

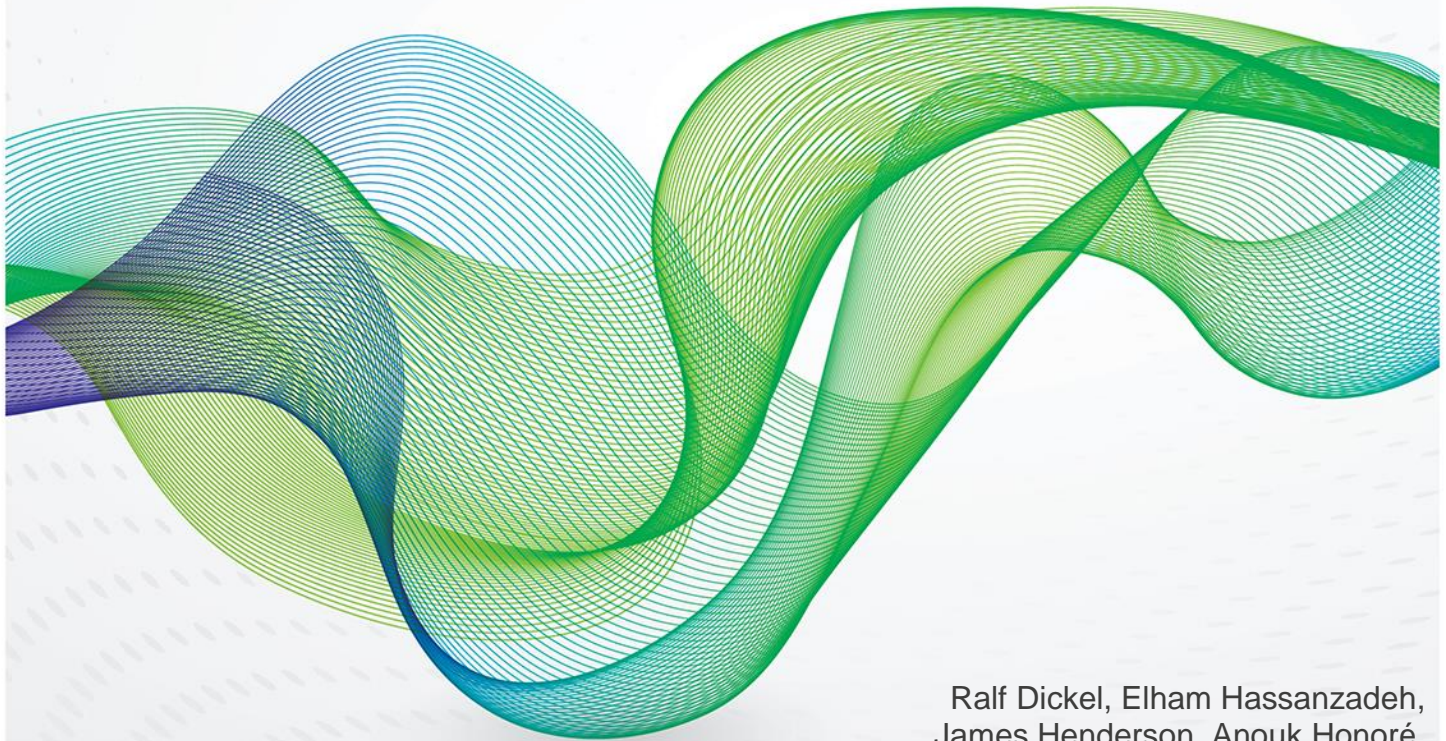


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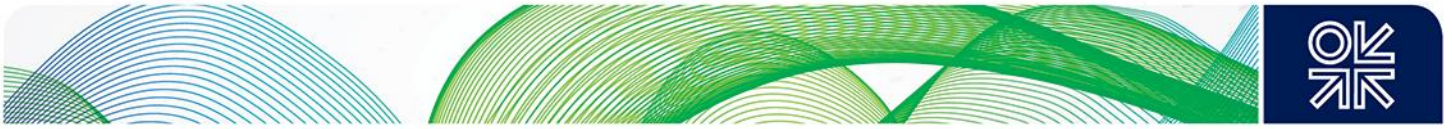
Reducing European Dependence on Russian Gas:

distinguishing natural gas security from geopolitics



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Preface

The aim of this paper is to fill a gap in the discourse on Russian and European gas issues, which has been opened up (again) in the wake of the 2014 Ukraine crisis. It was galvanized by the need to correct simplistic judgements by political and media commentators on the possibilities of a rapid reduction of Russian gas exports to Europe.

This paper is, in every sense, a 'team effort' by staff of the OIES natural gas research programme to summarize much longer and more detailed research work which we have already published, or will shortly publish. The principal authors of the individual sections are:

- European indigenous gas supply – Anouk Honoré
- North Africa and East Mediterranean gas – Laura El-Katiri
- Caspian and Central Asia – Simon Pirani
- Iran and Iraq – Elham Hassanzadeh
- The role of LNG – Howard Rogers
- Infrastructure issues – Katja Yafimava
- Alternative sources of energy supply and potential for demand reduction – Ralf Dickel and Anouk Honoré
- Reducing Ukrainian dependence on Russian gas – Simon Pirani
- The Russian response – James Henderson and Katja Yafimava
- The geopolitical arguments – Simon Pirani and Jonathan Stern

I am the principal author of other sections with overall editorial responsibility for the text.

Many thanks to all the contributors for meeting challenging deadlines, to Catherine Gaunt for editorial support, and Kate Teasdale for making everything else happen.

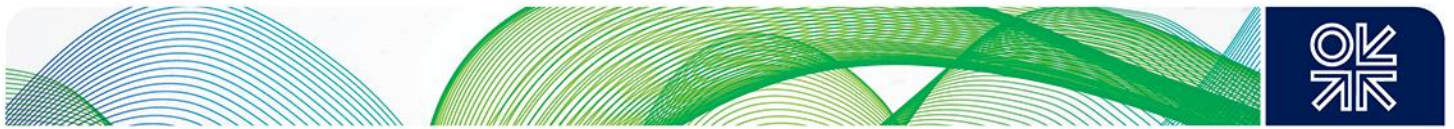
Jonathan Stern

Oxford, October 2014.



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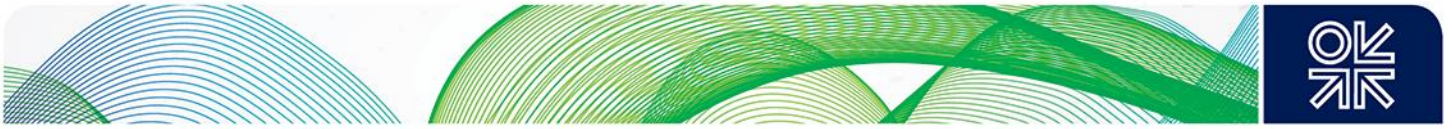


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Executive Summary

The main finding of this paper is that there is limited scope for significantly reducing *overall* European dependence on Russian gas before the mid-2020s. However, countries in the Baltic region and south-eastern Europe which are highly dependent on Russian gas, and hence extremely vulnerable to interruptions, could substantially reduce and even eliminate imports of Russian gas by the early 2020s, by a combination of LNG supplies and pipeline gas from Azerbaijan. Similar measures could reduce (but not eliminate) the dependence of central Europe and Turkey on Russian gas. In the majority of countries, there is limited scope to reduce gas with oil products, and to the extent that it is replaced by coal in power generation carbon emissions will increase significantly.

Up to the mid-2020s, European companies are contractually obliged to import at least 115 bcm/year of Russian gas (approximately 75 per cent of the 2013 import level), a figure which reduces to around 65 bcm by 2030. Even if long-term contracts disappear, our modelling shows a requirement of at least 100 bcm/year of Russian gas up to 2030, and in some scenarios up to twice that volume. The main additional source of non-Russian gas for Europe up to 2030 will be LNG; pipeline gas imports from domestic and other imported sources are not envisaged to increase substantially and may decline. Russian gas deliveries to Europe will be highly competitive with all other pipeline gas and LNG (including US LNG) supplies throughout the period to 2030, and Gazprom's market power to impact European hub prices may be considerable.

Countries with strong geopolitical fears related to Russian gas dependence will need to either terminate, or not renew on expiry, their long-term contracts with Gazprom. This will result in substantial additional infrastructure costs for LNG import terminals and pipeline connections, or investments in alternative energy sources, energy conservation, and efficiency measures.

Whatever the political relationship between Russia, the European Union, and individual European countries, a continued natural gas relationship will be necessary and needs to be carefully managed. The most immediate problems are: a resolution of the Ukrainian transit situation, and a successful conclusion of the EU's regulatory treatment of the South Stream pipeline. Once the immediate crisis has passed, both sides need to discuss the future role of gas in EU energy balances, together with its potential contribution to the EU's ambitious carbon reduction targets.



Introduction

The Russian reaction to political events in Ukraine in 2014, and specifically its annexation of Crimea, military involvement in the separatist movements in eastern Ukraine, and the Malaysian airlines MH17 disaster, has generated a great deal of commentary about European dependence on Russian energy in general and natural gas in particular. The price dispute which led to termination of Russian supplies to Ukraine in June 2014, and the possibility of interruptions of gas supplies to Europe, led to renewed calls for diversification of European gas supplies and reduction of Russian imports. These discussions have repeated a great deal of the geopolitical and security discourse around European imports of Russian gas which has been heard periodically over the past 40 years during both the Soviet and post-Soviet periods, but particularly during the Russia–Ukraine gas crises of January 2009 and January 2006. The OIES natural gas research programme has published a number of books and papers on these crises, Russian and CIS gas issues, and European gas supply and demand issues.¹

This paper has two major aims: first to examine the realistic options for reducing European dependence on Russian gas in three time frames – 2015, 2020, and 2030. In so doing it examines the alternative gas and non-gas options for reducing dependence on Russian gas; it also provides some idea of the possible costs of alternatives to Russian gas, who will pay these costs, and the likely competitiveness of Russian versus alternative gas supplies. The second aim is to distinguish natural gas security from geopolitical arguments, given the concern that freedom of action in EU and national foreign and security policies will be constrained for fear that Russia will retaliate by cutting off gas supplies.

It is also important to say what this paper is not addressing: it is not dealing with general security issues surrounding European gas, and it is not considering the impact of potential interruptions of Russian gas deliveries (either due to Ukrainian or Russian actions) on different European countries. We and others have covered such subjects in previous work.² What we seek to do in this paper is to examine the potential for reducing European dependence on Russian gas and contrast this with assertions by some commentators that this can be quickly and easily achieved.

This paper is structured in seven chapters: following this introduction Chapter 1 looks at volumes, contractual obligations, definitions of dependence, and projections of gas demand for countries highly dependent on Russian gas. Chapter 2 reviews non-Russian gas supply sources for Europe in terms of likely volumes and necessary infrastructure. Chapter 3 examines non-gas alternatives to Russian gas supplies. Chapter 4 looks at how Ukrainian dependence on Russian gas might be reduced in the context of the current crisis, and the impact of this on European imports of Russian gas. Chapter 5 looks at likely Russian responses to European actions. Chapter 6 examines the geopolitical arguments in favour of reducing Russian gas supplies, and Chapter 7 summarizes and draws some conclusions. In this paper, we have aimed at brevity. Rather than lengthy textual and data exposition, we have summarized the research that we and others have already published on these issues. We encourage those seeking further explanation of our data and conclusions to consult our more detailed research.

¹ See (among others and most recently): Henderson and Pirani (2014); Honoré (2014); Yafimava (2011); Pirani (ed.) 2009; Pirani et al. (2009), Stern (2006).

² Most recently Pirani et al. (2014).



1. European Dependence on Russian Gas

1.1 Russian gas exports to Europe: volumes and contracts

Russian gas exports to Europe exceeded 100 bcm in virtually every year in the 1990s; rose to more than 160 bcm/year in the mid-2000s and fell below that level only in the late 2000s before recovering to pre-recession levels in 2013 (Table 1).³

Table 1: Russian Gas Exports to European Countries 2003–2013 (bcm*)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
WESTERN											
Austria	6	6	6.8	6.6	5.4	5.8	5.4	5.6	5.4	5.4	5.2
Belgium	0	0	2	3.2	4.3	3.4	0.5	0.5	0	0	0
Denmark	0	0	0	0	0	0	0	0	0	0.3	0.3
Estonia	0.8	0.9	1.3	0.7	0.9	0.6	0.8	0.4	0.7	0.6	0.7
Finland	5.1	5	4.5	4.9	4.7	4.8	4.4	4.8	4.2	3.7	3.5
France	11.2	14	13.2	10	10.1	10.4	8.3	8.9	8.5	8.2	8.6
Germany	35	40.9	36	34.4	34.5	37.9	33.5	35.3	34.1	34	41
Greece	1.9	2.2	2.4	2.7	3.1	2.8	2.1	2.1	2.9	2.5	2.6
Ireland	0	0	0	0	0	0	0	0	0	0.3	0.5
Italy	19.8	21.6	22	22.1	22	22.4	19.1	13.1	17.1	15.1	25.3
Latvia	2.4	1.2	1.4	1.4	1	0.7	1.1	0.7	1.2	1.1	1.1
Lithuania	2.9	2.9	2.8	2.8	3.4	2.8	2.5	2.8	3.2	3.1	2.4
Netherlands	2.3	2.7	4.1	4.7	5.5	5.3	4.3	4.3	4.5	2.9	2.9
Switzerland	0.3	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.4
Turkey	12.9	14.5	18	19.9	23.4	23.8	20	18	26	27	26.7
United Kingdom	0	0	3.8	8.7	15.2	7.7	11.9	10.7	12.9	11.7	16.6
Sub-Total	100.6	112.2	118.7	122.5	133.9	128.7	114.2	107.5	121	116.2	137.8
EASTERN											
Bosnia and Herzegov	0.2	0.3	0.4	0.4	0.3	0.3	0.2	0.2	0.3	0.3	0.2
Bulgaria	2.9	3	2.6	2.7	2.8	2.9	2.2	2.3	2.5	2.5	2.9
Croatia	1.2	1.1	1.2	1.1	1.1	1.2	1.1	1.1	0	0	0.2
Czech Republic	7.4	6.8	7.4	7.4	7.2	7.9	7	9	8.2	8.3	7.9
Hungary	10.4	9.3	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	0.1	0.1	0.1
Poland	7.4	6.3	7	7.7	7	7.9	9	11.8	10.3	13.1	12.9
Romania	5.1	4.1	5	5.5	4.5	4.2	2.5	2.6	3.2	2.5	1.4
Serbia	1.9	2.3	2	2.1	2.1	2.2	1.7	2.1	2.1	1.9	2
Slovakia	7.3	7.8	7.5	7	6.2	6.2	5.4	5.8	5.9	4.3	5.5
Slovenia	0.7	0.7	0.7	0.7	0.6	0.6	0.5	0.5	0.5	0.5	0.5
Other countries	0	0	0	0.4	0.5	0.6	1.2	2.1	1.3	0.8	1.2
Sub-Total	44.6	41.8	42.9	43.9	39.9	43	38.5	44.5	40.7	39.6	40.8
GRAND TOTAL	145.2	154	143.5	166.4	173.8	171.7	152.7	152	161.7	155.8	178.6
Deliveries under long term contracts**					158.8	168.5	142.8	138.6	150.3	139.9	166

*data in Russian cubic metres – to convert to European units reduce by 7.97%. **deliveries under long-term contracts represent volumes which are believed to be delivered from Russian gas fields to Europe; the higher totals include gas delivered by Gazprom but sourced from elsewhere.

Sources: Gazprom in Figures: 2005–2009, p.56; 2008–2012, p.63; 2009–2013, p.67; Stern (2005), Table 3.1, p.110; Long term contract data from GazpromExport.

³ Data in this section refer to all gas sold in Europe by the Gazprom Group in Russian cubic metres (which need to be reduced by 7.97% to convert to European cubic metres) and includes the Baltic countries in Europe.



However, all of the increase in volumes has been in (to use Cold War terminology) Western Europe, while Central and East European countries imported less Russian gas in 2013 than they did not only 10 years previously, but also less than in the early 1990s, primarily because of reduced demand, economic restructuring and much higher prices than during the Soviet era. The vast majority of the 'west' European increase stems from two countries: Turkey which doubled its imports over this period, and the UK, which imported no Russian gas prior to 2005 but had become Gazprom's fourth largest market by 2013 – although it is unlikely that any Siberian molecules were physically delivered to the UK, rather this was most likely gas of non-Russian origin acquired and resold by Gazprom Marketing and Trading (Gazprom's UK-based marketing subsidiary).⁴ Aside from these countries, only Italy and Poland imported *significantly* more (in other words, more than 1 bcm) Russian gas in 2013 than they did a decade earlier, and many imported significantly less (Table 1).

Russia, and specifically Gazprom, is the largest single supplier of gas to European countries. In 2013, Gazprom exported a record volume of gas to Europe, significantly exceeding deliveries in the 2008–2012 period (Table 1) and, due to a fall in European demand and deliveries from other indigenous and external suppliers, representing 34 per cent and 30 per cent respectively of European imports and demand.⁵

The vast majority of Russian gas exports to Europe are sold on long-term contracts varying from 10 to 35 years in length. These contracts, which are legally binding and subject to international arbitration, contain take-or-pay clauses which require buyers to pay for a minimum annual quantity of gas, irrespective of whether they take that quantity. In the post-2008 period, the take-or-pay level in many of these contracts was reduced from 85 to 70 per cent.⁶ Figure 1 illustrates the profile of Russian long-term contracts with European buyers, showing that at an assumed 70 per cent take-or-pay level, European buyers are committed to purchasing more than 125 bcm of gas from Gazprom in 2020 and around 70 bcm in 2030.⁷ There are significant limitations on the options to reduce the volumes in these contracts, or to terminate contracts before expiry.⁸ Thus far, despite difficult renegotiations and a large number of arbitration proceedings, no such actions have been reported. Indeed, we are aware of only two European contracts for Russian gas which have not been extended at expiry, one of which involved Russian gas being sold to other buyers in the same country.⁹

⁴ This accounts for at least part of the difference between the grand total figures in Table 1 and the long-term contract figures which represent gas which was delivered to Europe from Russian sources.

⁵ IEA Natural Gas (2014). Note this data relates to 35 European countries including the Balkans and Turkey, data for EU member states can be found below (see note 14).

⁶ All European long-term gas contracts are subject to commercial confidentiality, which means that it is difficult to be categorical about their terms; for details of the changes since 2008 see Stern (2012, ed.), especially pp. 59–66.

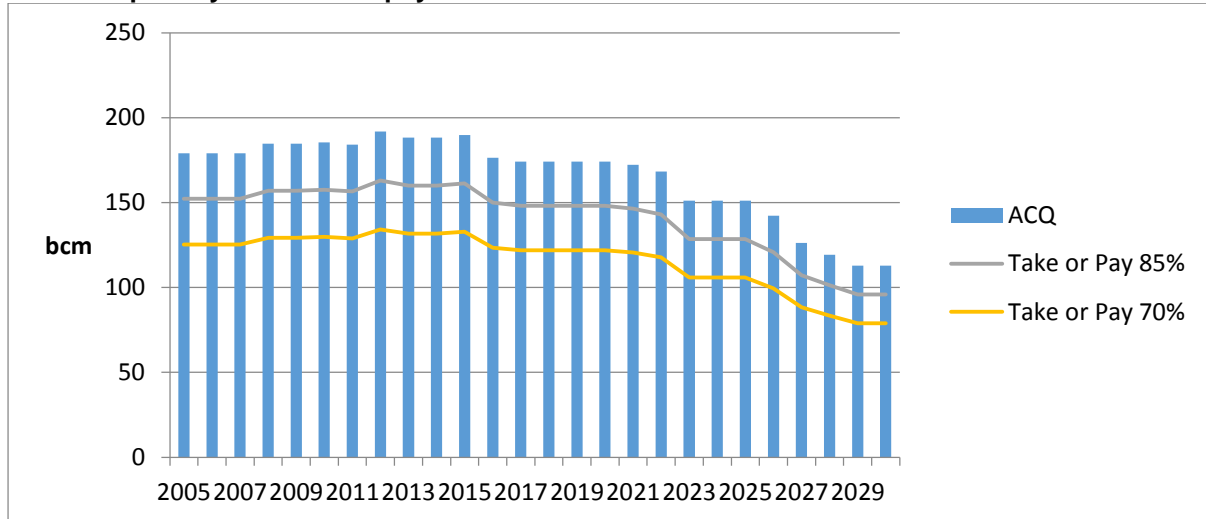
⁷ These figures may understate the position, particularly up to 2020, because they do not include some countries with long-term contracts which expire before that date. The figures are in Russian units, the corresponding European units are 115 bcm in 2020 and 65 bcm in 2030.

⁸ As already noted, annual take-or-pay levels in many contracts have been reduced, but this may have the effect of extending the life of contracts as buyers are still contractually obliged to take volumes over a longer period.

⁹ For details of renegotiations and arbitrations see Henderson and Pirani (2014), Chapter 3. The Croatian contract was not renewed on expiry and that country replaced Russian gas with supplies from Italy (although small deliveries recommenced in 2013); the first Turkish contract with Botas was not renewed but the gas was sold to other buyers, mainly Gazprom affiliates.



Figure 1: Russian long-term export contracts with OECD European countries to 2030: annual contract quantity and take-or-pay levels*



*Data in Russian units; not including Baltic and south East European countries (aside from Turkey and Greece)

Source: ERI RAS in Henderson and Pirani (2014), Figure 3.3, p.60.

Long-term contractual commitments are, therefore, an important starting point for any discussion of reducing – or of making any significant change in – the volumes of Russian gas deliveries to European countries. In the exchange of letters between Russia’s President Putin and the EU’s President Barroso in April 2014, the latter reminded the Russian president that:¹⁰

The contractual reliability of the Russian Federation as a supplier of gas is at stake in this matter...I would like to recall that supply contracts are between European companies and Gazprom. It therefore continues to be Gazprom’s responsibility to ensure the deliveries of the required volumes as agreed in the supply contracts. The European Union has repeatedly stated that we expect commercial operators on all sides to continue respecting their contractual obligations and commitments.

The final sentence provides clear confirmation at the highest EU level that the obligations in Russian long-term gas contracts with European companies are expected to be fulfilled by both sides, irrespective of any political crisis in Ukraine or between the latter and the Russian Federation. Therefore, even if it were possible to replace Russian gas supplies with other sources of energy and gas (which will be the main subject of this paper), aside from *force majeure* there are no circumstances including sanctions which would allow either European companies or Gazprom to renounce the overall volume offtake obligations in their long-term contracts.¹¹ In the meantime, it will be important to see whether Russian contracts which expire in the next several years in countries such as Lithuania (2015) and Hungary (2016) will be extended or replaced by non-Russian gas. Another option for countries which consider Russian gas imports to constitute an unacceptable geopolitical threat to their national security – but which are unable to access alternative supplies at acceptable costs – would be to replace gas with other fuels in their energy balances.

¹⁰ Letter from President Barroso to President Putin, European Commission Statement, Brussels, 17 April 2014.

¹¹ This may be the reason why – at least up to September 2014 – no European sanctions have been placed on the Russian gas industry which might allow Gazprom or European companies to declare *force majeure* i.e. that sanctions are preventing them from fulfilling their long-term contract obligations.



1.2 Statistical measures of dependence and vulnerability

Many commentators on European dependence on Russian gas start with reserve estimates which show that Europe is 'surrounded by gas reserves', and draw the conclusion that there is plenty of gas available to replace Russian supplies.¹² Others observe that Europe has more than 80 bcm of gas storage capacity and nearly 200 bcm of LNG import capacity and therefore 160 bcm of Russian imports can easily be replaced.¹³ This section addresses the problems of arithmetic analysis, which is extremely popular with commentators seeking to demonstrate the existence of simple solutions which would reduce European dependence on Russian gas.

In its May 2014 Communication on European Energy Security Strategy, the European Commission (EC) summarized dependence on Russian gas as follows:¹⁴

Six Member States depend from Russia as single external supplier for their entire gas imports and three of them use natural gas for more than a quarter of their energy needs. In 2013 energy supplies from Russia accounted for 39% of EU natural gas imports or 27% of EU gas consumption.

There are several problems connected with the interpretation of dependence statistics, the most obvious being that (with the exception of countries which have no other source of gas) the figures change every year, with 2013 being a record level which is substantially higher than the 2008–2012 period (Table 1). More importantly, arithmetic dependence can be misleading if interpreted as a measure of vulnerability to an interruption of supplies. This is particularly the case for countries where considerable volumes of gas are traded (imported and exported) each year, so that the percentage (of either gross or net imports) of Russian gas fails to accurately reflect the alternative gas import options available to these countries should Russian supplies be interrupted.¹⁵

Figure 2 shows a simple dependence chart with European imports of Russian gas (adjusted to European units) plotted against European demand for the period 1990–2013. From this it is clear that the share of imports was relatively steady (in the range of 20–25 per cent) until 2013, when European demand fell and Russian exports increased, at which point it reached 28 per cent of the total (similar to the EU figure of 27 per cent cited above).

¹² For a table of gas reserves in a range of countries see Appendix 1.

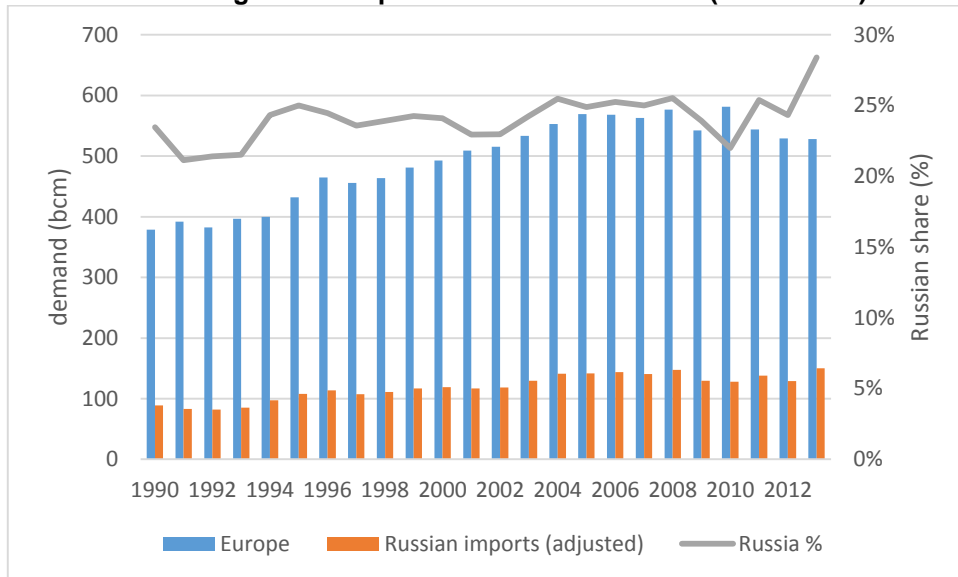
¹³ Bryza (2014) is a good example of this type of commentary.

¹⁴ EU Commission (2014c), p.2.

¹⁵ This is because countries which trade (i.e. import and re-export) may have the option not to do so if they do not have enough gas to meet domestic demand.



Figure 2: Share of Russian gas in European demand 1990–2013* (bcm and %)



Source: EIA International Energy Statistics Database, based on 40 European countries.

For these reasons, the 2014 EC security strategy document uses two different metrics: an estimate of resilience against interruptions – the so-called N-1 standard;¹⁶ and a country-specific supplier concentration index (SCI). In 2013, 16 member states met the N-1 standard for natural gas; those which did not were Bulgaria, Greece, Lithuania, Estonia, Slovenia, Sweden, Ireland, Luxembourg, and Portugal.¹⁷ The failure of the first five countries to meet this standard relates to their dependence on Russian gas.

¹⁶ This standard requires Member States to ensure that, in case of disruption of their single largest piece of gas infrastructure, the capacity of the remaining infrastructure could satisfy an exceptionally high demand level; it also requires developing physical reverse-flow capacity subject to a potential cost/benefit analysis. These measures were set out in Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010, Concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC, *Official Journal of the European Communities*, 12.11.2010, L295/1.

¹⁷ EU Commission (2014d), p.112.

Table 2: EU Member State Country-Specific Concentration Index* for Natural Gas supplies from outside the European Economic Area 2000–2012

	2000	2005	2009	2010	2011	2012
Austria	42.7	49	63.7	61.8	79.8	96.8
Belgium	7.8	5.1	11.8	7.8	14.6	1.6
Bulgaria	87.5	76.8	97.3	85.8	74.1	69.5
Croatia	16.8	15.3	11.7	10.4	0	0
Czech Republic	61.1	56.4	46.6	57.3	118.5	79.3
Denmark	0	0	0	0	0	0
Estonia	100	100	100	100	100	100
Finland	100	100	100	100	100	100
France	14.5	8.8	6.3	4.7	5.1	4.2
Germany	15.1	17	11.6	14.1	15.7	15.3
Greece	60.5	71.3	38.1	39.8	40.1	35.7
Hungary	44.3	36.8	51.2	57.5	48.9	63.4
Ireland	0	0	0	0	0	0
Italy	24.7	17.9	16.6	16.4	16.1	16
Lithuania	100.1	101.3	100.7	99.4	100.5	100.1
Luxembourg	100	100	6.9	6.9	6.9	6.8
Latvia	103.9	111.5	130.1	38.2	119.7	129.5
Netherlands	0	0.8	0.5	0.5	0.2	0.4
Poland	30	22.7	31	38.8	41.1	34.7
Portugal	76.9	56.9	37	42	46.2	38.6
Romania	3.9	9.1	2.2	2.7	3.6	3.3
Slovenia	51.2	51.3	31.9	32.5	28.2	20.1
Slovakia	97.6	105.6	116.8	99.8	109.9	82.3
Spain	39.4	25.2	19.8	19.8	24	26.5
Sweden	0	0	0	0	0	0
UK	0	0	0.4	2.2	0.5	n/a

*The SCI is computed as the sum of squares of the quotient (multiplied by 100) of net positive imports from a partner to an importing country (numerator) and the gross inland consumption of that fuel in the importing country (denominator). Smaller values of SCI indicate larger diversification and therefore lower risk.

Source: EU Commission (2014d), Table 12, pp.151–2.

The country-specific supplier concentration index shown in Table 2 is a measure of diversification and the exposure of countries to suppliers outside the EU and European Economic Area (EEA).¹⁸ The index reports values between 0 (no import) and 100 (where the entire consumption comes from a single supplier). Values above 100 indicate use of storage (for example Latvia); the values may also

¹⁸ Since Norway is not an EU member state, it was important to include EEA countries in order to count its supplies as 'European'.



be overly high in countries which transit large volumes of Russian gas (such as Austria and the Czech Republic) due to the fact that intra-EU trade movements are not reported as exports.¹⁹

With the exception of Portugal, the countries in Table 2 with a concentration level above 30 per cent are all highly dependent on Russian gas. The value of this methodology is its ability to show how dependence changes over time: increasing (Austria and the Czech Republic), decreasing (Bulgaria and Greece), and remaining relatively constant (Poland). However, this assumes that supplies from outside Europe are more insecure than those from European sources – a widely accepted assumption, but one which needs to be questioned empirically.

Table 3: Non-EU Member State Imports of Russia Gas and Estimated Supplier Concentration Index, 2013*

	Imports of Russian Gas (bcm)	Estimated Supplier Concentration Index (SCI)
Turkey	26.7	38.36
Serbia	2.0	56.47
Bosnia & Herzegovina	0.2	100
FYROM	0.1	100

*calculated using IEA data and therefore may not be completely comparable to the data in Table 2.

Source: IEA Natural Gas (2014), pp.II.8–9, Table 3, pp.II.34–37, Tables 17–18.

Three further observations are relevant here: first, many of the largest European gas markets (Germany, UK, France, Italy, Netherlands, and Belgium) have relatively low concentrations (SCIs of 4–18 over the period) of non-European supplies; Spain, which had an SCI of 20–40, imports no Russian gas. Second, that at least some of the countries noted above which do not meet the N-1 standard (Sweden, Luxembourg, and Slovenia) and are therefore relatively vulnerable to interruptions, have low non-European supply concentrations. Third, European dependence on Russian gas needs to be considered in a wider geographical framework than limiting the analysis to EU member states. The vulnerability of Bosnia & Herzegovina and Serbia was graphically illustrated during the January 2009 Russia–Ukraine crisis;²⁰ Turkey is Gazprom’s second largest customer and Russian gas accounted for around half of total supply in the early 2010s.²¹ For this reason, we have applied the SCI methodology to these countries and Table 3 shows the total dependence of Bosnia & Herzegovina and FYROM; together with the significant dependence of Serbia and, to a lesser extent, of Turkey. In relation to dependence on Russian gas, and security of supply, it is therefore logical to concentrate on whether and how countries with high dependence/supplier concentration could substantially alter their situation, using projections of their gas demand levels up to 2030.

1.3 European gas demand projections to 2030

Table 4 shows gas demand scenarios for those countries which are – and are likely to continue to be – highly dependent on Russian gas (with an SCI exceeding 30) up to 2030.

¹⁹ In 2013 these ‘exports’ (in reality transit) amounted to 40.5 bcm for Austria and 7.1 bcm for Czech Republic, see IEA *Monthly Natural Gas Survey*, July 2014, Table 4, p.17.

²⁰ This applied less to FYROM which still retained oil-switching capability. See Pirani et al. (2009) and Kovacevic (2009).

²¹ Rzayeva (2014), pp.27–31.

Table 4: Gas Demand Projections for Countries Highly Dependent on Russian Gas 2015–2030 (bcm*)

	Gas Demand in 2013	Russian Gas Imports in 2013*	Gas Demand Projections			
			2015	2020	2025	2030
CENTRAL EUROPEAN COUNTRIES						
Austria	8.53	4.79	8.53	7.54	7.60	7.11
Czech Republic	8.47	7.27	8.08	8.69	8.68	9.94
Slovakia	5.81	5.06	4.72	4.86	6.19	7.66
Poland	18.31	11.87	15.73	17.08	19.49	21.07
Hungary	9.28	5.52	10.65	11.12	10.37	9.79
TOTAL	50.4	34.51	47.70	49.30	52.33	55.57
BALTIC COUNTRIES						
Estonia	0.68	0.64	0.34	0.38	0.41	0.43
Latvia	1.73	1.01	1.83	1.93	2.05	2.13
Lithuania	2.71	2.21	3.24	3.47	3.75	4.03
Finland	3.48	3.22	2.33	2.35	2.72	3.06
TOTAL	8.6	7.08	7.74	8.13	8.92	9.65
SOUTH EAST EUROPEAN COUNTRIES						
FYROM	0.16	0.09	0.12	0.12	0.12	0.12
Bosnia/Herzegovina	0.19	0.18	0.26	0.27	0.29	0.30
Bulgaria	2.59	2.67	2.89	3.03	3.14	3.29
Serbia	2.52	1.84	2.30	2.30	2.30	2.30
Greece	3.84	2.39	4.32	4.10	3.85	3.64
TOTAL	9.3	7.17	9.89	9.82	9.69	9.65
GRAND TOTAL	68.3	48.76	65.33	67.25	70.95	74.86
Turkey	45.64	24.57	49.56	59.26	65.58	70.62

*converted to European units by reducing data in Table 1 by 7.97%

Sources: 2013 demand for OECD countries from IEA Natural Gas (2014), Tables 3 and 8, pp. 8–9, 16–17; Russian imports from Table 1; 2015–2030 projections from Honoré (2014).

An important conclusion from Table 4 is that for the three groups of countries which are highly dependent on Russian gas, demand is expected to increase by less than 7 bcm during the period 2013–2030: in Central Europe by 5.2 bcm, in the Baltic countries by 1.05 bcm, and in south-east Europe by 0.4 bcm. In 2030, total demand for gas in countries highly dependent on Russian gas in the Baltics and south-east Europe will be 19.3 bcm. In Central Europe, demand is much larger, particularly in Poland (which has significant domestic gas production and an SCI which is significantly lower than other countries in the region). Table 4 sets Turkey apart, as its gas demand is of a completely different order of magnitude and in the 2020s will approach the sum of all other countries. This data provides useful metrics for considering how much gas would be needed to replace Russian gas in the most dependent European countries up to 2030.

Chapters 2–5 review the potential for non-Russian gas supplies and the non-gas options available to Europe and Ukraine up to 2030.



Appendix 1: Conventional natural gas reserves and reserve to production ratios for current and potential suppliers to Europe, end 2013

	Reserves (trillion cubic metres)	Reserve/Production Ratio (years)
Azerbaijan	0.9	54.3
Kazakhstan	1.5	82.5
Norway	2.0	18.8
Netherlands	0.9	12.4
Russian Federation	31.3	51.7
Turkmenistan	17.5	>100
UK	0.2	6.7
Uzbekistan	1.1	19.7
Iran	33.8	>100
Iraq	3.6	>100
Qatar	24.7	>100
Algeria	4.5	57.3
Egypt	1.8	32.9
Libya	1.5	>100
USA	9.3	13.6
Canada	2.0	13.1

Source: BP Statistical Review (2014), p.20.



2. Alternative Sources of Gas Supply to Europe: volumes, time frames, and infrastructure requirements

2.1 Supply options

2.1.1 European indigenous gas supply – conventional and unconventional

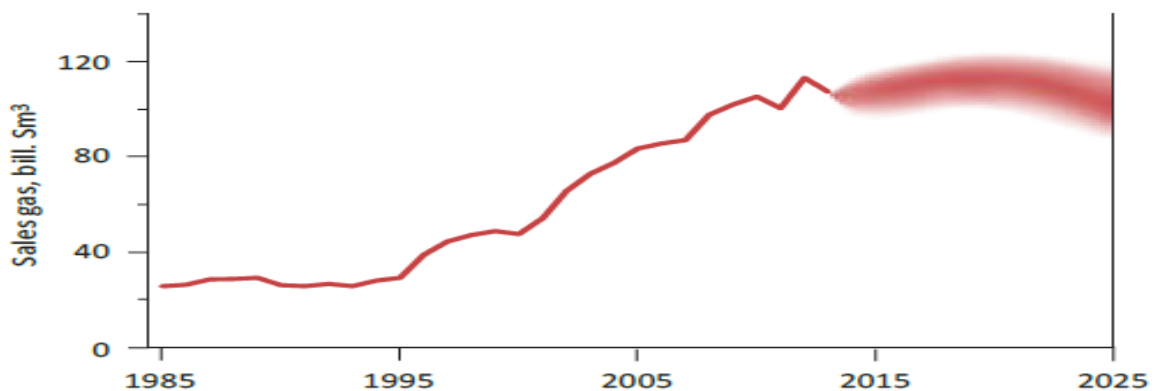
Conventional gas production

In the early 1970s, European indigenous production covered most of the region’s gas demand. By 2013, due to faster growth rates of consumption and a decline in gas production since the early 2000s, it only accounted for around 57 per cent of demand.²² European production is falling everywhere apart from Norway, and as a result, despite slow demand growth expected up to 2030, Europe will become increasingly dependent on imports. The following paragraphs look at the uncertainties surrounding future indigenous production and at the prospects for an increase in output up to 2030.

Two countries represented 70 per cent of the indigenous production in 2013 – Norway: 109 bcm and the Netherlands: 86 bcm. These countries are also the two main sources of indigenous gas for the other European countries. Production from the UK continental shelf (UKCS) is still significant, at about 38 bcm, but it only represents about half of the national needs. Another 19 countries produced gas in 2013; this was used by their national markets, except for Denmark which exported small quantities.

In 2013, **Norway** was the world’s third-largest gas exporter behind Russia and Qatar and the biggest natural gas producer in Europe (21.6 per cent of regional gas consumption). Nearly all Norwegian gas is sold on west European markets via pipeline and this gas has partly offset the loss of both volumes and flexibility from the UKCS in the 2000s. However, projections from Norway’s Ministry of Petroleum in Figure 3 show gas sales in the range of 100–125 bcm in 2020, and 75–115 bcm in 2025 (from 103 bcm in 2013).²³ The impression therefore is of plateau and possible decline in the late 2010s and early 2020s. This could be reversed if more reserves are discovered, particularly in the Barents Sea where exploration is still at an early stage. But gas exports – whether by pipeline or LNG – from the far north are likely to be high cost.

Figure 3: Sales Gas from Norwegian fields 1985–2025 (bcm)



Source: The Ministry of Petroleum and Energy (2014), Figure 4.16, p.45.

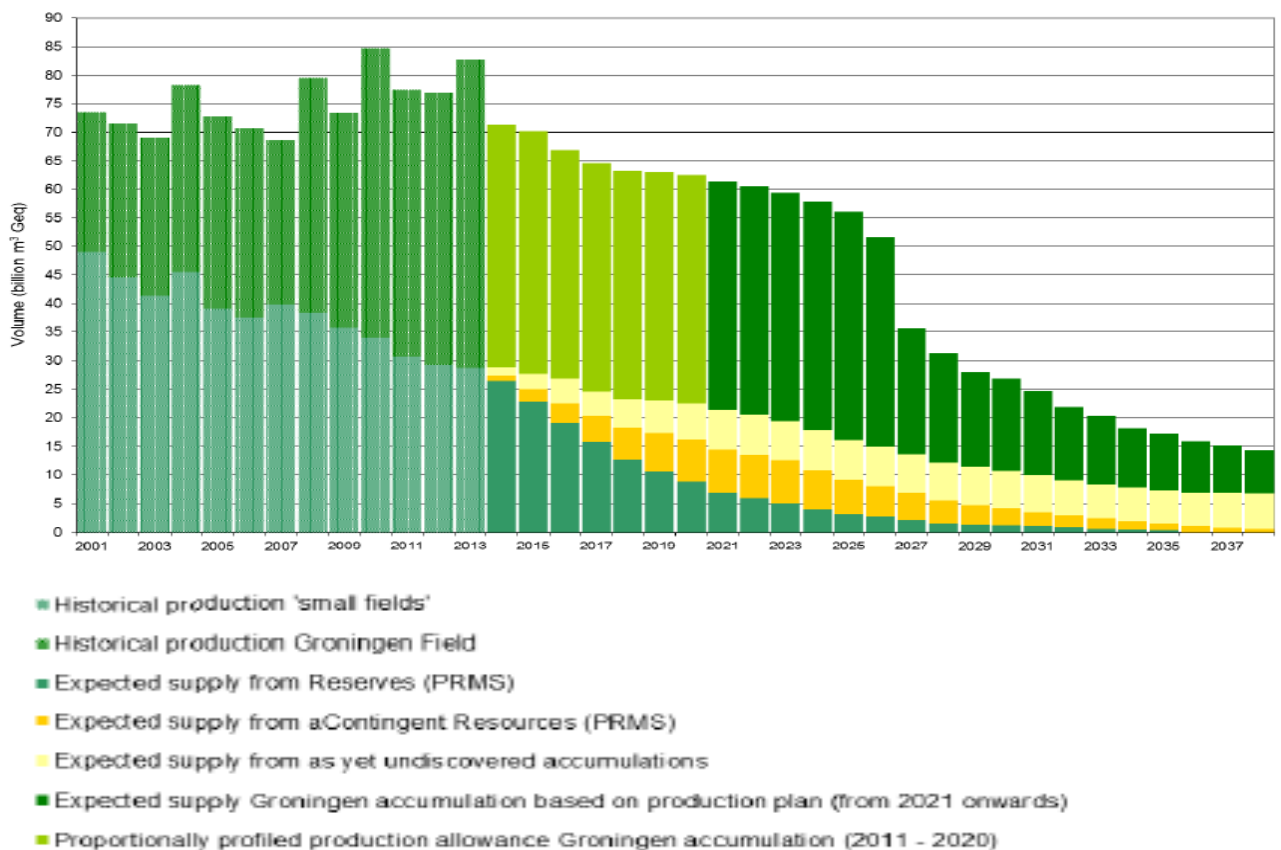
²² Data for OECD Europe in IEA Natural Gas (2014), calculated from pages II.4 and II.8

²³ Scenario up to 2025: Ministry of Petroleum and Energy (2014), p.45. Data in standard cubic metres converted to normal cubic metres by multiplying by 0.948.



In 2013, **the Netherlands** was the largest European producer and exporter of gas after Norway. Total production peaked in 2010 and since then has declined marginally, a trend which Figure 4 shows is due to accelerate in the 2010s. The Groningen field is one of the ten largest gas fields in the world, with production of nearly 54 bcm in 2013. But following fears of earth tremors, production in the areas most at risk will be reduced by 80 per cent (rather than entirely, to ensure a sufficient supply of natural gas during periods of peak demand, such as the coldest days); limits on Groningen production for 2014, 2015, and 2016 have been set at 42.5, 42.5, and 40 bcm, respectively.²⁴ After 2016, the situation will be evaluated to decide on further restrictions; as a result, a continuation of the maximum annual production of 40 bcm²⁵ is assumed until 2020, followed by a rapid decline reaching 16 bcm by 2030.

Figure 4: Historical and estimated future production of natural gas in the Netherlands 2001–2038 (bcm)



Source: Netherlands (2012), p.25.

The **United Kingdom** produced 38 bcm in 2013, almost all from offshore fields, mostly from the North Sea but also the Irish Sea. The decline in UKCS production from its peak of about 120 bcm in 2000 has been relatively steep but is expected to level off in the late 2010s.²⁶ Department of Energy and Climate Change scenarios show that production will decline further in the 2020s to reach about 20 bcm in 2030 as shown below in Figure 5.27

²⁴ Government of the Netherlands (2014).

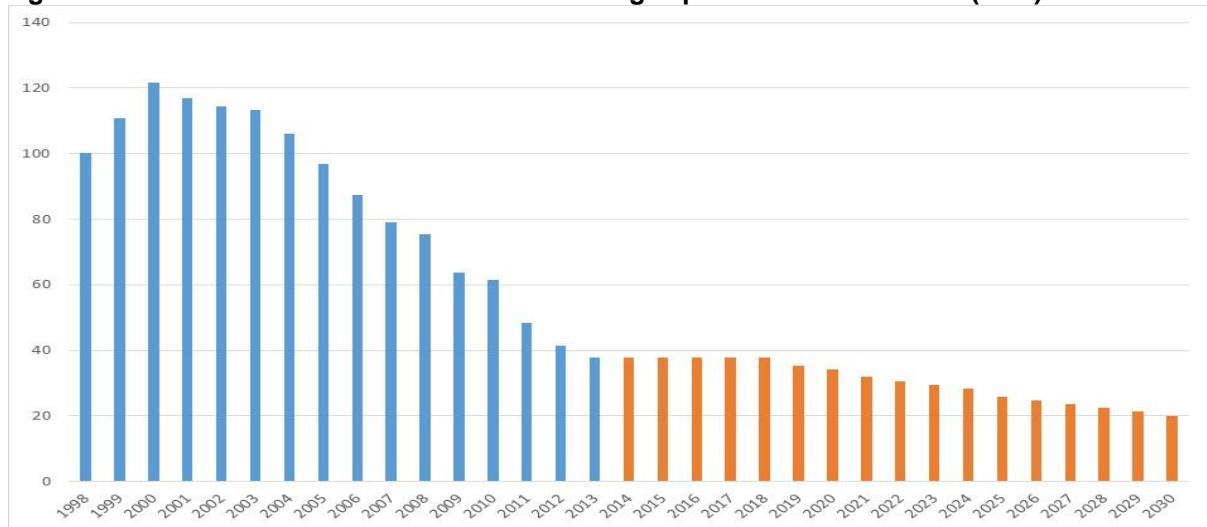
²⁵ Groningen Gas Equivalent (heating value of 35.17 MJ/Nm³).

²⁶ IEA (2014c), *Energy Supply Security, emergency response of IEA countries*, p.473; http://www.oilandgasuk.co.uk/economic_report/production.cfm.

²⁷ DECC (2014).



Figure 5: Historical and estimated UK net natural gas production 1998–2030 (bcm)



Source: DECC (2014).

Elsewhere in Europe, **German** production amounted to 11.7 bcm in 2013, but is expected to decline at an average of 5 per cent per year to less than 5 bcm/year by 2030. **Romania** produced 10.6 bcm in 2013, but levels are expected to decline to 6 bcm/year by 2030.²⁸ **Italy** still produces more than 7 bcm of gas a year but is in long-term decline; **Poland** produced more than 6 bcm in 2013 but conventional gas is also in decline. **Denmark** is a net exporter of natural gas, but production peaked in 2005 (at 10.4 bcm) and has been in decline since then.²⁹ No other European country produces more than 2 bcm/year.

Table 5 shows scenarios for indigenous gas production in Europe for 2015, 2020, and 2030. Production is expected to decline from 282 bcm in 2013 to about 266 bcm in 2015, mostly due to the limit imposed on production from the Groningen field in the Netherlands. By 2020, indigenous production could decline by another 20 bcm as a result of sharper decline in the Netherlands, UK, and Germany. By 2030, European conventional gas production is expected to be about 172 bcm, a reduction of 110 bcm compared with 2013. Table 5 also shows that the total is very dependent on the three largest producers, which account for 82–84 per cent of the total throughout the period.

Table 5: Indigenous conventional gas production in European markets 2013–2030 (bcm)

	2013	2015	2020	2030
Norway	109	109	110	100
UK	38	38	34	20
Netherlands	86	71	63	26
Other	49	48	39	27
TOTAL	282	266	246	172
Norway/UK/Netherlands	83	82	84	84

as a % of total

Sources: Figures 3–5, *Danish Energy Agency (2014)*, *IEA*, *author's own analysis*

²⁸ OIES estimates.

²⁹ See *Danish Energy Agency (2014)*, p.19



Unconventional gas in Europe

Much attention has been devoted to the prospects for unconventional, especially shale, gas in Europe. Recoverable shale gas reserves are estimated to be 16 trillion cubic meters (tcm), far above tight gas at 3 tcm, and coal bed methane at 2 tcm.³⁰ While high expectations exist for shale gas production, it is unlikely that this will significantly change the supply landscape at the regional level in the time frame considered in this paper. Production may be significant at the national level but most probably not this side of 2020.

There is no homogenous approach to shale gas exploration around Europe.³¹ About 20 countries have allowed exploratory drilling, although in countries such as Spain regional bans exist. The most advanced market is Poland, where 64 exploratory wells had been drilled as of June 2014, of which more than 20 have been fracked. The Polish authorities expected an additional 20 wells and the first commercial production before the end of 2014.³² However, the promise of the early 2010s has not been maintained and companies such as ExxonMobil, Marathon, Total, ENI, and Talisman have pulled out because of disappointing results and a complicated fiscal and regulatory landscape. Nevertheless, other companies, such as Chevron, ConocoPhillips, and smaller companies such as San Leon Energy, have achieved positive results after fracking.

The next most advanced country is the UK, which decided that exploratory drilling and fracking could resume in December 2012, following a one year halt due to earth tremors recorded in the vicinity of Blackpool in 2011. While reserves are judged to be significant, it is difficult to estimate how much gas could be produced until the well flow rates have been tested.³³ The government has placed great emphasis on shale gas exploration and production and has announced several measures designed to lessen opposition from local communities and attract investment.³⁴ However, the lengthy planning and consent process – not to mention large potential public opposition and disruption from protestors – complicate the picture. In other countries progress is even slower, and most activity is at a very preliminary stage. Some countries (and regions of countries) have imposed outright bans on drilling and fracking.

While the hope was that shale gas could flatten the projected decline of conventional production, as of 2014 it is too early to estimate if and when significant quantities of shale – or any other unconventional gas – will be produced. In a 2010 paper published by OIES Gény proposed three scenarios – low, medium, and high potential³⁵ – if commercial shale gas production in Europe began in 2015, unconventional gas production was not expected to exceed 4.2 bcm³⁶ before 2020. By 2030, the range represented in each scenario goes from 28 to 100 bcm/year, the upper bound of which is viewed as a very optimistic but not 'totally unrealistic production level'.³⁷ However, production of 8 bcm/year would necessitate 300 wells drilled per year (from 25 pads) over 10 years (based on a

³⁰ EU Commission (2014e), p.4.

³¹ Despite concerns over possible pollution and seismic consequences of hydraulic fracking, the European Commission did not regulate and instead published a list of non-binding recommendations on minimum principles applicable to exploration or production using high volume hydraulic fracking on 22 January 2014. Source: EU Commission, Energy and environment website: http://ec.europa.eu/environment/integration/energy/unconventional_en.htm.

For more information, see IEA (2014b), p.82.

³² Reuters UK, 31 July 2014, 'Poland cuts estimate for shale gas exploration wells', <http://uk.reuters.com/article/2014/07/31/poland-shalegas-minister-idUKL6N0Q438P20140731>.

³³ On 27 June 2013 the British Geological Society doubled its estimate of shale gas resources (in place, as distinct from recoverable) in the north of England to (a central estimate of) 37 tcm.

³⁴ Government of the UK (2014).

³⁵ Gény (2010).

³⁶ Data in Tcf converted in bcm by multiplying by 0.0283

³⁷ Gény (2010), p.62



Barnett Shale Well analogue).³⁸ Thus to reach production levels of even 28 bcm/year could require 800–1000 wells to be drilled each year for 10 years – an activity level which currently seems unimaginable. Perhaps for this reason, the IEA’s 2013 World Energy Outlook sees less than 20 bcm/year of shale gas being produced in Europe in 2035.³⁹

Green gas / biogas

Green gas, or biogas, is produced from organic materials – it is thus a form of renewable/sustainable energy – via digestion (chemical process) or gasification (a thermal process which is still in its infancy). Biogas can be considered a direct substitute for natural gas and can be used in many of the same applications: heat, steam, electricity generation and co-generation, the vehicle fuel market, feedstock in the chemical industry (fertilizer), and grid injection (it has to be upgraded to biomethane⁴⁰ before it can be injected into the natural gas grid). Biogas can be considered as indigenous production and can be viewed as improving security of supply.

Most of the Member States in Europe have a biogas roadmap as part of their National Renewable Energy Action plans. However, biogas production is reliant on support from national legislation such as feed-in tariffs (FITs), tax systems, or subsidies. In 2012, there were 13,800 biogas plants in Europe, representing more than 7.4 GW_{el} of installed capacity. More than 60 per cent of these plants (8,700) were in Germany alone, where most biogas is converted into electricity and heat in cogeneration units.⁴¹ Total production of biogas in Europe was about 14 bcm in 2012, with Germany responsible for more than half (53 per cent) the total, followed by the UK (15 per cent), and Italy (less than 10 per cent); other countries have much smaller levels of biogas production.⁴² In 2013, there were more than 200 methanization plants in 15 European countries (Austria, Switzerland, Germany, Denmark, Spain, Finland, France, Hungary, Iceland, Italy, Luxembourg, Netherlands, Norway, Sweden, and the UK) and biomethane was injected into the gas network in ten countries (Austria, Switzerland, Germany, Spain, Finland, France, Luxembourg, Netherlands, Norway, and the UK).⁴³ Germany was in the lead with 130 plants as of November 2013, representing 76 cubic metres of combined injection capacity per hour.⁴⁴ The biomethane is mostly used in CHPs, but its application as a transport fuel is also developing in, for example, Sweden and Germany. In 2012, Van Foreest estimated the cost of biomethane production at: €29/MWh from sewage feedstock, €38/MWh from landfill processes, and €75/MWh from co-digestion.⁴⁵

The level of biogas production expected in 2020 in the National Renewable Energy Action Plans is expected to double to about 28 bcm/year in 2020.⁴⁶ More optimistic scenarios exist: from 48 bcm/year in 2020, European Biomass Organization; up to 200 bcm/year, Institute for Energy and Environment.⁴⁷ These scenarios may be unrealistic, or at best unlikely, due to a number of uncertainties such as: the continuation of financial support to the development of biogas; the sustainability of biomass production with its impacts on ecosystems; the effect of competition on cultivated land between biomass production and food and feed production; and the issue of

³⁸ See Rogers (2013).

³⁹ IEA (2013), p.121.

⁴⁰ The CO₂ is removed while the share of methane is increased to meet the quality standards for natural gas

⁴¹ European Biogas Association website.

⁴² EurObserv'ER (2013), p.47.

⁴³ European Biogas Association (2013).

⁴⁴ EurObserv'ER (2013), p.45.

⁴⁵ See Van Foreest F. (2012), p. 40, Figure 20.

⁴⁶ European Biogas Association (2013).

⁴⁷ See Van Foreest F. (2012), Introduction.



deforestation. Nevertheless, in the period up to 2030 – and certainly up to 2020 – biogas is likely to make a much greater contribution to European natural gas balances than unconventional gas.

2.1.2 North Africa

North Africa has been a longstanding European gas supplier (Algeria, Egypt, and Libya) and transit route (Tunisia and Morocco).⁴⁸ Endowed with both oil and natural gas, North Africa’s producers – Algeria, Egypt, and Libya – hold a total of 7.8 tcm of proven conventional gas reserves, 8.2 tcm of technically recoverable undiscovered conventional gas resources, as well as an estimated 26 tcm of technically recoverable shale gas resources.⁴⁹ Growing trans-Mediterranean gas trade since the early 1980s has turned North Africa into Europe’s second-largest external supplier of natural gas, with total exports to Europe of 44 bcm in 2013 (Table 6).

However, while all of these attributes render the region a potential key source of incremental European gas supplies in the long term, the short- and medium-term outlook for an increase in North African gas exports to Europe looks increasingly bleak. The dual challenges of attracting sufficient new upstream investment – a task complicated by the region’s deteriorating investment climate following the onset of the Arab Spring in late 2010 – and of tackling the surge in the region’s domestic gas demand, will be key factors influencing North Africa’s gas export potential over the coming years. Taking into account all current investment and output delays, this will push any net increase in North African gas exports beyond 2020.

Table 6: North African gas balances, 2013

	Marketed production, 2013 <i>bcm</i>	Exports, 2013		Export capacity	
		Gross exports, <i>bcm</i>	of which to Europe, <i>bcm</i>	European pipeline, <i>bcm</i>	Global LNG, <i>bcm</i>
Algeria	78.6	40.3	38.3	53	33
Egypt	56.1	3.7	0.4	0	16
Libya	12.0	5.7	5.2	11	3
Region	146.6	49.7	43.9	64	52

Source: Cedigaz (2014), BP (2014) and authors’ estimates

Faltering production and rising demand

A snapshot view of North Africa’s past years of gas sector performance reveals the profound challenges faced by all three regional gas producers. Algeria’s natural gas production, at 78.6 bcm in 2013 (Table 6), has fallen from its near-time high of 86 bcm in 2008, and falls far short of previous production targets of 85 bcm; thus rendering the former Algerian government production target of 100 bcm by 2015, in the words of a recent APICORP report, ‘irrelevant’.⁵⁰ A series of multi-year project delays that included delays in the delivery of key infrastructure projects, and three previous bidding rounds that attracted only muted interest, have considerably affected Algerian plans to have been ramping up gas output since the late 2000s. Several factors – policy reversals related to Algeria’s hydrocarbon law during the 2000s that have continued to strengthen the role of national oil company

⁴⁸ For an overview over the history of North African gas exports to Europe, see e.g. Darbouche (2011), Darbouche and Mabro (2011) and Otman (2011).

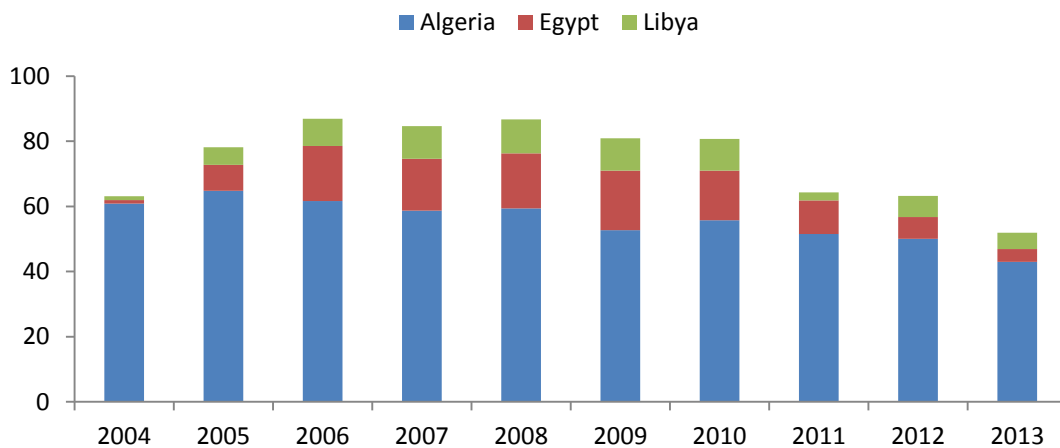
⁴⁹ EIA International Energy Statistics; U.S. Geological Survey (2013); EIA/ARI (2013).

⁵⁰ Aissaoui (2013), p.2.



Sonatrach in all projects, bureaucratic deadlock and, in view of rising project risks, increasingly unattractive fiscal terms – have played a large role in muting interest in Algeria’s hydrocarbon sector over many years.⁵¹ The January 2013 militant attacks on gas production plants at Tiguentourine/In Amenas further helped constrain Algeria’s gas output, through damage to two of the 11 bcm facility’s three producing trains, one of which remains offline at the time of writing.⁵² Algeria’s total LNG export volumes have declined in absolute terms.⁵³ Figure 6 shows the overall downward trend in North African gas exports since 2009.

Figure 6: Gross North African gas exports, 2004-2013 (bcm)



Source: El-Katiri/OIES.

Egypt and Libya suffered from even sharper decline rates than Algeria in the wake of the years of political turmoil that followed the removal of both countries’ long-term political leaders – Hosni Mubarak and Muammar Gadhafi in February and October 2011 respectively. While Egypt’s gas production facilities have remained largely unaffected by the unfolding of the country’s post-revolutionary instability,⁵⁴ its energy sector has been severely affected by the absence of consistent decision-making and by competing government priorities; Egypt’s energy sector has also been caught in the midst of the country’s mounting debt crisis, which has prevented its government from reinvesting and paying foreign partner companies for their gas. Outstanding receivables in Egypt’s oil and gas sector of more than \$7.5bn at the time of writing⁵⁵ also act as a fundamental constraint factor on current project development, as upstream developers have held back investment due to unpaid government debt. Gas production in 2013 of 56 bcm was 11 per cent lower than its all-time high of 63 bcm in 2009, and the monthly production figure in June 2014 was 3.28 bcm below the corresponding month of the previous year.⁵⁶

Libya’s oil and gas sector is in profound disarray after more than three years of domestic infighting; this situation appears to be becoming more widespread as rival militias from different parts of the

⁵¹ For more background, see Darbouche (2011). See also ‘Doubts Persist Over Algeria’s Bid Round’, *Middle East Economic Survey*, 57:23, 6 June 2014; ‘Algeria: Politics Unchanged, Oil & Gas ‘Must Do Better’, *Middle East Economic Survey*, 57:17, 24 April 2014; ‘Algeria’s upstream round faces setbacks’, *Petroleum Argus*, 13 June 2014.

⁵² For example: ‘In Amenas gas plant still below capacity’, *Argus Gas Connections*, 16 July 2014.

⁵³ For example: ‘Bid Round Puts Algeria’s New Hydrocarbon Law To The Test’, *Middle East Economic Survey*, 57:4, 24 January 2014; ‘Algeria’s upstream round faces setbacks’, *Petroleum Argus*, 13 June 2014.

⁵⁴ Production facilities have been unaffected, but export infrastructure – chiefly Egypt’s Sinai gas export pipeline to Israel and Jordan, has been attacked multiple times since early 2011.

⁵⁵ ‘Egypt Receivables Hit Record \$7.5bn’, *Middle East Economic Survey*, 57:32, 8 August 2014.

⁵⁶ Data based on BP and Bloomberg data; ‘Egyptian gas production down in June’, *Petroleum Argus*, 14 August 2014.



country fight over control of the country's key cities and infrastructure – including oil and gas fields. Libya's unfolding civil war continues to cause frequent disruptions to the country's gas production. Production, export, and storage facilities at Libya's largest onshore field, Wafa, were halted in November 2013,⁵⁷ while its export and storage facilities at Melitah port closed in February 2014.⁵⁸ These disruptions have impacted Libya's gas exports to Italy, which have not yet returned to their 2010, pre-conflict, levels and have fluctuated continuously since the return of production in October 2011.⁵⁹ Gas exports to Europe were completely suspended for almost eight months in March 2011, as a result of the unfolding civil war and subsequent UN and European sanctions against the Gadhafi regime until its fall in October 2011.⁶⁰

Contrasting the recent faltering in North Africa's gas output, natural gas demand in domestic markets has been surging – the result of growing population, rising living standards, decade-long policies fuelling domestic industries, and the all-important power sector increasingly reliant on domestically produced natural gas. Gas prices in Algeria, Libya, and Egypt – which are some of the world's lowest – have acted as an additional catalyst for the surge in domestic demand, upholding citizens' expectations of energy as a low-cost good provided by the state as a form of in-kind social transfer.⁶¹

The medium and long term: 2020–2030

North Africa's medium- and long-term gas export potential is subject to a considerable degree of uncertainty. Not only does a history of project delays over the past years suggest potential for similar delays in the future, but the region is also far from having recovered politically from the disruptive effects of the Arab Spring. Libya's currently deteriorating domestic situation precludes any sensible outlook for the country's medium-term gas output potential, there having been no foreign access to production sites since the eruption of conflict in March 2011, and there are no prospects for any near-time new exploration work. Recurring political turmoil, changing governments, and terrorist attacks remain key political risks that may still affect Egypt, as the country's new government under General Al-Sisi⁶² has yet to prove itself a stabilizing force; in Algeria, the future holds a potentially fraught post-Bouteflika leadership transition.

Political factors taken aside, there is scope for a future expansion of North Africa's role as a natural gas exporting region post-2020. IEA medium-term projections offer some positive outlook for Algerian gas, albeit somewhat lower than the country's past projections, with net production increasing to around 88 bcm by 2019, raising Algerian exports by a modest 10 bcm (to around 50 bcm) by the end of the decade.⁶³ A number of key projects under the country's South West Gas Project, partly delayed from earlier this decade, indeed show potential to ramp up Algeria's production capacity, although at first some smaller projects are expected to feed into sustaining, rather than increasing production – up to the later part of the decade.⁶⁴ Our estimates see slightly lower figures for exports, with higher

⁵⁷ 'Libya demonstrations halt gas exports to Italy', *Petroleum Argus*, 12 November 2013.

⁵⁸ 'New shut-ins exacerbate Libyan recovery fears', *Petroleum Argus*, 14 February 2014.

⁵⁹ Part of the fluctuations can be ascribed to reduced gas demand from Italy, with ENI reportedly having negotiated similar reductions to its take-or-pay volumes with Libya as with Algeria. See Darbouche and Fattouh (2011), 31–32.

⁶⁰ For background see Darbouche and Fattouh (2011), p.29.

⁶¹ For a background to the MENA countries' energy subsidies problem, see Fattouh and El-Katiri (2012) and Darbouche (2012). For more recent developments, see Sdravovich et al. (2014).

⁶² Egypt's new government, led by former army general Abdel Fattah Al-Sisi, was sworn into office on 8 June 2014, for the time being ending the three years of political chaos that had followed the resignation of former President Mubarak, and the subsequent ousting of Egypt's first elected government after Mubarak under the Muslim Brotherhood in July 2013.

⁶³ IEA (2014b), p.204.

⁶⁴ Aissaoui (2013), p.2.



domestic Algerian consumption, at 49 bcm in 2020, leaving an export volume of 41 bcm – barely more than 2013, but rising to 60 bcm in 2030 almost entirely due to LNG exports (see Table 7).⁶⁵

By contrast, Egypt's gas exports are expected to continue on a downward trend, as the country is seen as unlikely to raise its own gas production to a level that could sustain both exports and projected domestic demand growth until the end of the decade. Indeed, Egypt's unfolding energy crisis is set to profoundly affect North Africa's regional gas export over the long term, as projected (moderate) Algerian export growth will be unable to compensate on a net basis for losses from Egypt and also, potentially, from Libya as well. By the end of the decade, North African net exports are hence expected to be further reduced, rather than increased, Algeria being a critical balance factor that will keep regional net exports from falling further.

Egypt's Petroleum Ministry actually forecasts that the country's natural gas production will average at 56 bcm for the fiscal year of July 2014–June 2015, which is less than the predicted consumption of 58 bcm.⁶⁶ This projected supply gap means that Egypt will undoubtedly become a net importer of gas within the next year. The country is currently negotiating potential gas supply options via a floating LNG re-gasification facility offshore its Red Sea coast, with first LNG imports planned for autumn 2014.⁶⁷ Among Egypt's current projects, BP's West Nile Delta (WND) development is scheduled (after delays) to bring some 10 bcm onstream in 2014.⁶⁸ In the medium term, new awards (which include the North Thekka offshore and North El Arish Offshore blocks to Edison/Petroceltic and Dana Gas respectively) have raised hopes for future new developments to help reverse Egypt's falling production, though these projects are insufficient to feed into export projects any time soon.

A potentially important factor in North Africa's future gas dynamics may be played by unconventional resources, as Algeria (with some 20 tcm) is estimated to hold the world's fourth largest shale gas reserves after the USA, China, and Argentina.⁶⁹ However, Algerian plans to double production capacity from 2013 with the help of shale gas 'within the next ten years', and Sonatrach's declared target of producing 30 bcm of shale gas by 2020, should be treated with caution.⁷⁰ Success in exploration and development efforts for shale gas in Algeria could shift the centre of gravity of North Africa's future gas output growth during the 2020s towards more unconventional resources. Most recent amendments to Algeria's hydrocarbon law, aimed at boosting participation at its latest (January 2014) bidding rounds, were designed to raise incentives for the development of unconventional resources and were initially welcomed by the industry, but with only four out of 31 licensing blocks awarded in September 2014, expectations for a quick Algerian shale gas bonanza appear to have evaporated.⁷¹ However, issues such as unit development cost and water availability are key

⁶⁵ Our estimates assume an average growth in Algerian domestic gas consumption of around 6% per year – an average between the Algerian government's two central domestic demand forecasts of 5% and 7.1% over the coming years.

⁶⁶ 'Egypt Heads For Gas Deficit', *Middle East Economic Survey*, 57:6, 7 February 2014.

⁶⁷ 'Egypt to issue 2-year LNG import tender', *Petroleum Argus*, 22 May 2014; 'Egypt Plugs Gas Supply Gap With LNG Cargoes', *Middle East Economic Survey*, 57:20, 16 May 2014.

⁶⁸ 'Egypt prepares for summer energy crunch', *Petroleum Argus*, 28 March 2014; 'Egypt Signs Gas PSAs', *Middle East Economic Survey* 57:7, 14 February 2014.

⁶⁹ EIA/ARI (2013).

⁷⁰ 'Unconventional gas to double Algerian output', *Petroleum Argus*, 18 October 2013; 'Algeria touts shale gas ambitions', *Petroleum Argus*, 25 July 2014.

No certainty can yet be given for the feasibility of Algerian shale gas development, for the challenges to be overcome in developing Algeria's – and potentially later on Libya's – shale gas resources are multiple. They include the unknown quality of shale resources, as well as the remote location of Algeria's shale gas reserves in the south-west and far east of the country – problematic not least in view of raised security concerns in the aftermath of the In Amenas attacks for existing projects – coupled to absent infrastructure, unconventional oil services, skilled geoscientists, and lacking water resources. The author thanks Ali Aissaoui for his very helpful comments on this in a previous draft of this paper.

⁷¹ 'Algeria Set To Sign First Shale Contract', *Middle East Economic Survey* 57:24, 13 June 2014; 'IOCs pick up four of 31 exploration blocks offered in Algeria's fourth round', *Platts*, 30 September 2014.



uncertainties which should be borne in mind. If Algeria is finding the development of conventional gas a challenge, shale gas is likely to be harder still. Unconventional gas is expected to be produced in Algeria from tight gas plays, with the Ahnet project planned to come online in 2018. This is in addition to further unconventional resource potential in Egypt and Libya, as well as North Africa’s gas-poor neighbours, Morocco and Tunisia, though these prospects remain remote and, at present, uncertain.

Table 7: Projected North African Gas Exports 2015–2030 (bcm)

	2015		2020		2030	
	PIPE	LNG	PIPE	LNG	PIPE	LNG
Algeria	28	16	20	21	22	38
Libya	8	0	10	0	15	6
Egypt	0	0	0	0	0	3
TOTAL	36	16	30	21	37	47

Source: El-Katiri/OIES

2.1.3 East Mediterranean gas

The late 2000s saw a tremendous change of energy fortunes for the East Mediterranean. Sandwiched between the traditionally hydrocarbon-rich Middle East and North Africa, the East Mediterranean has in the past been seen as the only stretch of land in the wider regional context that did not hold oil or natural gas.⁷² Israel, Palestine, Lebanon, and their European neighbour Cyprus, all of whose offshore territories straddle the Levant basin, have been long-term importers of the majority of their energy needs, primarily in the form of oil but, where available, also in the form of natural gas, supplied until 2011 from Egypt and (initially, via a swap agreement) Syria.⁷³ Since 2009, the discovery of sizeable natural gas resources (of around 975 bcm) offshore Israel and Cyprus has significantly transformed the region’s energy outlook, from a long-term importer of energy to a potential exporter of natural gas whose strategic location close to the European market could render the East Mediterranean a potential future gas supplier to Europe.⁷⁴ With exploration ongoing offshore Israel and Cyprus, additional resources with significant potential are also likely to be discovered offshore Lebanon and Syria.⁷⁵

Exports to 2020

With several field development projects underway and legal export obstacles cleared, Israeli production could rise to 8–10 bcm/year by 2016/2017 and increase to around 10–15 bcm, depending on available export markets. Domestic demand will continue to consume more than half of the country’s incremental production in the short term, but export negotiations are already well advanced with neighbouring countries: Egypt, Jordan, and the Palestinian Territories.⁷⁶ Israeli gas exports to its immediate Arab neighbours are both commercially and politically appealing, given the proximity of the market and the existing gas pipeline infrastructure in place for local market supply. Both Egypt and Jordan also hold the potential to host Israeli LNG exports as transit hubs into the Mediterranean and the Red Sea. Existing and, since 2012, increasingly idle LNG facilities in Egypt would in principle offer

⁷² Former Israeli Prime Minister Golda Meir was famously quoted in the 1970s as saying ‘Let me tell you something that we Israelis have against Moses. He took us 40 years through the desert in order to bring us to the one spot in the Middle East that has no oil.’ E.g. quoted in: ‘Moses’s oily blessing’, *The Economist*, 16 June 2005.

⁷³ For a detailed background, see Darbouche, et al. (2012) and El-Katiri (2013).

⁷⁴ For a recent update across the East Mediterranean, see *Oxford Energy Forum* (2013).

⁷⁵ A 2010 US Geological Survey suggests the Levant basin could hold as much as 3.45 tcm of natural gas and 1.7 billion barrels of oil resources – valuable natural resources for current and future East Mediterranean producers, as well as for their potential export markets, of which some two-thirds could yet be discovered. U.S. Geological Survey (2010).

⁷⁶ Henderson, S. (2013); El-Katiri, L. (2013).



Israel low-cost access to liquefaction infrastructure, solving the problems faced by Egypt's LNG operators in supplying their existing contractual commitments, including to the Asian premium market.⁷⁷

A series of initial agreements was concluded during the first half of 2014 by members of Israel's development consortia and Egyptian operating partners, Jordanian utilities, and the Palestinian Authority over the supply of Israeli gas into these markets, as well as the option to directly supply Egypt's LNG producers with Israeli offshore gas. Conclusion of these agreements, together with the small volumes agreed with the Palestinian Authority, could provide some 12 bcm/year of Israeli pipeline gas for regional markets and exports via Egyptian LNG terminals for the coming 15–20 years. Adding to these volumes later during the 2020s could be a realistic possibility, contingent on regional politics and market conditions.

The ambitious plans, based on initial resource discoveries, for Cyprus to become an exporter of LNG, received a setback due to disappointing drilling results in 2013. Further exploration activity could, however, provide the necessary additional gas resources to enable Cypriot gas exports.⁷⁸ With the notable exception of Israeli LNG exports via Egyptian liquefaction facilities, therefore, no East Mediterranean LNG project is likely to come online until at least the end of the decade.

Beyond 2020

Israeli gas production has made rapid progress since 2010; this has been due not only to relatively stable policymaking, but also to an increasing urgency to develop the first field since the 2009 discoveries. Depending on the pace of Israel's offshore gas developments, the country may hold export potential well beyond the 12 bcm we have suggested as a possible figure for 2020. In 2013, the Israeli Cabinet decided to permit exports of up to 40 per cent of the country's gas reserves. The initial cabinet order licensing Israeli gas exports was based on reserves of up to 950 bcm; Leviathan's June 2014 reserve additions would add another 40 bcm of export volume.⁷⁹ This would bring Israel's maximum total exports to 440–450 bcm for the period up to 2040. Assuming some 20 bcm/year for export to 'neighbouring countries' (including from the already producing Tamar field⁸⁰), this could suggest additional export capacity of 15–18 bcm/year of Israeli gas from 2020–2040.⁸¹

Price and market uncertainties, in addition to the region's complicated geopolitical setting, mean that East Mediterranean pipeline gas is far from an easy option for the European market. Exporting Israeli gas to Europe by pipeline remains a secondary option with very limited immediate prospects. The most direct route, via subsea pipeline to Turkey, has been extensively discussed but remains fraught with difficulties.⁸² Turkish-Israeli relations, historically difficult and, more recently, deteriorating following Israel's 2014 Gaza offensive, substantially complicate trans-Mediterranean energy

⁷⁷ For the export of Israeli gas via Egyptian LNG plants, a direct sub-sea pipeline link from the offshore Leviathan field would be a more likely option than Israeli reliance on the existing (and frequently attacked) existing onshore pipeline route via the Sinai. The cost for the 500 km marine pipeline has been reported as being estimated at around \$2bn, comparable to the Turkish pipeline option. 'Israel's pipeline hopes', *International Gas Report*, Issue 753, July 2014, p.10.

⁷⁸ Until its disappointing October 2013 appraisal drilling, Cyprus' export potential alone was generally proposed to be around 35 bcm by 2025. E.g. Ellinas, C. (2013) 'Cyprus LNG: optimizing the export options', in *Oxford Energy Forum* (2013), p16.

⁷⁹ For a discussion (prior to Leviathan's reserve hike), see Even and Eran (2014). For Leviathan's reserve upgrade, see e.g. 'Leviathan 3Tcf Boost', *Middle East Economic Survey* 57:29, 18 July 2014.

⁸⁰ Announcement of the Cabinet Secretary at the conclusion of the Cabinet Meeting of 23 June 2013.

⁸¹ For example at the end of 2013, Noble suggested its own production potential in Israel could reach 20 bcm/year within the next ten years, a volume which would allow Israel to export around a third to a quarter of its annual production based on forecast figures for domestic demand. Noble was reported in December 2013 as expecting to be producing up to 2 bcf/d 'within ten years'; Tzemach Committee report consumption estimates as quoted in Even and Eran (2014), 198.

⁸² For an overview over the Israel–Turkey gas option, see e.g. Linke, K. and Vietor, V. (2010, eds.) and Henderson, S. (2013).



cooperation.⁸³ More importantly, however, the only available sub-sea pipeline route for Israel passes through Cyprus' exclusive economic zone (EEZ), a problem since Cyprus currently rules out the use of this route to Turkey in the absence of a comprehensive settlement of the Cyprus question. Further Israeli gas exports to Europe beyond Turkey would, moreover, necessitate the construction of around 500 km of pipeline (across mountainous terrain) between landfall on the southern coast of Turkey to the TANAP pipeline in the north-east of the country, a cost which is frequently overlooked in these discussions. The economics of this link appear questionable under current assumptions for European pipeline gas price ranges in the 2020s, and relatively small volumes of Israeli gas. However this would not rule out exports of gas to Turkey, for use in the south of the country.

Similar commercial problems would also apply to Cypriot pipeline gas if it were ever to reach the Turkish mainland. Despite the fact that this is the logical and lowest-cost route for Cypriot gas towards Europe, it remains currently impossible on political grounds, a situation that is unlikely to dissipate in the foreseeable future without a comprehensive solution to the 40-year unresolved Cyprus question.

With pipeline prospects to Europe looking difficult, Israel may eventually consider floating LNG, and Cyprus could make a similar decision. In both cases this, however, will be a long-term option, contingent in the case of Cyprus on the size and economic viability of future gas discoveries, and for Israel on technology availability (the potential FLNG supplier Woodside having withdrawn from a share in Israel's Leviathan field) and on the scale of potential offtake via this route, given the development of exports via alternative routes in the meantime. Initial discussion of shared LNG facilities with Cyprus has so far seen little progress, this is due to a combination of: delays in Cyprus, the cost of piping Israeli gas to Cyprus (reportedly more expensive than Israel's pipeline option to Turkey), and the availability to Israel of more tangible, commercially attractive alternative options.⁸⁴

Summary and Conclusions

Table 8 shows that no East Mediterranean gas should be expected to flow to Europe before 2020 with the possible exception of small volumes of Israeli LNG via Egyptian LNG terminals. While figures for 2030 are inevitably speculative, if there are additional discoveries, combined with political stability, it is possible that 13–18 bcm/year of LNG could be exported outside the region by 2030, some of which would be expected to be sold in Europe.

Table 8: Likely Exports of East Mediterranean Gas 2015–2030 (bcm)

	2015	2020	2030
Israel:			
LNG	0	6*	8
Pipeline gas to neighbouring countries**	0	7	10
Cyprus:			
LNG	0	0	5–10
TOTAL LNG (potentially to Europe)	0	0	13–18

*Only possible via Egyptian LNG terminals **most likely to Palestine, Jordan and Egypt but could include Turkey.

Source: Author

⁸³ Amongst other things, Israel's apology to Turkey over the shooting of nine Turkish pro-Palestinian activists at the 2010 Gaza flotilla incident was seen as a major important step to improve mutual relations. The two countries remain deeply divided on ideological grounds, including over the issue of Palestine. Most recently, Turkish Energy Minister Taner Yıldız was quoted in August 2014 as saying that Israeli gas exports to Turkey would be impossible as long as the Israel–Gaza conflict persists. 'Udas Report: Turkey forbids completion of gas deal with Israel until peace with Gaza achieved', *The Jerusalem Post*, 6 August 2014.

⁸⁴ 'Israel: Gas Boom Targets Turkey', *Middle East Economic Survey* 57:13, 28 March 2014.



2.1.4 Caspian and Central Asia

The idea of a pipeline or pipelines, to bring gas to Europe via Turkey from the Caspian region, and parts of the Middle East, has figured in European policy discussions since the 1990s. The most likely sources of gas for such a corridor are Azerbaijan and Turkmenistan in the Caspian region, Iran, and the Kurdish area of Iraq.

The 'Southern Gas Corridor'

In 2002 the first discussions, supported by the European Commission, took place between five companies on the Nabucco pipeline project; this aimed at building a 31 bcm pipeline from Turkmenistan, across the Caspian Sea, via Azerbaijan, Georgia, and Turkey to south-eastern Europe.⁸⁵ By 2008, this had turned into the 'Southern Corridor' officially endorsed by the European Commission as part of the Second Strategic Energy Review.⁸⁶ But the project remained an expression of political will rather than commercial reality. No firm agreement on supply could be reached with Turkmenistan, and hopes of building a trans-Caspian pipeline (TCP) were stymied by the sea's political and legal status. (Essentially, the two largest littoral states, Russia and Iran, had no interest in encouraging such a pipeline and therefore no interest in resolving the legal dispute over the sea's status.⁸⁷) While in the mid 2000s it had been assumed that there would always be demand in Europe for southern corridor gas, the prospects for such demand, even in the 2020s, were thrown into doubt following the 2008–2009 economic crisis and recession. The consequence was that in 2013, when it came to setting in motion the principal Azeri project for the southern corridor – the second phase of the Shah Deniz field (Shah Deniz 2), which will start producing 16 bcm/year of gas in 2019 – no other sources of supply had been secured for the corridor, and no clear sources of demand identified. The companies in the Shah Deniz 2 consortium (BP, Total, Statoil, SOCAR, Lukoil, NICO, and TPAO) therefore opted to open the southern corridor in a reduced form: expansion of the South Caucasus pipeline; construction of the Trans Anatolian pipeline (TANAP) across Turkey, which will carry 16 bcm/year in the first instance; and construction of the Trans Adriatic Pipeline (TAP) to take 10 bcm/year onwards to Italy.

The scaling-down of the southern corridor showed that although economic factors – availability of supply and transport capacity, and demand forecasts – were decisive, they became subordinate to political aspirations in the wake of the 2008–2009 economic crisis. Here we survey the availability of supply and transport capacity for any possible expansion of the southern corridor up to 2030.

Azerbaijan. The available gas comprises: volumes from currently producing fields; Shah Deniz 2 production; and possible volumes from other projects currently in development phase. Current production of natural gas from Shah Deniz phase one (associated gas from the ACG oil field and small volumes from other offshore and onshore fields) is about 16–17 bcm/year. These volumes are used for Azeri domestic consumption (about 7 bcm/year in recent years) and exports to Russia (1–2 bcm/year), Georgia (1.5 bcm/year), Turkey (6.3 bcm/year), and a small volume to Iran, almost all of which is swapped for gas supplied by Iran to the Nakhchivan enclave. Production from these existing assets is expected to remain at the current level through most of the 2020s. Domestic demand may rise, and exports to Russia may be slightly reduced. But in any case, no significant additional volumes from these assets would be available for export.

The Shah Deniz Phase 2 project is expected to go into production in late 2018, and to start exporting to Europe in late 2019. Of the 16 bcm/year of output, 6 bcm will be sold to Turkey and 10 bcm to

⁸⁵ For a history of the Nabucco pipeline and the Southern Corridor, see Hafner and Tagliapietra (2013), pp. 125–35.

⁸⁶ *EU Energy Security Review and Solidarity Action Plan: Second Strategic Energy Review*, MEMO 08/703, Brussels, 13 November 2008.

⁸⁷ See Pirani (ed.) (2009), pp. 282–3, 298–9 and 403–4; Pirani (2012), pp. 99–102.



Europe (including 1 bcm each to trading companies in Greece and Bulgaria, and 8 bcm to Italy and adjacent hub markets).⁸⁸ In addition to Shah Deniz, there are several offshore Caspian fields and exploration prospects that could increase Azerbaijan's gas production in the 2020s. One field, Absheron, has been declared commercial (but is yet to achieve FID) under a PSA (with Total as operator, GDF Suez, and SOCAR); production is expected to start in 2021, with 3–5 bcm/year in the initial phase. Beyond that there are other fields and exploration prospects that could be developed under PSAs or joint ventures, subject to exploration success and/or appraisal drilling.

SOCAR officials have projected an increase in production to 40–45 bcm of sales gas by 2025;⁸⁹ this assumes 9–14 bcm/year of gas from the new offshore projects by that date and must therefore be regarded as a maximum level. It seems likely that there would be a call on some of this gas from Azerbaijan's domestic market, and from Georgia. We estimate that 3–8 bcm/year of additional gas could become available for export to Europe at some point in the 2020s.

Turkmenistan. Turkmenistan has very large gas reserves and is currently increasing production in order to meet its substantial export commitments to China. In 2013, Turkmenistan produced about 50–55 bcm of gas (including 13–18 bcm consumed domestically and exports of 10 bcm to Russia, 7 bcm to Iran, and 20 bcm to China).⁹⁰ In order to increase exports to China to 65 bcm/year, it aims to increase production to 95–100 bcm by 2016. However, despite ample reserves and production potential, there is no export route by which Turkmen gas can reach Europe, and it is unlikely that a route can easily be established. The three possible routes are:

- North-west through Russia, via existing infrastructure. This may be disregarded for the purposes of this paper, since gas imported via this route would not reduce European dependence on Russia.
- Southwards through Iran, via existing infrastructure, and then westwards via Turkey. This will only become relevant if and when international sanctions on Iran are lifted; thereafter, agreements would have to be made to renovate and re-commission the infrastructure, pipeline links across Turkmenistan (linking the largest gas fields to this export pipeline) completed; and other commercial arrangements made. This is possible in the second half of the 2020s, but probably not before.
- Via a Trans-Caspian pipeline (TCP) to Azerbaijan, and thence via Georgia and Turkey to Europe. This would be possible providing that (i) the legal status of the Caspian Sea were settled, or at least that Turkmenistan and Azerbaijan agreed that this was not an obstruction; and (ii) commercial arrangements can be made for this major infrastructure undertaking. Previous proposals for a TCP have failed to find a way to surmount either of these two hurdles.

A further obstruction to opening any of these routes is Turkmenistan's own long-standing gas export policy: to sell gas on its border, requiring purchasers to take all the transit risk. It was China's ability to work with Turkmenistan on this basis that enabled it to become the main buyer of Turkmen gas; given Turkmenistan's small population and revenue requirements, there is no reason to think this policy will be changed in the foreseeable future.⁹¹

⁸⁸ BP Press release, 19 September 2013.

⁸⁹ 'Scalability as Drawn', *Azerbaijan 2012: The Business Year*, Azerbaijan Presidential Administration/The Business Year, Baku, 2012, pp. 92–3; and presentation by Khoshbakht Yusifzade, vice-president of SOCAR, at the Caspian Oil and Gas Conference, Baku, May 2012.

⁹⁰ Author's estimates. No official information is available on gas production or sales.

⁹¹ This argument is made at length in Pirani (2012), p. 16–17 and 99.



Other Central Asian Gas

Uzbekistan is a major gas producer (50–60 bcm/year in recent years), and Kazakhstan an expanding one (about 12 bcm/year in recent years, likely to rise to 20–25 bcm/year in the 2020s). Most Uzbek and Kazakh gas is consumed domestically; small quantities (7–10 bcm/year from each) are exported to Russia; and both countries have concluded framework agreements, and some contracts, with China, providing for exports via the Turkmenistan–China pipeline, which started in 2013 from Uzbekistan. It is possible that Uzbek and Kazakh exports to Russia will fall in the 2020s, but there will be calls on this gas from China and from their domestic markets. There are hypothetically three ways that Uzbek and Kazakh gas could reach the European market:

- Kazakh gas could be transported by pipeline across the Caspian Sea to Azerbaijan, and thence to Europe. But the volumes available are negligible (assuming that exports to China remain minimal, and exports to Russia cease, perhaps 10 bcm/year at some point in the 2020s), and the trans-Caspian crossing would be longer than in the case of Turkmenistan. Such a prospect may therefore be disregarded, at least until a Turkmenistan–Azerbaijan pipeline has been completed.
- Kazakh gas could be transported through Russia to Azerbaijan and thence to Europe. The costs involved, and the fact that Russia would be required to transport the gas, mean that this prospect can be disregarded for the purposes of this paper.
- Kazakh and/or Uzbek gas could be transported via Russia, via existing pipelines, to European destinations. (Such sales were conducted, with the gas bought and resold by Gazprom and other Russian companies, from the mid 1990s to 2009.⁹²) Since by virtue of geography this trade would remain under Russian control, it can be disregarded for the purposes of this paper.

Summary and Conclusions

Table 9 summarizes our estimates of gas available for export from Azerbaijan and Central Asia up to 2030. We see Azerbaijan as the only country which will substantially increase its exports of pipeline gas to Europe prior to 2030, with 30 bcm becoming available by that date, only half of which will progress beyond Turkey to the rest of Europe. We see Central Asian gas exports progressively increasing in volume but focused on China, with exports to Russia stabilizing at relatively low levels, and modest intra-regional trade. No export of Central Asian gas to Turkey or the rest of Europe is likely in this time frame, and for this reason it would probably be more accurate to refer to a Caspian (and possibly Middle East) pipeline, rather than a corridor, to Europe.

⁹² Pirani (2012), pp. 77–80, and Stern (2012, ed.), pp. 200–4.

Table 9: Likely Exports of Caspian and Central Asian Gas 2015–2030 (bcm)

	2015	2020	2030
Azerbaijan:			
Turkey	5.6	13	15
Other Europe	0.7	10	15
Georgia/Russia/Iran)	2.2	5	7
Turkmenistan:			
Europe	0	0	0
China	37	47	65
Russia/Iran/Central Asia	19.7	13	15
Uzbekistan:			
Europe	0	0	0
China	2	10	20
Russia	7	5	5
Kazakhstan:			
Europe	0	0	0
China	2	3	10
Russia/Central Asia	6	4	6.5

Source: Pirani (2012) and author's estimates

2.1.5 Iran and Iraq

Iran

Despite its world-class reserves, Iranian exports are complicated by many uncertainties.⁹³ First and foremost, Iran's ability to engage in international gas trade, to a large extent, depends on complete or partial removal of US and international sanctions.⁹⁴ Although the prospects for a rapprochement between Iran and the international community have improved following the election of President Rouhani in 2013, it may take Iran several years, depending on the scale and timing of the lifting of sanctions, to secure access to international capital and to the technologies required for substantial development of its natural gas resources.

Iran has long had the ambition of becoming a major gas exporter, including to Europe. After many years of mismanagement and underperformance by the previous administration, the Rouhani government has shown a desire for the country to become a major regional and international gas player. Although many projects have been proposed for the export of gas to Europe, all involve a significant degree of complexity. The Trans-Adriatic-Pipeline (TAP), first proposed in 2008, was expected to export 5.5 bcm/year of gas to Switzerland.⁹⁵ The project, however, was abandoned as a result of US pressure and the EU ban on the import of Iranian gas.⁹⁶ Following the improvement of political relations between Iran and the international community, the project may be revived, but at

⁹³ As of 2013, Iran's proven natural gas reserves are around 34 tcm. See Appendix 1.

⁹⁴ Hassanzadeh (2014 forthcoming), pp.78–82.

⁹⁵ Adibi and Fesharaki, (2011).

⁹⁶ Also in August 2014, NIOC announced that some European countries have expressed interest in reviving the Nabucco project, which was formally abandoned in June 2013 after the Shah Deniz Consortium chose Trans-Adriatic Pipeline (TAP) as the preferred route to deliver Azeri gas to Europe. NIGC (2014).



present there are no details on the time frame and expected volume.⁹⁷ In the case of the proposed Iran–Iraq–Syria–Mediterranean pipeline export project, the gas is highly unlikely to go beyond Iraqi borders for the foreseeable future, due to ongoing civil war and political instability in Syria.⁹⁸ Also the limited export volumes to Iraq – starting from 1.5–2.5 bcm/year in 2015 and reaching 10 bcm/year in 2018 – are expected to be fully consumed in Iraqi industrial and power sectors, leaving no gas surplus for re-export.⁹⁹

There are serious doubts about the viability of the proposed Armenia–Georgia–Ukraine pipeline on economic and – following Russia’s annexation of Crimea – geographical grounds.¹⁰⁰ Aside from these options, exports to Europe via Turkey using existing infrastructure, are the most feasible option prior to 2020.

Irrespective of the technical and geopolitical feasibility of these proposed routes, the second major uncertainty over the export of Iranian gas to Europe is the availability of sufficient gas for export markets over and above Iran’s domestic requirements. Iran’s growing domestic consumption (due to population growth, market expansion, and gas for oil substitution policies, oilfield gas reinjection requirements, and the development of added-value industries) has severely impacted the country’s ability to make available sufficient gas for export markets. With the required investment and technology, Iran could increase production capacity to around 210–230 bcm/year by 2018, but this is expected to be mainly allocated to domestic and regional export markets.¹⁰¹ After meeting growing domestic demand – expected to reach 200–220 bcm/year before 2020 – and supplying gas to the already contracted export markets of the neighbouring countries of Turkey (10 bcm/year), Iraq (10 bcm/year), and Oman (5–10 bcm/year), any gas available for export to the rest of Europe is expected to remain marginal prior to 2020.¹⁰²

Beyond 2020, depending on how fast Iran can develop the remaining phases of the South Pars and other major discovered gas fields, the country’s total production capacity could reach around 350 bcm/year by 2030.¹⁰³ It is only then that significant exports to Europe can be envisaged, provided that the required infrastructure can be made available. Any direct gas export to Europe requires extensive infrastructure, very significant sources of funding, and long-term agreements which would take Iran and its potential European partners at least 10 year to develop (from Heads of Agreement to first export volumes). The time scale will probably be even longer for LNG exports, due to the complex technical and commercial nature of such projects. Exports of around 10–20 bcm/year to Europe through Turkey via the existing infrastructure are possible in the 2020s, but it is unrealistic to imagine more substantial volumes becoming a reality until after 2030.¹⁰⁴ This conclusion pre-supposes that the political forces within Iran which oppose exports do not prevail, given that reinjection of gas into oilfields (for secondary and tertiary recovery) and additional investment in petrochemicals can be argued to provide a higher return for the country than gas exports.

⁹⁷ Fars News Agency (2014). <http://www.farsnews.com/newstext.php?nn=13930519000578>

⁹⁸ Hassanzadeh (2014 forthcoming), p.41.

⁹⁹ Ibid.

¹⁰⁰ The initial idea was for an offshore pipeline between Georgia and Ukraine, but the Crimean annexation has made this much more difficult.

¹⁰¹ This can be achieved through full development of phases 12, 15, 16, 17, and 18 of South Pars which are expected to come on stream by 2017. www.shana.ir/fa/newsagency/219614/.

¹⁰² The gas export contract with Pakistan is unlikely to see gas flows for years to come due to numerous uncertainties over gas pricing, the Pakistani government’s inability to finance the construction of the pipeline on its side, security threats, and the economic viability of the project resulting from the withdrawal of India.

¹⁰³ Hassanzadeh (2014 forthcoming), p.160

¹⁰⁴ Ibid, pp.160–2



Iraq

As of 2013, Iraq's proven reserves of conventional natural gas amounted to 3.6 tcm.¹⁰⁵ Production, mainly of gas associated with oil, increased to 15.6 bcm in 2013, due to rising oil production together with the government's determination to reduce gas flaring and increase the share of gas in the country's energy balance.¹⁰⁶ Ongoing political and security problems in Iraq: terrorist activity, sectarian violence, political disagreement between the federal authorities and the Kurdistan Regional Government (KRG) – not least over permission to export oil and gas – make it difficult to be optimistic about the stability needed to increase gas production and exports by a significant amount.¹⁰⁷ In addition, the country's chronic shortage of electricity will make it difficult to export gas until more reliable power production is restored to the major population centres. Most of this new generation capacity will need to be gas-fired. A large share of gas production in this period is expected to be associated with oil production, and is therefore dependent on the extent and speed with which flaring can be reduced.¹⁰⁸ Non-associated gas fields, however, are believed to be the most reliable source of supply for export projects, especially in Kurdistan where fields exist close to the Turkish border, although this again throws up questions relating to the authority to export without the agreement of the Baghdad government, and how quickly the power requirements of the region can be met.

In 2012, the IEA set out three scenarios for Iraqi gas exports:¹⁰⁹

- A high scenario where exports started around 2017 and increased to 10 bcm by 2020 and around 25 bcm by 2030;
- A central case where exports start in 2020 and increase to around 18 bcm by 2030;
- A delayed case where exports do not start until around 2025 and remain at negligible levels through 2030.

Given the security situation in the country since 2012, it is very difficult to believe that the high scenario is feasible, and a position between the central and delayed cases seems the most realistic. Following that logic, one would not expect exports to begin until after 2020, and build up to perhaps a maximum of 10 bcm/year by 2030. Early exports would probably come from Kurdistan and would be delivered to Turkey, with very little gas finding its way through to European countries.

2.1.6 The role of LNG

LNG imports, which are generally viewed as being able to provide immediate and diverse supplies, are frequently regarded as the most promising alternative source of non-Russian gas supplies to Europe. Re-gasification capacity of nearly 200 bcm/year at European LNG terminals was less than 22 per cent utilized in 2013, and although imports may have risen slightly in early 2014, most terminals have substantial spare capacity.¹¹⁰ The problems of replacing Russian gas with LNG imports centre around whether the LNG can be delivered to countries which are heavily dependent on Russian gas, and whether LNG prices will be competitive with Russian gas. The answers to these questions involve complex issues of supply/demand and price dynamics of global LNG trade.¹¹¹ These issues cannot be

¹⁰⁵ See Appendix 1. There are estimates that the ultimate recoverable gas is considerably higher, exceeding 7.5 tcm. EIA (2013).

¹⁰⁶ BP Statistical Review 2014, p.22; Yacoub and Rutledge, (2011).

¹⁰⁷ IEA (2012), Chapters 13–16, pp. 387–498; EIA (2013).

¹⁰⁸ For details of the flaring problem see IEA (2012), pp. 442–4.

¹⁰⁹ IEA. (2012), Figures 16.11 and 16.13, p. 494 and 498.

¹¹⁰ Nominal European re-gasification capacity in 2013 was 198.6 bcm and imports were 43 bcm (not including reloads), GIIGNL (2013), p.8 and 31.

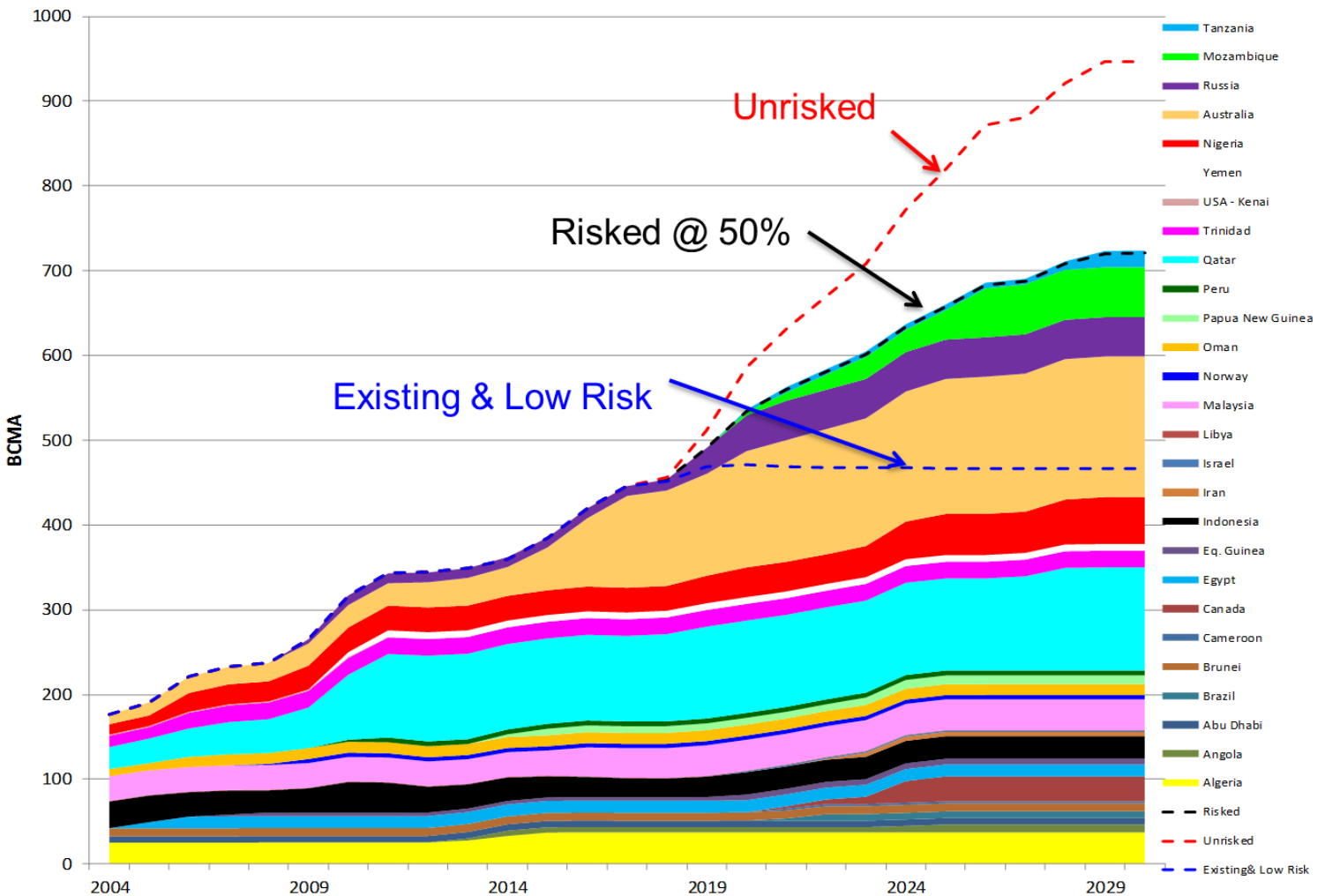
¹¹¹ And also transportation capacity availability discussed in Section 2.2.



addressed in detail in this brief section, but by means of several figures we highlight the main considerations over the three time periods under consideration in this paper.¹¹²

Over a one-year horizon it does not seem likely that Europe will be able to access *substantial* additional volumes of LNG, although with lower Asian spot cargo demand in 2014, there is a potential for greater volumes than in 2013. Japanese nuclear stations are only being reopened slowly (not significantly reducing that country's immediate need for LNG); Chinese (and other Asian) LNG demand is expected to continue to rise and *substantial* new supply is not expected to be fully on stream until 2015 (at the earliest). However, the outlook for 2020 and 2030 is entirely different.

Figure 7: Global LNG Supply outside the USA 2004–2030



Source: Ledesma/Rogers, OIES

US LNG export projects with a capacity of 113 bcm/year are at various stages of development, of which 94 bcm/year of export capacity had received non-FTA approval by September 2014.¹¹³ However, final investment decisions (FID) have only been taken for 40 bcm/year of capacity, and

¹¹² These issues are considered in much greater detail in Rogers (2012), Henderson, J. (2012), Rogers and Stern (2014), Rogers and Stern (2014 forthcoming).

¹¹³ The USA has Free Trade Agreements with a number of countries, however of these only South Korea is a significant LNG importer. Non-FTA approval grants permission for a proposed facility to export LNG to all other destinations.



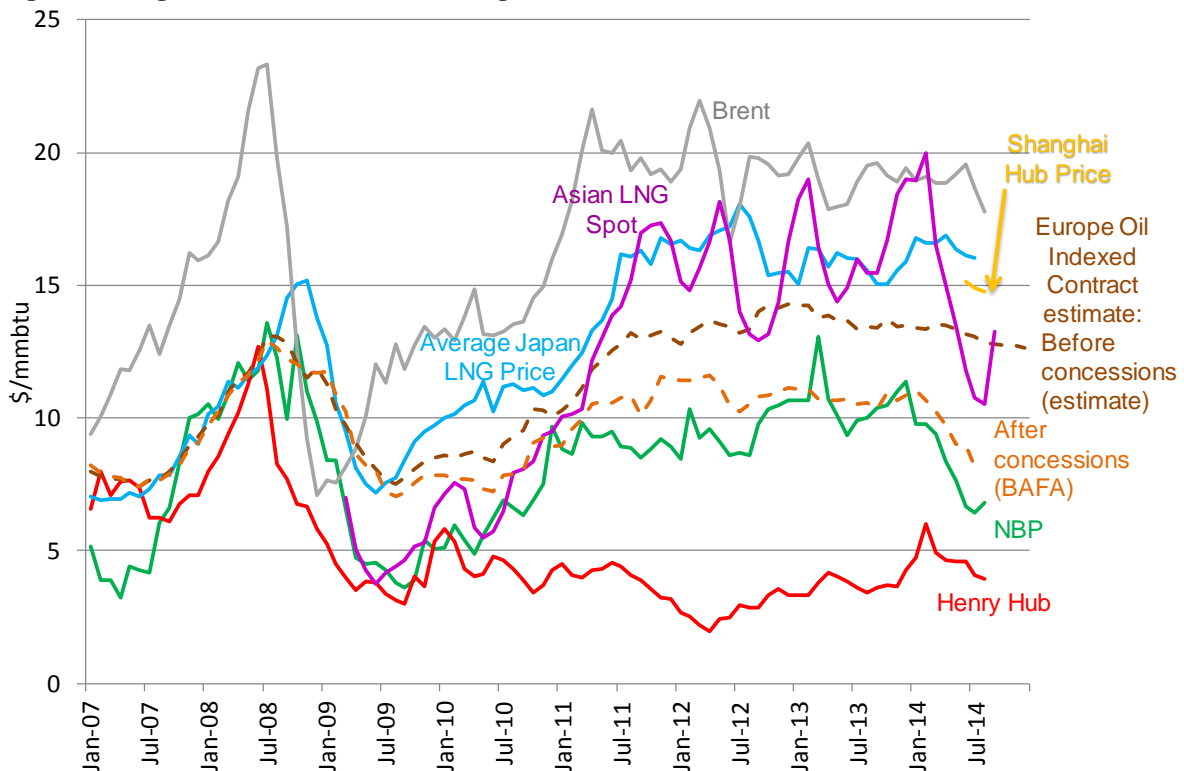
although other projects will undoubtedly be approved over the coming months and years, the first project will only begin to export in late 2015, rising to full capacity in 2018, and the second in 2019. Given the four-year lead time for construction, additional projects cannot start deliveries significantly before 2019 (and 2020 is more likely).

Figure 7 shows that between 2014 and 2020 non-US LNG supply will rise by around 100 bcm/year from projects already under construction, and could be as much as 150 bcm/year. By 2030, non-US LNG supply may double from its 2014 level to 700 bcm/year which, if US supply reaches more than 100 bcm/year, will massively increase global LNG trade. The problem is to know how much of this LNG will be available to Europe. The principal determinants of this are likely to be:

- The growth of Chinese (and to a less extent other Asian) LNG demand;
- North American gas prices and the consequent viability and size of North American LNG exports;
- In a 'tight' global LNG market, the willingness of European buyers to compete for available LNG with Asian, Middle Eastern, and South American buyers;
- In a 'loose' global LNG market, the willingness of Gazprom to lower its prices in order to keep 'surplus' LNG supplies out of Europe, and whether indeed this would be effective.

To a significant extent, the outcome of these uncertainties will depend on the trajectories of regional gas prices over the period up to 2030.

Figure 8: Regional Gas Prices 2007–August 2014



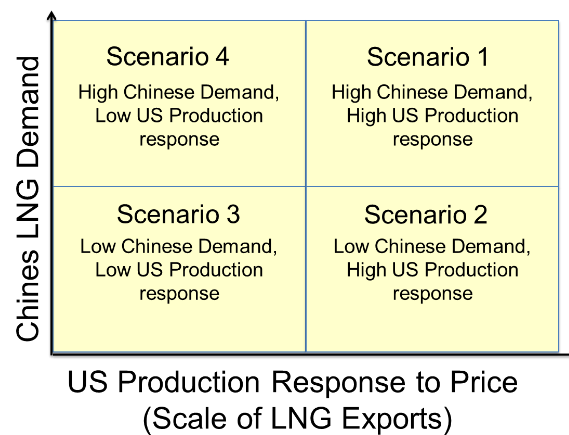
Source: Rogers/OIES

Figure 8 shows gas and LNG prices from the USA (Henry Hub), the European hubs (exemplified by the UK's NBP), different estimates of European oil-indexed prices, Japanese LNG imports (JCC-



linked contract and spot prices), and Shanghai hub prices.¹¹⁴ Regional prices converged strongly in 2008 and then diverged to probably their widest ever range during 2011–2013, seeming to converge again by mid-2014 (although it remains to be seen whether this is a long-term trend). The consequences of price differentials in the regional markets will be very important for the availability of LNG for Europe. During 2008–2010, very low Henry Hub prices (caused by the shale gas revolution) meant that much LNG which had been intended to be sold in the US market was diverted to Europe, keeping prices relatively low. Post-Fukushima (during 2011–2013) very high Asian prices, relative to their European counterparts, caused a progressive pull on flexible LNG supplies to be sold in Asia – accounting for the very low utilization level of European re-gasification capacity.

Figure 9: Scenarios of Chinese gas demand and US Gas production



Supply/demand dynamics in each of the major regional markets will determine the trajectory of prices in the period up to 2030. In other research we have modelled scenarios (described in Figure 9) for Chinese LNG demand and US LNG exports and examined the consequences for Russian gas deliveries to Europe.¹¹⁵ Summarizing a complex situation as briefly as possible, the model shows that for:

- Scenario 1 – high Chinese demand/high US exports: Russian gas exports to Europe climb to more than 200 bcm/year in the late 2010s, and fluctuate in the range of 170–190 bcm/year during the 2020s.
- Scenario 2 – low Chinese demand/high US exports: Russian exports to Europe crash down to 100 bcm/year in the early 2020s and fluctuate between that level and 120 bcm/year up to 2030.
- Scenario 3 – low Chinese demand/low US exports: outcome similar to Scenario 1, but not so extreme, with Russian exports in the range of 150–180 bcm/year throughout the period, aside from a brief dip below 150 bcm/year in the early 2020s.
- Scenario 4 – high Chinese demand/low US exports: the best scenario for Russia, with exports to Europe climbing steadily to 230 bcm/year in the late 2010s and remaining at 210–250 bcm/year up to 2030, with question marks about Russia’s ability to deliver, and Europe’s willingness to accept, such high volumes.

The model results show that continuing Russian exports to Europe at or above 2013 levels depends critically on avoiding a combination of low Chinese gas demand and high US LNG exports – two parameters over which Gazprom and the Russian government have little control. However, it is significant that even in the worst case for Russian gas exports, deliveries of 100–120 bcm/year are maintained throughout the period, suggesting that although LNG supplies can reduce Europe’s

¹¹⁴ For a full explanation of these prices see Stern (2012, ed.), Chapters 3,4,10, and 11.

¹¹⁵ An early version of this model was published in Rogers (2012), an update will be published later this year in Stern and Rogers (forthcoming 2014).



dependence, there will still be a need for at least 100 bcm/year of Russian gas in the period up to 2030. This result is interesting, in that it has not been constrained by the contractual obligation of European buyers to meet future take-or-pay levels in the continuing portfolio of legacy long-term contracts. However, this analysis underlines the physical difficulties posed by a desire on the part of Europe to materially reduce its future dependence on Russian gas, quite apart from its contractual obligations, (discussed in Chapter 1).

Future price dynamics: Russia and LNG

In all the scenarios of possible futures discussed, we view Russia as having an ability to deliver pipeline gas to Europe at volumes of up to 250 bcm/year.¹¹⁶ Although Russia will generally seek to maximize the price it can obtain in the future (by the management of physical volumes of exports to Europe) either under hub-indexed contracts or direct hub sales, our research (see Chapter 5) estimates that Gazprom's most expensive Yamal Peninsula gas makes an acceptable upstream return at a European border price above \$7.50/mmbtu (including Russian export tax).

Non-US LNG projects in the future are increasingly likely to take FID on the basis of some 60 to 70 per cent of volumes contracted with Asian buyers, based on a mixture of oil- and hub-indexation (a hybrid model), with the balance potentially sold as spot cargoes. Clearly the eventual destination of LNG supply will be determined by the ability of buyers to accept contractual volumes and the relative prices of Asian (and other regional) spot markets and European hubs.

US LNG projects will take FID on the basis of a mixture of offtake commitments from Asian buyers and portfolio players/aggregators. In the first instance, the target regional market will be Asia which, to support FID, would require an expectation of a price spread to Henry Hub at least equal to tolling fees and shipping costs. A fall back assumption, in the event that the Asian market was (at least temporarily) saturated, would be to assume the diversion of some volumes to Europe, provided that the price spread between European hub price and Henry Hub was expected to be at least equal to tolling fees, shipping costs, and re-gas fee.

Once the new LNG facilities are in operation, however, capital costs and (in the case of US export projects) tolling fee commitments are 'sunk costs', and the supply of the LNG would be expected to continue, provided that the destination market price covered variable costs. In the case of US LNG these equate to the cost of buying the feed gas at a Henry Hub-related price, together with the shipping and any re-gas costs.

In a 'tight' global market for LNG, Asian spot prices would be high and Russia would be tempted to optimize its volume/price strategy for Europe, resulting in hub prices which were:

- in the short run lower than the cost of attracting LNG away from Asia to Europe; this probably through substituting fuel oil in the Asian power and (possibly) industrial markets;
- not high enough to spur decisions to invest in new LNG supply in the longer run, either from the USA or from other suppliers.

In a 'balanced' market, where global LNG supply and demand are in equilibrium, Russia would manage physical volumes of gas to Europe to maintain hub prices at a level below that which would create the incentive for an acceleration of new LNG supply project investment, either from the USA or other supplier regions. Estimating such a price level – which would maintain a broadly stable or growing demand for Russian gas in Europe – would be fraught with difficulty, but an indicative level might be around \$10.5/mmbtu.

¹¹⁶ See Chapter 5 for details.



In a 'loose' or well-supplied global market, LNG in excess of the requirements of Asian and other markets would enter the European markets to be sold on the hubs (as it did in 2010 and 2011). In this situation Russia could:

- reduce its physical exports of pipeline gas to Europe to protect prices for the duration of the 'glut' (but not raise prices sufficiently to spur new LNG investment);
- maintain or even increase physical supply to Europe to lower prices to the point where LNG supply was reduced at 'source'.

This latter course of action might not succeed, however, except at extremely low prices. Non-US LNG variable costs would, perhaps, amount only to shipping and re-gas costs (potentially in the range of \$2.50–4.00/mmbtu). US LNG variable costs would amount to Henry Hub plus possibly \$2.00/mmbtu to cover shipping and re-gas costs to European hubs. The Russian response to a 'loose' or well-supplied LNG market would be based on its assessment of the likely duration and on its relative loss of revenue in holding back or increasing supply in order to influence prices.

Those looking to the LNG market as an alternative to Russian pipeline supplies will perhaps find little comfort in the above analysis. For LNG project developers, Asia is the target destination market, whether for long-term contracted or spot volumes. Apart from the relatively small volumes of existing contracted European LNG supplies, future LNG imports to Europe will be a consequence of trends in wider global gas supply and demand fundamentals, in the main relating to North America and Asia (notably China). From a European perspective, however, in three of the four scenarios described above, there is a competitive tension between the price Russia may wish to secure for its European exports (influenced by physical supply management) and the incentives provided by high European hub prices (and through arbitrage Asian LNG spot prices) for new LNG supplies, whether from the USA or elsewhere. That being said, Russian pipeline gas imports to Europe, even in the scenario where these are at their lowest level, are still substantial (100–120 bcm/year) in the 2020s, in line with the take-or-pay levels of the aggregate of the current portfolio of long-term contracts for Russian pipeline gas, which will endure through that period.

2.2 Bringing non-Russian gas to Europe: Infrastructure Issues

The principal options for additional non-Russian sources of supply to Europe prior to 2020 are LNG and Azeri pipeline gas (arriving via Turkey). Of these sources, LNG is potentially the more important, albeit subject to wider fundamental global trends. Azeri gas will not exceed 10 bcm in 2020, and although larger volumes are possible by 2030 they will certainly not rival the capacity of European LNG import terminals. In addition to the availability and affordability of these alternative supplies, the location, capacity, and interconnectivity of infrastructure is an important factor determining whether these supplies will be able to reach markets and in what time frame. Europe has an extensive (albeit unevenly distributed) pipeline infrastructure, with entry points situated predominantly at its northern and eastern borders. Thus, despite Europe's high overall level of gas infrastructure coverage, Baltic, central-east, and south-east countries which rely on Russian gas for all or most of their supplies have long been characterized by a lack of interconnections with the rest of Europe, and a near absence of LNG import terminals; this will begin to change only in the mid to late 2010s.

Despite the inherent desirability of securing multiple supply options, particularly for countries which are highly dependent on Russian gas, post-Soviet supply diversification aspirations have met with limited success, in large part because for much of this period, non-Russian gas remained significantly more expensive.¹¹⁷ Europe's dependence on Russian gas is geographically biased towards the Baltic countries, and to the east and south-east of Europe (with the exception of Poland, these are relatively small gas markets) which raises important issues in respect of how alternative supplies might be

¹¹⁷ In the post-2008 period this has been disputed (mainly) by the Baltic States and Poland, see Stern (2014), pp. 92–7.



brought to these regions, either through existing or new infrastructure. Importantly, most existing infrastructure in the region was built with the purpose of delivering Soviet gas to the region. Not surprisingly, existing interconnection points between individual European countries' gas networks only allowed for unidirectional (westward) flow. High dependence on Russia was compounded by high dependence on one transportation route (such as the Ukrainian/Balkan and Belarusian corridors) with virtually no pipeline or LNG infrastructure enabling these countries to source non-Russian gas. Construction of such new infrastructure would have required significant investment which these countries could not afford, especially as their economies went into decline in the 1990s and also were undergoing restructuring; this led to significant gas demand reduction, thus undermining the *commercial* logic of investment in new infrastructure. Yet these countries continued to consider supply diversification away from Russian gas as being politically desirable, and they have intensified their efforts to do so following the recovery of their economies in the 2000s.

2.2.1 EU infrastructure and regulatory initiatives¹¹⁸

The EU made its first financial contribution towards enabling construction of infrastructure in, inter alia, central and south-east Europe in the aftermath of the 2009 Ukrainian crisis¹¹⁹ (which had demonstrated the region's high vulnerability to transit interruptions of Russian gas flows via Ukraine). In 2009 the EU set up the European Energy Programme for Recovery (EERP)¹²⁰ under which €3.8 bn were to be invested into various energy projects (of which €1.36 bn was designated for gas infrastructure).¹²¹ A significant part of this funding was awarded to central and south-east regional investment projects, enabling 'reverse' gas flow at the existing unidirectional interconnections, together with the construction of new interconnections between countries where these were previously lacking.

Many interconnection projects have already been completed under the EERP, including: Hungary–Croatia, Romania–Hungary, Poland–Czech Republic, and Bulgaria–Romania; several projects reinforcing domestic gas networks and enabling reverse flows were completed in Austria, Poland, Latvia, Lithuania, the Czech Republic, and Slovakia. Both Greece–Bulgaria (IGB) and Slovakia–Hungary interconnections are expected to be commissioned in 2015. Some projects have faced significant delays, for example the reverse-flow project in Romania, which includes the linking of the 'transit' system to the national gas system.¹²² The EERP funding has also co-financed the construction of an LNG import terminal in Poland (see next section). The EERP has also contributed towards the establishment of bi-directional pipeline networks in Europe and therefore better connection between western and eastern parts of Europe.¹²³

By exposing significant vulnerabilities in Baltic and central/south-east European countries, the 2009 Russia–Ukraine crisis gave a strong impetus towards the development of new EU legislation aimed at

¹¹⁸ For more detail on EU infrastructure and regulatory initiatives see Yafimava (2013) and Yafimava (2015 forthcoming).

¹¹⁹ In the past financial period (2007–13), the EU financed mainly feasibility studies with a total amount of €155 mn under the TEN financing, see Regulation (EC) 680/2007 of the European Parliament and of the Council of 20 June 2007 laying down general rules for the granting of Community financial aid in the field of the trans-European transport and energy networks, *Official Journal of the European Union*, 22.6.2007, L162/1.

¹²⁰ Regulation (EC) No 663/2009 of the European Parliament and of the Council of 13 July 2009 establishing a programme to aid economic recovery by granting Community financial assistance to projects in the field of energy, *Official Journal of the European Union*, 31.7.2009, L200/31. The Programme covers 3 broad fields: 44 gas and electricity infrastructure projects, 9 offshore wind projects, and 6 carbon capture and storage projects.

¹²¹ For the map showing all EERP projects see <http://ec.europa.eu/energy/eepr/projects/>

¹²² Report from the Commission to the European Parliament and the Council, *On the implementation of the EERP*, COM (2013) 791 final, 18.11.2013.

¹²³ Some funding was also spent on a number of projects in north-west and south Europe including France–Spain and France–Belgium interconnections.



strengthening gas security: the regulation on security of gas supply ('Security Regulation')¹²⁴ (entered into force in late 2010) and the regulation on guidelines for trans-European energy ('Infrastructure Regulation').¹²⁵ The Security Regulation introduced common standards for security of gas supply including, among other elements, binding infrastructure standard N-1 (by 3 December 2014) and the obligation of reverse flows for TSOs (by 3 December 2013) on all cross-border interconnection points between member states. It also introduced minimum supply standards, placing an obligation to ensure gas supply to the protected customers in the following cases: extreme temperatures during a seven-day peak period, any period of at least 30 days of exceptionally high gas demand, and for a period of at least 30 days in case of the disruption of the single largest gas infrastructure. Given that further investment in infrastructure would be required to meet the Regulation's legally-binding standards (although some exemptions have been granted), the EU has established a regular budget (under its new Connecting Europe Facility CEF) for co-financing the construction of such infrastructure, with €9.1 bn earmarked for this purpose over the 2014–2020 period.¹²⁶ The Infrastructure Regulation introduced a category of (infrastructure) projects of common interest (PCI) which would be eligible for CEF funding; and established a procedure for selection of PCIs.¹²⁷

Crucially, only a project that contributes towards the creation of one of four 'priority corridors' (north–south interconnections in western Europe, north–south interconnections in central-eastern and south-eastern Europe, the southern gas corridor, and interconnections in the Baltics) would be considered against a set of specific PCI criteria and (if awarded a PCI status) eligible for funding under CEF. The first PCI list was adopted in October 2013 and included 106 gas infrastructure projects.¹²⁸ The PCI projects in the north–south, central-east, and south-east corridor include, inter alia: a Czech Republic–Poland interconnection upgrade; Poland–Slovakia, Slovakia–Hungary, Austria–Czech Republic, Bulgaria–Greece (IBG), Bulgaria–Serbia interconnections; and an LNG terminal in Croatia. The PCI projects in the southern corridor include virtually all pipelines which have been discussed as potential routes for delivering Caspian gas to Europe,¹²⁹ the most realistic of which include the pipelines for bringing Azeri Shah-Deniz 2 gas to Europe (for example, the expansion of the South Caucasus pipeline and the construction of TAP and TANAP). The Turkey–Bulgaria interconnection (ITB) is another PCI project which is included in the southern corridor.

The ability to bring alternative supplies to central-east and south-east Europe is constrained not only by physical congestion (where the level of demand for actual deliveries exceeds the technical capacity at some periods of the year) but also by contractual congestion (where the level of firm capacity demand exceeds the technical capacity). According to ACER, at least one third of total interconnection point sides in the EU were congested during Q4 2013.¹³⁰ Most of the congestion observed in north-west Europe occurred at the interconnection points between: Germany and the

¹²⁴ Regulation (EU) 994/2010 of the European Parliament and of the Council of 20 October 2010 Concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC, *Official Journal of the European Union*, 12.11.2010, L295/1.

¹²⁵ Regulation (EU) 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009, *Official Journal of the European Union*, 25.4.2013, L115/39.

¹²⁶ Regulation (EU) No 1316/2013 of the European Parliament and of the Council of 11 December 2013 Establishing the Connecting Europe Facility, amending Regulation (EU) No 913/2010 and repealing Regulations (EC) No 680/2007 and (EC) No 67/2010, *Official Journal of the European Union*, 20.12.2013, L348/129.

¹²⁷ Regulation (EU) 347/2013 of the European Parliament and of the Council of 17 April 2013, op.cit.

¹²⁸ EU Commission (2013). 'The 2013 PCI list' which includes many of the projects, particularly interconnections, already supported under EERP, is available at http://ec.europa.eu/energy/infrastructure/pci/doc/com_2013_6766_en.pdf

¹²⁹ Although it was TAP, which was chosen by Shah Deniz 2 partners for flowing Azeri gas to Europe, the list also contains the ITGI project and a pipeline following the Nabucco West route. Furthermore, the list contains a Trans-Caspian pipeline.

¹³⁰ ACER Annual Report on contractual congestion at interconnections points (period covered Q4/2013).



Netherlands (both directions), Germany to Denmark, Interconnector IUK (both directions), and within Germany and France. Some congestion was identified which involved interconnection points between Germany and Austria, Germany and Poland, Germany and the Czech Republic, and from France to Spain.¹³¹

Implementation of the Third Energy Package (TEP), and specifically its Congestion Management Procedures (including short-term Use-It-Or-Lose-It provisions), would allow for more efficient utilization of existing infrastructure by reducing contractual congestion. The planned inclusion of mechanisms enabling construction and utilization of incremental and new capacity into the Capacity Allocation Mechanisms Network Code (CAM NC) would create a framework for market-based investment in new infrastructure, thus complementing the PCI approach. In so doing, by reducing contractual and physical congestion, the TEP would contribute towards facilitating alternative pipeline gas and LNG supplies to the Baltic countries, and central-east and south-east Europe, through existing and new infrastructure.

2.2.2 The LNG situation

According to Gas Infrastructure Europe (GIE) data,¹³² in 2014 Europe had around 185 bcm of LNG re-gasification capacity, mostly concentrated in north-west (UK, France, the Netherlands, and Belgium) and south-west (Italy, Spain, and Portugal) Europe – 179.76 bcm (97.1 per cent), whereas there was only 5.3 bcm (2.9 per cent) in south-east Europe (Greece) and none in the Baltic region (Table 10).¹³³ In 2013, Europe only imported 43 bcm of LNG (~22 per cent of capacity) but potential imports are demonstrated by the data for 2009–2010, when imports exceeded 80 bcm.¹³⁴

Given the geographical flexibility provided by LNG, in theory more could be delivered to central-east and south-east Europe. However, in reality, the ability to flow LNG eastwards in a network which was designed for predominantly westwards and southwards flows would be limited by the continuing presence of infrastructure bottlenecks (despite the system's increased reverse-flow capability in line with the Security Regulation). This situation could only be changed by significant new investment in infrastructure. LNG flows eastward would be made even more difficult in a crisis, as such a situation would place additional limitations under scenarios of high demand and simultaneous maximization of all remaining import sources and of storage use across Europe.¹³⁵

¹³¹ Although having found significant contractual congestion, ACER calls for cautious treatment of the report's results due to issues of data consistency and availability and the shortness of the observed period.

¹³² GIE (2014).

¹³³ Here classification by region is purely geographic and hence differs from CEER regional classification of countries participating in Gas Regional Initiatives (GRIs).

¹³⁴ Based on data from the International Group of Liquefied Gas Importers, see GIIGNL (2013).

¹³⁵ R. Prieto, 'The role of LNG in the security of supply context', presentation made at the Madrid Forum, 6 May 2014.

Table 10: European LNG re-gasification capacity relevant to countries dependent on Russian gas: existing and planned

Country	EXISTING AND UNDER CONSTRUCTION		EXISTING AND PLANNED/ PROPOSED		
	2013 (GIIGNL)	Winter 2014/15	Winter 2015/16	2020	2030
Italy	15.4	14.7	14.7	46.7	51.3
Poland			5*	5	5
Lithuania		4*	4	4	4
Latvia				5	5
Estonia			2.5	6.5	6.5
Finland				8	8
Croatia				2	2
Greece	5	5.3	5.3	17.3	17.3
TOTAL	20.4	20+4*	26.5+5*	94.5	99.1
EU-28 (excluding small scale LNG)	186.4	185+4*	203.8+5*	326.3	333.4
Turkey	12.2	12.2	12.2	12.2	12.2
Ukraine			5	10	10

* Start of operation

Source: GIE (2014). Numbers rounded to one decimal place; for 2030 data it is assumed that no new LNG import capacity will be added after 2022 (as the GIE database provides data up to 2022 only); data for 2013 is from GIIGNL (2013).

Baltic region LNG

A floating storage and re-gasification unit (FSRU) in **Lithuania** (Klaipeda, 4 bcm) and an LNG import terminal in **Poland** (Świnoujście, 5 bcm) are the first LNG import facilities to be built in the Baltic region – the Klaipeda terminal is expected to start operation in late 2014, and the Świnoujście terminal in 2015. Other countries in the region also wish to build their own LNG import facilities: **Latvia** is considering construction of an LNG terminal at Riga (potentially providing 5 bcm of capacity in 2016) while **Estonia** is considering a number of LNG terminals including: Paldiski (2.5 bcm in 2015), Muuga Tallinn (4 bcm in 2018), and Sillamäe. **Finland** is considering the construction of an LNG import terminal near Helsinki (Finnigulf LNG) which would become operational in 2017 and be capable of importing 8 bcm. The Finnish, Latvian, and two Estonian (Paldiski and Muuga Tallinn) planned facilities have a PCI status, but none had taken a final investment decision (FID) by September 2014.

In 2013, the gas requirements of all three Baltic countries and Finland were met exclusively by Russian pipeline gas imports, whereas more than half of Poland's requirements came from Russia (and the rest from domestic production).¹³⁶ Table 10 shows that Lithuania's Klaipeda terminal would be sufficient to cover all of the country's gas import requirements up to 2030 while also having some

¹³⁶ In April 2014 Poland implemented physical reverse flow on the Yamal–Europe pipeline thus enabling it to source gas from Germany and the Czech Republic, see EU Commission (2014d), p.47.



spare capacity for imports to neighbouring Latvia and Estonia in the interim.¹³⁷ In addition, Table 10 shows that if *all* LNG import capacity that is currently under consideration in the four countries (one in Finland, one in Latvia, and two in Estonia, in addition to the Lithuanian terminal) is built, then the combined LNG import capacity of the region could reach 23.5 bcm/year by 2020, which is more than double the projected consumption in that year (see Table 4). This suggests that not all of this capacity will be built, and it would not be realistic to expect EU funding to be provided for all the projects.¹³⁸ However, increased interconnection between countries would allow the region to reduce its dependence on Russian pipeline gas to one third of its import requirements, with no need for new LNG terminals.¹³⁹

Poland's gas consumption, of around 18 bcm in 2013, is more than double that of the Baltic region (discussed above). Given that this figure is projected to decrease slightly to 17 bcm in 2020 and then to reach 21 bcm by 2030 (Table 4), the Polish Świnoujście import terminal capacity would be sufficient to cover slightly less than one third of Poland's consumption by 2020 and around one quarter by 2030. The Poland–Lithuania interconnection (GIPL), if built by 2019, would allow Poland to access new Baltic LNG facilities – (some of) which are expected to be constructed by 2020 – particularly if their capacity exceeds regional Baltic demand.

South-east European LNG

The only LNG import terminal in south-east Europe is located in south-eastern **Greece** near Athens (Revithoussa, 5.3 bcm) for FID has been taken on expansion to 7.3 bcm by 2016. Two FSRUs, each with a capacity of 5 bcm, are planned by 2016 in north-eastern Greece, close to the border with Bulgaria and Turkey (Alexandropolis INGS and Aegean Sea, both have PCI status but neither have taken FID).¹⁴⁰ **Croatia** is also considering the construction of a floating re-gasification unit (FRU) – Krk Island, which would provide 2 bcm of import capacity by 2017 (this has PCI status but no FID).

In 2013, almost all the import requirements of Bulgaria, Serbia, Bosnia & Herzegovina, FYROM, and Slovakia were covered by Russian pipeline gas (which needed to transit across Ukraine). The shares were somewhat lower for Hungary, Slovenia, and Greece (around two-thirds of import requirements). Croatia is the only country in the region with minimal dependence on Russian gas, having completely ceased imports in 2011, recommencing with very small quantities in 2013 (see Table 1).

For south-east Europe, the Greek LNG Revithoussa terminal (5.3 bcm) is the main existing relevant piece of infrastructure for reducing dependence on Russian gas.¹⁴¹ Greece's own consumption stands at around 3.8 bcm, thus leaving 1.5 bcm of spare capacity which could be used by other buyers. Given that combined Greek and Bulgarian demand is not projected to exceed 7 bcm in 2030, and should Revithoussa's capacity be expanded to reach 7.3 bcm in 2016, the terminal will have sufficient capacity to cover the demand of both countries, especially since both countries should be importing 1 bcm each of Azeri gas by 2020. However, upgrades might be required on the Bulgarian and Greek

¹³⁷ For demand projections see Table 4. Lithuania's supply contract with Gazprom will expire at the end of 2015 and it remains to be seen whether (some part of) this will be extended or renewed, see B. Bradley and M. Seputyte, 'Lithuania may end Gazprom contract when LNG terminal starts work', 3 January 2014, *Bloomberg Businessweek*, www.businessweek.com/news/2014-01-03/lithuania-may-end-gazprom-contract-when-lng-terminal-starts-work.

¹³⁸ The ACER opinion on the draft list of PCIs labelled these projects as 'competing', see ACER, *Opinion of the Agency for the Cooperation of Energy Regulators*, No 15/2013 of 18.7.2013 on the draft regional lists of proposed gas projects of common interest 2013. All four of these LNG projects are on the 2013 PCI List but with a note that a PCI status has been granted to any *one* of these (and not to all of them).

¹³⁹ For example: construction of offshore link between Finland and Estonia (Balticconnector), capacity increase on Latvia–Lithuania and Estonia–Latvia interconnections, and upgrade of the Klaipėda–Kiemėnai pipeline allowing the gas delivered to the Klaipėda LNG terminal to flow across Lithuania to Latvia and Estonia. All of these projects are on the 2013 PCI List.

¹⁴⁰ Both FSRUs are on the 2013 PCI List but (just as in the case of Baltic LNG facilities) with a note that a PCI status has been granted to any *one* of them.

¹⁴¹ Turkey has significant re-gasification capacity (~12 bcm) at two terminals, but given its expectations of significant demand growth it is unlikely that it would become a significant channel for gas imports into south east Europe countries.



domestic networks to enable the gas to be brought from Revithoussa to the northern part of Greece, to its border with Bulgaria. The two planned FRSU facilities close to the Greek border with Bulgaria (Alexandroupolis INGS and Aegean Sea) would make supply to Bulgaria logistically easier, but it is doubtful that the Revithoussa expansion and *both* FRSU facilities will go ahead.

The new Croatian FRU Krk Island terminal (see above) would also allow the countries in the region, particularly in the Balkans, to source small quantities of LNG, with a number of pipelines envisaged to be built towards Hungary, Slovenia, and Italy; an expansion of the existing Croatia–Slovenia interconnection is also envisaged.¹⁴² South-east Europe could also strengthen its access to LNG by using Italy's significant LNG re-gasification capacity (around 15 bcm which is expected to triple by 2020 although not all of this is likely to be built) and the existing, as well as planned (Omišalj-Casal Borsetti) offshore gas pipelines between Italy and Croatia.

2.2.3 Pipeline gas: the Southern Corridor

The only non-Russian pipeline gas supply which will definitely be available for Europe by 2020 is Azeri gas (Shah Deniz 2) arriving across Turkey. The buyers of this gas include Bulgargaz (around 1 bcm), DEPA (around 1 bcm), E.ON (around 1.6 bcm), Enel, Gas Natural, GDF SUEZ, Shell, Axpo Trading, and Hera Trading. This suggests that, apart from Bulgaria and Greece, no other country in south-east Europe has contracted gas arriving via the Southern Corridor. Once the gas is delivered through the TANAP pipeline across Turkey to the border with Greece, it would then be delivered via the TAP pipeline (which is on the PCI list) across Greece and Albania and then across the Adriatic Sea to southern Italy. Although the Southern Corridor would deliver new gas to the region, it will not impact the supply situation of the highly dependent Balkan countries of Serbia, Bosnia & Herzegovina, and Macedonia unless pipeline connections are built.

2.2.4 Conclusions: likely infrastructure developments 2015–2030

Very little can be achieved in a one-year time frame in terms of pipeline gas for either north/east-central or south-east Europe. However, new LNG terminals in Lithuania and Poland will provide the possibility of importing LNG to the Baltic region, which has relied exclusively on pipeline (Russian) gas; the Lithuanian terminal is expected to receive its first cargo in December 2014.

Importantly, for all of these LNG facilities to have an impact on the region's ability – especially that of countries such as Serbia, FYROM, and Bosnia & Herzegovina which are located further away from LNG terminals and have more limited interconnections with the 'outer' countries of south-east Europe (for example Bulgaria, Greece, and Croatia) – to source LNG and reduce its dependence on Russian gas, significant investment would be needed to increase interconnection capacities and upgrade domestic pipelines in the region. Azeri gas, arriving in south-east Europe by the end of this decade, would not change the supply situation of the Balkans significantly without the necessary interconnections and domestic network reinforcements.¹⁴³ Given that the overall consumption of these three non-EU Balkan countries (Serbia, FYROM, and Bosnia & Herzegovina) is not envisaged to reach 3 bcm by 2030 (Table 4) and their access to EU funding might be more limited compared to that potentially available to EU member states such as the Baltic countries, it is realistic to expect that construction of this supporting infrastructure might be a longer-term prospect, thus implying continuing high dependence on Russian gas (and, in the absence of South Stream, on Ukrainian transit).

¹⁴² All of these are also on the 2013 PCI List.

¹⁴³ Some of these and other projects were considered within the Balkans Gas Ring Concept, the implementation of which would have strengthened gas security of the region as well as provided for its further gasification. Energy Community Treaty (2009).



South-east Europe would be able to increase its access to LNG delivered to import terminals in Greece and (to a lesser extent) in Turkey via Greece–Bulgaria (IGB) and Bulgaria–Turkey (ITB) interconnections; IGB is expected to be commissioned in 2015¹⁴⁴ whereas ITB, which was expected to be commissioned in March 2014, appears to have been delayed and at the time of writing its completion date was unclear.¹⁴⁵ The other existing relevant LNG import facilities are located in the western part of Europe – and although they could potentially be used for bringing non-Russian gas to north/east-central and south Europe, this will probably remain a post-2020 prospect due to significant infrastructure limitations on eastward flow. However, in the short term there is some scope for swaps.

More significant improvements could be made by 2020, and especially 2030, by which time it would be possible to build both LNG and pipeline interconnections to enable Baltic and south-east European countries to access alternative gas supplies which would significantly reduce (and in some cases completely eliminate) their dependence on Russian gas. In the Baltic region this task would be less challenging for Lithuania, Latvia, Estonia, and Finland, and more difficult for Poland. In the south-east European region it would be less difficult for the region's 'outer' countries (Bulgaria, Croatia, and Greece), but significantly more difficult for the three 'inner' Balkan countries of Serbia, FYROM, and Bosnia & Herzegovina.

The major constraint on the ability of all countries to implement (even some of) their planned projects is the cost. Despite the EU's efforts in promoting and financing new infrastructure, existing facilities (and projects which have taken FID) will not be sufficient for a significant reduction of these countries' dependence on Russian gas. The 2013–2022 Ten-Year Network Development Plan (TYNDP), developed by ENTSOG, suggests that 'due to the lack of appropriate infrastructure being available to bring other sources', supply dependence on Russian gas will increase if only the infrastructure projects which have taken FID are taken into account.¹⁴⁶ According to the EC, referring to ENTSOG data, even if all FID projects are implemented, central-east and south-east Europe will still maintain a high share of dependence on Russian gas in 2022: Finland, Estonia, Latvia, Poland, Slovakia, Hungary, Bulgaria, FYROM, Serbia, Bosnia & Herzegovina, Croatia – over 60 per cent; the Czech Republic, Romania, north-east Germany, Lithuania – 40–60 per cent.¹⁴⁷ However, it notes that if non-FID projects are also implemented by 2022 – including the non-FID projects in the Southern Corridor – only Poland and Latvia will maintain supply dependence on Russian gas in the range of 40–60 per cent, Lithuania – in the range of 20–40 per cent, whereas the dependence of others will decrease to below 20 per cent.¹⁴⁸ ENTSOG estimated the total cost of FID projects (excluding storage) at around €8.8 bn and the total cost of non-FID projects – at around €60 bn.¹⁴⁹

¹⁴⁴ EC website http://ec.europa.eu/energy/infrastructure/pci/doc/pci_6_8_1_en.pdf.

¹⁴⁵ Bulgaria's Ministry of Economy and Energy, www.mi.government.bg/en/themes/gas-interconnection-turkey-bulgaria-itb-913-347.html.

¹⁴⁶ TYNDP 2013–22, ENTSOG (2013).

¹⁴⁷ EC (2014d), p. 59. Also see TYNDP 2013–22, ENTSOG (2013), p. 114..

¹⁴⁸ *Ibid.* p. 59.

¹⁴⁹ TYNDP 2013–22. ENTSOG (2013) notes that the cost might well be higher as not all projects submitted for the TYNDP 2013–22 had cost estimates.



3. Fuel Substitution, Conservation, and Efficiency

3.1 Introduction

The role of gas in the energy mix is driven by the overall consumption of energy, which is a function of GDP and energy efficiency, and by competition with other fuels in the different sectors. Reducing gas consumption will, *ceteris paribus*, reduce import needs. A reduction of Russian imports depends partly on the relative attractiveness (mainly the price and availability) of Russian gas compared to other gas sources – unless it is the consequence of a political decision.¹⁵⁰ (Alternative gas supplies are considered in other sections of this paper and therefore are not addressed again here.) Termination or substantial reduction of Russian gas deliveries would likely trigger an increase of gas prices, which may have the effect of curtailing gas demand (impacting comfort or economic activity) or triggering substitution by other fuels.

Reducing dependence on Russian gas can be achieved by cutting gas consumption: by limiting the energy use covered by gas, by improving energy savings and efficiency, or by replacing gas with alternative fuels. Natural gas can be replaced directly by biogas in pipelines, and by other fuels at the burner tip. It can be replaced indirectly by other fuels in power generation, and in final energy consumption by other final energies (by producing heat from electricity instead of gas, for example). The possibilities and the range of actions depend on the costs of these measures and, just as importantly, on the timeframes under consideration: 2015, 2020, and 2030.

In a one-year timeframe, there are only limited solutions. Russian gas can be replaced by available alternative fuels – if the necessary infrastructure is in place – or by a reduction of gas consumption. An immediate possibility is to use less gas at the expense of comfort and economic activity, perhaps as a result of price spikes driven by scarcity. This partly happened during the 2009 Russia–Ukraine transit crisis in south-eastern Europe, where households disconnected from the network in large numbers, and had to resort to wood fires.¹⁵¹ Especially for countries which are completely dependent on Russian gas, any reduction of supply can only be compensated by either reducing energy consumption or by replacing gas by other energies.

3.2 Substitution of oil products and coal

Direct substitution by other fuels, such as oil products (gasoil and fuel oil), would be possible in situations where the substitution takes place at the burner tip. There is little scope for this in the residential and commercial sector, as it is unrealistic for the sector to maintain alternative equipment. The reintroduction of oil products into the industrial and power sectors would reverse the trend of the last 20 or more years, where oil products have been replaced with gas due to its properties of being easy to regulate and clean burning. However, with appropriate financial incentives, this reversal might happen within the limits of the fuel oil infrastructure still in place, and of environmental legislation. An indicative estimate of the potential is the decline of oil consumption in industry during the last ten years, assuming that the infrastructure used 10 years ago is still in place and functioning. In 2004, consumption of gasoil and residual fuel oil in six continental European gas markets (which comprised 64 per cent of the gas demand in EU 25) was 57mt, of which households accounted for 34mt, the service and commercial sector for 14mt, and industry for 9mt.¹⁵² It is highly unlikely that households

¹⁵⁰ In what follows, it is assumed that attempts to reduce dependence on Russian gas supplies would not entail fundamental changes in democratic planning procedures, in the policy instruments being used and even in commercial decisions.

¹⁵¹ Kovacevic (2009).

¹⁵² Stern (2007).



which have switched to gas would have maintained their oil burning equipment; this reduces the potential for switching in these markets to a maximum of 23mt (which would replace approximately 27 bcm of gas) and probably substantially less.

By the early 2010s, only limited amounts of oil-fired power generating capacity remained in Europe, as a consequence of the Large Combustion Plant Directive (LCPD) and/or conversion of oil-fired plants for environmental reasons. In some countries, such as Italy, many oil-fired plants were converted to coal, which was considered to be a lesser evil (and a cheaper one). In addition, even if the capacity is still operational and assuming that these plants are competitive (at 2014 prices), heavy fuel oil is no longer used – with the exception of bunkers. The use of oil-fired generation could be restricted in many countries and may require government authorization, although this would normally be given during security events, such as a supply crisis (for instance in Italy in February 2012 when gas supply was low and temperatures were very cold). Such authorizations would be time-limited and possibly restricted to specific plants, although this may differ from country to country. In the countries most dependent on Russian gas: Finland has more than 10 GW of oil-fired capacity,¹⁵³ Turkey 8 GW, and Hungary 5 GW. Smaller markets have more limited capacity, but all except Poland and Greece operate their oil-fired capacity at very low load factors, which means that these plants could, in theory, be called for backup or replacement of (part of) gas generation in times of emergency (Table 11).

In the power sector, electricity produced from gas can be substituted by electricity produced by other readily available fuels, not just oil. The main option, and one which can be done quickly and on a much larger scale than by using oil products, is to use additional coal, although this would add significantly to carbon emissions (and potentially create other environmental problems). Switching from gas to coal has already happened (in the early 2010s) due to competitive coal prices relative to gas, and low carbon prices in the EU ETS system.¹⁵⁴ Flat power demand and rapid growth in renewables such as wind and solar PV (due to commercial or policy priorities these are already used at maximum possible levels) also contributed to the decline in the share of electricity generated from gas to just above 15 per cent in 2013 (compared with 24 per cent in 2008).¹⁵⁵ As of 2014, natural gas is used mostly in applications (like CHP) which must run, or when gas-fired stations are needed to meet short-term capacity (such as peak shaving, which does not involve large gas volumes).¹⁵⁶ As a result, gas-fired plant has already been displaced by cheaper (coal/lignite and nuclear) alternatives, which has limited the potential for additional switching in the 2010s.

¹⁵³ This is the total figure which includes single-fired capacity, but also multi-fired capacity for which we do not know the share that can be run on oil. Source: IEA Electricity (2014), Part IV, Table 15.

¹⁵⁴ In 2013, the CO₂ price in the EU ETS was around €5 per ton, compared with €25–30 per ton in 2008.

¹⁵⁵ Data for OECD Europe, from IEA Electricity (2014), p.III.33, Table 2.4.

¹⁵⁶ With the notable exception of the UK, where a coal-to-gas switching happened from spring 2014, triggered by lower NBP prices, the closing down of coal capacity under the Large Combustion Plant Directive, and the national carbon floor price which were implemented in April 2013.

Table 11: Oil-fired generating capacity and utilization in 2012 and 2013

	Capacity that can use liquid fuels (single or multi fired -solid,liquid,gas- in which case, total capacity is shown) in 2012 in GW	Gross production from oil in 2013 in TWh	Load factors in %
Estonia	2.33	0.1	0.49
Finland	10.1	0.3	0.34
Greece	2.51	5.4	24.56
Hungary	5.41	0.1	0.21
Poland	0.46	1.8	44.67
Slovak Republic	1.05	0.4	4.35
Turkey	8.15	1.7	2.38

Source: IEA Electricity (2014).

Existing coal plants have to comply with the LCPD, of which about 60 GW have opted out and will be retired by the end of 2015 (at the latest),¹⁵⁷ and the Industrial Emissions Directive (IED), for which generators have to submit plans for opting-in or opting-out by end-2014. If the plants are opted out, they will be allowed to run a maximum of 17,500 hours between 2016 and 2023 without complying with the new emission limit values, and will then need to be retired. It is too soon to determine the exact impact on the coal fleet (and the older gas plants), but the Directive will have more impact in countries such as the UK, Poland, and elsewhere in eastern Europe; and less in others such as Germany or France. The restriction of output from coal-fired plants due to the LCPD/IED might result in a need – probably sometime in the 2020s (but not in the 2010s¹⁵⁸) – to run gas-fired power capacity at higher load to compensate for coal-fired power generation, if no alternatives to coal and gas are available. Aside from those already under construction (about 15 GW mainly in Germany but also in the Netherlands and Turkey), the number of new coal plants will be limited. Investment decisions are complicated by low baseload electricity prices and the difficulty of obtaining approval for construction due to environmental regulations (mostly in western Europe).

This regional picture of the generation sector differs from country to country depending on the situation in each market.¹⁵⁹ In those countries most dependent on Russian gas, making a judgment on switching potential and timescale requires detailed information about plant age and availability, and the logistics of bringing alternative fuels to centres of consumption. In 2014–2015, *at least on paper*, it seems possible to switch all the electricity produced from gas plants to coal plants in the Czech Republic, Finland, Estonia, Poland, Bulgaria, Slovakia, and Slovenia. In Greece, most of the electricity from gas could be generated from coal. In Turkey, a gas-to-coal switch would be realistic for about 50 per cent of gas-fired capacity, while the figure for Hungary is 10 per cent, but it is zero in Latvia and Lithuania. These figures are important because for Estonia, Finland, Greece, Bulgaria, and Slovenia, the power sector accounted for more than 40 per cent of gas consumption in 2011.

If we apply the same methodology in 2020, it seems possible that all electricity from gas plants could be generated from coal plants in Austria, the Czech Republic, Estonia, Finland, Poland, Bulgaria, and Latvia (which in this scenario will have sufficient coal capacity for this by 2020). In Slovenia, most of the electricity from gas could be generated from coal plants, but not all. Coal plants alone would only be able to cover about 50 per cent of the electricity generated from gas plants in Austria, Greece, and Turkey, while in Hungary, they could probably only cover about 10 per cent. By 2030, *in theory* all electricity from gas plants could be easily be generated from coal plants in Austria, the Czech

¹⁵⁷ OIES estimate.

¹⁵⁸ See Honoré (2014), for more information.

¹⁵⁹ For more information, see *ibid*.



Republic, Estonia, Finland, Poland, Bulgaria, and Latvia. Coal plants could cover most of the electricity from gas in Greece, but only about half in Turkey, about a quarter in Slovenia, and only about 10 per cent in Hungary and Slovakia.

It is important to stress that these are *theoretical judgments* about switching possibilities in the power sector. In reality, an interesting period to look at is January 2009, when Russian gas deliveries were interrupted for several days (but not to the Baltic countries). Although one would expect to see switching from gas to coal (and oil), when this period is compared with the corresponding period in January 2007 and 2008, the data does not reflect this. However, this observation is constrained by the lack of available data for many markets that are highly dependent on Russian gas; the same data limitations apply for gas-to-oil switching. Based on electricity generation data by fuel, the only obvious gas-to-oil switching happened in Hungary, and some could be seen in Greece. This is perhaps a counter-intuitive result, although probably less surprising because oil plants are being shut down and capacity is limited.

Availability of data complicates more definite conclusions being made about real switching potential. On paper, some switching appears possible between coal and gas and, in a more limited range, between oil and gas. With these substantial caveats: in 2015 about 16 bcm of gas consumed in the power sector (out of about 25 bcm that would be consumed without any switching) could be substituted in the 13 countries wholly or highly dependent on Russian gas.¹⁶⁰ By 2020, about 14 bcm of gas could be substituted out of the 28 bcm that would otherwise be consumed. By 2030, the saving could rise to about 20 bcm out of the 35 bcm that would be used in the power sector without switching.¹⁶¹ To reiterate: these conclusions only relate to countries which are highly dependent on Russian gas; for the whole of Europe the figures are potentially much larger – in the range of 50–60 bcm for 2015–2030.¹⁶² Again, although these are reasonable conclusions on paper, they face some challenges in reality, the most important being the much higher greenhouse gas emissions if part (or all) of the electricity produced from gas were to be produced from coal (and some from oil).

In summary, in the 13 countries mentioned above (and listed in footnote 160), we estimate the potential for switching to other fuels from gas primarily sourced from Russia, as 16 bcm in 2015, 14 bcm in 2020, and 20 bcm in 2030. However, any solution chosen to reduce gas consumption will depend on price levels of alternative fuels. The attractiveness of energy efficiency and saving, and non market-based renewables increases with higher gas (and fuel oil) prices. The possibilities also depend on investment levels and are subject to different time horizons; for instance five years for industrial investment, up to 10 years for infrastructure and new coal/nuclear plants, and much longer to replace building stock.

3.3 Low carbon options

3.3.1 Biogas

The direct replacement of gas by renewables is confined to biogas, which is climate neutral and has some potential for direct substitution of natural gas. The main applications for biogas are: heat and power generation, feedstock in the chemical industry, fuel for transport, and grid injection. There are no significant developments expected in this sector up to 2020. The level of biogas production expected in the National Renewable Energy Action Plans is about 28 bcm/year by 2020.¹⁶³ However,

¹⁶⁰ Austria, Bulgaria, the Czech Republic, Estonia, Finland, Greece, Hungary, Latvia, Lithuania, Poland, Slovakia, Slovenia, and Turkey.

¹⁶¹ For more information about the scenarios 'without switching', see Honoré (2014), Appendices.

¹⁶² Calculated based on data in Honoré (2014).

¹⁶³ See Section 2.1.1 for more information about biogas potential and problems.



even this number is uncertain as it depends not only on continuous financial support to the development of biogas, but also on the sustainability of biomass production with its impacts on ecosystems, on food and feed production, on cultivated land, and the issue of deforestation.

3.3.2 Renewables, heat, and nuclear power

The potential to replace gas with other renewables is more complicated as substitution is not direct. The processes using gas for heating could be replaced by processes using electricity – such as the use of heat pumps in new buildings (the best example), and also direct heating and heat storage systems using cheap electricity. In a low- or zero-energy house all heating might be covered by the exhaust heat of electric appliances. Both solutions have been used in new buildings in Germany over the last ten years.¹⁶⁴ Governments are also looking at increasing the generation of heat (and cooling) in buildings from renewable energy sources rather than fossil fuel (including natural gas) systems, as stated in their Renewable Energy Action Plans.¹⁶⁵

While renewables benefit from priority dispatch in power generation,¹⁶⁶ wind and solar – the two fastest-growing renewable energy sources in Europe – are both intermittent and unpredictable. Their availability depends on external factors such as sunshine and wind. They cannot be switched on and off as needed, unlike other power plants. As a result, direct substitution of gas plants by renewables is limited. However, their growing share in the mix, and flat growth of power demand post-recession, has had a major impact on power generation from gas. In 2008, electricity from gas represented 24 per cent of the total and renewables only 3.8 per cent (19 per cent including hydro). By 2013, gas represented only 16.7 per cent of the mix, while renewables were up to 9.3 per cent (26.2 per cent including hydro).¹⁶⁷

There is no coherent strategy on nuclear power in Europe, but the nuclear generating fleet is ageing. The 136 nuclear reactors in Europe (the EU plus Switzerland) were technically designed for a lifetime of up to 40 years.¹⁶⁸ Currently, the reactors have an average age of 29 years. Several important gas markets such as Italy, Turkey, and Austria do not have nuclear in their energy mix, while some countries (Germany by 2022, Belgium by 2025, Spain in 2028, and Switzerland in 2035) have decided to phase out nuclear. In other countries (for example the UK) plants will be closed, having reached the end of their operating lives. The use of existing plants may also be curtailed following political decisions – such as the position in France where the share of nuclear production in total power generation should be reduced to 50 per cent by 2025 compared to about 75 per cent in 2013 (although how this objective is to be reached was still unknown at the time of writing).

There are only four new reactors under construction in Europe: one in Finland, one in France (both are EPRs of 1600 MW which are experiencing budget and time overruns), and two in Slovakia (each 440 MW).¹⁶⁹ Several countries have expressed interest in building new reactors (for instance the UK, Netherlands, and Sweden) or in introducing nuclear in their mix (Poland, Turkey). However, due to construction lead times, no new reactors (apart from those already under construction) will be operational prior to 2020. It would be optimistic to see any *substantial* increase in nuclear power production in Europe post 2020, mostly because of high costs, but also due to phase-out decisions. The main issue for nuclear power is, rather, prolonging the operating life of existing stations beyond original design, and acceptance by the population. Failure to achieve this will mean the decline will accelerate.

¹⁶⁴ Dickel R. (2014), p.71

¹⁶⁵ http://ec.europa.eu/energy/renewables/action_plan_en.htm.

¹⁶⁶ Renewables also benefit from interdiction of significant curtailment, see Directive 2009/28/EC for more information.

¹⁶⁷ IEA Electricity (2014), p.IV.59, Table 3; Honoré A. (2014), pp.39–40.

¹⁶⁸ www.euronuclear.org/info/encyclopedia/n/nuclear-power-plant-europe.htm.

¹⁶⁹ www.euronuclear.org/info/encyclopedia/n/nuclear-power-plant-europe.htm.



3.4 Energy saving and efficiency

An EU press release of 23 July 2014 states that: the 'European Commission proposes a higher and achievable energy saving target for 2030' but without giving further details. The EU commission claims that:

... for every additional 1% in energy savings, EU gas imports are expected to fall by 2.6%, decreasing our dependence on external suppliers.¹⁷⁰

This is not explained in any detail and – given the complexity of energy saving across all fuels as well as within the gas sector – sounds like a rather hypothetical statement. The impact assessment says that:¹⁷¹

Energy efficiency has a significant impact on security of supply and the level of gas imports in particular. Energy efficiency policies achieving 40% savings, would result in 2030 in lowering gas imports by as much as 40% in comparison to 2010, whereas in the Reference the imports would grow by 5% in that year. Already energy savings of 30% achieve a 22% decrease. Net energy import decreases translate into savings in the energy fossil fuels imports bill. For the period 2011–2030 cumulative savings range from €285 bn to €549 bn and for the period 2031–2050 from € 3349 bn to € 4360 bn.

EU policy has ambitious goals for 2020 and 2030 regarding renewables and energy efficiency improvements, which would both lead to a reduction of gas imports, but implementation has been slower than planned. Regarding the target of a 20 per cent increase in energy efficiency for 2020:

... the Commission estimates that the EU will achieve energy savings of around 18–19% in 2020. It should be noted that about one third of the progress towards the 2020 target will be due to the lower than expected growth during the financial crisis. It is therefore important to avoid complacency about reaching the 20% target.¹⁷²

Even in Germany, which has ambitious goals on de-carbonization – by fostering renewables and improving energy efficiency – the second (like the first) monitoring report on the implementation of the *Energiewende* was rather sobering in terms of the gap which needs to be bridged in order to achieve the 2020 goals for energy efficiency and energy saving (especially the refurbishment of existing building stock). By contrast, Germany is on track to reach its renewable targets in 2020.¹⁷³

Ambitious energy efficiency improvements are not so much a technical issue as more an implementation and a social/economic issue. The large variety of instruments and methods is demonstrated by the National Energy Efficiency Action Plans (NEEAPs) that every member state has to submit every five years. Over time, improvements in energy efficiency become more difficult once the 'low hanging fruit' has been harvested. As a result, the markets located in north-west Europe, for instance, will have limited possibilities to lower gas consumption via improved energy efficiencies, due to past investments and technologies already in place, compared with other regions of Europe.

In transport, the improvement of energy efficiency has no major impact on the use of gas, as it is only used to a minor extent, so far. In industry, energy efficiency is an ongoing commercially driven process implemented during the investment cycle. In the residential sector, the driver is new buildings (with increasingly strong requirements regarding CO₂ emissions to be met by insulation and use of renewables), and the rate and depth of refurbishment of the existing building stock. Because the

¹⁷⁰ EU Commission (2014a), EU Press release of 23 July 2014, http://europa.eu/rapid/press-release_IP-14-856_en.htm

¹⁷¹ EU Commission (2014b), Section 6.2.1, p.71.

¹⁷² EU Commission (2014b), p.4

¹⁷³ See Statement on the second monitoring report by the German Government for 2012, by Expert Commission on the 'Energy of the future monitoring process, summary March 2014', www.bmwi.de/English/Redaktion/Pdf/statement-on-the-second-monitoring-report-by-the-german-government-for-2012,property=pdf,bereich=bmwi2012,sprache=en,rwb=true.pdf.



largest potential for saving gas is in heating, the potential saving depends on new building (and demolishing old buildings) and refurbishment rates. Refurbishing existing buildings to an almost climate-neutral building standard is not commercial without state support. In addition, one cannot necessarily assume that energy efficiency in households is spread equally over all energies (gas oil is used in a more decentralized way than gas, which is often found in urban and centralized applications).

3.5 Conclusion

It is very difficult to give an exact figure for how much Russian gas could be substituted by non-gas alternatives, whether by other energy sources or demand-reduction through conservation and efficiency.¹⁷⁴ In 2015, the potential to reduce gas consumption is confined to fuel substitution, mainly by returning to the use of fuel oil in industry and by replacing gas in power generation by oil products and coal. It would be surprising if Europe could replace more than (the annual equivalent of) 20 bcm of Russian gas with oil products, and this would not be sustainable for more than a few months. The potential for replacing gas with coal in power generation is much greater – particularly in countries highly dependent on Russian gas, where *in theory*, seven countries could replace all gas generation with coal in 2015, 2020, and 2030.¹⁷⁵

By 2020, the oil product switching potential is likely to decline. Potential coal switching increases, but is dependent on tolerance of CO₂ emission increases, and failure to meet standards imposed by EU Directives which would otherwise limit the burning of coal. Restrictions on coal become even more important by 2030. With this caveat, our rough estimate is that coal switching in power generation could replace 14 bcm and 20 bcm of gas in 2020 and 2030 respectively in the 13 countries most dependent on Russian gas. However, additional coal and nuclear in the power generation sector have become problematic, as a result of stricter environmental regulations which would penalize coal, and opposition to new nuclear stations. Low wholesale electricity prices, driven by rising renewable capacity and escalating construction costs, are further obstacles to new nuclear stations and to coal with carbon capture and storage. When power generated by natural gas is replaced by other fossil fuels, such as coal and fuel oil, this creates contradictions between the objectives of security, competitiveness, affordability, and de-carbonization.

Substitution by renewables is more complicated – apart from a potential 10–15 bcm of direct substitution by increased biogas production by 2020. Other renewables are replacing gas (but also other fuels) indirectly via the power grid. Renewables (excluding hydro) represented close to 10 per cent of the power mix in Europe in 2013, up from about 4 per cent in 2008. In just five years, the share of renewable energy has grown rapidly – almost entirely at the expense of natural gas, which has been less competitive than coal and nuclear. Renewable energy can replace part of the generation from gas (and other fuels) and push natural gas plants to run as back-up rather than as middle or baseload, limiting the volumes of gas needed in the power sector up to 2030 (and beyond).

In a time horizon of five years, there is a limited potential to reduce gas use by higher energy efficiency, especially through better building insulation. The ambitious EU target to improve energy efficiency by 20 per cent by 2020 may be beyond reach in many countries. By 2030, a substantial reduction of gas use would depend on a major scaling up of energy efficiency, mainly in buildings, but this would require very substantial incentives beyond today's programmes. By 2030, there is

¹⁷⁴ Such calculations would require country by country, sector by sector, analysis of this potential; we have not carried out such analysis for this paper.

¹⁷⁵ The countries are: the Czech Republic, Finland, Estonia, Poland, Bulgaria, Slovenia, and Slovakia in 2015; and Austria, the Czech Republic, Finland, Estonia, Poland, Bulgaria, and Latvia in 2020 and 2030. The phrase 'in theory' is important because it highlights the importance of knowing the condition of existing coal plants and the ability to transport larger quantities of coal to those plants.



substantial potential to replace natural gas in all sectors, but it will require additional policy instruments and sustained political will. There are also clear policy synergies between increased renewables and improvements in energy efficiency on one hand and improved security of energy supply from imported fuels on the other. Putting figures on such potential is beyond the scope of this paper. However, we caution against the EU projection that energy efficiency policies could result in a reduction of 40 per cent of gas imports by 2030 (in comparison to 2010) which we believe to be somewhat 'heroic'. Even if correct, it would say nothing about the extent to which Russian gas imports would be reduced, which will depend on the competitiveness of different sources of gas (discussed in other chapters of this paper).



4. Reducing Ukrainian Dependence on Russian Gas

4.1 Introduction

The military conflict in Ukraine, the political hostility between Russia and Ukraine, and the resulting disruption of the Ukrainian economy, form the background to potentially far-reaching changes in the Ukrainian gas market. In the period up to 2030, while it is possible that physical volumes from Russia will continue to be the major part of Ukraine's gas supply, it is also likely that the commercial arrangements will be transformed. Ukraine will probably become partly or wholly integrated into the European market, and while its storage capacity could be an important benefit, its transit business will continue to decline and could all but disappear.

This chapter considers, first, the possible outcomes of the current political and security crisis for the Ukrainian gas market; second the options for Ukraine to reduce its dependence on Russian gas, and finally how it might be partly or wholly integrated into the European market and the implications of such developments (focusing on the period up to 2020).

In broad terms, Ukraine's gas demand is currently 50 bcm/year (down from 70–80 bcm/year in the mid 2000s). About 18 bcm can be expected from domestic production; in recent years it has been 20–21 bcm/year, but 1.5 bcm/year from Chernomorneftegaz (based in Crimea) should now be excluded, and a further small reduction assumed due to the political/military and economic crisis. This leaves an import requirement of about 32 bcm/year. The current Gazprom–Naftogaz contract is the obvious source for such imports, but these have stopped due to the dispute over contract terms. The only other sources of imported gas for the next few years are: deliveries from Russia to non-Naftogaz companies outside the contract and reverse-flow deliveries from Europe.

Reverse-flow gas deliveries have been carried out with the participation of utilities and other companies active in the gas market based in central and eastern Europe; 100 per cent (or very close to 100 per cent) of such gas will have physically originated from Russia. While the transit of Russian gas across Ukraine functions normally, these reverse-flow deliveries, which could reach 17 bcm/year by 2015, are an additional call on the European market's stock of gas. If transit across Ukraine is halted for any reason, there would be shortages of gas across central and eastern Europe and it is unlikely that any would be available, at least not at short notice, for reverse-flow deliveries to Ukraine.

4.2 The current crisis

In mid June 2014, Russian gas supplies to Ukraine under the Gazprom–Naftogaz contract ceased; Gazprom started arbitration proceedings against Naftogaz Ukrainy for unpaid bills (claimed by Gazprom to be \$5.3 billion, although some of this amount is disputed) and Naftogaz started arbitration proceedings on import prices. Previous interruptions of supply (notably, the gas disputes of January 2006 and January 2009) led rapidly to negotiations at corporate and political levels, and then to a settlement; however, on this occasion, up to the time of writing (late September, three months after the supply cut-off) there have been no negotiations at corporate level. (There have been trilateral political meetings with EU representatives, at which Russia and Ukraine have given assurances that their dispute will not hinder flows of Russian gas to Europe, but no negotiations on the substance of the dispute.) A further risk is of the trade war between Russia and Ukraine, which is related to the military conflict, impacting the gas trade. Specifically, on 14 August the Ukrainian parliament approved legislation giving the government powers to impose sanctions on Russian companies, including Gazprom.¹⁷⁶ Ministers specified that, were the powers to be used, Naftogaz could be prevented from entering into contracts with Gazprom, and European companies would then have to buy Gazprom gas

¹⁷⁶ The law can be found at <http://zakon2.rada.gov.ua/laws/show/1644-18>.



at Ukraine's eastern border, in the absence of transit arrangements; Naftogaz emphasized that no decision has been taken to use the powers.¹⁷⁷

The fact that gas supplies to Ukraine were halted in June 2014, and that gas storages in both Ukraine and Europe were comparatively full, meant that the immediate effect of the cut-off has been limited, although at the time of writing the municipal authorities in the Ukrainian capital, Kyiv, and in other cities, had already halted hot water supplies for certain periods of the day. But if the dispute with Russia over gas imports is not resolved by the winter – and specifically by the first quarter of 2015 – there could potentially be a serious supply crisis.

Naftogaz has stated that, by making use of gas in storage and reverse-flow deliveries from Europe, it can get to the end of 2014 without very serious supply disruptions to customers.¹⁷⁸ But if imports from Russia are then not resumed, there is a danger of serious energy cutbacks and a resulting humanitarian and economic crisis (in addition to the humanitarian and economic impact of the military conflict). A set of estimates discussed in government puts Ukraine's gas requirement for Q1 2015 at 17.3 bcm; this is set against a supply of 8.3 bcm (Ukraine's own production, plus gas pumped out of storage), plus a possible 2.7 bcm from reverse-flow deliveries (which can only operate if transit of Russian gas to European destinations continues). This suggests a shortfall over the winter of 6.3 bcm, although the Ukrainian prime minister and energy minister have both referred to a possible shortfall of 5 bcm. One proposal for reducing demand is to ration gas for industrial customers by 1 bcm/month from October; even in the best case (one in which transit, and therefore reverse flow, continue to operate) this still leaves demand for Q1 2015 substantially (by at least 2 bcm) in excess of supply.¹⁷⁹

We make no attempt here to speculate on the outcome of the Russia–Ukraine dispute, other than to say:

- (i) it is clearly in the commercial interests of both Gazprom and Naftogaz to resolve the dispute;
- (ii) insofar as the Russian government has no political interest in being perceived as responsible for a humanitarian crisis, it has an interest in resolving the dispute;
- (iii) the same applies to the Ukrainian government; and
- (iv) the state of extreme political hostility between the two governments may prevent an agreement being made.

This winter, it is also possible that the crisis will escalate, with transit of gas to Europe being disrupted, possibly by volumes bound for Europe being diverted (with or without government sanction) for use in Ukraine. On the other hand, even without a settlement of the dispute over the Gazprom–Naftogaz contract, ways may be found to deliver gas to Ukraine, possibly by arrangements with companies in eastern regions not sanctioned by Kyiv, delivery to non-Naftogaz companies to which the Ukrainian government agrees, or ad hoc arrangements made as a result of European or other international intervention.

¹⁷⁷ Reuters, 14 August 2014, 'Ukraine approves law on sanctions against Russia'

¹⁷⁸ 'Glava Naftogaza: Ukraina smozhet proiti zimu bez rossiiskogo gaza', *Zerkalo Nedeli*, 4 July 2014; 'Antigazovyi sezon 2014–2015', *Zerkalo Nedeli*, 18 July 2014.

¹⁷⁹ 'Antigazovyi sezon 2014–2015', *Zerkalo Nedeli*, 18 July 2014; S. Dolinchuk, 'Zakupki gaza u Rossii neizbezhny', *Forbes Ukraine*, 26 August 2014.



4.3 Reverse-flow options

During this year's dispute, the Ukrainian government and Naftogaz Ukrainy have attempted to promote measures to diversify away from Russian gas supply. The only one of these schemes likely to be implemented this year, or indeed at any time before 2020, is the expansion of reverse-flow deliveries.¹⁸⁰ Naftogaz has stated that existing pipeline capacity from Poland (1.5 bcm/year) and Hungary (5.5 bcm/year) allows for 7 bcm/year of deliveries, although some industry sources suggest that real capacity, particularly from Hungary, is lower. Under an agreement between Eustream, the Slovakian transit company, and Naftogaz brokered by the European Commission, reverse-flow capacity via Slovakia has been supplemented with the construction of a new stretch of pipeline (400m at Vozhany, bringing back into use a decommissioned pipeline). This will eventually bring capacity via Slovakia to 10 bcm/year, although that figure may not be reached this winter.¹⁸¹ By next year, 17 bcm/year of capacity could be available, although industry sources think it is more likely to be a maximum of 15 bcm/year. Clearly there could be a further expansion of reverse-flow capacity in future years, particularly via Slovakia and also via Romania.

4.4 Moving the delivery points of European contracts

Another proposal made by Naftogaz is that the sales point for Russian gas to European companies be moved from the western border of Ukraine to the western border of Russia. Andrei Kobolev, Naftogaz's CEO, stated on 13 August that this would protect European gas purchasers from the effect of possible sanctions on Gazprom (such sanctions could be imposed under legislation adopted by Ukraine in early August).¹⁸² While such arrangements are possible in the future – and are indeed likely, as and when the single-buyer model for the Ukrainian market is abandoned (see below) – it is very unlikely that this proposal will be accepted either by Gazprom, or by the European purchasers of its gas, either this year, or at any time prior to 2019 (when the contract under which Naftogaz transports Russian gas across Ukraine expires). The future of gas transit across Ukraine in the 2020s depends in large part on whether transit diversification projects (North Stream 3 and 4, South Stream) have been completed; this will in turn determine the options for Gazprom and its European buyers.¹⁸³ But until then, Gazprom has every commercial reason to resist moving the sales point, which would undermine its market position. Moreover, amended contracts would be subject to the provisions of the EU's Third Energy Package, creating a further set of unwelcome consequences. In addition, the European purchasers of Gazprom's gas have no reason to accept this proposal, which would mean them taking Ukrainian transit risk without any clear benefit in exchange.

4.5 Impacts on Ukrainian and European gas markets

During winter 2014/15, Ukraine could suffer serious energy shortages, unless either the contractual dispute with Russia is resolved and/or alternative arrangements for gas imports are made. Reverse-flow deliveries are likely to continue to develop, whether or not the contractual dispute with Russia is involved. But in 2014/15, 15 bcm/year is probably the absolute maximum of capacity available; technical and commercial difficulties may mean that reverse-flow deliveries will be at a much lower level this year.

¹⁸⁰ See Pirani et al. (2014), pp. 14–15; Henderson and Pirani (2014), pp. 189–91.

¹⁸¹ Naftogaz Ukrainy presentation, April 2014, 'Principle supply routes and capacity from/to Ukraine'; 'Revers gaza iz Slovakiï nachnetsia 2 sentiabria', *Zerkalo Nedeli* 1 September 2014.

¹⁸² Naftogaz Ukrainy press release, 'Trilateral Negotiations Needed To Guarantee European Energy Security', 13 August 2014.

¹⁸³ See Section 2.2.



In the period up to 2020, reverse-flow deliveries could grow, even to levels sufficient to cover Ukraine's entire import requirement, but this is unlikely if, for example, the Gazprom–Naftogaz contract remains in place and is amended to the satisfaction of both parties, or if Gazprom sells gas to non-Naftogaz buyers in Ukraine. It seems pointless to speculate more precisely about volumes because of the large number of variables.¹⁸⁴

From the standpoint of the European market, reverse-flow deliveries represent an extra call on European gas supply, with the amount exported directly to Ukraine from Russia being reduced by the same amount. If transit of Russian gas across Ukraine to Europe is halted for a short period (such as days or weeks), it is very unlikely that reverse-flow deliveries would be made to Ukraine, since there would be a general gas shortage in central and eastern Europe. In the unlikely event that transit was halted for a long period, creating a serious humanitarian crisis, it could be technically possible to bring volumes of non-Russian gas (in the form of LNG, for example) to central Europe and thence to Ukraine by means of reverse flow (see Section 2.2). However, in such a situation, an acute shortage of gas in central and eastern Europe would probably mean that normal price-setting dynamics would cease to operate.

4.6 Post-2020: possible integration of Ukraine into the European market

It now seems very likely that the post-Soviet gas relationship between Russia and Ukraine – under which Gazprom acts as the monopoly supplier to the Ukrainian market and Ukraine is the major transit corridor for Russian gas exports to Europe – will come to an end by 2030. This will be an outcome of the economic decoupling of Russia and Ukraine that has already been underway for two decades, and, more directly, of the 2014 political and military conflict. It also seems likely that Ukrainian gas consumption will continue its gradual decline, and that Ukraine will become partly or wholly integrated into the European gas market.

The Gazprom–Naftogaz contracts for gas and transportation finish at the end of 2019. These contracts commit Naftogaz to buy 52 bcm/year of gas, with an 80 per cent take-or-pay commitment, and to transport 110 bcm/year of gas to Ukraine's western border. The supply contract has an oil-linked pricing structure, together with some unusually strict conditions imposed by Gazprom when it was signed in 2009, in the light of previous non-payment and contractual breaches by Naftogaz. The contract was amended in the course of political negotiations in 2010, but the pricing structure was left unchanged, although most of Gazprom's major sales contracts with European customers have since been amended in the light of changed market conditions.¹⁸⁵ The cessation of gas supply to Ukraine in June 2014 amounts, de facto, to a breakdown of the contract; if and when the political and military crisis is resolved, it will either be renegotiated or terminated. But the post-Soviet gas relationship between Russia and Ukraine – based on parallel sales and transit contracts between Gazprom and Naftogaz – will end in 2019, at the latest.

Given the changes in the European gas market, in Gazprom's commercial relationship with its main counterparties, and in Russia's relationship with Ukraine, it is inconceivable that the Gazprom–Naftogaz contract will be replaced with anything similar. This contract, and the annual sales contracts that preceded it, were underpinned by political agreements (either formal intergovernmental agreements or informal agreements negotiated at government level); the changed political relationship between Russia and Ukraine makes it unlikely that these will be concluded in the future. Without such agreements, there is no commercial rationale for Gazprom as the seller to continue a

¹⁸⁴ Including: the outcome of the military conflict, the outcome of the political disputes between Russia and Ukraine, the future of the gas contract, the short-term economic outlook in Ukraine, and consequent changes in gas demand.

¹⁸⁵ See e.g. Henderson and Pirani (2014), pp. 184–8.



single-buyer arrangement. The Ukrainian government, in line with its gas market reform plans, is also unlikely to support such an arrangement. So once the contract comes to an end, whether in 2019 or before, it is likely to be replaced with arrangements under which gas is imported by several buyers.

The move to a multi-buyer model had already begun in 2013, when non-Naftogaz companies accounted for about half of Ukraine's gas imports. This move is likely to combine with other changes that will provide the conditions for Ukraine's partial or total integration into the European gas market as follows:¹⁸⁶

- (i) gas market reform, passed into law in 2010, is now more likely to be implemented, particularly at the insistence of the IMF which, via commitments in its large and expanding loan programme to Ukraine, is putting strong pressure on the government to push reform forward;
- (ii) the break up of Naftogaz (at least in its present form) in the course of such reforms;
- (iii) the renewal, after the conclusion of the current crisis, of international investment in the Ukrainian upstream, resulting in the presence in the market of IOCs and other foreign companies who will also lobby for gas market reform;
- (iv) the reform of transit and storage arrangements along market lines, allowing Ukraine's large storage capacity near its western border to be used by European companies, together with the likely freeing-up of transport capacity that has previously been used by Gazprom.

The process of integration into the European market, and domestic market reform, is also likely to be strongly influenced by Ukraine's politically influential business groups and those that head them (the 'oligarchs'). As and when the gas market opens, these strong domestic players will no doubt use their resources, their strength in other economic sectors, and their political influence, to establish positions in the gas sector.

None of these changes will alter the structure of Ukraine's gas supply. It will continue to rely first on domestic production which, given favourable conditions and substantial investment (neither of which are guaranteed) could increase from 18 bcm/year to 25 bcm/year by 2030. This assumes the recovery of production that has been disrupted this year by military conflict, and the development of conventional and unconventional projects sufficient both to make up for the natural decline of production from Naftogaz's main onshore fields and to bring on 7 bcm/year of incremental production. The unconventional projects include those operated by Shell under a PSA (but currently suspended due to *force majeure*) and others subject to pre-PSA agreements with Chevron and with a consortium led by ExxonMobil and Shell¹⁸⁷.

Second it will rely on direct imports, and imports via reverse flow, of Russian-produced gas. If Ukraine's integration into the European market makes progress, and reverse-flow capacity continues to expand, it is possible that small volumes of non-Russian LNG (imported, for example, via Poland, the Baltic countries, or even Croatia) could find their way to Ukraine. Such volumes, however, are very unlikely to make any significant contribution (they will not exceed 2–3 bcm/year), and would more likely be priced out of the Ukrainian market by Russian-produced gas under most likely scenarios. There has also been much discussion about the possibility of building a re-gasification terminal, or of commissioning a floating terminal, on Ukraine's Black Sea coast. However, given the dire state of the Ukrainian economy, were the substantial sums needed for such a project to be available, higher-priority uses would probably be found for them.

It is likely that Ukraine will continue to reduce its dependence on Russian gas by reducing gas consumption. Consumption fell sharply in 2009–2013 for three main reasons:

¹⁸⁶ This paragraph, and the next two, amplify points made in *ibid*, Chapter 7.

¹⁸⁷ For more details see *ibid*, pp. 191–2. On the Shell project, 'Shell otlozhila raboty na luzovskoi ploshchadi', *Interfax-Ukraina*, 21 August 2014.



- reduced consumption in industry due to the recession;
- energy efficiency measures in industry, district heating, local government, and the residential sector, stimulated by higher gas tariffs; and
- switching to coal (which accounted for about one-third of the fall in consumption of Russian gas).

It is probable that consumption can be further reduced by: energy efficiency measures, continued switching to coal, and the development of Ukraine's considerable renewable energy resources (in particular peat and other biomass). Reduction of gas consumption to 40 bcm/year by 2030 seems entirely plausible, leaving an import requirement of 15–20 bcm/year, depending on the progress of domestic production.

4.7 Conclusions

The conclusions regarding the reduction of Ukrainian dependence on Russian gas and the impacts on the European market up to 2030 are:

(i) On the expiry of the Gazprom–Naftogaz contract, at the end of 2019 or earlier, it is likely that volumes of Russian gas will be available to purchase on Russia's western border by numerous buyers. In the first instance, that will mean trading companies supplying Ukrainian customers with up to 32 bcm/year. If gas is available on Russia's western border, such purchases will replace the reverse-flow trade; if this is not the case, reverse-flow trade could cover Ukraine's total import requirement within a few years.

(ii) Gazprom and its European counterparties are unlikely to move the point at which sales are made to the western border of Russia under current contracts. Once these contracts expire – mostly during the 2020s and 2030s – western European counterparties *might* seek to buy Russian gas at Russia's western border, depending on: Gazprom's readiness to sell there, the level of Ukraine's integration into the European market, and the availability or otherwise of gas transited via non-Ukrainian routes (such as North Stream and South Stream).

(iii) Ukraine's own import commitment (this might be around 30 bcm/year in 2020, falling to 15–20 bcm/year in 2030) will continue to be met entirely, or overwhelmingly, by Russian gas. It is likely that, after the termination of the current Gazprom–Naftogaz contract in 2019 or even before, volumes will not be delivered under any similar contract but via sales to multiple buyers at Russia's western border, or via reverse flow.

(iv) Due to these changes, for the purposes of market analysis, Ukraine's gas balance will probably best be viewed as part of Europe's gas balance after the conclusion of the Gazprom–Naftogaz contract.

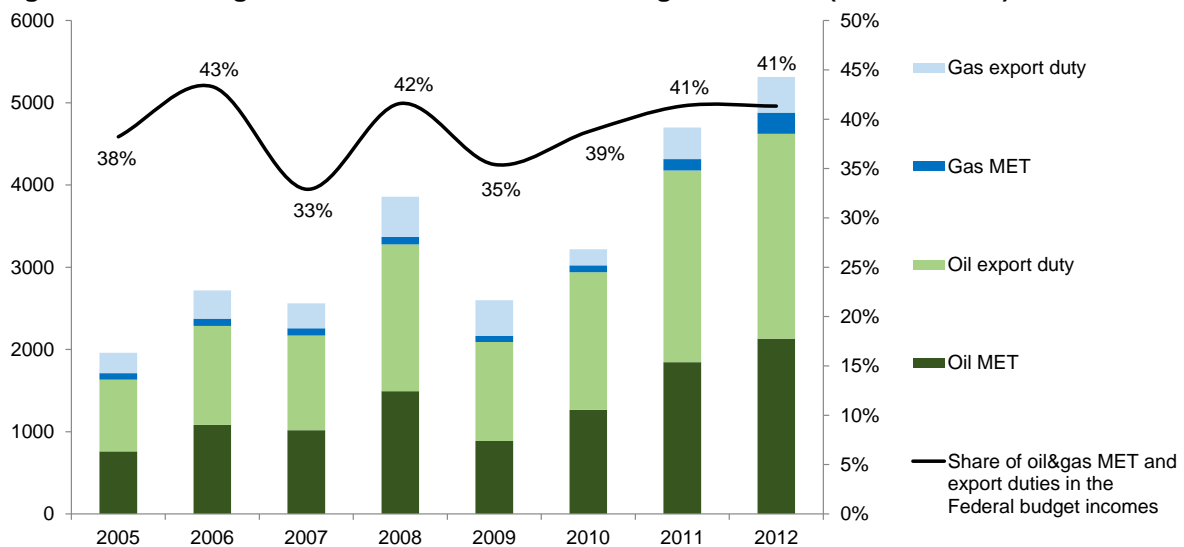


5. The Russian Response

5.1 Introduction

Russia's general response to claims from the EU and its member countries that they will attempt to reduce their dependence on Russian gas has been one of cynical disbelief.¹⁸⁸ Europe has made these claims before, in particular after the Ukraine crises in 2006 and 2009 but the results have been negligible. However, this somewhat sanguine Gazprom approach to the threat of European supply diversification must be set against the fact that in reality both Gazprom and the Russian economy do have a significant need to maintain, and even grow, sales to the region.

Figure 10: Oil and gas contributions to Russian budget revenues (billion rubles)



Source: www.roskazna.ru/federalnogo-byudzheta-rf/yi/.

From a Russian budget perspective, gas has never played as significant a role in generating tax revenues as oil, as can be seen in Figure 10; nevertheless, 2013 revenues from the gas export tax (which is generated entirely from sales to Europe) do account for 4 per cent of the total at present, which is significant at a time when the Russian economy as a whole is on the brink of recession.¹⁸⁹ Furthermore, over time this share will have to grow, as the contribution of oil taxes is almost certain to fall because of the many fiscal incentives that the Russian government has had to offer oil companies to invest in new regions.¹⁹⁰ The threat of a decline in overall oil production has led to tax holidays being offered for developments in East Siberia, offshore, and the Arctic, as well as for the development of unconventional oil. When these developments start to produce hydrocarbons and replace the decline in full tax-paying existing fields, then overall tax revenues will almost certainly fall, unless there is a dramatic rise in the oil price. The gas sector is the obvious source of replacement revenues, with the export tax likely to be the main generator. Pipeline sales to Europe will continue to provide the majority of this for the next decade, as Russian LNG exports are export tax-exempt and pipeline sales to Asia will not reach significant levels until the mid-2020s.¹⁹¹

¹⁸⁸ *Wall Street Journal*, 23 May 2014, 'No weaning Europe off Russian gas says Gazprom'.

¹⁸⁹ Reuters, 13 May 2014, 'Russia economy likely to be in recession at the end of Q2'; for more on the taxation of Russian gas and its importance for the Russian economy see Henderson and Pirani (2014), Chapter 1, especially pp. 28–31.

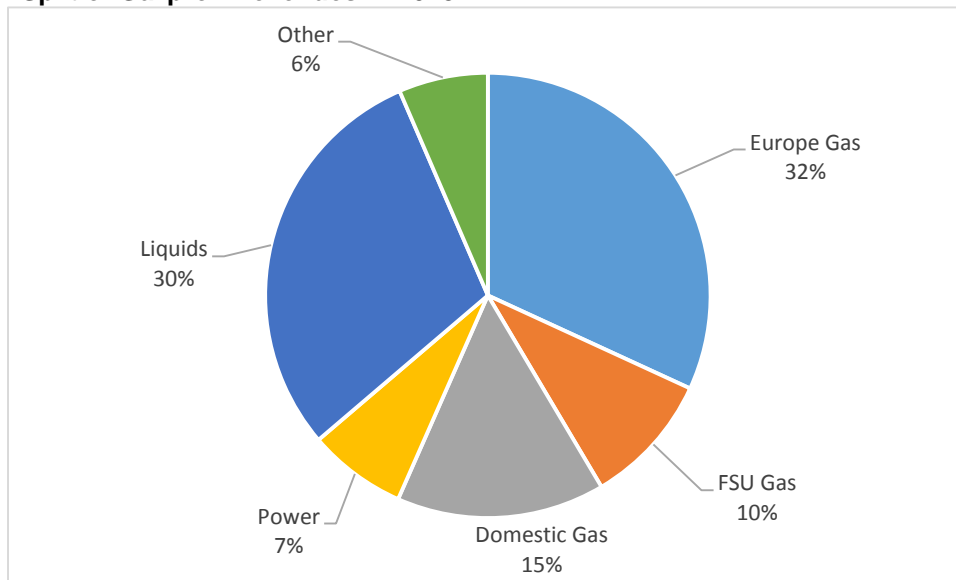
¹⁹⁰ Pravda.ru, 13 September 2013, 'Russia has only 7 years before oil crisis?'.

¹⁹¹ Moshkov (2014), p.12.



As a result it is clear that Russia can ill afford to see revenues from European sales decline, and the same is true for the monopoly exporter of pipeline gas, Gazprom. The company has made significant efforts over the past decade to diversify its business, both across the gas sector and into power generation and liquid hydrocarbon production and refining. But European gas exports still contribute the largest share of the company’s revenues. Gazprom’s gas sales (to Europe, the FSU, and the domestic market) accounted for 57 per cent of total company revenues in 2013 (see Figure 11); with sales to Europe making up 56 per cent, and accounting for 32 per cent of the total. As a result, Gazprom’s financial results would suffer a significant blow if its non-FSU exports were to fall sharply, with the profitability of these sales being underlined by the fact that they account for more than half of gas revenues while accounting for only a third of production.¹⁹² Indeed the impact may already be being felt, as the fall in European hub prices during 2014 is likely to have significantly reduced Gazprom’s earnings from exports.

Figure 11: Split of Gazprom revenues in 2013



Source: Graph created from data in Gazprom’s IFRS Financial Statements for 2013

Despite this continuing reliance on European sales, which certainly provides clear evidence of the ‘mutual dependency’ between Europe and Russia in terms of energy flows, Gazprom and the Russian government have, nevertheless, made plans to diversify export markets to reflect not just political concerns but long-term commercial logic. As such, many of the potential Russian responses discussed below can be seen as part of a long-term plan irrespective of sanctions and European diversification goals, although of course they may now be accelerated by the geopolitical situation post Crimean annexation.

5.2 A shift towards Asia

A prime example which shows how Russia’s long-term plans have been accelerated by the Ukraine crisis is the May 2014 contract to sell East Siberian gas to China. Russia’s Eastern Gas Programme has been in place since 2007,¹⁹³ and an expansion of gas exports to Asia was a core plank of the Russian energy strategy published in 2009,¹⁹⁴ but Gazprom and CNPC had spent a decade haggling

¹⁹² Gazprom Management Report accompanying IFRS Financial Statements for 2013, p.29.

¹⁹³ Henderson, J. (2011), p.8.

¹⁹⁴ Energy Strategy of Russia, Resolution of the Government of the Russian Federation No. 1715, 13 November 2009.



over price, volumes, and exact sources of supply.¹⁹⁵ However, the catalyst of the Ukraine crisis provided the impetus for President Putin to insist on Gazprom reaching a deal during his visit to Beijing in May 2014,¹⁹⁶ and tax incentives were provided to the company in the form of a mineral extraction tax (MET) royalty exemption in order to ease the price negotiations. As a result, Gazprom will construct a new pipeline (Power of Siberia) to deliver 38 bcm/year from fields in Irkutsk and Yakutia at a price of around \$11/mmbtu at the Russia/China border,¹⁹⁷ helping to make Russian gas very competitive in the Asian market. As such, political necessity and fiscal support finally allowed a logical commercial agreement to be reached.

The deal will have minimal direct impact on Europe, other than perhaps to free up LNG that might otherwise have been sold into China for alternative markets. The eastern gas which Russia will use to supply China is not connected to any west-facing pipelines in Russia, and so would not have been available to Europe; this means that Gazprom's Asian strategy cannot be interpreted as a significant risk to its western customers. In the longer term, however, Gazprom is hoping to increase its exports to China by opening a new pipeline route from West Siberia via the Altai Republic into north-west China; Gazprom company CEO Alexei Miller has already hinted that negotiations on this option recommenced as soon as the first eastern deal had been signed.¹⁹⁸ In theory, completion of the 'Altai pipeline' could allow Gazprom to alternate gas flows between its eastern and western customers, depending on the prices offered in each market, creating a real market diversification option (see Chapter 6).

However, two major caveats have to be made. The first is that China has always been keen to avoid being exposed to Russian market manipulation and has made its reluctance to accept a western import route clear.¹⁹⁹ This reluctance has been underlined by the fact that CNPC already imports gas from Turkmenistan (and to a lesser extent from Kazakhstan and Uzbekistan), with imports set to rise to 65 bcm/year over the next few years (see Section 2.1.4 and Table 9).²⁰⁰ One of the issues with Turkmen gas is the distance it has to travel to the main Chinese markets on the east coast, increasing the delivered cost, and Russian gas delivered into Xinjiang (China's western province where the Turkmen gas arrives) would face the same problem. It is much more economic for China to receive Russian gas in the east, where the growing demand is located.²⁰¹

Secondly, even if Gazprom did manage to negotiate a west Siberian (Altai pipeline) export contract with China, it would have no difficulty in finding the gas to fill what is expected to be a 30 bcm pipeline. The development of the Bovanenkovskoye field on the Yamal peninsula, combined with the growth in third-party production in Russia and the stagnation of the European, FSU, and domestic markets has left Gazprom (and potentially other producers) with a significant oversupply of gas that is unlikely to be dissipated for a decade at least.²⁰² As a result, a deal to sell West Siberian gas to China would use up some of this extra gas, rather than cause a displacement of supplies from Europe. Of course if European gas demand grows substantially in excess of what is currently foreseen (see Chapter 1), there could be some risk of competition between Europe and China, but this issue is unlikely to be critical until 2030 at the earliest. Again, all else being equal, increased imports of Russian pipeline gas would result in lower Chinese LNG imports; these being available for other markets, including Europe.

¹⁹⁵ For background see Henderson and Pirani (2014), Chapter 8; Paik (2012), Chapter 3.

¹⁹⁶ *Financial Times*, 21 May 2014, 'China and Russia sign \$400 billion gas deal'.

¹⁹⁷ Moshkov (2014), p.5

¹⁹⁸ *RT Business*, 21 May 2014, 'Russia and China seal historic \$400bn gas deal', and see Chapter 6.

¹⁹⁹ Henderson, J. (2011), p.9.

²⁰⁰ Henderson and Pirani (2014), Chapter 14.

²⁰¹ Chen (2014), p.16.

²⁰² Henderson and Pirani (2014), Chapter 7.



5.3 A move into the LNG market

Allied to the move towards Asia, Gazprom and two of its emerging domestic competitors, Novatek and Rosneft, started to develop plans for LNG projects.²⁰³ Again, this has not been a direct response to the risk of declining sales to Europe, but it can be seen as part of an overall plan to diversify into new markets. Gazprom has been selling LNG from the Sakhalin 2 project since 2009 and has plans for a further three projects: two in Asia (expansion of Sakhalin 2 and the development of a 10–15 million tonne plant at Vladivostok) and one in the west (Baltic LNG, with a potential 7.5 million tonne capacity).²⁰⁴ Meanwhile Novatek's Yamal LNG project is underway, underpinned by significant government support in terms of tax breaks and infrastructure construction; this project is planned to come onstream in 2017/18.²⁰⁵

The LNG will travel both east and west, contracts having been signed with CNPC and Gas Natural, amongst others; this underlines the potential role of LNG to open new markets for Russian gas across the world. Gazprom's Vladivostok plant will clearly target the Asian market, reaching as far as India, while Baltic LNG will offer gas both to Europe and the emerging South American market, increasing the company's sales portfolio. In competition to this, however, Rosneft is now in partnership with Alltech to develop the Pechora LNG plant. If this scheme ultimately receives export approval it will provide another potential route for Russian gas to reach western markets.²⁰⁶ All these schemes will clearly have to respond to competition from other LNG projects under development in the global gas market but, overall, the Russian government is manifestly encouraging its major energy companies to expand the country's gas export potential.

In practical reality, though, these diversification plans are far from being set in stone, as the debate about the logical order of developments and the companies to lead them is ongoing. None is more heated than the debate about the future of LNG on Sakhalin Island, where the commercially logical expansion of the existing Sakhalin 2 plant is competing for gas with the Vladivostok project, and is also at the heart of a dispute with Rosneft over Sakhalin 1's plans for an additional stand-alone project on the island.²⁰⁷ It may be that the current geopolitical crisis and Russia's increasing isolation could result in a domestic political drive to see companies work more closely together to provide the optimal outcomes for Russia (in this case, the use of gas on Sakhalin to expand the existing plant rather than building a new stand-alone alternative), but the outlook remains unclear.

Furthermore, it is also possible that many of the proposed LNG projects will have to be put on hold or postponed indefinitely due to the sanctions being imposed by the EU and the USA. In the short term, constraints imposed on the debt-raising ability of Russian companies – particularly Rosneft and Gazprom – are posing questions about whether even the more advanced projects – such as Yamal LNG – can go ahead on schedule, while the less advanced projects – such as Vladivostok LNG and Sakhalin 1 – could easily be significantly delayed. Furthermore, if LNG technologies are ever added to the sanctions lists, then all the proposed schemes could be pushed back by a number of years, as the necessary equipment is not readily available outside the USA and the EU. As a result, from a European perspective, the impact of Russia's LNG strategy is unlikely to be dramatic. This is either because the gas being sold is unlikely to undermine specific sales to the continent (and indeed could expand overall global gas supply) or because the LNG schemes themselves may well be delayed or postponed due to the increasing sanctions being imposed on Russia (which in turn could increase the importance of European exports).

²⁰³ Mitrova (2013), p.3.

²⁰⁴ Ibid. p.19.

²⁰⁵ Ibid. p.28.

²⁰⁶ *Upstream Online*, 13 June 2014, 'Rosneft moves ahead with plans to take control of Pechora LNG'.

²⁰⁷ *World Gas Intelligence*, 2 October 2013, 'LNG Rivalry Mounts at Russian Titans'.



5.4 Removal of Gazprom's export monopoly – less likely?

The potential introduction of LNG into Russia's gas export strategy has also catalysed a shift in the governance of the sector, in the form of the ending of Gazprom's export monopoly. This could be of significance to European gas customers over the next few years. In December 2013 the Russian government passed a law allowing the development of LNG projects by companies holding licences with a specific LNG remit (Novatek's Yamal LNG) and state companies operating offshore gas assets (Rosneft's Sakhalin 1 project).²⁰⁸ Although the new law is very specific, essentially allowing just two non-Gazprom projects, it nevertheless marks a major shift in policy and has encouraged competition in the export of Russian gas for the first time. The Ministry of Energy has an oversight role to ensure that Gazprom's existing contracts are not undermined, but in reality this could be the start of a new model for the Russian gas sector.

Given President Putin's propensity for controlling the Russian energy sector via its state-owned companies, it would almost certainly be wrong to conclude that there will be any dramatic shift in Gazprom's position in the short term, indeed its status is likely to be considered even more vital in the face of increasing external political pressures from the USA and the EU. However, it is no longer inconceivable that the Russian authorities could countenance a gradual introduction of third parties into the country's pipeline export portfolio, as they see the need for Russian gas to be competitive in all its markets. Asia is being used as something of a testing ground in this respect, first with LNG being liberalized, and then with discussions now being initiated about access for third parties to the Power of Siberia pipeline for domestic and export sales.²⁰⁹ President Putin himself has asked the government to explore the possibility of Rosneft and others selling gas to Asia via the pipeline, and the energy minister has suggested that as much as 25 bcm/year of the 61 bcm/year capacity of the pipeline could be filled with non-Gazprom gas.²¹⁰

As far as pipeline gas sales to Europe are concerned, there has been no explicit threat to Gazprom's monopoly to date. However, the Russian authorities are undoubtedly aware that one of the main EU issues with Russian gas imports is that they are controlled by a single state-owned monopoly provider; indeed the prospect of non-Gazprom players being permitted to put gas through South Stream has been discussed with a view to addressing third-party access regulations under the Third Energy Package.²¹¹ Given that Novatek already sells gas to a European utility (EnBW) using gas traded on the hub market,²¹² it would not be too great a stretch to suggest that this transaction could become a sale of Russian gas transported through a Gazprom pipeline. Furthermore, Rosneft's Head of Gas Vlada Rusakova raised the issue of non-Gazprom European exports in public for the first time, stating that:

... the key thing is to increase exports to Europe at the market price and make sure nobody else replaces Russian gas. The name of the supplier should not make any difference to the state budget.²¹³

The political tension that has existed both between Russia and the EU since the Crimean annexation, and between Gazprom and the EU Energy Commission over many years of debate over the Third Energy Package, means that any change in Russian strategy that could be interpreted as a concession is unlikely in the near term. However, it is not impossible to think that, once the political landscape is calmer, Russia could start to adjust the governance of its pipeline export policy to address security of supply concerns in Europe, by involving more than one party in the export sales. Realistically, though, this is unlikely to have any material impact before the end of the current decade.

²⁰⁸ Mitrova (2013), p.5.

²⁰⁹ *Interfax*, 23 May 2014, 'Independent producers could gain access to Power of Siberia pipeline after its expansion – Novak'.

²¹⁰ *Financial Times*, 22 July 2014, 'Putin suggests ending Gazprom pipeline monopoly'.

²¹¹ *Interfax*, 15 May 2014, 'South Stream will benefit from third party access rules'.

²¹² *Moscow Times*, 16 July 2012 'Novatek signs deal to supply gas to Germany's EnBW'.

²¹³ *Argus, FSU Energy*, 20 August 2014, 'Rosneft makes its case'.



5.5 Price competition with alternative pipeline gas and LNG supplies

Gazprom's pricing strategy in Europe is likely to be of more immediate relevance; this has already been responding to market conditions, irrespective of the EU's emerging desire to find alternative sources of gas. Although Gazprom continues to cling to its fundamental belief in oil-linked long-term contracts,²¹⁴ it has been forced over the past three to four years to adjust its prices to hub levels, due to arbitration cases brought by its customers and the realization that it has been losing market share due to the high price of its gas.²¹⁵ The result was first that an element of hub indexation was introduced into many contracts; base prices were then adjusted and combined with rebates to compensate for the annual difference between its contract price and the average spot price, effectively guaranteeing that its customers would not lose out.²¹⁶ The impact on Gazprom's price to Europe relative to the UK spot price (NBP) is shown in Figure 12, where it is quite clear that any premium that Gazprom had been charging has been removed completely.²¹⁷

5.6 Competitiveness of Russian gas in relation to LNG supplies

Looking to the future, there have been a number of indications that Gazprom will continue to pursue a policy of price competitiveness in Europe. Two years ago, when the issue of US LNG imports arriving in Europe was first mentioned, GazpromExport CEO Alexander Medvedev confirmed that his company would be prepared to undercut this potential new source of supply to maintain Russian sales.²¹⁸ More recently, Gazprom has acknowledged that it might have to make further price concessions in Europe; this is due both to the fall in spot prices in 2014, and also to the risk of losing customers who are considering diversifying away from Russian gas.²¹⁹ This would seem to provide clear evidence that Gazprom understands the importance of maintaining market share in the short term, in order to avoid a permanent destruction of its position in Europe in the longer term. It is therefore prepared to offer a competitive price – both to ward off alternative gas supply and to defend the position of gas against alternative fuels.

This appears to undermine arguments in favour of collective purchasing of Russian gas by an 'Energy Union', which also seems problematic in relation to European competition rules. Any such collective purchase would make it very difficult to main a system of hub-based pricing – since presumably the collective purchase system would also include a price mechanism – which would affect the evolving competition in European gas markets. However, it is possible that Gazprom would welcome such a development.²²⁰

²¹⁴ *Interfax Energy*, 29 May 2014, 'Gazprom mounts defence of oil indexation'.

²¹⁵ Henderson and Pirani (2014), pp.64–70.

²¹⁶ For details see Henderson and Pirani (2014) Chapter 3, especially pp. 58–66.

²¹⁷ This applies to competitive markets with operating hubs, it does not apply to other markets, including many of those highly dependent on Russian gas; hence the 2012 DG COMP investigation into Gazprom's contracts with eight of these countries.

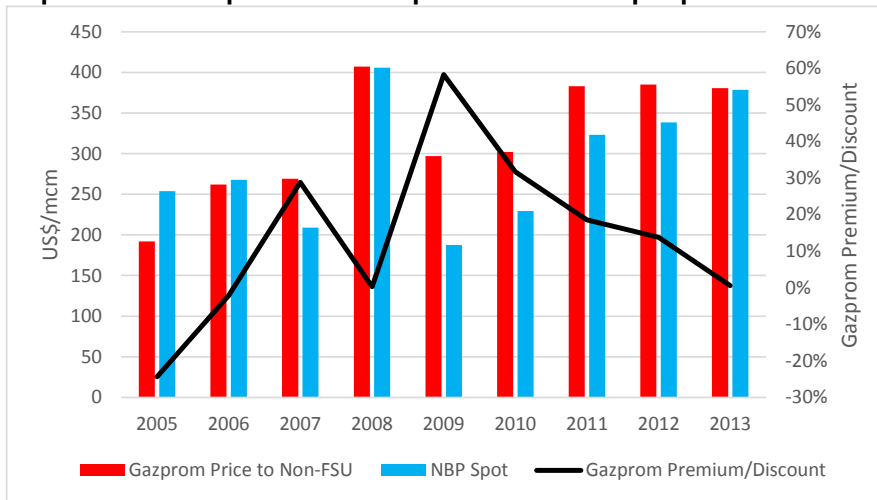
²¹⁸ *Bloomberg*, 19 February 2012, 'Gazprom sees US exporting LNG in decade, downplays competition'.

²¹⁹ *World Gas Intelligence*, 20 August 2014, p.4 'Gazprom admits sanctions hit'.

²²⁰ Donald Tusk, 'A united Europe can end Russia's energy stranglehold', *Financial Times*, 21 April 2014 (and see also Chapter 6).



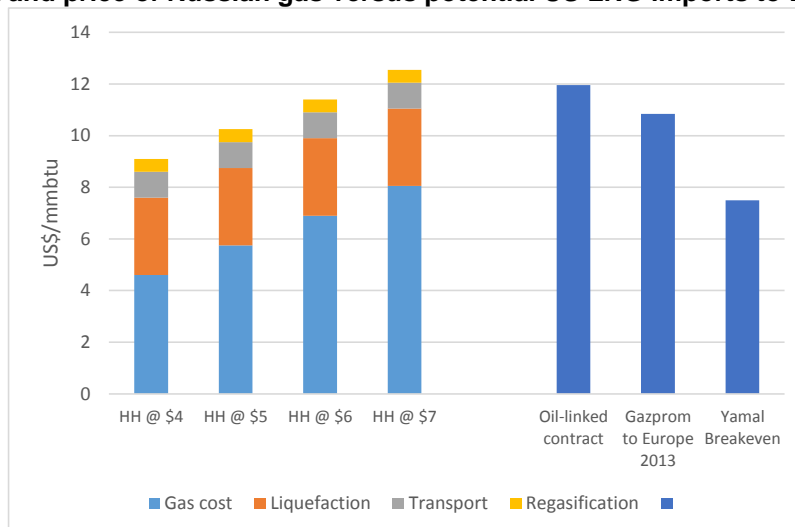
Figure 12: Comparison of Gazprom contract prices and NBP spot price



Source: Data from Gazprom IFRS Financial results, 2005–2013, Argus.

It would also seem that Gazprom has the capacity to meet the challenge of alternative gas sources on a ‘cost of supply’ basis. Analysis of the cost of Russian gas versus that of potential US LNG imports is shown in Figure 13. This makes the point that on a fully oil-equivalent basis (using an 11 per cent slope relative to Brent) and also using the somewhat discounted price charged under its European contracts in 2013, Gazprom could be undercut by US gas at or just above current Henry Hub prices of \$4/mmbtu (after a 15 per cent premium to allow for gas shrinkage plus liquefaction, transport, and re-gasification costs). Gazprom’s 2013 prices would only be competitive if Henry Hub rose to \$6/mmbtu, while a fully oil-linked price would require Henry Hub to reach almost \$7/mmbtu before Russian gas could compete. However, it is also clear that Gazprom has the ability to reverse this position, given the low estimated cost of supply of Yamal gas to Europe. Essentially, it would appear that Gazprom could price its gas down to \$7.50/mmbtu and still make a 10 per cent real rate of return on a full cost basis, and could push prices even lower on a marginal cost basis, if it was determined to compete with US LNG or other alternative gas on price.²²¹

Figure 13: Cost and price of Russian gas versus potential US LNG imports to Europe



Source: Author’s calculations based on Gazprom and Cheniere data

²²¹ Henderson and Pirani (2014), p.385.



Beyond the ability of Gazprom and Russia to compete on price, however, is the question of the way in which it may choose to do this. One response would be to continue the current strategy of re-negotiating existing contracts, when forced to do so by consumers demanding a lower price or a rebate; in the short term this appears to be the most likely outcome, with E.ON having opened a new arbitration case in July 2014 to which Gazprom must respond or on which a tribunal must rule.²²² However, an alternative tactic, and one which appears to be becoming gradually more acceptable to the company, would be to increase the amount of gas that the company trades on the European spot markets. Gazprom could then eventually provide a mixture of long-, medium-, and short-term contracts, as well as spot gas priced on the basis of the European traded market. The company has resisted this strategy for a long time, arguing that the liquidity at the majority of European hubs is not high enough and that the potential volatility in prices cannot provide the security required for long-term gas developments. Nevertheless, the amount of gas that the company is trading in Europe is growing by the year. From a figure of only 2 bcm in 2005, Gazprom sold 11 bcm of gas outside its long-term contracts in Europe in 2013,²²³ and its trading subsidiary Gazprom Marketing and Trading, based in London, provides a platform for further expansion in this direction.

It is certainly feasible, therefore, to consider that Gazprom could develop a marketing strategy in line with its main European rival, Statoil, which now sells a significant part of its gas into the continent at spot prices.²²⁴ This strategy would avoid any accusations of monopolistic pricing, assuming it was carried out across all markets, and would potentially give Russia significant market power, given its status as the largest supplier into the region. It would also allow it to adjust production in order to manoeuvre the market price to a level at which alternative supplies would be discouraged – or at the very least to demonstrate to consumers the cost of choosing a more expensive non-Russian source of supply because it is seen as more secure.

5.7 Existing export infrastructure and decisions on new pipelines

Currently (nearly) all Russian gas that arrives at an EU border has to travel via Ukrainian and Belarusian transit corridors, or via the transit-avoidance Nord Stream pipelines (Map 1) which transport Russian gas from the St Petersburg region to northern Germany across the Baltic Sea.²²⁵ Although these corridors provide Gazprom with sufficient *physical* capacity to deliver gas under its existing long-term supply contracts (LTSCs), the Russian company believes itself to be short of *reliable transit* capacity. This belief appears justified given the dismal record of transit reliability throughout the 1990s and the 2000s – a period marked by a series of transit crises in respect of both Ukrainian (2006 and 2009) and Belarusian (2004 and 2010) corridors.²²⁶ Gazprom eventually achieved an acceptable level of transit security in the Belarusian corridor through its acquisition of the Belarus network in 2011 (this was ultimately made possible due to the Nord Stream-induced erosion of Belarus's transit power). However, Gazprom has failed to ensure the security of its most problematic (Ukrainian) corridor, either through acquisition of the network or through (a threat of) investment into South Stream (Map 2) – another transit-avoidance pipeline system which would transport Russian gas from the Anapa region to Bulgaria across the Black Sea.

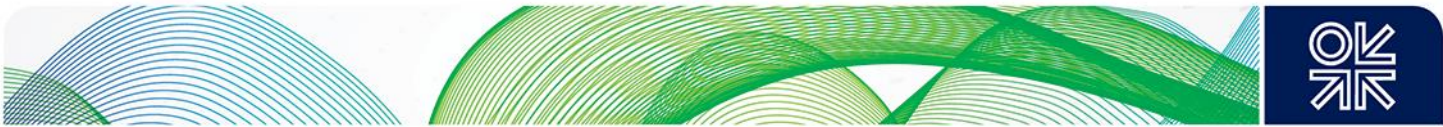
²²² 'E.On files suit against Gazprom', *Platts European Gas Daily*, 8 July 2014, pp.1–2. The importance of this arbitration is that it concerns Gazprom's largest European customer so that, as they were in 2012, other customers will be strongly influenced by the outcome of the proceedings.

²²³ Gazprom Investor Day presentations in March 2011 ('All you need is Gas', Slide 17) and February 2014 (Investor Day 2014, Slide 22).

²²⁴ *Financial Times*, 19 November 2013, 'Statoil breaks oil-linked gas pricing'.

²²⁵ The only exception is Gazprom's direct pipeline exports to Finland, to the delivery point on the Russia–Finland border.

²²⁶ Yafimava (2011), pp. 81–92.

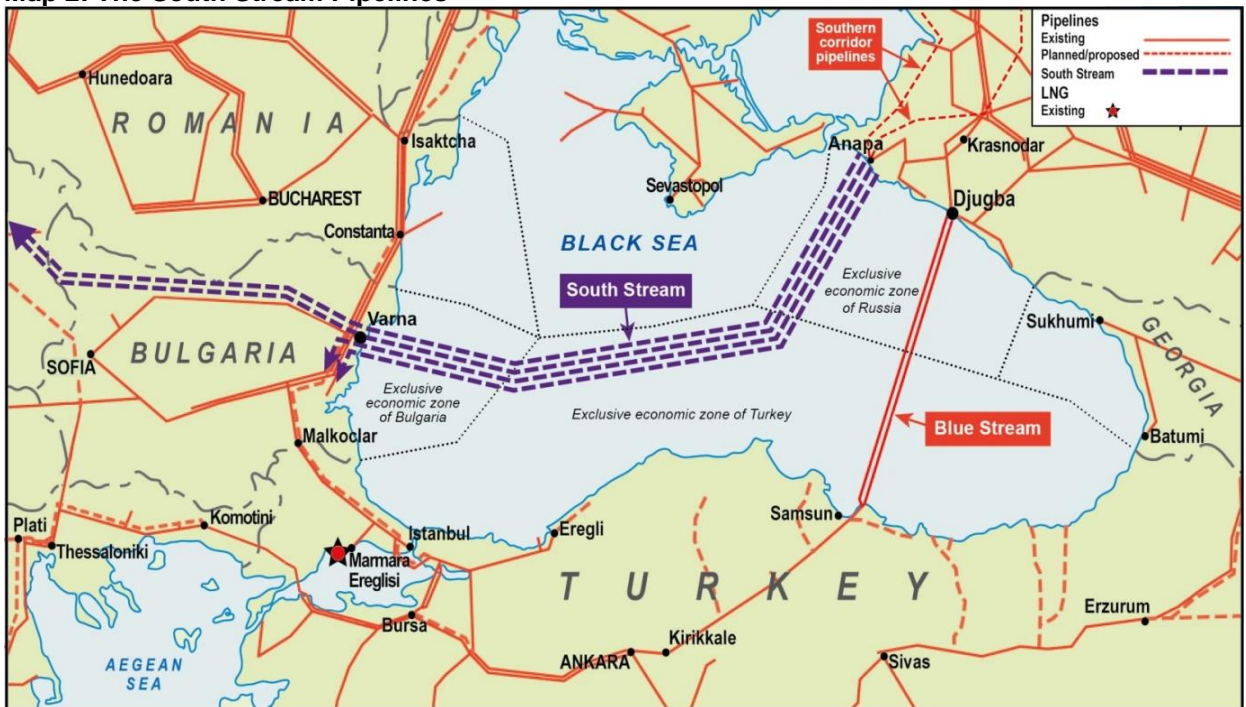


Map 1: The Nord Stream Pipelines



Source: OIES

Map 2: The South Stream Pipelines



Source: OIES



The 2009 Ukrainian transit crisis caused a major gas security crisis in Europe; no Russian gas was delivered to Europe across Ukraine for two weeks in winter, and some south-east European countries suffered a humanitarian emergency.²²⁷ Both Gazprom and Ukraine came out of this crisis as losers: Ukraine's reputation as a reliable transit state was destroyed, whereas Gazprom suffered huge reputational and financial damage (prior to the 2009 crisis Gazprom had maintained an impeccable delivery record on its European exports, with deliveries continuing largely unaffected even through the periods of disintegration of the Comecon bloc and the USSR).²²⁸

The 2009 crisis further strengthened Gazprom's determination to build South Stream; the project, which was initially planned to be two lines with capacity of 31 bcm, was expanded to four lines with a total capacity of 63 bcm/year. The first pipeline is scheduled to go into operation in late 2015; all four lines are planned to be completed in 2020. Should all four lines be built, Gazprom would (at 2013 export levels) be able to completely abandon the Ukrainian transit corridor. Should the 2014 Ukraine supply crisis develop into another transit crisis, it would further strengthen the South Stream rationale. According to Medvedev, should transit flows across Ukraine be halted, Gazprom could send 55 bcm through Nord Stream, 33 bcm through Yamal–Europe, and 16 bcm through Blue Stream, giving a total of 104 bcm. This would leave it short of export capacity for around one third of its European exports.²²⁹

The major advantage of both Nord Stream and South Stream pipelines for Gazprom is that they would deliver gas directly to Europe, thus eliminating all transit risk. Yet this gas will still have to be transported across multiple borders and over long distances inside Europe before it reaches LTSCs delivery points – the geographical location of which goes far beyond the Russian border.²³⁰ Such transportation is governed by the EU Third Energy Package (TEP) adopted in 2011; this mandates regulated third party access (TPA) to pipeline capacity based on published tariffs (or their methodologies) approved by national regulatory authorities (NRAs), unbundling of transmission assets, and certification of transmission system operators (TSOs). Notably the TEP *in its current form* does not provide a procedure for the construction and utilization of *new* pipeline capacity, although such a procedure is under development by European regulators, TSOs, and the European Commission (EC), in the form of a Capacity Allocation Mechanisms Network Code (CAM NC) amendment; this is expected to become applicable in 2017/18.²³¹ Until this procedure is developed, *all* pipeline capacity (existing and new) would fall under the current TEP rules – unless an exemption is granted by an NRA and approved by the EC. Thus, although transit-avoidance pipelines would potentially establish a transit-free geography for Russian gas exports to Europe, thus resolving a problem of insecure transit, they face another major problem – that of complying with the changing European regulatory environment.

Gazprom has applied for an exemption in respect of the Nord Stream onshore extensions in Germany – OPAL and NEL. However, up to the time of writing it has been unable to utilize their full capacity. Although the German regulator granted an exemption allowing Gazprom to use 100 per cent of OPAL, the EC capped it at 50 per cent. Gazprom and the EC then negotiated for more than a year, reaching a solution which allowed Gazprom to utilize 100 per cent of capacity, unless some of the capacity was wanted by a third party. The EC had been expected to approve this exemption by March 2014, but it delayed the decision citing technical issues; it also linked the delay to the worsening EU–

²²⁷ Pirani et al. (2009), p. 23.

²²⁸ The other two problematic episodes were the interruption of Baltic supplies just prior to the break-up of the Soviet Union, and the January 2006 interruptions – which were minor in comparison to their 2009 counterparts. Stern (2006).

²²⁹ A. Medvedev's presentation at the Gazprom Investor meeting, 3 March 2014.

²³⁰ Yafimava (2013), pp. 32–5.

²³¹ Yafimava (2015 forthcoming).



Russia relationship in the aftermath of Russia's annexation of Crimea and continuing instability in eastern Ukraine.²³²

Given its negative experience with OPAL, Gazprom has not applied for an exemption for the South Stream pipelines but has based the project solely on a set of intergovernmental agreements (IGAs) signed with host countries. However, the EC has deemed these IGAs in breach of the TEP, calling for them to be re-negotiated or renounced, and has otherwise threatened infringement procedures against the member states concerned.²³³ The Russian government declared that the IGAs take precedence over the TEP, stating that the EC has failed to prove that the IGAs are non-compliant with the TEP;²³⁴ it has also made a request for consultations under the WTO, alleging the discriminatory nature of the TEP.²³⁵

Meanwhile, the South Stream host countries face a choice: either renounce the IGAs, thus making themselves liable to penalties imposed by Russia; or retain the IGAs intact, thus making themselves liable to penalties imposed by the EC.²³⁶ Certainly, renegotiation of IGAs would provide the least confrontational – and least costly – solution. It is reasonable to assume that the Russian government would agree to renegotiation if there were a reasonable expectation that this would lead to South Stream being given either regulatory treatment amounting to an exemption regime, or a regime based on the Open Season procedure (currently being developed as part of the CAM NC amendment, see above). This regulatory treatment would need to include a TPA requirement; this, however, would be limited by capacity, and done in such a way, that Gazprom was able to fulfil its existing contractual obligations in the event that transit across Ukraine becomes partly or fully halted.

The regulatory problems faced by Gazprom in respect of both Nord Stream and South Stream pipelines have been significant but not insurmountable, with progress having been made on both issues before they got hijacked by the worsening EU–Russia political relationship over Ukraine, which has heavily impacted the parties' ability and willingness to negotiate. The EU has (once again) begun questioning the political acceptability of Russian gas (see Chapter 6 – Geopolitical arguments) and hence the advisability of constructing new routes for bringing Russian gas to Europe. Furthermore, the EU, which has signed and ratified an association agreement with Ukraine,²³⁷ would find it difficult to support South Stream as it would further decrease the Ukraine's transit power and its leverage against Russia.

Should Ukraine choose to apply this leverage and interfere with transit flows, it is south east European countries (including some EU and some non-EU EnCT member states) that would be significantly affected by supply cuts; these areas have limited means to significantly improve their security of supply prior to 2020 (Section 2.2). Should the first line of South Stream, which would deliver Russian gas directly to south-east Europe, start operating in late 2015, then the 2015/16

²³² In September 2014, the EC said that will make a decision on OPAL by the end of October 2014, 'European Commission has delayed its decision on OPAL until the end of October' (in Russian), *Interfax*, 15 September 2014.

²³³ 'EC: Russia should apply for South Stream exemption', *Natural Gas Europe*, 7 December 2013.

²³⁴ 'Chizhov: there is no proof that South Stream is not compliant with the EU law', *Vzgliad*, 27 June 2014, available at www.vz.ru/news/2014/6/27/693041.html.

²³⁵ 'European Union and its Member States – certain measures relating to the energy sector, request for consultations by the Russian Federation', 8 May 2014, available at [https://docs.wto.org/dol2fe/Pages/FE_Search/FE_S_S006.aspx?Query=\(%20@Symbol=%20\(wt/ds476/1%20\)\)&Language=ENGLISH&Context=FomerScriptedSearch&languageUIChanged=true#](https://docs.wto.org/dol2fe/Pages/FE_Search/FE_S_S006.aspx?Query=(%20@Symbol=%20(wt/ds476/1%20))&Language=ENGLISH&Context=FomerScriptedSearch&languageUIChanged=true#)

²³⁶ Serbia, which is one of South Stream host countries, is not an EU member state, hence the EC powers in respect of the Serbia's IGA are limited (albeit not negligible) due to Serbia's membership in the Energy Community Treaty (EnCT).

²³⁷ EU Parliament ratifies the EU–Ukraine Association Agreement, EU Parliament press release, 16 September 2014, available at www.europarl.europa.eu/news/en/news-room/content/20140915IPR62504/html/European-Parliament-ratifies-EU-Ukraine-Association-Agreement.



winter would be the last one when the region's security of supply remains exposed to transit risk. If Ukrainian transit remains a major risk, as seems likely, then the EC will be under pressure from countries in south-east Europe to find a resolution with Russia, especially if the offshore section of the pipe has been completed on schedule in 2015. This leaves the EC with a very difficult choice to make in respect of South Stream.

Gazprom also has a difficult choice to make. In the face of European plans to diversify away from Russian gas, it could spend billions of euros on new pipeline capacity in a bid to demonstrate that increased security of transport is being offered, effectively establishing a transit-free geography for its European exports. However, this carries the risk of an inability to utilize pipeline capacity at a level sufficient for rerouting gas flows from the existing transit corridors, due to the TEP requirements. Alternatively, Gazprom could halt all its pipeline plans, leaving Europe at the mercy of the existing transit pipeline systems and all the transit issues involved. The risk of this strategy is that it could further strengthen the resolve of Europe to diversify away from Russian gas. In addition, in following such a course of action, Gazprom would expose itself to the risk of failing to deliver on its existing European LTSCs (see Chapter 1) due to a shortage of *reliable* transit capacity, thus potentially losing billions of dollars in damages and suffering further reputational losses. The 2014 Ukrainian political crisis appears to have further strengthened Gazprom's resolve to choose the first option, in which it has been firmly supported by the Russian government. With large sections of South Stream apparently going ahead – onshore Russia having been laid already, and the Black Sea offshore starting in late 2014 – the EU and its member states will have to make their choice very soon.



6. The geopolitical arguments

As the Ukrainian crisis worsened during 2014, arguments were increasingly heard to the effect that Russian gas dependence had become 'dangerous' for Europe in general, because of its dominance in the context of deteriorating political relations, leaving Europe open to blackmail. The argument runs that such gas dependence may limit Europe's freedom to impose political and economic sanctions on Russia, for fear that the latter will retaliate by cutting off gas supplies. This leads on to fears that freedom of action in foreign and security policies will be constrained, particularly for European countries which are wholly or largely dependent on Russian gas; and that these countries may not support general European policies in relation to Russia, or be unable to resist Russian political and economic initiatives, because of their gas dependence.

Similar geopolitical arguments have been repeated many times during the past 40 years of European gas trade with Russia. However, the 2014 Ukrainian crisis has fundamentally changed the political and strategic relationships of the post-Soviet period between Russia and the European states in ways which may not be quickly reversed:

- European countries (as well as the USA) have imposed quite substantial sanctions; and in response Russia has imposed counter-sanctions; creating (what in September 2014 seemed to be) an escalating trade war;
- NATO, to which most European countries belong, has accused Russia of invading Ukraine;²³⁸ and in addition to political and military events in eastern Ukraine, the Russian annexation of Crimea will remain a divisive issue for many years;
- The gas sector has (thus far) been excluded from sanctions,²³⁹ but the general deterioration in the relationship has had a strong impact at the political level, where there is a reluctance on the part of the European Union and individual member states to conduct any dialogue with Russia on natural gas. This means that moving forward on pipeline projects such as South Stream (already complicated even before the Ukraine crisis), has become even more difficult, and the reaction to events in Ukraine has contributed to undermining the gas relationship.

There have been three types of western reaction to the events in Ukraine that are of relevance to gas issues:

First, there are arguments by leaders of Baltic and other eastern European countries which are heavily dependent on Russian energy imports, that reducing this dependence has become more urgent in the light of events in Ukraine. Notably in May, President Dalia Grybauskaitė of Lithuania denounced 'great Russian chauvinism' and 'the methods of [the 1930s]' which, she said, had motivated the annexation of Crimea. In this context, she underlined the urgency of opening alternative gas supply routes, including Baltic LNG terminals.²⁴⁰

Second, there are arguments to the effect that the Ukraine crisis gives renewed urgency to attempts to coordinate European energy policy in such a way as to reduce Russia's market power (such attempts have historically registered little success). Donald Tusk's 'Energy Union' proposal is the most recent example of such a position; it was expressed by the former Polish prime minister who, in September 2014, was elected as President of the European Council. He argued, in respect of the situation in Ukraine, that 'Europe should confront Russia's monopolistic position with a single European body charged with buying its gas'; that stronger mechanisms 'guaranteeing solidarity

²³⁸ See *Joint Statement of the NATO-Ukraine Commission*, NATO Press Release, 4 September, 2014.

²³⁹ In September 2014, sanctions had not been applied directly to gas supplies, equipment, or technology but had severely limited Gazprom's (and Gazprombank's) ability to raise finance on European and US markets.

²⁴⁰ 'Lithuania President warns of growing "Russian chauvinism"', *Voice of America*, 8 July 2014.



among member states' in case of energy cut-offs and 'adequate energy infrastructure' be developed; and that obstacles to investment in increased coal production should be removed.²⁴¹

Tusk's proposals imply a reduction in Russian gas imports; other commentators spell this out. Matthew Bryza, the former US ambassador to Azerbaijan, went so far as to claim that Russia's President Putin 'tried to intimidate European leaders by suggesting that the Kremlin might redirect natural gas from Europe to China', and that 'Europe can do without Russian gas; it is Moscow that cannot afford to carry through its threat.'²⁴²

The third type of argument that has been advanced as a result of the Ukraine crisis is that European dependence on Russian gas should be reduced, not as a general precaution arising from the deterioration in EU–Russia relations, but in order to confront a specific danger. As Professor Alan Riley of City University wrote, there is a danger that 'an aggressive Russia may begin to see natural gas more as a political lever than a source of revenue', and use to political ends its ability to reduce supply to Europe; and that 'given the annexation of Crimea, the threat to Ukraine and the prospect of further aggression', the mutual dependence on which the EU–Russia gas trade has rested is 'no longer a reliable principle'. Riley argued that '[Russia's] willingness to use European gas supplies as a political lever' will have been 'reinforced' by the agreement to sell gas to China, which is 'an alternative customer for Russia's huge gas supplies'.²⁴³

With respect to China, it should be recalled that the May 2014 agreement (for the sale of 38 bcm/year of gas, about one quarter of the volume that Russia has delivered to EU countries in recent years) will make China an alternative customer only in a very limited sense. These exports will be supplied from fields in east Siberia, through pipeline infrastructure not connected to the west Siberian fields that supply Europe, thus supplies could not be 'redirected'. In the event that Russia and China sign an additional contract for supplies from western Siberia (via a new Altai pipeline) then there would be the possibility, according to President Putin, that:²⁴⁴

... we will be able to connect the European part of our gas pipeline system to the Eastern one. And this, from the point of view of export opportunities, from the point of view of broadening geography of gas grids in our own country, will give us a great advantage in regulating the flows consistent with the situation on global gas markets – either to the West, in larger quantities and more efficiently, or to the East.

In geopolitical terms, this could be seen as 'threatening' to switch exports away from Europe to China for political and security reasons. In commercial terms, it may be seen as simply acknowledging that Russian exports to Europe are unlikely to grow (and may fall) due to market stagnation and diversification initiatives, while China has the fastest growing gas market in the world. It may also be connected with the ability to utilize the huge volume of gas which Gazprom could produce on the Yamal Peninsula – for which it looks likely that there will be limited west-facing markets over the next decade.²⁴⁵

As for Riley's broader point – that Russia may use gas as a political lever against Europe – it may be noted that, so far, both Russia and the western powers have done their best to prevent the conflict in Ukraine, and issues arising from it, from impacting gas trade. Even with Russian supplies to Ukraine having been cut off since mid-June 2014, both Russia and Ukraine have insisted that they will not allow the dispute to interfere with transit to Europe. With regard to the sanctions, the western powers have taken care to exclude the gas sector.²⁴⁶ Of course it is in the nature of a serious military and

²⁴¹ Donald Tusk, 'A united Europe can end Russia's energy stronghold', *Financial Times*, 21 April 2014.

²⁴² Bryza (2014).

²⁴³ Alan Riley, 'Sapping Europe's Energy Security', *New York Times*, 26 May 2014.

²⁴⁴ 'Gazprom begins building Power of Siberia gas pipeline', *Interfax Russian and CIS Oil and Gas Weekly*, 28 August–3 September 2014, pp. 8–11.

²⁴⁵ Henderson and Pirani (2014), Chapter 11.

²⁴⁶ With the exception of the financial sanctions on Gazprom and Gazprombank mentioned earlier.



political conflict that escalation (including escalation which may not be under the control of governmental players) will mean that gas transit and other trade could be – is even likely to be – disrupted. But there is no evidence at present that Russia intends to use a ‘gas weapon’, defined as reducing or cutting off supplies to European countries in order to force compliance with its political and strategic aims.²⁴⁷

The relevant point for this paper, however, is that there is a widespread perception that it may do so in future, which drives the discussion on reduction of Russian gas imports and diversification of European gas supplies. From a national government perspective, the main protagonists of these discussions appear to be the Baltic countries – especially Lithuania and Estonia – and Poland.²⁴⁸ Other highly dependent countries in south-east Europe do not appear to share these concerns – or at least not to the same extent. Indeed many of these countries appear to have welcomed the opportunity to participate in the South Stream pipeline, despite the fact that such a large piece of infrastructure may significantly reinforce their dependence on Russian gas. One explanation for this may be that south-east European countries are geopolitically fearful of Russian retaliation if they resist South Stream. Another may be that they see Russian gas as the best solution to their future energy needs.

The legacy of Soviet dominance in many Baltic, central, and south-eastern European countries provides the major rationale for many of the politicians and commentators in these countries taking a geopolitical view of dependence on Russian energy (and particularly gas) supplies. Those with historical reasons to fear invasion from the east have had such fears reawakened by recent events in Ukraine. This is entirely understandable and legitimate, but such fears seem over-played for countries which are EU and NATO members, and to be based on perceptions of threats which may not be more widely shared in Europe. However, for those countries which view Russia’s gas imports as geopolitically dangerous and as posing an unacceptable threat to national security, the logical course of action will be to terminate their contracts before these expire (which will be expensive), or not to renew them on expiry and either import alternative gas, or use alternative energy supplies (options which we explore elsewhere in this study). Such actions could also be expensive, and for this reason countries which do not share the perception of the geopolitical threat may have a different view on the desirability and urgency of reducing dependence on Russian gas imports.

²⁴⁷ For detail on this issue see Henderson and Pirani (2014), pp. 91–101.

²⁴⁸ For a detailed account of Baltic–Russian gas relations see, Grigas, A. (2012), ‘The Gas Relationship Between the Baltic States and Russia: political and commercial realities’, OIES, NG 67. For even more detail, including other energy sources see Grigas (2013).



7. Summary and Conclusions

Every time there is a gas crisis between Russia and Ukraine (notably in 2006 and 2009), and political events involving Russia which can be construed as threats to European security, there are calls from both European and US commentators for Europe to reduce its dependence on Russian gas. These calls have been heard with renewed force in the wake of the 2014 Ukrainian political crisis and the Russian annexation of Crimea. There is limited value in a constant repetition of calls to reduce European dependence on Russian gas without analysis of the extent to which, and a suggestion of the time frame within which, this could be a reality, as well of the implications for Europe as a whole and for specific countries. This paper set out to address these questions, in three time frames: 2015, 2020, and 2030.

7.1 Contractual obligations, dependence and demand

The scope for reducing Russian gas deliveries to Europe is limited by the contractual obligations of European companies to import minimum quantities, these figures are: in excess of 115 bcm of Russian gas in 2020 and around 65 bcm in 2030 (at a take-or-pay level of 70 per cent), compared with a 2013 import level of 153 bcm.²⁴⁹ Failure to take these volumes (or a termination of contracts prior to expiry) would expose importing companies to international arbitration claims amounting to tens (and potentially hundreds) of billions of euros. In addition, our modelling of European gas demand and global gas and LNG supply found that, independent of long-term contracts, Europe will still need a minimum of 100 bcm – and in some scenarios in excess of 200 bcm – of Russian gas in the period up to 2030.

However, the three groups of countries with high dependence on, and vulnerability to interruptions of, Russian gas in: Central Europe (Austria, the Czech Republic, Slovakia, Poland, and Hungary); the Baltic Region (Estonia, Latvia, Lithuania, and Finland); and south-east Europe (FYROM, Bosnia & Herzegovina, Bulgaria, Serbia, and Greece) have significant opportunities to access alternative supplies.²⁵⁰

7.2 European gas production

European conventional gas production is expected to fall by 110 bcm/year (or by 40 per cent) in the period 2013–2030, the actual figures being very dependent on the three main producers – Norway, Netherlands, and the UK. No significant unconventional (shale gas, tight gas, and coal bed methane) gas production is likely prior to 2020, and less than 20 bcm of production from those sources by 2030. The outlook for (renewable) biogas is more optimistic with a possible increase from 14 bcm in 2012 to 28 bcm in 2020, and perhaps to 50 bcm in 2030, although problems of subsidy make the larger figures uncertain. It therefore seems likely that Europe will only be able to replace at most around half of the decline in conventional gas with unconventional/renewable production, and much of this would not be available until the second half of the 2020s. Therefore, despite the fact that European gas demand will not increase greatly during the 2013–2030 period, the requirement for gas imports will increase – although not substantially.

²⁴⁹ These data have been converted into European cubic metres (i.e. reduced by 7.97%) to be consistent with the data in the rest of the chapter. In Russian units, the figures are 125 bcm in 2020 and around 70 bcm in 2030, compared with a 2013 import level of 166 bcm. See Table 1 and Figure 1.

²⁵⁰ Turkey is also significantly dependent on Russian gas, but falls into a category of its own because of its geographical location and the size of its gas market.



7.3 Alternative gas imports and infrastructure

Europe is surrounded by regions with substantial gas reserves, but ensuring the production and delivery of those reserves is complicated. Looking at likely exports of pipeline gas to Europe by 2020, the main increase will be from Azerbaijan (16 bcm of additional gas is firmly contracted) counterbalanced by a decline of 6 bcm from North Africa due to lack of production capacity, rapidly rising domestic consumption, and political instability. Projections for 2030 are extremely speculative and show that, compared with 2020 levels, an additional 20–40 bcm of pipeline gas could be available from Iran, Iraq, and Azerbaijan. However, each source has its own specific combination of geological, policy, and geopolitical risk factors.

The main beneficiary of this additional pipeline gas is likely to be Turkey, which could be importing 35 bcm (from the Middle East and Caspian region) by 2030, which would help to reduce dependence on Russian gas in percentage terms, although Russian import volumes will probably be maintained and may even increase somewhat. New non-Russian pipeline import volumes will also help highly dependent countries in south-east Europe – especially Greece and Bulgaria which have each contracted 1 bcm of Shah Deniz 2 gas. If more of the remaining 8 bcm of Azeri gas contracted by non-Turkish companies were sold in south-east Europe, by 2020 it would drastically reduce the dependence of the other countries (FYROM, Bosnia & Herzegovina, and Serbia) which rely heavily on Russian gas. By 2030, if 10 bcm of additional gas can be sourced from Azerbaijan, Iran, and Iraq, additional pipeline connections could eliminate the dependence of Balkan countries on Russian gas.

The main source of alternative gas for Europe will be the global LNG market which comprises a wide range of countries including the USA. Global LNG trade could double to 700 bcm/year by 2030 – excluding the USA which could contribute in excess of an additional 100 bcm. With nearly 200 bcm of re-gasification capacity – of which only 22 per cent was utilized in 2013 (compared with 48 per cent in 2010) – it is clear that Europe could import much larger volumes, depending on the global LNG supply/demand balance and prices in other regions (specifically Asia). Our modelling suggests that the key determinants of LNG availability for Europe will be US export availability and Chinese LNG demand. Thus, to the extent that China buys larger volumes of pipeline gas from Russia, it may need correspondingly less LNG and this could benefit Europe. Nevertheless, as mentioned above, the model (which does not take into account take-or-pay obligations in existing contracts) does not see Europe importing less than 100 bcm/year of Russian gas up to 2030, and in most scenarios significantly more than that figure.

If two or three new receiving terminals are built, it will be possible for highly dependent Baltic countries to reduce, and probably to phase out, Russian gas by the early 2020s, replacing it with LNG. This could be achieved at lowest cost if the countries could agree to share terminal capacity and create pipeline interconnections, rather than each building national facilities. Despite the opening of its LNG receiving terminal in 2015, eliminating dependence on Russian gas will be more difficult for Poland because of the relatively large size of its gas demand. But expansion of LNG import capacity and interconnection with Baltic terminals could make a significant contribution. In south-east Europe, new and/or expanded LNG terminals in Greece, Croatia, and possibly Italy could make a significant contribution to reducing Greek and Bulgarian dependence, but not much difference (without additional pipeline connections) to Serbia, Macedonia, and Bosnia & Herzegovina. It is difficult to make a judgement on the extent to which additional LNG deliveries to the high-capacity LNG terminals in north-west Europe (the UK, Belgium, and the Netherlands) could reverse flows through to central Europe (Poland, Hungary, the Czech Republic, and Slovakia) to replace Russian gas. Linking potentially underutilized Italian LNG terminals by reverse flow to Austria could be more straightforward. This will also be important in relation to the reduction of Ukrainian dependence on Russian gas (see below). In general, infrastructure expansion – which would include interconnectors and reverse flow (envisaged by the EU's PCI projects) – should allow gas to flow more freely around Europe, but this will entail additional costs, with significant impacts being unlikely before the early 2020s.



7.4 Fuel substitution, conservation, and efficiency

It is very difficult to give an exact figure for how much Russian gas could be substituted by non-gas alternatives, whether by other energy sources or by demand reduction through conservation and efficiency. In 2015, the potential to reduce gas consumption is confined to fuel substitution, mainly returning to the use of fuel oil in industry and by replacing gas in power generation by oil products and coal. It would be surprising if Europe could replace more than (the annual equivalent of) 20 bcm of Russian gas with oil products; this would not be sustainable for more than a few months and would involve substantial additional costs. By 2020, oil product switching potential will have declined significantly and will probably disappear by 2030.

The potential for replacing gas with coal in power generation is much greater. *In theory*, all 13 countries most dependent on Russian gas can replace substantial volumes of gas with coal, and seven countries could replace all gas generation with coal.²⁵¹ Coal switching will be dependent on acceptance of CO₂ emission increases, and failure to meet standards imposed by EU Directives, which will otherwise limit the burning of coal without carbon capture and storage. Restrictions on coal become even more important by 2030. With these caveats, our rough estimate is that coal switching in the 13 countries highly dependent on Russian gas could replace 14 bcm and 20 bcm of gas in 2020 and 2030 respectively. New coal and nuclear stations have become problematic as a result of stricter environmental regulations which would penalize coal, public opposition to new nuclear stations, and escalating construction costs. Gas has already lost market share to renewables (wind and solar) and this will continue in many countries, although a limit may be reached due to the need for back-up when these sources are unavailable. The role of natural gas compared with that of other fossil fuels depends on how the objectives of security, competitiveness, affordability, and de-carbonization will be balanced.

In a time horizon of five years, there is a limited potential to reduce gas use by higher energy efficiency, especially through better building insulation. The ambitious EU target – to improve energy efficiency by 20 per cent by 2020 – may be beyond reach in many countries. By 2030, a substantial reduction of gas use will depend on a major scaling up of energy savings and efficiency, mainly in buildings, but this will require very substantial incentives beyond current programmes. By 2030, there is a substantial potential to replace natural gas in all sectors, but this will require additional policy instruments and sustained political will. Putting figures on such potential would require far deeper analysis than this study has conducted. However, we believe the EU projection – that energy efficiency policies could result in a reduction of 40 per cent of gas imports by 2030 (in comparison to 2010) – to be somewhat ‘heroic’.

7.5 Reducing Ukrainian dependence on Russian gas

On the expiry of the Gazprom–Naftogaz contract at the end of 2019 (or earlier if the two parties can agree), it is likely that significant volumes of Russian gas will be available on Russia’s western border for sale to a large number of buyers. Initially, this will mean trading companies supplying Ukrainian customers with up to 32 bcm/year. If gas is available on Russia’s western border, such purchases will replace reverse-flow trade; if it is not, reverse-flow trade, within a few years, will cover anything up to Ukraine’s total import requirement. Ukraine’s own import requirement, up to 30 bcm/year in 2020, possibly falling to 15–20 bcm/year in 2030, will continue to be met entirely, or overwhelmingly, by Russian gas (whether directly or via reverse-flow schemes). Starting in 2020, for the purposes of market analysis, Ukraine will probably be best incorporated into Europe’s gas balance.

²⁵¹ By increasing the load factor of existing coal-fired stations and reducing those of gas-fired units. The seven countries are slightly different depending on the date between 2015 and 2030 but include: Austria, Bulgaria, the Czech Republic, Estonia, Finland, Latvia, Slovakia, Slovenia, and Poland.

7.6 The Russian response

Even before the events of 2014 Gazprom had, for many years, been negotiating to sell pipeline gas to China and a contract was finally signed in May 2014, with the possibility of a second contract by the end of this year. Should both contracts become reality, this would mean that by the early 2020s, Russia could be exporting around half the volumes to China that it exported to Europe in the early 2010s. While there has been speculation that such a development would constitute a threat to European supplies, this is highly unlikely not only for contractual reasons, but also because the majority of gas being sold to China (and other Asian countries) will be from fields with very limited connections to European markets.

General Russian aspirations to diversify gas exports away from European pipeline markets, through the use of LNG, have been impacted by EU and US financial sanctions, but in any case such exports will mainly be targeting Asian markets. While Gazprom has already lost its export monopoly in relation to LNG, relaxation of its pipeline gas monopoly in Europe, which was the subject of serious discussion before the 2014 crisis, currently seems less likely.

By 2013, Russian gas exports had aligned with hub price levels in competitive European markets. Our analysis suggests that Gazprom's most expensive (Yamal Peninsula) gas can be delivered to an EU border for less than \$8/MMbtu (€20/MWh) and provide a 10 per cent real rate of return on a full-cost basis; on a marginal-cost basis, Gazprom could supply gas at lower prices. As a result, we believe that Russian gas will be cost-competitive with all new sources of gas supply to Europe (including US LNG). Indeed Gazprom may be in a position to sell substantial additional gas on European hubs, reducing prices to the point at which LNG imports could be limited.

Gazprom responded to the increasing problems of gas transit across Ukraine (and to a lesser extent Belarus) by building new infrastructure – the Blue Stream pipeline to Turkey, and Nord Stream 1 and 2 pipelines (to Germany) – and is in the process of building the first two South Stream pipelines to south-east Europe. Despite the fact that these new pipelines resolve transit problems, and hence increase energy security, they have been resisted on the grounds that they reinforce European dependence on Russian gas and contravene elements of the Third Energy Package. With South Stream under construction, and no agreement between Russian and EU authorities over the extent to which Gazprom will be permitted to utilize the capacity of the pipeline in EU member states, it is not clear how this situation will be resolved. The need for resolution may become acute if no agreement is reached regarding utilization of Ukrainian transit capacity.

7.7 The geopolitical arguments

The 2014 Ukrainian crisis has fundamentally changed post-Cold War political and strategic relationships between Russia and European states in ways which may not be quickly reversed. The contention that dependence on Russian gas creates unacceptable geopolitical risks in relation to national security is based on a widespread perception – realistic or otherwise – that Russia has used, and intends to use, gas as a political lever in its relations with European countries. The legacy of Soviet dominance in many Baltic, central, and south-eastern European countries is the major reason why many politicians and commentators in these countries take a geopolitical view of dependence on Russian energy – and particularly gas – supplies. Those with historical reasons to fear invasion from the east have had such fears reawakened by recent events in Ukraine. For those countries which view Russia's gas imports in this context, the logical action will be to terminate their contracts before these expire (which will be expensive), or not to renew them on expiry. This will require either imports of alternative gas supplies, or the development of alternative energy supplies. Some actions (extra LNG import capacity and reverse flow) may be relatively inexpensive and are already addressed by the PCI projects.



Countries which do not share these geopolitical threat perceptions may have a different view on the urgency and cost of reducing dependence on Russian gas imports. The question of whether additional infrastructure costs should be borne by individual countries, or funded by the EU, may also be an important determinant of the speed with which dependence can be reduced. In addition, it should not be assumed that alternative supplies will necessarily be cheaper than Russian gas.



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