The dynamics of natural gas supply coordination in a New World
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Chapter 9
Gazprom’s investment strategy in an uncertain, competitive gas market

9.1 Introduction
This chapter contains the application of the real-options game model discussed in Chapter 8. By means of exploratory research in the form of separate case studies, Gazprom’s investment strategy will be ascertained in light of market outcomes on a sub-regional level by applying the Chapter 8 toolbox and the model. Written from Gazprom’s perspective, the case studies pertain to the Turkish and various sub-regional European gas markets. This chapter opens with Case study 1, an assessment of Blue Stream, a historical or ex post case. Subsequently, Case study 2 deals with the South Stream pipeline and Case study 3 with the Nord Stream pipeline.

The case studies each have a similar structure: they begin with a brief background description of the market in question, followed by a conceptual discussion about market uncertainty. Market uncertainty involves demand-side factors such as potential market demand itself as well as pricing. Then, the various potential gas suppliers to the sub-regional market in question are reviewed and assessed. Other investment variables are then considered in accordance with the conceptual toolbox, such as geopolitical factors, regulatory barriers, etc. This is followed by an overview of the possible or planned institutionalisation of the project in question (and in the case of the Blue Stream its institutionalisation as it really occurred).

In all three case studies the real-options game model is then applied, which is a stylised approach to market demand uncertainty and potential gas supply competition in the form of a potential entrant. The model’s outcome, namely the overall value of the various projects in question, is then provided. In Case study 1, where the Blue Stream is discussed, the application of the model is followed by a discussion of the gas market’s structure as it has evolved since the start of operations of that pipeline in the Turkish gas market. As for the South and Nord Stream pipelines, which are yet to be constructed, potential scenarios (from Gazprom’s perspective) concerning ex-post market structures in the respective sub-regional gas markets are then discussed. Each case study ends with a reflection on the use of the model, the respective outcomes, the model’s assumptions and their limits.

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9.2  CASE STUDY 1: Gazprom versus competition in the Turkish gas market during the 1990s

This case study pertains to the Turkish market as it was during the late 1990s. Booming gas demand in Turkey and the construction of the oil BTC pipeline through the Caucasus prompted Russia (Gazprom) to build the Blue Stream pipeline. The pipeline's construction had a major impact on Turkey's gas market structure while the pipeline's commercial value still hangs in the balance, years after its final investment was made (in 2008, approximately half of the total capacity was utilised). Set in the 1990s, this case study is a reconstructive investigation of the strategic value of Blue Stream in view of possible gas flows from newly sovereign Central Asian states and Iran to Turkey (and beyond, as will be shown in Case study 2).

9.2.1  Background

According to many projections made during the early 1990s, the Turkish gas market was to become a booming growth market. Russian gas already played a role early on during this period. The Soviet Union had become an important gas supplier to the Turkish market in 1987, after it started its gas exports to large numbers of European countries during the 1960s. In order to accommodate these Soviet supplies, a trunk line was constructed from the Bulgarian border to Ankara in 1986. In 1990, the Turkish government announced that they also desired to purchase LNG from Algeria (and from Nigeria later on), a move that would help to counterbalance Turkey's large purchases from the Soviet Union [Hacisalihoglu 2008]. After the break-up of the Soviet Union in 1991, the Central Asian states of Kazakhstan, Uzbekistan and Turkmenistan became independent and started acting as sovereign net gas-exporting countries with their own goals and strategies. In the early to mid-1990s, their general attitude reflected a desire to break away from Russia. Russia itself entered a brief period of politico-economic chaos. As a result, combined with higher domestic gas prices, gas for Russian demand decreased during the first part of the 1990s.

The key aspect to the behaviour of the Central Asian countries is that they correspondingly sought to export their resources, both oil and gas, through routes other than the ones that led to and through Russia, which dated from the old Soviet days. This was the heritage from the Soviet Union as described in Chapter 5 and 6 in Smeenk [2010]. A westward export strategy seemed a real possibility for the Caspian countries, particularly for Turkmenistan, because Turkey (and Europe) were recognised as the closest hard currency markets. These were expected to have a significant increase in demand for gas in the years following the collapse of the Soviet Union. In the same period, Iran was also expected to start its export to Turkey and Europe and to become a considerable supplier. The threat of these projects to Gazprom's revenues in Europe combined with increasing pressure on the Russia's gas balance, encouraged Gazprom to take pro-active action in developing its value chain. Simultaneously, Turkey was
seeking to strengthen its relations with Iran and other Caspian countries [Akdeniz et al. 2002; Hacisalihoglu 2008]. Besides its increasing gas demand, Turkey could and can also be considered as a bridge for gas (and other energy flows) to connect European off-take markets with the Caspian region and the Middle East, see also Case study 2 [Kilic and Kaya 2007]. For a schematic overview of the various export routes from the Caspian Sea region to Turkey, see Figure 9.1.

Figure 9.1 Schematic overview of competing gas supply and transport routes to the Turkish gas market in 1999

9.2.2 Market demand in Turkey: A booming gas market during the late 1990s
Natural gas became important for Turkey during the 1980s, as a new emerging economy, having been introduced in 1981 as a primary fuel. Turkey’s economic activity has spurred on the need for primary energy, and gas had a substantial share in the primary energy mix in 1999: approximately 15 percent. Power generation played (and still plays) an important role in the demand for gas (in 2000, 60 percent of the total demand for gas, according to Botas). Much of this demand was and is concentrated in the Western (Marmara area) and Southern parts of
Turkey, specifically around Ankara, Izmir and Istanbul. For a number of reasons, including environmental, geographic, energy security, economic and political ones, Turkey had chosen natural gas as the preferred fuel for power generation, of which new capacities were to be added [Hacisalihoglu 2008]. Turkey’s gas demand was therefore expected to grow by 5 to 8 percent annually between 2000 and 2020, one of the highest growth rates in the world during that period [privately disclosed company data; Stern 2005]. Domestic gas production in Turkey is not significant: less than 3 percent was coming from domestic gas supply sources, increasing the pressure to import.

Figure 9.2 Turkey’s natural gas consumption from 1984 to 2000

![Graph showing Turkey's natural gas consumption from 1984 to 2000.](image)

Source: own analysis, based on BP [2008]; MENR [2007].

Government-owned entities dominated the Turkish gas sector, so government policies had a large impact on fuel choices. The Turkish gas company Botas had a monopoly on gas imports. After Turkey’s financial crisis in 1999, substantial reforms were pushed through by the IMF, which had resulted in liberalisation and a partial privatisation of the gas sector. A key element of the IMF reforms was a requirement for a phased divestment of import contracts by Botas, which will be discussed later on in this case study [Hacisalihoglu 2008; OECD 2002].

In order to appreciate the possible strategic significance of the Blue Stream pipeline, one needs to look back at the period of time when the investment decision was made. In 1999, Turkey

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62 In 1988, gas began to be exploited for residential and commercial purposes in Ankara [Ozturk and Hepbasli 2003]. In the first part of the 1990s, it continued with Istanbul and Bursa, and then in the mid-1990s with Eskisehir and Izmir [Aras and Aras 2004].
was consuming 12.4 bcm, up from only 8 mcm in 1983, consuming 9.7 bcm by 1997, see also Figure 9.2 [Ministry of Energy and Natural Resources 2007; BP 2008]. According to various projections, gas demand was projected to grow rapidly, from between 16.4 and 16.5 bcm in 2000 to between 57.2 and 65.7 bcm in 2020 (which corresponds with a 4.7 to 6.3 percent growth per annum from 2000-2020; see also Figure 9.6). It was by all accounts projected to be a booming gas market. Therefore, the prospects for various potential gas suppliers to the market appeared favourable. Supplying the Turkish market however was by no means a risk-free venture. The possibility always existed that demand in Turkey could remain sluggish or even fall, resulting in a potential oversupply of the Turkish gas market (see also Figure 9.6).

Price risks associated with additional supplies to the Turkish gas market also influence the level of market uncertainty, besides the aforementioned volume (or demand) risk. During the 1990s, (Brent) oil prices were quite volatile and low, which encouraged a deferral of investment and therefore the stimulation of a wait-and-see strategy. Some forecasts at the time (1999) estimated a constant Brent oil price (in real terms) of $17.00/bbl. This would imply a Turkish gas price around Ankara of approximately $55-60/mcm in 1999 dollars. Because of the low and relatively volatile gas prices, investors may indeed be encouraged to defer their investments, i.e., a wait-and-see strategy, if their total cost for, e.g., supply and transport are below the actual gas price and/or relatively high when compared with the gas supply costs of potential competitors.

9.2.3 Various potential gas suppliers to the Turkish market (1991-1999)

Gas suppliers to Turkey were few in the immediate post-Cold War period from 1991 to 1999. Russia delivered a maximum of 16.2 bcm via two contracts with the Turkish gas company Botas. These volumes travelled through its Trans-Balkan pipeline, running via the Ukraine, Moldavia, Romania and Bulgaria. In 1987, the Soviet Union began supplying Turkey with 5.66 bcm, resulting in a 25-year contract for 6 bcm/y until 2011. In 1997, Gazprom and Botas agreed to increase gas supplies via a 50/50 joint venture, Turusgaz, with a maximum of 8 bcm/y, starting in 1998 and lasting until 2021 [Hacisalihoglu 2008]. Modest LNG imports began with Algerian and Nigerian LNG volumes (respectively, a maximum of 4 bcm/y, from 1994 to 2014, and 1.2 bcm from 1999 to 2021). As mentioned above, Turkish domestic gas production accounted for less than 3 percent (around 0.7-1 bcm/y), which was not expected.

62 Additional transportation costs should also be take into account for transport from the off-take centres to the borders of Turkey. In that time, Cedigaz suggests that for long-distance gas transportation $17.50/mcm would be a conservative approximation for each 1,000 km. For example, extra costs of circa $20/mcm from Ankara to the eastern border.
to increase in the coming decades, and thus gas imports had to increase in tandem with demand.\footnote{Major gas producers in Turkey include Arco, the Turkish State Petroleum Company (TPAO) and Shell [Hacisalihoglu 2008].}

During the late 1990s, some ten gas-exporting countries had announced pipeline and LNG projects in order to supply the growing Turkish gas market. The Turkish government was encouraging these plans in order to promote the diversification of its gas suppliers. Several infrastructure projects to bring pipeline gas from Iran, Iraq, Egypt and the Caspian area were announced. In addition, plans were drawn up to increase (pipeline) imports from Russia and LNG supplying countries, such as Egypt, Yemen and Qatar [Demirbas et al. 2004; Hacisalihoglu 2008]. All the gas import agreements were held by Botas, which had signed eight long-term sales and purchase contracts with six different supply sources (contracting a total of 67.8 bcm, which were higher than some demand forecasts) [Ozturk and Hepbasli 2003].

Iran became the first possible large supplier to the Turkish market and did indeed begin modest exports in 2001. During this period, Iran was seen as a large threat to Gazprom’s market share in Turkey and Europe. In 1996, the construction of the Tabriz-Erzurum gas pipeline began, with a maximum capacity of 20 bcm/y, connecting Iran with Turkey. From 2001 onwards, Iran started to supply gas to the Turkish market, with a maximum of 10 bcm/y until 2025.\footnote{The underlying contract, which was not solid, was partly based on Turkmen gas deliveries to Iran, which started in 2002 with 4 bcm [US Department of Energy 2009b]. The Iranian gas had to come from the non-associated Kangan regional fields and also from associated sources around Ahwaz [Hacisalihoglu 2008].} Combined with other possible suppliers looking to supply the Turkish market, the Turkish off-take from Iran was disappointing and therefore Iran did not manage to reach its full load factor [US Department of Energy 2009b; CIEP 2008].

In December 1997, Russia and Turkey signed a 25-year deal under which Gazprom would construct a new gas export pipeline to Turkey for 14.15 bcm of gas annually by the early 2000s [Yazici and Demirbas 2001; Hacisalihoglu 2008]. The investment decision for the construction of the transportation capacity had to be made in 1998 or 1999. Gazprom had three options to increase its supply to the Turkish market. The first option was to increase the capacity of the existing Trans-Balkan pipeline and its existing capacity towards Turkey via brownfields. This was not the most advantageous option, because Gazprom had significant transit problems in Ukraine and Bulgaria (see also Part II). In the mid 1990s Turkey already suffered shortages of Russian gas (in early 1994, daily deliveries of Gazprom’s gas were reduced by about 50 percent) due to Ukrainian diversion of transit volumes [Stern 2005]. The second option was a transport route via Georgia and Armenia to Erzurum in eastern Turkey. This
option was also not favourable, because the main off-take markets were located around Ankara and in the Istanbul/Marmara region in the west and not in the eastern part of Turkey. Moreover, this greenfield investment involved potential political risks. Therefore a direct link under the Black Sea would be a better option [Stern 1999].

The proposed Blue Stream project included a pipeline of 1213 kilometres in length running from Izobilnoye, north of Stravropol in Russia’s North Caucasus region, across the Black Sea via the Turkish port of Samsun to Ankara (see Figure 9.3). The gas available from the Siberian gas basin could be used for filling the pipeline. Gazprom’s proposal to construct two 372 kilometres off-shore greenfield pipelines implied building the pipelines at record depth (up to 2150 metres) and in very difficult water conditions [Stern 2005]. The dual off-shore pipeline – twice 8 bcm/y – was expected to cost $3.2 billion (including the costs of some Russian onshore pipelines and compression facilities, accounting $1.7 billion), whereas the Turkey’s onshore section of Blue Stream was expected to cost $339 million.

Figure 9.3 The Blue Stream project

In mid-1998, Turkey and Egypt announced a plan to construct a gas pipeline from Egypt to Turkey under the Mediterranean. However, this was too ambitious an idea, and Egypt opted...

627 Eventually, the Blue Stream project could be extended to other Mediterranean countries, such as Lebanon, Syria and Israel.
628 Gas storage facility at Stavropol could be used for back-up supplies [Stern 2005].
for supplying the Turkish market through LNG (4 bcm/y) [Hacisalihoglu 2008; OECD 2002]. Other LNG supplies from Yemen and Qatar were under consideration as well (4 bcm/y, respectively 3.1 bcm/y). According to expert interviews, gas supplies from Iraq (10 bcm/y) via a greenfield pipeline were also proposed, however, the Iraqi supplies were on hold during this time due to UN sanctions.

Figure 9.4 Trans-Caspian Gas Pipeline project

As was noted, during the 1990s, plans were proposed for the diversification of gas export and transport routes from the Caspian Sea region to Western markets, with the aim specifically of circumventing Russia. One of these projects focused on the Turkish gas market. A possible pipeline to the West – the so-called Trans-Caspian Gas Pipeline (TCGP) – had been on the table for serious consideration by different investment consortia of national and international oil firms as far as implementation was concerned. The proponents of the TCGP were ready to push the project forward and feasibility studies on the possible pipeline route had been carried out, such as a joint venture including Bechtel, General Electric and Royal Dutch Shell and a joint venture including Royal Dutch Shell, ChevronTexaco, ExxonMobil and Kazakh the national oil company, Kazakhoil. The bottom-line of these studies were a gas pipeline from Turkmenistan (close to Turkmenbashy), underneath the Caspian Sea, across Azerbaijan and Georgia, and on to Turkey (see also Figure 9.4). Some studies also explored Kazakh and Azeri
supplies alongside the Turkmen one.\(^{429}\) The TCGP presented Turkmenistan with a valuable opportunity to export gas westwards, underneath the Caspian Sea and away from Russia, both increasing its bargaining power vis-à-vis Russia as well as offering the closest hard currency market to the Caspian countries that was expected to have a significant increase in demand for gas. Figure 9.5 provides an overview of the potential exports from the Caspian region in a base case scenario (e.g. Turkmenistan, Kazakhstan and Azerbaijan), taken into account domestic demand.

**Figure 9.5** Potential exports from the Caspian region in 1999 – base case scenario

From the mid-nineties four other ‘calls’ on Caspian gas were under consideration: to Iran, Pakistan (and Afghanistan), China and Russia.\(^{430}\) It was debatable, however, whether Turkmenistan and other Caspian countries could fulfil all these projects, totalling some 160 bcm\(^{\text{y}}\)\(^{429}\), which is significantly higher than the estimates made in Figure 9.5. Some groups within the Turkish government stated that a pipeline from Turkmenistan was a top priority, although the pipeline would compete against the proposed Blue Stream pipeline, as well as possibly against Iranian and LNG supplies [Demirbas et al. 2004; Hacisalihoglu 2008].

However, it was questionable whether Turkish demand would grow rapidly enough to absorb all proposed volumes of natural gas from Iran, Caspian region, Russia and LNG supplying countries, in addition to gas slated to be supplied by Russia, Algeria, and Nigeria

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\(^{429}\) The costs associated with the TCGP were estimated at $3.8 to 4.1 billion (including CAPEX compressor capacity and a Kazakh section along the Caspian Sea of $0.57 billion).

\(^{430}\) In Case study 2 and Chapter 6, a more in-depth analysis of the Caspian region is presented.
[Hacisalihoglu 2008]. Figure 9.6 presents an overview of the existing and pending supply distribution over Turkey’s demand projections in 1999. Indeed, if all projects would have been realised, the Turkish gas market would have been oversupplied, even in the mid-term scenario of Botas.

![Figure 9.6 Existing and pending supply distribution over Turkey’s demand projections from 1999 onwards](image)

Referring now to Figure 8.2 in Chapter 8, the growth potential of Turkish gas imports was high, while Turkey was in close proximity to two very large potential pipeline gas suppliers besides Russia: Iran and Turkmenistan (and possibly other Caspian countries), and some smaller potential LNG suppliers. This high degree of competition could induce Gazprom to maintain a pro-active investment strategy in order to preserve and increase its market share in the Turkish gas market. Yet, the low and relatively volatile gas/oil prices at that moment may also encourage a wait-and-see strategy. In order to better grasp the trade-off between the commitment and postponement values, regarding the uncertainty about price and volume,

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431 Turkey could become an important transit centre for gas exports to Greece and beyond in case of oversupply [Hacisalihoglu 2008].
one should focus more in detail on the cost structure of the different competitors towards the Turkish gas market.

**Figure 9.7** Comparative unit costs to deliver gas to the Turkish gas market in Ankara – base case scenario in 1999 $/mcm

As described in Chapter 7, the LRMC of (new) supplies, influenced largely by economies of scale in transport and upstream production capacity, consists of production and transportation costs, transit fees and royalties, the latter two types of cost are included when applicable. Based on available data on gas supply costs involved in the Caspian Sea region, OME [1999] and privately disclosed company data, one can roughly conclude that four suppliers could deliver gas to the Turkish market on a profitable basis, taking into account the forecasted gas prices in Turkey in 1999 (around $60/mcm, see Figure 9.7). Due to low transportation costs, Iran, Iraq, Russia and Azerbaijan could deliver gas at a cost of below or around $60/mcm. Other proposed pipeline suppliers, Turkmenistan and Kazakhstan, had a unit cost level above $60/mcm: $67/mcm, and $81/mcm respectively. In the case of higher gas prices and/or an optimistic scenario of (transport) costs, supplies from this region could therefore become profitable. The possible entry of LNG played a smaller, fringe role with smaller volumes and lower economies of scale: LNG from Algeria, for example, has a unit cost of roughly $92/mcm to

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*A value of US$20 per mcm has been assumed as the cost to transport the gas from Erzerum (East Turkey) to Ankara.

Source: own analysis, based on OME [1999]; privately disclosed company data.

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432 A said before, the gas price at that moment was based on an oil price of $17 bbl in 1999.$
Turkey, whereas Egypt LNG costed $97/mcm and Nigerian over $110 per mcm. LNG supplies were not competitive under these price circumstances.

Iran and, to a (much) lesser extent Iraq, had considerable potential to become a large supplier to the Turkish market. However, Iranian supplies to the West were unlikely, given due the Iran-Libya Sanction Act (ILSA), while Iranian production capacity remained uncertain. Similarly, Iraqi supplies were 'on hold' as well during this period due to UN sanctions. As described in Figure 9.5, Turkmenistan (and Kazakhstan) also had a large export potential, but the TCGP had and has to compete with other pipeline projects (for example, from Iran in terms of source but also from Russia in terms of gas volume availability as a result of Russian initiatives to secure Turkmen gas volumes). At the time, Azerbaijan had a limited export potential (see also Figure 9.5). The TCGP and the possibility of seeing Turkmen (possibly to match up with Azeri and Kazakh gas) gas flows materialise to Turkey was significant for Gazprom from a strategic point of view, because it represented major new sources of gas from newly independent and sovereign states upon which Russia now depended for those same volumes. Simultaneously, the same gas would compete with Russian gas, potentially loosing market share beyond Turkey in the process.

Referring to Figure 8.3 in Chapter 8, the nature of competition potentially emanating from the Caspian region (including Iran) was therefore significant in terms of economies of scale in transport and production capacity as well as in terms of distance to market. Given the sensitive role of Central Asian gas volumes in Russia’s own supply and export balance, the urgent need for a strategic investment ostensibly legitimised an aggressive strategy. Section 9.2.6 of this case study includes the application of the real-option game model in an effort to assess this urgency and measure the strategic impact of the decision regarding the Blue Stream pipeline Gazprom ultimately took.

9.2.4 Other investment variables relevant to the Caspian pipelines and Blue Stream
Other factors besides the geo-economic considerations played an important role in the Blue Stream case as far as new gas supplies are concerned. These should be considered in a conceptual matter in line with Barnes et al. [2006], which has been outlined in the conceptual toolbox in Chapter 8. It will focus mainly on supplies from the Caspian region and Russia. Some of these issues are already mentioned under Section 9.2.3. The investment climate for private investors in the Caspian region for instance, especially Turkmenistan and Iran with a great export potential, was not that favourable. The government of Turkmenistan under president Niyazov was perceived as an unreliable partner, offering little protection in guaranteeing the sanctity of contracts. The political future, the rule of law and legal regime of the country were not stable and unfavourable [Olcott 2006]. The Iranian gas sector was also severely under-
developed and it suffered from a lack of investment capital due to the different sanctions in place, including the ILSA sanctions, severely undermining any export ambitions. The general investment climate in Russia was also unfavourable. Private (Western) investors had little means to secure investments in the Russian gas sector, in which Gazprom had a quasi-monopoly. As a result of Russia’s financial crisis in 1998, modest capital was available for financing greenfield projects [Victor and Victor 2006].

Besides the generally flawed investment climate, the possible Turkmen, Kazakh and Azeri supplies were subject to possible transit risks in the south-Caucasus. After the break-up of the Soviet Union, the Caspian Sea was exposed to legal struggles of ownership, whereby Russia delayed the possible realisation of the TCGP underneath the Caspian Sea by insisting that the project did not satisfy environmental regulations [Amineh 2003]. Possible Central Asian transport routes to Turkey via Iran were blocked by the US and the sanctions in place. In the process of assessing the TCGP’s feasibility, different external governmental actors were involved for geo-economic reasons. As was described in Chapter 3, the US sought to break-up Russia’s transport (and production) monopoly over gas flows from the Caspian Sea region. This strategy was supported by political instruments and international organisations such as the World Bank (this will be discussed under Section 9.2.5 in this case study).

The Blue Stream was a direct offshore link between Russia and Turkey without any involvement of third parties, which resulted in a minimum level of transit risks and political interference. As described earlier, transit risks were growing in Ukraine and Bulgaria during the 1990s. According to expert interviews, various political factions in Turkey had diverging preferences when it came to the different potential suppliers for the Turkish gas market. In the meantime, according to some sources, unconventional measures were perhaps taken by Russia to influence Turkey’s political dialogue in its favour. There is some speculation as to whether this included providing Bulgaria (as a trans-Balkan transit country) with some form of financial incentive in exchange for manipulating the physical flows to Turkey and thus encouraging policy-makers in Turkey to opt for the construction of the Blue Stream. Combined with a possible time delay in attaining transit permits, Gazprom (and Turkey) desired to have a direct route towards the Turkish market, instead of boosting the existing capacity to Turkey [Stern 2005]. Russia also had geo-strategic and -economic interests in the Caspian region, as described in Chapter 3. Combined with existing transit problems this provided a positive incentive for a pro-active investment policy with respect to the Turkish market.
9.2.5 Institutionalisation of the Blue Stream and Caspian pipeline projects

Before the model will be applied, it is necessary to assess the organisational and financial institutionalisation of (strategic) pipeline investment from a practical point of view. The strategy and instruments of the Blue Stream and Caspian projects, varied substantially, which could influence the capability to make a strategic investment. The Blue Stream project was part of a strategic alliance between the Italian gas and oil company ENI and Gazprom. The involvement of a Western partner, backed by both governments, was deemed necessary to make the project bankable, because of financial and technical reasons. The project was an exponent of ultra deep-water pipeline technology (up to 2150 metres) and therefore also a technically risky commercial project [Victor and Victor 2006]. ENI could mitigate these technical risks due to earlier experiences. Gazprom and ENI hold a 50 percent interest in the joint venture each and ENI also attained a 50 percent share in the pipeline’s capacity, allowing ENI to sell gas from its Astrakhan gas field on the North West shore of the Caspian Sea [Stern 2005].

In the growing Turkish gas market, a direct sales strategy seemed the most advantageous option from Gazprom’s perspective, which is in line with De Jong’s [1989] competitive coordination mechanism. However, as a result of Gazprom’s relatively weak organisational capabilities and BOTA’s monopoly in the Turkish market, a business model of long-term contracts seemed the most viable one in order to ensure Gazprom’s position. As mentioned in section 9.2.4, some political factions in Turkey supported the construction of the Blue Stream pipeline and new flows from Russia at a political level.

ENI provided the majority of the $3.2 billion financing. Its return on equity has been realised from the margin between purchase and sales gas price. For strategic reasons, ENI accepted a lower return and took greater risks. Gazprom’s return on equity and loss of income from repayment of both onshore and offshore loans could have been made from gas sales to Botas and ENI and the equity what was provided by ENI. The equity investment, the distribution of risks, and reward allocation between Gazprom, ENI and Società Nazionale Metanodotti (SNAM) were complex. The repayments of the loans were based on gas contracts between SNAM (a subsidiary company of ENI) and Gazprom, thus being completely de-coupled from the project itself. This resulted in less expensive loans via the so-called warehouse construction (see also Figure 8.4 in Chapter 8), provided by five commercial banks and in which Ministry of International Trade and Industry of Japan (MITI) and the Italian export credit agency Servizi Assicurativi del Commercio Estero (SACE) had given guarantees. Figure 9.8 is a detailed overview of the likely financial structure of the Blue Stream project. In late 2001, the laying of

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[69] The joint development of the Astrakhan gas field was also part of the strategic alliance between Gazprom and ENI. So far, no ENI produced equity gas was going through the Blue Stream. In addition, no really significant new development of that gas field has since taken place [Stern 2005].
the offshore lines started and it was completed in October 2002, which was within acceptable limits for such a risky project [Stern 2005].

Figure 9.8 Likely reconstruction of financial structure of the Blue Stream project

In addition, according to expert interviews, in order to ensure its strategic success on the Turkish market and to moderate Iranian supplies, Gazprom had engaged in an aggressive negotiation strategy with regard to the price setting. The Iranian NIGEC/NIOC had offered Botas an import price of $65/mcm (with Ankara as the delivery point), whereas Gazprom had settled a gas import price of $75/mcm. After Iran’s offer, Gazprom reduced its price substantially by treating the Blue Stream project as a sunk cost, therefore willing to bear the full gas transport cost. In other parts of the value chain, the Russian government and Gazprom had embarked on a pro-active policy as well, including the use of political instruments, including pipeline diplomacy. Russia has also been able, as mentioned, to delay the possible realisation of the TCGP across the Caspian Sea on environmental grounds. Meanwhile, according to expert interviews, Gazprom locked in new Turkmen supplies at more favourable rates than its TCGP competition, which reduced the availability of gas supplies to that project.
The institutionalisation of the pipeline of Gazprom’s competition differs from the Blue Stream project. The TCGP project had to be financed on a purely commercial basis through project financing. As mentioned previously, joint ventures included the participation of both national and international oil firms. These entities had no strategic interest in a pipeline, except for shipping gas on a purely commercial basis. However, via political instruments and institutes, such as the Bretton Woods institutions, Western countries were able press forward with the realisation of a direct gas corridor from the Caspian region. Besides the attempt at breaking up the Caspian upstream sector for international energy firms, the US introduced some instruments for realizing alternative transport routes from the region. New pipeline routes from the Caspian region directly to the West were stimulated via the ‘East-West-corridor policy’, which was backed up by a transit policy document of the former Clinton Administration (also see Chapter 11).

According to expert interviews, international financial institutions, such as the World Bank and the European Bank for Reconstruction and Development (EBRD), were also encouraged to help finance pipeline projects from the Caspian region directly to the West. Also some political factions in Turkey favoured the Trans-Caspian pipeline as an alternative to the Russian proposal.

During the 1990s, Europe had a relatively passive policy towards the Caspian region and its gas reserves. The EU only signed an umbrella agreement in 1999 under its Interstate Oil and Gas Transport to Europe (INOGATE) programme, based on the European Energy Charter of 1991 in order to reduce European dependency on OPEC countries and to guarantee access to energy supplies (see chapters 6 and 7 in Smeenk [2010]).

9.2.6 Application of the real-option game model to the Blue Stream case

The essence of the application of the model is an analysis of Blue Stream as a potential strategic investment for Gazprom, by employing the embedded real-options game framework described in Section 8.4 of Chapter 8. The application of this model pertains to the Turkish gas market discussed descriptively in the previous sections, taking into account both opportunities and threats (i.e., vis-à-vis potential competitors). Given the presence of potential competitors on the one hand and demand uncertainty on the other, the goal is to ascertain the overall expanded value of the Blue Stream pipeline project using a simplified model, in other words, the descriptive analysis above must therefore be stylised. To the greatest degree possible, the as-
sumptions below are designed to approximate real world figures and numbers in the context of specific market circumstances and gas infrastructure investments.

9.2.6.1 Assumptions and parameter values

**Operational assumptions:**

a. We assume that the Turkish gas market consists of a duopoly, with Gazprom on the one hand and a potential competitor on the other, with the latter acting as a potential entrant for new market demand with an 8 bcm/y pipeline, both on a distance of 1,213 km to the off-take market (offshore section: 470 km; onshore section in total: 753 km). (No account is taken of potential LNG suppliers at this stage.)

b. Gazprom faces the choice in 1999 (i.e., stage I) of building or deferring the construction of the Blue Stream pipeline across the Black Sea to Turkey in the face of potential entry by a competitor (see Figure 8.9 in Chapter 8).

**Parameter value assumptions:**

a. **Average operating gas transport costs in the base case:** In the base case, both players are assumed to make commercial investments only, i.e., constructing small-diameter pipelines with a capacity of 8 bcm/y, which only have a technical ramp-up phase. In this case it means both players do not undertake early strategic commitment (in the market), meaning the operational unit costs remain at: $c_g = c_p = \$9.93/mcm$. At this point, neither player yet benefits from economies of scale.

b. **Average operating gas transport costs in the proprietary case:** The construction of the Blue Stream is a proprietary investment. Gazprom decreases its average operational unit costs from $9.93/mcm to $8.54/mcm as the pipeline has greater economies of scale (from 8 bcm/y in the base case to 16 bcm/y in the proprietary case). This represents the move away from the base case and towards the proprietary case. The competitor is assumed to use an 8 bcm/y commercial pipeline capacity at the same distance (i.e., the base case situation with an average operational unit costs of $9.93/mcm).

c. **First-stage strategic pipeline investment (K):** The initial cost of building the Blue Stream, K (totalling $2.245 billion), is defined as the difference between the CAPEX for Blue Stream minus the ‘theoretical’ CAPEX for a normal 8 bcm/y commercial investment, I (totalling $0.955 billion).

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456 See the conceptual discussion on definitions held in the toolbox in Chapter 8.

457 In order to calculate the ‘theoretical’ CAPEX as well as the average breakeven operating costs per unit, account is taken of steel price indices, inflation, the WACC (k), the risk-free rate (r), fuel and compression costs, etc. (see Chapter 8). The real, historical figures are used for the proprietary case here. The base case ‘theoretical’ pipeline CAPEX calculation is based on 2009 input data; including a steel price index correction (primarily for inflation) obtained from privately disclosed company sources. The inflation is assumed at 1.1 percent, according to Eurostat data for the Euro area.
d. Follow-up investment outlay by either Gazprom or the competitor (I): Follow-up investment outlay, made after stage I and thus after the incumbent’s strategic investment, corresponds with a base case commercial 8 bcm/y pipeline investment ($0.955 billion).

e. Initial demand parameter ($\theta$): For simplicity, initial gas market demand in the Turkish gas market is assumed to be 18.25 bcm ($\theta = 18.25$) at $t_0$ as detailed in Section 8.4.5.

f. Binomial up or down demand parameters (u and d): In the model, demand is assumed to be stochastic, moving up or down with binomial parameters $u = 2$ and $u = 0.5$, both at the beginning of periods 1 and 2 in stage II. Starting at $t_3$ there is a ‘steady state’ of 25 years, i.e., no more upward and downward moves, as detailed in Section 8.4.5.

g. The risk-free interest rate: The risk-free discount rate is assumed to be 5.5 percent ($r = 0.055$).

h. The risk-adjusted discount rate: The rate at which profits in the last stage are to be discounted by is set at 8.5 percent ($k = 0.085$). The project’s expected annual cash flows extend over a period of 25 years, acting as an annuity.

i. Risk-neutral probabilities: Given u, d, k and r, it can be determined that $p = 0.32$ and $1-p = 0.68$.

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438 The risk-free rate is based on the yield-to-maturity in October 1999 of a 10-year Euro-denominated (or the equivalent thereof) German government bond [Tradingeconomics.com 2009].

439 For lack of historical data, we have used the actual risk-adjusted discount rate (the WACC). We therefore do not make a distinction here between the rate prevailing in 1999 and 2009 (see case studies 2 and 3). Given the availability of the sensitivity analyses (see Figure 9.11), such changes in the WACC do not have a crucial impact, though it remains an important element in determining the overall net project value. The WACC is based on information provided in expert interviews, where a WACC of between 8 and 9 percent was proposed as being appropriate, which is in line with the regulated pipeline business.
Figure 9.9 The proprietary case for Blue Stream vis-à-vis the competitor

Assumptions:
- First-stage strategic pipeline investment by Gazprom: \( K_G = 2,240 \text{ mln} \) 
- Follow-up (second-stage) investment outlay by either Gazprom or its competition: \( I_G = I_E = I = 960 \text{ mln} \)
- Initial demand parameters: \( \theta_0 = 18.25 \text{ bcm} \) (with \( \theta_1 = u \theta_0 \) or \( d \theta_0 \))
- Binomial up or down demand parameters: \( u = 2.00; d = 1/u = 0.50 \)
- Risk-free interest rate: \( r = 0.055 \)
- Risk-adjusted discount rate: \( k = 0.085 \)
- Operating costs:
  - No investment (base case) \( 9.93 \)
  - Proprietary investment \( 8.54 \text{ $/mcm} \)

Note: monetary amounts are in million$. Source: own analysis.

Figure 9.9 is an overview of the various payoffs to Gazprom and the competitor in a decision tree, which is a direct application of Figure 8.9 in Chapter 8. Each node corresponds to an up- or downward move in demand and the resulting decisions of Gazprom (denoted in Figure 9.9 and elsewhere by the letter G) and the competitor (or potential entrant, denoted in Figure 9.9 and elsewhere by the letter E), respectively, to invest or defer (further) commercial investments \( G\{I,D\} \) and \( E\{I,D\} \) in stage II while in stage I only Gazprom is assumed to invest as an incumbent. The highlighted (red) branches along the tree indicate the optimal actions along the equilibrium path.

The model is now explained in 6 distinct steps (steps a. through f.). For period 2 in stage II, we take the case in which demand has moved upward in period 1 (i.e., branch u), and do not
elaborate here on either the case in which demand falls or the base case. Notice that Figure 9.9 will be approached through backward induction, i.e., bottom-up.

9.2.6.2 Model application and backward induction

a. Stage II, Period 2, Sub-game 1 (in Figure 9.9; frame)

State of demand in the Turkish market: At the beginning of period 2 in stage II, demand has already shifted upwards once in period 1, from 18.25 bcm to 36.5 bcm. In period 2 in stage II demand either shifts upwards again, to 73 bcm, i.e., \( \theta_2 \) (i.e., \( \theta_2 \times u \times u \)), or falls back to 18.25 bcm, \( \theta_2 \) (i.e., \( \theta_2 \times u \times d \)).

* State of demand in period 2 in stage II: \( \theta_2 \) (i.e., \( \theta_2 \times u \times u \)) = 73 bcm

If demand rises to 73 bcm in period 2 in stage II, the two model outcomes with the optimal payoffs for Gazprom are the ones where it ends, respectively, as a dominant firm or leader (S-L) and as monopolist (M), respectively. From the competitor’s perspective it is compelled in this sub-period either to invest in the case when demand rises in period 2, becoming a follower (S-F) in the process and obtaining a payoff of 1,365, which is greater than deferring and obtaining 0. So the competitor ends this particular sub-game with its own decision to invest even though Gazprom may prefer to obtain 10,631.

* State of demand in period 2 in stage II: \( \theta_2 \) (i.e., \( \theta_2 \times u \times d \)) = 18.25 bcm

If demand shifts to 18.25 bcm in period 2 in stage II, the competitor will lose on its investment, obtaining -940 as a follower. Therefore, the competitor subsequently opts for deferral, obtaining 0 rather than -940, which implies that Gazprom is able to become a monopolist (M) in this particular sub-game if demand falls, deterring entry altogether in the Turkish gas market. In this situation, Gazprom is able to severely limit the competitor’s profitability (thanks to its strategic investment), compelling it to choose between 1) not entering the market or 2) being compelled to accept substantially lower profits as a follower (S-F), while Gazprom obtains a payoff of 241.

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\[ \text{All state project values are noted in $ millions.} \]

\[ ^{111} \text{Gazprom would thus become a monopolist in outcome (M) in the event that the competitor defers in the case of a rise in demand in period 2, obtaining 0 instead of 1,365. So the competitor, having the last word in this sub-game (for it still has a chance to invest with a rise and/or fall in demand), will obviously choose 1,365 rather than 0, in which case it invests (} E\{D,/1\} \text{ in follow-up capacity, i.e., in a pipeline with only a technical ramp-up phase, making gas available to the market quickly in order to earn a commercial return on investment.} \]
b. Stage II, period 2, sub-game 2 (in Figure 9.9, frame 2)

- State of demand in period 2 in stage II: \( \theta_2 \) (i.e., \( \theta_o \times u \times u \)) = 73 bcm

Referring to Figure 9.9, sub-game 2 yields dominant payoff values of 1,933 and 4,866 for Gazprom and the competitor, respectively. In this particular sub-game, Gazprom makes the last move of the game, as it deferred investment in the first period and demand has yet to shift, its actions themselves acting as a constraint on what the competitor can choose for. Thus the competitor may have preferred obtaining 10,177 rather than 4,866, however Gazprom is able to invest commercially, adding commercial pipeline capacity, ending as a leader (S-L) with a payoff of 1,933.

- State of demand in period 2 in stage II: \( \theta_2 \) (i.e., \( \theta_o \times u \times d \)) = 18.25 bcm

Sub-game 3 yields payoffs of -860 and 61 for Gazprom and the competitor, respectively. Here it is Gazprom which ends the game as a follower (S-F) while conversely the competitor ends as a leader (S-L).

c. Stage II, Period 2, sub-games 3 and 4 (in Figure 9.9, frames 3 and 4)

In the same manner as has been done in the first two sub-games discussed above, the optimal strategies are derived for sub-games 3 and 4.

- Sub-game 3: State of demand in period 2 in stage II: \( \theta_2 \) (i.e., \( \theta_o \times u \times u \)) = 73 bcm

The competitor is now again in a position to make the last move in the sub-game, which acts as a constraint on Gazprom’s choices. However, in this panel of the sub-game (frame 3), Gazprom did not invest commercially in period 1 and neither did the competitor (see below). Both Gazprom and the competitor have the incentive to invest, ending in a duopoly model outcome (C), with payoff values 3,972 for Gazprom and 3,366 for the competitor, respectively.

- Sub-game 4: State of demand in period 2 in stage II: \( \theta_2 \) (i.e., \( \theta_o \times u \times d \)) = 18.25 bcm

Given the additional penalty that arises in the case of a deferral twice in periods 1 and 2, Gazprom has the dominant strategy to supply a quantity at a negative state project value. Conversely, the competitor has a dominant strategy to defer, which leads to a monopoly outcome for Gazprom. Gazprom ends with a payoff of -718 and the competitor with 0.

d. Stage II, Period 1, games 1 and 2 (in Figure 9.9, frames 5 and 6):

- Game 1: State of demand in period 1 in stage II: \( \theta_1 = \theta_o \times u \) = 36.5 bcm

The results listed above for the various sub-games are fed back into the first period of the second stage by backward induction. Here Gazprom has built a strong position by investing stra-
technically in stage I. In this first period of stage II, the payoffs include values 20, 1,048, 26 and 732 for Gazprom and -239, 411, 708 and 1014 for the competitor, resulting from the state-contingent project values above (i.e., from the various sub-games). A duopoly model outcome results in period 1, when Gazprom and the competitor both decide to invest already in the first period (in period 1, stage II) yielding payoffs 20 for Gazprom and -239 for the competitor. Both parties opt for deferral at this stage, obtaining values 732 and 1014, respectively, despite an initial rise in demand.

e. **Backward induction of period 1 (stage II), to stage I:**
Finally, the period 1 payoffs for Gazprom help determine, again via a next step of backward induction, whether the strategic investment is worth making net of its initial capital investment cost, $G_K$, the amount invested in excess of a base case pipeline of 8 bcm/y. The stage I payoff for Gazprom is -321 while for the competitor it is 305. When the strategic investment is subtracted as well, i.e., the amount obtained from $K - I$, the overall NPV for Gazprom of building Blue Stream is -2,516. Thus, according to the real-option game model, the Blue Stream case demonstrates that the pipeline has an overall negative Net Project Value of $2,516 million, which is far below the overall NPV (i.e., including the option value) under the base case of $305 million (refer to the top right two numbers in Figure 9.9).

f. **The various value sub-components**
As noted in the model, the total value of the early strategic investment can be measured by using formula 8.5. The composition of a total value into the different strategic value components is discussed below.

The game is initiated at an initial demand level of 18.25, and the binomial parameters $u = 2$ and $d = 0.5$ determine a number of different demand levels. Table 9.1 below shows how the equilibrium actions ($Q^*_c$), profits ($\pi^*_c$), the state-contingent project values (NPV$_c$), and the various value components (the direct, reaction, pre-emption and postponement values) vary with different levels of demand. As has been shown in the games and sub-games above, every demand level leads to dominant strategies on the part of both players.

For simplicity, the following numerical explanation is based exclusively on the model’s results in the last row in panel B, Table 9.1, specifically the case in which demand has risen twice to 73. Here, Gazprom ends up as a leader firm (S-L), where it supplies 33 bcm/y with a profit of 542. In this specific case, Gazprom uses its existing infrastructure adjacent to the capacity of the Blue Stream pipeline. At this level of demand, and given the cost functions as a result of the proprietary investment, Gazprom has effectively been able to ensure a large share of the
market as a dominant or leading firm. The competitor ends as a follower producing 15 bcm/y, merely half of what Gazprom supplies.

**Table 9.1** Second-stage equilibrium state project values and strategic effects for different market structures and states of demand for the base and proprietary pipeline investment case

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<td>27</td>
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<th>Panel A – Base Case</th>
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<td>Market Structure (Static)</td>
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<th>Panel B – Proprietary Pipeline Strategic Investment</th>
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<td>Demand</td>
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<th>Market Structure (Dynamic)</th>
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Note: Totals may not add up due to rounding. Monetary amounts are in million$. Source: own analysis.

The proprietary case must be compared with the base case (panel A of Table 9.1) in order to determine the difference between making the strategic investment commitment and remaining at the original level of economies of scale, i.e., not building Blue Stream and sticking to an 8 bcm/y pipeline. In the base case, at the same level of demand, the NPV is 3,563 and both firms produce 21 bcm/y via existing and new infrastructure. Since the overall NPV is positive in the base case, the postponement value of investing strategically is zero.

**The direct and strategic value**

As was explained in the Section 8.4.1 of Chapter 8, the net commitment value consists of various components: the direct, reaction and pre-emption values (refer to the appendix in Chapter 8 for a detailed explanation of how these values are calculated). These values are shown in panel B of Table 9.1: The direct value of Blue Stream for Gazprom, attained due to the benefits of economies of scale alone is 305. The additional value of undermining the profitability of the potential entrant’s investments is 104, i.e., the strategic reaction value, while the value of altering the structure of the market altogether, the pre-emption value of Blue...
Stream, is 1,576. This last value is the value attained by shifting from a model outcome involving duopoly (C) to one where Gazprom ends as the leading firm (S-L).

The postponement and net commitment values
The strategic reaction value and the pre-emption values together determine the strategic value. The net commitment value, which is computed by adding the direct to the strategic value, is therefore 1,984 (= 305+104+1,576). In this case the postponement value is zero, because in the base case scenario the NPV is also positive as a result of strong upward demand potential.

The overall Net Project value
Finally NPV\(_G\) of Blue Stream for Gazprom is the NPV in the base case (3,563), added to the net commitment value (1,984) and the postponement value (0), which is 5,548 in total, i.e., $5,548 million.\(^4\)\(^4\) Note that this is not the Overall Net Project Value of the Blue Stream pipeline to Gazprom (which has been determined as −$2,516 million; see the end of the previous step e). The value of $5,548 million, which has been reconstructed here as illustration of the sub-component analysis, is to be found as one of the end-of-period-2 values in Figure 9.9 (see in bottom-left box, indicated as frame 1).

9.2.6.3 Sensitivity analysis
Sensitivity analyses are designed in this context to measure the effect of changes in input variables, such as the binomial upward-move parameter (u), the risk-adjusted discount rate (r), commercial investment (I) and strategic investment cost (K) on NPV\(_G\). Sensitivity analyses are made on all four input variables of the model. The most significant and remarkable results are mentioned below for the Blue Stream pipeline.

1) Overall Net Project Value versus sensitivity to changes in upside market demand potential
Refer to Figure 9.10 below, which shows the sensitivity of NPV\(_G\) to changes in upward market demand potential, u. The change in value of the upward demand potential parameter u, varying in the sensitivity analysis between values of 1.01 and 2, is positively related to NPV\(_G\). In the base case of no pipeline with larger capacity (i.e., lower economies of scale), the project value increases monotonically (see top part of Figure 9.10) with upward market demand potential, as expected from option theory. Considering the positive relationship between overall Net Project Value and upward demand potential, the graph (lower part of Figure 9.10) exhibits two remarkable discontinuities. These ‘negative jumps’ can be explained from the strategic competitive interaction in Gazprom’s market.

\(^4\) The postponement value is a negative number in case the static NPV is below zero for the base case, added, when applicable, by the option value when deferring a commercial investment (I) in period 1 in stage II.
In Figure 9.10, starting from \( u = 1.01 \), Gazprom is a monopolist (M) due to its proprietary investment. When upward market demand potential reaches a level of 1.65, demand increases sufficiently for an entrant to enter the market, which is when the model outcome shifts from monopolist (M) to leadership (S-L). The second jump in Figure 9.10 reflects another shift in the model outcome from leadership (S-L) to duopoly (C). However, for all parameters of \( u \), \( \text{NPV}^* \) remains negative for Blue Stream given the model’s application.

**Figure 9.10** Overall Net Project Value as function of upward market demand potential, \( u \) (with \( d \) fixed at 0.50)

![Graph showing NPV* as a function of WACC](image)

Source: own analysis.

2) Overall Net Project Value versus sensitivity to changes in the WACC

Refer to Figure 9.11 below, which shows the sensitivity of \( \text{NPV}^* \) to changes in the risk-adjusted discount rate \( k \) (i.e., the WACC). From the rise in the slope of the curve, it can be derived that the \( \text{NPV}^* \) rises substantially with a small decrease in \( k \), both in the base and proprietary cases. This result is logical, because future cash flows are discounted at a lower rate (i.e., a higher present value), with the \( \text{NPV}^* \) rising most rapidly in the interval \( (0 < k < 11) \), in both the proprietary and base cases. This sensitivity analysis shows that when Gazprom accepts a lower risk-adjusted rate of return, the strategic value components rise in the overall Net Project value. In the proprietary case, \( \text{NPV}^* \) experiences two jolts at separate values for \( k \) of 10
and 23 percent. These small jumps in the curve are related to the change in market outcome as result of the competitor’s entry.

**Figure 9.11** Overall Net Project Value as function of the WACC

![Graph showing NPV* vs. WACC](image)

Source: own analysis.

3) Overall Net Project Value versus sensitivity to changes in average operating costs per unit

Refer to Figure 9.12, which shows the sensitivity of NPV*$_c$ to changes in OPEX (c). With an increase in c, the NPV*$_c$ of the project decreases in the various value components of the pipeline: both in the direct value of attaining greater economies of scale, as well as in the deterrence effect. The small jumps in the curve are related to the change in market outcome from monopolist (M) to leadership (S-L) after $60-65/mcm$ for Gazprom.
9.2.7 A reflection on Blue Stream and competitors’ projects outcomes: ex-post Turkish gas market structure

The model: Limitations

The model is able to provide a quantitative assessment of the Blue Stream project regarding market demand uncertainty and potential entry. The model helps explain the strategic value, which transcends the commercial value as far as deterring entry is concerned. The overall value that the model has determined for the Blue Stream project is highly negative at approximately –$2.5 billion. Apart from the precise value, this implies a clearly negative verdict on the project. In support of this model verdict, we have learnt from various expert interviews that Blue Stream is generally felt to be a commercial disaster, though it did lock out other potential gas suppliers from the Turkish gas market in the process.

Of course the application of the model has its shortcomings. The most important ones are listed below:

1) The model only accounts for two players; it cannot simulate or account for a greater number of gas suppliers, while in the real world obviously there are many more existing and/or potential gas suppliers.
2) The model, composed of a two-stage game, only lasts for a limited number of periods. After the game has taken place, the situation is assumed to remain in a steady state, where developments remain frozen. Of course, real world developments are highly dynamic, not static as the model suggests, and continue long after the ‘game’ is finished.

**Model results: Discussion**

The application of the real-option game model in the Blue Stream case demonstrates that the pipeline is has a negative overall NPV of $2.5 billion, given of course the various assumptions and simplifications that have been made when introducing the model. This means the project was a financial fiasco both commercially, as well as strategically. Nevertheless, the pipeline did have some deterrence effect in the real world, since it locked other important suppliers in the region, such as Turkmenistan and Iran, out of the Turkish market. On the basis of the sensitivity analysis above, the pipeline may well have had a greater direct value if its economies of scale had been higher (i.e., a pipeline capacity greater than 16 bcm/y), combined with higher initial market demand.

According to expert interviews, the 16 bcm/y capacity was the highest possible technically achievable limit of offshore capacity in the late 1990s, exacerbated by the complex nature of the Black Sea’s sea floor. Furthermore, expert interviews reveal that the pipeline’s low utilisation rate after its completion (as it occurred historically in the real world) added to the pipeline’s loss in commercial value. According to these interviews, Gazprom treated Blue Stream as a sunk cost (i.e., by not charging its customers part of the total transport costs of the pipeline), which artificially enhanced the economies of scale. In this way it (still) serves as a deterrent. This underlines the importance Gazprom may perhaps attribute to deterring entry in the Turkish market.

The Blue Stream project in real world thus was successful with respect to potential long-run competition. However in hindsight, the anticipated growth in gas market demand was too optimistic and other (legal) aspects came into play, which may have rendered Gazprom’s investment in the Blue Stream premature. With regard to the real world, the model naturally has its limitations (see the end of this chapter).

**Ex post analysis: was Blue Stream a premature investment?**

By 2004, Turkey was consuming 22.4 bcm of gas, importing 13.1 bcm worth of those volumes from Russia through the Blue Stream and via the ‘longer’ route through the Trans-Balkan pipeline. In 2008, Turkey consumed 37.2 bcm, 21.4 bcm of which came from Russia.
This afforded Gazprom a stable 58 percent share of the emerging Turkish gas market in 2004 and 2008 market. Other pipeline gas contenders in Turkey in 2008 included Azerbaijan (through the South Caucasus Pipeline – SCP, see also below) at 4.6 bcm (12 percent), Iran at 4.1 bcm (11 percent), Turkey’s LNG imports included 4.1 bcm from Algeria (11 percent) and 1.0 bcm from Nigeria (3 percent). Other supplies were produced domestically (1 bcm) [IEA 2009a; Gazprom 2009]. After the US invasion of Iraq in 2003, Iraq also became a potential source, but by no means a secure gas exporter to Turkey and beyond.

Had Gazprom ignored the potential of Turkey’s dynamic demand growth and given up on the risky Blue Stream project, Turkey’s demand may well have been satisfied by a greater share of gas from the other suppliers mentioned, by means of both pipeline and LNG flows as well as possible Trans-Caspian gas flows from Turkmenistan. Gazprom’s move thus resulted not only in a large market share; it limited other suppliers’ penetration in the Turkish market. Essentially, combined with Gazprom’s price setting policy and Russia’s pro-active policy in the Caspian upstream sector, Gazprom pre-empted flows originating from Turkmenistan through the TCGP. Additionally, Turkmen gas flows to Russia were contracted. To a more limited extent, Iran’s possible exports were also pre-empted. However, according to the results of the model application, the Blue Stream project was a very expensive strategy in order to preserve its position in the Turkish (and European) market.

Blue Stream did not discourage market entry of small Iranian/Turkmen’s supplies, entered via the construction of pipeline from Iran to Turkey in 2001, respectively LNG re-gasification terminals. However, these volumes are not substantial (by case, circa 1-7 bcm/y in 2007). The pipeline also has not discouraged market entry of Azeri gas. Namely, after the (unexpected) discovery of the Shah Deniz field in 1999 in Azerbaijan, another pipeline project became subject of discussion, the so-called South Caucasus pipeline (SCP). The SCP runs parallel to the BTC pipeline from Baku via Georgia and connects with the Turkish gas network, close to Erzurum. However, the volumes were not substantial and therefore not a significant threat to Gazprom (a maximum of 6.6 bcm/y from 2006 to 2020).

Given the negative value of the overall NPV, we could be compelled to conclude that Gazprom’s investment in the Blue Stream pipeline has just as well been premature, given Turkey’s

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43 This is measured in European bcm’s from Gazprom [2009]. IEA [2009b] estimates Russia’s exports to Turkey at 22.5 bcm in 2008.
44 The current capacity is 8.8 bcm/y. After 2012 the capacity could still be raised to 16-20 bcm/y (see also Case study 2). The pipeline has approximately cost $1 billion. At a later stage Georgia wanted to off-take Azeri gas as well, partly as a compensation of the right to transit through the country. Moreover, Georgia wanted to diversify away from Russia’s gas [US Department of Energy 2009b; Stern 2005].
market uncertainty and relative small absolute market volume. Among other factors, as a result of the political crisis and the economic recession in Turkey during the beginning of the 2000s, the previously expected growth of the Turkish gas market proved to be too optimistic. Combined with all new signed import contracts, this resulted in a period of contractual oversupply of the Turkish gas market. Moreover, in 2001, Turkey passed a Natural Gas Market Law, with the intent of ending government control of the natural gas sector; in order to eliminate inefficiencies and harmonize its energy policy with that of the EU. The IMF also pushed for the liberalisation of the Turkish gas sector. This included the break up of Botas into separate units for natural gas import, export, storage and distribution by 2009. Pressing Botas’ break-up might also be seen as a countervailing move on the part of the IMF to reduce Gazprom’s strategic advantage. Botas was not allowed to sign new import contracts until its share in imports fell below 20 percent of the national consumption [State Planning Organisation 2005; Hacisalihoğlu 2008].

Consequently, both the management of Botas and the Turkish Ministry in charge wanted to renegotiate their contract with Gazprom and halted Turkish off-take. At the end of 2003, a new contractual agreement had been signed for 8 bcm/y in which the corresponding price was reduced and the tax regime amended. Due to these problems, the relationship between Botas and Gazprom was undermined. Hence, Gazprom examined possible exports via the Blue Stream pipeline to Syria and Israel, in which case Turkey would become a transit country. From a theoretical point of view, Gazprom expanded its strategic growth option geographically. The same can be said for the European market: securing the Turkish market may be seen as an important stepping stone in capturing future European demand. Moreover, Gazprom bought an interest of 40 percent in the distribution company Bosphorus gas, in order to sell its gas directly on the Turkish gas market [Victor and Victor 2006; Stern 2005].

The Blue Stream pipeline was subject to financing and organisational feasibility issues too. Notably, it was built in the immediate aftermath of Russia’s 1998 financial crisis. In order to mitigate off-take risks, Gazprom signed long-term contracts with Botas. By using Eni, these and other country risks were partially mitigated. Moreover, the Blue Stream pipeline also reduced the transit risks for Russia’s gas supplies to Turkey, particularly with regard to the longer Balkan route. The Blue Stream case offers the benefit of hindsight, being a historical example that can be used to better understand examples of future potential strategic moves, such as those described in case study 2 and 3. In Case study 2, the Blue Stream pipeline is also dealt with on a sub-regional rather than at a regional, country level.
9.3 CASE STUDY 2: Gazprom versus competition in the SSEE gas markets

Case study 2 is an investigation of how Gazprom’s Blue Stream strategy in Turkey can be repeated, this time on a larger scale. The market under consideration is South Southeastern Europe (SSEE), a region where consumption is expected to rise and where import-dependency already stands at 80 percent. In addition, this region is the potential gateway for pipeline gas flows from the Caspian Sea region to other parts of Europe through Turkey (c.f., Case study 1). For Gazprom, the stakes are thus high. New Russian gas flows could materialise via slated Gazprom’s midstream projects such as South Stream and maybe via current overcapacity in the Blue Stream (and/or a new extension). Given the historical case of Blue Stream and other existing infrastructure and flows within the SSEE gas market, the period of analysis is set in the future. Gazprom faces a newer, yet similar, threat to the one presented in Case study 1 through a possible aggregation of Caspian (and Iranian, Middle East) supplies via the so-called ‘southern corridor’. In addition, Gazprom faces possible competition from LNG suppliers and North African pipeline gas suppliers in SSEE markets.

9.3.1 Background

Composed of a diverse set of gas markets, the SSEE gas market is a relatively immature market, compared to the NWE market. There are two sides to this gas market in terms of maturity. On the one hand there are the Italian, Austrian and Hungarian gas markets, which are quite mature in terms of infrastructure as well as the connection between these two markets and the remainder of the European gas market as a whole. The Italian market itself accounts for the bulk of gas consumption in this sub-region, equalling more than all the remaining gas markets in it combined. On the other hand, there are much smaller, comparatively less well-developed gas markets in infrastructural terms, such as Greece and gas markets of the former Yugoslavian countries (Slovenia, Croatia, Serbia, Bosnia-Herzegovina, and Macedonia), Bulgaria and Albania. Romania is a mature gas market, but not well interconnected with the remainder of the European gas market. In addition, some countries such as Greece and the Balkan countries, still have embryonic gas markets, combined with relatively low absolute demand. All these countries, except Greece, were once part of the CMEA system of gas distribution. In a category of its own is the Turkish gas market, which was discussed at length in the previous case study. The Turkish gas market is geographically farther removed from the remainder of the European gas market.

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In this study, SSEE is defined by Austria, Hungary, Former Yugoslavian countries (Slovenia, Croatia, Serbia, Bosnia-Herzegovina, and Macedonia), Romania, Bulgaria, Albania, Greece, Italy and Turkey.

The most quoted proposal is the Nabucco project, planned to start from the Turkish border. Other midstream projects are also under consideration (or are already under construction) to connect pipeline capacity from the Eastern border of Turkey with the off-take markets in Europe, such as White Stream, IGI and TAP.
With the likely increasing import-dependence of the SSEE gas market on sources of pipeline gas and LNG outside Europe, due to possibly rising demand and lower indigenous supplies, room is made for other existing and/or potential suppliers. As was briefly mentioned in Chapter 5, this sub-region of the European gas market is primarily dependent on pipeline supplies from Russia and Algeria, and, to a more limited extent, from Norway, Iran, the Netherlands, Libya and Azerbaijan. LNG producers, such as Qatar and Nigeria, are also shipping modest gas volumes to some of the SSEE markets. It is mainly these pipeline and LNG suppliers, which could more deeply penetrate this section of the European gas market, as can other gas suppliers farther away. Figure 9.13 provides a schematic overview of gas transport and supply to SSEE (see also Map 5.1 in Chapter 5).

Figure 9.13 Schematic overview of competing gas supply, transport routes and delivery points, from the Caspian region and Russia to the SSEE market

Note: excluding existing and planned/proposed supplies and transport routes from Europe, Algeria, Libya, and LNG suppliers; not all transit countries are included; The overview is schematic and therefore not accurate. Source: own analysis, company information; figure adapted from StatoilHydro information.

9.3.2 Demand-side factors in the South Southeast European gas market

From Gazprom’s perspective, the first step in assessing whether or not to invest strategically in the South Stream project is ascertaining market uncertainty on the demand side. This first step is prescribed in the conceptual toolbox in Chapter 8. In this particular case, the demand of all the various countries in the SSEE region is aggregated into one single whole for analytical simplicity. Volume (and price) risks play an important role in the SSEE market. It holds much
potential in the way of additional import requirements, a fact which fits into the overall pattern of declining pan-European gas production and rising import-dependency. Capitalising on rising SSEE import-dependency by capturing the increased market potential in this market may provide an incentive for suppliers to competitively establish a position in there.

Though at an aggregate level oil is the dominant fuel in the primary energy mix in the SSEE markets, the potential for gas is rising, in both the power generation and industrial sectors. Indeed, currently, most of SSEE’s natural gas is used for power generation and industry. Turkey has large growth opportunities, both in absolute and relative terms and relies currently almost equally on oil, gas and coal for its energy consumption [BP 2009]. The gas markets in Hungary, Austria, Bulgaria and Italy are mature, whereas Italy is by far the largest gas market (around 80 bcm in 2008) in SSEE [BP 2009]. Romania’s gas market is highly mature, natural gas being the most prominent energy source in this country; its domestic production is expected to decline from around 10 bcm/y to almost nil over next two decades. For Hungary too, gas has an important share in the primary energy mix, followed by oil and coal. In Italy and Austria, gas also has a significant share, although oil is the most dominant primary energy source, whereas coal is the traditional energy source in Bulgaria. Figure 9.14 shows that Italy, Turkey and Romania developed as the largest consumers of gas in SSEE in terms volume. Combined with the other relatively small gas markets, gas consumption in the SSEE markets has increased from 26 bcm in 1965 to 165 bcm in 2008 [BP 2008; 2009].

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**Only Serbia relies on coal instead of oil [IEA 2009].**
Figure 9.14 Natural gas consumption in SSEE markets until 2008 per country

Government-owned monopolies dominated the gas sector in SSEE for decades and still do so in most SSEE markets. As a result of EU-level liberalisation and privatisation processes, combined with the adjoined goal of creating a single internal gas market within the EU, the different markets were forced to open their markets to competition. In Italy, SNAM (part of the ENI group), Enel and Edison dominate the Italian gas sector. In Austria and Greece, OMV and Depa, respectively, still have a monopoly over import contracts. In some former CMEA-countries, which became EU-members in the period 2004-2007, Gazprom and West-European gas companies have entered the markets through greenfields, M&As, and joint ventures with existing government-owned gas companies.448 Most of the Balkan countries and Turkey are not subject to EU legislation, and therefore are still dominated by government-owned monopolies. In 2008, Gazprom acquired a controlling stake in Serbia’s government-owned oil and gas monopoly National Energy Services (NES) [Financial Times 2008b]. Turkey, however, as described in Case study 1, was forced to liberalise and partially privatise its gas sector by the IMF [OECD 2002; Hacisalihoglu 2008]. Nevertheless, Botas is still the dominant player in Turkey.

According to industry estimates, gas will remain important in the region and it will increase in importance in the energy mix of the different SSEE gas markets. In absolute terms, Italy and Turkey are identified as the most attractive markets by volume. Relatively, other markets are

448 For example, Hungary’s gas company MOL has accomplished a joint venture (Panrugas) with Gazprom. Government-owned gas companies still play an important role in these markets (MOL in Hungary, Bulgargaz in Bulgaria, and Romgaz and Conet in Romania).
expected to grow faster, but in absolute terms they are less significant (some only reaching a consumption level of 6 bcm between 2008 and 2030). Due to declining domestic production in Romania, the growth of imports in this market is substantial.

Nevertheless, there still are volume risks in these SSEE markets (for some suppliers, relatively even more risks). At first, the fundamental volume risk is related to uncertainty about GDP development and the corresponding gas demand growth. The economic crisis of 2008/09 had resulted in a demand reduction and may have an impact on gas demand in the mid-term, depending on the length and depth of the crisis (see also Figure 9.15). Secondly, the Balkan countries still have embryonic gas markets and there are limited interconnections and distribution networks to connect new trunk lines with the main off-take centres. Although the EU and the US financed feasibility studies during the 1990s to stimulate cross-border initiatives, the Balkan region is not yet well-developed in terms of cross-border pipeline networks [SECI 1998]. These littoral states and the related risks may lead to a passive attitude on the part of gas exporters when considering whether to invest in greenfield projects. Thirdly, in some former CMEA-countries there is discussion about the (supplementary) role of Russian (Gazprom’s) gas in the primary energy mix for security of supply reasons. This is largely a result of the Russia-Ukraine gas disputes of 2005/06 and 2008/09 and the absence of interconnections (and other crisis management mechanisms) to manage possible supply cuts. Finally, some contracts are still based on subsidised prices in several countries (e.g. Romania and Bulgaria) as a barter deal for Gazprom’s transits via these countries [Stern 2005]. Introducing market prices that conform to these contracts may lead to lower gas demand since they may be driven up as a result.

On the price side as a whole, market uncertainty is relatively high. Gas prices are largely tied to oil and oil product prices in the SSEE markets. Oil prices are volatile and have fallen from $147/bbl to $40/bbl in late 2008, and back to $70-80/bbl in the winter of 2010. These oil prices have their impact on long-term contracts in Europe, albeit with a six-month lag. However, the long-run marginal and unit costs of the different supply and transport options of most of the various suppliers are still lower than the current gas prices. Gas trading on a short-term basis via gas-to-gas competition is less prevalent than is the case in the NWE market. The Central European Gas Hub (CEGH) at Baumgarten (in Austria) and Punto di Scambio Virtuale (PSV) in Italy are European gas trading hubs, which are less liquid than the UK’s NBP.

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449 See chapters 6 and 12 in Smeenk [2010] for a deeper analysis on the Russia-Ukraine transit relationship and the impact on Russian supplies and transport to Europe as well as the relevant historical context.
9.3.3 Various potential gas suppliers to the SSEE markets

The SSEE market is supplied by a number of different suppliers in the form of both pipeline gas and LNG. Traditionally, the SSEE gas market as a whole is not an LNG importing region, though some countries, such as Italy and Turkey, have begun to import modest amounts of LNG (see below). Existing pipeline gas supply flows come from indigenous production and mainly from two major pipeline gas suppliers outside this sub-region: Algeria and Russia (see Figure 9.15).

1) Volumes which are produced and consumed domestically:

From 2008 to 2040, the level of indigenous production has decreased from 23 bcm in 2008 to 20 bcm in 2020, and is projected to decrease further to 4 bcm and 0 bcm by the years 2030 and 2040, respectively. Nearly all produced gas is consumed domestically.⁴⁵⁰

2) Volumes which are supplied through existing LNG and pipeline contracts from outside the SSEE market and outside the EU:

Algeria supplies Italy and Slovenia by pipeline and it exports small LNG volumes to Turkey (in total 31 bcm in 2008). Russia supplied a total of 68 bcm to the region in 2008. Despite the ability of Turkey and Italy to afford a greater diversity of supplies, the countries in SSEE rely mostly on Russian gas. Norway (8 bcm in 2008) and the Netherlands (9 bcm in 2008) have some long-term contracts with companies in the northern periphery of SSEE (mainly in Italy). Libya supplied 10 bcm in 2008 to Italy via the Greenstream pipeline. Azerbaijan and Iran are carrying some gas to the Turkish market (both around 4-5 bcm in 2008), although these contracts are not solid. Finally, Nigeria supplied 1 bcm worth of LNG in 2008 to the Turkish market. According to privately disclosed company data, other supplies not included above which may have changed hands were part of contractual swaps (mainly between German and French gas companies and Gazprom).

3) Volumes which could arrive in the SSEE gas market through new capacity in the form of LNG and/or pipeline gas:

Most of the existing contracts will expire in the second decade of this century. Only Gazprom is likely to maintain substantial contractual obligations (and thus also the volumes) in the SSEE market as a whole. Based on the available information about contracts, a certain amount will doubtlessly be renewed, holding mostly for pipeline gas from existing producers, such as Algeria. However, assuming that the contracted volumes will expire in the coming years, there is space for new supplies, due to possible increasing demand and decreasing domestic production (circa 75 bcm in 2020 and 200 bcm in 2030). As a result,

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⁴⁵⁰ The domestic production is largely concentrated in Romania (11.4 bcm in 2008), Italy (9.3 bcm in 2008), and to a lesser extent Croatia (2.9 bcm in 2008), Hungary (2.6 bcm in 2008), and Austria (1.5 bcm in 2008). Other SSEE countries produced less than 1 bcm in 2008 (BP 2009).
a large number of pipeline and LNG projects are planned and proposed for the coming decades.

**Figure 9.15** Existing and pending supply distribution over SSEE demand projection (2001-2040)

Referring to Figure 9.15, a high degree of oversupply can be discerned when adding all the various potential projects up to volumes provided through existing supply contracts, as well as the volumes arising from the possible extension of these contracts. The flows materialising on the basis of existing contracts from suppliers outside Europe alone account for some 138 bcm in 2020 (including indigenous production of 10 bcm), that is to say with the exclusion of possible volumes rolled-over from existing supply contracts. In addition, aggregating all re-gas and pipeline capacity under construction, study or proposal, exporting countries can supply the SSEE market with an additional potential of 205 bcm in 2020. The market structure of competition from a Russian perspective (by using the first matrix in Chapter 8, Figure 8.2) in
SSEE appears fairly oligopolistic. Below is a more detailed analysis of the various gas infrastructure and suppliers likely to play key roles in the SSEE market vis-à-vis Russian gas.

Possible new pipeline supplies from Russia

As described in Case study 1, the Trans-Balkan pipeline was one the first pipelines which catered first Soviet, and now Russian gas to SSEE markets, followed by the Blue Stream pipeline to Turkey at turn of the century. Before the construction of the Trans-Balkan pipeline, other Soviet pipelines (e.g., the Transgas pipeline) were connected to Italy, Austria and Hungary through the Ukrainian pipeline system. The latest of Gazprom’s proposals for a new gas pipeline to Europe is South Stream; this initiative was announced in June 2007. This proposed gas pipeline would become the second offshore pipeline to cross the Black Sea (and of course Blue Stream is the first one to do so).451

The South Stream pipeline increases the Europe’s gas import capacity, particularly for Italy, and to a lesser extent Austria, Bulgaria, Hungary and the Balkans (and probably Romania). South Stream’s initially projected offshore capacity was 31 bcm/y, gradually scaled up to 47 bcm/y in March 2009 and then even to 63 bcm/y in May 2009 [WGI 2009a], respectively, in an apparent bid to improve its economies of scale. The South Stream is scheduled to be finalised before the end of 2015, subject to a degree of uncertainty.452 South Stream is slated to transport gas from Russia, Turkmenistan and Kazakhstan. However, it is unclear whether sufficient gas volume will be available for South Stream (see also Chapter 6). Figure 9.16 provides an overview of the various stakeholders of the project and other details pertaining to the South Stream pipeline.453 From the point at which the pipeline lands ashore in Bulgaria onwards, South Stream would in principal be subject to EU legislation (except for some Balkan countries). This implies TPA for the pipeline’s capacity, which eliminates the exclusive right of using the capacity by the pipeline’s owners (Gazprom and ENI). Possibly, the project may be exempted from TPA.

451 The pipeline runs from Beregovaya on the Russian Black Sea coast to Varna in Bulgaria and from there onwards, splitting up between two proposed branches: southwards via Greece (or Macedonia and Albania) to Italy; and northwards via Serbia to Hungary and (via Slovenia) to Austria in Baumgarten. Discussions are also underway that may see the pipeline land in Romania rather than in Bulgaria. Gazprom had also purchased 50 percent of Austria’s Central Europe Gas Hub (CEGH) in Baumgarten, also see Chapter 6.

452 The offshore section is expected to cost EUR2.3 billion, while the total cost of the entire route would be EUR8.6-20 billion, according to the latest estimations of Gazprom and ENI [WGI 2009a].

453 ENI and Gazprom hold a 50 percent interest each in the offshore section. It is expected that EDF will attain a 20 percent stake in the offshore section by reducing ENI’s and Gazprom stake by 10 percent, although negotiations are still underway [WGI 2009a].
**Possible new pipeline supplies from Turkey’s eastern border**

In the public debate about European gas imports much discussion has arisen concerning the export potential of the Caspian Sea region for European gas markets.\(^{454}\) In the Caspian Sea region, Turkmenistan and Azerbaijan could potentially supply Europe with additional gas. However, Europe must compete with Iran, Russia and China for volumes from the region (also see Chapter 6). Gazprom also committed itself to purchasing new gas supplies from Turkmenistan, and possibly other Caspian suppliers against market-based prices, which will reduce the availability of gas supplies to Europe.

Iran may one day become a major potential gas exporter to Europe, though this currently is theoretical and a long-term prospect. According to IEA [2008d], there is unlikely to be enough production capacity to supply additional volumes to Europe in the mid-term, as a result of a lack of investment capital due to the Iran Sanction Act (ISA) sanctions, and other political risks.\(^{455}\)

\(^{454}\) Chapter 6 provides an overview of the export potential in the Caspian region.

\(^{455}\) Iran is currently only exporting a small amount of gas to Turkey via the Tabriz-Erzurum gas pipeline (a maximum of 9 bcm/y, and there were significant difficulties in fulfilling this gas contract) [IEA 2008d]. The only pipeline commitment to a
In the mid-term, other feasible trans-Turkey gas supplies could materialise from Egypt and Iraq, and possibly other Middle Eastern gas exporting countries in the longer-term. Egypt may become a pipeline supplier to Europe, with a volume of around 2 bcm/y through the Arab Gas Pipeline (AGP). Although Iraq has relatively low-cost (associated) gas reserves, and some (unofficial) agreements are signed, Iraqi gas available for exports is still subject to a great deal of uncertainty due to country and legal risks and increasing domestic demand [CIEP 2008].

From the area of Georgia, Iran, Iraq, Syria and Turkey, there is also competition in terms of gas flows (i.e., gas shipping) destined further downstream into the European (and SEE) markets, i.e., the southern corridor, also see Figure 9.13 above.

1. The possible Caspian and Middle Eastern supplies on the Eastern border of Turkey could feed the domestic system of Turkey for its rising demand. According to Botas, demand could reach 56 bcm/y by 2015 and 76 bcm/y by 2030. Turkey’s current contractual surplus is set to become a deficit from 2012 onwards, although the current economic crisis could change this outlook [IEA 2008c].

2. Turkey could re-export Caspian and Middle Eastern gas to other European markets via two proposed pipelines using Turkey’s domestic gas pipeline network (foreign shippers may perhaps ship these volumes as well). Once having arrived at this point, these flows could tap into the Turkey-Greece-Italy Interconnector (TGII) and/or the Trans-Adriatic Pipeline (TAP) [IEA 2008c].

3. The Nabucco pipeline does not connect new gas fields with the European market. It should be seen starting from the Baumgarten hub in Austria in the EU en route to Turkey via Bulgaria, Romania, and Hungary, ‘in search’ of new supplies from both the Caspian region. These could include Iran and potentially other Middle Eastern gas sources. It is a joint venture of gas companies of the mentioned five countries, together with German Rheinisch-Westfälisches Elektrizitätswerk (RWE) [CIEP 2008]. It is designed to construct a gas corridor that realises transmission and supply diversification, primarily independent of Russian influence and therefore heavily backed diplomatically by the US and the EU.

European supplier was made in March 2008 with the Swiss energy company Elektrizität-Gesellschaft Laufenburg AG (EGL) for gas deliveries (5.5 bcm/y) via the existing Iran-Turkey pipeline and the aforementioned Trans-Adriatic pipeline to EGL’s power plants in Italy [IEA 2008d].

The AGP pipeline has a maximum capacity of 10 bcm/y and links Syria via Jordan to Egypt, and then extended to Turkey and Iraq by 2009. Egypt supplies are very uncertain given the increasing domestic demand and planned LNG liquefaction capacity [CIEP 2008].

The TGII pipeline aims to link Turkey, Greece and in a second stage, Italy, the first leg between Turkey and Greece already in operation, with an initial capacity of 3.5 bcm/y (to be extended to 11 bcm/y). The TAP pipeline would connect Greece to Italy via Albania, estimated to be operational in 2012 with an initial capacity of 10 bcm/y (up to 20 bcm/y) [IEA 2008c]. StatoilHydro’s participation in Azeri Shah Deniz field, combined with a 50 percent share in the TAP pipeline may improve project’s bargaining power in acquiring Azeri supplies [IEA 2008c].

The initial stage of 8-10 bcm/y is expected to come on stream by 2014, whereas full planned capacity (at 31 bcm/y) is expected to be reached by 2019 [IEA 2009b].
4. The White Stream pipeline aims to bring Caspian gas across the Black Sea from Georgia either to directly to Romania, or via the Crimea in the Ukraine (Ukraine actively promotes the project), independent from transit (and supplies) through Russia and Turkey. The initial capacity is slated at 8 bcm/y, which could rise to 32 bcm/y. The commercial and supply feasibility of White Stream is still subject to much uncertainty [IEA 2008d].

**Figure 9.17 The Nabucco project**

<table>
<thead>
<tr>
<th>Pipeline project</th>
<th>Shareholders</th>
<th>Governments/business involved</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nabucco</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- Planned transportation capacity 31 bcm/yr
- Diversification from Russian gas supply – additional gas supply for Europe
- Increasing bargaining power EU versus Russia

**Possible new pipeline supplies from North and West Africa (excluding Egypt)**

During the 1980s, Algeria, Tunisia and Italy constructed the TransMed pipeline from Algeria to Sicily in Italy (and Slovenia) via Tunisia. In 2008 the TransMed gas pipeline was extended from 27 bcm/y to 33.5 bcm/y [CIEP 2008]. Another planned gas pipeline, the Gasdotto Sardegna Italia (GALSI) pipeline, will connect the Algerian supply sources with Sardinia and further to Livorno in Toscana (Italy). Its design capacity is 8 bcm/y and is expected to be

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[De Jong 2008]. Figure 9.17 provides an overview of the Nabucco project and its shareholders.

The White Stream pipeline is formerly known as the Georgia-Ukraine-European Union (GUEU) pipeline.

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[459] The total expected cost are EUR7.9 billion. The six shareholders have granted a third-party access exemption for 50 percent of the total capacity, whereas the other 50 percent are open for third-parties [De Jong 2008].

[460] The White Stream is formerly known as the Georgia-Ukraine-European Union (GUEU) pipeline.
operational in 2012 [CIEP 2008].\footnote{Sonatrach works in partnership with four Italian companies in constructing the pipeline (Sonatrach’s share in the consortium is 41.6 percent). According to the agreement between Sonatrach and Gazprom, it is possible that Gazprom will have a stake in the GALSI pipeline.} The availability of gas in the Algerian gas system might increase if the Trans-Saharan Gas Pipeline (TSGP) from Brass in Nigeria via Niger to Algeria were to be built.\footnote{The TSGP has a maximum volume of 20-30 bcm/y and is planned to operate in 2015 onwards. Gazprom, Total and Sonatrach have expressed an interest to participate in a planned Trans-Saharan gas pipeline (in order to gain access to Nigeria’s vast gas reserves) [Financial Times 2009b].}

Libya has built only one gas pipeline (the Greenstream) directly to Sicily in Italy, which has a transportation capacity of 8 bcm/y (the pipeline could be extended to 11 bcm/y by mid-2010s) [CIEP 2008].

New re-gasification capacity in the SSEE market

During the late 1970s, the first SSEE’s LNG re-gasification terminal was built in Panigaglia in Italy (capacity of 3.5 bcm/y). This project was followed by two re-gas terminals in Turkey (in the Marmara region and Izmir, respectively 6.5 bcm/y and 6.0 bcm/y) and one in Greece (Re-vithoussa, 1.4 bcm/y, with an expansion of 3.8 bcm in 2007). The LNG market in SSEE is still embryonic, but is likely to expand in the coming decades (mainly in Italy). Two re-gas terminals are already under construction in Italy (with a combined capacity of 11.8 bcm). On Krk Island in Croatia, one re-gas terminal is planned with a capacity of 8 bcm/y, while other planned and proposed re-gas terminals are located in Italy (i.e., in Sicily, Brindisi, an extension of Panigaglia, Le March, and Rosignano).\footnote{Outside Italy some LNG regas terminals are also under consideration, such as in Albania, which is part of the Trans-Adriatic pipeline project [Cédigaz 2008]. However, these are still too speculative to taken into account.} This capacity is no guarantee for actual LNG supplies, so it still uncertain as of yet whether LNG is available in order to fill the re-gas terminals.

Following the conceptual procedure designed to assess whether or not to invest strategically, developed in Chapter 8, demand is assessed given the information above along with the slated supplies (which includes potential LNG flows). Given the base case scenario of demand growth, one can discern a high degree of oversupply in SSEE markets by 2010. This can be deduced by adding existing supply contracts. Added to this are newly forthcoming volumes arising from the new possible supply contracts, volumes pertaining to which could be provided via midstream greenfields to Europe. The market structure of competition from a Russian perspective (by using the first matrix of the conceptual toolbox in Chapter 8, Figure 8.2) in SSEE appears fairly oligopolistic.

An examination of the different levels of economies of scale attainable for gas volumes channelled to the SSEE markets helps assess to what extent certain sources can compete with Rus-
sian gas, depending on the netback prices involved. In terms of gas supply costs, Azerbaijan, Iran, Iraq, Algeria and Egypt by pipeline are all competitive sources of gas for Russia in the SSEE market. Other Caspian countries (e.g. Turkmenistan) and Libya are also competitive for Russia, with their unit costs undercutting those of Russia. These potential suppliers therefore impose a threat in market power terms (price-cost margin) vis-à-vis Russia. Moreover, the next generation of gas production in Russia (but also, for instance, in Turkmenistan) will have to come at higher unit costs, which may reduce Russia’s relative market power in price-cost terms. In terms of unit costs, the possible entry of LNG played a smaller role, largely due to lower economies of scale (although this tends to differ by source).

Iranian, Turkmen, Algerian and, to a lesser extent, other Caspian and North African suppliers have the potential to become important suppliers to the SSEE markets. However, Iranian supplies to Europe are highly uncertain due to ISA sanctions. In addition, Iran and other Caspian countries already have other export commitments. Referring to the second matrix in Chapter 8, Figure 8.3, the competition level of Algerian and aggregated Caspian and LNG supplies is significant. Therefore, combined with the strategic importance of the Caspian production capacity in Gazprom’s gas balance, and the relatively low market uncertainty, Gazprom may again consider a strategic investment. This will be examined on the basis of the application the quantitative model in the next section of this case study.

**Gas supply costs to the SSEE market**

In terms of total or long-run marginal gas supply costs, of which the economies of scale in transport and upstream production are key determinants (see Figure 8.3 in Chapter 8), Libya and Algeria are the most competitive sources of gas in the SSEE market (respectively $109/mcm and $95/mcm), due mainly to the proximity of these countries to the SSEE market by pipeline, especially in the case of the Italian market. Sources such as Iran and Iraq clock in at $85/mcm and $97/mcm for new gas for SSEE. The long-run marginal costs of supply costs for LNG from Qatar and Nigeria are slightly higher (also see Section 7.7 on market power). Indicative long-run marginal costs in 2020 for gas from Turkmenistan through South Stream costs $215/mcm compared with $152/mcm for gas from Turkmenistan to Greece and $185/mcm to Italy. In terms of LNG, Nigerian LNG costs $172/mcm and from Qatar $154/mcm. Algerian LNG for the SSEE market costs $161/mcm [IEA 2009c].

### 9.3.4 Other investment variables in relation to new investment projects

Before applying the model, other factors with regard to new gas supplies should be considered in a qualitative matter, in line with Barnes et al. [2006].
1) Foreign investment climate in gas supplier countries

As an extension of Case study 1, the focus here is primarily on supplies from the Caspian region and Russia. The most important gas-rich regions that could potentially supply the SSEE gas market(s), where the investment climate could have a considerable impact on available supplies (and most relevant for South Stream) are the Caspian Sea region, Iran and Iraq, the southern corridor countries. As has been highlighted in Chapter 6, the investment climate for private investors in the Caspian Sea region is not favourable; few companies have established a firm presence in the region. As covered in Chapter 6, due to international sanctions, political risks and an unattractive buy-back scheme in place for foreign investors in the oil and gas sector, Iran’s investment climate also leaves much to be desired.

In Russia, private (Western) investors perceive relatively limited access to secure investment terms and ownership rights. In addition, Gazprom has a monopoly over Russia’s gas exports. Inasmuch as this perception has an impact on Gazprom’s access to Western know-how and technological expertise in dealing with difficult projects, it can affect the potential for the development of a number of upstream resources. In order to mutually share benefits and risks, foreign investments in Russia are in general based on asset-swap constructions and joint ventures [Victor and Victor 2006]. Conversely, Gazprom is often impaired in its access to downstream assets by EU-level initiatives, such as those included in the Third Energy Package, which specify a limit on foreign holdings within the European gas markets; consider for that matter the ‘Gazprom clause’ [De Jong 2008].

2) Transit, permit and regulatory risks

Both Russian and Caspian gas flows are exposed to transit risks. Central Asian supplies are subject to uncertainty over permits concerning offshore transport via the Caspian Sea, because the Caspian Sea does not suit simply into any existing categories offered by international law. The uncertainty surrounding the definition of the Caspian basin either as a sea or a lake, combined with environmental concerns (which Russia has sounded, see below), may result in delaying the construction of any offshore pipeline [IEA 2009c]. Iranian transit offers no alternative, because of US-driven political sanctions. The political instability in the South Caucasus, meanwhile, was exacerbated by the Georgia-Russia conflict in August 2008. This brief clash increased perceived transit risks and made it more difficult to finance new pipeline projects in this region.

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464 Most of these issues are already covered in Chapter 6, and in particular in Case study 1.
465 For instance, in 2008 a number of foreign investors (e.g., Total, StatoilHydro, Shell and Repsol) backed out of Iran, also refer to Chapter 6.
The role of Turkey cannot be understated, it is the lynch-pin for gas volumes from the Caspian Sea region to European markets, playing an important strategic role as a key potential transit state for a number of sources. A possible new gas corridor via Turkey is exposed to direct security risks when it comes to impact of separatist Kurdish activities in South-eastern Turkey. More importantly, however, Botas is not satisfied with the transit role it is has been relegated to (on a cost plus basis). Turkey wants to create a gas hub, where it can act as a middleman, buying and selling gas and capturing the resulting economic rents [De Jong 2008].

South Stream would bypass Ukraine and Turkey—in which the strategy underlying South Stream differs from the Blue Stream strategy—and insulates Gazprom’s gas supplies to SEE from any political risk in transit countries (e.g. Ukraine, Moldova, and Turkey) between Russia and the EU [CIEP 2008]. Possibly transit in Balkan countries outside the EU may also result in some problems, because these countries are not subject to all EU and/or international legislations. Within the EU, pipeline investments are subject to regulation and other EU legislation, which expose a pipeline investor to policy and regulatory risks. For instance, TPA may undermine strategic investments, because a pipeline investor is forced to ‘share’ its capacity with potential competitors unless an exemption is awarded.

3) Geopolitical factors
Geopolitical factors most certainly play a central role in the South Stream case. Two important geo-economic forces compete with one another in terms of gas flows: on the one hand, the US and some factions within Europe want to break-up Russia’s transport (and production) control over the Caspian gas, thus weaning European gas markets off their dependence on Russian gas (for an extensive discussion on the geo-strategic roles of the Euro-Atlantic community, see Chapter 8 and chapters 3 and 11. On the other hand, Russia aims to maintain its control over volumes from the Caspian Sea region and their flow to European gas markets. These oppos-
ing forces are the result of broader geo-strategic agendas. As far as the potential institutionalisation of pipeline initiatives backed by the US are concerned, the various actors have some political instruments to stimulate (non-commercial) investments in the Caspian region, which were already mentioned in earlier chapters and will be further discussed below.

9.3.5 Organisational and financial institutionalisation of the South Stream and Caspian pipeline projects

The strategy and instruments designed to realise possible pipeline investments varies both for the South Stream and the southern corridor. In the case of South Stream, Russia uses vertical energy diplomacy to ensure the project’s success. Russia employs foreign policy tools such as government-backing of Gazprom’s investment initiatives. In South Stream’s case, Russia has nurtured close bilateral ties with Italy and Bulgaria, for example, and has important traditional ties with Serbia, to which the South Stream is to branch off. Agreements between government officials in various transit countries and Russia has subsequently facilitated business-to-business progress. In a way similar to Nord Stream (see Case study 3) political commitment could act in support of long-term take-or-pay contracts between Gazprom and mid-streamers in the SSEE market (e.g., ENI, OMV, MOL), where government support in the off-take countries can alleviate demand uncertainty. In model terms, Gazprom as a firm employed Russia’s vertical energy diplomacy to secure upward demand potential.

At the firm level, Gazprom’s potential vertical agreements with mid-streamers in the SSEE market(s) are in line with De Jong’s [1989] joint venture coordination mechanism. Mature markets often feature greater tendencies towards cooperation between firms (also refer to Chapter 4), where the most important off-take countries in the SSEE market are still experiencing development toward a more mature market. Different from the Nord Stream strategy, no gas contracts have been concluded as of yet [De Jong 2008]. The South Stream project, in line with the Blue Stream, is part of a strategic alliance between the ENI and Gazprom, possibly added by Electricité de France (EDF). Gazprom and ENI hold a 50 percent interest in the joint venture of the offshore section each. The mid-streamers, such as ENI and EDF, play a critical role for Gazprom in the Italian and other markets through their position as incumbents in that market, and their political backing from their respective governments.

Asian gas (Kazakhstan, Turkmenistan and Uzbekistan), as well as from the point of view of broadening co-operation with importing countries (Ukraine, Moldova, and Trans-Caucasia). I believe this to be very important both from the perspective of guaranteeing the geopolitical interests of Russia as well as to assist in the integration process of the post-Soviet area” [IEA 2008d, pp. 16 - 17].

In the onshore transit countries, Gazprom cooperates with the national gas companies and in Bulgaria it also cooperates with ENI. Intergovernmental agreements have been signed between Russia and Bulgaria, Serbia, Hungary and Greece. Negotiations are underway to sign the relevant agreements with Austria and Slovenia.
The involvement of a Western company is necessary in the project, for financing and technical reasons. In line with the Blue Stream project, the repayments of the loans could be based on gas contracts between SNAM (a subsidiary company of ENI) and Gazprom, thus completely de-coupled from the project itself. This may result in less expensive loans via the so-called 'warehouse' construction (see Figure 8.4 in Chapter 8). However, it is uncertain whether these largely strategic commitments can be reasonably financed, especially in light of the economic crisis in 2008/09. Linking Western ‘cash-rich’ mid-streamers to these projects in exchange for upstream interests appears to be a workable solution.

As for horizontal energy diplomacy, Gazprom is actively involved in up- and midstream projects in other gas supplying surrounding Europe’s southern flank, such as Libya and Algeria, which were mentioned in Section 9.3.3. Russia has important traditional political ties with these two countries dating from the days of the Soviet Union. Russian government officials join Gazprom delegations in facilitating business arrangements. In the cases of both Libya and Algeria, Gazprom has expressed extensive interest in further involvement along the gas value chain. For example, Gazprom has announced an interest in taking a stake in the Greenstream pipeline consortium (also see above) and buying Libya’s total gas export portfolio [Argus Gas Connections 2007]. As explained extensively in Chapter 7, Russia is also involved in Algeria and appears to perceive North African gas suppliers as strategically important partners. By means of horizontal energy diplomacy, government-level relations help spearhead shared investments between Russia and Algeria as well as Libya. Egypt is another potential partner in this regard. Moreover, the Russian government is actively involved in acquiring Caspian production of Gazprom’s supply portfolio [Goldthau 2010].

As for the institutionalisation of the southern corridor pipeline(s), different mechanisms come into play. Project supported by the US and the EU (i.e., Euro-Atlantic) are based on a different, more market-orientated agenda. Therefore, these projects preclude vertically integrated, government-backed solutions as portrayed by the Russian approach described above. In general, the Transmission System Operators (TSOs) have no economic-strategic interests in a pipeline (i.e., they have no stake in the actual commodity), the only interest they have is shipping gas on a commercial basis. For instance, the Nabucco pipeline is intended to be owned by mid-streamers, which do not have any significant upstream interests (yet). Such a business model limits Nabucco’s bargaining position and its overall feasibility, particularly with regard to attaining supplies and reducing the strategic viability of these projects. Some pipeline pro-

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674 For Russia, this has come as an expedient in delaying the possible realisation of the Trans-Caspian route underneath the Caspian Sea (also discussed in Case study 1). Russia concluded a deal with Kazakhstan on the countries’ division of the Caspian Sea. Additionally, although it was likely not the reason, the Russo-Georgian conflict in August 2008 has resulted in additional perceived investment risks with regard to Georgian transit.
jects, as mentioned above, are (partly) owned by up-streamers, which could stimulate their feasibility.

In recent years, through both political instruments and financial institutions, such as the IMF, the World Bank and the EBRD, the Euro-Atlantic community attempts to stimulate gas flows from the Caspian Sea region. The US mainly has a geo-strategic and economic interest to moderate Russia’s influence in the West, as mentioned in Chapter 3 and chapters 3 and 11. The World Bank and the EBRD could facilitate pipeline investments by means of favourable loans for projects that aim to secure a European stake in the Caspian Sea region. Whereas the EU and its institutions maintained a relatively passive stance towards the Caspian Sea region and its gas reserves, since 2006 the EU has a more proactive policy towards the region. For instance, the planned Caspian Development Corporation (CDC) aims to create an entity to aggregate and catalyse gas production and infrastructure development by constructing a mechanism for co-ordinated gas purchasing. In this manner, a cluster of Western organisations, companies and institutions aim to replicate the ‘warehouse’ model, mainly by using Western loans from international financial institutions for financing such projects instead of long-term gas contracts. Although this is a significant change from Europe’s earlier classical approach, producers in Caspian region may not accept the creation of ‘middlemen’, because such entities may capture large resource rents.

9.3.6 Application of the model to the South Stream case
As a next step, we apply the real-option game model to the South Stream case. From a country-level application, we move to a sub-regional one. The goal is the same as in the Blue Stream: to assess the overall value of the South Stream pipeline in the face of market uncertainty and potential rival moves. An important aspect to take into consideration is that South Stream is a project, which is yet to be built and the effects of which, at the time of this writing, still lie far into the future (i.e., it is an ex-ante analysis). To the greatest degree possible, the assumptions below are designed to approximate real world figures and numbers in the context of the relevant market circumstances and gas infrastructure investments.

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471 Endorsed by the European Council, the Energy Council and the European Parliament, the CDC is a mechanism designed to act as a purchasing consortium for Europe gas buyers, though the concept is still rather ambivalent. The terms of reference of a feasibility study which is being promoted by the European Commission, the World Bank and the EIB are outline the goal of providing gas producers in the Caspian Sea region with the "visibility on prospective aggregated gas demand from the EU, in order to trigger a firm commitment on their side to supply natural gas to the EU in sufficient quantities and for the long-term [Eurogas 2009]."

472 Another proposal to encourage the Nabucco project was launched by the EU as well, in which it decided to allocate EUR200 million from the European Economic Recovery Plan [Euractiv.com 2010]. A pro-active policy of (continental) Europe towards the Caspian region or cooperation with Russia’s infrastructure proposals may undermine US predominance in the region [Euractiv 2010].
9.3.6.1 Assumptions and parameter values

Operational assumptions:

a. We assume the SSEE gas markets collectively consist of a duopoly, with Gazprom on the one hand and a potential competitor on the other, with the latter acting as a potential entrant for new market demand with an 8 bcm/y pipeline, both on a distance of 3,212 km to the off-take market (offshore section: 908 km; onshore section in total: 2,304 km). (No account is taken of potential LNG suppliers at this stage.)

b. Gazprom faces the choice in 2009 (i.e., stage I) of starting to build or deferring the construction of the South Stream pipeline across the Black Sea to Bulgaria onwards in the face of potential entry by a competitor.

Parameter value assumptions:

a. Average operating gas transport costs in the base case: In the base case, both players are assumed to make commercial investments only, i.e., constructing small-diameter pipelines with a capacity of 8 bcm/y, which only have a technical ramp-up phase. In this case it means both players do not undertake early strategic commitment to the market, meaning the operational unit costs remain at $c_e = c_e = 80.4 \text{ mln/bcm}$. At this point, neither player yet benefits from economies of scale.

b. Average operating gas transport costs in the proprietary case: The construction of the South Stream is a proprietary investment. Gazprom decreases its average operational unit costs from $80.4/mcm to $15.4/mcm as the pipeline has greater economies of scale (from 8 bcm/y in the base case to 63 bcm/y in the proprietary case). This represents the move away from the base case and towards the proprietary case. The competitor is assumed to use an 8 bcm/y commercial pipeline capacity at the same distance (i.e., the base case situation with an average operational unit costs of $80.4/mcm$).

c. First-stage strategic pipeline investment (K): The initial cost of building the Blue Stream, K (totalling $11.275$ billion), is defined as the difference between the CAPEX for South Stream minus the ‘theoretical’ CAPEX for a 8 bcm/y commercial investment covering the same distance, I (totalling $8.788$ billion).\textit{474}

d. Follow-up investment outlay by either Gazprom or the competitor (I): Follow-up investment outlay, made after stage I and thus after the incumbent’s strategic investment,

\textit{474} See the conceptual discussion held in the toolbox in Chapter 8.

\textit{474} In order to calculate the ‘theoretical’ CAPEX as well as the average break-even operating costs per unit, account is taken of inflation, the WACC (k), the risk-free rate (r), fuel and compression costs, etc. (see Chapter 8). In this case, the ‘theoretical’ value of the CAPEX for South Stream is used (see Chapter 8 for a definition of ‘theoretical’ values), which approximates the average of publically listed figures for the pipeline. The base case ‘theoretical’ pipeline CAPEX calculation is also based on 2009 input data, obtained from privately disclosed company sources. The inflation is assumed at 2.8 percent (based on the first half year of 2009), according to Eurostat data for the Euro area.
corresponds with a base case commercial 8 bcm/y pipeline investment covering the same distance ($8.788 billion).
e. **Initial demand parameter** ($\theta_o$): For simplicity, initial gas market demand in the SSEE gas market is assumed to be 120.6 bcm ($\theta_o = 120.6$) at $t_0$ as detailed in the conceptual description in Chapter 8.

j. **Binomial up or down demand parameters** (u and d): In the model, demand is assumed to be stochastic, moving up or down with binomial parameters $u = 1.48$ and $d = 0.68$, both at the beginning of periods 1 and 2 in stage II. Starting at $t_3$, there is a 'steady state' of 25 years, i.e., no more upward and downward moves, as detailed in Section 8.4.5.
f. **The risk-free interest rate**: The risk-free discount rate is assumed to be 3.4 percent ($r = 0.034$).

g. **The risk-adjusted discount rate**: The rate at which profits in the last stage are to be discounted by is set at 8.5 percent ($k = 0.085$). The project’s expected annual cash flows extend over a period of 25 years, acting as an annuity.
h. **Risk-neutral probabilities**: Given $u$, $d$, $k$ and $r$, etc., it can be determined that $p = 0.35$ and $1-p = 0.65$.

Figure 9.18 is an overview of the various payoffs to Gazprom and the competitor in a decision tree, which is a direct application of Figure 8.9 in Chapter 8. Each node corresponds with an up- or downward move in demand and the resulting decisions of Gazprom (denoted in Figure 9.18 and elsewhere by the letter G) and the competitor (or potential entrant, denoted in Figure 9.18 and elsewhere by the letter E), respectively, to invest or defer (further) commercial investments ($G\{I, D\}$ and $E\{I, D\}$) in stage II while in stage I only Gazprom is assumed to invest as an incumbent. The highlighted (red) branches along the tree indicate the optimal actions along the equilibrium path.

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475 The risk free rate is based on the yield-to-maturity in October 2009 of a 10-year Euro-denominated (or the equivalent thereof) German government bond [Tradingeconomics.com 2009].

476 The WACC is based on information provided in expert interviews, where a WACC of between 8 and 9 percent was proposed as being appropriate, which is in line with the regulated pipeline business.
Figure 9.18 Gazprom’s proprietary case for South Stream vis-à-vis the competitor

Assumptions:
First-stage strategic pipeline investment by Gazprom: $K_G = 11.2$ mln$
Follow-up (second-stage) investment outlay by either Gazprom or its competition: $I_G = I = 8.8$ bln$
Initial demand parameters: $\theta_0 = 120.26$ bcm (with $\theta_1 = u \theta_0$ or $d \theta_0$)
Binomial up or down demand parameters: $u = 1.48; d = 1/u = 0.68$
Risk-free interest rate: $r = 0.034$
Risk-adjusted discount rate: $k = 0.085$
Operating costs:
No investment (base case) $c_{G0} = \theta_0 = 80.35$ 80.35 $/mcm$
Proprietary investment $c_{E0} = \theta_0 = 15.42$ 15.42 $/mcm$

Note: monetary amounts are in billion$.

Source: own analysis.

Just as in Case study 1, for period 2 in stage II, we take the case in which demand has moved upward in period 1 (i.e., branch $u$), and do not elaborate here on either the case in which demand falls or the base case. Notice that Figure 9.18 will be approached through backward induction, i.e., bottom-up.

9.3.6.2 Model application and backward induction\(^{77}\)

a. Stage II, Period 2
The upward and downward movements in demand in the leftmost branch of the tree (see Figure 9.18 above) and corresponding decisions to invest in follow-up capacity by Gazprom and

\(^{77}\) All monetary amounts are noted in $billions rather than $millions as in Case study 1.
the competitor (after a strategic investment has been made by Gazprom) yield the following dominant routes based on the state-contingent project values:
• Sub-game 1: For Gazprom: 157 and 28 and 0 on both accounts for the competitor.
• Sub-game 2: For Gazprom: 83 and 18; for the competitor: 19 and 0.
• Sub-game 3: For Gazprom: 103; for the competitor: 7.
• Sub-game 4: For Gazprom: 19; for the competitor: 0.

b. Stage II, Period 1
The values listed above are fed back into period 1, on the basis of which Gazprom invests commercially, while the competitor defers. The competitor is unable to obtain its highest possible payoff in period 1 of stage II, i.e., 2, given Gazprom investment in this period for a payoff of 68. In Game 2, rather than investing, both players opt for a deferral in order to avoid a duopoly outcome in period 1 in which both would be worse off than under a deferral. Gazprom obtains 3 rather than 4 and the competitor obtains 0. As Smit and Trigeorgis [2004] argue, Gazprom may also prefer to remain unpredictable.

c. Backward induction of period 1 (stage II), to stage I
Finally, the period 1 payoffs for Gazprom help determine, again via a next step of backward induction, whether the strategic investment is worth making net of its initial capital investment, \( K_c \), the amount invested in excess of a base case pipeline of 8 bcm/y. The stage I payoff for Gazprom is 25 while for the competitor it is 3. When the strategic investment is subtracted as well, i.e., the amount obtained from total CAPEX – I, the overall NPV (NPV^G) for Gazprom of building South Stream is $14 billion into which has been factored all the upward and downward movements in demand, rival moves and resulting the NPVs resulting from each market outcome. The NPV^G under the proprietary case is greater than under the base case (i.e., $14 billion for the proprietary case is higher than $3 billion for the base case). According to the result from the model, Gazprom should thus invest in the South Stream.

d. The various value sub-components
The model’s application to South Stream yields value components in the same manner as in the Blue Stream case, using formula 8.5.

The game is initiated at an initial demand level of 120.6 bcm, and the binomial parameters \( u = 1.48 \) and \( d = 0.68 \) determine a number of different demand levels over the model periods. Table 9.2 shows how the equilibrium actions (\( Q^*_c \)), profits (\( \pi^*_c \)), the state-contingent project values (NPV^G), and the various value components (the direct, reaction, pre-emption and postponement values) vary with different levels of demand. Hence, as has been shown in the
games and sub-games above; every demand level leads to dominant strategies on the part of both players. The example is taken of $\theta^*_x$ (i.e., $\theta^*_x \neq u \neq u$), where demand is 263 bcm/y.

Table 9.2 Second-stage equilibrium state project values and strategic effects for different market structures and states of demand for the base and proprietary pipeline investment case

<table>
<thead>
<tr>
<th>Demand (θ)</th>
<th>Market Structure (Static)</th>
<th>Quantity ($Q^*$)</th>
<th>Profit ($z^*$)</th>
<th>NPI($\pi$)</th>
<th>Market Structure (Dynamic)</th>
<th>Postponement value</th>
<th>Base Case NPI($\pi^*$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>55</td>
<td>Cournot Nash</td>
<td>0</td>
<td>0</td>
<td>(9)</td>
<td>Abandon</td>
<td>18*</td>
<td>9</td>
</tr>
<tr>
<td>81</td>
<td>Cournot Nash</td>
<td>0</td>
<td>0</td>
<td>(9)</td>
<td>Delay</td>
<td>9</td>
<td>0</td>
</tr>
<tr>
<td>120</td>
<td>Cournot Nash</td>
<td>13</td>
<td>0.2</td>
<td>(7)</td>
<td>Abandon</td>
<td>7</td>
<td>0</td>
</tr>
<tr>
<td>178</td>
<td>Cournot Nash</td>
<td>33</td>
<td>1</td>
<td>2</td>
<td>Defer</td>
<td>8</td>
<td>10</td>
</tr>
<tr>
<td>263</td>
<td>Cournot Nash</td>
<td>61</td>
<td>4</td>
<td>29</td>
<td>Abandon</td>
<td>0</td>
<td>29</td>
</tr>
</tbody>
</table>

Panel B – Proprietary Pipeline Strategic Investment

<table>
<thead>
<tr>
<th>Demand (θ)</th>
<th>Market Structure (Dynamic)</th>
<th>Quantity ($Q^*$)</th>
<th>Profit ($z^*$)</th>
<th>Direct value</th>
<th>Strategic Reaction value</th>
<th>Pre-emption value</th>
<th>Commitment value</th>
<th>Postponement NPI($\pi^*$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>55</td>
<td>Monopoly</td>
<td>20</td>
<td>0.4</td>
<td>4</td>
<td>0.1</td>
<td>1</td>
<td>12</td>
<td>(9)</td>
</tr>
<tr>
<td>81</td>
<td>Deferral</td>
<td>0</td>
<td>0</td>
<td>11</td>
<td>0.1</td>
<td>1</td>
<td>12</td>
<td>(9)</td>
</tr>
<tr>
<td>120</td>
<td>Stackelberg</td>
<td>52</td>
<td>3</td>
<td>20</td>
<td>7</td>
<td>9</td>
<td>35</td>
<td>(7)</td>
</tr>
<tr>
<td>178</td>
<td>Monopoly/Stackelberg</td>
<td>81</td>
<td>7</td>
<td>32</td>
<td>18</td>
<td>18</td>
<td>66</td>
<td>(6)</td>
</tr>
<tr>
<td>263</td>
<td>Monopoly</td>
<td>124</td>
<td>12</td>
<td>51</td>
<td>22</td>
<td>55</td>
<td>128</td>
<td>0</td>
</tr>
</tbody>
</table>

* Additional 6 bln$ to postponement value because of additional investment (I) in order to realise total project’s CAPEX.
Note: Totals may not add up due to rounding. Monetary amounts are in billion$.
Source: own analysis.

For simplicity, the following numerical explanation is based exclusively on the model’s results in the last row in panel B, Table 9.2, specifically the case in which demand has risen twice to 283 bcm. Here, Gazprom ends up in a monopolist market outcome (M), supplying 124 bcm/y via its existing infrastructure and the South Stream pipeline with a profit of 12. At this level of demand, and given the cost functions as a result of the proprietary investment, Gazprom has effectively been able to ensure its position as a monopolist, the competitor locked out of the market altogether.

The proprietary case must be compared with the base case (panel A of Table 9.2 above) in order to determine the difference between making the strategic investment commitment and remaining at the original operating unit costs, i.e., not building South Stream and sticking to an 8 bcm/y pipeline. In the base case, at the same level of demand, the NPV is 29 for Gazprom, supplying 61 bcm/y via its existing and new infrastructure, while the competitor supplies 61 bcm/y as well (also at an NPV of 29).
The direct and strategic value

The net commitment values are shown in panel B of Table 9.2: The direct value of South Stream for Gazprom, attained due to the benefits of economies of scale alone is 51. The additional value of undermining the profitability of the potential entrant’s investments is 22, i.e., the strategic reaction value, while the value of then altering the structure of the market altogether, the pre-emption value of South Stream, is 55. This last value is the value attained by shifting from a model outcome involving duopoly (C) to one where Gazprom ends as a monopolist (M).

The postponement and net commitment values

The strategic reaction value and the pre-emption values together determine the strategic value. The net commitment value, which is computed by adding the direct to the strategic value, is therefore 128 (= 51 + 22 + 55). In this case the postponement value is zero, because in the base case scenario the NPV is also positive as a result of strong upward demand potential.

The overall Net Project value

Finally NPV*\text{G} of South Stream for Gazprom is the NPV in the base case (29), added to the net commitment value (128) and the postponement value (0), which is 157 in total.\textsuperscript{478} Note that this is not the overall Net Project value of South Stream to Gazprom.

9.3.6.3 Sensitivity analysis

Pursuant to the approach used in Case study 1, the most significant and remarkable results are mentioned below for South Stream:

1) Overall Net Project Value versus sensitivity to changes in upside market demand potential

As in the Blue Stream case, the change in value of the upward demand potential parameter \( u \), varying in the sensitivity analysis between values of 1.01 and 2, is positively related to \( \text{NPV}^{*}\text{G} \). Considering the positive relationship between overall Net Project Value and upward demand potential, the graph (higher part of Figure 9.19) exhibits two remarkable discontinuities. These ‘negative jumps’ can be explained from the strategic competitive interaction in Gazprom’s market (notably a shift in the model outcome from monopolist (M) to leadership (S-L), and from S-L to duopoly (C)).

\textsuperscript{478} The postponement value is a negative number in case the static NPV is below zero for the base case, added, when applicable, by the option value when deferring a commercial investment (I) in period 1 in stage II.
2) Overall Net Project Value versus sensitivity to changes in the WACC

Refer to Figure 9.20 below, which shows the sensitivity of NPV* to changes in the risk-adjusted discount rate k (i.e., the WACC).
From the rise in the slope of the curve, it can be derived that the $\text{NPV}^*_{G}$ rises substantially with a small decrease in $k$, both in the base and proprietary cases. This result is logical, because future cash flows are discounted at a lower rate (i.e., a higher present value), with the $\text{NPV}^*_{G}$ rising most rapidly in the interval ($0 < k < 13$), in the proprietary case, while the base cases $\text{NPV}^*_{G}$ rises only slowly. This difference is very pronounced here, much more than in the Blue Stream case. This sensitivity analysis shows that when Gazprom accepts a lower risk-adjusted rate of return, the strategic value components rise in the overall Net Project value. The critical value of $k$ (the internal rate of return) is around 13 percent.

3) $\text{NPV}^*_{G}$ versus sensitivity to changes in unit operating costs

Refer to Figure 9.21, which shows the sensitivity of $\text{NPV}^*_{G}$ to changes in OPEX ($c$). With a decrease in $c$, the $\text{NPV}^*_{G}$ of the project rises in the direct various value components of the pipeline: both in the direct value of attaining greater economies of scale, as well as in the deterrence effect. Direct value rises strongly, given upward market potential and the absolute size of the SEE gas market. The jump in the curve is related to the change in market outcome from monopolist (M) to leadership (S-L) after $40-45$/mcm for Gazprom.
9.3.7 Market-outcome scenarios

The market outcome scenarios are reviewed at an aggregate European level in Chapter 10, though at a sub-regional level Gazprom can end up as a quasi-monopolist, a dominant or a non-dominant firm as a result of its investment behaviour, or vice versa (also see Chapter 8). If Gazprom is to end up in a more dominant position at a sub-regional level in SSEE, it will have to invest more heavily than in scenarios where it ends up as a non-dominant firm. At the country or sub-regional level, Gazprom may end up as a quasi-monopolist or even as a monopolist.

At a sub-regional level, in the case of the SSEE region, Russia not only has a geopolitical interest in maintaining its influence in the Caspian Sea and Central Asian regions but also a geo-economic one. The loss of control over flows from this region to European gas markets through alternative routes (e.g., southern corridor) could spell disaster for Russia in terms both of lost market share and possible needed gas supplies for the domestic and export markets.

9.3.8 Reflecting on the application of the model and the conceptual toolbox

Model results: Discussion

According to the application of the model in this ex ante case, Russia essentially pre-empts Caspian supplies (to some extent) by making an early strategic investment in the form of South Stream. The South Stream serves as a strategic option for access to future gas demand.
growth in the SSEE gas market while acting as a deterrent or a barrier to entry to protect that market share. Thus a similar effect as was achieved by South Stream as by Blue Stream, except that in the case of the former it is essentially repeated on a larger scale and with lower unit costs, with a pipeline covering a longer distance.

The application of the real-options game model shows that there is an overall NPV value that goes beyond the mere static NPV value for the South Stream project, with an overall NPV of $14 billion. This result is obtained despite the considerably high first stage strategic pipeline investment, which Gazprom is compelled to make (i.e., the irreversible of early commitment for South Stream). Yet as opposed to Blue Stream, South Stream yields a positive final, overall NPV. The sensitivity analysis of the overall NPV to unit costs provides an explanation for why this is the case: with a capacity of 63 bcm/y (and assuming optimal utilisation of the pipeline), unit costs are reduced to such an extent that sufficient direct value results. With an 8 bcm/y ‘base case’ pipeline covering the same distance, the overall NPV would have been negative (lower than -$10 billion) at unit operating costs of some $80/mcm.

The contribution of the model to the South Stream case is to serve as a contrast to the Blue Stream case. Where Blue Stream possessed only limited economies of scale over its length, South Stream possesses four times the capacity, accessing a market several times larger than the Turkish gas market in volume terms. Thus, if the upward potential, initial demand and economies of scale are great enough, the project can serve its potential role as an option on further growth and as a tool to shape the market structure to one’s advantage. Results in the sensitivity analyses show that at lower levels of demand, the project naturally becomes unprofitable in overall NPV terms.

The conceptual toolbox: additional factors to take into consideration and scenarios

The conceptual toolbox helps to assess what other investment variables may be at play, such as regulatory risk. The toolbox specifies that Gazprom should only consider a strategic investment in the pipeline if it can attain a TPA exemption for its pipeline capacity within EU territory. Without a TPA exemption Gazprom has to release its capacity to third parties. Then, its investment can be seen as a ‘shared’ investment. According to Smit and Trigeorgis [2004], shared investments in a contrarian, competitive setting (i.e., quantity competition) never have a substantial value from a strategic point of view. In the gas industry it is even detrimental without binding commitments with competitor(s). The possible strategic value can only be achieved by aggregating supply flows from different suppliers (e.g., direct strategic value via economies of scale). Moreover, encouraged by the current financial-economic crisis in 2008/09, Gazprom is dependent on strong European mid-streamers in order to finance and organise its strategic investments.
In summary, Gazprom’s investment policy with respect to the SSEE market could have different outcomes, given its competition, the prevailing market uncertainty, government policy and its ability to finance and organise its investment. Institutionalising the South Stream investment together with its partner(s) is an essential prerequisite for Gazprom if it wishes to successfully realise the project’s success. Signing long-term contracts with European buyers, backed by vertical gas diplomacy, enables Gazprom to ensure its market position in volume term in the SSEE market. Alternatively, Gazprom may reserve (additional) capacity for short-term deals, contracting its own production through wholly owned subsidiaries such as Gazprom M&T, for example. As a business model, the latter is driven more by a price-based strategy.

In a scenario involving a wait-and-see strategy, Gazprom may at least temporarily abandon its investment until a gas volume contract is signed to cover the pipeline investment. Postponing the investment may certainly also be motivated by European policies (e.g., involving TPA). Gazprom may still see South Stream as a priority in terms of it acting as a deterrent to its competitor(s). Depending on the level of competition, Gazprom may pursue a proactive strategy with regard to its competitors, in order to ensure its market position in SSEE.

As will be covered in Chapter 10, Gazprom could decide to invest in additional capacity in South Stream, partly on a commercial basis (i.e., additional supply contracts) and partly strategically in order to diversify transit country risk (mainly in Ukraine), which gives Gazprom the option to divert gas flows from existing transit countries. In order to evaluate gas infrastructure investment decisions, a decision and/or policy-maker should consider the infrastructure’s commitment value vis-à-vis postponement value, in addition to its static value. However, it should also take into account ‘practical’ issues with respect to gas infrastructures, which is captured by the conceptual toolbox.

In the second case study, Gazprom, with the support of the Russian government, may deter jointly packaged Azeri, Turkmen, Iranian entry into the SSEE market (e.g., through the Nabucco pipeline). Here too, Gazprom may be inclined to act aggressively yet again in order to protect its position in the SSEE market and deter entry. Given its repeated announcements of enlarging the capacity (and thus the economies of scale) of the South Stream pipeline, one could see this as a form of signalling or coordination, i.e., a tacit message to potential competitors in this market. Deterring Iran, a large gas reserve-holder within economic reach of the SSEE market, may well be an important driving force behind South Stream (besides Blue Stream). By contrast, Gazprom and Russia appear to cooperate with North African exporters such as Algeria and Libya through shared investments along the value chain.
CASE STUDY 3: Gazprom versus competition in the NWE gas markets

Case studies 1 and 2 consider Russia and the Caspian region at country- and sub-regional levels. In Case study 3, the roles of pipeline gas versus LNG will be considered in terms of volume, also at a sub-regional level, with price risks discussed at the conceptual level. Using the same principles as was set out in the first two cases, the Northwest European (NWE) market can now be analysed from Gazprom’s perspective. The case is used to argue why Gazprom faces the same type of strategic problem in a market such as NWE as it does in SSE, even though different factors are at play here. The focus in this case is on Gazprom and a major up and coming LNG exporter, Qatar, which itself pursues a multi-market export strategy.

For Gazprom, the prize in this case is a large market share in NWE, a situation in which it can draw the market structure to its advantage. Just as in the second case involving an aggregation of Caspian gas exporters potentially bundling their export volumes through a pipeline such as Nabucco, strategic interaction is likely. Indeed, competition is possible between Gazprom and Qatar for market share in the NWE market, with pipeline gas on the one hand and LNG on the other shaping the balance of future possible supply scenarios. Following the same procedure as was carried out in Case studies 1 and 2, one can sequentially use the conceptual toolbox and the stylistic model developed in Chapter 8 to assess whether or not to invest strategically.

9.4.1 Background

Centred on the North Sea, the NWE market is the most mature gas producing area in Europe. Gas production picked up after the discovery of the Groningen field (the Netherlands) in the late 1950s and Norway and the UK became important producers during the 1970s and thereafter. Gas consumption in this part of the European market increased steeply throughout the 1970s, spurring the development of infrastructure and sub-regional trading from Norway to the UK and the continent. The NWE market is, for all intents and purposes, a mature one in terms of infrastructure. Norway is linked to European markets through a network of sub-sea pipelines, while the UK is connected to the European continent through the Interconnector and the Balgzand Bacton Line (BBL). Both the UK and Norway are linked to the Netherlands which itself is an important supplier to the region. Germany, France, Belgium (and even Austria and Italy) are all off-takers of gas from the NWE region. Traditionally a supplier, the UK became import dependent in the early 2000s.

The European gas market in general, but NWE in particular, has undergone immense structural changes with the opening up of national markets to competition as the new EU regula-

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For this research, NWE is defined by Ireland, the UK, Denmark, Germany, the Netherlands, Belgium, Luxemburg, and France. In line with Case study 2, the demand for gas in NWE is aggregated for simplicity.
tions, sector-wide directives of 1998 came into effect. The aim of EU policy-makers is to create one single European internal gas market open to competition from within and outside the Union. This has fostered the view that there should be more spot trade, even though long-term contracts are expected to remain the bedrock for much of Europe’s gas flows [CIEP 2008]. Of all the sub-regional European markets, spot trading has achieved the greatest level of evolution in the NWE market and short-term prices here have developed accordingly. Figure 9.22 provides a schematic overview of gas transport and supply to NWE (see also Map 5.1 in Chapter 5).

Figure 9.22 Schematic overview of competing gas supply and transport routes from pipeline and LNG suppliers to NWE market

9.4.2 Demand-side factors in the Northwest European gas market

Per reference to the conceptual toolbox in Chapter 8, assessing market uncertainty is an important first step in ascertaining whether to make a (strategic) investment in new up- and mid-stream projects, as has been done in the previous two case studies. As is the case for the SSEE market in Case study 2 (and indeed for any market), volume (and price) risks play an important role in the NWE market as well, though relatively less so than is the case in the SSEE market. The NWE market holds much potential in the way of additional import requirements, a fact which fits into the overall pattern of declining pan-European gas production and
rising import-dependency. Capitalising on rising Northwest-European import-dependency by capturing the increased market potential in this market may provide an incentive for suppliers to competitively establish a position in there. After all, Europe’s Northwest European markets, such as Germany, the UK and France, include some of the most important economies in Europe.

One of the more traditional gas consuming regions in Europe and a natural hub for shorter-term gas trade due to its maturity, the NWE market is an important centre of consumption as far as gas is concerned. Gas enjoys a primary energy share of 40 percent in the UK, 38 percent in the Netherlands, 30 percent in Ireland, 24 percent in Germany, 24 percent in Denmark, 21 percent in Belgium and Luxemburg and 15 percent in France [BP 2009]. In absolute terms too, these national markets combine to form a very large market with considerable future needs, particularly in the face of the projected decline in regional production. According to BP [2009], the NWE market accounted for some 285 bcm worth of gas consumption in 2008, which accounts for 60 percent of total gas consumption in the EU, see Figure 9.23.

Almost in all countries, national champions, such as E.ON Ruhrgas and RWE in Germany and Gaz de France in France, are responsible for gas imports from outside their respective countries. The relative differences between the various NWE markets are noteworthy: The UK, Germany, the Netherlands and France account for the largest amounts of consumption. These facts and figures should lead one to believe that any Gazprom export strategy to this region (and to Europe in general) is likely to focus on these markets. Indeed, Gazprom’s ambitions to gain access to the British market (via its 100 percent wholly-owned subsidiary GMT and its direct, already existing position in the German market (through a joint venture with Wintershall–Wingas) bear witness to Gazprom’s interest in these markets and their possible place in its export strategy. For comparison’s sake, these markets are comparable in importance to the Italian market in the SSEE market (see Case study 2).

Still, there are some uncertainties regarding additional (Russian) volumes to the NWE gas market. First, the current economic crisis of 2008/09 has resulted in a demand reduction in the short-term and probably in the mid- to long-term as well (see Figure 9.24 below). Second, the newly imported gas from remote areas, via long distance pipelines and LNG, will also require additional cross-border transmission capacity within the EU and thus also in NWE. However, EU regulatory barriers and uncertainties may hamper the corresponding investments, a factor which also impacts major greenfield investments upstream. This will increase the investment risks of the export pipelines from outside the EU to the EU member states as
well [Correljé et al. 2009]. Third, there are some political debates about the (supplementary) role of Russian (Gazprom’s) gas in the primary energy mix for security of supplies reasons (see also Chapter 6), largely as a result of the Russia-Ukraine gas disputes in 2005/06 and 2008/09. Though this is a more pressing ‘issue’ in East European EU member states, it could become an issue in the NWE region as well.

Figure 9.23 Natural gas consumption in Northwest Europe (1965-2008)

On the price side, market uncertainty is substantial. Gas prices are tied to oil and oil product prices in Germany and the Netherlands as well as France (and indeed this is the case for much of the bulk of Europe’s imported and indigenously produced gas). In the UK and to a more limited extent in the continental countries, gas is traded on spot markets where spot price markers are an indication of short-term, gas-to-gas prices which respond more sharply and in a more volatile way to demand or supply shocks than do prices in long-term contracts. With oil prices rising almost inexorably from $40/bbl onwards in 2004, reaching $147/bbl in mid-2008, only to come crashing down to around $40/bbl again in late 2008, and back to $70-80/bbl in the winter of 2010, volatility in oil prices is high when taken over a period of five years. Oil prices have their impact on long-term contracts in Europe; though with a six-month

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480 See also Correljé et al. [2009] for an in-depth analysis of the current hurdles in cross-border transmission investments within the EU, with a focus on NWE.

481 However, in reality NWE is better prepared for supply disruptions – compared to Central and (South-)Eastern Europe – owing to a sufficiently developed gas network and storage facilities. According to expert interviews, gas storage facilities within the NWE market could supply gas with a minimum of 3 months in case of supply disruptions.
time lag. Long-term contracts help cushion the effects of sudden demand movements on gas spot markets. Spot markets are centred on trading hubs which have achieved different levels of liquidity as well as volume (also see Chapter 5). A new trend is for LNG and pipeline gas suppliers to reserve capacity for short-term supplies to the wholesale markets and via the hubs, notably LNG producers and from Norway and Russia by pipeline, though volumes are still small [CIEP 2008]. The NBP, TTF and Zeebrugge are the region’s most important spot markets, with physically trade volumes at NBP having reached 67 bcm in 2008, or around a quarter of total NWE consumption [IEA 2008a]. Indeed, an important difference between the SSEE and NWE markets is the presence and role of relatively well-developed spot markets, of which NBP is the most important and liquid one.

9.4.3 Various potential gas suppliers to the Northwest European market

The NWE market is supplied by a number of different suppliers in the form of both pipeline gas and LNG. Traditionally, NWE is not an LNG importing region. Only when France is included in the total LNG import balance is the share of LNG is worth mentioning. Existing pipeline gas flows come from indigenous production, being greater in relative terms than corresponding domestic indigenous supplies in SSE. Another major difference between NWE and SSE which is worth noting is that while Algeria is important in SSE (particularly with regard to Italy), it is Norway which is an important together with Russia as far as pipeline gas flows are concerned. Per reference to Figure 9.24, there are four ‘types’ of gas supplies which shape and will continue to shape the NWE market:

1) Volumes which are produced and consumed domestically:

From 2008 to 2036, the level of indigenous production, is projected to decrease from 173 bcm in 2008 to 91 bcm in 2020 and onwards to 45 bcm and 14 bcm by the years 2030 and 2036, respectively.

2) Volumes which are produced and consumed mainly within the NWE market but exported in an intra-European fashion:

The first layer in Figure 9.24 also includes those volumes, which are delivered through existing supply contracts. Volumes here include gas from the UK (to Belgium, Germany, France through the Interconnector) and from the Netherlands and Denmark to other

The NBP hub saw physically traded volumes rise to 67 bcm and 961 bcm worth of traded volume in 2008 [IEA 2009]. The TTF and Zeebrugge each reached a level of 19 and 9 bcm of physically traded gas and traded gas 60 bcm and 45 bcm, respectively [IEA 2009]. The CEGH reached physical trade occurring at a level of 5 bcm in 2008, while traded volumes rose to 13 bcm [IEA 2009]. The yardstick for hub pricing is the replacement value of the gas rather than the market value principle; contractual prices for natural gas are always geared to the energy content of the gas involved [Energy Charter Secretariat 2008; Davis 1984].

France imported 7.3 bcm from Algeria, 1.0 bcm from Egypt, 2.3 bcm from Nigeria and almost 0.4 bcm from Qatar, for example. Belgium also imports LNG, importing 2.3 bcm from Qatar in 2008. The UK is one of the ‘newer’ LNG importers, importing 0.3 bcm in 2008 from Algeria and 0.5 bcm from Trinidad and Tobago in 2008 [IEA 2009].

This level of gas production includes what the Netherlands produces and consumes domestically.
NWE markets. The share of the volumes is set to shrink unless they are extended, and some of these extensions are likely.

3) **Volumes which are supplied through existing LNG and pipeline contracts from outside the NWE market and outside the EU:**
The third category of flows includes volumes from Norway, Russia, Qatar, Algeria, Egypt and Nigeria. These account for a significant portion of total volumes contracted in the projection period (volumes from these countries are set to reach 170 bcm in terms of contracted volumes by 2015). For this category of volumes, the utilisation rate of some existing pipeline and re-gas capacities is often below 100 percent. Suppliers could use the spare capacity in order to increase volumes, without any large greenfield investments. If the demand growth is substantial enough and if it is possible, suppliers could decide to increase the capacities of the current pipeline system via additional compression.

4) **Volumes which could arrive in the NWE gas market through new capacity in the form of LNG and/or pipeline gas:**
These volumes are yet to be secured through long-term contracts or through diverted or ‘flexible’ supplies. The last category of gas flows have yet to materialise and the relevant infrastructure is either under construction or has yet to be built especially as far as Norwegian, Russian and LNG flows originating from currently slated greenfield projects. A total of some 117 bcm worth of re-gas capacity (both under construction and proposal) is likely to be available in the NWE market from 2020 onwards. This capacity is provided by a number of new LNG terminals in France, the UK, the Netherlands, and to a lesser extent Germany, Belgium and Ireland.

Not all 117 bcm worth of capacity is likely to be utilised fully, with some currently planned utilisation resulting from newly signed long-term contracts. However, one must assume they represent a certain potential market share because the capacity in place makes throughput available. So as a rule of thumb, it is assumed here that, in order to provide a picture of what could come on stream, all slated re-gasification and pipeline capacity is included in the overall supply assessment.\(^{80}\)

Consider Figure 9.24, here one can discern a high degree of oversupply when adding all the various potential capacities of infrastructural projects up with volumes provided through existing supply contracts as well as the volumes arising from the possible extension of these contracts (in a manner similar to Case study 2). The flows materialising on the basis of existing

\(^{80}\) On average, around 70 percent for pipeline flows, and the average utilisation faction of re-gasification terminal is even lower.
contracts from suppliers outside Europe alone account for some 320 bcm in 2015 (including indigenous production of 120 bcm), i.e., with the exclusion of possible volumes rolled-over from existing supply contracts. In addition, aggregating all regas and pipeline capacity under construction, study or proposal, exporting countries can supply the NWE market with an additional potential of 221 bcm in 2015. The market structure of competition from a Russian perspective (by using the first matrix in Figure 8.2, Chapter 8) in NWE appears (again) fairly oligopolistic. Below is a more detailed analysis of the various gas suppliers likely to play key roles in the NWE market vis-à-vis Russia.

**Figure 9.24 Existing and pending supply distribution over SSEE demand projection (2001-2036)**

- **Indigenous production**
- **Existing pipeline contracts Norway**
- **Existing pipeline contracts Russia**
- **Existing LNG contracts Algeria**
- **Existing LNG contracts Qatar**
- **Other existing contracts***
- **Regas capacity under construction‡**
- **Regas capacity under study/proposal‡**
- **Possible pipeline capacity from Russia†**
- **Possible pipeline capacity from Norway††**
- **Demand projection**
- **Demand projection with correction of economic crisis**

* Including some flexible LNG volumes (up to 1.6 bcm/y).
** Including new signed long-term volume contracts via Nord Stream (up to 16.5 bcm/y).
*** Among others, Egypt LNG (up to 5.7 bcm/y); Equatorial Guinea LNG (4.5 bcm/y); Nigeria LNG (4.3 bcm/y).
† Nord Stream (over capacity or self contracted via GMT: 11-51 bcm/y).
†† Europipe III (23.6 bcm/y) and Skanled (9 bcm/y).
‡ Mainly in France, UK and the Netherlands, but also one in Germany. 

Note: Existing volume contracts are based on ACQ bcm/y. Linear trend extrapolation (via the method of least squares) after 2030 for indigenous production (based on 2020-2030) and demand (based on 2025-2030).

Source: own analysis, based on GIE [2009]; Cedigaz [2009]; CIEP [2008]; privately disclosed company data.

**Possible new pipeline supplies from Russia**

Currently, Gazprom is transporting its gas to NWE via the old Soviet pipeline system through Ukraine and via the Yamal-Europe pipeline, which is connected to the Wingas network in Germany and onwards. The Yamal-Europe pipeline has not reached its full load factor (currently utilisation is around 70 percent). Gazprom could decide to increase its volumes through the existing Yamal-Europe pipeline (by also building additional compression on that route). This investment decision offers the option to stall major investments with regard to new
The Nord Stream gas pipeline is designed to bring additional gas to Western and Northwest Europe from Russia. The gas pipeline runs across the floor of the Baltic Sea, avoiding the existing transit countries of Ukraine and Belarus with which Gazprom has recently clashed over gas contracts (2008/2009). Instead, the pipeline must transit the territorial waters of a host of North European nations, some or most of whom have reservations about the planned project [CIEP 2008] (see Section 9.4.4 below). In Nord Stream’s first phase, the plan for the project is for the pipeline to be connected with the Shtokman gas field in the Barents Sea, once brought on-stream, even though Nord Stream likely to be completed before the Shtokman project is brought on stream. Initially, one of Nord Stream’s two pipelines will be operational from 2011 onwards, with a transport capacity of 27.5 bcm/y. A parallel pipeline will be laid to double the annual transport capacity to around 55 bcm/y – expected to come on stream as early as 2012, see Figure 9.25 [CIEP 2008].

Figure 9.25 The Nord Stream project

<table>
<thead>
<tr>
<th>Shareholders</th>
<th>Governments/business involved</th>
</tr>
</thead>
<tbody>
<tr>
<td>X%</td>
<td>Onshore transit</td>
</tr>
<tr>
<td>Share in project</td>
<td>Offshore transit</td>
</tr>
<tr>
<td>X%</td>
<td>Offshore and offshore transit</td>
</tr>
</tbody>
</table>

- Planned transportation capacity 55 bcm/y
- Extra volume of Russian gas for Northern and Western Europe
- Avoiding Ukraine and Belarus – diversifying transit risk

* From 2011 a transport capacity of 27.5 bcm/y, full capacity in 2012 (expected).
** Wingas, E.ON Ruhrgas-Gazprom M&T, GDF Suez, Dong. Main offtakers – other (transit) countries may take off gas as well.
*** The project could be extended to the UK. Then, Germany and the Netherlands will become transit countries.

Source: own analysis, based on Gazprom and Nord Stream information.

Currently, 16.5 bcm/y worth of the capacity line currently under construction is already sold to companies by means of long-term contracts. A part of the remaining 39 bcm/y worth of capacity is already ‘self-contracted’ by GMT (6 bcm/y). The remaining capacity (33 bcm/y) is not coupled to any concrete gas flows, at least not yet [Nord Stream AG 2009]. However, this capacity could well be coupled to volumes in the pipeline if Gazprom chooses to commit such volumes, either through self-contracting or long-term contracts with buyers. Gazprom has signed an agreement with the following European companies: Dong Energy, Denmark (1 bcm/y); E.ON Ruhrgas, Germany (4 bcm/y); GdF Suez, France (2.5 bcm/y); Wingas, Germany (9 bcm/y). Gazprom holds a 51 percent interest in the joint venture, Dutch Gasunie 9 percent (in exchange for an option to Gazprom to buy a 9 percent stake in the BBL pipeline from the Netherlands to the UK), and the German companies BASF/Wintershall and E.ON Ruhrgas hold 20 percent each. Other parties have shown interest in buying a stake in the Nord Stream project. For example, Gaz de France Suez is negotiating its participation [Nord Stream AG 2009].
For Russia, the UK, France and Germany are key markets simply in terms of size, and so they form part of Gazprom’s expansion drive in the NWE market. Being the largest markets by volume, these three markets’ rising import needs offer valuable market share yet to be captured. From a Russian perspective, leaving any additional investments aside which it may need to build further economies of scale and expand its market share may relinquish Gazprom’s market share to possible entrants. Through its subsidiary, GMT, Gazprom is aiming to expand its gas trading activities (e.g., self-contracting) mainly in the UK. At the same time, Gazprom’s long-term contractual volume commitments with European mid-streamers, which are seen falling from 70 bcm in 2015 to 68 bcm in 2020 and 2025, respectively, may be renewed. If Gazprom chooses to extend these contracts and the buyers are willing to do so, then this will help secure Russia’s overall market share in the region. The Nord Stream alone will carry 16.5 bcm worth of long-term gas volume contracts in its first phase, while from 2012 onwards the pipeline could potentially carry another 39 bcm worth of gas, now held as excess capacity booked by Gazprom itself (6 bcm/y already contracted to Gazprom M&T).

All-in-all, the large number of potential gas-exporting entrants in the NWE market, at supply costs similar and often lower than those of Gazprom (especially per reference to greenfield investments with high long-run marginal costs, such as Yamal and to a lesser extent Shтокman) through LNG is likely to provide Gazprom with an incentive to make an investment in capacity expansion. Additionally, market uncertainty is low, with import needs for the NWE market certain to grow and prices remaining as unpredictable as they have historically always been.

Possible supplies from Norway and Algeria

Based on the available information about contracts, a certain amount will almost doubtlessly be renewed, holding mostly for pipeline gas from existing producers, such as Norway. Norway’s exports are not likely to exceed 115 bcm by 2012. Almost all Norwegian gas will be exported to Europe in the coming decade(s). Newly produced gas from the Ormen Lange will be sold in the spot and short-term markets in the UK via the Langeled pipeline (around 20 bcm/y according expert interviews). Only gas from the Snøhvit field can potentially be exported as LNG to markets outside Europe (around 6-11 bcm/y in 2010-15). By making use of excess transport capacity, Norway could optimise its export revenues from gas sales [CIEP 2008]. Depending on fiscal and regulatory conditions and gas prices, StatoilHydro’s oil and gas export strategy may yet shift, possibly resulting in an increase of Norwegian production and export [OME 2007; CIEP 2008]. As mentioned in Case study 2, According to expert interviews, Algeria is currently focusing on a growth strategy via pipeline supplies to Italy. Therefore, Algeria is not likely to exceed exports of 20 bcm/y to the entire French market,
having either limited or fixed LNG export ambitions to that and other markets. Norway and Algeria, though they are considerable and mature gas suppliers, are thus not likely to pose as much a threat as LNG flows do.

Re-gasification: Possible LNG flows to NWE

Indeed, the most important single threat in terms of volumes comes from the theoretical 130 bcm/y worth of volumes (assuming full utilisation of the corresponding re-gasification capacity). This capacity is owned either by mid-streamers (e.g., GDF Suez, E.ON Ruhrgas) or by vertically integrated international energy firms with a strong position in the LNG value chain through, for example, self-contracting strategies or a combination of both. Value chains such as those managed by ExxonMobil and Qatar Petroleum (from Qatari projects) can also form a threat in that Russian gas in the NWE market may have to compete with additionally contracted LNG from this joint venture (in excess of what is currently contracted). 487

Assuming all the 130 bcm/y worth of re-gasification capacity are built, this capacity can make possible a vast flow of LNG to the NWE market. This could represent a major threat to Gazprom’s potential market share in NWE. Since these flows could come from a number of different players, from Qatar to Nigeria, the competition can be said to be somewhat oligopolistic. In the long run, however, only Qatar, Nigeria and Algeria have significant market power in the Atlantic Basin and this has a direct bearing on market structure in the NWE market (also see Chapter 7). The NWE market will increasingly become part and parcel of the trans-Atlantic LNG market. Market power in the Atlantic Basin therefore also translates into market power in the NWE market. From an oligopolistic point of view, any amount of future LNG imports in NWE may act as a form of competitive entry with respect to Russian gas (in volume terms). As was explained in Chapter 7, Qatar pursues a multi-market LNG export strategy and much of its LNG volumes have yet to make their impact on the NWE market. Of the various potential players in the European market(s), and especially also in the NWE market, Qatar is the most significant newcomer in LNG terms. Qatar chose for a strategy involving economies of scale in its LNG shipping and liquefaction, not only in the US and in Asian markets, but also in Europe (for a more extensive overview of Qatar’s sales and market strategy, refer to Chapter 7). 488

487 South Hook LNG, Milford Haven, and Grain LNG terminal. Qatar Petroleum (67.5 percent), ExxonMobil (24.15 percent), and Total (8.35 percent) are the shareholders of South Hook LNG and the shareholders of Grain LNG are National Grid, BP, Sonatrach, E.ON, Iberdrola, Centrica, Gaz de France, part of a broader multi-market LNG strategy on the part of this ‘NOC-IOC’ partnership.

488 According to expert interviews, Qatari LNG arrives in the NWE market at a cost of $3,29/mmbtu in 145,000 cubic meter tankers, $3.05/mmbtu in 210,000 cubic meter tankers and $2.96/mmbtu in the supergiant 250,000 cubic meter tankers, a ten percent total reduction in unit costs. Indeed, Qatargas chief al-Suwaidi has claimed that “we knew we would have to compete with pipe gas in a number of countries, especially Europe. So this was one of the drivers for pushing up sizes [of] trains and ships. We really wanted to compete in those markets” [WGI 2009f]. As in Europe, LNG is positioned
Gas supply costs to the NWE market

In terms of total or long-run marginal gas supply costs, of which the economies of scale in transport and upstream production are key determinants (see Figure 8.3 in Chapter 8), the UK and Norway are the most competitive sources of gas in the NWE market, due mainly to the proximity of production sites in the North Sea to the NWE markets. Sources such as Snøhvit LNG from Norway and Yamal are the more expensive possible sources of new gas for NWE, and if brought on stream in sufficient capacity, they could benefit from economies of scale. The total gas supply costs for LNG from Qatar and Nigeria are significantly lower (also see Section 7.7 on market power). According to the IEA [2009], indicative long-run marginal costs in 2020 for gas from Shtokman through Nord Stream costs $234/mcm compared with $204/mcm from Yamal, $91/mcm from Norway, $175/mcm from Nigeria (by LNG), $174/mcm from Qatar (by LNG), $177/mcm from Algeria (by LNG) for the NWE market.

9.4.4 Other investment variables concerning Nord Stream supplies

Before applying the model, other factors which influence new gas supplies should be considered in a qualitative matter, in line with Barnes et al. [2006]. A number of investment variables should be taken into account with regard to the Nord Stream project, listed below.

1) Foreign investment climate in gas supplier countries

The factors to be taken into consideration as far as Russia’s investment climate is concerned, have already been covered in Case study 2. For a more of detailed overview of the investment climate in Qatar, for example, refer to Chapter 7.

2) Transit, permit and regulatory risks

Although the Nord Stream pipeline circumvents onshore transit through third countries, the Nord Stream project leaders still had to consult with all nine countries around the Baltic Sea; and in five of these the project still requires (environment) permits. These consultations can delay the construction process, though the construction process appears to be underway [WGI...]

Based on expert interviews, an indication of the long-run marginal costs for the NWE market is given by the relative values of the long-run marginal costs of various sources. Take the Norwegian Troll gas field, for example, in the North Sea. It is the most expensive source of gas for the NWE market. LNG from Snøhvit, offshore Norway’s northern coast, costs roughly half per unit as gas from Troll. Gas from Nigeria, also in the form of LNG, costs roughly a quarter as much as Troll gas while LNG from Qatar clocks in at 18 percent of Troll in per unit terms, comparable with LNG from Algeria. The cheapest source of gas in the NWE market is gas from the Netherlands’ Groningen field, costing roughly 10 percent as much as gas from Troll. The long-run marginal cost of gas from Shtokman in the form of LNG and new sources in Yamal are likely to be a great deal higher relative to Troll.
The Nord Stream project also faces significant uncertainty about the timing of investments in German pipelines due to EU regulatory matters [Correljé et al. 2009]. Pipelines originating from outside the EU, landing on EU territory, where gas exits the pipeline and enters the EU pipeline grid may also be subject to TPA. While subjection to TPA can act as brake on the strategic and proprietary value of its capacity, Nord Stream is not subject to TPA legislation. The Nord Stream companies are thus able to use Nord Stream’s capacity in a proprietary manner.

3) The geopolitical dimension

For a more extensive review of the broader geo-strategic context in which Russia’s pipeline investment strategy fits (including Nord Stream), including the extra-regional role of the US, see chapters 3 and 11. Suffice it to be said here in the specific case of Nord Stream that within Europe, there is a rough division between European countries with a traditionally more trans-Atlantic relation with the US and the more continental actors. On the one hand, trans-Atlantic countries, such as the Netherlands, support the construction of the Nord Stream, while others such as the Baltic countries, Sweden and Poland generally oppose the project.73 France, Germany (and Italy, as was mentioned in Case study 2), the more continental countries, but also the Netherlands tend to favour the project. Moreover, the European Commission assigned to the Nord Stream project a Trans-European Network (TEN-E) status, making Nord Stream a key project for European security of supply [Gazprom 2009a].

9.4.5 Organisational and financial institutionalisation of the Nord Stream project

Since the mid-seventies, the German-Russian gas relationship solidified through the establishment of the so-called Orenburg pipeline deal, backed largely by the German government, as mentioned in Part II of Smeenk [2010]. An important element in how Gazprom pursues the institutionalisation of the Nord Stream lies in how it uses vertical energy diplomacy to secure Nord Stream’s success. Russia employs foreign policy tools such as government-backing of Gazprom’s investment initiatives. In Nord Stream’s case, Russia has nurtured close bilateral ties with Germany (and other off-take countries, such as the Netherlands and France), and agreement between government officials subsequently facilitated business-to-business progress. Thus political commitment acted in support of long-term take-or-pay contracts between Gazprom and German mid-streamers such as E.ON Ruhrgas at the firm level, where government

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73 For some of the LNG re-gas facilities in the NWE market, such as South Hook re-gas terminal in the UK, TPA exemption is also granted, which provides LNG re-gas terminals with a similar, proprietary value. As for LNG, it is not exposed to any major transit risks in the same way as pipeline gas volumes are. However, re-gas terminals do face Not In My Backyard (NIMBY) issues in certain specific local municipalities.

74 The Baltic countries favour overland alternatives, on the grounds of the Nord Stream’s environmental risks, complaining simultaneously about deprivation of transit revenues the Nord Stream causes them.
support in the off-take countries can alleviate demand uncertainty. In model terms, Gazprom as a firm employed Russia’s vertical energy diplomacy to secure upward demand potential.

At the firm level, Gazprom’s vertical agreements with mid-streamers are in line with De Jong’s [1989] joint venture coordination mechanism. Mature markets often feature greater tendencies towards cooperation between firms (also refer to Chapter 4). The mid-streamers, E.ON Ruhrgas and BASF, play a critical role for Gazprom in the German market through their position as incumbents in that market, and their political backing from the German government.

The Nord Stream project can be seen as part of a public-private ‘win-win framework’ between government-controlled companies in Russia on the one hand, and private entities or counterparts in off-take countries on the other, such as in Germany, via ‘vertical swaps’ value chain and joint ventures. This type of agreements provides an upfront economic value and incentivises greenfield investments (also for smaller gas fields [Van der Linde 2007]. The public-private partnership between Russia and off-take countries can ensure Gazprom’s market share in Europe and deter (to some extent) the flexible LNG flows.

In addition to the business model of long-term contract backed by governments, Gazprom increasingly engages in selling ‘flexible supplies’ not committed to country and regional markets, see also Chapter 10. Gazprom also applies this new business model in respect to the Nord Stream via gas sales of Gazprom M&T in mainly liberalised markets, such as the UK. This business model is in the in line with De Jong’s [1989] competitive coordination mechanism, which is mostly applied in growth markets, such as the UK (also refer to Chapter 4). However, it is uncertain if Gazprom may increase substantial volume growth via GMT due to possible difficulties of managing downside risks of this business model, particularly in light of the buyers’ market since the end of 2008.

The asset swaps and joint ventures offer German companies security of supply in the form of access to upstream resources, while Gazprom could improve its security of demand by integrating in the EU downstream, towards end-consumers. Wintershall and E.ON Ruhrgas have a 24 percent share each in Servometregazprom, which is a Russian license-holder to the exploration of the Yuzhno Russkoye gas field, whereas Gazprom owns 51 percent. E.ON Ruhrgas and Gazprom also develop the Russian power market in another joint venture and E.ON Ruhrgas has a 6.5 percent stake in OAO Gazprom. E.ON Ruhrgas received further natural gas produced at the wellhead in Russia and is delivered through the joint venture by Gazprom, based on prices comprised of an average value of domestic Russian sales and Russian export sales. With Wintershall’s agreement, Gazprom increased its stake in Wingas 49 percent. Wingas is active in transport, direct sales and storage in and outside Germany. In exchange for E.ON Ruhrgas upstream interests, Gazprom received minority stakes (up to 49 percent) in E.ON Ruhrgas’ subsidiaries in Central European gas markets (e.g., Hungary). For an overview of these firm-level agreements, see also [Boon von Ochsee 2009b].

For Gazprom, another driver may be the need to maintain its options in its supply position, given its possibly tight supply balance in the mid-term [De Jong et al. 2010]. Even though it should be noted that recently domestic demand has fallen markedly.
The first business model of long-term contracts backed by governments fits into Russia’s perception of the central role of the state in general, and the government in particular, in energy-related and strategic matters important to the national interest. In a broader sense, this approach also fits into Russia’s perception of the importance of gas as a source of relative advantage, see Chapter 3.

Since this case study is about the interaction between pipeline gas and LNG flows, horizontal energy diplomacy in the case of Nord Stream is relevant insofar as Russia is expanding ties with fellow gas-exporting LNG countries. Russia pursues greater ties with these countries on both a bilateral basis and through the GECF (also see Chapter 10).

Currently the Nord Stream is privately funded, and officially it has not applied for any public funding. In line with Case study 2, the Nord Stream may be financed by means of a warehouse construction (also see the conceptual toolbox in Chapter 8), where the repayments of the loans of the greenfields are based on gas contracts between European mid-streamers and Gazprom. Such a construction facilitates access to a guaranteed income stream and therefore higher credit rating for the project, and therefore less expensive loans as a result of higher credit ratings. The business model of flexible supplies is exposed by relative higher financial risks.

9.4.6 Application of the model to the Nord Stream case

Similar to the South Stream case, the real-option game model can also be applied to the Nord Stream case. The goal is the same as in the previous two cases. Nord Stream is a project which is still under construction, whose effects, at the time of this writing, still lie far into the future, which is in line with the South Stream case (i.e., it is an ex ante analysis). In this particular case, entry is assumed to take place in the form of LNG. To the greatest degree possible, the assumptions below are designed to approximate real world figures and numbers in the context of specific market circumstances and gas infrastructure investments.

9.4.6.1 Assumptions and parameter values

Operational assumptions:

a. We assume the NWE gas markets collectively consists of a duopoly, with Gazprom on the one hand and a potential competitor on the other, with the latter acting as a potential entrant for new market demand with an 8 bcm/y pipeline, both on a distance of 2,137 km to the off-take market (offshore section: 2,220 km; onshore section: 917 km). An LNG supplier is assumed to act as a potential entrant. For simplicity, the operating unit costs for LNG entry are assumed similar to that of an 8 bcm/y pipeline.
b. Gazprom faces the choice in 2009 (i.e., stage I) of committing to building or deferring the
construction of the Nord Stream pipeline across the Baltic Sea to Germany onwards in
the face of potential entry by a competitor (see Figure 8.9 in Chapter 8).

Parameter value assumptions:

a. Average operating gas transport costs in the base case: In the base case, both players are
assumed to make commercial investments only, i.e., constructing small-diameter pipelines
with a capacity of 8 bcm/y. In this case it means both players do not undertake early stra-
tegic commitment to the market, meaning the operational unit costs remain
at $72.4 mln/bcm. At this point, neither player yet benefits from econo-
 mies of scale. The competitor is assumed to have unit costs associated with a typical 8-10
bcm/y LNG train (e.g., such as those operated by the RasGas and Qatargas ventures in
Qatar), the operating unit cost of which is comparable to some pipeline gas sources in the
NWE market (assuming full utilisation of facilities, of course).

b. Average operating gas transport costs in the proprietary case: The construction of the
Nord Stream is a proprietary investment. Gazprom de creases its average operational unit
costs from $72.4/mcm to $18/mcm as the pipeline has greater economies of scale (from 8
bcm/y in the base case to 55 bcm/y in the proprietary case). This represents the move
away from the base case and towards the proprietary case. The competitor is assumed to
use an 8 bcm/y commercial pipeline capacity at the same distance (i.e., it does not invest
strategically) resulting in similar operating unit costs as an LNG chain (from liquefaction
to re-gasification, see above).

c. First-stage strategic pipeline investment (K): The initial cost of building the Nord
Stream, K (totalling $14 bln), is defined as the difference between the CAPEX for Nord
Stream minus the ‘theoretical’ CAPEX for a 8 bcm/y commercial investment covering the
same distance, I (totalling $6 billion).

d. Follow-up investment outlay by either Gazprom or the competitor (I): Follow-up in-
vestment outlay, made after stage I and thus after the incumbent’s strategic investment,
corresponds with a base case commercial 8 bcm/y pipeline investment covering the
same distance ($6 billion).

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494 See the conceptual discussion held in the toolbox in Chapter 8.
495 LNG from Qatar, for example, possesses roughly the same unit costs as pipeline gas from the UK and Norway according
to expert interviews. In reality LNG is more flexible and price-sensitive between regional gas markets rather than produced
and sold on the basis of quantity alone, see Chapter 8.
496 In order to calculate the ‘theoretical’ CAPEX as well as the average breakeven operating costs per unit, account is taken of
inflation, the WACC (k), the risk-free rate (r), fuel and compression costs, etc. (see Chapter 8). In this case, the real value is
used for the offshore pipeline section, excluding the CAPEX for the compression. The ‘theoretical’ value of the CAPEX is
used for the Russian onshore pipeline section to connect on the Russia’s UGTS (see Chapter 8 for a definition of theoretical
versus actual values of the different projects). The base case ‘theoretical’ pipeline CAPEX calculation is also based on 2009
input data, obtained from privately disclosed company sources. The inflation is assumed at 2.8 percent (based on the first
half year of 2009), according to Eurostat data for the Euro area.
e. **Initial demand parameter** \( (\theta_0) \): For simplicity, initial gas market demand in the NWE gas market is assumed to be 95.83 bcm \( (\theta_0 = 95.83) \) at \( t_o \) as detailed in the conceptual description in Chapter 8.

f. **Binomial up or down demand parameters** \( (u \text{ and } d) \): In the model, demand is assumed to be stochastic, moving up or down with binomial parameters \( u = 1.84 \) and \( d = 0.54 \), both at the beginning of periods 1 and 2 in stage II. Starting at \( t_1 \), there is a 'steady state' of 25 years, i.e., no more upward and downward moves, as detailed in Section 8.4.5.

g. **The risk-free interest rate**: The risk-free discount rate is assumed to be 3.4 percent \( (r = 0.034) \).\(^{497}\)

h. **The risk-adjusted discount rate**: The rate at which profits in the last stage are to be discounted by, i.e., the risk-adjusted discount rate, is set at 8.5 percent \( (k = 0.085) \).\(^{498}\) The project’s cash flows are discounted over a period of 25 years, acting as an annuity.

i. **Risk-neutral probabilities**: Given \( u, d, k \) and \( r \), it can be determined that \( p = 0.32 \) and \( 1-p = 0.68 \).

Figure 9.26 is an overview of the various payoffs to Gazprom and the competitor in a decision tree, which is a direct application of Figure 8.9 in Chapter 8. Each node corresponds with an up- or downward move in demand and the resulting decisions of Gazprom (denoted in Figure 9.26 and elsewhere by the letter G) and the competitor (or potential entrant, denoted in Figure 9.26 and elsewhere by the letter E), respectively, to invest or defer (further) commercial investments \( \{G_I,D\} \) and \( \{E_I,D\} \) in stage II while in stage I only Gazprom is assumed to invest as an incumbent. The highlighted (red) branches along the tree indicate the optimal actions along the equilibrium path.

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\(^{497}\) The risk free rate is based on the yield-to-maturity in October 1999 of a 10-year Euro-denominated (or the equivalent thereof) German government bond [Tradingeconomics.com 2009].

\(^{498}\) The WACC is based on information provided in expert interviews, where a WACC of between 8 and 9 percent was proposed as being appropriate.
Just as in Case study 1, for period 2 in stage II, we take the case in which demand has moved upward in period 1 (i.e., branch u), and do not elaborate here on either the case in which demand falls or the base case. Notice that Figure 9.26 will be approached through backward induction, i.e., bottom-up.

9.4.6.2 Model application and backward induction

### a. Stage II, Period 2

The upward and downward movements in demand in the leftmost branch of the tree (see Figure 9.26) and corresponding decisions to invest in follow-up capacity by Gazprom and the
competitor (after a strategic investment has been made by Gazprom) yield the following dominant routes based on the state-contingent project values:

• Sub-game 1: For Gazprom: 167, 16; for the competitor: 7, 0.
• Sub-game 2: For Gazprom: 104, 10; for the competitor: 50, 0.
• Sub-game 3: For Gazprom: 142; for the competitor: 39.
• Sub-game 4: For Gazprom: 10; for the competitor: 0.

b. Stage II, Period 1

The values listed above are fed back into period 1, on the basis of which Gazprom invests commercially, while the competitor defers. In Game 1, the competitor is unable to obtain its highest possible payoff in period 1 of stage II, i.e., 2, given Gazprom investment in this period for a payoff of 61. In Game 2, rather both investing, both players opt for a deferral in order to avoid a duopoly outcome in period 1 in which both would be worse off than under a deferral. Gazprom obtains -0.7 rather than -0.6 and the competitor obtains 0. As Smit and Trigeorgis [2004] argue, Gazprom may also prefer to remain unpredictable. A similar result was obtained at this stage in Case study 2.

c. Backward induction of period 1 (stage II), to stage I

Finally, the period 1 payoffs for Gazprom help determine, again via a next step of backward induction, whether the strategic investment is worth making net of its initial capital investment, $K_c$, the amount invested in excess of a base case pipeline of 8 bcm/y. The stage I payoff for Gazprom is 61 while for the competitor it is 6. When the strategic investment is subtracted as well (i.e., the amount obtained from total CAPEX – I) the overall NPV (NPV$^*$) for Gazprom of building Nord Stream is 4, which is lower than the value under the base case (i.e., $4 billion for the proprietary case is lower than $6 billion for the base case). The model’s application to the Nord Stream case conveys an overall NPV for Nord Stream that is lower than the base case NPV. This result suggests that it is better to postpone the strategic investment.

d. The various value sub-components

The model’s application to Nord Stream yields value components in the same manner as in the Blue and South Stream cases, using formula 8.5. The game is initiated at an initial demand level of 95.83 bcm, and with the binomial parameters $u = 1.84$ and $d = 0.54$ determine a number of different demand levels result as in the previous two cases. For simplicity, the following numerical explanation is based exclusively on the model’s results in the last row in panel B, Table 9.3, specifically the case in which demand has risen twice to

See Figure 9.15 for dominant routes in the rightmost branch of the tree.
324 (i.e., \( \theta_u \times \theta_u \times \theta_u \)). Here, Gazprom ends up as dominant leader firm (S-L), supplying 180 bcm/y via its existing infrastructure and the Nord Stream pipeline with a profit of 16. At this level of demand, and given the cost functions as a result of the proprietary investment, Gazprom has effectively been able to ensure its position as a dominant firm, the competitor compelled to follow with 36 bcm/y (S-F).

Table 9.3 Second-stage equilibrium state project values and strategic effects for different market structures and states of demand for the base and proprietary pipeline investment case

<table>
<thead>
<tr>
<th>Demand</th>
<th>Market Structure (Static)</th>
<th>Profit ( \pi^e )</th>
<th>NPV ( \pi^* )</th>
<th>Postponement value</th>
<th>Base Case NPV ( \pi^* )</th>
</tr>
</thead>
<tbody>
<tr>
<td>28</td>
<td>Cournot Nash</td>
<td>0</td>
<td>0.06</td>
<td>0</td>
<td>6.0</td>
</tr>
<tr>
<td>52</td>
<td>Cournot Nash</td>
<td>0</td>
<td>0.06</td>
<td>0</td>
<td>0.0</td>
</tr>
<tr>
<td>96</td>
<td>Cournot Nash</td>
<td>8</td>
<td>0.06</td>
<td>0</td>
<td>5.0</td>
</tr>
<tr>
<td>176</td>
<td>Cournot Nash</td>
<td>35</td>
<td>1</td>
<td>6</td>
<td>20.0</td>
</tr>
<tr>
<td>324</td>
<td>Cournot Nash</td>
<td>54</td>
<td>7</td>
<td>0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Demand</th>
<th>Market Structure (Dynamic)</th>
<th>Quantity ( Q^e )</th>
<th>Profit ( \pi^e )</th>
<th>Direct value</th>
<th>Strategic Reaction value</th>
<th>Pre-emption value</th>
<th>Commitment value</th>
<th>Postponement value</th>
<th>Base Case NPV ( \pi^* )</th>
</tr>
</thead>
<tbody>
<tr>
<td>28</td>
<td>Monopoly</td>
<td>5</td>
<td>0.03</td>
<td>0.3</td>
<td>0</td>
<td>6.0</td>
<td>6.0</td>
<td>6.0</td>
<td>6.0</td>
</tr>
<tr>
<td>52</td>
<td>Defer</td>
<td>0</td>
<td>0</td>
<td>3</td>
<td>0</td>
<td>2.5</td>
<td>0.0</td>
<td>-0.7</td>
<td>-0.7</td>
</tr>
<tr>
<td>96</td>
<td>Monopoly</td>
<td>39</td>
<td>2</td>
<td>12</td>
<td>3</td>
<td>6</td>
<td>21</td>
<td>16</td>
<td>16.0</td>
</tr>
<tr>
<td>176</td>
<td>Monopoly/Stackelberg</td>
<td>79</td>
<td>6</td>
<td>27</td>
<td>12</td>
<td>16</td>
<td>55</td>
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<td>Stackelberg</td>
<td>180</td>
<td>16</td>
<td>54</td>
<td>21</td>
<td>24</td>
<td>100</td>
<td>0</td>
<td>167.0</td>
</tr>
</tbody>
</table>

* Additional 6 bln$ to postponement value because of additional investment (I) in order to realise total project’s CAPEX.

Note: Totals may not add up due to rounding. Monetary amounts are in billion$.

Source: Own analysis.

The proprietary case must be compared with the base case (i.e., panel A with panel B of Table 9.3) in order to determine the difference between making the strategic investment commitment and remaining at the original level unit costs, i.e., not building Nord Stream and sticking to an 8 bcm/y pipeline. In the base case, at the same level of demand, the NPV is 66 for both Gazprom and its competitor with each supplying 84 bcm/y via its existing and new infrastructure. In the proprietary case, Gazprom goes ahead with the strategic investment, creating a shift, which cannot occur when neither firm invests in additional economies of scale, remaining at the original operating unit costs \( c_G = c_E = $72.4 \text{mln/bcm} \).

The direct and strategic value

The net commitment values are shown in Table 9.3: The direct value of Nord Stream for Gazprom, attained due to the benefits of economies of scale alone is 54. The additional value
of undermining the profitability of the potential entrant’s investments is 21, i.e., the strategic reaction value, while the value of then altering the structure of the market altogether, the pre-emption value of Nord Stream, is 24. This last value is the value attained by shifting from a model outcome involving duopoly (C) to one where Gazprom ends as a leader (S-F).

**The postponement and net commitment values**
The strategic reaction value and the pre-emption values together determine the strategic value. The net commitment value, which is computed by adding the direct to the strategic value, is therefore 100 (=54+21+24). In this case the postponement value is zero, because in the base case scenario the NPV is also positive as a result of strong upward demand potential.

**The overall Net Project value**
Finally NPV\(_G\) of Nord Stream for Gazprom is the NPV in the base case (66), added to the net commitment value (100) and the postponement value (0), which is 167 in total.\(^{301}\) Note that this is not the overall Net Project value of Nord Stream to Gazprom.

### 9.4.6.3 Sensitivity analysis
Pursuant to the approach used in Case studies 1 and 2, the most significant and remarkable results are mentioned below for Nord Stream pipeline.

1) Overall Net Project Value versus sensitivity to changes in upside market demand potential
As in the previous case studies, the change in value of the upward demand potential parameter \(u\), varying in the sensitivity analysis between values of 1.01 and 2, is positively related to NPV\(_G^*\). In the base case of no pipeline with larger capacity (i.e., lower economies of scale), the project value increases monotonically (see the top part of Figure 9.27) with upward market demand potential, as expected from option theory. Considering the positive relationship between overall Net Project Value and upward demand potential, the graph (lower the part of Figure 9.27) exhibits a remarkable discontinuity. This ‘negative jump’ can be explained from the strategic competitive interaction in Gazprom’s market. Gazprom is in a monopolist (M) zone due to its proprietary investment. That is, it enjoys being a monopolist until upward market demand potential reaches a value of 1.65, demand increases sufficiently for an entrant to enter the market, which is when the model outcome shifts from monopolist (M) to a model outcome involving Gazprom as a leader (S-L).

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\(^{301}\) The postponement value is a negative number in case the static NPV is below zero for the base case, added, when applicable, by the option value when deferring a commercial investment (I) in period 1 in stage II.
For the Nord Stream, the overall NPV is negative below the upward demand potential of \( u = 1.45 \). This means initial market demand must swing upwards by 40 percent per period in order for Nord Stream to be worthy of a strategic investment. Only between \( u = 1.45 \) and 1.65 the proprietary overall NPV exceeds the base case NPV before crashing down. Afterwards, it rises gradually, but well below the value and rate of increase of the base case NPV. An important difference between this case and South Stream is that market demand potential in the NWE market, though high (\( u = 1.48 \)), is less promising than demand potential in the SSEE market (\( u = 1.84 \)). When we consider and compare the information included on demand potential in Case study 2 with that included here for Case study 3, initial demand yet to be ‘covered’ for South Stream is greater than is the case for Nord Stream. In the interval roughly of \( (1.45 < u < 1.68) \), the proprietary Nord Stream case NPV is greater than the base case NPV.

**Figure 9.27** Overall Net Project Value as function of upward market demand potential, \( u \) (with \( d \) fixed at 0.55)

2) **Overall Net Project Value versus sensitivity to changes in the WACC**

Refer to Figure 9.28 below, which shows the sensitivity of NPV\(_c^*\) to changes in the risk-adjusted discount rate \( k \) (i.e., the WACC). From the rise in the slope of the curve, it can be derived that the NPV\(_c^*\) rises substantially with a small decrease in \( k \), both in the base and proprietary cases. This result is logical, because future cash flows are discounted at lower rates (i.e.,
a higher present value), with the \( \text{NPV}_c \) rising most rapidly in the interval \((0 < k < 7)\). In the proprietary case, therefore, the critical value of \( k \) to invest strategically is around 7 percent. In the base cases \( \text{NPV}_c \) rises less steeply, though faster than it does in the corresponding graph for South Stream. This sensitivity analysis shows that when Gazprom accepts a lower WACC, the strategic value component values rise in the overall Net Project value. In the proprietary case, \( \text{NPV}_c \) experiences a jolt at \( k \approx 21 \) percent. This small jump in the curve is related to the change in market outcome as result of the competitor’s entry, as a result of an increase in the WACC for both players.

The main difference between Nord and South Stream is that upward market demand potential is lower in the former case. A much lower WACC is required for the Nord Stream in order for it to be attractive from a strategic point of view.

**Figure 9.28** Overall Net Project Value as function of the WACC

3) Overall Net Project Value versus sensitivity to changes in unit operating costs

Refer to Figure 9.29, which shows the sensitivity of \( \text{NPV}^*_c \) to changes in OPEX \((c)\). Also similar to the South Stream case is the relationship between a fall in operating unit costs and overall NPV. Lower unit operating costs have an overall strategic impact on potential competition. Yet only at $14.48/mcm and below does Nord Stream’s overall NPV exceed the base case NPV (at a level of $6,200 billion). South Stream, by contrast, becomes more attractive than its
own base case version at a level of $40.18/mcm. The small jump in the curve is related to the change in market outcome from monopolist (M) to leadership (S-L) after $75/mcm for Gazprom.

Figure 9.29 Overall Net Project Value as function of unit operating costs, \( c \)

### Market outcome scenarios

The market outcome scenarios are reviewed at an aggregate European level in Chapter 10. At a sub-regional level Gazprom can end up as a quasi-monopolist, a dominant or a non-dominant firm as a result of its investment behaviour, or vice versa (also see Chapter 8). At a sub-regional level, in the case of the NWE region, can end up in a more dominant position at a sub-regional level in SSEE. Gazprom would have to invest more heavily than in scenarios where it ends up as a non-dominant firm. Investing in brownfield rather in greenfield projects may enable Gazprom to take a more passive role and become a less-than-dominant firm. At the country or sub-regional level, Gazprom is not as likely to end up even as a quasi-monopolist in the NWE market. In this specific sub-region, the NWE market, Gazprom faces greater potential LNG flows and entry than in SSEE markets.
9.4.8 Reflecting on the application of the model and the conceptual toolbox

Model results: Discussion

The model’s application for Nord Stream demonstrates that LNG can act as a powerful competitor in the NWE market (and other regional markets in general, for that matter) when it achieves unit costs similar to a base case pipeline of 8 bcm/y. Of course, this may lead one to think Case study 3 is essentially a pipeline-to-pipeline competition game (as in Case study 2). However, the relationship between the various sources and in what form gas is supplied is based here on unit cost, so that it becomes irrelevant whether gas arrives in the form of LNG or pipeline gas, in volume terms. LNG has an interregional dimension that pertains to pricing rather than quantity or volume (see Chapter 10 for a discussion on pricing in this regard).

The main model’s main result is that Nord Stream’s overall NPV (some $4.3 billion, under the proprietary case) is less than the base case NPV ($6.3 billion). The sensitivity analysis shows that with a substantial upward potential in market demand, Nord Stream becomes more profitable in overall NPV terms. In addition, the acceptance of a lower WACC by Gazprom vastly aids in facilitating a strategic investment and improves its overall NPV at a steep rate. In such a case, Gazprom sees gas pipeline transport as an option to ensure its position on the commodity market. Even as far as unit costs are concerned, the base case has more favourable chances at success than the Nord Stream does up to unit operating cost level of some $20/mcm, below which Nord Stream becomes attractive vis-à-vis the base case.

It is interesting to note that Nord Stream appears to enjoy some of the same benefits as South Stream does, primarily in terms of economies of scale and the size of the initial market demand. Yet despite a surge in market demand due to the upward potential of \( u = 1.84 \), Nord Stream remains less attractive than the base case in an important set of intervals (see figures above). Nord Stream’s overall NPV, for example, exceeds that of the base case only when demand rises by 1.45 upwards to roughly 1.68, as the base case maintains its value and as the model outcome changes from monopoly (M) to leadership (S-F). The base case pipeline for the Nord Stream case remains as attractive as the proprietary case at around 7 percent. Nevertheless, the impact on the market’s overall structure (i.e., the model outcomes discussed), may imply considerable value of the Nord Stream project.

The novelty of an increasingly interregional gas market is that large volumes of gas, which could previously not be exported over long distances, are now within economic reach of the various regional gas markets and in sufficient quantities to support economies of scale. The choices Gazprom makes, particularly with regard to market uncertainty and the potential threat of entry on the part of LNG, are likely to affect the regional gas balance in NWE and therefore also in the Atlantic Basin (i.e., through interregional volumes). Competition does not necessarily manifest itself for Gazprom in the form purely of pipeline gas from potential competitors in the Caspian Sea region. Yet here only true giants reserve-holder such as Qatar or Iran able to sustain such large flows to regional gas markets. Gazprom may either compete with Qatar as an LNG entrant or it may cooperate with Qatar by postponing investment or jointly coordinating flows through a shared investment.
The conceptual toolbox: additional factors to take into consideration and scenarios

The conceptual toolbox also helps assess what other investment variables may be at play, such as regulatory risk, just as in the case of South Stream. The effect of EU regulations as far as TPA is concerned may make such a wait-and-see approach more attractive, even though for now, Nord Stream is not treated by TPA legislation of the EU. In order to ensure its market position in volume terms in the NWE market, Gazprom has already signed long-term contracts for 16.5 bcm/y, backed by vertical pipeline diplomacy. In addition, Gazprom has contracted 6 bcm/y of its own production via Gazprom M&T for short-term deals. The latter business model, see also Chapter 2 in Smeenk [2010], is driven more by a price-based strategy. As will be discussed in Chapter 6, Gazprom could decide to invest in additional Nord Stream capacity, partly on a commercial basis (e.g., additional supply contracts) and partly in a strategic manner in order to diversify transit country risk (mainly in Ukraine). This provides Gazprom with additional benefit of having an option to divert gas flows from existing and troublesome transit countries. In order to evaluate gas infrastructure investment decisions, a decision and/or policy-maker should consider the infrastructure’s commitment value vis-à-vis postponement value, in addition to its static value. However, it should also take into account ‘practical’ issues with respect to gas infrastructures, which is captured by the conceptual toolbox.

Pipeline gas flows versus LNG-driven gas flows

The flexible nature of the LNG value contrasts sharply with the rigidity of pipelines: the capacity of a re-gas terminal can be more flexibly used than a pipeline’s capacity because of the added benefits of interregional LNG arbitrage and the negligible costs of reserving capacity in a re-gas terminal (versus the sensitivity of maintaining free capacity in a pipeline). Exclusive ownership of re-gas terminals (such as the one owned by ExxonMobil and Qatar Petroleum, see above) in various markets acts as a strategic option on future growth in various markets at the same time (from an interregional perspective). This reflects the added value of LNG which pipelines only have intra-regionally (in the case of several pipelines serving as alternative routes to different parts of a regional market. Of course, LNG flows as such are also exposed to downside interregional price risks. In the end, the balance of demand and supply in the NWE market affects the interregional availability of LNG, particularly in the Atlantic Basin.

9.5 Case studies: conclusion

The case studies act as illustrations of how uncertain demand and the potential entry of a competitor can be taken into account by combining real-options with game-theoretic principles. For all intents and purposes, the application of the real-option game model has shown that value can be derived from an increase in economies of scale in transport capacity for long-distance gas pipelines, which can act as a deterrent against possible entry (if unit costs are indeed actually brought down, which depends on the utilisation of the pipeline). These gas pipe-
lines can be employed by Gazprom to protect and/or expand market share making early strategic investments. Regional gas market structures can thus be influenced by individual projects, which is inherent to an industry characterised by an oligopolistic market structure and a capital-intensive value chain.

Such strategic reasoning attributes to the Blue Stream, the South Stream and Nord Stream pipelines, as we have argued in the case studies, a strategic value beyond merely commercial elements involved. As a result, we argue that pipelines (and other such gas transport infrastructures and value chains) can serve as tools to ensure Gazprom’s position as ‘market maker’. Via the application of the real-option game model, we contribute the notion that such infrastructural investments are never isolated phenomena; they may fit into a broader, regional or extra-regional strategic agenda that is not simply about short-term profit-maximising behaviour. Simultaneously, the application and use of the real-option game model highlights the importance of a wait-and-see approach, i.e., a postponement strategy where large lumpy investments are mothballed until they may appear to be necessary to compete with others after all.

From the model’s perspective, the Blue Stream emerges as a failure both from a commercial as well as an economic-strategic point of view. Greater economies of scale, combined with a greater initial demand, may have made the project more successful from the outset. Yet South Stream is accorded a positive overall NPV, owing partially to larger economies of scale and greater upward demand potential. Despite high economies of scale, the Nord Stream, by contrast, is accorded an overall NPV inferior to its base case NPV. Lower upward demand potential is an important factor in Nord Stream’s overall Net Project value. The Nord Stream is important in that, conceptually, it takes into account LNG entry. Though LNG is assumed to correspond with an 8 bcm/y pipeline for reasons of simplicity, LNG entry in Case study 3 is less about a volume-oriented approach but rather about a price-oriented one. In the South and Nord Stream cases, the acceptance on the part of the investor of a lower return on investment vastly contributes to facilitating a strategic investment and improves its overall NPV at a steep rate. The sensitivity analyses with regard to the different input variables demonstrate that there is no single answer and highlight the importance of investigating changes in the value of overall NPV vis-à-vis input variables. In principle, the greater the probability of downside demand, the greater the value of postponing strategic investment. The case studies convey this point from a conceptual and a model perspective.

It should be emphasised again that the model is clearly a gross and crudely fashioned simplification of real world developments. The model can explain some of the strategic aspects of why Gazprom has constructed and may still construct various pipelines. These pipelines potentially serve as deterrents, which can alter market structures within regional gas markets, particularly
in Europe. The case studies explain the nature and potential results of competition in regional and sub-regional gas markets and helps us to better comprehend the dynamics involved. However, the model cannot account for the interaction amongst more than two suppliers, where the gas industry is invariably characterised by more than two suppliers in any given market.

Other model assumptions, which remove it further from real world gas industry considerations, include the restriction to optimisation of quantities, whereas pricing plays an equally important role. The model also considers competition at a sub-regional and regional level whereas an interregional dimension is left out. Other issues such as taxes are also excluded. At the project level, the model cannot account for factors such as the financial and organisational feasibility. Another important omission in the model is inherent in the two-stage nature of competition between gas suppliers: while the model consists of only two stages, real world developments are often indefinite. Alternative fuels, such as nuclear energy, for example, may or may not become more attractive than gas as a function of political or economic preferences, especially when one player has a real dominant role in the gas market. This can adversely impact the potential of gas in wider energy markets. A politically determined course, which seeks to exclude Russian gas, poses a serious risk to capturing additional gas market share for Gazprom, as do regulatory barriers and permit risks (e.g., TPA, antitrust regulation). On that note, the general investment climate also plays an important role in the various regional and sub-regional gas markets.

Vertical energy diplomacy helps Gazprom ensure, at a government level, to secure access to possible gas market demand growth and to minimise the likelihood of downward demand moves as prescribed in the model. European mid-streamers and off-takers play an important role in this regard, being the actors, at a firm level, that purchase Russian gas and have substantially interests in the value chain such as vertical swaps. Moreover, signing long-term contracts with European buyers enables Gazprom to ensure its market position in volume terms in the European market. Such a strategy is most likely in (near-)mature markets. Alternatively, Gazprom may reserve (additional) capacity for short-term deals, contracting its own production through wholly owned subsidiaries such as Gazprom M&T, for example. As a business model, the latter is driven more by a price-based strategy and used to be applied growth markets. Gazprom also shares pipeline investments and other components of the value chain with regional European gas-exporting countries (particularly in North Africa), using government-level instruments, which pertains to horizontal energy diplomacy.

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[89] In contrast, the model ascribes a substantial value in the event that a player becomes dominant or a monopolist. From a practical point of view, such outcomes also have their drawbacks, resulting in lower corresponding values and other practical difficulties (e.g., by competition authorities and the pressure of substitutes).
Geo-economic and geopolitical factors are also forces which the stylised model cannot account for and which can underpin strategic investments. The toolbox in Chapter 8, and the conceptual discussions in the case studies themselves, is an effort to account for these factors conceptually. Some of the factors the model leaves out may incline Gazprom towards making strategic investments. The individual games depicted by the case studies each lead to various sub-regional gas balances and market outcomes, such as quasi-monopoly, dominant and non-dominant outcomes. As will be shown in Chapter 11, geopolitical forces may incline Gazprom towards a more aggressive investment strategy. An aggregate European level, these outcomes feed back into investment decisions, and ultimately have an important impact on the merit order, as will be discussed in Chapter 10 in Smeenk [2010]. In order to achieve the various outcomes, various levels of investment (both up- and mid-stream) can be made, depending on the outcome in question.