. In terms of the period of pure downwards trend, the 2008/9 fall was sustained for some three months longer and, in current money, that fall continued for about $20 per barrel further.

Beyond the mere direction of prices, there is little else that links the two negative price shocks. In the simplest description, the dynamics in 1985/6 were primarily determined by changes in producer policy and the consequent rise of OPEC supply. While that policy was determined by the cumulative impact of the five previous years of sharp falls in demand accompanied by rising non-OPEC supply, by the time the price falls began global oil demand had begun to rise again, and demand developments were not the key factor in tracking the path of the crisis. By contrast, in the 2008/9 cycle the primary dynamic has been falling demand, and it is the path of demand that is likely to be key in bringing the cycle to an end. The earlier crash was supply-led and sparked by producer policy, the latest has been demand-led and was sparked by a rapid deterioration in the prospects for global economic growth.

While the price fall has brought a supply-side reaction, traders seem likely to maintain their bias towards looking to the demand side for signs of either further erosion or the green shoots of any underlying recovery. In trying to work out when the climate for demand will look better to the market, one factor will be the point at which the attrition in demand forecasts begins to ease off. The element of surprise to demand revisions in 2008 is quite how narrowly focused demand side forecasting errors have been. In particular, it has been variations in US demand that have dominated the divergence between forecast and actual demand. For example, compare the current (at time of writing, January 2009) tabulations of 2008 demand as made by the main forecasting agencies, with their projections of the same as they stood in December 2007. Between those dates, the OPEC Secretariat revised down its projection for the level of global oil demand by 1.23 mb/d. Of that, the downwards revision for OECD demand was 1.8 mb/d, and of

Figure 1: Price behaviour in 1985/6 and 2008/9 compared. WTI prices, $ per barrel



Source: Barclays Capital

that the revision for North America was 1.45 mb/d. In the case of the US Energy Information Administration (EIA), global demand was revised down by 1.25 mb/d, OECD demand was revised down by 1.67 mb/d, and US demand was revised down by 1.49 mb/d. Put another way, in the case of both the OPEC and EIA forecasts, the USA was the main source of negative forecast error. Indeed, oil demand outside of the USA was revised upwards over the course of 2008.

> "the key feature that makes the 2008/9 cycle different is that its cause lay primarily in demand conditions"

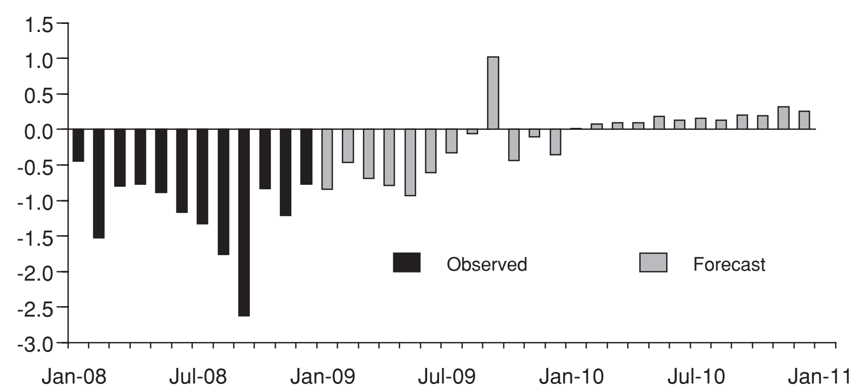
The downwards demand surprise for the International Energy Agency (IEA) was also heavily weighted towards the USA, although with the IEA having begun the year with by far the most optimistic view of likely overall growth, the downgrades have been slightly more evenly spread. The IEA revised its 2008 forecast down by 2.03 mb/d between December 2007 and January 2009, while OECD demand was revised down by 2.3 mb/d and US demand was revised down by 1.43 mb/d.

In summary, across the main sets of forecasts the revisions of US demand in 2008 have been an order of magnitude higher than for the rest of the world combined. The pattern of revisions has been such that US demand was revised down by between 6% and 7.5%, while the revision for the rest of the world combined ranged from an upwards revision of 0.3% to a downwards revision of 0.7%. The above suggests that the recent tendency among analysts in particular to concentrate on demand growth out of China and the Middle East as the key driver of oil market balances may well be misplaced. In the long term, the cumulative demand pressure from those areas is indeed central. However, if you want to get the immediate dynamics of the global oil demand outlook correct, then it is the US number that seems the most urgent to pin down.

The USA appears to be the key element of any forecast and the source of most potential error, because it is US demand that swings the most in response to changes in economic conditions and in other stimuli. Further, the track record over the course of the current decade suggests that it is US demand that is the hardest to forecast accurately. In terms of the distribution of the error within the US forecast, tracking the EIA forecasts for the individual products for each month across 2008 puts the average downwards revision at less than 5% for gasoline, between 7% and 8% for jet fuel, diesel and heating oil, and above 10% for residual fuel oil and petrochemical feedstocks. Errors appear to grow larger the further one moves down the demand barrel, perhaps simply because it tends to be those heavier elements of industrial demand that are most sensitive to both the economic cycle and to relative prices.

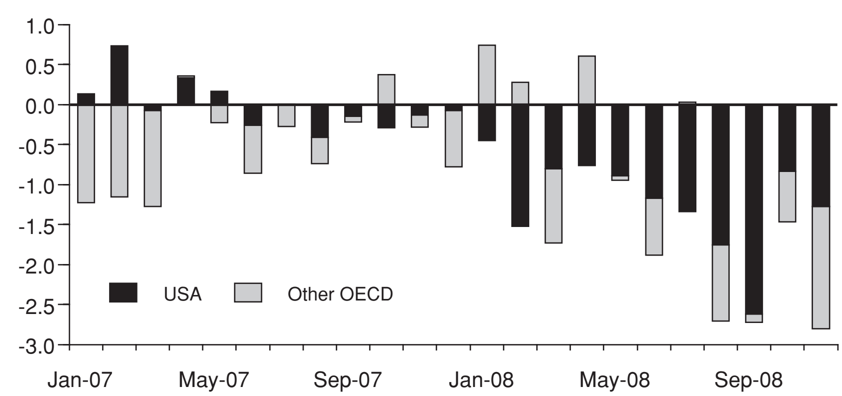
For the demand side to start to look more positive, or at least to appear as if it is on the mend, we believe that three conditions need to be met. First, the US data would need to stabilise, showing declines no worse than about 5% in the first half of 2009, thus stabilising expectations before some favourable year-on-year dynamics kick in over the course of Q3. Our own monthly projections are broadly in line with the shape of those of the EIA, as shown in Figure 2. The sharp

Figure 2: US oil demand, observed and forecast y/y changes. Million b/d, y/y change



Source: Energy Information Administration

Figure 3: OECD oil demand, split by US and non-US. Thousand b/d, y/y change



Source: Joint Oil Data Initiative

but temporary y/y improvement forecast for September 2009 is a key part of those projections. September 2008 was so severely distorted by hurricane and some other effects that a y/y demand increase of less than 1 mb/d for September 2009 would be considered as very weak. Overall, the pattern appears far stronger in the second half of the year, helped on by a series of favourable base effects and by the potential return to at least modest q/q GDP growth following the declines expected in the first half of the year.

> "it is US demand that swings the most in response to changes in economic conditions"

The second condition for relatively swift recovery would be that the extreme sensitivity of US demand to the economic cycle is not echoed in future data for other OECD areas, and most particularly in Europe. Outside the USA, the OECD demand profile showed little evidence of being on any severely weakening trend, or indeed on any trend at all, until the particularly weak data point seen in November 2008 raised some doubts (see Figure 3). There are some base effects at work that might lead one to discount that data point somewhat and not treat it as conclusive, but any spread of systematically weakening demand to Europe would be likely to prolong the trough in prices. That last data point in Figure 3 does however seem to at least sound a warning bell, and the apparent sharp tail off in macroeconomic performance across the OECD in the final quarter of 2008 suggests that there could be an element of further weakness yet to come.

The third condition would be that non-OECD demand growth merely slows, rather than disappearing altogether or becoming negative. Up to this point non-OECD demand has tended to be subject to upwards revisions. Further, the sharp falls in net non-OECD oil demand growth for 2009 projected in the main forecasts of between 50% and 65% already appear to assume a fairly downbeat macroeconomic environment. At this point a sharper deterioration remains possible, but is perhaps not yet in the base case. Overall what we appear to be in the middle of is a sharp macroeconomic-related downshift in global oil demand, with a swing in demand that is heavily weighted towards the USA. While that dynamic remains in place, we suspect that the current fear factor associated with accelerating rates of demand loss shows a reasonable chance of abating by mid-year. The sensitivity of US oil demand remains one of the dominant drivers of market balances and sentiment, and hence a US-centric approach to the small print and mechanics of the demand data appears relatively justified for the moment.

Ivan Sandrea asks what is next for the oil and gas industry?

The year 2008 marks the end of another period in the history of the oil and gas (O&G) industry. It started in 1999 with the Mergers and Acquisitions (M&A) wave and recovery in oil prices from record lows, and represents one of the strongest expansionary periods in the last 30 years. Between 1999 and mid 2008 oil and gas prices rose each year to record highs; cumulative industry M&A activity reached a historical record; total industry investment in E&P also grew 400% (real terms) to reach record highs; world liquids and gas production capacity rose 11 mb/d (14%) and 70 bcf/d (28%) respectively; global oil and gas reserves expanded; and profits reached record levels despite a large increase in costs. But from summer 2008 onwards oil prices began to fall, a credit induced severe global recessionary environment became obvious, global oil demand growth weakened versus trend, and signs of cuts in investment began to appear. Looking back, industry consensus suggests that most of the same signs featured in three other periods (1973–1981, 1982–1987, and 1988–1998). This is shown in Table 1.

Each period can be associated with discontinuities leading to different responses by major industry players (i.e. IOCs and NOCs), consumers, and governments. Nationalisations, new types of cars, the timing of the North Sea oil development, efficiencies, the rise of unconventional energy, market openings, and changes in demand growth from the trend are all examples of discontinuities. History also shows that at the end of each period most people, including the experts, failed to predict the events that followed and failed also to visualise the next period. We still remember when in 1999 *The Economist* predicted

Table 1: Recent Industry Periods: Key Statistics at End-periods

Periods	*1973–81*	*1982–87*	*1988–98*	*1999–08*
Prices WTI ($/b)	75	31.8	17.1	105
Liquids capacity (mb/d)	72	73	78.6	89
Gas capacity (bcf/d)	142	174	221	295
Real Capex ($bn/y)	191	80	140	400
Oil reserves (bnboe)	687	910	1068	1250
Gas reserves (Tcm)	86	111	149	180

Note: Oil prices crashed in 1986, 1998 and 2008

Source: StatoilHydro internal analysis, Sandrea 2005, *BP Statistical Review*, some figures for 2008 are projected.

$5 oil into eternity and how it saw the future of the industry!

In 2009 we are likely to see the start of new discontinuities and new events, and the only surprise should be the timing. It would be naive to ignore the potential effects of the recent volatility in oil prices, the current recession, and the adjustments taking place fairly rapidly in several important countries in the areas of finance, economics, energy, security, and politics at the same time that society and industry are finding new ways to interact with the natural environment.

Just as one of the most eventful years in modern history ends, some are already asking three questions that are familiar to the industry. First, what is going to happen to oil prices in the future? Second what will be the demand for oil, how fast will it recover, and how will it be met? And third, how will the major players respond strategically? Given that we cannot predict and that the past was unstable, at least partial answers can be provided by making sense of recent facts (see Table 2); the future tends to be largely a function of today's facts plus anything that we don't know but that is certain to come.

Table 2: 2009 Starting Point and Recent Significant Events

Macro	*O&G Industry Specific*
100% of global oil demand growth depended on Asia, developing countries, three-year contraction in the OECD	Limited capacity to increase global oil production above 1.5% pa, and gas production above 3% pa
Ability of consumer to pay higher energy prices than previously thought	A rapid strategic shift towards complex projects (unconventional in OECD, everything East of Suez, and technology plays)
Rapid demographic and technological changes that suggest future oil demand growth may be slower	Higher costs, some structural others cyclical; introduction of CO_2 taxes
New set of leaders who appear to focus on economic and social stability, rather than cold war-based policies	Increasing competition from all kinds of players
Start of a severe economic and financial recession in OECD countries; questioning of the architecture of all significant financial institutions	Oil prices below the level that starts to affect the investment framework of the industry

The Price Question

No one can predict the future level of oil and gas prices, but when thinking about the matter two facts are clearly significant. The upper limit which reflects the price all consumers (i.e. people, industry, and governments) can afford to pay. And the lower limit which reflects the price industry players need in order to cover the costs of producing and processing oil and gas. Like all variables, the ability to pay for energy and industry costs are dynamic variables; how we think about and model oil and gas prices in the future must also be dynamic.

Naturally, prices should fluctuate between the two, and if they extend much beyond these limits for whatever reason(s) something is bound to happen. In recent years, new players (i.e. mainly financial investors) began to increase their participation in the oil market, and soon predicted prices of up to $200/b (even as the economy, demand and refining margins took a nose dive!). Today, there is evidence that financial players are linked to the sharp rise and collapse in prices (due to bad models and false interpretations of how the oil markets worked) that took place in a matter of months.

In the period that just ended, for the first time in decades many consumers could afford to pay higher energy prices than previously thought – as a result the value of energy resources increased. Nevertheless after a certain level ($90/bbl +) prices started to badly hurt some important consumers. From 1999 to 2006, prices increased gradually and this kept demand in check, spurred new thinking, allowed profits to be generated and investment to rise – all of which are good for the world; but the commodity bubble, which caused prices to rise too rapidly in 2007 and 2008 abruptly interrupted an important process. On the cost side, due to structural and cyclical factors linked to prices, industry costs increased putting pressure on margins and the cost of new projects. This topic is fairly complex, but it is a fact that the cost structure of the industry is in transition from a lower to a higher structure. OPEC was aware of everything, which explains why it tried to maintain a flexible approach to prices whilst referring on numerous occasions to the damage caused by extreme speculative behaviour in the oil markets.

Today oil prices are well below the level that producers and consumers would consider 'fair' – that is a price that will sustain producers' economies while not slowing down economic growth in consumer countries. At the recent London Energy meeting (December 2008) the 'fair' price was identified as $75/bbl.

Without making any predictions, it is highly likely that when global economic conditions improve, oil prices will rapidly return close to the upper band, whatever this might be, and continue the trend to what consumers can afford to pay.

The Demand Question

Major consumers and industry players care about future demand. It is a fact that global oil and gas demand continues to grow, more recently driven by emerging powers such as China, but it is also a fact that today the world consumes 12 mb/d less oil than what the top planners told us ten years ago. In the last decade major downward revisions have also been made to long-term demand prospects. Last year, the EIA revised down global oil demand in 2020 sharply from the previous year's forecast and since 2001 cumulative downward revisions for 2020 now exceed 20 mb/d! The story for gas demand is similar, particularly in the USA, where major downward revisions have been made over the years. In these revisions, price has been a factor but others such as lower GDP and taxes have also played a role. The types of car we use and energy efficiency have evolved fairly rapidly, and continue to surprise the experts.

At the same time, it has also become apparent that for some of the natural resources, the level of consumption is more dependent on what can be delivered from the different types of resources at a given point in time than on anything else. The behaviour of non-renewable petroleum resources is not reversible once certain thresholds are crossed; this may be Malthusian and a subject of much debate, but it is the evidence of years of O&G production history. Production growth rates fluctuate with the type of reserves coming on stream and technology used (i.e. conventional onshore, offshore, deepwater, unconventional, arctic, and technology plays). Table 3 shows that historically, the offshore has sustained higher rates of growth than the onshore. It is therefore possible that the global O&G endowment (17+ tn boe in-place of which 1.5 tn boe have been produced) can only sustain a maximum rate of consumption/production growth whatever this might be.

> "there is evidence that financial players are linked to the sharp rise and collapse in prices"

Many doubts continue to arise about the ability of O&G production capacity to meet future demand.

Table 3: Historical Growth Rates, annual percentage growth

	Global Oil Demand	*Oil Production*		
		Global Onshore Crude	*Global Offshore Crude*	*Global NGIs + Unconventionals*
1973–81	0.7	-1.3	9.2	4.5
1982–87	1.1	-0.3	5.4	5.1
1988–98	1.2	-0.3	4.9	4.7
1999–08	1.3	0.5	1.5	4.4

	Global Gas Demand	*Gas Production*		
		Global Onshore Crude	*Global Offshore Crude*	*Global NGIs + Unconventionals*
1973–81	2.8	0.6	7.5	n.a.
1982–87	3.3	3.1	3.2	-0.1
1988–98	2.1	1.2	5.8	15.5
1999–08	2.9	2.2	2.8	5.9

Source: StatoilHydro internal analysis, Sandrea 2005, *BP Statistical Review*, some figures for 2008 are projected.

Probably the number one question is what the oil production decline rates are or how much the industry needs to replace each year. Gas is rarely questioned as it is assumed that there are bountiful reserves, many yet to go on stream. A recent IEA report estimated that the global oil production decline rate is 5.2% per year, which appears fairly high. A back of the envelope calculation which relates global oil production, global capacity expansion by year, and gross oil production increments by year, indicates that global decline rates do not exceed 3% per year. For the USA, the rate is about 1% per year.

It is impossible to predict what future world capacity will be, but nature is telling us that the growth rate of world O&G productive capacity will be slower, that it will be sustained by significant EOR possibilities, advancing technology, and the improving ability of consumers to pay for energy resources. The new projects (600+ in total) being executed represent at least 25% of current global O&G production capacity, and are certainly different and more complex than past ones. The decline rate of oil and gas resources is the main challenge of the industry but this has been true since oil was first produced.

The resources that have been discovered are vast and the industry is working to produce these and increase the recovery rate; but perhaps the world won't need as much as we think today. On the demand side, we have to ask whether the growth of oil demand in China can continue at high rates forever, and if the current levels of petrol taxes in major consuming countries can co-exist for long with a strong desire to protect the environment, energy diversification, and more efficiency. Regarding gas, can the experience of the USA with the rise of unconventional gas and lower demand be repeated in Europe, Russia, and China?

Where Does the Industry Go from here?

In contrast to the inherent uncertainties of the previous questions, the answer to this is more predictable. After more than a century, the major industry players are already producing something from nearly every type of petroleum reserve from most regions in the planet. The industry has had time to work in more places than any other industry, and along the way it has considered where it wants to stay and where it would like to establish itself for the long term. Seventeen plus trillion barrels of oil and gas resources in place discovered (excluding gas hydrates, shale oil) is no small amount.

How the most important industry players (IOCs and NOCs) and others will respond strategically is more uncertain for the short term than for the long term. In the short term, the industry will need to adjust and respond to changing conditions in the macro environment. That is, players may engage in M&A, restructure, divest non core assets, reduce capex of short-term pay back marginal projects, and delay some projects to save costs.

But for the long term, the players that see future in O&G, it is hardly an open question. This is because from the early 2000s onwards, many companies made drastic changes to the strategy in order to tackle the full suite of reserves in sight, which now covers pretty much everything we know.

Looking at the E&P activity since 2003 of the top ten international O&G companies (Exxon, Shell, BP, Total, Chevron, Conoco, Eni, Petrobras, Petronas, and StatoilHydro) it is clear that these companies set out with a new focus to access additional reserves and production via M&A, organic, and exploration. In the last five years alone, they accessed 9.8 mboe/d of future production of which a large portion includes unconventional energy and large complex projects. Production from the pre salt, a new source and perhaps even a large discontinuity, also forms part of the new access.

"The vast majority of the discovered and yet to be found resources in the world are in just 30 countries"

All new efforts focused on 20 countries, the very same ones that provided the bulk of production in 2003. These countries account for 85% of the total production of the top 10 companies, and represent 2.2 tn boe of discovered reserves (~10 tn boe in place) in the world. In a portfolio context, these companies currently produce 25 mboe/d (entitlement basis) from 57 countries, and the newly accessed production represents about one-third of the total the industry (ex NOCs) is set to develop over the next 20 years.

Some new discoveries have been made in countries with a limited history of hydrocarbons (i.e. Ghana, Mauritania, and Uganda). This is good news, but most geoscientists would concede that these new discoveries are outside the places where hydrocarbons have accumulated. The vast majority of the discovered and yet to be found resources in the world are in just 30 countries, and there are nearly 200 countries in total. The impact of these new discoveries to the global industry and the world continues to be very small.

"is our industry destined to continue to go through extreme boom and bust cycles or might it at some point see a more steady development?"

The most important producing NOCs in the world – those that are generally very long on resources and account for the bulk of productive capacity – also made changes to their strategy in recent years. Of course they could have gone abroad too, but in fact they took a look around and decided that something new could be done at home. Companies like Aramco, Pemex, Qatar Petroleum, and ADNOC have embarked on significant long-term expansion projects either alone or with partners, many of which are complex and represent the next generation of projects. Other NOCs, such as the Asian ones, expanded at home but also began to adventure outside and participate in new types of projects such as deepwater.

Final Observations, the Long View

In general, the future is unpredictable and will be unstable. The O&G industry is no exception. While the exact level of future energy prices, demand, and capacity, can not be predicted, nevertheless a future path for each may be visualised. Prices will move along two dynamic bands, oil and gas demand may not grow as much as we think, whilst production capacity will be there to meet energy demand. In contrast to conventional wisdom, a potential maximum rate for consumption/capacity growth does not need to be a problem nor translate into rising oil and gas prices for eternity.

The industry will continue to work the large resources already discovered and look for new finds; its focus will remain on the areas where hydrocarbons have or might have accumulated. The major IOCs and NOCs are already running on nearly every fossil energy track. There are certain limits in the O&G industry and many challenges, but it will adapt; there are plenty of fossil fuels and possibilities in new energy too. However, is our industry destined to continue to go through extreme boom and bust cycles or might it at some point see a more steady development?

Bassam Fattouh studies the behaviour of spreads between the prices of oil futures contracts of different maturities

Introduction

One of the very interesting features in the recent behaviour of crude oil prices has been the increase in the variability of the spread between the oil futures prices at different maturities. Figure 1 shows the daily spread between the first-month and the second-month NYMEX Light Sweet Crude Oil futures contract (WTI contract) over the period 1997 to 2008. The figure reveals the following three interesting features. The first one concerns the high volatility of the spread especially towards the end of our sample. During the period 1997–2008, the mean of the spread stood close to zero but with a relatively high standard deviation of $0.87. The maximum and minimum values that the spread has taken (excluding the two spikes which were driven by last-minute positioning due to contract expiry) range from -$6.99 to +$2.4 during this period.

The second interesting feature is the frequent switches between backwardation and contango. While the crude oil market is expected to spend most of its time in backwardation, examining more recent data and focusing on the front part of the futures curve suggest the opposite. As can be seen from this figure, since 1997, the oil market has witnessed many switches from backwardation to contango. In fact, in our sample the first-month futures crude oil prices were below the second-month prices more than 55% of the time. In other words, the crude oil market has been in partial contango for longer than it has been in backwardation.

The third observation concerns the persistence of backwardation or contango regimes. In April 1997, the oil market entered into a contango which lasted until August, 1999. In May 2002, the market entered in a long backwardation which lasted until mid 2003. In November 2004, the market entered in prolonged contango which lasted until mid 2007. In October 2008, the market switched to a contango which many observers expect to last for a long time.

The large variability of the spread, the occasional switches from backwardation to contango, and the persistence of the regimes raise a series of questions: what can explain the dynamic behaviour of the spread in recent years? Is the behaviour of the spread really unusual? This article tries to provide answers to the above questions by drawing some lessons from the period 1997–2008. But before discussing these episodes in detail, it is worth considering very briefly how economists explain the variability of the spread and highlight some of the limitations when applied to the oil market.

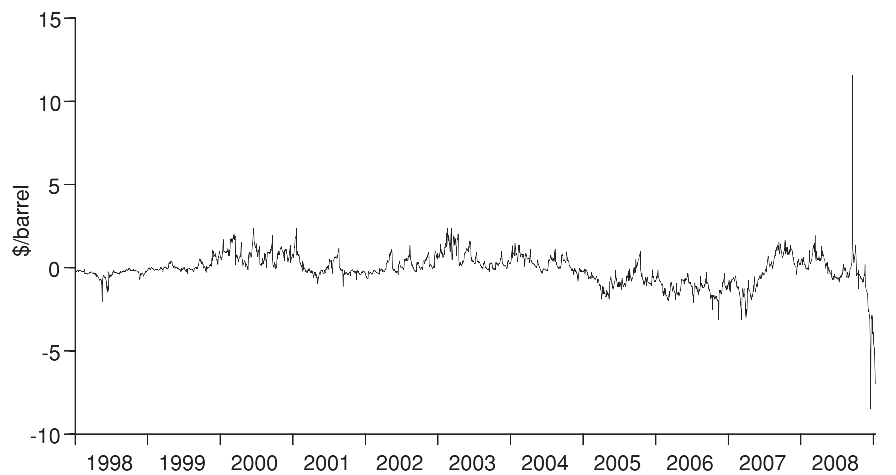
What Does Theory Tell Us?

One way to explain the variation in the basis is in terms of a risk premium which arises in the process of transferring risk from hedgers to speculators. Specifically, the basis can be written as the sum of the following two main components: the expected change in the spot price and the ex-ante risk premium. The risk premium can be positive or negative (and hence the basis can take negative or positive values) depending on investors' beliefs, endowments, and preferences.

An alternative theory, the theory of storage, explains the difference between the futures price and the spot price of a commodity in terms of interest foregone in purchasing and storing the commodity, storage costs, and the convenience yield. The latter was defined by Brennan and Schwartz in 1985 as a yield or benefit that 'accrues to an owner of physical asset but not to an owner of a contract for future delivery of the commodity'. The convenience yield affects the basis through arbitrage. When the convenience yield goes up, the attractiveness of holding futures contract relative to physical stocks goes down. This will lower the futures price and increase the spot price until an equilibrium relationship between the two is attained.

Studies based on the storage model relate the convenience yield directly to the level of inventories. Generally, the theory of storage suggests that marginal convenience yield falls with inventory but at a decreasing rate. At low levels of inventory, the marginal convenience yield is larger than carrying costs and the spot-futures price spread is positive. As the level of inventories goes up, the marginal convenience yield falls towards zero and the spot-futures price spread becomes negative and converges towards the cost-of-carrying the commodity. More recent models describe the convenience yield as a financial call option held by storage agents. The call option can have value when, for example, demand shocks create a positive probability that agents can sell their stocks at higher price during the storage period.

Figure 1: First-Month WTI Contract minus Second-Month WTI Contract



Source: Energy Information Administration (EIA) website

What is Missing in These Models?

While these models are very useful in explaining the behaviour of the spread, there are three features that one should consider in the context of the crude oil market. The first is related to the feedback mechanism and the possibility that the market can enter into a reinforcing feedback. The second feature is related to the oil market structure where OPEC can play the role of an active or a passive quantity adjuster which can affect the process of inventory accumulation and the behaviour of the spread. The third feature is related to the fact that reinforcing mechanisms can lead to the dislocation of key benchmarks used for oil pricing with wide implications on the behaviour of key spreads such as the WTI-Brent spread or time spreads.

Reinforcing Dynamics

While most empirical studies focus on how changes in inventories affect the variability of the spread, the feedback mechanism from the spread to inventories is rarely explored. These feedbacks are important as they often result in reinforcing dynamics which may take a long time to break. Specifically, increases in the level of inventories would push prices for immediate delivery down as a higher level of inventories is often interpreted as a sign of a well-supplied market. At the same time, the convenience yield of holding inventories goes down pushing the futures price upward. The end effect is a widening spread between prices for immediate delivery and prices for future delivery. This in turn will induce further accumulation of inventories as traders take advantage of the spread. This process can continue for a long time and can be broken in either of two ways. At a sufficiently high level of inventories, the marginal storage becomes increasingly expensive. Alternatively, oil producers can decide to cut supplies and prevent physical traders from accumulating inventories.

In 1998, the oil market was trapped in such a reinforcing mechanism. A decline in oil demand due to the Asian financial crisis and a market perception that OPEC supplies have increased resulted in a sharp fall in prompt prices relative to oil prices for future delivery. This triggered the accumulation of crude oil which led to the decline in spot prices and widened the contango. This reinforcing contango was broken after a series of output cuts which saw OPEC draw more than 1 billion barrels from 1999 to early 2000.

While reinforcing contango is usually associated with sharp declines in oil prices, this does not necessarily have to be the case. In 2006, the reinforcing contango and the associated rise in inventories went hand in hand with rising oil prices. This is because the spread and not the price level drives these dynamics. As long as futures prices are rising faster than prompt prices, these reinforcing mechanisms are likely to prevail. Thus, in 2006 while the inverse relationship between inventories and prices collapsed, the relationship between inventories and the spread remained intact.

> "the feedback mechanism from the spread to inventories is rarely explored"

These dynamics can also work in the opposite direction as occurred in the first half of 2008. Despite evidence of a weaker oil demand growth, declining inventories continued to push up spot prices (falling inventories are seen as indicating a supply shortage). Now let's suppose that refineries thought at that time that the rise in oil price is only temporary and that weaker oil demand will eventually bring prices down. This would induce them to use their own stocks. Thus, although oil demand growth was slowing down, spot prices kept rising as traders were coordinating on public signals about declining inventories. This deepened and prolonged the backwardation and decreased the incentive to hold stocks as it was not profitable to do so. This process can continue until stocks reach minimum operating levels or until there is a change in market sentiment as happened in the second half of 2008.

This leads us to the current behaviour of the spread which as can be seen from Figure 1 has entered into a contango which many market participants expect to last for a long time. The current dynamics are very similar to what happened in 2008. Fears about the impact of deteriorating prospects of the global economy on oil demand have been placing a downward pressure on oil prices. While both the front end and the back end of the oil price curve have seen sharp declines in the past few months, long-term oil prices have fallen more slowly. This may be due to concerns about long-term supplies as the market expects that the current crisis will induce a slowdown in investment and tighter oil market conditions in the future. Alternatively, this behaviour may be due to the current weakness of the market in the short term, where the bulk of the trading activity is concentrated. Either way, the term-structure has shifted to contango, with the price of the first month futures contract falling below the prices of subsequent contracts for each maturity. This term structure is providing incentives for traders to accumulate inventories. Higher levels of inventories are in turn leading to further falls in oil prices which is widening the contango. The problem is that the contango is so steep that the incentive to stock may last a long time.

The Role of OPEC

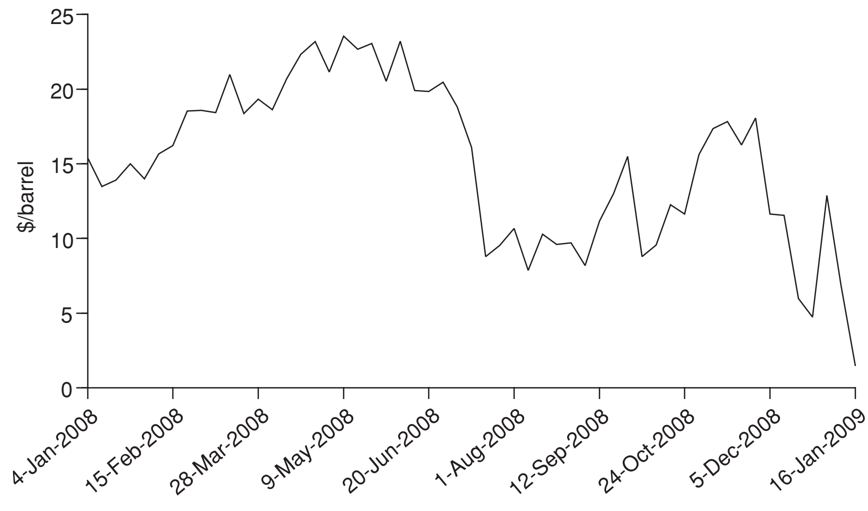
Unlike other markets, OPEC can affect the rate of accumulation of inventories either through an active or passive policy. In terms of active policy, OPEC can decide to target the level of inventories. Specifically, high levels of stocks may increase the incentive for OPEC to engage in output cuts if the Organization feels that high stock levels can induce a sharp downturn in oil prices. OPEC cuts would have the effect of lowering inventories and raising the price at the front end of the futures curve increasing the probability of the basis moving back into backwardation. The speed at which OPEC can achieve this depends on the tightness of market conditions and how effective OPEC is in implementing these cuts. This can explain the switches in 1997 and 2006 from contango to backwardation.

In terms of passive policy, OPEC can continue to supply upon demand based at prevailing market prices. This will help balance the market without an increase in inventories. These dynamics were present in the first half of 2008. Despite the fall in demand, excess supply did not appear in the market and we did not witness any significant rise in inventories as OPEC passively adjusted its output to counteract the decline in oil demand.

The Breakdowns of the Benchmark

The third distinguishing feature of the oil market is that these reinforcing mechanisms affect the behaviour of a key benchmark with very wide implications on oil prices. Since the adoption of formula pricing in 1986, WTI has served as one of the main international benchmarks, along with Brent and Dubai, against which other types of crude oil are priced. Thus, reinforcing dynamics affect the entire pricing mechanism and arbitrage between markets. Furthermore, the time spread affects the attractiveness of oil as a financial asset by affecting the roll return on passive futures-based commodity investment i.e. the return from selling the expiring contract and buying the new front month contract (in a contango the roll return is negative).

Figure 3: Cushing WTI Spot Price minus Mexico Maya Spot Price ($/barrel)



Source: EIA

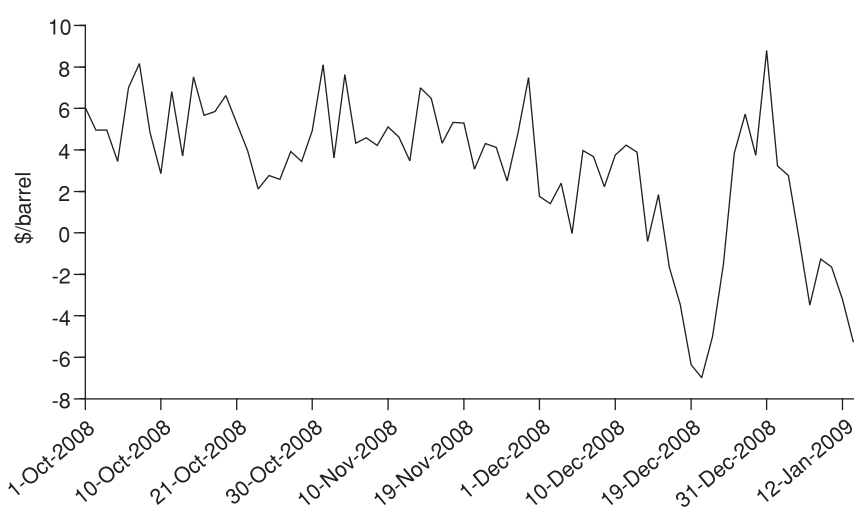
It has long been recognised that the link of the WTI price to oil prices in international markets can be dictated by infrastructure logistics. In 2007, due to logistical bottlenecks which resulted in a large build-up of inventories at Cushing, Oklahoma the WTI disconnected not only from the rest of the world, but also from other US regions. In the current market conditions, something similar is taking place though the cause for the build-up is different. Due to a reinforcing contango, Cushing is being flooded with inventories. Crude inventories at Cushing have grown from 14.383 million barrels in October 2008 to almost 33 million barrels by 19 January 2009, an increase of more than 18.5 million barrels. This increase in crude oil inventories is concentrated in Cushing and not in the rest of the USA. This is because traders can implement the arbitrage most effectively at Cushing, which is the delivery point for benchmark West Texas Intermediate.

The effects of this rapid build-up of inventories in Cushing are widespread and affected the oil price structure in three major ways. First, the feedback is creating distorted sets of time spreads as reflected in the large differential between months with front month spreads reaching $7 and much higher for further away maturities .

Second, the WTI decoupled from Brent, as reflected in the large differential between the prices of the two international benchmarks (see Figure 2). Although WTI and Brent are of similar quality (light and sweet), WTI has been trading at large discounts to Brent. Since 6 January the differential has been widening, reaching more than $5 on 19 January.

Third, the build-up of stockpiles around the area of Cushing has also resulted in the sour-sweet crude oil price differential narrowing to very

Figure 2: Cushing WTI Spot Price minus European Brent Spot Price ($/barrel)



Source: EIA

low levels. Figure 3 shows that while WTI was trading at a premium of more than $23 to Mexican Maya Blend in mid 2008, the differential has narrowed considerably and in 9 January 2009 Mexican Maya was trading at a discount of less than $7 per barrel. This can also be explained by the fact that most OPEC production cuts are usually concentrated on heavy crudes.

In short, WTI's dislocation has had serious implications across the various crude oil markets, resulting in unusual price differentials. These effects, however, do not imply that the local market is not functioning well. On the contrary, price movements are efficiently reflecting the local supply-demand conditions in Cushing. The main problem is that when localised conditions become dominant, WTI can no longer reflect the supply-demand balance in the USA, nor act as an international benchmark for pricing the millions of barrels of oil imported into the USA.

"the link of the WTI price to oil prices in international markets can be dictated by infrastructure logistics"

Conclusions

While the media often focuses on the sharp swings in oil price, there have been some interesting feedbacks unfolding in the term structure of oil prices with wide consequences on the international pricing system, financial investment, inventories and OPEC behaviour. These feedbacks are not new to the oil market, but the current environment seems to have amplified price distortions. While the market will eventually succeed in eliminating these distortions and market dislocation, the fact remains that these reinforcing feedbacks seem to have become more common in recent times. This suggests that we need to get prepared for some more sharp irregularities in months to come.

LNG Trading: Overview and Challenges

Axel Wietfeld and Niels Fenzl

The Need for LNG

In the 27 countries of the European Union, growing demand for gas over the next decade or so will create a need for new import projects covering 140 bn m³ p.a. – needs which are not going to be covered by Russian and Norwegian imports alone. Diversification is required to avoid a singular dependency, which is not conducive either to supply reliability or to an acceptable price level. This is why international corporations are looking to North Africa, West Africa, the Middle East and Asia for new sources of supply. That being so, there are five countries – Iran, Qatar, United Arab Emirates, Nigeria and Algeria – which now number in the world's Top Ten in terms of natural gas reserves. However, it is from these countries that the delivery of gas is usually made by ship, in the form of LNG (liquefied natural gas), and not by pipeline.

Definition of LNG and Costs

The worldwide LNG market is basically divided into two regions: the Pacific Basin and the Atlantic Basin. The LNG chain involves a liquefaction plant with several 'trains' situated in the producer country; marine transport with LNG tankers; and regasification terminals in the receiving country where the LNG is temporarily stored in tanks before being regasified and fed into the pipeline network.

With investments well into the US$-billions, the liquefaction plant represents the biggest cost factor within the LNG chain. The LNG chain initially involves natural gas being refrigerated to approximately -162 °C, at which point it condenses to a liquid and takes up only 1/600 of its original volume. For a large-scale plant, then, as currently being built in Qatar with a planned capacity of 7.8 mn t LNG p.a. (≈10 bn. m³ p.a.), investments of between US$900 and 1500 per t LNG p.a. are required or anything between US$7 and 12 bn in total. In comparison, a regasification terminal of the same scale and constructed for US$0.8–1.2 bn comes over as relatively affordable. For an LNG tanker with a load capacity of, say, 265,000 m³, you have to reckon between US$250 and 290 mn. At the time of writing, the going charter rate is between US$45,000 and US$70,000 a day.

In the 1990s, the LNG industry was able to achieve considerable cost reductions based on improved efficiency, design innovations, greater professional project management and, in particular, economies of scale.The first LNG projects in the 1960s had a capacity of 0.5 mn t LNG p.a. whereas the liquefaction plants of today are being put up for 7.8 mn t LNG per annum. Plus, the possible load capacity of the LNG tankers has grown from approximately 30,000 m³ to 265,000 m³, another reason why specific costs have gone down substantially. All the same, the engineering, procurement & construction (EPC) costs for liquefaction plants have shot up over recent years. This was largely due to the rising cost of raw materials and other input materials, the low number of suitable contractors and the shortage of engineers in this specialist field.

Meanwhile, it has emerged that energy consumptions along the LNG chain are actually much lower than hitherto widely assumed –

- liquefaction approximately 7%,
- shipping approximately 0.15% per day and
- regasification approximately 1.5%.

All in all, energy consumptions can usually be kept to below 10%, correlated of course to the technology deployed and, in particular, to actual shipping distance.

Pipeline versus Ship

The debate, about what distance between production and receiving country leads to an entire LNG chain having an advantage over pipeline transport, is as old as the LNG industry itself.

The solution to this problem (which may at first seem trivial) is a complex one. Thanks to high fixed costs and low variable costs, the LNG cost line is flat whereas the pipeline cost line is very steep. In the literature, a point of intersection between the pipeline line and the LNG line is frequently hypothesised at a distance of 3000–5000 km. This oversimplified view is, in our opinion, not tenable.

Over the course of a given period, the gridlines can shift and strongly correlate with capacity or economies of scale. Furthermore, pipeline costs are dependent on territorial contingencies (onshore, offshore, mountain ranges) not to mention that port and passage fees – through the Suez Canal, for instance – can affect pricing. Also the transport distances via pipeline and LNG deviate typically. However, there exist other crucial reasons more of a strategic nature in favour of LNG, namely:

- no transit countries, and thus the avoidance of protracted political and commercial negotiations;
- relatively straightforward capacity extension;
- technical necessity, since a hook-up to a pipeline network is practically impossible due to geological peculiarities (e.g. Japan's island position); and
- flexible routing, and thus the exploitation of arbitrage possibilities.

This, in sum, underscores the necessity of always weighing up all the criteria with regards to various options when taking an investment decision.

Price Formation on the LNG Market

In contrast to the situation with crude oil, the LNG market has not yet seen the development of a globally valid price for the market: there are price differences in the USA, Europe and Asia. There are also certain differences in the pricing of LNG both on the spot market and in long-term contracts.

Prices on the spot market are usually set in the short term for individual or for a few consignments and, are often based on Henry Hub[1] or NBP[2] for the Atlantic and JCC[3] for the Pacific Basin.

As a rule, however, long-term LNG prices are linked either to crude oil and/or refined oil products or to price developments with NBP and/or Henry Hub. This means that linkages to the NBP and oil products are prevalent for the European market, that Henry Hub governs pricing in the USA and that the crude oil pricing known as JCC governs the Asian area. The pronounced rise in demand for LNG over recent years compared to supply has led to an increase in the general LNG price and thus to an increase in the asking price for long-term LNG contracts. It remains to be seen which impact liquefaction capacity that comes on-stream in the next years will have on long-term prices.

Nevertheless, LNG prices also come under the influence of other interdependencies. For instance, price development with infrastructure in the whole LNG sector and price developments on markets for alternative fuels such as heating oil, coal and uranium also play their part in pricing strategies.

However, with more fluidity of LNG trade being on the way, we will also see a convergence of world-wide LNG prices.

Supply–Demand Balance

The biggest producing countries on the supply side in 2007 were Qatar (approx. 38 bn m^3), Indonesia (29 bn m^3), Malaysia (28 m^3), Algeria (22 bn m^3) and Nigeria (21 bn m^3). Due to their geographical position, these countries are clearly well poised to deliver to certain regions – i.e. Indonesia and Malaysia deliver to the Pacific Basin while Algeria supplies first and foremost Spain and France.

The position of Qatar and other Middle East countries lends them a special significance in the LNG business: this region can serve both the Atlantic and the Pacific Basins. The LNG producers of the Middle East can therefore react flexibly to regional price differences and generate additional profit in the process. Thanks to the production capacities currently available, this region can influence market balance and, as a consequence, the price level.

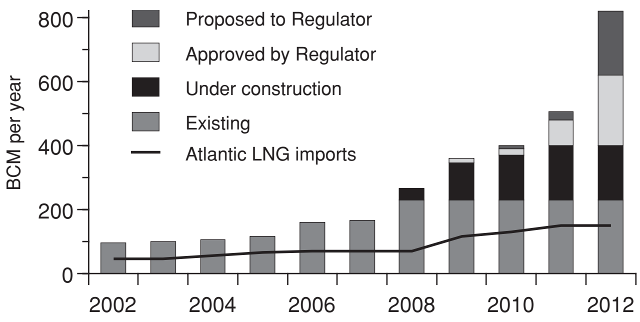
Qatar is expected to achieve LNG output of approximately 78 bn m^3 in 2010. Its significance can only grow in the future. By 2015, Qatar with over 98 bn m^3 LNG p.a. will be far and away the world's largest producer of LNG. Nigeria will be second with an output of 45 bn m^3, and Australia will be the third largest supply country.

The demand side nowadays is dominated by the Pacific Basin with imports of 126 bn m^3 p.a., the biggest importers being Japan (86 bn m^3) and South Korea (30 bn m^3). In the Atlantic Basin (89 bn m^3), today's biggest receiving countries are Spain and Portugal with 34 bn m^3 combined and the USA with 20 bn m^3 per annum.

That inequality between Pacific Basin and Atlantic Basin is set to balance out by 2015. Asia has generally been the premium-price market of choice for sellers, but there will be simply insufficient demand in this region to absorb the increase in supply. Indeed, a preponderance of deliveries to the Atlantic Basin seems likely after 2015. This development is based on the rising demand predicted for the USA where LNG consumption was just a few months ago expected to grow beyond 100 bn m^3 p.a. in the future. On the one hand, such an increase in US natural gas and thereby LNG consumption could arise from the introduction of a stringent carbon dioxide trading regime in the USA and a consequent increase in gas power plants; on the other hand the need

1 Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). It is a point on the natural gas pipeline system in Erath, Louisiana.
2 NBP = National Balancing Point, a virtual trading location for the sale and purchase of natural gas in the UK.
3 JCC: Japan Crude Oil Cocktail = average price of crude oil imported by Japan

Figure 1: Atlantic Basin Regas Capacity vs. Atlantic LNG Imports 2002–2012



Note: Regasification capacity for approved and proposed terminals is based on project sponsor dates. LNG import outlook 2009–2012 based on Global Fissures Scenario

Source: CERA – Cambridge Energy Research Associates, 2008

for US gas imports might be lower as a consequence of increased gas production from shales over the next few years and lower general demand due to the economic crisis. The UK too will play a role in balancing the equation, with its forecast growth of 40 bn m³ per annum.

The complexity of the LNG landscape is also growing considerably. In fact, some of the producing countries such as Qatar and Egypt have opted for moratoria while Indonesia appears to be having supply problems. Altogether, we can speak of an increasing presence in Africa and the Middle East on the part of NOCs who are now faced with a choice of using their gas reserves for the LNG export market or holding on to them for domestic requirements. That being the case, IOCs are faced with the real challenge of gaining access to gas reserves in order to feed future LNG projects.

Shipping

If the additional LNG quantities expected for the future are to be dealt with, investments in LNG fleets are going to be necessary. Although 300 LNG tankers already plough the oceans, a further 100 are on order. At the same time, we can assume an increase in ship size from today's standard of 145,000 m³ to 265,000 m³ (Q_{max}). The first Q_{max} carrier with a capacity of 265,000 m³ was delivered to Nakilat, Qatar's LNG shipping arm, in August 2008.

Regasification

Regasification terminal projects are gaining in importance for Europe and the USA in particular since they act as an anchor-point for a diversified portfolio. Each project has its own individual obstacles to overcome – the availability of LNG, approvals, regulations, access to third-party customers and the need to guarantee reliable operations for several users. Additionally, just like liquefaction projects, regasification terminal projects faced significant price increases of up to 75% with capacity charges reaching 70 UScents/mmBtu compared to 40 UScents/mmBtu in 2002. Nevertheless, a good number of projects have been successfully implemented globally over the last few years.

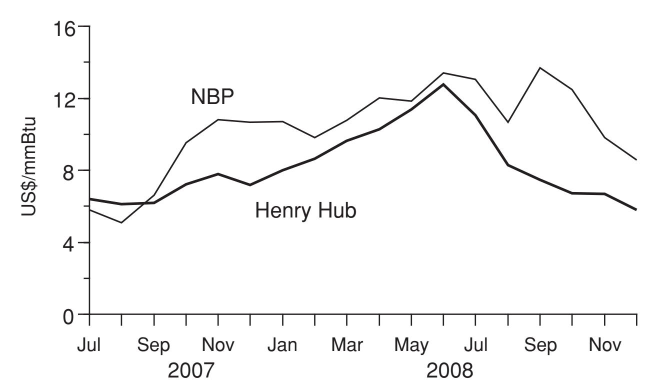
Anyone taking a close look at the regasification capacities available until 2010 will realise that they outstrip expected supply quantities considerably (see Figure 1). The rationale that persuades corporations to secure themselves capacities at the terminals lies in being able to exploit the arbitrage possibilities provided by surplus capacity – 'arbitrage' being defined here as the exploitation of regional price differentials on the LNG market. Consequently the booking of regasification capacity is considered more and more an option payment to place gas in a particular market than an investment linked to fixed volumes. In this way, LNG tankers can be dispatched in the short term either to American or European regasification terminals and corporations can profit from price fluctuations. However, there is a difference between physically existent capacity and available capacity, meaning that access (or not) to a regasification terminal for new players often acts as a barrier to getting on to the market.

When it comes to operating the arbitrage business lucratively, the *sine qua non* is an adequate margin between the purchase of the LNG and the sale of natural gas on the target market, a margin which covers not only the transport costs but also the charge levied on an unused slot in another regasification terminal. 'Slot' here is defined as the right of an LNG supplier to unload a tanker at a regasification terminal and subsequently have the LNG temporarily stored, regasified and fed into the natural gas pipeline grid. To optimise the use of regasification capacity and still be able to benefit from arbitrage opportunities some Atlantic Basin players established swap arrangements allowing both parties involved to utilise regasification capacity on both sides of the Atlantic.

In addition to the regasification of LNG some operators of LNG terminals install equipment for the reloading of LNG which will then be transported to other locations.

As Figure 2 illustrates, there can be good possibilities for arbitrage between the USA and Britain. From September

Figure 2: Example of Arbitrage Opportunities at NBP and Henry Hub in 2007/08



2007 until the end of October 2008, for example, it was profitable for LNG players to reroute deliveries destined for the USA to Britain and thus make additional profit. However, in the case of 2008 spot prices in the Pacific Basin exceeded price levels in the UK. Consequently LNG cargoes were diverted to Asia, and UK regasification terminals still remained idle.

Thanks to the formal oil–gas price linkage in place on the European mainland and to NBP notation in the UK, arbitrage possibilities also exist in Europe. However, these possibilities will recede with the construction of pipeline connections (such as the Balgzand Bacton Line and the Interconnector) between Britain and the European continent. What is more, via the Langeled Pipeline, Norway is able in the short term to either decrease or increase supplies to the UK and also benefit from temporarily higher NBP prices. In effect, peak prices can be shaved, at least partly, and arbitrage possibilities can be contained.

Spot Trading and Short-term Trading

Apart from regasification terminal availability, the exploitation of arbitrage possibilities is also boosted by the growth in spot trading and short-term trading. The spot market alone now accounts for approximately 15% of the total LNG market, which corresponds to a trebling of that share since 2000. In 1997, the share taken by short-term trading was very low. Yet the spot market is not a mature liquid market. Spot transactions are still primarily organised within existing supply chains. It will take some time before short-term transactions are as routine as with the oil business. Before the global financial crises in summer 2008, we could observe international banks becoming active on the LNG spot trading scene.

Let us give one example of how player intervention on the spot market can be significantly influenced by fluctuations in a given supply situation in a given region. When, as the result of an earthquake in Japan on 16 July 2007, a TEPCO nuclear power plant had to shut down, the shortfall in power supplies was compensated for by increasing the use of gas-fired power plants. However, to guarantee the gas supplies then required, the Japanese power supply companies stepped up their activities on the spot market and so bought in 15 additional LNG deliveries until summer 2008. That jump in demand had a clear effect on spot market prices. With the collapse of Japanese nuclear capacity and with the high demand for LNG in Asia anyway, it became all the more difficult for other world regions – such as the USA and Europe – to buy in spot cargos.

Peak prices were also seen in China during the summer months in 2008. High natural gas demand for air conditioning, but also for the summer Olympics caused a natural gas shortage in China. Consequently LNG prices of over 20 US$/mmBtu had to be paid.

Particularly as a consequence of the growing spot market the swap potential will continue to grow. A swap describes an agreement between two LNG players where the vessel of one player is satisfying the delivery obligation of the other and vice versa. Thereby the players aim to shorten the travel durations of their respective vessels which leads to the reduction of shipping costs and an increased availability of their vessels. For example a vessel leaving Algeria for Japan and at the same time another vessel enroute from Australia to France could be rearranged in a way that the Algerian cargo would be heading to France and the Australian cargo would be sent to Japan. Since 2005 swappable volumes increased from 0.42 bn. m³ p.a. to 9.5 bn m³ in 2007 with huge worldwide potential for the future.

The availability of spot volumes in the Atlantic Basin is expected to increase at least until 2010 with liquefaction capacity from e.g. Northwest Shelf Train 5, Sakhalin 2, Yemen LNG, Tangguh and Qatargas's 2 and 3 coming on-stream in 2009/10 adding around 90 bn m³ per year. With the Pacific Basin being well supplied with LNG at the same time volumes will be forced to flow into the Atlantic Basin thereby increasing liquidity and reducing pricing on the spot market. However, the availability of long-term contracts will remain constrained as barely any tenders for new projects are expected.

Conclusion

LNG can contribute to closing any gaps that may arise on the European energy market and, similarly, by creating greater diversification for the supply and demand countries as well as improve supply security all round.

The high prices in the Pacific Basin complicated the purchase of LNG quantities under competitive conditions for players in the Atlantic Basin. This was a situation exacerbated by the virtually exploding demand for LNG deliveries and the delays with liquefaction and regasification projects, delays caused by the shortage of suitable contractors and labour. As a consequence of the economic turmoil and the demand reduction, especially in Asia, more spot cargoes are nowadays heading towards Europe. The North American LNG market acts as a sink for residual demand.

Demand for LNG is set to grow by 7% annually between 2008 and 2015 – i.e. to about 180 mn t per annum. Just in Europe, the LNG share of gas volume will increase from today's 10% to nearly 20% in 2020.

On today's current market, which is still predominantly a sellers' market, international players will have a distinct advantage over regional actors since the global players are obviously better poised to meet producer expectations with regard to serving different markets. In addition, the dominant sellers' market will further weaken, as the increase in supply of up to 300 bn m³ p.a. should make more competitively priced LNG available.

An increasing globalisation of LNG flows is likely due to companies' strategic positioning, the development of flexible LNG portfolios and pricing arbitrages. The spot market too will gain in significance and surpass its current 15% share of the market as a whole. Arbitrage as well as swap possibilities will increase as a consequence, even if these approaches are vulnerable to physical restrictions such as shipping distance, gas quality and market access.

Asinus Muses

Lapdog no longer

Asinus has been pleased to observe that years of loyalty to Washington have finally paid off for the UK. For surely no other country can boast influence comparable to having invented the United States' new creed, chanted across the country and the world. The source? The theme song of Britain's much loved children's television character, "Bob the Builder/Can we fix it?/Bob the Builder/YES WE CAN".

Cultivating carrots

Current geopolitics certainly could do with some fixing, and it looks like the new US President has a novel approach. Barack Obama is everybody's friend, confidant, and hero, and to oppose him just looks grumpy. While Asinus has no problem with grumpy, it is rarely a winning political strategy. World leaders used to the convenience of a hostile USA for rallying support will have to re-think their approach. In the global struggle for influence the USA is further aided by the dramatic collapse of the oil price, and here the obvious similarity between leaders of nations and the humble donkey provides the key: the US always had a bigger stick, but as we could have told you this is not always the most effective tool. Thus Asinus suspects that the decisive variable for geopolitics in 2009 is the carrot. Several of the competing nodes in the newly-multipolar world, notably Venezuela, Russia, and Iran, rely on oil money to irrigate their own carrots, which they have used to gain influence around the world. With their crop looking somewhat withered, the USA now has the perfect opportunity to show that it is the world's number one distributer of this tasty, healthy snack.

For those who doubt my proposed typology, what better example of donkey diplomacy than the gassy exchanges between Ukraine and Russia? We know the new year has arrived by the sight of these two immovable asses playing chicken. They finally agreed to blink once they had racked up the requisite number of frozen European households, at which point President of the European Commission José Manuel Barroso declared himself 'very disappointed' with their behaviour. With the primary tools of European diplomacy appearing to be the threat of grave disappointment and heavy disapproval, while a nod and a pat on the head comprise the reward for good behaviour, Asinus feels that Europe still has not grasped the whole carrot-stick concept.

...and a hedge

The emerging spirit of co-operation may be further aided by Saudi Arabia's declaration that $75 is a fair price for oil. It's a shame they did not say so when oil was at $140. But Robert Mabro's ideal of a globally-shared reference price appears to be gaining recruits. Indeed, the Mexicans are so keen on the idea that they went ahead and sold 90 percent of their 2009 exports at around $80 WTI-equivalent.

This is a rare coup. Being a neighbour to the world's richest and most powerful oil importer has always been a challenge: as it was put by the creator of the modern Mexican state, Porfirio Díaz, at the beginning of the last century, 'Poor Mexico. So far from God, so close to the United States.' So close, indeed, as to have been partly incorporated in the 1840s after the USA annexed Texas. In his less historically-rigorous moments Asinus asks himself what the world would have looked like had Mexico retained the oil reserves subsequently discovered in the Lone Star State. He is now picturing T. Boone Pickens eating not from a platter of steaks, but from an *olla* of the chocolaty and spicy Mexican *mole*.

If selling oil at $80 a barrel looks smart, acquiring 2 million barrels of oil for the price of a dinghy and a few rocket-propelled grenade launchers looks like real business sense. Such was the achievement of a group of Somali pirates who hijacked a Saudi oil tanker in November, and who finally released the ship and its crew in January. But even such pirates are prey to the incredible shrinking oil price, receiving a mere $3 million in ransom, or $1.50 per barrel. Asinus asks himself if the moment will arise when even this looks pricey.

...and how about some tulips?

The other great criminal scheme of the day we owe to Wall Street genius Bernard Madoff. He set up a classic Ponzi game in which one round of investors receives payment from the next round of investors, and everyone makes money as long as the game continues. But when the market realises that there is nothing underpinning the game, new investors dry up, and whoever is left holding the bag discovers it to be empty. Asinus grasps the idea, but is struggling to see the distinction between this and the housing bubble, the oil price bubble, and good old seventeenth-century Dutch tulips. The only difference I can find is that in the Madoff case, there was one person who wasn't fooling himself into thinking it was sustainable. Ignorance is bliss, and knowledge is criminally actionable.

Even the bursting bubble has not taken the bounce out of Shell and Exxon Mobil's step. They still managed to report the highest annual profits ever for any firms on their respective continents. But as oil company profits cruise through the crisis, Total is suffering a mini winter of discontent with workers at its Lindsey Oil Refinery in the north of England, who are angry that their 'greedy employer' is importing cheaper Italian and Portuguese workers in their place. The problem, as ever, is the distribution of the pie. Like I said, they should stick with carrots.

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