automakers alike, while Obama supports a ten-year $150 billion Clean Energy Fund, with emphasis on both R&D and working retraining. (McCain emphasises tax breaks for R&D rather than government spending.)

The fuel of choice for power generation is going to be a major source of conflict, whoever the next president is. Coal has many environmental problems, but much political support in both parties; even green Democrats listen to coal miners' unions. As a result, policies to reign in emissions from coal combustion are heavily focused on new technologies, including those that allow economical carbon sequestration. Only Obama seems ready to ban construction of 'traditional coal facilities'.

Nuclear power's public perception remains schizophrenic, with many environmentalists still opposed to it, but growing support among the general public. A McCain administration is likely to encourage new power plant construction, and while neither Democrat will evince the same level of support, either one might come to accept it. Given Barack Obama's more populist credentials, he is the most likely to push for wind and solar over nuclear, while the more pragmatic Clinton has noted the benefits of 'emission-free' nuclear power.

And while the traditional liberal view of microeconomic regulation, such as requiring specific technologies for emission control, appears to have become discredited, nonetheless, the two Democrats are much quicker to emphasise government spending programs in support of new energy technologies, particularly renewables, especially where they appear to provide for the creation of new jobs. McCain, on the other hand, emphasises R&D and deregulation as means to improve overall efficiency of energy programs.

Also, both Democrats can be expected to adopt much stronger etatist attitudes, attempting to 'correct' market imperfections, something the current oil price has highlighted. While it is possible that they will attempt to reign in 'speculation' such as investment in the commodity index funds, the complexity of the task should defeat them. More likely, an SPR drawdown such as occurred in 1996 to dampen then-exorbitant crude prices, would be used to deflate the current oil price bubble.

In the past, energy-policy making (and policy analysis) has suffered from a boom and bust cycle largely correlating with energy prices – and public attention. However, this seems somewhat less likely this time, as worries about global warming, energy security, and high energy prices are much less likely to fade as quickly as similar problems in the past. Thus, not only will energy policy-making for the new administration be a high priority, but unlike previous administrations, early efforts seem less likely to be abandoned when they meet resistance.

Of course, given past policy failures, often caused by overreaction to transient problems, this can hardly be considered a good sign.

Comments on Gas Demand, Contracts and Prices

James T. Jensen

The February issue of the *Oxford Energy Forum* contained five excellent articles on the future role of natural gas. There appear to be two recurring themes – strong growth in gas demand and issues of contracting and pricing.

Gas Demand Growth

Superficially, there appears to be a conflict between Michael Stoppard's optimistic description of the very large increase in LNG capacity between now and the year 2010 and Jonathan Stern's more subdued recounting of the forces that are likely to constrain future gas supply. In fact, the two positions are not inconsistent since they focus on two different time periods. With a four- to five-year lead time between the initiation of a new LNG (or pipeline) project and its completion, Stoppard is effectively describing capital expenditure decisions that were set in motion between 2003 and 2006. Stern is asking whether the present growth in gas supply is likely to continue once the existing wave of new capacity is finally completed.

Much has changed in world energy markets since the early part of this decade. In 2000 North America experienced its gas price shock, and revived its long-dormant interest in LNG. Spain was in the midst of a surge in demand for LNG that would make it the Atlantic Basin's largest LNG importer by 2002. And by 2004 the UK had changed from a net exporter of North Sea gas to a net gas importer.

But perhaps the biggest change has been in energy price levels. In 2003, Brent crude averaged less than $29 per barrel. Last year it averaged more than $75 – up 160 percent over 2003. Gas prices have also risen, but their increase has been far more modest, substantially altering the earlier relationship between gas and oil prices.

Obviously, there has been a rather dramatic change, not only in absolute energy price levels, but in the relative prices of fuels that compete with one another in the marketplace. And it raises two interesting questions: What effect will the uneven energy price increases have on interregional gas trade? and What determines the price of long- term gas supply? When coupled with the fact that construction costs of both pipelines and LNG facilities have risen substantially in the last several years, it should not be surprising that there is a lot of soul-searching going on over capital investment decisions for new gas projects.

Both the IEA and the EIA, in their periodic forecasts, have weighed in on the first question. Both agencies have been progressively reducing their projected estimates of gas demand and increasing their estimates of gas production. The net effect of these two price responses has been to squeeze the expected level of interregional gas trade required to balance supply and demand.

Last year, Jensen Associates undertook a study for the California Energy Commission projecting world LNG trade out to the year 2020. Our estimates came in well below most other public projections. They were based on two assumptions: 1) they accepted the view of the IEA and EIA that high prices have depressed the long-term outlook for interregional gas trade, and 2) they concluded that there are increasing constraints on the potential for new supply projects. These include both those geopolitical constraints that Stern has outlined in his OEF piece, but also concerns about costs and the technological and economic challenges inherent in increasing reliance on Arctic gas supplies for new projects.

While the forecast for the California Energy Commission focused on LNG, it necessarily had to make assumptions about the balance between LNG and pipeline trade. In this context, it is worth noting that both North America and Northeast Asia will be dependent on LNG for their interregional imports, while Europe, China and India have both supply options. On the supply side, the two largest long-term future potential suppliers are the Middle East and the FSU (Russia plus the Central Asian Republics). The Middle East supplies are likely to be predominantly in the form of LNG while the FSU's will be largely by pipeline.

It is apparent that our low forecast rests on conservative assumptions, both of the future demand for gas, and of the willingness of suppliers to provide it. What can go wrong with these assumptions?

On the supply side, there are obviously great uncertainties. Relying for future supply on countries that have not previously been LNG exporters (or even gas exporters) and have not shown much enthusiasm for LNG is problematic at best. The supply estimates could be higher or lower and the results will have a significant effect on future supply/demand balances and on prices.

On the demand side, the 800 pound gorilla in the room is carbon regulation, which has the potential to shift much of the stationary energy demand to gas. If the optimistic gas demand forecast materialises in the face of supply constraints, it would obviously threaten substantial price increases.

Contracts and Pricing

A common assumption during the early days of gas market liberalisation was that gas would become just another internationally traded commodity. Long-term contracts would become obsolete and an LNG-based international pricing system would develop. To date, gas has failed to follow that script. While international gas markets are more flexible than they used to be, and LNG provides a degree of interregional price arbitrage, the long-term contract is far from dead. And there is no consistent international approach to gas pricing.

Two major differences between gas and oil are gas capital-intensive, front-end-loaded investment pattern and for pipelines, at least, geographic inflexibility. The first characteristic means that projects are usually debt-financed and someone has to assume the obligation to cover debt service. And the second characteristic exposes buyers to the risk that their suppliers will fail to deliver.

Burckhard Bergmann addresses the second issue in describing Germany's need to compete for future supply and to diversify its supply risks. He suggests that the future industry structure will include some mix of long-term contracts and spot market transactions.

He speaks from the perspective of the country that imports more Russian gas than any other except the Ukraine, and is thus in the centre of the controversy between Russia and the European Community over supply reliability. But Germany is not alone. The issue of third country transit rights has long plagued natural gas pipeline projects and has often fostered less economic LNG projects as a means of avoiding the geographic limitations of pipelines.

The contract issue is essentially about risk sharing for capital-intensive gas projects. While the North American gas markets have largely dispensed with long-term contracts, there is nothing inherently inconsistent between long-term contractual relationships and free markets. For capital-intensive projects, the contract provides assurance to the financing agency of debt service coverage by the parties to the agreement. It also provides a mechanism for risk-sharing between buyer and seller. (Not to mention rent sharing with host governments) The old adage, 'The buyer takes the volume risk and the seller takes the price risk' has led to take-or-pay clauses for the buyer and price escalation clauses for the seller in traditional contracts.

The concern for financial risk protection remains, even in fully-liberalised markets. For new pipeline investment in North America, for example, the sponsor holds an 'open season' for potential shippers to acquire capacity. If the project is viable, the shippers then assume a ship-or-pay financial obligation to the project sponsor. While not a long-term contract in the traditional sense, the resulting control of capacity may also inhibit more flexible commodity competition. .

In traditional contracts, the pricing clause was most commonly linked to oil prices – crude oil in Northeast Asia, oil products in Europe. But in the liberalised markets of North America and the UK, where gas-to-gas competition prevails, such clauses put the buyer in an impossible position when gas prices fall below oil levels. A resulting temptation to protect the buyer by linking pricing clauses to gas market indicators, such as Henry Hub or the NBP, effectively shifts much of the project risk to the seller, since the buyer can so easily cover his risk by trading in the liquid spot market. The response of the sellers is to integrate downstream through what might be described as self contracting. Increasingly, we are seeing project venture partners contracting with their own ventures to sell the gas downstream in North America or the UK. The contract commitment is still there, but it has moved upstream from the earlier buyer/seller interface.

Stoppard calls this group 'aggregators' and describes how they provide destination flexibility similar to that provided by the spot market. As he points out, they are most common in the Atlantic Basin, where North America/Europe arbitrage is active, and the Middle East, which can act as the arbitrage agent between the Atlantic and Pacific Basins.

However, the flexible Atlantic Basin contracting is largely focused on the liberalised markets in North America and the UK. Much of the Continent still retains traditional long-term contracts. The fault line between the two systems runs down the middle of the North Sea between the UK and the Low Countries and inward from the Continent's Atlantic LNG re-gasification terminals.

Many long-term contracts – both LNG and pipeline – are now in a state of flux. The price caps and S- curves in oil-linked contracts that were included to protect buyers from oil price shocks are now protecting buyers from what suppliers argue is a new permanent level of world energy prices. Japanese LNG prices averaged 101 percent of JCC (the Japanese crude price indicator) in 2002; but in 2006, they averaged only 64 percent. Vigorous efforts at contract renegotiation and a number of international contract arbitration disputes are underway in essence to resolve the question: What determines the price of long-term gas supply? This raises the issue of gas pricing, a recurrent theme in a number of the articles.

Theorists would argue that its value should be established by price competition in a free market. But a number of the articles point out that pricing systems differ in various parts of the world, and describe some of their departures from the ideal. Thierry Bros argues that the liberalised UK market may have worked well in surplus, but as the UK has become a net importer, it provides a highly volatile pricing system with little or no price guidance for making long-term investment decisions. In short, it does not provide the answer to the question: What is future gas worth? And financial derivatives have lost some of their lustre as a tool to provide long-term future price certainty following the Enron debacle.

Stern discusses the common underpricing of gas practised by gas-exporting countries and describes some of the market distortions that result, both in the Gulf and in Russia. Simon Pirani details Russian progress towards adopting European netback pricing as a means of correcting these distortions.

The Unanswered Question

During the 1970s and 1980s, when North America and the UK restructured their gas industries, the working assumption was that market competition would set gas prices and oil prices would be irrelevant. In such a formulation, the traditional long-term contract, with its linkage to oil prices, was viewed as a relic of an over regulated era.

The position of both those market structure options has changed significantly since that time. North America and the UK both liberalised when their domestic markets were in surplus and supplier competition cut prices below oil parity levels. Now the surpluses in both regions have disappeared and they – like the Continent and Northeast Asia – have become importers.

When the North American supply surplus disappeared in 2000, oil prices once again became important through inter-fuel competition in boiler applications. The UK had a short price run-up following its transition to net import status. But both regional markets are now in sufficient balance that they are in gas-to-gas competition – their prices remain well below oil parity levels.

There has also been a substantial change in the position of the oil-linked contractual markets on the Continent and in Asia. The use of oil-shock-limiting clauses in long-term contracts has effectively decoupled gas and oil prices in many of these markets. In 2007, the relationship between border prices and Brent for the six largest Continental markets ranged from 58 percent in Italy to 72 percent in Spain. In Japan it was 59 percent; in Korea 73 percent. But there is some evidence that the low relative prices in Northeast Asia have enabled some buyers to cross-subsidise spot LNG cargoes at prices well above oil parity.

The push by producers to restore the oil link, either by contract renegotiation or international arbitration, is strong. Few would argue that oil prices any longer have the competitive meaning that they once had, but it has been difficult to find a suitable substitute. But Tokyo Electric's efforts to replace its lost nuclear generation suggests that – were Japan markets fully liberalised – gas and oil prices might still be indirectly linked.

In Northeast Asia tight markets, suppliers' efforts may well meet with success. On the Continent, the competition from the gas-to-gas competitive supplies delivered via LNG or the pipeline links to the UK is beginning to penetrate some of the Continental markets. The current pressures are downward, not upward.

So the question remains: How do you place a value on long-term gas supply? It is a question that is important in making major gas project investment decisions, but I am not sure that anyone has an answer.