International Gas Union

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Wholesale Gas Price Formation 2012

- A global review of drivers and regional trends

IGU
INTERNATIONAL GAS UNION
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Wholesale Gas Price Formation

PGCB STUDY GROUP 2

Gas: Sustaining Future Global Growth

International Gas Union

Foreword

Following the successful 25th World Gas Conference in Kuala Lumpur in June 2012, we have decided to print some of the study reports presented at the conference as special IGU publications, including this report on "Wholesale Gas Price Formation" written by Study Group 2 of the IGU Strategy Committee (PGCB).

The updated results of the IGU Strategy Committee's global review of wholesale gas price levels and price formation mechanisms were first made available in June 2012 for participants at the World Gas Conference. The full report is now also available on www.igu.org.

Historically, gas prices have not been in the news to the same extent as oil prices. This is changing as the share of gas in global energy consumption continues to increase, volumes of internationally traded gas are greater than ever before and different price formation mechanisms have had serious commercial implications both for producing and consuming nations. The rapid growth in shale gas production in North America and fundamental shifts in LNG supply patterns across the global gas market relate to strong intercontinental linkages between supply, demand and price. At the same time this report sets out the large variations in wholesale gas prices across the world that result from the different prevailing price formation mechanisms.

Natural gas is an abundant resource, it is clean and cost-competitive, and should therefore play an important role in the mitigation of climate change in every region of the world. However, the way wholesale gas prices will be determined in the future will have a significant influence on sustainable market growth.

Promoting international understanding of natural gas pricing and wholesale gas price formation trends is important for the future success of the global gas industry by enabling participants in new and established gas regions to learn more about the different approaches that are being used. It is my hope that this publication can serve as an example of how we can all benefit when vital information is carefully gathered, analysed and shared.

August 2012

Torstein Indrebø
Secretary General of IGU

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A. Preface

This part of the report was prepared by Study Group B2 under the chairmanship of Mike Fulwood, Nexant Limited. We are grateful for the significant contributions by all the participants of Study Group 2 but especially sections of the report prepared by Floris Merison (Gasterra), Porter Bennett (Bentek Energy), Najla Jamoussi (Cheniere), Anna Golebiowska (PGNIG) and Sara Carciente de Blas (Total). Additional information was provided by R K Jain and Vivek Neelam (GAIL), Olga Tschekina (Gazprom), Graeme Bethune (Energy Quest) and Roland Lajtai (HUPX). While all group members were active, we would particularly like to thank Sergey Komlev (Gazprom), Nick Blessley (Qatar Petroleum) and Valerie-Ann Duval (GDFSuez) for their insightful comments on the drafts of the report. Finally, thank you to all members of the IGU who responded to the now regular survey of wholesale gas prices, which forms a key part of the report.

Mike Fulwood
Nexant UK Limited

B. Introduction

The 25th World Gas Conference (WGC) in Kuala Lumpur will be the second conference at which PGCB has presented a report on Gas Pricing. PGCB first established a sub-group on gas pricing for the 2006 to 2009 triennium culminating in the 24th WGC in Buenos Aires. The remit of the sub-group for Buenos Aires was to carry out a comprehensive analysis of gas price formation models at regional level and to investigate future trends and the factors which could help to minimize price anomalies and contribute to sustainable market growth.

The report to the 24th WGC reviewed the original bases for the pricing of gas, from the costs of exploration and production, competition with oil and, in many countries, price controls through to the development of gas-on-gas competition in liberalising markets. The sub-group also undertook the first two surveys of gas pricing mechanisms, covering the years 2005 and 2007. These surveys found that around one-third of all gas is priced through "gas-on-gas competition", with the second biggest mechanism being "regulation below cost" at just over one-quarter. The share of gas under "oil price escalation" was around one-fifth of the total. In respect of trends the surveys found that the share of "gas-on-gas competition" was growing, primarily at the expense of "oil price escalation", while "regulation below cost" had also increased although largely due to faster growth in gas consumption. The report noted that the development of "gas-on-gas competition" and its extension from North America and the UK into continental Europe is a trend that is likely to be enhanced by the development of a global LNG market. The review of pricing mechanisms also highlighted another significant and developing aspect – that of volatility of prices. It found that the impact of local short-term supply and demand imbalances, and volatility in the oil prices, has translated into significant short-term volatility in gas prices. While this may not be helpful for long term planning, it was concluded that it is a feature of the markets and was here to stay. The challenge for the industry was to develop mechanisms to mitigate unwanted risks associated with this volatility.

The remit of this report for the 2009 to 2012 triennium was to build on the work of the 2009 WGC and specifically to cover the following;

- Take forward the IGU global survey of national wholesale prices and gas price formation methods. Include two more years of data, share lessons learned and identify future trends;
- Study the level and implications of gas market globalisation in terms of the effect on wholesale gas price formation and the potential for price convergence across established and new gas hubs;
- Study of the price drivers will develop from the last triennium to include, on the one hand, the political requirements for the "affordability" of gas, and on the other, more advanced trading concepts of price elasticity and volatility;
- Examine the impact of carbon tax or cap and trade policies on gas price formation; and
- Investigate regional pricing models, both for indigenous and international supplies, and examine "whether or not gas can be subject to the same rules as other commodities".

There was much discussion of the details of this remit within the Study Group. It was concluded that not all the areas and issues could be covered in sufficient depth with the resources and time available. This was particularly the case in respect of the "affordability" of gas and a detailed analysis of price elasticity. In respect of price drivers the focus would be on an analysis of competing fuels to gas in different markets, hub trading and pricing patterns and price volatility.

The report of the Study Group is structured as follows:

- Section C covers the Wholesale Gas Price Formation Survey for 2009 and 2010, together with further analysis of changes over time.
- Section D is entitled Globalisation or Regionalisation of Gas Prices and covers gas price convergence, and whether convergence differs when supply is tight or plentiful compared to demand, whether gas is different from other commodities, the future of oil price indexation and whether parallel pricing mechanisms can continue to co-exist globally or even regionally.
- Section E covers Price Drivers including an analysis of competing fuels to gas, hub trading and pricing patterns in North America, price volatility and long run marginal cost as a price driver.
- Section F covers the Impact of Carbon Tax or Cap and Trade Policies on gas price formation.
- Section G Is the Conclusions.

C. Wholesale Gas Price Formation Survey

1. Introduction

The idea for a survey of wholesale gas price formation mechanisms arose at the beginning of the triennium leading to the 2009 World Gas Conference. The Strategy, Economics and Regulation Programme Committee (PGCB) had set up a new sub-group to consider gas pricing, with a key remit to carry out a comprehensive analysis of gas price formation models. The sub-group decided to carry out a survey of current pricing mechanisms around the world, not only for gas traded internationally, but also for gas produced and consumed within countries. IGU members were surveyed and provided data for almost 100 countries, and the survey responses were collated and analysed by Nexant. The 2009 World Gas Conference presented the results of the surveys for the years 2005 and 2007. Two further surveys for the years 2009 and 2010 have been undertaken in this triennium.

The focus of the gas pricing sub-group, and the surveys, was very much on wholesale prices, which can cover a wide range. In fully liberalised traded markets, such as the USA and the UK, the wholesale price would typically be a hub price (e.g. Henry Hub or the NBP). In many other countries, where gas is imported, it could typically be a border price. The more difficult cases are countries where all gas consumed is supplied from indigenous production, with no international trade (either imports or exports) and the concept of a wholesale price is not recognised. In such cases the wholesale price could be approximated by wellhead prices or city-gate prices. Generally the wholesale price is likely to be determined somewhere between the entry to the main high pressure transmission system and the exit points to local distribution companies or very large end users.

The initial data collection was done on a country basis. The data were then collated to a regional level using the standard IGU regions shown in the figure below. Most of the regions are defined along the usual geographic lines, although the IGU includes Mexico in North America, and divides Asia into a region including the Indian sub-continent plus China, called Asia, and another region including the rest of Asia plus Australasia which is called Asia Pacific.

Figure 1. ***IGU Regions***

Data for each country were collected in a standard format. As an example, a data collection form for the UK is shown in the figure below. Individual country gas demand may be supplied from any one combination of three sources – indigenous production, pipeline imports and LNG imports (storage is ignored for the purpose of this analysis). For each of these three sources separately data was collected on what percentage of the wholesale price for that category is determined by each mechanism. In some countries, one single mechanism was found to cover all transactions and that mechanism, therefore, was allocated 100%. In many cases, however, several mechanisms were found to be operating, in which cases estimates were made of the percentages for each price mechanism. The only constraint is that the total for each source of gas must add up to 100%.

Information was also collected on wholesale price levels. This covered the annual average price and the highest monthly average price and lowest monthly average price. All prices were converted to $/MMBtu. A comments section was included to identify and acknowledge the source of the information and any other useful information.

All data in the IGU study on gas volumes for consumption, production, imports and exports is taken from the IEA database, supplemented where necessary by the US Energy Information Administration and any specific country and/or regional knowledge.

Figure 2. ***Data Collection Form***

Country	United Kingdom					
Region	Europe					
Volumes 2010: BCM	Consumption	Production	Imports		Exports	
			Pipeline	LNG	Pipeline	LNG
	98.0	59.7	34.4	18.7	13.4	0.0
Wholesale Price Formation	Domestic Production		Imports			
			Pipeline		LNG	
Oil Price Escalation	18.0%					
Gas-on-Gas Competition	82.0%		100.0%		100.0%	
Bilateral Monopoly						
Netback from Final Product						
Regulation: Cost of Service						
Regulation: Social and Political						
Regulation: Below Cost						
No Price						
Not Known						
Total	100.0%		100.0%		100.0%	
Estimated 2010 Wholesale Price Range ($/MMBTU)	Average		High		Low	
	$5.99		$7.51		$4.50	
Comments	The EU Energy Sector Inquiry found that in the UK around 40% of long term contracts use a market based gas price index as the escalator. The remaining 60% predominantly use oil price indexation with some inflation element. However, less than 30% of domestic UK production is now thought to be under long term contract with the other 70% being traded on the spot market and therefore automatically priced on the NBP index (source for this information was an OIES study on the UK gas market updated for recent data from IEA and Heren). It is thought that all pipeline and LNG imports are priced against the NBP. UK imports pipeline gas from Norway, Netherlands, Belgium and Germany and LNG from Trinidad, Qatar, Egypt and Algeria.					
Completed By	Mike Fulwood - Nexant					

2. Different Price Formation Mechanisms

In preparation for the initial survey in 2005, a series of discussions were held at the PGC B2 sub group meetings on the definition of different types of price formation. It was decided to use for categorisation purposes the wholesale pricing mechanisms described in Box 1.

Box 1. ***Types of Price Formation Mechanisms***

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

In looking at the different price formation mechanisms, the results have generally been analysed from the perspective of the consuming country. Within each country gas consumption can come from one of three sources, ignoring withdrawals from (and injections into) storage – domestic production, imported by pipeline and imported by LNG. In many instances, as will be shown below, domestic production, which is not exported, is priced differently from gas available for export and also from imported gas whether by pipeline or LNG. Information was collected for these 3 categories separately for each country and, in addition, pipeline and LNG imports were aggregated to give total imports and adding total imports to domestic production gives total consumption. For each country, therefore, price formation could be considered in 5 different categories:

- Indigenous production (consumed within the country, i.e. not exported)
- Pipeline imports
- LNG imports
- Total imports (pipeline plus LNG)
- Total consumption (indigenous production plus total imports).

Each country was then considered to be part of one of the IGU regions, as described in the Introduction, and the 5 categories reviewed for each region. Finally the IGU regions were aggregated to give the results for the World as a whole.

In terms of the presentation of results, the World results will be considered first, followed by the Regional results for the separate regions – North America, Latin America, Europe, Former Soviet Union, Middle East, Africa, Asia and Asia Pacific.

As well as collecting information on price formation mechanisms by country, information was also collected on wholesale price levels in each country. These results on a country and regional basis are also presented together with an analysis of price trends.

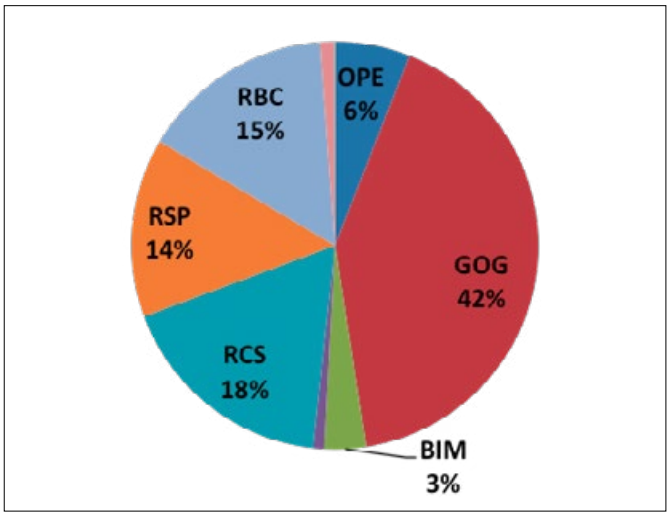
3. Results of the 2010 Survey

The results of the 2010 survey will firstly be considered at the World level for the year 2010, before moving on to discuss changes in price formation mechanisms over time from the surveys for 2005, 2007 and 2009.

World Results

Indigenous Production

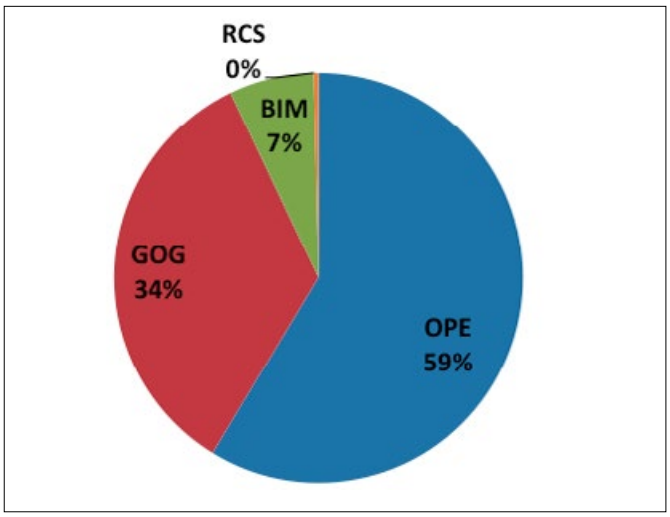
*Figure 3. **World Price Formation 2010 – Indigenous Production***



Indigenous production, consumed in own country, accounted for around 2,300 bcm in 2010, slightly less than 70% of total world consumption. The largest single price formation category were GOG – accounting for some 42% - mainly in North America, UK in Europe and Russia in the FSU. Regulated prices accounted for some 47% in total, spread broadly equally across all three sub-categories – RBC, RSP and RCS – largely the Former Soviet Union, Asia, Asia Pacific and the Middle East. There is a small amount of OPE in Europe, Asia Pacific and Asia.

Pipeline Imports

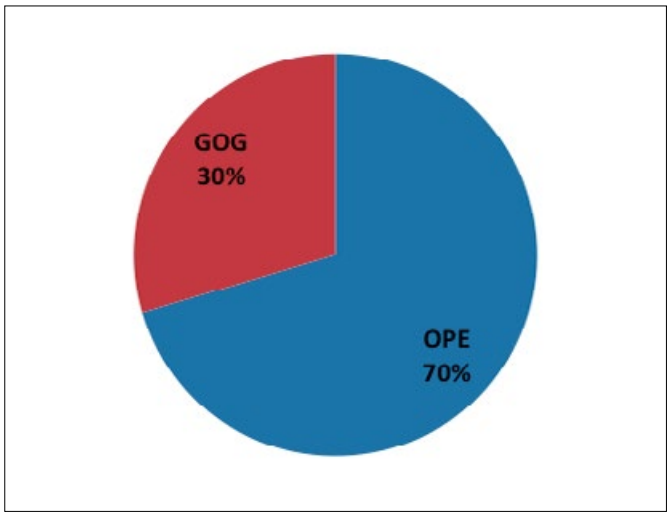
*Figure 4 . **World Price Formation 2010 – Pipeline Imports***



Pipeline imports at 710 bcm account for some 22% of total world consumption. Three categories account for internationally traded pipeline gas – OPE mostly in Europe, but with some in the FSU; GOG in North America with small amount in Europe into the UK and BIM almost all intra-Former Soviet Union trade.

LNG Imports

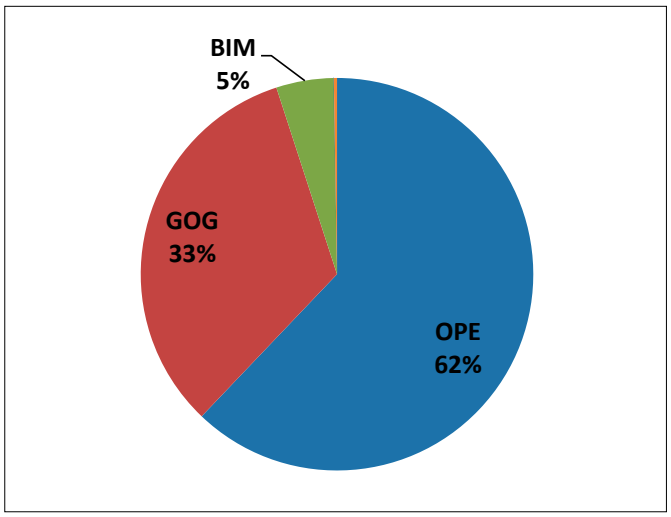
*Figure 5. **World Price Formation 2010 – LNG Imports***



LNG imports at almost 300 bcm account for some 9% of total world gas consumption. Internationally traded LNG is largely dominated by OPE into Europe, Asia and Asia Pacific. GOG is mainly North America with some spot LNG cargoes into Europe and Asia Pacific

Total Imports

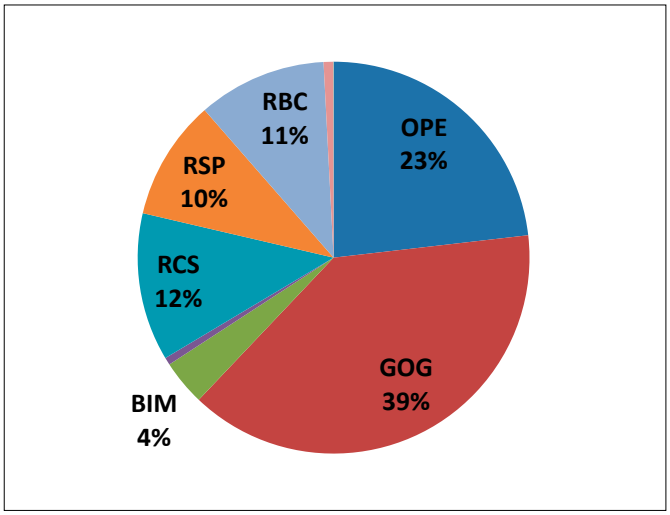
*Figure 6. **World Price Formation 2010 – Total Imports***



Total imports at just over 1,000 bcm account for some 30% of total world consumption. 59% is OPE with Europe (pipeline mainly) and Asia Pacific (LNG) dominating. GOG is both pipeline and LNG imports, in both North America and Europe, with some in Asia Pacific, while BIM is largely intra-Former Soviet Union pipeline trade.

Total Consumption. The 2010 results for total world consumption are summarised in Figure 7.

*Figure 7. **World Price Formation Mechanisms 2010***



The largest single price formation category in 2010 was gas-on-gas competition at 39%. This was across all categories – indigenous production (especially in North America), pipeline imports and LNG imports. Oil price escalation accounted for some 23%, but was largely in pipeline imports and LNG imports. The three regulated categories accounted in total for some 33%, split broadly equally between the three – cost of service, social and political and below cost. The regulated categories were almost exclusively from indigenous production.

In Table 1 below the regional breakdown by price formation category is highlighted.

*Table 1. **World Price Formation 2010: Regional Breakdown Summary***

2010	Total Consumption - BSCM									
	OPE	GOG	BIM	NET	RCS	RSP	RBC	NP	NK	TOT
North America	0.0	827.2	0.0	0.0	0.0	0.0	0.0	12.0	0.0	839.2
Latin America	24.7	24.3	6.9	16.1	9.0	59.3	0.0	0.0	0.0	140.3
Europe	349.4	217.2	2.4	1.0	12.4	5.8	0.5	4.7	0.9	594.2
Former Soviet Union	81.5	180.9	29.5	0.0	258.7	20.4	88.3	2.8	0.0	662.0
Middle East	23.4	2.9	30.0	2.3	0.0	139.0	171.0	2.7	0.0	371.2
Africa	7.4	0.0	4.2	0.8	0.8	1.9	86.7	0.7	0.0	102.6
Asia	90.3	3.7	3.2	0.0	112.0	26.9	3.3	0.0	0.0	239.4
Asia Pacific	187.1	25.8	47.3	0.0	9.5	73.6	0.0	3.2	0.0	346.5
Total World	**763.7**	**1 282.1**	**123.4**	**20.2**	**402.4**	**326.9**	**349.8**	**26.1**	**0.9**	**3 295.4**
	23.2%	*38.9%*	*3.7%*	*0.6%*	*12.2%*	*9.9%*	*10.6%*	*0.8%*	*0.0%*	*100.0%*

The gas-on-gas competition category is obviously dominated by North America, but in Europe with the UK market and the continental trading hubs it is also important. The contributions from Asia and Asia Pacific largely reflect spot LNG sales. The survey also records a significant amount of gas-on-gas competition in the FSU region, specifically Russia. This reflects the changes in the domestic Russian market which has seen the larger consumers, in a number of Russian regions, being allowed to trade directly with independent producers at negotiated prices, with the producers competing with each other. Previously much of this sector was price regulated, as the rest of Russian domestic consumption is, largely supplied by Gazprom. However, it should be emphasised that, clearly, this is not the same degree of competition, as experienced in the US or UK markets, because the prices are effectively capped at the Gazprom regulated price.

The oil price escalation category is dominated by imported gas under long term contracts, linked to oil product prices, into Europe, as well as the LNG contracts into Asia Pacific, linked to crude oil prices. In addition, there is now a significant element of oil price escalation in the FSU region, principally the exports from Russia to Ukraine and Moldova, plus purchases by Russia from Central Asia countries, linked to a basket of oil product prices similar to the contracts to Western Europe but at a discounted level. The level in Asia is a combination of LNG imports and indigenous production in China, Pakistan and India.

The Bilateral Monopoly category is important in some of the intra-FSU trade and indigenous production in Qatar, Australia and New Zealand. In Australia, outside the spot market in Victoria, the majority of gas is sold under 10 to 15 year contracts where the price of gas is fixed initially and then changes in line with inflation. The initial base price reflects the market fundamentals at the time of negotiation.

The three regulated categories – cost of service, social and political and below cost – are found predominantly in indigenous production in the FSU and Middle East, plus China, Malaysia and Indonesia.

It should be emphasised that choosing the categorization of price formation mechanisms in individual countries is not an exact science. In particular, the distinction between the gas-on-gas competition and bilateral monopoly categories in, for example, Australia may be becoming increasingly blurred. Since the first IGU survey for 2005, wholesale prices under the BIM category have risen to be much closer to, what might be called, "market" levels.

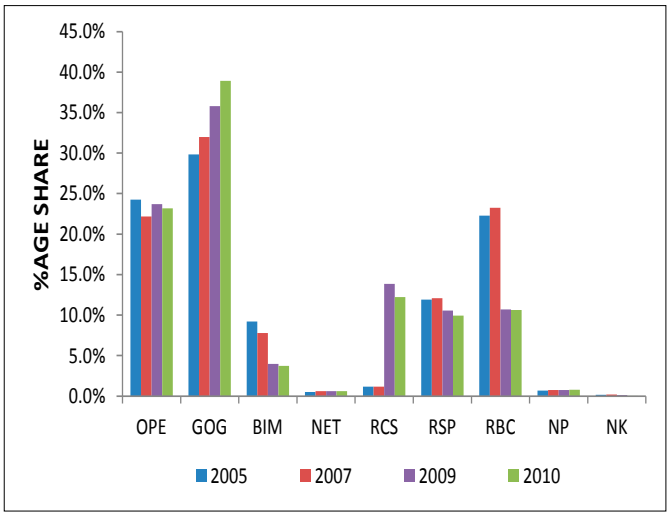
Changes in Price Formation Mechanisms

As the 2010 survey has followed the three other surveys in 2005, 2007 and 2009 surveys, it enables an analysis of changes in the relative importance of price formation mechanisms to be undertaken. Changes in the relative importance of the different price formation mechanisms can occur either because of differential growth in consumption between countries or because price formation mechanisms themselves change.

While world consumption grew by just over 15% between 2005 and 2009, this masked very different changes between regions. Consumption in Europe and the Former Soviet Union was largely flat, in contrast to a more than 60% increase in Asia – India and China – and a 45% plus increase in the Middle East. The decline in Europe would imply that the oil price escalation category would decline in importance while the rise in Asia and the Middle East would suggest the regulated categories increasing, although this would be partly offset by the lack of growth in Former Soviet Union consumption.

The figure below shows the respective percentage shares in the different price formation mechanisms for 2005, 2007, 2009 and 2010.

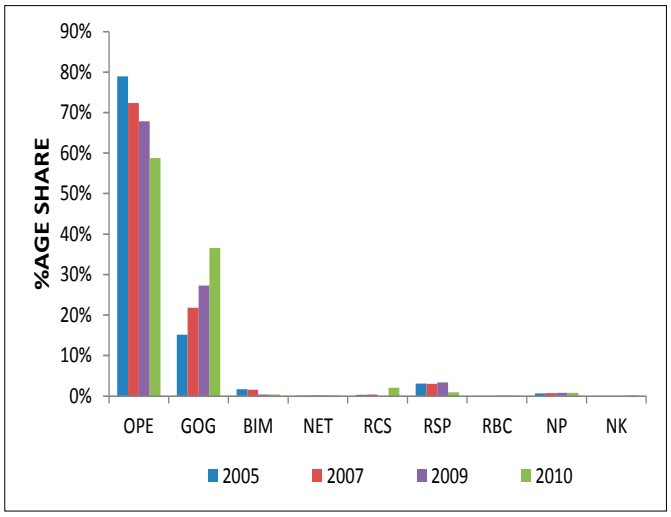
Figure 8. ***World Price Formation Mechanism Shares: 2005 to 2010***



The main increase has been in the gas-on-gas competition category rising from 30% in 2005 to 32% in 2007, to 36% in 2009 and 39% in 2010. If consumption patterns had not changed between regions from 2005 to 2010 the GOG category share would have been some 2% higher in 2010 at 41%. The key change from 2007 to 2009 and 2010 was in the Former Soviet Union following the changes in the domestic Russian market, which has added some 5.5% to the share since 2007. Excluding the change in the Russian domestic market, the increase in the GOG category would have been 1.5% since 2007. This is principally due to the change in Europe where the share of the GOG category has been rising steadily from 2005 through 2007 and 2009 as the importance of continental trading hubs

increased, at the expense of oil price escalation. In addition, in 2010 in Europe, the move to gas-on-gas competition has been enhanced by the introduction of elements of spot price indexation in long term contracts. The changes in Europe are illustrated in Figure 9 below. By 2010 the share of gas-on-gas competition in Europe had reached over 36% compared with 15% in 2005. The gas-on-gas competition share in Asia Pacific increased between 2005 and 2007 but declined from 2007 to 2009 as the impact of the recession resulted in declines in spot imports into Japan, South Korea and Taiwan, although this was partly reversed in 2010. The oil price escalation share declined between 2005 and 2007, but then the structural change in the intra-FSU market as pricing switched from bilateral monopoly, led to an increase in its share, followed by a further small decline in 2010. Apart from this structural change, the underlying decline over time has been wholly down to the changes in Europe, partly offset by a slight increase in the share in Asia between 2007 and 2010, as the new East Coast Indian production came on-stream and Chinese imports increased.

Figure 9. ***Europe Price Formation Mechanism Shares: 2005 to 2010***



The bilateral monopoly share has been in steady decline from over 9% in 2005 to around 4% in 2010. This reflects wholly the changes in FSU's price formation mechanisms. The overall share of the three regulated categories has declined marginally from 2005 through to 2010, to around 32%, although based on the more rapid growth in consumption in some of the areas where regulated pricing is predominant, the share should have stayed the same or even risen slightly if price formation mechanisms had not changed, away from regulation. The key change has been within the regulated categories with a switch in Russia from below cost to cost of service of a share of 7% of total world consumption. This change in categorization reflects the fact that Gazprom no longer makes losses, on an average cost basis, on regulated sales into the domestic market, although prices are still below the level at which it would be economic to replace the gas production – see Box 2 for a brief summary of gas pricing in Russia.

Box 2. ***Gas Pricing in Russia***

The Russian gas market currently functions in two modes: regulated and non-regulated. Gazprom is the major natural gas supplier in the regulated sector, whereas independent gas producing and oil companies dominate supply in the non-regulated sector.

On December 31, 2010, the Government of the Russian Federation adopted Regulation № 1205, which envisaged further improvement of the governmental regulation moving towards its step-by-step liberalization. The Regulation provided a transitional period from 2011 through 2014, during which the conditions will be created for practical application of market-based pricing mechanisms for natural gas produced by Gazprom Group based on equal yield of gas supplies to the domestic and foreign markets.

In order to bring the prices to the equal yield level during the transitional period, the Federal Tariff Service (FTS of Russia) was instructed to establish decreasing coefficients. These coefficients are an integral part of the pricing formula, taking into account specific features of pricing in the domestic market. The Russian Government set the variance limits for the period from 2013 through 2014, which are calculated based on the average level using a pricing formula. Such variances range from – 3 to 3 percentage points.

The said pricing principles will be applied for the gas supply to all consumers other than households (the share of households in Gazprom's sales is 19 %).
The concerned Ministries were instructed to develop coordinated position about transport tariffs regulation instead of gas prices regulation since 2015.

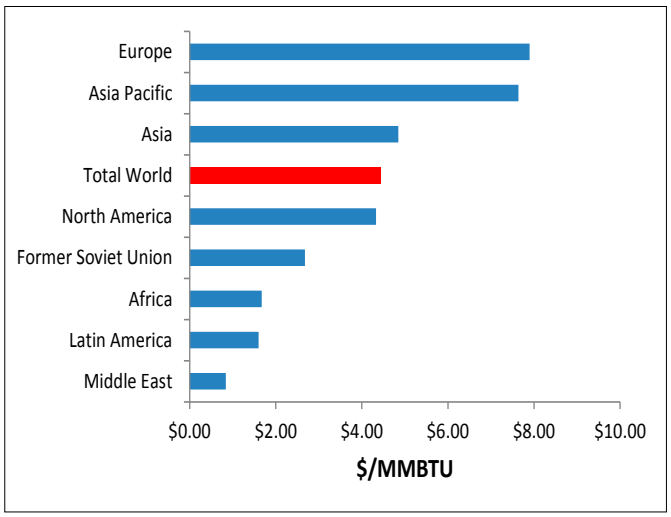
One of the objectives of the Russian natural gas market development is to improve and expand the use of e-commerce for selling physical natural gas and to start using stock-exchange technologies for trading derivatives (futures for natural gas).

In 2010, Gazprom carried out a number of measures to prepare and organize natural gas sales using stock-exchange technologies. Federal executive authorities are considering a draft regulation to be agreed upon, which envisages OAO Gazprom's right to sell natural gas on electronic trading floors and at commodity exchanges at prices that are not regulated by the government.

Wholesale Price Levels

As well as collecting data on price formation mechanisms the IGU study also collected information on wholesale price levels in 2010. The results here should be treated as broad orders of magnitude, since the definition of wholesale prices is quite wide. It is typically a hub price or a border price in the case of internationally traded gas, but could also easily be a wellhead or city-gate price.

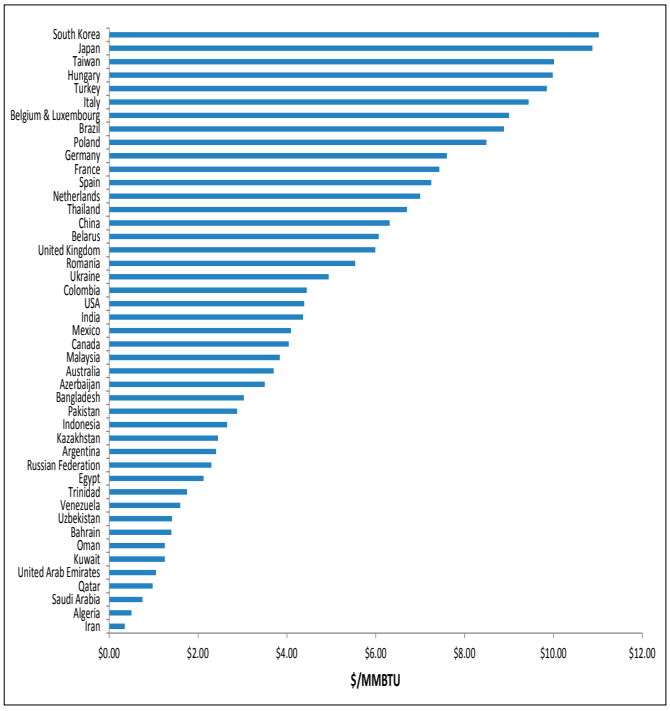
*Figure 10. **Average 2010 Wholesale Prices by Region***



The figure above shows a snapshot of price levels for 2010. From year to year, wholesale prices can obviously change significantly. Generally the highest wholesale prices are in regions where, it could be said that, there is more "economic" pricing – i.e. gas-on-gas competition and oil price escalation – in Europe, Asia Pacific and North America – although the decline in spot prices in the latter has brought prices down, to around the world average compared to previous surveys. With both China and India increasing wholesale prices recently, the average price in Asia in 2010 was actually above North American spot prices. The lowest wholesale prices are generally where regulation dominates in the Middle East, Africa and the Former Soviet Union.

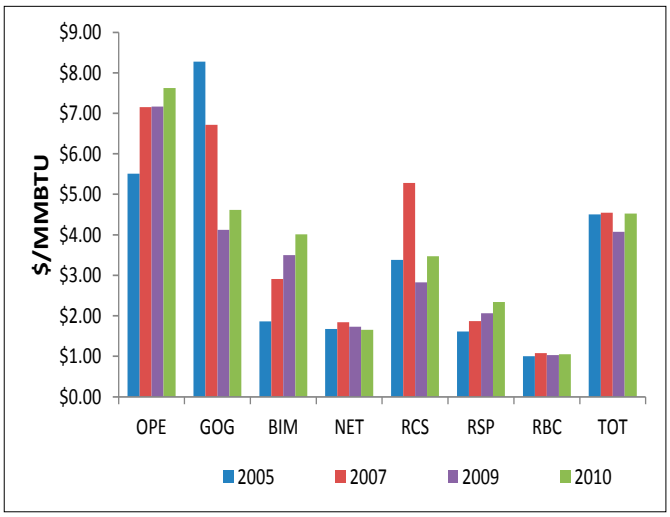
These conclusions are illustrated more clearly in the figure below which considers wholesale prices at the individual country level, at least for those countries with more than 10 bcm annual consumption. The highest wholesale prices in 2010 were found in the LNG dependent countries in Asia Pacific (South Korea, Japan and Taiwan). These were followed by a whole host of European countries headed including Germany, France, Spain and the Netherlands. Prices in the UK were lower than in the main gas importing countries in Europe, while the decline in spot prices in the US market, meant that prices there were actually lower than in China and a similar level to India. At the bottom of the chart were generally countries where wholesale prices were subject to some form of regulation – largely Middle East and North African countries.

*Figure 11. **Average 2010 Wholesale Prices by Country***



In respect of changes in the levels of wholesale prices, average prices around the world have changed little from 2005 through 2007 and 2009 to 2010. However, there have been significant changes to price levels in the different price formation categories.

*Figure 12. **Changes in Wholesale Price Levels: 2005 to 2010***



Average wholesale prices were just over $4.50 per MMBtu in 2010, up slightly from the $4.00 level in 2009 but similar to the levels in both 2007 and 2005. Over the period gas-on-gas competition prices have been on a generally declining trend from being the highest prices in 2005 at over $8.50 to just under $4.60 in 2010 – slightly higher than in 2009 but still around the world average. In contrast oil price escalation prices have risen consistently reflecting increasing oil prices over the period. Bilateral monopoly prices have also been consistently rising but this reflects the transition, especially in intra-FSU trade, towards more market related pricing.

D. Globalisation or Regionalisation of Gas Prices

1. Introduction

This section considers the implications of gas market globalisation on gas prices and assesses whether prices might be expected to converge over time across established and new gas hubs. If markets don't globalise but remain more regional, why might this happen and could parallel pricing mechanisms continue to co-exist.

The section begins by considering the issue of gas price convergence and divergence. Price convergence does not necessarily mean that prices are the same but that they reflect basis or transportation differentials. The convergence or divergence of prices may differ in periods of tight or surplus supply relative to demand. The growing LNG market may also impact price convergence as might the liquidity and transparency of gas trading in regional markets.

Whether gas is different from other commodities will also be assessed and if it is, why is it different. The argument is sometimes put forward that a key reason that there is no globally traded gas market, is that gas is fundamentally different from most other commodities, which are traded globally.

The arguments for and against oil price indexation in long term contracts are discussed and the future of oil price linkage evaluated. Finally, an assessment will be made as to whether parallel pricing mechanisms can co-exist in the global or even regional markets.

2. Gas Price Convergence
Recent History of Global Gas Price Movements

In considering gas price convergence, it is important to understand what is meant by it. It could be defined as a situation where all prices (for the same product in different geographies) are the same. However, this does not seem to be a particularly meaningful definition, although some commentators in the European market sometimes suggest that any deviation in prices between the trading hubs is a sign of market deficiency, rather than markets actually working. In respect of the discussion in this section, price convergence does not necessarily mean that gas prices should be the same everywhere but that they are impacted by the same factors and ultimately would reflect basis or transportation differentials.

*Figure 13. **World Gas Prices***

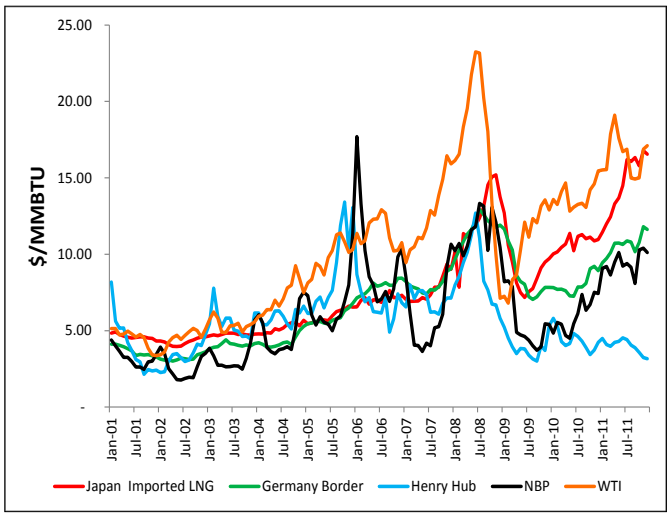


Figure 13 shows the evolution of key gas prices around the world and the oil price, as depicted by the WTI price[1]. The Japan Imported LNG price and the German Border price are largely driven by oil price linkage under long term contracts, while the Henry Hub and NBP spot prices are subject more to the market fundamentals. Spot prices show greater volatility but average contract and spot appear to be reasonably close through to 2008. From mid-2008 spot prices decoupled in a significant manner from contract prices, falling sharply as the demand for gas started to decline and more supply was becoming available. Contract prices also declined as oil prices fell back but a clear gap opened up compared to spot prices.

From mid to late 2009, another phase was entered with the German Border Price diverging from the Japan Imported LNG price reflecting more spot gas imports into Germany and renegotiation of long term contracts. Then in the second quarter of 2010, NBP started to diverge from Henry Hub as the UK was affected by supply issues and later by the very cold weather. Henry Hub prices, however, remained at low levels as the supply of shale gas increased rapidly. NBP prices, briefly in the winter period at the beginning of 2011 matched the German Border price but fell back in the summer of 2011. The German border price now includes a significant element of spot prices and the pure oil indexed contract price was thought to be some $1.50 per MMBTU higher than the average Germany border price in 2011.

Figure 14 below shows the evolution of North American spot prices. North American spot prices generally move together but not always maintaining the same differentials. Relative to Henry Hub, Opal and New York City Gate exhibit significant periods of diverging differentials, at least prior to 2010, since when there has been a narrowing of differentials. More detailed specific analysis of North American prices is covered in the next section on Gas Price Drivers.

*Figure 14. **North American Spot Prices***

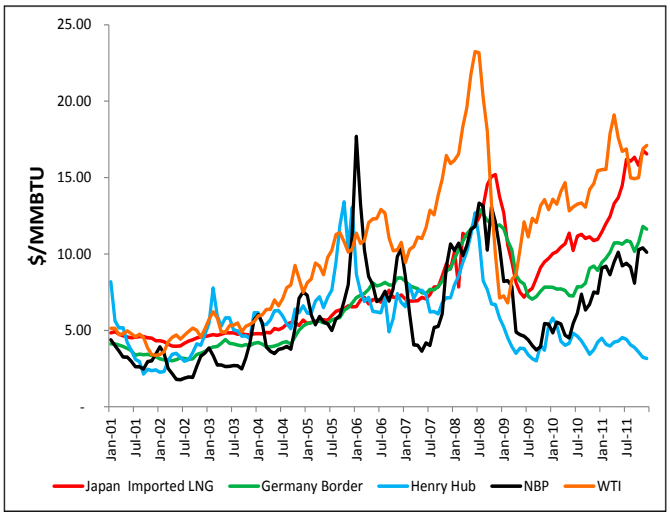


*Figure 15. **European Spot Prices***

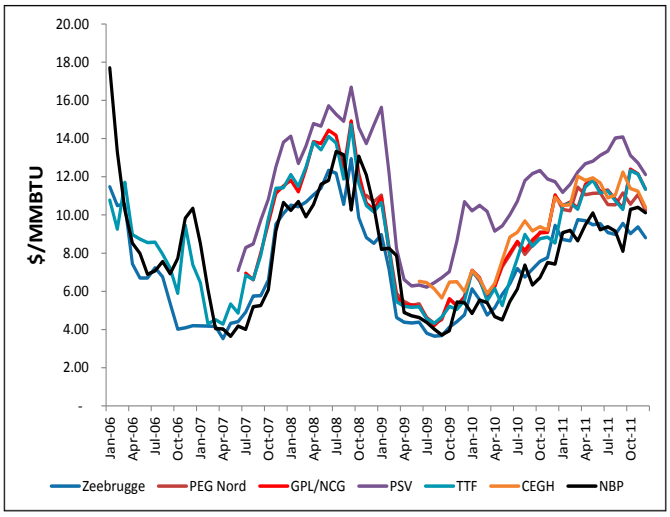


Figure 15 shows the behaviour of European spot prices, which have also generally moved together and, in fact, probably exhibit much closer correlation than do North American spot prices. The Italian spot price – PSV – is the "outlier" but this reflects the lack of liquidity and real competition in the Italian market.

In all the figures there is evidence, over relatively short periods of time of prices converging and diverging, in response to market conditions. In the last 3 years, the conditions in the world

[1] *The German Border price includes implicitly an allowance for transportation costs from the supply source to the German border, but there is no explicit element, although some contracts may contain a fixed element*

market have swung from being very tight (2008) to oversupply (2009/10) and then a tightening in European and Asian markets but continued oversupply in North America (2010/11). In very tight conditions spot prices converged towards the oil linked contract prices, which could be deemed to be a proxy competing prices. In the European markets spot gas "competes" with contract gas, so in a tight market, where spot gas is in demand, prices get pulled towards the "competing price". In an oversupplied market, spot and contract prices clearly decoupled, and with oversupply on a global basis in 2009 and early 2010, spot prices in North America, Europe and in the Far East converged. This changed again as market conditions diverged with tightening markets in Europe and Asia and continuing oversupply in North America, so spot prices diverged again. North America effectively decoupled from the rest of the world, as LNG imports were reduced to minimum levels.

The growing LNG trade around the world, and particularly the emergence of Qatar as a large exporter to Europe and North America as well as Asia Pacific, suggests there is more scope for price convergence (as we have defined it) and for linkages between different regional markets. The period of global oversupply, through 2009 and early 2010, exhibited clear price convergence in the spot markets of Europe, North America and Asia Pacific. There still appears to be a degree of convergence in spot prices in Europe and Asia Pacific, although the latter have been more affected by the Japanese earthquake and tsunami and the aftermath. The break in the linkage between the different regional markets has come in North America, where the shale gas revolution has virtually eliminated the need for LNG imports – in effect any gas trade outside North America. This decoupling may well be a short term effect, however, with two possible factors that could lead to a recoupling – firstly, rising demand in North America which outstrips supply, resulting in more LNG imports and secondly, exports of LNG from North America, from liquefaction plants as opposed to re-exports, which link North American supply to the rest of the world.

Liquidity and Transparency in Regional Gas Markets

For gas prices to converge in regional markets, it can be argued that liquidity and transparency in those markets is a necessary condition. Certainly within Europe, the Italian PSV hub price is often out of line with other European spot prices, and the lack of liquidity and competition is often cited as the reason, as well as possible transportation constraints[2].

Assessing liquidity and transparency, however, is not necessarily a simple matter. The table below is taken from the IEA's Medium Term Oil and Gas Markets 2011 publication.

Table 2. ***Traded and Physical Volumes at European Hubs***

Traded - bcm	NBP	Zeebrugge	TTF	PSV	PEG	GASPOOL	CEGH	NCG
2003	611.0	38.6	2.3	-	-	-	-	-
2004	551.9	41.1	6.2	1.1	0.3	0.0	-	-
2005	500.1	41.7	11.6	2.6	4.0	0.4	0.8	-
2006	615.2	45.1	19.1	7.1	7.0	1.2	8.9	0.2
2007	902.6	40.2	27.3	11.5	11.1	4.8	17.7	6.6
2008	960.8	45.4	60.2	15.6	16.5	9.7	14.9	25.3
2009	1,016.1	64.9	76.1	23.5	23.1	28.6	22.8	56.0
2010	**1,236.9**	**65.2**	**106.5**	**43.1**	**27.8**	**62.1**	**34.1**	**84.1**
Physical – bcm								
2003	52.5	10.2	1.3	0.1	-	-	-	-
2004	53.2	10.6	2.3	1.0	0.2	-	-	-
2005	53.7	8.4	3.8	2.0	2.7	0.3	0.7	-
2006	60.6	8.6	5.9	4.8	3.8	0.8	4.7	0.1
2007	66.8	7.9	7.4	6.8	5.1	2.2	6.9	4.1
2008	66.6	9.1	18.7	7.7	6.6	4.4	5.2	14.4
2009	74.6	12.9	25.0	11.0	8.1	12.9	7.6	25.0
2010	**106.7**	**12.9**	**31.3**	**21.5**	**8.7**	**25.3**	**10.9**	**31.3**

Sources: National Grid, Gas Transport Services, Huberator, GRTgaz, TIGF, CRE, Gashub, Gaspool, Aequamus, Net Connect Germany, SNAM Rete Gas

There is evidence of clear growth in both traded and physical volumes, which suggests increasing liquidity, but what is enough liquidity. One measure of this is the so-called churn rate, which divides the traded volumes by the physical volumes. Churn rates at the NBP have been consistently well over 10, but most of the continental European churn rates are around 2 to 4, apart from Zeebrugge which is a bit higher. The question remains what is an acceptable churn rate, to assess liquidity, and what is actually being measured. The physical volumes don't necessarily cover all the gas flows in that country or region, and the traded volumes don't always reflect all the trade volumes, especially OTC deals which may not get reported by the TSO. The above figures indicate there is a big difference in churn ratio between NBP and TTF. However if all traded OTC volumes are considered (not only those reported by the transmission system operators) the picture becomes different. Estimates by ICIS-Heren suggest that when the OTC traded volumes are included for TTF the churn ratio is comparable to NBP.

The table below makes another adjustment to the churn calculation. The traded and physical volumes are now compared with a measure of gas flows in the country – this is measured as production plus imports but could be consumption plus exports.

[2] *Transportation connectivity will be addressed in the next section in the context of the North American gas market*

Table 3. ***Traded Flows v Total Flows***

2010 BCM	GB	BE	NL	FR	DE	Total NWE*
Production	57.1		70.5		10.6	81.1
Pipeline Imports	35.0	18.1	17.0	35.0	92.8	162.9
LNG Imports	18.7	6.4		13.9		20.4
Total Flows	110.7	24.6	87.5	48.9	103.4	264.3
Traded Volumes	1236.9	65.2	106.5	27.8	146.2	345.7
Physical Volumes	106.7	12.9	31.3	8.7	56.6	109.5
Churn	11.6	5.1	3.4	3.2	2.6	3.2
Traded / Total Flows	11,2	2.7	1.2	0.6	1.4	1.3
Physical / Total Flows	0.96	0.53	0.36	0.18	0.55	0.41

**** The sum of BE, NL, FR and DE***

The total flows in GB are fairly close to the physical volumes at the NBP, which is not that surprising since almost every molecule flows through the NBP in the GB market. However, the situation is somewhat different in the continental European markets. It is not clear what proportion of the total gas flows would actually flow through the hubs in any case. The ratios of physical to total flows in the continental European markets range from 0.18 in France to 0.55 in Germany, with an average for the 4 continental NWE markets of 0.41. In terms of traded volumes the ratio in GB is 11.2 – pretty much the same as the churn – and in continental NWE the ratio is 1.3.

Could this ratio of traded volumes to total flows of 1.3 in continental NWE be considered an acceptable measure of liquidity? In the US, the FERC have begun collecting data using Form 552 on gas market transactions. Form 552 collects information from market participants that sold and purchased 2.2 million MMBtu or more of physical gas in the reporting year, roughly the amount of gas used by a 90MW peaker power plant running every day for 9 hours. This covers all but the smallest participants. The latest data available is for 2009 which showed that there were reported physical gas market transactions totalling some 56 tcf, compared to total flows (production plus imports) of 24 tcf, which gives a ratio of 2.3. The actual ratio is probably higher since Form 552 will not pick up every physical market transaction. The FERC reports also notes that some 70% of the 56 tcf of market transactions were indexed trades, the prices of which were reliant on indices prepared by market publications based on reported fixed price transactions. Form 552 reported that 22% of the 56 tcf were fixed price transactions (the remaining 8% being NYMEX based or triggered). Out of the 22% only just over a half were actually reported to the market publications to set the indexed prices. Thus something like 6 tcf of transactions set the price for 39 tcf of indexed transactions.

The analysis of liquidity above only considers the physical gas market. In the US and GB there are also sizeable futures markets, plus traded options in the US. In 2010, NYMEX reported over 64 million Henry Hub futures contracts traded, which is a monthly contract totalling 10,000 MMBTU. The total volume covered by these contracts, therefore, is some 1,800 bcm, compared to US total flows (production plus imports) in 2010 of 716 bcm, giving a ratio of over 25. For the NYMEX traded options, some 26 million contracts were traded again of 10,000 MMBTU, giving a total volume of 7,365 bcm and a ratio of just over 10. Combining the futures and traded options gives a combined ratio of over 35.

In the GB market in 2010, the ICE reported some 4.2 million futures contracts traded of varying duration from daily to monthly to quarterly to seasonal, although the vast majority

were monthly. The ICE contract is 5 lots of 1,000 therms per day – 5,000 therms per day in total. If it is assumed that all the contracts are monthly (which is an underestimate since there are a reasonable number of quarterly and seasonal contracts traded) then that gives a total volume of around 1,800 bcm, compared to GB total flows of 110.7 bcm, giving a conservatively estimated ratio of over 16.

Churn ratios are not the only way of considering liquidity. Other assessments include the ability to trade very large quantities of gas, over and above the standard lots or contracts, which would require a lot of depth to the market, and looking at the bid-ask spread, with a narrower bid-ask spread implying the market has more liquidity. ICIS-Heren calculate a "tradability" score for the various European hubs, measuring the narrowness of bid/offer spreads across the curve, how easy it is to trade at the posted prices and the number of market participants. Looking this way at the markets, suggests there is not much difference in the tradability at NBP and TTF.

The discussion of liquidity above has focussed on the North American and European markets. While there are some spot LNG trades in Asia, there are no trading hubs as in North America or Europe, whether physical or virtual. The trade publications have all been publishing, in more or less details, price assessments, especially for Japan and Korea, but there does not appear to be adequate liquidity yet, with the assessments based on very limited actual trades. A key element that distinguishes the Asian markets from the North American and European markets, is the lack of market liberalisation, in the downstream and end user markets. In China and India, for example, different customer groups are charged different gas commodity prices, implying an element of cross-subsidy. In Korea, Kogas remains the monopoly wholesaler and in Japan, the big utilities enjoy monopoly power still.

In the European markets, there are some potential threats to trading liquidity. The European Market Infrastructure Regulation (EMIR), which is being discussed by the European Parliament and Council, is intended to move OTC Derivatives trading to centrally cleared exchanges. The current intention of EMIR appears to be to include physical transactions as well as financial transactions in the definition of OTC Derivatives. If this definition is maintained it may well significantly increase the cost of trading for large physical players and could eliminate small physical players entirely, maybe reducing market liquidity, since moving to centrally cleared exchanges involves the posting of cash as collateral.

The European Council has also adopted the Regulation on Energy Market Integrity and Transparency (REMIT). REMIT will introduce the concepts or prohibitions of insider trading and market manipulation, better known in the financial sector (included in the Market Abuse Directive), into the energy sector and expose energy companies and others trading in this sector to the possibility of severe penalties for 'abusive' behaviour. For the major physical players in the market, especially producers, the definition of insider trading and market manipulation, may be very difficult. Is the diversion of a LNG cargo, to a more profitable market, manipulation or just sensible trading, and how does a producer cover a short position if there are problems at the wellhead or on platforms?

What are we to conclude from this analysis?

- The GB market has a much higher physical market transaction ratio than in the US – some 11.2 to 2.3 – but this may reflect the fact that it is much easier and cheaper to trade physical volumes at the NBP in GB than in the US, as well as GB having only one pipeline system which everyone has to use.
- The US market has a much higher derivatives (futures and options) ratio than the GB market – around 35 compared to a conservative 16 for the GB market
- The overall physical and derivatives ratio in the US is around 38 and in the GB market just over 27
- The continental North West Europe physical market transaction ratio of 1.3 is significantly lower than in GB and around half the US physical market ratio. The ratio for some markets in Europe (in particular TTF) is much higher when all traded volumes (not only those nominated to the system operators) are counted as well.
- A high physical market transaction ratio is not necessary for a truly liquid market, as is shown in the US, but, in the absence of that, a thriving derivatives market is necessary. There is very little derivatives trading in the continental European markets, so a seemingly low physical market transaction ratio, apart from TTF, is not compensated for by a high derivatives ratio. The high GB physical market transaction ratio is probably an anomaly in that it is an extremely cost effective way of trading and may in part be a substitute for the futures market.

3. Is Gas Different From Other Commodities?

In this sub-section some of the properties where gas could be considered to be different from other commodities, are discussed. These properties have an influence on the tradability of gas and could be relevant for the choice of a pricing mechanism. An important source for this sub-section is the report "Energy is not Coffee", published by JIN Foundation in 2005[3].

Transportation Costs

Most gas production fields are far away from the gas markets. To transport gas from the place of production to the end user markets requires high investments in either pipeline systems or, in the case of LNG, in liquefaction, shipping and regasification

[3] *www.jiqweb.nl*

facilities. This is high compared to other commodities. The JIN report suggested that the transport cost element in the final end user gas price could account for between 20% and 70% of the total price, compared to 10% to 30% for electricity and for commodities such as aluminium and coffee less than 5%. Clearly to trade items such as currencies there are no transport costs.

In commodity markets, storage is usually an important source of flexibility. In the gas and electricity markets, storage plays a much smaller role, with other sources, in particular production flexibility, being relied on. This is illustrated in the table below, again taken from the JIN report.

Table 4. ***Qualitative Assessment for Usage of Flexibility Sources within Various Commodity Markets***

Prime sources of flexibility	Production flexibility	Line pack	Storage	Interruptible contracts	Imported flexibility	Conversion capacity	Total
Aluminium	2	1	5	1	1	n.a.	10
Coffee	1	0	6	1	2	n.a.	10
Currencies	n.a.	n.a.	10	n.a.	n.a.	n.a.	10
Gas	6	1	2	1	1	-1	10
Electricity	6	1	n.a.	1	2	n.a.	10

Flexibility for commodities such as aluminium and coffe comes predominantly from storage, which would be relatively low cost. For gas, storage investment is a much higher cost and in many cases relies on the right geology to be available. In comparison to other commodities, the availability of storage and other flexibility sources for trading purposes in the gas markets are relatively low. Only in a few cases are gas storages being built specifically to facilitate (short term) trading. In the future more storage may be needed, if more flexibility in gas supply is required with more wind in the power generation mix.

Constant Volume Equilibrium

For gas, dedicated networks are required to deliver gas to the market. In these networks it is technically required to broadly maintain a constant volume equilibrium. To ensure security of supply in the pipeline systems, input and output have to be balanced continuously. In the gas markets this is supported by linepack, which can absorb some short-term fluctuations. Water has a similar requirement for constant volume equilibrium as gas, while electricity the problem is even more extreme since not even linepack is available to provide some flexibility. Other commodities usually do not have this requirement, illustrated in table 5 below from the JIN report, which negatively influences the tradability of gas.

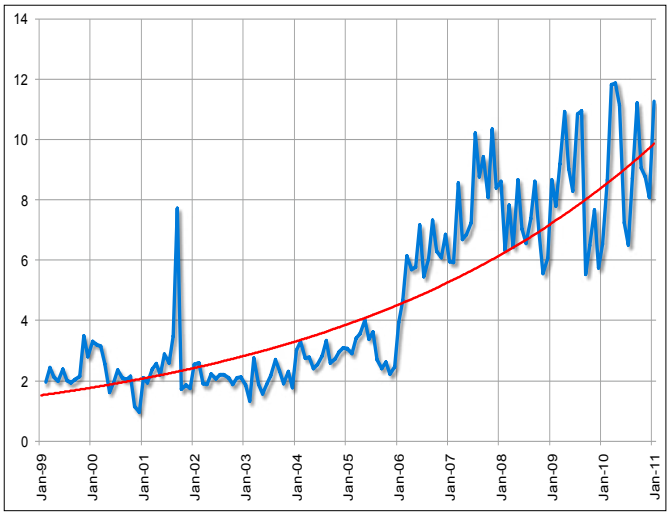
Table 5. ***Constant Volume Equilibrium Constraint in Selected Commodity Markets***

Constant volume equilibrium constraint	Yes/No
Aluminium	No
Coffee	No
Currencies	No
Gas	Yes
Water (for illustration)	Yes
Electricity	Yes

Liquidity of Trades at the Exchanges

In the three preceding paragraphs, the properties of transportability, storability and need for constant equilibrium have been discussed. These properties negatively influence the tradability of gas compared to other commodities. Based on this one would expect a lower liquidity of natural gas on the traded markets. The figure below shows the ratio of the combined volumes of traded futures for oil compared to gas NYMEX, ICE and TCM in the last 10 years. The traded volume of gas futures is lower than oil futures and this gap has increased in recent years. However, based on the analysis above, gas trading in the US and the UK could certainly be said to be liquid. It would not be necessary to have as much liquidity as in the oil market to be classified as a liquid trading market.

Figure 16. ***Ratio of Oil and Gas Traded Futures Volumes***

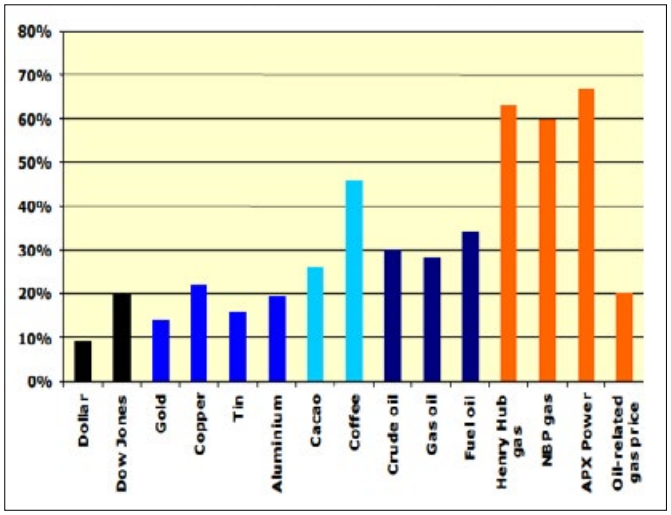


Source: Sergey Komlev, Gazprom Presentation

Volatility

Related to the lower tradability of gas, the volatility of hub based gas prices is high in comparison to other commodities. This is being illustrated in the graph below[4]. In this graph, hub based gas prices have a high volatility and oil-related gas prices have a lower volatility. In turn, the volatility of oil price-linked gas prices is lower than the volatility of oil prices. This is caused by the "time lags" in the oil-linked gas prices, where the oil prices used for the calculation of the gas prices are rolling averages of time periods of several months or quarters. This higher volatility level is likely to be related to the higher cost of storage and the need for a constant volume equilibrium. The issue of volatility is discussed further in section E below.

Figure 17. ***Volatility of Gas Versus Other Commodities***



Source: Pricing Natural Gas, CIEP Energy Paper, January 2008

4. Future of Oil Price Indexation

The Rationale for Oil Price Indexation

In the report to the previous 2006-2009 triennium, a section was included about the origin of individual pricing mechanisms. In this section, the history was described concerning the "market value" gas pricing principle that originated in the Netherlands in the 1960s and has been dominating big parts of Continental Europe and Asia during the last decades. The original basic idea of the market value principle was that the price of gas to a given customer should be at the level of the price of the best alternative to gas. In the early markets, the best alternative to gas was typically heavy fuel oil or gas oil[5], hence the development of oil price indexation.

Starting from the market value principle, there are also other arguments for oil price indexation. These include:

- **Competition between oil and gas on the demand side.** Though direct competition between gas and oil "at the burner tip" has decreased, there are still regions and market segments where oil and gas compete. An example of this is the heating sector in Germany. In countries like Japan, oil products still play an important part in the industrial and power generation energy mix, competing with gas. It could also be argued that even in Europe, where the role of oil has diminished in power generation, that there remains a virtual relationship:
  - Merit order puts oil products and gas in the same category of fuels used in peak or semi-peak. In that sense, there is a stronger competition with oil products than with coal which is used in base load only.
  - Oil products are a reserve fuel for many power plants and industries if gas supply fails.
  - Finally, to the extent that gas begins to play a more significant role as a transportation fuel, either in road vehicles or as a bunker fuel for ships, competition between oil and gas could increase
- **Competition between oil and gas on the supply side.** On the production side, there is often considerable competition of resources (money, equipment, manpower) between gas and oil. In the longer term technologies such as gas-to-liquids might increase gas-to-oil competition on the demand side as well as the supply side
- **Shareholders prefer oil price related risk**. Many shareholders of gas (and oil) producing companies are comfortable with an oil price related risk profile of their investment and may prefer not to change this. The oil price linkage has, in the past, supported long term investments

[4] *Source: Pricing of Natural Gas, The outlook for the European Market; Clingendael International Energy Programme, January 2008. The method of calculation of volatility is not described in this publication*

[5] *Source: Strictly the discussion is about competing fuels indexation rather than oil indexation but in practical terms most long term contracts incorporate oil indexation*

- **Pricing via a third commodity**. Pricing via oil provides with immunity against price manipulation by dominant suppliers on the markets, where the number of suppliers is limited. No major gas supplier, or buyer, can influence the price of oil or oil products.
- **Higher confidence in the tradability of oil than gas.** As has been outlined above, oil is traded at exchanges to a greater extent than gas giving more confidence that the oil price is transparent and less subject to market manipulation. Because of the difficulties of transporting and storing gas as compared to oil, as well as the lower volumes traded, the confidence in the transparency and reliability of the traded gas markets is diminished.. In many regional gas markets the number of buyers and sellers is limited.
- **Oil prices have lower volatility.** Also as described above, the volatility of oil prices is lower than volatility of gas prices, and due to the smoothing out of oil prices in oil price indexed gas contracts through averaging, the volatility of oil price indexed gas is even lower.
- **High level of acceptance of oil price indexation.** Oil price indexation has a high level of acceptance in large parts of the international gas industry. Many key players are comfortable with oil indexation and large financial interests are attached to this. A possible change to other pricing mechanisms will cause resistance.
- **Resource value of hydrocarbons.** All hydrocarbons should, in an ideal world, have the same resource value on an energy equivalent basis, with the BTUs being valued the same.

The Arguments Against Oil Price Indexation

As indicated in section C, the share of gas priced in the oil price escalation category has been decreasing from 2005, especially in Europe. The share of gas priced in the gas-on-gas competition category has increased. From 2009, the decoupling of the prices of traditional oil-indexed gas and the gas priced against gas-on-gas prices has accelerated this trend.

The key arguments "against" oil price indexation include:

- **Separate markets.** The market for gas is now separate from oil, based on (regional) demand and supply. If a separate pricing mechanism for gas is established, there is no need to price gas against another commodity any more. Especially when prices of oil and gas are decoupled for a longer period of time, there is a large incentive to switch from oil-indexation to gas-indexation.
- **Other alternatives.** Direct gas-to-oil competition is losing its relevance. Gas is more and more competing against electricity and/or coal, nuclear and renewables – see next section.
- **Political support.** Increasing competition is high on the political agenda in some regions. Often this is seen to be associated with lower prices. Separate pricing for gas is often considered to increase competition and has during the last few years in many cases led to lower prices as compared to oil-indexed prices.
- **Political support for short term contracts.** This is related to the argument above. Prices based on oil indexation are often associated with long term contracts. Gas-on-gas competition prices are more often associated with shorter term contracts. The promotion of gas-on-gas competition could be a means to reduce the dependence on long term contracts.
- **Better interconnection between regional gas markets.** Regional gas markets are better interconnected through new pipelines and new LNG (receiving) terminals. This supports liquidity on demand and supply side for natural gas and thereby independent price discovery. For example, Qatar is a large volume supplier that can supply all markets but with Asia currently as the premium market, a lot of LNG will be attracted to those markets.
- **Reduced fear for market power.** The greater diversity of supply and market linkage, noted above, is reducing market power. The current situation of ample supply has reduced the fear for market domination by a few large suppliers. In many regional markets, the number of players has increased. The level of comfort on the hub pricing reliability in many regional gas markets has increased. There are more suppliers to Europe but still a much lower and limited number than compared to the USA.

The Future of Oil Price Linkage in Long Term Contracts

The future of oil price linkage is currently being debated and fought over in the European markets. Many downstream markets in Europe appear to have changed away from true oil indexation to be closer to spot pricing. Large end users in Germany, France, Italy and the Netherlands seem to be increasingly buying gas under one year contracts where the base price relates to the spot market while the price moves up and down through the year in line with oil product prices. With a significant gap between spot gas prices and the oil linked long term contract prices, this situation may be untenable for the large wholesalers and hence the number of contracts that are currently in dispute.

How the future of oil price linkage in Europe develops may in part depend on circumstances outside the control of the key players:

- Gas demand in Europe has not been growing much in the past few years and, as such, no additional volumes under long term contracts have been signed. This trend may continue in the future
- The gap between oil linked long term contract prices and spot prices opened up in 2009 and despite recent rises in spot prices in Europe the gap is still there. If this gap is closed then the pressure for contract renegotiation may be abated. Whether this gap is closed may depend on the developments in the oil market. If oil prices declined again then the gap could well diminish. On the other hand, if oil prices rose, the gap might widen and hence increase the pressure for contract renegotiation

- Global gas supply has been increasing, driven by the development of shale gas in the USA and new LNG projects coming on-stream. Shale gas had a dramatic impact on prices in the USA and in the longer term the development of shale gas in other areas, particularly Europe, could also impact prices

Fundamentally, in Europe at least, the future of oil price linkage would seem likely to be most dependent on the future supply – demand situation. A scenario of weak gas demand, abundant low cost supply of gas and rising oil prices would be most likely to accelerate the move away from oil linkage towards a fully-fledged spot market. In contrast, stronger demand, more constrained supply and lower oil prices may sustain oil price linkage for some time. The situation in Europe, however, cannot be looked at in isolation, since there are more global impacts in the gas market now. Rising demand for gas in Japan following the reduction in nuclear power generation has reduced the amount of LNG available for Europe, thereby "tightening" the market. The debate over the future of oil price indexation in long term contracts is separate from the debate on contract duration. There is no reason to suggest that long term contracts will not be required in the future. In Europe, as elsewhere in the world, there is the requirement to develop additional infrastructure and pipelines, in particular, need to be underpinned with long term contracts to book the capacity at least. If the main producers are then being asked to book this capacity they are likely to seek long term contracts for the sales of the gas and also may be seeking certain commitments on the gas sales price. Even in the US, utilities enter into longer term contracts to ensure volume security, with the price linked to hubs and the basis differential. Some producers in the US also appreciate the security of demand afforded by longer term contracts.

In contrast the Asian market remains very different from the European market. Security of supply is a key driver, especially in Japan, Korea and Taiwan. The monopolistic nature of the downstream markets in these countries also means that end users effectively have no exposure to lower spot prices at times when there are large gaps compared to the oil linked prices. One of the political drivers for change to the contracts is, therefore, missing. India and China are also different markets. India imports some LNG at the current prices in the region but appears to be limited in its ability to pay high prices for significant quantities of LNG, preferring to interrupt supplies to customers rather than import more. China, on the other hand, has been increasing domestic prices for gas, although they are still not at the levels to fully cover the cost of newly imported pipeline gas and LNG. This may limit China's willingness to import in significant quantities.

5. Can Parallel Pricing Mechanisms Continue To Co-Exist?

It is clear that parallel pricing mechanisms exist around the world and even in the same markets – see Box 3 on India and Box 4 on Australia. In many markets regulation has created and perpetuated different mechanisms, in other markets it has been the contractual arrangements with long term contracts being priced differently to short term contracts.

However, it is not necessarily the different price mechanisms which create tensions between market participants and regulatory authorities but different price levels. If price levels are little, or no, different, then participants are much less likely to complain.

Price mechanisms can move towards each other and be integrated to some degree. As noted before, it is possible to have a price based on oil indexation, where the price level is tuned on gas hub (forward) price levels. In Continental Europe this is common place. This is an example of integration of the OPE and GOG price formation mechanisms.

At the global level, the continuation of parallel pricing mechanisms is most likely, in the longer term, to be dependent on the ability of the major gas suppliers, in particular, to separate the markets. The rapid increase in LNG trade, with Qatar as the focal point, has led to the disparate markets of North America, Europe and Asia interacting a lot more. However, that has not led yet to major changes in pricing mechanisms, especially in the Asia market.

A significant development which could well change the dynamics of pricing in the Asian market, in particular, is the move towards the export of LNG from North America. Cheniere have signed a number of conditional contracts, to export from their Sabine Pass terminal, where the price is based on a percentage of Henry Hub, plus a fixed fee (to cover liquefaction costs), for delivery on a fob basis. Adding in the shipping cost to the destination market, gives a possible benchmark price for that market, against which spot cargoes would "compete", as opposed to the current competition with JCC-linked contracts. Sabine Pass seems unlikely to be the only export terminal from North America with more in the Gulf Coast area having already received partial approval – for FTA countries[6] – while there are a number of planned terminals in Western Canada.

[6] *FTA approval allows the LNG to be exported to countries where the US has a free trade agreement. Sabine Pass also has non-FTA approval.*

Box 3. ***Gas Pricing in India***

The landfall price for domestic production of Natural Gas is determined by Government of India (GoI). However, the basis for the determination of prices is different for different Exploration & Production (E&P) fields/blocks.

Natural Gas in India is produced from blocks that can be classified under following three E&P regime.

1. Initially, GoI provided E&P blocks to Government Owned Companies on nomination basis.
2. During 1992-1993 to 1997-1998, GoI invited private parties/consortium to carry out the E&P activities in specific sedimentary basins of India. During aforesaid period, Production Sharing Contracts (PSCs) were signed that provided for the formula for determination of Gas Price.
3. Since 1998-1999, GoI has introduced the New Exploration and Licensing Policy (NELP) and invited bids from various entities/consortiums to qualify for E&P activities in designated sedimentary basins of India. Standard PSCs are signed with each winning entity/consortium. These PSCs, inter alia, states that the entity shall be free to market their produce however, the price at which the Gas shall be sold is to be determined at Arm's Length Principle. Further, such price/formula to calculate price shall require approval of GoI.

For the E&P fields given on nomination basis, GoI revises price of the gas keeping in view the social and political scenario. For the E&P fields under pre-NELP era the Gas Prices are either a Fixed Single Price or based on formula linked to basket of fuel oils. For the E&P fields under NELP regime, Gas is sold based on the formula approved by GoI. Currently only one E&P field from NELP regime is producing and the formula to determine Gas Price is linked to international crude price.

Till recently, majority of domestic Gas was coming from the E&P fields given by GoI on nomination basis. However, the situation has changed in recent times and now the produce from NELP field has over-taken the produce from the ageing and depleting E&P fields given on nomination basis. In view of above, GoI has revised the landfall gas price, for produce from nomination field, almost equal to that produced from the NELP field.

The present Landfall Gas Prices for domestic produce are in the following range:

Sr. No.	Type of E&P Field	Landfall Price Range for Domestic Gas (on NCV Basis)
1.	Nomination Basis	US $4.20/MMBTU to US $5.25/MMBTU
2.	Pre-NELP	US $3.50/MMBTU to US $5.73/MMBTU
3.	NELP	US $4.21/MMBTU

In addition to above, India is also one of the major importers of LNG. LNG is sourced, both, on long-term basis as well as from Spot Market. For the import of LNG, on long-term basis, India pays a price linked to international crude price on GCV/GHV.

Box 4. ***Gas Pricing in Australia***

The Australian domestic gas industry commenced in the 1960s and gradually developed as a separate market in each state, based on a monopoly sellers and monopoly buyers. Over the last twenty years the five eastern states have gradually become linked by pipelines such that there are now multiple sellers and buyers. Pricing continues to be based on long-term bilateral contracts (on both east and west coasts), with a base price escalated by a percentage of inflation. Ex-field prices under long-term contracts continue to be low in global terms. However Victoria has had a small formal spot market for around a decade and, with government encouragement, formal spot markets are now also developing in other states.

The Australian domestic gas market is relatively small: 17.5 bcm per annum on the east coast (half supplied from offshore fields) and 9.5 bcm per annum on the west coast (almost all supplied from offshore fields), with long distances for gas transmission. On the east coast, gas has always had to compete with cheap coal, the basis for some 85% of power generation. The major markets for gas have been power generation and large energy-intensive industries such as aluminium and fertiliser production.

Although Australia has had an LNG export industry since the late 1980s, it has been limited to two west coast projects and has had little influence on domestic gas. However the growth of LNG demand in North Asia together with exploration success offshore Western Australia and the development of coal seam gas in Queensland have driven rapid growth in LNG, with three major projects under construction on the west coast and two on the east coast, with many other potential projects.

In Western Australia, the domestic market is largely reliant on development of LNG projects, which also supply domestic gas. However the domestic gas supplied must compete with oil-linked LNG contracts. Offshore development costs have also increased considerably. As a result contract prices have increased from US$2-3/mmbtu to US$6-8/mmbtu and are beginning to be linked to oil or diesel prices. (For many resource projects gas competes with diesel).

On the east coast long term contract prices are currently US$3-4/mmbtu and spot prices have been lower. There is currently a surplus of short-term gas as gas fields are developed for LNG projects. However it is also difficult for domestic buyers to secure long-term gas contracts as the major gas producers' focus on developing sufficient reserves for their LNG projects.

Going forward, on the east coast, gas requirements for LNG are likely to dominate the domestic market. The two LNG projects currently under development will require around 25 bcm per annum and there are further projects in the queue. To be competitive with LNG, long-term domestic contracts for base-load supplies may therefore ultimately move to being oil-linked to compete with North Asian LNG. At the same time there are likely to be substantial volumes of short-term gas, both as LNG projects ramp-up and resulting from shut-downs of LNG plants for regular maintenance. This is likely to facilitate development of the spot market, particularly for power generation. The asymmetry between short and long-term prices is also likely to encourage further development of gas storage.

E. Gas Price Drivers

1. Introduction

In considering gas price drivers, the work of the last triennium will be developed, by undertaking a detailed analysis of the competing fuels to gas by different markets and different geographies. Pricing patterns in North America between different hubs will be considered to understand price drivers in a competitive gas market, as well as analysing the convergence and divergence of prices.

The issue of price volatility was analysed extensively in the report from the last triennium. This section will review whether volatility is "good" or "bad" and how financial instruments can be used to offset volatility. Finally the impact of the marginal delivered supply cost to key markets, as a price driver, will be assessed.

2. Competing Fuels Analysis
Overview

One of the remits for this triennium was to look at price elasticity. However, this remains a difficult concept encompassing both short term and long term elasticity. In considering price elasticity, the fuels gas competes with are important especially in the key markets for gas – industry, residential and other and power. However, looking at the market shares of each fuel does not necessarily show the extent of competition:

- Gas is not always substitutable for other fuels in some applications e.g. electricity for many appliances and applications in buildings
- Gas requires a dedicated pipe network for delivery and many centres of population an activity may be outside the gas supply area

In spite of these drawbacks market share analysis can produce useful insights. Generally the more diverse the number of fuels and market shares the greater the scope for competition e.g. if a fuel has a dominant share in a market sector in a country then there is less competition than if market shares are more evenly spread. The extent of diversity/competition can be measured by the Herfindahl-Hirschman Index (HHI). This is a commonly accepted measure of market concentration and is widely used by competition authorities and in anti-trust law. It is defined as the sum of the squares of the market shares of firms within an industry, where the market shares are expressed as fractions. The result is proportional to the average market share, weighted by market share. As such, it can range from 0 to 1.0, moving from a huge number of very small firms to a single monopolistic producer. Increases in the HHI generally indicate a decrease in competition and an increase of market power, whereas decreases indicate the opposite. The measure is essentially equivalent to the Simpson diversity index used in ecology.

In terms of its use for analysing competing fuels for gas in the key sectors, the aggregation of competing fuels across different countries and regions, can be more accurately represented **by giving more weight to markets where there is greater competition as opposed to market where there is less competition.** For example, if gas dominates a market and other fuels have a small share, then this market would be given less weight in the aggregation calculation than in a market (of equal size) where market shares are more evenly spread. The methodology described below uses the HHI for each sector in each country to adjust the weight of that sector in any aggregation by different sectors or by countries.

Methodology

The fuels considered in the market share analysis are Coal and Peat, Oil and Oil Products, Natural Gas, Nuclear, Hydro, Geothermal, Renewables, Combustible Renewables and Electricity and Heat. All data is taken from the IEA energy databases. The key market sectors considered for gas are only the main stationary sectors of Industry, Residential and Other, and Electricity Generation. The transportation sector, which is almost totally dominated by oil and oil products, is excluded.

The methodology is to consider for each market sector the market shares for each fuel and then calculate the HHI for each sector in each country.

As noted above the lower the HHI the greater the diversity of fuel supply and the greater the scope for competition and, as a result, sectors in countries with lower HHIs should get more "weight" in any aggregation

The methodology for each sector in each country, once the HHI has been calculated, is as follows:

- Divide consumption of competing fuel by total consumption for sector, less the consumption of natural gas (gives the market share for fuel excluding natural gas)
- Multiply result by 1 minus the HHI for the sector (gives greater weight to more diverse sectors)
- Multiply the result by natural gas consumption for the sector
- Result will be for each competing fuel a figure in tonnes of oil equivalent giving the importance of that fuel as "competition" for natural gas

When these are aggregated across countries and regions, this should give a more accurate reflection of competing fuels than simply looking at market shares. It is important to note that the outcome of the calculation is to eliminate gas as a fuel and then look at the relative importance of the remaining fuels as "competition" for gas in that sector. The gas consumption by sector and the HHI factor are then used to aggregate the shares of each country into regional groupings and at the global level .

Results

The results are presented by the 3 key sectors for gas consumption – industry, residential and other and electricity generation – and in total for primary energy. The top 45 countries in terms of annual gas consumption were analysed and the figures aggregated by region. In the figures below results are shown by each sector at the World Level, for the Main Importing Countries[7], USA, Germany, UK and Japan.

At the World level, the main trends have been a decline in the share of Coal as a competing fuel to gas and a rise in Combustible Renewables (this includes the use of waste and biomass). Electricity is the largest competing fuel but the share has not changed that much over time, nor has the share of Oil changed. For the Main Importing Countries, Coal has been on a declining trend, with Electricity's share rising. Oil's share has only started to decline significantly since 2000.

Industry

At the country level, Electricity is the main competing fuel in the USA, Germany and the UK while Oil is more important in Japan. In the USA, Combustible Renewables[8] have become more important since the late 1990s. Coal has been declining as a competing fuel in Germany and the UK. The share of Oil as a competing fuel to gas has broadly been maintained in the 4 main countries.

Residential and Other

At the World level, Electricity is the main alternative fuel to gas in the residential and other sectors and its importance has been increasing over time, mainly at the expense of Oil. This has been particularly true in the Main Importing Countries such as Germany and Japan as the use of Oil as a heating fuel has been displaced by Gas and Electricity

Electricity Generation

At the World level, Coal is the main competing fuel to gas and its share has been increasing over time. Nuclear and Hydro are the next most important competing fuels, while the share of Oil has been declining. In the Main Importing Countries, Oil, with Nuclear, was the main competing fuel, but its importance has declined significantly, with Coal being much more important. At the country level, there are significant differences with Oil having very little role in electricity generation in the USA, Germany and the UK. Oil is a much more important in Japan in electricity generation but even there its share is declining being displaced by coal and nuclear as the main competing fuel to gas.

Total: Primary Energy

The total for primary energy has been calculated by summing the competing market shares for the 3 key sectors but additionally taking the shares of competing fuels in the electricity sector and substituting these for electricity in the industry and residential and other sectors.

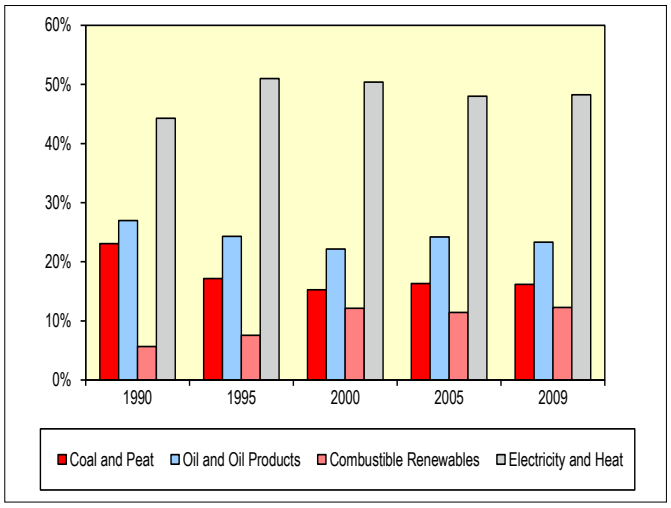
At the World level, Coal is increasingly the main competing fuel to gas, with Oil in decline and Nuclear and Hydro marginally increasing. Renewables – Combustible as well as Wind and Solar - are increasing their share. For the Main Importers, Oil was the key competing fuel until 2005, when it was displaced by Coal, and is now losing market share to Nuclear, Hydro and Renewables. This trend is well illustrated by the changes over time in Germany and Japan. In the USA and UK, Coal has always been the main competing fuel, but in both countries Nuclear has replaced Oil and Renewables are becoming more important.

[7] *The 8 largest importing countries – France, Germany, Italy, Spain, Turkey, Japan, Korea and Taiwan.*

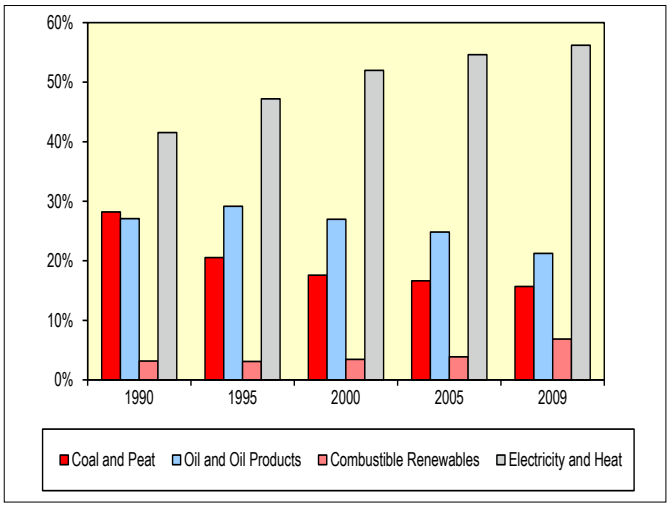
[8] *Combustible Renewables also includes waste and biomass.*

Figure 18. ***Competing Fuels: Industry***

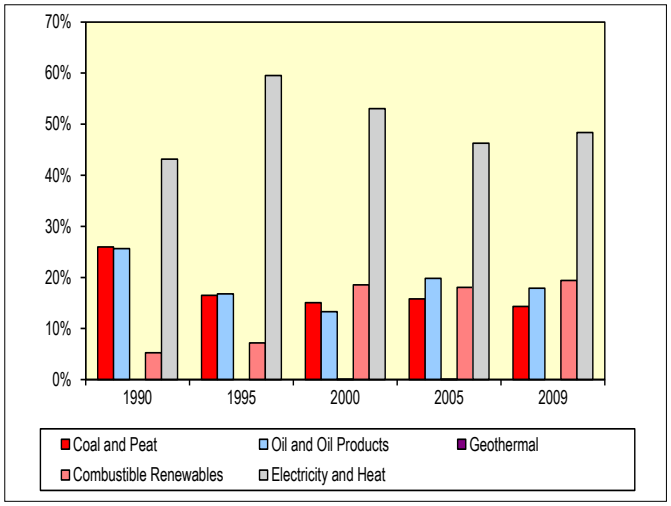
World



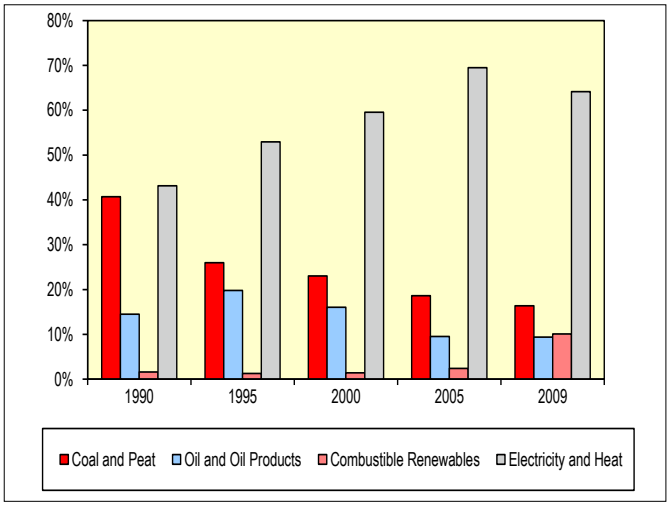
Main Importers



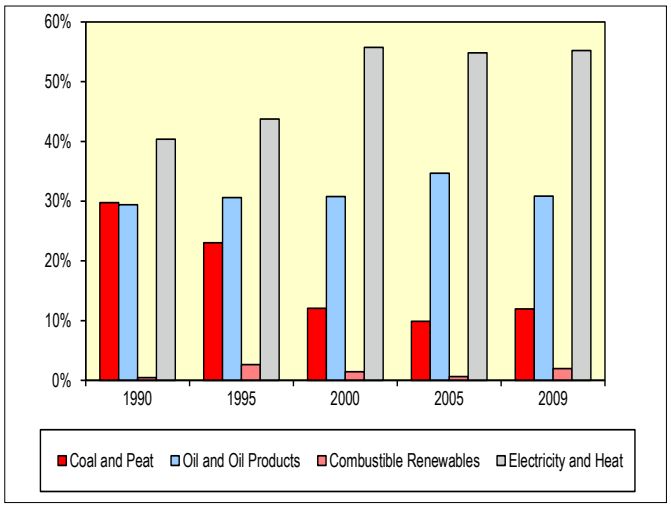
USA



Germany



UK



Japan

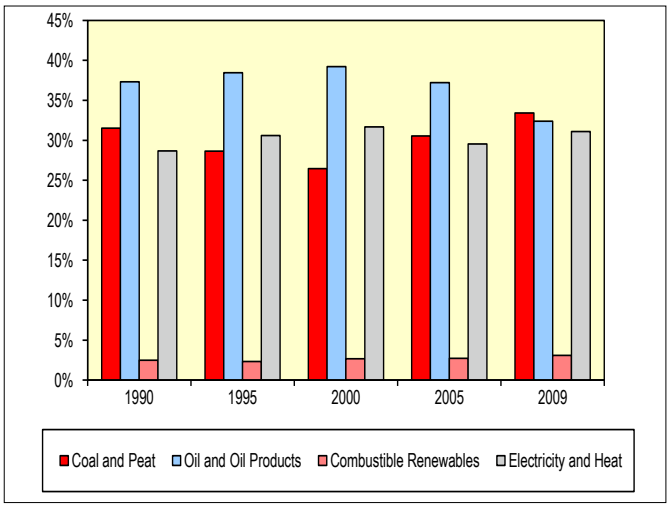
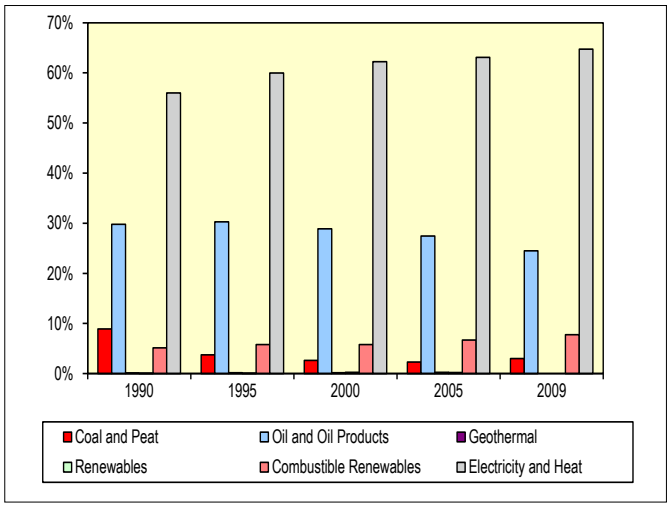
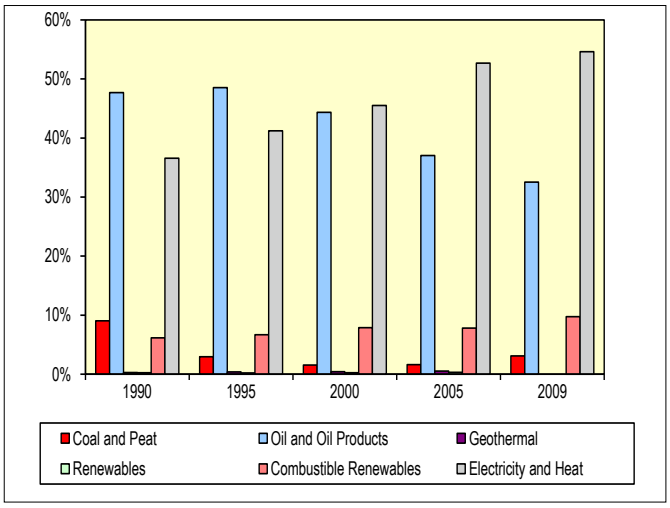


Figure 19. ***Competing Fuels: Residential and others***

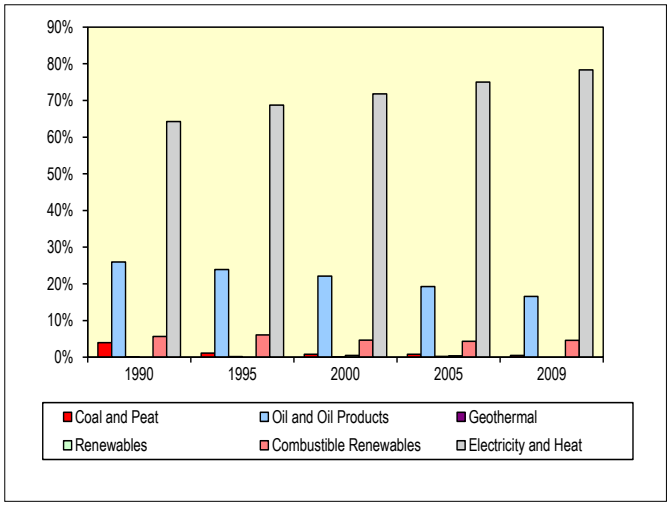
World



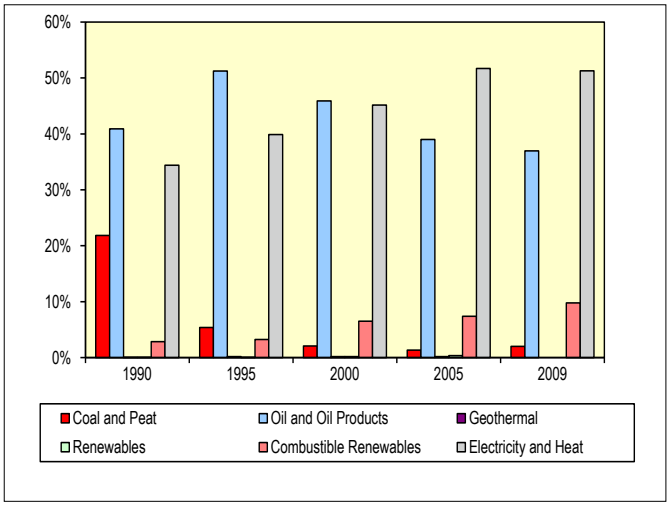
Main Importers



USA



Germany



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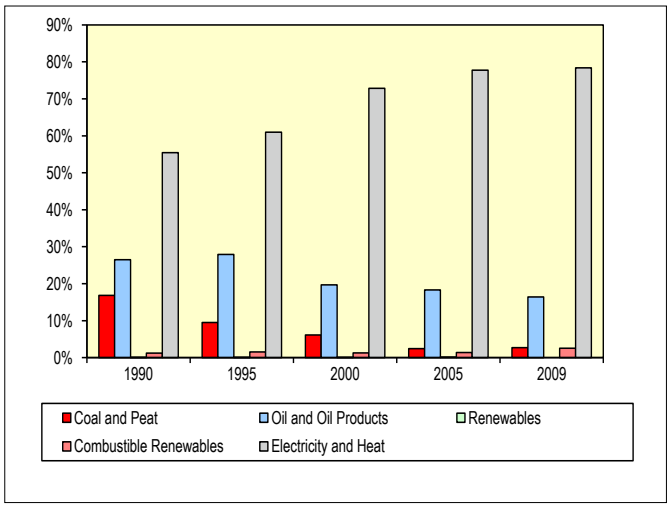


Japan

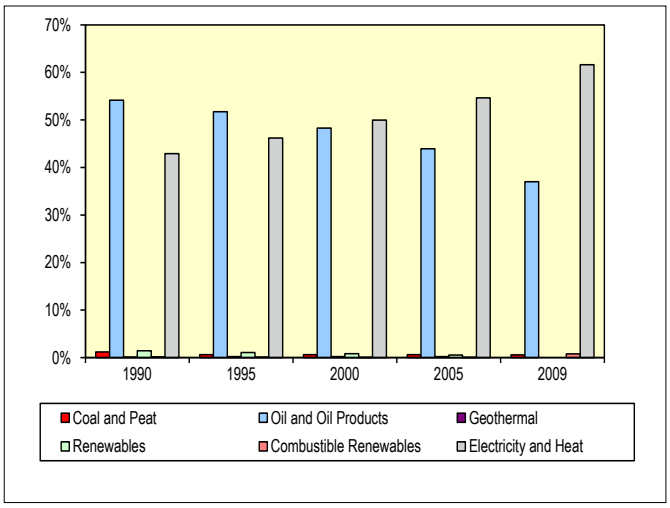
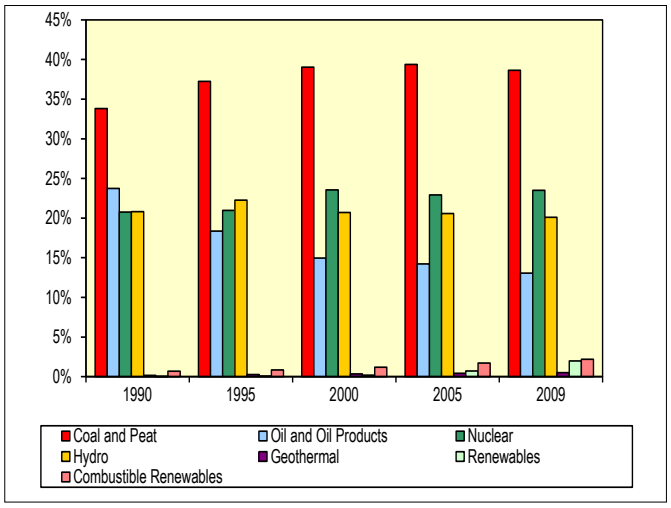
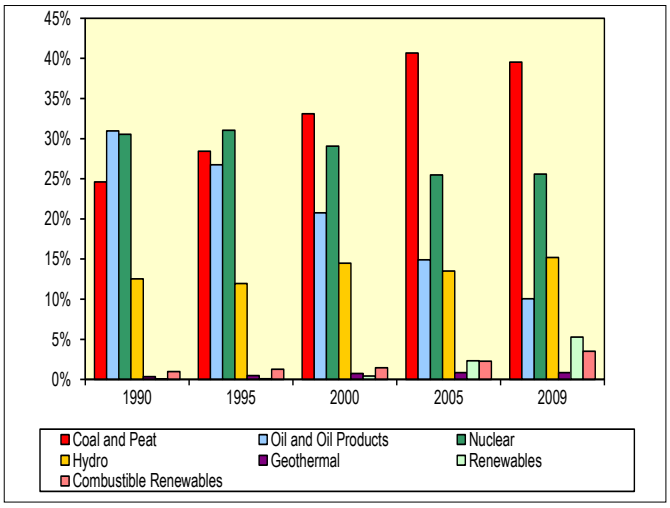


Figure 20. ***Competing Fuels: Electricity Generation***

World



Main Importers



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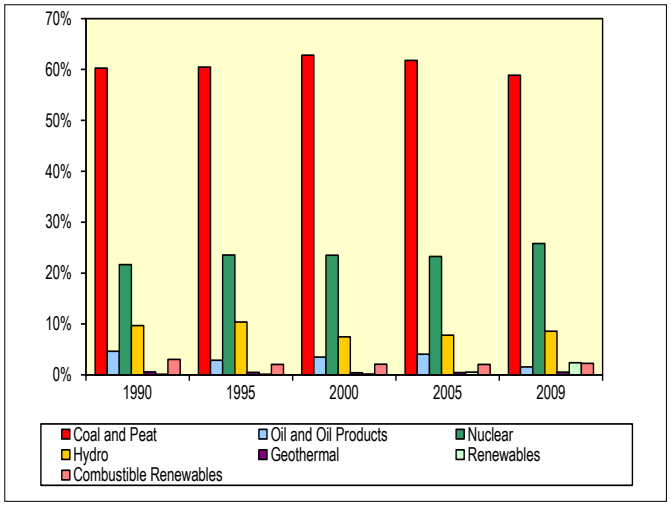
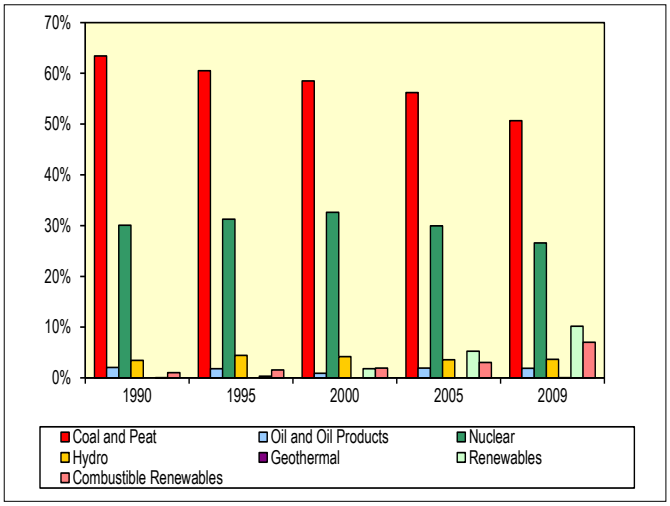


Germany



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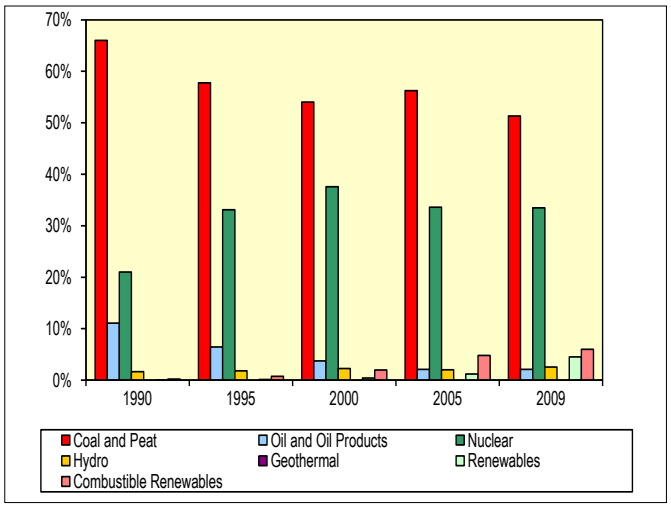


Japan

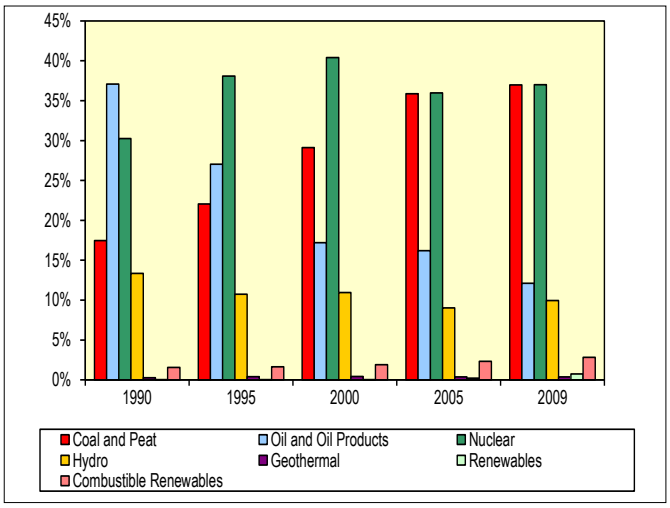
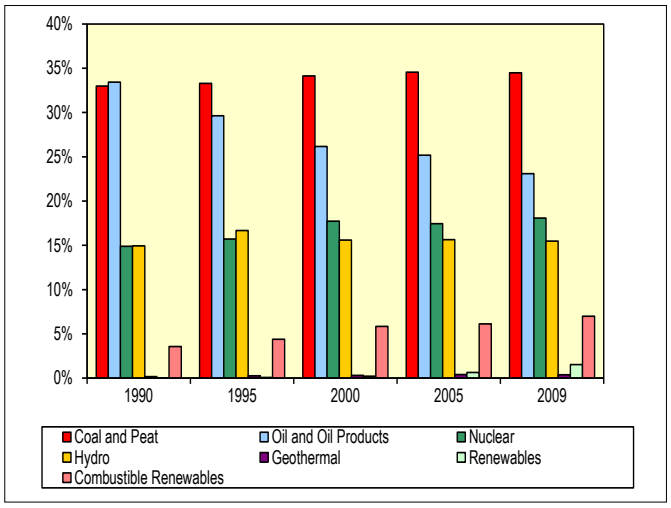
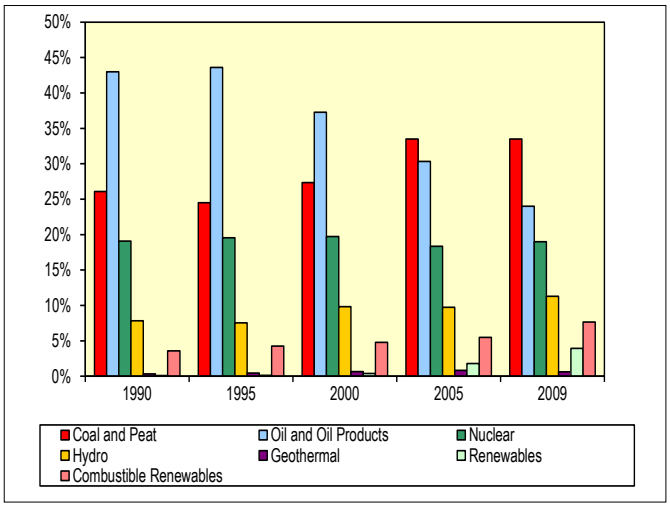


Figure 21. ***Competing Fuels: Total***

World



Main Importers



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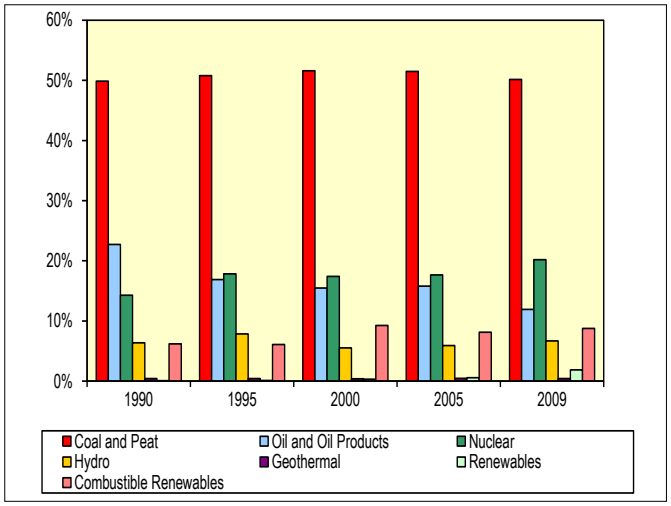
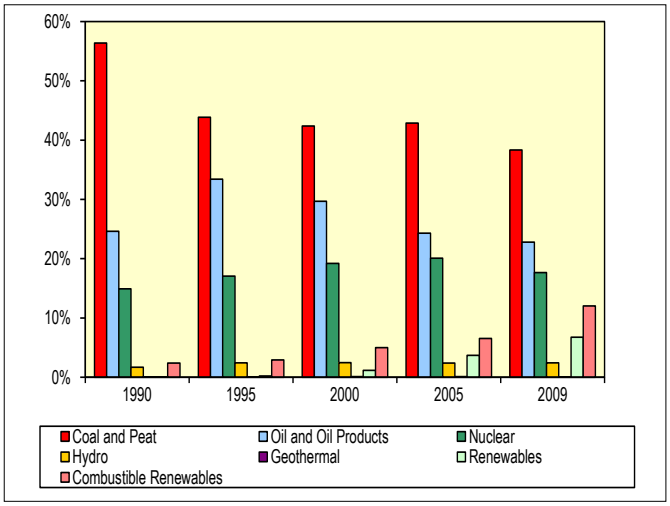
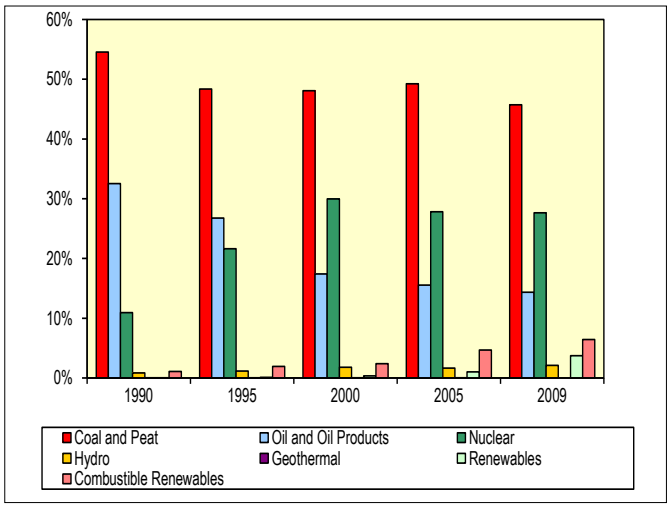


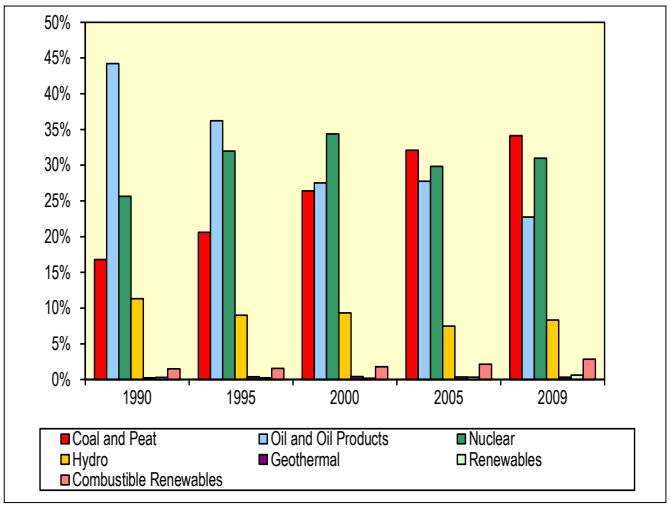
Germany



UK



Japan



Conclusions

The price of gas is influenced by the price of competing fuels in its key markets – industry, residential and other and electricity generation. In the heating markets, predominantly residential and other and some industry the price of the competing fuels is more important in respect of the decision to invest in the fuel burning equipment and is a longer term decision, since short term switchability is not an option. In these markets electricity is the main competing fuel to gas and has been increasing its share. Oil is also the alternative in the heating market, and often the only choice outside the gas supply area, but its importance has been declining particularly in the Main Importing Countries.

In the process industries and electricity generation, the price of competing fuels relative to gas is important in the longer term for the installation of equipment, and in the short term because of the ability to switch between fuels. In the Industry sector, Electricity is generally the main competing fuel, but Oil has maintained its importance, particularly in Japan. However, in Electricity Generation, the importance of Oil has declined sharply, particularly in the Main Importing Countries. Only in Japan is oil an important source of electricity generation but even there its share is declining.

At the level of Total Primary Energy, there appears to be a consistent trend with Coal displacing Oil over time as the main competing fuel to gas. In some countries, Nuclear has overtaken Oil in importance, although that may reverse following the Fukushima incident in Japan, and there are initial indications of significant growth in Renewables.

Box 5. ***Competitiveness of Natural Gas in Hungary***

In Hungary gas consumption is almost equally shared between households (37%), industries (31%) and power generation (32%). About 11-12 years ago in Hungary, there were huge expectations towards natural gas. Gas fired power generation solutions started to become popular, which led to a boom in the gas demand. On the other hand, natural gas supplies were already dominated by few importers. Consequently, the gas prices doubled in the last 5-6 years, which again led to a counter reaction of the market. Gas demand started to decrease. Even though, gas became an important, but expensive energy source. This brought a market restructuring with the booming of the renewable energy sources (RES) sector, the development of clean coal technology, and the renaissance of the nuclear generation, which latter is questionable looking at the recent nuclear catastrophes.

The dominance of natural gas in the fuel mix in the three largest market segments in Hungary is clearly observable, which increases the vulnerability of natural gas to high market prices. The following critical influencing factors negatively affect the competitiveness of gas:

- Households have access to other fossil fuels and renewable energy sources
- Willingness to invest in cheaper fuel spreads
- Consumption efficiency spreads
- Limited or missing GDP growth prevents expansion and development
- The market moves towards cheaper electricity market price compared to gas price

As a result of increasing gas prices, consumers start to consider alternative solutions, which led to a restructuring of demand. In urban areas electricity heating and/or solar panel installations spread together with the improvement of housing efficiency rates, while in rural areas renewable energy sources substitute gas. On the other hand in the commercial and industrial sector consumption rationalization spreads, other organic fuels step in as substitutes to gas, as well as electricity generation from by-products or RES in own power plants is increasing market share.

The regulation on the historically oil price escalated natural gas pricing has been recently changed in Hungary to protect the residential end-users from high gas prices. Based on the regulation, the calculation of the residential gas price is defined considering the difference of the ENDEX TTF Gas quarterly average price and the gas price set in the long term contracts. In case the ENDEX TTF Gas price is cheaper, the applicable gas price is calculated by considering 40% ENDEX TTF Gas price and 60% the long term contract gas price. Otherwise, the long term contract gas price provides the price. Because the Western European gas spot prices are not able to significantly affect the Hungarian market prices, further strategic steps are required by the Hungarian government, to open up the market.

Supporting this new path the Hungarian government initiated the development of a Hungarian natural gas exchange to be launched by the beginning of 2013. It is a national objective to open up the Hungarian gas market towards the Western European free markets where gas-on-gas competition is present. To found the basis of gas-on-gas competition in the CEE region and to make the interconnection of gas markets possible, the Central Eastern European Gas Exchange (CEEGEX) Ltd. has been established and will launch the Hungarian natural gas exchange at the beginning of 2013

3. Hub Trading and Pricing Patterns in North America

The North American gas market is the best example of a relatively free gas market and provides a vivid depiction of how regional price disparities arise and how markets then allocate investment capital to resolve these price disparities.

Between 2005 and 2010, U.S. dry natural gas production grew from 49.5 Bcf/d to 59.1 Bcf/d largely due to an unexpected and sharp increase in shale gas production coupled with tight sands gas production in the Rocky Mountain region of the U.S.[9] While the growth in U.S. gas production has been impressive, equally significant is the transformation of the North American interstate pipeline grid, as approximately 602,000 miles of pipeline have been added since 2007[10]. These pipeline capacity additions have occurred in response to local price differentials that reflect supply/demand imbalances and pipeline constraints.

The objective of this section is to describe how the North American market has been transformed over the past four years and suggest some of the most salient lessons for markets elsewhere in the world. It is based on data derived from a variety of sources. The North American pipeline flow and price information is provided by BENTEK Energy, an operating unit of Platts, which is a division of The McGraw-Hall Companies. Natural gas production data is provided by HPDI, a division of Drilling Information.

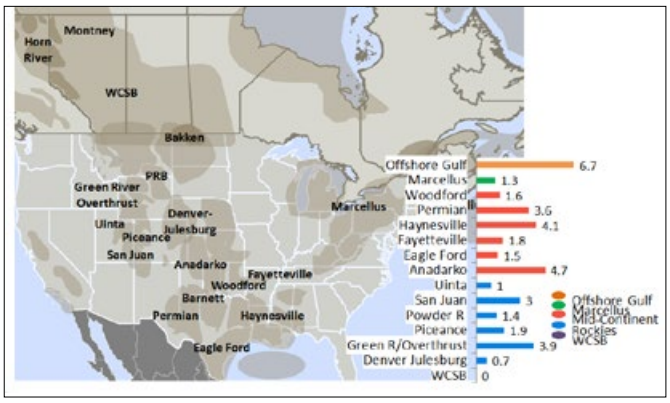
North American Market

The United States is the world's largest producer of natural gas; with the U.S. and Canada combined, the North American natural gas market is responsible for about 26% of total global gas production. Figure 22 depicts the major North American natural gas basins and the relative size of the most significant plays. The North American supply structure has four basic regional components:

- Rockies – includes production in Wyoming, Utah, Colorado, Montana and the Dakotas.
- SE Gulf – includes production in eastern Texas, Louisiana, Arkansas, eastern Oklahoma and the Gulf of Mexico (GOM).
- Midcontinent – includes production in western Texas, western Oklahoma, Kansas and Missouri.
- Appalachia – includes production in Pennsylvania, Ohio, New York, West Virginia, Virginia, Kentucky and Tennessee.

Natural gas is also produced in California, Illinois, Michigan, Mississippi and Alabama, but production in these states is very small when compared to production in the four areas identified above.

Figure 22. ***Major N. American Natural Gas Production Areas & 2010 Production***

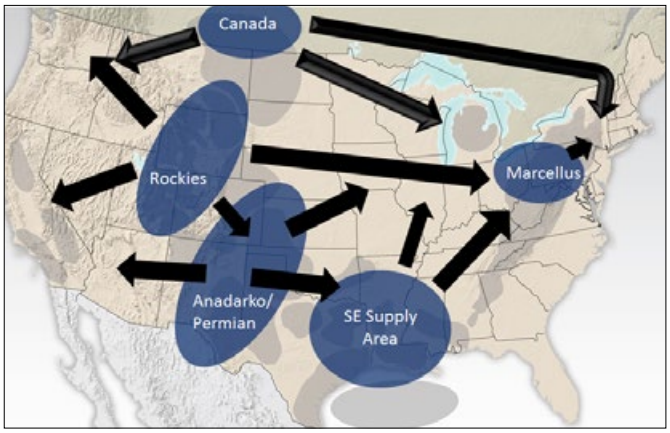


Source: Bentek Energy

The North American interstate and intrastate pipeline system moves gas from the various supply centers to markets throughout the U.S. and Canada. The system entails some 217,000 miles of interstate pipelines (pipelines that cross through multiple states or Canadian provinces) and 89,000 miles of intrastate pipelines (primarily located in Texas, Oklahoma and Louisiana). Figure 23 identifies the major market options that the pipeline network allows producers in each region. They can generally be described as follows:

- Rockies – gas is consumed within the region, flows to West Coast markets, Midwest markets primarily in the Chicago area, and to the Northeast via Ohio.
- SE Gulf – gas is consumed within the region, and flows to the Midwest, Northeast, Southeast and occasionally west across Texas to markets in California.
- Appalachia – gas is consumed in the Northeast, Midwest and in eastern Canada.
- Midcontinent – gas is consumed locally and flows to markets in the Midwest, Southeast and California.
- Canada – gas is consumed in Canada and flows to U.S. markets on the West Coast, and in the Midwest and Northeast.

Figure 23. ***Generalized N. American Pipeline Flows***



Source: Bentek Energy

[9] *Dry gas is defined as gross withdrawals minus gas used for repressuring wells, gas that is vented or flared, non-hydrocarbon gases, and extraction losses. Source: U.S. Energy Information Administration, 2011. www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm*

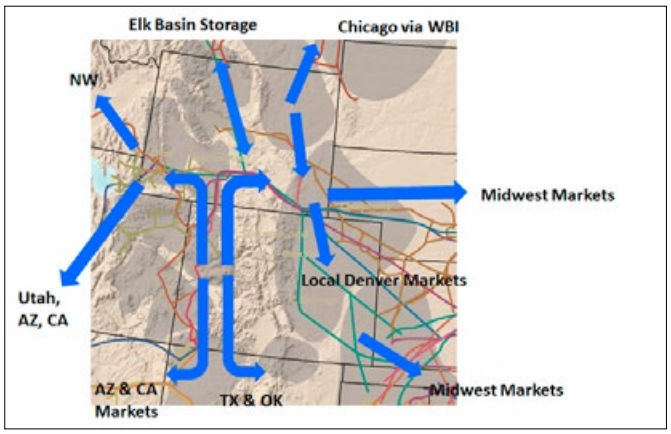
[10] *ICF International, North American Midstream Infrastructure Through 2035 – A Secure Energy Future. Prepared for the INGAA Foundation, 2011.*

The Market in 2007

In 2007 the North American market was on the cusp of a dramatic transformation. Natural gas production in 2007 rose by slightly more than 4% over 2006, or 2.1 Bcf/d. At that time, most actual U.S. growth and expected growth focused on basins in the Rockies. Between 2005 and 2007 the Powder River, Green River, Uinta and Piceance regions of Wyoming, Utah and Colorado accounted for 40% of the incremental gas produced onshore and were the areas expected to grow most dramatically in the coming years.

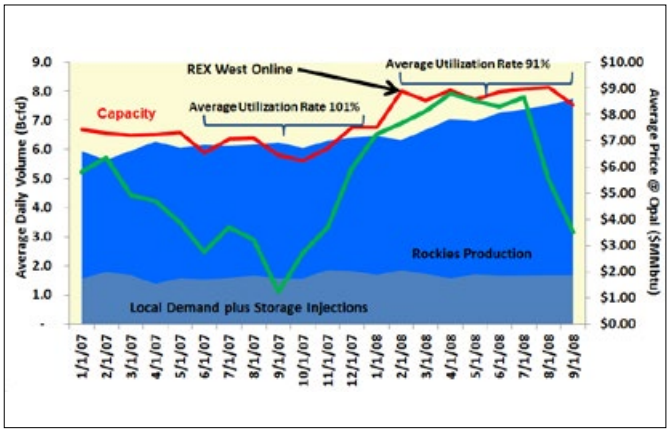
Unfortunately, growth in the Rockies was problematic. Demand within the states that encompass the Rockies' production region was relatively limited, particularly in the non-winter months. A variety of options were available to producers to export their gas to other non-Rockies markets as shown in Figure 24. Gas could flow up Northwest pipeline to the Pacific Northwest; through Kern River and several other options to California markets; through El Paso and Transwestern pipelines to Texas and Oklahoma markets; and through Williston Basin, Colorado Interstate and Kinder Morgan to markets in the Midwest. Combined these various routes had a total export flow capacity of approximately 6.7 Bcf/d.

Figure 24. ***Natural Gas Flows From Major Rockies Producing Regions***



The Rockies' strong production growth soon exceeded export pipeline capacity. As production grew, export pipeline capacity became a constraint that forced Rockies' producers to sell their gas at a discount to the North American "average" cash price as reported at Henry Hub in Louisiana. During the summer of 2007, the constraint problem became acute. Figure 25 compares total production in the Rockies (light and dark blue areas) to total export capacity. The green line depicts natural gas prices as reported by Intercontinental Exchange (ICE).

Figure 25. ***Export Constraints Drove Rockies Gas Price Declines in 2007***



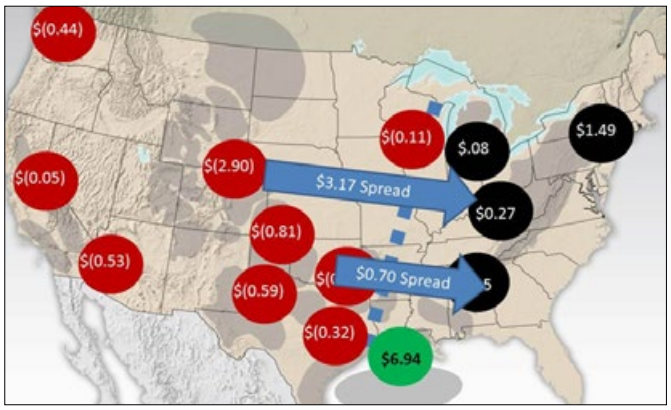
In June 2007 several pipelines unknowingly scheduled maintenance for the same few days and thereby reduced total export capacity by nearly 0.7 Bcf/d. Unfortunately, the maintenance coincided with a sharp uptick in supply. Because capacity became constrained prices quickly fell to as low as $0.05 per MMBtu at Opal in SW Wyoming. The average price in June fell to $8.32 at the Cheyenne Hub compared to $12.61 at Henry Hub.

Later that year in September, Cheyenne Plains Pipeline had a fire at one of its major compressor stations in Kansas and its capacity was reduced by 0.8 Bcf/d. As usual in September, the market and prices are soft. With export capacity reduced and local demand low, prices fell precipitously to an average of $3.89 for the month, $3.84 below the corresponding price for Henry Hub.

The price situation in the Rockies had to change in order for Rockies production to continue to grow. Failure to fix the problem reduced returns, thereby placing Rockies producers at a competitive disadvantage in capital markets relative to producers in other areas. The magnitude of change needed is shown in Figure 26. The map shows the average basis for a sample of key supply and demand points in the U.S.

In North America cash prices are settled at numerous pricing points that have been established over time as reflecting local market conditions. Henry Hub in Louisiana (depicted in green) is the central point because it is the settlement point for NYMEX as well as being a cash settlement point in its own right. Red circles indicate that the price of gas is lower than Henry Hub, meaning that producers selling gas at these points receive less for their gas than do producers able to sell at closer to Henry Hub prices. Black circles indicate prices are higher than Henry Hub. The black circles are limited to the eastern half of the U.S. and reflect the fact that in 2007 very little natural gas was produced east of the Mississippi River.

Figure 26. ***Average Basis At Selected U.S. Pricing Points in 2007***



Whether a price is higher or lower than Henry Hub reflects supply and demand fundamentals. When prices approximate Henry Hub, supply and demand are roughly in balance. When prices fall far below Henry Hub, the market is saying "we have too much gas, please come buy it." The greater the differential, the louder the market is crying for greater demand. Conversely, when market prices exceed Henry Hub, the market is saying, "please send me your gas, I need some". The wider the differential, the greater is the call for more gas.

In 2007 the differential between Cheyenne, a key Rockies price point, and eastern Ohio, a key demand area, was $3.17. Farther south, the west-east differential also existed. The differential between Carthage in east Texas and Transco Station 85, a key SE demand point, was $0.70. Market signals were clearly telling producers to send their gas east, but pipeline constraints were limiting the flow. The market was sending producers a clear signal to invest in more eastward-flowing capacity. Without the investment they could not capture more of the "Eastern premium."

The Market Transformed

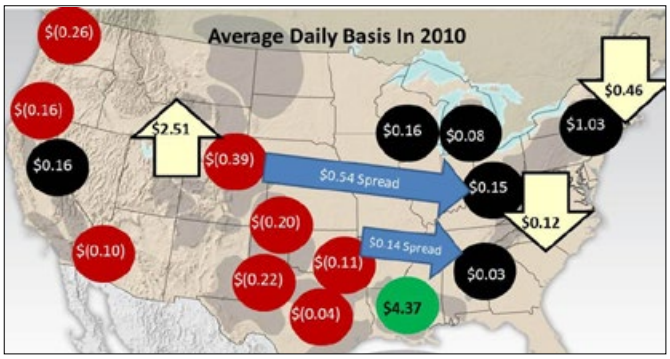
Between 2008 and 2010 pipeline investment coupled with rising production of shale gas transformed the North American natural gas market. In 2005 interstate pipeline investment in the U.S. began to rise. Initially, pipelines such as Cheyenne Plains and REX were intended to allow growing Rockies supply to move to Midwest and Eastern markets. The Rockies Express Pipeline (REX), a $6 billion pipeline constructed to flow gas from western Colorado through southern Wyoming to markets in Chicago and eastern Ohio, was the most significant. With REX producers signalled their willingness to invest significant sums to shrink the $3.17 west-to-east differential and improve the value of their Rockies reserves.

While REX was being constructed the potential of shale gas became evident. Exploration of the Barnett Shale in east-central Texas began in the 1980s, but it was only in the mid-2000s that Mitchell Energy, then Devon and eventually Chesapeake evolved horizontal drilling and hydraulic fracturing techniques to a point where they were able to produce significant productive results. By 2007, producers had learned how to adapt these techniques to drive production growth in the Haynesville in central Louisiana, and the Fayetteville and Woodford areas of Arkansas and Oklahoma. The $0.70 differential in the SE/Gulf area described earlier reflected the fact that production in these areas was growing faster than the pipeline capacity to export gas from the area to markets in other parts of the country.

Between 2008 and 2010, numerous pipeline projects were undertaken to reduce the west-to-east differentials. The REX project mentioned earlier was the first, but the growing shale production in east Texas, Louisiana and Oklahoma prompted construction of some 69 interstate and intrastate pipeline projects in the Southeast with more than 30 Bcf/d of capacity. Many of these pipelines were aimed at improving connectivity within the SE, but several also increased export capacity from the region to markets in the Midwest, East and Southeast. All told, producers underwrote some 6.5 Bcf/d of incremental west-to-east capacity during the 2007-2010 period.

Lower differentials resulted. Figure 27 shows average prices in 2010. Where the Cheyenne-to-Ohio differential averaged $3.17 in 2007, in 2010 it averaged $0.39. Similarly, the SE differential shrank from $0.70 to $0.14. More generally, locational differentials nationwide in 2010 approximated the variable transportation rates that would be incurred when moving gas from one point to another, a classic sign of a relatively efficient market. Producers, through their investments, equalized the value of their commodity across the country.

Figure 27. ***Average Basis At Selected US Pricing Points in 2010***



Conclusions

The North American natural gas market has experienced a profound transformation over the past six years. Production levels have grown an average of 3% per year, much faster than virtually anyone expected in 2005. As a result of sharply higher supply, NYMEX prices have fallen from an average price of $8.69 in 2005 and $8.86 in 2008 to $4.37 in 2010 and even further to $4.00 in 2011. The North American supply/demand balance has changed so profoundly that the forward curve Henry Hub prices does not foresee much of an increase in the gas price. However, the possibility of significant levels of US LNG exports, noted above, may cause US prices to rise. What makes this transformation all the more impressive is the corresponding change that has occurred in the continent's pipeline infrastructure. A major reason for the production surge is the advent of shale development; one key feature of the shale development is that it has occurred in many places that only had limited midstream (gathering and processing) capacity and access to the interstate system. As a result, more than 602,000 inch-miles of new gathering, intrastate and interstate pipelines have been constructed since 2007. While many of these pipeline projects have limited geographic impact on the national grid, several led by REX have opened up major delivery corridors, connecting growing supply areas to new markets. In total these pipeline projects represent more than $32 billion (US) of investment by private entities (principally producers), which leads to the central conclusion of the paper.
The relatively open market that exists in North America, enables price signals to drive infrastructure development. In 2007 pipeline constraints meant that Rockies producers received slightly better than half the price received by producers located in the Gulf and East Texas. Recovering the differential served as an attractive motivation to invest in the incremental capacity needed to equalize prices, and create a more complete and free-flowing natural gas infrastructure network to accommodate production growth for years to come.

4. Price Volatility

Volatility

Price volatility is the relative rate at which the price of a good or service fluctuates within a period of time. If the price of a commodity moves up and down dramatically and unexpectedly within a specific period of time then the underlying commodity is said to have high price volatility and vice versa. Understanding volatility in the natural gas market is important as its behaviour directly impacts capital investments in gas production and consumption as well as hedging decisions.

Variables that trigger imbalances in the supply or demand of natural gas could affect volatility by inducing price movements, which are needed to equilibrate the supply and demand conditions in the market. These variables include temperature changes and weather systems, infrastructure bottlenecks, shocks in the prices of substitute fuels, geopolitical and economic issues as well as speculation and market manipulation in less competitive environments. The frequent introduction of new information can also inject additional volatility in prices in markets where new information is frequently introduced. The US market - being the most liquid and with a fairly frequent flow of information - tends to be more volatile than other less liquid and more regulated markets. The US market, just like other gas markets, is subject to demand shocks, often weather-related, to which supply cannot instantaneously respond. As a consequence, gas prices will rise. However, over a matter of weeks, the US has a rather elastic supply base that, with the help of a sizeable storage capacity, can lead to a prompt response to market signals, which then reduces prices As a result the fact that prices go up and then down relatively quickly leads to a high "measured" volatility. The measured volatility would not be as high in a market where the supply base was not so elastic and/or where storage was not so readily available.

Risks Associated with Volatility

Price volatility results in financial exposure for producers and consumers alike. A high degree of price volatility is generally unfavourable to market players since dramatic price fluctuations increase financial uncertainties and escalate risks. Natural gas producers are sensitive to price volatility as they tend to be exposed to price risk for extended periods of time. The lead time between committing financial resources to produce the commodity and realizing sales after actual flows may be 9 to 12 months. Additionally, the period of production required for a payback on investment might be 5 to 10 years. High price elasticity adds another layer of risk for producers. While movements toward higher prices attract investments in additional production, uncertainty about the sustainability of demand levels at those prices creates added risk. High volatility makes quick responses to market signals somewhat perilous. In the same way, consumers or gas buyers who are heavily reliant on natural gas to sell their products or services are vulnerable during periods of high volatility especially if their ability to readily switch between fuels is limited. Volatility brings about uncertainties pertaining to procurement costs as well as product and services pricing, which in the end affects competitiveness. Buyers need to have the ability to procure reliable supplies of gas with some confidence about cost levels. The risks of recurrent and dramatic price shocks are detrimental to most business models and traders can help market players devise strategies to mitigate these risks.

How to Manage Volatility

Traders find opportunity in volatile markets in at least two ways. Traders offer market participants (producers and consumers) risk management services in order to mitigate volatility. When

producers are contemplating investments to produce gas, they assess the economics of their investments based on the forward natural gas market. To assure they realize these prices when gas production comes on line, they will look to traders to hedge forward the expected production schedule. In the simplest hedging strategy, a trader would buy a fixed price financial swap from the producer at a small discount to the forward market price. The trader will sell the swap in the market to offset the purchase for a few cents higher and earn the difference between the purchase price from the producer and the sale price from the market. Another hedging strategy is for the producer to enter into a costless collar. The producer can establish this by simultaneously buying a put and selling a call, whereby the option premiums are offsetting. This strategy sets a range of prices that the producer will realize for the gas between a cap (ceiling) and a floor. The producer collects money when the market price of gas settles below the floor price and pays money when the market price of gas settles above the ceiling price. These strategies will lock in the revenue stream that was expected at the time of investment and insulate the producer from price volatility. The inverse strategies can be applied for a natural gas buyer.

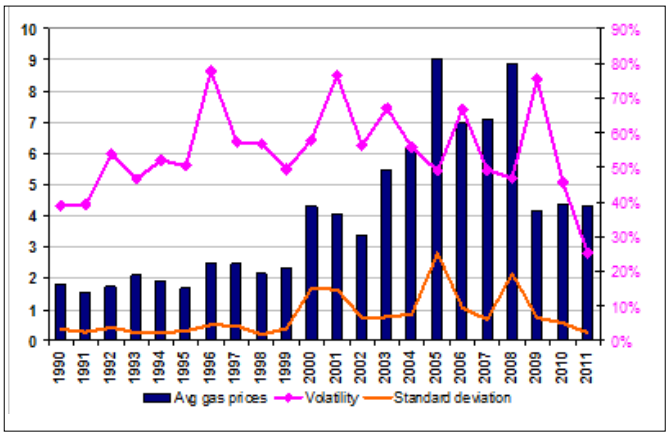
There are many additional variations of hedging strategies that traders can offer and typically the margin to the trader increases for more complicated strategies and in more volatile markets. In speculative trading, traders attempt to predict the direction of the market and will take open positions based on that prediction. Larger market movements or more volatility will net the trader greater profits assuming the market moves in favour of the trade. However, a disciplined trader will have stop loss measures to limit losses if the trade goes negative, in addition to a profit taking exit strategy. Clearly, it would be more difficult to make money in speculative trading if the market is stagnant. It is worth noting however, that risk management instruments to mitigate the effects of volatility will not necessarily decrease the costs of buying or increase the price of selling natural gas in the longer run. On the contrary, there are fees associated with administering hedging programs, which will result in higher costs. The goal of managing volatility is to realize predictable costs or revenues and reduce risks.

It should also be noted that many players in the gas market choose to accept volatility and actually prefer not to hedge. This might be said to be particularly true of the producer community, whose shareholders invest because of the exposure to gas price or oil price risk, and want to be able to invest and get out of the market at the time of their own choosing. Volatility provides upside as well as downside.

The US Market and Volatility

The US natural gas market has for some period been characterized by relatively high price volatility (see chart), particularly during the years following deregulation and the introduction of open access in the late 1980's and early 1990's. In the US, natural gas prices are set by market forces and therefore the value of gas reflects the fundamentals of supply and demand. Buyers and sellers operate in a free price environment with very limited regulations and are subject to market vagaries that can trigger higher levels of price variation. However, despite the considerable variability that natural gas price patterns in the US have shown over the past two decades, the market has only been subjected to significant price spikes a few times during the period. These spikes occurred in the winters of 1996, 2000, 2003, 2005 and in the summer of 2008 and have for the most part been attributed to weather anomalies or hurricane disruptions, except in 2008 when gas prices increased in tandem with the hike in crude prices. Since then, prices have collapsed and volatility has dropped as the 2008/09 global financial crisis suppressed industrial demand and significant volumes of unconventional gas started coming into the market.

Figure 28. ***Price and Volatility***



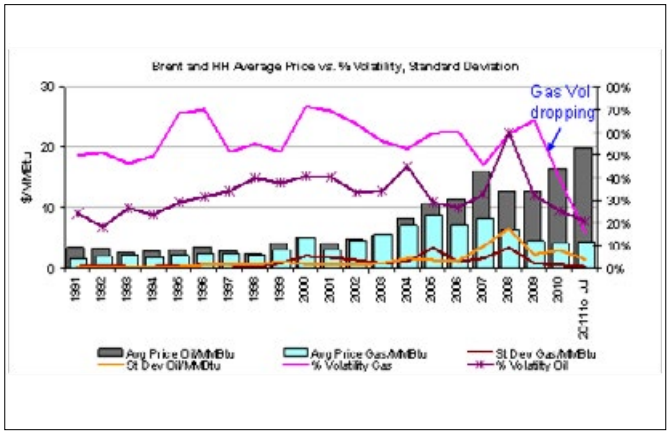
Will Gas Price Volatility Diminish in the US Market

The shale gas phenomenon has had and will likely continue to have a pronounced effect on curbing volatility and its impact on market participants. Increased production from shale gas resources will not only boost supply availability but will also decrease the U.S reliance on declining, hurricane-susceptible-gas from the offshore Gulf of Mexico. The U.S. produced an average of 59.1 Bcf/d of natural gas in 2010, of which more than 65% is unconventional with shale gas representing more than a quarter of total output. This production mix will continue to lead to lower volatility as is starting to be the trend as shown in the graphic above Increasingly, these resources are found closer to demand centres, which will eventually flatten the basis differentials between traditionally disparate supply and demand areas as the need for long distance transportation is diminished. Production from resource bases such as the Marcellus shale is expected to flatten if not reverse the price differential between the midcontinent and the east coast as output ramps up and

the supply demand balance is tipped. In general, output can be brought to market faster, vulnerability to supply disruptions from hurricanes will decrease and uncertainties about supply would be reduced. Industry players believe the US will for the next decades continue to enjoy relatively low natural gas prices as a result of the boom in unconventional gas resources.

In addition to the increased availability of gas supply, the technological advances in extracting shale gas, have contributed to changing the fundamentals affecting gas and oil supply and demand balances. Gas is now a growing resource and oil's availability remains constrained, which if continued could sustain the recent trend of their price de-coupling even beyond the domestic U.S. market. The gas supply surge and increased commercialization of gas resources via LNG have already helped reduce the reliance on traditional supply sources and facilitated in easing the price correlation between oil and gas in some markets. With gas in the U.S. currently priced at around a fourth of the value of oil in thermal terms, LNG and gas contracts that correlate with spot gas market indices could be more immune from oil market price shocks amid political turmoil in most oil producing countries.

Figure 29. ***Oil and Gas Price Volatility***



Although it is difficult to predict with certainty where volatility levels will go in the future, the impact of volatility will likely be moderated in the low gas price environment that industry participants expect for years to come as a result of this shale gas bounty. Lower deviations in absolute dollar amounts are in store even in the unlikely scenario where volatility levels remain the same. Relatively low percentage volatility in an environment of high prices can result in greater economic exposure than a higher degree of volatility in a moderately priced market.

5. Long Run Marginal Cost as a Price Driver

This section has considered a number of drivers that might impact gas prices including the fuels gas competes with, in various markets, the impact of infrastructure constraints and changing supply patterns using the North America market as an example, and review of volatility and how financial instruments can be used to offset it. In this final part, the cost of delivering gas to the market will be considered, in particular the role of long run marginal cost (LRMC) as a price driver.

Figure 30. ***Supply and Demand for Gas***

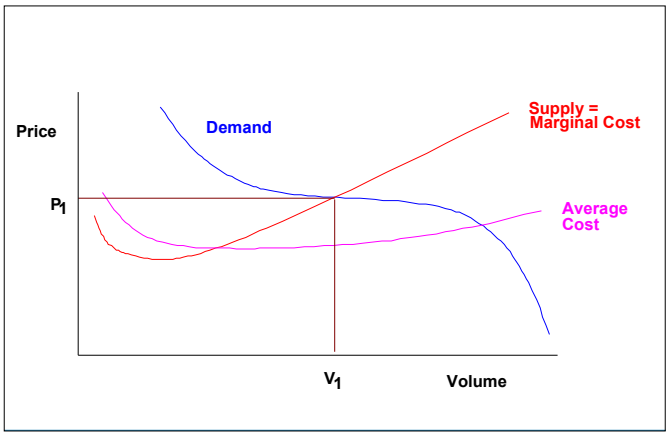
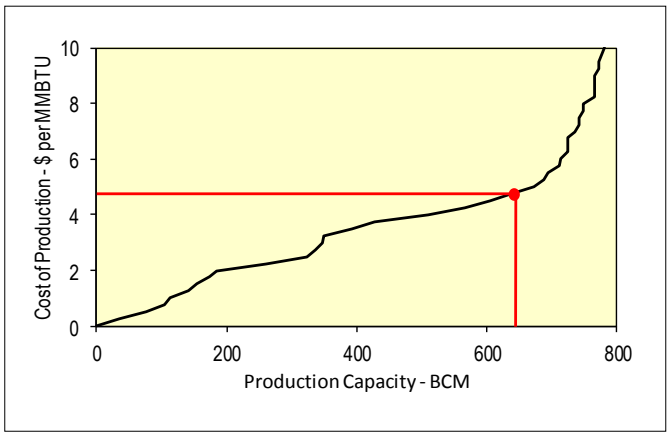


Figure 30 depicts an example of how the supply and demand for gas might interact in a competitive market such as North America. It is assumed that the price is set so as to clear the market based on the following parameters:

- The demand curve is inelastic at high prices and low prices, where there is little scope for fuel-switching, and elastic in the middle range where demand for gas can change readily depending on relative fuel prices;
- The supply curve is identical to the LRMC; and
- The average cost curve cuts the LRMC curve at its low point, and then the demand curve at a lower price than the competitive market price.

In this competitive market, the equilibrium market clearing price would be equal to the LRMC, which is rising as more volume is brought to the market. In respect of the North American market, the additional volume could come from additional drilling for conventional or unconventional gas or more imports by pipeline or LNG. An example supply curve for US gas production is shown in Figure 31. Any imports of gas by pipeline or LNG would add additional effective capacity.

Figure 31. ***US Supply Curve***



Source: Nexant World Gas Model. The cost of production represents the wellhead cost and there would be additional costs to deliver the gas to market hubs.

In the real world the observed actual market price can be expected to diverge from the LRMC for a number of reasons:

- Most commodity markets, particularly those such as gas, where storage of the product is not easily available, do not adjust instantaneously to changes in supply and demand fundamentals, and so will tend to "move towards the equilibrium price", but are likely to be overtaken by other events which change the equilibrium price again. The actual price, therefore, will be trying to adjust towards the equilibrium price, but may never actually get there. While competitive markets can be described as being "efficient" most of the time, meaning that prices adjust rapidly to the new equilibrium, they are not necessarily efficient all the time, which means the actual price would differ from the equilibrium price over significant periods of time.
- Depending on the point at which the demand curve cuts the supply curve it could be the short run marginal cost (SRMC) which is the market clearing level rather than LRMC Commodity markets are renowned for overshooting, partly because of the stickiness in supply reacting to demand and vice-versa, but also because of the lack of perfect information. Price may need to rise above the equilibrium price to encourage more supply into the market or fall below the equilibrium price to encourage more buyers into the market.
- The spot gas market is not a fully competitive market in every case and will be influenced by other prices such as the price of gas under long term contracts in the region as well as competing fuels. For example, the UK NBP price may be largely determined by supply and demand under gas-on-gas competition, but part of that "gas competition" will be with long term contract price gas in continental Europe, largely linked to oil product prices, as the UK both exports and imports gas. Similarly the price of spot LNG in the Far East will be impacted by long term LNG contract prices, linked to JCC. In the North American market, the situation is somewhat different in that there is not the equivalent of the long term contract price but it might be expected that spot prices would in part be impacted by the prices of competing fuels, especially in the power generation market and especially coal prices.

In practice the market price of gas might be expected to settle somewhere between the cost curve, as represented by the LRMC, and the competing price, whether this is the price of a competing fuels or competing gas under long term contracts. Where the market price does settle would be largely impacted by the tightness of the market. The tighter is the market then the closer the market price might be expected to be to the competing price and the slacker is the market the closer the market price might be expected to be to the LRMC price.

It is important to understand that there is no reason why the market price should not go above the competing price or below the LRMC price depending on the level of the "market tightness". It is reasonable to suggest that this phenomenon has been observed in recent years. For example, since early 2009 Henry Hub prices have been consistently below $5, and for much of the time below $4. Most industry experts would consider that this was below the LRMC Price, even given the supply-demand balance in the USA. This would suggest that many producers continue to produce and sell gas at below the LRMC, but above the short run marginal cost of fields already developed and in production.

F. Impact of Tax or Cap and Trade Policies

1. Introduction

The intention of this section is to assess how a carbon tax or "cap and trade" policies would affect gas price formation. The section will begin with a brief history of international climate policy and move on to a description of carbon tax and cap and trade policies and the advantages and disadvantages of them both. Finally the possible impact on gas prices of a carbon tax or cap and trade policy will be assessed and the level of gas demand, both in absolute terms and relative to other fossil fuels.

2. International Climate Policy

A Brief History of International Climate Policy

As early as 1988 - Intergovernmental Panel on Climate Change (IPCC) starts warning about climate change. The result was, in 1992 the Earth Summit in Rio de Janeiro: Signing of U.N. Framework Convention on Climate Change (UNFCCC), which entered into force in March 1994. This set a voluntary goal of reducing emissions from developed counties to1990 levels by 2000.

In December 11, 1997 the Kyoto Protocol was adopted. This was ratified by 186 nations, but not the United States. The goal was to collectively reduce emissions of GHGs at least 5% in 2008-2012 compared to the baseline year 1990. 3 flexible mechanisms were considered:

- International emissions trading (global cap-and-trade)
- Clean Development Mechanism (offsets)
- Joint Implementation (using comparative advantage)

On February 16, 2005, the European Union's Emissions Trading Scheme (EU-ETS) was launched. This covered 12,000 installations in 25 countries and 6 sectors. The facilities covered included electricity and heat production plants greater than 20MW capacity, oil refineries, coke ovens, metal ore and steel installations, cement kilns, glass manufacturing, ceramics manufacturing, and paper, pulp and board mills

In Late 2007 – Governments adopted the Bali Roadmap, launching negotiations toward a new global climate agreement and this was followed in December 2009 by the Conference of the Parties (COP) in Copenhagen, Denmark, with the goal being to discuss a replacement for the Kyoto Protocol and deliver a comprehensive new climate change agreement post-2012. However, a binding agreement for long-term action was not achieved, but a 'political accord' was negotiated by some 25 parties including US & China, referring to a collective commitment by developed countries for new and additional resources, including forestry and investments through international institutions, that will approach $30 billion for the period 2010 – 2012.

In August 2010 there was a Conference of the Parties (COP) in Cancun, Mexico, which reached agreement recognizing:

- that climate change represents an urgent & potentially irreversible threat to human societies & planet, & thus requiring a urgent address by all Parties
- that most of observed increase in global average temperatures since mid-20th century is very likely due to the observed increase in anthropogenic GhGs concentrations
- a reduction of global GHG emissions to hold the increase in global average temperature below 2°C above pre-industrial levels
- a "Green Climate Fund" to assist poorer countries in financing emission reductions and adaptation

However, no agreement was reached on how to extend the Kyoto Protocol, nor how the $100 billion a year for the Green Climate Fund will be raised, or whether developing countries should have binding emissions reductions or whether rich countries would have to reduce emissions first

Finally between November 28th and December 9th, 2011, COP 17 was held in Durban, South Africa. This did not reach any binding agreement only an agreement to negotiate a new and more inclusive treaty and establish a Green Climate Fund.

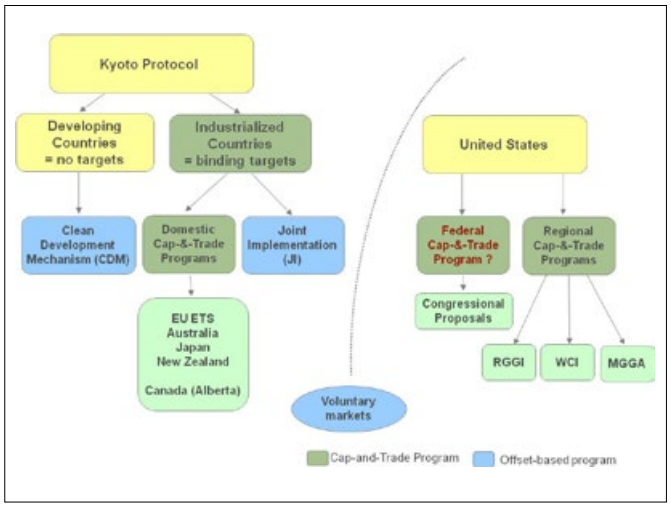
International Carbon Market Mechanisms

A Market Mechanism helps to create a price for GHG emissions and allow market forces to minimize the cost of making substantial reductions stimulate technology & innovation.

The Major Mechanisms are:

- Emissions Cap-and-Trade
- Carbon Tax or Per Ton Emissions Charge
- Renewable Portfolio Standard (RPS) with Certificates Trading
  - A minimum amount of electricity will come from renewable sources
  - RE providers compete to supply the load-serving entity with certificates, ensuring that the lowest cost RE is obtained
- Low Carbon Fuel Standard (LCFS) with Certificates Trading
  - All fuel must meet a low carbon fuel standard by a certain date, i.e. carbon attributable to fuel must be reduced by X% by date.
  - Instead of making all producer meet the standard, producers can buy credits from other producers that are able to exceed the standard
- "Individual Transferable Quotas"

Figure 32. ***International Carbon Market Mechanisms***



3. Cap and Trade v Carbon Tax

Description

A Cap-and-Trade policy works as an overall emissions cap set by the Government, with tradable allowances issued which grant businesses the right to emit a set amount. The amount that can be emitted generally declines each year. Businesses which can reduce their emissions faster can sell their allowances to those who would otherwise have to play more to comply. Under Cap-and-Trade emissions reductions are fixed by a cap and the price of carbon is a function of supply and demand in the emission market.

A Carbon tax policy works by the Government imposing a tax per ton of carbon emitted. The emissions reduction is uncertain but the price of carbon is known and set at the level of the tax.

Why a Cap and Trade System

Cap-and-Trade should produce the desired environmental targets at the lowest cost whereas the outcome under a carbon tax is unknown in terms of emissions reductions. Cap-and-Trade provides effective price signals and responds to changing economic circumstances. It is also more flexible and can be readily linked to establish a single comparable global carbon market

Why a Carbon Tax

A Carbon tax will lend a degree of predictability to energy prices, providing cost certainty, whereas Cap-and-Trade is likely to aggravate price volatility. A Carbon tax is transparent and easy to understand and can be implemented relatively quickly, can be applied to all market sectors, while Cap-and-Trade generally apply mainly to the power generation sector. A Carbon tax raises revenues for Governments which could be used to cut taxes elsewhere or be spent on other energy saving projects.

4. Possible Impact on Gas Prices: USA Analysis

Since both Cap-and-Trade and Carbon tax are relatively new policies with little experience of how they operate around the world. In determining the possible impact on gas prices, therefore, much of the available analysis relies on a more theoretical approach. The analysis below draws heavily on calculations using US market data which is often more readily available than in other countries.

Economics of Pricing:

The Cost of CO_2 Restrictions in the Production of Electricity

Electrical production accounts for approximately 40% of the CO_2 produced in the U.S. (of which 33% comes from coal). With current technology, replacing all existing coal generation plants with modern state-of-the-art coal generators would reduce CO_2 emissions by only 5%[11].

Our goal is to calculate the cost of a CO_2 constraint (such as would result from cap-and-trade and other similar policies) by modeling the displacement of coal by gas in the production of electricity. We assume that at present, and for at least the next decade, base load electrical generation capacity will come from coal and natural gas, and the process of reducing CO_2 emissions in the United States will be substantially through the displacement of coal-fired generation by natural gas. The difference in carbon intensity between marginal coal generators and natural gas generators allows us to calculate the cost of a CO_2 constraint. Beyond that period, reductions in CO_2 must come from reductions in transport fuels or the replacement of gas electricity generation by nuclear power or renewables, etc...

The cost per metric ton of CO_2 emissions that would make marginal a gas generator with a heat rate Rk, depends on the cost of coal and gas as fuels and the capital cost of gas generators:

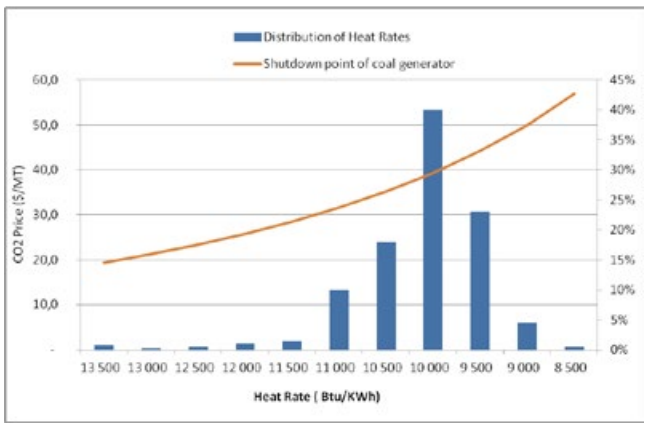
Rj = *heat rate of generator (coal = R1 = 8870 Btu/kWh*[12]*; gas = R2 = 6800 Btu/kWh)*
Ej = *CO_2 emission (coal = E1 = 0.839 MT of CO_2 per MWh; gas = E2 = 0.361 MT of CO_2 per MWh)*
aj = *CO_2 produced per MWh (Ej/Rj)*
bj = *Capital cost (coal = b1 = $28/MWh; gas = b2 = $10/MWh)*
cj = *Fuel cost ($/MMBTU) = Fuel Price ($/MMBtu) * heat rate (kWh/Btu)*
Fuel Price (coal = c1 = $1.5/MMBtu; gas = c2 = $5.0/MMBtu),

dj = Variable overhead and maintenance costs (coal = d1 = $8/MWh; gas = d2 = $2/MWh)
Pj = price of electricity revenue ($/MWh) = a1+b1+c1+d1 = a2+b2+c2+d2

The distribution of heat rates of coal generators in an important element. Approximately 90% of coal generators in the US have heat rates between 9,500 Btu/kWh and 11,500 Btu/kWh, as opposed to the modern efficient plant assumption of 8,870 Btu/kWh in the calculation above. This concentration in the heat rates of coal generators is what determines the shape of the curve that relates the price of CO_2 emissions to a reduction in CO_2. This concentration of heat rates also restricts the range over which CO_2 prices are effective in managing the displacement of coal by gas.

Figure 33. ***Distribution of the Heat Rates for Coal Generators in the US by Capacity and CO_2 Prices***

(assumed coal price = $1.50/MmBtu and gas price = $5/MmBtu)

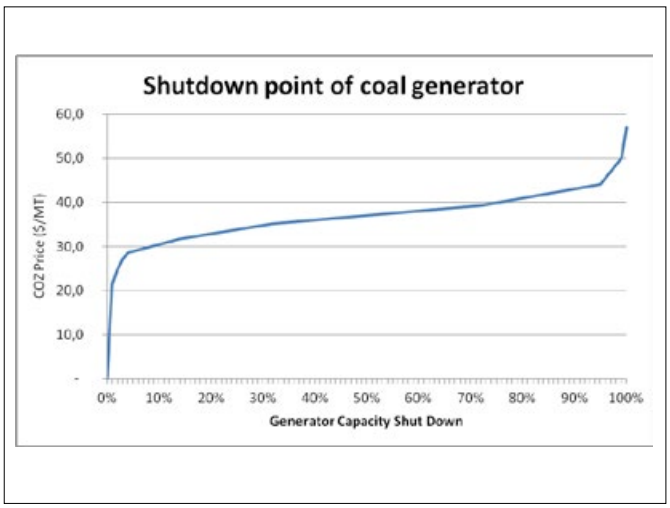


In the sample calculations, at a coal price of $1.50/MmBtu and a gas price of $5/MmBtu, a CO_2 price of $28.50/Mt would cause around 10% of coal generation capacity to shut down. At a CO_2 price of $45/Mt, 90% of coal generation capacity will shut down. These high numbers represent the theoretical shutdown point of existing coal generators (point when average variable cost is greater than the price). Calculating the CO_2 price for various values of the price of coal and gas results in shifts of the curve, but the property of a narrow operating band remains. This narrow band of prices has two interesting implications:

- The price of CO_2 that eliminates coal generation is not sufficiently high to have a large impact on the consumption of petroleum. So, any CO2 price that would significantly reduce the consumption of transport fuels would have to be of a level that would completely shut down coal generators.
- The narrow range for the CO_2 price means that the elasticity of coal generator capacity with respect to the price of CO_2 emissions is very high. This means that the supply of coal generator capacity would very sensitive to the price of CO_2 emissions that could result from cap-and-trade. The high elasticity of coal generators coupled with the fact that short run demand for electricity is very inelastic creates the possibility that cap-and-trade will result in high volatility in the market for electricity. The elasticity of coal generator capacity is above 6 for a percent change of coal generation shut down less than 70. A 1% change in the price of CO_2 emissions would cause 6% of coal generation capacity to shut down.

Figure 34. ***Price of CO_2 as a Function of Coal Generator Capacity Shut Down***

(assumed coal price = $1.50 MmBtu & gas price = $5 MmBtu)



[11] In 2008, total U.S. CO_2 emissions were 5.92x109 metric tons, of which 1.95x109 metric tons were produced by coal generating electricity. 1.99 x109 MWh were produced by coal generators. The CO_2 that would be produced if the existing stock of coal generators were replaced by modern generators (using MIT numbers for modern coal generators) is:

1.99 x109 MWh x 0.839 tons/MWh = 1.67 x109 tons or [(1.95-1.67) x109 tons / 5.92 x109 tons] x 100 = 4.98%

[12] This is the assumption for a modern coal generator, i.e. an efficient one, and not the least efficient which would be the marginal coal plant

The Role of Fuel Switching in Lowering CO_2 Emissions from Electricity Production

The marginal fuel-switching costs from highly carbon-intensive sources of energy (such as coal) to lower carbon-intensive sources for power and heat generation (such as gas) constitute another important determinant of the CO_2 price. A carbon-pricing policy could discourage the use of CO_2-emissions-intensive fuels and generation technologies. The third phase of the European Union Emissions Trading Scheme (EU ETS) starting in 2013, together with the possible emergence of new carbon market mechanisms and carbon taxes (e.g., in Australia, Chile, some Chinese provinces, Japan, Korea, Mexico, New Zealand, and some US states), could trigger significant changes in the operation of electricity generators.

Fuel switching, especially from coal to gas, is an effective short- to medium-term measure used to abate CO_2 emissions in electricity generation. In the presence of a price on CO_2 emissions, fuel switching will be the first-business response to reduce operating costs and CO_2 emissions.

The econometric methodology measures the responsiveness of fuel use in electricity generation to changes in international coal, gas and oil markets – in economics terms, it estimates fuel price "elasticities" of demand.

The following function estimates the total fuels cost:

$$Si = \alpha i + \beta iq \log Q + \beta ik \log K + \alpha i1 \log P1 + \alpha i2 \log P2 + \alpha i3 \log P3$$

where:

Sj = total fuels cost, where index I = 1, 2, 3 refers to coal, gas and oil;

Qi is electricity generated from fossil fuels;

K is generation capacity;

Pi are fuel prices;

βiq, βik and αij are regression parameters

The underlying estimate of the cost function can be assumed to stay the same, but changing cost shares will affect elasticities and therefore, the size of response to carbon prices. For example, a high elasticity, such as in the case of the oil-gas elasticity in the US, can be due to a low cost share of a fuel in the generation mix.

The "cross-price elasticity" is defined for changes in the price of only one fuel (and changes in the use of another fuel) as:

ηx (elasticity of demand of fuel X to the price of fuel Y) = = [% change in demand of fuel X] / [% change in price of fuel Y]

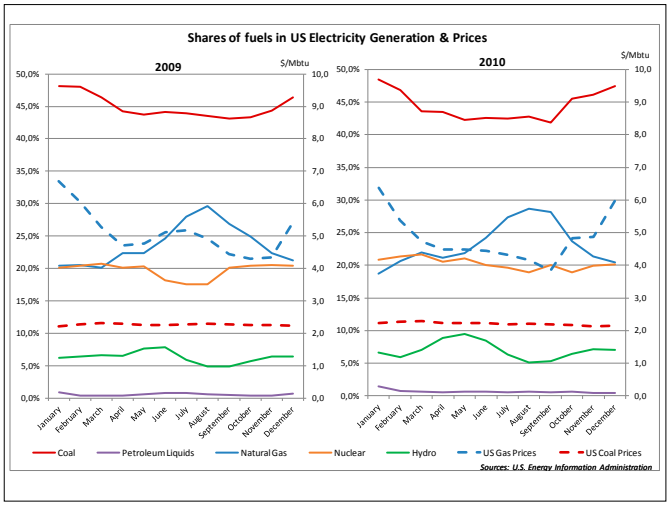
However, since CO_2 is emitted by both coal and gas, changes in the price of CO_2 simultaneously affect costs of coal and gas generation. We therefore need to use another measure of substitution, and one of the classic definitions, the "behavioural elasticity of substitution":

σ (elasticity of substitution between fuels X and Y) = [% change in relative demand] / [% change in relative price]

The switching between coal and natural gas in the US power sector provides us with an illustration of how fuel use is affected by relative fuel prices. Although there is currently no carbon price in place at the federal level in the United States, the core of the analysis is an estimation of changes in fuel use in response to price changes. Estimates suggest that the cross-price elasticity from changes in the price of gas to changes in the demand for coal is 0.263 while the cross-price elasticity from changes in the price of coal to changes in the demand for gas is 8.802. This would suggest that a 50% increase in the price of gas would trigger a 13.2% (0.263 x 50%) increase in demand for coal. Likewise, a 50% increase in the price of coal would, theoretically, increase gas demand by 440% (8.802 x 50%).

The next figure shows a clear correlation between short-term seasonal changes in fuel prices and fuel choice. Coal price does not demonstrate great seasonal fluctuation. However, the seasonal nature of natural gas fluctuations creates seasonal variation in the price of coal relative to gas.

Figure 35. ***Shares of Fuels in US Electricity Generation and Prices***



Interrelationship between the CO_2 Prices and Gas, Coal and Power Prices

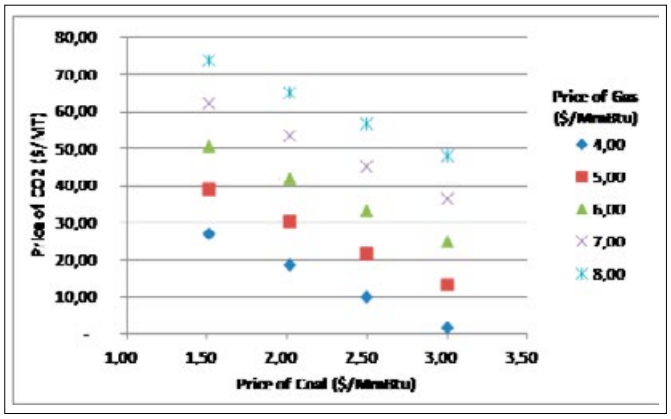
There are several studies on the influence of gas and coal prices on CO_2 price, of which:

- Christiansen et al. (2005) identified several factors as being the price determinants in the EU Emission Trading Scheme (EU ETS): policy and regulatory issues; market fundamentals, including the emissions-to-cap ratio, the role of fuel-switching, weather and production levels.

- Mansanet-Bataller et al. (2007) and Alberola et al. (2008a) were the first analysts to uncover econometrically the relations between energy markets and the CO_2 price.
- Bunn and Fezzi (2009) further quantify the mutual interactions of electricity, gas and carbon prices in the daily spot markets in the United Kingdom. By using a structural, co-integrated vector error-correction model, they showed how the prices of carbon and gas jointly influence the equilibrium price of electricity. They derived the dynamic pass-through of carbon prices into electricity prices, and the response of electricity and carbon prices to shocks in the gas price. Gas drives carbon, whilst both carbon and gas drive electricity prices. The recent National Petroleum Council Report, which calculated the levelised cost of electricity, suggested that at carbon prices below $50/MT, natural gas is advantaged relative to coal and nuclear, but above $50/MT, nuclear is more advantaged, certainly at higher levels of gas prices above $12/MMBtu. At gas prices less than $6/MMBtu, nuclear would only become advantaged at carbon prices over $100/MT. Natural gas has a clear advantage over coal at prices below $10/MMBtu whatever the carbon price.
- The general conclusions were that a shock on gas prices increases the overall prices of the 3 commodities. However, the temporal dynamics and the magnitudes are different. In fact a gas price increase has its highest impact over the first few days and then its effect fades.

A possible way to calculate the sensitivity of the price of CO_2 to the price of fuels is to calculate the price of CO_2 that would shut down a given fraction of the coal generating capacity as a function of fuel price. For example, we can calculate the price of CO_2 emissions that would shut down 70% of coal generating capacity. This would require shutting down coal generators with heat rates greater than 10,000 BTU/kWh.

Figure 36. ***Relative Prices to Shutdown 70% of Coal Generating Capacity***



Any forecast about the price of gas and coal must be conditional on policy. The price of gas will depend substantially on the increased demand for gas from electrical generation. The demand for gas will depend on policy decisions about nuclear power and renewables.

Impact of Carbon Tax Conclusions

A CO_2 tax could influence CO_2 prices through a number of different mechanisms pulling in different directions. Almost certainly a CO_2 tax would make electricity more expensive, which would a downward pressure on demand. It would also increase the costs of operating gas fired power plants. Both of these factors would put downward pressure on gas prices. However it would also increase the costs for generators using coal, who would seek higher electricity prices and perhaps close some capacity. This mechanism could increase the price the price of electricity and hence the price that generators are willing to pay for gas.

In the short/medium term gas is competing with coal. However over the very long term – say 20 plus years – the competing technology might be renewables. Since renewable power generators won't have to pay CO_2 tax, at first sight there would be no forces to offset the downward pressure on gas prices in this situation. However even here the answer is not entirely straightforward: most renewable energy sources are not fully dispatchable, so as the proportion of renewable energy in the mix rises, there is an increasing need for load balancing, which in turn increases the value of flexible capacity such as gas fired power plants.

As to the question of whether a CO_2 Tax would help or harm gas prices, the answer is likely to depend on:

- the competing fuels
- the time horizon
- the efficiency of the existing gas powered fleet, and its competitors
- the level of the CO_2 tax
- the existing level of gas and oil prices
- the load curve
- the future development of technology in terms of cost and efficiency

Overall our consensus view is that a CO_2 tax of $30-40/Tonne would provide a modest boost to gas prices in the short/medium term (up to 5 years) but could depress prices in the longer term (beyond 20 years). Clearly the level the tax was set at would be a key factor.

[13] *Realizing the Potential of North America's Abundant Natural Gas and Oil Resources. National Petroleum Council, 2011. www.npc.org.*

F. Conclusions

This report on Wholesale Gas Price Formation for the 2012 World Gas Conference was intended to build on the work undertaken for the previous World Gas Conference in 2009. Specifically, the Wholesale Gas Price Formation Survey was continued for 2009 and 2010; the extent to which there is globalisation or regionalisation of gas prices and particularly the future of oil price indexation was examined; an analysis of price drivers including a review of competing fuels to gas and hub trading and pricing patterns in North America; and an analysis of the impact of carbon tax or cap and trade policies on gas price formation.

A key conclusion of this report comes from the Wholesale Gas Price Formation Survey for 2010 which confirms the continuing trend towards gas-on-gas competition in world markets and away from oil price indexation. The share in the gas-on-gas competition category has risen from 30% in 2005 to 32% in 2007, to 36% in 2009 and 39% in 2010. The key change from 2007 to 2009 and 2010 was in the Former Soviet Union following the changes in the domestic Russian market, which has added some 5.5% to the share since 2007. The share in Europe, though, has been increasing steadily from 2005 through 2007 and 2009 as the importance of continental trading hubs increases, at the expense of oil price escalation. In addition, in 2010 in Europe, the move to gas-on-gas competition was enhanced by the introduction of elements of spot price indexation in long term contracts. By 2010 the share of gas-on-gas competition in Europe had reached over 36% compared with 15% in 2005. The oil price escalation share declined between 2005 and 2007, but then the structural change in the intra-FSU market as pricing switched from bilateral monopoly, led to an increase in its share, followed by a further small decline in 2010. Apart from this structural change, the underlying decline over time has been wholly down to the changes in Europe, partly offset by a slight increase in the share in Asia between 2007 and 2010, as the new East Coast Indian production came on-stream and Chinese imports increased.

Despite the trend towards gas-on-gas competition, there is little evidence, as yet, of any move towards a global gas price, even to the extent that prices might move together, reflecting only basis differentials. In fact, with the surge in shale gas supply in the US, Henry Hub prices seem to have largely decoupled from gas prices elsewhere in the world, trading at much lower levels than European and Far East spot prices. European hubs have seen an increase in trading and liquidity but only at the NBP, and possibly TTF, could trading and liquidity claim to be at the sort of levels approaching the US market.

The debate on the future of oil price indexation in long term contracts continues, especially in European markets. The key arguments from the supporters of the continuation of oil price indexation in contracts would appear to rest largely on the competition between oil and gas not only in the end user demand markets, but also on the supply side, the greater confidence in the tradability of oil as opposed to gas and the lower volatility in oil prices. The proponents of a move away from oil price indexation point to the lower level of competition between oil and gas in the end user demand markets, that gas is now clearly a separate commodity market from oil and the view that growing LNG trade brings more linkages between the previously separate regional markets, thereby enhancing trade and liquidity. There are some examples that oil price indexation and gas-on-gas competition price mechanisms are integrated to some degree. In some end-user European markets prices move through the year in line with oil prices, but with the base price level determined on gas hub (forward) price levels.

The section on gas price drivers analysed some of the key issues in more detail; in particular, the trends in competing fuels to gas in different markets. Oil and oil products, remain important alternatives to gas and electricity in the residential and commercial markets (the predominantly space heating load markets), but its importance has been declining in all markets, and the extent to which oil actually competes with gas, once a gas network has been built is questionable. In the industrial market, electricity largely remains the key alternative fuel to gas, with coal and oil also important competing fuels. Oil has been generally declining as a competing fuel, but in Japan oil is still widely used in industry and is the key competing fuel to gas. Finally, in the power generation market, coal is seen as the main competing fuel to gas, with nuclear and hydro also important alternatives. In many markets such as the US, UK and Germany, oil as a power generation fuel has almost disappeared. Even in Japan, where it was once the main alternative to gas, oil has been in constant decline and is well behind coal and nuclear as alternatives to gas.

Gas price drivers in the US market are also discussed and illustrates that large divergences in spot prices, over and above the normally expected transportation differentials are not only possible for sustained periods of time, but in some cases may also be desirable. The large differential that opened up between Henry Hub and Rocky Mountain gas signalled the need to develop more pipeline infrastructure to evacuate Rockies gas to more profitable markets. Once this was built the basis differentials narrowed and currently the development of shale gas reserves in different areas of the US is causing basis differentials to change again.

A discussion of price volatility, focussed on the US market, notes that high levels of volatility creates uncertainty for all the players in the market, especially for producers and end users. In a fully liquid trading market, however, there are tools through which buyers and sellers can limit volatility and hedge positions. Volatility, however, also serves a useful purpose in that it provides price signals. Measuring volatility

in percentage terms is not always the most appropriate way to look at the issue. The same percentage volatility in a high price environment exposes the participants to greater monetary risk than in a lower price environment.

The marginal cost of delivered gas is also seen as an important price driver, but its impact varies depending on market conditions. In a tight market, "competing" prices to spot gas are likely to be a key factor – these competing prices could be a competing fuel, such as coal in the power generation market, or a competing gas price, such as the long term oil linked contract price. In a surplus market, however, marginal cost becomes more important in terms of a possible floor for prices, although there would appear to be evidence from the US at least that the short run marginal cost may be the real floor rather than the long run marginal cost.

The analysis of the impact of a carbon tax or cap and trade policies on gas prices is still at a relatively early stage, since there is little or no experience or data to take into account. Preliminary conclusions from modelling in the US suggests that, at least at low levels of a carbon tax, short term demand for gas would rise at the expense of coal, thereby putting upward pressure on gas prices. The longer term impacts at possibly higher levels of carbon tax remain more difficult to quantify but economic theory would suggest that at some point gas begins to lose market share in the power generation sector to renewables.

There have been significant changes in gas prices and gas price formation mechanisms in the last five years and this seems set to continue in the near future. The whole long term contracting structure in Europe, using oil price indexation, is under pressure and some contracts are in arbitration and some in the process of being renegotiated, as buyers seek to move to spot or hub-based pricing. The fundamental argument on the future of oil price indexation in Europe would seem largely to come down to the extent to which the hub and spot trading markets are sufficiently liquid such that the participants can have full confidence in the price transparency, ability to trade and the lack of any market manipulation, allowing the underlying forces of supply and demand to be fully taken into account. Changes in the Far East – the other major market area, excluding of course North America – have been very little so far. This seems unlikely to change in the near future in the absence of any significant moves towards the liberalisation in the downstream end-user markets in Japan, Korea, China and India in particular. It was the drive to liberalisation and the introduction of competition into North America and Europe (starting with the UK) which drove the change in pricing mechanisms in those areas.

A1. Appendix 1

Wolesale Gas Price Formation Survey – Summary regional data

1. 2010 Survey

2010	Total Consumption - BSCM									
	OPE	GOG	BIM	NET	RCS	RSP	RBC	NP	NK	TOT
North America	0.0	827.2	0.0	0.0	0.0	0.0	0.0	12.0	0.0	839.2
Latin America	24.7	24.3	6.9	16.1	9.0	59.3	0.0	0.0	0.0	140.3
Europe	349.4	217.2	2.4	1.0	12.4	5.8	0.5	4.7	0.9	594.2
Former Soviet Union	81.5	180.9	29.5	0.0	258.7	20.4	88.3	2.8	0.0	662.0
Middle East	23.4	2.9	30.0	2.3	0.0	139.0	171.0	2.7	0.0	371.2
Africa	7.4	0.0	4.2	0.8	0.8	1.9	86.7	0.7	0.0	102.6
Asia	90.3	3.7	3.2	0.0	112.0	26.9	3.3	0.0	0.0	239.4
Asia Pacific	187.1	25.8	47.3	0.0	9.5	73.6	0.0	3.2	0.0	346.5
Total World	**763.7**	**1 282.1**	**123.4**	**20.2**	**402.4**	**326.9**	**349.8**	**26.1**	**0.9**	**3 295.4**
	23.2%	*38.9%*	*3.7%*	*0.6%*	*12.2%*	*9.9%*	*10.6%*	*0.8%*	*0.0%*	*100.0%*

2. 2009 Survey

2009	Total Consumption - BSCM									
	OPE	GOG	BIM	NET	RCS	RSP	RBC	NP	NK	TOT
North America	0.0	793.7	0.0	0.0	0.0	0.0	0.0	9.5	0.0	803.2
Latin America	19.8	17.3	6.0	16.2	13.0	58.3	0.0	0.0	0.0	130.6
Europe	378.7	152.4	2.3	1.0	0.0	18.6	0.4	4.6	0.0	557.9
Former Soviet Union	62.1	109.1	24.6	0.0	303.4	14.6	88.3	3.6	0.0	605.7
Middle East	19.8	0.9	32.9	0.5	0.0	128.2	159.8	4.3	1.1	347.3
Africa	6.9	0.0	3.5	0.8	0.7	8.8	77.0	0.7	0.0	98.3
Asia	69.5	6.9	3.1	0.0	100.0	29.8	3.3	0.0	0.0	212.5
Asia Pacific	170.8	18.7	49.4	0.0	8.6	65.9	0.0	0.0	2.9	316.2
Total World	**727.5**	**1 099.2**	**121.8**	**18.5**	**425.6**	**324.0**	**328.7**	**22.6**	**4.0**	**3 071.8**
	23.7%	*35.8%*	*4.0%*	*0.6%*	*13.9%*	*10.5%*	*10.7%*	*0.7%*	*0.1%*	*100.0%*

3. 2007 Survey

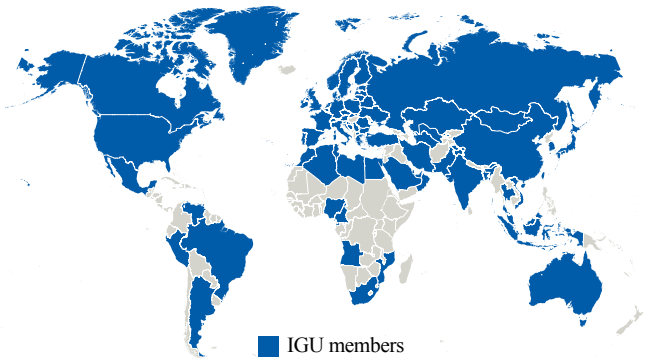
2007	Total Consumption - BSCM									
	OPE	GOG	BIM	NET	RCS	RSP	RBC	NP	NK	TOT
North America	0.0	799.5	0.0	0.0	0.0	0.0	0.0	11.5	0.0	811.0
Latin America	23.6	11.3	6.0	16.3	10.9	64.9	0.0	0.0	0.0	133.0
Europe	417.7	126.1	9.0	0.9	2.3	17.3	0.0	4.2	0.0	577.4
Former Soviet Union	0.0	6.8	136.9	0.0	0.0	16.9	478.3	3.7	0.0	642.6
Middle East	6.5	0.0	27.4	0.4	0.0	116.7	152.9	3.0	1.5	308.3
Africa	5.6	0.0	2.9	0.9	0.0	8.7	75.1	0.8	0.0	94.1
Asia	53.9	6.3	8.5	0.0	15.9	86.6	3.6	0.0	0.0	174.8
Asia Pacific	170.3	26.7	46.7	0.0	6.9	57.4	0.0	0.0	4.6	312.5
Total World	**677.5**	**976.6**	**237.4**	**18.5**	**36.0**	**368.5**	**710.0**	**23.1**	**6.0**	**3 053.6**
	22.2%	*32.0%*	*7.8%*	*0.6%*	*1.2%*	*12.1%*	*23.3%*	*0.8%*	*0.2%*	*100.0%*

4. 2005 Survey

2005	Total Consumption - BSCM									
	OPE	GOG	BIM	NET	RCS	RSP	RBC	NP	NK	TOT
North America	0.0	752.6	0.0	0.0	0.0	0.0	0.0	9.5	0.0	762.1
Latin America	24.8	2.8	7.9	12.7	11.3	64.5	0.0	0.0	0.0	123.9
Europe	457.8	87.7	9.9	0.8	1.8	17.8	0.0	4.0	0.0	579.8
Former Soviet Union	0.0	0.0	171.0	0.0	0.0	17.4	442.0	2.3	0.0	632.7
Middle East	1.4	0.0	21.1	0.3	0.0	103.9	123.6	2.5	1.5	254.3
Africa	5.1	0.0	2.3	0.9	0.0	8.5	67.8	0.8	0.0	85.3
Asia	47.6	0.0	9.7	0.0	13.8	68.3	4.1	0.0	0.0	143.5
Asia Pacific	157.1	10.5	42.0	0.0	6.5	59.9	0.0	0.0	3.5	279.5
Total World	**693.8**	**853.5**	**263.8**	**14.7**	**33.4**	**340.3**	**637.6**	**19.1**	**5.0**	**2 861.2**
	24.2%	*29.8%*	*9.2%*	*0.5%*	*1.2%*	*11.9%*	*22.3%*	*0.7%*	*0.2%*	*100.0%*

IGU

The International Gas Union (IGU), founded in 1931, is a worldwide non-profit organisation promoting the political, technical and economic progress of the gas industry with the mission to advocate for gas as an integral part of a sustainable global energy system. IGU has more than 110 members worldwide and represents more than 95% of the world's gas market. The members are national associations and corporations of the gas industry. The working organization of IGU covers the complete value chain of the gas industry from upstream to downstream. For more information please visit www.igu.org.



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