Pricing the “Invisible” Commodity

Discussion Paper

Author: Sergei Komlev
Contracts Structuring and Pricing Directorate, Gazprom Export

11 January 2013
Contents

Preface .................................................................................................................................................. 3
Introduction ........................................................................................................................................ 9

Part 1: Critical Analysis of the Supply and Demand-Based Natural Gas Pricing Mechanism .......... 10
  1.1 The Fair Price of Gas – Empirical Evidence ............................................................................. 12
  1.2 Reasons Why Supply and Demand Pricing Leads to Gas Being Undervalued ..................... 19
    1.2.1 The Financialization of Commodity Markets .................................................................... 19
    1.2.2 Bundled Commodity Sales ................................................................................................. 20
    1.2.3 Gas Flaring ......................................................................................................................... 21
    1.2.4 Shale gas ............................................................................................................................. 24
  1.3 Remedy to the ‘Little Brother’ Syndrome .................................................................................. 29
  1.4 Rationale for Oil Indexation ..................................................................................................... 33
  1.5 Rationale of Indexing Gas to Other Commodities .................................................................. 37
    1.5.1 Use of Coal or Electricity as Indices .................................................................................... 38
    1.5.2 Wood Pellets as an Alternative Index ................................................................................. 39

Part 2: Studies in the Hybrid Pricing System .................................................................................. 42
  2.1 Pricing from a Systems Point of View ....................................................................................... 43
  2.2 The Role and Function of Hubs in the Hybrid Pricing System ............................................. 45
  2.3 Hub Prices as Derivatives of Contract Prices in the Hybrid Pricing System; or “The Emperor Wears No Clothes” ............................................................................................................. 49
    2.3.1 Hub Discount to Contract – One-Sided Balancing ............................................................ 52
    2.3.2 Hub Discount to Contract – Price for Security of Supply and Flexibility ....................... 55
  2.4 Destruction of the Hybrid Pricing System – The Road to Nowhere ....................................... 56
Preface

“Living is easy with eyes closed, misunderstanding all you see…”

The Beatles, Strawberry Fields Forever

This paper is about the pricing of natural gas. It summarizes several years of in-house research conducted by the Directorate of Contract Structuring and Pricing at Gazprom Export, the export arm of Gazprom.¹ In-house research is rarely made public, because its target audiences are typically comprised of corporate decision-makers, colleagues in charge of operational work or, in some cases, company partners. But the necessity of sharing the results of our current research with a broad industry audience is dictated by several reasons.

First, we are not satisfied with the analysis currently being undertaken on natural gas pricing by a number of established sources, because this research is, by and large, one-dimensional in that it focuses only on the study of supply and demand dynamics in Europe. In our view, such research does not account for the complicated state of the European gas market, which today finds itself at a crossroads and in search of a future development path. It is the aim of this paper to provide an assessment of European natural gas pricing that is more reflective of the current market environment than what has been put forth by the established experts based on purely theoretical constructs and hypothetical market structures.

The real state of the European gas market often plays out very differently from what market theorists would have you believe. By this, we mean that European gas hubs are unable to provide a true indication of whether the market is long or short on gas. This failure stems from the fact that European hub pricing is not reflective of total supply and demand, but rather only of the residual volumes that remain after long-term oil-indexed contracts have met the bulk of that demand. Spot prices respond to the supply and demand developments of these residual volumes, but their baseline trajectory is benchmarked to the long-term contracts. As a result, supply and demand imbalances in the European gas market as a whole manifest themselves in a manner that renders the conventional theories put forth in economic textbooks inadequate to explain the spot price movements. In a later chapter, we will examine price responses to market imbalances in more detail.

That conventional energy market analysis remains an inadequate framework to support and sustain a healthy gas industry is evidenced by its inability to predict recent gas market shocks, or even to offer a credible explanation of their origins afterwards. This, together with the market distortions discussed above, should serve as a warning signal to the industry – and to those who study its workings. The outcome of these distortions is the lasting inability of hub-based pricing to provide sustainable price signals that support global investment in natural gas.

This brings us to the regrettable conclusion that the majority of gas market participants have a fundamental misunderstanding of the mechanisms that cause these shocks. Indeed, what value does it provide to predict an endless gas supply glut only to discard that prediction just a few months later? The divergence of hub and contract prices after the 2008 economic crisis brought mainstream energy analysts to the almost unanimous conclusion that the price of oil-indexed and spot-priced gas had decoupled, once and forever, a development which many of these analysts proudly claimed to have predicted a long time ago. The mysterious re-convergence of these prices in Europe in the third quarter of 2010 came as a major surprise to them. We will pay special attention to this convergence in this paper, as we

¹ My acknowledgments go out to all members of the Gazprom Export work team and especially to Valery Nemov, whose contributions were crucial to the preparation of the final draft of this paper.
demonstrate that the explanations provided by J. Stern and H. Rogers in their March 2011 paper are not convincing.  

We believe that what is lacking today is a comprehensive study of global gas pricing that presents a broader view of the market, unencumbered by the self-imposed theoretical strictures of mainstream industry analysts. This view would take into account the pricing behavior of a variety of exchange-traded commodities – beyond those that are used as inputs for the gas industry – and would place special focus on the effects of the financialization of global commodities on natural gas pricing. Financialization is one of the key reasons (all of which will be explored in great detail in later chapters) why natural gas must be treated as a unique commodity. Once these reasons are understood, it becomes easier to explain why the use of long-term contracts and pricing via a third commodity are justified globally and in the European gas market in particular. This paper is our attempt to fill this void by presenting an in-depth, ideology-free study on international gas pricing.

We do not doubt the ability of industry analysts to conduct in-depth research of complicated gas market mechanisms. We instead explain the absence of such fundamental research by the fact that there has been no demand for it. The future direction of the European gas industry in the eyes of European policy-makers remains clear and bright – and very narrowly defined, requiring the inclusion of hub-pricing in long-term supply contracts and the unequivocal obligation on the part of third (i.e., non-EU) country suppliers to deliver gas under existing contracts at prevailing hub prices, despite the fact that said producers have no way of influencing these prices beyond the specific terms of current contracts. There is no interest in research that questions or undermines, in any way, the mainstream understanding of this ‘fair’ distribution of rights and responsibilities. The only obstacle in achieving this utopia is Gazprom, which does not want to sacrifice its own reasonable and legitimate interests in order to subsidize the recovery of the European economy with cheap gas.

We have already shared some of the results of our research in industry publications and at various industry conferences. But the lack of attention given to our work, and the unwillingness of some to critically review our arguments, has been discouraging. It came as an unpleasant surprise that the authors of “The Pricing of Internationally Traded Gas”, which was published by the Oxford Institute for Energy Studies in October 2012, decided to ignore the multiple, credible arguments that were brought into the public domain in support of oil-indexation in long-term supply contracts. This head-in-the-sand behavior demonstrates a refusal to engage constructively with those who offer opposing viewpoints.

This tendency to ignore views that contradict the mainstream was partly explained in a comment to a Gazprom Export paper that was published by the European Energy Review in May 2012. Below is an excerpt from this comment:

“I realize it should no longer surprise me, but I continue to be taken aback by the continuing and sustained failure of leading gas market participants, politicians, policy-makers and regulators to engage with those advancing critiques of their positions when the former advance these positions publicly in publications or in ‘public

---


3 By ‘limitations’, we mean that such analysts typically only understand market activity as it relates to textbook theory of supply-and-demand economics. All market activity, in their view, must be a reflection of these supply-and-demand forces.

4 Financialization is a term that describes an economic process that attempts to reduce all value that is exchanged (whether tangible, intangible, future or present promises, etc.) either into a financial instrument or a derivative of a financial instrument.


consultations' or at various forums whether virtual (such as here) or at conferences, seminars and workshops.

Statements are made, positions are advanced and the views of interested parties are solicited. Those who express sentiments that are pleasing to the 'powers-that-be' receive a pat on the head; those who offer critiques, irrespective of how soundly based they might be, are, most often, simply ignored or, occasionally, rejected and dismissed without any apparent consideration.

The result is a 'dialogue of the deaf' and the frequently dangerous, but extremely comfortable and self-serving, ‘group-think’ concocted by the leading market participants, governing politicians, policy-makers and regulators endorses and supports whatever they find convenient and politic to implement – without any proper consideration of the collective interests of the vast majority of citizens and consumers.”

– Hugh Sharman

We view this paper as a way to present our ideas in a structured way that, we hope, will finally lay the groundwork for a practical and unbiased discussion on natural gas pricing that is much needed by the industry today. The last thing we want is to be mistaken as solely representing the producers’ point of view. Change must be mutually beneficial for buyers and sellers if it is to succeed. Yet the interests of the producer cannot be separated from the interests of the industry as a whole, and vice versa. We hope that this paper will help to address the current stalemate that exists between opposing viewpoints, which can perhaps be best described as the ‘dialogue of the deaf’ noted above. To that end, throughout this paper, we make a point to consider the arguments made by the other side and to evaluate them carefully.

Our analysis is focused on Europe but is based on global comparisons. This approach enables us to distinguish the specific characteristics of gas pricing in Europe and how they contrast with pricing dynamics in other regions. It is this thorough examination of the unique qualities of the European gas market – namely, the relationship between contract and hub prices within the hybrid pricing system – that differentiates our research from the mainstream approach, which sees no real-life connection between the two pricing mechanisms or else prefers not to notice it. Our examination brings us to the conclusion that the two pricing mechanisms are deeply interconnected, and that hub prices are, in fact, derivatives of Gazprom’s (and other exporters’) long-term contract pricing structures.

Our intention is to provide a thorough analysis of different gas pricing mechanisms, but not for the sake of labeling one method superior to another or of endorsing any one mechanism. Instead, our role lies in comparing these various pricing methods, with the ultimate objective of presenting an answer to the fundamental question: Under what conditions do the advantages and disadvantages of different pricing methods create critical imbalances between the interests of the producer and the consumer? In fact, the main conclusion of this paper is that the best choice for Europe is to have both long-term oil-indexed contracts and hub pricing operating as one synergistic system.

Although our view is that dialogue and compromise regarding energy policy are necessary whenever possible, there is one trend in European policy-making that we cannot support. This trend is to adopt policies based on abstract general principles without a thorough understanding of their practical implications. This leads to situations in which the pursuit of well-intentioned goals without a proper understanding of real-life conditions brings unintended consequences that ultimately undermine achieving those goals.
Unfortunately, such thinking tends to dominate European policy-making. A primary example of this was the adoption of a single EU currency, a decision which was made without a thorough understanding of its potential unintended consequences. The rationale behind the 1999 decision was that having one currency would facilitate the economic and political integration of the various individual member states. But there was one impediment to a properly functioning common currency market that was not properly acknowledged – the absence of a monetary and fiscal union. The current debt crisis is the cost that Europeans have to pay for this mistake. The euro, once meant to underpin the single market, may now end up undermining it. The problem is no longer how to strengthen the single currency, but how to save it. To quote Hugh Sharman again:

“The ability to create and maintain optical illusions and to attempt to suspend disbelief indefinitely is truly remarkable. But, inevitably, reality has a horrible habit of coming crashing in. We’ve seen it already – and continue to experience it – with the Euro crisis. Events conspire to reveal the grand designs for what they are – grand designs motivated by the very best of intentions but without adequate substance or foundation.

The EU’s electricity and gas market policies – and the associated climate change policy – comprise a similar grand design. Events may not conspire to reveal the hollowness of this grand design as they so devastatingly did with the Euro project, but reality will not be prevented indefinitely from coming crashing in.

And that’s why I make this plea to the major market participants, governing politicians, policy-makers and regulators: please engage constructively with those of us advancing critiques of what you are attempting to implement; we share your goals and good intentions, but nobody has a monopoly on wisdom; collaboratively and collectively we can have effective disputation to secure valuable common ground as the basis for sensible and effective implementation; the alternative is a low-level, low-intensity replication of the Euro crisis.

Is that what you really want??” – Hugh Sharman

Unfortunately, EU energy policy is not immune to wishful thinking. There have been numerous examples of the EU rushing to implement energy policies based on theoretical concepts, but without a clear understanding of their possible real-world implications. We will discuss a number of these examples below to demonstrate that this is a recurring problem in European energy policy development, as demonstrated by the EU Third Energy Package, the attempt to address energy security and the promotion of renewable energy development.

The EU’s Third Energy Package7 was unveiled in 2007 amidst much fanfare – and boastful claims that market unbundling would create a single gas and electricity market that would, among other purported benefits, lower energy costs for Europeans. As evidence, the paper accompanying the legislation cited price decreases as a result of electricity market integration in the EU from 1998 to 2006.8 No such evidence was provided for the gas sector. In fact, unbundling in the early 2000s did not result in lower gas prices for UK customers. Proponents of the Third Package stated that this was likely the result of certain external factors; however, would it not have been prudent to study these external factors in depth before championing such a policy? It could well be that these or other external factors will always prevent consumer price benefits from materializing from gas market liberalization.

The belief that if it works for one market, then it will work for all markets, has tended to guide the decision-making processes of many EU politicians and regulators. This is yet another instance of the EU’s tendency to implement policies based on textbook theories, without regard for the often disastrous consequences such policies can have on the workings of the market.

One of these disastrous consequences is the effect the Third Energy Package is having on European energy security. The stated objective of the Third Energy Package is to facilitate gas flows within the EU, but politically-motivated decisions contradict this objective, and diversifying away from ‘dependence’ on Russian gas has now become a cornerstone of EU energy policy. Unfortunately, and irrationally, the EU’s phobias surrounding Russian gas supply have had the effect of suppressing the flow of gas into the EU, thereby threatening the continent’s energy security. A primary example of this paradox is the OPAL pipeline, a natural extension of the Nord Stream pipeline on EU territory. Although there are no bidders for pipeline capacity other than Gazprom, EU regulators will not allow a single shipper to control more than half of the total pipeline capacity, thereby leaving the remaining half unutilized. There is simply no economic rationale for these policies, as even under the EU’s supply diversification scenarios, Russia will remain a dominant supplier to Europe for many years ahead.

The promise of EU policy-makers to lower energy prices has been undermined by the EU’s misguided policies on energy security and renewable energy. The commitment to the decarbonization of power generation through renewable energy has turned out to be a costly and misinformed exercise, with the perverse result that global emissions may actually increase and consumer prices are on the rise. While Europe now produces less carbon, it effectively consumes more carbon because imports of goods from countries that use carbon-intensive processes have increased. Natural gas, the cleanest fossil fuel, is seen as having little place in Europe’s hostile business environment, while dirty coal is being championed for narrow political reasons. As a result of these market distortions, inter-fuel competition – which was mediated in the past through energy markets as the allocator of resource efficiency – has given way to administrative decision-making. Administrative decision-making is widely known to be divorced from reality. Thus, we again see how EU administrative policy produces results that undermine the EU’s own objectives.

This has never been more true than when it comes to EU policies surrounding energy market liberalization, of which the transition to hub-based gas pricing is a key initiative. While aiming to provide for market-based price-setting mechanisms, the hub pricing initiative has instead become another of the EU’s ‘grand designs’, in which textbook theory and lofty ideals trump inherent market realities. Perhaps what is most astonishing is that those who advocate transitioning to a hub-based pricing understand the potential negative consequences of this move – but they advocate for it anyway. J. Stern and H. Rogers, the Oxford Institute’s two leading experts on European gas pricing, agree that a change in the pricing principles will:

---

9 The hot-button issue of energy security was predictably overblown after the Ukrainian transit crisis of January 2009. For reasons unknown, the EU decided not to launch an investigation into the causes of this crisis. Instead, they issued the expedient verdict that ‘gas supplies from Russia are insecure.’ The EU then proudly introduced a new security regulation called the N-1 Rule. This Rule requires that each Member State have sufficient infrastructure capacity to be able to withstand a supply disruption from its single largest supply source. This regulation has led to the construction of underutilized pipelines and reverse flow capacity, the costs of which are transferred to end-users by transit system operators.

10 In December 2012 EU granted Gazprom temporary permission to utilize full capacity of OPAL without paying fines. We view this decision as a victory of common sense, although permission lasts for only six months and its prospects are unclear.

11 Less visible are the other ‘costs’ associated with the EU’s renewable energy policy, such as feed-in tariffs and subsidies for renewable energy, policies that favor preferential dispatch for renewables, and higher carbon taxes on conventional fuels.

• Cause major problems for existing long-term contracts, some of which may not survive;
• Disproportionately favor the end-user by allowing buyers to schedule nominations in a way that will depress hub prices; and
• Grant suppliers the ability to accumulate significant market power and control European hub prices through supply management.\textsuperscript{13}

These concerns were echoed in a discussion paper recently issued by the Centre on Regulation in Europe (CERRE): “It remains to be seen whether the move to a new market environment will change the relative bargaining power for the European buyers and the main gas suppliers, possibly to the detriment of European consumers. A further open issue is related to the expanding role of short-term transactions. How will the latter impact investments? Will a more marked boom-and-bust pattern result?”\textsuperscript{14}

We agree with all of these statements and concerns. However, we cannot agree with the assertion – which these experts would appear to be making – that a malfunctioning hub-based pricing model is better than the existing and proven mechanism of oil-indexation. The ideologically-driven policy of opposing long-term oil-indexed gas contracts may be motivated by the best of intentions, but – similar to the EU’s other misguided initiatives, discussed above – it has no grounding in reality; consequently, it will have a disastrous effect on European gas supply, energy security, and price stability. We hope that by presenting a thorough analysis of gas pricing alternatives that accounts for real-world conditions in the European gas market, we can serve as a reality check to those seeking to implement such policy changes.

Introduction

"I had thought of painting and powdering my face and all that there was to show of me, in order to render myself visible, but the disadvantage of this lay in the fact that I should require turpentine and other appliances and aconsiderable amount of time before I could vanish again. Finally I chose a mask of the better type, slightly grotesque but not more so than many human beings, dark glasses, greyish whiskers, and a wig."

The Invisible Man, by H.G. Wells, Chapter 23.

The world of commodities falls into two broad groups. The larger group is comprised of commodities that are exchange traded. These commodities typically have a global reference price. Among the few exceptions is electricity; due to the prohibitive costs and logistical impracticability of setting up transmission lines across continents, prices for this exchange-traded commodity are set regionally rather than globally.

The second and smaller group of commodities is not exchange traded. The general trend is that the number of such commodities is becoming fewer and fewer. Iron ore is a prime example of this trend. Just a few years ago, the dominant form of trade in iron ore consisted of long-term contracts negotiated on an individual basis between the producer and the consumer. Today, it is the exchange that sets the global price for iron ore. There still remain the so-called ‘outlier’ commodities that are highly unlikely to become globally traded any time soon, if ever. Therefore, while there is a global reference price for orange juice, there is none for alcoholic beverages, milk or water. The physical characteristics of these beverages, coupled with government regulations on their production and distribution, have made them incompatible with the exchange trade. But the buyers and sellers of these commodities appear satisfied with the status quo and are not pushing for change.

Natural gas, however, stands alone among commodities, as it cannot be attributed to either of these groups. Natural gas became a NYMEX\textsuperscript{15}-traded commodity in 1990, only ten years after oil, and a UK exchange-traded commodity another ten years later. In contrast to oil, however, there is no global price for natural gas. Moreover, there has historically been a clear tendency to ‘de-globalise’ the price of natural gas as regional price-setting models have become entrenched. And, at least in Europe, there is no agreement between the buyers and sellers of natural gas as to the future evolution of the gas pricing model.

Natural gas presents a unique case because it is the only commodity in the world that, in many cases, is indexed to another commodity. In the vast majority of cases, oil or oil products play the role of this other commodity. For example, in Asian long-term gas supply contacts, the gas price is directly linked to crude oil by the use of discounting coefficients.

Opinion leaders in European gas pricing often conclude their speeches with the now-perfunctory statement that the status quo must be changed as there is no other commodity besides natural gas that is traded on 15-25 year contracts or priced in relation to a third commodity. They also voice their amazement that oil indexation is still in use.

This paper will demonstrate the many credible reasons why natural gas must be treated as a unique commodity. In doing so, we will provide a case in defense of retaining oil-indexation and the long-term contract both globally and in the European gas market.

\textsuperscript{15} The New York Mercantile Exchange.
Part 1: Critical Analysis of the Supply and Demand-Based Natural Gas Pricing Mechanism

In this chapter we will offer comparisons of the two main pricing mechanisms or methods used by the natural gas industry: the first mechanism, which is based on the substitution price of an alternative fuel (i.e., oil indexation), and the second, which is based upon supply and demand equilibrium (hub pricing). We will present a number of arguments, supported by empirical evidence, in favor of maintaining this first pricing method in European long-term gas supply contracts. While the arguments are many and varied, they all coalesce around one central tenet: that natural gas markets are plagued by a number of systemic distortions that prevent them from functioning properly, and that this failure to produce the appropriate price signals necessitates the pricing of natural gas via an alternative fuel.

In the second chapter of this paper, we study pricing systems or models depending on which one of the two pricing methods plays a leading or dominant role in a given gas market. The distinction between pricing systems/models and pricing mechanisms/methods brings us closer to the realities of the global gas markets. We discern at least five alternative models for natural gas depending upon which price-setting mechanism is dominant. Therefore, it remains a critical mistake that the prevailing wisdom in the industry is to ignore the interaction of these different pricing mechanisms within the European gas market. The very unique qualities of the European hybrid pricing model will be discussed in detail in the following chapter.

The ‘distorting’ characteristics of natural gas markets were certainly evident in the early years of the industry, when natural gas production required significant investment at a time when market mechanisms were under-developed and therefore unable to guarantee security of supply and demand. As the gas industry has matured, it seems to have become conventional wisdom that there is no longer any rationale for oil indexation in long-term gas supply contracts. However, we will argue that the rationale for oil-indexation in Europe (and, indeed, globally) does still hold, now more than ever before, but that this is no longer the result of an immature market; rather, it is the result of a dysfunctional, mature commodity market. In that respect, this paper will serve as a case study of the systemic failure of the natural gas pricing model based on supply and demand.

The many factors that cause natural gas to be undervalued when sold on a gas-indexed basis vary in both nature and duration. Some of these factors are systemic in nature, such as neglect on the part of financial investors and the selling of associated gas as a bundled product with oil, which devalues the natural gas component by motivating sellers to optimize their sales portfolio in favor of petroleum. As a result of these policies, producers are more or less indifferent to the value of gas as a commodity per se, preferring to offset the losses incurred from their gas sales with the much larger profit earned from their oil sales.

Hedging is another factor that causes a deferred producer response to over-production. However, this price-depressing factor is of a transitory nature. Mature futures markets enable producers to lock in profits for years ahead. But this results in limited supply flexibility in response to price changes when the forward curve is favorable to producers (contango). Even in the event that the realized price turns out to be lower than the expected price, a properly hedged producer should have nothing to lose. For example, while cash prices remain depressed in the U.S. (and, indeed, are not even sufficient to cover the costs of gas

---

16 Contango is when the futures price is above the expected future spot price. Because the futures price must converge on the expected future spot price, contango implies that futures prices are falling over time as new information brings them into line with the expected future spot price. [http://www.investopedia.com/articles/07/contango_backwardation.asp#ixzz2FcdV5Coxs](http://www.investopedia.com/articles/07/contango_backwardation.asp#ixzz2FcdV5Coxs)
production), this has not discouraged companies from producing despite the fact that they are selling their product at a much lower price than what they would have earned five years earlier. This demonstrates the dysfunctional role that hedging plays in influencing underlying supply trends; such mechanisms simply do not function properly in natural gas markets but rather have a lasting delay. Under a backwardation scenario\(^\text{17}\) – in which the forward curve moves downward and below production costs – there is no chance for the supplier to hedge his price and make a profit. Investment in gas production therefore decreases once these hedging gains begin to evaporate.

It is true that there are no perfect markets; perfect markets exist only in textbooks. In many commodity markets these real-life imperfections can be neglected because they fall within certain acceptable limits and the price signals they generate are sufficiently responsive to supply and demand imbalances to allow the necessary investments to be made. This, however, is not the case for natural gas. The outcome of these market distortions is the lasting inability of the supply and demand-based pricing mechanism to provide sustainable price signals that support investment in the industry. We do not lay claim to the assertion that this situation will last forever, but it is clear that these market distortions are largely dependent upon the unique characteristics of natural gas.

It is also true that while commodity markets have no obligation to support investments in the short term, they do have this obligation in the mid and long term. When a volumetric adjustment to price does not occur for a significant period of time – as we will see has been the case in the U.S. starting from August 2008 onward – it is a clear sign of a dysfunctional market.

We do not expect that the U.S. will transition to alternative pricing mechanisms or introduce regulatory measures to support producers and resolve the problem of under-pricing. The rebalancing of the U.S. gas market will occur as a result of the traditional boom-and-bust cycle, as has occurred several times throughout the history of the U.S. gas industry, when painful market readjustments resulted in extended periods of high prices that drove down demand considerably. These readjustments came after periods of low prices had previously led to supply destruction. One such example of this boom-and-bust cycle was the prolonged period of depressed gas prices seen in the U.S. in the 1990s, which led to a boom in gas-fired combined-cycle power generation. This, in combination with lower gas production that resulted from under-investment in the upstream gas sector in the 1990s, drove up prices to record levels by the mid-2000s.

We believe that, over the long-term, an efficient remedy to the dysfunctions seen in the gas market will be achieved not by means of oil indexation or any other form of replacement value pricing, but rather via the ‘natural’ forces of the market – i.e., through direct and enhanced competition between natural gas and oil in emerging sectors such as transportation. Only direct competition between the two fuels will allow gas to behave as a regular commodity. We will review that option in a later section named “Remedy to the Little Brother Syndrome.” However, this process may take many years to happen.

In the meantime, returning to the realities of the current market, we will show in this chapter that the shale gas revolution in and of itself is not the cause of price distortions in the fully liberalized gas market of the U.S. However, the business practices stemming from it have created many of the dysfunctional pricing behaviors we are now seeing in the market. The shale gas phenomenon has created the illusion of a nearly infinite supply of natural gas in

\(^\text{17}\) Normal backwardation is when the futures price is below the expected future spot price. This is desirable for speculators who are "net long" in their positions: they want the futures price to increase. So, normal backwardation is when the futures prices are increasing. http://www.investopedia.com/articles/07/contango_backwardation.asp#ixzz2FIKEyYi
the minds of financial investors – and, since we are all familiar with the dictates of supply and demand based pricing, ‘abundance’ often equates to ‘cheap.’

As an example, shale gas has undermined any interest in natural gas as a currency hedging commodity for financial investors. Shale gas producers have broadly used forward curve price risk mitigation over the past five years, thus reducing their sensitivity to the current depressed price environment. Many of these producers have also focused on shale oil as a much higher value product. Unfortunately, this also results in the production of significant additional volumes of gas as a by-product of the shale oil production process. Thus, while shale oil allows producers to become marginally profitable, the additional volumes of gas that are dumped on the market as a result only lead to a further depression in the gas price. We will examine the impact that shale gas production has had on natural gas pricing in the U.S. market in a special section. Our intent here is to show that price distortions in the fully liberalized gas market of the U.S. are only getting worse. The outcome of these distortions is the inability of supply and demand-based pricing mechanisms to provide sustainable price signals that support investment in the industry.

Discussion of the fair price of natural gas makes sense only when there is agreement over the criteria to be used to validate or judge price fairness. We believe that a major indicator of price fairness is whether the price is supportive of investment in the gas industry at least in the mid-term. Using this as our key criterion, we will begin with a critical evaluation of the popular statement that oil-indexation leads to the overpricing of natural gas. The available evidence simply does not support this statement.

1.1 The Fair Price of Gas – Empirical Evidence

The oil-indexed pricing mechanism, which originated in Europe in the 1960s and was later adopted in Asia, still dominates the international gas trade. The second main price-setting mechanism – based upon the fundamentals of supply and demand (also known as gas-on-gas competition) – first developed in the U.S. and expanded to Continental Europe via the UK. Today, Europe is witnessing an unprecedented level of confrontation between those who support maintaining the status quo (the gas suppliers) and those who advocate transitioning to full gas-on-gas competition (the consumers). While Europe is currently the main battleground, the implications of this dispute could stretch far beyond European borders. If hub pricing gains the upper hand in Europe, Asia will be the last remaining stronghold of oil-indexed pricing, making the battle between these two competing pricing structures effectively a global one.

Although J. Stern and H. Rogers in their March 2011 paper claim that spot prices can exceed the oil-indexed contract price for relatively long periods of time in instances where the market is short of gas, the focus of the current standoff is not some theoretical future price advantage, but rather the actual price levels seen under these two prevailing price-setting mechanisms. The unanimous message that Gazprom receives from its clients is the following: “We do not care much about pricing principles or models; we just want better-priced gas.”

Maria van der Hoeven, the Head of the International Energy Agency (IEA), summarized the viewpoint of European consumers in the following way: “The oil-index pricing structure of many gas contracts is precisely what is keeping prices high in Europe – prices which are
cannibalizing European demand."\textsuperscript{18} It is not clear from this statement at what price level this ‘cannibalization’ would start.

The implication in what many other European politicians and regulators claim is that ‘fair’ gas prices should be close to current hub levels in the U.S. But to what extent? That is not clear either. In November 2012, van der Hoeven attempted to assuage Australian gas producers at their national energy conference by saying: "Let’s be honest, a [gas] price of US$2.50 per MMBtu as we’ve seen in the United States doesn't cover all costs, so it's impossible to have prices like this in other parts of the world."\textsuperscript{19}

In contrast to their European customers, gas producers, including Gazprom, support oil-indexation as the optimal pricing mechanism for natural gas. On 15\textsuperscript{th} November 2011, at their inaugural gas summit in Doha, representatives from the member countries of the Gas Exporting Countries Forum (GECF) resolved to: “Acknowledge the need to reach a fair price for natural gas based on gas to oil/oil products price-indexation with the objective of an oil and gas price convergence, taking into account its [gas’s] advantages both in terms of energy efficiency and environmental premium.”\textsuperscript{20} This statement suggests that the GECF is supportive of a gas price that falls within the band of existing oil-indexed contracts.

Taking into consideration the significant range seen in today’s global gas prices – with prices in Japan up to five times higher than those in the U.S. – and the conflicting interests of the two main ‘adversaries’ in the debate over price setting, it becomes obvious that agreement on what constitutes a fair price for natural gas will be extremely hard to come by. J. Stern, in a September 2012 interview with \textit{The Moscow News}, said that he regards current hub prices in Europe as being high enough: “Today, European spot prices are around €24-27/MWh, which would have been considered a very high price in 2006-2007 when oil-linked prices were below €20/MWh.”\textsuperscript{21} However, gas suppliers may strongly disagree with Stern’s statement that US$9.00/MMBtu is a ‘very high price,’ since current hub prices constitute only half the price of crude on a parity basis, compared with 70 percent in 2007.

Over the past ten years, despite their conflicting fundamentals, a broad range of exchange-traded commodities, including metals and agricultural and chemical products, has grown by 2.7 to 3.2 times in U.S. dollar terms (see Exhibit 1 below). This is within the same range – 2.8 times – as the oil-indexed gas price as measured by the German BAFA import price index.\textsuperscript{22} While the Japanese oil-indexed LNG import price grew by 3.5 times (ratio of 2011/2001 prices), which only slightly outpaces the growth band for the three major commodity groups and was significantly below the price increase (4.3) seen for oil and oil products over this same period. This was the result of the broad use of the S-curve, price caps, collars and lowering coefficients in oil-indexed gas contracts, that collectively serve as an indication that these contracts are not immune to gas-on-gas competition.

\textsuperscript{18} “IEA Head Sees No Golden Age Soon for European Gas, by Georgina Prodhan, Reuters, 4 October 2012.

\textsuperscript{19} “IEA Says World Oil Markets Remain Well Supplied, by James Grubel and James Regan, Reuters, 19 November 2012.


\textsuperscript{22} The Federal Office of Economics and Export Control (BAFA) gas price is a publicly quoted and transparent indicator of the value of pipeline gas into the German market. It is the weighted average import price to Germany as reported to BAFA each month by actors in the German market.
Is the tripling of the oil-indexed gas price reasonable and fair? There are reasons to believe so. When a product’s pricing dynamics match those of other raw commodities – including those that are necessary inputs to the manufacture of that product – it gives investors confidence that they will be able to successfully launch a new investment cycle. By contrast, zero growth in the Henry Hub gas price has put long-term investments in dry gas production at risk in the U.S. because producers must buy the commodities necessary for their investments at an inflated price.

Exhibit 2, below, further demonstrates this trend. When measured in calorific terms, over the past ten years oil-indexed gas prices in Continental Europe have grown at a lower rate than other energy commodities such as coal and electricity.
Since the early 2000s, the Henry Hub gas price has lost about 20 percent of its value, while the NBP price has strengthened by only 70 percent, as measured in U.S. dollars. For comparison purposes, we should mention that this 70 percent price growth is on par with the growth seen in The Economist’s Big Mac index over the same time period.

The logical conclusion from this is that the oil-indexed gas price is not expensive. Rather, its price growth over the past ten years is on par with that seen in a broad range of exchange-traded commodities. This conclusion is supported by the fact that there was no concern that the oil-indexed price was overblown in 2001.

**1.1.2 Rising Development Costs**

An important matter to consider in this regard is the rising cost of natural gas exploration, production and infrastructure. Upstream construction and operating costs have continued to increase over recent years, and do not look set to abate any time soon (see Exhibit 3). After a dramatic rise in the middle of the last decade, upstream costs began trending upwards again in late 2009 after declining for a year following the financial market collapse in 2008. Between the third quarter of 2009 and the third quarter of 2012, the costs of constructing new oil and gas facilities, as reported in the IHS CERA Upstream Capital Costs Index (UCCI)\(^{23}\) rose by 13 percent – the largest increase since 2007. In the twelve-month period from September 2011, upstream costs increased by 3 percent.\(^{24}\)

---

\(^{23}\) “IHS CERA December 2012 Capital Costs Analysis Forum: Summary of All Indexes—Historical and Outlooks.” The IHS CERA Upstream Capital Costs Index (UCCI) tracks costs associated with the construction of new oil and gas facilities. Values are indexed to the year 2000, meaning that capital costs of $1 billion in 2000 would be $2.18 billion in 2010.

\(^{24}\) OGJ Online, July 2, 2012.
This marked increase in upstream capital costs was driven in particular by the rising costs of steel, equipment and labor. Upstream steel costs rose 11 percent between the third quarter of 2009 and the third quarter of 2012, which also helped to drive the 11 percent increase in equipment costs during this same time period. Operating costs also rose significantly, due to sustained high oil prices that resulted in higher prices for cleaning solvents and feedstocks. According to IHS, upstream capital costs are expected to raise a further 4-5 percent in 2013.

**Exhibit 3: Growth in Upstream Capital Costs**

![Graph showing growth in upstream capital costs](image)

Source: “IHS CERA December 2012 Capital Costs Analysis Forum: Summary of All Indexes.”

As summarized in Exhibit 4 below, following the financial crisis of 2008 capital expenditures for liquefaction projects have risen to as high as US$4,000/ton.
The post-financial crisis behavior of major commodity indices irrespective of the fundamentals of their own markets shows that these commodities have fully returned to pre-crisis price levels. The Upstream Capital Cost Index indicates that production and development costs have also recovered globally. Yet Henry Hub prices have not, demonstrating yet again that a supply and demand-based pricing mechanism for natural gas leads to abnormal behavior. Discounted hub gas prices put long-term investments at risk because producers must buy the commodities necessary for those major investments at an inflated price. Only oil-indexed pricing brings gas prices in line with the behavior of other exchange-traded commodities. As demonstrated below in Exhibit 5 (see the first figure on the left), the pricing history of spot natural gas (as represented by the Henry Hub) remains a distinct outlier compared to the other commodities shown. In contrast, the figure on the right clearly shows that oil-indexed gas tracks more closely with other commodities. Since oil prices tend to move in sync with other basic commodities, there is no argument to be made for the statement that oil-indexation artificially inflates the price of gas in long-term contracts.
What is obvious from these analyses is that the gas-to-gas pricing system leads to gas being significantly undervalued. Measured by calorific value, the Henry Hub gas price equals only 20 percent of the oil equivalent price, and the NBP price equals only 40 percent of the oil-equivalent price. There is no rationale for such a huge discount; natural gas has truly come of age and is an important energy source to fuel the global economy. However, when it comes to pricing in liberalized markets, natural gas remains a ‘little brother’ of oil.

The point of this argument is that natural gas producers have good reason to question the quality of price signals that these mature, liberalized markets provide, especially when hub pricing in such markets leaves the distinct impression that it is designed to hold back gas prices.

Does this mean that gas markets cannot function on their own without utilizing a pricing method based on indexation via a third commodity? Are the failures associated with the hub-based pricing mechanism temporary, or are they systemic in nature? Let us make one relevant observation: It is frustrating that producers seem to be the only party interested in finding the right answer to this question.

In its ‘Golden Age of Gas’ scenario, the International Energy Agency projected that global gas demand would rise to 5.1 trillion cubic meters in 2035 – an increase of 1.8 trillion cubic meters over today. Obviously, such growth will require that significant investments be made in upstream and downstream capacity many years in advance of when the forecasted supply is needed. However, as mentioned earlier, while upstream costs have recovered globally, Henry Hub prices have not.

Cost escalation in new upstream gas and LNG projects – as well as in the infrastructure that is needed to take those products to market – makes it necessary to sign new long-term supply contracts at oil-linked prices, not only to provide secure revenue for the upstream and infrastructure developer, but also to keep gas price movements in line with other industry commodities. A gas pricing mechanism that does not track these other commodities is
simply unsustainable. The question then becomes: Will lenders provide funding for projects that do not retain oil-indexed pricing (i.e., for projects lacking a guaranteed source of revenue) in their sales contracts? As future investments in the natural gas industry will depend on this answer, long-term contracts can be considered highly valuable to both the seller (who requires revenue certainty) and the buyer (who requires supply security).

### 1.2 Reasons Why Supply and Demand Pricing Leads to Gas Being Undervalued

Our empirical analysis indicates that a pricing mechanism based on supply and demand does not meet the criteria for price fairness because it is not supportive of investment in the industry. This state of affairs could be resolved by hub price adjustments that would cover production, liquefaction and transportation costs for new projects. However, this is not the case in the gas industry, where markets do not perform their balancing functions properly and, in some cases, are simply dysfunctional. What are the reasons behind this set of circumstances?

#### 1.2.1 The Financialization of Commodity Markets

To arrive at an explanation as to why hub prices are depressed and lag behind the growth of other commodities, we will focus first on developments in the liberalized markets of the U.S. We cannot accept the argument that the abnormal behavior of hub pricing is a result of the financial crisis. Other commodities were also hit by the crisis but their prices have behaved differently.

We consider that the abnormal pricing behavior of hub-based gas prices is due to a factor that emerged in 2006-2007 and which has produced strong downward pressure on these prices. This factor is related to the ‘financialization’ of commodity markets and the emergence of a special breed of financial investors. These investors turn to commodities as a safe haven for investment at times when major paper currencies are losing their value.

A decade ago, commodity markets were a relatively quiet backwater of the global financial markets, where the main participants were almost exclusively producers and consumers involved in the routine process of hedging their operational risks. According to Barclays Capital, the combined value of commodity index swaps, exchange-traded commodity products and medium-term commodity notes was just US$6 billion at the turn of the millennium in December 2000.

This picture changed as financial investors seeking to hedge against inflation sunk hundreds of billions of dollars into the commodities market. In the second quarter of 2008, these assets surged to US$270 billion. Indeed, it was these financial investors who were directly responsible for the bubble in commodities markets that burst in August 2008. Although commodity investors reduced their appetite in the face of the global economic crisis, this appetite subsequently returned with volumes reaching a new peak of US$350 billion in the fourth quarter of 2010, after the announcement of a second round of quantitative easing (known as ‘QE2’) by the U.S. Federal Reserve. The Federal Reserve’s recent announcement of yet another round of quantitative easing – QE3 – has only added to the interest in commodity markets, making it very possible that another bubble is in the making.
Trading in commodities by financial investors is a force that gives its own momentum to pricing structures. Commodity prices are determined not only by fundamentals but by the investments of market participants who are not directly connected with the goods in which they trade. The choice of a commodity as a financial paper asset does not increase its real demand, but it does increase its price.

The financialization of energy markets would not create problems if the funds were spread more or less evenly across a broad spectrum of commodities. However, this has not been, and is not currently, the case. There were the so-called ‘darlings’ – i.e., the preferred commodity investments – of the financial markets, as well as the ones which were overlooked, of which natural gas was one. Although the total sales value of globally-traded oil is only four times the sales value of natural gas exports (as measured in U.S. dollar terms), financial markets have not regarded natural gas as an attractive hedging instrument for inflation risk mitigation. Due to weak interest on the part of financial investors and unlike other commodities, spot gas prices have been supported only by core-market fundamentals. This support, however, has not been enough to give hub-based gas prices the level of momentum that other commodities in the market receive.

There is a practical reason why natural gas futures have not taken off as an inflation hedge. Commodities chosen as a hedge against inflation must feature a standardized pricing structure in global markets. Natural gas does not fit this description, with its diverse pricing structures, varying degrees of price seasonality, and expensive storage requirements. Natural gas also tends to be sold more locally than oil, as the vast majority of gas is still transported by pipeline. The continuing emergence of mobile liquefied natural gas (LNG) in transport and other alternative applications has led to a higher correlation between geographical markets, but not to the extent that would enable gas to catch up with the broader commodity price trend.

It remains in doubt whether financial markets will ever consider natural gas as an instrument for inflation hedging. For one thing, commodity investment is becoming more physical amid increasing paper commodity market regulations. Gas will hardly become the darling of exchange-traded physical funds under these circumstances, as storage, transportation and insurance costs for gas are much higher than for oil and metals.

Commodities are financial instruments that bear no interest profit, but when traditional paper currencies lose their value they are often seen as natural, real-world hedges against inflation. Additional value comes from the appreciation of the commodity due to its core-market fundamentals. Therefore, predictions of an endless gas glut are not supportive of gas becoming a darling of the financial markets. There remains a significant amount of controversy among gas producers and consumers as to the timing of the gas supply glut, with many producers claiming that it is already over.

The lesson to be learned from this is that the glut in global currencies has led directly to the commodity price boom. Gas, unless it is oil-indexed, has not taken, and most likely will not take, any advantage of this boom. Therefore, the premise that gas prices should be dictated by spot markets does not give any reassurance to gas producers.

1.2.2 Bundled Commodity Sales

There are additional factors to those discussed above that affect hub-priced gas prices. In the UK, associated gas deliveries by major natural gas supplier Norway play a secondary or auxiliary role to its oil deliveries. Portfolio optimization on the part of Norwegian suppliers to
the UK in many instances jeopardizes the value of gas in favor of oil, which occasionally results in negative gas prices at the National Balancing Point, or NBP.

Portfolio optimization in favor of liquids is a long-term factor that depresses gas prices. This force has become even stronger with the introduction of shale gas and the divergence of oil and gas prices. As prices for shale oil are up to ten times higher than shale gas prices, producers are flooding the market with associated gas volumes, ignoring the negative pressure on prices that these volumes create. That natural gas is considered valueless as a stand-alone product is evidenced by the practice of gas flaring.

1.2.3 Gas Flaring

The strongest evidence of natural gas's role as the ugly stepchild of oil production lies in the long and troubling issue of gas flaring, which illustrates the technical, operational, economic and commercial differences between oil and gas in energy commodity markets. Perhaps this situation is best summed up by a story we heard from an American friend, which goes as follows:

"...So an oilman walks into a bar and sees his neighbor and long-time competitor sitting on a barstool, looking very disappointed and frustrated.

The first one says, ‘Hey, why so sad?’
The second one responds ‘I’m broke.’
His concerned friend asks, ‘Problems with the new well?’
‘We hit target depth on Tuesday, three days ahead of schedule.’
‘Have you fracked it yet?’
‘Yes, everything went just fine.’
‘So the well came in dry?’
‘No, far worse: lots and lots of natural gas.’"

To the consumer, a Btu or kilojoule of energy supplied by natural gas has, for all intents and purposes, the same value as a Btu of energy supplied by oil. Geologically, oil and gas are found in the same formations, generated by the same processes and typically produced from the same wellbore. The main difference between the two hydrocarbons is what it takes to get that Btu at the wellhead to the generally indifferent consumer: transportation and storage. And that is where gas loses in undue competition to oil or liquids in the upstream.

Simply put, you cannot store or transport natural gas in a bucket or a barrel, at least at normal atmospheric temperatures and pressures. Instead, gas must be stored and transported in a continuously sealed system of high-pressure pipes or cryogenic vessels from the wellhead to the point of use. Thus, the hunt for new oil and gas resources has always created a commercial and environmental dilemma. Exploration identifies new resources, usually in remote locations where natural gas infrastructure and interested customers are nowhere to be found. Something must be done with the produced gas.
For at least the first century of organized oil and gas development, producers confronting this dilemma did what was commercially and operationally expedient: put the oil in a barrel, railroad car or ship and flare off the produced gas. Absent storage and transport infrastructure, gas becomes just an inconvenient waste product of oil production. According to the IEA, construction of a gas pipeline costs 30-times more than construction of oil pipeline (for a similar calorific volume).

Pressured by UN mandates since at least 1992, as well as by World Bank-lending policies to oil-producing nations, oil and gas producers have been steadily reducing gas flaring through reinjection into the producing reservoir (such as in Alaska’s Prudhoe Bay, where 260 MMcm of gas is produced each day along with crude oil, only to be compressed and reinjected), local gas utilization initiatives, gas pipeline construction to major markets and, most recently, investment in LNG production, storage and transport systems to condense the gas to liquid (which increases its energy density 600-fold) and deliver it to distant markets around the globe. Shell’s sustained efforts in Nigeria since the early 1990s to capture, liquefy and ship associated gas production to Europe and Asia is a textbook example of this latter approach, which has since been replicated by many others. Note, however, that the environmental, social and economic benefits of such efforts to reduce gas flaring come at a cost of tens of billions of U.S. dollars. This effort would be economically impossible without the high value of LNG – commensurate with oil – in most global markets. Gazprom has spent similar sums bringing associated gas production from distant fields in Siberia to European markets, as well as by investing in LNG solutions. The result is a steady reduction in gas flaring around the world, as shown below in Exhibit 6.

**Exhibit 6: Estimated Flared Gas Volumes, 2007-2011**

![Graph showing estimated flared gas volumes, 2007-2011](image)


The U.S., with its extensive gas pipeline network and political focus on environmental management, has generally led the way in eliminating the practice of gas flaring, but 2011 proved different. The U.S. had the largest single-country increase in gas flaring, growing from 4.6 Bcm in 2010 to 7.1 Bcm in 2011. The reason? The Bakken shale oil boom in North Dakota.
As with so many oil basins in the early years of development, North Dakota is a remote place, with little existing gas infrastructure other than two large pipelines traversing the state which were built to transport Canadian gas to U.S. markets. With prevailing oil prices at ten times prevailing gas prices (due to the shale gas boom, further discussed below), swelling Bakken Shale oil and gas production from thousands of new wells has overwhelmed existing transportation infrastructure. While the crude oil from this production boom has found its way to market via an ad hoc system of available pipelines, rail cars and trucks, the associated gas production has not. Given prevailing U.S. gas prices, it is difficult to justify new pipeline gathering systems on commercial grounds. So, as shown in Exhibit 7 below, flared gas volumes have risen while gas prices have fallen.

**Exhibit 7: Flared Gas in North Dakota**

![Flared Gas in North Dakota](image)

Source: North Dakota Chamber of Commerce.

It is certain that the amount of gas that was flared would decrease rapidly if producers were able to earn a fair price for their associated gas volumes. But, absent any price incentive, flared gas volumes from the Bakken Shale will continue to rise.

Besides the obvious environmental damage incurred, many gas-flaring countries often suffer from chronic power shortages and stagnating gas export volumes, both of which could be rectified if the gas were able to be used and sold at fair market value. In Iraq, for example, the amount of gas flared is enough to fuel the entire country's electricity requirements. The ability to sell this gas at an oil-indexed price – i.e., a price that approximates the true value of the underlying commodity – would help to solve this problem.

All of this suggests that, rather than seeing a fundamental shift in the global gas market, we instead are witnessing a brief and unsustainable situation in North American gas markets. It is this dysfunctional system that the short-sighted bureaucrats and politicians of importing nations seek to foist upon regional gas markets, believing it to be the shortest path to cheap gas supplies, despite the obvious problems seen in the North American market.
1.2.4 Shale gas

The key factor that is depressing gas prices in the U.S. is shale gas production. Low hub prices are not a result of low shale gas production costs, as is often the perception. IHS CERA estimates that the North American market is awash in approximately 145 MMcm per day of excess supply.25

In fact, our analysis shows that the all-in costs of major shale gas producers are often more than US$2.00/MMBtu higher than the Henry Hub price. Hedging gains in 2008, 2009 and the first half of 2010 have allowed shale gas producers to continue to drill. Thus, the U.S. shale gas miracle has been, in large part, paid for with the money of the ill-fated financial investors who hold these hedges. As has been noted earlier in this paper, this is because U.S. financial markets – principally futures markets – enable producers to lock in profits for years ahead. Thus, present-day low cash prices do not discourage producers from selling, even though these producers were able to sell their product at a much higher price three years prior. As a result, supply-to-price adjustment mechanisms do not function properly but with a lasting delay.

A second major market distortion which has allowed shale companies to continue producing at a time when costs exceed revenues has come from the capital markets and merger and acquisition activity. As the future value potential (quite apart from current profitability) of shale development became evident to capital markets and traditional upstream players who had previously discounted the future prospects for North American oil and gas production, the money poured in. In this way, financially-distressed shale gas producers have been able to monetize portions of the putative future value they had created through loans and investments in future cash flows.

The oil and gas majors that had systematically trimmed their exposure to U.S. gas markets and encountered difficulty booking major additional hydrocarbon reserves elsewhere in the world now returned to the U.S. searching for substantial additions to proven reserves (as well as technologies that could be redeployed elsewhere). Purchasing financially distressed shale companies could make a significant addition to these reserve bookings. A perfect example of this is ExxonMobil’s acquisition of XTO Energy, which accounted for 80 percent of the reserves that ExxonMobil added in 2010.

There are several other factors that have led shale producers to continue drilling in this high-cost, low-price environment. One factor relates to the U.S. system of mineral rights ownership and contracting practices. In the U.S., the owners of surface properties such as farms and houses also own the mineral rights to anything buried below the surface. Thus, U.S. rules force shale gas companies that are seeking to exploit mineral rights over a broad geographic area to negotiate and acquire mineral leases from all property owners in the affected area. This is a rare practice, as in most countries mineral rights belong to the state. Consequently, producers that had acquired an enormous amount of land requiring near-term development in 2006-2008 were compelled to spend money on drilling that land or else risk losing their drilling rights – and with them the future revenue needed to cover the large upfront investments that had been made to secure those land leases. In this way, operators continued to drill and produce even when the returns from the sale of that production were subpar. This has led to a large volume of gas coming onto the market that was needed simply to allow producers to maintain their leases.

Another factor relates to investment from foreign investors, who had initially responded slowly to the U.S. shale boom and then paid a premium price to buy into the active drilling

programs of the smaller independent producers. These foreign investors utilize front-loaded purchase payments and liberal development cost-sharing terms from joint venture agreements to effectively subsidize development costs, thereby distorting the economic decision to drill. Often, the main objective of such investors is not to earn a profit, but rather to gain the technical expertise that they can transfer to their upstream operations back home.

As a result of the developments described above, U.S. Henry Hub prices are currently depressed and unlikely to recover substantially in the near term. If the business model of gas exporters was based on hedging, like that of shale gas producers, they would theoretically be able to keep on selling their gas in the U.S. at any price, be it US$1.00 or US$2.00/MMBtu. However, this is not the case.

The untenable situation caused by the North American shale gas boom has led to what should be a temporary oversupply situation and very low prices. Henry Hub gas prices bottomed out at around US$2.00/MMbtu (US$70/Mcm) at the end of the 2011-2012 heating season, well below both the five-year historical price range (as shown in Exhibit 8 below) and the replacement costs required for most prospective gas resources. And yet producers continue to invest in shale development despite the fact that the all-in costs needed to maintain such development exceed market prices. A sampling of U.S. shale gas producers shows that weighted average all-in costs in 2011 rose 16.9 percent over the prior year, the second year in a row that costs increased significantly.

**Exhibit 8: U.S. Spot Gas Price Trends, 2006-2012**

![U.S. Spot Gas Price Trends, 2006-2012](image)

*Sources: U.S. Department of Energy (DOE), U.S. Energy Information Administration (EIA), April 2012.*

More importantly, average all-in costs exceeded the weighted average oil and gas price realizations by US$43.78/Mcm, or 20.5 percent. Exhibit 9 below demonstrates that producers’ all-in costs of producing shale gas have consistently exceeded their realized prices for gas sales over the past several years.
Exhibit 9: All-In Costs for Group per $/Mcme Produced; Total Cash Costs for 2012

The deterioration in gas prices since 2009, coupled with an 83 percent increase in negative revisions to natural gas reserves in 2011 over the prior year, is likely to lead to eventual – and potentially significant – capital losses. As an omen of what the future might hold for U.S. developers, several major foreign shale investors, including BHP Billiton and BP, have recently taken multi-billion dollar write-downs on their U.S. shale investments due to their respective government’s requirement that companies discount future revenue to present value, something not required by the U.S. Securities and Exchange Commission (SEC).

The U.S. Energy Information Administration’s (EIA) Financial Reporting System\(^\text{26}\) reports that oil and gas producers in the U.S. earned only a 4.5 percent return on equity in 2009, four percentage points below the average return reported by the Census Bureau’s All Manufacturing Companies index, a key industry benchmark. Significant additional write-downs can be expected in 2013, when U.S. producers will have to price their booked reserves against the much-lower average gas prices that prevailed in 2012.

Just several months ago, ExxonMobil’s CEO Rex Tillerson complained that the U.S. natural gas glut was depressing market prices and, consequently, was proving insufficient to cover production costs as a result of dramatically decreased profits. Although in shareholder and annual meetings ExxonMobil had insisted that it was not losing money on gas, Tillerson privately told a meeting at the Council on Foreign Relations that “We are all losing our shirts today. We’re making no money. It’s all in the red.”\(^\text{27}\)

In a properly functioning market this should lead to reduced investment in gas development and declining production, particularly with shale gas wells that experience first-year production decline rates of 50-85 percent. However, a fundamental point of this paper is that natural gas behaves differently from other commodities and therefore displays an irregular

---

\(^{26}\) Thirty major energy companies reported their financial and operating data in 2009, the last year for which data was available.

response to underlying changes in supply and demand. Instead of curbing investment, for instance, the low gas price environment seen in the U.S. has led producers to simply shift investment to oil and gas liquids. As the first figure in Exhibit 10 below shows, the substantial decline in the shale rig count for dry gas-prone targets over the past year has been eclipsed by the even more substantial increase in targeted shale drilling for oil and liquids. And yet total natural gas production has continued to increase in this same time period. The question inevitably arises: Why has natural gas production grown (as evidenced by the second figure in Exhibit 10) while natural gas rig counts and average spot prices have decreased substantially?

Exhibit 10: Gas-Directed vs. Oil-Directed Shale Rig Count (Figure 1) and Total Natural Gas Rig Count vs. Total Natural Gas Production (Figure 2)

Sources: Pace Global, Baker Hughes and EIA. Data shown for the U.S.
The logical conclusion to this set of circumstances is that the market is not sending the appropriate signals to industry participants. This, essentially, is where the difference between natural gas and other commodities rears its ugly head. Natural gas is a co-product – effectively a ‘little brother’– of oil and natural gas liquid (NGL)-directed drilling activity, with as much as 80 percent of the energy-equivalent production from new liquids wells actually being natural gas. Since there is no distinction between liquids-rich gas-directed drilling, which may result in higher gas production, and oil-directed drilling, which presumably will produce more oil than gas, a misleading picture is drawn as to the extent to which current drilling activity will result in oil, condensate, gas liquids or dry gas production.

In this environment, regional gas surpluses are maintained at a time of low natural gas prices, sending infrastructure planners and investors an artificial price signal that gas is cheap and inexhaustible. This, in turn, has led to a situation in which lower gas prices continue to stimulate new demand, particularly in the power generation sector, with pipeline and LNG exports serving as additional sources of demand growth. Gas-fired power generation in the U.S. equaled the output of coal plants for the first time in May 2012, and in recent months there has been a significant change in the U.S.’s net pipeline gas export balance with Canada and Mexico. Potentially more significant, whereas the U.S. was anticipated to be a major importer of LNG just a few years ago, there is now an increasing number of proposals to export LNG from the U.S. to higher-priced markets in Asia and Europe.

In short, this state of affairs is unsustainable. The race to secure future value in shale gas production has led to sustained operating losses. Only when prices abruptly and dramatically rise – as they must – will we see a return to natural gas drilling. The true cost of this phenomenon – providing enough cash flow to sustain needed investment in new gas wells – will only become evident in coming years after many years of underinvestment. Consumers will then be compelled to pay inordinately high prices until drilling budgets are revised and implemented in what promises to be a multi-year process. This, in turn, will set up the next price crash, with recent investors in gas-consuming or -exporting infrastructure expected to bear the full burden of operating losses, idle assets and unrecovered capital investment.

In the U.S., the shale revolution will likely run the course of past U.S. asset and resource booms such as the California Gold Rush of the 1840s and the dot.com boom of the 1990s. U.S. gas producers are already suffering the after-effects of a characteristically American resource grab and investment rush. The implications of this resource grab are represented by the ‘shale development money wheel’: first there is a rush of new capital to secure ownership and control of reserves, followed by the drilling of wells to establish reserves and to deliver value to private land owners. Current low gas prices and high development costs are then ignored in favor of attempts to maximize the perceived long-term opportunity. As with past booms, there will be losers as well as winners as the excesses and bad bets come home to roost.

---

28 Excluding the distortions represented by proceeds from the sale of some of that future value, sale of incidental assets in shale development, and increased borrowing.
1.3 Remedy to the ‘Little Brother’ Syndrome

At this point, one may ask whether we are arguing that, as a result of these market distortions, natural gas will never become an independent commodity but that it will remain indefinitely indexed to oil in order to protect its value. The answer to this is no. There is a natural remedy to the little brother syndrome – the furthering of direct competition between oil and gas that will bring their prices closer over the long run. Inter-fuel competition between oil products and natural gas is indeed growing and leaves us with the hope that one day gas will rid itself of this little brother syndrome in pricing. This competition will occur in non-traditional markets such as the transportation sector due to the increasing popularity of natural gas-powered vehicles and the use of LNG as bunker fuel.

Gazprom Export has closely followed the EU’s initiatives to reduce greenhouse gas emissions. If we look at the most recent EU goals for the transportation sector – targeting an overall 60 percent reduction in carbon emissions by 2050 – we come up against some stubborn facts. The utility of transportation technologies is highly dependent on their portable fuel capacity, which determines both range and performance. For heavy-duty trucks, it is a leap of faith that 95 percent of the fleet will be at least partly electrified via hybrid-drive and mobile fuel cell systems. This may well be possible someday, but not without fundamental scientific breakthroughs in electricity storage systems and major engineering advances in mobile fuel cell power systems. For shipping, one proposed advancement is actually a reversion to wind power, harkening back to the days of sailing tall ships. Indeed, this may appeal to one’s romantic sensibilities, but the concept itself has little grounding in reality. This may help to explain why, until now, there have been few serious alternatives to petroleum fuels in the transport fuel market.

However, this trend is now set to change. A cursory look at the benefits of natural gas reveals the reasons for its increasing popularity as a transport fuel: natural gas is abundant, has a diversity of supply sources close to transport markets, and offers far lower emissions of pollutants such as carbon dioxide (\(\text{CO}_2\)), sulphur oxide (\(\text{SO}_x\)), nitrogen oxide (\(\text{NO}_x\)), and particulate matter (PM) than petroleum. Further, natural gas is considerably cheaper than traditional petroleum fuels.

Arguably, natural gas’s most important advantage is that it offers fewer emissions of harmful, ozone-depleting substances at a time when emissions from road and marine traffic are under increasing scrutiny around the world. As discussed earlier, the EU’s most recent goal for the transportation sector targets a 60 percent overall reduction in carbon emissions by 2050. At the same time, the International Maritime Organization (IMO), the European Union (EU) and other nations are actively seeking to reduce emissions from the shipping sector. To address these concerns, IMO member states ratified a treaty on the International Convention on the Prevention of Pollution from Ships, known as MARPOL 73/78. Specifically, Annex VI of the treaty calls for a reduction in \(\text{NO}_x\) and \(\text{SO}_x\) emissions from the shipping sector. There are two levels of requirements: those that apply globally, and those that apply only in IMO-designated Emissions Control Areas (ECAs).

MARPOL 73/78 will reduce the maximum allowable sulphur content in bunker fuel from the current 3.5 percent (which became effective 1 January 2012) to 0.5 percent as of 1 January 2020, pending the results of a feasibility review that is due to be completed no later than 2018. In ECAs, the sulphur limit was reduced to 1.0 percent (from 1.5 percent) on 1 July 2010 and will be further reduced to 0.1 percent starting 1 January 2015. \(\text{NO}_x\) emissions,

meanwhile, must be reduced by 80 percent (from current levels) in ECAs and by 20 percent globally. The emissions levels associated with natural gas compared with traditional bunker and vehicle fuels are presented below in Exhibit 11.

**Exhibit 11: Comparison of Emissions by Fuel Type**

![Comparison of Emissions by Fuel Type](image)

Source: Gazprom. Note: CH = Hydrocarbons. Soot = Particulate matter.

To date, the IMO has approved three ECAs: one covering the Baltic Sea, the North Sea and the English Channel; a second one for North America; and a third ECA covering parts of the Caribbean. Other regions, including the Mediterranean and Black Seas and East Asia, are also under consideration. The stricter environmental regulations in effect in ECAs mean that shipowners effectively have three options to comply with new emissions limits: 1) secure low sulphur (but expensive) marine gasoil or diesel; 2) install costly sulphur and NOx abatement technologies; or 3) transition to LNG. In short, LNG is the only fuel which meets new ship emissions limits in ECAs. It is expected that a significant percentage of ship owners will make the switch to LNG once these new ECA regulations take effect post-2015.

The situation is similar with road transport. In the EU, vehicles must meet mandatory emission reduction targets established for new cars, light trucks and heavy-duty vehicles, known as the Euro I – VI standards. The most recent Euro VI standard, adopted in 2009 and effective in 2013, sets a passenger vehicle fleet standard of 0.500 grams per kilometer (g/km) of carbon monoxide (CO), 0.080 g/km of NOx and 0.170 g/km of PM. In addition, the passenger vehicle fleet average for all new cars is subject to voluntary limits (of 130 g/km of CO₂ by 2015 and 95g/km by 2020. In addition to complying with these new exhaust emissions limits, natural gas engines also emit far less noise compared to compression ignition engines, making vehicle operations possible 24-hours a day. As constraints on carbon and other emissions are tightened and the price of petroleum fuels relative to natural gas rises, owners will increasingly consider replacing or reconfiguring their vehicles with engines capable of using natural gas or LNG as fuel.
Let’s take a look at the projected demand for natural gas in transportation. Major international consulting agencies and industry associations have provided their forecasts of this oil-to-gas dash (Exhibit 12 above). The consensus among these organizations is that natural gas is expected to capture significant market share from traditional petroleum-based fuels in both marine and road transport. In fact, this oil-to-gas dash, a major revolution in transportation, is silently taking place already.

Aside from bunkering and road transport, there are several other applications – such as fuel for mining and drilling equipment – where natural gas can compete effectively with traditional petroleum-based fuels. The mining industry represents a particularly noteworthy opportunity for natural gas fuels, especially considering that leading equipment providers have developed super heavy-duty natural gas engines suitable for applications in mobile mining.
At present, more than 7.5 billion liters of diesel are consumed by the 28,600 haul trucks employed by the world’s top-ten mining companies. Another 126 million tons of diesel are consumed each year in hydraulic fracturing. Because a single fracturing job can require 7,800 gallons (246 tons) of diesel (at a cost of up to US$5.00/gallon), substituting natural gas for diesel can result in annual fuel savings of US$1.3 million per rig.

Primarily as a consequence of lower natural gas fuel costs, the operating cost per kilometer of a heavy-duty vehicle fueled with LNG can be substantially lower than an equivalent vehicle utilizing diesel fuel. While natural gas vehicles are, in general, more costly to acquire than their conventional fuel counterparts, lower cost natural gas fuel and minimized operating costs over the life of the vehicle allow for a rapid return on any capital premium. This helps to explain why LNG-fueled tractors, rigs and haul trucks are becoming more prevalent globally. Like natural gas-fueled refuse trucks and urban buses, successfully utilized in many urban environments for years, these LNG vehicles are highly valued for their cost effectiveness and low levels of noise and air emissions.

You may ask why the transition from oil to gas – which represents the next great revolution in energy and transportation markets – is only taking place now, considering that natural gas offers such obvious benefits. There are several reasons for this.

The first major problem with using gas as transport fuel is its lower energy density. Prior to the development of small-scale LNG applications, compressed natural gas (CNG) was the prevailing means of utilizing natural gas in transport. However, even when compressed to around 200 atmospheres, natural gas has only 25 percent the energy content of diesel fuel. Add to this the greater weight of the pressurized tanks needed to contain CNG, and the advantage of conventional liquid fuels becomes clear. In the past, the poor energy density of CNG limited the use of natural gas in the transportation sector to light-duty vehicles and public intercity transportation.

The solution to the density problem came from LNG. LNG has an energy density more than double that of CNG. Compared with diesel, the lower density of LNG is partly compensated for by a significantly higher calorific value on a weight-for-weight basis (54 MJ/kg for LNG versus 46 MJ/kg for diesel fuel), resulting in an energy density roughly 60 percent that of diesel. LNG is the only fuel that approximates the fuel density and operational performance of, diesel. Simply put, no other fuel is as practical an alternative to diesel fuel for heavy-duty vehicles operating over long distances and/or fuel-intensive duty cycles. Natural gas allows for vehicle range and performance that is comparable to traditional petroleum fuels, but without increasing life-cycle costs. With the possible exception of long-haul flights and rail transport, LNG has made nearly all transportation industry sectors viable for natural gas penetration, from long-haul trucking to maritime shipping to 300-ton heavy-duty trucks in the mining industry.

The second reason is purely economical. Natural gas is much cheaper than oil products on an energy-equivalent basis. The (oil-indexed) German border price of natural gas is around half as expensive as Brent crude and one-third the price of automotive diesel fuel. These prices do not include tax, which provides further advantages to natural gas when one considers the applicable tax regimes for the competing fuels.

The huge expansion in global LNG manufacturing and distribution capacity over the past decade is another reason for the increasing popularity of natural gas in transport markets.

---

31 Ibid.
32 The BAFA price averaged US$10.19/MBBtu in July 2012. Automotive diesel prices were US$43.00/MBBtu with taxes included.
Lastly, improvements in ship, engine, distribution and storage design technologies have opened up enormous opportunity for gas to be used as fuel in road and marine transport. While reciprocating engines have operated on natural gas for decades, it is only in recent years that LNG has been used as bunker fuel in a variety of vessels, from passenger and platform supply vessels to military and patrol boats, tankers and tugs. Engine technologies that run on LNG or in dual-fuel mode are widely available and offer superior fuel quality and higher efficiency (per Btu) than their petroleum counterparts, resulting in lower operating costs and reduced emissions. New engines under development aim to reduce methane emissions even further – by up to 70 percent. A number of new technologies and methods – such as pressure increase in fuel tanks, onboard reliquefaction, and using the gas as fuel – have been developed to manage boil-off gas (BOG), once considered a significant concern by ship owners.

Meanwhile, improvements in fueling and storage capabilities mean that LNG can be stored onboard with a smaller loss of cargo capacity than was previously assumed. Intermodal containers are also increasingly used which allow LNG to be unloaded in bulk or individually discharged for transport by truck or rail car to inland destinations.

In sum, small-scale LNG technology adoption is rapidly accelerating in Europe, the U.S. and Asia. Meanwhile, new advancements are under development that will further accelerate this trend in the near future.

1.4 Rationale for Oil Indexation

As stated earlier, the convergence of oil and the gas prices via increased competition in the transportation sector is the only way to remedy the so-called ‘little brother’ syndrome which currently prevents gas from becoming a truly full-fledged independent commodity. But it will take years for this remedy to play its role in bringing oil and gas prices closer together.

Here we come to a major point of disagreement with the mainstream analysts who treat this diversion in oil and gas prices as an indication that oil-indexation in gas pricing has lost its relevance once and forever. We completely disagree with this view. On the contrary, gas producers need protection now, more than ever, in order to maintain their investment programs. This protection can only come from oil-indexation.

Critics of oil indexation often claim that it is outdated because there is limited demand-side substitution between oil and gas. J. Stern claims that in the 1970s, when petroleum products were used extensively by European power stations and large-scale industrial plants, oil-indexation was justified, but markets have changed and oil products have been increasingly forced out of power generation and other stationary uses. Therefore, the original logic of oil as the replacement fuel for gas is no longer supported by reality.  

It is true that day-to-day demand side substitution has not been the case in Europe for more than 20 years. However, limited day-to-day substitution or even its absence does not rule out a deep-rooted relationship between oil and gas. As in the case of pricing based on supply and demand, we believe that pricing based on substitution value does not require a large number of actual transactions. For instance, the West Texas Intermediate (WTI) price represents less than two percent of the oil used in the U.S. but its price is representative of all the oil liquids consumed. According to the FERC, less than 15 percent of real-life (i.e.,

physical) transactions set the price for natural gas in the liberalized gas market of the U.S., with the remainder benchmarked in one way or another to these transactions.

Oil and gas still compete head-to-head in the residential sector, which remains a major outlet for natural gas consumption in Europe. One-third of houses in Germany still use oil products for heating. There is still rationale for oil indexation in power generation in countries where oil products play an important role in the energy mix, such as in Japan. Even though there is not much demand-side substitution between oil and gas in the European power generation sector at present, gas effectively replaced oil in European power generation, but there is still more than a virtual relationship between the two fuels:

- Merit order in Europe puts oil products and gas in the same category of fuels used in peak or semi-peak generation. In that sense, there is a stronger competition with oil products than with coal, which is used in base-load generation only;
- Oil products are a reserve fuel for many power plants and industries should the gas supply fail.

The oil-gas linkage will only strengthen in the future as a result of direct competition in the transportation sector due to the increasing popularity of natural gas-powered vehicles and the use of LNG as bunker fuel. In the longer-term, technologies such as gas-to-liquids (GTLs) should increase gas-to-oil competition on the demand as well as the supply side.

An additional rationale for oil-indexation lies in the fact it helps to make gas inflation-indexed. The oil-product linkage in the gas pricing formula performs the function of a universal deflator better than any other man-made price index, be it the CPI or PPI.

When presenting a critical review of the supply and demand-based pricing mechanism, it would be disingenuous not to acknowledge the shortcomings of the current oil price. The issue is not with oil-indexation, however, but with volatility in oil prices. This volatility is a direct result of the use of oil as a global hedge against inflation. The oil market is driven not only by physical demand for the product but also by investors’ fears that paper currencies will further decline in value.

Exhibit 13 below provides us with strong evidence of this trend. One does not need to be an energy expert to see that the price of oil precisely follows inflationary expectations. This means that investors are using oil as a safe haven to hedge their currency risks.
In order to estimate to what extent this practice distorts oil prices, we quantified the impact of hedging on crude oil prices. The results of this analysis, which show a negative correlation between Brent and the U.S. dollar index, are presented below in Exhibit 14.

---

34 The correlation model for oil price behavior in relation to the U.S. Dollar index was developed by Vyacheslav Kusov.
As shown in Exhibit 15 below, the oil price is significantly less volatile when stripped of its hedging functions. In actual terms, the difference between the historic Brent price and its ‘filtered’ version ranges from US$1.00 in 2009 to US$20.00 in 2012. Stripped of its hedging function, the oil price does not differ critically from its actual price, indicating that oil remains the best instrument for replacement value pricing.
1.5 Rationale of Indexing Gas to Other Commodities

“There is still a close correlation with putting in place LNG supply infrastructure – from upstream to plants and so on – and delivering that to the market. There is quite a close correlation to oil prices over time. There is zero correlation, frankly, with anything else that might be considered as a price maker.”

- De la Ray Venter, Shell’s global head of LNG, 25th World Gas Conference, Kuala Lumpur.

When gas supply contracts are indexed, they are typically, but not always, indexed to oil prices. In general, producers have been more comfortable with oil-indexation than other
indices. The producers, often national or international oil companies, take the view that their shareholders both understand and accept oil price risk without resistance. End-users, on the other hand, have sometimes felt that electricity, coal, orimulsion, or even used vehicle tires should be considered as viable alternatives. These customers have argued for indices relating to their own businesses (such as metals, chemicals, electricity, inflation, and so on). Hence, various indices have been added to the oil-indexation formula from time to time. However, as we will show below, oil continues to remain the best option available. This is primarily a result of the difficulty of finding another commodity that, as is the case with oil, can be characterized by the following:

- Boasts a liquid and transparent global trading market;
- Serves a major role either as a competitor to natural gas or as a product of gas consumption; and
- Is an acceptable index to a broad range of gas end-users and suppliers.

Surveying the options, it is quickly evident that a commodity price index that satisfies the pricing criteria of a single category of end-users will not be generally acceptable. This is because of the wide divergence in the absolute and relative cost and substitutability of gas, compared with other inputs, in the production of steel, petrochemicals, aluminum, fertilizers and glass, to name only a few examples. Further, the role and economic value of gas in each of these manufacturing processes differs widely, and the pricing of each potential substitute for gas is based on so many other factors as to make any one selection objectionable to the majority of gas end-users.

1.5.1 Use of Coal or Electricity as Indices

Two possible exceptions to the above are coal, as the current primary competitor to gas for power generation market share, and electricity, as the single largest commodity product of gas use.

There is some history of indexing natural gas to coal, particularly in countries such as Germany that rely heavily on coal for electricity generation and industrial use. The superiority, or even equivalence, of coal as a relevant index substitute for oil in the future, however, is subject to strong challenge. Coal is exclusively a fuel for baseload power generation, while a large portion of the gas used in power generation is for higher-value mid-merit and peaking capacity. In the future, as intermittent power sources like wind and solar energy play an eventually dominant role in the fuel mix, coal generation will be relegated to an ever-smaller portion of baseload power supply while natural gas will increasingly find its best use as the fuel of choice for load tracking as intermittent power production rises and falls over the course of a day.

The relative value of gas over coal will only grow as it becomes the essential backstop to keep the electric grid balanced as other supplies and demand vary. This value would become the exclusive property of the gas purchaser if coal indexation were to become the norm. This is further exacerbated by the substantially higher carbon footprint of coal versus gas. As EU countries seek to reduce the amount of carbon they emit, coal generation will become increasingly irrelevant in future years, again leading to a higher value for natural gas for a similar heat content.

Electricity, being a publicly-traded commodity, has a different but related set of problems. The value and cost of electricity vary hourly as demand shifts and the mix of resources used
to meet this demand changes based on both availability and cost. However, the cost of an ever-increasing share of power generation in Europe is not defined by pure market conditions. 'Must-run' renewable power generation is heavily subsidized throughout Europe (see Exhibit 16 below), meaning that the price of renewable power is significantly lower than its cost of production. Therefore, gas suppliers with sales contracts indexed to power prices would increasingly be forced to bear a portion of this overall social subsidy in the form of power prices that are artificially suppressed via subsidies to renewable competitors.

**Exhibit 16: Average Additional Power Costs due to Renewable Subsidies per MWh (2012-2020)**

![Graph showing average additional power costs due to renewable subsidies per MWh (2012-2020).]

Sources: Eurostat, Reuters, various country published documents, and Pace Global.

Further, there is circular logic in pricing a generation fuel against a power market that dispatches on the basis of the lowest-cost power supply. The largest single component in the cost of gas-fired generation is the fuel itself. Power marketing pricing against the cost of fuel inputs would therefore match gas pricing against the price of power. That is, the price of gas would be used in large part to set the price of power which in turn would set the price of gas. This would permit generation fleet owners to arbitrage the spark spread, capturing economic rents that would otherwise flow to the fuel supplier.

While price-indexation substitutes for oil must certainly be acknowledged as theoretically viable alternatives, the specific inherent problems of every potential substitute must be compared against the alleged problems of the oil index. It is in this direct comparison that the candidates offered to date have been found wanting.

### 1.5.2 Wood Pellets as an Alternative Index

Some industrial consumers and EU regulators have proposed that the price of wood pellets, primarily used in Europe for co-firing with coal in large industrial boilers and power stations, be linked to that of natural gas. However, the rationale for linking natural gas prices to those of wood pellets, rather than to crude oil as the best alternative fuel, is premature at best.
The wood pellet market, while growing, is still many years from reaching the volumes that we see in oil markets, or even in the markets for natural gas and LNG. Worldwide, only about 150 co-firing power plants are in operation. Much of the production in wood pellets is in Europe and North America. North American wood pellet production, which was over 8 million tonnes in 2011, is estimated to reach 15 million tonnes by 2017. Total wood pellet demand for heating in the EU is expected to surpass 22 million tonnes by 2020. By contrast, the global LNG trade in 2011 reached 240 million tonnes, according to the International Group of LNG Importers.

Exhibit 17: Global Wood Pellet Consumption, 2011

Current market for wood pellets is largely traded on the basis of fixed, long-term contracts ranging from one to ten years and remains relatively illiquid. Recently, producers have increasingly been trading on the spot market as offtakers are adjusting their operational and risk management strategies. Responding to requests from buyers for spot volumes, producers are becoming more willing to keep 10-15 percent of their production available for spot trading. The Argus northwest Europe wood pellet index reports that in 2011 spot volumes reached 683,000 tonnes, or 5.7 percent of total trade volume. Compared to oil and gas, however, wood pellets remain a small niche market with extremely limited liquidity, and that market remains dominated by long-term contracts.

One area in which there is some overlap between biomass and natural gas is with synthetic natural gas, or bioSNG. BioSNG is derived from the gasification of biomass such as wood chips and is being looked at with interest by countries such as Sweden, which has few indigenous natural gas resources. There are at present a small number of pilot plants in Europe demonstrating the viability of bioSNG, which are generally built on the scale of 50-100 MW capacity. Small-scale gasification/combined heat and power (CHP) is another area of focus for the wood chip market, operating in the 50KW-1MW range. These applications are meant to be small and distributed and have not yet gained significant ground with respect to natural gas-fired CHP power plants.


Given wood pellets’ small and illiquid market and the low penetration rate of biomass boilers, even with the advances in bioSNG, indexing natural gas to biomass lacks an adequate supporting rationale. Further, the market for wood pellets is so heavily distorted by government support programs that any attempt to index natural gas to wood pellets will naturally be skewed and not representative of market fundamentals. Although some have attempted to make a comparison of wood pellets with natural gas as an alternative fuel, wood pellets are simply not directly substitutable for natural gas as they are with coal and therefore should be considered a poor substitute for oil as an index to natural gas.
Part 2: Studies in the Hybrid Pricing System

In logic, an argumentum ad populum (Latin for "appeal to the people") is a fallacious argument that concludes a proposition to be true because many or most people believe it. In other words, the basic idea of the argument is: "If many believe so, it is so."

In the first part of this paper we discussed the deficiencies of a natural gas pricing mechanism based on supply and demand and the rationale for retaining the oil linkage. The subject of discussion for this second chapter is the current pricing system in Europe. What we often hear is that third-party (non-EU) suppliers must respond to the dramatic, even 'tectonic', changes that have taken place in Europe over the past few years by offering wholesale adjustments to their long-standing and proven pricing mechanisms. Opponents of oil indexation insist that Europe is not only willing but is ready to abandon the current pricing model in favor of transitioning to a supply and demand-based pricing. J. Stern, one of the major opinion-makers in European pricing, is convinced that Gazprom is waging a losing battle to preserve its long-term oil-indexed contracts. Some analysts take this argument even further by referencing their own opaque assessments indicating that more than half of European gas is already sold on a gas-index basis. In this way, they try to convince the general public that a move to hub pricing in Europe is a fait accompli.

In this chapter, we will return to the subject of the contemporary gas market in Europe to determine reasonable pathways for its future development. However, before we look forward, it is imperative that we first review the current situation. In other words, we must answer key questions about the contemporary market environment:

- Are hub prices ready to take over for oil-indexed prices in long-term contracts?
- What will happen if the market transitions to hub-pricing right away?

It is our view that European hubs must meet the following two requirements (at a minimum) in order to produce a sustainable gas price benchmark. These requirements are as follows:

- Firstly, these prices should serve as a genuine market barometer, reflecting the totality of supply and demand conditions in Europe, or at least of a large segment of it, such as Northwest Europe; and
- Secondly, hub prices should be self-defined, fully independent from oil-indexed prices, and not influenced by the fundamentals of another market.

Many mainstream European analysts, such as R. Harmsen and C. Jepma, from the University of Groningen, have no doubt as to the capability of existing gas hubs to meet these requirements. Harmsen and Jepma claim\(^{37}\) that day-ahead prices at six Northwest European hubs have moved in tandem since 2007. According to these experts, Northwest European hubs constitute an integrated market that operates solely on the basis of supply and demand. However, the authors refrain from asserting that the integrated gas prices seen in Northwest Europe should serve as a benchmark for the pricing of long-term import contracts from non-EU countries. Harmsen and Jepma are careful to avoid offering any opinion as to whether integrated hub prices correlate with long-term oil-indexed contracts or if they are, in fact, independent from these prices.

J. Stern and H. Rogers, of the Oxford Institute of Energy Studies, insist that there should be “a single mechanism for pricing gas” and that hub prices “accurately reflect changing supply and demand conditions.” Despite their imperfections, the authors argue, European hubs provide the best indicator of market prices, and it is these prices which long-term contracts should strive to reflect. Although Stern and Rogers provide no empirical evidence, they claim that “in theory, as well in practice” hub prices are driven by their own fundamentals and therefore can be higher or lower than oil-indexed prices. What these analysts mean to say is that gas hub prices are not closely correlated with oil-indexed prices and therefore are not driven by oil market fundamentals. It is this assertion that we seek to disprove.

In a recent study of European market hubs, P. Heather, also from the Oxford Institute of Energy Studies, agreed with his colleagues that European hubs are mature enough to serve as a price benchmark. However, he was referring only to the NBP and TTF. Other hubs, in contrast, do not play a role in price setting but are instead used to balance physical portfolios. Although the author of the report shares the same conclusion as his colleagues, his acknowledgement that some hubs act as no more than a balancing point represents a deviation from the mainstream view.

Contrary to the conclusions of mainstream analysts, we believe that existing hub prices in Europe do not meet any of the above-mentioned requirements and therefore cannot act in a price-setting role. What makes these prices so different from prices that originate, for example, at U.S. hubs? Before delving into the details of these conclusions, we should note that Continental hubs operate only within the framework of existing contractual relationships – of both short- and long-term duration – that directly affects the functioning of these hubs. And yet the coexistence of different pricing mechanisms and their potential interactions are completely ignored by mainstream analysts.

2.1 Pricing from a Systems Point of View

In order to determine the readiness of Continental European hubs to act as a universal price-setting mechanism, one must first evaluate the various pricing models that are currently available globally. Among the four existing pricing models (U.S., Europe, Australia and Asia), only the U.S. pricing system is universally acknowledged to be driven purely by supply and demand forces. Hub prices in the U.S. are solely dependent on North American market dynamics and are not influenced by any other pricing mechanism. The Henry Hub serves as the main pricing point around which all other North American prices are based. Although there was a strong positive correlation between Henry Hub prices and oil prices from 1993 to 2008, from 2009 to 2012 that correlation disappeared completely with a correlation coefficient of -0.44.

On the opposite extreme is the Northeast Asian pricing model, where the majority of gas (LNG) is sold on a long-term basis with close to 100 percent oil-indexation. Although similar contracts can be found in Europe with respect to LNG contract deliveries, it is unlikely that this pricing model would become established on the Continent, even though it is fully acceptable to gas producers. Instead, it is more likely that Northeast Asia will adapt its pricing model similar to the European hybrid system. The Platts Japan Korea Marker (JKM) price index for spot or prompt-month LNG cargoes – which serves as a proxy for hub-priced gas in Northeast Asia – does not differ much from the average same-month country portfolio.

---

39 “Continental European Hubs: Are They Fit for Purpose?”, P. Heather, Oxford Institute of Energy Studies, NG 63, June 2012, p. 46.
40 Correlation analysis here and mentioned below was conducted by Alexey Gnatyuk.
of long-term oil-indexed contracts. The JKM index of over-the-counter (OTC) trades serves as an indication that prompt–month prices there strongly correlate with oil-indexed prices.

Australia, as in so many other dimensions, represents a special pricing case for gas that we call an ‘eclectic’ model. The Australian gas market is roughly divided into two disconnected parts – east and west. Most natural gas is sold under bilateral long-term contracts based on the substitution value of alternative fuels. In the eastern province of Victoria there is a small spot market originating its own prices that differ from prices in the western part of the country.

The European two-tiered pricing model is represented as a combination of oil-product indexed long-term contracts and hub pricing. We use the term ‘hybrid’ to indicate that these different pricing methods do not exist in parallel worlds like in Australia or Oxford Institute research papers, but are instead closely interconnected and operate as a single, unique mechanism.

It is not surprising, perhaps, that those who call for changes on the Continent, including the afore-mentioned British consultants, do not point their fingers straight at the otherwise logical choice, the U.S. liberalized pricing model. Rather, they point their fingers at something else: a fifth type of pricing model, some elements of which are represented by Norwegian and Dutch long-term contracts indexed to hubs that are already present in the existing hybrid model. One of our clients dubbed this model the ‘re-engineered’ pricing model. We would tend to call it ‘genetically modified,’ because this model combines two incompatible things.

That is, the proponents of this fifth model want to move toward hub pricing while maintaining the terms of the existing long-term contracts that place firm obligations on the supplier to maintain a high degree of flexibility. That situation is untenable for traditional suppliers who must take all the risks of price uncertainty without any means of affecting hub price formation, and who must incur the substantial additional costs of providing supply flexibility in these long-term contracts without any reciprocal benefits or tangible rewards. We doubt the viability and stability of a pricing system in which such contracts would be promoted to play a dominant role. A shift to such a pricing system would be detrimental to many of the existing long-term contracts that are a cornerstone of energy security for import-dependent Europe.

Put differently, while there are five options available (Exhibit 18), in reality the choice for the European gas market is between the existing hybrid model and the U.S. pricing model. Indeed, if you want U.S.-type pricing based on supply and demand and there are liquid hubs available, then there really is no need for long-term contracts. If you prefer long-term contracts as a security of supply instrument then you must adhere to the existing hybrid pricing model. But ‘genetically modified’ pricing that combines the buyers’ choice of the best features of the two worlds is a product that is hard to sell to the gas supplier. There are reasons as outlined in the first part of this paper as to why the U.S. pricing model would also not be the best choice for the supplier. That is why our preference is to stay with the hybrid pricing model that has proven its effectiveness over many years.

Nevertheless, there is strong pressure on Gazprom to adopt this ‘reengineered’ pricing model. There are analysts who suggest that changes to the hybrid pricing model can be carried out in an evolutionary way, simply by means of increasing the share of the spot component in long-term contracts at the expense of oil indexation. However, in order not to place an undue financial burden on the supplier – which incurs additional costs by offering enhanced flexibility provisions in its long-term contracts – increasing the share of the spot component would need to be compensated for by reducing the supply flexibility and allowing enhanced interruptibility of long-term contracts. And that is exactly the opposite of what Europe really needs.
### Exhibit 18: Pricing Model Options for the Continental European Gas Market

<table>
<thead>
<tr>
<th>Model</th>
<th>Applicable To</th>
<th>Description</th>
<th>European Supplier Acceptance?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil-indexation</td>
<td>Northeast Asia</td>
<td>• Long-term contracts</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• 100% indexed to crude oil</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• No hubs, OTC trades</td>
<td></td>
</tr>
<tr>
<td>Hub</td>
<td>North America</td>
<td>• Near absence of long-term contracts</td>
<td>No. Not the best option for Continental Europe</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Pricing based on supply &amp; demand</td>
<td></td>
</tr>
<tr>
<td>Eclectic</td>
<td>Australia</td>
<td>• Hub pricing and LT contracts indexed to alternative fuels</td>
<td>No. Cannot be applied to Europe.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Geographically separated markets</td>
<td></td>
</tr>
<tr>
<td>Hybrid</td>
<td>Continental Europe</td>
<td>• Primarily, long-term oil/oil product indexed contracts</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Limited gas-indexed component in long-term contracts</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Hub pricing</td>
<td></td>
</tr>
<tr>
<td>Modified</td>
<td>Continental Europe (?)</td>
<td>• Long-term contracts linked to gas indexes</td>
<td>No. Supported by buyers. The system is not stable and inevitably transforms into the U.S. pricing model.</td>
</tr>
</tbody>
</table>

Source: Gazprom Export.

### 2.2 The Role and Function of Hubs in the Hybrid Pricing System

"How funny it’ll seem to come out among the people that walk with their heads downward!"

*From “Alice’s Adventures in Wonderland”, by Lewis Carroll*

The European gas market represents a combination of oil-indexed long-term contracted gas, short-term end-user contracts and hub-priced gas. The European pricing model is best described as a hybrid – a term originally coined by the Clingendael Institute in the Netherlands to denote the two different pricing methods that exist concurrently in the Continental European gas market.

The Clingendael Institute concludes that “there is no strong evidence that the current hybrid situation, in which both forms of gas pricing co-exist, cannot continue. There are also no overriding reasons to intervene in the market practices of price formation. Both systems have their advantages and disadvantages under different market conditions, and to some extent complement each other in the current markets. Different types of risk and the
appreciation thereof by the trading parties will determine particular choices of pricing rules and contracting conditions.”

Unfortunately, the arguments put forth by the Clingendael Institute were not expanded upon by mainstream gas analysts. No dedicated research of the hybrid market model was proposed, nor were there any major attempts to understand its mechanisms. Indeed, with the future blueprint of the European pricing model assumed to be based on supply and demand, there seemed to be little interest in determining whether this pricing model was even practical.

J. Stern and H. Rogers also use the term ‘hybrid’ when describing the existing pricing model in Europe, but ‘hybrid’ to them is simply another name to denote the existing two-tier pricing structure, i.e., the divergence of contract and hub prices. Here, the term ‘hybrid’ clearly bears a negative meaning. They claim that this system emerged after 2007 when prices between the two methods started to diverge. Stern and Rogers do not even consider the possibility that there might still exist interdependence between these two prices.

There is also a tendency among European analysts, regulators and politicians to suffer an inferiority complex when comparing their existing pricing model with that of the liberalized U.S. or British variants. The meaning of the word ‘liberalized’ is, in itself, key to understanding this complex. This word implies that the existing pricing system on the Continent, dominated by long-term oil product-indexed prices, is itself archaic and outdated.

On the contrary, Continental Europe has developed a unique hybrid pricing system based on the symbiotic coexistence of oil and gas indexation. Under the existing model, oil-indexed prices play a leading and dominant role, while hub prices play a balancing and subordinate role. Combined, this comprises a well-functioning and highly competitive system, although competition manifests itself in a different way than the U.S. model. What we hope to demonstrate in this paper is that the Continental market not only has its own unique organization, but that it is mature enough to perform the functions it was designed for: that is, to ensure secure and flexible supply to meet the needs of the European market in both the near and long term. Thus, there is no reason for such an inferiority complex.

Although we consider the hybrid pricing system to be the best choice for Europe, we probably will disappoint those advocates of ‘uniform pricing principles’ by claiming that hub prices originating in the hybrid model are of a special nature. Hubs can be reasonably liquid and their prices aligned but this does not mean that they can — or should — serve as the exclusive pricing mechanism for Europe.

In that sense, the desire by certain market participants to transition to supply and demand-based pricing cannot be accomplished in the near-term because existing hub prices on the Continent are not a function of total supply and demand or even of a large segment of it, such as in Northwest Europe. Although Continental hub prices are reflective of supply and demand conditions (as will be discussed in more detail later on), Continental hubs do not indicate total supply and demand dynamics. Instead, they play the role of balancing the residual volumes that remain after long-term oil-indexed contacts meet the bulk of demand.

Therefore, Continental hub pricing is not a function of total supply and demand but a function of something quite different: of balancing and arbitrage of all kinds, between different contract pricing structures, between contract and spot prices, between hubs, between the UK and the Continent (see Exhibit 19 for a schematic description of how the Continental hub hybrid pricing system operates).

There is significant empirical evidence supporting our statement that hub prices are not reflective of total supply and demand market equilibrium. The most illustrative piece of evidence is the behavior of hub prices in the aftermath of the Ukrainian transit crisis in January 2009, when up to 250 million cubic meters per day (MMcm/d) was not being delivered to Gazprom’s European clients for nearly two weeks. But this drop in supply produced virtually no effect on the perfectly aligned Continental hub prices, as the volumes offered at the hubs did not change dramatically.

**Exhibit 19: Prices on Continental Hubs are not a Function of Total Supply and Demand**

It is important to note that due to the lack of sufficient physical interconnections between Continental hubs and the border off-take points specified in long-term contracts, pipeline gas suppliers from non-EU countries are not able to sell large quantities of gas on the hubs or to source gas on the hubs in order to meet their clients’ requirements, as marked in Exhibit 19 above with an “X”. The ability of pipeline suppliers from non-EU countries to directly affect Continental hub prices is highly limited.

\[ PH_{CE} \neq F(S_{CE}, D_{CE}) \]

\[ PH_{CE} = \text{hub price in Continental Europe} \]

\[ SH_{CE} = \text{total supply} = SH_{CE} + SHEU_{CE} + SLNG_{CE} + SUK_{CE}, \]

where:

- \( SH_{CE} \) – sales to hubs by importers
- \( SHEU_{CE} \) – sales to hubs by end-users (ToP obl.)
- \( SLNG_{CE} \) – LNG supply to hubs
- \( SUK_{CE} \) – UK supplies through the Interconnector & BBL
- \( DHI_{CE} \) – demand by importers for hub gas
- \( DHEU_{CE} \) – demand by end-users for hub gas
- \( DUK_{CE} \) – UK deliveries through the Interconnector and BBL

\[ PH_{CE} = F((SH_{CE} + SHEU_{CE} + SLNG_{CE} + SUK_{CE})/(DHI_{CE} + DHEU_{CE} + DUK_{CE})) \]

Source: Gazprom Export.
The specific nature of natural gas price signals in Europe is demonstrated by the extremely low churn ratios at Continental hubs. In order to produce sustainable price signals, the churn ratio must be at least 15. In Europe, only the NBP meets this condition; the Continental markets do not pass this test. Some analysts say that low churn ratios on the Continent are a reflection of the transition phase, and that, as hub markets mature, churn ratios will grow. We are pessimistic in this respect. It is not because European financial institutions are reluctant to play with the forward curve. Rather, it is extremely hard to predict what the price on a balancing market will be in two or three years’ time because these prices are not about supply and demand but about arbitrage opportunities. These are largely the result of the hybrid system in which they arise, and they are by nature transitory, location-specific and independent of aggregate supply and demand: thus hardly the basis for rational longer-term price discovery.

Continent hub churn ratios, as shown in Exhibit 20, are low and do not look likely to increase. In any event, hub markets on the Continent are a paradise for arbitrageurs already. In this sense, it is a mature market by now and quite distinct from the U.S. model.

**Exhibit 20: Churn Ratio at European Hubs**

Source: CERA.

A summary of the fundamental differences between the two pricing models is presented in Exhibit 21 below. Continental European supply portfolios contain a multiplicity of supply prices. This contrasts with the U.S., where local hub gas pricing is ultimately referenced against the Henry Hub price. Portfolio optimization on the Continent falls upon the gas procurement managers who evaluate and select from among the existing supply options.

There is another point that needs to be made when describing the existing hybrid model: oil-indexation does not act as a barrier to competition in the European market. On the supply side, there is robust and growing gas-on-gas competition between and among Russian, Norwegian, Algerian, Qatari and other gas suppliers, as the major importing countries have multiple supply contracts and therefore also the means to optimize their portfolio of imported gas supplies.

The existing contracts that Gazprom has with its European clients alone allow for a supply boost of 50 bcm per annum, from the current 140 bcm to 190 bcm per annum. Competition
on the Continental market is already robust and gas importers have other supply options available to them. If they prefer to take only 140 bcm of Russian gas, that means that there are other sources of cheaper gas that could be acquired through other long-term contracts or on the hubs.

**Exhibit 21: Fundamental Differences between the U.S. and Continental European Pricing Models**

<table>
<thead>
<tr>
<th></th>
<th>USA</th>
<th>Continental Europe</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Hub price is a function of aggregate U.S. and local/regional demand and supply</td>
<td>Hub prices are a function of short-term arbitrage opportunities and balancing requirements net of firm contract supplies</td>
</tr>
<tr>
<td>2</td>
<td>USA</td>
<td>Continental Europe</td>
</tr>
<tr>
<td></td>
<td>Determined by the Henry Hub price plus location-based value differential (basis)</td>
<td>Multiplicity of prices</td>
</tr>
<tr>
<td></td>
<td>Company supply managers minimize the price of gas portfolio through volume allocation among contracts plus net hub purchases or sales</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>USA</td>
<td>Continental Europe</td>
</tr>
<tr>
<td></td>
<td>Vast majority of gas is sold at location-adjusted hub prices</td>
<td>Physical trade volumes on hubs that represent primary sales are small</td>
</tr>
<tr>
<td></td>
<td>Handful of long-term contracts are for LNG sales and incorporate ‘diversion’ clauses</td>
<td>The remaining volumes of traded gas come from long-term pipeline gas contracts</td>
</tr>
<tr>
<td>4</td>
<td>USA</td>
<td>Continental Europe</td>
</tr>
<tr>
<td></td>
<td>High churn ratios</td>
<td>Churn ratio below 4 (low, but sufficient for balancing function of the hubs)</td>
</tr>
</tbody>
</table>

Source: Gazprom Export.

### 2.3 Hub Prices as Derivatives of Contract Prices in the Hybrid Pricing System; or “The Emperor Wears No Clothes”

Our investigation into the hybrid pricing model brings us to a second important and, in a way, unexpected conclusion: that, as a result of interconnected relationship between hubs and long-term contracts, hub prices are in fact derived from Gazprom’s and other producer’s long-term contracts; and that the more integrated hubs become, the stronger is the link between hub prices and the oil market.

Our analysis shows that NBP and TTF prices are not only reasonably aligned with each other but that they also have a strong positive correlation with Gazprom’s oil-indexed prices, with coefficients of 0.75 and 0.79, respectively. In real-life terms, this means that the baseline curve for spot prices is determined not by supply and demand dynamics at the hubs but by the oil-indexed contracts: the higher the contract prices due to oil price escalation, the higher the hub prices. It would be correct to say that existing hub prices are a double derivative. While our contracts are derivatives of the oil product price, hub prices in their turn are derivatives of that derivative. The self-contained validity of a price signal originating on these hubs is subject to reasonable doubts.
Indeed what driver – other than rising oil prices – caused the growth in hub prices after October 2009? According to the conventional logic of mainstream industry analysts, hub prices that ‘accurately reflect changing supply and demand conditions’ should be moving in the opposite direction (i.e., downward) as a result of the slump in demand triggered by the economic crisis and the massive inflow of LNG redirected from the U.S.

Let us repeat it once again: in the existing hub pricing model there is only one benchmark: oil-priced gas. Other gas prices are merely derivatives of this one benchmark. Once the importers who typically hold long-term contracts with multiple suppliers have exercised their arbitrage options, they set a ‘soft’ price ceiling for the entire hub market. Hub prices in the mature hybrid pricing system that emerged in Europe after 2007 behave in a structured way and settle at a discount to contract prices, only occasionally equaling the contract price.

Hub prices are no longer seasonally higher than contract prices in such a system; typically, in the past, winter spot prices tended to be higher than winter contract prices. But at that time spot price behavior was less dependent on long-term contract prices than now.

Exhibit 22: Asymptotic Contract and Spot Price Behavior

Exhibit 22 does not indicate this flip because it is based on the monthly TTF index. The flip lasted for several days.

In today’s mature hybrid pricing system, the relationship between hub and contract prices may best be described by the mathematical term, ‘asymptotic’. The asymptote in our case is the distance between contract and hub prices that approaches zero when demand at the hubs strongly exceeds supply. In the few and not lengthy occasions where spot gas is more expensive than contract gas, it is the result of having insufficient infrastructure capacity at a time of high demand, as occurred most recently during a cold snap in Europe in February of 2012. As infrastructure becomes more developed and the EU domestic market more integrated, we may assume that such instances will happen even less frequently.

42 In mathematical terms, an asymptote is a straight line that is closely approached by a plane curve so that the perpendicular distance between them decreases to zero as the distance from the origin increases to infinity. Thus, the straight line continually approaches but never meets the curve.

43 Exhibit 22 does not indicate this flip because it is based on the monthly TTF index. The flip lasted for several days.
That asymptotic relationship explains the paradox of UK hub prices. UK prices are in theory completely 'delinked' from oil prices, but in reality they are driven by oil indexes, which is not the case in a true supply and demand-based pricing model such as in the US. Generally speaking, the UK gas market functioned as a truly hub-priced model only prior to the Interconnector construction. When Continental arbitrage became possible, it emerged into a regional sub-system of this larger market dominated by oil indexation.

It is important to address the contract and spot price divergence issue, as this has earned considerable and inaccurate coverage in the press. Press reports present price divergence as a matter of unfair and burdensome oil-indexed contract prices versus fair, transparent and cheaper hub prices.

Reality is much more complicated than this simplified and argumentative interpretation. Hub prices are derivatives of the contract prices that set a baseline trend for their behavior. The principal difference between the two prices is the quality of the products offered. Gas that comes under long-term arrangement represents a more valuable product than hub gas because it offers a combination of supply security and flexibility of deliveries. In fact, what Gazprom brings to its clients is more than a commodity – it is gas plus the related services necessary to deliver a secure and flexible source of supply.

That is why our weaknesses – higher prices – are merely reflections of our strengths. The major reason for price divergence as it is singled out by the market is a combined value of security and the flexibility provided by long-term pipeline suppliers. Hubs offer no flexibility but a commodity in lot-fixed sizes that requires time and effort to structure its delivery to consumption site. In many cases, Continental hubs are not liquid enough and cannot offer security of supply comparable to these long-term contracts. Therefore, one could reasonably ask, “What should be the combined premium for flexibility and security in long-term oil indexed contracts compared to the hub price?”

The second reason why spot prices typically lag behind contract prices is the dominance of one-sided balancing on Continental hubs. That reason also explains the asymptotic behavior of hub prices. As balancing markets, hubs above all serve to correct mistakes in demand assessment by the market participants. In situations of short-term under-supply, it is more convenient and cheaper (when prices do not differ much) for wholesalers to rely on existing long-term contractual arrangements to secure additional deliveries. That is why hub prices do not cross the contract price line for significant periods of time. When hub prices approach contract levels, consumers cease buying gas at the hub and instead switch to contract deliveries.

In the case of over-supply, selling gas at the hub is a quick fix. A good example of this is the Finnish market, a ‘gas island’ with consistently lower hub prices than those offered by a single supplier under long-term contracts. In a balancing market where certain quality aspects (i.e., security and flexibility) do not play a major role – such as in the electricity market – mistake corrections should occur in both directions more or less evenly. However, gas hubs in Continental Europe tend to one-sided corrections in favor of higher-quality contract gas. This raises the question of whether one-sided balancing is serious enough of an issue to warrant its own discussion. We will now show that the 2008-2009 time period encompassed one of the watershed events in the history of the European gas industry, but that this was wrongly interpreted as a tectonic change indicative of the complete divergence between hub and oil-indexed contract prices.
2.3.1 Hub Discount to Contract – One-Sided Balancing

Let us make a brief detour into history. The gas year begins on the 1st of October. In mid-2008, when new contracts were being negotiated, market participants had expectations of tight supplies and therefore were demanding as much gas as possible. They were also accepting of high prices. The economic crisis that shortly followed came as a major surprise and gas consumers soon realized that they did not need the volumes that they had ordered from importers, as depicted below in Exhibit 23. Importers in their turn were not able to meet their minimum purchase quantity requirements contracted from exporters.

Exhibit 23: Over-Contracting: Model of Market Behavior for 2008 and 2009 Gas Years

But there is a fundamental difference in the execution of take-or-pay obligations under the long-term contracts that Gazprom offers its clients and the short-term, one- or two-year contracts that the customers of our clients have. Long-term contracts offer a ‘make-up’ gas option (not to mention ‘flexible take-or-pay’ terms in some cases) that allows customers to take quantities not needed in the current year in later years, provided that prepayment is made.

Industrial end-users, distribution companies, and other second-tier wholesalers lost their right to this option as the result of EU policy aimed at easing the process of switching from one supplier to another. In the past, many end-users held contracts lasting up to 15 years with their long-established suppliers. EU regulations shortened the duration of downstream contracts in order to enhance competition. B KartA in Germany introduced limitations on contract duration (up to two years) beginning on the 1st October 2007. In the middle of the crisis that had started in August 2008, end-users and distribution companies had only two options – to pay fines for gas that was not taken, or to dump the gas on trading hubs, thus reducing their losses by the revenues they were able to earn from those sales.

Gas volumes under take-or-pay obligations that are dumped on the hubs, in our view, put enormous pressure on hub prices and represented the main reason behind the divergence in spot and contract prices. This divergence was wrongly taken by many analysts as signal of a complete divergence of oil-indexed and gas-indexed prices. In reality it was an
unintended consequence of depriving end-users and distribution companies of the make-up gas. If the make-up gas opportunity had been available, there would have been no need to dump take-or-pay gas on the hubs. No major divergence of hub and contract prices would have taken place as a result.

Take-or-pay obligations exist not only between exporters and importers but also between the former and second-tier wholesalers, distribution companies, and industrial end-users. These obligations comprise up to 80 percent of annual contract quantities. One-sided balancing turned out to be the only way to correct mistakes in demand assessment.

New short-term contracts came into force starting October 1, 2010. End-users and second-tier wholesalers tried their best to minimize their contract obligations. The conventional wisdom of the market was: Why should we buy expensive gas from Russia when we can get it cheaper on the spot market whenever we need it?

But it is also true that the dumping, or forced sale, of gas at hubs has stopped. This ‘under-contracting’ led to additional demand for spot gas, naturally leading to a rise in hub prices. Gazprom clients (importers) responded to the new market situation by increasing their respective offtakes above the Minimum Annual Quantity. Some of them executed the make-up option, as shown in Exhibit 24. Undercontraction however was short lived and did not last as long as the overcontraction that started in Q4 2008 and ended only in Q3 of 2010. Undercontraction was short lived because industrial end-users and second-tier wholesalers promptly adjusted for their incorrect expectations of hub gas availability by executing additional short-term contracts with the importers.

Exhibit 24: Under-Contracting: Model of Market Behavior: Q4 of 2010

Two gas years (2008 and 2009) of abominably low spot prices in Europe have created the illusion that gas has lost its link to oil once and forever. This is not true and could not happen, simply because oil-indexed contract prices serve as the benchmark for the Continental market as we discussed above.
One egregious example among many supporting this assertion is the increase in hub prices that occurred in the third quarter of 2010 that is shown in Exhibit 25 below. This development was not at all reflective of underlying changes in the supply-demand balance. Instead, the increase in hub prices occurred despite the ongoing economic recession and resulting decline in demand, and despite the fact that substantial volumes of Qatari gas were reaching the European market. Expectations of a new wave of LNG, as reflected in the low futures prices seen at the end of 2009, were negatively affecting sentiment in the market, but these did not affect the real price curve. Contrary to economic theory and conventional wisdom, these additional volumes of Qatari gas did not lead to a decline in the spot price but rather to a major increase in hub prices and their convergence with oil-indexed contract prices. It is clear that the overall supply/demand balance affects Continental hub prices only to a limited extent, and that discontinuation and resumption of one-sided balancing can have a significant and unexpected effect on prices.

Our analysis of the correlation between the Gazprom/TTF prices spread and the inflow LNG to Europe from 2009 to 2011 yields similar conclusions. According to the logic of supply and demand driven markets, the more LNG that comes to Europe the larger should be the spread between contract and hub prices. Correlation analysis refutes this logic, however: it showed a negative (!) -0.65 correlation between the volume of LNG deliveries to Europe and the size of the Gazprom/TTF price gap. The real logic of the hybrid pricing system argues against these conventional perceptions.

Exhibit 25: Supply and Demand Theory does not Explain Recent Trends in Continental Hub Pricing

---

44 Not capable of explaining the increase in hub prices that occurred in the third quarter of 2010, many analysts simply preferred to ignore it, claiming that the gap between hub and contracts prices narrowed as a result of an abnormally cold winter, the Fukushima nuclear disaster, and/or the turbulent political environment in North Africa. In reality, the increase was caused by new contractual arrangements which took effect on October 1, 2010. Dumping of the previously over-contracted gas volumes stopped, causing an escalation in hub prices. Similarly, the divergence in oil and gas prices that occurred during the 2008/2009 gas years was largely the result of the dumping of large volumes of gas on Continental hubs. Gas volumes under take-or-pay obligations dumped on the hubs put enormous pressure on spot prices, resulting in a divergence in spot and contract prices. This was misinterpreted by many analysts to mean that a complete and permanent divergence in oil-indexed and gas-indexed prices had taken place.
2.3.2 Hub Discount to Contract – Price for Security of Supply and Flexibility

Our analysis of price curves shows that the average spread between the prices of long-term contracts and those on Continental hubs (as represented by the TTF) from 1 October 2008 to 1 October 2010 was about US$115 per mcm, and about US$70 per mcm in the next two gas years, from 1 October 2010 to 1 October 2012.

Taking into consideration that this large-scale one-sided balancing on Continental hubs ended in Q3 2010 and that this price-depressing factor subsequently declined in importance, we assume that its contribution to the widening of the hub-contract price gap is around US$45 per mcm (US$115 – US$70). Based on this estimate, the combined premium for security of supply and flexibility embedded into the long-term contracts compared to the hub price is about US$70 per mcm (the more recent hub-contract gap).

Gazprom has long maintained that, to the extent that the fuel oil-indexed prices exceed prevailing spot prices, the associated premium is, in effect, payment for the capital and operating costs incurred by Gazprom for gas production, pipeline capacity and gas storage to assure that 100 percent of the maximum contract volume is available to its customers every day, whether they need it or not, as well as to provide a high level of flexibility. Existing long-term contracts have a certain level of built-in flexibility with Gazprom obligated to deliver the nominated amount (within the contractual range) or else pay a penalty.

A major difficulty comes with evaluating the premium for security of supply. We may assume the amount of the fines that Gazprom must pay if it fails to meet its clients’ obligations as a suitable proxy for that premium.

The cost of gas storage, that could be dramatically decreased with flexible-take contracts compared to a flat-take contracts, provides a workable proxy for the premium for flexibility evaluation.

We used the cost of one full cycle of underground gas storage under a typical contract of one year as an estimation of the premium built into the long-term contract price to account for daily supply flexibility. This cost covers working gas capacity, injection, and send-out. One full cycle of gas storage is defined as the sequence of injection and withdrawal of the maximum volume of working gas. All things being equal, working gas is more expensive if its injection-withdrawal cycle occurs over a shorter period, i.e., multiple cycles are carried out during a year. The cost of one storage cycle was defined as the annual cost divided by the number of cycles per year in order to minimize the frequency of cycle factor. Our analysis shows that the average cost of one storage cycle in Continental Europe for 29 tariff plans in 26 storage locations is equal to approximately US$64 per mcm.

Obviously, not all gas bought under flat-take contracts needs storage: a portion of the volume is cycled through gas storage while another portion is consumed directly. But the real value of contract flexibility is higher due to other factors, such as the use of pricing arbitrage on hubs. This is possible when the volume of gas delivered under long-term contracts is reduced in favor of purchasing spot gas when hub prices are depressed.

These factors do not represent an exhaustive list of all the reasons that explain the positive difference between long-term contract and hub prices. But they should provide some much-needed context to the pricing debate, which until now has not fully reflected all of the market dynamics at work.

We assume that the flexibility premium should be growing in importance with time as demand for gas becomes more and more dependent on the unpredictable weather
conditions due to increased role of renewables in power generation and temperature driven demand for gas in residential sector. Fully acknowledging the value of flexibility in supply contracts Norwegian producers modernized their contracts by removing flexibility options. Statoil’s CFO T. Reitan said recently: “You have to remember that long-term contracts are also contracts of flexibility, in which you can change the amount of gas every day according to your needs. More spot means that we take that flexibility back.”

2.4 Destruction of the Hybrid Pricing System – The Road to Nowhere

“Alice thought she had never seen such a curious croquet-ground in her life… they all quarrel so dreadfully one can't hear oneself speak--and they don't seem to have any rules in particular; at least, if there are, nobody attends to them…”

From “Alice’s Adventures in Wonderland” by Lewis Carroll

We fully understand our clients who tell us that they do not care about theoretical pricing models but prefer spot-priced gas primarily because it is cheaper. However, when we tell them to buy more from hubs to lower the average price of their portfolio, they say that they cannot fully rely on hubs as their source of supply and would still prefer to get gas from us but at a gas-indexed price.

Demands by advocates of the ‘re-engineered’ pricing model that producers be fully responsible for price risks in long-term contracts alter the fragile balance of interests between the buyer and seller. Fulfilling these demands will lead to nothing but termination of the long-term gas supply contracts in their current form as these new contracts will not be able to underwrite the investment programs of the exporters. The fact that buyers continue to seek the security and flexibility provided by long-term contracts is testament to the unsuitability of hub pricing to fill the entire needs of the European market.

Changes in the pricing model that have been proposed for Continental Europe will bring the existing hybrid system to a collapse. We cannot support market reforms that are conducted without a full comprehension of their consequences. Reformists should be careful when giving competitive advantages to one group of market participants at the expense of another or introducing obligatory benchmarking to hubs on the regulated end-user markets. They should clearly understand that what they are reforming is a unique market. It is a different beast than the U.S. market and therefore must be treated in a way that allows long-term oil-indexed contracts and spot gas to complement each other. These are not mutually exclusive propositions - oil-indexed or spot gas. The hybrid market is better for all participants.

So far, competition enhancement policy has only divided European gas market participants. A broad group of market players has emerged that have no import contracts, bring no gas to Europe under long-term arrangements, and are not responsible for gas storage or delivery. Advantages without responsibilities for this group of players results in unfair competition. If market reformists are not pursuing the implicit aim of pushing importers out of the business, what they must do is protect the holders of long-term upstream contracts from unfair rules of the game and promote their position as guarantors of the security of supply. Offering participants of end-user supply tenders should meet strict qualification standards, including a requirement to have import contracts. Such qualification standards are effectively employed in Turkey. That qualification is also important for security of supply purposes as many discount suppliers without import contracts have already gone out of business (like

TelDaFax in Germany) because they were not able to keep their promise to deliver cheap gas when hub prices start to converge with contract prices.

Gazprom has the firm obligation to deliver (or else be subjected to fines) in accordance with the daily nominations coming from a buyer. If it accepts the proposition of making contract and spot prices comparable by lowering contract prices, hub prices definitely will respond by decreasing further by the security-flexibility premium inherent to the long-term contracts.

That is, any additional decrease in the oil-indexed contract price - accomplished either by decreasing the base price or increasing the component that is indexed to hub pricing - would result in a further downward slide of the entire price system due to the feedback loop described above. These adjustments, in turn, trigger new requests from end-users to renegotiate their contract prices downward. This process of price erosion may perfectly suit the buyer, but it is unacceptable to the supplier and ultimately unsustainable. In the case of 100 percent gas indexation, any take-or-pay obligations on the buyer’s side lose their function as a guarantee of demand security because buyers can dispose of excess volumes on hubs with no risk to their revenues. Exhibit 26 below illustrates how 100 percent gas indexation can result in predatory pricing by buyers. As we have previously discussed, transitioning to gas-indexed contracts will not change the balancing role of European gas hubs.

As prices here are not determined by total supply and demand, relatively small volumes of gas bought for dumping purposes can bring day-ahead prices down. Losses as a result of dumping by a cartel of buyers will be fully compensated the next day with a profit when the lower day-ahead price from the previous day devalues the entire supply portfolio.46 Predatory pricing remains possible until the volumes needed to reduce hub prices equal the amount of gas consumed.

Producers from third countries will run the intolerable risk of gas price erosion because there is virtually no force in Europe interested in preserving the value of natural gas. Producers in the EU - i.e., the Dutch and the British - are not interested in selling their gas below cost, even though it is still cheaper than the gas provided by non-EU suppliers, which have to deal with higher transportation and liquefaction costs. Indigenous producers have unrestricted access to the hubs and can buy gas to meet their contractual obligations when hub prices drop precipitously. Production, therefore, can be resumed in a swing mode when prices are higher than costs.

Pipeline producers from non-EU countries, however, do not have easy access to market hubs and will find themselves disadvantaged as a result. If the oil-linked benchmark price ceases to exist, exporters selling gas under long-term contracts in Europe will be forced to accept prices irrespective of how low they are, and without any means of managing their price risk as sellers in truly liquid markets can.

---

Exhibit 26: Dumping by Buyers’ Cartel in Case of 100 percent Indexation

Transitioning to the U.S. model, that of hub pricing without long-term contracts and direct sales by natural gas producers, is not a suitable option for Europe. As a matter of fact, Europe is increasingly import-dependent and there are oligopolistic structures on both sides of the market that will end up opening a Pandora’s Box of endless conflicts.

With oil-indexation in place, consumers of gas in Europe are protected from any form of price manipulation by the dominant suppliers because none of these suppliers is able to influence the price of oil. It is not Gazprom but the European companies that are fighting a losing battle to adopt a U.S.-style hub model that will undermine the security of supply its proponents claim it will achieve.