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forum

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It is well known that Russia is heavily dependent on its energy sector, from both an economic and a political perspective. As a result, the fall in the oil price over the past two years and the dramatic changes taking place in the global gas market are having significant consequences for both the Kremlin and Russia's domestic energy companies. However, instead of reviewing the increased risks for Russia from the change in global energy markets, this edition of the *Oxford Energy Forum* discusses how Russia has started to adapt its policies and commercial strategies in a number of different areas. Some of the new strategies appear very positive, while others carry inherent risks, but all show how the world's largest producer of hydrocarbons is being forced to respond politically and commercially to the shock of lower commodity prices.

In the first article *Christopher Granville* assesses the potential risks to the oil and gas sector from the Russian government's need to balance the budget in a low oil price environment. Increased taxes from oil and gas production and exports are clearly one possible source of extra revenue, but Granville argues that the Kremlin understands the risks this could create for the industry and will focus instead on trying to reduce spending across the economy. However, in reality this may not be practically possible, meaning that oil and gas companies could face a stealth increase in their overall tax burden.

Tatiana Mitrova then discusses one of the key factors underpinning the survival of Russia's hydrocarbon industry in 2016, namely the devaluation of the ruble and its impact on cost competitiveness. The Russian government's decision not to protect the domestic currency as the oil price collapsed has significantly enhanced the position of exporting industries, reducing their costs in US$ terms, but Mitrova argues that this benefit has limited further upside and could indeed be reversed if the oil price recovers. What is needed for long-term competitiveness to be maintained is systemic improvements in business practices across the industry.

From an oil industry perspective, *Nina Poussenkova* then considers the growing role of Rosneft in the sector, which is particularly relevant following its recent acquisition of fellow state company Bashneft in the controversial privatization. This latest purchase seems to have been driven by Rosneft's concerns over its production outlook, and Poussenkova questions whether the dominance of the state oil company will be positive for future Russian oil output. She also asks whether Rosneft's

CONTENTS

Russian energy issues in a volatile environment

diversification into the gas sector and into other, more non-core, activities will distract the company from its main production objective.

Rosneft's funding constraints and its need to continue new field development have led to a growing trend towards partnership with foreign companies, especially those from countries perceived as allies. *Vitaly Yermakov* picks up this theme in a discussion of Russia's, and Rosneft's, growing relationship with India and its key oil and gas companies. He highlights two important trends, the first being a need to bring in partners who can help with the financing of new projects, and the second being Russia's desire to find alternatives to Chinese investment in Russia, as the need to avoid dependence on Russia's southern neighbour in the East is increasingly being seen as politically and commercially vital. He also highlights the continuation of a Russian 'upstream–downstream' strategy which has seen Rosneft take an interest in an Indian refining business to balance the upstream deals done in Russia.

Diversification is a theme that *Simon Pirani* picks up in the gas sector, but on this occasion it is the more traditional story of a desire to buy less Russian gas. He considers how one key export market for Gazprom, Ukraine, has reduced its import requirement through a combination of falling demand, purchases of reverse flow gas from Europe, and a drive to increase domestic output. This has put Ukraine in a stronger position in its commercial relations with Russia ahead of the looming negotiation over gas transit, as the 2019 deadline for the end of the current contract with Gazprom approaches.

The other element in this negotiation is Russia's own plan to diversify its transit options, and *Katja Yafimava* addresses this issue in her article on the progress being made in the Black Sea with the Turkish Stream pipeline. She reviews the volatile history of the project, which has reflected Russian relations with both the EU and Turkey, and assesses the most likely development plan and the future capacity of the pipe. She also considers the potential for the South Stream project to re-emerge in a smaller form (South Stream 'lite') and looks at the potential impact of all these options on possible gas transit volumes through Ukraine after 2020, concluding that countries in south-east Europe will remain dependent on this route for some time.

Thierry Bros then looks at Gazprom's overall pipeline strategy and discusses whether the company is becoming more commercially realistic with its spending plans. He asserts that Gazprom's traditional 'gold-plated' strategy of building capacity to meet all possible demand scenarios was possible in a world of continually growing gas demand, but suggests that the company is developing more cautious plans for a new less optimistic era. He uses the development of the Power of Siberia pipeline in the Far East as an example of how Gazprom is adapting to market needs and is creating more flexibility in its expansion programme. He argues that this could also have interesting implications for the EU as it reflects on its need for Russian gas in the future, despite its political concerns.

Development of flexibility has been the main driver behind Russia's LNG strategy, but as *James Henderson* discusses in his article, the corporate focus in this area is now more on Novatek than Gazprom. The emergence of domestic competition for Gazprom started in 2013 when LNG exports were liberalized, and it would now seem that Novatek is set to become Russia's largest LNG player, as its Yamal LNG project comes to fruition while Gazprom's plans lag behind. Indeed, so confident is Novatek about its future that it already has a second project at the planning stage, raising the possibility that it could become the dominant Russian player in this arena.

Finally, on a more domestic note *Fedor Veselov et al* provide a review of the electricity sector, focusing in particular on the implementation of the continuing reform process. They argue that the use of a complex capacity payment system has led to overcapacity in the generation market, with older more inefficient plants remaining online beyond their theoretically useful life. On a more positive note they also suggest that this problem is gradually being remedied and that the operational efficiency of the sector should therefore increase, as decommissioning accelerates and a wave of investment in new plant is encouraged.

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Russia's macroeconomic problems and the risks to the oil and gas sector

Christopher Granville

As is the case with all petrostates, Russia's macroeconomic stability hinges, to a large extent, on the credibility of government efforts to adjust the public finances to 'lower for longer' oil prices. This is the time of year when progress on fiscal adjustment can most easily be gauged, as the government's definitive federal budget for the three years ahead gets submitted to the State Duma in late October and must complete its parliamentary stages in time to be signed into law by President Putin at the end of December.

From the perspective of Russia's oil and gas industry, the government's fiscal policy matters in two main ways.

- The first – which is equally important to the rest of the Russian economy and, for that matter, all stakeholders in the country – hinges on whether the risk to fundamental economic stability from the oil price shock can be contained, with the core of this challenge lying in the public finances and public debt – which must be placed onto a stable footing on conservative oil price forecasts.
- The second point is more specific to the oil and gas sector (though this also has wider relevance given the industry's continued importance to the Russian economy). To the extent that the government manages to stabilize the public finances, will this achievement rely on continued increases in the tax burden on oil and gas companies?

Overall adjustment on track

On the first theme, the government's federal budget proposal for 2017–19 displays a clear commitment to the necessary fiscal adjustment. And it seems safe to assume that the huge majority secured by the pro-Kremlin United Russia party in September's parliamentary election virtually guarantees that the draft budget will be enacted without material amendments.

The two highlights are:

- A conservative average oil price assumption of US$40/bbl for the entire three-year period.
- A determination to make the spending side shoulder the main burden of fiscal consolidation (sticking to a commitment that Putin made in 2014 not to increase taxes for the remainder of his presidential term ending in 2018).

The broad budget framework that emerges from these starting points is summarized in the table below.

Focusing on the spending projections, the planned reductions in nominal terms amount to substantial real-terms cuts – even if deflated by no more than the Central Bank's ambitious inflation target of 4.7 per cent average in 2017 and 4 per cent thereafter (resulting in the real year-on-year spending cut being marginally smaller in 2017 than it was this year, see 'Annual changes in federal budget spending' opposite).

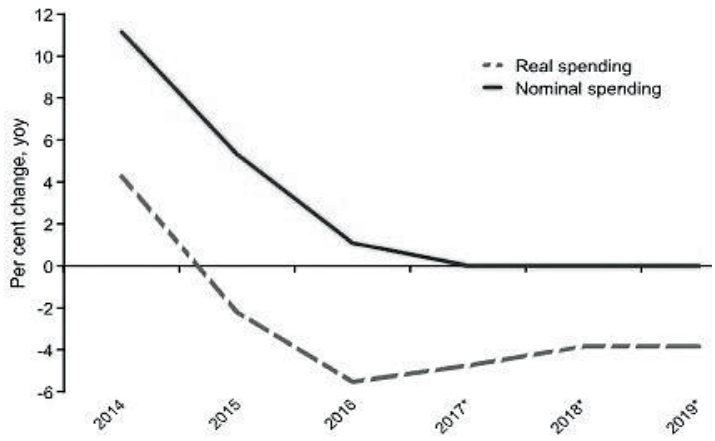
Federal budget projections 2016–19

	2016	2017F	2018F	2019F
Spending (RUR trillion)	16.4	16.2	16.0	16.0
Revenue (RUR trillion)	13.4	13.5	14.0	14.8
Deficit (% of GDP)	3.7	3.2	2.2	1.2
Primary balance (% of GDP)	–3.1	–2.4	–1.3	–0.3

Source: Ministry of Finance of the Russian Federation

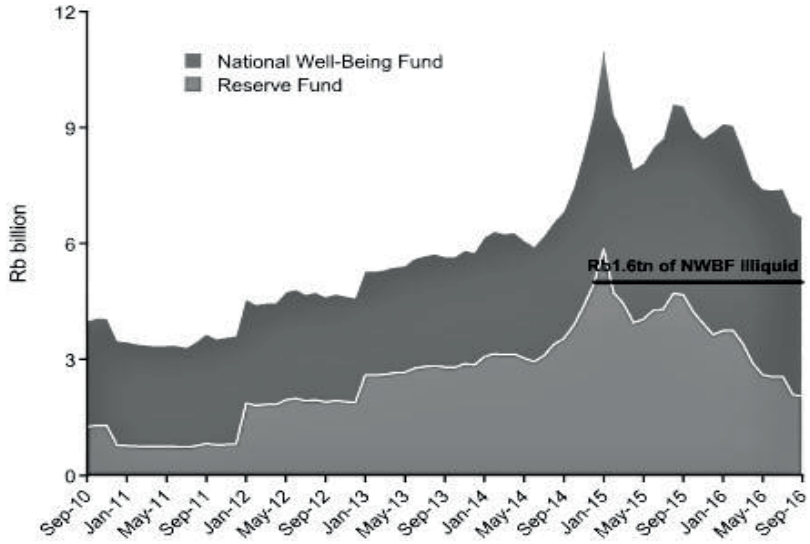
'THE RUSSIAN ECONOMY EXPERIENCED ITS SECOND STRAIGHT YEAR OF RECESSION IN 2016 …'

The Russian economy experienced its second straight year of recession in 2016 – albeit milder (with real GDP set to fall by around 0.5 per cent) than last year's sharp contraction of 3.7 per cent. Although the economy is expected to return to growth next year, the official forecast that real GDP will expand by 0.6 per cent is hardly a stellar bounce back; the growth forecasts for 2018 and 2019 – respectively 1.7 and 2.1 per cent – would still leave the Russian economy continuing to lose share of global output. Against this background, it may seem strange that the Russian government has adopted a strategy of fiscal austerity. There might seem to be a good case for postponing the necessary fiscal consolidation and using fiscal policy to boost demand, which would in turn facilitate fiscal adjustment. The arguments for such a strategy might also include the country's ample 'fiscal headroom': Russia has very low public debt (only about 15 per cent of GDP in 2016) and substantial remaining resources in government funds – the Reserve Fund (RF) and National Well-Being Fund (NWF). These funds were accumulated from budget surpluses when the oil price was high (see 'Reserve Fund and National Well-Being Fund balances' opposite) precisely for the main purpose of cushioning painful fiscal adjustment following any oil price correction.



Annual changes in federal budget spending

*Based on the latest Ministry of Finance proposals
Source: Ministry of Finance of the Russian Federation



Reserve Fund and National Well-Being Fund balances

Source: Ministry of Finance of the Russian Federation

The key policymakers in the government and Central Bank remain resolutely opposed to any such Keynesian counter-cyclical stimulus. Their strategy hinges on the conviction that Russia's previous growth model – based on high oil prices and expanding domestic consumption – is dead and must be replaced by a new model based on private investment, believing that this is the only path to increased productivity, without which Russia will have no prospect of sustainable development (given the country's demography, growth through factor accumulation may be safely ruled out). On this view, the first essential condition for stimulating private investment is to achieve – for the first time in Russia's post-Soviet history – a low and stable inflation rate of 4 per cent. The Central Bank's tight monetary policy in pursuit of this goal (real interest rates now stand at 5.5 per cent) would be undermined by an expansionary fiscal stance. Getting inflation down requires a reduction in the budget deficit. Besides supporting the Central Bank, Finance Ministry officials also argue that businesses would be much less likely to invest if they saw growing budget deficits and feared future tax hikes being imposed to rein in those deficits.

The next question that must be answered to make sense of the situation – and assess whether Russia is set on a credible path of stabilization and adjustment – is why President Putin is supporting this policy of monetary and fiscal restraint that is crimping the recovery of domestic demand after a severe recession, in the politically sensitive period leading up to the March 2018 presidential election. The spending squeeze will be further increased by the need to offset the signalled indexation of pensions and some other transfers by deeper cuts in discretionary spending – mainly state investment programmes. Those cuts will have to include the defence budget which, since the start of this decade, has been a sacred cow. Surely Putin would prefer, in a pre-election year, to stimulate growth by expanding state investments and, above all, deliver real-terms increases in social spending.

'PUTIN'S DECISIONS … DEMONSTRATED HIS STRONG SENSE OF THE DANGER OF ALLOWING THE PUBLIC FINANCES TO GET OUT OF CONTROL.'

The main part of the answer to this question about Putin's striking support for his economic team in the teeth of criticism from politicians and various industry lobbies probably lies in the depleted state of those same government funds that financed his largesse ahead of the last presidential election in 2012. Putin's decisions, as well as his rhetoric during his 15 years at the helm, have demonstrated his strong sense of the danger of allowing the public finances to get out of control. As well as overall stability, at stake here is the stable hold of his

Federal budget deficit financing in 2016–17 (RUR trillion)

	2016 RUR3tn deficit	2017 RUR2.8tn deficit	2018 RUR2.0tn deficit	2019 RUR1.2tn deficit
Net debt issuance	0.58	1.02	0.97	1.02
Funds drawdown				
From RF	2.14	1.15	0	0
From NWF	0	0.67	1.16	0.14
Privatization	0.38	0.14	0	0
Balance of RF	1.0	0	0	0
Liquid balance of NWF	**3.0**	**2.6**	**1.4**	**1.3**

Note: The financing items do not correspond exactly to the forecast deficits owing to Ministry of Finance accounting practices

Source: Ministry of Finance of the Russian Federation, TS estimates

ruling establishment on power. This imperative now hinges on conserving resources in the government funds. The table below shows the officially forecast call on the two funds.

Putin has repeatedly stated that the funds should not be fully depleted. This would ensure the availability of emergency funding in the event of new shocks. What if, for example, the winter of 2017/18 produced a further oil price collapse combined with renewed geopolitical tensions interfering with Russia's access to bond markets? The table above shows that even then, the government could tap substantial NWF resources and thereby avoid a politically disastrous build-up of wage and pension arrears. But this safety net depends on sticking to the austerity implied by the proposed 2017–19 budget. In this light, accepting some up-front austerity amounts to a rational political insurance premium. It means foregoing the pre-election pork barrel that was rolled out in 2011–12. But, as demonstrated by the result of last September's parliamentary election, Putin's post-Crimea popularity provides a viable substitute for the time being – and most likely this effect will not wear off substantially before the 2018 presidential election.

Specific risks to the oil and gas sector: better than last year

Turning to our second question (how far this fiscal adjustment comes at the expense of the oil and gas industry) the short answer is that although, once again in this year's budget round, oil and gas taxation is the exception to Putin's tax stability rule, the programmed tax increases are not that material – and are less onerous than last year. The headline number is an overall increase of RUR170 billion. The Finance Ministry would maintain that this hike is consistent with tax stability since it merely implements plans introduced in 2013–14. This goes, in particular, for the increase in royalties (mineral extraction tax) on the gas sector, which has historically been much more lightly taxed than oil. This hit to gas producers accounts for over half the overall increase. In the case of the oil companies, a RUR322 billion MET hike is offset by a RUR219 billion reduction in export duties on oil products. Here again, the government is implementing a previously announced 'tax manoeuvre' and, in pleasant contrast to last year when the duty cut was postponed, the plan now is back on track.

The proposed budget projects a 6 per cent increase in oil and gas tax revenue based on these marginal tax increases and on the expected continued increase in production (if only by 0.7 per cent after this year's 2 per cent increase – though this sits uncomfortably with Russia's present public commitment to freeze output in support of OPEC's plan to reduce production by up to 1mbd). But the Finance Ministry has gone out of its way to point out that this oil revenue increase will lag the growth of nominal GDP, reflecting an important broader trend of a marked decline in the contribution of the proceeds of oil and gas taxation to total federal budget revenues. This share peaked in mid-2014 at 52 per cent, but by the third quarter of this year had fallen back to 36 per cent. It is worth noting in this connection the forecasts in the Finance Ministry's latest draft long-term budget projections out to 2034 that have also just been submitted to the Duma. These see oil tax revenues falling from 5.8 per cent of GDP to 3.6 per cent. Apart from the expectation of a stably low oil price, the main reason for this is that production will increasingly come from new fields that enjoy MET tax concessions.

Residual risks from the 'heavy lifting' of fiscal adjustment

So far, we have discussed the implications of the Russian government's fiscal plans as if they were fully realistic. Even on that assumption, the overall pace of consolidation is leisurely – indeed, in fundamental terms, inadequate. This would be all the more true if the revenue projections in the proposed 2017–19 budget prove over optimistic – especially in such areas as improved tax collection. It would appear that, even if the spending discipline holds up, the federal deficit that is supposed to be reduced to 1 per cent of GDP

by 2020 will still be nearer 2.5 per cent in 2019 as a result of the proposed efficiency gains in tax collection proving difficult to attain in full.

This risk may be reduced by the apparent political will to take tough spending and tax decisions, once the presidential election is out of the way. On the spending side, a core measure will have to be steady increases in the pension age, which Putin has signalled that he will probably accept – but only after 2018. As for taxation, the temptation to extract higher state rents from the oil and gas industry will strengthen as Russia enters into the 'heavy lifting' phase of fiscal consolidation. This risk will be camouflaged by discussions – these have already been a feature of this year's budget round – on introducing a returns-based framework for upstream taxation in place of the present MET (which is levied on revenues). The Finance Ministry's stated concern is that this shift would entail unaffordable transition costs. In reality, the officials running fiscal policy would be almost certain to attempt a stealth increase in the overall tax burden on oil and gas companies in Russia.

'THE TEMPTATION TO EXTRACT HIGHER STATE RENTS FROM THE OIL AND GAS INDUSTRY WILL STRENGTHEN …'

Cost dynamics in the Russian energy sector

Tatiana Mitrova

After a significant increase during the 2004–8 period, when a combination of rising global energy demand and increasing consumption of Russian hydrocarbons in international and domestic markets created inflationary pressure, the period 2009–14 saw energy costs stabilize but at a relatively high level. In addition to the pressure created by booming energy markets, a number of additional factors also drove up the cost of producing hydrocarbons in Russia.

'THE PERIOD 2009–14 SAW ENERGY COSTS STABILIZE BUT AT A RELATIVELY HIGH LEVEL.'

Cost pressures

1 As Soviet-era fields continued to mature, higher levels of capital expenditure have been required to slow production declines. In addition, the development of new fields has moved to increasingly remote areas (such as East Siberia) where the lack of existing infrastructure has pushed up costs.

2 Russia's geography has also not helped, with severe climatic conditions in many regions adding to the infrastructure burden and the difficulties of producing and transporting oil and gas.

3 Russia's relatively limited service industry has also been an issue. Despite the arrival of international companies such as Schlumberger and Halliburton, and the growth of domestic players such as Integra and Eurasia Drilling, the limits of drilling and oilfield service capacity have been reached, increasing cost pressure.

4 Transport costs are also fundamentally high, because of the landlocked nature of the majority of Russia's resources and the long distance between regions such as West Siberia and any significant markets.

5 High levels of corruption have also added another unseen layer of costs onto the more traditional oil and gas industry costs (Russia is ranked 119 out of 168 countries in terms of corruption levels, with 1 being least corrupt – see 'Corruption by Country/Territory', Transparency International's website: www.transparency.org/country#RUS).

6 The political and commercial risks of doing business in Russia have also led to the industry having a high cost of capital compared to other countries (about 16 per cent – see the website of WACC Expert: www.waccexpert.com).

7 High transaction costs are also apparent due to the inefficient regulatory environment and numerous bureaucratic barriers.

8 Finally, comparatively high labour costs have also been a feature in Russia as, according to Sberbank CIB, top management in Russian companies has been among the most highly paid in the world.

Given these relatively high costs, it has been assumed that the sharp declines in hydrocarbon prices seen since early 2014 would be a major threat to the competitiveness of Russian exports and the overall sustainability of the Russian economy, which had got used to being very dependent on hydrocarbon export revenues. Oil and gas, for example, contributed more than 50 per cent of federal budget revenues in 2014 and around two-thirds of export revenues.

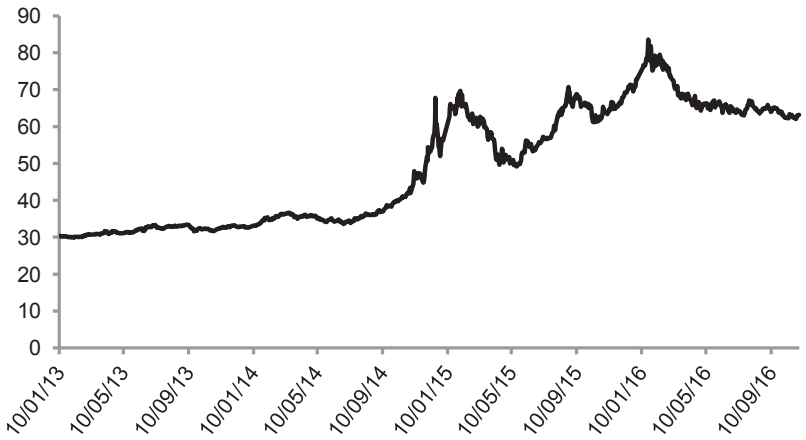
Policy change allowing currency fluctuation

However, in a marked change of strategy compared to the recession of 2009, the Russian government has not tried to protect the national currency during the current economic crisis. Since the oil price began to drop in 2014, the Russian Central Bank has introduced a policy of allowing the exchange rate to float freely, and as a result the ruble has depreciated significantly against the US dollar and other major international currencies. Having started at around RUR32 = US$1 in 2014, the Russian currency fell to a low of RUR80 = US$1 in early 2016 as the oil price plummeted from over $100 per barrel to below $30 per barrel (see 'Ruble to US dollar exchange rate'). Both have since recovered (the oil price to around $45 per barrel and the ruble exchange rate to RUR65 = US$1) and a level of stability now seems to have returned to the market. Nevertheless, it is clear that the new Central Bank strategy has had a very significant negative impact on the Russian population (whose savings are now much lower in US$ terms) but also a very positive impact on the Russian budget and on the competitiveness of Russian exports.

There are a number of positive aspects to this currency fluctuation:

- Firstly, the decision to allow such a massive currency depreciation has ensured that the budget remains more or less balanced as its revenues (expressed in rubles) have not declined and all its costs have also remained the same, as they are all in rubles. As a result, although a 4 per cent budget deficit is expected in 2016, this is much lower (and more manageable) than might otherwise have been the case).
- Equally as important, the devaluation has also significantly enhanced the global competitiveness of Russian energy exports, as it cut production costs in dollar terms. Since all the Russian energy companies incur most costs in rubles and their exports are priced in US dollars, this has meant an ability to generate higher profits in the domestic currency. In particular, salary costs nearly halved in US dollar equivalent terms, and the same reduction has also been seen in the prices of metals, Russian equipment, domestic services and, of course, taxes. The overall result has been that average CAPEX costs in the Russian oil and gas upstream have decreased by approximately 35 per cent (see 'Russian oil companies have called a critical price per barrel', 13 January 2016, RBC website, www.rbc.ru/business/13/01/2016/5694fb659a79471c576b43f5), and OPEX by 40–45 per cent.
- The upshot has been that, despite lower oil prices, economic crises, and sanctions, in 2015 Russian oil companies increased their oil output by 1.4 per cent to 10.7 mb/d, and in 2016 the growth is continuing. According to the Russian Energy Ministry, oil output growth will have reached 2 per cent by the end of the year, bringing Russian oil production to a post-Soviet high of more than 11 mb/d, surprising many analysts and commentators who had been expecting a sharp decline amid the current economic and political troubles.
- Furthermore, a combination of high production and modest domestic demand for petroleum products (due to the impact of the economic recession) has inevitably led to export growth. The last two years have seen an unprecedented rise in Russian oil export volumes both to Europe and to Asia – in 2015 Russian oil companies increased their exports by 9 per cent, and in 2016 the government is expecting another significant increase.
- Although gas production has been constrained by weak European, CIS, and domestic demand, the outlook for 2016 is optimistic as low oil prices have made the element of Russian gas sold under long-term oil-linked contracts one of the cheapest and most attractive options in the European market. Meanwhile the share of Russian exports sold on spot markets has also had a competitive

'THE LAST TWO YEARS HAVE SEEN AN UNPRECEDENTED RISE IN RUSSIAN OIL EXPORT VOLUMES BOTH TO EUROPE AND TO ASIA.'



Ruble to US dollar exchange rate

Source: Ministry of Finance of the Russian Federation

advantage, due to the ruble devaluation which has lowered its cost of supply. As a result, in January–August 2016 Russian gas exports to Europe increased by 11 per cent.

- The benefits have not just been felt by the oil and gas industries, though, as coal output and exports have also reacted to the currency devaluation, with both coal production costs and railroad transportation tariffs (which are nominated in rubles) having decreased significantly in dollar terms. This has suddenly made Russian coal one of the most attractive options on the global coal market, and as a result coal production in Russia grew by 6 per cent during the first nine months of 2016, while coal exports have increased by 7.5 per cent during the same period.

Limited opportunities for further cost reduction via currency fluctuation

However, although ruble devaluation has clearly brought benefits, its impact is now stalling. The government is realizing that the main ruble devaluation has occurred already, and it does not expect any further serious decline of the national currency. According to the recent 'Long-term Forecast of the social-economic development of the Russian Federation up to 2035' (see Gazeta.ru website: www.gazeta.ru/business/2016/10/19/10259831.shtml#page2), by 2025 the ruble to dollar exchange rate is projected to reach a level of RUR77 = US$1 (implying an additional 30 per cent devaluation during the next nine years). Therefore the potential for further cost reduction via this route would appear to be much more limited. Companies and the government are therefore trying to utilize the current window of opportunity as much as possible by maximizing short-term output and exports. However, all the stakeholders involved realize that, although there is a clear benefit to be gained in the short term, this does not provide a longer-term sustainable solution for the Russian energy industry. Unless real reforms and improvements in both business and institutional practices are implemented in the short to medium term, then it seems inevitable that systemic inefficiencies and high country risks will push the costs up once more, and that this pressure could even be exacerbated by any rebound in oil prices, which could encourage a strengthening of the ruble.

'ALTHOUGH RUBLE DEVALUATION HAS CLEARLY BROUGHT BENEFITS, ITS IMPACT IS NOW STALLING.'

In conclusion, then, the ruble devaluation may have deferred a number of key issues for the Russian energy industry, but there is little doubt that these will have to be faced in the not too distant future if oil and gas exports are to remain a competitive and sustainable source of income for the Russian budget.

The Rosneftization of the Russian oil sector

Nina Poussenkova

The recent acquisition of Bashneft by Rosneft reignited the debate about the 'creeping renationalization' of the Russian oil sector. However, the process is not so straightforward since it is also expected that 19.5 per cent of Rosneft's shares will be sold soon as part of a government privatization plan to raise funds for the budget (after the IPO held in 2006, the share of the state in Rosneft's authorized capital shrank to 75.2 per cent). As a result, the process might actually be called the 'Rosneftization' of the Russian oil sector.

'ROSNEFT IS GETTING BIGGER WITH EACH NEW ACQUISITION AND ACCOUNTS FOR AN INCREASINGLY LARGE SHARE OF DOMESTIC OIL PRODUCTION.'

What is certainly clear is that Rosneft is getting bigger with each new acquisition and accounts for an increasingly large share of domestic oil production. Furthermore, the company is diversifying into the gas industry and shipbuilding, thus expanding its influence over the Russian economy in general. And with its unrivalled 'administrative resource', it can also determine certain rules of the game regarding the domestic and foreign policy of Russia. The extent of Rosneft's lobbying potential was clearly demonstrated during negotiations concerning Bashneft, when government officials were debating whether it made sense to allow Rosneft to participate in the privatization process. Andrei Belousov, assistant to President Putin, and Arkadiy Dvorkovich, Vice Premier, were actively opposed. However, to no one's great surprise, Igor Sechin, Rosneft's CEO, won. He proposed a scheme whereby the state's budget revenues would be maximized: Rosneft would buy 50.08 per cent of the authorized capital of Bashneft (60.16 per cent of its voting shares) for RUR329.7 billion (US$5.2 billion). This scheme would

provide more funds for the budget than other contenders (such as LUKOIL, Tatneft, NNK, Antipinsky Refinery, etc. who had expressed interest in Bashneft) had been proposing. The Bashneft acquisition would then raise the capitalization of Rosneft and, therefore, it would be possible to sell 19.5 per cent of the company for more than $11 billion in a second privatization auction, theoretically increasing revenues for the state.

Limited growth?

Over the past decade, Rosneft has evolved from a small player with some 20 million tonnes/y of crude production in 2003 into the number one Russian oil company by aggressively acquiring attractive assets:

- Severnaya Neft in 2003,
- Yuganskneftegas in 2004,
- Udmurtneft in 2006,
- YUKOS in 2007,
- TNK–BP and Itera in 2013,
- Bashneft in 2016.

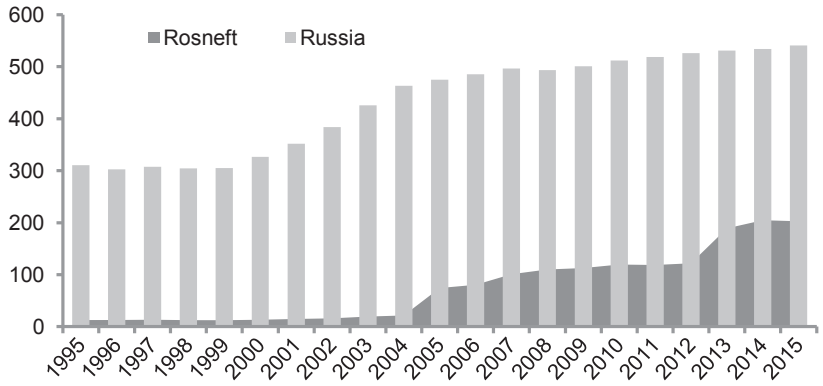
It has become the world's biggest public oil company with 34.5 billion boe of proved reserves (as of 31 December 2015 under the SEC classification). It would seem, then, that Rosneft's current strategy is strongly determined by its desire to be the 'largest fish in a huge pond', with its humble past perhaps partially explaining its unquenchable thirst for growth – and power.

In 2015, Rosneft produced 202.8 mt of oil, accounting for 37 per cent of the total Russian output – with an additional 20 mt of Bashneft's oil production, it would have accounted for 41 per cent. This lion's share of domestic extraction entails serious responsibilities, since the situation in the sector and the growth of domestic crude production actually now largely depend on Rosneft's ability to create value.

Rosneft claims that its history of growth via acquisition gives it unique experience of integrating new assets, according to its press officer Mikhail Leontiev. However, having successfully integrated these assets, it has consistently faced the problem of then ensuring further organic growth in production. As is clear from the graph below 'Russia's and Rosneft's Oil and Condensate Production 1995–2015', following explosive growth due to acquisitions, Rosneft's oil production has stabilized and is even declining: in 2013, it produced 189.2 mt; in 2014, 204.9 mt; and in 2015, 202.8 mt; while in 2016 the company's main hope is to maintain crude extraction at the 2015 level. It has compensated with rising gas production, which has grown from 38.2 bcm in 2013 to 62.5 bcm in 2015, and Rosneft intends to increase this level to 100 bcm by 2020, when it aims to account for over 20 per cent of the domestic gas market. In general, having produced 254 mtoe of hydrocarbons in 2015, Rosneft plans to achieve output of 300 mtoe by 2020.

However, Russia's key priority at present is oil production, which generates a far greater share of export revenues and taxes for the budget than gas. As the country's leading producer, and its national oil company, Rosneft has a major responsibility to contribute to the stability, and indeed growth in oil output, but its performance to date has been patchy. For example, in 2015, Samaraneftegas, the former subsidiary of YUKOS located in the Volga–Urals region, produced 12.1 mt of liquid hydrocarbons from mature fields, 5.3 per cent more than in 2014, while Verkhnechonskneftegas – responsible for developing the Verkhnechonsk field in the Irkutsk region (the second-biggest field in East Siberia after Vankor) – yielded 8.6 mt, 5.4 per cent more than in 2014. However, other subsidiaries are doing less well. Samotlorneftegas, which accounts for 10 per cent of Rosneft's output, produced 20.9 mt in 2015, 4.7 per cent less than in 2014 (Samotlorneftegas, a former subsidiary of TNK–BP, has 97 per cent of reserves concentrated in the legendary Samotlor field that produced 150 mt/y at its peak in the mid-1980s).

'ROSNEFT HAS A MAJOR RESPONSIBILITY …TO THE STABILITY, AND INDEED GROWTH IN OIL OUTPUT, BUT ITS PERFORMANCE TO DATE HAS BEEN PATCHY.'



Russia's and Rosneft's oil and condensate production, 1995–2015 (mt/y)

Source: Neft I Capital

Jewel in the crown?

Of particular concern is the situation in West Siberia (West Siberia accounted for 62 per cent of Rosneft's oil production in 2015) where Yuganskneftegas, Rosneft's biggest upstream subsidiary, accounts for 31 per cent of the company's output. This production subsidiary demonstrated double-digit growth when it belonged to YUKOS in the early 2000s, but is now struggling. The output of its giant mature fields (such as Priobsk, Mamontovsk, Malobalyksk, and Prirazlomnoye) grew by 23.1 per cent to 66.49 million tonnes (mt) between 2005 and 2009, but by 2015 this had fallen to 62.4 mt. Consequently, Rosneft is now focusing on improving performance at its main brownfield sites. Eric Liron, a company first vice president, has stated that average decline in oil extraction by Yuganskneftegas had been reduced from 4.3 per cent in 2014 to 0.9 per cent in 2015, and that he hoped production from its fields might increase to 68 mt over the next three years.

Rosneft's other major problem is one of its more recent field developments, Vankor, which was discovered during the Soviet era. This giant field is located in East Siberia and contains 500 mt of proved oil and condensate reserves and 182 bcm of gas reserves. Rosneft launched production in 2009 and output was expected to reach 25 mt/y at its peak. However, the field disappointed and reached a high of only 21.4–22 mt/y, staying at this level for three years and accounting for 11–12 per cent of Rosneft's total output. Production then began to shrink, and Rosneft stated that it expects a fall of 1 mt to 21 mt in 2016, with fears that the decline might then accelerate so that production might drop to 13 mt by 2020.

This has raised a number of fundamental questions about the Vankor field concerning the reasons for and implications of its decline. In particular, it is unclear what the major causes have been:

- Complex geology?
- A shortage of state-of-the-art technologies and qualified personnel?
- Mistakes in the scheme of development of the field?
- Insufficient fiscal incentives?

The opinions of experts differ, although they suspect it is a combination of the first three factors. However, all believe it is a serious blow to Rosneft and may point to further issues for the company.

Rosneft's response has been to commission a number of major new fields in East and West Siberia in order to reach its 2020 output target. For example, in the period 2016–20 the company expects that the development of the Suzunskoye (expected to yield over 4 mt/y of oil at peak), Tagulskoye (over 4 mt/y), and Lodochnoye (some 2 mt/y) fields will offset declines at Vankor, and in fact all three will add to the overall output in the Vankor cluster, using existing infrastructure in the region.

'ROSNEFT FACES ONE OTHER KEY ISSUE … IT IS FINANCIALLY CONSTRAINED FOLLOWING ITS ACQUISITION SPREE.'

Unfortunately, Rosneft faces one other key issue, namely that it is financially constrained following its acquisition spree. In response, it has invited a selection of Indian companies as partners into the Vankor project: ONGC, Oil India, Indian Oil, and Bharat PetroResources will own 49.9 per cent in Vankorneft. However, although they bring money, their experience of operating in harsh Arctic conditions is very limited and they will contribute little in the way of technical expertise.

A similar problem of experience and expertise faces Rosneft's exploration programme, which now has a special focus on the continental shelf. However, the company has had very little exposure to offshore activity, and plans to partner with international companies have been undermined by sanctions. A good example of this is the Arctic well drilled with ExxonMobil in September 2014 which discovered the Pobeda field in the Kara Sea. It has since remained dormant, as ExxonMobil is now banned from operating in the Russian Arctic and Rosneft has insufficient capability to develop the field on its own.

Given all of these concerns, the acquisition of Bashneft will be an 'acid test' of Rosneft's ability not only to integrate assets but also to derive lasting growth from them. Indeed, the Bashneft case is particularly interesting, because it was a dynamically growing company that accounted for 29 per cent of the total increment of Russia's oil production in 2015 and so it will be interesting to see if Rosneft fails to continue this trend.

Bashneft's oil extraction grew from 15.4 mt/y in 2012 to 19.9 mt/y in 2015, and it achieved impressive results on both extremely mature and new fields. Its production in Bashkiria, a very old petroleum province of Russia, increased from 15.1 mt in 2013 to 16.1 mt in 2015, while in Nenetsk Autonomous Region (a new area) it rose from 0.3 mt in 2013 to 1.4 mt. Not surprisingly, experts believed that Bashneft's management team was one of the best in the Russian oil sector.

However, Rosneft has fired all of Bashneft's top managers following its acquisition, with Andrei Shishkin, vice president of Rosneft for energy, localization, and innovation, becoming its new president. Clearly there is a

real concern as to whether this radical replacement of Bashneft's leadership will benefit Rosneft, raising a similar question to that asked in 2007 after Rosneft acquired all the oil assets of YUKOS. Will the new subsidiary be completely dissolved in Rosneft and lose its identity and outstanding performance, or will it help to raise the efficiency of Rosneft overall to new levels by transplanting some of its best practices to the parent company? Only time will tell, but the answer could be crucial for the Russian oil industry as a whole.

Unlimited ambitions?

It would seem that Rosneft is not content with just being the biggest in the oil industry, but it also wants to conquer other sectors as well. It has already become the number three gas producer in Russia, and now plans to enter the LNG business, with GE and Rosneft subsidiary Itera intending to establish the first mini plant for production of LNG in Russia. This move followed Rosneft's success, together with Novatek, in amending the law on gas exports, thus eroding Gazprom's export monopoly; Rosneft is now also expanding into gas processing. Rosneft and Sinopec plan to build a gas processing and gas and petrochemical complex in East Siberia (annual throughput capacity of 5 bcm of gas), providing another challenge to Gazprom's position in the Russian market.

In addition, Rosneft has begun to develop a major focus on shipbuilding after it became involved in the Zvezda shipbuilding complex in the Far East of Russia – a project it is implementing with Gazprombank and Rosneftegas. In September 2016 alone, together with the Far Eastern Center of Ship Building and Ship Repair, Rosneft signed agreements with Hyundai Heavy Industries, Daewoo Shipbuilding & Marine Engineering, Exxon Neftegas, GE, Siemens, and Fincantieri to develop this new business line. These projects will contribute to an important diversification for the Russian economy, as well as help to industrialize Russia's Far East region and to improve living standards there. Nevertheless, it is perhaps surprising that the national oil company is taking on this burden at a time when its core business needs its full attention. Many commentators have argued that Rosneft is spreading itself too thinly, especially at a time of low oil prices, raising the question as to whether core oil production growth can be achieved. If not, the company may feel compelled to acquire yet another domestic player to underpin its position. In which case the Rosneftization of the Russian oil sector may have further to go.

'MANY COMMENTATORS HAVE ARGUED THAT ROSNEFT IS SPREADING ITSELF TOO THINLY …'

Securing the future: the implications of India's expanding role in the Russian oil sector

Vitaly Yermakov

There are no quick deals in the international oil business, with years of careful preparation and positioning usually preceding the announcement of big ticket projects. The recent deals that have allowed India's oil companies to enter Russia's oil sector via the purchase of stakes in Vankorneft (VN) and Taas-Yuryakh Neftegasodobycha (TYN) – two key Rosneft brownfield onshore production subsidiaries located in the northern part of Krasnoyarsk territory and in Sakha-Yakutia republic in East Siberia – are no exception to this general rule.

There are two important drivers that are motivating the Russian side:

- Firstly, Rosneft, a key driving force behind the expanding cooperation with India, is trying to address the problem of financing the development of the Vankor cluster, which has emerged as an important new oil producing province, a key source of crude oil for the ESPO pipeline, and a foundation for Rosneft's existing long-term oil supply contracts with China.
- However, from an alternative perspective, Russia has also become wary of creating too much dependence on a monopsonistic buyer (China), and has therefore also been trying to diversify its eastern exports and is attempting to build leverage via advancing joint projects and asset swaps with alternative resource-hungry countries such as India.

Part sale of Vankorneft to Indian consortium

As a result, two opportunities that had originally been offered to Chinese companies have now been snapped up by Indian competitors. On 5 October 2016 Rosneft announced the closure of

'TWO OPPORTUNITIES THAT HAD ORIGINALLY BEEN OFFERED TO CHINESE COMPANIES HAVE NOW BEEN SNAPPED UP BY INDIAN COMPETITORS.'

two transactions agreed earlier in June at the Saint Petersburg International Economic Forum. The first deal was a $2.02 billion sale of 23.9 per cent of Vankorneft JSC to a consortium of Indian companies consisting of Oil India Limited (the leader of the consortium), Indian Oil Corporation Limited, and Bharat PetroResources. As of 1 January 2016 the Vankorskoye field contained 2P commercially extractable reserves assessed at 265 million tonnes of oil and condensate and 88 bcm of gas according to the PRMS classification used by SPE International. (Rosneft reported that the deal valued the reserves at Vankorskoye at $3.4/boe.) The Vankorskoye field has been producing since September 2009 and reached a plateau of about 22 mt/y (440 kb/d) of oil output in 2013.

Interestingly this is the second sale of equity in the field to an Indian company, as earlier in 2015 Rosneft sold 15 per cent to India's ONGC Videsh for $1.27 billion and it is currently negotiating the sale of a further 11.2 per cent; this will reduce Russian interest in the field to a simple majority of 50.1 per cent. As a result, a foreign consortium will own almost half of one of Russia's largest producing oil fields, and it is a pointed reminder to China that it will be Indian companies, and not a Chinese NOC, which will be exporting oil via the ESPO, despite the final destination of the crude.

Indian purchase of Taas-Yuryakh Neftegasodobycha stake

The second deal was the $1.12 billion sale (to the same Indian consortium) of a 29.9 per cent stake in Taas-Yuryakh Neftegasodobycha LLC; this company has been developing the Srednebotuobinskoye field since October 2013. Again, the deal had originally been offered to a Chinese company, but then apparently was retracted over a disagreement on price. As a result, India has acquired another significant oil interest in Russia's eastern regions, as the field's ABC1+C2 reserves stand at 166 million tonnes of oil and condensate and 180 bcm of gas, while production in 2015 was 0.9 mt/y (18.4 kb/d) of oil. According to the development plan, the field will be producing 5 mt/y (100 kb/d) of oil when it reaches its plateau in a few years' time, with the assistance of BP, which was also sold a 20 per cent stake (in 2015).

These deals have important implications, some of them near term, and some longer term, as Russia attempts to continue its 'pivot to Asia' while also seeking to raise short-term funds to support the continued growth of its oil industry and the financing of the federal budget.

The financing of Russia's federal budget

This latter concern appears to be one driver of the current sale of Russian upstream assets to the Indians, as Rosneft needs to raise additional cash to pay for the purchase of a 50.08 per cent state interest in Bashneft, which the Russian state has recently sold to raise funds to reduce its budget deficit (which has reached 3.5–4 per cent of GDP in 2016). The stake in Bashneft had been valued at $5.3 billion, and Rosneft has been ordered to pay this price as it has essentially been given exclusive rights to purchase the company ahead of its private sector rivals. The Russian state seems to have closed its eyes on the 'one hand giveth and the other taketh away' nature of the Bashneft 'privatization' by a state-owned company, so long as it receives a high acquisition price that would allow it to finance this year's federal budget deficit and maintain nominal control over oil assets that are changing hands. As a result, the Indian companies' payment for Rosneft upstream assets helps Russia close a near term financial gap and effectively allows Rosneft to continue its expansion in the Russian oil sector – an interesting variation on a similar theme from 2003/4 when Chinese financing allowed Rosneft to gobble up a bankrupted YUKOS.

Russian deals with India send signal to China

A second important consideration is that in forming closer energy ties with India, Russia is simultaneously sending a signal to China that the 'pivot to the east' may be structured in a way that reduces Russia's dependence on the largest buyer of its oil in Asia. China has been waiting patiently to improve its negotiating position before committing to large investments in Russia, thinking that low oil and gas prices have been boosting its leverage and improving its terms of trade. However, it is now clear that Russia has become impatient with this tactic and has decided to demonstrate that China 'is not the only game in town', even if these latest deals are relatively symbolic and do not change the overall balance of economic bargaining power. Russia will remain reliant on China as by far the largest market for its hydrocarbon exports in the East.

'IN FORMING CLOSER ENERGY TIES WITH INDIA, RUSSIA IS SIMULTANEOUSLY SENDING A SIGNAL TO CHINA …'

Upstream–downstream model

Thirdly, it is also important to see how the deals with the Indian companies stand in relation to Russia's general strategy of energy asset swaps with foreign players. This can be defined to an extent as an 'upstream–downstream' model in which foreign investors can receive access to Russia's upstream assets in exchange for financing, technology transfer, and security of supply in the form of Russian equity in the downstream assets of its partners in their home countries. Overall Russia's strategic goal is to create integrated cross-border energy value chains that can protect existing markets and open up new channels for Russian oil and gas exports, thus underpinning the continuous and sustainable development of Russia's oil and gas resource potential.

Russia's energy strategists have been promoting this idea for the past 10 years, first in the West, where it ran into politically motivated resistance, and now increasingly in the East. The 'grand design' was initially formulated in 2006 and was heavily promoted during Russia's chairing of the G8 summit in Saint Petersburg, when Russia's current First Deputy Prime Minister Igor Shuvalov described a bold vision of Russia's expanding energy role in an interview in May 2006 ('Putin ne shutit', Igor Shuvalov's interview to *Nezavisimaya Gazeta*, 23 May 2006).

Essentially Russia has been seeking expansion on the basis of a series of *quid pro quo* commercial relationships between Russian state-owned firms and foreign partners. The upstream–downstream asset swaps between Gazprom and the German BASF group that were completed in October 2015 were the most successful example of the realization of Russia's strategic plan.

'RUSSIA HAS OFTEN VIEWED THESE PROSPECTIVE LONG-TERM BUSINESS PARTNERSHIPS AS PILLARS FOR BUILDING GEOPOLITICAL ALLIANCES …'

However, the fact that Russia has also often viewed these prospective long-term business partnerships as pillars for building geopolitical alliances has prompted accusations of using 'the energy weapon' to advance its geopolitical agenda and has made the West vary of supporting it. When this general sentiment merged with the aftermath of the conflict in Ukraine, the overall energy relationship between Russia and the EU became one of mistrust and mutual accusations.

However, in spite of the obvious failure to establish large-scale energy partnerships in the West via the 'upstream–downstream' model, its key principles are alive and well in Russia's negotiations with prospective new partners in Asia. Indeed, it is worth noting that the upstream deals between Rosneft and Indian companies are only the first part of a larger transaction that is still in the making. Rosneft and the trading company Trafigura have been in negotiations to purchase 49 per cent each in Essar Oil's downstream assets in India. These include a highly complex and modern 20 mt/y refinery owned by Essar Oil in Vadinar (located in Gujarat, on India's north-west coast), the deep-water marine terminal for crude oil and the largest Indian network of filling stations, with a total of 2,700 locations. Essar and the Russian consortium have reached a preliminary agreement to close the deal in 2016. If finalized, it would provide a logical conclusion to another example of 'upstream–downstream' cooperation, and provide Russia with access to India's fast growing economy and its expanding energy needs.

India's need for new sources of oil supply

For India, a country that is emerging as a new source of global economic growth and a key driver of incremental growth in global oil demand, the deals with Rosneft are important for two reasons.

- First, India's oil production has essentially been flat over the past five years, at levels just shy of 0.9 mb/d, while demand has risen by more than 25 per cent in the same time period. As a result, the country has to import about 70 per cent of the oil it consumes, and this import requirement is set to grow quickly over the next decade as the economy develops and per capita income increases.
- Second, in spite of current structural oversupply in the global oil market and low international oil prices, a market rebalancing is looming on the horizon.
- It is therefore critical for India, where oil demand is extremely price sensitive, to find ways to 'hedge' against a possible increase in the future oil price. Securing significant upstream positions with one of the largest global oil producers, while also ensuring long-term oil supply for its downstream industry, provides one answer to India's inherent energy supply problems, as well as providing an important strategic link with a long-term political ally.

Ukraine's dramatic gas import diversification

By Simon Pirani

Ukraine is cutting direct imports of Russian gas to near zero. It is on its way out of the former Soviet energy trading system which, within the next few years, will start to look very different.

Ukraine imported just 6.3 bcm of gas in January–September 2016. In October, the state oil and gas company Naftogaz Ukrainy secured a $500 million World Bank loan to pay for 2.5 bcm of 'reverse flow' imports over the winter. Naftogaz had 14.7 bcm of gas in storage at the start of the heating season and, barring freakish cold, could get through the year with no Russian imports at all. Full-year imports will likely be 9–10 bcm, down from 16 bcm in 2015, 22 bcm in 2014, and 29 bcm in 2013.

All this year's imports have been 'reverse flow' – so called because gas, mostly of Russian origin, physically flows back to Ukraine from central European countries. 'Reverse flow' has, since 2013, offered price competition with direct Russian imports. During the last two years of military and political conflict, it has been supported financially by Brussels in the name of minimizing Ukrainian energy dependence on Russia.

Decline in gas consumption and in Russian imports

Ukraine's gas import volumes are falling because of a precipitous decline in gas consumption. Total gas demand has fallen from 42.6 bcm in 2014 to 33.8 bcm in 2015. In the first nine months of 2016 it was 20.7 bcm, down 10 per cent year-on-year.

'UKRAINE'S GAS IMPORT VOLUMES ARE FALLING BECAUSE OF A PRECIPITOUS DECLINE IN GAS CONSUMPTION.'

There are some short-term specifics reflected in these numbers.

- First, the removal from Ukraine's gas balance of Crimea (annexed by Russia in 2014) and of parts of the heavily industrialized Donetsk and Lugansk regions (controlled by Russian-supported separatists).
- Second, a 10 per cent decline in GDP in 2015, which hammered industrial output and energy demand, reflecting the toll taken by military conflict and the international economic slowdown. The economy recovered to projected 1 per cent growth in 2016.
- Third, IMF arm twisting to raise tariffs for residential customers and district heating companies to cost recovery levels – pretty much ignored by successive governments between 2008 and 2013 – has finally produced results. And that is focusing attention on energy saving.

'Taking advantage of low international gas prices, the authorities accelerated the increase in gas and heating prices to full cost recovery one year ahead of schedule', the Fund enthused in its September 2016 review of Ukraine's finances. From here, a quarterly adjustment mechanism will keep consumer prices at par with import prices, and full liberalization is due in April 2017. The market for industrial consumers was fully liberalized in October 2015.

The fall in gas consumption in the last three years is the second chapter of a story that began in 2006. That year, demand hit a post-1990s high of 75 bcm. Since then, demand fell each year (except for a brief upward blip in 2011), reaching 50 bcm in 2013.

The beginning of a shift from energy-intensive industries (such as metals and chemicals) to newer ones was one of the causal factors; as was some energy saving, after gas prices for industry were brought in line with import prices in 2006.

High gas prices in 2009–12 led to some switching to coal – although, since then, military conflict has disrupted coal production. Output fell from more than 80 mt/y (up to 2013) to less than 40 mt in 2015. Ukraine has been compelled to import small amounts of coal from South Africa.

The reduction of gas consumption and Russian imports is one of three deep-going changes in the Ukrainian energy sector. The others are the decline of gas transit, and regulatory reform.

'RUSSIA HAS AS LITTLE ENTHUSIASM FOR GAS TRANSIT THROUGH UKRAINE AS UKRAINE HAS FOR PURCHASING RUSSIAN GAS.'

Gas transit

Russia has as little enthusiasm for gas transit through Ukraine as Ukraine has for purchasing Russian gas. So Gazprom is pushing two transit diversification projects: the Turkish Stream pipeline, on which an intergovernmental agreement was signed in October in Istanbul, and the second phase of the Nord Stream pipeline via the Baltic Sea to Germany – which European political opposition could slow down, but probably not stop.

At some point after Russia's current gas transit contract with Ukraine expires in 2019 – but not before then – the Ukrainian corridor will likely be used only for residual volumes that cannot go by other routes. One possibility being mooted in Brussels is to remove regulatory obstructions to North Stream II in exchange for a Gazprom commitment to take a reduced but steady quantity of gas (20–30 bcm/y?) through Ukraine.

In any case, much of the pipeline system – which Naftogaz says has 302 bcm/y entry capacity and 178 bcm/y exit capacity, including 146 bcm/y towards Europe – will have to be decommissioned.

Regulatory reform

As for regulatory reform, a mass of EU-compatible market reform legislation has been passed, at the IMF's insistence, and in spite of sometimes stubborn parliamentary resistance. The passage through parliament of a law providing for a genuinely independent gas and electricity market regulator was the most recent success. (At the time of writing it was awaiting the president's signature.) Rationalization of oil and gas royalties has also sparked an increase in production by non-state companies; in a future of higher oil prices and political calm, the upstream could grow.

'THE LONG, TROUBLED RUSSIA–UKRAINE GAS MARRIAGE IS OVER, AND THE LAWYERS ARE ARGUING ABOUT WHO GETS WHAT …'

Russian gas and trading relationships

Whatever happens next, the long, troubled Russia–Ukraine gas marriage is over, and the lawyers are arguing about who gets what (literally, at the Stockholm arbitration court, where Naftogaz and Gazprom have made $67 billion worth of claims against each other for breaches of contract).

While European politicians tend to focus on courting Ukraine, the consequences for Russia are at least as important. Gazprom has lost its largest customer for gas exports – in the 1990s Ukraine imported 80 bcm/y, in 2006 it imported 54 bcm (compared with Germany's 34 bcm) ... and henceforth it may directly import nothing.

The breach with Ukraine is part of a larger picture of the former Soviet states loosening their ties with each other. In the gas sector, trading relationships have lasted longer, in part because of the gas supply system, a 1970s engineering marvel. But now the strongest bond, with Ukraine, is breaking; ties with the Baltic states have already broken.

Since completion of the Turkmenistan–China gas pipeline in 2007, Russia's link with Central Asia has also been fading: Turkmenistan's gas trade with Russia has ended (imports, many of which were transported to Ukraine in the 1990s, were zero this year) and the two sides are settling their differences in an arbitration court.

Ukraine's emerging energy system will be more efficient, and more diversified both by fuels and by trading partners. Russia's system will also be more efficient, as a result of market reform, and it too will diversify; international sales of oil will remain the key and, in gas, Russia's reduced trade with former Soviet countries will give way to an expanding Asian export business and, possibly, a renaissance in European sales in the 2020s.

The revived Turkish Stream: what, where, and when?

Katja Yafimava

Turkish Stream (an offshore Black Sea pipeline from Russia to western Turkey) reflects the desire of both the Russian government and Gazprom to develop a new route for delivering its gas to southern Europe and western Turkey, thus reducing Ukraine's transit monopoly over Russian gas exports to these regions (see map on the next page). As such, it is part of Gazprom's transit-diversification strategy, adopted in the late 1990s in response to the insecurity (non-payment, debt accumulation, and unauthorized offtakes) associated with transit across Ukraine and other post-Soviet countries.

Progress made by the project

Turkish Stream only made glacial progress during 2015, following its launch in December 2014. The parties – Russia and Turkey – failed to sign a promised intergovernmental agreement (IGA) and Turkey delayed the grant of several permits necessary for the project to proceed, while cancelling some others that had been granted. The slow progress is mostly explained by the failure of Gazprom and the Turkish state gas company, Botas, to resolve a number of key commercial issues including, most importantly, a request by Botas for a gas price discount. Indeed in October 2015 Botas even submitted the price discount issue to international arbitration. Furthermore, the project has also suffered delays due to the Turkish general elections in June and November 2015 and the subsequent government changes.

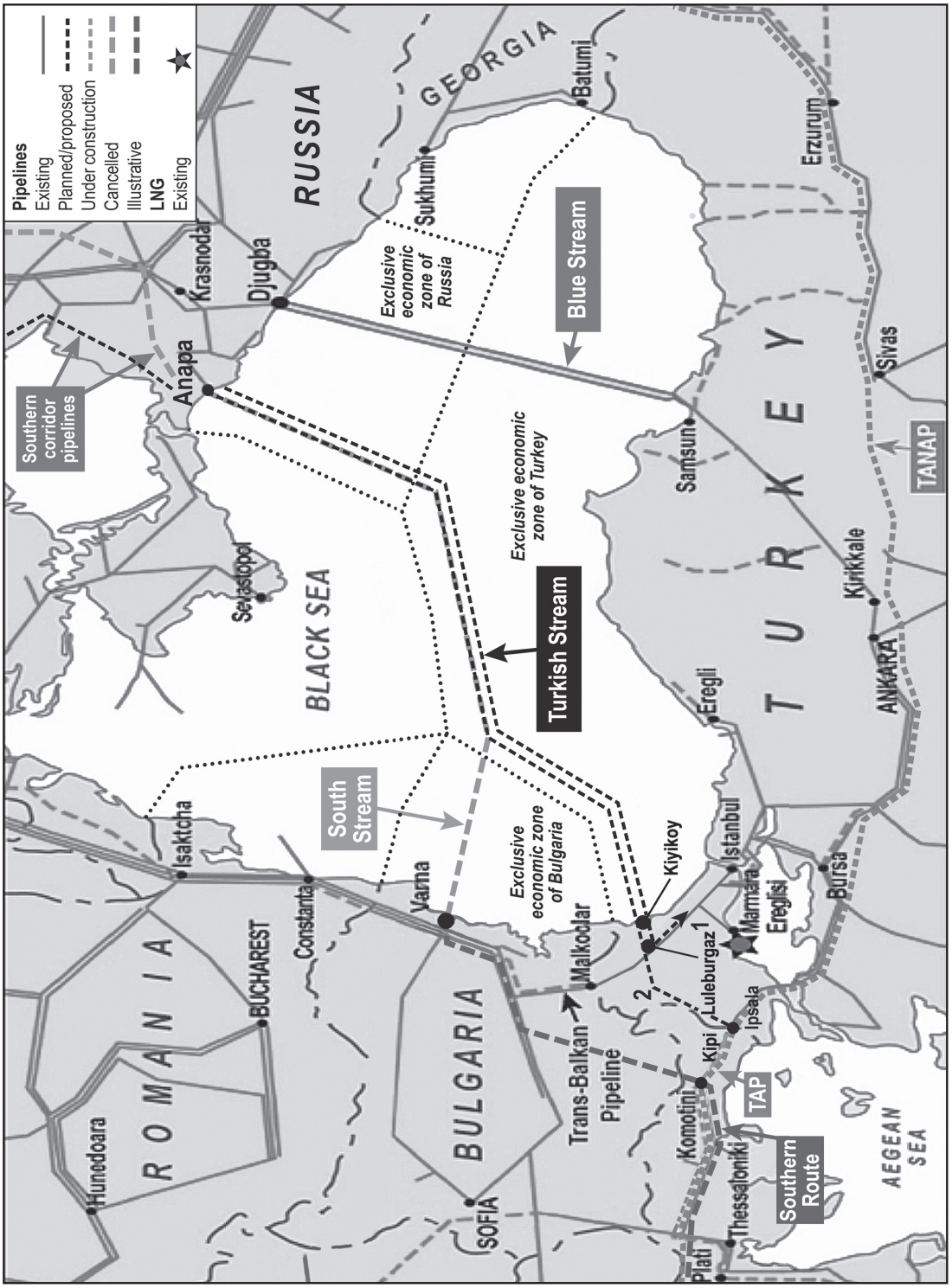
In November 2015 Turkish Stream disappeared from the headlines completely, when it was put on hold by Russia as part of its overall suspension of bilateral cooperation with Turkey (after the Turkish government had authorized the shooting down of a Russian military aircraft while it was on combat duty in Syria). No further progress on the pipeline was made until an apology was received from the Turkish president, but once this necessary (for Russia) condition had been fulfilled, the two countries' presidents finally met in August 2016, and it was decided to re-activate cooperation on a number of energy (and other) projects, including Turkish Stream.

The project has progressed smoothly since then. Several permits were (re) issued in September, including the first construction permit and the survey permit for the two strings of the offshore section of pipeline in the Turkish exclusive economic zone (EEZ) and territorial waters. The IGA was signed in October by the Russian and Turkish energy ministers, in the presence of Presidents Erdogan and Putin, and it is understood that it provides for the construction of two strings offshore and an onshore transit pipeline across the Turkish territory up to the EU border for supplies to the European market. Furthermore, it allows Gazprom not to build the second offshore string if the onshore transit pipeline is cancelled. To this end, the Russian president, Vladimir Putin, and the Russian foreign affairs minister, Sergey Lavrov, have both stated that the onshore transit section will only be built if the European Commission (EC) provides 'written guarantees' that the project can be implemented on European territory. Correspondingly, the IGA does not set the terms for the construction of the latter, deferring it to a separate protocol (which may or may not be signed). Thus Gazprom's minimum commitment under the IGA appears to be the construction of one string offshore, and the company is expected to build and own this entire offshore section while the onshore part, connecting the acceptance terminal with the Turkish transmission system (for supplies to the Turkish market), would be built and paid for by Botas. The onshore transit pipeline (for supplies to the European market) would be built by a (yet to be formed) Russian-Turkish joint venture.

It is worth noting that the signing of the IGA was not conditional on the resolution of the disagreement over a gas price discount between Gazprom and Botas, and indeed Gazprom and Botas have not yet fully resolved their dispute, although they have agreed on the price discount mechanism. This suggests that the project should proceed on schedule, and given the parties' agreement on a price discount mechanism, it is reasonable to expect an agreement on the size of a discount as well as subsequent termination of arbitration proceedings in the near future.

'TURKISH STREAM WOULD SEEM TO HAVE A GOOD CHANCE OF BEING IMPLEMENTED BY 2020.'

As a result, Turkish Stream would seem to have a good chance of being implemented by 2020, in particular because Gazprom is interested in increasing its direct supplies of gas to Turkey, which is one of its biggest, and fastest-growing, markets. On the other hand, Turkey appears keen to secure further access to Russian gas due to a lack of realistic alternatives (although it may be reluctant to increase its dependence on Russia too significantly) and it also has aspirations to make itself a gas hub in southern



Turkish Stream pipeline and the alternative 'Southern Route' pipeline

Europe. Gazprom and Russia are likely to be cautious about encouraging this ambition, and may also have concerns about Turkey becoming too large a transit route for Russian gas, but at present it seems that an adequate compromise has been reached.

Proposed route and size

However, the newly revived project will certainly be more modest than the original proposal (which envisaged the construction of four strings of 15.75 bcm each for a total capacity of 63 bcm). Only one string is likely to be built by 2020, thus allowing Gazprom to deliver all of its contracted supplies to the Turkish market without having to transit its gas across Ukraine, once the existing transit contract expires at the end of 2019. However, the outlook is more uncertain for the second string (for onward deliveries to Europe) as Gazprom's ability to transport gas further on through EU territory (for example, either via the TAP or IGI/Poseidon pipelines) would require a resolution of complex regulatory issues with the European Commission (EC). Furthermore, the second string of Turkish Stream has a potential 'competitor' in the form of Gazprom's alternative 'southern route' pipeline to Europe (see map) which would run across the Black Sea in parallel to the first string of Turkish Stream but land in Bulgaria rather than in Turkey (thus replicating the offshore route of the cancelled South Stream project). Notably, in February 2016 Gazprom signed a memorandum of understanding (MoU) with Greece's DEPA and Italy's Edison, on supplies of Russian gas to Greece and onwards to Italy across the Black Sea and (unspecified) 'third countries'. Geography suggests that Russian gas could arrive in Greece across the Black Sea either via Turkey or Bulgaria. The fact that the MoU did not specify a concrete country via which gas would be delivered to Greece, suggests that either the second string of Turkish Stream (via Turkey) or the 'southern route' (via Bulgaria) could be built.

'THE EU WANTS TO PRESERVE UKRAINE'S TRANSIT ROLE AND IS OPPOSED TO ANY PIPELINES THAT WOULD ENABLE GAZPROM TO REDUCE THAT ROLE.'

Issues of timing

The (changing) context of EU–Turkey and EU–Russia political relations will be important in determining whether and when either the second string of Turkish Stream or the 'southern route' pipeline will be built. In particular, the EU wants to preserve Ukraine's transit role and is therefore opposed to any pipelines that would enable Gazprom to reduce that role. Furthermore, the EU might not want to increase the transit role of Turkey (which would happen should the second string of Turkish Stream be built) beyond that which it will play in respect of Azeri gas supplies to Europe via TANAP/TAP. This is especially true given that the EU's regulatory power vis-à-vis Turkey is non-existent (as Turkey does not subscribe to the EU *acquis*) and its political power vis-à-vis Turkey is decreasing (in the aftermath of the failed coup). This thinking could increase the chances of Gazprom's 'southern route' – rather than the second string of Turkish Stream – being considered as part of the EU-led CESEC (Central and South Eastern Europe Gas Connectivity) initiative, aimed at improving gas security in central and south-east Europe. The EC's willingness to consider this option might depend on its assessment of security of transit across Ukraine post-2019.

In any event, it appears highly unlikely that either a second string of Turkish Stream or the 'southern route' will be built by 2020 (the same applies to Nord Stream 2 where delays beyond 2020 are likely after the abandonment of the joint venture between Gazprom and its European partners). This suggests that southern European countries will continue to depend fully on Ukrainian transit for their supplies of Russian gas post-2019, whereas Turkey will be able to escape it completely with one string of Turkish Stream to be built by 2020.

'SOUTHERN EUROPEAN COUNTRIES WILL CONTINUE TO DEPEND FULLY ON UKRAINIAN TRANSIT FOR THEIR SUPPLIES OF RUSSIAN GAS POST-2019 …'

Last but not least, the security environment in the Black Sea region is a major factor determining whether and when any of the aforementioned pipelines will be built. The rapidly changing fortunes of Turkish Stream demonstrate this with abundant clarity.

From Nord Stream 1 to Power of Siberia 1: a change in mind-set from Soviet planning to capitalist unknowns!

Thierry Bros

The old gold plated strategy failed to address new risks

Building an international pipe is the most difficult part of the gas chain as it has many requirements, not the least being a seller and a buyer willing to be linked on a long-term basis; intergovernmental agreements; project finance or significant free cash flow for the capital expenditure; high technological capability; and high security measures. This is why we have often seen much more pipe in PowerPoint presentations than laid in the ground (the Nabucco and Galsi lines being good examples). To address those issues, in the old days, Gazprom's strategy was first to contract with buyers on an oil indexed basis and then to build the required infrastructure using state-of-the-art technology, regardless of any other risks that could materialize later. Hence, it created a very resilient infrastructure that can meet peak demand. A few examples of this old mindset include:

'BUILDING AN INTERNATIONAL PIPE IS THE MOST DIFFICULT PART OF THE GAS CHAIN …'

- The building of Nord Stream 1 in 2010–2 without taking into consideration the EU third energy package that is now causing this pipe to be used at a maximum of 77 per cent of its full capacity;
- The development of the Bovanenkovo field and the construction of associated export pipelines after signing (in 2005–6) major European export contracts without taking into consideration the risk of a drop in gas demand in Europe that has subsequently led to renegotiations of those contracts;
- The starting of the construction of the South Stream pipeline across the Black Sea in 2012 without, again, taking into consideration the risk that the EU Commission could ask for third-party access, leading to the effective building of the now stranded Russkaya compressor station.

'GAZPROM HAS 150 BCM/Y OF SPARE PRODUCTION CAPACITY AND AROUND 100 BCM/Y OF SPARE TRANSPORTATION CAPACITY TOWARDS EUROPE.'

This gold plated strategy was acceptable in a world where gas demand was always growing and where Gazprom, the export monopoly for Russian piped gas, was rich enough to bear all the costs. In this old world, Gazprom was investing/paying and its customers were benefiting from secured supply. However, the result is that today Gazprom has 150 bcm/y of spare production capacity and around 100 bcm/y of spare transportation capacity towards Europe. In addition, Gazprom's problems have been exacerbated by its failure to acknowledge the potential challenge from US LNG exports, catalysed by the shale gas revolution, which has further added to an excess of gas supply available to Europe.

In our new world, where markets are providing short-term pricing, this gold-plated strategy is always loss making for the producer, who will never benefit from spikes in prices because he has constructed a continuous potential for oversupply. However, Gazprom has at least started to adapt to this new European situation by selling gas not only via traditional long-term contracts (with reduced oil indexation) but also via auctions, via Gazprom Marketing & Trading and via its 100 per cent owned European utility, Wingas (Wingas was founded in 1993 by Gazprom and the BASF subsidiary Wintershall; in 2015, Gazprom took over all Wintershall's shares and Wingas became a wholly owned Gazprom subsidiary).

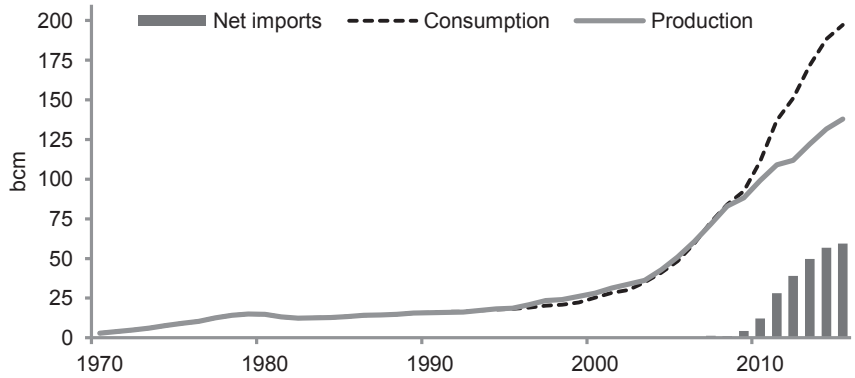
Finally, in a new Russian world, where competitors (Rosneft, Novatek) are lobbying to access spare export capacity, this old strategy is becoming riskier as competitors may be able to convince the State to amend Gazprom's export monopoly over pipeline gas, allowing them to use the spare capacity that Gazprom has itself constructed. It is becoming clear that Gazprom is now anticipating this problem; for example, the reduction in size of the Turkish Stream pipeline from four strings to two strings (halving the capacity to 31.5 bcm) shows that Gazprom is not willing to invest in spare capacity any longer. The first line will allow Russia to completely halt the 15 bcm/y of gas that currently transits Ukraine to Turkey, while the second line will meet growing Turkish gas demand and perhaps, in future, bring marginal extra volumes to Europe by linking to the Southern Gas Corridor. Gazprom's spending will be limited by reducing the size of Turkish Stream, and by using the pipe already delivered for South Stream and allowing the currently redundant Russkaya compression station to be put into operation.

The severe slowdown in Chinese imports reduces the need to fast track a full speed Power of Siberia

A similar realization that construction of excess pipeline capacity is no longer a viable strategy is also dawning in the east. Here, Gazprom's dominance started in 2002, when it was nominated as coordinator of Russia's Far East Gas Programme and selected as the single gas exporter. Government approval of this position was formally given on 15 June 2007, and in May 2014 Gazprom and CNPC signed a Sales and Purchase Agreement for gas to be supplied via the eastern route (Power of Siberia gas pipeline). The 30-year agreement provides for Russian gas deliveries to China at a peak rate of 38 bcm/y.

'CHINA SHOULD, IN THE NEXT 15 YEARS, OVERTAKE RUSSIA AS THE THIRD-BIGGEST GAS CONSUMER …'

This export project was catalysed by the fact that Chinese gas demand grew by an astonishing 15.1 per cent per annum in 2005–15 (although this growth has recently slowed, to +4.7 per cent in 2014/15). In the last 10 years, China has overtaken Mexico (in 2007), Saudi Arabia (in 2008), Canada and Japan (in 2010), Iran (in 2013), and is now the fourth-biggest gas consumer after the USA, the EU, and Russia. China should, in the next 15 years, overtake Russia as the third-biggest gas consumer, but its compound average annual growth rate (CAAGR) for demand is likely to stay close to the rate witnessed last year; the growth in China's gas imports is therefore also slowing, even though its domestic production growth has slowed (to 4.8 per cent in 2014/15). Since becoming a net importer in 2007, China's net imports have grown by 60.8 per cent per annum (2007–15), but in 2015 this figure was only 4.5 per cent. This implies that forecasts of future import requirements need to be revised down, with potentially significant implications for Russia and Gazprom (see the graph reproduced above).

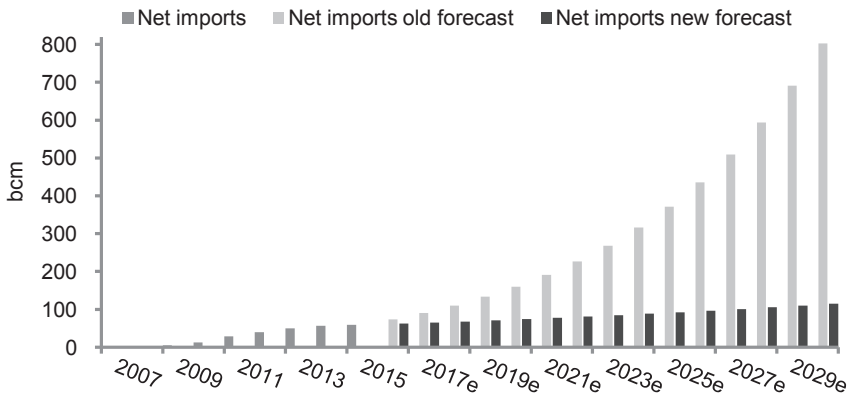


China: net imports are slowing down sharply…

Source: BP Statistical Review June 2016, thierrybros.com

Two future scenarios are shown in the second graph (below), and the difference between them is stark, especially when compared to the potential capacity of the Power of Siberia pipeline. In the high case, if we assume that the growth rate seen between 2007–15 was to continue for both consumption and production, Chinese net imports would increase by more than 38 bcm (the capacity of Power of Siberia) in only two years (between 2020e and 2022e). In contrast, if we assume that the new norm is what we witnessed in 2014/15, then a similar growth in Chinese net imports would take a decade (2020e–2030e). Unfortunately for Russia it would now seem that the more likely outcome is rather on the lower side than on the upper side of these forecasts.

As a result, it would seem that the risk for Gazprom is that a similar story to that seen in Europe could emerge, and the company could find itself having over-contracted to sell gas at high prices only to find that demand does not meet expectations and customers start to re-negotiate once pipeline capacity has already been built. If history repeats itself then the new norm in China could again lead to contract renegotiations and legal arbitration



… and should grow much more slowly in the future

Source: BP Statistical Review June 2016, thierrybros.com

'GAZPROM NEEDS TO BE WARY OF COMMITTING TOO EARLY TO MAJOR PIPELINE CONSTRUCTION THAT COULD CREATE MORE OVERCAPACITY.'

cases with the goal (for the buyer) being to achieve lower prices (and possibly volumes) in an oversupplied world. As a result, Gazprom needs to be wary of committing too early to major pipeline construction that could create more overcapacity.

Gazprom has learned and will be smarter going forward

However, unlike the situation in Europe, it would appear that Gazprom is learning its lesson. Anticipating lower Chinese gas import growth, Russia appears to be slowing its export ambitions. The 2954 km Power of Siberia 1 could be operational from 2019 (45 km were laid in 2015 and the 2016 target is 400 km), but it now seems that the ramp-up to full capacity will take more than the originally planned five years. Gazprom will put the eight compressors needed to achieve full capacity on line more slowly during the 2018–25 period in order to limit upfront capital spending and also to avoid creating spare capacity (otherwise Rosneft, its emerging competitor, could make a claim to use it to export its own gas to China). Moreover, the second potential pipeline to China, Power of Siberia 2 from West Siberia to western China, is now unlikely to be needed anytime soon and negotiations appear to have ceased. As a result, it would seem that, even if a price war takes place in Europe due to Gazprom's spare capacity and the emergence of US LNG, a similar situation appears less likely in China post 2020.

'THE OLD ASSUMPTION THAT GAZPROM WILL ALWAYS OVERINVEST IN TRANSPORT CAPACITY TO GUARANTEE SECURITY OF SUPPLY TO ITS EUROPEAN CLIENTS COULD ALSO PROVE WRONG …'

Furthermore, the old assumption that

'EUROPE WILL NOW ALSO HAVE TO SHARE THE BURDEN OF SECURITY OF TRANSPORT.'

Gazprom will always overinvest in transport capacity to guarantee security of supply to its European clients could also prove wrong in the future. Security of transport should not be borne only by the supplier. The good old days when European contractors were paid by Gazprom to lay pipes for the benefit of European consumers are over; Europe will now also have to share the burden of security of transport. The stress test will take place on 1 January 2020 as Russia has stated that it will not renew its transit contract via Ukraine that expires on 31 December 2019, leaving Europe short of Russian gas post 2020e unless a Nord Stream 2 solution is found soon. The EU Commission therefore has some interesting choices to make as it seeks to balance its political desire to diversify away from Russian gas with its commercial need to ensure security of gas supply for Europe.

Novatek leads the advance of Russian LNG

James Henderson

Russia's LNG industry is set to take a significant step forward in 2017, although this step will be made not by Gazprom but by one of its emerging competitors, Novatek. The Yamal LNG project is set to come on line by the end of the year, providing Russia's first new LNG output since the Sakhalin 2 project sent out its first cargo in 2009. Gazprom is also planning some progress next year, with a plan to take a final investment decision (FID) on the third train at Sakhalin 2 and, possibly, to also confirm the development of Baltic LNG in the west. However, the constant delays and postponements that have marked Gazprom's LNG strategy to date suggest that it is more likely that Novatek will become the leader of Russia's LNG strategy over the next decade.

'… LIKELY THAT NOVATEK WILL BECOME THE LEADER OF RUSSIA'S LNG STRATEGY OVER THE NEXT DECADE.'

Novatek's Yamal project

It is becoming increasingly apparent that Novatek's promise, which had been greeted with much scepticism in recent years, that the 16.5 million tonne (mt) Yamal LNG project would come online in 2017, is set to be fulfilled. Concerns over financing to cover the project's $27 billion cost, which were exacerbated by the inclusion of Novatek on the US sanctions list, were removed earlier in 2016 when Chinese banks finally confirmed that they would provide $12 billion of project finance. This was combined with offers from Russian banks and the Russian state to reach $20 billion of lending, with the

remaining $7 billion being provided by the shareholders. Indeed, with the shareholders now including CNPC and the Silk Road Fund, it was always likely that funds would ultimately be provided from China for this project, in stark contrast to the lack of financial support for Gazprom's projects in the east of Russia. In addition, 3 mt of LNG per annum has been contracted by CNPC, again underlining the Chinese interest in the project.

'THE FIRST TRAIN OF YAMAL LNG IS NOW VERY LIKELY TO BE OPERATIONAL BY THE END OF 2017 …'

Although the first train of Yamal LNG is now very likely to be operational by the end of 2017, the timing of trains 2 and 3 is slightly less certain, with the 2018 and 2019 start dates having the potential to slip depending on market conditions. Nevertheless, Novatek will still become Russia's largest LNG producer by the end of 2020 as Gazprom, which currently supplies 10.5 mt/y out of Sakhalin 2, has no new projects that could be on stream before 2021 at the earliest. This reflects not only the general struggle for all LNG developers to justify new projects when global gas prices are so low, but also the political and corporate problems which Gazprom faces as it seeks to respond to domestic and global gas market challenges.

The Sakhalin project

The expansion of the Sakhalin 2 project with a third 5.5 mt train would appear to be one of the most logical and commercially sensible new LNG projects in the global gas industry at present. A brownfield expansion close to the key markets of north-east Asia, the project should breakeven at a price of $6–7/MMBtu. Although this is higher than the current spot LNG price in Asia, it is much lower than many competing projects and should encourage both lenders and investors to proceed.

However, the key dilemma for Sakhalin 2 is accessing a secure source of supply, as both the obvious options have problems. Rosneft and ExxonMobil have excess gas potential at the Sakhalin 1 project, where 8 bcm/y is currently being reinjected to support oil production and where the development of the gas sections of the Chaivo field can provide even more output. This would be more than sufficient to supply a 5.5 mt train at Sakhalin 2, but the dispute over a fair price for the gas has been running now for a decade. The Sakhalin 1 partners originally planned to export the gas via pipe to China but were blocked by Gazprom, with its pipeline export monopoly, and since then neither side has found a way to agree on a transfer price for the gas to Sakhalin 2. Rosneft has even gone so far as to propose its own independent LNG project on Sakhalin (Far East LNG) and although the economics of this appear dubious, the concept is retained as bargaining leverage.

Meanwhile, Gazprom itself continues to pursue the development of its own gas resources in the Sakhalin 3 licence, where three fields have been discovered. Unfortunately, the largest of these, South Kirinskoye, has significant technical challenges and it has also been sanctioned by the US authorities, meaning that Gazprom's plans to develop in partnership with a foreign oil company (most likely Shell) have been put on hold. As a result, the company's commitment to take an FID in 2017 is at risk due to domestic and international politics, as well as the operational difficulties faced by Gazprom.

Baltic LNG

At the same time a promise to develop the Baltic LNG project – a possible 5–10 mt scheme aimed at markets in the west – by 2021 may also be difficult to keep. Meeting this target would also require an FID in 2017, but it remains unclear why such a large project close to the European market would be needed when Gazprom already has an excess of gas to export via pipeline. Potential access to new markets in South America and the Middle East could be one response, but with the global gas market being oversupplied at present it seems very possible that Baltic LNG could also be deferred, especially as its main international supporter (again Shell) has a large number of other LNG options following its recent acquisition of BG Group.

Gazprom's dilemma

Delays in both these projects, when added to the postponement (or cancellation) of the Shtokman and Vladivostok LNG schemes, leave Gazprom's plans to become a major force in the global LNG business looking very unfulfilled. Furthermore, the Russian government will be disappointed that the country's position as a global energy superpower is being undermined by Gazprom's relative failure.

This may well explain why the Kremlin has been keen to support alternative projects, with Yamal LNG at the forefront. Not only does Novatek appear to be a more efficient and motivated company, but its project is located in a strategically important area (the Arctic) and can help with the economic development of one of Russia's poorest regions (the Far North). When combined with the benefit of close personal relations

'… THE COUNTRY'S POSITION AS A GLOBAL ENERGY SUPERPOWER IS BEING UNDERMINED BY GAZPROM'S RELATIVE FAILURE.'

between Novatek's owners and the Kremlin, it is perhaps not surprising that financial and fiscal support, as well as infrastructure development, has been provided. When this help is added to the natural advantages which the Yamal LNG project enjoys (very low upstream costs and low LNG operating costs due to the low temperatures in the region), the breakeven price of the project can be very competitive despite the remote geographical location. On a full cost basis, the project can breakeven at $7–8/MMBtu in Europe, while on a cash basis this falls to below $4/MMBtu.

Arctic LNG and risks relating to imported technical equipment

So confident is Novatek becoming in the positive outlook for Yamal LNG that it is already talking confidently about a second project nearby. Arctic LNG would be located on the Gydan peninsula opposite Yamal, and the source of gas would be fields already discovered there which are similar in nature to the South Tambey field which is the foundation of the Yamal project.

'… ONE OF THE KEY RISKS FOR ALL RUSSIAN LNG SCHEMES … THE MAJORITY OF THE MOST IMPORTANT TECHNICAL EQUIPMENT NEEDS TO BE IMPORTED.'

One significant difference with this new project, though, would be that it would aim to address one of the key risks for all Russian LNG schemes, namely that the majority of the most important technical equipment needs to be imported. Indeed, it is interesting to note that much of the key liquefaction equipment for Yamal LNG has been provided by US companies, in particular by Air Products, and this has been a major source of potential risk. To date LNG equipment has not been included in the list of technical parts that cannot be supplied under US or EU sanctions, but worries that it might be in future have inspired a drive by the Russian authorities to encourage domestic manufacturing of the key elements of the LNG chain. The vast bulk of the equipment for the Yamal LNG project has been floated in from the USA or Asia on huge barges, but plans for a manufacturing centre in Murmansk are now starting to emerge, with Novatek at their heart. The company's Arctic LNG project is currently planned to be based on gravity-based platforms that would be manufactured in Russia, and the hope is that indigenously produced liquefaction equipment will also be available. If a Novatek-led project can help to achieve this goal ahead of any new Gazprom scheme moving forward with a similar strategy, then Novatek could indeed become Russia's undisputed LNG leader.

Russian power sector approaching the next investment 'wave' but power companies are still mulling the key decisions

Fedor Veselov, Andrey Solyanik, and Irina Erokhina

Domestic and export demand

The Russian electricity sector is one of the largest in the world with an installed capacity in 2015 of 243 GW and production of 1048 TWh of electricity within the centralized (on grid) area of energy supply. Furthermore, even though there is technical integration with the power systems of neighbouring CIS countries, the Russian system is mostly focused in the domestic market, with export volumes not exceeding 10–15 TWh. In addition to these CIS exports, supply is provided to Finland and the Baltic states (totalling near 7 GW in 2015), while in the East, electricity exports to China are increasing and reached 3.3 TWh in 2015. Overall, though, total exports account for less than 2 per cent of electricity generation in Russia.

'THE RUSSIAN ELECTRICITY SECTOR IS ONE OF THE LARGEST IN THE WORLD WITH AN INSTALLED CAPACITY IN 2015 OF 243 GW.'

While domestic demand is on the rise, it has still not recovered to its level in 1990 – after the economic crises in 2008–9 and 2014–15 slowed growth rates. In the last year, electricity demand within the main grid areas was close to 1036 TWh, while an additional 25 TWh was produced and consumed as self-generation. Over the longer term, demand growth is expected to be in the range of 1.3–1.5 per cent per year, meaning that by 2035 electricity consumption will have increased by 30–35 per cent, whereas GDP is expected to grow by up to 45–75 per cent. This gap reflects the energy efficiency improvements that are expected in the Russian economy due to a structural shift towards less energy intensive industries, as well as upgrading of the power system.

Power plants and investment plans

Most of the generating capacity in Russia consists of thermal plants (165 GW, or 67 per cent of the total capacity, in 2015), and 55 per cent of these thermal plants are combined heat and power (CHP) units that also produce heat for the country's extensive centralized heating system. The non-fossil fuel generation capacity is mainly made up of hydro (51 GW, or 21 per cent) and nuclear (27 GW, or 12 per cent) plants. Non-hydro renewable sources are currently very limited, with less than 800 MW of capacity (although some biomass plants are accounted for as thermal generation). In terms of fuel inputs, gas is the dominant fuel for electricity production (its share of total fuel consumption in the power sector already exceeds 70 per cent); most gas-fired plants are located in European Russia, along with most of the nuclear plants. In contrast, electricity in the eastern regions is mainly generated from hydro and coal-fired plants.

'… ONE OF THE MAIN PROBLEMS IN THE SECTOR IS THE DETERIORATING QUALITY OF MANY OF THE GENERATING ASSETS.'

However, one of the main problems in the sector is the deteriorating quality of many of the generating assets. The average age of thermal plants in Russia is 32 years (the age of coal plants is even higher at 37 years); in addition, most of the existing thermal power plants use steam cycle for generation with low efficiency (an average of 38 per cent overall and only 34 per cent for coal-fired plants). The transmission and distribution system is also rather old and as a result electricity losses are high (10 per cent in 2015), while the country's heat supply system has also become less efficient, with an average life in excess of 25 years and heat losses generally around 30 per cent.

This situation has led the Russian government to launch a number of investment initiatives over the last five to seven years.

- The first initiative is aimed at the commissioning of 26 GW of modern thermal capacity (mostly CCGT and CHP) under Capacity Supply Agreements (CSA). These special investment contracts encourage energy companies to build new power units in return for a 15-year capacity tariff based on an estimate of each company's regulatory asset base (such a tariff is known as an RAB-based tariff).
- The second is focused on support for the nuclear sector given its crucial role for energy security and low-carbon development. Currently five nuclear units are under construction and approximately 13 GW of nuclear capacity are set to be commissioned in the next two decades. In part, these new units will replace existing units that will be retired, but they will also increase the overall installed nuclear capacity to 35–37 GW.
- The third initiative is related to the development of renewable sources, again using capacity supply agreements to encourage the development of wind and solar plants. Initially support is being provided for 5.8 GW of new renewable plants, but it is planned that by 2035 total renewable generation will rise to 30–45 TWh (2–3 per cent of total electricity production), compared with 2 TWh at present.

Reform of the power market

Until the mid-2000s the Russian power market functioned as a set of regional vertically integrated energy supply companies and large power plants acting as subsidiaries of the nationwide, state-controlled power company United Energy Systems (RAO UES). Then a series of reforms, initiated 10 years ago, aimed at improving both the operational efficiency and the investment attractiveness of the sector.

A transition to a competitive electricity market, as opposed to state-controlled tariff regulation, was considered to be the main tool to improve operational efficiency. A spot (day-ahead) electricity market with hourly nodal pricing was launched in 2007, and was fully liberalized in 2011 (except for regulated supplies to households, which account for 15 per cent of demand). The spot market is supplemented by a balancing market, and has become very responsive both to variations in power demand as well as fuel input prices. For example, spot prices in north-west Russia grew rapidly until 2012 in response to the sharp increase in gas prices over the same period, until parity was reached with prices in Finland, at which point electricity export volumes fell from 10 to 4 TWh. Since 2014, however, as demand and gas prices have stabilized, spot electricity prices have also become much less volatile. In 2015 spot prices were 1100 and 870 RUR/MWh in European Russia (the 1st price zone) and Siberia (2nd price zone) respectively, with the price gap mainly being driven by the difference in marginal fuel costs between gas (in the 1st price zone) and coal (in the 2nd price zone) plants.

'THE ESTABLISHMENT OF A COMPETITIVE MARKET WAS FOLLOWED BY THE LARGE-SCALE RESTRUCTURING AND PRIVATIZATION OF THE POWER SECTOR.'

The establishment of a competitive market was followed by the large-scale restructuring and privatization of the power sector. The government retained

'… DESPITE THE PRIVATIZATION INITIATIVE, THE RUSSIAN GOVERNMENT STILL REMAINS THE LARGEST OWNER …'

control of the grid companies and the System Operator, as well as the hydro and nuclear plants, while the thermal generating assets were transferred to new owners, both Russian and foreign (including Enel, E.On, and Fortum). However, consolidation since the initial sales has meant that 30 per cent of thermal capacity is now once again concentrated in state-controlled companies, while the state-controlled gas company, Gazprom, also controls a further 20 per cent of thermal plants. As a result, despite the privatization initiative, the Russian Government still remains the largest owner in the restructured power sector.

Alongside the privatization process, which provided the first wave of new investment, the government reforms also included the introduction of mechanisms to support long-term investment via RAB-based regulation of transmission and distribution services, as well as capacity payments for generation, both of which are outlined below.

Capacity payments

Capacity payments currently form almost 30 per cent of the total revenues for suppliers in the wholesale market, but these payments have a complex structure.

- Firstly, special regulated prices are applied to 15–20 per cent of capacity in order to ensure the supplies of households and other preferred consumers.
- Secondly, a competitive zonal capacity market (KOM) was launched in 2010 as a year-ahead market with strong price cap regulation. It was developed to compensate in part the fixed operating and maintenance costs of generators and was applied to all existing capacity, as new capacity has its own special remuneration (described later). In 2015 generators obtained nearly RUR150 billion, or 35 per cent of total capacity payments, from this KOM, and even some capacity which did not qualify for the KOM payments also received guaranteed remuneration at regulated tariffs, because it was defined as 'system-required' or 'must-run' generation.
- Thirdly, as mentioned above, almost all new projects are now developed under the Capacity Supply Agreement regulations. The Government is therefore obliged to accept all the relevant capacity into the supply balance and to pay it the RAB-based capacity price (adjusted for the spot margin). The volume of this remuneration has increased by a factor of five in the last five years and in 2015 it reached RUR170 billion, accounting for 40 per cent of total capacity payments (in other words, exceeding the payments from KOM).

The main problem with this complex capacity payment system is that it has led to a significant oversupply of generation capacity due to the slow demand growth that has resulted from the weakness in the Russian economy. The regulated tariff-based compensation mechanism (CSA) was focused on capacity additions, but the competitive year-ahead capacity market did not provide an adequate mechanism to encourage the phasing out of existing old and inefficient plants. As a result, between 2008 and 2014 the maximum load increased by 5.5 GW (+3.7 per cent), while the installed capacity increased by almost 22 GW (+10.4 per cent). Indeed, the actual capacity surplus (over the reserve margin) in the market is estimated to be almost 25 GW (or 15 per cent of the total capacity requirement) and it is unlikely to decrease significantly in the next five years.

However, as of 2016 the zonal capacity market has been modified to encourage generators to decommission inefficient capacity. They can either bid lower capacity four years ahead at a higher cap price or retain existing capacity but at the lower (–25 per cent) price. Initial experience has shown that this approach has worked to an extent, as some generators have decided to close several units. However, this pricing model does not solve the more strategic problem of the need to find appropriate price signals to encourage investment in the modernization of existing capacities. Therefore, the development of a new capacity market mechanism to encourage investment activity by replacing the administratively driven CSA contracts is still on the agenda, and further action is also required to introduce demand response mechanisms in the capacity market.

Prices for electricity and pricing policy

The development of new market models, investment incentives, and efficient regulation measures are also closely related to the more general priority of pricing policy in the power sector. During the period when new (both competitive and tariff) pricing mechanisms were being introduced (up to 2011–12) prices rose rapidly, although slightly more slowly than gas prices. However, over the past four years, prices have become more stable, with the average retail price in 2015 being 3460 RUR/MWh, while the level in European Russia was 5 per cent higher than this and in Siberia 20 per cent

'OVERSUPPLY AND EFFICIENCY IMPROVEMENTS IN GENERATION WERE NOT TRANSLATED INTO PRICE EFFECTS …'

Actual wholesale and retail prices in Russia, 2015 (RUR/MWh)

	European Russia			Siberia		
	January	June	December	January	June	December
Spot price	1000	1130	1080	920	700	860
Wholesale price (spot+capacity payments)	1400	1525	1553	1233	1117	1296
Retail price	3390	3420	3730	2550	2490	2780

Source: Market Council database

lower, due to relative fuel input costs. The implied average wholesale price (spot plus capacity payments) in 2015 ranged between 1550 RUR/MWh in European Russia and 1250 in Siberia. For the future, the government is currently assuming that real growth in prices will not exceed 1–2 per cent in the period out to 2035, mainly due to a desire to restrain inflation as part of the country's macroeconomic policy.

The approach of a new investment 'wave'

The recent results of market reform can be deemed successful from an investment perspective, as they have stimulated activity. However, many decisions were driven by administrative action rather than market activity, so they did not reflect the fundamental change in electricity demand growth rates. This has led to overcapacity in the system, an excessive price burden on consumers, and dangerous levels of debt in many energy companies. Furthermore, oversupply and efficiency improvements in generation were not translated into price effects because of the steady growth in capacity payments.

Nevertheless, the overcapacity does provide a unique opportunity to improve competition in the capacity market and to start the next investment 'wave'. In contrast with the first one, this will be focused on the substitution of old and existing plants (in other words, it will not involve any net capacity input). Indeed, over 120 GW of existing thermal plants must be retired and rehabilitated due to their age, but these decisions are currently being postponed due to current market conditions

Details of future changes in capacity prices and payments that would provide a stimulus for the required large-scale renovations are still being discussed, but should be approved in the near future. One conceptual idea suggested by the authors is that new capacity pricing rules may be complemented by a mechanism of 'renovation certificates' (similar to the 'green certificates' in the EU) to create additional market drivers for the investment decisions that are needed.

'… PLANNED CHANGES IN THE MARKET WILL ENCOURAGE THE DECOMMISSIONING OF UP TO 7–10 GW PER YEAR TO 2020, WITH SOME SUBSTITUTION BY NEW UNITS.'

It is anticipated that planned changes in the market will encourage the decommissioning of up to 7–10 GW per year after 2020, with some substitution by new units. This trend, coupled with moderate growth in system capacity requirements, will result in a reduction of the capacity surplus from around 25 GW in 2020 to 5 GW or lower in 2025 and to zero by 2030. At that point a third investment 'wave', beyond 2030, will be directed once more towards the development of new capacity.

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