Strategic Eurasian Natural Gas Model for Energy Security and Policy Analysis

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To demonstrate the model, a social benefit-cost analysis of the Nord Stream gas pipeline project from Russia to Germany via the Baltic Sea is provided. It is found that Nord Stream project is profitable for its investors and the project also improves social welfare in all market power scenarios. Also, if transit countries (Ukraine and Belarus) exert substantial market power then the economic value of Nord Stream to its investors and to society improves substantially. We also found that the value of Nord Stream investment is rather sensitive to the degree of downstream competition in European markets and that lack of downstream competition might result in the negative value of the Nord Stream system to Gazprom.

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Strategic Eurasian Natural Gas Model for Energy Security and Policy Analysis[1]

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Abstract

The mathematical formulation of a large-scale equilibrium natural gas simulation model is presented. Although large-scale natural gas models have been developed and used for energy security and policy analysis quite extensively (e.g., Holz (2007), Egging et al. (2008), Holz et al. (2009) and Lise et al. (2008)), this model differs from earlier ones in its detailed representation of the structure and operations of the Former Soviet Union (FSU) gas sector. In particular, the model represents: *(i)* market power of transit countries, *(ii)* transmission pipelines in Russia, Ukraine, Belarus and Central Asia, *(iii)* differentiation among gas production regions in Russia, and *(iv)* gas trade relations between FSU countries (e.g., Gazprom's re-exporting of Central Asian gas).

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[1] This working paper presents preliminary research findings, and you are advised to cite with caution unless you first contact the author regarding possible amendments.

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1. Introduction

Competition, decarbonisation and security of supply are the main principles of European energy policy (EC, 2006; EC, 2008a). Thus, the importance of natural gas in the EU is expected to increase since natural gas, as an energy carrier, has relatively low carbon content compared to other fossil fuels (such as coal or oil).[4]

In 2009, natural gas consumption in the EU totalled 503 billion cubic metres (bcm) (or about a quarter of total primary energy consumption) (IEA, 2010). By 2030, consumption was projected to grow at an average annual growth rate of +0.6% (EC, 2008b) or +0.7% (IEA, 2009).[5] Meanwhile, by 2030 EU indigenous gas production is anticipated to decline substantially (EC, 2008b), and thus consumption has to be increasingly met with external sources.

In 2009 major suppliers to the region - Norway, Russia and Algeria - together exported around 51% of all gas consumed in the EU. Russian gas exports alone cover around one quarter of the EU's natural gas consumption, or 6.5% of the bloc's primary energy supply (Noël, 2008; Noël, 2009). Over 90% of Russian gas exports are transported through Ukraine and Belarus before entering European markets.[6] Russia's "difficult" relations with key transit countries on its Western border - Belarus and Ukraine - have resulted in several major gas transit disruptions. These include transit disruptions through Belarus for 3 days in June 2010 and through Ukraine for 4 days in January 2006 along with, most severely, two weeks in January 2009, affecting millions of customers in South-Eastern Europe and the Western Balkans (Pirani et al., 2009; Kovacevic, 2009; Silve and Noël, 2010).

Since the breakdown of the Soviet Union, Gazprom has pursued a strategy of diversifying its export options to Europe, beginning with the construction of the Yamal-Europe pipeline in the 1990s (Victor and Victor, 2006). It has continued more recently with the Nord Stream and South Stream projects – under the Baltic and the Black Sea, respectively. Once operational, these two projects would have a total capacity larger than the current volume of gas being transported through Ukraine to Europe. Therefore, as argued by Gazprom and its large West-European clients, these projects should increase the security of gas supplies to Europe (Gazprom, 2010c; E.ON, 2010; BASF, 2010b; GDF SUEZ, 2010; Gasunie, 2010; Gazprom, 2010e; ENI, 2007; EDF, 2010). Indeed, the importance of these two projects to the security of supply to Europe cannot be overestimated. If materialized, their total export capacities would constitute 23% of the EU's

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[4] Natural gas is in a favourable position in the European electricity generation industry, especially in the context of regulating greenhouse gas emissions. Gas-fired power plants emit roughly half the CO_2 per KWh of electricity output compared to coal-fired power plants.

[5] Although, on average, annual growth in gas consumption in Europe during the past twenty years exceeded the annual growth of energy consumption, experts are skeptical that this demand growth will continue in the future (see e.g., (Noël, 2009)).

[6] Own calculations based on (ENTSOG, 2010; Naftogaz of Ukraine, 2010; Gazprom, 2010a; Yafimava, 2009).

annual consumption, or 39% of the EU's total gas imports. Despite their importance to supply security, rigorous analyses of the economics of these projects are very limited.

Therefore, the research objective is to develop a gas simulation model which can be used to analyze the economics of security of supply pipelines, particularly the Nord Stream and South Stream pipelines. While large-scale gas simulation models have been formulated and used extensively in the analysis of the security of gas supplies to Europe, e.g., Holz (2007), Egging et al. (2008), Holz et al. (2009) and Lise et al. (2008), the model presented in this paper differs from earlier models in its detailed representation of the Former Soviet Union gas sector. The transit activities of Ukraine and Belarus are explicitly modelled, while their transit/transmission pipelines are represented in detail. Russian gas production is distinguished by its dominant producer - Gazprom - and independent gas companies (oil producers and small gas companies in Russia), as well as by its production regions (both current and future regions, such as the Yamal Peninsula and the Shtokman field). The Russian transmission system and export pipelines from Central Asia to Russia are also presented in the model with a sufficient level of detail. Central Asian gas production and sales to Gazprom that are further re-exported to Europe/CIS are also explicitly modelled. Gazprom's exports to Belarus, Ukraine and Moldova, as well their indigenous gas production, are also explicitly represented in the model. This level of detail in the representation of the Former Soviet Union[7] (FSU) gas "region" in a computational economic model is unique and represents one of the major contributions of this work.

The aim of this paper is to detail the mathematical formulation of the model and the assumptions and data used, as well as demonstrating the model's capabilities. For this purpose, an analysis of the following questions will be presented:

- How do perfect and imperfect competition models differ in their evaluation of the Nord Stream pipeline project (and why)?
- Assuming that transit countries exert substantial market power against Gazprom, would consumers and Gazprom be better off if Nord Stream is built?

The rest of this paper is organized as follows. The existing literature is reviewed in the next section. The model is presented in Section 3 and its validation is discussed in Section 4. Section 5 presents the results and analysis. The paper concludes with a discussion of future developments of the model.

[7] In this research, by FSU countries the following are meant: Russia, Ukraine, Belarus, Moldova, Kazakhstan, Uzbekistan, Turkmenistan and Azerbaijan. Although Estonia, Lithuania and Latvia were also members of the USSR, they are referred to as countries of Western Europe in this research.

2. Literature Review

In the following, the existing literature on natural gas modelling is reviewed and there is a discussion of where this model fits into the existing literature. First, there is a review of the complex, large-scale gas computational models that have been applied to the analysis of gas supply security to Europe. Then, there is an outline of research that has used theoretical (economic) models to analyze natural gas developments in the Former Soviet Union (FSU) countries. Lastly, there is a brief overview of applied game-theoretic literature that focuses on strategic interactions between Russia and its gas transit countries.

Using a strategic European gas simulation model, GASMOD (Holz et al., 2008), Holz (2007) analyzed the role of Russian gas in European markets and the effects on prices and consumption of Russia withholding exports. GASMOD is a two-stage successive oligopolies gas market model (Holz et al., 2008). GASMOD explicitly considers imperfect competition in upstream production (first stage) and downstream gas trading (second stage) in European markets. In both stages, market participants can exert market power by playing a Cournot game. The relationships between traders and upstream producers are modelled *à la* Stackelberg, i.e., traders are price-takers with respect to producers' border prices. The geographical coverage of the model is wide – on the demand side it includes all European markets, and on the supply side it includes major exporters to Europe. The underlying market structure implemented in GASMOD (successive oligopolies) is similar to the structure of the static GASTALE model developed by Boots et al. (2004).

A more detailed strategic European gas simulation model was developed by Egging et al. (2008). The model contains a detailed presentation of market players (such as producers and traders, LNG liquefiers and regasifiers, storage and transmission operators, etc.) on the supply side, whereas the demand side is represented by 52 consuming countries, three seasons (low demand, high demand and peak) and three consumption sectors (residential, industrial and power generation). The market structure that their model implements is different from that of GASMOD and the static GASTALE model (Boots et al., 2004). Egging et al. (2008) assumed that only traders, as international market players, can exert market power vis-a-vis consumers by playing the Cournot game against other traders. According to Egging et al. (2008), one of their contributions is the application of their model to the analysis of the security of gas supplies to Europe.[8]

Lise and Hobbs (2008) extend the static version of the GASTALE (Boots et al., 2004; Egging and Gabriel, 2006) model to include the dynamics of investment in infrastructure capacities (such

[8] For example, one of their analyzed scenarios involves the curtailment of gas supplies to Europe through Ukraine, with another case involving the disruption of gas flows from Algeria to Europe.

as storage, pipelines and LNG infrastructure). Similarly to the model developed by Egging et al. (2008), the dynamic GASTALE model contains a detailed representation of both the supply and demand sides. The market structure of the dynamic GASTALE model is similar to the market structure assumed in (Egging et al., 2008). Lise and Hobbs (2008) assumed that only producers have market power. The primary purpose of extending the GASTALE model to include dynamic investment is to address the policy question of energy corridors to Europe. The dynamic GASTALE model was particularly used to study the security of gas supplies to Europe.[9]

Lastly, there is the TIGER model developed at EWI Cologne (Lochner and Dieckhöner, 2010). The TIGER model is a linear optimization model with a very detailed representation of the physical gas infrastructure of Europe. The model results are based on the infrastructure and cost fundamentals of the natural gas market and, therefore, the strategic considerations of market players are not taken into account (Lochner and Lindenberger, 2009). The model is extensively applied to an analysis of the impact of major gas import infrastructure and gas flow interruption scenarios on the operation of the European natural gas network (see, e.g., (Bettzuege et al., 2010; Lochner and Lindenberger, 2009; Lochner and Bothe, 2007)). While all previous large-scale models explicitly represent the market power of different players in the European gas market, the TIGER model assumes perfect competition, which makes it less appropriate for studying strategic interactions between market participants in the European gas market.

The research focus of the above gas models was primarily on: (*i*) market power of downstream suppliers in European markets, and (*ii*) how these markets would react to a possible disruption of gas supplies from major exporters (such as Russia, Algeria and Caspian producers). Thus, the detailed presentation of upstream activities outside EU borders, particularly the gas sectors of Ukraine, Belarus, Russia and Central Asia (e.g., a detailed presentation of pipeline networks, producing regions, the market power of transit countries and commercial gas relations between these countries) was not necessary in previous gas models. Therefore, the contribution of this work to the natural gas modelling literature is to include detailed modelling of the FSU gas sector in a large-scale strategic gas market simulation model.

A detailed presentation of the FSU gas sector in a large-scale gas simulation model is necessary for the analysis of the economics of the Nord Stream and South Stream pipeline projects. These two projects are perceived to enhance the security of gas supply to Europe and are important for European gas consumption since their combined export capacities would constitute 23% of the EU's annual consumption (or 39% of the EU's total gas imports). Moreover, a detailed construction of the FSU gas sector in European gas market model is also needed to understand

[9] Lise et al. (2008) studied the effects of gas flow interruptions from Algeria and Russia to Europe and from Azerbaijan and Iran/Iraq to Turkey.

Russia's ability to exert market power in Europe. As Smeers (2008) noted, gas producers compete against one another through the transmission system. Thus, Russia's ability to exert market power in Europe depends, among other factors, on its relations with transit countries (Ukraine and Belarus) and whether these transit countries exercise market power on transit of Russian gas to Europe. The market power of producers and transit countries is currently the driving force behind most discussions of the security of gas supplies to Europe (Smeers, 2008). As Smeers (2008, p. 41) argues:

> *It is certain though that very few would mention security of gas supply if resources were owned by one thousands producers and not reside in a few hands. One would not interpret Russia trying to get market prices (possibly excessive, but in any case non discriminatory) from Ukraine or Belarus as a political move if Russia were just one small producer among many. It would just be a normal market operation: Ukraine and Belarus have had to pay Western market price or be cut off. This trivial observation makes it clear that the market power of the producers is the driving theme of most of the discussion of security of supply.*

Thus, upstream gas activities in the Former Soviet Union (FSU) countries and the market power of transit countries (particularly Ukraine and Belarus) deserve much greater attention in any analysis of the security of gas supplies to Europe (Smeers, 2008).

The analysis of the natural gas sector of FSU countries using economic models (mostly using a non-cooperative game theoretic framework) has gained considerable interest from researchers since the mid-1990s. During the 1990s and early 2000s, a push for market reforms and liberalization of national economies in the FSU countries spurred interest in researching gas relations between these countries in different contexts: (*i*) Russian gas exports to Europe and the country's relations with transit countries (Grais and Zheng, 1996), (*ii*) gas pricing policies in Russia (Tarr and Thomson, 2004) and (*iii*) Russia's gas transportation options to Europe and its relations with transit countries (Chollet et al., 2000; Hirschhausen et al., 2005). Since the mid-2000s, Russia's gas relations with its key transit countries (Belarus and Ukraine) have deteriorated, resulting in several gas transit disruptions to Europe; thus the economic modelling of FSU gas relations has again gained interest among researchers but primarily in the context of the security of gas supplies to Europe (Bolle and Ruban, 2007; Morbee and Proost, 2008; Sagen and Tsygankova, 2008).

Lastly, another interesting stream of literature on modelling gas relations between FSU countries using applied game-theoretic models (such as cooperative bargaining models) is represented by (Newbery, 1994; Hubert and Ikonnikova, 2003; Hubert and Ikonnikova, 2004; Hubert and Suleymanova, 2008; Hubert and Ikonnikova, 2009). More specifically, this research is concerned with questions of strategic investment in large-scale gas pipelines in the context of bilateral (Newbery, 1994) and multilateral bargaining (Hubert and Ikonnikova, 2003; Hubert and Ikonnikova, 2004; Hubert and Suleymanova, 2008; Hubert and Ikonnikova, 2009) between Russia and its largest transit countries (such as Ukraine and Belarus).

In contrast to the large-scale gas market simulation models discussed above, the latter two research streams (cooperative and non-cooperative game theoretic models) lack any detailed representation of the downstream side of the European gas markets or the strategic interactions between gas exporters to Europe, and have a rather loose presentation of the upstream gas sector of the FSU countries. The consequence of neglecting these important market developments is that conclusions based on their analysis might change substantially once these market developments are accounted for.

Therefore, the primary objective in developing a large-scale gas simulation model here is to "bridge" this gap. By doing this, a contribution is made to the literature on large-scale gas simulation models by creating an explicit representation of the FSU gas "region". By using this Eurasian gas model we will be able to refine and obtain new insights into the strategic nature of gas relations between FSU countries that have been overlooked by previous economic and applied game-theoretic models.

3. Model Description

3.1. Modelling Framework

In the natural gas modelling literature (Mathiesen et al., 1987; Golombek and Gjelsvik, 1995; Golombek et al., 1998; Boots et al., 2004; Zwart and Mulder, 2006; Holz et al., 2008; Egging et al., 2008; Lise and Hobbs, 2008), a framework that is often used to model imperfect competition among market participants (usually, upstream producers and/or downstream suppliers) 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 unilaterally deviate from his own actions, given his opponents' actions (Tirole, 1988).

In a gas market model, a player's objective is to maximize his profit given a set of constraints (such as production or transmission capacities constraints). Under certain conditions, such as a concavity of objective functions (for maximization problems) and convexity of feasible regions, the Karush-Kuhn-Tucker (KKT) conditions are both necessary and sufficient conditions for optimality of the maximization 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 maximization and market clearing conditions (supply equals demand) in the model. Due to the necessity and sufficiency of KKTs 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 here, consider a simple problem that a gas producer might face:

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

subject to

$$q \leq Q \quad (\lambda) \tag{2}$$

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

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

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

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

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

The set of conditions (3-4) is 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 optimization 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 (Gabriel and Smeers, 2005). Applications of the MCP to energy market modelling are numerous (see, e.g., above-cited gas models; Smeers (1997) and Gabriel and Smeers (2005) provide an overview of natural gas market modelling using the MCP, and Hobbs and Helman (2004) discuss the application of MCP to electricity market modelling). The existence and uniqueness of the results for a class of gas market models formulated as MCPs has been established by Gabriel et al. (2005a). Large-scale simulation models formulated as MCPs can be efficiently solved with commercial solvers such as PATH.

3.2. Structural Assumptions

3.2.1. Model Structure

The scope of the model presented here is medium- to long-term. European countries face substantial energy challenges over this period of time, such as declining indigenous production, reliance on a relatively small number of external gas exporters coupled with increasing risks of supply disruptions, and rising carbon prices that may increase demand.

The structure of the model is summarised in Figure 1 (for European markets) and Figure 2 (for the FSU gas sector). The model represents major gas producers and consumers in Europe and in the Former Soviet Union although the model could also be used to represent gas markets elsewhere in the world. Producers and consumers are connected by pipeline networks and the LNG bilateral shipping network. Gas producers sell gas to suppliers[10] who in turn re-sell to final markets. Gas producers can either export gas through pipelines (e.g., Producer *i1*, Figure 1) or as LNG (e.g., Producer *i2* to Country C, Figure 1). In order to import LNG, consuming countries need regasification terminals (e.g., Country C, regasifier *r1*).

[10] Hereinafter, the terms "supplier" and "trader" are used interchangeably. A gas supplier/trader is understood as a large utility company which has gas import contracts with upstream producers. A supplier/trader buys gas from producers and then re-sells it to final customers.

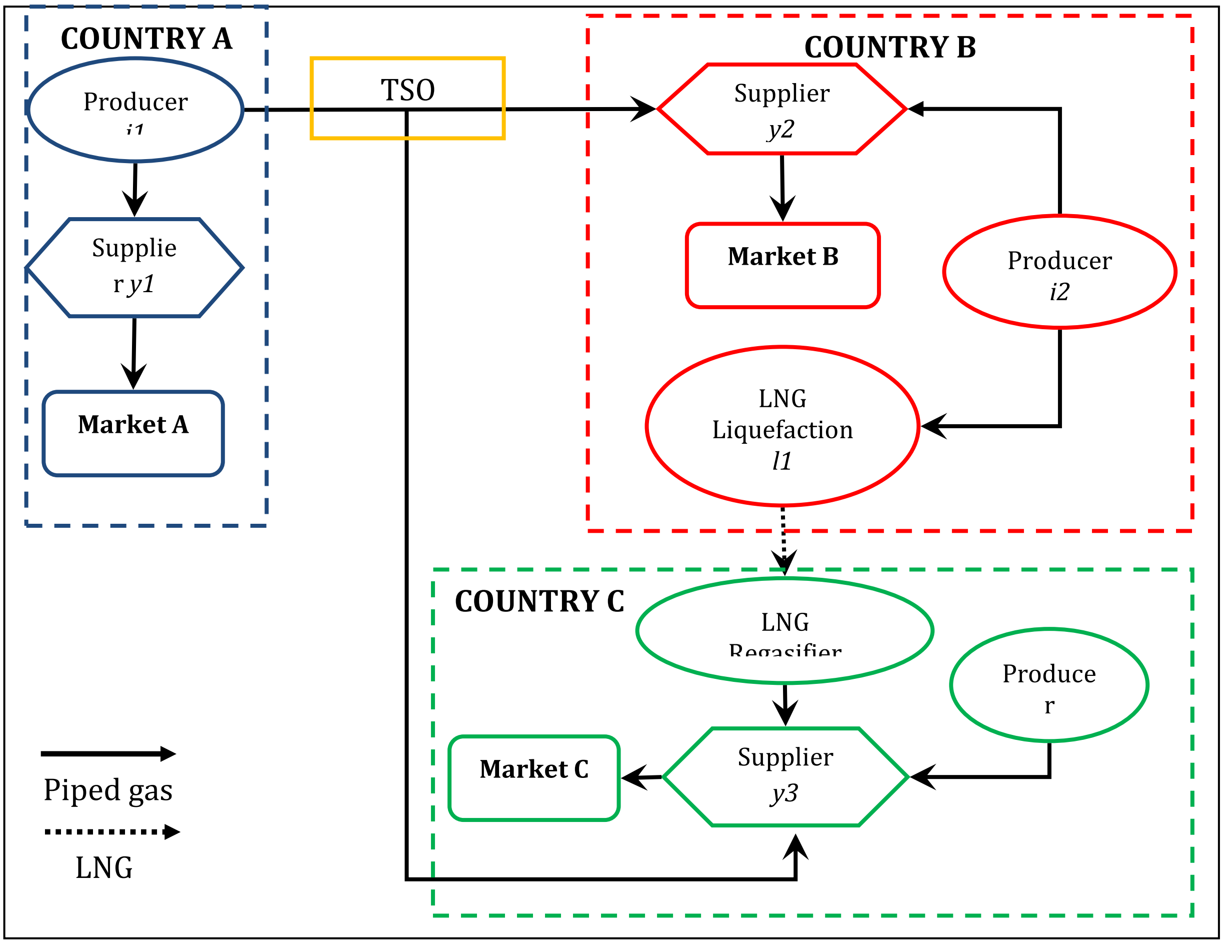

Figure 1: Schematic of the Structure of the European Sub-model

The FSU gas sector model is based on the structure in Figure 2. For transparency, the activities of vertically integrated companies such as Gazprom and Naftogaz of Ukraine are modelled separately.[11] Modelling each subsidiary of an integrated company as a separate player is similar to modelling the integrated company as one problem, provided that the relationships between subsidiary companies are modelled as competitive (price-taking). The proof of this statement is given in Appendix A.

[11] Egging et al. (2008) modelled the activities of vertically integrated companies similarly.

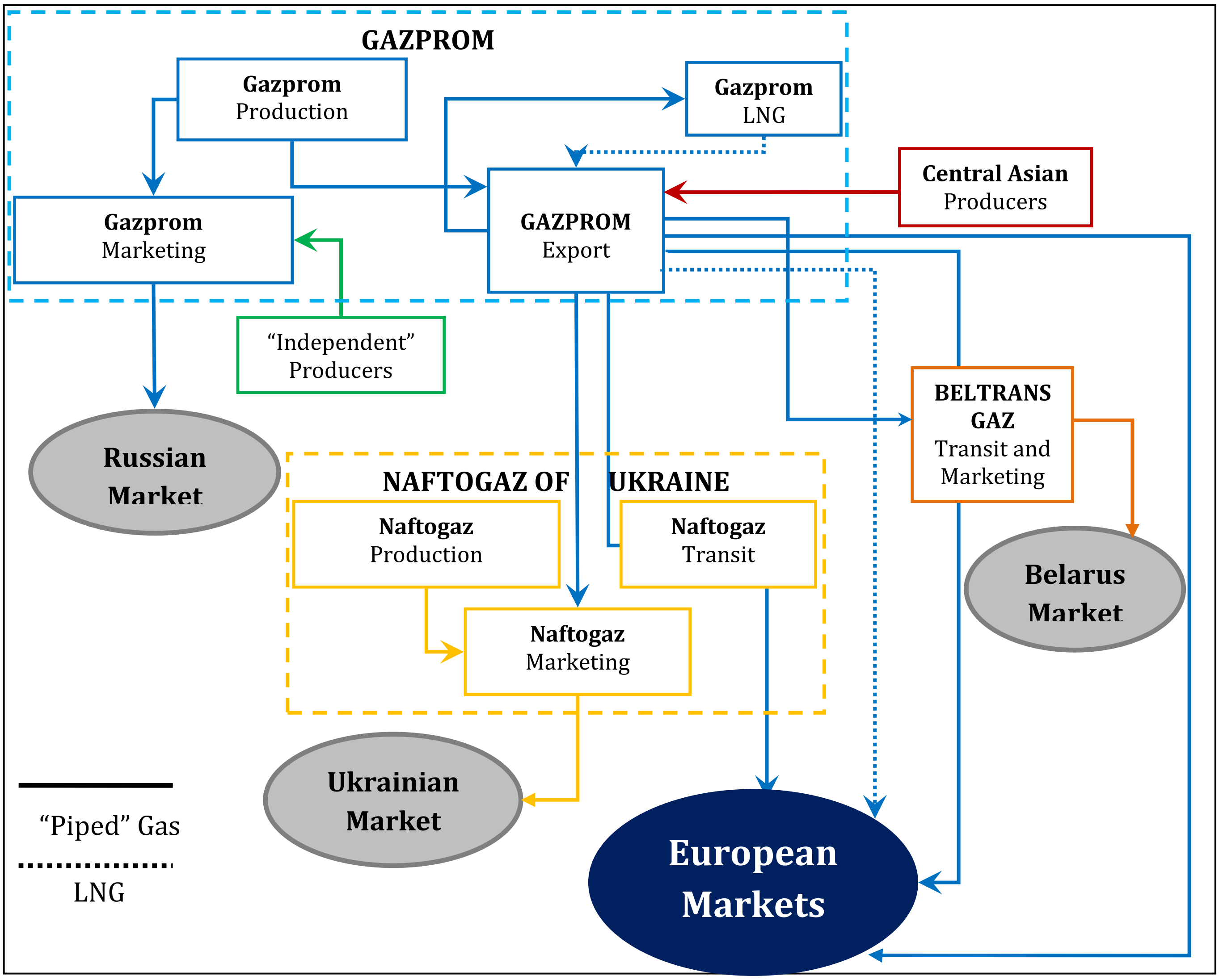

Figure 2: Schematic of the Structure of the FSU Gas Sub-model

It is assumed that each FSU gas market is dominated by a state-owned supplier, which is consistent with reality. For example, in Russia the dominant domestic supplier is "Mezhregiongaz" (Gazprom's subsidiary), and in Ukraine it is "Gas of Ukraine", a subsidiary of Naftogaz of Ukraine. (For simplicity, a domestic supplier like Gazprom Marketing or Naftogaz Marketing is called a "marketing" company in Figure 2.) Since gas companies are completely or majority state-owned, it is assumed that they have a legal obligation to supply the domestic market at regulated prices (Sagen and Tsygankova (2008) make a similar assumption in their model of the Russian gas sector).[12] The suppliers meet domestic demand by purchasing gas from indigenous production or by importing gas from other entities. For example, in this model Gazprom Marketing buys gas from "independent" gas producers and from Gazprom Production to meet Russian domestic

[12] For example, Ms. Vlada Rusakova, a member of Gazprom's management committee and Head of Gazprom's strategic planning department, stated that Gazprom is legally responsible for meeting domestic demand at regulated prices (Grivach, 2006).

demand. Similarly, in Ukraine Naftogaz Marketing purchases gas from Naftogaz production and it has to import gas from Gazprom Export, since domestic demand exceeds indigenous production.

Gazprom Export is Gazprom's subsidiary responsible for international marketing and export activities. Gazprom Export holds a monopoly position in exporting Russian gas to European and CIS markets (Gazprom, 2010b). It is assumed that to meet its export obligations Gazprom Export can purchase gas both from Gazprom Production and from Central Asian producers (Figure 2). In order to export gas, Gazprom Export has to contract transport services through Ukraine and Belarus, paying transit fees to Naftogaz Transit (through Ukraine) and Beltransgaz (through Belarus) respectively. Gazprom Export can also export gas directly to consuming countries (e.g., through Blue Stream to Turkey and through Nord Stream and South Stream to Europe, if the latter two projects materialize as planned by Gazprom). Gazprom plans to enter the global LNG market with anticipated LNG projects such as Shtokman and on the Yamal Peninsula; therefore, this model includes the possibility of Gazprom exporting gas as LNG.

There are two connections between the FSU sub-model (Figure 2) and the European sub-model (Figure 1). One is through Gazprom Export's activities, as the blue oval in Figure 2 "European Markets" is the market model in Figure 1. The other is via the activities of transit countries (Ukraine and Belarus).

3.2.2. Investment decisions in capacity expansion

The model we implement is a static one, i.e. we are focusing only on operational decisions, such as how much of natural gas to produce and sale under limited production capacity or how much pipeline transport capacity to allocate given physical transport constraints. Investment in capacity expansion (such as production, pipeline and LNG capacity) is assumed exogenous to the model. Sensitivity analysis is done on major assumptions concerning physical constraints and results of this analysis are reported in Section X. Investment decisions concerning capacity expansion in a large-scale natural gas simulation model have been implemented, among other researchers, by Zwart and Mulder (2006), Lise and Hobbs (2008), Egging et al. (2009).

3.2.3. Behaviour of market players in the model

The model allows the following players to be simulated as having market power:

1. producers (e.g., Producer *i* in Figure 1 or Gazprom Export in Figure 2)
2. transit countries (e.g., Ukraine and Belarus in Figure 2)
3. suppliers (e.g., Supplier *y* in Figure 1).

3.2.3.1. The successive exercise of market power by producers and suppliers

Producers are assumed to exert market power against downstream suppliers by playing a Cournot game with other upstream producers. If there is market power at both the supplier and production levels, a successive structure to the market game is assumed in which producers anticipate (*à la* Stackelberg) how suppliers react. The GASMOD (Holz et al., 2008) and static GASTALE (Boots et al., 2004) models have a similar market structure. Thus, the effective demand for gas producers reflects the exercise of market power by suppliers in their downstream market, and the slope of this effective demand is consistent with Cournot market power among the suppliers and the elasticity of final demand (Boots et al., 2004).

The assumption that producers anticipate how suppliers react and that suppliers treat the border price as given (i.e., suppliers are price-takers with respect to border prices) is not entirely true concerning large suppliers, who may have some market power vis-à-vis gas producers.[13] In contrast to the successive oligopoly relationship between producers and suppliers embodied in this model, the "traditional view" of the European gas markets is that producers and suppliers act simultaneously to extract the whole monopoly profit from the market and then share that profit according to their relative bargaining power (Smeers, 2008). Compared to the successive oligopoly approach, such vertical coordination to exercise market power can result in greater sales and lower prices and therefore a smaller loss of welfare (Smeers, 2008).

One way to accommodate such vertical coordination in this model's structure is to assume that only producers (or only suppliers) exert market power and that suppliers (producers) receive a fixed mark-up from final gas prices, assuming that the relative bargaining power of suppliers (producers) reflects the mark-up they receive (Smeers, 2008).

3.2.3.2. Representing transit market power

In this model, transit market power is represented by the conjectured transit demand curve approach, which assumes that large transit countries (e.g., Ukraine and Belarus) believe that they face a declining effective demand curve for their services with an assumed slope, rather than deriving a slope based on market fundamentals. For example, if Ukraine conjectures that Gazprom's transit quantity will diverge from its equilibrium value (x^*) in proportion to the change

[13] As Smeers (2008: p.19) noted:

> *"Global oil and gas companies may have lost a lot of bargaining power to acquire resources in Russia and Kazakhstan and some are kicked out of Venezuela; still they retain bargaining power at the EU border when it comes to buying and marketing natural gas."*

in Ukraine's transit fee from its equilibrium *tf**, the resulting conjectured transit demand equation is

$$(x - x^*) - M(tf - tf^*) = 0, \quad M < 0 \tag{5}$$

where *(x-x*)* is a change in demand for transportation services that the transit country conjectures will happen if it changes its transit fee by *(tf-tf*)*, and *M* is a conjectured slope for the transit demand curve.

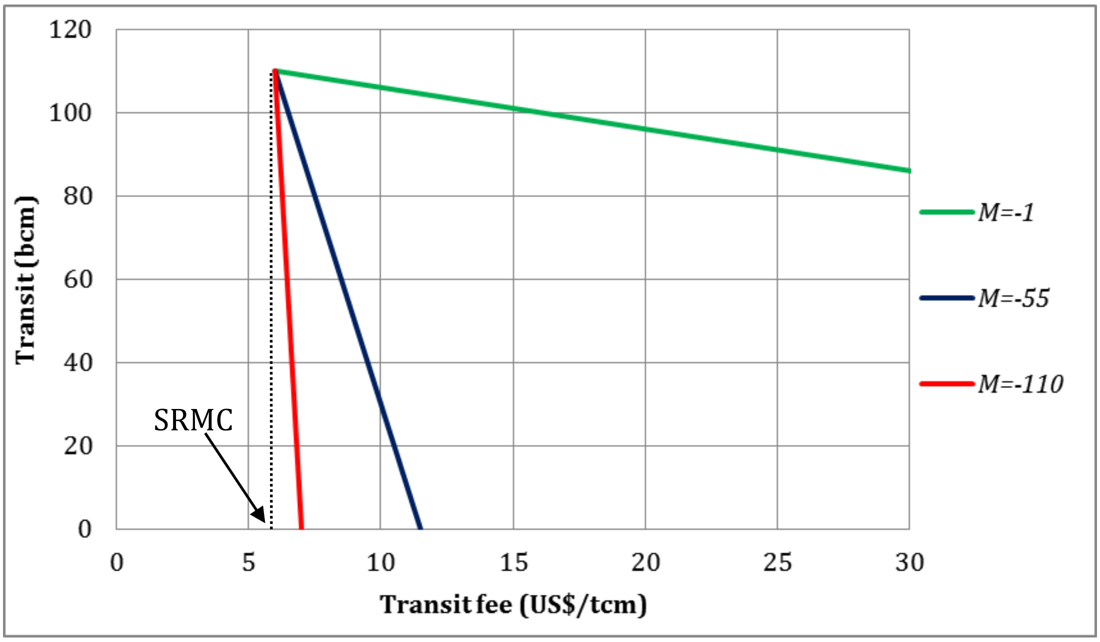

Figure 3: Ukraine's Conjectured Transit Demand Curves

In Figure 3, as an example, the transit demand curve for Ukraine under different values of conjectured slope *M* is plotted.[14] It can be seen from this figure that if the slope of the transit demand curve is large enough (e.g., *M=-110*), then small changes in the transit fee will cause large changes in the transit quantities. This is possible if, for example, Gazprom has substantial transport capacities in alternative pipelines that "bypass" Ukraine. *M=-110* was chosen as an example to represent the scenario of Gazprom building both the Nord Stream and South Stream pipelines (with a total capacity of 110 bcm). In this scenario, Ukraine conjectures that a unit increase in the transit fee may cause Gazprom to divert up to 110 bcm from Ukraine to alternative pipelines. This is why the transit demand curve is very steep (the "red" curve in Figure 3) and close to its short-run marginal cost (SRMC). In this scenario, Ukraine prices its transit service

[14] The transit demand slopes plotted in Figure 3 are for expositional purpose only. The values of *M={-1;-55;-110}* are taken to clarify the meaning of *M* in the context of Gazprom's bypass pipelines. Sensitivity analysis of *M* is provided in Appendix G.

close to the competitive price, which is logical since if Gazprom has capacity that allows it to totally avoid Ukraine, then there is no market power left for Ukraine to exercise. The scenario of *M=-55* corresponds to Gazprom building Nord Stream only (its transport capacity is 55 bcm).

Where the conjectured slope is negligible (e.g., *M=-1*), Ukraine believes that any change in its transit fee has little effect on the quantity Gazprom ships through Ukraine, e.g., because Ukraine believes that Gazprom has no alternative export pipelines. In Figure 3 the transit demand curve with the slope *M=-1* ("green" curve) is almost flat.

In general, a conjectural variation shows a firm's belief about the reaction (or variation) of another firm to potential adjustments in the first firm's actions. In the case being considered here, this belief is captured in the form of an exogenous parameter, *M*, expressing the derivative of the transit quantity with respect to the transit price. It is easy to see that at the limit eq. (5) is the definition of the derivative of the transit quantity with respect to the transit fee:

$$\lim_{\Delta \to 0} \frac{\Delta x}{\Delta tf} = \frac{\partial x}{\partial tf} \stackrel{\text{def}}{=} M < 0 \qquad (6)$$

where $\Delta x = x - x^*$ and $\Delta tf = tf - tf^*$

Despite the appeal of its simplicity, the conjectural variations approach has theoretical limitations (Smeers, 2008). In general, economic theorists view conjectural variations as being the endogenous result of a dynamic game (Dockner, 1992); therefore, interpreting it as a constant parameter in a static model might be misleading (Friedman, 1983). Also, the firm's conjecture about another firm's response need not be correct (Friedman, 1983) and is highly dependent on precise market conditions.

Therefore, the conjectured transit demand slope, *M*, is treated parametrically and a sensitivity analysis of this parameter is provided (see Appendix G). Despite these shortcomings, as has been shown above, the conjecture transit demand function has an intuitive and practical interpretation. Furthermore, it allows the model user to conveniently explore oligopolistic behaviour between competitive and monopolistic extremes.

Finally, the application of the conjectural variations approach to representation of market power is quite common in the energy market modelling literature. For example, the conjectured supply function has been applied in natural gas market modelling (e.g., Egging and Gabriel (2006), Egging et al. (2008) and Zwart and Mulder (2006)). The conjectured supply function represents traders' conjectures about variations in the supply from other traders in response to deviations in supply from the first trader. The conjectural variations approach is also widely used in the electricity market modelling literature, for example in the form of the conjectured supply function and the conjectured transmission price function (Day et al., 2002; Hobbs and Rijkers, 2004; Hobbs et al., 2004). In (Hobbs and Rijkers, 2004; Hobbs et al., 2004), the conjectured transmission price function represents a generator's belief about how its demand for transmission services affects the cost of transmitting power between two points. In this sense, the conjectured transmission price function, as applied in (Hobbs and Rijkers, 2004; Hobbs et al., 2004), has an inverse relationship to the conjectured transit demand function here because, in the first case, the generator believes that increasing demand for power transmission might drive up prices, whereas in this case the transit operator conjectures that an increase in the transit fee might depress transit flows through its pipelines.

3.2.3.3. Bilateral market power in the FSU gas sector

Modelling gas relations between buyers and sellers in FSU countries (Russia, Central Asia, Ukraine, Belarus and Moldova) represents a challenge for several reasons. First, the gas sector in the FSU countries is heavily regulated. Consequently, (*i*) natural gas is underpriced compared to its opportunity cost, and (*ii*) the gas "markets" are barely contestable, as the gas sector is dominated by a state-owned incumbent. Therefore, applying the Cournot framework (as it is applied to European markets) might not be appropriate for the FSU countries, where market fundamentals are not yet in place and where there is significant market power on the part of both buyers and sellers. Alternatively, a cooperative bargaining framework might be suitable for the analysis of bilateral gas monopolies in the FSU. Therefore, the following bilateral gas relations are modelled using the cooperative bargaining framework (see Appendix B for details):

1. Gazprom Export–Naftogaz Marketing
2. Gazprom Export–Beltransgaz
3. Gazprom Export–Central Asian gas producers
4. Gazprom Marketing–Russian "independent" gas producers.

3.2.3.4. Competitive access to the gas infrastructure

Apart from producers, suppliers and transit countries, all other market participants (such as transmission system operators and operators of liquefaction and regasification terminals) in the model are assumed to possess no market power. Therefore, transmission costs and the costs of LNG services are priced efficiently, i.e., access to pipelines and LNG facilities is granted to those market players who most value the services (i.e., based on marginal willingness to pay). This would result in charges based on (long-run) marginal costs and a congestion premium in case of pipeline or LNG facility saturation (Cremer et al., 2003; Gabriel and Smeers, 2005). Since congestion in natural gas transmission does not yet seem to be a major concern (Gabriel and Smeers, 2005), it is assumed here that users of pipelines and LNG facilities do not pay the congestion premium when pipelines and LNG facilities are saturated.[15] Thus, these congestion fees are used as a mechanism to simulate the efficient allocation of scarce pipeline and LNG capacities (Gabriel et al., 2005a; Gabriel et al., 2005b; Zhuang and Gabriel, 2008). The assumption of the efficient pricing of access to gas pipelines and LNG infrastructure is consistent with other strategic gas models (e.g., (Gabriel et al., 2005a; Egging et al., 2008; Lise and Hobbs, 2008)).

Smeers (2008) argues that efficient pricing of access to gas infrastructure is somewhat optimistic and diverges from the reality of gas market development in Europe (Smeers, 2008). However, recent agreements between private companies and European antitrust authorities (such as the capacity release programme agreed between GDF SUEZ, ENI, E.ON and EC) promise more competitive access to both transmission pipelines and LNG import terminals in Europe (EC, 2010; EC, 2009a; EC, 2009b).

Further, to represent the case when free access to the gas infrastructure and competitive pricing are not the norm in European markets, a scenario is simulated where pipeline (cross-border) and LNG import/export capacities are drastically limited, either because of physical saturation or because of restrictive practices found by the European Commission (EC, 2010, EC, 2009a, EC, 2009b) (see Appendix G).[16] The effect of this scenario on gas markets can be evaluated against the benchmark case of efficient access pricing for infrastructure.

3.3. Model Notation

3.3.1. Sets and Indices

$n \in N$	Set of all the nodes in the model, which includes the production, LNG liquefaction, regasification and transhipment nodes.
$N'(n)$	Set of nodes N' adjacent to node n. Nodes are connected either by gas pipelines or by LNG bilateral shipping links. LNG bilateral shipping links are only formed between LNG liquefaction terminals and regasification terminals.
$r \in R \subset N$	Set of regasification nodes R, a subset of all the nodes.

[15] The profit of the corresponding player is here adjusted ex-post to remove the resultant congestion costs.
[16] The "restrictive" pipeline access scenario is inspired by Smeers' (2008: p.34) suggestion.

$l \in L \subset N$	Set of liquefaction nodes *L*, a subset of all the nodes
$c \in C$	Set of 'non-FSU' consumption countries. *N(c)* is denoted as a set of gas off-taking nodes in country *c*. This could be either pipeline border points, LNG regasification terminals or indigenous production points.
$i \in I$	Set of all 'non-FSU' gas producing firms. For this model version there is an allocation of one firm to one production node[17]
N(i)	Set of nodes where *i* can produce gas
$y \in Y$	Set of all 'non-FSU' suppliers who buy gas from producers and exporters and re-sell it to final markets
$j \in J$	Set of all gas producers and exporters who sell gas to suppliers, *Y.* This includes all 'non-FSU' producers, *I,* and Gazprom Export, *G*
G	Variables and parameters associated with Gazprom Export are denoted with the letter *G*
$f \in F$	Set of FSU consumption countries. *N(f)* is denoted as a set of gas off-taking nodes in country *f*.
$u \in U \subset N$	Set of entry nodes of transit pipelines (Ukraine and Belarus)
$u' \in U'(u) \subset N$	Set of nodes *u'* that are directly connected to node *u*
$k \in K$	Set of 'FSU' producers, *K*
$t \in T(f)$	Set of suppliers that serve node *f* (In the implementation in this paper there is one supplier per consumption node, *f*, but more general implementations can be made).
K(G)	Set of 'FSU' producers who have commercial relations with Gazprom Export (*G*) (i.e. buying/selling gas)
K(t)	Set of 'FSU' producers who have commercial relations with supplier a *t* (i.e. buying/selling gas)
T(k)	Set of suppliers, *T,* who have commercial (gas buying/selling) relations with a

[17] The exception is Russia, where two firms are assigned - Gazprom and "independent" producers. If required, the allocation of firms to different production sites can be easily altered in the model.

producer, k (i.e. buying/selling gas)

T(G)	Set of suppliers, T, who have commercial relations with Gazprom Export (purchasing and selling gas)
N(k)	Set of production nodes, *N,* where producer k can be located
N(t)	Set of nodes, *N,* through which supplier t can import gas

3.3.2. Variables

For clarity of presentation, an asterisk (*) is used to denote variables that are exogenous to a particular market player's maximization problem. The variables might be exogenous to one or more players, but such variables are endogenously determined in the model. This is done either through market clearing conditions or through the maximization problems of other players.

Subscripts are used for indexation, and superscripts denote that a particular variable (or parameter) belongs to a particular type of player in the model. For example, s_{jync}^{Y} means the quantity of gas purchased by supplier y from upstream firm j and re-sold in market c through node *n.* Superscript Y denotes the sales variable for suppliers operating in European markets. Further, where necessary, buying and selling relationships between players are specified using the following notation: leftwards arrow (←) to denote "*from*" and rightwards arrow (→) to denote *"to"*. For example, $h_{tkn}^{T\leftarrow K}$ means gas purchases by supplier T from producer *K,* and $s_{ktn}^{K\rightarrow T}$ means gas sales by producer K to supplier *T*.

3.3.2.1. European sub-model

Supplier's Decision Variables

s_{jync}^{Y}	Quantity of gas purchased by supplier y from upstream firm j and re-sold in market c through node n.	Bcm/a

Producer's Decision Variables

s_{inc}^{I}	Producing firm i's total gas supply to all suppliers in market c through node n	Bcm/a
$x_{inn'}^{I}$	Producer i's transportation variable from node n to the next node n'	Bcm/a
$xl_{inn'}^{I}$	Producer i's LNG shipping variable from liquefaction node $n \in N(l(i))$ to	Bcm/a

	regasification node $n' \in N'(r)$	
q_{in}^{I}	Producer *i*'s production at node $n \in N(i)$	Bcm/a
	TSO's Decision Variables	
$d_{nn'}^{TSO}$	TSO decision variable regarding gas flows from node *n* to the next node *n'*	Bcm/a
	LNG Decision Variables	
q_{n}^{liq}	LNG liquefaction quantities at node $n \in N(l)$	Bcm/a
$q_{n'}^{regas}$	LNG regasification quantities at regasification node $n' \in N'(r)$	Bcm/a
	Price Variables	
p_c	Average consumer retail gas price in consumption country *c*	US$/tcm
bp_c	Border price for bulk gas in market *c*	US$/tcm
$tc_{nn'}$	Transmission price from *n* to *n'* including congestion premium	US$/tcm
$p_{n'}^{regas}$	LNG regasification price at node $n' \in N'(r)$	US$/tcm
p_{n}^{liq}	LNG Liquefaction price at node $n \in N(l)$	US$/tcm

3.3.2.2. FSU Sub-model

	Supplier's Decision Variables	
s_{tf}^{T}	Supplier *t* gas sales for final consumption in market *f*	Bcm/a
$h_{tkn}^{T \leftarrow K}$	Supplier *t* gas purchases from producer *k* and gas producing node $n \in N(k)$	Bcm/a
$h_{t}^{T \leftarrow G}$	Supplier *t* gas purchases from Gazprom Export *(G)*	Bcm/a
	Producer's Decision Variables	
$s_{ktn}^{K \rightarrow T}$	Producer *k* gas sales (produced from node $n \in N(k)$) to supplier *t*	Bcm/a
$s_{kn}^{K \rightarrow G}$	Producer *k* gas sales (produced from $n \in N(k)$) to Gazprom Export (*G*)	Bcm/a

q_{kn}^{K}	Producer *k* gas production from $n \in N(k)$	Bcm/a
	Gazprom Export	
s_{nc}^{G}	Gazprom Export's total gas sales to all suppliers in market $c \in C(G)$ through node $n \in N(c)$	Bcm/a
$s_{tnf}^{G\rightarrow T}$	Gazprom Export's gas sales to supplier $t \in T(f)$ in consumption country *f* through node $n \in N(t)$	Bcm/a
$h_{kn}^{G\leftarrow K}$	Gazprom Export's gas purchases from producer *k* and node $n \in N(k)$	Bcm/a
$x_{nn'}^{G}$	Transport variable from *n* to *n'*	Bcm/a
$xl_{nn'}^{G}$	LNG shipping variable from $n \in N(l(G))$ to $n' \in N'(r)$	Bcm/a
	Natural Gas Transit	
$tf_{uu'}$	Decision variable representing the transit fee through pipeline *(u,u')*	US$/tcm
$d_{uu'}^{TR}$	Transit operator's decision about how much transit capacity through *(u,u')* to render to Gazprom Export	Bcm/a
	Price Variables	
$p_{ktn}^{K\rightarrow T}$	Price of gas produced from $n \in N(k)$ by producer *k* to supplier *t*	US$/tcm
$bp_{t}^{G\rightarrow T}$	Gazprom Export's sales (border) price to supplier *t*	US$/tcm
$p_{pz}^{K\rightarrow G}$	Sales prices of gas produced from $n \in N(k)$ by producer *k* to Gazprom Export	US$/tcm
$p_{uu'}^{TR}$	Congestion premium through transit pipeline *(u,u')*	US$/tcm

3.3.3. Exogenous Parameters and Functions

3.3.3.1. European sub-model

Supplier's Parameters/Functions

DC_c	Unit distribution cost in market *c*	US$/tcm
R_c	Number of suppliers serving market *c*	

Θ_c^Y	0-1 parameter: Θ_c^Y=0 if suppliers serving final market *c* are competitive players, and Θ_c^Y=1 if those suppliers are instead Cournot players in the final market *c*	

Producer's Parameters/Functions

$TPC_i(\cdot)$	Producer *i*'s total production cost	US$
CAP_{in}^{PR}	Producer *i*'s production capacity as available at node *n*	Bcm/a
Θ_{ic}^I	0-1 parameter: Θ_{ic}^I=0 if producer *i* behaves competitively, and Θ_{ic}^I=1 if producers are Cournot players in market *c*	

TSO's Parameters/Functions

$TC_{nn'}^{TSO}(\cdot)$	Total transmission cost to transport gas from *n*∈*N* to *n'*∈*N'(n)*	US$
$CAP_{nn'}^{TSO}$	Capacity of pipeline *(n,n')*	Bcm/a
$LOSS_{nn'}^{PIPE}$	Loss factor due to fuel consumption by compressors along pipeline *(n,n')*	fraction of gas transport per km

LNG Parameters/Functions

$SC_{nn'}$	LNG unit shipping cost from *n*∈*N(l)* to *n'*∈*N'(r)*	US$/tcm
$TC^{liq}(\cdot)$	Total cost of gas liquefaction (assumed linear in this model, although more general formulations are possible)	US$
CAP_n^{LIQ}	Total liquefaction capacity at node *n*∈*N(l)*	Bcm/a
$TC^{regas}(\cdot)$	Total cost (linear) of LNG regasification	US$
$CAP_{n'}^{REGAS}$	Total regasification capacity available at node *n'*∈*N'(r)*	Bcm/a
$LOSS_{nn'}^{LNG}$	Total loss factor during LNG liquefaction, shipping and regasification from *n'* to *n*	fraction of gas shipments

3.3.3.2. FSU Sub-model:

Supplier's Parameters/Functions

DC_f	Unit distribution cost in market *f*	US$/tcm

$D_f(\cdot)$	Demand function in market f, which depends on the regulated average retail price P_f^{REG}	Bcm/a

Producer's Parameters/Functions

$TCP_k(\cdot)$	Producer k's total production cost	US$
CAP_{kn}^{PR}	Producer k's production capacity available at node $n \in N(k)$	Bcm/a

Gazprom Export's Parameters/Functions

Θ_c^G	0-1 parameter: Θ_c^G=0 if Gazprom Export behaves competitively in market c, Θ_c^G=1 if Gazprom Export is *à la* Cournot in market c	

Natural Gas Transit Parameters/Functions

$TC_{uu'}^{TR}(\cdot)$	Total transit cost (linear) through pipeline *(u,u')*	US$/tcm
$M_{uu'}$	Conjectured transit demand slope through transit pipeline *(u,u')*, $M_{uu'}$<0	Bcm/US$/tcm
$CAP_{uu'}^{TR}$	Transportation capacity through transit pipeline *(u,u')*	Bcm/a
$\Theta_{uu'}^{TR}$	0-1 parameter: $\Theta_{uu'}^{TR}$=0 if transit through pipeline *(u,u')* is priced competitively, and $\Theta_{uu'}^{TR}$=1 if the transit country is assumed to exercise market power vis-a-vis Gazprom Export over the transit pipeline *(u,u')*	

3.4. Profit Maximization Problems

3.4.1. European Sub-model

3.4.1.1. Supplier Model

The supplier's objective is to maximize its profit (π_y^Y) from purchasing gas from upstream firm *j* through node *n* at border price bp_{yc}^* and re-selling it to final market *c*:

$$\max_{s_{jync}^Y \geq 0} \pi_y^Y = \sum_{j \in J, n \in N(c), c \in C} s_{jync}^Y \left(p_c - bp_{yc}^* - DC_c\right) \qquad (7)$$

The border price, bp_{yc}^{*}, is exogenous to the supplier's problem, however it is determined endogenously in the model (as denoted by the asterisk). Supplier y has to pay a distribution cost, DC_c, to sell gas to the final customers in c. Further, it is assumed that suppliers treat the border price as given, i.e. they are price-takers with respect to border prices. This formulation of the supplier's problem has been used previously, for instance by Boots et al. (2004).

The following are the first-order (Karush-Kuhn-Tucker, KKT) conditions for the downstream profit maximization problem (7):

$$0 \leq s_{jync}^{Y} \perp \left[p_c - bp_{yc}^{*} - DC_c + \frac{\partial p_c}{\partial s_{jync}^{Y}} s_{jync}^{Y} \right] \leq 0, \qquad \forall c \in C \tag{8}$$

Then the expression for the border price is derived from (8) as follows:

$$bp_{yc}^{*} \geq p_c - DC_c + \frac{\partial p_c}{\partial s_{jync}^{Y}} s_{jync}^{Y}, \qquad \forall c \in C \tag{9}$$

In this model version, for each country, c, one aggregate demand function is assumed, i.e. gas consumption is not differentiated by sector (e.g., industrial, household, power sectors, etc.); more detailed formulations of the demand side are, of course, possible (e.g., (Egging et al., 2008; Lise and Hobbs, 2008)). Following Boots et al. (2004), a linear demand function for natural gas is assumed as follows:

$$p_c = B_c + A_c \sum_{j \in J, y \in Y, n \in N(c)} s_{jync}^{Y}, \qquad \forall c \in C \tag{10}$$

where $B_n > 0$, $A_n < 0$ are parameters to be calibrated at assumed elasticity and price-quantity pairs for the base year (2009) (see Appendix C, Table C.1).

Similarly to Boots et al., (2004), it is assumed that suppliers in market c are identical[18] and cannot be discriminated between, so $bp_{yc}=bp_c$ and furthermore the sales variable of upstream firm j to market c is $s_{jnc}^{J} = \sum_y s_{jync}^{Y}$. If supplies to market c are strictly positive, then by taking into account the assumed symmetry of suppliers in market c we can use expression (10) to express the border price for market c as follows:

[18] As Smeers (2008) argues, this assumption does not correspond to the reality of European downstream gas markets.

$$bp_c = \hat{B}_c + \hat{A}_c \sum_{j \in J, n \in N(c)} s_{jnc}, \qquad \forall c \in C \tag{11}$$

where:

$$\hat{B}_c = B_c - DC_c, \qquad \forall c \in C \tag{12}$$

$$\hat{A}_c = A_c \left[\Theta_c^Y \left(\frac{R_n + 1}{R_n} \right) + (1 - \Theta_c^Y) \right], \qquad \forall c \in C \tag{13}$$

The latter expression accounts for whether the supplier market is assumed to be competitive or Cournot (Θ_c^Y=0 if suppliers serving market c are competitive players, and Θ_c^Y=1 if suppliers are Cournot players).

3.4.1.2. Producer Model

The producer's objective is to maximize its profit (π_i^I) by choosing how much gas to sell to market *c* (s_{inc}^I) through node *n*. It also has to choose the production quantity (q_{in}^I) at node *n,* paying total production costs (*TPC$_i$*). Following Golombek and Gjelsvik (1995), Egging et al. (2008) and Lise and Hobbs (2008), the total production cost is assumed to be an increasing function of the production rate q_{in}^I (for details see Appendix C, Table C.6). The production cost function (*TPC$_i$*) is assumed to be separable over time, so inter-temporal production constraints and costs (arising from, e.g., depletion effects) are not considered.[19] More general functions could be considered (e.g., (Zwart and Mulder, 2006; Gabriel et al., 2003)). Apart from production costs, transport expenses from nodes *n* to *n'* are also incurred, either through pipelines ($x_{inn'}^I$) and paying transmission costs ($tc_{nn'}^*$), or through LNG vessels ($xl_{inn'}^I$), paying liquefaction (p_n^{liq*}), shipping ($SC_{nn'}$) and regasification costs ($p_{n'}^{regas*}$). The resultant producer's maximization problem is as follows:

$$\begin{aligned} \max_{s_{inc}^I, q_{in}^I, x_{inn'}^I, xl_{inn'}^I \geq 0} \pi_i^I \\ = \sum_{n \in N(c), c \in C(i)} s_{inc}^I bp_c - \sum_{n \in N(i)} TPC_i(q_{in}^I) - \sum_{n \in N} \sum_{n' \in N'(n)} x_{inn'}^I tc_{nn'}^* \\ - \sum_{n \in N} \sum_{n' \in N'(n)} xl_{inn'}^I \left(p_n^{liq*} + SC_{nn'} + p_{n'}^{regas*} \right) \end{aligned} \tag{14}$$

subject to

[19] It should be noted that the producer model presented here is only an approximation to the complicated engineering problems of petroleum extraction in the real world.

$$s_{inc} + \sum_{n' \in N'(n)} \left[x^I_{inn'} + xl^I_{inn'} - \left(1 - loss^{pipe}_{n'n}\right)x^I_{in'n} - \left(1 - loss^{lng}_{n'n}\right)xl^I_{in'n}\right] \leq q^I_{in'} \tag{15}$$

$$(\beta^I_{in} \geq 0), \qquad \forall n \in N(i), c \in C(i)$$

$$q^I_{in} \leq CAP^{PR}_{in}, \qquad (\gamma^I_{in} \geq 0), \qquad \forall n \in N(i) \tag{16}$$

As indicated by eq. (15) (preservation of mass balance at node *n*), the gas pipeline network is modelled as a transhipment problem with a constant proportion of losses.[20] Detailed technical phenomena, such as line pack or nonlinear pipeline shipment costs as a function of total flow, are not considered; more sophisticated representations are possible (e.g.,(O'Neill et al., 1979; De Wolf and Smeers, 1996; Midthun et al., 2009)).

The KKT conditions for (14) are

$$\forall s^I_{inc}: \quad 0 \leq s^I_{inc} \perp \left(bp_c + \frac{\partial bp_c}{\partial s^I_{inc}} s^I_{inc} \Theta^I_{ic} + \beta^I_{in}\right) \leq 0 \tag{17}$$

$$\forall q^I_{in}: \quad 0 \leq q^I_{in} \perp \left(-\frac{\partial TPC_i(q^I_{in})}{\partial q^I_{in}} - \beta^I_{in} + \gamma^I_{in}\right) \leq 0 \tag{18}$$

$$\forall x^I_{inn'}: \quad 0 \leq x^I_{inn'} \perp (-tc^*_{inn'} + \beta^I_{in}) \leq 0 \tag{19}$$

$$\forall xl^I_{inn'}: \quad 0 \leq xl^I_{inn'} \perp \left(-p^{liq*}_n - SC_{nn'} - p^{regas*}_{n'} + \beta^I_{in}\right) \leq 0 \tag{20}$$

$$\begin{aligned} \forall \beta^I_{in}: \quad 0 \leq \beta^I_{in} & \\ & \perp \left(s_{inc} + \sum_{n' \in N'(n)} \left[x^I_{inn'} + xl^I_{inn'} - \left(1 - loss^{pipe}_{n'n}\right)x^I_{in'n} - \left(1 - loss^{lng}_{n'n}\right)xl^I_{in'n}\right] - q^I_{in}\right) \\ & \leq 0 \end{aligned} \tag{21}$$

$$\forall \gamma^I_{in}: \quad 0 \leq \gamma^I_{in} \perp (q^I_{in} - CAP^{PR}_{in}) \leq 0 \tag{22}$$

Note that in (17) the mark-up term $\frac{\partial bp_c}{\partial s^I_{inc}} s^I_{inc}$ is multiplied with the exogenous 0-1 parameter Θ^I_{ic} (Θ^I_{ic}=0 if producer *i* behaves competitively, and Θ^I_{ic}=1 if producer *i* behaves *à la* Cournot in market *c*).

[20] Flow conservation at a particular node is expressed as inequality rather than equality as this allows the model to be solved more efficiently. The solution of the model with flow conservation expressed as equalities is the same as in the case of inequalities.

3.4.1.3. *Efficient TSO Model (Non-FSU)*

It is assumed that the transmission cost through the pipeline *(n,n')* is priced efficiently, i.e. it is assumed that TSOs behave competitively and grant access to the pipeline infrastructure to those market players who value transmission services the most. This would result in a transmission charge based on marginal costs and a congestion premium in case pipeline *(n,n')* is saturated (Cremer et al., 2003; Gabriel and Smeers, 2005). Thus, the TSO objective is to

$$\max_{d_{nn'}^{TSO}\geq 0} \pi^{TSO} = \sum_{n\in N\backslash U,\ n'\in N'(n)} \left[d_{nn'}^{TSO} tc_{nn'}^{*} - TC_{nn'}^{TSO}(d_{nn'}^{TSO})\right] \tag{23}$$

subject to

$$d_{nn'}^{TSO} \leq CAP_{nn'}^{TSO}, \qquad (\gamma_{nn'}^{TSO} \geq 0), \qquad \forall n \in N\backslash U, n' \in N'(n) \tag{24}$$

KKT conditions

$$\forall d_{nn'}^{TSO}:\ 0 \leq d_{nn'}^{TSO} \perp \left(tc_{nn'}^{*} - \frac{\partial TC_{nn'}^{TSO}(d_{nn'}^{TSO})}{\partial d_{nn'}^{TSO}} + \gamma_{nn'}^{TSO}\right) \leq 0 \tag{25}$$

$$\forall \gamma_{nn'}^{TSO}:\ 0 \leq \gamma_{nn'}^{TSO} \perp (d_{nn'}^{TSO} - CAP_{nn'}^{TSO}) \leq 0 \tag{26}$$

3.4.1.4. *LNG Model*

In order to export LNG, upstream firm *j* liquefies natural gas and then ships it to consuming markets, where the LNG will be regasified for final consumption. As with TSOs (other than Ukraine and Belarus) who manage transmission pipelines, it is assumed that liquefiers and regasifiers behave competitively and price LNG services efficiently (this is consistent with previous gas models where the LNG value chain has been explicitly modelled; see, e.g., (Egging et al.,2008)).

Further, it is assumed that the producer retains ownership of the gas and contracts transport services, as opposed to a situation where the transporter buys the gas from the producer at the point of liquefaction. Since it is assumed that LNG services (liquefaction and regasification) are priced competitively, this assumption does not change the results (see Appendix A for the proof of this statement).

Liquefaction

The objective of liquefiers is to maximize the value of liquefaction services (27) given their constraints on liquefaction capacity (28):[21]

$$\max_{q_n^{liq}} \pi^{LIQ} = q_n^{liq} p_n^{liq*} - TC^{liq}(q_n^{liq}) \tag{27}$$

subject to

$$q_n^{liq} \leq CAP_n^{LIQ}, \qquad \left(\gamma_n^{LIQ} \geq 0\right), \qquad \forall n \in N(l) \tag{28}$$

The KKT conditions for (27) are

$$\forall q_n^{liq}:\ 0 \leq q_n^{liq} \perp \left(p_n^{liq*} - \frac{\partial TC^{liq}(q_n^{liq})}{\partial q_n^{liq}} + \gamma_n^{LIQ}\right) \leq 0 \tag{29}$$

$$\forall \gamma_n^{LIQ}:\ 0 \leq \gamma_n^{LIQ} \perp \left(q_n^{liq} - CAP_n^{LIQ}\right) \leq 0 \tag{30}$$

Regasification

LNG needs to be regasified in order to supply final customers. The regasifier maximizes the profit gained from the provision of regasification services (31) subject to capacity constraints (32):

$$\max_{q_{n'}^{regas}} \pi^{REGAS} = q_{n'}^{regas} p_{n'}^{regas*} - TC^{regas}(q_{n'}^{regas}) \tag{31}$$

subject to

$$q_{n'}^{regas} \leq CAP_{n'}^{REGAS}, \qquad (\gamma_{n'}^{REGAS} \geq 0), \qquad \forall n' \in N'(r) \tag{32}$$

The KKT conditions for (31) are

$$\forall q_{n'}^{regas}:\ \ 0 \leq q_{n'}^{regas} \perp \left(p_{n'}^{regas*} - \frac{\partial TC^{regas}(q_{n'}^{regas})}{\partial q_{n'}^{regas}} + \gamma_{n'}^{REGAS}\right) \leq 0 \tag{33}$$

$$\forall \gamma_{n'}^{REGAS}:\ 0 \leq \gamma_{n'}^{REGAS} \perp \left(q_{n'}^{regas} - CAP_{n'}^{REGAS}\right) \leq 0 \tag{34}$$

[21] After solving the model, where appropriate the profit of the liquefaction operator is added to the overall profit of the producer who in reality owns the liquefaction facility. Since the liquefaction facility is priced competitively, this does not alter the results. Proof of this statement is in Appendix A.

3.4.2. FSU sub-model

3.4.2.1. Supplies to the domestic market

In the following, the modelling of gas supplies for consumption in Russia, Ukraine, Belarus and Moldova is discussed. Each of these markets (f) is served by the state-owned gas supplier, t. The supplier's main goal is to meet domestic demand, D_f, at the regulated price, P_f^{Reg}. The supplier t can do so by purchasing gas from indigenous production ($h_{tkn}^{T\leftarrow K}$) or by importing gas from Gazprom Export ($h_t^{T\leftarrow G}$), paying them the wellhead price ($p_{ktn}^{K\rightarrow T*}$) and border price ($bp_f^{G\rightarrow T*}$) respectively. Thus, the objective of the supplier is to maximize its profit (π_t^T): [22]

$$\max_{s_{tf}^T, h_{tkn}^{T\leftarrow K}, h_t^{T\leftarrow G}\geq 0} \pi_t^T = s_{tf}^T\left(P_f^{Reg} - DC_f\right) - \sum_{k\in K(t)}\sum_{n\in N(k)} h_{tkn}^{T\leftarrow K} p_{ktn}^{K\rightarrow T*} - h_t^{T\leftarrow G} bp_f^{G\rightarrow T*} \tag{35}$$

subject to

$$s_{tf}^T - D_f\left(P_f^{REG}\right) = 0, \qquad \left(\alpha_f^T - free\right), \qquad \forall t \in T(f), f \in F \tag{36}$$

$$s_{tf}^T \leq \sum_{k\in K(t)}\sum_{n\in N(k)} h_{tkn}^{T\leftarrow K} + h_t^{T\leftarrow G}, \qquad \left(\beta_f^T \geq 0\right), \qquad \forall t \in T(f), f \in F \tag{37}$$

KKT conditions:

$$\forall s_{tf}^T: \quad 0 \leq s_{tf}^T \perp \left(P_f^{Reg} - DC_f + \alpha_f^T + \beta_f^T\right) \leq 0 \tag{38}$$

$$\forall h_{tkn}^{T\leftarrow K}: \; 0 \leq h_{tkn}^{T\leftarrow K} \perp \left(-p_{ktn}^{K\rightarrow T*} - \beta_f^T\right) \leq 0 \tag{39}$$

$$\forall h_t^{T\leftarrow G}: \; 0 \leq h_t^{T\leftarrow G} \perp \left(-bp_f^{G\rightarrow T*} - \beta_f^T\right) \leq 0 \tag{40}$$

$$\forall \alpha_f^T: \qquad \alpha_f^T \perp \left(s_{tf}^T - D_f\left(P_f^{REG}\right)\right) = 0 \tag{41}$$

$$\forall \beta_f^T: \quad 0 \leq \beta_f^T \perp \left(s_{tf}^T - \left[\sum_{k\in K(t)}\sum_{n\in N(k)} h_{tkn}^{T\leftarrow K} + h_t^{T\leftarrow G}\right]\right) \leq 0 \tag{42}$$

3.4.2.2. Gas Production

The objective of a gas production company is to maximize its profit (π_k^K) by deciding how much to produce (q_{kn}^K) from each region ($n \in N(k)$) and how much to sell to each supplier t and

[22] Note that since P_f^{REG} is exogenously fixed, (35) is equivalent to the cost minimization problem.

Gazprom Export (G). Producers sell gas at the wellhead prices (p_{ktn}^{K*} and $p_{kn}^{K\to G*}$), subject to production constraints (44-45).

$$\max_{s_{ktn}^{K\to T}, s_{kn}^{K\to G}, q_{kn}^{K}\geq 0} \pi_k^K = \sum_{t\in T(k), n\in N(k)} s_{ktn}^{K\to T} p_{ktn}^{K\to T*} + \sum_{n\in N(k)} s_{kn}^{K\to G} p_{kn}^{K\to G*} - \sum_{n\in N(k)} TCP_k(q_{kn}^K) \tag{43}$$

subject to

$$\sum_{t\in T(k)} s_{ktn}^{K\to T} + \sum_{n\in N(k)} s_{kn}^{K\to G} \leq q_{kn}^K, \qquad (\beta_{kn}^K \geq 0), \qquad \forall k \in K, n \in N(k) \tag{44}$$

$$q_{kn}^K \leq CAP_{kn}^{PR}, \qquad (\gamma_{kn}^K \geq 0), \qquad \forall k \in K, n \in N(k) \tag{45}$$

KKT conditions:

$$\forall s_{ktn}^{K\to T}: \quad 0 \leq s_{ktn}^{K\to T} \perp (p_{ktn}^{K\to T*} + \beta_{kn}^K) \leq 0 \tag{46}$$

$$\forall s_{kn}^{K\to G}: \quad 0 \leq s_{kn}^{K\to G} \perp (p_{kn}^{K\to G*} + \beta_{kn}^K) \leq 0 \tag{47}$$

$$\forall q_{kn}^K: \quad 0 \leq q_{kn}^K \perp \left(-\frac{\partial TCP_k(q_{kn}^K)}{\partial q_{kn}^K} - \beta_{kn}^K + \gamma_{kn}^K\right) \leq 0 \tag{48}$$

$$\forall \beta_{kn}^K: \quad 0 \leq \beta_{kn}^K \perp \left(\sum_{t\in T(k)} s_{ktn}^{K\to T} + \sum_{n\in N(k)} s_{kn}^{K\to G} - q_{kn}^K\right) \leq 0 \tag{49}$$

$$\forall \gamma_{kn}^K: \quad 0 \leq \gamma_{kn}^K \perp (q_{kn}^K - CAP_{kn}^{PR}) \leq 0 \tag{50}$$

3.4.2.3. Gazprom Export

The objective of Gazprom Export is to maximize its profit (π^G) from gas sales to the export market, *c*, through node *n* (s_{nc}^G) at the border price (bp_c) and from exporting to FSU markets *f* through node *n* ($s_{tnf}^{G\to T}$) at the border price $bp_f^{G\to T*}$. In order to export gas it has to purchase gas ($h_{kn}^{G\leftarrow K}$) at prices ($p_{kn}^{K\to G*}$) set by gas producers. Also, it has to transport gas to final markets ($x_{nn'}^G$), paying a transmission price ($tc_{nn'}^*$ including transit fees through Ukraine and Belarus). The resultant profit maximization problem for Gazprom Export is:

$$\max_{s_{nc}^G, s_{tnf}^G, h_{kn}^{G\leftarrow K}, x_{nn'}^G, xl_{nn'}^G \geq 0} \pi^G$$

$$= \sum_{n\in N(c)} \sum_{c\in C(G)} s_{nc}^G bp_c + \sum_{t\in T(G)} \sum_{n\in N(t), f\in F} s_{tnf}^{G\to T} bp_f^{G\to T*}$$

$$- \sum_{k\in K(G)} \sum_{n\in N(k} h_{kn}^{G\leftarrow K} p_{kn}^{K\to G*} - \left(\sum_{n\in N} \sum_{n'\in N'(n)} x_{nn'}^G tc_{nn'}^* \right. \tag{51}$$

$$\left. + \sum_{n\in N} \sum_{n'\in N'(n)} xl_{nn'}^G (p_n^{liq*} + SC_{nn'}^G + p_{n'}^{regas*}) \right)$$

subject to

$$s_{nc}^G + \sum_{t\in T(G)} s_{tnf}^{G\to T} + \sum_{n'\in N'(n)} \left[x_{nn'}^G + xl_{nn'}^G - \left(1 - loss_{n'n}^{pipe}\right) x_{n'n}^G - \left(1 - loss_{n'n}^{lng}\right) xl_{n'n}^G \right]$$

$$\leq \sum_{k\in K(G)} h_{kn}^{G\leftarrow K}\ , \qquad (\beta_n^G \geq 0), \qquad \forall n: n \in \left(N(G) \cup N(k)\right), c \in C(G) \tag{52}$$

Gazprom Export maximizes its profit (51) subject to flow conservation constraints (52). The KKT conditions for (51) are

$$\forall s_{nc}^G: \qquad 0 \leq s_{nc}^G \perp \left(bp_c + \frac{\partial bp_c}{\partial s_{nc}^G} s_{nc}^G \Theta_c^G + \beta_n^G \right) \leq 0 \tag{53}$$

$$\forall s_{tnf}^G: \qquad 0 \leq s_{tnf}^G \perp \left(bp_f^{G\to T*} + \beta_n^G \right) \leq 0 \tag{54}$$

$$\forall h_{kn}^{G\leftarrow K}: \quad 0 \leq h_{kn}^{G\leftarrow K} \perp (-p_{kn}^{K\to G*} - \beta_n^G) \leq 0 \tag{55}$$

$$\forall x_{nn'}^G: \qquad 0 \leq x_{nn'}^G \perp (-tc_{nn'}^* + \beta_n^G) \leq 0 \tag{56}$$

$$\forall xl_{nn'}^G: \quad 0 \leq xl_{nn'}^G \perp \left(-p_n^{liq*} - SC_{nn'}^G - p_{n'}^{regas*} + \beta_n^G \right) \leq 0 \tag{57}$$

$$\forall \beta_n^G: \qquad 0 \leq \beta_n^G$$

$$\perp \left(s_{nc}^G + \sum_{t\in T(G)} s_{tnf}^{G\to T} \right.$$

$$+ \sum_{n'\in N'(n)} \left[x_{nn'}^G + xl_{nn'}^G - \left(1 - loss_{n'n}^{pipe}\right) x_{n'n}^G - \left(1 - loss_{n'n}^{lng}\right) xl_{n'n}^G \right] \tag{58}$$

$$\left. - \sum_{k\in K(G)} h_{kn}^{G\leftarrow K} \right) \leq 0$$

Note that, similarly to producer *i*, Gazprom Export's mark-up term $\frac{\partial bp_c}{\partial s_{nc}^G} s_{nc}^G$ is multiplied with the exogenous parameter Θ_c^G (Θ_c^G=0 if Gazprom Export behaves competitively in market *c*, Θ_c^G=1 if Gazprom Export is a Cournot player in market *c)*.

3.4.2.4. Transit pricing through Ukraine and Belarus

The transit country maximizes its profit from rendering transit services to Gazprom Export as follows:

$$\max_{tf_{uu'}d_{uu'}^{TR}\geq 0} \pi^{TR} = \sum_{u,u'} [tf_{uu'}x_{uu'}^G + (d_{uu'}^{TR}p_{uu'}^{TR*} - TC_{uu'}^{TR}(d_{uu'}^{TR}))] \tag{59}$$

subject to

$$d_{uu'}^{TR} \leq CAP_{uu'}^{TR}, \qquad (\gamma_{uu'}^{TR} \geq 0), \qquad \forall u \in U, u' \in U'(u) \tag{60}$$

The first term ($tf_{uu'}x_{uu'}^G$) in the brackets is the revenue gained due to the exercise of market power, while the second term is the profit under efficient transit pricing (similarly to the efficient TSO model (23)), where $p_{uu'}^{TR*}$ is the congestion premium determined by market clearing conditions (74). As was discussed earlier, to represent market power in gas transits through Ukraine and Belarus, the conjectured transit demand curve approach is applied with the following slope:

$$\frac{\partial x_{uu'}^G}{\partial tf_{uu'}} \stackrel{\text{def}}{=} M_{uu'} < 0 \tag{61}$$

Then, the following are the first-order (KKT) conditions for the transit country profit maximization problem (59):

$$\forall tf_{uu'}: \quad 0 \leq tf_{uu'} \perp (x_{uu'}^G + M_{uu'}tf_{uu'}) \leq 0 \tag{62}$$

$$\forall d_{uu'}^{TR}: \quad 0 \leq d_{uu'}^{TR} \perp \left(p_{uu'}^{TR*} - \frac{\partial TC_{uu'}^{TR}(\cdot)}{\partial d_{uu'}^{TR}} + \gamma_{uu'}^{TR}\right) \leq 0 \tag{63}$$

$$\forall \gamma_{uu'}^{TR}: \quad 0 \leq \gamma_{uu'}^{TR} \perp (d_{uu'}^{TR} - CAP_{uu'}^{TR}) \leq 0 \tag{64}$$

If $d_{uu'}^{TR}, tf_{uu'} > 0$, then the transit price through pipeline *(u,u')* that Gazprom Export should pay is

$$tc_{uu'}^{*} = p_{uu'}^{TR*} - \frac{x_{uu'}^{G}}{M_{uu'}}, \qquad M_{uu'} < 0 \tag{65}$$

3.4.3. Market Clearing Conditions

In this section all the market clearing conditions that are needed to equate demand with supply are gathered. The following market clearing constraints (66) require that the average final price matches the inverse demand function at the equilibrium point:

$$p_c^{*} - \left(B_c + A_c \sum_{j \in J, y \in Y, n \in N(c)} s_{jync}^{Y} \right) = 0, \qquad \forall c \in C \tag{66}$$

and the following market clearing conditions (67) define the effective border price (as derived in Section 3.4.1.1.) :

$$bp_c^{*} - \left(\hat{B}_c + \hat{A}_c \sum_{j \in J, n \in N(c)} s_{jnc} \right) = 0, \qquad \forall c \in C \tag{67}$$

Market clearing conditions (68) equate demand for transmission services through pipelines *(n,n')* with TSO's supplying of such services:

$$d_{nn'}^{TSO} - \sum_{i \in I} x_{inn'}^{I} + x_{nn'}^{G} = 0, \qquad (tc_{nn'}^{*} - \ free), \qquad \forall n \in N \backslash U, n' \in N'(n) \tag{68}$$

The market clearing conditions necessary to equate supply and demand for liquefaction services are as follows:

$$q_n^{liq} - \sum_{n' \in N'(r)} \left[\sum_{i \in I(l)} xl_{inn'}^{I} + xl_{nn'}^{G} \right] = 0, \qquad \left(p_n^{liq*} - free\right), \qquad \forall n, \in N(l) \tag{69}$$

and the market clearing constraints below ensure that demand for regasification service equals supplies:

$$q_{n'}^{regas} - \sum_{n \in N(l)} \left[\sum_{i \in I(r)} xl_{inn'}^{I} + xl_{nn'}^{G} \right] = 0 \qquad (p_{n'}^{regas*} - free), \qquad \forall n' \in N'(r) \tag{70}$$

The wellhead prices that producer k receives are obtained from the market-clearing conditions that balance supply and demand for gas:

$$s_{ktn}^{K \to T} - h_{tkn}^{T \leftarrow K} = 0, \qquad (p_{ktn}^{K \to T*} - free), \qquad \forall k \in K(t), t \in T(k), n \in N(k) \tag{71}$$

$$s_{kn}^{K \to G} - h_{kn}^{G \leftarrow K} = 0, \qquad (p_{kn}^{K \to G*} - free), \qquad \forall k \in K(G), n \in N(k) \tag{72}$$

The market clearing conditions that ensure that the total purchases ($h_t^{T \leftarrow G}$) by supplier t from Gazprom Export are equal to the total sales by Gazprom Export ($\sum_n s_{tnf}^{G \to T}$) to that supplier through the border points ($n \in N(t)$) are as follows:

$$\sum_n s_{tnf}^{G \to T} - h_t^{T \leftarrow G} = 0, \qquad (bp_t^{G \to T*} - free), \qquad \forall t \in T(G), f \in F \tag{73}$$

The congestion premium ($p_{uu'}^{*}$) through transit pipelines *(u,u')* is defined through the market-clearing conditions that ensure that the transit quantity demanded by Gazprom Export ($x_{uu'}^{G}$) through pipelines *(u,u')* equals the transit capacity supply ($d_{uu'}^{TR}$):

$$d_{uu'}^{TR} - x_{uu'}^{G} = 0 \qquad (p_{uu'}^{TR*} - free), \qquad \forall u \in U, u' \in U'(u) \tag{74}$$

Gathering all the KKT conditions and market clearing constraints presented above forms the MCP, which is coded in GAMS and solved with PATH solver. Since the objective functions of the maximization problems of market participants are concave and the associated constraints are convex, the solution to the MCP is a simultaneously global optimum to all the individual maximization problems in the model. Thus, the solution to the MCP is also a Nash equilibrium of the market game implemented in this model.

4. Model Validation and Results from Sensitivity Analysis

A validation of the model has been performed as follows. First, the model's results were verified to confirm that all the constraints, such as production, pipeline and LNG capacities, as well as energy balances at each node are satisfied by the solutions. Secondly, the numerical results produced by the model have been compared with real market data for the years 2008 and 2009 (see Appendix G, Tables D.1a, D.1b and D.2).

Comparison of the model with historical data shows that in general the model's results are in line with actual market outcomes for the years 2008 and 2009. In particular, model validation with 2008-2009 data shows that among three assumptions on market structure, namely (*i*) double marginalization (producers and traders exert market power in sequence), (*ii*) upstream oligopoly (only producers exert market power), and (*iii*) perfect competition, the upstream oligopoly market assumption produces results that are closer to the observed market data (price and consumption) than the results under the other two market assumptions. The double marginalization assumption produces much higher final prices and lower quantities than the other solutions. This is generally in line with the theory of double marginalization (Spengler, 1950). Furthermore, these prices are much higher (and quantities much lower) than in reality, consistent with Smeers' (2008) observation that double marginalisation is an inappropriate characterization for European gas markets. On the other hand, the perfect competition assumption inflates final gas consumption quite substantially compared to real market data. Consequently, the average final prices in European markets are much lower than the observed real prices. Therefore, motivated by these results, the upstream oligopoly market structure was selected for the Base case scenario.

It should be noted that there is one common feature in the three market power scenarios - diversity of the gas sources for particular markets plays a crucial role in determining prices and consumption. Less diverse countries in terms of supply sources always suffer higher prices and lower consumption compared to the prices and consumption of those countries that have more diversified supply sources. In contrast, countries with a diverse supply portfolio enjoy lower prices and higher consumption than would be the case otherwise. In general, this observation is line with economic intuition regarding market power and competition. Therefore, the model behaves in a predictable way which is in line with fundamental economic intuition and theory.

Sensitivity analyses (see Appendix G, Tables G.3 and G.4) show that the model's results are fairly robust in terms of major structural assumptions. Particularly, the Base Case solution was tested against ten alternative scenarios of structural assumptions (such as the elasticity of demand parameter, gas demand growth, production, pipeline, LNG import and export capacities) (see Appendix G, Box G.1). The sensitivity results are reported in terms of a robustness index that describes the responsiveness of the model output to a change in input parameters in a manner analogous to the elasticity concept (see Appendix G, eq. G.1). As a result, among these alternative assumptions, the most critical input parameters appear to be (in order of importance): (*i*) the production capacities of the two largest producers in the model – Russia and Norway, and (*ii*) the elasticity of demand.

Moreover, the direction of changes in input parameters matters. Thus, a <u>decrease</u> in the production capacities of Russia and Norway is very critical to the model's results (prices, consumption, profits and welfare), whereas an <u>increase</u> in production capacities of these two countries has little effect on the model's outputs. Similarly, a decrease in the elasticity of the demand parameter is more critical to the model's results than an increase. In general, a one percentage point (p.p.) decrease in the production forecast of Russia and Norway relative to the Base Case forecast changes the final prices by more than 0.5 p.p. for most of the countries in this model (with a few countries seeing changes in prices of more than 1 p.p.), whereas a 1 p.p. decrease in the elasticity parameter produces an average increase in final prices of 0.37 p.p.

It should be noted that, contrary to our expectation, variations in pipeline capacities (cross-border) have only a marginal impact on the model's results. For example, a 1 p.p. decrease in cross-border pipeline capacities relative to the Base Case assumption increases final prices by an average of 0.04 p.p. and decreases model-wide consumption by 0.03 p.p. compared to the Base Case solution (see Appendix G, Tables G.3 and G.4). Similar sensitivity results were obtained regarding the LNG import/export capacities. Therefore, although the assumption of efficient pricing of access to and congestion in infrastructure capacities in this model diverges from the European market reality, these results indicate that these assumptions might not drastically bias the model results.

In general, changes in other inputs (e.g., demand forecast) have very little effect on the model's results – a 1 p.p. change in all other input parameters only changes the model results by 0-0.2 p.p.

Finally, sensitivity scenarios (see Appendix G, Box G.2) were run to check the robustness of the model's results against different assumptions about the conjectured transit demand slope, *M*. The results show that different assumptions about the transit conjecture parameter only substantially affect the profits of transit countries (see Appendix G, Table G.5). However, in general, different conjectured transit demand slopes only slightly modify the model results (such as final prices and consumption) - within a range of 1% from the Base Case results.

5. Results

5.1. Base Case Results

Figure 4 reports natural gas consumption by sources obtained from the Base Case solution. In this scenario, total gas consumption in Europe will increase from 622 bcm in 2010 to 685 bcm by 2030 (+0.5% CAGR). The increase in gas consumption in Europe will be increasingly met with external gas supplies. Gas imports through pipelines from Russia, Norway and Algeria will total 371 bcm in 2030 (+0.6% CAGR from 2010). LNG will import a total of 230 bcm in 2030 or 34% of total consumption (in 2010 LNG imports constitute 26% of total European gas consumption). Indigenous gas production in Europe will decline steadily through to 2030 (-2.8% CAGR) and total 83 bcm.

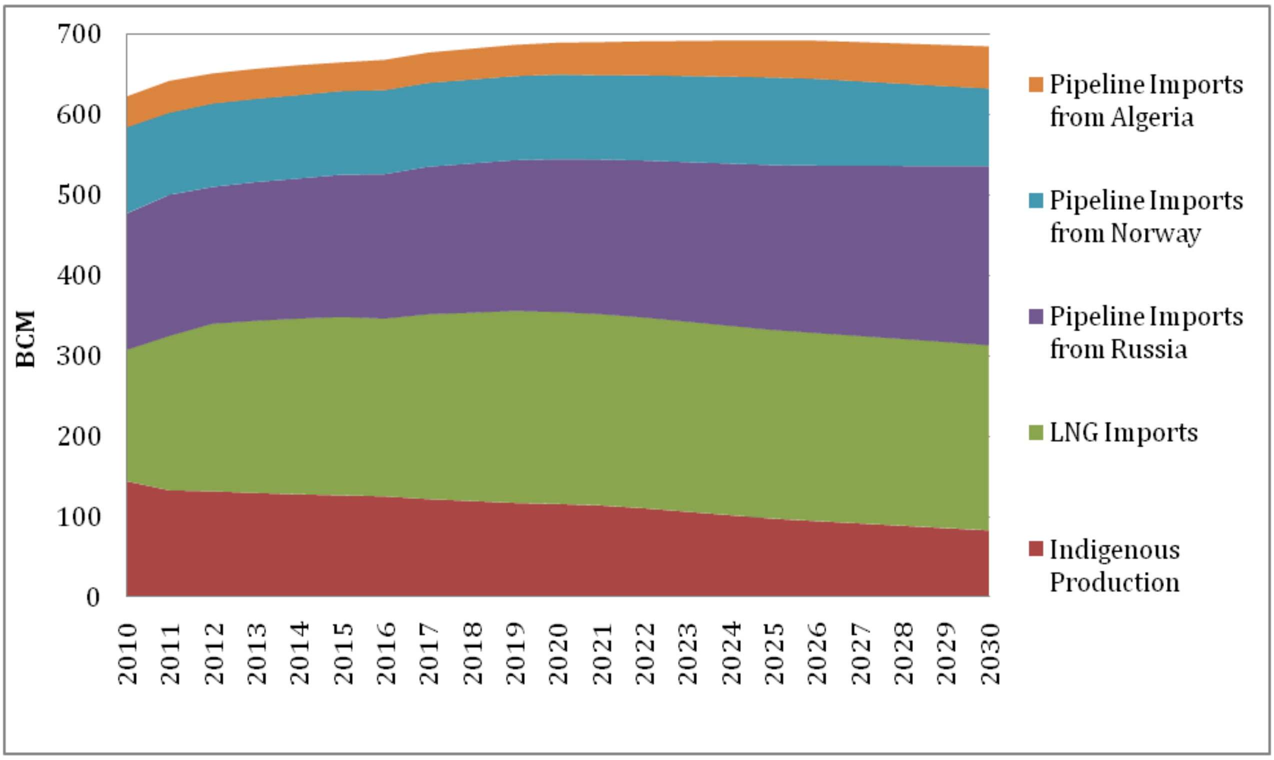

Figure 4: Breakdown of Gas Consumption by Sources for European Countries[23]

It should be noted that total gas consumption in Europe peaks in 2025 (Figure 4) at the level of 692 bcm and declines to 685 bcm in 2030. This is because the model does not include investment decision in production and transport infrastructure; therefore, gas supplies at the end of the modelling period (2025-2030) are rather limited and constraint the growth in natural gas consumption.

[23] Includes all countries as reported in Table C.1 (Appendix C) except for the FSU countries

The development in final gas prices obtained from the Base Case solution differs slightly between regions (Figure 5). Natural gas prices may differ substantially among countries due to both the geography of production and consumption (such as transport costs involved in delivering gas from producers to consumers) and market structures (such as competition between gas producers). Therefore, due to the lack of upstream gas competition, the final (quantity-weighted) average price for Eastern Europe and Balkans is 16% higher, on average, than the gas price for Western and Southern Europe. Moreover, Western and Southern European gas prices see a slight decrease between 2010 and 2015 due to increased LNG regasification and the new pipeline capacities to be commissioned during this period. In general, the (quantity-weighted) average prices of the two regions increases at a CAGR of around 1.7% through to 2030.

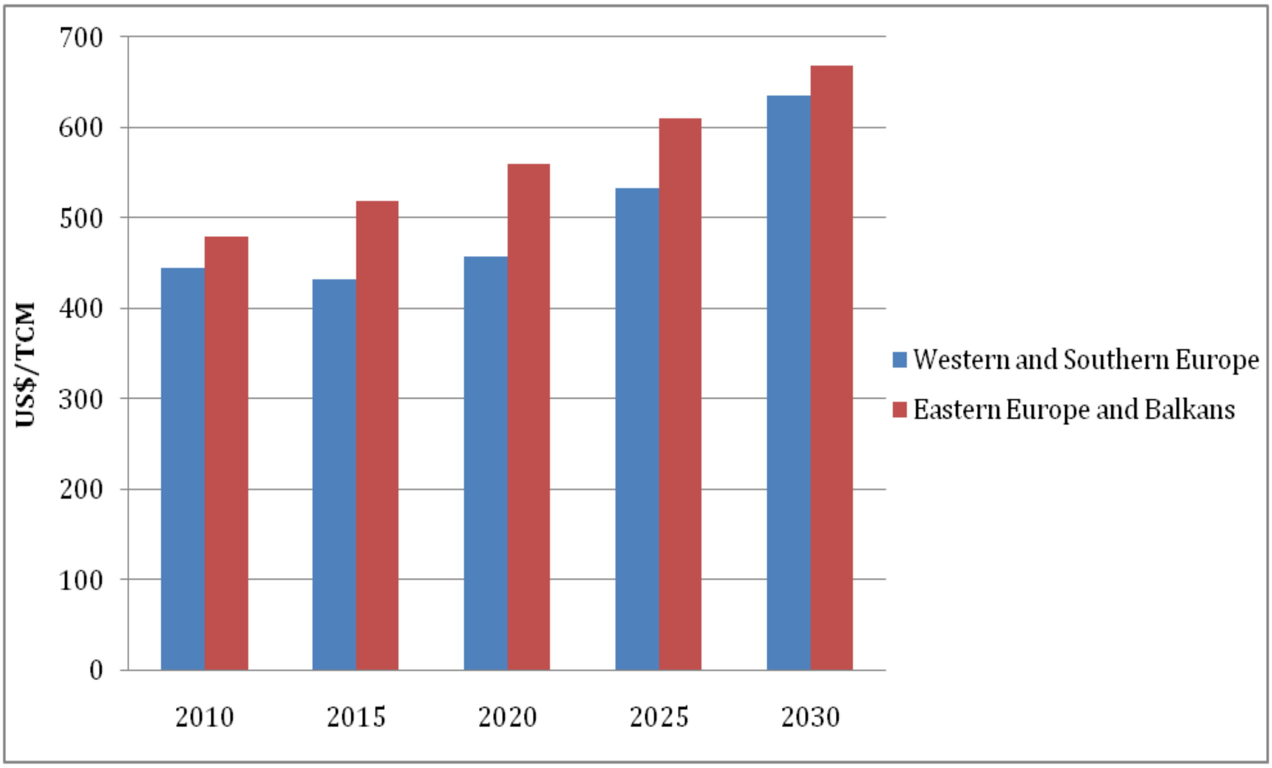

Figure 5: Dynamics of Average Final Prices

Figure 6 shows the Base Case result for Russian natural gas exports to Europe through different transit routes (for details of current Russian gas export routes see Appendix H: Table H.1). In the Base Case (Figure 6) it is assumed that Russia's bypass pipelines, Nord Stream and South Stream, come online gradually (Nord Stream and South Stream are assumed to be fully operational in 2012 and 2017 respectively). It can be seen from Figure 6 that once these two projects are built Russian gas transits through Ukraine will be diverted to these two projects. Total transit through Ukraine in 2017 (after South Stream's operation) reduces to 22 bcm, versus 128 bcm in 2011. Therefore, once the bypass projects are built Ukraine's role as a transit country becomes marginal and Gazprom only uses Ukraine's transit system to transport some gas to Moldova, Poland, Slovakia and Romania, i.e. to those markets where it is assumed that gas cannot be reached with bypass pipelines. On the other hand, it can be seen from Figure 6 that there is no impact from bypass pipelines on transit flows through the Belarusian section of the Yamal-Europe pipeline.

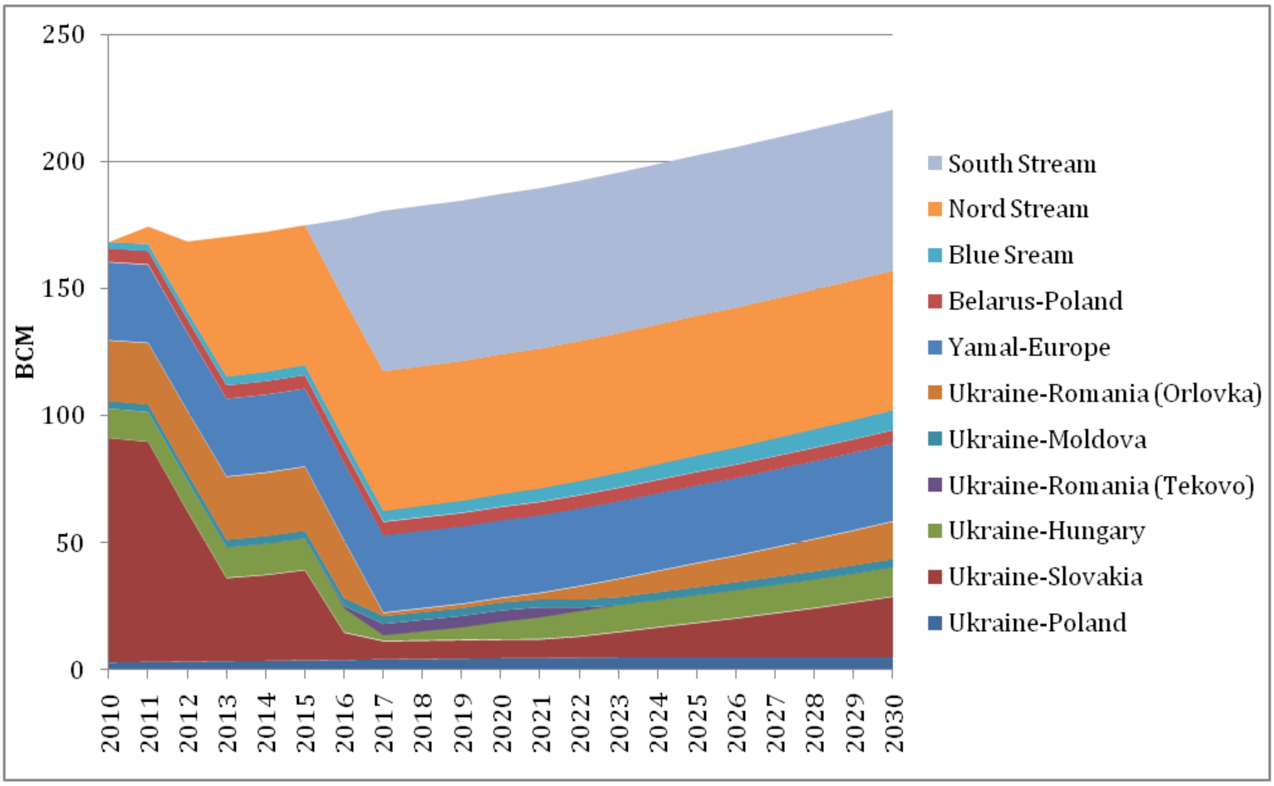

Figure 6: Russian Gas Exports to Europe by Main Transit Pipelines

5.2. Investment in Nord Stream, Market Power and Social Welfare

The aim of this section is to show the model's capability by analysing the effects of different market structures on changes in social welfare resulting from Nord Stream investment.

5.2.1. Assumptions and Scenarios

For this analysis, Base Case data are assumed (as outlined in Appendix C). However, it is assumed that South Stream is <u>not</u> built. This assumption is required to focus solely on Nord Stream evaluation (note that in the Base Case scenario both the Nord Stream and South Stream pipelines are built).[24] Table 1 reports the market power scenarios analysed here.

[24] Investment in South Stream and its interactions with Nord Stream will be analysed in a forthcoming paper

Table 1: Market Power Scenarios

	Successive market power	Double marginalization	Upstream oligopoly	Perfect Competition
Cournot Producers	√	√	√	
Cournot Traders	√	√		
Transit market power	√			

In the successive market power scenario it is assumed that, apart from producers and traders, transit countries also behave imperfectly. In this scenario, transit market power is represented with the conjectured transit demand function. The application of this function requires the specification of the slope $M_{uu'}$ of the conjectured transit demand curve. This slope can be interpreted as the transit country's belief about Gazprom's ability (measured as a fraction of existing transit capacities) to divert gas from transit pipelines if the transit fee is raised by some amount (e.g., by US$1/tcm):

$$M_{uu'} = -F \times CAP_{uu'}^{TR} \tag{75}$$

where $CAP_{uu'}^{TR}$ is the capacity of the transit pipeline *(u,u')* and F is a percentage number (details of transit pipeline capacities are documented in Appendix C, Table C.3). For the purpose of this analysis, an arbitrary small F (1%) was chosen which results in a rather small conjectured slope.[25] This small conjectured transit slope was chosen to simulate the hypothetical case of transit countries believing they have substantial market power vis-a-vis Gazprom.[26] A sensitivity analysis with alternative assumptions about the conjectured transit demand slope is presented in Appendix G.

When transit countries are assumed not to exert market power (double marginalization. upstream oligopoly and perfect competition cases), their transit fees are exogenously fixed at 2010 levels (for details of the transit fees through Ukraine and Belarus see Appendix C).

In scenarios when traders are exercising their market power (i.e. successive market power and double marginalization scenarios), it is assumed that each gas market is served by four traders, which generally corresponds to the current structure of most Western European gas

[25] For example, the existing transit capacity through Ukraine to Western Europe (i.e., Ukraine-Slovak border) is 92.6 bcm/a; thus, the result of applying F=1% is a conjectured slope of M=-0.926. This conjectured slope expresses Ukraine's belief (not necessarily correct) that an increase in transit fees might force Gazprom to divert gas from Ukraine by up to 0.926 bcm/a (if this proves more efficient for Gazprom).

[26] This case was more realistic during the 1990s and early 2000s, when Gazprom had no alternative export routes other than using Ukrainian and Belarusian pipelines to export gas to Europe.

markets. However, number of traders in each market is treated parametrically and sensitivity analyses are provided in Appendix I.

For the analysis of Nord Stream investment, data on the costs of the pipeline project and corresponding transport costs are required. The methodology and data used for costing the Nord Stream system are discussed in Appendix E and F. The results of the estimation of transport costs through the Nord Stream system are in Appendix C, Table C.9.

5.2.2. Impact on Gazprom and Transit Countries

Table 2 summarizes Gazprom's and transit countries' annualized profits under different scenarios. The annualized profits were calculated at a 10% discount rate over the period of 25 years.

Table 2: Gazprom's and Transit Countries' Annualized Profit (US$ bn/year)

			Gazprom	Transit Countries
Successive market power	Nord Stream is built	[1]	80.4	1.3
	Nord Stream is not built	[2]	77.7	3.4
	Changes	[3]=[1]-[2]	**2.7**	**-2.1**
Double Marginalization	Nord Stream is built	[4]	80.8	1.2
	Nord Stream is not built	[5]	80.5	1.7
	Changes	[6]=[4]-[5]	**0.3**	**-0.5**
Upstream Oligopoly	Nord Stream is built	[7]	112.1	1.8
	Nord Stream is not built	[8]	109.5	2.5
	Changes	[9]=[7]-[8]	**2.6**	**-0.7**
Perfect Competition	Nord Stream is built	[10]	86.4	2.7
	Nord Stream is not built	[11]	90.7	2.7
	Changes	[12]=[10]-[12]	**-4.3**	**0.0**

From Table 2 one can see that the annualized value of the Nord Stream system to Gazprom is positive in all cases except in the perfect competition case. In the successive market power scenario, the positive value of Gazprom's investment in the Nord Stream project (US$ 2.7 bn/y) is majorly driven by transport cost reduction (see Table 3). The reduction in total transport cost is due to:

(i) lower unit transport cost from Russia's major gas producing regions to Germany (Russia's largest market in Western Europe) using the Nord Stream route than using the Ukrainian route (see Figure 7), and

(ii) reductions in transit fees through Ukraine and Belarus once the Nord Stream pipeline is operational (see Figure 8). This decrease in transit fees is due to lower transit flows through their pipelines (gas flows are diverted to the Nord Stream

system). Since transit market power is modelled using a conjectured transit demand function (with an assumed negative slope), lower transit flows reduce transit fees.

Table 3: Gazprom's Total Transport Cost and Gas Exports to Europe over 25 years

		Transport cost (US$ bn)	Gas Exports (bcm)	Cost per unit (US$/tcm)
		[1]	[2]	[3]=[1]/[2]
Successive market power	Nord Stream is built	348	3645	95.4
	Nord Stream is not built	379	3436	110.2
Double Marginalization	Nord Stream is built	340	3823	89.1
	Nord Stream is not built	319	3634	87.7
Upstream Oligopoly	Nord Stream is built	445	5195	85.7
	Nord Stream is not built	411	4681	87.7
Perfect Competition	Nord Stream is built	541	6551	82.6
	Nord Stream is not built	436	5331	81.8

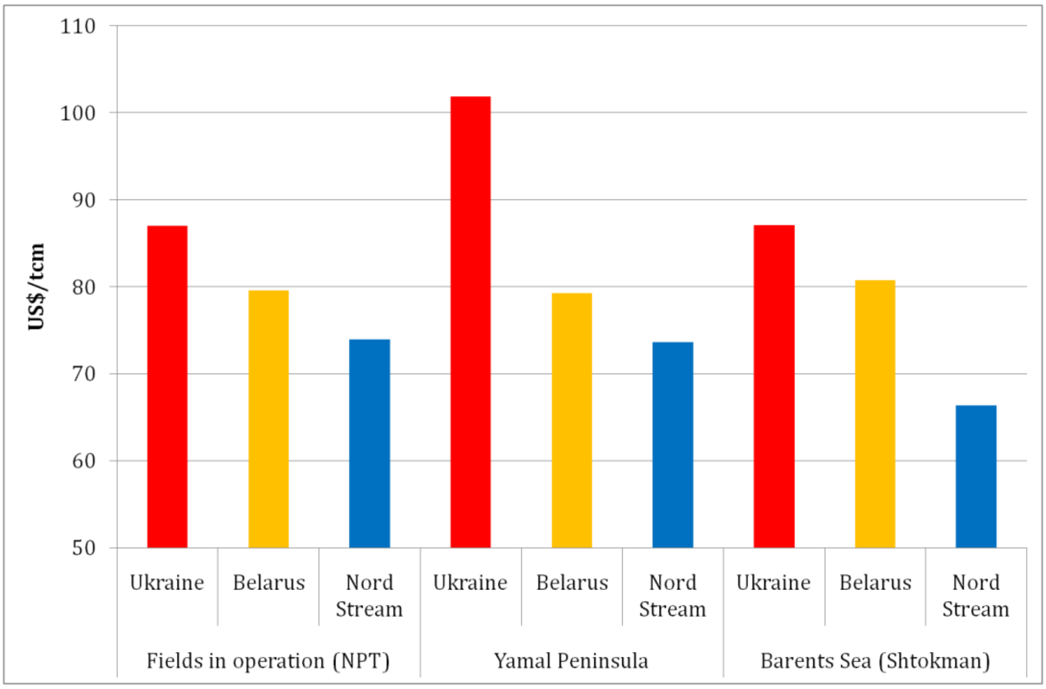

Figure 7: Transportation Costs from Russia to Germany

Note: Unit transport cost through the Nord Stream system was calculated assuming that the system would be fully utilized (lower utilization of the transport system would increase its unit transport cost). The Belarusian route in this figure is the Northern Light pipeline system, not the Yamal-Europe pipeline which is owned by Gazprom. The final delivery point for the Ukrainian and Belarusian Northern Light routes is the German-Czech Border (Olbernhau). The final delivery point for the Nord Stream route is Greifswald, Germany (the end point of the offshore Nord Stream).

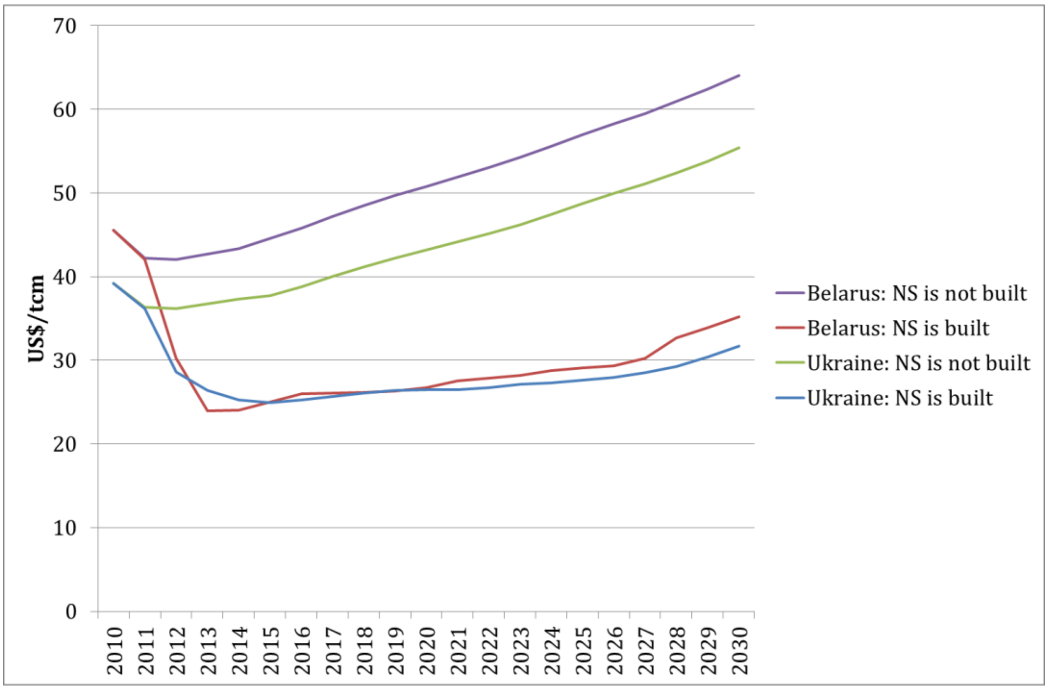

Figure 8: Transit fees through Ukraine and Belarus under the Successive Market Power Scenario[27]

Note: the Belarusian route in this figure is the Northern Light pipeline system, not the Yamal-Europe pipeline which is owned by Gazprom; NS – Nord Stream

In the double marginalization case, the annualized value of Nord Stream investment to Gazprom is positive, but rather marginal (US$ 0.3 bn/y). Strategic behaviour by traders lowers gas sales for final consumption, and thus modifies both final and border prices and, consequently, the margin they earn (see Table 4).

Table 4: Average Annual Consumption and Prices in Europe: 2010-2030

		Successive market power	Double Marginalization	Upstream Oligopoly	Perfect Competition
Russian gas export to Europe (bcm/y)	NS is built	134	141	192	248
	NS is not built	126	133	177	204
Consumption in Europe (bcm/y)	NS is built	569	575	674	754
	NS is not built	567	572	663	710
Gazprom's market share in Europe	NS is built	24%	24%	28%	33%
	NS is not built	22%	23%	27%	29%
Average[a] border prices (US$/tcm)	NS is built	416	414	491	357
	NS is not built	427	420	510	434
Average[a] final prices (US$/tcm)	NS is built	674	669	503	374
	NS is not built	680	673	523	448

Note: [a] quantity-weighted; NS – Nord Stream

[27] The reported transit fees through Ukraine and Belarus are averages (quantity-weighted).

Lower gas demand reduces the utilization of the Nord Stream system (see Table 5) and therefore Gazprom has to pay cost for unused transport capacity of the Nord Stream system.[28] This cost is reflected in higher per unit transport cost of Gazprom's gas exports when Nord Stream is built (Table 3: US$ 89.1/tcm) compared to the case when the pipeline is not built (Table 3: US$ 87.7/tcm). Nevertheless, Nord Stream investment allows Gazprom to expand its sales in Europe (Table 4: "Gazprom's market share in Europe" – 24% vs. 23%); thus, higher revenue from larger market share offsets Gazprom's increased total transport cost and thus the value of Nord Stream investment is still positive, however, marginal.

Under the upstream oligopoly case (only producers exercise market power), investment in Nord Stream also brings positive value to Gazprom (US$ 2.6 bn/y). This is primarily due to overall transport cost savings (Table 3) and Gazprom's expansion of sales in Europe (Table 4). In this market power scenario, utilization of the Nord Stream system is maximized (Table 5) because gas demand is higher due to perfect competition among traders.

Table 5: Transportation through the Nord Stream system (bcm)

	Successive market power	Double Marginalization	Upstream Oligopoly	Perfect Competition	Nord Stream's Capacity
2011	6.9	6.9	6.9	6.9	6.9
2015	40.8	31.6	55.0	55.0	55.0
2020	48.0	40.2	55.0	55.0	55.0
2025	51.3	44.3	55.0	55.0	55.0
2030	55.0	52.5	55.0	55.0	55.0
Average Utilization rate (2011-2030)	88%	76%	100%	100%	

Finally, in the case of perfect competition, investment in Nord Stream negatively impacts Gazprom's profits (US$ -4.3 bn/y) because of non-strategic behaviour by producers who see border prices as fixed and sell gas until the marginal cost equals the border price. Thus, by having invested in Nord Stream, Gazprom exports more gas than it would have otherwise (Table 4) and so border prices decrease (because of inverse demand functions) and so does its profitability. In a sense, under perfect competition, not investing in Nord Stream would have the inadvertent effect of an oligopolistic-like restriction of supply, which would increase Gazprom's profits relative to the Nord Stream case.

As one would expect, Nord Stream has a negative impact on the profits of transit countries in all market power scenarios. Compared to the Ukrainian route and the Northern Light pipeline

[28] Cost of unused transport capacity of the Nord Stream system is calculated as the product of unit transport cost through the system (as reported in Appendix C: Table C.9) and the difference between Nord Stream's capacity and its actual usage (see Table 2.5).

system, the Nord Stream pipeline is a cheaper option for carrying Russian gas to Western European markets (Figure 7). This is the major economic reason why Gazprom diverts gas away from the Ukrainian transit system and from the Belarusian Northern Light system, and consequently reduces their profits. However, in the perfect competition scenario there is no impact from Nord Stream on transit flows (and consequently profits) through Ukraine and Belarus because, in this scenario, demand in Europe is substantially higher due to marginal cost pricing by producers and traders. Thus, the Nord Stream project provides additional net export capacity to Europe.

5.2.3. Impact on Traders, other Producers and Consumers

In general, it is found that Nord Stream has a negative impact on the profitability of all other producers supplying gas to European markets (see Table 6). With a cheaper transport option (Nord Stream), Russian gas gains a greater market share than if there was "no" Nord Stream (see Table 4), and consequently the market share and profit of all other producers fall.

By definition, traders' total economic profits are zero when they behave competitively (perfect competition and upstream oligopoly scenarios). Traders' profits are strictly positive only when they can modify final and border prices (and consequently their profits) by strategically "withholding" sales to consumers (successive market power and double marginalization scenarios). In this scenario, Nord Stream investment positively affects the profitability of all traders (Table 6).

Table 6: Annualized Profit of all Traders and other Producers (US$ bn/year)[29]

			All Traders	All Other Producers	Consumer Surplus
Successive market power	Nord Stream is built	[1]	135.2	125.0	266.7
	Nord Stream is not built	[2]	132.7	131.6	263.3
	Changes	[3]=[1]-[2]	**2.5**	**-6.5**	**3.4**
Double Marginalization	Nord Stream is built	[4]	135.9	124.3	269.9
	Nord Stream is not built	[5]	133.6	128.5	267.2
	Changes	[6]=[4]-[5]	**2.3**	**-4.1**	**2.7**
Upstream Oligopoly	Nord Stream is built	[7]	0.0	171.6	372.5
	Nord Stream is not built	[8]	0.0	180.9	361.3
	Changes	[9]=[7]-[8]	**0.0**	**-9.3**	**11.2**
Perfect Competition	Nord Stream is built	[10]	0.0	126.5	472.2
	Nord Stream is not built	[11]	0.0	166.4	417.3
	Changes	[12]=[10]-[12]	**0.0**	**-40.0**	**54.9**

[29] The annualized profits were calculated at a 10% discount rate over the period of 25 years.

Table 6 shows that consumers benefit from investment in Nord Stream in all market power scenarios. Further, the higher the competition among producers and traders, the higher is the benefit of Nord Stream to European consumers. In a perfectly competitive "gas world", the benefit of Nord Stream to consumers is almost three times higher than in a scenario where producers behave imperfectly (upstream oligopoly). In the case of double marginalization, the benefits of Nord Stream to consumers are quite limited (the benefits are US$ 2.7 bn/year) compared to the other market power scenarios.

5.2.4. Impact on Overall Market Efficiency

The basic criterion used to evaluate the Nord Stream investment is the change in market efficiency or social welfare, ΔSW, defined as:

$$\Delta SW = SW^{NS} - SW^{No\ NS} \tag{76}$$

$$SW = Gazprom\ Profit + Transit\ Profit + Producer\ Profit + Trader\ Profit + Consumer\ Surplus \tag{77}$$

where SW^{NS} is the social welfare when Nord Stream is built and $SW^{No\ NS}$ is the social welfare if the Nord Stream system is not built.

Table 7 summarizes the annualized changes in profits and welfare (ΔSW) resulting from investment in Nord Stream relative to the scenario of "no" Nord Stream investment. The annualized changes were calculated at a 10% discount rate over the next 25 years.

Table 7: Annualized Net Gains (Losses) Resulting from Investment in Nord Stream (US$ bn/year)

	Successive market power	Double Marginalization	Upstream Oligopoly	Perfect Competition
Gazprom's Profit	2.7	0.3	2.6	-4.3
Profit of transit countries	-2.1	-0.5	-0.7	0.0
Profit of all other Producers	-6.5	-4.1	-9.3	-40.0
Profit of all Traders	2.5	2.3	0.0	0.0
Consumer Surplus	3.4	2.7	11.2	54.9
Social Welfare	**0.01**	**0.7**	**3.8**	**10.6**

As can be seen from Table 7, impact of Nord Stream investment on social welfare is positive in all market power scenarios. There are almost no changes (US$ 0.01 bn/y) in market efficiency when producers, traders and transit countries exert market power (the successive market power case). Thus, under this market power scenario, investment in the Nord Stream project only re-distributes profits among market participants. In all other market scenarios, investment in the Nord Stream project improves overall market efficiency. Moreover, the higher the competition between market participants along the supply chain, the larger is the benefit of Nord Stream investment to market efficiency.

6. Conclusions

In this paper the mathematical formulation of the equilibrium gas simulation model was presented. This model is different from previous gas models in its detailed presentation of the FSU gas sector. The inclusion of details of the FSU gas sector in the large-scale gas simulation model was mainly motivated by the analysis of policy questions related to the anticipated structural changes in gas exports from the FSU region to the European markets (such as route diversification by Russia), and the possible impact of these changes on European gas markets and participants.

The model was demonstrated by analysing a Base Case scenario of European gas market development (2010-2030) in which only producers may exert market power while all other market participants are assumed to be price-takers. In the Base Case scenario it was also assumed that Russia's bypass projects, Nord Stream and South Stream, would be built according to Gazprom's plan. Findings from the Base Case scenario suggest, among other things, that in light of the decline in indigenous gas production in Europe, the role of Russian gas is still important but quite limited (between 2010 and 2030 the market share of Russian gas increases modestly from 26% to 32%), and that Europe's growing import requirements are increasingly met with LNG imports (the market share of LNG expands from 26% in 2010 to 34% in 2030). This result is in line with the findings of Holz et al. (2009). We also found that once the Nord Stream and South Stream pipelines become operational, the role of transit countries, especially Ukraine, in transporting Russian gas to Europe becomes rather marginal. However, gas flows through the Yamal-Europe pipeline (Belarus) are not affected by these two pipelines.

The model's capability was also shown by carrying out an analysis of investment in Nord Stream and its implications for profits for individual market parties, as well as for overall market efficiency. It was found that investment in Nord Stream is unattractive to its investors only when all market participants are price-takers (which does not conform with current market realities), whereas under market power scenarios Nord Stream appears to be an economically attractive project to its investors (Gazprom and European energy companies). We also found that investment in the Nord Stream project is rather sensitive to the assumption regarding the level of downstream competition in European markets.

As was shown in the results section, the economics of Nord Stream are mainly driven by: (*i*) lower total transport costs from different production regions in Russia to final consuming markets in Europe compared to the Ukrainian route and the Northern Light system (Belarus), (*ii*) the changing geography of gas production in Russia which also modifies Gazprom's transport cost structure in favour of the Nord Stream route, and (*iii*) the possible exercising of market power by transit countries (Ukraine and Belarus).

Without a detailed representation of the FSU gas "region" in this model it would not be possible to see that Nord Stream can be an economically profitable project on its own (at least in our oligopoly simulations), without strategic bargaining considerations found by Hubert and Ikonnikova (2003), Hubert and Ikonnikova (2004) and Hubert and Suleymanova (2008). Using the large-scale gas simulation model, we were able to analyse the Nord Stream project in terms of market efficiency and social welfare. Here, it was found that Nord Stream improves market efficiency in all market power scenarios, and that the higher the degree of competition between market participants, the more European consumers gain.

The validation of the model with historical data shows that in general the model's results are in line with actual market outcomes for the years 2008 and 2009, and that the behaviour of the model is consistent with economic intuition. Moreover, the sensitivity analysis shows that the model's results are fairly robust in terms of major structural assumptions.

This model can be used for the analysis of other policy questions concerning the regional gas trade in Europe and CIS (including Central Asia). For example, in (Chyong et al., 2010; Chyong, forthcoming) this model was used to analyse the economic value of Gazprom's investment in the Nord Stream and South Stream pipeline projects under different assumptions about market development, transit pricing policy and transit disruption scenarios.

Further model enhancements are desirable. First, inter-seasonal gas storage should be included in the model (e.g., as in (Egging et al., 2008; Lise and Hobbs, 2008)). The inclusion of inter-seasonal gas storage in the model might refine the results concerning Nord Stream investment. One of the advantages of using the Ukrainian route compared to Gazprom's existing and new routes is cheap access to large underground storage areas in Ukraine. Therefore, once gas storage areas are accounted for, one might find that total transport and storage costs along the Ukrainian route are lower than those costs along Gazprom's existing or new export routes - such as Nord Stream. Also, having gas storage areas in the model would enable a more detailed analysis of transit disruption scenarios. Secondly, geographical coverage of the model could be expanded from regional to global (e.g., as in (Egging et al., 2009)), as well as representing the demand sector in greater detail (e.g., gas demand divided by sectors and regions instead of representing each country with one demand function). Regional gas markets have become more interconnected recently through increased gas trading in its liquefied form. Therefore, having a global gas model would, of course, refine the results presented above. Moreover, this will allow us to address important questions concerning the globalization of the natural gas trade and energy security on both regional (particularly Europe, CIS and Asia) and global scales. Additionally, the model could be elaborated so that it can endogenously expand capacity (such as pipeline and LNG terminal capacity) (e.g., (Lise and Hobbs, 2008; Egging et al. 2009)). This would allow analysis of questions concerning optimal investment in gas infrastructure. Moreover, this would allow analysis of the cost efficiency of Nord Stream investment both in terms of alternative capacities and routes. Further, probabilistic elements could also be included in the model (e.g., (Zhuang and Gabriel, 2008; Gabriel et al., 2009)). For example, this would allow inclusion of uncertainty in demand growth. Exogenous probabilities of gas flow disruptions through transit countries could also be specified and then, given that risk, the model can then determine the optimal reaction of market players in terms of investment in capacity expansion (such as storage, “bypass” pipelines and LNG terminals), sales and production.

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APPENDIX A. Modelling vertically integrated companies

Suppose that a vertically integrated company has two subsidiary companies responsible for gas production (q) and gas sales (s). The aim is to show that modelling these two companies separately is equivalent to modelling the vertically integrated company as a single problem, provided that the relationships between subsidiary companies are competitive. Let us consider the case of vertically integrated company as follows:

$$\max_{s,q\geq 0} \pi^I = sp(s) - qc \tag{A.1}$$

subject to

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

$$s - q = 0 \quad (\gamma - free) \tag{A.3}$$

where π^I is the profit of the vertically integrated company, $c>0$ – unit production cost, Q – production capacity, $p(s)$ is the inverse demand function of the following form $p=b-as$.

Then, the KKT conditions for (A1) are

$$0 \leq s \perp p + \frac{\partial p}{\partial s}s + \gamma \leq 0 \tag{A.4}$$

$$0 \leq q \perp -c + \lambda - \gamma \leq 0 \tag{A.5}$$

$$0 \leq \lambda \perp (q - Q) \leq 0 \tag{A.6}$$

$$\gamma \perp (s - q) = 0 \tag{A.7}$$

If s, $q>0$ and $q<Q$, then it is easy to show that the solution to (A.4-A.7) is

$$s^* = q^* = \frac{b-c}{2a} \tag{A.8}$$

and the total profit of the integrated company is

$$\pi^I = \frac{b-c}{2a}\left(b - a\frac{b-c}{2a}\right) - c\frac{b-c}{2a} = \frac{(b-c)^2}{4a} \tag{A.9}$$

However, if $q>Q$, that is production constraint (A.2) is binding, then the solution to (A.4-A.7) is

$$s^* = q^* = Q \tag{A.10}$$

and

$$\pi^I = Q(b - aQ) - cQ = Q(b - aQ - c) \tag{A.11}$$

Now consider two separate problems – one for sales:

$$\max_{s \geq 0} \pi^s = s[p(s) - p^*] \tag{A.12}$$

and one for production:

$$\max_{q \geq 0} \pi^q = q[p^* - c] \tag{A.13}$$

subject to

$$q \leq Q \quad (\lambda) \tag{A.14}$$

where π^s is the profit from sales, π^p is the profit from production, and p^* is the wellhead price, which is determined by market clearing condition (A.15):

$$s - q = 0 \quad (p^* - free) \tag{A.15}$$

Below are the KKT conditions for (A.12) :

$$0 \leq s \perp p + \frac{\partial p}{\partial s} s - p^* \leq 0 \tag{A.16}$$

and for (A.13):

$$0 \leq \mathrm{q} \perp \mathrm{p}^* - \mathrm{c} + \lambda \leq 0 \tag{A.17}$$

$$0 \leq \lambda \perp (\mathrm{q} - \mathrm{Q}) \leq 0 \tag{A.18}$$

If *s, q>0* and $q<Q$, then the solution to (A.16-A.18) is

$$s^* = q^* = \frac{b - p^*}{2a} \tag{A.19}$$

$$p^* = c \tag{A.20}$$

and total profit is

$$\pi^I = \pi^s + \pi^p = \frac{b-p^*}{2a}\left(b - a\frac{b-p^*}{2a} - p^*\right) + \frac{b-p^*}{2a}(p^* - c) = \frac{(b-c)^2}{4a} \tag{A.21}$$

In case $q>Q$, that is (A.14) is binding, the solution to (A.16-A.18) is

$$s^* = q^* = Q \tag{A.22}$$

$$p^* = b - 2aQ \tag{A.23}$$

and the profit of the integrated company is

$$\pi^I = \pi^s + \pi^p = Q(b - aQ - p^*) + Q(p^* - c) = Q(b - aQ - c) \tag{A.24}$$

Since the resultant profits are identical, that is (A.21)=(A.9) and (A.24)=(A.11), modelling the separate activities of an integrated company as being price-taking (competitive) with respect to each other yields the same results as modelling the integrated company as one problem.

Q.E.D.

APPENDIX B. Bilateral Market Power in the FSU gas sector

This appendix describes a simple two-person bargaining game with transferable utility (gains are measured in a common currency, e.g. US$) between a buyer (Player B) and a seller (Player S). Player B is a downstream player in the sense that it makes a profit from re-selling gas bought from player S to final customers.

The bargaining game is said to be a game with transferable utility if, in addition to the strategy option available to players, each player can: *(i)* give any amount of money to any other player, or (*ii*) simply destroy money (Myerson, 1991, 384). Each unit of net monetary outflow decreases the utility of a player by one unit. Thus, players' utilities are assumed to be linear in money, i.e. if player B decides to transfer t money to player S, then the loss in player B's utility due to the transfer of t is the same as the gains received by S from this transfer t. When there is transferable utility, a two-person bargaining problem can be fully characterized by three numbers (Myerson, 1991: p. 385):

1. Π is the maximum transferable utility available to the players if they cooperate,
2. π_S^d is the disagreement payoff to player S, and
3. π_B^d is the disagreement payoff to player B.

According to Myerson (1991: p. 385), the Nash bargaining solution (Nash, 1953) of a game with transferable utility is:

$$\pi_S^* = \pi_S^d + \frac{1}{2}\left(\Pi - \pi_S^d - \pi_B^d\right) \tag{B.1}$$

$$\pi_B^* = \pi_B^d + \frac{1}{2}\left(\Pi - \pi_S^d - \pi_B^d\right) \tag{B.2}$$

which indicates that the seller's and the buyer's profits, π_S^* and π_B^*, are guaranteed by their disagreement payoffs (π_S^d; π_B^d) and half of the total surplus from cooperation.

The maximum transferable utility (or profit) Π is achieved if both players are modelled as a vertically integrated company (joint profit maximization), or (as argued in Appendix A) if buyers and sellers behave perfectly competitively. Therefore, sales/export relations between FSU countries in the model in the main text are assumed to be competitive. The connection between the model presented in the main text and the bargaining model in this appendix is that the former is used to define the maximum joint profit Π and the disagreement point (π_S^d; π_B^d). Having obtained Π and (π_S^d; π_B^d) from the equilibrium gas model, the analysis of the bargaining game is done ex-post.

APPENDIX C. Data and Assumptions for the Base Case

1. Structural Assumptions

In the Base Case it is assumed that only producers behave imperfectly by behaving a là Cournot. This assumption was chosen because the results obtained under this market power scenario are more consistent with historical data than other market power assumptions (successive oligopolies and perfect competition assumptions). Sensitivity analysis of alternative structural assumptions is discussed in Appendix G. Gas producers located in the following countries are assumed to be perfectly competitive:[30]

- Germany
- Italy
- Poland
- Romania
- Hungary.

Moreover, gas produced in these countries is prioritized for domestic consumption and is not exported.[31]

2. Natural Gas Demand

In this model, the linear demand function for natural gas is used as specified by eq. (10) in Section 3.4.1.1. The price elasticity of the demand function is as follows:

$$\varepsilon_c = -\frac{\partial Q_c^0}{\partial p_c^0}\frac{p_c^0}{Q_c^0} \tag{C.1}$$

Then, using (C.1), the parameters of the linear demand function are as follows:

[30] This assumption seems plausible since the import requirements of European countries are much higher than their indigenous production. Moreover, security of supply concerns would not allow domestic production to be "withheld" for strategic reasons. Smeers (2008: p. 25) argues that modelling domestic EU producers as a competitive fringe that cannot exercise market power is more adequate. Holz et al. (2008) made a similar assumption.
[31] Holz et al. (2008) made a similar assumption concerning the EU's indigenous gas production.

$$A_c = -\frac{p_c^0}{\varepsilon_c Q_c^0} \text{ and } B_c = p_c^0\left(1 + \frac{1}{\varepsilon_c}\right) \tag{C.2}$$

Linear inverse demand functions are specified at assumed elasticity and 2009 price-quantity pairs (see Table C.1).

Table C.1: Market Prices, Consumption (2009) and Assumed Elasticity

Country	Consumption[a] (bcm)	Price[b] (US$/tcm)	Elasticity[c]
Western and Southern Europe			
Finland	4.3	611.2	-0.7
Baltic States[32]	4.6	525.2	
Austria	8.8	583.5	
Belgium	18.5	593.8	
Spain and Portugal	38.7	622.3	
France	44.5	607.1	
Netherlands	48.8	625.3	
Italy	81.3	654.8	
UK	90.8	513.7	
Germany	92.6	648.9	
Eastern Europe and Balkans			
Slovenia	1.0	687.3	-0.7
Bulgaria	2.7	594.1	
Balkan States[33]	2.7	542.3	
Croatia	2.9	388.8	
Greece	3.5	704.4	
Slovak Republic	6.1	583.9	
Czech Republic	8.2	547.5	
Hungary	11.3	565.0	
Romania	13.8	276.7	
Poland	16.4	442.2	
Turkey	35.1	475.9	
FSU			
Moldova	3.0	245.0	-0.5
Belarus	17.9	190.0	
Ukraine	59.0	187.0	
Russia	429.5	60.5	

Source: [a] (IEA, 2010); [b] for FSU countries (Pirani et al., 2010); for all other countries - (IEA, 2010; Eurostat, 2010); [c] for FSU countries (Tarr and Thomson, 2004), for all other markets (Holz et al., 2008).

[32] Baltic States: Estonia, Lithuania, Latvia; Iberian Peninsula: Spain and Portugal
[33] Balkan States: Serbia, Bosnia and Herzegovina, Macedonia and Albania

In order to analyse future scenarios (up to 2030) of gas market developments using the model, projections of both gas demand and prices are needed. For the Base Case, the IEA's WEO 2009 forecast ("reference case") is used (IEA, 2009). Therefore, the following compound annual demand growth rate (CAGR) is assumed for the Base Case (2010-2030):

- +0.7% for Western and Southern Europe
- +0.8% for Eastern Europe and Balkans
- +0.4% for FSU Countries.

Since energy demand forecasts face many uncertainties, a sensitivity analysis is conducted on the demand forecast for the Base Case results (see Appendix G). For gas price projection it is assumed that gas prices will increase at an average CAGR of 1.4% (2010-2030), which is based on the forecast of natural gas price made by the IEA (2009) in its reference case.

3. Production Capacities

To use the model to explore future scenarios of gas market developments it is necessary to make assumptions about future production capacities. This section reports the assumptions for the Base Case. The Base Case forecast of production capacities for most countries in this model is based on the reference case of IEA's WEO 2009 (IEA, 2009) (see Table C.2).

The data on the Romanian and Polish gas production outlooks are based on (EC, 2008b). The Hungarian production profile was obtained from projections made by experts from the Hungarian Energy Office (Kőrösi, 2006).[34] For the Norwegian and Russian production forecasts, (Soderbergh et al., 2009) and (Soderbergh, 2010) are relied on, respectively. The authors provide detailed forecasts of natural gas production in Norway (Table C.2 row 12-14) and Russia (Table C.2 row 19-21) by major producing regions. Their forecasts have been modelled using a bottom-up approach, building field-by-field, and then adding production from contingent and undiscovered resources. The Russian production forecast provided by Soderbergh (2010) is quite close to Russia's official gas production forecast (Shmatko, 2009). In Appendix G the results of the sensitivity analysis on the Norwegian and Russian production forecasts are provided. Ukrainian production is assumed to decrease at an average rate of 1.2% p.a. The decline rate is based on the gas production forecast for Eastern Europe (EC, 2008b).[35] The production outlook of Central Asian countries and countries from the Middle East and North Africa (MENA) and Latin America

[34] The forecast was up to 2015, so the projection of Hungarian gas production was extended based on the average growth rate assumed in (Kőrösi, 2006)

[35] The justification for this assumption is that the production fields in Ukraine are mature, which is quite similar to those of some Eastern European countries such as Romania and Hungary; thus, without any publically available data on Ukrainian gas production forecasts, this assumption is relied upon.

(Trinidad and Tobago) are derived as production less domestic demand (i.e. export capacities). Production and demand forecasts for these countries are derived from the reference case of the IEA's WEO 2009 (IEA, 2009).

Table C.2: Natural Gas Production Capacities (bcm/y)

		2009	2015	2020	2025	2030
1	Algeria	62	76	86	94	103
2	Azerbaijan	8	11	18	25	33
3	Denmark[a]	9	6	3	2	1
4	Egypt	18	17	15	11	7
5	Germany	14	13	13	12	11
6	Hungary	3	1	1	0	0
7	Italy	8	7	7	7	6
8	Kazakhstan	4	10	18	26	34
9	Libya	11	14	19	26	35
10	Netherlands	79	71	64	52	43
11	Nigeria	37	44	56	78	109
12	Norway: Barents Sea	6	14	22	25	24
13	Norway: North Sea	64	66	62	55	48
14	Norway: Norwegian Sea	43	43	46	37	31
15	Oman	12	3	0	0	0
16	Poland	6	5	5	5	5
17	Qatar	70	140	150	166	185
18	Romania	11	10	10	9	9
19	Russia: Shtokman	0	0	5	33	64
20	Russia: Western Siberia	690	675	575	475	380
21	Russia: Yamal Peninsula	0	100	170	270	350
22	Trinidad and Tobago	34	34	38	43	48
23	Turkmenistan	27	74	84	94	104
24	UK	62	44	31	23	19
25	Ukraine	21	20	18	17	16
26	Uzbekistan	15	15	15	16	17

Source: [a] (DEA, 2010)

4. Pipeline Capacities

Table C.3 presents the cross-border pipeline capacities used in the model. There is no explicit modelling of intra-country transmission systems in the current version of the model, i.e. unlimited transmission capacities within a country are assumed. The primary source of cross-border pipeline capacities is (ENTSOG, 2010). In addition, various other sources are relied on for cross-border pipelines not covered in (ENTSOG, 2010).

Table C.3: Capacities of Cross-border Pipelines

From	To	Capacity (bcm/y)	From	To	Capacity (bcm/y)
Algeria	Spain	11.14	Italy	Slovenia	0.91
Algeria	Italy	34.26	*Kazakhstan*[d]	*Russia*	*54.80*
Austria	Germany	8.39	Libya	Italy	9.99
Austria	Italy	37.06	Netherlands	UK	15.33
Austria	Slovenia	2.45	Netherlands	Belgium	28.03
Austria	Hungary	4.19	Netherlands	Belgium	14.70
Azerbaijan[a]	Russia	10.00	Netherlands	Germany	13.54
Azerbaijan[b]	Turkey	7.00	Netherlands	Germany	31.81
Belarus	Lithuania	10.50	Netherlands	Germany	9.08
Belarus	Poland	30.60	Norway	UK	13.87
Belarus	Poland	5.25	Norway	UK	25.55
Belarus[c]	Ukraine	28.90	Norway	France	19.71
Belarus[c]	Ukraine	6.00	Norway	Belgium	15.33
Belgium	UK	25.39	Norway	Germany and Netherlands	42.38
Belgium	Netherlands	10.21	Poland	Germany	30.60
Belgium	Germany	9.25	Romania	Bulgaria	26.50
Belgium	France	28.04	Russia[e]	Belarus (Yamal-Europe)	33.00
Bulgaria	Macedonia	0.76	Russia[f]	Belarus (Northern Lights)	51.00
Bulgaria	Greece	3.54	Russia[c]	Ukraine (Sudja)	113.00
Bulgaria	Turkey	15.35	Russia[c]	Ukraine (Sokhranivka)	135.10
Czech Republic	Germany	15.55	Russia[e]	Turkey (Blue Stream)	16.00
Czech Republic	Germany	37.57	Russia	Latvia	5.40
France	Switzerland	7.14	Russia	Finland	8.15
France	Spain	3.12	Slovak Republic	Czech Republic	40.46
Germany	Poland	1.12	Slovak Republic	Austria	52.44
Germany	Austria	3.51	Slovenia	Croatia	1.74
Germany	Switzerland	17.34	Spain	France	1.25
Germany	France	20.03	Turkey	Greece	0.99
Germany	Belgium	15.88	Ukraine[c]	Poland	5.00
Germany	Netherlands	13.38	Ukraine[c]	Slovakia	92.60
Germany	Czech Republic	12.89	Ukraine[c]	Hungary	13.20
Hungary	Croatia	6.64	Ukraine[c]	Romania	4.50
Hungary	Serbia	4.57	Ukraine[c]	Moldova	3.50
Hungary	Romania	1.66	Ukraine[c]	Romania	26.80

Source: [a] (Korotkov, 2009); [b] (BP, 2010b); [c] (Naftogaz of Ukraine, 2010); [d] (Yenikeyeff, 2008); [e] (Gazprom, 2008); [f] (Yafimava, 2009).

Future pipeline capacities included in the model are presented in Table C.4. The reported capacities and start times of these pipelines are based on the official plans of the respective project sponsors (except for the South Stream system). The assumption in this work about the

South Stream route is based on (South Stream AG, 2010a). The exact capacities of the pipelines which are part of the system are not yet known. Therefore, the reported capacities are assumptions. It is assumed that the start time of the South Stream system is 2016, in line with Gazprom's official plan (Gazprom, 2010e).

Table C.4: Future Pipelines in the Model

From	To	Capacity (bcm/y)	Start time
Nord Stream System[a]			
Russia	Germany (Nord Stream Offshore)	55.0	2011-2012
Germany	Czech Republic (OPAL)	35.0	2011
Germany	Germany, Rehden (NEL)	20.0	2012
Czech Republic	Germany (Gazelle)	32.0	2011
South Stream System			
Russia	Bulgaria[36]	63.0	2016
Bulgaria	Serbia	43.0	2016
Bulgaria	Greece	20.0	2016
Greece	Italy	20.0	2016
Serbia	Hungary	43.0	2016
Hungary	Austria (Baumgaren)	21.5	2016
Hungary	Slovenia	21.5	2016
Slovenia	Austria (Arnoldstein)	21.5	2016
Algerian Export Pipelines			
Algeria	Spain (Medgaz)[b]	8.0	2010
Algeria	Italy (Galsi)[c]	8.0	2014

Source: [a] (Nord Stream AG, 2010a; OPAL, 2010; NEL, 2010; NET4GAS, 2010); [b] (Medgaz, 2010); [c] (Galsi, 2010)

5. LNG Capacities

As for LNG, all producers who currently export LNG to Europe, as reported in (BP, 2010a), are included. The liquefaction capacities of LNG exporters included in the model are assumed to grow at rates as reported in WEO 2009 up to 2013 (IEA, 2009) (see Table C.5 below). Any attempt to look beyond that date for developments in liquefaction capacities is rather speculative, so it is assumed that liquefaction capacities are at the level of 2013 thereafter. This gas market model is a regional model which does not include other demand regions such as the North American and Asia Pacific regions, which are important LNG importing regions. Therefore, not all LNG exports might be available for European consumption. However, for this analysis it is assumed that any demand for LNG from Europe may be satisfied, given the export capabilities of LNG producers.

[36] South Stream offshore

This might be true if European gas demand was high, which would push gas prices upwards and thus make LNG exporters willing to export more LNG to Europe. Another justification for this assumption is rapid developments in unconventional gas in North America which will free LNG capacities for Europe in the future.

As for regasification capacities in Europe, the model includes all regasification terminals as of 2009. The forecasting of LNG regasification capacities in Europe is based on (Gas Strategies, 2007). The Gas Strategies regasification data were gathered in 2007 during high energy prices and strong demand in Europe, and thus some of the LNG regasification projects may look very speculative now. For this reason, for the Base Case it is assumed that 50% of the Gas Strategies forecast of LNG regasification capacities will materialize (see Table C.5). This assumption is checked with a sensitivity analysis (see Appendix G).

Table C.5: LNG Liquefaction and Regasification Capacities

	2009	2015	2020	2025	2030
LNG Liquefaction					
Algeria	28	41	41	41	41
Egypt	16	16	16	16	16
Libya	1	1	1	1	1
Nigeria	30	31	31	31	31
Norway	6	6	6	6	6
Oman	15	15	15	15	15
Qatar	73	105	105	105	105
Russia's Shtokman	0	0	20	20	20
Trinidad and Tobago	20	20	20	20	20
LNG Regasification					
Belgium	9	9	9	9	9
France Atlantic	13	23	23	23	23
France Mediterranean	13	17	17	17	17
Italy	12	65	65	65	65
Netherlands	0	12	12	12	12
North-West Spain[a]	15	20	20	20	20
Poland	0	3	3	3	3
South-East Spain	44	66	66	66	66
UK	47	72	72	72	72

[a] Includes capacity of LNG terminal in Portugal

6. Production Costs

Usually, natural gas production comes from several fields simultaneously with distinct cost structures. We assume that the cheapest gas fields are developed and produced first. This leads to an increasing marginal cost function in the following form (Golombek and Gjelsvik, 1995):

$$TPC'(q) = \kappa + \rho q + \mu \ln\left(1 - \frac{q}{CAP^{PR}}\right) \quad \text{(C.3)}$$

$$\kappa, \rho > 0, \mu < 0, q < CAP^{PR}$$

where κ is the minimum per unit cost, ρ is the linearly increasing per unit cost, and μ is the maximum per unit production cost. The parameters for the production cost function for each producer in our model are presented in Table C.6. These parameters were computed based on a large number of sources.

Table C.6: Production Costs

Country	Region	Parameters of Marginal Production Cost Function		
		κ	ρ	μ
Russia	Western Siberia Fields[a]	15.12	0	-3.13
	Orenburg[b]	2.08	0	-2.71
	Yamal Peninsula[b]	7.65	0	-9.97
	Shtokman Field[b]	10.81	0	-14.08
Ukraine[c]		5.9	0	-7.69
Central Asia[f]		5.36	0	-6.98
Norway	North Sea[b]	5.63	0	-7.33
	Norwegian Sea[b]	4.99	0	-6.50
	Barents Sea[b]	11.24	0	-14.64
UK[e]		83.69	0.0293	-4.88
Netherlands[e]		27.90	0.1116	-9.35
Denmark[e]		55.79	0.2036	-9.35
Germany[e]		83.69	0.0209	0
Italy[e]		83.69	0.2357	0
Poland[e]		83.69	0.5551	0
Hungary[e]		83.69	1.0182	0
Romania[e]		83.69	0.2315	0
Algeria[d]		22.97	0.1104	-2.50
Egypt[d]		27.74	0.3634	-4.00
Libya[d]		24.42	0.3431	-3.50
Qatar[d]		6.51	0.1317	-6.10
Oman[h]		1.713	0	-2.232
Trinidad and Tobago[e]		27.90	0.0683	-7.67
Nigeria[e]		27.90	0.0781	-7.67

[a] Derived using data in (World Bank, 2009)
[b] Derived using data in (OME, 2001; IEA, 2003; IEA, 2009; World Bank, 2009)
[c] Derived using data in (Pirani, 2007)
[d] Derived using data in (OME, 2001; IEA, 2003; IEA, 2005; IEA, 2009; World Bank, 2009)
[e] Source: (Egging et al., 2008)
[f] Derived using data in (IEA, 2009); Includes: Azerbaijan, Turkmenistan, Uzbekistan, Kazakhstan
[h] Derived using data in (OME, 2001)

7. Transport Costs

7.1. Transmission costs within EU

Existing transmission tariffs in European countries are extremely complex and vary greatly from one pipeline system to another. For transmission costs in Western European countries we rely on a comprehensive study by Arthur D. Little (2008), who provides a detailed comparison of gas transportation tariffs charged by the transmission system operators of 12 West European countries.

For transmission tariffs through other countries, not covered in (Arthur D. Little, 2008), we use official tariffs published by the TSO of the respective country (e.g., through Hungary, Slovakia, the Czech Republic, etc.). Lastly, when data on transmission costs are not published, transmission costs are estimated using the methodology discussed in (van Oostvoorn, 2003).

7.2. Transmission costs within Russia

7.2.1. The existing transmission system

Following the World Bank (2009), it is assumed that, in Russia at least, transmission costs for gas exports should be priced at the long-run marginal cost (LRMC) of a new transmission pipeline. Up-to-date publicly available estimates of LRMCs for gas transmission within Russia are rather rare and inconsistent (Table C.7). For instance, OME (2001) estimated the LRMC of transporting gas from Russia's production regions to different export routes at US$ 2.00/tcm/100km. On the other hand, the World Bank (2009) estimated the LRMC of gas transmission in Russia at US$ 1/tcm/100km and, specifically for gas transportation on the Yamal Peninsula (difficult terrain), at US$ 2.5/tcm/100km.[37]

The gas transmission tariff approved by the Russian Federal Tariff Service (FTS) might be a good approximation of LRMC, assuming that the FTS retains a two-tier system of transmission tariffs with gas exports being priced at the LRMC of a new transmission pipeline and the domestic market benefiting from depreciated long-installed pipelines[38] (FTS, 2010; World Bank, 2009).

[37] These estimates are based on 12% of the real rate of return (World Bank 2009: p. 247)

[38] However, the cost differential between these two markets is negligible, since there are increasing needs to rehabilitate and expand the existing grid (see e.g., (FTS, 2010; World Bank, 2009: p. 247)).

Table C.7: Estimates of the LRMC of Gas Transmission in Russia

	OME (2001)	World Bank (2009)	FTS (2010)[a]	IEA (2009)	(Tarr and Thomson, 2004)	Average
LRMC, US$/tcm/100km	2.0	1.0	1.9	1.6	1.0	1.5
LRMC (difficult terrain), US$/tcm/100km	n/a	2.5	n/a	n/a	n/a	2.5

[a] Calculated at the official exchange rate of RUB 30.51 per 1 US$ as of 23 August 2010 (CBR, 2010)

Since the pipeline costs are essentially linear in terms of distance over similar terrain (ECT, 2006), total transmission costs between Russia's production regions and export points are simply the product of distances between producing regions and export points and the average values of LRMC reported in Table C.7.[39] Resultant transmission costs for Russia are presented in Table C.8.

Table C.8: LRMC of Gas Transmission in Russia (US$/tcm)

FROM \ TO	Russia-Ukraine border (Sudja)	Russia-Ukraine border (Sokhranivka)	Russia-Belarus border (Smolensk)	Nord Stream (Vyborg)	Blue and South Streams (Dzhubga)
Nadym-Pur-Taz (Urengoi Field)	48.20	47.94	42.88	52.83	54.86
Volga (Orenburg Field)	26.30	16.31	31.96	40.96	23.97
Yamal Peninsula (Bovanenkovo Field)	63.05	62.78	42.53	52.48	69.70
Shtokman	42.16	46.42	37.90	32.25	57.61
Alexandrov Gai[a]	18.77	8.78	24.50	33.50	16.51
Azerbaijan-Russia Border	19.92	15.28	31.96	46.82	12.76

[a] Alexandrov Gai is the compressor station near the Kazakhstan-Russia border. This is the gas import point from Central Asia into Russia.

7.2.2. Nord Stream and South Stream

Transportation costs through the Nord Stream and South Stream systems were calculated in two steps:

(i) The initial construction costs of the Nord Stream and South Stream systems were estimated, and then

(ii) the levelized transportation costs (LTC) over the economic life of the gas pipeline projects were derived.

[39] Calculations of transmission costs on the Yamal Peninsula are based on the LRMC reported by World Bank (2009) (Table C.7, second row)

The LTC through the Nord Stream and South Stream pipelines includes construction costs, capital costs, operating and maintenance costs and profit tax. Appendix E contains a detailed outline of the methodology and data input required for derivation of the levelized transport cost. The initial estimates of the construction costs of the Nord Stream system and relevant data and assumptions required for the LTC calculations are in Appendix F (Section 1). The construction costs of the South Stream system were derived using the pipeline cost methodology discussed in Appendix D. Other input data and assumptions needed for the calculation of the LTC through the South Stream system are outlined in Appendix F (Section 2). Tables C.9 and C.10 outline the results of the estimates of LTCs for the Nord Stream and South Stream systems.

Table C.9: Levelized Transportation Costs through the Nord Stream System (US$/tcm)

	Gryazovets-Vyborg	Nord Stream Offshore	Opal	Nel	Gazelle
Max	26.1	30.2	6.2	13.7	3.1
Average	20.6	21.1	4.9	11.1	2.5
Min	15.5	13.8	3.7	8.6	2.0

Table C.10: Levelized Transportation Costs through the South Stream System (US$/tcm)

From	To	Max	Average	Min
Offshore pipelines				
Russia (Dzhubga)	Bulgaria (Varna)	23.7	16.9	11.4
Greece (Igoumenitsa)	Italy (Otranto)	15.9	11.8	8.3
Onshore pipelines				
Bulgaria (Varna)	Serbia (Zajecar)	11.2	8.4	6.0
Bulgaria (Varna)	Greece (Petrich)	9.2	6.9	4.9
Greece (Petrich)	Greece (Igoumenitsa)	12.0	9.0	6.4
Serbia (Zajecar)	Hungary (Subotica)	11.3	8.5	6.1
Hungary (Subotica)	Austria (Baumgarten)	7.6	5.7	4.0
Hungary (Subotica)	Slovenia	5.6	4.2	3
Slovenia	Austria (Arnoldstein)	5.0	3.7	2.7

For South Stream in Bulgaria, it is assumed that the pipeline will be connected to the existing grid there; therefore, for sales to Macedonia through South Stream, Gazprom should pay the existing transit fee because it uses the existing transmission system of Bulgaria. The same is true for Gazprom's sales to Turkey through South Stream.

7.3. Transport costs through Ukraine, Belarus and Central Asia

7.3.1. The exogenous transit fee through Ukraine

According to the current long-term transit contract (Ukrainska Pravda, 2009), since 2010 the transit fee through Ukraine, T_n, has been determined as follows:

$$T_n = A_n + K_n \tag{C.4}$$

$$A_n = 0.5 \times A_{2010} + 0.5 \times [A_{n-1} \times (1 + I_{n-1})] \tag{C.5}$$

$$K_n = \frac{0.03 \times P_n}{L} \times 100 \tag{C.6}$$

where A_{2010}=US$2.04/tcm/100km; for 2010, $A_{n-1}=A_{2010}$; I_n is the inflation rate in the European Union; for 2010 I_{n-1}=0; K_n is the fuel gas component of the transit fee formula, which is determined monthly; P_n is the Ukrainian annual average import price; L – transit distance through Ukraine (1240 km); Subscript n – relevant year of transportation.

In this gas simulation model, fuel gas required for compressors along pipelines is assumed to be provided in kind by producers/shippers.[40] Therefore, K_n is not considered as part of the transit fee through Ukraine (i.e., K_n=0) in the forecasting of the transit fee through this country. The forecasting of the transit fee through Ukraine up to 2030 is based on the transit pricing formula specified by eq. (C.5). According to (C.5), the calculation of the transit fee requires the forecasting of the inflation rate. Possible future values of the inflation rate have been simulated, taking its value as an uncertain variable with a historical distribution of the average inflation rate in 1997-2009. The average value of the transit fee obtained from the simulations is US$ 2.07/tcm/100km.[41]

7.3.2. The transit fee through Belarus

In 2010 Gazprom pays US$ 1.88/tcm/100km to Beltransgaz as the transit fee for using the Belarus transit system (Northern Light, which is owned by Beltransgaz) (Gazprom, 2010d). For gas transportation services through the Belarus section of the Yamal-Europe pipeline, Gazprom pays only US$ 0.49/tcm/100km to Beltransgaz since Gazprom is the sole owner of the pipeline section (Ryabkova, 2010). This fee includes only the operating and O&M costs of the pipeline.

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[40] Most transit/transmission operators in Europe (e.g. BOG in Austria, NET4GAS in Czech Republic, and Eustream in Slovakia) ask shippers to provide fuel gas in kind.

[41] The minimum value is US$ 2.06/tcm/100km and the maximum value is US$ 2.08/tcm/100km.

7.3.3. The marginal cost of using transmission pipelines in Ukraine and Belarus

Since the transit systems of Ukraine and Belarus (the Northern Light system) were built during the Soviet era using similar materials and technology to those used for the construction of the Russian transmission system, it is assumed that the LRMC through Ukraine and Belarus is similar to the LRMC in Russia (Table C.8, average value). Table C.11 reports the LRMC through Ukraine and Belarus.

Table C.11: LRMC through Ukraine and Belarus (US$/tcm)

		Russia (Sudja)	Russia (Sokhranivka)	Belarus (Kobryn)	Belarus (Mozyr)	Russia (Smolensk)
Belarus	Lithuania (Kotlovka)	n/ap				6.86
	Poland (Brest)					8.99
	Ukraine (Kobryn)					8.99
	Ukraine (Mozyr)					5.45
Ukraine	Poland (Drozdovychi)	n/ap	n/ap	5.75	n/ap	n/ap
	Slovakia (Uzhgorod)	18.10	22.53	8.39	10.79	
	Hungary (Beregovo)	18.10	22.53	8.39	10.79	
	Romania (Tekovo)	18.10	22.53	8.39	10.79	
	Moldova (Anan'iv)	n/ap	14.38	n/ap	n/ap	
	Romania (Orlovka)	n/ap	17.62	n/ap	n/ap	

n/ap – Not applicable

7.3.4. The Central Asia-Centre Pipeline

In 2008, the transit fee through the Central Asia-Centre pipeline which brings Central Asian gas into Russia was US$ 1.4/tcm/100km (Yenikeyeff, 2008). This value is assumed in the Base Case scenario.

7.4. Other transport costs

7.4.1. *The Norwegian pipeline system*

The calculation of transport costs through the Norwegian transmission system is as follows. Efficient pricing of gas transmission through the Norwegian system is assumed, i.e. based on the LRMC of the new transmission system being similar to the existing one. The current value of the investment cost of the Norwegian transmission pipelines is based on (NPD, 2010). For the calculation of LRMC through a particular transmission pipeline, a 10% real interest rate is assumed. The economic life-time of a pipeline is assumed to be 25 years and corporate income tax is 28% (Norwegian Ministry of Finance, 2010). The results of the calculations are presented below (Table C.12).

Table C.12: LRMC of the Norwegian Transmission System (US$/tcm)

TO / FROM	UK (St. Fergus)	UK (Easington)	France (Dunkerque)	Belgium (Zeebrugge)	Germany and Netherlands (Emden/Dornum)
North Sea (Troll Field)	54.46	7.78	11.81	36.81	21.94
Norwegian Sea (Asgard Field)	64.22	15.56	21.57	46.58	31.71
Barents Sea (Snøhvit Field)	86.59	37.92	43.94	68.94	54.08

Since there is no pipeline connection between the Barents Sea and the existing Norwegian transmission system, a new pipeline with a capacity of 20 bcm/y is assumed. This capacity corresponds to the forecast of peak production from the Barents Sea (which is around 25 bcm less the liquefaction capacity of Snøhvit LNG plant, 6 bcm/y). This assumption is necessary for the calculation of marginal transportation costs from the Barents Sea to different pipeline export points.

7.4.2. The Algerian and Libyan export pipelines

Transport costs for Algerian and Libyan gas through export pipelines are based on (OME, 2001).

7.5. Pipeline Losses

Pipeline losses of 0.125% per 100 km are assumed (Desertec, 2010).

7.6. LNG Liquefaction, shipping and regasification costs

In this model version, a constant marginal cost for LNG liquefaction and regasification is assumed, i.e. $\frac{\partial TC^{liq}(q_n^{liq})}{\partial q_n^{liq}} = mc_{liq} > 0$ and $\frac{\partial TC^{regas}(q_{n'}^{regas})}{\partial q_{n'}^{regas}} = mc_{reg} > 0$. Based on (EIA, 2003), mc_{liq}=US$ 49/tcm and mc_{reg}=US$ 12.50/tcm. The calculation of the LNG shipping cost is as follows. A representative harbour in each country was chosen and approximate distances were calculated between each pair of LNG countries in the model. Then, taking into account distances and assuming that a LNG vessel cruises at an average speed of 20 knots,[42] approximate voyage days between a liquefaction site and a regasification terminal were estimated (see Table C.13).

[42] This speed has been accepted in the LNG vessel market as the most optimal speed for LNG carriers (MAN Diesel A/S, 2010).

Table C.13: Voyage Days from Liquefaction Sources to Regasification Countries[43]

		Liquefaction Country								
		Norway	Russia[a]	Algeria	Libya	Qatar	Oman	Egypt	Trinidad & Tobago	Nigeria
Regasification country	UK	4.3	4.4	3.8	6.2	13.7	12.7	7.0	8.8	9.8
	Germany	3.6	4.2	4.8	7.1	14.6	13.6	8.0	9.1	10.8
	Italy	8.0	8.7	2.4	3.0	10.3	9.3	3.8	9.9	9.9
	France Atlantic	4.9	5.3	3.6	5.9	13.4	12.4	6.8	8.0	9.6
	France Mediterranean	7.9	8.4	2.1	3.2	10.0	9.5	3.9	9.5	9.5
	North-West Spain	5.2	5.8	2.8	5.0	12.7	11.7	6.0	8.1	8.1
	South East Spain	7.3	7.8	1.5	3.4	10.9	9.9	4.3	8.9	8.9
	Zeebrugge	3.9	4.4	4.3	6.6	14.1	13.1	7.5	9.3	10.2
	Turkey	9.8	10.4	3.9	2.4	8.6	7.6	2.1	11.5	11.5
	Poland	3.9	4.4	5.8	8.1	15.6	14.6	9.0	10.1	11.8
	Greece	9.5	10.2	3.6	2.0	8.6	7.6	2.1	11.2	11.2

[a] Shtokman Field
Source: own calculations based on (Sea Rates, 2010)

Finally, shipping costs are obtained as the product of voyage days and the assumed daily charter rate for LNG vessels. The charter rate varies greatly due to several factors – the price of the vessel, financial costs and the O&M costs of the ship, as well as the global LNG demand and supply situation. For example, according to (EIA, 2003), the daily charter rate could be as low as US$ 27,500 per day and as high as US$ 150,000 per day. The current (2010) charter rate for spot vessels is reported at US$ 37,500 per day (LNG OneWorld, 2010). An average charter rate of US$ 71,500 per day is assumed. Following the California Energy Commission (2003), the fuel losses during LNG liquefaction, shipping and regasification applied in the model are as follows: (i)

- Liquefaction – 9%;
- Shipping – 0.15% per day;
- Regasification – 2.5%.

[43] In addition to cruising days, the voyage days reported in Table C.11 also include the one day required for loading and unloading of LNG (Coyle and Patel, 2009).

APPENDIX D. Pipeline Cost Methodology

Cost calculations for onshore pipelines follow the bottom-up engineering model as described in (World Bank, 2009). The results of this model are presented in Figure D.1 below.

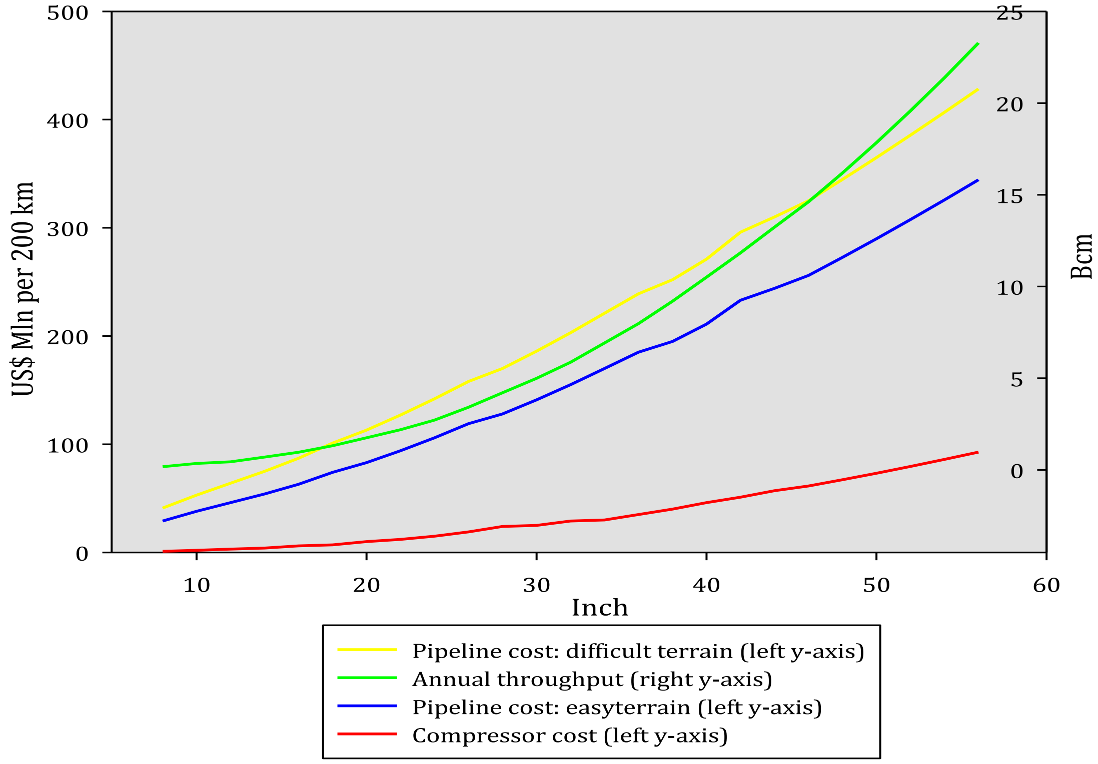

Figure D.1: Pipeline and Compressor costs
Source: (World Bank, 2009)

The assumption for pipeline pressure is 40/60 bar.g (suction/delivery), which corresponds to the design of most regional gas transmission systems (World Bank, 2009). Using higher pressure pipelines, for example 100 bar.g pipes with a diameter of 56 inches, could yield 32 bcm/year of throughput. However, the costs of pipelines and compressors would also rise significantly. Using the data provided in Figure D.1, the estimated total costs of onshore pipelines are:

for easy terrain

$$PC_i^{onshore} = 0.0947D_i^2 + 2.5829D_i + 3.9135 \quad \text{(D.1)}$$

and for difficult terrain

$$PC_i^{onshore} = 0.0947D_i^2 + 4.0829D_i + 3.9135 \quad \text{(D.2)}$$

where $PC_i^{onshore}$ – cost of pipeline *i* (including compressors cost), D_i – diameter of the pipeline *i*.

Publicly available data and information on offshore pipeline costs are rather limited. Data were assembled on offshore pipeline projects built during 2002-2008 in the US (EIA, 2010) and offshore pipelines in the Norwegian North Sea system (NPD, 2010). The data points are quite limited in number (41 projects in total – see Table D.1 for descriptive statistics) for very precise econometric analysis (see Table D.1 for descriptive statistics); however, a sensitivity analysis will be provided on the obtained costs to gain some possible South Stream cost ranges.

Table D.1: Descriptive Statistics of Offshore Pipeline Projects

	Sample Size	Mean	Max	Min	Std Dev	Std. Error
Cost (2008 US$ mln)	41	924.30	5311.30	3.36	1305.01	203.81
Pipeline Capacity (mmcm/a)	41	8754.70	27010.00	0.70	8657.88	1352.13
Pipeline length (km)	41	234.80	1200.00	1.61	290.81	45.42

Using the assembled data, the equation is estimated in the following form:

$$ln(PCC_i^{offshore}) = C_i + \alpha ln(Distance_i) + \beta ln(Capacity_i) \tag{D.3}$$

where $PCC_i^{offshore}$ is per unit capital cost of offshore pipeline *i*,

The first estimation of eq. (D.3) indicates that there is a positive autocorrelation (DW=1.107). The autocorrelation is removed by transforming the data. The resulting estimation of eq. (D.3), which satisfies the major assumptions of the classical regression model, is presented in Table D.2 below.

Table D.2: Offshore Pipeline Cost Model

	Unstandardized Coefficients		Standardized Coefficients	t	R	R^2	F	Durbin-Watson
Coefficients	B	Std. Error	Beta					
Ci	5.766	0.842		6.846	0.873	0.762	60.973	1.910
α	0.903	0.131	0.585	6.882				
β	-0.773	0.073	-0.897	-10.555				
Dependent Variable: $ln(PCC_i^{offshore})$								

The negative coefficient β (-0.773) means that there are economies of scale associated with the capacity of a pipeline. A higher capacity results in a reduction of the capital cost per unit of pipeline capacity.

APPENDIX E. Levelized Transportation Cost Calculation

The levelized transportation cost through a gas pipeline is calculated using eq. (E.1).

$$LTC = \frac{PV\ of\ Total\ Life-cycle\ Cost}{PV\ of\ Total\ Gas\ Transported\ over\ the\ economic\ life\ of\ the\ pipeline} \tag{E.1}$$

<u>Present Value of Total life-cycle cost = (1)+(2)+(3)+(4)+(5)</u>

(1) Investment Costs=*E(PCC) + E(CCS) + other costs*

$$E(PCC) = IEC_p \times CF_p \tag{1.1}$$

$$E(CCS) = IEC_c \times CF_c \tag{1.2}$$

E(PPC) is the Expected Pipeline Construction Cost;

E(CCS) is the Expected Cost of Compressor Stations;

IEC_p is the Initial Estimated Cost of constructing a particular pipeline of the Nord Stream system;

CF_p is the uncertain cost factor of pipeline construction. This is a random variable which is uniformly distributed between [0.9; 1.3]; [44]

IEC_c is the Initial Estimated Cost of compressor stations;

CF_c is the uncertain cost factor for compressor stations. Again, this is a random variable which is uniformly distributed between [1; 1.3];

Other costs include:

Upfront payment to obtain financing (in case of Nord Stream offshore only) – this is a one-off payment to secure the financial proposal issued by lenders to the borrower (usually termed

[44] The lower bound represents a 10% discount on the initial cost estimates because in 2006-2009 steel and construction prices increased far above historical rates. The upper bound (1.3) allows the cost of a pipeline to be inflated by 30% from IEC_p. An increase in cost by 30% from initial project budget is based on Barinov (2007), who surveyed the cost overruns (and their reasons) of capital intensive projects with a focus on oil and gas industry in the CIS.

commitment fees).

(2) $$-\sum_{n=1}^{N}\frac{Depreciation_n}{(1+Discount\ Rate)^n}\times Tax\ Rate$$

This is the present value of depreciation tax benefit over the economic life of the pipeline (N=25).
The depreciation is determined by the straight-line method. For simplicity, we assume zero scrap value and decommissioning costs at the end of the depreciation period. The assumption is made because the depreciation period is much shorter than technical lifetime of a gas pipeline.

(3) $$+\sum_{n=1}^{N}\frac{O\&M_n}{(1+Discounr\ Rate)^n}\times(1-Tax\ Rate)$$

This is the present value of the annual operating and maintenance costs of the pipeline and compressor stations. Annual O&M for the pipeline is determined as a % of the capital costs of the pipeline (item 1 above).

(4) $$+\sum_{n=1}^{N}\frac{Cost\ of\ Debt\ Financing_n}{(1+Discount\ Rate)^n}\times(1-Tax\ Rate)$$

The present value of annual payments for debt financing (where applicable) is added to the total life-cycle costs of the pipeline.

(5) $$+\sum_{n=1}^{N}\frac{Loan\ Amortization_n}{(1+Discount\ Rate)^n}$$

This is the present value of loan amortization (where applicable). In the case of 100% equity financing (e.g. the Gryazovets-Vyborg pipeline on Russian territory) this item is not included in the total lifecycle cost of the pipeline.

Present Value of Total gas transported over the life-cycle cost is derived as follows:

(6) $$\sum_{n=1}^{N}\frac{Utilization\ Rate\times Pipeline\ Design\ Capacity}{(1+Discount\ Rate)^n}$$

The utilization rate (%) is the average transportation capacity usage rate over the economic life of the pipeline (N=25). We assume a 100% utilization rate but we also show calculations for the case of a 75% utilization rate.

Box E.1: Calculation of Levelized Transportation Costs

All necessary inputs and assumptions for the calculation of levelized transportation costs (LTC) through Nord Stream and South Stream are provided in Appendix F below.

APPENDIX F. Data and Assumptions for the Derivation of the Costs of Nord Stream and South Stream

1. Nord Stream

1.1. Investment Costs

1.1.1. Gryazovets-Vyborg Pipeline

The construction costs of the Gryazovets-Vyborg (GV) pipeline in Russia are presented in Table F.1.

Table F.1: Construction Costs of the Gryazovets-Vyborg Pipeline

	Construction Cost (US$ Bn)	Length of Pipeline laid (km)
2006	0.73	144
2007	1.05	156
2008	0.88	163
2009	1.39	134
2010	2.34	320
Total	6.39	917

[a] Based on the official average annual exchange rates for the respective years obtained from Central Bank of Russian Federation (CBR, 2010).
Source: (Gazprom, 2005; Nazarova, 2009; Korchemkin, 2010; Nazarova, 2010)

The total cost of compressors to be installed along the Gryazovets-Vyborg pipeline was derived as follows. The Ukrainian producer of industrial equipments, Frunze, reported that it has produced four 25 MWh compressor units for installation at the beginning of the Gryazovets-Vyborg pipeline (Frunze, 2010). The reported total cost of these compressors is US$52 mln (Ukrrudprom, 2010). Thus, if the total compressor power along the pipeline will be 1266 MWh, then the estimated cost of the compressors to be equipped along the pipeline should be around US$ 660 mln. However, as was reported by Gazprom, the Portovaya Compressor station (366 MWh), which will compress gas before entering the Nord Stream offshore line, will be equipped with Rolls-Royce compressor units with very advanced technology (52 MWh per compressor unit) (Gazprom, 2010f). It is thus reasonable to assume that 366 MWh of compressors purchased from Rolls-Royce might cost Gazprom considerably more than those from a Ukrainian producer. We have factored this in as a cost overrun on purchasing compressors for the pipeline. Therefore, the expected costs of the compressor stations along the Gryazovets-Vyborg pipeline are calculated as:

$$E(CCS_{GV}) = 1266MWh \times US\$52mln \times CF_C \qquad \text{(F.1)}$$

1.1.2. *Nord Stream Offshore*

Initial estimates of the construction costs of the Nord Stream offshore are based on the official figure of €7.4 bln, as quoted by Nord Stream AG (NSAG) (Nord Stream AG, 2010a). However, as noted above, there might be overruns or delays which would affect project costs.[45] Major drivers of construction cost uncertainty include the uncertain costs of steel, construction, engineering and procurement. The expected construction cost for the offshore pipeline is:

$$E(PCC_{NSO}) = €7.4 \times CF_C \qquad \text{(F.2)}$$

1.1.3. *OPAL, NEL and Gazelle Pipelines*

The capital costs of OPAL and NEL are quoted at €1 bln each (OPAL, 2010; NEL, 2010). For the Gazelle project, the official figure for the capital cost is €400 mln (NET4GAS, 2010). As a starting point for the calculation of the expected construction costs of these pipelines we use these official figures:

$$E\left(PCC_{Opal}\right) = €1bln \times CF_p \qquad \text{(F.3)}$$

$$E(PCC_{Nel}) = €1bln \times CF_p \qquad \text{(F.4)}$$

$$E(PCC_{Gazelle}) = €400mln \times CF_p \qquad \text{(F.5)}$$

1.2. *Financial Costs: Discount and Interest Rates*

1.2.1. *Gryazovets-Vyborg Pipeline*

Since Gazprom is financing the construction of the Gryazovets-Vyborg pipeline, the discount rate applied to the project is based on Gazprom's weighted-average cost of capital, WACC, in 2003-2009 (see Table F.2). We treat WACC as a random variable which is uniformly distributed in the following range [0.889; 0.1541], with a lower (upper) bound corresponding to the minimum (maximum) WACC in 2003-2009.

[45] Indeed recent news, quoting a representative of the Nord Stream pipeline, reported that the cost of the offshore pipeline could rise to €8.8 bln (Neftegaz, 2010).

1.2.2. Nord Stream Offshore

Debt Financing

At the end of August 2009, Nord Stream's offshore owner and operator confirmed that Request for Proposals for the raising of senior debt for financing Phase 1 development have been issued to the commercial bank market. According to NSAG, the construction of the offshore pipeline is to be financed with 30% equity from shareholders (Gazprom, BASF/Wintershall, E.ON Ruhrgas, Gasunie and GDF-Suez) and 70% senior debt. As of mid-March 2010, Nord Stream AG has completed a financial deal with the commercial banking market on the financing of the first phase of construction. Nord Stream AG has procured a total debt requirement of approximately €3.9 bln for Phase 1 from a combination of the following (Mangham, 2009):

- A syndicated covered loan of up to €3.1 bln provided by a pool of 26 commercial banks. The loan is covered by the Export Credit Guarantee Programmes of Germany (Hermes) and Italy (SACE), as well as the Untied Loan Guarantee Programme of Germany (UFK).
- A syndicated loan facility on an uncovered basis for an amount of up to € 800 mln.

The structure of the loan guarantee is as follows:

- € 3.1 bln loan as a 16-years loan facility covered by the export credit agencies Hermes and Sace, as well as by Germany's loan guarantee programme (UFK), which covers political and commercial risks similarly to Hermes. Hermes will cover €1.6 bln, UFK - €1 bln and Sace - €500 mln.
- There is also an €800 mln, 10-year uncovered commercial loan.

The pricing of the debts is as follows:

- The €800 mln commercial uncovered loan pays a margin of 275 basis points (bps) over EURIBOR pre-completion, 430 bps until year 7 and 450 bps thereafter. The commitment fee is 110 bps.
- The Hermes, UFK and Sace loans pay a margin of 160 bps, 180 bps and 165 bps over EURIBOR respectively. The commitment fees are 65 bps, 75 bps and 65 bps, respectively.

Based on these financial conditions, the interest rate on the debt finance is expressed as follows:

$$I_{NSO}^{D} = c \times (\sum_{j} a_{j\times}[p_j + EURIBOR]) + (1-c) \times (\sum_{T} a_T \times [p_T + EURIBOR]) \qquad \text{(F.6)}$$

where c is the share of covered loan in the total debt finance, a_j is the share of each export credit agency in the total covered loan, p_j is the price of each covered loan, a_T is the share of the total length of the covered loan with a price p_T, and EURIBOR is the Euro interbank deposit rate.

As can be seen from the financial conditions for phase I, the loan is a long-term deal and the pricing of that loan is based on EURIBOR, so we need the trend of EURIBOR for 16 years into the future (the length of the covered loan). We assume that EURIBOR is a random variable with a distribution similar to its trend in 1999-2009. This makes the EURIBOR trend in our cash-flow model random.

Equity Financing

Since there are no details yet of the financial conditions of the second phase of the Nord Stream offshore pipeline, we assume that the remaining investment costs are financed by NSAG shareholders. The costs of equity financing are discussed below.

Project Discount Rate

Taking into account the cost of debt financing and using the data on the cost of capital for the Nord Stream investors (see Table F.2), we have derived the WACC of the offshore pipeline, which serves as the basis for the discount rate of the cash-flow model:[46]

$$DR_{NSO} = \left[d_{NSO} \times I_{NSO}^{D} + (1 - d_{NSO}) \times \left(\sum_{i} e_i \times WACC_i \right) \right] \qquad \text{(F.7)}$$

where d_{NSO} is the share of debt financing in the NSO project, e_i - share of each shareholder in equity financing, $WACC_i$ is the cost of capital of each shareholder respectively, I_D – the weighted-average interest rate on the debt.

The WACC of each investor in the project is assumed to be a random variable which is uniformly distributed with minimum and maximum values as specified in Table F.2.

[46] We assume that the WACC of the other two shareholders of the Nord Stream offshore, Gasunie and GDF SUEZ, are similar to those of E.On and BASF, since data on the capital costs of Gasunie and GDF SUEZ were not publicly available. This assumption would not substantially undermine our results since both Gasunie and GDF SUEZ have relatively small shares in NSAG.

Table F.2: WACCs of Shareholders of Nord Stream AG

	Gazprom	BASF	E.ON Ruhrgas
2002	n/a	n/a	n/a
2003	8.98%	n/a	10%
2004	9.03%	n/a	9%
2005	8.91%	n/a	9%
2006	9.13%	10%	9%
2007	11.32%	9%	9%
2008	15.07%	10%	9%
2009	15.41%	9%	9%
Min	**8.98%**	**9%**	**9%**
Max	**15.41%**	**10%**	**10%**

Source: (BASF, 2007; BASF, 2010a; Bernotat, 2010)

1.2.3. OPAL, NEL and Gazelle projects

According to BASF's 2009 annual report (BASF, 2009), Wingas has borrowed €500 mln to finance the OPAL project. The interest rate, I^{D}_{opal}, on this loan is 2.5%. However, no information on the length of this loan has been provided. Thus, we assume that it is a short-term loan (3 years), taking into account its relatively small size. We ran a sensitivity analysis on this assumption and found that a short-term loan of 3 years will result in just a 7.8% increase in the levelized transportation cost compared to a longer-term loan of 10 years. Thus, the assumption of the length of the loan contributes minimally to the cost calculations. The discount rate for the OPAL project is derived as follows:

$$DR_{opal} = \left[d_{opal} \times I^{D}_{opal} + \left(1 - d_{opal}\right) \times WACC_{opal}\right] \qquad \text{(F.8)}$$

where d_{opal} is the share of debt financing, I^{D}_{opal} is the interest rate on the loan; $WACC_{opal}$ is the capital cost of Opal's major investor (BASF and E.ON) and is treated as a random variable with uniform distribution from [0.09; 0.10].

No public information is available on the financing details of the other two pipelines, Nel and Gazelle. We assume that they are fully financed by the project sponsors, i.e. Wingas and NET4GAS (former RWE Transgas Net, owned by RWE AG (RWE, 2010a)). We use BASF's WACC (see Table F.2) for the discount rate in cost calculations for the Nel project. For the Gazelle project discount rate we use RWE's WACC (9%-10%) in 2002-2009 (RWE, 2010b).

1.3. O&M Costs

Information on the operating and maintenance (O&M) costs of pipelines is difficult to obtain because the considered pipelines are not yet in operation, so common practice in the literature is followed and O&M costs are assumed to be a fixed fraction of the investment costs of the pipeline (ECT, 2006; Krey and Minullin, 2010). The annual O&M costs of pipelines are assumed to be 0.3% of the expected investment costs (Wintershall, 2010). For annual O&M costs of compressor stations, 4% of the expected cost is assumed (Wintershall, 2010).

1.4. Taxation and Depreciation

Depreciation and taxation are based on the taxation system of the country through which the pipeline passes. For pipelines in Germany (OPAL and NEL), the effective corporate tax rate, including trade tax and solidarity tax, is between 29-32% (CFE, 2010), so we assume a rate of 30%. For the Gazelle pipeline, according to KPMG, the relevant corporate tax in the Czech Republic in 2010 would be 19% (KPMG, 2009).

For the Nord Stream offshore pipeline, according to Nord Stream AG, the taxation issue would mainly be under Swiss jurisdiction as the company is registered in Kanton Zug with a headquarters of around 140 staff (Nord Stream AG, 2010b). According to the tax system of Switzerland and Kanton Zug (Müller-Studer, 2009), Nord Stream AG enjoys special tax privileges because the company falls under the category of 'mixed company', i.e. a company whose main operations are not in Switzerland.[47] The effective corporate tax for this type of company is 10.125% (Müller-Studer, 2009).

2. South Stream

2.1. Capacity and timing of the project

The assumed South Stream route is based on the recent publicly available project documentation from the developers (see Figure F.1 below) (South Stream AG, 2010a). The exact capacities of the pipelines, which are part of the South Stream system, are not known yet. Therefore, the reported capacities here are assumptions (see Table F.3, below). The assumed start date of the South Stream system is 2016 (Gazprom, 2010e). It is assumed that, like the Nord Stream project, South Stream will be launched in stages. In 2016, half of the assumed capacity of each pipeline section of the system will be operational. The system's designed capacity (63 bcm) will be available from 2017.

[47] At least 80% of operations should be outside Switzerland (Müller-Studer, 2009).

Table F.3: South Stream Pipeline System

From	To	Number of lines	Capacity per line (bcm)	Total Capacity
Offshore pipelines				
Russia (Dzhubga)	Bulgaria (Varna)	4	15.75	63.00
Greece (Igoumenitsa)	Italy (Otranto)	2	10.00	20.00
Onshore pipelines				
Bulgaria (Varna)	Serbia (Zajecar)	2	21.50	43.00
Bulgaria (Varna)	Greece (Petrich)	1	20.00	20.00
Greece (Petrich)	Greece (Igoumenitsa)	1	20.00	2016
Serbia (Zajecar)	Hungary (Subotica)	2	21.50	43.00
Hungary (Subotica)	Austria (Baumgarten)	1	21.50	21.50
Hungary (Subotica)	Slovenia	1	21.50	21.50
Slovenia	Austria (Arnoldstein)	1	21.50	21.50

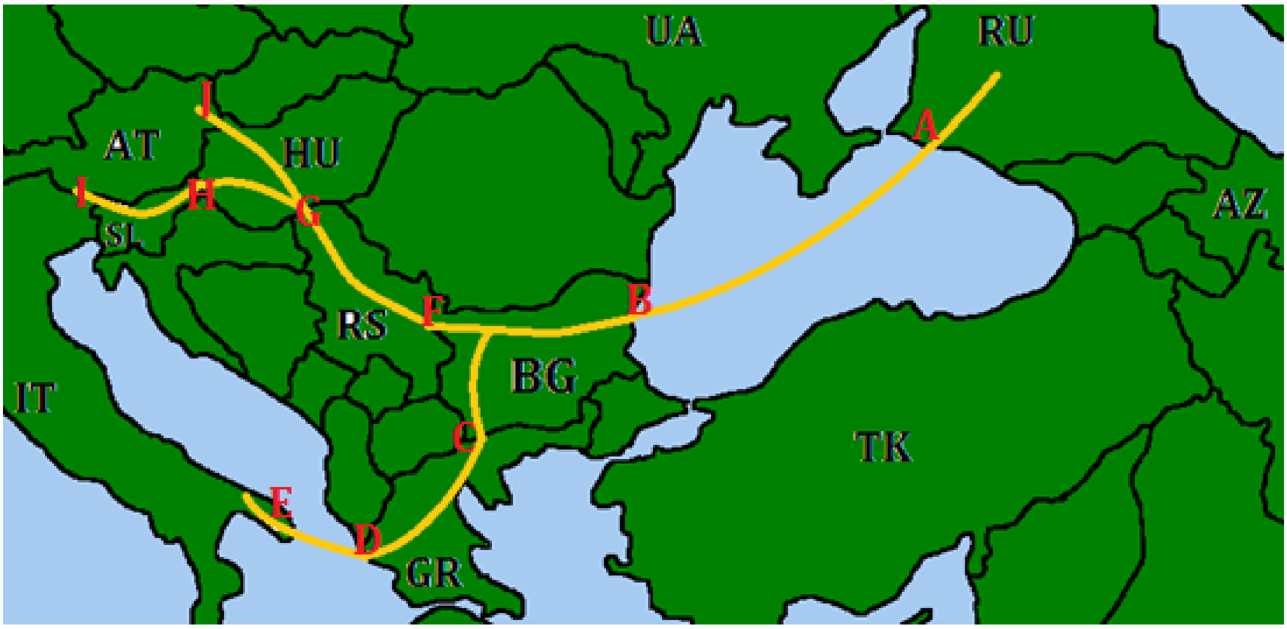

Figure F.1: Assumed Route for the South Stream Pipeline System
Source: based on South-Strea.info

2.2. Cost of capital and project discount rate

Since feasibility studies of South Stream's pipeline sections have not started yet, it is necessary to make assumptions about the cost of capital and relevant project discount rates. These assumptions are based on publicly available information and particularly use data on the financing of South Stream's sister project – Nord Stream (see Appendix F, Section 1.2.2).

It is assumed that the financing strategy for the South Stream offshore project is similar to that for the Nord Stream project. Therefore, the construction of the offshore pipeline would be financed with 30% equity from shareholders (Gazprom, ENI) and 70% debt. The cost of capital for debt financing is assumed to be similar to the Nord Stream financing cost (see Appendix F, Section 1.2.2).

Gazprom's weighted-average cost of capital (WACC) is assumed to be to be in the range of 8.89%-15.41% (Zak, 2006; Lyutyagin, 2010), while the WACC of European energy utility companies is assumed to be 9%-10% (similar to the WACC of such companies as E.ON or BASF, see Table F.2).

It is assumed that Gazprom's stake in all the pipeline sections of the South Stream system is 51%, while its European partners hold the remainder.

2.3. Project cost overrun

The costs of large-scale pipeline projects may overrun or their construction may be delayed, which would affect project costs. Major drivers of construction cost uncertainty include the costs of steel, construction, engineering and procurement. Taking into account uncertainties in project implementation (in terms of delays and budget overruns), the expected construction cost of each pipeline section of the South Stream system is determined as follows:

$$E(TC_n) = CF \times PC_n \tag{F.9}$$

where $E(TC_n)$ is the expected total cost (including compressor costs where appropriate) of the pipeline section n of the South Stream system; and PC_n is the estimated initial project cost. The costs of the pipeline and compressors are estimated (where appropriate) for each section of the South Stream system based on the methodology described in Appendix D above, and CF is the cost factor of pipeline construction, which is a random variable which is assumed to be uniformly distributed between [0.9; 1.3]. The lower bound represents a 10% discount on the initial cost estimates because in 2006-2009 steel and construction prices increased far above historical rates. The upper bound (1.3) allows the cost of a pipeline to be inflated by 30% from the initial estimate, PC_n. An increase in costs of 30% above the initial project budget is based on (Barinov, 2007).

2.4. O&M costs

The annual O&M costs of the South Stream pipelines are assumed to be 0.3% of the expected investment costs (Wintershall, 2010). For the annual O&M costs of compressor stations, 4% of the expected cost is assumed (Wintershall, 2010).

2.5. Taxation and depreciation

The taxation and depreciation applied to pipeline projects is based on the taxation system of the country through which the pipeline passes:

- Bulgarian corporate tax is assumed to be maintained at 2010 levels - 10% (IFC, 2010a);
- Corporate tax in Greece is 25% (IFC, 2010b). The offshore part of the project between Greece and Italy is assumed to be under Greek tax jurisdiction;
- Serbian corporate tax is at the level of 2010 - 10% (IFC, 2010d);
- Hungary – 16% (IFC, 2010c);
- Slovenia – 22% (IFC, 2010e).

The operator of South Stream offshore pipeline, South Stream AG, is registered in Kanton Zug, Switzerland (South Stream AG, 2010b). The taxation procedure applied to companies registered in Kanton Zug is briefly discussed above (Appendix F, Section 1.4). The effective corporate tax applied to the operation of the South Stream AG is 10.125%.

APPENDIX G. Model validation and sensitivity analysis

In this appendix, model validation with historical data (2008-2009) and different sensitivity analyses are documented. In Section 1 of this appendix, the model is calibrated with historical data from 2008-2009 and the model results are compared under different assumptions of market power with historical data. In Sections 2 and 3, the sensitivity of model results to changes in exogenous assumptions (such as demand, production, pipeline and LNG capacities, conjectured transit demand slope) is tested.

1. Consistency with historical data

The results of the model calibrated to the 2008-2009 data are presented in Tables G.1a, G.1b and G.2. In general, successive oligopolies (where both producers and traders exert market power in sequence) result in much higher final prices and lower quantities than in reality. This is generally in line with the theory of double-marginalization (Spengler, 1950). On the other hand, the perfect competition assumption inflates the results quite substantially. In this case, the average final price in Europe is much lower than the observed real price, and consumption is also much higher than the real data.

In general, the results obtained from the upstream oligopoly assumption are in line with historical data. Also, they are more consistent with real data than the results obtained from the other two market power assumptions.

There is one common feature in the three market power scenarios - the diversity of the gas sources plays a crucial role in the results in terms of final prices and consumption. Less diverse countries in terms of supply sources always enjoy higher prices and lower consumption than in reality. In contrast, countries with a diverse supply portfolio enjoy lower prices and higher consumption compared to reality. In general, this observation is line with economic intuition regarding market power and competition. Therefore, the model behaves in a predictable way which is in line with fundamental economic intuition and theory.

Table D.1a: Model Validation with Historical Data: 2008-2009

	CONSUMPTION (bcm)						PRICES (US$/tcm)					
	real data		model results		Difference		real data		model results		Difference	
	2008 [1]	2009 [2]	2008 [3]	2009 [4]	2008 [3]/[1]	2009 [4]/[2]	2008 [5]	2009 [6]	2008 [7]	2009 [8]	2008 [7]/[5]	2009 [8]/[6]
UPSTREAM OLIGOPOLY												
Austria	9	9	8	9	94%	98%	584	583	637	604	109%	104%
Belgium	19	18	19	20	100%	109%	618	594	622	518	101%	87%
Bulgaria	4	3	3	2	73%	79%	391	594	545	775	139%	130%
Balkans	3	3	2	2	74%	77%	471	542	649	720	138%	133%
Baltic States	6	5	4	4	72%	80%	303	525	424	678	140%	129%
Czech Republic	9	8	7	7	83%	90%	528	547	657	629	124%	115%
Germany	98	93	104	100	106%	108%	734	649	667	574	91%	88%
Finland	5	4	4	3	80%	80%	726	611	938	784	129%	128%
France	46	45	47	48	102%	109%	600	607	580	531	97%	88%
Greece	4	4	4	4	100%	101%	883	704	885	696	100%	99%
Croatia	3	3	2	2	68%	73%	338	389	491	538	146%	138%
Hungary	13	11	11	10	86%	90%	527	565	632	645	120%	114%
Spain and Portugal	43	39	40	39	94%	101%	602	622	652	613	108%	98%
Italy	88	81	97	97	110%	120%	585	655	502	472	86%	72%
Netherlands	49	49	45	50	94%	102%	566	625	617	604	109%	97%
Poland	16	16	16	16	97%	98%	502	442	525	453	105%	103%
Romania	16	14	17	15	107%	113%	350	277	316	227	90%	82%
Slovakia	6	6	5	5	73%	78%	521	584	724	766	139%	131%
Slovenia	1	1	1	1	95%	102%	604	687	650	668	108%	97%
Turkey	37	35	32	32	88%	92%	585	476	681	531	116%	112%
UK	99	91	102	99	103%	109%	612	514	586	446	96%	87%
Average [a]	***27.3***	***25.6***	***27.2***	***27.0***	***100%***	***106%***	***603***	***582***	***597***	***527***	***99%***	***90%***
DOUBLE MARGINALIZATION												
Austria	9	9	8	8	87%	87%	584	583.5	689	688	118%	118%
Belgium	19	18	17	18	88%	95%	618	593.8	724	638	117%	107%
Bulgaria	4	3	2	2	57%	60%	391	594.1	632	936	161%	158%
Balkans	3	3	2	2	57%	58%	471	542.3	759	865	161%	160%
Baltic States	6	5	3	3	57%	60%	303	525.2	488	823	161%	157%
Czech Republic	9	8	7	6	75%	78%	528	547.5	715	722	135%	132%
Germany	98	93	90	86	92%	92%	734	648.9	823	720	112%	111%
Finland	5	4	3	3	61%	61%	726	611.2	1130	954	156%	156%
France	46	45	42	42	92%	95%	600	607.1	671	653	112%	108%
Greece	4	4	3	3	79%	80%	883	704.4	1145	907	130%	129%
Croatia	3	3	2	2	54%	57%	338	388.8	558	630	165%	162%
Hungary	13	11	9	8	69%	71%	527	565.0	762	799	144%	141%
Spain and Portugal	43	39	40	38	94%	99%	602	622.3	652	631	108%	101%
Italy	88	81	85	80	96%	99%	585	654.8	617	668	106%	102%
Netherlands	49	49	41	43	84%	87%	566	625.3	694	738	123%	118%
Poland	16	16	13	13	80%	80%	502	442.2	647	570	129%	129%
Romania	16	14	15	13	92%	96%	350	276.7	391	291	112%	105%
Slovakia	6	6	4	4	59%	60%	521	583.9	827	921	159%	158%
Slovenia	1	1	1	1	79%	80%	604	687.3	783	883	130%	129%
Turkey	37	35	26	26	71%	75%	585	475.9	824	649	141%	136%
UK	99	91	85	81	86%	89%	612	513.7	736	593	120%	115%
Average [a]	***27.3***	***25.6***	***23.6***	***22.8***	***87%***	***89%***	***603***	***582***	***710***	***662***	***118%***	***114%***

[a] Average final prices are quantity-weighted

Table D.1b: Model Validation with Historical Data: 2008-2009

	CONSUMPTION (bcm)						PRICES (US$/tcm)					
	real data		model results		Difference		real data		model results		Difference	
	2008 [1]	2009 [2]	2008 [3]	2009 [4]	2008 [3]/[1]	2009 [4]/[2]	2008 [5]	2009 [6]	2008 [7]	2009 [8]	2008 [7]/[5]	2009 [8]/[6]
PERFECT COMPETITION												
Austria	9	9	9	10	105%	110%	584	583.5	546	498	93%	85%
Belgium	19	18	20	20	107%	110%	618	593.8	558	510	90%	86%
Bulgaria	4	3	3	4	73%	153%	391	594.1	541	148	138%	25%
Balkans	3	3	3	3	87%	105%	471	542.3	557	503	118%	93%
Baltic States	6	5	3	7	51%	155%	303	525.2	515	110	170%	21%
Czech Republic	9	8	8	9	98%	106%	528	547.5	545	498	103%	91%
Germany	98	93	115	107	117%	115%	734	648.9	553	505	75%	78%
Finland	5	4	6	7	120%	159%	726	611.2	517	100	71%	16%
France	46	45	48	49	104%	111%	600	607.1	563	516	94%	85%
Greece	4	4	5	5	123%	134%	883	704.4	589	360	67%	51%
Croatia	3	3	2	2	53%	78%	338	388.8	566	511	168%	131%
Hungary	13	11	13	12	98%	110%	527	565.0	539	485	102%	86%
Spain and Portugal	43	39	42	40	97%	104%	602	622.3	629	587	105%	94%
Italy	88	81	89	92	101%	114%	585	654.8	574	527	98%	81%
Netherlands	49	49	49	55	102%	113%	566	625.3	553	505	98%	81%
Poland	16	16	16	16	95%	98%	502	442.2	536	454	107%	103%
Romania	16	14	11	18	71%	133%	350	276.7	495	145	141%	52%
Slovakia	6	6	6	7	98%	111%	521	583.9	539	492	104%	84%
Slovenia	1	1	1	1	105%	118%	604	687.3	564	509	93%	74%
Turkey	37	35	38	43	103%	122%	585	475.9	557	327	95%	69%
UK	99	91	104	107	105%	118%	612	513.7	569	385	93%	75%
Average [a]	***27.3***	***25.6***	***28.1***	***29.3***	***103%***	***115%***	***603***	***582***	***722***	***667***	***120%***	***115%***

[a] Average final prices are quantity-weighted

Table D.2: Model Validation with Historical Data - Total Expenditure on Gas Consumption

	Real Data		Market Power Scenarios	Model Results		Difference	
	2008 [1]	2009 [2]		2008 [3]	2009 [4]	2008 [3]/[1]	2009 [4]/[2]
Total Expenditure on gas Consumption (US$ bln)	345	312	Double Marginalization	352	317	102.0%	101.6%
			Upstream Oligopoly	341	298	98.8%	95.6%
			Perfect Competition	333	281	96.3%	89.9%

2. Sensitivity analysis: Demand parameters and infrastructure capacities

The assumed gas demand projection and infrastructure capacities to be installed between 2010 and 2030 are rather uncertain parameters in the Base Case. Therefore, the robustness of the Base Case results is tested against the following sensitivity scenarios that reflect uncertainties in the model parameters (Box G.1):

Sensitivity Scenarios	Description
N1	Elasticity of demand is 100% lower than was assumed in the Base Case, i.e ε_n=-1.4
N2	Elasticity of demand is 100% higher than was assumed in the Base Case, i.e ε_n=-0.35
N3	Russian and Norwegian production capacities are 20% higher than they were assumed to be in the Base Case (see Table C.2 for production capacities assumed in the Base Case)
N4	Russian and Norwegian production capacities are 20% lower than they were assumed to be in the Base Case
N5	High demand case: gas demand in 2010-2030 is assumed to grow at a CAGR of: • +1.40% for Western and Southern Europe; • +1.60% for Eastern Europe and Balkans; • +1.20% for FSU Countries.
N6	Low demand case: gas demand in 2010-2030 is assumed to grow at a CAGR of: • +0.35% for Western and Southern Europe; • +0.40% for Eastern Europe and Balkans; • +0.30% for FSU Countries.
N7	LNG regasification and liquefaction capacities are 100% higher than was assumed for the Base Case (see Table C.5 for the Base Case LNG capacities)
N8	LNG regasification and liquefaction capacities are 100% lower than was assumed for the Base Case
N9	Cross-border pipeline capacities between EU member states (including the Turkish-Greek interconnector) are 100% higher than was assumed in the Base Case (see Table C.3 and C.4 for cross-border pipeline capacities);
N10	Cross-border pipeline capacities between EU member states (including the Turkish-Greek interconnector) are 100% lower than was assumed in the Base Case.

Box G.1: Sensitivity Scenarios

The results of the sensitivity analysis are summarized in the following Table G.3. The robustness of the model output is measured with the following criteria:

$$\frac{R_N^S - R_{BC}}{R_{BC}} \bigg/ \frac{I_N^S - I_{BC}}{I_{BC}} = C_I^R \qquad \text{(G.1)}$$

where R_N^S is the output parameter under sensitivity scenario N (e.g. final prices or profits), R_{BC} is the same output parameter under the Base Case scenario, I_N^S is the input parameter under sensitivity scenario N (e.g. parameter for elasticity of demand or production capacities etc.), and I_{BC} is the same input parameter under the Base Case scenario. Thus, if:

- $|C_I^R| \in [0;0.2]$, then, holding all other input parameters unchanged, changes in parameter *I* are <u>not critical</u> to the output, *R;*
- $|C_I^R| \in (0.2;0.5]$, then changes in parameter *I* are <u>moderately critical</u> to the output, *R;*
- $|C_I^R| \in (0.5;1]$, then changes in parameter *I* are <u>critical</u> to the output, *R;*
- $|C_I^R| \in (1; +\infty)$, then changes in parameter *I* are <u>very critical</u> to the output, *R*.

Table G.3: Sensitivity Analysis of the Base Case results

Country	Base case [1]	Sensitivity Scenarios N1 [2]	N2 [3]	N3 [4]	N4 [5]	N5 [6]	N6 [7]	N7 [8]	N8 [9]	N9 [10]	N10 [11]
FINAL PRICES (US$/tcm)[a]											
Austria	700	581	998	697	806	735	690	697	703	606	798
Belgium and Luxembourg	532	553	614	525	602	593	505	391	671	500	517
Bulgaria	885	659	1368	883	992	908	883	883	887	887	884
Balkans	816	625	1256	814	923	839	814	814	818	818	864
Baltic States	775	580	1208	773	888	796	774	775	776	776	775
Czech Republic	654	572	913	651	751	694	641	629	686	652	683
Germany	605	566	794	600	699	654	587	570	655	598	644
Finland	897	661	1400	894	1010	918	896	897	898	898	896
France	425	486	502	420	523	481	405	366	582	422	440
Greece	453	476	573	450	541	505	436	399	630	442	467
Croatia	611	484	928	608	719	633	609	609	612	605	610
Hungary	814	630	1242	811	921	838	811	812	815	815	812
Spain and Portugal	450	497	563	447	518	504	432	404	580	427	470
Italy and Switzerland	420	471	503	417	505	472	403	379	512	410	450
Netherlands	608	596	755	600	678	665	583	501	717	574	683
Poland	508	499	688	506	609	560	489	452	541	480	524
Romania	290	268	366	287	400	323	282	289	291	291	289
Slovakia	871	662	1346	869	979	893	869	870	873	873	870
Slovenia	715	612	1085	713	797	742	712	727	714	716	801
Turkey	539	456	742	537	647	576	530	430	604	537	539
UK	389	456	432	373	472	448	365	317	518	358	403
Gazprom Profit, US$ bn	117.7	141.5	131.1	124.6	108.0	138.4	111.9	106.7	140.3	120.9	118.4
Statoil Profit, US$ bn	49.9	53.7	60.3	50.7	51.9	56.6	47.3	43.7	62.3	47.4	53.2
Producer Profit: Rest of World, US$ bn	125.7	144.3	146.4	125.2	160.8	149.1	119.1	119.0	132.7	121.5	136.4
Transit Profit, US$ bn	1.0	2.3	0.6	1.1	0.5	1.3	0.9	0.8	1.4	1.4	0.9
Consumer Surplus, US$ bn	386.9	257.4	579.1	391.4	330.1	382.5	383.6	427.8	327.3	398.5	370.5
Social Welfare, US$ bn	681.3	602.3	917.4	688.9	651.2	727.8	662.8	698.1	663.9	689.7	679.3
Consumption: Western and Southern Europe, bcm/y	564	645	489	568	525	583	552	592	516	573	550
Consumption: Eastern Europe and Balkans, bcm/y	112	134	96	112	96	116	109	119	107	113	111

[a] reported values are averages (2010-2030)

The robustness criteria (G.1) are presented in Table G.4. Table G.4 is the "traffic light" of the sensitivity of the Base Case results to changes in important assumptions. As can be seen, across our ten sensitivity scenarios only two input parameters have the most critical impacts on model results – the elasticity of demand and the production capacities of the two largest producers in the model (Russia and Norway) ("red and yellow" highlights in Table G.4). A decrease in production capacities (scenario N4) is more critical to the model results than an increase in production capacities (scenario N3). In general, a one percentage point (p.p.) decrease in the production forecast of Russia and Norway relative to the Base Case forecast changes the final prices by more than 0.5 p.p. for most of the countries in this model (with a few countries seeing changes in prices of more than 1 p.p.). Changes in other inputs have very little effect on the model's results – a 1 p.p. change in all other input parameters only changes the model results by 0-0.2 p.p. ("green" highlight throughout Table D.4). In general, the model results are fairly robust to changes in major structural input parameters.

Table G.4: Results of Sensitivity Scenarios - Changes Relative to the Base Case Results

Country	Sensitivity Scenarios									
	N1	N2	N3	N4	N5	N6	N7	N8	N9	N10
	FINAL PRICES									
Austria	-0.17	0.43	-0.02	0.76	0.05	-0.01	0.00	0.00	-0.13	0.14
Belgium and Luxembourg	0.04	0.15	-0.07	0.66	0.11	-0.05	-0.26	0.26	-0.06	-0.03
Bulgaria	-0.26	0.55	-0.01	0.60	0.03	0.00	0.00	0.00	0.00	0.00
Balkans	-0.23	0.54	-0.02	0.65	0.03	0.00	0.00	0.00	0.00	0.06
Baltic States	-0.25	0.56	-0.02	0.73	0.03	0.00	0.00	0.00	0.00	0.00
Czech Republic	-0.13	0.40	-0.03	0.74	0.06	-0.02	-0.04	0.05	0.00	0.04
Germany	-0.06	0.31	-0.04	0.78	0.08	-0.03	-0.06	0.08	-0.01	0.06
Finland	-0.26	0.56	-0.01	0.63	0.02	0.00	0.00	0.00	0.00	0.00
France	0.14	0.18	-0.06	1.15	0.13	-0.05	-0.14	0.37	-0.01	0.04
Greece	0.05	0.27	-0.04	0.97	0.12	-0.04	-0.12	0.39	-0.02	0.03
Croatia	-0.21	0.52	-0.02	0.89	0.04	0.00	0.00	0.00	-0.01	0.00
Hungary	-0.23	0.53	-0.02	0.66	0.03	0.00	0.00	0.00	0.00	0.00
Spain and Portugal	0.11	0.25	-0.03	0.76	0.12	-0.04	-0.10	0.29	-0.05	0.04
Italy and Switzerland	0.12	0.20	-0.04	1.01	0.12	-0.04	-0.10	0.22	-0.02	0.07
Netherlands	-0.02	0.24	-0.06	0.58	0.09	-0.04	-0.18	0.18	-0.06	0.12
Poland	-0.02	0.35	-0.01	1.00	0.10	-0.04	-0.11	0.07	-0.06	0.03
Romania	-0.08	0.26	-0.04	1.90	0.11	-0.03	0.00	0.00	0.00	0.00
Slovakia	-0.24	0.55	-0.01	0.62	0.02	0.00	0.00	0.00	0.00	0.00
Slovenia	-0.14	0.52	-0.01	0.57	0.04	0.00	0.02	0.00	0.00	0.12
Turkey	-0.16	0.37	-0.02	1.00	0.07	-0.02	-0.20	0.12	-0.01	0.00
UK	0.17	0.11	-0.22	1.06	0.15	-0.06	-0.19	0.33	-0.08	0.03
Producer Profit: Rest of World	0.15	0.17	-0.02	1.39	0.19	-0.05	-0.05	0.06	-0.03	0.09
Gazprom Profit	0.20	0.11	0.30	-0.41	0.18	-0.05	-0.09	0.19	0.03	0.01
Statoil Profit	0.07	0.21	0.08	0.20	0.13	-0.05	-0.12	0.25	-0.05	0.07
Transit Profit	1.16	-0.46	0.05	-2.39	0.21	-0.15	-0.21	0.30	0.31	-0.17
Consumer Surplus	-0.33	0.50	0.06	-0.74	-0.01	-0.01	0.11	-0.15	0.03	-0.04
Social Welfare	-0.12	0.35	0.06	-0.22	0.07	-0.03	0.02	-0.03	0.01	0.00
Consumption: Western Europe	0.14	-0.13	0.03	-0.35	0.03	-0.02	0.05	-0.09	0.02	-0.02
Consumption: Eastern Europe	0.19	-0.14	0.02	-0.72	0.04	-0.03	0.06	-0.04	0.01	-0.01
Legend:	$\lvert C_i^R \rvert \in [0;0.2]$		$\lvert C_i^R \rvert \in (0.2;0.5]$		$\lvert C_i^R \rvert \in (0.5;1]$		$\lvert C_i^R \rvert \in (1;+\infty)$			

3. Sensitivity analysis: conjectured transit demand slope

The following sensitivity scenarios (Box G.2) were run to check the robustness of the results against different assumptions about the conjectured transit demand slope, M.

Scenarios	Description
A	This scenario is described in Section 4.2.2. The following conjectured transit parameters are assumed: $\mathrm{M}_{\mathrm{uu'}} = -\mathrm{F} \times \mathrm{CAP}^{\mathrm{TR}}_{\mathrm{uu'}},$ F = *1%* where $CAP^{TR}_{uu'}$ is the capacity of the transit pipeline *(u,u')* (for details of transit pipeline capacities see Table C.3)
B	In this scenario, the following conjecture parameters are assumed: $\mathrm{M}_{\mathrm{uu'}} = -\mathrm{F} \times \mathrm{CAP}^{\mathrm{TR}}_{\mathrm{uu'}},$ F = *25%*
C	The conjecture parameters for this scenario are as follows: $\mathrm{M}_{\mathrm{uu'}} = -\mathrm{F} \times \mathrm{CAP}^{\mathrm{TR}}_{\mathrm{uu'}},$ F = *50%*
D	For this scenario, the conjecture transit parameters are as follows: $\mathrm{M}_{\mathrm{uu'}} = -\mathrm{F} \times \mathrm{CAP}^{\mathrm{TR}}_{\mathrm{uu'}},$ F = *75%*
E	In this scenario, it is assumed that transit countries have extremely limited bargaining power vis-a-vis Gazprom: $\mathrm{M}_{\mathrm{uu'}} = -\mathrm{F} \times \mathrm{CAP}^{\mathrm{TR}}_{\mathrm{uu'}},$ F = *100%* This situation is possible when Gazprom has alternative routes that have a capacity equal to the capacities of transit pipelines (e.g., when Gazprom completes the construction of Nord Stream and South Stream, which will allow it to totally bypass Ukraine as a major transit corridor)

Box G.2: Scenarios of the Market Power of Transit Countries

As can be seen from Table G.5 below, the important conclusion is that different assumptions about the transit conjecture parameter only substantially affect the profits of transit countries. In general, different transit conjecture parameters only slightly modify the model results - within a range of 1% from the Base Case results.

Table G.5: Sensitivity Analysis: Market Power of Transit Countries

Country	Base case	Sensitivity Scenarios									
		A	B	C	D	E	Change (%)				
	[1]	[2]	[3]	[4]	[5]	[6]	[2]/[1]	[3]/[1]	[4]/[1]	[5]/[1]	[6]/[1]
FINAL PRICES (US$/tcm)[a]											
Austria	700	700	692	692	692	692	100.0%	98.8%	98.8%	98.8%	98.8%
Belgium and Luxembourg	532	532	530	530	530	529	99.9%	99.5%	99.5%	99.5%	99.5%
Bulgaria	886	888	879	878	878	878	100.1%	99.1%	99.1%	99.1%	99.1%
Balkans	817	818	808	808	808	808	100.1%	99.0%	99.0%	98.9%	98.9%
Baltic States	776	775	775	775	775	775	99.9%	100.0%	100.0%	100.0%	100.0%
Czech Republic	655	654	648	648	648	648	99.8%	99.0%	98.9%	98.9%	98.9%
Germany	605	604	599	599	599	599	99.9%	99.0%	99.0%	99.0%	99.0%
Finland	897	897	897	897	897	897	100.0%	100.0%	100.0%	100.0%	100.0%
France	425	424	420	420	420	420	99.9%	98.9%	98.9%	98.8%	98.8%
Greece	454	453	450	449	449	449	99.9%	99.1%	99.1%	99.1%	99.1%
Croatia	611	613	603	602	602	602	100.2%	98.6%	98.5%	98.5%	98.5%
Hungary	814	816	806	805	805	805	100.2%	98.9%	98.9%	98.9%	98.9%
Spain and Portugal	450	450	447	447	447	447	99.9%	99.4%	99.3%	99.3%	99.3%
Italy and Switzerland	421	421	416	416	416	416	100.0%	98.9%	98.9%	98.8%	98.8%
Netherlands	608	608	605	605	605	605	100.0%	99.5%	99.5%	99.5%	99.5%
Poland	508	538	505	504	504	504	105.8%	99.3%	99.2%	99.2%	99.2%
Romania	291	292	282	282	282	282	100.5%	97.1%	96.9%	96.9%	96.8%
Slovakia	872	870	863	863	863	863	99.8%	99.0%	99.0%	98.9%	98.9%
Slovenia	715	715	709	709	709	709	100.0%	99.2%	99.2%	99.2%	99.1%
Turkey	540	541	540	540	540	540	100.1%	100.0%	100.0%	100.0%	100.0%
UK	390	389	387	387	387	387	99.9%	99.5%	99.4%	99.4%	99.4%
Gazprom Profit, US$ bln	117.7	119.2	121.6	121.7	121.8	121.8	101.3%	103.4%	103.5%	103.5%	103.5%
Producer Profit: Rest of World, US$ bln	175.6	177.8	175.7	175.6	175.6	175.6	101.2%	100.0%	100.0%	100.0%	100.0%
Transit Profit, US$ bln	1.0	2.2	0.2	0.1	0.1	0.1	212.3%	17.8%	9.3%	6.4%	4.9%
Consumer Surplus, US$ bln	386.9	386.4	389.5	389.5	389.5	389.6	99.9%	100.7%	100.7%	100.7%	100.7%
Social Welfare, US$ bln	***681.3***	***685.6***	***687.0***	***687.0***	***687.0***	***687.0***	100.6%	100.8%	100.8%	100.8%	100.8%
Consumption: Western and Southern Europe, bcm/y	564	564	566	566	566	566	100.0%	100.3%	100.3%	100.3%	100.3%
Consumption: Eastern Europe and Balkans, bcm/y	112	111	113	113	113	113	99.2%	100.6%	100.6%	100.6%	100.6%
Transit through Ukraine, bcm/y	60	55	63	63	63	63	92.0%	106.2%	106.3%	106.4%	106.4%
Transit through Belarus, bcm/y	29	13	30	30	30	30	43.6%	102.7%	102.7%	102.7%	102.7%
Transit fee through Ukraine, US$/tcm	17.45	34.59	5.83	5.09	4.83	4.69	198.2%	33.4%	29.2%	27.7%	26.9%
Transit fee through Belarus, US$/tcm	10.37	55.62	5.81	4.27	3.75	3.49	536.6%	56.1%	41.2%	36.2%	33.7%

Appendix H. Russia's Current Gas Export Routes to Europe

As of 2008, Russia's overall gas export capacity through pipelines to Europe, including Turkey, is around 214 billion cubic metres (bcm) (see Table H.1). There are two main routes which Gazprom currently uses to export gas to Europe: through Ukraine and Belarus.

Table H.1: Gazprom's Existing Export Options

Transit		
Final Markets	Design Capacity, bcm/y	Actual volume transported in 2008, bcm/y
Through Ukraine		
To Western and Eastern Europe	92.6	75.5
To Poland	5.0	4.8
To Hungary, Serbia and Bosnia-Herzegovina	13.2	12.1
To Romania	4.5	2.0
To Romania, Bulgaria, Greece, Macedonia and Turkey	26.8	22.5
Through Belarus[48]		
To Poland and Germany	36.3	35.2
To Lithuania	6.4	2.8
Direct Sales		
To Finland	8.1	4.8
To Latvia and Estonia	5.4	1.3
To Turkey via Blue Stream	16.0	9.3
Total	214.3	170.3
Share of Ukraine in Transportation of Russian Gas Exports, %	66.3	68.6
Share of Belarus in Transportation of Russian Gas Exports, %	19.9	22.3

Sources: Own calculations based on (ENTSOG, 2010; Naftogaz of Ukraine, 2010; Gazprom, 2010a; Yafimava, 2009; Chyong, forthcoming)

Direct gas sales to final markets constitute some 9% of total exports to Europe (including Turkey). The rest of Gazprom's exports are transported through Ukraine and Belarus. Before 2003, nearly 95% of all Russian gas exports went through Ukraine.[49] Due to past conflicts between Russia and Ukraine over the terms of the gas trade, including transit fees, import prices and debt clearance by Ukraine, Russia has initiated several pipeline projects to bypass Ukraine. One of these projects is the Yamal-Europe I gas pipeline which traverses Belarus and Poland. The total throughput of Yamal I is 30.6 bcm/year (ENTSOG, 2010). Yamal-Europe I serves as the basis of Russia's northern gas export corridor to Europe.

[48] We only report export capacity through Belarus to Poland and Germany; export capacity through Northern Light which re-enters Ukraine has been omitted in this table for simplicity.
[49] Authors' own calculations based on Gazprom (2010a), Naftogaz of Ukraine (2010), Yafimava (2009).

The delivery point through Yamal-I is at Mallnow on the Germany-Poland border (near Frankfurt-am-Oder).

The majority of Russian gas exports to Europe still traverse the southern gas export corridor, via Ukrainian territory. In 2008, around 68% (see table A1) of all Russian gas exports to Europe were transported through Ukraine. The delivery points of Russian gas through Ukraine are: (*i*) the Ukrainian-Slovak border, (*ii*) Baumgarten Gas Hub (Austria), and (*iii*) the Czech-German border (Waidhaus and Olbernhau).

Appendix I. Sensitivity Analysis of Downstream Competition

In order to assess the effects of downstream competition on Nord Stream investment and its impact on market efficiency, some sensitivity analyses have been conducted. The following downstream market competition scenarios are analysed (Table I.1):

Table I.1: Downstream market competition scenarios

	Low Competition Case	Base Case	High Competition Case
Number of traders per country	1	4	8

The results presented in Section 5.2 are based on the Base Case downstream market competition scenario; the impact of alternative assumptions (i.e., low and high downstream competition cases) on profits of market participants and on social welfare is reported in Table I.2. As can be seen from Table I.2, changes in profits of market participants and social welfare due to investment in the Nord Stream project vary among downstream competition cases. However, the basic conclusion that the higher competition between market participants, the higher is the benefit of Nord Stream investment to social welfare is robust to the level of downstream competition.

Table I.2: Annualized Net Gains (Losses) Resulting from Investment in Nord Stream under different downstream competition scenarios (US$ bn/year)

	Successive market power			Double Marginalization		
	Low Competition Case	Base Case	High Competition Case	Low Competition Case	Base Case	High Competition Case
Gazprom's Profit	-1.5	2.7	4.2	-1.9	0.3	1.1
Profit of transit countries	-0.2	-2.1	-3.1	0.0	-0.5	-0.7
Profit of all other producers	-1.4	-6.5	-7.2	-1.1	-4.1	-4.5
Profit of all Traders	0.9	2.5	1.6	0.6	2.3	2.3
Consumer Surplus	0.5	3.4	4.8	0.4	2.7	4.1
Social Welfare	**-1.7**	**0.01**	**0.4**	**-2.0**	**0.7**	**2.2**

As can be seen from Table I.2, the negative impact of Nord Stream investment on social welfare under the low competition case (successive market power and double marginalization scenarios) is majorly driven by losses incurred by Gazprom, other producers and transit countries. Under the low competition case Nord Stream investment affects Gazprom's profit negatively (Table I.2: US$ -1.5 bn/y for the successive market power scenario and US$ -1.9 bn/y for the double marginalization scenario) because of extremely low demand for gas in Europe (Table I.3). Therefore, due to low demand, the Nord Stream pipeline is not fully utilized (see Table I.4) and Gazprom has to pay cost for unused capacity of the Nord Stream system.[50] This cost outweighs Gazprom's additional revenue from extra market share (Table I.3) and therefore investment in the Nord Stream pipeline has a negative value for Gazprom in the low competition cases. Negative impact of Nord Stream investment on profits of other producers is mainly due to the loss of their market share (slightly, see Table I.3) to Gazprom once the pipeline is built. Also, when Nord Stream is built, Gazprom re-directs some of transit flows through Ukraine and Belarus to the new route and thus negatively impacts profits of transit countries (Table I.2: Successive market power scenario and low competition case).

Table I.3: Average Annual Consumption and Prices in Europe under different competition scenarios: 2010-2030

		Successive market power			Double Marginalization		
		Low Competition Case	Base Case	High Competition Case	Low Competition Case	Base Case	High Competition Case
Russian gas export to Europe (bcm)	NS is built	64	134	155	65	141	163
	NS is not built	61	126	147	63	133	156
Consumption in Europe (bcm)	NS is built	381	569	615	381	575	622
	NS is not built	380	567	612	381	572	619
Gazprom's market share in Europe	NS is built	17%	24%	25%	17%	24%	26%
	NS is not built	16%	22%	24%	16%	23%	25%
Average[a] border prices (US$/tcm)	NS is built	339	416	450	338	414	446
	NS is not built	341	427	462	339	420	454
Average[a] final prices (US$/tcm)	NS is built	994	674	597	995	680	605
	NS is not built	993	669	589	994	673	596

Note: [a] quantity-weighted; NS – Nord Stream

Table I.4: Transportation through the Nord Stream system (bcm)

		Successive market power			Double Marginalization		
	Nord Stream's Capacity	Low Competition Case	Base Case	High Competition Case	Low Competition Case	Base Case	High Competition Case
2011	7	3	7	7	0	7	7
2015	55	5	41	52	0	32	45
2020	55	8	48	55	0	40	51
2025	55	6	51	55	6	44	55
2030	55	21	55	55	16	53	55
Average Utilization rate (2011-2030)		17%	88%	99%	7%	76%	94%

[50] Cost of unused transport capacity of the Nord Stream system is calculated as the product of unit transport cost through the system (as reported in Appendix C: Table C.9) and the difference between Nord Stream's capacity and its actual usage (see Table I.4).