Fresh impetus for Sino Gas & Energy

Damon Evans
SINGAPORE

AUSTRALIAN-LISTED Sino Gas & Energy, which focuses on unconventional gas in China, is on the verge of ramping up production in the prolific Ordos basin.

Over the past five years, the Ordos basin in Inner Mongolia has doubled its gas output and is responsible for almost 40% of China's expansion in production.

Energy research firm Wood Mackenzie estimates basin-wide production could hit 7.3 billion cubic feet a day (cf/d) by 2020, suggesting this growth will continue.

And Sino Gas & Energy, one of a handful of foreign unconventional specialists operating in China, plans to be a part of this growth story. The company has a large, high-quality asset base, which convinced its newly appointed chief executive, Glenn Corrie, to get on board.

Its acreage holds about 4 trillion cf of recoverable gas – roughly the same volume held in Woodside's Pluto field off Australia that feeds a liquefied natural gas (LNG) export plant – plus another 4 trillion cf of prospective gas, Corrie told *Petroleum Economist*.

Gas prices are rising and domestic demand far outstrips supply, meaning the company should make good returns if it successfully commercialises the gas.

Corrie previously managed Shell's global gas and LNG strategy team in The Hague and more recently was responsible for oil and gas projects at Singapore's state-owned investment firm Temasek.

Cheaper than shale

Sino Gas & Energy develops projects that produce tight gas and coal-bed methane (CBM), processes that are easier and less expensive than extracting shale gas in China.

The cost of producing gas from its Ordos basin acreage is estimated at around $2 per million British thermal units (Btu), much less than the break-even price for shale-gas production, which is about $14/million Btu.

Tight gas from the Ordos basin looks well placed on the Chinese supply cost curve. On top of this, the basin is positioned close to existing demand centres, as well as major pipelines, making rapid expansion possible.

The company has publicly announced sales contracts pegged at $7/million Btu. But Corrie expects future sales prices closer to $10/million Btu as city-gate gas prices have risen strongly since the initial deal was sealed.

With the cost of drilling below $2 million per well, and recoveries estimated to range from 1 billion to 2 billion cf/d per well, the economics stack up favourably.

Horizontal fracture-stimulated wells are pumping around 4.5 million cf/d at a constrained rate, which Corrie thinks could rise to 8 million or 9 million cf/d.

Yet, despite sitting on several trillion cf of gas in the world's fastest-expanding gas market, the Beijing-based company appears undervalued. Its proved plus probable (2P) reserves are worth A$720 million ($650 million) yet its market value is around A$360 million.

It is trading at nearly half its risked net asset value, while its peers trade at an average 80-90% of risked net asset value.

Based on the value of the company relative to its 2P reserves, Sino Gas & Energy looks cheap at around $5-6/barrel of oil equivalent (boe). Its peer group trades on average at $18-20/boe. The company's peers are thought to be China-focused CBM player Green Dragon Gas, companies with assets in China and other listed unconventional players.

Corrie, who joined the company in August 2014, explains that Sino Gas & Energy might be disadvantaged by a lack of major profile and suffers from a China discount.

Ready to start

The company's pilot project has previously been delayed, but is forecast to start production this year.

Shares in Sino Gas & Energy trade around A$0.23 on the Australian Securities Exchange. But Macquarie has a price target of A$0.35 set at a 13% discount to risked net asset value of A$0.40.

As the number of wells drilled has passed 80, the investment bank thinks that Sino Gas & Energy's tight gas assets across the Linxing and Sanjiaobei production sharing contracts have become less risky.

This is mainly because the explorer is expected to move into pilot production and ful-field development over the next two years.

A better understanding of the tight gas resource will probably prove more relevant than rising production rates, with initial flows shoring up the longer-term rates of deliverability from reservoirs

The 30-well pilot programme, which will produce 20 million to 25 million cf/d, plans to ramp up output by the end of this year.

But a better understanding of the tight gas resource will probably prove more relevant than rising production rates, with initial flows shoring up the longer-term rates of deliverability from reservoirs.

Full field development should see output hit 150 million cf/d or more after 2017, which would be enough to comfortably supply at least two 300 megawatt power plants.

Not all analysts are fully convinced by the company's growth forecasts, however.

Some cite delays in government approvals as well as questions about the company's ability to fund drilling as the main barriers to growth.

But following a $90 million strategic tie-up with Hong Kong-listed oil and gas explorer MIE, which now holds 51% of Sino Gas & Energy's operating company in China, the Australia-listed player looks fully funded until it starts the overall development plan.

The biggest risk is delays for approvals, says Corrie. But with activity shifting from appraisal to development, aligning various partnerships could prove challenging too.

Still, the arrival of Phil Bainbridge as chairman, who has a long track record of working constructively with partners and government should help smooth the way.

Most recently he helped manage relations with ExxonMobil and the Papua New Guinea (PNG) government for Australia's Oil Search, which is a joint partner at the US major's PNG LNG export venture.

And impending shift to full development will mean more sales agreements will need to be fully negotiated.

Meanwhile, the pending back-in right of national oil companies means Sino Gas & Energy team's expertise in managing relations with partners could prove equally as important as its technical skills. ●

Ineos makes a move into shale

Helen Robertson
LONDON

PETROCHEMICAL company Ineos has outlined plans to pay local communities 6% of revenues from future shale-gas production, bettering earlier compensation pledges made by its peers in the sector and the government.

But sections of the UK public remain deeply sceptical of the emerging industry, and of hydraulic fracturing (fracking) in particular.

And with limited exploration and no certainty over how much shale gas can be commercially produced until more test drilling has been done, it's difficult for the public to quantify these potential benefits.

In late September Ineos unveiled its plans to give 6% of revenues from future shale-gas production to homeowners, landowners and communities located close to shale wells. It said this could amount to a £2.5 billion ($3.9 billion) giveaway over the life of its shale gas production. Ineos said its figures are based on the assumption that UK shale-gas wells would be comparable to typical ones in the US.

Wells in the US' Marcellus shale play are expected to have an average 30-year lifespan.

Revenue

The firm said that people who own property and land directly above an Ineos shale gas well would receive a 4% share of the revenue once the well is producing.

Over the lifetime of a single well, home- and land-owners would receive over £1.3 million and the community £600,000, Ineos said.

Communities living near wells would share 2% of the revenue, which Ineos estimates would be worth a total of about £125 million, with contributions going towards community benefits such as new schools and hospitals.

For people living in what Ineos calls "a shale gas community" – an area around 100 square kms from a cluster of its planned 200 shale wells – around £375 million would be split between them over the life of the project.

Ineos entered the UK shale sector in August when it bought BG Group's 51% stake in the PEDL 133 licence in Scotland's Midland Valley. The remaining 49% stake in the block is owned by Dart Energy, which is also operator.

Ineos' compensation pledge is generous compared to that offered by other UK-based companies, but it is far below payments made to US landowners who allow shale drilling on their property. In the US, landowners own mineral rights so they negotiate leases with energy firms allowing them to drill on their property.

They can also negotiate royalty payments for a percentage of revenue from producing wells. These can differ from state to state. Pennsylvania sets a minimum 12.5% royalty rate but they can be as high as 20%.

The UK situation is slightly different. In June 2013, energy firms signed up to a Community Engagement Charter through trade body UK Onshore Oil & Gas (UKOOG). Through the charter firms pledged to pay 1% of revenues to local communities, once a well is producing, in addition to £100,000 per site during the exploration and development process.

Local authorities would also be able to keep 100% of business tax rates for shale-gas operations, the government said, rather than the usual 50%.

UKOOG said two-thirds of the revenue would be distributed at local level while the remainder would be allocated at national level.

The UK Business and Energy Minister, Matthew Hancock, said Ineos' planned revenue sharing was a vote of confidence in the UK shale gas sector.

Ineos chairman and founder, Jim Ratcliffe, called his company's pledge "a game changer for the UK's shale industry", adding it would ensure the rewards of shale-gas production were shared out fairly.

However anti-shale campaigners are deeply sceptical, with Greenpeace, one of the sector's most vocal critics, branding Ineos' pledge a "bribes and bulldozers approach" to get the public on side with shale.

John Blaymires, chief operating officer of shale-gas player IGas told the Fracking North conference in September that the intention of the payments is not to bribe locals into accepting shale-gas development, but rather to share its benefits.

"People are not going to be 'bribed' by this, but the potential benefits are significant along with the business rates. This could start to add up substantially – to up to £10 million per site," he said.

The Department of Energy and Climate Change (DECC) said that energy companies making payments to communities is not unusual and added that people who live near wind farms may also receive them.

Christopher Guelff, deputy head of DECC's Office of Unconventional Gas and Oil, told the conference that developing domestic gas reserves, such as shale, was essential for maintaining the UK's domestic energy supply and cutting carbon emissions.

"If you can enhance your energy security, it would be a responsible thing to do," Guelff said.

Rising imports

Government estimates show that without new sources of domestic gas, by 2025 the UK could be importing about 70% of its gas demand.

The UK's National Grid, the country's power transmission operator, said this could reach more than 90% by 2035 if the country fails to invest in domestic reserves, such as shale.

IGas' Blaymires said the country's industry would also suffer if shale isn't developed. "If we don't start developing new sources of domestic gas locally there is a real danger petrochemical companies will move to the US, putting UK-based jobs and industry at risk," he told the conference.

He added that tens of thousands of jobs would be created if a UK shale gas industry emerged, adding it would support the petrochemical industry by supplying lower-priced gas for feedstock.

Ineos' shale licence covers 330 square kms in Scotland's Midland Valley, near its Grangemouth oil refinery and petrochemicals complex. The firm is currently building facilities to import US shale gas into Grangemouth, allowing it to take advantage of lower-priced US gas for petrochemicals feedstock. It hopes it will eventually be able to use UK shale gas as both a fuel and feedstock.

Much of the recent public

Firm buys into second Scottish licence

Helen Robertson, LONDON: Ineos has bought into its second shale gas licence in Scotland's Midland Valley, but needs to start drilling to get a better idea of how much oil and gas could be extracted from the acreage.

On 13 October, the petrochemical company said it bought an 80% stake in Aberdeen-based Reach Coal Seam Gas (Reach CSG). The deal sees Ineos acquire Petroleum Exploration and Development Licence (PEDL) 162, awarded to Reach CSG in 2008. Reach CSG has carried out some appraisal work on the licence.

As part of the deal, Ineos will act as operator for PEDL 162 and will also fund initial appraisal activity, consisting of two vertical wells and a 3-D seismic survey, covering 100 square kms of the 400 square km licence area. The Reach CSG deal is subject to relevant regulatory approvals, with completion expected by mid-November. The licence is next to PEDL 133, which Ineos partly farmed into when it bought a 51% stake from BG Group in August. The remaining 49% stake in PEDL 133 is held by Dart Energy, which is also the operator.

Both licences are near the company's Grangemouth oil refinery and petrochemicals complex, the company's largest manufacturing site by volume.

A recent survey carried out by the British Geological Survey (BGS) said the Midland Valley could hold between 49.4 trillion cubic feet (cf) and 134.6 trillion cf of shale gas, giving a mid-range estimate for the resource of 80.3 trillion cf.

However the BGS survey included the caveat that an accurate estimate of the area's potential recoverable resource is difficult because of complex geology and limited available good-quality data. ●

opposition to shale gas development has been a reaction to the government's plans to amend the UK's land access laws.

Under English law as it now stands, subsurface mineral rights are vested in the crown but companies with licences to extract oil and gas must negotiate access with the landowners under whose property the resources are found, or face possible prosecution for trespass.

Trespass could prove particularly problematic for prospective shale-gas producers, as horizontal drilling could constitute trespass beneath land owned by multiple landowners.

DECC's Guelff said the current trespass laws – where the operator needs permission from the owner of the land immediately around the site and around the horizontal wells it wishes to hydraulically fracture – is excessively in favour of landowners.

"We feel this may be slightly over the top but it may also be cumbersome to follow through. The experience for someone at the surface of a lateral well is notional," Guelff said.

"My department is not pursuing shale in isolation. It's part of an integrated energy policy. This access right also enables renewables to operate and is essential for geothermal development."

The government is proposing to allow onshore oil, gas and geothermal producers to drill under privately-owned land, below 300 metres, without first seeking consent of the landowner.

The proposal also states that such sub-surface access would automatically trigger a payment of £20,000 per well.

This cash would be paid to the community.

Access rights

UKOOG welcomed the proposed amendments, saying it will give the oil and gas and geothermal industries similar underground access rights to the coal mining, water and sewage industries.

"The current system involves significant potential delays and costs without benefit either to the oil and gas industry or the landowner," said Ken Cronin, chief executive of UKOOG.

"Horizontal drilling for natural gas and oil from shale typically uses a well of six to nine inches in diameter typically at least a mile below the surface," Cronin added. "Landowners on the surface will not notice this underground activity, it will have no impact on their day-to-day lives and, at this depth, the land is not in use by the landowner."

If these proposed amendments to land access rights are adopted, operators will still need to apply for a number of environmental and planning permits from DECC, the Health and Safety Executive and the Environment Agency.

However for some anti-shale campaigners, the government's planned amendments indicate it is supporting the shale industry at the expense of the environment and is not listening to public opinion.

Damien Short, a University of London Lecturer in Human Rights, told the fracking North conference that the public's perception that the government is prioritising the needs of industry over public opinion is solidifying resistance to shale.

"The extraordinary expansion of the unconventional gas industry has led to questions about social power and the rights of the individual and local communities," Short said. "Local groups (in the UK) are concerned about the perceived close relationship between the industry and the government and a lack of evidence-based policy, they suggest, because of misinformation and receiving the hard sell."

Short said that unless this perception is changed there are likely to be more protests, such as the one at Balcombe outside Cuadrilla Resources' site, last year.

A recent University of Nottingham study suggests UK public opinion on shale gas has improved since the six-week long Balcombe protests, but only slightly.

The latest study, which recorded public opinion on shale gas between 9 September and 11 September, indicated approval for shale gas has increased, from 18.4% to 21%. Despite this slight improvement, the rate remains significantly below the 39.5% approval rate the university recorded in July last year, shortly before the Balcombe protests.

This indicates both the industry and the government have much work to do to convince the public shale gas development will be beneficial to them. ●

Chevron farms out Duvernay acreage in $1.5bn deal

Helen Robertson
LONDON

CHEVRON has sold a 30% stake in its Canadian Duvernay shale acreage to a unit of the Kuwait Foreign Petroleum Exploration Company (Kufpec) for $1.5 billion.

Chevron Canada will retain a 70% stake in the acreage, located around 200 kms northwest of Edmonton, in Alberta, and will remain the operator. The deal is expected to close in November.

Chevron said the acreage holds liquids-rich shale resources in an area of around 330,000 net acres in the Kaybob area of the Duvernay shale play.

The purchase price includes cash paid at closing as well as a portion of Chevron Canada's share of the joint venture's future capital costs, Chevron said.

Jeff Shellebarger, president of Chevron North America Exploration and Production Company, said the company was encouraged by its early exploration results at Duvernay and views the area as an exciting growth opportunity for the company.

Test wells

Kufpec said Chevron's Duvernay test wells – drilled over the past five years – showed it is liquids-rich and comparable with the Eagle Ford shale play in the US.

Chevron Canada has drilled 16 wells at Duvernay so far and hydraulically fractured 13 of them. Chevron said test drilling showed initial production rates of up to 7.5 million cubic feet (cf) of natural gas and 1,300 barrels of condensate a day. Chevron recently began a pad drilling program which is intended to evaluate the play's potential further, optimise reservoir performance and cut costs. This will take place between 2014 and 2017.

The move marks Kufpec's debut in the North American shale sector and is part of a long-term strategy to share knowledge with international firms and raise Kuwait's domestic oil output.

Last year Kuwait produced around 3.1 million barrels of oil a day (b/d). It wants to scale that up to 3.5 million b/d next year, then to 4 million b/d by 2020.

Vast reserves: The Duvernay is expected to produce up to 7.5 million cf a day

To achieve its production targets, Kufpec will need help from international oil companies.

However its heavily regulated oil sector hinders further exploration and production.

Kuwait has a constitutional ban on foreign ownership of resources, which has hampered investment in its domestic oil sector.

The government, however, realises that to reach its 2020 oil-output target, it needs help from foreign companies and is trying to boost their presence in the country's energy sector.

Shaikh Nawaf Al-Sabah, Kufpec's chief executive, said the deal with Chevron was "securing the future of the company" and provided the Kuwaiti firm with the opportunity to develop shale technology outside of Kuwait.

The Duvernay shale play, located in west-central Alberta, is thought to be one of the most prolific shale resources in North America.

Wood Mackenzie, a consultancy, estimates Duvernay holds around 13 billion barrels of oil equivalent (boe) and expects production to average 1 million boe a day by 2024.

Around half of that is expected to be dry natural gas, with the remainder comprised of higher value crude and natural gas liquids.

The Duvernay shale play has seen increasing investment and drilling activity in recent years.

As well as Chevron, Shell, ExxonMobil and ConocoPhillips have all taken major positions there, while Canadian explorers are also looking to tap into the resource's potential riches.

Athabasca Oil owns the most acreage in the play, while Encana, Talisman Energy and a slew of smaller independents also have big holdings.

The US Energy Information Administration estimates Canada has the fifth largest shale gas reserves in the world with 573 trillion cf thought to be recoverable – nearly 8% of the global estimated total.

Vast reserves

Canadian government estimates are even more bullish, suggesting there is 2,900 trillion cf of shale gas in-place in British Columbia alone, while Alberta could have up to 1,986 trillion cf. However access to infrastructure has been a key obstacle to generating cashflow from some of Canada's large shale gas fields, especially when competing with lower costs and abundant supplies in the US.

Getting Canada's unconventional reserves to new markets will depend on the progress of planned liquefied natural gas (LNG) export projects, curbing cost inflation and agreeing contracts with buyers, particularly in North Asian markets.

The difficulties for the sector were highlighted at the end of July when US firm Apache, Chevron's development partner for a planned LNG terminal at Kitimat on Canada's west coast, said it was pulling out of the project, citing an estimated price tag at $15 billion.

Forward sales for 60-70% of gas linked to oil prices are essential for projects, such as Kitimat, to proceed, Chevron insists. Yet while preliminary construction work has begun, Chevron has yet to secure any buyers. ●