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Markets and long-term contracts: The case of Russian gas supplies to Europe

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Abstract Different hydrocarbon producer sales strategies have widely divergent implications for the value of Gazprom's gas exports to Europe. In particular, hydrocarbon producers have commonly pursued two alternative sales strategies: (i) pure commodity production (border sales) and (ii) integrated supply, trading and marketing (ISTM). The impact of these two strategies on Gazprom's export profits are examined under three sets of scenarios: (a) the possible entry of low-cost producers, (b) oil price dynamics and (c) the future of LTCs (pricing and volume structure). We also analysed how Statoil shifted its sales strategy in light of structural changes in European gas markets and conclude that the company began employing an ISTM strategy when the market in North-west Europe became liquid.

Thus, when a market is mature, with an increasing number of buyers, the best sales strategy for a large hydrocarbon producer should be based on flexibility and increasing its use of market trading to maximise the value of its commodity. We conclude that an optimal export strategy for Gazprom should involve both a substantial and increasing portion of uncommitted volumes that can be traded in markets (gas hubs) and, if needed, some form of bilateral forward contract with a minimum take-or-pay level to secure infrastructure finance.

Keywords Long-term contracts, vertical integration, market trading, gas, Gazprom, Statoil, gas pricing, equilibrium energy modelling

JEL Classification **L140, L130, Q47, Q48, Q410, P28, O13**

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Markets and long-term contracts: The case of Gazprom sales strategies to Europe

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Figures

Tables

Abbreviations and definitions

bcm – billion cubic metres

bcm/year – billion cubic metres per year

tcm – thousand cubic metres

$/tcm – USD per thousand cubic metres

bn – billion

bn/year – billion per year

NPV – net present value, calculated assuming 10% discount rate

mmBTU – million British Thermal Units

$/mmBTU – USD per million British Thermal Units

bbl – barrel of crude oil

$/bbl – USD per barrel of crude oil

VMF – vertical market failure

LTC – long-term contract

Conversion factors

$/mmBTU = 0.0272*$/tcm

Disclaimer

The purpose of examining multiple market and non-market scenarios is to conduct 'stress tests' for the two possible gas sales strategies. The scenarios examined are not predictions. Whenever possible, we devised these scenarios to be as close as possible to the industry's expected possible paths of future gas market developments. However, these scenarios are not intended to replicate possible market developments; some may be hypothetical and do not necessarily conform to the current established view of the future of the gas markets. For example, one scenario is Qatar's removal of the exploration moratorium and the further expansion of its production capacity; this may not be realistic given the current environment of low oil and gas prices. Nevertheless, this scenario has a positive probability of occurring, making it a form of 'high-impact, low-probability event'. Our intention is to test the robustness of hydrocarbon producers' sales strategies in an uncertain world and not to provide 'price forecast'-type analysis.

1. Introduction

The European gas industry has undergone dramatic changes in the last ten years, and the traditional business model for monetising gas resources – quasi-vertical integration between buyers and sellers using a series of large and long-term contracts (LTCs) to trade gas and finance both transmission and production facilities – seems no longer fit for purpose. The aim of this research is (i) to explain why the traditional business model is not appropriate and may be detrimental for major gas producers and (ii) to quantify the costs and benefits of the different strategies available to sellers in the new gas market reality that is emerging in Europe. We analyse these issues by looking at the strategic responses available to Gazprom, Russia's state-owned gas producer and the largest supplier to Europe. This is a particularly interesting case study that deserves our attention for several reasons.

The ongoing structural changes in the European and global oil and gas market environment have motivated Gazprom to rethink its export strategy. Gazprom has announced several proposals in the past, and in the last two years in particular, of which one represents the most radical change since the inception of gas exports from the Soviet Union to Europe.[2] In the aftermath of the decision to cancel the South Stream pipeline project, which was supposed to run from Russia to Bulgaria and onwards to Europe, Gazprom stated that it was considering changing its traditional sales strategy in Europe from 'from wellhead to burner tip' to the 'border' sales strategy. In particular, according to an official speech made by Gazprom's CEO (Miller, 2015), the proposed border sales strategy would build pipelines to the EU border, from which European gas importers (Gazprom's clients) would build missing pipelines and transport gas to European markets. The implications of this change in strategy for Gazprom's business model are: (i) a retreat to the external EU border, (ii) limited or no participation in wholesale trading, (iii) passive or no engagement with end customers in Europe and, hence, (iv) increasing dependence on market dynamics without the ability to actively price Gazprom gas in traded markets. Put differently, Gazprom may be transformed into a pure commodity producer, focusing on the upstream segment of the gas value chain only. In the rest of this paper, we show that this strategy is detrimental for hydrocarbon producers selling their commodities in liberalised markets in general and for Gazprom's own position in Europe in particular. The analysis of Gazprom's sales strategies deserves our attention for two main reasons. Firstly, in terms of the market, Gazprom is the largest gas reserve holder in the world and is one of dominant suppliers to Europe, supplying roughly one third of the entire market. Hence, any drastic changes in its sales and investment strategy will affect the gas market structure in Europe for decades to come (see e.g. EC DG Energy's letter regarding the cancellation of the South Stream project to the head of ENTSOG[3]). Secondly, in terms of policy,

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[2] Media and trade press have discussed these proposals extensively.
[3] The letter is available here:
http://www.entsog.eu/public/uploads/files/publications/TYNDP/2015/COM_20150227_Ares975241SouthStream.pdf, accessed 15 April 2015

Gazprom's sales strategy affects the way in which European energy policy will develop, not only because of the importance of gas in the energy mix of the region and national security considerations but also for the revenue it brings to the Russian state budget.

Aside from the significance of this case study for the current energy policy debate in Europe (and other regions facing similar dilemmas), the general question of which business model and sale strategy hydrocarbon producers should pursue in liberalised and uncertain markets is perhaps the most important dilemma that such producers face. Based on the vertical value chain of the oil and gas industry, at least two business models can be distinguished: (i) pure production and (ii) integrated production, supply, trading and marketing (ISTM). As the name suggests, the second model is a strategy that tries to capture the whole value chain; it is also commonly referred to as the integrated oil and gas business model, whereby producers participate in activities further downstream, such as wholesale trading, processing, transportation, logistics, storage and direct sales and marketing. It is important to note the different roles that trading and marketing functions play within the overall organisational structure of hydrocarbon producers and their contribution to generating sales, revenue and profit. For example, a midstream company (utility company) may see the trading function as supplemental to its main activity – marketing final energy products – and hence use wholesale trading to hedge their downstream (main) position. By contrast, upstream producers tend to see trading functionality as a means of hedging their produced commodity and marketing activity as a means of hedging and supporting their trading business. The pure production strategy focuses instead on production specialisation, and pure producers do not engage in wholesale trading. Gazprom's proposed border sales strategy can be regarded as a pure production model.

In general, the degree of downstream participation varies from one oil and gas producer to another, depending on their competitive advantages, produced commodities (oil or gas or both), organisational culture, history and values. At one end of this spectrum are companies such as BP (with its renowned Integrated Supply and Trading division) Shell, Total, Statoil, BG Group, GasTerra and ENI, which actively participate in wholesale gas trading. At the other end are pure producers such as Sonatrach, Anadarko, Apache, BHP Billiton, Marathon Oil and Woodside, which have limited or indeed no wholesale gas trading and direct sales and marketing interests. Somewhere between these two extremes are companies such as ExxonMobil, Chevron and Gazprom, which have established gas trading and marketing activities that are rather limited in scale and scope. Note that this list is not conclusive: it is not our aim to provide an exhaustive listing and categorising of all oil and gas companies in terms of their degree of vertical integration and business strategies. Instead, these companies serve as examples and are listed in no particular order. This list is also based on the gas value chain and would therefore be different for the oil value chain.

The choice of business strategy along these two extremes – pure production versus ISTM business models – is not straightforward. There is ongoing debate in the management and strategy literature over the appropriate sales strategy for producers of commodities such as oil, gas and coal in changing and complex (liberalised) markets. For example, Kose et al. (2013) analysed thermal coal production in Asia Pacific in an oversupply environment and concluded that coal producers can increase profitability and reduce earnings volatility by expanding their activities downstream into trading, marketing and logistics. Similarly, Himona et al. (2014) analysed whether international oil companies (IOCs) should disintegrate and concluded that they should remain integrated; in particular, physical trading was found to contribute 7-8% of IOCs' downstream profit and physical trade was identified as a 'glue' that binds all value chain parts of the oil industry, allowing IOCs to optimise and enjoy integration benefits. Corsini et al. (2013) stressed the importance of trading and portfolio optimisation when markets are complex and liberalised. The report looked at possible strategies for European gas buyers ('midstreamers') in liberalised markets and discussed the importance of trading and portfolio effects for midstreamer profitability rather than relying on the business cases of individual contracts. By contrast, Forrest et al. (2011) championed the idea that specialisation is the future and that integrated oil and gas market players (producers that are integrated with supply, trading and marketing functions) have lower effective stock prices[4] than pure upstream (or pure downstream) players and are less incentivised to develop reserves than pure producers.

Our research aims to contribute to this management and strategy debate. Furthermore, to our knowledge, a systematic quantification of the costs and benefits of these business strategies has not yet been attempted in the academic literature on energy economics. The costs and benefits for oil and gas producers should be judged on a case-by-case basis; however, in general it has been suggested that the integrated oil and gas business model is less risky than the pure upstream or downstream models (Forrest et al., 2011). This is primarily because downstream participation is a natural hedge for upstream players when commodity prices fall (Sheppard, 2015; Zhdannikov and Bousso, 2015; Mercatus Energy Advisers, 2014). However, such hedging comes at a price for oil and gas producers: according to Forrest et al. (2011), the effective stock price and reserve-replacement ratio for integrated players are lower than for 'focused' players. This is not surprising as holding an option has a price. Other benefits of downstream participation for oil and gas producers include flexibility and portfolio effects (see Kose et al., 2013; Corsini et al., 2013) as well as market intelligence (Sheppard, 2015; Dison, 2011). In this regard, integrated players, having better market understanding that stems directly from participating in wholesale trading, are able to behave strategically by not developing reserves as quickly as may be expected in a competitive market or as fast as pure upstream producers would do. Pure producers can therefore be seen as price-takers, and,

[4] Measured in Forrest et al. (2011) as EV/EBITDA.

hence, they tend to focus on optimising their cost side and upstream performance rather than exploiting market opportunities and engage in active price setting in addition to standard cost optimisation. Indeed, the transaction cost economics perspective suggests that one of the rationales for downstream integration by upstream producers is to 'exploit market power and raising barriers to entry' (see e.g. Stuckey and White, 1993), and this has traditionally been done via bilateral bargaining and LTCs between gas buyers and sellers in the absence of spot trading. However, when downstream gas markets are liquid and liberalised, the ability to exploit pricing power optimally is only possible when producers participate actively at the wholesale trading level, giving them more accurate information about market dynamics and allowing for better pricing strategies. Note that this argument may not necessarily be applicable to the crude oil market and the exploitation of market power by large oil producers. This is because the oil market is so liquid and deep, with an extremely competitive shipping market, making oil trading less logistically challenging. Hence, market intelligence is not particularly important for oil producers to exercise their pricing power. By contrast, to even exploit price arbitrage in the European pipeline gas market, gas players must have excellent understanding of local commodity markets and regulatory regimes as well as transport capacity markets and these have to be coordinated activities. Thus, we argue in this paper (with empirical evidence) that exploitation of gas price arbitrage and pricing power can only be achieved with the ISTM business model. This is another contribution of this research to the literature on energy economics. Almost all research papers on gas market modelling (amongst others, see, e.g., Zwart and Mulder, 2006, Holz et al., 2008, Lise and Hobbs, 2008, Gabriel et al., 2012, Abada et al., 2013, Chyong and Hobbs, 2014, Growitsch et al., 2014), if they assume that some market participants have pricing power, would justify this choice based on rather simplistic view, such as by looking at the size of gas reserves that exporting countries have.

The main conclusion of our research paper is that when a market is mature, with an increasing number of buyers, the best sales strategy for a large hydrocarbon producer should be based on flexibility and increased usage of market trading to maximise the value of its commodity. This suggests that an optimal export strategy for Gazprom should contain a substantial and increasing portion of uncommitted volumes that can be traded in markets (gas hubs), while the rest should be based on some form of bilateral forward contract with a minimum take-or-pay level to secure infrastructure finance, if needed. We explain these and other important findings in the rest of this paper, which is structured as follows. In the next section we discuss the role of markets and long-term bilateral supply contracts in the coordination of economic exchanges between buyers and sellers. Section 3 discusses the evolution of the European gas industry and the rise and fall of bilateral LTCs in particular. Section 4 looks at the different sales strategies available to gas producers in liberalised markets and examines how Statoil, the largest Norwegian gas producer, reacted to changing market conditions. Section 5 presents the results of quantifying the costs and benefits of the different strategies available for upstream firms in increasingly open and liberalised markets, using Gazprom's potential sales strategy as a case study.

Finally, we discuss the results and policy implications in Section 6 and outline the main conclusions in Section 7.

2. Coordinating economics exchanges: The role of contracts and markets

The economic literature points out to two major organisational forms that support exchanges between economic agents: (i) markets and (ii) vertical integration. Of course, there is a continuum of organisational forms between those two extremes, including joint ventures and LTCs (quasi-vertical integration), and the choice of organisational form depends on the characteristics of the transaction in question. Choosing an organisational form to facilitate trade has long been at the heart of economic thinking, particularly within the transaction cost economics literature led by scholars such as Coase, Williamson, Klein and Goldberg (Coase, 1937; 1972; Williamson, 1971; 1975; 1979; 1983; 1985; Klein et al., 1978; Klein, 1980; Goldberg, 1976; Goldberg and Erickson, 1987) and others following a similar approach. Joskow (1985) summarises the basic theory behind the transaction cost approach by explaining the choice of governance structure: markets or long-term vertical relationships. In addition to the traditional costs elements usually incurred during any production process (such as land, labour, capital and materials), there are also transaction costs associated with the exchange of economic goods between agents; for example, costs relating to drafting, enforcing and potentially breaching contracts. These transaction costs are real economic costs that should be considered alongside traditional cost items in the cost-minimising decision-making problem.

In general, there is a set of characteristics that may influence the nature and magnitude of transaction costs: (i) the uncertainty and complexity of transactions, (ii) the need for and degree of relationship-specific sunk investments to support transactions, (iii) the trade-off between the cost and benefit of internalisation versus reliance on market transactions and (iv) the regularity of transactions. Crucially, the need for and magnitude of relationship-specific investments to facilitate trade are the most important characteristics, which, in combination with the other factors mentioned, could give rise to very high transaction costs associated with potential exchanges. In particular, high uncertainty means that contracts may be incomplete, in the sense that they are unable to specify every possible state of nature that could affect the performance of the parties under the contract. As such, the incompleteness of contracts would not create significant problems were it not for the involvement of a high degree of relationship-specific assets that must be developed ex ante to facilitate the exchange. Furthermore, the frequency of transactions should only matter when high (sunk) investment costs were involved in establishing bilateral trade because subsequent transactions represent opportunities for haggling and the higher the frequency of those transactions, the higher the risk of opportunistic behaviour among the parties involved in the trade. According to Williamson (1983), there are four types of asset specificity that may partition an industry into a smaller number of bilateral oligopolies:

1. Site specificity – the vertical relationship is arranged such that related facilities are located close to one another; for example, to minimise transport and inventory costs.
2. Physical asset specificity – appears when investments in equipment can only be utilised by one or both parties to the transaction and there is little value in utilising these assets in alternative ways.
3. Human capital specificity – emerges when employees develop specific skills required for a particular transaction.
4. Dedicated assets – arises when investments are made only to serve a specific transaction and would not have been developed otherwise; thus, should the contract underpinning the exchanges be terminated prematurely, the dedicated asset would be underutilised.

A combination of vertical integration and LTCs is the preferred mode of organising trade when the numbers of buyers and sellers are effectively limited by a high degree of asset specificity coupled with a high frequency of transactions and capital intensity. For example, Stuckey and White (1993) outline the conditions under which vertical integration and LTCs are the preferred organisational form for economic agents to coordinate exchanges:

1. existence of vertical market failure (VMF);
2. presence of market power in adjacent stages;
3. possibility to exploit market power and raise barriers to entry;
4. response to industry life cycle (immature or declining markets).

Of the above factors, the existence of market failure in vertical relationships strongly motivates economic agents to seek integration along the value chain as a means of organising exchanges. The most important and frequent reason for market failure in vertical relationships is a combination of a small number of buyer and sellers, a high degree of relationship-specific sunk investments involved in transactions and the high frequency with which such transactions occur.

In an industry with a small number of participants, transaction terms – price and volumes – are determined by the balance of power between buyers and sellers, a balance that is unpredictable and unstable. Many markets appear to have numerous participants on each side; however, in reality they are composed of groups of bilateral oligopolists due to high switching costs. Here, the degree of asset specificity is important because once these investments are made, they turn the seemingly large number of buyers and sellers on both sides of the market into a bilateral monopoly or oligopoly situation, which is prone to ex post opportunistic behaviour on both sides of the transaction.

Furthermore, the problem of asset specificity is exacerbated if the asset is durable and intense. Highly capital-intensive investments exacerbate the losses arising from potential ex post hold-up situations, while the durability of assets (possibly coupled with frequent or repeated interactions) increases the time horizon over which the risks of such opportunism may arise. Thus, the primary reason for an effectively reduced number of buyers and sellers is that the specificity, durability and intensity of an asset raise switching costs to the point where only a small number of buyers are truly available to sellers and vice versa.

Thus, to mitigate the risks of ex post opportunism arising from intense, durable and relationship-specific assets involved in such transactions, vertical and quasi-vertical integration would seem to be a solution (Stuckey and White, 1993). It appears that the degree of asset specificity is the most important characteristic influencing the risk of hold-ups. If an asset has a relatively low degree of relationship specificity and is less durable and intense, a standardised transaction or contract would suffice and there would be no need for LTCs or formal vertical integration to mitigate ex post opportunism since potential losses would be substantially lower.

All of the factors that give rise to a high transaction cost structure were present at the beginning of the development of the natural gas industry in Europe and persisted until European authorities launched the liberalisation of the electricity and gas markets in Europe. As the transaction cost theory predicts, the European gas industry was developed based on a system of complex LTCs between buyers and sellers. However, as we argue in the next section, the rationale for LTCs in the European gas industry has vanished and companies should now adopt sales strategies in accordance with changes in the market structure, specifically, the number of buyers and sellers and the importance of specialised assets.

3. The evolution of the European gas industry: From a system of bilateral contracts to market institutions

The transaction cost framework discussed above is a helpful tool for understanding the evolution and organisational complexity of the natural gas trade in Europe. LTCs drove the development of the gas trade in Europe, and the first such contracts were signed between European companies to develop the gas reserves of the giant Groningen gas field in the Netherlands (Energy Charter Secretariat, 2007).

Consistent with the transaction cost framework, the rationale for setting up LTCs is to protect buyers and sellers from ex post opportunism arising from the highly asset-specific, durable and capital-intense investments involved in: (i) the development of upstream production and gas treatment facilities, (ii) long-distance international pipelines and (iii) national transmission and distribution systems at the local level. This protection takes the form of agreed minimum payments to sellers irrespective of actual offtake by buyers – the so-called minimum take-or-pay level. Thus, the buyer takes volume risks, whereas the seller agrees to settle the transaction at a price that is (slightly) below the price of competing fuels, which are usually oil products. The subsequent change in contract price is pegged to a basket of oil products and other competing fuel prices at the 'burner tip' (final markets); therefore, the seller takes price risks since he does not control the pricing of gas and relies on the pricing dynamics of competing fuels. This arrangement ensures that gas stays competitive with other fuels in an environment when there is no gas-to-gas competition. Furthermore, the pricing in such agreements is used as a mechanism to divide the rent associated with producing, transporting and marketing gas between sellers and buyers.[5]

As such, the emergence and evolution of the natural gas trade in Europe fits neatly with the transaction cost economics framework. Table 1 outlines the main characteristics of the industry using transaction cost economics terminology. From this we can see that the two most important factors that constitute the foundation of LTCs supporting gas trade and investment in Europe are: (i) industry structure (number of buyers and sellers) and (ii) asset characteristics. The latter have changed dramatically over the past 20 years, and the rationale for and role of LTCs in the European gas trade has diminished significantly. The reasons for this decline are elaborated below.

Table 1: Evolution of international gas trade: From LTCs to markets.

	1970s	2000	2014
Number of sellers	16	34	48
Number of buyers	18	56	71
Asset characteristics:			
Specificity	High	High/moderate	Moderate/low
Intensity	Upstream: high Midstream and downstream: high		Upstream: high/moderate Midstream and downstream: high/moderate
Durability	20+ years		
Transaction frequency	High		
Uncertainty	High		
Vertical coordination mechanism	Most transactions via vertical integration and LTCs		Half of transactions conducted on spot markets

Notes: Numbers of sellers and buyers (in brackets) are based on counts of gas-exporting and -importing countries provided by the International Energy Agency (IEA) in its 2015 Natural Gas Information report (IEA, 2015a).
Source: Author's assessment.

[5] On using LTCs to distribute the gains from trade between contracting parties see Masten, S. and Croker, K. 1985; Crocker, K. and Masten, S. 1988; Mulherin, J.H., 1986.

3.1. European gas industry structure: From bilateral oligopolies to organised market trading

The international gas trade has expanded dramatically since the early 1970s, when the industry structure was balanced with low number of gas-exporting and -importing countries (16 sellers and 18 buyers). By 2000, these numbers had more than doubled to 34 gas exporters and 56 gas importers. By 2014, the market structure was dominated by sellers; the number of exporters had reached 48 while the number of buyers had increased to 71 (IEA, 2015a).

We could argue that overall, the market has witnessed a dramatic increase in the total number of participants. Traditionally, the gas markets have been regional in nature, reflecting large-scale infrastructure investments along the whole value chain and the capital requirements to build transport pipeline networks to supply gas to end consumers in particular. This means that the effective number of trading partners in each of the regional markets – North America, Europe and Asia – is in fact substantially lower. However, these regional markets have become increasingly linked by gas trade via seaborne routes, using liquefied natural gas (LNG) vessels to trade gas over greater distances. From the late 1960s until the mid 2000s, there was a general trend of cost reduction due to technological improvements across the whole LNG value chain (Stern, 2006; Greaker and Sagen, 2008). This, coupled with demand uptake in remote consumption centres relative to production locations, allowed LNG to emerge as one of the fastest-growing internationally traded commodities over 1960–2014, when annual growth in LNG exports averaged 14% pa.[6] Over this period, there was a proliferation of the number of LNG-exporting countries, starting with Algeria, the first LNG exporter: in 1975 there were only four exporters, whereas by 1995 this figure had reached eight, and by 2014 there were 20 LNG exporters (including re-exports from Europe). Furthermore, and as we shall discuss below, LNG contracts are generally comparably smaller in terms of annual offtake quantity and shorter in duration than pipeline gas contracts. This suggests, among other things, that as it is more flexible in terms of transport mode, LNG trade is less asset specific than trade via pipelines. Therefore, the uptake in LNG trade not only increased the effective number of trading partners but also introduced more flexibility to both sides of the market.

While the number of exporters and importers increased worldwide, market liberalisation and the ability to tap into global LNG markets meant that the number of buyers and sellers also increased in European gas markets, reflecting trade in organised market exchanges (gas hubs or spot markets). The liberalisation process began with the 1991 Gas Transit Directive, and the subsequent legal battle between European antitrust authorities and major exporters to remove destination clauses from long-term pipeline and LNG import contracts. This was followed by the first two energy packages (1996 and 2003) and then by the third energy package (2009).

[6] Author's calculation based on Poten and Partners LNG trade database, accessed through the Bloomberg Terminal.

In the 1990s and early 2000s, the EU antitrust authorities were successful in negotiations with exporters to remove the destination clauses from long-term LNG and pipeline gas contracts. These clauses were seen as major impediments to market competition in Europe as they prohibited importers from reselling gas to other market geographies and segments. The antitrust authorities then targeted the largest European gas importers, such as GDF Suez, ENI and E.ON, expressing concern that these companies used exclusive access to gas transportation facilities to effectively limit competition in their market areas. As a result, these companies reached agreement with the competition authorities to reduce their long-term capacity reservations (capacity release programmes were agreed between GDF Suez, Eni and E.ON) to allow new suppliers to enter the market (European Commission (EC), 2009a; EC 2009b; EC 2010). At the same time, national antitrust authorities also looked into the state of market competition further downstream, including LTCs between second-tier suppliers and larger importers. For example, Germany's national antitrust authority (BKartA) introduced limitations on contract duration and supply quotas for a period of three years (2007–2010) to enable more downstream competition by allowing second-tier buyers to switch suppliers (European Competition Network, 2010). As a result of this regulatory intervention, many second-tier suppliers, such as power generators and local distribution companies, became part of the gas value chain.

The pricing of gas in LTCs has also undergone substantial changes. The liberalisation of gas markets in Europe coupled with (i) increased investment in LNG import terminals to benefit from global LNG trade and (ii) low gas demand following the economic crisis of 2008 and increased inter-fuel competition (e.g. uptake of coal and renewables in electricity generation) forced European buyers to renegotiate pricing mechanisms in their traditional contracts with pipeline suppliers. As such, since around 2010, a pricing system has emerged in Europe that is based on long-term oil-indexed contracts as well as market prices settled in trading hubs (the National Balancing Point – NBP – in the UK and the TTF in Continental Europe).

As a result of these regulatory interventions and changes in market dynamics, it is estimated that the overall volume of spot gas trade in Europe stood at 43% in 2013 (Société Générale, 2013), rising to 61% in 2014 (International Gas Union, 2015), with the remainder being undertaken via traditional oil-indexed long-term bilateral contracts.

Thus, the organisational form of gas trade in Europe has changed quite dramatically, with increasing trade volumes being transacted through organised markets rather than being dominated by bilateral contracts, as used to be the case. This point is also reinforced by the fact that the emergence of spot and futures markets for gas trade greatly reduces transaction costs of long-term contracting because (i) contracts are standardised and hence easily transferable (traded) and (ii) prices are set transparently via multiple trades rather than costly bilateral (re)negotiations.[7]

Furthermore, as we shall discuss below, the industry structure in Europe developed in response to changes in regulatory developments as well as to the degree of asset specificity involved in gas trade.

3.2. Characteristics and evolution of gas infrastructure assets in Europe

In the early days of the European gas industry, buyers and sellers relied on very large LTCs (in terms of offtake quantities) to develop gas fields and finance long-distance, cross-border pipelines and transmission and distribution systems. These LTCs essentially covered at least two part of the gas value chain: (i) production and (ii) transportation. On the buying side, buyers were vertically integrated (usually state-owned) companies, which helped them develop and control national transmission and local distribution systems as well as gas sales and marketing. On the selling side, producers were responsible for developing gas fields and the associated infrastructure as well as large-scale, long-distance pipelines that usually crossed the borders of more than one country. This is particularly true for Russian gas supplies, whose pipelines sometimes crossed more than three countries before reaching delivery points in Europe.

Thus, the traditional model – 'from wellhead to burner tip' – was effectively broken by EU legislation introduced to increase competition at the midstream and downstream levels of the European gas markets (see discussion above). Among other fundamental changes brought about by this legislation, one particular structural shift was the so-called 'unbundling' or breaking up of vertically integrated utility companies on the buy side, which could no longer control infrastructure components of the gas business. Transmission and distribution within Europe, previously seen as natural monopolies, are now managed by independent companies and are subject to regulation in terms of service quality and tariff setting. Thus, on the buy side at least, the transportation component became a separate regulated business activity and was no longer part of the chain of traditional LTCs between producers and buyers. A second structural shift was the introduction of third-party access to transport infrastructure in Europe; i.e. should there be demand for access to transport capacity, the independent operator should grant such access subject to technical and other requirements that are transparent to all market participants. Together these two changes meant that gas transportation infrastructure in Europe no longer posed a high risk for opportunism because these regulations essentially reduced the degree of asset specificity involved in gas transactions between buyers and sellers. Although investment in transmission and distribution is still durable and capital intensive,

[7] For a detailed discussion on this point see Doane and Spulber, 1994.

albeit less so than it used to be, it is now less risky due to these sectors being regulated monopolies: if there is enough demand for new capacity, then the infrastructure is build and the capacity price regulated under some form of tariff regulation.

In addition to changes in how gas transport infrastructure is governed in Europe, both pipelines and LNG, as a mode of transporting gas, have been subject to substantial cost reductions – or capital intensiveness – due to technological improvements. For a detailed discussion of cost reductions in pipeline and LNG transport see, for example, papers by Cornot-Gandolphe et al. (2003) and Jensen (2003). All else being equal, lower capital intensiveness leads to lower risks and potential losses arising from the ex post hold-up problem. The reduced risk of hold-ups together with the changes in organisational form for the investment in and management of transport assets in Europe means that there is no longer a rationale for including these assets in traditional long-term purchase contracts between buyers and sellers, as was the case when the industry began to develop in the 1960s and 1970s.

Turning now to the selling side, production facilities, such as gas wells and treatment facilities, are not highly asset specific per se and can be used to produce gas for sales to any buyer or market provided that transportation to these markets and buyers is already established. Thus, the high asset specificity in the gas industry lies simply in transportation assets[8], and in Europe, a part of these assets is now under regulation and poses a low risk of hold-ups. The only remaining issue is the long-distance pipelines connecting producers to European border points, most of which have already been developed as part of the first wave of LTCs between major producers (Russia, Norway and Algeria) and European buyers and have since been fully or substantially depreciated. We exclude from this discussion the issue of the transit monopoly and associated risks of supplying Russian gas to Europe, which is beyond the scope of this paper. However, let it suffice to say that the perceived high monopoly power of transit countries and associated risks of rent expropriation by such transit countries motivates producers, such as Russia, to seek new capacity that it can control via LTCs or some other form of vertical integration.[9] Nonetheless, going forward it is expected that the need for such 'transit-bypass' transport capacity will be minimal relative to the overall potential trade volume between Russia and Europe.[10]

[8] For a detailed discussion of this point see Doane and Spulber, 1994.
[9] For example, the Belarus transit system, which is co-owned by Russia and Belarus, or the Blue Stream and Nord Stream pipeline investments that helped Russia reduce its dependence on traditional transit routes were carried out as joint ventures with Russia's major gas buyers in Europe.
[10] Abstracting away from the politics of pipeline gas sales to Europe in light of the geopolitical tensions between Russia, Ukraine and Europe, the need for new bypass capacity is minimal since Russia has already invested in alternative transport capacity that bypasses Ukraine substantially in the past. Similarly, to completely circumvent Ukraine, Russia would require another transport route with

The above suggests that the role of LTCs in European gas trading will diminish substantially in the coming decades due to a decrease in (i) capital intensiveness and (ii) the level of asset specificity associated with changes in the regulatory regime governing the investment in and management of transport assets in Europe in particular and liberalisation process in general as well as higher volumes of LNG in overall gas trade (LNG is a more flexible mode of trade and is hence less asset specific). Next, we discuss some further empirical and theoretical studies on the changing nature of the gas trade in Europe and the implications for LTCs.

3.3. Evidence of the declining role of LTCs in the European gas trade

The theoretical literature on LTCs in the gas industry outlines the conditions under which markets or LTCs dominate. For example, Doane and Spulber (1994) showed that changes in the regulatory framework towards increased competition through unbundling, third-party access and the regulation of pipelines in the US gas industry decreased transaction costs between buyers and sellers, thereby enhancing spot trade. As discussed above, Doane and Spulber also stressed that the reduction in transaction costs comes from the fact that third-party access and the regulation of pipelines means that purchase contracts do not need to be tied to a specific pipeline and producer–buyer pair. Brito and Hartley (2002) applied a microeconomic (search) model and showed that the length of long-term LNG contracts was likely to diminish with (i) the decreasing capital intensiveness of the assets involved in LNG transactions, (ii) increasing cost of capital (discount rate) and (iii) a larger number of players in the market (suppliers and buyers). Brito and Hartley (2007) and Hartley (2015) also suggest that the role of long-term LNG contracts will diminish as spot market liquidity increases. In particular, Hartley (2015) uses a microeconomic model to show the link between increased LNG market liquidity, greater volumes, and destination flexibility in contracts and increased short-term and spot market trades, reinforcing increases in market liquidity.[11] Similar findings were obtained by Parsons (1989), who applied an auction model to find the 'strategic' value[12] of long-term gas contracts signed by producers such as Russia, Norway and Canada. Parsons found that the value of such contracts for the producer diminishes as (i) the number of wholesale buyers increases and (ii) the cost structure decreases prior to spot sales (capital intensiveness).

There is also empirical work that analyses the impact of the changing structure and asset specificity of the European gas industry on LTCs and on contract duration in

roughly 50–60 bcm/year, which is about 30% of its expected total annual contract volume to Europe in the next two decades.

[11] This theoretical prediction is in line with the view of some gas market analysts in Europe, who state that if spot trade exceeds 50% of all traded volume, the move towards complete spot trade is irreversible (see e.g. presentations and speeches by Thierry Bros, researcher from Société Générale).

[12] Defined in Parsons, 1989 as the difference between the value of the commodity in the LTC and the sales price in a more competitive market.

particular. For example, von Hirschhausen and Neumann (2008) conducted an econometric analysis of over 300 LTCs and found an inverse relation between contract duration and (i) deliveries to the restructured markets of the US and UK as well as to the post-1998 markets of Continental Europe (i.e. after the first energy package), (ii) contracts not linked to substantial new investment and (iii) those signed by new market entrants. All else being equal, these findings suggest that as gas markets in Europe are liberalised and mature further (i.e. there is no need for substantial investment in infrastructure) and market entry increases (as discussed in the previous section), the duration of LTCs will decrease.

A similar econometric analysis of 224 LNG contracts was conducted by Ruester (2009[i]), who found that: (i) as asset specificity decreases, so does the duration of LNG contracts; (ii) post-2000 LNG contracts are generally shorter than those signed before that period; and (iii) in the presence of high price uncertainty, contract duration tends to be lower. The last two conclusions are important in the sense that (i) post-2000 LNG contracts are shorter because of substantial cost reductions achieved across the whole LNG value chain and (ii) when prices are uncertain, the benefits of LTCs diminish due to potential profit from arbitrage, as prices tend to fluctuate more, while the cost of holding such contracts becomes higher in the sense of their 'incompleteness', as discussed in the previous section. This is especially true in the given examples of contract renegotiations between European buyers and sellers post-2008.

We conduct back-of-the-envelope econometric analysis following the work of Joskow (1987) and von Hirschhausen and Neumann (2008) but with some refinements to show empirically that the role of LTCs in Europe is declining. In particular, as argued in previous sections, we show that LNG trade is less asset specific than pipeline gas trade (in terms of technology, shipping is more flexible than piping); hence, LNG contracts should, on average, be shorter than pipeline gas contracts. Secondly, we include contracts signed by LNG 'portfolio' players (such as BP, BG and Shell) as a proxy for increased global spot and short-term trading and expect that these contracts are substantially shorter than both traditional LNG and pipeline gas contracts. Thirdly, we show that contracts with deliveries after 1998 to north-west European gas markets – the most liberalised market with sufficient liquidity – are substantially shorter than other pipeline contracts and also substantially shorter than those with deliveries to the remaining European gas markets. We also include other variables (see Appendix 1) following Joskow (1987) and von Hirschhausen and Neumann (2008). We estimate the effects of the above considerations on the duration of LTCs (Equation 1) using a database of 631 LNG and pipeline contracts gathered from publically available sources.[13,14]

[13] Here, contract duration is measured as the difference between contract start and end dates.

$$L_i = Constant + \beta_1 Q_i + \beta_2 Q_i^2 + \beta_3 Dummy_i^{NWE\_Post98} + \beta_4 Dummy_i^{Rof\_EU\_Post98} + \beta_5 Dummy_i^{FlexibleLNG} + \beta_6 Dummy_i^{LNG}, \quad (1)$$

where L_i is the duration of contract i, Q_i is the annual contract quantity (ACQ), $Dummy_i^{NWE\_Post98}$ is a dummy variable taking the value 1 if the contract was for deliveries to the UK, Germany, Belgium, France or the Netherlands after 1998 and 0 otherwise, $Dummy_i^{Rof\_EU\_Post98}$ is a dummy variable taking the value 1 for a contract delivered to the rest of the EU (excluding the north-west European markets mentioned above) after 1998 and 0 otherwise, $Dummy_i^{FlexibleLNG}$ is a dummy variable taking the value 1 for contracts delivered from portfolio LNG suppliers (such as BG or BP), i.e. contracts not tied to a particular production location, and 0 otherwise, and $Dummy_i^{LNG}$ is a dummy variable taking the value 1 for all LNG contracts in the sample and 0 otherwise.

Our original database contained 672 contract entries. We excluded contracts with duration of less than five years so as not to exaggerate the effect of market liberalisation on the duration of LTCs. As such, following industry practice (see, for example, reports by the GIIGNL[15]), we consider an LTC to be any contract with duration of at least five years.[16] Descriptive statistics and estimation results are reported in Appendix 1 and the main conclusions are shown in Table 2 and below.

The results confirm the findings of the earlier empirical and theoretical work on LTCs discussed above. In particular, we found that:

1. Contracts delivered to north-west European gas markets after the enactment of the first energy package (1998) were substantially shorter – by six years on average – than the other contracts in the sample. They were also significantly shorter – by around four years –than the same contracts delivered to other European markets, where spot markets are substantially underdeveloped. Contracts delivered to other European markets after 1998 were also generally shorter ($\beta_4 = -1.9$) than the other contracts in the sample. As such, market liberalisation in Europe, together with a general reduction in the capital

[14] The data was obtained from a database of contracts for pipeline gas and LNG published online by researchers from the German Institute for Economic Research (DIW) (Neumann, et al., 2015) as well as from Poten and Partners' LNG contract database, accessed through the Bloomberg Terminal.
[15] An annual publication on the state of the LNG market issued by the International Group of Liquefied Natural Gas Importers (GIIGNL). These reports contain information on the share of spot and short- and long-term trade and contain definitions of spot and short-term contracts. http://www.giignl.org/publications.
[16] In their analyses, von Hirschhausen and Neumann (2008) and Ruester (2009) included contracts with duration of less than five years. Although this would not change their conclusions, it could bias the results in favour of spot market and shorter contract duration as these short-term contracts were in force after 1998 and could potentially exaggerate the effect of downstream competition and European market liberalisation on the duration of LTCs.

intensiveness of infrastructure assets, has indeed reduced the role of LTCs, specifically, by negatively affecting the duration of such contracts.

2. LNG contracts were shorter on average than pipeline gas contracts. This confirms our thesis that (i) LNG is more flexible by nature and (ii) access to LNG markets reduces the overall level of asset specificity involved in gas trade, especially for European pipeline gas trade.
3. Moreover, flexible LNG contracts were 2.5 years shorter on average than pipeline gas contracts and 0.7 years shorter than the average LNG contract. This confirms the argument that as trade becomes more flexible, the role of LTCs will diminish.[17]
4. Finally, as suggested by the transaction cost economics framework, the presence of dedicated assets, measured indirectly as the volume of ACQ, increases contract duration but at a diminishing rate (the slope of ACQ squared term β_2 is negative) (see Joskow, 1987 for details).

Table 2: Estimation results of determinants of LTCs for natural gas.

Independent Variables	**Regressors**	**L_i – Contract duration (Eq. 1)**
Constant		19.248 (0.754)
Q_i	β_1	0.836*** (0.172)
Q_i^2	β_2	-0.022*** (0.008)
$Dummy_i^{NWE\_Post98}$	β_3	-6.007*** (0.867)
$Dummy_i^{Rof\_EU\_Post98}$	β_4	-1.905** (0.775)
$Dummy_i^{FlexibleLNG}$	β_5	-2.594*** (0.976)
$Dummy_i^{LNG}$	β_6	-1.841*** (0.679)
R-squared		0.129
Adjusted R-squared		0.120
No. observations		631

Standard errors are reported in parentheses; *** indicates significance at the 99% level; ** indicates significance at the 95% level.

To summarise, the theoretical literature and empirical evidence suggest that the European gas industry has changed dramatically in the last 20 years in response to regulatory, technological and industrial dynamics. The industry has gradually transformed from domination by state-owned monopolies and rigid bilateral

[17] Recent LNG deals between EDF and Cheniere and EDF and Kogas are examples of a trend towards even greater flexibility for LNG trade. This requires traditional pipeline suppliers to Europe to re-think their sales strategies.

contracts to a more competitive market. Thus, it is important to understand alternative (i.e. non-LTC) sales strategies in the newly established European gas market order. This is the aim of the following section.

4. Sales strategies in the new European gas order

Since 2010, the European gas industry has witnessed several waves of LTC price and volume renegotiations by European utilities and leading upstream producers and gas suppliers, such as Statoil, GasTerra, Sonatrach and Gazprom. Due to the commercial sensitivities of these contract renegotiations, no details about pricing and other settlement provisions are publically available; however, we can conclude from various trade publications and official press releases that:

1. Gazprom has focussed on defending oil indexation and has offered retroactive discounts on existing contracts, introducing a limited degree of spot indexation; in some instances it has made discounts on 'P0' – initial contract prices (the netback value of a basket of competing fuels);
2. Sonatrach has also focused on defending oil indexation and has agreed to give retroactive discounts and also to reduce minimum take-or-pay provisions;
3. GasTerra has been less defensive of the old pricing system and more willing to offer rebates and introduce more spot indexation in its contracts;
4. among the big suppliers, Statoil has offered the most flexibility in terms of pricing and volumes – it is estimated that 75–80% of Statoil's total export to Europe is currently spot indexed (Figure 1).

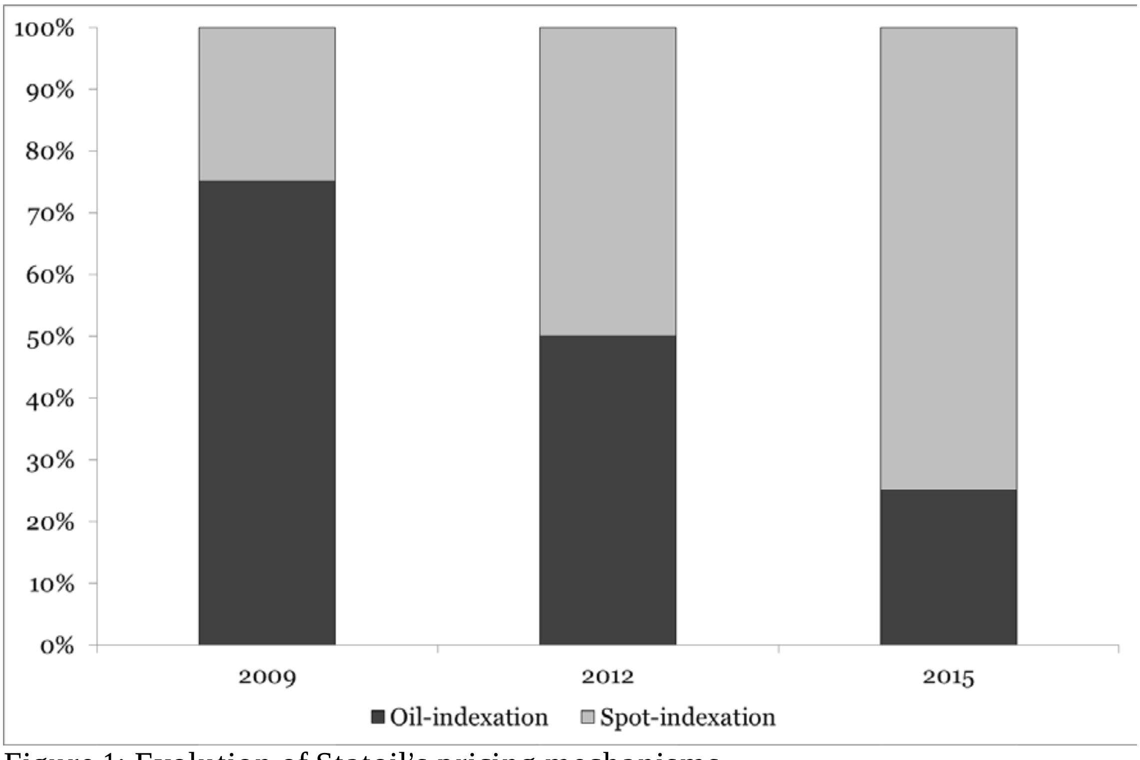

Figure 1: Evolution of Statoil's pricing mechanisms.
Source: Sætre (2013).

The flexibility that Statoil has shown in adapting to structural changes in the markets is believed to be a source of its strength; it is something that has allowed the company to strengthen its position in the short term[18] and may bring greater shareholder value in the medium term, especially when gas market demand in Europe recovers, providing more trading and arbitrage opportunities.

To turn structural changes in the markets into competitive advantage, Statoil has quickly changed its sales strategy, shifting away from rigid LTCs towards increased sales through traded markets as well as direct marketing and sales to end users (Figure 2).[19] As noted, spot-indexation as a pricing mechanism now dominates Statoil's sales portfolio. Thus, Statoil is becoming increasingly like the ISTM gas business entity. Of course, the natural question for our research is why Statoil decided to be the 'first mover' and to embrace spot indexation and wholesale trading so fully.

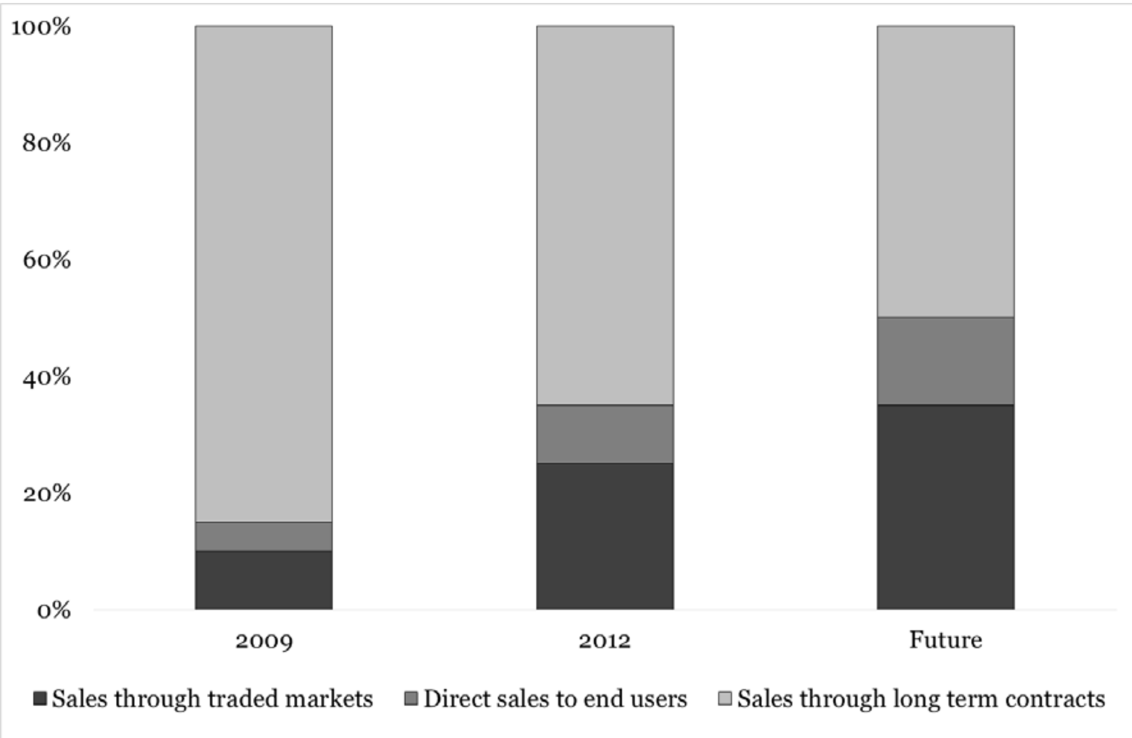

Figure 2: Evolution of Statoil's sales channels
Source: Sætre (2013).

A combination of factors allowed Statoil to quickly see structural changes not as threats but as business opportunities, including:

1. Statoil is mandated by the Norwegian government to be a single export 'channel' for all gas coming out of equity participation by Statoil and the

[18] In particular, pricing flexibility allowed the company to take market shares from Gazprom and Sonatrach in 2012.
[19] For example, its recent deals with large industrial customers and electric utilities (e.g. contracts with Stadtwerke Düsseldorf and Koch Supply and Trading) are examples of innovative deals that allowed Statoil to enjoy higher margins by bypassing the traditional importers.

government; thus, Statoil is responsible for marketing and sales for 80% of Norwegian gas production;
2. among the major European gas suppliers, Statoil has the flexible capacity to follow demand and arbitrage opportunities.

Statoil's geographical position is one important source of flexibility: the Norwegian gas production system is connected directly to the most liquid trading hubs in north-west Europe. Statoil has six delivery points, all of which are in the largest and most liquid hubs: NBP and TTF.[20] The average distance between the gas fields in the Norwegian continental shelf and these delivery points is 400–1,200 km; this is six times shorter than Russian gas has to travel before entering north-west Europe, four times shorter than Caspian gas routes to Central Europe and three times shorter than Algerian gas routes to Southern Europe. In combination with its two large gas fields, Troll and Oseberg, which have production flexibility and act as swing capacity, Statoil's geographical position means that the company can react proactively to price fluctuations at hubs, optimise its production and sales and exploit arbitrage opportunities in north-west Europe more easily than any other major supplier in Europe. A simple econometric analysis showing the relationship between net gas outputs[21] (Q_i) from the Troll and Oseberg fields and market factors highlights these points:

$$\begin{aligned} Q_i = Constant + \beta_1 NBP + \beta_2 Season + \beta_3 SpotIndex + \beta_4 ActiveTrading \\ + \beta_5 RU\_Undersupply14 + \beta_6 DummyUK1 + \beta_7 DummyUK2, \end{aligned} \quad (2)$$

where *NPB* is the day-ahead spot price (monthly averages), *Season* is a dummy variable taking the value 1 between October and March and 0 otherwise, *SpotIndex* is a dummy variable taking the value 1 for 2012, when the positive effect of increased spot indexation allowed Statoil to take market shares from other suppliers, and 0 otherwise, *ActiveTrading* is a dummy variable taking the value 1 for 2011–2015, the period when structural shifts in the market affected Statoil's contracts, pricing and sales strategy, and 0 otherwise, *RU_Undersupply_14* is a dummy variable taking the value 1 for the winter of 2014/2015, when Russian supplies to Europe were minimised due to a number of factors, including reducing oversupply and stopping Ukrainian imports from Europe, and 0 otherwise, *DummyUK1* is a dummy variable taking the value 1 for the period between October 2006 and July 2007, representing the effects of a temporary gas glut in the UK due to increased importation from the Langeled and BBL pipelines and failure of the IUK to export the surplus to Continental Europe (Poten and Partners, 2007), and 0 otherwise, and *DummyUK2* is a dummy variable taking the value 1 for the winter of 2005/2006, to account for tight

[20] St Fergus (UK), Easington (UK), Dunkerque (France), Zeebrugge (Belgium), Emden (Netherlands) and Dornum (Germany).
[21] We excluded from the estimation gas production volume that goes into oil injections. Thus, net gas output from Troll and Oseberg represents marketable gas. By excluding gas production for enhanced oil recovery, we separate the possible effect of oil price dynamics on gas output from these two fields.

supply condition in the UK[22], and 0 otherwise. The regression (Eq. 2) is estimated using monthly data from January 2001 to March 2015, and the results are reported in Table 3.

Table 3: Flexibility of Troll and Oseberg net gas output: Econometric results.

Independent Variables	Regressors	Troll output	Oseberg output	Troll and Oseberg output
Constant		1.422	0.064	1.486
		(0.108)	(0.034)	(0.118)
NBP	β_1	0.064***	0.015***	0.080***
		(0.017)	(0.005)	(0.019)
$Season$	β_2	0.978***	0.164***	1.142***
		(0.084)	(0.026)	(0.092)
$SpotIndex$	β_3	0.591***	0.186***	0.776***
		(0.175)	(0.055)	(0.192)
$ActiveTrading$	β_4	-0.242**	-0.097**	-0.339**
		(0.123)	(0.039)	(0.135)
$RU\_Undersupply14$	β_5	0.659***	0.188**	0.847***
		(0.237)	(0.074)	(0.260)
$DummyUK1$	β_6	0.565***	-0.064	0.502***
		(0.165)	(0.052)	(0.181)
$DummyUK2$	β_7	-0.432	0.030	-0.402
		(0.267)	(0.083)	(0.292)
R-squared		0.581	0.357	0.617
Adjusted R-squared		0.563	0.330	0.600
No. observations		171	171	171

Standard errors are reported in parentheses; *** indicates significance at the 99% level; ** indicates significance at the 95% level.

As expected, Troll and Oseberg, serving as Norwegian swing production capacity, show the most flexibility in reacting to changes in market dynamics. Production from these two fields follows spot prices (NBP) closely with the expected positive sign ($\beta_1 > 0$: higher spot prices lead to higher output and vice versa) and this output–price relationship is statistically significant.[23] Furthermore, Statoil's swift decision to introduce a much bigger share of spot indexation in its contracts paid off in 2012, when Norwegian gas sales to Europe reached 114 bcm (one of the highest levels in its history of supplying gas to Europe), and this lead to an average increase in production from both fields ($\beta_3 > 0$) of roughly 0.59 bcm/month (Troll) more than

[22] See 'Rogers and Howard (2010). "LNG trade-flows in the Atlantic basin, trends and discontinuities," *Oxford Institute for Energy Studies*' for a detailed account of the reasons behind these spikes.

[23] Note that we also included (in Eq. 2) the Average German Import Price (AGIP) as a proxy for oil-indexed gas contract price to see if outputs from these fields closely tracks AGIP. We found no statistically significant relationship between outputs and AGIP. We also used AGIP instead of NBP prices in Eq. 2 and found a statistical significant (positive) relationship between AGIP and outputs from these two fields; however, the relationship was much weaker compared to that found using NBP prices (comparison based on the significance level, P, of the beta coefficients).

the average monthly production in the sample. Similarly, when Russia limited its supplies to Europe during the winter of 2014/2015, this led to an immediate reaction by Statoil to increase production from both fields in that period ($\beta_5 > 0$) by 0.847 bcm/month.

The most interesting and striking result is the estimation of coefficient β_4, which is negative. This means that output from both fields in the period 2011–2015 is lower on average than in the analysed sample, and this result is statistically significant. There are several possible explanations for the negative coefficient β_4. One could argue that the lower output from Troll and Oseberg observed after 2011 was the result of a natural decline in field pressure. We can rule out this hypothesis since gas production from Troll started in 1996 and the production rate has not yet peaked because, according to the Norwegian Petroleum Directorate (NPD, 2015a), initial recoverable gas from Troll is more than 1.4 tcm and as of 2014, around 35% of that had been depleted. Similarly, gas production from Oseberg has also not yet peaked: production started in 2000 and as of 2014, around 35% of the total recoverable (113 bcm) gas had been depleted (NPD, 2015b).

For the Troll output, one potential explanation for the lower output observed since 2011 is that the field has been undergoing major maintenance work due to the breakdown of a compressor station, which limited its flexibility during winter periods. The maintenance work started around 2013 and was completed in mid 2015. Looking at the monthly production data from Troll, we can confirm that the maintenance work did indeed affected the flexibility of the field; however, this only occurred for the winter of 2013/2014, when production was 11% lower on average than output during the winter of 2012/2013. Nonetheless, this one-off effect does not change the significance of the coefficient β_4, which measures the average monthly output for 2011–2015 compared to 2001–2010 and not just the peak periods. Furthermore, the effect could have dragged down the seasonal dummy coefficient β_2, but this coefficient is still statistically significant. We also introduced a separate dummy variable for the winter of 2013/2014 to control for the effect of field maintenance on Troll output and on the coefficient β_4, but the dummy is statistically insignificant. Moreover, we are not aware of any maintenance work at the Oseberg field after 2011.

One final possible explanation for this result ($\beta_4 < 0$) is that the period 2011–2015 coincided with a period of 'demand destruction' in Europe, which was due to the prolonged financial crisis and increased inter-fuel competition in the power-generation sector. Indeed, total European gas consumption in this period fell by 6.2% year-on-year (YoY) (Figure 3: EU gas consumption, left exhibit), and one can conclude that outputs from these two fields followed a general trend of demand reduction observed in that period. However, we can rule out this explanation for the following reasons. In the same period, Norwegian production actually grew by 0.6% YoY (Figure 3: Norwegian gas production, left exhibit). Secondly, Norwegian exports to Europe in that period also grew by an average of 4% YoY (Figure 3: right exhibit), the highest export growth rate among the major suppliers (in the same period, Russian and Dutch supplies grew by an average of 2% YoY, while Algerian exports declined by an average of 12% YoY due to its immovable position on oil-indexation).

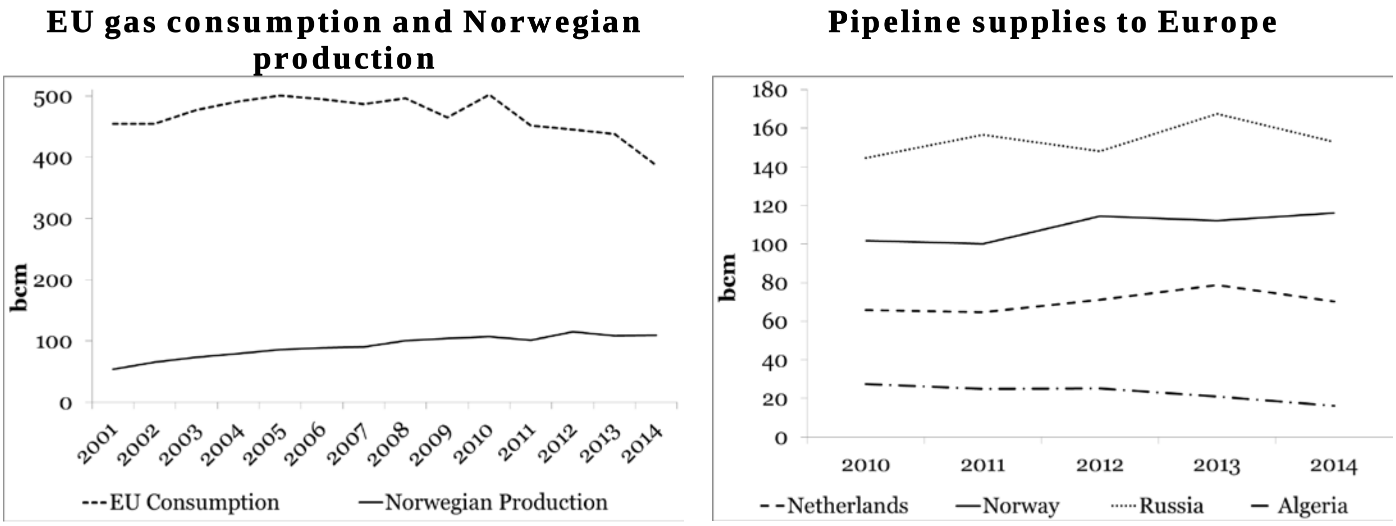

Figure 3: EU Gas Consumption and pipeline supplies by major producers.
Sources: EU consumption and Norwegian production are from BP (2015) and Pipeline supplies to Europe from IEA (2015b)

Altogether, this means that while production and exports from Norway to Europe grew over 2011–2015, monthly outputs from Statoil's Troll and Oseberg fields were 10% and 41% lower on average, respectively, than the monthly average output since 2001 (as noted, this reduction in outputs is statistically significant, β_4 Table 3). We consider this to be a startling manifestation of a new gas sales strategy in a liberalised market – one that is based on direct and active trading and engagement with spot pricing. Clearly, these two fields serve as marginal fields and, as such, its flexibility means Statoil is able to respond optimally to spot prices and market dynamics: in an environment of oversupply and increased inter-fuel competition from other energy sources, the ability to shift production from flexible fields to future periods to place upward pressure on current spot prices surely creates value for Statoil. However, such a strategic response is only possible when a company is actively participating in liquid trading markets to understand market dynamics fully and benefits from information flows.

The responses of other suppliers highlight their current competitive positions but also these suppliers' visions of where the European gas markets are moving to. It is clear that GasTerra and Statoil saw the imminent collapse of the old contracting and pricing regime as both were flexible with regard to both volumes and the incorporation of spot pricing into their contracts. By contrast, Gazprom's response formally retained the dominance of oil indexation but gave discounts and retroactive rebates to cover the differences in oil and spot prices, and as such, Gazprom was able to win back its market share in 2013, when its exports grew by 13% relative to 2012. However, the overall performance of Gazprom in that period was less impressive compared to Statoil's performance (2% YoY growth compared to Statoil's 4%).

Another interesting response came from Algerian Sonatrach, which was able to defend the dominance of oil indexation in its contract; however, this came at the expense of decreased volumes, specifically, this resulted in an average decline in pipeline exports to Europe of 12% YoY in 2011–2014. By contrast, both Statoil and GasTerra have been actively trading in the markets and took the opportunities posed by market liberalisation to scale-up their marketing activities selling directly to large industrial customers and power generators. This allowed them to bypass traditional importers and therefore enabled them to capture some of the downstream margin not available before.

In traditional LTCs the take-or-pay and carry-forward clauses grant buyers with offtake flexibility and are thus burdensome for producers, which have to retain production and transport capacity to accommodate buyers' requests for increased offtake, sometimes at short notice. Under LTCs, the pricing of these bundled products was fairly uncomplicated and was indexed to a basket of competing fuels (oil products in particular). However, when spot markets emerged in Europe, moving to spot indexation would not necessarily correctly reflect the value of those bundled products for producers in rigid LTCs. Realising this potential shortcoming, both Statoil and GasTerra agreed to move to spot indexation but also introduced greater product variety to define more clearly those additional benefits that were previously bundled together in LTCs. For example, many market participants in North-west Europe now offer, among others, the following hub-based sales products:

1. flat volumes, where those customers who wish to have offtake flexibility or price certainty (fixed price or indeed oil indexing) pay extra;
2. varieties of structured products that reflect the needs of customers, such as temperature-dependent products;
3. standardised products at virtual trading hubs;
4. other services such as balancing and flexible procurement profiles.

In a nutshell, Statoil and GasTerra have transitioned from pure commodity producers to sellers of structural solutions around a core commodity: they have become gas producers with integrated supply, trading and marketing activities. And this strategy is expected to pay off in liberalised and increasingly liquid markets as it allows these companies to learn about their customers' preferences, needs and expectations. Note that central to the Statoil's ISTM strategy is the development of strong trading functionality to support upstream production, hedging and profit generation; its direct marketing activities seem to supplement trading and production activities. Put differently, marketing activities for large hydrocarbon producers, such as Statoil, exist to hedge and supplement trading activities.

Overall, Statoil leveraged this position with enhanced wholesale trading, seeing the ISTM model as a substitute for a system of rigid bilateral contracts. From Statoil's financial reports we can understand that its business model is organised around two main units: (i) development and production (DP), both in Norway and internationally, and (ii) marketing, midstream and processing (MMP), which was known as marketing, processing and renewables before the 2015 reorganisation. The MMP division is responsible for the marketing, trading, transportation and processing of oil, petroleum products and natural gas. It is therefore is a single trading and marketing channel for all of Statoil's and the Norwegian government's (State's Direct Financial Interest, SDFI) equity gas (Figure 4). According to its financial reports, most of the MMP division's business values come from wholesale gas trading, and the contribution of MMP to the group's overall operating profit was ca. 15% in 2014.[24] The profitability of the MMP unit is the margin between the transfer price and the invoiced (realised) price (Figure 5). The transfer price is what MMP pays for gas received from Statoil's development and production subsidiary (Figure 4: DP Norway) and also to the SDFI for gas traded and marketed on behalf of the government. The pricing mechanism established for the transfer price is based on market-based arrangements, which reflect Statoil's sales portfolio (Statoil, 2012). The invoice price is the actual price that the MMP gets from selling SDFI and DP Norway gas, and this invoiced price depends on the strength of the performance of traders and marketers working in the MMP division.

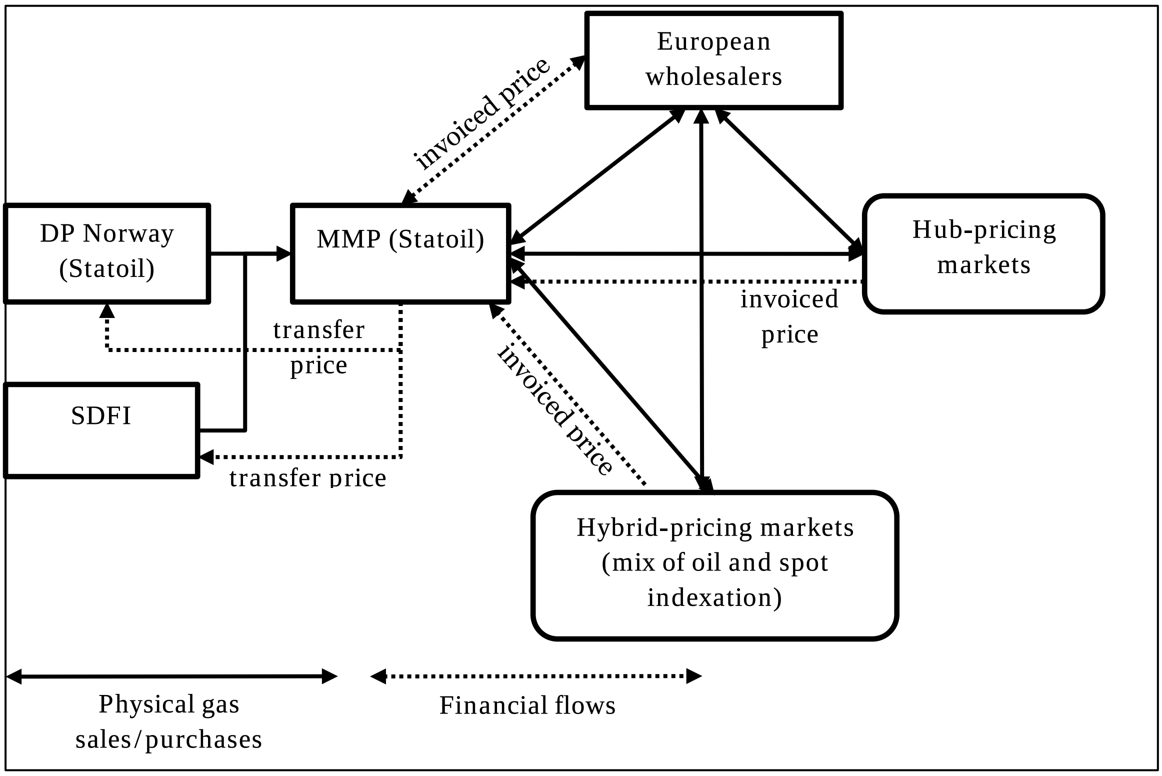

Figure 4: Simplified schematic of Statoil's organisational model of gas sales, marketing and trading.

[24] Note that the overall value of a trading unit (in terms of a percentage of overall profit) for a gas producer varies according to commodity prices.

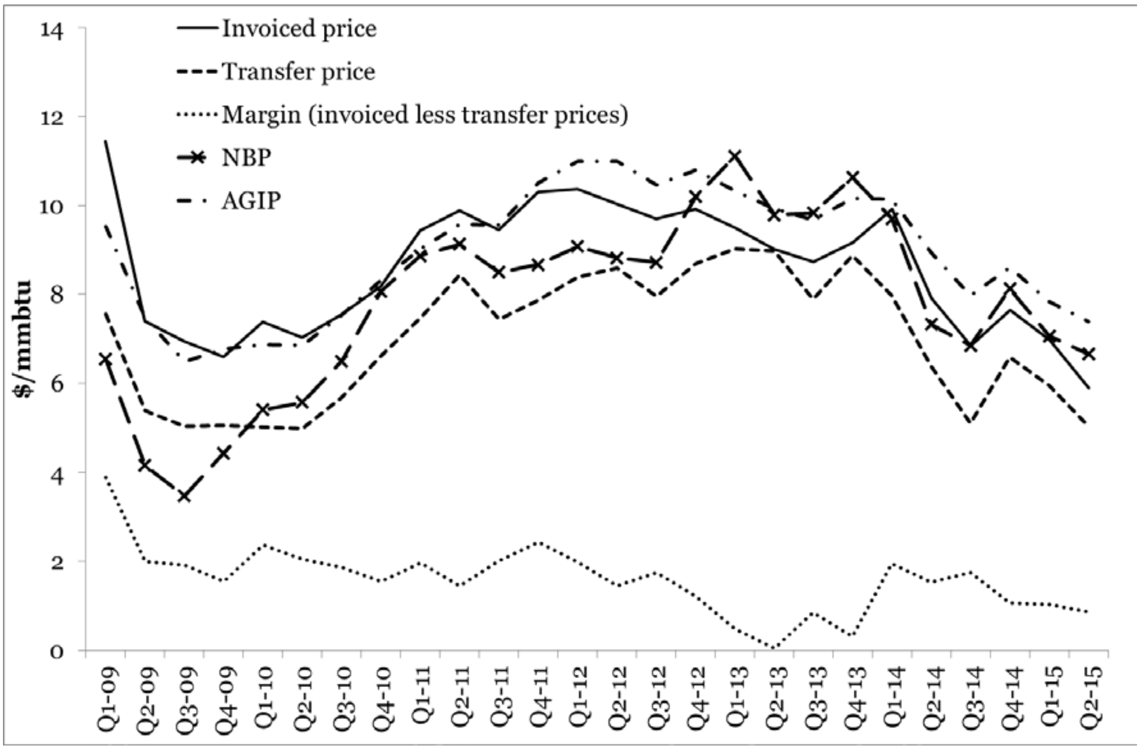

Figure 5: Statoil's invoiced and transfer prices.
Source: Author's calculations based on Statoil's quarterly reports, available from the company's website.

Figure 5 shows both the invoiced and transfer prices based on Statoil's financial reports. Note that before major gas price renegotiations, Statoil's invoiced price closely tracked the AGIP, which represented the oil-indexed gas price before renegotiations (around 2011). Since around 2012, Statoil's invoiced price diverged from AGIP, becoming cheaper and more volatile in response to market dynamics rather than the oil-indexed price. It seems that Statoil's transfer prices also track a combination of both AGIP and NBP: before renegotiations it follows AGIP dynamics, but after price reviews it follows NBP dynamics more closely. Note that after 2011, AGIP was partially decoupled from a purely oil-indexed price formula because, being an average import price for all sources into Germany, AGIP also includes Statoil's invoiced prices, with an increasing share of spot indexation.

As such, the value of Statoil's MMP, or the ISTM sales model more generally, is that it allows commodity producers to better optimise their sales and production decisions in response to market conditions. It also gives an extra margin by taking arbitrage opportunities and capturing downstream margins through direct marketing activities. In addition to these benefits, the ISTM model is also able to react strategically to market dynamics; for example, by reducing supplies when markets are oversupplied (similar to the empirical results we found for the outputs of Statoil's swing production capacity). Thus, the optimal exercise of pricing power does not come solely from the size a producer's gas reserves but rather stems from a combination of large reserves and ISTM activities.

Had Sonatrach or Gazprom accepted full spot indexation without developing ISTM activities, then they would probably not be able to enjoy prices higher than Statoil's transferred prices and, most probably, would see prices even lower than those levels. One can conclude that full spot indexation without ISTM capabilities would turn Sonatrach and Gazprom into price-takers.[25] This explains why Sonatrach was the most ardent supporter of oil indexation and also why Gazprom went for partial spot indexation, reflecting its stronger downstream position relative to Sonatrach. However, Gazprom's position in the spot markets is limited to its trading arm, Gazprom Marketing and Trading, which does not enjoy the same scale, scope and privileges as Statoil's MMP, as the single export, trading and marketing channel for all gas coming out of equity participation between the Statoil group and the Norwegian government. Had Gazprom channelled all of its future sales through a marketing and trading division, its profits would have been considerably higher. Quantifying the impact of this strategy on Gazprom's profits is the aim of the rest of this paper.

5. Economics of Gazprom's sales strategies in Europe

5.1. Characterisation of sales strategies and modelling considerations

For our quantitative analyses we look into the two possible sales strategies available to Gazprom: (i) the border sales strategy suggested by Gazprom (see e.g. Miller 2015) and (ii) the ISTM sales strategy discussed above. Note that these two sales strategies could supplement sales through existing LTCs, some of which last longer than 15 or 20 years. This section therefore discusses the implementation of these sales strategies in the modelling and analytical framework.

Gazprom's proposed border sales strategy corresponds to a model of a pure upstream producer, whereby it has rather limited knowledge of the wholesale market and takes the pricing of gas at trading hubs as a given, that is, being price-taker. One may argue that retreating to the borders is not a 'dumb' strategy, as we describe, and that Gazprom can always respond to market and non-market dynamics by 'adjusting the gas valve' at its borders. However, we consider this strategy to be politically risky in that it triggers further diversification efforts from EU countries. It is evident that even with the current political tension between Europe and Russia, the official policy of Brussels and countries that are highly dependent on Russian gas is to diversify away from Russia. Therefore, a more 'intelligent' border sales strategy in this sense would appear commercially implausible for Gazprom. Furthermore, even if Gazprom adjusts the gas valves purely for commercial reasons (i.e. responding to the glut in

[25] They have been price-takers under full oil-indexation nonetheless. However, at least none of the gas players in Europe were able to influence oil prices, and, hence, the perception and argument of 'fairness' of oil-indexation exists.

the global markets), one could argue that it would either under- or over-sell relative to the optimal volume that the market could take, and, therefore, there is little basis for correctly adjusting the gas valves. Thus, in the border sales strategy scenario we do not consider this type of 'intelligence' and instead consider that if Gazprom pursues a border sales strategy for the uncontracted volume, then it will most likely be a price-taker. In such a situation, Gazprom will attempt to price its gas to cover all capital and operating expenses, i.e. pricing on a long-run marginal cost basis.

At the other extreme is the integrated model – the ISTM sales strategy – which has at least one advantage over border sales in that it allows producers to engage actively with trading and pricing at the wholesale level and, hence, potentially allows for more optimal – or at least responsive – strategic sales behaviour compared to border sales and other strategies (such as the recent sales auctions organised by Gazprom). The two sales strategies are depicted in Figure 6 below.

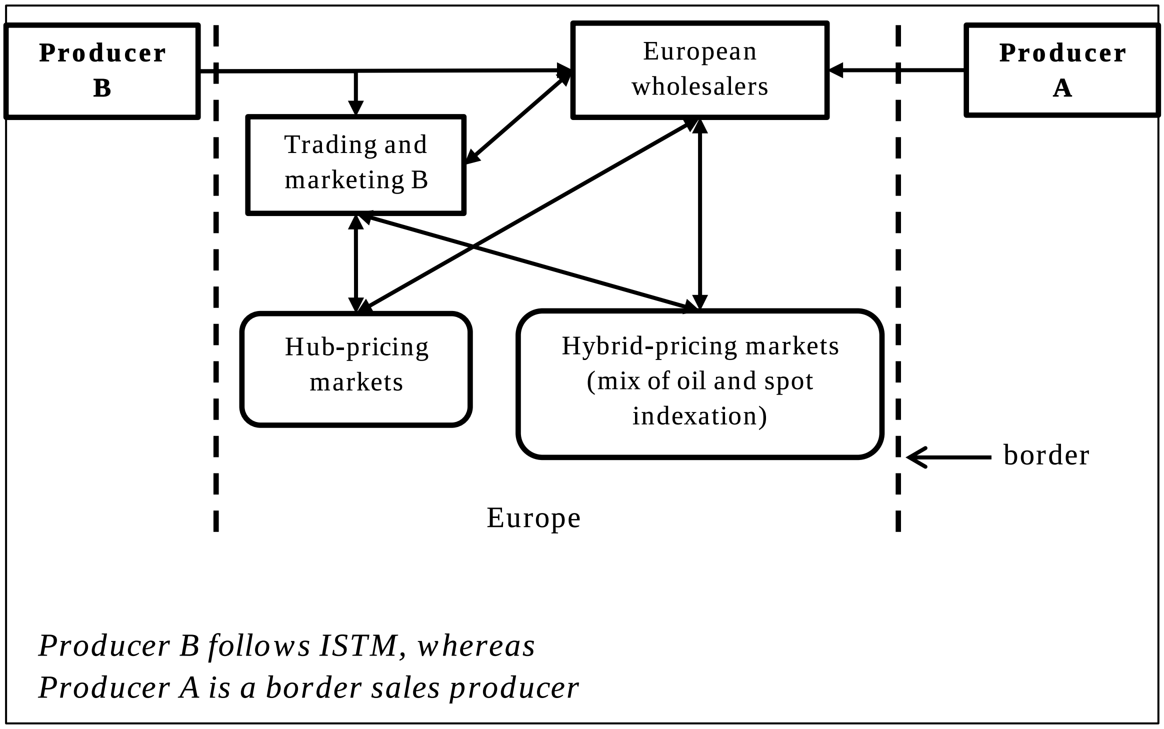

Figure 6: Simplified schematic of ISTM and border sales strategies.

We evaluate the impact of the two sales strategies on Gazprom's export profits. These strategies are evaluated for incremental volumes of export into Europe: the volumes that are above the already-contracted volumes under Gazprom's existing LTCs.

1. Border sales strategy: Sales under already-signed LTCs with pricing based on some form of oil indexation with marginal spot indexation but supplemented by border sales for incremental (uncontracted) volumes (see Figure 7).
2. ISTM sales strategy: Sales under already-signed LTCs with pricing based on some form of oil indexation with marginal spot indexation but supplemented by direct trading and sales at the liquid trading hubs of north-west Europe for incremental (uncontracted) volumes (see Figure 7).

For the border sales strategy we assume that gas buyers from Europe will buy incremental gas volumes at the Russian border at a competitive price (based on the long-run marginal supply cost) and then transport the product to European markets for resale. However, under the ISTM strategy we assume that Gazprom it able to pursue active trading and direct sales at hubs. We believe that this is a valid assumption given that Gazprom has many well-established downstream subsidiaries in Europe, such as Gazprom Marketing and Trading (London), which can take care of trading and direct sales on behalf of the entire group, similarly to Statoil's MMP division.

As noted above, one benefit of wholesale trading is the opportunity to learn and understand market dynamics and price-quantity responsiveness (i.e. price responsiveness or price elasticity of demand, PED) in the markets and, hence, to develop an optimal export strategy based on different products, contracts and integrated solutions. Conversely, a border sales strategy, as suggested before, translates into price-taking behaviour as producers in this situation do not participate in wholesale markets and therefore have no (less) credible information about market dynamics; such producers are focused only on selling a commodity.

In a nutshell, the difference between the two strategies in our quantitative analysis and modelling is that under ISTM, Gazprom can exploit pricing power, while under its border sales strategy, Gazprom's pricing strategy is price-taking. Hence, our research question is whether pricing power in a liberalised market with potential entry from low-cost producers would be better for Gazprom than pursuing border sales and being a price-taker. More formally, Gazprom's export profit, π_i, is defined:

$$\max_{q_i \geq 0} \pi_i = q_i p\big(q_i + q_{-i}(q_i)\big) - C(q_i), \tag{3}$$

where q_i is sales to the market, $p\big(q_i + q_{-i}(q_i)\big)$ is wholesale price which depends on total supplies to that market $Q = q_i + q_{-i}(q_i)$ and $q_{-i}(q_i)$ is supplies by other exporters (non-Gazprom) which is a function of sales volume by Gazprom, $C(q_i)$ is Gazprom's total supply cost function to that market such that $C'(q_i) > 0$, $C''(q_i) > 0$. Note that profit function (3) is a simplified version of the function used in the global gas market model that incorporates many other features such as contractual and physical constraints and other decision variables, such as dispatch, injection and withdrawal etc. Thus, marginal profit should be:

$$\frac{\partial \pi_i}{\partial q_i} = p + \frac{\partial p}{\partial q_i}\left[1 + \frac{\partial q_{-i}}{\partial q_i}\right] q_i - \frac{\partial C}{\partial q_i}, \tag{4}$$

where $\frac{\partial p}{\partial q_i} < 0$ is a slope of the demand curve and $\frac{\partial q_{-i}}{\partial q_i} = \theta$ is the constant "conjectural variation" (CV). Note that for $\theta = -1$ yields the pure competition game, while $\theta = 0$ represents the Cournot game.

Therefore, under ISTM strategy we assume $\theta = 0$ and as for the border sales strategy – $\theta = -1$. We define the net benefit of the ISTM model for Gazprom (annual average), ν, as the difference in profits from realising these two alternative sales strategies:

$$\nu = \frac{\sum_{t=0}^{25}\left(\frac{\pi_{i,t}^{ISTM} - \pi_{i,t}^{BorderSales}}{(1+r)^t}\right)}{25}, \quad (5)$$

where π_i^{ISTM} is Gazprom's total profit under the ISTM sales strategy and $\pi_i^{BorderSales}$ is the total profit under the border sales strategy. Both profit (pre-tax) streams are discounted at an interest rate of 10% (r) over a time horizon of 25 years (2015–2039). Obviously, as Eq. (4) and (5) suggest, the costs and benefits of these strategies depend on a number of issues, including:

1. the cost structure of firms competing in European gas markets;
2. the behaviour of market players – price-taking or exercising pricing power;
3. price responsiveness or PED in the European gas markets;
4. infrastructure characteristics, such as the available supply capacity (production, pipelines and LNG terminal capacities) and investment costs to expand capacity.

Note that other benefits of the ISTM sales strategy that are commonly discussed in the oil and gas industry, such as portfolio optimisation, operational and logistical benefits and trading with flexible and diverse products are not considered as part of this modelling exercise. Furthermore, we do not value the marketing part of the ISTM model since this would require very detailed and sophisticated modelling that is beyond the scope of this paper. Marketing and further downstream activities include participation in the electricity generation sector, carbon trading, energy efficiency and other end uses of gas as an energy carrier and product (e.g. for the chemical industry). These other benefits were discussed in the previous section. Here, we argue that these micro-level, operational benefits of ISTM are in fact an integral part of ISTM's strategic value creation: the ability to exploit market opportunities to raise pricing power and the ability to actively engage in pricing go hand in hand with day-to-day trading in liquid markets. Thus, the primary aim of this paper is to show that the benefit of ISTM at the macro and strategic level is the ability to understand wholesale markets and, hence, the possibility of exploiting pricing power for large integrated players. Furthermore, as we show, the ISTM sales strategy also has a strategic options value that gives integrated players the ability to respond strategically to disruptive events in gas markets, such as entry by very-low-cost producers or increased inter-fuel competition due to strategic investments on the buyers' side.

Taking into account the above considerations, we use a global gas market model to simulate different market and non-market scenarios and quantify the costs and benefits of the two strategies. In the next section we discuss the methodology, assumptions and scenarios for this analysis.

5.2. Methodology, assumptions and scenarios

The global gas market model (see Appendix 2 for a general description and Chyong and Hobbs, forthcoming, for a detailed description) has been developed to conduct quantitative analyses of important market and policy issues affecting gas markets. For details of the data and assumptions used in the model, see Appendix 3. The model is founded on basic microeconomic concepts and game theory principles, namely:

1. Each player in the model maximises his profit given a set of constraints (such as production or transmission capacity) and the endogenous actions of the other market participants.
2. The upstream natural gas market is concentrated such that some large gas producers and exporters have pricing power: in economic terms, they can see market elasticity of demand and can therefore actively price gas by withdrawing sales volume to increase prices and profit; however, the model can also simulate price-taking behaviour.

We model the whole gas market value chain, including the following market players with the corresponding competition behaviour:

1. gas production and trading – can be modelled as imperfectly (exercising market power) or perfectly competitive (price-taking);
2. pipeline and LNG – pipeline transport as well as LNG regasification and liquefaction services are priced efficiently, i.e. with no market power;
3. LNG shipping – marginal cost-based pricing;
4. gas storage – storage operations are priced efficiently, i.e. with no market power;
5. final markets – represented by inverse demand curves that show how the clearing (equilibrium) price depends on total supplies to that market.

Using the global gas market model, we estimate Eq. (5) for a set of scenarios as outlined in Table 4 below. We develop these scenarios to test the robustness of the two sales strategies under a threat of market entry by low-cost producers. Thus, the difference between Scenarios A (B) and C (D) will illustrate the net benefit of the two sales strategies under conditions of market entry by low-cost producers.

Table 4: Analysed scenarios and their main characteristics.

	Border sales	**ISTM sales**	**Entry of low-cost producers**
Scenario A	Yes		
Scenario B	Yes		Yes
Scenario C		Yes	
Scenario D		Yes	Yes

Our assumption for Russia's export potential to Europe is based on the following considerations. We take the average gas exports to Europe (excluding Turkey but including Ukraine) in 2010–2014 as a starting point and then assume that Russia is able to scale up its production by 50 bcm/year (reference scenario for our analyses). The difference between the assumed total export potential and the total annual contract quantity (ACQ) to Europe gives us a possible scenario for how much gas (free volumes or uncontracted gas) is available for either the border sales strategy (Scenarios A and B) or the ISTM sales strategy (Scenarios C and D). Figure 7 shows these assumptions.

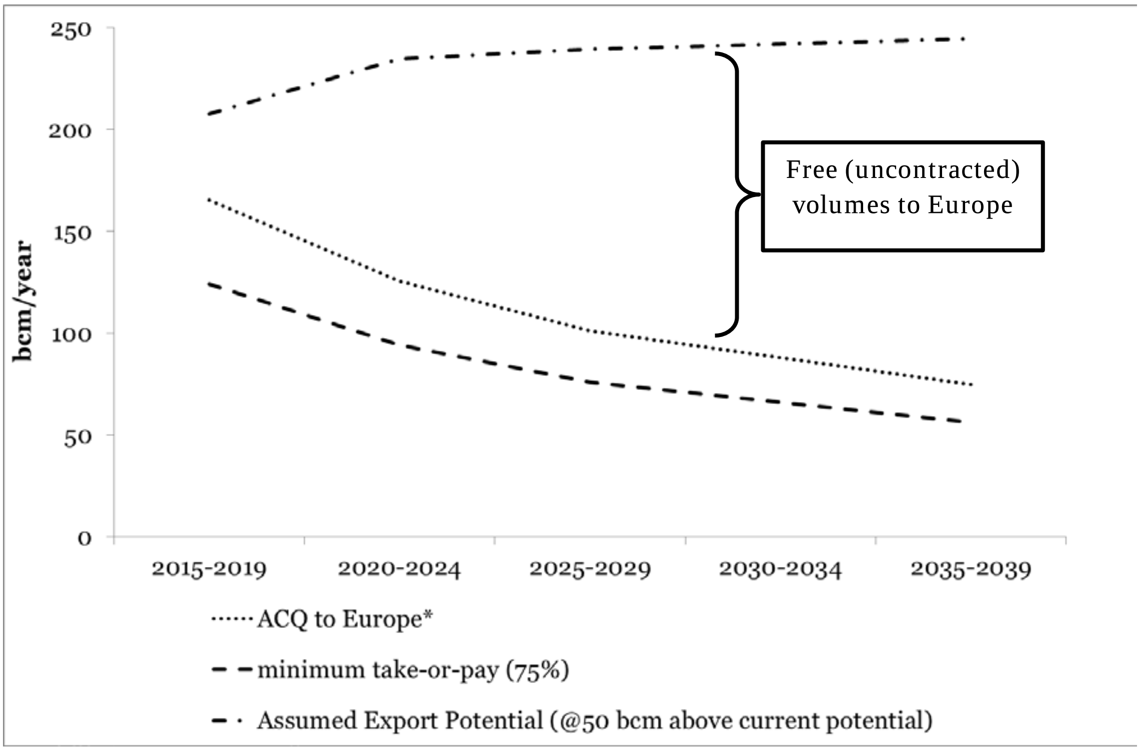

Figure 7: Russia's export potential and uncontracted volumes.
Note: * ACQ figures exclude contracts to Turkey but includes volumes to Ukraine.
Source: ACQ is based on actual exports to Europe in 2010–2014, as reported by Gazprom, and the decline rate in the contract volumes in 2015–2039 is based on the assumptions and data reported in Mitrova et al., (2015).

The purpose of examining a scenario of market entry by low-cost producers (Scenarios B and D) is to conduct a 'stress test' of Gazprom's possible sales strategies and is not to argue for particular future developments of global supply and demand. Examples of possible market entry by low-cost producers are numerous. For example, consider the potentially negative impact of the US LNG exports[26], and in particular possible impact of additional export volumes that could come out of the Middle East region, for example, Iran, Iraq and indeed cancellation of Qatari's exploration moratorium and hence possible ramp up of additional export volume from Qatar. In addition to the possibility that Qatar may cancel its exploration

[26] The CEO of Cheniere recently stated that the LNG Sabine Pass project could deliver LNG to Europe at $4.50/mmbtu, which is believed to be very close to Gazprom's short-run marginal cost to Europe, including taxes (see http://blog.argusmedia.com/how-will-gazprom-handle-the-lng-glut/).

moratorium, note that as the uncontracted volume of Qatari gas production increases (estimated to be around 40 bcm/year by 2025, rising to 100 bcm by 2035, assuming no expansion of current production capacity), Qatar could face a similar dilemma to Gazprom with regard to the two sales strategies. Currently, Qatar is selling most of its volumes under long-term oil-indexed contracts. However, as we move to an oversupply environment, there is increasing pressure from buyers to at least partially index their LNG contracts to spot price indices. In this situation, Qatar may well decide to supplement its long-term sales with border sales to defend its market share and hence flood international markets with extremely low-cost gas. Qatar's incentives to flood the markets with cheap gas could be fuelled further if the country observes that, in addition to the pressure from US and Australian LNG exports, Gazprom is pursuing a similar strategy of aggressively taking over market shares. This may trigger Qatar to sell more gas at very low and competitive prices.
As noted, our analyses of these market entry scenarios aim to test the robustness of the two sales strategies and not to predict particular supply behaviour and future market dynamics. However, these examples stress that the probability of such market entries and supply behaviour is positive and, if they occurred, this would have a highly negative impact on Gazprom's business. However small these probabilities may be, such events are high-impact low-probability events that could remove unprepared business entities from the market completely. Thus, for the purpose of examining how Gazprom's possible sales strategies could mitigate this potential negative impact, we assume for Scenarios B and D that by 2025 low-cost producers could potentially export up to 100 bcm/year to global markets, rising to 200 bcm by 2035.[27] We also assume that such low-cost producers' sales strategies will likely maximise sales rather than prices, making them price-takers. This is most likely to be true of US exports but may also be the case in Iran and Iraq as well as Qatar, if it decides to defend its market position in light of increased upstream competition.

5.2.1. Representing LTCs in the gas market model

As noted, gas trade in Europe (and in other regions) is still dominated by bilateral LTCs (see Table A.7, Appendix 3 for the assumed annual contract quantity of the LTCs modelled in this analysis), with prices predominantly based on the oil price escalation (indexation) mechanism (see IGU, 2015). Long-term gas purchase contracts are complex documents with a number of clauses that can be extremely challenging to represent in the model. Taking this into account, we only model LTCs by specifying three important features of these contracts: (i) annual contract quantity (ACQ) agreed between the buyer and seller, (ii) minimum annual take-or-pay level and (iii) pricing mechanism. Thus, if π_i^S is the profit of the seller from selling gas to

[27] We also perform sensitivity analyses and assume that low-cost producers can export up to 300 bcm/year by 2035. In another round of sensitivity analyses we assume unlimited export potential. These sensitivity analyses are designed to stress test our results and should not be viewed as an attempt to forecast the production and export potential of the Middle East, US and other potential market entrants.

the buyer, b, under contract i and if π_i^B is the profit of the buyer, b, from reselling the gas imported under contract i, then in the simplest form and abstracting away from many features of the real contracts, we have the following profit functions:

$$\pi_i^S = q_i(P_i^C - \mathrm{C}) \quad (6)$$
$$\pi_i^B = q_i(p^* - P_i^C) \quad (7)$$
$$\text{s.t.}$$
$$q_i \le ACQ \quad (8)$$
$$q_i \ge M_i ACQ, \quad (9)$$

where q_i is the actual annual offtake volume, which cannot exceed the agreed ACQ (Eq. 8) but cannot be less than the agreed minimum take-or-pay level (coefficient M_i, representing an annual percentage of the ACQ, Eq. 9), P_i^C is the contract price, C is an exogenous parameter representing total supply cost and $p^*(q_i, q_{-i})$ is the clearing price in a particular traded market, which depends on supply and demand conditions, infrastructure capacity availability and possible endogenous mark-ups by traders due to pricing power. LTCs are one way for producers and importers to have quasi-vertical integration without embracing formal integration due to various legal and other considerations (such as competition law preventing such an explicit integration). Thus, in the old model of governance of the gas industry in Europe, producers and importers entered into these bilateral contracts and used the contract price, P_i^C, as a mechanism to divide the entire rent 'from wellhead to burner tip' available to them from producing, transporting and selling gas to final customers in Europe (see Smeers, 2008 for a detailed discussion of these issues). Formally, by combining Eq. 6 and 7 we have the combined profit, π_i^I, available for a producer and importer from entering into contract i:

$$\pi_i^I = q_i(p^* - \mathrm{C}) \quad (10)$$
$$\text{s.t.}$$
$$q_i \le ACQ \quad (11)$$
$$q_i \ge M_i ACQ \quad (12)$$

Note that since $p^*(q_i, q_{-i})$ is a function of the total supplies into that market, large suppliers realising the effects of supplies on market prices may supply to that market less (but within the bounds of the specified offtake volumes, Eq. 11 and 12), thereby raising prices above marginal costs. Pricing power is explicitly modelled in our global gas market model (see Appendixes 2 and 3 for more details).

When the contract price, P_i^C, substantially deviates from the market price, p^*, the pricing and other terms (such as the minimum take-or-pay level) can be re-negotiated between the seller and the buyer. The deviation in the two prices may happen as a result of supply and demand shocks in the oil and gas markets; in the last five years, the European gas industry has seen numerous examples of such contract renegotiations.

One factor that could lead to substantial deviation between contract prices and market prices is increase in oil prices (especially in 2010–2014 period). As noted earlier, one pricing mechanism that has been the dominant form of gas pricing in Europe is oil price indexation. Therefore, P_i^C is usually a function of crude oil prices and/or its derivatives (gasoil and fuel oil). Each LTC has its own unique pricing formula, and for our analyses it would be ideal to have information about the pricing of each contract that Gazprom has with European buyers. However, this information is confidential. Therefore, we use the average oil-indexed contract price, which is approximated using the following formula, as suggested by Stern and Rogers (2014):

$$P^{Oil-indexed} = 0.666667 + 0.007619P^{GasOil} + 0.008571P^{FuelOil}, \tag{13}$$

where $P^{Oil-indexed}$ is the average oil-indexed gas price, P^{GasOil} is the average of the previous nine months' gas oil prices (in \$/tonne) and $P^{FuelOil}$ is the average of the previous nine months' fuel oil prices (in \$/tonne). Furthermore, linear relationships exist between gas oil and fuel oil prices and crude oil price (Brent). The estimated relationship is as follows[28]:

$$P^{GasOil} = 8.5333P^{Brent} + 5.3868 \tag{14}$$
$$P^{FuelOil} = 5.9347P^{Brent} - 24.857, \tag{15}$$

where P^{Brent} is the Brent oil price in \$/bbl and this price is based on our oil price scenarios (Figure 8).

Thus, if $P_i^C \gg p^*$, then we assume that P_i^C will be brought in line with p^* by directly reflecting p^* in the contract price as follows:

$$P_i^C = \alpha p^* + (1-\alpha)P^{Oil-indexed}, \tag{16}$$

where $\alpha = [0; 1]$ is the weight or share of market prices directly influencing the contract price. Furthermore, the practice of gas contract renegotiation in Europe in the last five years shows that apart from introducing market prices directly into the contract price formula, buyers and sellers also agreed to adjust the level of contract prices to eliminate any price differentials between contract and market prices as well as to reduce the minimum take-or-pay level, M_i. For our analyses, in the subsequent sections we consider only two possible means of contract renegotiation: (i) introducing a higher level of market prices, i.e. increasing α and/or (ii) reducing the minimum offtake level, M_i. Note that when $\alpha = 1$, contract prices are 100% determined by market prices, and hence, any differences in the levels of the two prices automatically adjust such that contract prices equal and perfectly correlate

[28] Linear regressions were run between gasoil/fuel oil and Brent crude oil monthly prices to determine these equations (14) and (15). All data were taken from the Bloomberg Terminal.

with market prices. This is the case for full spot-gas-price indexation, where oil prices no longer determine gas contract prices.

As for our reference scenario, we assume that the average contract price Gazprom charges European importers under existing LTCs has a 10% share of market prices (i.e. $\alpha = 10\%$[29]), while the average for the minimum take-or-pay level for all its contracts is assumed to be 75% (i.e. $M_i = 75\%$); for example, Mitrova et al. (2015) assume a similar minimum offtake level for Russian gas contracts with European buyers.

5.2.2. Sensitivity analyses

Several important factors may impact the future of European gas markets in general and Russian supplies to these markets in particular: (i) oil price dynamics, (ii) long-run PED and (iii) LTC features – minimum take-or-pay levels and pricing mechanisms (oil–spot indexations or a mix of the two). We maintain the view that oil prices will remains fairly low but recover slowly, as suggested by recent market expectations (Figure 8: Based on the August 2015 forward oil curve through to 2022).

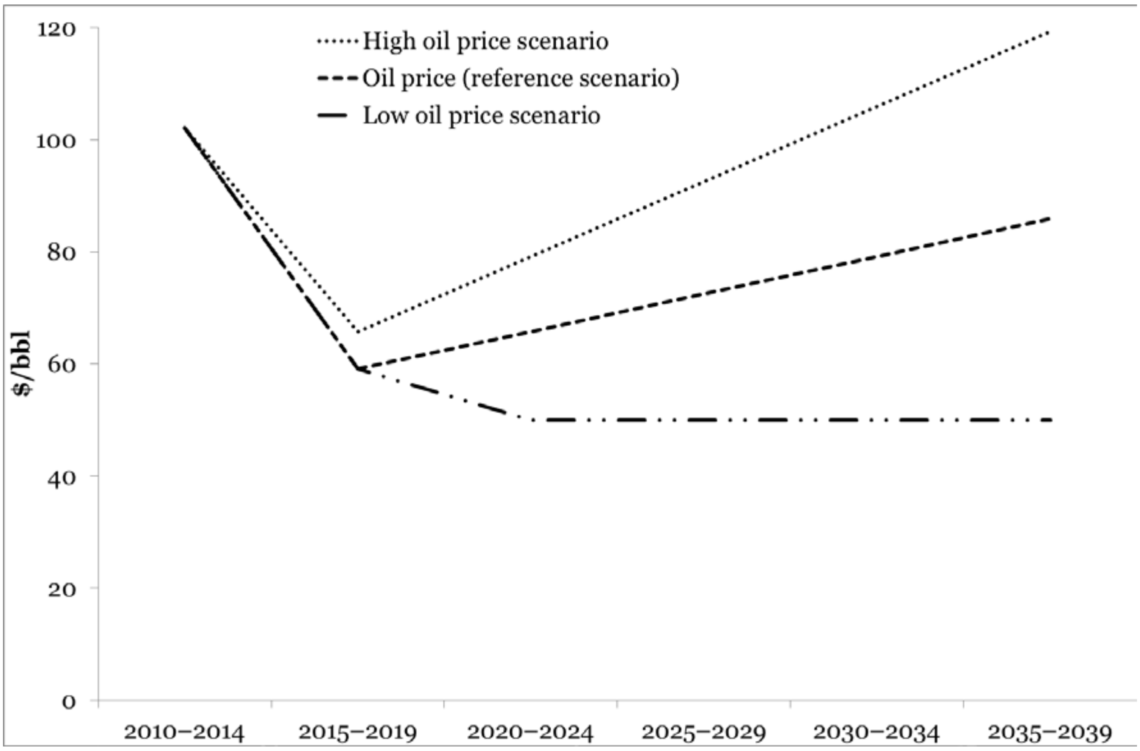

Figure 8: Oil price assumptions in the model.

[29] Gazprom estimates that in 2014 at least 6.4% of its exports to Europe were linked to market prices, while the rest of the export volume was determined by oil- and quasi-oil-indexed prices; see Komlev, S., 2015; other sources, such as Credit Suisse, estimate that at least 12% of exports from Russia are indexed to market prices.

Note: The low-oil-price scenario up to 2022 is based on the forward curve as of mid August 2015, as reported in the Bloomberg Terminal; the data beyond 2022 is our extrapolation based on this forward curve. For details of the linear equation describing the forward curve, see Appendix 3.

However, the results of the modelling exercise depend on the input parameters and assumptions we make; therefore, to test the robustness of our results and conclusions we also perform a systematic sensitivity analysis with different parameters of the factors mentioned. In particular, we test Scenarios A–D against a set of different assumptions about (i) future oil price dynamics (see Figure 8), (ii) long-run PED and (iii) the minimum take-or-pay level of Gazprom's existing LTCs with European buyers (for details of these contracts, see Appendix 3). For the high-oil-price scenario, we double the slope of the forward curve, meaning that the oil price will recover twice as fast as the price in the reference case (and real market expectation as of August 2015) (see Appendix 3 for details), reaching the 2010–2014 average price level by 2030. In the low-oil-price scenario we assume an oil price world of $50/bbl from 2020 onwards.

In the next section we report the main findings of this quantitative analysis.

Table 5: Elasticities and take-or-pay levels for sensitivity analyses.

PED	**Minimum take-or-pay (ToP) level (M_i)**[30]
1. Very inelastic: -0.1	1. Minimal take-or-pay level: ToP=10%
2. Reference scenario: -0.223	2. High degree of flexibility: ToP=25%
3. Moderately inelastic: -0.75	3. Some degree of flexibility: ToP=50%
4. Unit elasticity: -1	4. Reference scenario: ToP=75%

5.3. Results

5.3.1. Why Gazprom should adopt an ISTM strategy

Gazprom should not pursue a border sales strategy because this strategy generally leads to inferior results in terms of profitability: compared to ISTM, the border sales strategy results in substantially lower profits. For example, in the reference case, if Gazprom adopts a border sales strategy, its export volumes will increase, placing downward pressure on spot prices. In this case, Gazprom's potential loss of profits under the border sales strategy compared to ISTM would be roughly $2.4 bn/year over 25 years.[31] The potential loss arising from the border sales strategy compared to ISTM model could be as low as $1.7 bn/year and as high as $15.6 bn/year (NPV), depending on various factors that we discuss in detail below. In other words, for every thousand cubic metres of export sales, the ISTM strategy could bring

[30] For the sake of brevity, we undertake the scenario analysis for the take-or-pay parameter assuming our reference scenario.

[31] This calculation takes into account the contract price with a 90/10 split between oil and spot indexation for all existing contract sales and additional sales under the border sales strategy at a competitive price (marginal cost of supply).

additional profit of $11–99, assuming an average of 158 bcm/year in sales to Europe (as in 2010–2014). Thus, the benefit of the ISTM model is that in this situation the optimal export strategy takes into account not only prices and marginal supply costs but also the price-quantity responsiveness (i.e. PED) of the markets. Ignoring the information about PED translates Gazprom's border sales strategy into price-taking behaviour, thereby supplying European markets until prices equate to marginal supply costs. Since Gazprom's production costs are some of the lowest in Europe, this price-taking behaviour results in lower (spot) prices, thus undermining Gazprom's contract prices as well as spot sales. By contrast, one strategic benefit of ISTM is that it allows Gazprom to supply European markets with the 'correct' amount of gas, which depends on PED. Thus, the benefit of the ISTM sales strategy is that it does not flood the markets with relatively cheap gas, which would undermine Gazprom's profitability. This is the basic economic value of ISTM compared to the border sales strategy. Importantly, however, ISTM also has strategic and options values for Gazprom, which we will discuss below.

5.3.1.1. Resilience to contract price renegotiation

If Gazprom opted for a border sales strategy, it would endanger its own contract position because the difference between the average oil-indexed contract price (assuming a 90/10 split between oil and spot indexation) and settled market prices in Europe is quite large in all three oil price scenarios; only in a world of $50/bbl oil price would the oil-linked contract price be cheaper than spot prices, albeit the contract price would still be marginally higher than spot prices until 2030 (see Figure 9). In this situation, the border sales strategy would 'cannibalise' Gazprom's export profits. Furthermore, given its history of contract renegotiations with European buyers during 2010–2014, Gazprom would be forced to renegotiate contracts once again, with the potential outcome of adjusting base contract prices and moving towards full market price indexation in its contracts in order to eliminate price differentials. Apart from the scenario of low oil prices (i.e. $50/bbl over 2015–2035), the situation with price differentials in favour of market prices is, in general, insensitive to either border sales (see Figure 9) or ISTM (see Figure 14). Nevertheless, the fact remains that there is an increasingly high risk of contract price renegotiation as we move forward into an oversupply market environment.

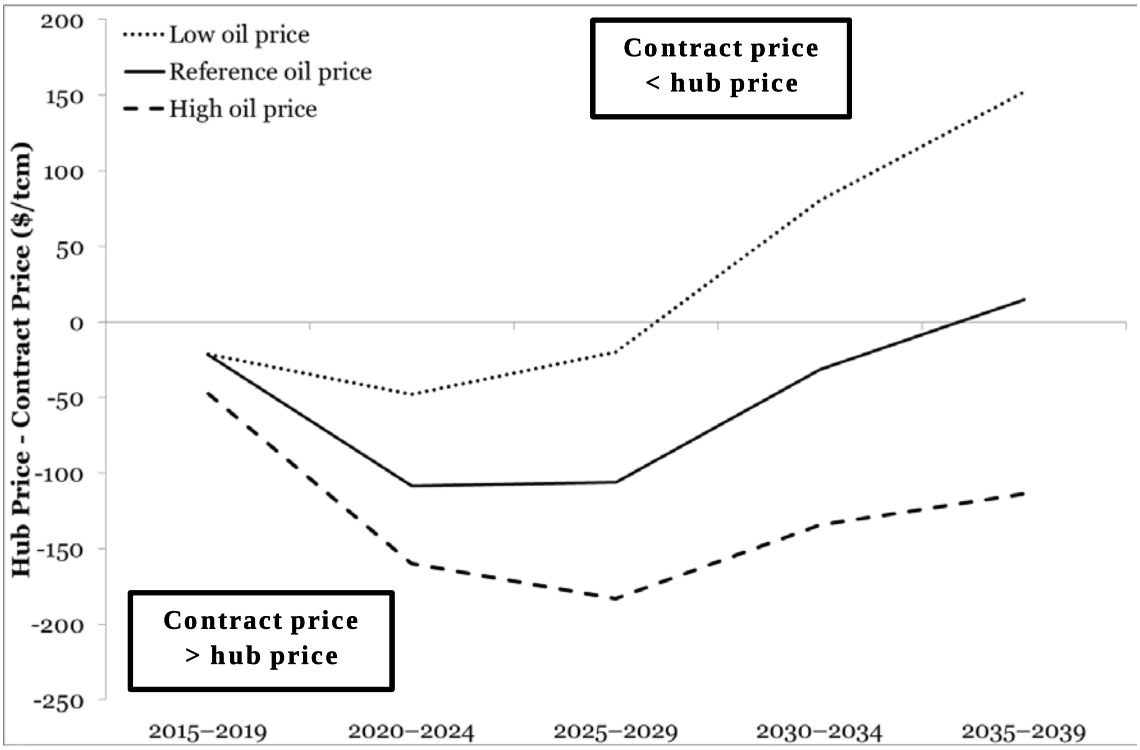

Figure 9: Differences between average oil-indexed contract and hub prices under the border sales strategy (reference scenario).

Thus, if the risk of re-contracting is high and increasing spot indexation in Gazprom's contracts is inevitable (as discussed in the next section), our results (Figure 10) suggest that Gazprom should adopt the ISTM sales strategy.

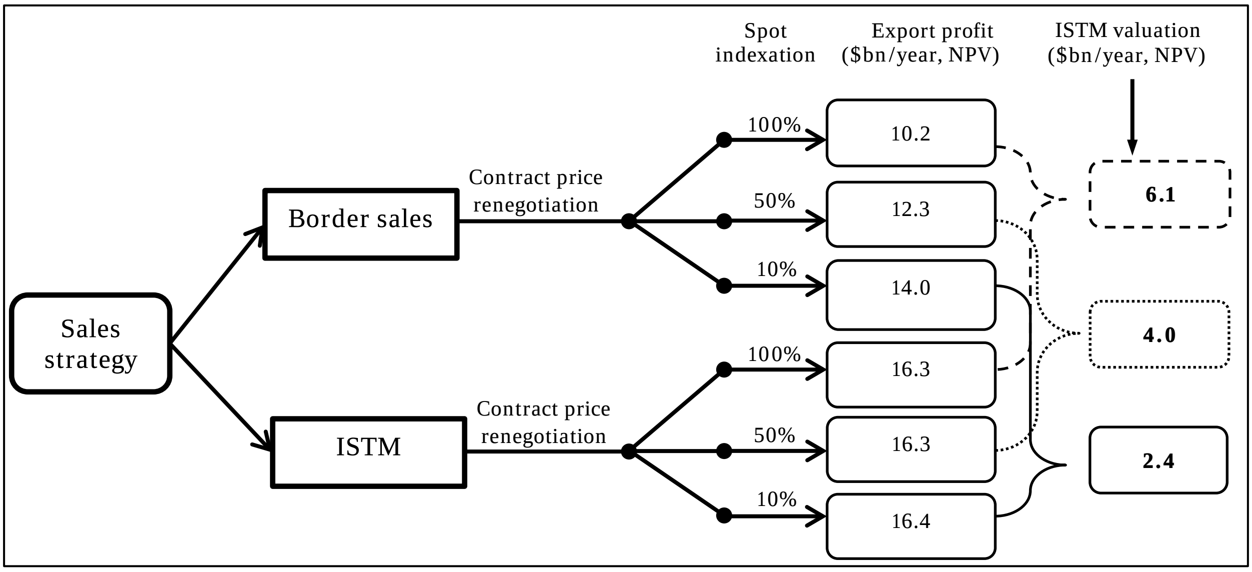

Figure 10: The value of the ISTM vs border sales strategy under risk of re-contracting: Price renegotiation (reference scenario).

In this situation, the ISTM sales strategy could generate additional profit of at least \$2.4 bn/year (NPV) under status quo pricing (90/10 oil–spot split), and this value rises as the share of spot indexation in Gazprom's contracts increases, reaching \$6.1 bn/year in additional profit under full market price (hub) indexation.

Furthermore, when contract prices are higher than spot prices, buyers could demand that Gazprom reduces the minimum take-or-pay level (M_i). Indeed, it is understood that Algerian Sonatrach agreed to reduce the minimum offtake level substantially in exchange for preserving oil indexation in its contracts with Italian importers. Thus, should Gazprom make concessions to its buyers and reduce the minimum take-or-pay level in exchange for a status quo pricing structure (90/10 oil–spot indexation), this would lead to a substantial reduction in its export profits if the company pursued the border sales strategy: at a 50% minimum take-or-pay level, its profit would be reduced by around $2.2 bn/year, while profits would shrinks to $9.4 bn/year (from $14.0 bn/year) under extreme conditions of minimum take-or-pay, i.e. 10% of ACQs. By contrast, under the ISTM sale strategy Gazprom's export profit would be substantially higher under all examined take-or-pay levels (see Figure 11).

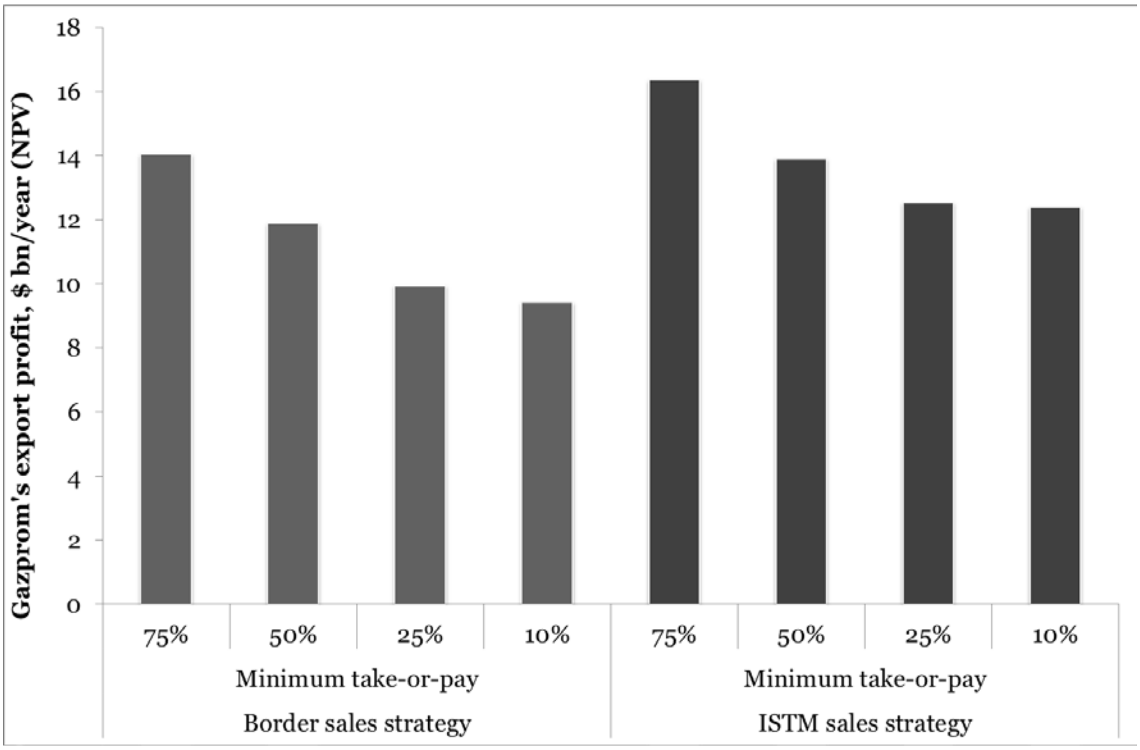

Figure 11: The value of the ISTM vs border sales strategy under the risk of re-contracting: Minimum take-or-pay renegotiation (reference scenario).

Thus, the value of ISTM as a hedge against possible contract renegotiations is fairly high for Gazprom. At the same time, the cost of implementing the ISTM strategy would be fairly negligible since Gazprom, as noted before, already has a presence in wholesale trading in Europe (e.g. through its trading arm, Gazprom Marketing and Trading, in London).

5.3.1.2. Resilience to the entry of low-cost gas producers

As noted, the global gas markets are likely to be oversupplied in the next five to ten years, with increasing competition between 'upstreamers'. This will inevitably put more pressure on the oil price indexation in existing LTCs. This situation could be exacerbated by the potential entry of low-cost producers into the global gas trade; as these producers would flood the markets with cheap gas, the average oil-indexed contract price, a proxy for Gazprom's average contract price, could be even more expensive than spot prices. Thus, low-cost producers' entry into global trade would further incentivise European buyers to renegotiate their contracts with Gazprom, demanding adjustments to base-price levels and also pushing for more spot indexation (see price differentials in Figure 12). This would negatively affect Gazprom's potential profits even further, should the company choose a border sales strategy. For example, if low-cost producers enter the markets, the losses to Gazprom under the border sales strategy could be as much as $1.5 bn/year if all contracts are fully adjusted and indexed to spot prices.

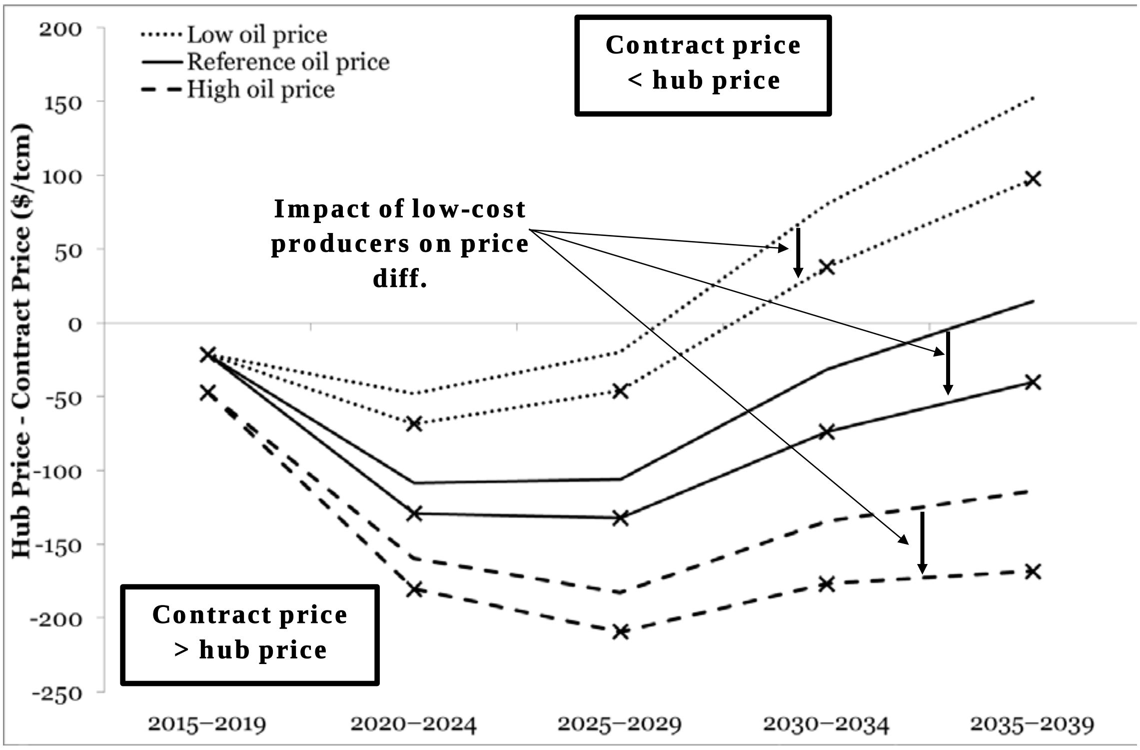

Figure 12: Differences between average oil-indexed contract and hub prices under the border sales strategy: Impact of low-cost producers (reference scenario).

By contrast, the ISTM sales strategy would ensure that if Gazprom's contracts were fully adjusted and indexed to spot (market) prices when low-cost producers entered the markets, then Gazprom would receive substantially higher profits: when contracts are 100% spot indexed, ISTM results in $5.6 bn/year more in profit than under the border sales strategy (Figure 13). Not surprisingly, the net benefit of ISTM is lower if the share of spot indexation is low (10%) – $1.9 bn/year – because higher prices under ISTM are not 'passed along' fully through Gazprom's contract prices. Note that market entry by low-cost producers could generally have a negative impact on the value of ISTM: the net benefit would be $5.6 bn/year, compared to $6.1 bn/year when low-cost producers do not enter the markets (Figure 10). This is primarily due to the lower spot prices towards the end of the 2030s, when gas production and exports from low-cost producers should be fully ramped up.

Nevertheless, the ISTM strategy would in any case generate substantially higher profits for Gazprom than the border sales strategy in all market scenarios: oil price dynamics, possible configurations of contract pricing and minimum offtake structures (oil–spot indexation and minimum take-or-pay levels) or the potential entry of low-cost producers.

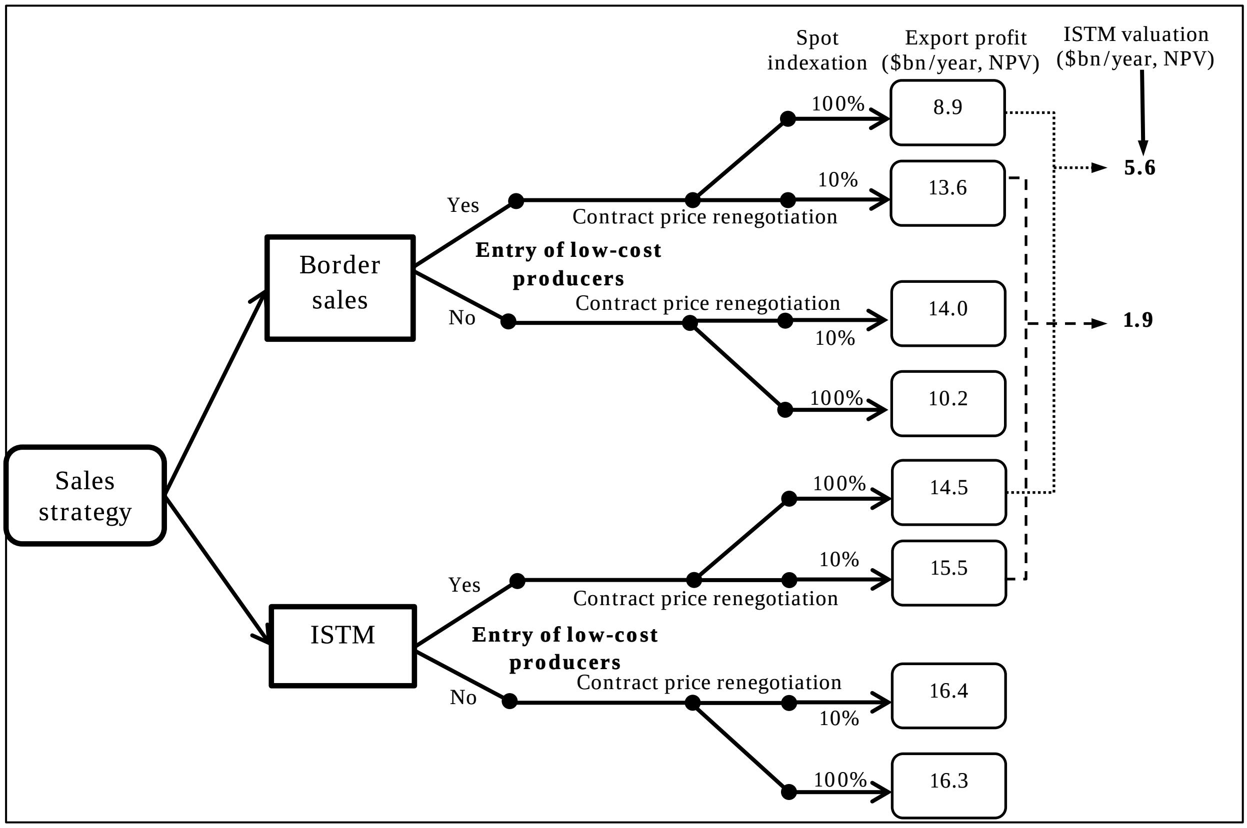

Figure 13: The economic value of the ISTM vs border sales strategy under the risk of re-contracting and the entrance of low-cost competitors (reference scenario).

In fact, the ISTM strategy would not only generate higher profits for Gazprom but also reduce the risk of re-contracting (such as price and volume renegotiation): the differential between the average oil-indexed contract price and spot prices in north-west Europe would be substantially lower (Figure 14). Under the ISTM strategy, contract prices would be even lower than spot prices when oil prices stay at $50/bbl, which is not entirely unrealistic.

However, when oil prices are that low ($50/bbl) Gazprom may face strong economic incentives to switch all of its contracts to full spot indexation as this would ensure higher profits than sticking with the 90/10 split between oil indexation (with a low oil price of $50/bbl) and spot indexation. By contrast, if oil prices were high, Gazprom would have an incentive to minimise the exposure to spot indexation; however, this may not be a credible strategy given its (negative) experience with price renegotiation with European buyers over 2010–2014, when hub prices were substantially lower than Gazprom's contract prices (Figure 14: solid and dashed curve). If oil prices rose to fairly high levels (e.g. as in the high-oil-price scenario), it would be even more difficult (compared to 2010–2014) for Gazprom to oppose contract price adjustments and move towards full market price indexation, given the increasing competition from low-cost producers (committed US LNG export projects as well as LNG from Iran, Kurdistan, Qatar, Australia and East Africa).

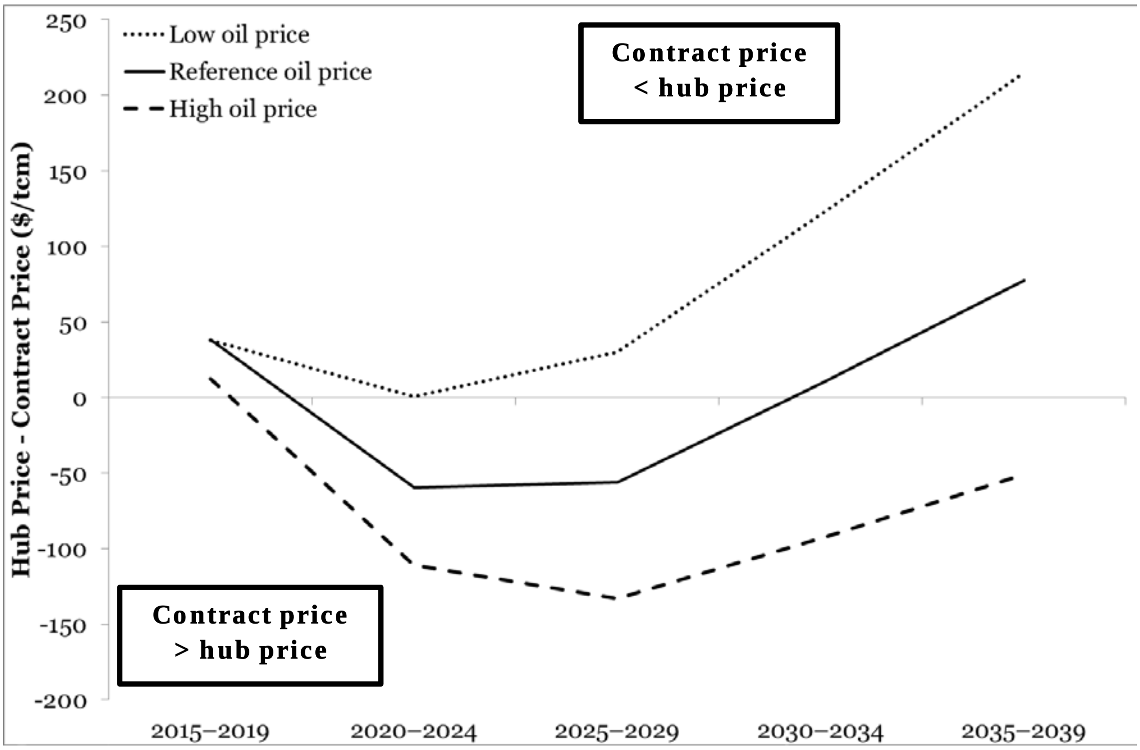

Figure 14: Differences between average oil-indexed contract and hub prices under the ISTM strategy (reference scenario).

This result suggests that under the ISTM sales strategy, Gazprom has strong economic incentives to switch to full spot indexation, either because of the higher profits this strategy would allow (Figure 15: low-oil-price scenario) or the need to accommodate buyers' requests to adjust contract prices and introduce a higher share of spot indexation, as buyers may find spot prices cheaper than oil-indexed contract prices when oil prices are high (Figure 15: reference and high-oil-price scenarios).

To summarise, the border sales strategy is always inferior to the ISTM strategy in that it gives Gazprom substantially lower export profit. Furthermore, when ISTM is considered, it appears that a move towards a higher share of spot indexation would be a profit-maximising strategy in all of the oil price scenarios considered. Thus, in the rest of this paper we consider that increasing spot indexation in Gazprom's contracts is economically more justifiable as this results in higher profits. Therefore, in the following sections we discuss the impact of ISTM on Gazprom profits assuming full spot indexation.[32]

[32] Results under the assumption of 15% (and 50%) shares of spot indexation in Gazprom's contracts are available from the author upon request.

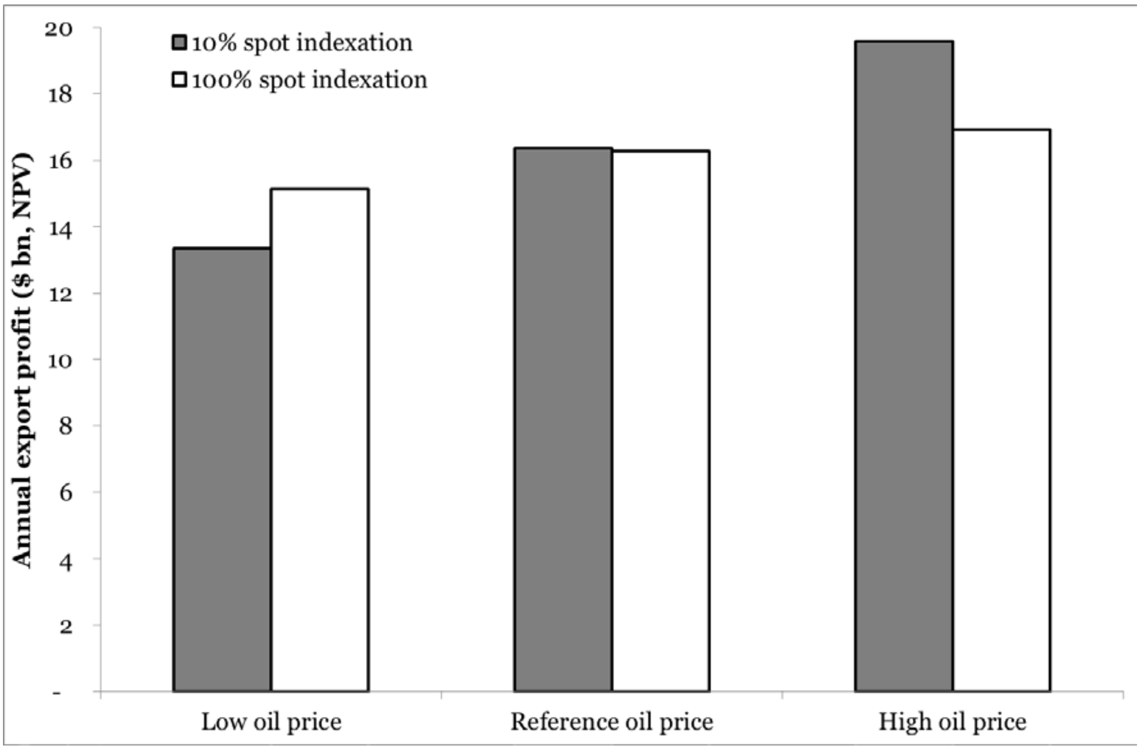

Figure 15: Gazprom's annual export profit under the ISTM model and different oil price scenarios and shares of spot indexation (reference scenario).

5.3.1.3. Capturing higher value when (downstream) markets are competitive

Apart from hedging against the downside of possible changes in pricing structures as well as higher upstream competition (entry of low-cost producers), ISTM can also better capture the upside from increased competition in downstream markets, either because of increased inter-fuel competition (cheap coal and subsidised renewables) or increased gas-to-gas competition. Increased downstream competition translates into higher market price responsiveness (i.e. PED). In a highly competitive market, a 1% increase in price leads to a greater than 1% reduction in the quantity demanded at that price (i.e. |PED|>1). This is possible if buyers can easily switch and have access to alternative fuels (coal or renewables in electricity generation) and/or to global LNG and liquid spot markets for sourcing cheaper gas options. In fact, in this situation, the net benefit of ISTM for Gazprom increases as downstream competition rises (Figure 16): in a less competitive market situation (|PED|=0.1), the ISTM strategy generates $6.3–7.8 bn/year in additional profit compared to the border sales strategy, depending on oil price dynamics. As markets become more competitive, the ISTM strategy could generate $1.7–3.0 bn/year more profit than under the border sales strategy (Figure 16: grey bars).

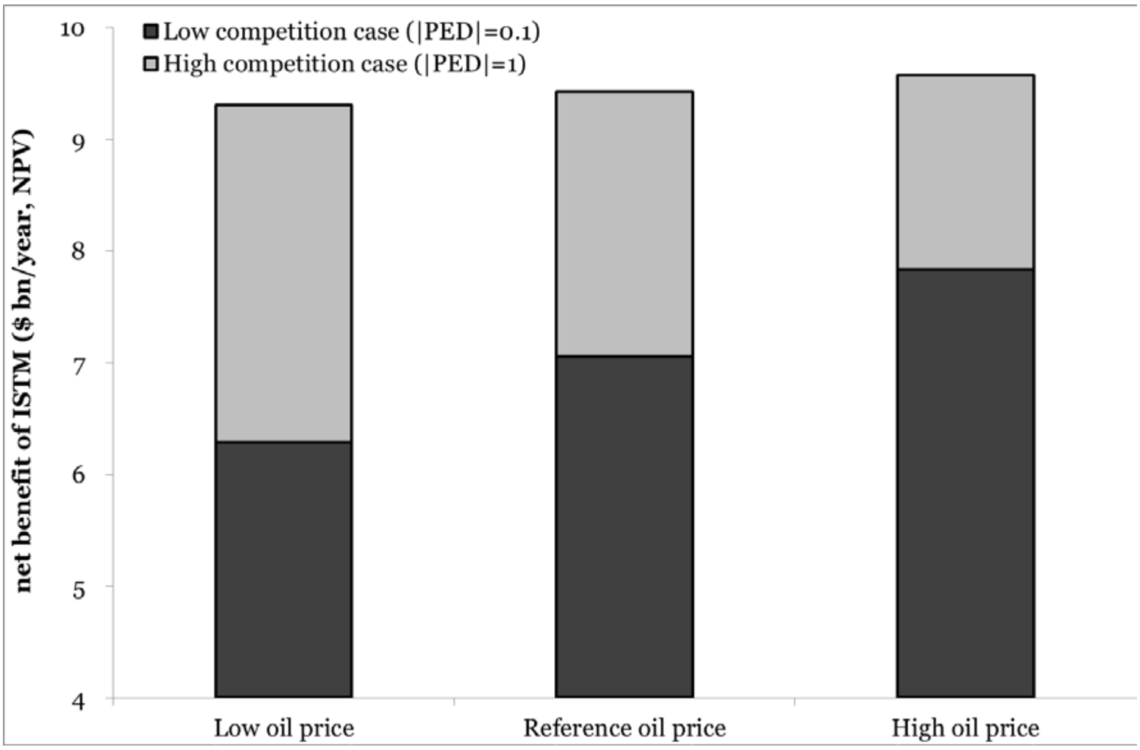

Figure 16: Net benefit of ISTM relative to the border sales strategy under increased downstream market competition and full spot indexation (reference scenario).

The driver behind this additional profit growth is that sales under the ISTM strategy take into account important information about market conditions – PED, or the state of downstream market competition. Therefore, Gazprom exports the 'correct' amount of gas at the best price it can achieve given all other market and industry conditions, such as competitors' responses, cost structures and physical capacities.

5.3.1.4. Option value of the ISTM strategy

We can summarise the costs and benefits of the two sales strategies as follows:

1. The border sales strategy is beneficial when the objective is to maximise sales quantity and not profit from those sales. Although this may carry some market reputational value for Gazprom (such as becoming a market leader), it has many downsides, including: (i) that increased sales quantity could lead to higher investment costs for developing increasingly challenging and remote gas fields, which could overheat Russia's economy as well as the opportunity cost of regulated domestic prices; and (ii) the opportunity costs of missing potentially higher profits from alternative, albeit more sophisticated, sales strategies such as ISTM.
2. The ISTM strategy focuses on maximising the value of Gazprom's gas reserves, which does not necessarily coincide with maximising sales quantity. Indeed, the profit-maximising sales strategy appears to be that which limits gas sales to raise prices sufficiently high given all market conditions, such as pricing structure (oil–spot indexation), oil price dynamics and the state of upstream and downstream market competition. In each of these scenarios (and we have run

multiple scenarios totalling 216 simulations with our global gas market model to check the robustness of our claims and results), ISTM is the superior sales strategy. As such, ISTM is both a hedge and a profit-maximising strategy.

Figure 17 summarises these benefits of ISTM quantitatively compared to those of the border sales strategy under the reference oil price scenario. Assuming 90/10 oil–spot indexation and a 75% minimum take-or-pay level, the border sales strategy would generate $14.0 bn/year (NPV) in total export profit, while ISTM would generate $16.4 bn/year, $2.3 bn more than the export profit under border sales. As noted, the basic value of ISTM under the current pricing structure (10% indexation) comes from the fact that under ISTM, Gazprom’s optimal export strategy would take into account not only prices and marginal supply costs but also PED.

In addition to its basic economic value, ISTM has option value in that it could potentially shield Gazprom from the negative impact of market dynamics. We have shown that it would be increasingly difficult for Gazprom to defend the current LTC structure (pricing and minimum take-or-pay levels) regime because in most cases, Gazprom’s oil-indexed prices are expected to be higher than spot prices (Figure 9 and Figure 14). In this situation, Gazprom’s export profits under the border sales strategy would decrease substantially: under 50% spot indexation, the total profit would fall from $14.0 bn/year to $12.3 bn/year (NPV), and this would fall further to $10.2 bn/year in the case of full spot indexation. If low-cost producers entered the international gas trade, thus depressing spot prices further (Figure 12), then Gazprom’s export profit could fall as low as $8.5 bn/year under full hub indexation. Thus, the option value of the ISTM strategy is the difference between what Gazprom could achieve by pursuing the border sales strategy under the current contractual regime – $14.0 bn/year – and what it might actually receive should pricing and market structure changes go against their favour (higher spot indexation in its oil-indexed contracts and the entry of low-cost producers) (Figure 17).

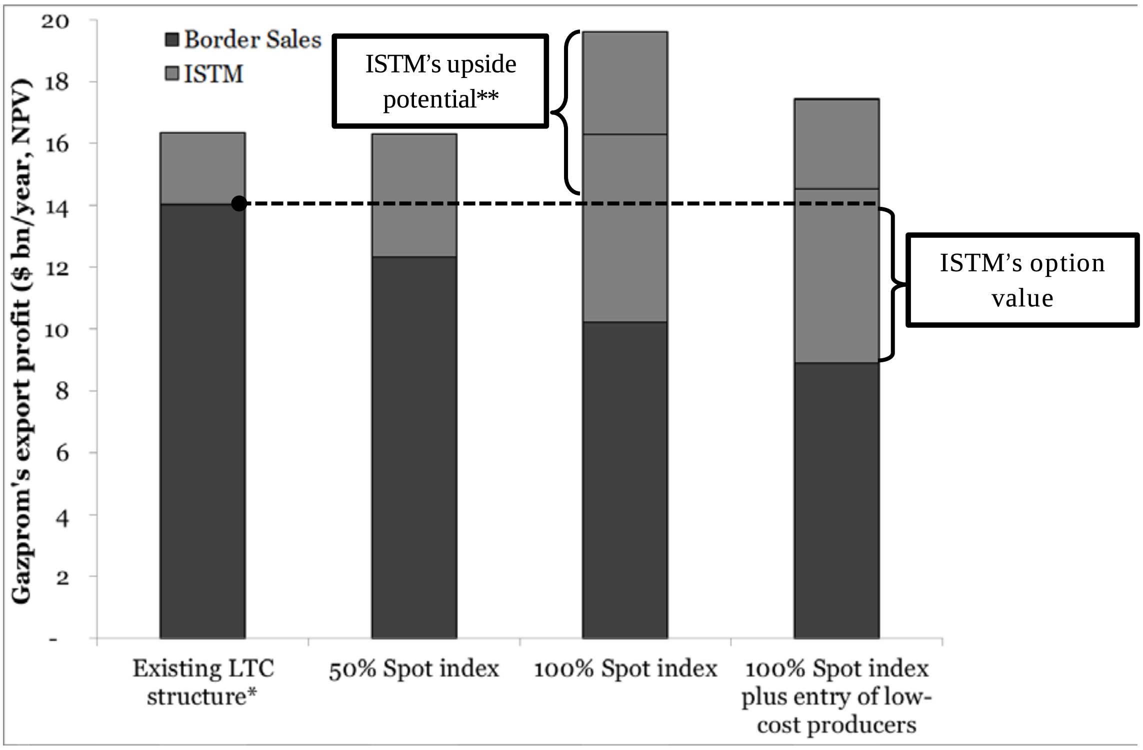

Figure 17: Gazprom's export profit under the border sales and ISTM strategies and different market scenarios (reference scenario).
Note:* we assume a 75% minimum take-or-pay level and 90/10 oil–spot indexation for existing LTC structures; ** For example, if downstream markets become more competitive, as represented by the value of the price elasticity of demand, ISTM captures more value than border sales strategy would allow.

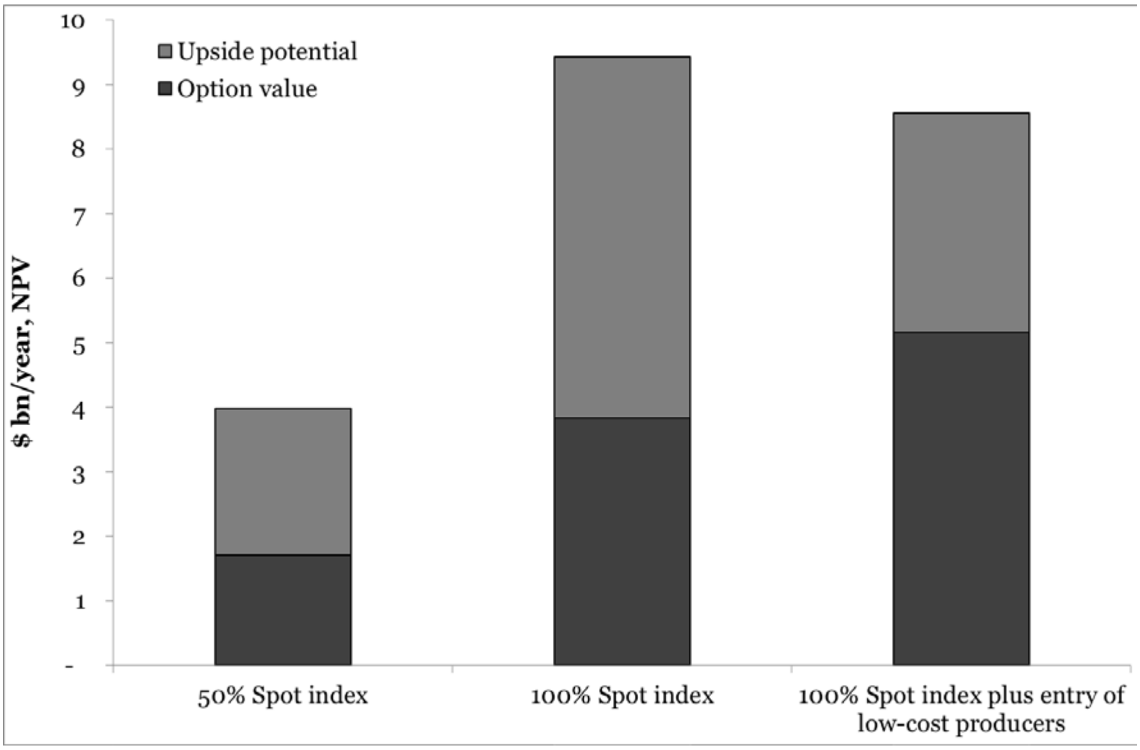

Figure 18: ISTM's option value and upside potential (reference scenario).

Thus, the option value of the ISTM strategy increases as pressure from buyers to increase the spot indexation in existing contracts builds up. Should the buyers and Gazprom agree to 50% (100%) spot indexation, the option value of ISTM would reach $1.7 ($3.8) bn/year (NPV) (see Figure 18). In the case of low-cost producers entering the markets, the option value of ISTM would be the highest: $5.1 bn/year (NPV), which reflects the downside of the border sales strategy when low-cost producers enter the markets.

ISTM can also capture the upside potential, increasing Gazprom's annual export profit substantially and above what Gazprom could achieve by pursuing the border sales strategy. Under 50% (100%) spot indexation, if Gazprom adopted ISTM, the upside potential could give Gazprom additional profits of $2.3 ($5.6) bn/year (NPV) (Figure 18: grey bars). This upside potential includes ISTM's ability to price Gazprom's produced gas actively in traded markets (similar to Statoil's sales and production strategy from its swing capacity, the Troll and Oseberg fields), and this upside potential increases further if downstream markets become more competitive.

The results of our quantitative analysis were based on running the global gas market model for various market scenarios (216 in total). These market scenarios represent a combination of possible oil price dynamics, the state of downstream market competition, possible structures of existing LTCs and scales of entry for low-cost gas producers. The intention behind analysing these market scenarios is to 'stress test' the two sales strategies and understand their abilities and limitations in maximising the value of gas exports for Gazprom. In no way should these scenarios be viewed as market dynamics forecasts. Instead, these scenarios, or combinations thereof, should be viewed as 'grey swan'-type of events, which while having a fairly low (but positive) probability until a chain of unforeseen events triggers their realisation could still dramatically affect Gazprom's bottom line. The ISTM strategy gives Gazprom the flexibility and optionality to shield against these negative market scenarios by being able to 'chop off' the negative part of the 'fat-tail' distribution of Gazprom's profitability under a range of future market developments. Figure 19 explains this argument more conceptually assuming that instead of 216 scenarios the two sales strategies were tested against thousands of different scenarios. Thus, by limiting the impact of negative market developments on the range of possible profitability, the ISTM strategy either 'alters' market expectations of Gazprom's profitability further to the right, away from negative events, or increases Gazprom's expected profitability.

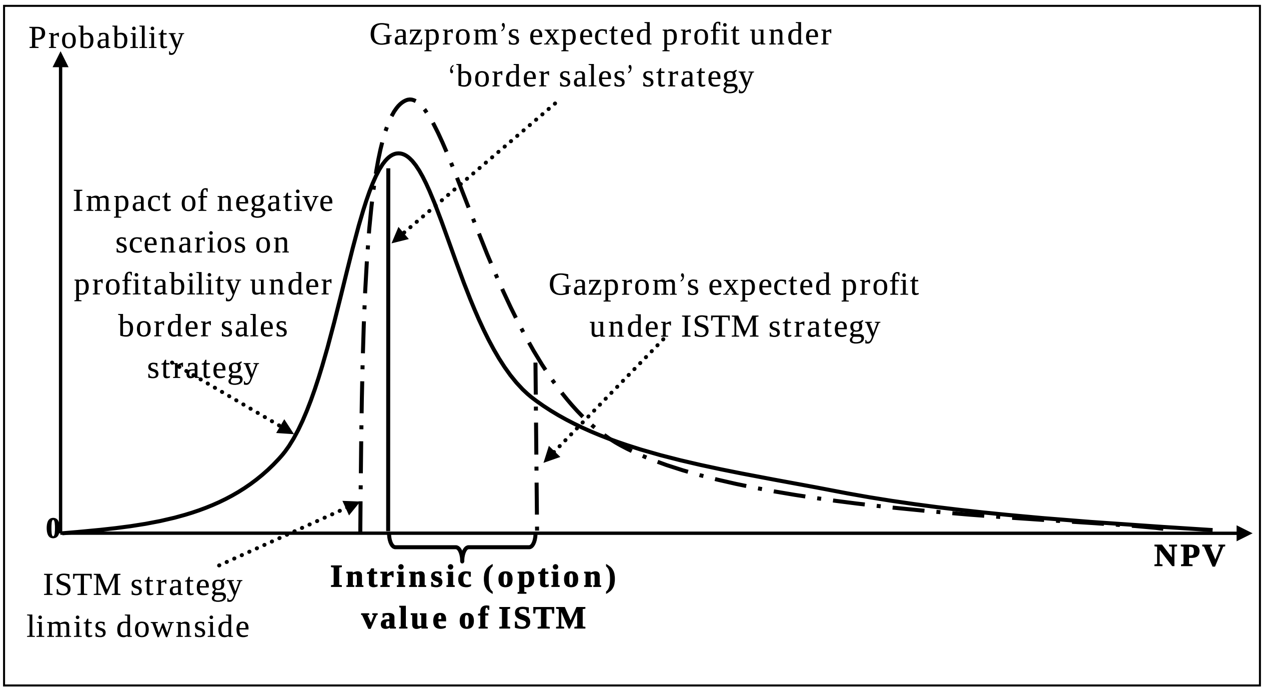

Figure 19: Flexibility and optionality provided by the ISTM sales strategy

6. Discussion

We have looked at the strategic benefits of an ISTM sales strategy and the optionality that it would give Gazprom in an increasingly liberalised and complex gas market. In addition to its strategic value, ISTM may also bring other benefits, such as capturing additional margins by going further downstream, introducing structured and tailored products to suit the needs of market participants and, hence, the ability to price discriminate depending on customers' preferences towards volume and price certainty or flexibility (see Section 4). All things considered, the ISTM strategy would be better for Gazprom in terms of generating higher export profits than the border sales strategy while allowing Gazprom to react to changing market dynamics more optimally. In this section we argue that a gradual switch to spot indexation and channelling growing export volumes[33] through a single marketing and trading division (like Statoil's MMP) would not only be a profit-maximising strategy for Gazprom (and other large exporters to Europe) but would also fit with the recently established market structure and regulations in Europe. We also argue that a combination of the ISTM strategy, spot indexation and trading liquidity could be a substitute for the traditional long-term bilateral oil-indexed contracts that existed before recent renegotiations.

A. The role of contracts and markets along the European gas value chain

[33] Either because of additional demand in Europe for Russian gas or because of a reduction in minimum take-or-pay levels for its existing contracts.

As discussed in Section 3, the rationale for long-term bilateral contracts, among other things, is to deal with the possibility of opportunistic behaviour, to minimise transaction costs and to secure financing for investment.

As noted, opportunism may arise when relationship-specific investments must be realised before trade can occur, and in such situations, both parties may exercise their bargaining power to expropriate quasi-rents arising from sunk investments. However, since the late 1990s, the European gas industry has undergone substantial changes, among which are the introductions of gas transport regulations and open access to infrastructure capacity. This has meant that the level of transaction-specific investment in bilateral contracts has been reduced, and hence, the rationale for large and relationship-specific contracts between upstream and downstream players to cover both commodity and national transmission pipeline and storage capacity has been diminished or removed entirely (we come back to the question of international pipelines later). Put differently, the introduction of regulations for transport infrastructure and third-party access has meant that sellers can supply gas to any potential customer taking into account the cost of transport and the degree of upstream competition. Even if a producer is connected to potential buyers through only one pipeline, that pipeline tariff is now regulated, and hence, the tariff policy cannot be used to expropriate a producer's quasi-rents. The empirical evidence in Section 3.3 points to the fact that after the introduction of regulatory model for gas transport infrastructure in Europe, the average duration[34] of LTCs has been significantly reduced, reflecting the lower levels of asset specificity associated with the introduction of gas infrastructure regulations in Europe.

Furthermore, as a result of the structural changes in regulations and market organisation, there are now two types of organised trading markets in Europe: one for gas commodity (such as NBP and TTF) and another for gas capacity (such as the gas capacity trading platform PRISMA, which began in late 2015) (Figure 20). As the spot and futures trading of gas commodity and capacity increases, bilateral LTCs are becoming redundant as a means of minimising transaction costs because prices are established transparently through multiple trades in these organised markets. Therefore, spot markets are expected to replace bilateral LTCs as a device for minimising the cost of price negotiations and searching for trading partners as liquidity increases and markets deepen. This in turn will increase the volatility of spot and short-term prices, creating demand for hedging products and, therefore, uptake in futures markets. Thus, both spot and futures markets allow individual market players to hedge their positions according to their preferences and the nature of their business without the need to commit to rigid bilateral LTCs. Thus, for risk-sharing and hedging purposes, spot and futures prices should guide investment decisions and hedging strategies.

[34] A metric measuring the level of asset specificity.

This does not necessarily mean that there will be no role for bilateral long-term (forward) contracts between producers and buyers (power generators and industrial customers or aggregators and resellers) for gas commodity or between producers (buyers) and transmission and storage system operators for transport and storage capacities (Figure 20). However, the role of the bilateral forward contract will no longer be to safeguard against opportunism. Instead, the purpose of these forward contracts will be to give some assurance to market players who seek alternative hedging products to those proposed in the organised spot and futures markets. The need for such contracts would depend on the effectiveness of organised spot and futures markets in delivering risk-management options to market participants.

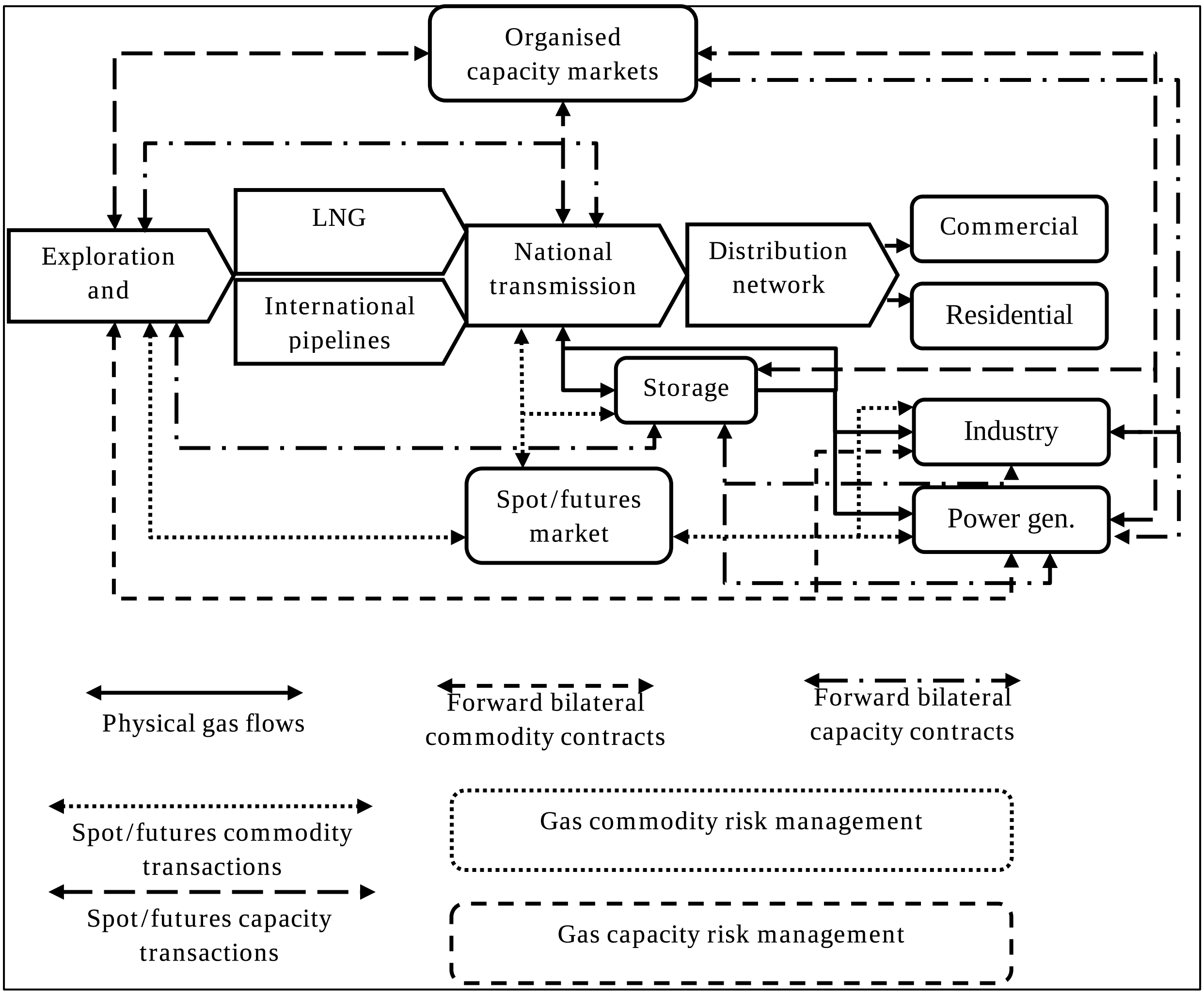

Figure 20: Organisation of the gas value chain in Europe: Physical flows, contracts and markets.

Thus, going forward, both forms of gas trade organisation may co-exist in Europe. Organised spot and futures markets as well as bilateral forward contracts and the balance between the two will depend on their effectiveness in providing market participants with risk-management options and the possibility of minimising transaction costs.

As noted, prices in the organised markets are set transparently through multiple trades and are subject to supply and demand conditions as well as participants' expectations. This, in turn, reduces transaction costs for those who choose to participate in these markets. As such, an interesting issue (and perhaps the most debated one) is the pricing mechanism that should be used in forward bilateral contracts when spot and futures markets are well established. We consider this question next.

B. Forward bilateral contracts

B.1. Pricing mechanisms

Joskow (1988) discusses three forms of pricing in bilateral LTCs, analysing coal supply contracts as a case study: (i) fixed-price contracts, (ii) escalating-price contracts and (iii) market-price contracts. Joskow suggested that fixed-price contracts have poor properties in that they almost always incentivise the parties to breach and renegotiate a contract when uncertain events occur that lead to costs or price increases or decreases that differ markedly from expected values at the time of signing. According to Joskow, escalating-price contracts, and 'base price plus escalation' in particular, have good properties in that they closely track changes in producers' input prices as well as general productivity changes affecting other gas producers and thus minimise the risk of non-compliance and contract renegotiations. However, escalating-price contracts cannot isolate parties from the breaches and haggling that arise because of demand-side or supply-side shocks, which produce substantial differences between contract prices and the market value of gas. In this regard, recent price renegotiations between European buyers and major gas producers are evidence of this argument. Indeed, as Joskow highlights, neither fixed-price nor escalating-price contracts can deal with unanticipated shocks. In this regard, bilateral LTCs with prices pegged to spot and futures market prices are the only contracts that can properly insulate contracting parties from haggling arising from unanticipated shocks that would change short- and long-run equilibriums. The only downside of market price contracts, as Joskow notes, is that if these bilateral forward contracts have a substantial level of 'embedded' relationship-specific investment, then the hold-up problem may still arise in that market prices will not reflect fully sunk costs should the parties terminate the contracts prematurely.

Thus, if bilateral forward contracts were to exist along with traded markets, then the appropriate pricing mechanism that would minimise the cost of haggling would be market-based pricing or spot indexation. We documented extensively in Section 3 how the level of relationship-specific investment has been reduced dramatically due to the fall in the cost of transport technologies and, most importantly, the regulatory regime developed around gas transportation, including regulated tariff setting and third-party access. Furthermore, due to the maturity of the gas markets in Europe, no major surge in gas demand is expected, and hence, no major investments are required from the buyers' side. Going forward, gas import needs may increase in

Europe because of (i) a fall in indigenous supplies and (ii), for example, switching from coal to gas in the power-generation sector due to climate and environmental requirements. However, these import requirements do not need the specific (capital-intensive) investments that were required in the early days of gas penetration, when capital investments were required to 'gasify' large areas of Europe. Therefore, spot indexation in forward bilateral contracts would be an efficient pricing mechanism reflecting the established regulatory regime and market realities in Europe. Furthermore, the rationale for these forward contracts would be mainly to deal with price and volume risk management. For example, one may expect that in a tight market environment, a buyer may pay a premium for a guaranteed volume that cannot be obtained through traded markets or, indeed, the seller may give a discount to ensure that a minimum volume is sold, perhaps because the seller anticipates entry from a competitor and thus an oversupplied market.

All in all, forward bilateral contracts may co-exist with traded markets; however, to avoid costly haggling, these contracts will need an increasing share of spot indexation rather than oil indexation, which does not reflect the realities of European gas market dynamics today.

B.2. Take-or-pay minimum and financing infrastructure

As noted, the take-or-pay clause that would ensure the minimum offtake level may be required if gas trade is undertaken using new infrastructure. Going forward, we would, however, expect that these contracts would have a rather low level of minimum take-or-pay. For example, one could expect that import contracts linked to investments in bypass pipelines that would ensure secure gas transport from Russia to Europe may have minimum take-or-pay clauses. These bypass pipelines may require large upfront investments. But again, the primary purpose of these bilateral contracts between Gazprom and European buyers would be to minimise the cost of borrowing to finance the pipeline, not to shield parties from opportunism. For example, Gazprom may wish to set a minimum take-or-pay level that would be just enough to guarantee stable repayment of debts over a period of time required by the lenders, while the rest of the volume through the new pipeline could be channelled through Gazprom's single trading and marketing division (just like Statoil's MMP). In this way, as our modelling results suggest, Gazprom's export profit would be maximised.

C. Implications for Gazprom's export strategy to Europe

Our results suggest that Gazprom has a fairly simple choice to make with respect to its future sales strategy in Europe: would it like to receive higher profits for its government and shareholders than those given by its status quo sales strategy? If the answer is 'yes', then it would make sense for Gazprom to gradually channel increasing volumes of gas through a single trading and marketing division that would actively participate in wholesale commodity and capacity trading, reflecting all the benefits this trading division could bring to Gazprom, as discussed in Section 5.

Moreover, other alternative sales and pricing strategies would be detrimental to Gazprom's position in Europe (see Section 5).

Our results and discussions do not, however, exclude traditional bilateral LTCs, which may well co-exist with the traded markets if demand for such contracts exists. The costs and benefits of entering into such forward contracts would depend on market dynamics (e.g. tight vs oversupply) and the degree of competition (both downstream and upstream). As such, having a trading and marketing division responsible for the majority of sales would help Gazprom to evaluate the costs and benefits of these bilateral contracts comprehensively and, therefore, devise an optimal sales and pricing structure.

As for the dilemma between oil and spot indexation, should Gazprom wish to have oil indexation as a pricing mechanism for a portion of its produced gas, then it could do so. It could sign LTCs with its single export and trading division (just like the transfer price between Statoil's production division and Statoil's trading division, see Section 4) and agree that the pricing in these contracts (transfer price) would be pegged to oil and oil products, or to any other product that Gazprom's production division chooses. Then, the invoice price or realised market price would be set by the trading and marketing division based on, for example, market dynamics and Gazprom's overall strategic interests. Aside from the Statoil example, there are other examples of such intra-company pricing policies. For example, we understand that the pricing of Total's equity production from Yamal LNG will be fully indexed to oil (as Total, being a major oil producer, wants to have this hedge) and that all the equity volume will be sold to Total's trading arm, which in turn will trade and market LNG under market price conditions.[35]

One important issue to highlight is that as markets mature and transactions take place through traded markets, the ISTM business model will become a hedging tool for those producers who want to optimise production and sales portfolios as well as actively price their gas commodity. In a nutshell, ISTM is becoming a substitute for a system of bilateral contracts to extract more economic rents for Gazprom's gas reserves. Rent extraction used to be conducted through bilateral contracts and bargaining between few buyers and sellers, but in traded markets, rent generation is possible only with the adoption of an ISTM sales strategy.

7. Conclusion

In this research paper we have shown that the role of long-term contracts (LTCs) with oil indexation as a pricing mechanism is declining and that the establishment of spot market trading as a dominant form of gas trade governance is imminent in Europe. We have discussed within the framework of transaction cost economics the

[35] Based on our private discussions with a Total representative.

reasons why LTCs were signed in the early days of the European gas industry and the reasons why their role is now diminishing rapidly. The collapse of the system of bilateral contracts is due to a substantial decrease in the level of asset specificity that facilitated gas trade in the first place. This decrease in asset specificity is due to (i) liberalisation and the introduction of pipeline regulations in Europe and (ii) the reduction in capital intensiveness of transport technologies, allowing more entry into the market, particularly from LNG players. The role of LTCs may co-exist with organised trading markets as long as there is demand and supply for such contracts. However, the primarily role of these rigid bilateral forward contracts will be to manage price and volume risks as well as to minimise the cost of financing new infrastructure.

In light of these fundamental changes in market environment, we investigated the alternative sales strategies available for oil and gas producers when markets are liberalised and become increasingly complex, rendering a simple trade model based on LTCs no longer fit for purpose. In particular, we focused on two types of sales strategies: (i) pure production and the border sales model and (ii) the integrated production, supply, trading and marketing model (ISTM). While investigating the responses of Europe's largest gas suppliers to these structural changes, we found that Statoil, Norway's largest gas producer and one of the largest suppliers to Europe, has quickly changed its sales strategy from passive sales and pricing to an ISTM model, realising that this new strategy, with increased wholesale trade and direct marketing activities, brings higher profits. We also found, through an extensive modelling exercise and the examination of more than 200 market scenarios, that should Gazprom adopt an ISTM sales model and, specifically, introduce a single division responsible for trading and marketing (just like Statoil's marketing, midstream and processing – MMP – division) and increasingly channel all export volume through this division, its export profits would increase substantially. The ISTM sales model would have numerous benefits for Gazprom, as we have shown in Section 5. To summarise these benefits, the ISTM strategy:

1. Fits with the current market realities and enhances Gazprom's competitive advantages – as the largest gas reserve holder with comparably low costs for supplying to Europe – and hence its export profitability.
2. Has options value because it gives Gazprom resilience to the negative impact of market and industry dynamics and shocks. Under this sales strategy, its export profit would be very resilient to contract renegotiations (increased spot indexation and lower take-or-pay levels) and the entry of low-cost producers into the markets.
3. Can better capture the upside potential of market developments, increasing Gazprom's annual export profit substantially and above what Gazprom could achieve by pursuing the border sales strategy. This upside potential includes ISTM's ability to price Gazprom's produced gas actively in traded markets, and this upside potential is further increased if the downstream market becomes more competitive

Thus, we can conclude that it would be rational for Gazprom to adopt an ISTM sales strategy and, in particular, to channel an increasing share of its export volume through a single trade and marketing division and switch gradually to full spot indexation, allowing it to enjoy the full value of the strategy. Gazprom should realise that the higher share of spot indexation in its existing LTCs, the higher Gazprom's profits if all volumes are channelled through a single trading and marketing entity: profit maximisation is only guaranteed when Gazprom is involved in active trading in the wholesale gas commodity and capacity markets. These results are robust under various assumptions and market scenarios. However, even with the current dominance of oil indexation and take-or-pay levels (90/10 oil–spot indexation in Gazprom's existing contracts), the ISTM sales strategy would bring higher value to Gazprom than a border sales strategy.

Note that the obtained results related to the economic benefits of ISTM strategy relative to the border strategy were quantified at the macro and strategic level. However, there are of course other benefits of the ISTM sales strategy that are commonly discussed in the oil and gas industry, such as portfolio optimisation, operational and logistical benefits and trading with flexible and diverse products are not considered as part of this modelling exercise. Furthermore, our results do not include the value the marketing part of the ISTM model since this would require very detailed modelling that is beyond the scope of this paper. Marketing and further downstream activities include participation in the electricity generation sector, carbon trading, energy efficiency and other end uses of gas as an energy carrier and product (e.g. for the chemical industry). We leave the quantification of these other micro level benefits for future research.

Appendix 1: Simple econometric analysis of determinants of long-term gas contracts

Descriptive statistics

	N	Range	Min	Max	Sum	Mean		Std. dev.	Variance	Skewness		Kurtosis	
	Statistic	Statistic	Statistic	Statistic	Statistic	Statistic	Std. error	Statistic	Statistic	Statistic	Std. error	Statistic	Std. error
Contract_Duration	631	37.00	5.00	42.00	11582.50	18.3558	.26198	6.58092	43.309	-.200	.097	.213	.194
ACQ	631	29.95	.05	30.00	1414.11	2.2411	.11065	2.77946	7.725	4.899	.097	38.379	.194
ACQ_SQRT	631	900.00	.00	900.00	8036.14	12.7356	2.3493	59.01386	3482.636	12.367	.097	172.098	.194
NWE_EUpost98_Dummy	631	1.00	.00	1.00	64.00	.1014	.01203	.30213	.091	2.647	.097	5.021	.194
Rof_EUpost98_Dummy	631	1.00	.00	1.00	74.00	.1173	.01282	.32200	.104	2.385	.097	3.699	.194
Flexible_LNG_Dummy	631	1.00	.00	1.00	44.00	.0697	.01015	.25489	.065	3.387	.097	9.500	.194
LNG_Dummy	631	1.00	.00	1.00	504.00	.7987	.01597	.40127	.161	-1.494	.097	.232	.194
Valid N (listwise)	631												

Model summary[b]

Model	R	R square	Adjusted R square	Std. error of the estimate	Change statistics					Durbin-Watson
					R square change	F change	df1	df2	Sig. F change	
1	.359a	.129	.120	6.17215	.129	15.369	6	624	.000	1.516

a. Predictors: (Constant), LNG_Dummy, Rof_EUpost98_Dummy, Flexible_LNG_Dummy, ACQ_SQRT, NWE_EUpost98_Dummy, ACQ.
b. Dependent variable: Contract_Duration.

ANOVA[a]

Model		Sum of squares	df	Mean square	F	Sig.
	Regression	3512.854	6	585.476	15.369	.000b
1	Residual	23771.522	624	38.095		
	Total	27284.376	630			

a. Dependent Variable: Contract_Duration.
b. Predictors: (Constant), LNG_Dummy, Rof_EUpost98_Dummy, Flexible_LNG_Dummy, ACQ_SQRT, NWE_EUpost98_Dummy, ACQ.

Coefficients[a]

Model	Unstandardised coefficients		Standardised coefficients	t	Sig.	95.0% confidence interval for B	
	B	Std. Error	Beta			Lower bound	Upper bound
(Constant)	19.248	.754		25.539	.000	17.768	20.728
ACQ	.836	.172	.353	4.849	.000	.497	1.174
ACQ_SQRT	-.022	.008	-.198	-2.768	.006	-.038	-.006
NWE_EUpost98_Dummy	-6.007	.867	-.276	-6.931	.000	-7.708	-4.305
Rof_EUpost98_Dummy	-1.905	.775	-.093	-2.457	.014	-3.428	-.382
Flexible_LNG_Dummy	-2.594	.976	-.100	-2.659	.008	-4.510	-.678
LNG_Dummy	-1.841	.679	-.112	-2.712	.007	-3.175	-.508

a. Dependent Variable: Contract_Duration

Coefficient correlations[a]

Model		LNG_Dummy	Rof_EUpost98_Dummy	Flexible_LNG_Dummy	ACQ_SQRT	NWE_EUpost98_Dummy	ACQ
Correlations	LNG_Dummy	1.000	.110	-.116	-.017	.295	.164
	Rof_EUpost98_Dummy	.110	1.000	.033	.020	.149	.011
	Flexible_LNG_Dummy	-.116	.033	1.000	-.036	-.010	.048
	ACQ_SQRT	-.017	.020	-.036	1.000	.084	-.843
	NWE_EUpost98_Dummy	.295	.149	-.010	.084	1.000	-.074
	ACQ	.164	.011	.048	-.843	-.074	1.000
Covariances	LNG_Dummy	.461	.058	-.077	-9.112E-005	.174	.019
	Rof_EUpost98_Dummy	.058	.601	.025	.000	.100	.001
	Flexible_LNG_Dummy	-.077	.025	.952	.000	-.009	.008
	ACQ_SQRT	-9.112E-005	.000	.000	6.341E-005	.001	-.001
	NWE_EUpost98_Dummy	.174	.100	-.009	.001	.751	-.011
	ACQ	.019	.001	.008	-.001	-.011	.030

a. Dependent variable: Contract_Duration

Appendix 2: Simplified description of strategic global gas market model

The strategic gas market model incorporates horizontal oligopolistic relationships between upstream producers, transmission and liquefied natural gas (LNG) shipping network constraints and operational and investment decisions over a 25-year time horizon. A notable feature of the model is its ability to simulate not only perfectly competitive gas markets but also imperfect competition in the gas supply chain. In particular, for the latter, the model can take into consideration the fact that producers and suppliers can exercise their pricing power (market power) by adjusting production and supply levels, respectively, in order to raise wholesale prices and, hence, marginal revenue. The model is founded on basic microeconomic concepts and game theoretic principles, namely:

1. Each agent in the model maximises his profit given two types of decisions – (i) operational (sales, dispatch) and (ii) investment (capacity expansion) – and a set of constraints (such as production or transmission capacity constraints) and endogenous actions of the other market participants.[36]
2. The upstream natural gas market is concentrated. As such, there is the possibility for large gas producers to play the market by pushing up prices and, hence, profits; however, the model can also operate under a perfect competition mode (i.e. marginal cost pricing) by gas producers.

We model the full gas market value chain, including the following market players and their corresponding competitive behaviour:

1. **gas producers** – can be modelled as being imperfectly (exercising market power) or perfectly competitive (marginal cost pricing);
2. **gas traders** – can be modelled as being imperfectly (exercising market power) or perfectly competitive (marginal cost pricing);
3. **pipeline transmission operator** – prices pipeline transport services efficiently, i.e. with no market power;
4. **LNG terminal operator** – prices liquefaction and regasification services efficiently, i.e. with no market power;
5. **LNG shipping** – marginal cost-based pricing;
6. **gas storage operator** – prices storage operations efficiently, i.e. with no market power;
7. **final markets** – represented by an inverse demand curve that tells us that the clearance (equilibrium) price depends on total supplies to that market.

The main outputs from this set of models are:

- equilibrium prices and final gas consumption for all markets considered in the model[37];
- equilibrium prices for gas transmission services and LNG services (liquefaction, shipping, regasification);
- gas trade quantities between contracted parties;
  production quantities at each production field (node) or group of fields (country-level aggregation);
- storage withdrawal/injection quantities;
- gas flows for both modes of transportation – pipeline and LNG shipping;

[36] Note that the term ‘agent’ refers to the basic decision-making unit in the model and could denote a country, firm or collection of firms or countries, depending on the level of aggregation needed for the research project.

[37] The notion of ‘equilibrium’ prices simply means that prices are determined at the intersection of demand and supply.

- investment in production capacity;
- investment in pipeline and LNG capacity;
- investment in storage capacity (withdrawal, injection and working volume capacities).

In the natural gas market modelling literature, a framework that is often used to model imperfect competition among market participants is the Cournot non-cooperative game. In this game, a Nash equilibrium is a set of actions (e.g. quantity of gas sales) such that no market participant (player) has an incentive to deviate unilaterally from his own actions, taking into account his opponents' actions. In a gas market model, an agent's objective is to maximise his profit given a set of constraints (such as production or transmission capacity constraints). Under certain conditions, such as a concavity of objective functions (for maximisation problems) and convexity of feasible regions, the Karush–Kuhn–Tucker (KKT) conditions are both necessary and sufficient for the optimality of the maximisation problem. Therefore, the essence of modelling the gas market system is to find an equilibrium that simultaneously satisfies each market participant's KKT conditions for profit maximisation and the market clearing conditions (supply equals demand) in the model. Due to the necessity and sufficiency of the KKT conditions for global optimality when the players' problems are convex, this solution is a Nash equilibrium of the market game embodied in the model. To illustrate the underlying mathematical structure of the model, consider a simple problem that a gas producer may face:

$$\max_{q\geq 0} \pi = qp(q) - C(q) \tag{A.1}$$

subject to

$$q \leq Q\ (\lambda), \tag{A.2}$$

where q is a sales variable, $p(q)$ is an affine inverse demand function, $C(q)$ is a production cost function such that $C'(q)>0$, $C''(q)>0$ and Q is the producer's production capacity. Then, the KKT conditions for (1) are

$$0 \leq q \perp p + \frac{\partial p}{\partial s} q + \lambda - C'(q) \leq 0 \tag{A.3}$$

$$0 \leq \lambda \perp (q - Q) \leq 0. \tag{A.4}$$

The symbol $\perp$ denotes orthogonality, which in the case of (A.3) is a more compact way of expressing the following complementarity relationship:

$$0 \leq q, p + \frac{\partial p}{\partial s} q + \lambda - C'(q) \leq 0, q\left(p + \frac{\partial p}{\partial s} q + \lambda - C'(q)\right) = 0.$$

Together, Conditions A.3 and A.4 form a set of complementarity conditions, or a complementarity problem. If there are also equality conditions, the problem is known as a mixed complementarity problem (MCP). Gathering these conditions for all optimisation problems combined with all market clearing conditions (such as supply equals demand) in the gas market system forms a market equilibrium problem in the form of an MCP. The applications of the MCP f0r energy market modelling are numerous. Large-scale simulation models formulated as MCPs can be efficiently solved with commercial solvers such as PATH.

Appendix 3: Input data and assumptions of the global gas market model

The model has been calibrated to simulate global gas trade for all major importing, exporting and producing regions. Table A.1 outlines countries and regions in the model.

Table A.1: Market and production regions in the model.

Market regions		Production regions	
Region	**Countries**	**Region**	**Countries**
Nordic and Baltic	Denmark, Sweden, Norway, Finland, Estonia, Latvia, Lithuania	**Africa**	Egypt, Algeria, Morocco, Libya, Mozambique, Tanzania, Nigeria, South Africa, Tunisia, Angola, Congo, Cote d'Ivoire, Gabon
North-west Europe	Germany, Netherlands Belgium, Luxembourg, France, UK, Rep. of Ireland	**Australia**	Australia, New Zealand
Iberian Peninsula	Spain, Portugal	**China**	China, Hong Kong
Italy and Switzerland	Italy, Switzerland	**Europe**	Denmark, Sweden, Norway, Germany, Netherlands, UK, Austria, Hungary, Poland, Romania, Italy, Ukraine
Central and Eastern Europe	Austria, Czech Rep., Hungary, Slovakia, Poland,	**India**	India, Pakistan
South-east Europe and Balkans	Greece, Bulgaria, Romania, Slovenia, Croatia, all former Yugoslav republics, Moldova	**Middle East**	Bahrain, Iraq, Iran, Jordan, Kuwait, Oman, Qatar, Saudi Arabia, Syria, UAE
Ukraine	Ukraine	**Rest of Americas**	Chile, Argentina, Bolivia, Brazil, Colombia, Cuba, Peru, Trinidad and Tobago, Venezuela
Russia	Russia, Belarus	**East Asia**	Bangladesh, Myanmar, Vietnam, Malaysia, Philippines, Thailand, Indonesia, Brunei
Turkey and South Caucasus	Turkey, Armenia, Georgia, Azerbaijan	**Central Asia**	Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan, Uzbekistan
China	China, Hong Kong	**Russia**	Russia
India	India, Pakistan	**North America**	US, Canada, Mexico
South-east Asia	Vietnam, Thailand, Singapore, Philippines, Myanmar, Malaysia, Indonesia, Brunei, Bangladesh		
Japan, Korea and Taiwan (JKT)	Japan, Korea, Taiwan		
Rest of Americas	Brazil, Argentina, Bolivia, Chile, Colombia, Venezuela, Trinidad and Tobago, Peru		
Middle East	Qatar, Saudi Arabia, UAE, Bahrain, Syria, Oman, Kuwait, Yemen, Israel, Jordan, Iraq, Iran		
North America	US, Canada, Mexico		

Furthermore, we assume linear inverse demand functions, p_m, for markets as follows:

$$p_m = B_m + A_m \sum_p s_{p,m}, \tag{A.5}$$

where index m denotes the markets represented in the model and $s_{p,m}$ are the sales of producer p in market m. The price elasticity of the demand function is as follows:

$$\varepsilon_c = -\frac{\partial Q_m^0}{\partial p_m^0}\frac{p_m^0}{Q_m^0} \tag{A.6}$$

Then, using (A.5) and noting that $\frac{\partial Q_m^0}{\partial p_m^0} = \frac{1}{A_m}$, the parameters of the linear demand function are as follows:

$$A_m = -\frac{p_m^0}{\varepsilon_m Q_m^0} \text{ and } B_m = p_m^0\left(1 + \frac{1}{\varepsilon_m}\right), \tag{A.7}$$

where p_m^0 and Q_m^0 are reference price and consumption in markets m, respectively. These demand functions are specified at the assumed price elasticity of demand (PED) and average price–quantity pairs for 2010–2014 (Table A.2).

Table A.2: Consumption, prices and elasticity of demand used for demand curve estimation.

Region	**Consumption, bcm/year**	**Price, $/tcm**	**Long-run PED**
Nordic and Baltic	19	387	
North-west Europe	282	357	
Iberian Peninsula	37	436	
Italy and Switzerland	79	438	
Central and Eastern Europe	52	392	
South-east Europe and Balkans	30	447	
Ukraine	52	336	
Russia	490	94	-0.223
Turkey and South Caucasus	58	439	
China	142	611	
India	94	598	
South-east Asia	173	610	
Japan, Korea and Taiwan	181	613	
Rest of Americas	158	601	
Middle East	411	74	
North America	873	141	

Source: Consumption comes from IEA, 2015a, prices come from the Bloomberg Terminal.

Note that the assumed long-run PED for the model is the average of the estimated PED taken from the literature (see Table A.3 below).

Table A.3: Long-run and short-run PED.

	Long-run PED	Short-run PED	Region
Bernstein and Madlener (2011)	-0.16	-0.04	US
Joutz et al. (2009)	-0.18	-0.09	US
Maddala et al. (1997)	-0.273	-0.001	US
Dahl (1993)	-0.3	-0.3	US
Bernstein and Griffin (2006)	-0.36	-0.12	US
Asche et al. (2008)	-0.1	-0.03	EU
Berkhout et al. (2004)	-0.19	n/a	EU
Average	-0.223	-0.10	

In terms of producers' market power, we only consider that Russia and the Middle Eastern producers have the ability to affect prices by changing their sales strategies, reflecting their (i) vast gas resources and (ii) developed export capacity. However, since producers from these two regions are essentially government controlled, we also assume that they are price-takers in their respective 'home' markets.

The model has been calibrated for 2010–2014 using the above consumption, prices and PED data. Note that the model reproduces the 2010–2014 data (market prices and consumption) reasonably well (see Table A.4) without any changes to the exogenous variables, such as changing PED and producers' market power assumptions (see Chyong and Hobbs, 2014). This suggests that all input data for the model (capacities, supply curves, investment costs etc.) as well as its formulation appear to be correct.

Table A.4: Consumption and prices: Model results vs 2010–2014 data.

	Consumption, bcm/year		**Price, $/tcm**	
	2010–2014	**Model**	**2010–2014**	**Model**
Nordic and Baltic	19	17	387	528
North-west Europe	282	274	357	403
Iberian Peninsula	37	38	436	392
Italy and Switzerland	79	78	438	458
Central and Eastern Europe	52	50	392	450
South-east Europe and Balkans	30	29	447	529
Ukraine	52	50	336	384
Russia	490	475	94	107
Turkey and South Caucasus	58	55	439	539
China	142	149	611	480
India	94	98	598	502
South-east Asia	173	178	610	533
Japan, Korea and Taiwan	181	179	613	635
Rest of Americas	158	171	601	372
Middle East	411	418	74	68
North America	873	939	141	93

To derive the demand curves for the rest of the modelling time horizon (2015–2035), we assume market demand and prices similar to those observed in 2010–2014. Implicitly, we assume no growth in gas consumption. While this is a conservative assumption, it guarantees that we do not overestimate the benefits of the ISTM sales strategy since, all else being equal, growth in demand would mean that the slope demand curves would be 'flatter' and, hence, sales under the market power assumption would result in higher profit. Furthermore, note that since the model has the capability to expand production and transport capacities endogenously, future clearing prices would be determined by a mix of factors, such as (i) supply costs (investment and operational production and transport costs), (ii) producers' supply behaviour (price-taking vs price-making) and (iii) physical infrastructure bottlenecks.

The long-run marginal production cost curves used in the model take the following functional form:

$$MC = Aexp^{Bk}, \tag{A.4}$$

where k is the cumulative development of gas reserves and A and B are the parameters to be estimated using data from the MIT gas study.

The cost curves data for major gas producing regions are provided in MIT (2011). In this report, the cost curves were derived for two oil-price scenarios – low and high – reflecting uncertainty over the cost of oil and gas upstream development, which is highly depended on oil prices. In particular, the average oil price in 2004 was considered to fit a low-oil-price scenario, whereas the oil price in 2007 was taken as a high-oil-price scenario. This corresponds to oil prices of $38/bbl in 2004 and $73/bbl in 2007. Table A.5 provides the estimated parameters for the marginal cost curves in Eq. A.4 based on the MIT data.

Table A.5: Estimated parameters for production cost curves.

Region	**Low-oil-price scenario**		**High-oil-price scenario**	
	A	**B**	**A**	**B**
Africa	22.8701547	0.0001044	29.8205089	0.0001076
Australia	52.7281116	0.000359	70.914024	0.0004098
China	23.4258209	0.0005274	34.2321183	0.000517
Europe	26.9195842	0.0001526	32.1785032	0.0001759
India	12.3490103	0.0014732	17.4745555	0.0014858
Middle East	8.8039929	0.0000287	17.7116173	0.0000245
Rest of Americas	28.0009901	0.000097	38.9329627	0.0001074
East Asia	16.5499778	0.0001632	24.360129	0.000117
Central Asia	26.5270134	0.0001121	36.3271092	0.0001167
Russia	13.9904275	0.000035	20.3362935	0.0000333
North America	32.6513226	0.0000506	67.6024863	0.0000493

Source: Author's estimation based on data from MIT (2011).

We use the forward oil price curve as of mid August 2015 and input this curve into the model. This, in turn, determines the cost of developing gas resources. The forward curve takes the following specification:

$$Oil\ Forward\ Curve = \begin{cases} 102.066\ for\ t = 0 \\ 6.6967 * t + 52.37\ for\ t \neq 0 \end{cases}, \tag{A.8}$$

where t is the time period in the model, measured in five-year increments. The model starts with t=0, corresponding to the 2010–2014 time period. Thus, according to Eq. A.8, oil prices in 2015–2019 (t=1) are expected around $59.067/bbl, while for the reference period (2010–2014) the average oil price was very high, at $102.066/bbl.

The price for long-term oil-indexed contracts is approximated using the following formula, as suggested by Stern and Rogers (2014):

- oil-indexed contract price [$/mmbtu] = (0.666667 + 0.007619 * (average of previous nine months' gas oil prices in $/tonne) + 0.008571 * (average of previous nine months' fuel oil prices in $/tonne).

Linear relationships exist between gas oil and fuel oil prices and the crude oil price (Brent). The estimated relationship is as follows:

- gas oil price [$/tonne] = 8.5333 * (Brent oil price in $/bbl) + 5.3868
- Fuel oil price [$/tonne] = 5.9347 * (Brent oil price in $/bbl) - 24.857

The marginal cost curves will switch from low to high (Table A.5) if the expected oil price exceeds $73/bbl. The oil price is treated parametrically, and sensitivities around the 'slope' of the forward curve (Eq. A.8) are carried out to identify sensitivities of the results to oil price assumptions.

Note that MIT's data on cost curves include fields already in production. As such, we should calibrate these cost curves to take account of investment in gas resources that has already taken place (sunk investment). Failing to account for this sunk investment would result in overestimation of gas reserves. This may lead to double-counting and, potentially, low equilibrium prices because the model will consider investment in gas resources from the very beginning of these cost curves, resulting in low investment costs. Thus, to circumvent this potential bias, we use the following procedure:

1. The average annual production rate in the period 2010–2014 was used as the initial production capacity in the model (the production data were taken from IEA (2015a)).
2. We then multiplied this production rate by twenty years, assuming that gas producers usually develop gas fields so as to sustain a targeted rate of production for about 20 years, corresponding to the useful lifetime of production and gas treatment assets in the upstream sector. Hence, the logic here is that since we observe the maximum production rate in the last five years, it is appropriate to assume that producers have already invested in the

development of gas reserves, the total size of which would allow them to sustain that production rate for 20 years. We use these derived total developed reserves as the starting point for the cost curves in the model (Table A.6 outlines the production capacities and developed reserves).

Table A.6: Initial production capacity and developed reserves assumed in the model.

Region	**Initial production rapacity, bcm/year**	**Developed Reserves, bcm**
Africa	212	4235
Australia	68	1,360
China	111	2,223
Europe	280	5,608
India	70	1,404
Middle East	553	11,060
Rest of Americas	177	3,544
East Asia	243	4,859
Central Asia	201	4,025
Russia	685	13,708
North America	937	18,740

Finally, in the modelling of gas markets, we take into account all existing long-term contracts (LTCs) for both LNG and pipeline gas. This is taken from Poten and Partners' LNG contract database and other publically available sources, with the exception of producers from Russia, Europe (including Norway) and Africa. For these three regions, due to lack of information on producers' long-term sales commitments, we take all export volumes in 2010–2014 from these regions to all markets and assume that these figures are representative of the annual contract quantity (ACQ) in their long-term supply commitments to various regional markets. Furthermore, we assume a minimum take-of-pay level of 75% of the defined ACQ (Table A.7), consistent with the academic view (e.g. Mitrova et al., 2015).

Table A.7: ACQs from producers to consumers (bcm/year)

Production region	**Market**	**2010–2014**	**2015–2019**	**2020–2024**	**2025–2029**	**2030–2034**	**2035–2039**
Africa	North-west Europe	7.5	5.6	3.7	1.9	0.0	0.0
	Iberian Peninsula	24.7	18.5	12.4	6.2	0.0	0.0
	Italy and Switzerland	24.5	18.3	12.2	6.1	0.0	0.0
	South-east Europe and Balkans	0.9	0.0	0.0	0.0	0.0	0.0
	Turkey and	5.3	4.0	2.7	1.3	0.0	0.0

	South Caucasus						
	China	1.5	1.1	0.7	0.4	0.0	0.0
	India	0.6	0.0	0.0	0.0	0.0	0.0
	South-east Asia	0.3	0.0	0.0	0.0	0.0	0.0
	Japan, Korea and Taiwan	8.1	6.1	4.0	2.0	0.0	0.0
	Rest of Americas	1.3	0.0	0.0	0.0	0.0	0.0
	Middle East	0.5	0.0	0.0	0.0	0.0	0.0
	North America	2.1	0.0	0.0	0.0	0.0	0.0
Australia	China	6.2	27.9	28.8	28.8	25.7	4.5
	India	0.4	2.0	2.0	2.0	2.0	0.0
	South-east Asia	2.6	8.8	8.8	8.8	8.0	0.0
	Japan, Korea and Taiwan	28.1	68.2	68.9	56.0	46.9	16.6
Europe	Nordic and Baltic	5.0	3.8	2.5	1.3	0.1	5.0
	North-west Europe	181.6	136.2	90.8	45.4	1.8	181.6
	Iberian Peninsula	3.8	2.8	1.9	0.9	0.0	3.8
	Italy and Switzerland	13.8	10.4	6.9	3.5	0.1	13.8
	Central and Eastern Europe	11.3	8.5	5.7	2.8	0.1	11.3
Middle East	North-west Europe	19.2	19.6	13.1	11.9	10.3	0.0
	Iberian Peninsula	7.5	6.4	6.0	1.1	0.0	0.0
	Italy and Switzerland	6.3	6.3	6.3	6.3	1.3	0.0
	Central and Eastern Europe	0.3	1.4	1.4	1.4	1.4	0.0
	China	5.6	6.8	6.8	6.8	6.8	2.4
	India	10.2	10.2	10.2	8.8	0.7	0.0
	South-east Asia	0.0	2.7	2.7	2.7	2.7	0.5
	Japan, Korea and Taiwan	47.7	49.6	35.9	14.9	6.6	0.0

Rest of Americas	Iberian Peninsula	3.6	3.6	1.3	0.0	0.0	0.0
East Asia	China	7.7	7.7	7.7	7.7	6.2	0.0
	Japan, Korea and Taiwan	63.3	44.8	25.5	9.6	1.7	0.5
Central Asia	China	18.1	30.0	30.0	30.0	30.0	30.0
Russia	Nordic and Baltic	8.3	7.9	7.2	5.8	5.0	4.2
	North-west Europe	63.1	59.8	55.0	43.9	38.0	32.1
	Iberian Peninsula	0.0	1.4	3.4	3.4	3.4	3.4
	Italy and Switzerland	18.8	17.8	16.4	13.0	11.3	9.5
	Central and Eastern Europe	34.6	32.8	30.1	24.0	20.8	17.6
	South-east Europe and Balkans	15.5	14.7	13.5	10.8	9.3	7.9
	Ukraine	30.9	30.9	0.0	0.0	0.0	0.0
	Turkey and South Caucasus	26.9	25.5	23.4	18.7	16.2	13.6
	China	0.0	1.6	4.1	4.1	0.0	0.0
	Japan, Korea and Taiwan	10.0	10.0	10.0	10.0	3.3	0.0
	Rest of Americas	2.7	2.7	2.7	2.7	0.0	0.0

Source: LNG contracts came from the Bloomberg Terminal; the rest were calculated based on IEA 2015a information.

The remaining assumptions and data dealing with pipeline and LNG trade connections and capacities as well as associated short-run and long-run marginal costs are documented in our earlier paper (Chyong and Hobbs, 2014).

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