Fostering LNG Trade:

Developments in LNG Trade and Pricing

Energy Charter Secretariat 2009

Disclaimer

Information contained in this work has been obtained from sources believed to be reliable. However, neither the Energy Charter Secretariat nor its authors guarantee the accuracy or completeness of any information published herein, and neither the Energy Charter Secretariat nor its authors shall be responsible for any losses or damages arising from the use of this information or from any errors or omissions therein. This work is published with the understanding that the Energy Charter Secretariat and its authors are supplying the information, but are not attempting to render legal or other professional services.

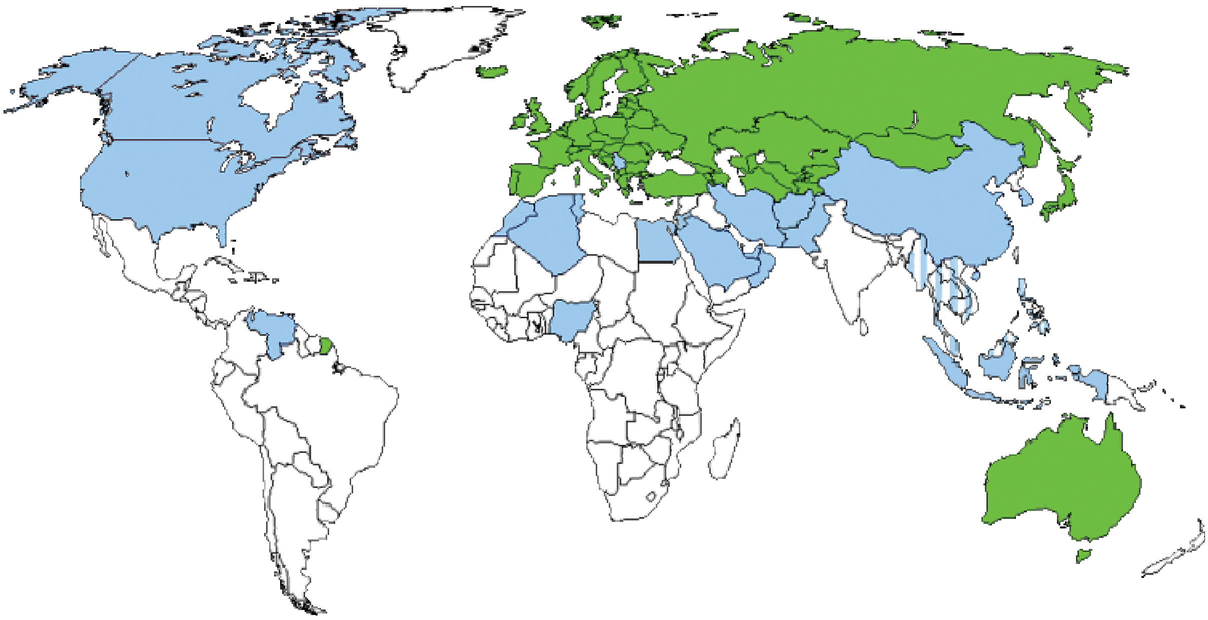
Boulevard de la Woluwe, 56
B-1200 Brussels, Belgium

ISBN: 978-905948-079-7 (English PDF)

The Energy Charter Treaty

The Energy Charter Treaty is a unique legally-binding multilateral instrument covering investment protection, liberalisation of trade, freedom of transit, dispute settlement and environmental aspects in the energy sector. It is designed to promote energy security through the operation of more open and competitive energy markets, while respecting the principles of sustainable development and sovereignty over energy resources. The Treaty is the only agreement of its kind dealing with intergovernmental cooperation in the energy sector, covering the whole energy value chain (from exploration to end use) and all energy products and energy-related equipment.

Based on the Energy Charter of 1991, which was a political declaration signalling the intent to strengthen international energy ties, the Energy Charter Treaty was signed in December 1994 and entered into force in April 1998. To date, the Treaty's membership covers fifty-one states plus the European Communities, which together represent nearly 40% of global GDP. There are also twenty-three observers, as well as ten international organisations with observer status.



<u>Members of the Energy Charter Treaty:</u>

Albania, Armenia, Austria, Australia, Azerbaijan, Belarus, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, European Communities, Finland, France, Georgia, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Kazakhstan, Kyrgyzstan, Latvia, Liechtenstein, Lithuania, Luxembourg, Malta, Moldova, Mongolia, the Netherlands, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Tajikistan, the former Yugoslav Republic of Macedonia, Turkey, Turkmenistan, Ukraine, United Kingdom, Uzbekistan

<u>Observers:</u>

Afghanistan, Algeria, Bahrain, Canada, China, Egypt, Indonesia, Iran, Jordan, Korea, Kuwait, Morocco, Nigeria, Oman, Pakistan, Palestinian National Authority, Qatar, Saudi Arabia, Serbia, Tunisia, United Arab Emirates, United States of America, Venezuela
(vertical stripes denote the countries of ASEAN)

<u>International Organisations with Observer Status:</u>

ASEAN, BASREC, BSEC, CIS Electric Power Council, EBRD, IEA, OECD, UN-ECE, World Bank, WTO

Foreword

Since the Secretariat published the pricing study “International Pricing Mechanisms for Oil and Gas: Putting a Price on Energy” (2007) and the LNG study “Fostering LNG Trade: Role of the Energy Charter” (2008), there have been major changes within the energy sector and more widely. These changes have created the need to update and expand the earlier publications.

One difficulty that markets, policy makers and investors face in the energy sector is the long lead times between project initiation and completion. The element of time complicates the future supply and demand. For LNG, the delay between the final investment decision (FID) on the construction of a plant and the project start-up is typically four years, or more. In these circumstances, the pricing signals which initially justify a new project do not necessarily provide an accurate indication of the supply needed to balance future demand. For this reason, it has been the case frequently that supply may finally come on-line under very different market conditions from those that existed when the project was originally conceived.

In this study, the LNG supply, demand and costs in the volatile market that prevailed in the middle part of this decade are considered in detail. The particular focus is on how these factors affected LNG pricing and trade patterns.

The report was written by Jim Jensen, a consultant and a co-author of the two abovementioned studies, under the supervision and guidance of Ralf Dickel, Director for Trade and Transit of the Energy Charter Secretariat. The study greatly benefited from discussions with delegates from the Energy Charter member governments in the Trade and Transit Group meeting held in May 2009.

This report is made publicly available under my authority as Secretary General of the Energy Charter Secretariat and without prejudice to the positions of Contracting Parties or to their rights or obligations under the Energy Charter Treaty or the WTO agreements.

André Mernier
Secretary General
June 2009

Table of Contents

List of Figures

Chapter 1. Introduction

The goal of the worldwide trend towards liberalisation of natural gas markets has been to let "gas-to-gas" market competition set prices for the commodity. In an ideal world, competition would drive equilibrium prices to the long run marginal costs of the supply just necessary to meet demand.

But international gas markets – and particularly LNG markets – still depart substantially from the competitive ideal, so that price determination is extremely complex. And the departures from ideal commodity competitive conditions differ substantially by region so the goal of an international gas pricing system in which LNG trading establishes world gas prices remains elusive.

Pipeline and LNG investments pose special problems for the competitive commodity model. The investments are capital-intensive with long lead times between project initiation and completion. They are front end loaded in that revenue does not usually begin until the project has been completed. And they typically have low short run marginal costs, even if long run costs remain high. This is particularly true in the case of domestic supply, which often determines the prices against which imports must compete.

Because they are capital-intensive, they have traditionally been debt-financed, and lenders have commonly required long-term contracts to insure debt service. The long-term contract also provides clauses that share project risk between buyer and seller. The old adage, "The buyer takes the volume risk and the seller takes the price risk" has led to take-or-pay clauses for buyers and pricing clauses for sellers. The pricing clauses in Northeast Asia and in most of Europe have traditionally utilised oil-linked pricing. The original Japanese pricing clauses, later adopted by other Northeast Asian importers, pegged gas prices to the cost of crude oil imported into Japan where crude oil as well as fuel oil was used for power generation. The original Algerian pricing clauses utilised a basket of crude oils for their escalation clauses. Later LNG contracts into Europe also use a mix of oil products, which was typical of pipeline contracts. These pricing clauses effectively defeat the goal of gas-to-gas price competition as a means of establishing gas prices. The process of market liberalisation has been slow and oil-linked pricing remains common in much of the world.

The long lead times between project initiation and completion also complicate the price response. For LNG, the delay between the final investment decision (FID) on plant construction and project start-up is typically four years or more. Thus the current pricing signals, which justify a new project cannot provide the timely supply needed to balance current demand. And the resulting supply may finally come on line under very different market conditions.

The disparity between short run and long run marginal costs tends to lend great price volatility to prices in markets such as North America or the UK, where domestic supply predominates over imports. During domestic surpluses, prices may well fall significantly below long-term equilibrium levels. Thus the pricing of LNG must find a way to deal with such pricing volatility in the target market.

Chapter 2. LNG Supply and Demand

2.1 The Evolution of the Current Market

The first commercial shipments of LNG were Atlantic Basin movements from Algeria to France and the UK in 1964. But after early Atlantic enthusiasm for LNG cooled, Northeast Asia became the driving force for LNG trade. By 1997 Japan, Korea and Taiwan accounted for 76% of world LNG imports. In that year the six electric and gas utilities based in Tokyo, Osaka and Nagoya alone accounted for more than 50% of world trade.

But since 1997, interest in the Atlantic Basin has returned and supported much higher growth in LNG trade. During the 14 years between 1997 and 2011, when LNG plants under construction will be completed, LNG growth rates will average 8.4%; for the previous 14 years they averaged only 4.7%

The reasons for renewed Atlantic Basin growth are varied; they include:

- The inability of North American supply to keep up with demand
- The transition of the UK from net exporter to net importer
- The interest in gas fired combined cycle power generation which is driving growth in countries, such as Spain
- European interest in supply diversification

The sharp change in the outlook for Atlantic Basin LNG demand began in Spain in 1999 as gas-fired power generation began to take hold. By 2002, Spain had become Europe's largest LNG importer. Then in the winter of 2000/2001, severe gas shortages in North America created a "gas price shock" reviving long-dormant North American interest in LNG. And then, in anticipation of the UK's coming transition from net exporter to net importer in the winter of 2005/2006, the UK became a major LNG target market.

The winter of 2005/06 was a "perfect storm" for world gas markets. In North America, hurricanes Katrina and Rita severely affected production. In the UK, the transition from net exporter to net importer created new import demand. In Spain poor hydro conditions created demand for gas fired combined cycle gas turbines (CCGTs) to generate power and on the Continent, there was a cold winter. The result was severe competition for LNG cargoes and sharp price spikes.

The appearance of inadequate LNG supply to serve world markets continues. While markets in the Atlantic Basin have relaxed somewhat, panic buying in Northeast Asia has kept Pacific Basin markets tight. The Asian market conditions are primarily due to supply problems in Indonesia and a nuclear upset at Tokyo Electric in Japan.

For years, the largest and most reliable LNG supplier, Indonesia has recently been unable to meet its contract commitments and fell about 10% below contracted levels in 2007. The Indonesian problem stems from declining production in its older fields, under investment in new supply, political unrest and a desire to use more of its gas internally.

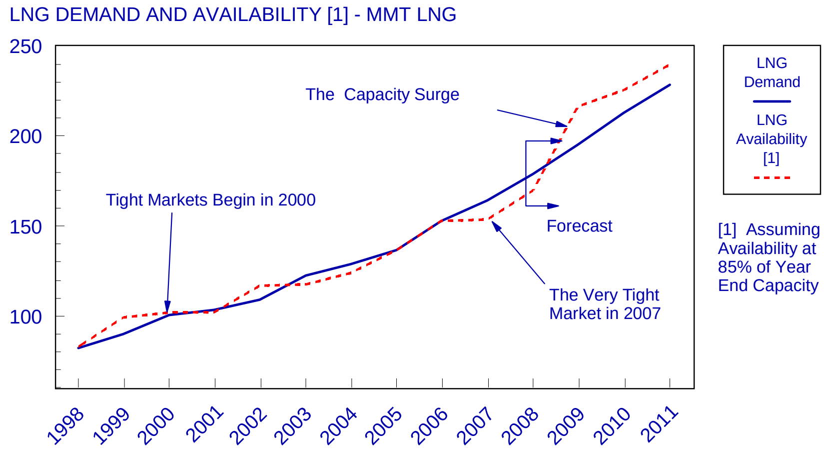
In Japan, a 2007 earthquake on a fault near Tepco's largest reactor forced the extended shutdown of 7 reactors. Tepco's effort to replace the lost generation has been highly disruptive of both LNG and oil markets in Asia. The tight Asian markets have attracted spot LNG cargoes from the Atlantic Basin and driven up spot prices throughout the world. In 2008 Algeria, Egypt, Equatorial Guinea, Nigeria, Norway and Trinidad all delivered spot cargoes to Japan.

2.2 Projected Outlook

The overheated Asian market comes at a time when new supplies – with their four year or more lag time from FID to completion – have had difficulty keeping up with demand. The result has been an extended period of very tight markets.

But that is about to change as a surge in new capacity ordered in the 2004/2005 time frame is about to come on line. Figure 1 compares demand with potential LNG "availability" (defined as 85% of year end capacity), for the period 1998 to 2007 and a Jensen Associates estimate of the balance out to 2015. The potential for reversing the recent chronic shortages is apparent.

Figure 1: Comparison of LNG Yearend Capacity with Demand, Showing the Potential Capacity "Surge"

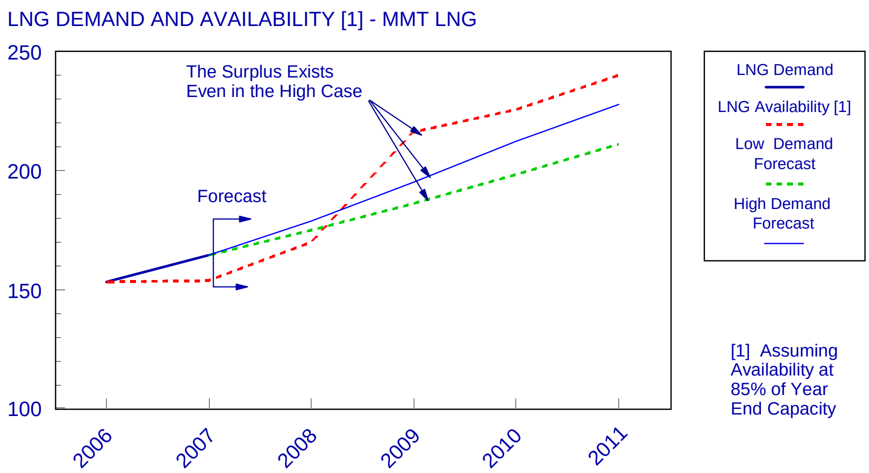


Source: Jensen Associates

The supply forecast to 2011 largely represents plants under construction and thus is a fairly reliable estimate of what will come on line. While this forecast anticipates a continuation of the surplus for 2012 and beyond, all of the capacity additions in 2012 are in probable plants that have not yet received their FIDs and thus must be regarded as more uncertain.

The demand forecast assumes that the recent rate of growth can be sustained in the period out to 2015 as the new capacity comes on line. With this estimate, the surplus is 5% of the expected demand as is illustrated in Figure 2.

Figure 2: Potential Capacity "Surge" for both High and Low Demand Scenarios



Source: Jensen Associates

But several factors suggest that the demand estimate could be on the high side. The impact of the current world financial crisis will undoubtedly have a negative effect on demand and on the ability to finance plant construction, but its full extent is difficult to determine. However, the emergence of a surprisingly large increase in North American domestic production has substantially reduced earlier expectations of the need for LNG imports into the region. Since North America was expected to account for about 30% of world growth in LNG demand, any substantial drop in the forward estimate for North America has a substantial impact on the forecast.

While both of the international forecasting agencies – the US Energy Information Administration and the International Energy Agency – have expected that higher prices would bring forth additional production, neither anticipated that the supply effect in North America would be so large. To illustrate in its most recent Annual Energy Outlook 2008, the EIA expected US production to be 5.5% greater in 2015 – nine years after its 2006 base year. Actual production for 2007 was actually up 4% over 2006 and the first nine months of 2008 were actually up 7.2% over a similar period a year earlier. Proved reserves increased 12.6% in 2007 relative to 2006.

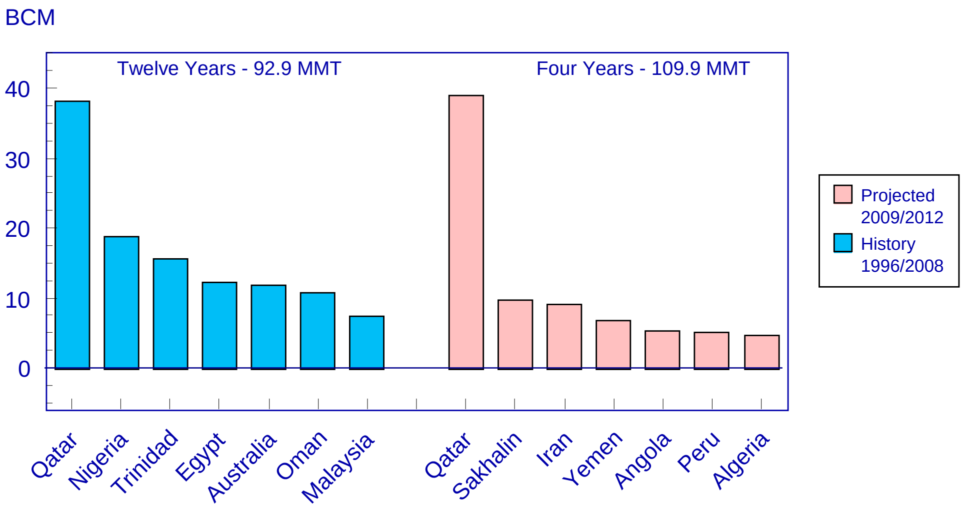
The unexpected increase in US production is the result of higher prices and technological developments – formation fracturing and horizontal drilling – to make a very large resource base of gas from shale formations economic to develop. The principal uncertainties in projecting a continuation of such production performance is the effect on drilling of weakening prices and the possibility of rapid decline rates for this unconventional production.

Figure 2's low case assumes that there is no growth in North American LNG demand between 2007 and 2015. In this case, the surplus (assuming the financial crisis does not reduce the later year capacity additions) is nearly 14% greater than demand.

2.3 Sources of Supply

The capacity increase has been concentrated in a limited number of countries. Between 1996 and 2008, seven countries – Qatar, Nigeria, Trinidad, Egypt, Australia, Oman and Malaysia – accounted for 95% of all the additions to capacity. See Figure 3. Qatar, alone represented 32% of the total additions. In the projections to 2015, seven countries – Qatar, Russia (Sakhalin), Iran, Yemen, Angola, Peru and Algeria – account for 86% of the additions. Qatar has an even bigger share, 42% of the total.

Figure 3: Top Seven Increases in LNG Export Capacity:
History – 1996/2008; Projected – 2008/2012 (million tons)



Source: Jensen Associates

The outlook beyond 2015 is considerably more uncertain. The importance of Qatar's contributions during the period from 1996 to the end of the forecast period is apparent. Qatar's decision to participate aggressively in LNG made it the world's largest exporter in the first eight years from its initial production in 1997. When its fourteenth train starts up in 2010, Qatar will account for 29% of the world's LNG capacity. Its North Field, together with South Pars on the Iranian side of the boundary line, is the world's largest gas field. But it is a complex field geologically, and Qatar wants to see how it behaves before making any further export commitments. Also, the country wants to make sure that production is preserved for future generations. Therefore, Qatar has declared a moratorium on further expansion for the time being.

Three countries – Iran, Australia and Nigeria – have the largest number of proposed supply projects that have not yet reached FID. But there are uncertainties in each case that make it difficult to project how rapidly that supply will materialise.

In the Middle East, only Iran seems likely to make a significant contribution to LNG capacity beyond 2012. Iran holds about 30% of the joint field with Qatar, and is developing its share with 20 blocks (23 if the gas proves to be there) of about 10 BCM each. However, it has a rapidly growing domestic demand and complex oil fields that require gas reinjection to maintain oil production. The first ten blocks are committed to domestic markets and reinjection.

International sanctions applied to Iran over its nuclear programme have made it difficult for the country to acquire LNG technology and experienced EPC contractors. While it seems to be proceeding on its first LNG project with local construction firms despite international sanctions, the difficulty of proceeding in such a political environment and some internal political resistance to gas export creates significant uncertainties as to when and how Iranian LNG will grow.

Australia has a substantial gas resource base and a large number of potential LNG projects. And while it has a stable political environment, two problems may limit the rate at which it will increase its export level. The country's pool of trained labour is heavily taxed by growth, making Australia a very costly construction environment. And Western Australian concern for preserving domestic supply and Federal concern for carbon emissions have slowed the approval process. Nevertheless, Australia's contribution to future supply will be large.

Nigeria flares more natural gas than any other country in the world and has been pressuring the oil companies to develop outlets for the gas. It, too, has a large number of proposed projects, but political unrest that at times has forced the shutdown of oil production has clouded the climate for new investment.

2.4 LNG Demand

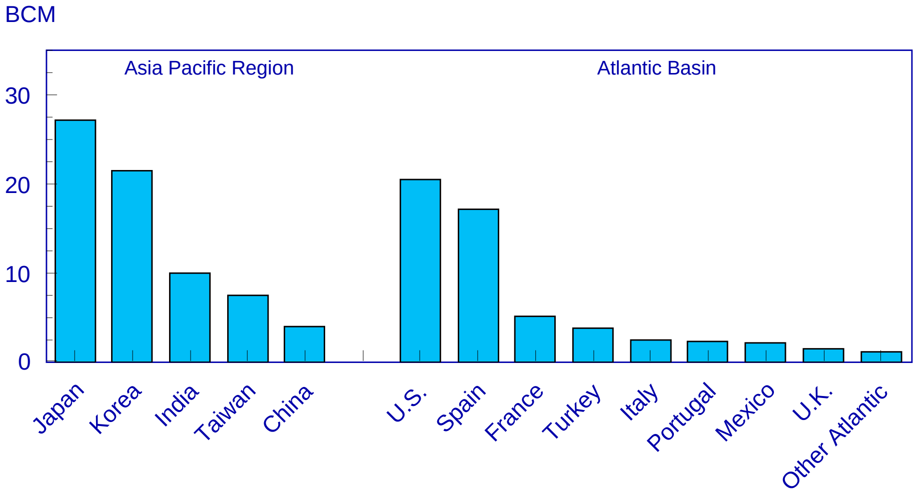
The fastest growing markets over the period since 1996 have remained in the Asia Pacific region – Japan with 27.2 and Korea with 21.4 BCM. But the emergence of Atlantic Basin demand is evident by the fact that the next two largest increases were the US with 20.6 and Spain with 17.2 BCM. These increases are shown in Figure 4.

Projecting regasification capacity is less reliable than projecting liquefaction capacity. One of the major problems is that there is no uniformity in the way in which countries report capacity and thus totals may include inconsistent "apples and oranges". The capacity of the vaporisation unit itself provides a measure of "peak capacity". But since the unit is a small part of overall terminal capex, there is little penalty for oversizing it, and since surplus peak capacity is valuable for handling seasonality or peak intraday electrical generation loads, oversizing is common.

But the capacity of the storage tanks and the tanker off-loading facilities may also limit how much LNG the terminal can handle on an ongoing basis. Thus it is also common to report "annual" or "sustainable" capacity, which might be a much lower figure than peak capacity.

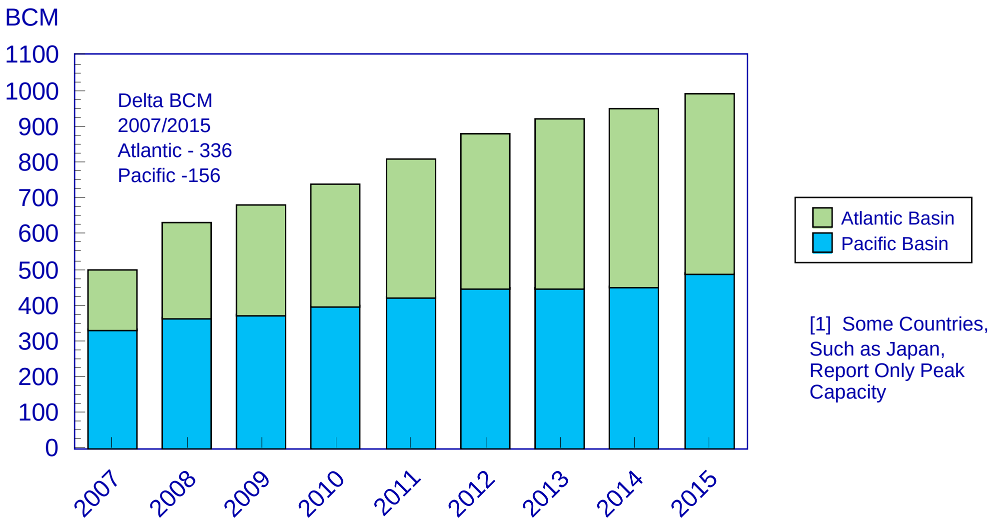
Japanese estimates are on a peak capacity basis, which implies that its terminals operated at a 36% capacity factor in 2007; yet it has traditionally contracted at a 90% take or pay level. The other problem is that lead times for terminal expansion decisions can be much shorter particularly with the emergence of floating terminals – and out-year projections based on published plans may understate what will actually happen. Figures 5, 6 and 7 show the growth of regional regasification capacity. They include only operating, firm and probable capacity (or in several cases, expansions based on demand growth rates).

Figure 4: Increase in LNG Imports 1996/2007 (BCM)



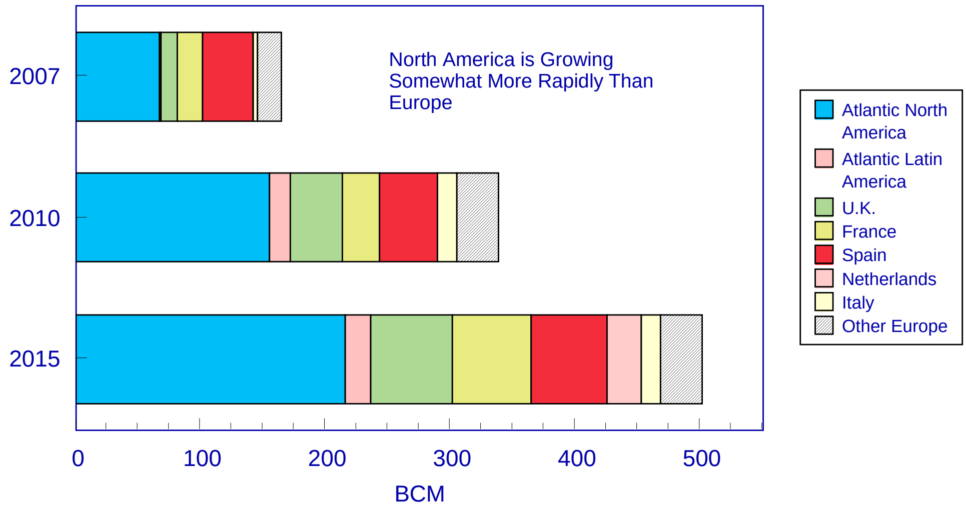
Source: Jensen Associates

Figure 5: Projected World LNG Regasification Capacity by Region, Based on Annual Sustainable Capacity where Possible (BCM) [1]



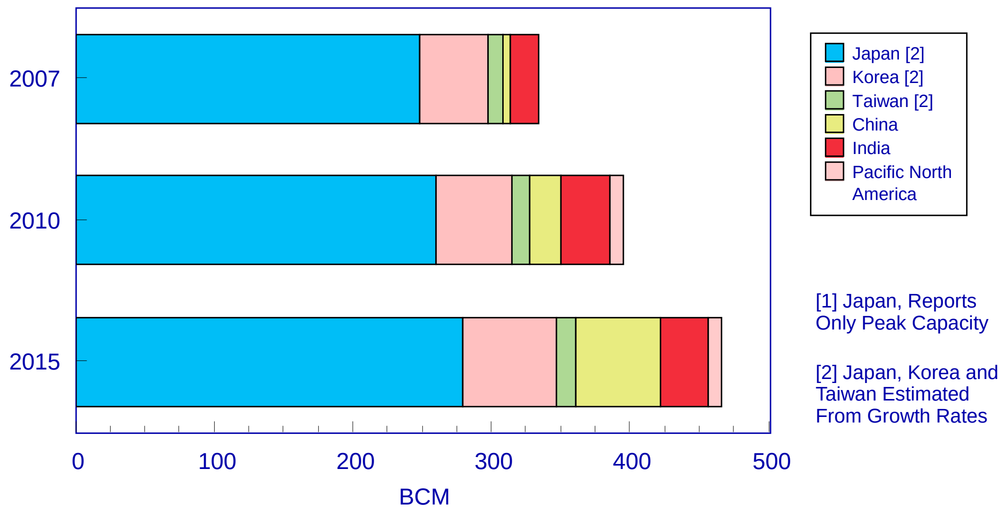
Source: Jensen Associates

Figure 6: Projected World LNG Regasification Capacity, Atlantic Basin (Firm Only) (BCM)



Source: Jensen Associates

Figure 7: Projected World LNG Regasification Capacity, Pacific Basin (Firm Only) (BCM) [1]



Source: Jensen Associates

One new technical development is the growth of floating regasification terminals. They arose out of the development of the “Energy Bridge” concept for tanker design, which places the regasification unit on the vessel itself. The vessel then discharges gas into a special loading buoy for transmission to shore.

The intermittent delivery of gas implied by this system has limited its application. However, the mooring of such vessels near a market effectively provides a movable regasification terminal. In this case, the regasification vessel is supplied with liquid from conventional tankers. The initial applications have been based on existing regasification tankers, but the optimisation of the design for pure terminal use is proceeding

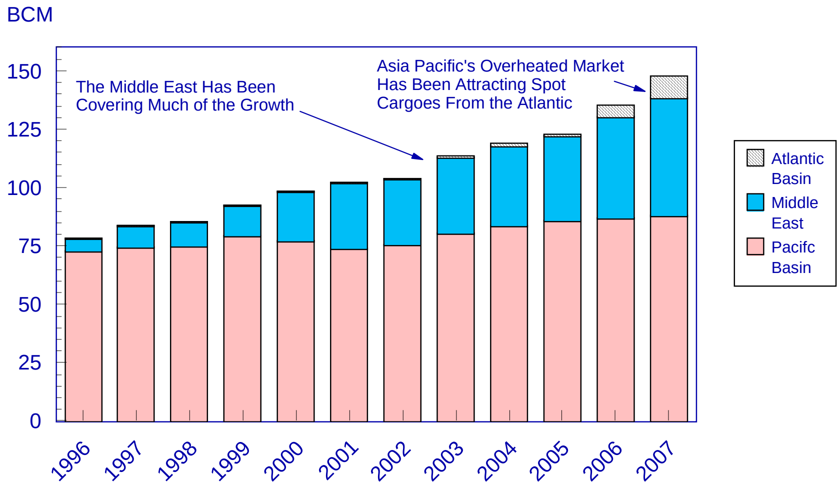
Argentina has already installed one of these tanker/terminals at Bahia Blanca and three more will go into operation this year in Brazil. They provide an easy way for a developing market to get started. They have their drawbacks, however. Since the optimum design for receipt terminal storage is larger than the tankers that will service it to allow for scheduling contingencies, the use of existing regasification vessels as terminals limits the size of the tankers that can serve the terminal.

2.5 Regional Supply Balances

For many years, both the Atlantic Basin and Pacific Basin markets were largely self-contained. As recently as 1996, the only contractual movement into a market region from outside the region was the shipment from Abu Dhabi to Japan. Interregional spot cargoes were small and infrequent.

But the rapid growth of Asia Pacific markets in the late 1990s began to outrun Pacific Basin supply. Industry response was to turn increasingly to the Middle East, a trend that provided the market stimulus for the development of LNG markets in Qatar. In 1996, the Japanese Abu Dhabi import accounted for only 7% of Asia Pacific supply. By 2007, Middle East imports had grown to 34%. In addition, under the tight Asian market conditions, spot cargoes from the Atlantic Basin accounted for another 6%. This is illustrated in Figure 8.

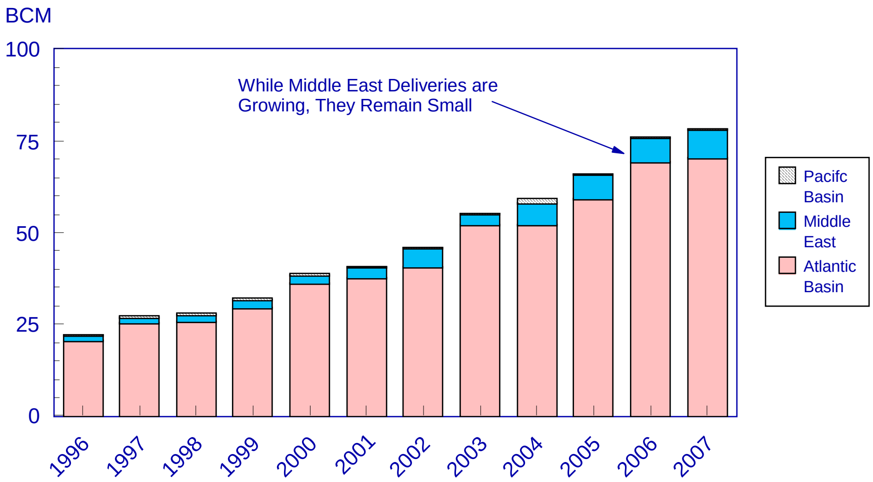
Figure 8: Asia-Pacific Basin Market Receipts, by Producing Region (BCM)



Source: Jensen Associates

The growth of the Atlantic Basin market has been able to tap regional sources for much of its growth. This includes Trinidad, West Africa (primarily Nigeria), North Africa (primarily Egypt) and now northern Norway. As a result, shipments from the Middle East into the Atlantic Basin have only risen from 7% of demand (spot cargoes from Abu Dhabi) to 10% in 2007. These trends are shown in Figure 9.

Figure 9: Atlantic Basin Market Receipts, by Producing Region (BCM)



Source: Jensen Associates

2.6 LNG Tanker Capacity

In anticipation of the rapid growth of LNG trade, and particularly the long haul, Middle East/North America trade, the industry has been building tankers at a much faster rate than the current growth of trade would support. The resulting current capacity surplus is shown in Figure 10.

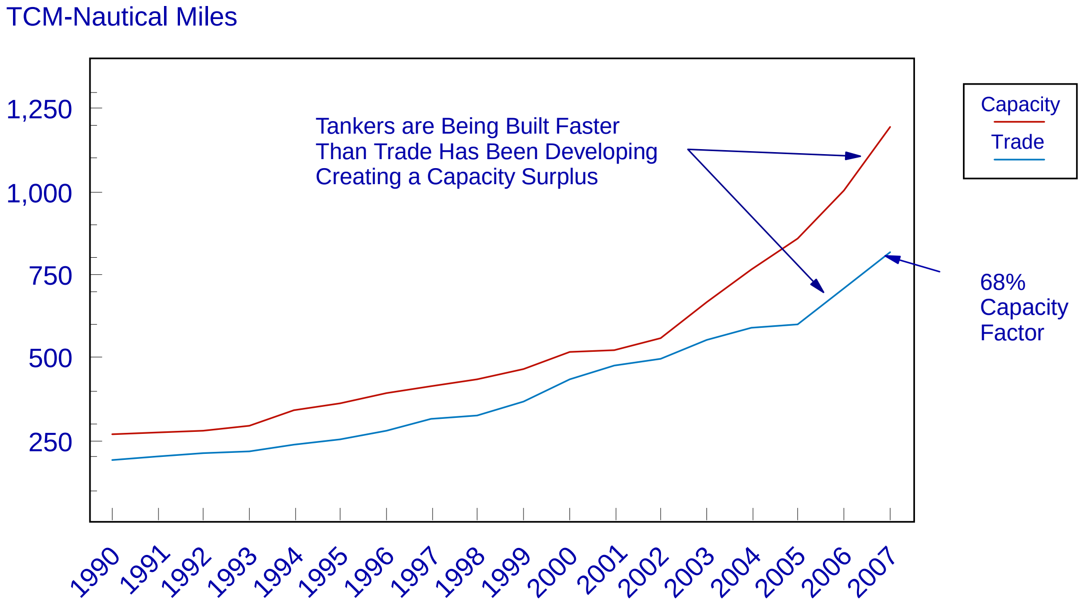
The capacity surplus is one reason why the market has been able to support long haul spot trades from the Atlantic basin to Northeast Asia. While short-term trade (up to 3 years) accounts for 19.8% of total trade, it accounts for 26.3% of the total capacity utilisation (measured in TCM/nautical miles). The average length of current LNG movements under long-term contract is 3,324 nautical miles. The average length of short-term movements is much greater at 4,795 nautical miles.

The tanker surplus will only intensify, because of the size of the tanker "order book". Capacity delivered in 2007 set a record. And capacity being delivered in 2008 is 87% greater than that delivered in 2007. Figure 11 compares recent annual tanker capacity deliveries to those remaining on the order book for delivery in 2008 and beyond.

If the financial recession significantly reduces demand and if North American growth is adversely affected, the potential for surplus capacity will only increase. The importance of the North American trade to tanker requirements is illustrated by the fact that it requires 43% more tanker capacity to move LNG from the Middle East to Lake Charles in the US Gulf than it does to Japan and 92% more than it does to Spain.

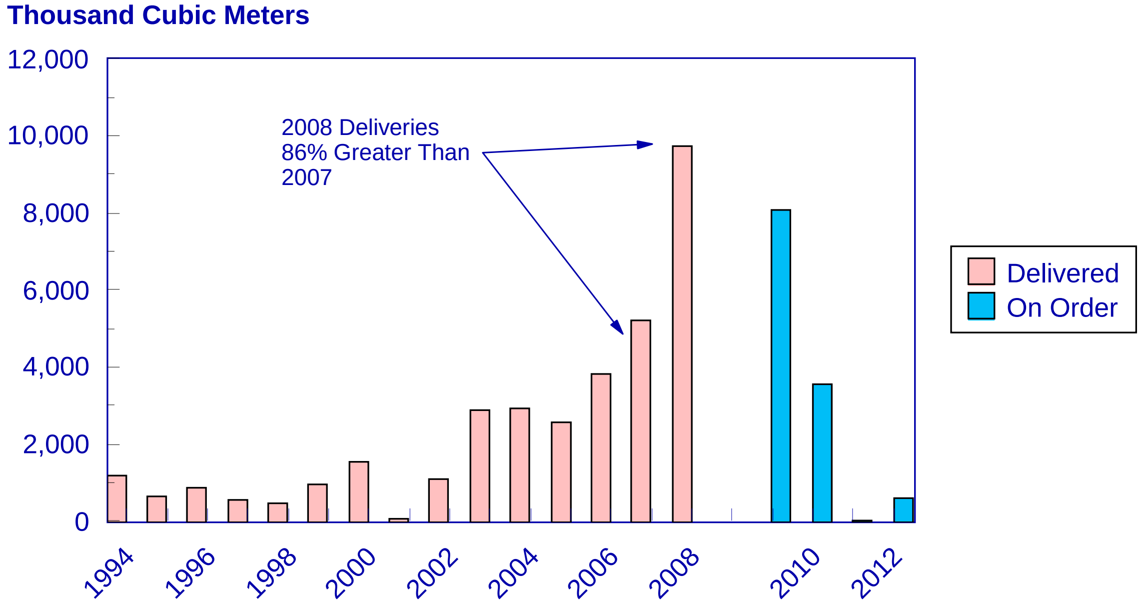
The fact that Qatar is distant from the major markets in North America, Europe and Northeast Asia has led that country to emphasise economies of scale to minimise costs, both in the size of its LNG liquefaction trains and in tankers. While the most common trend in tanker sizes currently features vessels in the 150,000 cubic meter class, Qatar has featured two designs – the "Q Flex" with a typical capacity of 216,000 cubic meters and the "Q Max" design of 260,000 cubic meters. Twenty-nine Q Flex tankers have been delivered or are on order. Seven Q Max tankers have been ordered.

Figure 10: Capacity of the LNG Tanker Fleet Compared with LNG Trade, Measured in TCM-Nautical Miles



Source: Jensen Associates

Figure 11: Capacity of LNG Tankers Delivered, by Year of Delivery, Delivered through 2008 (thousand cubic meters)



Source: Jensen Associates

Chapter 3. LNG Costs

During the late 1990s and early 2000s, LNG costs were steadily declining and there was a widespread expectation that the trend would continue and be a major driver of the growth of LNG trade. But in the early part of this decade, severe cost inflation set in and costs are now much higher that they were expected to be in the earlier period.

Unfortunately, there are very few LNG projects completed in any one year and their costs may vary significantly based on design constraints and local conditions. That fact, together with the fact that plants have been exposed to changing cost inflation over an extended period of plant construction, limits the amount and value of publicly available cost data making it very difficult to get a reliable current handle on what is happening to costs

3.1 Liquefaction Plants

During the earlier period of declining costs, there was a widespread expectation that typical plants were approaching a capital cost level of about $200 per ton. Much of the decline was attributable to scale economies that came from larger plant sizes. Figure 12 illustrates the scale effect. It utilises typical costs from a 2008 perspective.

Until the late 1990s, train sizes were limited by existing compressor designs to about 2.5 million tons per train. Then designs began to break free of those limitations and train sizes have been rising steadily ever since.

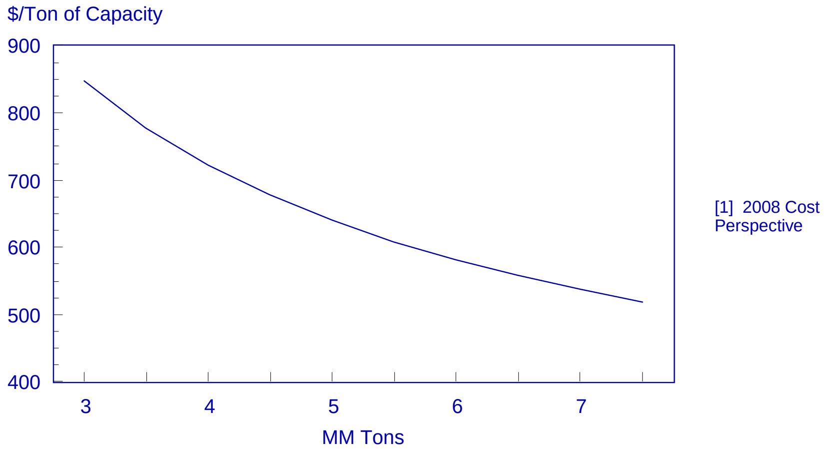
Because of its distance from the major LNG markets in North America, Europe and Northeast Asia, Qatar has pioneered the “super sizing” of trains and tankers. When its final train goes on line in 2010, six of Qatar’s fourteen trains will have a 7.8 million ton capacity. The largest train elsewhere is 5.2 million tons. Figure 13 shows the trend in train sizes between 1990 and 2012.

In the early part of this decade, the pattern of declining costs dramatically reversed and costs are now rising. Figure 14 provides four illustrative cost estimates for the same LNG facility made at different periods. While materials inflation has been a factor in rising LNG costs, most LNG plant inflation is attributable to the overload of experienced Engineering, Procurement, Construction (EPC) contractors. In addition to cost inflation there are frequently substantial individual variations from typical costs for LNG plants. Sometimes these result from special problems affecting individual plants: sometimes it is the result of problems in assembling enough skilled labour in remote locations.

Three recent high cost plants have been Norway’s Shohvit, Russia’s Sakhalin 2 and Australia’s Pluto. The first two appear to have been affected by the challenges of construction in an Arctic environment, while Pluto may be an example of remote construction. The costs of these plants have come in at 33% to 125% higher than the level on which the costs in Figure 12 are based.

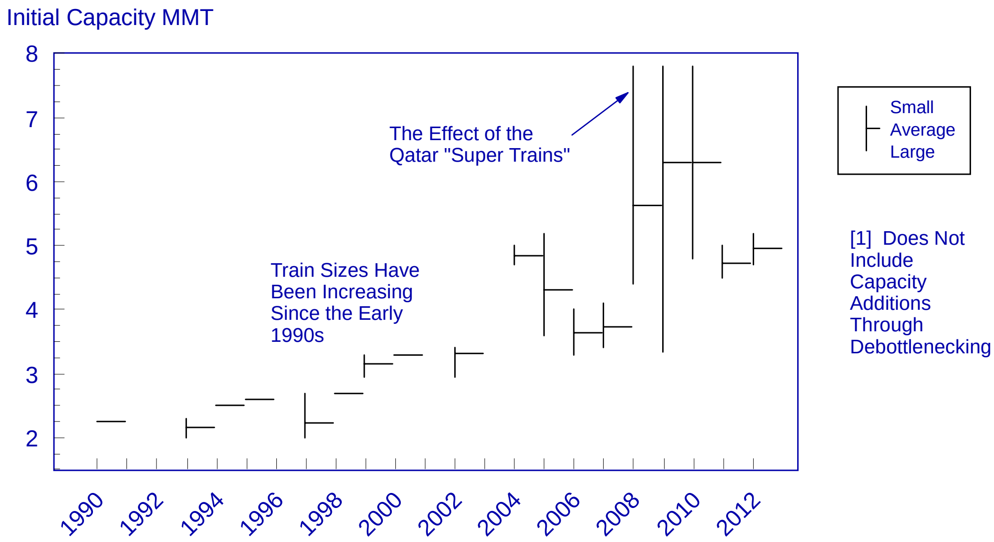
One LNG project that made its Final Investment Decision (FID) in 2008 is the Gassi Touil LNG liquefaction facility in Algeria. Its construction bid came in at roughly double estimates that were used in the Figure 12. But since costs for individual plants can vary significantly, particularly if there are special “problem” issues, it is not clear how representative this single quote is of the current market.

Figure 12: Illustrative Capital Costs for a Greenfield Liquefaction Plant, as a Function of Scale (million tons) [1]



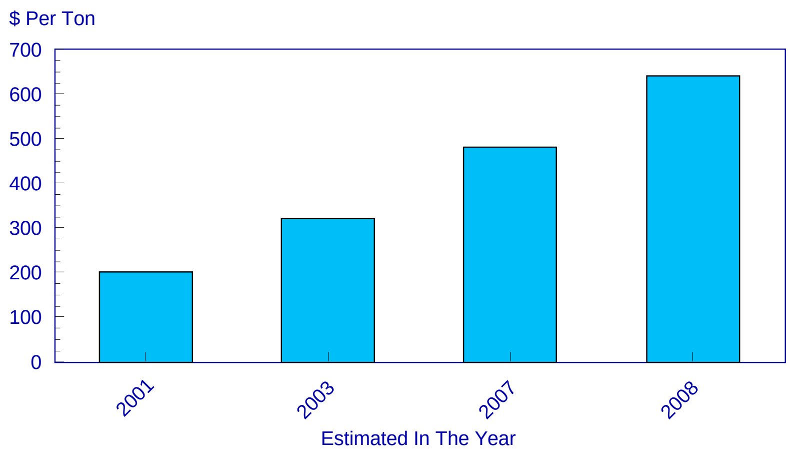
Source: Jensen Associates

Figure 13: Changes in Liquefaction Train Sizes, by Plant Start-up Date (million tons) [1]



Source: Jensen Associates

Figure 14: Illustrative Capital Costs of a New 4.5 MMT Greenfield Liquefaction Plant, from Different Time Perspectives (USD per ton)



Source: Jensen Associates

3.2 Regasification Terminals

There are large variations in the costs of regasification terminals, based largely on specific local conditions. But the same pressures that have escalated liquefaction plant costs are also operating for regasification plants.

One offset is the development of the floating regasification terminals that have the potential to reduce costs substantially in those cases where they make sense. For example, the basic capital cost of one of the regasification tankers used as a floating terminal represents probably less than half of that of a fixed on shore terminal before adding in harbour and other infrastructure required to utilise it in that role.

3.3 Tankers

Costs for tankers have also been rising but not as dramatically as for liquefaction plants. And the increases have been partially offset by some limited scale economies for larger tankers. The average size of the tankers launched in 2000 (excluding small specialty vessels) was 137,200 cubic meters. While the average size had risen to 150,900 by 2007, this included several of Qatar's Q Flex vessels. Excluding these, the average size was only 147,500, a 7% increase.

Chapter 4. LNG Pricing

There are now four major regional markets whose gas pricing patterns influence the price of LNG in world gas trade. They are: North America, the UK, the European Continent, and Northeast Asia. Two emerging LNG markets – China and India – gas importers with both pipeline and LNG options, have not yet developed consistent pricing patterns of their own.

The market regions differ in their sources of gas supply, their reliance on contracts, and the extent to which they have liberalised their gas industries. These factors have had a strong influence on price behaviour and thus affect the way in which LNG is priced to compete in their markets.

4.1 The Structure of the Industry and Its Influence on Price Behaviour

The structure of the gas industry has developed much differently from that of the oil industry. Two industry characteristics are largely responsible for the differences. First, because investment in gas transportation is both highly capital intensive and front end loaded, it has relied heavily on debt financing. This has usually required long term contracts, both to guarantee debt service and to share project risk between buyer and seller.

Second, despite the fact that petroleum exploration and development are not inherently monopolistic, gas is most commonly transported through piping systems, which in most cases exhibit strong natural monopoly characteristics. As a result, gas transmission and distribution have traditionally been regulated, either as public utilities as in the US and Japan, or as government monopoly companies as in the UK or France.

For countries whose gas supply was domestic, as was the case in the US, Canada or the UK, downstream regulatory jurisdiction ultimately led to government price intervention upstream. Countries relying on imports for supply had little jurisdiction over upstream pricing and pricing terms were negotiated between buyer and seller.

It is this distinction historic supply reliance on domestic sources or on imports that probably most clearly defines current regional pricing patterns. Importers have traditionally relied on long term contracts negotiated between buyer and seller; most of these contracts still remain in force.

4.2 The Emergence of Gas Market Liberalisation as a Determinant of Gas Pricing

The failure of a system of wellhead price controls in the US in the 1970s ultimately led the US in 1978 to reject heavy intervention in gas pricing in favour of market liberalisation. This was designed to allow gas-to-gas commodity competition to establish market prices rather than setting them by government regulation or by reference to alternate fuel values in contracts. The method by which the US liberalised had a severe impact on Canadian export markets forcing Canada to adopt similar policies soon after. The UK, under the Conservative Government of Margaret Thatcher, also adopted gas market liberalisation after first privatising the Government monopoly, British Gas.

To be successful, gas industry liberalisation entails four preconditions:

- There must be competitive gas available to the market
- Customers must be free to choose among suppliers
- The transmission system must be open to shipment by competitive suppliers (“open” or “third-party access”)
- And pipeline access must be non discriminatory

All four steps have been successfully achieved in the US, Canada and the UK which have a high share of domestic supply; short term commodity trading has now largely replaced long term contracting in those markets, and remaining long term contracts – mostly for cross border trade – are pegged to indictors reflecting gas to gas competition. This in contrast to import dependent regions: Despite efforts of the European Community to liberalise its gas industry, the progress there is far from complete. And there has been comparatively little effort to liberalise gas markets in Northeast Asia.

There were three common early assumptions about a liberalised gas industry in gas to gas competition. First, the pricing of other energy sources, such as oil, was largely irrelevant. Second, the traditional long-term contract with its oil price linkage could not survive since one could not sell oil linked gas in a commodity market priced below oil. And third, the growth of interregional gas trade, both by pipeline and as LNG would soon spread gas to gas competitive markets throughout the world, thereby undermining the traditional contract system. So far, the gas industry has failed to follow that script.

The conceptual model works in North America and the UK since many producers of domestic gas compete to create a very liquid commodity market. It can best be described as "commodity gas-to-gas" competition.

Henry Hub is a major pipeline junction in South Louisiana serving much of the north and east of the US. Since it is a natural physical commodity trading point, it has become the centerpiece of the North American gas pricing system. And it is the logical point of reference for the paper transaction market – the futures contract of the New York Mercantile Exchange (NYMEX). Prices for other "hubs" throughout North America are also reported in the trade press and the difference between their prices and Henry Hub are known as "basis differentials".

Pricing in the UK is based on a theoretical pricing point on the transmission system known as the National Balancing Point or NBP. It, like Henry Hub, has become the basing point for gas commodity and paper trading in the UK Gas to gas competition will reflect specific regional characteristics which go beyond the global market developments. This was demonstrated by the price hikes in UK in the cold winter of 2004 while the major storage facility Rough was out of operation and vice versa by the negative price on the Balancing point in Oct 2006 when due to the need to sell associated gas (to be able to monetise oil or condensate production) combined with a test run of the Langeled pipeline sellers had to pay to get rid of their gas.

However, for most of the Continent and Northeast Asia there is little or no domestic gas competition. For many European countries local production was originally provided by government monopoly companies and producer competition was limited or non-existent. In all but the Netherlands and Denmark, local production covers a small portion of domestic demand and domestic producers are price-takers.

Thus, even for those markets that have liberalised, competition is primarily with other companies buying on long term contract. There is no liquid transaction market for domestic commodity gas. The relevant question in such markets is thus whether or not the competitor has better terms on his contract. Such competition might better be described as "contract gas-to-gas competition".

4.3 Potential Sources of Competition for Contract-Dependent Markets – Pipelines

It is the third assumption – that the growth of interregional gas trade would soon spread gas to gas competitive markets throughout the world – that has proved to be ineffective in much of Continental Europe and Northeast Asia. For Northeast Asia, which is dependent on LNG imports for supply, the agent for competitive change would have to be a liberalised trading market in LNG cargoes. But Europe is exposed, not only to LNG, but also to pipeline supply from the liberalised UK market via pipelines crossing the North Sea.

There are three problems with pipeline competition as a means of opening up the contract-dependent markets. First, some countries have been slow to liberalise, retaining government control of their gas monopolies and resisting third-party access. And, second, the existence of a large body of legacy contracts makes it difficult to superimpose flexible trading on the system. The European Community has been actively trying to address these two issues.

But the third issue is somewhat more difficult in that is an operational problem. In many cases, the pipeline grid itself has capacity constraints that can cause congestion on the system. Thus it often does not lend itself to third-party access to long distance movements of commodity gas. Because of the difficulty of acquiring access for long distances, it is much easier for a British producer to compete in the Netherlands than it is to attempt to compete much farther east, such as Austria, for example. That is why markets in the Netherlands and Belgium are more competitive than those farther east.

Thus the European fault line between the two systems – liberalised commodity trading and contract dependency – lies in the English Channel between the UK and the Low Countries and at the Atlantic regasification terminal outlets on the Continent.

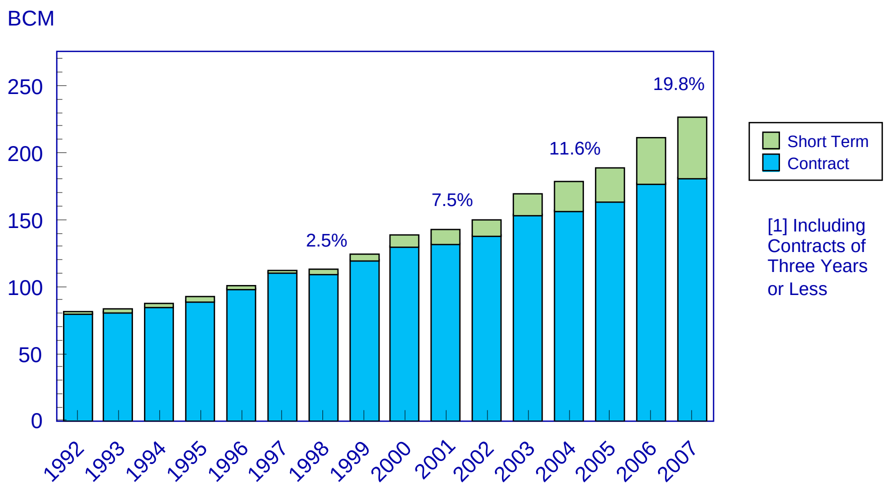
4.4 Potential Sources of Competition for Contract-Dependent Markets – LNG

The ability of pipeline trading to provide commodity competition in gas markets is necessarily restricted by geography and capacity constraints. LNG is far more flexible since LNG cargoes can go anywhere in the world. Thus LNG trading is the prime force in the development of a global gas market.

The traditional long-term contract commonly linked specific buyers and sellers facilities in a relatively inflexible pairing. The ability of LNG to introduce commodity competition into world markets depends heavily on the emergence of “destination-flexible” cargo trading.

The most obvious form of destination-flexible trade is the growing short-term market. “Short term” includes spot, short term “balancing” trades among long term contract holders and contracts of three years or less. Figure 15 shows the growth of short-term trading from less than 2% of trade in 1993 to nearly 20% by 2007.

Figure 15: Short-term Trading in LNG (BCM) [1]



Source: Jensen Associates

But short-term trading is not the only source of destination-flexible volumes. Another form of flexible volumes is the relatively recent development, which might be called “self-contracting”.

The traditional long-term contract linked specific LNG supply to specific customers. Since most of these traditional customers were either regulated utilities or government monopoly companies, they could usually absorb an oil-linked pricing clause if the government overseers agreed to the contract and allowed the buyer to pass along the pricing consequences to its customers. The seller in these contracts was often the production joint venture acting on behalf of the venture partners as a group.

Since oil linked-pricing clauses may put the buyer in a difficult position in markets where gas to gas competitive prices fall below oil, such clauses have largely disappeared in the fully liberalised markets of North America and the UK Buyers would prefer a linkage to gas market indicators, such as Henry Hub in the US or the NBP in the UK But since the buyer can so easily resell unwanted volumes in the liquid spot market with limited financial loss, his risk has been significantly reduced. Risk has thus migrated upstream to the seller. The response of sellers has been to "self-contract" marketing directly to the end use market.

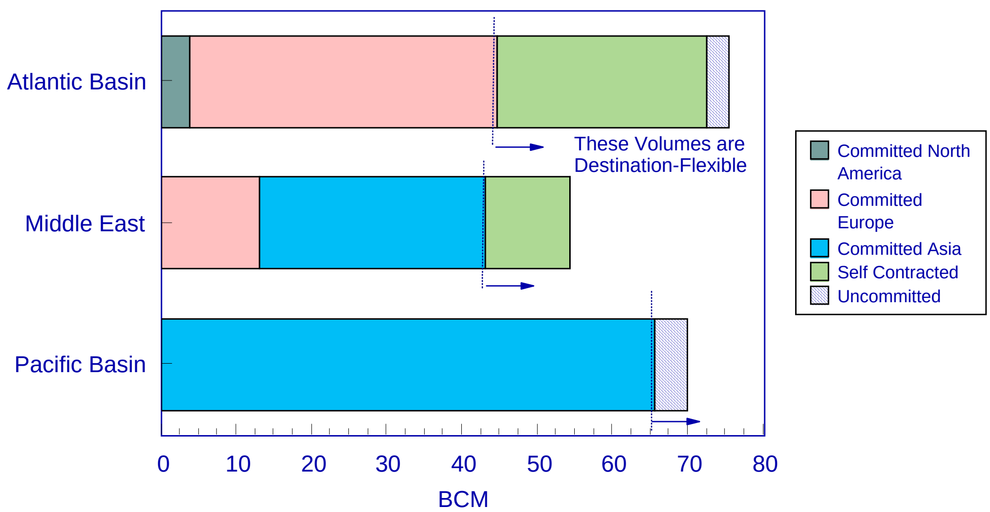
Increasingly, one or more partners are contracting with the joint venture for volumes that they can market independently without specifying the ultimate destination. These, like short term volumes, are destination flexible.

Nigeria's Bonny project illustrates this new pattern. The first three trains of the project were originally contracted to various European customers under traditional contract terms. But trains 4 and 5 have contracted with Shell and Total, two of the NLNG partners, which are now free to take their volumes anywhere they see fit. Both Trinidad and Egypt have moved increasingly towards destination flexibility by permitting producers to toll volumes through liquefaction for marketing directly.

While the most common self-contracting pattern is a sale to one of the venture partners, other variations are possible. A producer that is not a partner, such as BG in Equatorial Guinea, may be the buyer or the venture itself, as Qatargas in its partially owned South Hook terminal in the UK may commit to sales volumes. The common theme is that the seller is not contractually committed to a specific market and thus has destination flexibility.

The Atlantic Basin has the largest proportion of destination flexible volumes. In 2008, fully 41% of Atlantic Basin capacity was flexible. See Figure 16. The Middle East also has significant flexible volumes at 21% of capacity. But Asia continues to rely on long term contracting with only 6% destination flexible.

Figure 16: Regional Contract Commitments – 2008, Showing Uncommitted or Self-contracted Volumes (BCM)



Source: Jensen Associates

4.5 Price Formation in the Liberalised Commodity Markets

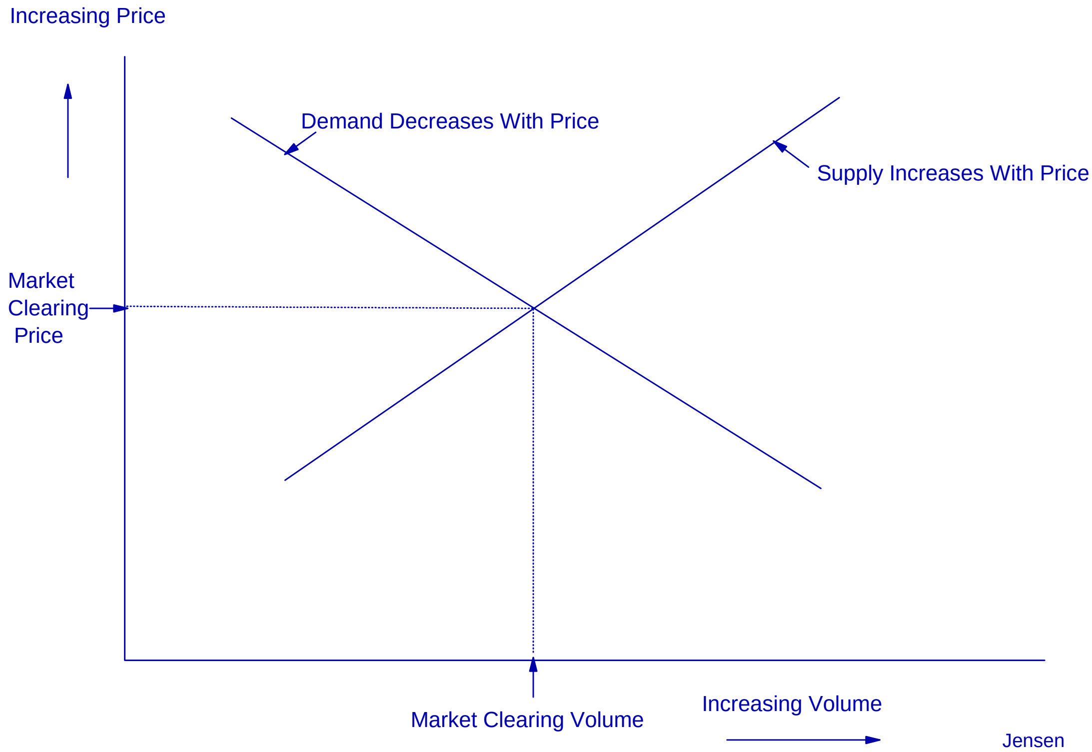
The early price behaviour of both North American and UK markets appeared to confirm early expectations that gas-to-gas competition would decouple gas pricing from oil pricing. Since both North America and the UK liberalised when they had substantial supply surpluses, they experienced severe producer price competition and their gas prices were indeed well below those of oil. But both regional commoditised markets have shown that, in shortage, inter-fuel competition can set prices that may be indirectly linked to oil after all.

The decoupling of oil and gas prices in surplus and the recoupling during shortage is economically rational. Economic theory (Figure 17) outlines the behaviour of price to changes in supply and demand. But for gas, demand is a function of its market share in inter-fuel competition and thus is dependent on competitive fuel prices such as oil.

Short term demand can be quite inelastic – with volatile pricing – when oil has been displaced from dual fired boiler markets (Condition 1 in Figure 18), and relatively elastic – with stable pricing when limited gas supply forces dual fuel customers to switch to oil. (Condition 2 in Figure 18).

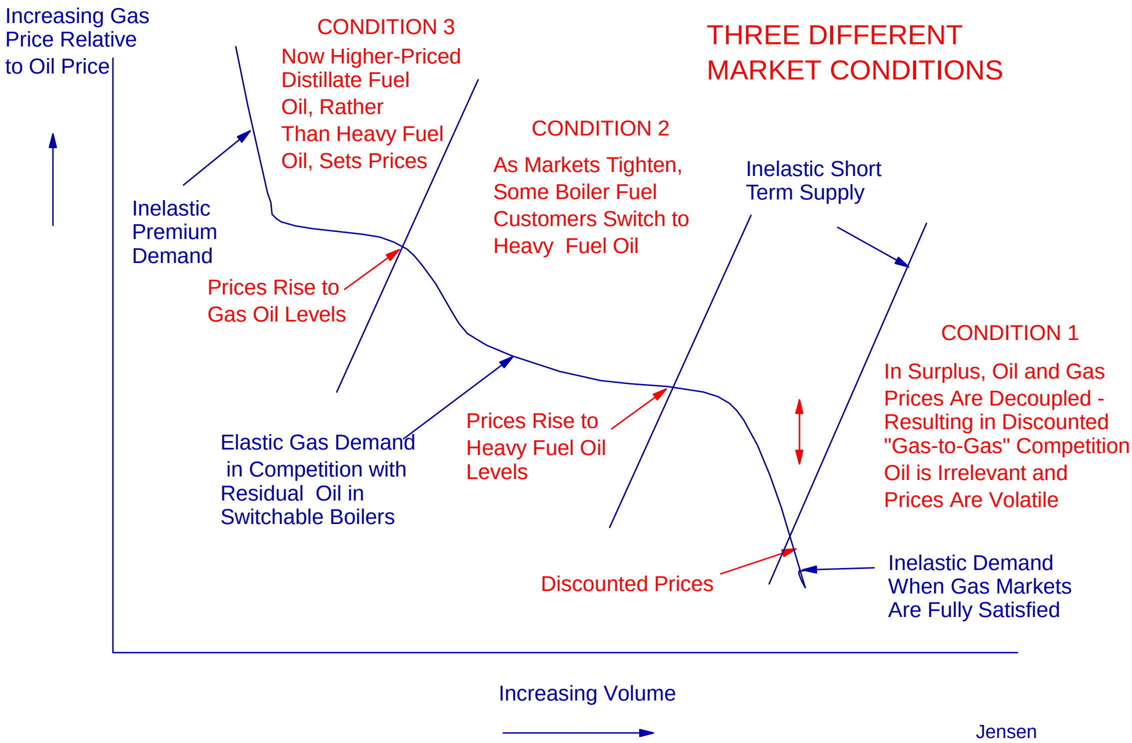
Both the US and UK recent experience with oil and gas prices illustrate the economic driving forces on price. Both regions started with decoupling, but both have experienced prices that are higher than oil prices. Recently, both regions have been in gas to gas competition with gas priced below oil and thus in a position to threaten the oil linked contractual markets with price competition. Figure 19 shows a recent comparison of the US Henry Hub gas price with the WTI oil price. Figure 20 provides a similar comparison for the UK NBP price and Brent.

Figure 17: Theoretical Behaviour of Supply, Demand and Price According to “Economics 101”



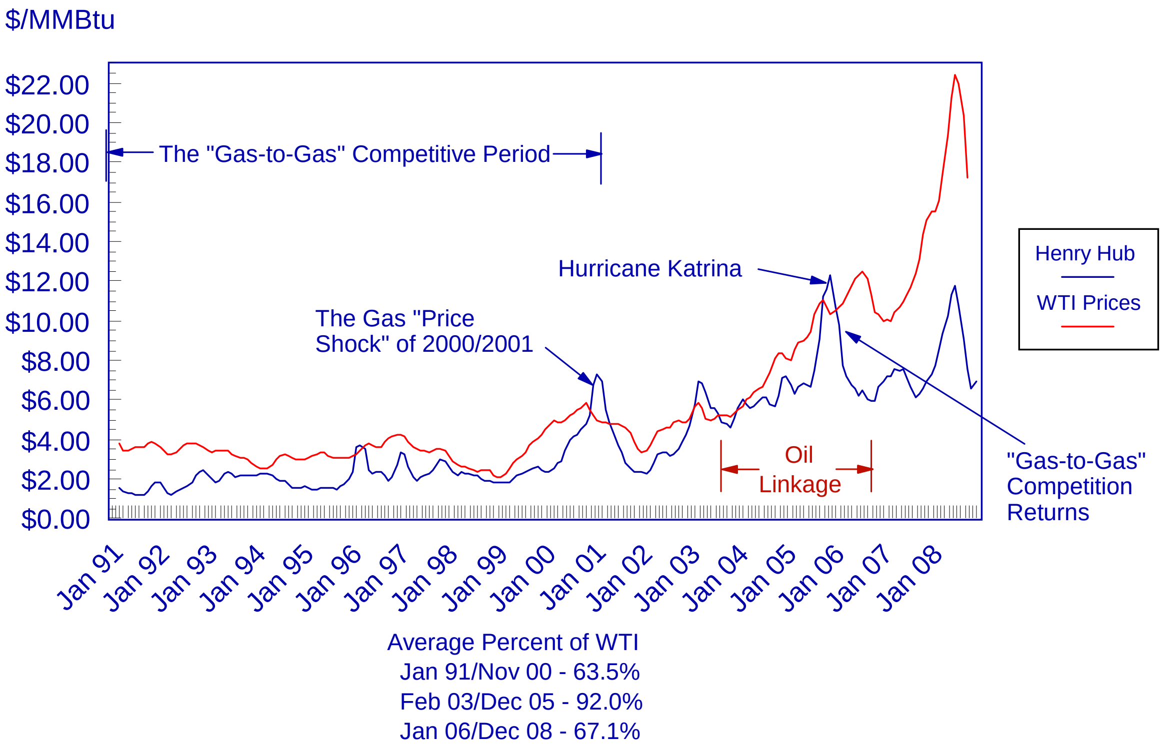
Source: Jensen Associates

Figure 18: A More Realistic US Short-term Gas Supply/Demand Curve



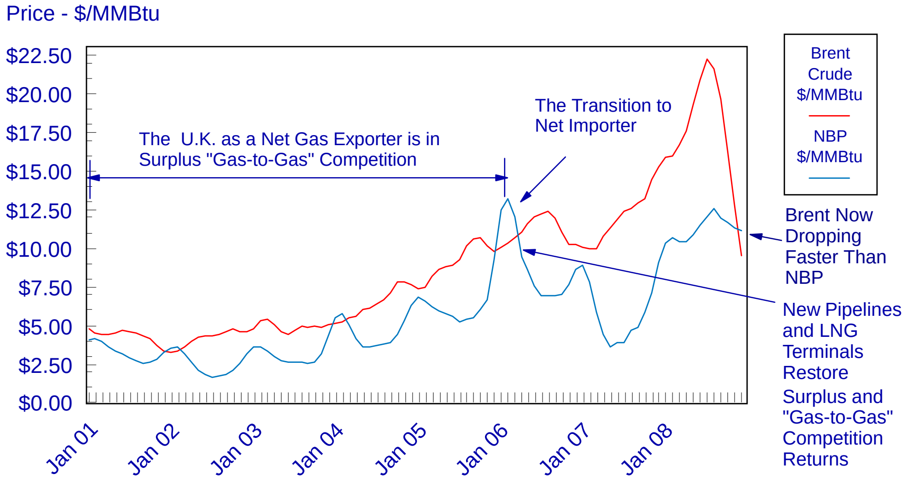
Source: Jensen Associates

Figure 19: Henry Hub Gas Prices Relative to WTI Crude Oil Prices (Three Month Moving Average)



Source: Jensen Associates

Figure 20: Relationship between Brent Crude Oil Prices and UK Gas Prices at the National Balancing Point (NBP) (Three Month Moving Average)



Source: Jensen Associates

4.6 Atlantic Basin Price Arbitrage Potential Provided by Destination Flexibility

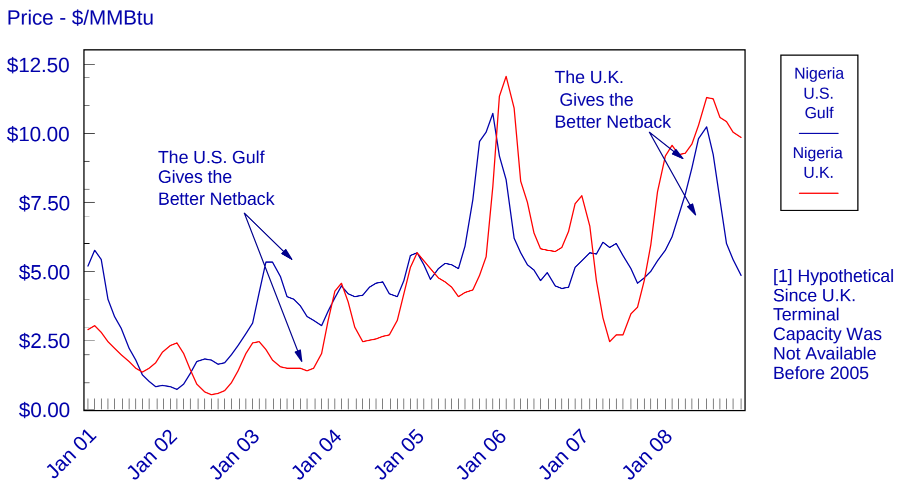
With destination flexibility, suppliers can move cargoes to the market, which will provide the best netback. Because of the flexibility of the Atlantic Basin market, price arbitrage between Europe and North America has been growing rapidly. Figure 21 illustrates how such arbitrage would work using a Nigerian supply as an example.

The Figure traces the netbacks a Nigerian shipper would have received had he shipped to the US Gulf Coast or to the UK between 2001 and 2008. The example is hypothetical in that the UK lacked import terminal capacity before 2005, but because the UK's NBP quotation is both liquid and transparent, it is used here as a proxy for European prices.

For much of the time between 2001 and 2006, the US Gulf provided better netbacks. However, more recently, the UK has been a better target market.

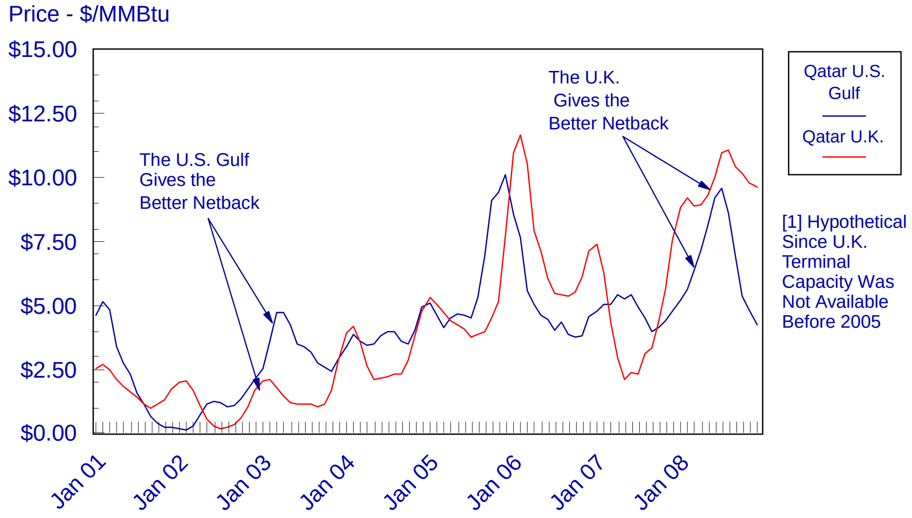
Figure 22 shows the same netback comparison, as it would apply to a shipper in Qatar. Although the netbacks are lower, reflecting the greater distance from market, the patterns are very similar.

Figure 21: Atlantic Basin Arbitrage – Hypothetical Netback to Nigeria from the US Gulf and from the UK [1]



Source: Jensen Associates

Figure 22: Atlantic Basin Arbitrage –
Hypothetical Netback to Qatar from the US Gulf and from the UK [1]



Source: Jensen Associates

4.7 Pricing in the Contract-Dependent Markets – Northeast Asia

Northeast Asia, without significant domestic production, has developed its gas industry based on LNG imports. When the first LNG contracts were negotiated with Japanese buyers, Japanese power generation was heavily dependent on oil firing, crude oil as well as heavy fuel oil. The early pricing clauses tied price escalation to crude oil prices the Japanese Customs Clearing Price for Crude Oil JCC or “the Japanese Crude Cocktail”. This precedent was adopted by Korea and Taiwan, as well as by some Chinese contracts. And although there have been some modifications over time, the precedent remains for Northeast Asia and has been hard to break.

The basic form of the typical Asian contract is in the form – Price = Constant+Slope*JCC, where the price and the constant are quoted in $/MMBtus and JCC is quoted in $/Bbl. For an extended period of time price formulas for the Pacific Basin were relatively stable, with the principal competition among suppliers coming in the form of changes in the constant or in side terms, such as price floors and ceilings.

This stability began to deteriorate as China first entered the market in the early 2000s. At the time, sharp competition among Australia’s North West Shelf, Indonesia’s Tangguh and Qatar’s Rasgas led to substantial discounting off earlier terms as the competitors sought to gain first mover status into this new market. North West Shelf got the Shenzen contract and Tangguh got the Fujian contract. The trade press reported that prices in both contracts were substantially below previous contract levels.

But the discounting was short-lived. The sharp increase in oil prices starting 2005 put upward pressure on LNG pricing, causing sellers to rethink the value of discounting. And the new contracts for North West Shelf and Tangguh reduced the level of competition at the same time that the market was tightening. The Chinese were unable to reproduce their earlier success and the transition to a sellers’ market slowed new contract commitments.

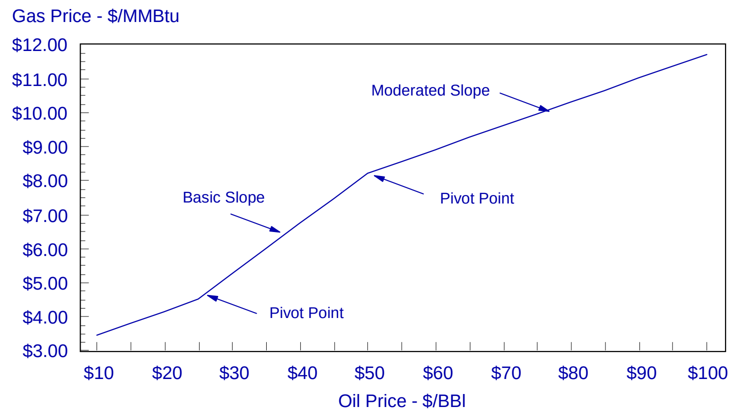
One of the features of the Pacific Basin market was the development of “S curves” as a means of reducing price risk. As oil prices became more volatile, oil-linked pricing clauses posed significant risks to the original price expectations of the contracting parties. For the sellers, an oil price collapse risked making the venture unprofitable and suppliers became interested in some form of price floor. But as a trade off for granting such a shift in risk, buyers wanted upside protection. In simplest form this could be a core relationship (called the “slope”) where the linkage between oil and gas prices operated, but floor and ceiling prices could be added to offset risk. But more common is a change in the oil/gas price relationship – or slope – above and below certain price levels ("pivot points"). Figure 23 illustrates a typical S Curve.

Since the "S curves" limit price response in times when oil prices are high or low, they can have the effect of decoupling oil and gas prices when oil prices rise above the upper pivot point. Until the recent oil price collapse, suppliers were contesting S curves who argued that S curves were designed for "temporary" oil price volatility and high oil prices were the new norm.

The effect of this decoupling is illustrated in Figure 24. One side effect of the resulting ceilings on contract prices is that it may be possible for Northeast Asian buyers to cross subsidise spot cargo purchases of LNG in competition with Atlantic Basin customers. During the recent tight gas markets, some customers have had to switch to heavy fuel oil. This suggests heavy oil prices were setting competitive fuel prices at the margin. Japanese customers, having much of their volumes locked in below oil levels could therefore be somewhat undisciplined in their spot cargo price offerings.

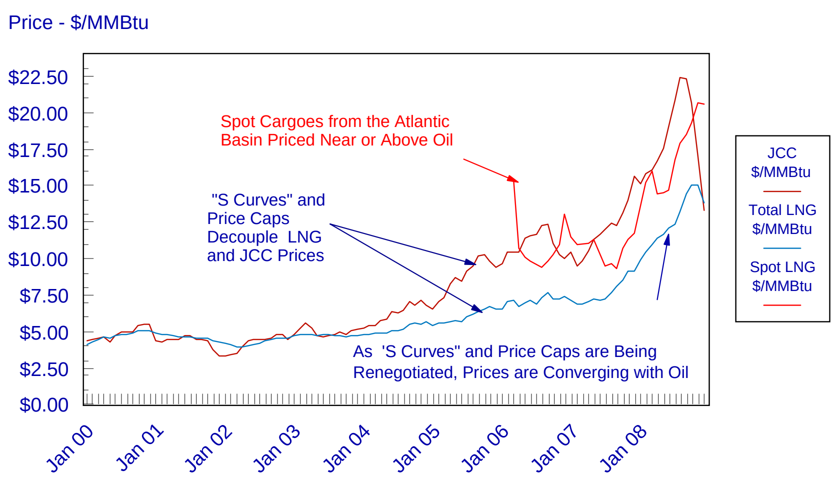
Japanese import statistics report price and volume by exporting country. Therefore, by determining the prices of imports from those countries that have no long-term contracts, it is possible to estimate spot prices. These imports from non-contract sources are all in the Atlantic Basin.

Figure 23: An "S Curve" Illustrated
(Basic Slope – 0.1485, Pivot Points at USD25 and USD50)



Source: Jensen Associates

Figure 24: Decoupling of Japanese LNG and Crude Oil Prices through "S Curves" and Price Caps as JCC (Oil) Prices Rise – a Comparison of Oil and LNG Prices, Including Spot Cargoes from the Atlantic Basin

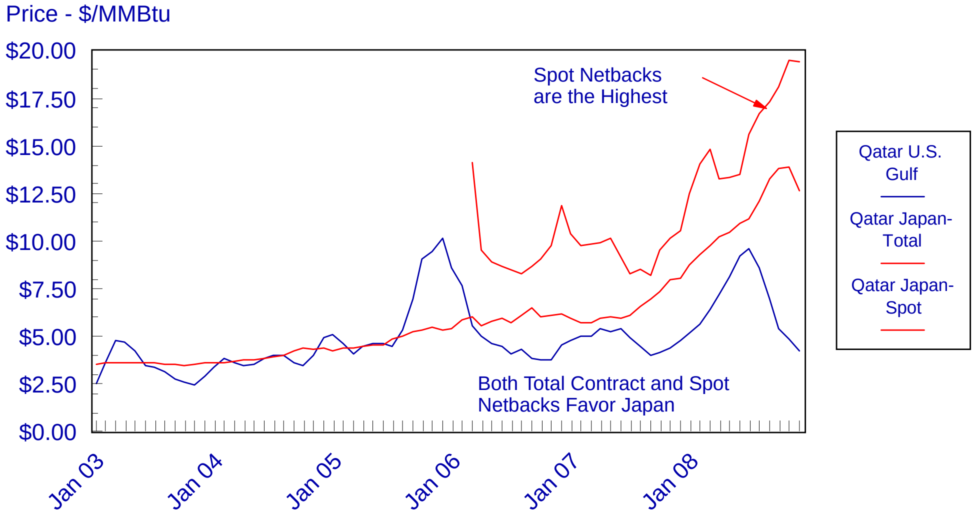


Source: Jensen Associates

4.8 The Middle East as a Source of Arbitrage Between Atlantic and Pacific Basins

Because there is limited market flexibility in the Northeast Asian market, there is no effective pricing arbitrage in the Pacific Basin. However, the Middle East plays a role in arbitraging Pacific and Atlantic Basin prices. This is shown in Figure 25. While at times the US Gulf has provided better netbacks, the recent experience favours Japan, even with contract prices capped by S curves. The very large advantage for spot cargoes is apparent.

Figure 25: Arbitraging the Atlantic and Pacific Basins – hypothetical Netback to Qatar from the US Gulf and from Japan (Including Spot Cargoes) [1]



Source: Jensen Associates

4.9 Pricing in the Contract-Dependent Markets – Continental Europe

Continental Europe has developed its substantial gas grid based on imported pipeline supply – supplemented by some LNG. In this regional market, long term contracts for imports were established early in the development of the industry and many of them remain in force.

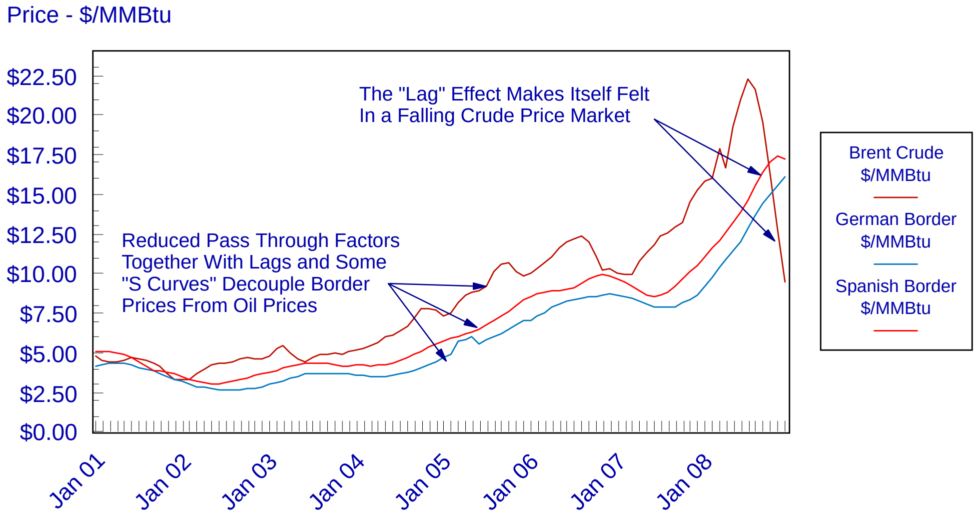
Continental European pricing precedents were effectively set by the Netherlands in its pricing policies for domestic gas from its super giant Groningen field in 1962. At the time the Dutch Government established a policy that gas should be valued at the prices of the fuels it competitively displaced regardless of the cost of supply. While this concept was introduced at a time of stable oil prices in the beginning of the 1960s, the concept included from the start the possibility of a regular price review to adapt the pricing to changes in the market. When oil prices later started to increase price escalation clauses in export contracts were tied to market based percentages of light fuel oil together with high and low sulphur heavy fuel oil.

One of the moderators was the adoption of “pass through factors” that had the effect of sharing the risk between buyer and seller. At a pass through factor of 1.0, the seller assumed the entire price risk, but a pass through factor in the usual order of 0.8-0.9 shifted some of the risk to the buyer.

The contracts also typically utilise lags between the recording of the oil price changes and their effect on the gas price. The effect of these two features – pass through factors and lags – has been to reduce the linkage between oil and gas prices, particularly in markets with rising oil prices. During a period of price increases they work like a discount, however during price drops (especially steep price drops like in 1985 and 2008) they risk pricing the gas out of the market. The relationship between European gas prices and oil prices is illustrated in Figure 26.

The introduction of LNG into Europe brought the challenge of adapting contracting practices in the broader worldwide LNG market to the specifics of European contracting. Therefore some features of Asian contracts have been adopted in some European LNG contracts. For example, some European LNG contracts contain S curves and some have linkages to crude oil prices.

Figure 26: Brent Crude Oil Prices Compared with German and Spanish Border Prices (Three Month Moving Average)



Source: Jensen Associates

Chapter 5. Current Pricing Trends

The sharp changes in energy price levels and the market shifts between buyers' and sellers' markets has severely complicated the patterns of price negotiation. Thus price competition that once seemed to be relatively stable within regions has now provided significant differences depending on the state of the market and the relative bargaining power of buyer and seller at the time price negotiations take place.

5.1 Atlantic North America

The first major modern expansions of Atlantic Basin supply were the projects in Trinidad and Nigeria, which started up in 1999. Trinidad's first train contracted with Cabot (now Suez) for the Everett terminal and with Enagas (the contract was later transferred to Gas Natural). While these appeared to be traditional contracts, the Everett contract was on a netback basis and thus exposed to North American price volatility. But the location of the terminal at the extremity of the US pipeline system provided a substantial basis differential over Henry Hub thereby minimising price risk. The original Nigerian contracts were with Continental European customers so that traditional contracts were insulated from commodity price competition.

Most of the new terminals in Atlantic North America have been built by or have been contracted to self-contracting suppliers. At the end of 2008, there were twelve operating LNG receipt terminals in Atlantic North America – nine in the US, two in the Caribbean and one in Mexico. Of the nine US terminals, two were designed for receiving on-board regasification vessels and were primarily used for trading.

The total annual capacity of the nine was 114 BCM of which 73% was committed to companies that can be described as self-contractors. Of the remainder, 16% was controlled by companies that might best be described as traders and only 11% was committed to companies purchasing for their own use or for resale. Thus only a small portion actually involved traditional supply contracting. This group included Everett as well as a chemical company purchaser in the Gulf Coast that had yet to sign a contract.

There was a limited amount of long-term contracting and presumably none that used oil linkage in the pricing clause. There were some deals done by self-contractors purchasing from other suppliers in which Henry Hub was used as the pricing indicator. It was usually stated as a percentage of the Henry Hub quote (93% or even higher, for example). But if the self-contractor controlled receipt terminal capacity with a significant basis differential over Henry Hub, the effective netback was significantly higher and it minimised the buyer's price risk.

5.2 The UK

The UK opened its first modern terminal in 2005 and by the end of 2008 it had four terminals with 33 BCM of capacity. One of these was a specialty terminal designed to receive regasified volumes from an on-board regasification vessel. Like the North American LNG terminals, the largest percentage of capacity was committed to self-contracting companies. Fully 67% of the capacity was controlled by self-contractors, while 21% was controlled by companies buying for their own account, but with access to domestic production as well. The trading terminal represented 13% of the capacity.

5.3 Spain

Spain not only accounted for 47% of Continental European LNG imports in 2007, but because of its rapid growth in LNG demand, it was responsible for 65% of the total increase in LNG imports over the previous decade. Thus it was the focus of long-term contracting in Europe. In 2007, long-term contracts accounted for more than 80% of total imported volume.

At the end of 2007, Spain had six terminals with an annual capacity of 54 BCM. Three of the terminals are owned by Enagas, the former Government gas monopoly. One is owned by a consortium of electric utilities, one in Bilbao by a supplier partnership, which includes BP and Repsol, and one by a consortium primarily of interests outside the gas industry.

Since all terminals are operated as third-party access facilities, it is probably incorrect to say that capacity is "controlled" by any particular class of companies. But, assuming that Enagas together with the electric utilities represent established companies buying for their own account, fully 83% of the capacity can assumed to be traditional contracted capacity. The outside ownership percentage of the one investor's consortium might classify its portion of capacity as "trading capacity". And two suppliers built the Bilbao facility, so it might be considered as "self-contracted" capacity. By this definition, 83% of the capacity is contract capacity, 13% self-contracted capacity and 4% as trading capacity.

Liberalisation of Spanish gas markets is well advanced. Spain has unbundled its transportation system from gas marketing, has established third-party access on both pipelines and LNG terminals, and permits customers to choose their own suppliers. It also has liberalised its electricity industry, with open and competitive trading in a power pool. But Spain, unlike the UK, US or Canada remains largely contract-dependent. Thus it is a market in "contract" gas-to-gas competition rather than one in "commodity" gas-to-gas competition.

Spain's pipeline attachment to the European grid has limited capacity, which effectively insulates the Spanish market from the UK price competition that affects northern Europe. But, the competitive challenge to this system is both LNG spot cargo competition and the ability of some competing sellers to negotiate more favourable terms for contracts than others. The electric utilities have been responsible for much of the growth in demand. In 2007, electric utility demand accounted for 35% of total Spanish gas demand.

The utilities are particularly vulnerable to competition. If they have not negotiated sufficiently favourable contract terms, they risk not being dispatched because their gas prices do not provide them with low enough power prices for the power pool. Because utilities have been relatively aggressive in their approach to price negotiation, contracts in Spain have a wide variation in pricing clauses with different approaches to oil-linkage.

There are basically three different ways in which individual contracts have been modified away from the traditional Continental linkage to oil product prices:

- Lower pass through factors at higher oil prices
- The use of price caps and S curves
- Non-oil indexation

While gas purchased for the traditional residential, commercial and industrial market has been subject to some modifications, such as lower pass through factors and S curves, the greatest departure from traditional Continental oil product linkage has come from the power generation sector. Most of these contracts have either totally dispensed with oil clauses or sharply limited their effect on prices. One of the most popular alternatives is to key the price escalation clause entirely to power pool prices. In this way, the buyer guarantees that he will "be in the market" when competitive bidding for power dispatch takes place. Several other contracts mix power pool prices with oil indicators and several others employ price caps keyed to Brent crude oil prices.

5.4 Other Europe

The rest of Europe, other than the UK and Spain, had nine operating terminals at the end of 2007 with a regasification capacity of 62 BCM. Most of the capacity at a new offshore Italian terminal at Rovigo and half of the capacity at Belgium's Zeebrugge terminal are committed to self-contractors. A non-industry company has built one terminal in Turkey. As a result, 19% of the European capacity can be regarded as self-contracted, 10% as trading capacity and the remaining 71% as conventional contract capacity.

France, Turkey, Italy and Portugal accounted virtually all of the LNG demand growth over the decade from 1997 to 2007 in the region for. In 2007, only 3% of total LNG demand in these countries was covered by short term volumes, so long-term contracts predominated. None of these countries has proceeded very far towards market liberalisation so presumably all of the contracts for the expanded volumes were conventional oil-linked contracts.

5.5 Northeast Asia and China

For many years, pricing clauses in Northeast Asia were comparatively stable and pegged to JCC, the Japanese Crude Cocktail. The most common form of the relationship was an equation – P=Coefficient*JCC+Constant, where P and the Constant were expressed in $/MMBtus and JCC was stated in $/Bbl. The coefficient is usually referred to as the "slope". The introduction of price caps and S Curves introduced "pivot points", at oil price levels where a cap or floor took over, or the slope of the S Curve changed.

The Asian slope in effect combined two different concepts. It combined the physical relationship between the heating values of oil and gas together with a potential discount off a strict oil parity relationship.

The European approach to pricing clauses was different. Since European pricing relied on oil products that had different heating values, European pricing clauses separated out the physical relationship between units of prices for oil and units of prices for gas. Then, if the pricing clause chose to change that relationship, it utilised a separate "pass through factor" to moderate it. A pass through factor of 1.0 meant that the gas component of the pricing formula was priced at parity with the oil. A pass through factor of 0.9 meant that gas price component was only 90% of (crude or fuel) oil parity.

For an extended period of time, the most common slope for Northeast Asia was 0.1485. But, since the commonly accepted heating value for JCC was 5.8 million Btus/Bbl, an Asian slope of 0.1724 (the reciprocal of 5.8) would be the equivalent of a separately specified pass through factor of 1.0. The more common 0.1485 slope meant that JCC gas price term was discounted to 86% of the oil price – in European terms, a pass through factor of 0.86.

However, because the final pricing formula adds back a constant, some of the discount was nullified. For example, at an oil price of $25/Bbl, a constant of $0.60 would restore full parity to the oil and gas price, assuming the 0.1485 slope. But since the JCC term increases linearly with increasing oil prices but the constant does not, the effective pass through factor declines with rising oil prices. In the example, an oil price of $100/Bbl would result in a final gas price of only 90% of parity.

The early comparative stability of Asian pricing has been upset by a series of somewhat disruptive market events. China first entered the market in 2002 with its Guangdong and Fujian projects. In a comparatively soft market, competition among Australia's Northwest Shelf project, Indonesia's Tangguh and Qatar's Rasgas to gain "first mover" status on the Chinese market set off a mini price war. Russia's Sakhalin 2 project joined the competition soon after.

At a time when the average price of LNG into Japan was $4.25, Guangdong gained an equivalent price estimated at $3.29 from Australia and Fujian a price of $2.96 from Indonesia. But by 2004, a rapid increase in oil prices drove up Asian LNG prices and the market tightened substantially. The early Chinese contracts were subsequently renegotiated to a higher level in the higher price environment.

The tight markets drove up the oil-linked LNG Asian contracts and triggered S curve ceilings. Furthermore, some of the contracts limited the oil price ranges over which the S curve limits operated. Thus some contracts were driven into an "out-of-range" position as oil prices rose above their limits. Typically these range-limited contracts allowed the S curve slope to continue to operate, but on a provisional basis subject to later renegotiation.

Producers tended to regard the ranges of the basic slopes and pivot points as providing protection against "temporary" fluctuations in oil prices. They began to argue that higher prices were the new "norm" and found whatever justification they could to reopen the pricing clauses. A number of these contracts went into international arbitration.

But in a sellers' market, new and renewal contract negotiations sought to address these issues and restore the earlier linkage between oil prices and LNG prices. Some negotiations took the approach of using a much higher constant to get prices into a higher oil price range, accepting a lower slope as a trade-off. This was particularly true where the price clause included some "out-of-range" price recovery. But negotiations now seem to have settled more into a pattern of slightly steepening slopes. Qatar reportedly asked for a 0.16 slope in some of its negotiations. Slopes now seem to have settled nearer 0.1554. The constants have also been adjusted to get to an agreed-upon price level in the negotiations.

But the most common target of new and renewal contract negotiation has been the S curve itself. One early renegotiation steepened the S curve slope, but more commonly S curves are being removed altogether. In negotiations, S curves have been reportedly removed in contracts involving Malaysia, Indonesia's Bontang and Tangguh, the Timor Sea's Bayu Undan, and Australia's Northwest Shelf as well as several self-contracting sales.

One source that resists the elimination of the downside protection that S curves provide is the Australian projects. Because several of these projects are very costly (in part because of high Australian construction costs) suppliers are still seeking some sort of floor price protection. This applies to Pluto and Gorgon. One project also presumably has a financial backstop provided by the buyer in the event of low prices.

5.6 India

India had two operational LNG terminals at the end of 2007 – at Daheej and Hazira in the province of Gujarat. In addition, it has the controversial partially completed terminal at Dabhol, which was originally to have been supplied by Enron before that company's collapse. The combined capacity of the two operational terminals is 10.4 BCM. Daheej (67% of the capacity) is operated by Petronet, the Indian Government jointly owned LNG company and purchases on a long-term contract with Rasgas in Qatar. Hazira is jointly owned by Shell and Total and is designed as an "arbitrage" terminal when those companies find netbacks from the Indian market to be attractive. Thus 67% of the capacity could be classified as buyer contract capacity and 33% as self-contracted capacity.

Petronet's original Rasgas price, which was firm for the first five years, was reported to be $2.53. But after the initial period, the price was to be keyed to JCC, with floors and caps.

5.7 Pacific North America

The only existing terminal on the west coast of North America is the Sempra Costa Azul in Baja California. This terminal is designed to serve both Mexican and California markets. Its capacity is 10.3 BCM.

The terminal was built and is operated by Sempra, a California gas utility. Half the capacity has been acquired by Shell, which presumably can operate it as a part of its Pacific Basin arbitrage portfolio. Sempra has a long-term contract with BP from Tangguh in Indonesia for it's half of the capacity. Thus, half the capacity can be considered buyer contract capacity while the other half represents self-contracted capacity.

The pricing terms for Sempra's contract are keyed to California border prices. However, supposedly BP has diversionary rights to half the volume with the additional value split between buyer and seller.