LNG Trade-flows in the Atlantic Basin:
Trends and Discontinuities

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NG 41

March 2010

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ISBN
978-1-907555-08-4

PREFACE

In the late 2000s, LNG became one of the hottest energy issues around with a surge of new supplies coming on to global markets. Hailed as the catalyst for creating a "global gas market" (despite confusion as to what that might mean), LNG turned from being a minority to a mainstream gas interest, with countries in different parts of the world opening up regasification terminals which will allow them imports from diversified sources. In the midst of these projects coming on stream, the 2008 global recession saw markets swing from severe shortage to surplus and prices falling accordingly.

While many studies have charted the progress of liquefaction and regasification projects at various stages of development in different countries and geographical regions, this one attempts something more complex: to explain the supply, demand and price dynamics of the three major regional gas markets in North America, Europe and Asia in order to demonstrate how these markets have become connected through LNG, and how those connections may develop as business and energy/natural gas cycles unfold.

This is the first study of LNG supply and demand from the Natural Gas Programme since our first major publication back in 2004. It is also the first time that one of our authors has developed a model in order to illuminate the operation and interaction between different gas markets. There is a tendency for academic energy models to be "black boxes" where the data and results are very difficult to verify. The model developed in this study explains the methodology behind the estimation of the interaction of LNG and natural gas flows with prices. The model is updated monthly with public domain data allowing projections to be validated on an ongoing basis.

The arrival of Howard Rogers has added enormously valuable industry-based knowledge and perspective to the research of the Gas Programme. It would have been extremely difficult for anybody without his long experience of gas analysis to devise such a powerful modelling methodology within such a relatively short time. We are very fortunate that he joined the Programme at a pivotal moment in the evolution of global LNG trade, and his ongoing analysis of the different regional markets informs all of our work on gas supply, demand and pricing.

Jonathan Stern

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Introduction

This paper is written at a time of significant change in the markets which import Liquefied Natural Gas (LNG) for some or all of their natural gas requirements. In 2009, the weak natural gas demand (a consequence of the global economic recession) observed in key Asian LNG importing countries, Europe and North America provided an uncomfortable backdrop for still burgeoning US domestic gas production and the imminent surge in global LNG supply as liquefaction projects, which achieved financial sanction some 4 or 5 years previously, commenced production.

In terms of natural gas 'geography' the paper confines its focus to the natural gas consuming areas impacted by LNG; being those mentioned above and the new emerging or 'niche' markets of South America and the Middle East, and of course the LNG suppliers.

The period spanning the end of the 1990s to 2010 has seen significant changes in the sphere of natural gas in these geographies. These include:

- a changing perception of the availability of supplies of natural gas,
- a pro-liberalisation policy-driven gradual change in market structures in continental Europe,
- in Asia the growth in spot LNG purchases to offset the decline in Indonesian LNG export towards the end of the period,
- general LNG supply project slippage.

In the case of Asia this represented a small but ideologically significant departure from the 'A to B' long term contract paradigm. North America and the UK, as liberalised markets with once plentiful domestic supply, during this period built significant re-gasification infrastructure capacity in anticipation of becoming major LNG importers.

Despite these changes each of the regional markets has retained its own distinguishing characteristics, both structural and 'behavioural', (in terms of security of supply concerns and supply contracting preferences), which will shape their interaction in a global gas sense, facilitated by the growth in LNG supply.

LNG cargo arbitrage, initially between the USA and continental Europe can be traced back to the early to middle 2000s, followed by the inclusion of Asian LNG markets from 2005 onwards. With the growth in regas capacity in Europe and North America and with LNG supplies on the rise, Europe is placed in a position where, within infrastructure and contractual constraints, it can to a degree substitute pipeline imports (priced off oil products) and LNG (priced at the margin off North American gas-on-gas competition 'spot' prices). The paper develops a framework for quantifying the scope for such arbitrage in order to identify the conditions in which prices across the Atlantic Basin can converge or conversely de-link.

The paper does not foresee the development of a global, liquid traded commodity market as has developed in oil; the lower energy density and hence the cost of transportation infrastructure and storage (and the historic tendency for long term contracts to remunerate the investment in such supply systems) would mitigate against a rapid transition to such a state. What has happened however is the partial undermining of the 'national incumbent' gas purchaser in Europe, the adoption of limited spot purchases of LNG in Asia and the development of distant long-lead time supplies of LNG for the liberalised gas markets of North America and the UK.

On the one hand such developments encourage the growth of global linkages between regional markets, facilitated by LNG. On the other hand, given the limited demand and price elasticity of natural gas, the likelihood that the new system will successfully synchronise long lead time LNG and pipeline import supply and unpredictable demand growth is questionable. North American onshore production flexibility, given its shorter investment lead times, may emerge as a key stabilising supply-side factor.

For this reason, in addition to focusing on the scope for price convergence through arbitrage in the Atlantic Basin, the paper also explores the consequences of the 'system' in which supply and demand becoming periodically unbalanced and the specific response mechanisms (through price signals) which will, over time, bring it back into balance.

The paper derives a set of future assumptions (a 'quantitative envelope') and develops a modelling framework to explore the trends and discontinuities for the period to 2020. A suite of modelled cases are discussed to illustrate the scale of the system de-stabilisation likely in the period to 2012 and the scale of price-driven response necessary to re-balance it.

The dynamics of the system described in this paper will be plain to observe, in the real world, given the occurrence of the 'perfect storm' which is, in early 2010, currently impacting this system:

- an unforeseen high level of US domestic production.
- demand levels below those anticipated, due to the economic recession,
- since October 2009, the huge growth in LNG supply, much of which is inherently destination flexible or 'self contracted',

In terms of structure:

Chapter One provides background and context to the development of the Atlantic Basin gas markets and the LNG trade.

Chapter Two develops a framework for future market interaction through LNG and pipeline gas arbitrage

Chapter Three derives an envelope of future assumptions and explores the trends and discontinuities emerging from the modelling framework.

Chapter Four states the Author's conclusions.

1. Atlantic Basin Gas Markets and the Growth of LNG Trade

What is LNG?
Liquefied Natural Gas is gas which has been cooled to minus 161 degrees centigrade where it condenses into a liquid phase at atmospheric pressure. Compared with its gaseous form, LNG's energy density is 600 times greater and as such offers the potential for marine transportation to distant markets in specially constructed ships. The LNG supply chain comprises the upstream gas field development and pipeline transportation to the liquefaction plant where processing and cryogenic cooling converts it to a liquid. The LNG is stored in insulated tanks adjacent to a loading jetty where it is transferred to an LNG tanker. On arrival at a receiving port on the destination market coast, the LNG is transferred to storage tanks prior to re-gasification and entry into the market distribution system.

Although the capital investment required to construct such a chain is considerable, upwards of $5 billion for a 9 bcma LNG project[1] , the industry 'rule-of-thumb' assumption is that LNG is the more economic alternative compared with a pipeline for distances in excess of 2,000 to 3,000 miles. This is a very rough guide as various factors will introduce a significant degree of variability to this.

With its prolific growth post 2000, LNG has captured the imagination of industry traders and analysts not only in terms of its ability to link distant suppliers and consuming countries but more especially the ability, under certain circumstances, to change its destination market in mid voyage. For those in the gas sphere who would like gas trade to become more akin to oil's liquid global trade profile, LNG is a particularly interesting prospect.

The first 'experimental' LNG cargo was shipped from Lake Charles in the US to Canvey Island in the UK in 1958, however the first commercial project commenced in 1964 between Algeria as a supplier to both France and the UK, and Libya to Italy and Spain. The Alaska – Japan project also emerged in this period. In 1972 North African LNG began to supply the US giving rise to the re-gas facilities at Lake Charles, Elba Island and Cove Point. LNG trade to the US grew during the 1970s but contracted post 1979 due to the deregulation of the US market which was followed by nearly two decades of low natural gas prices. European trade continued to grow[2].

While the Atlantic Basin can be viewed as the 'birthplace' of the LNG industry it was eclipsed relatively early on by the Pacific Basin as Alaska, Indonesia, Malaysia, Australia, Brunei and Abu Dhabi launched projects to supply initially Japan and subsequently South Korea and Taiwan.

By the year 2000 Europe's LNG imports at 32.1 bcma were a third of those of Asia (98.3 bcma) but significantly more than those of North America (6.8 bcma). In Europe France, Spain and Italy had been joined by Belgium, Greece, Portugal and Turkey as LNG importers, although the UK has stopped importing[3]. Nigeria and Trinidad and Tobago had emerged as new regional suppliers to Europe and Qatar, Oman and UAE were also targeting the European market in addition to Asian markets.

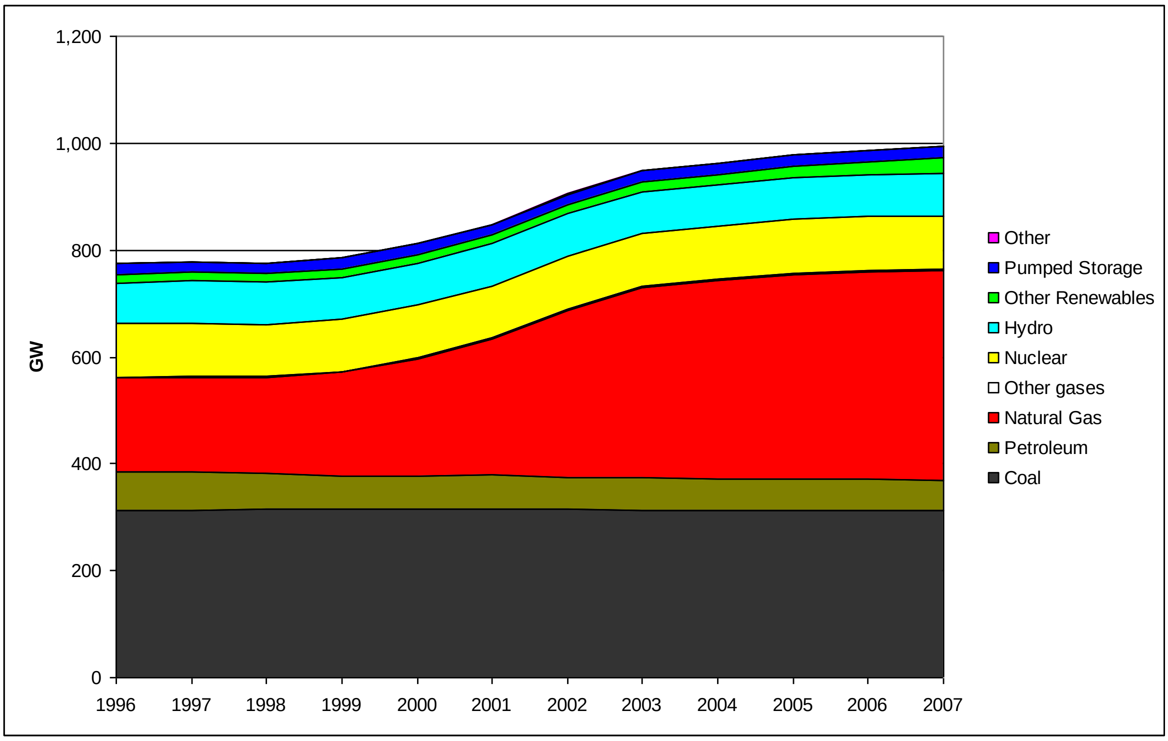
[1] Jensen 2004, p. 6.
[2] Jensen 2004, p. 8.
[3] Cedigaz 2004, p. 17.

North America Gas Market Structure and Developments
The year 2000 probably marked the end of an era in the Atlantic region natural gas markets which was characterised by:

- High demand growth (1990 – 2000) in both Europe (3.0%/year) and North America (2.2%/year) driven in the main by the adoption of the Combined Cycle Gas Turbine in the power generation sector[4].
- A perception of abundant, low cost gas supplies, especially in North America and the UK North Sea.
- Within Europe a strong national gas market identity, often 'owned' by a midstream incumbent.
- Apart from the transit of contracted gas, there was limited freely-traded cross-border flow of gas. The exceptions to this were trade between Canada-US and Mexico-US and between the UK and NW Europe after the opening of the UK-Belgium Interconnector in October 1998.

The best illustration of the energy sector's belief in plentiful competitive natural gas supplies is provided by the astonishing surge in new Combined Cycle Gas Turbine (CCGT) capacity in the US between 1999 and 2003.

Figure 1. US In-Place Generation Capacity 1996 – 2007

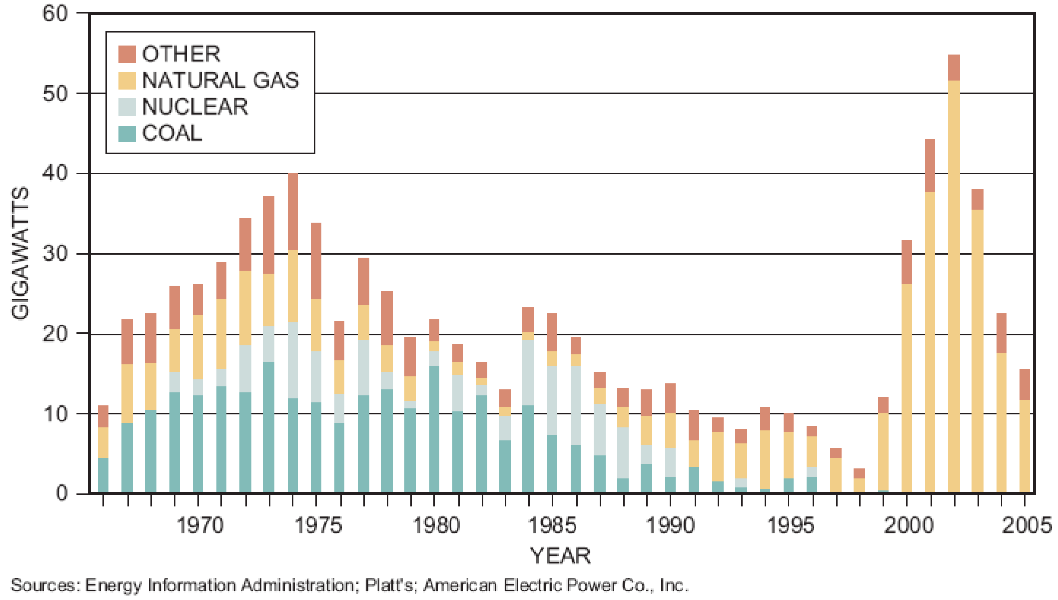


Source: EIAa, Table 2.1

During the period shown in Figure 1, new CCGTs added 219 GW to US generation capacity – a 28% increase on total 1997 generation capacity. The picture is even starker in the context of annual capacity additions over a longer historical period. Figure 2 shows that the overwhelming majority of additions to capacity after 1996 were from gas-fired plant.

[4] BP 2009, Derived from Data in 'Gas Consumption Bcm' Spreadsheet.

Figure 2. Comparison of US Installed New Generation Capacity

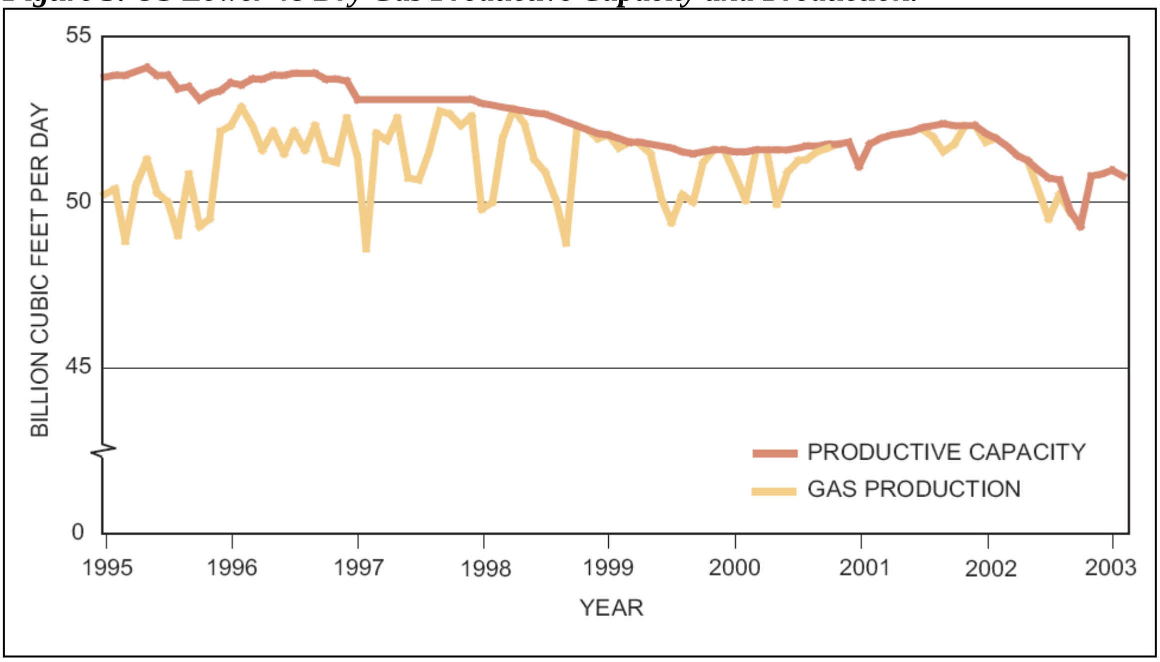


Source: NPC 2003, p. 90.

But just as the aforementioned surge of new CCGT capacity neared completion, North America suddenly found itself in a 'tight' natural gas supply situation.

Although not immediately apparent at the time, by the end of the 1990s the US had lost its 'cushion' of spare production capacity from existing wells (Figure 3) such that by year 2000 producing gas wells were running at full capacity on a year round basis. The role of providing supply flexibility now fell solely to seasonal and short-term storage facilities.

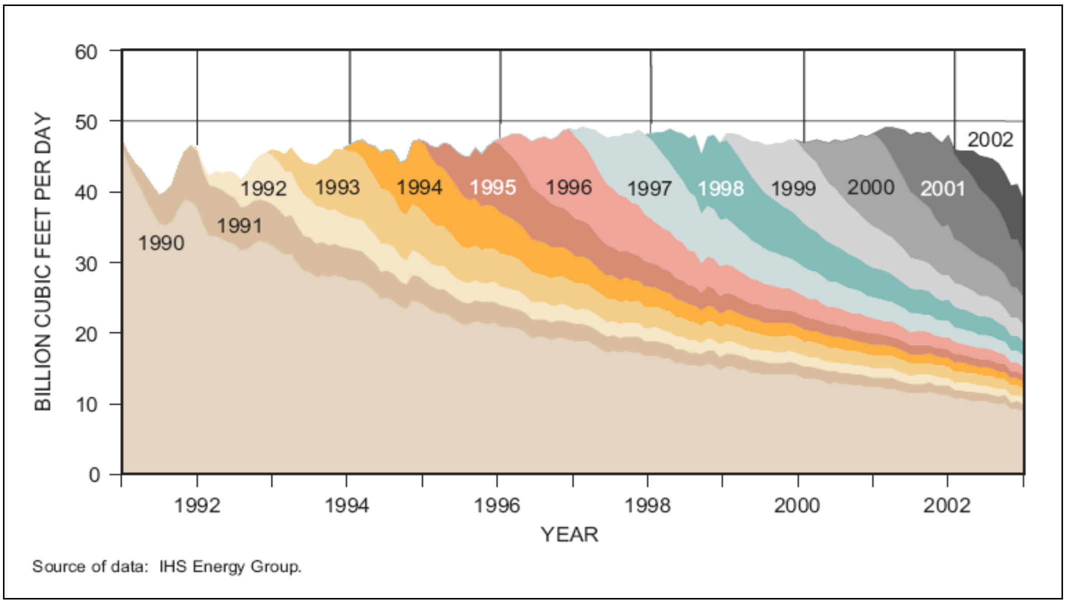
Figure 3. US Lower 48 Dry Gas Productive Capacity and Production.



Source: NPC 2003, p. 20.

In addition to the loss of spare production capacity, the incremental production per new well drilled was also falling, in spite of technological advances to accelerate early year production for a specific new gas well. This had the effect of increasing the underlying decline rate, necessitating an increase in annual drilling intensity of new wells merely to keep production constant at an aggregated level (Figure 4)[5].

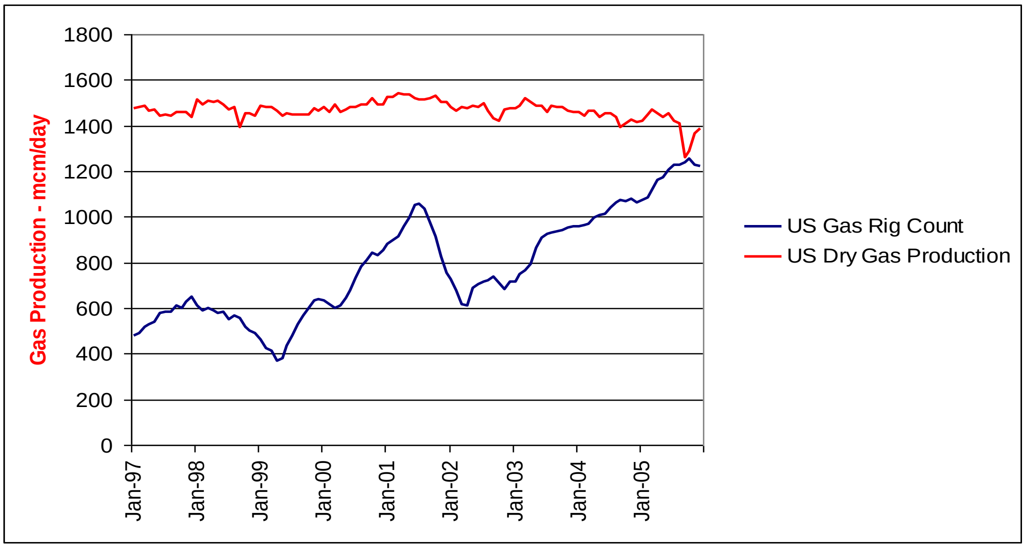
Figure 4. US Lower 48 Wet Gas Production by 'Vintage Year' of Gas Well Production Start



Source: NPC 2003, p. 160.

From Figure 5 it can be seen that from a peak in 2001, US gas production declined through the remainder of the period to 2005 (at an annualised rate of 1.5%) despite the general increasing rig count trend. (The temporary production drop towards the end of 2005 was caused by hurricane Katrina).

Figure 5. US Dry Gas Production and Gas Rig Count 1997 - 2005

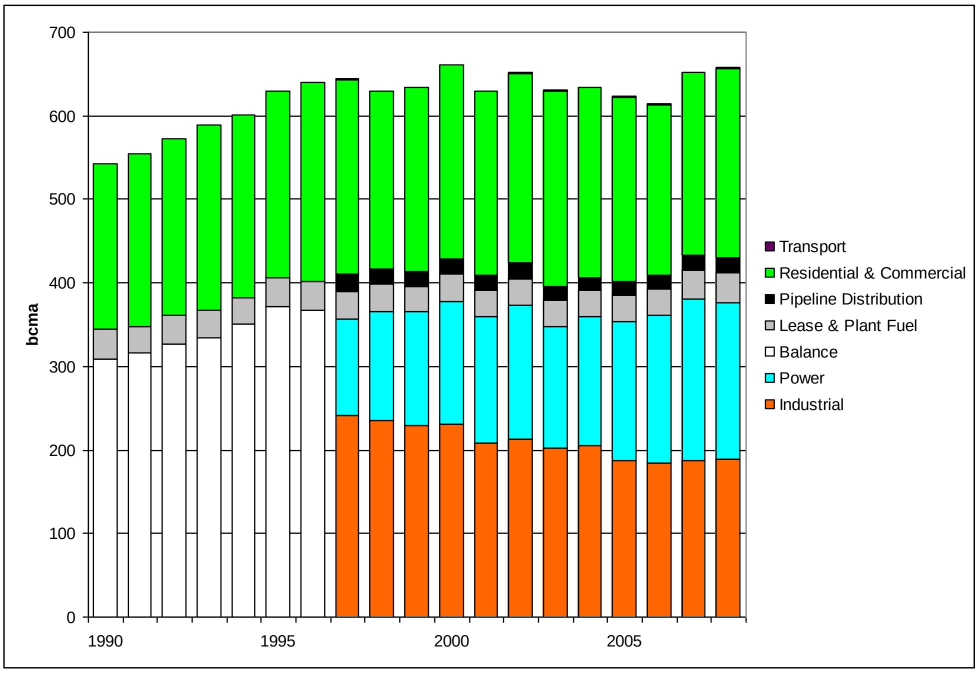


Source: Baker Hughes 2009, EIAb, Dry Gas Production Data.

[5] Note that the data in Figure 4 for 2002 production is incomplete.

The consequences of this new 'supply constraint' for North America were two-fold. Firstly it heralded a period where prices, driven primarily by supply-demand balances in this liberalised market, exhibited seasonal volatility in response to market fundamentals, at times reaching price levels unthinkable by historical standards. Secondly the impact of high and volatile gas prices, (relative to countries where domestic market gas prices were linked to oil or oil products or subsidised, and therefore less volatile), appears to have contributed to a decade-long erosion of gas consumption in the industrial sector.

Figure 6. US Natural Gas Demand by Sector 1990 - 2008



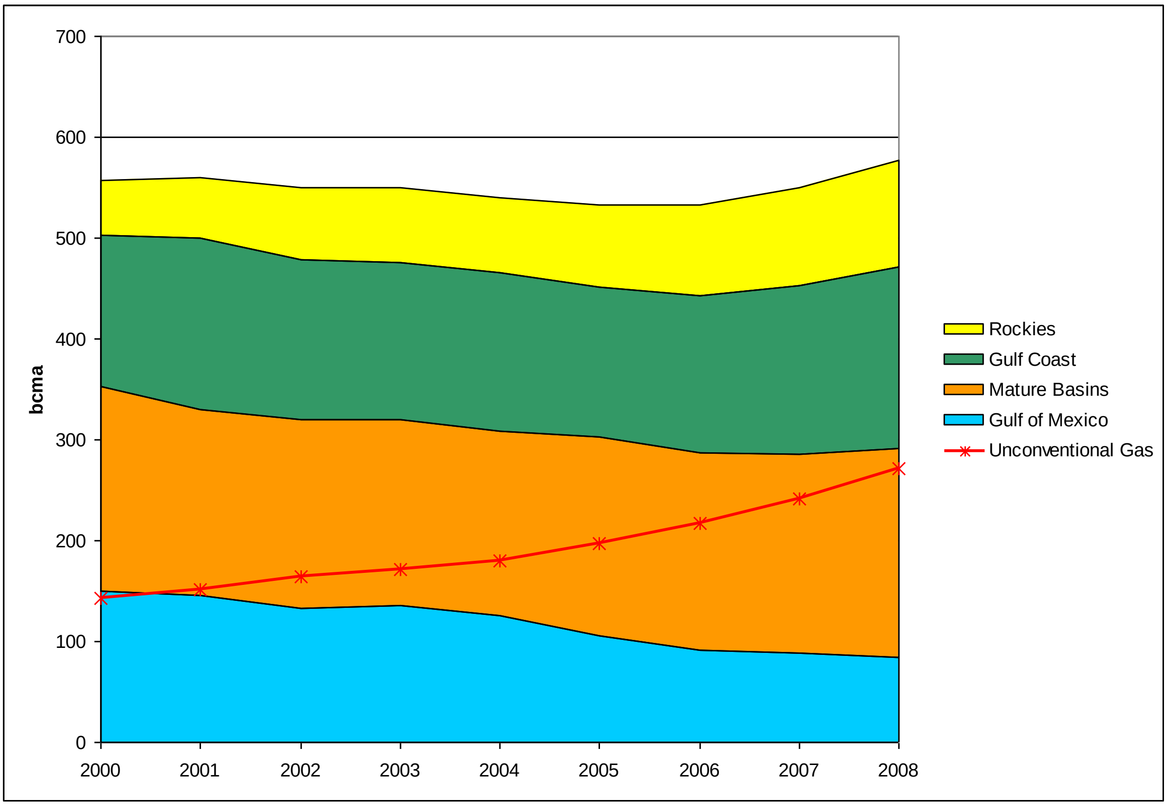
Source: EIAb, Gas Consumption by Sector Data

Figure 6 shows US natural gas demand by sector between 1990 and 2008. (Data for the industrial and power sectors became separately available in 1997). The decline in industrial demand and the increase in natural gas consumption in the power sector are evident.

Exploring the degree to which industrial consumption has been directly affected by gas prices as opposed to being a consequence of a gradual economic structural shift away from energy intensive industry is beyond the scope of this paper.

The most startling development in the North American natural gas market post 2000, has been the spectacular turnaround in domestic natural gas production since 2006. In the early 2000s the Oil and Gas Majors, in general, were reducing upstream investment in gas in North America and focussing on international LNG projects. However the US and Canadian 'Independents' who lacked the capital and global footprint to embark on five-year lead-time, capital intensive international projects, were perfecting innovative development strategies for North American 'unconventional gas' – shale gas, coal bed methane and tight gas.

Figure 7. US Lower 48 Regional Wet Gas Capacity 2000 – 2008



Source: Vermier 2009, Slide No 7; Based on CERA Analysis

The result of their efforts was spectacular and largely unforeseen; no less than a reversal of the decline in US gas production as shown in Figure 7, and a significant growth from 2006 onwards.

This upturn in North American natural gas production has implications of global significance which will be discussed later in this Chapter.

North America represents some 28% of global natural gas consumption and is one of the few regional natural gas markets which are 'liberalised' in the sense that prices are determined by the forces of supply and demand. A brief description of how this market structure developed follows:

In the **US** long running concerns over the potential market power of interstate pipeline companies led to numerous legislative and regulatory initiatives since the 1970s. Ceiling prices at the producing well were increased or removed through legislation in 1978 and became completely deregulated in the early 1990s. Interstate pipeline companies were prohibited from reselling gas and so could no longer own the gas they transported. Institutional structures such as market hubs, futures and options markets and secondary markets for pipeline capacity rights developed[6].

In **Canada** prior to 1985, natural gas prices were set by agreements between the Federal Government and the Province of Alberta. Gas prices were based on crude oil prices with Local Distribution Company rates and terms regulated by provincial regulatory boards. The 1985 Agreement on National Gas Markets and Pricing eliminated the regulation of gas

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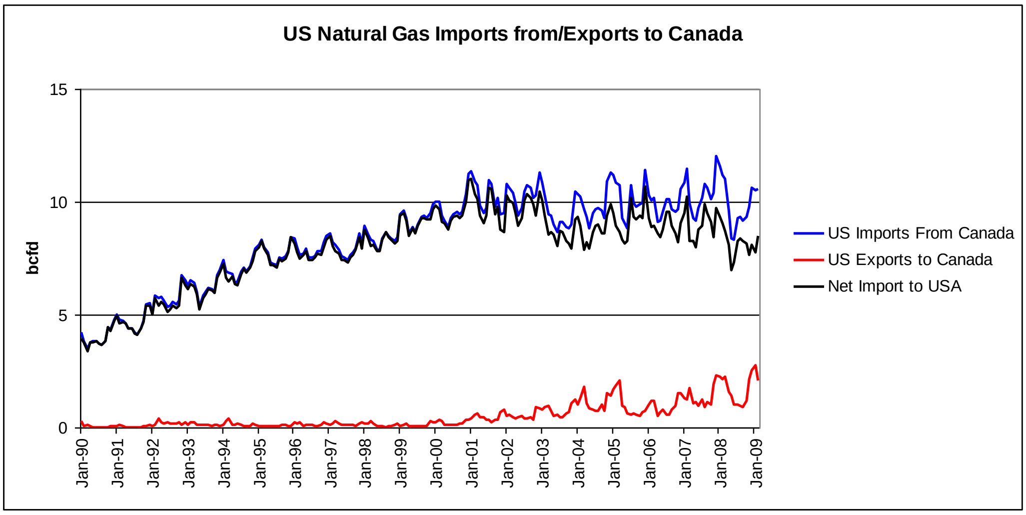
[6] EIA 2009c

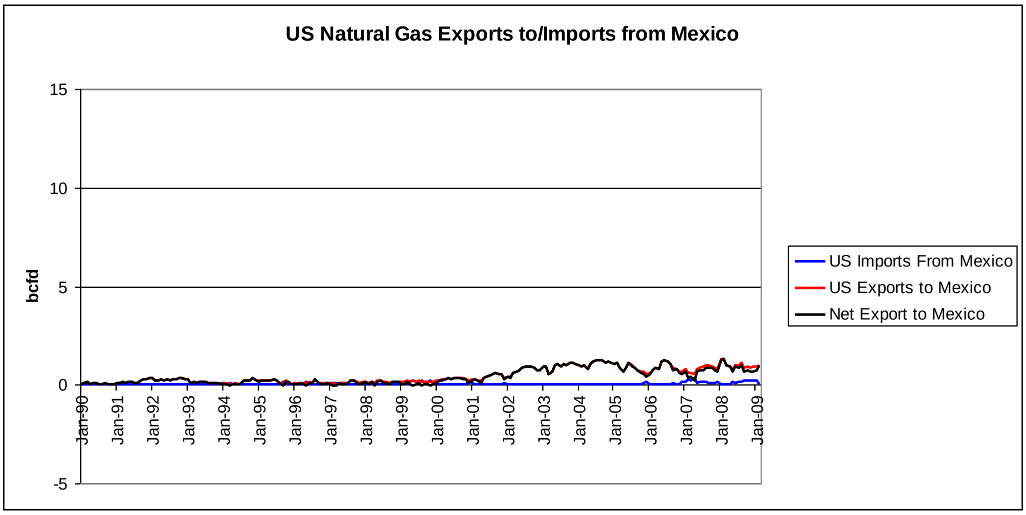
commodity prices, instead allowing price to be determined by competitive forces[7]. This was undoubtedly heavily influenced by the trend towards deregulation in the US which has consistently imported Canadian gas throughout this period of market evolution.

In **Mexico**, although a high proportion of domestic supply is associated gas (co-produced with oil) and the upstream monopolistic presence of Pemex might tend to counter competitive price formation, prices are based on a netback of those prevailing in Texas. This situation is a result of Mexico's membership of NAFTA and the emergence of two-way gas flows between Mexico and California and Texas[8].

Figure 8 shows the cross border natural gas trade between the US and Canada and Mexico respectively.[9] The increased two-way flow since 2000 has reinforced netback pricing from US trading hubs.

Figure 8. Cross Border Natural Gas flows (monthly) between US and Canada and Mexico



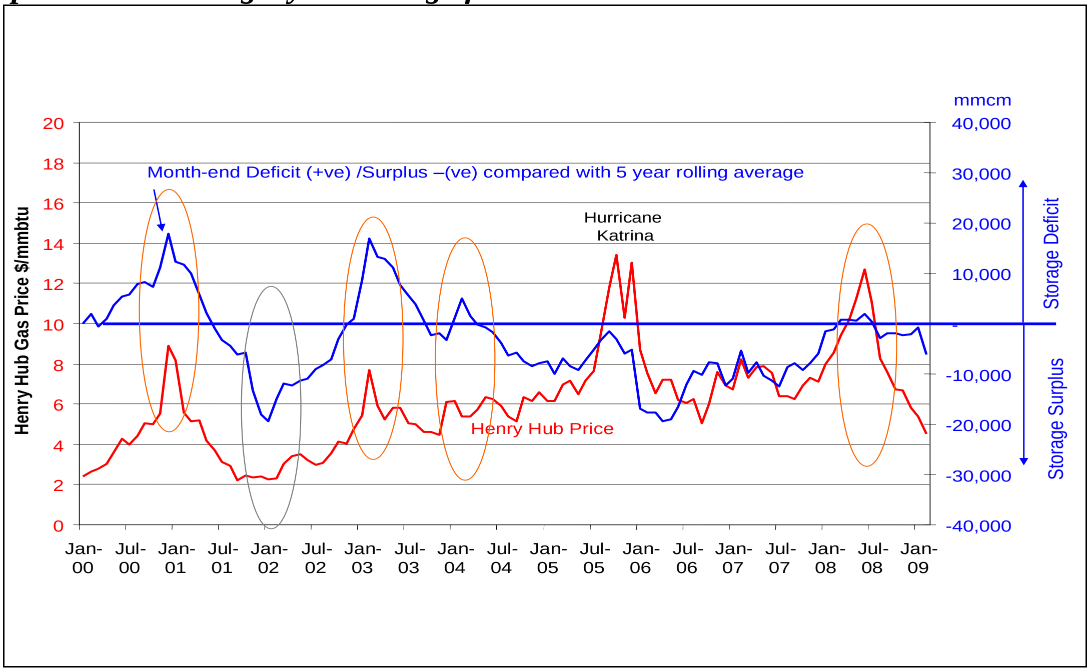


Source: EIAd

[7] Reid 1999, pp. 2, 3
[8] Rosellon & Halpen 2001, pp 1 – 14.
[9] EIA 2009 d

Figure 9 shows the supply-demand fundamentals during the period 2000 – 2005 in the US natural gas market. Allowing for the underlying run-up in gas price during the period, shorter term price peaks and troughs correspond to times when storage inventory was below (deficit) or above (surplus) the rolling 5 year average for the specific month in question. Thus, in the absence of any price-responsive short term supply mechanism, the market takes the current storage position as an indicator of the supply/demand balance.

Figure 9. US Henry Hub Natural Gas Price vs. end month Storage Deficit/Surplus compared with Rolling 5 year average for the month.



Sources: EIAe, Argus

Despite the fact that the North American natural gas market has been effectively 'liberalised' (i.e. natural gas as a commodity has its price determined by supply and demand), there is a tendency to assume that the US natural gas price is inevitably linked to oil price. The hypothesis that gas prices will naturally follow oil prices was supported by findings of an econometric study published by the EIA in 2006, which analysed crude prices and Henry Hub natural gas prices[10]. Its key findings were that:

'…natural gas and crude oil prices historically have had a stable relationship despite periods where they may have appeared to decouple. The statistical evidence also supported the a priori expectation that while oil prices may influence the natural gas price, the impact of natural gas prices on the oil price is negligible…oil prices are found to influence the long run development of gas prices but are not influenced by them.'

Two frequently cited reasons for the oil – gas price linkage are the following:

- The upstream industry in North America has the option to drill for either oil or gas with essentially the same stock of rigs and human resources; if the price of one is more advantageous, resources will be re-deployed accordingly.

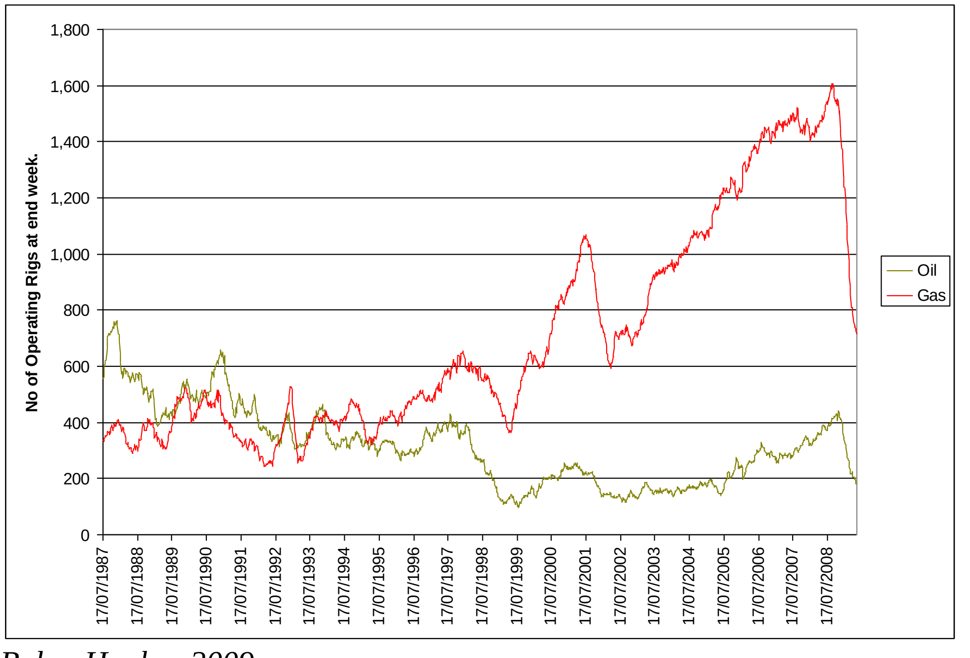
[10] Stern 2007, p25

- Oil and gas compete for the same end-user markets and so their prices are linked.

Both these points may have been valid at some point in the past (probably in the period 1950-1995), but their relevance since that time is dubious.

Figure 10 shows the number of operating rigs drilling for oil and gas respectively in the US from mid 1987 to mid 2009. The disparity in oil and gas rig counts since the end of the 1990s suggests it is unlikely that rig re-deployment between oil and gas is a significant driver of gas price.

Figure 10. US Gas and Oil Operating Rig Count 1987 - 2009

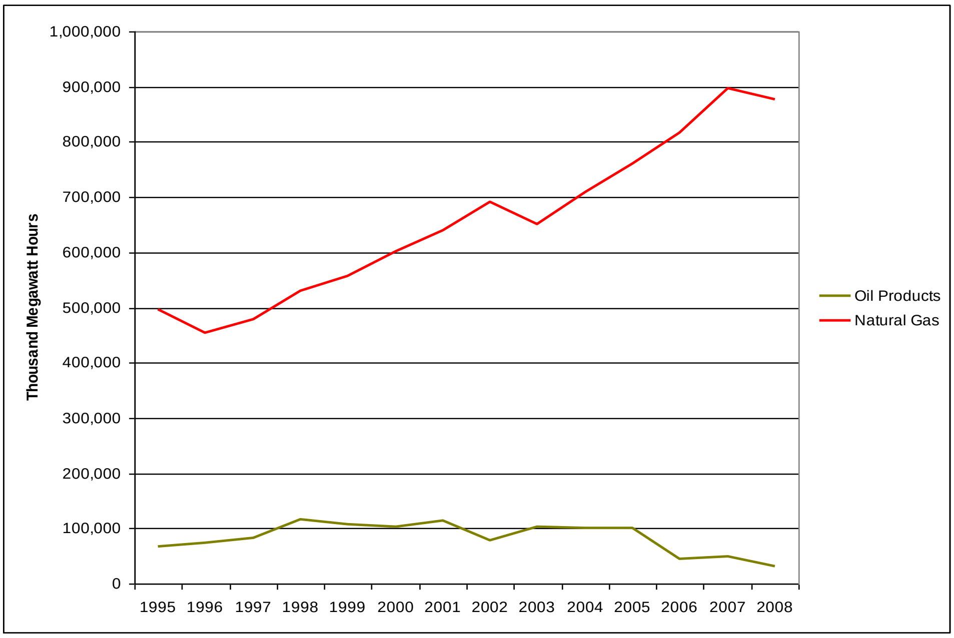


Source: Baker Hughes 2009

True competition between oil and gas has rapidly diminished in the domestic space heating sector as gas transmission systems have been expanded, and in the power generation sector since the introduction of the CCGT in the 1990s. This is shown in Figure 11.

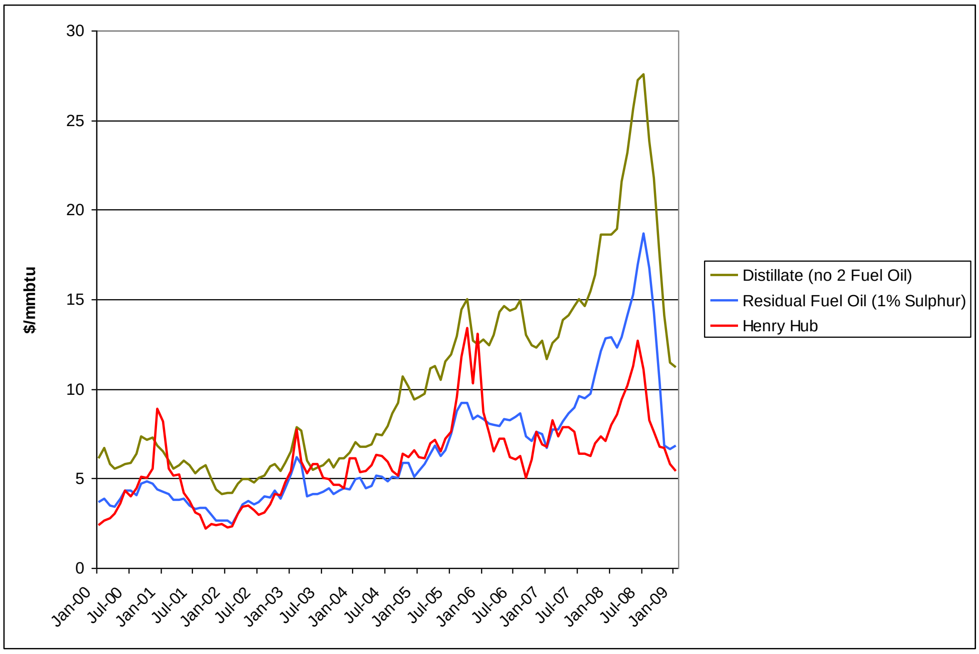
Data for the period 2000 to 2009 would suggest a more accurate hypothesis: that ‘oil and gas prices in the US only establish links infrequently because there is only limited burner tip competition, and this only pertains within a certain range of supply-demand tension’. This is shown below in Figure 12. For the period January 2000 to January 2006 Henry Hub price was for the great majority of the time between residual fuel oil and distillate prices. The Henry Hub price spikes of 1Q 2001 and 1Q 2003 took Henry Hub up to or through the distillate price. From 3Q 2002 to 4Q 2003 and for much of 2005 Henry Hub appeared closely linked to the residual fuel oil price. Since January 2006, apart from a short period of linkage in winter 2006-2007, Henry Hub has been below residual fuel oil price.

Figure 11. US Power Generation Produced from Natural Gas and Oil Products



Source: EIA 2009f

Figure 12. Henry Hub Natural Gas Price and Competing Oil Products Prices 2000 – 2009

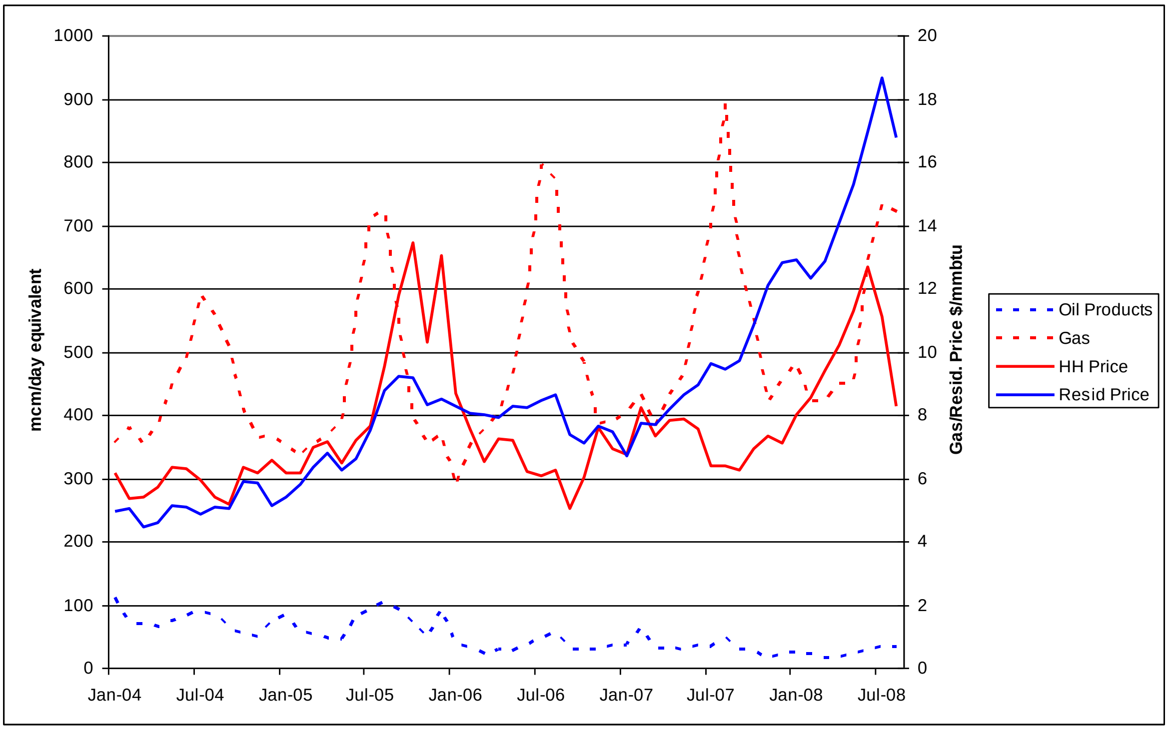


Source: Argus

Figure 13 helps to rationalise this in physical fuel switching (i.e. genuine fuel competition) terms in the power generation sector. The dashed red line represents monthly natural gas consumption in the US power generation sector (in mcm/day) and the dashed blue line oil products consumption in the power sector (in mcm/day gas equivalent). Also shown are Henry Hub and residual fuel oil prices in $/mmbtu. In the period to the end of 2005, the variation in oil product consumption in the power sector appears reasonably well linked to the price differential between residual fuel oil and natural gas. Oil products consumption varied between 55 mcm/day and 100 mcm/day (gas equivalent).

Post January 2006 when Henry Hub prices were predominantly lower than residual fuel oil prices, oil products consumption was consistently lower – around 28 mcm/day (gas equivalent). From this we can deduce that in the power generation sector there is a natural gas – oil products switching band which in terms of historical performance is in the range of 70 mcm/day in physical size. The switching band is activated when gas prices rise to meet residual fuel oil prices. A relatively tight supply situation for natural gas allows its price to break through the residual fuel oil price barrier once the physical switching band has been fully utilised.

Figure 13. Gas and Oil Products Consumption in US Power Sector vs. Relative Prices 2004 - 2008



Source: EIAg

(For further analysis of gas and oil product competition in the US see *Jensen*).

Post 2006, the hypothesis that oil and gas prices in the US only establish links infrequently because there is only limited burner tip competition, and that this only pertains within a certain range of supply-demand tension, is a reasonable working assumption. Foss states: 'In sum, the price relationships between natural gas, crude oil and oil products present a mixed bag of indicators. Natural gas can, at times, be influenced by and correlated with oil prices. Natural gas can also decouple from oil and oil products.'[11]

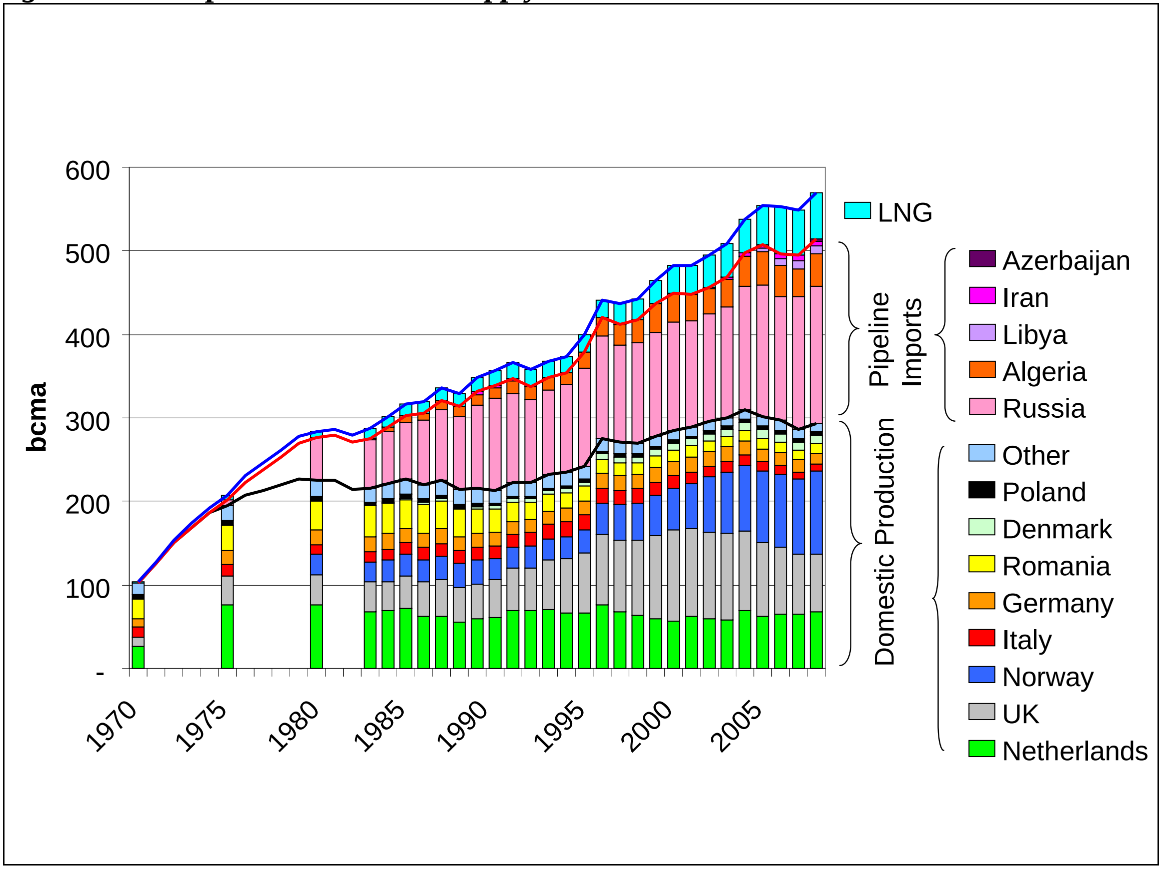
The IEA[12] broadly supports this position although they do cite the competition for upstream investment as a potential linkage.

[11] Foss 2007, p 8
[12] IEA WEO 2009, pp 513, 514

European Gas Market Structure and Developments

Figure 14 shows the sources of natural gas supply to Europe from 1970 to 2008.

Figure 14. European Natural Gas Supply 1970 – 2008



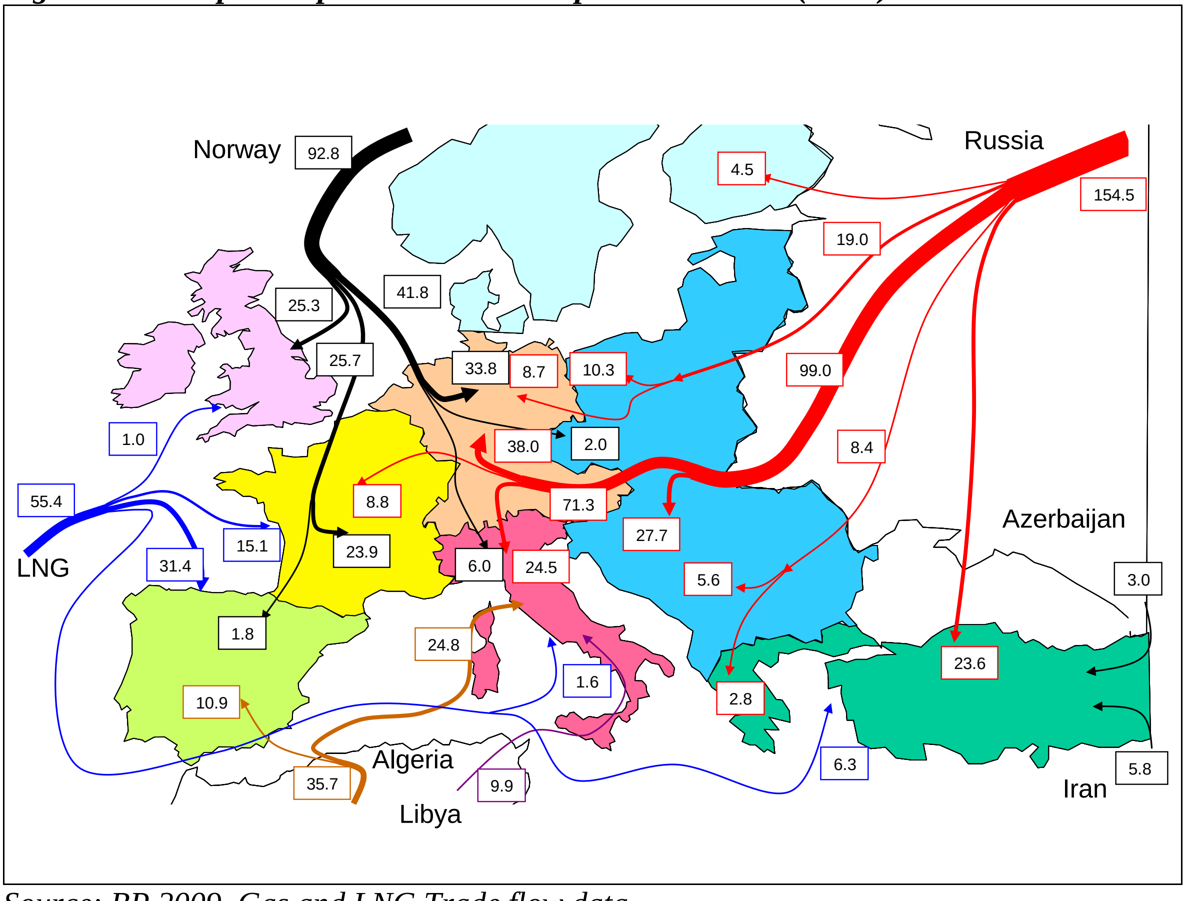
Sources: Cedigaz 2004 pp 2-9, BP 2009 natural gas consumption tables

While pipeline imports began to make a significant contribution to Europe's gas supply requirements by 1980, by 2008 they represented 39% (excluding Norway), and LNG imports 10%.

Figure 15 shows the flows of pipeline gas and LNG imports into Europe for 2008, and provides a picture of which regional blocs are served by the various import sources.

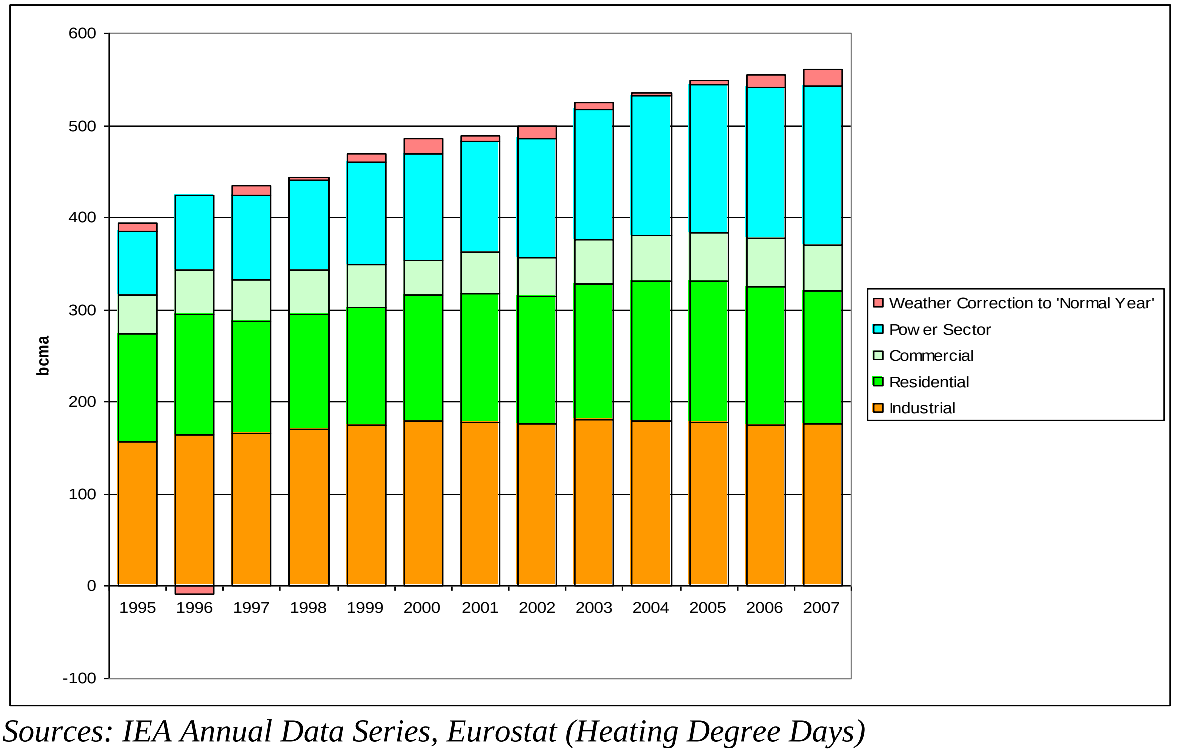
European gas demand (Figure 16), which had been growing at an annual average rate of 4.3% from 1995 to 2000, slowed to an annual average growth rate of 2.1% from 2000 to 2007. Although difficult to demonstrate in a quantitative sense, the demand slowdown was likely due to a combination of market maturity (particularly so in Northern Europe), and stagnation in demand in the industrial sector due to high gas prices and long-term but progressive relocation of energy intensive industries away from Europe. The power generation sector showed the strongest growth.

Figure 15. European Pipeline and LNG Import Flows 2008 (bcma)



Source: BP 2009, Gas and LNG Trade flow data

Figure 16. IEA Europe demand by sector 1995 - 2007

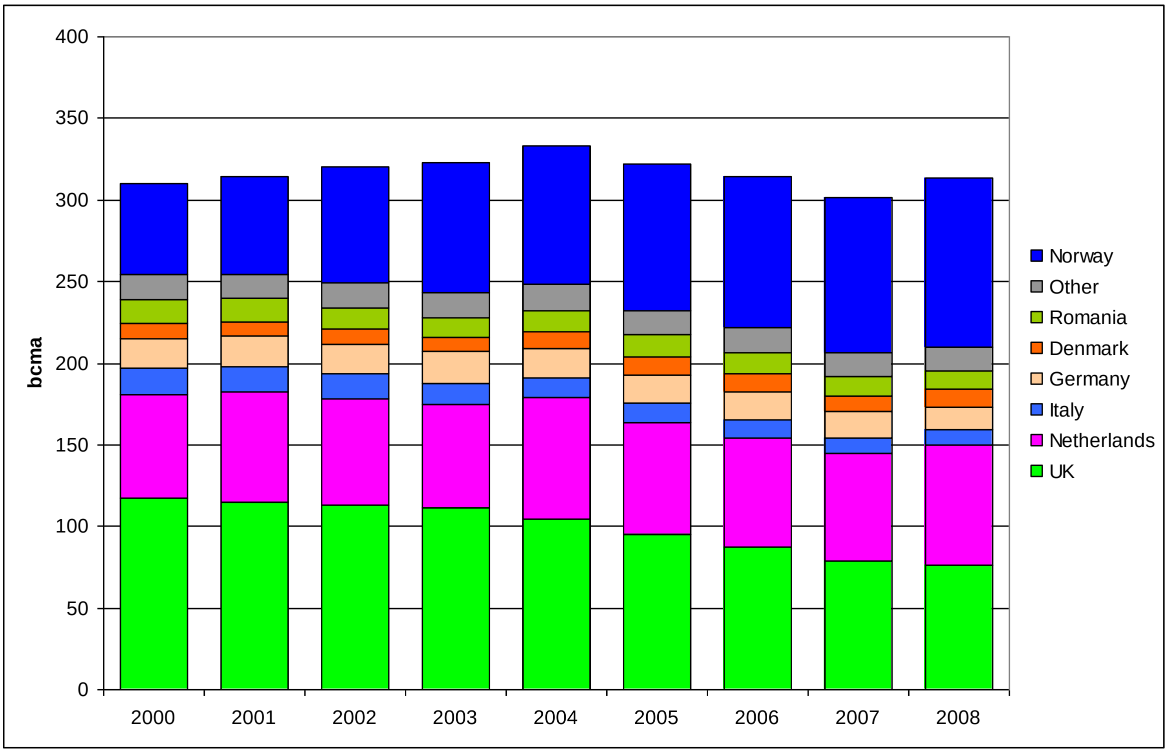


Sources: IEA Annual Data Series, Eurostat (Heating Degree Days)

In the early 2000s a continuation of power sector gas demand growth led policy makers to question where the additional supply might come from, given the likelihood that the majority of incremental volumes would be imported gas. The ongoing disharmony between Russia and Ukraine prompted concern as to the reliability of supply from this quarter, despite Russia's excellent record as a reliable supplier since the 1970s. January 2006 saw Russia shutting off gas supplies to Ukraine with collateral damage of restricted supply to some European countries, albeit brief. A more fundamental concern was the growing realisation that in order to substantially increase exports to Europe, Russia would need a substantial investment in key upstream projects such as the Yamal (Bovanenskoye) and Shtokmanovskoye fields both to offset the ongoing decline from its giant Soviet-era fields and to meet Russian domestic demand, which in the period 1999 to 2005 grew at an annual average rate of 2%.[13]

The oft repeated mantra 'Europe is surrounded by a sea of gas' seemed to offer scant comfort in the context of little tangible progress being evident, (at the time), in securing these supplies. The Nordstream project was the focus of attention through much of this period (from West Siberia, via the Baltic Offshore to Germany and potentially the UK). However, this project increasingly came to be recognised as a 'Ukraine transit avoidance route'; rather than one offering significant net incremental gas supplies[14]. Attention and energy was focussed on the Nabucco or '4th Corridor' project, spurred on by the success of the Azerbaijan Shah Deniz project in successfully delivering gas to Turkey via a new pipeline. The Nabucco project at the time of writing has political and downstream support but still crucially lacks the committed upstream supply required to underpin such an ambitious scheme. (For further discussion of these issues see Pirani 2009, pp. 404-406)

Figure 17. European Domestic Production 2000 - 2008



Source: IEA Monthly Data Series

[13] BP 2009, Gas Consumption sheet.
[14] It should be added however that the Shtokman field, whose likely start date is uncertain, may provide future additional supplies via the Nordstream pipeline.

A key exacerbating factor was, with the exception of Norway, the ongoing decline in European domestic production, especially in the UK, (Figure 17). Given the encyclopaedic data and production forecasts available on North Sea UK Sector, coupled with a dearth of new gas discoveries in the preceding years, it is astonishing, in retrospect, that the onset of decline in the UK sector should have come as a surprise. The Department of Trade and Industry and the UK Offshore Operators Association were, in the early 2000s, on a joint aspirational mission to maintain UK oil and gas production 'flat to 2010'[15]. This 'Canute-like' stance meant that when, in due course, it became evident that UK gas production had commenced its decline, precious time had been lost. As a consequence, the delayed implementation of new import projects was a key contributory cause of the tight supply situation which faced the UK gas market during the period 2004 to 2006.

The period 2000 to 2005 also saw a sustained increase in the level of gas prices in Europe (See Figure 18).

Figure 18. AGIP and Brent 2000 – 2005

Sources: Gas Matters, Platts

In the late 1990s the Average German Import Price (AGIP), (a blend of oil indexed long term contract gas prices from Russia, Norway and the Netherlands), had remained in the $2 to $3/mmbtu range. A rise in the price of oil and oil products in 2000 took the AGIP price, (linked to oil product prices with a 6 – 9 month lag), to $4/mmbtu briefly by the end of

[15] UKOOA 2004

2000. After a lull in 2001 the oil price began its sustained rise, taking AGIP to $4/mmbtu for 2003 and 2004 and then on up to around $7/mmbtu by the end of the following year.

The structure of the continental European natural gas market has been heavily influenced by the discovery and commercialisation of the Groningen Field in Holland and pipeline imports from Russia/Former Soviet Union. Gas from the Groningen field was priced, not on its underlying cost of supply or on the basis of supply and demand but on the basis of competitiveness with the final consumer's alternative non-gas fuels. This is often termed the 'market value principle' or alternatively the 'netback market approach'[16]. The approach was subsequently adopted for contracted pipeline and LNG imports to continental Europe. In the UK cost-based pricing was the main principle used in the negotiation of contracts between the state monopoly buyer British Gas and upstream producers in the pre-liberalisation era (pre-1996)[17]. This led to a wide range of contract prices depending on the cost base and gas:liquids production ratio of fields specific to the contracts negotiated.

Contracts for European pipeline imports initiated from the 1970s to the present day are typically 20 to 25 years in duration. The buyer has the right to nominate up to an annual amount (the Annual Contract Quantity – or ACQ) but must take or in any case pay for an annual quantity equal to the 'Take or Pay' level (TOP), which is typically some 85% of the ACQ on an annual basis. Additional flexibility is employed at the monthly or daily level provided that in the course of a gas contract year an amount at least equal to the TOP is paid for.

Pricing of long-term contracted gas imports is generally linked to the price of Gas Oil and/or Fuel Oil, by a formula negotiated and defined in the contract:

Pn = Po +a*(av Fo(n-x ..n-1))+b*(av Go(n-x ... n-1))

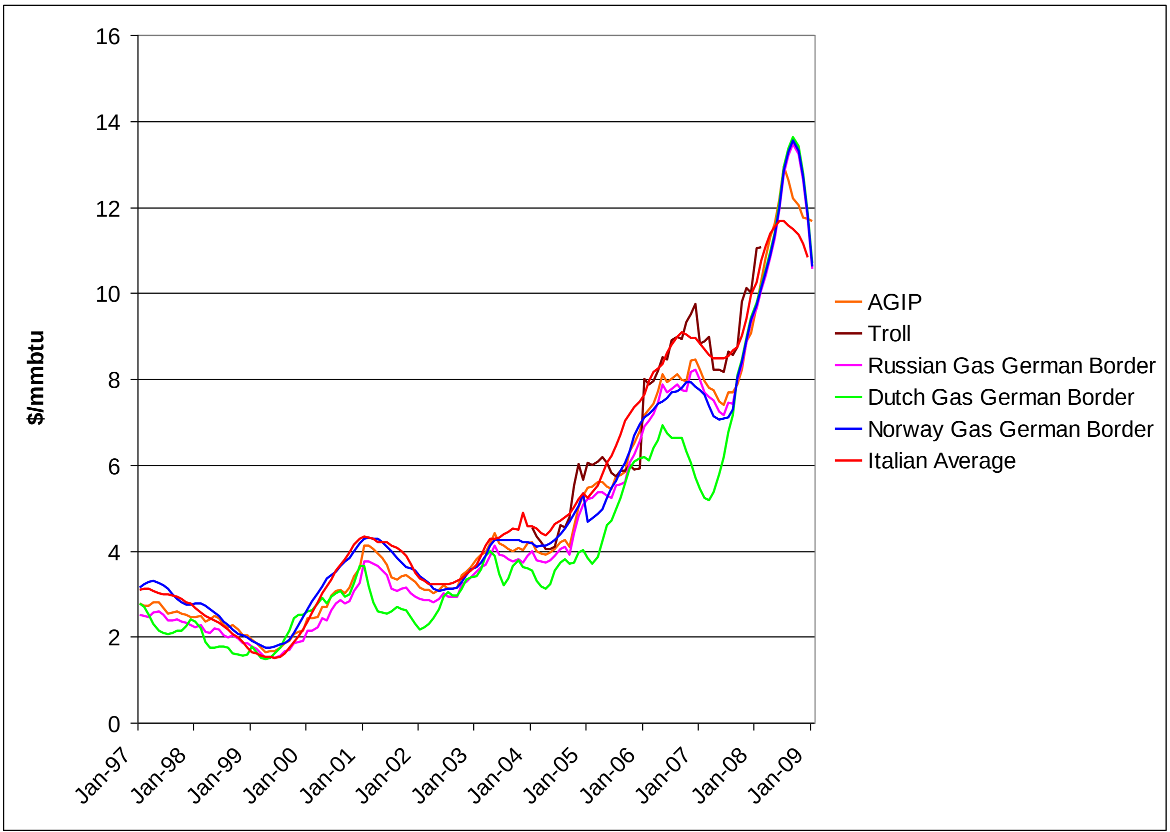
The price in month n equals the initial contract price (Po) plus:

- A constant **a** multiplied by the average of the last x-1 month's Fuel Oil prices,
- A constant **b** multiplied by the average of the last x-1 month's Gas Oil prices

The values of the key variables are confidential to the parties to the contract, however they have over time been inferred from border price data. These contracts also provide for periodic price re-negotiation, or 'price re-openers' if market conditions change significantly. For this reason, in continental Europe there is a significant level of price similarity in contract gas from different sources (Figure 19). This was not the case in the UK, where contracts did not provide for price re-opener negotiations.

[16] Stern 2007, pp 2-3
[17] Stern 2007, p 4.

Figure 19. Oil Indexed Gas Prices in Europe 1997 - 2009



Sources: Argus, Gas Matters

Prior to 1990 the UK market was dominated by British Gas – then the nationalised state monopoly. Successive legislation served to progressively undermine this position, critically that which allowed upstream producers to sell gas direct to the power sector and large industrial users. This catalysed the monetisation of the 'backlog' of undeveloped offshore gas discoveries which then competed aggressively for customers in the power and industrial sectors. BG's market share loss was such that it was unable to sell-on the take or pay quantities under its field-specific long term contracts, and was increasingly priced out of the market. BG also had to publish its industrial prices and hold them at those levels for a defined period, allowing its competitors to undercut them with impunity.

Facing significant financial exposure BG was forced to re-negotiate many of its North Sea purchase contracts and transform them to non-field specific long term supply contracts. Although possibly some 25% of UK production is still sold under these surviving supply contracts, their disparate pricing formulae have resulted in a significant degree of scatter and as a result these do not influence the traded UK gas price.

The UK market became effectively liberalised in the mid 1990s with the NBP (National Balancing Point) becoming a virtual hub[18].

[18] For a full account of this see Wright 2006.

A cursory summary of the key steps towards the goal of achieving a pan-European liberalised gas market is bulleted below[19]:

- **The First Gas Directive**: Adopted in May 1998, the Directive set out the initial steps towards changing industry structure and network access conditions by introducing legal unbundling and negotiated and regulated third party access.
- **The Second Gas Directive** sought to accelerate the process by calling for liberalised access for business consumers by 2004 and for all consumers by 2005. The Directive also sought to shift gas market regulation away from governmental supervision to the control of independent regulators. After two years of amendment, compromise and resistance the second Gas Directive was finalised and adopted in June 2003.
- **The Third Package**, adopted in August 2009, included provisions for the co-operation of national regulators, the unbundling of pipeline transmission systems from sales and marketing activities, third party access to storage facilities and the submission to anti-competition scrutiny of gas sector-related asset purchases by non EU entities.

It would be an understatement to say that the strategy adopted by the large incumbents throughput this period was one of ‘retreat at the slowest pace possible’. The seeming lack of wholehearted support by national level governments has also served to reduce the pace of change. The ‘tight’ supply position and consequent high and volatile prices in the liberalised UK and US gas markets during the middle of the 2000s did little to highlight market liberalisation as a worthy goal. Fundamentally however, the existence of long term oil-indexed contracts providing a significant proportion of continental Europe’s supply does tend to work against the creation of a truly liberalised market where prices are set by gas on gas competition – a phenomenon termed ‘vertical foreclosure’ in the lexicon of competition regulation.

This is not to say that the period was without its successes in terms of achieving some pro-competitive measures, namely:

- **The disbanding of the GFU**: In June 2001, after sustained pressure from the EU competition authorities, Norway abolished its centralised gas sales organisation (GFU) in response to the EU position that joint sale and purchase organisations thwarted competition. Individual equity holders in gas-producing fields now have the responsibility for marketing and selling their own gas.[20]
- **Release Gas Programme**: Release gas programmes were introduced to overcome inadequate access to gas supplies or pipeline capacity. Release gas programmes have occurred in France, Austria, Germany and Italy (on a model tried before in the UK). Given that the price paid by new entrants for release gas is inevitably linked to the price paid by the releasing incumbent, release programmes are unlikely to significantly raise competition levels in a material sense.
- **Destination clauses**: These provisions within many long term gas contracts within Europe forbade the re-selling of gas to national markets outside the

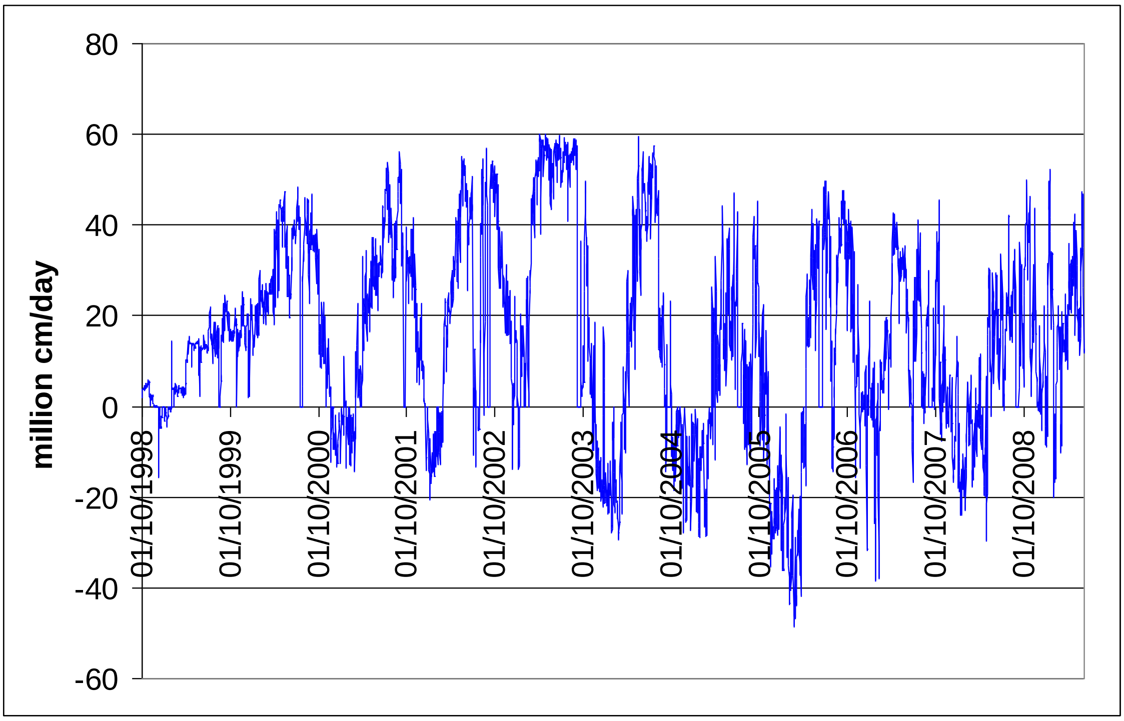
[19] Haase 2008, pp. 23-31.
[20] Bradley, Angell, McManus 2008 p.5.

original destination market. As a consequence of competition rules, such provisions were removed from contracts, including those of Gazprom, Sonatrach and LNG sellers.[21]

Despite the moves by the European Commission to liberalise the continental European gas market it is still, in the author's opinion, in a state of 'suspended animation': held back by the interests of its gas market incumbents who have little incentive to change and whose long term contractual arrangements with suppliers are difficult to reconcile with the liberalised gas market model epitomised by the UK and North America. This 'clash of paradigms' is a key feature of a later section of this paper and is at the heart of the new global dynamic in gas market arbitrage.

In October 1998 the Bacton Zeebrugge Interconnector pipeline (IUK) was opened, connecting the newly liberalised UK gas market with that of continental Europe [22]. The pipeline is able to switch its flow direction in response to the position of its capacity owners. Figure 20 shows the daily flows through this pipeline between October 1998 and June 2009. The flow pattern is one of significant summer export from the UK during the summer periods from 1998 to 2006 (N.B. The dip in summer 2002 was due to the pipeline being shut down due to operational problems). During the same period the winter seasons saw imports coming into the UK from continental Europe. The underlying explanation for this dynamic was the relatively low provision of seasonal gas storage in the UK as its old 'swing' fields declined.

Figure 20. Bacton-Zeebrugge Interconnector Daily Pipeline Flows 1998 - 2009
(+ = export from UK, - = import to UK)



Source: IUK

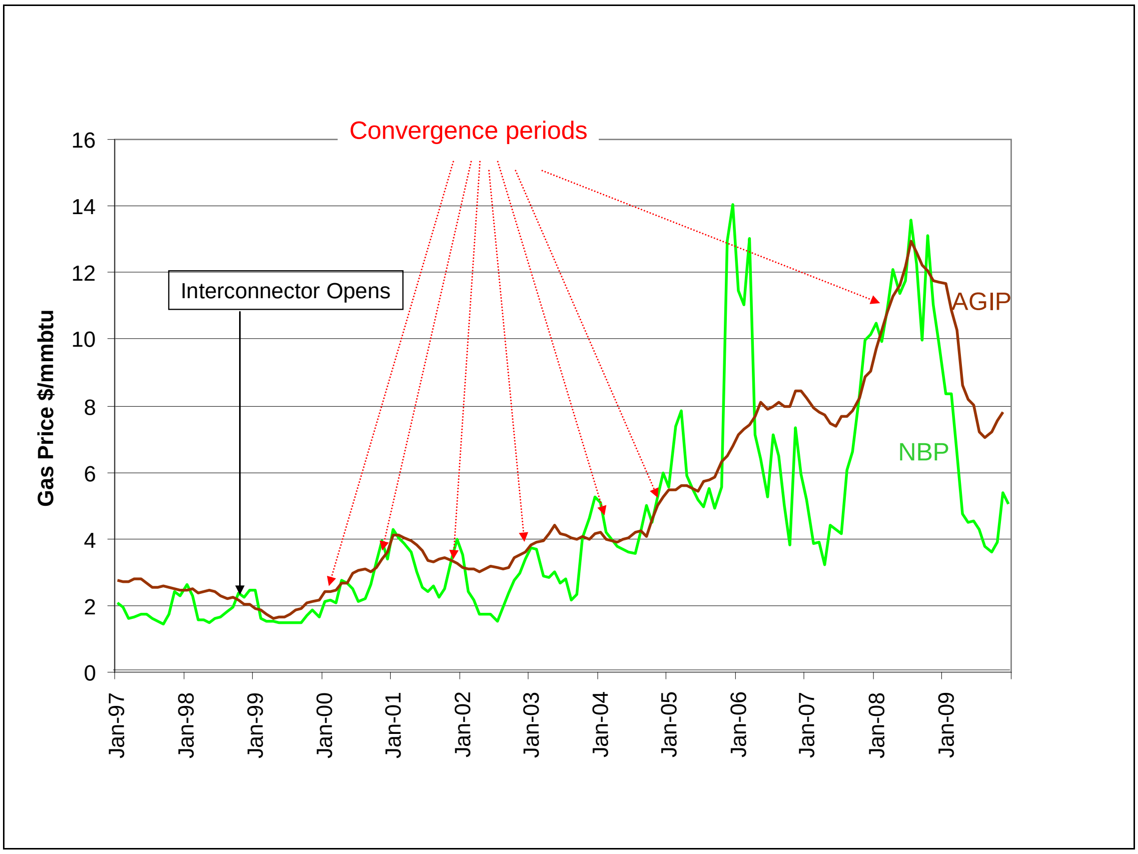
[21] Smith 2005
[22] See Futyan 2006

The summer export volumes peaked in 2003, with the decline in subsequent years driven by the reduction in UK domestic production. Similarly the scale of winter imports can be observed to increase through to the end of 2005. In October 2006 the Langeled pipeline from Norway to the UK was completed, allowing additional imports to the UK. A year later the Ormen Lange field commenced production adding further to UK gas imports.

The additional supplies from Norway appear to have stabilized the trend of reducing summer exports and growing winter imports through the Bacton-Zeebrugge Interconnector and in addition appear to have increased the short term volatility of daily flowrates.

Following the opening of the IUK, UK and continental oil indexed gas prices were reasonably well correlated through to the spring of 2001 (Figure 21). The years 2001 to 2003 were characterised by reasonably close price correlation during the winter months but with NBP de-linking and falling during the summer. 2001 to 2003 was a period of peak summer export of gas from the UK. From 2004 onwards, evidence of increasing supply tightness is apparent.

Figure 21. UK NBP Spot Price and German Average Import Gas Price (AGIP) January 1997 – November 2009



Sources: Argus, Gas Matters

In 2004 and early 2005 there is close correlation between the UK and continental prices but in 4Q05 NBP de-links and soars to unprecedented price levels. An early spell of cold weather increased UK demand in November 2005. It was soon apparent, however, that owners of gas in storage in continental Europe were not prepared to send as much gas to the UK as price signals called for due to their concerns over having sufficient storage inventory to meet the demands of their own domestic customers through the rest of the winter. These concerns were driven by public service obligations which are widespread in continental Europe. Throughout that winter Asian LNG markets were bidding in excess of $15/mmbtu for spot LNG cargoes as Indonesian underperformance reduced availability of contracted LNG in those markets. The tight UK supply situation was further exacerbated by operational problems at the UK's largest seasonal gas storage facility (the depleted Rough gas field) which reduced supply in 1 and 2Q 2006.

In October 2006 famine turned to feast when the Langeled pipeline came onstream and low UK prices continued until late 2007 when NBP once again converged with AGIP up until 3Q08. This later convergence was in all probability due to the tightening of supply due to the ongoing decline of the UK's domestic gas production.

Let us now examine the mechanics of the North West Europe hubs which are the physical interface between 'spot gas' and oil indexed pipeline gas.

Figure 22. North West Europe Trading Hub Dynamics

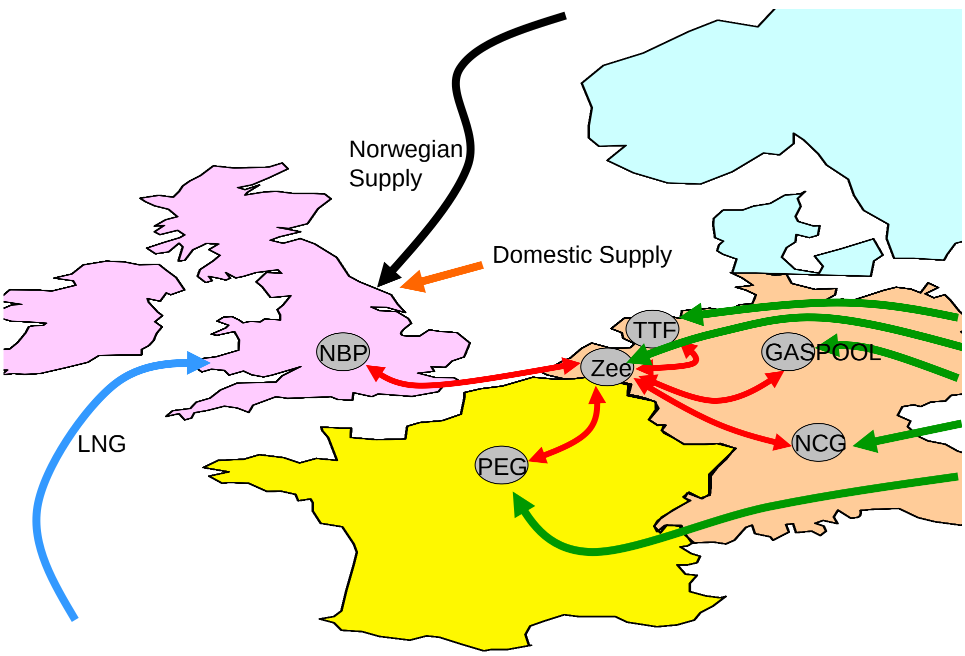
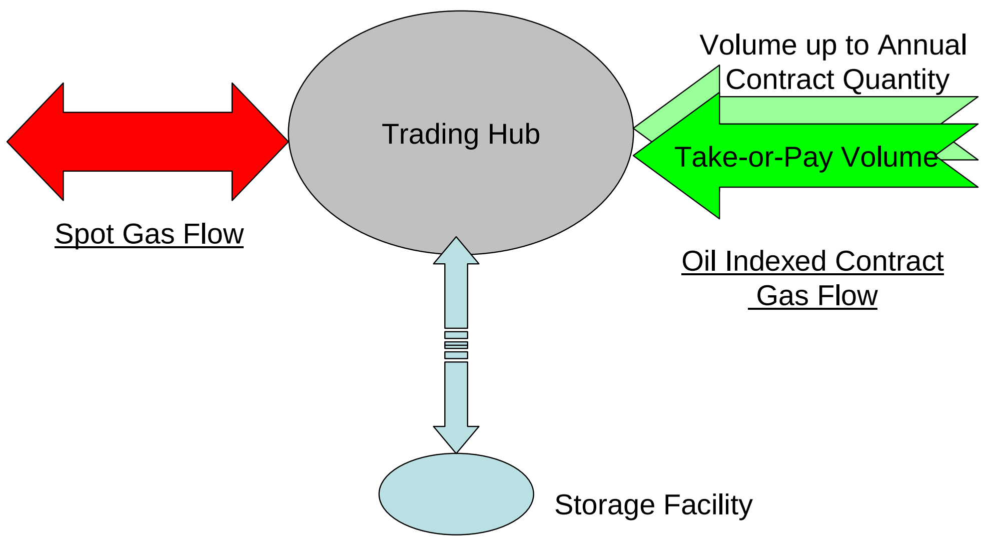


Figure 22 is a representation of the North West Europe gas trading arena. The interaction between UK spot-priced gas and oil-indexed gas which was seen in the previous two figures has given rise to the formation of the Zeebrugge Hub at the continental European end of the Bacton-Zeebrugge Interconnector and the four developed hubs of PEG (France), TTF (Netherlands), Gaspool (North Germany) and NCG (South Germany). All these continental Hubs are effectively embedded in 'oil-indexed gas territory' but they do provide a market place or platform to trade between oil indexed gas (green arrows) and spot-priced gas (red arrows). As UK domestic production declines it is being supplemented by Norwegian imports and by growth in LNG imports (both pricing off UK traded gas i.e. NBP). The existing and planned regas terminals in the UK look set to establish it as North West Europe's 'Offshore Unloading Jetty'; effectively enabling spot gas to overflow into the continental heartland markets and compete with oil-indexed gas at the Trading Hubs. Not shown here but enhancing this dynamic is the ability of the

Zeebrugge LNG regas terminal and by 2012, once commissioned, the GATE LNG terminal in the Netherlands, to receive spot cargoes.

So how does the arbitrage dynamic operate at the trading hubs ?

Figure 23. Dynamics of North West Europe Trading Hubs



A hub is schematically represented in Figure 23. Let us consider two cases:

- **The spot gas price is lower than the oil-indexed gas price**: In this situation, midstream gas players at the hubs will buy up more spot gas and buy less oil indexed gas. This will have the effect of pulling more gas out of the UK and causing the NBP price to rise. As the demand for oil-indexed gas falls, buyers with long term contracts will reduce their nominations – effectively taking gas 'out of the system' as it is left in the gas field upstream. This process repeats itself until either:
    - **NBP has risen to equal the continental oil-indexed price; or,**
    - **The supply of oil-indexed gas has been reduced to its take-or-pay level and the process of arbitrage can proceed no further.**

- **The spot gas price is higher than the oil-indexed gas price:** In this situation, midstream gas players at the hubs will buy less spot gas and buy more oil-indexed gas. This will have the effect of pulling less gas out of the UK (and could send gas which was oil-indexed into the UK), causing the price to fall. As the demand for oil-indexed gas rises, buyers under these long term contracts will increase their nominations- effectively bringing extra gas 'into the system' through higher upstream production. This process repeats itself until either:

- **NBP has fallen to equal the continental oil-indexed price; or,**
- **The supply of oil-indexed gas has been increased to its annual contract quantity (ACQ) level and the process of arbitrage can proceed no further.**

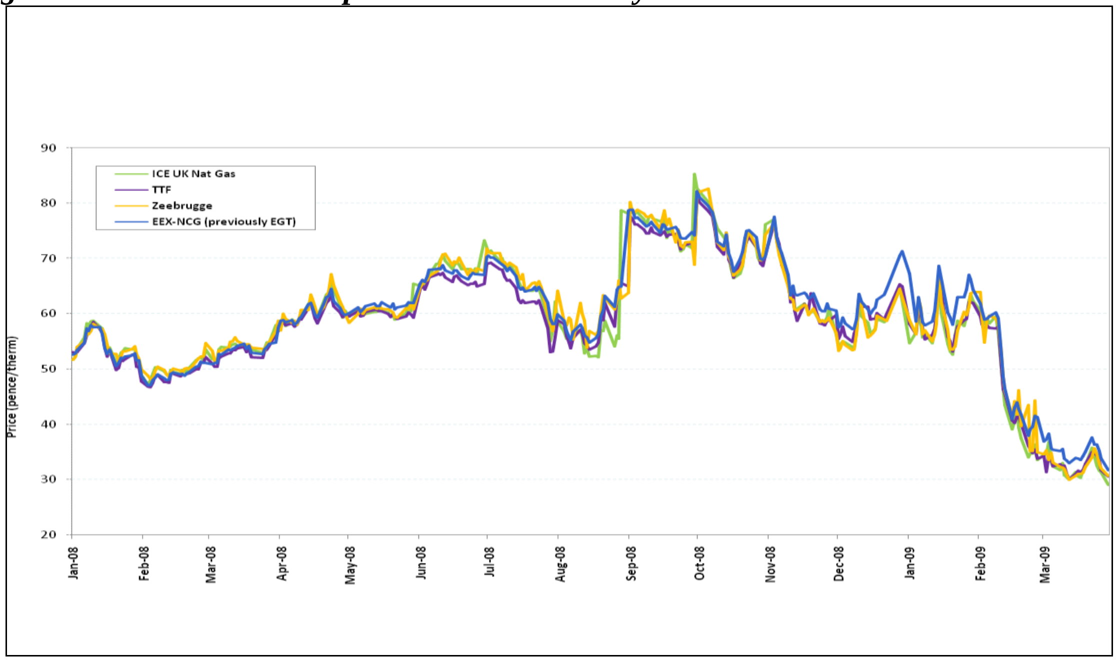
Three overlays on this central concept need to be noted:

- The arbitrage can be 'time parked'[23] by the use of gas storage facilities. Historically, storage usage in continental Europe has been driven by a conservative 'utility' mindset[24], however the author believes that much of the current and future salt cavern storage development in North West Europe is driven by the prospect of spot vs. oil-indexed price arbitrage.
- It is likely that arbitrage is restricted by pipeline infrastructure bottlenecks, ('connectivity'), as well as by contractual flexibility limits.
- The reference to take-or-pay and annual contract quantity levels as limitations at the monthly level is simplistic. In practice there is greater short term flexibility as long as these levels are adhered to on a cumulative basis by the end of the 'gas contract year' which runs from October 1st to September 30th.

This framework explains the recurrence of price convergence in Figure 21.

Evidence of the scale of linkage between North West Europe's gas trading hubs is difficult to establish in terms of transportation capacities, however the evidence for price linkage is compelling, as is shown in Figure 24, which is only possible with physical connectivity between these hubs and gas flows through IUK and BBL.

Figure 24. North West Europe Hub Prices January2008 – March 2009



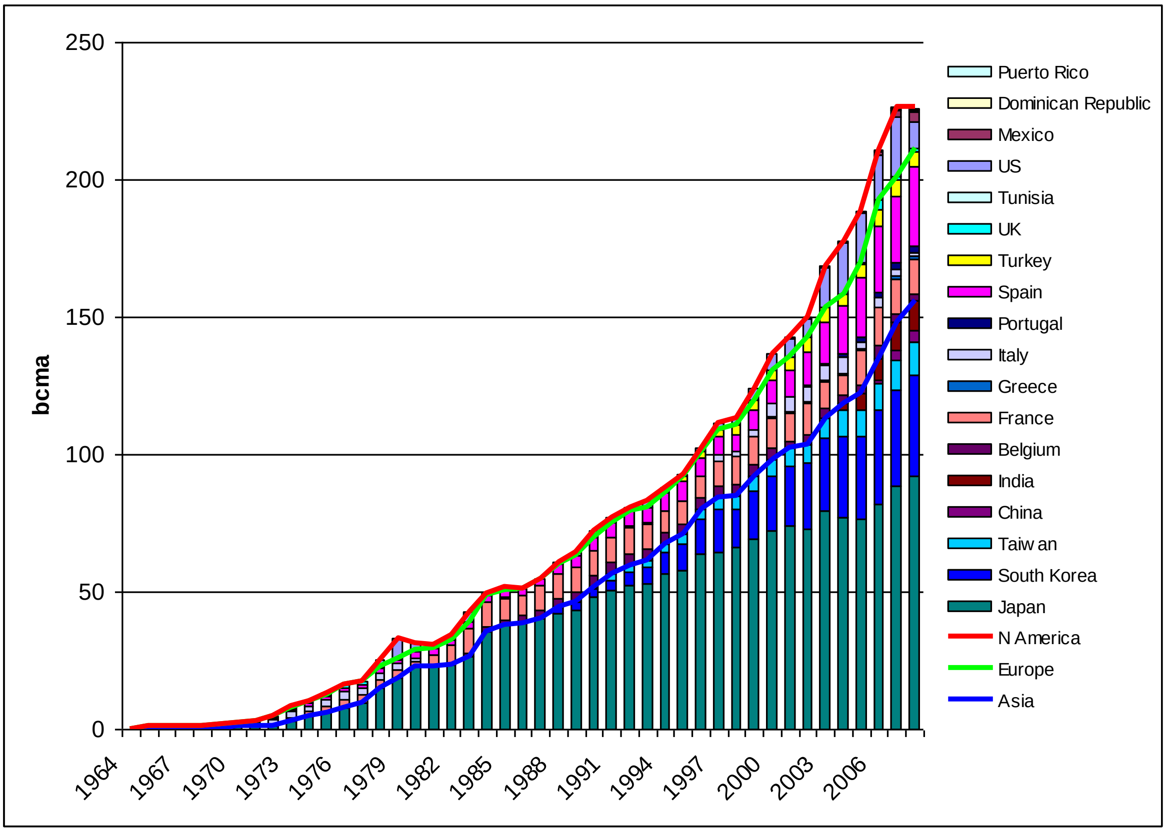
Source: ICE (Intercontinental Exchange)

[23] 'Time Parked' – shorthand for the action of trading entities injecting into storage gas purchased at low prices with the intention of withdrawing and selling this during periods when the hub price is higher.
[24] 'Utility Mindset' – with reference to storage this means only using storage to meet demand peaks and to provide supply security.

Asia LNG Market Structure and Developments

As depicted in Figure 25, Asia (and in particular Japan) began to dominate the global LNG picture by the late 1970s and continues to be the largest single importing regional market. Japan, South Korea and Taiwan, lacking significant domestic production, rely on LNG for their natural gas requirements. The market context and supply security mindset so engendered has been largely responsible for the somewhat 'traditional' supply contracting custom and practice which has characterised Asian LNG.

Figure 25. Global LNG Imports by Country 1964 - 2008

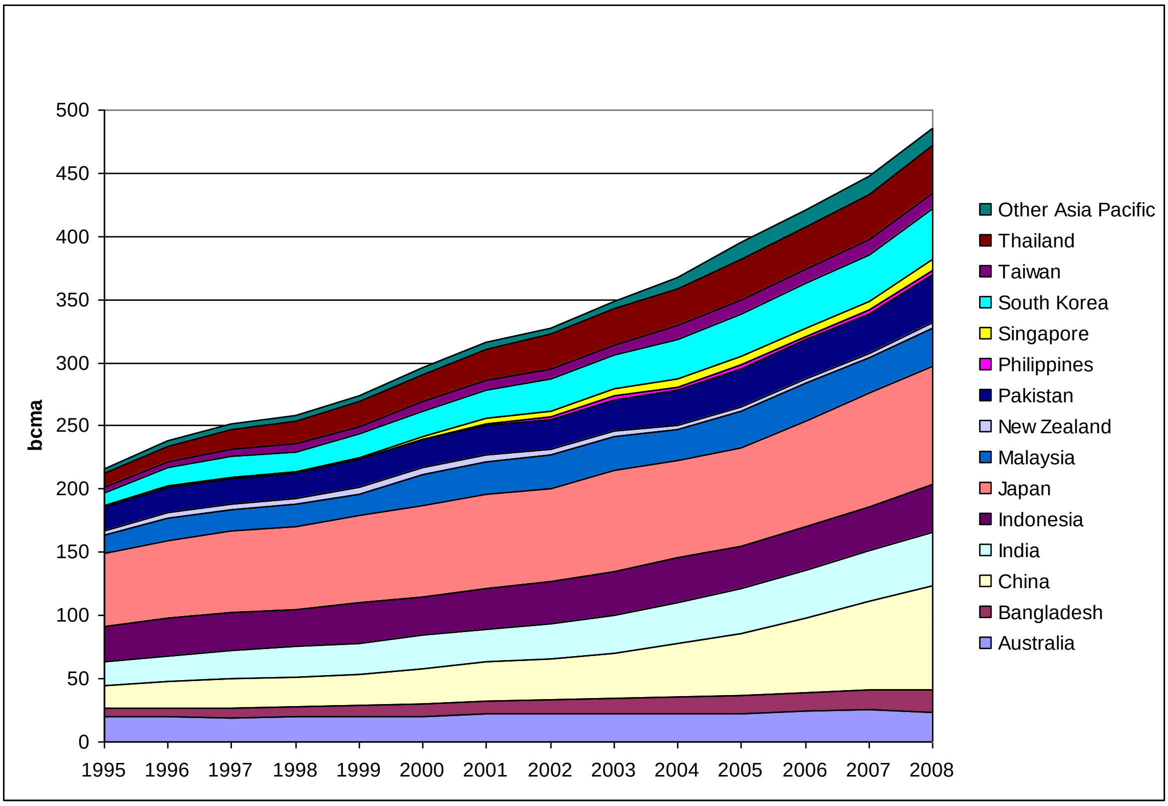


Sources: Cedigaz 2004, BP 2009 (Gas Trade Movements LNG)

Asia's gas consumption (Figure 26) grew at 6.5% per annum from 1995 to 2000 and continued at 6.4% per annum from 2000 to 2008.

What is interesting is the variation in demand growth rates over the period 1995 – 2008 between countries with Australia and Japan in the 1 to 4 % p.a. range on the one hand and South Korea and China at 11.0% and 12.6% respectively (Figure 27).

Figure 26. Asia Annual Natural Gas Consumption 1995 - 2008



Source: BP 2009, (Natural Gas Consumption sheet)

Figure 27. Asia Compound Annual Average Demand Growth 1995 - 2008

	Compound Annual Average Growth in Demand %
Australia	1.4%
Bangladesh	6.8%
China	12.6%
India	6.3%
Indonesia	2.3%
Japan	3.8%
Malaysia	6.4%
Pakistan	5.7%
South Korea	11.0%
Taiwan	8.6%
Thailand	9.6%

Source: BP 2009 (Natural Gas Consumption sheet)

The Asian natural gas supply-demand dynamics are better grasped by grouping the countries in terms of import dependence during this period:

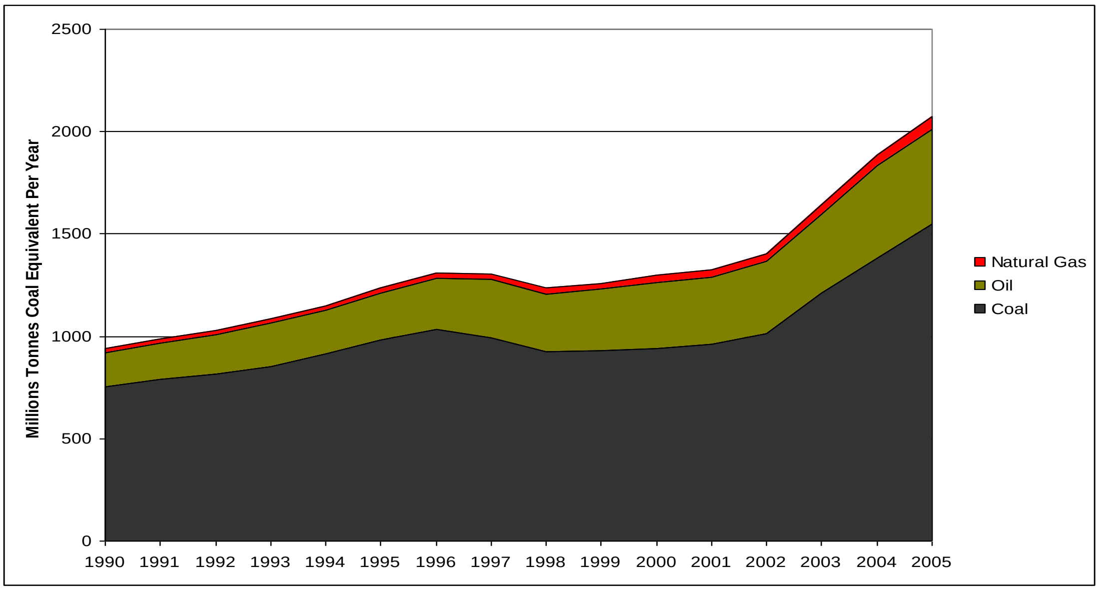
Producers with a surplus for export: Australia, Indonesia, Malaysia. It should be noted that in the case of Indonesia in particular, the high rate of growth of domestic consumption has started to limit the scope for LNG exports, and this trend is increasing.

Producers meeting indigenous demand: Bangladesh, New Zealand, Pakistan, Philippines, Thailand.

Net Importers: China, India, Japan, South Korea, Taiwan

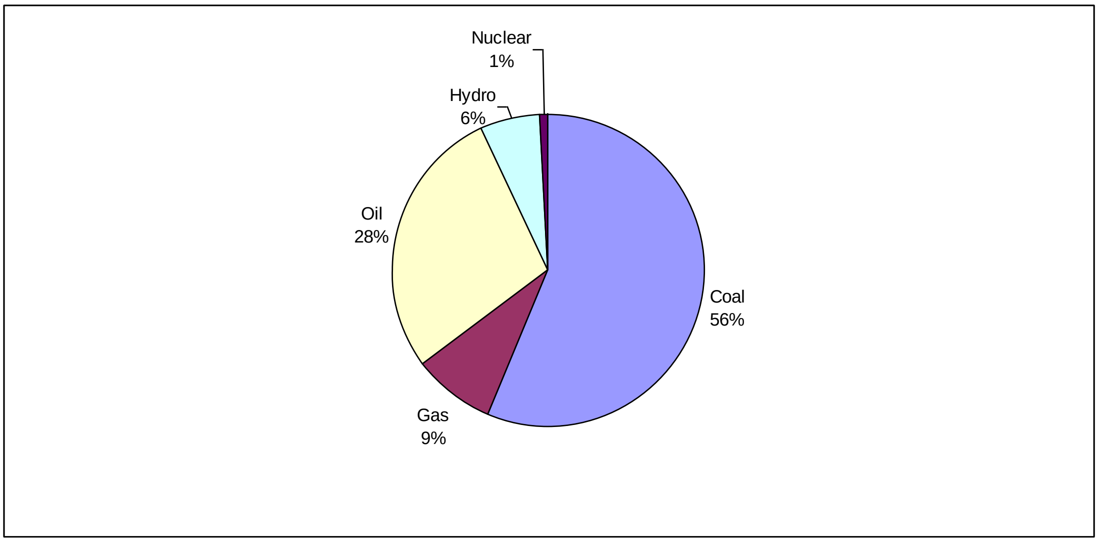
However before we look at the natural gas trade flow dynamics it is important to appreciate how small a share of primary energy natural gas currently represents in this region. For instance, in China natural gas in 2005 constituted only 3% of fossil fuel consumption (Figure 28), and in 2006 natural gas contributed only 9% of India's primary energy consumption (Figure 29).

Figure 28. China Fossil Fuel Consumption 1995 - 2005



Source: OIES Asia 2008, Table 2.1, p. 9.

Figure 29. India Primary Energy Consumption 2006

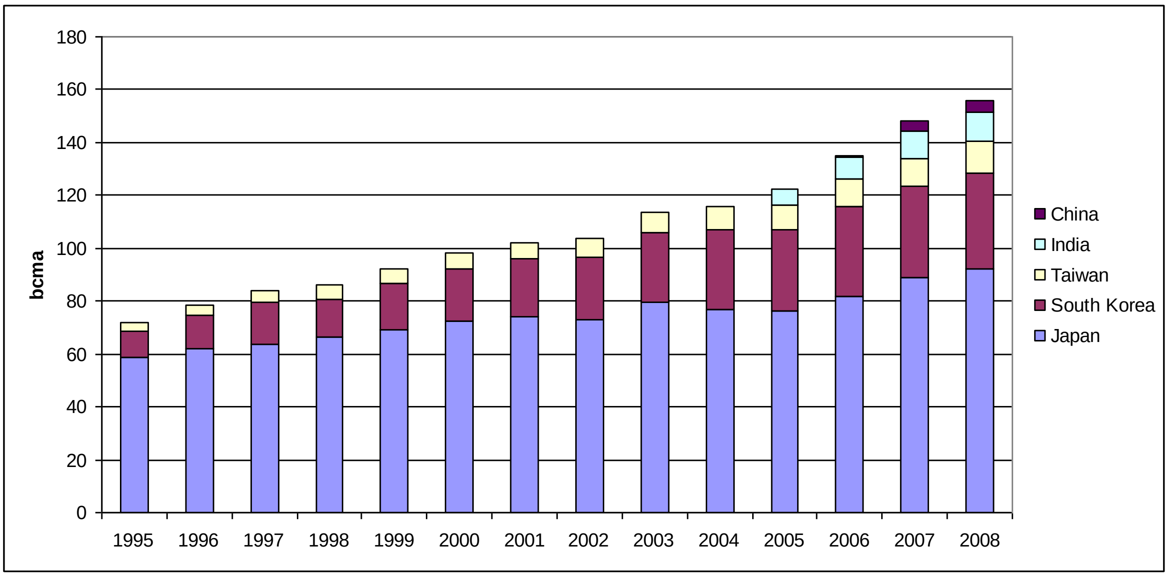


Source: OIES Asia 2008, Table 2.1, p. 9.

Data for Asia is unfortunately not particularly comprehensive and therefore a region-wide natural gas consumption sectoral analysis is not presented here.

Figure 30 shows the growth in LNG imports in Japan, Korea and Taiwan, (where LNG is the only significant source of natural gas) and India and China, where LNG supplements indigenous production in meeting natural gas demand.

Figure 30. Asia Market LNG Imports 1995 - 2008



Source: BP 2009, (LNG Gas Trade Sheet)

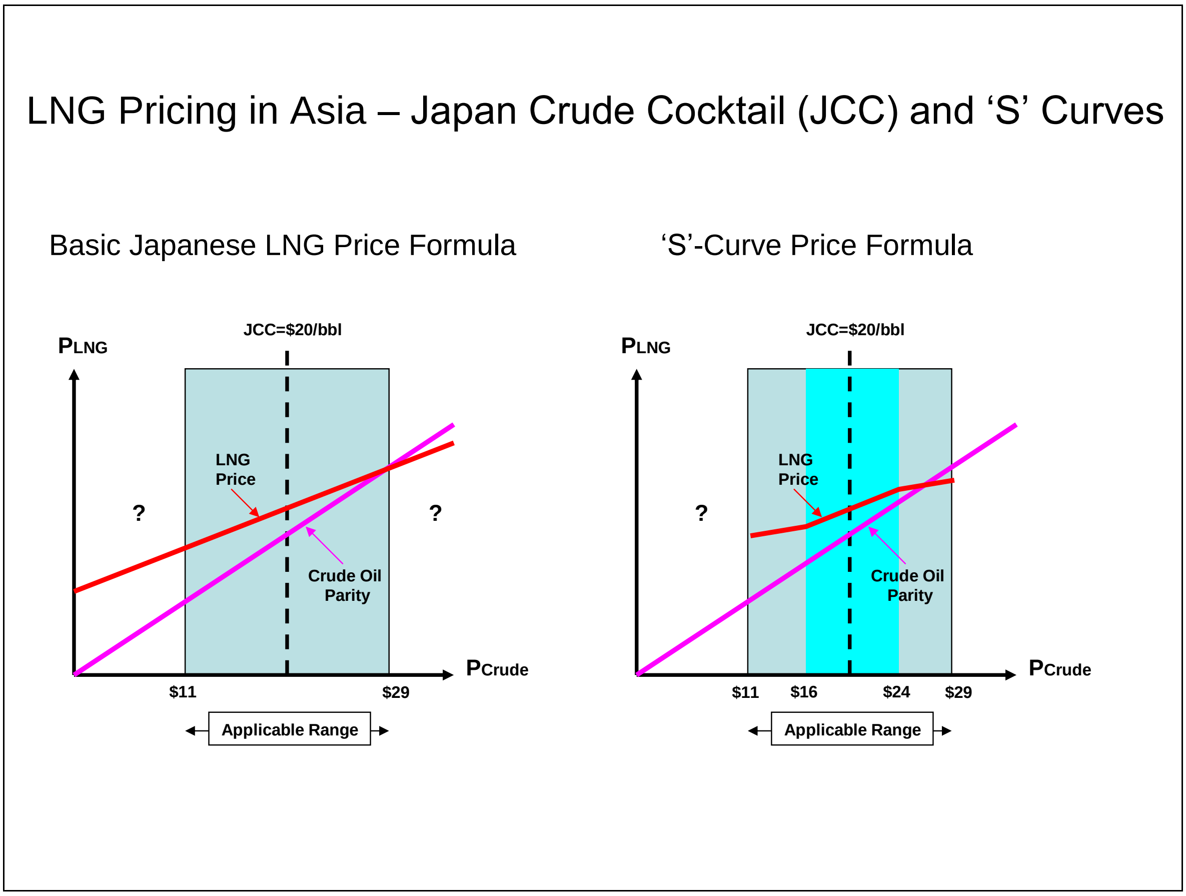
The jump in Japanese LNG imports in 2007 was in part caused by the prolonged shutdown of the 6.6MW Kashiwazaki Kariwa nuclear power plant in July 2007 following a severe earthquake. Two units of the plant were re-started in late 2009 and early 2010.

The traditional Asian LNG project featured a carefully structured system of risk sharing amongst the participants, central to which was the long term LNG (Purchase and Sales) contract, typically of 20 years or longer duration. As with long term pipeline contracts the risk sharing logic of the contract is often expressed by the phrase 'the buyer takes the volume risk and the seller takes the price risk'. Most contracts featured 'Take-or-Pay' provisions to assure buyer off-take at a minimum level, to guarantee cash flow to the seller, and a price indexation clause to expose the seller to energy price fluctuations.

In the typical setting nearly all buyers were government monopoly or franchised utility companies from OECD countries and sellers typically major or national oil and gas companies. The level of credit-worthiness of participants facilitated favourable financing terms[25]. In its original form the LNG contract envisaged a system in which particular trades are self-contained, involving a specified liquefaction facility as the source of LNG and dedicated tankers to transport it to its specific destination.

[25]'Jensen 2004, p 15.

Figure 31. LNG Pricing in Japan and Asia



Source: OIES Asia 2008 Appendix Two, pp. 406 – 407

The prices in early LNG contracts to Japan were fixed for the 15 to 20 year agreement term. Following the oil price shocks of the 1970s, by the mid 1980s price formulae in most contracts were of the form:

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

Where
P(LNG) is the price of LNG in $/mmbtu.
P(Crude Oil) is the price of crude oil in $/bbl.
A and B are constants.

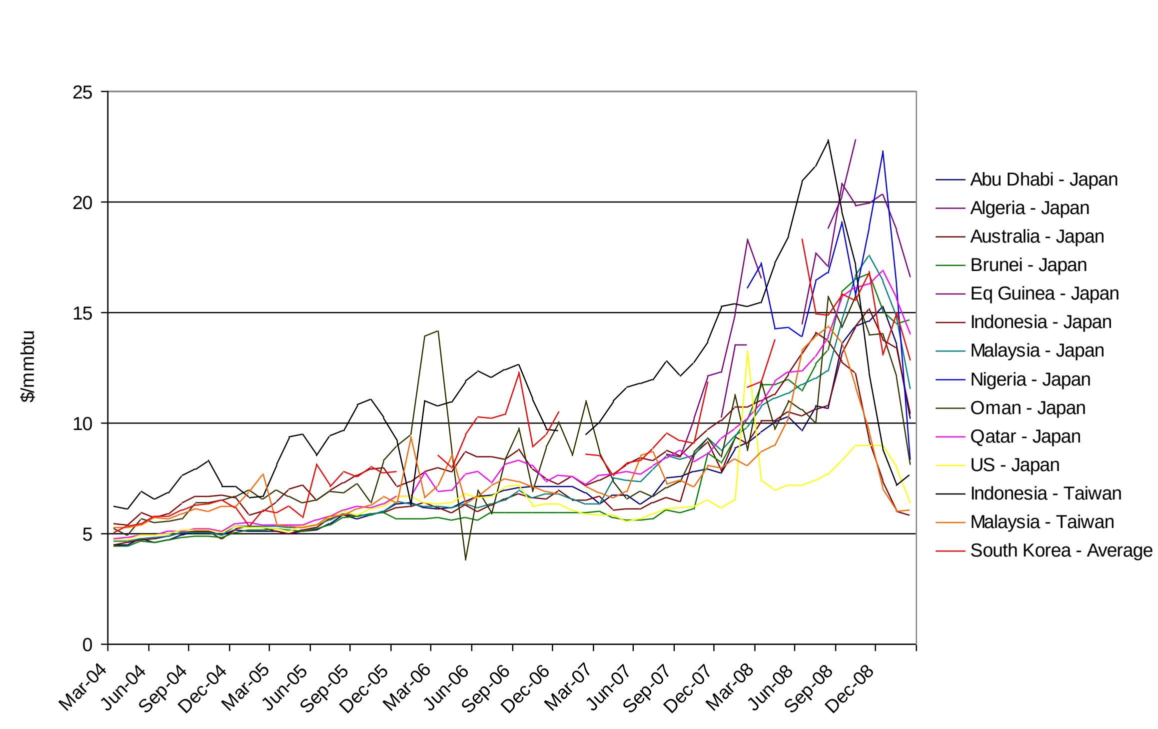
In most Asian LNG contracts the oil price is the average of imported crude into Japan, often referred to as JCC (Japanese Customs Cleared, or alternatively in the vernacular 'Japanese Crude Cocktail'). The oil prices used are either prior month actuals or a time-averaged value for a specified period of prior months.

In many of the Japanese price formulae negotiated in the late 1980s the multiplier and constant in the formula gave a relationship between LNG and oil price which is represented graphically on the Left Hand Side of Figure 31. At low oil prices the LNG is above crude oil parity price but the premium erodes as oil prices rise and the two lines converge at around $26 to $30/bbl. At the time these contracts were negotiated, prices above $29/bbl or below $11/bbl were viewed as exceptional, i.e. had a low probability of occurrence. Should such circumstances arise, buyers and seller agreed to 'meet and discuss' how the price of LNG would be derived. South Korea and Taiwan adopted a similar approach in the late 1980s and early 1990s, but the straight line relationship was not restricted to an applicable range.

In the early 1990s when many Japanese contracts came up for renegotiation, the impact on LNG prices of 'extreme' oil prices was mitigated by the introduction of the 'S'- Curve relationship, shown on the Right Hand Side of Figure 31. Further modifications were made to this approach in the 2000s to further soften the impact of high oil prices.[26]

For a regional market which espouses the importance of 'stability' and 'long term relationships', the data available on LNG import prices in these markets paints a surprisingly diverse picture (Figure 32).

Figure 32. Asian LNG Prices – March 2004 – February 2009



Source: Argus

Whilst in March 2004 the import prices of LNG in the Asian importing markets were reasonably tightly bounded, by 2008 the combination of different oil price escalators and the plethora of S curves and differing indices and parameters have resulted in a wide divergence of price for what is essentially the same commodity. Note that each of these data series represents a 'bundle' of individual contracts; the range at the individual contract level will be wider.

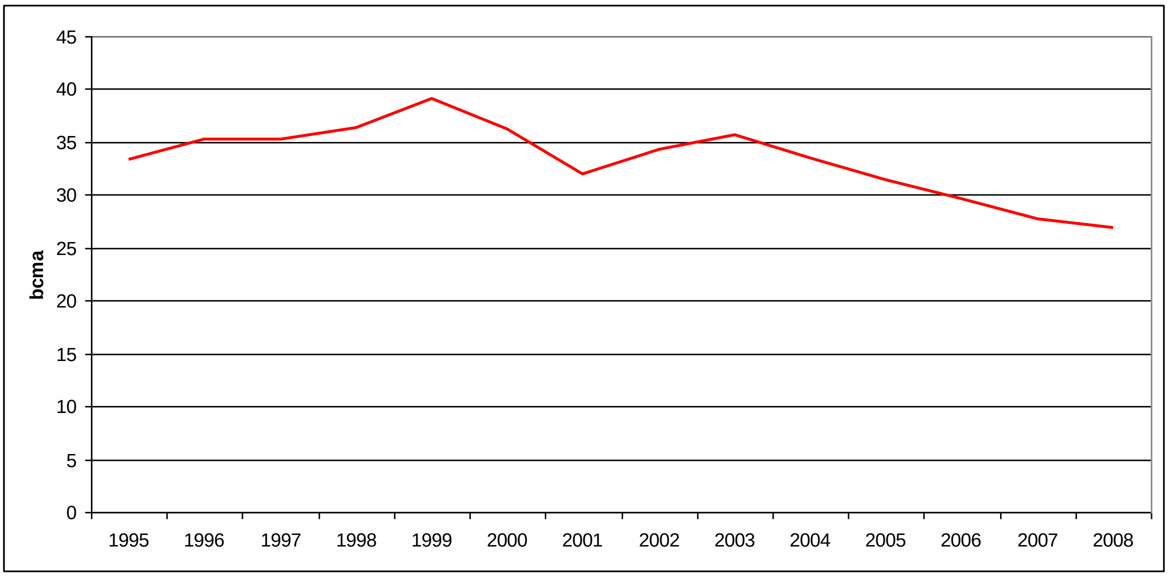
The early 2000s became a challenging time for the prevailing contracting philosophy of the Asian LNG market due to:

- The under-performance of Indonesia as an LNG exporter as shown in Figure 33.
- The rapid growth in natural gas demand as shown in Figure 26.

[26] OIES Asia 2008, Appendix Two, pp 405 – 408.

- The slippage of LNG supply projects generally, as shown later in Figure 37.
- Recurring Japanese nuclear generation problems requiring increasing usage of LNG-fired units.
- A decision by Korea to restrict LNG imports to those under contracts by power generation companies and to preclude city gas companies from signing new LNG import contracts.[27]

Figure 33. Indonesia LNG Exports



Source: BP 2009, Cedigaz 2004

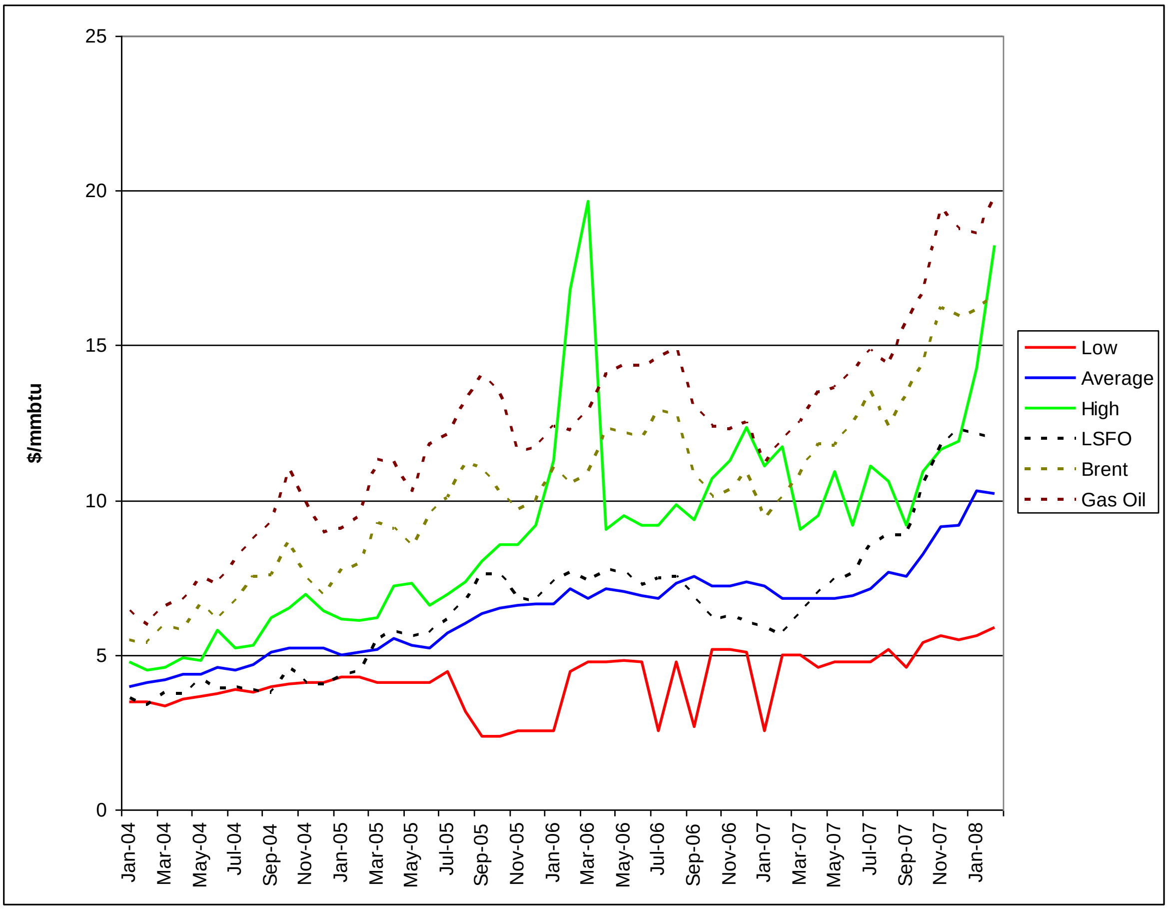
Due to the lack of suitable geological structures and possibly also as a consequence of rapid gas market growth, Asia is poorly provided with gas storage other than in the form of LNG regas storage tanks. Due to the almost total reliance on LNG as their natural gas supply, Japan, Korea and Taiwan have tended to keep LNG storage tanks relatively full and to meet winter demand through additional winter LNG imports.

The factors listed above drove Asian LNG importers to enter the spot market for LNG in the winters of 2005/2006, 2006/2007 and 2007/2008 to a significant extent, pulling spot cargoes out of the Atlantic Basin. The prices paid varied widely with no obvious pattern. It is known that Japan and Korea burn residual fuel oil, crude and distillate in their power generation sectors and some, if limited, correlation to these substitute fuels can be seen in Figure 34.

For the winter of 2005/2006 the high spot LNG prices exceeded gas oil prices. There is no rational explanation for this other than that this was a period of general supply tightness with Hurricane Katrina having hit much US gas production and the UK market also in a tight position. In winter 2006/2007 there appeared to be a more rational correlation between high LNG spot prices and gas oil price. In winter 2007/2008 high spot prices appear to be correlated to residual fuel oil (LSFO). Suffice to say that the general market awareness of the extent of Asia spot LNG purchase during this period impacted the markets of Europe and to some degree indirectly North America in the first half of 2008. (For a wider appreciation of the implications of LNG pricing relative to alternative fuels in Asian markets please see *Miyamoto & Ishiguro 2006*).

27 OIES Asia 2008, pp 174 - 211

Figure 34. Range of Asia LNG Spot Prices 2004 – 2008



Source: FACTS 2008

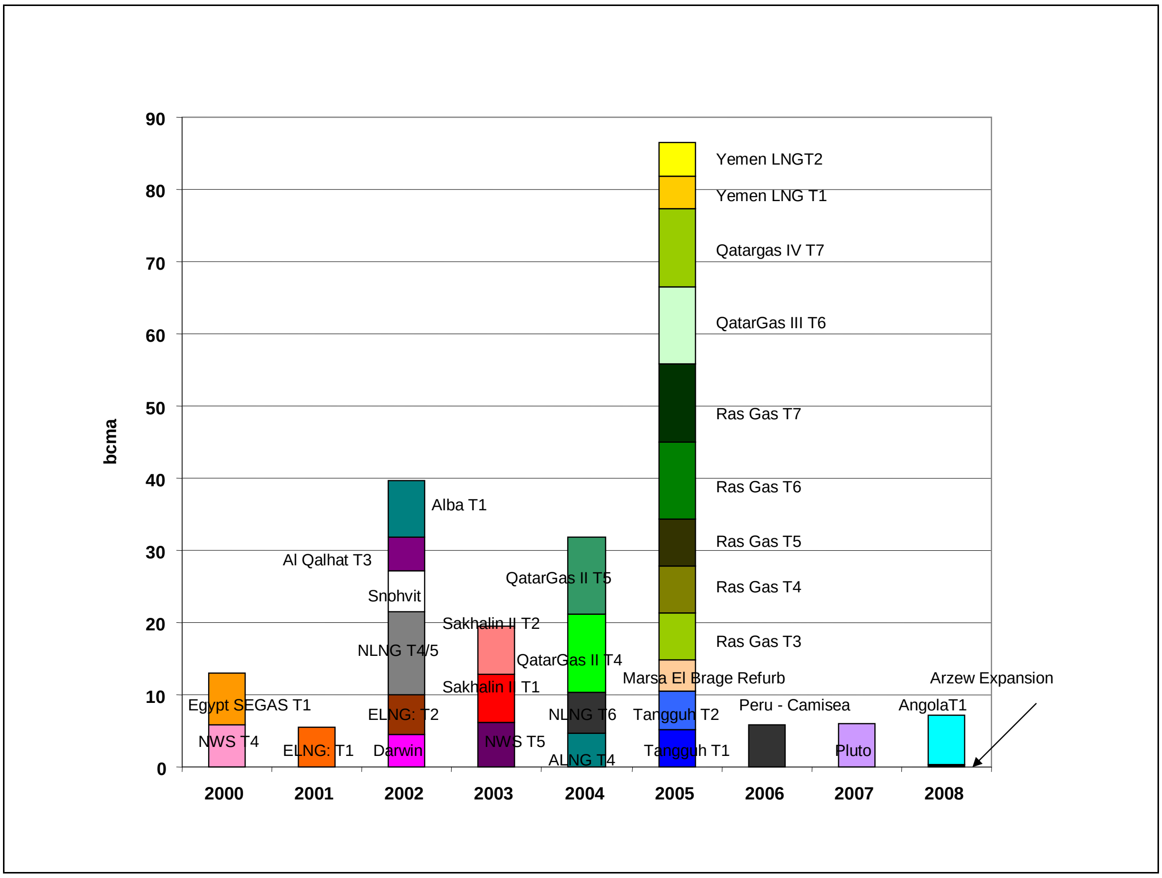
The Renaissance of LNG

As we have discussed in previous sections the concern of importing markets from 2000 to 2005 was how anticipated future gas demand growth would be met by supply given:

- The ongoing decline in indigenous production in Europe and North America.
- The uncertainty on timing and incremental volumes available from pipeline import projects for Europe particularly and
- The unexpected decline in LNG supply from Indonesia.

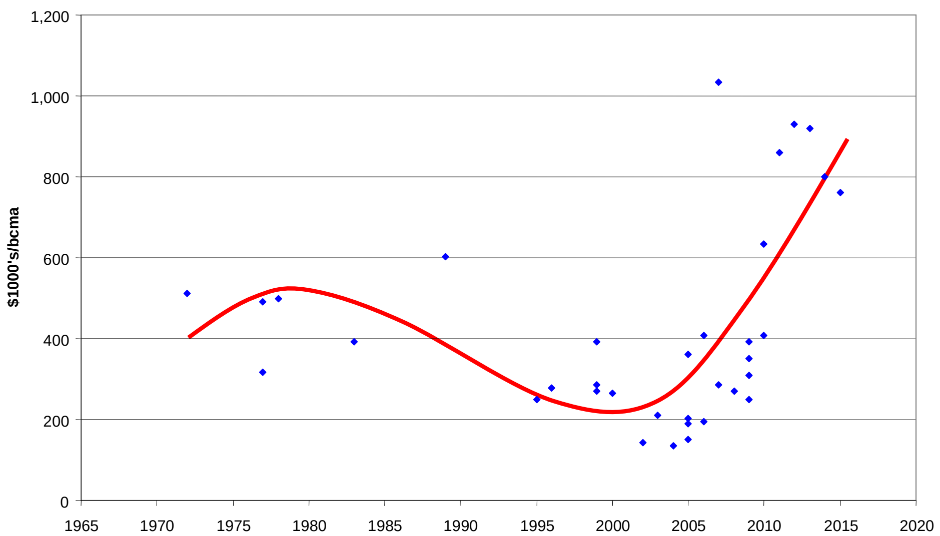
The prevailing industry perception of a 'tight' market for the foreseeable future provided fertile ground for the progression of numerous LNG supply projects. The surge in LNG FID's (Final Investment Decisions) is shown in Figure 35. There was an unprecedented activity peak in the period 2002 - 2005 which subsequently strained the capacity of the few specialist liquefaction engineering contractors able to construct this number of liquefaction plant simultaneously. Coming on top of the rise in commodity prices, this resulted in a reversal in the downward trend in unit liquefaction capital costs (Figure 36), thus challenging project economics and available financing and constraining the pace of new commitments later in the period. These factors conspired to cause an ongoing slippage in the aggregate (industry) ten year forecast of future LNG supply capacity, as is shown in Figure 37.

Figure 35. LNG Supply Capacity Achieving Final Investment Decision



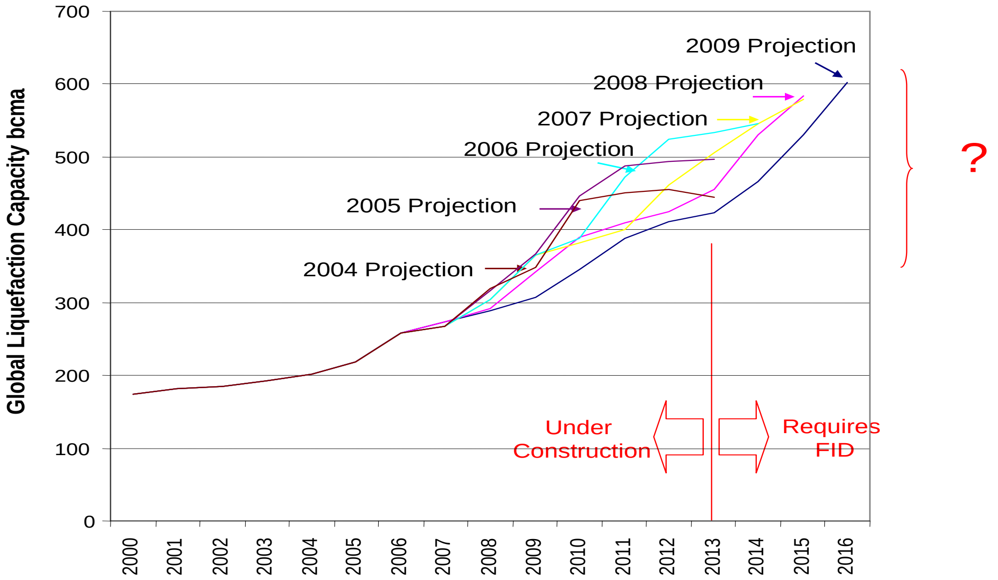
Source: Company Reports

Figure 36. LNG Liquefaction Capex (2008 Dollars) by Year of Start-Up



Source: Vermier 2009, Slide 12

Figure 37. LNG Supply Growth Continues to Slide

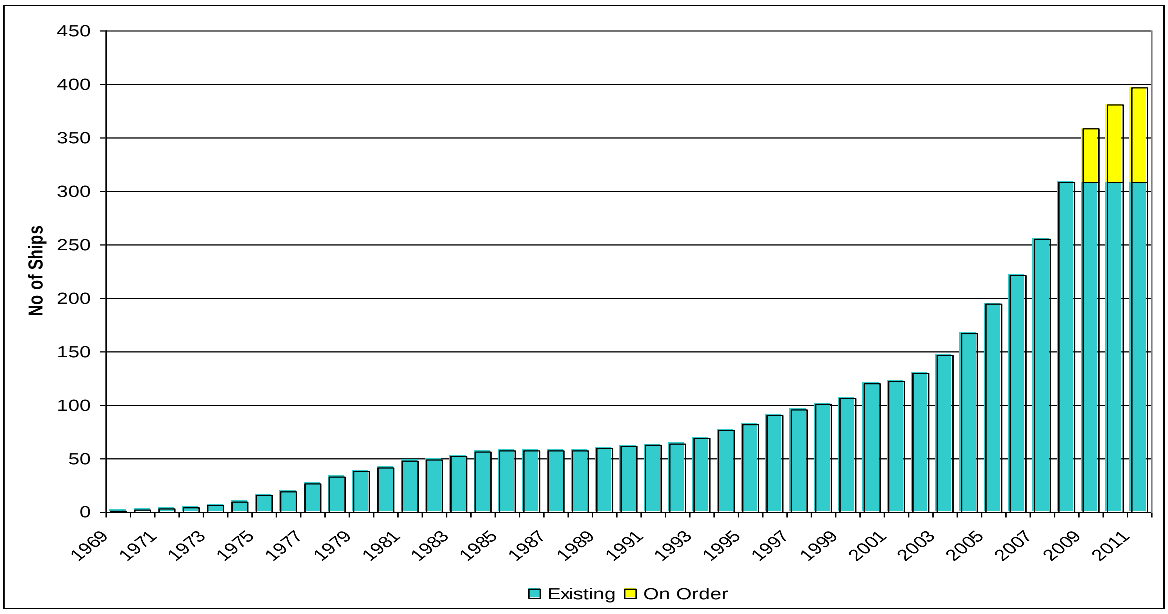


Source: Poten 2008, p. 9.

These constraints had a lesser impact on the relatively more straightforward segments of the LNG supply chain; namely LNG shipping and re-gasification terminals. As can be seen in Figure 38 and 39, these saw very significant growth rates – out of synch with the upstream liquefaction projects.

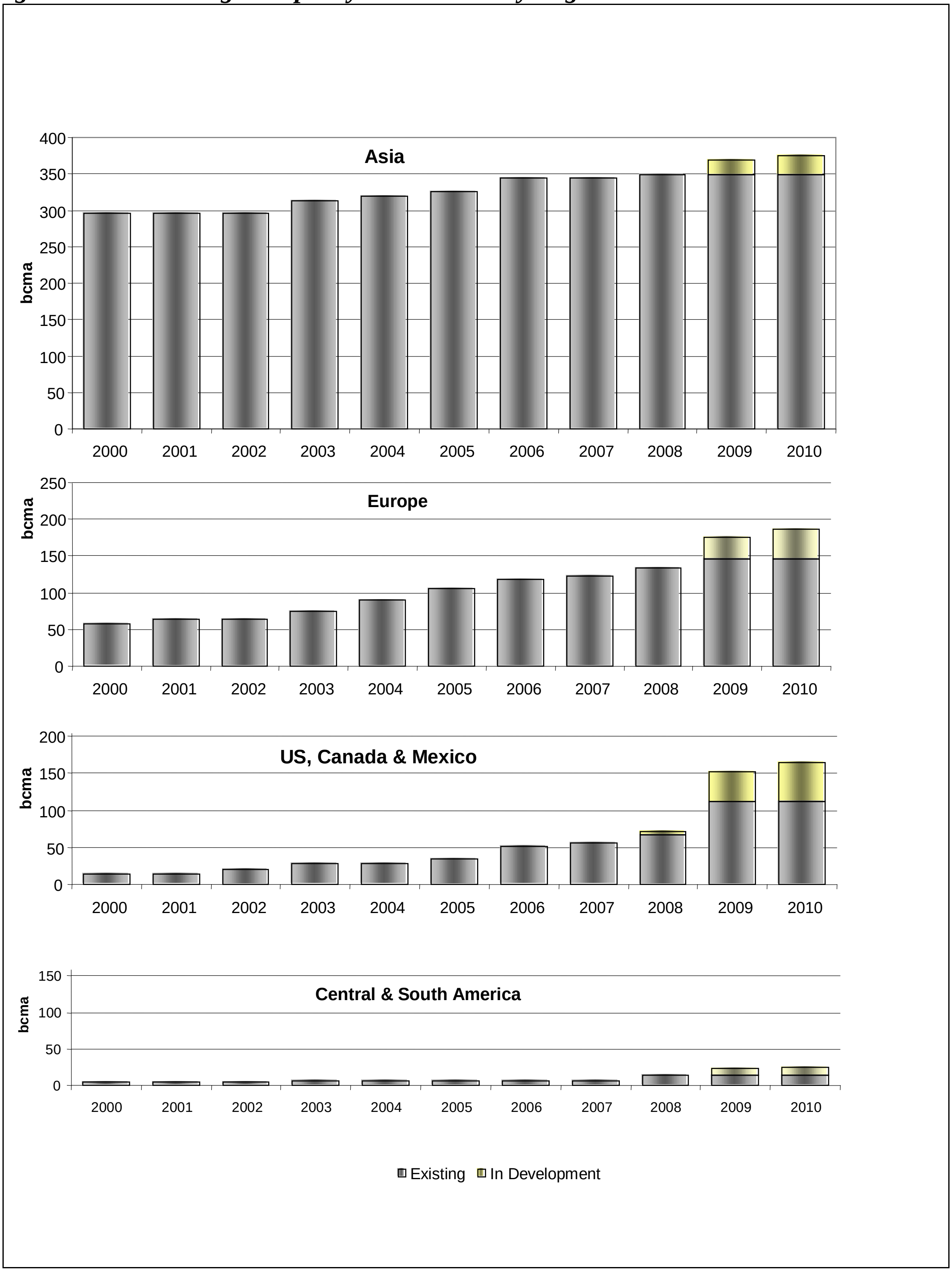
The key point from this is that neither re-gasification capacity nor shipping availability are likely to become constraints to LNG expansion at the global and even regional level.

Figure 38. LNG Fleet – Existing and On Order



Source: Gas Strategies 2009

Figure 39. Global Regas Capacity 2000 – 2010 by Region



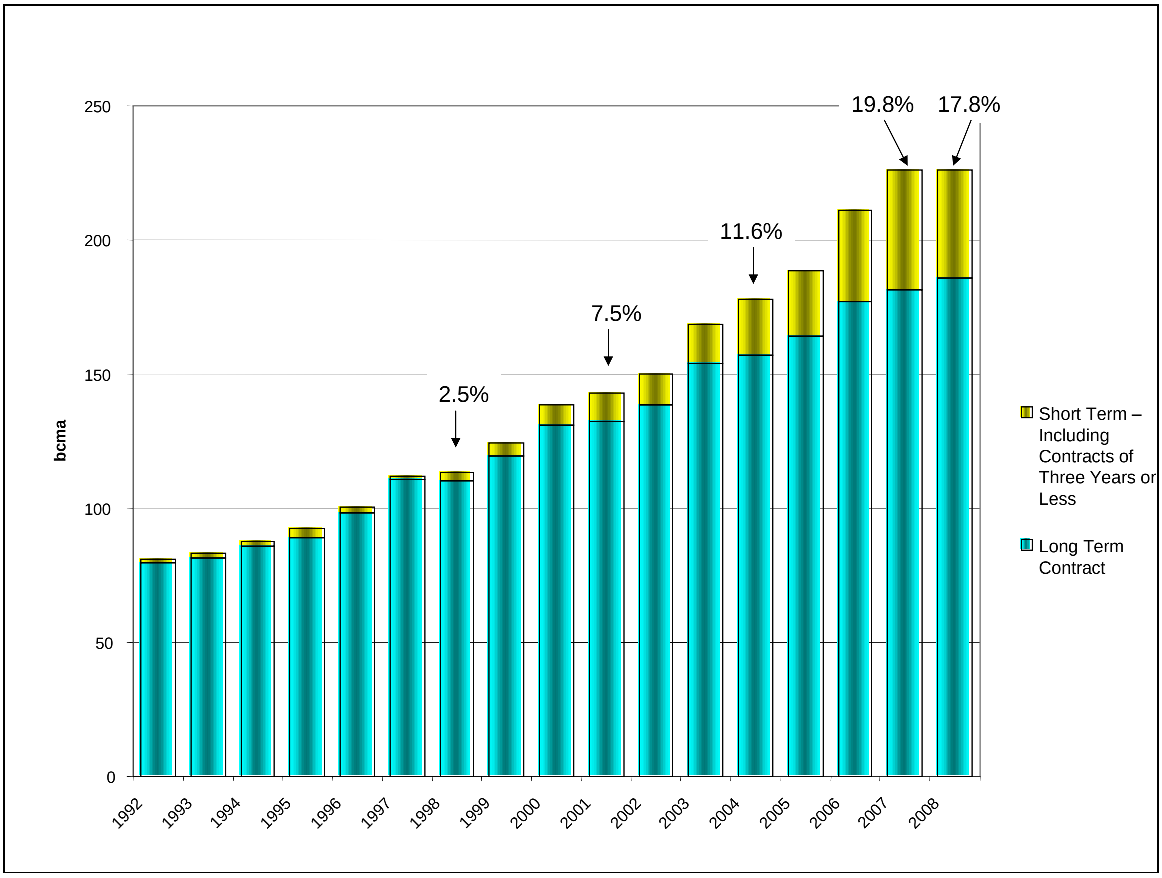
Source: WoodMac 2008a

The Mechanics of LNG Arbitrage and Activity to Date

Clearly the evidence of spot LNG purchases by Asian buyers since 2005 is part of a wider move to 'loosen up' the rather rigid business model of the traditional LNG business in response to the irresistible motivation of short term self interest. Indeed given LNG's uniquely mobile format, in the context of inherently disparate regional market pricing structures, it was almost inevitable that sooner or later the 'trading mindset' would gain ground over the 'long term relationships' paradigm.

The framework in which this trend can be analysed and quantified is the core of this paper and the substance of Chapter 2. The next part of this section describes the mechanics of LNG arbitrage.

Figure 40. Short Term Trading in LNG 1992 - 2008



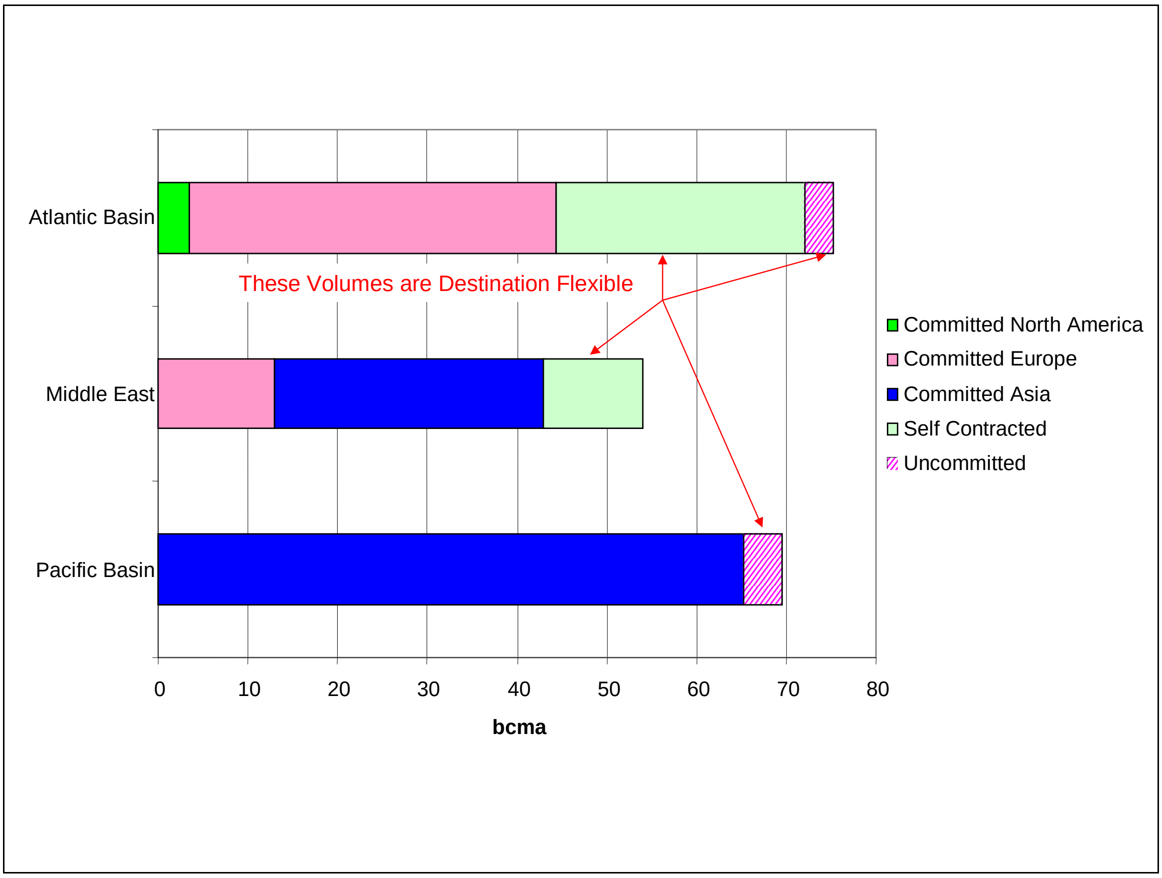
Source: Jensen 2009, Slide 23

By way of an overview, Figure 40 shows the growth of LNG sales classed as 'short term' i.e. either spot sales or contracts of less than three years in duration. The majority of these trades offer the potential for additional profit for the seller realised by diverting an LNG cargo from the original destination market to an alternative, higher priced opportunistic sale. This can be effected only where the original buyer (under the prevailing contract) consents to such a trade inevitably induced by a share of the resulting profit margin.

Polina Zhuravleva[28] describes four models of LNG arbitrage and three examples of short term sales which fall short of a strict definition of arbitrage. An overview of her taxonomy is contained in Appendix 1.

Flexible mechanisms have evolved to exploit short term price differentials for a limited number of contracted LNG volumes. By 2012, significant volumes of LNG from new supply projects will become available for which market destination has been deliberately kept flexible.

Figure 41. Regional LNG Contract Commitments – 2008 Showing Uncommitted or Self Contracted Volumes



Source: Jensen 2009, Slide 26

The segmentation of global LNG supply shown in Figure 41 is explained as follows.

- The 'committed' tranches are those under traditional long term contracts, however, as we have seen above, if buyer and seller are amenable, it is possible for some of these volumes to be diverted to exploit price opportunities in markets other than that which was the originally intended destination.
- The 'Self Contracted' tranche represents a relatively new phenomenon, primarily represented by BG with Equatorial Guinea and ExxonMobil/Qatar Petroleum with their Qatar LNG Projects. Instead of the traditional oil-indexed take-or-pay long term contracts with in-country incumbents, this form of contract involves the International Oil & Gas Company effectively

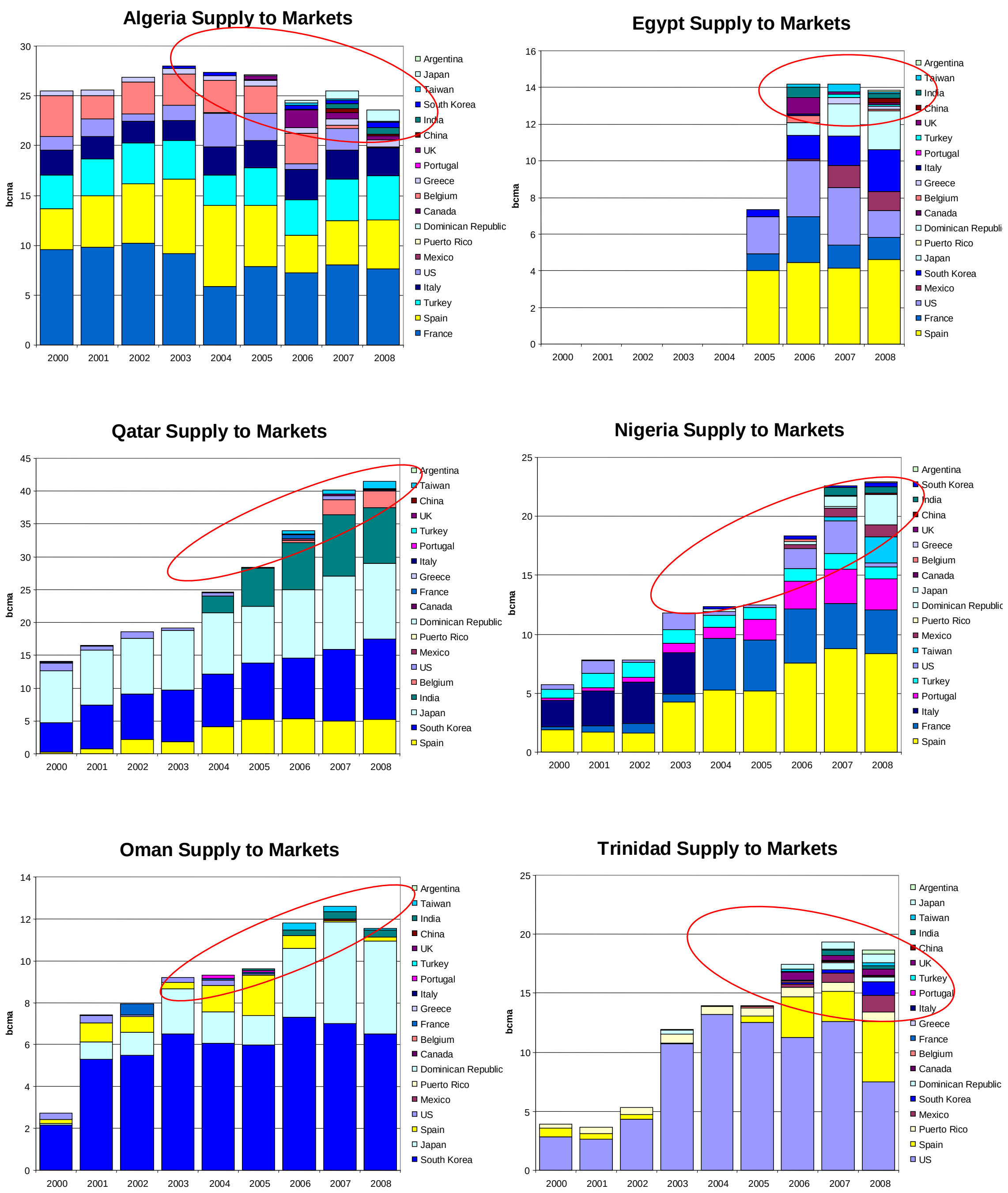
[28] Zhuravleva 2009.

using its balance sheet as security and contracting to take the LNG volume and place it in the market offering the best netback at the time. These self-contracted segments represent significant volumes and are inherently price-seeking flexible volumes mainly, but not exclusively, intended for Atlantic Basin markets.

- 'Uncommitted Volumes' to date have been largely those cargoes which have been produced:
    - in excess of envisaged early liquefaction train performance, before contracts have fully 'kicked in' at ACQ,
    - where the buyer has chosen to exercise downward flexibility on contract volumes towards minimum take or pay levels and where the seller wishes to produce at full capacity and sell the balance to uncontracted buyers in an opportunistic manner.

The reality of the significant increase in short term opportunistic LNG trading is shown in Figure 42 which shows the actual supply patterns of Algeria, Egypt, Qatar, Nigeria, Oman and Trinidad from 2000 to 2008. At the beginning of the period LNG deliveries were broadly in line with contractual provisions but since the mid 2000s we can see the fragmentation of LNG deliveries which has been facilitated by the mechanisms described above and incentivised by the regional price differentials created by different regional market pricing structures. The areas circled in Figure 42 highlight the opportunistic sales in the second half of the period.

Figure 42. Supply Patterns of Six LNG Producers 2000 - 2008



Sources: BP 2009, Waterborne LNG

Market Developments in 2008 and 2009 - The Perfect Storm

To conclude this descriptive, context-setting chapter we summarise the main market dynamics we have observed since 2000:

As we left the 1990s with the expectation of abundant, low cost natural gas a number of developing trends heightened concern over supply sufficiency:

- In North America gas production began to decline despite the rising rig count in the period 2001 – 2005. Prices became volatile with extreme high price excursions in response to weather and hurricane events.
- In Europe, concerns mounted over the ability of future imported gas supplies to keep pace with anticipated demand growth, especially in the power generation sector. Long term contract prices rose significantly as oil products prices began their sustained climb. UK prices became volatile with weather/event driven high price excursions as domestic supplies declined.
- In Asia the unforeseen decline in Indonesian LNG output and slippage in LNG projects led to Asian importers 'outbidding' Atlantic Basin buyers for spot cargoes; this was perhaps exacerbated by the prospect of India and China on the horizon as new LNG importers.

The 'supply response' to these developments was two-fold:

- A wave of new LNG projects was sanctioned with FIDs peaking in 2005. However this intensity of activity strained contracting sector capacity, resulting in project slippage and liquefaction unit cost inflation.
- In parallel the decline in North American domestic production was reversed due to the successful development of technology and approaches to exploit 'unconventional gas' namely shale gas and coal bed methane.

In parallel, the LNG world became more flexible in response to the arbitrage opportunities available during the 2005 – 2008 period and also by virtue of new projects with market destinations kept deliberately flexible.

The unexpected increase in North American production has threatened to oversupply the domestic market and as a consequence US prices have softened in response. However some of the new LNG supply about to come onstream was at least notionally tagged to the North American market. Traded markets were likely to soften as a consequence even without the 2009 slump in gas demand caused by the economic recession.

Recession-driven demand reductions for natural gas have been apparent since 4Q 2008 and are particularly evident in the Asian markets of Japan, Korea and Taiwan and generally in Europe.

The high production levels in North America combined with reduced demand levels in many LNG importing markets, coupled with the imminent significant growth in LNG supply will result in LNG-facilitated market interaction on a scale hitherto unknown.

The likely trends and discontinuities thus generated are examined quantitatively in Chapter Three. Chapter Two develops the analytical framework to facilitate this.

2. The Framework for Future Market Interaction through LNG and Pipeline Arbitrage

Introduction

This section describes a modelling framework which is able, subject to certain constraints and simplifications, to explore how the three main regional gas markets interact, especially as they become increasingly linked by LNG trade-flows.

Most modelling frameworks in the sphere of natural gas tend to be ‘cost of supply- based’ despatch models with, at some stage, linear programming having a key role in defining the ‘optimal’ solution. The attraction in the use of Linear Programming is that it produces a unique solution for systems which have multiple possibilities but for which iterative analysis arrives at the ‘objective function’ of, typically, a ‘lowest cost of supply’ solution.

Applying such an approach to the real world of natural gas certainly has its attractions, however it does tend to presume that the system does or ‘should’ conform to a ‘perfect market’ in its behaviour. Rightly or wrongly the real world of natural gas only approaches this paradigm in the liberalised markets of North America and the UK. Constraints can be added to models such as:

- for oil-indexed contract supply, the ‘cost of supply’ can be substituted by the oil product indexed price, driven off a view of future oil prices.
- ‘must flow’ rules for contract take-or-pay volumes.

Such models rapidly become highly complex to set up and to diagnose the rationale behind a supposed ‘solution’. If a model scope is constrained to focus on a specific regional market it becomes flawed by the inability to address the changes in LNG supply between regions which might come about as a consequence of price differentials. On the other hand, if such a model does attempt to cover all major LNG consuming regions, it quickly becomes hostage to the need to forecast the overwhelmingly important (but highly elusive) nature of the future North American supply cost curve.

Having had mixed experience with such approaches in the past, the author derived a more direct and transparent framework with the following conceptual elements:

- A monthly global balance encompassing all natural gas supply and demand of which LNG is one component.
- Regions included in this balance are:
    - Europe (including Norway and Turkey), Asian LNG importers, US, Canada and Mexico and new LNG ‘niche markets’ outside the above regions.
    - All global LNG supply.
- Supply and demand are projected at a national market level but dynamics are analysed at a regional level due to ‘degrees of freedom’ constraints.
- Instead of a Linear Programming approach, the analysis is ‘behavioural rules’ based and the main focus is the arbitrage – driven dynamic between oil-indexed European pipeline gas and LNG which can be diverted between Europe and North America.

This chapter describes the analytical framework so created and the quantitative analysis it produces.

The Global LNG Analysis Conceptual Framework

From our previously discussed observations of the interaction between the liberalised UK market and oil-indexed Europe since the opening of the Bacton-Zeebrugge Interconnector, and the observed behaviours of the Asian and North American markets with regard to LNG, we derive the following behavioural 'Rules' for the regions:

Asia: For Japan, Korea and Taiwan, LNG represents the only significant supply of natural gas. Security of supply is a fundamental concern for these markets. These markets have entered into binding long-term contracts for LNG supply, however since 2005, due to the slippage of new LNG supply projects and the underperformance of Indonesia as an LNG supplier, they have resorted to purchasing spot LNG at prices equating, at times, to crude and even distillate equivalent levels. These markets, for reasons of geology, lack underground gas storage. They tend to keep their re-gas storage tanks at high inventory levels – again for supply security reasons, rather than profiling inventory through the year so as to take advantage of lower summer spot LNG prices. In short we assume that these markets take 'first call' on global LNG supply according to their forecast demand, paying whatever price is required to secure spot supply over and above contracted supply if necessary. India and China differ in that they also have indigenous natural gas supply. This said however, prior to 2011 demand is limited by re-gas terminal capacity and forecasts of LNG supply are bounded by these infrastructure constraints.

North America: We have seen in Chapter 1, that such is the connectivity across borders, the US, Canada and Mexico can be treated as one supply/demand 'bloc'. In this liberalised market, the price of natural gas is determined by supply and demand. Where there is a linkage with oil products it operates only when the supply-demand balance allows for limited physical substitution in the power sector. In response to the observed decline in domestic natural gas production in the early 2000s many LNG regas projects were initiated such that by end 2009 some 100+ bcma of regas capacity will be available. Since 2006 however, the successful exploitation of 'unconventional gas' has meant that North America currently has little need for LNG.

Import infrastructure not being a constraint, LNG will flow to North America if:

- There is a tightening of the supply-demand balance (reflected in storage inventory trends compared with rolling average levels) which, reflected in the price of gas, attracts 'flexible' LNG away from other regional markets to give producers a better net-back.
- Other regional markets, (given the level of prevailing natural gas demand, their own domestic gas production and commitments to take minimum quantities of pipeline gas imports), do not, or cannot absorb the LNG supply available. In these circumstance LNG will be directed towards the North American market and in the first instance serve to increase storage inventories there.

It should be noted that from historical data, there appears to be a 'minimum level' of LNG imports into the US of around 9 bcma. It is unclear whether this represents a suite of supply contracts or is preferred source of local supply due to regional pipeline bottlenecks.

Europe: In terms of a spectrum of security of supply needs and market structure, Europe lies somewhere in between the Asian LNG importers and North America. Europe has domestic production but needs to import pipeline gas and LNG. Europe has a 'hybrid market of a mainly 'oil-indexed' continental 'mainland', and a liberalised UK; joined to the Continent by the Bacton – Zeebrugge Interconnector and the BBL pipeline (currently flowing Netherlands to UK but potentially bi-directional in future).

With domestic supply (including Norway) covering around half of its consumption, but with the expectation that this will in aggregate decline post 2012, Europe region obviously needs to import gas. It has options however:

- It has to import the take-or pay volumes under its long-term oil indexed pipeline contracts with Russia, Algeria, Libya, Iran and Azerbaijan.
- It can choose to take additional long-term oil-indexed pipeline gas up to the Annual Contract Quantity. (In practice there is monthly flexibility on minimum and maximum takes as long as the take or pay quantity is met within the 'Gas Contract Year' which runs from October 1st to September 30th of the following calendar year).
- It has to take delivery of, or pay for, its take-or-pay volumes of LNG where it has long-term contracts. It can however, with the seller's agreement or otherwise (dependent on the nature of the contractual arrangement), divert some of these contractual volumes elsewhere.
- In the case of LNG imports for the UK, there is no requirement for physical import and these volumes are entirely flexible.
- LNG (and pipeline gas form Norway) imported into the UK which is, at the margin, in excess of domestic demand and storage injection requirements can 'overflow' as 'spot priced' gas to Belgium (and in time possibly Holland) and onwards to the trading hubs of North West Europe where buyers can decide whether or not to purchase it in preference to oil-indexed gas.

In late 2009, the volume of global LNG supply was projected to increase by roughly 50% in the course of the next three years. Much of this additional LNG is inherently destination-flexible in nature (see Figure 41). The scene is now set for an unprecedented interaction between formerly separate and distinct regional gas markets.

Europe, being the 'hybrid' (i.e. oil indexed plus spot priced) regional market has a key role to play. If we distil the commercial position of Europe into that of a 'market importer and wholesale supplier' two scenarios are illustrative:

- **North American Prices Higher than European Oil-Indexed Natural Gas Prices:** The incentive is for Europe to divert flexible LNG to North America and 'back-fill' with oil-indexed pipeline gas by increasing nominations under its long-term pipeline contracts). This provides the European importer/wholesaler with a net trading profit in its upstream supply portfolio. The additional LNG arriving in North America increases storage inventory and depresses price. Logically Europe will continue to divert LNG to North America and increase its take of oil-indexed pipeline gas until either:

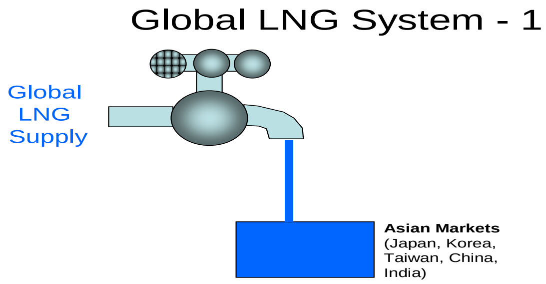
- **North American prices reduce to converge on European Oil Indexed Prices (at which point there is no incentive for further arbitrage).**
- **The nominations under long-term pipeline contracts reach Annual Contract Quantities or maximum short-term limits at which point the arbitrage dynamic ceases, despite a residual arbitrage price incentive.**

- **North American Prices Lower than European Oil-Indexed Natural Gas Prices:** The incentive is for Europe to buy flexible LNG to import to European markets and reduce nominations of oil-indexed pipeline imports under long term contracts. This provides the European importer/wholesaler with a net trading profit. The reduction in LNG arriving in North America reduces storage inventory and increases price. Logically Europe will continue to buy flexible LNG for import into Europe and reduce its take of oil-indexed pipeline gas until either:

    - **North American prices increase to converge on European Oil Indexed Prices** (at which point there is no incentive for further arbitrage).
    - **The nominations under long-term pipeline contracts reach Take or Pay or minimum short-term limits at which point the arbitrage dynamic ceases, despite a residual arbitrage price incentive.**

Step by Step Description of the Conceptual Framework
The above description of the arbitrage dynamic is illustrated schematically below in a 'step-wise' manner. Note that 'Henry Hub' is used as a shorthand for North American natural gas prices.

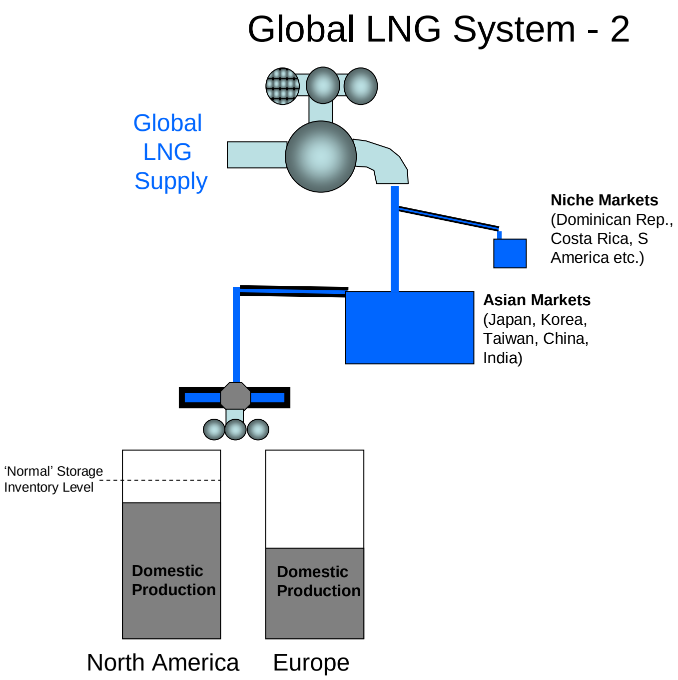
Figure 43. Global LNG System – 1



In Figure 43 we start with a conceptual representation of the Global LNG Supply as a tap (in North American a 'faucet'). First call on this supply is assumed to be the markets of

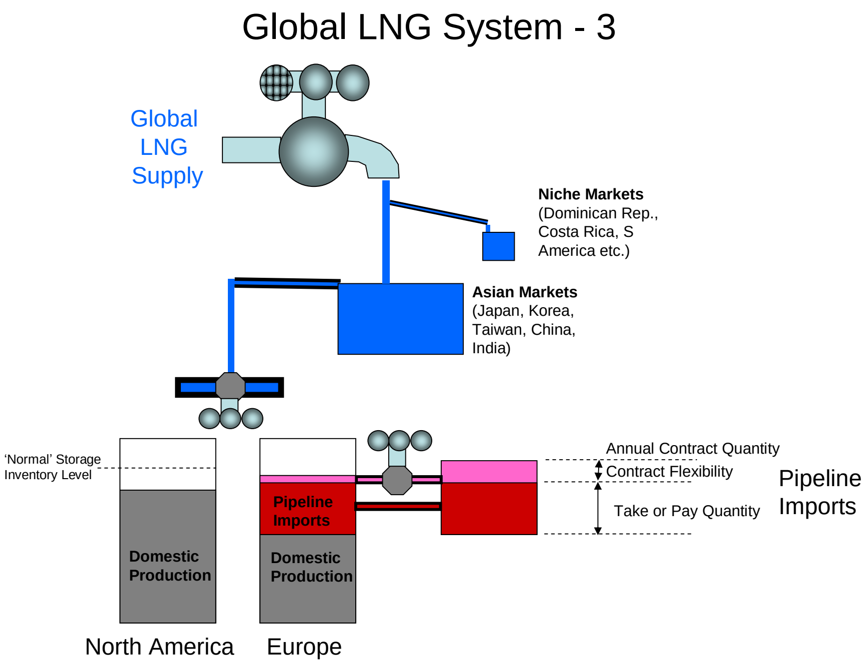
Asia i.e. Japan, Korea, Taiwan, China and India, represented by the filling of this 'tank'. In terms of timescale we are considering demand and supply at a monthly level.

Figure 44. Global LNG System – 2



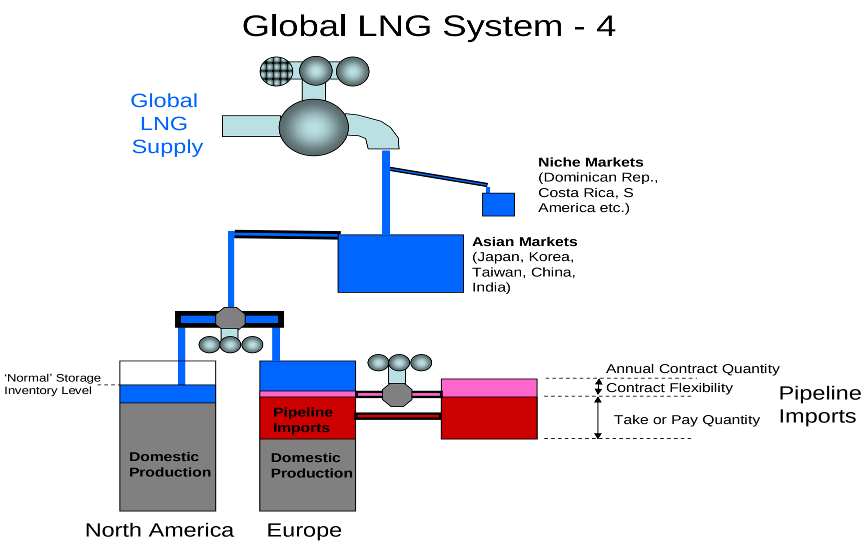
In Figure 44 we have added more components to the system. Firstly we have acknowledged the new and 'niche markets' which call on a relatively small portion of the global supply and our forecast of their demand for LNG removes this from the pool available. Secondly we have added in the demand 'buckets' for North America and Europe but have stopped short, at this stage, of addressing their LNG import requirements (this comes later). We recognise in this schematic however that North America and Europe have domestic production (grey) which makes a significant contribution to meeting domestic demand. For Europe, the full extent of demand (immediate and storage injection requirement), is represented by the top of the bucket. For North America (a liberalised market) we recognise that the dotted horizontal line represents the point at which immediate consumption has been satisfied and storage injection effected to bring storage levels to their 'five year rolling average levels'; this being the level, for the month in question, the traded market regards as average, or 'par for the course'. Storage inventory levels above this point would tend to drive the market to be concerned about oversupply and to drive natural gas prices downward; and storage inventory levels below this level would do the opposite – as we observed from historical data (Figure 9).

Figure 45. Global LNG System – 3.



In this step we have acknowledged the import of oil – indexed pipeline gas into Europe from Russia, Algeria, Libya, Iran and Azerbaijan. The two components of this supply are (i) the compulsory 'take or pay' quantity – in red in Figure 45. which is assumed to flow to Europe regardless of any other conditions, and (ii) the 'Contract Flexibility' amount in pink, which is the optional additional gas buyers can nominate between take-or-pay levels and ACQ levels. In Figure 45 Europe has elected to take a small portion of this Contract Flexibility gas.

Figure 46. Global LNG System – 4



In Figure 46 we see the allocation of remaining LNG between Europe and North America such that Europe's full import requirements are met and in North America gas storage inventory has reached 'normal' levels. This is a situation where North American prices converge with oil-indexed European prices; since if North America required one extra LNG cargo it would have to pay the equivalent of oil-indexed European prices in order for Europe to release the cargo and back-fill it by raising nominations on pipeline imports from Russia or North Africa. See Figure 47.

Figure 47. Global LNG System – 5

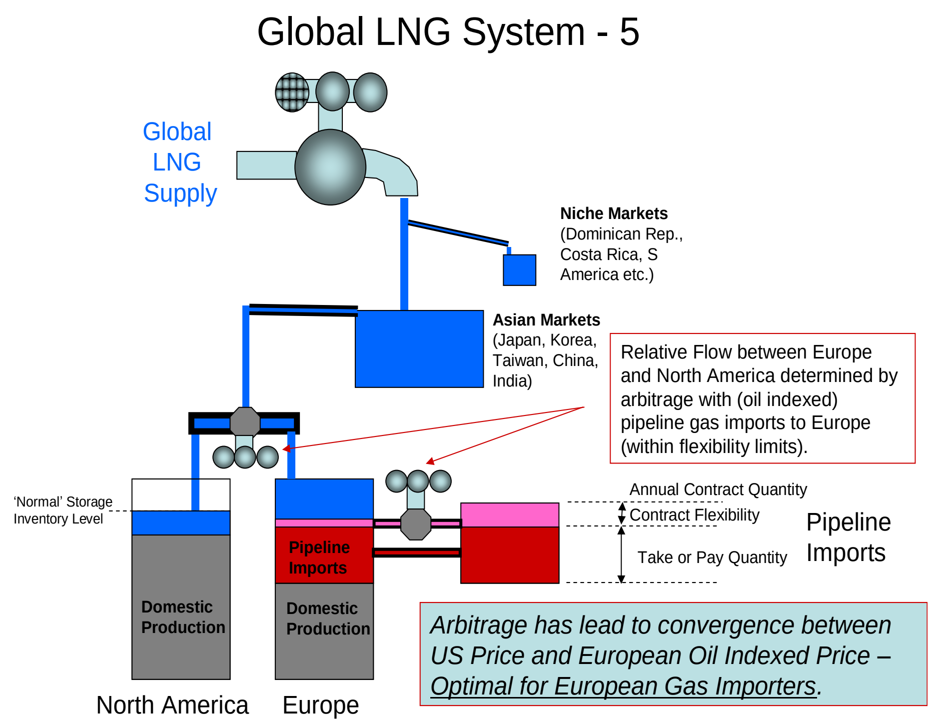
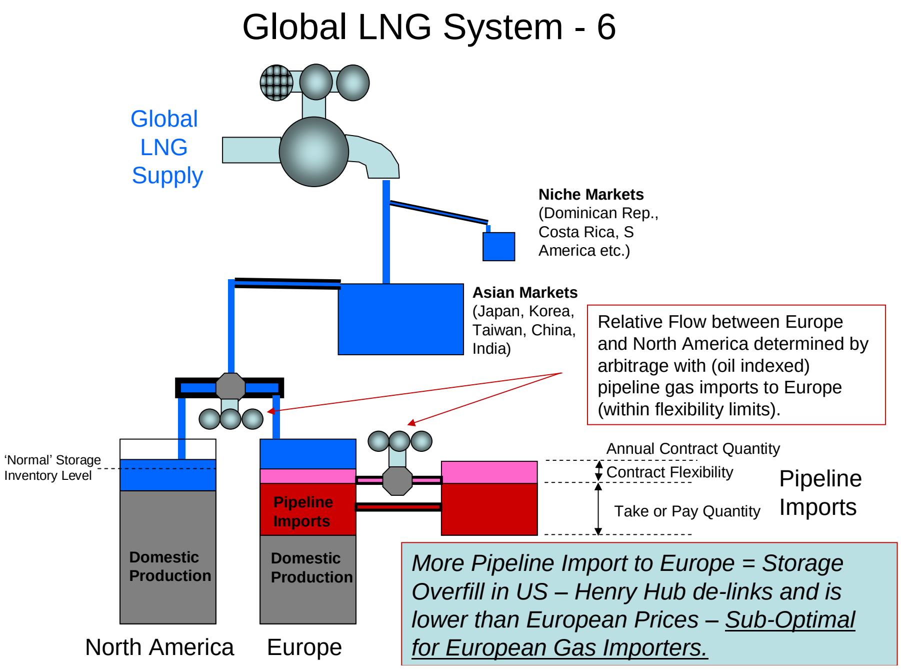


Figure 47 represents the 'end-point' of an arbitrage 'episode' in which the European gas importers/buyers have optimised their position in terms of the cost of their gas supply.

To confirm this we will examine two examples.

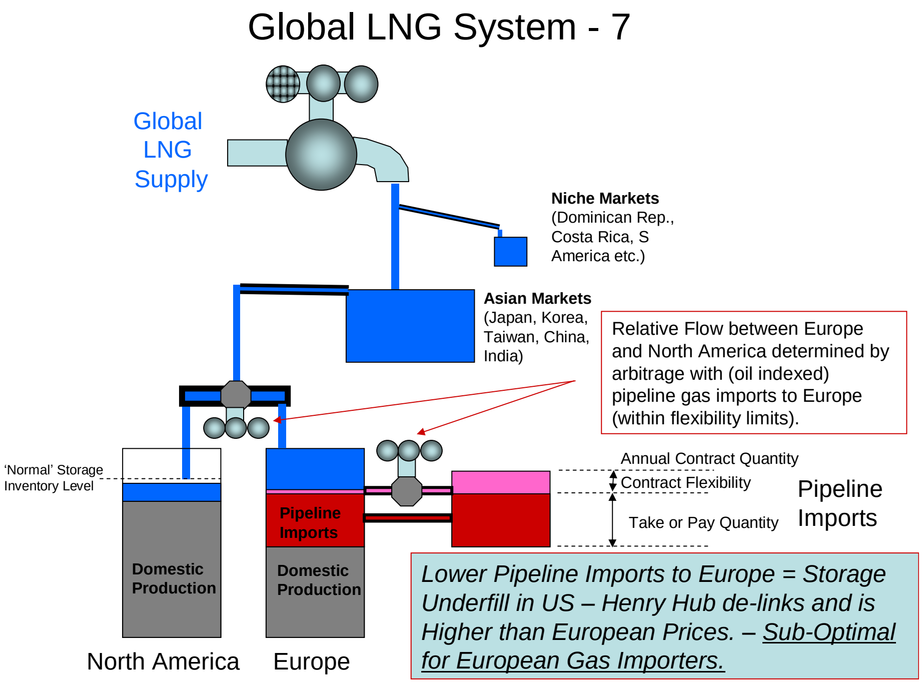
In Figure 48 we see a situation where (compared with Figure 47) Europe is importing a higher quantity of optional oil-indexed pipeline gas above Take or Pay levels. When the available LNG is allocated between Europe and North America the result is that North American Storage Inventory levels are higher than 'normal' in terms of the rolling average for the specific month in question. In this situation we would expect Henry Hub prices to be de-linked from European oil-indexed prices and lower. This represents an opportunity for Europe's gas importers/buyers. They can attract LNG to Europe (and away from North America) at the lower Henry-Hub prices and reduce their nominations of higher priced oil-indexed pipeline gas by the same volume. The reduced flow of LNG to North America will however reduce storage inventory levels and cause Henry Hub prices to increase. Europe will logically keep buying 'flexible' LNG volumes and reducing its nominations on oil-indexed pipeline gas until the reduced LNG volume into North America is sufficient to take storage inventory to levels at which Henry Hub prices have converged on European oil-indexed price levels.

Figure 48. Global LNG System – 6



In Figure 49 we see the converse situation. Here optional volumes of oil-indexed European pipeline imports are minimal. Once LNG has been used to fulfil Europe's total import requirement, the remaining LNG volume has been directed to North America. This however has left North America with a storage inventory below the 'normal' level for the month in question. In this situation we would expect Henry Hub prices to be de-linked and above European Oil-Indexed prices.

Figure 49. Global LNG System – 7



This again represents an arbitrage opportunity for European buyers/importers. They can re-direct some of their LNG imports to North America to secure the higher prices and back-fill with cheaper oil-indexed pipeline gas. As they do so they are increasing the supply of LNG to North America and increasing storage inventory and in so doing reducing Henry Hub prices. They will logically continue to arbitrage until Henry Hub is reduced to convergence with European oil-indexed pipeline gas.

Thus the situations represented in Figures 48 and 49 are unsustainable from the point of view of arbitrage dynamics. The incentives for European buyers/importers to secure additional value through arbitrage will result in them re-balancing the disposition of LNG and pipeline gas imports to achieve the situation in Figure 47; where Henry Hub and European oil indexed prices are converged.

However, other factors may prevent the perfection of this arbitrage dynamic.

Figure 50. Global LNG System – 8

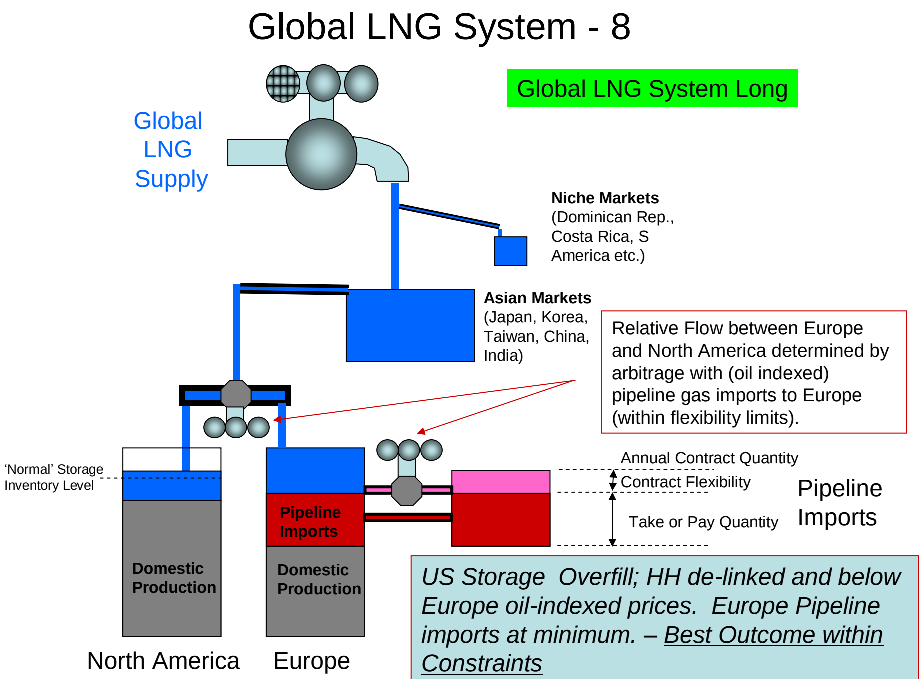
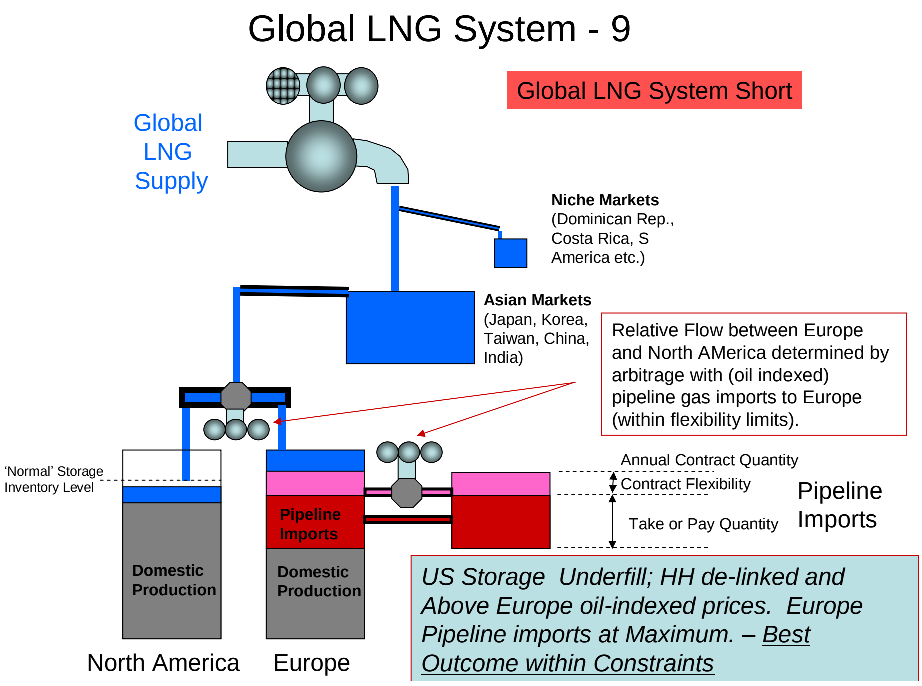


Figure 50 shows a situation where there is an abundance of LNG supply. Europe has reduced its take of pipeline imports down to take or pay levels and has filled its remaining import requirement with LNG. The remaining LNG has gone to North America, however it has taken storage inventory to above 'normal' levels for the month in question and we would expect Henry Hub to be de-linked and lower than European oil-indexed prices. Given the obligation on the part of Europe to take delivery of the 'Take or Pay' pipeline contract volumes, Europe cannot take full benefit of this remaining arbitrage opportunity.

In Figure 51 we see the situation when there is a relative scarcity of global LNG supply. Europe has nominated up to the maximum quantity of oil-indexed pipeline imports, however the balance of LNG supply after meeting Europe's import requirements is insufficient to bring North America storage inventory to the 'normal' level for the month in question.

Figure 51. Global LNG System – 9



In this situation, Henry Hub will be de-linked and higher than European oil indexed price and Europe, at maximum pipeline import level, cannot benefit from the remaining arbitrage opportunity.

Applying this framework to the world's natural gas markets which are 'connected' by LNG we can summarise a high level arbitrage-driven dynamic as follows:

The markets of North America, Europe and Asia which are impacted directly or indirectly by LNG imports, despite their different market-price structures and security of supply concerns, can be described as having a 'system dynamic' which is heavily influenced by arbitrage, especially between oil-indexed European pipeline gas and LNG which has flexibility as to its ultimate destination.

Where possible within physical constraints, this arbitrage dynamic will tend to bring about a convergence of North American natural gas prices and European Oil Indexed prices.

To bring this into perspective however, convergence can only take place where Europe is able to utilise its pipeline import flexibility. To put this in context: the markets (excluding small niche LNG markets) impacted by LNG amount to 1,600 bcma of natural gas consumption and the band of flexibility of Europe's oil indexed pipeline imports is some 40 bcma (this being the difference between pipeline import take or pay and annual contract quantity levels).

When supply and demand trends diverge outside this 'convergence envelope' (i.e. European Pipeline Imports have hit either ACQ upper limits or take or pay lower limits), this is reflected as high or low de-linked prices at Henry Hub through the following cascade:

Supply is Short, European Pipeline Import Levels at Annual Contract Quantity:

- North American Storage Inventory falls below normal levels, prices rise and are de-linked and above European Oil Indexed Prices.
- Once prices rise to residual fuel oil equivalent, fuel switching commences in the US power generation sector – which progressively destroys some 70 mcm/day (see page 13) of natural gas demand and keeps natural gas prices on par with residual fuel oil for the duration of this switching band.
- Once the switching band is completed prices will continue to rise until:
  - a switching band with distillate is reached (size unknown) and/or
  - demand destruction takes place with gas-intensive industries such as fertilizer plants closing down for the duration of the price spike.
- A high price excursion for more than 4 to 6 months is likely to result in an increase in drilling activity which will bring on new supply after a time lag of circa 12 months
- If this situation continues (or is expected to continue) for the 'foreseeable future' one would expect an acceleration of LNG projects with the North American/UK market in mind (time lag 4 to 5 years from sanction to new supply).

Supply is Long, European Pipeline Import Levels at Take or Pay quantity:

- North American storage inventory rises above normal levels, prices fall and are de-linked and below European Oil Indexed Levels.
- If prices fall to a level where coal is displaced in the power generation sector, this is likely to provide a 'soft floor' to gas prices by increasing gas demand at the expense of coal consumption. This is a progressive process and is moderated by the range of coal prices across North America and the reduced fuel flexibility as a consequence of regulatory structure in some generating regions.
- If prices remain low for a period of 4 - 6 months one would expect a reduction in the number of active drilling rigs and in extreme cases the temporary shut-in of producing gas wells.
- If this situation continues (or is expected to continue) one would expect potential, more marginal LNG projects to be deferred, bearing in mind that once the market outlook appears more favourable they will have a 4 to 5 year lag from sanction to production.

Simplifying Assumptions

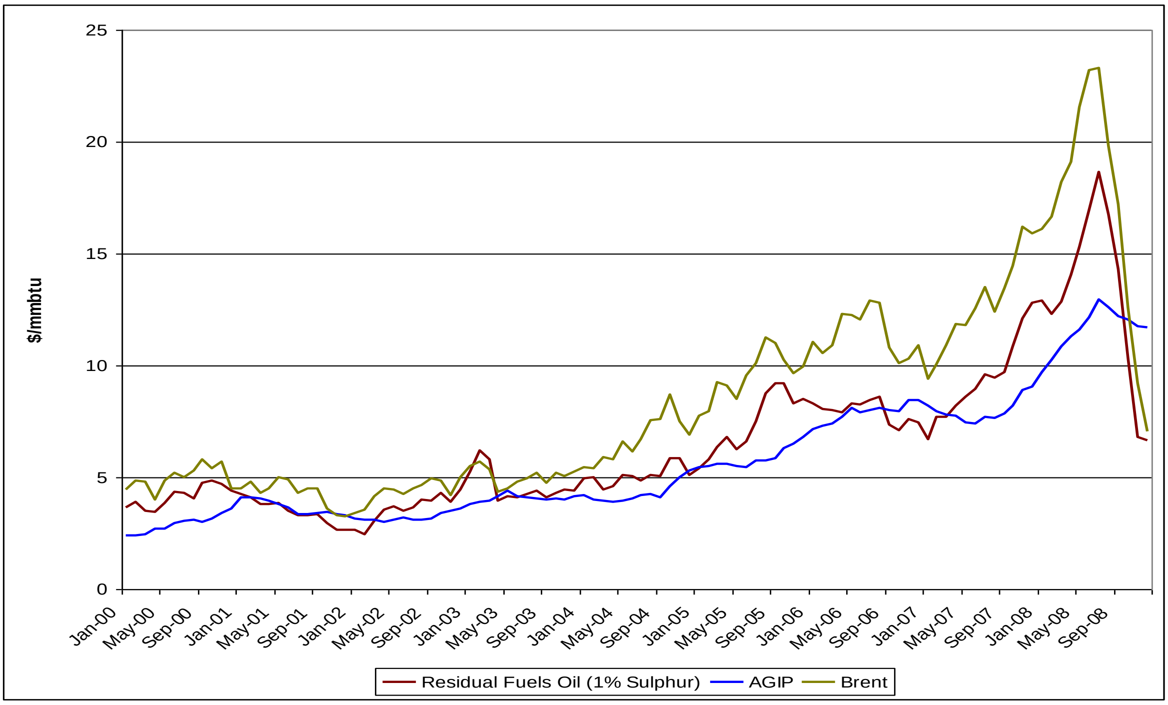
The conceptual framework described above has been developed into a model by the author on a monthly basis. In essence the model is a balance for natural gas supply, demand and storage with the results of arbitrage between Europe and North America determined by logic tests and the consequences reflected in regional pipeline import levels and storage inventories.

The **disadvantages** of this approach are:

- Most of the forward assumptions (forecasts) of supply and demand are, by definition, external to the model.

- Absolute price levels of European pipeline gas can be driven from a forecast of oil (and hence oil products) prices and while the model will identify time periods of convergence and de-linkages, it cannot predict the scale of price divergence between Henry Hub and European Oil Indexed pipeline gas. The scale of deviation of North American Storage Inventories from historic monthly 'norms' should however give an indication of the severity of price de-linkage.
- The model does not address the fuel switching band which operates in North America. When oil (and products) prices are on a rising trend, AGIP (a proxy for European Oil-Indexed Prices), having a 6 to 9 month rolling average lag against oil price, will tend to be below residual fuel oil prices for a time. When oil prices are relatively steady for 12 months they (i.e. AGIP and residual fuel oil) can converge. In Figure 52 the period January 2001 to January 2002 saw reasonable convergence between AGIP and Residual Fuel Oil.

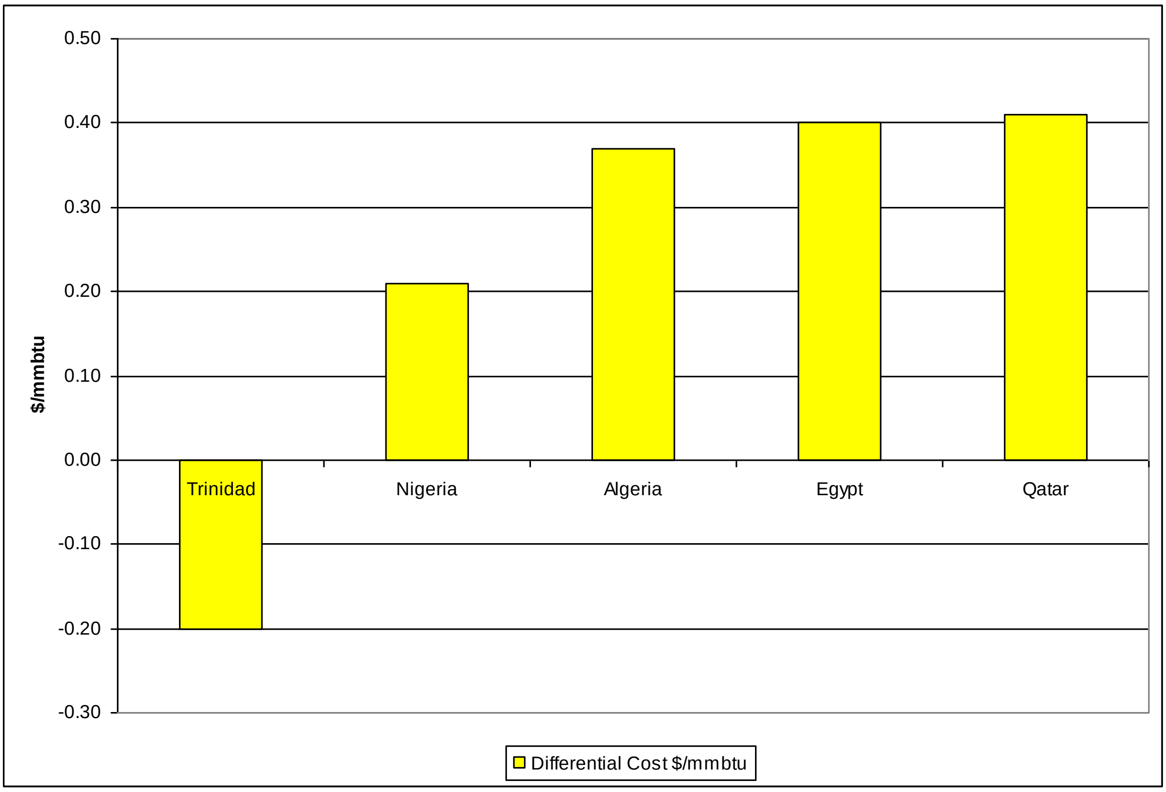
Figure 52. US Residual Fuel Oil Prices, AGIP and Brent Prices



Sources: EIAh, Gas Matters, Platts

- Due to the limit on the 'degrees of freedom' in this modelling approach, the UK (NBP price) and NW Europe Hub prices cannot be separately identified in the price convergence logic test. However, apart from periods where North America is only taking its observed minimum LNG supplies, the UK NBP price and the traded prices at the NW European Hubs will essentially track Henry Hub. There may be a difference due to the differential LNG shipping cost (see Figure 53) of around 40 cents per mmbtu. The exception noted here was the case for most of the time prior to 2009 however this is unlikely to prevail in the future once the new LNG supply comes on-stream post 2009 and North America takes in excess of its supply contract quantities of LNG.

Figure 53. Differential LNG Shipping Cost: Lake Charles vs. Isle of Grain



Source: Waterborne2009a pp 9 – 15.

On the other hand, the **advantages** of this approach are:

- The limited amount of 'within model' complexity allows for a transparent understanding of the dynamics of the system. There is no 'over sophistication' in the balance solution which is 'out of character' with market behaviour (often to be found in LP models and software platforms).
- Although many of the assumptions and forecasts are derived exogenously this has the advantage of making the researcher explore more fundamentally what is happening/likely to happen in the system (Chapter 3 will illustrate this point).
- Unlike many models the approach allows recent historic actual data to be transitioned into the near, medium and longer term. The discipline involved in this again allows insights into current market developments which are difficult to achieve with more sophisticated but purely future-focussed modelling approaches.

Other key **simplifying assumptions** in the model are:

- **Natural Gas Demand**: for the gas consuming countries modelled demand is derived by compiling, where possible, historic monthly demand data and combining this 'monthly shape' of demand with future annual forecasts. The framework allows for discrete monthly increments to be added to simulate, for example, the potential for periods of fuel switching. For Europe the author has also researched the correlation between temperature and natural gas demand in order to derive a best estimate of recent months in advance of IEA actual data being released[29].

- **Asian LNG Demand**: For Japan, Korea and Taiwan LNG demand equates to total natural gas demand (with a small allowance for indigenous or coal-derived supply). With Waterborne LNG data back to 2004 at a monthly level the 'monthly shape' can thus be derived and combined with future annual demand forecasts to produce a future monthly forecast. One significant area of uncertainty is the impact of nuclear downtime in the Japanese power generation sector, and to a lesser extent fuel switching in that sector between LNG, coal, crude and residual fuel oil. For India and China it is possible to base future annual natural gas demand forecasts on sources such as the IEA and EIA as well as future domestic production and pipeline import projections. Given the degree of uncertainty surrounding these projections however, deriving the LNG import requirement 'by difference' is not without its perils. Prior to 2011 LNG imports in China and India will be limited by re-gas capacity which at least puts a boundary around the uncertainty.

- **Domestic Supply**: For Europe (at a country level) and North America there is sufficient public domain and IEA data available to base a future annual forecast on and also a good historic monthly series to derive a monthly shape for domestic supply. For the US there are two special issues. The first relates to a sometimes very large 'balancing item'[30] in the otherwise apparently comprehensive data series from the EIA [31]. This needs to be taken into account in any global balance model. The second is that future US and Canadian production may have to be 'tuned' in order for the global system to come within a tolerable LNG-connected balance in future periods. This issue will be specifically addressed in Chapter 3.

- **European Pipeline Imports**: Data from Cedigaz on pipeline contracts from Russia, Algeria, Libya, Iran and Azerbaijan can be summed to arrive at the total ACQ of oil-indexed long term pipeline imports. The annual take or pay volume is assumed to be around 85% of this figure. In addition to this however there will be a monthly tolerance above ACQ and below TOP to reflect the seasonality on demand. Derived historical data provides clues to the additional flexibility. Any downward flexibility is likely to be reduced however in periods of low gas demand in order that Europe meets its take or pay obligation within a gas contract year (1st October to 30th September).

- **Treatment of Norway**: Since the opening of the Langeled pipeline which, in addition to Vesterled, now provides significant additional UK import capacity for Norwegian gas, the treatment of Norway is something of a dilemma. As we are not specifically modelling the UK as a distinct supply-demand entity separate from continental Europe we can use an historic

[29] See *IEA Monthly Data Series*

[30] The Balancing Item is the adjustment required to be made to the EIA production estimate in order that supply, demand and storage inventory change is balanced. While this may be large at times there is no satisfactory analysis forthcoming as to why this has not been progressively eliminated through time.

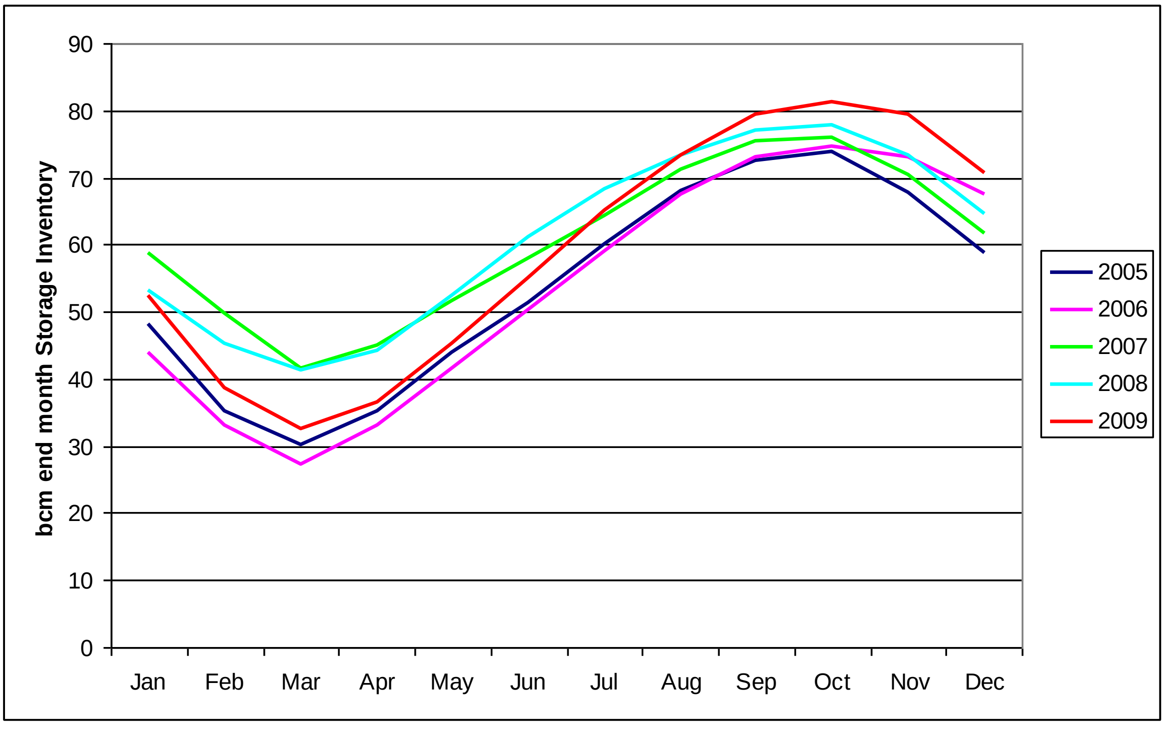
[31] See *EIAb*

Norwegian monthly production shape combined with future annual production forecasts. It is implicitly assumed that if continental long term contract buyers require less gas under contract than has been the case historically, the balance will in effect flow to the UK.

- **Netherlands Production**: As the largest continental European gas producer, the Netherlands provides supply under contract to adjacent countries. The Netherlands future production is modelled in a similar fashion to that of Norway – i.e. by combining a future annual production forecast with an average monthly profile taken from actual production rates in recent years.

- **European Storage**: Historical data on European storage inventory is obtained from the IEA monthly data series, Gas Storage Europe's website service, the German Energy Ministry and to a lesser degree Eurostat. Future storage assumes a generic storage fill pattern (a 'target trajectory') for a 'normal' weather year. Also included is an assumed build rate for new seasonal storage facilities. Figure 54 shows historical data on European Storage Inventory from the above sources, normalised to align broadly with GSE's view of maximum working gas capacity.

Figure 54. European Storage Inventory

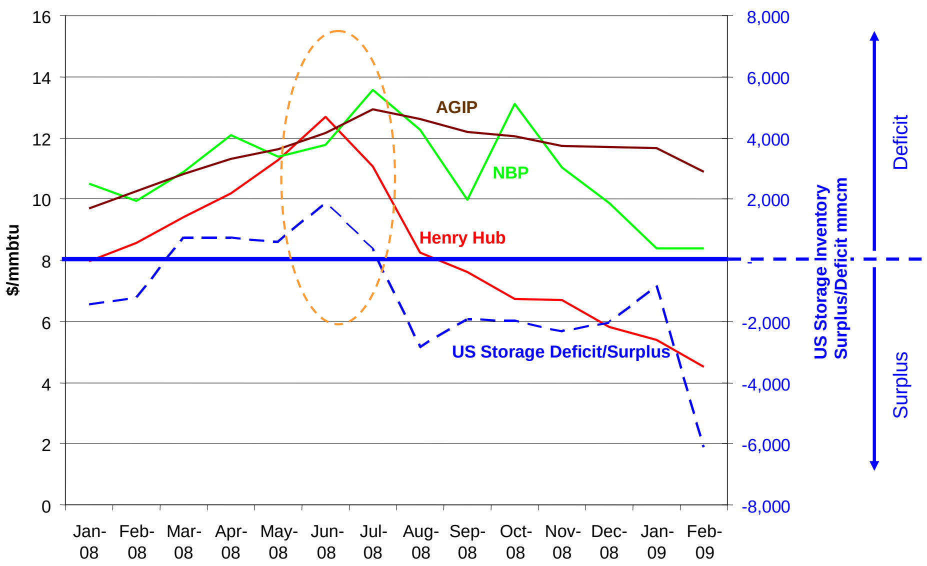


Sources: IEA Monthly Data Series, GSE

One challenge to modelling this is the need to 'splice' a credible trajectory from the most recent actual date to the achievement of the next, typically, October target peak – especially if the most recent winter was unusually warm or cold. Failure to achieve a relatively smooth inventory build during the summer will result in a disruption to pipeline and or LNG flows in the model framework.

- **North American Storage Levels**: In this conceptual framework we have made the assertion that, as long as European Pipeline Import levels lie somewhere between monthly minimum and maximum levels, a North American storage level which is in line with a rolling average or a 'market expectation' for the month in question will equate to a Henry Hub price which is converged with European Oil Indexed pipeline import prices. In a future world where North America is reliant on LNG supplies above its contractual minimum LNG volumes to meet demand and storage inventory build this should be valid. For example, if storage inventory was marginally lower than market expectations, bringing it back into line would require the attraction of flexible LNG currently headed for Europe. Europe would be happy to allow the redirection and back-fill with pipeline imports as long as the price received for the LNG was just slightly higher than oil indexed pipeline import prices. Conversely, if North American storage volumes were slightly higher than market expectations, Europe would become interested in attracting LNG away from North America and back out a similar volume of more expensive oil-indexed pipeline gas. Qualifications on this are firstly that incremental shipping costs could create a 'dead band' of price – depending on the source of incremental LNG and, secondly, that response times in 'real life' are slower than 'Excel'(!) – such that a lag of one or two months could be expected before this comes into play, with onshore gas storage, regas tank inventory and floating LNG storage providing the inventory buffer.

Figure 55. US Storage Surplus/Deficit and Atlantic Prices



Sources: EIAi, Gas Matters, ICIS Heren

An illustration of the emergence of this effect is shown in Figure 55. In early 2008 US storage inventory became depleted due to relatively cold weather in 1Q – taking the dashed blue line above the blue axis. As the storage deficit persisted, Henry Hub rose until by May and June it was on a par with UK NBP and continental Europe Oil Indexed (AGIP) pipeline prices. At the time there was some confusion in market sentiment regarding the credibility of the most recent data on North American domestic production which appeared to be growing more strongly than most observers had predicted. Prior to the verification of this domestic production data around mid year, it is suggested that the North American market in May and June was anticipating the need to attract LNG from Europe in order to reduce the storage deficit. Once the data on domestic production growth was verified it became clear to the market that North America could easily achieve its end injection season normal storage inventory levels without the need to compete with Europe for additional LNG imports. In fact this was comfortably achieved as Figure 55 shows, and Henry Hub prices de-linked from European prices from July 2008 onwards.

- **Re-gas Capacity US and Europe**: In Chapter 1 we examined the considerable build in re-gas capacity earlier in this decade and asserted that it was highly unlikely that this would constitute a barrier to LNG import levels in the future.

- **LNG Supply Forecasts and Characteristics:** Using monthly historical data of LNG production by supplier and knowing their individual liquefaction 'nameplate' capacities it is possible to develop a monthly ratio of LNG production to capacity at a supplier country level. Typically LNG output is lower during the summer season (ambient temperature impacts the operation of the liquefaction process) and maintenance periods will obviously reduce output. For new trains coming on-stream a 'commissioning curve' can be assumed during initial ramp-up. Assuming start-up dates for new liquefaction projects, a global LNG supply forecast can be derived at a monthly level. This is examined quantitatively in Appendix 2. Comparing the forecast with actuals reveals good agreement apart from 2009. This is primarily due to underperformance by Nigeria and Algeria who both claimed Force Majeure[32]. This situation requires close monitoring as the volumes (of around 20 bcma) would, if they had been produced, have flowed to North America, broadly doubling LNG imports there through most of 2009.

Apart from these apparent anomalies an LNG project, once it is operating has a relatively low Short Run Marginal Cost of Supply. In large part this is due to the tendency of LNG project developers to 'segment' the supply chain, creating different ownership entities for the upstream field development, liquefaction train, shipping and regas terminals. Each segment typically contracts for capacity with the next, on a 'send or pay' contractual basis. Once in operation there is a greatly reduced economic rationale for shutting in production in response to low prices – as the only cost savings to be made are probably the variable operating costs of the upstream fields which are very low on a unit basis. The rational assumption therefore is that once an LNG project is on-stream it will tend to continue to produce at maximum rates. The situation in Nigeria and Algeria deserves monitoring

[32] See Glossary for definition of Force Majeure

however to determine whether production is deliberately being withheld for reasons other than short term economic rationale i.e. an anticipation of greater revenues in the future if prices increase.

- **European minimum LNG imports**: LNG and pipeline gas imports can be interchanged across the European continent, as a direct exchange in Spain, France and probably to a more limited extent in Italy, Greece and Turkey. For NW Europe the UK acts as an intermediary importing more or less LNG and connecting its spot gas supplies to the satellite trading hubs of North West Europe via the Interconnector. At present we cannot quantify the potential scale of the NW Europe connectivity available for this mechanism, although the incentives would certainly emerge to expand transportation capacity should such a bottleneck emerge. Accepting that connectivity may be an issue we can apply a constraint to the model to force it to accept a minimum quantity of LNG, based on historically observed minimum monthly levels.

- **European LNG contract price**: We have not directly addressed either the contractual nature or oil-price indexation basis of much of the LNG imported by Continental Europe. What we have done instead is to assume that:

    - there is a minimum 'must take' volume for Continental European LNG Imports – reflecting a possible lack of connectivity and degree of rigidity in some contracts which precludes cargo diversions.
    - generally there is sufficient flexibility in Atlantic Basin LNG volumes to take advantage of arbitrage opportunities – as illustrated in Figure 41.
    - pipeline take or pay obligations take precedence in terms of imports into Europe. In a low demand period, if there is insufficient physical storage to take contracted LNG take or pay volumes – they will be diverted to North America albeit for a sales price lower than the contracted price. Although this represents a marginal financial loss it is better than paying for gas not taken at all.

This concludes the description of the conceptual model framework. Chapter 3 will use this framework to understand the dynamics currently at play in the market and also to explore the likely emerging trends and discontinuities.

3. Future Assumptions, Trends and Discontinuities Emerging

Introduction
This chapter takes the conceptual framework outlined in the previous chapter and, having derived a credible assumption envelope for key variables, applies the framework to explore key trends and discontinuities, primarily focussing on the Atlantic Basin arena.

Future Assumptions: Natural Gas Supply and Demand Fundamentals and LNG Import Requirements
The future assumptions of national and regional demand, domestic production, pipeline imports and LNG supply are discussed and set out in Appendix 2. This is not intended to be an exhaustive derivation of future supply and demand forecasts. The main focus is on the key uncertainties which will influence market dynamics in the medium to longer term.

Future Trends and Discontinuities Emerging from Modelling Framework
At this point, having developed our modelling framework and derived our initial set of future assumptions in Appendix 2, we can look at the prognosis for future trends and discontinuities.[33]

We will use a standardised set of graphics to examine the future in two time periods:

- The period up to 2015;
- The period to 2020.

The 'Current Momentum' Case
The first of three 'futures' we will examine with the aid of the model framework is what we call the 'Current Momentum' Case. Essentially this is characterised by taking at face value the future assumptions described in Appendix 2 and quantifying the outcome at a 'whole system' level.

The critical assumptions for this case are:

- No significant near term reduction in North America domestic production.
- Expansion of LNG supply on current start-up timings with no major outage problems assumed post 2009. Apart from an assumed continuing 10 bcma of 'general underperformance' to mid 2011, it is assumed that LNG producers do not deliberately hold back supply from the market.
- Apart from an assumed 10% Take-or Pay rollover from contract year October 08 – September 09, all European pipeline gas importers must honour their take-or pay obligations (assumed at 85% of ACQ).

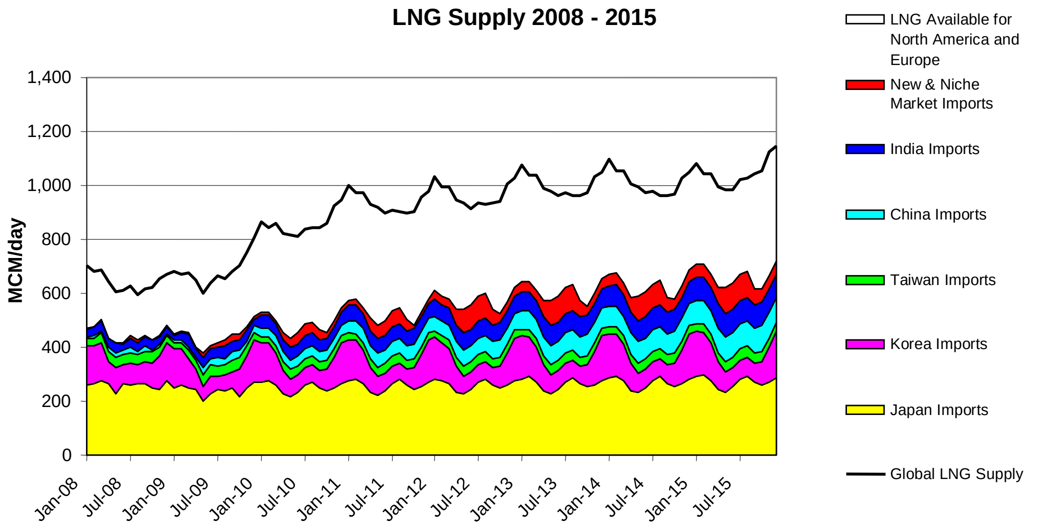
This set of assumptions, although quite widely held either individually or collectively, results in an unsustainably oversupplied global system which does not have the necessary storage capacity to cope.

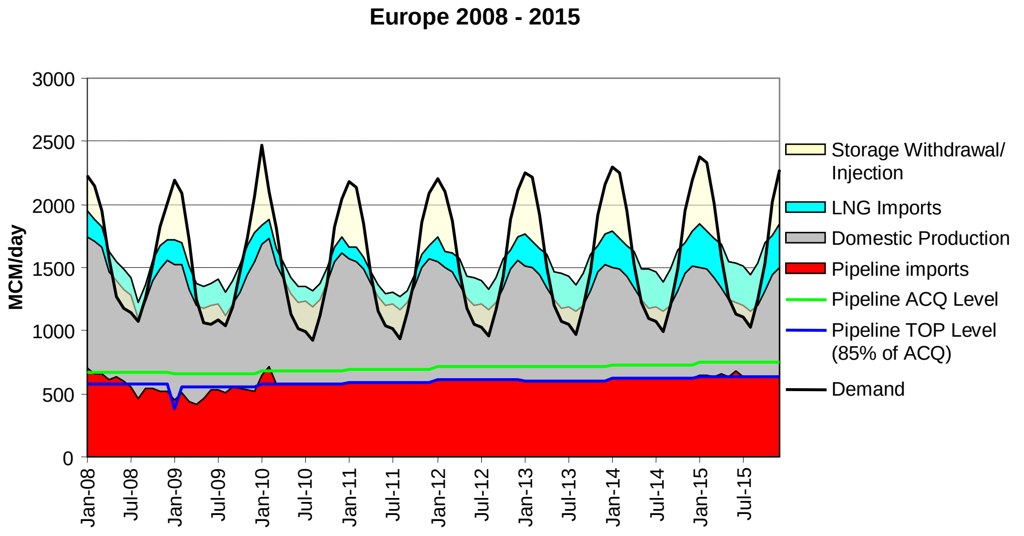
Having demonstrated this, subsequent cases are developed to show how the system could respond to accommodate the situation to 2015 and to 2020.

[33] Although historical demand data was not available at the time of writing to cover the extremely cold month of January 2010 in Europe and North America, the author has reflected this through an estimate.

The suite of 'Current Momentum' case results graphics follow:

Figure 56. Current Momentum Case to 2015 – Global LNG Supply and Europe





Source: Author's Analysis

In the LNG Supply graphic of Figure 56, the top black line represents total global LNG supply on a monthly basis. The graph shows the portion of this consumed by the Asian importers (Japan, Korea, Taiwan, China and India) and by the new Emerging and Niche markets. The balance of supply (the white area) is what will be delivered either to European or North American markets.

The European graph shows total demand (black line) with domestic production shown as grey, LNG imports in blue and pipeline imports (Russia, Algeria, Libya, Azerbaijan and

Iran) in red. Storage injection and withdrawal volumes are shown as the semi-transparent cream coloured layer. This graph of Europe shows a number of important features:

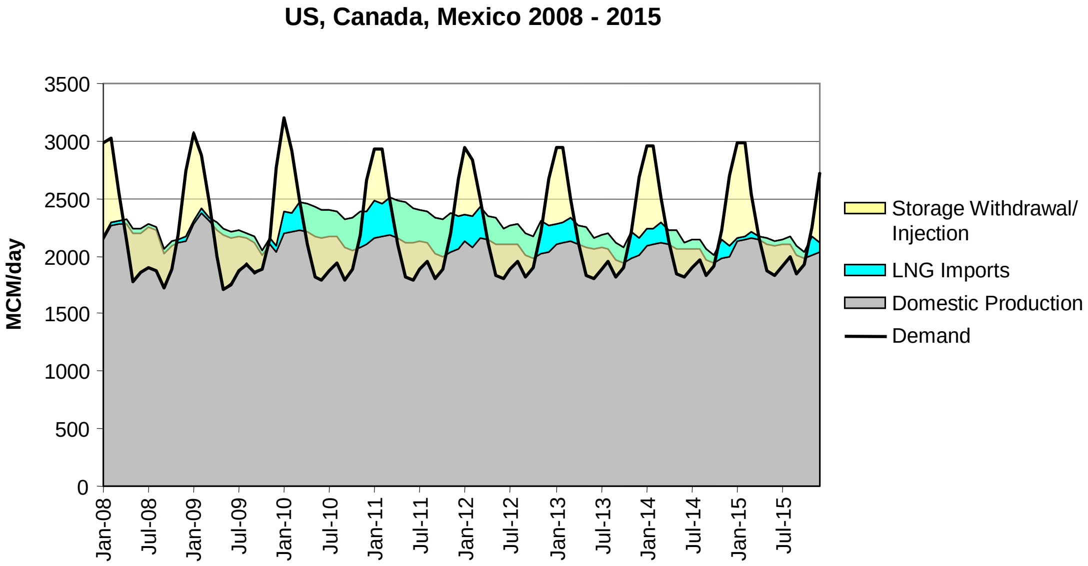
- The January 2009 dip in pipeline imports are a consequence of the Russia-Ukraine crisis.
- The continuing low take of pipeline gas imports in 2009, (derived actuals to end October 2009), leading to a 10% under-delivery on 1st October 2008 – 31st September 2009 contract year take or pay levels. Post 2009 it is assumed that pipeline import take or pay levels are honoured at an assumed 85% of annual contract quantity. The model envisages Europe taking no more than these levels until 2015 when there are occasional monthly imports above these levels.
- The lowered demand levels relative to 2008 and the adherence to pipeline contract take or pay levels squeeze the import volumes of LNG to Europe until 2012, when demand begins to noticeably recover.

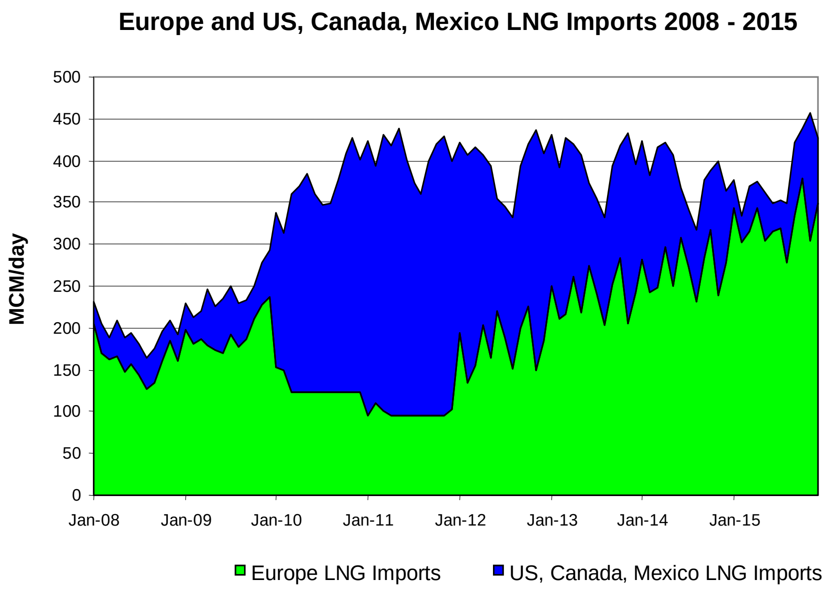
We will revisit some of these assumptions to derive further cases.

Figure 57 shows the situation in North America where near term demand is depressed but domestic production continues at around 2009 levels. The key dynamic here is the major surge in LNG imports from January 2010 onwards, peaking in 2011 and then following a diminishing trend to 2015.

The second graphic in Figure 57 shows the relative size of LNG imports into North America and Europe. From early 2010 to the beginning of 2012, LNG supply surges into North America as Europe has no physical room to absorb it, while honouring pipeline take or pay commitments.

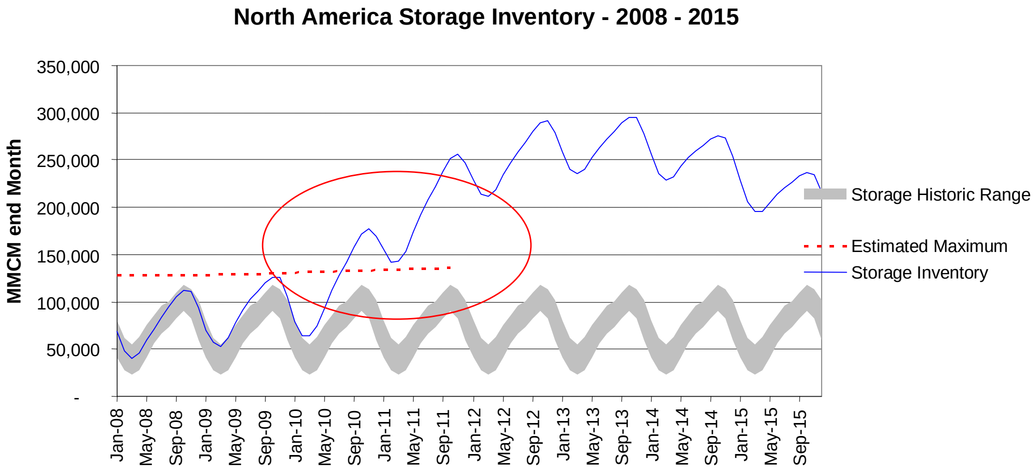
Figure 57. Current Momentum Case to 2015 – North America and Atlantic LNG

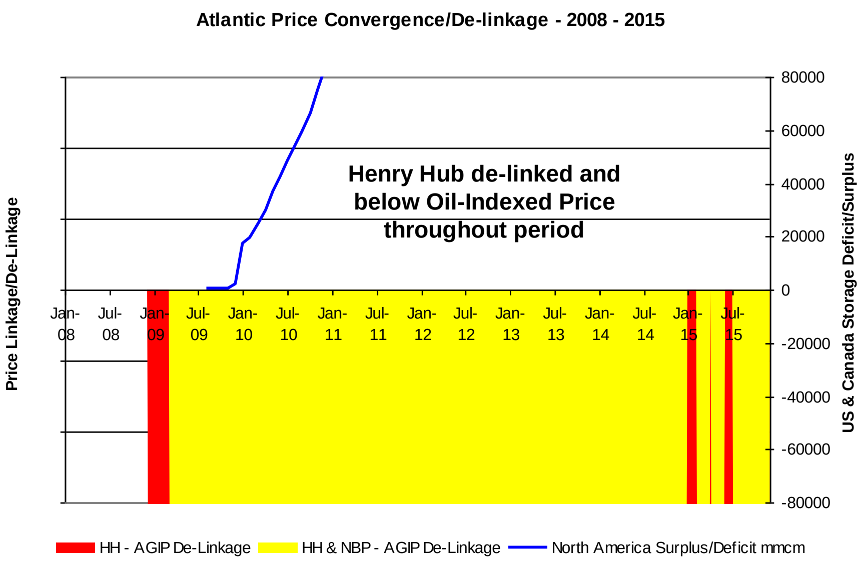




Source: Author's Analysis

Figure 58. Current Momentum Case to 2015 – North America Storage and Atlantic Price Linkage





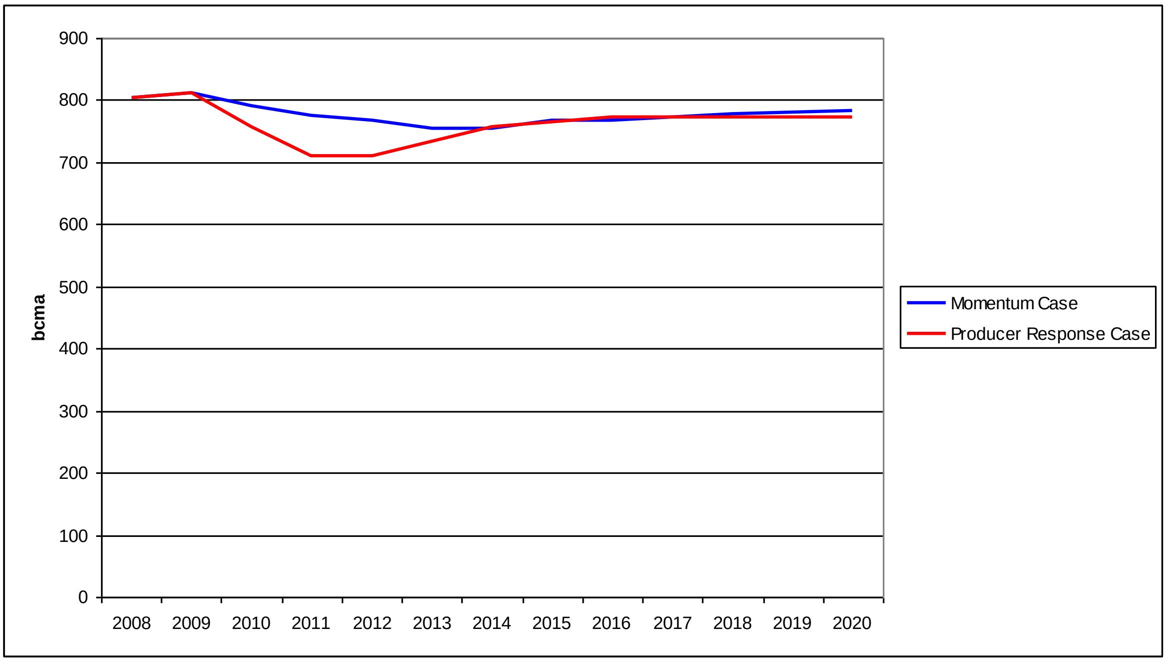
Source: Author's Analysis

The top graphic in Figure 58 shows North American storage inventory with the dotted red line representing the maximum physical storage capacity. This confirms the unreality of the 'Current Momentum' case. Clearly, beyond mid 2010 it is not physically possible (from a storage viewpoint) for North America to import the volumes of LNG represented here and continue with domestic production at 2009 levels. The Atlantic price graph in Figure 58 represents (above the horizontal axis) the US & Canada storage surplus (blue line). The yellow areas of the graph indicate that both Henry Hub and NBP are de-linked and lower than the oil-indexed AGIP price. The red area indicates a period where NBP may be converged with AGIP while Henry Hub is de-linked and lower. Clearly the price implications of such a case would be an extremely low Henry Hub and NBP price by mid 2010 which would undermine the validity of the production assumptions thereafter.

The Producer Response Case

The Producer Response Case is one where UK and North American natural gas prices are significantly weakened as new LNG trains ramp up supply. In the Producer Response Case all assumptions are the same as those in the 'Current Momentum' Case apart from US and Canadian Production, which relative to previous assumptions, is assumed to drop by some 35 bcma in 2010, 65 bcma in 2011 and 55 bcma in 2012. Thereafter it gradually recovers. (Figure 59).

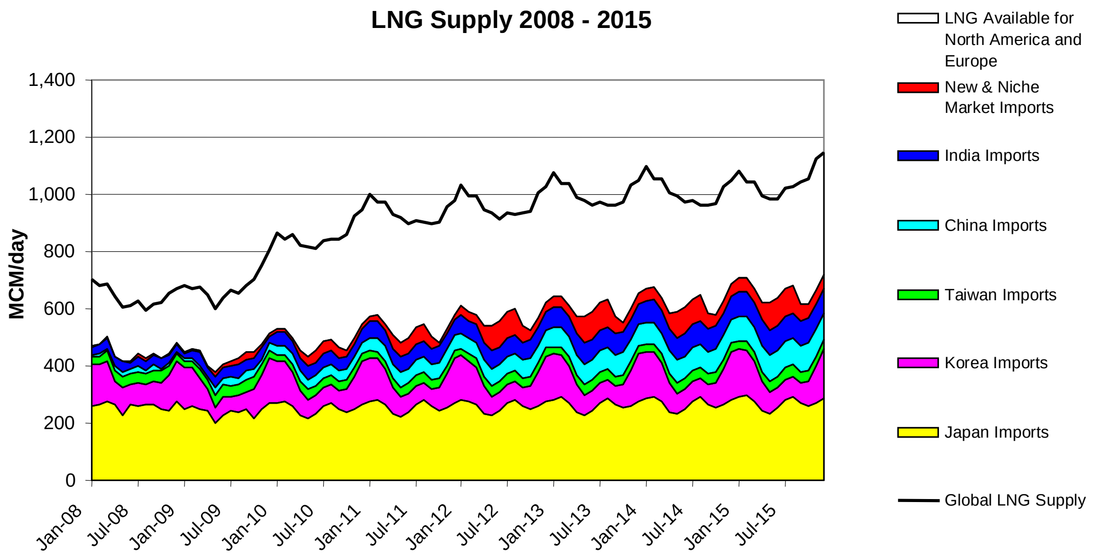
Figure 59. Assumptions for future US Canadian and Mexican Production

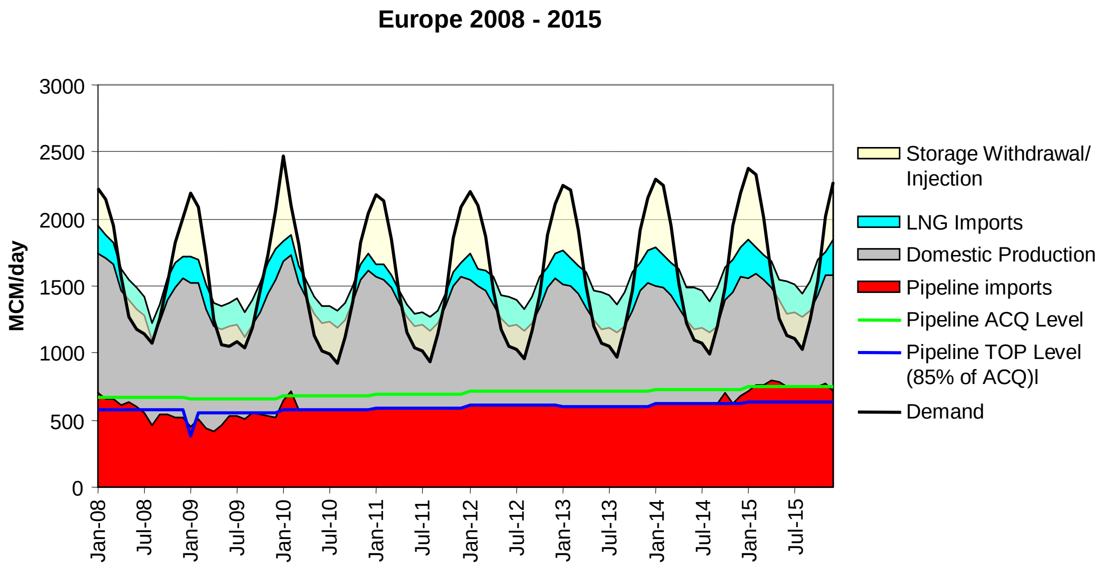


Source: Author's Analysis

In Figure 60, the global LNG supply situation is unchanged from the 'Current Momentum' case. The second European graph still shows the squeeze on European LNG imports caused by lower demand and adherence to take or pay pipeline import levels in the 2010 and 2011 period. From the middle of 2014 onwards however, European pipeline imports increase above take or pay levels. This is a consequence of the lowered North American domestic production reducing the cumulative storage surplus and increasing competition for LNG between Europe and North America.

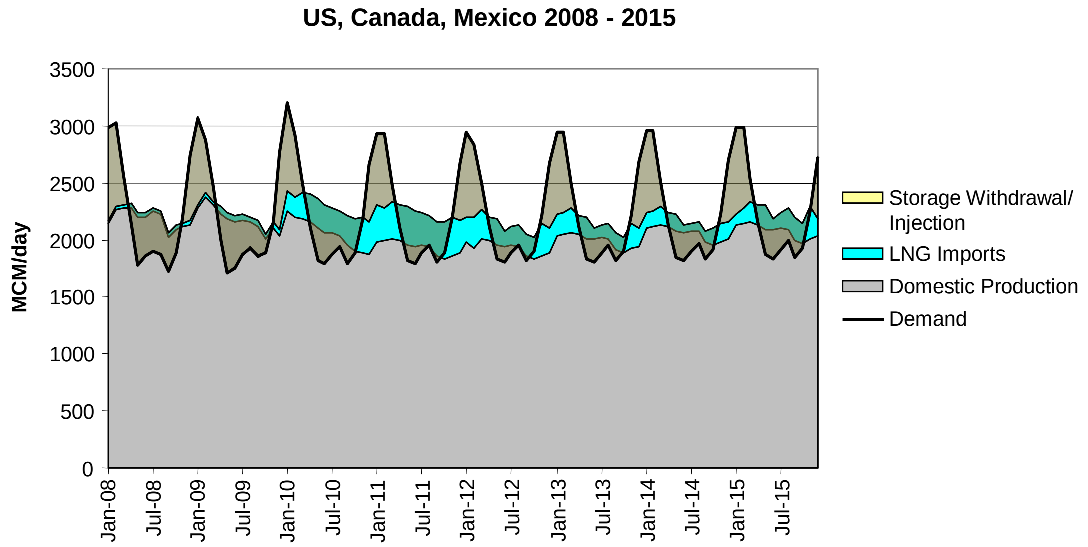
Figure 60. Producer Response Case to 2015 – Global LNG Supply and Europe

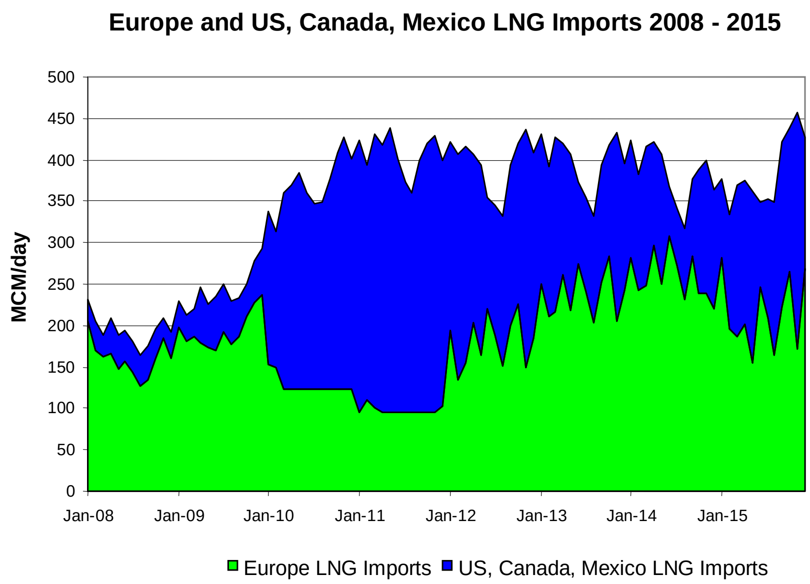




Source: Author's Analysis

Figure 61. Producer Response Case to 2015 – North America and Atlantic LNG



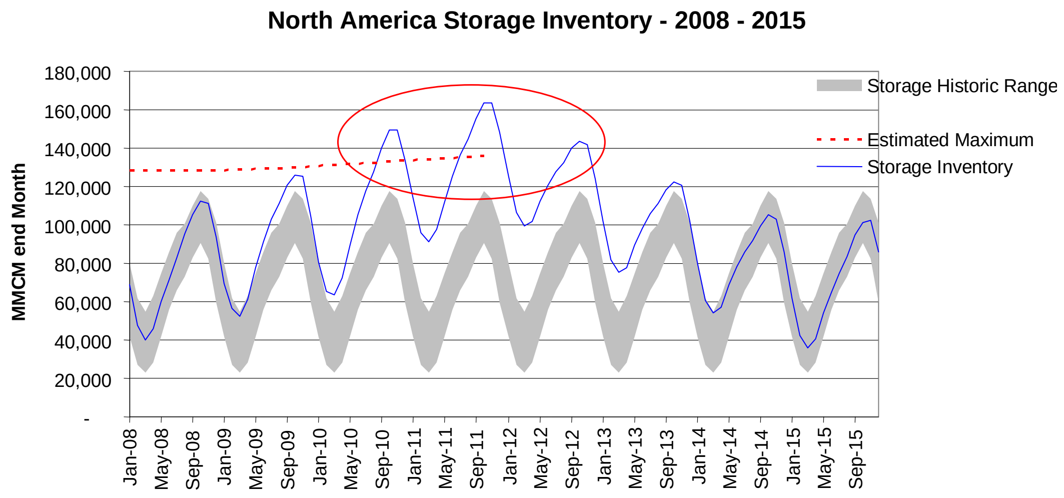


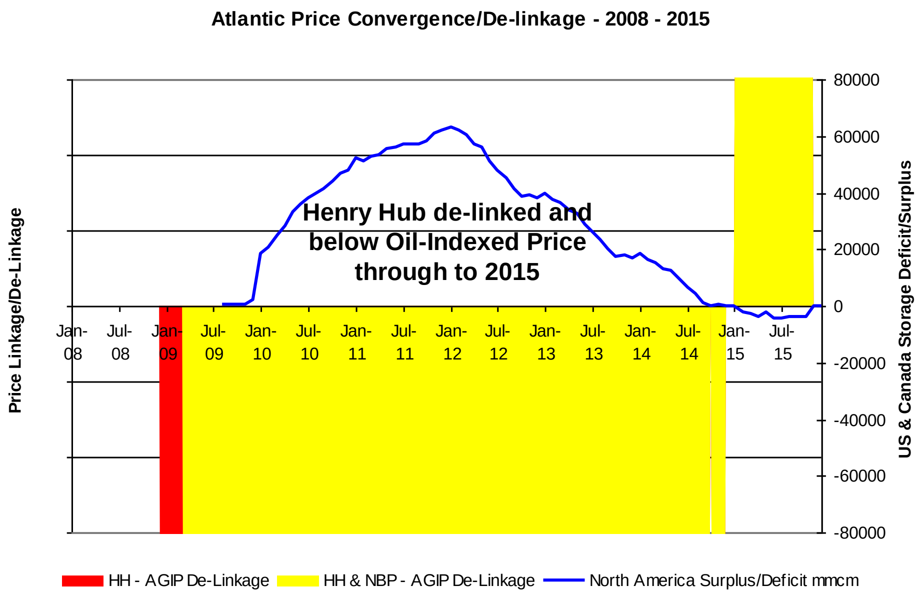
Source: Author's Analysis

The North America graphic in Figure 61 shows the lowered domestic production 'making room' for substantially higher LNG volumes throughout the period with some reduction by 2015 as domestic production recovers.

The LNG graphic in Figure 61 again shows the near term surge of LNG into North America as Europe is unable to take high levels of LNG and at the same time honour its pipeline import take or pay quantities.

Figure 62. Producer Response Case to 2015 – North America Storage and Atlantic Price Linkage





Source: Author's Analysis

The North American storage graphic in Figure 62 still shows modelled storage inventory levels in excess of physical available capacity during 2010 and 2011. From 2012 onwards however, we see signs that the system is tightening and by 2014 the modelled storage inventory level is within the historical minimum – maximum range.

The blue trend on the price indicator graph in Figure 62 tracks this surplus/deficit position. The prognosis is that both NBP and Henry Hub prices would be de-linked and below AGIP to the beginning of 2015. During 2015 there is a storage deficit although probably not sufficient to cause a major escalation of Henry Hub and NBP above oil-indexed price level.

Although the ‘Producer Response’ case has reduced the imbalances seen in the ‘Current Momentum’ case it still strays beyond the boundaries of what is manageable with current North American storage capacity.

The European Contract Flexibility Case

The Producer Response case represents a continuation, to mid 2014, of the difficult circumstances that importers of oil-indexed pipeline gas have found themselves in since early 2009. Prices for spot gas on trading hubs, for much of 2009 were about half the price of oil-indexed pipeline imports. Oil-indexed gas importers have had difficulty meeting take-or-pay obligations due to loss of end-user demand to competing spot gas, and may well be facing three painful choices:

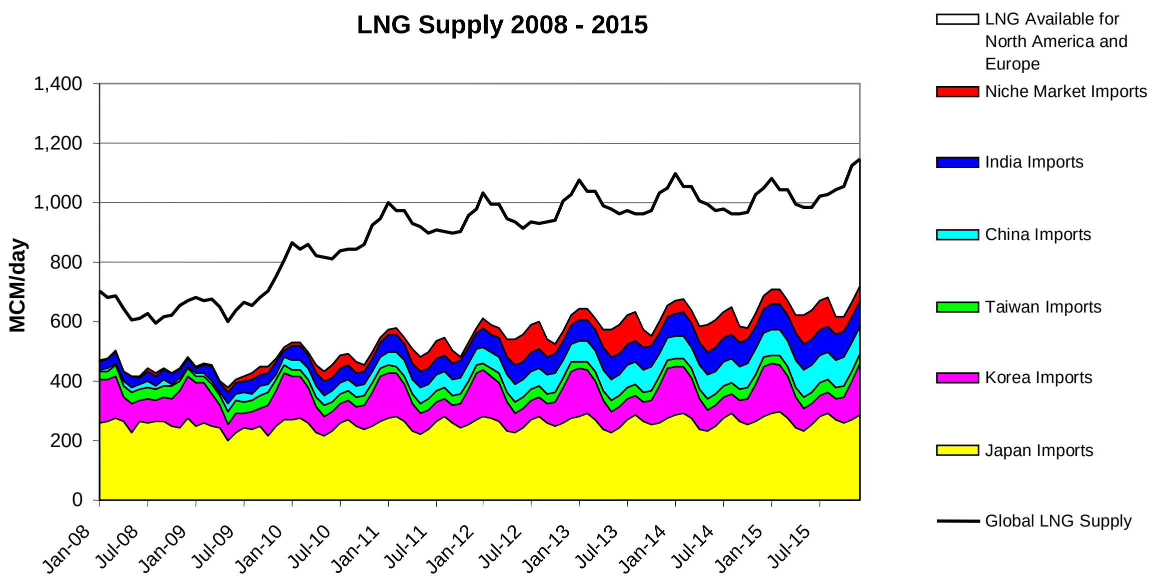
- Pay for take or pay gas quantities but not physically take all of it, thus incurring significant financial loss. (Note: We have assumed in this framework that 10% of the 2009 contract year gas is ‘rolled over’ for physical delivery in the next or future contract year(s).

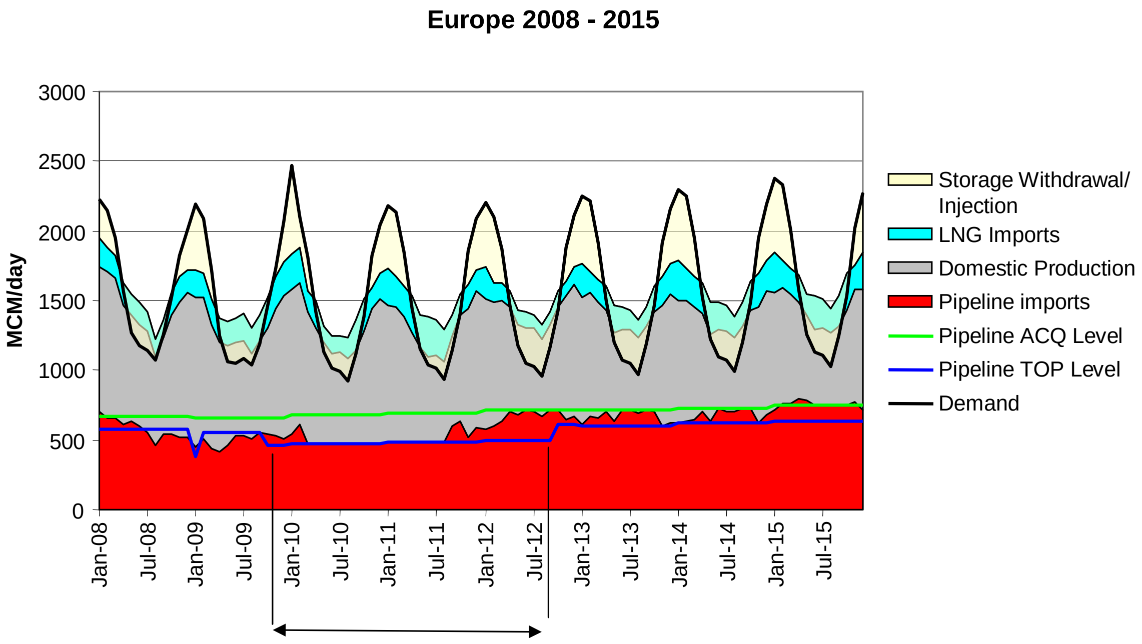
- Pay for take or pay gas quantities, take the full physical quantity and mitigate the financial loss by re-selling it on a traded hub at spot prices. At 2009 gas prices this would halve the loss but would still be substantial. If the ‘home market demand’ for these mid stream buyers has been reduced both by the recession and by competing spot gas volumes the issue may then become whether infrastructure connectivity is sufficient to allow the balance of the TOP volume to be sold out on national hubs without further drastically reducing those prices.

- Re-negotiate downward flexibility in TOP levels to reduce the financial exposure. This of course directly impacts the revenue of upstream sellers and only the prospect of the financial collapse of a buyer as a ‘long term strategic partner’ is likely to result in such an outcome.

In the European Contract Flexibility case, we allow TOP volumes to be reduced from the base assumption of 85% of annual contract quantity down to 70% from October 2009 to the end of September 2012.

Figure 63. European Contract Flexibility Case to 2015 – Global LNG Supply and Europe

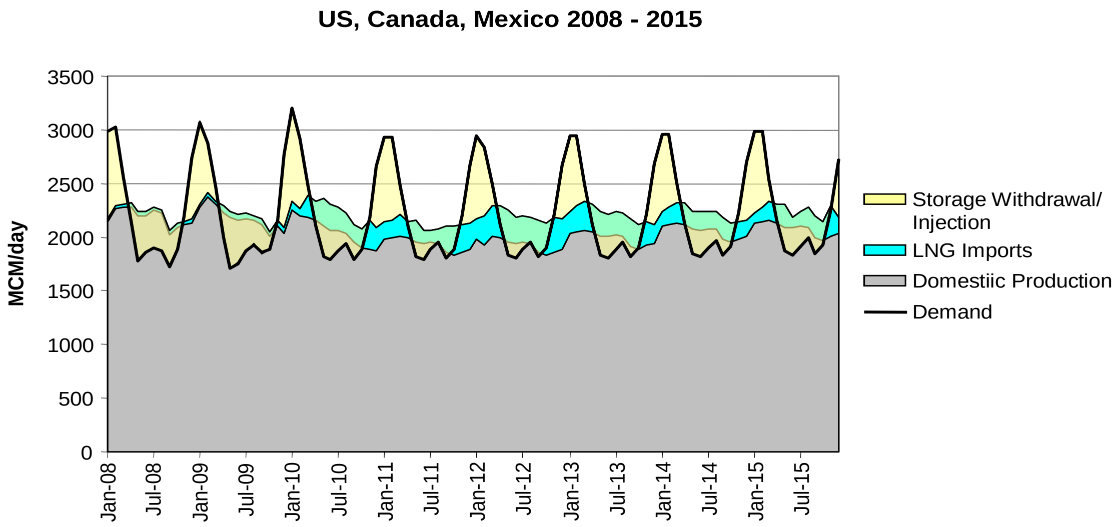


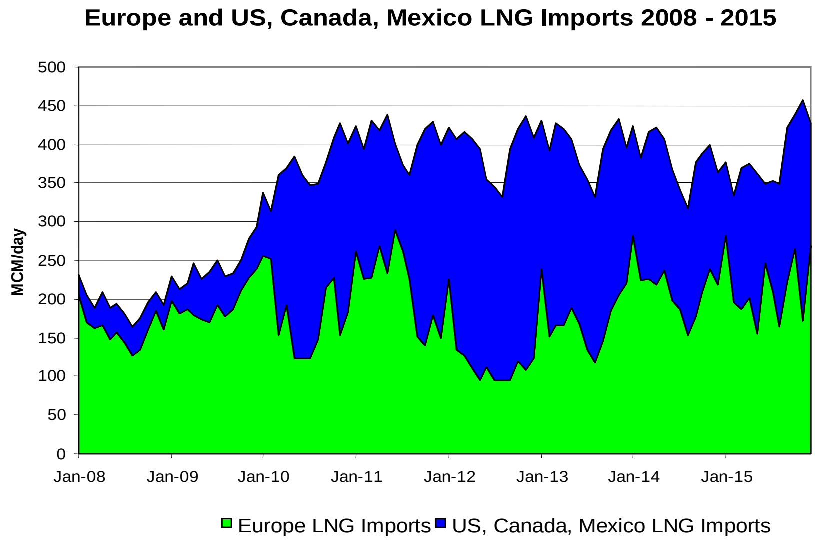


Source: Author's Analysis

In Figure 63, the LNG global supply view has remained unchanged compared with the Producer Response case. The European graph shows the impact of reducing take or pay levels in the period to end September 2012 in that it allows Europe to absorb more LNG than in the Producer Response case. As the system tightens from 2012 and beyond, European pipeline imports vary comfortably between TOP and ACQ levels until 2015 when the system is projected to tighten further.

Figure 64. European Contract Flexibility Case to 2015 – North America and Atlantic LNG flows.

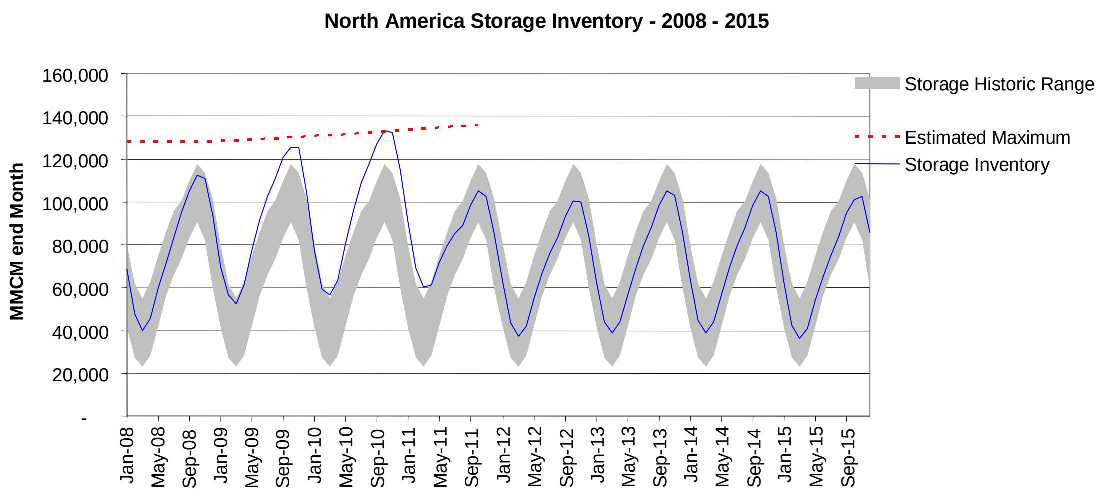


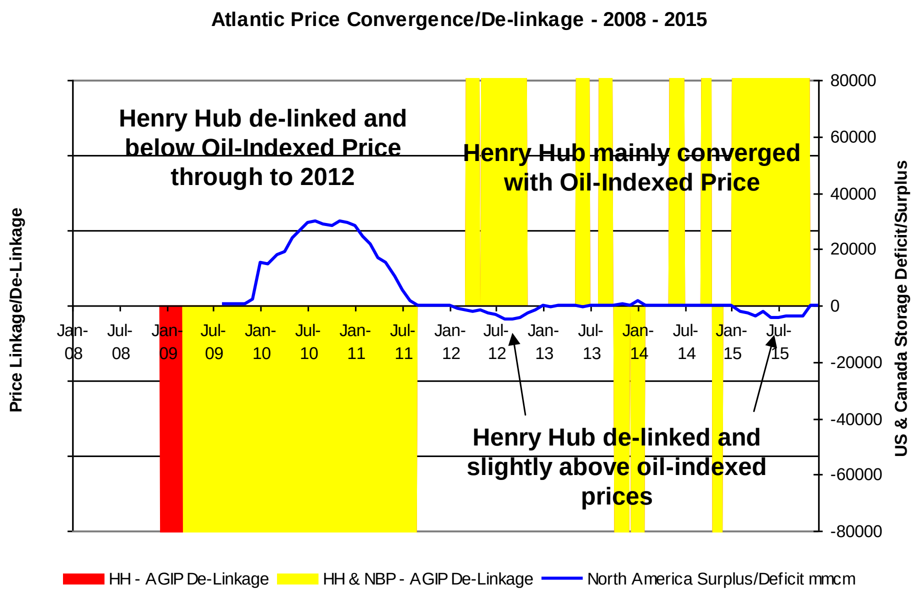


Source: Author's Analysis

In North America although there is still a surge in LNG imports in Figure 64, it is not as severe as in the Producer Response Case. The North America and Europe LNG import chart shows Europe maintaining much higher LNG import levels in 2011.

Figure 65. European Contract Flexibility Case to 2015 – North America Storage and Atlantic Price Linkage.



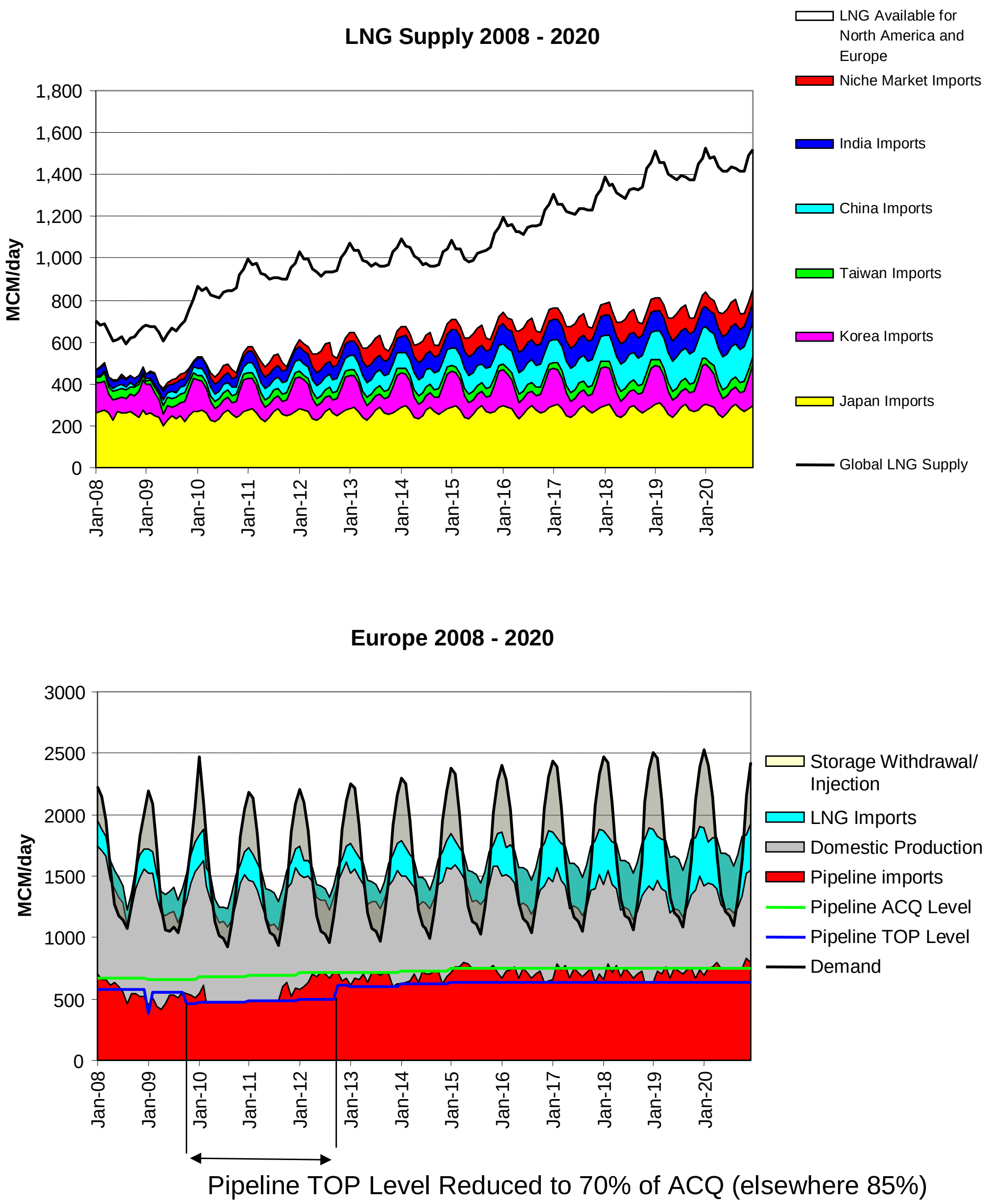


Source: Author's Analysis

In the European Contract Flexibility case the North American storage position is manageable although in 2012 and 2015 there are modest deficits (Figure 65). The price graphic shows that in the period 2012 to 2015, there is likely to be general convergence between Henry Hub, NBP and AGIP with the prospect of the spot prices de-linking and rising above AGIP/residual fuel oil by the end of 2015, although probably not significantly.

The Longer Term
This section looks at the period to 2020 on this European Contract Flexibility Case.

Figure 66. European Contract Flexibility Case to 2020 – Global LNG Supply and Europe

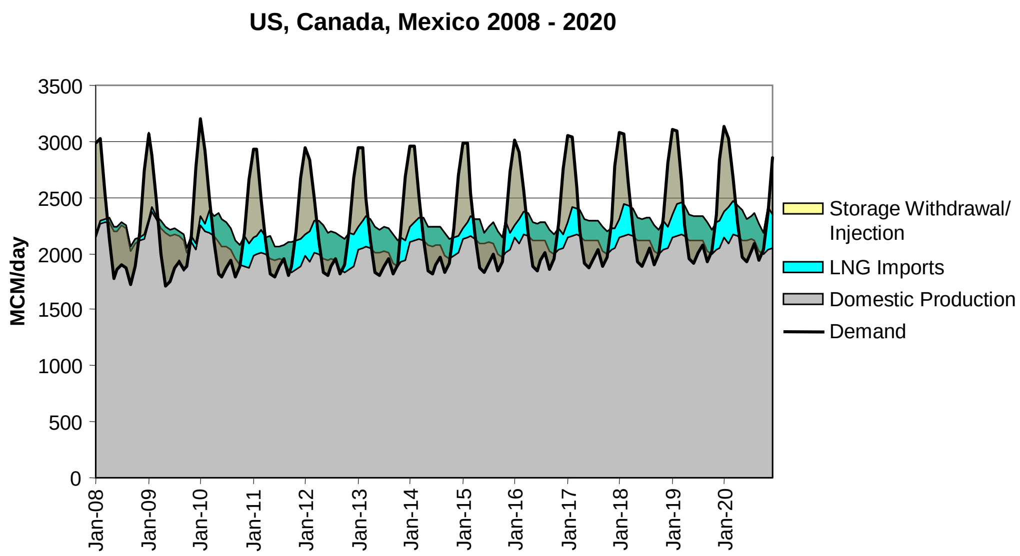


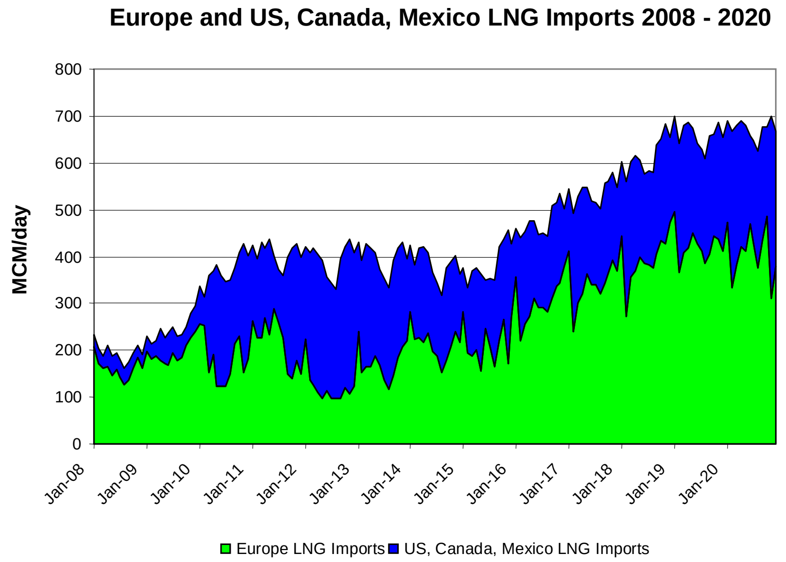
Source: Author's Analysis

The LNG supply graphic in Figure 66 shows the growth of the next 'wave' of new projects, significantly those in Nigeria and Australia in the 2015 - 2020 timeframe.

The European graphic in Figure 67 shows domestic production noticeably in decline post 2015 while LNG imports are steadily increasing. Pipeline import levels vary between take or pay and annual contract quantity levels generally throughout the period post 2012.

Figure 67. European Contract Flexibility Case to 2020 – North America and Atlantic LNG Flows

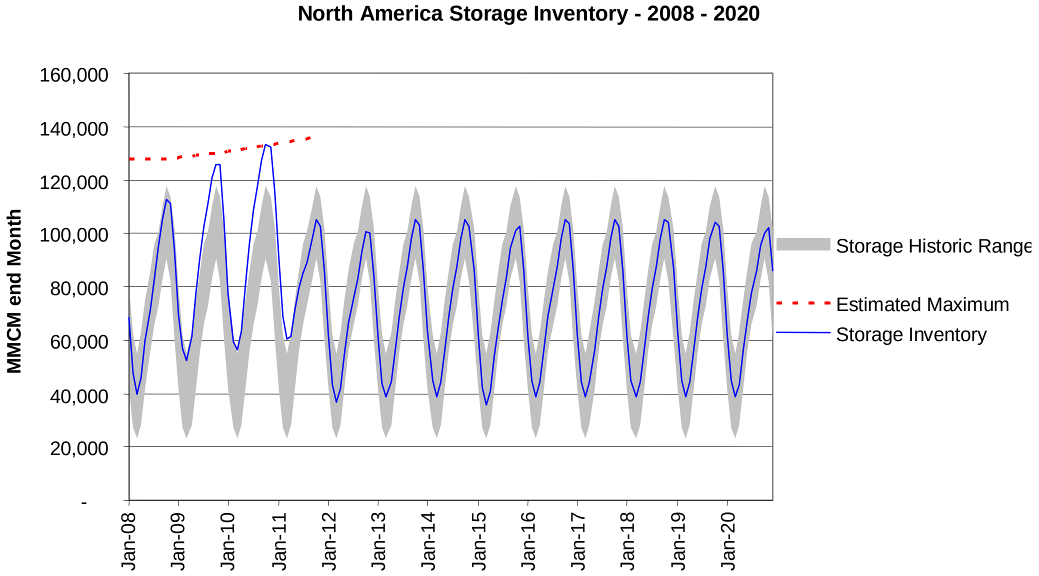


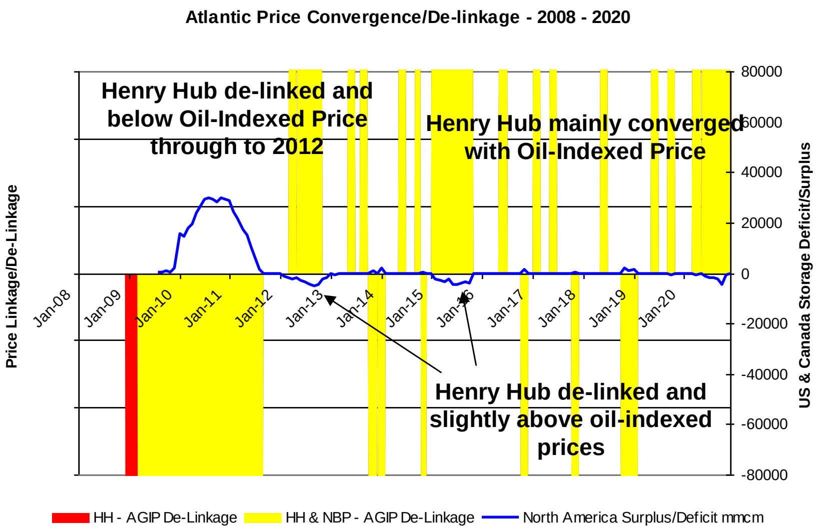


Source: Author's Analysis

In North America, LNG imports in Figure 67 remain high in historical terms even as Europe significantly increases LNG imports beyond 2015 to offset its declining domestic production and to meet demand growth.

Figure 68. European Contract Flexibility Case to 2020 – North American Storage and Atlantic Price Linkage





Source: Author's Analysis

And finally, after a mildly 'tight' market around the middle of the next decade, North American storage inventory in Figure 68 remains broadly in line with historic average levels. This is reflected in the price graph in Figure 68 which shows Henry Hub and NBP converged post 2015.

It must be stressed that the results of the European Contract Flexibility case are a direct consequence of the underlying global supply and demand assumptions. If these change significantly, this could very easily result in a less balanced system. The purpose of presenting these graphs however is to illustrate the way in which the new 'LNG-connected' system dynamics transmit prices and physical flows between regions.

The key dynamic illustrated here has been the system response to an 'oversupply' situation caused by a 'perfect storm' combination of:

- high US and Canadian production due to the growth of unconventional gas,
- reduced demand for natural gas caused by the economic recession,
- the surge in LNG supply from new projects sanctioned in the early to mid 2000s.

The instability thus created has been absorbed by a combination of a price-driven reduction in North American production and a temporary, although significant, additional flexibility in European pipeline minimum contract volume take or pay requirements.

Whether North American production dynamics and response times will behave in the way assumed in this analysis is a key uncertainty. For example, if North American production remains resilient despite low prices this would place greater strain on the ability of Europe's oil indexed pipeline importers to sell-on their contractual minimum volumes. An effective take or pay level lower than the 70% level used here would be necessary.

When demand recovers, a slower build-up of North American production than that assumed here would lead to an 'overshoot' taking Henry Hub and NBP prices above those of oil-indexed prices. This leads to a more general question of the ability of 'shorter lead-time' supplies (e.g. North American gas) to respond and adjust to sudden increases in supply from 'longer lead time' sources such as LNG.

4. Conclusions

In the period spanning 2000 to 2009 the global gas system has changed from being comprised of individual national or regional markets to one where inter-regional tradeflows have a noticeable impact on both the physical supply-demand dynamics, and in some circumstances prices.

It is overly simplistic and at best premature to claim that the growth in LNG supply since 2005 has created a 'global market for natural gas'. The low energy density of natural gas (in gaseous form) compared with oil and oil products leads to a requirement for far greater investment in gas transportation and storage infrastructure per unit of energy. This characteristic of the natural gas supply chain, as much as contractual constraints, will exert a dampening effect on the logical momentum towards a truly liquid global market (in the same sense as the global oil market) for this commodity.

This said, the changes which have taken place since 2000 have set the scene for new dynamics which will re-characterise the supply and pricing patterns in many countries and regions which import, or are about to import, significant quantities of natural gas. In this respect the key 'enabling' structural changes since 2000 are:

- The need (or perceived need) and capability for the liberalised markets of North America and the UK to import significant quantities of future LNG – pricing off domestic market trading hubs.
- The undermining of 'destination' clauses in the European market by EU competition rules.
- The underperformance of Indonesia as an exporter of LNG to Asian markets and the delay of contracted supply from new LNG projects.
- The increased willingness of LNG buyers and sellers, driven by short term 'enlightened self interest' to introduce flexibility into their contractual arrangements and share the additional profit margin afforded by LNG arbitrage.

These structural changes have driven the following 'behavioural' changes or challenges to the various regional markets:

- In response to the Indonesian underperformance and project delays, Asian markets resorted to the purchase of spot or short term supply. In the 2009 demand downturn some (Japan, Korea, Taiwan) were allegedly seeking to reduce imports below contractual minima.
- In Europe the phase out of destination clauses has weakened the linkage which enabled a national market incumbent to match forecast national demand with contracted supply. While behavioural inertia and cross-border infrastructure capacity constraints will constrain the pace of change, the future is likely to be characterised by the need to contract new supplies for the European market in aggregate. This carries inherently more forecasting risk, especially when contracted supply may be in competition with spot supply at traded hubs.
- In North America and the UK, actual or perceived tightening of supply relative to demand has led to the development of new import projects, especially those involving LNG. Uncertainty in predicting both domestic demand and supply beyond the current year sits uneasily with the need to gauge the timing and scale of investment in new LNG projects which have a lead time of 4 - 5 years.

Thus we now have a 'system' of natural gas markets which to varying degrees are linked by LNG supply, comprising the Asian markets of Japan, Korea, Taiwan, China and India, the European Region and North America. Their aggregate annual natural gas consumption amounts to some 1,600 bcm.

The framework developed in this paper, based on observed dynamics to date and the combination of contractual mechanics and LNG arbitrage response:

- **assumes** that the Asian Markets will continue to import the volumes of LNG they require to meet domestic consumption even where this requires paying premium spot market prices. There is an inherent uncertainty in forecasting the LNG import needs of China and India given their demand growth upside and the scale and timing of future domestic production and pipeline imports, but for the next year or so, LNG imports are bounded on the upside by known re-gas capacity limits.
- **accounts for** the anticipated volumes of LNG destined for new 'niche' markets leaving the LNG supply available for Europe and North America. Given the very low short run marginal costs of supply for LNG projects it is assumed that LNG production will not be curtailed in response to price, at least for economic reasons.
- **models the** Atlantic Basin LNG dynamic as a function of the interaction of oil-indexed pipeline gas imports into European markets (from Russia, Algeria, Libya, Azerbaijan and Iran) and LNG – pricing at the margin off North American traded prices:
    - From a starting point of North American prices being lower than European pipeline import oil-indexed prices, one would expect European importers to lower their nomination of pipeline gas and attract more, cheaper, LNG. The net effect is to reduce supply to North America where prices respond to the changing levels of storage inventory. This process would continue until either:
        - North American prices had risen to converge with European oil indexed prices at which point the arbitrage would cease; or,
        - European pipeline imports would reach the seasonally adjusted 'take or pay' levels and could fall no further. Thus North American prices would remain below European oil indexed prices.
    - From a starting point of North American prices being higher than European oil-indexed import prices, one would expect European importers to increase their nomination of cheaper pipeline gas and divert more LNG to North America to take advantage of the higher price. The net effect is to increase supply to North America where prices would respond to the changed level of storage inventory. This process would continue until either:
        - North American prices had fallen to converge with European oil indexed prices at which point the arbitrage would cease; or,
        - European pipeline imports would reach the seasonally adjusted 'contract quantity' levels and could rise no further. Thus North American prices would remain above European Oil Indexed prices.
- **recognises** the additional 'real world' constraints of LNG contractual flexibility and infrastructure. The above dynamic is bounded by a minimum level of European and North American LNG imports. Another qualification is that while using the term 'price convergence' across the Atlantic Basin, there would in fact be a price differential, equivalent to the incremental LNG shipping cost between Europe and North America which is of the order of $0.40/mmbtu in 2009. Provided that North America was importing more than its observed minimum LNG quantity we would expect the UK price to follow that of North America, subject to the differential LNG shipping cost.

From a 'systems' perspective, the above dynamic represents a means by which the new 'global system', albeit comprising regional markets of differing structures and behavioural drivers, seeks to balance supply and demand through price signals and arbitrage. The use of the flexibility band in Europe's long term pipeline gas import contracts is a means of physically adding or removing gas from the system i.e. literally by altering upstream production levels. However the scope of this physical adjustment is relatively minor in scale. In annualised terms the flexibility in contractual take amounts to only some 40 bcma in an aggregated LNG-connected natural gas market of 1,600 bcma. Accepting the hypothesis that in the future 'getting supply levels right' will be more difficult than in the past, it is likely that there will be periods where the system will veer out of balance by more than the 40 bcma pipeline contract 'cushion'.

Following the logic developed above and noting other observed dynamics in the paper we can describe the characteristics and response mechanisms of a 'very tight' and a 'very loose' supply-demand world as follows:

The 'very tight' world would be one where despite European pipeline levels being at their contractual maxima throughout the year, North American (and UK) prices were higher than oil indexed European prices. The following response sequence would seek to redress the situation:

- North American gas storage inventory would be reduced to below average levels for the specific month in question.
- In North America as natural gas price rises above that of residual fuel oil one would expect to see fuel switching come into effect. Depending on the level of switching capacity maintained in the future, one would expect this switching band to progressively reduce gas demand by some 15 to 20 bcma. This response would be relatively rapid.
- If North American prices remained at or above residual fuel parity for several months one would expect to see an increase in gas drilling intensity – with a domestic supply response within say 12 months.
- If the upstream industry expected North American and UK prices to remain high for the foreseeable future then one would expect to see increased focus on developing new longer lead time supply (4 to 5 years), such as:
    - New LNG projects in Nigeria, Australia and potentially Qatar (assuming the lifting of the moratorium on the North Field).
    - Unconventional gas production in Europe.
- On the demand side, sustained high prices in North America and the UK would exacerbate the trend of 'demand relocation' of gas intensive industries to countries where prices are lower, often due to state subsidy or regulation.

- In time the response mechanisms above would bring the system back to a point where the European – North American pipeline – LNG arbitrage dynamic would again provide the price-driven balancing mechanism.

The 'very loose' world would be one where despite European pipeline levels being at their contractual minima throughout the year, North American (and UK) prices were lower than oil indexed European prices. The following response sequence would seek to redress the situation:

- North American gas storage inventory would increase to above average levels for the specific month in question, within end - October physical limits.

    - In North America (and the UK) as natural gas price competes with coal in power generation, one would expect to see switching from coal to gas come into effect. This response would be relatively rapid.
    - If North American prices remained at or below the economic cost of supply of domestic production for several months one would expect to see a decrease in gas drilling intensity – with a domestic supply response within say 12 months.
    - If the upstream industry expected North American and UK prices to remain low for the foreseeable future then one would expect to see a deferral of new longer lead time supply (4 to 5 years), such as new LNG projects.
    - On the demand side, sustained low prices in North America and the UK might alleviate the trend of 'demand relocation' of gas intensive industries to countries where prices are low, often due to state subsidy or regulation.
- In time the response mechanisms above would bring the system back to a point where the European – North American pipeline – LNG arbitrage dynamic would again provide the price-driven balancing mechanism.

Clearly at the end of 2009 the system is in the 'very loose' state and most of the corrective mechanisms listed above are in play to bring it back into a position of balance where the European – North American pipeline – LNG arbitrage dynamic will resume as the balancing mechanism. The timing of the rebalancing dynamic will also be impacted by the following specific factors:

- The rate at which natural gas demand growth resumes during the post – recession economic recovery period.
- The trajectory of domestic North American production as a key balancing force. Production shut-in could be forced by low prices and constrained storage capacity during 2010.
- The emerging period of net decline in European domestic production from 2012 onwards as Norwegian production reaches a plateau.
- The limited scope for growth in additional pipeline imports to Europe post 2012.
- The impact of deferral of future LNG projects – resulting in lower growth in global LNG supply from around 2012.

The expectation is for a tightening of the system by 2012 - 2013.

In the immediate future the following responses have been postulated and modelled to illustrate what is required to keep this 'system' within the bounds of physical reality, given the surplus of imminent supply relative to demand. These responses include:

- A reduction in North American domestic production of the order of 7 to 8 % in 2011-2012 compared with 2009 levels.
- A relaxation of European pipeline import contract take or pay levels from 85% of Annual Contract Quantity down to 70% from October 2009 to end September 2012.

The dynamics of the system described in this paper will be plain to observe given the occurrence of the 'perfect storm' which is currently impacting this system:

- an unforeseen high level of US domestic production.
- demand levels below those anticipated due to the economic recession,

- since October 2009, the huge growth in LNG supply, much of which is inherently destination flexible or 'self contracted',

The combination of assumptions used in the analysis in this paper have resulted in a modelled outcome where the system recovers its balance by 2012 and remains stable to 2020, with traded prices generally converging on oil-indexed price levels post 2012. Given the uncertainties in many of the assumptions, it is equally possible that the dynamics of this new global system, given the relatively long lead times of significant tranches of new supply remote from importing markets would imply *a succession of cycles rather than the achievement of a stable converged global system.* This would also have significant implications for price volatility in the liberalised markets of North America and the UK with periodic enhanced trading opportunities at hubs on the interface of oil-indexed and liberalised market 'blocs'.

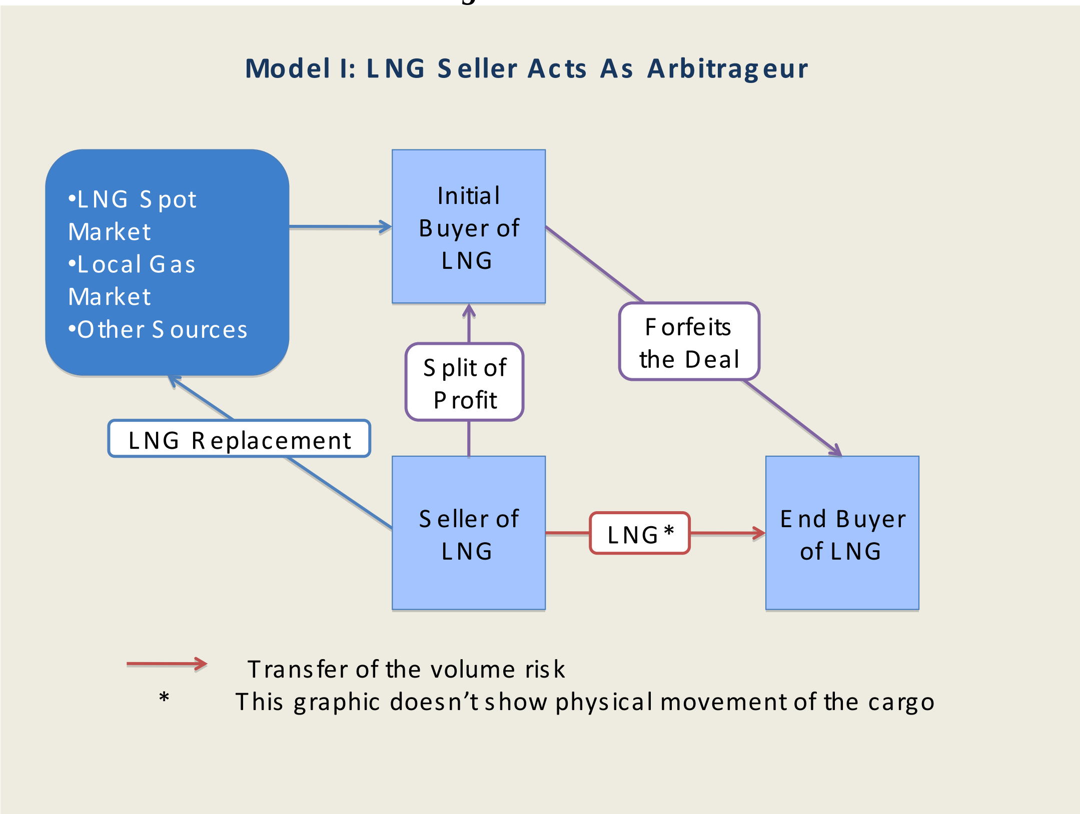
5. Appendix 1 : Models of LNG Arbitrage

Polina Zhuravleva[34] describes four models of LNG arbitrage and three examples of short term sales which fall short of a strict definition of arbitrage. The following description is an extract from her paper. All the true arbitrage models assume that the Seller1 of the LNG has a contract (whether it is a long-term, short-term or even a spot contract) with the Initial Buyer and is obliged to supply a cargo on these terms at a fixed date.

Model 1 – Seller Arbitrageur

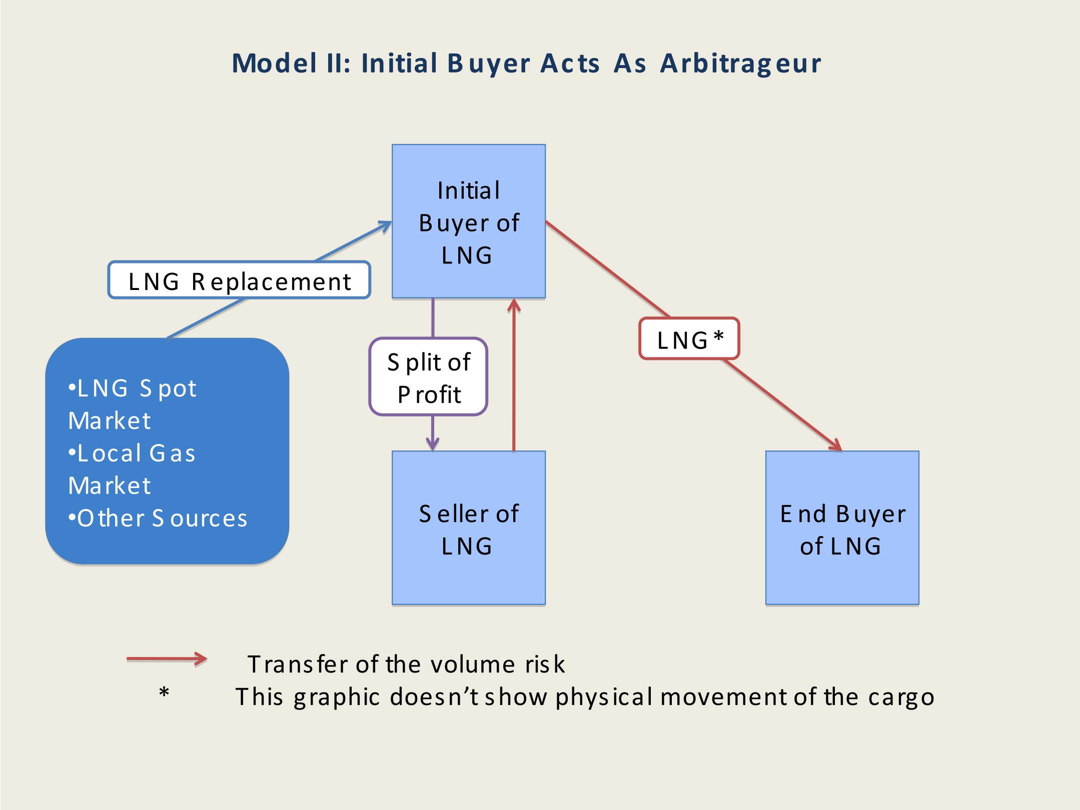
The first model (Figure A1.1), implies that the Seller initiates the arbitrage and takes the role of arbitrageur. The Seller, who has a contract with the Initial Buyer to deliver the LNG cargo on day N, sees the opportunity to sell this cargo in another market and acquire the margin. The Seller may offer the Initial Buyer the chance to forfeit the deal and share the margin. The diverted LNG cargo may have to be replaced by an equivalent quantity of gas from the LNG Spot Market, from domestic production or from pipeline imports. If the price differentials are high enough to cover transaction costs, the arbitrage deal is viable. The split of the profits is agreed between the contracting parties. In this example, the Initial Buyer has a veto over the destination of the cargo and can refuse to agree to the diversion.

Figure A1.1 – Model 1 : Seller-Arbitrageur



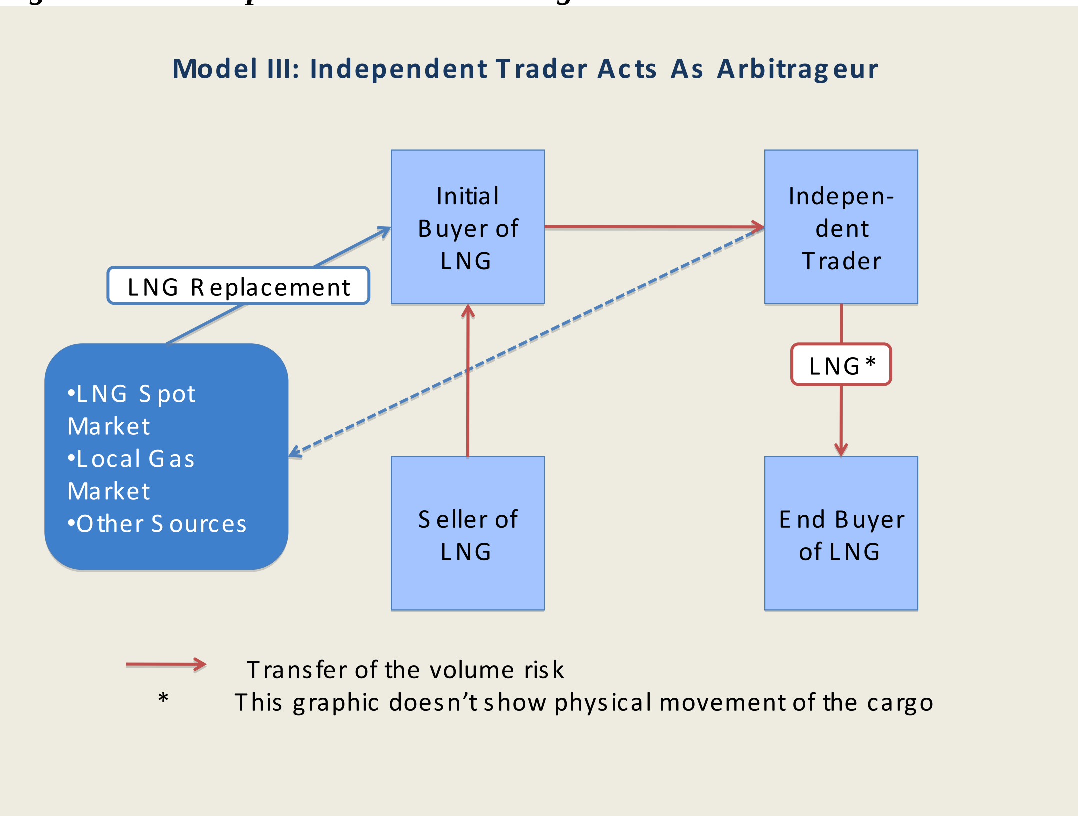
[34] The Nature of LNG Arbitrage, and an Analysis of the Main Barriers for the Growth of the Global LNG Arbitrage Market, OIES, July 2009.

Figure A1.2 – Initial Buyer - Arbitrageur



In this model (Figure A1.2), the Initial Buyer decides to divert the cargo to a market that offers a higher price. There can be two reasons why the Initial Buyer decides to divert the LNG vessel: first, the cargo can be replaced by cheaper gas from domestic production, from cheaper pipeline gas imports or by LNG from the spot market; or, simply, the buyer might not physically need the cargo. If contractual clauses allow cargo diversion (or if it was agreed with the seller), the Initial Buyer sends the cargo to the End Buyer and, in most cases, has to split the margin with the Seller. If replacement of the diverted cargo is required, it is the Initial Buyer's responsibility. If a destination clause is incorporated into the LNG contract, arbitrage by the Initial Buyer will be restricted.

Figure A1.3 - Independent Trader-Arbitrageur



In this model (Figure A1.3), another player appears in the transaction – the Independent Trader. An Independent Trader buys the cargo from the Initial Buyer (seldom from LNG Seller) or gets the right to divert the cargo to another customer offering a higher price. Whether the participants split the profit depends on the individual agreements and varies from case to case. If replacement of the diverted cargo is required, it also depends on the agreement whether the Initial Buyer or an Independent Trader will replace it.

Model 4 - LNG Reloading

LNG Reloading has been used at Huelva terminal in Spain and at the Zeebrugge LNG terminal. This is a relatively new category of cargo diversion and implies a purchase of the LNG cargo, discharge from the vessel into the storage tank and a subsequent reloading into another ship. This enables terminal users at to ship the cargoes to other markets and take advantage of price differentials. In the case of Zeebrugge the contractual destination clauses preclude diversions of the LNG; but the cargoes are delivered under DES (Delivered Ex-Ship) arrangement. Once the cargo is discharged into the Zeebrugge storage tanks, its title passes to the terminal capacity user (GdF Suez, Electricite de France or Distrigas). This allows re-export of the LNG without violating the contract and avoids profit sharing with the initial LNG seller. The reloaded LNG is diverted to higher priced markets, thus acting as a 'market balancing force'; and so it can be regarded as arbitrage.

Non-Arbitrage Short Term LNG Transactions

The following are examples of short term LNG transactions which would not normally fit a definition of arbitrage, i.e. that the transaction was motivated by price differentials between the markets and thus contributes to arbitrage equilibrium.

Physical LNG Cargo Swaps

Figure A1.4 Physical LNG Cargo Swaps

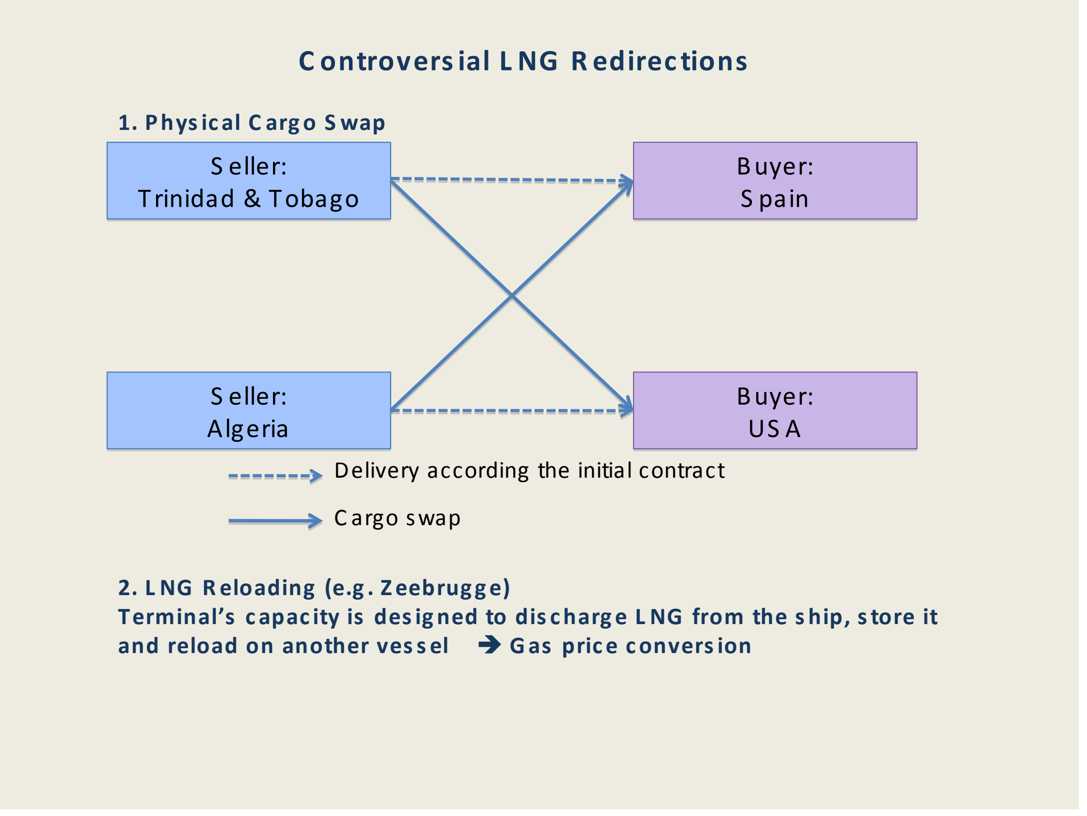
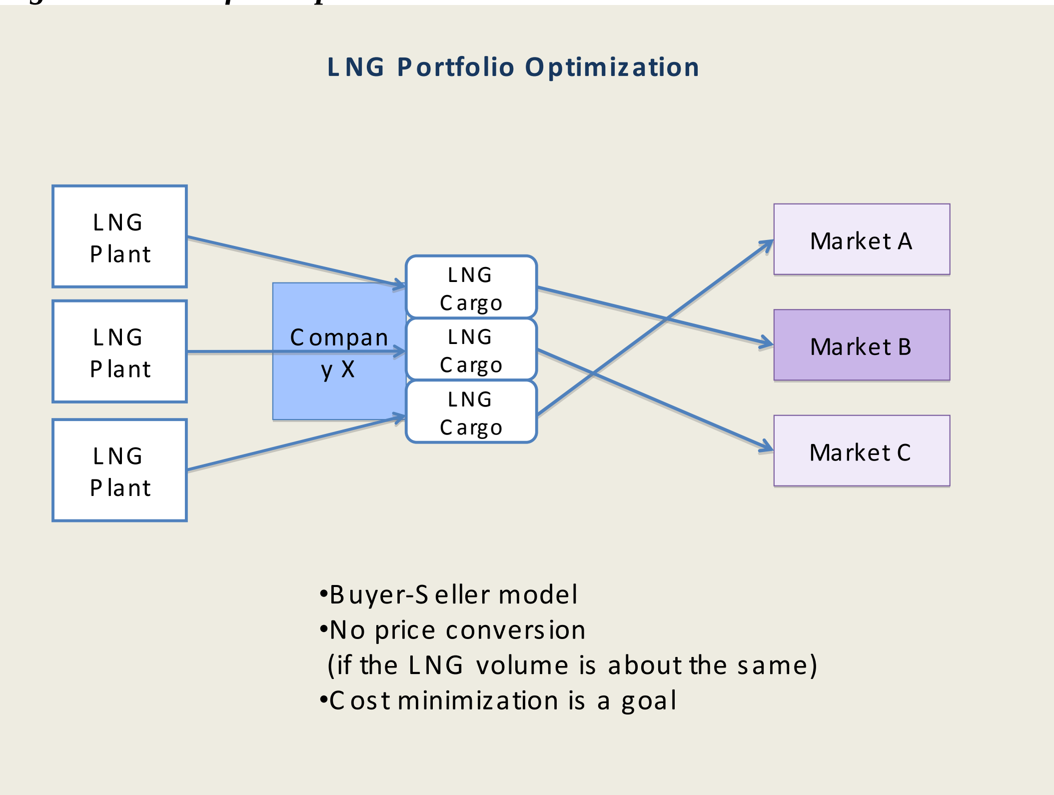


Figure A1.4 shows an example of two cargoes that are located in different countries (e.g. Trinidad and Tobago and Algeria). In accordance with the contract the Algerian cargo is allotted to the USA, while the cargo from Trinidad and Tobago is committed to Spain. In order to reduce transportation costs and possible taxes (or, in some cases, the costs for LNG quality management) the parties decide to swap the cargos and share the resulting profit. However, this profit arises from cost minimization, not from exploiting price differentials. Therefore this type of LNG redirection does not lead to price convergence and does not comply with the definition of arbitrage.

Portfolio Optimisation

Figure A1.5 Portfolio Optimisation



Portfolio optimization (Figure A1.5) is often mistaken for LNG arbitrage. Portfolio optimization means profit maximization by means of cost reduction. In the example above company X possesses three cargoes allotted by the LNG producers and the company has three buyers awaiting the cargoes. Theoretically, all these three LNG cargoes are committed, but the company X can decide which cargo goes to which market, thus optimizing its portfolio and increasing its profit. This scheme looks more like a series of cargo swaps within a company. As the amount of LNG going to each of the markets is pre-determined then market prices are not affected, thus it should not be regarded as arbitrage.

Spot Trading in LNG

Figure A1.6 Spot Trading in LNG

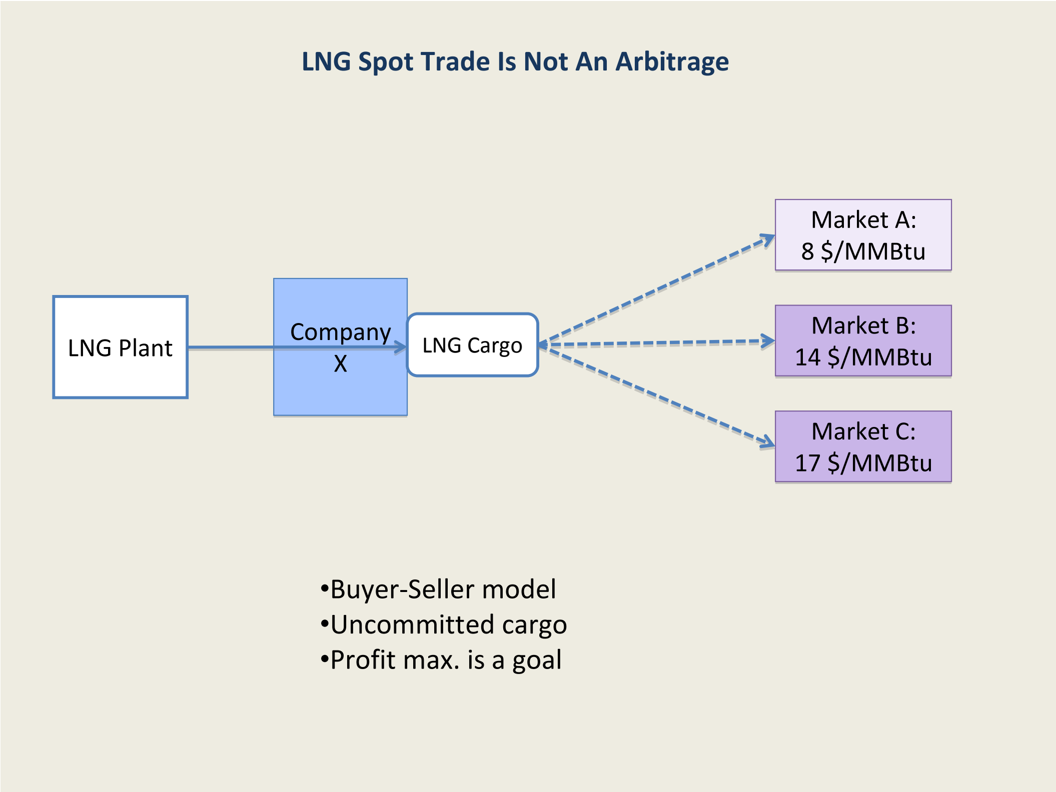


Figure A1.6 illustrates a spot transaction. A spot trade implies that a single or several LNG cargoes were produced by the LNG plant for company X and are not committed to any specific market. There are several markets willing to pay different prices for these cargoes. Company X is a seller and decides to which market the cargoes will be delivered. Logically, the company is likely to choose the market that allows for the highest profit, however, transportation costs, fees and other factors must be taken into account. This is a seller-buyer model, usually called a spot trade transaction. From a purist standpoint, arbitrage implies that more than 2 parties are involved into the trade and more than one market is affected by the transaction, spot trade should not be seen as arbitrage. However from a 'global system perspective' if one accepts that the LNG will be produced and delivered to a point of consumption, then spot trading will tend to target higher priced markets with spot cargoes, thus reducing the prices offered for subsequent LNG cargoes.

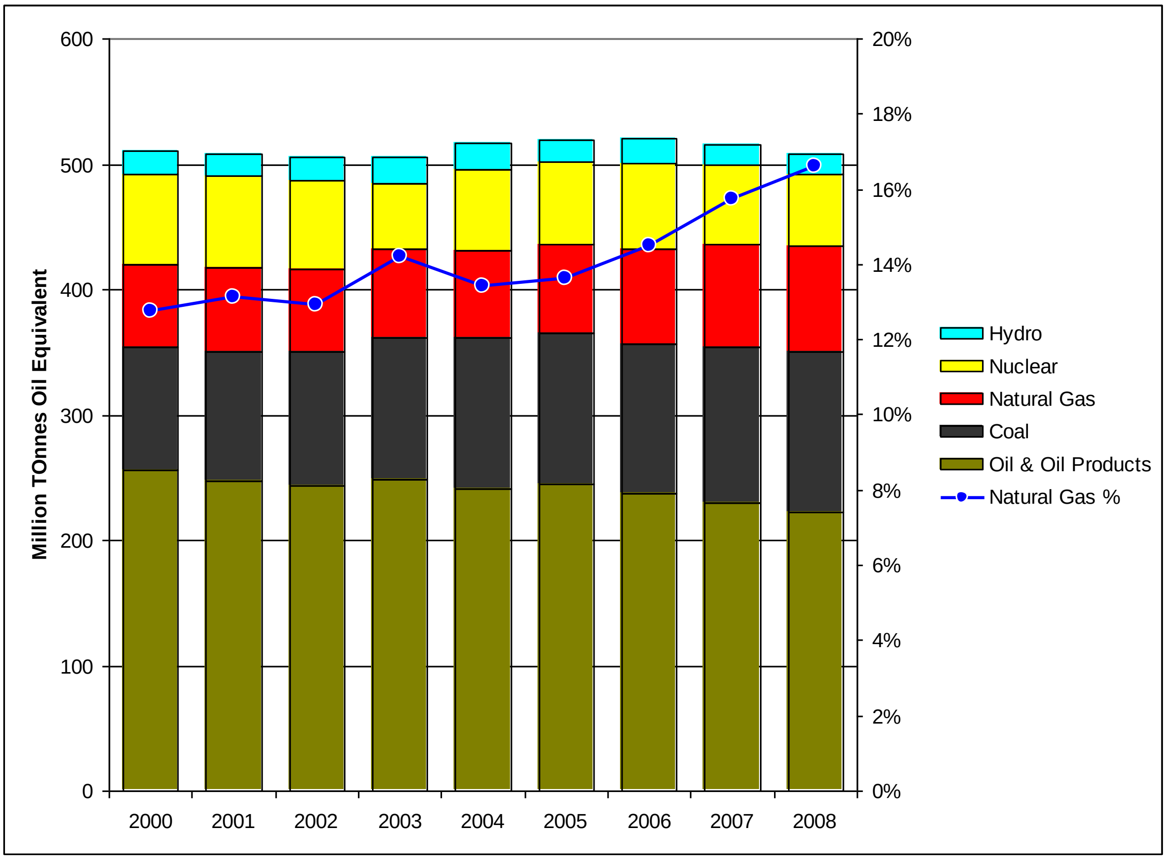
6. Appendix 2: Natural Gas Supply and Demand Fundamentals and LNG Import Requirements - Key future assumptions

Asian Markets

Japan

In 2008 Japan consumed some 40% of global LNG supply and although this percentage is likely to reduce in future, clearly Japanese demand is a key element in the overall analysis. Even before the present economic recession, Japan's primary energy consumption appeared to have reached a plateau in the 2004-06 period and subsequently declined in 2007 and 2008.

Figure A2.1. Japan Primary Energy Consumption by Fuel

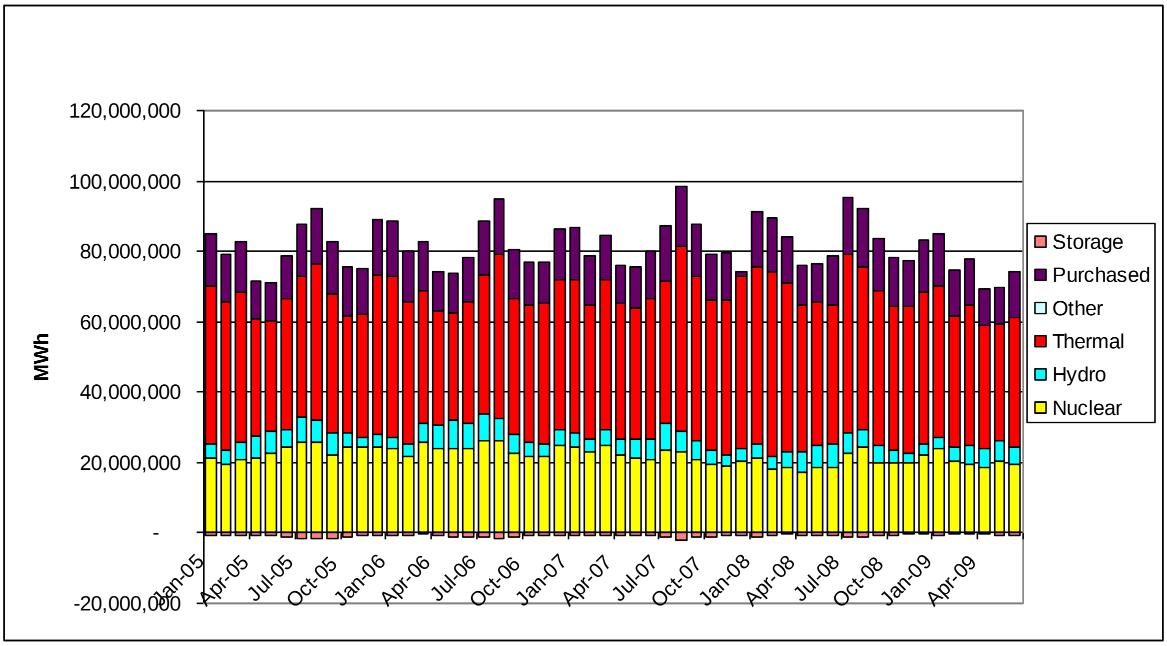


Source: BP 2009

Post 2005, Figure A2.1 implies that natural gas and coal have gained at the expense of oil & oil products and nuclear. Gas increases its share from 13% to 16%. The reduction in nuclear energy consumption is explained by the shutdown of a key plant following an earthquake in 2007 (see page 29).

Figure A2.2 shows the monthly sources of power generation for the ten largest Japanese power companies. The 'purchased' category refers to power bought from companies not included in this group. Since July 2007 it is clear that nuclear generation is lower than in the preceding period, and that overall generation was relatively stable in the 2006 to early 2008 period, after which the impact of the recession can be seen. From this data it would appear that the thermal generation sector has borne the brunt of the reduced electricity consumption.

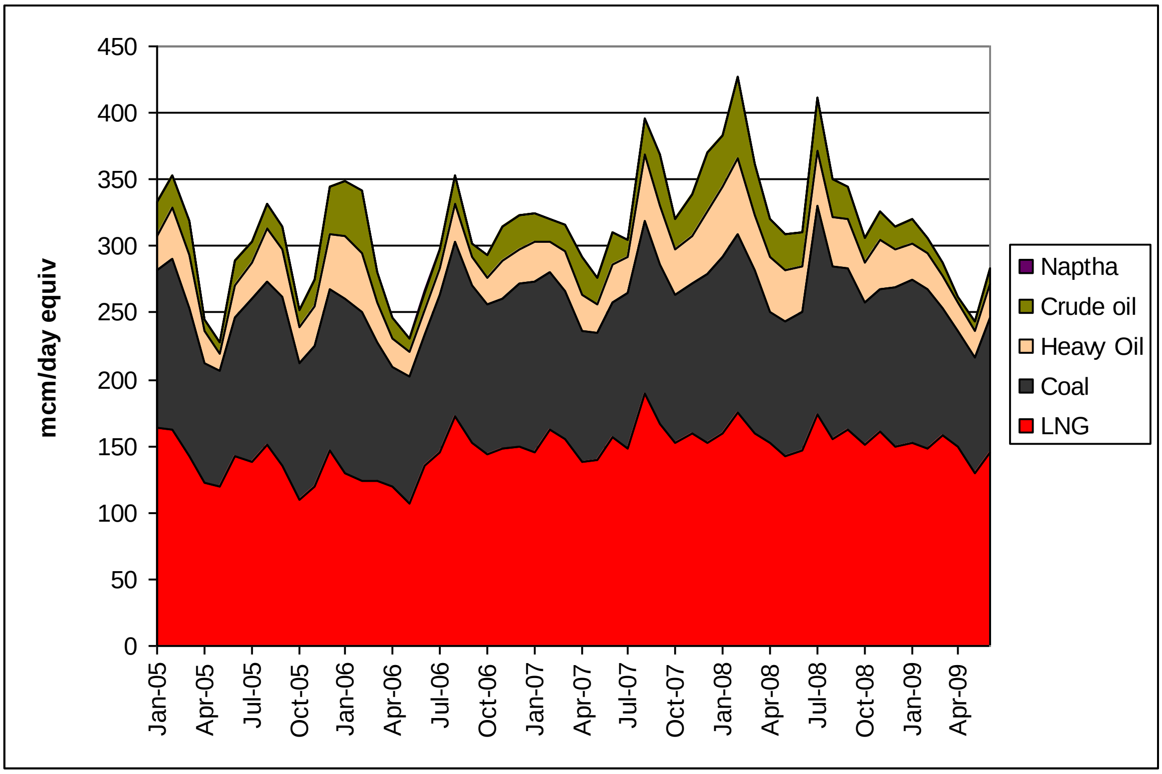
Figure A2.2. Japan 10 Company Power Generation



Source: FEPC

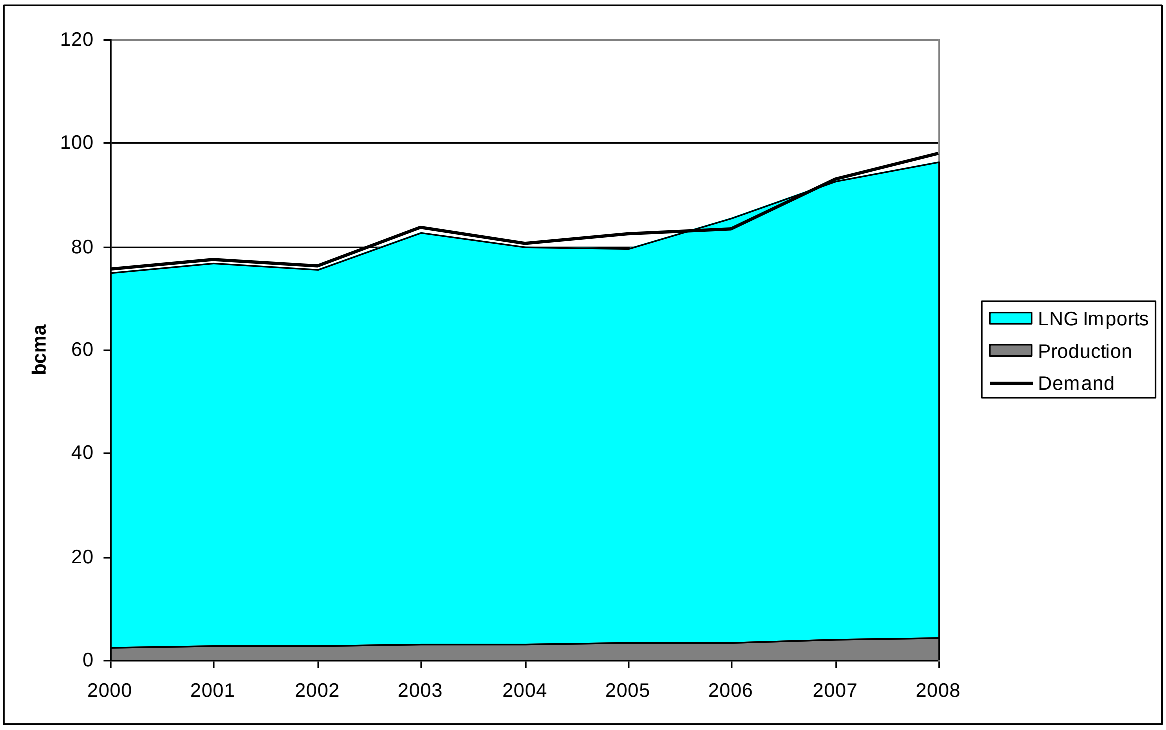
Looking at the relative consumption of fossil fuels within the thermal generation sector for the same 10 companies, (Figure A2.3), shows that until April 2009, LNG consumption held up well compared with coal, crude oil and heavy fuel oil which appeared to be used to manage seasonal and other fluctuations.

Figure A2.3. Fossil Fuel Consumption in Japanese Power Sector – Top 10 Companies



Source: FEPC

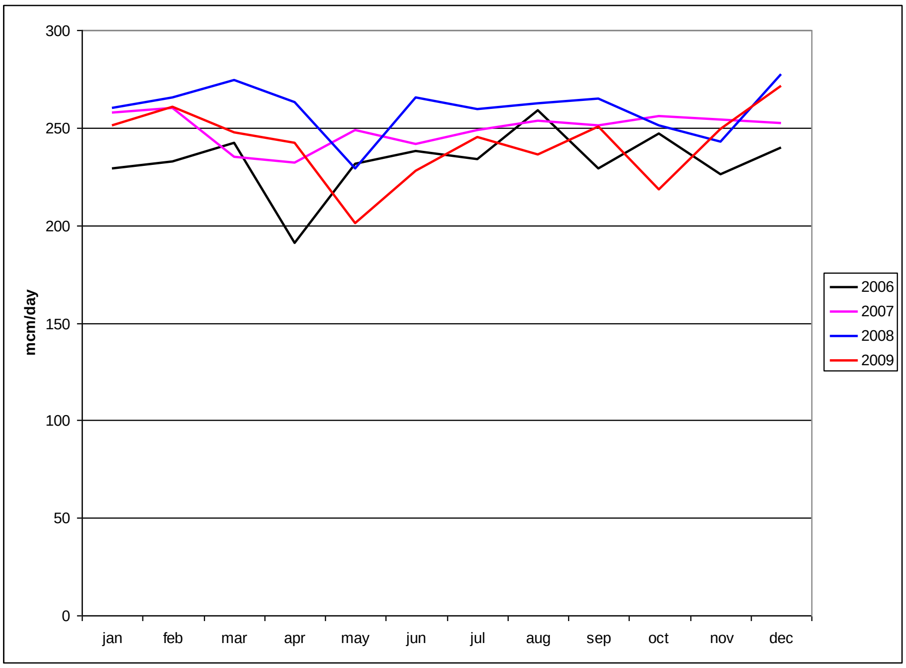
Figure A2.4. Japan Natural Gas Supply and Demand 2000 – 2008



Source: BP 2009, IEA Monthly Data Series

Figure A2.4 shows the total Japanese natural gas annual supply and demand position and clearly shows the increase in demand in 2007-08. Whether such increased consumption will continue once Japan's nuclear sector recovers to more typical historic output levels is now a moot point as the economic recession has overtaken these considerations and has depressed demand overall.

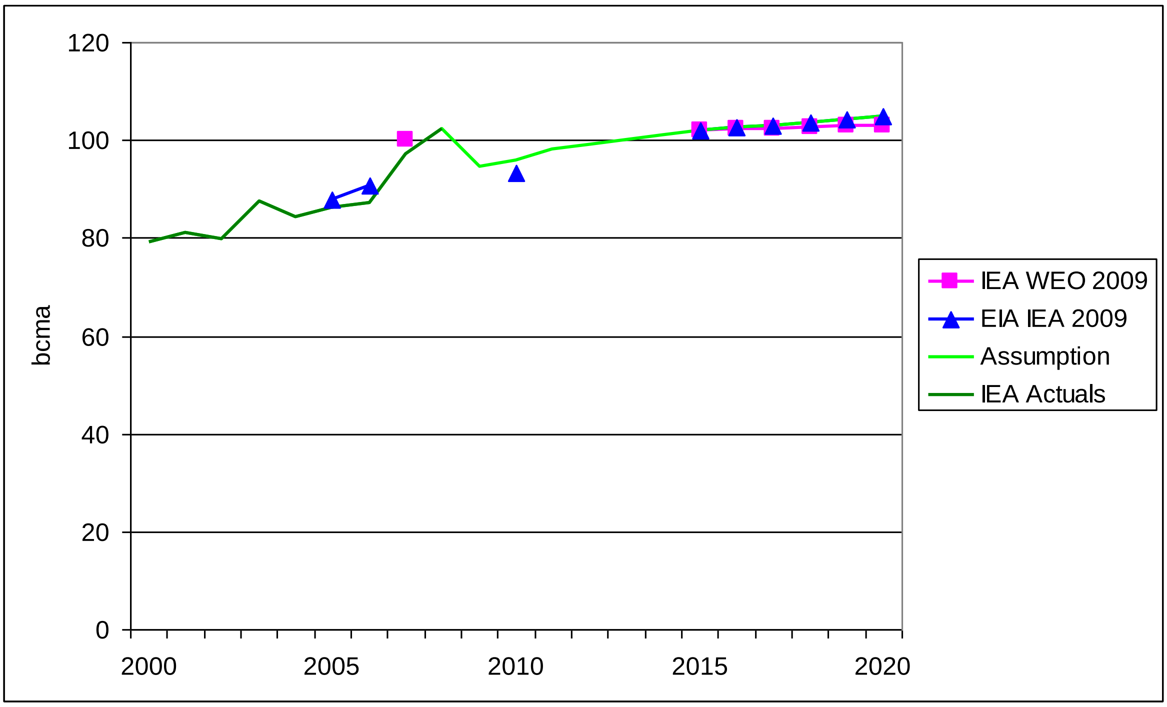
Figure A2.5. Japanese LNG Imports 2004 - 2009



Source: Waterborne LNG

Figure A2.5 shows monthly LNG imports in 2009 trending well below those of the previous year until recovering in November and December. In April 2009 the major Japanese utility companies indicated that LNG imports for Fiscal year 2009 (commencing April 1st) would be 9% lower than Fiscal Year 2008.[35]

Figure A2.6. Future Japanese Gas Demand



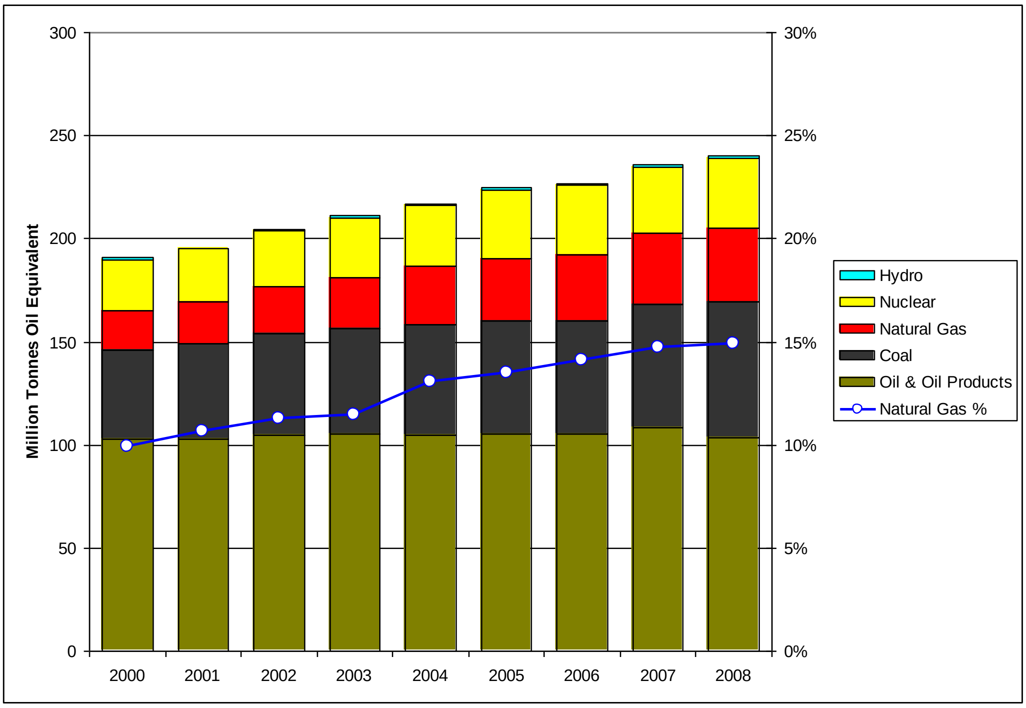
Sources: IEA Monthly Data Series, IEA WEO 2009, EIA k

Figure A2.6 shows historical actual demand data and for future scenarios; those of the IEA and EIA. The green 'Assumption' line is that used in this analysis.

[35] Waterborne LNG Asia Report 3rd April 2009, page 8.

South Korea

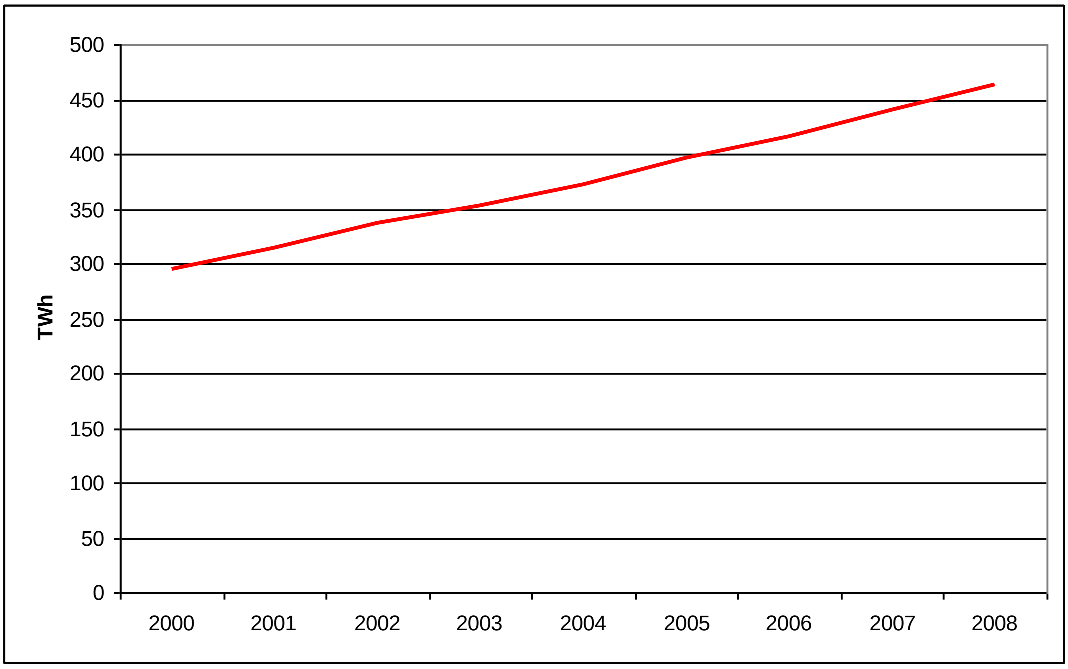
Figure A2.7. South Korea Primary Energy Consumption 2000 – 2008



Source: BP 2009

Figure A2.7 shows South Korean primary energy consumption on a steady growth trend to 2008 with Natural Gas and Coal accounting for most of the increase. Over the period gas' share of primary energy grew from 10% to 15%.

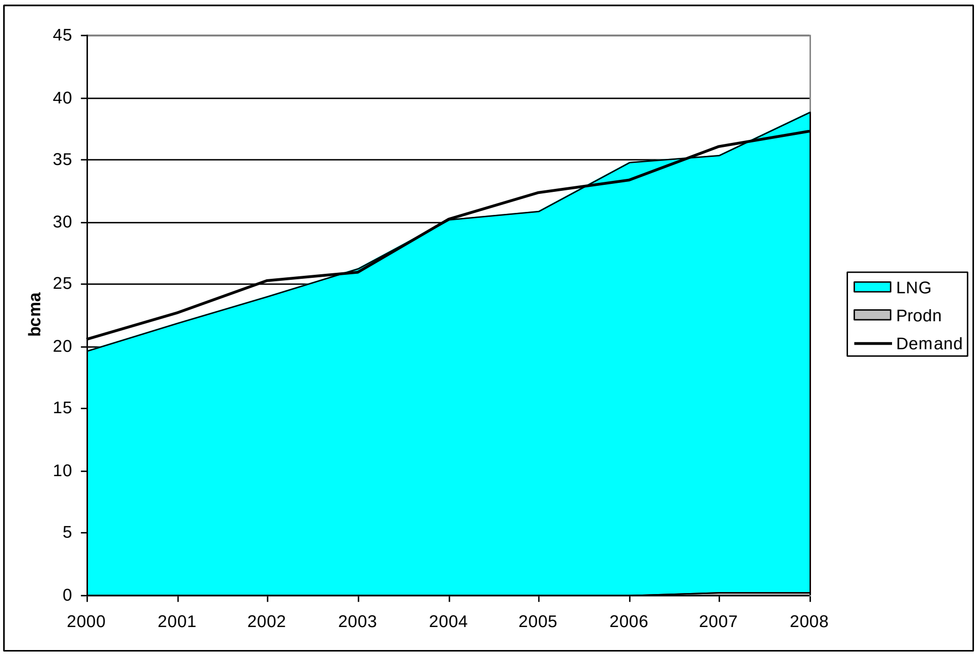
Figure A2.8. South Korea Electricity Generation



Source: BP 2009

While comprehensive data on Korean power sector fuel usage is not readily available, Figure A2.8 shows a strong consistent growth trend of 4 – 5% pa.

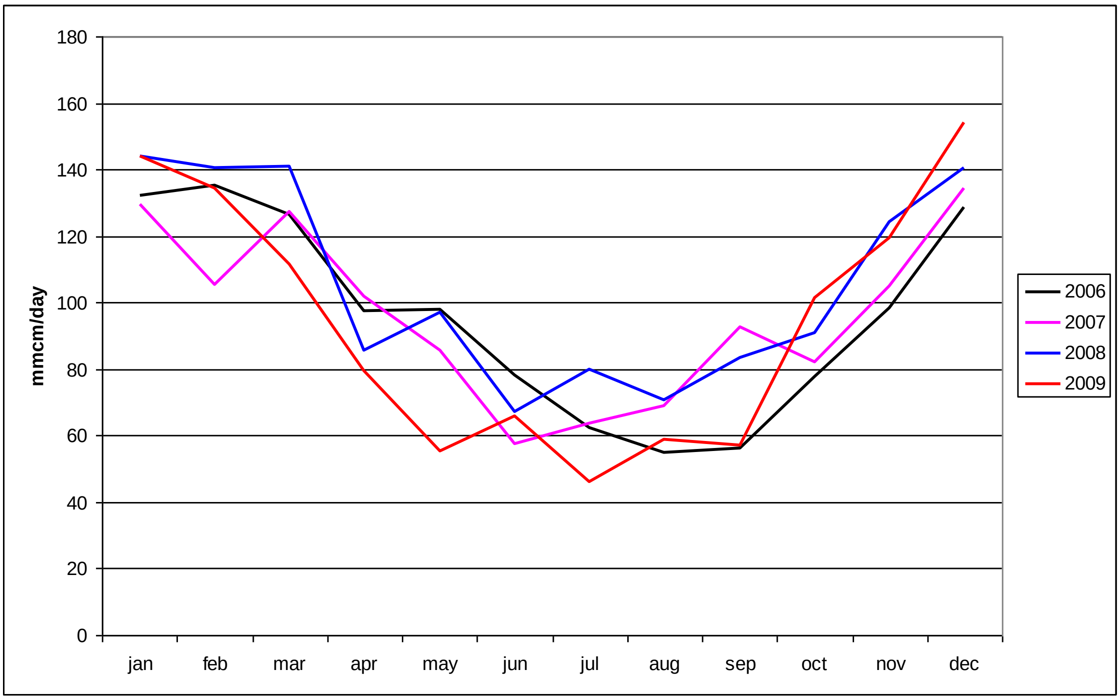
Figure A2.9. South Korea Natural Gas Supply & Demand



Sources: BP 2009, Waterborne LNG, IEA Monthly Data Series

Figure A2.9 shows South Korea's natural gas supply and demand position from 2000 to 2008. Apart from very minor domestic production beginning in 2007, South Korea relies on LNG for all its natural gas supply. The picture here is one of steady growth however, as with Japan, the impact of the 2009 economic recession has changed this post 2008.

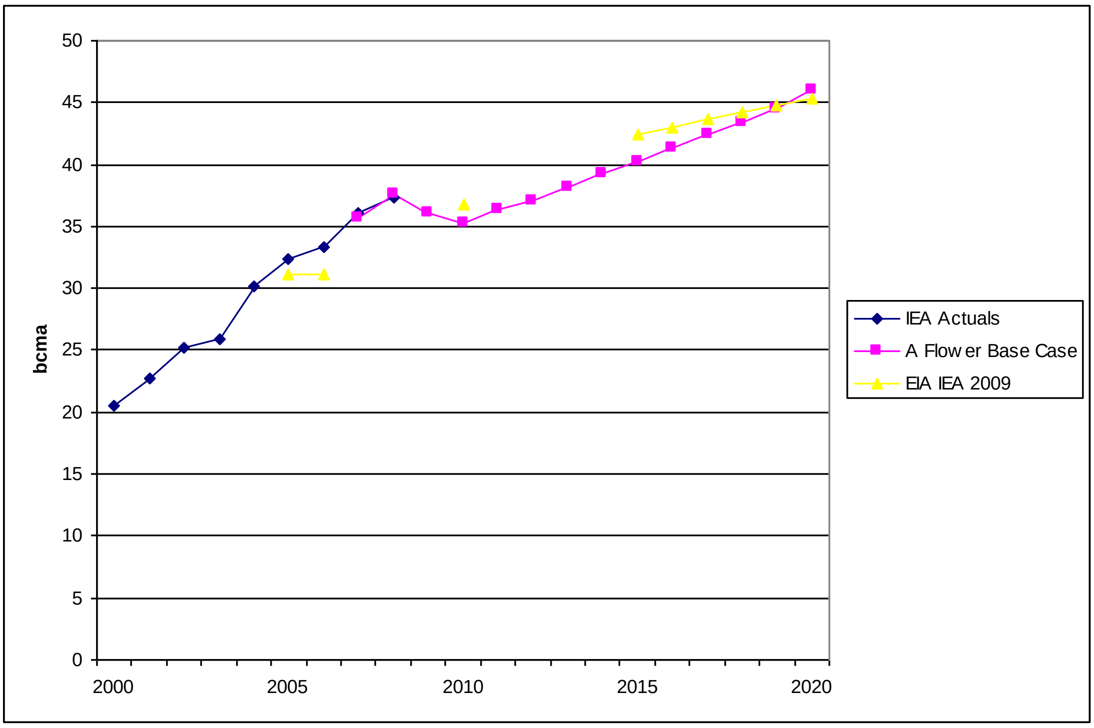
Figure A2.10. South Korea Monthly LNG Imports



Source: Waterborne LNG

In the first half of 2009 LNG imports were down 12% compared with the previous year (Figure A2.10). In the final quarter of 2009 however, demand had recovered to the levels observed in 2008.

Figure A2.11. South Korea Future Gas Demand

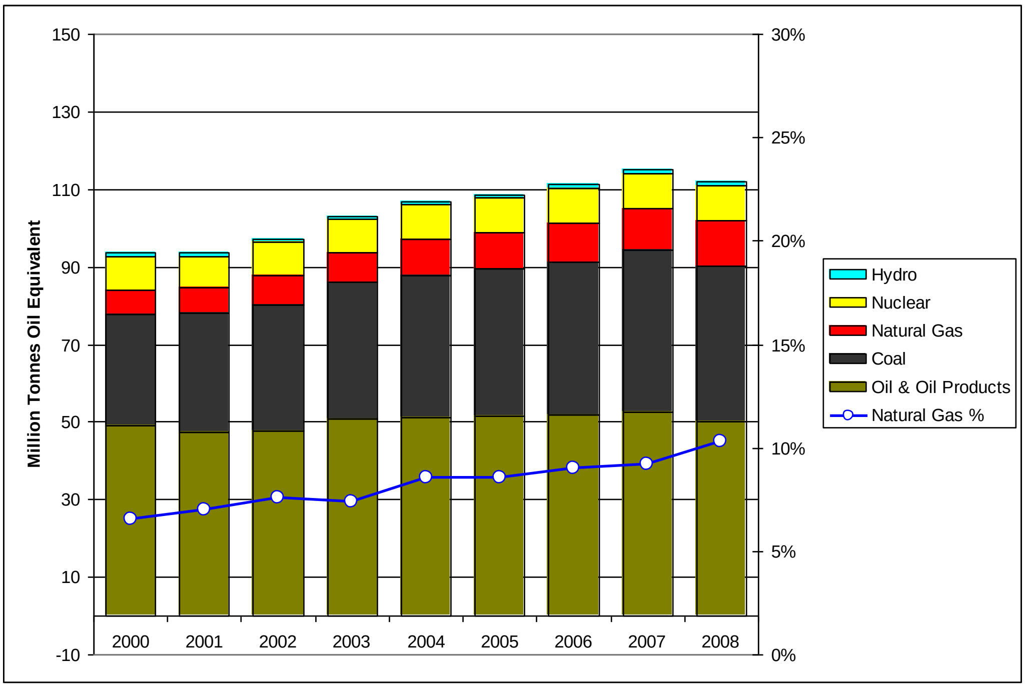


Sources: IEA Monthly Data Series, EIAk, Flower 2009c

Figure A2.11 shows historical actual demand data and future scenarios from the EIA and Andy Flower. Andy Flower's 'Base Case' scenario for future demand is used in this analysis.

Taiwan

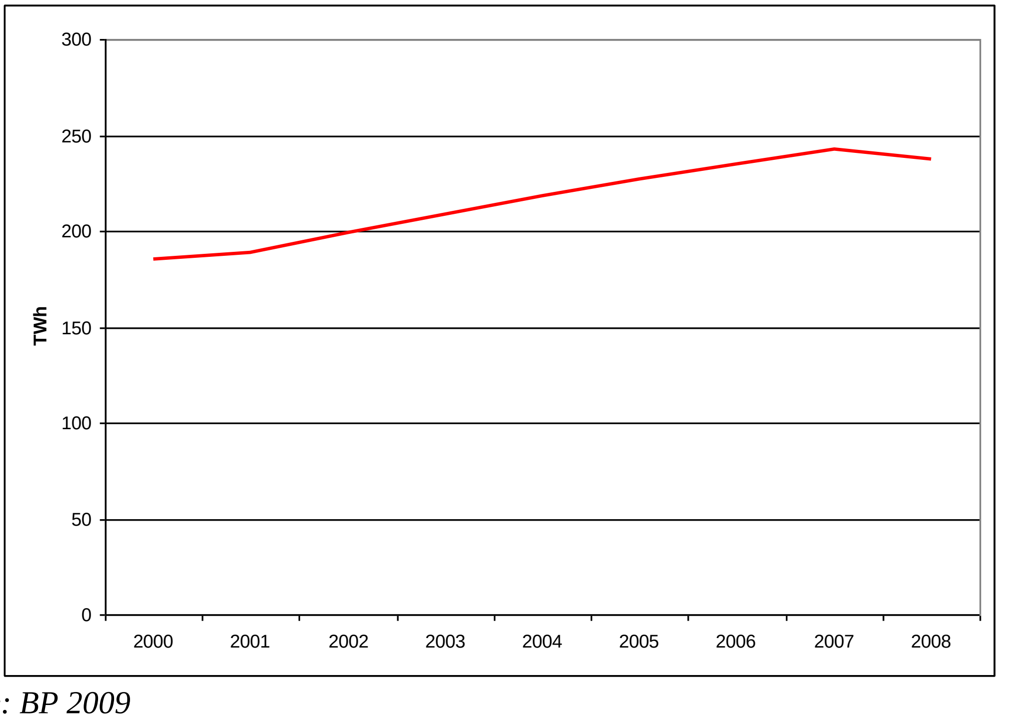
Figure A2.12. Taiwan Primary Energy Consumption



Source: BP 2009

While its primary energy consumption is about half of that of South Korea, Taiwan has a broadly similar pattern of fuel usage. From 2003 to 2007 gas and coal were the fuels showing the greatest consumption growth (Figure A2.12). By 2008 natural gas still accounted for only 10% of primary energy consumption.

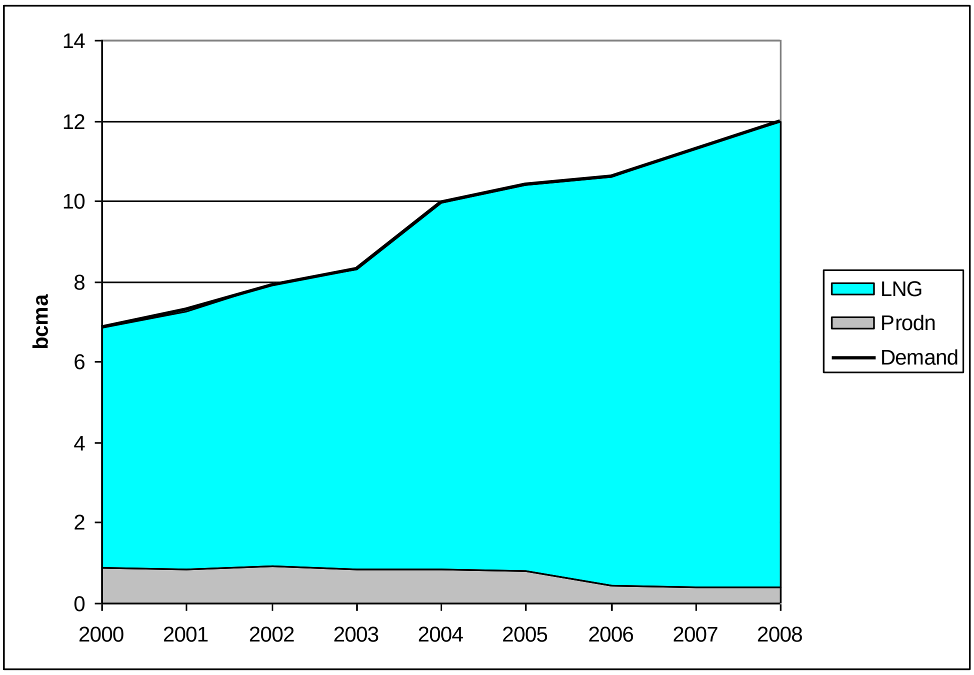
Figure A2.13. Taiwan Electricity Generation



Source: BP 2009

The steady growth in power generation seen in the early part of the decade faded somewhat in 2008 in line with a similar pattern in primary energy consumption (Figure A2.13).

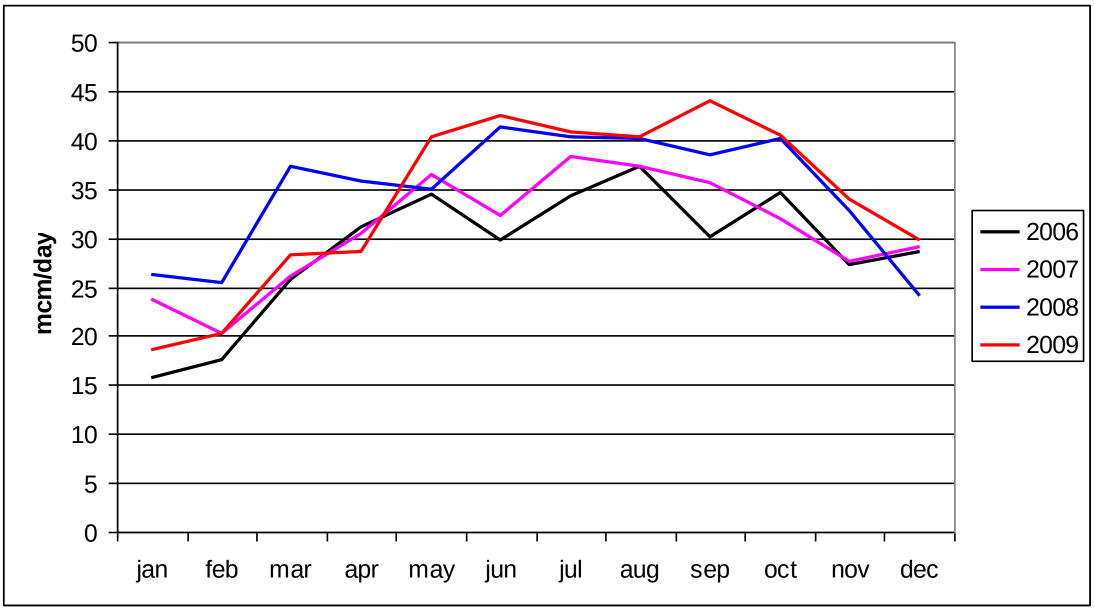
Figure A2.14. Taiwan Natural Gas Supply & Demand



Sources: BP 2009, EIAj

Figure A2.14 shows the Taiwanese natural gas supply and demand position from 2000 to 2008. With domestic supply waning, Taiwan's demand growth is overwhelmingly met by LNG imports.

Figure A2.15. Taiwan Monthly LNG Imports

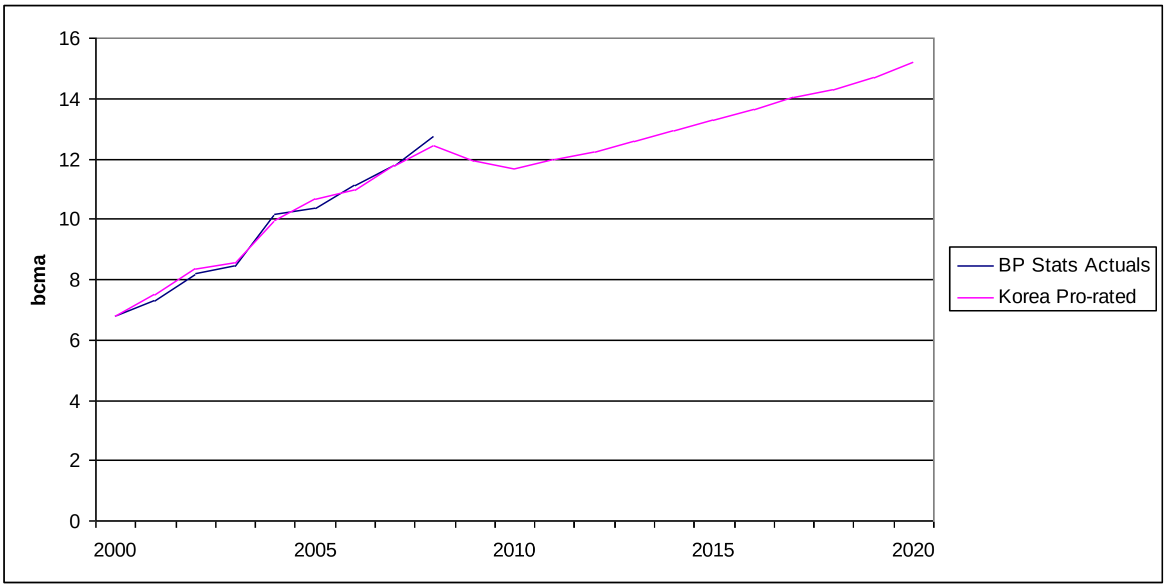


Source: Waterborne LNG

Taiwan has a summer peak demand load which is reflected in the pattern of LNG imports shown in Figure A2.15. Of note is the 13% reduction in imports in the first half of 2009 compared with the same period in the previous year. In the second half of 2009 however, LNG imports exceeded those of 2008.

In the absence of external scenarios to act as benchmarks, the demand forecast for Korea has been prorated based on historic actual demand data for Taiwan. This is illustrated in Figure A2.16. Given the relatively small scale of Taiwan's demand compared with that of Japan and Korea this was deemed by the author to be an acceptable assumption for the purpose of the analysis.

Figure A2.16. Taiwan Future Natural Gas Supply & Demand



Source: BP 2009

China

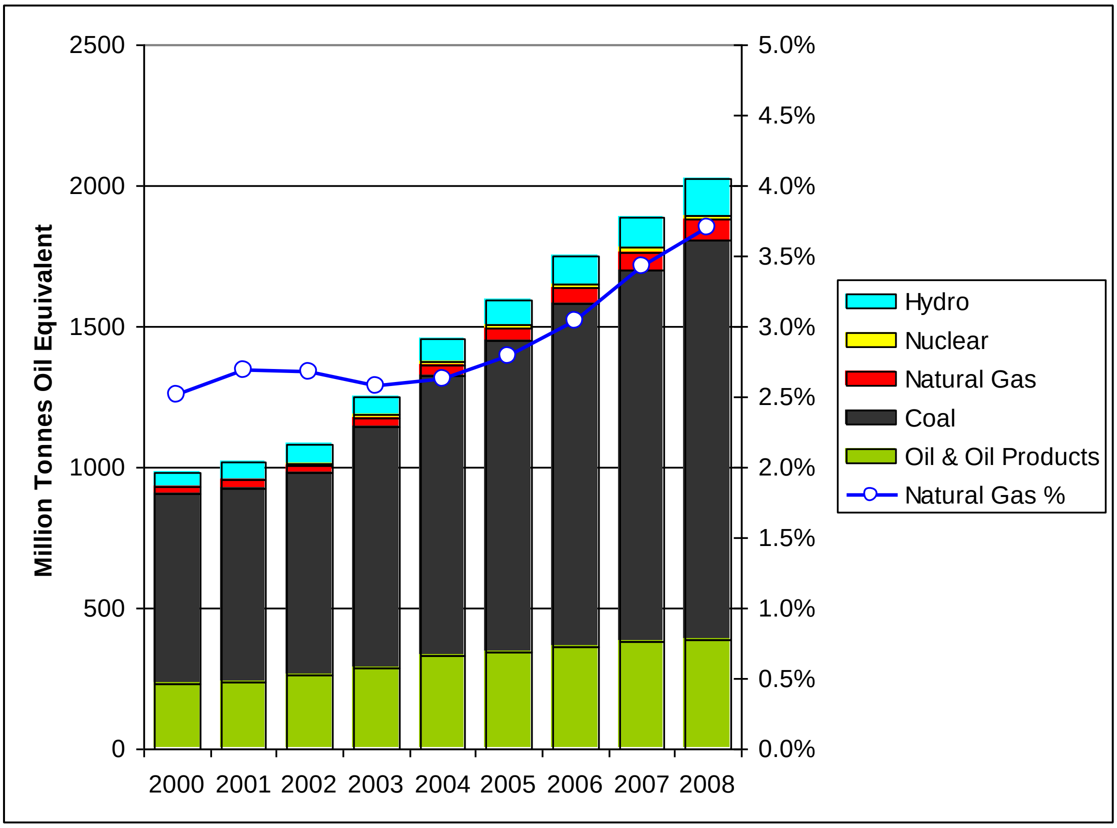
Unlike Japan, South Korea or Taiwan, the bulk of China's natural gas consumption is met by indigenous production. Although China has, since 2006, been a relatively minor LNG importer it has the potential, post 2011, to have a significant impact on the global LNG balance. Understanding the likely future gas supply-demand balance for China is not without its difficulties however, as potential supply sources exceed current conventional views of future demand. Pipeline imports from Turkmenistan will commence in 2010 via a major extension of China's West-East Pipeline project which was completed at the end of 2009. The build-up to planned levels of 40 bcma will be phased in line with the development of upstream supply sources, but is likely to be reached around 2012 - 2013. In addition, a pipeline from Myanmar is expected to be completed by 2012, providing an additional 8 to 10 bcma.

Figure A2.17 shows China's primary energy consumption by fuel from 2000 to 2008. The striking features from this graph are:

- The rapid pace of primary energy consumption growth; a compound annual average growth rate of 9.5%.
- The dominant role of coal in primary energy supply: coal consumption has doubled since 2000.

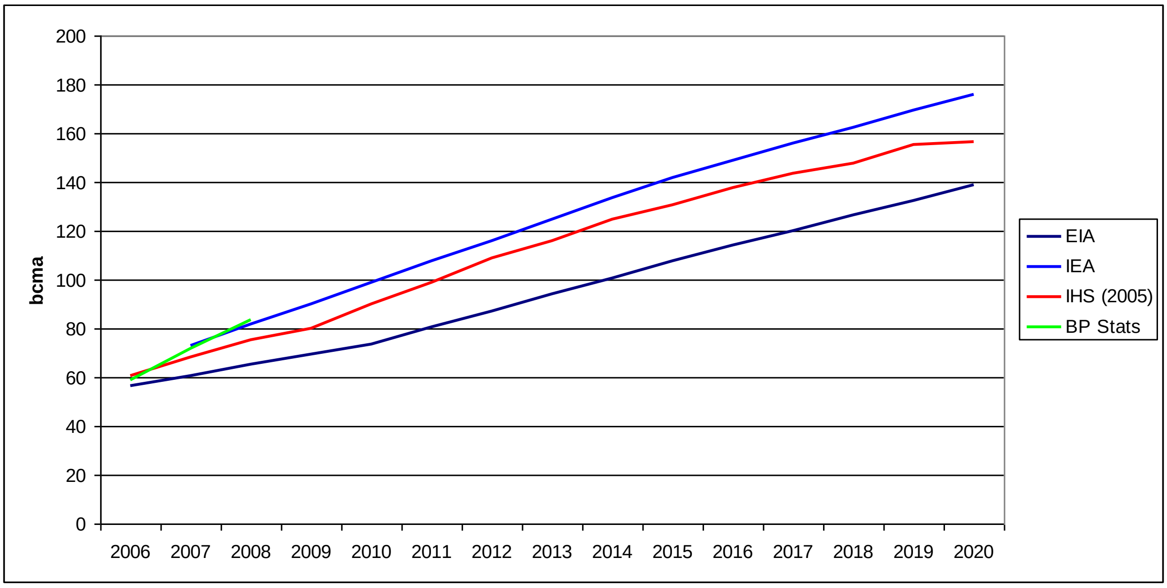
- The very small (but growing) share of gas in primary energy consumption; growing from 2.5% to 3.7% in the period shown.

Figure A2.17. China Primary Energy Consumption 2000 – 2008



Source: BP 2009

Figure A2.18. China Natural Gas Demand 2006 - 2020



Sources: IEA WEO2009, EIAk, IHS 2005, slide 19, BP 2009

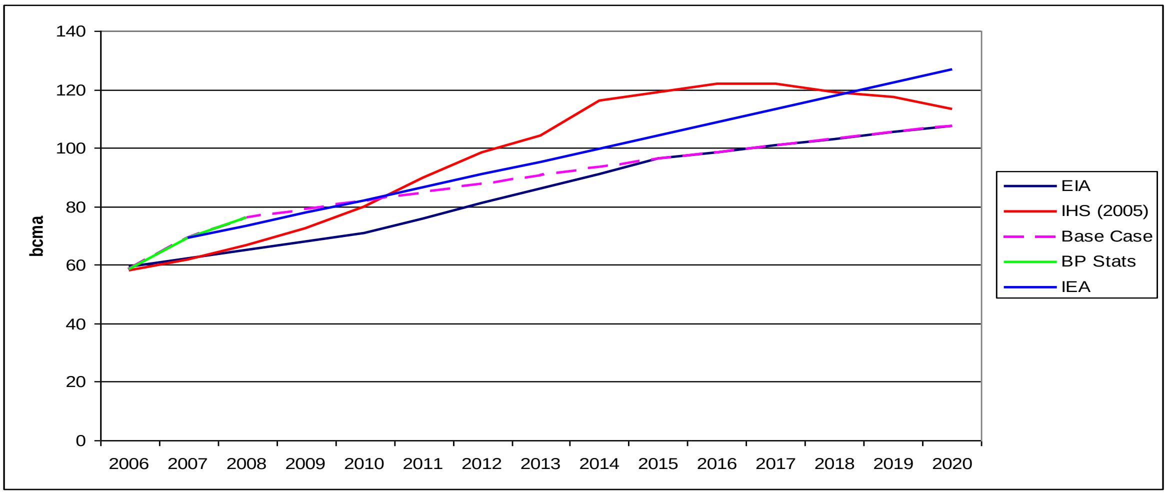
The challenges posed in deriving credible future assumptions for Chinese LNG import requirement are therefore:

- The difficulties of predicting gas consumption growth given its small but growing share of a rapidly growing primary energy base in China.
- Predicting the supply mix (domestic production, pipeline imports and LNG) given uncertainties in all these components.

Figure A2.18 shows three scenarios for natural gas demand in China and actual data for 2006 – 2008. The IEA scenario is most in line with recent data and this has been used as a starting point.

Figure A2.19 shows views of domestic natural gas production from the same sources.

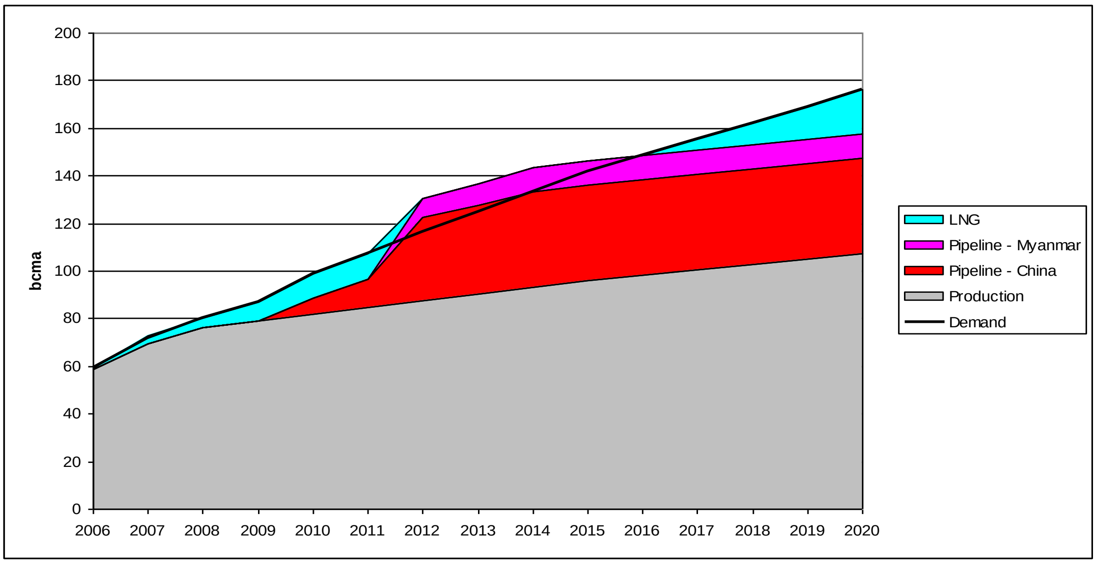
Figure A2.19. China Domestic Natural Gas Production 2006 - 2020



Sources: WEO2009, EIAj, IHS 2005, slide 19, BP 2009

Clearly there is a wide range of uncertainty. The dashed purple line is the assumption used in this analysis.

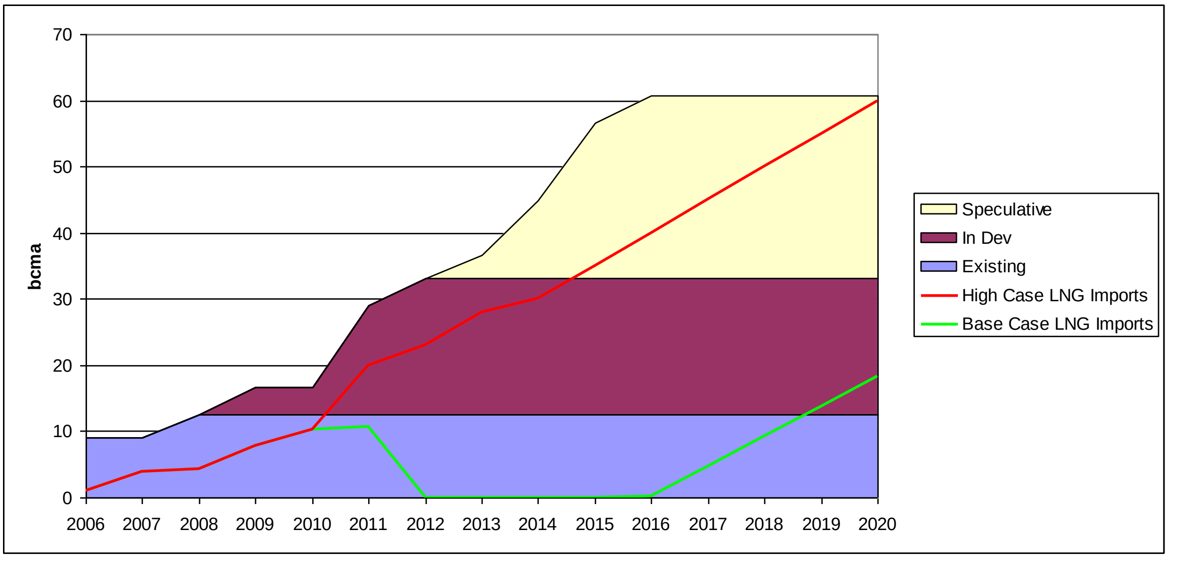
Figure A2.20. China Natural Gas Supply and Demand – Initial View



Sources: Author's analysis.

Putting together an initial supply and demand balance for China on this basis, with an assumed phased build-up in pipeline imports from Turkmenistan (including contributions from Kazakhstan and Uzbekistan) and Myanmar, gives rise to the position shown in Figure A2.20. At face value this shows no requirement for LNG imports from 2012 to 2015 and the aggregate of domestic production and pipeline imports exceeding demand in this period. China is progressing with a number of new re-gas terminals which would allow it to significantly exceed the future LNG import levels shown in Figure A2.20.

Figure A2.21. China Re-gas Capacity and Views of Future LNG Imports



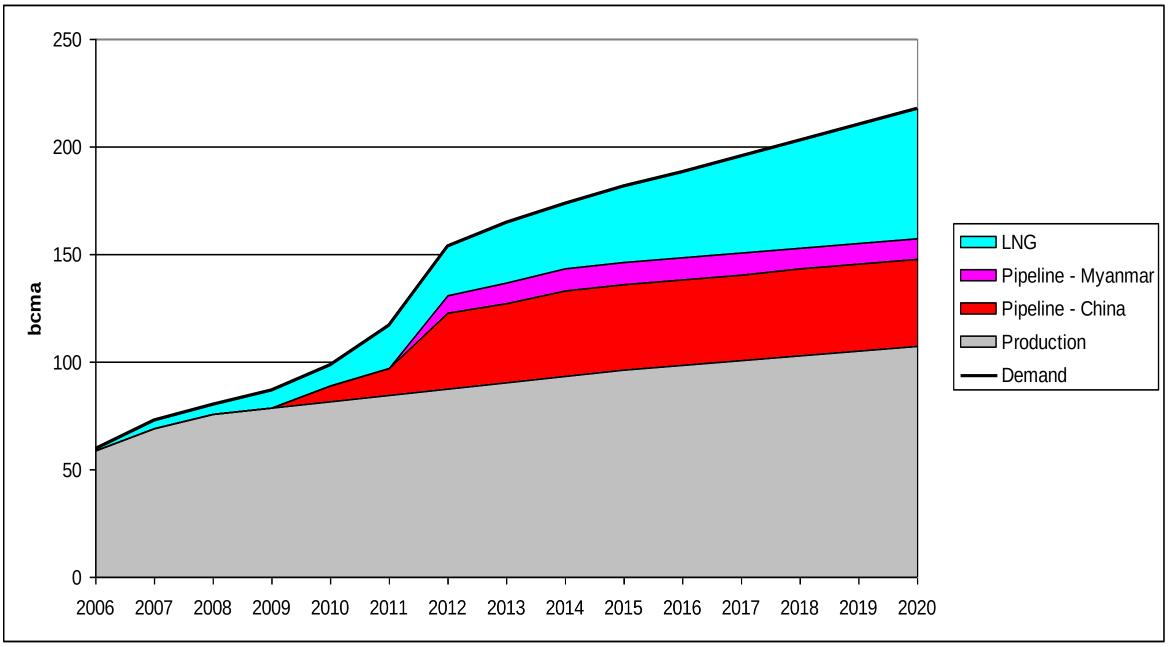
Sources: Flower 2009a (Existing and In Development Re-gas data), WoodMac (Speculative Re-gas data), Author's Analysis

For the purpose of this analysis we will assume that:

- Given the very low current share of primary energy consumption of natural gas in China, there is considerable upside to future gas demand, subject to import supply and transportation and distribution infrastructure.
- Although there is considerable growth by 2020 in both domestic production and pipeline imports from Turkmenistan and Myanmar, this need not necessarily preclude growth in LNG imports, provided that industries in the vicinity of re-gas terminals are able to absorb these volumes.

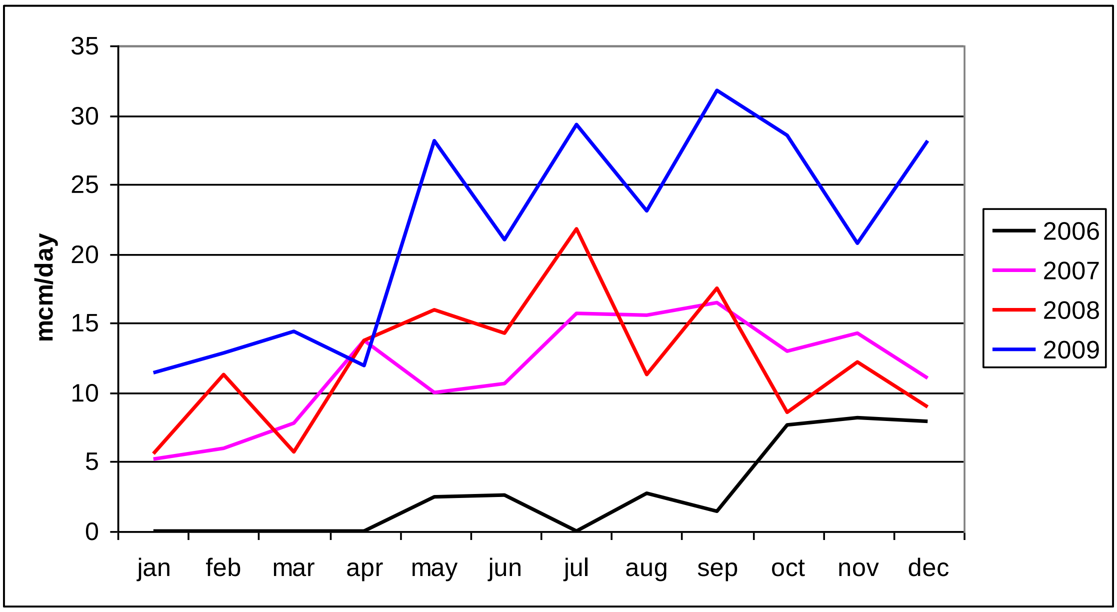
While it is unlikely that all speculative re-gas projects will proceed to construction, Figure A2.21 suggests the ability of China to import significantly more LNG than we have derived from the initial Supply-Demand balance shown in Figure A2.20. A projection of LNG imports more in line with future re-gas capacity build is shown in Figure 2.21 as the red 'High Case'. This is the assumption carried forward into subsequent analysis in this paper. Figure A2.22 shows a re-worked China natural gas supply and demand balance with this assumed higher future level of LNG imports.

Figure A2.22. China Natural Gas Supply and Demand Balance with High Case LNG Imports.



Sources: Author's Analysis

Figure A2.23. Chinese Monthly LNG Imports.



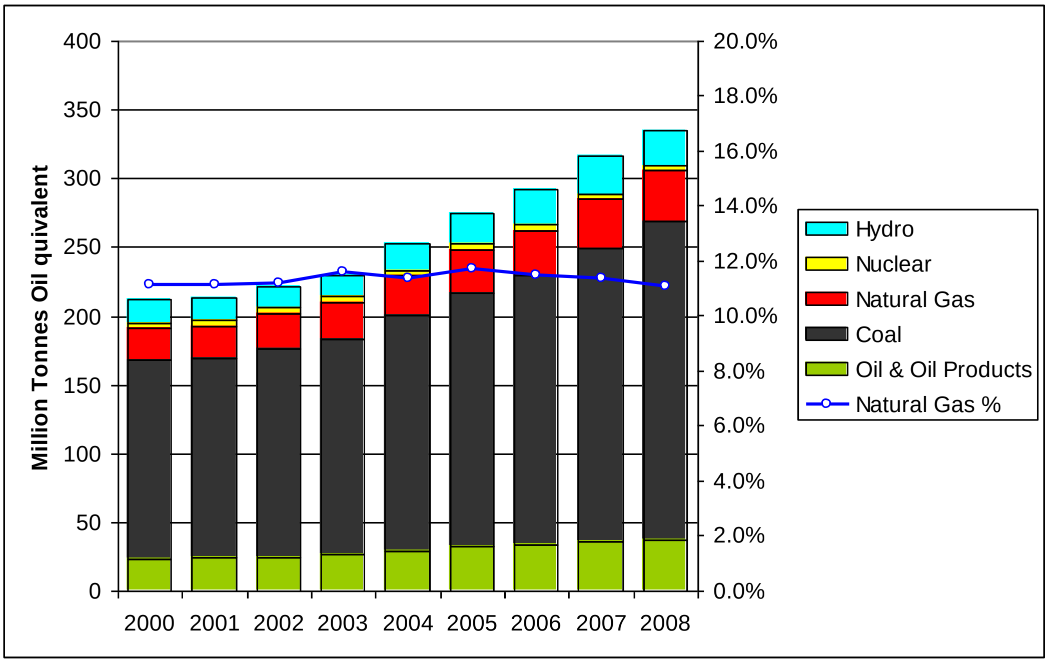
Source: Waterborne LNG

Figure A2.23 shows monthly actual Chinese LNG imports from January 2006 to December 2009. Although flows in 2009 were somewhat erratic, the data for 2007 and 2008 indicate a summer-biased import pattern.

India

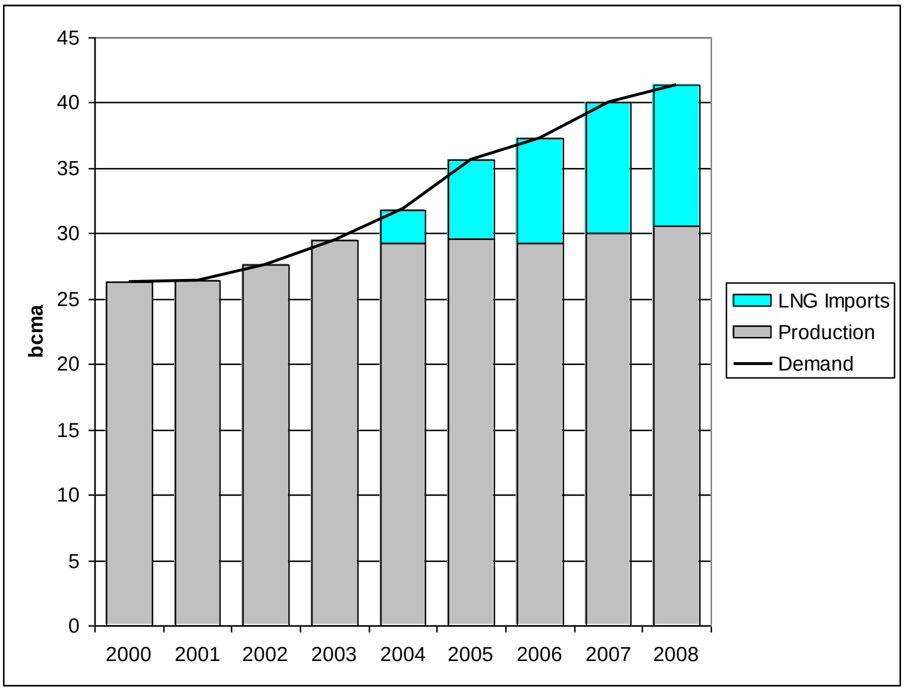
Figure A2.24 shows very clearly the dominance of coal in India's primary energy make-up from 2000 to 2008. In this period primary energy consumption grew at an annual average rate of 5.9%. Natural gas' share held at around 11 to 12 % through the period.

Figure A2.24. India Primary Energy Consumption 2000 - 2008



Source: BP 2009

Figure A2.25. India Gas Supply & Demand 2000 - 2008



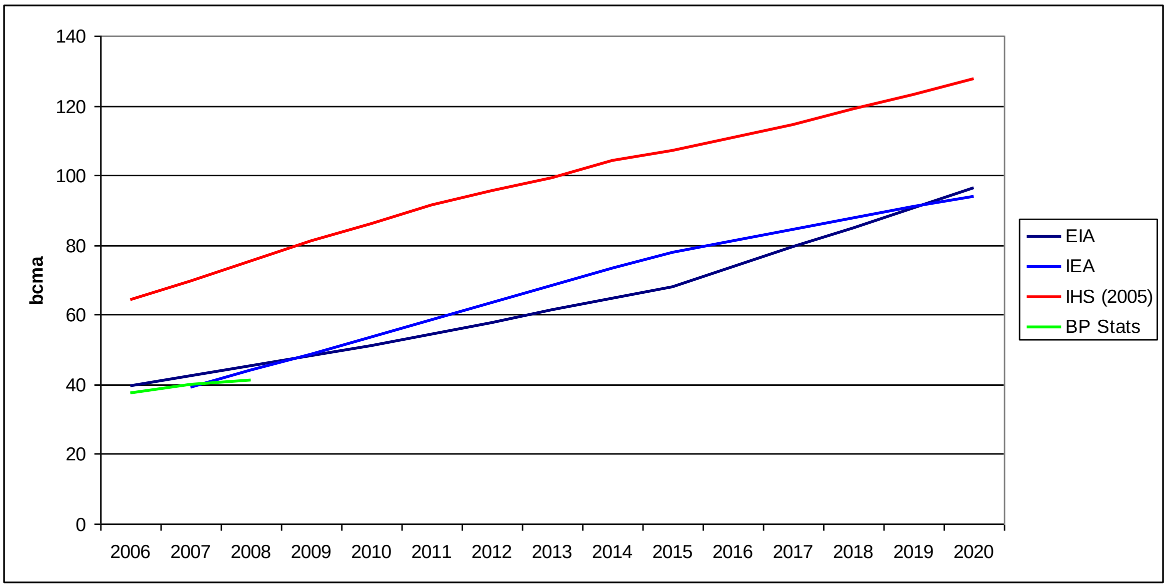
Source: BP 2009

India's natural gas position is shown in Figure A2.25. Demand grew by 5.8% per annum through the period. 2004 saw the start of LNG imports as demand outstripped domestic supply.

As with China, gas' relatively low share of primary energy, combined with a high growth economy in the context of the 2009 economic recession, make forecasting future demand challenging.

Figure A2.26 shows three demand scenarios for India's natural gas demand to 2020.

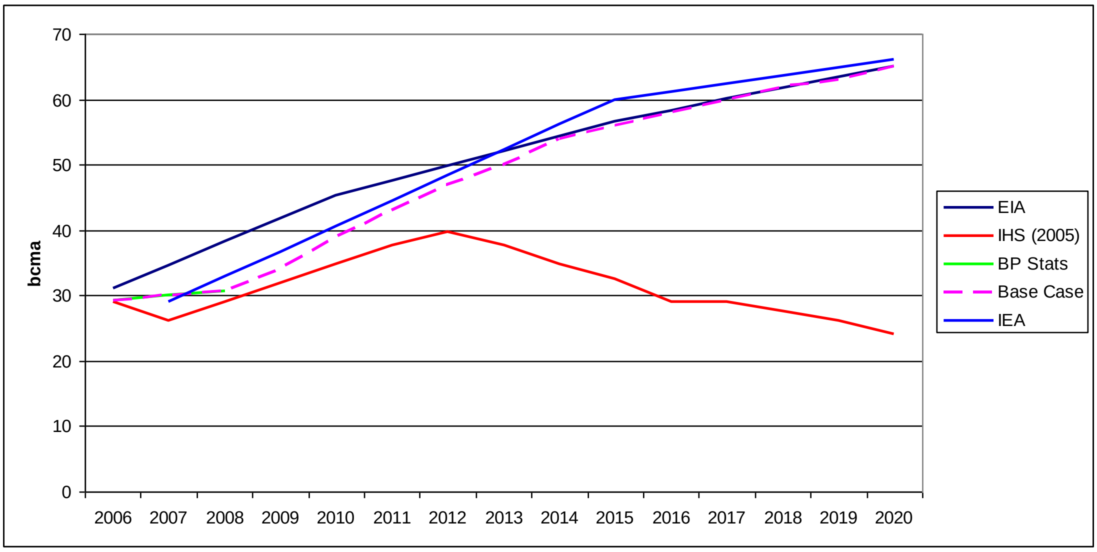
Figure A2.26. India Natural Gas Demand 2006 - 2020



Sources: IEA WEO2009, EIAk, IHS 2005, slide 19, BP 2009

The IHS view (made in 2005) is much higher than those of the IEA and EIA, between which there is convergence by 2020. For this analysis the IEA WEO2009 scenario was used as an initial basis.

Figure A2.27. India Domestic Natural Gas Production 2006 - 2020

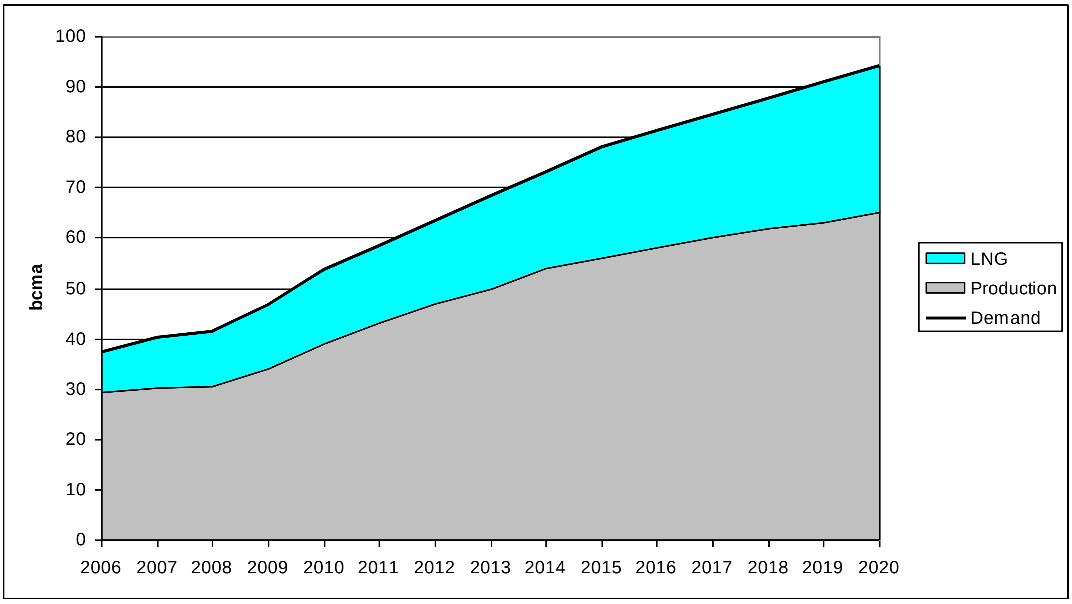


Sources: WEO2009, EIAj, IHS 2005, slide 19, BP 2009

Figure A2.27 shows reasonable similarity between the EIA and IEA scenarios for domestic natural gas production (albeit they are high relative to actual data in 2006 – 2008) and a contrast with the 2005-based IHS view. The Base Case chosen is the dashed purple line which tracks the general IEA and EIA trajectory.

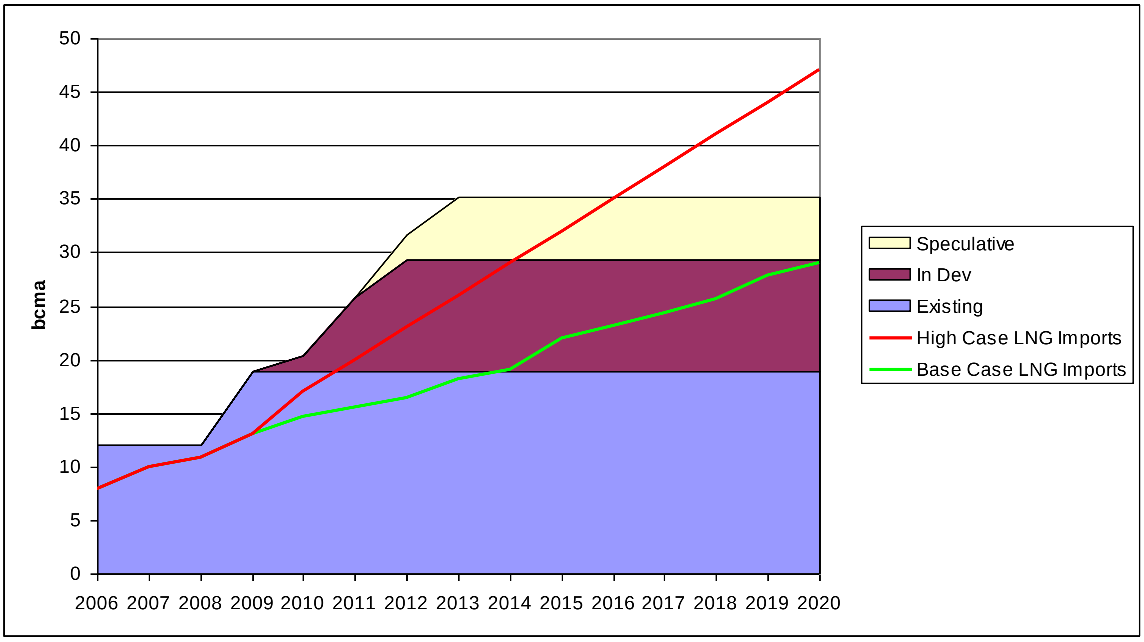
The initial India natural gas supply and demand balance is shown in Figure A2.28, which assumes no pipeline imports from, for example, Iran via Pakistan or from Turkmenistan in the period to 2020.

Figure A2.28. India Natural Gas Supply and Demand – Initial View



Source: Author's Analysis

Figure A2.29. India Regas Capacity and LNG Imports

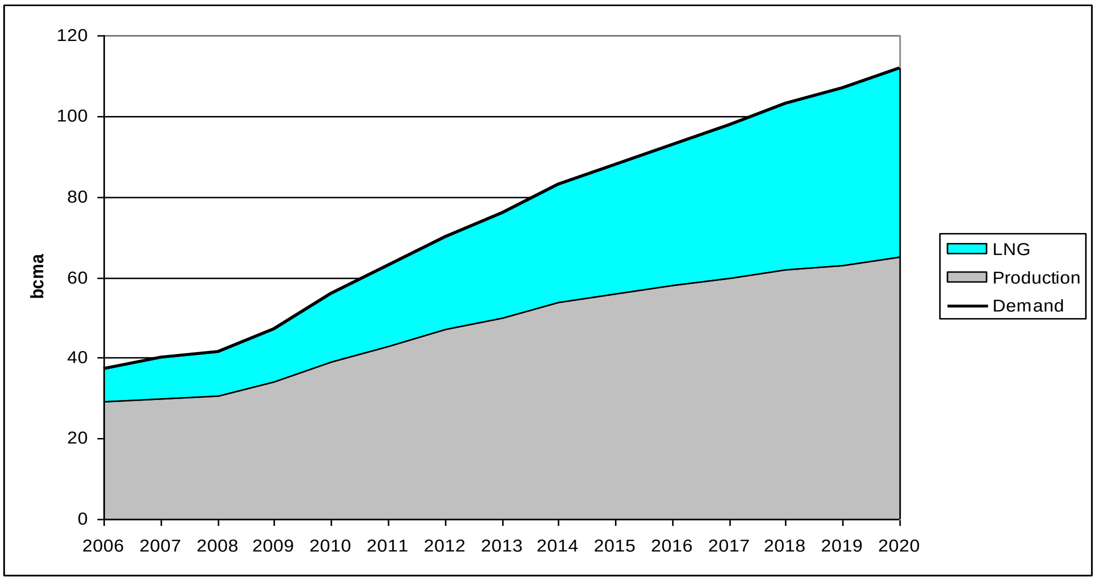


Sources: Flower 2009b (Existing and In Development Re-gas data), WoodMac (Speculative Re-gas data), Author's Analysis

As with China, India is progressing new re-gas projects which will increase its import capacity for LNG from 2011. The growth in re-gas capacity is shown in Figure A2.29 together with an initial 'base case' view of LNG imports and a potentially higher LNG import case.

We will use the High Case LNG Import assumptions in subsequent analysis. For completeness the Indian future natural gas supply & demand position is re-constructed in Figure A2.30 with the higher LNG import assumption and consequently higher demand.

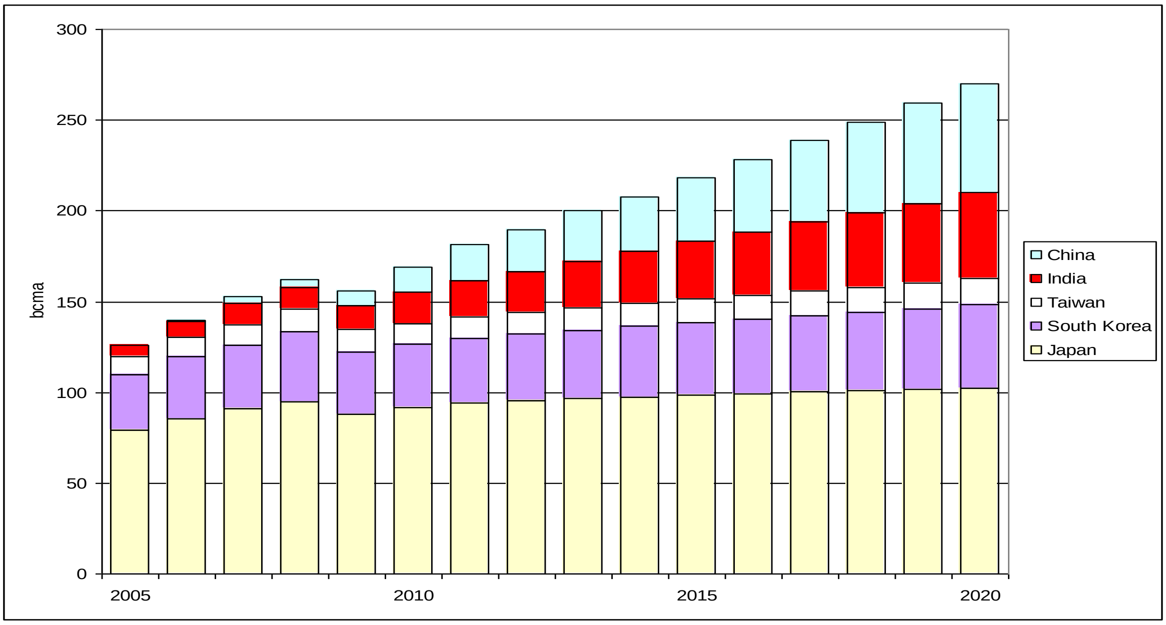
Figure A2.30. India Natural Gas Supply and Demand Balance with High Case LNG Imports.



Source: Author's Analysis

Figure A2.31 shows the aggregate LNG import requirement for the existing Asian LNG markets to 2020, and the impact of India and China's growing LNG requirement.

Figure A2.31. Asian LNG Import Forecast



Source: Author's Analysis

Europe

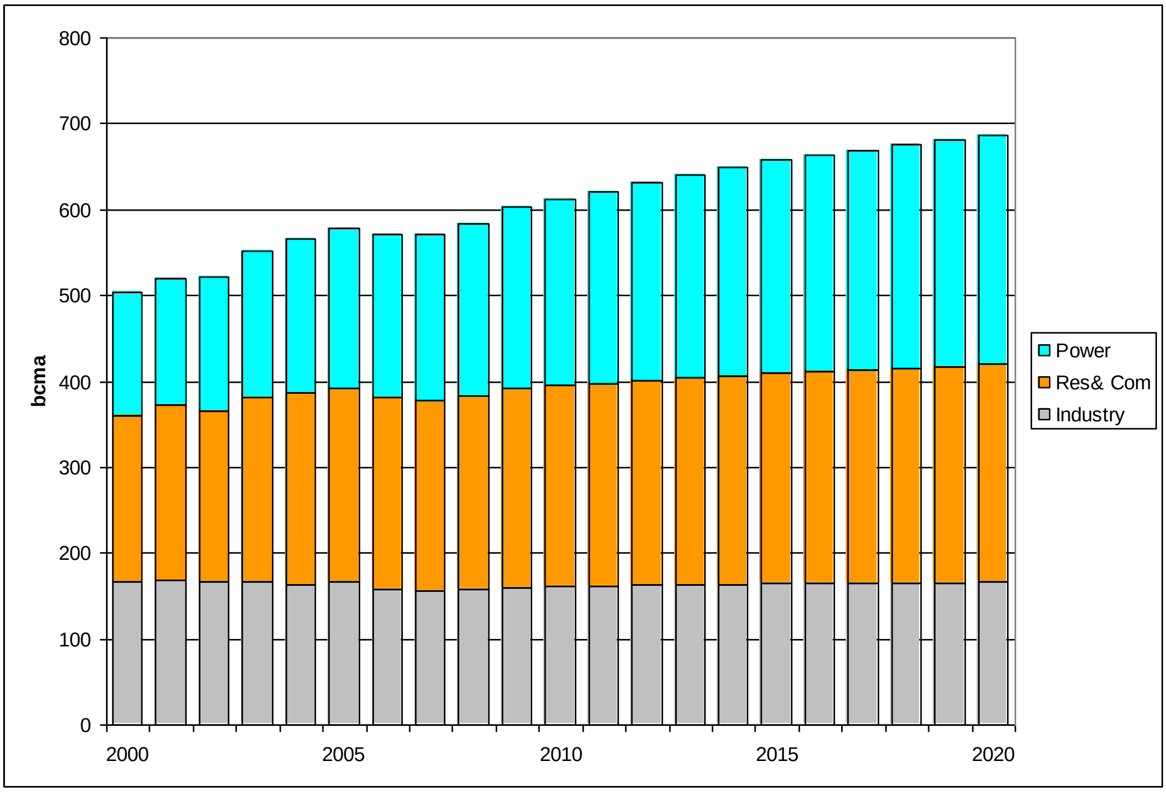
Europe, for the purposes of this model framework, includes:

Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, UK.

Demand

Figure A2.32 represents a 'consensus' view of European natural gas demand prior to the onset of the 2008 / 2009 economic recession. It is broadly consistent with the IEA WEO 2008 for comparable geographies. Overall growth from 2008 to 2020 is 1.4% CAGR[36], with growth of 0.4% pa in the Industrial sector, 1.0% in the Residential and Commercial sector and 2.4% in the power generation sector.

Figure A2.32. European Demand – Pre-Recession View

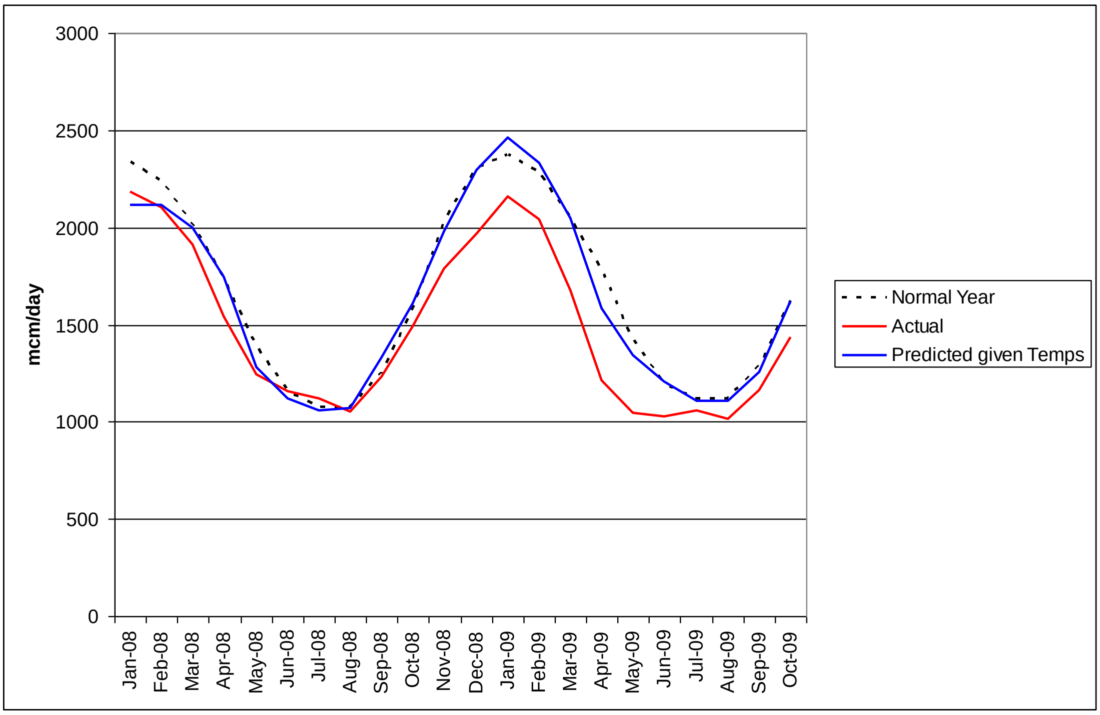


Source: IEA Annual Data Series, IEA WEO 2008, Author's Analysis

From 4Q 2008 onwards it became apparent that natural gas consumption was falling short of levels expected for the prevailing temperatures[37]. This is illustrated in Figure A2.33.

[36] CAGR = Compound Average Annual Growth Rate.
[37] Weather Underground

Figure A2.33. European Demand January 2008 – October 2009



Source: IEA Monthly Data Series, Author's Analysis

Based on a correlation between average monthly temperature and demand for the major gas consuming countries of Europe, Figure A2.33 shows:

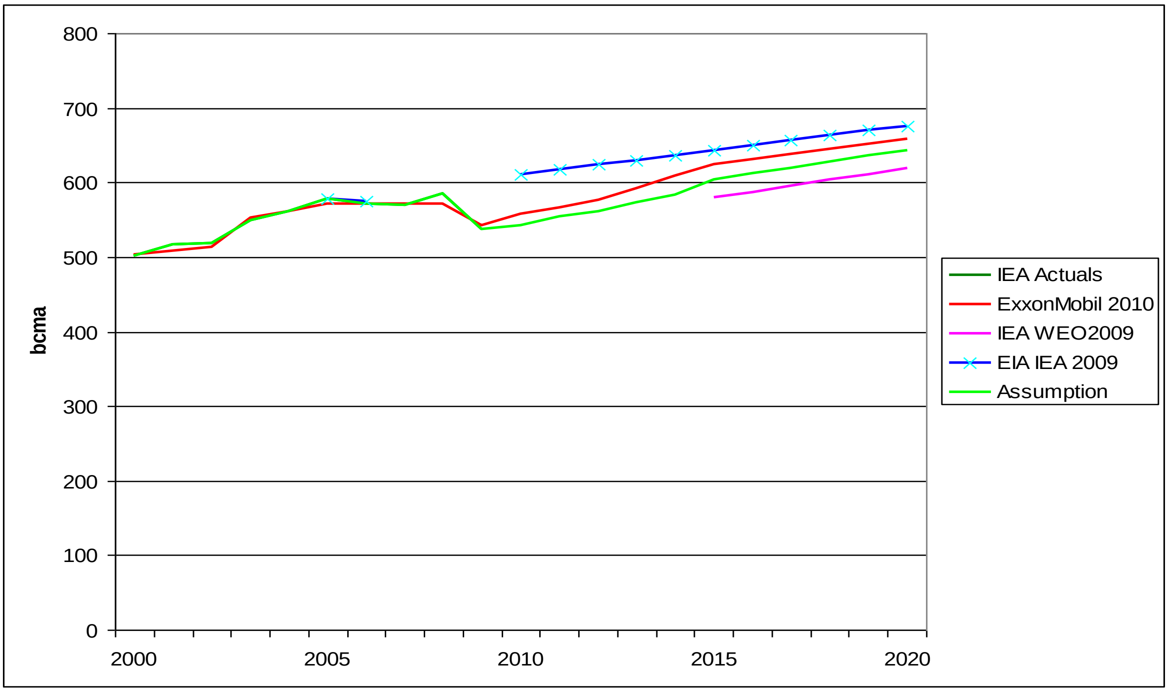
- Demand already beginning to undershoot expected levels for the prevailing temperatures in Spring 2008 – potentially caused by space heating efficiency measures in response to price.
- A growing and sustained divergence between actual demand and demand expected at the prevailing temperatures from 4Q08 onwards.
- Some apparent narrowing of the 'actual vs. predicted' gap in 3Q 2009, possibly due to increased industrial sector demand as the recession-related inventory run-down cycle ended.

Actual gas demand in the period Jan 2009 to October 2009 was 8.5% lower than the same period in 2008 and 14% lower than what would be expected at the prevailing temperatures.

In constructing our future demand assumption envelope for Europe the major uncertainty is the demand recovery trajectory post – recession. Figure A2.34 shows actual European demand to 2008 and future scenarios from the IEA, EIA and ExxonMobil. The EIA scenario does not appear to have incorporated recessionary demand destruction and the IEA does not provide annual data points for the period between 2009 and 2015. A working assumption was derived by taking a trajectory in between the IEA WEO2009 scenario and the ExxonMobil scenario, which is shown as the light green line in Figure A2.34.

Given the prevailing uncertainty on the timing and pace of gas demand growth as Europe emerges from recession, the author has not re-appraised the future sectoral demand analysis. (see Honore, Forthcoming 2010)

Figure A2.34. European Demand Assumptions

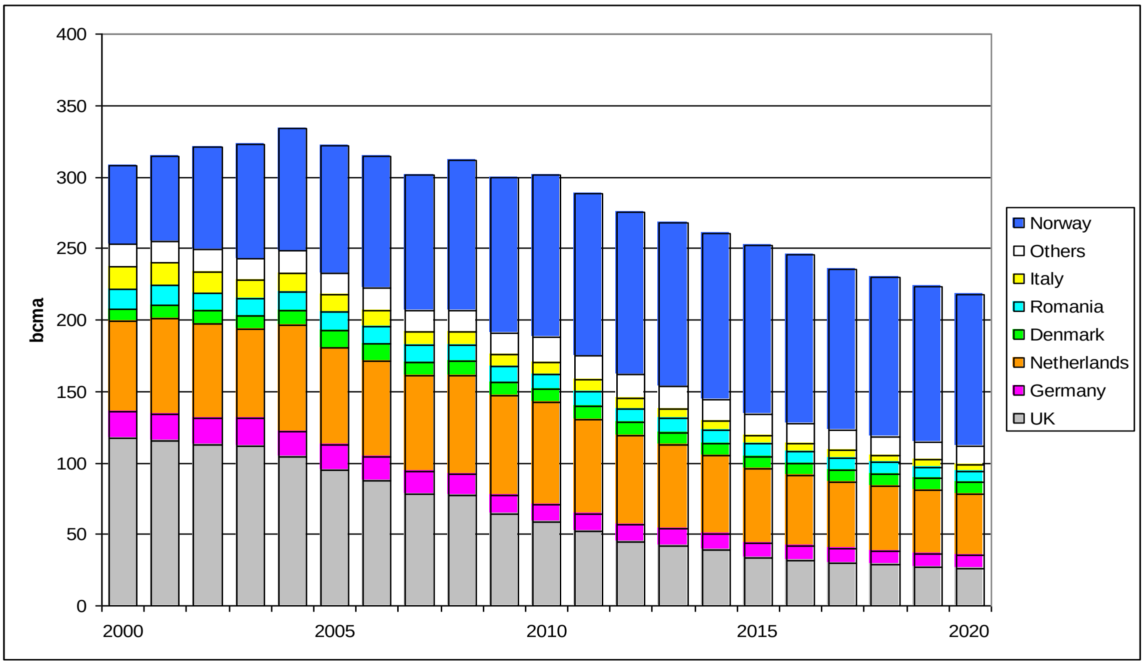


Source: ExxonMobil 2009 p.29, IEA WEO2009, IEA Monthly Data Series, EIAk

The other aspect of demand to consider is the seasonal monthly demand variation. In the modelling framework, historical monthly demand profiles are combined with future annual demand to produce a monthly forecast at a country level which is then aggregated to a European region total.

Domestic Production

Figure A2.35. European Natural Gas Production



Sources: IEA Monthly Data Series, National Grid, NPD, OGP, Author's Analysis

Historical actual production is taken from the IEA Monthly Data Series and key estimates of future production levels from:

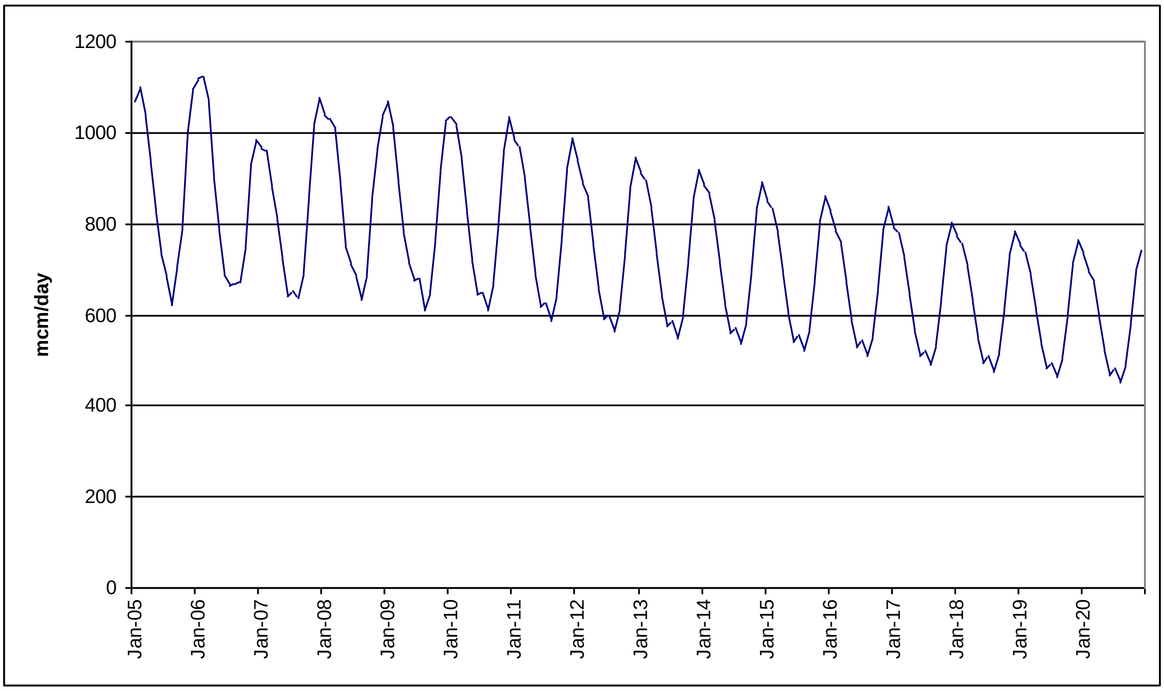
- The Norwegian Petroleum Directorate to benchmark future Norwegian Production.
- The International Association of Oil and Gas Producers, for Netherlands Production
- National Grid to benchmark UK production future decline.

Future production levels for other European producing countries were calculated by extrapolation of existing trends.

Figure A2.35 shows actual European domestic production from 2000 and the assumed trend to 2020. The figure shows decline at varying rates in all countries except Norway. Norway is able to offset decline elsewhere in Europe until 2010. Beyond 2010 the aggregate European production trend is one of decline.

During 2009 and in 2010, given the success of unconventional gas production in the US and Canada, there has been considerable interest in Europe's unconventional gas production potential. At this stage however, there is uncertainty as to the scale and timing of future European unconventional gas production. The IEA WEO 2009 envisaged only some 15 bcma of unconventional gas production in Europe, post 2020[38].

Figure A2.36. European Domestic Production – Monthly Basis



Source: IEA Monthly Data Series, Author's Analysis

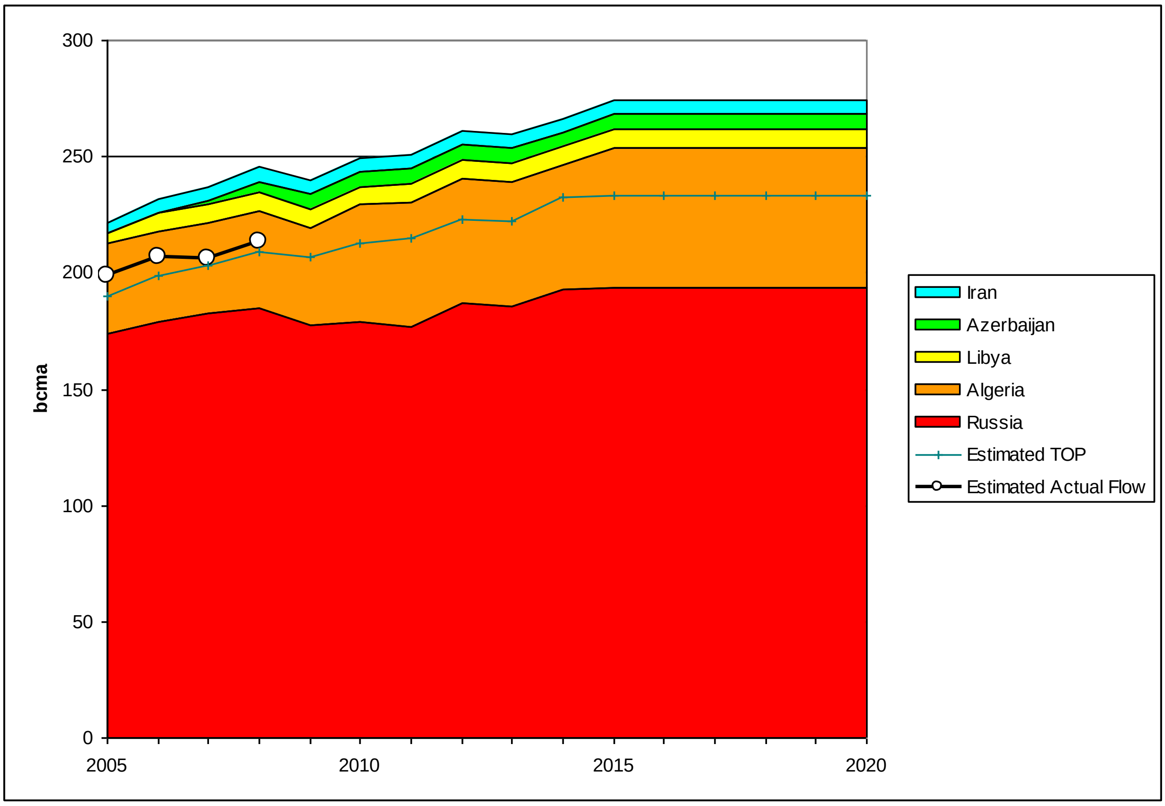
Figure A2.36 shows historic actual data to early 2009 and the future projection obtained by applying an average monthly profile to future annual production forecasts at a country level. In addition to the decline in absolute production the summer – winter flexibility is also reduced.

[38] IEA WEO 2009, p. 478

European Pipeline Imports

Using Cedigaz's annual summary of pipeline contacts [39] it is possible to derive a view of the aggregate Annual Contract Quantity (ACQ) of gas from Russia, Algeria, Libya, Azerbaijan and Iran. This is shown in figure A2.37.

Figure A2.37. Annual Contract Quantities of Pipeline Imports to Europe



Sources: BP 2009, Cedigaz 2008, IEA Monthly Data Series, Author's Analysis.

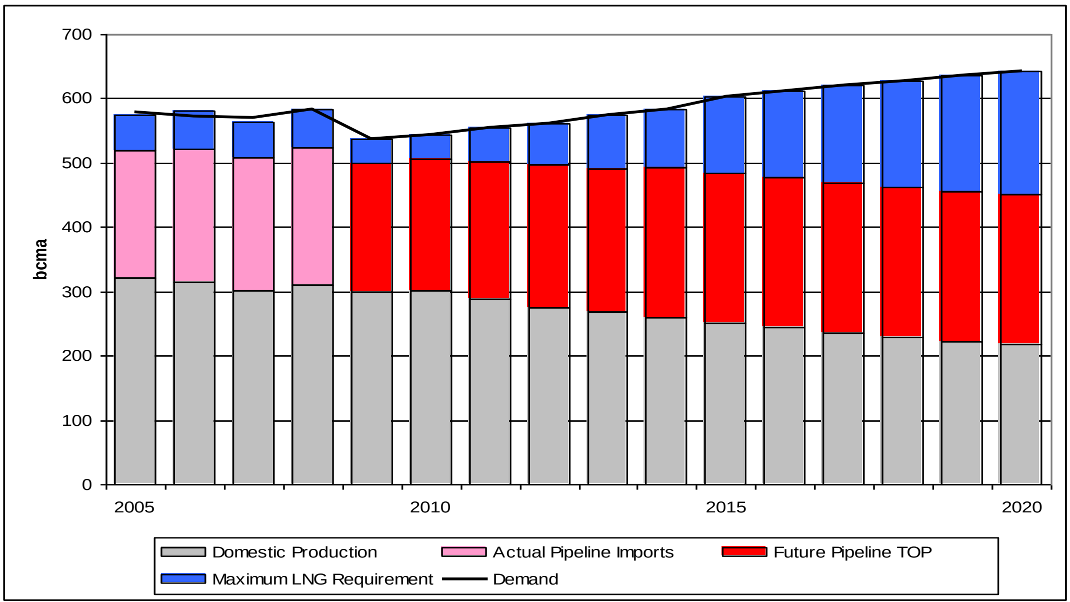
In any one year the Cedigaz data shows the aggregate of new, existing and expiring contracts. For the purpose of the modelling framework, aggregate supplier ACQs were kept constant from 2015 onwards. Superimposing a view of actual import flows for 2005 to 2008 shows that flows were close to Take or Pay levels in this period (assumed to be 85% of ACQ on average). Once the new contracts associated with Nordstream (Russia) and Medgaz (Algeria) begin there is little foreseen growth in new pipeline imports to Europe in this timescale. It has been assumed that the Nabucco project is not operational prior to 2020 and that South Stream, if it is implemented in this timescale, does not bring incremental new gas supply to Europe (i.e. it is a means for re-routing transit gas around Ukraine).

Within a contract year the modelling framework allows for additional monthly flexibility outside the Take or Pay and ACQ limits although a check is then made to ensure that Take or Pay obligations for the year are met. If this is not the case, these flexibility limits can be narrowed until this condition is met.

[39] Cedigaz 2008

LNG
Combining the assumptions for future European demand, pipeline imports at take or pay contract levels and domestic gas production allows us to take a view of maximum LNG requirements. These are shown in Figure A2.38, growing to reach some 190 bcma by 2020.

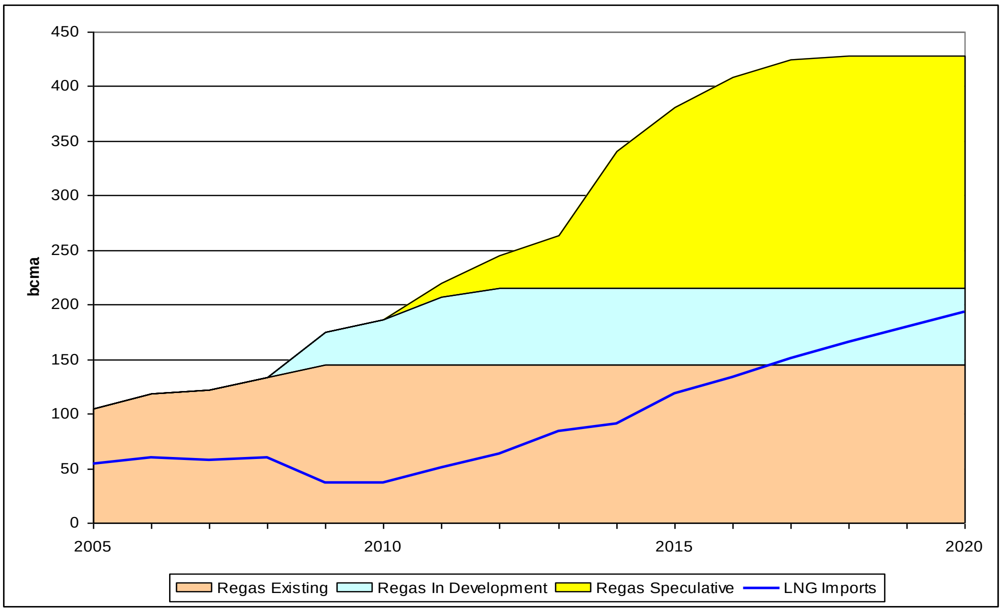
Figure A2.38. Sources of European Supply.



Source: BP2009, Author's Analysis

As a sense check, Figure A2.39 compares these annual LNG import volumes (blue line) with a view of European re-gas capacity in 'existing', 'in development' and 'speculative' categories. In aggregate, Europe has sufficient re-gas capacity either existing or in development to meet the 2020 import requirement. Where additional capacity is required there is more than sufficient lead time to construct this.

Figure A2.39. European Maximum LNG Import Requirement and Regas Capacity



Sources: WoodMac 2008a, Author's Analysis

Gas Storage

The model framework uses European storage to provide part of the supply flexibility to meet seasonal demand variation. Due to the nature of the modelling approach seasonal storage is handled as follows:

- Historic actuals are derived from a combination of IEA Monthly Data and Gas Storage Europe (GSE) data.[40]
- A future storage new-build rate of around 2.5 bcm per year of working gas capacity is assumed.
- A typical annual injection-withdrawal profile has been derived from historic data. Combining this with the projected working gas capacity allows the future path of total European storage inventory to be projected assuming an ‘average’ year in terms of weather – related demand.
- Great care must be taken in transitioning from the most recent actual data into the ‘generated’ future inventory forecast in order to avoid large anomalous inventory movements in the transition zone.

North America

The future assumptions used in the modelling framework are described below for the US, Canada and Mexico demand and domestic production.

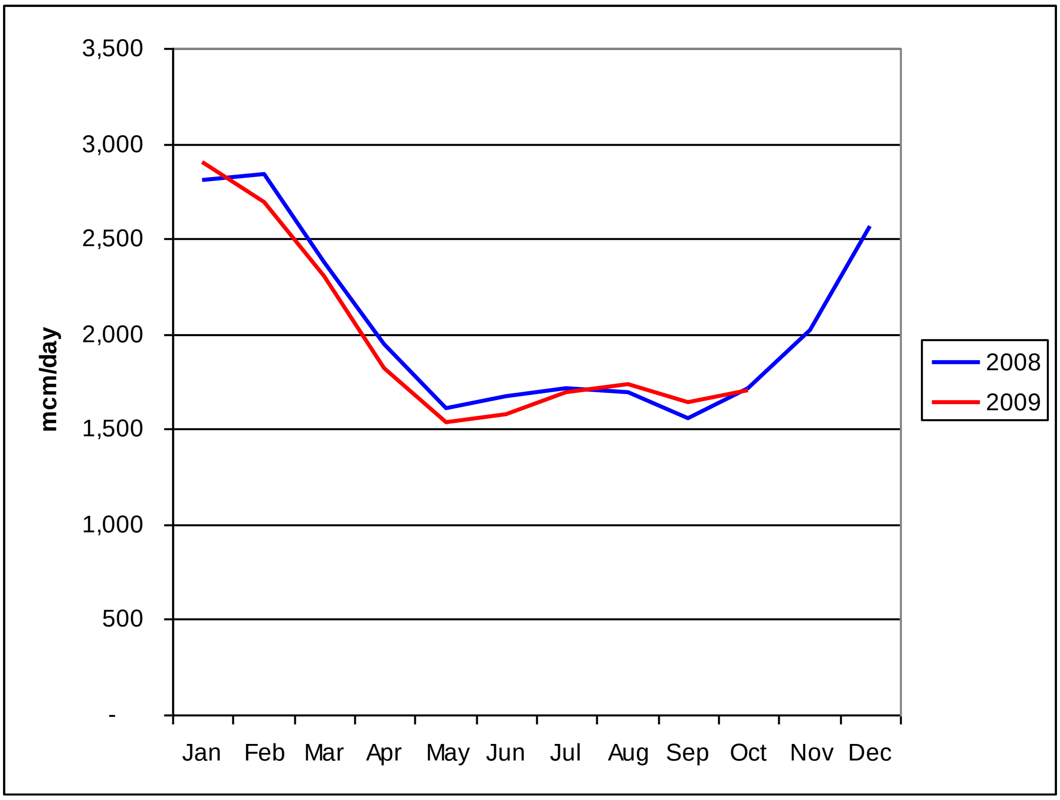
US Demand

Despite its size and relative maturity there has for some while been a lack of consensus between market observers as to the future growth in US natural gas demand. Industrial demand has been on a 10 year downward trend and the residential and commercial sector is arguably saturated. Power generation has been the most dynamic sector in terms of consumption growth, however around 50% of power generation continues to be coal-fired. The most optimistic forecasters generally assumed further growth in gas fired generation given the relatively low number of new coal fired plant under construction or planned. The more pessimistic observers may well have shied away from high gas demand growth forecasts, because of the implication that additional LNG imports would be needed (before the potential for unconventional gas exploitation at scale became apparent).

The economic recession has had only a muted impact on gas demand in Canada and the USA. This is shown in Figure A2.40. For the period January 2009 to October 2009, gas demand was 2.1% lower than the same months of 2008. The EIA in its monthly Short Term Energy Outlooks has commented that the fall in industrial sector gas demand in the USA has been offset by increased consumption in the power generation sector.

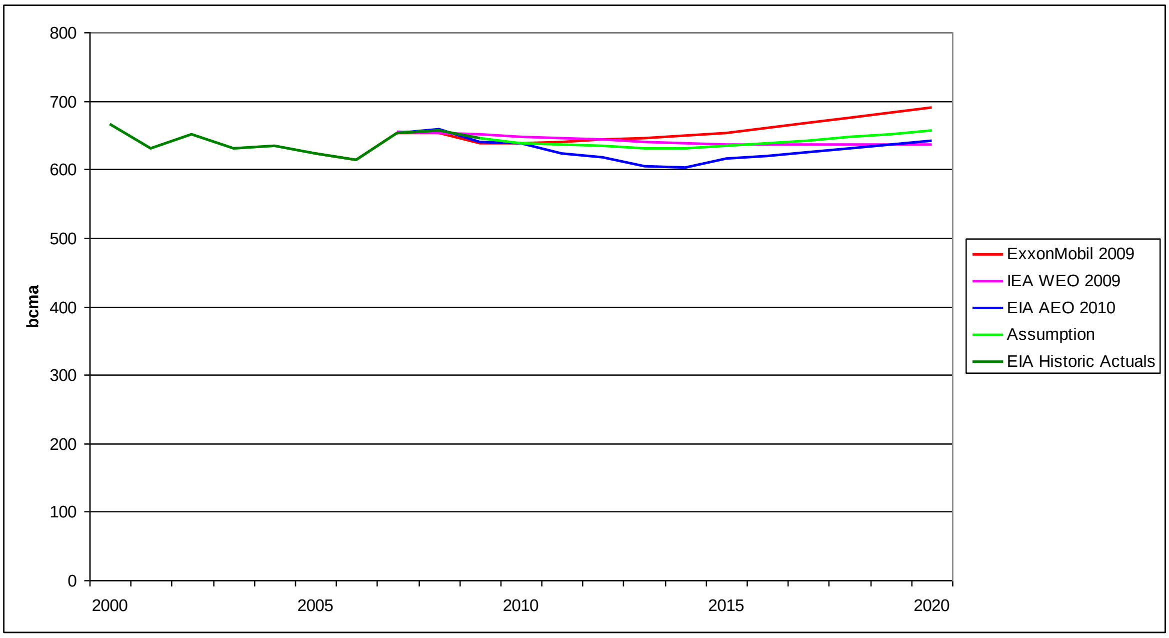
[40] Note that the IEA data includes all national inventory including line pack. The author believes that this figure is calculated by deriving stock changes month-on-month and therefore cumulative errors may well have crept in over time. The GSE data although recently much improved in terms of coverage, lacks historical continuity. Judgement must be applied in arriving at a view of end month ‘actual’ storage inventory.

Figure A2.40. USA and Canada Gas Demand 2008 and 2009.



Source: EIAb

Figure A2.41. Range of Views of Future US Natural Gas Demand

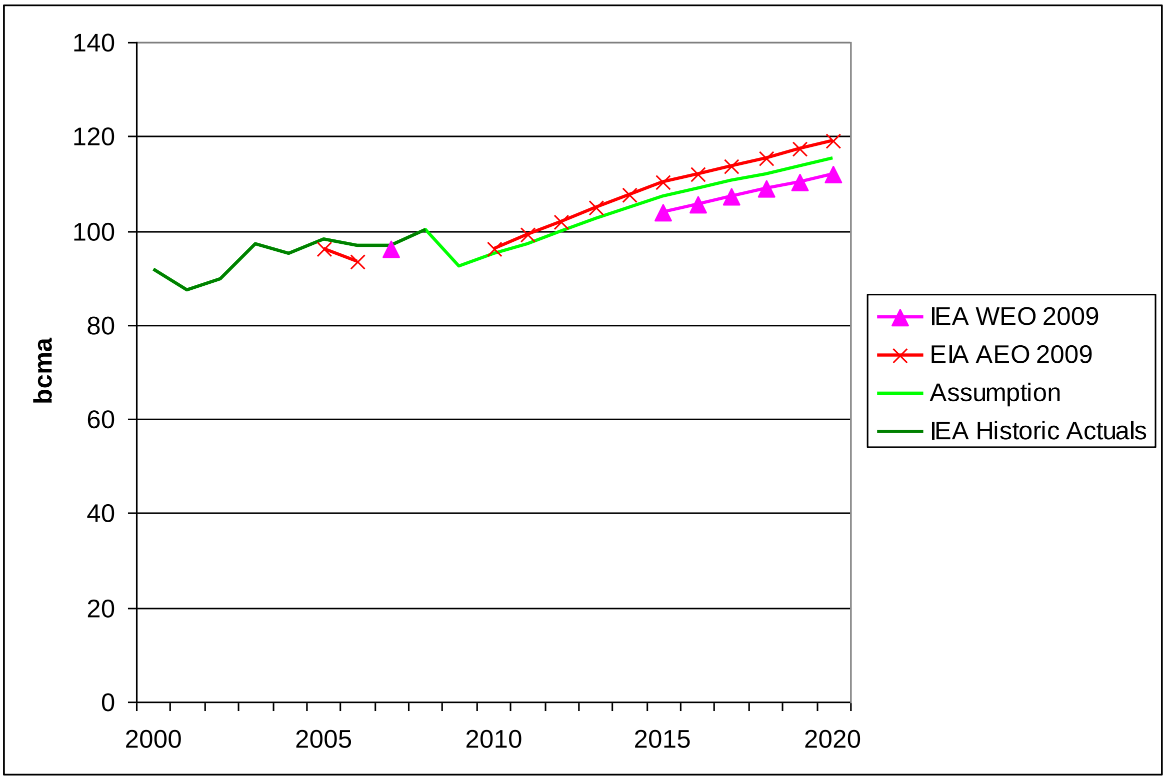


Sources: EIAl , ExxonMobil 2009 p 29, IEA WEO2009

Figure A2.41 shows historical annual US gas demand data from 2000 to 2008 and future demand scenarios from ExxonMobil, the EIA and the IEA. These views vary significantly with ExxonMobil anticipating growth post 2015 and the EIA anticipating a decline in gas demand over the period 2010 to 2014. Closer inspection of the sectoral data behind this data set reveals an assumption of a reduction in gas in the power generation sector. For the purposes of the subsequent analysis in this paper the author took a simple average of the three scenarios – shown as the light green line.

Canadian Demand

Figure A2.42. Range of Views of Canadian Natural Gas Demand



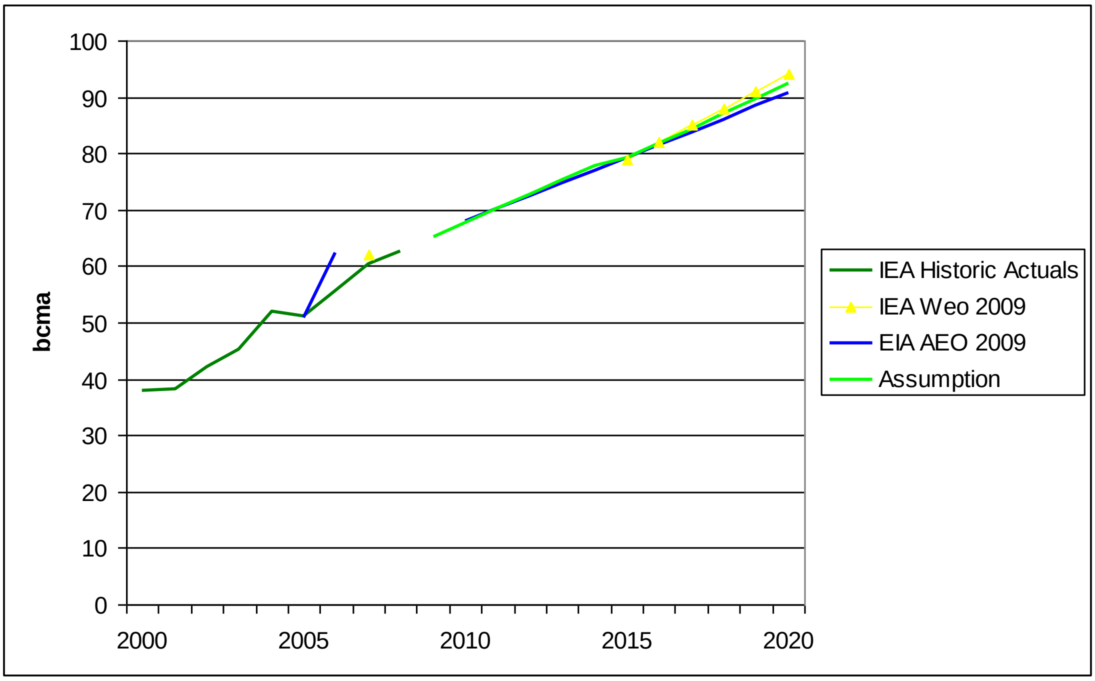
Sources: IEA WEO2009, IEA Monthly Data Series, EIAk

Figure A2.42 shows historical actual Canadian demand together with future demand scenarios from the IEA and the EIA. For the analysis in this paper an average of the two was taken – shown as the light green line.

Mexican Demand

Figure A2.43 shows historical Mexican natural gas demand actuals together with IEA and EIA scenarios of future demand levels. Apart from a seemingly anomalous data point for 2006 from the EIA, future demand views are relatively consistent and an average of the IEA and EIA scenarios was used for this paper (shown as the light green line).

Figure A2.43. Mexican Natural Gas Demand Scenarios

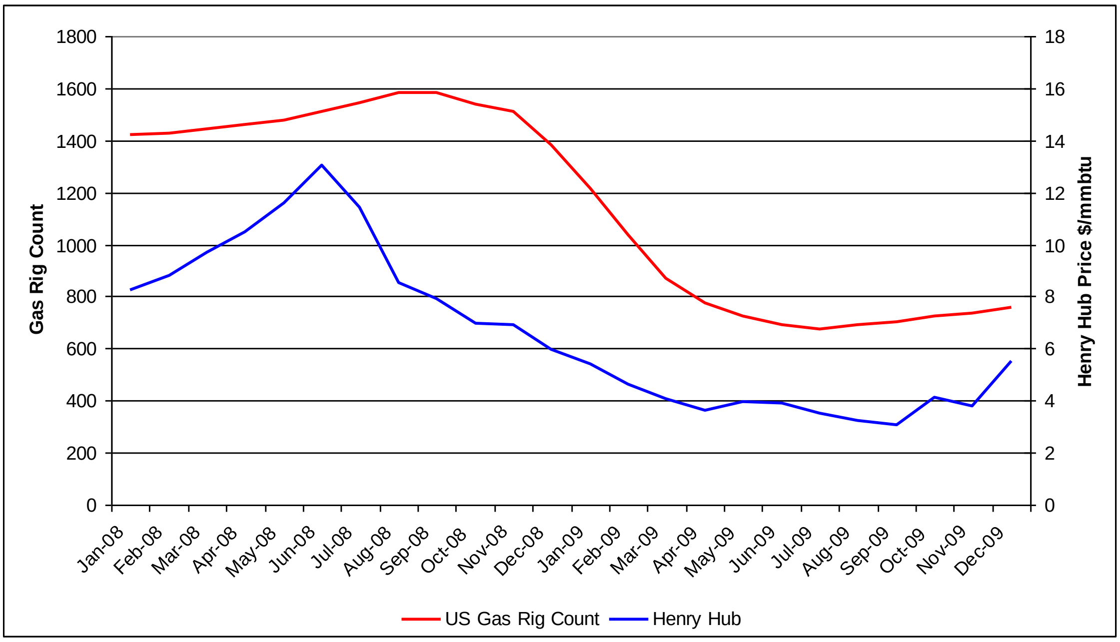


Sources: IEA Monthly Data Series, IEA WEO2009, EIAk.

North American Production

In Chapter 1 we noted the post 2005 turn-around in the prospects for US production due to the successful exploitation of 'unconventional' gas - coal bed methane and especially shale gas. Industry commentary in 2008 alluded to shale gas 'plays' needing of the order of $6 to $8/mmbtu gas price to support economic development. More recently in 2009, the figures quoted vary and some estimates are lower. Figure 2.44 shows the drastic reduction in gas-focussed drilling activity in the US since spot gas prices declined.

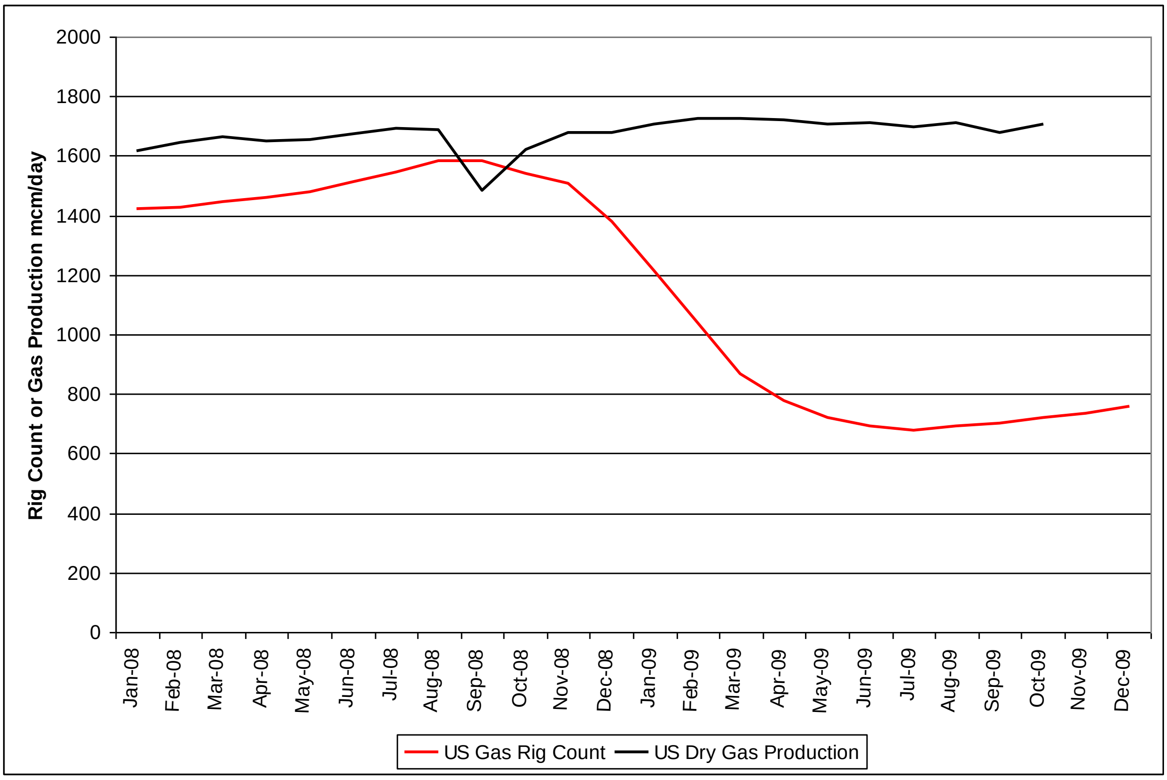
Figure A2.44. US Gas Rig Count and Henry Hub Price



Sources: Argus, Baker Hughes 2009

Despite the reduction in gas rig count (by July 2009 it was 43% of the September 2008 level), up to October 2009, the impact on US dry gas production levels appears to be muted (Figure A2.45).

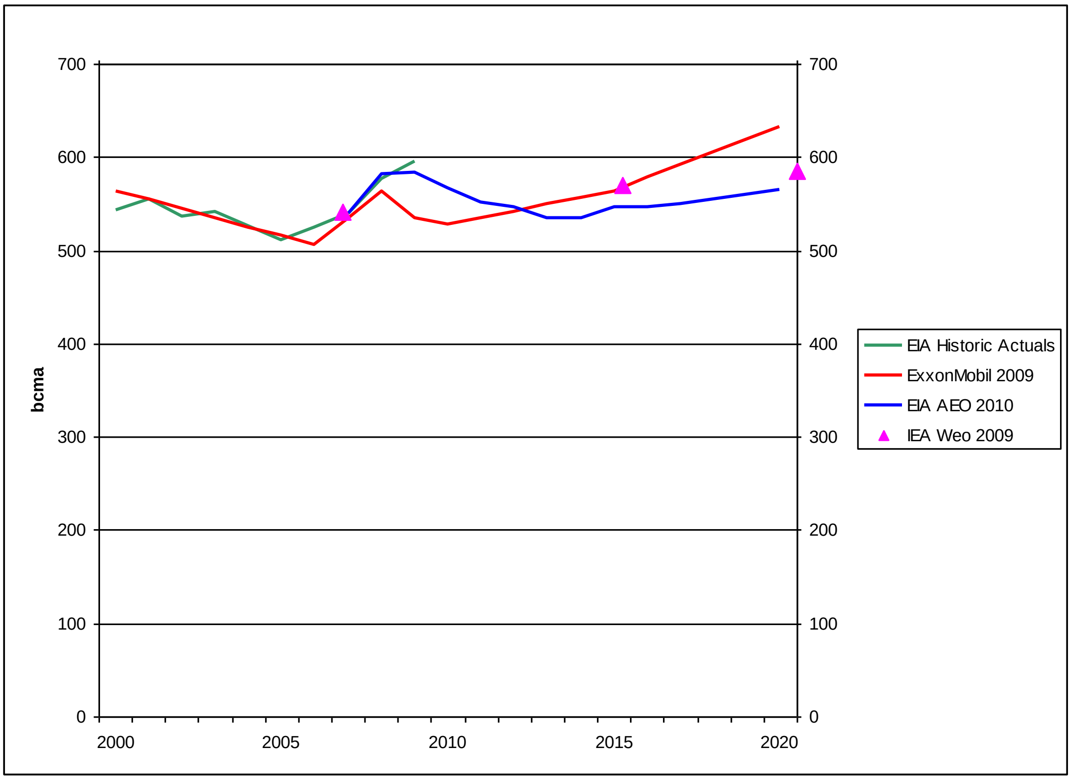
Figure A2.45. US Gas Rig Count and US Dry Gas Production



Sources: EIAb, Baker Hughes 2009

Note that the dip in production in September and October 2008 was a consequence of Hurricane Gustav. Although gas production shows a minor reduction from around March 2009, this is not proportional to the rig count reduction, implying a significant lagged response or alternatively that US drilling activity is concentrating on higher productivity gas prospects.

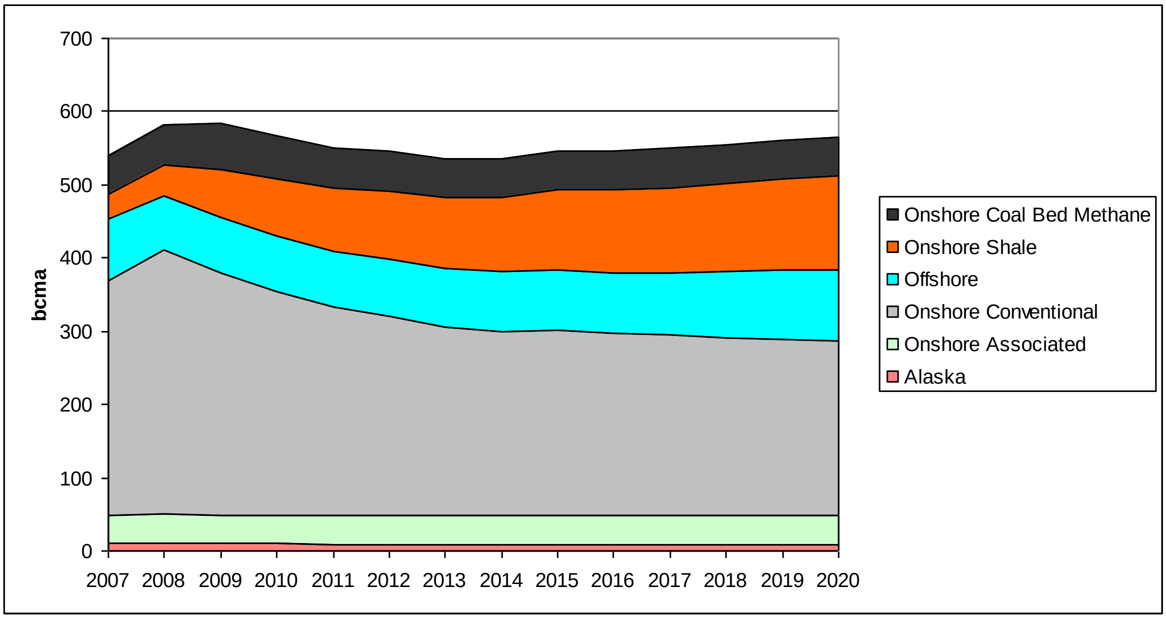
Figure A2.46. US Natural Gas Production



Sources: EIAb, EIAl Table 14, ExxonMobil 2009, P. 29, IEA WEO2009

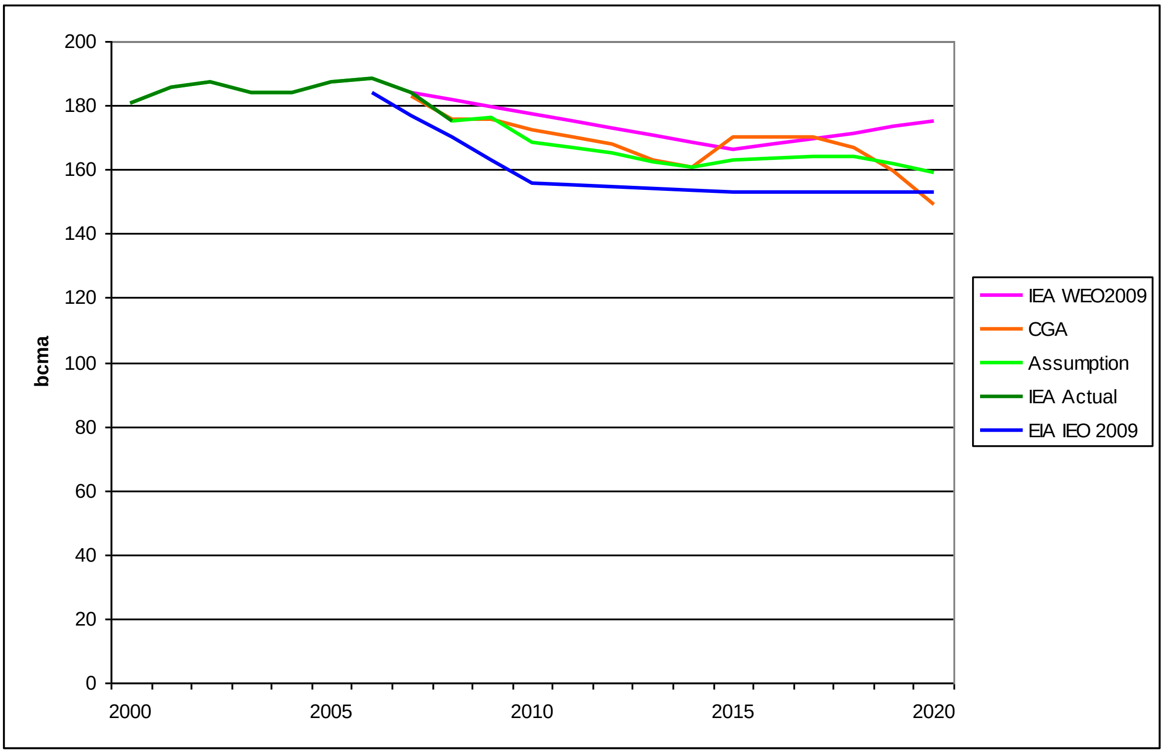
There is a significant variation in the scenarios for US production (Figure A2.46). For the purpose of this analysis we will take the EIA case as the starting point. The EIA assessment of production from different gas types is shown in Figure A2.47. Note the increasing contribution from shale gas and coal bed methane and the decline in conventional gas production.

Figure A2.47. US Natural Gas Production by Type



Source: EIAl Table 14

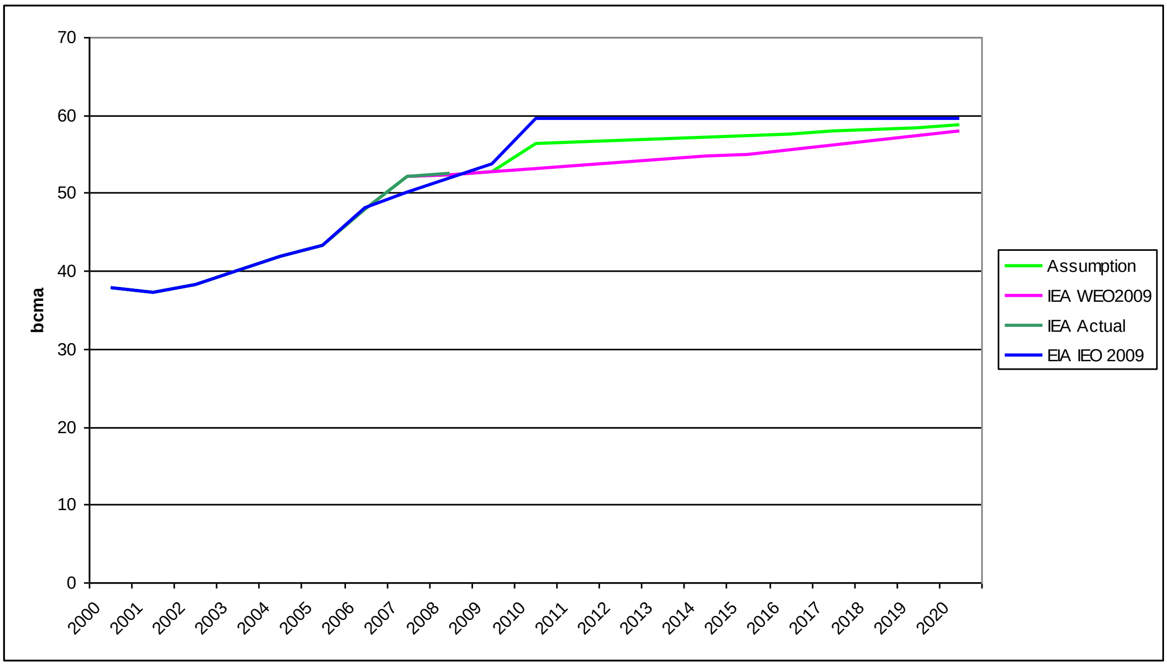
Figure A2.48. Canadian Natural Gas Production



Sources: IEA Monthly Data Series, IEA WEO 2009, CGA 2009 P 2, Figure 1, EIAj

Canadian production is shown in Figure A2.48. All sources envisage the decline in Canadian production, which began in 2007, continuing until around 2015. An average of future views was taken for this analysis. This is shown as the light green line.

Figure A2.49. Mexican Natural Gas Production



Sources: EIAj, IEA Monthly Data Series, IEA WEO 2009

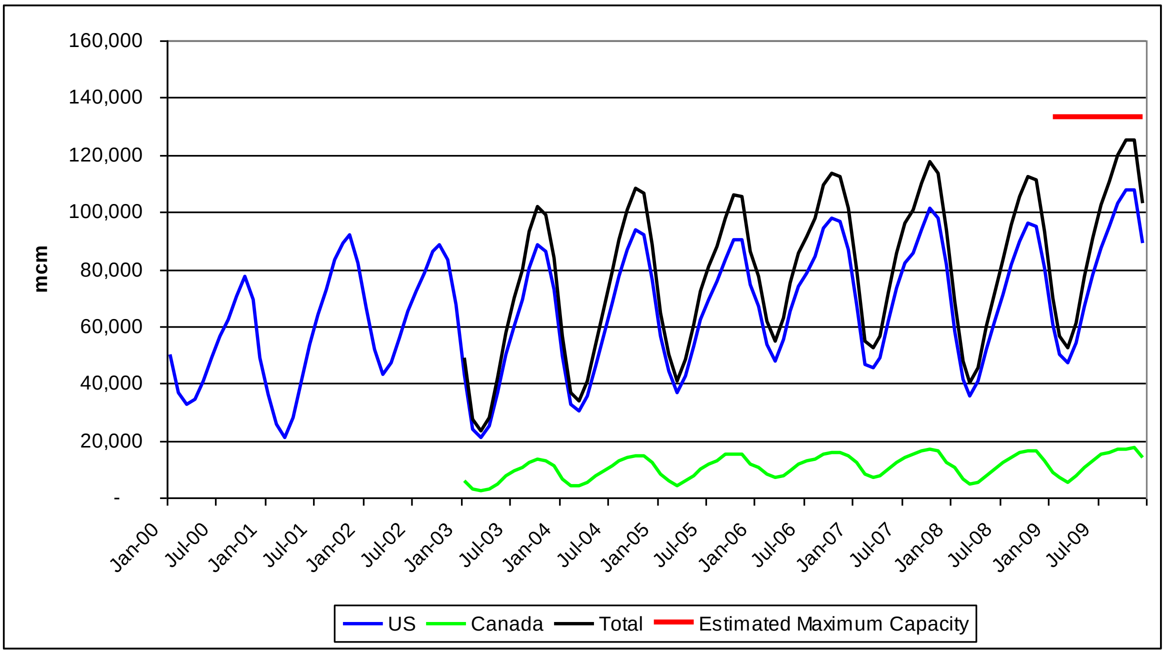
Figure A2.49 shows scenarios for Mexican gas production from the EIA and IEA. An average of the two was taken for this analysis (shown as light green).

The annual production forecasts derived in this section for the US and Canada should be considered merely as a 'starting point'. These will be revised as a consequence of the model framework later in this Chapter, in response to price dynamics induced by LNG arbitrage.

Storage capacity
As we noted in Chapter 1, storage inventory is a key indicator of impending shortage or surplus of natural gas supply in the North American market. In Chapter 2 the framework description clearly identifies US and Canadian storage as the de-facto short term balancing mechanism for global LNG shortage or surplus. Figure A2.50 shows the pattern of end-month storage inventory for the US and Canada in the period 2000 to the present (Canadian data available from January 2003).

A recent assessment of US working gas storage capacity[41] undertaken under the auspices of the EIA placed this in the range 110 to 122 bcm (3,889 to 4,313 bcf). It was noted that these figures had risen by 2.6% and 4.3% respectively since a similar assessment had been undertaken in 2008. No comparable assessment for Canadian storage was found however adding the maximum observed storage value (17.4 bcm for November 2009) gives a range for US and Canada combined of 127.5 bcm to 139.5 bcm. The mid point of this range (133.5 bcm) is shown on Figure A2.50 as an indicative maximum capacity.

Figure A2.50. US and Canada End Month Storage Working Gas Capacity



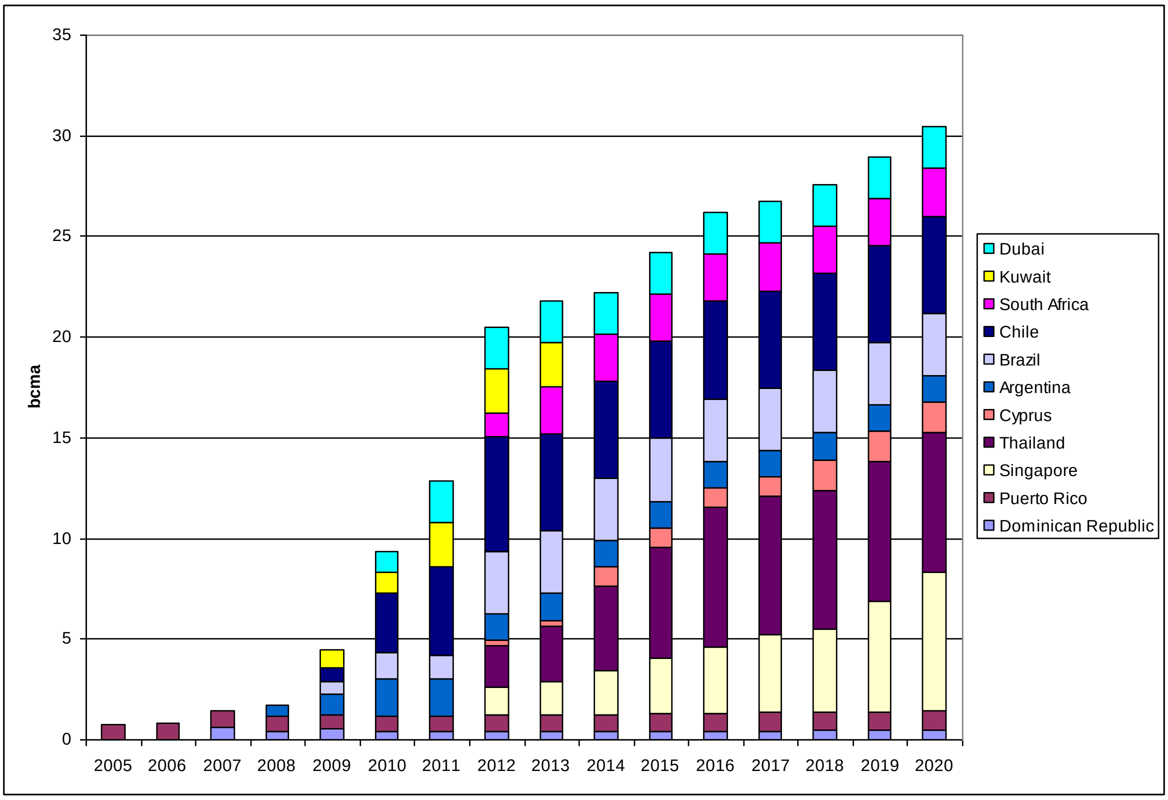
Sources: EIAe, CGA, La Rose 2009

Re-Gas Capacity
The US, Canada and Mexico have since year 2000 built significant LNG regas capacity which at end 2009 is estimated to total some 150 bcma. Regas capacity is highly unlikely to present a bottleneck to LNG imports in the decade to come.

[41] La Rose 2009

LNG Niche Markets
In addition to the established LNG markets described previously, there are several 'niche' or new LNG markets which whilst unlikely to directly influence LNG arbitrage dynamics do need to be accounted for, in terms of their consumption of part of the global LNG supply 'pool'. The Dominican Republic and Puerto Rica have been small but consistent LNG consumers since the early 2000s. In South America Argentina, Brazil and Chile have commenced imports. In the Middle East Kuwait has commenced imports and is likely to be followed by Dubai from 2010 onwards. In addition schemes are likely for South Africa, Cyprus, Thailand and Singapore. An annual estimate of demand from these markets is shown in Figure A2.51.

Figure A2.51. New LNG Market Annual Demand

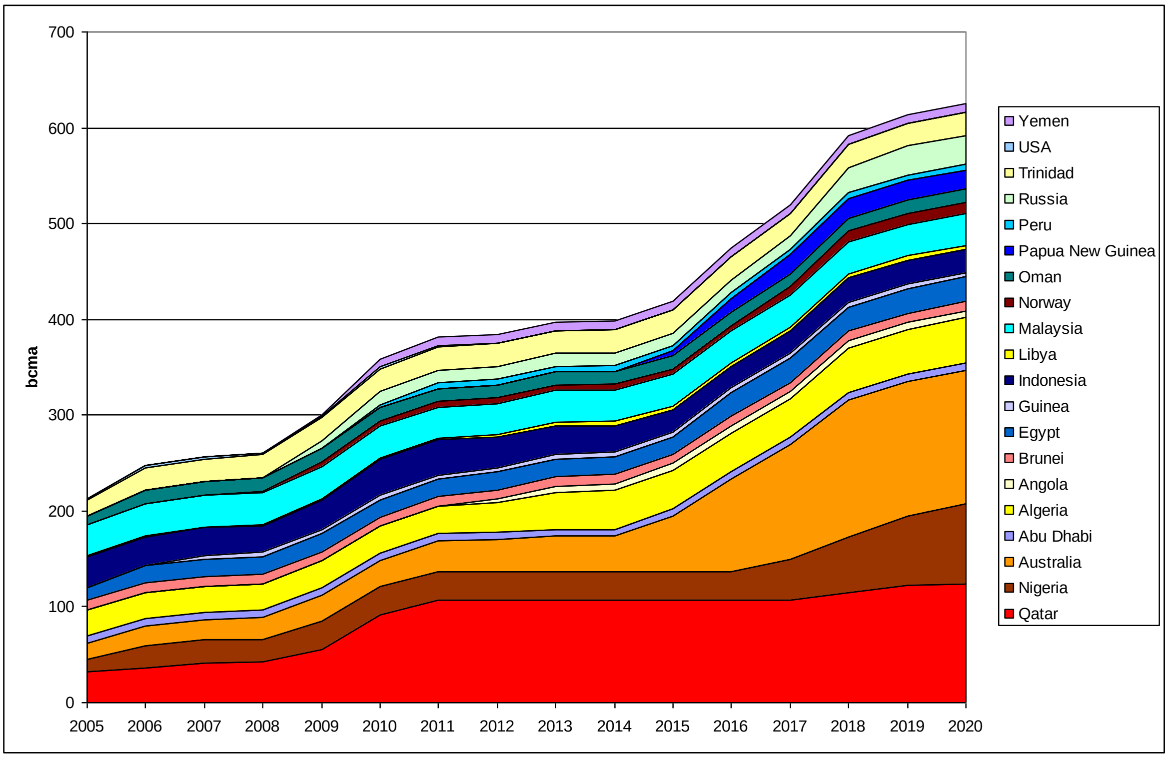


Sources: Waterborne LNG, Company Reports, Author's Analysis

Demand for LNG for these markets is difficult to predict as in most cases it is acting as a supplementary supply to indigenous production and/or pipeline imports. An additional complexity lies in the fact that many of these markets are likely to be seasonal LNG importers.

Global LNG Supply
The past and future LNG liquefaction picture has been assembled from a variety of natural gas media sources and is shown in Figure A2.52.

Figure A2.52. Global Liquefaction Capacity

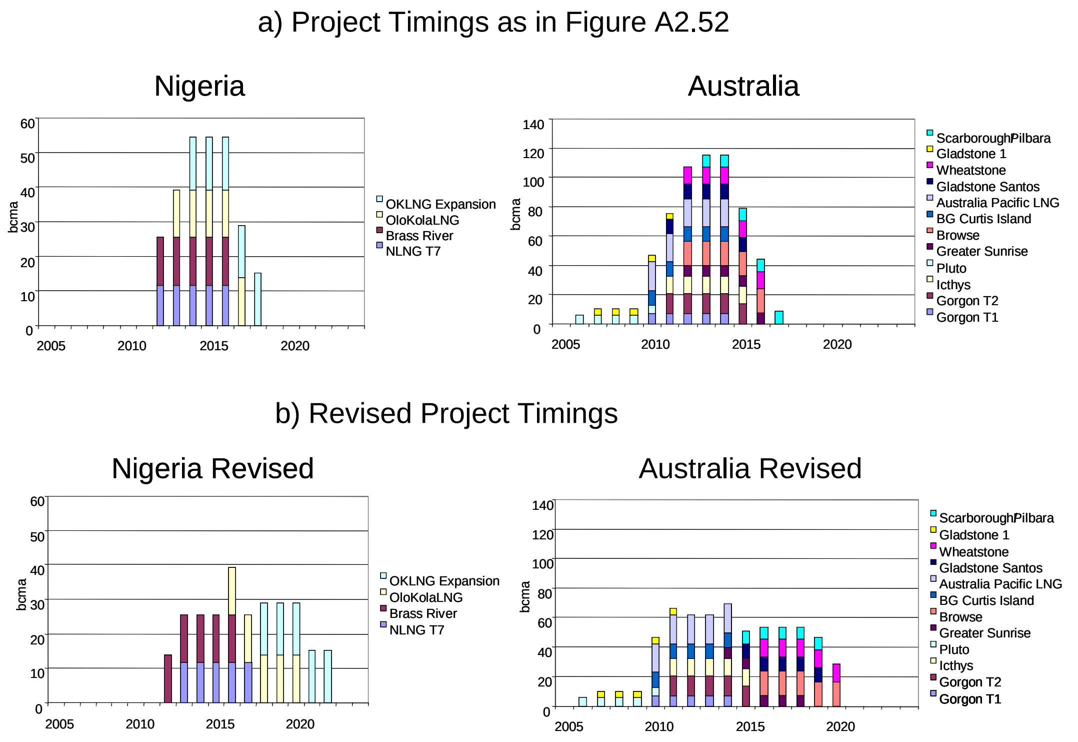


Source: Argus, Company Reports, Author's Analysis

Two points are of note relating to Figure A2.52. Indonesian capacity in existing trains (Arun and Bontang) has been tapered down during the period to reflect declining effective capacity due to reduced feed gas availability. (Note this does not apply to Tangguh). Secondly, the timings for projects which have not yet received Final Investment Decision approval have been delayed by two years. This exacerbates the hiatus in supply growth in the 2012 to 2015 period. Prior to 2015 the major growth in new capacity is from Qatar; beyond 2015 the major growth potential is from Australia and Nigeria. Also shown is the potential for Qatar to de-bottleneck its liquefaction trains which increases supply in 2019. Clearly there are major uncertainties on the timing of projects beyond 2015 and more critically whether Nigeria and Australia will be able to develop so many new projects simultaneously.

To illustrate this point, Figure A2.53 a) shows a plot of the liquefaction plant capacity over the likely construction period for new projects in Nigeria and Australia on the timings used for Figure A2.52. The objective here is to identify the scale of co-incident construction activity on several projects, using the project liquefaction capacity as a proxy for project scope. The projects were re-phased (b) to derive a more credible project intensity profile.

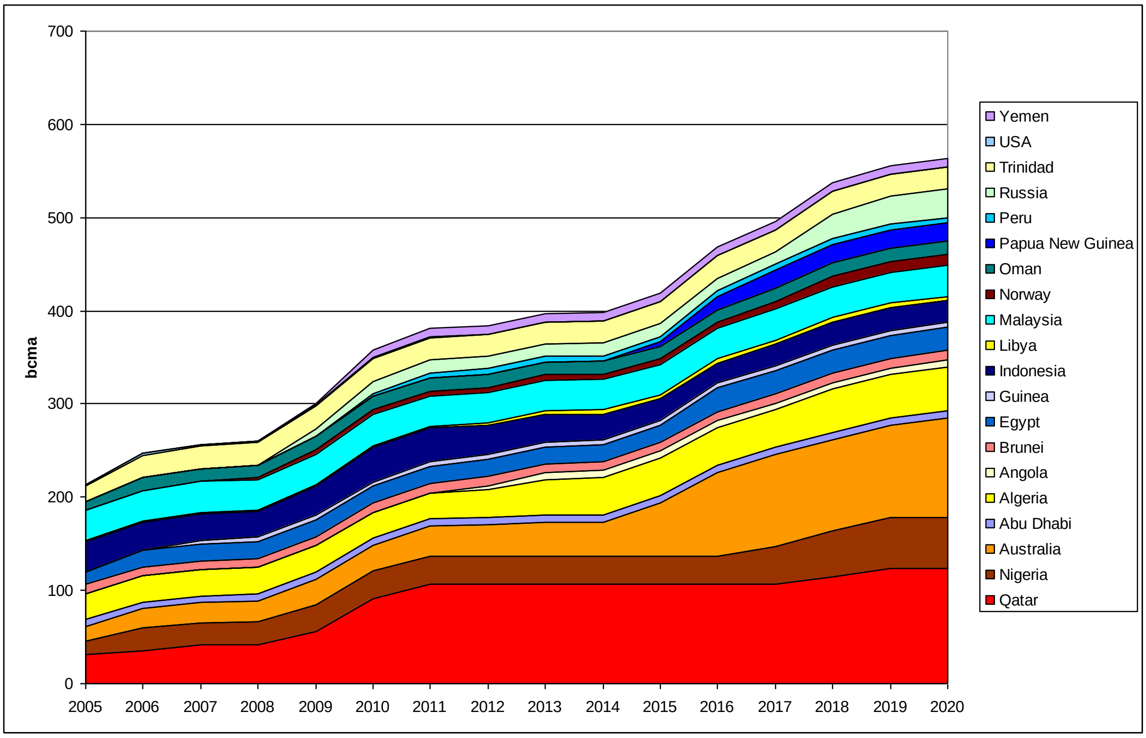
Figure A2.53. Nigerian and Australian LNG Project Intensity and Re-phasing.



Source: Argus, Company Reports, Author's Analysis

The revised project timings were used to construct the annual liquefaction capacity shown in Figure A2.54 and used as the basis of evaluating supply.

Figure A2.54. Global Liquefaction Capacity with Re-Phasing



Source: Argus, Company Reports, Author's Analysis

The challenge is now to translate a view of annual liquefaction capacity into a forecast of monthly LNG supply. The three elements in this process are described in outline below:

Monthly throughput variances
Although the general financial imperative is for liquefaction plants to operate at maximum throughput all year round, two factors prevent this from actually occurring in reality:

- Higher ambient temperatures reduce the output of the liquefaction plant making actual output seasonal in shape.
- Maintenance shutdowns periodically take plant out of service.

Looking at historic actual data at a supply country level enables an 'average monthly profile' to be derived – as a ratio of nameplate liquefaction plant capacity.

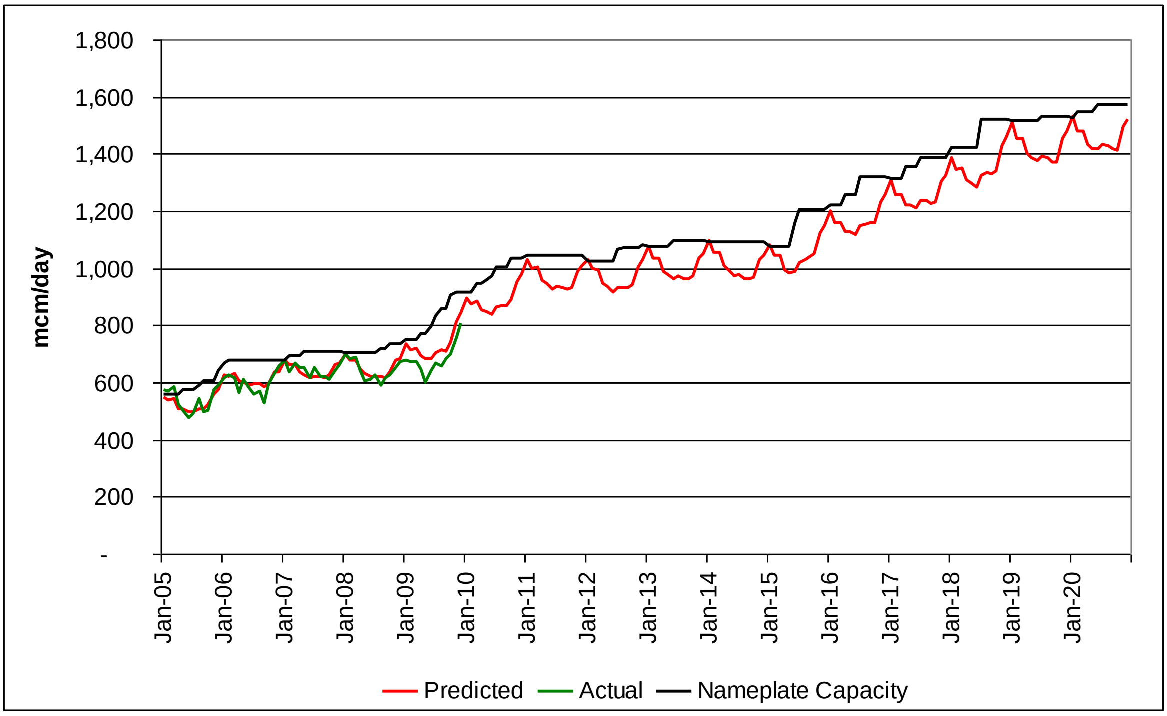
Commissioning Curves
When a new liquefaction plant is brought into service it may take several months before it reaches design capacity. While specific data is not generally available in the public domain, the assumption used in this analysis is that the plant begins operation at 25% of capacity, reaches 90% after 6 months and 100% after 12 months.

Ad-hoc Underperformance/Overview
Prior to 2006 liquefaction plant reliability was regarded as high. With the trend to larger trains since this time, we have seen several examples where plants have suffered downtime either due to technical problems or gas availability problems. These need to be factored in as specific assumptions.

Combining these steps allows us to assemble a forecast for global LNG supply at a monthly level of detail. This is shown in Figure A2.55 together with the nameplate capacity and a comparison of forecast and actual output for the historic period.

Note that there is a good match between forecast and historical values up until January 2009. Nigeria and Algeria suffered liquefaction and/or feed gas problems and declared contractual Force Majeure during 2009 which in large part explains the difference between forecast and historical values. The last three months of 2009 however show encouraging agreement between forecast and actual. A key feature of this chart is the significant ramp-up in LNG volumes from October 2009 when the commissioning of new LNG trains reinforces the normal seasonal increase in LNG output.

Figure A2.55. Monthly Global LNG Supply



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http://tonto.eia.doe.gov/dnav/ng/hist/n5020us2m.htm

EIAf: EIAdata on power generation fuels
http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html

EIAg: Table of Net Generation by Energy Source:
http://www.eia.doe.gov/cneaf/electricity/epm/table1_1.html,

EIAh: Fuel prices from download at:
http://tonto.eia.doe.gov/dnav/pet/hist/a313600002m.htm

EIAi: Storage working gas inventory data at:
http://tonto.eia.doe.gov/dnav/ng/ng_stor_sum_dcu_nus_m.htm

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Glossary

AGIP: Average German Import Price of natural gas at the German border.

Annual Contract Quantity (ACQ): The quantity that, under a gas contract, a buyer has the right to nominate and the seller the obligation to deliver.

Asia: In this paper Asia includes Pacific gas producers and consumers.

Associated Gas: Gas which is from a field which also produces oil.

BBL : shorthand for the Balgzand (Holland) to Bacton (UK) pipeline.

Bcf/d, bcf/d, bcfd: billion cubic feet per day. (equivalent to 10.34 bcma).

Bcma, bcma: billion cubic metres per annum.

Coal Bed Methane: methane which is held within the structure of the coal matrix by adsorption. This may be produced in commercial quantities when the coal is de-pressurised and de-watered in situ through drilling and the application of suitable well technology.

Combined Cycle Gas Turbine (CCGT): a gas-fired power generation plant which has a high pressure gas turbine cycle and a steam cycle.

Dry Gas: Natural gas which has had some of its naturally occurring components of ethane, propane, butane and heavier hydrocarbon components removed through processing in order to achieve sales specification.

Europe: As defined for the purpose of modelling in this paper Europe includes: Austria, , Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, UK

FID: Final Investment Decision: usually in the context of an LNG project, this is the joint decision on the part of the investment companies and any state entities to proceed with the full development of a project through to commercial operation.

Force Majeure : is a common clause in contracts which essentially frees both parties from liability or obligation when an extraordinary event or circumstance beyond the control of the parties, such as a war, strike, riot, crime, or an event described by the legal term "act of God" (e.g., flooding, earthquake, volcanic eruption), prevents one or both parties from fulfilling their obligations under the contract. However, force majeure is not intended to excuse negligence or other malfeasance of a party, as where non-performance is caused by the usual and natural consequences of external forces, or where the intervening circumstances are specifically contemplated.

Gas oil: refined petroleum fraction corresponding to diesel.

GW: Gigawatt, i.e. 1 billion watts

Hub : the location, physical or virtual, where a traded market for gas is established.

Henry Hub: Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). It is a point on the natural gas pipeline system in Erath, Louisiana where it interconnects with nine interstate and four intrastate pipelines. Spot and future prices set at Henry Hub are denominated in $/mmbtu (millions of British thermal units) and are generally seen to be the primary price set for the North American natural gas market.

IEA Europe : In terms of data on natural gas IEA Europe includes: Austria, , Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, UK. The IEA is the International Energy Agency.

Independents: a term used to describe oil and gas companies which do not have the size and scale of operations of the 'majors'. Historically they have tended to focus activities at a national or continental level, but this is no longer necessarily the case.

Interstate Pipeline: a trunk pipeline carrying natural gas across US state boundaries.

IUK: the shorthand name for the Bacton (UK) to Zeebrugge (Belgium) bi-directional gas pipeline, which is owned by Interconnector (UK) Ltd.

Linear Programming : Linear programming (LP) is a mathematical method for determining a way to achieve the best outcome (such as maximum profit or lowest cost) in a mathematical model for a list of requirements represented as linear equations

Liquefaction Plant: A large scale processing plant in which natural gas is cryogenically cooled to minus 161° centigrade where it becomes a liquid at atmospheric pressure.

LNG: Liquefied Natural Gas

Local Distribution Company: a generic term for an organisation which purchases wholesale natural gas at the 'city gate' and sells it on a retail basis to end-users.

LSFO: Low Sulphur Fuel Oil

Mcm/day, mcm/day, mcm/d, mcmd: Million cubic metres per day**.**

MCM, mcm, mmcm; million cubic metres

Mmbtu: Million British thermal units

Mtce, mtce: million tonnes coal equivalent

Mtoe, mtoe: million tonnes oil equivalent (equivalent to 1.21 bcma of natural gas)

National Incumbent: a term to describe, usually in a European context, a natural gas midstream company which currently or formerly enjoyed a monopoly position in the supply chain either as an arm of the state or through the existence of a regulatory system in which competition levels are/were low.

NBP: the UK's National Balancing Point: a virtual point (hub) in the National Transmission System where gas trades are deemed to occur. It is also used as shorthand for the UK spot gas price.

Normal year: A year in which ambient temperatures correspond to long range historical averages.

North America: The USA, Canada and Mexico

Oil and Gas Majors: A term generally used to describe the group of the largest publicly owned international oil and gas companies.

Oil Indexed Gas Prices: gas prices which are subject to contractual negotiation which are determined by a formula (or formulae), containing rolling averages of crude oil or defined oil products prices.

Productive Capacity: of gas wells, this relates to the maximum sustainable production available from wells which are in existence. Production may be lower than this value if some wells are being partially choked in.

Regas Terminal: (Regasification terminal) a terminal which receives LNG via an unloading jetty and temporarily stores it in an insulated storage tank in liquid form. When gas is required the LNG is gasified by providing a heat input prior to entering the distribution grid.

Residual Fuel Oil: (Resid.) Heavy oils that are "leftovers" from various refining processes. Most often used in marine boilers and in heating plants.

Rig Count: the number of rotary rigs which are actively drilling on a given date. These are essentially working on exploration or development wells and represent the activity level of new production capacity development.

Self Contracted: this refers to the situation where a participant commits to purchase (usually) an annual quantity of LNG over a term of several years, backing it with a parent company guarantee rather than a sales agreement with a specific customer. This allows the participant to sell the gas flexibly in a range of geographical markets.

Shale Gas: natural gas formed in fine-grained shale rock (called gas shales) with low permeability in which gas has been adsorbed by clay particles or is held within minute pores and microfractures.

Short Run Marginal Cost of Supply: the short run variable cost of gas production from well-head to market. This would exclude any prior capital expenditure and any costs which had been committed to under long term lease or contractual obligation.

Spot price: the price of gas determined through trading – i.e. determined by supply and demand and/or gas on gas competition. Usually refers to as 'prompt' rather than futures prices.

Storage Inventory: the quantity of working gas volume in storage. Working gas is distinct from 'cushion gas' which is only withdrawn from storage when a storage site is decommissioned.

Swing Field: a term used to describe a UK gas field where by virtue of a field-specific gas sales contract signed with a buyer, the field is required to deliver significantly higher daily volumes in winter than in summer.

Take or Pay (TOP): sometimes called the 'minimum bill', this is the quantity of gas which, during a gas contract year, a customer is obliged to pay for regardless of whether it physically takes it for resale or not.

Tight Gas: natural gas found in sandstone or carbonate reservoirs (called tight gas sands) with low permeability which prevents the gas from flowing naturally.

Wet Gas: gas which has not had its naturally occurring components of ethane, propane, butane and heavier hydrocarbon components removed through processing.

Working Gas: see Storage Inventory.