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The Future of Russian Oil Production in the Short, Medium, and Long Term

Introduction

This paper has two major goals. The first is to update reports published by the Oxford Institute for Energy Studies in April 2015 and February 2017 which both assessed the short-term outlook for Russian oil production in the light of sanctions and the first OPEC+ agreement which committed Russia to a production cut of 300,000 bpd from January 2017. Both these papers argued that, despite the impact of sanctions on the financing of the Russian oil sector and the availability of international technology in some spheres (most specifically offshore, the Arctic, and shale oil), the immediate impact on Russian oil production would be low due to the number of new projects already under development or close to production.

Indeed, it was already clear in February 2017 that the main constraint on Russian oil output in the short-term would be the low oil price and the resulting cooperation between OPEC and non-OPEC producers to constrain production in order to reduce the oversupply of oil in the global market. As will be discussed below, the initial plan for a six-month production cut by the OPEC+ group was ultimately extended to 18 months, and then after only a six-month period of increased output a new agreement was put into place at the start of 2019. As a result, the full potential of Russian production has yet to be proven, with the Russian oil companies remaining frustrated at the necessity of holding back new fields and restraining production at many existing assets.

However, questions about the future of Russian oil production now extend beyond the short-term. It is now widely accepted, and this paper will assert once more, that Russian oil output is not about to fall and indeed should rise for at least two to three years following the end of any OPEC+ agreement. A more fundamental question is what will happen beyond the early 2020s, when the current pipeline of greenfield projects will be exhausted and new fields will be needed. Will the impact of sanctions then be felt more keenly, or will the Russian oil industry be able to find both new opportunities in the heartlands of West Siberia and also to develop new areas such as East Siberia (where production is already growing), the continental shelf and various forms of "hard-to-recover" oil without the support of many of the international oil majors?

This paper will first analyse the history of production since 2016 and will then look at the short-term outlook for the period to 2025 from existing assets and known new fields. It will then assess the potential of a number of new areas for production growth, namely enhanced production from existing assets using secondary and tertiary recovery techniques; opportunities in new regions of Russia outside the heartlands of West Siberia and European Russia; the upside from hard-to-recover oil, including shale, tight oil, and heavy oil deposits; the potential for increased output from Russia's offshore areas; and the development of the huge resources in the Russian Arctic. We will also consider the possible changes in the tax regime that might encourage development in all these areas, before providing conclusions on the likely drivers of Russian oil production through the next decade and beyond.

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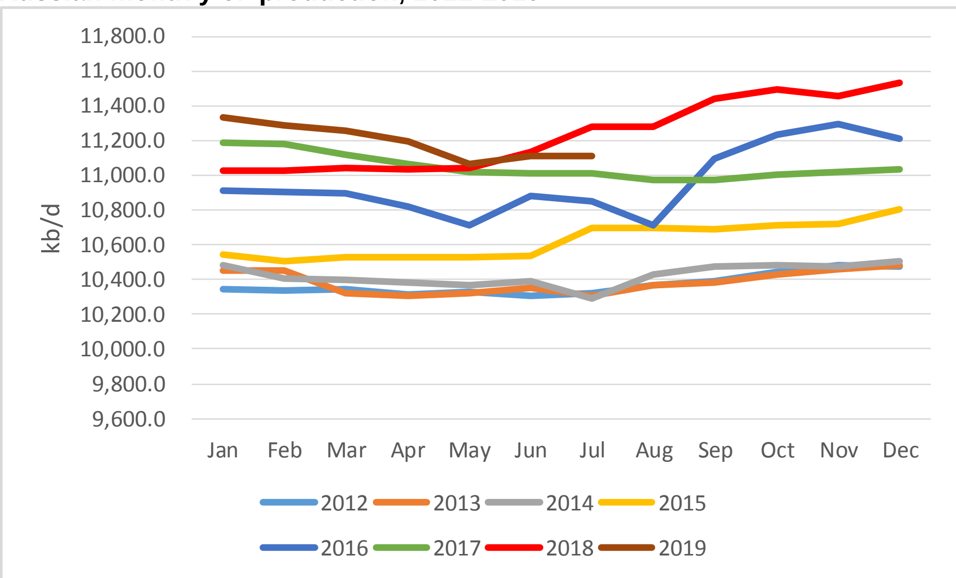
It should be noted that the production forecasts in this report are assessed in two ways – one using company data to provide the basis for future analysis and one using a bottom-up regional approach. This allows the authors to cross-check their analysis and provide a greater level of confidence that the production outlook is achievable both from a resource and a corporate strategic perspective.

A review of recent history

Figure 1 shows monthly Russian oil production since 2012 and underlines the significant growth that occurred over that period, especially between 2014 and the end of 2016. Indeed, the jump in output in the second half of 2016 is very pronounced and occurred at a time when Russia was in negotiation with OPEC over the possibility of joining its production cuts. At the time there was a high level of cynicism about the sustainability of production above 11.2 mb/d, with many believing that it had been artificially inflated to create a higher base for any future cut. The trajectory of the graph towards a peak in Q4 2016 and the fact that October production from that year was used as the basis for the subsequent production cut certainly suggest that there was some truth in this. However, the levels then achieved in the second half of 2018, when the restraint was temporarily halted, also confirm that the new higher level was not a one-off.

Figure 1: Russian monthly oil production, 2012-2019



Source: Argus Media, Authors' Analysis

A look at Russian oil company output over the past three years provides some more details behind these trends. It should be noted that the figures are for the companies' core subsidiaries, and therefore may not reflect the total numbers published by the companies themselves. For example, Rosneft also owns Bashneft and 50 per cent of Slavneft as well as having an interest in other jointly owned ventures, meaning that its overall net output was closer to 4.7 mb/d than the 3.9 mb/d shown below. Nevertheless, the key trends are clear, as the majority of companies maintained or reduced production in 2017 before increasing it somewhat in 2018 once the artificial limits imposed by the OPEC+ agreement had been lifted in the second half of the year. Note that the total figure for 2017 does not reflect the full OPEC+ reduction because the cuts were introduced slowly over the first half of the year.

Rosneft, which now accounts for over 40 per cent of total output when all its interests are included, epitomised the situation, with the company dialling back output at some of its key subsidiaries while also delaying some new developments in order to keep within its production targets. The company CEO, Igor Sechin, was a vocal opponent of compliance with the OPEC+ agreement, but nevertheless it is clear that his company did make a significant effort in 2017 to keep production well below the company's potential before increasing output in 2018. Other major companies such as Lukoil and

Surgutneftegas followed the same pattern, although neither had the portfolio of new projects to increase output in 2018. There were, however, a couple of notable exceptions. GazpromNeft had consistently complained about being restricted by the production constraints just as a number of its new fields were coming onstream, with the Prirazlomnoye and Novy Port assets being the prime examples, and it is clear from the table below that it did continue to increase output despite the generally flat average trend in the industry as a whole. Tatneft also saw production rise, albeit marginally, as it continued to focus on its brownfield redevelopment strategy and argued that any reduction in production from its older fields would be difficult to recover.

Table 1: Russian oil production by company (2016-2018)

	2016	2017	2018
Rosneft	3799	3778	3866
LUKOIL	1662	1637	1642
SurgutNG	1239	1213	1219
GazpromNeft	757	791	797
Tatneft	575	580	585
Slavneft	300	286	275
Bashneft	428	413	381
Russneft	140	140	142
Gazprom	348	356	392
Novatek	161	194	324
Other	1556	1562	1645
Russia Total	**10965**	**10951**	**11268**

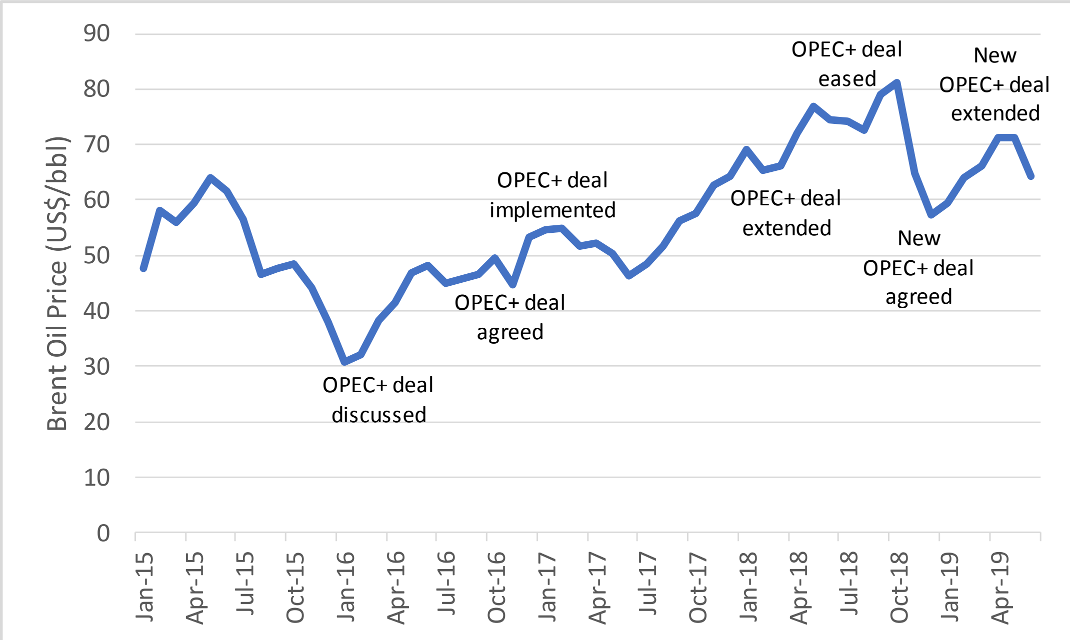
Source: Argus Data

The OPEC+ Agreement and its impact on Russian production

In our 2017 paper we identified that projects already in the pipeline, combined with efforts to slow the natural decline of brownfields, could push oil production from an average of below 11 mb/d in 2016 to around 11.5 mb/d by 2020 before going into gradual decline towards 2025. However, even as that paper was being published, the impact of the first OPEC+ agreement between OPEC and non-OPEC producers was starting to take effect. Figure 2 below shows the timing of the various agreements between the key producing nations over the past two and a half years, and it is clear that the threat of low oil prices has caused a significant change in strategy in Russia. Having promoted the goal of production growth between 2014 and 2016, the Russian authorities have now combined the goals of managing the oil price with the more political objective of increasing the country's influence in the Middle East to produce a strategy of cooperation with OPEC and Saudi Arabia in particular.

As is clear from Figure 2, the first serious negotiations concerning cooperation with OPEC took place in early 2016, when the oil price was heading towards a low of $30 per barrel. This was unacceptable for Russia, whose federal budget only broke even at $40-50 per barrel, and was especially worrying for many Middle Eastern countries where, despite low production costs, social and budgetary requirements necessitated an oil price of $80 per barrel or more. Although initial negotiations broke down in April 2016 over the proportional allocation of production cuts, agreement was finally reached in December of the same year for an overall reduction of 1.5 mb/d, with Russia contributing 300,000 bpd of this, using its October 2016 output as the base. As can be seen, the implementation of the deal occurred in January 2017, and although the initial market reaction was negative, the cuts were ultimately effective in reducing high global stock levels and bringing the supply-demand situation back into balance, leading to an increase in the oil price towards a $60-70 per barrel range by the end of the year. Concern that a rapid ending of the agreement could lead to an immediate reversal of oil prices led the cartel to extend its restraint into 2018, with the OPEC+ group ultimately concluding that the end date should be June 2018. By this point the oil price had reached $80 per barrel.

Figure 2: The Brent oil price and the OPEC+ negotiations



Source: EIA and Authors' additions

However, a combination of events then combined to push the oil price lower again. Initially the return of OPEC+ oil to the market in H2 2018 seemed to be well timed, as the re-imposition of sanctions on Iran was set to reduce exports from that country. Unexpectedly, though, the US issued a number of waivers to purchasers of Iranian crude which allowed oil to flow more freely than expected, and when this volume was added to recoveries in Libyan and Nigerian production and a renewed surge in US shale oil output, the market again became unbalanced. Oversupply of crude and rising stock levels led the oil price to fall below $60 per barrel once more, resulting in a second OPEC+ agreement being reached in December 2018 designed to take 1.2 mb/d off the market, with Russia this time contributing 228,000 bpd from a level based on its output in October 2018 (when it produced just under 11.5 mb/d). This agreement was then extended in June 2019, and will last for a further 6-9 months, in other words until the end of Q1 2020.

Figure 3 below shows how Russian production has compared to the levels agreed with OPEC over the past two and a half years. The initial agreement had a gradual implementation period, with the full 300,000 bpd only being reached in May 2017, but as the graph shows Russian companies did achieve a high level of compliance with the agreed deal during 2017. As often happens with agreements on output constraint, compliance started to weaken somewhat as the deal extended into 2018, but nevertheless the Russian cut was never less than 200,000 bpd.[1] The only exception to this was in June 2018, when it was clear that the agreement was coming to an end and Russian oil companies had already begun to ramp up their output as a result.

The second OPEC+ deal came into force in January 2019 and was again implemented on a gradual basis. The full 228,000 bpd cut was reached in April, and production in May, June and July has been below the target level. This is not particularly surprising as Russian production does tend to be at its lowest level in the second quarter due to weather-related and maintenance issues. In addition, limited

[1] The calculation of Russian compliance is somewhat complicated by the conversion factor from tonnes of oil (which the Russian authorities report) to barrels per day (in which the production cut was agreed). For the purposes of this analysis we have used an industry standard conversion factor of 7.3 barrels per tonne. If a higher figure is used, then the production cut can look larger in barrel terms. The Russian authorities appear to have used a larger conversion factor in some instances to argue for greater compliance with the production cuts, basing their analysis on a more specific understanding of the quality of the oil being produced across the country.

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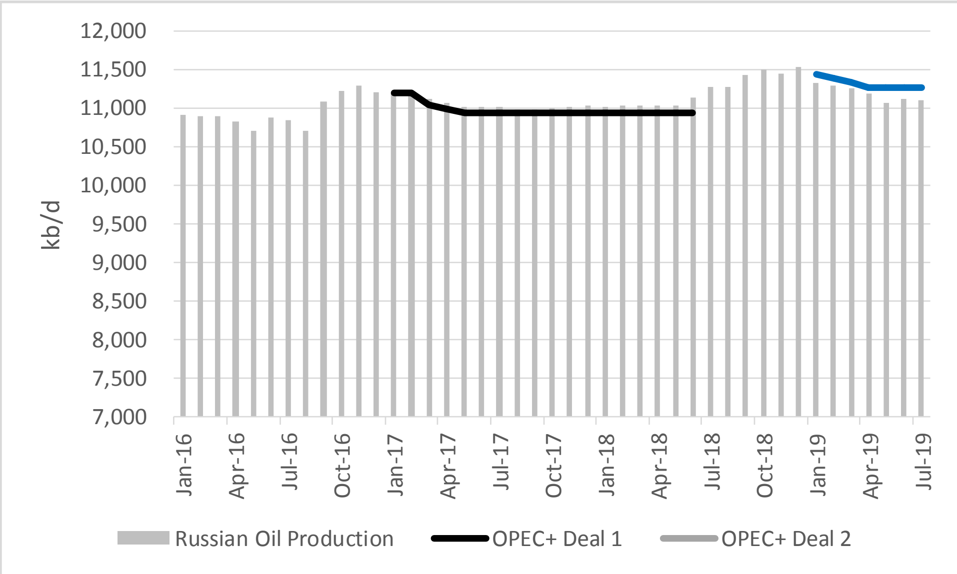
availability of pipeline capacity forced companies to reduce production (due to a contamination incident in the Druzhba export pipeline). As a result, the true test of compliance with the second deal will come in the remaining months of 2019, although as President Putin has recently reiterated his personal support for an extension of the deal into 2020, it would be surprising if there was a significant change in output in the short term.

Figure 3: Russian compliance with OPEC+ agreements



Source: Argus Data and Authors' Additions

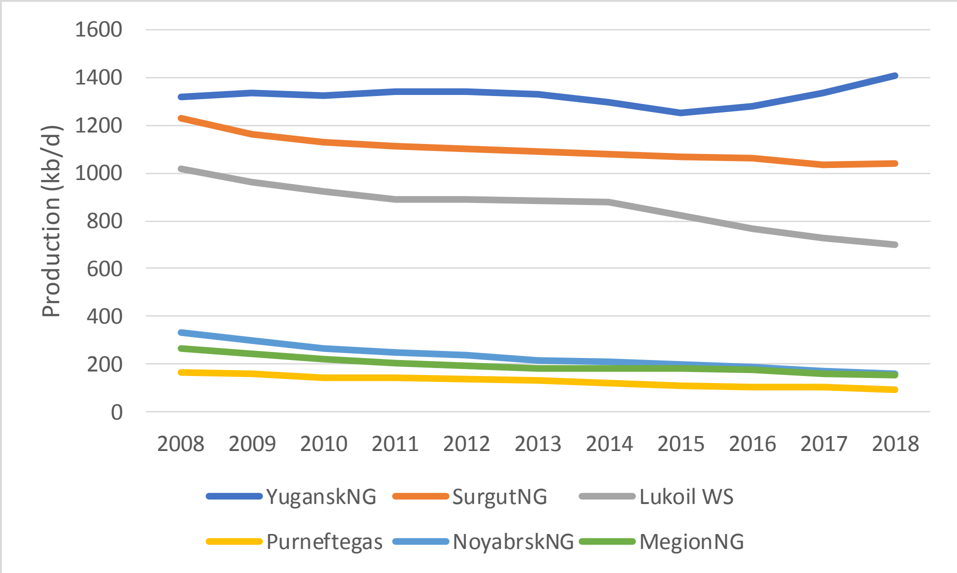
The short-term production outlook

As a result, there seem to be few, if any questions about the very short-term production outlook. The current OPEC+ deal sees Russian output at approximately 11.25 mb/d for the remainder of this year and potentially for the first quarter of 2020 (if the deal is extended to its full nine month potential) and it would be a surprise, given recent compliance by Russian companies, if this was not close to the actual outcome.

The more interesting issue, therefore, is what could happen after the deal ends and for the sake of argument, we will assume that this will occur in 2020. Russia production will then be driven by a combination of brownfield management (optimising the decline of existing assets) and new (greenfield) developments.

The Russian oil industry has been very successful at managing the natural decline of existing fields using increasingly complex recovery techniques, and the further opportunities to exploit these skills will be discussed in more detail below. However, the success to date can be seen in the performance of six of the country's largest production companies, all of which are subsidiaries of the Russian oil majors. Yuganskneftegas, Purneftegas (both Rosneft), Surgutneftegas, Lukoil West Siberia, Noyabrskneftegas (GazpromNeft) and Megionneftegas have demonstrated a combined average rate of decline of 2 per cent per annum over the past decade, compared to a natural decline rate for fields in West Siberia of around 10-15 per cent per annum. It is clear that improved reservoir management techniques have been having an impact: a particularly good example is Lukoil which has managed to decelerate production decline at its West Siberia subsidiary by increasing the number of horizontal wells that it is drilling and optimising their efficiency by design enhancement. The company has also started to use wells with a smaller diameter in order to lower costs and further optimise performance. In our production forecast to 2025 we have assumed that progress such as this will continue and that the overall decline in Russian production can be held to similar rates as in the past decade.

Figure 4: Production from six major production companies in Russia (2008-2018)



Source: Argus Media

As far as new developments are concerned, these are a combination of new fields that have recently been brought onstream and are still in growth mode (we include anything that has started production since 2014 in the analysis below) and brand new assets that are set to begin production in the next few years. Since our last paper in 2017, several assets have commenced production and most of the major companies now have significant developments underway. For example, Rosneft has been very active in the East of Russia, bringing Stage 2 of the Sredne Botuobinskoye field online at the end of 2018, with peak output of 100,000 bpd expected by 2021. In addition, the Kuyumba field will also be reaching peak production of 60,000 bpd at the same time, while in West Siberia the Tagul field is one of numerous smaller fields close to the Vankor cluster that will be compensating for the decline in that major field. Tagul came online in 2018 and will reach a peak of 90,000 bpd in the early 2020s. Rosneft has brought Russkoye, a new "hard-to-recover" oilfield online, again in West Siberia, where an extensive drilling programme over the next few years should see production reach 130,000 bpd by the mid-2020s.[2]

Lukoil is also focussing on "hard-to-recover" reserves, which receive significant tax breaks, and expects production from its Yaregskoye and Usinskoye fields to ramp up over the next few years, driven largely by steam injection technology. The company also has a major offshore focus in the Caspian, where the existing Filanovsky and Yuri Korchagin fields are increasing output as new stages of their development are brought online. In addition, a new field, Rakushechnoye, is currently under appraisal and is expected to come into production in 2023.

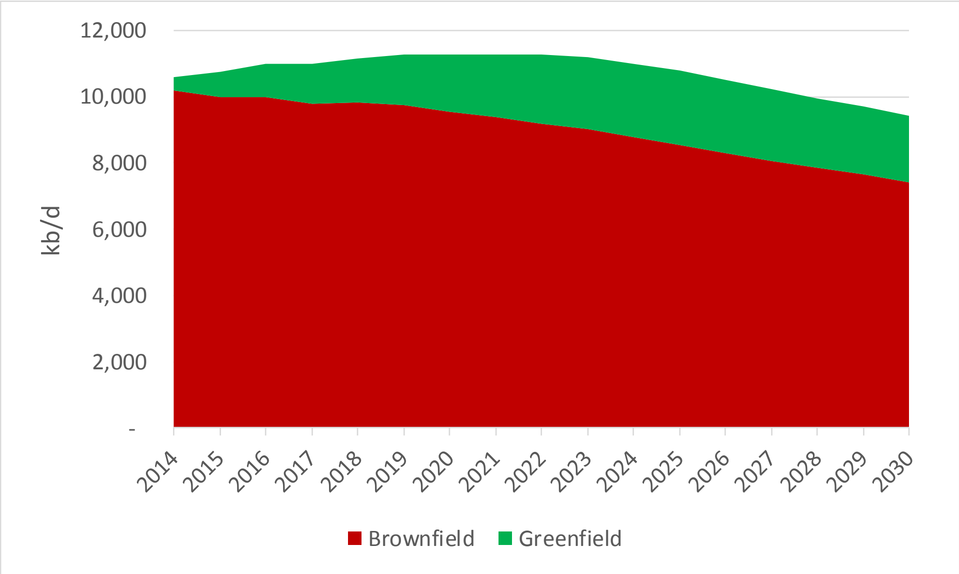
Finally, GazpromNeft has also been very active in bringing new fields into development. Its Arctic fields Novy Port and Prirazlomnoye have been growing output over the past few years and are now close to their peak, although further increases from both are expected in 2019, but the company has also been developing a major new production area in the north of West Siberia around the Messoyakha group of fields. East Messoyakha has been in production since 2016, and output is expected to exceed 100,000 bpd in 2019 before peaking at 120,000 bpd in the early 2020s. The use of multi-lateral horizontal wells has helped to overcome difficult geological conditions, and the economics of the field have also been enhanced by export duty concessions that will run to 2024. A new asset, West Messsoyakha, is also being appraised, and as this asset is essentially an extension of the main field it is expected that the same technologies will be used to bring the 185 mm barrels of

[2] Rosneft presentation, Full Year 2018 Results, slides 18-21

reserves online in 2021. Meanwhile GazpromNeft has a number of other fields that are in the process of being fully developed, mainly located in the heartland of West Siberia, with the emergence of the Tazovskoye, Severo-Ambusrgskoye, Pestsovoye, and Yen-Yakhinskye fields underlining the continued potential of the region.

In order to create a production profile for Russia over the period to 2030 we have analysed the performance of every production company over the past 5-10 years and extrapolated the performance of their brownfield assets to create an overall production decline for existing assets. This is shown in dark red in the graph below, with the average decline rate being 2.3 per cent per annum, as although a number of the main existing assets show a recovery in production after the end of the OPEC+ deal, they then revert to their more natural decline through to the end of the period. Onto this we then add the new developments that have come online since 2014 and which are still rising to peak output as well as new fields that have been identified but not yet put into production. This combination is shown in green and shows overall production in Russia to be maintained at 11-11.25 mb/d through to 2022/23 before going into gradual decline.

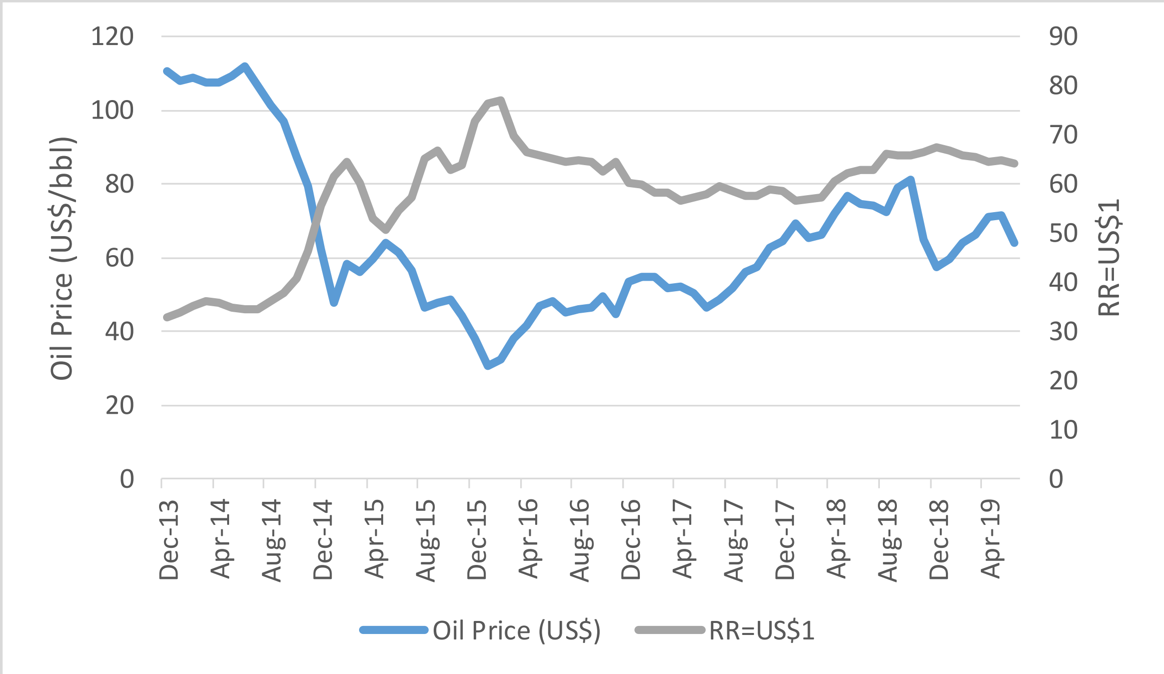
Figure 5: Russia production forecast to 2025



Source: Authors' Analysis

It should be emphasised that this forecast is based on the assumption that Russian oil companies implement their field development plans based on an oil price in the range $60-70 per barrel and a US$/RR exchange rate of US$1=RR65. The latter forecast is particularly important as the weakness of the rouble has been a huge benefit to all Russian exporters, and particularly oil and gas companies, over the past five years. The Russian government initially allowed the rouble to float freely versus the dollar in 2014 in the aftermath of sanctions being imposed due to the Ukraine crisis, and as can be seen in Figure 6 this allowed the currency to weaken at times when the oil price fell, providing a significant cushion for oil producers. Subsequently the Central Bank of Russia took a decision in 2016 to maintain the weakness of the rouble by reinvesting surplus dollar revenues into the currency market, and Figure 6 shows how the link between the oil price and the rouble has been broken since then. This has provided a consistent benefit to oil producers, allowing them to keep their costs low in US$ terms and improve the economics of their producing assets.

Figure 6: The US$-RR exchange rate versus the Brent oil price



Source: Central Bank of Russia, EIA, Authors' Analysis

This macro-economic benefit is further supplemented by the sliding tax scale which protects Russian oil companies at low prices but benefits the Russian government more at higher prices. Since the publication of our report in 2017 the Russian authorities have announced an adjustment which will gradually remove the current export tax while simultaneously increasing the Mineral Extraction Tax (MET) royalty paid on each barrel produced. The net effect for the oil companies is very marginal as one change effectively offsets the other. As a result, the impact of movement in the oil price on company cashflow shown in Figure 7 will not alter significantly over the next few years. As can be seen, the incremental benefit to companies of a $10 increase in the oil price is quite small, but the breakeven price of oil production is low (close to $10 per barrel in cash terms and around $35 per barrel on a full cost basis assuming development costs of around $6 per barrel) due to the sliding level of oil taxation. This tax system gives confidence to the oil companies to invest in new fields in the knowledge that they will not be at risk from sharp falls in the oil price, especially if they have also managed to secure tax discounts that are available for more remote or difficult to develop fields. For example, GazpromNeft's Prirazlomnoye and Novy Port fields will pay no export duty until 2032 and currently also receive a preferential MET rate set at below half of the normal level.

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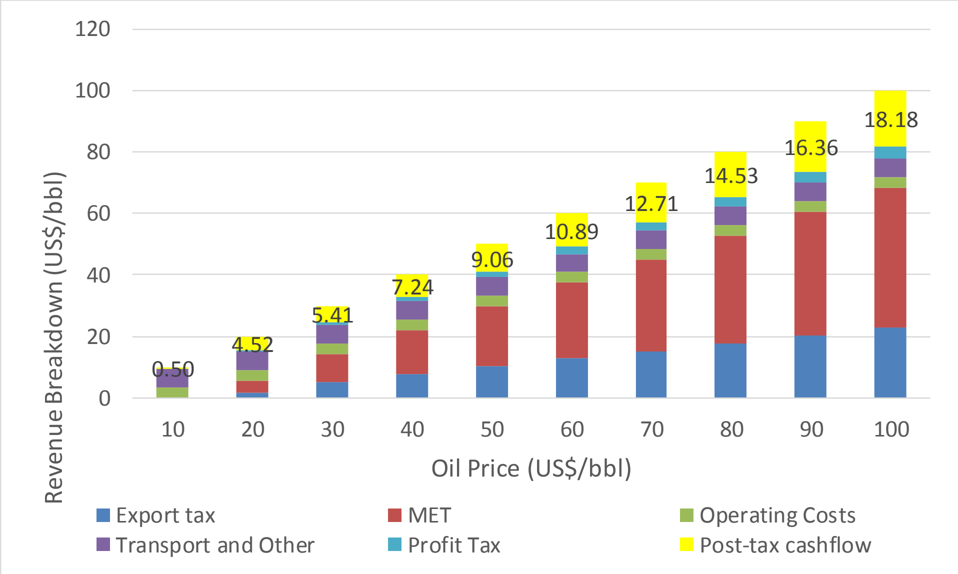
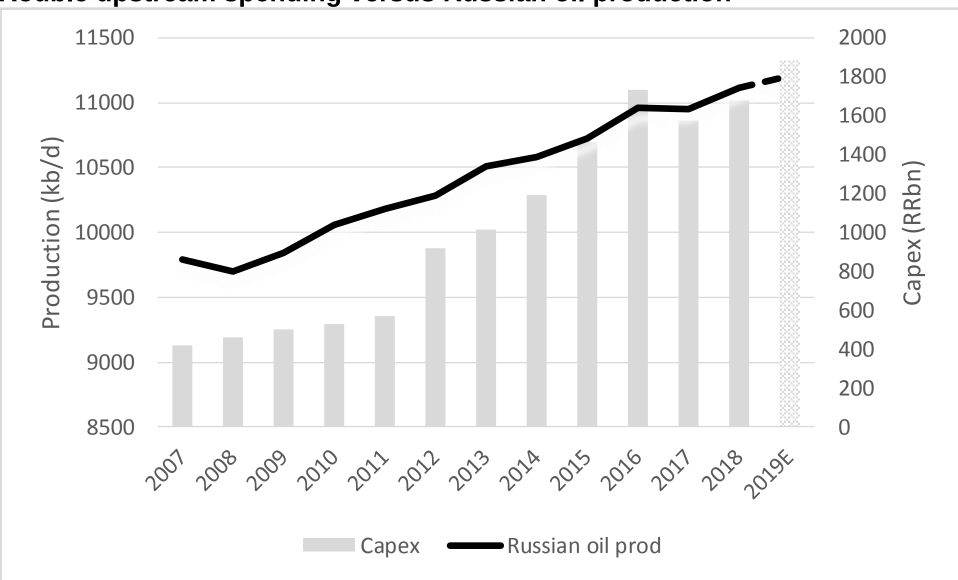
Figure 7: The impact of the Russian tax system on company upstream cashflow at various oil prices in 2019



Source: Authors' Analysis

As a result of both the benefits of the weak exchange rate and the preferential tax system, we are confident that Russian oil companies will be keen to invest in new production once the limits of the current OPEC+ deal are lifted. In order to see the impact of this, we have also carried out a simple modelling exercise to compare corporate expenditure in the upstream business in Russia with expected production outturns, with the results shown in Figure 8. We have undertaken a regression analysis of rouble expenditure versus production outturn since 2007 and found an R2 of 0.96, suggesting a high level of correlation. We have then applied this to the expected expenditure in 2019, as estimated in the Barclays Global E&P Spending Outlook 2019 to generate an estimate for production this year. As can be seen, the model anticipates an increase in oil output of around 1 per cent for an approximate 12 per cent increase in rouble expenditure.

Figure 8: Rouble upstream spending versus Russian oil production



Source: Authors' Analysis

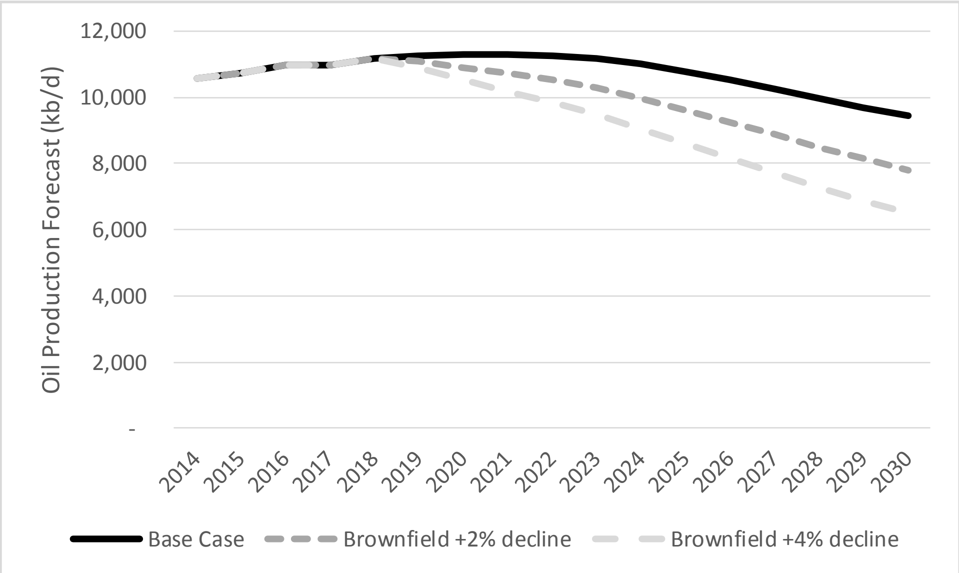
Clearly this result must be treated with some caution, not only because the model is a very simple one but also because Russian oil company expenditure is likely to be cut back due to the extension of the OPEC+ deal. As a result, the outturn in 2019 is likely to be flat, rather than a 1 per cent rise. Nevertheless, the model does provide some grounds for further confidence that when the deal expires, any increase in spending on upstream assets will result in growth in Russian oil production, at least in the short term.

The longer-term outlook is less certain

However, although the short-term outlook for Russian oil production appears robust, questions do emerge about the longer-term outlook. As can be seen in Figure 9, even the Base Case estimate goes into relatively sharp decline after 2025, falling to 10 mb/d by 2030. This may just reflect the natural pessimism inherent in any oil production forecast, because fields that may be producing in 2030 have just not been identified yet. It could also, though, reflect the increasing maturity of Russia's core producing regions and highlight the necessity to explore in new areas and develop new production bases. We will address some of these in the next section.

An additional concern is that our long-term forecast for brownfield decline, of 2-3 per cent per annum, may be too optimistic if the current performance cannot be maintained as fields move further into their final years. The dotted lines in the graph show accelerated brownfield decline curves (an extra 2 per cent and 4 per cent per annum respectively) and highlight the potential for much lower overall output by 2030 in these scenarios. It will be difficult to assess exactly how optimistic or pessimistic our Base Case scenario is until the current OPEC+ deal has ended and we can analyse the subsequent reaction of the Russian oil companies, but nevertheless the decline in the second half of the next decade does highlight the need for new provinces in Russian to be explored.

Figure 9: Estimates of potential longer-term decline in Russian oil production

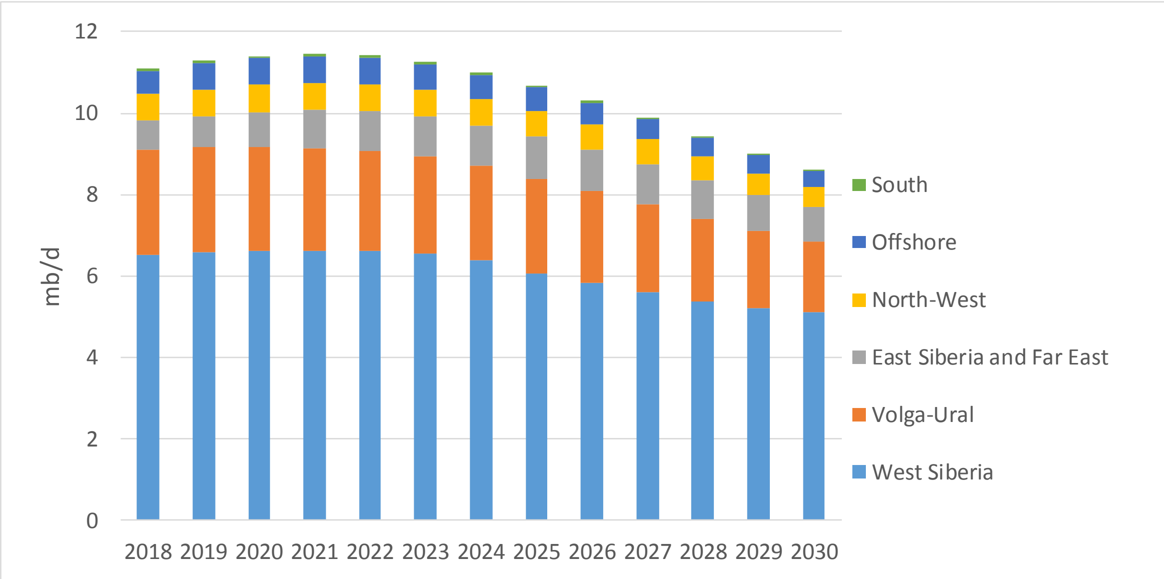


Source: Authors' Analysis

The outlook on a regional basis

As has been noted above, our Base Case forecast based on analysis of corporate performance assumes that companies continue to optimise performance at their key assets using secondary and tertiary recovery methods. This will obviously become increasingly hard to achieve as existing methods are exhausted and more complex technologies are required, many of which will need to be imported at relatively high cost. It is interesting, therefore, to compare the company analysis carried out at OIES with the regional analysis carried out by our colleagues at the SKOLKOVO Energy Centre in Moscow, the results of which are shown in Figure 10 below. As can be seen, the overall output figure in 2030 of just over 8 mb/d is close to the "Brownfield+2 per cent" case in the corporate analysis above, implying that the regional analysis assumes a more normal decline curve for average oilfields in Russia. In other words, it confirms that the corporate analysis assumes continued technology progression, especially in slowing the brownfield decline, and therefore it is important to assess how this may be achieved. Indeed, an overall question is how can the Russian oil industry achieve the target set for it by the Ministry of Energy of maintaining production at 550 mm tonnes per annum (11.05 mb/d) until the end of the next decade? In other words, will the Russian oil sector be able to fill a 2.5 mb/d gap by 2030, particularly when it seems that its major producing regions (West Siberia and the Volga-Urals) will be in permanent decline by then?

Figure 10: Russian production forecast by region



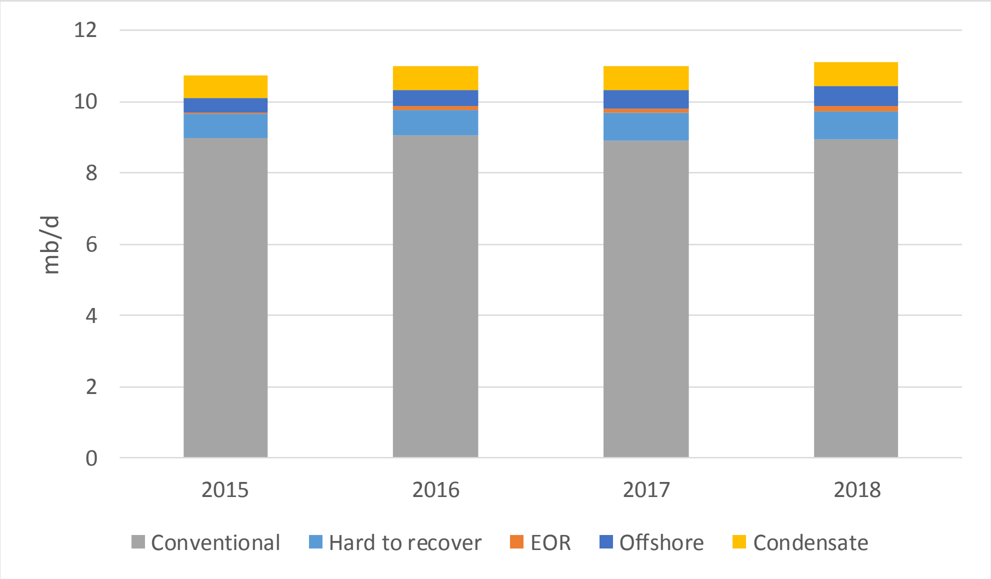
Source: SKOLKOVO Energy Centre

The task is made more difficult by the fact that sanctions are limiting the provision of some of the more complex technologies in Russia, while the weakness of the rouble, while generally beneficial, is increasing the cost of imports. Meanwhile, financial sanctions have forced Russian companies to tighten their budgets and to prioritise which technological areas they are able to focus on, as it seems unlikely that all opportunities can be exploited at one time. As a result, it would appear that, as a general assessment, the following strategies to maintain Russian oil production are being implemented broadly in the order suggested here:

1. Enhance efficiency in mature and new fields with conventional reserves, in particular by encouraging the development of a competitive domestic oilfield service industry to allow the manufacturing of more equipment domestically and to improve the digitalization of all the production processes.
2. Active development of smaller satellite fields close to existing infrastructure.
3. In-depth development of mature traditional fields using tertiary enhanced oil recovery methods (EOR).
4. Development of hard-to-recover reserves, including shale oil but also other deep and more technical reservoirs.
5. Development of offshore fields, including the long-term development of Russia's extensive Arctic resources.

In terms of numbers 1 and 2 above, the Russian oil industry is already making some progress, although with some questions over drilling efficiency. The progression of new fields that has been delayed as a result of the OPEC+ agreement includes a number of smaller assets that are satellites around existing fields, and it is clear that these fields are already helping to underpin conventional field development in Russia. The rebound in production at Yuganskneftegas shown in Figure 4 is one example of how satellite fields are being developed in mature areas, and Figure 11 below underlines how important output from conventional fields continues to be in Russia. However, as will be discussed below, the impact of each well has been in decline and costs have been rising, emphasizing the need to focus on the most efficient and cost-effective technologies at existing and new fields.

Figure 11: Breakdown of production in Russia by asset type



Source: SKOLKOVO Energy Centre, Moscow

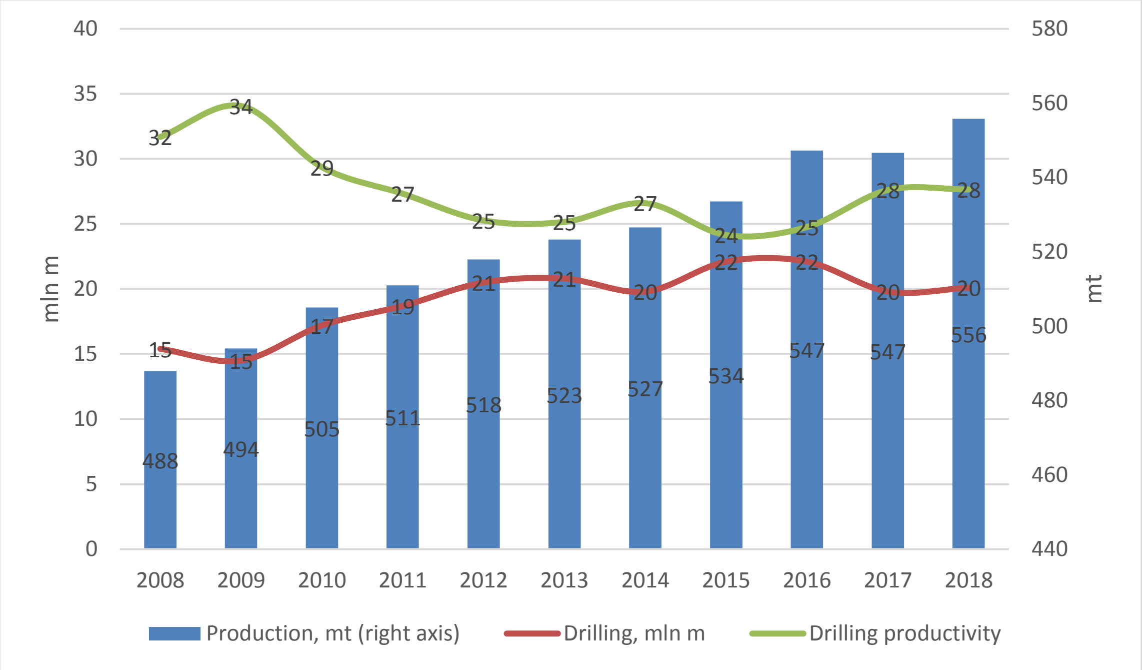
Drilling efficiency – mixed performance a concern

One particular area for concern is that during the period from 2008 to 2019 the efficiency of drilling declined by 13 per cent in Russia, as although production rose by 14 per cent during this period the actual volume of drilling increased by 31 per cent. At the same time, in the country's largest oil producing region - the Khanty-Mansi Autonomous district - the situation looks even more dramatic, with output decreasing by 15 per cent, despite an increase in production drilling of 66 per cent. As a result, the drilling efficiency in Khanty-Mansi Autonomous Okrug decreased by 49 per cent.

It should be noted that in many cases, decreased drilling efficiency is associated with an increase in the share of hard-to-recover reserves, which will be discussed below, as well as the natural depletion of existing fields, which is a particular problem in mature regions such as Khanty Mansi.

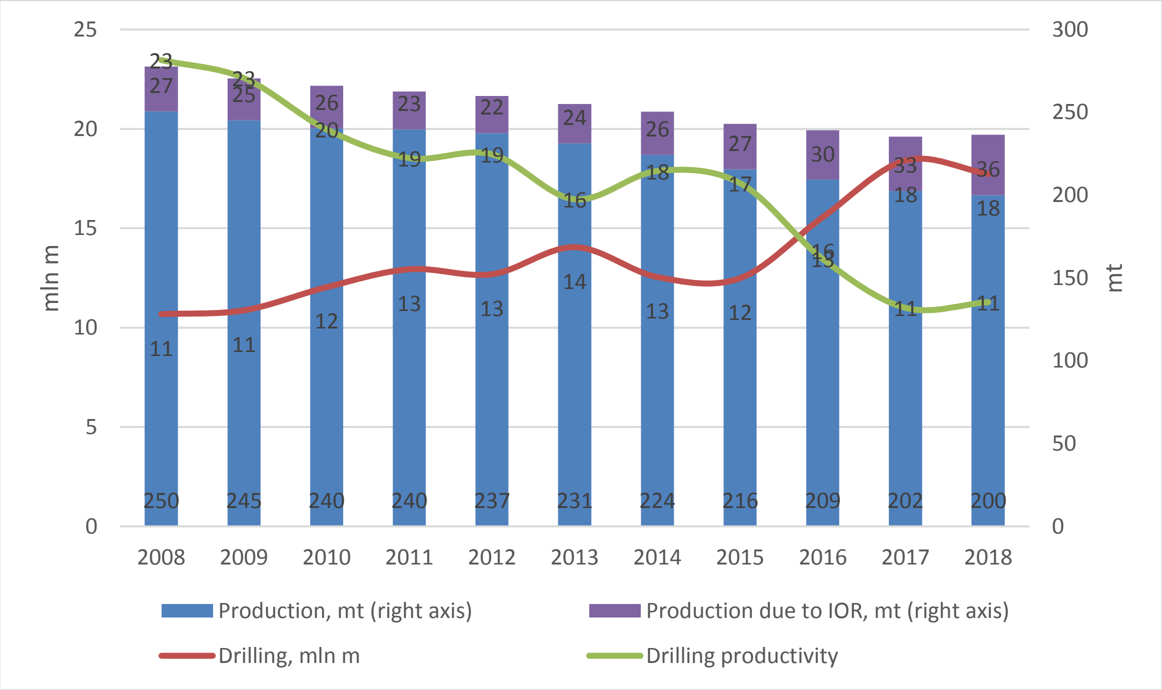
Furthermore, although the long-term review offers disappointing results, an analysis of the last 2-4 years offers more positive dynamics. In Russia as a whole, from 2015 to 2018, production growth amounted to 4 per cent, while drilling volumes decreased by 9 per cent, implying that drilling efficiency increased by 15 per cent. A similar situation was observed in the Khanty-Mansi Autonomous Okrug. In 2018, the region managed to stabilize production for the first time in ten years, also against the backdrop of a decrease in production drilling. This increase in production against a background of stable drilling volumes is the result of an increase in the use of horizontal drilling in Russia, as well as a rise in the use of other methods to stimulate production. Indeed, in the Khanty-Mansi Autonomous Okrug, production due to Intensified Oil Recovery (IOR) grew from 27 to 37 mm tonnes for the period 2008-2018, and its share of total production in the region reached 15 per cent in 2018 compared to 10 per cent in 2008. This positive news, though, is somewhat offset by a rising water cut, which reached 86 per cent on average in 2018, and higher costs, which have increased by a factor of 2-3 times over the past decade despite the devaluation of the rouble. As a result, the challenge to keep Russian oil production stable is clear.

Figure 12: The dynamics of drilling and production in Russia



Source: Deloitte, Ministry of Energy RF

Figure 13: The dynamics of drilling and production in the Khanty-Mansi Autonomous Okrug



Source: Deloitte, V.I.SHPILMAN RESEARCH AND ANALYTICAL CENTRE FOR THE RATIONAL USE OF THE SUBSOIL

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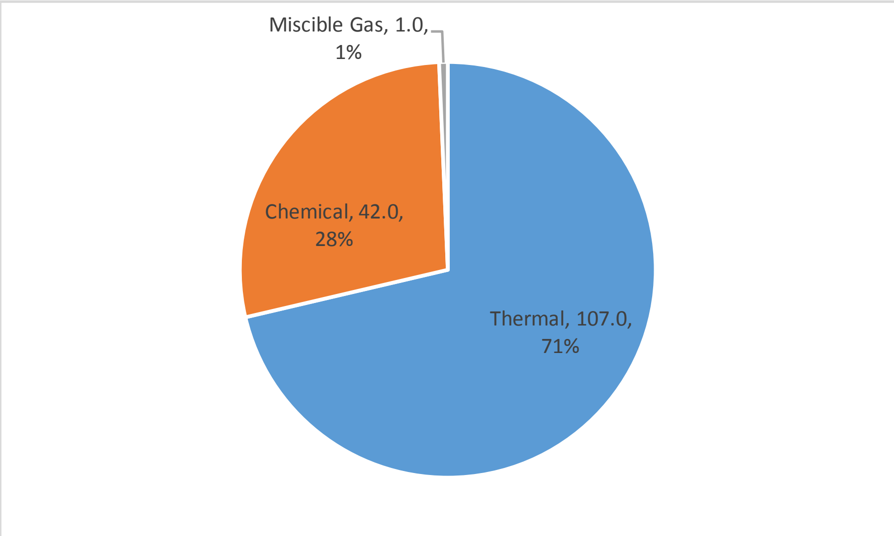
Enhanced Oil Recovery

Given the issue with drilling efficiency, it is becoming clear that one of the areas where interaction between oil companies and the oil service sector needs to be improved is in the implementation of Enhanced Oil Recovery (EOR). EOR is defined by the IEA as the use of tertiary methods to increase the recoverability from oil reservoirs after the primary (natural reservoir pressure) and secondary (water or gas injection) methods have been exhausted. There are a number of different types of EOR, including steam heating, injection of miscible gases to increase oil viscosity, chemical flooding, the introduction of microbes to break down heavy oil, combustion flooding (essentially setting fire to some underground oil to increase flow), and the use of downhole vibrations. However, as shown in Figure 14, the most popular in Russia are the use of steam to heat oil and decrease its viscosity, the use of chemicals (polymers and surfactants) to increase the viscosity of water injected into the reservoir to enhance its ability to push more oil out, and to a lesser extent the use of miscible gas, which mixes with the oil and allows it to flow out of the reservoir more easily.

Figure 14: Enhanced Oil Recovery in Russia (2018, kb/d)



Source: SKOLKOVO Energy Centre, Moscow

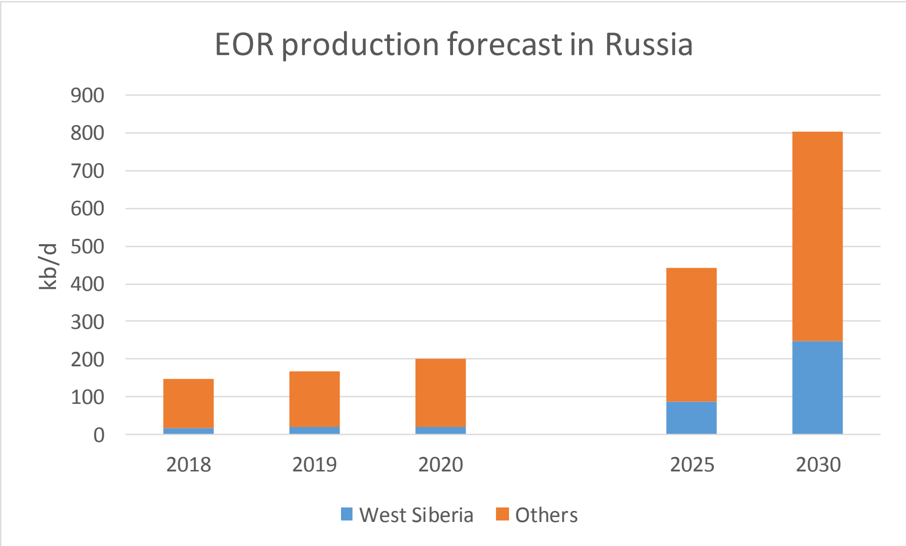
EOR is not a new concept in Russia. It was successfully deployed in the late Soviet era under the “State Development Programme of EOR”, which managed to add 240 kb/d of production between 1985 and 1990. However, the collapse of the Soviet Union brought an end to the programme of pilot projects, which the overall production from EOR falling to 150 kb/d by the middle of the decade and the average recovery rate for oilfields in Russia falling to 30 per cent or below, well behind more developed countries such as Norway where more than 50 per cent of oilfield reserves would normally be recovered.

It should be noted though that the definition of EOR can vary dramatically, and some Russian companies have included factors such as hydraulic fracturing, horizontal wells, and side-tracking, which would normally be regarded as primary or secondary recovery methods. Figure 14 above shows a total figure of 7.5 mm tonnes (c.151 kb/d) which is very close to the IEA estimate for Russia of 150 kb/d but is well below the sum of various company estimates in Russia which total around 320 kb/d. This is to a large extent because the use of thermal methods to extract high-viscosity oil from the start of field life are not classified as EOR under the standard terminology. As a result, much of the heavy oil produced by Tatneft, which the company classifies as EOR, is - strictly speaking - not, which reduces its EOR production from 175 kb/d to only 35 kb/d. To an extent this is semantics, as the techniques are of course the same, but it is important to note that the Russian estimates of EOR can differ markedly from international assessments.

Under the strict definition (in other words excluding the Tatneft steam projects from the start of field life) there were 27 EOR projects in Russia in 2018, with more than half of the output coming from 14 projects in the Volga-Urals region (mainly the Romashkinskoye field operated by Tatneft), another third coming from Timan Pechora in NW Russia (the Usinsokye and Yaregskoye fields) and 11 per cent originating in West Siberia. As noted above the most commonly used EOR method is steam injection (thermal) although chemical EOR is increasing fast and now accounts for more than one quarter of the total. Indeed, Shell and Gazpromneft are currently trialling the use of the ASP (alkaline-surfactant-polymer) flooding method at their JV in the Salym field, and the initial technical results have been very encouraging, with the recovery rate in certain parts of the field having been increased from 48 per cent to 65 per cent, comparable with the best international performance.

However, this pilot project has also highlighted some of the key issues with EOR in Russia, namely the current need to import many of the chemicals and the digital modelling systems that are required to make the process work efficiently. These are very expensive, making the breakeven for EOR relatively high (the IEA estimates $55-65 per barrel, compared to around $30 per barrel of conventional primary production in Russia) and this underlines the need to localise the entire EOR value chain by cooperating with domestic oilfield service companies. In particular, it will be vital to manufacture chemicals (polymers and surfactants) and the equipment to inject them close to the well-sites where they will be used, which could significantly reduce the operating costs of an EOR project in Russia. This is vital because operating costs account for 40 per cent% of the total expenditure on an EOR project, with injection of chemicals being a continuous process throughout the field life, and it is likely that state support (in the form of tax breaks but also encouraging industry dialogue and partnership to encourage research and development of pilot projects) may be needed to encourage the development of large enough plants to supply multiple fields and therefore generate synergy benefits. The benefits could be significant though – Gazpromneft has stated that EOR could produce as much as 2 mb/d in Russia by 2030, and although this seems overly optimistic, a more conservative government estimate suggests that a target of 800 kb/d by the end of the next decade could be achievable (Figure 15).

Figure 15: Production forecast from EOR in Russia



Source: SKOLKOVO Energy Centre, Moscow

‘Hard to Recover’ oil

Another important growth opportunity is Russia’s unconventional oil resources, including tight and shale oil and generally referred to in Russia as “difficult to recover” reserves. Again, US and EU sanctions have undermined progress, because they have banned the provision of technology and finance to develop Russia's shale resources, but both Russian and international companies are now exploring non-shale unconventional plays as momentum starts to build to develop this huge potential resource base. The key initial work has been done in the Bazhenov shale, a resource that lies below the traditional West Siberian oil reservoirs and which could contain up to 75 billion barrels of oil resources, making Russia potentially the largest shale oil play in the world.[3] The Russian Ministry of Natural Resources originally believed that as much as 1.5 mb/d could be produced from these resources over time, and although estimates have since been lowered and sanctions have caused delays, the significant potential remains.[4] Domestic companies such as Rosneft, Gazprom Neft, and Lukoil have spent considerable time reviewing the asset, and international companies such as Statoil and BP are now investigating other non-shale unconventional plays that can be explored without contravening sanctions.[5] Numerous problems still remain, not least of which is likely to be the provision of adequate equipment to drill the many thousands of wells that will ultimately be needed, but again the government has offered tax breaks to encourage investment and is urging its major companies to continue exploration. Real progress will only be made once sanctions are lifted, but tight oil certainly provides an important source of future production growth.[6]

One key issue, though, is the definition of "hard-to-recover" reserves and production, as even government institutions struggle to agree on official figures. For example, the State Commission for Reserves (SCR) has stated that hard to recover production totaled 1.8 mb/d in 2017 while the Ministry of Energy (ME) put the figure at a much lower 0.8 mb/d due to its tighter definition of which reservoirs should be included. Table 2 shows the different calculation that were used, and the outcome is important because tax breaks are offered for the various types of reservoir that are included within the hard-to-recover definition.

Table 2: Estimate of "Hard-to-Recover" oil production in Russia (mb/d)

	2016	2017	2018E
Total SCR	**1,48**	**1,75**	**2,01**
Tumen formation	0,63	0,74	0,86
Low permeability	0,65	0,78	0,91
Highly viscous	0,14	0,16	0,18
Bazhen	0,01	0,01	0,01
Abalak formation	0,04	0,04	0,04
Domanik and Khadum formations	0,01	0,01	0,01
Total ME	**0,74**	**0,76**	**0,78**
Tumen formation	0,46	0,47	0,48
Highly viscous	0,02	0,03	0,04
Other hard to recover	0,26	0,26	0,26

Source: SKOLKOVO Energy Centre, Moscow

Some very specific criteria are applied to oil reservoirs to determine what level of tax breaks are due to companies that develop them, with discounts to the MET being offered for fields that are either:

- Highly depleted (more than 80 per cent) or with a high water cut (more than 90 per cent)
- In complex reservoirs with low porosity or permeability

[3] US EIA, June 2013, 'Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the US'
[4] The most recent Energy Strategy has an estimate of 20 mtpa (400,000 bpd) by 2030
[5] Interfax, 31 Jan 2017, "Rosneft, Statoil start pilot drilling at tight oil blocks in Samara"
[6] Henderson, J. (2013) *Tight Oil Developments in Russia* WPM 52, Oxford Institute for Energy Studies (https://www.oxfordenergy.org/publications/tight-oil-developments-in-russia/)

- Contain highly viscous oil
- Have levels of gas saturation or quality which require expensive equipment to ensure adequate oil production
- At great depth (more than 4000 metres)
- Have a very high reservoir temperature (1000 degrees centigrade or more)
- Have a reservoir temperature close to the freezing temperature of paraffin and resins

Any fields which qualify under the above characteristics (which are defined in more detail in the legislation) are entitled to tax breaks, and of course companies fight to prove that as much of their oil as possible is classified as hard-to-recover. This is becoming increasingly easy to do, however, as the Ministry of Natural Resources has highlighted that hard to recover oil is becoming ever more prevalent in Russia, with two thirds of proven reserves (73 billion barrels out of a total of 110 billion) now being defined in this way. As such, it is widely recognised that although only 7 per cent of total Russian production comes from this source at present, this share will have to increase over time if overall output is to meet its target.

There are two key issues, though, if production is to increase. The first is that a significant amount of the equipment and software required to develop the significant resources is currently under sanctions. Although only shale oil has been officially sanctioned, western companies tend to be reluctant to supply any of the banned products, even if they may be used elsewhere. As a result, equipment for horizontal drilling, software for hydraulic fracturing operations, high pressure pumps, drill pipes and casing strings, steerable rotary systems and gas purification equipment are all in short supply and will require a significant amount of research and development to ensure their availability from domestic companies, especially as individual reservoirs and fields will require specific solutions.

Furthermore, the regulation remains inadequate as the privileges and benefits on offer for the development of different forms of hard-to-recover oil vary widely and the methodologies for their implementation frequently change. In reality the state needs to decide which resources it wishes to be developed first and then offer appropriate incentives to stimulate the activity which is required to develop the major potential within Russia's hard-to-recover resources. The upside is highlighted in Table 3, which details the resources (not reserves) that have been identified so far. As can be seen, almost 10 billion tonnes are technically recoverable (c.75 billion barrels) and even if only a small part of this is exploited it is reasonable to estimate that production by 2030 could double to reach 1.5 mb/d.

Table 3: Hard to Recover Resources in Russia (billion tonnes)

	Technically recoverable hard-to-recover reserves (AB_1B_2+C_1C_2), Billion tonnes, 2017
Total hard to recover	**9,6**
Bazhen	0,7
Abalak	0,2
Domanik	0,1
Khadum	0,02
Tumen	3,1
Low permeability	2,9
Highly viscous	1,3
Highly developed	1.3

Source: Presentation of State Commission for Mineral Reserves, 2019

Offshore oil production

Russia currently produces 580 kb/d from its continental shelf, with half of this coming from the Sakhalin region in the Far East of the country. In particular, the Sakhalin 1 project (operated by Rosneft and ExxonMobil) has been a major producer since the mid-2000s and the Sakhalin 2 project (Gazprom and Shell) also produces liquids. However, the potential for extra production from this region appears limited, and the major interest for the future is centred on the Caspian Sea, where LUKOIL is already producing from a number of fields, and the Arctic, where GazpromNeft has one operating offshore field, Prirazlomnoye. Having said this, the major player in the Russian offshore over the next two decades is likely to be Rosneft, given the vast amount of acreage that it has acquired over the past few years (see below).

As far as the Caspian Sea is concerned, LUKOIL is focused on three main assets. The largest of them, the Filanovsky field, contains around 950 mm barrels of oil and came onstream in 2016, and has now reached its peak output of 145 kb/d which it is expected to sustain into the early 2020s. Its second field, Yuri Korchagin, is much smaller with an output of 45 kb/d and is also at peak output having come online in 2010. It is expected to go into decline in the early 2020s. Finally, the company has made a small satellite discovery close to the Filanovsky field which it has named Rakushechnoye, which is expected to come online in 2023 and to have an ultimate output of around 25 kb/d. As such, output from the Caspian Sea should remain stable for a few years before going into decline after 2025, unless major new discoveries are made.

The Russian Arctic – huge potential but undermined by sanctions

If there is one region that has been hit hardest by US and EU sanctions then it is the Russian Arctic, which contains potential resources estimated at 240 billion barrels of oil equivalent but which is in geographically challenging waters and which will require significant amounts of finance and new (for Russia) technology to exploit it. In addition, the economics of any Arctic projects when oil prices are below $80[7] per barrel are challenging, although the Russian government has provided some tax incentives to encourage development of the area. For further production growth Arctic oil needs more tax benefits, in particular a reduction in the co-efficient for calculating MET. This topic is being actively discussed by the Russian government and relevant companies, but as the parties have not yet reached a consensus, we make only very modest assumptions about future production from the region (see below).

Initial interest in the area was catalysed by Rosneft's partnership with ExxonMobil, which initially focused on the South Kara Sea but then spread to licences across the Arctic region. ExxonMobil brought not only money but the experience of operating large projects in remote areas, and also managed to persuade the Russian government to introduce a tax regime for the offshore regions of Russia that would allow high cost projects to make a reasonable return. The taxes for various offshore regions are shown in Table 4, where it can be seen that the most lenient is for the Arctic region.

Table 4: Tax calculations for areas of the Russian offshore

Group	Location	IRR target	Royalty rate
1	Baltic/Azov Seas	16.5%	30%
2	Shallow waters of the Black Sea, Pechora and White Sea, southern part of the Okhotsk Sea, offshore Sakhalin	18.5%	15%
3	Deep waters of the Black Sea, the northern part of the Okhotsk Sea, southern part of the Barents Sea	20.5%	10%
4	Offshore projects in the Arctic (includes Kara Sea), the northern part of the Barents Sea, the Eastern Arctic	22%	5%

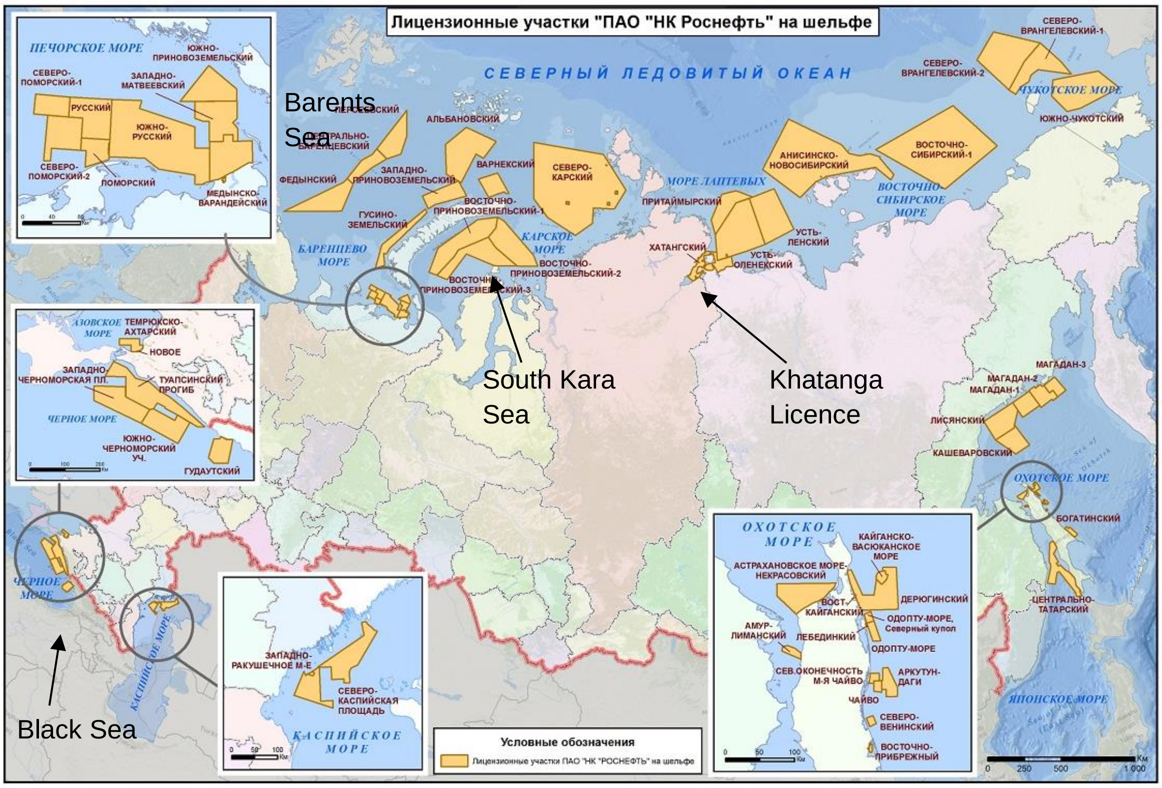
Source: Russian Tax Service

[7] SKOLKOVO estimates based on Russian Ministry of Energy

The excitement around ExxonMobil's involvement reached a peak in October 2014 when its partnership with Rosneft made a first discovery in the South Kara Sea (subsequently named "Pobeda" or "Victory") with initial estimated reserves of 750 mm barrels. However, the company was then immediately forced to pull out due to the imposition of US sanctions which forbade US companies from continuing any activity in prohibited zones, even if contracts had been signed before the sanctions law was imposed. As a result, ExxonMobil has had no further part to play in the Arctic since then and its JV with Rosneft has effectively become dormant.

Despite this Rosneft has at least claimed to be continuing its development of the Arctic region, and as can be seen in Map 1 its licences in the North are very extensive. Its other foreign partnerships, with Equinor and ENI in the Barents Sea, have also been inactive since the imposition of sanctions, but Rosneft has attempted to continue some exploration alone, encouraged by President Putin to keep Russia's Arctic oil aspirations alive. In particular in 2016/17 the company mobilized equipment to drill a well on its Khatanga license in the Laptev Sea, although the fact that the base for operations was onshore with a horizontal well stretching out into the offshore area perhaps underlines the lack of Russian experience in operating offshore rigs. Nevertheless, a discovery of oil shows was made and is under further investigation. We have, perhaps optimistically, shown some 70 kb/d of production from this discovery towards the end of the next decade, although this forecast is somewhat speculative. Furthermore, this is really the extent of Russian oil company exploration in the Arctic offshore since 2014, and given the timescales that would be involved in any development, never mind the money and technology, it seems almost inconceivable that any other new production will emerge from the region at any time before 2030.

Map 1: Rosneft's licences in the Russian offshore region



Source: Rosneft at https://www.rosneft.com/business/Upstream/Offshoreprojects/

For the longer term, though, it is worth noting that sanctions have catalysed a drive to create an offshore operating base in Russia, with Rosneft again at the fore. It has taken ownership of the Zvezda port in the city of Bolshoi Kamen in the Russian Far East. Ultimately it is planned that this shipbuilding complex would be able to manufacture all the heavy equipment needed for offshore exploration and production, including rigs, large support vessels, and all forms of offshore marine equipment. At present Zvezda is still building an order book, but support from the Russian authorities is strong and the intention is certainly that Russia should become less dependent of international equipment for its offshore industry.

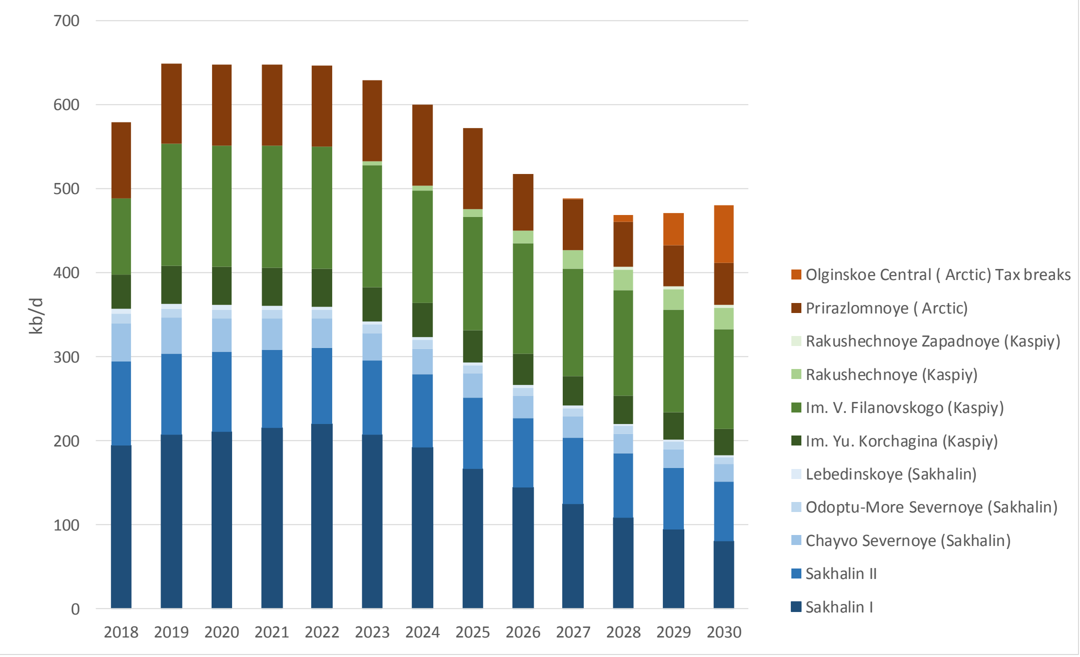
Slow progress in other offshore areas

As can be seen in Map 1, Rosneft also has licences in the Black Sea, where it has a joint venture with Italian company ENI. As the water depths here are well in excess of the 500 metres covered by US and EU sanctions, activity has also been very slow since 2014, although Rosneft has carried out some seismic work in the region. The company is also active in the Sea of Azov, where it has cooperated with LUKOIL since 2003. One discovery, called Novoye, has been made and a small amount of production was generated from the first well (70,000 barrels were produced). A second well is set to be drilled, but any production from the field is likely to be minimal. Rosneft has also made a small discovery in the Caspian Sea (West Rakushechnoye, close to a LUKOIL field mentioned above) and although reserves are small (around 80 million barrels), a limited amount of production is expected by the end of the decade.

Conclusion on Russian offshore

The Russian offshore has vast resource potential, but the cost of exploiting it and the technology and experience that will realistically be required to make a success of it mean that the impact of sanctions has been enormous, as foreign companies have essentially backed away from the area completely. Rosneft, and to an extent LUKOIL and GazpromNeft, have continued to operate in the region, but realistically the main hope for the next decade is that existing production can be maintained before it goes into gradual decline. Over time Russian companies and shipyards may acquire the expertise for a fuller development of the region, and we have included some production from one new Arctic discovery in our forecast, but in reality the removal of sanctions, if and when that occurs, will be the real catalyst for extensive new activity. Given that this is unlikely any time soon, our estimate for Russian offshore production, shown in Figure 16, is somewhat pessimistic but gives some hope that by the end of the period the Arctic region may start to reverse the decline. For example, the Central Olginskoe field has huge production potential, but can only be put into operation with significant tax benefits.

Figure 16: Estimate of future production from Russian offshore fields



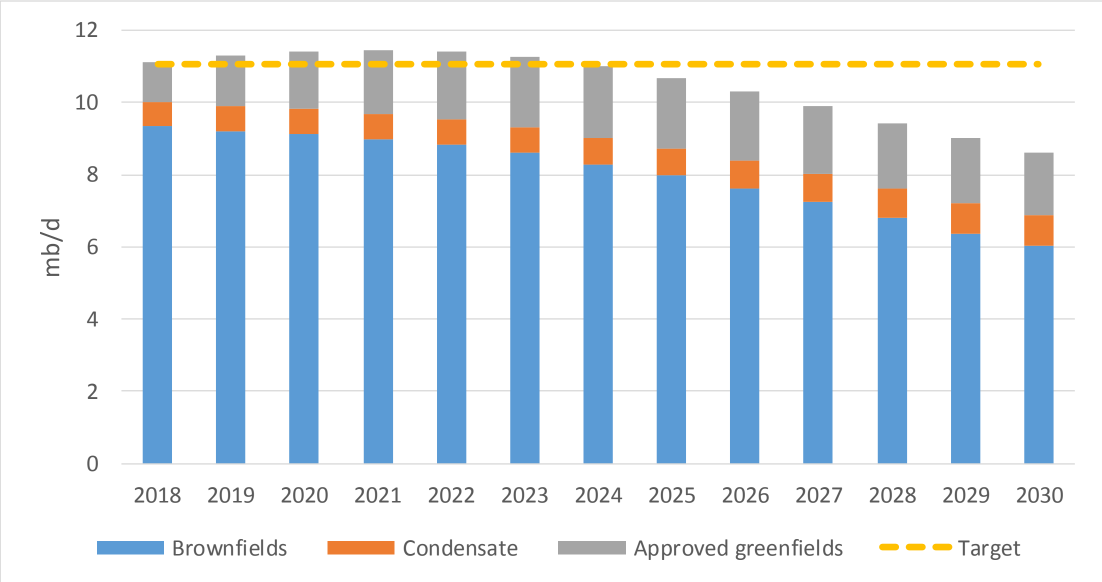
Source: SKOLKOVO Energy Centre

Overall conclusions

The Russian Energy Minister, Alexander Novak, has set a target for Russian oil production to remain stable at 550 mmt per annum through to 2030 (just over 11 mb/d). This is a slight reduction on today's output but is nevertheless a tough target for the Russian oil industry given the likely decline in existing fields over that period (see Figure 17). The key challenge over the longer term will be to find new regions for oil production as well as enhancing the performance of existing fields.

In the short term there is little risk of a decline, however. The key constraint on Russian oil output is the agreement with OPEC to restrain production through to the end of 2019, and possibly into the first quarter of 2020. However, once this is lifted the potential for output to increase to close to 11.5 mb/d is clear, as both older brownfields and new greenfield projects have the potential to boost production through to the early 2020s.

Figure 17: The Ministry of Energy target for Russian oil production



Source: SKOLKOVO Energy Centre, Moscow

The key question for the longer term, though, is how the 2.5 mb/d gap identified in Figure 17 can be filled. An analysis of Russian company performance over the past five years would suggest that one source will be improved performance from brownfields, where there has been significant success slowing the natural decline of increasingly mature fields. However, what is also very clear is that the impact of US and EU sanctions will start to have a greater impact as time progresses and Russia starts to rely on the development of new areas such as the Arctic, the continental shelf and shale oil.

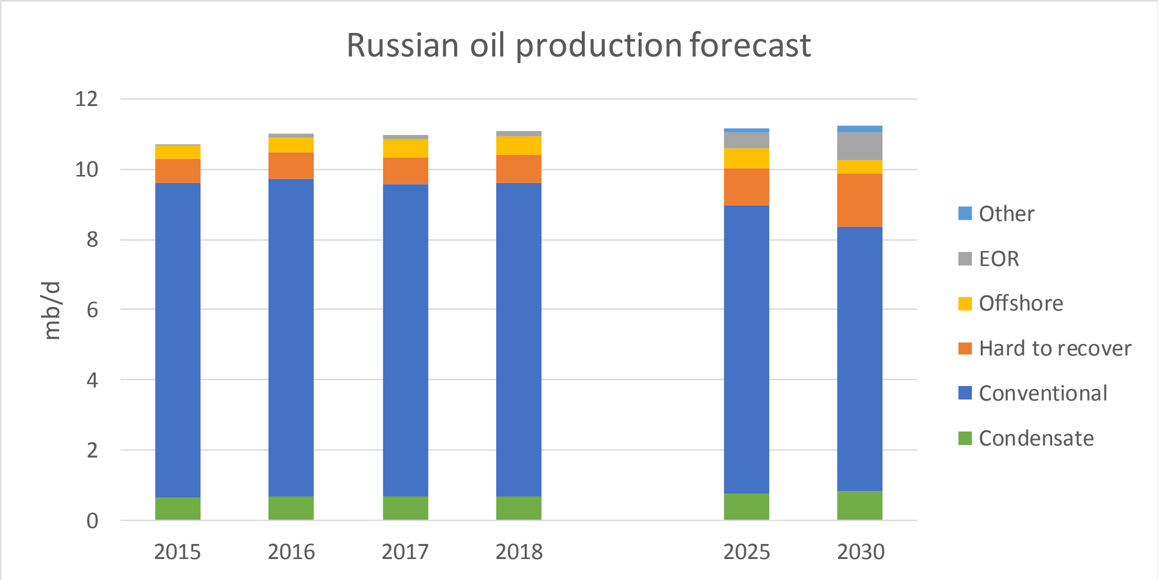
The use of enhanced oil recovery (EOR) techniques has been prevalent in Russia since the Soviet era, but the economics have been challenging at low oil prices. Furthermore, there is a clear need to develop a domestic manufacturing industry for the production of chemicals needed in the process and the equipment to inject them into reservoirs. If this can be achieved, with state support, then there is significant upside potential over the next decade. Our estimate is that EOR output could reach 800 kb/d by 2030 (from 150 kb/d in 2018) but other more optimistic forecasts see the potential for 2 mb/d.

The development of shale oil (in particular the Bazhenov layer) will be difficult while sanctions remain in place, but there are a number of other horizons within the "hard-to-recover" definition that are supported by tax breaks and which could produce more oil. The resource potential is certainly enormous, with a technically recoverable estimate of 75 billion barrels, but once again the key will be how fast this can be exploited given infrastructure and financial constraints in Russia. In 2018 760 kb/d was produced from this source, and it is possible that this could double by 2030 under current circumstances, although if sanctions were to be lifted this could accelerate sharply.

The most significant opportunity, though, is on Russia's continental shelf and especially in the Arctic region, where potential resources totalling 240 billion boe have been identified. LUKOIL has been the initial leader in this field with its production from the Caspian, while GazpromNeft also has some offshore output from its Prirazlomnoye field. However, Rosneft is the dominant force with existing production from Sakhalin and vast swathes of licences across the whole Russian offshore. Its focus was on the Arctic with ExxonMobil as its main partner, but activity here has been curtailed by the strict application of sanctions. Rosneft has conducted some activity alone and made a discovery in the Laptev Sea are which could be online by 2030, but overall the potential for significant production before 2030 is now very small. Efforts are being made to create a domestic manufacturing base for offshore equipment, which could reduce the impact of sanctions to an extent, but in reality the costs involved and the need to acquire offshore experience means that production from Russia's offshore is likely to decline by 2030 from the current level of 580 kb/d to around 400 kb/d. It could rebound thereafter, if Russian oil companies and the domestic oil service industry continue their commitment to the region, but that remains beyond the realm of our forecast in Figure 18.

Overall, then, it would seem that Russia does have the opportunity to meet the Russian Energy Minister's target to keep oil output over 11 mb/d for the next decade. Indeed, if the country's import substitution strategy is a success then it could even exceed the target, as there is little doubt that the resources are in place. A combination of performance enhancement at existing fields, exploitation of EOR techniques and hard-to-recover reserves, plus some efforts to maintain offshore oil output should be enough to meet the overall goal. Perhaps the more interesting question, though, is what could happen if sanctions are lifted. At that point, the potential of all these resources could be released rapidly, leading to a surge in output towards 12 mb/d or above.

Figure 18: Russian oil production potential to 2030



Source: SKOLKOVO Energy Centre, Moscow