October 2020

Quarterly Gas Review: Gas Price Volatility and Changing Dynamics in Southern Europe

Introduction

In this latest OIES Gas Quarterly we provide our continuing review of global gas prices while also focusing on some recent themes in the important gas markets of southern Europe, and in particular Turkey. We start, as usual, with a look at various price indicators which demonstrate what we believe are some key market trends, and some dramatic changes which have occurred since our July Quarterly. In particular, our LNG Tightness Indicator, which shows the margin for US LNG exporters, has improved significantly over the past three months and has turned positive for the first time since April. In addition, the outlook for 2021 has also got much better, with the prospect of US LNG suppliers being able to cover their cash costs and, by 2023, perhaps even their full (long-run marginal) costs.

This prospect has been caused by a jump in prices all along the forward curve and also by the opening up of the margin between the Henry Hub price in the US, TTF in Europe and the ANEA price in Asia. However, our second price analysis, which compares changes in storage utilisation and changes in the TTF gas price, raises an important question about whether the forward curve is too optimistic, as it would seem to imply a change in stock levels that would only be achieved through a significant jump in demand (perhaps via a very cold winter) or further shut-ins of supply in 2021. Our third graph, which monitors activity on Gazprom's ESP, underlines the continued competitiveness of Russian gas in Europe but also confirms that Gazprom has been avoiding direct price competition in Europe over the past six months, preferring to focus on longer term rather than spot sales. Meanwhile in Asia the gap between oil-linked LNG prices and the JKM spot price has closed completely, as the impact of lower oil prices earlier in 2020 is now feeding through to LNG contract prices. This may relieve the pressure for contract renegotiation in the short-term. Finally, the domestic wholesale price in China has been relatively stable, but the gap with the JKM spot price has now closed significantly thanks to the sharp jump in the latter over the past month, encouraging some thought that a link between the two may be possible in time.

In our main articles this quarter we focus on activity in and around the gas markets of southern Europe. The first article, by Jack Sharples, highlights the sharp decline in Gazprom's sales of gas to Turkey over the past 12-24 months. Increasing competition from LNG and now also from Azerbaijan has seen Russian volumes fall by more than 50 per cent since 2017, and with a number of contracts up for renewal the question of the future of Russian gas in this important market is under question. This is particularly concerning for Gazprom at a time when the new Turk Stream pipeline has only just started to supply new volumes, raising the issue of whether its full capacity will ever be needed.

Gulmira Rzayeva continues this theme as she looks at the implications of Turkey's new gas discovery in the Black Sea. Although the Turkish authorities have claimed reserves of 320bcm, albeit only based on one exploration well, there remains some doubt as to whether the new field will be economic given the technical and geographical challenges that must be faced. Nevertheless, with President Erdogan asserting that gas will be flowing by 2023 (conveniently the 100th anniversary of the Turkish Republic), the bargaining power of Turkish companies in the renegotiation of many gas contracts that are due to expire over the next few years would seem to have been enhanced.

Finally, Mostefa Ouki looks at gas exports from Algeria. He considers the main reasons for a sharp decline in 2020 but also questions whether the country's growth ambitions are realistic and how they may be achieved, if at all. The key issues would appear to be the rapid increase in domestic demand due to subsidised prices as well as concerns over stagnating indigenous production, but Mostefa also concludes that Algeria may now finally have to reconsider its export marketing strategy and move away from its demands for oil-linked prices.

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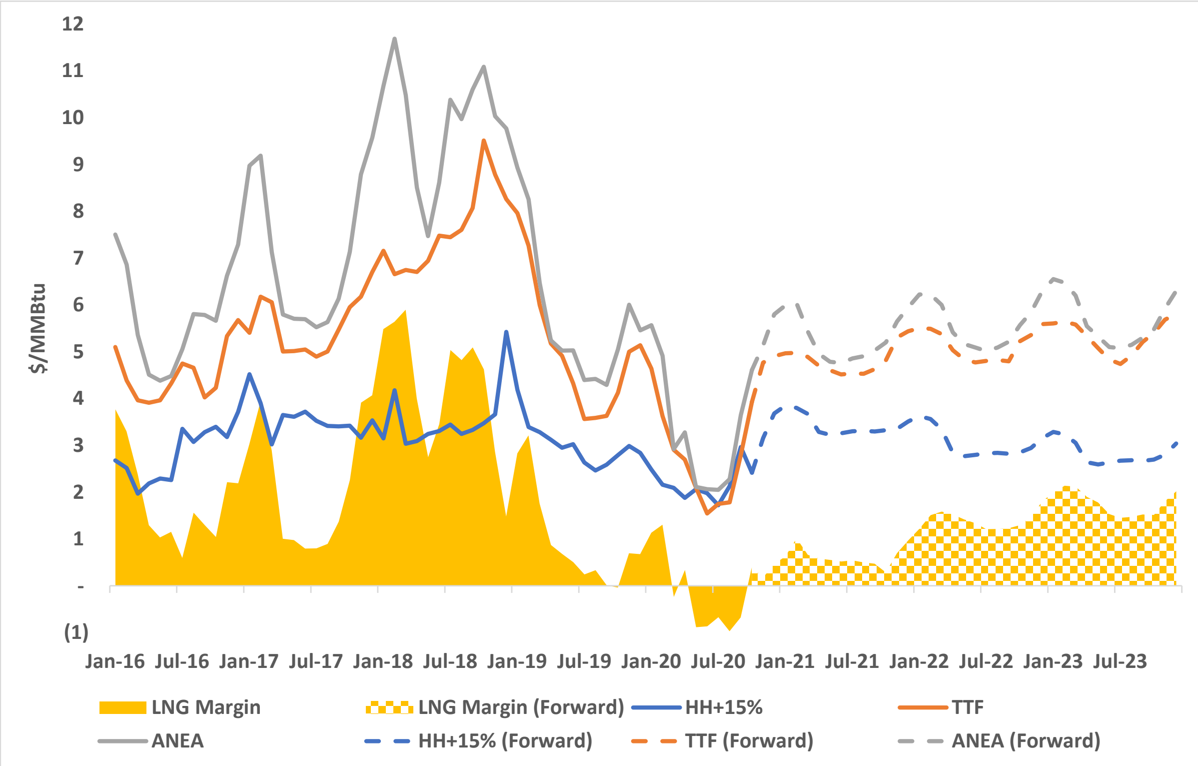
1. Gas Price Analysis

1.1 LNG Tightness – cash margins have gone negative

Firstly, we consider our "LNG Tightness" analysis as an indicator of how profitable existing export projects are and whether there is a need for new FIDs in an already oversupplied global market. The graph below is based on data from Argus Media and shows the prices for TTF in the Netherlands, the ANEA spot price in Asia and the Henry Hub price[1] in the US. It then calculates the highest netback from Europe or Asia to the Gulf of Mexico based on the relevant transport costs. The LNG Tightness calculation is then shown on a historical basis and also based on futures prices, and provides an indication of whether developers in the US can expect to recover the cost of liquefaction on the Gulf Coast (which is generally estimated at around $3/mmbtu based on the traditional Cheniere contract). A margin in excess of $3 – as it was in 2018 - would provide an obvious incentive for new projects while a margin well below this suggests a more oversupplied market.

Figure 1.1: An Assessment of "LNG Tightness"[2]



Source: OIES, based on data from Argus Media

Since March 2020, when the COVID 19 pandemic started to cause lockdowns in Asia and Europe leading to economic decline and a fall in energy demand, the margin has been negative, implying that US LNG exports were losing money on a cash basis. This led to almost 200 cargoes being shut in, which started to impact the market during the summer months. Since then demand has rebounded, and indeed is now at levels close to those seen in 2019 on a monthly basis, and when this has been combined with supply side issues (for example an oil workers strike in Norway) prices across the worked have jumped and the more usual gap between US, European and Asian prices has started to open again. Although the Henry Hub price in the US has risen on the back of a decline in associated gas production and continued coal-to-gas switching, prices in Europe have increased even more, with TTF more than doubling from a monthly average price[3] of $1.75/mmbtu in July to $3.93/mmbtu in October.

[1] 115 per cent of Henry Hub
[2] Forward curve as at July 10 2020
[3] Month ahead price

Meanwhile in Asia the ANEA price has leapt up from an average of $2.05/mmbtu in July to $4.61/mmbtu in the same three-month period, with the result that the margin for LNG sales out of the US Gulf has turned positive for the first time since April.

Looking to the future, the forward curves suggest that this trend is likely to continue into 2020, and although we are slightly sceptical about the strength of the TTF curve in Europe next summer, it would seem that the prospects for US LNG are set to improve over the next few years. The margin does not improve enough to cover full costs until 2023, but in the meantime it would seem that cash costs will be covered to an increasing extent, assuming that the forward curve price is achieved. In a new Oxford Energy Comment ("$2 Gas in Europe: Groundhog Day?" published on Oct 16th 2020) Mike Fulwood does challenge this outlook, and indeed the analysis of storage utilisation and the TTF gas price shown in Figure 1.2 outlines his main concern.

1.2 Movements in European storage utilisation and gas prices

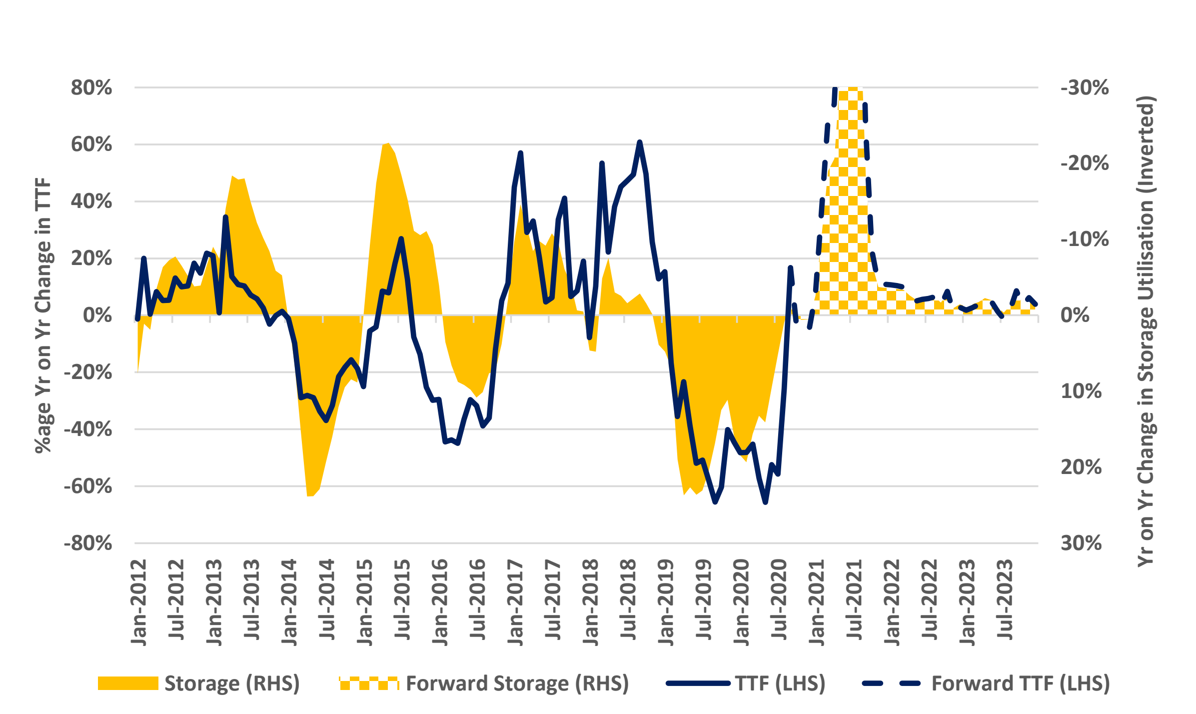
As another measure of the state of the gas market we have developed a methodology to compare the futures curve for TTF and the implications for storage levels in Europe. Figure 1.2 shows the historical correlation between the year-on-year change in storage utilisation and the year-on-year (YoY) change in the TTF gas price in Europe. As we identified in a recent paper[4] there appears to be a relatively strong correlation between the two measures, and while any statistician knows that correlation does not imply causality it would seem that the two are both driven by the same supply and demand factors. As a result, if one can estimate the outcome for one of the measures, then one can make a reasonable prediction for the other.

The outlook for storage utilisation is generally easier to predict than that for prices since changes in the former tend to move relatively slowly. However, we can reverse this as the futures curve provides a market-based outlook for prices from which one can infer an implied outcome for storage utilisation. One can then assess what the implications of this implied outcome are and therefore whether they are credible. By a process of reverse logic one can then provide an opinion on the underlying market conditions that must underpin the forward curve.

The graph below plots the YoY change of the forward curve through to 2023 and also plots the implied change in storage utilisation (inverted) that should implicitly accompany this price movement based on the correlation inferred from the historical relationship. With the forward curve currently showing a sharp increase in the TTF price to just over $4.50-5.00/mmbtu in Q2/Q3 2021, compared to $2/mmbtu this year, the implication for storage levels in Europe is that they must be set to fall very significantly compared to 2020. Our calculations suggest that storage utilisation would need to be up to 50% lower in summer 2021 compared with this year to justify such a sharp rise in the gas price. This would imply either that storage withdrawals during the winter 2020/21 will have to be much higher than during winter 2019/20 (in other words we really need a cold winter) or that summer injection levels in 2021 must be much lower than in 2020, with storage withdrawals possibly continuing well into the summer. Having said this, it should be noted that the forward curve rise in prices is well outside the observations that the correlation is based on, and it may not be appropriate to extrapolate outside this range. The year-on-year change in prices since 2012 has been in the range plus/minus 60 per cent, and the year-on-year change in storage utilisation in the range plus/minus 20 per cent. Any predictive power of the relationship established is only valid within the range of the historical observations and, even then, there will be a statistical error and range around the correlation. All that might be concluded, therefore, is that storage utilisation by the end of 2021 would be lower than the end of this year – there would be a net withdrawal over the year.

[4] Fulwood M. & Sharples J. (2020) "$2 gas in Europe (Part III): Down, down, deeper and down", Oxford Energy Comment, Oxford Institute for Energy Studies

Figure 1.2: YoY change in storage utilisation and TTF gas price[5]



Source: OIES, with data from Argus Media

European demand is expected to recover somewhat from its decline in 2020, although the fall this year looks like being much less than previously thought, with gas on power being particularly robust. Overall global demand in 2021 may rise above the levels seen in 2019, but LNG supply will also have continued to rise sharply as existing projects continue to ramp up and new projects come online. As a result, it would seem that only two occurrences could result in storage utilisation being lower next year. Either a significant amount of LNG supply would need to be shut in (possibly between 15 to 20 bcm) or else Asian demand, which has been very resilient in 2020, will need to grow much more rapidly than most forecasters expect – and well above levels seen historically. If neither of these outcomes transpire, and especially if European storage fills again in 2021, as it did in 2019 and is doing again this year, then it would seem that the futures price for TTF could prove very optimistic. We leave it for readers to draw their own conclusions.

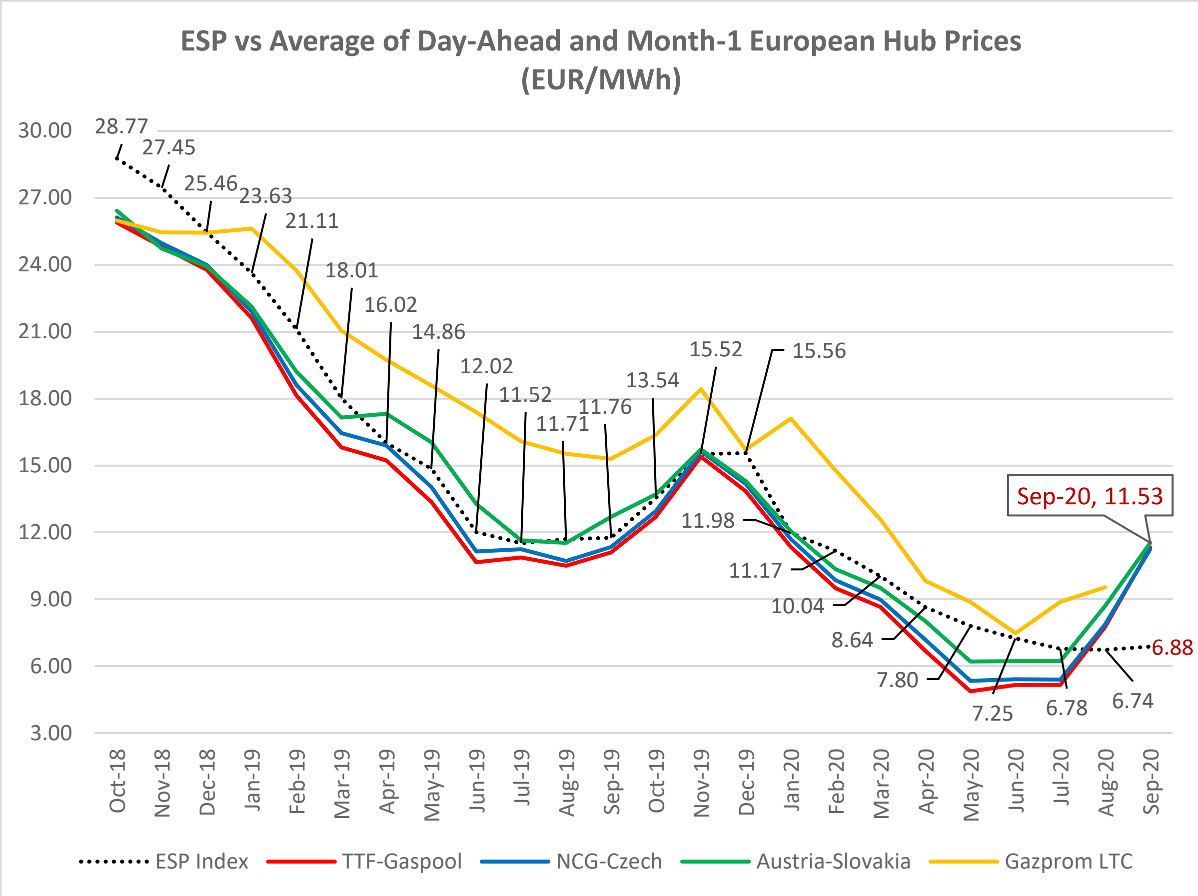
1.3 The Price at Gazprom's Electronic Sales Platform

One other source of flexibility in Europe is pipeline supply, and a key component of that is Russian gas exports. We therefore believe it is important to monitor key indicators of Gazprom's sales strategy in Europe, one of which can be found by examining the activity on the company's Electronic Sales Platform (ESP). The ESP is used to sell extra Russian gas to fill pipeline export capacity and to top-up long-term contract sales. Indeed, for some time now the ESP Index (the average of ESP prices across a number of delivery points) has shown a price lower than Gazprom's LTC price, and this has continued in 2020. However, while January and February showed a dramatic increase in volumes of short-term gas on the ESP, indicating that Gazprom was offering very competitive gas to make up for a decline in long-term contract sales (as buyers had been nominating down to take-or-pay levels due to lower demand and the availability of cheap gas on European hubs) the rest of the year has shown a marked change in strategy. We noted in the July Quarterly that the majority of sales were now for month, quarter, season or even year ahead, indicating that Gazprom had no intention of actively engaging in a short-term price war but was trying to lock in longer-term sales in a very difficult market. This trend has seemed to continue into Q3, with the majority of sales continuing to be for 3-months ahead or more. However, as

[5] Forward curve as at October 14 2020

can be seen from Figure 1.3, Gazprom's sales price remains very competitive, and indeed in August and September was below hub prices in Europe, which jumped sharply. As a result, it may be that we are starting to see a shift in Gazprom's sales strategy towards offering prices that encourage increased export volumes as the market in Europe starts to recover. The real evidence for this will be seen if the discount of the ESP Index to European hubs continues into the winter months, and we will therefore be monitoring this closely.

Figure 1.3: The Price at Gazprom's Electronic Sales Platform versus European Hubs



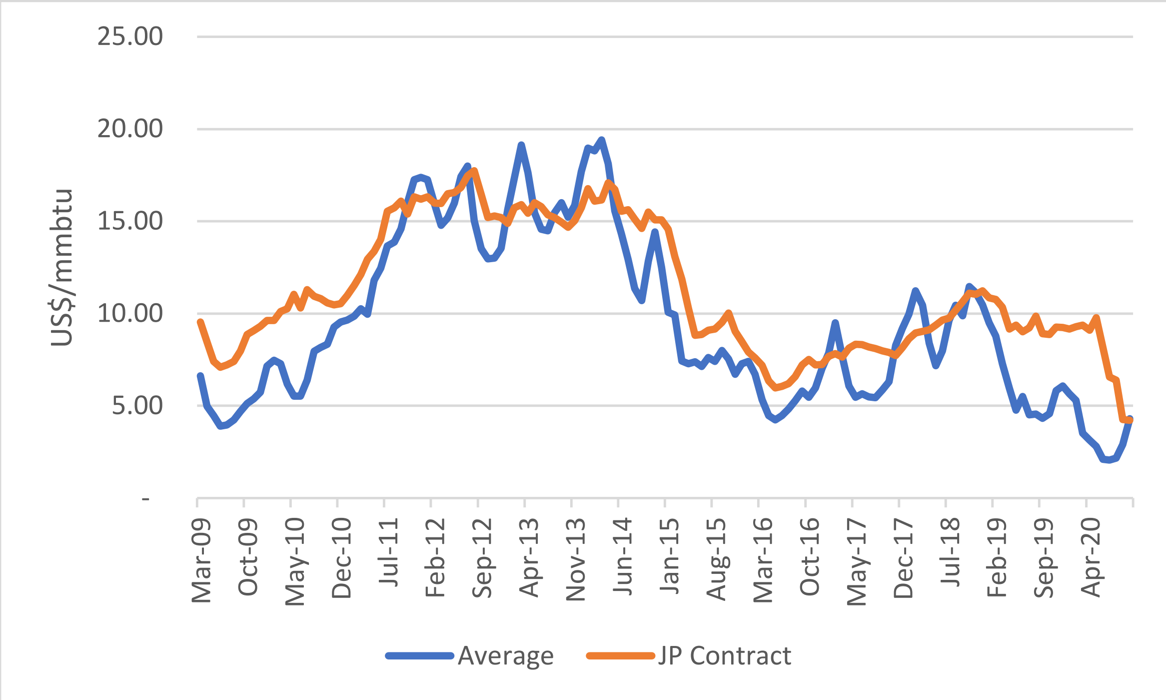
Source: GazpromExport, Argus Media, OIES

1.4 JKM spot price versus LNG contract price in Asia

The relationship between contract and spot prices in Asia continues to be of significant interest. As we have noted at various times, customers tend to demand change in the formation of prices when their impact causes them to suffer very substantial financial losses. This certainly occurred in Europe when spot and contract prices diverged and customers began to demand a move away from oil-linked pricing to hub-based prices, catalysed by new EU rules on market liberalisation. The trend away from oil-linked pricing in Asian contracts has been much more gradual, and indeed some might argue that it has barely started, but as Figure 1.4 shows, a significant divergence between spot and contract prices emerged in 2019 and then widened in the first half of 2020, creating a significant incentive for customers to act at a time when buyers clearly have significant bargaining power. The number of arbitration cases started to increase, albeit from a low base, and rumblings of discontent from those tied into higher-priced oil-linked contracts has grown.

However, as we noted in our last Quarterly, low oil prices in the first half of 2020 were bound to feed through into the Japan Contract Price at some point, and as Figure 1.4 shows, this has happened at the same time as the spot market price has rebounded slightly as economic conditions have improved. As a result, the two prices have converged for the first time since the end of 2018, albeit at a much lower level than any suppliers might have hoped. Given the fact that oil prices have remained relatively low since the start of the COVID-19 pandemic - albeit that they have rebounded from below $30 to around $40 per barrel - it is likely that the Japan Contract Price will also remain at or around current levels for a few months at least. It will therefore be interesting to see if the JKM spot price moves to a premium if the market continues to tighten over the winter months in the Northern Hemisphere and whether this eases the pressure for contract renegotiations.

Figure 1.4: JKM spot price versus Japan LNG contract price (US$/mmbtu)



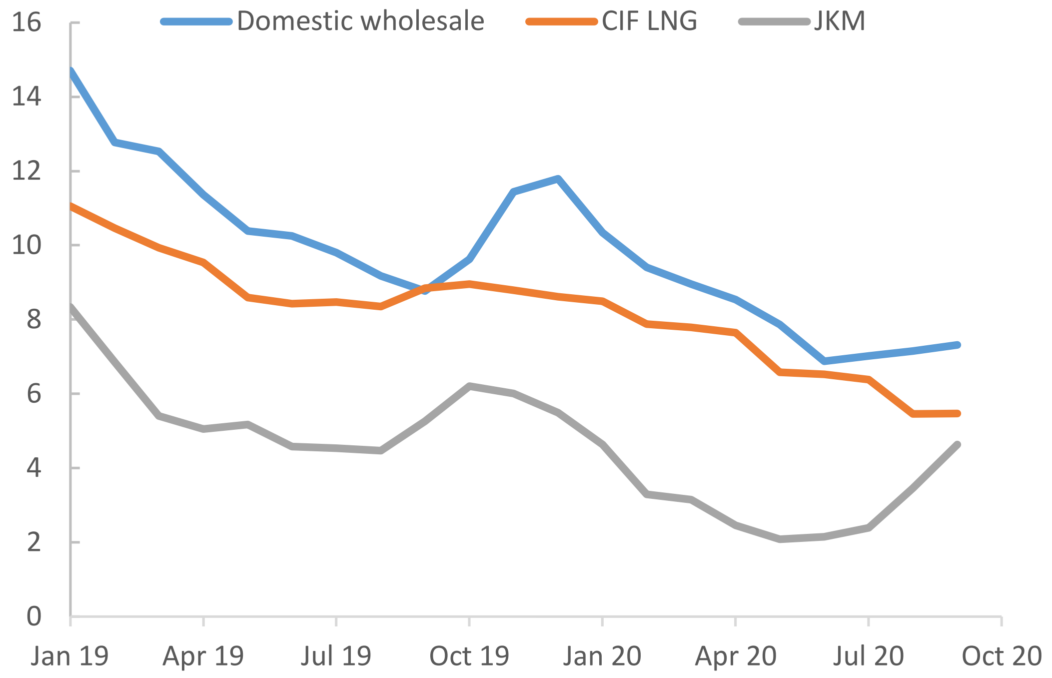
Source: Platts data, OIES analysis

1.5 Chinese domestic price versus LNG import price

An increasingly important indicator in Asia is the Chinese domestic gas price versus the LNG import price level, and we continue to monitor this on a quarterly basis. The market continues to expect that low spot JKM prices will filter through to domestic prices, leading to an uptick in China's gas demand. However, as the chart below highlights, although the average domestic wholesale price is trending in a downward direction, it remains above the level of the JKM price. The domestic wholesale price throughout 2020 is more than $4/mmbtu lower than its 2018-19 average, although this is partly due to the government's request that the majors reduce their sales prices and a mandate, back in February 2020, to cut city-gate prices. With oil-linked contract prices now starting to decline it is interesting to note that the differential to JKM has narrowed to its lowest point in the past few years, although an increase in spot purchases (as opposed to term contracts) has helped. As such, lower international gas prices have supported China's LNG demand at the expense of pipelines but have not materially supported gas demand growth. That said, given abundant supplies and relatively low prices, the government could reinvigorate the coal-to-gas switch this winter, leading to an uptick in demand.

The domestic price has increased slightly over the past couple of months, suggesting some recovery in domestic demand as wholesale prices are at record lows. As prices move closer to the international spot price, the argument for a more direct link increases. While the government is unlikely to liberalise prices altogether, it will want to see domestic prices reflect international movements more regularly, at least for as long as international prices are low. However, a dilemma remains because while Beijing wants lower prices to encourage end-user demand, the divergence between spot and term LNG prices is weighing on the majors. Moreover, Beijing would also like to maintain sufficient incentives for the majors to keep producing domestic gas, suggesting that some level of administrative intervention will remain. Nevertheless, reform efforts do seem to be continuing despite the overwhelming impact of the Covid-19 pandemic and as the gap between the domestic price and JKM narrows, it becomes easier to link the two more closely.

Figure 1.5: Chinese gas prices compared to JKM (US$/mmbtu)



Source: NBS, SHPGX, Platts, OIES

2. Is Gazprom losing the Turkish market, and why?

According to Gazprom's own data, its sales to Turkey peaked in 2017 at 29 bcm.[6] In that year, deliveries to Turkey in H1 totalled 14.2 bcm.[7] Yet by H1 2020, Gazprom's half-year deliveries to Turkey had fallen to just 4.7 bcm, while imports from competing suppliers had grown substantially, even in a context of an ongoing overall decline in total Turkish gas imports. This decline was especially marked in 2020: as recently as February 2020, Russia was the largest source of Turkish gas imports. Yet in March 2020, Russian pipeline flows to Turkey were lower than pipeline imports from both Iran and Azerbaijan, lower than LNG imports under LTCs from Algeria and Qatar, and lower than Turkey's combined spot LNG imports from a range of suppliers. In early September, the Russian business broadsheet, Kommersant, even ran a headline, 'The Turkish Market Has Expired' above an article discussing the topic of Russia's declining gas exports to Turkey.[8] This begs the question: What happened?

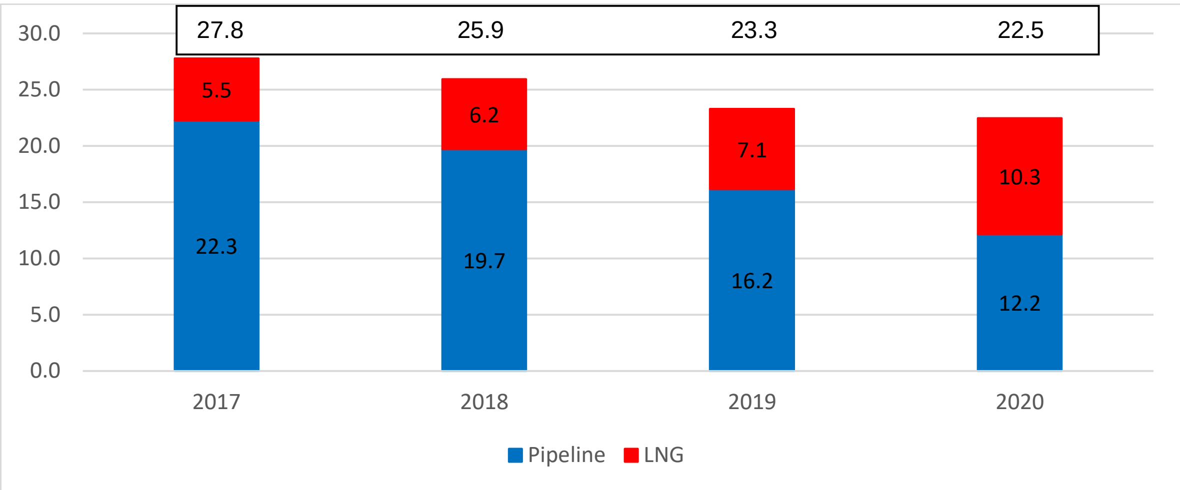
The overall decline in Turkish gas imports

First and foremost, Gazprom is competing with other suppliers for a share of a shrinking Turkish import market. As Fig.1 below illustrates, Turkish gas imports for the first six months of the year declined by 19 per cent (5.3 bcm) between 2017 and 2020. This is being driven primarily by the decline in demand for gas in power generation, as the shares of domestically-produced energy (coal, lignite, wind, solar, and hydro) increase. According to data from Turkey's Energy Market Regulatory Authority (EPDK),

[6] Source: Gazprom in Figures 2015-2019 (https://www.gazprom.com/f/posts/72/802627/gazprom-in-figures-2015-2019-en.pdf), 2010-2014 (https://www.gazprom.com/f/posts/29/761233/gazprom-in-figures-2010-2014-en.pdf) and 2005-2009 (https://www.gazprom.com/f/posts/56/123567/reference-figures-2005-2009_1.pdf) and Annual Reports for 2002-2004.
[7] Data sourced from Argus Direct ('Turkish Gas Imports'), originally reported by the Turkish Energy Market Regulatory Authority (EPDK).
[8] 'Turetskii istek' ('Turkish Expired'), *Kommersant*, 4 September 2020. https://www.kommersant.ru/doc/4476830

between 2017 and 2019, power-sector gas demand fell from 20 bcm to 10 bcm. Industrial demand has plateaued in the face of weak economic growth and the depreciation of the Turkish Lira, while residential demand also stabilised in 2017-2019 after several years of growth. These trends then intensified in the first half of 2020, as the impact of COVID-19 showed in both power sector and industrial demand reductions.[9]

Figure 2.1: Total Turkish gas imports in H1, 2017-2020 (bcm)

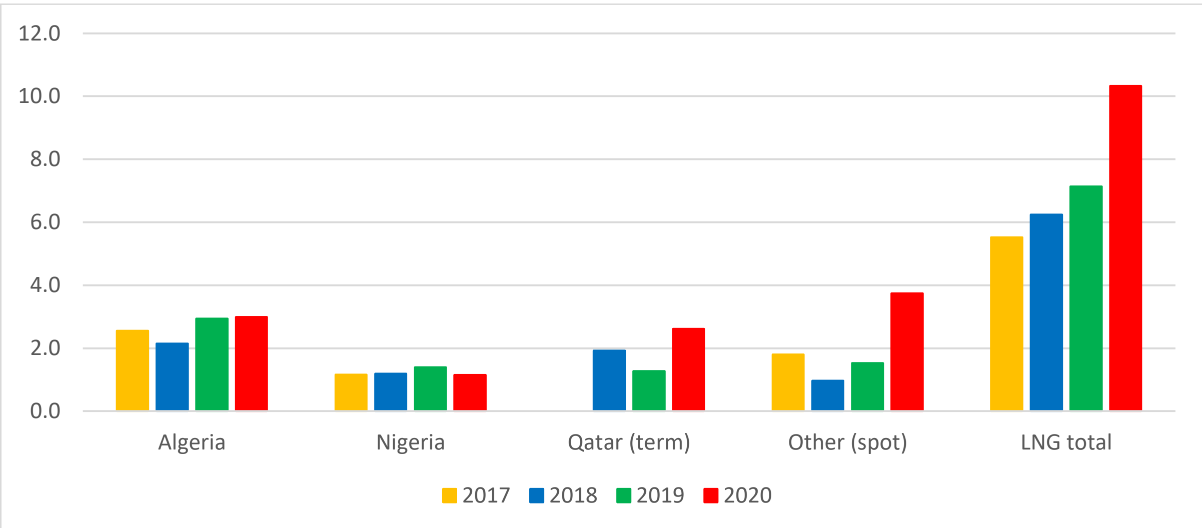


Source: Data from Argus Direct, originally reported by the Turkish Energy Market Regulatory Authority (EPDK)

The shift from pipeline to LNG imports

Secondly, the balance between pipeline and LNG imports has shifted. In H1 2017, pipeline imports accounted for 80 per cent of the total, whereas by H1 2020, that share had fallen to 54 per cent. This has been influenced by two factors. The first was the start of a three-year, 1.5 mtpa LNG supply contract between Botaş and Qatargas, with deliveries commencing in October 2017 and the second was the growth in spot LNG imports, which doubled between H1 2017 and H1 2020. This is being driven by the increased availability and price competitiveness of spot LNG supplies, in the context of a supply-long global LNG market.

Figure 2.2: Turkish LNG imports by supplier in H1, 2017-2020 (bcm)



Source: Graph by the author. Data sourced from Argus, originally published in monthly reports by the EPDK

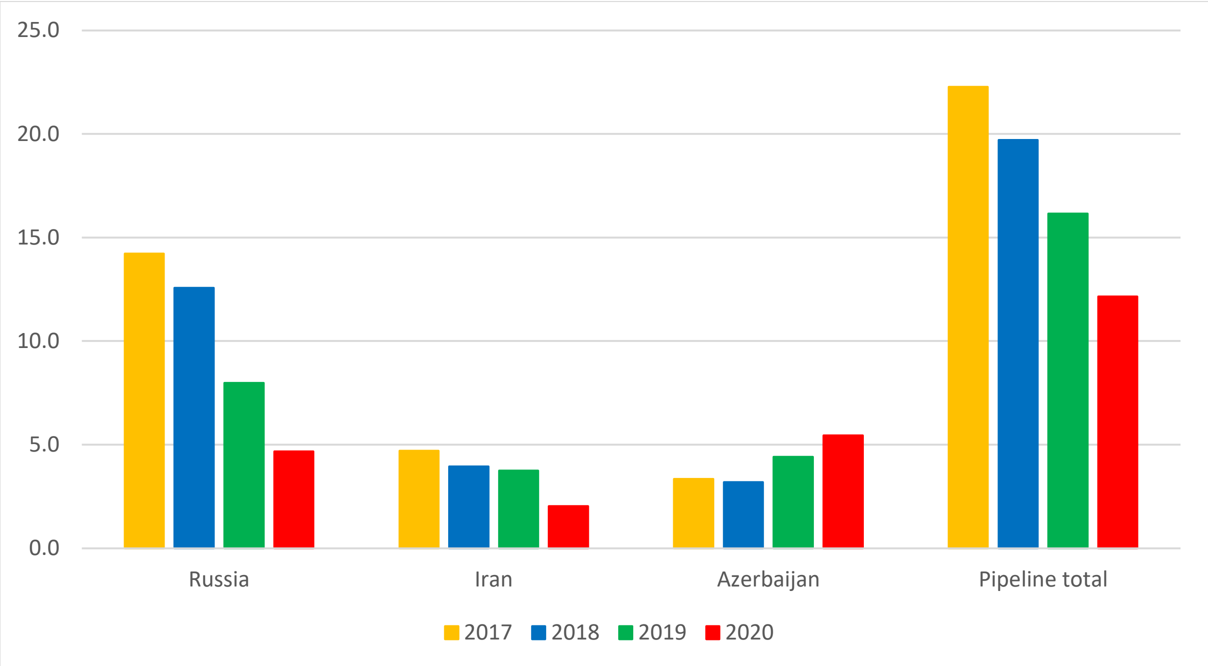
[9] Rzayeva, G., 2020. The Renewal of Turkey's Long-Term Contracts: Natural Gas Market Transition or 'Business as Usual'? OIES Energy Insight 72, September. See pages 5-10.

Competition among pipeline suppliers, Azerbaijan gains at the expense of Russia and Iran

Even with declining Turkish pipeline imports, Russia has seen its share of those imports reduced. In H1 2017, Russia accounted for 64 per cent of Turkish pipeline imports, but by H1 2020, that share had fallen to 39 per cent. In a similar vein, pipeline imports from Iran showed a moderate decline between 2017 and 2019, and a more pronounced year-on-year decline in 2019-2020. That latter decline is related to an explosion on the Iran-Turkey pipeline connection on 31 March 2020, with supplies not resuming until 3 July.[10] During the supply hiatus, reports suggested that Turkey was both bowing to pressure from Washington to replace its Iranian pipeline imports with US LNG, and seeking to pressure Iran to reduce its prices.[11]

By contrast, pipeline imports from Azerbaijan rose, displacing both Russian and Iranian pipeline supplies. A key development here was the start of commercial gas supplies from the Azeri Shah Deniz 2 project to Turkey via the Trans-Anatolian Pipeline (TANAP) on 30 June 2018.[12] The TANAP itself was formally completed on 30 November,[13] while the Trans-Adriatic Pipeline (TAP) – which connects with TANAP on the Turkey-Greece border and will deliver gas via Greece and Albania to Italy – is due for completion by the end of 2020.[14]

Figure 2.3: Turkish pipeline imports by supplier in H1, 2017-2020 (bcm)



Source: Graph by the author. Data sourced from Argus, originally published in monthly reports by the EPDK

[10] 'Iran resumes gas exports to Turkey', Tehran Times, 3 July 2020. https://www.tehrantimes.com/news/449520/Iran-resumes-gas-exports-to-Turkey

[11] 'Turkey eyes leverage as it drags feet on Iran gas pipeline repairs', S&P Global Platts, 22 May 2020. https://www.spglobal.com/platts/en/market-insights/latest-news/oil/052220-feature-turkey-eyes-leverage-as-it-drags-feet-on-iran-gas-pipeline-repairs

[12] TANAP, 2019. TANAP is ready to deliver natural gas to Europe. *Press Release*, 1 July. https://www.tanap.com/media/press-releases/tanap-is-ready-to-deliver-natural-gas-to-europe/

[13] 'Turkey and Azerbaijan mark completion of TANAP pipeline to take gas to Europe', Reuters, 30 November 2019. https://www.reuters.com/article/us-turkey-energy-tanap/turkey-and-azerbaijan-mark-completion-of-tanap-pipeline-to-take-gas-to-europe-idUSKBN1Y40CP?utm_source=reddit.com

[14] TAP AG, 2020. Trans Adriatic Pipeline Completes Offshore Section. *Press Release*, 20 June. https://www.tap-ag.com/news-and-events/2020/06/09/trans-adriatic-pipeline-completes-offshore-section

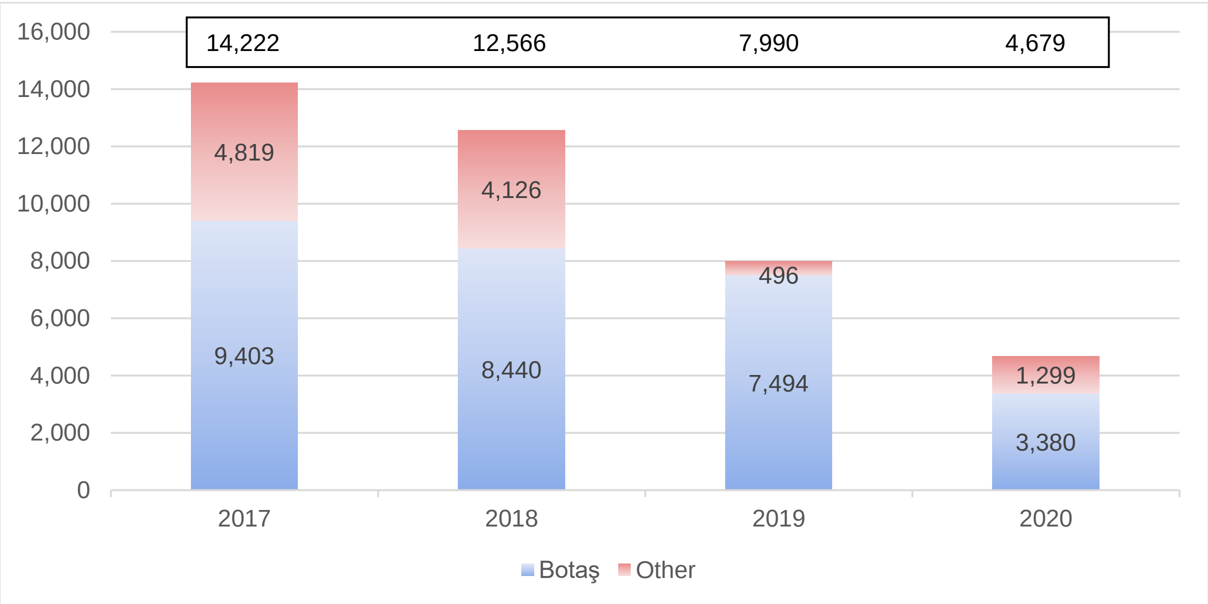
Contractual issues

From Gazprom's perspective, there is a clear distinction between its long-term contracts with state-owned Botaş and its long-term contracts with seven private companies, that have substantially reduced their offtake as they struggle to compete with Botaş on the domestic Turkish market. Those companies are Akfel Gaz, Avrasya Gaz, Bati Hatti, Bosphorus Gaz, Enerco Enerji, Kibar Enerji, and Shell Enerji.

Gazprom currently holds 10 bcma of contracts with those private companies, of which 4 bcma will expire at the end of 2021, 1 bcma will expire in 2036, and 5 bcma will not expire until 2043. Gazprom also has two contracts with Botaş, of which 4 bcma will expire at the end of 2021 and 16 bcma will expire at the end of 2025.[15] In 2017, Gazprom supplied 28.7 bcm to Botaş and the private companies – 96 per cent of the 30 bcm annual contractual amount (AQA). This fell to 23.6 bcm (79 per cent of the AQA) in 2018 and 15.2 bcm (51 per cent of the AQA) in 2019. Given that Russian pipeline exports to Turkey in H1 2020 stand at just 4.7 bcm, it remains possible that total Russian pipeline exports to Turkey in 2020 will not surpass 10 bcm - just one-third of the AQA. However, given its recent investment in Turk Stream, Gazprom may be unwilling to jeopardise its relations with Botaş by enforcing stringent take-or-pay penalties, with the hope that Turkish imports of Russian gas will eventually rebound.

Starting from the premise that the AQAs are split evenly between H1 and H2, Gazprom's supplies to Botaş and the 'group of seven' in H1 2017 were around 95 per cent of their H1 AQAs. But in H1 2019 that fell to 75 per cent of the Botaş' H1 AQA and just 10 per cent of the combined H1 AQAs of the 'group of seven'. In H1 2020, those respective percentages were 34 per cent and 13 per cent. This suggests that the first wave of decline in Gazprom's supplies to Turkey were focused on the seven private companies in H1 2019, while in H1 2020 the dramatic year-on-year decline concerned Gazprom's supplies to Botaş.

Figure 2.4: Gazprom supplies to Botas and the combined seven private companies in H1, 2017-2020 (mmcm)



Source: Graph by the author. Data sourced from Argus, originally published in monthly reports by the EPDK

Looking ahead

In the near term, Botaş' 1.5 mtpa LNG import contract with Qatargas will expire at the end of 2020. That will be replaced by a three-year, 1.2 mtpa contract with Total, which was signed in June 2020. When Gazprom's 4 bcma of contracts with four of the private importers (Avrasya Gaz, Bosphorus Gaz, Enerco Enerji, and Shell Enerji) expire, they will almost certainly not be renewed. There is also a chance that

[15] See page 22 of Rzayeva (2020) and the note at the end of this article.

Gazprom's 4 bcma contract with Botaş will not be renewed, leaving only Gazprom's 16 bcma contract with Botaş linked to the Blue Stream pipeline.

Botaş' contracts with Nigeria LNG (1.4 bcma) and the Azerbaijan Gas Supply Company (6.6 bcma - Shah Deniz 1) both expire in April 2021. Its contract with Sonatrach for Algerian LNG (4.4 bcma) expires in October 2024 and a contract with the National Iranian Gas Company (NIGC) for pipeline supplies (9.6 bcma) expires in July 2026.[16]

In this context, it is unlikely that Gazprom's supplies to Turkey will rebound in the near future. Indeed, they may remain constrained unless the Turkish market embarks upon a period of price-driven gas demand growth, and even then, Gazprom's price competitiveness will remain a key issue, alongside the extent to which state-owned Botaş is willing to see its dependency on a single large supplier (Russia) creep up back again at a time when there are plenty of alternatives available.

Note: The current state of the Turkish gas market, and the issues around its contractual relationships with the companies supplying that market (including Gazprom), are analysed in more detailed by my colleague, Gulmira Ryzaeva, in her recent OIES Insight paper, 'The Renewal of Turkey's Long-Term Contracts: Natural Gas Market Transition or 'Business as Usual'?', published in September 2020.[17]

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3. What are the implications of Turkey's new gas discovery?

On 21 August, Turkish President Recep Tayyip Erdoğan announced the discovery of a sizeable new gas field in the Tuna-1 block in the Black Sea. The new field, named Sakarya, apparently contains 320bcm of gas, and is located around 170 kilometres offshore close to the maritime border with Bulgaria and Romania. The find has created great excitement in political circles as Turkey seeks to reduce its dependence on gas imports and has hopes of becoming a gas hub in South-East Europe, but it remains to be seen whether commercial reality and technical challenges may yet dampen the prospects of the new field.

The Sakarya Field

The fact that only one well has currently been drilled, and even that has yet to be completed, means that there is little detailed information about the Sakarya field, which in itself is reason for some scepticism about the early claims being made in Turkey. At the time of the announcement the well, which was being drilled by the Fatih drilling vessel, still had 1000 metres left to drill before reaching its target depth of 4525 metres. The Turkish authorities have claimed that more reserves could yet be discovered in the remaining geological layers, but at this stage it is too early to define any estimates as the reserves are based on only one well. Indeed, it is unclear whether the Turkish authorities themselves see the 320bcm initial estimate as "recoverable reserves" or as "reserves in place". The latter would seem more likely, meaning that the actual producible reserves would be considerably less, although they could of course be increased by further discoveries at lower levels.

A further note of caution is underlined by the depth of the reservoir – 4,525 metres is very deep for any well – and the depth of the water in which drilling is taking place. The Black Sea is around 2000 metres deep at the field location. Both factors are likely to make any future development expensive and technologically challenging, especially as there is no supporting infrastructure in the region. The only analogous discovery in the area is the Neptun field in Romanian waters, which was discovered by Petrom and Exxon eight years ago. The technical operational and regulatory challenges that have been faced at this field have led to ongoing delays in taking the final investment decision (FID) and indeed have caused Exxon to indicate its intention to leave the project. It is likely that Sakarya will be equally

[16] See page 12 of Rzayeva (2020) and the note at the end of this article.

[17] Rzayeva, G., 2020. The Renewal of Turkey's Long-Term Contracts: Natural gas market transition or 'business as usual'? *OIES Energy Insight 72*, September. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/09/Insight-72-The-Renewal-of-Turkey%E2%80%99s-Long-Term-Contracts.pdf

challenging, and so President Erdogan's forecast that first gas would be produced in 2023 appears to be very optimistic. Indeed, the fact that this date coincides with the 100th anniversary of the foundation of the Turkish Republic would tend to suggest that the target for first production has more of a political rather than a commercial logic. A more realistic estimate for first gas would seem to be the second half of the decade, given the need for further appraisal drilling before any development plans can be assessed.

Another consideration is that TPAO, the Turkish state oil company, currently owns 100 per cent of the licence and has yet to make any announcement about involving foreign partners to share the risk and to bring technical and operating experience. While it is by no means certain that a foreign company could speed up the development (Neptun clearly shows the potential problems) it is nevertheless the case that TPAO itself has limited experience of offshore development in such a harsh geographical environment and at geological depths that can often bring the challenges of high pressure and tight reservoirs. As a result, banks and other lenders of project financing would probably be more confident in providing the funds that will be required if a more experienced partner was part of the consortium.

Map: Location of the Sakarya field

Source: Ahval News

Implications for the Turkish market

Having said all this, the discovery nevertheless could provide an important opportunity for Turkey to increase domestic production and, more importantly, reduce its reliance on imported gas. Assuming for now that the field resources are 320 bcm, and accepting that annual gas production would depend on the number and depth of the wells and on the precise reservoir parameters, an initial estimate for future production is that it could range between 5 and 8 bcm/year. Significantly this is around 10-18 per cent of Turkey's annual natural gas consumption, which in 2019 was 45.2 bcm.

Given Turkey's energy balance it is almost certain that this gas would be consumed in the domestic market, where it would most likely help to reduce Turkey's dependence on Russia. As discussed in the previous article, Gazprom has already been losing market share in Turkey, mainly as a result of the fact that the Russian gas price in 2019 and the first half of 2020 was the highest imported pipeline gas price in Turkey – ranging from $235-250/thousand cubic meters across the period. For this reason, Turkey decreased gas imports from Russia by almost 50 per cent in 2019 leaving Gazprom's market share at only 30 per cent last year and 18 per cent in the first six months of 2020. As a result, Turkey can be expected to use any volumes from its new discovery to further reduce its commercial, and political, reliance on Russia, especially if Gazprom refuses to change the oil-linked pricing terms that it currently applies in its contracts with Botas and other private Turkish gas companies.

Importantly, the new natural gas discovery has come at a time when Turkey is making preparations for the impending renegotiation of long-term gas sales contracts with its current suppliers.[18] The authorities have promised structural changes in the domestic gas market and its long-awaited liberalisation with the goal of freeing the gas sector from the burden of long-term contracts (LTCs) with oil-linked prices, take-or-pay (ToP) obligations and destination clauses. As a result, the new discovery is very timely, as it not only coincides with market liberalisation plans but also with a situation where all the current LTCs with pipeline suppliers will expire during the 2020s. In 2021 alone, 16 bcm/year of LTCs will expire, of which 8 bcm/year is Gazprom gas, half imported by BOTAŞ, and the remainder by seven private sector importers.

In 2021 a further four private sector companies – Bosphorus Gas, Enerco, Avrasiya Gas, and Shell – will also re-negotiate and renew their contracts. Furthermore, the pressure to reduce imports from expensive sources such as Russia is very clear. Already two private companies, Enerco and Avrasiya Gas, have failed to meet their obligations under their contracts with Gazprom, failing to import any Russian gas in 2019 and the first eight months of 2020 and as a result are facing severe ToP penalties. It would therefore seem obvious that they will not want to renew their contracts with Gazprom which currently amount to 3 bcm/year (Enerco – 2.5 bcm/year, Avrasiya Gas – 0.5 bcm/year).

Although any gas production from Sakarya is unlikely to come online before 2025, the prospect of increased indigenous production could create an important new bargaining tool for Turkish gas companies, and may encourage them to take a more assertive line in their negotiations with Gazprom. Furthermore, with gas demand in Turkey having declined for the past five years (except for 2017), and with Turkey having access to cheap spot LNG, while Botas has also increased gas imports from Azerbaijan by nearly 30 per cent since 2018, the state gas company may also not need to renew its 4 bcm/year contract with Gazprom, imported via Blue Stream. Under this level of contractual pressure, and with Turkey able to demonstrate that it has alternative sources of supply, Gazprom may even be persuaded to move away from its traditional oil-linked pricing formula towards a price based on European hubs, as it has been forced to do for the majority of its European customers.

Conclusions

Turkey's new gas discovery has come at a very convenient time, as Botas and the private gas companies are set to renegotiate all their pipeline import contracts over the next decade. Given the early stage of exploration at the Sakarya field, and the uncertainties that therefore remain, it is unclear exactly how much leverage this will provide, but when it is combined with other factors such as the availability of cheap LNG (at present) and the increase of Azerbaijani imports, as well as declining indigenous demand, it can certainly help in negotiations. Gazprom would appear to be under the greatest pressure, as the highest cost importer of gas to Turkey under oil-linked contracts, and the recent completion of the Turk Stream pipeline adds to the complexity of the situation. Gazprom may well have to make concessions on its pricing strategy if it wishes to keep Turk Stream 1 full of gas for the Turkish market while dedicating Turk Stream 2 for exports to Europe. However, the real benefits to Turkey will only come if the long-promised market liberalisation is finally completed, which would not only encourage more competition but could also turn Turkey into the gas hub that its government appears to desire.

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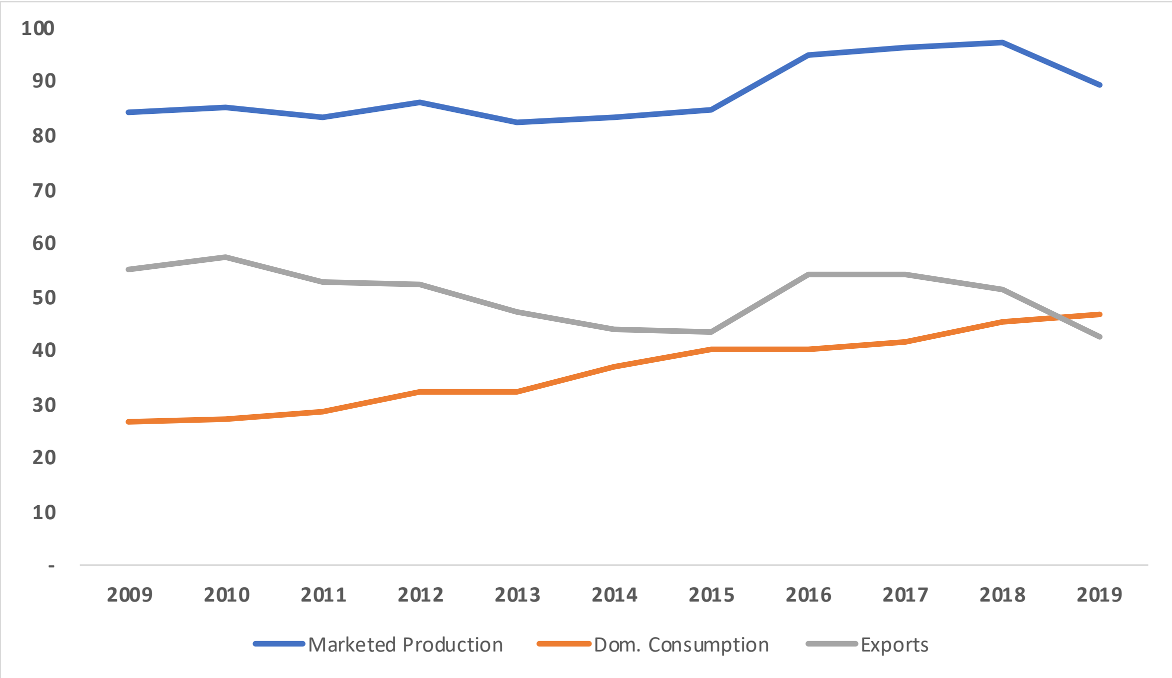
[18] See a more detailed paper on this topic by Gulmira Rzayeva – The Renewal of Turkey's Long Term Contracts: Natural gas market transition or "business as usual" on the OIES website at https://www.oxfordenergy.org/publication-category/gas-programme/

4. Algeria's constrained gas exports

A fragile situation

Over the last ten years, Algeria's natural gas exports have stagnated or declined, with the exception of a rise in 2016, as shown in the figure below. This year, the Covid-19 health crisis with its adverse impact on gas demand in international gas markets, especially in Europe, has worsened this declining export situation. The fierce competition among existing and new gas exporters for a share of a depressed European gas market combined with very low spot market prices have further weakened the competitiveness of Algeria's oil price-linked gas exports. This is leading to an inevitable change of Algeria's gas export strategy, as announced repeatedly by Algerian energy policy decision makers over the last two years. But the gas export strategy is only one of the key factors involved in addressing the constraints faced by Algeria's gas exports.

Figure 4.1: Algeria's Gas Balance (bcm): 2009–2019



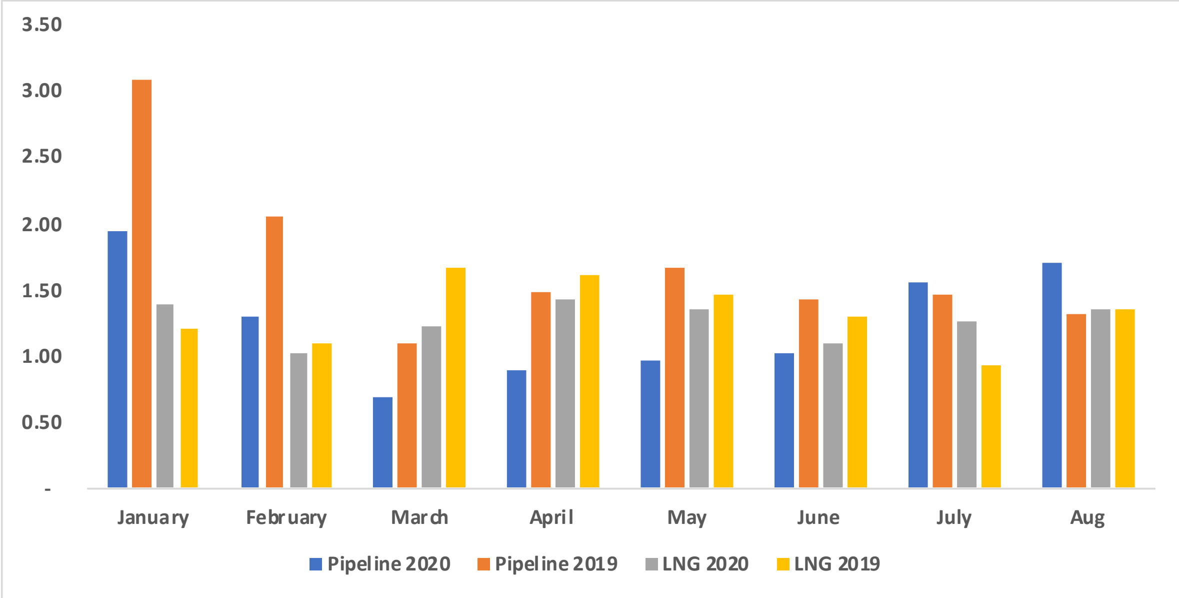
Source: GECF and OPEC, 2020

Export constraints

From January to August 2020, Algerian gas pipeline exports to Europe dropped by 26 per cent compared to the same period in 2019, while the fall in LNG exports during these eight months was much less pronounced (about 5 per cent), as illustrated in Figure 2. It should be noted that Skikda's LNG infrastructure in eastern Algeria was shut down from December 2019 to July 2020 for maintenance and also due to an incident. Sonatrach stated that this temporary plant closure did not affect Algeria's LNG exports and that the loss of Skikda's LNG capacity was compensated by an increase in the utilization of Arzew's LNG export capacity in western Algeria.[19]

[19] Sonatrach (2019). 'Travaux de maintenance et de révision du méga train du Complexe GNL de Skikda', press release, 17 December. https://sonatrach.com/presse/travaux-de-maintenance-et-de-revision-du-mega-train-du-complexe-gnl-de-skikda

Figure 4.2: Algerian gas pipeline* and LNG exports (bcm): Jan-Aug (2019, 2020)



*excluding exports to Tunisia and Morocco

Source: ENTSOG and Platts, 2020

The falling trend in Algeria's gas exports reflects the combined pressure of stagnating/declining natural gas production and rapidly rising domestic gas consumption. Although these gas supply and demand side constraints are fundamental drivers of the declining gas export trend, they are not the only factors affecting Algeria's gas exports. Other critical and interrelated factors continue to adversely impact the level of gas sales overseas.

Firstly, subdued European gas demand has resulted in limited imports, especially from non-price competitive and non-flexible sources of gas supply. This is quite important for Algeria which depends heavily on exports to Europe. As shown below, in 2019 OECD Europe accounted for 85 per cent of Algeria's gas exports, with the bulk of these exports going to southern Europe, mainly Italy and Spain. Therefore, constrained European gas markets directly affect Algeria's potential gas export levels. Furthermore, given the increasing focus on the decarbonisation of Europe's economies, the prospects for European gas imports in general could be further constrained in the future.

Secondly, as indicated above, the intense competition among existing and new gas exporters for a share of Europe's depressed gas markets plus a significant drop in international gas market prices have put more pressure on oil price-linked gas exports such as Algeria's, favouring hub-priced and more flexible spot LNG transactions. According to the Algerian Ministry of Energy, Algerian gas 'was sold in Europe at $6/MMBtu on average',[20] when spot market prices in Europe were below $2/MMBtu. This unsustainable situation explains in part the recent decline in Algerian gas pipeline exports to southern Europe.[21]

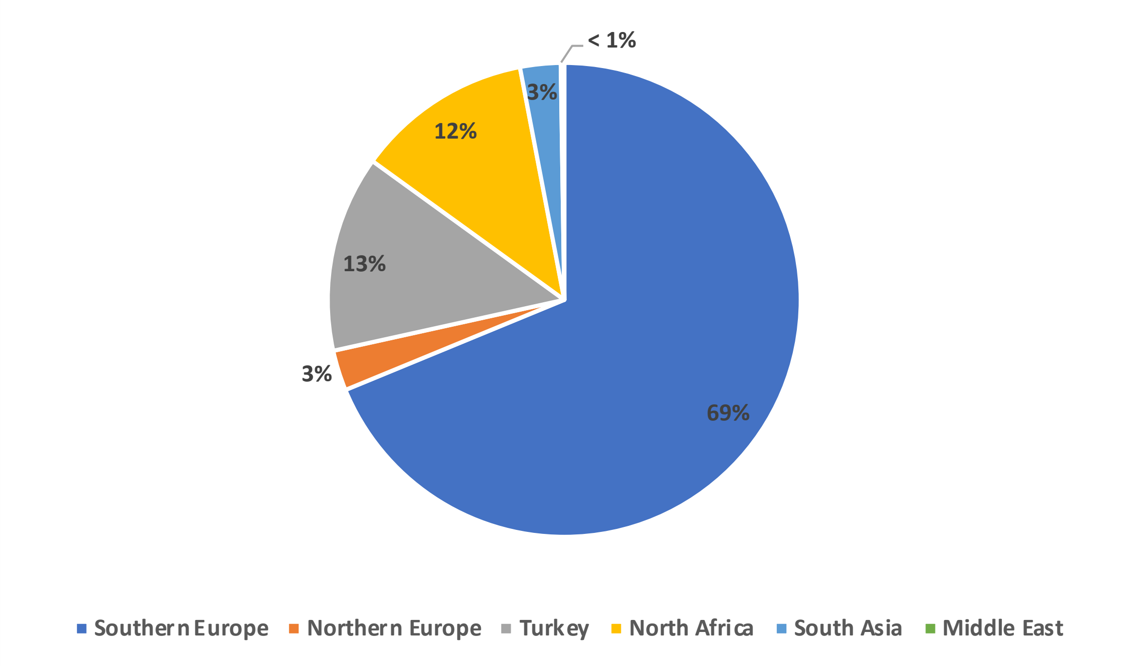
Thirdly, the absence of an adaptable Sonatrach gas marketing strategy is a factor that has seriously constrained Algeria's gas exports to Europe. While Russia's Gazprom and Norway's Equinor (previously known as Statoil) have been adjusting, sometimes reluctantly, their export strategies as a result of the fundamental changes in European gas markets, Sonatrach has remained fixated with its

[20] Alger Chaine 3 (2020). 'Invité de la redaction – Abdelmadjid Attar – Ministre de l'Energie", 21 July. https://www.radioalgerie.dz/chaine3/linvité-de-la-rédaction

[21] Calik, A. (2020). 'Algerian Gas To Italy & Spain Sees First Half Crash', *MEES*, 17 July. https://www.mees.com/2020/7/17/economics-finance/algerian-gas-to-italy-spain-sees-first-half-crash/8c388370-c832-11ea-be1a-61d4dc176a8f

standard, unsustainable gas trade model. In recent years, this has finally changed and both Sonatrach and the Algerian Ministry of Energy have acknowledged the fact that they will have to adapt to new gas market realities.[22] Over the last few months, this has consistently been reiterated by Sonatrach and the newly appointed Minister of Energy, but it has clearly not happened fast enough to alter the situation in 2020.[23,24]

Figure 4.3: Algeria's gas exports by region - 2019



Source: BP and GIIGNL, 2020

Fourthly, the high frequency of Sonatrach management changes has not helped the formulation and implementation of a consistent and well-defined new gas marketing strategy. As mentioned above, there has been a clear understanding within Sonatrach of the need for a change of gas marketing approach, but the climate of uncertainty created by recurrent management changes has not been conducive to the full development and execution of a new strategy, apart from some timid adjustments.

However, the huge pressure to mitigate further declines in Algeria's hydrocarbon export revenues and the appointment in June 2020 of a new minister of energy, who has a very good understanding of the issues at stake, should enable the formulation and implementation of an adaptable gas marketing policy. It is not yet clear whether fundamental changes in Algeria's gas marketing approach have taken place already, especially with reference to the renewals or amendment of gas contracts with several European gas importers (including the very recent amendment of contracts with Spain's Naturgy).[25] Nevertheless, Sonatrach is keen to grow its natural gas exports and although a change of gas marketing strategy will take time to yield results in today's uncertain gas market situation, it would seem that the Algerian authorities may have finally got the message that the time for delay is over.

[22] Ouki, M. (2019). 'Algerian Gas in Transition: Domestic transformation and changing gas export potential', Oxford Institute for Energy Studies, NG 151, October. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/10/Algerian-Gas-in-Transition-NG-151.pdf

[23] Mansour, T. (2020). 'Toufik Hakkar : « Sonatrach joue le rôle du pivot au niveau national et régional »', *La Patrie News*, 3 August.
https://www.lapatrienews.com/toufik-hakkar-sonatrach-joue-le-role-du-pivot-au-niveau-national-et-regional/

[24] Alger Chaine 3 (2020).

[25] Sonatrach (2020). 'Accord gazier entre SONATRACH et NATURGY', press release, 8 October.
https://sonatrach.com/presse/accord-gazier-entre-sonatrach-et-naturgy

Growth ambitions

This will be an important shift because Sonatrach is aiming to expand and diversify its gas export portfolio. It is investing in the refurbishment of some of its existing LNG capacity[26] and a few years ago acquired two new relatively large LNG carriers to potentially cover long-haul gas trade. It is also currently expanding the capacity of its LNG port facilities at Skikda.

In its overall strategy (SH 2030) issued in 2018, Sonatrach stated its objective of allocating '50 per cent of the gas marketed to new markets and to focus on value-added outlets'. However, the reality is that Sonatrach will undoubtedly have to focus on existing European gas markets, especially those of southern Europe, where Algerian gas is most cost-competitive. The reference to high value markets reflects Algeria's constrained gas supply and the need to extract as much value as possible from its gas exports. But in a buyers' market that is likely to persist for some time, with an increasing number of competing sources of gas supplies, such gas export ambitions would be extremely difficult to achieve without a significant, and government-supported, change in marketing strategy.

Conclusion

Stagnant or declining gas production combined with unrelenting growth in domestic gas consumption is continuing to frustrate Algeria's ambitions to expand its gas exports, and indeed the adverse impact of these two key constraints is acknowledged and is constantly being discussed. However, other important and interlinked factors are also constraining gas exports and will need serious attention too. In particular, a more competitive international gas market will require a more adaptable Sonatrach approach to gas marketing approach, as the limits of the company's current strategy have been exposed by the COVID-19 crisis and its negative impact on European gas demand. It would seem that a shift may be occurring, which could temporarily stem Algeria's declining gas export trend with possible modest export increases in the short term, but with the challenge of decarbonisation also emerging, a fundamental re-think of export policy may be needed to diversify away from Europe. Furthermore, in the medium to long term, a sustainable increase in Algeria's natural gas production and the restraining of the country's domestic gas demand growth are fundamentally necessary if Algeria is to sustain its gas export revenues.

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[26] *Business Insider* (2020). 'Air Products To Supply Cryogenic Heat Exchangers For Sonatrach's GL1Z LNG Facility', 9 September.
https://markets.businessinsider.com/news/stocks/air-products-to-supply-cryogenic-heat-exchangers-for-sonatrach-s-gl1z-lng-facility-1029573196#