NATURAL GAS WORLD
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NEWS. ANALYSIS. OPINION.

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TURKISH STREAM ON *PUTIN'S* TERMS

(PG. 2)

NATURAL GAS WORLD

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EDITORIAL: CHALLENGES AHEAD

After decades of (mostly) carefully managed stability, global energy markets have changed almost beyond recognition in the past five years. The next five are no doubt equally prone to dramatic but unsuspected technological, commercial and geopolitical upheavals.

The US shale oil and gas revolutions have reduced Opec's importance and capped prices, while energy efficiency and renewable technologies are eroding demand for gas. This is not a good time to be long in either hydrocarbon, except for integrated companies with a petrochemicals or refineries business to extract more value. Even a small rise in the crude oil price draws more rigs on line, with the resulting drop in price affecting much of the world's trade in LNG – and some of the pipeline gas – as well.

With \$100/barrel Brent crude, \$15/mn Btu gas and unbreakable chains of contracts apparently consigned to the history books, the new situation of oversupply demands a much tighter focus on savings. Traders can add value at the expense of the integrated players and the market can no longer support the incumbent suppliers who used to buy low and sell high. Now they must buy even lower and sell almost as low. Long term contracts can always be prised open and sometimes, but by no means always, the prices cut.

The excitement of North American shale gas-to-LNG projects of a handful of years ago has gone: projects on the western side of the Rockies are postponed as world markets just have no appetite for LNG even at today's much reduced prices. The opening of the expanded Panama Canal in July was a relief particularly for companies holding liquefy-or-pay contracts with Cheniere, as it gave them shorter journey times to Latin America and Asia, helping the profitability. But even brownfield US Gulf Coast LNG projects are no longer a licence to print money.

Against these developments, both the money and time it will take to bring such little gas all the way from the Caspian Sea to Europe seem unnecessary from today's standpoint, but gas is not only a long-term business; it is also political and the Southern Gas Corridor is symbolic of the importance to the European Union of a diverse portolio.

Politics includes not only attracting new suppliers to Europe, but restricting the growing influence of the old ones, such as Russia. Unchecked, it would supply even more gas. The controversy over Nord Stream 2 has been instructive, with strident opposition in many quarters, not least in Russia's former satellite states.
No such qualms appear to affect Turkey though, whose government is now once more friendly with Russia and whose parliament has been sidelined. The two autocratic presidents, Recep Tayyip Erdogan and Vladimir Putin, can now discuss energy projects with less fear of contradiction.

And there are surprising developments too at a national level: the UK has been in the headlines a lot lately, first with the Brexit referendum and then with the announcement that the government wanted to re-read the contract with EDF to build Hinkley Point C. The former could see the UK marginalised, its gas hub becoming less relevant than it was: even a few years ago it was mentioned in the same breath as the famously liquid US Henry Hub; now it is losing ground to the Dutch Title Transfer Facility. And the latter could be a chance for the government also to review capacity mechanisms and other systems that have arisen in the UK – and elsewhere in Europe – in order to fill the gap that a market used to occupy.
In the Netherlands, there are problems with gas production from Groningen; France continues to debate the necessity of fracking; Egypt has the upstream capacity to transform gas markets in the eastern Mediterranean; even small fluctuations in the growth of the Chinese economy can have a big impact on the LNG market; and so on.

Gas clearly has a vital role to play in business, although as industrial demand wanes, particularly in Europe, it needs to fill other areas, such as transport and power generation. The power markets of Europe are ripe for redesign, with the costs of balancing being properly apportioned this time round.

Natural Gas World will address questions like this: its aim is to weigh up arguments and point the reader towards possible outcomes based on what is factual and accurate, and informed by several decades of industry knowledge rather than wishful thinking. We look forward to welcoming you as a subscriber.

- NGW

TURKISH STREAM – ON PUTIN'S TERMS

Russia's president Vladimir Putin held talks in St Petersburg August 9 with his Turkish counterpart, Recep Tayyip Erdogan, as the two heads of state normalise relations. But while the Turkish leader said after their meeting that the 63bn m^3/yr Turkish Stream gas pipeline project to deliver Russian gas to Turkey would be built, Russia's leader appears to be keeping his options open.

"The Turkish Stream project will be implemented," Russian agency Tass quoted Erdogan as saying after the meeting, "We'll be taking the necessary steps to back Russian gas supplies to Europe via this gas pipeline together with involved ministries and departments," he added.

Turkey's ambassador to Russia, Umit Yardim, managed expectations the day before, saying he doubted the two sides would sign an agreement on Turkish Stream in the near future. "The talks have been going on, but we are still far from signing the agreement," he told Russia 24 TV channel.

Russia, however, has already submitted to Turkey the road map for building Turkish Stream, its energy minister Alexander Novak told Russian television August 9.

Describing it as a "detailed plan and schedule of events," he said the two sides would soon progress to a signature. The plan is to agree and sign a draft intergovernmental agreement in October and start work on the first, 15.75bn m^3/yr string once all the permits have been issued.

Putin said there were no doubts that Turkish Stream will happen and that work would start soon but that as far as exports beyond Turkey to the European Union were concerned, terms would have to be discussed.

Only four days before meeting Erdogan, Putin was in Bulgaria, discussing a possible revival of the South Stream project that would have seen a Black Sea gas pipeline terminate in Bulgaria. And just 24 hours before the meeting, Putin was in Baku discussing tripartite energy co-operation between Russia, Azerbaijan and Iran.

Overall, Russia will most likely want to make use of its own infrastructure to carry gas to the Russkaya compressor station at Anapa on its Black Sea coast by building the Turkish Stream pipeline onward to a landfall at Kiyikoy, on the coast of Turkish Thrace.

However, Bulgaria's prime minister Boyko Borissov said Russia and Bulgaria have agreed to set up working groups to look at the possible resumption of work on South Stream – the project that Putin himself discarded in place of Turkish Stream – indicating Moscow has additional leverage in negotiations with Ankara.

The first two strings of the originally planned 4-string 63bn m^3/yr Turkish Stream system at least have strong justification: the physical pipe for the initial two strings has already been delivered, either in full or in great part, and is on the dockside at the Bulgarian port of Varna. And although Russia does not expect an absolute end to all transit of gas through Ukraine after 2019, Gazprom has said it will wind down transit through Ukraine once Nord Stream 2 is on line to 15-20bn m^3/yr.

One 15.75bn m^3/yr string of Turkish Stream can therefore replace current gas deliveries flowing to Bulgaria, Greece and, above all, Turkey, across Ukraine and via the Trans-Balkan pipeline. A second 15.75bn m^3/yr string can be used to meet an expected increase in Turkish gas demand over the next several years. It also can be used to deliver around 10bn m^3/yr of gas to customers in the European Union if Gazprom should seek space on the Trans-Adriatic Pipeline (TAP) now being laid from Turkey's border with Greece to southern Italy.

What Putin had to say to Azeri president, Ilham Aliev, when they met in Baku August 8 with regard to Azerbaijan's own gas export prospects, has not been published. The state oil company of Azerbaijan (Socar) is the main driving force – and 58% shareholder – in the giant \$9.3bn Trans-Anatolian Pipeline (Tanap) which will carry an initial 10bn m^3/yr to the EU as well as 6bn m^3/yr more to Turkey en route. But while the Tanap and TAP systems are designed to carry twice these initial volumes, no fields have yet been identified as the sources.

When the partners in developing the upstream Shah Deniz field, the South Caucasus expansion, Tanap and TAP – the string of projects whose pipeline sections are collectively known as the Southern Gas Corridor – took final investment decision in late 2013, untouched giants offshore Azerbaijan were expected to provide the gas.

But the collapse of oil and gas prices and revenues as well as problems meeting domestic and export requirements mean Azerbaijan will struggle to supply additional gas much before 2025. This creates an opportunity for others.

In this context, Putin's trilateral discussions with Aliev and Iran's president Rouhani yielded another element in an increasingly intriguing puzzle: a joint statement in which the three leaders specifically agreed to work together on the shipment and delivery of gas. So just maybe there's an opening for Tehran to use the Southern Gas Corridor to carry Iranian gas to Europe.

From Moscow's perspective the advantages of using a Turkish landfall just 100 km down the Black Sea coast from Burgas are obvious. It would not have to cope with EU legislation and regulation in any shape or form, unlike the problems confronting North Stream II, Gazprom's current pipeline project in the Baltic.

Turkish Stream would also help to cement a strategic alliance, at least in energy issues, with Turkey, and put an end to the kind of dreams, entertained by Erdogan during the nadir of Turkish-Russian relations last autumn, that somehow Turkey could do without Russian gas altogether. Russian gas last year accounted for 55% of Turkey's 48.4bn m^3 of gas imports and for a similar proportion of its demand. Russian sources, commenting just before the meeting, told Tass that "the issue of discounts for the Russian gas supplied to Turkey has long been on the top of the agenda."

- NGW

THE RISING COMPETITIVENESS OF GAS

Most investment is made in conditions of uncertainty. The key task for strategists is to identify those uncertainties and guide investment accordingly, says Professor Nick Butler.

European power demand is no longer increasing with GDP. Over the last ten years it has actually gone down by 4%. In Germany, for example, power demand has been on a downward trend since 2006, going only slightly up last year. Data suggest we are past peak demand. It is clear that this decreasing trend is here to stay.

This also affects gas demand, noting that not all gas is used for power generation. European gas demand was 11% lower in 2014 than 2004. There was a slight increase in 2015 but it was still second lowest since 1995. In Germany it was down by 14% and in the UK by 9%.

The main factors contributing to this trend are:

- Efficiency of use
- Robustness of coal subsidies, plus low costs, plus absence of a meaningful carbon price
- Growth of renewables – direct support through subsidies, mandated shares, Europe-wide targets

The net result is falling demand and falling prices as we all well know.

What could change that picture?

Without change the current trends may persist. So what could change the picture?

- Removal or serious reduction of subsidies for renewables
- Surge in demand for power
- Shortage of supply of other fuels leading to a rise in their costs
- Scarcity of natural gas

Renewables

Renewables are now entrenched. Capital has already been invested and the marginal cost of production is very low. In addition, renewable costs are on a downward track. There are also potential technical breakthroughs in prospect.

In other words, renewables are here to stay, with or without subsidies. They are becoming more cost-effective and will carry on increasing their penetration of the European power market.

Demand for power

Demand for power is a function of economic growth. The outlook in Europe is not great. Efficiency gains are likely to continue. Smart meters, new materials, and so on, are contributing to this. There is also gradual improvement of capital stock. And then there is the advent of electric vehicles, but growth is slow and a surge is some way off.

Shortage of other fuels

There is no shortage of coal, either domestic or imported, and costs are and will remain low. And there is nothing else in short supply, except perhaps lithium for Tesla batteries. In an age of plenty there is ample supply of gas globally, but not within the EU, where indigenous production is going down, needing imports.

Outlook for gas supply

Within the European Union, there is not much hope. Gas in the UK Continental Shelf is without question in permanent decline and the outlook in Norway is somewhat uncertain beyond 2020. And there is no real prospect of substantial quantities of shale in Europe – not even in the UK. So the need to increase imports over time is very likely.

The world is awash with LNG and there is more to come with new additions from Australia and the US over the next five years. This glut of LNG has led to low prices to support exports. Gradual return to nuclear in Japan is reversing the surge in gas demand there, contributing further to this glut.

The production of shale gas is the US, driven by continuous improvements in fracking technology, is at an all time high and expected to carry on increasing at a high rate for many years to come.

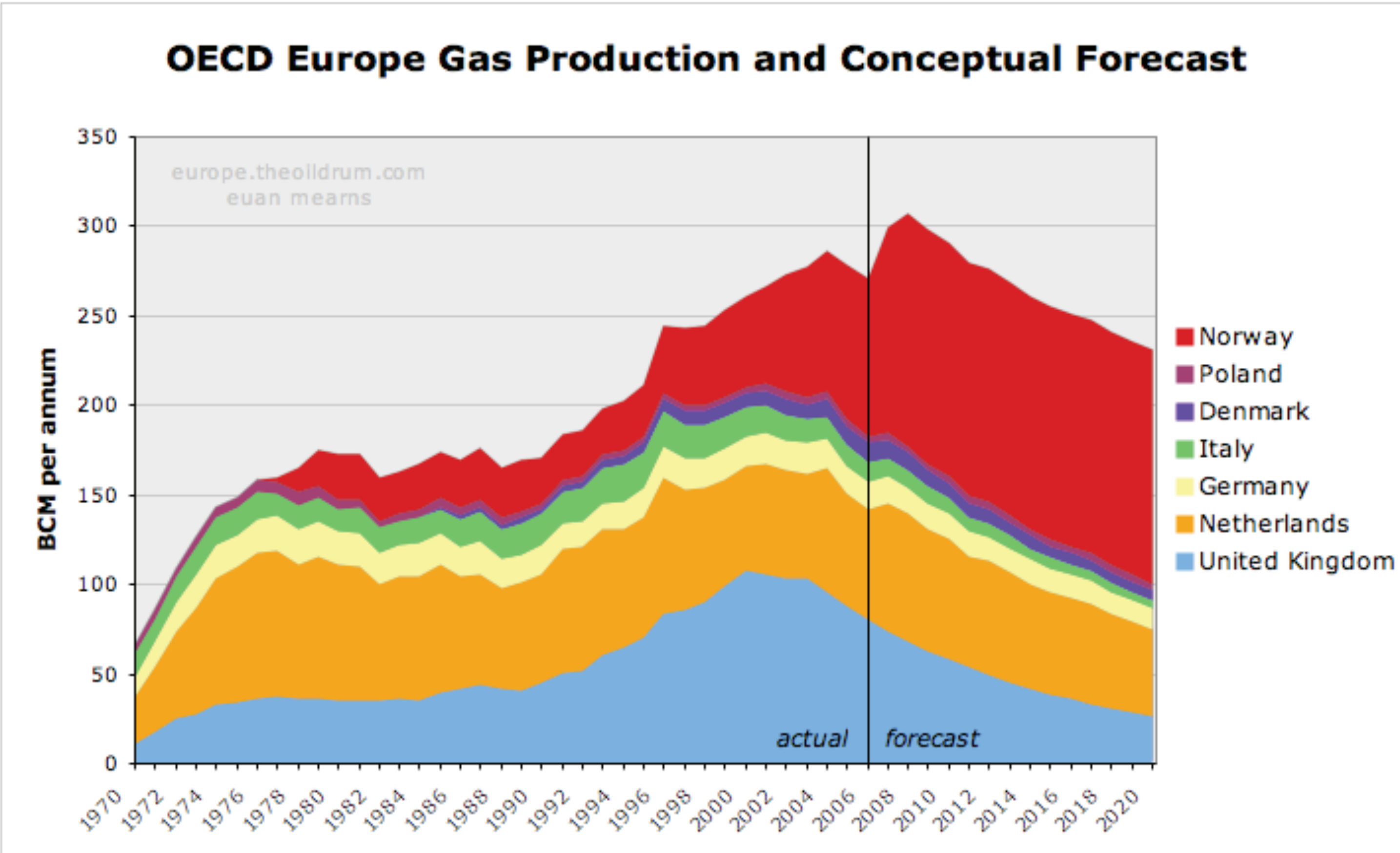
The main issue is China, which is determined to avoid dependence on any external supplier or vulnerable trade route. This increases pressure for a greater degree of self-reliance by developing its own resources including shale gas, production of which is already on the increase. Major shale gas developments would reduce the need for gas imports. The assumption that China will need to import more coal, oil and gas year by year is no longer valid. China's historical growth in imports appears to be coming to an end, as the pace of economic change intensifies. That means even more gas becoming available to find a home in the global market.

For Europe the key issue is Russia. Its deals with China are not progressing as planned. As a result, Gazprom will be even more dependent on the European market. And it has the capacity to deliver even more gas to Europe.

Nord Stream 2 is a major factor in this. The question is whether that is likely to go ahead. This comes down to political decisions in Germany and EU. However, it is more likely to proceed than not. The issues in terms of Ukraine and eastern Europe can be resolved through concessions. Gazprom is certainly very keen to maintain, if not increase, its European gas market share.

Global gas prices and trends

The world has entered an age of plenty in



terms of energy resources. The impact of this on gas is more supply than demand growth, with the result that prices are likely to stay weak for a very long time. It has become a buyers' market. There is also increasing pressure on highest cost producers with the risk that assets that are expensive to develop may remain stranded. To put it another way, we are past peak gas in Europe. The best prospect is a plateau or slight increases in demand. But indigenous gas supply is on a permanent downwards trend and the need for imports will keep increasing.

Gas should be a central option for power generation based on cost, availability and impact on reducing emissions. There are multiple sources, so there is no security of supply issue.

In terms of competitiveness in the power sector low gas prices help – even if it doesn't help gas producers too much. But there are still plenty of alternatives, with gas being squeezed by subsidized renewables and cheap coal, especially if coal is protected by the absence of a carbon pricing. That is one real uncertainty.

The key message for investors is very simple. Gas is still needed but it is better to avoid high cost projects. This also applies to takeovers that need high prices.

This may be a downbeat message for gas producers and suppliers, but they need to face realities and avoid being caught by costly surprises.

- NGW

"The world has entered an age of plenty in terms of energy resources. The impact of this on gas is more supply than demand growth, with the result that prices are likely to stay weak."

UKRAINE MOVES INTO THE FAST LANE

Over the past few years, Ukraine has made much progress in liberalising its gas market, including cutting subsidies, offering transit tariffs to third parties and developing network codes along European Union lines.

With the loss of Crimea and the war in the east with Russia spurring it on, Ukraine's monopoly importer Naftogaz Ukrainy has made an effort to knit itself into the European market and find alternative suppliers to Gazprom.

Naftogaz has introduced the liberalising policies of the EU's Third Energy Package, pushing for the corporate unbundling of its massive but ageing transmission system from Naftogaz' gas supply and production businesses. The matter has been held up by government though, perhaps worried about the subsequent sale of this strategic asset to foreign investors, which has long been a problem for parliament to approve.

Ukraine's liberalisation has started from a very low base and a new research paper published by the Oxford Institute of Energy Studies – The Ukrainian residential gas sector: a market untapped – advises that there is still a lot to be done.

For example retail prices for the domestic sector need to go up before energy efficiency will improve and demand come down, the authors argue. This will require political will. Reforming the Ukrainian energy market has proven very hard in the past owing to the population's reluctance to see gas as a commodity that has a market price.

"Many former post-Soviet states have similar issues as Ukraine with subsidised energy prices, leading to low energy efficiency, high costs for the state budget and less profitable domestic gas extraction. Reformers should take advantage of the currently very low international prices for natural gas by decreasing or removing price subsidies, while also introducing efforts to increase energy efficiency. However, for the last decade almost every Ukrainian government has agreed with the International Monetary Fund, as a part of a package of reforms, to rapidly decrease the subsidies for natural gas, with no apparent progress.

"The framework presented in this paper for calculating the effects on the size of the gas market could be used by policy makers seeking to evaluate the effects of a whole or partial subsidy removal of natural gas," the report says.

The largest inefficiencies result from large energy losses during the production and distribution of hot water by the district heating companies (DHCs), with an estimated 59% of the total energy lost. A comparable number for German DHCs is 32%, the report says.

Additionally, the corporate governance reforms of Naftogaz and its subsidiaries will play an important role in creating a stable and non-corrupt Ukrainian business environment for natural gas. Further on, the pipeline system might be partly sold off, bringing in useful revenue – although the country's role as a major transit route from the east appears to be ending, with Gazprom planning to retain about 20bn m^3/yr of entry capacity against exit capacity of 150bn m^3/yr. The authors doubt if western investors will be quick to bid for a minority stake in this asset, were it to come to the market in Ukraine's present state.

Major problems are corporate governance and regulation, as well as the need for major rehabilitation and upgrading of the pipeline network and storage system. A transparent, reformed Naftogaz with better corporate governance practices, subject to independent and professional oversight might be able to overcome the historical deficiencies of the company and root out malpractices as well as allow the company to become profitable in the long term, the authors say.

"Naftogaz seems serious about the corporate governance reform of the company and the pressure from international organisations such as the EBRD has been very strong, so there is a decent chance that Naftogaz will start acting more like a modern corporation in the coming years," they say.

Energy security: Ukraine has the most storage capacity in Europe, after Russia (Credit: Naftogaz Ukrainy)

Ukraine's energy regulator NCEPUR is in a worse position: "according to the Third Energy Package, this entity needs to be fully independent from the government and act as a neutral arbiter of the gas market. As of April 2016, the necessary changes in legislation are not yet passed. Currently, the legal foundation of NCEPUR is unclear, with the president still having the legal power to establish and liquidate the body at will, a right which has twice previously been used to dismiss NCEPUR's management," they say.

As import prices increase in the future, NCEPUR may fail to adjust the domestic prices accordingly. Similarly, with possibly increasing rates of non-payment among consumers due to the recent subsidy removal, the public pressure to decrease prices could also rise.

There has also been an opaque arbitrage opportunity owing to the parallel existence of two markets: subsidised household gas, supplied by state UkrGazVydobuvannya (UGV); and industry, which pays a market price that has been ten times greater. "Having a system with very low levels of metering of gas consumption, until recently the case in Ukraine, makes it easier to get away with these practices," the authors write. However, the low prices are responsible for the continuing stagnation of UGV.

In 2014 households (including district heating companies) consumed 22.1bn m^3 of natural gas, out of which 13.9bn m^3 came from UGV, which had to sell it at subsidized prices to Naftogaz, and 8.2bn m^3 came from imports.

And past irregularities cast a shadow over the present as well. During the privatization of gas distribution companies [oblgazy] in 2012, Gaztek, the company owned by businessman Dmytro Firtash – who is now exiled – won 14 out of 17 bids, allegedly acquiring the regional gas companies for prices far below market rates, often without real competition. The authors say that Firtash's business group "controls some 70% of the Ukrainian gas distribution market. In essence, a state-monopoly has been exchanged for an almost private monopoly."
The government claims it would like to produce 27–30bn m^3/yr by 2020 and become a net exporter of gas. However, the future remains very uncertain as the industry remains skeptical about the effectiveness and consistency of the reforms and many international players cancelled a number of important projects. This may continue until reforms are considered to be genuine and effective and potential investor confidence is restored.

Ukraine moves to offer transit capacity

Ukraine's gas transporter UkrTransGaz is conducting a non-binding market demand survey for short-haul border-to-border transportation services, it said July 19, giving a week for bids.

The services will allow gas transportation from/to Ukraine's borders with Poland, Slovakia, Hungary and Romania. Shippers may apply for up to 12 options, with each of the four countries linked to one of the other four through Ukraine, the gas flowing in either direction.

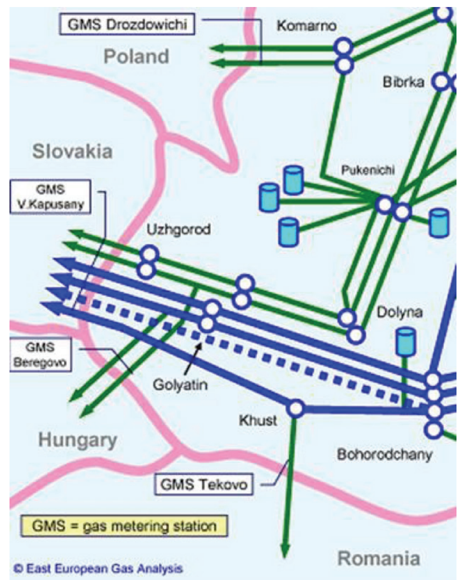
The services will be provided on a firm and/or interruptible basis without access to the virtual trading point in Ukraine. The tariff will be disclosed later after consultation with the Ukrainian regulator. At this stage a discounted tariff is envisioned in order to properly allocate costs between short- and long-haul transportation customers according to the draft EU Network Code on Harmonised Transmission Tariff Structures for Gas. Ukraine's gas transportation system is directly connected to eight countries, of which four are EU members. The average distance between interconnection points of the neighbouring EU countries is about 200-250 km. "We believe that Ukraine can significantly contribute to the interconnectivity, improve security of supply and facilitate cross-border trade in central and eastern Europe," UkrTransgaz' executive director for strategy and business development Sergiy Makogon told NGW.

Ukraine has imported no gas contractually from Gazprom since last November and Naftogaz put off buying gas from the west until this July. With storage running low – it was 32% full as of mid-July – the European Commissioner for Energy Union, Maros Sefcovic, urged Ukraine to resume trilateral talks on buying gas from Russia ahead of winter.

He told Ukraine's prime minister Volodymyr Groysman in Brussels July 21 that it was in the mutual interest of Naftogaz and Gazprom to agree on the terms for the purchase of Russian gas. The EC stood ready to facilitate trilateral talks, if requested, as it had for the past two winters.

Naftogaz Ukraine CEO Andriy Kobolev said the company was "grateful to the EC for the proposed help in conducting the trilateral negotiations" and ready to participate in such a meeting in the nearest time and place suitable to all parties.

- NGW



Ukraine's gas transport system: EU exit points

"As import prices increase in the future, NCEPUR may fail to adjust the domestic prices accordingly."

OILFIELD SERVICES NOT OUT OF THE WOODS YET

Contractors suffered larger losses or lower 1H or 2Q 2016 earnings thanks to lower oil prices, the deferral of billions of dollars' worth of major oil, gas and LNG developments and the costs of redundancies.

Low oil prices made for another poor quarter, but most feel that the low oil price challenges have now reached the bottom of the cycle with better outcomes in 2017 at the earliest.

Speaking to ***The Times*** July 25, Ian Taylor, the CEO of giant commodities trader, Swiss-based Vitol, said it could take a year or two to absorb the 500-600mn barrels of crude in the system. He expected the overhang to persist for another two years. "On balance we do think it will tighten a bit next year. But every time we run the numbers we think it's going to be a little bit less."

Norway's Aker Group gave some grounds for cautious optimism, hinting there might be light at the end of the tunnel. It said that its 2Q 2016 net asset value and that of its holdings adjusted for dividend was Nkr24.7bn ($2.9bn), up 29% compared with 1Q 2016.

CEO Oyvind Eriksen said this was "the strongest quarterly increase since 2006," with the gain in Det norske alone (50%-owned by Aker) being Nkr4bn. "What a reminder of the continued value potential in oil and gas!" he noted. Aker said that 49% of its gross asset value of Nkr31.7bn in 2Q 2016 were oil- and gas-related, of which 32% being Det norske, 16% oil services (Aker Solutions, Akastor, Kvaerner) and 1% other.

Pre-tax 2Q 2016 profit of Nkr742mn was up 54%. Among important contract wins in 2Q 2016 was the umbilical system for the Zohr gas field offshore Egypt, valued at over Nkr1bn.

At the other end of the scale, Halliburton reported a $3.2bn loss from its continuing operations, a third as much again as its $2.4bn loss in the preceding first quarter. Revenues in April-June were 9% lower at $3.84bn – of which $1.5bn in North America, down 15%, and $2.3bn elsewhere, down 4% – and its operating loss was 26% greater at $3.88bn, mostly as a result of the May 1 cancellation of a planned merger with Baker Hughes.

Putting a brave face on it, CEO Dave Lesar said: "Our 2Q results showed resilience in the face of another challenging quarter marked by lower activity levels and continued pricing pressure around the globe."

Halliburton's termination fee paid to Baker Hughes, after the US Justice Department issued a negative decision on anti-trust grounds, together with related costs, came to $3.52bn in 2Q 2016 and $583mn in 1Q 2016. Excluding those items Halliburton's adjusted operating income was $62mn in 2Q, compared with $225mn in 1Q 2016.

The world's biggest oilfield services company Schlumberger reported a Q2 2016 net loss of $2.16bn July 21, down from a profit of $501mn in Q1 2016, despite the rising oil price; and down from a profit of $1.124bn in Q2 2015.

CEO Pal Kibsgard said: "In the second quarter market conditions worsened further in most parts of our global operations, but in spite of the continuing headwinds we now appear to have

Halliburton, in the red (Photo credit: Halliburton)

reached the bottom of the cycle. As we continued to navigate this challenging environment, we again delivered robust pretax operating income, operating margin, and free cash flow." Revenue over the quarter rose 10% sequentially, reflecting a full quarter of activity from the Cameron businesses that contributed $1.5bn. The drilling segment saw the biggest fall in margins over the period.

The acquisition of Cameron, which was completed April 1, "will result in the industry's first complete drilling and production systems, which will be enabled by Schlumberger expertise in instrumentation, data processing, control software, and system integration," it said. Pre-tax revenue fell 12%, with the major fall in North America thanks in part to a 25% drop in the US land rig count, while international revenue fell 9% owing to weaker activity, continued pricing pressure, and a large-scale cutback in Venezuela. "However, our wide geographical footprint and broad technology portfolio continued to offer unique advantages that helped to mitigate these effects," he said.

With a global reach, its products have been designed to deal with most adverse geology and geography that the pursuit of oil and gas production can throw at it, and its quarterly results are littered with trademarked products that further reduce manpower and save time, bringing more oil and gas to the surface for the same cost. For example its Rhino XS reamer "has a single-piece body that allows for higher tensile and torque-load capacity, while Well Commander tools enable operators to boost circulation to remove cuttings at strategic points in the drillstring. As a result, the customer" – in this case BP, offshore Azerbaijan – "saved 48 hours of rig time on an offshore platform."

US drill services giant Baker Hughes reported 2Q 2016 revenue of $2.4bn, down by 39% year-on-year. Pre-exceptionals, it made a net loss of $911mn (versus a loss of $188mn in 2Q 2015) after steep declines in North America rig counts.

Yet after accounting for just over $3bn of impairment and restructuring charges, offset by Halliburton's termination fee of $3.5bn, its Hughes' adjusted net loss was $392mn – still larger than its 2Q 2015 loss of $62mn.

France's Technip said its 2Q adjusted revenue was 9% lower year-on-year at €2.8bn, but made a net profit of €123mn – in contrast to a net loss of €307mn in 2Q 2015. It also said it had received a successful early conclusion of the antitrust review from US regulators of its planned merger with FMC. Order backlog however fell to €13.5bn at end-2Q 2016, from €18.8bn a year before.

Italian contractor Saipem reported 1H 2016 revenues of €5.3bn, almost flat year-on-year, with a net profit of €53mn, compared with a 1H 2015 loss of €920mn. Order backlog was €13.9bn at end-June 2016, compared to €15.8bn six months earlier. CEO Stefano Cao said "robust" results were owing to "excellent performance in the execution of offshore engineering and construction projects."

Norway-listed Subsea7 achieved a "good 2Q" as, despite revenues down 29% year-on-year to $961mn, its net 2Q profit increased 55% to $136mn and its order backlog at end-June of $7.1bn was $0.6bn up on three months earlier. Among the highlights, its work on the Tullow-operated TEN oil and gas field development off Ghana was "substantially completed" – with first oil expected next month. Offshore Egypt, first gas was achieved in May at Ha'py field on the East Nile Delta project with fabrication and testing underway on the West Nile Delta phase one project.

- NGW

BRAZIL'S NEW ERA OF OPPORTUNITY

Brazil's oil and gas sector is on the verge of its biggest transformation in decades, with unprecedented opportunities for new entrants to the market, according to new research by the Washington-based Atlantic Council.

This is in spite of the economic and political problems the country is currently facing, the international relations think tank said in its report Oil & Gas in Brazil: A New Silver Lining?

State-run Petrobras, still reeling from a major corruption scandal, has seen its debt soar, forcing it to cut investment, lower production forecasts and put assets up for sale in the last year. In January, Petrobras cut its 2016-2020 investment plan by 5% to $93bn. The indebted company had already slashed its investment plans to $98.4bn from $130.3bn.

At the same time, Petrobras made a 20% cut to its oil and gas reserves. The company has also undertaken an "aggressive plan to sell assets and focus its efforts on exploring reserves in the pre-salt layer," the report said. The company, which for years dominated Brazil's energy landscape, has never experienced such a "profound transformation," it added.

However, the contraction of Petrobras and other traditional players leaves a gap for new companies that are keen to increase their role in Brazilian exploration and production, the Atlantic Council said. Indeed, it presents a "unique moment" for those companies interested in increasing their presence in Brazil, it added.

"Opportunities are now opening up for new companies that will work with Petrobras in future – we have never seen this before in Brazil," commented Decio Oddone, the director of port services firm Prumo Logistica and ex-CEO of Petrobras, during a debate held by the think tank in Washington.

Downstream bonanza

In particular, the downstream gas business is entering a new period of opportunity, he said. "We have never tried a more open sector in the downstream gas business," he added.

"A few years ago only small service companies wanted to be in Brazil and they would partner with someone else – normally construction companies," he noted.

Now the construction companies are in trouble too – divesting assets and experiencing problems related to compliance – which gives new companies a chance to get a foot in the door.

There are other signs of optimism as well, said Jason Fargo, the Latin America lead at the US publisher Energy Intelligence. The bill ending Petrobras' mandatory operatorship indicates that the country is more willing to open up to new investors, he said. In February, Brazil's Senate approved legislation that relieves the company of its role as mandatory stakeholder and sole operator in pre-salt deepwater oilfields.

Nonetheless he said there is still a "wait and see" attitude among many in the industry. "There is still a great deal of uncertainty about stability – about who's running government but also policies," he said. If the impeachment of Dilma Rousseff takes place in August, that "would give some confidence that the new government at least has some staying power," he said.

The main factors determining how much opportunity there will be in Brazil's upstream sector are the success of Petrobras' divestment plan and the removal of the requirement that makes Petrobras the only operator in pre-salt, analysts at consultancy Wood Mackenzie told NGW.

The country also needs to organize bidding rounds for exploration blocks on a regular basis, with a schedule, and make regulatory improvements on local content and unitization agreements, they added.

"The success of these measures, which are already taking place or are under discussion, will create opportunities for new players and meet the main demands of the companies already operating in Brazil," said Luiz Hayum, upstream research analyst at WoodMac.

"Removing the requirement that Petrobras operates all acreage within the pre-salt polygon makes a lot of sense, and is necessary – in the long-term – if Brazil is to maximise the exploitation of its oil and gas resources," said Ruaraidh Montgomery, senior analyst at WoodMac.

'Limited LNG sales': WoodMac

In the gas markets, opportunities for sellers of LNG will remain limited, cautioned the consultancy's Latin America energy markets analyst, Ricardo Gonzalez. "We expect that during 2016 LNG imports will fall to roughly half the levels seen in recent years," he said, owing to the return of normal hydro output: "The spectacular growth in gas demand seen in recent years was driven by the power sector."

Petrobras and contractors in Brazil have been "dramatically and significantly impacted" by the economic and political problems the country is facing, the CEO of Chariot Oil & Gas, Larry Bottomley, said in an interview with NGW. Conversely, Petrobras' divestment of assets has increased opportunities for other players, he added.

"Independents can access services in the country more easily and at lower costs," he said. London-headquartered Chariot has 100% equity in four licences offshore the northeast of Brazil, in the Atlantic margin.

Aside from the crisis facing Brazil, the general prospectivity of the country hasn't changed, he commented: "All Brazil's basins have been extremely successful in the past. The geology and petroleum systems remain the same."

"The pre-salt, Santos and Campos basins are where the bulk of investment has occurred in the past few years. These will still be where most of the investment goes but Brazil is still very underexplored as a whole," he added.

Independents' day comes

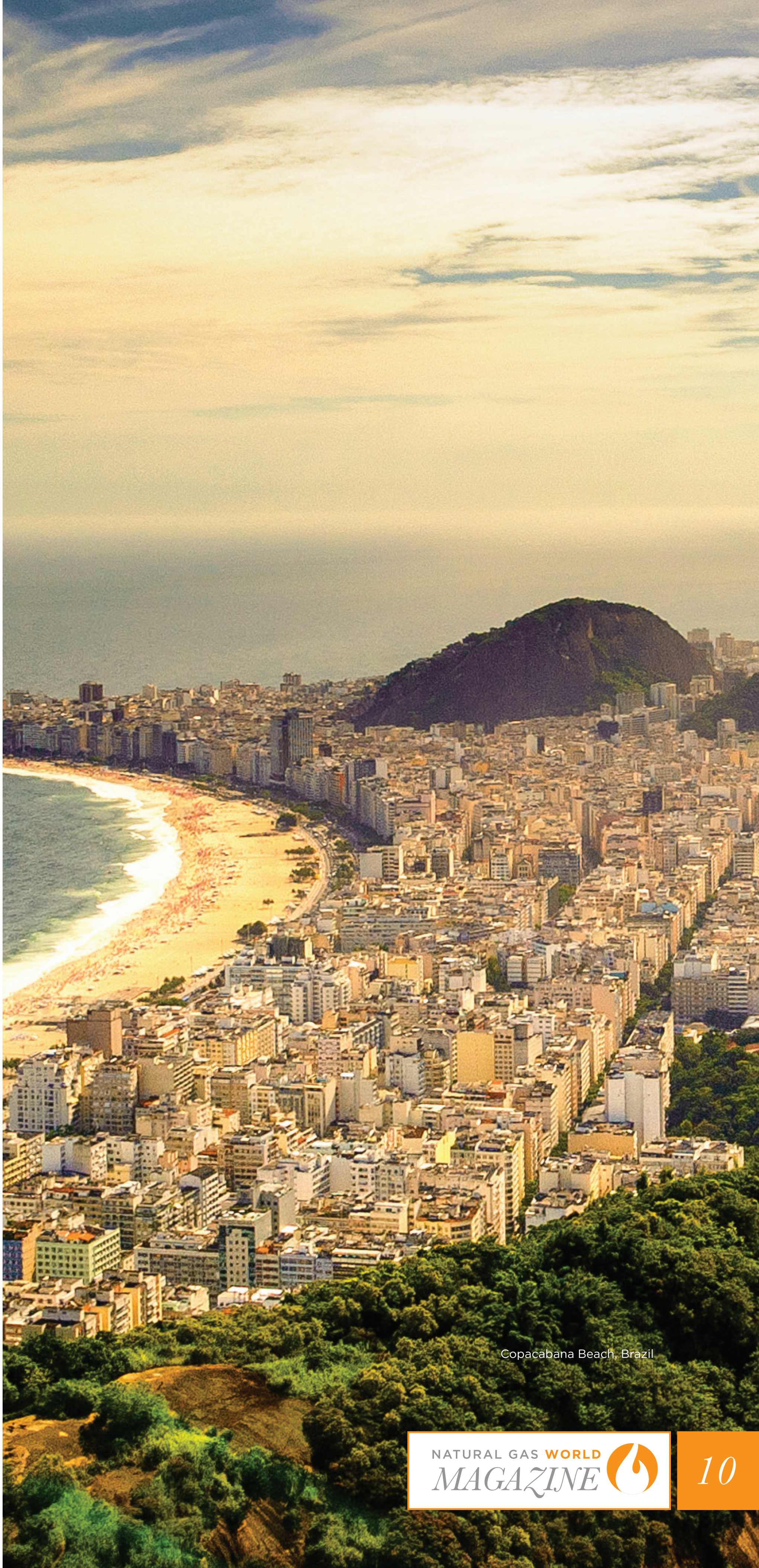
A GeoPark spokesperson told NGW that the Latin America-focused explorer also sees great opportunities for independents following on from the Petrobras divestment programme. This is because state oil companies "usually keep the most attractive assets in the country and a marginal disposal could represent an interesting acreage/production increase for an independent like GeoPark," he said.

Onshore Brazil, there is an opportunity for independent companies, including local ones, he said. "The divestment of onshore assets will allow Petrobras to gain operational efficiencies and focus in what they do best, which is the ultra-deep water offshore. The sector and the country represent a big opportunity for investors," he added.

However promising the prospects, improvements are needed to boost investment in the sector, he said. There needs to be greater agility in approval of M&A transactions and granting of environmental licenses, especially in the case of small independents, he commented.

For Bottomley, Latin America's largest nation still needs to compete in the medium-term with other countries that also offer good prospectivity. "If the business environment in Brazil were simpler, it would be more competitive with other countries in a low oil price environment," he said.

- Sophie Davies, Buenos Aires



Copacabana Beach, Brazil

SOCAR'S CASH-FLOW PROBLEM

It will be years before Azerbaijan breaks even on the Southern Gas Corridor, while the money needs to be found now. Low oil prices make third party lending more urgent.

Azerbaijan has been negotiating with international financial institutions to borrow $5bn to fund its share of the construction costs of the Southern Gas Corridor (SGC) gas export route, finance minister Samir Sharifov said on 20 July.

He told UK daily Financial Times that talks are in progress with the World Bank (WB), the European Bank for Reconstruction and Development and the Asian Development Bank.

A WB spokesman told NGW July 20 that it is considering supporting Azerbaijan's investments in the SGC because of its critical importance to energy security in the region and to Azerbaijan's development priorities. "At this moment, we are reviewing ways to support the investment in cooperation with other financing partners and will fully disclose project documents in the course of project preparation," the bank said.

Azerbaijan has already sold $1bn Eurobonds and is preparing to sell the same again in further bonds to finance SGC. A source at WB told NGW June 2 that "Baku has applied to the WB for a loan of $500mn, the talks are under way... the process should be wrapped up by the end of the year."

The European Bank for Reconstruction and Development (EBRD) has confirmed that it started talks to provide direct financing of €500mn and attract €1bn from banks for TAP, of which Socar is a 20% owner.

The current cost of SGC including upstream work on Shah Deniz 2 (SD2), is now estimated at around $40bn, including $9.3bn for the Trans Anatolian gas pipeline (Tanap), $6bn for the Trans Adriatic pipeline (TAP) and $23.8bn for developing SD2 as well as the expansion of the South Caucasus line (SCPX)

The project is expected to deliver 6bn m3/yr to Turkey and 10bn m3/yr to EU by 2021 and this volume to reach 31bn m^3/yr in the 2020s, although where that remaining gas will come from is not known.

The Azerbaijani project has been approved by the European Commission as one compliant with the Third Energy Directive. It could help the EU to diversify gas exports and reduce dependence on Russian Gazprom, whose gas supplies about a third of the European market. During 2015 Gazprom exported about 159bn m^3 to Europe, including 27bn m^3 to Turkey. However, Gazprom eyes more gas sales to EU by 2021.

The Azerbaijani pipeline does not pose an immediate threat to Russian gas in Europe, said RusEnergy consultant Mikhail Krutikhin. He mentioned that there will be serious competition after 2020 when it is planned to increase gas export. "After 2023-2026 gas could be exported not only from Azerbaijan, but also from Iran, Turkmenistan as well as Iraqi Kurdistan, where the volume of potential export exceeds 30bn m^3/yr. Some of the Russian gas could be ousted from the southern Europe, including the Italian market," said the expert.

Azerbaijan's total gas output increased slightly, while the commercial gas production decreased by 9% in 1H 2016.

Future gas supplies would of course depend greatly on gas price competitiveness. It would also depend on getting access to these other gas sources. Political and legal disputes have made it difficult over the last 20 years for Turkmenistan to export gas by crossing the Caspian. In any case, Turkmenistan is giving priority to Asian markets such as China who can advance financing on generous terms and provide the work-force.

Iran is giving priority to its own domestic

AZERBAIJAN'S SHARE OF SOUTHERN GAS CORRIDOR COSTS (IN $BN)

	TOTAL ORIGINAL ESTIMATE (DEC 2013)	COSTS REVISED ESTIMATE (JUN 2016)	SOCAR STAKE %	AZERBAIJANI ORIGINAL SOCAR STAKE COST	COSTS REVISED SOCAR STAKE COST
UPSTREAM SD2 26 WELLS (6) OFFSHORE (15) SANGACHAL (2)	23	18.9	16.67%	3.83	3.15
SCP	5	4.9	16.67%	0.83	0.82
TANAP	11-12	9.3	58%	6.38 - 6.96	5.28
TAP	5	6	20%	1	1.2
TOTAL	c.44 - 45	39.1		c.12.04 - 12.62	10.45

Source: NGE

demand and needs gas for reinjection into its oilfields to maintain oil productions. It too is eying exports to neighbouring Asian countries. Kurdistan exports are stuck with problems and security challenges. And on top of these the volatile situation in Turkey and its future relationship with the EU has brought in additional complexities.

Baku prioritises gas re-injections, oil sales

Socar vice president Rahman Gurbanov told NGW July 20 that this year, commercial gas output would fall slightly as more gas is needed for re-injection into the Azeri-Chirag-Guneshli (ACG) oil block to maintain crude oil production level. The block accounts for three-quarters of Baku's total oil output. Rahimov said that thanks to the greater gas re-injection, crude oil output from AGC actually rose in the first half of this year by 0.4% to 21.04mn mt in 1H16.

He said that Baku had expected a drop in oil output over this period, but that didn't happen, although it is expected in the latter half of the year. Azerbaijan's oil production is expected to fall by 1mn mt to 40.745mn mt in 2016. Associated gas accounts for 45% of Azerbaijan's total gas production and a fifth of the country's commercial gas output.
Gurbanov said that for Baku, keeping oil output high is the priority. Azerbaijan's commercial gas production is expected to fall slightly to 18.5bn m3 in 2016. This poses additional challenges to SGC accessing more gas in the future.

Baku eyes other gas markets

Alongside the participant countries in SGC, including Greece, Albania and Italy, Socar is also eyeing gas exports to Romania and Albania. The state company has already signed a MoU with Albania to export gas (through the Interconnector Greece-Bulgaria), while the company signed another MoU with Romanian Transgaz on July 19.

The MoU envisages cooperation between the companies in the field of gas transportation and gas transit using Romania's capacity.

The memorandum also envisages the possibilities of exporting LNG and natural gas to the Romanian market and its sale on the basis of long-term or spot contracts, with the Azerbaijan-Georgia-Romania Interconnector project also named.

It was mentioned during the signing ceremony that the memorandum will open the possibility for deeper cooperation between Socar and Transgaz and expanding operations in southeast **Europe and the Balkan region.**

"The memorandum will also contribute to expansion of cooperation between the countries in field of energy, in particular, gas supply, transportation, marketing and sales," said Socar.

Accessibility to other gas sources and gas price competitiveness are issues SGC will have to grapple with before these plans can be turned to reality. This is a very expensive project and, while it has strong political support, in the longer term it will have to compete with other gas supplies to Europe on price if it is to go beyond the 10bn m^3 committed to Europe now.

Securing the gas supplies necessary to improve the economics of the project and make a difference in Europe remains a crucial issue. In the current global energy market, with low gas prices expected to be with us for a long time, if not forever, it will be difficult to attract funding for new projects unless they make full commercial sense.

- NGW

Flame Towers, Azerbaidjan

BREXIT MEANS UNCERTAINTY

The UK prime minister Theresa May has repeated that Brexit means Brexit, and elements in her own party will hold her to that. But nobody quite knows what that phrase means or what terms she can expect to secure from her former colleagues in the European Union.

Britain's decision to leave the European Union in the June 23 referendum is propelling the country towards uncharted waters. With the exception of Greenland – in a 1982 dispute over fishing rights, it left a very different EU from today's – no other country has done it so there is no precedent. The most that can be assumed is that some kind of relationship with its former allies will be devised that approximates to one that already exists between the EU and another country, for example Norway or Turkey.

Until 2009 there was no express provision for withdrawing from the EU. Article 50 of the Lisbon Treaty expressly provides for this. It leaves a country's decision to leave the EU to its own constitutional requirements. There has been lobbying in the EU itself to force the UK's hand and trigger Article 50. UK prime minister, Theresa May, spent the first month in office visiting European heads of government to reassure them of continuing UK co-operation in some spheres of public life but is not able to enter talks over terms before triggering the article.

EU energy and international law specialist Ana Stanic says that since the outcome of the referendum is not legally binding under the UK constitution, crowdfunded lawyers led by David Pannick QC and Rhodri Thompson QC have indicated an intention to judicially review any government decision to trigger withdrawal without an Act of Parliament. There has been speculation that Theresa May will find a way round the Fixed-Term Parliament Act, under which the next is due in 2016 and call a general election, with exiting the EU on the manifesto.

Paragraph 2 of Article 50 is clear that the decision to withdraw rests with the UK and that the EU cannot legally force the UK to trigger the withdrawal. David Davis, the new Secretary of State for Exiting the EU, made clear that the UK will not send the notification to the European Council this year.

Stanic says that once triggered, the two-year period to hammer out the agreement setting out future relations between the UK and the EU will start ticking. The only way of extending this period is with the unanimous agreement of the European Council. Since this may be difficult to achieve, it is suggested that it might be an idea not to trigger the withdrawal until an agreement is reached with the EU that the two-year deadline will not apply and that the UK will remain in the EU until a mutually satisfactory agreement is reached. This is unlikely to be acceptable to the EU but perhaps an agreement could be reached to extend the period of negotiations to three or perhaps five years instead. Greenland's departure took three years.

Regardless of how long the UK will have, the new deal will need to be approved by a qualified majority of the council and is subject to European Parliament's approval.

The government is said to be considering the different agreements that countries such as Norway, Switzerland, Canada and Turkey have with the EU as the possible framework. As a member of the World Trade Organisation (WTO) and signatory to WTO Agreements in case no deal is struck with the EU before the deadline expires, the UK would find itself in the same position in respect of goods as Australia and the US are today vis-a-vis the EU by invoking the most-favoured nation provision.

Stanic says EU law including competition law and state aid would not apply. The Norway model is unlikely to be the option favoured by the government since it would require the UK to adopt all EU law – including in the field of energy – without having any say in its adoption; to contribute to the EU budget; and to allow the free movement of people. The free trade agreement agreed between Canada and the EU may be a better model albeit most services, agricultural goods and fisheries are not covered.

It would seem that a customs union along the lines of the one Turkey has with the EU with limited free movement comes closest to meeting the requirements of the leave campaigners. And perhaps some version of it would also be in the EU's best interest. At this point it is not clear that cool heads will prevail in the negotiations and ensure the best interests of both are attained in any upcoming divorce.

In terms of oil and gas, the Brexit vote has exposed a greater amount of uncertainty in the world than many had foreseen. That, and the oil price, could provoke more change in the gas market. First, it could quicken the growth of the Dutch Title Transfer Facility (TTF) over the UK NBP. Traders already preferred dealing in euros and now this trend will be reinforced if the UK is seen as a bit-part player in the energy market.

But in general, whatever the challenges are, in terms of oil and gas the UK is in a good position to weather any storms. Brexit would not change the way oil companies operate in the North Sea. Provided the transition is negotiated smoothly, oil and gas trade flows are unlikely to be disrupted.

The Wood Mackenzie chairman said Brexit is unlikely to have a big Impact on UK oil and gas markets. He added that the UK "buys a lot of energy from Europe, especially gas, and there is no question it is one of Europe's largest markets ... But, it can just as easily buy liquefied natural gas from the US or elsewhere if any proposed tariffs prove to be too high." As a result, the general conclusion is that it is unlikely that Brexit will have a negative impact for UK's oil and gas.

How would you like your Brexit – soft or hard?

Lawyer Marc Hammerson, partner at US firm Akin Gump, does not see Brexit having much direct impact on the upstream

View of London Bridge, London, United Kingdom

where decisions are affected by the oil price, reserves and tax. The possibility of a second Scottish referendum on independence from Westminster is something that Brexit has revived. And it has weakened the currency, increasing the cost of imports.

Brexit could also weaken the market for mergers and acquisitions, although that market has been weak for some time. And it could impact the midstream and downstream sectors, depending on whether the UK went for what he called a 'soft Brexit' where the UK was so similar to Norway in terms of movement of labour and so on that the Leave camp might feel the referendum was pointless; or 'hard Brexit.'

Anything that jeopardised the movement of energy across Europe, such as higher trading or network access or other costs would be bad for the government of the day, he said. "If we go for 'hard Brexit' then there will be a medium and long-term effect on UK midstream and downstream space," he told NGW.

The Scottish question

The inhabitants of Scotland voted by 62-38 in favour of the UK remaining in the European Union. Nicola Sturgeon, leader of the Scottish Nationalists' Party, whose goal is independence from Westminster, could use this to argue for another referendum on that question, having lost the one held in 2015.

Independence would certainly result in Scotland securing the lion's share of UK offshore reserves – but the problem is that these are massively diminished compared to the glory days of the 1980s. According to the latest (June 2016) BP Statistical Review of World Energy, the UK currently has just 0.2 trillion m^3 of recoverable gas and 2.8bn barrels of recoverable oil reserves.

In terms of fields, almost all the oilfields and well over three-quarters of the gas fields would fall on the Scottish side of any likely maritime boundary line between an independent Scotland and the remnant United Kingdom.

It could well prove a jaded inheritance. The UK's oil and gas industry is not in the best of health. Declining opportunities prompted a 15% reduction in the workforce in 2015 and, a month before the Brexit referendum, the Fraser of Allender Institute's 24 annual oil and gas survey anticipated a further 17% job reduction in 2016.

At present, just about the only growth sector in the UK offshore industry is decommissioning facilities, commonly dubbed the funeral industry.

In terms of fields, almost all the oilfields and well over three-quarters of the gas fields would fall on the Scottish side of any likely maritime boundary line between an independent Scotland and the remnant UK.

- NGW

SOUTH AFRICA generates mixed messages

Mixed signals from South Africa's government and its state-owned electricity supplier and generator Eskom have sent ripples of concern among potential investors in new gas projects.

State power giant Eskom sparked confusion in July when its CEO Brian Molefe suggested there would be no future power purchase agreements (PPAs) with independent power producers, beyond those already signed.

Although the government provided assurances that this would not affect its intention to develop renewables and gas, as part of the country's future energy mix, it sparked a lively debate in the nation's media. That's because South Africa is developing a gas-to-power program, expected to add 3.126 GW from independent producers' gas-powered generation.

South Africa is soon to open tender proposals for a project combining a new floating LNG import terminal with a new power plant – for which Eskom is expected to be the main customer. The LNG import terminal would be at one of three locations: Coega, Richards Bay or Saldanha Bay. Gas-fired generation, it's argued, could also provide a useful tool in managing the inherent intermittency of solar and wind power. The government hopes also that offshore gas exploration – and fracking in the onshore Karoo region –could provide indigenous sources of gas.

Siemens South Africa's CEO Sabine Dall'Omo was recently quoted by Bloomberg as saying that "gas can be a complete game-changer for the South African economy."

A World Bank report, Independent Power Producers in Sub-Saharan Africa, published in June, found that various attempts to introduce IPPs in South Africa were "half-hearted and unsuccessful" until four years ago, in part because of Eskom's dominance, but said that now private sector investments in IPPs to date totalling $19bn have been committed for projects totalling 6.327 GW of renewable energy. Eskom still however generates some 96% of the nation's electricity, compared with private generators (3%) and local authorities (1%). Moreover the report noted that Eskom's 42 GW installed capacity, at 2014, remained dominated by coal-fired plants (85%), followed by diesel and nuclear (5% each), pumped storage (3%) and hydro (2%).

Eskom is keen to point to its own capital projects costing an estimated $35bn that will add two 4.8-GW coal-fired complexes (Medupi and Kusile), a 1.332-GW pumped storage plant and two 100-MW renewable units. But the World Bank report says that most of this capacity is late and over-budget. It adds that it can "no longer be assumed that Eskom will remain creditworthy" adding that the present arrangement whereby an independent regulator is established and IPPs are permitted "could easily be undermined."

"Siemens South Africa's CEO Sabine Dall'Omo was recently quoted by Bloomberg as saying that 'gas can be a complete game-changer for the South African economy.'"

Economist Mike Schussler of economists.co.za , who closely monitors South Africa's energy policy, said he is "very worried" that Eskom appears to believes that the country's power requirements can be met without significant new back-up from gas and renewables.

"We may be seeing a repeat of the 1990s, when we were told there was too much electricity and Eskom would sell to anyone at any price. We will be okay in the near future, but the longer-term needs serious thought and action. Gas should be a great investment, but investors must be feeling very bad and very worried about investing," he suggested.

The chairman of the South African Independent Power Producers Association Sisa Njikelana agreed that uncertainty is affecting the investor climate. "Obviously, we can ill-afford to be in such a situation, given the current economic morass," he said. "At face value, the action taken by Eskom is fraught with risks of further eroding the existing level of confidence. While we need to be sensitive to the maintenance of global confidence on the power market, and also its impact on the economy as a whole, we also need to be primarily seized with domestic confidence as a matter of priority."

Professor Raymond Parsons from South Africa's North West University, who formerly headed Business Unity South Africa, compiles a regular index on the level of political uncertainty in the country, and warned of the "corrosive impact of policy uncertainty on investment decisions, including the energy sector."

"It has undermined our growth performance. Although Eskom's maintenance programme has clearly improved in recent times, it is not difficult to avoid load-shedding when the economy is flat on its back with a zero growth rate. The U-turn by Eskom on independent power producers (IPPs) is a clear example of the mixed signals and inconsistent energy policy that continues to bedevil the investment environment, and hence South Africa's growth outlook," he warned.

South Africa's shadow energy minister Gordon Mackay meanwhile suggested that, despite its public support for gas development, he believes the Pretoria government is putting the brakes on the development of the gas economy.

He said that Sasol – the major regional player in gas development -- is not receiving enough support to boost its imports of gas to South Africa from the rich reserves in Mozambique, which offer the best potential for significant natural gas expansion in South Africa: “The market conditions are not allowing for sufficient imports of gas, as Eskom is pushing for more coal and nuclear – which are more expensive than gas,” he said.
The opposition Democratic Alliance (DA) politician even suggested that there would be less scope for corruption in the development of gas than there would be in further expansion of coal and nuclear in South Africa: “That is why there is a lot of reluctance in government to import more gas.”

Saldanha Bay would be the best spot for new infrastructure for LNG imports, he said, adding however there were political considerations which might scupper this site, as Saldanha Bay is in the Western Cape province which is under DA control. The South African government says it has backed development of renewable energy and has also voiced support for more natural gas in the energy equation, partly because of international obligations following last year’s Paris climate change talks, and partly in an effort to reduce reliance on coal.

- John Fraser, Johannesburg

Eskom CEO Brian Molete (Photo credit: Eskom)

Ariel view of Fifa Stadium in Capetown, South Africa.

NORD STREAM 2 AND THE ROLE OF THE EUROPEAN COMMISSION

Critics of the Nord Stream 2 (NS2) pipeline within the European commission (EC) need to distinguish between the body's regulatory and political objectives, according to an academic.

The 50%-Gazprom owned Nord Stream 2 pipeline is seen either as a way of efficiently delivering gas to northwest Europe where production is declining; or as a tool of Russian foreign policy, driving a wedge between the former Soviet satellites and their western European rivals.

A new paper seeks to find a balance between these views, and comes down mainly on the side of the former.

Speaking at an event organised by the European Centre of Energy and Resource Security (Eucers) at Kings College, London, author Andreas Goldthau said that the pipeline would be a "litmus test" for the EC: "Is it a market watchdog or a political actor?" He said this had not been determined but the EC should be neutral in the way it thinks about the energy sector. It has to apply competition law if it suspects the market is being rigged but rules should not be applied selectively, he said.

He said there were no legal grounds for blocking the pipeline. Once the gas was landed all the capacity in the onshore pipelines would be sold on the Prisma platform and be controlled by the existing regulations on third-party access. Regulation is not the right forum for discussion of political objections, he said.

Two European Union energy commissioners – Miguel Arias Canete and Maros Sefcovic – have both voiced apprehension about the line: Canete has said that the EC will be vigilant about the rigorous application of EU law while Sefcovic has said that eastern European countries will clearly have their energy security reduced because of it.

But Goldthau, who cited both officials in his opening remarks, said that their concerns were used to support the geopolitical argument, whereas in fact the line would fulfil an EU objective of improving the gas market as long-term Russian contracted gas competed with hub-priced Russian gas and more interconnectors allowed gas to flow west-east. A precondition for that, he said, was physical integration and compliance with the appropriate regulations.

Nord Stream 1 emerges at Greifswald, northern Germany (Credit: Nord Stream)

A panel discussion after Goldthau had summarised his report considered the risks of a civil service acting also as a political entity. The EC might decide to apply certain rules to Gazprom that were not applied to other external suppliers for example, and these decisions could expose it to the risk of a judicial review.

According to Katja Yafimava of the Oxford Institute of Energy Studies, the EC had been reluctant to transfer sufficient decision-making powers to the Agency for the Co-operation of Energy Regulators, which was established by the Third Energy Package as an independent body. In either event, whether political or regulatory, market players needed transparency. At the moment the situation is unclear, she said.

Energy security consultant John Roberts said that Goldthau's report was fair up to a point: more gas meant more competition and more trade and security; but the interconnectors and LNG import terminals on which this cycle depend are relatively small in scale and not built out yet. There would still be a problem with European security of gas supply if a major supplier, be it Russia or Norway, failed to deliver as contracted, especially in southeast Europe and Turkey which are reliant now on transit through Ukraine.
And Gazprom had made no concessions, he said, with regard to allowing the Brotherhood line which crosses Slovakia to move into reverse flow, which could be a way of exerting pressure on Slovakia and Hungary.

He concluded the NS2 line was "obviously" both a commercial project and a geopolitical one; as well as the means by which Gazprom's western partners may be allowed to develop business within Russia. The EU would be right to take both political and commercial questions into account, he said, perhaps coming up with a 'bundled' solution for Gazprom to trade within Europe that dealt also with the loss of Ukrainian transit revenues and the anti-trust case against it.

Roberts' arguments are similar to those of former Hungarian regulatory chief Peter Kaderjak who said in May that allowing NS2 to proceed would increase price divergence in eastern Europe, lead to bottlenecks between Germany and the Czech Republic and between Czech Republic and Slovakia, and mean that Russian contractual gas flowing from east to west would prevent spot gas from entering eastern Europe. To a certain extent these issues were addressed in Eucers' paper.

Goldthau concluded the July 11 event by remarking that it might be true that gas was a public good, but that markets need to work. Europe falls short of the US gas market, he said. The EC should not be picking winners but should allow the market to do its job.

Eucers director Friedbert Pfluger described the paper, which – it is important to note – had been funded by the five western partners of Gazprom – Anglo-Dutch Shell, German Uniper and BASF, French Engie and Austrian OMV – as balanced and scholarly.

There are of course differing views summarized below, expounded by Thomas Cunningham, deputy director of the Atlantic Council's Global Energy Center.

In the debate surrounding NS2, he argues the project appears to be a threat to European energy integration, to say nothing of the potential impact on Ukraine's gas transit business or the country's political stability. The pipeline would allow the consortium that owns it to dictate the terms of gas shipments to central and southeastern European states, impacting north-south gas competitiveness within the EU and undermining gas diversification efforts in southeastern Europe. It would also exacerbate the politicization of energy along EU member state lines. Whatever the market implications of increased Russian gas transit via northern routes, or the legal basis by which the EC might intervene, the political implications of the project are divisive and controversial. It is in this third aspect that the absence of the UK as a tempering voice between western and eastern EU states will be most acutely felt.

Brussels sees the NS2 issue as problematic. The EC president Jean-Claude Juncker has also intervened. Writing to the eastern European states who objected to NS2 he said: "The outcry over Russia's plan to double its gas pipeline to Germany went beyond legal issues as the project would alter the EU's gas market landscape."

He also said NS2 could not be built "in a legal void, or only according to Russian law" and that the EC is discussing the matter with German authorities and regulators before it issues its assessment. He added: "If built, NS2 would have to fully comply, as any other infrastructure project, with applicable EU law, including on energy and environment. This is also the case for the offshore infrastructure."

However, Germany's chancellor, Angela Merkel, said that NS2 is an economic project and added that lifting EU sanctions against Russia did not depend on plans for the pipeline. Germany sees NS2 as crucial to its energy security, particularly in view of major reductions in the supply of Groningen gas.

In the meanwhile there are reports that Gazprom has agreed a role for Slovakia in the project. Given its lead role in Eustream and with Slovakia having taken on the EU presidency for the next six months, if confirmed such an agreement could have major implications.

And from the south, Russia-Turkey negotiations may be restarting on Turkish Stream – a proposed gas pipeline under the Black Sea – that would allow Russian gas shipments to Turkey to bypass Ukraine and could also allow for expanded Russian shipments to southeastern Europe.

The debate carries on. In the meanwhile the project's sponsors are proceeding with their plans to build the pipeline, with contracts already awarded for the linepipe and the contract for the laybarge vessel put out to tender.

The paper, Assessing Nord Stream 2, is available on the Eucers website.

- NGW

Landfall of Nord Stream Pipeline and large nuclear power Station.

PROMOTING NATURAL GAS VEHICLES IN INDIA

India has a mature natural gas vehicle industry but it needs shaping to fit better with the modern world. With the wave of LNG heading towards India and environmental concerns unabated, everyone could win.

The transportation sector is nowadays regarded as the salvation of companies holding more gas than they know what to do with. Bunkering and shipping have led the way, thanks to clean air initiatives in the US and the EU.

Road transport has always been there, but only as a small part of the story owing to the reluctance of investors to build cars that have almost nowhere to fill up; or of building filling stations with very little demand.

However the direction of travel in India is encouraging investors along the value chain, according to speakers at the NGV India Summit held in New Delhi mid-July. The country's natural gas vehicle (NGV) program is now close to two decades old in India. The 1990s witnessed a relentless campaign to improve the local air quality. This led the Supreme Court of India in 1995 to mandate the switch over to natural gas and resulted in installation of a body called The Environmental Pollution (Prevention and Control) Authority. Then, in 2001 the body recommended the use of compressed natural gas (CNG) among users and paved the way for India's first large scale CNG program in New Delhi. Since then India has seen the NGV fleet exceed 2.8mn vehicles on the roads.

Although the first-generation CNG program in Delhi and Mumbai yielded benefits, the time is right for the next generation as the environmental debate grabs the headlines in India. It was in this context that French energy giant Engie presented its concept 'LNG to Delhi' at the summit. The idea is to develop LNG fueling stations along the Mundra-Delhi corridor for heavy-duty vehicles. The plan envisages four LNG stations, one every 400 km. Stakeholders would be authorities, transporters, industrials, energy suppliers and truck manufacturers.

"The genesis of 'LNG to Delhi' concept lies in the debate revolving around pollution in Delhi. LNG-fuelled trucks can easily ply inside Delhi, where currently no diesel trucks are allowed. The Mundra-Delhi corridor,at 1,200 km, is long enough for this concept to be put into practice. We are ready to work with various stakeholders," Engie's Maneesh Varma, who is senior vice president for business development in India, told NGW.

Engie believes it can leverage its European experience where it is partner to the 'LNG Blue Corridors' project. The French major has developed three LNG stations for the project, two of which are operational since 2015 (South of Paris, South of France) and one is under development. Five other LNG stations are being developed by Engie under the 'Connecting Europe Facility' to link France, Germany and The Netherlands.

Conditions right

Another business developer at Engie, Ovarith Troeung, who is responsible for green transport, said conditions in India were right for creating demand for LNG in that sector. "India has everything: LNG terminals as well as a large consumer base. The only thing that is needed is proper implementation which can happen if the government facilitates the process by adequate legislation and regulatory framework," Troeung, who is based in Paris, told NGW.

Until about three years ago, Europe did not have many LNG stations but numbers have grown fast. Troeung believes this can happen in India as well if government legislation provides structure to the industry so that stakeholders such as consumers, vehicle manufacturers, energy suppliers and authorities can put in a collective effort.

India has four LNG terminals with close to 22mn metric tons/year of re-gasification capacity. Oil ministry expects country's LNG import terminal capacity to double in next six years. According to a document released by the ministry on June 3, the country's LNG terminal capacity will probably rise to 47.5mn mt/yr by 2022.

The four are at Dahej and Hazira in Gujarat, Dabhol in Maharashtra and Kochi in the state of Kerala. Capacity expansion of Dahej LNG terminal is expected from 10mn mt/yr to 15mn mt/yr by end of 2016. Further, a firm plan is in place to add another 2.5mn mt/yr at Dahej.

Space for both CNG and LNG

Despite the fact that CNG sector in India has grown rapidly since its take off in early part of this century and has attained a certain level of maturity, it is still plagued by severe infrastructure problems, which explains why CNG use has not spread beyond certain key cities. At about 15,000 km, the pipeline grid is insufficient to reach wider pockets of a country of India's size. Expansion is in progress but the pace continues to be slow owing to the cumbersome land acquisition process.

Varma said that this vacuum can be filled by LNG which can be supplied by trucks to the final consumer. "Just do not talk about the gas grid as there are other ways available to transport gas as well. I believe India will see growth in both CNG and LNG. On one hand pipeline network can expand and on the other hand LNG can be supplied to areas not connected with pipeline. What we call the 'virtual LNG pipeline'," he said.

Last month, Petronet LNG said it is looking to sell about 1.5mn mt/yr in India by transporting it via trucks to customers not connected by pipelines. Initially, Petronet would deploy the trucks from Kochi to Mangalore. This is primarily because its 5mn mt/yr re-gasification terminal at Kochi remains underutilised at mere 5% capacity owing to pipeline shortages.

Projecting LNG prices to remain benign in medium to long term, Varma believes this would be the right time for Indian

“The genesis of ‘LNG to Delhi’ concept lies in the debate revolving around pollution in Delhi.”

government to devise a fully-fledged plan for adopting LNG as transport fuel. He said Engie is ready to work with various stakeholders in developing the requisite plan.

Potential demand

India could potentially use about 5mn metric tons (mt)/yr of LNG in the near future by substituting high speed diesel (HSD) in rail and road transportation, GSP Singh, Deputy General Manager (Gas), Indian Oil Corporation (IOCL), told delegates.

The south Asian nation uses about 70mn mt/yr of HSD. The transportation sector uses about 28.5mn mt/yr. That works out at about 24mn mt/yr of LNG. “This is the kind of demand potential we are looking at. Even if we assume 20% of HSD users shift to LNG in coming years, it is about 5mn mt/yr. That is a significant figure,” said Singh.

However, Singh argued that for transport demand to reach its full potential, appropriate regulatory and statutory frameworks were needed. He said the government’s approach towards CNG and LNG sectors should be similar.

Domestically produced natural gas is allocated on a high priority basis to fully meet CNG demand. A similar approach would help make LNG a success since it has greater benefits compared with CNG, he said. LNG requires less refuelling and covers more distance per refuelling; it needs less storage space; and it is much safer since LNG is stored at very low pressure (6-8bar) compared with CNG (more than 200 bar). LNG can be pumped at high flow rate compared with CNG and thus saves time, Singh said.

There is no denying that if the right policies are designed LNG as transport fuel can be a big success in India. But is India capable of meeting the potential demand? According to Singh, the country is moving in the right direction when it comes to LNG infrastructure.

Availability of the fuel is not be a problem and distribution should not be hard because IOCL pioneered the concept called ‘LNG at Doorstep’ in 2007 and is also developing refuelling stations. Other major oil marketing companies and gas marketers in India are working in this direction as well.

Vehicle manufacturers have been slow to adapt but India’s biggest commercial vehicle manufacturer, Tata Motors, has made a start by developing India’s first heavy duty LNG fuelled truck, Prima 4032.S. It was tested at Tata Motors’ facility in Pune in June last year. Other manufacturers are looking at the segment as well and are waiting for proper policy to be devised.

The fuel price is another problem. Given the backdrop of low global LNG prices, Petronet LNG insisted on renegotiating its long term contract with RasGas. In December, the two parties signed a revised deal, which bases the price on a three-month average figure of Brent crude oil, replacing a five-year average of a basket of crude imported by Japan, the Japanese crude cocktail (JCC).

Petronet is reportedly looking to renegotiate its Gorgon deal with US ExxonMobil as well. The Gorgon gas is priced at a slope of around 14% of JCC, which Petronet thinks needs to be lowered.

Although, India faces certain challenges in turning LNG into a successful transportation fuel, these problems can be easily taken care of if all stakeholders such as government, regulators, fuel suppliers, vehicle makers and consumers collaborate, Singh said.

“Supply of LNG should not be an issue as sufficient receiving terminal capacity is being added on both west and east coasts. If government extends support in terms of policy, regulations, dedicated corridors for LNG on-board and necessary incentives, the sector will get the required boost,” he said.

- NGW

INDONESIA BIDS FOR MAUREL & PROM

ASIA-PACIFIC

Indonesian state-owned gas and LNG producer Pertamina has agreed with privately-owned French holding Pacifico to buy its 25% stake in French independent producer Maurel & Prom (M&P) for €4.20/share and said it is willing to buy M&P outright. That would value the company at $1bn.

Pertamina indicated August 1 that M&P would become its international development platform and that the experience and know-how of its teams would be key for its strategy's success. The €4.20 offer price is a 47% premium to M&P's last closing price on July 29. Pacifico will earn an additional €0.50 per M&P share if the Brent crude oil price exceeds $65/b for 90 consecutive trading days during calendar year 2017; that €4.70 represents a 65% premium to M&P's July 29 closing price.

Pacifico is owned by French businessman Jean-Francois Henin, who is also chairman of M&P.

M&P's net 1Q 2016 production was 23,717 barrels of oil equivalent/day, chiefly in Gabon (oil) and Tanzania where it operates the Mnazi Bay gasfield, as well as in South America and Canada. It also has a 21.37% stake in Nigerian producer Seplat which produced 25,695 boe/d in 1Q 2016, while in Asia, M&P has a 40% interest in 9,652 km2 Myanmar exploration block M2 which PetroVietnam operates with 45%

Subject to regulatory approvals, completion of the Pacifico deal, and a blessing from M&P's board, Pertamina said it will make a voluntary tender offer for Maurel & Prom on the same conditions.

Maurel & Prom said it is to convene its board to analyse the terms offered. As at January 1 2016, the company was 38%-owned by individuals, 25% by Pacifico, and 28% by institutional investors, while treasury shares amounted to 3%, employees' 1% and others 5%. The company was founded in 1813.

CHINA'S SHALE OUTPUT GROWS SLOWLY

ASIA-PACIFIC

China is working on building a substantial shale gas infrastructure in order to exploit its substantial amounts of gas in place. It has a long way to go: the ministry of land and resources (MLR) said national shale gas output was 4.47bn m^3 in 2015, and although that was an increase on the year before, it was still only two thirds of the government's target of 6.5bn m^3.

Things are improving. Sinopec's Fuling shale gas field in southwest China's Chongqing municipality produced 2.7bn m^3 during the first half of 2016. According to sinopecnews.com this is double the output in the same period of 2015. Gas sales have reached 2.6bn m^3 and Sinopec said both production and sales have overshot the targets set. The first phase of Sinopec's Fuling shale gas field in Chongqing went into production last year. Earlier this year, Sinopec announced its aim to produce 10bn m^3 of shale gas by 2020 from its Chongqing field. It further stated that the target is to have production capacity of 15bn m^3/yr by 2020.

PetroChina subsidiary Southwest Oil and Gas Field Company is moving ahead with the development of the Changning-Weiyuan shale gas demonstration area in Sichuan province. First half shale gas output stood at 1.154bn m^3. But the area was recognized as a national demonstration zone for shale gas exploration and development by the national energy administration over four years ago

More encouragingly, China Geological Survey (CGS) said a large shale gas and oil field has been discovered in Guizhou Province. Geologists discovered four layers of shale gas and oil gas in Anye Well 1 in Zunyi, CGS said, adding that a test conducted in one of the layers resulted in steady daily output of 100,000m^3. The accessible gas reserve in the well is estimated at about 100bn m^3.


Oil pump station, China

EXXON EXTENDS PNG LNG FEEDSTOCK

ExxonMobil agreed July 21 to buy US InterOil in a deal valued from $2.5bn up to $3.6bn, trumping Oil Search/Total's $2.2bn bid of a few days earlier.

This deal should strengthen ExxonMobil's position in the LNG market. Gas from Elk-Antelope can now be used to expand ExxonMobil's on-time and under-budget PNG LNG project.

The reason for the wide range in the estimated offer is that ExxonMobil said it would pay $45/share, but depending on the size of the Elk-Antelope gas fields this could rise to as much as $71.87 each. Current estimates put this at 6.2-10 trillion ft^3 of gas. Additional drilling is still in progress.

InterOil is developing the large Elk-Antelope onshore natural gas project in Papua New Guinea (PNG). It has a 36.5% share in the project. Total is the operator of Petroleum Retention Licence 15 (PRL 15), which contains the Elk-Antelope gas field.

ExxonMobil's Outlook for Energy 2040 report, released early this year, shows worldwide gas demand growing more than twice as fast as crude oil during this period. The report also says: "Through 2040, most of the world's oil and gas exports will likely be headed to the Asia Pacific region, where demand for energy is expected to grow far faster than local production."

InterOil's chairman Chris Finlayson said: "Our board of directors thoroughly reviewed the ExxonMobil transaction and concluded that it delivers superior value to InterOil shareholders. They will also benefit from their interest in ExxonMobil's diverse asset base and dividend stream." Oil Search, backed by its partner, the French major Total, refused to increase its offer and actually said that ExxonMobil's participation would help speed up development of the discovery.

This may lead to cooperation between ExxonMobil and Total in PNG to reduce costs of their projects as they compete in a low oil and LNG price environment.

PNG is attractive to both ExxonMobil and Total because of the low costs, its proximity to Asia and high-quality gas which contains condensates. ExxonMobil is already there with PNG LNG and now Total is committed to working with ExxonMobil. In addition to partnering Total and InterOil in Elk-Antelope and Papua LNG, Oil Search is also ExxonMobil's partner in PNG LNG.

On July 6, Total and its partners announced sites for development of Papua LNG based on gas from Elk-Antelope. The plan was to build the LNG plant adjacent to ExxonMobil's PNG LNG, about 20 km northwest of Port Moresby, with LNG exports expected in 2022.

Oil Search CEO Peter Botten told Bloomberg on July 21 that "an Exxon deal is welcome for Oil Search because it would drive integration between Papua New Guinea's two liquefied natural gas projects, lowering costs and making them more competitive in an over-supplied market." This could lead to a $2bn to $3bn saving. He added that cooperation between the two projects could drive down capital costs, optimize timing, the use of resources and contributions of various fields into the next phase of growth."

Botten also said that "We think, especially with cooperation between the two projects in PNG, that we're very well suited to being the lowest-cost producer feeding (LNG) into that market (Asian)."

Total, operator of the Elk-Antelope fields, confirmed that it was committed to cooperating with PNG LNG to maximize the value of the gas.

Elk Antelope LNG project in Papua New Guinea. Source: Oil Search Ltd.

INDONESIA OFFERS 15 BLOCKS

ASIA-PACIFIC

Indonesia has launched a new open bid split tender scheme to attract investors upstream. Falling oil prices and doubts about the value of contracts which producers have signed with the government have kept investors away from the promising region.

Indonesia is offering 14 conventional oil and gas blocks and one unconventional, Indonesia's ministry of energy and mineral resources (MEMR) director general of oil and gas I Gusti Nyoman Wiratmaja announced in Jakarta on July 18. Most of the blocks are in the east.

In a bid to entice private investors the Indonesian government has decided to change the concept for oil and gas tenders in 2016. "We are offering a new scheme," Tempo, a local news outlet, quoted I Gusti Nyoman Wiratmaja as saying. Seven work areas will be offered through regular auctions and seven for direct proposals.

The sole unconventional, shale, block offered through a regular tender is Batu Ampar in onshore East Kalimantan. Bungamas and Raja coal bed methane concessions will also be up for auction.
Investors can access the bidding documents until August 22. The regular auction is open until October 28, 2016.

MEMR's upstream business development director Djoko Siswanto said the government is offering investors management of the working areas using an open bid split scheme based on contractors' proposals. For non-conventional work areas, contractors can also get a sliding scale scheme, whereas the amount is calculated based on daily production.

He said: "The final assessment is a combination of a participant's proposed work program and their commitment, signature bonus and proposed sharing split."

The ministry is also preparing six new working areas for the second phase auctions. In addition, according to Oil and Gas Directorate General data, the government is considering offering at least 27 potential oil and gas blocks between 2017 and 2019.

Indonesia's oil and gas sector has good potential, but exploration and capital spending have been declining in recent years, partly as a result of the oil price collapse but also because of the lack of consistent policies, contract sanctity and uncertainties over cost recovery, among others.

Research from PwC shows that investment in Indonesia's oil and gas sector has stagnated. And over the last three years there has actually been a clear declining trend in terms of exploratory well drilling in the country. PwC's research concluded that at a time when funds for investment in oil and gas are scarce, Indonesia must adjust if it is to compete for such investments and if its oil and gas production is to increase.

NIGERIA NEEDS BACK-UP FOR GAS

EUROPE, MIDDLE EAST & AFRICA

Nigeria needs to explore alternative power sources such as solar, wind energy and coal to complement existing hydro and gas, the minister of power Babatunde Fashola said in July.

Addressing the second National Council on Power (Nacop) stakeholders' meeting organised by the ministry with a speech titled 'Achieving Incremental, then Uninterrupted Power', he said that the resultant effect of incessant vandalism of gas pipelines was a fall in the country's electricity capacity from 5 GW to 2 GW since February 2016. Nigeria has over 12.5 GW of installed electricity generating capacity, consisting of gas and hydropower plants. But problems such as a lack of maintenance mean only about 7 GW are available. And of that only 5 MW can be generated, provided fuel is available.

Fashola had earlier said that better utilization of gas resources would require the development of alternative back-ups to gas, liquefied petroleum gas (LPG) and condensate pipes, and that the country is poised to reduce its reliance on gas as an antidote to 'vandalism of pipelines'.

According to the minister, the militant Niger Delta Avengers have destroyed 23 gas pipelines across the Niger Delta states between February 14, when the attacks started, and June 2. There have also been 14 attacks on oil pipelines. As a result of that, "the 23 gas pipelines that we have are not getting enough gas to fire their turbines; so we are gradually becoming entirely dependent on hydropower which is coming from Kainji" dam on the Niger river.

"By the end of August, we should be able to improve power in Calabar, Ekot-Ekpeni, and from there evacuate some more power," added Fashola, who was Lagos state governor for eight years until mid-2015.

The minister's comments confirm what analysts have been saying for some while, that it will be difficult to attract and complete investments in new gas-fired power generation while gas supplies continue to be disrupted. An unofficial truce was declared in June but in mid-May a gas pipe was blown up.

In the same vein The Guardian Nigeria, citing gas operators in the country, reported July 13 that Nigeria's power sector lost an average of naira 2bn ($6.9mn) daily between May 27 and June 13 with gas accounting for over 85% of the total constraints.

Meanwhile an oil and gas worker told

NGW July 15 that Nigeria's gas revenue fell by $4bn last year, to $6.8bn in 2015 from $10.8bn in 2014.

Despite Nigeria's enormous natural gas reserves of over 185 trillion ft^3, the country is still faced with huge energy supply problems. Nigeria's vice president, Yemi Osinbajo, blames these problems on inadequate investment on gas facilities, gas flaring, inadequate gas infrastructure and vandalism. He said, "We have limited gas molecules to supply to the power plants. This is a result of many years of under-investment in gas gathering and processing for domestic consumption and also many years of gas flaring. Nigeria alone flares about half of the 40bn m^3 of associated gas estimated to be flared in Africa annually."

Nigeria's endemic problems in the oil and gas sector were described recently in a KPMG report. These include lack of planning, tedious and lengthy procedures for contract award, corruption, theft and vandalism of pipelines. President Buhari, who was inaugurated on May 29 2015, claimed that he will combat these issues, but the results are still to be seen.

Nigeria's minister of power Babatunde Fashola (Photo credit: Fashola/LinkedIn)

NW EUROPE FACES TIGHTER WINTER

EUROPE, MIDDLE EAST & AFRICA

Two sources of peak gas – UK storage and Dutch production – have been reduced this winter, but the shortlived surges in prices reflected a market that is able to cope.

Centrica said in mid-July that the UK's largest gas storage facility, the offshore Rough field, will not inject any more gas until spring 2017 and is unlikely to withdraw any gas until mid-autumn pending the outcome of a study.

The announcement caused prompt UK gas prices to fall as less would be needed for injection in the summer and winter delivery prices rose 10% to a 12-month high before subsiding once more.

The news followed the provisional decision in the Netherlands to cut output from the former swing field, Groningen, by a further 3bn m^3/yr for a five-year period from this October, another bullish signal the market took in its stride.

Rough has capacity for 150bn ft^3 (4.25bn m^3) but the volume now stored is only one-third of that, namely 50bn ft^3, so – unless there is a subsequent revision to Centrica Storage's (CSL) plans – that is now the maximum that will be available from Rough this winter.

Centrica Storage said July 15 in a 'Remit' notice that a 42-day outage, announced a month ago, to conduct pressure-testing revealed a problem at one well and indicated "potential uncertainties" at others, adding that the outage will be extended until March or April 2017. The study is expected to finish end October 2016.

"In the meantime because of the uncertainty as a prudent and safe operator CSL cannot inject or withdraw gas from Rough," it said July 15.

It hopes at least four wells will return to service for withdrawal operations by November 1, but CSL cannot increase the Rough reservoir pressure during the testing programme, which rules out injections.

Normally Rough is filled by the start of the winter season to its full 4.2bn m3 capacity. It represents about 90% of the UK's total normally available gas storage capacity of about 4.6bn m^3, most of the rest being quick-release salt caverns.

Groningen output falls

The value of Groningen as a household gas supply lay in the purchaser's ability to nominate more or less gas from GasTerra on a daily basis as temperatures rose and fell, but now the aim is to produce as steadily as possible over the year.

Abrupt changes in reservoir pressure were found to increase the risk of tremors, which were blamed for the damage done to buildings in the area. NAM declined to speculate on the monthly production profile as it is a preliminary decision but so far this year the output has been relatively stable: from a low of 2.19bn m^3 to a high of 2.68bn m^3.

NAM said it would study the documents and reports, on which the economy minister Henk Kamp based his preliminary decision.

Kamp said the latest decision means that gas output from the Groningen field will have halved since the current cabinet took office in 2012. He is thought to be acting reluctantly as there will be a lot less revenue flowing into the treasury from production and sales.

National grid operator GasTransport Services, which is state owned, advised that the new limit guarantees security of supply of low calorific gas for the Netherlands as well as gas for gas consumers in neighbouring countries who are dependent on low calorific gas from the Netherlands in an average year. In the event of a colder winter, an additional volume of natural gas of maximum 6bn m^3 can be produced on top of this from the Groningen field.

MAY PAUSES UK NUCLEAR

EUROPE, MIDDLE EAST & AFRICA

The UK government caught industry by surprise with its terse announcement that it would need to review the EDF Hinkley Point C contract before deciding whether to sign it.

According to some, the French decision on July 28 following a vote of 10-7 in favour had been brought forward from September only a week or two earlier. In that case the UK government was only sticking to its own timetable for a September signing, although some commentators saw it as a purely political announcement.

While there is a heated dispute in France over who knew what and when about the delay, there is now the prospect that the UK government will baulk at the risks and the costs associated with the project. China has made clear that it sees the nuclear plant decision as pivotal where its own investment plans in the UK are concerned, which include other nuclear plants which it will build on its own.

A former government colleague, business minister Vince Cable, emerged late July to tell people that May had not shared the then finance minister George Osborne's 'gung-ho' enthusiasm for Chinese investment in sensitive UK infrastructure.

There are no functioning projects of EDF's EPR technology anywhere and the two being built, at Flamanville in France and Olkiluoto in Finland, are running late and over budget. A recent discovery has meant that a key steel component of the Flamanville plant needs to be tested for brittleness, which will occur this summer. If problems are found, the original 2012 start date and €3.3bn cost could both overshoot the present 2018 start date and expected €10.5bn cost.

EDF hopes for better project management from now on, having control of Areva in a new company, New ANP, owned 51% by EDF, a development also announced July 28.

Energy consultant David Cox told NGW that the decision to postpone the government's verdict was "astonishing" and had to be seen as political. He said: "These are the same people who were in government before, admittedly in different jobs. They cannot undo the deal." He said July 29 that the UK needs nuclear energy, "on days like today, when wind generates 2% and nuclear 25% of the output." Nuclear capacity is being wound down over the next decade, with the last, Sizewell, due to shut by 2035. "This is bad timing and unnecessary posturing," he said. Building combined-cycle gas turbines would be good for gas, he said, but bad for the UK's emissions.

The Confederation of British Industry (CBI) was also in support of new nuclear, while not discounting the importance of gas: Michelle Hubert, CBI Head of Energy and Climate Change, told NGW in an email: "Shoring up our energy supply for the future is critical for businesses as they look to make long-term investment decisions. Gas plays an important role in UK energy, and should form part of a balanced energy mix that includes renewables, nuclear and carbon capture and storage."

Dr Jenifer Baxter, Head of Energy and Environment at the Institution of Mechanical Engineers, had assumed Hinkley Point C would go ahead once the French had approved it. "Given the UK is facing a 40-55% supply gap the UK government must put in place clear guidance for developing near and long term sustainable power generation that meets the needs of UK carbon targets, creates a good mix of low emission technologies and develops skills and economic growth in the sector," she said. The Institution of Mechanical Engineers is keen on small modular reactors to generate from 45-300 MW to meet local needs flexibly, but none exist yet.

There will be a need for gas in the generation mix for the foreseeable future, but more work needs to be done on efficiencies in the production, storage and transmission sectors as unabated fossil fuel is societally unacceptable, she told NGW. Carbon capture and storage plants exist commercially only as a form of enhanced oil recovery, as the European emissions market generates too low a carbon price to justify the cost of investment.

Energy consultant Lisa Waters of WatersWye told NGW she hoped the government was "doing a reality check on the costs of the project in light of the fact that the world has moved on. The contract looked very expensive, compared with other renewable technologies, and goes on far longer than any other contract for differences support as well. In the time available, investors could deploy other technologies such as biomass, combined-

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SONATRACH AWARDS GR7 PIPE CONTRACTS

EUROPE, MIDDLE EAST & AFRICA

Algerian state gas and oil producer Sonatrach signed two contracts, costing $348mn (dinar 38.9bn), for the construction of the 344km, GR7 gas pipeline in the Sahara, from el Menia in the Ghardaia district northwards.

The 21.2bn m^3/yr capacity pipeline will connect three Sonatrach-operated gas fields – Hassi Mouina, Hassi Ba Hamou and Ahnet, all due to start producing in 2019 -- to the Hassi R'Mel national gas despatching centre some 450km south of Algiers.

Sonatrach's pipelines operator TRC signed the two contracts. Both are with Algerian state companies. The first, for $156mn, is with Alfapipe for the supply of 48-inch diameter pipes to be delivered within 12 months. The second worth $192mn, with Cosider and Sonatrach subsidiary ENAC, covers engineering, procurement and construction, which is to be completed within 30 months.

Hassi Mouina, Hassi Ba Hamou and Ahnet are expected to produce at plateau 1.4bn m^3/yr, 1.8bn m^3/yr and 4bn m^3/yr respectively according to Ali Aissaoui's recent Oxford Institute for Energy Studies report. The first two fields are scheduled to start in April 2019, followed by Ahnet that July, but timelines in Algeria often slip.

Norway's Statoil has told NGE it began relinquishing its 75% operating interest in Hassi Mouina in 2014 and no longer has an interest in the field. Shell subsidiary BG pulled out as operator of Hassi Ba Hamou in 2013.

France's Total acquired a 49% stake in Ahnet in 2009 but pulled out of the planned $4bn tight gas development in 2014 when its economics began to look uncertain.

MALTA'S LNG FACILITY TO ARRIVE IN SEPTEMBER

Maltese prime minister Joseph Muscat was at a sailaway ceremony in Singapore August 1 for the Floating Storage Unit (FSU), Armada LNG Mediterrana. The vessel will act as a storage facility for LNG, which will be regasified onshore for use by the country's new gas-fired power stations.

Malta and Cyprus are the only two EU states without access to natural gas.
Muscat said the project will enable Maltese to "start breathing cleaner air" as it would "complete our breakaway from the old, inefficient and heavy fuel oil dependant plants, to a new energy mix, based on gas."

Critics have asked why Malta opted for simply a FSU, requiring a separate regasification plant to be built onshore, rather than the more conventional option of an FSRU (floating regasification and storage unit). Malaysia's Bumi Armada said the contract, which it was awarded in 2014, to convert the ship to an FSU was worth €300mn (332mn).

The vessel was converted in 17 months by Bumi Armada and Keppel Shipyards – working with Electrogas Malta, according to a statement from the Maltese prime minister's office, adding that it is expected to reach Malta in September.

Germany's Siemens, Azerbaijan state-owned Socar Trading, and the privately-owned joint venture GEM Holdings (owned by Maltese companies Gasan and Tumas) each have 33.333% equity in Electrogas Malta.

The FSU will be permanently moored in nearby Marsaxlokk Bay in southeast Malta. Nearby, Siemens was awarded a €175mn order by Electrogas Malta last year for the turnkey construction of a 200-MW gas-fired combined-cycle power plant (CCGT) at the existing Delimara power station. Reports indicated this will double the Delimara site's overall installed capacity to 400 MW.

Siemens told NGW August 3 that the new 200 MW-CCGT is effectively complete, undergoing tests and "will start commissioning soon."

ALGERIA'S IN AMENAS T3 RESTARTS

Train 3 of the In Amenas gas complex in Algeria's Sahara Desert has restarted, according to a statement from state producer Sonatrach carried by local media.

In Amenas T3 was badly damaged in an attack on the complex by Islamist militants in January 2013 in which 40 staff were killed and had remained shut until last month.

This August 4, the Algerian state news agency APS reported: "Sonatrach announces the restart of Train 3 of the Tiguentourine [In Amenas] gas complex since July 27 2016, after the completion of the repair works and integrity checking. After trains 1 and 2 were put on stream in 2013, the Tiguentourine complex is now running at its full production capacity with the restart of Train 3."

Norwegian Statoil, the largest shareholder at In Amenas, confirmed the restart to NGW on August 5.

However, while all three gas process trains are now back in working order for the first time since January 2013, Statoil says that 'full production' – at In Amenas, overall capacity is just over 9bn m3/yr – will not resume until work on compressors is finished later this year.

"It is correct that train 1 and train 2 were able to re-start soon after the attack in January 2013; train 3 will not add new production before new compressors are completed later this year," Statoil told NGW.

Statoil gives its average net In Amenas 2Q 2016 production as 16,700 barrels oil equivalent/day. As Statoil's share of In Amenas is 45.9%, that suggests that In Amenas total 2Q production was
36,385 boe/d.

Sonatrach, Statoil and BP jointly operate both In Amenas and In Salah in Algeria, though equity interests are different for each venture. Each complex has roughly 9bn m3/yr production capacity when fully operational, meaning each can contribute 10% of Algeria's marketable gas production.

In late July, In Salah CEO Maazou Slimane told APS that his complex had reached the equivalent of 9.1bn m3/yr and was expected to ramp up to 9.85bn m3/yr in September, much higher than its pre-March level of 5.1bn m3/yr.

BP and Statoil temporarily withdrew all foreign staff from Algeria in mid-March after an unsuccessful missile attack by militants on In Salah. Many had since returned, but Slimane said that the number of foreign workers at the complex would be reduced by 40% between now and the end of 2016. In Salah venture employs 1,800 staff, of whom 400 are foreigners.

In Salah is 1,200 km south of Algiers, while In Amenas is some 1,500 km southeast of the capital and close to the volatile Libyan border. Algerian authorities have stepped up security around gasfields since the 2013 attack.

EU FUNDS ESTONIA-FINLAND LINK

EU governments on July 15 agreed to a European Commission (EC) proposal to invest €263mn in key energy projects, of which the lion's share will go to build a gas pipeline between Estonia and Finland. Balticconnector, which once built will end Finland's dependence on Gazprom, will receive a €187.5mn EU grant. It is a 7.2mn m^3/d (254mn ft^3/d) bi-directional subsea gas transmission project that is scheduled for completion in 2019.

Its backers, Estonian gas and power grid operator Elering and Finland's Balticconnector, applied for the grant in April and have now received the maximum permissible 75% EU funding towards its estimated €250mn cost. For most projects, EU funding has been capped at 50%. But this venture is seen by the EC as "strengthening the security of supply in the eastern Baltic Sea region."

Late last year Gasum said an LNG import terminal and the Balticconnector link to Estonia were uneconomic, citing declining gas demand and poor economics. Since then the EU has stepped into cover up to 75% of the pipeline's costs, just enough to meet Finland's demands.

Finland and, until recently, the three Baltic states, were totally reliant on Russia for their gas. Balticconnector links them to the EU's gas markets, including Poland, and allows access to the Incukalns underground gas storage facilities in Latvia.

Matti Sainio, project director at Balticconnector, told NGW July 15 that the final investment decision is expected this autumn.

The project consists of an 82-km offshore pipe from Paldiski (Estonia) to Inkoo (Finland) that will operate at 80 bar, plus a 22-km onshore pipe in Finland at the same pressure, and a 47-km onshore pipe in Estonia at 55 bar, and gas metering and compressor stations at Kersalu (Estonia) and Inkoo.

The EC said that it would also fund the Estonian-Latvian interconnection to the tune of €18.6mn. It has already granted Balticconnector €5.4mn towards studies. Finland's gas consumption in 2015 was 3bn m^3, according to Eurogas, almost equivalent to the roughly 2.6bn m^3/yr capacity of Balticconnector. Estonia consumed 0.6bn m^3, Latvia 1.3bn m^3 and Lithuania 2.5bn m^3 last year, according to the same Eurogas data.

Under the EU's Connecting Europe Facility, €5.35bn was allocated to trans-European energy infrastructure for 2014-2020. The latest €263mn comes from that. A second 2016 call for proposals with an indicative budget of €600mn is ongoing and will close on November 8.

US LNG REACHES SPAIN

The tanker Sestao Knutsen, with 138,000m^3 of LNG aboard, arrived at the Reganosa terminal at Ferrol in northwest Spain on July 22, marking the first LNG delivery in Spain from the US, and the second US cargo to reach Europe. Both cargoes came from the Cheniere-operated Sabine Pass liquefaction terminal in Louisiana. Others from the US have been shipped in the meantime to Asia, Latin America and the Middle East. The ship departed again, having unloaded, on July 23.

Cheniere estimates that the US will become the third largest LNG supplier in 2020 with a production capacity of 60mn mt/yr. A statement from Reganosa said that Spain will become a leading US LNG importer because it is the European country with the most terminals, and that its own terminal is the ideal place to receive such flows.

The first US LNG cargo to be delivered to Europe arrived at the Portuguese port of Sines on April 26 2016 aboard Creole Spirit. Cheniere's Sabine Pass began selling LNG abroad for the first time in February, marking its emergence as a major exporter. The first shipment went to Brazil, with subsequent cargoes heading to Asia. But Asia is not proving an easy market, with subsequent cargoes shipped to Brazil, Argentina, Portugal and India. Thierry Bros, an analyst formerly at Societe Generale, said: "It's the start of the price war between US LNG and pipeline gas." A lot of LNG is coming into the global market over the next five to six years and, given market conditions in Asia, Europe may be seen as a market of last resort for excess LNG.

However, this does not appear to worry Gazprom as it does not expect it to be competitive against its pipeline gas supplies. Futures prices in the US for Henry Hub gas in July 2017 have risen from less than $2.50/mn BTtu in July 2016 to around $3.10. LNG buyers pay Cheniere a fixed fee ranging from $2.25/mn Btu for the first contract, signed with BG (now Shell) to $3/mn Btu for the last contracts, also including one with BG; plus 115% of Henry Hub price, plus shipping and regasification costs at the destination. This makes US LNG arriving in Europe in July $5.$6.38/mn Btu, which is expensive against Gazprom who can sell at well below $4/mn Btu and still be profitable.

This is why Cheniere LNG is not reaching the competitive hub-based markets of western Europe and ends up in the more isolated, unconnected, markets of Spain and Portugal that tend to be more expensive. But nevertheless Gazprom may feel the pressure sufficiently to be forced to keep prices of gas to Europe low.

Jonathan Stern, chairman of the natural gas research program at Oxford Institute of Energy Studies, said "US LNG supply to Europe may have strong geopolitical symbolism, but its current volume impact will be negligible, until the big volumes come on stream in 2018-19, and cargoes will probably go to higher value markets in Latin America and elsewhere."

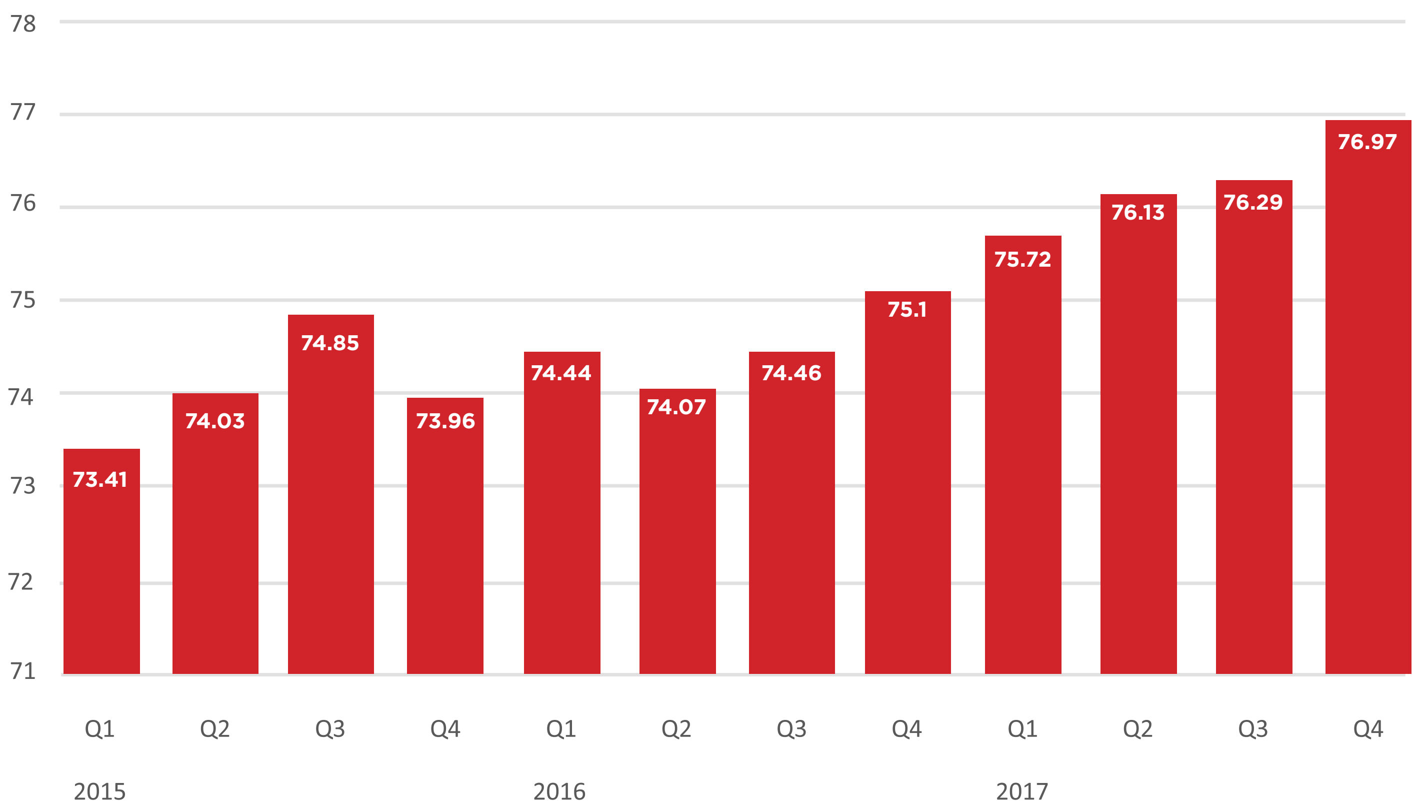
The other challenge is that US LNG

exports to Europe are arriving at a time when demand for gas has fallen by around 20% from its peak, due in part to a switch away from gas power generation, towards subsidised renewables and coal. This puts even more pressure on gas prices. Apart from its political significance, it remains questionable whether US LNG will become an important source for European gas markets.

Sestao Knutsen at the Reganosa terminal at Ferrol on July 22 (photo credit: Reganosa)

US DRY GAS OUTPUT: ACTUAL/FORECAST POST-Q2 2016

Dry gas output (bn ft³/d)



Source: Energy Information Administration

SABIC, EXXONMOBIL EXPLORE DEVELOPMENT OF US GULF COAST PETROCHEMICAL COMPLEX

AMERICAS

Saudi Arabian Basic Industries Corp. (Sabic) and ExxonMobil Chemical Co. are considering the potential development of a jointly owned 'world-scale' petrochemical complex on the US Gulf Coast, they said in late July.

The complex would include a steam cracker and derivative units and would be based in Texas or Louisiana near natural gas feedstock. The companies will conduct necessary studies and work with state and local officials to help identify a potential site with adequate infrastructure access which will yield a cost estimate and project schedule. The potential scale of this investment is such that it would have a transformational economic impact for the chosen region and state.

The president of ExxonMobil Chemical Company Neil Chapman said: "We have the capability to design a project with a unique set of attributes that would make it competitive globally. That is vitally important as most of the chemical demand growth in the next several decades is anticipated to come from developing economies."

In outlining the company's strategy, ExxonMobil's CEO Rex Tillerson said early this year "We are focused on maximizing benefits across the energy value chain." The company captures unique value from its diverse, high-quality resource base from exploration, development and production all the way through to the fuels, lubricants and petrochemical products.

ExxonMobil prides itself that its downstream and chemical businesses have the scale and integration across refining, lubricants and chemicals to maximise product value while driving operating efficiency. About 80% of the company's 5mn b/d refining capacity is integrated with chemical and lubricant manufacturing facilities.

Tillerson also said "We are advancing several downstream and chemical projects to increase feedstock flexibility, produce higher-value products and expand logistics capabilities to strengthen our competitive advantage in these businesses." The newly announced petrochemical complex fully fits this strategy.

Welcoming the new project, Sabic's CEO Yousef Abdullah Al-Benyan said "We are focused on geographic diversification to supply new markets... The proposed venture would capture competitive feedstock and reinforce Sabic's strong position in the value chain."
ExxonMobil Chemical and Sabic have worked together for 35 years in major chemical joint ventures in Saudi Arabia.
The decision to locate the new complex near natural gas sources, not only will provide it with low cost feedstock, but will also be welcomed by shale gas producers in the US. Both Texas and Louisiana have substantial shale gas resources, with the US going through a shale gas glut. In fact the US is awash with shale gas and according to EIA's Annual Energy Outlook 2016 will continue doing so to 2040 and beyond. The proposed petrochemical complex, should it go ahead, would expect to have plentiful and cheap gas supplies.

Last month, rival Shell took the final investment decision to build a major petrochemical complex in Pennsylvania, the heartland of cheap US shale gas. CEO Ben van Beurden said the company was treating petrochemicals as a growth opportunity, and the way to secure an advantage in that sector was through cheap gas. Commercial production expected to begin early next decade.

SONANGOL DROPS COBALT DEAL

AMERICAS

Angolan state Sonangol has called off its planned $1.75bn purchase of US producer Cobalt International's 40% operating interest in Angola offshore blocks 20 and 21.

Cobalt said during its 2Q results on August 2 that its new CEO Tim Cutt, appointed a month earlier, met with Sonangol chairwoman Isabel dos Santos and her team in late July to discuss the status of the transaction, first announced in August 2015.

"At this meeting, Cobalt and Sonangol jointly agreed that Cobalt would market Cobalt's 40% working interest in Blocks 20 and 21 to sell the assets to a third party," the US independent said.

"On August 1, Cobalt received a letter from Chairwoman Isabel dos Santos confirming Sonangol's support of such marketing and sale process. Given this agreement to market Cobalt's interest in Blocks 20 and 21, it is unlikely that the sale transaction between Cobalt and Sonangol will close pursuant to the terms of the August 2015 purchase and sale agreemen (PSA), and therefore it is likely the PSA will automatically terminate on August 22, 2016."

"Cobalt is currently preparing a data room for its Angola assets and will immediately commence the marketing and sale process," its statement added.

The US firm may be due a termination fee from Sonangol, but has yet to disclose any details until the latter definitively pulls its planned acquisition later this month.

Isabel dos Santos, Africa's richest woman on account of her equity stakes in various banking and oil company interests, was appointed as Sonangol chairwoman in early June by her father, Angola's president Jose Eduardo dos Santos. The president said earlier this year he would step down in 2018 but has since consolidated his family's levers of power. His son, Jose Filomeno de Sousa dos Santos, has headed the country's sovereign wealth fund since mid-2013.

Sonangol's annual report – published in recent weeks – acknowledged that 2016 would be a "difficult" year for the company because of low oil prices and reduced foreign investment. Although Angolan oil production increased slightly in 2015, there was a sharp decline in exploratory drilling relative to 2014.

Cobalt's 2Q 2016 results mentioned that it had received $250mn of Angolan sale proceeds. However, it has also expended money during the past 12 months on continued drilling operations on the blocks, all on the understanding that these would be refunded by Sonangol upon completion. In June 2016, Sonangol declared the Zalophus-1 gas discovery (2.8 trillion ft^3) on block 20 as commercial; BP and Sonangol each have 30% equity in the block, which is operated by Cobalt (40%).

Cobalt had hoped the $1.75bn cash infusion would bolster its finances. But this May, it was obliged to report that Angolan government approval of the deal was overdue.

On August 2, Cobalt reported a net 2Q 2016 loss from continuing operations

of $200.4mn, four times larger than its comparable loss of $53.4mn in 2Q 2015.
Cutt added August 2: "Although we would prefer the transaction with Sonangol to close, I am pleased that we can remarket these attractive liquid rich assets to third parties. The development cost environment has improved substantially, the fundamentals for medium to long term liquids pricing remains strong and we have delivered two new discoveries on Block 20."

TOTAL STARTS UP BOLIVIAN FIELD

AMERICAS

French major Total announced August 3 that it had started up the Incahuasi gas/condensate field, its first operated development in Bolivia. The field has a production capacity of 50,000 barrels of oil equivalent/day (boe/d).

Incahuasi is in the Andean foothills some 250 km from the southern Bolivian city of Santa Cruz de Sierra, in the Aquio and Ipati blocks. The development is operated by Total (50%) with partners Gazprom and Argentina's Tecpetrol (each with 20%) and Bolivian state YPFB (10%). The field was discovered in 2004 and its sub-surface depth is 5,636 metres.

"Incahuasi is one of the largest gas and condensate fields brought on stream in Bolivia. Its production will contribute to Bolivia's gas exports to Argentina and Brazil as well as domestic consumption", said Arnaud Breuillac, Total Exploration & Production president.

The first phase of the development involves three wells, 100 km of associated export pipelines, and a treatment plant with capacity to produce 6.5mn m^3/d (2.37bn m^3/yr) of gas and almost 6,000 b/d condensate. Phase two, involving three more wells, is currently under consideration.

Breuillac said that Incahuasi is Total's fourth field start-up this year globally, noting that its low-cost, long-production plateau would contribute to Total's production growth in 2016 and beyond.
Total has been present in Bolivia since 1996 and is one of the country's leading oil and gas companies, with 2015 equity production of 28,000 boe/d, mostly gas. In addition to the operated Incahuasi field, Total is a partner on the San Antonio, San Alberto and XX-Tarija Oeste (Itau) production licences. Total also operates the 7,800 km2 Azero exploration licence in the Andean foothills.

Gazprom and YPFB signed a memo of understanding in February 2007, which was followed up with exploration and appraisal agreements in 2008 including with Total. The Russian gas giant farmed in with a 20% stake to Aquio and Ipati blocks in 2010.

Incahuasi gross reserves (100% equity) are estimated at some 176bn m^3 gas and 15 million metric tons of condensate, according to Gazprom.

SHELL SHELVES N AMERICAN LNG PLANS

LNG

While Anglo-Dutch major Shell has decided to postpone two final investment decisions for LNG projects this summer, its two biggest rivals, ExxonMobil and BP, are still investing in new projects. But the oversupply means more destruction of value for the sellers as customers seek lower prices.

Shell's CEO Ben van Beurden said July 28 that the decision to turn the US Lake Charles terminal into an export facility – a plan BG had initiated some years ago – had been delayed; and earlier in the month it postponed the LNG Canada project decision, which was to have been taken this year.

That was despite his assertion that as a brownfield conversion, Lake Charles is among the cheapest of all North American projects, and his belief that LNG demand will grow in the 2020s. Hence, he said, projects that were starting up in the early years of the decade would have the advantage.

Most of Shell's LNG is going to Asia or Latin America, with the first cargo through the expanded Panama Canal headed for China. The low current gas prices in Europe may at the margin attract some small number of cargoes from the US, as a spot price could just about cover cash costs, Shell told NGW, being the sum of the Henry Hub price, the fixed liquefaction cost which ranges from $2.25-$3.00/mn Btu, depending on the contract; and the shipping and regasification costs, particularly if the supplier has a take or pay commitment on the LNG liquefaction or upstream supply.

Shell told NGW that US LNG suppliers or marketers would not enter into structural multi cargo deals, and certainly not make any new investments, at current prices and without more certainty on gas demand development in Europe.

"For now EU is essentially an opportunistic market, not good for customers or suppliers and over time does not support long term development of secure, affordable energy supply," the company said.

Its two rivals, which have a smaller LNG portfolio to begin with, announced expansion plans aimed at different markets.

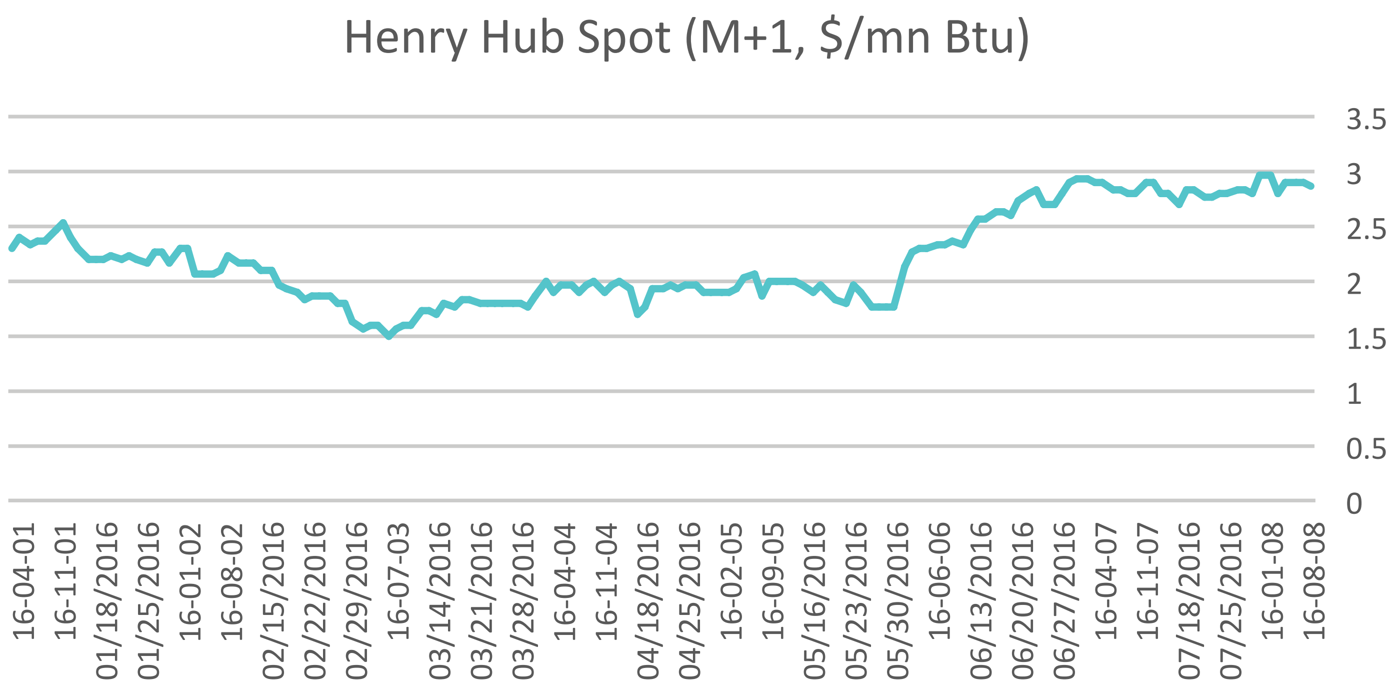
ExxonMobil is purchasing InterOil, its partner in the 6.9mn metric tons/year PNG LNG plant, having outbid Oil Search (see separate report). This deal gives it access to more gas for its own project, running off the 9 trillion ft^3 Hides resources.

The US major, in partnership with Qatar Petroleum has also reportedly entered into talks with Mozambique's licence-holders. Eni and Anadarko are planning to build an integrated LNG project, Coral LNG, with final investment decision due this year.

And BP this summer announced expansion of Tangguh LNG with the final investment decision on train 3. Sources said that with falling costs in the industry the project was now put at the lower end of the $8bn-$10bn range. About three quarters of the 3.8mn mt/yr output has been sold to the Indonesian state electricity company PLN. The rest is under contract to Kansai Electric Power Company in Japan, the other foundation buyer for Train 3. BP also announced compression would be added at Point Fortin, where Atlantic LNG operates a mature LNG export project. Funded entirely by BP, it will add some 200 mn ft^3 to the liquefaction trains from early next year for a few hundred million dollars.

These decisions are being taken in very different circumstances from earlier ones as some existing buyers are already over-contracted and trying to reduce volume and/or the price.

India's Petronet LNG, having successfully cut the pricing terms of its deal with Qatar's RasGas, is now looking to get a reworked deal from the Chevron operated Gorgon project offshore Australia. "When LNG deals are being done at 12% or 12.5% indexation, the Gorgon deal is certainly on the higher side," Press Trust of India quoted an official as saying. At the government's instance and that of its promoters, Petronet has written to ExxonMobil, the seller of Gorgon LNG, for reworking the price. Petronet would have to pay at least $6.5/mBtu, which is indexed to 14% of the Japanese Crude Cocktail (JCC) price. Petronet and ExxonMobil signed a 20-year, 1.4mn mt/yr deal in 2009. Spot LNG in Asia is available at $5-6/mn Btu whereas Gorgon LNG at current formula will cost $6.5/mn Btu at on oil price of $45/b. After adding 5% customs duty, shipping cost and regasification, the landed price of the Australian gas will be close to $9/mn Btu at the Kochi port, Press Trust reported.



Source: Energy Information Administration

PANAMA CANAL ADMITS FIRST LNG TANKERS

The BP-owned British Merchant sailed through the Panama Canal on July 26, the second laden LNG tanker to pass through since the expansion was completed. Reports indicated it loaded in Trinidad and was headed for Mexico's west coast. British Merchant can carry 138,000 m3 so can easily be accommodated by the newly expanded canal. A third LNG tanker is expected to transit in August.

These ships follow the transit on July 25 of the Shell-chartered Maran Gas Apollonia – measuring 289 m in length and 45 m in beam – which had previously loaded at Cheniere's Sabine Pass LNG terminal on the US Gulf Coast. Ship tracking sources indicate that the ship went on to the port of Gulei in southern China's Fujian province. "The transit of the first LNG vessel through the new Panama Canal locks is a milestone in the waterway's history," said Panama Canal Administrator and CEO Jorge L Quijano July 25: "LNG trade will greatly benefit from the expansion, and we look forward to welcoming even more LNG vessels through our great waterway. This transit marks the beginning of a new era that will result in cleaner and lower cost energy for the world."

The expanded canal can accommodate 90% of the world's LNG tankers by size, which the canal authority expects to have a major impact on global LNG flows. Trade sources say that vessels with capacity to hold 175-180,000 m3 should now be able to transit the expanded canal, larger than even Maran Gas Apollonia's 161,870 m3 capacity. With the US poised to become one of the world's top LNG exporters in the next five years, the canal will allow vessels departing the US east and Gulf coasts for Asia to enjoy significant reductions in voyage times (up to 22.8 days roundtrip), making US gas deliveries to major Asian importers very competitive, the authority said, while vessels departing the US Gulf for South America's west coast will similarly experience generous time savings.

LNG ships from Trinidad could head to Chile through the expanded canal, achieving savings of 6.3 days in transit time compared with rounding the Magellan Strait.

Providing further advantage, the canal company has instituted a new tolls structure to offer substantial cost savings to LNG vessels conducting roundtrip voyages. The new tolls reduce ballast fees for LNG customers who use the same vessel for a roundtrip voyage as opposed to using an alternate route, so long as the transit in ballast comes no more than 60 days after the laden transit was completed.

ENI DENIES CONTRACT DEFEAT

An acrimonious long-term contract dispute broke into the open in July with the loser vowing not to pay up. Italian Eni had agreed to buy gas from the Dutch marketer GasTerra for a period of years but sought to reduce the price of deliveries between 2012 and 2015.

While arbitration was pending, GasTerra agreed to drop the price, letting the buyer off what amounted to €918mn – or half the €2bn that Eni demanded. Eni lost the case but still refused to pay up. It said: "GasTerra considers that, by dismissing Eni's claim, the award restored the original contract price, on the basis of which GasTerra now claims an additional amount to be paid by Eni to GasTerra," Eni said.

But it disputes this is correct, so when GasTerra fought back with a counter-claim for €918mn against Eni, being the difference between what Eni paid under a provisional agreement since the start of the review period, and the actual contract amount due, plus interest, it refused to pay.

Eni said that its external consultants advised it to ignore GasTerra's interpretation and so it would not take the effect into account in its first-half results. Instead it is "seeking good faith discussions to agree on the extent of the 2012 price revision."

Gasterra instead has seized assets belonging to Dutch-registered Eni International to the value of €1.01bn, acting with the authority of the Amsterdam district court.

This measure, which was granted after a summary review only and without Eni being heard, does not prejudice the outcome on the merits of the proceedings, Eni said.

Eni considers that GasTerra's request for payment is unfounded and will take all necessary measures to protect its rights. With respect to the interim measures obtained by GasTerra, Eni is considering its position, pending the outcome of the arbitration proceedings. Eni will further seek compensation for any damages it incurs, due to GasTerra's legal actions," it said.

However an expert witness familiar with these cases said that if there is an arbitration clause in the contract, that is normally the final word and there is no provision for an appeal. This makes arbitration a risky undertaking and the results are often kept quiet when the buyer loses, making this case more unusual.

But other cases have also gone the sellers' way lately, with Lithuania losing its case against Gazprom. The court rejected all allegations regarding an "unjust gas price" for deliveries Gazprom made to Lietuvos Dujos between 2006 and 2015. Gazprom said in a statement expressing its satisfaction and adding that the decision is final and not subject to revision. Gazprom was a major shareholder for Lietuvos Dujos until June, 2014, when it sold its shares to comply with the EU third energy package:

In 2014 supplies of natural gas attributed to Eni from The Netherlands amounted to 13.46bn m^3, 16% of Eni's total supplies.

POWERNEXT REACHES FURTHER EAST

COMPANIES

Austria's and Germany's competition authorities have approved the creation of a Vienna-based company to run a trading platform for central and eastern Europe. This is an area where competition has been slow to develop owing partly to the dominance of Gazprom and partly because in some countries there is not much political will.

A joint company is being formed by Austrian Central European Gas Hub (CEGH) (49%) and Paris-based Powernext (51%), based in Vienna to ensure a local service for the Austrian market. Powernext owner, EEX, said August 4 that customers will benefit from access to the pan-European Pegas offering. Pegas is the central gas trading platform of EEX Group operated by Powernext.

As of the end of November, CEGH Gas Exchange spot and futures contracts will be operated on the Pegas platform under the Powernext rulebook and exchange licence. The agreement foresees the joint development of the Austrian as well as the central and eastern European gas markets. CEGH CEO Gottfried Steiner said traders would "substantially benefit from this cooperation, which will also enable spread trading to other European markets and further increase liquidity at the Austrian VTP."

Powernext CEO Egbert Laege described it as a "major step in the development of Pegas to become the one-stop-shop for European gas trading." He said Pegas' expansion into central and eastern Europe was a "key piece in our strategy to expand the geographical coverage of our offering."

Danish Gaspoint Nordic is going to join the Pegas platform by the end of the year. After the completion of the cooperation with CEGH, Pegas will cover the markets of Austria, Denmark, Germany, France, the Netherlands, UK, Belgium and Italy.
Subhead: Ascent links Petosivci to CEGH
Despite the limited number of net sellers in the region, CEGH does have credibility as a pricing tool: Ascent Resources told NGW that its gas sales agreement with Croatian INA would be linked to the CEGH. As an interim measure, it is selling gas from its Petisovci field in Slovenia at the border with Croatia, on a 12-month contract that may be renewed.

The deal offers worse margins than if Ascent were to treat the gas – which is slightly too rich in CO2 – in its own plant but that would require a permit to build a plant and so far it has not received an integrated pollution prevention and control consent, it said. This way, CEO Colin Hutchinson told NGW, the gas sales can start as early as next January although it needs to issue shares to buy the company controlling access to the INA-built pipeline linking the field to the border and that requires shareholder approval.

No production figures have been released but he told NGW that INA knew roughly how much gas to expect. The field's contingent resources are 456bn ft^3

SIEMENS HELPS POWER EGYPT

COMPANIES

Germany's Siemens marked a further milestone in its construction of three giant gas-fired power generation complexes in Egypt, each of 4.8 gigawatts, on August 11 when the first heat recovery steam generator (HRSG) modules for Beni Suef in Egypt began their five-week journey from South Korea.

On its arrival mid-September, the boiler is scheduled to be installed at the Beni Suef plant. In May, four Siemens gas turbines, each of 400 MW, were delivered to the same site from Germany. The Beni Suef complex is due to go online before summer 2017.

A total of 24 HRSGs are to be delivered to the three 4.8-GW combined-cycle power (CCGT) projects being built at Beni Suef, Burullus and New Capital, with eight such boilers for each plant. Dutch NEM, whose design was used to make the HRSGs in South Korea, was acquired by Siemens in 2011.

Siemens' three giant projects underway are just part of the massive expansion anticipated in the Arab Republic's generation capacity.

The contracts to install the three giant CCGTs, plus up to 2 GW of wind farms in Egypt (in the form of 600 wind turbines), plus a wind turbine blade factory at Ain Sokhna, were signed in June 2015 and are worth €8bn to Siemens as chief contractor, representing its biggest single order.

Egypt will need to invest $28bn in power generation, a report by ApiCorp said in May, to raise its generation capacity by 21 GW to reach 56 GW in 2020 – inclusive of the 14.4 GW that Siemens is now building. Tight gas supplies might deter new investment in generation capacity in the short term, it said. But once supplies start flowing by late 2017 from the 30 trillion ft^3 Eni-operated Zohr field – and from others' fields – investor anxieties would be allayed. An Egyptian newspaper reports that the country is coping with this summer's peak generation demands, thanks to LNG import capacity added last year.

Gas demand soars with temperature

Egyptian power plants' gas demand rose to a daily 3.75bn ft^3 (106mn m^3) in the second week of August, from 3.4bn ft^3/d the week before, because of extra air cooling resulting from high temperatures, Daily News Egypt reported on August 10 citing a source at state gas company Egas.

Egas has agreed with the electricity ministry to provide 3.9bn ft^3/d (110.5mn m^3/d) at peak this August to run the power plants, the source said, adding that Egas is regasifying 1.2bn ft^3/d of LNG at Ain Sokhna on the Red Sea, while a pipe from Aqaba in Jordan is running at its maximum of 0.1bn ft^3/d.

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