Study of LNG Pricing in Asia

A Dissertation report submitted to Department of Oil and Gas in partial fulfillment of requirements for Masters of Business Administration (Energy Trading)

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Student Declaration

I hereby declare that this submission is my own work and that, to the best of my knowledge and belief, it contains no material previously published or written by another person nor material which has been accepted for the award of any other degree or diploma of the university or other institute of higher learning, except where due acknowledgment has been made in the text.

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(__________________)

Priyank Ambar Gharote

Certificate

This is to certify that the summer internship report entitled "Study of LNG Prices in Asia", submitted by Priyank Ambar Gharote to UPES for partial fulfillment of requirements for Masters of Business Administration (Energy Trading) is a bonafide record of the dissertation work carried out by him under my supervision and guidance. The content of the report, in full or parts have not been submitted to any other Institute or University for the award of any other degree or diploma.

(________________)

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1) Introduction

1.1) LNG and Pipeline Gas Trade Development

The first international gas trade started in 1890 when Eugene Costa, a Canadian entrepreneur, began exports of gas to Buffalo in New York state from a well near Niagara Falls in Ontario, but there is no detail of pricing and within a decade the reserves were near exhaustion so the Ontario government anxious to retain the resources for domestic users banned the exports in 1901.

Gas trade in Europe started in 1946 when Soviet Union started exporting gas to Poland. The gas flowed through an existing pipeline and the volume did not exceeded 0.35 bcm/year and there is nothing known about the pricing arrangements.

The true start of international or at least regional trade began when Canada started exporting gas to USA in 1950. The history of internationally traded gas is very short comparatively to Oil or Coal. In 1960, global oil trade was 449 million tons (525 bcm) rising to 1263 million tons (1448 bcm) and global coal trade was 132 mt (100 bcm) in 1960. Whereas internationally traded gas was 5.3 bcm in 1960 rising to 45 bcm in 1970. Out of this total trade, half was between North American countries, a third in Europe, around 9 percent is Soviet imports from Iran and Afghanistan. The only trade in the Pacific begin in 1970 between Japan and Alaska.

Table 1.1-A

Growth of internationally traded gas (1950-2010) * (bcm)				
	Total	Pipeline	LNG	LNG % of total
1950	0.8	0.8	-	-
1960	5.3	5.3	-	-
1970	45.7	43	2.7	5.9
1975	125.4	112.3	13.1	10.4
1980	200.9	169.6	31.3	15.6
1985	228.9	178	50.9	22.2
1990	307.4	235.3	72.1	23.4
1995	464.9	371.7	93.2	20
2000	630.5	492.8	137.7	21.8
2005	861.7	672.8	188.9	22
2009	907	664.6	242.4	26.7
2010	1015.1	718.9	296.3	29.2

SOURCE: (Stern, Pricing of Gas in International Trade: An Historical Survey, 2012)

Table 1.1-A shows the evolution of international gas trade for 60 years between 1950 and 2010. There was four fold growth in gas trade in the 1970s. During 1990s the trade more than doubled and increased roughly 50 percent in the 2000s. Pipeline trade also followed similar pattern but it levelled off in the second half of 2000s. Majority of international gas trade has taken place in three major regions which includes: North America, Europe and Asia.

1.2) Development of gas pricing in North America

Canada has always been the largest exporter of gas in North America. In USA and Canada the gas industry is dominated by the private companies and their markets are well developed and isolated from the rest of the world. The US and Canadian markets are regulated by the state and federal governments. During this time in other regions of the world 'government policy' was and in some cases it still is the major determinant of the international gas pricing.

New York set up its first utility commission in 1907, in 1920 thirty five states followed suit of to ensure that prices (known as 'rates' in USA) charged by gas companies are 'just and reasonable'. In 1930, USA established Federal Energy Regulatory Commission (FERC) and its Canadian counterpart National Energy Board (NEB) was founded in 1959, both these organizations were formed to regulate interstate energy commerce which include pipeline and LNG trade between Canada, USA and Mexico.

In 1950s the Canadian gas was priced at \$0.22/MMBtu which was considered as distress price by Canadian National Energy Board (NEB) because it was not reasonable in relation to the public interest, reason for this is that the export price for Pacific Northwest gas market in Seattle (USA) was lower than the export price of nearby market Vancouver. To overcome this NEB set out three tests for determination of reasonable export price and developed a concept called **substitution value.**

Substitution value was crystallized in 1980 into Duncan-Lalonde formula which created an oil related price for Canadian gas exports to USA, the formula is expressed thus:

$X1/5.796 - X2 + X3 = P$

Where,

X1 was the FOB price of Canadian oil imports.

5.796 was the conversion factor from dollars per barrel to dollars per MMBtu.

X2 was the transportation adjustment factor.

X3 was the weighted average transportation cost of exporting gas to the USA.

P was the price of the gas in US\$/MMBtu.

In early 1980s, the USA gas demand fell and the production increased, due to which in 1984, FERC ordered all the buyers relieved of their obligation to import gas from Canada under 'long term contract' and the pipeline companies were required to provide non-discriminatory open access. During this period the US market become deregulated following 1978 Natural Gas Policy Act (NGPA) and this led to the development of the spot market based on **Henry Hub** prices. This also had effect in Canadian gas market, they had to shift towards **Volume Related Incentive Pricing (VRIP)** to recover volume sales and thereafter shift towards market pricing like USA.

In addition to gas trade between USA, Canada and Mexico, in mid 1980s in the USA numerous LNG import projects (Regasification terminals) were under various stages of operation, suspension and negotiation. All failed due to the pricing issue except **Distrigas peak shaving contract** between USA and Algeria for importing LNG at the terminal in Everett Massachusetts operated since 1971. Failure of these projects was the deregulation of the markets in USA and due to this the US government disapproved the import of LNG at prices higher than market prices.

USA become the first country in the world to move towards spot pricing at a hub by removing regulation of upstream pricing and providing open access to pipelines. Once market pricing was established on the basis of Henry Hub spot prices and NYMEX futures prices, it become impossible to consider other price basis for any supply whether domestic or imported and due to this LNG imports related to crude oil prices collapsed.

1.3) Development of Gas Pricing in Europe

Cost-related pricing (OECD Europe)

In OECD European countries the first gas field was discovered in Groningen (Netherland) in 1959, this started the export of Dutch natural gas in the north-west Europe. Other countries like Russia, Algeria and Norway which subsequently also started exporting gas to Europe get influenced by the Dutch gas pricing framework. Dutch gas pricing formula is known as Netback market value approach, Groningen principle, market value principle, etc. The Netback market value approach was widely used for long term contracts pricing in Europe in the 2000s.

The Netback Market Value Concept:

The netback value of gas to a specific customer at the beach/border is defined as follows:

Netback = Delivered price of the cheapest alternative fuel to the customer.

(-) Cost of transporting gas from the beach/border to the customer.

(-) Cost of storing gas to meet the customers demand fluctuations.

(-) Any gas taxes.

The weighted average netback value of all customer categories is used as the basis for the negotiation of bulk price at the beach or border.

In almost every country in Europe, gas was replacing oil, gasoil, fuel oil, etc. (which was being produced by the same company which was involved in gas production and supply). Therefore it become important to price gas in such a way that it compensate the companies for the loss of oil markets and at the same time convince the customers to switch towards gas, so the price of gas was based on those products in the ratio of gasoil and fuel oil of 50:50 or 60:40 respectively.

The Dutch gas contracts reflect daily and seasonal flexibility in terms of changes in the demand by the customer because the Dutch gas has to travel shorter distance to the gas markets for the supply of gas, they reflect both capacity and commodity charges. Other countries (Russia, Algeria and Norway) which were supplying gas has the contracts based on 'take or pay' clause, means the buyer has to take minimum quantity (85%) of gas of the annual contract quantity. These companies were delivering gas through much longer pipelines which means that they have ensure high capacity utilization (high load factor) in order to recover the money borrowed for financing the pipelines, LNG terminals, development of fields, etc.

This system of long term contracts ensured that there is no gas-to-gas competition in the market. The Dutch pricing model demonstrated that substantial profits can be made by selling gas in Europe and it also encouraged players outside Europe to export gas to Europe.

NBP Pricing (UK)

Apart from the oil linked gas pricing mechanism in OECD Europe, UK used cost plus pricing for gas. UKs only international exposure was Algerian LNG imports and Norwegian pipeline imports. Production in UK was started by UK Continental Shelf (UKCS) in 1960s. The state owned British Gas Corporation (BGC) was the buyer of UKCS gas. The pricing method used here was cost plus pricing, but there was a difference in indexation, with the dominant indices in the contracts being changes in costs, rather than competing fuels.

In 1980s, UK entered into long term contract with Norway for the supply of gas. While negotiating the price with Norwegian Frigg field, BCG agreed to keep the base price higher relative to UKCS and it was indexed to alternative fuels. The import from Frigg field contributed 25% of UK gas supply in the first half of 1980s. The average price paid by BCG for all its was 4.3 pence per therm and price paid to Frigg field was 12 pence per therm, due to this UKCS complained the government about the discrimination done by BCG to secure large volume of Norwegian gas. This led to the rejection of the Norwegian Sleipner import contract by the government and in 1984 government enforced liberalization of gas market and trade started.

In 1986, after the liberalization of gas market a virtual trading hub named National Balancing Point (NBP) was formed, this made the gas market transparent and accelerated the development of trade market in UK. The creation of virtual hub and traded market meant that the gas has to be sold and purchased at NBP prices. This also influenced the development of similar hub at other parts of Europe.

1.4) Asia Pacific LNG pricing (from fixed pricing to JCC)

LNG trade in the Asia Pacific region started in 1969 when Japan imported LNG from Alaska. There was no pipeline between two countries so LNG was the only option to commercialize Alaskan gas. At that time the fuel was new for both countries so it was difficult for them to negotiate commercial gas terms, perhaps due to these factors the Alaskan gas was sold at delivered (c.i.f.) price of $0.52/MMBtu which was fixed for a 15 year period without indexation and inflation adjustment, it only had one price reopener clause which stated:

(In case of any future LNG supply to Japan by foreign suppliers then in this case sellers will hold discussion with buyers concerning the price to satisfy all parties concerned.)

After the first export of gas by Alaska, other countries like Brunei, Indonesia, Australia and Canada also started exporting gas to Japan. Japans second LNG contract with Brunei was operationalized in 1972. Price of this contract was lower than the Alaskan contract at $0.486/MMBtu delivered at Tokyo and Osaka regasification terminals. There was no indexation, inflation adjustment or price reopener clause in it but it had take-or-pay provision which was very low for first five years but 97% thereafter.

Despite the original contractual provisions these ‘fixed’ prices did not last long. There was a huge 1973 -74 increase in crude oil prices which had impact on LNG and its price. In around 1980 most contracts moved to reflect the price of various crude oil imports in Japan (shown in table 1.4-A). In 1987 an amendment was made to the contract between Marathon and Tokyo Gas/Tokyo Electric, according to which the LNG price will be indexed as per the average of top 20 crude oil imported into Japan. This Japanese Customs Cleared crude oil price mechanism is often referred as Japanese Crude Cocktail (JCC).

Japanese LNG prices (MMBtu) 1969-87, c.i.f. Japan							
Fiscal Year	Alaska	Brunei	Abu Dhabi	Indonesia	Malayasia	Average	Crude Oil
1969	0.52					0.52	0.3
1970	0.52					0.52	0.31
1971	0.52					0.52	0.39
1972	0.57	0.49				0.55	0.43
1973	0.56	0.79				0.69	0.8
1974	0.87	1.44				1.3	1.94
1975	1.35	2.03				1.87	2.03
1976	1.73	1.92				1.89	2.14
1977	1.19	2.07	2.01	2.52		2.12	2.31
1978	2.15	2.2	2.21	2.78		2.4	2.34
1979	2.62	2.63	3.07	4.07		3.33	3.89
1980	5.56	5.59	5.95	5.45		5.55	5.6
1981	5.97	5.95	6.64	5.81		5.86	6.23
1982	5.79	5.78	6.17	5.62	5.54	5.73	5.84
1983	4.9	4.91	5.19	4.84	5.04	4.97	5.19
1984	4.87	4.8	5.17	4.76	5	4.84	4.95
1985	4.74	4.69	4.81	5.05	4.79	4.92	4.73
1986	3.19	3.26	3.89	3.46	3.29	3.41	2.7
1987	3.2	3.26	3.41	3.65	3.32	3.45	3.01

Table 1.4-A

SOURCE: (Stern, Pricing of Gas in International Trade: An Historical Survey, 2012)

During the time period between 1969 and 1979 LNG price was higher than oil price but still Japanese LNG buyers were willing to pay such high price for LNG because they were burning crude oil in power plants. Table 1.4-A shows that the fixed prices did not last long. Increase in crude oil prices from 1969 to 1964 led to progressive increase in LNG prices. After 1975, LNG prices began to move in step with crude oil prices. In 1987, an amendment was made in Marathon and Tokyo Electric/Tokyo Gas which led to indexation of LNG price to top 20 crude oils imported into Japan.

Contrasting the largely successful attempt by European importers against the oil parity pricing of gas in 1980s, the Japanese importers with little struggle accepted this form of pricing. The reason for this is that in 1970s and 80s, LNG replaced crude oil in Japanese power stations and as crude oil exporters such as Abu Dhabi and Indonesia became major LNG exporters, the logic of linking LNG prices to those of crude oil was rational as Japan was the first large scale importer of LNG in the world and this crude oil replacement set the standard for LNG pricing. Additional LNG is a substitute for liquid fuels and based on commercial logic the substitute will have to be priced in connection with the commodity it is substituting.

There are two parts to the story of JCC: the concept itself and the derivation of 'the slope' which means the adjustment of the LNG import price to the movement of crude oil prices. As far as concept is concerned an important development occurred in 1979 during negotiation of Malaysian contract between Petronas and TEPCO/Tokyo Gas (which was eventually signed in 1973). The Malaysian side did not wanted to use the index of Indonesian crude oil prices which had been adopted in the contract with Pertamina. Initially the agreement was settled at price on a significant premium to crude oil prices, but before deliveries started this was renegotiated to a formula to apply for first four year deliveries. Fifty percent of this price was linked to the average price of the crude oil imported into Japan which Malaysian referred to as cocktail (hence JCC) and fifty percent to the Official Malaysian Government Selling Price (OGSP) for crude oil. In this case the formula took account markets of both sides in negotiation.

In 1988 the Japanese ministry begin to publish monthly statistics of Japanese customs cleared crude oil price in its so called 'Yellow Book', a practice which still continues on its website. However, the Malaysian contract did not use the term JCC but by the early 2000s the term JCC began to feature in contracts.

The derivation of slope (the adjustment of the LNG import price to the movement of crude oil prices) is equally important. Throughout the history of LNG the most commonly used factor is 0.1485 (frequently referred as slope of 14.85 percent). This figure dates back to one of the first long term LNG contract signed between Pertamina (Indonesian oil and gas company) and Japan's Western buyers consortium (Chubu Electric, Kansai Electric, Kyushu Electric, Osaka Gas, Toho Gas and Nippon Steel) which was finalized in 1973.

The price formula results in premium over crude oil parity at low oil prices but the premium erodes as the oil price increase. Oil price linkage was adopted by all the projects supplying Japan but the 0.1485 factor remained unique to Indonesian LNG only until the collapse of the oil prices in late 1986. The non-Indonesian projects had been using crude oil parity pricing based on OGSP of crude oil. As the producers stopped selling crude oil at OGSP prices in the late 1980s and adopted much lower market prices, the buyers and sellers needed to find new approach to pricing that worked in low oil price environment for both the parties.

By the time other Pacific Basin importers (South Korea and Taiwan) started importing from Indonesia. Japan had already been importing LNG for past 15-20 years, and in 1990 it imported nearly 52 bcm of LNG, which accounted for 70 percent of global LNG imports. Due to this reason these importers had little option but to accept a crude oil pricing mechanism similar to that currently operating in Japan, and this has continued up to the present.

2) Literature Review

- (Energy, Facts Global, LNG Trading Series Pricing: Watch what you "Hub" for?, 2014). Issues such as price mix, price transfer mechanism and long term effects of hub pricing requires special attention. Hub exposure due to the new supply of LNG from US in future may result in diversification and complications of pricing. It may lead to the Hybrid pricing in future.

- (Rogers, The Impact of Low Gas and Oil Prices on Global Gas and Oil markets, 2015). The Impact of Low Gas and Oil Prices on Global Gas and Oil markets. Low oil and gas prices had an impact on the global LNG markets. Low oil prices will have an impact on the new LNG supply from US. Even if oil prices do not recover in next one or two year, it is unlikely that the Asian buyers will accept return to the JCC linked pricing unless accompanied by strong price review clause.

- (Handerson, Potential Impact of North American LNG Exports, 2012) The discovery of Shale gas has led to signing of long term contracts between US suppliers and Asian buyers for supply of LNG indexed to Hub. It will lead to structural changes in the pricing methodology in Asian LNG market.

- (Rogers & Stern, Challenges to JCC Pricing in Asian LNG Markets, 2014). There are many possible alternatives to the JCC pricing in the Asian LNG markets. JCC pricing mechanism is facing problems due to change in economic and market fundamentals arising from change in demand, supply and pricing patterns.

- (Fattouh, Rogers, & Stewart, The US shale gas revolution and its impact on Qatar's position in gas market, 2015). LNG exporters will face pressure to offer more flexible price indexation from US LNG exports, which offer volumes on a Henry Hub–related basis, rather than on an oil-based index, as Asian customers seek more diversified pricing structures.

- (Corbeau, Braaksma, Hussin, Yagoto, & Yamamoto,The Asian Quest for LNG in a Globalising Market, 2014)The recent and future changes in the gas market globally can lead to modifications of the global LNG and pricing situations.

3. Objectives

1) The main objective of this report is to understand the pricing of internationally traded gas in Asia with compare to other region.

2) To Understand Growth & Pattern the Prices in Asia Pacific, Middle East & other region.

3) Study of Volume of LNG trade in various region.

4). Research Methodology

Research Methodology is a way to systematically solve the research problem. In it I study the various steps that are generally adopted by a researcher in studying his research problem along with logic behind them.

TYPE OF RESEARCH-To make the comparative study of Asian, North American and European gas market pricing concepts. I have gone through various newspapers, research papers, websites and collected information and data from secondary sources.

Basically this is a type of exploratory research.

DATA COLLECTION

In data collection method I have collected the secondary data from the following source.

- Research Papers
- Secondary Data
- News paper
- Internet
- Journals
- Books

PARAMETERS OF RESEARCH

- Spot price of Oil and Gas
- Production
- consumption

- Reserves

The above fields are taken for data analysis primarily to find out the change in the LNG and pipeline gas export and import in North America, Asia and Europe. To find out the present and future consumption, production, reserves, etc.

RESEARCH DESIGN: The study is a cross sectional study because the data are being collected from many sources. Basically the study make the comparison of Asian, North American and European markets at a time on qualitative and quantitative research basis.

RESEARCH INSTRUMENT: This work can be carried out through secondary data based.

STATISTICS ANALYSIS

- Descriptive
- Comparative

TOOLS TO BE USED:

- MS Excel
- MS word

5) Data Analysis

5.1) Internationally Traded Gas Pricing in Europe

Development of Gas Contracting

In each European country the gas price for the end user is regulated and capped by the regulatory authority of that country. Whereas the sellers or producers can sell gas to any end user without any intervention by that country. In European countries gas is sold on basis of long term, medium term and short term contracts. Gas is sold to the country based on the existing gas structure of the country to which the gas is sold, so due to this price of gas is different for each country. Price is linked to alternative fuel of the importing country, especially petroleum products or crude oil. For example, if gas is used for heating then it will be indexed to gasoil (known as fuel oil in Germany) and if it is used for power generation then it will be indexed to heavy fuel oils.

The first gas field known as Groningen field was developed in 1950 in Netherlands, and the negotiation process for export of gas by Dutch to Germany, Belgium and France started in 1960. The Dutch concept of gas pricing was developed in 1962. They developed 'Netback Value Principle' which was different from 'Cost-Plus' approach used for pricing of town gas at that time. The difference between both pricing approaches is that in Cost-Plus approach, production cost, transportation cost, overheads and profit margin is added to arrive at the final sales price whereas in case of Netback Value Principle, market value of natural gas in inter-fuel competition is determined and then transport cost, overhead cost and profit margin are deducted at get the final sales price (Melling, 2010).

Netback Replacement Value Gas Price Formula:

$P_{O}=P_{O}+0.6*f_1*k_1*(GO-GO_O) ++0.4*f_2*k_2(LSFO-LSFO_O)$

Where**,**

$P_{O}=$ base price in eurocent per kWh (€c/kWh)

GO= price of gasoil in €/tonne net of all taxes and duties

LSFO= price of low Sulphur fuel oil with Sulphur content of 1% or less in €/tonne net of all taxes and duties

f= "delivery point" adjustment factors

k= energy conversion factors (Frisch, 2010).

As can be seen in formula given above, the pricing arrangements in European term contracts is based upon base price (Po) agreed between buyers and sellers. Originally the two indexation elements used in the formula were Gasoil (GO) also known as light fuel oil and Low Sulphur Fuel Oil (LSFO) also known as heavy fuel oil. In this pricing formula Gasoil basically represent commercial and domestic gas market, usually with weight of 60% in pricing formula and Fuel Oil represent industrial and feedstock applications, with weight of 40% in pricing formula.

In case of contract for supply of gas from Groningen field of Dutch to Germany the gas price was indexed to gasoil which was the main heating oil used in domestic sector in Germany. Similar to Asian contracts, “price review clause and take-or-pay clause” was also present in the European Gas Sales Agreements (GSA). Pricing terms in LNG contracts were similar to Pipeline contracts but there were two differences:

- It included transportation cost.
- Volume Flexibility was 95-100 percent, which was less than that in pipeline supply contracts.

Based on the Dutch pricing methodology other contracts that were signed include:

- Supply of LNG from Algeria to France (1964) and Belgium (1987)
- Gas export from USSR to Italy
- Norwegian Ekofisk (1977) and Statpipe (1985) exports
- Piped gas export from Algeria to Italy
- Norwegian toll supplies to Germany, Belgium, Austria, France and Spain (1996)
- UK exports to European countries
- Russian exports to FSU countries Ukraine, Belarus and Maldova (2005).
- LNG supply from Nigeria (1999) (Melling, 2010).

The UK Experience

In case of UK, gas development began in 1960s with the development of oil reserves in North Sea. Its contracting methodology was different from the Dutch pricing model, the key differences were as follows:

- The UK fields were offshore, so CAPEX and OPEX of those fields was very high compared to Groningen field.
- The UK field was very smaller in size then the Groningen field so it was not possible to sign long term contracts for export of gas, instead they had to import gas to meet their demand.
- The UK field was developed only for domestic production.

The UK started importing LNG in 1964 from Algeria through LNG terminal in Canvey Island. The Algerian sellers negotiated fixed price deal similar to initial LNG sales to US which had inflation as the main price element. For negotiation of pipeline gas import from southern North Sea, UK oil producers wanted oil indexation in sales contract but the monopoly buyer British Gas wanted inflation as main element of price formula, so the outcome was multiplicative formula with an element of inflation (Producer Price Index) and indexation to gasoil and HFO.

Divergence of Gas and Oil Markets in Europe

Historically in Europe gas was traded on basis of long term contracts linked to oil products but during the period of 1990s, the gas contracts indexed to oil products begin to weaken due to the following reasons:

- Elimination of oil products from stationary energy sectors.
- Cost and inconvenience of maintaining oil equipment's.
- Increased efficiency of gas burning equipment's.
- Tightening environmental standards.

Natural gas and oil are substitutes and the price formulae is designed to ensure that the customers continue to burn gas instead of oil because majority of customers switched from oil to gas because of the price incentive. If the customers again switch to oil then the gas importers will incur take or pay penalties in their contract and it will deprive the gas producers of their market. In the short term the consumers have the capability to switch existing plant from gas to oil in response to the price signal, but in the long run the consumers have the option of constructing either gas fired power plant, oil fired power plant or combination of both.

Table 5.1-A

Share of gasoil in total energy consumption of stationary sectors % (2004)					
	Industry	Household	Commercial	Power	TOTAL
Germany	5.3	21.2	25.1	0.6	11.6
France	8	16.6	27.6	0.2	10.2
Neitherlands	1.3	0.2	2.3	0.08	0.9
Belgium	2.6	33.8	27.9	0.06	14.6
Italy	3.1	11.2	3	0.7	4.8
Spain	5.1	17.4	20.6	0	7.5
TOTAL	4.9	17.7	18.9	0.4	9
Share of residual fuel in total energy consumption of stationary sectors % (2004)					
	Industry	Household	Commercial	Power	TOTAL
Germany	7.1	0	0	2.5	2.4
France	4.7	0.5	0.6	1.2	2
Neitherlands	0.1	0	0.2	0.1	0.1
Belgium	6.3	0	0.4	5.7	3.5
Italy	8.9	0.9	0	38.1	13.5
Spain	3.7	0.4	3.3	20.5	8.3
TOTAL	5.9	0.3	0.5	10.2	4.9
Share of gas in total energy consumption of stationary sectors % (2004)					
	Industry	Household	Commercial	Power	TOTAL
Germany	35.9	37.2	30.9	19.2	30.7
France	38.7	36.1	0	3.2	0
Neitherlands	44.4	75.7	53.3	67.6	59.7
Belgium	39.8	37.3	43.4	30.1	37.2
Italy	43.3	56.7	48.3	46.6	48.4

Spain	41.7	20.6	4.1	20	27
TOTAL	39.8	40.8	0	22.8	0

SOURCE: (Stern & Rogers, The Dynamics of Liberalised European Gas Market, 2014)

Table 5.1-A is showing the share of gas and its two main competing oil products: gasoil and residual fuel in four main energy markets. Gasoil is almost eliminated from the power market. Share of fuel oil in case of industrial sector is only significant in France (8%) which is highest and Germany (5%). Gasoil consumption in household is significant in all countries except Netherlands. Share of gasoil is higher in commercial sector than household sector in case of France, Germany, Netherlands and Spain. Residual oil is almost eliminated of all sectors except power with largest remaining shares with Germany (7%) and Italy (%).

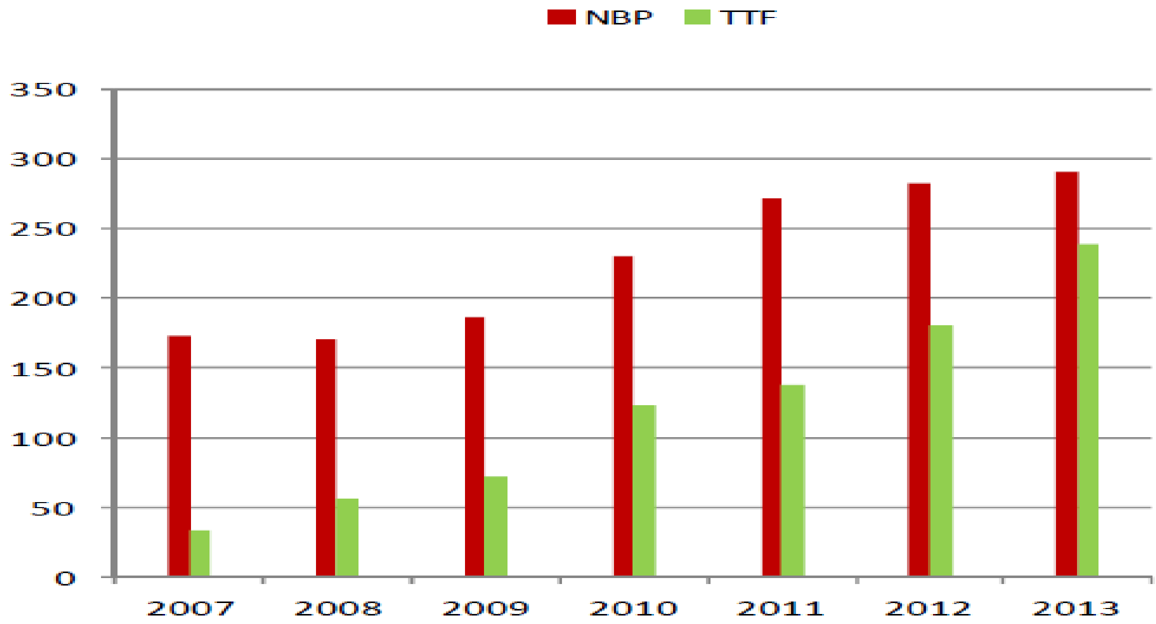
Gas has largest share in all stationary sectors of all European countries except power in France because of Nuclear Power and commercial sector in Spain. Hence, the relation of gas pricing to oil had already become questionable as gas has displaced oil in all four sectors. Though oil indexed pricing created inertia which allowed for the continuation of status quo, but this was to change post 2008.

The Rise of Spot Gas Markets and Hub Pricing

Spot gas or traded wholesale markets begin in mid-1990s with the development of National Balancing Point (NBP) in UK. NBP is still considered as the only mature gas trading hub in the European market. NBP has high liquidity and it is connected with continental Europe through two pipelines called Interconnector and Balgzand Bacton Line, and due to this it strongly influences the continental hubs. The two dominant trading hubs in continental Europe are Zeebrugge (Belgium) and Title Transfer Facility (Netherlands).

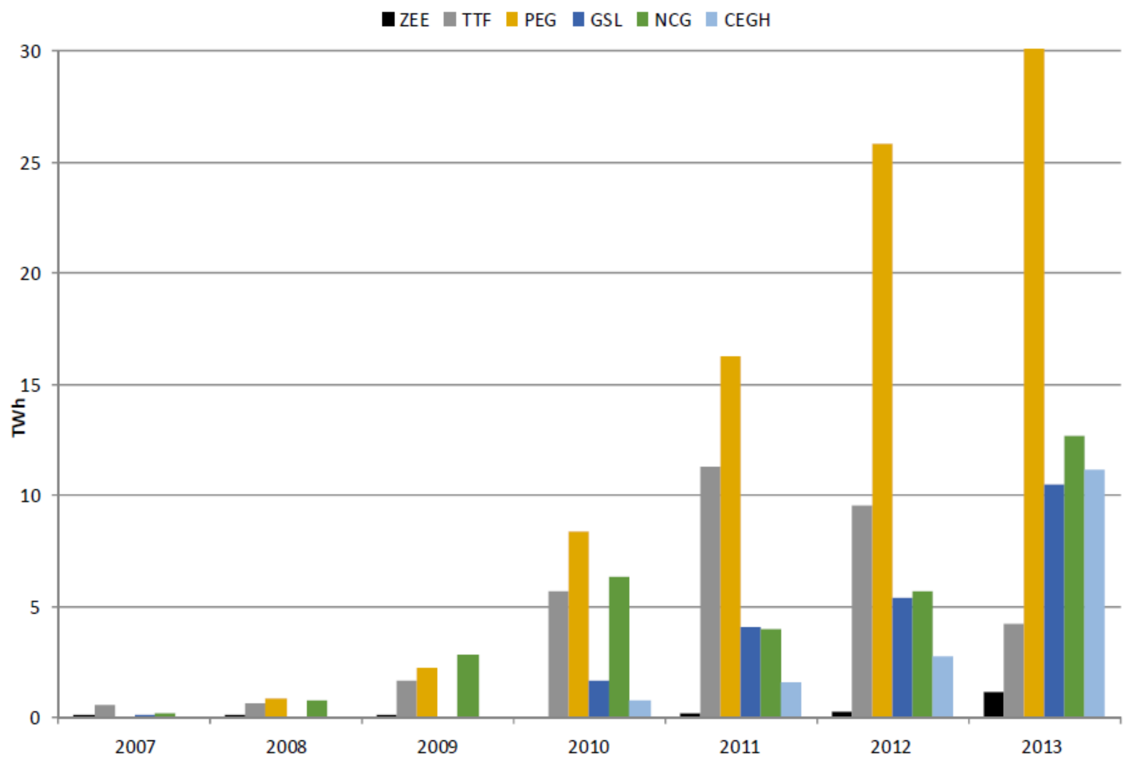
In period between 2009 to 2012, new LNG supply of 30Bcma flowed into Europe from Qatar, Yemen, Russia, Peru and Indonesia. This supply was originally been intended for USA but due to unforeseen development of shale gas this supply was diverted to Europe. This uncontracted gas supply flowed through UK to the continental Europe, and it increased the liquidity of European gas trading hubs. Other major trading hubs of continental Europe include EuroHub and NEW-Hubco (2002), two German hubs: Net Connect Germany (NCG) and Gaspool (2009), and Gas Exchange Point (GEP) of France.

Figure 5.1-A: Gas Volumes Traded, OTC Day Ahead 2007-2013 (Twh)



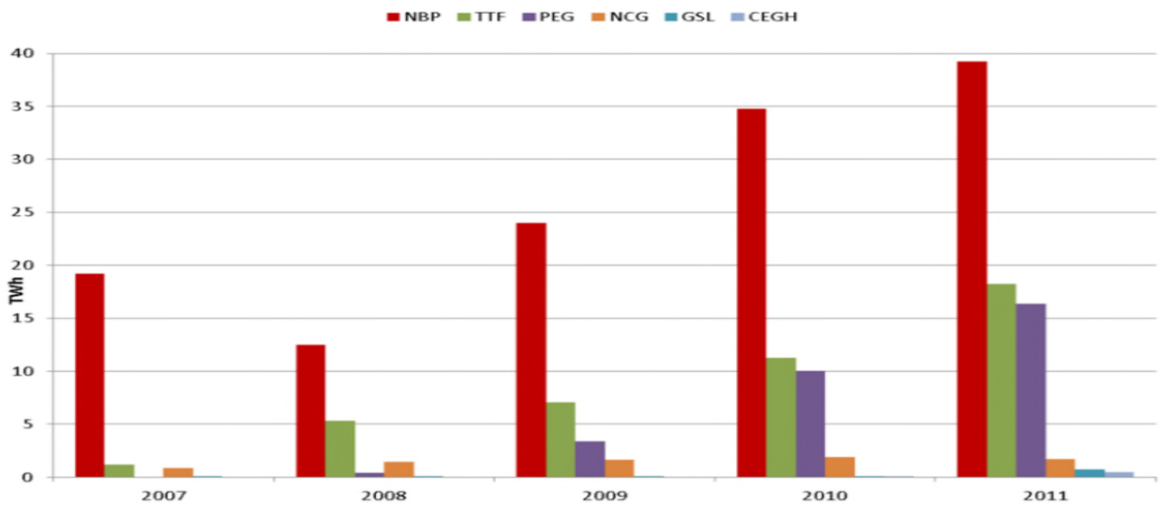
SOURCE: (Stern & Rogers, The Dynamics of Liberalised European Gas Market, 2014)

Figure 5.1-B: Exchange Traded Volumes, Day Ahead (Twh)



SOURCE: (Stern & Rogers, The Dynamics of Liberalised European Gas Market, 2014)

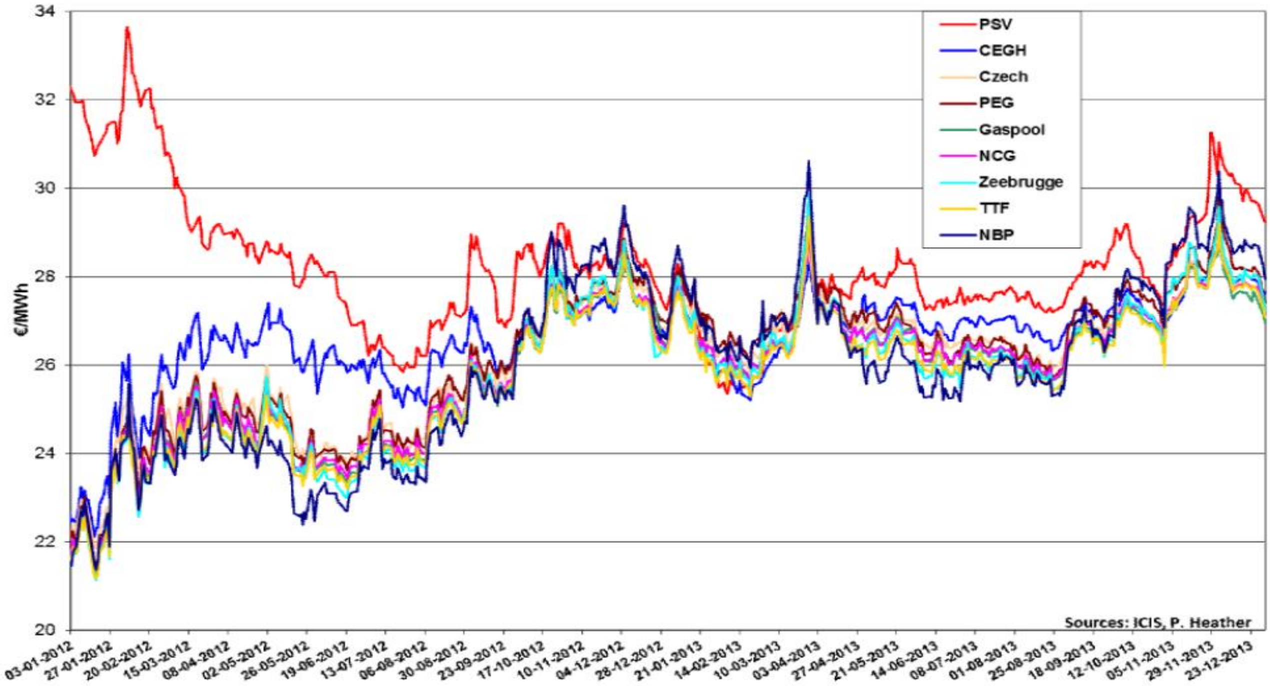
Figure 5.1-C: Exchange Traded Volume, Month Ahead (Twh)



SOURCE: (Stern & Rogers, The Dynamics of Liberalised European Gas Market, 2014)

As mentioned above, the rise of gas hubs in continental Europe was catalyzed by the flow of spot priced LNG from UK to continental Europe through pipelines. The increase in the volume of gas traded is shown in the figure 5.1-A, figure 5.1-B and figure 5.1-C. In 2013, NBP and TTF exchange traded volumes were around 12.6% and 7.4% below that in 2012 respectively. In October 2014, TTF OTC volume exceeded that of NBP (Stern & Rogers, The Dynamics of Liberalised European Gas Market, 2014).

Figure 5.1-D: European Hub Price Correlation Month Ahead Contracts Jan 2012-Dec 2013



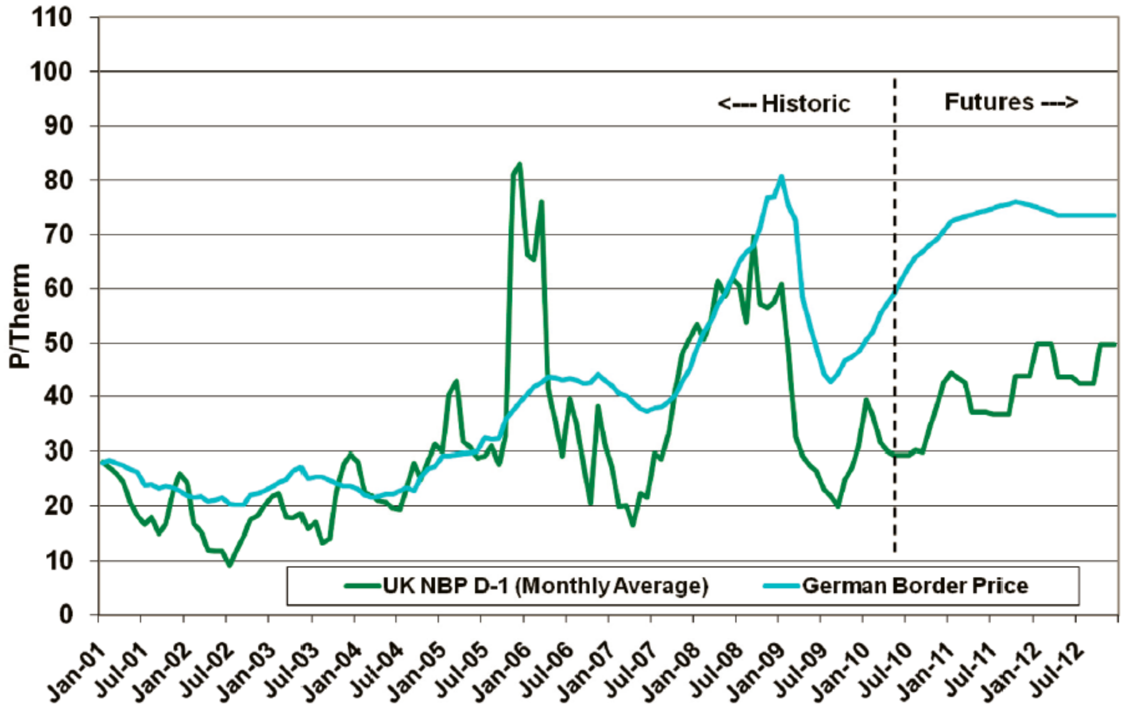
SOURCE: (Stern & Rogers, The Dynamics of Liberalised European Gas Market, 2014)

Figure 5.1-D shows the daily month ahead contract prices for all main European hubs. Prices are generally well correlated but at some periods there is price de-linkage. In 2011, NBP at times de-linked from other European hubs due to IUK gas pipeline capacity congestion. At times PSV and CEGH have also delinked from the north western European hubs during their early stage of development prior to 2012.

Europe's Two Level Gas Pricing System

In Europe, gas pricing system based on spot markets and oil price indexed gas price formulae has been coexisting for more the a decade. The two level of pricing in Europe is represented by the oil indexed contracts and the spot markets. The two most representative benchmark prices for both these prices are NBP (National Balancing Point) of UK and GBP (German Border Price) of Germany. GBP is average of oil indexed contracts that comprised 90 percent of gas supply in Germany in 2008, published each month by BAFA. The NBP is virtual trading hub and price reference point for all of the UK's traded gas market.

Figure 5.1-E: GBP vs NBP Day Ahead Price (Monthly Average)



SOURCE: (Melling, 2010)

The figure 5.1-E shows the development of the NBP and GBP prices since 2001 to 2012. Generally during summers spot prices tend to be lower than the price generated by oil indexed gas price formulae and in winters it is peak above this price level, but with the onset of the recession in 2008, this pattern has changed. In 2008 these two pricing systems reflected same price levels for gas with exception of seasonal variations.

From the above figure we can see that two gas pricing system is coexisting together, but there has never been a comfortable coexisting. When spot prices are above oil indexed price, there is minimal stress in oil indexed markets, rather the producer's call for upward price revisions. Small discounts in spot markets also present little stress to oil indexed markets but heavily discounted spot and future prices pose a serious threat to players with oil indexed positions as due to this markets will be oversupplied with market priced gas for foreseeable future.

5.2) Internationally Traded Gas Pricing in North America

Overview of North American Gas Market

Natural gas market in North America is linked to three countries (USA, Canada & Mexico). All the players in North America is Henry Hub price takers in one form or another. In North America, pricing of pipeline gas and LNG trade is related to the dynamics of Henry Hub pricing.USA and Canada does the largest bilateral gas trade in world in terms of both physical and financial liquidity. In 2000s the existing gas fields in both Canada and US started to decline and it was forecasted that US would become a major importer of LNG surpassing Japan. Indeed due to increase in the proved reserve of shale gas and production in USA showed strong Henry Hub price signal, due to which companies entered into the development of large shale basins.

First shale basin to commercialize was Barnett in Texas, other basins include Haynesville in Louisiana, Fayetteville in Arkansas and giant Marcellus in the northeast. Traditional locations of the US Lower 48 natural gas production (East and South Texas, Oklahoma, Coal bed methane fields of New Mexico and Colorado) also received capital infusion but these existing fields are at the stage of post decline. In 2010, US faced a dilemma of decrease in the natural gas prices due to rapid increase in the production and decrease in consumption.

Canada also followed the same path as US Lower 48, with the ageing conventional gas production (Western Canada Sedimentary Basin is maturing quickly), Canada also started drilling for the shale gas. Canada’s shale gas basins include Horn River and Montney in eastern British Columbia, these are under development. Offshore Atlantic Canada has also proved disappointing over the years. Mexico’s prime gas producing area, the Cantarell complex offshore Bay of Campeche is in the declining stage. Mexico has shale gas reserves at the southern end of Texas/Woodford/Barnett/Eagle Ford Complex, but they are dry gas fields which is a disadvantage for the time being.

In North America, USA dominates the gas trade. During the period of 1990 and 2000, Canada doubled its gas sale to USA but now it has reduced considerably due to maturity of the Canadian gas fields. This situation transferred advantage to the LNG imports and later US gas producers. Despite USA being the largest importer of gas from Canada, there are some locations in Canada which are served by US exports.

Table 5.2-A: North American reserves, production, consumption and trade

	USA				Canada				Mexico			
BCM(billion cubic meters)	1990	2000	2010	2015	1990	2000	2010	2015	1990	2000	2010	2015
Reserves	4795.3	5024.2	7716.6	9800	2725	1683	1727.5	2000	2025	853	490.3	300
Production	504.3	543.2	611	728.3	108.6	182.2	159.8	162	27.1	38.3	55.3	58.1
Consumption	553.9	660.7	683.4	759.4	67.7	92.7	93.8	104.2	29.2	41	68.9	85.8
% Change		**1990-2000**	**2000-2010**	**2010-2015**		**1990-2000**	**2000-2010**	**2010-2015**		**1990-2000**	**2000-2010**	**2010-2015**
Reserves		**4.70%**	**53.60%**	**26.90%**		**-38.24**	**2.64**	**15.77**		**-57.88**	**-42.52**	**-38.81**
Production		**7.70%**	**12.50%**	**19.10%**		**67.77**	**-12.29**	**1.38**		**41.33**	**44.39**	**5.06**
Consumption		**19.30%**	**3.40%**	**11.12**		**36.93**	**1.19**	**11.09**		**40.41**	**68.05**	**24.53**

	USA				Canada				Mexico			
BCM	**1990**	**2000**	**2010**	**2015**	**1990**	**2000**	**2010**	**2015**	**1990**	**2000**	**2010**	**2015**
IMPORTS												
Pipeline	20.7	99.6	92.7	74.6	0.5	2	20.7	21.8	0.4	2.9	9.3	20.5
LNG	2	6.3	12.1	1.7	0	0	2	0.6	0	0	5.7	9.3
%Change												
Pipeline		**381.16**	**-6.93**	**-19.53**		**300**	**935**	**5.31**		**625**	**220.69**	**120.43**
LNG		**215**	**92.06**	**-85.95**		**0**	**0**	**-70**		**0**	**0**	**63.16**
EXPORTS												
Pipeline	0.9	5	30	NA	40.5	99.2	91.8	74.6	0	0.3	0.8	0.05
LNG	1.5	1.8	1.8	0.4	0	0	0		0	0	0	0
%Change												
Pipeline		**455.56**	**500**	**NA**		**144.94**	**-7.46**	**-18.74**		**0**	**166.67**	**-93.75**
LNG		**20**	**0**	**-77.78**		**0**	**0**	**0**		**0**	**0**	**0**

SOURCE: Compiled by author from GIIGNL, BP statistical review and EIA

Table 5.2-A compares three gas market conditions of three North American economies across four time periods. In North America LNG imports increased during past two decades but significantly since 2000. LNG imports in USA peaked in 2007 at a level roughly double the 2010 receipts. LNG cargoes continued to enter USA in spite of abundant domestic production, reason for this is the obligations of the long term supply agreement, commitment of the exporters and need to maintain cryogenic conditions at LNG terminals. The bulk of the LNG imports into Canada goes to US north east through pipeline and Mexico's LNG imports is piped into Southern California. Table 5.2-A is also showing the growth in gas reserves in US due to shale gas revolution in comparison to Canada and Mexico. This led to the massive capital infusion by companies for the development of large shale basins.

The question of whether supply surplus in the North America can be exported as LNG to other countries and supply shortages can be fulfilled by LNG imports depends upon the Henry Hub price signal and the oil prices. Alaska has the largest potential of natural gas in North America. The Pacific Basin LNG trade which was started by Kenai LNG export facility, was set to end operations in2011, but post Fukushima demand kept the terminal open. LNG export option is more preferable than pipeline in Alaska because in pipeline transportation there is huge cost and development challenges.

Evolution of Henry Hub

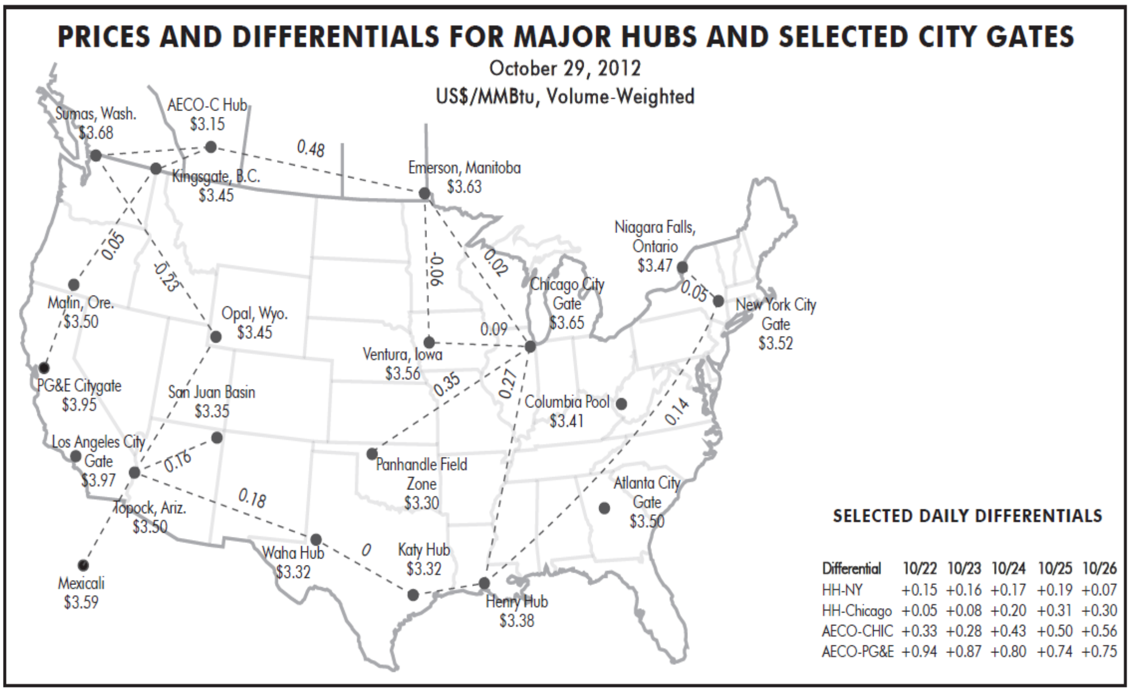
Henry Hub was established following the FERCs encouragement of market centers and hubs with order 636 in1992. In figure 5.2-A, it is shown that Henry hub located in southwest region, has a huge concentration of infrastructure and supply capacity which gives liquidity to physical and financial transactions. In Henry Hub both onshore and offshore production converges specially through Louisiana production sites. Infrastructure across the Henry Hub region include 18bcm of pipeline capacity across the Hub, 16 interstate pipelines connected to the Hub, underground storage capacity, large natural gas liquids processing and petrochemicals operations through which 180 customers conduct business regularly. Henry Hub region also has three quarters or 112bcm of LNG send out capacity of US LNG import facility. Henry Hub futures contract was established in 1991 when New York Mercantile Exchange (NYMEX) adopted Henry Hub as its contract location in 1989.

Alberta hub is the biggest hub of Canada which is equivalent to Henry Hub. There are many other locational concentrations of supply and infrastructure across North America which are at some points in the Lower 48 and places where Canadian infrastructure interconnects with US pipelines. There are 24 hubs and market centers in North America which trade against the Henry Hub index because it is the only location upon which methane future contracts and other derivatives are based.

Pricing in various market hubs and centers is relative to Henry Hub, it is dependent upon the supply and demand balances at pooling and demand sales point. Long term, forward and future price trends of gas is influenced by supply and demand fundamentals over time, regulatory changes, macroeconomic cycles and international trade, etc. Relative pricing and netbacks across market place, hubs and city gates gives crucial information about investment in downstream business segments.

City gates are the demand sales points. Natural gas which flows through meters in key intrastate and interstate pipeline market areas are monitored and controlled by the local distribution companies (LDCs) or gas utilities, it provides information pull or lack thereof, on natural gas volumes and deliveries on daily and seasonal basis. Figure 5.2-B shows the prices for major hubs and city gates.

Figure 5.1-B



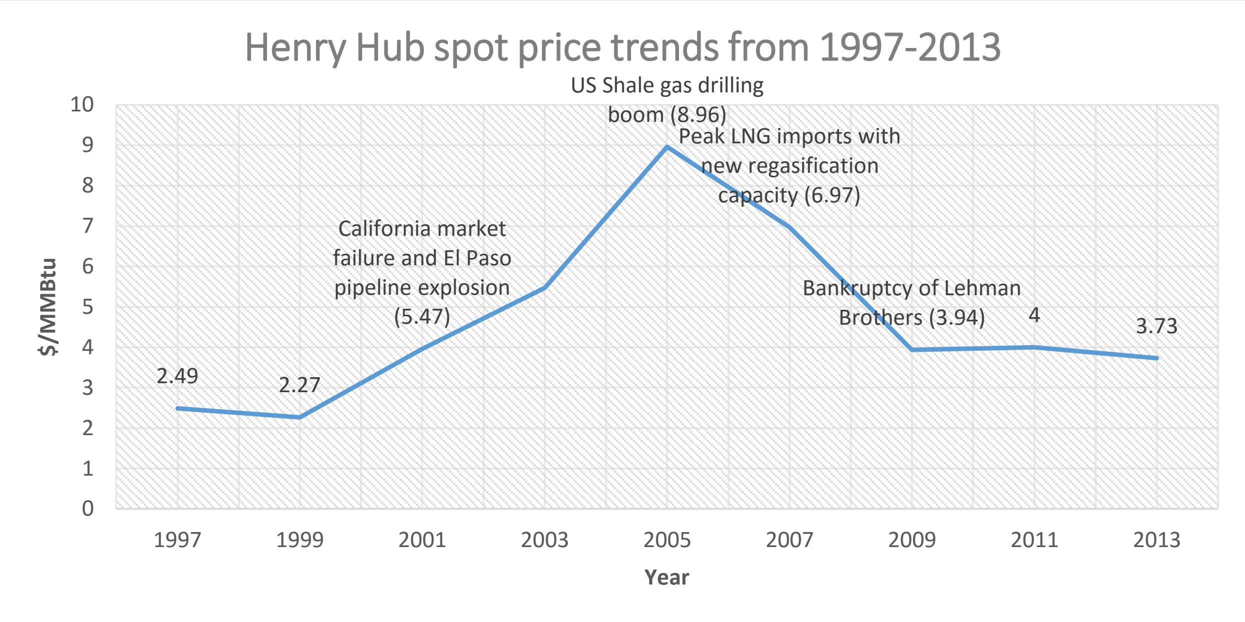
SOURCE: (intelligence, energy, 2012)

Figure 5.2-C is showing the Henry Hub spot price between the period 1997 and 2013.Henry Hub spot price remained around $2/MMBtu during second half of 1990s. The price of Henry Hub moved slightly higher since 2000s and it experienced four significant price spikes. During the period between 2000 and 2003 there was slow increase in Henry Hub spot price due to multiple reasons which includes the growth in demand for gas in electric power sector, El Paso pipeline explosion, and Enron Bankruptcy (it greatly reduced natural gas trading).

The second spike in the HH price took place in the winter of December 2005 due to the above reasons and decline in the gas production from the existing gas fields in US and Canada. It was believed that US will become major importer of LNG in the world overtaking Asia and by 2006 five regasification terminals were constructed in US. Qatar also prepared for this by building up to 77 MMPTA of capacity and commissioning largest LNG carriers Q-Flex with capacity between 210,000-216,000 cubic meter and Q-Max with capacity of 161,994,000 cubic meters.

The coincidence between the rising prices and the new shale gas production (conventional gas to unconventional gas) since 2000s led to the shale gas boom in 2007-2008, which started to increase the supply of gas in US. This led to the fall in HH spot price to $1.83/MMBtu in September 2008. After 2008 there were many small price spikes, but on an average it was oscillating between $2 to $4/MMBtu.

Figure 5.2-C



SOURCE: Compiled by author from EIA

LNG Trade Developments in North America

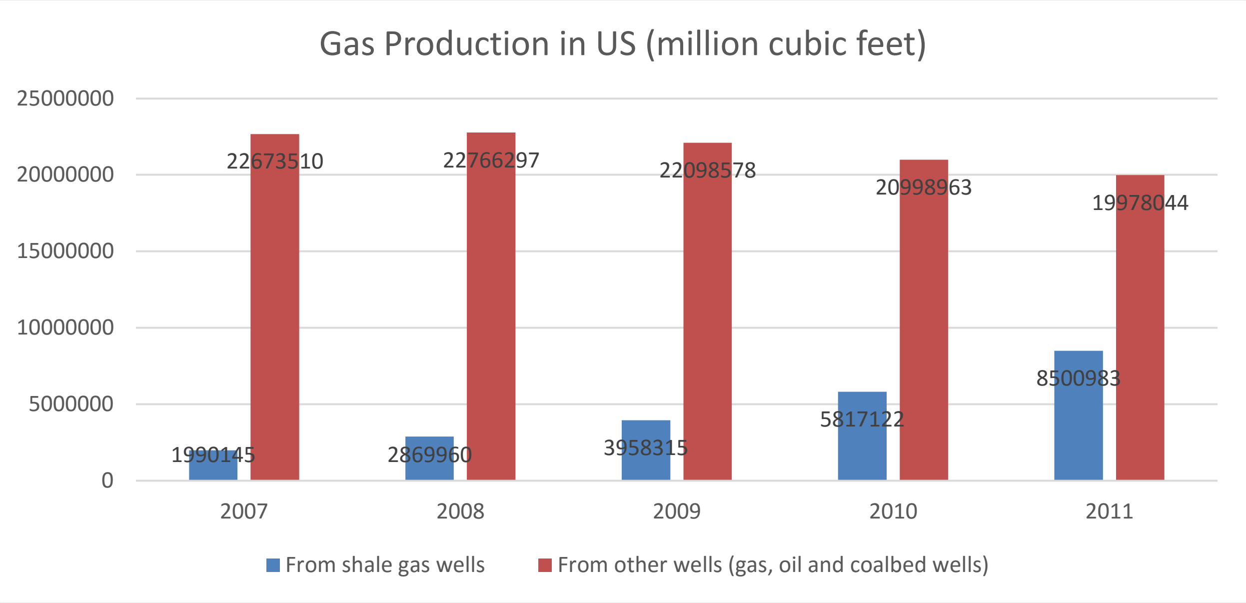
Since 1990s, North America was self-sufficient in gas production and significant amount of trade used to take place between the three countries (especially pipeline exports from Canada to US), but with decline of gas reserves the need for LNG imports arise in US and Canada.

The outcome of this was that there was a wave of proposals of LNG import projects at various locations like Lower 48 in US, Atlantic Canada (for meeting domestic demand and pipeline export to USA), and Mexico. The first new onshore import terminal commissioned was Cana port, in New Brunswick province, which exports through pipeline to New England (USA). To date in the Lower 48 five LNG import terminals have been built, west from Texas east to Mississippi along the gulf coast. Expansions were completed in three of the original four US import terminals (Cove Points, Elba Islands, and Lake Charles).

Three offshore, ship based delivery system have been implemented (Gulf Gateway which into a pipeline offshore Louisiana via pipeline buoy, Northeast Gateway and Neptune, to serve north-eastern US load). To supply gas to gas fire powered power generation plants, Mexico embarked on plans to make import terminals in Altamira, near Tampico on Mexico's Gulf Coast and just south of the US border to Costa Azul, on Mexico's north west Pacific coast. Costa Azul also exports natural gas to southern California via pipeline. Total LNG import and regasification of North America is 167mmtpa, 20% of world receiving capacity. According to US FERCs count, four more import terminals are proposed.

While in 2005 with the emergence of shale gas, all the import facilities that were built by US became useless. As expected, in 2011 North America became self-sufficient again and the prospect of exporting LNG from both USA and Canada now has the potential of transforming the global LNG market (especially Asia and Europe).

Figure 5.2-D

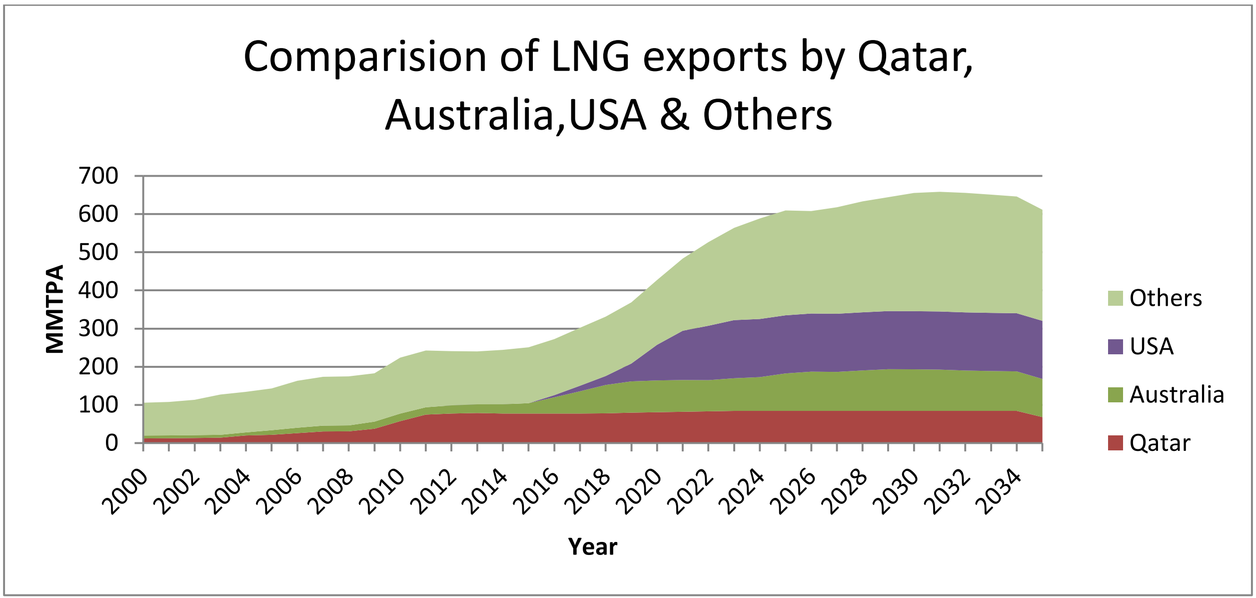


SOURCE: Compiled by author from EIA

Figure 5.2-D is showing the natural gas production between the period 2007-2011 from shale gas well and other gas wells (it includes coalbed methane well, oil well and gas well). In 2008 due to shale gas revolution there was 44% increase in shale gas production compared to previous year and it is increasing at a much faster rate. In 2007 the share of shale gas production was 8% of the total gas production in US and in 2011 it increased significantly to 42% of the total gas production in US.

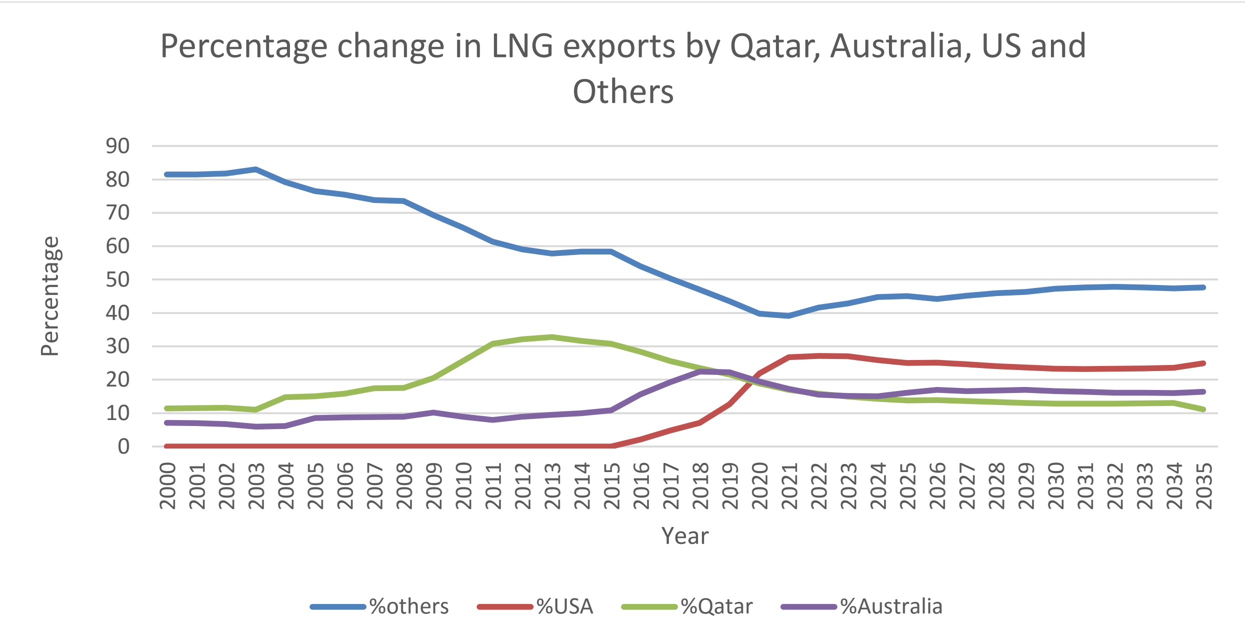
Owing to the growth of production surplus along with shale gas discovery and underutilized LNG import capacity, LNG export became the most important prospect for North American countries. The commercial logic of US LNG exports projects is clear from the price of domestic gas in US going down to \$2-3/MMBtu in 2012 and significant excess of production. The difference between the domestic gas price (Henry Hub) and the price in the international gas market is so huge that even after adding gas purchase, liquefaction and transportation cost the sellers can earn good margin.

Figure 5.2-E



SOURCE: Compiled by author from GIIGNL

Figure 5.2-F



SOURCE: Compiled by author from GIIGNL

Since 2000s the majority of LNG Exports used to come from Indonesia, Algeria, Malaysia and Qatar. In 2000, Indonesia exported 27.39 mmtpa (25% of total LNG export) of LNG. Qatar is biggest LNG exporter in the world and as seen in the figure 5.2-F and figure 5.2-E, exports from Qatar was highest in the year 2013 but in year 2014 the LNG export from Qatar dropped to 2.1 percent. Qatar has capacity to produce 77 million metric tons a year of the fuel, or 26 percent of the world's total. That is being challenged by Australia and the U.S., which are building a total of 99 million tons of annual capacity (33% of the world's total), according to estimates from BG Group.

With the Shale Gas revolution the LNG exports from US will start in the mid of 2016 and in around 2020 the LNG exports from US will reach more than 20% of the total world LNG exports, and including Canada the total LNG exports from North America in 2026 will be around 28% of the total world LNG exports. This increase of Henry Hub indexed LNG exports from North America will have an impact on the pricing structure around the globe.

Potential North American LNG Export Projects

In 2011, utilization of LNG import capacity was only 11% and clearly strong incentives exists to export the surplus production in future. In 2012, LNG exports projects were proposed, and the first export project that got FERC approval was Sabine Pass in Louisiana with capacity of 20mmpta, for construction and operation of the plant.

FERC also proposed additional 52mmtpa at four import terminal site of Texas at Freeport, Corpus Christi, Oregon and Louisiana. Potential LNG export sites another 51mmtpa (Cove Point and Maryland, one of the existing terminals; Hackberry and Louisiana, new import terminals; and Brownsville, Texas, Astoria and Oregon, new projects). All this makes a grand total of 123mmtpa of export capacity which is complete reversal of imports.

In Canada due to the US market conditions and Shale gas production, the import terminal project Kitimat is now proposed as export project to serve Pacific Basin, it got NEB certification in 2011. Other proposed export terminals include Douglas Island in Canada's West Coast with 7mmtpa capacity, a BC site in Prince Rupert Island with 7.6mmtpa capacity.

Henry Hub Indexed LNG Price Formula

The contracted price of US LNG sold on the long term basis is divided into two components: a percentage of Henry Hub and a constant a portion of which is linked to inflation. There are two types of LNG sales contracts in US: FOB sales contract and DES sales contract.

The contracted price of US LNG in case of FOB sales contract range from 115% HH linkage and a constant of 2.5 to 3.5, in case of DES sales contract the HH linkage is 120%. In the US LNG sales contract capital cost, operating cost and internal rate of return (IRR) is determined to find out the price of LNG (baseline price). Based on the assumed components of Facts Global Energy (FGE) in the US LNG sales price, the cost based baseline formula is derived as follows:

Henry Hub gas purchase price is assumed to be 100% and around 9% feeder gas is consumed during liquefaction process. So the Henry Hub linked component in the contract formula is 109% HH for FOB contract. In case of DES contract Henry Hub linked component is 116% HH because it also includes 7% boil-off for ship's voyage.

There are two components of the constant in the formulae: fixed constant and inflation linked constant. Assuming an internal rate of return (IRR) at 12% over 20 years with a plant availability of 92%, we can determine the required return on CAPEX. For Sabine Pass the constant component is about **US$2.0/MMBtu for FOB contracts.** On the shipping side, an IRR of 10% over 30 years was applied. Adding port and fuel costs, this works out to be about **US$2.1/MMBtu**. The fixed component varies from project to project depending on CAPEX, IRR or investment horizon.

Inflation linked component for the Sabine Pass is **US$0.4/MMBtu for FOB contracts** and on the OPEX component for shipping, the inflation linked component works out to be about **US$0.5/MMBtu** for the shipping process. By adding both fixed and inflation linked constants, the total constant component becomes **US$2.4/MMBtu** (~17% inflation linked) for FOB contracts and **US$5.0/MMBtu** (~18% inflation linked) for DES contracts.

The baseline formula for the Sabine pass contract would be:

P (LNG) for FOB contracts=109% HH + 2.4 (~17% inflation linked)
P (LNG) for DES contracts=116% HH + 5.0 (~18% inflation linked)

Using the same methodology, the baseline price for the Cameron LNG contract would be:

P (LNG) for FOB contracts=109% HH + 3.2 (~17% inflation linked)
P (LNG) for DES contracts=116% HH + 5.9 (~18% inflation linked)

US LNG Exports: Potential Impact on Global Gas Price Formations

LNG exporters in North America either owns production capacity or has access to the liquefaction capacity. There are some Asian consumers/owners of gas assets in North America like Petro china who will induce gas to their domestic markets at low Henry Hub indexed price. Both producers and sellers has the option to sell either in the domestic market or international market. They would prefer to sell natural gas on long term contract basis linked to oil to maximize their profit and recover CAPEX. Contract indexed to Henry Hub will only be used to ensure competitiveness in the international market

Their import of Henry Hub indexed gas will challenge the oil indexed imports, and this will also have an impact on the spot market in Asia. This flow of gas from US and Canada will interact with other supply and demand sources in LNG markets in Asia and affect the pricing methodology. According to the report published by Facts Global Energy, the LNG exports from North America can be indexed partly to oil and partly to gas. Mixed Hub pricing contract depends upon the joint movement of both oil and gas.

Example:

We can assume indexation component of LNG indexed 20% to Henry Hub and 80% to West Texas Intermediate (WTI).

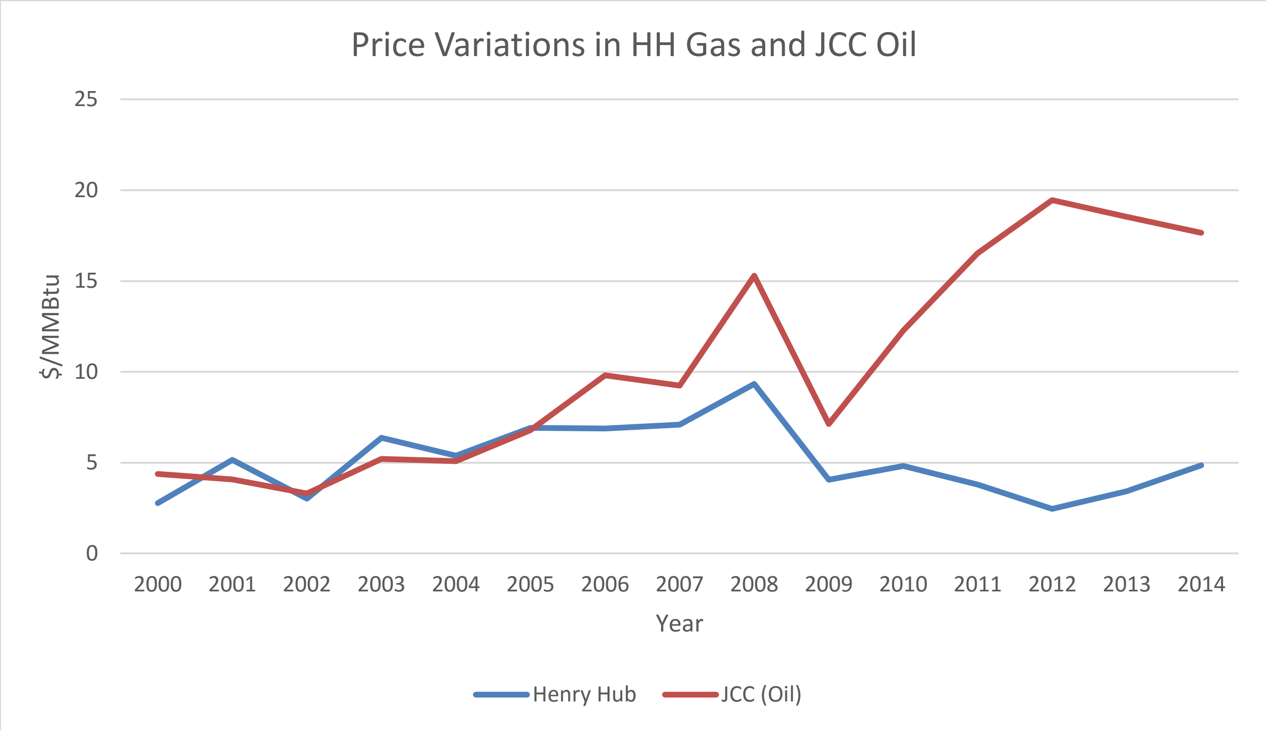
Where,

*The hub pricing is set at 1.25*HH+US$6.0

*Oil-indexed LNG is priced at 13%*Oil+US$0.7

There are many combinations that provide same LNG price, but not all these combinations are feasible. For example, $2/MMBtu for Henry Hub is not sustainable, and for HH= $7/MMBtu, the buyers may refuse hub exposure. Joint movement of natural gas and oil may result in complicated movements of the mixed price of LNG because the movement of LNG is linear but the relative movement of oil and gas is nonlinear.

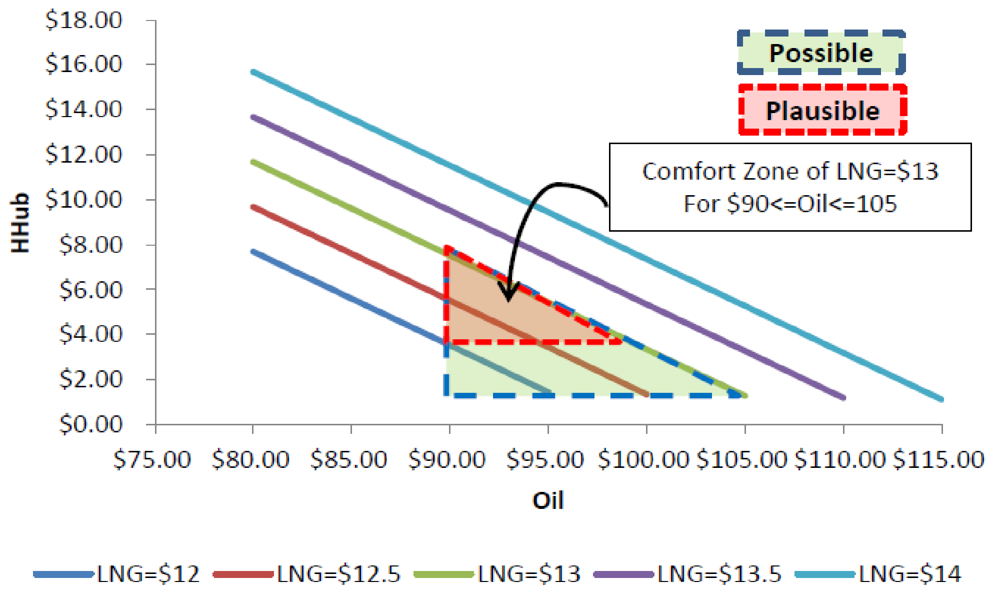
Figure 5.2-G



SOURCE: (Administration, Energy Information, 2015)

Figure 5.2-G is showing the highs and lows of Henry Hub and JCC oil from 2000 to 2014. Although JCC oil price is fairly stable but movements in the Henry Hub gas price can change the mixed LNG contract price because the price of Henry Hub is volatile. In short run, movements in the price of Henry Hub is based on the demand, supply and local market conditions of North America, and in long run movements of Henry Hub price may depend upon the type of fuel it is competing with, for example coal fired power plants, competition with diesel and gasoline, Whereas the price of oil is determined globally.

Figure 5.2-H: LNG Pricing Zones



SOURCE: (Energy, Facts Global, 2014)

An important issue in hybrid pricing is what combinations will result in favorable LNG prices.
Figure 5.2-H shows few important points. Let us also assume that the producer's market view of crude oil is between US$90/bbl to US$105/bbl. Then,

- Theoretically, hub prices between US$1.30 and US$7.50 will produce the target of an LNG price of US$13/MMBtu. Therefore, the possible world for US$13/mmBtu of LNG will consist of the green shaded triangle in the above graph.

- Practically, hub prices below US$3.50 may not be sustainable. Therefore, only hub prices between US$3.50 and US$7.50 are plausible in this scenario, resulting in the plausible region of the pink-shaded triangle above. Hence, if the real market moves outside this zone, then an LNG price of US$13/mmBtu may not be achievable.

- We have to also notice that the limited range of hub prices has also affected our original perception of oil prices. This is because the plausible zone now only covers oil prices between US$90/bbl and US$100/bbl.

For a US producer, hub prices below US$3.5/MMBtu will result in lower cash flows. For an LNG buyer, prices above US$7.50/MMBtu will miss the target weighted average cost of supply. Of course, the above arguments can be re-run for different market participants including sellers and portfolio players. If done so, the outcomes will have different ramifications for different market players (Energy, Facts Global, 2014).

5.3) LNG Pricing in Asia

LNG Pricing Evolution in Asia (1969-2000)

Since 1970s, in Asia LNG prices has been linked to crude oil. Japan was the first country in Asia that imported LNG indexed to crude oil. The new buyers (Korea, Taiwan, China and India) that emerged also adopted oil linked LNG pricing method. There were many variations in the pricing formulas during the course of time due to the changes in the market environment but the basic approach remained the same. In Asia LNG is basically sold under long term contracts which are linked to oil prices but in the recent years alternative pricing approaches like short term contracts and spot pricing has been used. The Asian countries use Japanese customs cleared crude oil price also known as Japanese Crude Cocktail (JCC) as oil index.

The first LNG contract was signed by Japanese buyers with Kenai project in Alaska and Brunei LNG in 1970s. The price was fixed in the nominal terms at a premium to crude oil on Btu basis for the duration of the contract, but after the first oil shock in 1973 pricing was shifted to oil linkage. In 1973, a c.i.f. (cost, insurance, freight) contract was signed between Japan's western buyers consortium (Chubu Electric, Kansai Electric, Kyushu Electric, Osaka Gas, Toho Gas and Nippon Steel) and Indonesia's oil and gas PSU (Pertamina) which established more significant relationship between LNG price and oil price. This price formula is described below:

P (LNG) = A × P (Crude Oil) + B

Where;

P (LNG) is the price of LNG in $/MMBtu.

P (Crude Oil) is the price of crude oil in $/bbl.

Where A and B are constants negotiated by the buyer and seller. The constant A is known as 'slope' and it is expressed in terms of percentage. In case of contract between Japan and Indonesia, A was 0.1485 (a slope of 14.85%). This constant A varies but historically, the most common value was 0.1485. The constant B was partly linked to inflation and partly to the actual cost of transportation of LNG from Indonesia to Japan.

This pricing formula approach benefit both buyers and sellers. Price which is at premium to crude oil provides protection against low crude prices to the sellers and discount to crude oil at high crude oil prices give protection to the buyers, but this is in the environment in which long run average price of crude oil is 20$/bbl. It is important for the buyers to provide this security to the suppliers as they may face financial problems. At higher oil prices, with reduction in the premium the buyers are benefitted, it gives them support for marketing of re-gasified LNG in the downstream markets.

After the third oil shock in 1985 the crude oil prices collapsed and fell under 10$/bbl, re-emphasizing the downside price risk for sellers. During that time the Official Government Selling Price (OGSP) was used as oil index for LNG pricing. OGSP is the crude oil price set by the Organization of Petroleum Exporting Countries (OPEC) led by Saudi Arabia, in this approach prices are set by supply and demand of crude oil. In OGSP pricing the buyers had to pay higher prices for the contract. Due to this over-payments the buyers and sellers had to find new pricing mechanism.

The S-curve and the 'Applicable Range'

In the mid-1980s the sellers were looking for increased protection from low oil prices which Japanese buyers, wanting to ensure that supply of LNG is not put at risk by sellers having to cut cost, were prepared to accept. In return buyers wanted reciprocity at higher oil prices. Owing to this reason 'S-curve' was introduced and adopted by the early 1990s for all the new Japanese LNG contracts.

In addition concept of 'applicable range' was also introduced, which fixed a narrow range of oil prices for the price formula. The range was from $11/bbl to $29/bbl. Buyers and sellers also decided to negotiate the price of LNG in case if the oil price goes out of the fixed range. It serves as a buffer to the oil prices diverging from its acceptable range. The typical price formula is shown below:

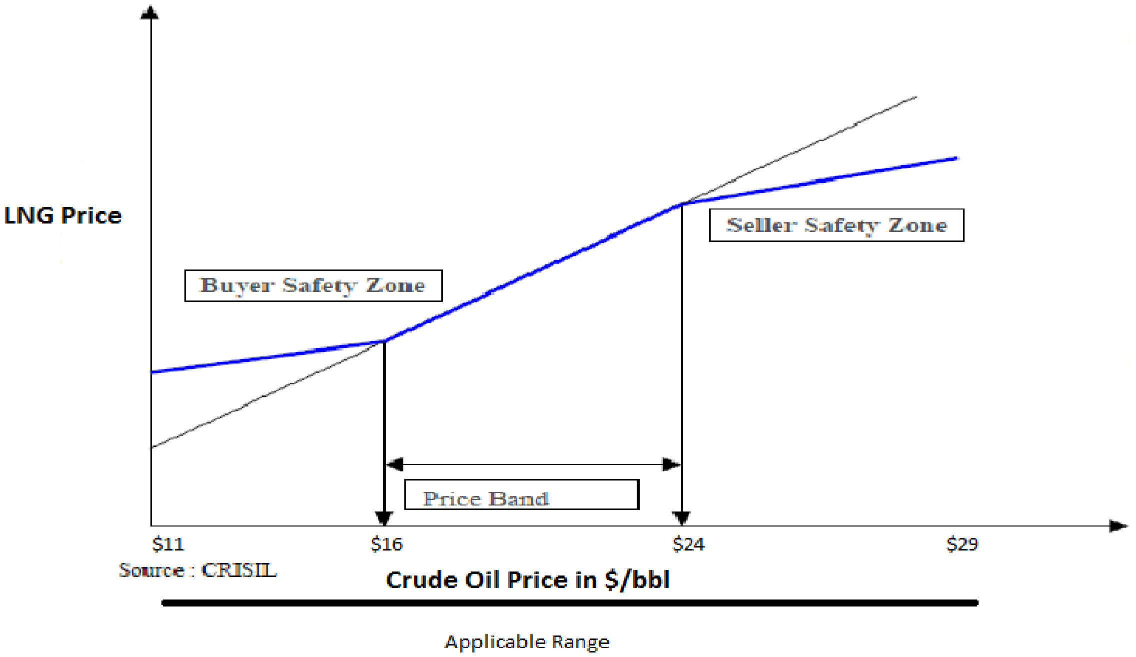
P (LNG) = 0.07 × JCC + B1 $11 < JCC < $16

P (LNG) = 0.1485 × JCC + B2 $16 < JCC < $24

P (LNG) = 0.07 × JCC + B3 $24 < JCC < $29

Here, the slopes in the lower and upper part of the price curve, the points at which slope changes (known as kink points) and the constants B1, B2 andB3 are negotiated by the buyers and sellers, it varies from project to project. Figure 5.3-A shows the S-curve and the applicable range applied on the long term contracts from the second half of 1980s.

Figure 5.3-A: S-curve



SOURCE: CRISIL

The basic LNG price formula is of the form:

P (LNG) = A * P (Crude Oil) + B

Where constants A and B are negotiated by buyers and sellers. This constant A varies but historically, the most common value was 0.1485. In a delivered ex-ship (DES) sale the constant B is typically between $0.60 and $0.80/MMBtu.

So a typical DES price formula would be:

P (LNG) = 0.1485 * P (crude oil) + 0.70

The reason due to which figure 0.172 is used because an average barrel of crude oil when burnt produces $5.8/MMBtu of energy. Therefore to convert from crude oil in $/bbl. to $/MMBtu, it has to be divided by 5.8 and 1/5.8 is approximately 0.172. If the price of crude oil is zero than the price of LNG in the crude oil parity formula would also be zero. For every $1/bbl increase in the oil price the LNG price increases by $0.172/MMBtu.

A crude oil parity formula for FOB would be:

P (LNG) = 0.172 * P (Crude Oil)

However in the case of the DES price formula if crude oil is zero, the LNG price would be $0.70/MMBtu. However, for every $1/bbl increase in the crude oil price the LNG price increases by $0.1485/MMBtu. This means that at an oil price of zero the LNG price is at a premium of \$0.80/MMBtu over crude oil parity. However, the premium reduces by \$0.0235/MMBtu (0.172 – 0.1485) for every \$1/bbl. increase in the oil price. Therefore, if the constant B is 0.70/MMBtu, the LNG price remains above the crude oil parity price up to an oil price of \$29.8/bbl (0.7/0.0235). The "S"-curve simply changes the rate at which the premium erodes.

In Indonesia, S-curves was introduced in 2000s, but in Indonesian contracts applicable range was not used. Other Asian countries kept using 'straight line' pricing approach. In case of Korea and Taiwan, they did not adopt the S-curve in their contract until 2000s except in one or two contracts. In 1992, despite the use of S-curve in the Japanese contracts the average price of the LNG imported into Korea and Taiwan become almost equal to the LNG import price in Japan.

Asian LNG Buyer's Market (2001-2005)

In the period of 2001 to 2005 the pricing contract moved away from the S-curve. During this 'buyers' market' period many projects were in the expansion phase and new projects were in the planning stage. At this phase of time the sellers seeking buyers for new LNG contracts commitment so that they can finance their new capacity projects, but the demand was very less and due to this competition between the sellers in the LNG market was very high. This resulted in lower slopes than those negotiated in the contracts before 2000s. In many cases, the contracts included price ceilings and floors which put upper and lower bound on the price. During this time the buyers those who were benefitted due to favorable prices were mainly India and China, other buyers who were benefitted at later stages include Korea and Taiwan, except Japanese buyers.

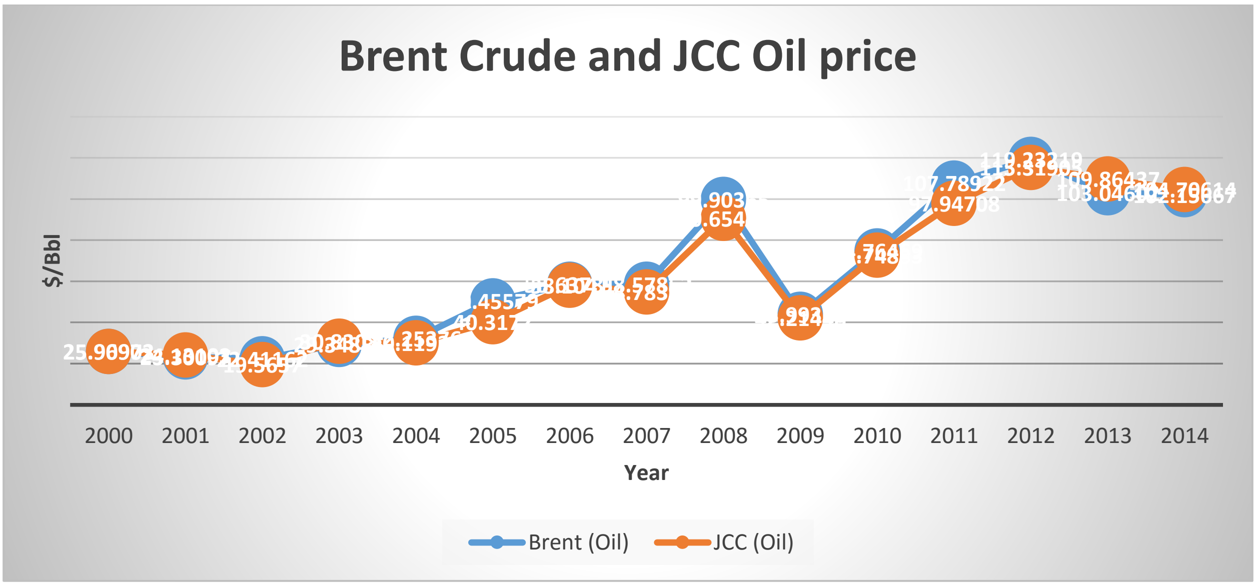
The first oil and gas buyer to take the advantage of this situation was CNOOC of China in 2001, for the supply of gas to Guangdong terminal in southern china. The contract was for the period of 25 years with 3.3mmtpa capacity. This contract had price cap of \$25/bbl and floor price at \$15/bbl on the oil price along with slope of 5.25%. There were total seven bidders for this contract out of which the most preferable bidder was North West Shelf. The final contract was signed in December 2004 and the delivery commenced in May 2006. The pricing formula in the Guangdong contract is on f.o.b. basis and it does not have price reopener clause. Since the start of the supply under the contract the JCC has been above \$25/bbl., and according to China's Customs Authority data the average price of LNG imported into Guangdong terminal (after adding cost of transportation) is \$3.20/MMBtu, which is the lowest priced LNG on long term contract basis in Asia.

During that period of time this was the lowest priced contract, other lower priced contract include supply of LNG by Indonesia's Tangguh project to the Fujian terminal in China and to POSCO and SK-Power in Korea, supply of LNG from Qatar's RasGas II to CPC in Taiwan, Korea Gas's contract with Yemen LNG, Malaysia's Tiga project, Russia's Sakhalin project, and the only Japanese low priced project with Qalhat LNG project in Oman.

LNG Seller's Market from 2005 onwards

In 2005 there was a shift towards sellers' market as some of the planned projects found buyers for their output, while others were delayed. In this environment the sellers were able to increase the slopes and it was also a time when the oil price begin to climb and reached above \$100/Bbl. (see figure 5.3-B) by 2008.

Figure 5.3-B



SOURCE: Compiled by Author from Wood Mckinze

In this high oil price environment, the price protection provided by S-curves was no longer of interests to the sellers, because they did not wanted to lose the upside potential due to high oil prices. Moreover the buyers were not in a position to press for a lower relationship with oil at high prices to protect their margin. Due to this reason the S-curve disappeared and both new contracts and the contracts before 2000s were reverted to straight line relationship with crude oil. The new price formulae was of the form:

P (LNG) = A × JCC + B

Where A is in the range 15% to 16.3% and B takes into account transportation costs in DES deals and was close to zero in most f.o.b. deals.

In the period between 2008 and 2012, the slope has reduced to 14 to 15 percent in new contracts. The constant B continues to be based on transport cost in DES contract and around zero in most f.o.b. contracts. S-curves has also been reintroduced in the recent contracts in Asia, including those with project supplied in coal bed methane (CBM) from Queensland. The new S-curve is different from the older version (pre 2000 version). In new version the ‘S’ is centered much higher than the old ‘S’ at \$60/bbl. The lower kink points range is \$30 to \$60 /bbl and the upper kink points range is \$90 to \$110 /bbl. Slope has also been reduced above and below the kink points to 3 to 3.5 percent from the older slope of 7 to 8 percent. Introduction of new S-curve is a requirement of buyers, but not the sellers. The new S-curve is for the projects agreed under construction in 2012, which will be operational after 2014

Price Reopener and Review

Before 1990s there was no price reopener clause in the long term contracts in Asia. The buyers and sellers used to review the price as and when required or when the circumstances result in price no longer reflecting market conditions. This has led to the fundamental changes in the pricing structure, including the move from fixed prices to oil linked prices in 1970s and introduction of S-curve from the first half of 1980s in response to changes in the oil price environment. Since the early 1990s, the buyers and sellers used to review the price as agreed in the contract, typically every five years. After 2003, the use of the applicable range to meet and discuss in good faith when JCC prices move out of the agreed price range, resulted in many negotiations. In case of other established markets like Korea and Taiwan there was no price reopener clause and limited modifications to prices being implemented.

Price negotiations with Japanese buyers have often been delayed, like the Abu Dhabi's ADGAS project took six years to resolve, but the delivery and receipt has never been interrupted. Furthermore, there are arbitration clauses in the contract but it has never been used except in case of Atlantic Basin. In recent Asian contracts there is a price reopener clause which has a fixed time in when it can be triggered, but it does not say anything about the factors to be considered while renegotiation.

Pricing of Short and Spot LNG Cargoes

Since early 2005, due to a combination of unexpected events like increase in demand, nuclear problems in Japan and shortfall in supply from Middle East and Pacific Basin (especially Indonesia) resulted in the buying of spot LNG cargoes by Asian buyers from Atlantic Basin. Large amount of supplies from Atlantic Basin are short and spot LNG cargoes, but now some medium term contracts are also in place.

Figure 5.3-C: Regional Split of Spot LNG volumes (2006-2012)

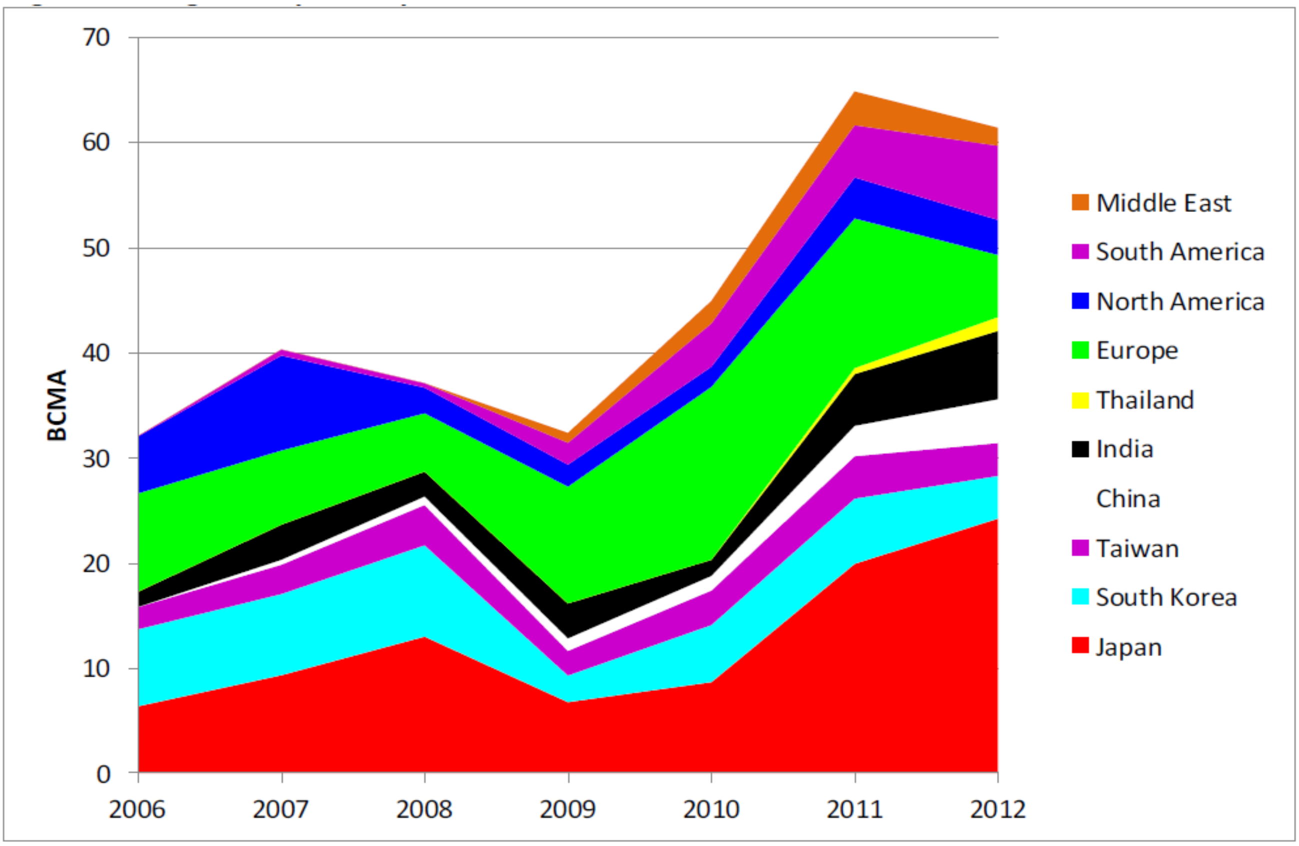
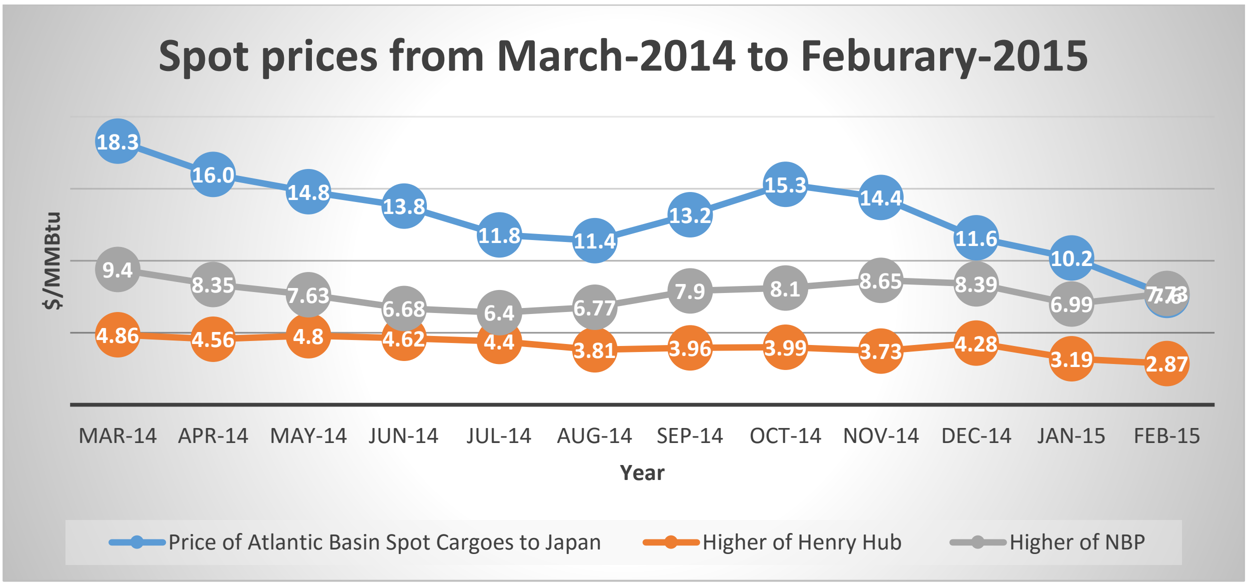


Figure 5.3-D



SOURCE: Compiled by Author from Platt's and METI

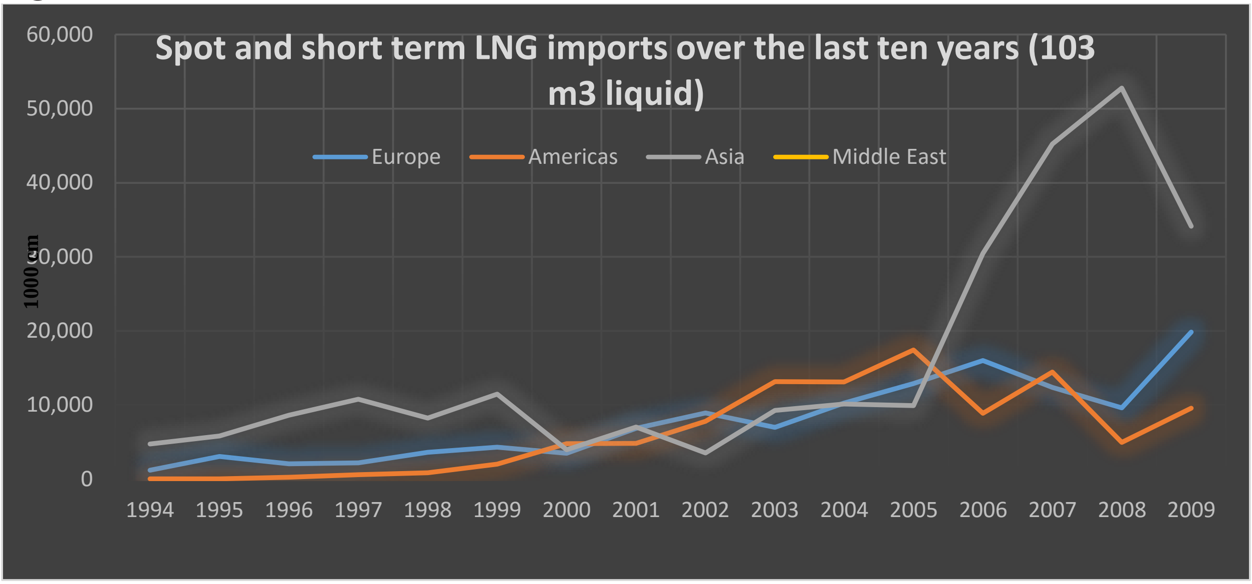
Spot and Short term pricing contracts are decided on the basis of Japan Korea Marker (JKM). JKM is the price published by Platts on first working day of each month. It provides the information of the pricing trends in the Spot and Short term market in Asia. It is not credible or reliable source so it is not used for long term contracts. The JKM price is prepared by asking sellers and tradersthe price at which they prepared offered cargoes, and the buyers the price at which they are prepared to buy cargoes. If the price of JKM is compared with HH month ahead price on the same day, then it can be observed that average HH price around $4/MMBtu but the average price of JKM is around $15/MMBtu. This shows why the Atlantic Basin spot cargoes are diverted towards Asian buyers rather then selling it to flexible markets of North West Europe.

Asia and its readiness for spot trade

It can be seen from figure 5.3-E below that Asia is the leader in short term and spot trade. This is mainly due to Japan and South Korea who are leading the Asian buyers in terms of imports.

Traditional long-term LNG contracts are gradually being complemented by LNG transactions that are more flexible in timing and location. These transactions are starting to serve as transmitters of price signals between regional gas markets. LNG spot trading, which represented 16% of global LNG trade in 2009, will develop further, but it will not replace long-term deals entirely, as these deals will underlie new project investment. In Asia the short term/spot trade is 8.5% of the total traded volume in Asia as compared to the global average of 16%. This shows there is significant scope for expansion of the short term/spot share in total volumes traded in the future.

Figure 5.3-E



SOURCE: Compiled by author from GIIGNL

Another important long term factor that will lead to more short term LNG trading activity in Asia is the fact that compared to the new LNG buyer in Asia like India and China whose expected demand for gas is estimated to grow exponentially in the coming years, Japan and South Korea demand for gas will remain stagnant and even according to some estimates contract. This is a cause of great concern for utilities in both the countries. The utilities are now demanding shorter term contracts with more quantity flexibilities to adjust to the new market situation they will be facing. This will further enhance the role of the short term and spot trading in Asia.

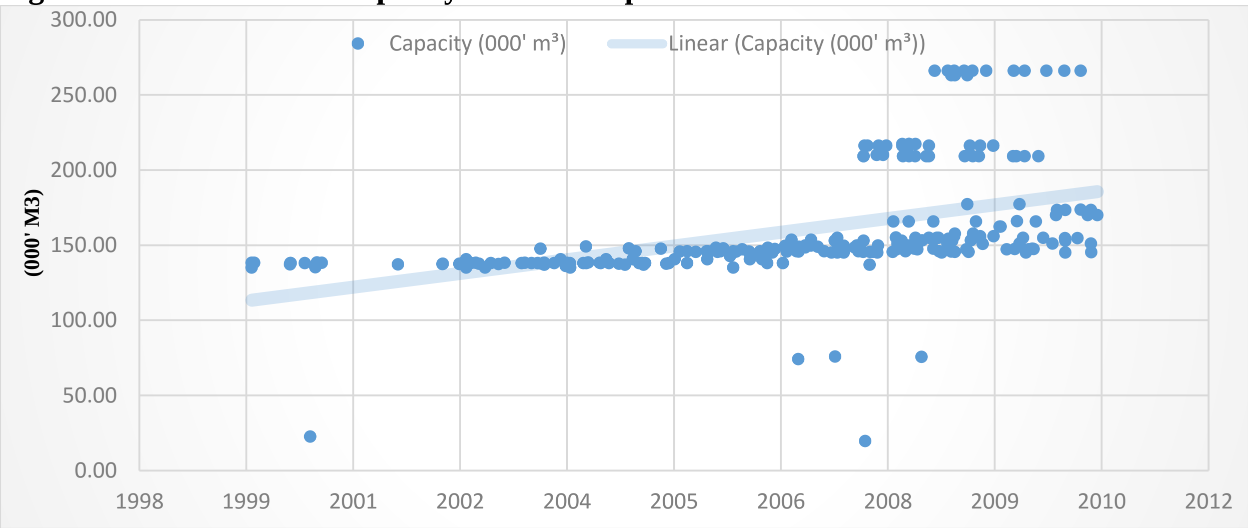
Any surplus LNG which sellers cannot hold on to is sold in the US or UK market as they have highly liquid markets with very active piped natural gas trading hubs like Henry hub and the National Balancing Point (NBP) to which LNG import prices will be linked.

Increasing share of liquid markets in the overall LNG market mix

Liquid markets are defined as markets were the asset traded should have some of the following features. The traded asset can be sold rapidly, with minimal loss of value any time within market hours. There are ready and willing buyers and sellers at all times in large numbers, which require low entry costs into the trading business of the asset. The probability that the next trade of the asset is executed at a price equal to the last one.

Among several factors which are changing LNG markets and bringing opportunities to buyers and sellers, two factors predominate. Firstly, long term trend towards lower plant cost has made it possible for investors to secure financing by selling only part of planned capacity under long-term contracts while retaining some non-committed capacity to be sold spot, short or long-term at a later date. Secondly, the increasing number and size of LNG tankers has increased the availability of capacity for LNG transportation and led to the creation of a more fluid market. These developments have created a positive environment for increasing the share of liquid markets in the overall LNG market mix.

Figure 5.3-F: Increase in capacity of LNG Ships over time



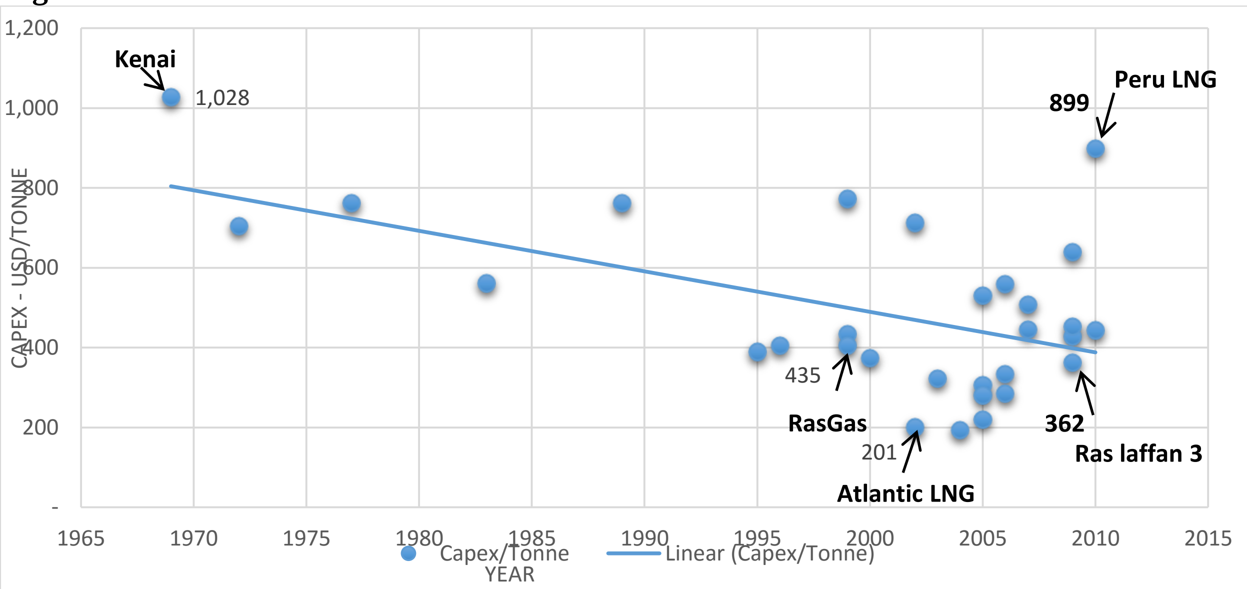
SOURCE: Wood Mac Tool

Figure 5.3-F is showing that currently 52% of the LNG fleet in the world is distributed between the capacity sizes of 130,000 to 150,000 cm. The smaller size vessels which generally are not in production anymore but still sail are between 50,000 to 130,000 m3 and constitute 22% of the total fleet size. The large ships between 150,000 to 180,000 m3 are 14% of the total fleet size. The new LNG ships which are currently being produced in shipyards are between 130-150,000 m3. Besides this, mega LNG ships of size 200 to 250,000+ m3, constitute 13% of the total LNG fleet.

Impact on liquid markets of lower plant cost and larger plant size:

LNG liquefaction plant costs in terms of CAPEX/tonne have been steadily declining from 1969 onwards (see Figure 5.3-G). This has made LNG more cost effective and a cheaper fuel. It has also given an impetus for growth and flexibility in LNG trade globally. Despite a spurt in cost inflation towards the end of the last decade the trend of long term decline in plant costs has taken place over the last decade. The decline in liquefaction plant costs and production cost of LNG is reported to be on account of optimization of design parameters, improved reliability and technological innovations.

Figure 5.3-G: Plant CAPEX/tonne decline over time



SOURCE: Wood Mac LNG Tool

It can be seen from the above chart that in 1969 the Kenai LNG project (Alaska, USA) was around $1000 per tonne. That figure has gradually come down over the years in spite the fact that LNG plant cost can vary significantly based on design constraints and local conditions. Around 2000 the plant cost of RasGas of Qatar was around $400/tonne, OLNG in Oman was $374/tonne and Atlantic LNG train 2 & 3 were at a low of $200/tonne. There has been spurt over the last few years because of inflation, but the long term trend remains.

The decline in the cost of LNG liquefaction plants was also attributable to scale economies that came from larger plant sizes. Over time the LNG industry has opted for larger train sizes and the Qatari's have recently commissioned the mega trains with a single train capacity of 7.5 MMTPA. Figure 3 below, which relates to 2008, illustrates the scale effect.

Challenges to the growth of LNG short term/spot market

- **Need for Global LNG Informational and Trading Platform**

There is no global authoritative transparent information system in place to accurately track and report in real time on price settlements and volumes movements. This is because the LNG 'Club' is a very tightly knit network of buyers and sellers who prize confidentiality in their commercial transactions. There is no commodity exchange for LNG and all trading is done over the counter (OTC). Spot cargoes are obtained through the execution of a Master Sale Agreement (MSA) between the buyer and seller. This MSA functions as an umbrella agreement for spot transactions. For short term contracts sellers or buyers sometimes float tenders or the seller's auction cargoes. There is no global information platform to facilitate spot transactions though there are sources of credible information e.g. Platts Japanese Korea maker (JKM), Argues etc.

- **Contractual Limitations**

Contractual constraints are a major barrier to short term/spot trade. Even if the market creates the conditions for a flexible trading system for cargo diversion, it will not be possible unless the contracts allow it. Destination Clauses and Ex-Ship arrangements make arbitrage and spot trading difficult. While there is a positive trend noticed in some contracts that allows more flexibility, contractual limitations are one of the most significant barriers to spot trade. However, the way the LNG market is developing contractual limitations are gradually being relaxed to allow cargo redirection.

1.1 Technical Restrictions

Two major technical issues are of standardization of LNG quality and LNG infrastructure. With regard to quality it is pertinent to note that LNG produced in various parts of the world is of differencing calorific value and this can further constrain flexible trading. There is 'Wet LNG' (high in propane and butane content) and 'Dry LNG' (predominantly methane with infinitesimal amounts of propane, butane and other rich gases).

As far as LNG infrastructure is concerned there are issues with compatibility, and this complicates spot trading to a significant extent. As it is customary practice in the LNG industry LNG projects were generally bilateral agreements between buyer and seller and the infrastructure was custom made to meet the logistical and economic needs of the specific project. Therefore, ship-shore compatibility and compatibility of the offloading and receiving equipment must be taken into account. For example, the new mega-sized Q-Max and Q-Flex ships can moor only in a few LNG receiving terminals. It is not always possible for importers to change and standardize their ports and equipment, and even if they can it will require additional costs and time.

- **Regulatory and Market Restrictions**

Some regulations may hamper spot trade and arbitrage, but others may encourage it. One example is the "use-it-or-lose-it" principle in most European countries. This means that, for example, a regas capacity owner should have some minimum number of cargoes coming into the terminal during a certain period of time; failing which, the allotted slots or capacity must be offered to third parties by the terminal Operator. So this regulatory policy of Use It or Lose It (UIOLI) rules are an impediment to spot market development. Even in the UK where the market is supposed to be fully free to respond to market signals, the government or regulators may interfere in shipping schedules and take action against shippers by revoking their shipping slot reservations in their respective regas terminals for future use, if they do not deliver LNG cargoes originally scheduled to be delivered, instead of diverting them to higher paying markets.

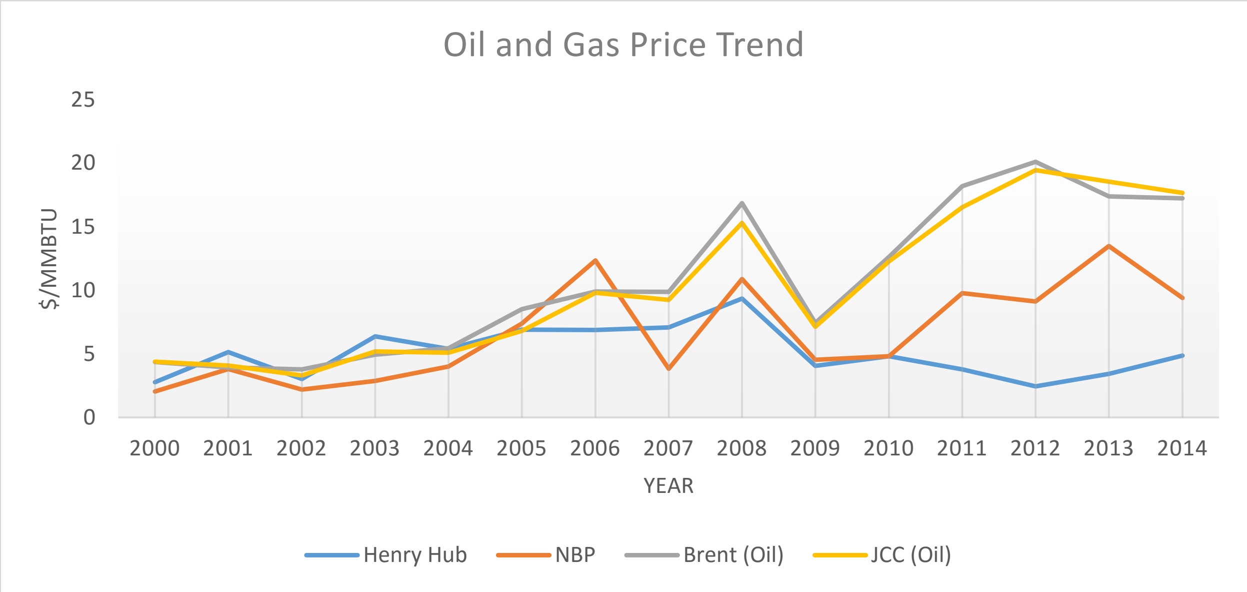
On the operational front LNG ship authorization and vetting processes often take a long time and are detrimental to spot and arbitrage transactions. For example, in Japan two months are required to get a ship approved by local authorities for delivery to Tokyo. Regulatory and market restrictions certainly influence the spot market and slow down its growth.

Atlantic Basin Hub Pricing: An alternative to LNG Pricing in Asia

As discussed earlier in this chapter, Asia has been a biggest importer of short and spot cargoes indexed to NBP in UK and Henry Hub in US. It has benefitted both buyers and sellers in terms of economic incentive to the sellers for diverting cargoes to Asia and security of supply for the buyers in Asia. Some Asian buyers, especially Japan have shown interest in long term contracts linked to Hubs in the Atlantic basin to take advantage of the price exposure and the price difference between oil and natural gas price that has increased after 2008. However, Asian buyers want to limit the import volume indexed to natural gas price due to following reasons:

- Henry Hub and NBP prices are very volatile as compared to oil price which can affect demand and supply. These prices can also be influenced by the traders speculating on the future price movements. It is difficult for the Japanese buyers to keep track the price movements.
- The system of use of the three month rolling average of JCC smoothens the price volatility of JCC indexed contracts, which is not in case of Atlantic Hubs.
- In case of Japan due to regulated fuel cost adjustment system it is difficult to purchase the LNG using alternative to JCC.

Figure 5.3-H

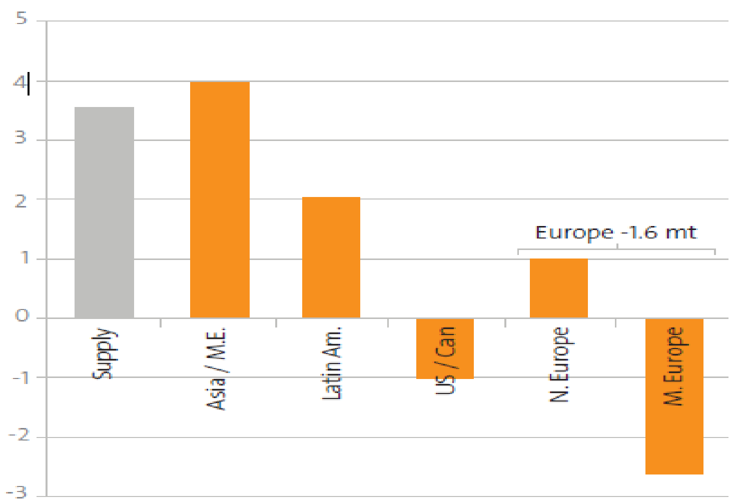


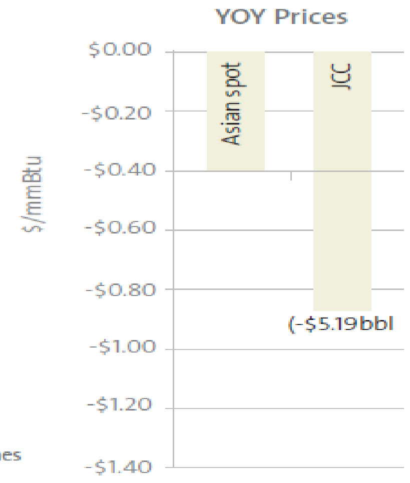
SOURCE: Compiled by Auther from Wood Mckinze

There are many risks in using new pricing machinism but still some Asian buyers are considering these alternatives. The expected export of Henry Hub linked LNG from US has made that possibility closer. The supply of LNG to Asia linked to Henry Hub will start at the mid of 2016. This supply will expose the Asian buyers to the long term LNG contracts indexed to Henry Hub prices. In 2012, the average of Henry Hub price was $2.50/MMBtu (see Figure 5.3-H), and if it remains same in future also then LNG from US will be at discount to JCC linked LNG price at $100/bbl.

In figure 5.3-H, the difference between oil and gas price and its volatility can be seen clearly, because from 2005 the oil and gas prices diverged drastically and the gas price has become very volatile (especially NBP), whereas oil price (JCC) has increased from $6.8/MMBtu in 2005 to $9.45/MMBtu in 2012. The movement of both JCC Oil and Brent Crude is almost same whereas in case of NBP and HH movement is different because from 2010 both NBP and HH has diverged apart. It is clear that Henry Hub price will take many years to become predictable and reliable and the supply of Henry Hub linked LNG will put downward pressure on the JCC linked LNG prices. LNG exports that will come from canada also has the potential to supply Hub indexed LNG to Asia, but the marketers of Kitimat LNG project of Canada have to supply oil linked LNG to payoff the investment in the project.

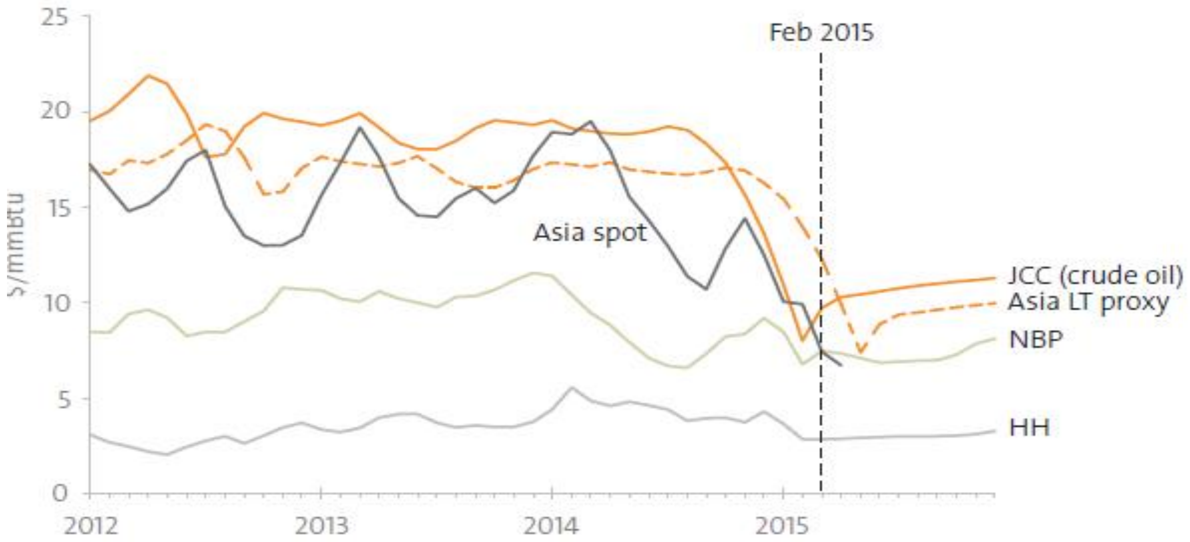
Trends of LNG Gas Prices:



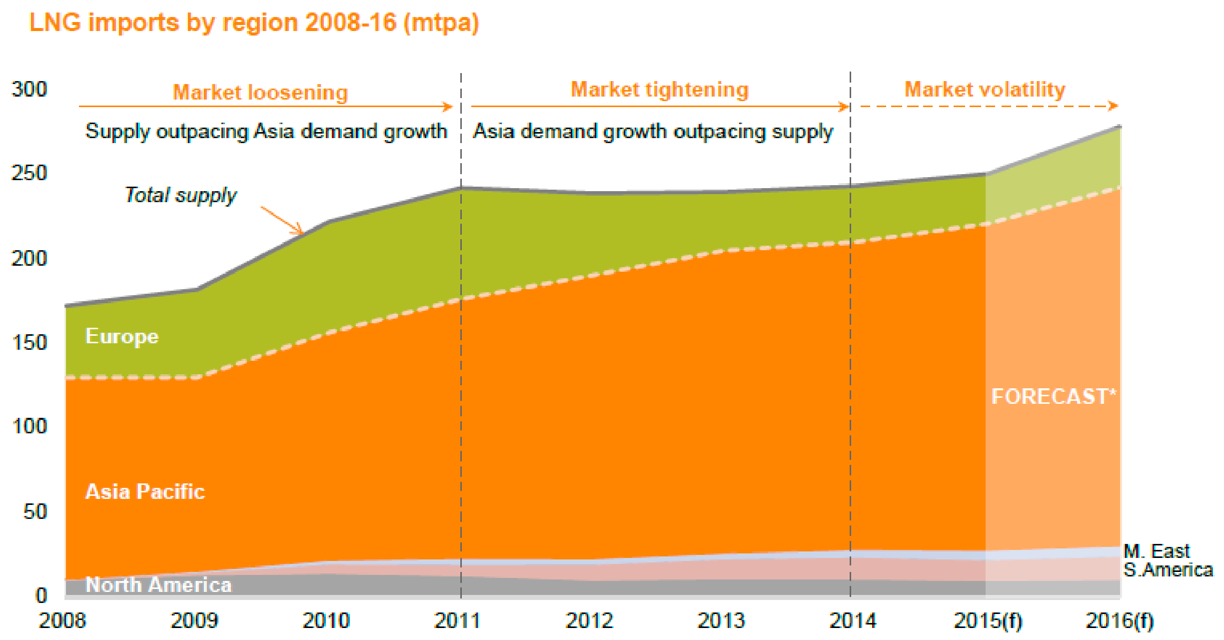


ource: BG Group interpretation of IHS Waterborne data (Jan 2015), delivered volumes
Platts, Petroleum Association of Japan
atin America - Argentina, Brazil, Chile, Mexico, Puerto Rico, Dominican Republic
Europe - France, Greece, Italy, Lithuania, Portugal, Spain and Turkey

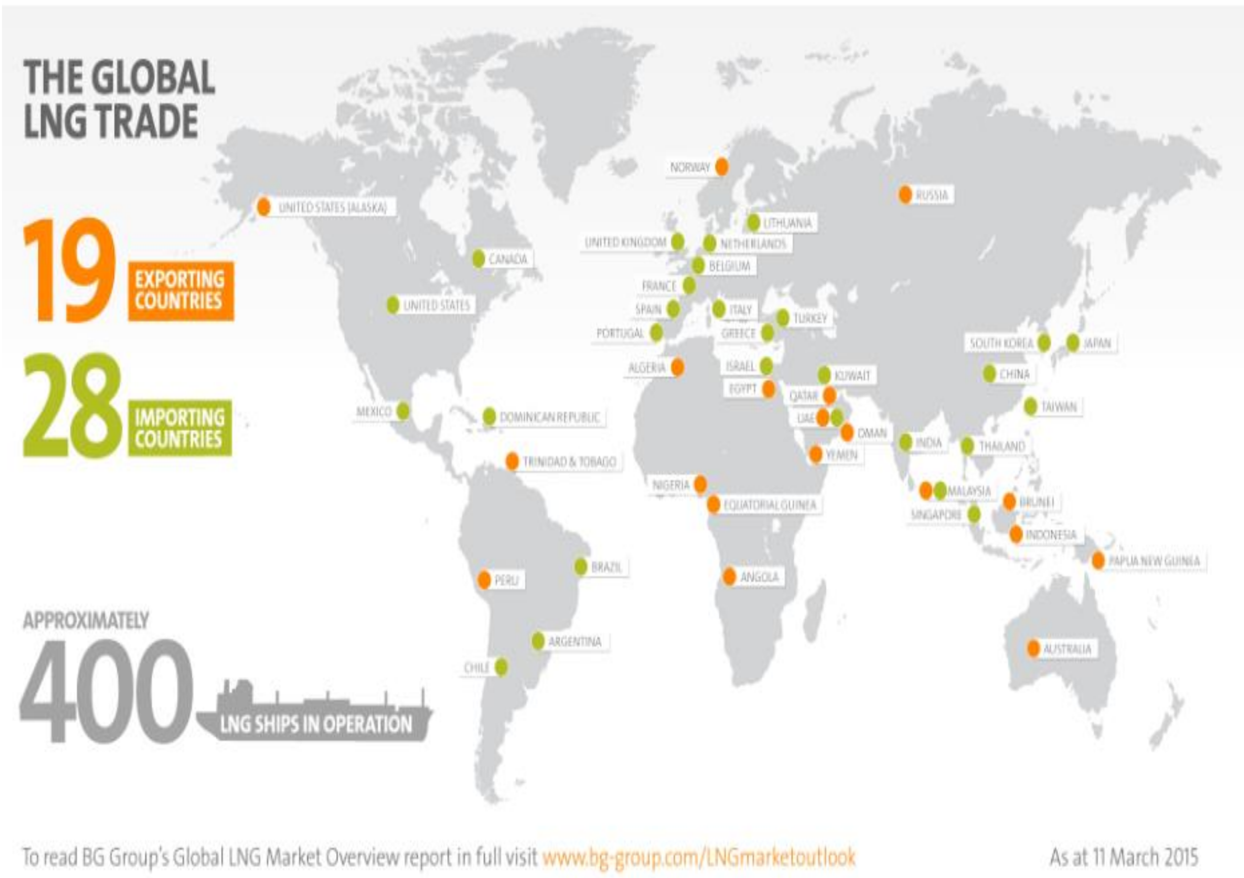
Figure 3: Asian spot prices have generally traded between crude oil (JCC) and European market price (NBP) levels. Long-term prices (Asian LT proxy shown) are generally indexed to crude oil, with a three month lag.



Source: Platts, Petroleum Association of Japan and Bloomberg (Feb 2015)
Note: Asia long-term proxy = 14.85%JCC(-3) + 0.50



Market Volatility & LNG Import



6) Conclusion

Around the globe the internationally traded gas market is divided regionally and their pricing methodology is also different for each region. The three biggest gas trading regions are Asia, North America and Europe. Majority of LNG trade takes place in Asia pacific region where Japan is the biggest importer of LNG. The biggest regional markets where pipeline trade takes place is North America and Europe. Pricing methodology is also different for each of these markets. In Asia LNG price is indexed to crude oil (JCC) price, in North America price is decided on the basis of gas-to-gas competition and spot market is present there. In Europe there is dual market in which gas-to-gas market and oil product indexation to gas is present. In spot market, price of gas is decided on the basis of demand and supply factors and its price is very volatile, whereas in case of Asia and Europe where oil and oil product indexation is used, the buyers and sellers enter into term contracts (also known as SPA) for buying and selling of gas and the price of gas is decided on the basis of crude oil parity.

The LNG market in Asia is developing from a market based fully on long term contracts to a more flexible market based on a portfolio of contracts of different durations with a steady growth in the short term and spot LNG trade particularly over the last decade. Some structural factors make it unlikely that LNG will easily develop the liquidity that exists in the oil market. The capital intensity of LNG projects and the cost of transporting and producing LNG require long-term contracts and make it difficult to justify permanent spare capacity on economic grounds. Nevertheless, short term/ spot trade will continue to be used to overcome short-term imbalances and it will grow because of the flexibility created by gas market liberalization and additional future terminal and transportation capacity. Some structural factors make it unlikely that LNG will easily develop the liquidity that exists in the oil market and long term trade contracts will continue to remain the foundation new projects.

The price differentials between North American, Asian and European markets is creating opportunities for North America for the export of hub indexed LNG. Currently only one US and one Canadian project have got construction and export approval but with the increase in LNG export from North America, there will be an potential impact on the current LNG global market and its pricing structure. The implication, therefore, for North American gas exports will be that the higher cost sources of imports will be pushed down the supply chain reducing the marginal cost of gas in the region.

The addition of hub pricing into LNG portfolios has added multiple levels of complexities. These complexities need considerable amount of attention. These issues include multi-dimensionality, non-linearity, LNG pricing targets, and so on. Failing to address such issues may result in unwanted risks and unpleasant surprises. Here are a few examples.

- A polar vortex in the US can result in expensive LNG for a Japanese buyer. The cold spell of January 2014 is a good example.
- A sustained drop in the price of crude oil may result in an overpriced LNG contract. The recent drop in the price of crude oil is a valuable reminder.
- Such volatilities are not a dollar for dollar and can be very unpredictable even if one of the commodities, say crude oil, is fairly stable.

In conclusion, the long term contract for the import of LNG indexed to crude oil will continue in the future but its share will substantially decrease. The import of spot LNG cargoes into Asia will increase in future and LNG market is expected to become more volatile. The share of new LNG from North America will increase in Asia and it will persuade the already existing LNG suppliers to adopt hybrid pricing methodology to sustain in the LNG market.

7) Recommendations

- Asian countries should continue with the existing long term contracts with the sellers to save themselves from heavy loss because of take-or-pay clause in the contract.

- Asian countries should sign more contracts for the import of hub indexed LNG from North America as it is cheaper than oil indexed LNG that it imports from existing sellers (especially Middle East). It will also exert pressure to the existing LNG suppliers to supply Cheap LNG to Asian countries.

- To decrease the price of the LNG imports from existing sellers, Asian countries should negotiate with existing suppliers to supply cheap LNG linked to hub or linked to both hub and crude oil (hybrid price).

- In this unpredictable gas trading environment where so many changes related to pricing strategy, supply and demand, decrease in the price of oil and gas, etc. is taking place, Asian countries should stop signing of long term contracts with its existing suppliers and to fulfill its demand for the short term, till the market conditions become normal, Asian countries should start importing more spot LNG cargoes.

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