The future of European gas after Groningen

Natural gas special report
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Gas production at Europe's largest gas field – the giant Groningen field onshore the Netherlands – will end in 2022, eight years earlier than planned, due to the risk of earthquakes in the region triggered by production drilling. The move will leave the European gas market 54 Bcm/year short compared with 2013. In our Special Report, "The Future of European Gas After Groningen", we focus on five themes examining how the European gas market will change and what consequences the shutdown is likely to have.

Why Groningen matters
Production at Groningen began in 1963, hitting a record high of 87.7 Bcm 13 years later in 1976. Infrastructure around the field was developed to supply consumers in the Netherlands, Germany, Belgium and northern France, supported by a combination of large production volumes and low costs. The Dutch field’s gas has less energy than gas from alternative sources, such as Russia, but European reliance on it has been significant. Groningen's gas contains a high concentration of nitrogen and is classed as low-calorific gas (L-gas), unlike alternatives from other sources with lower nitrogen content – high-calorific gas (H-gas).

Impact on European pricing
Groningen's phase-out is likely to have a moderately bullish impact on gas prices in Europe, as the market will be less flexible and more dependent on pipeline imports and LNG. This trend can already be seen in the 2022-21 contango on the pivotal Dutch TTF trading hub with 2022 prices almost Eur2/MWh above the 2021 price during 2019. At the same time, liquidity on the TTF is expected to continue rising with the upcoming single trading hub in Germany unlikely to become a serious rival.

Pipeline flows shift
The closure of Groningen, alongside declining gas production elsewhere in northwest Europe, means that by 2025 the region will need to replace about 45 Bcm of gas supply, according to S&P Global Platts Analytics. This shortage is likely to be partially covered by an increase in Russian gas, while Norwegian imports are set for slow decline. Russian gas can reach Europe via the first Nord Stream pipeline system, the Yamal-Europe corridor via Poland and via Ukraine, following a newly agreed five-year Ukrainian transit deal. In addition, Nord Stream 2 is expected to start flowing gas in late 2020. Gazprom aims to invest in around 250 Bcm/year of new production capacity to come online by 2025. Russian pipeline flows are also seeing a boost from spot sales on Gazprom Export’s electronic sales platform (ESP).

How LNG supply will change
The loss of the Groningen volumes comes as the global LNG market looks to remain oversupplied after a surge of new production coming online in the US Gulf Coast and Australia, leaving plenty of supply to fill the upcoming shortage in Europe. During 2019, the LNG glut became a key bearish price driver on the European gas hubs; however, looking ahead, market participants think further pressure may be limited.

Switching from L-gas infrastructure to H-gas
The Groningen phase-out will create a deficit of L-gas in the Dutch domestic market, as well as in certain parts of Belgium, France and Germany, sooner than expected. Work has long been underway to prepare Europe for the transition, including projects to convert more H-gas into L-gas, since L-gas networks are unable to accommodate H-gas.

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2000, before picking back up in pace as reserves at the smaller fields began to dwindle.

Indeed, extraction recovered to 53.87 Bcm in 2013, before production caps were put in place due to environmental concerns with the increase in frequency and size of earthquakes, which caused damage to local property.

Research into the field in terms of an environmental impact began in 2012 following a 3.6-magnitude earthquake in Huizinge, which also massively swung public opinion, prompting the creation of the State Supervision of Mines (SodM).

After the 32-year production high in 2013 and further seismic activity in the Lopppersum area in particular, the decision was made to cap output from Groningen, effectively limiting the amount of gas that would be able to be extracted on an annual basis.

In 2014, the cap was set at 42.5 Bcm, with the field coming close to breaking this limit with 42.41 Bcm produced.

This reduction was achieved by a steep drop in extraction from the Loppersum area, which saw production of 17.13 Bcm in 2013 fall to just 2.59 Bcm in 2014 in order to reduce the number of seismic events from the Groningen field.

However, extraction from the other three areas (Oost, Zuidwest and Eemskanaal) combined actually rose during the first year of the production caps, climbing to 39.8 Bcm in 2014 from 36.7 Bcm the year before.

Indeed, the number of seismic events at the field did initially decline as a result of the production cap in place, with 80 registered in 2014 from the 119 the previous year.

Nonetheless, further production cuts were introduced as public opinion continued to turn against gas.

But earthquake numbers subsequently failed to fall in line with weaker output — extraction fell back to 28.1 Bcm in 2015, 27.59 Bcm in 2016, 23.58 Bcm in 2017, and to its lowest in 50 years in 2018 at a mere 18.83 Bcm.

But the 3.4-magnitude earthquake that hit Zeerijp in January 2018 saw opposition to gas production at Groningen take an irreversible turn for the worse, with SodM advising the Dutch government to reduce production from the field to a maximum of 12 Bcm/year as soon as possible afterwards, something they took to heart with the current cap for Gas Year 2019-20 (October 1, 2019, to September 30, 2020) at 11.8 Bcm.

The Groningen field is currently slated to end gas extraction in 2022, a decision announced in September 2019.

— Gary Hornby
IMPACT ON EUROPEAN PRICING AND TTF LIQUIDITY

The accelerated phase-out of Groningen production has fuelled price support and volatility as a result of the expected greater dependency of the country on alternative sources of supply.

The soft European gas pricing outlook is expected to prevail in the short term to 2021 amid robust storage levels and unprecedented levels of LNG supply flows to the UK and continental Northwest Europe, according to Platts Analytics.

Such flows have kept a lid on European natural gas spot prices. The TTF day-ahead contract is expected to weaken further to average Eur10.40/MWh in 2020.

However, the rapid production decline and complete phase-out of the Groningen gas field by mid-2022 will mark a structural change in European gas and tighten the market.

The tide of US LNG currently flowing into Europe is also expected to recede from 2021, supporting a recovery in gas prices.

“The market noticed that [the Groningen shutdown] is creating a contango between 2021 and 2022 Cal TTF,” an Italian gas trader said.

The TTF Cal 21 contract opened almost Eur1/MWh above the Cal 22 in January 2019, but the premium disappeared over the course of 2019; the spread flipped at the end of November and Cal 22 had jumped to a 77.5 euro cent premium at the end of the year, Platts pricing data showed.

Production at the two remaining active Groningen gas fields in the Netherlands totalled only 650 million cu m in October, down more than 46% year on year because of the sharp reduction in the output quota for GY-19. This very rapid acceleration in Groningen production stems from the newly imposed GY-19 quota of 11.8 Bcm, which started October 1.

The new permit is below the one recommended by the State Supervision of Mines of 12 Bcm, already thought to be difficult to achieve while meeting the required gas demand.

This quick ramp down in domestic production will trigger a market tightness, leading to a recovery in Dutch TTF natural gas spot from 2021 to reach an average of Eur19.5/MWh in 2023, according to Platts Analytics.

Moderate boost

All else being equal, shutting down production at Groningen at an accelerated pace should provide a moderate boost to gas prices in Europe, according to Akos Losz, Senior Research Associate at the Center on Global Energy Policy, Columbia University, who has since left the position.

However, there is a real possibility that 2020 will see an even bigger glut hitting Northwest Europe during the low season, given the market’s oversupply, with any bullish price impact being washed away by a flood of LNG.

“However, the market is expected to tighten – at least temporarily – in the 2022-23 timeframe, just around the time when the shutdown of Groningen is scheduled to be completed,” Losz said.

“Once a tighter market takes hold, the loss of Groningen could have a more pronounced impact on prices and volatility, especially in times of seasonal peak demand. The loss of this supply flexibility can further exacerbate volatility and lead to sharper price spikes when the market is tight.” While the field is a key source of gas supply to the Dutch market, Groningen is also an important supplier of L-gas to customers in Germany, Belgium and France.

With Groningen ceasing production, despite recent field startups, North Sea production will also decline in 2022-23 which will further support prices.

Greater seasonal fluctuations and supply squeezes during the winter months are likely under the current strategy to optimize the use of the lower domestic production.

The wild demand swings in Europe in March 2018 triggered by the Beast from the East weather system are still fresh in traders’ minds. Greater Dutch dependency on its neighbors...
will result in further tightness on the spot market and could make price spikes more frequent.

Gas demand in northwest Europe has witnessed 16 Bcm swings over the past five winters, according to Platts Analytics, so the prevailing weather conditions will play a key role in how the system balances. This is a risk the country is willing to take to significantly reduce and eventually neutralize the earthquake risks.

Looking ahead and past the Groningen phase-out, the price spike should eventually soften. A new wave of LNG plant startups over 2024-26 will see a period of oversupply despite coal closures and declining domestic gas production.

Platts Analytics sees prices softening again below the EU coal switching point at Eur18/MWh but above Eur5/MWh. The TTF day-ahead contract for instance is forecast to ease to Eur17.20/MWh in 2024, falling to an average of Eur16.30/MWh in 2025.

Liquidity to stay
Liquidity on the pivotal TTF trading hub has been growing steadily over recent years, reaching 2,779 TWh in October 2019 – according to the latest data available from Gasunie – up from just 430 TWh in January 2011.

The number of active parties increased to 162 in November 2019 from 83 in 2011.

The TTF hub in terms of traded volumes leaves its European counterparts far behind: for comparison, liquidity at MIBGAS, the Iberian gas exchange, was just 4.38 TWh in November.

The shutdown of Groningen seems unlikely to harm the status of the TTF as Europe's premium gas hub or its trading volumes. Gas production in the Netherlands already dropped by more than half between 2013 and 2018, while TTF liquidity boomed.

Similarly, the merger of Germany's two gas trading market areas – NetConnect and GASPOOL – by October 2021, creating a single traded hub, stands little chance of rivalling TTF.

German hubs, historically, have been used more as market balancing tools rather than for curve trading. TTF, however, has become the main tool for traders to risk manage their gas portfolios given the hub's liquidity all the way down the curve. To grab that business from TTF is a big ask, according to market sources.

“There is no way a single German hub will outpace TTF,” a Dutch gas trader said.

— Antoine Simon, Kira Savcenko

GRONINGEN SHUTDOWN TO CREATE ENORMOUS L-GAS DEFICIT

The accelerated phasing out of production from the Groningen fields will create a huge L-gas deficit across Northern Europe, and far sooner than expected.

Geographically distinct L-gas market areas in the Dutch domestic market, and in certain transmission and distribution zones of Belgium, France and Germany, make up the demand centers for this variant of natural gas, and were first developed and constructed as exclusive regions in line with the development of onshore production from fields such as those at Groningen in the 1960s.

With the closure of Groningen now hastened, a considerable portion of the L-gas supply required to meet that demand will be missing both in the short term and far out on the horizon, meaning efforts to wean Northern Europe off L-gas will too have to be intensified in order to then fill the vacuum created by Groningen's absence, with current plans to do this jeopardized by the latest production quota cut.

Work has long been underway to prepare Europe for the transition from L-gas dependency to H-gas exclusivity, with expected shortfalls to be ultimately neutralized with existing initiatives already in place, namely the conversion of more conventional H-gas supplies into L-gas by process of diluting it with inert nitrogen, or more strategically adapting domestic L-gas infrastructure, large-scale users and household appliances to function with higher energy content.

These are necessary developments, since L-gas networks in Europe are unable to accommodate H-gas supply, and the two varieties of gas are not commonly interchangeable, meaning conversion is often a one-way process.

Moreover, the conversion of grid interconnection points to facilitate the transport of H-gas into exclusively L-gas regions is an added dimension of complexity that needs to
be factored into what is already a monumental challenge. Transmission and distribution networks would also have to discourage any additional connections to L-gas supply, although this is easier said than done.

At present, operator NAM – a joint venture between Shell and ExxonMobil – produces and sells Groningen gas to a single market maker, Gasterra, an unbundled supply and trading arm of former Dutch incumbent and current transmission system operator (TSO) Gasunie. The Dutch government owns 50% of Gasterra, with NAM’s parent companies making up an equal share of the remaining holding. Consequently, Gasunie, Gasterra and NAM all have to operate within the regulatory and legislative framework set out by the Dutch government with regard to Groningen production.

Gasterra, as well as meeting domestic requirements for L-gas, is the Netherlands’ prime exporter of the commodity to trading partners in neighboring Belgium, France and Germany, with many of these sales made under long-term sales agreements until 2029, the previous projected date for the closure of Groningen. These agreements would become increasingly compromised and difficult to honor without production volumes.

The extent of the overall undertaking required is formidable. According to TSO operators’ body Entsog, annual L-gas demand across these countries equates to 594 TWh/year. The Netherlands consumes the most, with 6.8 million domestic customers using 270 TWh/year, while Germany comes a close second with 4.9 million users consuming 230 TWh/year. Belgium and France have decidedly lower requirements of 50 TWh/year and 44 TWh/year respectively, requiring another 2.9 million domestic conversions between them.

While each country has its own arrangements for L-gas distribution, all will need to upgrade their existing infrastructure in order to make the transition.

The Netherlands
The Dutch government has pledged to increase capacity at existing H-gas conversion facilities, while fast-tracking new infrastructure for industrial users to reduce demand.

The Netherlands currently has 20 Bcm/year (or 18 Bcm/year in H-gas) of conversion capacity, which has been operating at almost full utilization after steep cuts in production, with operator Gasunie now frequently publishing warnings when capacity limits are about to be reached. Such capability used to be in response to weather conditions, but are now fulfilling a baseload supply role, now there is little seasonal flexibility from production or conversion.

Gasunie recently said it was confident of building enough H-L-gas conversion capacity ahead of the 2022 shutdown.

“The Dutch gas network, including additional quality conversion, is capable of accommodating the rapid reduction and closure of the Groningen field,” Bart Jan Hoevers of Gasunie said at the S&P Global Platts European Gas and LNG summit in September.

This includes an upgrade of existing facilities, expected to add 2.5 Bcm/year by January, and the commissioning of a new facility at Zuidbroek, which is currently scheduled to be operational in Q1 2022, providing an additional 7 Bcm/year. This required an investment of Eur500 million, for which socialized funds from 5%-10% higher network tariffs are expected contribute a significant proportion.

Moreover, there will be a new contractual agreement between the Dutch government and Gasterra to inject L-gas volumes into the Norg storage facility, using intensified summer conversions and injections. Given that conversion facilities were operating at approximately 75% capacity last summer, this will boost conversion by 3 Bcm/year in this current gas year. The total cost of this initiative will amount to Eur90 million.

On the demand side, Gasunie plan to prioritize conversion of 53 large-scale industrial L-gas users to H-gas supply, performing these upgrades between 2020 and 2022. The eight largest of these sites will reduce annual L-gas demand by 2.3 Bcm/year, while the remaining 45 will contribute a consumption saving of 1.1 Bcm/year, with a likely increase in network tariffs of 1%-2% to subsidize this.

The Dutch TSO admits that plans in Belgium, France and Germany cannot be accelerated by domestic initiatives, although it is planning for a 2 Bcm/year reduction in exports to these countries, with declining German demand accounting for most of this. The Netherlands exported 17 Bcm to Germany in GY-18, according to Gasunie data.

With demand across Northern Europe coming to 49.8 Bcm in GY-18, and the Groningen production quota reduced to 11.8 Bcm for GY-19, observers could be forgiven for thinking these measures do not go far enough, that production cuts cannot realistically be made without compromising security of supply, and questioning the feasibility of meeting pan-European demand with the current planned increases in conversion capacity.

Germany
As a domestic producer of L-gas, Germany still requires considerable imports to meet its own demand, with the Netherlands accounting for 60% of German L-gas supply, and most of this directly produced in Groningen under long-term contracts.

The country also has its own specialist storage facilities, such as EPE-L, Empelde and Nuttermoor in the northwest L-gas region, as well as considerable H-to-L gas conversion.
capacity of its own, operated by the NetConnect Germany and Gaspool market managers, with the most prominent of these plants being the Rehden facility, near its namesake H-gas storage site.

These existing assets could therefore help fill some of the supply gap left in Groningen’s absence, at least in the short term.

The German government has previously encouraged the origination of long-term supply contracts to ensure security of supply, while German regulator BNetzA has overseen innovations in balancing markets to resolve network any deficit or surplus. Such mechanisms, conducted by NetConnect and Gaspool, generated 10.7 TWh of transported volumes in 2017, with almost half of this pertaining to balancing through quality conversion.

Revenues received from conversion and neutrality charges are often ring-fenced for re-investment into new conversion facilities, much as they are in the Netherlands.

Germany has also made greater inroads into converting L-gas consuming regions to H-gas, with the entire city of Bremen fully converted at the end of 2019. The towns of Celle and Rees are close to completion, while the significant middle Rhine area is due for conversion between 2021 and 2023.

Other regions that require domestic conversion are Lower Saxony, North Rhine-Westphalia, Hesse, Rhineland-Palatinate and Saxony-Anhalt.

The German Association of German Transmission System operators, FNB, estimated that a tenth of current German demand will be converted every year from October 2020, which equates to 550,000 households a year.

Like the Netherlands, it will be prioritizing industrial switchovers, which individually consume more than 100 million cu m/year. Upgrades will occur gradually until 2025, at an overall cost of Eur7 billion, according to the latest FNB network development plan published in December.

This plan also incorporates 90 network expansion measures, incurring a Eur2 billion expenditure, and greater focus on H-to-L gas conversion. Domestic production is also expected to fall, with only gas delivered into the Norwega network to still produce by 2030. Production from the Elbe-Weser and Weser-Emms regions approximates to 6 Bcm/year of L-gas, with FNB forecasting this to halve by 2027.

FNB’s latest development plan saw little change from its previous edition, aside from a mildly accelerated switchover schedule. It had previously said that “at the current time, it is impossible to predict to what extent the renewed earthquake will affect the quantities and services available for Germany.” It did, however, acknowledge that flexibility in the physical delivery would be minimized, but overall viewed the situation as “uncritical.”

In terms of private investment, German energy company EWE recently finished construction of its own conversion facility, which will reduce import demand by 1.7 Bcm/year. It will ramp up H-gas imports from 2020 to make up the shortfall from a lower rate of import.

No official plans to enhance technical conversion capacity have been announced, with distribution network representative body ANRE EGU calling into question the economics of such a move in Germany.

“In theory, there would also be the possibility to technically convert the long-term available H-gas into L-gas. A central conversion of H-gas into L-gas for the entire supply area is technically feasible, but not economically viable” it said.

“In the long term, such a conversion would be significantly more expensive than a one-time conversion of the consumer device. For this reason, the decision was made to make a one-off investment in the German gas networks in the form of the described adjustment.”
Germany ultimately plans to phase out Dutch L-gas imports by 2027, despite some current long-term supply contracts extending beyond this date. Given the sharp fall in Groningen production, contracts could well be renegotiated and rewritten through arbitration, for reasons of extenuating circumstances.

Belgium

In a cold year, Belgium typically imports an annual volume of 5 Bcm, with over 3 million households and companies using L-gas supply from their distribution system.

The L-gas network has no geographical cross-over with Belgium’s H-gas network, and spans the provinces of Antwerp, Limburg, Brabant, Liege, Hainaut and Namur.

Physical conversions are planned over the summer months, and are well underway. Physical distribution upgrades were initiated in 2018, and will continue incrementally until 2029, according to GasChanges Belgium. Brussels, the country’s capital city, is expected to be converted in 2023.

Barring adjustments on compressors at interconnection points within the L-gas network, the only other major infrastructure project to be constructed in Belgium is not even for the benefit of its own consumers.

The currently under-construction Zeelink pipeline project is designed to directly connect North-Western German customers to Belgium’s Zeebrugge LNG terminal via the Belgian grid.

Developed by German TSOs Open Grid Europe and Thyssengas, its goal is to supply H-gas to traditional consumers of Groningen L-gas, in regions where domestic switchovers will occur sooner.

The pipeline will run through Aachen near Belgian the border, then northeast towards Dusseldorf, further north past Krefeld and Duisberg, before ending just north of Coesfeld. Gas is expected to start flowing through this route in March 2021.

The Zeelink project will be the culmination of a Eur600 million investment.

France

Codenamed ‘The Tulip Project,’ the domestic switchover in France is centred on the Hauts-de-France region, which predominantly receives L-gas from Groningen.

With supply contracts lasting until 2029, French TSO GRTGaz intends to entirely convert all distribution and transmission infrastructure to accept H-gas supply by this time, saying also that it requires “intervention by each client.”

France’s L-gas distribution is geographically separated into 20 districts, all with arterial H-gas connections in close proximity. The schematic of the L-gas transmission network itself alludes to an independent supply of L-gas to each of the 20 regions, making conversion less logistically challenging than in other parts of Europe.

After two years of planning, delegation and permissions, the pilot phase of the conversion began in 2018, and is set to run into 2020. These tentative steps will convert the sectors in Doullens, Gravelines, Grande-Synthe and Dunkirk before switching in any other part of the network is attempted.
The pilot phase will also see the creation of a new connection at Valhoun, which will link the H and L gas networks at this location, an equivalent upgrade at the existing Gravelines substation, as well as similar works at the Brouckerque and Speyker substations near Dunkirk.

In addition, an adaptation of the Arleux site will maintain injections of mine gas during the pilot phase, and as the full roll-out deployment phase gets underway.

GRTGaz has estimated investment into the pilot scheme at Eur42 million.

The deployment phase will begin in 2021, and will continue for the remaining eight years of the existing supply contracts. Across the entire timespan, regions will be converted independently and successively.

France has limited capacity for H-to-L gas conversions. The capability it does have will be eliminated at the beginning of the development phase, as infrastructure adjustments on the northern coast are performed.

Capacity at the main L-gas supply interconnection on the border with Belgium at Taisnieres will be halved in 2025, falling from its current throughput capacity of 230 GWh/d.

GRTgaz maintains that it is continual consultation with neighbouring TSOs also performing their own switchovers, although little mention has been made publicly of changes to be made to The Tulip Project since the Groningen decision.

**Meeting in the middle**
With L-gas supply and demand now deeply imbalanced following the Groningen production quota cut, a very delicate trade-off has to be struck between conversion utilization and domestic distribution switchover, with how best to utilize existing production also thrown into the equation.

In France and Belgium, there is no real balance to be struck, as these countries have limited capacity for quality conversion, and no persuasive reason to develop more. While existing capacity will be maximized in the coming years, the response has to very much be from the demand side.

The investment potential for German quality conversion is poor, meaning it will rely on domestic production and diminishing Groningen output for some time as it speeds up its switchover efforts. Given its endowments in quality conversion and storage, as well as a mixed-quality grid inside its borders, Dutch exports can more easily and conscientiously turn away from Germany.

While the Netherlands will soon have the capacity to fully quality convert for its domestic demand, should there be any delay in the current timetable for distribution switchover, existing and planned quality conversion capability could be insufficient to meet demand if the rapid decline of Groningen production comes to pass.

—— Neil Hunter

**PIPPINES: RUSSIAN FLOWS TO INCREASE**

A natural gas shortage after the Groningen phase-out is likely be partially covered by higher Russian pipeline flows – with the 55 Bcm/year Nord Stream 2 pipeline expected online by the end of 2020 – while Norwegian imports are set to start declining from 2023, according to Platts Analytics.

By 2025, Northwest Europe will need to replace about 45 Bcm of gas given the phase-out of Groningen and other declines in regional gas output. In terms of pipeline flows, this shortage is likely to be covered by an increase in Russian supplies of about 20 Bcm/year, with the rest being LNG.

**Russian supply overview**
Currently, Russian gas enters Europe through three main points. The first two, Nord Stream 1 imports via the German Greifswald entry point at around 55 Bcm/year, and Poland’s Kondratki flows reaching around 32 Bcm/year, are fully utilized routes with no serious disruptions expected.

Thirdly, Ukraine will transit 65 Bcm of Russian gas to Europe in 2020 and 40 Bcm/year in 2021-24 under the new five-year transit agreement reached late 2019. The deal was clinched after months of trilateral talks between the two countries and the European Commission. The Ukrainian entry point will be required at least until the Nord Stream 2 pipeline and TurkStream's second leg are up and running.

**NORTHWEST EUROPEAN GAS SUPPLY**

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Special report: Natural gas The future of European gas after Groningen
Even after this date, Ukrainian transit will still be necessary to cover periods of high demand given LNG uncertainty.

US sanctions have seen construction suspended on the Nord Stream 2 pipeline that will double the capacity of the gas corridor via the Baltic Sea to Germany to 110 Bcm/year. The most likely case for the pipeline is to come online in Q4 2020. However, technical and regulatory risks mean additional delays of up to six months are possible, taking into account the requirement to modify Russian pipelay vessels for the job, as well as possible hold-ups if waivers to the Danish permit are required. Nord Stream 2 was initially expected to be fully operational by the end of 2019.

Spot sales boost
Russian pipeline imports have been boosted of late by spot sales, with more volumes being delivered to Central and Eastern Europe. Since September 2018, an increasing proportion of Russian gas is sold on Gazprom Export’s ESP, with daily auctions set to be a permanent part of the company’s overall sales. In all, gas sales on the ESP totalled over 16 Bcm by the end of December.

Spot sales are also expected to boost market liquidity in Germany, where the largest volumes are delivered, as well as Central and Eastern European countries with historically lower liquidity.

Moreover, given that most CEE long-term contracts with Gazprom are oil-indexed, ESP sales into the region can result in more competitive pricing, potentially even reducing its reliance on long-term contracts.

Russian demand, production
Russian demand historically is weather-dependent, but improvements in heating efficiency have resulted in demand edging slowly downwards. Nevertheless, it is expected to remain stable in the period 2019-25.

Gazprom’s incremental production capacity to 2025

In power, more than half of demand in Russia comes from the industrial sector, which makes it dependent on economic growth. With sluggish GDP forecasts, CCGT demand will continue to fall over the next five years.

Gazprom is planning to invest in around 250 Bcm/year of new production capacity to come online by 2025, enough to compensate for the decline in production at the Soviet legacy fields in the Nadym-Pur-Taz region.

These new production capacities will feed into the export system to Europe, except for the Chayandinskoe and Kovyktinskoe fields that will be connected to Power of Siberia – a pipeline in Eastern Siberia that transports gas to China.

The other two exceptions are Kirinskoe and Yuzhno-Kirinskoe fields, which are part of the Sakhalin III LNG project.

Most of the new production will come from the Bovanenkovo gas field, which is already producing about 80 Bcm/year, and should reach its design capacity of 115 Bcm/year in 2021.

In addition to that, 25 Bcm/year will come from the development of the Neokom-Yurskie deposits, planned to start in 2025.

The total capacity of two lines of the Bovanenkovo-Ukhta gas pipeline, connecting the fields to the European transmission system, is 115 Bcm, just enough to ensure the gas transportation from Bovanenkovo.

Production in the declining “supergiants” of the Nadym-Pur-Taz region will be boosted by development of new layers, mostly from the Akhimov deposits at the Urengoye field. Additional capacity is set to reach 37 Bcm/year by 2025.
Most of Russia's gas field investments are aimed at those feeding pipeline networks to the West. Potential development of new export routes to China would take gas from the same fields that now feed into the transmission system to Europe, such as the Altai pipeline – with gas from Western Siberia, particularly from the Zapoloyarnoe and South Russkoe fields. NAM's underground gas storage facilities, is the site traditionally filled with Groningen gas so that production can be used more flexibly depending on the season. While the Gripskerk gas storage facility has been earmarked for closure, NAM Norg will now be able to inject converted H-gas, potentially adding a further 5 Bcm sink for H-gas in the summer.

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**Norwegian flows**

Norwegian piped production was 107 Bcm/year in 2019, down 6% year on year, with a slight increase expected in 2020.

However, it is unlikely to become a partial replacement for the missing Groningen gas, as depleting reserves at core fields and reduced development and exploration drilling since 2014 indicate a production decline from 2023.

Troll Phase 3 is set to start up in 2021 amid a tightening European gas market. However, the project is aimed at supporting longer plateau production rather than increasing export capacity. Considering Norwegian reserves are declining at an annual rate of 6% since 2014, Norwegian production is expected to enter a period of decline from 2023, shedding about 5 Bcm/year until 2025.

The next five years are likely to see a change in Norwegian flow patterns too: oversupply in the UK has already seen Norwegian flows shift towards the Continent. With the startup of the Baltic pipeline between the Norwegian sector of the North Sea and Poland, Norwegian flows are likely to shift towards the premium Central European markets.

**Smaller Dutch fields**

The Groningen phase-out will also not lead to higher output from the Netherlands’ 240 satellite gas fields, Minister for Economic Affairs and Climate Eric Wiebes said in late 2019.

Half of the country's smaller fields are in the North Sea, together accounting for about half of its gas production.

Those fields present a range of gas quality, meaning they do not have direct impact on the L-gas balance.

A small field like Pieterzijl is 10,000 times smaller than Groningen, but there are still some risks associated with extraction. For the small gas fields, around 15 damage reports arrive every year, while for the Groningen gas field there have been around 26,000 since March 2018, according to ministry data.

Production at those smaller fields is expected to continue falling by 5%-10% per year, but they are likely to produce larger volumes than Groningen in GY-19, with the gap widening until GY-22.

In a bid to reduce reliance on Groningen, the Dutch economy ministry decided to fill the Dutch Norg gas storage facility with L-gas. Norg, one of Groningen operator

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**LNG: BRIDGING THE PIPELINE SUPPLY GAP**

With the loss of Groningen volumes, continental Europe has lost its largest onshore gas field. However, this comes at a time when global LNG supplies have entered a cycle of oversupply.

A surge of new production coming online in the US Gulf and Australia, combined with an overhang of volumes as a result of consecutive mild winters in Asia, have narrowed pricing spreads between the Atlantic and Pacific.

The average spread between Platts JKM price for delivered cargoes into Northeast Asia was only 77 cents/MMBtu against Platts NWE month-ahead price for delivered cargoes into Northwest Europe.

As a result, production from projects in swing locations have increased their deliveries into Europe as a backstop destination for their cargoes. In 2019 six times as much LNG arrived from the US Gulf on Europe's shores compared with the 12/3 Bcm of gas that arrived in 2017.:

At the same time, Qatari volumes have grown 16% to 26 Bcm of gas over the past two years. Deliveries from Russia's Yamal LNG project into Europe also saw strong growth, ending 2019 at around 18.13 Bcm, up from 272 million cu m delivered in 2017.

As a result, LNG has been able to offset the lower Groningen production, though largely as a result of global oversupply pushing volumes into liquid and transparent markets.

And this availability of volume is likely to remain in the near term, with the US Gulf set to see its greatest increase in annual production capacity over 2020. Freeport, Cameron LNG, Elba Island and Corpus Christi will either begin commercial production or will be ramping up volumes from the start of 2020.

Platts Analytics data shows production from these projects alone adding 80.7 million cu m/d into global LNG supply at the start of 2020, and growing to 157 million cu m/d by the end of the year.

To put this volume in perspective, by the end of 2019, existing US LNG production was recorded at approximately
176 million cu m/d, a volume that so far has underpinned the sizeable growth in cargoes from the US into Europe.

Platts Analytics expects combined output of US Gulf coast projects, new and old, to reach 272.4 million cu m/d by the end of 2020. Even if cargoes from other sources like Qatar or the Yamal plateau over the coming year, that is still a sizeable volume that needs to be absorbed by the Atlantic and Pacific basins. Availability of cargoes to bridge any gap left by Groningen is unlikely to be a problem going forward.

The question is, will these cargoes find their way onto European shores? There are three components from a cargo perspective that will be central to driving cargoes into Europe.

The first is the transportation aspect of LNG. Assuming that severe events do not suddenly cause a significant change in fundamentals within the Pacific, spot cargoes from the US Gulf have a decision to make over whether to deliver into the Northeast Asian JKM market or Europe.

With the spread between JKM and northwest Europe averaging 77 cents/MMBtu over 2019, and a strong supply roll-out expected in 2020, market participants will be seeking to place volumes as efficiently as possible in an environment that will likely see cargoes staying in the basins in which they were produced.

This is supported by the fact that delivery times to the Asia Pacific via the Panama Canal are twice that of a delivery into Europe. It takes 12 days at an average of 17 knots from the US Gulf to deliver a cargo into Zeebrugge, Belgium, while in contrast, it takes 23 days for a cargo to reach Tokyo Bay at the same speed.

This allows two cargoes to be delivered into Europe in the same time that it takes a single cargo to be delivered into Northeast Asia, and does not require the payment of Panama Canal charges, which are approximately 21 cents/MMBtu.

This allows for more efficient use of shipping portfolios, instead of tying up tonnage on a long voyage for relatively limited gains, if any.

The second factor is that deliveries into European gas-related markets is risk. The ICE TTF contract allows a counterparty to hedge volumes from both a physical and financial perspective, ensuring the volumes can be absorbed into the grid while also setting a price position.

The option does not exist in the Pacific, as there are no equivalents within the markets of Asia in terms of physical deliveries. While the JKM derivative is liquid enough to cover price risk, the volume risk remains at the mercy of supply and demand within the region.

Third will be a pull factor from Europe from the perspective of buyers and price. Delivered LNG prices into Northwest Europe have diverged significantly from TTF hub prices as cargoes began to arrive in increasing volumes last year. As more supply looked for a home on the European grid, LNG cargoes have had to be sold at a discount in order to encourage buyers to purchase volumes over taking gas from the hub.

The differential between the Platts-assessed NWE month-ahead price for delivered cargoes has consistently been at a discount to TTF over the past six months, largely driven by the need to clear volumes into the grid as cargoes arrived at terminals in Northwest Europe.
With each cargo that arrived, the next came at a wider discount to the last in order to encourage the purchase of a cargo to replace the one that already been previously hedged for month-ahead delivery.

By the start of winter, LNG cargoes into Northwest Europe for February delivery were being assessed at $4.504/MMBtu, or the equivalent of a 50 cents/MMBtu discount to the February TTF forward contract. While sellers have had to bite the bullet in order to accept such steep discounts below hub prices, buyers have been more than happy to pick up volumes at such weak prices.

As a result, the ability to receive and regasify cargoes has also been highly sought after. LNG market participants reported that long-term capacity holders at terminals across Northwest Europe have been reluctant to release capacity over the past year, while traders secured delivery options into destinations in order to secure a position into the continent.

The LNG has also exerted downward pressure on European gas hubs over the past year, but looking ahead LNG market participants think further pressure is likely limited.

“I think that max LNG has already been priced in at this point,” a London-based LNG trader said, adding that it would be European fundamentals likely steering prices in the coming year.

In the near term, uncertainty around transit gas supply, the loss of Groningen gas and declining production elsewhere could leave a gap in European supply to fill. And there is likely to be plenty of LNG around to bridge this gap.

— Desmond Wong

LAST WORD

So, farewell Groningen. A major driving force of the European gas industry for decades, its final demise will be long lamented by veterans of the European gas market.

But in the end, the tide of popular opinion in the Netherlands turned against Groningen — and gas in general — far more quickly than many could have ever imagined.

Producing at more than 50 Bcm/year in 2013, it would have been inconceivable then to imagine the field being closed completely within 10 years.

The burden on the European gas market would be too great to shoulder, the argument would have been at the time. But as it happens, the huge growth in global LNG production capacity and Russia’s ability to keep gas flowing to Europe in ever greater volumes has meant the loss of Groningen is not as catastrophic as it once might have been feared.

Still, forcing NAM — the joint venture of Shell and ExxonMobil — to halt production at Groningen by mid-2022 will leave at least 450 Bcm of gas in the ground.

That, in turn, will hurt the Dutch treasury, whose revenues from gas production have fallen to well under Eur2 billion/year from an estimated Eur13 billion in 2013.

But economics were ultimately outweighed by politics in the Netherlands, the Dutch government unable to justify the continued risk of earthquakes and the damage they were causing to local property.

For the residents of the surrounding region, the production of gas from Groningen had turned into a never-ending nightmare, with a constant threat of serious earthquakes creating a climate of fear.

Dutch Prime Minister Mark Rutte said in 2018 that the safety of residents was “the only thing” to take into account when deciding the future of Groningen production.

Another big quake, with the potential to cause loss of life for example, would be hugely politically damaging for the government. A “do-nothing” policy was out of the question.

For the regional market, the phase-out does cause significant inconveniences though — requiring more conversion capacity to come online and users being forced to switch to H-gas.

Work will continue through the 2020s to enable consumers of Groningen gas to burn non-Groningen gas. But the hole left by Groningen does not seem to be worrying the European gas market as a whole, which is currently enveloped by bearish considerations.

With sufficient LNG and Russian imports, Groningen can be easily displaced.

On top of that, there is a growing backlash against gas in Europe, which could see some demand destruction for non-decarbonized gas.

A shift in attitude toward gas is taking place far more quickly than expected, leaving the industry struggling to keep up with the pace of change.

From youth protests to investment banks pulling funding from unabated fossil fuel projects, the role of gas as a bridge to a lower-carbon future is increasingly in doubt.

Policymakers are responding to the changing mood, with the European Commission planning to tighten EU sustainability criteria for funding gas infrastructure projects, and to propose a gas “decarbonization” legislative package by early 2021.
Companies also recognize the need to respond, with the “greenwashing” of the past seen as woefully inadequate against the background of ever-louder calls for a more rapid shift to clean energies.

It seems increasingly unlikely that any new mega gas projects in Europe — such as major new pipelines — will see the light of day, and big gas resources in regions such as the East Mediterranean or Black Sea may struggle to win financing.

Across the gas industry, the narrative is changing from excelling as a partner to renewables over the next few decades on the path to decarbonization to being part of the problem now.

And for Groningen, that reality has already dealt the field its final, fatal blow.

— Stuart Elliott