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CONTENTS

This issue of Forum turns its attention to two aspects of energy investment, LNG and Power Generation. Both are necessary, but both face structural problems – LNG mainly in the USA and Power Generation mainly in the EU. Our articles address the factors that tend to restrain the investment that, it could be argued, ought to be taking place with greater urgency than it is.

We start with LNG. David Ledesma describes the changing trading environment that is developing in the Atlantic Basin. This seems likely to encourage changes in the traditional supply chain which in the past has been largely dependent on long-term supply contracts. The USA is now the largest potential market for LNG (since its own production and Canadian imports have peaked) but not only major problems of planning controls have prevented the desired expansion of terminals, but also the nature of the liberalised US gas market, since the future expected market price for gas is a crucial input into the investment decisions. The UK is also a potential LNG importer, particularly with its direct link into the rest of the EU and its own liberalised gas market. Atlantic Basin trading and arbitrage seems likely to develop, but, with long-term supply contracts still tending to be the norm, it may be a slower progress than some market participants would prefer.

Ben Smith looks further into the scope for a future of spot, or short-term, markets in LNG, particularly in the Far East where, until now, the major LNG development has taken place. He describes the changes in the industry since the mid-90s, many of which would seem to provide an environment in which a spot market should develop. In practice it has not occurred, and this seems attributable to the nature of the Far Eastern market, where the large gas and electricity providers have so far shown little interest in changing their ways. This type of market development may have to take place in the USA or Europe rather than the Far East.

Julia Richardson and John Burnes look specifically at the US gas market, where LNG currently supplies about 2–3 per cent but could supply up to 10 per cent within a few years if new terminal capacity were constructed. There are plenty of proposals, but only four have been approved and none are yet under

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construction. Local opposition has frequently been successful. Meanwhile the four existing terminals are being expanded. Whether this activity will lead to a new market trading system remains uncertain. Many of the new proposals are based on long-term supply arrangements and there is the additional problem of interchangeability of LNG supply with domestic supplies due to specification differences. Nevertheless, there is an increase in spot market activity, in particular from Trinidad, and the logic of the situation seems to indicate that this will develop further.

Our second investment subject deals with power generation. Lindsay Tuthill describes the theoretical model that underlies the problem of whether to invest in 'clean' or 'dirty' generating capacity given the uncertainty of government policy and regulations on CO_2 emissions. For the purpose of her example a dirty plant is defined as coal-fired and a clean one as gas-fired, but the principle can be extended to other plant types. The variable in the models is the price at which CO_2 permits can be traded and, of course, the timing of their assumed introduction. The conclusion, which should surely be of some importance to governments, is that any delay in setting policy will delay investment, as will the perceived uncertainty about future policy change.

Tuthill deals in economic theory, and John Bower describes what is happening currently to power generation investment in the EU. It is the precise practical form of the theory. Gas-fired investment is being postponed and coal-fired generation being used to its utmost capacity. Although the first phase of the Emissions Trading Scheme is imminent, the second phase (2008 and beyond), which is relevant for investment decisions of today, remains in limbo. Bower goes on to describe the further complications introduced by the Large Combustion Plant directive which is designed to reduce emissions of oxides of nitrogen and sulphide and particulates. This simply gives further encouragement to generators to postpone their investment decisions.

Mark Lijesen and Gijsbert Zwart accept the current lack of investment but ask whether this yet constitutes a problem. They discuss the elements of an efficient market, the definition of reliability and demand response. They do not specifically deal with the CO_2 emissions trading problems but accept that one of the impediments to investment is uncertainty over future policy affecting prices. Their conclusion is not as uncompromisingly gloomy as that of Bower (or, by inference, of Tuthill) but the conditions they require for a soft landing certainly seem to limit the case for optimism.

Personal Commentary in this issue is by Philip Carroll who has described for us his involvement in the administration of the oil sector in Iraq as the first Director of the Office of Oil Policy in the Coalition Provisional Authority. Although much has changed since his departure, this account will, we are sure, be of considerable interest to our readers.

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Investment in LNG

David Ledesma asks why Atlantic Basin LNG is taking off

Introduction

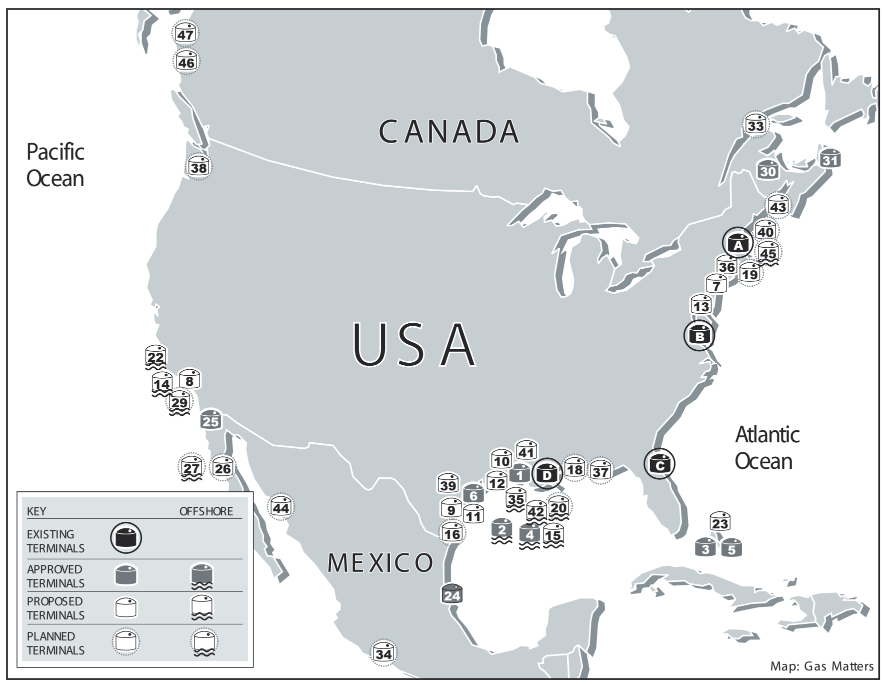
With global gas demand increasing nearly 3 per cent per annum, environmental pressures and buyers seeking to diversify from their traditional supply sources – be it through replacing their own production or by other imports – LNG is increasingly the fuel of choice. LNG suppliers are rushing to fill the demand/supply gap. In the UK, the USA, mainland Europe, Canada and Mexico, LNG is being heralded as at least part of the answer to narrowing that gap. That said, LNG currently accounts for less than 7 per cent of world gas consumption. For the countries involved in this fascinating business it represents, for buyers, an important energy source and, for sellers, a major and rapidly growing source of revenues and a means to monetise stranded gas. In 2003 122 million tonnes of LNG were transported – an increase of 25 per cent over 2000. In September 2004, world LNG supply capacity was 143 million tonnes per annum (mtpa), with 55 mtpa under construction. Global LNG capacity is expected to be nearly 200 mtpa by 2008 – doubling in less than ten years.

The business has changed considerably since the mid nineties, and it is commercial innovation that has led to the change. It has been supported by lower technical costs; new players entering the market; larger vessels (not necessarily owned by the supply projects or dominant utility buyers as they traditionally were); gas buyers' involvement in supply projects in their own right; flexible contracting terms to meet market requirements; and, creditworthy companies acquiring the complete output from LNG projects for on-selling via their own downstream facilities and/or on-selling ('trading') into different markets to improve revenues and develop new markets. What were once exclusively regional markets, with dedicated supply sources, are now in growing global communication as these developments drive new trade patterns.

Traditionally, LNG projects were developed on the back of gas reserves, on long-term contracts at oil-indexed prices. Such deals took many years to develop and were built on long-term relationships – often at governmental level. Since the mid-nineties, supply projects have been developed in growing interaction with – and often involvement from – buyers. In the Atlantic, this was pioneered by Atlantic LNG of Trinidad & Tobago, a project involving buyers from its 1992 inception and tailored from the beginning to fit tight market niches.

In the Atlantic Basin the traditional model of LNG chain development – in which the supply project develops and manages the LNG supply chain only up to the port of a utility buyer – has increasingly given way to different models of supply chain, although the new and old exist side by

Map 1: US LNG Terminals, 2004



EXISTING TERMINALS WITH EXPANSIONS
A. Everett, MA : (Tractebel)
B. Cove Point, MD : (Dominion)
C. Elba Island, GA : (El Paso)
D. Lake Charles, LA : (Southern Union)

APPROVED TERMINALS
1. Cameron*, LA : (Sempra Energy)
2. Port Pelican : (ChevronTexaco)
3. Ocean Cay (Bahamas)** : (AES Ocean Express)
4. Energy Bridge – Gulf of Mexico : (Excelerate)
5. Calypso (Bahamas)** : (Tractebel)
6. Freeport, TX : (Freeport LNG/ConocoPhillips)
25. Costa Azul, Mexico : (Sempra& Shell)
30. St. John, Canada : (Irving Oil & Chevron Canada)
31. Point Tupper, Canada : (Anadarko)

*Formerly Hackberry

**US pipeline approved; LNG terminal pending in Bahamas

PROPOSED TERMINALS UNDER CONSIDERATION BY FERC
7. Fall River, MA : (Weaver's Cove Energy)
8. Long Beach, CA : (Mitsubishi/ConocoPhillips)
9. Corpus Christi, TX : (Cheniere)
10. Sabine, LA : (Cheniere)
36. Providence, RI : (Keyspan & BG LNG)

Pre-filing with FERC
11. Vista Del Sol, TX : (ExxonMobil)
12. Golden Pass, TX : (ExxonMobil)
13. Crown Landing, NJ : (BP)
23. Seafarer (Bahamas) : (El Paso/FPL)
39. Ingleside, TX: (Occidental)
41. Port Arthur, TX (Sempra)

PROPOSED TERMINALS UNDER CONSIDERATION BY US COAST GUARD
14. CabrilloPort, CA: (BHP Billiton)
15. Gulf Landing, LA : (Shell)
20. Main Pass Energy Hub, LA : (McMoRan)
22. South California Offshore : (Crystal Energy)
35. Pearl Crossing, offshore Gulf of Mexico : (ExxonMobil)
42. Compass Port, offshore Gulf of Mexico (ConocoPhillips)

PLANNED TERMINALS
USA
16. Brownsville, TX : (Cheniere)
18. Mobile Bay, AL : (ExxonMobil)
19. Somerset, MA : (Somerset LNG)
29. California - Offshore : (ChevronTexaco)
37. Mobile Bay, AL: (Cheniere)
38. St Helens, OR : (Port Westward LNG)
43. Quoddy Bay, ME : (Quoddy Bay LNG)
45. Northeast Gateway, Offshore MA : (Excelerate)

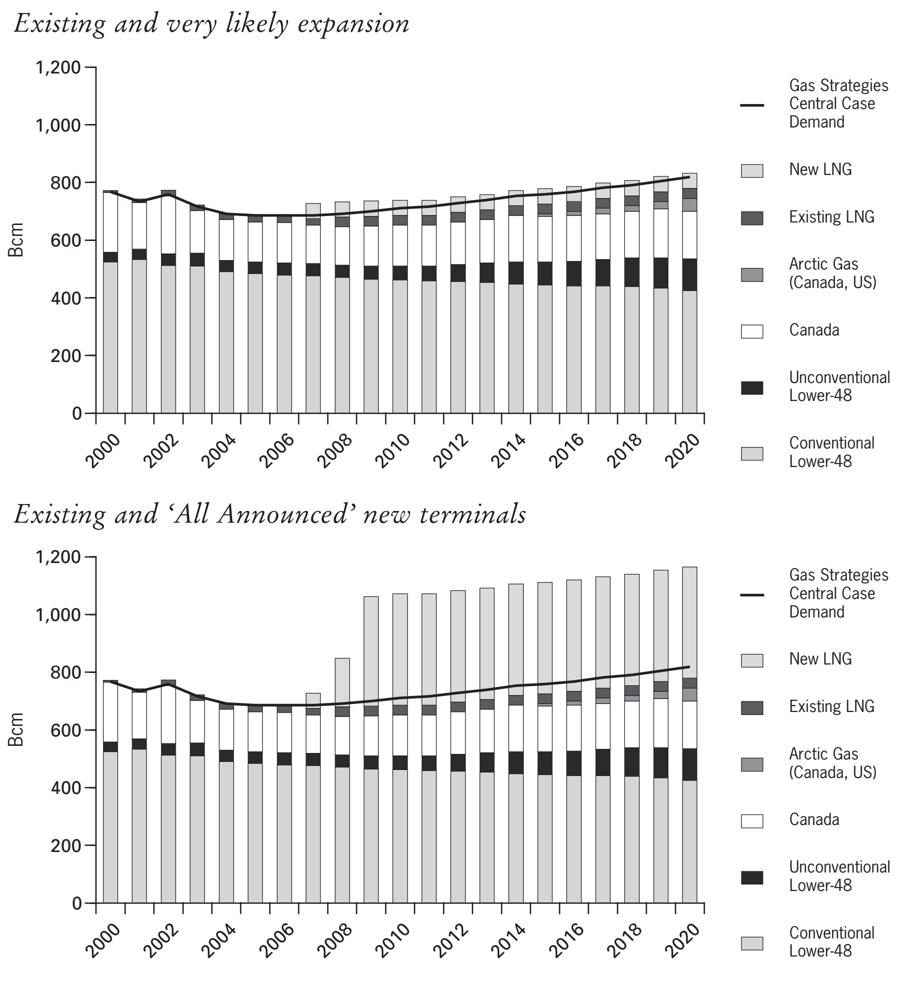
Mexico
24. Altamira, Tamulipas : (Shell)
26. Baja California : (ConocoPhillips)
27. Baja California - Offshore (ChevronTexaco)
34. LázaroCárdenas : (Tractebel/Repsol-YPF)
44. Sonora : (DKRW Energy)

Canada
33. Quebec City, QC : (Enbridge/GazMet/Gaz de France)
46. Kitimat, BC : (Galveston LNG)
47. Prince Rupert, BC : (WestPac Terminals)

Source: Gas Matters, August 2004

side. New models range from Atlantic LNG's various models (in the latest incarnation the partners even sell their own LNG separately) to the Egyptian varieties of ELNG and Segas, the latter developed almost entirely by the buyer, Spain's Union Fenosa Gas, as well as suppliers going further downstream. An important new component to many of these models involves one or more of the selling partners securing regasification capacity, and therefore LNG market outlets. BP and Repsol pioneered this development in the Atlantic, developing the Bilbao terminal for their Trinidad LNG but others quickly followed. The Egypt LNG I & II projects are being developed by BG and Petronas (which acquired Edison's interests), based on the markets of France, Italy, the UK and the USA; the partners have secured capacity in five terminals in these countries. ExxonMobil and ConocoPhillips with partners are developing US terminals to take LNG from new projects in which they have stakes in Qatar, as are ExxonMobil and Qatar Petroleum in the UK.

Figure 1: USA Gas Supply/Demand with Two LNG Terminal Capacity Cases



Source: Gas Strategies

LNG in the USA

The USA is the world's largest gas market but the 11 mtpa of LNG imported in 2003 represents only about 2 per cent of supply (which may be small but is significantly greater than the 0.1 per cent, of the mid nineties). Forecasts from the US Energy Information Agency (EIA) show that LNG imports are expected to increase fourfold to 40 mtpa by 2008 and around 90 mtpa by 2020 (Gas Strategies views this capacity estimate to be reasonable). The growth to 2008 will be absorbed through expansions of the existing LNG import terminals and Energy Bridge, but after 2008 these volume increases will depend on the development of new LNG importation capacity (see Map 1); though only a few of the 40 plus proposed new LNG terminals will be built. Figure 1 sets out Gas Strategies' view on US gas supply/demand under two scenarios for LNG terminal development.

This planned growth is being driven by increased US gas demand and limited ability to increase either US production or imports from Canada (also facing a supply squeeze). The shortfall of supply has driven US gas prices upwards and this, combined with its lower technical cost, has made LNG competitive in the US market.

Even the small number of new LNG terminals which are likely to materialise will substantially increase LNG import capacity. Realistic fears of local opposition to terminals (with the notable exception of Texas and Louisiana where big oil's installations mean jobs and money), have led to different LNG import facility options being developed. Excelerate Energy is bringing on this year the 'Energy Bridge' concept in the Gulf of Mexico using LNG vessels with on-board regasification facilities.

Other proposed new terminals include the use of gravity-based offshore structures (ChevronTexaco's Port Pelican project is the most advanced). Though it may be easier to secure the necessary approvals for these projects, they cost more than traditional land-based terminals and are costlier to expand. Other projects plan to use existing platform.

Terminals are also being proposed and developed in countries bordering the USA, thus getting around local US opposition and the American NIMBY ('Not In My Back Yard') mentality. Several terminals are being considered in Mexico (for California), although it has its own local and political issues; the Bahamas (Florida) and Canada. Many, although not all, of these projects will target the US market but, with both Canada and Mexico facing their own gas shortages for different reasons, a market will exist in these countries too. The Shell/Total terminal at Altamira, aimed at Mexican markets, has been approved.

Besides the major LNG companies, a range of companies small and large – such as Cheniere and Sempra – are developing US LNG terminals. Cheniere secured several good sites along the gulf coast, but may not operate them itself. The most advanced project it started, Freeport LNG, is now controlled by a combination of Freeport LNG and ConocoPhillips, which also secured two-thirds of the terminal's 1.5 Bcf/day regasification capacity. Cheniere has also signed a deal with Total for some throughput capacity at its proposed Sabine Pass terminal. The future of some of its other sites – Corpus Christi, Brownsville and Mobile Bay – is uncertain due to their proximity to some of the majors' own terminal proposals. Sempra is developing Cameron LNG (formally Dynegy's Hackberry project) but although EPC bids are expected soon, LNG supply is still not secured and therefore project progress has slowed.

LNG terminal capacity assures companies a gateway into the highly liquid US market, hence the wish of many to be involved. In addition, the larger companies see the import terminals as a means to work back up the LNG value chain and secure revenue positions in LNG production projects or to monetise upstream assets. BG, BP and Shell have notably built up LNG trading organisations, acquiring terminal capacity and vessels to meet their trading needs. As the US has a liberalised gas market it means that they are able to sell gas there with minimal volume risk but at market price. Investments have been made with the view that US gas prices will remain over $3.00/MMBtu, the level at which LNG imports from the Middle East are economic, and it is Gas Strategies' view that US Gas prices will remain in the band $3.50–4.50/MMBtu to 2020.

LNG Imports to the UK

The second fully liberalised gas market with a daily gas spot market is the UK. Currently self-sufficient and an exporter of gas, the UK is expected to become a net importer of gas in 2006/7, although the 'peak day' position is already very tight and necessitates some seasonal gas imports. To meet future requirements there are plans for three LNG terminals into the UK: Isle of Grain where National Grid Transco is converting an existing LNG peak-shaving plant into an LNG receiving Terminal (3.3 mtpa, due on in 2005, with plans to increase to 10.5 mtpa); ExxonMobil and Qatar Petroleum are planning the South Hook LNG terminal at an old refinery site at Milford Haven (7.8 mtpa with plans to increase to 15.5 mtpa); and BG, Petronas and Petroplus are partners in the Dragon LNG project, also at Milford Haven (6 mtpa). New pipeline projects to import gas from Norway and The Netherlands are underway; Russia is another potential pipeline source.

Gas Strategies' view is that LNG landed and regasified in the UK can compete successfully with the new planned offshore gas developments and pipeline supplies. The UK, in gas terms, should not be seen as an island. It is linked to the continent through the Interconnector (and in the future by other fixed point connections) and the price in the UK market is expected to be set by wider European supply and demand considerations. Should all these LNG import projects go ahead, even without the expansion plans, then the UK appears likely to remain an exporter of gas for some years, supplying the continent with surpluses.

As noted above, the UK has the only fully-liberalised gas market in Europe. European countries therefore, with their supplies mainly bought under long-term contracts with oil-indexed pricing, tend to have prices well above the cost of supply. Gas Strategies sees European gas prices continuing to be oil-linked for the remainder of this decade, with some gas to gas competition while the pace of European liberalisation proceeds slowly. European gas prices will therefore act as a key driver for UK gas prices and provide a market for any surplus gas volumes which, should all the UK LNG import terminal projects proceed, include volumes freed up through LNG imports. That said, delays in project schedules and the ability of LNG importers to redirect cargoes to other markets, primarily the USA, will provide a natural check and balance on LNG import volumes and gas prices.

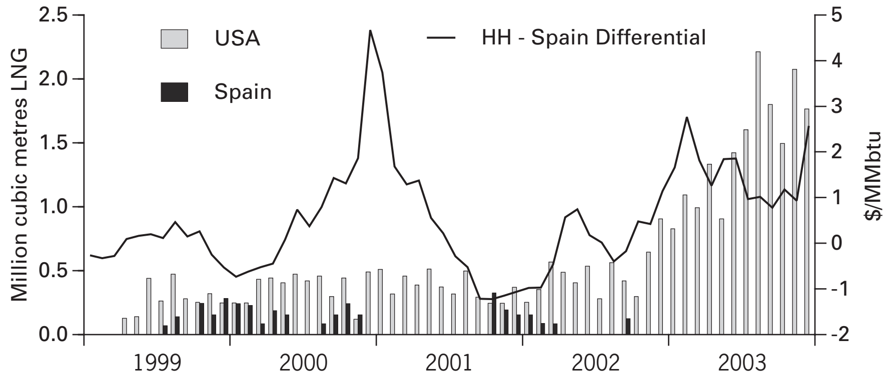
Atlantic Basin LNG Arbitrage

The distance between the European and US markets is not too far to prevent cargoes destined for one continent to be diverted to the other as contracts permit, at the cost of some disruption to shipping plans and the need for some additional shipping capacity. The primary reason for such trades is to take advantage of higher prices and it is this arbitrage opportunity that makes the Atlantic Basin so attractive to LNG suppliers and traders.

The first LNG project to really play the arbitrage game was Trinidad's Atlantic LNG. The contracts agreed with buyers allowed flexibility to divert cargoes to the higher priced market. Figure 2 shows the destination of Atlantic LNG volumes from 1999 to date vs. the Henry Hub-Spanish Gas Price differential.

When Spanish prices are high relative to the US, cargoes move to Spain. But when US prices are strong the number of cargoes moving to Spain reduces, or disappears. Also in the winter of 2003 (when almost no cargoes moved to Spain) there was additional demand for LNG from Asia. Japan's LNG demand rose in response to its nuclear power generation problems and South Korea purchased additional LNG cargoes to meet its winter peak gas demand. This extra demand meant that all additional Asian, Middle Eastern, and some Mediterranean cargoes – even a cargo from Trinidad – were heading east, resulting in reduced supply being available to meet US demand. This event, although a one-off, shows the new global dimension of the LNG business.

Figure 2: Atlantic LNG cargo destination vs. Gas Prices



Source: Gas Strategies

In 2003, approximately 20 per cent of Atlantic Basin trade was purchased on a short-term basis (i.e. not under long-term contracts). Such cargoes are priced according to the market in which they are sold and can be on a cargo by cargo basis, or as a series of cargoes. In the case of sales to the USA, most LNG sales are priced in relation to Henry Hub, but could be on a fixed price with the price exposure managed through the trading of Henry Hub futures.

Short-term LNG Trades and Trading of LNG

In order to encourage short-term trading of LNG several factors must be in place:

- LNG Production Capacity
- LNG Shipping
- Flexible LNG Contracts
- Sufficient LNG Import Terminal

With all these factors in place, LNG can be sold on a flexible short-term basis, which will provide a foundation for LNG trading in the Atlantic Basin. At present, limited surplus supply capacity is constraining short-term LNG trading. In the future with greater US and UK regasification capacity in place it should in theory mean that there is greater scope for short-term LNG trading. However, current plans are for a large percentage of this new regasification capacity to be tied up with specific supply projects. If this materialises as it is currently structured, there could be a reduction of this LNG trading potential.

Some Final Points

Increased demand for natural gas and reduced domestic production, together with environmental pressures, a desire for diversity and therefore, security of supply, has pulled LNG to the US and UK energy markets. In response, LNG project developers have created structures to provide the flexibility that these markets require and this, together with technical innovation, has reduced the cost of producing and transporting LNG. LNG from non-traditional sources, such as the Middle East, can now be economic in the US and UK markets.

On the market side, new types of LNG regasification facilities are being developed to meet local concerns, and this increase in terminal capacity, together with greater supply and different contractual structures, has encouraged the development of short-term LNG trading and arbitrage between Europe and the USA. All these factors have resulted in the 'take-off' of Atlantic Basin LNG and it is clear that it is an exciting place to operate in and will certainly remain so over the coming years.

Ben Smith considers the role of short-term trading in the LNG markets of the future

Until the late-1990s, the conventional wisdom had been that because LNG projects were so complex and expensive they had to be developed as fully integrated projects, from gas field to burner tip with clear dedicated revenue streams enabling project financiers to underwrite the massive costs involved. Now, as LNG is looked at as a possible answer to the demands of the massive markets of North America and Europe, can the LNG chain be sustained as the industry model or will players have to bear more risk for LNG to make an impact on the global gas market?

The model that the vast majority of greenfield LNG projects have used to date has been to secure long-term (usually 25 year) Sale and Purchase Agreements (SPA) with buyers with strong credit and to use the security of those LNG SPAs to finance the costs involved in development. Banks have been unwilling to take the risks unless all steps of the LNG chain from field development, through liquefaction, shipping, and regasification have been developed together and the banks can be comfortable that no third party can come between the customers' dollars (or yen) and the plant built with their funds. This has meant that projects have tended to have dedicated fleets of LNG tankers, whether operated by the LNG producer or the buyer, operating a 'liner trade' shuttling between the seller's liquefaction plant and the buyer's terminal. Effectively the shipping has acted as a floating pipeline.

Buyers, characterised by the Japanese monopoly utilities, have been of top grade creditworthiness, have usually had their own regasification terminals, and have often been able to secure for the project favourable financing from JBIC (Japan Bank for International Cooperation) or other similar sources. Typically they have been happy to commit to twenty-five year SPAs with prices linked to oil price indices, often with a floor price to guarantee the sponsors a rate of return. Such long-term contracts gave buyers security of supply.

As the industry matured, buyers increasingly took the initiative in terms of arranging shipping, which was often built by shipyards in the countries of the buyers (particularly in the case of Far Eastern buyers). The perceived advantages of this to the buyer were (1) national self interest – the corporate webs in Japan and Korea are tightly woven and if the utility companies could help the national shipbuilding industry then that was seen as being in the national interest; (2) economics – the shipyards of Japan and Korea were able to undercut the prices that other shipyards were able to charge and Asian buyers had confidence that they would be able to secure cheaper unit price shipping costs by purchasing and running shipping themselves compared to buying ex-ship.

The LNG industry until the mid-1990s was characterised predominantly by the supply of LNG to Japan, and from the mid 1990s to Japan and Korea, countries with no significant indigenous hydrocarbon reserves of their own. Asia still represents the biggest market (in 2002 Japan represented 49 per cent of the global market, Korea 16 per cent, and Taiwan 5 per cent).

A number of trends can be identified. The first has been that the price to get LNG (or more accurately regasified LNG) to market has dropped. This has been caused by striking technological improvements meaning that whereas in the 1980s gas liquefaction usually cost in the region of $400 per tonne of capacity, now costs are in the region of $200 per tonne of capacity, and shipping costs have come down from $1900 per cubic metre of capacity to $1200 over the same period.

The second trend is that North America and Europe are increasingly concerned about the decline of indigenous reserves of gas. This concern is manifested in two ways: prices have gone up and national governments have expressed fears of becoming dependent on a single (foreign) source of gas. Diversity of supply, and security of supply are big concerns, particularly in relation to a fuel that is usually delivered by pipeline.

The third trend is that the demand for gas is increasing. As the demand for cleaner energy in general and for power generation in particular continues, the vast majority of new generation being built is in the form of gas-fired combined-cycle power stations. This is fuelling the demand for natural gas.

> “Effectively the shipping has acted as a floating pipeline”

The fourth trend is that LNG has become the latest Big Thing in the hydrocarbons industry and every global player is keen to be able to show shareholders that it has a stake in the fuel being heralded as the solution to declining oil supplies. The causes of this phenomenon are probably partly the following:

- Most oil and gas companies' reserves of oil are aging, and those reserves that have not yet been exploited will be expensive and difficult to exploit; whilst looking for oil many companies have come across large reserves of gas, either gas fields or in the form of associated gas. Such reserves have been discovered but never exploited unless they were close to a potential market. Exploiting discovered reserves is much cheaper and lower risk than finding new reserves in politically or technically challenging circumstances.
- As environmental standards increase, the demand for gas (as a cleaner burning alternative to oil) has increased and the desire for oil companies to cut CO_2 by stopping the flaring of associated gas has also increased.
- LNG projects can be very profitable and, if well managed, can be a useful PR asset as well, showing companies overcoming technical adversity through the use of cutting edge technology to bring wealth to developing countries and ecological benefits to developed ones without even a hint of an oil spill.
- LNG excites investors, so the involvement in an LNG project can have a disproportionate effect on companies' share prices.

The LNG bubble effect has two consequences; firstly, players who perhaps are not big enough to take a stake in a whole chain are making 'merchant' investments in pieces of the chain (the classic examples are the terminals proposed for North America, but could also include such players as Golar, who, whilst admittedly having a long history in LNG, have focused on investing aggressively in LNG shipping – in addition to their existing fleet of seven they currently have six vessels under construction all without long-term charters lined up). Secondly, LNG projects are increasingly going ahead in circumstances that have in the past been too technically or politically challenging to make them worthwhile. Perhaps the best example of this is the Sunrise project that has had to get East Timor and Australia to decide on the sovereignty of the reserves that it intends to exploit and is looking at building the first floating liquefaction plant in order to exploit those reserves under the Timor Sea.

The fifth trend is that oil and gas companies are now much bigger than they were even ten years ago. Whereas in 1993 the total cost of an LNG chain of liquefaction plant, shipping, regasification terminal and a power plant would have represented 25 per cent of BP's market capitalisation, now it represents 2 per cent. This means that oil majors are now less dependent on project financing, and the strict financial structures insisted on by the banks. The majors have the scope to try and structure things in more flexible ways.

The sixth trend is the involvement of regulators. In Europe the European Commission has concluded lengthy negotiations with Gasprom, Sonatrach and Nigeria LNG agreeing not to put destination clauses restricting where cargoes can be delivered into contracts for the supply of LNG to Europe.

Looking at these trends it would be easy to conclude that LNG was on the cusp of moving to the oil trading model where production and consumption were connected with liquid markets and traders were able to match supply and demand according to market forces. On the surface all the required ingredients are there: increasing production, large liquid markets (which in the case of many markets are already trading gas on a commodity basis), a (relatively) easily transportable commodity, uncommitted shipping and terminals and buyers keen to contract with a variety of producers.

The role that LNG looks set to take is as the swing producer delivering gas to whichever market (Far East, Europe or North America) has the highest prices. LNG will be sold on a spot basis and traded just like crude. This, so the theory goes, will lead to a globally linked price of gas that will only be connected to the oil price by the demands of the market rather than through prices linked to oil indices as at present.

So why are spot cargo trades still such a tiny proportion of the LNG trade? In 2002 spot trades accounted for less than 10 per cent of cargoes delivered and Golar recently reported that spot requirements remained minimal for the second quarter of 2004. There is no doubt that sales of LNG on terms other than long term (i.e. 25-year terms) are growing (as late as 1999 short-term LNG trades were about 3.5 per cent of the total), and a large portion of those can be accounted for by the unprecedented flexibility that Atlantic LNG, the Trinidad producing company, gave its buyers to trade amongst themselves – meaning that in 2002 (despite 50 per cent of Atlantic's production being allocated to the Spanish market) over 90 per cent of it ended up in US terminals.

The obvious answer is that most projects developed up until now have their production fully committed (or almost fully committed) to long-term supply contracts and the flexibility granted under those contracts is limited. It may be trite to observe that long-term contracts generate long-term relationships but this too means that, to the extent that volumes are available in excess of those contracted under long-term contracts, existing customers are offered the cargoes first, usually on the same terms as the cargoes committed to on a long-term basis, meaning that such cargoes are not really being exposed to market forces in the same way that the oil spot market works. When Tokyo Electric suffered from the shut-down of a large number of its nuclear power plants in the summer of 2002 this did not have a particularly big effect on the global LNG industry. Yes, Tokyo Gas did end up buying more LNG to help make up the generation shortfall (and was helped by a relatively cool summer and measures to conserve energy) but those extra cargoes were, on the whole, acquired from existing suppliers on the terms of existing contracts.

It is true that probably the biggest impact on the spot cargo market has been the terms that Atlantic LNG offered its customers. Admittedly Trinidad and Tobago is well placed to be able to play off the two giant markets of North America and Europe but it does appear that the genie is out of the bottle and that buyers are asking for flexibility in their contracts that would have been unheard of in the early 90s.

It is not true, however, to say that the development of a spot market is simply evolution over time. Atlantic LNG has given its customers an interesting degree of flexibility and its customers have been able to trade their cargoes in value-adding ways. Oman LNG, on the other hand came to market slightly after ALNG but its customers are predominately in the Far East (Dahbol, Osaka Gas and Kogas). OLNG has some short-term customers but on the whole the OLNG contracts are 'typical' long-term LNG contracts with relatively restrictive destination clauses.

It is interesting to contrast the effect on the LNG industry of TEPCO's nuclear crisis (a situation involving one of the industry's key customers), with the gas price spike in the USA in the winter of 2000/01 (involving a relatively small LNG market). Whereas all suppliers (except Libya and Alaska but remarkably including the North West Shelf Project in Australia) scrambled to get cargoes to the States that winter, increased demand by Kogas and the Japanese buyers tended to be satisfied utilising existing relationships in a quiet and less dramatic fashion.

There are a large number of trends indicating that a market in LNG spot cargoes will develop and many players are positioning themselves to be ready when it happens, but the markets that the LNG industry is primarily reliant on (Japan and Korea) are not traded markets and the monopoly gas and electricity providers in those markets show little interest in developing spot markets. The primary impetus for change appears to need to come from the customers, and they are not desperate for change yet.

As Europe and the USA begin to represent a larger proportion of the LNG market, so the market forces in those countries will have a bigger effect on the industry. Already projects serving those markets are showing more of the flexibility required to develop spot markets.

What will this mean for project financing? The trend seems to be for the risk to shift up the supply chain and this is likely to continue. BP has recently concluded a contract with the US company, AES, to supply LNG to AES's IPP projects in the Dominican Republic for twenty years. The contract does not specify the source of the LNG, risk is on BP to source it. Will this be the way of the future?

Julia R. Richardson and John H. Burnes, Jr. look at the developing US LNG market

The United States is the largest natural gas consuming country in the world. As is true with other commodities, however, US demand for gas is outpacing the supply. The US domestic drilling rig count has nearly reached a three-year high, and continues to grow. But the consensus is that both domestic US supply and traditional imports from Canada are stagnant, if not declining, and unlikely to keep up with the projected growth in demand. At the same time, US gas prices have tripled since 1995, averaging roughly $5 per MMBtu throughout 2004.

Given North America's dwindling natural gas supplies and growing demand, both the government and the natural gas industry are looking to LNG imports to ease the shortfall. This rosy scenario for the LNG industry has its obstacles, however. One of the limiting factors is the amount of US regasification terminal capacity. There are four currently operating import terminals in the mainland USA (in Louisiana, Georgia, Maryland and Boston), plus one in Puerto Rico, and the LNG imported at those existing terminals currently supplies about 2–3 per cent of the US gas market. LNG could account for as much as 10 per cent of the market within the next three to four years, if the projected new terminal capacity comes on line by 2007, with LNG imports growing by 16 per cent per year between 2002 and 2025, according to the US Energy Information Administration (EIA). The questions are whether that capacity will be available, and when it will be constructed.

More than fifteen federal applications for LNG facilities are pending before the US Federal Energy Regulatory Commission ('FERC') (onshore projects) and the US Coast Guard (offshore projects). Both federal agencies are moving rapidly to review and approve new projects. Part of the reason for this flurry of proposals is the light-handed regulatory scheme created by FERC to stimulate new import projects. Congress passed a similarly business-friendly regulatory regime for offshore projects at the end of 2002. Although all the existing terminals have been reactivated, expansions have been approved, and additional expansions are being proposed, no new terminal construction has yet started. FERC has approved two new onshore terminals, and the US Coast Guard (which has a one-year time limit on its review) has approved two terminals, all four in the Gulf Coast area, but none of these recently approved projects are yet under construction. Apart from the US based terminals, a further number of new terminals have been proposed to be constructed in Mexico whence in theory natural gas could be delivered into the USA. It's highly unlikely, however, that any new terminals will be operational by 2007. Given the complexity of these construction projects, and the need to obtain supply arrangements and financing, the new terminals are at least 3–4 years away.

In addition, the industry's extraordinarily enthusiastic response to the market has been dampened to some extent by strong community opposition to a number of projects. Proposals for onshore terminals in California, Alabama and Maine have been withdrawn by their proponents as a result of community opposition. That local opposition is based largely on the emotive issues of safety and security concerns. On the other hand, the four projects in the Gulf Coast area recently approved by FERC and the US Coast Guard were not seriously opposed, and the commonly held view, therefore, is that projects may be easier to site in the Gulf Coast area. This result would be unfortunate for consumers, however, because that location requires significant transportation to the most weather sensitive markets in the Midwest and Eastern states. On the plus side, however, it means there would be less stranded pipeline infrastructure.

At the present time, expansion of existing terminals is still the best hope for new capacity in the short term. The four existing LNG terminals supply about 800 to 1.1 Tcf annually to the US market, if they are operating at their maximum capacity. Already announced expansion plans would raise the annual capacity of the existing LNG terminals to 1.7 Tcf by 2007–2008. The terminals are expected to import 630–650 Bcf this year, up from more than 500 Bcf in 2003 and double the amount imported in 2002.

> "the USA has quickly moved into the ranks of the top five LNG importers in the world"

If sufficient terminal capacity can be built, what is a realistic expectation for the US LNG market? Some industry experts predict that it will support more than 10 Bcf/day, perhaps as high as 13 Bcf/day within the next few years. In 2003, roughly 500Bcf was imported into the USA, with 51 per cent going to the terminal at Lake Charles, Louisiana; 30 per cent to Everett LNG in Boston; 11 per cent to Elba Island in Georgia, and 8 per cent to Cove Point LNG in Maryland (which only started import operations in September of that year). 2004 will reflect a full year's operation at Cove Point where an ambitious expansion plan has been announced.

Thus, in just a few short years, the USA has quickly moved into the ranks of the top five LNG importers in the world. The issue then arises as to whether this rapidly expanding new market will alter the traditional LNG market model, in which very long-term supply agreements are matched to equally long-term terminal capacity agreements. This traditional model has been a fundamental requirement of importers and lenders, and has tied specific supply sources to specific terminals. The domestic US gas sales market, on the other hand, has evolved into a market dominated by spot market sales, and fewer long-term firm transportation agreements.

The existing terminal operators seem to be following the traditional model to a large extent, as they or their shippers appear to be locking in long-term LNG import agreements tied to specific overseas liquefaction facilities. Many of the new terminals are also announcing similar arrangements. In turn, the long-term capacity agreements may well provide the financial assurances needed at the production end of the supply chain.

Another factor inhibiting the development of a robust spot market in LNG is the interchangeability of LNG with domestic gas supplies. Although there exists a wide range of Btu content around the world, US terminals are often designed with specific gas quality specifications, often tied to the expected source of international supplies. Some may have engineering or environmental limitations on the LNG that they can accept, or will have to modify their facilities to be more flexible.

On the other hand, there has been a significant amount of spot sales activity in recent years, as importers scrambled to take advantage of current market opportunities while development of long-term supply facilities and arrangements lagged behind. EIA reports that short-term, or spot imports, have increased, and attributes that trend to the growing involvement of major diversified oil and gas companies with upstream LNG assets. In other words, LNG can be diverted to the USA by liquefaction plant owners with available short-term supplies. The most common source of those supplies, whether short- or long-term, has been Trinidad and Tobago. Trinidad has dominated the US market for the last four years, accounting for nearly 75 per cent of total LNG imports. But other countries, such as Algeria, are ramping up their short-term sales.

If the major oil and gas producers are able to commercially link production facilities to multiple North American import terminals, the global spot market in LNG would obviously be enhanced. Seven of the top twenty US gas producers are now pursuing LNG projects, and at least three large Canadian projects are in the permitting process. In addition, the development of the US LNG market is attracting new potential suppliers to global LNG trade such as Russia, Australia, Bolivia, Norway and Egypt. Significantly, one-third of the current orders for LNG tankers through 2007 are not committed to a specific LNG project, which is a departure from historical industry practices and important for further development of the spot market for LNG.

If current growth levels continue, the United States will surpass Japan as the largest LNG importer in the world, but this is crucially dependent on the construction of the new import terminals that are in the planning stage. If this takes place and suppliers multiply as seems likely, and a favourable regulatory climate is maintained, the conditions will be created which could lead to a global spot market.

Investment in Power Generation

Lindsay Tuthill discusses theory and investment in new electricity generating plant

Energy, and specifically electricity, could well be claimed to be one of the most crucial inputs for achieving and sustaining the levels of productivity and economic growth experienced in the developed nations of the world. Indeed, an economy based upon the creation, distribution and sales of any variety of goods and services could not be created, let alone sustained, without the provision of vast amounts of energy. With the vast majority of the developed world's electricity generated through the combustion of fossil fuels, however, there exists a large negative externality problem associated with the gaseous and particulate emissions in the electricity generating industry. Most of the energy data and regulatory history mentioned in this article will focus on the experience of the United States, but the conclusions are readily generalised.

The emissions that have received the most attention in environmental policy circles over the past twenty years include greenhouse gases (carbon dioxide, methane, nitrous oxide, among others) and sulphur dioxide. As with any externality, the problem with the emissions from fossil fuel-fired electricity generation is the fact that the environmental damage is incurred, but this damage is not accounted for in the firm's production costs. In the United States, there have been several acts of legislation passed regulating and limiting the emissions of various gases at different times, but the first national, long-term environmental program based around the trading of emissions permits was established by Title IV of the Clean Air Act Amendments of 1990. Though this legislation affected only sulphur dioxide emissions, it was the first practical example of an economically efficient solution to the environmental externality problem associated with electricity generation. With the increased discussion of global warming and the negative effects of carbon dioxide (CO_2) and other greenhouse gas emissions, it can only be assumed that some form of legislation regarding the emissions of these pollutants is impending – we just can't be certain as to the date or degree of its arrival.

The problem facing electricity generating firms, then, is as follows. They know that given current conditions, generating electricity from coal is significantly cheaper than generating from gas – or from renewable sources. They are aware that their nation's livelihood effectively rests on their successful provision of electricity, but they are also aware of the increasing pressure for the government to approve a unified environmental program regulating the emissions of greenhouse gases, and specifically carbon dioxide. They are also aware of the fact that even if such a policy were created, it may be subject to change, as election years pass and the incumbent political party's beliefs are encountered.

As existing plants age and require retirement, firms are left trying to decide whether to continue replacing their old 'dirty' units with new coal-fired capacity that allows them to generate at a lower cost per kilowatt hour, or rather to replace them with new 'clean' gas-fired units, which will incur a higher cost per kilowatt hour for generation, but save the firm the permit costs associated with carbon dioxide emissions. The future prices of these permits are linked to future environmental regulations, and the firm can not predict future regulatory behaviour. Thus, the problem addressed in this article is that of an electricity generating firm's plant-type decision given uncertainty over future environmental regulations. We show that the lack of a firm and certain emissions policy leads to a reduction in and postponement of investment in cleaner generating alternatives.

The Models

The classical net present value theory of investment is not valid in this case because of the interaction of the uncertainty over future environmental policy and the irreversibility of the investment being considered. The construction of an electricity generating plant requires an irreversible investment, in that the money used to finance the plant can not be extracted in the future if market conditions should change. Say that a firm decides to build a 30 MW gas-fired plant today, only to find out four years from now that carbon permit prices have tumbled, leaving them with clean power plant that is much less profitable than a new coal plant would have been. There is then no way for that firm to recover the construction cost of its gas plant. That being true, the opportunity to invest in an electricity generating plant can be viewed as a financial call option, giving the firm the right, but not the obligation, to invest a certain amount in return for an asset (here, a power plant) of some value.

"the lack of a firm and certain emissions policy leads to a reduction in and postponement of investment in cleaner generating alternatives"

It is for this reason that the two models of the generating firm's plant-type decision are based on real options analysis in the spirit of Dixit and Pindyck's work. In each, we assume that if an environmental policy were to be enacted, it would be a tradable CO_2 permit scheme similar to that for SO_2 in the USA today, and each model incorporates a different stochastic process for the environmental policy variable (CO_2 permit prices). The first assumes that permit prices evolve according to a geometric Brownian motion (GBM) and the second according to a mixed Poisson-geometric Brownian motion (or jump-diffusion) process. As the permit prices rise, 'dirty' coal-fired plants become less and less profitable relative to 'clean' gas-fired plants, and there exists a certain critical permit price at which the default decision of 'build a dirty plant' switches, and it becomes optimal for the firm to build a clean plant. Above this critical permit price, firms are sufficiently confident that permit prices will not fall low enough in the future to render the clean plant's construction a foolish decision. Both models, then, investigate the optimal plant construction decision of an electricity generating firm, and both view the firm's decision as an optimal stopping problem and both are solved via dynamic programming.

These models assume that an electricity generating firm currently owns a coal-fired power plant of capacity *G* that they are preparing to retire. Upon retirement of the old plant, it is assumed that the firm would like to open a new one of the same size, *G*, (i.e. it would like to maintain its current capacity), and that, while it is possible to postpone the decision until the end of the life of the existing unit, the firm must then at the very latest, decide whether to build a new 'dirty' plant or a 'clean' one. If CO_2 permit prices do not reach their critical level before the end of the life of the firm's existing coal plant, we assume that the firm constructs a new 'dirty' plant to maintain its capacity. We define the dirty choice as a coal-fired combustion unit that produces a large quantity of CO_2 emissions, and we define the clean alternative as a natural gas-fired integrated gasification combined cycle (IGCC) unit, though the model could in fact be used to investigate the critical permit prices for any retrofitting investment decisions, or any clean plant that emits less CO_2 than the coal unit.

The uncertainty that the firm is facing is not related to future output (electricity) prices or fossil fuel input costs (we assume these are known and constant), but rather to potential future environmental regulations. We will therefore consider a stochastic environmental policy variable, namely a CO_2 permit price, whose future value is unknown, and we will assume that if the firm chooses to construct a clean generating unit, it would require only a fraction of the CO_2 permits that it would if it chooses to build a dirty plant. As is well known, firms will find it more profitable to operate dirty units in the absence of emissions charges, and we therefore assume that if CO_2 permit prices have not reached their critical level by the end of the life of the firm's existing coal unit, the firm will by default choose to construct a new dirty plant. Thus, these models seek an optimal investment rule that depends on the stochastic CO_2 permit price, describing where it is optimal to continue with the decision to build a dirty plant instead of a clean one, and where the opposite is true.

Because the investment in a clean power plant is irreversible and can be postponed, and because operating a dirty plant is preferable in the absence of emissions regulations, the models regard the ability to invest in a clean generating unit rather than a dirty one as a financial call option. Thus, we think of the firm as having the right, but not the obligation, to invest a certain amount in return for an asset (here, a clean power plant) of some value. The option to invest in a clean power plant gleans its value from the same source as a financial call option – from the downside risk associated with the future value of the clean plant, which, here, depends on the CO_2 permit price.

We consider the firm's decision as an optimal stopping, or free boundary problem. Given uncertainty over future environmental regulation, the continuation region in our case is the region in which it remains optimal for the firm to choose to construct a dirty plant instead of a clean one. As environmental policy changes and is revealed, it could eventually become optimal to construct a clean plant instead of a dirty one, bringing the firm's decision into the stopping region. The goal of these models, then, is to find the free boundary of this investment problem, or more specifically, to calculate the value of the option to invest in a clean plant rather than a dirty one, and to find the critical price of CO_2 permits that makes clean investment optimal.

The assumptions of two models used are exactly the same, except for the stochastic processes chosen for the policy variable. We assume that CO_2 permits, like the SO_2 permits currently traded in the USA, would be traded freely between firms, and can therefore be thought of as financial assets. Thus, in the first model, permit prices are assumed to follow a geometric Brownian motion, and evolve randomly over time with a certain drift rate. In the second model, CO_2 permit prices are assumed to follow a combined geometric Brownian motion and Poisson jump process (or a 'jump-diffusion' process), so that from time to time, the price of the permits can 'jump' as the regulator reduces or increases the number of permits available for trade in a given year. Between jumps, though, these permits are being traded as financial assets between firms, and the price is assumed to follow a geometric Brownian motion. The jump-diffusion model is separated into two cases: Case 1 where permit price jumps can be only positive, and Case 2 where jumps can be only negative.

Results

The results of the models are summarised in Table 1. In the stationary deterministic case, CO_2 permit prices are assumed to be known and to remain constant at all future dates. τ^* denotes the critical CO_2 permit price at which the construction of a new clean plant becomes optimal, and $F(\tau)$ denotes the option value associated with making no construction decision and waiting for more regulatory information.

It is obvious, then, that uncertainty over future permit values leads to a delay in the selection of the clean alternative in all scenarios other than the upward jump-diffusion case. This is due to the fact that uncertain environmental policy leads to the possibility that emissions permit prices may fall to a level below τ^* tomorrow, making the clean plant construction decision sub-optimal. The firm, therefore, is able to extract an option value in the presence of uncertainty and prefers retaining this option value to investing until permit prices have reached a level that ensures the optimality of the clean unit's construction. Because the critical τ^* is so much higher in the presence of uncertainty, the probability that permit prices will reach τ^* before the expiration of the firm's existing coal plant is lower, and the firm is more likely to replace its old unit with another new dirty one. Thus, the lack of certainty over future regulation makes it more likely that generation will remain dirty.

In the context of this example, it is optimal for the firm to replace its existing coal plant with the natural gas-fired IGCC soonest in Case 1 of the jump-diffusion model where permit prices can only jump upwards, then in the GBM model, and finally under the specifications of Case 2 of the jump-diffusion model. Here the critical τ^* in Case 2 of the jump-diffusion model is more than *twice* that of the stationary deterministic case. In other words, the probability that τ^* is reached and a new clean plant is built before the firm's existing coal plant expires is highest in Case 1 of the jump-diffusion model, followed by the GBM model, and finally by Case 2 of the jump-diffusion model. This implies that the dirty construction alternative is most likely to be chosen in Case 2 of the jump-diffusion model, when the firm faces the largest downside risk associated with the potential drop in future CO_2 permit prices.

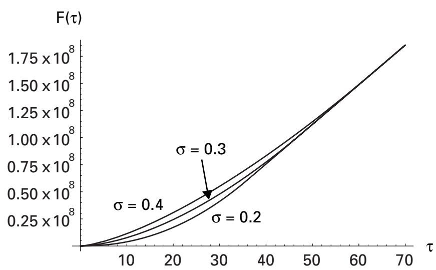
These results are also dependent upon the parameter values chosen. Figure 1 presents the value of the option to invest in the clean IGCC unit rather than the dirty scrubbed coal unit as a function of the price of CO_2 emissions permits for different values of sigma in the GBM model. Because of the stochastic process that permit prices are following in this model, a lower value of τ is equally likely in any period as a higher value of τ. It is, therefore, possible in this model to invest in a clean plant today only to find out

Table 1: Model Solutions for Various Permit Price Evolutions

Stationary Deterministic case	Geometric Brownian Motion	Poisson-GBM, Case 1: Only Positive Permit Price Jumps	Poisson-GBM, Case 2: Only Negative Permit Price Jumps
τ^* = \$23.16/ton of CO_2	τ^* = \$48.30/ton of CO_2	τ^*= \$11.59/ton of CO_2	τ^* = \$55.03/ton of CO_2
	$F(\tau) = 165{,}372\tau^{1.6}$		$F(\tau) = 27{,}607\tau^{1.9664}$

tomorrow that permit prices are lower than you had thought they would be and that the dirty plant would have been the better choice. Thus there is an opportunity cost of investing in the clean plant now in this model, which is defined to be the value for the option to invest. Figure 1 depicts the fact that when $\tau<\tau^*$, the firm continues to hold the option to invest in a clean plant (i.e. it postpones its investment decision). Once τ reaches the critical τ^*, however, the option is exercised. As Dixit and Pindyck have shown, the critical permit price at which the clean-instead-of-dirty option is exercised is found at the point where the value of the option to invest in the clean unit becomes tangent to the profits the firm receives.

Figure 1: F(τ) as a function of τ for different sigma values



It can also be seen from Figure 1 that increasing the variance parameter of the stochastic process future permit prices are following, σ, causes an increase in both the value of the option to invest in the clean unit, *F*(τ) and the critical permit price τ^*. Increasing the uncertainty of the permit-saving payoff associated with the clean generating unit, then, causes an increase in the value of the *option* to invest in the clean unit. This is because an increase in σ increases the variance in future values of τ, with the risk that tomorrow, the firm will learn that permit prices have fallen low enough so that constructing the dirty plant would have been the better decision. Thus increasing σ leads to a greater opportunity cost of investing in the clean alternative today rather than waiting (i.e. it increases the value of option to invest in the clean unit rather than the dirty one).

Recall that the firm will wait until the death of its current coal plant to make any new plant investments as long as τ is such that replacing the old coal unit with a new coal unit remains optimal. As long as $\tau < \tau^*$, increasing σ, the variance in permit prices, causes a general delay in any new plant investment. In the context of this example, this means that electricity generating firms will find it optimal to do nothing until the death of their existing coal unit and then build new scrubbed coal as long as τ does not reach τ^* before the last possible retirement date for the existing unit. Thus uncertain carbon emissions policy on the part of the government should cause both a delay and a suppression of investment in clean power plants, relative to the case where permit prices are certain and sufficiently high.

Conclusions

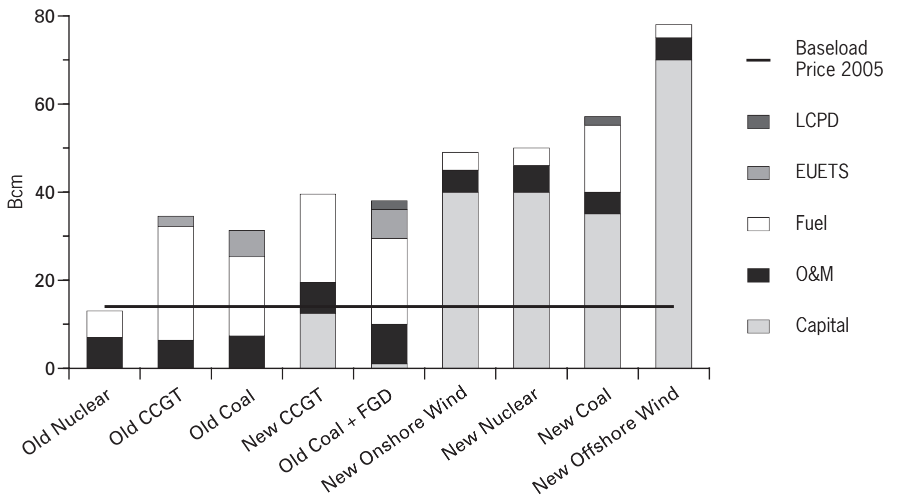
Both of the models discussed here suggest that uncertain carbon emissions policy leads to a delay in and reduction of investment in clean generating technologies. The greater is the environmental regulatory uncertainty, the more severe are these effects. Some uncertainty might be resolved through the establishment of a unified and certain carbon emissions standard, but we must use caution in this instance. Because of the time inconsistency issues associated with environmental policy (conflicting desires for economic growth and environmental preservation) from the government's perspective, generating firms will be left questioning the stability and permanence of any set environmental policy as long as the government retains the ability to eliminate, intensify, or relax emissions standards. The issue is not as complex when considering the government's ability to intensify emissions standards. When allowing the government the freedom to relax emissions standards in the future, however, we find ourselves in Case 2 of the Poisson-GBM model described above, in which the critical permit price that makes clean plant construction was the highest of all scenarios considered. In other words, certain environmental regulations will increase the arrival and quantity of clean plant investment, but in order for the government to achieve its goal of increasing the quantity of clean generating capacity in the nation while retaining the ability to relax emissions standards in the future, the original policy the government institutes must be more stringent than it would be if it were to relinquish the right to its subsequent alteration from the outset.

John Bower looks at the investment horizon for European power generation

The power generation industry in the UK, Germany and Spain is still heavily dependent on coal-fired generation capacity and recent rises in gas prices, still directly linked throughout most of Europe to oil prices, have made coal an increasingly attractive fuel. As a result, power generators in these countries are reluctant to invest heavily in new combined cycle gas turbine (CCGT) generation capacity. Indeed, at the time of writing old coal-fired plants are running at full capacity while some relatively new CCGT plant only run at peak demand periods or will only be taken out of mothballs to run in the coming winter months.

It is ironic that just as the EU is about to implement its emissions trading scheme (EUETS), which is designed to provide economic incentives to cut carbon dioxide (CO_2) emissions, in the three member states (UK, Germany, Spain) which emit the largest quantities of CO_2 from their power generation sectors, coal has become the fuel of choice since 2001. As a result, CO_2 emissions are rising. As a rule of thumb, for each megawatt hour (MWh) delivered from a coal-fired power plant to a customer's plug

Figure 1: UK marginal power generation costs and market price for 2005



socket approximately 1 metric tonne of CO_2 is emitted to the atmosphere but if produced from a state of the art CCGT plant the same MWh can be produced with only 0.4 metric tonnes of CO_2 emitted. For the UK, Germany and Spain the route to emission reduction is therefore clear, shutting down virtually every coal-fired power plant now in operation and replacing it with a new CCGT plant. However, it takes at least three years to plan, raise finance, construct and commission a new CCGT plant, even under favourable circumstances, and there is little evidence that the necessary capacity investment is either happening or even being planned.

Figure 1 shows the marginal cost of producing electricity in baseload from a range of different power plant assets in the UK, based on forward prices for 2005, and shows why investment in new CCGT capacity is not being made. The picture that emerges is that the present wholesale forward price for 2005 baseload electricity is being set by existing CCGT plant and that generators have a significant price incentive to operate their existing coal-fired generating assets at maximum capacity. Of greater concern is that the present market price is too low to provide any incentive to build new CCGT capacity. Though the price levels are different in Germany and Spain the picture is essentially the same with the power generation sector trapped in an investment limbo.

Lower than expected forward prices for CO_2 emissions allowances (EUAs) – at the time of writing around €8.50 per tonne of CO_2 (tCO_2) – have coincided with relatively high gas prices when compared to coal. The net result is that existing CCGT plant are being run only when absolutely necessary and investors see little prospect of making an attractive rate of return on new build CCGT plant.

It is not only forward fuel and EUA prices that have made new CCGT capacity investment unattractive. For individual generating firms, the quantity of EUAs they have been allocated for Phase I (2005–2007) of the EUETS by their respective governments under respective national allocation plans (NAPs) is now known but nothing has yet been decided for Phase II (2008–2012) or beyond. Given new build costs of about €500 million per GW of new CCGT capacity the total financing required to build, say, 50GW of new CCGT capacity will be of the order of €25 billion. Given the nature of power generation assets, with cashflows stretching some twenty years into the future, financiers, investors and boards of power generation firms must therefore now be thinking beyond Phase I of EUETS when considering new investment in power generation capacity. Unfortunately, EU politicians are still wrangling over Phase I of EUETS allowance allocations so the likely shape of Phase II of EUETS, or even if it will go ahead at all, is extremely uncertain and open to significant political risks.

These risks manifest themselves in the form of uncertainties about the amount of future allocations that power generators will receive as well as the price of buying in permits to cover any shortfall. Added to the present volatility in fuel prices and the increasing reliance of the EU on imported natural gas over the next two decades the required rate of return, sometimes called the 'hurdle rate', that investors now demand before providing capital to a new CCGT project is far higher than it was five years ago. Where banks were prepared to lend virtually unlimited amounts of non-recourse project finance to new CCGT projects in the late 1990s, at interest rates of 10 per cent or less, they now require significant equity participation by the participating utility and secured finance is offered at interest rates nearer 15 per cent. As a result, most power generators in the UK, Germany and Spain have taken the rational decision to delay making major investments in new CCGT capacity until at least the picture becomes clearer for allocations under Phase II of EUETS. Instead, they intend to comply with EUETS Phase I emission targets by buying-in any incremental EUAs they will require in order to continue operating their existing coal-fired plant at full capacity. Unless there is a dramatic rise in forward prices for EUA, or forward gas prices fall relative to coal prices there is little sign that power generators will change their wait and see investment stance.

> "most power generators in the UK, Germany and Spain have taken the rational decision to delay making major investments"

Though power generators are responding rationally to the relative prices of EUAs, coal and natural gas, and the cost of capital, delaying investment to await development in

EUETS Phase II, means that power generators are also choosing (largely by default) to delay investment that will be required to comply with the Large Combustion Plant Directive (LCPD). Aimed at reducing emissions of oxides of nitrogen and sulphur as well as particulates (dust), the LCPD allows generators to either fit the necessary environmental protection equipment such as flue gas desulphurisation equipment (FGD) to smoke stacks of their coal-fired generating capacity or apply for a derogation which allows them to run these plants for a further 20 thousand running hours after 1 January 2008 and then permanently close them thereafter.

> “the option to invest in old coal-fired capacity to comply with LCPD is therefore almost as unattractive as building new CCGT capacity”

As Figure 1 showed, retrofitting old coal-fired plant with FGD equipment not only requires investment of capital but also reduces plant efficiency and thereby increases CO_2 emissions. At present forward prices, the option to invest in old coal-fired capacity to comply with LCPD is therefore almost as unattractive as building new CCGT capacity. As a result few generators have chosen to make significant investment to comply with LCPD so far and most have indicated they will simply shut their coal plant under the LCPD derogation or have made no decision at all.

As CCGT plant will not be impacted by LCPD, because of the inherently clean nature of natural gas fuel, power generators that have significant coal-fired capacity could simultaneously comply with both EUETS and LCPD by just investing in new CCGT capacity and shutting down their old coal-fired capacity rather than investing in and retrofitting it with environmental protection equipment. The EUETS and LCPD therefore both impinge on the crucial decisions that power generators in the UK, Germany and Spain in particular now face – how to manage the switch from relying on existing coal-fired generation capacity to new CCGT capacity. In the case of the LCPD, there is a defined end date for the lives of all existing coal-fired generating capacity, which assuming coal-fired plant are still operating at full capacity in 2008 and beyond means that all must close by the end of 2010 or have fitted the necessary pollution control equipment. By accident rather than regulatory design, 1 January 2008 also happens to be the exact moment that Phase II of EUETS begins and 2010 is likely to be a crucial year in which dramatic capacity changes in the type of generating capacity being operated by major power generators in three large EU economies will have to take place.

The net result is that there is a serious risk that power generators will delay investment for as long as possible to await the outcome of possible changes to EUETS and LCPD and thereby compress the investment timetable for replacing their old coal-fired capacity into a three-year period beginning 1 January 2008. The likely outcome is very high and volatile prices as demand approaches the limit of available capacity and as gas prices are pushed even higher by the sudden demand for new gas supply to power newly commissioned CCGT plant. Of course, it could be argued that power generators will not delay their investment until the last possible moment because they will obviously know the potential impact on price levels and volatility and in anticipation of that bring forward their plans to take advantage of the increased investment returns on offer.

Unfortunately, that rational process of investment decision making can only take place if power generators can be reasonably sure that the LCPD will really be implemented as planned and if the EUETS allocation process for Phase II is such that coal-fired capacity which is fitted with the necessary environmental protection equipment will receive sufficient permits in order to be able to run for a sufficient number of hours and at a competitive price to pay back the capital investment. Given the history of negotiations over EUETS Phase I, which are still not completed some three months before it is due to come into force, it is unlikely that power generators will receive the necessary assurances on Phase II before the end of 2007. In addition, the UK government has signalled its intention to allow them to change their minds right up to 31 December 2007 and German and Spanish governments are likely to follow that lead. Yet further reason for generators to delay making investment decisions.

Mark Lijesen and Gijsbert Zwart analyse efficiency and sufficiency in power generation capacity

Growth of generation capacity has come to a halt since the restructuring of electricity sectors in continental Europe. Capacity investments have been close to zero in many European countries, except perhaps subsidised investment in renewables. Figures from UCTE (the coordinating body of European Transmission System Operators) indicate that in the Northwest European market (Germany, France and the Benelux), total installed capacity has remained more or less constant since 2000. Total consumption rose by 3 to 5 per cent during this period.

It is clear that capacity growth is lagging. It is not clear however whether this is a problem. Europe has a long history of public monopolies with an inefficiently high level of capacity which is currently decreasing. Furthermore, interconnection capacity has increased substantially in Europe, decreasing the need for high spare capacity levels.

Furthermore, the introduction of a European electricity market has also led to an increase in trade between countries, caused by traders wishing to exploit regional price differences. In the Netherlands, the net imported electricity increased by around 50 per cent after market liberalisation in 1998, inducing a drop in utilisation of domestic generation capacity. Despite growth in demand and negligible capacity additions, 1998 capacity utilisation levels were reached again only in 2001.

The overcapacity resulting from the pre-liberalisation era has been reflected in low wholesale electricity prices across Northwestern Europe. Prices for annual contracts have only recently approximated entry levels. It is hence not surprising that investors have been reluctant to expand capacity in recent years. Indeed, as prices are rising, one currently observes new investment initiatives in the Netherlands and Germany.

A more pertinent question is whether investments will be sufficient after the historically high level of overcapacity has been resolved. How one answers this question depends on the interpretation of the word 'sufficient'. From a perspective of supply security, sufficient relates to the ability of the system to absorb shocks in demand or in the availability of supply. From an economic efficiency point of view, sufficient may relate to a level where economically efficient outcomes are reached, i.e. where prices equal long-run marginal costs.

Capacity and Reliability Levels in an Efficient Market

In an efficient and competitive electricity market, competition will drive down prices towards the marginal costs of the highest cost unit needed to meet demand. Firms will however only invest in new capacity if they expect their total revenues to cover capital costs as well. In any market with fixed costs, producers will have to capture the scarcity rents that are needed for new investments. The structure of price formation when scarcity occurs is therefore at the heart of the determination of the competitive level of generation capacity.

One of the characteristics of electricity is its non-storability. This implies that demand fluctuations over time have to be met by available capacity. Scarcity rents occur when fluctuating demand at given capacity levels creates shortage of supply from time to time, causing prices to rise (scarcity may also arise when some of the capacity is unavailable, e.g. because of maintenance or technical failures). The increase in prices restores the balance between demand and supply in two ways. It suppresses demand and it renders spare capacity economically viable, even at lower load factors.

"Increasing efficiency on the demand side may lead to lower installed capacity levels, without necessarily compromising system reliability"

Efficient investment therefore implies that demand is rationed sometimes. Rationing may take place through voluntary demand response, when consumers decrease load or the system operator reduces its reserve requirements. Ultimately, rationing may take place through TSO-intervention, disconnecting entire areas (so-called load blocks). When the latter occurs in an efficient system, the price is set equal to the value of the lost load for these customers. Prices established during periods of demand response determine scarcity rents. Installed capacity levels in this efficient market will be sensitive to the precise form of the price-demand curve in this region, and in particular also to the system operator's behaviour under scarcity conditions when system reserves are dispatched.

The next issue concerns reliability: when is an electricity system reliable? Traditionally the public monopoly systems were designed such that installed capacity would be sufficient to meet likely demand levels. In an efficient market, voluntary demand response is a cornerstone of power system operation, and requiring a reliable power system never to cut back demand would be inconsistent. Reliability was traditionally directly related to installed capacity. An increase in the price elasticity of demand relaxes the need for capacity in favour of more efficient demand response, thus allowing similar levels of reliability at lower levels of capacity.

The reliability of the system may be defined by the need to curtail inelastic (e.g. residential) demand in equilibrium. The probability of this depends firstly on whether generator revenues during periods of demand reduction suffice to remunerate generation investment costs. Secondly, the magnitude of fluctuations in demand (compared to available demand response) or demand uncertainty matters. A reliable system therefore has a large capacity of voluntary demand response, high prices when this occurs, and low uncertainty about the future range of peak demand minus supply.

Beyond the Supply Curve: Demand Response Affecting Capacity Levels and Reliability

Both the levels of installed capacity and of reliability are determined largely by the structure of prices 'at the end of the supply curve', where industry load shedding and system reserve reduction set prices. We will now illustrate this, and the potential deviations from efficiency that may occur in this scarcity region, using the Dutch market as an example.

As demand reaches available capacity, demand response by consumers facing the real time price starts setting the spot price. In particular in the energy intensive industry (steel, aluminium), the per MWh value of electricity is sufficiently low as to make demand-side bidding attractive. Although recent empirical research in the

Netherlands suggests that the real time demand elasticity is very low (this relates to the reduction in *total* load due to spot price increases), still at least some 5 per cent of total system peak load is known to be available as demand response, at prices of several hundreds of Euros per MWh.

In the traditional central monopoly system, the incentives for firms to curtail their demand in periods of scarcity were low, as no real-time prices existed that reflected this scarcity. Since the introduction of a spot market, awareness of the value of demand response among large consumers has grown in the Dutch market. In judging the impact of the current lack of capacity investment and decline of reserve margins on system reliability one has to take into account this buffer capacity that arguably has increased as a consequence of the introduction of spot pricing. Increasing efficiency on the demand side may lead to lower installed capacity levels, without necessarily compromising system reliability.

In the Dutch system (as in other countries), the system operator annually contracts emergency reserves that serve to restore sufficient levels of spinning reserves in case of large contingencies. In those cases, real time prices are allowed to rise above the highest bids for reserve capacity in the system. In theory, when reserves are shed, prices should be related to the value of losing system load multiplied by the probability of this occurring. Obviously, the calculation of such parameters involves a great deal of discretion on the part of the system operator. In practice, the best thing one may wish for is clarity on pricing rules on these occasions.

Placing a larger value on reliable system operation implies increasing the value of lost load. A political desire to increase system reliability will logically entail a larger requirement for system reserves. This is exactly the content of recent policy measures in the Netherlands, which require the system operator to contract a larger amount of reserves. Note that these other considerations, such as reputation effects, may render a higher level of security efficient as well. A critical factor in the design of these reserves requirements will again be the price they will command when dispatched.

Is it Sufficient?

Can one expect these mechanisms to be sufficient? That depends on two factors: how large are fluctuations in peak demand compared to the stock of responsive demand, and which factors may limit investors reaching the optimal capacity level?

> “the larger the system, the lower the effect of random demand or supply shocks”

If demand fluctuates heavily, one cannot avoid occasional failures to meet inelastic demand, and blackouts will be an inevitable component of system balancing. This holds even if available demand response prices are sufficient to remunerate investment in capacity. The interconnected European transmission system plays an important role in suppressing demand fluctuations however: the larger the system, the lower the effect of random demand or supply shocks.

Secondly, do investors invest up to the equilibrium capacity? Two potential impediments may be envisaged. First, generator market power may lead to sub-optimal investment. Whether incumbent generators will be able to succeed in keeping prices above long-run average costs without provoking new entry depends on the existence of entry barriers such as lack of transparency or low liquidity. If entry barriers are minor, the market is contestable and the threat of entry will prevent scarcity rents from rising above the level needed to cover fixed costs. Higher entry barriers will lead to higher scarcity levels, that become manifest in a larger than efficient share of demand response in the balance between supply and demand, and consequently a lower reliability. The second impediment would be uncertainty over future policy affecting prices. This may lead to cycles in investment, decreasing reliability and increasing the required size of responsive demand.

The implications for policy makers point in the direction of regulatory control against consolidation and entry barriers. Furthermore, clarity on all policies affecting prices is likely to lower the risk of business cycles.

Conclusions

Capacity investments have declined in the Northwestern European generation market, but it would be premature to conclude that reliability of supply is at risk. Apart from the fact that many systems have started from a significant level of overcapacity, the emergence of spot markets has increased the importance of demand response as a means to match supply and demand. Reliability of supply may be attained at lower levels of installed capacity in an efficient system.

Efficient investments in new capacity require spot prices in periods of scarcity to reflect the value of demand that is reduced. A prominent role in this respect lies with the system operator: a significant part of demand response comes in the form of system reserves that are reduced in case of system shortage. Clear investment signals require clear rules regarding shortage prices and system operator behaviour under those circumstances, and a careful and transparent monitoring of system security. The level of reserve capacity itself influences the system’s resilience against supply and demand fluctuations.

Inefficient reliance on demand response occurs if investment is too low as a consequence of long-run market power due to entry barriers, or of a perceived uncertainty in investment climate, resulting in cycles in investment behaviour. System reliability can be maintained by monitoring developments and if necessary tuning reserve requirements. From an efficiency point of view it would be wiser to control against entry barriers (e.g. arising from market consolidation) and be clear on policy affecting prices.

Personal Commentary

Philip J. Carroll

(*By sharing my personal experiences, before, during and after the war, I hope to make clearer the realities of America's policies and actions, at least with respect to the Iraqi oil industry. My comments are strictly personal and are not intended to represent an official US statement.*)

In the fall of 2002, I received an unexpected call from the US Department of Defense asking for my help in its efforts to develop contingency plans for various sectors of Iraq's economy in the event that military action did occur. The Iraqi oil industry is, by far, the most important economic sector and would have to be back in operation quickly if the country was to recover from the effects of the fighting and move on to a more hopeful future. The planning effort was carried out by contractors under existing DOD contracts. The effort was intense. A number of scenarios were evaluated ranging from massive destruction of facilities and an uncooperative workforce, to more benign ones where physical damage was light and good relations with the oil workers could be maintained. For each of these potential outcomes, estimates were made of human, material, and financial resources that would be required. The organisational structure of the recovery effort was laid out and the process of identifying the people to do the jobs was begun.

By mid-January, contingency plans in appropriate detail were in place and documented. I bade farewell to my co-workers and returned to my peaceful life in retirement. Shortly after the war began, I received a second and more serious call from Washington. I was asked to take up the position of Senior Advisor to the Iraqi Ministry of Oil, and Director of the Office of Oil Policy in the Coalition Provisional Authority. In this role, I was to provide policy guidance to the Iraqis who would run the Ministry day-to-day and to play a liaison role with the professional governing authorities. Although spending the next six months in Iraq was not high on my list of 'things to do this summer', I quickly agreed to take on the task and began making plans.

The first steps involved pulling together a small team to accomplish the job ahead and to begin deploying it into Baghdad as soon as conditions would permit. I was very fortunate in the quality of the individuals that agreed to serve. Gary Vogler, a former US Army officer and employee of Mobil Corporation, was named as my principal deputy. His service over the next year and a half would prove to be extremely valuable not only to US interests but to those of the Iraqis. Three employees of the US Department of Energy, Clarke Turner, David Callahan, and Gary Holcomb would also play extremely important roles through the first six months. A fifth team member, John Kjar, was seconded to the Office of Oil Policy by the Australian government. This group was deployed to Kuwait in early April and was ready to move into Iraq as soon as possible.

The process of restoring and repairing damaged facilities would be planned and carried out under the supervision of the US Army Corps of Engineers. A special group of both military and civilian employees of the Corps was set up and named Task Force RIO (Restore Iraqi Oil). Under the command of Brigadier General Robert Crear, RIO set up its headquarters at Camp Doha in Kuwait. KBR, a subsidiary of the Halliburton Corporation was selected to be the initial prime contractor in the restoration effort.

The final, and perhaps most important part of establishing the team was to find strong Iraqi leadership. The policy from the start was to ensure that to the maximum extent possible, decision making and control of operations was to be in Iraqi hands. Fortunately, such leadership was immediately evident. A few days after the fall of Baghdad, Thamir al-Ghadhban, an employee of the Ministry under the old regime, acting on his own initiative, presented himself to the commander of the military unit that had occupied the Ministry building and facilities and asked permission to begin reassembling the staff and to establish some degree of control over the operations in the fields and refineries. Although severely hampered by lack of communications capability and limited freedom of movement throughout the country, Thamir al-Ghadhban was able to get the Ministry functioning. After several telephone conferences with him, we decided that he was the man to lead the Ministry during the transition period. He was offered the position of Chief Executive Officer which he accepted. His courage and professionalism were principally responsible for the progress made in the Oil Sector in 2003.

Coalition military planners gave full consideration to protecting and quickly seizing important oil installations. In general, this care produced excellent results. Only seven oil wells were blown up and these were quickly extinguished by the resources of Task Force RIO who entered southern Iraq even while heavy fighting continued further north near Baghdad. Production of crude oil was reestablished from the Rumayla field on 23 April 2003. Although damage to oil facilities was remarkably light as a result of combat, many installations would suffer very serious harm during the period of looting and lawlessness that followed the collapse of the old regime. It was decided that all looting and sabotage damage would be restored by Task Force RIO at American expense. Once Baghdad was under control, Gary Vogler and the team in Kuwait moved there and established working contact with Thamir al-Ghadhban and others at the Ministry of Oil. On 7 May 2003 I and other senior advisors flew from Washington directly to Baghdad.

During my first face-to-face meeting with Mr. Ghadhban on 8 May, we discussed and came to agreement on a general outline of our priorities. There were four objectives in our plan:

1. Provide needed fuels to the Iraqi people.
2. Ramp up crude oil production and exports as quickly as possible.
3. Begin planning for the restructuring of the Ministry of Oil to improve its

efficiency and effectiveness.

4. Begin thinking through Iraq's strategy options for significantly increasing its production capacity.

These priorities were deceptively easy to state, but would each be difficult to accomplish. The first two were of immediate importance. The last two were of a longer-term nature and while a start could be made on them, any decisions would have to await the creation of a new sovereign Iraqi government.

Driving to the Ministry of Oil for that first meeting, I saw for myself terrible evidence of the fuel crisis confronting the Iraqis. Gasoline lines, three cars wide, stretched for over two miles in front of a filling station near the Ministry. People were waiting two and three days in the blazing sun to buy a single tank of fuel. This unhappy scene was repeated across Baghdad and the entire nation. Liquefied petroleum gas (LPG), which the Iraqis use to cook their food was also in serious shortage. Strategic stocks of both fuels had been drawn down to near zero before and during the war. While the country's three major refineries were now operating again, at least part time, it was obvious that they could not meet demand. A massive import programme was organised using the capabilities of the State Oil Marketing Organisation (SOMO) and the contractor KBR. Soon hundreds of tanker trucks were rolling into Iraq every day from Turkey, Jordan and Kuwait, bringing in and distributing fuel. By early June, the gasoline lines in Baghdad were considerably shorter, but the problem of providing adequate fuel supply remains to this day. In the last half of 2003, over 1 million new cars were imported into Iraq, substantially increasing demand. There is a desperate need for a new major refinery and this is a high priority for the Oil Ministry.

The second priority, reestablishing Iraq's place in world markets, had to await the formal lifting of sanctions by the UN Security Council. This was accomplished on 24 May 2003, and actions to begin offering Iraqi crude oil for sale moved ahead. Although severely hampered by a lack of communications and computer capability, SOMO was able to conduct a tender auction during June and by the end of that month Iraqi exports were flowing through the Port of Ceyhan in Turkey and through Mina al-Bakr terminal on the Arabian Gulf. All financial proceeds from these sales would go into the Development Fund for Iraq, to be used solely for reconstruction and humanitarian relief in Iraq. This was strictly adhered to by the Coalition Provisional Authority throughout its civil administration of the country.

The capacity for crude oil production in Iraq before the war was estimated to be 3 million barrels per day when all fields were fully operational. Our projections in May 2003, recognising the damage done by looters and on-going acts of sabotage, were that we could realise about half of that capacity once exports began in July. The programme of repair and restoration was estimated to take 18 months so that full capacity would not be attained until the end of 2004. The actual ramp-up of production has run three or four months ahead of schedule and export revenues going into the Development Fund exceeded \$5 billion in 2003 alone.

It is, however, the successful operation of the nation's oil industry that is the most important factor in ensuring a new and prosperous Iraq. Although many facilities are somewhat dilapidated from years of lack of investment and maintenance, Iraqi engineers and operators have proved ingenious in achieving this goal: the single greatest impediment to their success has been providing adequate security for workers and facilities. Most oil installations came through the war with little damage but many suffered severe harm in the period of lawlessness and looting that immediately followed the collapse of the old regime.

The strategy for providing security to critical oil assets is multifaceted. Coalition forces have played an important role in security at major installations such as the Ministry of Oil headquarters and major refineries but the many other demands on their resources quickly showed that Iraqi security forces would have to be built up and deployed. In the summer of 2003, a contract was competitively bid to recruit, train, arm and equip the Iraqi Oil Police Force. By early this year, a force of 14,000 men had been deployed and increasingly took facilities security responsibilities from Coalition troops. Through early April the number of successful acts of sabotage had fallen sharply and hopes were high that the oil security issue was on its way to being resolved. However, beginning in late April a new concerted offensive was launched and another wave of pipeline attacks washed over the oil industry. As an adjunct to the Oil Police, the Ministry of Oil has entered into a number of contracts with tribal leaders all across Iraq to provide local security to their homelands. These relationships will be increasingly important as they provide more eyes and ears and much improved local intelligence.

Although many challenges lie ahead for Iraq's oil industry, I believe its future is bright. With the handover of sovereignty in July 2004 to Prime Minister Allawi's government and the appointment of Thamir al-Ghadhban as the new Minister of Oil, leadership is in strong hands and planning is moving ahead on the priorities of restructuring and setting the stage of expanding production. The people of the Iraqi oil industry are very professional and competent. And it's good that they are because the whole world will need significantly expanded Iraqi production to meet growing demands.

Asinus Muses

Instinct

If only he knew where to find the fundamentals Asinus reckons he could tell you what the oil price ought to be.

The End of the World?

Climate Change is getting serious. A scientific study claims that golf courses are liable to fungal disease and parched greens. And has the Archbishop of Canterbury some special insight when he warns that the viability of the human species is at risk because of a pending global ecological crisis?

Percentage Power

The average number of heatwaves predicted annually for Paris will, if global warming continues at its present rate, increase by more than 30 per cent by 2099 – from 1.64 to 2.15.

Perspectives

Asinus wonders whether it is of any relevance that the USA has a greater percentage of world coal reserves than Saudi Arabia has of oil reserves.

Limbering up

You have to be fit these days to tender for Projects. Shell advertises for a 'prequalification exercise' for a project in Nigeria. Are gyms provided?

Unfair

The Class Action Fairness Bill was knocked out in the US Senate because of amendments attached to it on curbing greenhouse gases.

A Renewable Solution

Asinus wonders whether, if he had attended the World Renewable Energy Network Conference, he would have left it knowing which energy sources were 'secure, sustainable, accessible and viable'.

Pit Stops

Asinus reads that, if he mixes urea with diesel in his truck, he will be able to meet the pollution emission levels in 2007. But where are the ureanals?

Market Research

If China already has 3000 TV stations and 250 million mobile phone users, how many cars will it have by 2010?

Men or Boys?

It seems these days that the measure of success for an oil company is its ability to repurchase its own shares rather than to invest in its business. If this is the effect of short-termism, is it what we need?

Blind leading the Blind

Asinus reads that the EU will fund research by European Business Schools to improve the understanding and management of Corporate Social Responsibility. He wonders what they've been teaching ever since they invented CSR.

Too many Cooks

Asinus is all in favour of accurate and timely public information on oil supply, consumption and stocks, and is, therefore, encouraged by JODI, the new Joint Oil Data Initiative being set up by IEA, OPEC, APEC, Eurostat, OLADE and UN. He hopes, however, that JODI will not be swamped by a mass of treated and untreated data, and that the six partners in combination will be able to add value to their existing individual efforts to keep us all informed.

Coals of Fire

At last it's happened. Russian coal is being imported to Newcastle, and we must alter our proverbial habits.

Money makes the World go Round

The USA is well on the way to borrowing $2 billion per day to finance its deficit, while trading on the world's foreign exchange markets is moving towards $2000 billion per day. This presumably translates into a healthy climate for bonuses and stock options.

What a Nuisance

A suit has been filed in New York against power companies which demands cuts in their CO_2 emissions under the federal common law of public nuisance. If successful, surely this principle has infinite possibilities. Asinus is ready to help anyone who has problems in identifying such nuisances.

Up to Date

The real price of gasoline in 2004 may be less than it was in 1979, but it's only economists who can readily use money that is 25 years old.

Comparisons

If you include the energy used to make the gasoline, get it to the filling station and then into your car, and do the same with the hydrogen that you need for your fuel-celled car, you will find that the total CO_2 emissions of your dirty petrol-driven car will be 374 grams per mile and of your clean fuel-celled car 436 grams per mile. If you doubt the calculation, please don't ask Asinus to do it for you.

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