# THE LNG REVOLUTION

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# The LNG Revolution

*This paper discusses the influence that the world-wide liberalization of the natural gas industry is likely to have on the future development of liquefied natural gas (LNG). The paper examines some of the barriers to the workably competitive commodity model for this complex cross-border trade and speculates about the likely future structure of the industry.*

> *Dialectic - The Hegelian process of change whereby an ... entity (thesis) is transformed into its opposite (antithesis), ... the combination ... resolved in a higher form... (synthesis)*
> *The American Heritage Dictionary*

Marx and Engels borrowed from Hegel's dialectics to describe revolution as a process in which the inevitable overthrow of capitalism would first be replaced by its antithesis - the dictatorship of the proletariat - to be ultimately followed by a synthesis - the withering away of the state and the formation of the classless society. The fact that no nation has yet demonstrated a viable third stage of the revolutionary process may simply indicate how difficult it is to predict the outcome of "synthesis".

But Hegel's view of the process of change provides a useful perspective from which to view the dramatic upsurge in interest in international trade in liquefied natural gas (LNG). For a segment of the energy industry that for a time seemed only of interest to the Asia-Pacific region, LNG is now undergoing its own revolution in the Atlantic Basin, the Mediterranean and the Middle East, as well.

A number of factors have combined to stimulate the new interest in LNG. The favorable economics of gas-fired combined cycle electricity generation has made gas the fuel of choice for power generation. There has been a substantial reduction in LNG costs making previously uneconomic trades appear attractive. Companies that once ignored gas discoveries are now concerned with monetizing stranded assets. And both Europe and the U. S. have become interested in finding supplements for traditional pipeline supply. But, arguably the real force for revolution in LNG has been the worldwide restructuring of the gas and electric industries. The clash between the highly-structured, traditional approach to long-term LNG contracting and the theoretical model of international gas and electricity as workably competitive commodity markets is the focus of the LNG revolution. How it will finally be resolved is at this point far from clear.

## The Traditional LNG Project

The traditional LNG project has been described as a "chain" whose ultimate success is at risk to the possible failure of its weakest link. There are effectively four (occasionally five) links to the chain - field development, in some cases a pipeline to the coast, the liquefaction facility, tanker transportation and the receipt/regasification terminal. Each element is capital-intensive and the investment is usually front-end loaded so that revenue does not begin to flow until the project is complete. Hence breakdowns and delays in any part of the chain have adversely affected capital recovery and project internal rate of return (IRR). Since LNG projects are usually international ventures, parts of the chain are subject to different laws and regulations - production and liquefaction subject to the fiscal and legal system of the producing country, regasification to consuming country regulations, and tankers operating in a kind of international no-man's-land. The fact that differing regulatory systems impact the success of the project introduces an element of political risk into the process.

Figure 1 illustrates a representative balance of the capital expenditures for several selected LNG trades. In the examples shown, the portion of the CAPEX budget in the receiving country is small - ranging from 9% to 13%. In contrast, the portion of the CAPEX budget that is spent in the producing country ranges from 51% to 70%, indicating the critical importance of the host country negotiations in the development of a project. Tanker expenditures vary with distance, the long haul Qatar/U.S. East Coast run having the highest percentage at 41% of the CAPEX budget.

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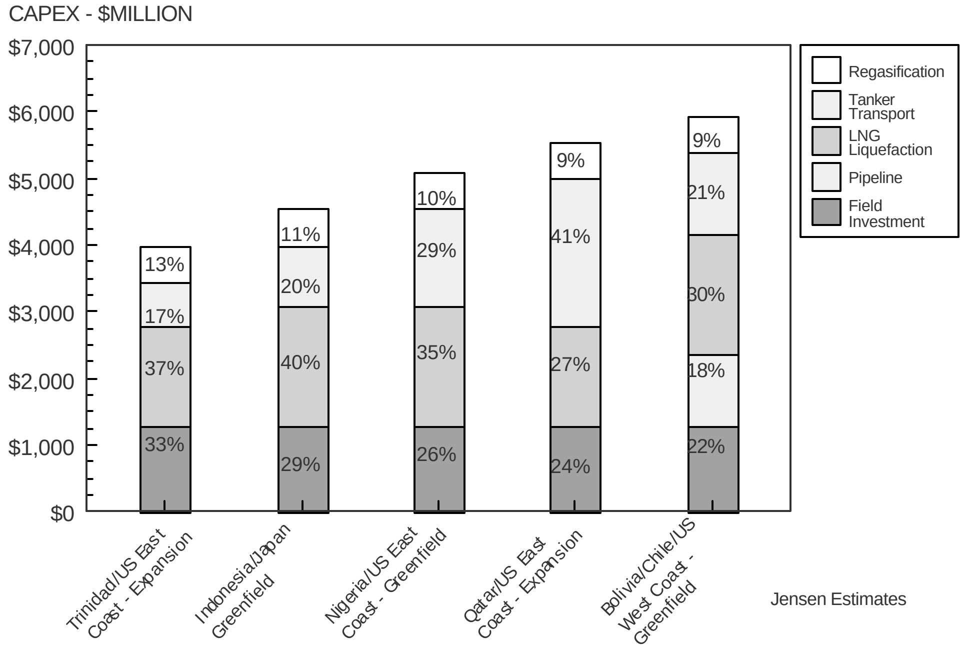
Figure 1

ILLUSTRATIVE CAPITAL EXPENDITURE PROFILES FOR SELECTED LNG PROJECTS

ASSUMING TWO 3.3 MMT TRAINS AND A FIELD INVESTMENT OF $3.85/ANNUAL MMBTU



The old way of doing business, now under attack, featured an elaborate system of risk sharing among the participants. Central to the project was the Sale and Purchase Agreement (SPA), the contract between buyer and seller for LNG. The point of delivery might be either f.o.b or ex ship, depending on which party assumed the tanker transportation responsibility, but in either case the operation of the receipt and regasification terminal was downstream of the point of delivery and thus outside the scope of the contract. Tankers might be owned by either buyer, seller or independent shipowners, but traditionally were dedicated to the specific trade, usually for the life of the contract.

Early contracts were typically for 20 years duration, although longer contracts were common. The risk sharing logic of the contract was embodied in the phrase ..."the buyer takes the volume risk and the seller takes the price risk". Hence most contracts featured take-or-pay provisions to assure buyer offtake at some minimum level and a price escalation clause to transfer responsibility for energy price fluctuations to the seller. The early contracts viewed oil, not gas, as the competitive target and thus "price risk" in the escalation clauses was largely defined in oil terms, a pattern that persists to this day.

The contractual terms binding creditworthy buyers and sellers enabled these LNG projects to obtain favorable financing, giving them a debt-equity ratio and cost of capital more nearly resembling utility financing than that of corporate equity investments. In the original pattern of LNG project development, nearly all buyers were either government monopoly or franchised utility companies from OECD countries, and thus buyer creditworthiness was usually not an issue.

Under the old ground rules, the purchasing utilities or government monopoly companies were effectively able to lay off some of the market risk to their end use customers. Once a contract was approved by the regulators or government overseers, the price and volume terms became part of the regulated resale rate structure and end users picked up the tab.

Both field development and liquefaction investments in the producing country have commonly been based on significant gas discoveries. Hence companies holding the relevant exploration licences have initiated most of the projects. The discoveries have been dedicated to the contract to insure a reliable supply for the project. Since the goal has been to provide full deliverability over the life of the contract, the deliverability "break" when production rates can no longer be sustained at contract delivery levels is important. For a twenty year contract, for example, it might take as much as twenty-eight years of reserve support to provide such a supply guarantee. A twenty-eight year RP ratio represents a conservative rate of field depletion with obviously adverse economic consequences for field economics. More flexible access to additional reserves near the liquefaction facility might well enable the project to utilize higher depletion rates.

The project developers have usually been joint ventures of several companies in the interests of spreading exploration risks. Their interests have been bound together in a "shareholders agreement" or a "joint venture agreement", depending on the nature of the license, with one of the group appointed as the operator. The effect of this structure is that companies have operated as if they were shareholders in a corporation, rather than as independent and competitive corporate entities. Thus marketing has usually been done by the venture rather than by the individual partners, a system which has reduced the number of competing marketers[1]. Competition exists but it has been between projects rather than among the individual participants in the venture.

While share ownership in both field development and the liquefaction facility may be the same, they often differ. In many license areas, particularly those using production sharing agreements, the national oil company (NOC) holds different interests in field development and in liquefaction even if the companies maintain their relative shares of the private sector portion. In Algeria, Sonatrach has until recently held the government monopoly for both exploration and for LNG liquefaction, and thus was responsible for both functions. In Indonesia, Pertamina had monopoly rights to the liquefaction facility, thus assuming responsibility for liquefaction and marketing on behalf of the producing partners.

[1] The Triundad project was the first to break this "venture marketing" pattern with much more flexible marketing agreements among partners

In most of the projects destined for the Japanese market, it has been common to offer a share of the upstream investment to the Japanese trading houses. In those cases where there are varying interests between production and liquefaction, some form of transfer pricing agreement is required to allocate revenues among the parties.

Throughout much of the producing world, tax regimes have been devised to capture a substantial part of the economic rent for the host government, and since oil has usually been the primary target, most tax regimes are focussed on oil terms. In some countries there is a single petroleum fiscal system that applies throughout the country, but many governments will vary their tax regimes to promote special exploration and development opportunities. Since oil-focussed tax terms commonly overtax gas[2], modifications to the government's tax code are often part of host country negotiations in LNG projects. In the case of those countries with production sharing contracts, the NOC's share of the venture may differ from what it would expect if oil production were the target. These variations in tax regime, particularly where the NOC is both an operating company and a part of the tax collection system, complicate liberalization of the traditional LNG project.

**The Antithesis - Open, Competitive Markets**

The theoretical model for the restructuring of the gas - and electric power - industries represents the antithesis of this highly-structured, risk-averse form of industrial organization. The restructuring process - first begun in the U.S., Canada and the U.K. - is predicated on the assumption that the traditional form of government monopoly or regulated public utility operation of electricity and gas is inefficient and that a system that introduces market competition inherently provides lower prices and more desirable service options for consumers. It envisions free market competition among buyers and sellers to set commodity prices for gas - "gas-to-gas competition". But since the supply of gas is usually geographically removed from its ultimate consumption, the model also envisions a competitive market for transportation capacity in a system that is subject to open - or third-party - access. For LNG, the model thus sees the "LNG chain" reconstructed efficiently through independent competitive offerings of each of the relevant links which are free to operate independently of one another. And since many market decisions involve time lags between buyers' and sellers' revenue objectives with volatile price behavior in the meantime, it also envisions a system of "risk management" through the use of various types of financial derivatives - futures contracts, options and swaps.
The advantages to this new antithetical model for LNG trade are significant. It is increasingly clear that competition provides a stimulus for cost reduction and innovation that benefit the ultimate consumer.

Asian customers in particular have been complaining about the rigidities inherent in the traditional LNG contract and welcome the possibility of negotiating for more flexible supplies. For the Japanese electric utilities, this means increased flexibility to dispatch gas-fired units in the intermediate and peaking portions of their sendout curves. For Korea, however, a large portion of the demand is for space heating, a seasonal demand that is difficult to serve within the constraints of a typical 90% minimum take-or-pay contract clause. In fact, for some time Korea Gas Corporation (Kogas) has purchased seasonal peaking supplies on the spot market over and above its long term contract commitments.

Since combined cycle power generation is the dominant driver for international natural gas demand growth, the restructuring of the electric power industry is an integral part of this new approach to LNG markets. By eliminating government or franchised monopoly positions, the restructuring process greatly multiplies the number of potential customers for LNG thereby enhancing the liquidity of the market. Not only are those power companies that have been previously served by a monopoly gas supplier now able to purchase on their own, but the emergence of the independent power producer (IPP) has created a whole new class of customers who are free to compete for their own gas supplies.

To make this new competition in the marketplace work, buyers need access to receipt terminal and regasificatation capacity. Hence, a policy of open access to receipt terminal capacity is an important part of the new LNG structure. Similarly, the ability to trade out surpluses or to cover shortages argues against the inflexible "destination clauses" in

[2] Natural Gas Clauses in Petroleum Arrangements, UNCTC Advisory Studies, United Nations 1987, p3

contracts that prohibit the initial buyer from reselling part of his volumes on the spot market. Both the terminal access and destination clause issues are part of current policy discussions in the European Union (EU).

For tanker transportation, the system provides greater flexibility than the older system of dedicated tankers. This has proved to be important in the Asia Pacific market over the past two years. Guerrilla activity in Indonesia's Aceh province in western Sumatra forced the shutdown of the Arun LNG facility for a time during the early part of 2001 and buyers had to find alternative supply. Then in the summer of 2002, Tokyo Electric (Tepco) was first forced to shut down five nuclear plants for safety checks (it now plans to shut down all 17) and entered the market for substantial fuel supplies to replace the lost nuclear generation. The impact of this effort has disrupted both fuel oil and LNG markets in Korea as well as Japan. In both the Indonesian and Northeast Asian cases, the availability of undedicated LNG tankers has made it easier for the market to adjust to the transport dislocations.

The new competitive model also provides for potential savings in tanker transportation costs. Under the traditional approach with tankers dedicated to bilateral trades, cross shipping with its inherent inefficiencies has become an increasing possibility. For example, ConocoPhillips is a part owner of the Cook Inlet, Alaska LNG project. It has been developing a potential LNG project in Darwin, Australia for its Bayu Undan reserves in the Timor Sea and at one pont had proposed to supply a new LNG terminal in Baja California for the California market. Had the latter deal been accomplished under the traditional dedicated tanker ground rules, the combined shipping distances would have been 10,547 nautical miles - 3,250 from Alaska to Japan and 7,297 from Darwin to Mexico. However, had it been possible to do a more flexible displacement deal in which the Cook Inlet gas was diverted to the California contract, while Bayu Undan gas replaced the Alaskan shipment to Japan, the effective transportation distances would be more than halved - 2,191 for the Cook Inlet shipment and 2,864 for the Darwin shipment for a combined total of 5,055 nautical miles. With the growing competition between Gulf and Southeast Asian supplies for both the Indian market and the Northeast Asian market, the possibility for cross shipping savings increases significantly.

The concept of opening competition to gas supply at the wellhead argues that the older, joint venture form of project marketing be replaced by competition among the joint venture partners with each partner responsible for finding his own customer outlets. This would have the effect of substantially multiplying the number of competitors in the marketplace and provide much greater liquidity in gas supply offerings.

Some LNG projects - Arun, for example - have been based largely on a single source of gas, so that the equity ownership in the underlying gas supply does not change over the life of the liquefaction facility. Increasingly common, however, is the situation where additional gas discoveries with differing equity ownership must be accommodated in later LNG liquefaction trains. This is the situation both in the other Indonesian LNG plant at Bontang in Kalimantan as well as in the new Trinidad project. The fact that Pertamina (the Indonesian NOC) was the monopoly liquefaction operator in Indonesia facilitated the inclusion of new producers in the Bontang expansions. However, under the more traditional model where equity ownership in the plant approximates equity ownership in the gas, the possibility of the original partners exercising monopoly power to exclude new entrants from liquefaction capacity clearly exists. Since such an exclusion clearly violates the spirit of free market competition among gas suppliers, the new industry model clearly suggests some form of open access in the liquefaction plant with the costs tolled out to the holders of the gas supply.

And finally, the new model of gas competition would substitute financial derivatives for the older, more rigid constraints inherent in long term contracts for the management of project risk. Nothing prevents a buyer and seller from entering into long term contracts, but the working assumption is that in a theoretical free market world, effective financial risk management should make traditional long term contracts much less relevant.

**The LNG "Revolution"**

If it is possible to put a starting date on the onset of the "revolution" in LNG, it probably falls shortly after the Northwest Shelf project in Western Australia went on stream in 1989. There followed a seven year period before the startup of the next greenfield LNG project - Qatargas in Qatar - the first new Middle East project in twenty-one years. In the interim, the U.S. Federal Energy Regulatory Commission (FERC) had launched its" Mega NOPR" (Notice of Proposed Rulemaking) in 1991 to establish the regulations for open access gas transportation, substantially advancing the process of restructuring of the U.S. gas industry. During this period U.K. was equally - if not more - aggressive in restructuring its gas industry and the process is now underway throughout the EU. Hence both sides of the Atlantic Basin LNG market are now operating under some form of industry restructuring that conceptually challenges the old way of doing LNG business.

The restructuring of gas and electricity markets is well advanced in the U.S., Canada and the U.K. and is proceeding rapidly on the Continent, as well. Therefore, the experiences in introducing the free market model into these markets offers some guidance as to how they might be adapted to LNG. One of the first symptoms of the emerging transition in onshore gas markets towards the newer restructured model was the development of a natural gas spot market. In the past several years, LNG has begun to develop its own short term markets, suggesting that LNG may well be retracing the path that onshore gas originally followed as it underwent restructuring.

While a very small short term LNG market has been in existence for nearly a decade, it has grown rapidly in the past several years. As recently as 1997, short term LNG transactions accounted for only 1.5% of international LNG trade. In the ensuing four years, the volume of short term transactions increased six fold and in 2001 accounted for 7.8% of international trade[3]. Many of these transactions, particularly in the Pacific Basin are better described as "short term"sales rather than genuine "spot" sales. Rather than representing open offerings of short term volumes as is the case in the spot market at Henry Hub, for example, they represent buyers and sellers attempting to manage shorter term LNG over or under-supply through bilateral deals with other parties.

The early appearance of the short term surpluses east of Suez in the early 1990s seemed to be more by accident than by design. It was the result of over eight million tons of debottlenecking capacity additions in Southeast Asia during a period when both Indonesia and Malaysia were adding expansion trains. It was sustained later in the decade by the slowdown in Asian markets and by the emergence of new export capacity from Qatar and Oman in the Gulf . But by 1999, further Middle East expansions (as well as the startup of Trinidad and Nigeria in the Atlantic Basin) institutionalized the surpluses and by now some of the excess capacity appears to have been created deliberately to enable companies to participate in spot and short term trading opportunities.

If one were to believe the trade press reports of firm commitments for new LNG projects, this surplus can only continue and a buyers' market for LNG is here to stay. Figure 2 shows the history of LNG liquefaction capacity since 1990 and my estimate of firm capacity together with probable and possible additions to the year 2012. Between 1990 and 2000, LNG liquefaction capacity grew by 86%. Figure 2 illustrates that it is easily possible to contemplate a liquefaction capacity increase of 144% over the next decade. LNG sceptics, however, will note that it has been usual in the LNG business for many more projects to be reported in the trade press than are ever actually built. The "filter" that has historically limited capacity growth has been the Sale and Purchase Agreement. Companies that have been unable to sign up customers for the new capacity have simply delayed - or in some cases abandoned altogether - the proposed expansions. Any projection of an ongoing and persistent buyers' market presumes that companies in the future will be more speculative in their capacity additions than they have usually been in the past.

The coincident growth of excess LNG export capacity at a time when both the U.S. and Spain were actively interested in supplemental LNG - the U.S. to offset lagging domestic supply and Spain to diversify away from its dependence on pipeline supply from Algeria - made them the prime targets for the trade. In 2001 the two countries accounted for 51% of spot market volumes.

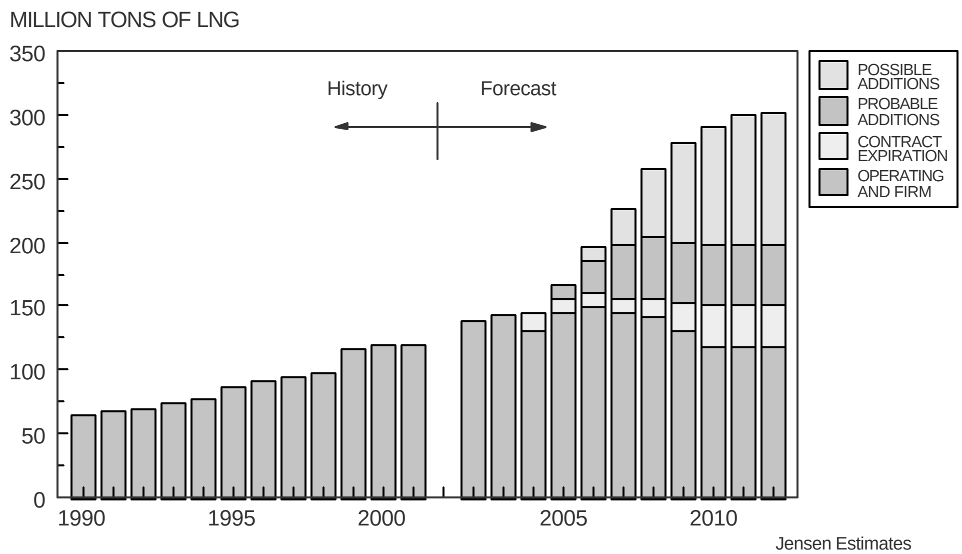
This active short term market on each side of the Atlantic has become the basis for the emergence of pricing arbitrage through the ability of shippers to deliver to Europe or to the U.S. based on the relative prices in the two markets. Hence,

[3] Flexibility in Natural Gas Supply and Demand: International Energy Agency, 2002, p109

Figure 2

HISTORIC AND PROJECTED LNG LIQUEFACTION CAPACITY

MILLION TONS OF LNG



for a business that was for a long time sufficiently fragmented geographically that the concept of a "world gas market" was unthinkable, LNG is now seeing the first elements of interregional gas price competition.

**The New LNG Market - The Initial Steps Towards "Synthesis".**

Just as the U.S. was a leader in the trend towards gas market liberalization, it has proved to be a leader in testing the limits of the theoretical free market model, thus suggesting that the ultimate shape of the LNG system will be a synthesis of the traditional and the new. The liberalized model assumes a market that is workably competitive so that no one participant can exercise market power. But the conspicuous failure of the U.S. energy merchant sector in the past two years suggests that not all parts of the complex gas and electricity markets are indeed workably competitive and that the ability to manipulate markets for economic gain does exist for some portions of the two systems.

It is clear that, in pursuing the apparent rewards in liberalized gas markets, some managements failed to recognize the offsetting risks that accompanied the new business practices. Hence an understanding of the way in which the LNG participants adapt to a similar shifting of risks and rewards among activities is essential to an understanding of the future structure of the industry. If the liberalization of the domestic U.S. market has proved more challenging than many expected, the cross-border nature of LNG trade should, if anything, make LNG markets even more so.
The future structure of the industry will largely be determined by the answers to a number of questions:

- Will the traditional Sales and Purchase Agreement survive in a restructured LNG industry?
- If so, what changes in terms will be necessary to make it more market responsive?
- What is likely to be the future equilibrium balance between short term and long term sales?
- How will prices be determined and how will they be reported?
- How effective will financial risk management techniques prove to be for LNG?
- How are the political risks affected by liberalization?
- How does technology affect the balance of risk and reward?
- What are the new risks and rewards that flow from the "de-integration" of the LNG chain?

The way in which the industry responds to these questions will go a long way towards determining its future structure.

**Will The Traditional Sales And Purchase Agreement Survive In A Restructured LNG Industry?**

The surplus of LNG offerings in the past several years has created a buyers' market in LNG. Thus it is possible, in theory at least, for buyers to contemplate the possibility of relying totally on short term or spot purchases - with reliance on financial derivatives for risk management - as the free market model would suggest. There is little evidence, however, that buyers are ready for such a radical step. Nor is there evidence that sellers are either. Both Mobil in Qatar and Shell in Oman in 1996 supposedly considered the option of justifying new LNG trains on the basis of large spot volumes, but rejected it as too risky[4]. In 2001 Nigeria, Qatar and Trinidad - the leaders in originating short term trade - shipped approximately 16% of their volumes as spot sales, but their expansions, like the financing of the original trains, have been based on underlying long term contracts. Since no supplier has yet undertaken to build a new facility on a speculative basis without a contracted outlet, the answer to the first question would seem to be that the long term contract is still alive and well

**If So, What Changes In Terms Will Be Necessary To Make Term Contracts More Market Responsive?**

The emergence of a buyers' market in LNG has tended to mask an underlying erosion in the ability of buyers to make the kind of long term contract commitments that were once the standard in the industry. The liberalization of gas markets has largely eliminated the ability of government monopoly or regulated utility buyers to lay off the volume risk on their

[4] World Gas Intelligence, January 26, 1996. p3

customers. Furthermore the emphasis on freer competition has exposed many buyers to interfuel-competitive price risks that were not envisioned at earlier period. And the financial community's concerns about the creditworthiness of some of the newer buyers, such as some Indian power plant purchasers, raises new questions about the riskiness of the traditional contract. Hence, even if long term contracts remain as a major part of the new LNG market, their volume and pricing clauses are likely to undergo substantial change.

The classic combination of a take-or-pay agreement coupled with an oil-linked pricing clause has been under fire for some time, even before more liberalized markets began to appear. Buyers are increasingly demanding greater take flexibility and the classic oil linkage, which could once be defended as a measure of interfuel competition, is no longer representative of the market as gas now rarely finds oil as its chief competitor. Oil-linked pricing remains, but in many cases because the contracting parties do not appear to have come up with a better alternative.

LNG projects are capital-intensive and thus there are severe economic penalties to projects that fail to achieve high capacity utilization rates. The take-or-pay clause, coupled with a price clause, in the traditional contract was the seller's guarantee of efficient facility utilization, but it exposed the buyer to the possibility of economic loss if the pricing clause later forced him to take volumes that were less attractive than he had envisioned when he first signed the contract. Clearly, the more responsive the pricing term was to the buyer's actual market situation, the less would be the loss.

The experience in Japan, which has been the Pacific Basin market leader, illustrates the nature of the problem. Before the recent resurgence in interest in Atlantic Basin LNG, six Japanese electric utilities accounted for nearly 40% of world LNG trade[5]. Three of them - Tokyo Electric in Tokyo, Kansai Electric in Osaka and Chubu Electric in Nagoya - alone nearly accounted for 30%. The Japanese contracts are linked to crude oil prices by reference to the Japanese Customs Clearing price for crude oil (JCC - often called the Japanese "crude cocktail").

When the precedents for the oil-linkage were first established, Japanese power generation was heavily dependent on residual fuel oil firing. The decision to tie LNG take-or-pay contracts to a crude oil pricing standard, indirectly linked the dispatch of the LNG and oil-fired generating units since both fuels were similarly affected by changes in world crude prices. This linkage effectively precluded the kind of rapid utility switching from gas to oil that has recently characterized the U.S. market.

But oil firing, which reached a level of 73% of generation in 1973, has fallen to 10% by 2001 (See Figure 3). The growth of base load coal and nuclear generation has not only squeezed out most of the oil generation, but it has increasingly forced LNG to assume some of the peaking role once carried by oil. Hence the interest in more flexible contracts.

The advantage of gas-fired combined cycle generation to the LNG supplier is that it permits a higher market price as its lower capital cost and higher thermal efficiency can be traded off against the higher capital costs of alternative generation. But that advantage for LNG becomes a substantial disadvantage in dispatching generating units since it locks in a high short run marginal generating cost for gas. Thus at times when an economic downturn might lead to overcapacity in generation, LNG dispatch levels should be selectively reduced absent the take-or-pay volume limitation. Since the Japanese utilities had a monopoly franchise, the economic inefficiency of "must run" status for LNG generation could be passed on to the customers. But as the Japanese electric industry itself liberalizes along with other markets for gas, this pass through behavior may be threatened.

The contract pricing problem is even more acute when the customer is a stand-alone independent power project (IPP) operating in a liberalized electricity economy. There a pricing formula that yields too high a price simply shuts the unit down as other units with lower marginal costs are preferentially dispatched. One of the great problems plaguing the Bolivia-to-Brazil pipeline has been the difficulty of financing new gas-fired IPP projects when they are at dispatch risk to hydroelectric power during high water periods.

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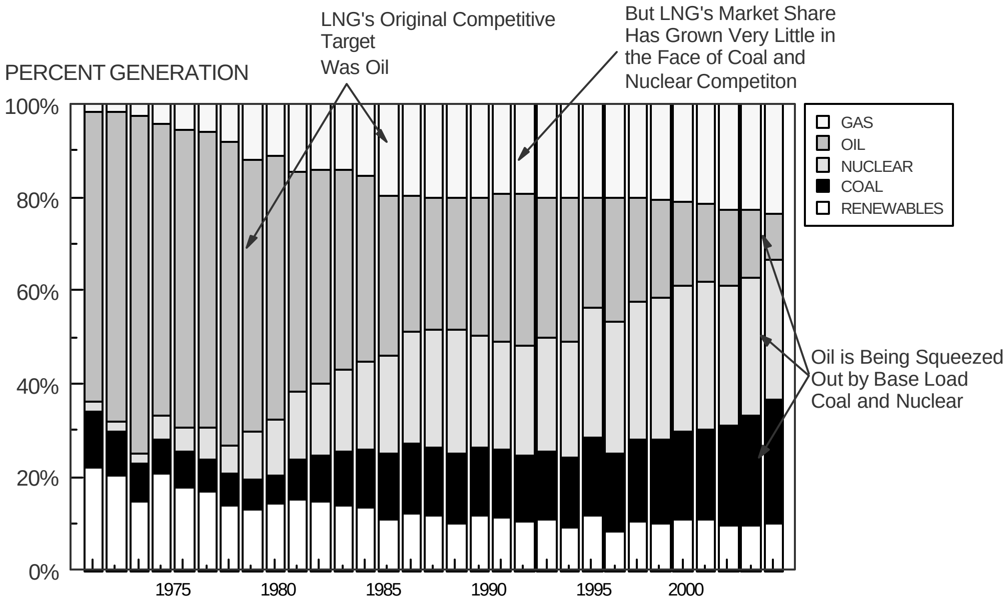
[5] Jensen Estimates based on corporate annual report data

Figure 3

SHARE OF JAPANESE POWER GENERATION BY ENERGY SOURCE

THE TRANSITION IN LNG'S COMPETITIVE TARGETS




Data Source EDMC Energy Trend, IEEJ, Tokyo

While one solution to the dissatisfaction with oil-linked pricing clauses has been to utilize coal or some mix of energy prices, a more logical candidate in a restructured gas industry in gas-to-gas competition is a price tied to a gas market indicator. In the U.S., the Henry Hub quotation is the obvious candidate for such a role. And as a forerunner to the possible spread of gas-linked pricing to Europe, Statoil recently signed a pipeline contract with Centrica in the U.K. that was to be linked to a gas market indicator[6].

There are three disadvantages to the use of a gas market indicator relative to an oil indicator as a measure of changes in energy prices. Gas prices appear to be more volatile than oil prices, even after accounting for their relatively more seasonal behavior. Second, the great geographic dispersion of market transactions together with gas's much higher transportation cost means that some geographic "place differential" or "basis differential" must be utilized to relate dispersed sales prices to the marker price. And finally, if the gas is delivered to the same physical market as the gas tracking price series, and if the market is sufficiently liquid that the transaction will not move the market, the effect is to eliminate most of the buyer's risk thereby transferring virtually all of the contract risk to the seller (What volume risk does the buyer assume if he can always turn around and resell the cargo at the same market price used in the contract?).

In the more traditional contract negotiations, contract flexibility has also been a target of buyers and in a buyers' market they have had some success at changing contract terms. This has taken several forms. It may involve reduction in the take-or-pay minimums or the inclusion of optional cargoes at the buyers discretion such as a Korean contract with RasGas[7]. Or it may involve eliminating destination clauses (that restrict the buyer's ability to resell volumes in excess of his requirements). This has been a major issue with the EU for European pipeline suppliers and has shown up in a Nigerian LNG contract[8]. In Japan, Tokyo Gas and Tepco have renegotiated a Malaysian contract to provide for a portion of the volume to be supplied f.o.b rather than ex ship, thus enabling buyers to control the resale of cargoes excess to the Japanese market[9].

The movement away from oil-linked price clauses in long term contracts to short term or spot market purchases or even term contracts with gas-linked pricing poses a substantial challenge to gas sellers. While one of the complaints of buyers about oil linkage is the volatility of oil prices, gas prices are, if anything, even more volatile.

For a time, the working assumption in the U.S. was that gas-to-gas competition had become decoupled from oil competition and thus variations in oil markets were no longer relevant to gas price formation. However, the gas price shock in the U.S. in the winter of 2000/01 reestablished oil-to-gas competition through the mechanism of residual fuel oil switching in utility and industrial boilers[10]. In fact, for a brief period during that winter gas prices appeared to be set at even higher levels by switching at the margin to distillate fuel oil. If North American gas prices can fluctuate among gas-to-gas, residual-oil-to-gas and distillate-oil-to-gas price levels, it argues that the U.S. gas market indicator ought to be more volatile than oil prices alone.

This is illustrated by Figure 4, which compares the volatility of Henry Hub spot gas prices with the U.S, Refiners Acquisition Cost of Crude Oil (RAC) over the past decade. Figure 4 also includes the purchase price of coal by U.S.

[6] Petroleum Intelligence Weekly, June 17, 2002 p7

[7] World Gas Intelligence, October 23, 2002, p1

[8] European Gas Markets, December 2002, p7

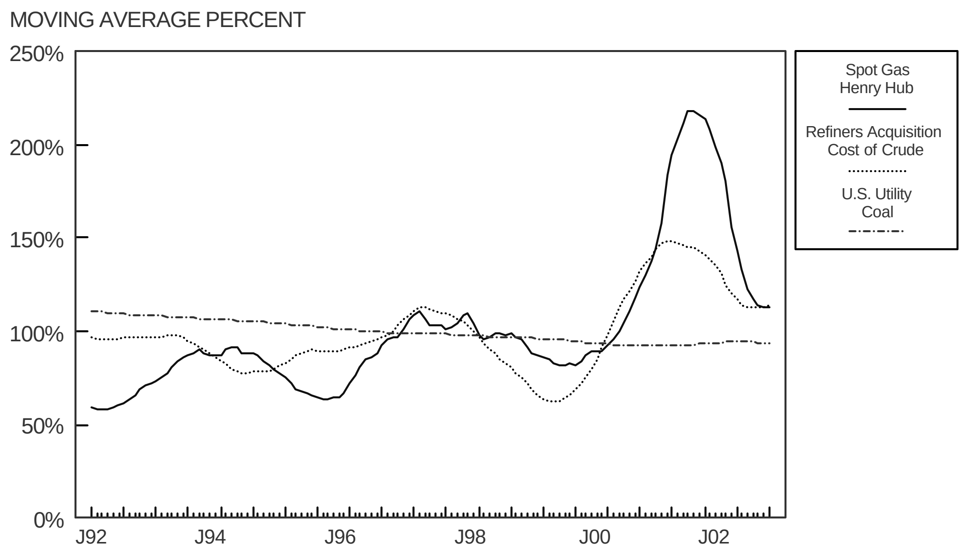
[9] Petroleum Intelligence Weekly, April 29, 2002

[10] Jensen, J., *The Outlook for U.S. Natural Gas Supply and Demand and the Potential Role for Liquefied Natural Gas*, A Presentation to the NAPIA/PIRA Joint Annual Conference, La Quinta, CA October 10, 2002 (unpublished)

Figure 4

GAS PRICE VOLATILITY COMPARED TO OIL AND COAL PRICE VOLATILITY

12 MONTH MOVING AVERAGE ABOUT 10 YEAR AVERAGE PRICE




Prices - EIA, World Gas Intelligence

electric utilities. The relative stability of the coal price illustrates the dispatch problem that both gas and oil generation may face in periods when their prices are high.

The existence of a world oil market is largely predicated on the low costs of tanker transportation coupled with the role of the Gulf as a supplier of last resort. Therefore the issue of oil "place" or "basis" differentials has usually not been a significant issue in oil price escalators. However, the much higher costs of gas transportation can cause substantially differing prices at different geographic locations. In the U.S. these basis differentials from the Henry Hub market are regularly monitored by trade press pricing services and market trading activity is often based on estimates of their future behavior.

The fact that basis differentials for markets removed from the pricing reference point can themselves vary quite widely introduces a further element of "basis risk" into the pricing equation. For the U.S. market, for example, an LNG delivery to the Everett, MA or Cove Point, MD terminals would be expected to enjoy a higher price than a delivery to Lake Charles, LA near the Henry Hub pricing point because of the basis differentials to Northeastern markets. Similarly, proposals to deliver LNG to California (or to Baja California in Mexico for reshipment to the U.S.) might normally expect a positive basis differential over Henry Hub.

However, the fact that local markets can easily be overloaded, sharply affecting the historic differential, introduces a new element of risk into the transaction. This phenomenon was illustrated in 1994/1996 when a pipeline expansion by Pacific Gas Transmission into the California market caused a collapse of the normally positive basis differential over Henry Hub (see Figure 5).

The closer the transaction is to the market reference location, the less the degree of basis risk in the transaction. An LNG delivery into Lake Charles might be expected to have little or no basis risk to Henry Hub. However, such a delivery, if made on a contract that was keyed to Henry Hub as a gas market indicator, would involve little volume risk to the buyer since he could quickly resell the volume in the highly liquid Louisiana market.

The effect of many of these new pricing and volume changes is to shift the market risk towards the seller. Thus the way in which sellers ultimately adapt to this new risk profile with have much to do with the future shape of the industry.

The liberalization of the gas industry has created a whole new class of buyers - the marketing companies. The marketing companies may be affiliates of either buyers or sellers - and thus their fundamental corporate trading interest arguably remains that of the parent - but the new system has spawned a new group of traders without the underlying upstream or downstream assets of the traditional market participants. Companies such as Enron, Dynegy and Williams have been prepared to take title to the gas and market it independently. Some of this group have undertaken ship-or-pay agreements on the new pipelines and for a time it appeared as if this new class of potential buyers would be prepared to become major customers for LNG contracts, adding liquidity to the market. But the bankruptcy of Enron and the subsequent financial problems of the marketing companies as a group have raised questions about the creditworthiness of companies that are not backed by solid physical assets and suggests that they may not be the players in LNG that they once were expected to be.

**What Is Likely To Be The Future Equilibrium Balance Between Short Term And Long Term Sales?**

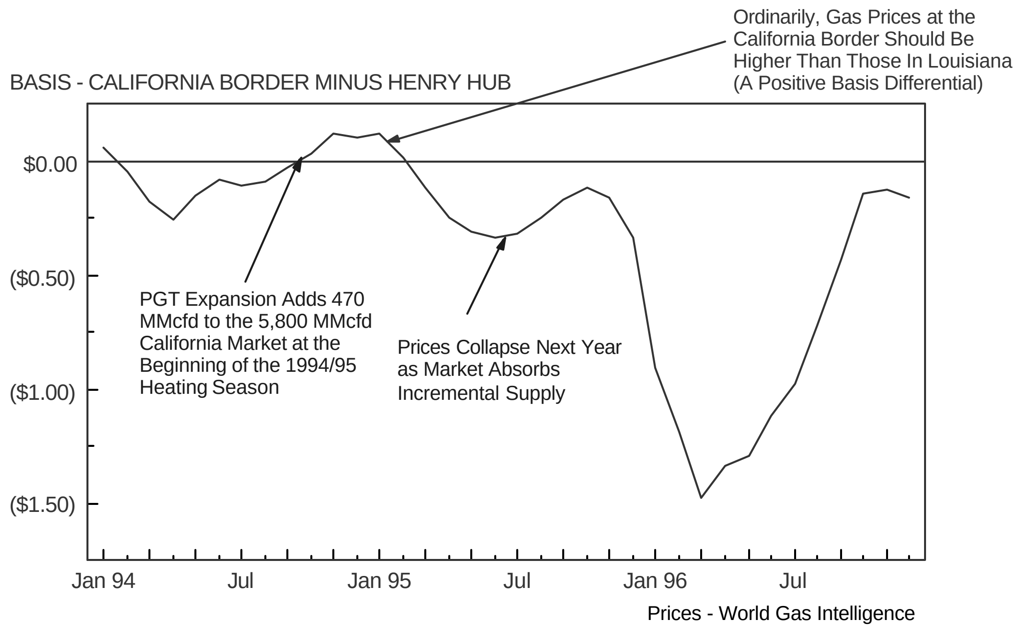
The Atlantic Basin has been more aggressive than the Pacific Basin in its use of the short term market, with the U.S. being the most active. Its spot volumes accounted for 44% of U.S. LNG imports in 2001 and represented 30% of total world short term trade[11]. To some extent this aggressiveness reflects the fact that the risk exposure for the LNG receipt terminals are a relatively small part of the CAPEX totals in the LNG chain, and the fact that LNG is such a small supplement to total U.S. gas supply.

[11] Cedigaz, Natural Gas in the World - 2001 Survey, p28

Figure 5

"BASIS RISK" - COLLAPSE OF THE CALIFORNIA BASIS DIFFERENTIAL FOLLOWING THE 1994 EXPANSION OF PACIFIC GAS TRANSMISSION

THREE MONTH MOVING AVERAGE



The largest short term purchaser in Europe has been Spain with 23%, but no other European purchaser exceeded 8% reliance on spot volumes in 2001. The reliance on short term markets in 2001 is illustrated in Table 1.

Table 1
SHORT TERM LNG AS A PERCENT OF TOTAL LNG IMPORTS AND
LNG IMPORTS AS A PERCENT OF TOTAL GAS SUPPLY

| | PERCENT SHORT TERM | LNG AS A PERCENT OF GAS SUPPLY |
|---|---|---|
| U.S. | 44% | 1% |
| Spain | 23% | 54% |
| Italy | 8% | 8% |
| France | 5% | 26% |
| Belgium | 3% | 16% |
| Korea | 9% | 100% |
| Japan | 3% | 97% |
| Taiwan | 1% | 86% |

But while most Atlantic Basin importers are using LNG to supplement a much larger pipeline supply, the Asian importers rely almost exclusively on LNG as their source of gas, making them more sensitive to supply risks. In the Pacific, Korea has been one of the more willing buyers to rely on short term market offerings, both because of the difficulty of accommodating its highly seasonal demand within the constraints of typical take-or-pay minimum volumes as well as uncertainties over the privatization of the government monopoly, Kogas, as Korea liberalizes. Still, Korean short term purchases in 2001 were only 8.6% of total imports. On the other hand, Japanese customers have shown a strong concern for security of supply, suggesting that they may be unwilling to adopt a more radical strategy. Japanese short term imports in 2001 were only 3% of total LNG, much of which was an attempt to offset the shutdown of the Arun plant in Sumatra. In any case, Japanese markets - not growing as rapidly as they were at an earlier period - are largely tied up in long term contracts. And the Japanese buyers, facing the expiration of an Arun contract in 2004 with its physically declining supplies, appear to have covered their incremental needs with new term contracts from Malaysia, rather than using the contract expiration as a opportunity to make greater use of the short term market.

For the most part, suppliers have been relatively conservative in the balance of spot and contract volumes in their mixes. This is illustrated in Table 2. Nigeria, Qatar and Trinidad shipped approximately 16% of their exports as short term volumes in 2001. Trinidad and Nigeria both started up new greenfield facilities in 1999, are rapidly adding additional trains, and have been key players in a precedent-setting Atlantic Basin arbitrage involving the U.S., Spain and Belgium.

Table 2
SHORT TERM LNG AS A PERCENT OF TOTAL LNG EXPORTS

| | PERCENT SHORT TERM LNG | | PERCENT SHORT TERM LNG | | PERCENT SHORT TERM LNG |
|---|---|---|---|---|---|
| Nigeria | 16.5% | Qatar | 16.4% | Indonesia | 6.0% |
| Trinidad | 15.9% | Oman | 11.1% | Malaysia | 2.5% |
| Algeria | 4.2% | Abu Dhabi | 4.4% | Australia | 2.2% |

The old take-or-pay contract required that the buyer undertake his volume obligation over the life of the contract, usually twenty years or longer. In addition, the contracts typically had a buildup period before plateau volumes were reached enabling the buyer to grow into his market commitment.

As the rigidities associated with the old style contract have softened, more volumes have become available for short term and spot sales. Since the seller's greatest concern is debt service while the loan obligation is still outstanding, it may increasingly be possible to tailor the contract length to the shorter period of loan payout, giving the seller greater flexibility to put volumes on the short term market. In addition, sellers seem more willing to ramp up to full liquefaction capacity during the contract buildup period, creating additional uncommitted early volumes. The slowing growth of the Northeast Asian market, when combined with the increasing train sizes that are dictated by economies of scale, has meant that it takes longer to assemble enough contract outlet in the Pacific Basin to justify a new liquefaction investment. In a competitive environment, companies appear to be more willing to commit to new facililties with only part coverage of capacity or take risks in buyer creditworthiness that might not have been considered prudent at an earlier period. The effect has been for suppliers to initiate more projects with uncommitted or unsecured capacity which is therefore available for placement in the spot market. And debottlenecking of existing capacity that is virtually already paid for is another source of flexible volumes.

If present patterns continue, suppliers will still utilize long term contracts - probably of shorter duration - to justify new greenfield facilities or expansion trains. However, a significant percentage of capacity is likely to remain available for short term or spot sales.

The Northeast Asian market has traditionally been risk-averse, in part because of its near total reliance on LNG for gas supply. Until Qatargas's signing of a contract with Spain's Gas Natural in April 2001[12], all Middle East liquefaction investments had been justified on the basis of Northeast Asian contracts. Thus the Middle East was originally considered a part of Pacific Basin trade.

However, the combination of events that created a Pacific Basin surplus in the 1990s initially forced small Pacific Basin volumes to seek outlet in the Atlantic Basin. Then, as major new Middle East capacity came on line that region seems to have taken on "balancing" or "swing" role between Atlantic and Pacific markets. The trend in regional short term trade is illustrated in Figure 6. While intra-regional short term trade remains the most important source of flexible volumes for both the Atlantic and Pacific, it is obvious that the Middle East has been playing a swing role for both regions.

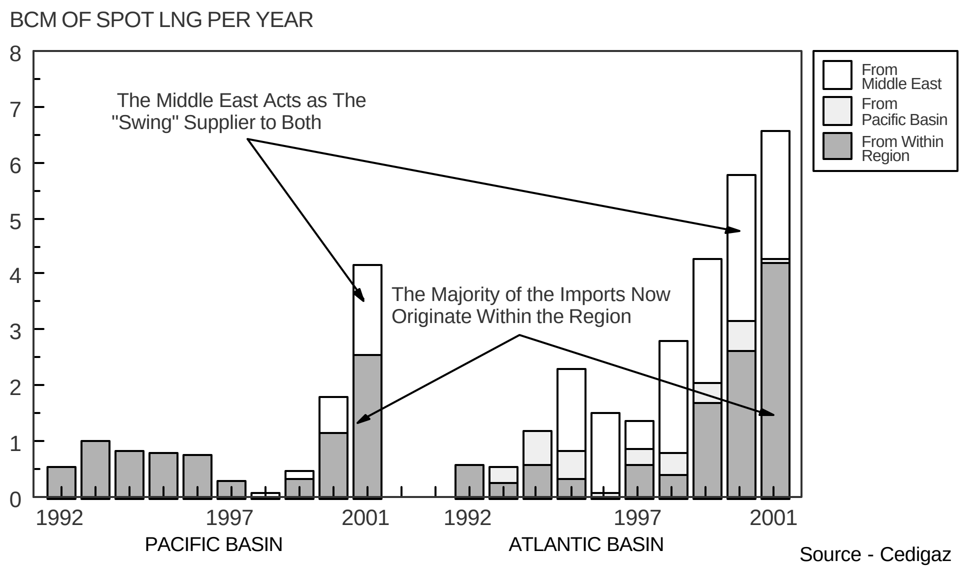
Since the startup of the Trinidad and Nigerian projects, the Atlantic market has developed a lively arbitrage between Europe and the U.S. As yet the rigidities of the Pacific Basin market has precluded similar developments in the Pacific

[12] Middle East Economic Survey, October 8, 2001, page A8

Figure 6

SOURCE OF SHORT TERM GAS IMPORTS - ATLANTIC BASIN VERSUS PACIFIC BASIN

BCF




Source - Cedigaz

Basin. However, the renegotiation of some of the region's long term contracts upon their normal expiration, and the possible development of a U.S. West Coast market may change that pattern.

**How Will Prices Be Determined And How Will They Be Reported?**

There are significant differences between the way in which sales transactions take place in onshore gas markets and in LNG. These differences suggest that the price determination model of the restructured gas pipeline industry may not provide an appropriate model for LNG.

Under the earlier system of federal regulation, North American interstate (or interprovincial) pipelines were regulated as merchant monopolies, purchasing gas in the field on long term contract and reselling it usually to locally-regulated gas distribution companies who served the end-use customers. Although prices were originally regulated, both for the producer and for the pipeline merchant, there were two logical transaction points in the system - the sale in the field into the pipeline and the sale out of the pipeline to the distribution company (under retail deregulation the second transaction point devolves to the end user).

With the restructuring of the industry, the pipeline merchant has been taken out of the loop, allowing producers in the field to compete directly for distributor or end-use business through open-access pipelines on whatever contractual basis buyer and seller can agree. The conceptual break between production - with its large number of competing producers - and transmission - which traditionally was viewed as a natural monopoly - is comparatively clear cut. Similarly, there are a large number of distribution and end use customers who used to buy from their pipeline merchants, but now are free to access a large number of producers, thereby providing the liquidity for workable competition at the wellhead and the result - gas-to-gas competition - is the fundamental basis for price formation.

When liberalization of gas markets in the U.S., Canada and the U.K. first began, there was sufficient surplus capacity in the field and in the transportation system that trading of gas and of transportation capacity was not significantly constrained by transportation bottlenecks. The physical trading of gas has taken place both in the field and at "hubs" where several pipelines converge to permit transfer of gas from one system to another. The hubs have become the natural transaction points for price formation.

The landmark North American hub has been Henry Hub in Louisiana, which is a basing point not only for physical transfers but also for futures transactions on the New York Mercantile Exchange (NYMEX). The price quotations for futures contracts are fully transparent giving reliable indications of the state of the market. Price quotations for physical delivery at Henry Hub and for many other points in the system are available from trade press pricing services, but these do not have the authenticity of transparent transactions on an exchange. Europe has been developing its own pipeline hub system. The U.K. is most advanced with market quotations available at Bacton, the U.K. terminus of the Interconnector to the Continent, for example. The Continent is less far advanced with hubs, but Bunde in Germany, for example, is beginning to emerge as a pipeline market trading point.

The break between the production sector and the transportation sector is much more ambiguous in LNG than it is in onshore pipeline gas. Whereas, the original existence of the pipeline merchant monopoly separated consuming or retail distribution buyers from producer sellers, LNG buyers and sellers have always negotiated directly with one another. And whether the sale was f.o.b or ex-ship, portions of what would be regarded in LNG as elements of the transportation chain remained under the control of the contracting parties - liquefaction for the sellers and regasification for the buyers. The most obvious "transportation" portion of the chain - tanker transportation - could hardly be called a monopoly, and was never treated as a "merchant" as were the pipelines. Thus, if there is to be open access to the LNG transportation system, the focus of the liberalization would appear to be on opening up liquefaction and receipt/regasification to third parties.

There is considerable doubt that applying open access policies to liquefaction facilities will prove to be particularly effective. The principal reason is that both producers and host governments may tend to resist the pressure to open up the system, while buyers may have limited incentive and little leverage to facilitate the change.

The evidence is somewhat inconclusive that there will be buyers willing to contract for liquefaction capacity in order to stimulate competition among the joint venture partners in LNG license areas. As conventional pipeline gas demand has grown, the need for new capacity has required investment in new facilities. The pattern that has emerged in North America to provide for new investment has been the use of the "open season" process. For pipelines, a sponsoring group asks for bids on new capacity and if a sufficient number of shippers respond the pipeline project can go forward. Shippers undertake a "ship-or-pay" commitment that resembles the take-or-pay contracting process in LNG. While shippers can buy and sell capacity, their initial commitment assures the financiers that a creditworthy company is prepared to cover debt service on the project, and thus the project is financeable. An obvious question is whether or not consumer/distributors or marketing companies see enough pricing advantage in opening up competition among a small number of producers behind the liquefaction plant that they will be willing to assume the liquefaction ship-or-pay obligation.

Three major pipelines have been financed under the new open access ground rules - Alliance Pipeline from British Columbia and Alberta to the U.S. Midwest, Maritimes & Northeast Pipeline from Nova Scotia to New England, and the Interconnector that links Bacton in the U.K. with Zeebrugge in Belgium. Although the distinction between producers, consumer/distributors with downstream assets, and the marketing companies is not hard and fast, it is possible to group the percent of the ship-or-pay responsibility held each. Table 3 is my judgment of such a breakdown for each system.

Table 3
PIPELINE SHIPPERS - PERCENT OF CAPACITY HELD BY TYPE

| | PRODUCERS | CONSUMER/ DISTRIBUTORS | MARKETERS |
|---|---|---|---|
| Alliance Pipeline | 48% | 13% | 39% |
| Maritimes & Northeast Pipeline | 31% | 42% | 27% |
| Interconnector[13] | 46% | 27% | 27% |

The consumer/distributors comprise a relatively small share of capacity holdings for both Alliance and the Interconnector. They are the largest group in the Maritimes & Northeast system. While this appears to suggest that buyers have been aggressively seeking capacity on the line, it is somewhat misleading. The original ship-or-pay responsibility was largely undertaken by the producers, but most of the downstream consumers have now signed long term take-or-pay contracts with the producers which effectively locks them into a particular supply. Hence, it is clear that the buyers did not undertake the shipping obligation in order to "shop" for cheap gas at the wellhead as the thrust of open access regulation intends.

The Interconnector, unlike the other two pipelines, was designed as a "balancing" line to run either direction rather than a classic "gut" pipeline (running one way from source to market) and thus the higher concentration of consumer/distributors on that system is more logical. Marketers represent a large group on the Alliance system, but many of these obligations were undertaken before the serious financial problems of the group developed and it is not

[13] Based on equity participation (information on current shipper obligations is not publicly available; data also excludes BG's share since its role at the time was as operator for the British gas grid)

clear the marketers would be as willing to undertake such obligations today. In short, the experience of the pipelines suggests that the producers - who now control liquefaction capacity anyway - are the most likely candidates to assume the ship-or-pay responsibility in an open access liquefaction regime.

Most production licenses behind LNG projects consist of no more than three to six joint venture partners, and the ownership of liquefaction is usually similarly concentrated. Certainly, producing governments - if they are so inclined - can require companies to market independently, rather than jointly as shareholders in a venture. But buyers wil not have as much to gain from the more limited competition, as they do in onshore pipeline markets where they can access many more producers.

There are other possible unintended consequences to an effort to open up competition at the wellhead by requiring open access to the liquefaction plant. The reason for joint venturing is usually to spread the exploration and development risks among a number of investors. While the ability to supply its share of the capital investment is a necessary prerequisite for any potential joint venture participant, its ability to market its share of production has not been an issue in an environment where the venture markets as a unit. Opening up the venture to competition among parties exposes venture decision-making to the marketing strengths and weaknesses of the partners.

In one way the problem is analogous to the marketing problems in some of the major Middle East oil concessions in the 1950s and 1960s. There, companies lacking the ability to market their shares of group production, effectively sold internally at discounts to other companies that were stronger marketers. For example, Shell negotiated long term equity sales agreements with Gulf in Kuwait and Amerada in Libya while Aramco operated an internal "overlift/underlift" agreement that enabled Mobil - a chronic overlifter - to sell more than its equity share of Saudi production out of Standard of California's (Socal) and Texaco's shares. Any effort to make joint venture partners compete with one another may well bring back internal sales mechanisms reminiscent of these earlier oil marketing vehicles.

If the effect of this effort is to reduce the effective ROI of the weaker sellers, it may shrink the number of companies willing to participate in LNG development ventures where the economics of the project are thin. While some NOCs, such as Pertamina and Sonatrach, are strong international gas sellers in their own right, NOCs in some countries are simply a disguised form of tax collectors. The entire relationship in production sharing contracts with NOC participation may be forced to undergo change.

But in any case, producing governments have a substantial financial stake in the success of their LNG ventures. While consumers may see price competition as one of the benefits of liberalization, producing governments will see it quite differently if independent marketing threatens their revenues or their ability to mount a strong marketing effort. Pressures to open up the venture system are likely to come from the coordinated efforts of the consumer countries - such as the EU - where they have leverage over suppliers. Producing governments may seek other ways to insure that the original venture partners do not discriminate against incremental new supply controlled by others.

Opening up access to receipt/regasification terminals has proved to be a contentious issue, both in the EU[14]and in the U.S.[15]. The EU's requirement that pipelines and LNG terminals allow open access has been challenged by the U.K. and Italy, who have argued that such regulation would inhibit investment in new LNG terminals for their markets, and thus case-by-case exemptions should be allowed. Detractors have argued that such a selective approach is discriminatory. One possible solution would be to permit the investors to control a portion of the capacity and require a limited portion to be open.

[14] World Gas Intelligence, October 30, 2002, p4

[15] World Gas Intelligence, January 8, 2003, p2

In the U.S., FERC has eased its requirement for open access at newly constructed terminals through an extension of its "Hackberry" decision. This permission for proprietary terminals was requested by potential investors in the terminals who argued that they were not prepared to invest in capacity without it.

Another major distinction between pipeline and LNG markets is in the size of the transactions. The large number of producers in North America, many with small volumes to sell, has created a market in which small transactions are normal. The standard natural gas contract on the NYMEX is for 4,000 MMBtu (4 MMcf of 1,000 Btu gas) and a single NYMEX transaction is limited to 50 contracts or 200 MMcf. In contrast, the natural unit of spot trade in LNG is the cargo, which for a typical 135,000 cubic meter vessel amounts to about 2,600 MMcf or 650 times the size of the NYMEX contract. This of itself limits the number of buyers who can effectively participate in spot LNG markets.

While the trade press pricing services routinely report on North American gas prices in the field, at market city gates and at pipeline hubs, the centerpiece of North American price formation is Henry Hub. It is uniquely situated in the center of one of the largest North American supply areas with 14 pipeline interconnections to facilitate physical trading of natural gas near its source of supply. Since the Louisiana and Texas Gulf Coasts supply much of the north and east of the U.S., Henry Hub's price fluctuations flow downstream to much of the U.S. market. Henry Hub's physical situation was instrumental in its selection as the reference point for the natural gas futures contract on the NYMEX, so that it represents an ideal bridge between the paper derivatives market and the physicals market.

For LNG, there is no central supply point whose price fluctuations influence markets world wide. And there are no conspicuous hubs at which physical supplies from a number of sources are commingled and traded. Thus LNG markets are very difficult for the pricing services to monitor. Most of the LNG pricing information is market, rather than supply, oriented and although some of it may be quite reliable - Japanese or U.S. Government LNG import price information - most of that is not sufficiently timely to be of value to a trader and often does not distinguish between market-priced spot volumes and formula-priced contract volumes. The early efforts to provide timely LNG pricing information, such as the French Montoir terminal quotations of the U.K. publication, European Gas Markets, focus on pricing in specific markets rather than on LNG pricing as a whole.

One solution is to price LNG in accordance with an onshore pipeline pricing reference point such as Henry Hub. While Henry Hub may be a good reference point for cargoes landed nearby at the Lake Charles LNG terminal, it is still delivered there as liquid subject to the costs of regasification and transportation to the main grid. Zeebrugge, in Belgium with its location as a pipeline terminus of the Interconnector from the U.K. and its LNG receipt terminal, would superficially appear to have similar characteristics as an LNG pricing hub. However, the fact that Zeebrugge lacks the active level of competition and the market liquidity that are required for a pricing reference point makes it unrealistic at this time. How these difficulties with price reporting of LNG markets will ultimately be resolved is far from clear.

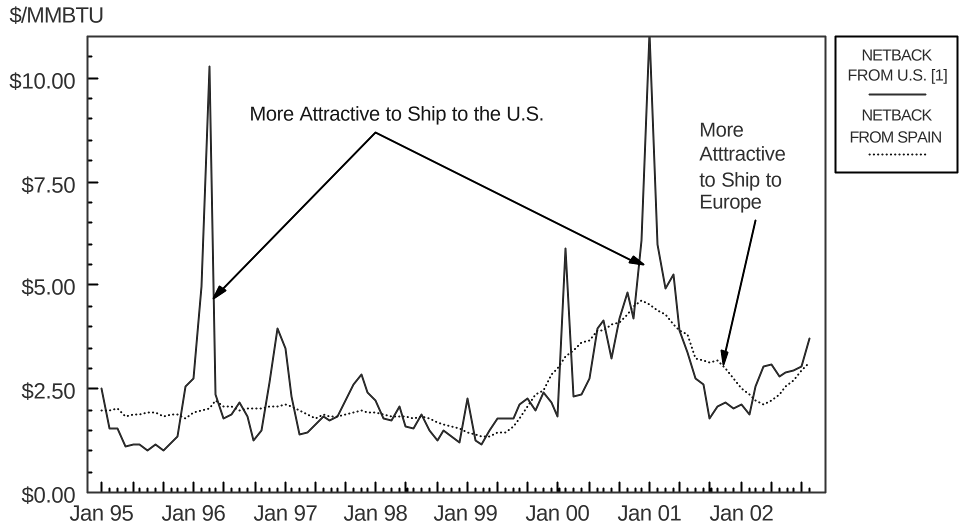
Despite the difficulties in providing a workable market pricing system for LNG, the Atlantic Basin has developed an active arbitrage market focussed largely on Trinidad, Spain, the U.S. and Belgium, with Nigeria and Algeria actively offering spot cargoes to the market, as well. The two largest spot importers - the U.S. and Spain - both provide pricing information, that while not timely and in some cases not reliable, does make it possible to illustrate how the arbitrage has worked in allocating cargoes. Figure 7 illustrates the relative price behavior as it might have been tracked as a netback to Trinidad. Trinidad and Nigeria have equivalent transportation costs to the Spanish market, while Trinidad has approximately a $0.40 advantage over Nigeria to the U.S. East Coast. Algeria has about a $0.40 advantage over both Trinidad and Nigeria for Spain, but it has a $0.20 disadvantage to Trinidad for the U.S. East Coast.

Much has been made of the possible development of a similar Pacific Basin arbitrage market when and if the California market for LNG develops. A Pacific market arbitrage would involve much longer shipping distances than does the Atlantic. For example, it would take twice as many tankers to deliver an equivalent amount of LNG from a possible Bolivian project (with a plant in Chile) to Japan as it would to California. For a shipper in Bontang, Indonesia, it would take nearly three times as many ships to deliver an equivalent amount to California as it now does to Japan.

Figure 7

HYPOTHETICAL NETBACKS TO THE LOADING PORT THAT A TRINIDAD SHIPPER WOULD HAVE REALIZED SHIPPING TO THE U.S. EAST COAST OR TO SPAIN

ASSUMING FULLY ALLOCATED TANKER COSTS




[1] Assuming a $0.35 Regasification Charge on the U.S. East Coast

Prices World Gas Intelligence

Despite the focus on a possible Pacific Basin arbitrage market, there is already a form of arbitrage between the U.S. market and the Pacific Basin by using the Middle East as a swing supply. Figure 8 illustrates the hypothetical netbacks that a Middle East shipper might have gotten by shipping to Japan, Spain and the U.S. East Coast over the past six years. The disparities in distances are not so great as require as much spare tanker capacity as a Pacific Rim arbitrage. A volume that five tankers could deliver from the Middle East to Japan would require six for the U.S. East Coast and four for Spain.

**How Effective Will Financial Risk Management Techniques Prove To Be For LNG?**

Before the gas trading companies got into their financial difficulties, many were promoting an ambitious concept of using financial derivatives for long term as well as short term risk management. Taken to its extreme, the seller no longer had to rely on long term contracts for his future cash flow but could utilize the longer term derivatives market in order to lock in prices and manage risk.

The NYMEX futures market has proved to be highly successful. It has provided a very liquid vehicle for hedging U.S. gas market transactions. It has enabled companies to stabilize revenues and profitability when market volatility would otherwise cause them to fluctuate unacceptably. And it has enabled buyers and sellers to lock in current market pricing conditions for physical transactions that will not take place until some time in the future. Applied to LNG, it would enable the parties to offset the sometimes irregular delivery of LNG cargoes. And a transaction for Middle East LNG for the U.S. East Coast can be locked in to the current market price despite the fact that it might take forty days for the vessel to deliver the cargo.

Futures quotations on the NYMEX exchange are available for thirty-six months into the future, and for longer term risk management, the over-the-counter swaps market extends the hedging period years into the future. While the NYMEX transactions are fully transparent, the swaps market lacks the transparency of the NYMEX exchange quotations.

The liquidity of the NYMEX market drops off significantly for later transactions, making it increasingly difficult to move large volumes without affecting the market. To pick a day at random, the report on NYMEX activity for January 16, 2003 showed an open interest of 55,840 contracts for February, the near month. For the May contract the open interest had fallen to 21,036 and for February 2004 it was down to 9,520. The December 2005 contract showed an open interest of only 1,709. There are no published figures for swaps activity, but the controversy of whether or not it can ever be liquid enough to hedge large long term LNG investments is not new.

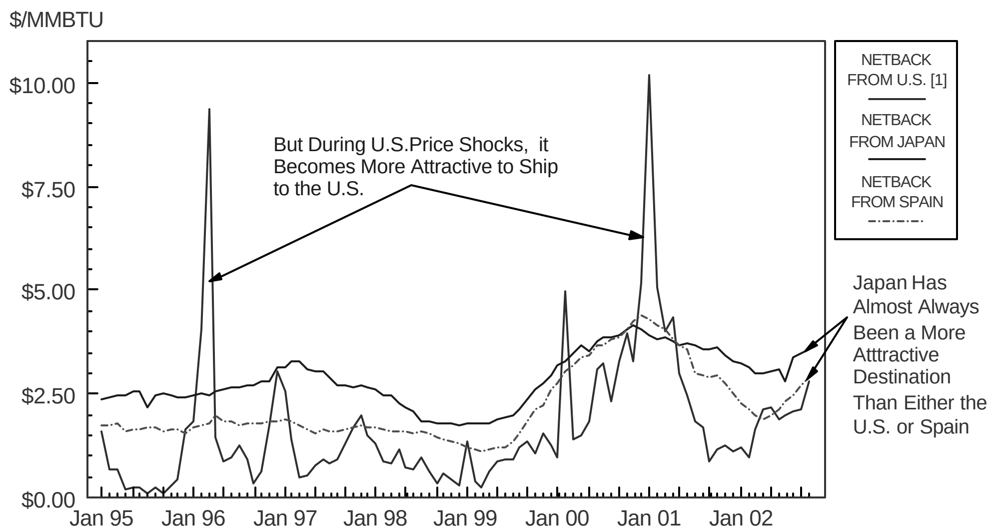
All financial derivatives depend on counter parties to offset the positions of those who want to hedge prices. For near months, market speculators contribute significantly to that role, but as contracts lengthen the market has relied more and more on the specialist market trading companies as the counter parties. The near collapse of the trading companies has markedly changed the outlook for long term risk management in LNG. Since some of the affected companies were leaders in the effort to develop the long term derivatives market, their problems - and in some cases complete withdrawal from trading activities - has sharply reduced the number of players who are prepared to accept that risk. If the idea that a financial derivatives contract could be used to hedge multi-billion dollar LNG investments was questionable before, it is now almost completely discredited. Who wants to buy a long term insurance policy if the insurer may go bankrupt before the policy has a chance to pay off?

The troubles of the marketing companies have revealed another difficulty with price monitoring. For market transactions that are not openly traded on the NYMEX, the trade press relies on contacts with buyers and sellers. It now appears that a number of company traders have deliberately misled the pricing services in an effort to manipulate the market. One El Paso trader has been indicted for allegedly providing false price information, and traders at least four other marketing

Figure 8

HYPOTHETICAL NETBACKS TO THE LOADING PORT THAT A MIDDLE EAST (QATAR) SHIPPER WOULD HAVE REALIZED SHIPPING TO THE U.S. EAST COAST, SPAIN OR JAPAN

ASSUMING FULLY ALLOCATED TANKER COSTS




[1] Assuming a $0.35 Regasification Charge on the U.S. East Coast

Prices World Gas Intelligence

companies are under investigation[16]. Since the trade press is the source for basis differential information, this suggests that the judgment of basis risk is riskier than it might otherwise appear.

**How Are the Political Risks Affected by Liberalization?**

The cross-border nature of LNG trade introduces a level of political risk that is largely absent in the more self-contained onshore pipeline markets. However, to be fair, the growth of cross-border pipelines, particularly those transiting third countries, is now introducing some of the same problems to pipeline markets.

The LNG industry got its lessons in political risk at an early point in its development. In the 1970s, the rapidly evolving Atlantic Basin LNG market was shaken by a pricing dispute between Algeria and its customers. With the startup of the last major liquefaction train at Arzew in 1980, Sonatrach achieved an export capacity of 26.3 BCM of LNG. However, the dispute caused a sharp drop in exports so that in 1980 Algerian capacity utilization fell to 23.2%. Not until 1990 would Algerian exports rise sufficiently to bring capacity utilization above 60%.

The dispute was compounded by the U.S. drive towards restructuring its gas industry, making it difficult to sell formula-priced gas in a gas-to-gas competitive market. The dispute shut down all four U.S. terminals for a time and both Elba Island, which reopened in 2001 and Cove Point, which has not yet reopened, were shut down for over twenty years. It also caused a severe surplus of LNG tankers, some of which did not come out of layup until their commitment to the Trinidad and Nigerian projects in the late 1990s.

However, many of the early problems of political risk seemed to have stabilized until new problems of political uncertainty have recently arisen in Indonesia, the world's largest LNG exporter. The guerilla activity of the Aceh separatists in western Sumatra was responsible for the temporary shutdown of the Arun liquefaction plant in 2001. And the secession of East Timor from Indonesia (final as of May 2002) caused the 1999 cancellation of the agreement with Australia for the Australia-Indonesia Joint Cooperation Area in the Timor Sea. This dispute, which affects both the Bayu Undan and Greater Sunrise LNG proposals, has not yet been fully settled[17] and has been a source of delay.

The companies have adjusted for these types of political risk by requiring higher hurdle rates where such risks are a factor in development. And they have caused companies to delay projects that were otherwise deemed economic. During the 1990s following the Gulf War, the Qatargas project found it difficult to sign up Japanese customers because of the perceived political instability of the Middle East[18] and the proposed Deltana gas development in Venezuela appears to have similarly suffered from the unrest in that country during the winter of 2002/03[19]. And at the buyers' end of the LNG chain, political problems in India - including, but not limited to Enron's Dabhol project - have set back a number of planned LNG projects[20]. India has also been affected by concern for the creditworthiness of some of the power generation buyers[21].

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16 World Gas Intelligence, December 11, 2002, p4

17 World Gas Intelligence, May 22,,2002, p5

18 Middle East Economic Survey, March 20, 1995, pA7

19 World Gas Intelligence, January 8, 2003, p1

20 Petroleum Intelligence Weekly, May 6, 2002, p5

21 World Gas Intelligence, November 28, 1997, p3

The impact of these risks on the newly restructured industry, is that it is very difficult for a planner to lay out a reliable forward estimate of capacity that is expected to come on stream to meet projected demand. This of itself introduces a potential source of instability in a market whose prices may be becoming increasingly volatile.

A second major source of political risk is the influence of changing tax regimes on supply projects. In an environment where tax regimes are often a part of the negotiations with the host government, their outcome clearly influences the ultimate feasibility of the project. The existence of a buyers' market for LNG with its implied competition among governments has served to discipline government demands in these negotiations, but a return to sellers' market conditions could alter this dynamic for those governments that do not have a uniform mineral tax code.

The difficulties inherent in siting receipt terminals has raised a new type of political risk to the LNG chain. In an effort to circumvent siting restrictions, several proposals have been made for terminals outside the U.S. for LNG that would primarily be intended for U.S. markets. While terminals in the Bahamas and in New Brunswick have been proposed, the most active interest has been in Baja California, Mexico for gas destined for the Southern California market. So far approvals have proved complicated to achieve[22] although active interest remains.

**How Does Technology Affect the Balance of Risk and Reward?**

The substantial cost reductions in LNG have been a major stimulus to the current revival in LNG's prospects. Probably the biggest single improvement in costs has been the increase in train sizes. The shift from steam-driven to gas turbine-driven compressors and the increasing size of the gas turbines has enabled LNG liquefaction train designs to break free of the 2-2.5 MM ton range which was common in the 1980s. Train sizes are now moving up to the 4 MM ton range and above.

The economies of scale in two 4 MM ton trains reduces the liquefaction cost of an 8 MM ton greenfield plant by nearly 30% compared to the cost of four 2 MM ton trains. And the increase in train sizes has not yet reached its limit. ExxonMobil is studying the economics of twin 7.5 MM ton trains for its "Qatargas 2" expansion for its proposed project for the U.K[23]. This might lower liquefaction costs by another 20%

Another group of technical innovations focusses on the increasing problems the industry faces in facilities siting in marine environments. This problem arises in two different ways - in receipt terminals and in liquefaction facilities.

The increasing popular resistance to receipt terminal siting and the costs of the necessary land have raised the possibility of marine terminals that address the siting problem. One possibility is the development of barge-mounted technology that would enable the terminal to be constructed in a shipyard and moored at the receiving location. A variant of this proposal is the construction of offshore terminals such as ChevronTexaco's proposal for Pelican Pass in Louisiana.

But perhaps the most innovative solution to the terminal siting problem is El Paso's proposed "Energy Bridge" technology. It would envision the regasification unit on the tanker itself, which could then deliver the regasified LNG directly onshore via pipeline. The advantages are clearly in the proposal's flexibility and ability to overcome the resistance of local groups. It has several disadvantages. Its high rate discharge system requires that the pipeline grid have the capability to absorb large flows and, while tankers can presumably be scheduled on a shuttle basis to minimize time off line, it probably needs backup storage to cover upsets in tanker arrivals. And its higher tanker cost may restrict it to shorter, dedicated runs where the expensive vessels can achieve high capacity operation.

[22] World Gas Intelligence, October 9, 2002, p2

[23] World Gas Intelligence, October 16, 2002, p1

In the producing area, the increasing development of remote offshore gas fields has led to the development of floating production platforms where liquefaction can be performed without the necessity to pipe hydrocarbon fluids long distances to an onshore gas processing and liquefaction plant. Shell's proposal for a Floating Liquefied Natural Gas Platform (FLNG) to develop its Greater Sunrise reserves in the Timor Sea has been pitted against ConocoPhillips's proposal to combine the Sunrise gas with its Bayu Undan gas in a multiphase pipeline from the fields to a Darwin, Australia liquefaction plant. The FLNG scheme combines some of the functions of production and gas processing with the liquefaction step so that it is difficult to make a direct economic comparison with stand-alone onshore liquefaction. Unfortunately, a recent economic evaluation concluded that neither approach was economic for the Sunrise reserves, thus clouding the decision as to FLNG's merits[24].

Another new technology with a potential impact on LNG is that of gas-to-liquids (GTL) conversion. Its potential effect on LNG is as a competitor for supply, and thus were a supply-constrained world to develop, its progress would be of significant importance to the LNG industry. The "large footprint" processes, such as those of Shell or ExxonMobil, need large gas reserves for support and are most competitive over long distances where their lower transportation costs give them a potential advantage. They thus are of special interest in places such as the Middle East. But since gas reserves are not limiting there, the two routes to gas commercialization do not now compete in the Middle East.

The "small footprint" technologies, such as Syntroleum or Rentech, are potentially much more able to compete over a wider range of locations. Sasol's process is intermediate in size. However, as yet, no direct competition between LNG and GTL has emerged and its effect on LNG does not seem to be an immediate one.

It is clear that LNG technological developments are proceeding and will be able to contribute to lower costs in the future. Whether costs will come down enough to make companies more willing to make speculative investments in new plants remains unclear.

**What Are the New Risks and Rewards That Flow From the "De-integration" of the LNG Chain?**

The theoretical free market model envisions a competitive market for each segment of the chain with its margins established by competition. But in a business where each link in the chain - production, pipelining, liquefaction, tanker transportation and regasification - is characterized by short run marginal costs that are low compared to long run costs, the risks inherent in uncoordinated investment is that prices may at times be very volatile. This raises the obvious question as to whether some links are inherently less risky than others. And in fact, are there portions of the chain where rents can be protected, enabling the holders of capacity to benefit from price weaknesses upstream?

The traditional LNG chain concentrated its economic rent upstream in field development. It was inherently a "netback" business in which margins for downstream activities were deducted from prices at the market to set the netback in the field. If the netback were high enough to justify field development the project was economically viable.
The peculiar characteristics of LNG have been that field development, the one element in the chain with the most significant variations in costs, and also commonly the most risky, was also a comparatively small part - perhaps 25% to 30% - of the combined investment. Thus a project developer had to set in motion an investment cycle by himself or by others that was perhaps three to four times the investment that he initially faced. And the netback status of LNG projects meant that small changes in downstream market prices were magnified -" leveraged" in American parlance or "geared" in English usage - at the wellhead. For a project whose margin was 30% of the combined chain margin, a 15% drop in the end market, if allowed to flow freely back to the wellhead, could result in a 50% drop in production margin. The fact that the point of transfer in the traditional long term contract excluded the regasfication margin moderated the risks to some degree, as did the development of special contract terms - floor prices and "S" curves - designed to provide the producer with some protection from severe drops in market prices.

[24] World Gas Intelligence, December 11, 2002

Wellhead costs vary significantly from project to project. At one extreme are those projects which have a "net negative opportunity cost" for the gas. This can occur in one of two ways. Some fields - Hassi R'Mel in Algeria or the Joanne and Judy fields in the North Sea are examples - are so rich in gas condensate that their development is economically feasible even if they were to flare the gas in the absence of a market. Since governments will not permit flaring for such fields, the gas can be transfer- priced internally at a negative value related to the cost of reinjection without adversely affecting overall return on investment. While there are very few fields so rich in condensate that they achieve "net negative opportunity cost" status, the economic contribution of condensate sales is a major factor in many if not most of the LNG projects to date.

The second way in which opportunity costs can be negative is when governments rigorously enforce restrictions on flaring of associated/dissolved gas from oil wells. To date, that has not been a big factor in LNG project development, but it is becoming more so. Flared gas often appears to outsiders to be a free good, but since it is often available only in relatively small quantities at low pressure at the wellhead separators, the cost of gathering and compression make its cost much higher by the time it reaches the plant gate. But if the producer must reinject to curtail flaring, the same economic logic applies as in rich gas condensate and a negative transfer price into liquefaction may be warranted. Restrictions on gas flaring in Nigeria and in Angola will put pressure on producers to put LNG projects together which might not have been feasible under earlier, lax flaring regulation. However, many projects do not have such favorable co-product credit economics. Hence they will be very concerned with price risk in the field and may not go forward if the that risk is viewed as too high.

In the netback economics that operate in LNG, rents tend to concentrate upstream in the host country, While it might be possible for the liquefaction plant to be operated in such a way as to retain some of the rent, in practice rents usually flow back to the field investment. This is both because the discovery gives the license holders some leverage over new participants that would like to invest in the liquefaction plant, and because - given the fact that most of the field investors are also plant investors - most have little reason to take the rent downstream from the field. In theory, a government entity that has monopoly rights to liquefaction, as does Pertamina in Indonesia, could try to exert its monopoly power, but it will not happen if the government perceives its role as that of facilitating the project. The government can take its share in other ways through the tax regime.

If the new competitive environment does indeed make it more difficult to secure volume guarantees from buyers at pricers acceptable to sellers, it argues that more of the integrated project risk has migrated to production and liquefaction. It may thus become more difficult to achieve the kinds of debt financing that characterized the old contract structure. In pipelining, the ship-or-pay contract signed by creditworthy shippers has provided the security to attract financing. But if the most logical shippers in the liquefaction plants are the producers themselves, it amounts to an equity investment on the part of the producers and probably should be expected to earn an equity return.

If companies perceive that they are operating in a higher risk environment, they may utilize a low "upset" price in their feasibility analyses to limit their exposure to downside risk. Or they may require a higher hurdle rate to justify the investment. Raising the hurdle rate of a liquefaction investment to 15% IRR for one that might earlier been justified at a 12% IRR would raise the liquefaction cost of service by about 15%.

In the Pacific Basin market, where security of supply remains as an important objective, the buyers' market has enabled buyers to negotiate equity positions in the upstream as a form of backward integration. Kogas has acquired a 5% share of Qatar's Rasgas project[25], China's CNOOC, Ltd. a 12.5% share of BP's Tangguh project[26], while Tokyo Electric and Tokyo Gas have tentatively acquired a 10.08% share in ConocoPhillips Bayu Undan[27].

But if buyers downstream in the Atlantic Basin market still have some control over final outlet, they may also be able to integrate upstream. Cabot/Distrigas (later acquired by Tractebel) and Repsol were both downstream companies that managed to acquire interests upstream in Trinidad. But pure marketing companies may lack the downstream control of market outlet for them to integrate upstream successfully.

The other major shift in risks and rewards involves the so-called "weak sellers" in the event that competition among joint venturers is actually introduced at the wellhead. In such a case, companies that must effectively take a discount to sell internally within the group, may find the wellhead investment unattractive and the policies could reduce the number of potential participants in joint ventures by excluding the smaller and weaker companies.

Most margins downstream of liquefaction have been constrained to utility-like levels and thus were not typically able to generate significant economic rents. LNG tanker transportation has always been regarded as a relatively stable margin business. In LNG, unlike in the more competitive oil tanker business, tankers were dedicated to specific trades and the long term charter made favorable financing available. And since tanker construction was competitive among a number of shipyards, and there was no shortage of competitive tanker operators the assumption of utility-like margins was warranted.

Uncommitted tankers began to appear both when they became available upon the expiration of contracts and several were brought out of layup for later use in the Nigerian project. Now, the new market environment has spawned a new group of uncommitted tankers that are free to operate in the short term market[28]. This suggests that the LNG tanker business will increasingly look like the oil tanker business. But LNG tankers represent larger investments, and the swing in tanker demand as long distance markets ebb and flow may make speculative tanker ownership somewhat riskier than speculative oil tanker ownership. However, the rewards can also be larger. Those who have the tanker capacity to deliver spot volumes to a market with very strong prices - as was the case in the U.S in the 2001/02 winter - stand to benefit substantially. The advantages to a large major company with multiple sources and multiple terminal outlets of keeping spare tanker capacity is clear. How much room there may be for purely speculative tanker operators is much less so.

Since most traditional buyers were either regulated utilities or government monopolies, downstream rents for receipt and regasification were commonly regulated. While the buyers may not have been as effective in restraining costs as they might have been under a competitive regime, their ability to take monopoly rents was constrained.

However, the restructuring of the industry together with the emergence of the environmental/land use issues in market countries is having a powerful influence on the terminal portion of the LNG chain. Resistence to new terminals has been a significant factor in efforts to expand U.S. imports of LNG. Terminals that Italian buyer Enel had planned for receipt of its contracted Nigerian LNG demand were thwarted by local resistence to new terminals, forcing international arbitration of the contract and an ultimate deal with Gaz de France to serve Italy by displacement[29]. A continuation of

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[25] World Gas Intelligence, August 26, 1999, p1

[26] Petroleum Economist, December 2002, p40

[27] World Gas Intelligence, March 13, 2002, p1

[28] World Gas Intelligence, December 11, 2002, p8

[29] World Gas Intelligence, September 30, 1997, p11

terminal siting resistance in importing countries threatens to create significant scarcity rents for those who hold the rights to existing terminal capacity.

The sharp increase in U.S. gas prices in the winter of 2001/02 gave rise to a rash of U.S. terminal proposals, not only for the U.S. itself, but for Mexico, the Bahamas and the Canadian Maritimes. Clearly, the ability to bring spot LNG cargoes into such a market offers the potential for significant rents that did not previously exist under the earlier, more structured LNG markets. And if terminal construction is to be restricted by siting objections, the market power that the holder of capacity might enjoy can be substantial.

The U.S., until its most recent decision to permit the construction of proprietary terminals, was requiring open access to terminals (with the exception of Everett, an intrastate entity). But since open season bid winners could control terminal access for the life of the agreement, the rents remained.

However, the attractiveness of terminals for independent marketers was diminished by the market events following the sharp price run up. A subsequent collapse in U.S. prices caused Europe to outbid the U.S. for cargoes in the emerging Atlantic Basin arbitrage and volumes to the U.S. sharply declined. This is illustrated in Figure 9, which shows LNG receipts at the three operating U.S. terminals from January 2000 to late 2002 compared to the sendout capacity of the terminals. The 70% capacity factor that the terminals achieved during the first nine months of 2001 fell to 22% for the following six months[30].

All of the U.S. terminals are more than twenty years old and their economics are largely based on sunk costs. However, a greenfield terminal that declined from a 70% capacity factor to a 22% capacity factor would see its cost of service nearly triple. This suggests that sellers may increasingly view investment in terminals as a means of integrating downstream while some of the independent merchants may find them too risky and withdraw.

**"Synthesis" - What Might it Look Like?**

The synthesis of traditional LNG practices and a theoretical competitive market may well not yield the same industry structure in all regions, nor is it likely to produce one corporate model that can be successful for all companies. The shifting of risks and rewards affects companies differently depending on their size and on where in the world they choose to operate.

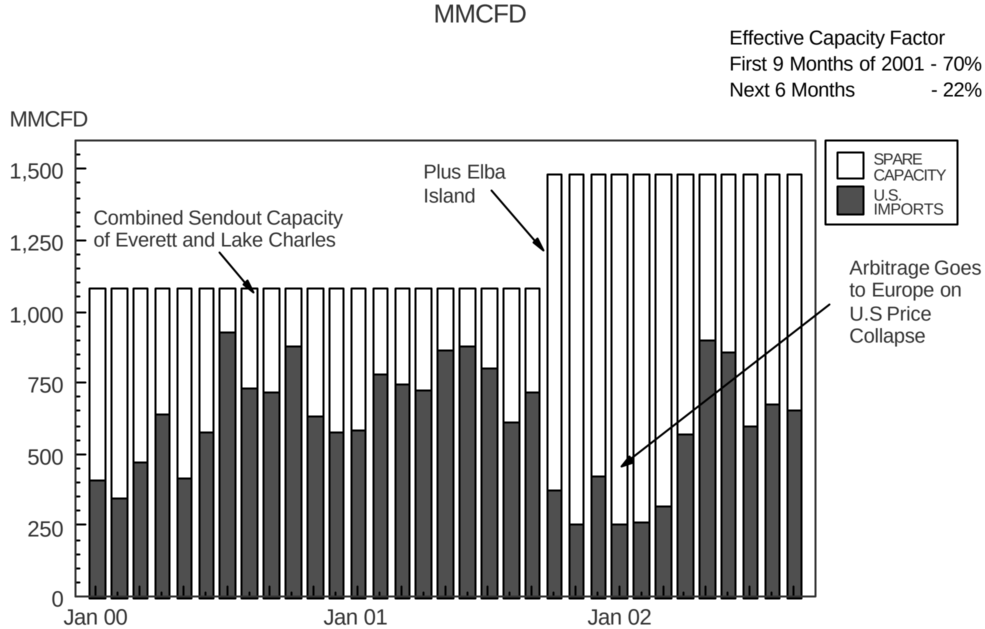
To date, "Asia" in markets has meant Japan, Korea and Taiwan. It is about to include China and India as well. And it may at some point also include the North American west coast as a part of the Pacific Basin.

The first three countries have little or no domestic gas industry so that their risk exposure to supply upsets is quite high. Although they do have some flexibility to switch to oil firing to replace gas-fired generation, they have shown little interest in taking the supply risks that a heavy reliance on spot markets would entail. Korea, the most venturesome of the three in the short term market, has never imported more than 10% of its LNG as short term gas. And the upsets in Asian LNG supply that have followed Tepco's shutdown of five nuclear reactors in the winter of 2002/03 may cause Kogas to rethink its short term supply policies.

For these three countries, liberalization does not appear to threaten the central role of the long term contract. Buyers may well be able to negotiate contracts of shorter duration with more flexible offtake provisions and with lower prices than have historically prevailed. And if the buyers' markets persist, it may enable more of the purchasers to integrate upstream, as several purchasers have done.

[30] The Everett terminal was also prohibited from landing several cargoes immiediately after 9/11 because of security concerns

Figure 9
COMPARISON OF U.S. LNG TERMINAL IMPORTS WITH CAPACITY
MMCFD



China's gas industry is in a state of flux as it tries to build new markets simultaneously with indigenous pipeline supply and with imported LNG. Initially, at least it is acting much like the traditional Northeast Asian buyers, so there has been very little evidence as yet that it is prepared to rely significantly on short term LNG to supplement its pipeline supply as have Europe and North America. This suggests that the historic reliance on contracts will continue for this part of the Asian market as well.

Perhaps the biggest influence that China has had on the potential outlook for long term contracting in the Pacific Basin has been its use of the competitive tender process for awardiing a contract for its proposed Guangdong terminal. This introduced a level of direct competition among suppliers that had not previously existed and supposedly led to significant reduction in contract price levels. To some extent, the coexistence of secure Asian contract outlets and their relatively high prices has provided an umbrella for Middle East suppliers to participate in European and North American spot trade. How a stronger bargaining stance on the part of the historic Asian purchasers will impact on the Atlantic trade is difficult to predict at this point.

Southeast Asian suppliers with quality gas reserves have a transportation advantage over the Middle East for the East Asian market, but low cost supplies from the Middle East have still been able to compete. If the present contracting patterns continue, this competition is likely to remain much as it has been, creating a niche for quality discoveries in Southeast Asia while still providing opportunity for Middle East supplies.

India is also an emerging part of the Asian LNG market and one whose proximity to Gulf supplies makes it a natural market for the Middle East. Although pipelining may make more economic sense for portions of the subcontinent, political constraints currently favor LNG.

To date, India's LNG contracting has been plagued with other political problems in developing a market for LNG. The dispute over Dabhol and the concerns of the financial community about buyer creditworthiness have concerned potential suppliers. While the long term contract is still the method of purchasing, suppliers must factor in the higher risk that this market has shown in its early efforts to import LNG.

The development of a North American west coast market is being actively pursued by both consumer/distributors as well as by suppliers with gas in Asia or in South America. Assuming the west coast can overcome California's resistance to terminal siting (perhaps with Mexican complicity), California trade would appear to be a vehicle for introducing Atlantic Basin style arbitrage into Pacific markets. But the distances are long and the tanker flexibility required to play both sides of the Pacific Rim is great. It would seem that a Pacific Basin arbitrage market, if it develops, will look quite different from the Atlantic Basin one.

The Atlantic Basin has been the leader in relying on short term markets and shows every evidence of continuing to do so. It also has led the way in developing a system of pricing arbitrage between Europe and the U.S. But no liquefaction plant expansion has yet been launched without a long term contract, suggesting that the trade will ultimately stabilize at some mix of short term and long term volumes. And if long term contracts remain as a "filter" that determines whether or not an LNG liquefaction project goes forward, the upstream supply may not ultimately be as robust as the trade press currently makes it out to be.

The traditional long term contract is under the greatest attack in the Atlantic Basin, particularly in the U.S. In the U.S.'s liberalized gas market with its growing reliance on market competition in the power generation sector, it is increasingly difficult to find customers who can honor the old commitment ..."the buyer takes the volume risk"... unless the pricing terms so closely match the short term market that the risk has effectively been transferred to the seller. For a time, it looked as if the independent merchants could perform the buyer's risk-taking role, but their financial difficulties over the past two years has seemingly limited the potential in that direction.

The traditional long term contract effectively enabled the gas producer to secure downstream market outlet without developing the integrated industry structure that has been common on the oil side of the business. But with the weakening of the buyer guarantee in the restructured North American gas industry, downstream integration in gas now looms as an option. And it is interesting to see that the balance may be shifting in favor of such a downstream integration option.

In the U.S. market, the control of the terminal capacity may be especially important. If siting restrictions give terminal capacity holders substantial market power, they are best situated to capitalize on the volatility of the U.S. market when prices are high. Figure 4 showed that the largest departure from average Henry Hub price performance over the last decade was upside rather than downside during its 2000/01 peak. A U.S. terminal operator who could buy in a distressed LNG spot market at that point and resell into the U.S.market was in a position to capture significant economic rent. This argues strongly for producers to acquire access to terminals rather than letting the merchants take that margin.

While other suppliers and other markets are important, the heart of the Atlantic Basin arbitrage involves the U.S. and Spain, focussing on Trinidad supply. Both Spain's Repsol and Belgium's Tractebel own shares in Atlantic LNG in Trinidad, but they also control terminal capacity downstream. Tractebel now owns the Everett terminal and Repsol has a financial position in Gas Natural in the Spanish market. Since Tractebel also has a stake in Belgium's Zeebrugge terminal, the two companies have had an unusual base from which to arbitrage North American and European prices. Their model has been that of regionally integrated companies, involving an equity share in liquefaction so situated that it can serve either continent, controlled terminal capacity at market and controlled shipping.

Only one of the four existing LNG terminals - Everett, with 13% of the combined capacity - is owned by a company with its own source of LNG. The other three are owned either by their original pipeline sponsors or by their successor companies. While the pipeline companies also have had active trading subsidiaries, much of the capacity has now been contracted under "open season" bidding rules to companies with upstream assets.

One industry estimate[31] is that Tractebel, together with BG, BP, Shell and Statoil - all companies with upstream assets - now control 95% of U.S. throughput capacity. One of the largest downstream commitments was made by BG in taking all of Lake Charles's existing capacity for 22 years[32]. It would appear that the interests of producers in integrating downstream is shifting the balance of U.S. terminal interest towards producers and away from the marketing companies.

This may well influence the pace and outcome of additional terminal construction in the U.S. The early rash of proposals for new terminal capacity following the sharp gas price runup of 2000/01 appeared to be heavily skewed in favor of merchant gas trading companies without upstream integration. For example, ten of the twelve terminal proposals that the EIA lists for the U.S. markets in a 2001 gas supply study[33] (assuming that Mexico's Altamira project is for Mexican consumption) were sponsored by companies without an equity interest in liquefaction. If the balance of interest is now shifting in favor of downstream integration and away from the merchant marketers, it would suggest that many of these earlier merchant-sponsored terminal proposals are no longer on the table.

Gas market liberalization is proceeding somewhat unevenly in the EU, with some countries aggressively restructuring their gas and electric industries but others holding back. But Europe is in an interesting competitive buying position as its industry liberalizes. If the Middle East is increasingly taking over the balancing role (i.e., prepared to ship east or west) for world gas markets, Europe has a built-in transportation advantage because of the much shorter tanker haul to Europe versus the U.S. Thus a holder of terminal capacity in Europe - particularly if its growth will be constrained by siting restrictions - is in an excellent position to capitalize at times when the market conditions are right. This argues for the upstream companies to attempt to secure European markets downstream, either through open season bidding or outright ownership, in order to preserve their margins in weak markets. The fact that the upstream companies have

[31] Private communication, Gordon Shearer, Poten & Partners

[32] World Gas Intelligence, April 19, 2002, p1

[33] U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply, Energy Information Administration, December 2001, p31

been arguing strenuously on both sides of the Atlantic - and in the U.S. successfully - that they need proprietary terminal capacity downstream is another evidence of the importance of downstream control in the feasibility of liquefaction investments.

The effect of all of these pressures on the future structure of the LNG industry is complex and analogies to oil industry structure are not necessarily relevant. From time to time, gas producing countries have met to discuss the possibility of a coordinated effort - an Organization of Gas Exporting Countries, similar in structure to OPEC, with perhaps Qatar in similar position in gas to Saudi Arabia in oil.

The differences between the two markets suggest that this concept is unrealistic. It is not the size of the proved oil reserves in the Gulf that gives the Middle East its influence over markets and prices. It is the low cost of production coupled with the low cost of oil tanker transportation that makes the Middle East potentially the low cost supplier to world wide markets. In contrast, the Middle East, for all its sizeable gas reserves, is a high long run marginal cost supplier to both East Asian and North American markets and thus cannot exert the type of influence on prices that it can in oil.

A more likely analogy to the development of the oil industry is the example of the "Seven Sisters" of the 1950s and 1960s. Then, seven integrated companies - BP, Esso, Gulf, Mobil, Socal, Shell, and Texaco - dominated world oil markets. Their influence was based on their control of most of the major oil concession areas and the downstream markets they had developed to move their supplies. Other significant oil companies existed, but their role was often specialized or regional.

The modern gas equivalent - the "Five Sisters" - is based not on control of world wide gas reserves, but on the sheer size of the companies. If it is true that the new free market model tends to shift project risk to the producers, thus making it more difficult to finance projects with debt in the traditional way, then self insurance through downstream integration and the acquisition of a diversified portfolio of LNG projects is a realistic alternative. And larger companies can afford the luxury of owning undedicated tankers to take advantage of special market situations when they arise. But the capital expenditure budgets required to follow such a diversified strategy are so large that few companies can afford it

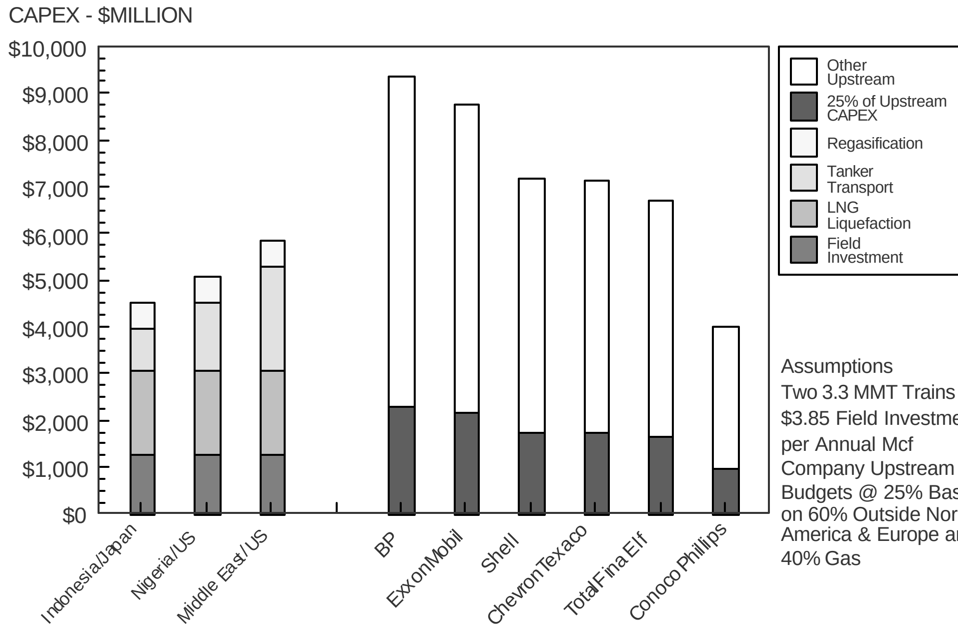
The wave of mergers and acquisitions in the oil business has created five "super majors" - BP, ChevronTexaco, ExxonMobil, Shell and TotalFinaElf. Another merger has created another large oil company - ConocoPhillips - but it is smaller than the other five. And one company, BG, has attempted to become an international integrated gas company starting from a gas, rather than an oil, base.

If one were to define a fully diversified position as one in which the company has liquefaction capacity in the three regional producing areas - Asia Pacific, Middle East and Atlantic Basin - control of tanker capacity and secure market outlet in the Atlantic and Pacific Basins either through terminal acquisition or long term contracts, then the total capital expenditure is quite high. Figure 10 illustrates the capital expenditures required for two train greenfield projects in each region. The combined total in the Figure exceeds $15 billion. And while companies can reduce their financial outlays thorough joint venturing, contracting and spreading the outlays over several years, these numbers are high compared to the capital expenditure budgets of even the largest oil companies.

Figure 10 also shows the upstream capital expenditure budgets for the five super majors together with Conoco/Phillips for the year 2001. A large portion of those upstream budgets is dedicated to exploration for oil or for gas in regions with pipeline outlet and thus is presumably not available for LNG. The composite upstream budgets of the five companies are dedicated roughly 60% for the world outside North America and Europe, and 40% of their reserve additions (in barrels of oil equivalent) are in gas rather than in oil. Taking 25% as a reasonable upper limit on the upstream capital available for LNG, only two companies, BP and ExxonMobil, had much as $2 billion available in 2001. Both Shell and BP break out their expenditures for "Gas and Power" which includes electricity investments but does not include LNG field development. In those two cases the Gas & Power budgets in 2001 did not exceed $500 million.

Figure 10

THE GREENFIELD LNG PROJECT "ENTRY FEE" COMPARED TO THE UPSTREAM 2001 CAPEX BUDGETS OF SELECTED COMPANIES




Assumptions
Two 3.3 MMT Trains
$3.85 Field Investment per Annual Mcf
Company Upstream Budgets @ 25% Based on 60% Outside North America & Europe and 40% Gas

Nor is the capital expenditure budget the sole barrier to entry upstream. Companies must have earlier taken a license position in an area where there are gas reserves of economic quality to support an LNG plant. And while it is possible to buy in later (particularly if one has downstream market power such as Kogas, CNOOC, Tepco and Tokyo Gas), this may be a costly way to acquire a diversified portfolio of production.

In fact, only three of the five largest companies qualify as fully diversified by having supply positions is all three regions - BP, Shell and TotalFinaElf. Even TotalFinaElf has not yet elected to acquire downstream capacity rights in North America and thus is not in the position to arbitrage both sides of the Atlantic Basin as can Repsol and Tractebel. Neither ExxonMobil nor ChevronTexaco have LNG production in the Atlantic Basin although ChevronTexaco's Angola and Nigerian projects are candidates for development. Exxon in the past has attempted unsuccessfully to develop a Venezuelan project at Cristobal Colon and the company has an interest in a possible Nigerian project.. ExxonMobil is currently attempting to operate in Atlantic Basin markets by building an import terminal in the U.K. based on Qatar supplies[34].

ChevronTexaco is the only one of the group without a position in the Middle East. But the fact that such a position is not easy to come by is illustrated by the fact that of the combined capacity of the four liquefaction facilities in the Middle East, the NOCs own 60% of the equity, Kogas and the Japanese trading houses own 12%, and four of the "Five Sisters" own the remaining 28%. No other oil company owns an equity share in any of the projects.

But just as the "Seven Sisters" were not the only profitable oil companies during the 1950s and 1960s, there will be other strategies for smaller companies that will still prove to be profitable in LNG. If the "Five Sisters" club is restricted to the largest oil companies, regional integrated positions are available at a lesser price tag. The "Atlantic Arbitragers" group includes BG, Repsol and Tractebel, and will eventually be joined by Statoil and the other partners in Norway' Snohvit project. These companies have been content to operate in the more open Atlantic Basin markets where they can arbitrage European and U.S. markets, leaving Middle East and Asia Pacific supply positions to others.
Other companies may limit their integration efforts to Europe following the example of ENI. Its acquisition of 50% of the Spanish electric utility, Union Fenosa, potentially gives ENI an integrated position between Nigerian and Egyptian supply and Italian and Spanish markets. The financial problems of the U.S. gas merchants have reduced the ranks of those companies wanting to participate in U.S. LNG markets without investing in upstream assets.

And in the Pacific Basin, the traditional contract is still possible, although perhaps on somewhat less favorable terms than used to be the norm. Conoco/Phillips' agreement with Tepco and Tokyo Gas appears to be a classic contract in the traditional fashion, but with the proviso that the two Japanese companies acquire a stake in the upstream.

If the ability to acquire complete LNG diversity is beyond the financial capabilities of any but the largest companies, the success of the others will depend on their creativity in finding and exploiting the niches in this complex system.

**In Conclusion**

The LNG "revolution" - the clash between the highly-structured, traditional approach to long term LNG contracting and the model of natural gas as a workably competitive commodity market - has been under way for more than a decade. In some respects its progress resembles the similar liberalization that has taken place in onshore gas markets in North America, the U.K. and is now taking place on the Continent. LNG has developed a significant short term market, the use of short term financial derivatives for risk management and what was once unthinkable - interregional price competition.

[34] World Gas Intelligence, October 16, 2002, p1

But just as the liberalization of the domestic U.S. gas market has proved more challenging than many expected - as witness the U.S. natural gas price shock of the winter of 2000/01 and the financial problems of the natural gas merchants - the complex cross-border nature of LNG trade should make LNG liberalization even more so.

The capital expenditures for field development and the liquefaction facility in the producing country represent the largest share of the capital budget of a complete LNG "chain". To date investors have continued to require long term contract commitments before they will proceed with such upstream investments. Therefore, the long term contract will probably remain the mainstay of the industry. However, the traditional contract is more likely in the Pacific Basin where the buyers are more risk-averse because of their almost complete dependence on LNG for their gas supply. In a buyers' market, however, they will continue to seek integration upstream and more flexible terms as a part of their contract commitments.

In contrast, the Atlantic Basin market has been much more flexible in its willingness to utilize the short term market. Thus, the degree of volume security implied by the buyer's commitment in the traditional long term contract has deteriorated, shifting more of the project risk to the producers. To accomodate this added risk, suppliers are more likely to try to control market volatility through downstream integration - acquiring control of receipt terminal capacity where "open season" bidding processes are used to allocate capacity or building proprietary terminals where regulations permit them. They will also try to cover risk internally through a diversified portfolio of LNG supplies, tanker transportation capacity and downstream commitments,

Because of the large capital expenditures required for complete LNG chains, such diversification will prove costly and only the largest super majors - the "Five Sisters" are likely to be able to achieve the highest levels of diversification involving supplies in the Asia Pacific region, the Middle East and Atlantic Basin, together with market outlets in both Asia and the Atlantic. Other smaller companies may choose regional integration, for example, Mediterranean supply for European markets. Where companies still control some level of downstream markets, upstream integration is an option. A special group in this smaller integrated category might be called the "Atlantic Arbitragers", since their access to integrated Atlantic Basin supply, tanker capacity and terminal outlets enables them to arbitrage North American and European prices through their ability to ship to Europe or the U.S. as the price signals dictate.

The outlook for the marketing companies without assets upstream is probably less favorable than it might have appeared two years ago. But the LNG business remains highly complex and opportunities for "niche" positions still exist, both for marketers and for companies with economically attractive gas discoveries. LNG is, after all, a growth business. But it is the essence of revolution that the old ways will no longer work as they once did, and that the revolutionaries that follow the old guard may not have the final answer either. However, those who understand the implications of Hegel's "synthesis" shoud be able to survive and prosper.