CHAPTER 3

RUSSIAN RESPONSES TO COMMERCIAL CHANGE IN EUROPEAN GAS MARKETS

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In volume terms, Russian gas sales to European customers reached their highest-ever level in 2005–8 (annual average of 168.4 Bcm). In 2009–12 they fell back significantly (to an annual average of 155.5 Bcm). A key cause of the change was the economic recession and its impact on European energy demand, but other factors were at work, including changes in the structure of European energy markets, and Gazprom's reaction to pricing trends. We have divided the discussion of Russian exports to Europe into two chapters: this chapter deals primarily with the commercial and logistical aspects of Russian exports and Chapter 4 deals mainly with the regulatory, political, and security issues. The conclusions relating to both chapters can be found at the end of Chapter 4.

Russian gas exports to Europe since the mid-2000s

The Soviet Union, and from 1992 the Russian Federation, have been exporting gas to the eastern part of Europe since the Second World War, and to the western part since 1967. However, in contrast to the near-constant growth of Russian gas exports to Europe up to the early 2000s, volumes peaked in 2007–8 and declined thereafter, returning to near peak levels only in 2013.[6] Table 3.1 shows Gazprom's exports to 25 European countries since 2005. These sales are of considerable financial importance to Gazprom, comprising just over half of the company's revenues over the past decade, although only 27–31 per cent of its sales by volume.[7]

An important statistical anomaly in Table 3.1 is that the 'Grand Total' is the volume that Gazprom delivers to European customers, which is not the same as volumes of gas delivered under long-term contracts to those customers (which we believe to be the gas that physically leaves Russia).

[6] Previous OIES publications (Stern, J.P., *The Future of Russian Gas and Gazprom* (Oxford: OIES/OUP, 2005), Chapter 3) focused on exports to Europe in the 1990s and early 2000s.)

[7] Figures are for 2002–3 and 2011–12, revenue figures are net of all taxes, ibid. Table 3.4, p.128; Management Report OAO Gazprom (2012), p. 35.

Table 3.1: Gazprom's exports to Europe, 2005–13 (Bcm)*

	2005	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013***
Austria	6.8	6.6	5.4	5.8	5.4	5.6	5.4	5.4	5.2
Belgium	2	3.2	4.3	3.4	0.5	0.5	0	0	0
Estonia	1.3	0.7	0.9	0.6	0.8	0.4	0.7	0.6	0.7
Finland	4.5	4.9	4.7	4.8	4.4	4.8	4.2	3.7	3.6
France	13.2	10	10.1	10.4	8.9	8.3	8.5	8.2	8.2
Germany	36	34.4	34.5	37.9	33.5	35.3	34.1	34	40.2
Greece	2.4	2.7	3.1	2.8	2.1	2.1	2.9	2.5	2.6
Italy	22	22.1	22	22.4	19.1	13.1	17.1	15.1	25.3
Latvia	1.4	1.4	1	0.7	1.1	0.7	1.2	1.1	1.1
Lithuania	2.8	2.8	3.4	2.8	2.5	2.8	3.2	3.1	2.7
Netherlands	4.1	4.7	5.5	5.3	4.3	4.3	4.5	2.9	2.1
Switzerland	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.4
Turkey	18	19.9	23.4	23.8	20	18	26	27	26.6
UK	3.8	8.7	15.2	7.7	11.9	10.7	12.9	11.7	12.5
Sub-Total	**118.7**	**122.5**	**133.9**	**128.7**	**114.8**	**106.9**	**121**	**115.6**	**131.7**
Bosnia and Herzegovina	0.4	0.4	0.3	0.3	0.2	0.2	0.3	0.3	0.2
Bulgaria	2.6	2.7	2.8	2.9	2.2	2.3	2.5	2.5	2.8
Croatia	1.2	1.1	1.1	1.2	1.1	1.1	0	0	0
Czech Republic	7.4	7.4	7.2	7.9	7	9	8.2	8.3	7.3
Hungary	9	8.8	7.5	8.9	7.6	6.9	6.3	5.3	6
Macedonia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.04
Poland	7	7.7	7	7.9	9	11.8	10.3	13.1	9.8
Romania	5	5.5	4.5	4.2	2.5	2.6	3.2	2.5	1.2
Serbia	2	2.1	2.1	2.2	1.7	2.1	2.1	1.9	1.2
Slovakia	7.5	7	6.2	6.2	5.4	5.8	5.9	4.3	5.4
Slovenia	0.7	0.7	0.6	0.6	0.5	0.5	0.5	0.5	0.5
Other countries	0	0.4	0.5	0.6	1.2	2.1	1.3	1.4	n/a
Sub-Total	**42.9**	**43.9**	**39.9**	**43**	**38.5**	**44.5**	**40.7**	**40.2**	**34.4**
Grand Total	**161.6**	**166.4**	**173.8**	**171.7**	**153.3**	**151.4**	**161.7**	**155.8**	**177.1**
Deliveries under long-term contracts			158.8	168.5	142.8	138.6	150.3	139.9	166.1

* These data differ from those provided in the original source because they show exports to the Baltic countries as 'European' exports whereas Gazprom counts them as 'exports to former Soviet Union (FSU) countries'.

** 2013 data are preliminary and are not consistent with previous years.

Sources: *Gazprom in Figures 2005–9*, p. 56; *Gazprom in Figures 2008–12*, p. 63; 'UK, Italy, Germany had biggest Russian gas import growth in 2013; Turkey led in H2', *Interfax Russian Oil and Gas Weekly*, 16–22 January 2014, p. 46..

The difference is the volume which Gazprom sources from elsewhere, by means of swaps and trading. For example, most of Gazprom's exports to the UK are in fact gas sourced from elsewhere.[8] This is not necessarily because the company does not have sufficient physical gas available – although during very cold winter periods this may be the case (see Chapter 4) – but because transportation distances and constraints within Europe mean that it is cheaper and easier to source gas from elsewhere.

While there is no completely consistent pattern in volume exports to individual countries, the trend is a general increase up to 2008 followed by a decline thereafter. By the early 2010s, Russian exports were significantly below the levels seen in the 2005–8 period. To some extent the data is misleading due to lack of temperature correction, which can account for substantial year-to-year differences, but the trend is clear: of 26 European countries importing Russian gas in the period 2005–12, two (Belgium and Croatia) have ceased imports entirely, 19 have reduced their imports during this period, and only five (Greece, Turkey, Poland, Czech Republic, and the UK) are importing larger volumes. In 2013 exports reached their highest levels since 2008 of around 166 Bcm partly due to a protracted spell of unusually cold weather in the early spring, and partly connected with price reductions discussed below.[9]

Figure 3.1 shows the profile of major Russian long-term export contracts to Europe up to expiry in 2035.[10] Contracted volumes peak during 2012–14 at around 180 Bcm/year and then decline gradually to around 140 Bcm/year until the late 2020s when they drop off substantially.

The outlook for European gas demand and imports

In historical perspective, the year 2005 may be seen as the end of the 'golden age of gas' in Europe.[11] For around three decades from the mid-1970s

[8] The company's 2007 Annual Report (61) states that, 'In December 2007, Russian natural gas started being supplied to the UK market through the BBL gas pipeline'. It is highly unlikely that this gas is physically sourced from Siberia – although there is no way to be certain. One source suggests that out of 11.7 Bcm sold to the UK in 2012, 8.1 Bcm was Gazprom's gas and 3.6 Bcm was acquired from other companies (*Russian Energy Monthly*, July 2013, p. 22).

[9] The figure of 163 Bcm is a preliminary Gazprom figure and does not include sales to the Baltic states of 4–5 Bcm, 'On Key Preliminary Results 2013', www.gazprom.com/press/miller-journal/ 14 January 2013.

[10] They do not include the Baltic States, Romania, Bulgaria, and former Yugoslav republics to which Gazprom delivered 12.5–13.0 Bcm in 2012.

[11] The 'golden age of gas' is a phrase coined by the International Energy Agency America (IEA) (*World Energy Outlook 2011: Are We Entering a Golden Age of Gas?*, Paris: IEA/OECD) to denote the possibility of a much larger share of gas in global energy demand following the shale gas revolution in North America. But it is used here simply to refer to an era of rapid market expansion.

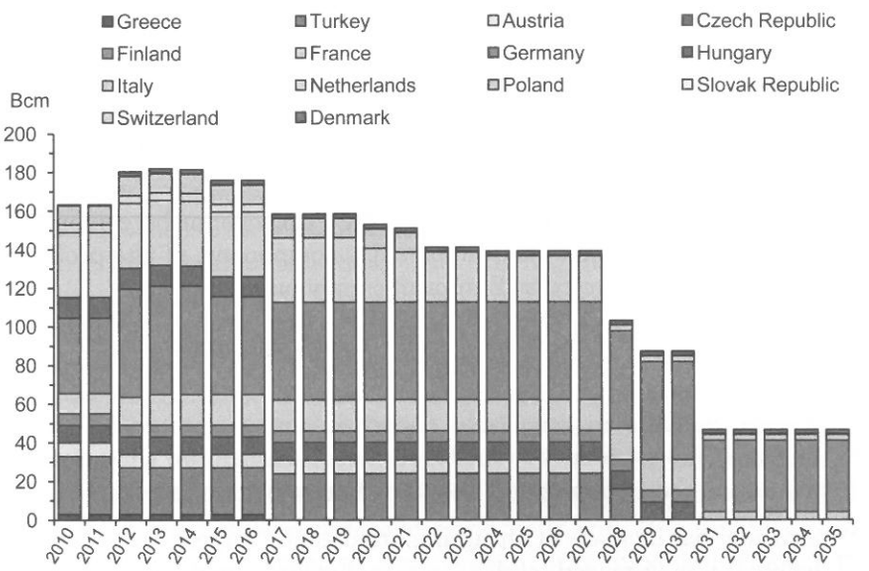


Figure 3.1: Russian long-term gas contracts with OECD European countries to 2035

Contracts with Baltic and some south-east European countries are not included.

Source: research by the Energy Research Institute of the Russian Academy of Sciences (ERI RAS) based on data from Cedigaz and Nexant.

to the mid-2000s, European gas demand increased steadily, as did imports of (former Soviet now) Russian gas. The reasons for this form an important part of European energy history: from the mid-1970s, gas progressively replaced oil products in the stationary energy balances of most countries, first in north-west Europe and then in central and southern Europe. In the major European markets, substitution of gas for oil products had largely been completed by the end of the 1990s.[12] Some sectors in individual countries (for example power generation in Poland and Germany which continued to favour coal), and some regions (notably the Balkans and south-east Europe where usage of oil products continued even in power generation), were resistant to this general trend.[13] During the 1990s and 2000s, power

[12] For a statistical analysis of these trends see the appendices to Stern, J.P., 'Is there a rationale for the continuing link to oil product prices in Continental European long-term gas contracts?', Working Paper NG19, OIES, 1 April, 2007, and Stern, J.P. 'Continental European long-term gas contracts: is a transition away from oil product-linked pricing inevitable and imminent?', Working Paper NG34, OIES, 1 September, 2009.

[13] For details of gas demand development in Europe up to the late 2000s see Honoré, A. *European Natural Gas Demand, Supply and Pricing: Cycles, Seasons and the Impact of LNG Price Arbitrage* (Oxford: OIES/OUP, 2010), Chapter 1.

generation in the form of combined cycle gas turbines (CCGTs) substantially increased gas demand, but by the middle of the decade, rates of growth had begun to slow. After 2005, demand plateaued and with the 2008 recession declined; by 2012 European gas demand had fallen to the level of 2002 – ten years of growth had been lost – and at mid-2013 this decline showed few signs of being reversed.[14]

The reasons for this decline are complex and cannot be explored in detail here.[15] There are at least four major components of the problems which gas has encountered in European energy balances:

- recession in Eurozone countries and slower than expected economic recovery;
- a huge increase in renewable energy in many countries – greatly facilitated by subsidies – in order to meet national and EU targets in relation to those sources and also to carbon reduction targets;
- a substantial increase in cheap imported coal – largely from the USA where it was displaced by shale gas production – made possible by the very low carbon prices produced by the EU Emissions Trading Scheme;
- high gas prices – especially for gas sold under long-term contracts with oil-linked prices – created by the post-2008 surge in oil prices to above $100/bbl.

These developments could be considered a short-term discontinuity caused by a coincidence of unusual events (recession, subsidized renewables, and cheap coal), or could be heralding the start of a secular decline of gas in European energy balances. An assessment of European gas supply and demand trends over the next decade is beyond the scope of this chapter; many different views and projections have been advanced.[16] For our purposes, the most important issue is the difference between European and OECD projections, and Gazprom's view of how European gas demand and the continent's need for Russian gas is likely to unfold over the next decade.

[14] In terms of temperature-corrected gas demand and excluding Turkey, which has been a rapidly growing market throughout the 2000s, the picture is even worse. *Natural Gas Information* (2012 Edition), Paris: IEA/OECD, Table 4, V8–9; *IEA Monthly Gas Survey*, January 2013, Paris: IEA/OECD, Table 1.1, 3.

[15] For more details see Honoré, A., 'Economic Recession and Natural Gas Demand in Europe: what happened in 2008–2010?', Working Paper NG47, OIES, 25 January, 2011 and Honoré, A. *The Outlook for Natural Gas Demand in Europe* (Oxford: OIES/OUP, 2014 forthcoming).

[16] For a range of estimates see *Sovremennie stsenarii razvitiia mirovoi energetiki: resultaty issledovanii 2009–12 gg*, Institut Energetiki i Finansov [Institute of Energy and Finance], 2012.

The most widely quoted scenarios of European gas demand are those of the International Energy Agency (IEA)'s World Energy Outlook (WEO). The 2012 edition of the WEO projected OECD European gas demand as falling from 569 Bcm in 2010 to 550 Bcm, before recovering to 585 Bcm in 2020.[17] The Agency's 2013 WEO, was substantially more pessimistic, with the corresponding demand scenario reaching just 537 Bcm in 2020 and not returning to the 2010 level until 2025.[18] Despite this, Gazprom management continued to be optimistic, with its CEO claiming that 'Europe needs more gas and … we are ready to supply as much as Europe wants'.[19]

However, even if these demand projections are directionally correct, this may not affect the volume of Russian gas which Europe will need to import. With declining European conventional gas production, and no significant unconventional gas production likely before 2020 (and perhaps substantially later), Europe will become increasingly dependent on imported supplies.[20] As far as pipeline gas is concerned, Norwegian supply has probably peaked and will plateau, but will not decline significantly until after 2020.[21] North African gas exports appear to have peaked, with Egyptian supplies in decline, and although transportation capacity exists (this could increase Algerian and Libyan exports), there is a lack of available gas due to delays in field development, rapidly rising domestic demand, and political turbulence.[22] A maximum of 10 Bcm of Southern Corridor gas from Azerbaijan will start to be delivered at the end of the 2010s (see Chapters 4

[17] New Policies Scenario, *World Energy Outlook 2012*, Paris: IEA/OECD, Table 4.2, p. 128. For details of compatibility between Russian and international gas data see Units and Conversions (page xvi).

[18] *World Energy Outlook 2013*, Paris: IEA/OECD, Table 3.2, p. 103.

[19] 'Role of pipeline gas in Europe to grow: LNG overestimated – Miller', *Interfax Russia & CIS Oil and Gas Weekly*, 30 May–5 June 2013, pp. 29–30.

[20] Despite huge publicity about the prospects for shale gas in Europe, no substantial research study from any source sees significant quantities of unconventional (including shale) gas being produced in Europe prior to 2020, and many do not believe this picture will change substantially even by 2030. See *World Energy Outlook 2013*, Figure 3.6, p. 118; *Unconventional Gas: Potential Energy Market Impacts in the European Union*, JRC Scientific and Policy Reports, European Commission Joint Research Centre, Luxembourg: European Union, 2012; Gény, F. 'Can Shale Gas be a Game-Changer for European Gas Markets?', Working Paper NG46, OIES, 1 December, 2010; BP Energy Outlook 2030, (London: BP, 2014), p. 55.

[21] We are treating Norway as an exporter to Europe rather than as an indigenous supplier. On its production outlook, see Johnsen, E. 'Norwegian gas update', paper presented at the FLAME Conference, Amsterdam, March 2013.

[22] This was the conclusion of Fattouh, B. and Stern, J.P. (eds.) *Natural Gas Markets in the Middle East and North Africa* (Oxford: OIES/OUP, 2011), Chapters 1–4, written before the 'Arab Spring' political turbulence which created considerably more uncertainty about future North African exports.

and 14). If any pipeline gas from the Eastern Mediterranean reaches Europe, the volumes and timeframe are likely to be similar.[23] This leaves Europe in the 2010s with two major sources of incremental gas – Russia, and LNG from a potentially large number of different regions, including North America. However, as we saw in the period after the Fukushima nuclear disaster in March 2011, and the progressive closure of Japanese nuclear power stations, LNG supplies apparently destined for Europe can very quickly disappear if demand and prices in Asia increase substantially.[24]

Changing European utility structures and competition

To explain why Gazprom's European export outlook has changed, it is necessary to say a few words about the changing European utility landscape at the beginning of the twenty-first century. The post-war organization of European gas industries was that, with rare exceptions such as Germany, each country had a dominant – usually state-owned – utility which controlled virtually the entire gas market. The commercial strategy of these utilities was to segment their customer base, depending on the ability of the customers to access alternative fuels (and hence the relative value of gas for each customer group), and to price differentially between (and sometimes within) classes of customer, confident that without access to alternative gas supply at transparent prices, their customer base was essentially captive.

The long-term gas contracts which the utilities signed with all major suppliers, domestic and foreign (such as Gazprom), reflected this relatively simple commercial model, but included sufficient flexibility to allow adaptation if and when market fundamentals changed. For the first several decades of European gas trade, they were largely successful in this task, greatly assisted by the fact that the dominant companies had a significant measure of control over market fundamentals, because they were mostly monopsony buyers and monopoly sellers to a customer base whose only alternative to buying their gas was to use a different fuel.

The dominant price mechanism in European long-term gas contracts was the netback market value principle, the origins of which can be traced back to the early 1960s.[25] According to this principle, the price paid by the

[23] Darbouche et al. 'East Mediterranean Gas: what kind of a game-changer?', Working Paper NG71, OIES, 19 December, 2012.

[24] In 2012, European LNG imports fell by 27% compared with 2011. Asian LNG imports rose by more than 9%, Japanese imports by 11%. 'The LNG Industry in 2012', Brussels: GIIGNL, 2013, p. 8.

[25] For details of this pricing structure and its historical importance in European gas markets see Stern, J.P. 'The Pricing of Gas in International Trade – An Historical Survey', in Stern, J.P. (ed.), *The Pricing of Internationally Traded Gas* (Oxford: OIES/OUP, pp. 40–84, 2012), especially pp.54–9.

gas company to the foreign or domestic gas producer, at the border or the beach, is negotiated on the basis of the weighted average value of the gas in competition with other fuels, adjusted to allow for transportation and storage costs from the beach or the border and any taxes on gas. In continental Europe the competitive fuels were largely oil products – gas oil and (heavy or light) fuel oil.

As gas expanded its market share, so the logic of the oil-linked price mechanism which had been established in long-term contracts began to disappear and, beginning in the 1990s, the pricing of internationally traded (and domestically produced) gas moved increasingly out of line with market fundamentals. However, this did not cause major problems because the commercial model of continental European gas utilities (described above) allowed them substantially to control national gas markets irrespective of these market fundamentals.[26]

But this control began to break down in the second half of the 2000s, when European energy regulation and competition law – sometimes reinforced, but often opposed, by national governments – created increasing momentum towards effective third-party access, ownership unbundling, and regulatory oversight. These developments, combined with the elimination of destination clauses (see below), completely transformed the regulatory and market context in which existing contracts were operating. Of fundamental importance were: the arrival of workable third-party access, and the emergence of hubs with transparent prices which could be readily accessed by any customer via the internet. By the end of the decade, most consumers in the largest EU gas markets increasingly had a credible choice of suppliers, and competition was spreading across north-west Europe under the twin influences of national regulators, and the network codes required by the EU Third Energy Package, which were aimed at liberalizing transportation across Europe and promoting the role of market hubs for price formation and trading.[27] (See Chapter 4.)

Other developments also had a significant impact on the long-term contracts of European gas utilities. The shale gas revolution collapsed North American gas prices from levels in excess of $10/MMBtu in 2008, to $2–4/MMBtu for most of the period since 2009.[28] In anticipation of gas shortages and high prices, nearly 200 Bcm of regasification capacity had

[26] For a definition and discussion of the economic and market fundamentals of gas pricing see *The Pricing of Internationally Traded Gas*, pp. 486–9.

[27] For a discussion on the evolution of European market hubs see Heather, P. 'Continental European Gas Hubs: are they fit for purpose?' Working Paper NG63, OIES, 14 June 2012.

[28] For details see Foss, M.M. 'Natural Gas Pricing in North America', in *The Pricing of Internationally Traded Gas*, 85–144.

been built in North America during the 2000s, with LNG supplies arranged to fill it. By 2009, those supplies were no longer needed in North America and large volumes of LNG became available for Europe. This exerted significant downward pressure on spot prices as oil prices began to march upwards beyond $100/bbl, while recession collapsed European (energy and) gas demand.

For European utilities this represented a 'perfect storm' of commercial problems: progressive loss of monopoly, surplus supply, falling demand, and sharply increasing long-term contract prices (because of the increase in oil prices). In 2009, European hub prices fell significantly, to levels as much as 50 per cent below oil-linked contract prices, and aside from short periods in particularly cold winters, have averaged 25–33 per cent below oil-linked prices since then (Figure 3.2).

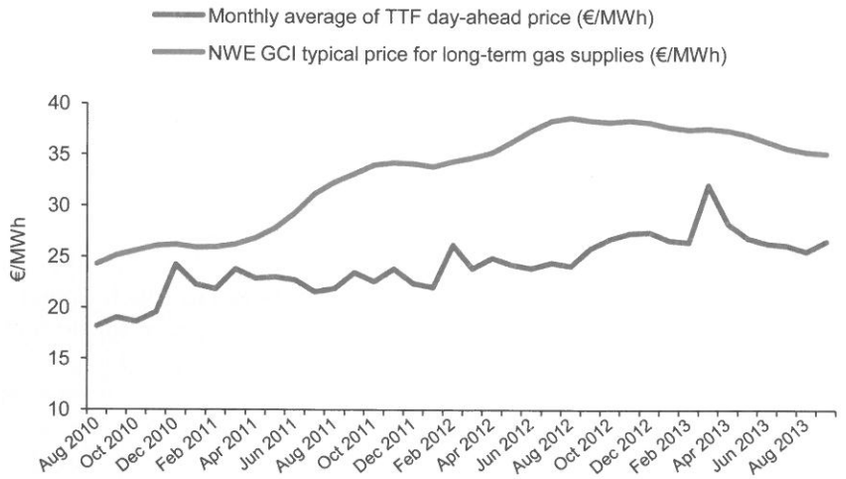


Figure 3.2: European long-term oil-linked and spot prices of gas (monthly averages), August 2010–September 2013

Note: TTF is the Dutch gas hub. The NWE GCI (north-west European Gas Contract Indicator) is a price, calculated by Platts news agency, in a typical 'pure oil-linked' contract formula.

Source: *Platts European Gas Daily Monthly Averages* for respective months.

Contractual – volume and price – problems

One of the major problems of writing about prices in long-term European gas contracts – whether with Gazprom or any other seller – is the degree of confidentiality of contracts, which prevents any detailed assessment which can be independently confirmed or verified. This should be borne in mind when reading the rest of this section.

When European demand crashed post-2008, many importing companies struggled to meet their contractual minimum take-or-pay (ToP) volumes. The impact of this on Gazprom was of special significance, because of the size and centrality of its supplies to the European gas market. Traditional take-or-pay levels in Russian long-term contracts are 85 per cent of annual contract quantity (ACQ).[29] Figure 3.3 shows the extent of purchasers' failure to meet ToP during 2008–10, which resulted in renegotiations between them and Gazprom. At the beginning of 2010, it was widely reported that a number of companies had demanded both reductions in contractual take-or-pay volumes, and reductions in prices.[30] As a result, Gazprom agreed with many of its customers that minimum ToP quantities would be reduced to 70 per cent of ACQ, and would be paid for at the contract price, but that any volumes taken in excess of minimum ToP would be sold at hub-based prices for three years beginning in October 2009.[31] Because we do not know how many customers received these concessions, Figure 3.3 shows an illustration of ToP commitments at both 85 per cent and 70 per cent; we believe that the actual level of ToP is at one of these levels.

Although Gazprom sold nearly 9 Bcm more gas to its European customers in contract year 2009/10 compared with 2008/09, the company's customers incurred take-or-pay liabilities (against a level of 85 per cent of ACQ) of 5 Bcm in 2009 and around 10 Bcm in 2010.[32] However the reasons were different: in 2009 the take-or-pay shortfall was spread across a number of companies, while in 2009/10 it was concentrated on ENI and Edison (Italy) and Botas (Turkey). The sharp drop in 2010 imports with

[29] 'Take-or-pay' clauses require the buyer to take an annual minimum volume of gas, or to pay for that volume whether or not it is taken. The post-2008 period is probably the first time in history that buyers had to pay for substantial volumes of gas which they were unable to take; for details see Stern, J. and Rogers, H. 'The Transition to Hub-Based Gas Pricing in Continental Europe', op. cit.

[30] These included E.ON, Wingas, Botas, Eni, RWE and Econgas. 'Europe rethinking contracts with Gazprom', *Interfax Russia & CIS Oil and Gas Weekly*, 4–10 March 2010, pp. 4–5.

[31] Anecdotal evidence suggests that these concessions were given to buyers in north-west and some in Central Eastern Europe. 'Gazprom agrees to sell a portion of gas delivery to Ruhrgas at spot prices', *Interfax Russia and CIS Oil and Gas Weekly*, 18–24 February, 2010, p. 20; Anton Doroshev, 'Gazprom adjusts gas pricing to defend market share', *Reuters*, 19 February 2010. http://uk.reuters.com/article/idUKLDE61I1M320100219?pageNumber=2&virtualBrandChannel=11700&sp=true.

[32] These volumes are for 'contract years' which in European gas contracts are usually 1 October–30 September, and are thus different from the calendar year data in Table 3.1 and Figure 3.3.

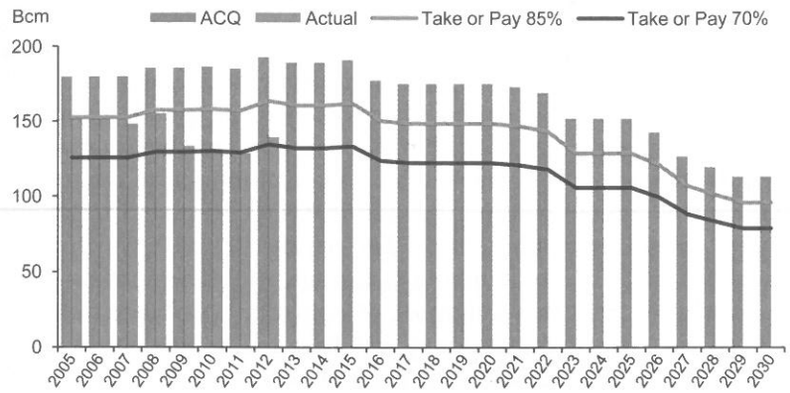


Figure 3.3: Russian long-term export contracts with OECD European countries to 2035: annual contract quantity and take-or-pay levels

Note: Contracts with Baltic and some south-east European countries are not included.

Source: Research by the Energy Research Institute of the Russian Academy of Sciences (ERI RAS) based on data from Cedigaz and Nexant.

recovery the following year is clearly visible in Table 3.1.[33] Figure 3.3 shows that, measured against a 70 per cent ToP level, in aggregate Gazprom's customers took their minimum quantities in 2011–12. By contrast, Table 3.1 shows that Russian export volumes in 2011 recovered principally because of significant increases in exports to Turkey (due to an increase in gas demand of 20 per cent compared with the previous year) and Italy (due to the loss of Libyan supplies for most of that year). While Italian imports fell back again in 2012 (although not to the same extent as in 2010), Turkish gas demand, and hence imports from Russia, continued to increase. Turkey became by far the most important non-CIS market for Russian gas after Germany. Preliminary data for 2013 (Table 3.1) show that exports were boosted to near-record levels by substantial increases in sales to Italy and Germany – the former due to continued problems with North African supplies and the latter affected by the drop in Norwegian deliveries and the need to refill storage – deliveries to other countries show no substantial changes.

[33] Turkish payments for gas not taken in 2010 exceeded $750m. 'Botas pays Azerbaijan, Russia, Iran over $1.6bn for unpurchased gas', *Interfax Russia & CIS Oil and Gas Weekly*, 6–12 September 2012, p. 57. ENI's take-or-pay shortfall was 5 Bcm in in 2011 and nearly 9 Bcm in 2010, 'Gazprom agrees to change terms for gas supplies to Italy', *Interfax Russia and CIS Oil and Gas Weekly*, 1–7 March 2012, p. 62. ENI's take-or-pay payments for the period 2009–11 exceeded $1.5bn (although not all of this amount was paid to Gazprom), 'Eni wants out of take-or-pay clauses in gas supply contracts', *Interfax Russia and CIS Oil and Gas Weekly*, 11–17 October 2012, p. 48.

Table 3.2: Russian long-term contract gas prices to European countries, 2010–13 ($/mcm)

	2010	*2011*	*2012*	*2013*
Germany	270	379	353	366
Switzerland	296	400	333	378
Italy	331	410	438	399
Denmark	0	480	394	382
Austria	305	387	394	402
France	306	399	398	404
Netherlands	308	366	346	400
Finland	273	358	373	367
Poland	331	420	433	429
Romania	325	390	424	387
Bulgaria	311	356	435	394
Slovenia	312	377	400	396
Hungary	350	383	416	418
Czech Republic	326	419	500	400
Slovakia	371	333	428	438
Serbia	341	432	405	386
Bosnia and Herzegovina	339	429	500	421
Macedonia	381	462	558	493
Turkey	326	381	416	382
Greece	359	414	475	469
Average*	**308.1**	**398.8**	**421**	**387**
Gazprom Average sales price**	**305**	**383**	**402**	

* Arithmetic average of prices for the year

** As quoted in Gazprom Annual Reports: 2012, p.77; 2011, p. 75. (converted in the source at average exchange rates of RR24–25 = $1, significantly lower than rates of RR29–30 from *Gazprom in Figures* 2008–12, p. 4.)

Sources: *Interfax Russia & CIS Oil and Gas Weekly*, 'OPAL decision, South Stream pipeline talks delayed', 6–12 March 2014, pp. 28–30.

European gas price data are confidential and cannot be independently verified, as was mentioned earlier. The data in Table 3.2 are believed to originate from Gazprom Export, because it is difficult to see where else journalists could have obtained such detailed country by country assessments.[34] The final two rows of the table show an arithmetic average of the figures for individual countries, and Gazprom's average received price (net of excise tax and customs duties), published in its Annual Reports, which should be a volume weighted average price. The data have a number of interesting features. In general, southern and (to a lesser extent) central Europe pay higher prices than do northern and western Europe. It has been hypothesized that this is due to the dominance of Russian gas in southern and central European markets and therefore the lack of any competitive pressure for Gazprom to reduce prices. However, this generalization does not hold true for all countries for all years.

It might be expected that countries further away from Russia in southern Europe would be required to pay more than their central and north European counterparts, due to additional transportation charges. In addition, the netback market pricing methodology (outlined above) ties the gas price to the prices of competing fuels. Countries that are still principally replacing oil products with imported gas – that is, some Balkan and other south European countries – will therefore not be in a position to resist demands for 100 per cent oil-based prices. With crude oil prices above $100/bbl, these will be extremely high. This is particularly the case for countries which are completely dependent on Russian gas.[35] Another possible explanation for price differences is that companies which enter into litigation with Gazprom to achieve lower prices (for example PGNiG in Poland in 2010–11 and RWE in the Czech Republic) are penalized with higher prices, whereas those who cooperate with Gazprom in projects such as South Stream (some companies in Hungary and Turkey) are rewarded with lower prices.[36] Such assumptions give rise to widespread claims that Russian gas pricing is 'political', a subject to which we return in Chapter 4.

However, following the events noted above, in respect of competitive and structural change in European gas markets since the late 2000s, gas pricing in north-western Europe, and some other countries, became increasingly competitive and determined at hubs. This caused very

[34] However, as noted above this is impossible to verify.

[35] However, there are exceptions: Table 3.1 shows that Croatia ceased importing Russian gas in 2011 when it received a more competitive offer from the Italian company ENI.

[36] 'Gazprom prices high for litigious in 2011, lower for South Stream Partners', *Interfax Russia and CIS Oil and Gas Weekly*, 14–20 June 2012, p. 47.

substantial problems, to which we now turn. It is very clear from Table 3.1 that by 2012 Russian gas exports remained around 10 per cent below the pre-recession highs of 2007/8. But despite this loss of market share, Gazprom remained unapologetic about its commercial strategy of defending price levels, if necessary at the expense of volumes. It pointed out that in 2012 its receipts from deliveries to 'far abroad' (in other words, non-CIS) customers exceeded $49bn, compared with the $50.8bn which it earned in 2008 – a 3.5 per cent drop in revenues, compared with a drop in volumes of more than 9 per cent.[37]

In 2009, Gazprom agreed that volumes taken in excess of minimum take or pay would be moved to hub-based prices for three years, as was noted above. The reasoning behind this was that by 2012, the recession would be over and pricing would have returned to normal – in other words, hub prices would return to oil-linked contract levels as gas demand recovered after the recession (and surplus LNG supplies were absorbed by fast-growing Asian economies).[38] As shown in Figure 3.2 this did not happen, but Gazprom remained insistent that it 'has no plans to abandon oil indexation', despite its acknowledgement that Norway, its major competitor on the European gas market, 'is actively moving to 100 per cent gas-indexed pricing which contributes to the expansion of its customer base'.[39] In a paper published in January 2013, Sergey Komlev, Head of Gazprom Export's contract structuring and pricing department, published an analytical defence of oil indexation.[40] However, as Figure 3.2 shows during 2010–13, with the exception of a few days in cold winter periods, not only did hub prices remain significantly below oil-linked contract levels, but (particularly in north-west Europe) hub prices became the dominant gas price mechanism.[41]

Gazprom's support of oil-indexed gas prices has been endorsed by Vladimir Putin – as both president and prime minister. Moreover, the 2013 Moscow Declaration of the Gas Exporting Countries Forum, over which

[37] Data from *Gazprom in Figures 2008–2012*, p. 66.

[38] 'Gazprom's Miller sees demand for gas slackening in Europe', *Interfax Russia & CIS Oil and Gas Weekly*, 10–16 June 2010 pp. 4–7.

[39] Gazprom Annual Report, 2012, pp. 76–7.

[40] The paper was published on line and is no longer available. For a commentary see Stern, J.P. and Rogers, H. 'The Transition to Hub-Based Pricing in Continental Europe: A Response to Sergei Komlev of Gazprom Export', OIES, 12 February 2013.

[41] The 2012 International Gas Union price survey (IGU) shows that in that year, 72% of gas sold in north west European countries – which represent 50% of total European gas demand – was sold at hub-based prices. *Wholesale Gas Price Survey 2013 Edition – a global review of price formation mechanisms 2005–2012*, International Gas Union, June 2013.

President Putin presided, emphasized that the Forum will:

> ... continue to support gas pricing based on oil/oil products indexation to ensure fair prices and stable development of natural gas resources.[42]

It may therefore be the case that oil indexation should be seen not solely as a Gazprom position but as a government and presidential position that Gazprom is required to implement.

But despite its public stance on oil indexation, starting in 2012 Gazprom began to agree a different type of price mechanism with its customers: the new mechanism retained the oil index but reduced the base price (the P0) in the pricing formula by 7–10 per cent – the effect of this was to bring the Russian price much closer to hub levels. A further mechanism was added which guaranteed buyers a limit on their exposure to hub pricing: at the end of the (one or two year) price period, if the price paid by the buyer under the new P0 + oil indexation formula exceeded the hub price by more than a defined percentage (reported anecdotally to be in the range of 5–15 per cent), the buyer would receive a 'rebate' reflecting the difference. In 2012, Gazprom set aside 114bn RR ($3.8bn) for rebates, and stated that the equivalent figure could be 'somewhat more' in 2013.[43] Gazprom could then claim that it had not compromised on the principle of retaining oil-indexed prices; and although buyers agreed to pay an uncompetitive price for their gas, they had a guarantee that a significant part of any difference between oil-indexed and hub prices would be repaid to them at the end of the period. This means that, from 2012 onwards, the prices in Table 3.2 are misleading unless the details of the rebate mechanism for individual countries are known. Figure 3.4 shows that, as a result of this new mechanism, from the beginning of 2013 Gazprom's prices fell from a level of more than 30 per cent above NBP in 2010, to less than 5 per cent above it and, despite its public stance (referred to above) the company can therefore be said to have adjusted to hub prices.[44]

International price arbitrations

A major reason for the change in pricing at the start of 2012 was that Gazprom's major customers, desperate to stem their losses, had entered

[42] Gas Exporting Countries Forum, Moscow Declaration of the GECF, The Second Gas Summit of the Heads of State and Government of GECF Countries, 1 July, 2013, Moscow, Para 5.

[43] According to Gazpom CFO Kruglov, 'Retroactive payments', *Interfax Russia and CIS Oil and Gas Weekly*, 27 June–3 July, 2013, pp. 62–3.

[44] This is not necessarily the case for all European markets, but it certainly applies to all the major customers of Russian gas.

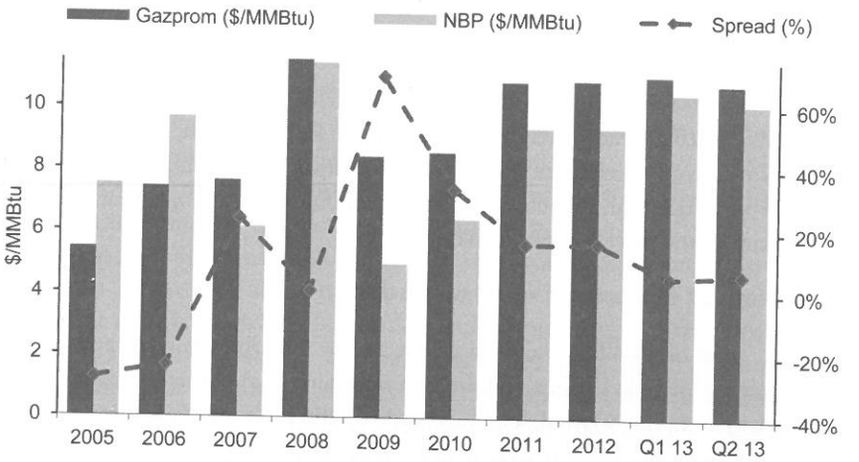


Figure 3.4 Russian gas export prices relative to NBP (month ahead)

Source: *European Gas Special*, Société Générale Cross Asset Research, 27 November 2013.

into international arbitration proceedings on the price terms of their long-term contracts. Over the approximately 40 year history of long-term European gas contracts, arbitrations had been extremely rare events. However, starting in the second half of the 2000s, they became much more frequent.[45] In 2010, the Italian company Edison initiated arbitral proceedings against the Gazprom/ENI joint venture Promgaz, although the case was subsequently settled. During 2011, Erdgas Import Salzburg, E.ON, and PGNiG announced that they had commenced arbitration proceedings with Gazprom, although agreement was reached on a new price mechanism (the P0 reduction combined with rebate mechanism described above) and proceedings were discontinued.[46]

In 2013, Gazprom's major arbitration case with the German company RWE, relating to the pricing of gas deliveries to the Czech Republic during 2010–12, reached a final judgement. These proceedings were extremely important in terms of both volumes and, potentially, in establishing a

[45] This applies not only to Gazprom but particularly to the Algerian company Sonatrach. As with all commercial issues related to European gas, it was the practice that even the existence of arbitral proceedings – let alone the result – was confidential. In the 2010s, more information about these proceedings has become available.

[46] 'Gazprom, E.ON revise contract retroactively from Q4 2010', *Interfax Gas Daily*, 3 July 2012, p. 5. In the Polish case, the price reduction was reported as 10%, resulting in a rebate of at least $420m for 2011. 'Gazprom, PGNiG agree gas-price adjustment, terminate arbitration proceedings', *Interfax Russia and CIS Oil and Gas Weekly*, 1–7 November 2012, p. 39.

benchmark for future litigation on oil-indexed gas pricing.[47] The judgement appeared to satisfy both parties, with RWE claiming that:

> … the tribunal awarded RWE a reimbursement for payments made since May 2010 and adjusted the purchase price formula of the contract by also introducing an element of gas market indexation, which according to the arbitral tribunal, reflects the relevant conditions on the gas market at the time of the price revision in May 2010.[48]

By contrast Gazprom Export stated that:

> … most of [RWE's] claims were rejected by the arbitration. As a result, the pricing formula has been adjusted in a certain way, but this adjustment is far away from the original demands made by RWE Supply & Trading CZ.[49]

The only conclusion that can be drawn from these statements is that the tribunal found that a significant proportion of the gas price should be determined by market (hub) prices.

Gazprom's price arbitration with Lithuania was ongoing at the time of writing, although there were discussions about whether this could be settled in the context of a new long-term contract (with a new price formula) starting in 2015.[50] Meanwhile Edison, which had settled similar proceedings in 2011, again filed for arbitration over prices in 2013 in the immediate aftermath of the RWE decision.[51]

[47] There are unconfirmed reports that the Tribunal awarded RWE a sum of €1.6bn. Note that the RWE price arbitration was additional to the arbitration on take-or-pay volumes (for the same contract) which was won by RWE with an award of €500m, although, at the time of writing, Gazprom was seeking to appeal the judgement. 'Gazprom unable to recover $500m from RWE under take or pay contract'; 'Court upholds ruling on Gazprom's take-or-pay claim against RWE, Russian company to appeal', *Interfax Russian & CIS Oil and Gas Weekly*, 18–25 October 2012, p. 58 and 11–17 July 2013, p. 32.

[48] 'Arbitration court rules in favour of RWE on price revision of its long-term gas supply contract with Gazprom', RWE Press Release, 27 June 2013.

[49] 'Gazprom Export on arbitration ruling on price review with RWE Supply & Trading CZ', Gazprom Export Press Release, 28 June 2013.

[50] 'Lietuvos Dujos H1 net profits rise 1.4%', *Interfax Russia and CIS Oil and Gas Weekly*, 25–31 July 2013, pp. 32–3. The price arbitration is in addition to another arbitral case which commenced in 2011, concerning the Lithuanian government's decision to unbundle Lietuvos Dujos's network assets into separate transmission (Amber Grid) and distribution businesses. Both of these proceedings are separate from the arbitration on heat tariffs at the Kaunas CHP plant.

[51] Anna Shirayevskaya and Tara Patel, 'Gazprom faces arbitration with Edison after RWE ruling', *Business Week*, 30 July 2013. www.businessweek.com/news/2013-07-30/gazprom-faces-arbitration-with-edison-after-ruling-on-rwe-price.

The 2012 EU competition investigation and Gazprom's export monopoly

Highly relevant to Gazprom's price renegotiations and arbitrations – although not *directly* connected with them – is the investigation by the European Commission's Competition Directorate (DG COMP) into Gazprom sales to eight Central and East European countries. One year after unannounced inspections of corporate records, DG COMP announced in September 2012 that it was opening proceedings against Gazprom for possible abuse of a dominant position on three grounds. First, Gazprom may have divided gas markets by hindering the free flow of gas across EU member states. Second, Gazprom may have prevented the diversification of supply of gas. Finally, Gazprom may have imposed unfair prices on its customers by linking the price of gas to oil prices.[52] In October 2013, DG COMP made it known that it was preparing a 'statement of objections' against Gazprom, but gave no indication as to how widespread the charges, and what the proposed remedies, might be.[53]

The case may have been somewhat over-hyped as 'the anti-trust clash of the decade', with the possibility of intransigent European Competition authorities and an equally intransigent Kremlin provoking a major crisis in EU–Russia energy and natural gas relations.[54] This is a possible scenario but not the most likely one. It is more likely that a DG COMP judgement against Gazprom would be followed by an appeal to the European Court of Justice (ECJ), which could take several years to resolve. However, any DG COMP finding that oil-linked prices are anti-competitive – even if an appeal against it were to be heard at the European Court of Justice – would severely damage what remains of Gazprom's ability to insist on retaining this mechanism, at least for sales to EU countries. Moreover, potential for confrontation remains. This was highlighted by the General Director of Gazprom Export, who made a connection between the investigation and the European price issue, asking:

> … could this be an attempt to use political methods to secure a reduction in Russian prices by artificial means?[55]

[52] 'Antitrust: Commission opens proceedings against Gazprom', EU Commission Press Release, 4 September 2012. http://europa.eu/rapid/press-release_IP-12-937_en.htm.

[53] 'EC preparing anti-trust charges against Gazprom', *Platts European Gas Daily*, 4 October 2013, p. 1.

[54] For details and scenarios see Riley, A. 'Commission v. Gazprom: the antitrust clash of the decade?' CEPS Policy Brief No. 285, 2012 and Sartori, N. 'The European Commission vs. Gazprom: an issue of fair competition or a foreign policy quarrel?', IAI Working Papers 13 March, 2013.

[55] 'Role of pipeline gas in Europe to grow: LNG overestimated, *Interfax Russia and CIS Oil and Gas Weekly*, 30 May–5 June 2013, pp. 29–34.

This is not the first EU Competition investigation into Gazprom contracts.[56] In the early 2000s, DG COMP opened an investigation into 'territorial sales restrictions' (more commonly known as 'destination clauses') in long-term gas contracts. At that time it was made abundantly clear that these were hard-core restrictions of competition, and illegal under European law. The relevance for the current investigation is that similar restrictions appear to be present in Gazprom's long-term contracts with the Baltic States, and should have been removed when those countries became EU member states in 2007.[57] If they are present, this represents a serious problem for Gazprom, which can hardly plead ignorance of the legal situation.

However, the immediate reaction of the Putin administration to the DG COMP investigation was to issue an executive order stating that Russian commercial entities such as Gazprom:

> … should supply information on their activities […] upon request from the authorities and agencies of foreign countries … only subject to prior consent of a respective federal executive body authorised by the Russian Government.[58]

In European circles, this order was generally interpreted as a direct instruction to Gazprom not to cooperate with the DG COMP investigation, although it is probably more correct to see it as a traditional Putin response, standing up for Russian interests against 'foreign intimidation'.

Questions have been raised as to how the competition authorities could construe linking the price of gas to oil prices as 'unfair', given that this had been the principal way of pricing gas in Europe for several decades prior to 2008. Part of the answer appears to be that for countries which had a choice of suppliers and could choose which gas to purchase, oil price linkage was not unfair. But for countries that were entirely dependent on Russian gas, a refusal to sell on terms other than oil linkage could potentially – under competition law – be considered abuse of a dominant position. This is reinforced by the export monopoly, which means that countries dependent on Russian gas have no alternative to buying from Gazprom.

In 2006, the legal status of Gazprom – or to be specific, the company's subsidiary Gazprom Export – in relation to exports, changed. Previously, Gazprom had a de facto, but not a legal, monopoly of gas exports. However,

[56] However, in that instance the investigation also involved contracts with other gas suppliers (notably Algeria), whereas this case involves only Gazprom contracts. For details see Stern, J.P. *The Future of Russian Gas and Gazprom*, op. cit., pp. 132–4.

[57] 'Gazprom allows Baltic customers to trade gas with third countries – paper', *Interfax Russia and CIS Oil and Gas Weekly*, 24–30 October 2013, p. 52.

[58] Executive Order 'On Measures to Protect Russian Federation Interests in Russian Legal Entities' *Foreign Economic Activities*. http://eng.kremlin.ru/acts/4401.

in the mid-1990s, companies such as Itera began to export gas to CIS countries and in the mid-2000s, Gazprom's de facto monopoly of exports to Europe was breached by Eural Transgas. Partly in response to these developments, and partly in response to the January 2006 Ukraine crisis, the 2006 Law on Gas Exports gave Gazprom a legal monopoly on exports.[59] Until 2012 there was no serious challenge to the export monopoly, aside from Novatek's 10 year contract to sell 2 Bcm/year of gas to the German company EnBW. Initially this gas will come from non-Russian sources, but Novatek made clear that it plans to

> … begin [the] initial process to create a consumer market for LNG and natural gas in Europe … [and] establish a market position when legislative changes are eventually made to exports of natural gas [from Russia].[60]

In relation to LNG, Gazprom's export monopoly was removed at the end of 2013, which would allow Novatek to supply EnBW with gas from the Yamal LNG project (Chapter 13).[61] The legislation allows two categories of companies to export LNG:[62]

- companies developing deposits of federal importance whose licence states that as of 1 January 2013 they are required to build LNG plants or send gas to be liquefied at other LNG plants;
- companies (and their subsidiaries) in which the state owns a stake of more than 50 per cent and which are developing offshore fields to produce LNG or gas produced under production-sharing agreements.

From this, it is clear that there is no blanket authorization for LNG exports and that relaxation of the monopoly over pipeline gas exports to Europe is not on the agenda. On the other hand, few would agree with the General Director of Gazprom Export that:

[59] *Federal'nyi zakon Rossiskoi Federatsii ot 18 Iiuliia 2006 g. 117-F3, Ob Eksporte Gaza*. To be precise: Article 3 of the law confers an exclusive right to export gas on the owner of the Unified Gas Supply System and its subsidiary companies, currently Gazprom and Gazprom Export.

[60] 'Novatek, EnBW sign long term supply deal', *Platts European Gas Daily*, 15 August 2012, p. 4.

[61] 'Russia to liberalise exports soon – Putin', *Interfax Russia and CIS Oil and Gas Weekly*, 3–9 October, 2013 pp. 26–7. Although at the time of writing it was not clear whether this would take the form of a blanket – or a case by case – exemption for LNG.

[62] 'Russian government approves bill on LNG export liberalisation', *Interfax Russia and CIS Oil and Gas Weekly*, 24–30 October pp. 12–13.

> … a unified export channel will be maintained not only throughout the life span of the current generation, but throughout the life spans of our children, grandchildren and great grandchildren.[63]

President Putin himself was far less definite and, when prime minister, did not rule out relaxation of the export monopoly in the future.[64] But his Executive Order in response to the DG COMP investigation formalizes the Ministry of Energy's approval of negotiations and renegotiations of long-term contracts and makes the Ministry part of the 'single export channel'. It also implies that, even should some type of unbundling of Gazprom's network be contemplated in the future (see 'Gas transmission and storage', page 136), the government itself might maintain a single export channel.

The transit diversification and avoidance pipelines

The break-up of the Soviet Union caused very substantial problems for the Russian gas industry. Not only were important assets suddenly located in different sovereign states, but what had been intra-industry transfers of gas and money needed to be commercialized. This caused immense problems, the consequences of which continued to be felt through the first two decades of the post-Soviet era, and some remained unresolved into the 2010s. The main transit corridor, carrying around 80 per cent of Russian gas to Europe, was through Ukraine; Moldova (an extension of the Ukrainian system to south-east Europe and Turkey) and Belarus (transiting gas to Poland and the Baltic States) were also important (see Chapter 7).

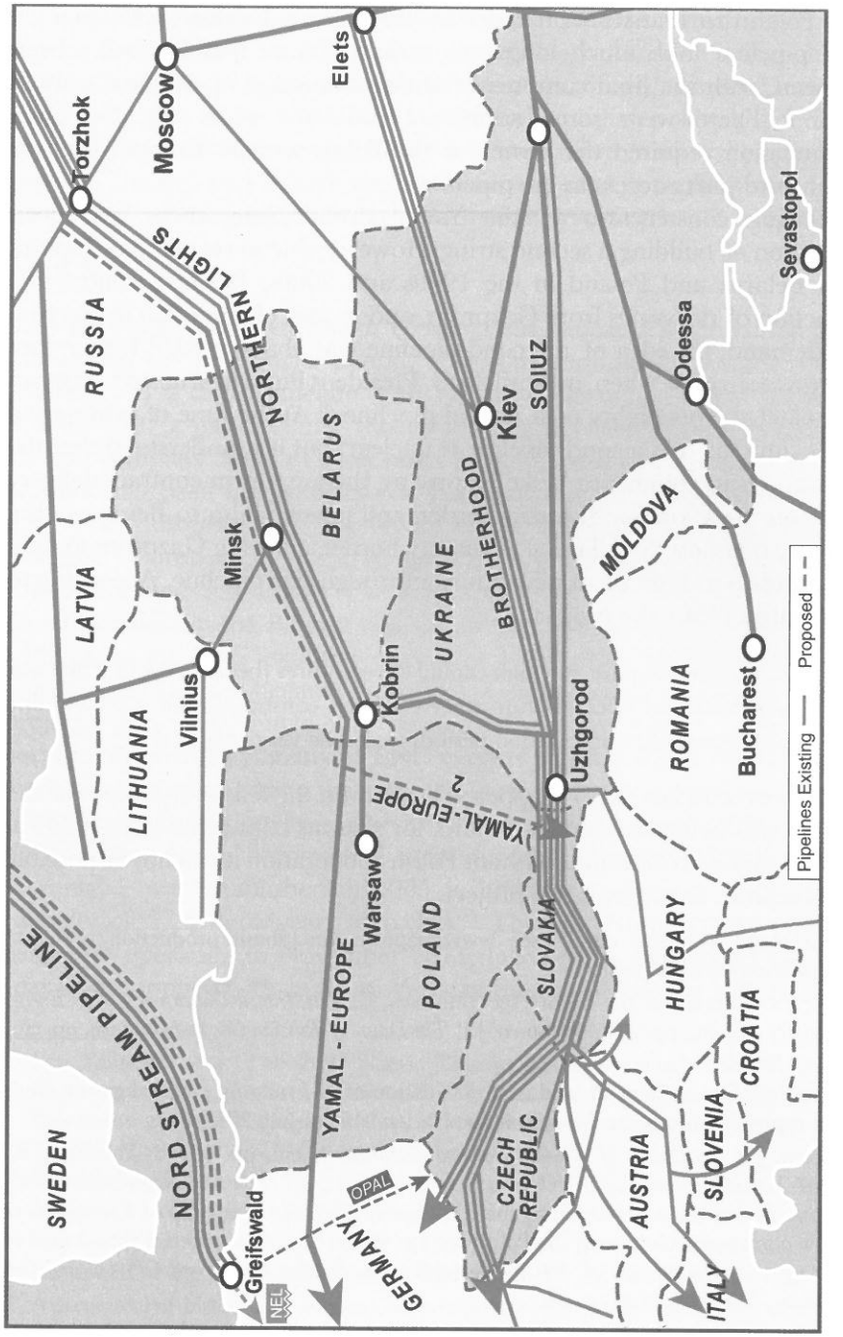
Yamal–Europe

The commercial and political difficulties in the gas relationships between Russia and the three western CIS transit countries have been extensively documented in previous OIES research.[65] As these problems unfolded in the 1990s so Gazprom began to consider gas delivery systems to Europe which would lessen its dependence on Ukraine. The first was the Yamal–Europe pipeline (Map 3.1) running from Torzhok in Russia across Belarus

[63] 'Role of pipeline gas in Europe to grow: LNG overestimated, *Interfax Russia and CIS Oil and Gas Weekly*, 30 May–5 June 2013, pp. 29–34.

[64] 'Russia might liberalise gas exports in future, Putin', *Interfax Russia and CIS Oil and Gas Weekly*, 6–14 October 2011, p. 49.

[65] Yafimava, K. *The Transit Dimension of EU Energy Security: Russian Gas Transit Across Ukraine, Belarus, and Moldova* (Oxford: OIES/OUP. 2011), Chapters 6–8; Stern, J.P. *The Future of Russian Gas and Gazprom*, op. cit., Chapter 2.



Map 3.1: The Ukrainian and Yamal–Europe pipelines

Source: Oxford Institute for Energy Studies.

and Poland to Frankfurt on Oder on the eastern border of Germany.[66] The pipeline took much longer to complete than had originally been foreseen, with the final compressor station becoming operational only in 2006.[67] There were some additional problems when the European Commission required the owner of the Polish section (Europol Gaz) to grant third-party access to the pipeline.[68]

During construction of the Yamal–Europe line, there had been discussion of building a second string. However, due to regular gas disputes with Belarus and Poland in the 1990s and 2000s, Poland's contractual reduction of deliveries from Gazprom, and its lack of intention to increase gas demand, the idea of a second pipeline was abandoned.[69] It therefore came as a surprise when, in April 2013, President Putin instructed Gazprom to look at the possibility of a second pipeline.[70] At the time of writing the exact route of this second pipeline is unclear; but it is understood that the intention is to connect to Velke Kapusany, the long-term contract delivery point on the Ukraine–Slovakia border, and possibly also to Beregovo, the delivery point on the Ukraine–Hungary border, allowing Gazprom to fulfil its contracts to both of those countries through this pipeline. According to Gazprom's CEO, the project:

> … does not require any high capital expenditures [because the first line was built with] an infrastructure reserve for the construction of a second line [and hence the construction period] would be very, very short.[71]

However, in late 2013 it appeared that even the feasibility study for the project was being blocked by Poland, for reasons connected to its political relationship with Ukraine. Without Polish cooperation it will not be possible for Gazprom to progress this project.

[66] For more technical details see www.gazprom.com/about/production/projects/pipelines/yamal-evropa/.

[67] For more details of the history see Yafimava, K. *The Transit Dimension of EU Energy Security*, op. cit., pp. 218–20; Stern, J.P. *The Future of Russian Gas and Gazprom*, op. cit., pp. 118–20.

[68] 'Commission requests Poland to stop violation of EU rules on internal gas market', European Commission Press Release, IP/10/945, 14 July 2010.

[69] Stern, J.P. *The Future of Russian Gas and Gazprom*, op.cit., pp. 120–2; Yafimava, K. *The Transit Dimension of EU Energy Security*, op. cit., pp. 218–49. Negotiations with Poland were also not helped by the controversy over the ownership of Europol Gaz (the company which owns the Polish section of the line). 'Gazprom, PGNiG unable to agree on appraisal of 4% in Europol Gaz, *Interfax Russia and CIS Oil and Gas Weekly*, 5–11 July 2012, p. 54.

[70] www.gazprom.com/about/production/projects/pipelines/yamal-evropa-2/.

[71] 'Gazprom sees agreement with Poland giving edge to Yamal–Europe 2 project', *Interfax Russia and CIS Oil and Gas Weekly*, 9–15 May 2013, p. 41.

Yamal–Europe is a transit-diversification pipeline which Gazprom expected would have the effect of demonstrating to Ukraine that, unless it changed its behaviour, it would lose lucrative gas transit business. However, not only did this seem to have little impact on Ukrainian policy, but periodic Belarusian transit crises caused Moscow to conclude that diversifying transit between Ukraine and Belarus was insufficient to solve its problems, and that a means of avoiding transit through both of these countries was required.[72]

Nord Stream

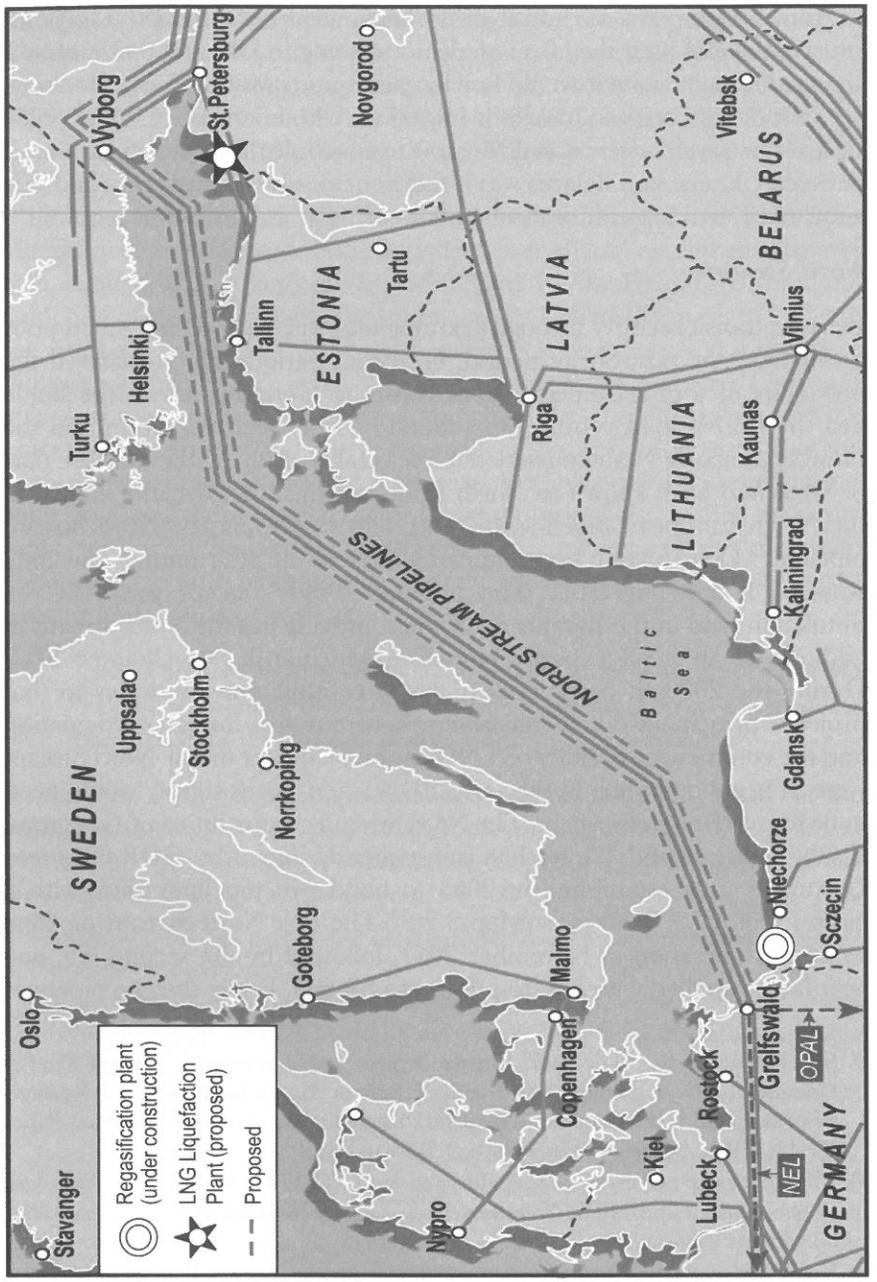
Because transit security through Ukraine and Belarus had remained poor throughout the post-Soviet period, Gazprom periodically considered the possibility of a direct pipeline from Russia to Germany across the Baltic Sea. In 1997 a joint venture was established between Gazprom and the Finnish company Neste to carry out a feasibility study of the offshore part of what had been known as North Transgas; this then became known as the North European Pipeline, before finally becoming the Nord Stream pipeline.[73] Construction began in April 2010, in the aftermath of the 2009 Russia–Ukraine gas crisis. The original 1990s concept was that the Shtokman field in the Barents Sea should provide gas for Nord Stream in addition to an LNG export terminal at Murmansk (see Chapter 11).[74] During the 2000s it became clear that a combination of delays to that project – principally due to uncertainties surrounding foreign participation and the commercial viability of LNG exports – meant that if Nord Stream were to begin operating in the early 2010s, then its gas supply would need to be sourced from elsewhere. The Nord Stream consortium – of Gazprom, E.ON Ruhrgas, and Wintershall (subsequently joined by GDF Suez and Gasunie) – was established in 2005 to build two pipelines each with a capacity of 27.5 Bcm/year (Map 3.2).[75] The first Nord Stream pipeline went into operation in November 2011, followed by the second line one year later, supplied with gas from Western Siberia. While the two pipelines

[72] See Yafimava, K., 'The 2007 Russia–Belarus gas agreement', Oxford Energy Comment, OIES, January, 2007 and Yafimava, K., 'The June 2010 Russian-Belarusian gas transit dispute: a surprise that was to be expected', Working Paper NG43, OIES, 1 July, 2010 for details of Belarus crises.

[73] For some early history of the pipeline see Stern, J.P. *The Future of Russian Gas and Gazprom*, op. cit., pp.120–2; Yafimava, K. *The Transit Dimension of EU Energy Security*, op. cit., pp. 94–6.

[74] For details of the Shtokman project and LNG exports see Chapters 8 and 10.

[75] A great deal of historical, technical, and corporate information on Nord Stream can be found on the company's website www.nord-stream.com/. Following the completion of the first two lines, claims have been made that the capacity of the system is in fact closer to 60 Bcm/year.



Map 3.2: The Nord Stream pipelines

Source: Oxford Institute for Energy Studies.

have a total capacity of 55 Bcm/year, delays and problems in utilizing the capacity of the onshore pipelines (NEL and OPAL) (see Chapter 4) have meant that until late-2013, capacity utilization remained at relatively low levels. In 2012, Gazprom proposed building two additional lines, Nord Stream 3 and 4, which would double the capacity of this corridor to 110 Bcm/year, with project documentation showing a preliminary timeline for both pipelines to be commissioned by the end of 2018.[76]

Blue Stream and South Stream

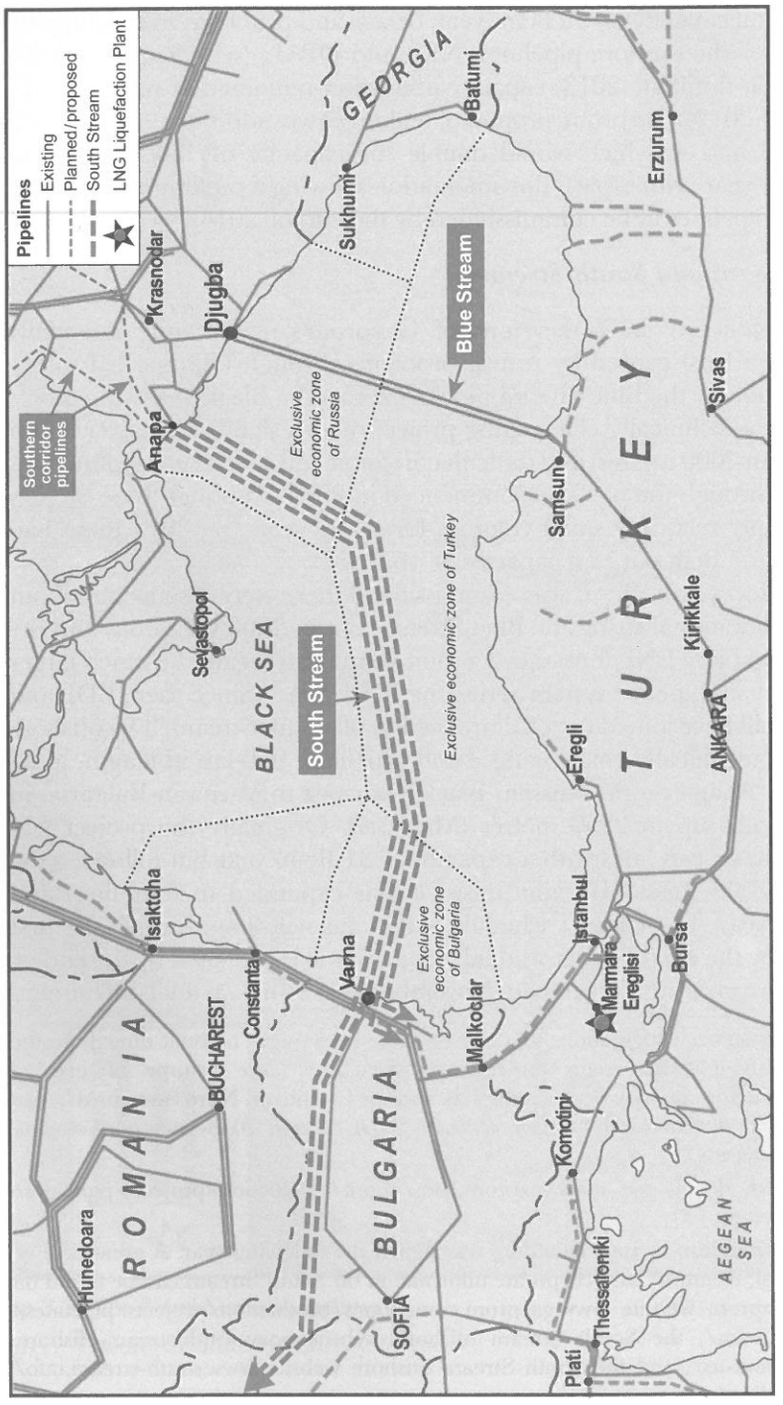
Security concerns in Turkey (one of Gazprom's newest and potentially biggest markets) caused by transit problems through Ukraine led to the construction of the Blue Stream pipeline across the Black Sea (Map 3.3).[77] This was a technically challenging project due to significant water depth (more than 2000 metres) and difficult corrosion and seabed conditions. Gas supplies through the pipeline commenced in 2003. Although Blue Stream carried only relatively small volumes for many years, by 2012 these had risen to 14.7 Bcm out of a capacity of 16 Bcm.

For a few years after it was commissioned there were discussions about building additional strings of Blue Stream, but in 2006 Gazprom and the Italian company ENI announced a joint venture to create the much larger South Stream pipeline system across the Black Sea.[78] Since then, EDF and Wintershall have joined the offshore section of South Stream. The offshore section is technically challenging – four pipelines, 930 km in length, to be laid from Anapa on the Russian Black Sea coast to Varna in Bulgaria, in water depths up to 2250 metres (Map 3.3). Originally the project was planned to be two lines with a capacity of 31 Bcm/year but following the January 2009 Russia–Ukraine crisis, it was expanded to four lines and 63 Bcm/year. The current schedule is that gas will flow through the first pipeline by the end of 2015, and full capacity will be reached by the end of 2017. Gazprom announced in November 2012 that a final investment

[76] There have been suggestions that one of these lines might be built directly to the UK, although this seems unnecessary given the large volume of existing transportation capacity between the UK and the Continent. Nord Stream AG, *Nord Stream Extension: project information document (PID)*, March 2013 www.nord-stream.com/extension/.

[77] For more details see www.gazprom.com/about/production/projects/pipelines/blue-stream/.

[78] A memorandum of understanding was signed the following year. A great deal of historical, technical, and corporate information on South Stream can be found on the Gazprom website www.gazprom.com/about/production/projects/pipelines/south-stream/, the South Stream offshore website www.south-stream-offshore.com/about-us/, and the South Stream onshore website www.south-stream.info/en/pipeline/.



Map 3.3: The Blue Stream and South Stream pipelines
Source: Oxford Institute for Energy Studies.

decision had been taken on the offshore section, and in 2013 tenders were issued for the steel and the laybarge(s) for the four pipelines and Gazprom Export signed a ship or pay agreement for the entire 63 Bcm/year capacity.[79]

As for the onshore European section of South Stream, during 2008–10 Russia signed intergovernmental agreements with seven European countries for the onshore section(s).[80] Although indicative route maps can be found on the company's website, at the time of writing no onshore route has been finally decided. Initial plans to build a southern leg to Greece and a northern leg to Austria had been abandoned due to lack of demand and an unfriendly regulatory environment (respectively). The onshore section of the project across Europe is facing significant regulatory challenges due to the implementation of the Third Energy Package and the Network Codes (see Chapter 4).

Much scepticism was expressed in Europe about the likelihood of South Stream being built and, as mentioned above, the project still has hurdles to surmount. However, construction of what the company is calling its 'Southern Corridor' project, comprising 2500 km of pipeline and 10 compressor stations to bring West Siberian gas to the Black Sea to supply South Stream, started in 2013.[81] The cost of this corridor is estimated at $17bn and these preparations, combined with tenders for equipment and construction of the offshore section, confirm that South Stream will go ahead, although there may still be uncertainty about the timetable of construction and gas flow.[82]

Motivations for transit avoidance pipelines

All of the transit avoidance pipelines are owned roughly 50 per cent (usually plus one share) by Gazprom and 50 per cent by a consortium of importing European utilities.[83] These pipelines are mainly replacing gas transportation

[79] Gazprom Press Releases, 'FID taken for South Stream offshore pipeline', 12 November 2012; 'South Stream Transport B.V. shareholders confirm terms and conditions of South Stream's offshore section construction', 4 October 2013.

[80] Hungary, Bulgaria, Serbia, Greece, Slovenia, Croatia, and Macedonia.

[81] Not to be confused with Southern Corridor pipeline from Central Asian/Caspian and Middle East countries to Europe. For details and maps see www.gazprom.com/about/production/projects/pipelines/southern-corridor/.

[82] Construction of the Bulgarian section of the line began in October 2013. 'Gazprom mulls raising 100 bln rubles with infrastructure bonds – paper', *Interfax Russian & CIS Oil and Gas Weekly*, 18–24 July 2013, p. 23; 'South Stream construction starts in Bulgaria', Gazprom Press Release, 31 October 2013.

[83] The partners in the pipelines are: Blue Stream: Gazprom 50%, ENI 50%; Nord Stream: Gazprom 51% E.ON 15.5%, Wintershall Holding 15.5%, GDF Suez 9%, Gasunie 9%; South Stream: Gazprom 50%, ENI 20%, EDF 15%, Wintershall 15%. The ownership of Europol Gas (Polish section of the Yamal–Europe pipeline) is 48% Gazprom, 48% PGNiG and 4% GazTrading, but in 2013 – following the death of the owner of GazTrading – the other two partners were negotiating to purchase its shareholding. 'PGNiG, Gazprom to discuss Yamal stakes', *Platts European Gas Daily*, 8 October 2013, p. 4.

via Ukraine and will therefore neither serve new markets nor provide for additional sales to existing markets. Moreover, there is uncertainty as to how rapidly demand for Russian gas in Europe will grow. All these circumstances have led to substantial discussion as to whether these ventures will be profitable or rather what the financial community refers to as 'value-destroying'. Research has shown that Nord Stream should earn a positive rate of return, but that the profitability of South Stream is considerably more doubtful.[84]

This raises the question as to why foreign partners are willing to invest in these projects, to which one answer is that foreign companies find it difficult to resist an invitation from Gazprom (and the Russian government) to invest in a project, due to their keenness to invest in upstream gas projects in Russia. For Nord Stream, the crucial element which persuaded E.ON Ruhrgas and Wintershall (the original investors) to participate was equity ownership in the Iuzhno-Russkoe gas field in Western Siberia; the only time that Gazprom has allowed foreign investment in a large Cenomanian gas field.[85] In addition, it is Gazprom which takes the major tariff risk in these pipelines, having signed ship-or-pay agreements with their owners for 100 per cent of their capacity.[86]

The transit-avoidance pipelines, in particular Nord Stream which has not involved any additional sales of gas to Europe since the first line was completed at the end of 2011 (see Table 3.3) have been an extremely costly exercise for Gazprom. In addition, as Mikhail Korchemkin has shown, even with new pipelines such as Nord Stream 1 and 2 in operation, Gazprom is still required to honour its ship-or-pay commitments in its existing transportation contracts with Slovakia and the Czech Republic, hence paying twice for transportation.[87] While Gazprom claims that 'at least a quarter of South Stream pipeline's capacity will be filled with gas

[84] For Nord Stream see Chyong, C.K., Noel, P., and Reiner, D.M.,'The Economics of the Nord Stream Pipeline System', University of Cambridge, EPRG Working Paper 1026, 2010; also 'Nord Stream internal rate of return 10% – sources', *Interfax Russian & CIS Oil and Gas Weekly*, 4–10 July 2013, p. 41.

[85] The importance of this field is that it produces large volumes of gas from shallow horizons; all other joint ventures with foreign companies involve fields with some degree of difficulty involving location, gas composition or depth. Both German companies, through asset swaps, have acquired a 25% share in Sevmorneftegaz which owns the licence to the Iuzhno-Russkoe field with 834 Bcm of proven and probable reserves and 180 Bcm of possible reserves (www.gazprom.com/about/production/projects/deposits/yrm/).

[86] 'Gazprom signs agreement on South Stream gas transportation', *Interfax Russia and CIS Oil and Gas Weekly*, 26 September–2 October 2013, p. 36.

[87] 'In 2012, the new export route to Waidhaus was four times more expensive than the old one', *East European Gas Analysis*, 1 June 2013.

under new contracts', this seems implausible, as finding an additional 15–16 Bcm/year of gas demand in south and south-eastern Europe does not seem possible, unless new contracts with Turkey can be concluded.[88] This means that the principal – if not the sole – purpose of South Stream (and of the majority of the rest of the transit-avoidance pipeline capacity) is to take gas currently flowing through Ukraine and transport it to the same customers via alternative routes. The cost can be justified only by the view that continued dependence on Ukraine is considered economically unattractive and/or posing an unacceptable security risk (see Chapter 4).

While the transit-avoidance pipelines are clearly projects which are dominated, in a corporate sense, by Gazprom, there is a very clear inference that President Putin takes a strong personal interest in their development and may be considered a key (and probably *the* key) political driving force behind them. Over the past decade, Putin appears to have taken a very public and personal role in encouraging – to the point of publicly ordering – Gazprom to create and accelerate the construction of Nord Stream, South Stream, and most recently Yamal–Europe 2.[89] The question therefore arises as to why Putin feels the need to play this role. For some, the answer is straightforward and is connected with widespread allegations that the political elite receive corrupt payments via equipment and service contracts for these large pipelines.[90] However, there are other major reasons, such as the determination of the Russian government to avoid dependence on Ukraine, and the importance of oil and gas supplies to the maintenance of Russia's geopolitical standing – to which we return in Chapter 4.

Export capacity utilization and contractual commitments

Table 3.3 provides an illustration of likely export capacity to Europe up to 2020 and compares this with average annual take-or-pay volumes under long-term contracts during this period. Up to 2015 it is assumed that no new capacity will be built (with the start of South Stream deliveries planned for the end of that year), and no significant investment in the Ukrainian network will mean that operational capacity will fall to 100 Bcm/year. In the minimum 2020 variant, it is assumed that four strings of South Stream will be built, but no other new capacity; and the operational capacity of the Ukrainian network will decline to 90 Bcm – or 50 Bcm if a decision is taken to close capacity. In the maximum 2020 variant it is assumed that all

[88] 'Construction of South Stream pipeline officially underway', *Interfax Russia and CIS Oil and Gas Weekly*, 6–12 December 2012, pp. 5–7.

[89] The same can also be said of LNG projects and Eastern Gas Programme pipelines. See Chapters 8 and 12.

[90] See the section on reform and governance in Chapter 12.

proposed pipelines – four South Stream, two additional Nord Stream, and another string of Yamal–Europe (via Belarus) – are built. The minimum and maximum capacity figures are then compared with two levels of exports: take-or-pay levels of 70 per cent and 85 per cent of annual contract quantity (ACQ) and 100 per cent of ACQ, the latter being significantly above the levels of physical delivery of Russian gas to Europe during 2009–12 (see Table 3.1).

Table 3.3: Russian gas export pipeline capacity to Europe, 2013–20 (Bcm/year)

Pipeline capacity	*2013*	*2015*	*2020*	
			Minimum	*Maximum*
To Finland	5	5	5	5
Through				
Belarus	48	48	48	63
Ukraine*	120	100	50	90
Blue Stream	16	16	16	16
Nord Stream	55	55	55	110
South Stream	0	0	32	63
Total	**244**	**224**	**237**	**347**
Surplus capacity at ToP level**	81–110	63–91	84–109	199–224
Surplus capacity at ACQ level**	52	34	58	173

* Useable Ukrainian capacity is estimated at 120 Bcm/year and, without substantial investment, is likely to decline during the 2010s. In 2013 the Ukrainian prime minister suggested that if Russian utilization fell below a certain level, two lines could be closed leaving only 50 Bcm of capacity.

** ACQ and ToP levels of 70–85 per cent are based on data from Figure 3.3 and therefore somewhat over-stated because not all contracts are included.

Source: adapted from Pirani, S. (ed.), *Russian and CIS gas markets and their impact on Europe* (Oxford: OIES/OUP, 2009), Table 12.8, p. 427.

Table 3.3 makes clear that, even with no further pipeline capacity availability in 2015, under most circumstances Gazprom will have substantial surplus export capacity throughout the decade.[91] The only situation in which Gazprom might find itself somewhat pressed would be if in 2020 it had built only South Stream, and Ukraine had carried through

[91] See Chapter 11 for a discussion of Gazprom's gas availability over this period.

the suggestion of its prime minister that it might close some unused capacity, leaving only 50 Bcm available.[92] However, this would imply a European import requirement of well above 180 Bcm/year which, while possible, is not likely. But if, on the other hand, Gazprom has four South Stream lines in operation by 2020 – which currently is the likely outcome as long as it is allowed to use the full capacity of these lines on-land (which as we shall see in Chapter 4 is by no means certain) – then, as long as 50 Bcm of Ukrainian capacity remains available, and even without additional Nord Stream and Yamal–Europe lines, it should be able to cope comfortably with increased European requirements. Only if (a) Ukrainian capacity is completely shut down, or Gazprom chooses not to use it, and (b) European demand for Russian gas rises above 200 Bcm/year, could the additional Nord Stream 3 and 4 and/or Yamal–Europe 2 capacity be needed.

Therefore, from a political perspective, during the 2010s Gazprom becomes progressively less dependent on Ukrainian transit capacity to Europe. By 2020 it can reduce transit volumes through Ukraine to very low levels. Unless it has reason to increase exports to around 200 Bcm/year, which market conditions currently do not suggest will be required, it could completely abandon Ukraine as a transit route for European exports. Indeed Aleksei Miller, Gazprom CEO, observed that:

> … when South Stream reaches its design capacity, Gazprom's transit risks for supply to its European consumers will be brought down to almost zero.[93]

But in two important respects this analysis is much too simple: first it assumes that if Gazprom builds new pipelines on EU territory, it can then reserve 100 per cent of their capacity for Russian gas. Second, it shows only *annual* capacity figures, whereas it is becoming increasingly important to know how much Russian gas can be delivered in the winter season – particularly on days of high demand (in Russia, CIS countries, and Europe). Discussion of these issues and overall conclusions on Russian gas exports to Europe can be found in Chapter 4.

[92] 'Ukraine may stop buying Russian gas due to high price – Azarov', *Interfax Russia and CIS Oil and Gas Weekly*, 19–25 September 2013, pp. 45–7.

[93] Gazprom Annual Report, 2012, p. 5.