ABSTRACT

The Atlantic Basin market has been transformed since 1999 with the start-up of Nigerian LNG and Atlantic LNG. Availability of spare ships (notably before and during the build-up phase of these projects) made increased imports into the US a possibility; robust US prices ensured that they happened. The prospect of increasing demand in the USA, driven by environmental considerations, power generation, and increasing cost of domestic supply has generated moves to open both the Elba Island and Cove Point LNG terminals. In Europe the rapid growth of gas demand to meet power generation needs in Iberia has generated strong markets for LNG, with new terminals being built, and old ones expanded.

LNG in the Atlantic Basin has been fundamentally different from the East in that it is competing with and complementing pipeline supplies. In continental Europe the gas market is gradually liberalising and contract prices remain indexed to oil prices but with liberalisation come opportunities and uncertainty. The US is a fully liberalised market, yet its highly developed futures market permits long-term commitments to supply. The gas price is also set with reference to this market and has been de-linked from oil. The strength and depth of its futures market with associated risk management instruments, is particularly useful for LNG trade, where price volatility during long and costly voyages can inhibit inter-regional trade.

The Atlantic Basin has begun to be seen as a source of innovation, with netback deals, gas producers marketing their own LNG rather than selling through a Joint Venture company, freight swaps, and capacity payments rather than Take or Pay. The scope to hedge has allowed optional sales into the USA, where sales have been secured, but have been diverted to more profitable markets if price moves have been appropriate. In a period during which Far East demand failed to meet expectations, the Atlantic Basin has provided a flexible outlet for cargoes from the East.

RESUME

Le marché du GNL dans le bassin Atlantique s’est transformé en 1999 avec l’apparition du GNL nigérian et Atlantique. La disponibilité de navires supplémentaires (notamment avant et pendant la phase d’élaboration de ces projets) a donné la possibilité aux États-Unis d’augmenter leurs importations ; la robustesse des prix américains a également joué un rôle important. La perspective d’augmentation de la demande aux États-Unis, due à des considérations d’ordre écologique, à la production d’électricité accrue et au coût croissant de l’approvisionnement domestique, a donné lieu à deux
initiatives : l'ouverture de terminaux de GNL à Elba Island et à Cove Point. En Europe, la croissance rapide de la demande en gaz pour répondre aux besoins de production d'électricité dans la péninsule Ibérique a créé des marchés forts pour le GNL, avec la construction de nouveaux terminaux et l'agrandissement de terminaux existants.

Le GNL dans le bassin Atlantique est fondamentalement différent de celui de l'Orient parce qu'il concurrence et s'ajoute à l'approvisionnement par gazoduc. En Europe continentale, le marché du gaz est progressivement en train de se libéraliser et les prix du marché restent indexés sur les prix du pétrole. Mais avec la libéralisation viennent non seulement des opportunités mais aussi une incertitude. Les États-Unis représentent un marché totalement libre, cependant, leur marché à terme extrêmement développé permet des engagements d'approvisionnement à long terme. Le prix du gaz est également fixé par rapport à ce marché et a été séparé de celui du pétrole. La force et la richesse de leur marché à terme avec leurs instruments de gestion des risques associés, s'avèrent particulièrement utiles pour le commerce du GNL, surtout lorsque la volatilité des prix pendant de longs et coûteux voyages peut empêcher le commerce interrégional.

Le bassin Atlantique a commencé à être une source d'innovation, avec des opérations netback, des producteurs de gaz commercialisant leur propre GNL plutôt que de faire appel à une société en participation pour le vendre, des échanges de fret, et des paiements suivant la capacité plutôt que des engagements "Take or Pay". L'étendue de l'opération de couverture a permis des ventes optionnelles aux États-Unis, lorsque celles-ci étaient garanties, mais elles ont été orientées vers des marchés plus rentables lorsque que les fluctuations de prix l'exigeaient. A un moment où la demande en Extrême-Orient ne répondait pas aux attentes, le bassin Atlantique a été un débouché souple pour les chargements provenant de l'Orient.
INTRODUCTION

There have been some substantial changes in the LNG world since LNG12 in 1998. Despite the bold project stands in the Perth exhibition hall we were staring into an abyss, with an economic crisis of uncertain duration ahead, and low prices, which reminded us again that LNG plants are large capital investments exposed to energy, mostly oil prices. The change in the LNG shipping market has been at least as large, moving from one in which ships were laid up to a market that is short of shipping.

However, perhaps the biggest change has been the transformation of the Atlantic Basin market, where two new LNG projects have started up, both subsequently selling expansions rapidly, and Henry Hub, the marker for US gas prices, which had been stuck around $2/mmBtu for years, has since been above $3 for 7 months, peaking at the time of writing (December 2000) at over $9. US terminals, which had been shut for 20 years are opening and all four terminals have changed hands.

It’s not just the US market which has transformed; LNG has entered the Caribbean market and there has been solid progress on import schemes in South America, while there have been substantial changes both to the facilities and market players in Europe.

This has all encouraged aggressive new supply projects to enter the market, competing with further expansions and refurbished facilities of existing suppliers. We should not forget that the market has also encouraged pipeline projects, several of which are looking much more likely to be developed than in 1998. It looks like there is a shortage of supply for the next few years until these expansions come on line, but the obvious concern is whether the market will thereafter rapidly flip into oversupply.

Scanning the LNG12 agenda one sees no mention of the USA in paper titles, and precious little of the Atlantic Basin. Yet the seeds were there. Representatives of the US terminals were in Perth meeting potential customers and assessing the scope to reopen, though meeting some scepticism. A Houston press report around that time said “the U.S. market for imported LNG went the way of bell-bottom pants and lava lamps”. Well in 1999 one of my daughters was wearing bell-bottom pants and the other had a lava lamp. Fortunately they’ve gone out of fashion again; I hope the same doesn’t happen to US LNG.

Yet the Atlantic Basin was where LNG started, first for storage, and later for international trade from Algeria to the UK. Algeria was for years the world’s biggest LNG producer and is still number two, and unique in offering both pipeline & LNG exports. The Algeria to US trade was however where LNG came to a fairly grinding halt, and subsequently suffered at least one false start, & that has made players wary of speculative investment in the market and particularly ships to serve it. It’s interesting that it was the US market which failed LNG, and it’s now arguably the US market which has the greatest potential for growth in the medium term, and for making significant changes in the market for the long term. If nothing else, US gas prices perhaps offer an opportunity to diversify some of the oil price risk, (depending on your view of whether they will be truly de-linked from oil prices in the future).
In this paper I’ll first identify some of the more obvious differences between the Atlantic Basin and Asia Pacific markets, before focusing on demand, supply and pricing in the Atlantic Basin (and in this I’ll include the Mediterranean). I’ll then talk about the changes in the market participants, before moving on to the way these characteristics interact to offer opportunities for new ways of marketing LNG, as well as optimising the way it works to deliver gas to customers.

**COMPARISON OF ATLANTIC BASIN AND ASIA PACIFIC MARKETS**

LNG in the Atlantic Basin is currently targeted on two separate, but very large, pipeline markets. As such it has had to compete with the pricing of pipeline gas in those markets. In the US this is a price which has until recently been dominated by a surplus of supply. In Europe it is related to oil products, reflecting that gas has had to compete with these products in its main markets, which have been predominantly industrial and commercial, with until recent years only peak loading power generation.

In the Far East LNG has opened up new markets for gas, and power generation has been a significant part of the demand from the start, so that LNG has had to compete with crude oil, and hence its price has been linked to crude. However, producers of LNG have sought a fixed element in the pricing in order, when prices are low, to have some cover for the high capital costs, and have in return forgone some of the upside when competing oil prices are high.

Thus the pricing in the West and the East is fundamentally the same, based on needing to compete with the consumers’ alternatives. However, in other respects there are considerable differences between the markets.

The first is in the extent of liberalisation in the markets. In the Atlantic Basin we have the full spectrum. We have large markets in the US and the UK which are nearly completely liberalised for both gas and power. We have countries in Europe that are beginning to respond aggressively to the EU Gas Directive, though there are some which are dragging their heels, and some which haven’t started. There is a similar range of development in Central and South America. In Contrast, all the Asia Pacific markets are at best just starting the journey to market liberalisation.

The Atlantic also has a wider range of existing and potential markets, which are more widely dispersed through the region. Currently seven European countries import LNG directly or indirectly, plus the US (including Puerto Rico), with several other countries considering imports. (It is interesting that, though one would have thought that LNG’s advantage is in being able to reach markets that are not supplied by pipeline, this has only recently been successfully achieved in Puerto Rico; all other supply has supplemented pipeline gas). In the East there are only three countries importing now, with two more seriously considering importing. While there are many terminals (mostly in Japan), they are not open to third parties, whereas an increasing number of Western terminals are becoming open. This is a function of the buyers in the East being utilities which effectively have monopolies in their markets, whereas in the West there are an increasing number and type of players buying LNG.

The flexibility inherent in the pipeline markets of the West, and the comparatively high summer demand for air conditioning, means that they can acquire additional volumes of LNG at any time of the year. We have seen Lake Charles terminal in the US at full capacity in June, whereas the East is characterised by the Korean seasonality of
demand, which has seen them send cargoes West in summer, while seeking extra cargoes in winter. There has been a lot of talk at LNG conferences about the need for flexibility from suppliers, particularly in the East. In the West there is considerable flexibility already, but most of it is provided by the markets.

While the Atlantic currently has fewer supply points than the East, they are more widely dispersed. There are existing and potential supply points on both sides of the Atlantic, so that LNG can in principle flow in several directions, whereas in the East the demand is generally to the East of the suppliers. The striking difference is that, by 2002, there will be a deficit of supply capacity in the Atlantic Basin, which will persist until new projects come on line after 2005, whereas in the East there is spare capacity in existing projects while sales build to contract levels, and a perception of many potential projects in the future.

Where there is surprisingly little difference between the Regions is in the potential demand growth. In fact, the potential in the Atlantic Basin is larger if LNG can take over from failing domestic supplies, but also more uncertain; being at the margin of a large market can lead to a wide range of possible demand. The risks were evident in the early 1980’s when deregulation of the US domestic market released supplies which shut off the nascent LNG imports at the time. Shell experienced these risks in 1990 when seeking to rejuvenate LNG imports via Cove Point, and two ships we acquired for this trade were left without employment.

Having outlined the differences between the East and West I’ll now explore these features of the Atlantic Basin markets in more detail, starting with demand and supply.

DEMAND

Forecasting demand for LNG in the Atlantic Basin is difficult because it depends first on the demand for gas, and then on the part of that demand that LNG can win. With that proviso, the demand is expected to exceed (8.4) % p.a over the next ten years rising from 33 mtpa to 74 mtpa. The factors driving this growth are an expectation of continued strong economic growth in the key markets of Southern Europe and the East Coast of the United States assisted by an opening of new markets in the Caribbean and Central and South America. Economic growth needs energy and natural gas will be the fuel of choice, meeting the targets of environmental conscious regulators and the needs of power pools and IPP’s. By the end of 2000 over 300 new power plants had been announced in the USA, of which over 90% are intended to be gas fired. The growth in electricity demand will drive gas demand and with it the import of LNG.

In both the Far East and Atlantic Basin markets the environmental issues arising from the international Greenhouse Gas Agreements have been recognised as encouraging gas consumption. In both markets it can be seen that “gas is good” through reduced CO2 emissions relative to coal fired plant. However during the 1999/2000 period of high oil prices there has been concern that, despite good life cycle economics for CCGT’s, emerging and growth markets (Korea, China, India) are not signatories to the agreements, and high fuel prices may encourage commitments to new coal fired plant. At the time of writing gas has held its own, with LNG import projects planned in China and India. However, despite similar increases in gas prices in the US and Europe, few coal fired plants are planned or have sought approval While in the Far East LNG has to fight its corner in the consumer choice between fuels, in the Atlantic Basin it is more gas on gas
competition that drives LNG. (However, the extreme gas prices in the US at the time of writing give cause for concern that gas may yet be priced out of some markets).

LNG has not been the only beneficiary of this increase in Atlantic Basin gas demand. Pipeline proposals and increased exploration activity also work towards satisfying this market need with new proposals and improved versions of old favourites in the US and European markets. Algeria is currently proposing new pipeline connections to Europe and new routes into Turkey will tend to cap potential LNG demand. Of the total increase in gas demand in the Atlantic Basin by 2010, LNG is expected only to capture around 20%.

Deregulation of the power and gas markets in Europe has led to an increasing convergence of the two markets. An important factor for demand in the Atlantic Basin will be progress of regulatory reform in European gas and power markets and the influence of large national champions. This will be felt particularly in the Southern European markets of Spain and Portugal, Italy, Greece and Turkey. It is worth asking whether the Mediterranean is really part of the Atlantic Basin or on its own? At the moment, serviced by Atlantic LNG and NLNG in addition to the more local Algerian supplies, the Mediterranean markets compete with the US for supply, but what will the implications of an Egyptian LNG project be? Will this effectively divert the non-Mediterranean supplies to the US, and indeed, will Egypt look to the US for markets too?

TERMINALS

The critical points for LNG access to markets are LNG shipping and terminals. As I mentioned earlier, both have had a fragile relationship with the US, which disappointed early investors in shipping and terminal capacity.

At the time of writing the Cove Point and Elba Island LNG terminals in the USA were preparing for reactivation, and the existing terminals in Spain were being expanded, while new LNG terminals in Europe were planned or under construction in Spain, Portugal, Italy and Turkey. The first terminal in the Caribbean has opened, with others planned, and Petrobras, in partnership with Shell, is making significant progress in developing the first LNG import terminal in South America at Suape.

In the US, open access regimes drawn from pipeline experience govern the release of capacity in new or reactivated LNG terminals, and tend to cap the returns to investors in the infrastructure. The rules in European markets are less clear.

What is clear is that in all markets, if demand is as forecast, new or expanded LNG terminal capacity will be required and, in a deregulated environment, this will require private investment and risk. Environmental and permitting controls may prevent new capacity emerging in the US and yet, judging from recent open seasons, all existing capacity could be sold. One wonders whether and how the US regulators will encourage investment in new terminals and what lessons from US experience arise for the European markets? The US market offers many lessons, both positive and negative, for pipeline regulation – the recent experience of regulation of LNG terminals is similarly mixed.

As a participant in two existing LNG terminals, and several proposed ones, in LNG shipping, downstream marketing and LNG exports, Shell is keen to see new and refurbished terminals in the Atlantic Basin brought to market quickly. With a supportive regulatory environment this should be possible without compromising existing industry standards, levels of safety and environmental performance.
SUPPLY

All this excitement in the Atlantic Basin has not gone unnoticed and, as a consequence, there has been a strengthened interest in new and existing supply projects. In particular, Algeria has overhauled and debottlenecked its plants, NLNG is following on from the success of its first three trains with an expansion project for two trains in 2005/6, and Atlantic LNG is working on further expansion. There are also two new projects in Venezuela, several different proposals for Egypt, progress on the Norwegian Snohvit project, and marketing efforts for Angola.

This outlook for Atlantic Basin supply would not have been recognised even 5 years ago, and for those involved in the origins of Nigeria LNG, this outbreak of proposed projects and the progress in the market must appear an unseemly rush.

If one were to contrast the success of the initial two train NLNG project with those that have come since, including Atlantic LNG (which started up around the same time but was agreed later), NLNG’s early history was a long, slow courtship. It was originally focused on the USA, a market killed at that time by a domestic production response, particularly from the Gulf Of Mexico and Canada. Thereafter NLNG successfully pointed at Europe and, via a conventional pricing approach and providing buyers with a diversification of energy sources, were able to build a solid base of customers for a committed project. NLNG also benefited from a very successful foray into speculative ship acquisition before the project was finalised, which made up for Shell’s earlier play. Despite the long gestation period, the base 2-train project is an outstanding success and has been producing at levels beyond design capacity on a sustainable basis in its first year of operation. This allowed 5 spot cargoes to be sold into the USA and led NLNG to order a 10th ship from Hyundai in addition to the 8th and 9th under construction for the 3rd train.

Atlantic LNG benefited from the changes wrought in the US market from deregulation and the introduction of futures markets, which gave the confidence for a buyer to provide an anchor market. It also used some of the features of the Atlantic market that have evolved over recent years which can make marketing different, and in many ways easier. I shall return to this later.

Two new projects stand out at the time of writing. The first is NLNG’s expansion on the back of success with trains 1 to 3, where NLNG is now seeking to diversify its risk portfolio with a US market position. Their marketing, and the market response, has given them confidence that the award of the project specification contract early in Q1 2001 will, by year end, lead to a final investment decision for 2 large trains and 8 ships.

The second is the progress seen in Venezuela where Shell has seen the potential for LNG for many years and now sees a Government and JV push for the project, complementing a market pull from the US that suggests a strong probability of success for VLNG. Both Nigeria and Venezuela are major resource holders in the region with sufficient reserves to support further expansions, not just for the US market, but also to create new markets in the Caribbean, Central America and Brazil.

PRICING

As I have said, pricing in Europe is similar to that in the Far East, in being linked to oil prices. North America is different in having a gas market which has been dominated by surplus supply and so stayed stubbornly low (leading to many comparison charts from...
envious Eastern LNG buyers!). Gas prices have thus shown little correlation to oil prices, until recently, when both have risen sharply, though mostly independently, since there is only a small part of the US market in which gas and oil compete. It seems that the low oil prices of 1998 led to closing marginal oil wells in the USA, resulting in the loss of associated gas production, and exacerbating the problem that was building because of low drilling rates for gas. This, along with strong demand growth has led to prices rising to levels up to four times the average of the 90’s, and nearly double the levels being paid in the East. It’s thus arguable that a fall in crude prices contributed (with a lag) to a rise in gas prices. However, few people seem to think that there will be much correlation, either positive or negative, between gas and oil prices, even though both are affected by economic growth and weather.

How important has this been to the renewed interest in LNG in the US? Certainly the high prices have contributed to the high level of imports, but interest in importing terminals was there when prices were little above $2, and was based on a longer term perception of rising demand and prices. There is some risk that a strong domestic production response (with lower cost methods mitigating the effects of the increasingly difficult production environments), will recreate a supply surplus, and lower the expectations of future prices. If this were to happen it could act like a switch, once again turning off this whole new sector of LNG activity. However, I believe this is unlikely, particularly in the current decade.

What makes US gas pricing particularly interesting is the transparency and ubiquity of Henry Hub as a pricing marker, and that it is traded in such a deeply liquid futures market. This allows buyers and sellers to agree to link a price to Henry Hub and then each separately adjust their pricing exposure using the futures, or associated derivatives markets.

It has been suggested that Henry Hub could be used as an index for European gas prices, but it would be a bold European who would willingly expose his business to the high price levels we are seeing now, deriving from a deficit of US supply, when there is no shortage in Europe. It is not for nothing that Brent is used as the marker for European (and other) crude prices, rather than be influenced by the local peculiarities of the WTI market. This is so even in a market where it is much easier for arbitrage to link and moderate the markets than for LNG, given that the freight required is about eight times cheaper than for LNG.

Taking this a stage further, is US-style pricing likely to spread to the East? I was trading crude in 1986, when the WTI and Brent markets were firmly established, and it was a widely held view that futures would rapidly spread to the East. Yet I understand from my old colleagues that the Asian crude market is basically unchanged even now. Thus it is not obvious that the Far East LNG market will change. After all, it is already priced on a spot basis, via a basket of crudes, all influenced by spot prices, and hence influencing the price of the oil products which compete with LNG. It would therefore be possible to offer risk management of the price too, though it would need to be based on over the counter swaps, and Shell might be prepared to consider providing these, though I doubt there is really an appetite for them in the market.

MARKET PARTICIPANTS

The number, and range of types of market participants in the Atlantic Basin is growing rapidly. On the supply side, which so recently was limited to the Government

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company Sonatrach marketing all Algerian LNG, we now have Nigerian LNG where marketing is conducted by the Joint Venture on behalf of the equity owners, and Atlantic LNG where the equity owners of the gas market their own LNG.

On the demand side in Europe, the monopoly utilities which have controlled LNG terminal capacity are slowly opening access to new players, and Shell has taken the opportunity to establish a gas marketing business in Spain. Others are building new terminals, which don’t involve the existing terminal owners. Meanwhile Tractebel has become the first player to own terminals on both sides of the Atlantic, and El Paso has capacity in two US terminals. Shell and BP have also secured US terminal capacity, and Enron and AES are both involved in terminals linked to power plants in the Caribbean.

The traditional downstream players are not meekly conceding ground. Apart from moving into each others’ markets they are also moving upstream and abroad. Repsol has acquired ships, a share of Atlantic LNG and a share of BP’s gas reserves in Trinidad, and Gaz de France is apparently seeking to expand its shipping activity, as well as acquiring upstream reserves and a share in the Snohvit project. BG of course moved upstream long ago, split up, and now its downstream offspring, Centrica, is moving abroad. Finally, Union Fenosa is seeking to leap straight from power producer into building the complete LNG chain from well in Egypt to power plant in Spain. These are just a few of many examples.

The upstream players are also seeking to move downstream. I have mentioned that Shell is active in Spain, but we are also setting up downstream activities in several other markets, including Brazil and Greece, complementing our long-established oil marketing businesses, and extending to retail sales. Others too are moving closer to the end consumer; Sonatrach is involved in a new terminal planned for El Ferrol in Spain, and BP’s move downstream from Trinidad to power generation in Spain has complemented Repsol’s move upstream.

Of course I must mention the spread of ownership of ships, where buyers are increasingly seeking to control the ships that deliver their LNG, and perhaps no longer purely linked to specific trade routes, but available for trading, which we will discuss next.

OPTIMISATION & TRADING

There has been much talk of spot LNG, but precious little of it. All players have sought maximum utilisation for their expensive assets, and spot trading is not necessarily the way to achieve this. Spot trading in oil came about because of the phenomenal surplus of shipping capacity after the 1973 oil crisis, the decline in demand for oil in the subsequent years, and the potential for tax optimisation. In LNG, when there were surplus ships they were laid up. The recent flurry of spot trading activity has been brought about by these ships being reactivated and traded relatively cheaply before joining NLNG, and using the considerable spare capacity in Lake Charles, an originally expensive, but now heavily depreciated asset.

Nevertheless, if prices in the US and European gas markets remain independent, there will be scope for large differences in price; large enough to meet the cost of LNG shipping and encourage Transatlantic movements – LNG from Europe to the US or vice versa, as long as there is spare capacity in ships and terminals.
This will be greatly helped by the ability to lock in price differentials via hedges on the Henry Hub futures market, which has enabled cargoes from Australia to undertake the 30 day voyage to the US with locked in economics. Such arbitrage possibilities would be enhanced if a similar European gas futures market were established.

However, this is not to say that there is no scope now for optimisation. A considerable amount of the scope has been utilised already. Cargoes from Trinidad, which were originally destined for Spain, are being diverted to the US, while the Spanish demand is met by pipeline or other LNG supplies. Such trades can greatly reduce the shipping cost of what might start as a sale from the Middle East to the USA. Scope for such optimisation comes from the wide distribution of supply and market points around the Atlantic Basin and the possibility of laden LNG ships passing each other going in the opposite direction, of which we have heard much.

In the Far East, where we hear of the same phenomenon, it is difficult to think where it occurs. There has indeed been much discussion of the inefficiency of LNG shipping, yet it’s not obvious to me that it is not about as efficient as it can be. Again, remembering my crude oil trading days, we were always theorising about back haul opportunities for crude, a market where there is a much greater diversity of demand and supply points. Yet we very rarely achieved them, and the ‘taxi rank’ of VLCC’s in the Arabian Gulf demonstrates that the time that crude carriers spend laden is much less than 50%, whereas dedicated LNG fleets get very close to that number. In the Asia Pacific nearly all of the LNG is going from the West to the East in comparatively large fleets where only one of the ships is less than fully employed. This is not to deny the scope to optimise via cooperation between the fleets, essentially to reduce the number of marginal ships, but I suspect that this is limited. Paradoxically, the trend in the East is towards buyers owning ships and hence smaller fleets, which will make it more difficult, even with cooperation, to ensure that they are fully employed, and I suspect that shipping efficiency is going to fall.

TRANSFORMING MARKETING

So, having set the scene, how is the Atlantic Basin market transforming marketing of LNG? There is no single factor or change, but a wide variety of factors which can change the approach, and many of these are associated with the US, but can be used to provide flexibility elsewhere. They are both short and long term (though there is a preference for long-term deals, optimising asset efficiency, as well as enhancing security).

The existence of the two large pipeline markets with their associated storage gives an ability rapidly to absorb LNG by displacing pipeline gas. A train of LNG is 8% of the Japanese market, but a much higher proportion of the market in the locations to which it is delivered, which are poorly connected to other demand centres, if at all. The train is only 1% of the US market, which is almost entirely interlinked. A 5% quantity tolerance on pipeline supplies goes a long way to absorbing the LNG. The very scale means that LNG is marginal and it can steal some of the market growth.

A critical point, which has helped reduce costs of supply projects, is that reliability of LNG supply isn’t so important where there is an established pipeline and storage backup. As mentioned earlier, the buyer can acquire flexibility via the domestic storage and swing markets, almost certainly more cheaply than it can be provided by leaving expensive LNG assets idle. Hence the buyer can offer flexibility to the supplier, or use it himself, as appears to have been the case in several deals, one of which was a term deal between
Oman LNG and Shell’s US affiliate where an outlet in the US was first secured, but all but the first two cargoes were subsequently diverted to a closer market, allowing Oman LNG to place more cargoes with the available shipping capacity.

This can be taken further by using the US market as an anchor market for starting new LNG projects, and then using the flexibility of the market to divert some of the LNG to start small markets, which could not provide sufficient demand for an LNG project on its own. This was done by Cabot, who provided an anchor for the Trinidad project, and then diverted some of the LNG to Puerto Rico. An extension of this approach is to use the ability to divert supplies as an insurance when selling to an outlet before you have resolved the ultimate source of supply. In this way new markets can be opened where there is no pipeline gas.

Where there is adequate pipeline backup at a European terminal, the same approach can be adopted; this is not something that relies on a futures market. Indeed, Spain provided the other anchor market for train 1 of Trinidad, and for much of trains 2 and 3. However, it’s unlikely that much of this LNG will ultimately go to Spain. As the US terminals open it is likely to be diverted to them, and replaced in Spain by LNG from other sources.

A problem with market liberalisation in the East is the uncertainty over who you will be selling to. In the US, liberalisation has gone past this period of uncertainty, and the end consumer need not be identified. The LNG buyer can sell the gas on the futures market, with no credit concerns, though the LNG supplier will still want to be assured that the buyer has the credit capacity to handle these and his other transactions.

If LNG sales are linked to a liquid futures market then this makes it easier for the financing banks both to measure and manage their risk, and hence makes financing easier. There may also be scope to enhance a project’s value by selling gas forward in the early years, locking in prices in the crucial part of the cash flow. The futures market and associated derivatives also make it easier to meet buyer aspirations for different pricing structures or, as mentioned earlier, he can simply create them himself.

The US is also where the logic of gas for power generation really powers through. In the Far East the proportion of gas-fired capacity is often an issue of policy – in the US it’s straight economics. For independent power producers gas not only provides capital and environmental advantages, but also hedgeable and hence readily financeable supply.

This flexibility can be important in developing associated gas, which forms a major part of the gas reserves in the Region. The Nigerian LNG project has greatly reduced the flaring of associated gas, and has done so without needing to compromise reliability of supply of LNG, but there are many other associated gas sources where conventional LNG schemes are not appropriate, or where gas supply is likely to be interrupted. For example, Shell is developing a floating installation to produce LNG and oil from offshore fields. Unlike Shell’s Floating LNG technology, which is designed to be as reliable as conventional LNG plants and hence suited to any market, the associated gas version is likely to suffer interruption to supply. The Atlantic Basin will probably be the preferred market for developing such schemes, given the flexibility that the market can provide.

Finally, there are many ways in which gas marketing in general has been transformed, with many new types of innovative customer offering being developed at both the industrial and retail levels, and with e-commerce increasingly playing a role. Much of this
has had its origins in futures markets, and competition between deregulated entities, and so these developments are more advanced in the Atlantic Basin than in the East. However, these apply to both pipeline gas and LNG, and are probably best covered in detail elsewhere. Nevertheless, they all enhance the fundamental advantages of the fuel itself and, as such, act to promote growth in its use.

CONCLUSIONS

I will now summarise and attempt to draw some conclusions. I have argued that the Atlantic Basin LNG market is substantially different from that in the Asia Pacific, and likely to remain so to a significant extent. Many of the differences derive from selling into markets that are dominated by domestic or imported supplies carried by pipeline, but the sheer size of the US market, its advanced state of liberalisation, and its liquid futures market are also important factors. The Atlantic Basin offers demand growth in the medium term that is more uncertain, but could be larger, than that in the East. It is a more flexible environment, where the market can assist development of LNG supply projects and new markets by offering some of this flexibility. The dispersion of demand and supply points also provides a more interesting environment for arbitrage and freight optimisation. As such I believe it has already transformed the marketing of LNG, and has scope to continue to do so. In my view what has been achieved and learned in the Atlantic Basin has only limited application in the East, but perhaps that is a subject we can debate.