NATURAL RESOURCES

September 2021

OIL AND GAS

OIL AND GAS VIEWPOINT

Natural gas prices surge

Natural gas markets globally have changed out of all recognition over the past year. Rather than supply surpluses there are now acute supply deficits which has taken prices to multi-year highs if not record levels. The swing from surplus to deficit outside the US reflects a combination of developments including buoyant demand, supply constraints and seasonally low inventories. Market tightness and rising prices in the US reflect a different set of dynamics. Here the key factors have been sharply rising exports of LNG and pipeline gas plus the impact of Hurricane Ida on Gulf of Mexico supplies. US supplies have also been constrained in 2020/21 by lower by-product gas production stemming from declining oil output. Near-term, natural gas prices could remain elevated given depleted inventories and a scramble for supplies ahead of winter in the northern hemisphere. As always, gas prices in the northern hemisphere are sensitive to weather conditions. Seasonally cold temperatures could continue to exert upward pressure on prices. Conversely, a mild winter would deflate them. Potentially higher Russian supplies following Nord Stream 2 may depress European prices in 2022. Longer term, the key issue is whether historically high gas prices will encourage more investment in supply. This would, of course, run counter to climate change policy.

- **European gas prices**: As of mid-September 2021, the UK NBP (National Balancing Point) benchmark price was £1.77/therm or $24.5/mm Btu. This compares with a mere £0.28/therm or $3.65/mm Btu a year previously and is comfortably at least a 20-year high for the NBP. In an increasingly integrated world for natural gas, the NBP marker is also very similar to the Dutch TTF, the northern European benchmark and indeed international LNG prices. Unusually, the NBP marker at about $145/boe is trading at a significant premium to the mid-September 2021 Brent price of $75/barrel.

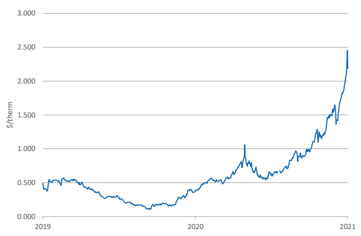
- **Europe gas supply-demand balance**: In Western Europe gas supplies have been constrained of late by a decline in pipeline deliveries from Russia reflecting technical issues and strong Russian demand. LNG supplies to Europe have also been constrained by robust demand in East Asia and disrupted logistics and processing in the US. Gas demand in Europe has been strong driven by seasonally hot conditions during the summer months, a decline in renewables power generation due to light winds associated with predominant high-pressure systems and the phasing out of coal-fired power stations. According to industry reports, UK wind power has only accounted for about 5% of power generation against planned levels of closer to 30%. A similar picture applies in Western Europe.

- **Europe gas inventories**: Reflecting the tight supply-demand balance European gas inventories are seasonally low given the late stage of the injection season. Based on industry reports, European gas storage utilisation is only about 70% currently which is much lower than typical early autumn utilisation rates of 90% plus. Given its dependence on pipeline gas imports, UK gas supplies are sensitive to storage utilisation in Europe. Note, the UK also has relatively little independent storage capacity. Existing facilities have capacity for only about 2% of domestic demand.

- **Forward NBP price**: In mid-September 2021 the NBP forward curve was in contango (near-term below forward prices) at the front-end for the first four months. Over the subsequent 18 months or so the curve then swings to marked backwardation (near-term higher than forward prices. The backend of the curve is broadly flat. Forward prices peak at 172p/therm ($23.7/mm Btu) for January 2022 deliveries before dipping to 66p/therm in early 2024. The front-end of the curve is indicative of a tight market but a loosening is expected in 2022 and 2023.

Please refer to the last page of this communication for all required disclosures and risk warnings.

Recent NBP price development



Source:Refinitiv

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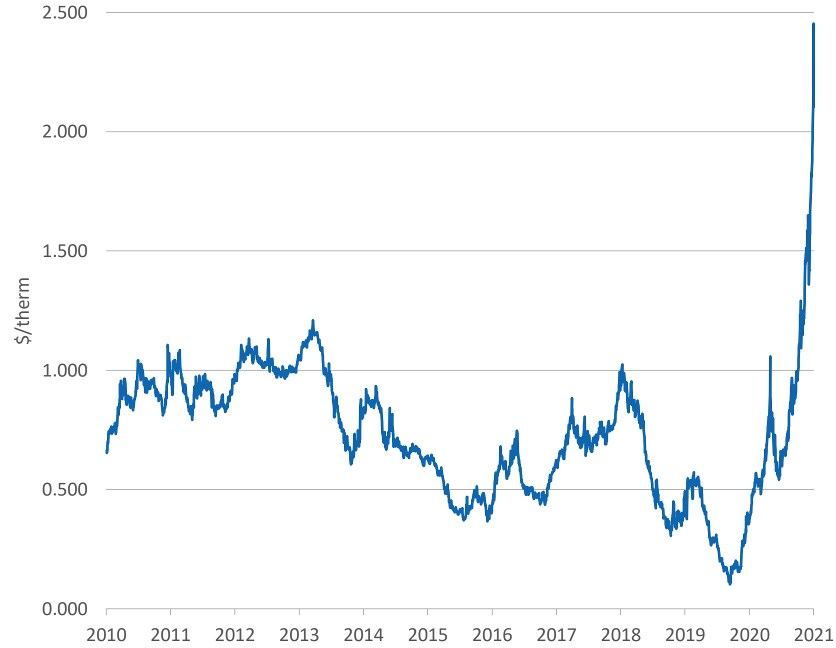
EQUITY RESEARCH

Exhibit 1: Long term NBP price trend



Source: Refinitiv

RUSSIA AND NORD STREAM 2

Largest supplier of gas to Europe: Russia is by far Europe's largest supplier of gas. Fluctuations in Russian supplies are one of the key influences on the European gas market. Based on PJSC Gazprom (world's largest publicly listed gas company) data, exports of both pipeline gas and LNG in 2020 to Europe were 200.7 bcm. This was down 8.6% on the previous year, somewhat greater than the 2.8% decline in the market. Russia's share of the market overall in 2020 was 36%, against 39% in 2019. Gazprom is traditionally the largest single supplier of gas to Europe. Shipments in 2020 of 174.9 bcm accounted for 32% of the European market. Since 2017, the Russian private company Novatek has supplied LNG from its Yamal facility on the Arctic coast to Europe.

Nord Stream likely to evolve as Gazprom's major export outlet: ----Gazprom's Nord Stream pipeline system is likely to evolve as its major export outlet. The Gazprom majority owned Nord Stream 1 pipeline was inaugurated in October 2012 and runs 1,200 km from Vyborg on the Russian coast of the Gulf of Finland to Ludmin near Greifswald on the German Baltic coast. Nord Stream 2 is 100% owned by Gazprom and largely parallels Nord Stream 1 starting from Ust-Luga on the Russian coast of the Gulf of Finland before coming ashore at Greifswald. It was completed on September 10, 2021, although testing and permitting are still required before operations can commence. Given the tightness of gas supplies in Europe, we suspect the Nord Stream 2 commercial start-up will occur before 2021 year-end. If not, we are probably looking at an early 2022 start-up.

------with capacity of 110 bcm/year: Nord Stream 2 has a capacity of 55 bcm or 1,942 bcf/year which is the same as Nord Stream 1 and provides a substantial increase in Russian export capability. Full capacity operation would boost Gazprom's existing export capacity to Europe by about 30%. To put Nord Stream 2 into context, its capacity is equivalent to approximately 65% of German consumption. A further advantage for Gazprom of Nord Stream 2 is that the sometimes-troublesome export link via the Ukraine can be bypassed if necessary.

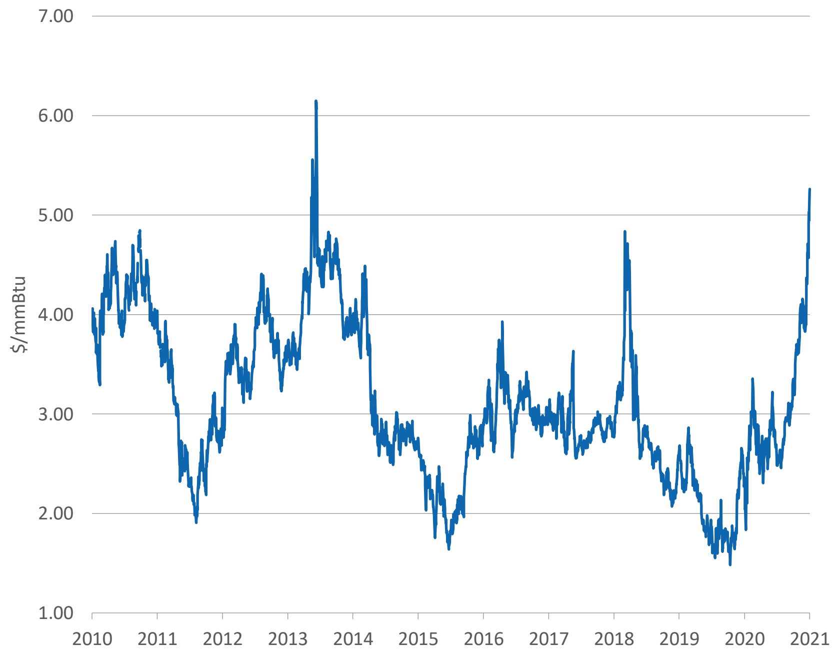
Link to giant Yamal gas fields with >100 years of reserves: Significantly, Nord Stream 2 is connected to Gazprom's giant gas fields onshore and offshore the Yamal peninsula on Russia's northwest Arctic coast. Yamal is believed in industry circles to have easily the world's largest gas reserves. Gazprom has suggested that its Bovanenkovskoye and Kharasaveyskoye fields at the Yamal gas production hub have reserves for over 100 years. Conceivably, the commencement of operations at Nord Stream 2 could help alleviate tightness in the European gas market in 2022. Little, however, is known about Gazprom's policy on shipments other than its willingness to comply with contractual obligations. During 2021 it is not clear why Gazprom apparently has not been willing to step-up shipments outside the existing contracts, given the ultra-attractive gas price backdrop. One extraneous factor restricting shipments has been a fire at a gas hub and processing plant in Siberia.

In our view, given the scale of its resource base and takeaway capacity, Gazprom is likely to continue to dominate the European gas market for the foreseeable future. The US and other LNG producers can-not in any way replicate Gazprom's supply capability.

US PRICES

Strong upward pressure in 2021: US gas prices have been subject to strong upward pressure in 2021, although this has been less pronounced than in Europe and the Pacific Rim. Natural gas prices in the US also remain well below European and international LNG levels. In mid-September 2021 the Henry Hub (Louisiana) benchmark was trading at $5.26/mmBtu, a post February 2014 high. For comparison, it plumbed a multi-year low of around $1.50/mm Btu in the late second quarter of 2020.

Exhibit 2: Henry Hub price trend



Source: Refinitiv

Loose supply-demand balance over most of the last 10 years: For much of the past ten years the gas supply-demand balance has been loose which kept US gas prices depressed in real terms. This reflected increasing supplies related to the development of the prolific Appalachian Basin and considerable by-product gas output stemming from oil-directed development in the shale basins of Texas and the Mid-Continent. Between 2010 and 2020 the Henry Hub marker only averaged over $4/mm Btu on two occasions in 2010 itself and 2014. For the period 2015 and 2020 the marker ranged between a low of $1.99/mm Btu

(2020) and $3.12/mm Btu which was distinctly marginal in profitability terms. Prices at some of the more remote hubs in Texas such as Agua Dulce and Waha traded at substantial discounts to the Henry Hub benchmark. This reflected both surging by-product gas production in the Permian Basin and inadequate pipeline takeaway capacity.

Market has tightened in 2021 reflecting a series of factors including an increase in LNG exports: During 2021 the gas market has tightened noticeably reflecting a complex series of factors. According to the EIA (Energy Information Administration the statistical arm of the Department of Energy), the key ones have been buoyant domestic consumption relatively flat production and perhaps most significantly, a sharp increase in LNG exports. The last mentioned was presumably driven by the powerful upward trend in international prices for the commodity. Since late August, the upward trend in natural gas prices has been given added impetus by Hurricane Ida. This for a time resulted in 90% or more of Gulf of Mexico production being shut-in. Anecdotal evidence suggests that around 75% of production was still off-line during mid-September.

Inventories below the five-year average: As a result of the tightening market, US injections of gas into storage have been below the five-year average. According to the EIA, US gas inventories at the end of August 2021 were 7% below the five-year average for the time of year. The EIA forecasts gas inventories at the end of the injection season in late October at around 3.6 tcf, 5% below the five-year average. We believe this may prove optimistic given the disruption caused by Hurricanes Ida and Nicholas together with buoyant demand. The EIA is looking for the Henry Hub to average $3.63/mm Btu in 2021 with averages of $4.0/mm Btu in both the third and fourth quarters. Given the strength of prices in August and September and tight market conditions, we believe the Henry Hub could easily average closer to $4.0/mm Btu in 2021. As always, prices will be sensitive to weather conditions in the fourth quarter. In recent years the pattern has been that mild conditions have tended to prevail in November and December in the principal gas consuming regions of the Atlantic North-East and Midwest.

More attractive pricing backdrop could stimulate higher production and lower prices in 2022: The consensus view is that US gas prices will come under pressure in 2022 from significantly higher production. This reflects presumed higher output stemming from both by-product gas production and stepped-up gas-directed drilling now that prices have clearly moved into the highly profitable zone of over $4/mm Btu. Much will depend not only on weather conditions and the status of the US economy but also LNG exports. Assuming that international LNG prices remain elevated, it would appear likely that US shipments will remain at a high level and probably test the limits of processing and shipping capacity. The EIA is forecasting the Henry Hub to average $3.47/mm Btu. The risks are arguably to the upside.

LNG PRICES

JKM marker has been trading around an historically $19/mm Btu. The key market for LNG is east Asia reflecting the relative lack of domestic production and pipeline imports. The benchmark for this region is the JKM (Japan-Korea-marker). As of mid-September 2021, the JKM was trading at about $19mm Btu which we believe is at or close to a record for the time of year. For comparison, the JKM averaged $5.49/mm Btu and $4.39/mm Btu in 2019 and 2020 respectively. Over the past 12 years the high point on a yearly average basis for the JKM was $16.56/mm Btu cif in 2013. Based on the year-to-date performance, we think it likely that this yearly average will be exceeded in 2021.

The JKM LNG marker has been buoyed in 2021 by a variety of supply and demand factors. Supply constraints have been imposed by several LNG facility outages while demand has been buoyed by both favourable weather-related influences (cold winter and hot summer) and the reopening of economies following an easing of coronavirus restrictions.

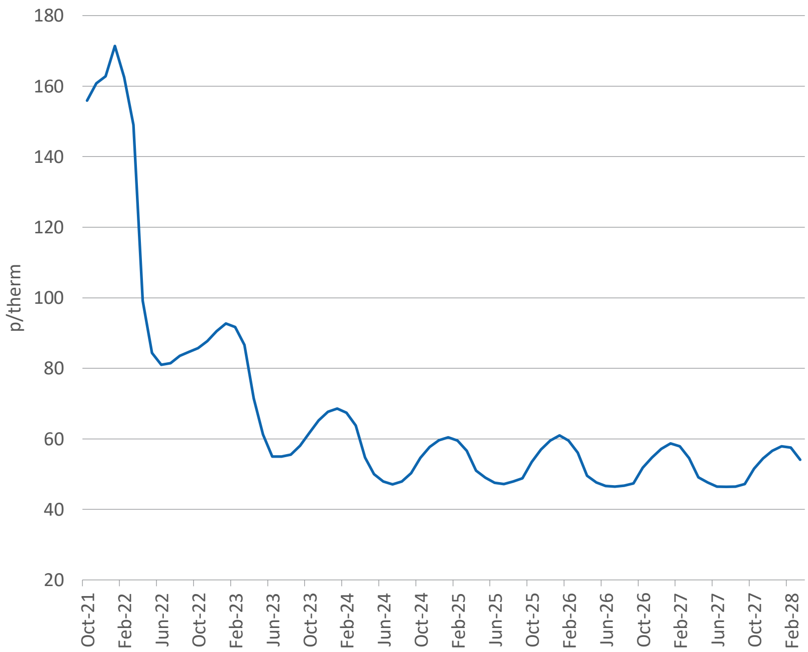
GAS PRODUCTION ECONOMICS

After a long period of depressed returns-----For much of the past ten years or more dry gas production has been a marginal activity from an economics perspective, particularly in the US. As indicated above, natural gas production economics has been transformed following this years' surge in prices. This observation stands despite what has probably been significant cost inflation in 2021 related to OCTG (oil country tubular goods), diesel, transportation, labour and a wide range of bought-in services.

--------profitability now look highly attractive in the US: In Exhibit 4 we show our model of gas production economics based on a hypothetical high-volume well in a US tight reservoir basin attracting Henry Hub pricing. Based on a mid-September Henry Hub price of $5.30/mcf the cash operating contribution would be $2.86/mcf for a margin of 62%. Allowing for F&D (finding and development) costs of $7.8m for a high-volume horizontal well with an EUR (estimated ultimate recovery) of 24 bcf, the fully accounted contribution would be $2.53/mcf. We have based the well cost and EUR on data published by the major US gas producer, Southwestern Energy (SWN: NYSE).

North Sea economics also now looks highly attractive----At prices north of $20/mcf presently North Sea natural gas production economics, we believe, are also highly attractive. Costs, of course, are much higher than onshore in the US but we believe at a price of $20/mcf the cash operating margin is substantial. Operating costs, we believe, might be in the region of $4/mcf while fully accounted costs excluding decommissioning might be around $5/mcf. In terms of the latter, we have assumed a well cost of $25m and an EUR (estimated ultimate recovery) of 24 bcf.

Exhibit 3: NBP forward curve



Source: Refinitiv

Current levels of profitability are not sustainable, but the forward curve still suggests a **comfortable position**: Clearly, prices of $20/mcf are not sustainable longer term given the potential for an influx of Russian gas and possibly LNG in due course. Presumably renewables will also make an increasing contribution to the energy mix over time while the current dominant high-pressure system and light wind backdrop is ephemeral. Based, however, on the NBP forward curve post 2023 with prices of around 55p/therm or $7.9/mcf the implied margin would still look very comfortable. It needs to be remembered that in the event of lower prices at the front end the whole curve is likely to shift downward.

Not surprisingly perhaps, LNG economics would appear favourable for producers currently. Taking a US independent such as Cheniere Energy buying gas based on the Henry Hub marker quote costs could be in the range $10-11/mm Btu. We are assuming here that liquefaction costs and transportation are equivalent to $5-6/mm Btu. This allows plenty of headroom vis-a'-vis the JKM marker price of $19/mm Btu.

Exhibit 4: US dry gas well production economics model

	$/mcf
Henry Hub price	5.30
Royalties	-0.66
Net realisations	4.64
LOE (lease operating expense)	-0.95
Pipeline tie-in/processing	-0.33
Production tax	-0.40
G&A	-0.10
Cash operating contribution	2.86
F&D (finding and development) cost	-0.33
Fully accounted contribution	2.53

Source: Southwestern Energy (SWN: NYSE) and Allenby Capital

Note: Royalty 12.5%

Production tax 7.5% of gross revenue

Well cost $7.8m (lateral 13,913 ft)

EUR (estimated ultimate recovery) 24 bcf (4mm boe)

Data are for hypothetical high volume horizontal dry gas well using a long lateral

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