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Preface

Currently gas markets are largely regional and segmented as the result of transport complexities, differences in regional price formation and regulatory factors. Natural gas is more difficult to transport than oil and if the distance is too large to bridge via transmission pipelines, natural gas has to be transformed in to liquefied natural gas (LNG) for transportation, for which the infrastructure is very costly.

Concerning price formation, natural gas priced are determined by supply and demand conditions in regional gas spot markets in the U.S., UK and Asia Pacific. In Contrary, in continental Europe gas is mainly imported through pipe lines and sold on long term contracts linked to the price of oil, albeit in some European countries market based-pricing is gaining ground. Meanwhile, Asia secures their gas requirement by importing expensive LNG, with trades being mainly settled through long term contracts indexed to oil prices. As a result of these factors, arbitrage at the global level driven by regional gas price differences has so far been limited.

On the other hand, the rapid growth in LNG markets more likely could shift gas price formation towards a more market-based system, supporting the possibility of convergence global gas prices. In addition, the gas prices in Europe are increasingly interlinked to gas spot prices instead of oil prices which resulted a growing share of globally traded gas on spot basis. Could these facts contribute to greater flexibility and increase gas liquidity which lead to a market integration?

This thesis is aimed to examine the facts and information that exist in the perspective; intersect to the possibility of shifting from regionally segmented in to a globally convergence market and how long the process will take; as well as its impact to gas markets in East Asia and Northwest Europe.

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Abbreviations

ASEAN	Associated of South East Asian
BAFA	Bundesamt fur Wirtschaft und Ausfuhrkontrolle
BCFD	Billion Cubic Feet per Day
BCM	Billion Cubic Meter
BIM	Bilateral Monopoly
CEGH	Central European Gas Hub
CO2	Carbon dioxide
EIA	Energy International Administrative
EMA	Energy Market Authority
FERC	Federal Energy Regulatory Commission
FSRU	Floating Unit
GSL	Gaspool Germany
GOG	Gas on Gas
HH	Henry Hub
IEA	International Energy Agency
JCC	Japan Crude Cocktail
LNG	Liquefied Natural Gas
NET	Netback from Final Production
NBP	National Balancing Point
NCG	National Connect Germany
NP	No Price
NYMEX	New York Mercantile Exchange
MSA	Master Sales Agreement
MTPA	Million Ton per Annum
OFGEM	Office of Gas and Electricity Markets
OPE	Oil Price Escalation
PEG	Points d’Echange de Gaz
PSV	Punto di Scambio Virtuale

RBC	Regulation Below Cost
RCS	Regulation Cost of Service
RSP	Regulation Social and Political
SPA	Sales & Purchase Agreement
TCM	Trillion Cubic Meter
TPA	Third Party Access
TSO	Transmission System Operator
TTF	Tittle Transfer Facility
UK	United Kingdom
U.S.	United States
ZEE	Zeebrugge Hub

Chapter 1

Introduction

Objective and Scope of Work

The international gas market over the last decades has evolved from being a rather dull, segmented and regionally divided market with a few sets of bilateral buyers and sellers, to become a more exciting market place with multiple actors and participants in a scenery dominated by geopolitical and economic power play.

In this atmosphere, numerous advocates of various interests are projecting a rapid development of a global gas market to some extent, supported by development of one or more market hubs, in Asia, whereas others insist of continuous segmentation for decades to come.

This thesis is an attempt to scrutinize the available information and evaluate/assess if the condition for a global market exists or is in the process of being met in the near or more distant future, say a decade or two from now, as well as the impacts to markets in East Asia (as the biggest LNG market in the world) and North West Europe (as being in transition in to a full market-based price).

The discussion of this thesis will cover three major regional market; Europe (UK and Continental Europe), North America (The U.S. in particular) and Asia Pacific (East, South, ASEAN and Oceania). Whereas the analytical approach is based on the concept of drivers and constraints that exist to reach an integrated market. The basic drivers of the process are divided in to categories of market structure (natural gas price, pricing mechanism and contract structure), market fundamentals and its evolution (supply, demand, hub development and trading liquidity) and role of LNG.

Background

Historically, natural gas plays a very essential role in the energy market. As concerns about climate change grew in early to mid-2000s, the worldwide energy industry has embraced natural gas as a foundation fuel for the 21st century. In support this view, the natural gas industry has focused on the many benefits of natural gas and has set forth a coordinated view that highlights natural gas as a relatively clean, affordable, reliable, efficient and abundant source of energy.

The gas market has experienced radical changes in North America and Europe over deregulation period and the elimination of monopolies system. The market successfully adapted itself to the more dynamic and competitive market that becomes the foundation for many forms of trade such spot trade and arbitrages, with more multiple actors and participants involved.

Number of fundamental prices drivers of natural gas such extraction, storage, index to alternatives source of energy, transportation, weather, regulations, technologies, etc., have been contributing to the changes of gas prices behavior. As the gas prices have taken the center stage of global media, the changes in gas prices result the great impact, directly affecting the economy, political and world industry.

Natural gas prices experience the considerable dissimilarity from one region to another. Since the beginning of 2010, North American prices have been relatively low, Asian prices relatively high and northwest European prices in between. The relationship of North American and Northwest European spot prices appears to have changed in early 2010. Before that time, they often followed similar paths; differences often reflected local conditions such as storage and tended to be temporary. However, in 2010 and 201, the differences have grown and appear to be longer.

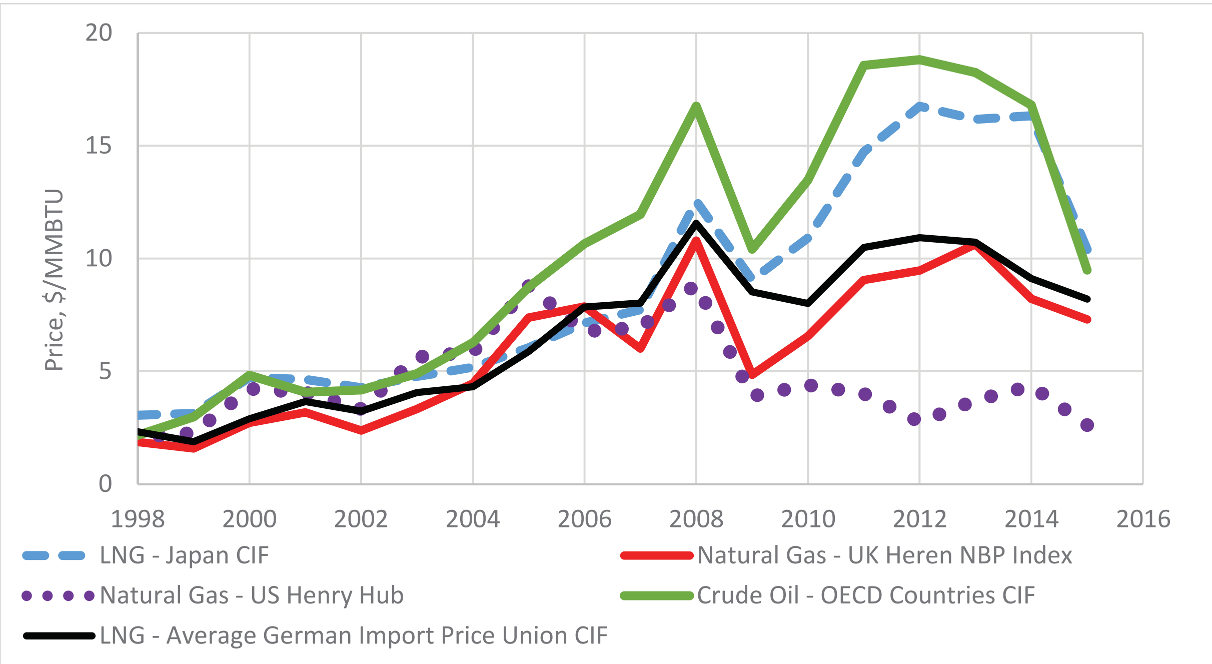


Figure 1.1 Gas prices in different markets – yearly distribution (Source: Platts, EIA, Argus, CME)

North American gas market are a highly mature and competitive, with many buyers and sellers. According to EIA, the U.S. production has grown 20% between 2010 to 2015. Henry Hub prices becomes the reference prices of North America. Prices at Henry Hub have been modest by the global standard since the financial crisis 2008/2009. The development and growth in shale gas production has allowed the U.S. to be the net exporter later by 2018 by various estimates.

Northwestern Europe has also developed strong spot markets, starting in the UK and now in Belgium, the Netherland and Germany. Spot prices at the UK National Balancing Point (NBP) generally track other northwestern European pricing points. Spot prices in Northwest Europe reflect a limited number of suppliers and relative dearth of local production. Key suppliers (Russia, and Algeria) supply much of their gas under long term contracts not directly reflected in the spot market and gas deliveries from Norway can vary.

The situation in Japan is similar to that in many Asian countries, where there is only a limited spot market. The prices largely reflect the long term contract that linkage to crude oil. Japanese natural gas price had been rising over the past years, even before the Fukushima disaster.

As Liquefied Natural Gas (LNG) supply grows, price differentials between major markets will narrow to the cost of LNG transportation. It is possible that significant part of LNG deliveries will be supplied under spot pricing. Therefore, the development of LNG will make the global natural gas markets more interdependent.

Since 2014, natural gas prices have been experiencing a significant fall in Asia and Europe on the back of the sliding oil price. Besides, as more LNG comes on the market, regional gas prices start to converge at a lower level. In contempt of each market has strong characteristic, the gas market in Asia Pacific, Europe and North America are increasingly interlinked.

Chapter 2
International Gas Market Structure

2.1 Overview of Global Gas Production and Consumption

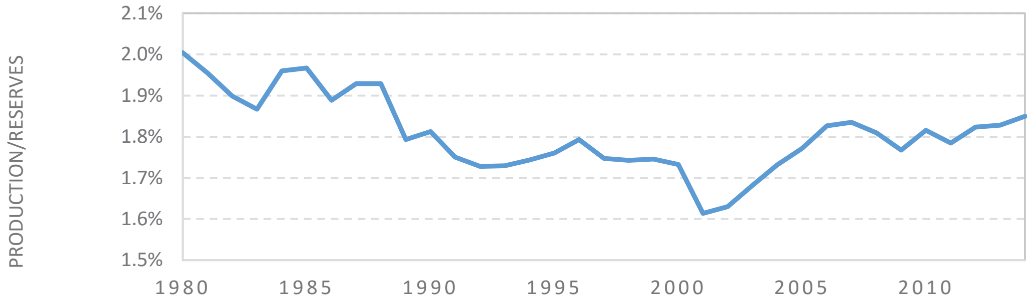
Proved Reserves and Production

In recent years, roughly 70% of natural gas flows across the globe are transported to market destinations within the country of production, while an additional 20% flows cross international borders through pipelines and nearly 10% is moved to market destinations as liquefied natural gas (LNG). The evolution of global natural gas market is dependent on natural gas resources/reserves and production in conjunction with the ability to meet the demands and supplies.

Natural gas resources are abundant and geographically diverse. Like oil, estimates of recoverable gas have grown over the last decade as the application of horizontal drilling and hydraulic fracturing technology has enabled economic extraction of unconventional gas resources that were previously considered too difficult or too costly to produce. The EIA estimates the world's remaining recoverable natural gas resources to be about 807 trillion cubic meter (TCM) as of year-end 2013, more than 200 times the natural gas the world currently consumes in a year.

From a global perspective, proved reserves of natural gas have continually grown over the last several decades in all regions, while natural gas production as a percentage of reserves has generally decreased (Figure 2.1). Much of the increase in conventional production comes from non-OECD (Organization for Economic Cooperation and Development) countries, with marked increases in the Middle East, China and Russia. Data from BP Statistical Review of World Energy 2015 shows that the global proved reserves of natural gas by year end 2014 is 187 TCM. Increases in the volume of proved reserves from 2000 to 2014 have been greatest in Qatar, Turkmenistan, Iran and correspondingly the largest reserves are currently found in the Middle East (79.8 TCM) and Eurasia (58 TCM).

As the natural gas production is projected to grow in almost all regions, the significant portion of this growth is likely to come from unconventional natural gas, particularly the shale gas produced in North America. From 2010 to 2013, North American unconventional gas production (primarily in the U.S.) grew by more than 30% to almost 1.6 billion cubic meter per day (BCMD), on par with Asia Pacific's total gas production. Within a few years, North America's unconventional gas output is expected to exceed the Middle East's total gas production. Around 2020, North America is expected to surpass Russia/Caspian as the largest gas-producing region.



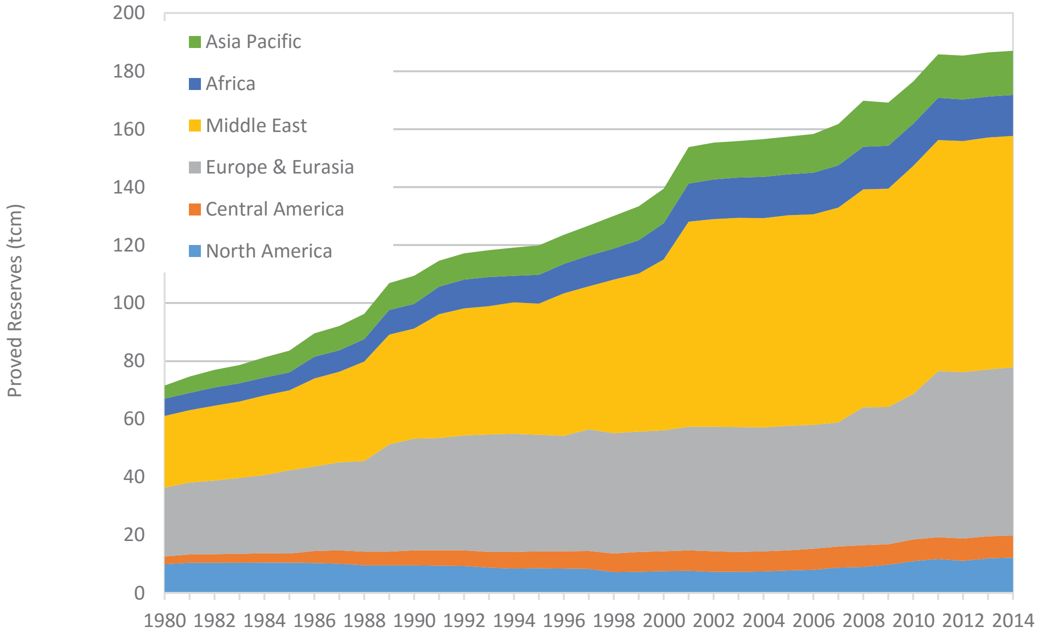


Figure 2.1 Yearly Production as the percentage of Proved Reserves and Proved Reserves of Global Natural Gas by year end 2014 (Source: BP Statistical Review of World Energy 2015)

Technologies to extract unconventional gas are being applied in other regions too, particularly Asia Pacific and Latin America. The growth of unconventional gas development and production in both regions is estimated, although the pace and scale of growth are not expected to match North America's due to differences in geology, governing policies, supporting infrastructure, market maturity and development economics. In Asia Pacific, which will see the fastest rate of growth in natural gas production of any region, unconventional gas is expected to account for 80% of production growth after 2025.

Globally, two-thirds of the increase in natural gas demand through 2040 is forecast to be met by unconventional gas. Exxon forecasted in Energy Outlook 2015 that by 2040, unconventional supplies are expected to account for 35% of global gas production, up from 15% in 2010. Nonetheless, investments to maintain and expand conventional gas production also are critical to meeting the world's demand for natural gas. Conventional gas production should continue to account for the majority of growth in Russia/Caspian, the Middle East and Africa. Conventional production is expected to grow in all regions except North America and Europe.

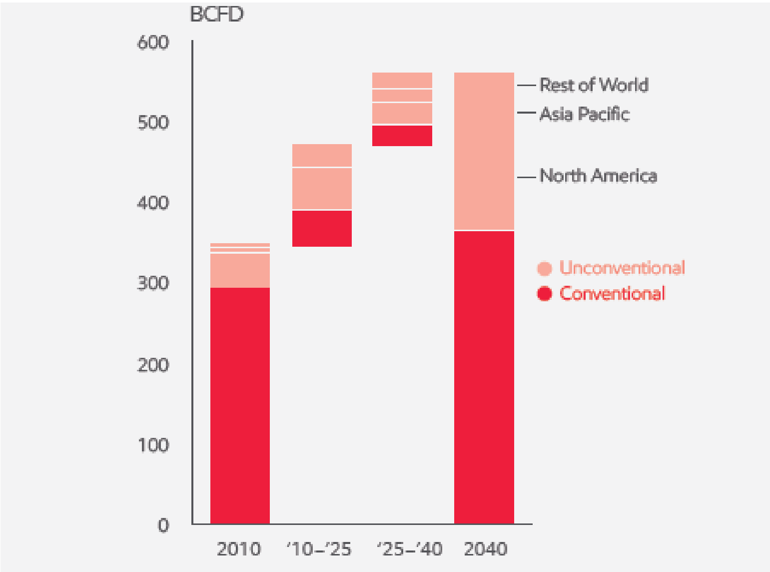


Figure 2.2 Global natural gas production by resource type (Source: Exxon Energy Outlook-2015)

In Asia, China has the most favorable conditions to establish shale gas production and has already begun to import the relevant technologies. It should be noted that the lack of gas infrastructure and strictly limited water resources will not allow China in short term to have production growth as fast as in the U.S.

To increase shale gas production, one needs a large number of modern drilling rigs. At present the appropriate fleet is available only in North America, where it is fully utilized. Global capacity to manufacture such drilling rigs is estimated at 300 rigs per year *(Lukoil, 2014)*. Lack of qualified personnel, as well as a lack of capacity for the water injection necessary for hydraulic fracturing will also constrain unconventional gas production around the world.

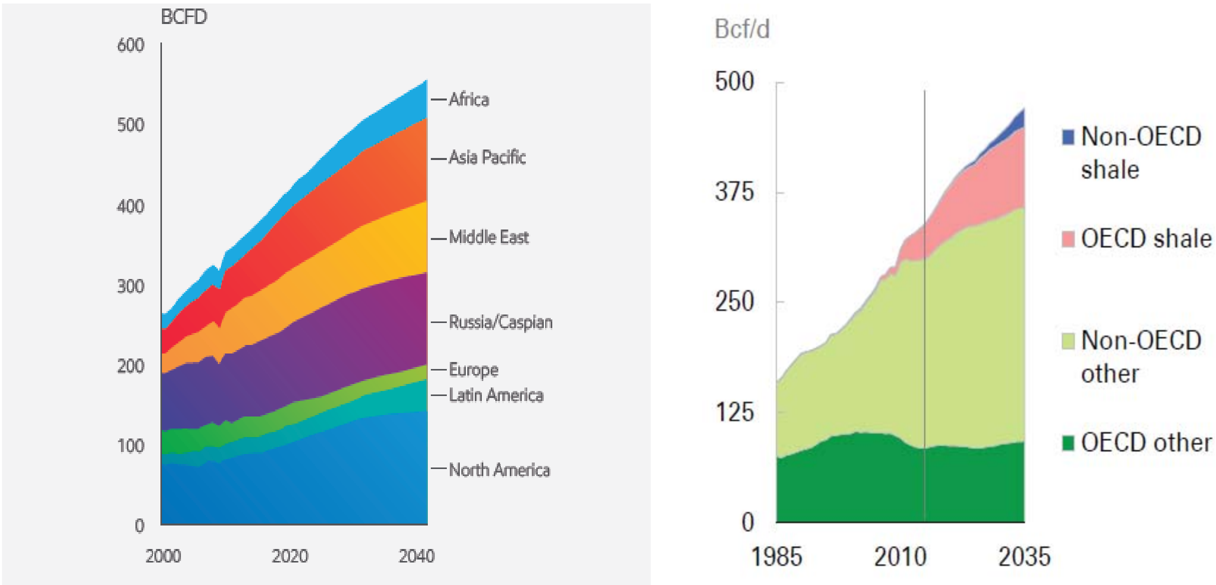


Figure 2.3 Global natural gas production and projection by region (Source: Exxon Energy Outlook-2015 & BP Energy Outlook-2016)

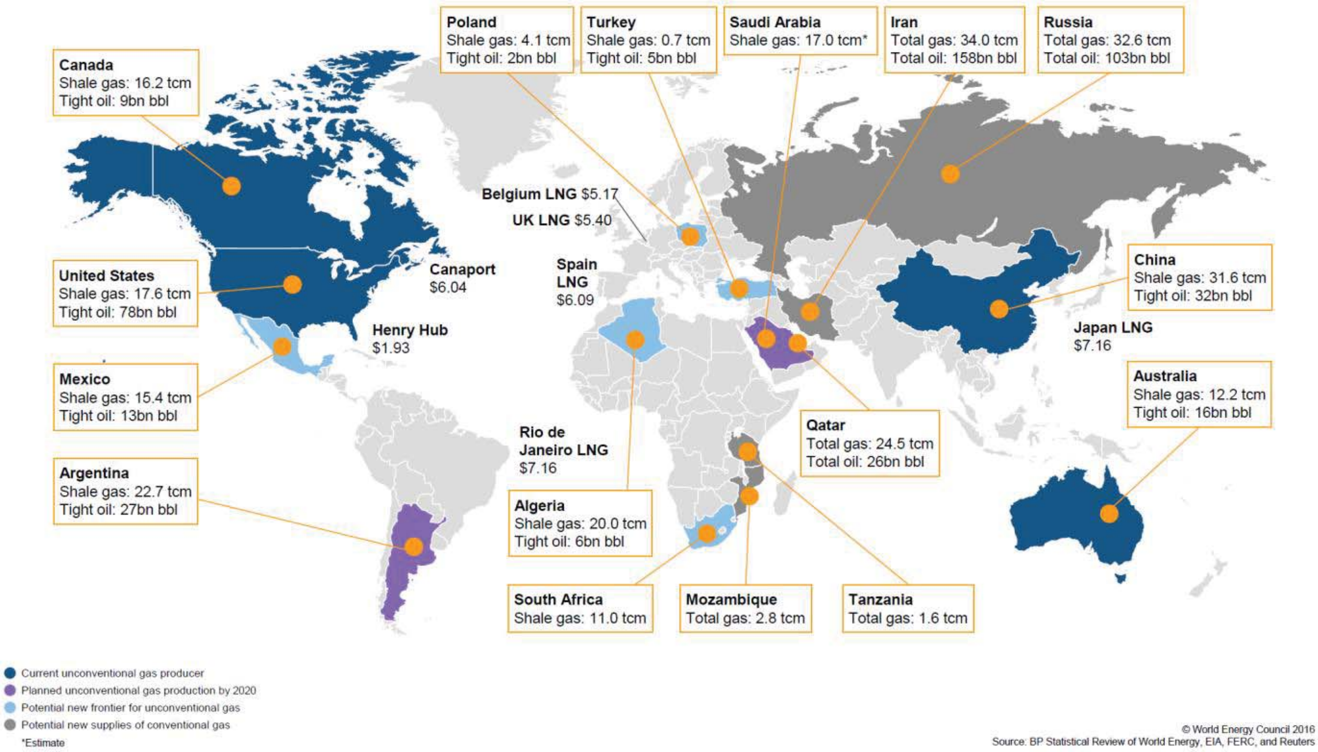


Figure 2.4 World unconventional gas phenomenon (Source: World Energy Council 2016)

According to data from EIA, as of 2013 all unconventional gas production made up an estimated 18% of global gas production. The majority comes from North America, with around 358 BCM produced in 2013, one-third of which is tight gas and just under half shale gas. As of 2015, shale gas output was still concentrated in the United States.

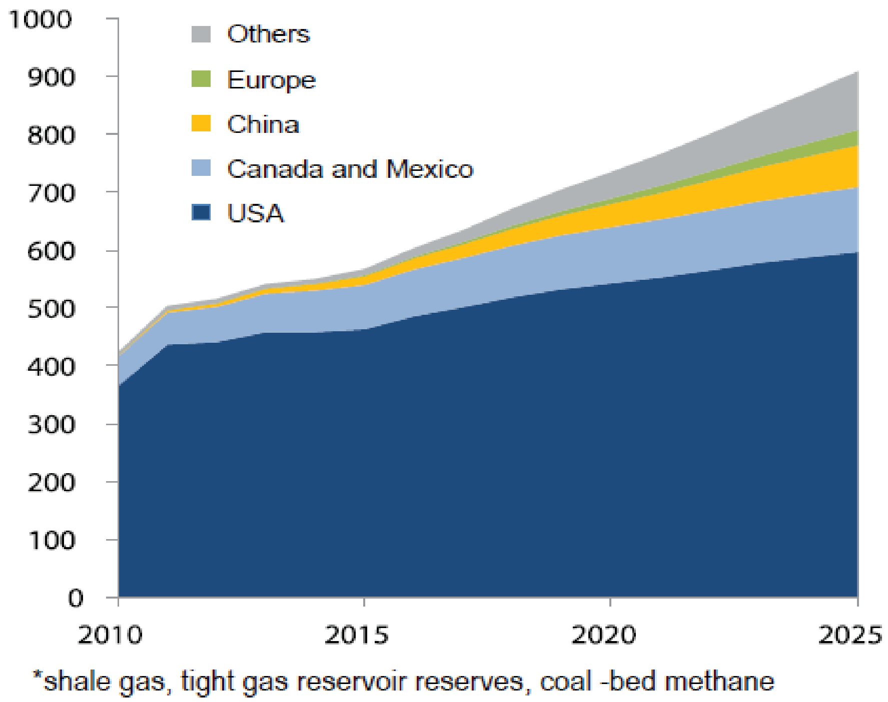


Figure 2.5 Unconventional gas production and projection in BCM (Source: EIA, IEA, LUKOIL Estimates)*

Consumption

Key growth factors in the demand for gas which initially was considered a by-product of oil production, were its environmental credentials (reducing CO2 emissions) and low cost in comparison with other types of fossil fuels. In Asia and Middle East, gas-fired electricity generation will replace coal and oil-powered plant respectively. Gas consumption will also continue to grow in North America. Another growth driver for gas-fired generation is the worldwide concern of safety and reability of the nuclear power. In addition to power generation, population growth will also contribute the growth in gas consumption in the residential and industrial sectors. Natural gas is expected to supply 135% more electricity in 2040 than in 2010 and overtake coal as the largest source of electricity.

China will be the major region for gas consumption growth and by 2040 will become one of the world's largest consumers and importer of gas. Currently, China already surpassed the U.S.

as the world's largest electricity consumer and its demand is projected to grow by more than 140% from 2010 to 2040.

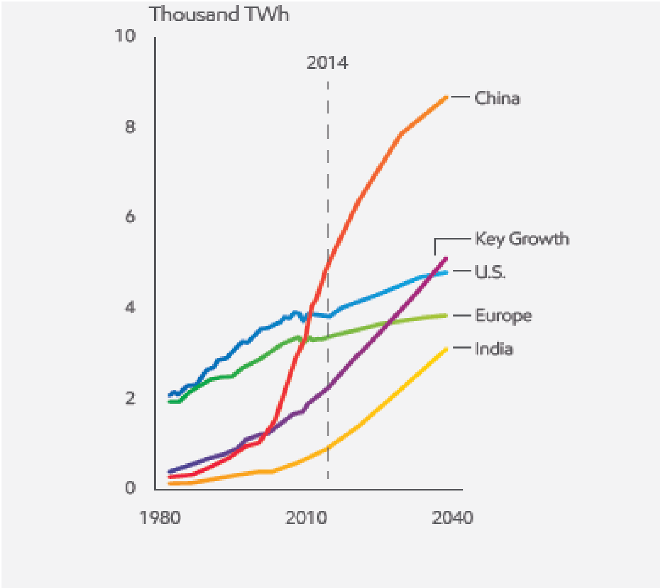


Figure 2.6 Electricity demand by country (Source; Exxon Energy Outlook-2015)

BP states in Energy Outlook 2016, that until 2035 global gas consumption will continue to grow at an annual rate of 1.8% with its share in primary energy gradually increasing. Therefore, gas consumption will have the highest rate of growth among other types of fossil fuels.

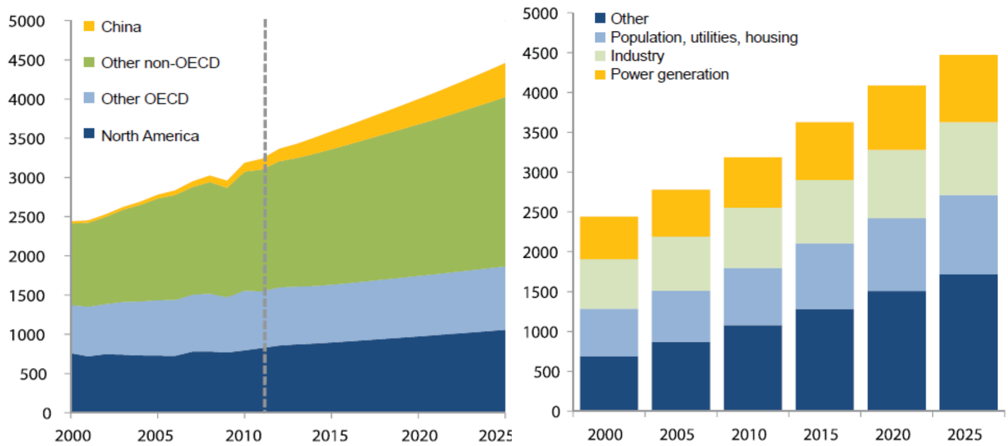


Figure 2.7 Natural gas consumption by region & sector, BCM (Source: IHS CERA, LUKOIL Estimates)

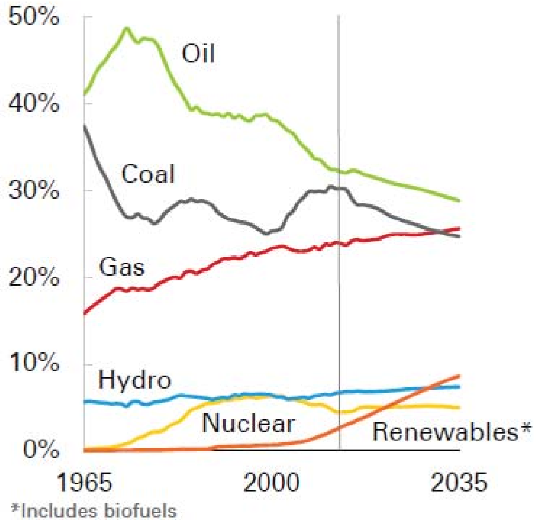


Figure 2.8 Shares in primary energy (Source: BP Energy Outlook-2016)

Trade

International trade in gas grows broadly in line with global consumption. But within that, LNG trade grows twice as fast as consumption, with LNG's share of world demand rising from 10% in 2014 to 15% in 2035. Over 40% of the increase in global LNG supplies is expected to occur over the next five years as a series of in-flight projects are completed.

The largest producer of LNG is Qatar, which held a 31% market share in 2014. Qatar has seen a massive expansion of its capacity, up more than 63 BCM since early 2009 to reach 105 BCM. Indonesia, Malaysia, Australia and Algeria are also significant LNG exporters. Australia, whose gas production is on track to increase by 230% from 2014 to 2020, is set to become the second-largest LNG exporter behind Qatar, overtaking Malaysia. Gorgon LNG, the largest LNG liquefaction plant in Australia with capacity of 21.5 BCM has accomplished its construction and will have the first LNG production by mid-year 2016, while some others were at advanced stages of construction, with all representing more than 80 BCM of new capacity. By 2035, LNG surpasses pipeline imports as the dominant form of traded gas. The growing importance of LNG trade is likely to cause regional gas prices to become increasingly integrated.

The growth of LNG coincides with a significant shift in the regional pattern of trade. The U.S. is likely to become a net exporter of gas later this decade, while the dependence of Europe and China on imported gas is projected to increase further.

Even though the long term contract is still central to the LNG trade, some significant changes has taken place in recent years. Over the past five years ago or so it has become acceptable in industry practice for even contractually committed LNG with a specified destination to be diverted to another market *(Zhuravleva, 2009)*. This is become the base definition LNG arbitrage which defined as a physical cargo diversion from one market to another, which offers high price. The diversion of the cargo can be regarded as arbitrage if the cargo was initially committed to first market and initial buyer in commercial contract.

One form is seen as LNG arbitrage is reload. LNG reload is a cargo diversion and implies a purchase of the LNG cargo, discharge from vessel in to the storage tank and a subsequent reloading of the LNG in to another ship. The reloaded LNG is diverted to higher priced markets, thus acting as balancing forces. For example, a buyer in Spain under long term contract with a supplier like Algeria or Trinidad can unload the cargo in Spain and reload it to another or the same vessel and ship it to Japan where prices were much favorable during some years.

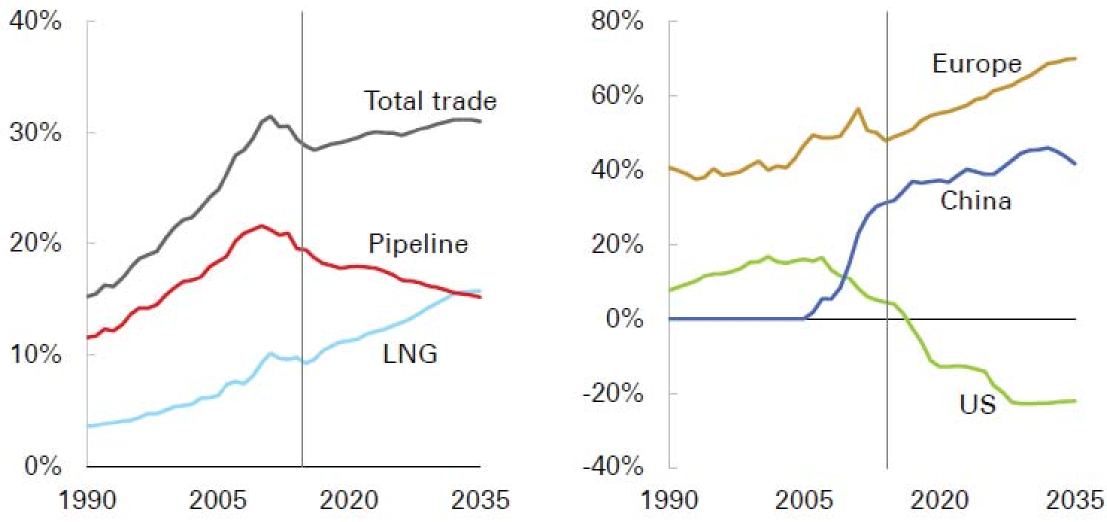


Figure 2.9 Gas trade as share of global consumption and gas imports by the largest consumers (Source: BP Energy Outlook-2016)

2.2 European Gas Market

European (UK and Continental Europe) gas consumption in 2015 accounted for around 14% of total world consumption. European gas market can be easily divided in two: the spot market of UK, where the gas is priced under GOG competition and the continental European gas market, with around 40% of the gas being imported from Russian pipelines under OPE.

GOG (Gas on Gas) remains the largest share in Europe, standing at 64% which takes place not only in northwest Europe but also in Mediterranean (Italy) and Central Europe who are trying to diversify their gas supply portfolio and decrease the Russian gas dependency. OPE (Oil Price Escalation) in 2015 is down to 30%. Both GOG and OPE is dominated by the pipeline imports. The regulated prices are on the domestic production in Romania, Poland, Hungary, Croatia and Bulgaria. The NP gas accounts for gas used in refineries and oil recovery in Norway *(IGU, 2016).*

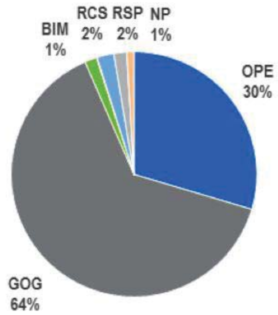


Figure 2.10 Europe price formation 2015 (Source: IGU Wholesale gas price survey 2016)

The Spot Gas Market of UK

Nowadays, natural gas market in UK is the second most competitive market in the world, after the U.S. market. The significant degree of competitiveness in the British market is given by the long process of transition from the British Gas monopoly to a liberalized model following the successful development of the oil reserves in the North Sea. The transition involved the privatization of British Gas, the establishment of the regulatory body OFGEM (Office of Gas and Electricity Markets), the restrictions in the supply area upon British Gas, the open access to the transportation and distribution network from third parties and the emergence of the free consumer, able to choose his supplier on a free market. When the gas market became open for the residential customers as well, in 1998, the natural gas price in England was defined as entirely competitive and National Balancing Point (NBP) was formed. NBP cannot be considered a physical hub, as the ones in North America, but a virtual hub in the transportation system created by regulatory means.

The transactions in NBP take place between players that already have reserved capacity to inject or withdraw gas in the transportation system operated by National Grid. National Grid is responsible for the physical transportation of gas, as shippers are required only to nominate quantities entering and/or exiting the network. Therefore, NBP is the main commercialization center in UK, having a churn rate above 25 in 2014. The natural gas prices are often indexed at

NBP, especially in the future market of natural gas Intercontinental Exchange (ICE). In Europe, NBP is also becoming a reference hub price.

The spot prices in Henry Hub and NBP were following a similar trajectory until 2010, when they decoupled due to the great natural gas supply from non-conventional sources in U.S. This caused, in fact, a decouple between the Henry Hub price and the oil price, as UK spot gas market is indirectly connected to the oil escalation market, via arbitrage with the European market, whose supply is given mainly by the oil indexed long term contracts.

Continental European gas market "as the battleground"

The natural gas market in Europe also suffered the liberalization process, as a result of the market integration policies implemented by the European Union. This process of deregulation leads to a progressive modification in the commercialization form and gas pricing. Unlike United States and UK market, the continental European gas industry is very concentrated. This high degree of concentration is explained, basically, by the fact that most of the European countries doesn't have gas resources and thus, are depended on imports.

Gas imported via pipelines in Europe comes from very few sources (Russia, Algeria and Norway) and is controlled by the state-owned companies. The supply concentration in Europe minimizes the negotiation possibilities for importing countries, as well as the importing gas is most of the time controlled by one company in each country. Therefore, the market is practically controlled by few huge companies, called national champions.

Natural gas wholesale pricing in Europe is facing two opposing ideologies, represented by the more traditional Oil Pricing Escalation and Gas on Gas competition in the spot markets. Around 40% of the gas supply comes via pipelines from Russia and is bought under long term contracts linked to oil prices. These contracts are usually on a period of over 20 years and have a "take or pay" clause of 85% (*Melling, 2010*).

The high dependency on the Russian gas raises some questions for the Europe, in the sense that Russia might encounter difficulties in supplying much longer Europe due to the lack of investments in its upstream segment. Another problem is the monopoly of Gazprom upon the gas exports for the European importing countries. Moreover, the pipelines' pathway from Russia to Europe passes through Ukraine and Byelorussia, who takes advantage of their geography position in the geopolitical game of natural gas. In order to reduce the Russian gas dependency, some countries in Europe start importing LNG, mainly from Qatar, Algeria and Nigeria. Also, projects for building pipelines were developing, i.e. the Nabucco project (which has been canceled due to a combination of geopolitical factors and business considerations), Trans Adriatic and Trans Anatolian pipelines that links the gas producing countries from Azerbaijan and Middle East to consuming countries as Austria, Germany and Chez Republic, avoiding Russian territory, but through Turkey, Romania and Hungary.

On the other hand, since the development of NBP in mid-1990s in UK, other hubs start emerging in the continental Europe. Still, their development is hindered either by the lack of supply liquidity or by obstacles to infrastructure liquidity at key transit points, such as border crossing within EU *(Melling, 2010).* However, NBP strongly influence the continental hubs due to its liquidity and the existence of two gas lines connecting the British market to continental Europe (Interconnector and Balgzand Bacton Line). Therefore, when spot gas prices are higher in continental Europe, there is an incentive for UK to export gas to the continent and the other way around.

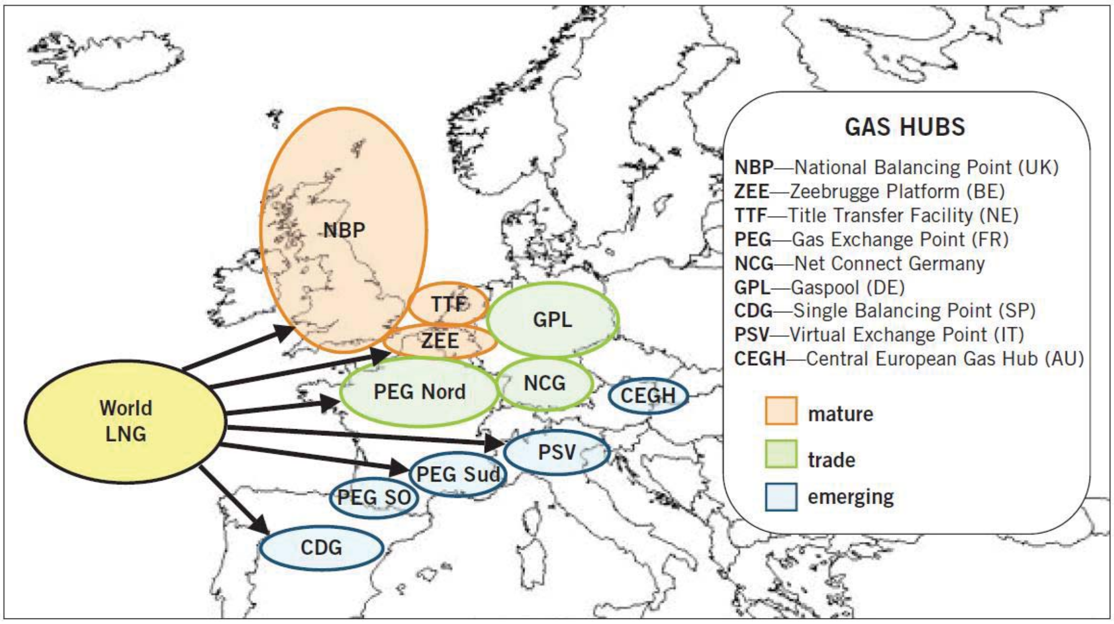


Figure 2.11 European Gas Hubs (Source: Melling, 2010)

Thus, the NBP price and the price in other spot markets follow the trends of the oil price, which still dominates the European gas supply. This convergence tendency appears in the medium term because the long term contracts from Russia, Algeria and Norway have take-or-pay clauses of 85%. Therefore, if the spot prices are lower than the oil price, it is possible to diminish the imports and buy the 15% of needed gas in spot market. On the contrary, if the spot prices are higher, spot markets loose the demand share that would use take or pay clauses.

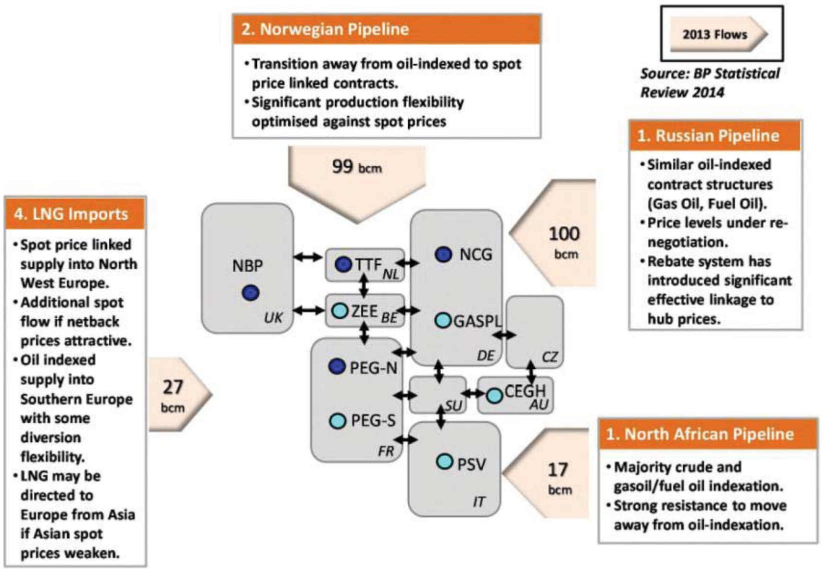


Figure 2.12 Diagram of European gas import (Source: Timera Energy, 2013)

Figure 2.12 shows the source of European gas import of European countries that have direct access to hub liquidity based 2013 gas flows. The boundaries of this ring are somewhat arbitrary depending on focus, but broadly include North West, Central and Southern Europe. Within this boundary, European gas supply can be grouped into several key sources by geography as illustrated. The other key supply dynamic that is not captured in these five categories are domestic production (dominated by declining field production in the UK and Netherlands) and gas storage capacity. Storage capacity as enabling the movement of gas between time periods, rather than as an outright source of supply. Seasonal storage acts to move gas from lower priced summer periods to higher priced winter periods. Fast cycle storage acts in a similar fashion but over a short time horizon.

Figure 2.13 shows the evolution of the gas prices in the most representative markets. In Europe, the benchmark prices are the UK NBP hub price and the average price of all German gas imports (BAFA). As the graph shows, the Oil Indexed Contract prices and German border prices were very similar until 2009, as very little gas was imported into Germany other than at oil-linked levels. However, due to the fact that the long term contracts start being renegotiated as a consequence of the increasing difference in oil prices and gas spot prices and a spot price index was introduced, and due to the increasing in the LNG imports in Europe as a mean to diversify the portfolio, a gap opened between the two prices, BAFA prices falling with about 10-15% (Stern & Rogers, 2014).

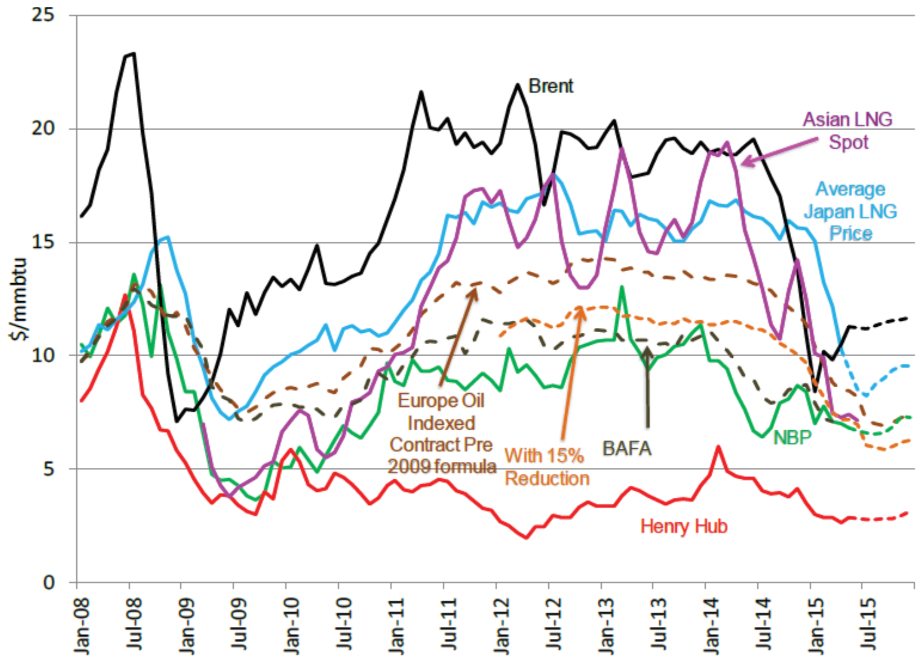


Figure 2.13 Regional gas price distribution vs crude oil price (source: EIA, ICIS Heren Index, BP)

LNG imports in Europe are also facing the two opposite pricing methodologies: traditional oil linkage, on one side, and market based prices, on the other side. Most of the LNG price imports received by the continental Europe are oil or gas oil linked. A new type of LNG imports emerge in Europe once the shale gas production in the U.S. hit, are indexed to Henry Hub, to which is added the liquefaction, regasification fee and the shipping cost.

The European markets are, therefore, more than ever characterized by the duality between oil-linked gas prices and spot prices in continental hubs, influenced by the NBP spot price. Even if most of the imported gas is priced under OPE, the transition to a Gas on Gas competition prices takes gradually place in continental Europe.

2.3 North American Market – Henry Hub

North America consumption in 2015 was 27% of total world consumption. GOG clearly dominates the North American market with fully liquid trading markets in the U.S. in which Canada and the wholesale price in Mexico being referenced to prices in the U.S. The small amount of NP (No Price) is in Mexico where Pemex uses the gas in refinery process and for enhanced oil recovery *(IGU, 2016)*.

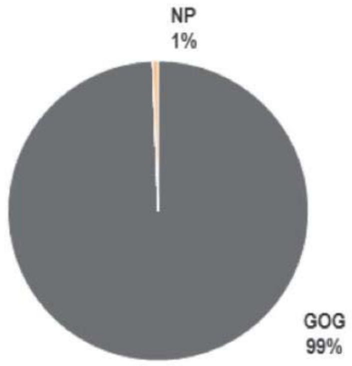


Figure 2.14 North America price formation 2015 (Source: IGU Wholesale gas price survey 2016)

United States gas market is the most mature market in the world, being the pioneers in the liberalization of natural gas industry. This process of liberalization resulted in a strong gas market and for the first time Gas on Gas competition is determining the gas price in the early 1990s. The robust spot market developed allows setting prices by the forces of supply and demand.

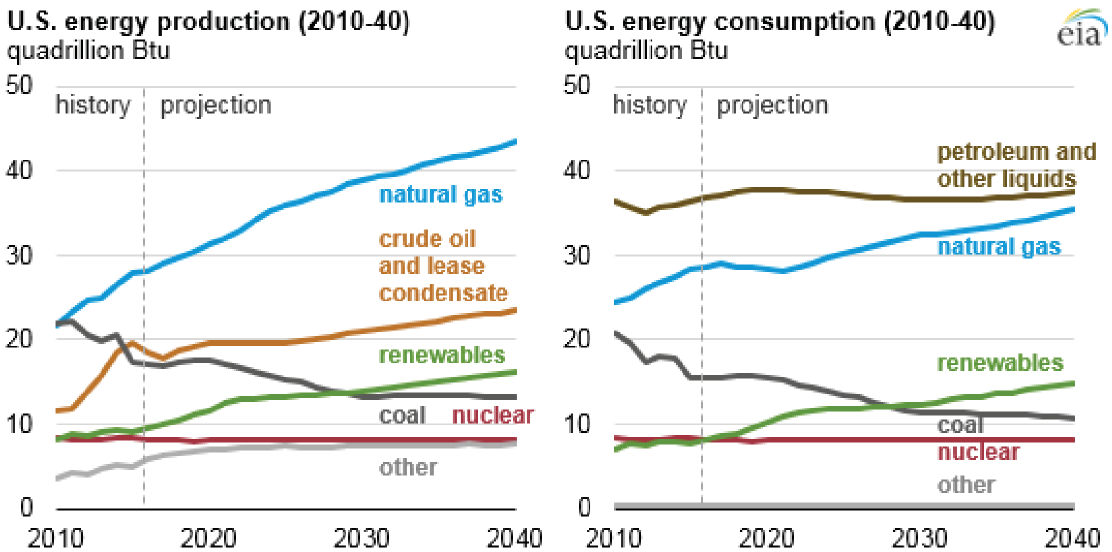


Figure 2.15 US long-term energy outlook (Source: EIA-Annual Energy Outlook 2016)

The trade takes place in physical hubs. In 2009 there were 33 active hubs in North America, of which 9 in Canada and 24 in United States. There are three types of hubs: production hubs, market hubs and commercialization centers. Production hubs are just interconnection points between two or more pipelines, whereas market hubs offer additionally storage services, ownership transfer and electronic commerce of gas. In addition of these, a commercialization center offers ancillary services (balance, dispatch and storage for balancing market). There are seven market hubs and 11 commercialization centers in the U.S.

The main commercialization center, Henry Hub, is the biggest in the world. It is placed in Louisiana, connects 12 pipelines and has three storage reservoirs. The price information given by the hub is used as reference point for contracts, in future markets and in derivatives markets of gas. The most known future market for gas is NYMEX (New York Mercantile Exchange), aimed to offer financial hedge services. In Henry Hub there are traded contracts for gas (molecule) to be delivered in one month and involves a daily fixed amount with the price established in the day the contract was signed. It can be considered the biggest gas spot market in the world. In general, every molecule of gas is sold and resold 100 times before its actually physical delivery (churn rate = 100), fact that assures a high liquidity of the market.

Nowadays, the North American market is considered to be one of the most competitive markets in the world, given its low prices in comparison to other markets. Looking at the overall picture of the natural gas prices in US, Europe and Asia, it is noticeable that until 2008 prices were convergent. Starting in 2008, spot natural gas prices constantly decreased (US and UK), and decoupled from the long term contract prices based on oil escalation (Germany, Japan), mainly as a result of an abundant domestic supply. Ever since the price in the U.S. remained low until today, whereas spot prices of UK start increasing back to the level of Germany's oil escalation price.

What keeps gas prices low in the U.S is the abundant domestic supply, the fall in demand due to the economic crisis and the export's limitation. The beginning of the crisis in 2008 coincides with the development of a non-conventional gas resource, the shale gas.

Shale Gas

Shale gas refers to natural gas that is trapped within shale rock formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas. Over the past decade, the combination of horizontal drilling and hydraulic fracturing has allowed access to large volumes of shale gas that were previously uneconomical to produce.

Hydraulic fracturing, commonly called "fracking", is the technique that enabled natural gas to be produced from shale in commercial quantities at economical costs. Water, chemicals, and sand are pumped into the well to unlock the hydrocarbons trapped in shale formations by opening cracks (fractures) in the rock and allowing natural gas to flow from the shale into the well. When used in conjunction with horizontal drilling, hydraulic fracturing enables gas producers to extract shale gas economically.

Shale gas is found in shale "plays," which are shale formations containing significant accumulations of natural gas, which share similar geologic and geographic properties. Production in Barnett Shale play in Texas started in 2000 and the experience and information gained from developing it have improved the efficiency of shale gas development around the country. Therefore, in 2008 starts the shale gas production in another five plays, creating a supply excess. An important play today is the Marcellus Shale in the eastern United States.

The increase in the indigenous production due to the exploitation of shale gas directly modified the dependency relations in the international market. Before 2008, the U.S. was a country with an increasing gas dependency. Besides the pipeline imports from Canada, the U.S. was importing LNG from Trinidad and Tobago, Nigeria, Algeria, Qatar and some others. However, higher domestic production has made imports unnecessary, leaving existing import capacity mostly idle, while the long term contracts for imports have been redirected to Europe or Asia. According to EIA Annual Energy Outlook 2016, the total production will exceed the internal consumption in 2018.

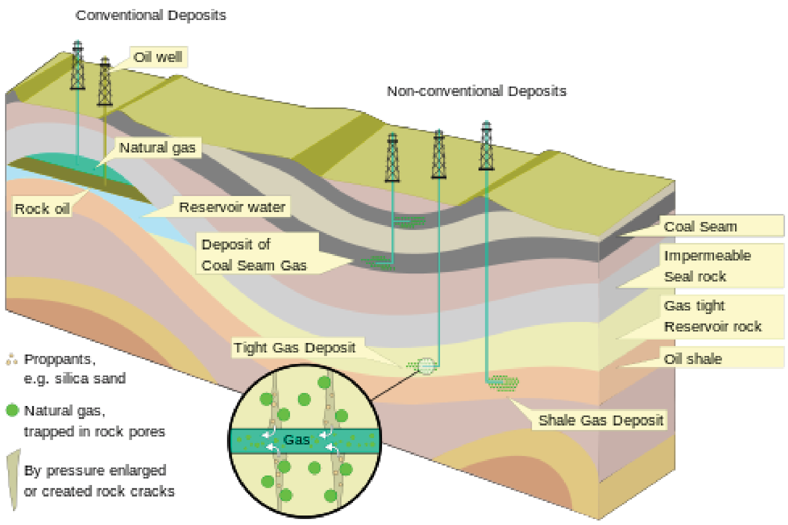


Figure 2.16 Geology structure of shale reservoir (Source: Wikimedia, Unconventional deposits)

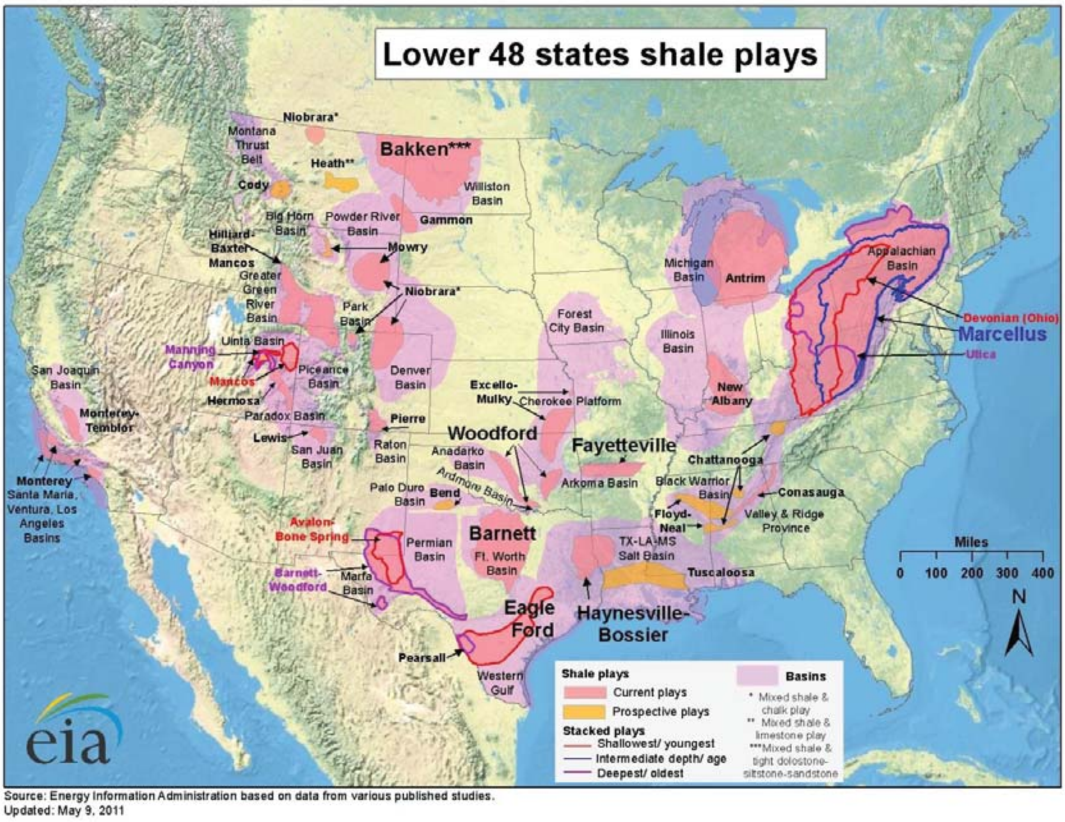


Figure 2.17 US shale gas plays (Source: EIA, 2011)

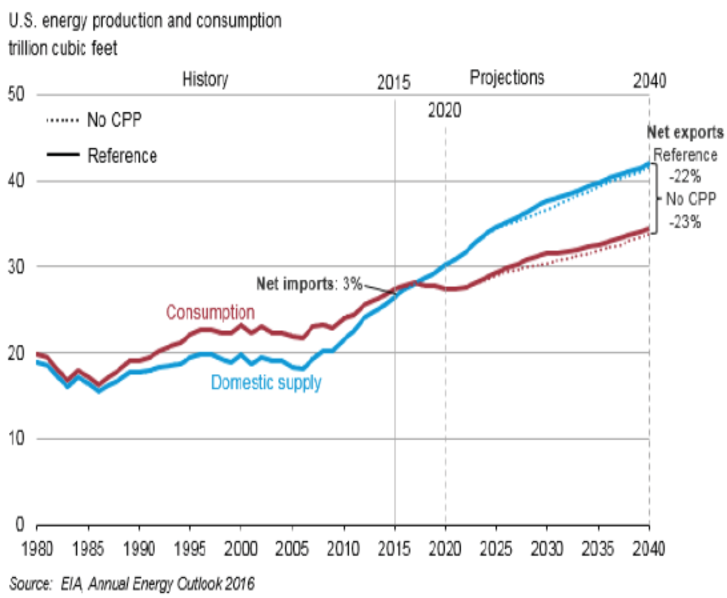


Figure 2.18 US Natural gas production, consumption and imports (Source: EIA 2016)

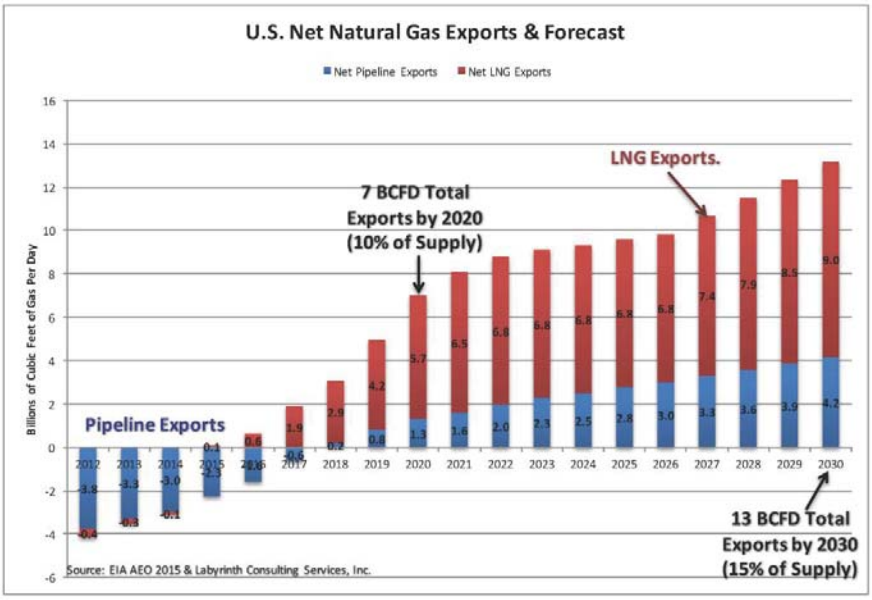


Figure 2.19 US Natural Gas Exports and Forecast (Source: EIA and Labyrinth Consulting Services, Inc.)

It also shows that the United States becomes a net exporter of natural gas in 2018, driven by LNG exports, increased pipeline exports to Mexico, and reduced imports from Canada. This decision might change radically the geopolitics of natural gas in North America.

2.4 Asian Pacific LNG Market

The Asia Pacific (South, East, ASEAN & Oceania) natural gas market is complex and fragmented. It is certainly not a geographically defined market: it is not highly interconnected by high pressure pipelines, like the Europe and North America natural gas markets. The main natural gas-consuming countries in Asia-Pacific are: China, Japan, India, South Korea, Thailand, Indonesia, Malaysia, Pakistan, Australia and Bangladesh. These countries consumed over 20 BCM respectively of natural gas in 2014.

The region has three separate markets with their distinct dynamics;

- The mature and well-established markets of Japan (basic plan, current and outlook of natural consumption in Japan as seen in Figure 2.20 and 2.21), Korea and Chinese Taipei, which are isolated, mainly supplied by LNG and have limited scope for further growth.
- The “emerging giants”, China and India, which will develop considerable natural gas demand supplied through both pipeline and LNG.
- The area of Oceania (ASEAN and Australia), which consists of several large LNG exporters (Malaysia, Indonesia, Australia and Brunei) and rapidly growing economies interconnected to a limited extent by pipelines.

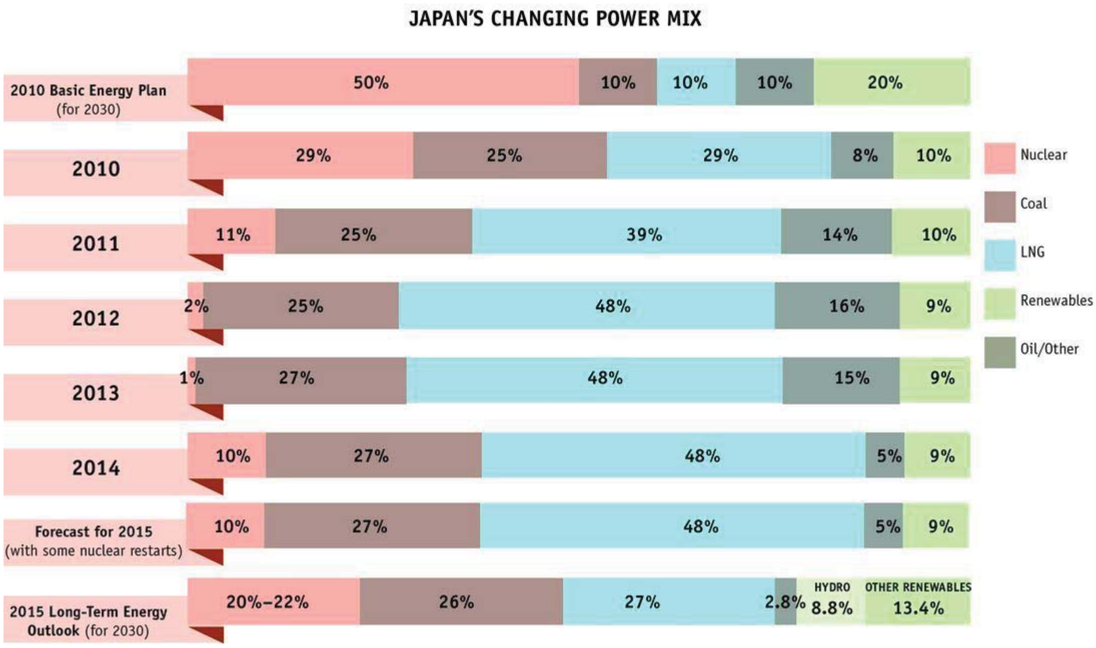


Figure 2.20 Japan's total energy consumption and outlook (Source: Patel, 2015)

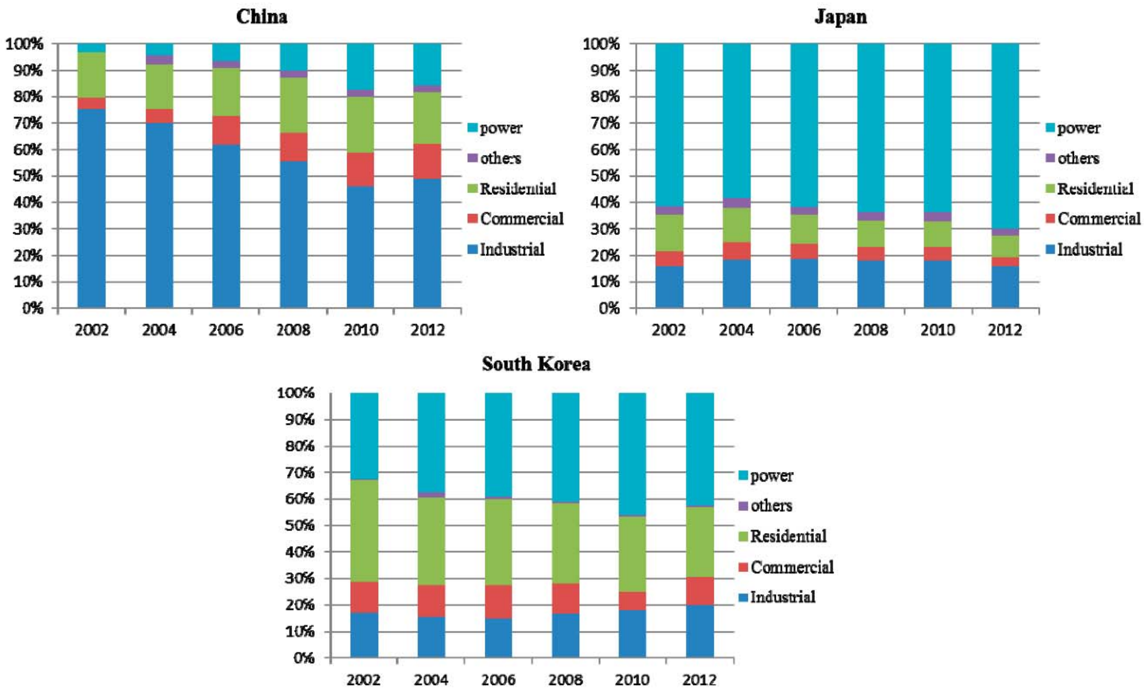


Figure 2.21 Natural gas consumption by sector in China, Japan and Korea (Source: Sustainability, 2015)

The natural gas market in the Asia Pacific region has undergone remarkable growth, to about 678 BCM in 2014. In 1998, total natural gas production in Asia-Pacific has lagged behind regional consumption (Figure 2.22). Natural gas consumption has grown by more than 450% since 1990, representing an average year-on-year increase of 18% for over two decades. Japanese consumption represented the mainstay of Asian natural gas demand (Fukushima nuclear power accident in 2011 increased the country's demand of fossil fuels, primarily the natural gas), especially in LNG, until 2009, when China surpassed Japan as the largest natural gas market in Asia. Japan and South Korea alone account for one half of the global LNG market, and growing LNG imports to China and India ensure that the Asia-Pacific will remain the key demand center for LNG trade.

The ASEAN (South East Asia Nations) that currently function as a large source of regional LNG production, in 2014 supplying about 63 BCM of LNG to satisfy broader Asia-Pacific demand, will see a marked change in their net export position. In the medium term, the net export position will decline as LNG production decreases and regional consumption increases. Malaysia and Indonesia as the main LNG exporter in this region are projected to be the net importer by 2020 *(METI, 2016)*.

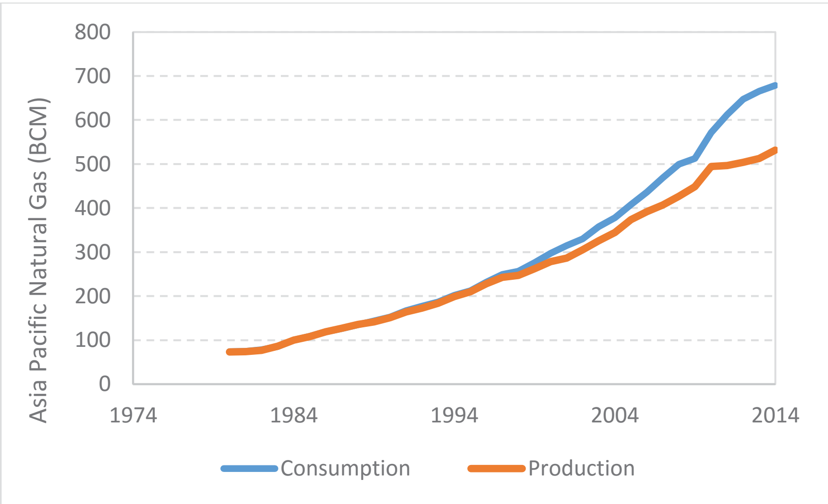


Figure 2.22 Asia Pacific Natural Gas production-consumption (Source: BP Statistical Review of World Energy - 2015)

By 2018, Australia is expected to become the world's largest exporter of LNG. The bulk of these exports have been purchased by Asian importers under long-term contracts, and the price of these is linked to the oil price. There are a number of factors that are likely to influence the Asia-Pacific LNG market over the next decade, including the emergence of the United States as a key supplier of LNG and the gradual change in the scale and composition of energy demand in

Asia. Australian production of LNG is expected to ramp up substantially over the next few years, providing a significant contribution to domestic output.

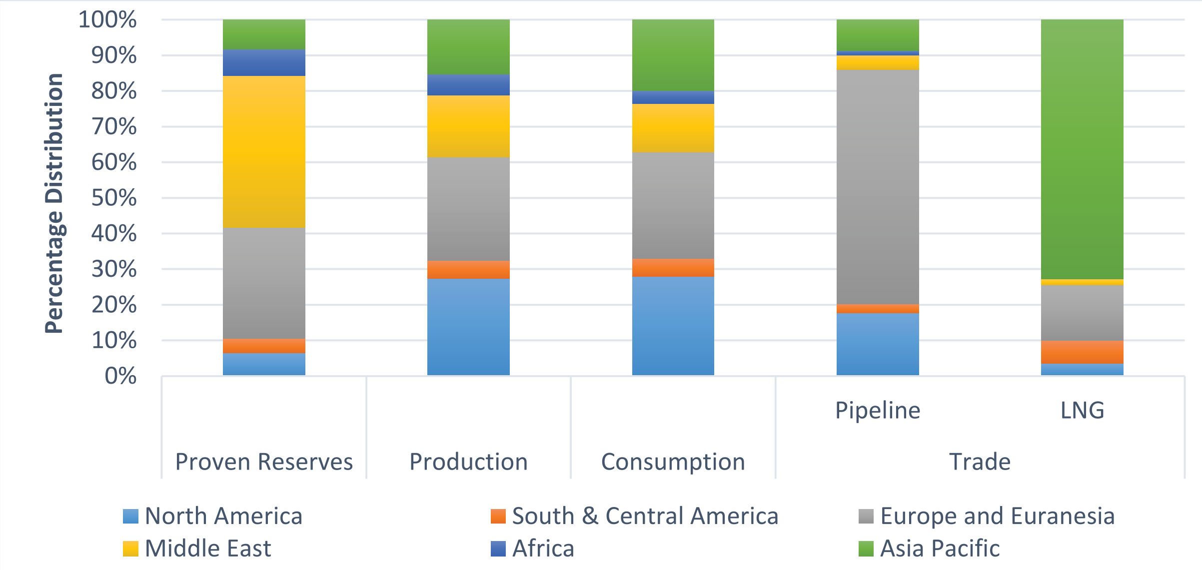


Figure 2.23 Global natural gas breakdown by region - 2014 (Source; BP Statistical Review of World Energy – 2015)

Asia will remain as the center of global liquefied natural gas (LNG) trade, the region accounts for nearly two-thirds of global LNG demand. The pipeline gas trade is also growing, and production of domestic gas in the rest of developing Asia is likewise rising rapidly.

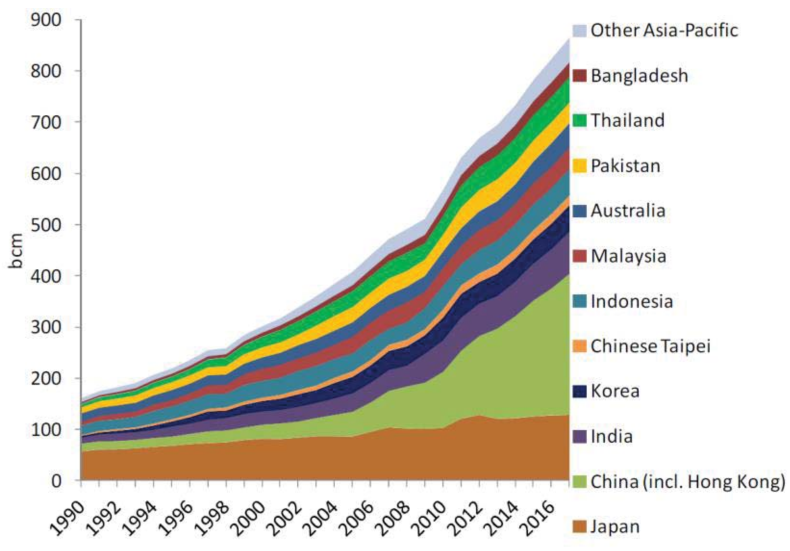


Figure 2.24 Natural gas demand in Asia Pacific (Source: EIA Energy Outlook 2016)

Chapter 3

Drivers and Constraints towards an Integrated Natural Gas Market

This chapter discusses the classification of the main drivers and constrains towards the formation of an integrated gas market and a global gas price. Price evolution is driven by internal factors: price formation and market structure of each market, evolution of supply/ demand, hub development and also by external factors as LNG trade that might facilitate arbitrage between markets.

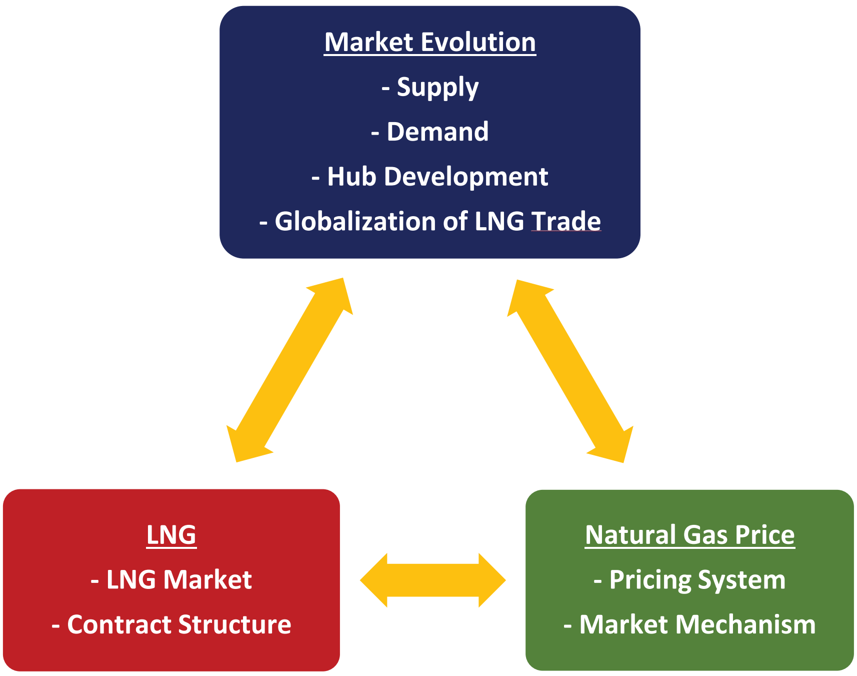


Figure 3.1 Drivers and Constraint of Global Natural Gas Market

3.1 Natural Gas Price

As indicated by the considerable divergence of prices, natural gas has distinct regional markets across the globe, and the correlation in prices among these markets moved apart in 2009 (Figure 3.2). The reason of market prices divergence in recent years is a result of the presence of two different pricing systems in conjunction with market circumstances that are accentuating pricing system differences and a limited market access for arbitrage. The Asian prices shown in Figure 3.2 are based primarily on an oil-indexed pricing system while the U.S. prices are based on the North American natural gas market where prices are determined in a competitive process between multiple natural gas suppliers (Gas on gas-based price). The UK prices are also gas-on-gas based, although they are more readily influenced by oil-indexed prices in continental Europe when arbitrage opportunities exist.

However, until 2008, the prices of these three regional markets were convergent with the difference was not greater than $2/MMBTU. Reasons for the change afterward in relative prices include: a downturn in global demand due to reduced economic growth associated with the global recession 2008-2009, increasing production and expanding natural gas storage volumes in the United States since mid-2000s (driven by shale gas developments), high European demand which reduced European natural gas storage inventories in winter time, and supply uncertainty associated with the diversion of LNG cargoes from Europe to Japan to help offset the loss of nuclear power generating capacity following the Fukushima disaster on March 2011 which pushing prices up to ~$15-18/MMBTU in Japan.

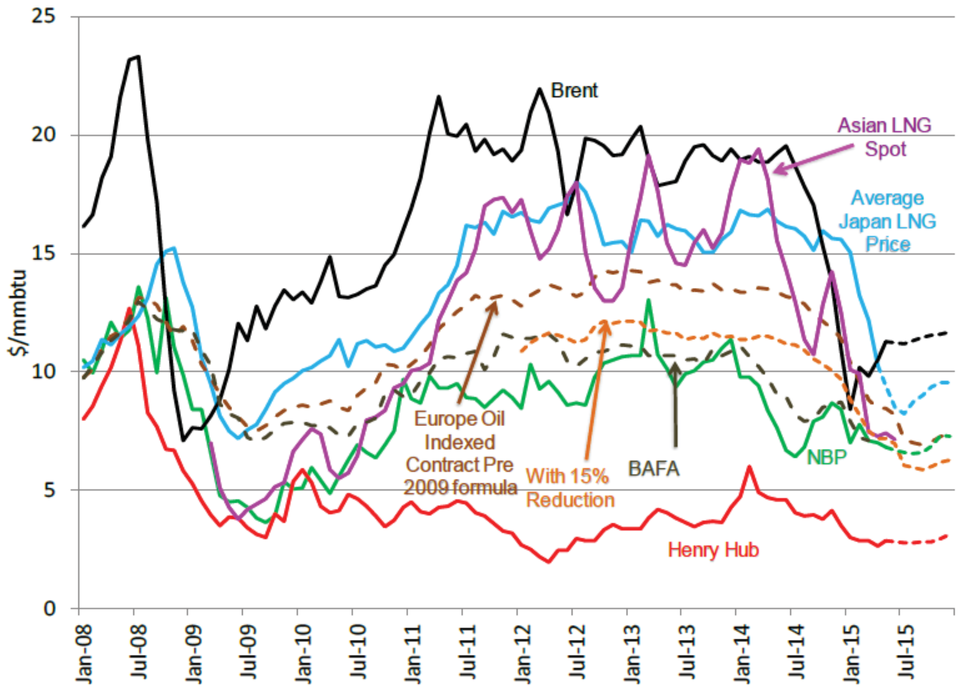


Figure 3.2 Regional gas price distribution vs crude oil price (source: EIA, ICIS Heren Index, BP)

For the period of 2011 to early of 2014 the regional gas prices appeared to be held within ranges which gave rise to significant inter-regional spreads:

- Henry Hub $2 to $5/MMBTU,
- European Hubs $8 to $11/MMBTU,
- Asian LNG contract prices $15 to $18/MMBTU
- Asian LNG spot prices (JKM) $13 to $19/MMBTU.

The primary causes for such spreads were:

- Henry Hub prices remaining under pressure due to shale gas production continuing to outstrip demand growth. With only Mexico as a (pipeline) export market, the U.S. gas prices remained low while production continued to grow.
- Crude oil prices above $100/bbl, kept Asian LNG oil indexed contract prices above $15/MMBTU. In Europe the linkage between prices of oil product and long term gas contract prices became rather muted towards the end of this period as producers such as Gas Terra and Statoil moved away from oil product indexation towards hub indexation and Gazprom introduced price concessions and rebates.
- The tightening of the global flexible LNG market as a consequence of the Fukushima disaster resulting in high and volatile Asian LNG spot prices and a progressive re-direction of LNG away from Europe and towards Asia, albeit at a pace which did not materially lower Asian spot LNG prices prior to 2014.

After 2014, European hub prices fell from over $11/MMBTU at the end of 2013 to $6.41/MMBTU in July 2014 due lower demand related to mild winter of 2013-2014, significantly predating the fall in crude oil prices. In Asia by mid-2014 LNG spot prices were in free fall. Initially this was attributed to a mild 2013-2014 winter in some Asian importing countries but a growing concern appeared to be the reduced pace of Asian LNG demand growth. By the third quarter of 2014 the gas market fundamentals in Europe and Asia were weighing heavily on those regional reference prices which were determined by supply and demand.

By end of 2014, the regional gas prices began to converge as multiple factors exerted downward pressure on prices around the globe. The oil prices which had been declining since June 2014 due to sluggish global demand and rising the U.S. oil production fell significantly following the 27th November 2014 OPEC Meeting, with Brent falling to level $66/bbl and below $50/bbl in January 2015. As oil prices fell in late 2014 and throughout 2015, traditionally oil linked prices in Europe and Asia also declined.

Given that, most of oil indexed contracts have a six months time lag against the oil price, Asian term import prices remained relatively steady through the end of 2014, with Japanese imports holding at the $15/MMBtu level. However, by 2015 the impact of lower oil prices took effect; the Japanese import prices at December landing at $8.13/MMBtu. The NBP price fell to around $6.50/MMBTU by the third quarter of 2015. Any increase in these gas reference prices will be subject to a recovery in oil prices, irrespective of gas market fundamentals.

3.1.1 Gas Pricing System

This diversity of pricing mechanism from national or regional gas markets can be explained by some of the specific characteristics of the gas industry. However, the economic logic behind the gas pricing has to follow, in general terms, there are two basic rules; it has to substitute in a competitive manner the other energy sources (that is being used or could be used) and it has to cover the production, transportation and distribution investments *(Almeida & Ferraro, 2013)*.

First of all, the importance of the transportation costs, which is high compared to other commodities. The gas transportation from the production place to the end user markets requires high investments in either pipeline systems or in case of LNG (liquefaction, shipping and regasification facilities). Due to the strong asset specificity of the gas industry, the projects of transporting gas from the source to the market are characterized by very high fixed costs and relatively low variable costs. Therefore, the very high initial cost needs to lock in future revenue streams to justify the project since the payback period is relatively long. Thus, gas trade highly depends on long term contracts or on keeping the vertical integrated utilities and create inflexibility in the gas commerce. The price formation of natural gas for a final consumer is dependent of the gas molecule price, as well as of the transportation and distribution cost, which can account for more than 50% of the final price. Besides, the determination of the transportation and distribution tariff can vary for different markets.

Natural gas can be transported via pipelines or seagoing vessels (LNG shipment). Commodity transport via seagoing vessels is the most efficient mode in term of cost of all transport options which also justifiable for the natural gas. In Table 3.1 and 3.2 are listed full cost of transport by LNG carriers from all the major LNG origins to the major LNG destinations in the world for November 2013 and May 2016 shipments (based on ICIS Heren for ships using the TFDE engine options). The data shows that sea transport is much more dependent on market condition (Halmø, 2016). The shipping costs of LNG for November 2013 (i.e from North Europe to Tokyo) is about 3 times higher than in May 2016 when LNG price declines as function of oil price drop. It gives the correlation to LNG price, at the same time frame LNG spot prices in East Asia were at 18-20 $/MMBtu which is more than four times the price for May 2016 at 4.225 $/MMBtu *(ICIS Heren LMD April 14th,2016).*

Another characteristic that influence the tradability of gas and its pricing is the storage ability as an important source of flexibility. In gas industry, storage plays a much smaller role than in commodities as coffee, as it requires higher investments and in some cases relies also on the right geology to be available. This makes even more difficult for the balance between input and output (demand and supply) to be maintained, a necessary condition for the security of supply.

The big difference in the contribution degree of gas in the national power generation mix is another salient characteristic that influence gas pricing. If the price of natural gas is above the prices of other substitute fuels, there is an incentive to replace gas in the power generation mix. Therefore, for every market there is a cap for the natural gas price. Historically, the commodity price maintained a direct link with oil price and its derivatives.

Gas pricing is directly influenced by the maturity of the national market and by the degree of the liberalization. A growing liberalized market with a large international LNG trade results into a fast evolution of gas pricing. The tendency of this market is to switch from oil indexed pricing of long term contracts to a price determined by market forces. In different countries, short term markets and spot markets for natural gas are developing, so that gas price has daily quotation resulted from the competition of more suppliers.

Natural gas pricing generally falls into three categories depending on the degree of regulation, the competitiveness of the market, and market liquidity *(Melling, 2010)*:

- Government-regulated prices, usually based on cost of service (RCS, RVP, RBC)
- Price indexation to competing fuels (commonly known as oil-indexed pricing/OPE)
- Spot market pricing in competitive gas markets (GOG, BIM, NET)

TFDE SHIPPING COSTS FOR MAY 2016 ($/MMBtu)	Middle East	North Africa	West Africa	Far East	Trinidad	Northeast Asia	Australia	N Europe
Tokyo	0.514	1.011	0.793	0.248	0.988	0.142	0.326	1.198
Pyeong Taek	0.489	0.986	0.771	0.228	0.966	0.173	0.320	1.172
Guangdong	0.416	0.912	0.700	0.163	0.894	0.227	0.263	1.098
Yung An	0.434	0.924	0.708	0.167	0.909	0.202	0.266	1.116
Singapore	0.321	0.815	0.612	0.124	0.805	0.315	0.192	1.000
Map Ta Phut	0.370	0.865	0.659	0.145	0.853	0.311	0.236	1.050
Hazira	0.167	0.660	0.584	0.294	0.905	0.487	0.333	0.845
Jebel Ali	0.099	0.643	0.637	0.349	0.887	0.543	0.389	0.827
Mina Al Ahmadi	0.103	0.668	0.663	0.374	0.913	0.568	0.414	0.853
Ain Sukhna	0.277	0.461	0.692	0.475	0.703	0.688	0.514	0.645
Aliaga	0.582	0.176	0.404	0.782	0.416	0.980	0.822	0.358
Revithoussa	0.583	0.167	0.395	0.783	0.406	0.981	0.823	0.348
Rovigo	0.630	0.179	0.408	0.830	0.419	1.029	0.870	0.361
Huelva	0.679	0.111	0.300	0.881	0.307	1.079	0.920	0.247
Sines	0.687	0.118	0.298	0.889	0.300	1.087	0.928	0.237
Rotterdam	0.761	0.190	0.369	0.964	0.351	1.163	1.003	0.171
Zeebrugge	0.757	0.186	0.365	0.959	0.347	1.159	0.999	0.173
Montoir	0.734	0.164	0.343	0.937	0.329	1.136	0.976	0.203
Isle of Grain	0.756	0.185	0.364	0.959	0.346	1.158	0.998	0.174
Sabine Pass	0.989	0.412	0.485	1.195	0.228	1.129	0.922	0.423
Altamira	1.000	0.422	0.495	1.208	0.231	1.427	0.928	0.435
Quintero	0.839	0.618	0.522	0.738	0.525	0.686	0.657	0.743
Guanabara Bay	0.709	0.377	0.306	0.690	0.286	0.873	0.633	0.501
Bahia Blanca	0.740	0.469	0.390	0.716	0.378	0.788	0.659	0.594

Table 3.1 LNG shipping cost - May 2016 (Source: ICIS Heren GLM, 2016)

SHIPPING COSTS ($/MMBtu)	Middle East	North Africa	West Africa	Far East	Trinidad	Northeast Asia	Australia	N Europe
Tokyo	1.905	3.075	3.103	0.805	3.912	0.380	1.149	3.896
Pyeong Taek	1.820	2.973	3.005	0.738	3.737	0.502	1.111	3.796
Guangdong	1.519	2.664	2.702	0.487	3.422	0.697	0.876	3.481
Yung An	1.561	2.708	2.738	0.486	3.467	0.632	0.858	3.526
Singapore	1.123	2.257	2.332	0.292	3.137	0.949	0.581	3.068
Map Ta Phut	1.333	2.472	2.539	0.386	3.341	0.943	0.780	3.287
Hazira	0.488	1.716	2.062	0.955	2.460	1.775	1.154	2.498
Jebel Ali	0.194	1.645	2.087	1.218	2.640	2.521	1.389	2.420
Mina Al Ahmadi	0.212	1.774	2.294	1.333	2.514	2.126	1.500	2.566
Aliaga	1.420	0.514	1.487	2.123	1.513	2.929	2.281	1.285
Revithoussa	1.414	0.479	1.451	2.113	1.477	2.917	2.252	1.249
Rovigo	1.605	0.531	1.504	2.306	1.530	3.114	2.446	1.299
Huelva	1.811	0.242	1.044	2.521	1.054	3.334	2.680	0.840
Sines	1.848	0.277	1.039	2.563	1.030	3.377	2.722	0.794
Rotterdam	2.147	0.557	1.325	2.844	1.228	3.683	3.023	0.507
Zeebrugge	2.147	0.557	1.325	2.844	1.228	3.683	3.023	0.507
Montoir	2.046	0.472	1.225	2.755	1.150	3.571	2.896	0.648
Isle of Grain	2.143	0.554	1.309	2.848	1.221	3.680	3.021	0.507
Sabine Pass	3.103	1.481	1.802	3.533	0.736	5.020	4.555	1.619
Quintero	2.915	2.380	1.958	2.836	1.969	2.633	2.512	2.895
Pecem	2.336	1.025	0.894	2.838	0.590	3.887	2.565	1.533
Bahia Blanca	2.621	1.728	1.368	2.876	1.380	3.046	2.602	2.262

Table 3.2 LNG shipping cost November 2013 (Source: ICIS Heren GLM, 2013)

Oil Price Escalation (OPE)	The price is linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases coal prices can be used as can electricity prices.
Gas-on-Gas Competition (GOG)	The price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK). There are likely to be developed futures markets (NYMEX or ICE). Not all gas is bought and sold on a short term fixed price basis and there will be longer term contracts but these will use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Also included in this category is spot LNG, any pricing which is linked to hub or spot prices and also bilateral agreements in markets where there are multiple buyers and sellers.
Bilateral Monopoly (BIM)	The price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time – typically one year. There may be a written contract in place but often the arrangement is at the Government or state-owned company level. Typically there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple buyers and sellers trading bilaterally.
Netback from Final Product (NET)	The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces. This may occur where the gas is used as a feedstock in chemical plants, such as ammonia or methanol, and is the major variable cost in producing the product.
Regulation: Cost of Service (RCS)	The price is determined, or approved, formally by a regulatory authority, or possibly a Ministry, but the level is set to cover the "cost of service", including the recovery of investment and a reasonable rate of return.
Regulation: Social and Political (RSP)	The price is set, on an irregular basis, probably by a Ministry, on a political/social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise – a hybrid between RCS and RBC.
Regulation: Below Cost (RBC)	The price is knowingly set below the average cost of producing and transporting the gas often as a form of state subsidy to the population.
No Price (NP)	The gas produced is either provided free to the population and industry, possibly as a feedstock for chemical and fertilizer plants, or in refinery processes and enhanced oil recovery. The gas produced maybe associated with oil and/or liquids and treated as a by-product.
Not Known (NK)	No data or evidence.

Table 3.3 Type of Pricing formation mechanism (Source; IGU Wholesale gas price survey 2016)

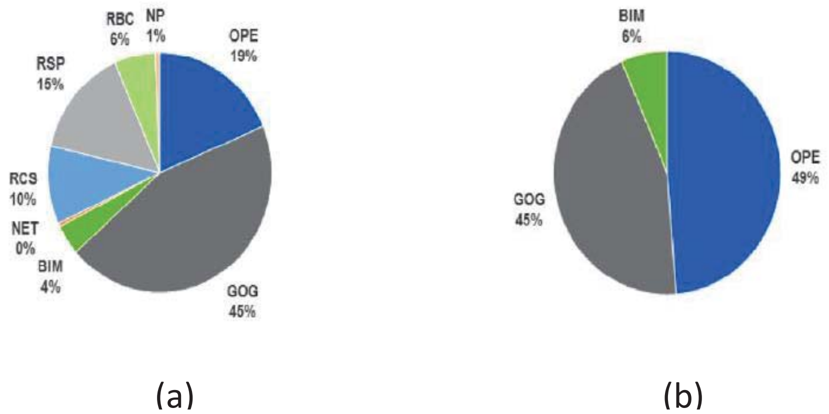


Figure 3.3

(a) Price formation mechanism 2015 on total world consumption; GOG has the largest share which is dominated by North America and Euranesia. OPE share is predominantly Asia Pacific and Europe

(b) Total imports in 2015 accounted for some 27% of total world consumption. Total imports are the sum of pipeline and LNG imports (Source: IGU Wholesale gas price survey 2016)

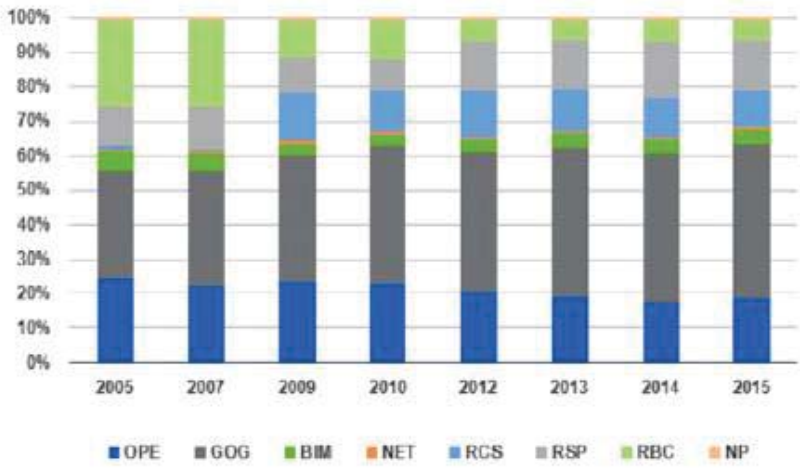


Figure 3.4 World Price formation from 2005 - 2015 (Source: IGU Wholesale gas price survey 2016)

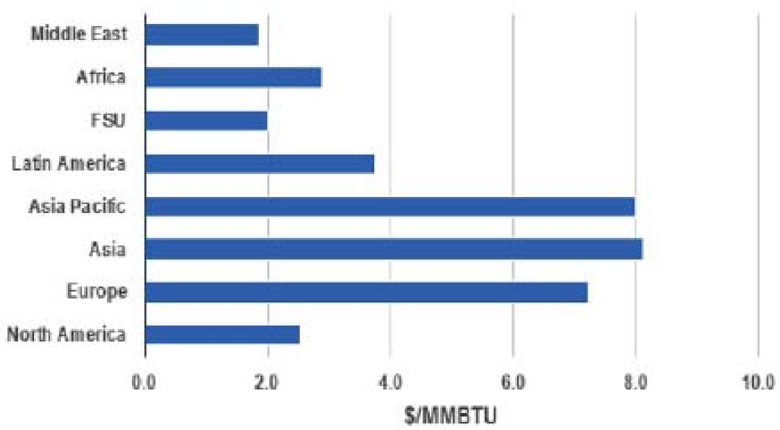


Figure 3.5 Wholesale prices level by region 2015 (Source: IGU Wholesale gas price survey 2016)

3.1.2 Pricing Mechanism in Different Markets

Gas markets are fragmented by legal and regulatory requirements, distance and different approaches to contracting. For achieving a global gas market and gas price, a homogenization in the market structures and price mechanisms would clearly help.

Unlike the global oil market, which reflects the global demand and supply, the international market for gas lacks international transparency and benchmarks. There is yet no international reference for gas price, each market pricing gas following different rules. In the U.S. and UK gas is priced based on regional supply and demand balance in the gas trading hubs (GOG mechanism): Henry Hub in the U.S. and National Balancing Point in UK. However, in continental Europe and Asia Pacific prices are characterized by the dominance of long-term contracts between gas producers and consumers, and a price mechanism linked to oil prices (OPE mechanism). These gas contract prices lack not only global transparency, but often regional transparency due to prices being commercially negotiated on confidential contractual terms.

Under GOG mechanism, the price of natural gas is indexed to competitively determined gas market spot prices which change in response to natural gas supply and demand. Under OPE mechanism, the price of natural gas is determined from oil market spot prices which change in response to oil supply and demand.

In this subchapter, the discussion refers to regions name based on IGU classification as seen in Figure 3.6.

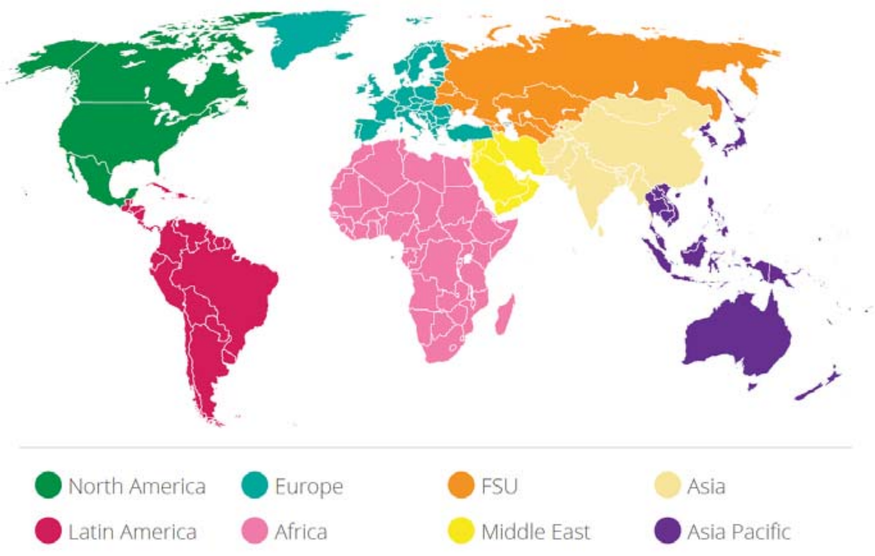


Figure 3.6 IGU Regions (Source; IGU Wholesale gas price survey 2016)

Price Trends in North America

As seen in Figure 3.5 virtually from 2005 to 2015, GOG has largest share in domestic production and pipeline trade in North America.

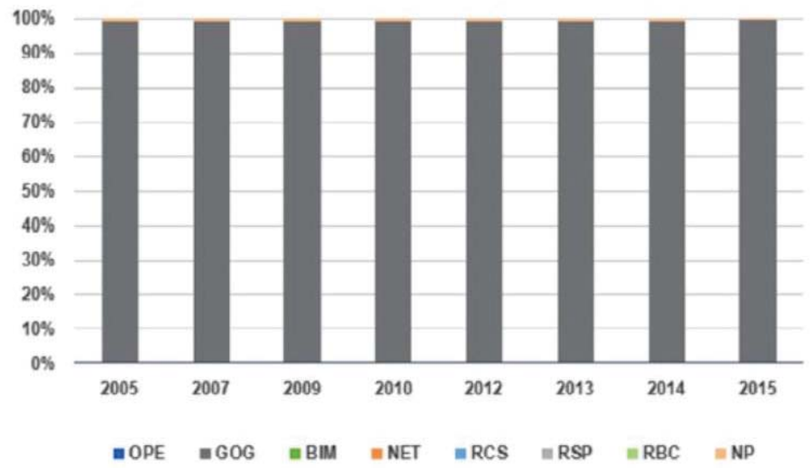


Figure 3.7 North America price formation 2005 - 2015 (Source: IGU Wholesale gas price survey 2016)

Price Trends in Europe

Europe is one of the regions where the most significant changes in price formation mechanisms have taken place, especially a continuous transition from OPE (from 78% in 2005 to 30% in 2015) to GOG (from 15% in 2005 to 64% in 2014). These changes are mainly reflected in the decline in the volume of gas imported under the traditional oil price escalation and increase in the imports of spot gas and increasing volumes traded at hubs. The ending of contracts or the renegotiation of the terms to include a proportion of hub/spot price indexation in the pricing terms and in some cases a reduction in the take or pay levels are the main means used to decrease the OPE utilization (*IGU, 2014*).

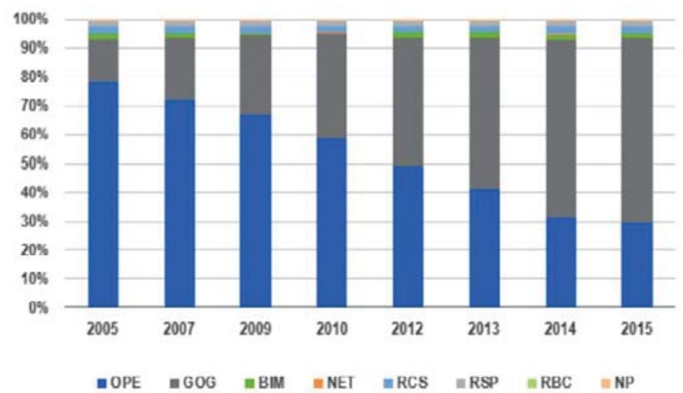


Figure 3.8 Europe Price Formation 2005-2015 (Source: IGU Wholesale gas price survey 2016)

Price Trends in Asia Pacific (Japan, Korea, SE Asia & Oceania)

There have been only minor changes in price formation mechanisms in this area since 2005 to 2015. GOG has risen from 14% to 17%, with OPE is steadily in level 50-60% and RSP down from 21% to 17%. Changes have not been consistent over time, but the rise in GOG largely has achieved due to the ascendant trend of spot LNG imports, mostly in Japan and Korea. The fall in the RSP share reflects the relatively sluggish growth in consumption in Indonesia and particularly Malaysia.

However, the pricing in this area is likely to remain predominantly oil indexed this decade. Japanese utilities intensified their interests in the U.S. LNG, but to accelerate the breakthrough in the oil-linked system, the Asian buyers would need to find more traditional sellers willing to sell them LNG at nonoil-indexed pricing *(IGU, 2015)*. Major LNG buyers in Japan and Korea expressed targets of around 20% of forwards LNG imports to be priced under GOG competition. Importing 20% of their gas demand from the U.S. will not be enough to fundamentally change the prevailing Asian Basin oil linked pricing dynamic *(J.P. Morgan, 2013)*. In addition, there is no guarantee that all the U.S. exports will be sold on a hub basis and the foreseen great Australian exports will be sold under oil price escalation.

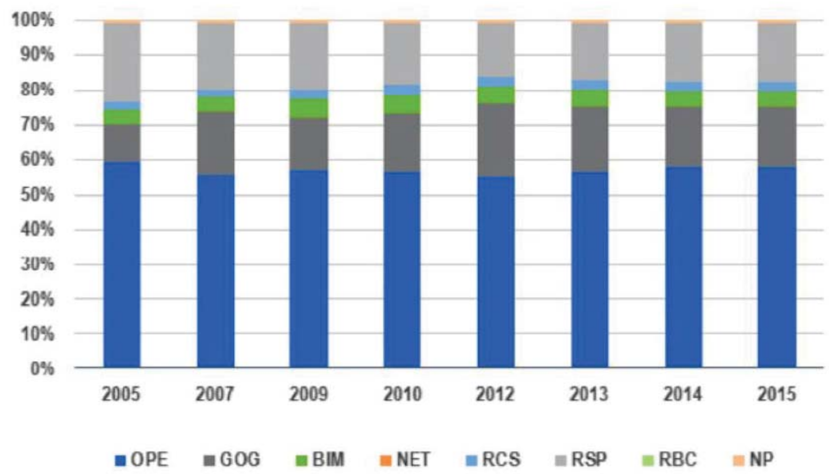


Figure 3.9 Asia Pacific price formation 2005-2015 (source: IGU Wholesale gas price survey 2016)

Price Trend in Asia (China & South Asia)

The changes in price formation mechanisms in this area have been dominated by China and India. There has been an increase in OPE from 35% in 2005 to 59% in 2015 largely at the expense of the regulated categories and BIM. The move from BIM to OPE reflected the change in the pricing of the Qatar LNG contract to India between 2007 and 2009, while the more recent rise in 2010 and 2012 was due to the start of pipeline imports into China from Turkmenistan, which are oil indexed under the contract, and a change in domestic production pricing in two provinces in China.

The changes in RSP and the corresponding rise in RCS was all due to the change in price formation in China as regulated prices were increased to economic levels. The decline in RBC largely reflected a change in some pricing in Bangladesh in 2009 to RCS and thereafter declining consumption in Myanmar. GOG is exclusively used in a spot LNG imports.

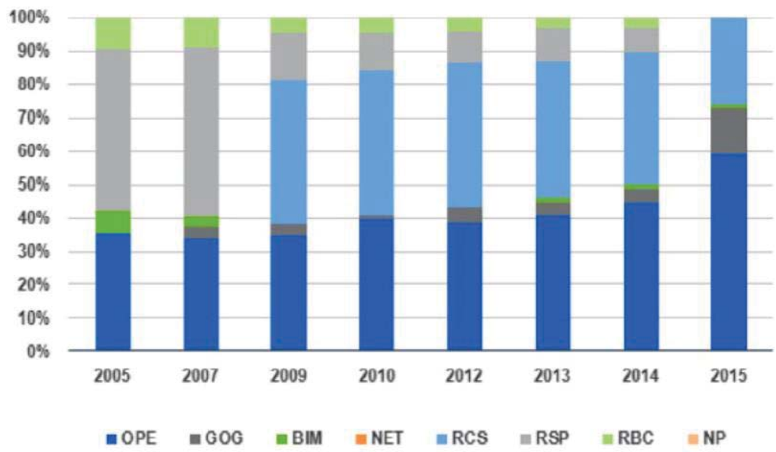


Figure 3.10 Asia price formation 2005-2015 (Source: IGU Wholesale price survey 2016)

Typical Gas Pricing formula based Oil Indexation

Accordingly, for many regions of the world, natural gas prices fluctuate in line with oil prices. This is true for most European markets (except for the United Kingdom) where the linkage between gas and oil prices is typically formalized by contract, so as oil prices move, gas prices automatically follow. In more recent years, the two largest gas markets in Europe, the UK and Germany, have set the two universally accepted reference points for natural gas prices; the UK National Balancing Point (NBP) and the German Border Price (GBP). In the United Kingdom, more than half the gas consumed is traded on spot markets with the virtual National Balancing Point (NBP) as the key trading point in the entry/exit based system.

Recent long-term contracts supporting large infrastructure projects between the United Kingdom and Qatar were at NBP prices rather than oil prices. The other half (of the UK gas market) is delivered according to terms of old North Sea prices, which incorporate many indices such as coal, inflation, electricity, fuel oil and gas oil. The German Border Price (GBP) is published in Germany by Bundesamt fur Wirtschaft und Ausfuhrkontrolle (BAFA) each month. BAFA publishes the total value of gas imports into the total value by the quantity to obtain the average gas prices known as the GBP *(Melling, 2010)*.

Under OPE, the exact formula used to calculate natural gas prices is contractually set, and these formulas vary among contracts. In general, the formula is typically a set base price plus the average price of oil at a designated benchmark over a preceding period of time multiplied by a coefficient. The coefficient essentially sets the relationship of the price per energy unit of oil versus natural gas, where a steeper curve indicates closer to a one-on-one relationship. A typical price formula for gas in NW Europe from the 1970s-1980s are as follows *(HalmØ, 2016)*;

$$P = P_o + A\, k_1\, (G_t - G_o) + (1\text{-}A)\, k_2\, (F_t - F_o)$$

Where: P = Contract price for gas

k_i = Conversion factor

G_t = Average price, light fuel oil for defined period

F_t = Average price, heavy fuel oil in defined period

A = Formula weight, light fuel oil (market share of fuel oil)

P_o, G_o, F_o = Gas and oil product prices at time of contract signing

Another important aspect of gas prices is that the Gas Year in Europe starts at 1st of October and ends on the 30th of September next year. Gas prices are indexed to the oil prices with a time lag of 6 months. Hence when oil prices vary dramatically, gas prices may exceed oil prices and cause major concern.

In the Asia-Pacific region, LNG contracts are typically based on the historical linkage to the Japanese Customs-cleared Price for Crude Oil (JCC or the Japanese Crude Cocktail). This is because when LNG trade first started in Japan, Japanese power generation was heavily dependent on oil, so early LNG contracts were linked to JCC in order to negate the risk of price competition with oil. The formula used in most of the Asia LNG contracts that were developed in the late 1970s and early 1980s can be expressed *(Statoil, 2010)* by:

$$P_{LNG} = (0.172 \times P_{JCCi}) + B$$

Where: 1 bbl crude oil = 5.8 MMBtu

Hence 1MMBtu = 1/5.8 bbl = 0.172 bbl

P_{LNG} = Price of LNG in \$/MMBtu

P_{JCCi} = Price of Japanese Crude Cocktail in \$/bbl

B = Constant in \$/MMBtu

The formula may also include an S-curve component to curb the LNG price at high or low oil prices. S-curves are clauses that change the relationship between oil and gas above or below thresholds. Instead of a linear link, gas prices do not rise/fall as much if oil prices rise/fall above certain thresholds. It reduces downside risk by forgoing some upside, it can even provide a floor/ceiling on prices. The oil index linked S-Curve contract regulates prices to protect consumers during periods of high oil prices while also protecting producers during low oil price ranges *(Wagner, 2015)*.

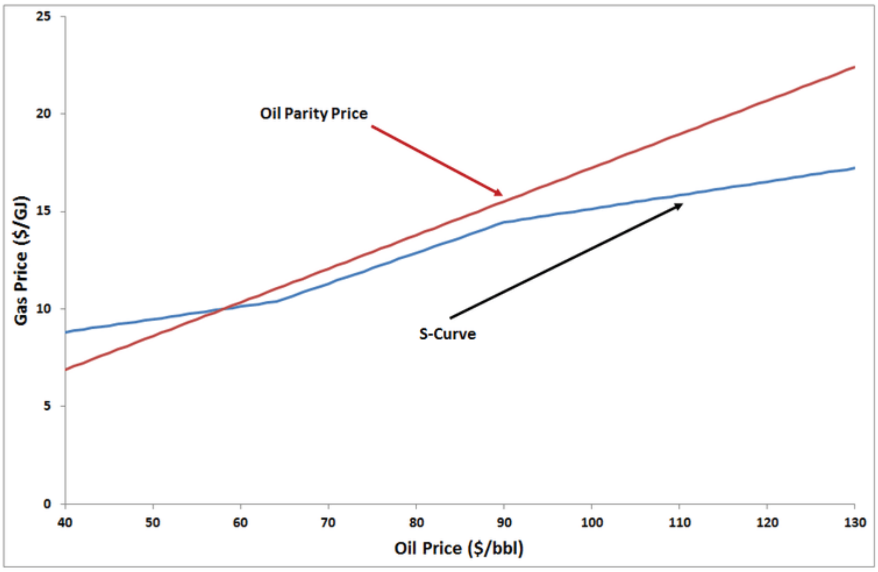


Figure 3.11 Japanese S-Curve Contract prices (Source: Leidos, Inc, EIA)

This pricing system applies oil supply and demand driven prices to natural gas and natural gas prices can continue to increase even when there is an oversupply of natural gas.

In contrast, a GOG pricing system generally reflects the balance between natural gas supply and demand, and includes multiple suppliers. As the ratio of natural gas supply to demand decreases, natural gas prices increase, which under the prevailing theory of supply and demand, may both temper demand and stimulate greater investment in natural gas production. Increases in natural gas production subsequently increase the supply to demand ratio which acts to moderate prices, beginning the cyclic behavior of new prices.

3.2 The Role of Liquefied Natural Gas (LNG)

Traditionally, natural gas is imported via transmission pipeline, connecting a producing region in one country to the domestic network of another one. This method originally is an extension of the local distribution system and become a choice for transporting large quantities of gas at the regional level. As it is seen as economically competitive, it accounts for nearly three quarters of the international market.

Pipeline transport entails two main limitations; the first is the dramatic increase in cost for long distances, especially when offshore sections are required. Over a few thousand kilometers, the feasibility of the pipeline is uncertain or indeed entirely precluded. Another limit is represented by the strong interdependence between exporter and importer that pipeline entails; in case of a problem upstream, the consumer cannot use the pipeline to import gas from other sources. Hence if the importing market cannot absorb all the volumes exported by the pipeline, the exporting country is forced to reduce its production. Those limits also play a central role in explaining why natural gas markets never evolved into a fully global market.

The changes in transportation costs affect the relative attractiveness of the pipeline and LNG options. In determining the most economic transportation method for a given supply route, distance and the transported volumes are the key factors. For short distances, pipelines, where feasible, are usually more economic, on the other hand, LNG is more competitive for long distance routes (*Halmø, 2016*). It can be seen in Figure 3.12, from supplier point of view, the cost acquired before transport is referred to LNG facilities and liquefaction costs (green line). Otherwise, if buyers intend to resell gas to another destination, there will be no cost of liquefaction to consider (red line). This is then become the basis of reload terminology in LNG arbitrage as discussed in Chapter 2.

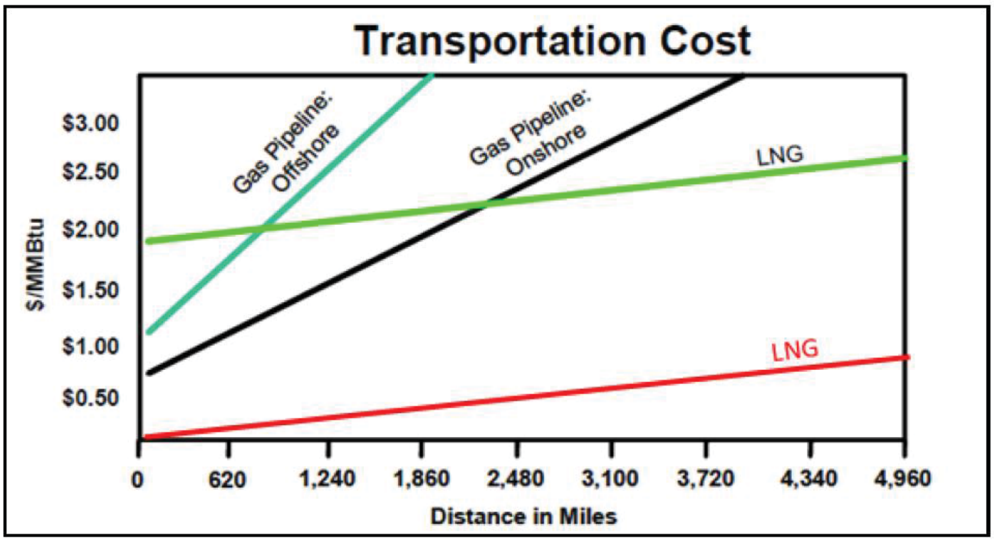


Figure 3.12 Indicative comparison of gas transportation costs for pipeline vs LNG transport cost. Note that red line for LNG cost for any LNG buyer, This is the basis for 'Reload' business (Source: HalmØ, 2016)

Liquefied natural gas (LNG) offers an alternative to piped gas whereby this evolution could be possible. In this process, gas is cooled to approximately −162°C at atmospheric pressure, becoming a fluid which can be transported by special tankers. LNG trade requires special terminals for liquefaction and regasification processes. The infrastructure is very expensive; export terminals, notably, can easily cost over 10 billion dollars per unit. However, once online, those terminals can supply natural gas to virtually any regasification terminal in the world, creating the technological conditions for a global market.

LNG represents approximately 30% of international natural gas trade and is used to meet both primary and peak natural gas demand. Japan and Korea, the two largest LNG importers jointly comprised 52% of the global LNG market in 2014. Both of these countries meet their entire natural gas demand with LNG. In contrast, other importers use LNG to balance regional supply and demand (i.e., Europe), or to meet a relatively small demand for gas (e.g., Taiwan, Puerto Rico, Dominican Republic, Chile, which jointly represent less than 10% of the global LNG market). Figure 3.14 & 3.15 shows the percent of natural gas share of imports and exports that was met by LNG in 2015 by global region and for selected countries.

In recent years, the Middle East (and Qatar in particular) has emerged as a swing producer, supplying both Atlantic and Pacific basins. Moreover, the expansion of the Panama Canal provides an opportunity for The U.S. Gulf Coast LNG to be traded in the Pacific Basin. Some of the challenges for inter-basin LNG trade are relatively high transportation costs compared to other energy products, and quality differences between Atlantic (lean) LNG streams and Pacific (rich) LNG streams.

Worldwide average LNG compositions							
	Nitrogen	Methane	Ethane	Propane	Higher HC	Gross/High Heath Value	Wobbe Index
	%	%	%	%	C4 + %	MJ/Sm3	MJ/Sm3
Algeria-Arzew	0,56	87,98	9	1,99	0,47	41,68	52,62
Algeria-Bethioua 1	1,2	87,59	8,39	2,12	0,7	41,01	51,96
Algeria-Bethioua 2	0,92	91,39	7,17	0,52	0	39,78	51,41
Algeria-Skikda	1,02	91,19	7,02	0,66	0,11	39,87	51,42
Egypt-Damietta	0,08	97,7	1,8	0,22	0,2	38,39	51,03
Egypt-Idku	0	97,2	2,3	0,3	0,2	38,61	51,19
Libya	0,69	81,57	13,38	3,67	0,69	44,02	53,82
Nigeria	0,08	91,28	4,62	2,62	1,4	41,76	52,87
Abu Dhabi	0,29	84,77	13,22	1,63	0,09	42,45	53,16
Oman	0,35	87,89	7,27	2,92	1,57	42,73	53,27
Qatar	0,36	90,1	6,23	2,32	0,99	41,58	52,65
Trinidad	0,03	96,82	2,74	0,31	0,1	38,82	51,29
USA-Alaska	0,17	99,73	0,08	0,01	0	37,75	50,62
Australia-NWS	0,09	87,39	8,33	3,35	0,84	42,74	53,4
Brunei	0,05	90,61	4,97	2,89	1,48	42,09	53,06
Indonesia-Arun	0,06	91,16	6,01	1,84	0,93	41,32	52,64
Indonesia-Badak	0,02	89,76	5,06	3,54	1,62	42,61	53,34
Malaysia	0,16	91,15	4,96	2,79	0,94	41,52	52,7

Table 3.4 Worldwide average LNG composition (Source: European Commission)

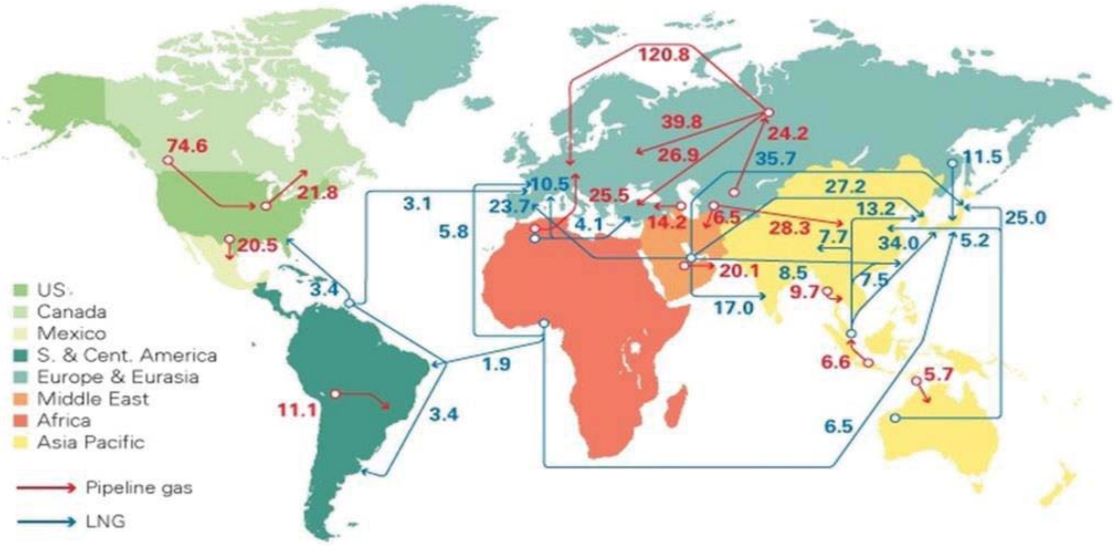


Figure 3.13 Worldwide overseas natural gas transportation (Source: BP Statistical Review 2016)

Total LNG trade reached 244.8 MT in 2015 which marks the largest year ever for LNG trade, surpassing the previous high of 241.5 MT in 2011. The startup of several new projects in Australia and Indonesia lead to higher supply, ramping up significantly enough to offset outages in Yemen, Egypt and Angola. Although the Pacific Basin remains the largest source of demand, growth was driven by Europe and the Middle East.

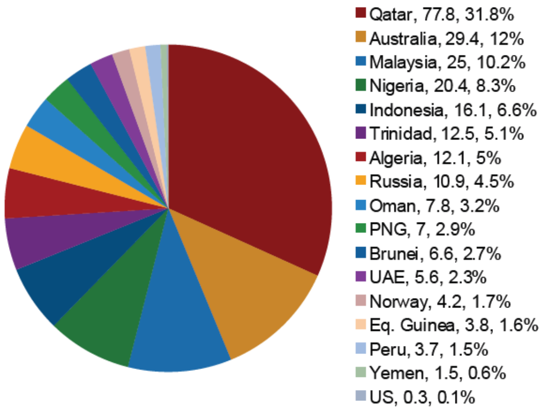


Figure 3.14 LNG exports and market share by country - in MTPA (Source: IHS, IGU World LNG Report 2016)

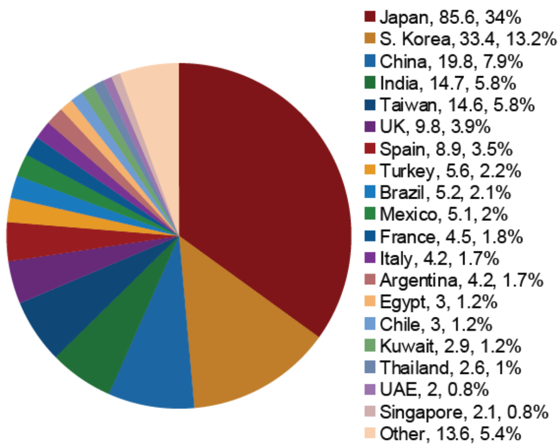


Figure 3.15 LNG imports and market share by country - in MTPA (Source: IHS, IGU World LNG Report 2016)

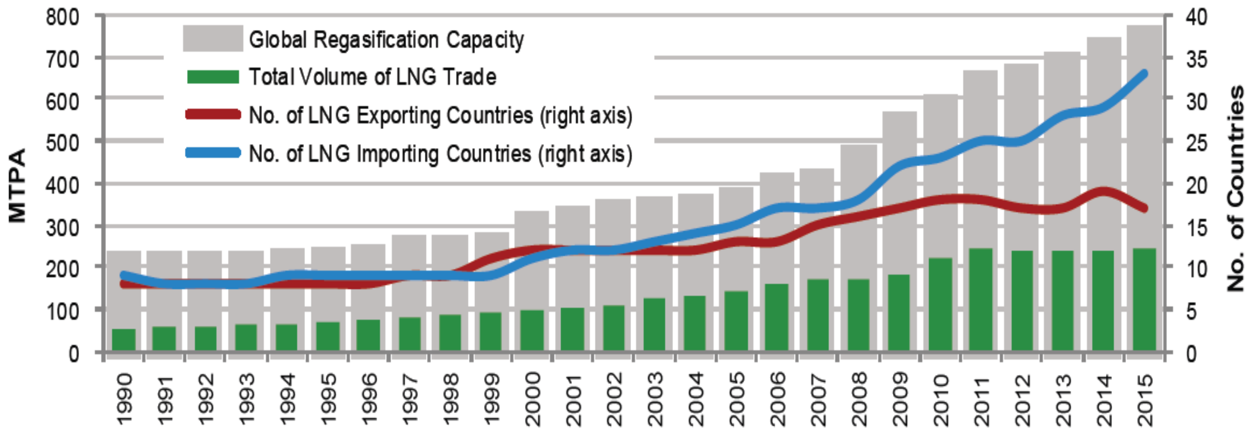


Figure 3.16 LNG trade volumes 1990-2015 (Source: IGU World LNG Report 2016, IHS, EIA)

3.2.1 The LNG Market

World LNG Consumer

Over the past decade, the LNG market has steadily expanded: from approximately 210 BCM of natural gas (equal to 157 MT of LNG) in 2006 to 340 BCM in 2015 (equal to 244.8 MT of LNG). Eastern Asia traditionally accounts for the largest part of the market. In fact, distance from the producing countries and geographical features such as insularity or limited availability of local energy sources created the conditions for an early and massive development of the LNG technologies in the region. In 2013, Eastern Asian countries accounted for three quarters of the global LNG consumption. Three final markets in particular provided the bulk of demand are Japan, South Korea and China.

- The Japanese economy is heavily industrialized, with large primary energy consumption combined with a particularly small domestic production of energy. As a consequence, it relies on imported fossil fuels both for transport (oil) and power generation (mainly natural gas). In 2010, Japan imported 66 MT of LNG, 32% of the world total – exclusively via LNG. After the Fukushima disaster, Japan substituted a significant share of its nuclear power generation with natural gas, increasing its dependence on LNG imports. Thus in 2015 Japan imported 85.6 MT, 35% of the world total.
- South Korea is similarly dependent on imported gas for power generation, and it is the second final market at the global level; it imported 33 MT of LNG in 2015, 13% of the world total.

- China which imported 19.8 MT, 8% of the world total. Unlike Japan and South Korea, the Chinese economy currently has a low level of dependence on imported energy, since it retains a large domestic production. However, its increasing final consumption and the need to reduce coal consumption in several polluted regions are driving a significant increase in natural gas imports, both via pipeline and LNG.

Besides those three large consumers, other growing Eastern Asian economies represent a dynamic market for LNG. In particular, Taiwan is a relatively mature market, while India is set to become one of the most important players at the regional and global levels in the coming decades. These countries imported 29 MT in 2015, i.e. slightly more than 12% of the world total.

Outside Eastern Asia, the most important LNG regional market is Europe. Demand in the region has been significantly reduced following the economic crisis and massive subsidies provided to renewable sources, which undermined final market for natural gas in the power generation sector. Moreover, the flexibility of LNG supplies allowed exporters to reroute their flows towards more dynamic markets after the onset of the current crisis. As a consequence, EU overall demand of LNG dropped from 58 MT in 2011 to 33 MT in 2013. Starting in 2014, the decline in European LNG consumption that has occurred since 2011 appears to have ended, with 2015 imports rising up to 37.5 MT as supply was redirected away from weaker Asian markets and Asia-NBP price differentials narrowed significantly. Four countries constitute the EU core markets: Spain (9 MT), the UK (9.8 MT), France (4.5 MT) and Italy (4.2 MT). Germany, the main European gas market, has no regasification capacity, relying on piped gas from Russia, Norway and Netherlands. The only other relevant natural gas market in the region, Turkey, imported 5.5 MT natural gas via LNG in 2015, and was not affected by the EU's economic crisis.

Latin America is a smaller but more dynamic regional market. Overall, its consumption amounted to 14.6 MT in 2015 with Mexico and Brazil as the larger importers. The increasing role of Latin America is driven by the general economic growth and is expected to continue, albeit at a slower pace. Other consumers from Middle Eastern; Jordan, Kuwait and UAE, are also minor importers with limited growth expectations.

World LNG Producer & Supplier

LNG production is currently dominated by a single giant player; Qatar. Qatar has relatively limited oil reserves but massive gas reserves ~ 24.5 TCM, equal to approximately 160 years at current production levels *(EIA, 2014)*. Due to its large internal production and significant international investments at the beginning of the 2000s, the country has dominated LNG markets for a decade. Exploiting its geographical position, Qatar is a major supplier to both Asian and European importers, partially rerouting its flows according to the evolution of final demand, a strategy which is not available to competitors reliant on pipelines. In 2015, Qatar exported 77.6 BCM via its LNG trains.

There are other four medium sized producers strongly focused on the Eastern Asian market; Malaysia, Australia, Indonesia and Nigeria. Malaysia and Australia together export more than 54 BCM of LNG, 16% of the LNG global market. Their gas industries are growing and both are expected to increase their export volumes. Indonesia on the other hand is a mature producer which is striving to maintain its current export levels (16 MT) and to supply its rapidly growing domestic market. Nigeria, by contrast, has a decreasing internal consumption and large reserves, but it is facing a deteriorating security environment, which prevents new international investments in upstream and export capacity. As a consequence, exports from the country are likely to remain at their current level (20 MT).

Other major supplies of LNG are small producers which export exclusively through LNG. The largest is Trinidad and Tobago, a small insular state in the Caribbean, which exported 12.5 MT in 2015 and is a key player in the region. Other relevant small producers are Oman (7.8), Brunei (6.6 MT) and Yemen (1.5 MT), followed by several other smaller ones.

Natural gas producing countries that export only a minor part of their total production via LNG represent a further category. The most important is Russia, the world's biggest exporter of gas, which in 2015 supplied more than 200 BCM of natural gas to international trade, 10.9 MT of which via the Sakhalin liquefaction terminal to East Asia market. Algeria exported 12 MT in 2014, while a much smaller amount was exported by Norway (4.2 MT). Incidentally, all three countries are major suppliers of the EU market via pipeline, thereby limiting the incentives to promote a massive development of their LNG capacity to supply their core markets.

Short term supply and demand

According to IGU LNG report 2016, the short-term LNG demand will reflect the same trends that occurred in 2015. The Pacific basin will likely remain the primary driver of demand growth despite recent signs of weakness, owing to contracted supply ramp-ups. However, there are potential downsides to the outlook from more nuclear restarts in Japan and additional economic

	Algeria	Angola	Australia	Brunei	Egypt	Equatorial Guinea	Indonesia	Malaysia	Nigeria	Norway	Oman	Papua New Guinea	Peru	Qatar	Russia	Trinidad	United Arab Emirates	United States	Yemen	Re-exports Received	Re-exports Loaded	2015 Net Imports	2014 Net Imports	2013 Net Imports	2012 Net Imports	2011 Net Imports
Egypt	0.35	-	0.07	-	-	0.13	-	-	0.07	0.06	-	-	-	1.70	-	0.06	-	-	-	0.59	-	3.02	-	-	-	-
Africa	0.35	-	0.07	-	-	0.13	-	-	0.07	0.06	-	-	-	1.70	-	0.06	-	-	-	0.59	-	3.02	-	-	-	-
China	0.38	-	5.73	-	-	0.20	2.90	2.98	0.44	0.06	0.06	1.47	-	4.93	0.19	0.06	-	-	0.30	0.14	-	19.83	19.81	18.60	14.77	12.84
India	-	-	0.84	-	-	0.79	0.32	0.13	2.22	-	0.59	0.07	0.07	8.81	-	0.24	0.12	-	0.32	0.41	(0.27)	14.67	14.48	12.92	13.99	12.74
Pakistan	-	-	0.19	-	-	0.19	-	-	0.19	-	-	-	-	0.41	-	-	-	-	-	0.13	-	1.11	-	-	-	-
Asia	0.38	-	6.76	-	-	1.18	3.22	3.11	2.85	0.06	0.65	1.53	0.07	14.15	0.19	0.30	0.12	-	0.63	0.69	(0.27)	35.61	34.29	31.52	28.76	25.58
Japan	0.75	-	18.71	4.30	-	0.46	6.02	15.56	4.56	0.06	2.36	3.97	0.15	14.59	7.78	0.06	5.42	0.16	0.22	0.46	-	85.58	88.69	87.79	87.26	78.76
Malaysia	0.40	-	0.33	0.19	-	0.06	-	-	0.19	0.14	0.13	-	-	0.13	-	-	-	-	-	-	-	1.57	1.60	1.62	-	-
Singapore	-	-	0.65	-	-	0.66	0.26	0.07	-	-	-	-	-	0.48	-	0.11	-	-	-	0.06	(0.21)	2.10	1.89	0.94	-	-
Korea	0.37	-	1.93	1.29	-	0.72	3.90	3.69	1.29	-	4.12	0.21	-	12.36	2.69	0.05	-	-	0.53	0.47	(0.28)	33.36	37.98	40.86	36.78	35.73
Taiwan	-	-	0.26	0.69	-	0.07	2.33	2.39	0.06	0.07	-	1.28	-	6.99	0.26	-	-	0.17	-	0.06	-	14.63	13.59	12.83	12.78	12.18
Thailand	-	-	0.20	-	-	-	0.07	0.13	0.13	-	-	-	-	2.06	-	-	-	-	-	-	-	2.58	1.31	1.42	0.98	0.72
Asia-Pacific	1.52	-	22.09	6.48	-	1.96	12.58	21.85	6.22	0.27	6.61	5.47	0.15	36.61	10.73	0.23	5.42	0.33	0.75	1.05	(0.48)	139.82	145.05	145.46	137.80	127.40
Belgium	-	-	-	-	-	-	-	-	-	-	-	-	-	2.62	-	-	-	-	-	-	(0.73)	1.89	2.13	1.10	1.91	4.45
France	3.27	-	-	-	-	-	-	-	0.80	0.35	-	-	0.20	0.28	-	-	-	-	-	-	(0.35)	4.54	5.17	5.80	7.48	10.68
Greece	0.27	-	-	-	-	0.06	-	-	0.09	-	-	-	-	-	-	-	-	-	-	-	-	0.42	0.40	0.51	1.07	0.95
Italy	0.03	-	-	-	-	-	-	-	-	-	-	-	-	4.13	-	-	-	-	-	0.04	-	4.21	3.35	4.25	5.23	6.43
Lithuania	-	-	-	-	-	-	-	-	-	0.33	-	-	-	-	-	-	-	-	-	-	-	0.33	0.11	-	-	-
Netherlands	0.17	-	-	-	-	-	-	-	-	0.70	-	-	-	0.60	-	-	-	-	-	-	(0.84)	0.63	0.80	0.32	0.61	0.56
Poland	-	-	-	-	-	-	-	-	-	-	-	-	-	0.08	-	-	-	-	-	-	-	0.08	-	-	-	-
Portugal	0.17	-	-	-	-	-	-	-	0.93	0.06	-	-	-	0.17	-	0.06	-	-	-	-	(0.23)	1.16	1.25	1.32	1.66	2.21
Spain	2.81	-	-	-	-	-	-	-	2.92	0.54	0.06	-	0.73	2.27	-	0.84	-	-	-	-	(1.27)	8.91	11.85	9.36	14.22	17.22
Turkey	2.86	-	-	-	-	-	-	-	1.10	0.14	-	-	-	1.20	-	0.12	-	-	-	0.13	-	5.55	5.32	4.24	5.74	4.58
United Kingdom	0.32	-	-	-	-	-	-	-	-	0.13	-	-	-	9.35	-	0.20	-	-	-	-	(0.20)	9.79	8.47	6.84	10.45	18.63
Europe	9.89	-	-	-	-	0.06	-	-	5.85	2.26	0.06	-	0.93	20.70	-	1.22	-	-	-	0.17	(3.63)	37.51	38.85	33.74	48.37	65.72
Argentina	-	-	-	-	-	0.12	-	-	0.83	0.50	-	-	-	0.31	-	1.94	-	-	-	0.50	-	4.19	4.68	4.93	3.82	3.19
Brazil	-	-	-	-	-	0.19	-	-	1.75	0.64	-	-	-	1.25	-	0.95	0.06	-	-	0.38	-	5.22	5.78	4.44	2.52	0.62
Chile	-	-	-	-	-	0.13	-	-	-	0.13	-	-	-	-	-	2.74	-	-	-	-	-	3.01	2.78	2.86	3.03	2.80
Dominican Republic	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.95	-	-	-	-	-	0.95	0.92	1.09	0.96	0.72
Puerto Rico	-	-	-	-	-	-	-	-	0.19	-	-	-	-	-	-	0.94	-	-	-	0.07	-	1.19	1.24	1.20	0.97	0.54
Latin America	-	-	-	-	-	0.44	-	-	2.77	1.27	-	-	-	1.56	-	7.52	0.06	-	-	0.94	-	14.56	15.41	14.51	11.30	7.88
Israel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.12	-	-	-	0.01	-	0.13	0.12	1.56	2.11	2.42
Jordan	-	-	0.07	-	-	-	-	-	0.71	-	-	-	-	0.58	-	0.20	-	-	-	0.25	-	1.81	-	-	-	-
Kuwait	-	-	0.20	0.13	-	0.07	0.07	0.07	0.42	-	0.46	-	-	0.69	-	0.41	-	-	-	0.40	-	2.90	2.73	1.08	1.24	1.18
United Arab Emirates	-	-	0.21	-	-	-	0.06	-	-	-	-	-	-	1.26	-	0.17	-	-	-	0.34	-	2.03	1.39	0.41	-	-
Middle East	-	-	0.47	0.13	-	0.07	0.13	0.07	1.12	-	0.46	-	-	2.53	-	0.90	-	-	-	1.00	-	6.88	4.24	3.06	3.35	3.61
Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.41	-	-	-	0.06	-	0.47	0.42	0.75	1.28	2.42
Mexico	-	-	-	-	-	-	0.19	-	1.49	0.06	-	-	2.54	0.50	-	0.30	-	-	-	0.07	-	5.13	6.87	5.97	3.55	2.92
United States	-	-	-	-	-	-	-	-	-	0.25	-	-	-	-	-	1.60	-	-	0.15	-	(0.18)	1.82	1.23	1.83	3.26	5.93
North America	-	-	-	-	-	-	0.19	-	1.49	0.31	-	-	2.54	0.50	-	2.31	-	-	0.15	0.13	(0.18)	7.43	8.53	8.54	8.09	11.27
2015 Exports	12.14	-	29.39	6.61	-	3.84	16.12	25.03	20.36	4.23	7.78	7.00	3.68	77.75	10.92	12.53	5.60	0.33	1.53	4.57	(4.57)	244.84				
2014 Exports	12.58	0.34	23.25	6.18	0.33	3.72	15.88	24.90	19.37	3.68	7.86	3.49	4.33	76.57	10.57	14.38	5.78	0.25	6.68	6.23	(6.23)		240.13			
2013 Exports	10.90	0.33	22.18	7.05	2.81	3.89	17.03	24.68	16.89	2.97	8.63	-	4.26	77.18	10.76	14.63	5.40	-	7.23	4.59	(4.59)			236.83		
2012 Exports	11.03	-	20.78	6.85	5.08	3.75	18.12	23.11	19.95	3.41	8.08	-	3.89	77.41	10.92	14.40	5.57	0.19	5.13	3.45	(3.45)				237.67	
2011 Exports	12.59	-	19.19	6.84	6.42	3.89	21.43	24.99	18.75	2.86	7.90	-	3.76	75.49	10.49	13.94	5.85	0.33	6.65	2.33	(2.33)					241.39

Note: Indonesia, Malaysia, and the UAE conducted domestic LNG trade in 2012- 2015. These volumes are not included above as they do not reflect international trade between countries. Sources: IHS, IGU

Table 3.5 World LNG Trade volume in MTPA (Source: IGU World LNG Report 2016) weakness in East Asia (particularly China). European demand fundamentals are set to remain weak but a large increase in Intra-Pacific trade will likely shift more Atlantic and Middle East volumes to Europe, giving it significant growth potential. Downward pressure on LNG prices from an expected abundance of supply and lower oil prices could lead more countries to quickly enter the market, particularly through the utilization of FSRUs (Floating Storage and Regasification Unit).

On the supply side, the first cargoes from the U.S. Gulf of Mexico has been delivered in February 2016, but the majority of the increase in supply will come from the Pacific Basin, particularly SE Asia and Australia. The majority of under-construction capacity in the U.S. is not expected to be completed until 2017 and later.

3.2.2 LNG Contract Structure

There are two main LNG contracts agreements in the market; long term (SPA/Sales and Purchase Agreement) and non-long term; short-medium term & spot trade (MSA/Master Sales Agreement). Traditional long term LNG contract address LNG quantity, price, duration, and transportation responsibility. The quantity of LNG that the buyer must purchase is usually "take or pay", in which the buyer must pay for the agreed volumes regardless of whether or not they take the volumes. An initial "buildup" period that is not subject to the take-or-pay requirements may be specified to allow the importing market to absorb and find buyers and to accommodate potential delays in the completion of the liquefaction plant. After the buildup period has ended, the quantity generally remains constant over the duration of the contract, although there may be some limited volume flexibility, such as allowing the buyer to reduce the volume obligation by a fixed amount. These traditional terms of long-term contracts are changing, with an increasing number of contracts that incorporate divertible options, allowing a buyer to re-route their LNG shipments as long as the new destination does not compete with other seller deliveries at the specified import terminals.

The shifting in the terms of long term contracts have been promoted by the generally lower GOG prices compared to oil indexed prices in recent years. In addition to clauses to allow cargo re-destination and resale, long term contracts are increasingly using hybrid pricing schemes in which a portion of fixed volume sales (i.e. 10% to 30%) may be under GOG prices with the remainder under oil indexation. A third area of ongoing change in long term contracts is the inclusion of opportunities for price re-negotiation (i.e. every 3-5 years) *(Leidos, 2014)*.

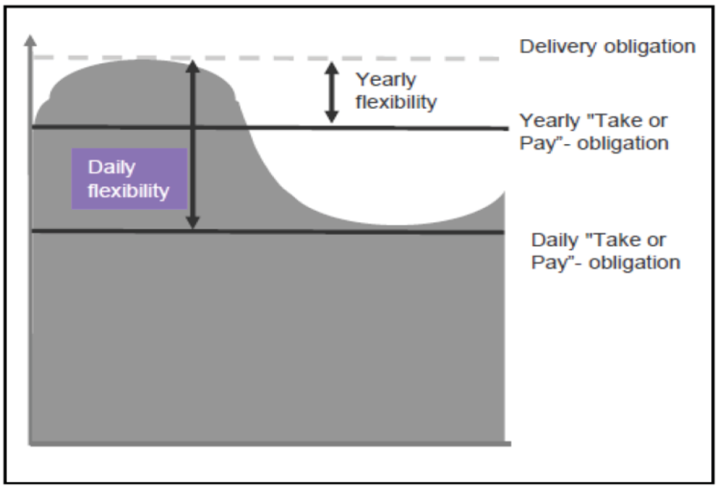


Figure 3.17 Structure of traditional long term contract with flexibility to the buyer (Source: StatOil, 2010)

In recent years, the proliferation of flexible-destination contracts and an emergence of portfolio players and traders has allowed for the growth of non-long term LNG trade, which was accelerated by shocks like those that resulted from the Fukushima disaster and the growth of shale gas in the United States *(IGU, 2016)*. In contrast to long-term contracts, short-term and spot trade contracts typically include a divertible option that allows re-destination of the contracted cargo. Therefore, the major driver in spot and short-term trade growth has been the increased use of divertible options in flexible contracts (both short and long term) that allows companies to arbitrage *(IGU, 2013)*.

The majority of trade growth has come from short-term trade (all volumes traded under agreements of less than two years). In 2015, short-term trade reached 65.9 MT, or 26% of total gross traded LNG. The incremental of short term trade came from the emergence of several new importers, primarily dependent on spot imports, and the commissioning of three new liquefaction plants although price differentials between basins declined significantly in 2015.

Medium-term contracts (between 2 and <5 years) have also become a more prevalent part of the non-long term trade, though they remain small compared to short-term volumes. Volumes delivered under medium-term contracts actually declined, from 9.7 MT in 2014 to 6.0 MT in 2015, as several contracts expired and others were filled increasingly with short-term volumes. Medium term contracts offer countries with uncertain future LNG needs, more security of supply for their minimum requirements than would be provided by short-term imports. They are favored by buyers hesitant to sign long-term contracts because of the availability of uncontracted and flexible supply.

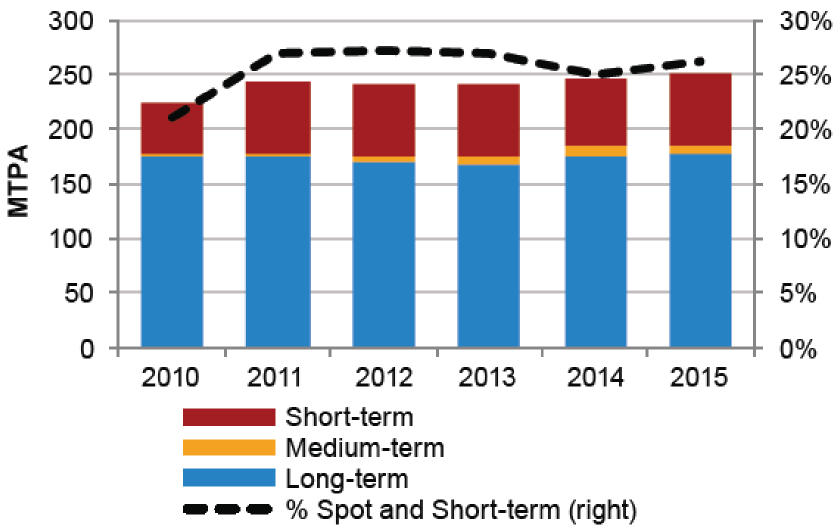


Figure 3.18 Short, medium and long term trade (Source: IHS, IGU World LNG Report 2016)

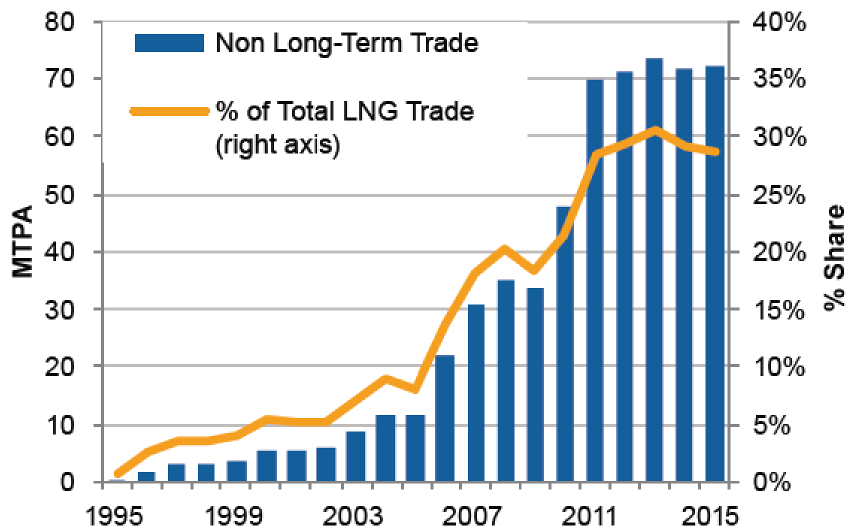


Figure 3.19 Non long term trade (Source: IHS, IGU World LNG Report 2016)

According to IGU 2016, the fast growth of non-long term contract is the result of several factors such as;

- The growth in LNG contracts with destination flexibility
- The increase in the number of exporters and importers
- The lack of domestic production or pipeline imports in Japan, South Korea and Taiwan

- The decline in competitiveness of LNG relative to coal (chiefly in Europe) and shale gas (North America)
- The large disparity between prices in different basins from 2010 to 2014
- The faster development timeline and lower initial capital costs of FSRUs compared to onshore regasification
- The large growth in the LNG fleet, especially vessels ordered without a long-term charter which has allowed low-cost inter-basin deliveries.

Contract structures affect the liquidity of the natural gas market. With the expanding role of the portfolio LNG players, there are the increasing potential for destination flexibility in LNG contract that increase “diversions” of cargos between markets and increase re-exporting of cargos, all of which increase liquidity and contribute to greater linkages between regions and markets. These new linkages between markets and the growing supply-side competition for premium Asian customers will expectedly provide some convergence of regional prices.

3.3 Market Evolution

The three principal markets (United States, South East Asia and Europe) faced stagnating domestic production alongside growth in local demand for gas in the beginning of the century. Growing demand for imports favored suppliers allowing them to set their terms. The main pricing principle was long-term indexed contracts where the price of gas was set based on the cost of alternative fuel, such as oil products.

The gas supplies were mainly delivered via pipelines as LNG capacities were limited. The long-term contracts and take-or-pay obligations were explained by the need to make large investments upstream. But by the end of the 2000s the situation has changed. Technological breakthroughs in the U.S. added to the reserves available for the production of large deposits of shale gas. Intensified exploration around the world led to discoveries of new prospective regions with large reserves.

The growth of LNG liquefaction capacities more than doubled over a decade. Falling demand, as a result of the global economic downturn and increasing supply, made European gas hubs that modeled after the the U.S. Henry Hub much more liquid. As a result, customers started to set terms on the international gas market and have a greater choice of supplies.

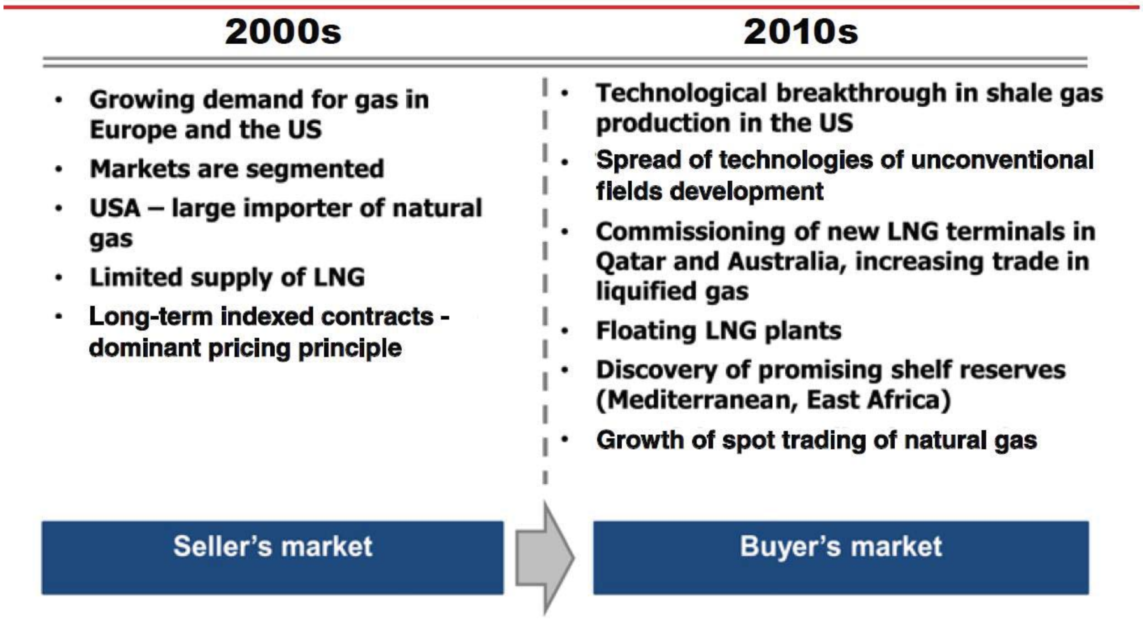


Figure 3.20 Global gas market shifts to buyer's market (Lukoil, 2014)

This downstream market liberalization appears to be having consequences on upstream market. Competition-based market encourages the development of stage where natural gas can be traded (i.e., hubs), which facilitate comparison of prices from competitive sellers and provide natural pricing benchmarks.

At the level of international trades, the natural gas market has traditionally been organized as bilateral trades between buyers and sellers who self-searched for their trade partners. In recent years, the international trades have increased with growth in LNG spot market trades. This trades are managed by LNG suppliers and increased by brokers.

The ongoing developments in international natural gas market structure (i.e., hub development) and gas trade may impact the further growth of LNG suppliers and buyers, increase gas liquidity and market competition, and reduce market risks. These developments will encourage greater efficiencies and lower global average natural gas prices. Furthermore, this will make natural gas more competitive compared to other energy options, thereby increasing natural gas demand.

3.3.1 Supply-side Drivers

In 2016, the role of natural gas in the global energy mix appears uncertain. Economic, geopolitical, and policy constraints have slowed demand growth in Asia and led to a decline in demand in Europe. On the other hand, suppliers in Australia, the Middle East, Africa, and North

America who bet on old forecasts for Asian demand growth are bringing plenty of new supplies to the market. With the influx of added supplies outpacing demand growth, the world is faced with a global supply glut and depressed natural gas prices, and suppliers with large inflexible investments in natural gas assets are scrambling to stay afloat.

New Development of Conventional Gas

Along with the progress in development of unconventional resources, new, large conventional gas reserves are being discovered in new regions of the world. The discovery of large gas reserves offshore East Africa has resulted in multiple liquefaction proposals in Mozambique (44 MTPA) and Tanzania (20 MTPA). Due to additional clarity in 2015 on field development plans and commercial momentum, some East African projects could begin operations in the first half of the next decade. However, project risks in both countries include evolving domestic demand requirements, a lack of infrastructure, and regulatory uncertainty.

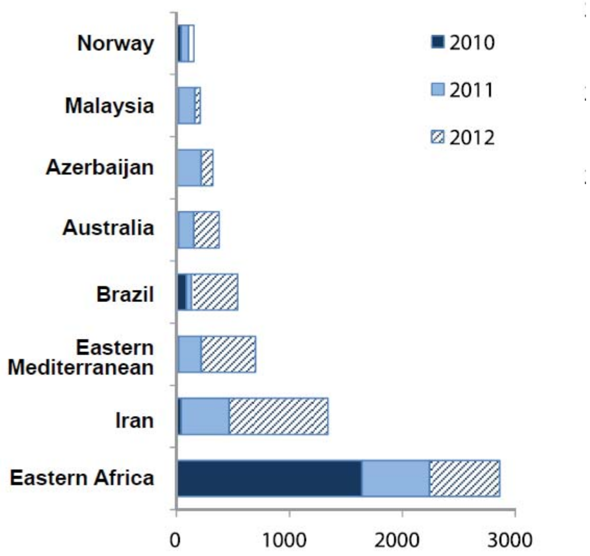


Figure 3.21 Conventional gas fields discoveries in 2012 in BCM (Source: IHS CERA, EIA, Ernst & Young)

South-East Africa has a good location for LNG deliveries to the Asia Pacific region. Taking into account growing interdependence between markets, competition in Europe will improve. To minimize costs, Chinese and Indian oil and gas companies are acquiring stakes in production projects around the region.

In Europe, the shelf of the Eastern Mediterranean may become a new global source of LNG by the beginning of the next decade. According to various estimates, aggregate recoverable offshore reserves of Israel, Cyprus, Lebanon and Egypt amount to several TCM of gas.

Considering the clouded international relations in the region as well as low domestic consumption, these countries will choose LNG as a way of exporting their gas surplus *(Lukoil, 2014)*.

Unconventional Gas Development

The development of unconventional energy resources, including shale gas and coalbed methane are generally expected to be the primary sources of growth in global natural gas supplies. As stated in chapter 2, globally two-thirds of the increase in natural gas demand through 2040 is forecast to be met by unconventional gas where unconventional supplies in 2040 are expected to account for 35% of global gas production. Additional natural gas reserves in other unconventional reservoirs include other tight formations and coalbed methane. In addition to the technological developments that launched the shale gas revolution in the U.S., new technological advances for exploiting tight formations continue to be made, suggesting the potential for continued development in technologies for extracting this resource *(NETL, 2013).*

For decades the North American oil and gas industry was trying to master the production of unconventional gas resources. The development is supported by technological breakthroughs in hydraulic fracturing and directional drilling, low population density in production regions and availability of water resources. The growth in production of unconventional gas will allow the U.S. to start exporting gas by the middle of the current decade, and, according to various estimates, to become a net exporter of gas by 2018.

Several other countries that have begun exploration of these types of resources, and shale gas in particular are Canada, China, Australia, Poland, Argentina, the Ukraine, India, Indonesia, Hungary, and others. Canada already produces some tight gas including small amounts of shale gas. China, the country with the largest amount of shale gas reserves, generally lacks the infrastructure (water, pipeline, etc.) to support near term use. However, the massive future Chinese demand for natural gas is a strong motivator for development of this indigenous resource. In China, 2014 targets from the Ministry of Land and Resources (MLR) indicate shale gas and CBM could grow to reflect at least 50% of domestic natural gas production by 2030. Wood Mackenzie has suggested that beyond 2025, there is a possibility that the successful development of China shale will influence a major portion of the supply/demand balance *(PE, 2013)*. This may be analogous to the effect of the U.S. shale gas development on the natural gas market in recent years (i.e., price impact, LNG oversupply, shift from coal).

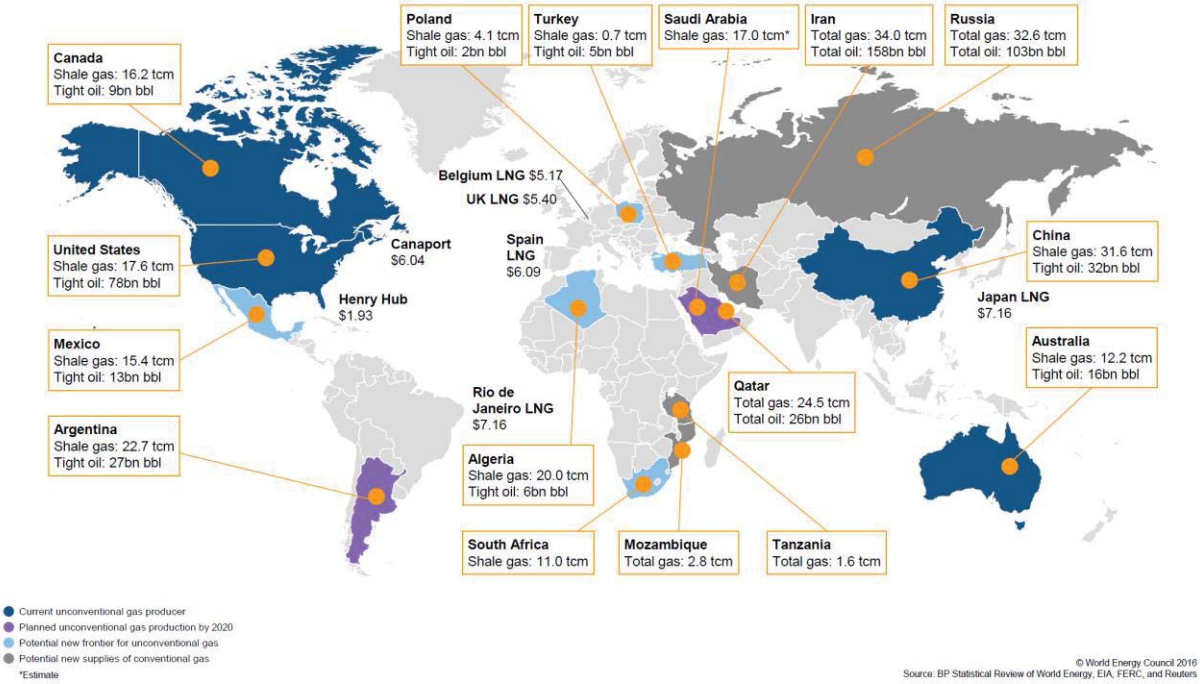


Figure 3.22 World unconventional gas phenomenon (Source: World Energy Council 2016)

Saudi Arabia has also made notable progress and is likely to become a commercial shale gas producer before 2020. Argentina's ventures into tight oil are also advancing at a notable pace. While there is strong interest in development of European shale gas reserves, development has been slowed by public concerns such as nearby high population densities and environmental impacts *(Golden Rules for Golden Age of Gas, 2012)*. For Russia, with its massive, developed, conventional gas supply, shale gas development "will be a minority pursuit for marginal players" *(PE, 2013/2014)*. Overall, within the next decade, some countries are expected to begin or to expand their development of shale gas activities. While some of these sources will not be economically recoverable, production at meaningful levels from reserves that are economically recoverable is still years away *(Leidos, 2014).*

CBM (Coal Bed Methane) is much more developed in the U.S. than in other countries. The U.S. CBM production began in the 1980's representing around 7 - 10% of total US natural gas production in recent years, and roughly 80% of global CBM production. Around 13 BCM (450 BCF) of coalbed methane was produced outside the US in 2012, primarily in Australia and Canada *(EIA, 2014)*.

While Australia's shale reserves are estimated at 12.2 TCM, shale gas development takes a back seat to Australia's world leading CBM projects. In eastern Australia, Queensland accomplished a world first in late 2014, using CBM as feedstock to produce LNG. CBM development represents about 40% of Eastern Australian domestic gas production in 2014 *(QA, 2015)*. As part of Australia's natural gas strategy to position itself as a major LNG supplier to Asia, CBM will grow substantially to support domestic consumption and LNG exports from the East Coast.

Pipelines

The evolution of the pipeline systems to serve growing economies will have a significant impact on natural gas supply, consumption, and the course of the LNG trade. Even the proposal of a pipeline may affect market dynamics. In addition to these, there are many gas pipelines in conceptual, proposed, planned, and developmental stages that will define the gas market infrastructure and supply demand characteristics of the market *(Leidos, 2014)*. Pipeline competition in stranded major markets can have large impact on the gas market with the possibility of making major markets like Japan, South Korea, and China behave more like the European market.

Pipeline based trade involve only pipeline and compressor stations. However, long distance pipelines usually involve transit countries which incidentally expose the risk of geopolitical interests of the various parties that are involved. A pipeline route that is subject to geopolitical interests may not always be the most economic route. Another issue of pipeline is different trade patterns. Pipeline projects have trading flexibility only to the extent that pipeline infrastructure is in place to redirect the required volumes to the market were the best price can be achieved. Pipeline trade is therefore restricted to regional trade patterns were price differentials are usually marginal.

LNG Capacities

A potential evolution towards a liquid market may come in the next decade, but it depends on the further expansion of the LNG export capacity and a larger diffusion of the import terminals, both in terms of capacity and the countries involved. A significant boost to the size of the LNG market will come from projects currently under construction and which are expected to be commissioned by the end of this decade. The most important aspect is liquefaction capacity, since import capacity is currently oversized, even if unevenly distributed. Local investments in more dynamic markets will be required, but in general regasification capacity is unlikely to represent a bottleneck for the market at this stage.

The largest share of this massive capacity expansion will take place in Australia. If all the new plants are fully utilized, the country's liquefaction capacity will expand from 32 MTPA in 2015 to 87 MTPA in 2021, surpassing Qatar as the world's largest LNG exporter. Indeed, more than half of the capacity currently under construction is located in Australia's offshore territory, allowing the country to exploit its vast reserves and its proximity to the Eastern Asian markets.

Russia and the United States also see their share in the LNG market increase dramatically. In Russia, Yamal LNG has been under construction and the first train is expected to come online in 2017, with all trains to be operational by 2019. If any delay, that will relate to the difficulty of Arctic environment and financing issues related to sanction against Russia. Once completed, it will bring Russia's capacity to 26 MTPA in 2021. In the U.S., the availability of cheap natural gas from non-conventional fields has created strong incentives for energy operators to export LNG, in order to capitalize on the differential between low domestic prices and high international prices. The Sabine Pass plant has produced its commissioning cargo in February 2016. Three of the under construction project are expected online by 2019 which leading to capacity of 15 MTPA (IGU, 2016).

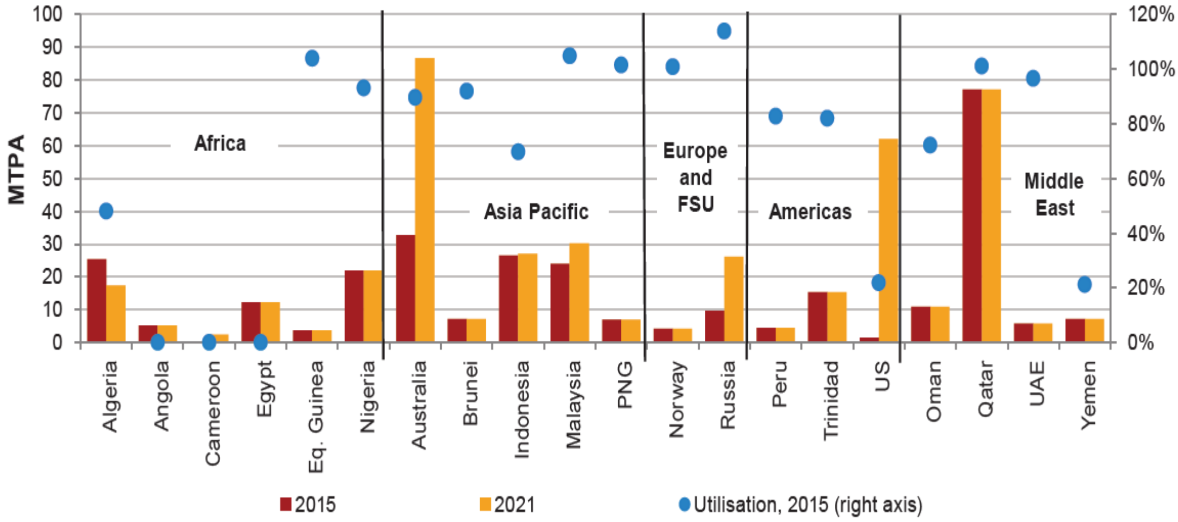


Figure 3.23 Liquefaction capacity by country in 2015 and 2021 (Source: IGU 2016, IHS)

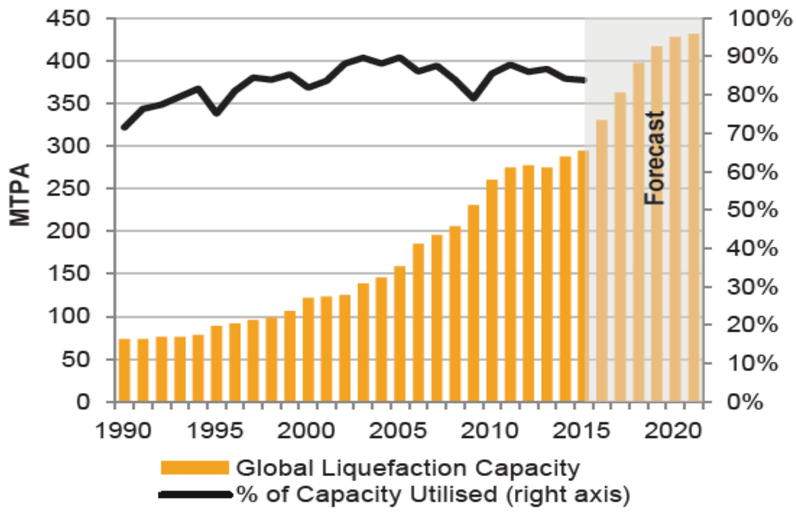


Figure 3.24 Global liquefaction capacity 1990-2021 (Source: IGU 2016, HIS)

3.3.2 Demand-side Drivers

The key driver of natural gas demand is economic growth and energy policy (the use of nuclear power, renewable energy and coal policy).

Economic Growth

Population and income are the key drivers behind growing demand for energy. The world's population is projected to increase by around 1.5 billion people to reach nearly 8.8 billion people by 2035. Over the same period, GDP is expected to more than double, around one-fifth of that increase comes from population growth and four-fifths from improvements in productivity (i.e. GDP per person). China and India together account for almost half of the increase in global GDP, with OECD economies accounting for around a quarter. Africa accounts for almost half of the increase in the world's population, such that by 2035 it is projected to have 30% more people than China and 20% more than India. Yet Africa accounts for less than 10% of the increase in both global GDP and energy consumption (BP Energy Outlook 2016).

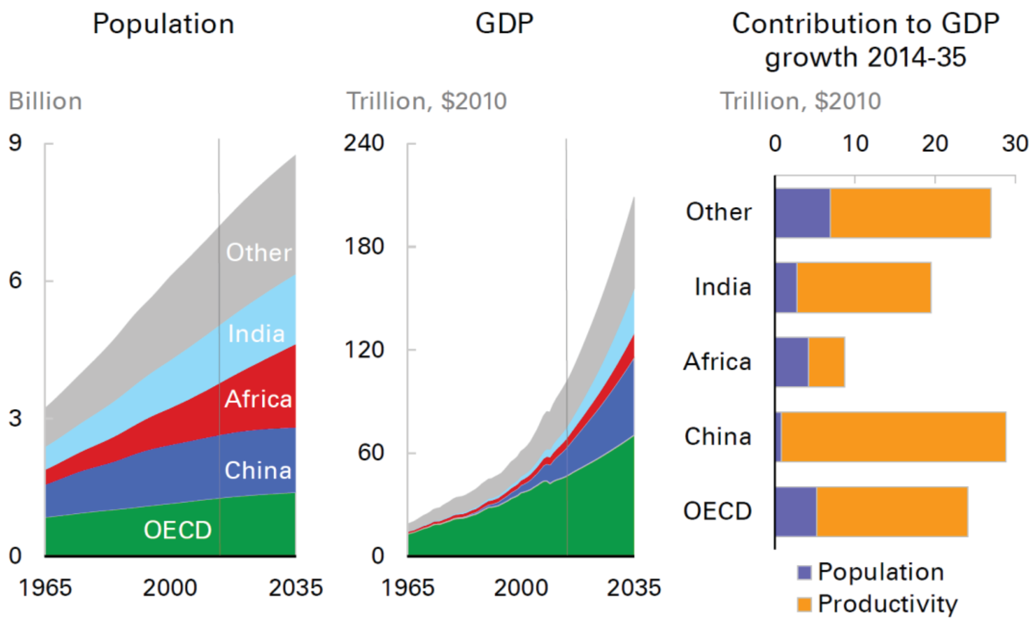


Figure 3.25 Population, GDP and Productivity (Source: BP Annual Energy Outlook 2016)

The growth in the world economy means more energy is required; energy consumption increases by 34% between 2014 and 2035. Virtually all of the additional energy is consumed in fast-growing emerging economies where energy demand within the OECD barely grows. The growth of energy is slower than in the recent past; 1.4% per annum (p.a.) versus 2.3% p.a. in 2000 which reflecting significantly faster falls in energy intensity (energy used per unit of GDP).

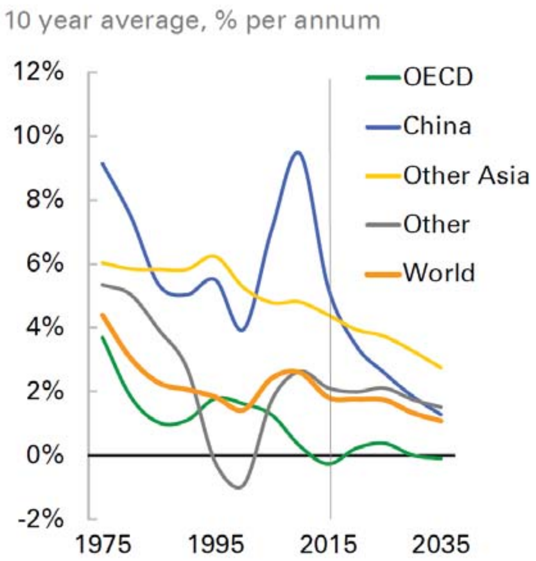


Figure 3.26 Energy consumption growth by region (Source: BP Annual Energy Outlook 2016)

China's energy demand growth slows as its economy rebalances, towards a more sustainable rate. By the final decade of the Outlook, China contributes less than 30% of global energy growth, compared with nearly 60% over the past decade. The sharp slowing in China's energy demand growth is partially offset by a pickup in other developing countries. India accounts for more than a quarter of the growth in global energy demand in the final decade of the Outlook, double its contribution over the past decade.

As the world economy grows, more energy is required to fuel the increased level of activity. However, rapid improvements in energy intensity mean that energy demand grows far less quickly than global GDP. OECD energy intensity declines at a faster rate than in the past 20 years, and the growing importance of China means the continuing declines in China's energy intensity have a bigger impact on the global trend. The energy intensity of other major non-OECD economies, including India and Africa, is projected to continue falling even as they go through the industrialization phase of their economic development.

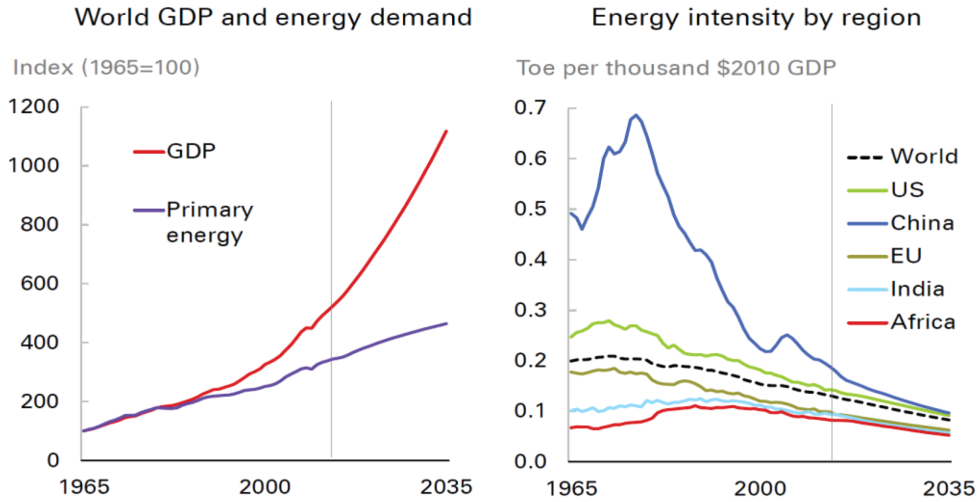


Figure 3.27 World GDP, Energy demand and Energy intensity (Source: BP Annual Energy Outlook 2016)

Energy and Environmental Policy

Future natural gas demand is significantly affected by energy and environmental policies. Policies that create stricter control of emissions can encourage a shift from other fossil fuels to natural gas, which is considered the cleanest of the fossil fuels, as well as a shift from natural gas and from the other fossil fuels to nuclear and renewable energy sources. The net result of these policies can be an increase or a decrease in natural gas consumption. Policies that are directed toward nuclear power and renewable energy have had particular impact on natural gas demand in recent years.

While the reductions in Japanese and South Korean nuclear power are significant for the regional natural gas market, the policies driving these shifts are not shared by other nations in the region. China and India are currently building more than 30 nuclear power, while dozens more are planned across the region, which will help temper natural gas demand in these countries *(Osamu & Kebede, 2013)*.

The continuation of policies that reduce nuclear power use after Fukushima disaster in 2011 affect the growth in LNG demand from the traditional LNG buyers in Japan and South Korea. However, the interest these countries have shown in diversification of energy supplies suggests not only reliance on acquiring LNG from multiple regions, but demand for other fuel types as well (coal and renewable energy). In contrast, policies in emerging Asian countries may be more likely to encourage the use of nuclear power.

Recently, there are plans to reactivate the nuclear power in Japan which will affect the natural gas demand in this country. Japan imports virtually all its fossil fuels. As a result of greater fossil fuel use and higher international oil prices during the past few years, Japan spent 60% more for fossil fuel imports in 2013 compared to 2010, an increase of $270 billion over three years *(EIA, 2015)*. This reversed Japan's trade surplus and created a widening trade deficit. Utilities have passed on some of the high cost for power production to consumers, and electricity prices have risen at least 20%. The current Japanese government believes that the use of nuclear energy is necessary to help reduce current energy supply strains and alleviate high electricity prices.

The EU has recently boosted their carbon emission target from a 32% to a 40% reduction in 2030 compared to 1990. In order to support carbon emission goals, a renewable energy target of 27% was also set for 2030. A substantial portion of the renewable energy goal is expected to be achieved through increasing renewable energy use for electric generation from the current levels of 21% to 45% in 2030. While in Asia, increases in renewable energy are being promoted by policies that are being driven by both energy security/diversification and environmental concerns. Solar power and geothermal are expected to contribute the bulk of generation the new renewable energy in ASEAN country *(Leidos, 2014)*.

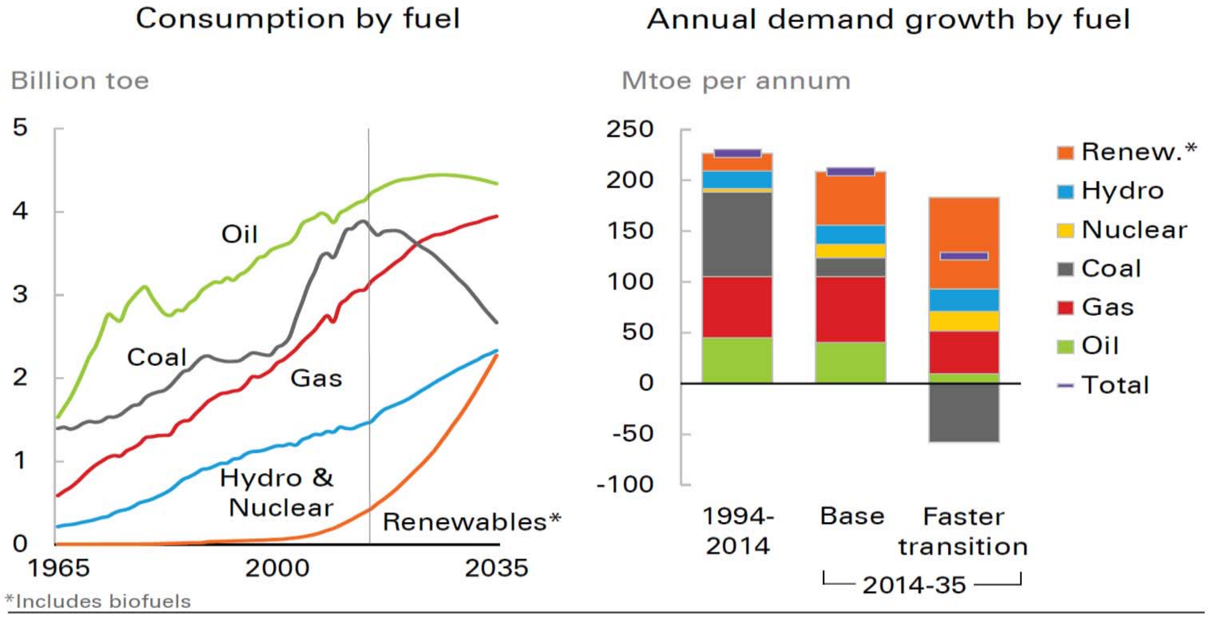


Figure 3.28 Energy consumption and fuel annual demand (Source: BP Annual energy outlook 2016)

In the United States, which after China has the second-largest electricity sector, natural gas use in the power sector will surpass coal this year for the first time ever. According to Maura Cowly (director of the international climate and clean energy campaign for the Sierra Club) United States has hit the point where coal is in a structural decline. In the United Kingdom, where coal launched the Industrial Revolution, Scotland on March 2016 shuttered its last coal plant and following by England sealed off its very last coal mine.

On March 2016 China government officials ordered the halt of more than 250 coal-fired power plants slated for construction in more than a dozen provinces. The move is part of China's ongoing plan to cap the use of dirty energy like coal that has contributed to massive air pollution and, in turn, sparked major protests by a growing Chinese middle class. Late last year, China announced a freeze on opening new coal mines, and is closing thousands of smaller mines. Other environmental concerns such as the massive consumption of water by coal plants in water-stressed regions such as northern China, also played a role. As did economics, A burst of cleaner energy options in China, including renewable energy such as hydroelectric power, has made coal plants increasingly economically unviable. Many coal plants in the areas targeted by Beijing's new order operate less than half the time.

And many of those same headwinds are working against coal in other parts of the world. A flood of natural gas rather than environmental regulation is crippling coal's future in the United States. International agreement to start tackling climate change, such as Paris Climate Conference 2015 (COP21) is pushing governments and companies around the world to focus on cleaner energy options.

3.3.3 Hub Development

Hub development is one factor leading to the global and convergence market. For hubs to be function, it needs certain liquidity (active in trades). In order to evaluate the depth, liquidity and transparency of the traded gas hubs there are 5 considerable key elements *(Heather, 2015)*;

- Number of market participants
  The more participants will increase the competition level of the markets.
- Traded products
  Products availability is an important consideration when comparing traded markets and evaluating their relative success. Liquidity attracts liquidity which in turn makes a market successful, increases its churn rate and allows it to develop into a 'mature' market able to provide reference prices.
- Traded volume
  The volumes have very essential role in the analysis of the development of a traded gas hubs. The traded volumes, compared to the overall size of market determine the churn rate which is probably the most important factor in determining the success of a traded market. Markets with very high absolute traded volumes also have a large churn rate, have a large and varied range of participants and are usually free from the manipulation of price.
- The tradability index
  A measure to narrow the bids/offers that spread across the trading curve. It would help to know the extent of any additional volumes at the next price after the best bid and offer. The closer the bid/offer spreads the more liquid a traded market, the further along the curve that there are close bid/offer spreads, the more mature and developed the market and the more volume available to at any given time which increase the liquidity in the market.

- The churn rates

  The churn rate is the ratio of traded volume to actual physical throughput or a measure of the number of times a package of gas is traded and re-traded between its initial sale by the producer and the final purchase by the consumer. The markets reached maturity when the churn is in excess of 10 times. If there are many participants that trade different products in large quantities, then the churn rate is likely to be high. The churn rate is used by traders as indicator of a market's liquidity. The churn is probably the most important single factor in determining the success of a traded market.

All elements are significant but the churn is the most leading factor. It is essential to analyze these 5 elements to permit a complete analysis although in fact not all of the elements are consistently available for all of the hubs. From the results it is possible to determine which hubs are mature, active, improving, or yet to show signs of development.

Liquidity is not only the factor that is considerable to create a successful trading in a hub. There are other 4 main requirements;

- Volatility is a measure of price movement in relation to market activity. Historically, financial markets have high liquidity and fairly low and consistent volatility, whereas energy markets are typically very volatile yet may also be very liquid. They are particularly sensitive to external information.
- Anonymity is the 'corner stone' of futures trading. This allows both big and small participants to trade alongside each other.
- Market transparency, means that traded volumes and prices are quickly disseminated in the public arena and this openness gives traders added confidence in the market in which they are trading.
- Traded volumes, simply relates to the total actual volume traded in any given market

Trading on a Hub is very much like trading on a stock exchange. This is fundamentally different from the traditional sales on long and shorter term contracts. The flexibility is obtained through the daily trades and the sizes of traded packages or stripes in the trade *(Halmø, 2016)*, as can be seen from Figure 3.29.

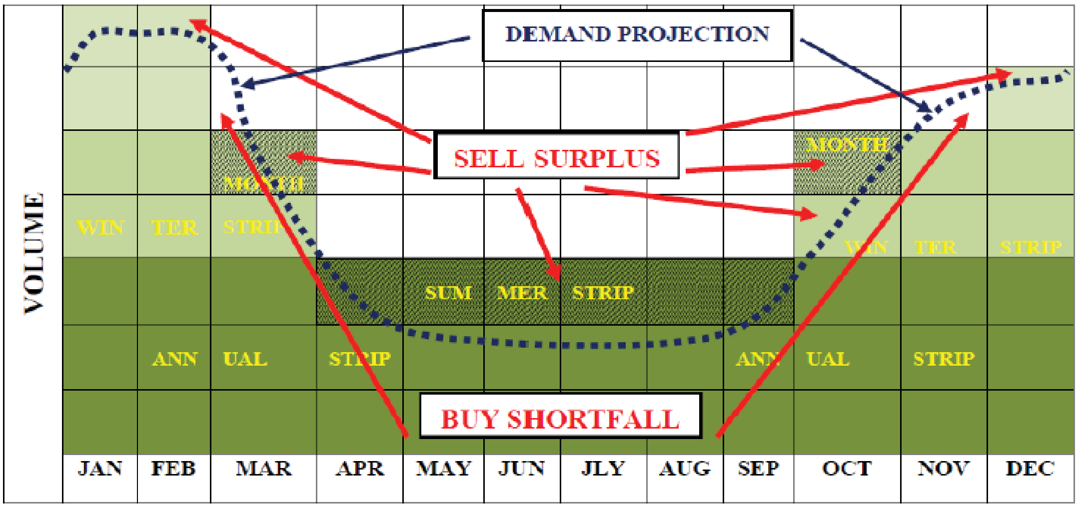


Figure 3.29 Portfolio hub trading by strip packages which absorb the needed flexibility over the year (Source: Heather, 2013)

Both buyers and sellers will want to trade at the hubs but their trading will be at different time with varying volume, thereby creating the initial liquidity. Liquid markets attract non-physical players and in turn the generated trading creates more liquidity.

Trading hubs can be places of physical exchange as is Henry Hub or as of virtual (contractual) exchanges such as the UK NBP. Hubs is developed under pricing system that will provide a benchmark price for competitive trades. As the maturity of natural gas market increases, the use of GOG based pricing increases as well, in particular as energy markets are more liberalized through deregulation.

Physical and virtual gas trading hubs have different set-ups to accommodate the different structures of their industries. In spite of that, both platforms have proven to be able to facilitate trade to sustain the transition towards a liquid futures market, and to generate reliable pricing signals for market participants.

Henry Hub

A physical hub is a geographical point in the network where a price is set for natural gas delivered on that specific location. A prime example of such a physical hub is that of the United States, the best functioning and most liquid natural gas market in the world, which essentially consists of a physical trading point (the Henry Hub in Louisiana), which sets the benchmark price for the entire North American trading area. However, the United States also has many regional physical trading hubs reflecting local and regional supply/demand balances. At these local hubs, natural gas is frequently traded at a differential from Henry Hub, taking into account regional disparities and production and transport costs to that specific regional hub.

In essence, the whole North American natural gas system operates around a price set by the natural gas exchange at Henry Hub, resulting in prices across the United States that differ, albeit staying reasonably close together. Within the U.S. geographical area, arbitrage opportunities between regional hub prices drive investments in transport capacity by private pipeline companies. However, for this to work in the markets of other countries would probably require a regulator that can regulate access to interconnecting pipelines throughout the gas market, such as the Federal Energy Regulatory Commission (FERC) in the United States. Henry Hub (HH) was not selected by the natural gas market regulator, but by the New York Mercantile Exchange (NYMEX), which was looking for a centrally located and sufficiently interconnected point for the exchange of natural gas ownership.

European Hub

Currently the European Union prefers to continue to integrate its natural gas markets through the establishment of virtual (regional) trading hubs. It builds on the existing arrangements of national TSOs and regulators (rather than creating one overarching European regulator) and an infrastructure built to facilitate long-term import contracts with national balancing and limited interconnections.

European hubs, in general, the European gas market is largely integrated as indicated by common price movements among the eight major hubs;

1. National Balancing Point (NBP) → UK
2. Title Transfer Facility (TTF) → The Netherlands
3. Zeebrugge Hub (ZEE) → Belgium
4. Central European Gas Hub (CEGH) → Austria
5. Gaspool (GSL) → Germany
6. National Connect Germany (NCG) → Germany
7. Points d’Echange de Gaz (PEG) → France
8. Punto di Scambio Virtuale (PSV) → Italy

In Europe, the process of hub development followed two very different courses: that of UK’s privatization and Continental Europe’s liberalization. As of today, UK has a fully liberalized, established and successful traded gas market which has reached maturity and the NBP is a very successful marker hub for the British Isles and some LNG deliveries to the Channel ports. All of UK's gas supplies are now priced against the NBP marker whether they are contracted or traded supplies. The entire market is liberalized both at the wholesale and retail level.

Continental Europe's liberalization of the energy markets was driven by the EU's political ambitions to create a fair market for all consumers and this it instigated through Directives which were part of 'Energy Packages' that also included reforms to the electricity markets *(Heather, 2015*). The process of transformation started in the late 1990s although the first real signs of change were apparent in the mid-2000s and then only in western Europe. Especially in eastern Europe, the process is still ongoing and it now seems likely that the whole process will also take and in total expectedly some other years to complete, just as it did in both North America and in UK. However, in western Europe, the Dutch TTF hub has now established itself as a marker hub for the north west European region and there are even plans for regional hubs in central Europe and south eastern Europe.

<table>
<tr><th rowspan="2">HUB</th><th colspan="4">Market Participants*</th><th colspan="3">Active**</th></tr>
<tr><th>2005</th><th>2011</th><th>2013</th><th>2014</th><th colspan="3">2014</th></tr>
<tr><td>NBP</td><td>c.80</td><td>c.160</td><td>c.180</td><td>c.200</td><td colspan="3">40</td></tr>
<tr><td>TTF</td><td>37</td><td>60</td><td>c.100</td><td>c.130</td><td colspan="3">30</td></tr>
<tr><td>NCG+GPL</td><td>n/a</td><td>n/a</td><td>c.80</td><td>c.95</td><td colspan="3">25</td></tr>
<tr><td>ZEE</td><td>53</td><td>78</td><td>78</td><td>82</td><td colspan="3">15</td></tr>
<tr><td>PSV</td><td>n/a</td><td>112</td><td>148</td><td>118</td><td colspan="3">12</td></tr>
<tr><td>CEGH/VTP</td><td>n/a</td><td>40</td><td>42</td><td>53</td><td colspan="3">10</td></tr>
<tr><td>PEG Nord</td><td rowspan="2">23</td><td rowspan="2">26</td><td rowspan="2">54</td><td rowspan="2">55</td><td>N</td><td>S</td><td>T</td></tr>
<tr><td>PEG S+T</td><td>10</td><td>5</td><td>0</td></tr>
<tr><td>VOB</td><td>n/a</td><td>n/a</td><td>n/a</td><td>16</td><td colspan="3"><10</td></tr>
<tr><td>AOC</td><td>n/a</td><td>n/a</td><td>43</td><td>70</td><td colspan="3"><5</td></tr>
</table>

*the number of companies registered to trade at each of the hubs, or registered as Shippers;
** the estimated number of participants who regularly trade.

Sources: 2005: E-Control; 2011: Heather (2012); Powernext; 2013, 2014: AEEG, CEGH; CNMC; GTS; Huberator; ICE; Ofgem; Parliamentary Wholesale Gas Market Report; Powernext; and from discussions with market participants and brokers.

Table 3.6 European gas hubs market participants 2005-2014 (Source: Heather, 2015)

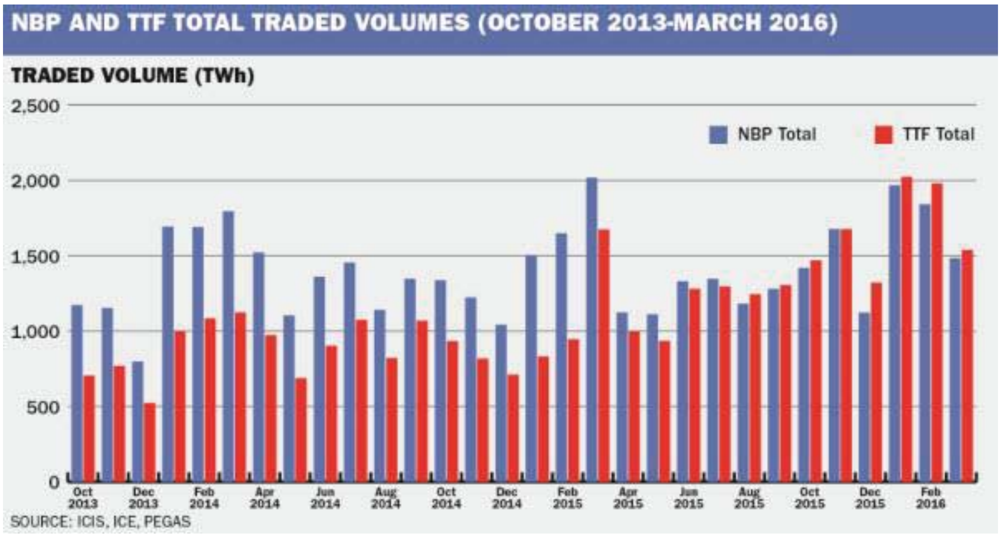
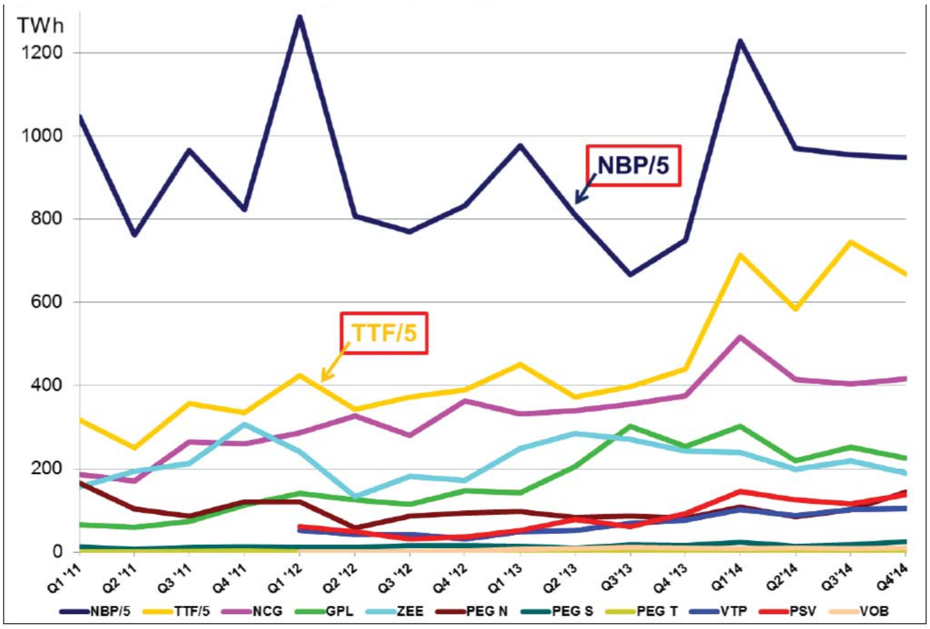
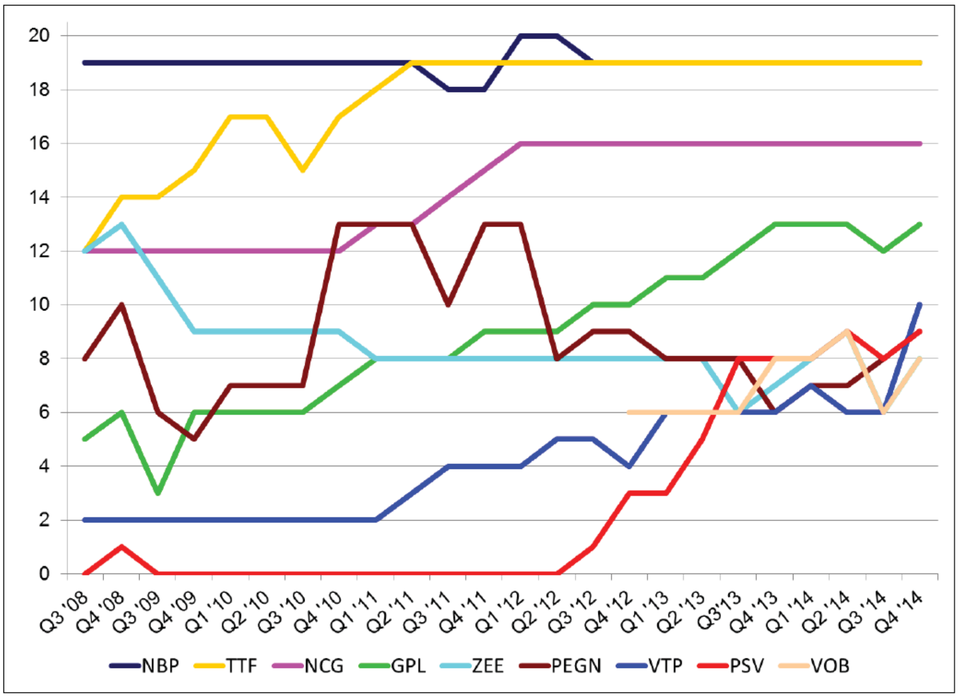


Figure 3.30 NBP & TTF total traded volumes in Twh (Source: ICS HEREN EGM)



Sources: LEBA; ICIS; ICE ; ICE-Endex ; EEX ; Powernext ; CEGH ; GME; P. Heather

Figure 3.31 Traded volume development, quarterly 2011-2014 (Source: Heather, 2015)



Sources: ICIS European Gas Hub Reports 2008-2014; P. Heather

Figure 3.32 ICIS Tradability Index 2008-2014 (Source: Heather, 2015)

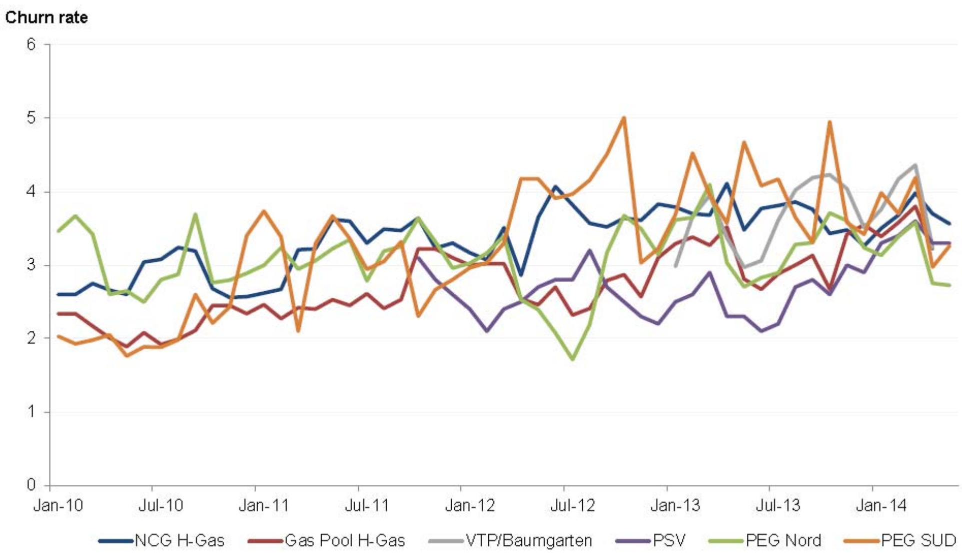


Figure 3.33 European hub churn rate (Source : StatOil, 2015)

HUB	Gas traded hubs churn rates*				
	2004	2008	2011	2013	2014
NBP	7	14.4	19.8	18.7	26.2
TTF	0.2	3.3	13.9	19.3	36.0
ZEE	2.5	5.1	4.1	5.5	4.9
CEGH/VTP	n/a	2.4	2.2	2.6	4.6
NCG+GPL	n/a	0.4	1.4	2.6	3.7
PEG Nord	n/a	0.4	1.0	1.4	1.6
PEG Sud	n/a			0.7	1.0
PEG TIGF	n/a			0.3	0.1
PSV	n/a	0.2	0.2	0.4	0.8
VOB	n/a	n/a	n/a	0.4	0.4

*Calculated on a Net Market Churn basis; not the same methodology in all years.

Sources: 2004: NBP: Heather (2010), p.35; TTF, ZEE: calculated from BP and IEA;
2008: Heather (2010), Table 6, p.19; Komlev [224] presentation 2011; calculated from BP and IEA;
2011,2013,2014: LEBA; ICE ; ICE-Endex ; EEX ; Powernext ; CEGH; GME; P. Heather.

Table 3.7 European gas hub net churn rate development 2004-2014 (Source: Heather, 2015)

2014	5 KEY ELEMENTS					
HUB	Active Market Participants	Traded Products*	Traded Volumes	Tradability Index (Q4)	Churn Rate	Score /15**
NBP	40	46	20505	19	26.2	15
TTF	30	45	13555	19	36.0	15
NCG	25	24	1750	16	3.7	10
GPL		21	1000	13		9
ZEE	15	17	850	7	4.9	7
PEG Nord	10	17	435	9	1.6	7
CEGH/VTP	10	11	400	10	4.6	6
PSV	12	11	525	9	0.8	6
PEG Sud	5	13	80	n/a	1.0	4
VOB	<10	n/a	35	8	0.4	4
PEG TIGF	0	4	5	n/a	0.1	3
AOC	<5	n/a	(165)	n/a	(0.6)	2/3

* Score /64 derived from the OTC and Exchange product categories in the Traded Products Table.
** Score based on each of the Key Elements scoring zero for Grey; 1 point for Red; 2 points for Amber; 3 points for Green.

Table 3.8 European traded gas hub development based on 5 key elements (Source: Heather, 2015)

Figure 3.34 European gas regions, markets and hubs (Source: Heather, 2015)

Asia Pacific Hub

IEA in EMA (Energy Market Authority) South East Asian Lunch March 2013 recommended the development of an Asian natural gas trading hub to better reflect supply and demand fundamentals. In addition, with the lack of a competitive spot market for natural gas, there is little incentive to change current commercial practices. This limits the options for both consumers and producers.

The lack of an established market highlights three dilemmas facing the Asia-Pacific: LNG price volatility, worsening air quality and growing carbon emissions, and the potential for the market to be coerced by dominant players. The development of regional natural gas trading hubs will prove critical to overcoming these inefficiencies, especially at a time when LNG imports are becoming an increasingly vital part of Asia's energy mix.

With the of rising LNG supplies in the region, particularly from Australia, and an increasing numbers of buyers especially in China, Singapore has potential to establish a domestic natural gas trading market to become a center of Asia Pacific energy hub of LNG trade. Singapore’s maturity and transparent financial system, strategic geographic location and experience as a trading center for oil make this country a strong contender for a regional natural gas market hub.

The biggest competitor is Japan (Tokyo), the world's largest importer of LNG, to become a regional center for LNG trade. Japan is in the process of fully liberalizing its domestic electricity market, starting next year. In the other hand, China (Shanghai), which has large pipeline imports, a growing number of LNG import terminals as well as domestic production, would also be a potential location for a natural gas trading hub, although its development is in its infancy.

There is currently no established LNG benchmark in Asia Pacific. Instead, most contracts are priced off a mix of oil, price reporting agency assessments, and regional contracts such as Britain's National Balancing Point (NBP) or the U.S. Henry Hub. A liquid market with a pricing index that more readily reflects regional supply and demand fundamentals will encourage meaningful growth of a cleaner energy source and help prevent the emergence of dominant market players that keen to dictate the terms of the market for political ends. The development of a natural gas trading hub in Asia will very much help to achieving these objectives.

3.3.4 Globalization of LNG Trade

This significant growth in LNG trade over the past few years has led to question whether the LNG markets have become “globalized” and whether LNG could ever trade as a global commodity. In order for this to happen, a number of factors would have to converge including;

- increased patterns and flow of international trade of LNG,
- the establishment of a single price,
- liquid trading, and
- flexibility of supply.

Among above factors, the establishment of a single price is perhaps the most complicated and difficult to achieve due to differences in the global pricing of natural gas. The price disparities suggest that global market liquidity is not sufficient to fully arbitrage between Atlantic and Pacific basins and the lack of price convergence is attributed to limitations in market access. However, increasing globalization of the natural gas market is indicated by inter-regional trades, and more specifically, inter-oceanic LNG trades between the basins (Figure 3.35).

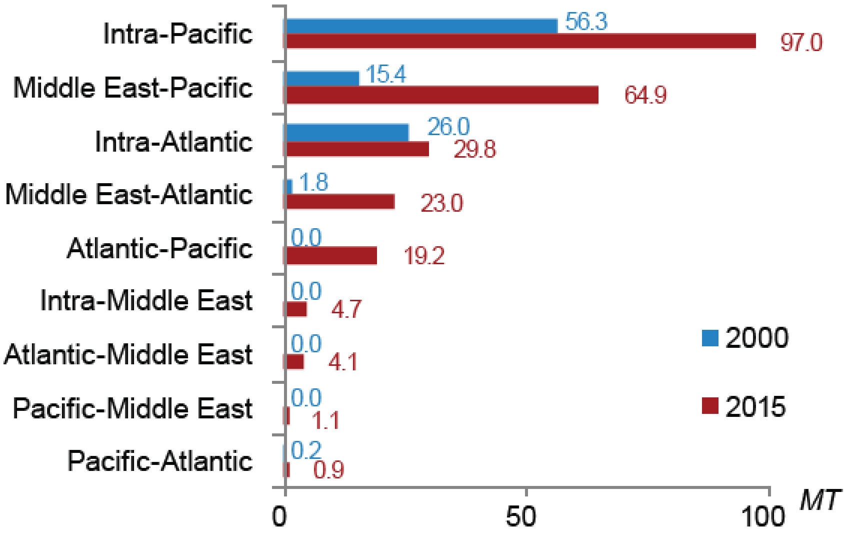


Figure 3.35 Inter-Basin trade 2000-2005 (Source: IHS, IGU World LNG Report 2016)

Chapter 4
The Future of Global Gas Market

4.1 The Transition of Pricing Mechanism and Competitive Market

In order to link the regional gas markets in to an integrated market, one basic need is to set the competitive pricing which is able to transmit the price signals between regions. Therefore, the pricing mechanism is the key central of gas market integration and become the core instrument of balancing between buyers and sellers.

Based on discussion in Chapter 3, oil indexation remains a powerful influence on European and Asian gas prices. In Asia, 84% of total imports which is dominated by LNG trade are accounted to crude benchmark (i.e. JCC). While in Europe, despite the growth of GOG pricing mechanism is increased over the years, the majority of long term pipeline contracts also remain indexed to oil products particularly in Mediterranean countries.

The mature market with long term contract which mainly linked to oil price is a non-competitive market. The price formula in long-term supply contracts is intended to establish a long-term price for gas on the basis of the value for gas perceived in the future by both the seller and the buyer. Pricing arrangement is adapted to response toward the market circumstances which can be achieved by renegotiation between buyer and seller. In the competitive natural gas market which can be found in the short term or spot markets based on GOG pricing mechanism, these renegotiation is considered to be an additional cost as it requires an extensive contract reviews, as the aim of the competitive market is to reduce the opportunity cost compared to other competitors and risk associated.

Concurrently, the natural gas price resulting from competition will increase the transparency in the gas market because commodity and transport capacity are priced separately, at levels reflecting their respective supply/demand balance. The introduction of competition thus allows for more efficient distribution of natural gas by companies throughout the value chain. Oil indexation simply cannot deliver the increased transparency and information required in a mature natural gas market. As price incentives to generate investments or to change the seller and buyer’s behavior are generated in a market that has very limited interaction with the gas market, it will be increasingly difficult for natural gas companies to efficiently supply customers as a market matures.

Introduction of competition in natural gas markets will generate price signals different from those generated by the oil market. A competitive natural gas price does not mean that natural gas has to be priced lower than equivalent oil-indexed volumes. It means that a market will price natural gas at its relative value in a specific energy mix, providing the buyers with a reliable, flexible and low carbon source of energy.

When it is organized properly, GOG pricing in a market can deliver market transparency and its investment requirements that is unable to achieve by oil indexed pricing. This will require the role of governments to allow markets determining a natural gas price without letting political considerations get in the way in the short term. Strengthening the role of an independent regulator of the natural gas market importantly will increase confidence of market parties and their willingness to play a full part in the market. The long term contract is not impossible to be in a competitive market, as long both parties, buyers and sellers has objective to reduce the associated cost that can be done by using a market based price.

In the U.S. and UK, the contractual natural gas market has been 100% market-based. In Northwest Europe (i.e. TTF Dutch, Gaspool Germany), the transition process from non-competitive to a competitive is obviously showed. The increase of GOG pricing mechanism is a result of declining of gas imported under oil indexed replaced by spot gas and increasing volume traded at hubs, reduction in take or pay levels and introduction to hybrid pricing were oil indexation is partly maintained within the corridor set by hub prices. This transition process is still ongoing for rest of European countries, in particular for Central Europe as the imported spot gas increased (from Germany).

In Asian market, a hub is required to facilitate the exchange of natural gas between parties, both spot and future, further to develop free market trading where gas prices would be determined in a competitive basis. Current situation where LNG trade is dominating the Asian market with linkage to crude price, the ability of a competitive natural gas market in this region will critically depend on the ability of the global LNG market to provide flexible and competitive supplies. These will reflect the nature of a competitive spot market with less demand for long-term contract arrangements and more demand for a short-term oriented. The possibility to develop a competitive natural gas market in Asia Pacific will takes time and will not automatically lower the gas prices in most markets. The move towards a competitive natural gas hub trading will also need the governments to signal whether they accept such a change to happen. Singapore, Japan (Tokyo), and China (Shanghai), each stands out for this position based on their current and future demand. A more destination-flexible LNG supply is needed to drive the momentum towards a gas trading hub in Asia, but without initial steps towards such a hub, flexible LNG would not have further places in Asia. If a competitive natural gas market in Asia were to succeed, a more responsive LNG supply system would be crucial to attract supplies to the market, thus increasing overall liquidity. Thus, fundamentally, the development of a hub in Asia such as Japan, China or Singapore strongly depends on:

1) Liberalization of gas markets → removal of monopolist, buyers access to multiple sellers, and transparency of prices and protection.
2) Number of actors/players in the exchange/hub → increase the competition in the markets.
3) Liquidity on the supply side → access to multiple sellers and sufficient volume on the move.
4) Flexibility in supply and demand → buyers is able to adapt its own needs such as selling and buying the surplus and deficiencies.
5) Storage → to absorb the oversupply/stocks.

4.2 LNG Challenges

An expansion of LNG trade and arbitrage as a factor that contributes to increase the liquidity of natural gas is the main link toward an integrated gas market. The fast growth of non-long term contractual markets is related to the situation when the supplier countries that are aggressively expanding their LNG liquefaction capacity create surplus of supply in world LNG markets. More intense GOG competition would see the emergence of a larger spot market with less volumes being sold on a long term contractual basis with prices linked to crude oil. The new liquefaction capacity across Australia, ASEAN and the U.S. in the various stages development will increase significantly those country's export capacity. Thus the surplus of supply of LNG would translate into a more significant spot market with prices reflecting greater GOG competition and less linkage to oil prices.

On the other side, the competition from other source of energy will affect the future demand of natural gas market. Japan as the largest LNG importer, recently has showed the signs to reactivate the nuclear reactor, motivated by the intention to reduce its dependencies toward the import of high cost fossil fuels. South Korea is not yet able to firmly establish the future usage around gas vs coal for the power sector. While India is facing the lack of infrastructures, domestic pricing and affordability of gas vs coal. These situations leave the most important market to China. The key source of uncertainty around Chinese demand is the scale of potential demand growth and competition to gas pipeline imports from Turkmenistan and Russia.

In term of flexibility, Australia as the 2nd largest LNG exporter is expected to deliver sizeable volumes since some new large export capacities has been in operation in 2015/2016 and the rest are to be commissioned at the end of this decades. But this will unlikely increase market flexibility, as most of these are long-term contracted with crude price-based.

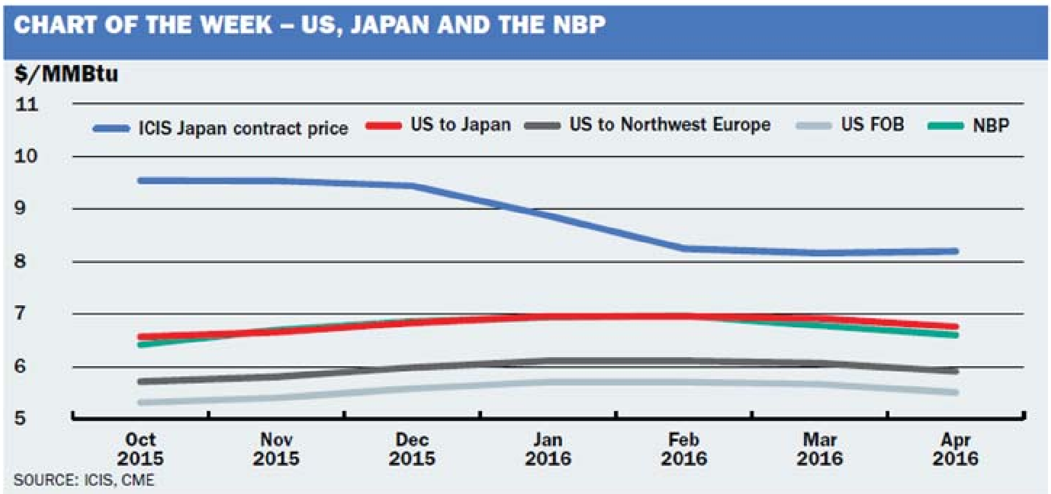
Another considerable source is from East Africa (Mozambique and Tanzania) which may become competitive with reasonable development cost to facilitate the trade between the Atlantic and Pacific basins, increasing the scope of competition for Qatar LNG (which also adapting its contracts to be more competitive to other suppliers). Despite the potential sources in East Africa, this region faces such development challenges; high development cost related to deep water drilling of gas sources, geopolitics and lack of infrastructures. Further, East Africa will likely need to apply long term contracts as the consequences of high development cost. One of the most flexible and most prepared sources are expected coming from the U.S. The Cheniere’s Sabine Pass has exported the first LNG cargo in early 2016 to Brazil and has reached Asia when the third cargo was delivered to India in April 2016. The Sabine Pass is built on business model that indexes the LNG to spot market prices and sold with destination flexibility although the LNG supply is long term contracted. Thus, it seems that natural gas developments in North America will increase overall flexibility to the LNG supply chain in the future.

Russia, as the main supplier in European natural gas market is set to be the determinant of LNG demand in Europe. A movement toward renewables for power generation will affect the total natural gas demand in Europe as well as the domestic production. Europe will likely continue to lean on Russia for pipeline flows, as Russia continues to show increasing flexibility in its contracts, moving away from both take-or-pay agreements and oil indexed contracts. Destabilization of Ukraine will cause European to pursue LNG’s option or otherwise to keep the marketplace competitive. It means that the Europe will be the last destination of LNG, acts as a sink for surplus international LNG volumes.

There are among considerable challenges faced by the LNG market in the upcoming years, after the prices have slid down lower in the recent years due to oil prices drop and hinder demand. The market would have to adapt going forward to greater international competition with the expectation that supply outpace demand through the rest of the decade. Thus, the future of LNG exports will be beneficial in term of consumer’s perspective than the suppliers.

Sensitivity Analysis of US LNG Landed Price

The U.S. approach has been to convert the receiving terminals for import of LNG to export facilities. These new facilities will be tolling facilities where the ownership of the facilities will be financed in the market as utility investments with “risk-free” utility returns (Halmø, 2016). Gas will be bought on the Henry Hub, liquefied and delivered FOB (Free On Board) to customers and shippers. The price model for such shipments from October 2015 to April 2016 is shown in Figure 4.4.



Note: The graph compares the current notional value of US FOB LNG according to the Cheniere-BG contract formula of Henry Hub front month * 1.15 + $2.25/MMBtu. ICIS Shipping costs have been added to produce approximate delivered prices to Northwest Europe and Japan. The ICIS Japan price is a forward estimate of the average long-term contract price.

Figure 4.1 Price shipment model from the U.S. to different destination (Source: ICIS Heren, 2016)

Henry Hub indexation currently appears to be very attractive, but it is important to distinguish between price level and price formation. A hub indexation does not always translate into low prices. Cheniere’s formula gives the price at which the buyer is buying the gas outside the liquefaction plant:

*US FOB LNG = [Henry Hub price * 115%] + tolling fee*

The transport cost is paid by the buyer. Therefore, the total price becomes;

$$US\ LNG\ landed\ price = US\ FOB\ LNG + shipping\ cost$$

The variable risks from US LNG landed price formula are the tolling fee and transportation costs. The tolling fee could vary for different plants, contracts and subject to inflation uncertainty. The transport cost is also an important variable which mainly consist of charter rate and fuel cost, and the value will vary mostly depend on market situation. In order to show that whether the U.S LNG landed price is competitive as shown in Figure 4.1, the sensitivity analysis based on different destination which is Tokyo (Japan), Bahia Blanca (Argentina) and Isle of Grain (UK) are calculated. The analyzed subjects are US LNG contract prices (*HH price*115%*), tolling fee and total cost of US FOB LNG with analysis range within 50% – 150%. The tolling fee in this analysis is based on BG's contract price which is $2.25/MMBTU and it is assumed that this fee is identical to different destination. In order to get broader sense of the U.S. LNG landed prices, the sensitivities are also applied to two different prices of international shipping; the maximum case (November 2013 price, when the LNG/natural gas price is on the peak) vs minimum case (April 2016). The data used in calculation is as follows;

For April 2016

Henry Hub price	= $1.9/MMBTU
US LNG Contract price	= (1.9*115%) = $2.185/MMBTU
Tolling Fee	= $2.25/MMBTU
Shipping cost (Minimum Case)	
Sabine Pass – Tokyo	= $1.133/MMBTU
Sabine Pass – Bahia Blanca	= $0.627/MMBTU
Sabine Pass – Isle of Grain	= $0.448/MMBTU

For November 2013

Henry Hub price	= $3.67/MMBTU
US LNG Contract price	= (3.67*115%) = $4.221/MMBTU
Tolling Fee	= $2.25/MMBTU

Shipping cost (Maximum Case)

Sabine Pass – Tokyo = $4.303/MMBTU

Sabine Pass – Bahia Blanca = $2.116/MMBTU

Sabine Pass – Isle of Grain = $1.526/MMBTU

Figure 4.1 is used as the reference for the projection of natural gas price from October 2015 to April 2016). The calculation shows that the U.S. LNG landed price are lower compared to NBP and 'US to Japan' price for all cases sensitivity when Henry Hub price and shipping cost of April 2016 are used. These results are shown in Table 4.1 and 4.2. Except for case when total cost is 50% higher, the U.S. LNG is not competitive compare to NBP and Argentina spot price. When the maximum shipping cost is applied to Isle of Grain and Bahia Blanca, the price generated within range sensitivity are still competitive. Not the same case to Japan, the U.S LNG is not beneficial when the maximum shipping cost case is applied.

US FOB LNG

		Sensitivity Analysis								
		Prices			Tolling Fee			Total Cost		
For April 2016		-50%	Fix	+50%	-50%	Fix	+50%	-50%	Fix	+50%
HH	$/MMBTU	0.95	1.9	2.85	1.9	1.9	1.9	0.95	1.9	2.85
sales fraction	$/MMBTU	115%	115%	115%	115%	115%	115%	115%	115%	115%
US LNG Contract		1.093	2.185	3.278	2.185	2.185	2.185	1.093	2.185	3.278
Tolling Fee	$/MMBTU	2.25	2.25	2.25	1.125	2.25	3.375	1.125	2.25	3.375
US FOB LNG	$/MMBTU	3.343	4.435	5.528	3.310	4.435	5.560	2.218	4.435	6.653

		Sensitivity Analysis								
		Prices			Tolling Fee			Total Cost		
For November 2013		-50%	Fix	+50%	-50%	Fix	+50%	-50%	Fix	+50%
HH	$/MMBTU	1.835	3.67	5.505	3.67	3.67	3.67	1.835	3.67	5.505
sales fraction	$/MMBTU	115%	115%	115%	115%	115%	115%	115%	115%	115%
US LNG Contract		2.110	4.221	6.331	4.221	4.221	4.221	2.110	4.221	6.331
Tolling Fee	$/MMBTU	2.25	2.25	2.25	1.125	2.25	3.375	1.125	2.25	3.375
US FOB LNG	$/MMBTU	4.360	6.471	8.581	5.346	6.471	7.596	3.235	6.471	9.706

Table 4.1 Sensitivity Analysis of US FOB LNG in term of contract prices, tolling fee and total cost

US LNG

		Sensitivity Analysis								
		Prices			Tolling Fee			Total Cost		
Apr-16	Destination	-50%	Fix	+50%	-50%	Fix	+50%	-50%	Fix	+50%
Ship cost_Max	Tokyo	7.646	8.738	9.831	7.613	8.738	9.863	6.521	8.738	10.956
	Bahia Blanca	5.459	6.551	7.644	5.426	6.551	7.676	4.334	6.551	8.769
	Isle of Grain	4.869	5.961	7.054	4.836	5.961	7.086	3.744	5.961	8.179
Ship cost_Min	Tokyo	4.476	5.568	6.661	4.443	5.568	6.693	3.351	5.568	7.786
	Bahia Blanca	3.970	5.062	6.155	3.937	5.062	6.187	2.845	5.062	7.280
	Isle of Grain	3.790	4.883	5.975	3.758	4.883	6.008	2.665	4.883	7.100

		Sensitivity Analysis								
		Prices			Tolling Fee			Total Cost		
Nov-13	Destination	-50%	Fix	+50%	-50%	Fix	+50%	-50%	Fix	+50%
Ship cost_Max	Tokyo	8.663	10.774	12.884	9.649	10.774	11.899	7.538	10.774	14.009
	Bahia Blanca	6.476	8.587	10.697	7.462	8.587	9.712	5.351	8.587	11.822
	Isle of Grain	5.887	7.997	10.107	6.872	7.997	9.122	4.762	7.997	11.232
Ship cost_Min	Tokyo	5.493	7.604	9.714	6.479	7.604	8.729	4.368	7.604	10.839
	Bahia Blanca	4.987	7.098	9.208	5.973	7.098	8.223	3.862	7.098	10.333
	Isle of Grain	4.808	6.918	9.028	5.793	6.918	8.043	3.683	6.918	10.153

Table 4.2 Sensitivity Analysis of US LNG prices in term of shipping cost

It means that at these points Cheniere can provide profitably natural gas to supply the global market with attractive prices, yet by considering the variable risks. But if the calculated prices are compared to current/future value of NBP, Japan and Argentina spot prices in 2016 (Table 4.3 & 4.4), it shows different fact that the U.S. LNG is not attractive as NBP prices pushed down, as as well as Argentina spot prices. Even for Japan, the price is projected lower in the future (>$7/MMBTU).

KEY OIL AND GAS PRICES 14 APRIL 2016

Contract	€/MWh	$/MMBtu
ICIS Heren NBP May '16	11.369	3.752
ICIS Heren TTF May '16	11.188	3.693
ICIS Heren RU-DE Contract May '16	15.261	4.985
ICIS Heren NO-DE Contract May '16	16.424	5.365
ICIS Heren NL-DE Contract May '16	15.777	5.153
ICIS Heren AL-SP LNG Contract May '16	15.085	4.927
NYMEX Henry Hub May '16	6.169	2.036
ICIS Brent Jun '16	23.217	7.662
NYMEX WTI Jun '16	22.515	7.438
ICIS Gasoil 0.1%	27.451	9.060
ICIS Fuel oil 1%	13.394	4.420

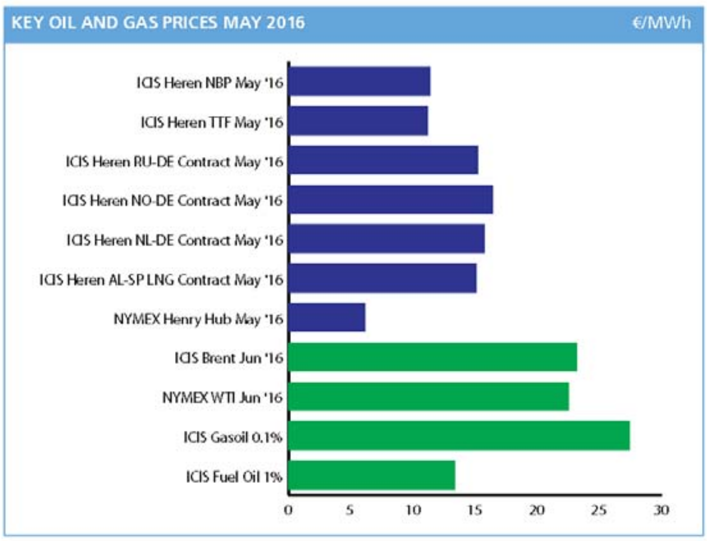


Table 4.3 Oil and Gas prices May 2016 (Source: ICIS Heren, 2016)

SPOT DES PRICES				$/MMBtu
Location	May '16	Week-on-week diff	Jun '16	Week-on-week diff
EAX	4.225	0.050	4.100	-0.025
Japan	4.250	0.050	4.125	-0.025
India	4.150	-0.050	4.100	0.000
Spain	4.000	-0.050	3.990	-0.060
Britain	3.537	0.011	3.390	-0.010
Argentina	4.330	-0.100	4.290	-0.100

Table 4.4 Spot Prices May-June 2016 (Source: ICIS Heren, 2016)

If the LNG prices in Asia and Europe are kept under pressure as supply increases and demand in key markets Japan and Korea weakens (offsets by South Asia/India), the U.S. needs to reassess the strategy for developing its LNG market in the future.

4.3 Globalization of Gas Supply and Pricing – Converging Market?

The Drop of Oil Price

Since in the middle of 2014, the oil price has experienced the significant drop which impact the natural gas markets, particularly for those markets where the prices are still contractual linked to crude prices. Additionally, there are also the substitution effect when users switch between oil and gas in response to the changes of pricing dynamics. It remains the uncertainty where the oil price would head next, whether the prices has entered the new era with different pricing environment or will bounce back as history suggested.

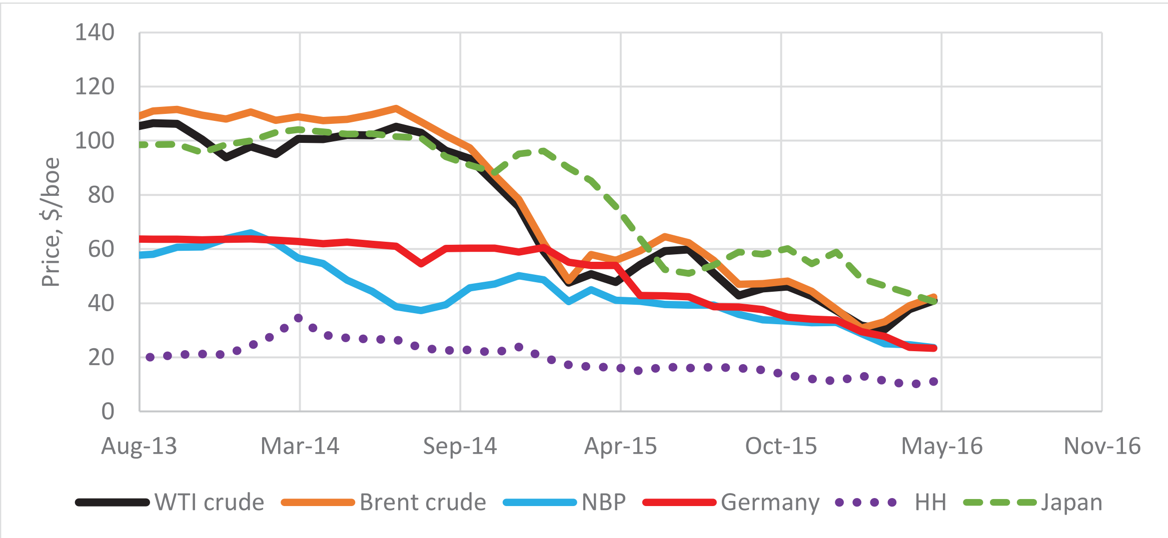


Figure 4.2 Natural gas price vs crude oil price in $/boe (Source; EIA, IMF)

The sharp decrease in oil prices has unique implications for three major regional gas markets. In the Asian market where the gas price is linked to crude price, the impact will be direct. The current lower price will cause less pressure on Asian buyers to renegotiate the contracts. The development of new LNG in Australia, which will add significant LNG volumes to Asian market will increase level of supply and downward pressure on prices even more. Other impact is a reduction among Asian LNG buyers for index diversification. Over the past few years, Asian buyers have looked the possibility to move away from oil in favor of US LNG–indexed volumes, whose prices became increasingly attractive compared with prices for oil indexed volumes when oil was about $100 per barrel. With oil prices now much lower, and with more uncertainty over the competitiveness of the U.S. LNG, Asian buyers have chance to review their diversification strategies.

In the U.S. and European markets, the impact will be indirect. If oil prices remain in the lower range ($45-$60) for extended period, the possible utmost outcomes in the U.S. market are delays in LNG projects and lower growth in export for natural gas due to uncertainty over the competitiveness of the U.S. produced LNG. The U.S. gas prices could also possibly increase.

In the European market, the lower gas prices potentially increased the volatility in hub prices, refer to statement that European’s role as a sink for LNG volumes in the current market context. In a scenario of low LNG prices in Asia, some LNG suppliers, such as Qatar and the U.S. could redirect part of their volumes to the European market, thus add the competition level between traditional pipeline suppliers (Norway, Russia, and Algeria). This could push European price to levels below the prices of the contract price that are indexed to oil/oil products at current prices.

Price convergence – Converging Market?

The significant drop of oil price importantly has reduced the divergence of natural gas price in three regional markets. Although at this point, Henry Hub prices and NBP prices act more resistance compare to Asian Market. The gradual price drop of NBP in Figure 4.4 since early 2015 is more related to the oversupply after relativity mild winter that has left stock gas unused. But despite all the supply pressure in Europe, low gas prices have not stimulated consumption sufficiently to boost demand significantly. Will this situation will lead to the global natural gas price convergence?

The price convergence is defined by ‘the law of one price’ (one of most basic and principle law in economics, firstly was stated by Cournot in 1927) which states that the same commodity will sell for the same price at the same time in any location *(Brazel, 2007)*. The theory is based on the assumption that differences in price will be eliminated by arbitrage opportunities. Being a theory, the law doesn't work perfectly in real life, since transportation costs and other barriers can challenge the free flow of goods across markets. However, as markets become more liquid and barriers are removed, product prices tend to converge. It happened in the case of oil markets. Figure 4.3, shows the distribution of crude benchmarks prices of North Sea Brent, Middle East and US.

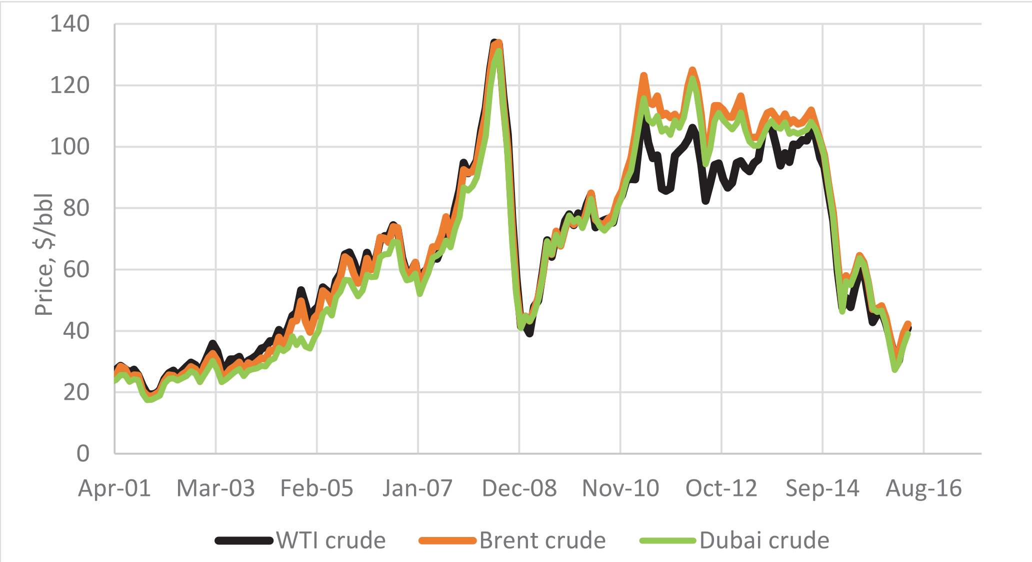


Figure 4.3 Crude oil price from three benchmarks in $/bbl (Source; EIA, IMF)

The following is the distribution of crude oil prices of benchmarks as per April 2016 as shown in Table 4.5.

Benchmark	Price	Apr-16
WTI-crude	$/bbl	40.96
Brent-crude	$/bbl	42.25
Dubai- crude	$/bbl	39.04

Table 4.5 Crude Oil Price as per April 2016 (Source: EIA, IMF)

The variance of the price data is 1.7 with standard deviation of 1.3, indicating a relatively narrow spread between these global benchmark crude values. Now consider the variance of a similar grouping of natural gas benchmark prices from the US, the UK and Asia, as shown in Table 4.6.

Commodity	Price	Apr-16		
HH	$/MMBTU	1.900	$/boe	11.02
NBP	$/MMBTU	4.063	$/boe	36.54
Japan	$/MMBTU	7.000	$/boe	40.60

Table 4.6 Natural gas price as per April 2016 in $/boe, 1 boe = 5.8 MMBTU (Source: EIA, IMF)

The variance of gas price data is 4.4 with standard deviation of 2.1, showing a wider spread between global benchmark natural gas values than those in crude. The spread of gas price data before year 2015 even gives the larger variance since the Asian's price was on the peak which range between $16-18/MMBTU. The comparison between oil and gas price and variance are shown in Figure 4.6.

The explanation for these is related to the liquidity of oil and gas in the global market. In term of international trading and consumption, oil is much more liquid compared to gas. The transportation and storage industry plays a vital role in the system of global trade to move oil from production to distribution. Crude oil is transported by two primary modes: tankers, which travel interregional water routes, and pipelines where most of the oil moves through for at least part of the route. The trade in oil is the largest category internationally and have strong demand from growing economies including China and India. While for gas, the transportation modes are also using transmission pipeline (for short distance) and via seagoing vessel as LNG. Large investment is required if gas is transported as LNG (combination of cost to transform gas to LNG and transportation cost for relative long distance).

According to data from BP Statistical Review 2015, as shown in Table 4.7, the liquidity of gas in the global market is only 10% compare to oil liquidity internationally (Table 4.8). To calculate the liquidity ratio of gas towards oil in the global market, the following formula is used:

*Ratio Gas/Oil Liquidity= Market size ratio of gas/oil * Trade ratio of gas/oil * fraction of moving cargo (LNG).*

	Oil	Gas		
	mill bbl/d	BCM/y	BCM/d	mmboe/d
Global consumption	92.09	3393	9.30	56.53
International Trade	56.74	997.3	2.73	16.62
Pipeline		664	1.82	11.06
LNG		333.3	0.91	5.55

1 BCM = 6.081 mmboe

Table 4.7 Oil & Gas 2014 data (Source: BP Statistical Review 2015)

Natural Gas/Oil market size (consumption)	Natural Gas/oil trade	Natural Gas as LNG	Natural Gas/Oil Liquidity
0.61	**0.48**	**0.33**	**0.10**

Table 4.8 Gas/Oil liquidity ratio

The above explanation simply concludes the liquidity of a commodity will affect the price variance in the market. The higher degree of trade and arbitration of a commodity in the market, the more liquid it is and consequently the variance of the price from different benchmark will be lesser and the price tend to integrate.

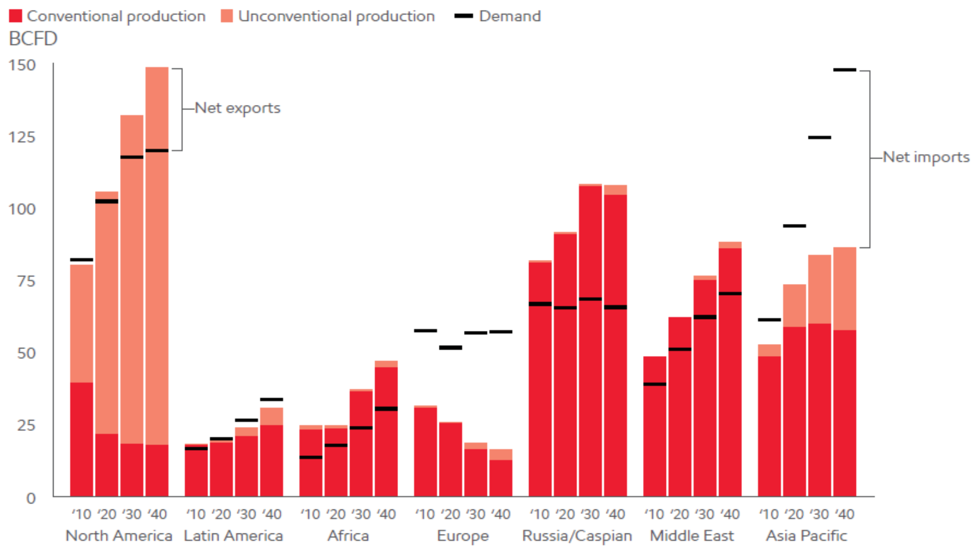


Figure 4.4 Gas trade balance by region (Source; Exxon Energy outlook 2016)

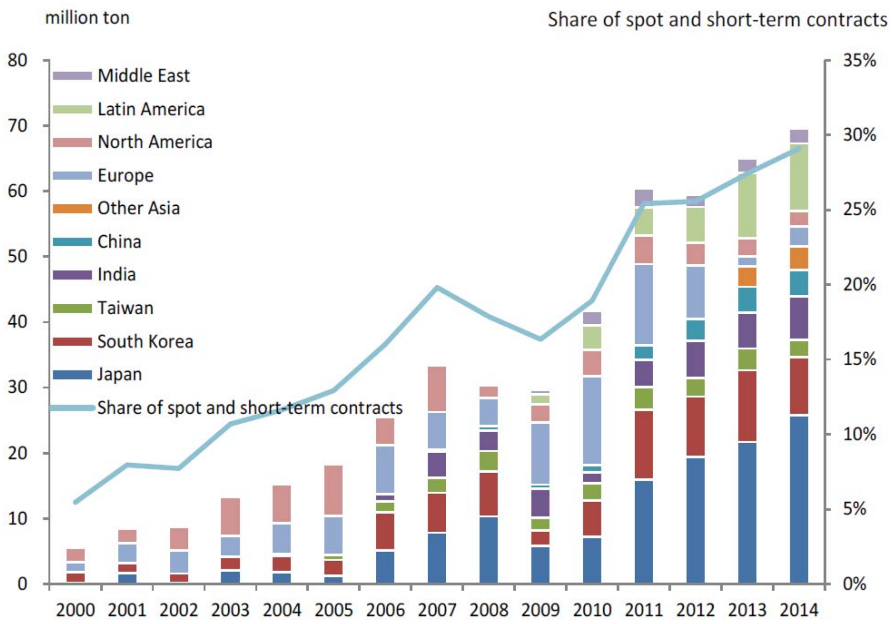


Figure 4.5 Increasing of spot trade and short term LNG Transaction (Source; GIIGNL, ANRE Data, METI 2016)

BP states in Energy Outlook 2016, that until 2035 global gas consumption will continue to grow at an annual rate of 1.8% with its share in primary energy gradually increasing. The growth of LNG infrastructures caused the volume of being traded around the world will continue expand and expected to be particularly critical to fulfill the demand in Asia Pacific and Europe (Figure 4.4). This estimates leads to the questions; what happen if the global LNG spot trade/arbitrage does increase in the future? What will be the effects on the market regarding to gas market price convergence?

The natural gas prices with market-based price will act more dynamic due to referring to the actual supply and demand in the market instead of reflecting the fundamentals of crude markets. Therefore, there is a possibility remains to a wide divergence between contract and market-determined pricing. The greater spot market liquidity also means more destination of LNG vessels. For years, these restrictions have limited the LNG market's ability to respond to changing market conditions (flexibility). Figure 4.7 shows the growth of LNG spot trade and short term contracts from 5% in 2000 to 30% in 2014, counted from global LNG trade.

With larger destination flexibility, the buyers will be likely more flexible, diverting unused vessels to highest paying market. When the liquidity of LNG market increases, the market efficiency will be achieved. Market takes control in price and vessel movements which will increasingly reflect the real supply and demand fundamentals in the global gas market. As that happens, increasing arbitrage opportunities reduce the price divergence of reginal markets. In case of arbitrages and spot trades of LNG reach larger than 50% of total LNG trade, most likely a paradigm shift toward regional gas price convergence will occur, not in the near future but possible in a term within 10-15 years from now.

Japan's Energy and Gas Market Liberalization

According to the revision of Japan's Energy Business Law, the culmination of liberalization of the power industry in Japan will come in year 2020, when power transmission and distribution will be separated from the nation's nine major power firms which currently take benefit of the regional monopolies. Liberalization of the gas industry will follow the deregulation of power sector. These will intensify the competition in which Japanese electric power and gas companies will be forced to be more market oriented.

At the same time, Japan as the largest world's LNG consuming country; consume more than 30% of LNG worldwide supply, these changes have potential for redefining on how the LNG market should be operated, particularly in East Asian region. Further, it should attempt in engaging price formation to achieve the reasonable LNG prices. Taking these substantial changes, it may strengthen Japan's potential to establish its self as one of an Asian LNG trading hub at the same time frame.

In line with the spirit of liberalization, Japan's Ministry of Economy, Trading and Industry (METI) has delivered the message that Japan has great chance and intention to create a flexible LNG market and LNG trading hub *(METI, 2016)*. Divergent of oil price vs the U.S. gas price, Asian's growth future demand of LNG, shift in major LNG from ASEAN/Middle East to the U.S./Australia and energy market liberalization in Japan are among factors that drive toward this intention. Japan's visions to LNG trade in the future are:

- Minimize the long term contract (by stabilize the supply and demand)
- Utilize arbitrage trading and abolish/relax the destination clause
- Prize stabilization and transparency which reflect LNG supply and demand

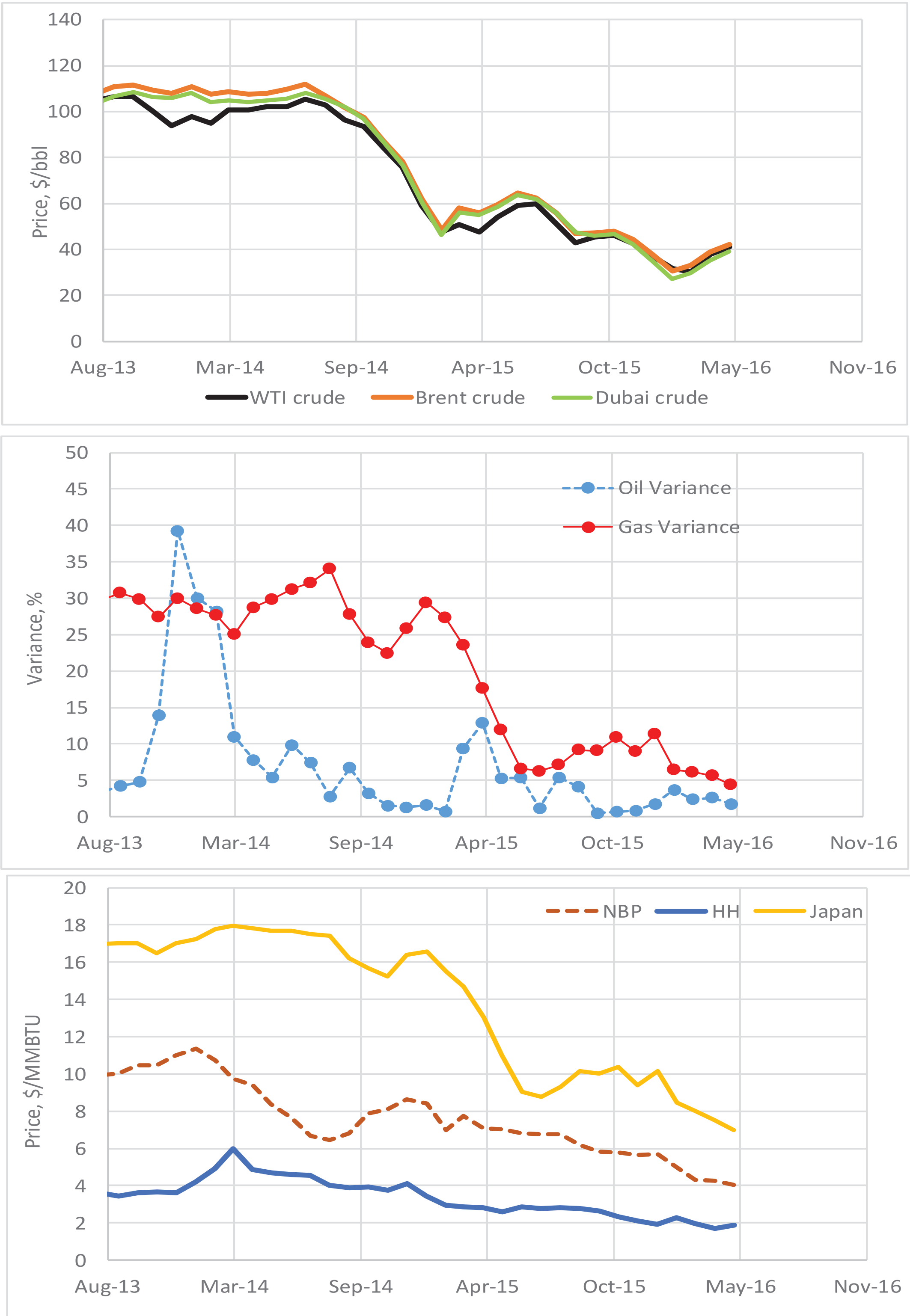


Figure 4.6 The comparison of crude oil price vs natural gas price and variances; 2013-2015 (Source; EIA, IMF)

4.4 Possible Impact on Markets in East Asia and NW Europe

Globalization of natural gas markets will substantially increase the level of international trade, and prices in different regions will become more integrated. What is the possible impact to market in East Asia and North West Europe if such of globalization and market integration occurred in the future? The revolution of the U.S. LNG from an LNG importer a decade ago to become a net LNG exporter can assist such this observation in context of LNG is the main linkage to this paradigm. The new large capacity of the U.S LNG and its intention to trade the LNG in different destination internationally will increase the competition to core LNG players, such as Qatar/Australia and Russia/Norway as the main natural gas supplier via transmission pipeline.

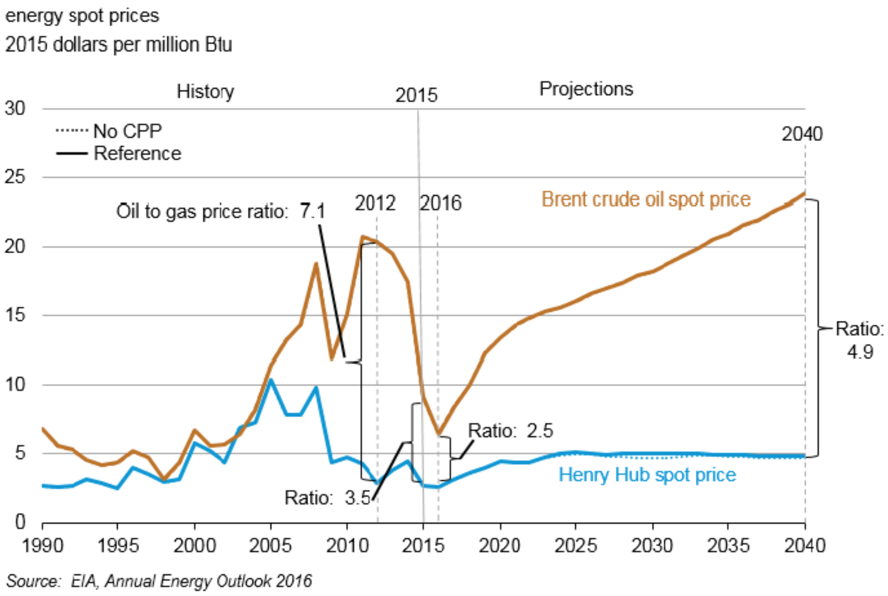


Figure 4.7 Projection of Brent crude price vs Henry Hub price (Source: EIA 2016)

Figure 4.7 shows the comparison between the projection price of Brent crude oil and Henry Hub prices. From 2016 to 2020 both oil and gas prices is at their greatest growth. After 2020, oil price is projected to continue growing, at a slower pace, while natural gas prices hold steady which is driven by continued improvements in extraction technologies (EIA, Annual Energy outlook 2016). The high oil price projection will give special advantage for the U.S LNG market outlook. East Asia countries, which mostly depend on the LNG supply from Australia under long term contract, will be triggered to look at the possibility of moving to other index prices, one of those is the U.S. LNG index volumes with price lower than oil index price, or to create a hub price that will reflect the real supply and demand fundamentals in Asian market.

Said that, actually in April 2016 is the first debut of LNG shipment from the U.S. shale gas to Asia (India). Consequently, if the U.S. LNG capacity is fully utilized and continue to deliver LNG to Asian countries such as Japan, Korea, China and India either in the spot market or under long term contract with market based price, the competition in market will increase significantly. Thus, it is not impossible to see the transition of pricing mechanism in Asian markets. These phenomena will likely stimulate the creation of the Asian hubs that can facilitate the exchanges of natural gas between parties, as long as the government, supplier, system operator and an independent regulator give their fully support.

While in Europe, particularly in North West Europe, where Russia, Norway and Algeria act as the supplier, the prospect of global wave of the U.S. LNG will create a certain condition where the European price will be pushed even lower to a certain level which is unprofitable for the U.S. LNG. According to ICIS Heren GLM (June 7th, 2016), the price of the summer gas of NBP for period July and August 2016 are estimated in level $4.9/MMBTU, stay low in line with the U.S. landed price to Europe. That said, the U.S. will become the price determinant; establish the direct pricing link between the U.S. shale gas production to European market. If these things happened, it could have the continuous effects across other regions and commodities (more likely what has happened in the oil market). In the other side, Russia should adopt a strategy of managing European prices to prevent new LNG projects being approved.

After all, the globalization will stimulate the competition level in natural gas market where the price signals between regions is easily transferred. It works contrariwise with what has discussed earlier in this chapter, where the competition, flexibility and liquidity contributes to increase the degree of a market integration and in the end the level of each will regain depends on the stage of globalization.

Chapter 5
Conclusion

- The increase of competition level in natural gas market with larger destination flexibility consequently will enhance the liquidity and market efficiency. Market will significantly reflect the real supply and demand fundamentals in the global gas market. As that happens, increasing arbitrage opportunities reduce the price divergence of regional market. If the spot trade and arbitrage of LNG reach larger than 50% of total LNG trade, most likely a paradigm shift toward an integrated natural gas market will occur, not in the near future but possible in a term within 10-15 years from now.
- One of important keys to reach the globalization is market liberalization, particularly in Asian region. In context of liberalization, the monopolist system that limits the level of competition and number of players in the market is removed. Buyers will have wider access to multiple sellers and increase prices transparency. In Japan, as the largest LNG consuming country (consumes 30% of total LNG), there is now an effort to liberalize its natural gas market and embrace to the market-based price in early 2020. As this happens in the near future, it is not impossible to accelerate the way to an integrated global market.
- In the global market situation, the abundant supply in Asia with low prices for some years creates a perfect condition for market competition and the transition of pricing mechanism. These will stimulate of creating the Asian hubs, especially in East Asia, that will facilitate the dynamics of the exchanges and become a source of market flexibility. Further, the hub needs to determine which pricing mechanism that reflects the best of gas supply and demand in Asian countries. Basing the Asian's index to the US LNG is not logical for time being, because it is only focusing to price level, not price formation.
- In order to meet the world demand, currently the international trade takes 30% of total natural gas market size; 20% of it flows internationally through pipelines and nearly 10% is moved to market destinations as LNG. This numbers are projected to grow larger as the demand of natural gas gradually increase. LNG is seen as the main linkage to market globalization. The flexible LNG spot trade and short term contracts (counted as only 30% of total LNG trade or

10% of total international trade) potentially is able to increase the liquidity of natural gas towards an integrated market.

- The development of the U.S. shale gas has brought the revolution of the U.S. role in international market. Based on projection from EIA, the U.S. will be the net exporter of LNG by 2018 with targeted destination countries in Asia, Europe and Latin America. Not only that, the U.S LNG export with market-based trade will enhance market competition, both from core LNG players (Qatar, Australia, Africa, Trinidad & Tobago) and gas pipeline provider (Russia, Norway and Algeria).
- The U.S. LNG are entering the market in a difficult period and will add downward pressure on prices across regional markets. On one hand, it will create the greater liquidity in supplies, increased competition and strengthen consumer bargaining power globally. All of these indicate the strong potential for the market to globalize. However, there is a challenge; includes the competition from other energy source; coal (India, Korea), the campaign of renewable energy that environmental friendly (Europe), and the reactivation of nuclear power plant (Japan).
- In north west Europe where Russia, Norway and Algeria as the main supplier of pipeline gas, the U.S. LNG export will enhance both price volatility and liquidity of natural gas. The price will be pushed down even more as the U.S. LNG becomes the price determinant. But on other side, the strategy to maintain the price should be adopted to prevent new LNG projects being approved, especially for Russia.
- The present thesis opens the paths for further study of some subjects that are not investigated deeper in this thesis such as the option for future Asian’s LNG index prices and how far the effect of East Asian’s market liberalization in perspective of energy consumers and suppliers, in connection with globalization of natural gas market.

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