

# World Petroleum Council Guide

## Unconventional Gas



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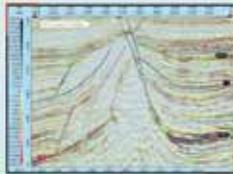
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## Unconventional Gas

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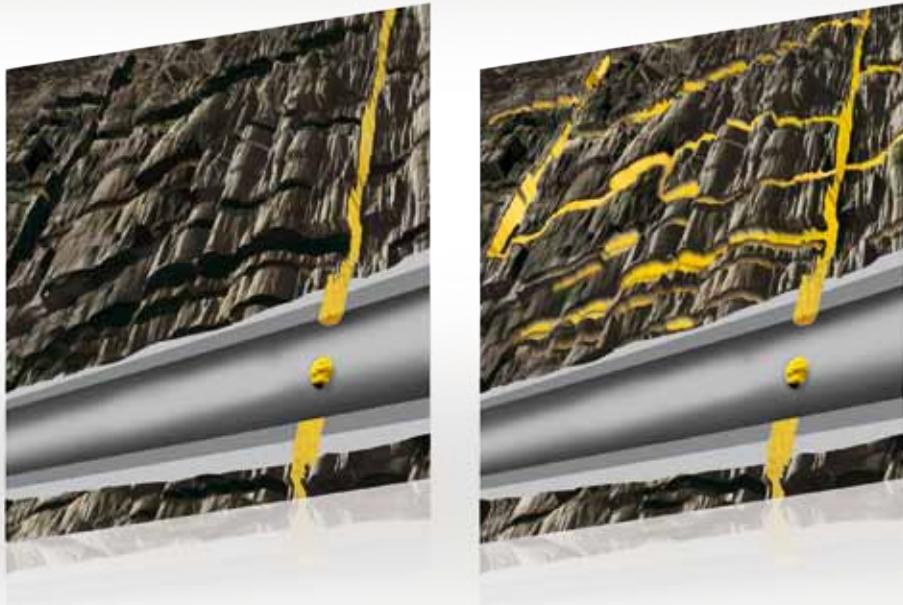
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# Contents

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The President's opening remarks	4	Shale gas water management	58
Message from the Director General	6	<i>By Brent Halldorson and Patrick Horner</i>	
WPC Vision, Mission, Values and Principles	8	Tight gas	64
WPC overview	10	<i>By Roberto F. Aguilera, Thomas G. Harding and Roberto Aguilera</i>	
A golden age of gas	18	Coal-bed methane	72
The importance of non-conventional gas	22	<i>By Mark Blacklock</i>	
<i>By László Varró</i>		CBM in Australia	78
Collaboration and technology	28	<i>By Georgia Lewis</i>	
<i>By Trevor Smith</i>		Unconventional gas in Canada	84
Unconventional gas and the environment: Addressing the environmental concerns	34	<i>By Michael Gatens</i>	
<i>By Andy Gibbins</i>		Unconventional gas in China	90
Unconventional gas and the environment: Emerging environmental issues	37	<i>By Xinhua Ma, Ning Ning, Hongyan Wang</i>	
<i>By Jennifer Hughes and Ana Coculescu</i>		Gas hydrate	96
Engaging with the community	40	<i>By Mark Blacklock</i>	
<i>By Georgia Lewis</i>		Gas-to-liquids	102
Shale gas	46	<i>By Mark Blacklock</i>	
<i>By Glenda Wylie</i>		Glossary	110
Shale gas around the world	52	Acknowledgements	113
<i>By Georgia Lewis</i>			

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Unless otherwise stated, the dollar (\$) values given in this book refer to the US dollar.





# The President's opening remarks

*Unconventional gas resources:  
Another re-invention of the  
petroleum sector*



Renato Bertani.

At an important energy conference held in Houston about 10 years ago, experts in gas supply and demand trends predicted a big drop in US gas prices by the early 2010s. They said gas prices would drop from the then \$8-10/mmBtu range to a much lower level closer to \$3/mmBtu.

They were spot on, but for the wrong reasons. The reasoning was the price drop would be caused by massive imports of LNG into the United States and a resulting gas supply glut. What actually happened was that, as has happened time and again over the last 150 years, the industry re-invented itself and started the revolution of unconventional gas resources. The United States is now meeting its internal gas demand with domestic resources, so plentiful that the country may become a big LNG exporter.

As happened with previous breakthroughs, such as the advent of 3D and 4D seismic and the engineering of rigs and facilities capable of tapping resources in deep reservoirs and deep offshore, the horizontal well and fracking technologies applied to unconventional gas resources create enormous challenges and opportunities for the industry.

Natural gas is currently the most promising source for providing sustainable, affordable and low-carbon energy for the economic development of the world. Unconventional resources will play an increasingly important part in the supply





balance. Recent assessments indicate that the potential of unconventional gas resources could not only exceed the current conventional reserves of about 170 tcm by a factor of three or more, but that they are also spread widely throughout the world, making them more readily accessible to the consuming markets.

The development of these massive resources on a global scale, however, requires strong cooperation between governments and petroleum companies to ensure that the interests of all stakeholders are protected and that, ultimately, benefits revert back to society.

To encourage the allocation of huge amounts of capital, services, equipment and human resources to unconventional gas developments, governments will have to enact regulatory frameworks that include: fiscal and contractual stability, appropriate and rigorously enforced health, safety and environment regulations, steady and predictable offerings of acreage in bid rounds, and concession or leasing terms that provide investors with sufficient time for the delimitation and development of the productive acreage.

The industry, in turn, will have to take a long-term view on capital deployment and return rather than purely seeking short-term profit. It will also be important to continuously improve operational efficiencies in drilling, fracking and reservoir management, mitigate impacts on local communities that large-scale operations may cause, and operate with zero tolerance in regard to safety and environmental shortfalls, particularly with respect to potential contamination of aquifers by fracking fluids.

In the end, the companies that will succeed in unconventional gas plays will be the ones that meet the four main business sustainability criteria: a fair return to shareholders, the creation of wealth for local communities and society, superior performance on safety and environmental protection, and the highest ethical standards in conducting business.

In order to give you a balanced picture of the issues, we have put together the WPC Guide on Unconventional Gas and hope you will find it a useful overview on the role it plays in the global energy mix.

Renato Bertani  
*President, World Petroleum Council*



# Message from the Director General

The WPC guides aim to show how innovative technologies are helping the oil and gas industry meet global energy needs.



Dr Pierce Riemer.

The purpose of WPC as a forward thinking organisation is to promote the management of the world's petroleum resources for the benefit of all. The triennial World Petroleum Congresses represent one means of doing this. Our Congresses and our 65 member countries offer a meeting place, a stage and a programme, with highly profiled leaders and specialists, from governments, companies, academia and NGOs. They offer opportunities for discussion and dialogue on issues that are crucial for the energy industry and society. Cooperation is essential.

Oil and gas represent resources that have brought improved lifestyles, as well as economic and social development to many and represent the majority of the total energy supply globally today. The importance of oil and gas will increase rather than diminish over the next few decades as we are certain that ample resources exist, which yet need to be proven and produced. The oil and gas industry will continue to play a central role in world energy supply for many years. Innovative technologies will help make this possible. Next-generation technologies are already underway to help supply the world with steadily cleaner forms of energy that we



will gradually see more of in this century. Billions of people are in need of energy: cleaner, affordable and delivered in socially acceptable ways. Oil and gas are central to ensuring economic and social development for all. We have witnessed much more attention to environmental and social responsibility during recent years. Both corporate and governmental governance have been challenged, and must strive for higher transparency and ethics.

In 1933, at the first ever World Petroleum Congress in London, experts worried that with the then demand for oil and oil products we would reach peak oil in the 1940s. In the mid-1940s they agonised over shortages predicted for the 1950s and history repeated itself in the 1970s, when similar papers were published and, of course, OPEC and IEA joined the fray. Today, the question is still asked: "Is peak oil behind us or ahead of us?" But even with OPEC's and IEA's worst case scenarios for the maximum predictions of world energy use, thanks to advanced technology, better utilisation and the advances in unconventional production it seems that peak oil is still some way into the future. We will need both conventional and unconventional energies.

Most experts agree that the four biggest challenges for the oil and gas industry going forward are: technology, geopolitics, the environment and a growing population. The key to finding solutions for each of those is strategic alliances and closer cooperation. More than ever, this is true in times of crisis such as the current global recession. WPC's 65 global member countries are all active in each of these areas. The WPC series of expert guides focuses on technical solutions and sharing this knowledge as a technical legacy for the future. This book is the first in a series that will highlight technical achievements and show how innovative technology is the key to delivering future world energy needs.

Dr Pierce Riemer  
*Director General, World Petroleum Council*



# WPC Vision, Mission, Values and Principles

## Vision

An enhanced understanding and image of the oil and gas sector's contribution to sustainable development.

## Mission

The World Petroleum Council (WPC) is the only organisation representing the global oil and gas community. WPC's core value and purpose centres on sustaining and improving the lives of people around the world, through:

- Enhanced understanding of issues and challenges
- Networking opportunities in a global forum
- Cooperation (partnerships) with other organisations
- An opportunity to showcase the industry and demonstrate best practice
- A forum for developing business opportunities

- Information dissemination via congresses, reports, regional meetings and workshops
- Initiatives for recruiting and retaining expertise and skills to the industry
- Awareness of environmental issues, conservation of energy and sustainable solutions

## Values

WPC values strongly:

- Respect for individuals and cultures worldwide
- Unbiased and objective views
- Integrity
- Transparency
- Good governance
- A positive perception of energy from petroleum
- Science and technology
- The views of all stakeholders
- The management of the world's petroleum resources for the benefit of all

## Principles

WPC seeks to be identified with its mission and flexible enough so that it can embrace change and adapt to it. WPC has to be:

- Pro-active and responsive to changes and not merely led by them
- Creative and visionary, so that we add value for all
- Challenging, so that our goals require effort to attain but are realistic and achievable





- Focused, so that our goals are clear and transparent
- Understandable to all

### Key strategic areas

- **World Class Congress** to deliver a quality, premier world class oil and gas congress.
- **Inter-Congress activities** to organise forums for cooperation and other activities on specific topics; and to organise regional events of relevance to WPC members and all stakeholders.
- **Cooperation with other stakeholders** to add value by cooperating with other organisations to seek synergies and promote best practice.
- **Communication** to increase awareness, of WPC's activities, through enhanced communication, both internally and externally.
- **Global representation** to attract and retain worldwide involvement in WPC.
- **Youth and gender engagement** to increase the participation of young people and women in oil and gas issues, including the establishment of a dedicated Youth Committee for the development of active networking opportunities with young people.
- **Legacy** to create a central WPC legacy fund to benefit communities and individuals around the world based on WPC's mission.

### World Petroleum Congresses

#### 2014 21st WPC Moscow

2011	20th WPC	Doha	1979	10th WPC	Bucharest
2008	19th WPC	Madrid	1975	9th WPC	Tokyo
2005	18th WPC	Johannesburg	1971	8th WPC	Moscow
2002	17th WPC	Rio	1967	7th WPC	Mexico City
2000	16th WPC	Calgary	1963	6th WPC	Frankfurt
1997	15th WPC,	Beijing	1959	5th WPC	New York
1994	14th WPC	Stavanger	1955	4th WPC	Rome
1991	13th WPC	Buenos Aires	1951	3rd WPC	The Hague
1987	12th WPC	Houston	1937	2nd WPC	Paris
1983	11th WPC	London	1933	1st WPC	London



# WPC overview

Since 1933, the World Petroleum Council (WPC) has been the world's premier oil and gas forum and is the only international organisation representing all aspects of the petroleum sector.

WPC will mark its 80th anniversary in 2013 having been established in 1933 to promote the management of the world's petroleum resources for the benefit of all. It is a non-advocacy, non-political organisation and has received accreditation as a non-governmental organisation (NGO) from the UN. WPC's prime function is to catalyse and facilitate dialogue among stakeholders, both internal and external to the petroleum industry, on key technical, social, environmental and management issues in order to contribute towards finding solutions to those issues.

Headquartered in London, the World Petroleum Council includes 65 member countries from around the world representing more than 95% of global oil and gas production and consumption. WPC membership is unique, as it includes both OPEC and non-OPEC countries with high-level representation from National Oil Companies (NOCs) as well as Independent Oil Companies (IOCs). Each country has a national committee made up of representatives of the oil and gas industry, the service sector, academia, research institutions and government departments. The governing body of WPC is the Council consisting of representation

from each of the national committees. Its global membership elects the President and an Executive Committee every three years to develop and execute its strategy. The Council also selects the host country for the next World Petroleum Congress from the candidate countries.

Every three years, the Council organises the World Petroleum Congress hosted by one of its member countries. The triennial Congress is also known as the "Olympics of the petroleum industry". It covers all aspects of oil and gas from technological advances in conventional and unconventional upstream and downstream operations to the role of natural gas and renewables, management of the industry and its social, economic and environmental impact. In addition to industry leaders and experts, outside stakeholders such as governments, other industry sectors, NGOs and international institutions also join the dialogue. To ensure the scientific and topical quality of the event, the WPC Council elects a Congress Programme Committee whose members are responsible for delivering the high-level content for its Congresses.

Moscow will be the host of the 21st World Petroleum Congress in 2014 ([www.21wpc.com](http://www.21wpc.com)).

Beyond the triennial Congress, the World Petroleum Council is regularly involved with a number of other meetings such as the WPC Youth Forum, the WPC-UN Global Compact Best Practice Forum, joint WPC/OPEC workshops and other regional and topical events on important industry issues.

## Legacy

As a not-for-profit organisation, WPC ensures that any surpluses from the triennial Congresses and other meetings are directed into educational or charitable activities, thereby leaving a legacy. The World Petroleum Council has set up a dedicated WPC Legacy Fund to spread the benefits beyond the host countries and its members and alleviate energy poverty through carefully selected projects.



The concept of leaving a legacy in the host country started in 1994 with the 14th World Petroleum Congress in Stavanger, Norway. After this Congress, the surplus funds were put towards the creation and building of a state-of-the-art Petroleum Museum in Stavanger.

The 15th World Petroleum Congress in Beijing adopted the issue of young people as a key aspect of its theme: "Technology and Globalisation – Leading the Petroleum Industry into the 21st Century". To support the education and future involvement of young people in the petroleum industry, the Chinese National Committee donated all computer and video equipment used for the Congress to its Petroleum University.

Profits from the 16th Congress in Calgary were used to endow a fund that gives scholarships to post-secondary students in several petroleum-related fields. The Canadian Government Millennium Scholarship Foundation matched the amount dollar-for-dollar, creating an endowment which

supported more than 2,000 students until its conclusion in 2010.

The 17th World Petroleum Congress was the first to integrate the concept of sustainability throughout its event. The Congress took responsibility for all the waste it generated. The congress and the accompanying Rio Oil & Gas Expo 2002 generated a total of 16 tonnes of recyclable waste – plastic, aluminium, paper and glass. All proceeds of the recycling activities were passed on to a residents' cooperative with 6,000 inhabitants located in the port area of Rio de Janeiro.

But the sustainability efforts did not stop there – an army of 250 volunteers collected 36 tonnes of rubbish in 10 days in a special community effort to clean up the Corcovado area before the Congress, donating all proceeds to the rubbish collectors, some of the poorest inhabitants of Rio. The Finlândia Public School also received a new lick of paint from our volunteers. The surplus funds for the Congress were used to set up the



The most recent World Petroleum Congress was held in Doha in December 2011.





The WPC legacy initiative started in 1994 when surplus funds from the 14th World Petroleum Congress were put towards the building of Stavanger's Petroleum Museum.

WPC Educational Fund in Brazil, which was further increased in 2005 with tax initiatives added by the Brazilian government.

The 18th World Petroleum Congress also chose a sustainability focus for the first-ever WPC to be held in Africa: "Shaping the Energy Future: Partners in Sustainable Solutions". Education was the

focus of the 18th World Petroleum Congress Legacy Trust, set up by the South African National Committee to provide financial assistance to needy young South Africans who wish to pursue a qualification in petroleum studies.

In 2008, with the 19th Congress in Madrid, the trend continued and the organisers selected a



WPC's first Youth Forum was held in Beijing in 2004.

number of projects and foundations to receive the surplus from the event for charitable and educational programmes in Spain and around the globe. The 19th Congress was the first one to offset all its carbon emissions and receive a certification as a sustainable event.

The most recent Congress in Qatar also offset all of its carbon emissions and has chosen a project to educate and support young people as recipient for the 21st WPC Legacy Programme.

#### Youth outreach

Youth is a critical factor in the sustainability of the oil and gas industry. Addressing and involving young people in the design of future energy solutions is therefore one of the major issues for WPC's 65 member countries. WPC recognises their significance to the future of the petroleum industry and the importance of giving the young

generation scope to develop their own ideas, talents and competencies to create viable solutions for the future of our world.

As part of its outreach to recruit and retain the next generation, WPC created its Youth Committee in 2006 to provide a channel through which young people have a direct involvement and say in the strategy and activities of the organisation. It aims to create and nurture a collaborative, global forum for young people to be heard, to champion new ideas within the petroleum industry, to promote a realistic image of the petroleum industry, its challenges and opportunities and to bridge the generation gap through mentorship networks.

In 2011, WPC launched a pilot Mentorship Programme to provide a bridge between international experts and the next generation of our industry. This programme is now in its second successful cycle and has already created 150 matches.





# ANH



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# A golden age of gas

Natural gas is set to play a bigger role in the world's energy mix thanks to the tapping of unconventional resources.

Natural gas is the cleanest of the fossil fuels. Composed primarily of methane, when natural gas is burnt it releases very small amounts of sulphur dioxide and nitrogen oxides, virtually no ash or particulate matter and lower levels of carbon dioxide, carbon monoxide and other reactive hydrocarbons compared to coal and oil. Burning natural gas produces around 45% less CO<sub>2</sub> than coal and 30% less than oil. However,

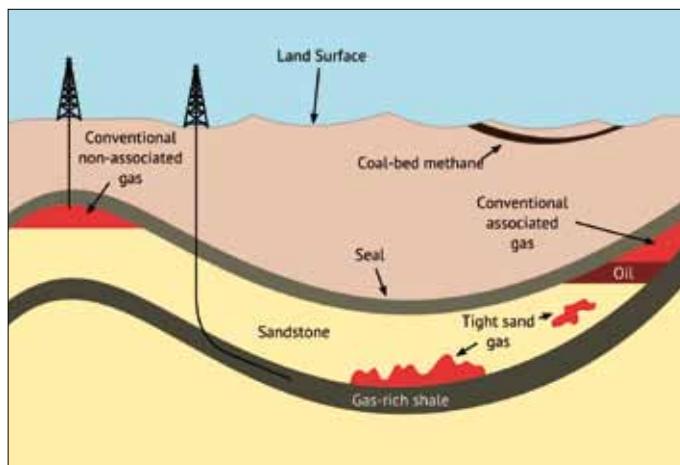
methane is a potent greenhouse gas and it is important to minimise direct releases or "venting" into the atmosphere at all stages of the gas chain from production to end-use.

Natural gas is a flexible fuel that is used extensively in electricity generation and competes increasingly in most end-use sectors.

Natural gas is not only clean and flexible; it is abundant and is set to play a bigger role in the world's energy mix. The International Energy Agency (IEA) assesses future energy trends using different scenarios; its latest Golden Age of Gas scenario sees gas use increasing by more than 50% to account for over 25% of global primary energy consumption by 2035. This would mean additional annual gas consumption of 1.8 trillion cubic metres (tcm) compared to 3.2 tcm in 2011.

## Geological primer

The world has vast resources of gas which were created when organic matter was buried and subjected to heat and pressure over millions of years. The gas was produced in source rocks and is stored in sedimentary rocks. As WPC's Guide to Energy Fuel for Life explains, an oil or gas field "is like a sponge, not some vast underground lake: oil



This diagram prepared by the US Energy Information Administration shows the geological nature of conventional gas and the three types of unconventional gas currently in production in schematic form.

and gas accumulate within porous rock formations in the earth's crust ... a layer of impermeable rock on top stops the oil and gas from escaping".

There are many divisions and sub-divisions of geological time, but the main ones that concern the gas industry are the Mesozoic (250-65 million years ago) and Paleozoic (540-250 million years ago) eras. These eras are divided into the following periods:

#### **Paleozoic**

- Cambrian (approximately 540-490 million years ago)
- Ordovician (490-445 million years ago)
- Silurian (445-415 million years ago)
- Devonian (415-360 million years ago)
- Carboniferous (360-300 million years ago)
- Permian (300-250 million years ago)

#### **Mesozoic**

- Triassic (250-200 million years ago)
- Jurassic (200-145 million years ago)
- Cretaceous (145-65 million years ago)

Sedimentary rocks are formed by the consolidation of deposits created by the settlement of sand, silt and other materials and are generally referred to by the name of the period during which they were laid down such as "Devonian Shale".

Within rock formations, the geological structure in which hydrocarbons build up to form a gas or oil field is called a "trap". "Structural traps" are formed by movements that fold rocks into shapes or juxtapose rocks along faults (lines of fracture along which one body of rock or section of the Earth's crust has been displaced relative to another). A "play" is a group of fields with similar trap structures.

Until relatively recently it was only viable to extract gas associated with oil (and much of that used to be flared) or non-associated gas from porous reservoirs, typically composed of sandstone or carbonates, where gas flows freely in the rock. This is known as conventional gas. Uncon-

#### **Darcy and permeability**

Permeability measures the ability of fluids to flow through rock (or other porous media). The darcy and millidarcy (md) are units of permeability, named after the French scientist Henry Darcy (1803-1858). For a rock to be considered as an exploitable hydrocarbon reservoir without stimulation, its permeability must be greater than approximately 100 md for oil reservoirs and 10 to 100 md for gas reservoirs. Reservoirs with lower permeability need to be stimulated by methods such as hydraulic fracturing and acidising. Darcy's work is celebrated by the Henry Darcy medal awarded annually by the European Geosciences Union.



#### **Resource estimates, H.H. Rogner**

A landmark assessment of global hydrocarbon resources was carried out in 1996 by the German energy economist Dr Hans-Holger Rogner working for the International Institute for Applied Systems Analysis (IIASA). He estimated global unconventional gas-in-place at an enormous 21,750 tcm of which the bulk was gas hydrates. The estimate for shale was 456 tcm, for coal-bed methane 257 tcm and for tight gas 210 tcm.



The recoverable proportion of the gas-in-place depends on technological and market developments. Rogner suggested some 215 tcm of unconventional gas was recoverable; this compared with the then proven reserves of conventional gas of 143 tcm and estimated additional reserves of 124 tcm.

To compare, in 2011 gas accounted for 23.7% of global primary consumption or 3.2 tcm.



ventional gas is harder to extract as it is contained in rocks with low permeability (see box) or in ice, but technological developments are now allowing these resources to be tapped.

The gas in low-permeability rocks is both adsorbed onto insoluble organic matter (adsorbed gas) and held in tiny pore spaces called micro-porosity (free gas).

There are four main types of unconventional gas and three are currently in production:

*Shale gas* – these deposits are trapped in shale, rocks made up of thin layers of fine-grained sediments, typically originally laid down in rivers, lakes

and floodplains. Shale formations have very low permeability and the gas is extracted by drilling – first vertically and then horizontally – and hydraulic fracturing or “fracking”. This involves pumping a blend of water, chemicals and “proppants” (often sand) into a well under high pressure to open up cracks in underground rock formations. The grains of sand keep the cracks open and thus allow the gas to flow. Other proppants may also be used.

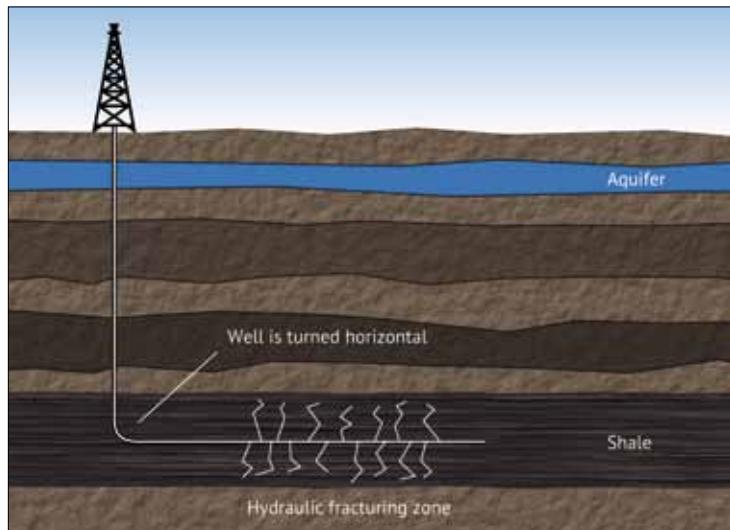
*Tight gas* – this is found in tiny pores in low-permeability rock formations which have to be stimulated before the gas will flow. Tight gas is extracted using a combination of drilling, hy-



Water management is a vital issue for the gas industry.



► Hydraulic fracturing involves pumping a blend of water, chemicals and proppants into a well under high pressure to open up cracks in underground rock formations.



draulic fracturing and acidising. The latter involves pumping acids into the well to dissolve the limestone, dolomite and calcite cement between the sediment grains of the reservoir rocks.

*Coal-bed methane* – natural gas found in coal beds formed by the decomposition of organic matter in coal. The gas is extracted by drilling and then depressurising by pumping water from the coal seam. In some cases stimulation is needed such as fracturing.

*Gas hydrate* – essentially methane frozen in ice and found in permafrost regions or subsea sediments. There are major hurdles to be overcome before commercial exploitation can begin and for the time being attention is focused on other unconventional gas plays.

This guide also looks at the gas-to-liquids (GTL) process.

### Environmental issues

Water stress is increasing around the world and all industrial users are rightly subject to intense scrutiny. Water management and groundwater protection are vital issues for the gas industry.

However, it is important to point out that the amount of water used by the gas industry is far less than that used in the two major consuming sectors: electricity generation and irrigation.

The technology central to the success development of unconventional gas, hydraulic fracturing, has come under fire because of concerns about the chemicals used and its potential to cause minor earthquakes under certain conditions. The industry is working to improve transparency and collaboration with landowners, mineral rights holders, regulators and communities.

Fracturing fluids typically comprise 99.5% water and sand and 0.5% chemicals. Many operators have signed up to FracFocus ([www.fracfocus.org](http://www.fracfocus.org)), the hydraulic fracturing chemical registry website which is a joint project of the US Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. The site allows members of the public to search for information about the chemicals used in the hydraulic fracturing of oil and gas wells and provides educational materials designed to help them put this information in perspective.





# The importance of non-conventional gas

By László Varró

Using more natural gas now can give the world more time to develop and deploy lower-carbon energy technologies.

Imagine that you had suggested in a 2005 climate negotiation that the United States would deliver a 40% emission reduction compared to its baseline. You would have been dismissed as a naïve idealist. Yet this is exactly what is happening: the latest EIA projection for US CO<sub>2</sub> emissions in 2035 is 40% below the 2005 projection for the same date. I'm cheating a bit, since the financial crisis will have a long-lasting effect on the level of GDP and consequently on emissions, but one of the most important reasons we finally have a rare piece of good news in our efforts to tackle climate change is two words: shale gas.

After generations of political campaigns ridiculed the notion of energy independence – whatever that means in an interconnected global economy – the rapidly declining oil import dependency and the emerging gas exports of the United States are redrawing the geopolitical maps of energy. The reason is again shale gas, and its younger, but muscular, twin brother, light tight oil. Impacting everything from population movements in the US Midwest to the strategic plans of major oil companies, the shale gas revolution is genuinely the most important shift in the energy landscape

since the 1950s, when the scale and concentration of conventional hydrocarbon resources in the Middle East became evident.

Of course, the great march of gas is not new. Its role in the global primary energy mix has been growing for decades, ever since the first oil shock drew attention to its ability to substitute for oil in all stationary applications, either heating or power generation. In fact, the share of gas in the global primary energy mix grew more rapidly in the 1970s and 1980s than in the last decade. Again, I cheat a bit: in the last decade, coal use in China grew so incredibly rapidly that in the great energy race, anyone who was not Chinese coal had to run fast just to stand still. In the rest of the world outside China, gas won, hands down. The emer-



The shale gas revolution is the most important shift in the energy landscape since the 1950s – drilling in the Eagleford Shale, Texas, USA.



gence of the combined-cycle gas turbine (CCGT) technology and the liberalisation of gas and power markets created a marriage made in heaven: a flexible, modular, low-capital-cost but high-efficiency power generation technology with relatively environmentally benign fuel. In every market economy, combined-cycle gas turbines have dominated new power generation investment almost irrespective of gas prices.

However, this very favourable picture on the downstream side was in stark contrast with the conventional understanding of the conventional upstream situation, which looked anything but a golden age. Of course there is plenty of conventional gas out there, we already knew that. However, the list of above-ground concerns began to look suspiciously like oil: apparently, terminal decline of domestic production in both the United States as well as in Europe; over a fifth of the resource base out of the game under Iran; increasing import dependency on more and more complex and expensive projects, and pipeline politics straight out of a James Bond movie. This was the golden age of think tanks worrying about gas, not the golden age of gas.

### Competing in the energy mix

The major difference between oil and gas is the exposure to competition. Nowadays, oil is predominantly used in the transportation sector. Here, where a moving energy source and consequently energy storage is needed, it has formidable advantages. Europe is a case in point: after decades in which excise taxes pushed end-user prices to the equivalent of hundreds of dollars per barrel, Europe does have diesel cars and smaller engines, but not solar-powered cars. The European transport system is firmly based on the internal combustion engine. Gas, on the other hand, is under competition; the actual competitor can vary according to whether the given energy policy supports nuclear power, cares about cli-

### 450 ppm

To limit the global temperature rise to 2°C above the pre-industrial level, scientists and policymakers generally aim to stabilise greenhouse gas (GHG) concentration at 450 parts per million (ppm) of CO<sub>2</sub> equivalent compared to today's level of just under 400 ppm.

<b>GHG concentration in 1959</b>	<b>315.97 ppm</b>
(when the first full year's data was collected)	

<b>GHG concentration in 2011</b>	<b>391.57 ppm</b>
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Source: Earth System Research Laboratory of the US NOAA

mate change or is willing to invest in renewables, but the competition is there.

Gas plays an important role in the power generation sector where a major competitor is coal. Indeed for 100 years, coal has been the backbone of power generation, and electricity use has been the most reliable indicator of industrialisation, urbanisation and social modernisation. A decade of double-digit growth of power generation that took place in China is not at all an historical outlier; it is perfectly comparable to the earlier experience of Western Europe or the United States, which by 1968 had 10 times the per capita electricity consumption of India today. Add to this the well-distributed global coal resources that are for all practical purposes unlimited and you will see why the door for a 450 ppm climate stabilisation (see box) is closing.

Electricity is the key battlefield of climate policy. Not only is it the largest and rapidly growing emission source on its own, but its decarbonisation would be a powerful enabling factor in other sectors like electric cars and heat pumps for buildings. The key problem with the decarbonisation of the electricity sector is that we are at the bottom of the pit, and we have not even stopped digging. As the world celebrates the 20th anniversary of the Rio Summit with a Rio+20 follow up, it is worth



In every market economy, combined-cycle gas turbines have dominated new power generation investment. This is the power plant at New York's JFK airport.

reflecting the progress that we have made towards a sustainable electricity system. Global electricity consumption has grown by two thirds, which is very, very good news as this means progress for the hundreds of millions of people who were lifted out from crippling poverty. However, that also means that emissions by a unit of electricity should have declined measurably just to stand still. Instead, the amount of carbon emitted per unit of electricity is 12% higher than it was in 1992, so not only did demand grow, but so did the carbon intensity of supplying it: in real life, electricity is carbonising rather than decarbonising, the sustainable electricity system is getting further and further away. The culprit behind this disturbing trend is increased coal use.

The dominance of coal in power sector emissions and the fundamental advantages of combined-cycle gas-fired power generation explain the alliance between climate policy and natural

gas. Some greens are sceptical; after all, natural gas is a fossil fuel, and without the application of carbon capture and storage (CCS), an electricity system dominated by natural gas would still have greenhouse gas emissions well above the acceptable level. All of this is very true. In the IEA World Energy Outlook 450 ppm scenario, the global average carbon intensity of a decarbonising power system falls below the carbon intensity of the best CCGTs around 2025. This is only a tactical alliance, as in the second stage of the journey towards a sustainable energy system, unabated gas burning will also have to go, equipped with CCS or replaced by genuine low-carbon sources such as renewables.

In the 450 ppm scenario, the share of gas in power generation and the absolute level of gas demand are both considerably lower than in our policy baseline, the New Policies Scenario, due to improved energy efficiency and greater deploy-





ment of nuclear and renewables in the 450 scenario. However, from the current level, gas demand continuously grows even in 450 ppm, whereas both coal and oil are projected to fall in absolute terms. There is nothing wrong in a tactical alliance that buys time and helps avoid an imminent defeat. CO<sub>2</sub> is a global stock pollutant. The only thing that really matters is its growing concentration in the atmosphere, which is determined by cumulated emissions over several decades, rather than emissions in an individual year. Although the Golden Age of Gas is not the final sustainable energy system, cumulative future emissions are substantially lower; consequently, we reach a critical CO<sub>2</sub> concentration level later, giving more time for the energy transformation. The door to 450 ppm is closing, but natural gas can keep it open for another decade or two. It is up to us to use this time well and deploy the low-carbon energy technologies in the necessary scale.

### Low-carbon technologies

This leads to another green concern: while the shale gas revolution does deliver short-term gains, cheap gas might lock out renewable energy and hinder the genuine low-carbon technologies. This concern might seem a bit of a luxury, considering how close we are to losing the chance for 450 ppm and how much we need any emission reduction wherever it comes from. Nevertheless, it is a concern that must be addressed, and luckily we have a useful test laboratory for this question in the United States.

The United States is the birthplace of the shale gas revolution and represents the overwhelming majority of global unconventional gas production. Today, unconventional gas accounts for over half of US gas production and has significantly reduced the need for imports. Although LNG redirected from North America does have a price impact, especially in Europe, the United States is the only major region so far where the uncon-

ventional revolution has led to really cheap gas. In fact, probably the most striking impact of unconventional gas is the amazing degree of disconnect in gas prices where Europe – but especially the Asia-Pacific region – suffers from gas prices several times higher than Henry Hub. Although a number of industry observers question the sustainability of the current North American price level, even pessimists project a price level that would be considered to be cheap in Europe or Asia. In addition, a measurable proportion of the US political system displays a less than complete enthusiasm for climate policy.

And yet in the United States, home of the forever-cheap gas, which is supposed to drive out investment into low-carbon sources, renewable energy is doing very well. Since 2005, when the first horizontally drilled, hydro-fractured well in the Barnett Shale started production, non-hydro renewable energy (mainly wind and solar) in the United States has doubled, and represents a sub-

### Henry Hub

The Henry Hub in Erath, Louisiana, USA is a distribution hub connecting nine interstate and four intrastate pipelines, which lends its name to the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). Spot and future prices set at the Henry Hub are denominated in \$/mmBtu (millions of British thermal units) and are the benchmark prices in the North American natural gas market.

#### *Average Henry Hub price per mmBtu*

2005	\$8.81
2006	\$6.74
2007	\$6.98
2008	\$8.86
2009	\$3.95
2010	\$4.39
2011	\$4.00
2012	\$2.36 (Jan-June)



stantial proportion of the total global increase of renewables. The increase of renewables in the United States is equivalent to the total wind and solar production of Germany. If anything, its growth accelerated in the past two years parallel to collapsing gas prices. Next year it is likely to fall, but this has much more to do with the stop-and-go cycle of federal renewable policy than with gas prices.

One can even argue that cheap gas even helps renewables in the United States, since as a consequence of the shale revolution, end-user electricity prices are falling even with renewable mandates. In Europe, the cost of renewables is additional to an electricity bill already burdened by the high cost of oil-indexed gas, which actually has a bigger impact on the cost of electricity than renewables. The impact of electricity costs on industrial competitiveness has emerged as a major policy concern. In the United States, however, fall-

ing power generation costs cushion the impact of renewable mandates and mitigate affordability concerns. In addition, cheap gas triggered an investment wave into gas turbine capacities whose inherent flexibility makes it easier to integrate variable renewables.

As for nuclear power, the first new nuclear plant construction that has been approved in any Western democracy since Fukushima is in Georgia, just an easy pipeline ride from Henry Hub. The notion that abundant natural gas will lock out low-carbon energy sources is an interesting theoretical concept, but let us worry about it if and when it actually happens.

### **Golden Rules**

Nevertheless, other green concerns about shale gas are perfectly legitimate and were analysed in great detail in a special report of the IEA's World Energy Outlook, the "Golden Rules for a Golden



Despite cheap unconventional gas supplies, non-hydro renewable energy in the United States has doubled since 2005 – the Klondike wind farm in Oregon.



"Age of Gas". One major concern is related to the climate impact of gas, others to the environmental sustainability and social acceptance of non-conventional production. The climate concern relates to gas leakage. Methane, the main component of natural gas, has a brutal greenhouse gas impact, several times that of CO<sub>2</sub>. Even a minor gas leakage can wipe out the climate advantages of gas, and unfortunately, with inadequate project management, gas venting does take place. Regulatory and management measures to minimise and preferably eliminate venting should be an integral part of the Golden Rules.

Local environmental and social concerns are plentiful – you have seen the movie: effect on the water table, land use, truck traffic, disposal of used fracking water, seismic events. A common theme is that the industry has to take them seriously, as these are legitimate concerns and have the potential to stop the unconventional revolution. It is true that hydraulic fracturing has been used since the 1950s, but nowhere near this scale. Unconventional gas requires an intensive operation; according to the Golden Rules projection, over a million wells will need to be drilled, with several million frac jobs, each involving hundreds of truck movements and thousands of cubic metres of water use.

The Golden Rules aim to ensure the responsible use of water, recycling of fracking liquids, as well as the reduction of chemicals use. It is also true that water contamination from fracking miles below or igniting a dormant seismic fault line to trigger an earthquake are extremely unlikely, but maybe not more unlikely than a blowout preventer failing at an offshore drill site or a tsunami destroying back-up power supply at a nuclear plant. In less than two years, Deepwater Horizon and Fukushima have created very understandable social scepticism in expert assurances by the industry itself. Consequently, the Golden Rules include explicit recommendations for smart seismic measurement in order to identify existing fault lines, as well as

proper well design and casing techniques. It will cost some, around 7% extra, but will still keep shale gas as a very competitive energy source.

A regulatory framework which maintains social acceptance by ensuring that unconventional development fulfills the Golden Rules is a strategic interest of the gas industry, since this is the foundation of the bright future of gas. On the other hand, with Golden Rules, the sky's the limit, and this will have broad macroeconomic impacts. Again, the United States is the taste of things to come.

High energy prices reinforce concerns over an already fragile macroeconomic situation; for oil, this is true in the United States as well. However, while expensive gas doubles the economic burden of oil in Europe and Asia, in the US shale gas is triggering an industrial renaissance: employment in the US gas industry is growing at a double-digit rate, a steel mill reopening in Pennsylvania to produce pipes, Du Pont relocating chemicals production from Asia, the shale revolution creates exactly the type of skilled blue collar jobs that were hit so badly by the financial crisis. In addition, for an average US middle-class family, the decline in energy bills has roughly as much impact on disposable income as wage growth, providing a much needed boost to consumer spending and service-sector job creation. Recovery from the financial crisis proved to be painful everywhere, but the United States is literally fracking its way out of the recession.

The gas is there for the Golden Age of Gas. It is abundant, well-distributed and can be produced in a safe and sound manner. Geology has done its job, now it is up to policymakers and the industry to add the Golden Rules, drill the wells, roll out the infrastructure and make it happen.

*László Varró is the Head of the Gas, Coal and Power Markets Division of the International Energy Agency ([www.iea.org](http://www.iea.org)) and was a roundtable panel member during the 20th World Petroleum Congress in 2011.*



# Collaboration and technology

By Trevor Smith

The key to unlocking unconventional gas is to work together and develop advanced technology.

The world has within its grasp the possibility of realising energy security, economic prosperity and environmental sustainability – on a national, regional and global scale – by understanding and utilising our vast unconventional gas resources. The key to unlocking gas shales, tight gas sands and coal-bed methane (CBM) has been and continues to be collaboration and advanced technology, which enable solutions to be identified,



Following trials at the Hugoton field in Kansas, the petroleum industry's first commercial hydraulic fracturing was carried out in Oklahoma in 1949 by Halliburton under a Stanolind patent.

developed and deployed that reduce the risks and costs of production and minimise the environmental footprint of developing these vital resources.

## An unconventional breakthrough

Development of unconventional gas (UCG) was launched in the early 1980s with the help of a large collaborative research programme led by the Gas Technology Institute (GTI). Their effort along with efforts by other organisations, notably the US Department of Energy, became a catalyst for experimentation and new technology development that has unlocked the vast potential of America's "new" natural gas and provided the world with a promising new energy future.

Research started in 1982 with a GTI (as the Gas Research Institute) led collaborative research programme initially targeting CBM. GTI managed a world-class team of experts from industry and academia and developed several technologies that enabled CBM to grow from nothing to making up almost 10% of total US gas supply in 2010. GTI's collaborative model was also used to manage parallel programmes for gas shale and tight sands production. Together, these three programmes led to the development of advanced hydraulic fracturing technology and a fundamental understanding of gas adsorption/desorption in rock formations. Hydraulic fracturing combined with advances in horizontal drilling are two key technologies critical to unlocking UCG resources today.

Credit for economically extracting gas from shale goes in large part to George Mitchell, former head of Mitchell Energy and Development Corporation (see box). Mitchell began experimenting in the 1980s with hydraulic fracturing – the 60-year-old process of pumping a mixture of water, chemicals and sand under high pressure underground – applied to dense shale formations to crack the rock and allow gas to flow freely from the formation.

Technology developed by GTI including microseismic for measuring fracture performance and





fracture modelling software were leveraged by Mitchell and dramatically improved their production results. Today, these technologies are key components in the operations of all fracturing service companies.

In 2002, Devon Energy Corporation acquired Mitchell and combined hydraulic fracturing with horizontal drilling to make shale gas wells more productive. Horizontal drilling enables a single vertical well to turn horizontally and follow a seam of shale for up to 3,000 metres. Devon's success freed the gas to flow in greater volumes and at a much lower unit cost than previously thought possible.

The key that brought about the UCG revolution in the US was bringing together the right partners

### **George P. Mitchell**

GTI presented George P. Mitchell, former Chairman of Mitchell Energy & Development Corp., with a Lifetime Achievement Award in 2010 for pioneering drilling and completion technologies that created a shale gas revolution. His unconventional thinking and passion changed the energy future in the United States and now has the potential to significantly impact the world.



For 17 years, Mitchell insisted the impossible was possible. The geologist and petroleum engineer believed in extracting gas from shale when the term "shale play" did not even exist. He drilled for gas in a rock formation known as the Barnett Shale found across northern Texas and enabled viable production through the first successful application of the hydraulic fracturing technique to dense shale formations.

and technology-based solutions to make these resources productive. Today's focus is on identifying, developing, and deploying technologies that enhance the economic efficiency and reduce the environmental footprint of field production activities. No two UCG plays have the exact same geological characteristics, so technology known to work effectively in one play may have to be adapted or re-invented altogether to make another play productive and economical.

### **Research partnerships**

In 2007, the Research Partnership to Secure Energy for America (RPSEA) was awarded a contract to manage the "Ultra-deepwater and Unconventional Natural Gas and Other Petroleum Resources Research and Development Program" created by the United States Energy Policy Act of 2005. GTI played a pivotal role in the start-up of RPSEA, a non-profit corporation composed of a consortium of over 150 top US related entities dedicated to increasing America's supply of energy. This role included establishing the technology road-map for the UCG R&D programme. The RPSEA programme is currently the largest publicly funded UCG technology programme in the world.

### **Resource assessment and technology development**

Collaborative projects such as GTI's recently completed New Albany Shale project and the current Marcellus Shale research project are working to better understand these plays' unique characteristics, their gas production potential and the techno-economic and societal challenges to their development.

The approach is based on 30 years of working with the global industry, academia and government policymakers to develop solutions for converting UCG potential into productive energy resources. Programme participants might typically include personnel from E&P operators and





It is important to prevent issues associated with water use from becoming an obstacle to the sustainable development of vital UCG resources.

service companies, universities, consulting firms, private research organisations, oil and gas associations, national labs and public geological surveys. GTI leverages its own capabilities with an extensive network of subject experts and focuses this talent on understanding and solving the specific challenges of a particular play.

GTI is currently seeking participants in a new collaborative programme on hydraulic fracturing called the "Field-Based Program to Enhance Hydraulic Fracturing Efficiency". This collaboration of shale gas developers, service companies and technology providers will establish a multi-well, multi-frac stage test site to conduct a number of field experiments in stages. The ultimate goal of the programme is to enable a more efficient fracturing process leading to higher production output per well, thus providing greater efficiency and reducing environmental impact.

### Water management and reuse technologies

GTI is developing water management methods and technologies that reduce demands for fresh-water, reduce the environmental impact of brine treatment and disposal, and ensure supplies of water for well drilling and completion for natural gas development:

One new technology is an "Integrated Water Management Methodology and Planning Tool" – a proprietary water-based life cycle computer model, which is used to forecast the water requirements, water output, water reuse capacity, salt generation, solid waste output, transportation and infrastructure requirements, and emissions outputs of an unconventional gas development area. Such a model enables developers and governments to identify the scale of water resources to be sourced and utilised; assess the costs of handling, treating and disposing of water; and collaborate on the development of sustainable solutions for region-specific water management challenges.

### UCG on LinkedIn

Another way to collaborate is through social media. LinkedIn, the online professional networking site, hosts a number of interesting industry groups. GTI manages a LinkedIn group specifically for professionals interested in working to realise the full potential of UCG resources. The group can be found by typing "Global Unconventional Gas" in the group search box. Membership is free.

### A world of abundant supply

In the United States UCG contributed about 10% of total production in 1990. Today it is over 50% and by 2020 it is expected to supply well over 60%. Gas shales are driving this growth.

North American gas shales already contribute over 250 mcm/d and are projected to grow rapidly. In 10 years, gas shales alone are expected to account for a third of North American natural gas production.



The worldwide pursuit of UCG including gas shales has only just begun. All currently published resource estimates for world supplies start with H.H. Rogner's 1997 "top-down" study of world hydrocarbon resources. Rogner estimated the world gas shale resource endowment to be 450 tcm.

The latest study of world shale gas potential came from the US Energy Information Administration (EIA) and was performed by Advanced Resources International (ARI) in 2011. EIA estimated that 187.5 bcm of technically recoverable shale gas existed in the 48 shale gas basins in the 32 countries it assessed. A true "bottom-up" assessment country-by-country is required as a next step in defining this potential.

Europe's UCG resource endowment and supply potential are large and production holds promise. Exploration is underway in several European basins including the Alum Shale of Sweden, the Silurian Shale of Poland, the Posidonia Shale in Germany, the Carboniferous sediments in The Netherlands and Germany, and the Mikulov Shale of Austria. Several companies are also seeking permits for shale gas prospects in south-east France in Languedoc Roussillon, the Cevennes mountains region and the Savoie area near the Swiss border. Poland is the furthest along in exploring for shale gas and may become the first European country to realise commercial production. However, some other governments in Europe such as France and Bulgaria, responding to fears regarding potential environmental impacts from hydraulic fracturing, have passed moratoriums on drilling and completing activities until some perceived risks can be further studied.

In addition to social and environmental challenges, Europe's UCG geology is challenging. Therefore, collaboration and the development and deployment of technology-based solutions tailored to each play is crucial for making Europe's unconventional resources economically productive, environmentally sustainable and socially acceptable.



Small pads minimise the surface impact of UCG operations – this drilling rig was set up in the middle of the Arlington Campus of the University of Texas.

China is being hailed as one of the next big shale gas regions. Various reports have indicated that China has potential reserves of between 144.4 and 495.5 tcm with possibly 36.1 tcm being technically recoverable. The recently published Shale Gas Development Plan jointly issued by the National Development and Reform Commission, Ministry of Finance, Ministry of Land and Resources and National Energy Administration has highlighted an objective of proving shale gas resource of 600 bcm and a recoverable reserve of 200 bcm with actual production of 6.5 bcm by 2015. To achieve this objective, the industry will need to collaborate on best practices and innovation of new technology, agree on effective business models, develop the resource efficiently and not at the expense of the environment, and define and clarify the legal and regulatory frameworks to enable rapid and sustainable development of shale gas.



In 2010, PetroChina began collaborating with international companies such as Shell, Chevron and Hess on joint studies and launched shale gas pilot developments in the provinces of Sichuan and Yunnan. The first shale gas appraisal well was completed in the south of the Sichuan Basin and commercial gas flows were obtained.

UCG exploration is underway in many other parts of the world, including Australia (a global leader in CBM production), New Zealand and southern Africa, and there are also initial efforts underway in Venezuela, Argentina and Chile to understand the resource potential of tight sands and gas shale.

### What clean, abundant, affordable gas makes possible

The “discovery” of UCG has transformed the conversation around natural gas in the US from one of depleting reserves, high prices and a future reliance on LNG imports to one of abundance, affordability and domestic energy security. As development occurs throughout the world, it opens up tremendous opportunities for energy security, reducing climate change risk and economic prosperity through wealth creation, capital investment and high paying jobs.

### Providing energy security

An abundant supply of “home-grown” gas has the potential to change the energy trade balance between nations. It may be that those countries around the world who have traditionally imported the bulk of their energy from elsewhere may instead become self-reliant or even energy exporters.

### Reducing climate change risk

Abundant supplies of UCG transform global debates over climate change abatement strategies. With a carbon footprint at least 30% lower per Btu than oil and 45% cleaner-burning than coal, natural gas is highly desirable bridge fuel to a low-carbon, sustainable energy future and will play

a prominent role in the energy mix for decades to come.

New climate regulations that place a price on carbon emissions will shift relative economics in favour of more natural gas consumption rather than coal in electric power generation. Natural gas power plants can also be built more quickly than coal-fired plants.

Gas facilitates the development of renewable energy. Because gas plants can be fired up and down quickly (unlike coal and nuclear) natural gas can better supplement wind and solar power facilities, whose output varies with the weather. New gas supplies leading to more stable prices could also support more transportation fleets being converted to natural gas without requiring major infrastructure improvements. Additional technology developments could also make the economics of passenger car utilisation more attractive over time.

### *Creating wealth, jobs and investment*

Energy development means economic development. The economic and energy security implications of more abundant, affordable natural gas include increased job creation and economic activity, increased tax revenues, investment in energy infrastructure, expanded use of gas for power generation and transportation fuel, lower energy and feedstock prices for industrial manufacturing, and lower energy prices for consumers.

Penn State University (PSU) recently estimated that the Marcellus Shale gas industry in the Commonwealth of Pennsylvania generated \$12.8 billion in economic activity and \$1.2 billion in state and local taxes in 2011, and \$13 billion in consumer savings over the last two years from lower gas costs. In terms of job creation, the study estimated that 156,000 jobs were supported by shale gas development in 2011 and that number would grow to over 256,000 jobs by 2020. The PSU study captures job creation in just one state and from just one resource!





In addition, energy-intensive manufacturing companies often relocate in search of cheaper energy in order to remain globally competitive. Regions with abundant supplies of natural gas will be more successful at attracting and retaining direct capital investment and the high paying jobs that come with it.

IHS-CERA estimates that as of 2010 shale gas production was supporting about 71,000 manufacturing jobs (39,000 direct manufacturing jobs and another 32,000 jobs along the supply chain) and that this could reasonably rise to 124,000 by 2020. PricewaterhouseCoopers estimates that lower feedstock and energy cost could help US manufacturers reduce natural gas expenses by as much as \$11.6 billion annually and support the employment of approximately one million workers by 2025. Natural gas is an important ingredient to make ethylene which goes into the production of chemicals and fertilisers.

Shale gas alone has attracted large amounts of capital investment. In fact, over \$200 billion in shale

gas related investment has been transacted since 2007 with the US attracting 80% of that investment.

### The road ahead

The potential benefits of developing global unconventional gas are not guaranteed. There are distinct and diverse challenges facing each of these resources in addition to the need for technology transfer and support, not to mention environmental assurance and the need to enrol stakeholders in what UCG makes possible. Collaboration between producers, service companies, NGOs, policymakers, thought leaders, industry associations, universities and investors combined with the right advances in technology will be crucial for these resources to reach their full potential.

*Trevor Smith is Program Manager at GTI – a leading non-profit research, technology development and training organisation solving important energy and environmental challenges for the global natural gas and energy industry for 70 years ([www.gastechnology.org](http://www.gastechnology.org)).*



Argentina is already producing tight gas and has enormous shale gas potential.





# Unconventional gas and the environment

What are the issues surrounding unconventional gas and its future in the global energy mix?

## Addressing the environmental concerns

The modern world is based on hydrocarbons for energy, fuel and feedstock. Such resources are, of course finite. The world has rightly started to focus on sustainability. Better use of resources, improved energy efficiency, recycling, use of alternative fuels and use of alternative materials are required. However the switch takes time and as global population increases, our thirst for hydrocarbons will continue – and as its use becomes more developed and widespread, it is important to monitor the relevant environmental issues.

Natural gas is the cleanest of the fossil fuels. For the same amount of energy produced, it produces lower emissions of carbon dioxide than other fossil fuels. Unconventional gas is the “new kid on the block”. By far the most common form of unconventional gas is shale gas. This is gas which is trapped in shale rock deposits, deep underground. Shale gas is very abundant. Vast quantities have already been discovered in the USA and suitable geological formations exist in many parts of the world. Unconventional gas has the potential to significantly extend the hydrocarbon future of the planet.

But the development of shale gas has not been without issues, with news stories of gas coming from taps in people’s homes, pollution of drinking water supplies and earth tremors “triggered” by hydraulic fracturing fuelling the debate. It is therefore important that accurate information is disseminated to the public on unconventional gas (see *Engaging with the community, pages 40-45*). Around the world, energy companies are working hard to ensure unconventional gas activities are conducted without damage to the environment.

It is important to focus on the many benefits of unconventional gas. Shale gas gives countries energy security. When gas is available locally, transportation costs and risks are minimised and significantly less energy is required to move the gas. The US is an example of these benefits as it is no longer reliant on imports of gas. This availability helps to reduce CO<sub>2</sub> emissions as producing power from gas generates lower emissions than coal or oil.

If well-designed and safely managed, it is possible to have shale gas drilling sites which are safe and have no long-term environmental impact. The shale gas is separated from the aquifer (water supply) by several kilometres of hard rock. Provided that the well is sealed properly, there is negligible risk of water contamination in relation to chemical use. Properly designed and built wells also help ensure there are no “blow outs” that can lead to atmospheric releases of gas. These sites are safe and have no adverse environmental impact provided that the site is well managed with trained staff, strict procedures for storage and handling, and regular audits. Similarly, procedures can be put in place to minimise the risk of seismic events around areas where activities such as hydraulic fracturing are taking place.

Regulation is well developed in the US and Europe. This is an extra layer of protection to ensure that producers act responsibly. For example, the US has the Environmental Protection Agency (see box over), while the EU has implemented the Inte-





Around the world, energy companies are working hard to ensure unconventional gas activities are conducted without damage to the environment.



## EPA and unconventional gas

With the US leading the world in unconventional gas production, the country's Environmental Protection Agency (EPA) has addressed the environmental issues with clear regulations and recommendations to ensure best practice. Here are some examples of EPA's regulatory work with the gas industry:

- **Air quality issues:** EPA, the Department of the Interior, other federal agencies and states are working to better characterise and reduce air emissions and their associated impacts. Through the Natural Gas STAR programme, EPA and partner companies identified cost-effective technologies and practices to reduce methane emissions from the natural gas sector. Through the Clean Construction USA programme, EPA promotes more efficient technology and cleaner fuels to reduce emissions from hydraulic fracturing equipment and vehicles. EPA also administers Clean Air Act regulations for natural gas production, including regulations on reporting greenhouse gas emissions.

- **Recommending waste water recycling:** Re-use of waste water from hydraulic fracturing is, in

part, dependent on the levels of pollutants in the waste water and proximity of other fracturing sites that might re-use the wastewater. This practice has the potential to reduce discharges to treatment facilities or surface waters, minimise underground injection of wastewater and conserve water resources.

- **Using surface impoundments for storage or disposal:** EPA is evaluating industry practices and state requirements on the issue of using surface impoundments (pits or ponds) for storing or disposing of waste. Under consideration is the need for technical guidance on the design, maintenance and closure of pits under the Resource Conservation and Recovery Act to minimise potential environmental impacts.
- **Clean Water Act (CWA) compliance:** EPA is updating chloride water quality criteria for the protection of aquatic life under the CWA. EPA has recommended water quality criteria which are used by states when updating relevant water quality standards. These criteria are being updated and a draft document is expected in early 2013.

The screenshot shows the official website of the United States Environmental Protection Agency (EPA). The top navigation bar includes links for 'Advanced Search', 'A-Z Index', 'Match', and 'Share'. The main menu features 'LEARN THE ISSUES', 'SCIENCE & TECHNOLOGY', 'LAWS & REGULATIONS', and 'ABOUT EPA'. The central content area is titled 'Natural Gas Extraction – Hydraulic Fracturing' and features a large image of a wellhead. Below the image, a text box explains the environmental impact of natural gas extraction, mentioning shale gas reserves and the use of diesel fuel. A sidebar on the right provides information on 'Natural Gas Drilling Toolkit', 'What's New' (including a May 2012 draft permit for oil and gas hydraulic fracturing), and 'Sign up for hydraulic fracturing email alerts'. Another sidebar lists 'Additional Information' and 'Other Pages of interest'.



grated Pollution Prevention and Control (IPPC) Directive. IPPC manages the activities of significant sites, called "installations" by regulating how the site is operated, as well as waste production, management and emissions control. Sites must be operated under permit using IPPC-prescribed "Best available techniques". In granting licences, it is important for authorities to stipulate that the site be returned to its original state at the end of its life.

However, this does not mean operators have always been environmentally responsible. The biggest risk to the environment and the focus of the anti-fracking lobby is the risk to contamination of water supplies. For example, in the US, some companies have paid out very large sums of money in settlement of claims. This has mainly been for faulty cement casings on the wells, which have allowed gas to leak into private water supplies. While the companies involved refuted the claims, they still agreed paying a settlement and improving the design of the wells, stating that this was the right thing to do. In any case, the importance of good engineering practices cannot be overstressed to prevent water contamination from poor well casings.

Land damage is another risk for unconventional gas producers. In the same region of the US, there have been reported cases of blow outs from wells. These are releases during the drilling operation caused by a sudden surge of pressure in the well. In a properly designed well, blow-out protection devices will be installed and tested regularly. However, there have been reported cases of these protection devices failing to operate (generally due to poor maintenance), with the subsequent blowouts leading to releases of drilling fluids and hydrocarbons and causing local soil as well as groundwater contamination.

## Conclusions

While we must move towards a more sustainable future, there will always be some need for hydrocarbons. Unconventional gas can play a major

part in that low-carbon future, providing a clean-burning fuel which generates lower emissions. However, as with any potentially hazardous industry, it is essential to ensure that the companies involved have the necessary expertise, highly trained and skilled staff, and that sites are designed and operated to the highest safety standards.

Effective and active regulation is also essential to ensure full compliance in the interests of environmental protection. Regulators must have the power to stop operations in the event of non-compliances.

*By Andy Gibbins, Director of GLAS Consulting, a UAE-based management consultancy for the oil, gas and petrochemicals sector. ([www.glasconsulting.org](http://www.glasconsulting.org))*

## Emerging environmental issues

Further study and technical developments, as well as ensuring sound regulations are put in place, are all essential if issues such as exploiting gas hydrates, preventing gases, e.g. methane escaping and averting acidisation are to be dealt with in an environmentally sound manner.

- Gas hydrates (solid, ice-like material containing predominantly methane and small quantities of other gases bound in a lattice of water molecules) appear to be the vastest gas resources on the planet. Their commercial exploitation, once achieved, could potentially resolve the issue of methane being emitted in the atmosphere if the Arctic permafrost melts or the temperature of the oceans rises. General concerns have been raised, such as the potentially catastrophic effect of exploiting such an unstable chemical substance if the actions of operators are not properly regulated and monitored, and a high risk of producing earthquakes through the removal of methane hydrates from deep sea beds.

The study of gas hydrates is in its infancy and a commercially viable method of extraction has not yet been found. Once such a method is developed, its potential impacts can be discussed.



- Very few studies have been undertaken on the concerns raised by gas, such as methane, escaping from gas extraction operations. The lack of studies means there is little consensus on the level of leakage. Technology exists to minimise methane escaping from fracking operations, as well as from pipeline transmission and gas storage. Regulators can require that such technology be implemented by operators. In some jurisdictions, the air pollution caused by methane is an offence and operators can be liable for prosecution if methane is emitted.
- Operators can also be required to undertake air control tests to ensure methane is not emitted into the atmosphere from unconventional gas operations.
- High water use is of particular concern when unconventional gas extraction takes place in countries or regions where drought conditions have been prevalent, such as Australia. Water is difficult to transport so most commercial activities extract the water they use locally. If large amounts are used for fracking, this will impact on the water table and ecology of the

### Can renewable gas be considered as unconventional?

While unconventional gases are generally defined by the non-traditional or advanced extraction techniques required, the term has also been used by biogas producers. Rolf Stein, CEO of Advanced Plasma Power, explains how he sees renewables as fitting into the unconventional definition in the UK market: "It has been proposed that large quantities of unconventional renewable gas will be required in the coming decades to replace at least a proportion of fossil gas supplies, to allow the UK to meet its greenhouse gas reduction targets whilst continuing to use gas for heating."

Stein says that a portion of this renewable gas will be derived from wet wastes but this will need to be supplemented by alternative "unconventional" means of production to meet demand. "It will be necessary to develop an alternative pathway to manufacture renewable gas, such as bio-substitute natural gas or bio-SNG, from biogenic waste resources," he says.

An example of this is advanced conversion technologies (ACT) which transform waste into energy. Advanced Plasma Power has developed a process called Gasplasma which creates clean, hydrogen-rich synthesis gas (syngas). The process involves a fluid-bed gasifier and a plasma converter and the company is already operating a

plant in Swindon, UK, which converts municipal solid waste into syngas.

"There is huge potential for [the technology] to be successfully applied to the creation of bio-SNG and the resulting gas will meet the specification to enable it to be injected into the gas network and distributed as a domestic and commercial heat/energy source," says Stein.

The UK government's Department of Energy and Climate Change website reiterates this, saying that there will be an increased role for ACT in the years to come, using gasification or pyrolysis to create new forms of renewable gas. Gasification is the partial oxidation of an organic feedstock to produce syngas. Pyrolysis produces syngas by relying on the application of heat to a feedstock in the absence of oxygen. These are alternatives to anaerobic digestion, which is the microbial digestion of the feedstock to release heat, methane, hydrogen sulphide, carbon dioxide and, under certain conditions, hydrogen gas. The disadvantages of this include the health threat the microbes pose to people and animals and the sensitivity of the microbes to changes in the feedstock, meaning it needs constant circulation of a reactor fluid, constant operating temperature and pH.





area, and it will also limit the amount of water for other activities taking place in the area.

- "Acidising" is another issue that can arise when extracting tight gas using chemicals in water to dissolve rock under which such gas can be found. While this is a different process to fracking, similar environmental impacts could arise from acidising because chemicals are pumped into the ground, which could cause groundwater contamination. It also raises the issue of wastewater treatment so as to limit potential contamination of land and other water sources through the disposal of untreated wastewater. Finally, this process also raises the question of what chemicals are being used to dissolve the rock and whether or not they affect humans and the environment (see *Shale gas water management*, pages 58-63).
- Different jurisdictions have taken different approaches to regulating fracking fluids in the interests of preserving the environment. In the state of New South Wales, Australia, a moratorium on fracking is in place. Once this is lifted, following the finalisation of an inde-

pendent review on fracking and well designs, operators will be required to acquire licenses and permits giving them the right to use the water that they require under the same conditions and costs as other commercial users.

In France, Poland and some Australian states, gas extraction operators can be prosecuted for causing groundwater pollution. Other countries impose stringent requirements on the types of chemicals which can be used in fracking water. The Australian state of Queensland has banned the use of a cocktail of chemicals referred to as BTEX (benzene, toluene, ethylbenzene and xylene). Similarly, operators can be required to have the chemical mix used in fracking operations tested to ensure that they are not harmful to humans and the environment and submit the test results to regulators for verification.

*By Jennifer Hughes, Special Counsel, Environmental Markets, and Ana Cociulescu, General Associate, Environmental Markets, Baker & McKenzie (Sydney office) [www.bakermckenzie.com](http://www.bakermckenzie.com).*



Measuring stream flow in British Columbia, Canada – water use is an important concern in unconventional gas operations.





# Engaging with the community

By Georgia Lewis

Being a good neighbour makes good business practice for unconventional gas producers in the exploration and production process

Energy companies are aware that social and environmental considerations must be taken into account on all unconventional gas projects. To ensure projects are successful from the start, an important first step is to engage communities early and extensively. There are ways to ensure communities remain informed about the processes involved, controversies are averted and open communication is achieved between all stakeholders.

An example of a controversy surrounding unconventional gas production was the release of “flaming tap” pictures and videos showing water from household taps being set alight. Anti-fracking campaigners believed these cases to have been caused by methane migration into fresh water aquifers as a result of poor hydraulic fracturing practices. While subsequent investigations showed that the water supplies involved (which were often private ones) contained naturally occurring methane and that the local aquifers had not been affected, the dramatic images have remained in the public’s mind.

Concerns about the chemicals used and accounts of fracking causing earthquakes have added to the controversy, and some countries

have banned or placed moratoria on fracking in response to public pressure. It is up to the companies and regulatory agencies involved to ensure that industry best practices are followed, particularly as regards protecting groundwater during vertical drilling by a combination of protective casing and cement, and to make the case for safe and efficient unconventional gas production.

Kerstin Duhme, a Managing Director with FTI Consulting, outlines how a lack of positive communication about the benefits of unconventional gas could even threaten Europe’s shale gas future. “Opponents of shale gas are currently dominating the European political, media and public debate,” she says. “The French, Bulgarian, Romanian and Czech governments have already enacted restrictions against hydraulic fracturing, and there is fierce debate in a number of other countries. Unless those who understand what shale gas could do for Europe take up the baton and start positively communicating its benefits, the shale revolution could be over in Europe before it’s even started.”

One example of an energy company publicly responding to community concerns is that of Cuadrilla Resources in the UK. Fracking trials near Blackpool conducted by Cuadrilla were deemed by an independent study to be the “likely cause” of earth tremors in the area. Mark Miller, the company’s CEO responded by telling the media that the company “unequivocally” accepted the findings of the report and it was “ready to put in place the early detection system that has been proposed in the report so that we can provide additional confidence and security to the local community”.

Andy Gibbins, Director of GLAS Consulting, a UAE-based management consultancy for the oil, gas and petrochemicals sector, says “good, two-way dialogue” is vital to stop fears escalating and to ensure that misinformation is not disseminated among communities.

“There is undoubtedly a need to engage with the local populations via the media, in writing and



in face-to-face town hall meetings," he says. While pressure groups can dominate proceedings, Gibbins says it is important to "address all of the [environmental] concerns, otherwise the doubt will always remain and stories will be exaggerated via the local grapevines".

### The importance of a strong media strategy

Dwight Howes and Michael Joy, of Reed Smith, an international law firm with a large energy industry practice, echo Gibbins' sentiments. Both are members of the firm's Energy and Natural Resources Group and they agree that a clear media strategy that is accessible and fact-based must be put in place by energy companies. As the media is often the first source of information for members of the public, this is something that should be a top priority for energy companies.

"It is important to have media strategy, a clear set of bullet points and to have them readily available – they need to be clear and direct," says Howes. "This is essential, especially in regards to [information about] preventing fracking fluid and produced water from spilling, ensuring well-casings are tight and sealed, and groundwater is not contaminated."



Images of flaming water taps, like this one taken from the film *Gasland*, have been seized upon by anti-fracking protesters.

Joy warns of the dangers of making the media strategy too simplistic: "The big mistake made by oil and gas companies with their media programme is they have relied too heavily on dumbing down complex scientific principles. The public doesn't typically understand the complexities. People in the oil and gas industry are talking over the public and anti-industry groups with an agenda develop catchphrases and soundbites that effectively scare the public."

A media strategy that clearly explains scientific information is important for transparency, accord-

The screenshot shows the homepage of ENERGY IN DEPTH. At the top, there is a navigation bar with links to "What's EID?", "Meet the Team", "Just the Facts", "Library", "Multimedia", and "Blog". Below the navigation bar is a large banner with the text "COLD, HARD FACTS ON HYDRAULIC FRACTURING" and a subtext explaining EID dispels myths about fracking. To the right of the banner are buttons for "Learn More", "TOUR THE VIRTUAL WELL SITE", "JOIN ENERGY IN DEPTH SIGN UP", and "JOIN THE CONVERSATION FOLLOW US" with social media icons for Facebook, Twitter, and YouTube. At the bottom left is a photo of a snowy landscape with a drilling rig, and at the bottom right is a section titled "In The News" with a small globe icon.

Now in its third year of operation, the website [www.energyindepth.org](http://www.energyindepth.org) is part of a campaign to provide information on the development of shale and tight gas assets in the US.





ing to Joy: "It is good for media managers to be organised and focused and have bullet points but it is also good to be specific about the drilling, about processes that protect groundwater and the like."

Using the internet is another powerful way to engage with communities. Chris Tucker, a Managing Director for FTI Consulting, explains how the Energy In Depth ([www.energyindepth.org](http://www.energyindepth.org)) website the firm devised as part of their strategic communications work, has emerged as an important tool for energy companies to engage with the media and communities.

"When we launched Energy In Depth back in the days of antiquity, also known as 2009, very few of the reporters, stakeholders and opinion-leaders we initially engaged had ever heard of 'hydraulic fracturing' – one reporter asked whether the term referred to a water-skiing accident," Tucker recalls. "Gradually, though, as the issue evolved, and as producers sought to develop shale resources in new parts of the country [the US], our campaign evolved right along with that.

"Indeed, what started as little more than a bare-bones website housing a handful of studies and fact sheets has grown over the past three years into what many now consider the US industry's lead research and rapid response platform on issues relating to onshore oil and natural gas production," says Tucker.

Following on from the success of Energy In Depth, several EU and US companies have joined forces to create Shale Gas Europe, a website that is slated for launch in late 2012.

### Practical ways to involve communities

Along with a solid media strategy, energy companies need to be proactive when it comes to community engagement and address concerns before they turn into serious problems.

Joy says that a community engagement policy is critical: "You need to engage early and often and with the right people.

"It is better to come into a community and talk about who you are as a company, your company philosophy, explain systems where there is concern and make sure there is someone in a position of authority for people with specific concerns, who can answer their questions," he says. "The community wants to hear from people in charge, the project manager, the regional manager. And they need to be easily identified [by the public]. This is a challenge."

"Be upfront with folk locally – get a dialogue started before you roll the trucks out," says Howes. "Good relations at a local level are most important. It's critical before engaging in any operations to identify community leaders, the mayor, city councillors, approach them one-on-one. Let them know what is going on, negatively and positively as oil and gas operations are not without a footprint – road use, traffic, noise."

A major part of ensuring the community is onboard with unconventional gas projects is to publicly address two very important elements of the energy company's presence in a region – a road-use agreement and an emergency response plan.

"Before activities commence, it is important to determine what role the municipality will play and also be ready to train local first responders," says Joy. "They need to know about the well site, road access, where things are on a local level.

"Well fires are a very rare occurrence but they are not usually the kind of event that a local fire service can deal with without expert help, he adds."

Getting to know the community on a one-to-one level is essential, according to Tucker who describes the best community engagers as those who are "the hardest working".

"They know each of their mineral-owners by their first name, they hold community picnics and bring in science and engineering experts from around the country to answer questions – and they're honest, above all. They're not afraid to admit when mistakes are made or accidents





### Corporate social responsibility case study: Nexen

Introducing a comprehensive corporate social responsibility (CSR) programme is another way energy companies can successfully engage with communities. Nexen is one such energy company which has done just that at its shale gas operations in Colombia.

Nexen was one of the first companies to explore for shale gas in Colombia, commencing a drilling programme of four wells in late 2011. Their activities cover a total area of approximately 600,000 hectares.

As part of the company's policy of giving back to the communities where they operate, Nexen has supported a wide range of charitable foundations and local initiatives in Colombia. These include nutrition programmes for children, seniors and people with disabilities, youth education programmes and sponsorship of an organisation that supports children receiving

cancer treatment in Bogota, Colombia's capital.

Improvements to a milk cooperative used by two communities near the Colombian exploration operations have also been supported by Nexen. This included new cooling and storage tanks which doubled capacity as well as renovations to the facility.

A spokesperson for Nexen says this collaborative approach between communities and stakeholders has created partnerships for the company's successful operation in Colombia, which has so far employed 71 people – 38 Colombian staff members, 28 Colombian contractors and five expatriate employees. "There is an expression in Colombia that 'government gives you a permit, but the community gives you permission'. We work very closely with communities to obtain and keep that permission," he says.



Sueva was the first of Nexen's four shale gas wells in Colombia.



Robbert de Weijer, CEO, Australia, Dart Energy, addresses a town hall meeting in Sydney on CBM development.

occur. At the same time, they're absolutely relentless when it comes to correcting misinformation when it appears," says Tucker.

He adds that energy companies must be seen in their communities as "good neighbours". As well as regular site visits for residents and members of the media, trade associations, consultancies and advocacy groups can help energy companies by "taking on the task of educating broad swathes of the public about the basics of development and standing up when needed to set the record straight".

The advent of social media has also changed community engagement, according to Tucker: "These days you can reach a lot of people very easily – unfortunately, so too can those who oppose responsible oil and gas development and often, their messages lend themselves much better to the medium of a 140-character tweet than the technical white papers we put out."

However, Tucker maintains that despite this, "time, attention and substance" are still crucial for getting an informed message across.

Communities can also benefit financially from an energy company's presence.

"Be obvious about doing business locally, buying equipment locally, engaging local contractors, have a positive impact on local business," says Joy. This is a way for unconventional gas projects to create local jobs and improve the tax base.

Tucker sums up the need for high standards for every part of the unconventional gas development industry, be it technical, safety-related or in terms of communication and community engagement: "Our product is superior; now we need to make sure that our processes meet that same standard."

*Georgia Lewis is the Deputy Editor at International Systems and Communications.*



### Community engagement case study: Pennsylvania

Chris Tucker shares a case study centred on a small town in Pennsylvania: "Here in the States, we've been faced with the task of responding to the lobbying efforts of some NGOs to pass local resolutions and ordinances hostile to natural gas development – legislation that essentially tries to 'zone' shale exploration out of town, essentially establishing what amounts to a de facto ban.

"Of course, when the relevant policy issues devolve to the local and/or municipal level, you can basically throw away the tactical blueprint you were using back when you were running a national campaign. I remember one case in particular in which a small Pennsylvania town was considering such a resolution, a town very near to where I was raised.

"When we found out what was about to happen there, we convened a series of town hall meetings, and actually invited the mayors of several nearby towns where shale development was already taking place. We also paid a small fee to commission a legal brief outlining several potential practical externalities that the town board might not have considered in the context of this resolution. Finally, we organised a letter to the board that was signed by 30 small business owners in the town – all folks in support of responsible development.

"In the end, the resolution was rejected – in unanimous fashion, which was a nice surprise. And we were able to use that momentum to organise similar campaigns in other small towns, sending a message that two can play the local game."



Where shale gas development has become a local issue, such as in Pennsylvania, a community-focused approach is beneficial.



# Shale gas

By Glenda Wylie

Shale gas production in the USA has become economically viable and is environmentally sustainable thanks to technological advances. The rest of the world can benefit from the US experience.

Hydrocarbon production from shale formations has an enormously valuable potential as a part of the energy mix now, and into the future in markets across the world.

Development of the shale resources is largely due to the improvement of three important technologies, horizontal drilling and accurate well placement within the resource play; advances in resource characteristics, formation evaluation and completion modelling to determine the quality and quantity of the hydrocarbon actually stored; and improved horizontal fracture design, monitoring, optimisation and cost-effective methods for fracture placement. Overall, there are eight important development benchmarks that a shale development must meet (*see box*).

The production from a shale formation isn't always limited to natural gas; it can include dry gas, wet gas, oil or a combination of these resources, depending on the shale's level of thermal maturity. Examples of formations containing a combination can be found at the Eagle Ford Shale play in Texas or at the Marcellus in the eastern United States.

Unlike conventional reservoirs, where economic viability is largely determined by reserves and

drilling techniques, the commercial viability of shale reservoirs depends on productivity and efficiencies. The economics of shale development require continuous efforts similar to a factory approach to improve efficiencies in drilling, completion and fracturing operations, while also reducing non-productive time.

Every shale reservoir has a unique set of geological, mineralogical, geochemical, petrophysical and geomechanical properties. As such, each basin and each well requires specialised integrated evaluation analyses and models. There are major factors that development and production solutions must address: fracturability (the tendency of the resource play to be effectively fracture stimulated); producibility (the capability for the optimised drilling and completion designs to sustain commercial production); and the capability of the development to meet current and future economic and environmental constraints.

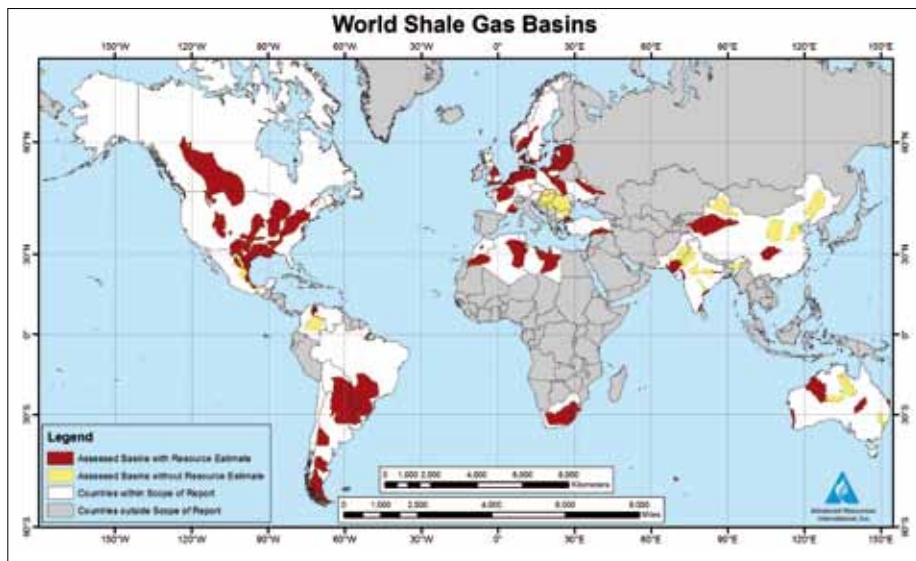
## Geographical and geological considerations

Productive shales are fine-grained, organic-rich, and mineralogically complex sedimentary rocks that extend over large geographic areas. They are self-sourcing reservoirs that not only generate the hydrocarbons but also store them due to extremely

### Development benchmarks for sustaining a shale project

- Acceptance by the people living in the region
- Favourable governmental conditions and economic incentives
- Right technology
- Right expertise
- Consumer market
- Favourable basin conditions
- Infrastructure
- Economic production





The shale gas resources in 14 regions containing 32 countries were assessed in 2011 by Advanced Resources International for the US Energy Information Administration. The study estimated gas-in-place of 708 tcm and technically recoverable gas of 186 tcm.

low formation permeability that prevents fluid migration. Formation natural stresses, human-induced stresses, pore pressure, formation depth, geology and mineralogy significantly influence resource deliverability and hydrocarbon quality and economics.

Four general types of shale hydrocarbons resource plays are predominant today and more of a variety of shale types will produce in future years as better technology is developed and new shale resource types become available to develop:

- **Type 1** Fractured organic mudstone with high carbonate content (such as the Barnett Shale). Primary production occurs through a 50/50 mix of gas released from fractures and microporosity, and through gas desorption off the organic and clay material. This is primarily a dry gas resource play.
- **Type 2** Laminated sands embedded in organic-rich shales (such as the Bakken Formation). Primary production is through

the thin sands and primarily is an oil resource play.

- **Type 3** Organic-rich black shale (such as the Marcellus Shale). Primary production occurs through gas desorption and has been known to contain gas, condensate and oil.
  - **Type 4** A combination of the other three types (such as the Niobrara Shale). Production is through desorption, matrix and fractures. Plays that cover large areas show more variation in local geology, formation depth and thermal maturity. An example of a large-area play is the Marcellus Shale with estimated reserves of 14 tcm, which covers portions of the US states of Pennsylvania, New York, Ohio, West Virginia, Virginia, Tennessee and Maryland. Examples of plays confined to smaller areas include the Eagle Ford Shale, which covers a portion of south Texas, the Barnett Shale in central Texas and Haynesville Shale, which takes in parts of Arkansas, Louisiana and Texas.
- Local geography and existing infrastructure





Hydraulic fracturing is customised to the unique requirements of each shale formation.

can have an impact on the success of a shale play. For example, factors such as the size and quality of available roads and whether the terrain is hilly or whether water is available can all influence development strategies.

Formation depth also needs to be considered. The depth to the formation influences thermal maturity, bottomhole temperatures, pressures, drilling time and overall well economics. The Haynesville play is relatively deep and involves high-pressure, high-temperature conditions, whereas the Marcellus play is relatively shallow and is only mildly overpressured in the most productive areas. Pore pressure is also an indicator of reservoir quality – higher pressures typically reflect a high degree of gas generation and storage.

The Brittleness Index (BI), a measure of the ability of the rock to crack or fracture, also assists shale play developers when they evaluate a well and field. This ability is primarily related to shale mineralogy and rock strength. Brittleness increases with an increased percentage of quartz and/or

carbonate, as is the case in the Barnett, and Woodford (Oklahoma) plays. It decreases with increasing clay and organic matter, as is in the Marcellus case. The BI serves as a guide for placement of perforations, isolation points and fracture stages.

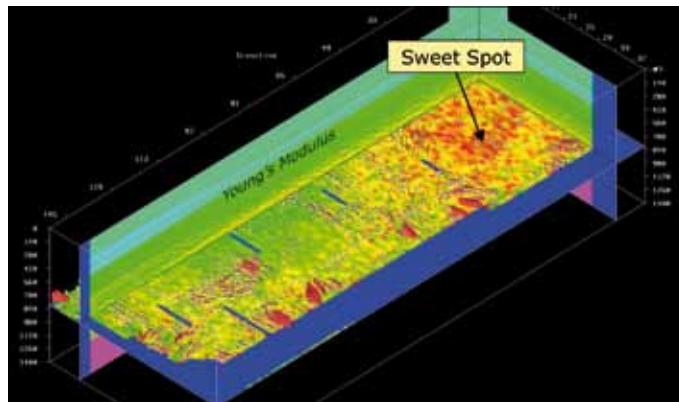
Shale operators are moving towards water-based drilling fluid systems because of cost and environmental concerns. For each play, customised formulations are developed to address the unique requirements of each shale formation.

Hydraulic fracture fluids pumped in a particular well will depend on the brittleness of the well and its ductility. A highly brittle formation such as the Barnett uses water fracturing. However, formations (such as Haynesville and Eagleford) use hybrid fracturing (water followed by a thin viscous gel and sometimes followed by a conductivity enhancer near the wellbore). Hybrid fracturing has significantly improved the hydrocarbon recovery results of more ductile shale formations.

Sound water management practices are also vital. An adequate water supply is essential for



Advanced seismic processing and analysis of 3D surveys can identify shale gas "sweet spots".



hydraulic fracturing. To reduce demand on water supply and disposal facilities, and to reduce the environmental impact, shale producers are encouraged to treat, recycle and reuse flowback and produced water.

### The importance of good data analysis

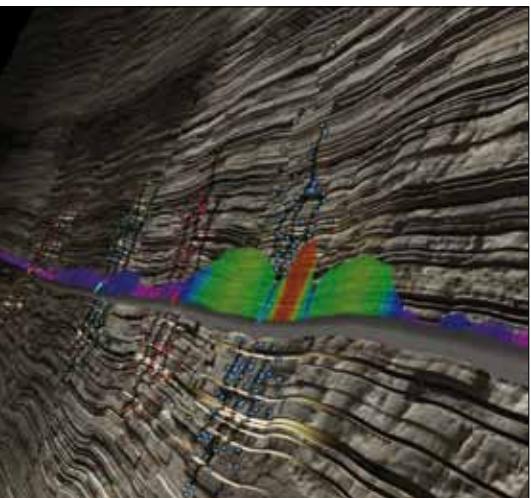
It is important for developers to have a defined exploration and development data strategy in place – this results in greater efficiencies, increases the number of successful completions and reduces the number of low-producing wells. This reduces development costs and increases production, both of which are essential for improving project economics.

The main focus in shale development is determining how to optimise the completion and continuously maintain optimum production throughout the life of the well and resource play. The economics of shale development require continuous efforts to improve efficiencies in evaluation, drilling, completion and fracturing operations while minimising non-productive time. Understanding the similarities and differences between shale resource plays is central to optimum development and good project economics. Lessons learned in one shale play can often be applied directly, or with modification, to other shale plays to reduce the "shale learning curve."

It is important to analyse data from proposed shale plays carefully to achieve the best results in

### Factors that influence changes in development strategy

- *Geological* – Identification of geohazards, faults and karst topography (a geological formation shaped by the dissolution of a layer or layers of soluble bedrock)
- *Geochemical* – Variation in lithology (the general characteristics of rock), mineralogy and thermal maturity
- *Geomechanical* – Changes in the stress field (tectonic shifts, faults or production)
- *Petrophysical* – Changes in porosity, permeability, saturation and bottomhole pressure
- *Logistics* – Availability of fluids, proppant, equipment and human resources
- *Economics* – Well costs, product prices, net present value (NPV) and return on investment (ROI)
- *Environmental* – National, regional and local regulations, resource sustainability, safety, cultural sensitivity



Microseismic monitoring combined with distributed temperature sensing can provide precise information about which zones have been treated and fracture placement.

terms of production, economic viability and environmental protection. Data acquired during the drilling, well-placement and evaluation phases are interpreted and the results are used to maximise borehole exposure in the reservoir sweet spot. This information is then used to determine the best completion and fracture-treatment designs. The fracture treatment is then monitored through microseismic mapping in real time to allow rapid changes that will benefit the next hydraulic fracturing operations and well placement, and help achieve maximum production.

Geomechanical models are used to improve drilling efficiency, fluid selection and well placement, to maximise fracture placement and to minimise well instability issues. The models also help predict pre-drill pore pressures.

Production-history matching is used to compare actual production rates with predicted values to determine whether the well completion is functioning optimally. If not, production monitoring (evaluation) is then used to identify the problem. Following a production analysis, re-frac-

turing can return the well to maximum production.

Feedback loops are built into every step of this process so that continuous improvements can be made and production is optimised throughout the well's entire life cycle. Technology is rapidly changing in the shale arena. Previously, hydraulic fracture models were stand-alone planar fracture models. Today, integrated complex fracturing network models for the individual wells are integrated into field models containing the seismic data, as well as individual and field evaluation data, and this is then compared to previous shale developments. This allows for quicker, optimised decisions to be made for the developing shale resource and with fewer people than when shale resource plays initially began to be investigated for development.

### Hydraulic fracture precision methods

Fracture placement in thinly bedded, highly mineralised, laminated shale formations requires pinpoint accuracy. Selection of the best zones for fracture placement uses local best practices, which are based on brittleness, total organic carbon content and interval/mineralogical analyses. The entrance for the fracture needs to be as straight as possible to reduce drag and provide easy hydrocarbon flow into the wellbore. It has been found that big hole charges provide better flow than deep penetrating charges when dealing with ductile shales. There are four main methods of reservoir access for fracture placement:

- *Wireline perf-and-plug methods* offer flexibility and precise placement of fractures but are time-consuming and can involve equipment failures. The location of the fracture stimulation along the length of a borehole is set by inserting a composite plug at the bottom of each zone to be fractured. A set of perforating guns is run down the wellbore on wireline to make the perforations. Following the fracturing treatment, the composite plugs

are drilled out generally with coiled tubing.

- *Mechanical sliding sleeve completions* are faster, less costly and require minimal or no intervention. This technique involves the mechanical actuation of a completion tool that opens ports through which wells can be hydraulically fractured. This can be achieved by hydraulically or mechanically means, by dropping one or more balls into the fluid flow. The balls block a narrowing in the completion tool, letting fluid pressure build to a level that opens the sleeve.
- *Coiled-tubing processes* deliver fast, pinpoint stimulation methods that can be tailored for each interval along the horizontal wellbore. A specialised connection along with jointed pipe and coiled tubing enables longer length horizontals to be drilled, completed. This process can provide greater stimulated reservoir volume that usually correlates with improved production.

- *Ball-sealer processes* do not require shutdown of pumping operations. As each fracturing treatment is completed, ball sealers are pumped to temporarily plug the open perforations. When the treatment pressure rises to indicate the perforations are effectively plugged, the next interval is perforated and treated.

### Continuing development

While great strides have been made in shale gas extraction and production technology, it is an arena that continues to improve. The technology is advancing through the integration of individual scientific disciplines in the areas of productivity, economics and environmental sustainability.

*Glenda Wylie is Technical Marketing Director at Halliburton ([www.halliburton.com](http://www.halliburton.com)) where she focuses primarily on unconventional hydrocarbons.*

### Workflows used in the shale development life cycle

This overview of the main tasks and workflows involved in analysing a shale play throughout its entire life cycle demonstrates how much analysis and research is required before hydraulic fracturing can take place. In addition, ongoing analysis is important during a well's life cycle and afterwards so that lessons can be learned for future developments.

- Collect and review existing outcrop, field and basin studies; well logs, cores, drill cuttings and well histories
- Run and interpret 3D seismic surveys
- Acquire core and log data
- Perform laboratory core-evaluation tests
- Develop log-based petrophysical model
- Calibrate the log model using core and formation analysis data
- Assure cementing design and fluids are compatible with formation

- Design initial completion programme; select perforation and completion intervals
- Select fracture fluid and conductivity enhancer.
- Select proppant: type, size, concentration and pumping schedule
- Perform diagnostic fracture injection tests to determine formation properties and calibrate the log model
- Optimise fracture treatment design
- Perform fracture stage treatments
- Perform post-fracture diagnostics including microseismic mapping analysis and tracer scans
- Use results to optimise fracture design for future wells
- Run production-log surveys at fixed intervals and analyse the results
- Use results to optimise fracture design for future wells



# Shale gas around the world

By Georgia Lewis

The success of the USA in producing shale gas has spurred other countries to look at exploiting their shale gas resources.

While the USA has the world's most highly developed shale gas sector, it is China which has the greatest potential. According to the US Energy Information Administration (EIA) 2011 study, China's technically recoverable shale gas resources are 36 tcm compared to 24 tcm in the USA. The EIA study



Algeria is Africa's largest gas producer.

then ranks Argentina, Mexico, South Africa and Canada. Whether shale gas is developed to achieve domestic energy security, for export or both, it is clear that the sector has a strong future. Separate articles in this guide look at unconventional gas developments in China and Canada; here we look at what some other countries are doing.

## Algeria

Algeria is Africa's largest gas producer and a major exporter, and is looking to build on its successful conventional gas business by developing the unconventional sector. National oil company (NOC) Sonatrach has been evaluating tight gas production at existing fields with partners BP and Statoil, and is now keen to develop shale gas. It expects to drill its first appraisal well by the end of 2012.

Estimates of shale gas-in-place in Algeria range from 95 to 112 tcm. However, only a small proportion of this will be technically recoverable – the EIA's study put it at 6.5 tcm. Sonatrach says the best zones for shale gas exploration are the western parts of the Illizi, Ahnet-Gourara and Bechar basins.

Amendments to Algeria's oil and gas laws were made in 2006 with a view to encouraging more exploration and, in 2012, the government has again looked to revise these laws to encourage foreign investment in shale gas with fiscal incentives on offer. Sonatrach signed a cooperation agreement with Eni in 2011 and has been talking to a number of other international companies including ExxonMobil and Royal Dutch Shell.

## North Africa

Algeria's neighbours in North Africa – Libya, Morocco and Tunisia – have similar geological characteristics. Indeed, the Ghadames Basin traverses eastern Algeria, southern Tunisia and north-western Libya and contains two major organic-rich shale formations. Libya also has the Sirt Basin in its northern-central region. According



Argentina already produces tight gas and is now seeking to develop shale gas.

to the EIA study, Libya has the highest estimated technically recoverable shale gas resources of 8.2 tcm, while those of Morocco and Tunisia are smaller – less than 1 tcm each.

The Office National des Hydrocarbures et des Mines (ONHYM) is Morocco's national agency for overseeing oil and gas development. As regards unconventional resources, appraisal of oil shale deposits in Tarfaya and Timahdit is underway and it is hoped that the shale gas sector can enjoy similar development in the years ahead.

Tunisia's NOC, Entreprise Tunisienne d'Activités Pétrolières (ETAP), has highlighted the Lower Silurian Tannezuit shale formation in the Ghadames Basin as the most interesting unconventional play.

### **Argentina**

Since 2009, Argentina has been a net gas importer and the government is promoting unconventional gas development to meet growing demand from national resources. Argentina already produces

tight gas and is now seeking to develop shale gas. The country's technically recoverable shale gas resources were estimated at 22 tcm in the EIA study; official Argentine figures have not been disclosed yet.

Companies including YPF, American Petrogas, Apache, Pluspetrol and Tecpetrol are drilling pilot wells. YPF is the country's major player in the petroleum industry and the government has taken control of the company by nationalising the bulk of Repsol's stake.

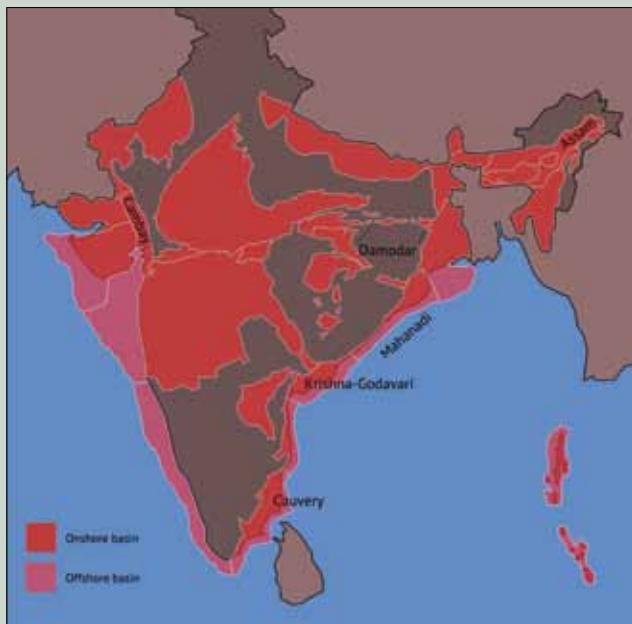
The Neuquén Basin is the focus of interest with the areas targeted for shale development including Vaca Muerta, Los Molles, Agrio and Mulichinco. The Vaca Muerta play is considered to be similar to the Eagle Ford and Haynesville plays in the USA and, as such, it is expected that current North American interest in this region will result in knowledge-sharing as well as investment.

Plans were announced in July 2012 for a potassium mine in Mendoza in the western region





### Indian basins with good shale gas prospects.



of Argentina, built by Brazilian mining company Vale, and involving the development of shale gas as an energy source.

#### Brazil

With its rapidly growing economy and gas import dependency, Brazil has a clear incentive to develop shale gas. The country's technically recoverable shale gas resources are estimated by the EIA at 6.4 tcm.

In particular, the Minas Gerais region could prove to be an important area after Cemig, a power utility controlled by Minas Gerais state, reported promising results from shale exploration in two wells. Three more wells are planned and Cemig is now seeking partners to further the development of shale gas in the region. The population of Minas Gerais is 19.6 million people and it is

Brazil's third-largest economy out of 27 states, after São Paulo and Rio de Janeiro. Blocks in this industrial hotspot are also held by NOC, Petrobras, and Royal Dutch Shell.

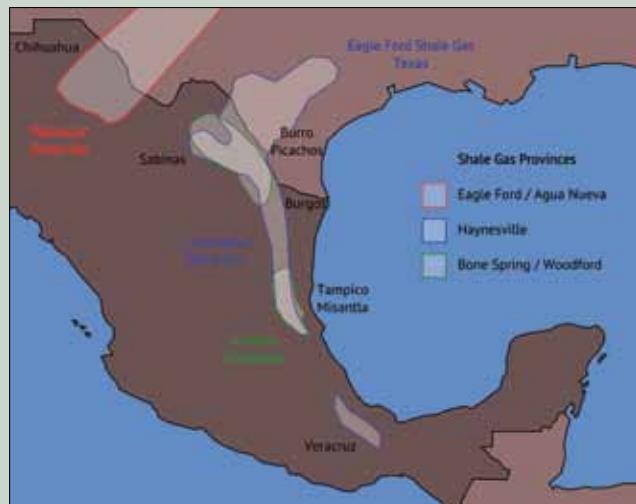
#### Colombia

Colombia is South America's third largest oil producer and is keen to increase gas production by capitalising on its shale gas resources. These are estimated by the country's Agencia Nacional de Hidrocarburos (ANH) at 1 tcm.

Royal Dutch Shell, ExxonMobil, Chevron and Nexen are among the companies who have shown interest in developing Colombia's shale gas plays. Nexen has already commenced drilling with a programme that started in late 2011 involving four wells on two of the four blocks the company has been exploring.



### Mexico's potential shale resources.



ANH plans to auction 109 oil and gas blocks for exploration and development rights, of which 30 are unconventional gas. Contracts for successful bidders are expected to be signed at the end of 2012. Under these contracts, the unconventional gas exploration period will be eight years, split into two three-year phases followed by a two-year phase.

ANH is offering incentives to companies keen to explore unconventional gas blocks with a 40% discount on royalties. It is expected that Colombia's gas production will continue to outpace consumption, leaving plenty of room for exports. The bulk of these exports will continue to flow east to Venezuela via a pipeline, although other regional markets such as Panama are considered to have great potential.

#### India

Debasish Das of Hindustan Petroleum (HPCL) told delegates to the 20th World Petroleum Congress in 2011 that India's most promising shale gas prospects are the Mesozoic shales of the Cauvery,

Krishna-Godavari and Mahanadi basins, and the Tertiary shales of the Cambay, Krishna-Godavari and Assam basins. The country's technically recoverable shale gas resources are estimated to be 2.8 tcm.

The Directorate General of Hydrocarbons and the Ministry of Petroleum & Natural Gas are working on the changes required in the exploration laws for shale gas to be produced, because current exploration licences do not include unconventional sources. However, companies can undertake preliminary investigations and, in January 2011, Oil & Natural Gas Corporation (ONGC) tapped the country's first shale gas at Durgapur in the Damodar Basin.

The Indian authorities are planning the first auction of shale gas blocks by the end of 2013.

#### Mexico

Mexico's national oil company, Pemex has identified five geological provinces with shale gas potential: Chihuahua, Sabinas-Burro-Picachos,



Poland's first successful shale gas appraisal well – Lubocino-1 – was drilled by PGNiG.

Burgos, Tampico-Misantla and Veracruz. Overall, it estimates the country's shale gas resources at up to 13 tcm and has started a test drilling programme. The first gas was produced from the Emergente-1 well in the state of Coahuila in 2011, and Pemex plans to drill another 175 wells by 2015.

However, there are challenges facing the nascent Mexican shale gas industry such as developing national regulations and water management. Mexico's most promising shale is found in Coahuila, but it is also one of the country's driest

areas and there will be competing demands for the water needed for large-scale hydraulic fracturing.

### Poland

In Europe, Poland has been the focus of attention for shale gas exploration, although a recent study by the Polish Geological Institute puts recoverable resources at around 1 tcm compared to 5 tcm previously estimated by the EIA.

Speaking at the 20th World Petroleum Congress in 2011, Dr Jerzy Stopa of AGH University of Science & Technology highlighted how exploiting this resource would be a boon for Poland's economy and energy security.

There are three major shale gas basins in Poland, the Baltic Basin, the Lublin Basin and the Podlasie depression, and 17 companies are involved in prospecting. The four companies with the biggest interests in Polish shale gas prospecting are the Polish Oil and Gas Company (PGNiG), Marathon Oil Petrolinvest and 3Legs Resources.

In Wejherowo, a licence area in north-west Poland, Lubocino-1, the first successful appraisal well for shale gas has been drilled by PGNiG. The results are being evaluated and are considered promising. There are now plans to drill the Lubocino 2H horizontal well and start pilot production in the second half of 2013 with commercial production in 2014.

### South Africa

The EIA study estimated South Africa's shale gas resources at 13.7 tcm. However, plans for developing the shale gas industry were put on hold in April 2011 when the government introduced a moratorium in response to environmental concerns about operations in the Karoo region. The Department of Mineral Resources is due to make recommendations soon about the way forward, and the country's growing demand for energy will be an important consideration. A developed shale gas industry in South Africa also has the potential



to be part of a regional energy solution with neighbouring countries.

Companies with shale gas production ambitions in South Africa include Royal Dutch Shell, Falcon Oil & Gas and Bundu Oil & Gas.

### Conclusions

While the US leads the way in terms of commercialisation and development of the shale gas sector, other countries are clearly keen to be part of the shale gas revolution. In some countries, such as Poland, significant exploration has already taken place, while for other countries, such as India, the resources are certainly present but much needs to be done in terms of infrastructure and investment before full exploitation is viable.

Across the world, there are similar challenges faced by countries as they seek to develop their nascent shale gas sectors – environmental concerns need to be addressed, technology needs to advance so that hard-to-access gas resources can be safely reached, adequate investment needs to be raised and regulation needs to be in place to ensure shale gas is developed safely, economically and with widespread benefits for all stakeholders. The world is facing an exciting and interesting time in the arena of shale gas development with improved energy security and economic prosperity becoming a real possibility for many countries.

*Georgia Lewis is the Deputy Editor of International Systems and Communications.*



South Africa's Karoo region has major shale potential but environmental safeguards need to be agreed.



# Shale gas water management

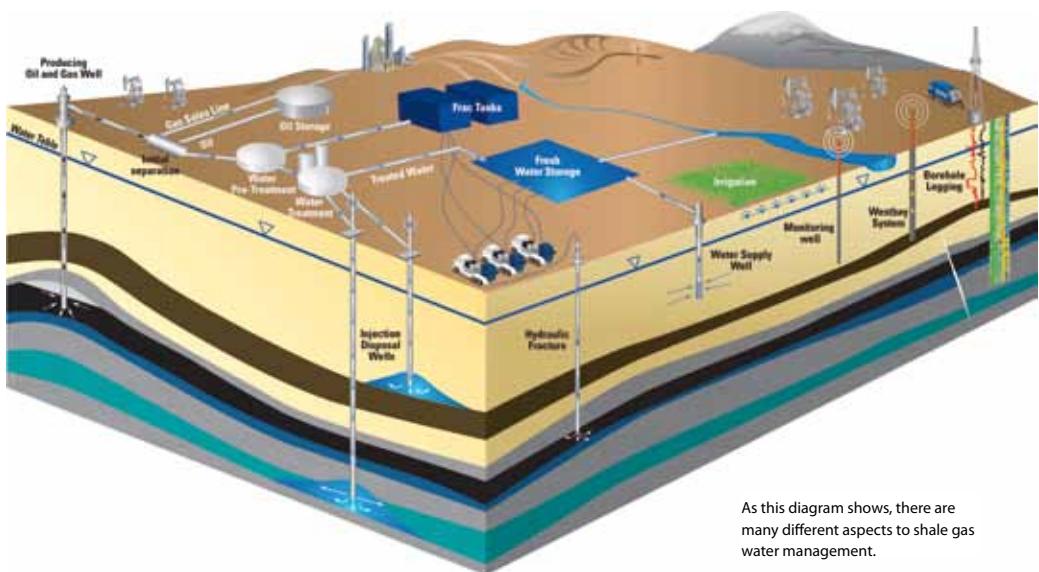
By Brent Halldorson and Patrick Horner

The North American industry is setting high standards in managing costs and logistics in water management for shale gas producers globally.

Hydraulic fracturing, or “fracking”, is the most effective technique for extracting shale gas. This involves injecting fresh water underground to fracture the formation, increasing permeability and thus gas flow. As such large volumes are involved (60,000 to 140,000+ barrels), effective water management practices are essential. After a frac is

completed, a large portion of the frac fluid returns to the surface as flowback water. This contains high concentrations of dissolved salts, frac chemicals and formation minerals. Effective implementation of water recycling technologies and treating flowback for re-use as frac fluid reduces the impact of many issues associated with shale gas water management including cost, truck traffic, water availability and disposal availability.

The treatment and handling of flowback is complex. Considerations include: salinity, residual frac chemicals (polymers), hydrogen sulphide ( $H_2S$ ), naturally occurring radioactive material, carbonate scales, iron scales and sulphate scales. The overall water management strategy involves collating information such as water sourcing and disposal costs and logistics, examining formation geology and how that impacts flowback water chemistry, and frac fluid compatibility. Other considerations include the regulatory environment, and the availability of cost-effective technology. Furthermore, flowback water is highly variable and its composition is affected by factors such as subsurface geology, the length of time



As this diagram shows, there are many different aspects to shale gas water management.



the water has been in contact with the formation and the chemical composition of the frac water.

The role of water in fracking and its environmental impact has become a contentious public issue and an important environmental concern for operators and the entire industry. By making the recovery of and beneficial re-use of a portion of the brackish water efficient and cost-effective, an environmental liability can become an asset.

### Flowback overview

Flowback is defined as the return of the fluid to the surface after a completion of a frac job. The quality and quantity of the flowback depends on a number of factors: the quality of initial source water used to make the frac fluid, the frac fluid chemical programme, formation geology, contact of the frac fluid with formation waters, and the time the fluid spends underground and on the surface after the frac. The source water makes up more than 99% of the total frac fluid and, as a result, impacts the quality of the flowback.

Components of source water such as dissolved salts, minerals, organic material and/or bacteria will either return to the surface in the flowback or potentially react with the frac or formation chemistry.

Chemical additives, usually polyacrylamide friction reducers, are another important component of flowback. The type and amount of chemical additives varies depending on the geology and completion strategy. The chemical additives used during fracking are designed to remain dissolved in the frac fluid under different conditions and, as a result, return to the surface in the flowback. Formation geology is another factor impacting flowback quality – shale formations are generally a composite matrix of carbonate shale and salt crystals.

During fracking, the frac fluid comes in contact with the formation geology and dissolves salt and formation minerals, returning these to the surface in the flowback. The amount of dissolved material

in the flowback is a result of the formation geology and time spent underground. The longer the flowback remains in the formation, the more contact it has with formation geology and, as such, the more dissolved solids it will contain. The solubility of the formation is another factor impacting the amount of dissolved solids in the flowback.

As discussed, the time spent underground increases the level of dissolved solids. After the flowback returns to the surface, time is also an issue as bacteria start growing, resulting in the breakdown of organic material and, if sulphates are present, can cause the formation of hydrogen sulphide. H<sub>2</sub>S poses a health risk to the industry and the public so bacteria control is a major concern.

When the flowback returns to the surface it contains dissolved salts, dissolved minerals, residual frac chemicals, frac chemical degradation products, bacteria, suspended solids, normally occurring radioactive material, volatile organics, hydrocarbons and ammonia. The concentration of these materials varies from play to play, from well to well within the same play and from day to day on the same well.

Because of these variables and ever-changing composition, flowback water is challenging to treat.

### How water can be fouled by fracking

#### ● **Suspended solid accumulation**

Residual suspended solids not removed in the pre-treatment system can settle at low velocity points or deposit on surfaces. Suspended material can also precipitate (form as a solid) with increases in temperature and concentration.

#### ● **Organic fouling**

Organic material in the feed water can precipitate with an increase in concentration and/or temperature. This material can deposit on surfaces and/or coagulate smaller suspended solid particles that wouldn't otherwise be a problem.



Submersible pumps in one of the Tsea Lakes, Horn River Basin, Canada supply water for shale gas fracking operations in the area.

#### ● **Calcium carbonate scale**

Sufficient concentrations of calcium and carbonate can cause  $\text{CaCO}_3$  scale. The potential for  $\text{CaCO}_3$  scale formation increases as temperature and concentration increase. Carbonate scales are generally white, chalky and acid-soluble.

#### ● **Sulphate scale**

The presences of sulphate and barium, strontium, and/or calcium can cause  $\text{BaSO}_4$ ,  $\text{SrSO}_4$  and/or  $\text{CaSO}_4$  scale. The potential for sulphate scales to form increases with concentration. Sulphate scales are generally white, hard or glasslike, and acid-insoluble.

#### ● **Silica scale/deposition**

Silica can form solids in four ways: surface deposition (depositing directly to surfaces), bulk precipitation (particles collide to form larger particles), complexing (metal hydroxides bind with silica to form particles) and silica

polymerisation (silica molecules combine to form long strings). As silica fouling is impacted by metal hydroxide precipitation, its potential increases with temperature, concentration, and is highly impacted by pH. Silica deposits range from quartz-like hard scale to slimy deposits (generally white, grey, green or brown – the colour can vary depending on the metal hydroxides involved).

#### **Water management decision factors**

An effective shale gas water management strategy is a balancing act. Public safety is of paramount importance. There is no evidence to suggest that shale gas fracking poses a risk to drinking water or contaminates surface water, assuming the well is properly constructed and cased. But the handling risks include spillage, potential vehicle accidents and the possible release of flowback into surface water as the result.





Reducing truck traffic associated with water hauling reduces the risk of accidents, the release of flowback to the environment and the impact on surrounding communities. Heavy truck traffic can damage roads often not designed for heavy hauling, and create congestion, pollution and dust. Strategies that minimise traffic often improve the willingness of communities to cooperate with energy producers.

The regulatory environment must be carefully considered by energy companies. Regulations often dictate how much water can be stored on the surface, storage containment, types of pipelines allowed and rules around discharge and disposal of flowback and produced water.

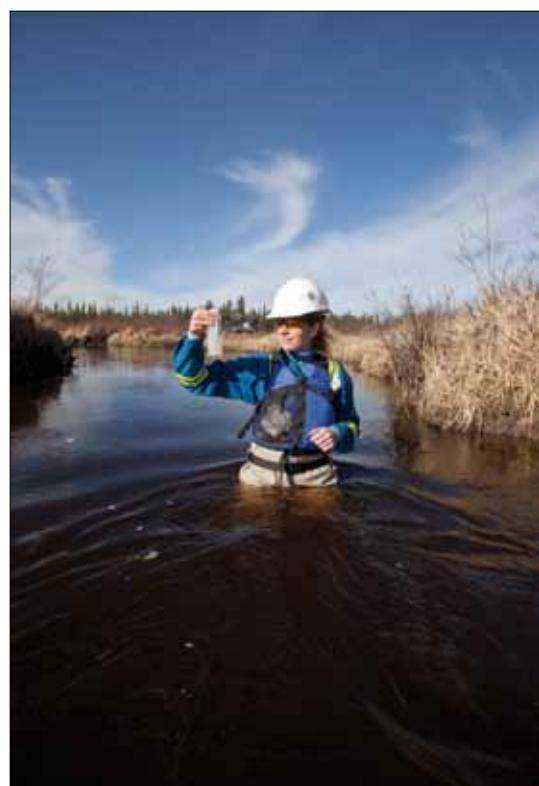
Environmental liability is another concern. Spill-related incidents related to the transportation and storage of flowback can be costly. Reducing the risk of spills is critical. Clean-up of salt water spills, specifically in environmentally sensitive areas or near watersheds, is expensive. A management plan that reduces the potential for spills and releases helps reduce long-term costs.

Shared long-term access to source water and disposal is also critical. Water and disposal sources often have sufficient supply in the early stages of field development but demand increases as activity increases – demand can exceed the supply. Producers need to look at long-term supply with respect to the collective demand of all local water users. Water supply issues are challenging in areas where competition for water sources is high such as arid climates, urban areas, or industrial and agricultural regions. Industrial or municipal waste water sources can often be used as source water with minimal treatment. Facilities accepting flowback can be designed to accept other industrial waste, reducing overall treatment costs and creating more make-up water for re-use.

The quality of water used to develop the frac fluid and how this impacts well production is a critical factor in developing a water management

strategy. Multivalent ions and chlorides in the water can limit friction reducer effectiveness and drive up horsepower costs for frac pumping. The type and dose of friction reducer can be adjusted to accommodate for higher total dissolved solids (TDS) water but at added cost.

The scaling tendency of source water, usually caused by poor compatibility of source water with formation water and poor compatibility of re-use water, is another consideration. Scaling can occur within the formation, potentially creating reduced permeability and ultimately reduced gas production. Scaling can also damage equipment casing, reducing functionality.



Water quality is sampled in the creeks emptying out of the Tsea Lakes in the Dilly Creek area as part of Nexen's water monitoring programme.



The safe storage and transportation of waste water from fracking operations is important on environmental and community engagement terms.

Bacteria in frac fluid can cause formation bio-fouling, reducing permeability and gas production. The presence of sulphate-reducing bacteria (SBR) can form H<sub>2</sub>S, making the well sour, creating safety issues and increasing costs. Permeability and gas production can be reduced by metals in water, specifically iron, which can oxidise and form deposits, and by suspended solids in the frac fluid such as sand, silt, clays and scale particles. As shale gas formations are a composite of carbonate shales and salt crystals, the use of low TDS frac fluid will increase dissolution of formation salts, potentially increasing reservoir permeability and gas production. Understanding the relationship between frac fluid water quality and long-term well production is crucial when conducting a cost/benefit analysis of water treatment technologies for a good water management plan.

#### Treatment options

There are three types of flowback management strategies: disposal, re-use and recycling.

In disposal scenarios, fresh water is transported to site from available sources and flowback is transported to an injection well for disposal. The disposal scenario is often chosen if there is an inexpensive, abundant supply of fresh water nearby and nearby injection wells can handle the flowback disposal volumes. However, as fresh water availability decreases, costs increase and/or distance to injection wells for disposal increases, making the disposal scenario less appealing.

Re-use involves primary treatment of flowback to remove suspended solids and soluble organics, then blending the treated water with fresh water to generate frac fluid for a new well. Re-use reduces the amount of fresh water required and eliminates the need for disposal if all flowback can



be treated and re-used. Re-use is often the least expensive strategy.

Recycling involves high-level treatment of flowback water to produce a fresh water quality product. The recycled water is blended with make-up water from freshwater sources to generate a low-TDS frac fluid. Recycling is used when fresh water costs are high, a high quality, low-TDS frac fluid is desired, or when other logistics (such as fracking schedules) do not permit re-use. Producers that transfer frac fluid via temporary above-ground pipelines ("fastlines") may recycle to minimise potential environmental liability from spills or fastline ruptures.

During an active fracking programme, natural gas producers are faced with inconsistent flowback water containing total suspended solids (TSS) ranging from 100 to 3,000 ppm and total dissolved solids (TDS or salts) ranging from 5,000 to 200,000 ppm.

A clarifier can pump flowback from the customer's source, such as a frac tank or pit, into the unit using an adjustable chemical system. Solids settle to the bottom where they are collected and dewatered. Clean brine is then pumped out of the system to a designated location. Mobile clarification units allow shale gas producers to recycle water on demand from different locations.

A major benefit of re-using water is that it reduces the financial, social and environmental costs associated with water transportation. Migration of the water treatment process near the wellhead is becoming an industry best practice and aligns closely with the risk management policies of many stakeholders.

Evaporation technology can be used to recycle contaminated water cost-effectively. For water contaminated by dissolved salts, evaporation involves boiling a solution so that contaminants remain in the liquid phase, while pure water vapour evaporates and can be condensed into distilled water.

Mechanical vapour recompression (MVR) evaporation is a leading means of treating waste water. It differs from conventional evaporation in that a compressor is used to input the energy required to generate steam rather than a heat source such as a boiler. High energy efficiency is achieved by utilising the latent heat of the condensing steam as the primary energy source for boiling the waste-water. Conventional distillation requires 1,000 Btu/lb of steam, while MVR evaporation requires less energy to maintain boiling, theoretically as low as 25 Btu/lb of steam produced.

For re-use or recycling technology to succeed, the cost of treatment has to be less than the cost of disposal.

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With large amounts of water needing to be delivered to the well head, effective water management is vital in terms of running costs and environmental impact.



# Tight gas

By Roberto F. Aguilera, Thomas G. Harding and Roberto Aguilera

Natural gas production from tight gas formations: a global perspective.

The potential endowment in tight gas formations rivals the endowment from conventional gas accumulations and could help meet the world's burgeoning demand for energy, which is forecast to increase 60% by 2035. However, the economic, technical and environmental challenges involved in the commercialisation of this vast and largely untapped resource are many and overcoming them demands a multi-disciplinary approach involving geoscience, engineering and economics.

Tight gas sands, so called because the reservoir rock is usually sandstone, have been defined in different ways by different organisations but a unique definition has proven elusive. The original definition dates back to the US Gas Policy Act of 1978 that required in-situ gas permeability to be equal to or less than 0.1 md for the reservoir to qualify as a tight gas formation. At present, this is probably the most commonly accepted definition.

An alternative definition indicates that tight gas is "contained in low-permeability sandstone and carbonate reservoirs where reservoir stimulation or specialised drilling technology is required to establish economic flow rates and recovery".

Regardless of the preferred definition, natural fractures are extremely important to unconventional gas reservoirs, and the assessment and characterisation of these fractures (and other determinants of permeability) in unconventional plays is a high priority R&D need.

## Development

The world's largest producer of tight gas is the USA. Volume production started in the 1960s, but development was spurred by R&D and tax breaks in the 1980s. In 1970, tight gas accounted for 4.7% of total US gas production; it reached 11% in 1990 and 26% in 2010 with production of 157 bcm.

The US is followed by Canada, where a precise breakdown between tight gas and shale gas pro-

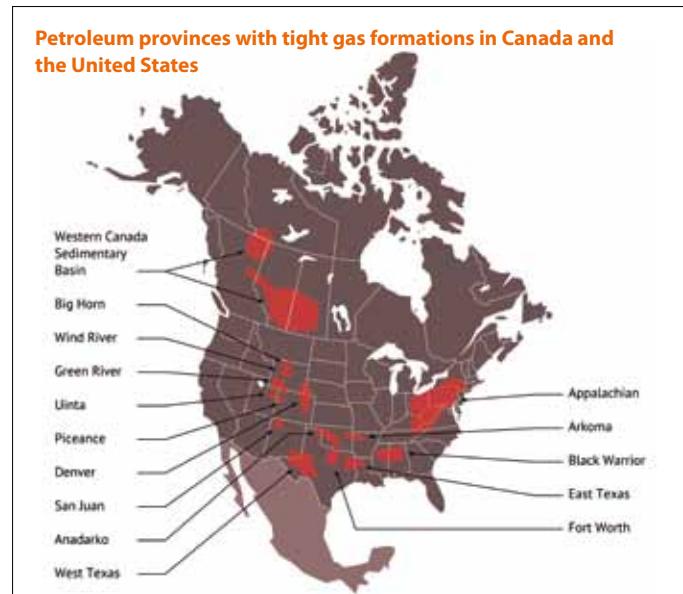


A drilling rig in the Greater Natural Buttes tight gas play of eastern Utah, USA.





Figure 1.



duction is not available, and China which produced 16 bcm in 2010 (16.9% of total gas production). There is some tight gas production from the North Sea fields in Europe, while Argentina started tight gas production in 2009.

These developments can mostly be attributed to technological innovations in horizontal drilling and hydraulic fracturing or fracking. As with shale gas, this technique is almost always necessary to generate commercial flow rates. However, tight gas reservoirs usually have higher recovery rates than shale gas deposits. Environmental concerns have been raised by some commentators about the unsustainable use of freshwater and contamination of aquifers during the fracking process. However, advances have been made in the treatment of waste water so that it may be reused, thus alleviating the drain on freshwater supplies. Also, advances in well design and casing cementing prevent the leakage of water or methane from the well.

The technically recoverable tight gas estimated presently (12.9 tcm) in the US lower 48 states and

in the Western Canada Sedimentary Basin is stored in 15 petroleum provinces (see Figure 1). The conventional gas endowment for the same North American petroleum provinces is estimated at 13.4 tcm. Thus tight gas endowment rivals that of conventional gas. China's tight gas resources have been estimated at 16 tcm by PetroChina.

In addition to the current producers, there are ongoing efforts to explore for or initiate development of tight gas reservoirs in many other countries including Australia, Algeria, Brazil, Egypt, Oman, Venezuela and various European countries. These are incipient efforts, but they should prove fruitful in the long run.

### Geologic setting

The main geologic school of thought at present indicates that tight gas is found in "basin-centre" or "continuous gas" accumulations such as the Deep Basin of the Western Canadian Sedimentary Basin. There is an opposing point of view, however, indicating that most tight gas fields occur in low-





Tight gas production in Argentina began in 2009 from the Aguada Pichana field in the Neuquén Basin.

permeability reservoirs in conventional structural, stratigraphic or combination traps that are usually referred to as "sweet spots".

### Conventional gas as a proxy to tight gas reservoirs

Exploration and production of tight gas sands have come of age in the US, are coming of age in Canada and will come of age in the rest of the world within the coming years. We use data and experience from the US and Canada – and more limited information from other countries – to convey the message that knowledge of conventional gas reservoirs can be used as a proxy for the evaluation of unconventional tight gas traps. The proxy is supported by (a) geology, (b) discovery process analysis, (c) North American comparisons between endowments of conventional and tight gas, and (d) a gas resource pyramid.

### Geology

Amos Salvador said in an American Association of Petroleum Geologists' study that "tight gas reservoirs should occur in all or nearly all petroleum

provinces of the world". A similar assessment is provided by H.H. Rogner who indicates that "tight gas reservoirs are present in almost every petroleum province and occur at very shallow to very deep depth". This assessment is certainly borne out in the Deep Basin of Canada where sweet spots were recognised in tight gas sands in the early 1970s. Similar conditions are also observed in shallow formations in southern Alberta and Saskatchewan where infill drilling and application of new technologies in the late 1990s led to new discoveries and additional tight gas production.

The descriptions by Salvador and Rogner are significant as there are 937 recognised petroleum provinces throughout the world. On the other hand, the technically recoverable tight gas recognised at this time in the US lower 48 states (9.9 tcm) is stored in only 14 petroleum provinces. In Canada, the technically recoverable tight gas (3 tcm) is stored in only one province. The comparison begs the question – how much additional tight gas might be stored in the remaining 922 petroleum provinces? There is geologic evidence that tight gas formations are generally found in older rocks within the same

petroleum provinces where conventional gas is produced. This has been observed, for example, in the Deep Basin of Canada, the Wamsutter field in Wyoming of the US, the In Amenas and In Salah fields in Algeria and the Khazzan and Makarem fields in Oman. These observations lend credence to the notion that where there is conventional gas, there is also tight gas.

#### **Discovery process analysis**

The discovery process indicates that the largest fields with the best rock properties are put into production first. As we reported during the 19th World Petroleum Congress in 2008, the process can be simulated with a variable shape distribution (VSD) model.

The VSD model, which was validated by successfully comparing calculated and actual recoverable hydrocarbon volumes published by the US Geological Survey (USGS), provides better fits than models based on power law or fractal distributions. An example of the VSD results, for conventional gas, is presented in *Figure 2*.

The lower curve (black diamonds) corresponds to 136 petroleum provinces, excluding the United



The gas processing plant at the Changbei tight gas field in China's Ordos Basin.

States. The corresponding gas endowment of 288 tcm is estimated by the USGS World Petroleum Assessment (2000). The endowment calculated by the VSD model (red continuous line) for the same 136 provinces is 289 tcm. When the petroleum provinces of the United States are included, the USGS estimates a gas endowment of 330 tcm in a

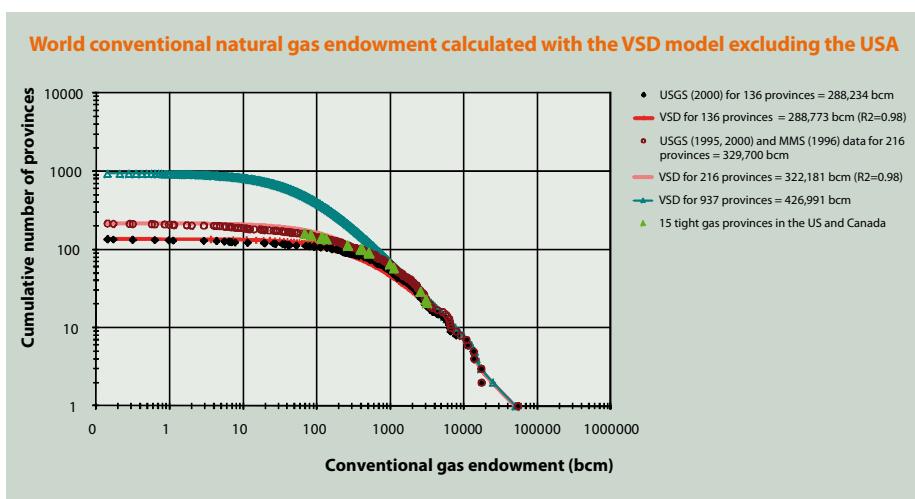


Figure 2.

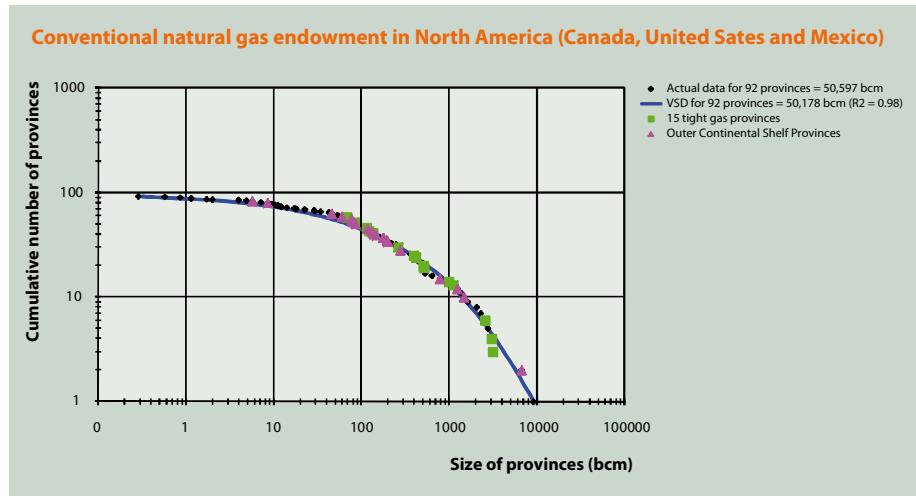


Figure 3.

total of 216 provinces. This is represented by the middle curve (open circles) and is similar to the 322 tcm calculated by the VSD for the same 216 provinces (pink continuous line). Note that these volumes do not include reserve growth or unconventional gas.

Next, the VSD is extended out of sample to generate an estimate of the conventional gas endowment in the 937 petroleum provinces of the world. This application is important because 528 out of those 937 provinces had not been evaluated previously. The top curve of *Figure 2* corresponds to 937 provinces where each data point represents a province and the summation of all the points gives a total conventional gas endowment of 427 tcm for the world. The indication that there are large volumes of tight gas globally comes from the observation that, where there is conventional gas there is also tight gas in older rocks.

#### North America gas comparison

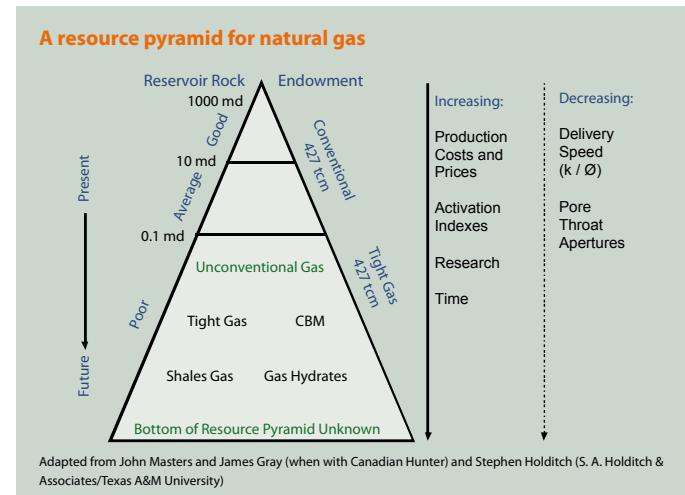
Conventional gas endowments for 92 North American petroleum provinces are plotted in *Figure 3*. The actual endowment is equal to 51 tcm. The VSD-calculated endowment is 50 tcm, a very

good comparison. The graph also highlights data for 14 provinces in the US and one in Canada where tight gas, in addition to conventional gas, has been found and tested. Combined US and Canada original gas-in-place in tight gas formations is equal to 184 tcm. A conservative average recovery factor of 7% leads to a technically recoverable volume of 12.9 tcm of tight gas.

The conventional gas endowment estimates from USGS publications were also plotted for the 15 petroleum provinces, with the VSD model closely reproducing the USGS data: the actual conventional gas endowment volume for the US and Canada is equal to 13.4 tcm, while the VSD model gives an endowment of 13.6 tcm. These volumes compare with 12.9 tcm of technically recoverable tight gas in the US and Canada. Given the volumes are of the same order of magnitude, it can be derived that, for the US and Canada, the technically recoverable volume of tight gas rivals that of the conventional gas endowment. We conclude that in the US and Canada there is a significant potential endowment in tight gas formations that rivals the endowment from conventional gas accumulations.



Figure 4.



As discussed earlier, tight gas reservoirs are present in all or nearly all petroleum provinces of the world and occur at very shallow to very great depths. Given the work being performed in several countries to unlock this resource, we extend the North American findings to other petroleum provinces around the world. Thus, the conventional gas endowment of 424 tcm calculated for 937 petroleum provinces will likely be rivalled by technically recoverable gas from tight formations. This forecast conforms well to Salvador's qualitative assessment in his AAPG study that "although the distribution and magnitude of tight-sand accumulations elsewhere in the world is not well known, it can be said with assurance that large volumes of gas are present in these low-permeability reservoirs".

#### Gas resource pyramid

Various versions of a resource pyramid have proven very useful in illustrating the distribution of resources throughout the world. Figure 4 shows such a pyramid adapted for the case of gas. The upper part of the pyramid shows good reservoir rock with high permeability, large pore throats

and large process or delivery speed. In the middle of the pyramid we have average reservoir rock. However, the gas volumes are larger than in the upper part of the pyramid. All characteristics mentioned above are average. We do not know where the bottom of the pyramid lies (i.e. the lower limit of reservoir producibility). What we do know, on the positive side, is that the volumes in the lower part of the pyramid are very large. Tight gas found in this region has low permeability and thus the exploitation requires a larger activation index, improved technologies, higher gas prices and perhaps government incentives to make these resources attractive to operating companies. All of these requirements apply to the 427 tcm of technically recoverable tight gas presented earlier.

Although the production costs of unconventional gas are typically higher than conventional gas costs, improvements in technology have reduced the costs of producing unconventionals (including tight gas) to the point where, in some instances, these costs are lower than those of conventional gas. Nevertheless, recent gas market prices in North America have been low enough to slow the development of unconventional gas.



## Growing energy demand

The UN expects the world's population to reach 8.5 billion in 2035 (it passed the 7 billion mark in October 2011), and we estimate that global primary energy consumption will grow to 20,000 million tonnes of oil equivalent by 2035 (compared to 12,275 mtoe in 2011). The good news is that this forecast would easily be met with the current endowment of conventional gas and technically recoverable tight gas. In addition, there are significant economic and environmental advantages to the use of gas for electrical power generation. In the longer term, there is also potential for natural gas vehicles and gas-to-liquids conversion. Advances in gas transportation technologies (e.g. liquefied natural gas) will also aid in globalising gas markets and thus increase the share of gas in the future energy mix.

The economic and technical challenges involved in commercialisation of this vast resource are many and overcoming them will depend on a multi-disciplinary approach.

In our view, the cornerstone of the whole project is the proper geologic understanding of tight gas sands. Then comes formation evaluation by petrophysics and well testing. The next segment is associated with the reservoir; how to access it, how to complete wells in it and how to

stimulate the wells. The key ideas are intercepting natural fractures, not damaging the natural fractures and developing the correct, environmentally-benign hydraulic fracturing procedure. The reservoir engineering segment includes: an estimation of the resource base in naturally fractured tight gas sands; volumetric, material balance and simulation evaluations; and determinations of the optimum well spacing. These are all areas of ongoing research by the GFREE team at the University of Calgary (see box).

## Future potential

There is a significant potential endowment in tight gas formations that rivals the endowment from conventional gas accumulations. Thus, tight gas formations have the potential to contribute a significant volume of the gas that is needed to satisfy global primary energy consumption that is estimated to reach nearly 20,000 mtoe by 2035. Technological innovations will also have to be supplemented by environmental and social considerations. However, concerns over climate change should continue to provide impetus for usage of the cleanest fossil fuel of all: natural gas.

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## GFREE

GFREE is a target-oriented research programme developed by the Schulich School of Engineering, University of Calgary, Canada, which aims to increase natural gas rates and recoveries from low permeability formations. The programme uses an integrated approach that includes geoscience (G), formation evaluation (F), reservoir drilling, completion and stimulation (R), reservoir engineering (RE), and economics and externalities (EE).



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# Coal-bed methane

By Mark Blacklock

The release of methane from deposits of coal was once seen only as a hazard; today this methane is a valuable resource.

The world's coal was formed over millions of years as plant material decomposed and was compressed, in the process generating natural gas which was stored in coal seams. For centuries, this gas was only seen as a hazard which could be deadly for miners. The gas had to be vented from coal mines, giving rise to more recent environmental concerns as methane has a global warming potential some 25 times greater than CO<sub>2</sub>.

Today, coal-bed methane (CBM) – or coal-seam gas as it is known in some countries – accounts for

11.8% of Australian, 9% of US and 5.7% of Canadian gas production, and has the potential to play an important role in the energy mix of many other countries around the world.

CBM is extracted from virgin coal seams; the gas from working mines is known as coal-mine methane (CMM) and that from closed mines as abandoned-mine methane (AMM). CBM can generally be fed into the normal gas transmission and distribution system, whereas CMM and AMM are less pure and their use tends to be restricted to local power and heat generation.

## Extraction

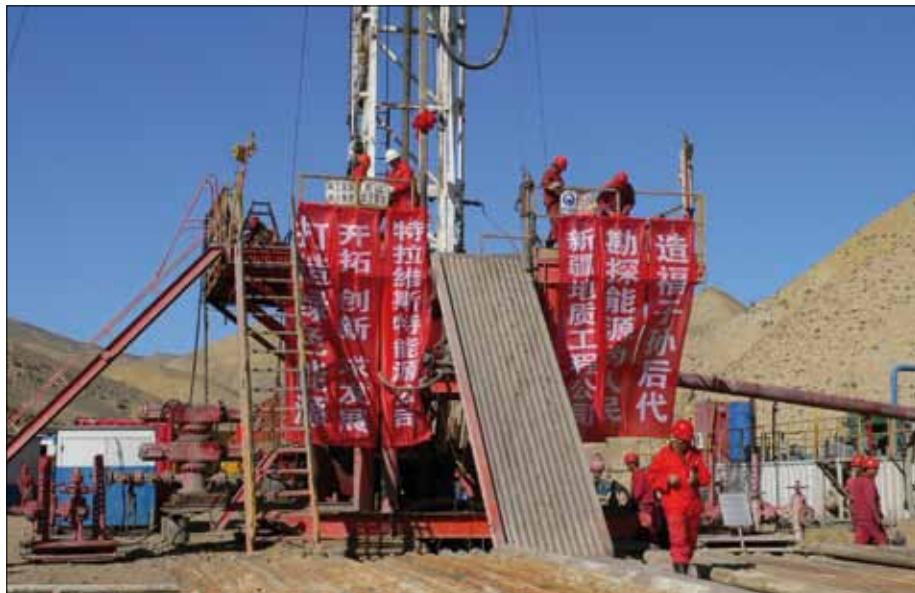
The natural gas generated by coalification is largely methane, although small amounts of nitrogen and carbon dioxide may also be present. The gas adsorbs to the surface of the coal and is held there by the pressure of water which is also present in coal. Depending on the formation, the coal's natural fractures or "cleats" can also contain free gas or water. A cubic metre of coal can contain six or seven times the volume of natural gas that exists in a cubic metre of a conventional sandstone reservoir.

Coal is ranked according its hardness. The lowest-rank coal is soft lignite, followed by bituminous coals and then anthracite. The best prospects for CBM production are mid-ranking bituminous coals with thick seams, high gas content and good permeability.

CBM is extracted by drilling a well, "dewatering" and in some cases stimulation. Dewatering involves pumping water from the coal seam to lower the pressure which causes the gas to desorb and flow via the cleats into the well. The produced water needs to be disposed of by reinjection or treated for use elsewhere, for example to irrigate crops. In some CBM plays with particularly low porosity the well has to be stimulated by hydraulic fracturing or "cavitation" which involves enlarging the original wellbore.



The Condamine power plant in Queensland, Australia is fuelled by CBM.



China is targeting CBM production of up to 10 bcm by 2015 – a CBM well in the Liuhuanggou area of Xinjiang Province.

### North America

CBM production began in the US in the late 1970s with development being spurred in the 1980s by a combination of a research programme and tax credits via the 1980 Crude Oil Windfall Profit Tax Act. The tax credits gave the industry time to develop new technologies that were able to sustain CBM production after the credits expired. They ceased for new wells in 1993, but gas produced from wells drilled before the cut-off date continued to receive credits until the end of 2002.

The first area to be developed was the Black Warrior Basin in Alabama, followed by the San Juan Basin in New Mexico and Colorado. Output was low throughout the 1980s and accelerated in the next decade with the Powder River Basin in Montana and Wyoming becoming particularly productive. In 1990, US CBM production was 5.5 bcm and by 2000 it had reached 39 bcm. The latest figure (for 2010) is 55 bcm with about two-thirds coming from the San Juan and Powder

River Basins. This is 9% of total US gas production and over half of the world's CBM output.

The US Potential Gas Committee estimates the country's CBM resource at 4.5 tcm of which 525 bcm are proved reserves according to the US Energy Information Administration.

Canada is the world's number two CBM producer with just over 8 bcm (*see Unconventional gas in Canada, pages 84-89*). The Canadian Society for Unconventional Resources estimates that the country has a CBM resource of 22.7 tcm with between 1 and 3.6 tcm recoverable.

### Asia-Pacific

China, Australia, India and Indonesia are the biggest coal producers in Asia-Pacific (they rank in the world's top five along with the US) and have the region's greatest CBM potential.

China's Ministry of Land and Resources has estimated the country's CBM resource at 36.8 tcm with about two-thirds in eastern China. Produc-





India's CBM production is currently small but is expected to increase.

tion was 1.57 bcm in 2010 and the target is to reach up to 10 bcm by 2015 and 50 bcm by 2030 (see *Unconventional gas in China*, pages 90-95).

Australia has the region's most developed CBM sector (see *CBM in Australia*, pages 78-82) with confirmed plans to export 35 bcm a year as liquefied natural gas (LNG) and additional projects under evaluation. However, the honours for the first CBM to LNG production went to Indonesia in April 2011, when CBM from Sanga-Sanga in the Kutai Basin in East Kalimantan was supplied to the Bontang LNG plant for export. The country's CBM resource is estimated at 12.8 tcm and is concentrated in the South Sumatra, Barito and Kutai Basins.

India's CBM resource is estimated at 4.6 tcm and the country's first CBM flow came from a well drilled by the Oil and Natural Gas Corporation (ONGC) in the Jharia coal field, Jharkhand in 1997. That was also the year the government adopted a CBM policy and four licensing rounds were subsequently launched. So far, 33 blocks have been awarded covering an area of 17,300 km<sup>2</sup> spread over the states of Andhra Pradesh, Assam, Chhattisgarh, Gujarat, Jharkhand, Madhya Pradesh, Maharashtra, Orissa, Rajasthan, Tamil Nadu and West Bengal.

Commercial production started in 2007 from the Raniganj South block in West Bengal operated by Great Eastern Energy Corporation. CBM production is currently small – 80 mcm in 2011 out of total gas production of 46 bcm – but is expected to increase to around 2.7 bcm/year by 2015 as more blocks enter commercial production.

The government is also seeking to develop national expertise in CMM recovery and utilisation. The Ministry of Coal worked with the UN Development Programme and Global Environment Facility to fund a demonstration project at Moonidih mine. This project ran from May 2008 to June 2010 and used recovered methane to generate electricity for the mine.

### Russia

As Russia has the world's largest reserves of conventional gas it has less incentive to develop unconventional gas. However, the country does have a significant potential CBM resource – 83.7 tcm according to Gazprom – some 13 tcm of which lies in the Kuznetsk (also known as Kuzbass) Basin in south-western Siberia. A research centre called Uglemetan was set up in 2002 to promote the sector's development.





Gazprom's pilot CBM facility in the Taldinskoye field.

In 2005, Gazprom established a research and testing site at the Taldinskoye field in the Kuznetsk Basin and launched pilot operations of seven exploratory wells in 2009. The gas is used to generate electric power and to refuel vehicles at the Taldinsky coal strip mine. Gazprom is targeting annual CBM production of 4 bcm in the medium term and 18-21 bcm in the longer term.

#### Rest of the world

Southern Africa has great CBM potential but, although pilot wells have been drilled in South Africa, the focus is on Botswana. The latter has an estimated CBM resource of 5.5 tcm in the Kalahari-Karoo Basin where Tlou Energy has completed an exploration and testing programme and is working towards pilot production.

In Latin America, the focus is on Colombia where the National Hydrocarbons Agency (ANH) estimates a resource of up to 1 tcm. A CBM test well was drilled in the Cerrejón coal field in 1996 and CBM licence blocks began to be awarded in

2004. Drummond Coal has a number of projects at various stages of development.

In Europe, Poland is the largest coal producer and several mines use CMM for heat and power generation, as Professor Jerzy Stopa told the 19th World Petroleum Congress in 2008, but there is no CBM production as such. Other traditional European coal producers have been evaluating CBM and the UK is about to start commercial production. Dart Energy will produce CBM from a site near Airth in Scotland initially for power generation and later for injection into the gas grid. The UK has an estimated CBM resource of 3 tcm.

All the countries with significant deposits of coal that are evaluating their CBM potential can learn from the experience of the current major producers in establishing a supportive fiscal and regulatory regime which protects the environment and allows a valuable resource to be developed.

*Mark Blacklock is the Editor-in-Chief of International Systems and Communications.*

# Coal Bed Methane – a viable solution to India's energy needs



The environmental, technical and economic advantages of Coal Bed Methane (CBM) have made it a global fuel of choice. India has the world's fourth largest proven coal reserves and estimates suggest that there will be a 10% increase per year in natural gas demand for the next five years. The opportunity remains for India to exploit unconventional energy sources, and particularly CBM, given its current reserves.

Great Eastern Energy Corporation Ltd (GEECL), listed on the London Stock Exchange, is the Indian pioneer in exploration, production, and distribution of CBM, holding two licences: the gas producing Raniganj (South) block in West Bengal, with 2.35 tcf of original-gas-in-place (the result of upgrades of 466% for 3P reserves from 2009 to 2012); and the Mannargudi Block. Five years ago GEECL announced that the company had commercialised CBM from its Raniganj (South) block. It was a giant step forward in harnessing a source of clean energy that was hitherto untapped in India. The Indian market is characterised by strong demand, driven by a large population and energy intensive industries. This demand, coupled with a limited local energy supply, has created a significant and growing market for natural gas. Given the absence of new domestic conventional oil and gas sources, CBM is now considered as an alternative source for augmenting the country's energy resources.

Methane is the main energy source in natural gas and CBM is simply methane found in coal beds. Many countries have been using it for years to meet their energy needs. The Raniganj (South) block find promised to drive more such discoveries across India, and ultimately ease the country's energy burden.

According to India's Directorate General of

Hydrocarbons, the country is estimated to have around 4.6 trillion cubic meters (162 trillion cubic feet) of CBM reserves. One trillion cubic feet of natural gas is enough to generate about 100 billion kilowatt hours of electricity or fuel 12 million natural-gas-fired vehicles for one year.

Great Eastern Energy sells its gas directly to various local industries such as steel and glass companies. It has invested in and built its own pipeline – a dedicated network of approximately 100 kilometres which connects the area around the block through the industrialised belt to cater to the various industries it supplies directly. The main pipeline from Great Eastern's gas gathering station to its central gathering station in Asansol was completed in January 2009 with further pipeline completions from Asansol to Kulti and Asansol to Durgapur completed in April 2009 and October 2009 respectively. Metering systems have been installed at the plant and customer premises to adjust for the pressure and measure the quantity of gas being used. It is controlled by Great Eastern until the point of consumption so there are no intermediaries involved.

The company has an aggressive drilling campaign, aiming to reach 300 wells by 2016/17, with which it expects to fully develop its producing block. The supply-demand dynamics in the Indian gas market are extremely attractive and are likely to remain so for the next twenty years. In a recent McKinsey report *Powering India: The Road to 2017*, a statement concerning Indian power demand stipulates that in the next ten years, this is likely to surpass 300 GW; and that meeting this demand will require a five to tenfold increase in capacity. As India will also need to reduce its dependence on imported fuels, the opportunity for CBM is clear and unlimited.



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# CBM in Australia

By Georgia Lewis

Australia has ambitious plans to become the world's largest exporter of liquefied natural gas and the coal-bed methane sector is playing an important role.

By 2020, Australia will have overtaken Qatar to become the world's top exporter of liquefied natural gas (LNG) and CBM will account for 30% of exports in addition to supplying the domestic market. Three CBM to LNG projects have already been given the go-ahead; they will tap the country's CBM resource of 6.6 tcm.

Today, CBM (locally known as coal-seam gas) accounts for 11.8% of Australia's gas production. The producing states are Queensland, which has the bulk of the country's CBM resources, and New South Wales (NSW). Exploration is underway in other states.

While the coal industry has a long history in Australia dating back to 1797 when the first coal was discovered in Point Solander, NSW, exploitation of CBM resources is relatively new. It wasn't until 1976 that CBM exploration began in Queensland's Bowen Basin, and 1996 that commercial production started at the Dawson Valley project, NSW, adjacent to the Moura mine.

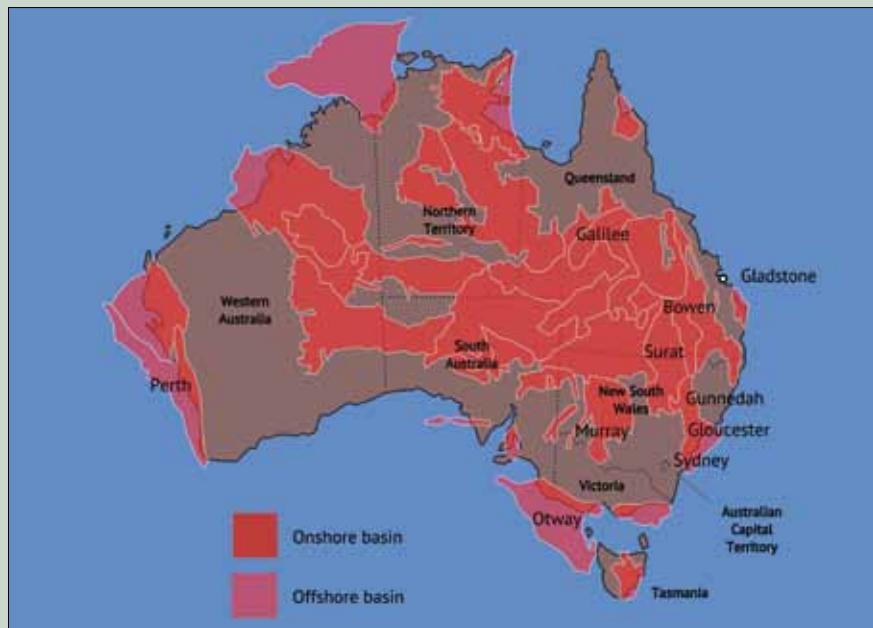
Production of CBM has grown from zero to 1.1 bcm in 2003, 2.2 bcm in 2006 and 6.2 bcm in 2011, with Queensland's Bowen and Surat Basins accounting for 97%. The sector has benefited from the Queensland Government's Cleaner Energy Strategy of 2000, which mandated that 13% of the state's electricity be generated by gas-fired power stations. The percentage was increased to 15% for 2011 and there is provision to raise it to 18% by 2020. In NSW, CBM is produced from the Sydney and Gunnedah Basins (see Figure 1).



Drilling operations at Fairview in the Bowen Basin in Queensland started in 1994 and the first CBM was sold in 1997. Production has been steadily increased.



### Main basins for CBM production and exploration in Australia



**Note:** Gladstone is where Australia's CBM to LNG liquefaction plants and export terminals are being built.

Figure 1.

Gunnedah is also the site for further CBM exploration, as are the basins of Gloucester (NSW), Galilee (Queensland), Murray-Darling (NSW, extending into Victoria and South Australia), Otway (which straddles South Australia and Victoria) and Perth (Western Australia).

#### CBM to LNG

For the time being, Australia's CBM is supplied to the domestic market but from 2014 exports as LNG will start. The gas will be piped 400-600km from fields in the Bowen and Surat Basins to liquefaction plants on Curtis Island near Gladstone in Queensland. Three projects have been given the go-ahead and another is being evaluated.

Queensland Curtis LNG is a venture of BG Group's Australian subsidiary Queensland Gas

Company and will have two liquefaction trains each with a capacity of 4.25 mtpa (5.8 bcm). The first train is set to start up in 2014 and the second in 2015.

Gladstone LNG, whose partners are Santos, Petronas, Total and Kogas, will have two 3.9 mtpa (5.4 bcm) trains both of which are due to enter service in 2015.

Australia Pacific LNG (partners Origin Energy, ConocoPhillips and Sinopec) will have two trains of 4.5 mtpa (6.2 bcm) with one starting up in 2015 and the other in 2016.

Awaiting a final investment decision is the Arrow LNG joint venture of Shell and PetroChina. This would have an initial two trains each with a capacity of 4 mtpa (5.5 bcm). Future expansion would bring the total capacity to 18 mtpa (24.8 bcm).



The gas processing plant at the Spring Gully CBM field in the Bowen Basin, Queensland.

### Regulating the CBM sector

Australia's Federal Government can intervene in state CBM proposals but only if they are likely to have a significant impact on a matter of national environmental significance. Under the Australian Constitution's separation of powers, state and territory governments have primary responsibility for environmental issues.

The limited Federal Government powers are enshrined in the Environment Protection and Biodiversity Conservation Act of 1999 (the EPBC Act). However, the EPBC Act has still imposed around 300 conditions on the Queensland-based CBM to LNG projects, mostly relating to aquifers and groundwater-dependant species. The implementation of these conditions is monitored by the Federal Government's Department of Sustainability, Environment, Water, Population and Communities. Under these conditions, all CBM operators need to provide a regional groundwater management model as well as a cumulative impact report relating to all listed species and

ecological communities within and outside the project areas.

The Commonwealth Water Act 2007 relates to water management in the Murray-Darling Basin, where exploration has been taking place. Under this act, a Basin Plan is being developed to set strict guidelines for sustainable water diversion by land users, including CBM operations. The act also requires that an independent study be undertaken before any licence is granted for CBM operations on floodplains which have an underlying groundwater system that is part of the Murray-Darling Basin inflows.

In the states of NSW and Queensland, coal-mine methane is administered by mineral resources legislation and CBM is administered by petroleum resources legislation.

The governments of the states and territories are responsible for land access for mining operations. However, if a project is approved under Federal law, the social and economic impact of the activities on agricultural land needs to be con-



sidered. The Federal Government can also place conditions to minimise the impact of any clearing that takes place on land that is protected under national environment law.

Human health issues in relation to CBM activities are primarily governed by state and territorial laws, but national environmental laws still need to be considered where appropriate.

State governments are usually responsible for monitoring CBM operations to ensure any potential risks are managed and ensuring regulatory compliance. Any CBM operations that have been approved under national environment law require regular reporting and independent auditing to ensure they are adhering to strict Federal conditions.

### **CBM and water management**

In Australia, measures are taken to ensure that water at CBM facilities is handled in an environmentally sound manner. This includes the safe handling of co-produced water as well as minimising the hydrogeological impacts on subsurface.

Water, which occurs as by-product of CBM production, is frequently treated so it can be used for town water supplies, industrial facilities such as coal mines and abattoirs, irrigation of farmland



Australian Prime Minister Julia Gillard (*second from right*) at the ground-breaking ceremony for the Gladstone LNG plant in May 2011.

and horticultural developments. The means of treating and disposing of water is subject to the relevant state laws for each production facility.

In the Surat Basin, a detailed water management study was undertaken in 2004 to examine the potential impact on groundwater resources and recommended the discontinuation of evaporation ponds as the primary means of disposal for CBM

### **Coal-mine methane – A case study**

Australia is the world's third largest coal producer and the industry is working to reduce methane emissions. In Queensland, CMM is used for power generation at Moura, German Creek, Moranbah North and Oaky Creek, and in NSW at Appin, West Cliff, Teralba, Tahmoor and Glennies Creek. The West Cliff mine in NSW operated by BHP Billiton Illawarra Coal is a good example of CMM use.

Since 1995, Illawarra Coal has been using methane drained from coal seams prior to mining to fuel power plants near the townships of Appin and Douglas Park. However, not all the methane associated with the coal seam could be drained

and small amounts were present in the ventilation air exhausted from the underground operations. Methane concentrations in mine ventilation air are typically less than 1.25% by volume, which is not freely combustible with conventional combustion systems.

In 2007, Illawarra Coal, in partnership with emission control specialist Megtec Systems and with funding from the Federal Government's Greenhouse Gas Abatement Programme, introduced a new type of power plant to use the extremely dilute methane in the ventilation air to generate 5MW of electricity for use within the mine.



Landowners at Mount Hope Station, Queensland sample treated water from CBM production which is used for crop irrigation.

water. Instead, it is the responsibility of the producers to treat CBM water to a standard defined by Queensland's Department of Environment and Resource Management before disposal or reuse.

On a national level, the Australian Government plans to spend AU\$200 million (\$201 million) over the course of five years from 2012 to support the work of the Independent Expert Scientific Committee. This committee will provide advice to governments across Australia about CBM approvals where they have significant impacts on water. Bioregional assessments and research into the impact of CBM and coal mine developments on how to reduce the impact on water resources will be undertaken.

Studies that have already been undertaken or are in progress under the Water Act 2007 that are relevant to the CBM industry include assessments of the Murray-Darling Basin via the national Groundwater Assessment Initiative and the Healthy Headwaters Programme, the Namoi Water Study for NSW and the Great Artesian Basin Water Resources Assessment, which covers a vast area taking in NSW, Queensland, South Australia and the Northern Territory. Geoscience Australia prepared a report for the Federal environment minister, on issues relating to the three CBM to LNG projects in Gladstone, Queensland and the related dredging

of Gladstone Port's western basin. The minister also appointed a panel of independent experts to advise the Federal Government on CBM water management in Queensland as per the EPBC Act. This panel advises on the adequacy of water management plans which the companies must submit for approval.

### Other environmental issues

As well as concerns about safe, cost-effective water management, there are other environmental issues which the players in the Australian CBM sector have taken into account. Land use is a major issue for CBM producers to consider and it is important to consult all stakeholders as to the best way to manage the land. In Queensland, for example, CBM exploration permits are not granted within 2km of the boundaries of towns with more than 1,000 inhabitants. Greenhouse gas production is another aspect of CBM production that is an ongoing concern for Australian companies and state governments.

Environmental groups in different states have protested against the hydraulic fracturing required for some CBM production. Groups such as the Hunter Valley Protection Alliance, which campaigns in areas surrounding Sydney, have achieved some success in pressuring governments to limit activities and improve environmental policies. Indeed, the NSW Government introduced a moratorium on fracking in December 2010 pending a review of the chemicals used. Meanwhile, Queensland has banned the use of benzene, toluene, ethylbenzene and xylene in fracking fluids.

Provided the environmental concerns are addressed, the Australian CBM sector has the potential to grow significantly, supplying domestic energy needs, generating export revenues and providing employment.

*Georgia Lewis is the Deputy Editor of International Systems and Communications.*



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# Unconventional gas in Canada

By Michael Gatens

Canada has abundant resources of unconventional gas and is ramping up production to ensure long-term supplies to domestic and export markets.

Unconventional gas (UCG) in its various forms has become the dominant source of future natural gas supply in Canada, which is the world's third largest producer of natural gas. The Canadian Society for Unconventional Gas (CSUG) was formed in 2002 to help promote the responsible development of unconventional gas in Canada. In 2011, CSUG changed its name to the Canadian

## Gas resources in Canada

	Resource (tcm)	Recoverable gas (tcm)
Conventional gas	19.6	10.1
Tight gas	37.1	6-13.5
Shale gas	31.4	3.6-9.7
Coal-bed methane	22.7	1-3.6
Total	110.8	20.7-36.9

Source: CSUR

Table 1.

Society for Unconventional Resources (CSUR) to add tight oil to its mandate. CSUR estimates that Canada has over 110 tcm of natural gas in-place, excluding gas hydrates, with 20-37 tcm recoverable using current technologies (*see Table 1*). Over 50% of the future recovery is estimated from unconventional sources.

At the maximum producing gas rate in Canada's history of some 500 mcm/day, the above recovery estimates represent over 100 years of gas supply. As large as this potential is, it will likely continue to grow. For example, in June 2012, Apache announced a new shale play in the Liard Basin of British Columbia. The company estimates this has the potential to recover 1.36 tcm from the Apache land base, which is only 14% of the play area.

Currently, Canada is producing about 400 mcm/d of natural gas with roughly 45% coming from unconventional sources (*see Table 2*) and the bulk of this from Alberta and British Columbia. As access grows to new areas throughout the country, additional resource capacity is likely.

## Early development

UCG development in Canada began in the 1970s, with the Elmworth tight gas field in Alberta by Canadian Hunter Exploration. John Masters and James Gray of Canadian Hunter presented the unconventional resource triangle, which is still widely used (*see page 69*), to demonstrate the vast potential resource in lower quality, more



A coil drilling rig at a CBM well in Linden, Alberta.





A completed CBM well head in Strathmore, Alberta.

difficult-to-produce, low permeability ("tight") gas reservoirs.

Despite this early innovation, Canadian UCG development was dormant through the 1980s and 1990s due to an abundant supply of conventional gas in the Western Canadian Sedimentary Basin, lack of market access and low gas prices. Fortunately, UCG technology continued to evolve in the United States with research efforts by the Gas Research Institute, the Department of Energy and their contractors leading to significant advances. Complex UCG reservoir characterisation models, advances in hydraulic fracturing, horizontal drilling and micro-seismic technologies all led to significant growth in UCG production. By 2000,

UCG accounted for 30% of total US gas production, up from 13% in 1990.

Starting in the late 1990s, Canada experienced a decline in conventional production, an expansion in pipeline capacity, increased demand and higher gas prices that created a positive environment for UCG development. The "shallow gas play" of stacked sands (including tight sands) in south-east Alberta and south-west Saskatchewan was expanded. Innovative drilling and completion practices to lower costs and increase production and increased recovery by infill drilling were keys to this growth.

Building on this success, the industry applied shallow gas technologies to the "dry" Horseshoe Canyon CBM play that underlies much of southern Alberta. The Horseshoe Canyon coals occur in multiple, stacked layers at shallow depths and do not contain or produce significant water, thus the "dry" designation.

Commercial Horseshoe Canyon production was established in 2001 and over 15,000 wells have been drilled, leading to a peak rate of 21.2 mcm/d in 2009 and an estimated recovery of 280-340

#### Current Canadian gas production

	bcm	%
Annual production	144.6	100
Of which: Tight gas/shale gas	56.8	39.3
Coal-bed methane	8.3	5.7

**Source:** Author's estimates as precise data are not currently available

Table 2.



Canada is developing shale plays in the Horn River Formation.

bcm. Simultaneously, the “wet” Mannville coals of Alberta were developed using horizontal wells to dewater the coals and achieve commercial rates. Combined, these coals account for 22.6 mcm/d of current Canadian CBM production and over 700 bcm of recoverable gas. Due to low gas prices, development of these coals has slowed, but significant potential remains for these and other coals in the future.

#### Shale revolution

In the early 2000s, the use of horizontal drilling and multi-stage horizontal fracturing in UCG reservoirs in the US, starting with the Barnett Shale play in Texas, led to an incredible expansion in UCG activity and production. Commonly referred to as the “shale gas revolution”, it has led to an increase in US gas production from 543 bcm in 2000 to 651 bcm in 2011, with the UCG share rising to 67%. The share of recently developed shale plays alone is 33%.

This revolution has found its way to Canada. In 2007, the “hybrid” (tight sands, silts, shales) Montney

play took off along the Alberta/British Columbia border with horizontal, multi-frac completions yielding daily well rates of 140,000 to 200,000 cubic metres or more. Today, over 1,000 wells have been drilled in this play which is currently producing 45 mcm/d and is estimated to contain 2-5 tcm of recoverable resource in British Columbia alone. It also includes areas with high natural gas liquids content, which makes it attractive even when gas prices are relatively low.

Concurrently, innovative application of multiple fracture treatments in vertical wells targeting the multiple stacked tight sands, silts and shales in the deep Alberta portion of the Western Canadian Sedimentary Basin has also led to expansive production growth. This is in the same area as the Elmworth field developed by Canadian Hunter back in the 1970s. Over 85 mcm/d is currently being produced from multiple stacked Cretaceous UCG zones in this area, which is projected to grow to 140 mcm/d in five years and recover over 2 tcm.

In addition to these CBM and tight gas or hybrid plays, Canada is developing true shale plays.





In the Horn River Basin and Cordova Embayment of north-east British Columbia, the Muskwa and other shale formations are estimated by CSUR to contain 20 tcm of resource. Pilot and early commercial developments have led to current production of around 17 mcm/d from prolific horizontal wells. The recent announcement by Apache of the Liard Basin shale potential to the west of the Horn River Basin in BC and the Yukon only adds to this potential.

The Duvernay Shale underlies a large part of Alberta and is a known source rock for many conventional reservoirs in the Western Canadian Sedimentary Basin. Over \$4.2 billion has recently been spent at land sales to acquire Duvernay rights and on early test wells. Some of these early horizontal well tests have been promising for gas and natural gas liquids. Further to the east, promising tests in the Utica shale in Quebec and shale/tight gas formations in Nova Scotia and New Brunswick also show great future potential. Current activity is slow due to a lack of recent oil and gas activity, let alone UCG activity, in these jurisdictions, prompting governments and regulators to proceed cautiously.

### Challenges

Clearly, UCG is important to Canada's energy supply now, and has immense potential for future growth. However, many obstacles must be managed if responsible development of this vast potential is to proceed. Currently, the relative glut of gas production in North America has led to low gas prices, and activity has slowed. It is a good time to reflect on the challenges which face UCG development in Canada in the present and future.

Canada's UCG must earn the social licence to operate in the diverse jurisdictions in which UCG is found across the country. Societal concerns, elevated by reports from south of the border, have created concerns about fracturing, water use, surface land impacts, air quality and other activities

or impacts associated with UCG development. Many companies have long recognised the need for meaningful stakeholder engagement to address these concerns with local communities, First Nations, provincial/federal governments, regulators, non-governmental organisations and the general public. Despite the fact that many of the "new" practices associated with UCG development have been commonplace and well-regulated for years, better engagement, communication and education is needed to overcome local fears and develop best practices necessary for each jurisdiction.

Organisations like CSUR and the Canadian Association of Petroleum Producers (CAPP) have played leadership roles in promoting improved stakeholder engagement on UCG issues. When CBM activity became significant in Alberta in the early 2000s, a government-led Multi-Stakeholder Advisory Committee was formed to deal with CBM development issues which led to improved industry practices and new regulation. Alberta and British Columbia have and continue to modify existing and develop new regulations to deal with UCG-specific activities. Quebec has established a moratorium on fracturing to allow for more consultation, and both Nova Scotia and New Brunswick have delayed or closely managed UCG development to ensure adequate regulations and enforcement capacities are in place before moving ahead.

In addition to these stakeholder challenges, UCG has many technical and economic hurdles which must be overcome to achieve its full potential in Canada. Currently, low gas prices are inhibiting development. Canada has historically relied on the US as its sole export market, and the success of UCG in the US has reduced its need for Canadian imports. Many of Canada's UCG plays are in extreme environments which require special practices, limit access and add to project costs as compared to other jurisdictions. As other sectors of the industry and economy improve, access to



Many of Canada's UCG plays are in extreme environments.

services, equipment and qualified labour can also be problematic.

### Opportunities

Despite these challenges, the opportunities are many, starting with the vast resource of 91 tcm.

Canada is politically stable and has experienced, capable regulators in mature oil and gas producing regions. Most of Canada's resource is owned by the Crown, and many jurisdictions provide incentives to industry to drill in expensive, challenging areas and to develop infrastructure for bringing the Crown's resource to market. The land tenure system for acquiring and holding leases is among the world's best and strict data reporting requirements ensure good competition and accelerated technology development.

Canada also has a deep, expert pool of talent to draw upon: Calgary has the world's second largest concentration of petroleum technical specialists (after Houston). In addition, Canada's west coast provides excellent access to export markets in Asia, to offset the loss of the US market in the future.

Two liquefied natural gas (LNG) projects have been approved by the National Energy Board and several others are in various stages of planning.

In summary, Canada has a vast UCG resource and a growing UCG industry which is working towards achieving responsible development, now and in the future, in jurisdictions across Canada, to markets around the world. CAPP estimates UCG production in Canada will reach 200-280 mcm/d in 2020; excluding much of the Cretaceous tight sands in Alberta.

It is incumbent upon all Canadian stakeholders to work together to ensure that this great resource is developed to the ultimate benefit of all Canadians, while minimising the negative impacts of this development. Canada also has an opportunity to export its experience and knowledge to other countries of the world as they too, begin to explore and develop their own UCG resources.

*Michael Gatens is the CEO of Unconventional Gas Resources ([www.ugresources.com](http://www.ugresources.com)). He presented papers and chaired sessions during the 18th World Petroleum Congress in 2005 and the 19th in 2008.*



## Canada's LNG projects fuelling Asia

Canada's LNG export projects are centred on Kitimat (*pictured below*), a coastal community in British Columbia about 650km north-west of Vancouver which sits at the head of Kitimat Arm. This offers good access for LNG tankers which would supply markets in Asia where gas sells for a much higher price than in North America.

Kitimat LNG is a joint venture of Apache, EOG Resources and Encana to build a liquefaction plant at Kitimat using feed gas from Apache's and EOG Resource's shale plays in British Columbia and Alberta. The plant would have one liquefaction train with a capacity of 5 mtpa (6.9 bcm) with the possibility of adding a second train. It is planned to be built on First Nations land under a partnership with the Haisla First Nation. (First Nations is a term that collectively refers to various Aboriginal peoples in Canada who are neither Inuit nor Métis.) A final investment decision is awaited and start-up is projected in 2017. Kitimat LNG's owners will separately develop the Pacific Trails pipeline to transport the gas to their terminal.

Canada LNG is led by Royal Dutch Shell with three partners based in major LNG importing countries: Mitsubishi, Korea Gas Corporation (KOGAS) and PetroChina. The plant would have an initial capacity of 12 mtpa (16.5 bcm) with two liquefaction trains and be supplied by a new pipeline from north-east British Columbia to be built by TransCanada Corp. The gas would come from the Horn River and Montney shale plays. Engineering work and environmental assessments are underway and start-up is envisaged in 2019 if a final go-ahead is given.

BC LNG Export Cooperative is a joint venture between the Haisla First Nation and LNG Partners for a floating liquefaction plant off the Haisla reserve. The capacity would be 700,000 tonnes initially rising to 1.8 mtpa (0.97-2.5 bcm) and the plant would be supplied by the existing Pacific Northern Gas pipeline. Start-up is currently given as 2014 but this seems optimistic given that a final go-ahead is still awaited.

A fourth plant has been proposed by Petronas of Malaysia (which recently bought Canada's Progress Energy) using shale gas from the Montney play.





# Unconventional gas in China

By Xinhua Ma, Ning Ning and Hongyan Wang

The development of unconventional gas in China is still in the early stages and faces a number of challenges, but the sector is expected to account for up to half the country's gas production by 2030.

China's natural gas production has more than tripled over the last 10 years thanks to the rapid development of the conventional gas sector. But consumption has increased nearly five times over the same period. Developing the unconventional gas sector will help China meet growing demand.

In 2010, unconventional gas production accounted for 18.6% of China's total gas production; this share is forecast to rise to between 40% and 50% by 2030 (see *Table 1*).

China started commercial production of tight gas in 2006 and output was 16 bcm in 2010. Coal-bed methane (CBM) has reached the early stage of commercialisation, with production of 1.57 bcm in 2010; while shale gas is at the stage of resource evaluation and technology research.

The country's tight gas resource has been assessed by the Research Institute of Petroleum Exploration and Development (RIPED) as 16 tcm, with 10% classified as proved reserves. The Ministry of Land and Resources carried out a CBM survey in 2006 and assessed the CBM resource at depths up to 2,000 metres as 36.8 tcm, although so far only 290.2 bcm have been proved. Both the Ministry and RIPED have carried out recent assessments of the shale gas resource which they put at around 31 tcm. According to rough estimations, there could be 84 tcm of gas hydrates but their exploitation is some way in the future.

## Tight gas

The Ordos Basin, which is China's second largest sedimentary basin, accounts for 84% of tight gas production although tight gas is also found in the Sichuan and other basins (see *Figure 2 over*).

The Ordos Basin covers an area of 380,000km<sup>2</sup> of which the tight gas area is about 80,000km<sup>2</sup>. It

## RIPED

The Research Institute of Petroleum Exploration and Development was established in 1958. It is the R&D centre of China National Petroleum Corporation (CNPC) and its subsidiary PetroChina. RIPED's research activities cover most aspects of the upstream petroleum business including strategic development planning for CNPC/PetroChina's global upstream business, R&D for major fundamental applied theories and techniques, and E&P technical support for the company's oil and gas projects.



RIPED is based in Beijing and has three branch institutes in Langfang, Hebei Province; Lanzhou, Gansu Province; and Hangzhou, Zhejiang Province.



► Sulige is China's largest tight gas field.



has a resource volume of 9 tcm and proved reserves of 1.1 tcm. The deposits are distributed mainly in the Carboniferous and Permian layers, with the average depth of the Permian formation being 3,295 metres. The quantity of recoverable gas varies from 27 to 65 million m<sup>3</sup>/km<sup>2</sup>.

The main tight gas field is Sulige, operated by PetroChina, where extensive field tests and research were needed before commercial production could start. Developing Sulige cost-effectively was particularly challenging because there is considerable variation in the distribution of the reservoirs and their physical properties. Production reached 10.5 bcm in 2010 when the cumulative number of gas production wells was 3,816 (100

horizontal) of which 3,222 (91 horizontal) were producing wells.

### CBM

China's CBM development is concentrated in two areas, the Qinshui Basin of Shanxi Province and in the east of the Ordos Basin, where there is a stable distribution of coal layers with high gas content. The Qinshui resource is 7 tcm and proved reserves are 254.7 bcm; in total, there are eight basins with a resource of more than 1 tcm, which are mainly distributed in central and western China.

Some 5,246 wells had been drilled by the end of 2010 with a production capacity of 3 bcm and actual production of 1.57 bcm. PetroChina is the

#### China's gas production development plans (bcm)

	2010 (actual)		2015		2030	
Total gas	94.5	100%	150	100%	250-300	100%
Tight gas	16.0	16.9%	30	20%	40-60	16-20%
CBM	1.57	1.7%	10	6.7%	30-40	12-13.3%
Shale	0	0	3	2%	30-50	12-16.7%
Total unconventional	17.57	18.6%	43	28.7	100-150	40-50%

Table 1.

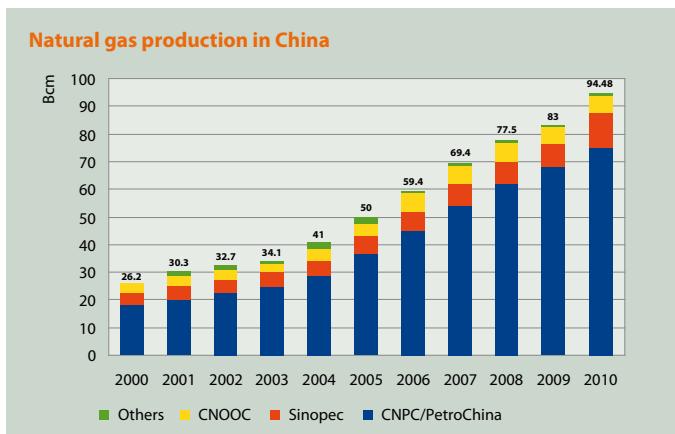


Figure 1.

China's gas production has grown dramatically but so has demand; consumption in 2010 was 108 bcm with LNG and pipeline imports supplementing domestic production.

largest producer and its CBM development in the Qinshui Basin is primarily concentrated on the Zhengzhuang and Fanzhuang blocks. In Fanzhuang the buried depth of coal ranges from 185 to 1,300 metres and 483 production wells (438 vertical and 45 horizontal) had been drilled by the end of 2010. Average daily flow rates of 1,400m<sup>3</sup> for vertical and 6,100m<sup>3</sup> for horizontal wells have been achieved.

China United Coal Bed Methane (CUCBM) was the first company to start CBM production in

2005; and a number of other Chinese and foreign companies are involved in exploration and production (E&P) activities.

#### Shale gas

China's marine shale covers an area of 2.8 million km<sup>2</sup> and the most promising areas for shale gas development are the Longmaxi formation of the Silurian system and the Qiongzhusi formation of the Cambrian system. These are shales in the

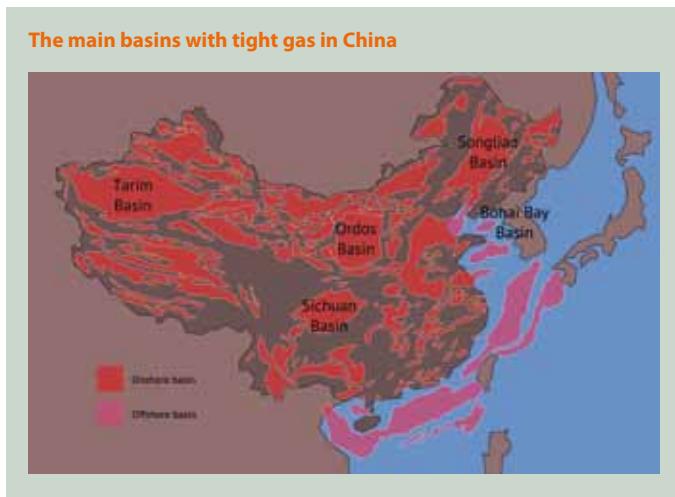


Figure 2.



Checking gas connectors at the Changbei field in the Ordos Basin, a tight gas project operated by Shell as a joint venture with PetroChina.

Sichuan Basin and its surrounding area with a single layer thickness ranging from 30 to 50 metres. The total area is about 72,000km<sup>2</sup>, with an estimated resource of 9.5 tcm.

Shale gas research and assessment started in 2005; a shale gas R&D centre was established by the National Energy Bureau in 2010 and a national pilot area project was confirmed in 2011.

A total of 23 shale gas wells (20 vertical and three horizontal) have been drilled of which 16 (15 vertical and one horizontal) have been fractured and nine have produced gas.

PetroChina has completed nine wells (seven vertical and two horizontal) and is drilling a further four wells (two vertical and two horizontal) as part of its Changning-Weiyuan and Zhaotong pilot

China United CBM is jointly owned by CNOOC and China Coal.



China has already built two West-East gas pipelines to supply demand and plans two more.

project. The first well (Wei 201) was completed in April 2010 to a depth of 2,840 metres and the first multi-stage fracturing of a horizontal well was carried out in 2011.

Wei 201 is in the eastern limb of the Weiyuan structure and the target layer was the dark shale in the Longmaxi and Qiongzhusi formations. However, the gas flow was unstable and the anticipated fracturing results were not achieved. There was more success with the Ning 201 well, which was completed in August 2010 to a depth of 2,560 metres. Ning 201 is in the Changning block and

the target layer is the black shale in the Longmaxi formation. Fracturing and gas testing has been carried out on two high-quality layers and has proved that Changning is one of the sweet spots for shale gas.

Sinopec has completed five appraisal wells in Qiandong, Wannan and Chuandongbei and two have achieved commercial production; while Yanchang Petroleum has obtained gas from three wells in Yan'an in the Ordos Basin. CNOOC also has a pilot drilling programme.

### Challenges

Unconventional gas is expected to play an increasingly important role in supplying China's gas demand but there is a lot of work to be done to determine its true potential. While there is preliminary data for CBM, nationwide resource surveys and evaluation for shale gas and tight gas have yet to be carried out. It is necessary to improve the unconventional gas reservoir formation theory and establish the evaluation standards. It is also necessary to speed up development of the geophysical, drilling and completing, and horizontal fracturing technologies.

Further development of technology is essential to reduce costs and improve well production rates, and thus ensure the cost-effectiveness of unconventional gas production. For tight gas, multilayer evaluation and multistage stimulation technologies need to be refined; for CBM, "pinnate" horizontal well drilling (*see box*) and completion technologies for middle and high rank coal together with cavity completion technologies for low rank coal are needed; while shale gas needs sweet spot screening, tight core testing and multistage horizontal well stimulation technologies.

It is also important to consider environmental issues such as the surface impact of the large number of wells required and their water use. Stimulating unconventional gas wells by hydraulic fracturing requires considerable amounts of water but,





unfortunately, China's unconventional gas resource is generally distributed in the western desert and southern densely-populated areas. These challenges need to be addressed to ensure sustainable development.

China's natural gas industry is developing rapidly. Although the unconventional resource is abundant and has significant potential, the sector is still in the early development stage and faces many challenges. Cooperation will help the Chinese ener-

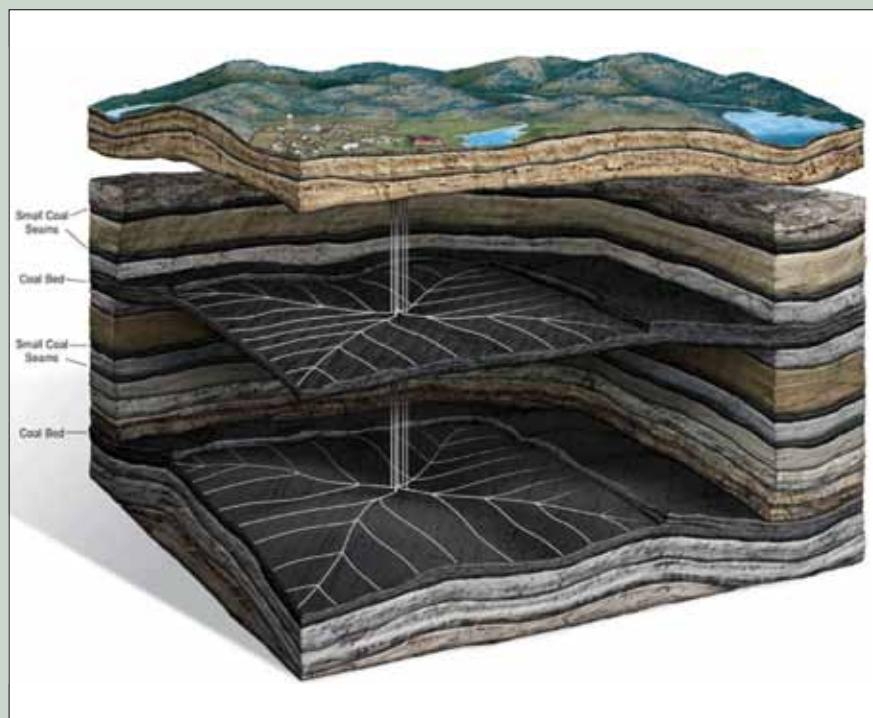
gy industry to face these challenges, to speed up unconventional gas E&P and to meet the country's demand for natural gas.

Xinhua Ma is Vice President, PetroChina Exploration and Production Company ([www.petrochina.com.cn](http://www.petrochina.com.cn)); Ning Ning is Vice President and Hongyan Wang is Senior Engineer at RIPED's Langfang branch. This is an edited version of a paper presented at the 20th World Petroleum Congress in 2011.

### Pinnate drilling

Pinnate (like a feather in appearance) refers in this context to the branches of horizontal well bores. When a horizontal well is drilled the initial bore is

vertical with horizontal bores subsequently spreading out in several directions; each initial horizontal well bore can then branch out in more directions.





# Gas hydrate

By Mark Blacklock

Gas hydrate represents a potentially enormous energy resource and research teams around the world are working to see if production can become commercially viable.

Natural gas hydrate is a lattice of one methane molecule surrounded by a "cage" of six frozen water molecules. Found in permafrost regions or subsea sediments, methane hydrates are believed to store several times more energy than all forms of conventional hydrocarbons combined. In the

last three decades, global resource assessments of between tens and hundreds of thousands of tcm have been made. What matters, though, is the volume of gas concentrated in sediments that can be commercially recovered, and a recent study using a petroleum systems approach (see box) estimated gas-in-place at a conservative but still substantial 1,226 tcm.

However, methane hydrates are only stable in a limited range of pressures and temperatures, and there are major environmental and technical hurdles to be overcome before commercial exploitation can begin. Intensive research is underway – with Canada, China, India, Japan, Korea and the USA the main countries involved – but for the time being, commercial attention is focused on other unconventional gas plays.

## Discovery

The discovery of hydrate dates back to the early 19th century as a result of experiments carried out with chlorine by the chemist Humphrey Davy and his assistant Michael Faraday. In 1823, Faraday



Gas hydrate being flared during the winter of 2007 from the Mallik production research well in Canada's Mackenzie Delta.



published a paper describing a strange substance that resulted as chlorine atoms became encased in ice crystals. He called it chlorine clathrate hydrate.

The petroleum industry first started studying hydrates in the 1930s, when they were observed forming in natural gas pipelines in colder climates. However, at this stage, hydrates were a problem to be dealt with if they blocked a pipeline. It was only when naturally occurring hydrates were found in the late 1960s and early 1970s that researchers began to wonder if they had commercial potential. The first onshore discovery was made in sub-surface sediments in the Messoyakha gas field in the Western Siberian Basin, followed by one in sediments of the North Slope of Alaska. The first offshore hydrates were recovered from the Black Sea in 1974.

A major discovery was made in 1981, when the research vessel *Glomar Challenger* was collecting ocean bottom sediment cores as part of the Deep Sea Drilling Project (the predecessor of the current Integrated Ocean Drilling Programme). A core taken off the Pacific coast of Guatemala included a one-metre-long sample composed almost entirely of methane hydrate. This discovery led to a series of research programmes to increase understanding of methane hydrates with the ultimate aim of developing production methods.

As G. A. Cherkashev and V. A. Soloviev of the Russian Research Institute for Geology and Mineral Resources of the Ocean told the 17th World Petroleum Congress in 2002, theoretically, there are three approaches to gas recovery from hydrates: to raise temperature, decrease formation

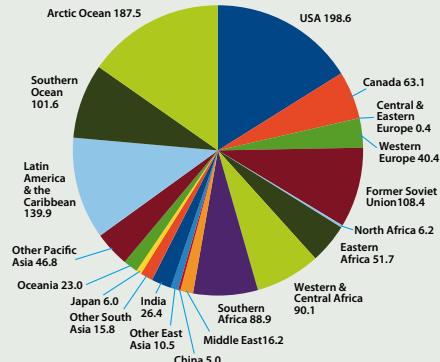
### A global resource potential of 1,225 tcm

As part of the Global Energy Assessment conducted by the International Institute for Applied Systems Analysis (IIASA), Hydrate Energy International (HEI) carried out a new evaluation of gas hydrate resource potential using a petroleum systems approach. The evaluation resulted in calculations that support the probability of a large volume of hydrate being present in sand reservoirs in polar and deepwater sediments.

HEI assessed every continental margin worldwide, incorporating geological models of likely sand distribution with prior interpretations of the occurrence of gas hydrate stability conditions. Under the guidelines of IIASA, the results were reported for the 18 regions defined by the United Nations. In addition, separate resource assessments were conducted for the Arctic Ocean without regard for national boundaries, and for the Southern Ocean (from the coast of Antarctica north to 60 degrees south latitude).

The median estimates for gas-in-place in hydrate-bearing sands are summarised in the pie chart and full results can be found in *Global Energy Assessment: Toward a Sustainable Future*, Cambridge University Press, 2011.

**Calculated gas in-place in hydrate-bearing sands (median, tcm)**  
Total median = 1,226.4 tcm





pressure and to use inhibitors to shift phase equilibrium.

### Canada and Japan

As Japan has minimal conventional hydrocarbon resources and is the world's second largest importer of gas, the Japanese government is particularly interested in the potential of methane hydrates as a domestic energy resource. Japan's hydrate deposits are offshore and it cooperated with Canada to carry out initial research in the onshore environment.

Concentrated gas hydrates were proved in the Mackenzie Delta area of Canada's Northwest Territories in 1998, and the world's first trial to produce methane by dissociating the subsurface hydrate was carried out there in 2002.

A joint Canadian/Japanese research team drilled the Mallik well in 1998 and discovered hydrate-bearing sediments in sand layers at depths ranging from 890 to 1,100 metres below the permafrost zone. The original partners, the Geological Survey of Canada and Japan National Oil Corporation (JNOC), then joined forces with research bodies in Germany, India and the USA to carry out a production test in 2002. They succeeded in producing about 470 m<sup>3</sup> of gas using hot water circulation.

The next step was to confirm that methane hydrates dissociate continuously over a longer period of time and to trial the depressurisation method. This was carried out in 2007 and 2008 by Natural Resources Canada and JNOC's successor, the Japan Oil, Gas and Metals National Corporation (JOGMEC). The 2008 test produced a total of 13,000 m<sup>3</sup> of gas at a rate of 2,000-4,000 m<sup>3</sup> per day for six days.

Meanwhile, in Japan, the eastern Nankai Trough had been highlighted as a hydrate prospect by drilling and seismic surveys. In 2004, 32 exploratory test wells were drilled there in water depths ranging from 700 to 1,000 metres and found

concentrated methane hydrates. The Research Consortium for Methane Hydrate Resources in Japan (MH21), which was set up in 2002 and brings together JOGMEC, the National Institute of Advanced Industrial Science and the Technology and Engineering Advancement Association of Japan, is now working towards an offshore production test.

### China

According to Xinhua Ma, Ning Ning and Hongyan Wang of PetroChina in an update to their paper presented at the 20th World Petroleum Congress in 2011, China has made good progress in the development of core drilling and hydrate exploration technologies since 2005.

Offshore hydrates were discovered in 2007, when drill cores were taken between April and June that year from wells in the Shenhua area of the northern South China Sea. The expedition was mounted by the China Geological Survey, Guangzhou Marine Geological Survey and Ministry of Land and Resources.

Eight sites were drilled in water depths of up to 1,500 metres, with testing and sampling to 250 metres below the seabed. A comprehensive programme of borehole logging, coring, sampling and onboard analysis was conducted at five sites. Analysis of the data revealed the presence of thick sediment layers rich in gas hydrate at three of the sites. The gas released from the hydrate was found to be more than 99% methane.

Onshore methane hydrates were discovered in Qinghai Province in 2009, and further offshore exploration work was carried out in 2010 using a newly commissioned survey vessel *Ocean VI*.

### India

Gas hydrate exploratory research in India is being led by the Ministry of Petroleum & Natural Gas under the National Gas Hydrate Programme (NGHP) with participation from the Directorate



General of Hydrocarbons, national E&P companies (Oil and Natural Gas Corporation – ONGC, GAIL India and Oil India) and national research institutions (National Institute of Oceanography, National Geophysical Research Institute and National Institute of Ocean Technology).

Some of India's offshore potential was proven in 2006 when a 39-well drilling programme discovered a large concentrated hydrate zone. In total, 21 of the wells hosted successful drill cores which were taken in water depths of between 900 and 2,600 metres. A report on the findings was presented by Dr Pushpendra Kumar of ONGC at the 19th World Petroleum Congress in 2008.

The *JOIDES Resolution* scientific research vessel left Mumbai in April 2006 on a four-month expedition to explore four Indian offshore areas: Andaman, Kerala-Konkan, Krishna-Godavari and Mahanadi. Its big achievement was to find a 128-metre thick gas hydrate layer in the Krishna-Godavari Basin off the east coast, an area known for its large conventional natural gas discoveries. Near the Andaman Islands, the research team also found one of the thickest and deepest gas hydrate occurrences yet known located in volcanic ash layers as deep as 600 metres below the seafloor. In addition, the expedition established the existence of a fully-developed gas hydrate system in the Mahanadi Basin of the Bay of Bengal.

The NGHP is currently focusing on gas hydrate reservoir delineation and resource estimation in the Krishna-Godavari Basin and the identification of promising sites for a second expedition in 2013-14. Based on the results of this expedition, pilot production testing is planned for 2015-16.

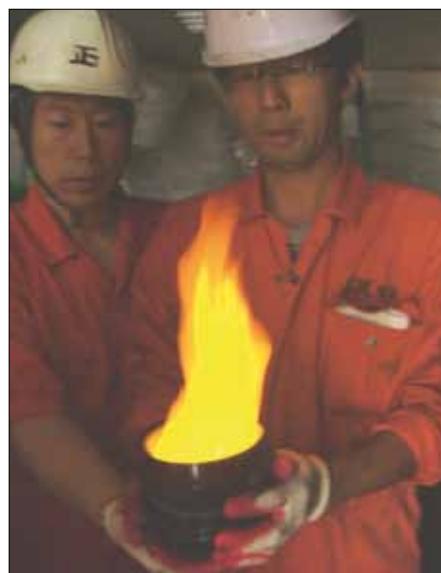
### Korea

As Dae Huh, Jahyoung Lee and Huen Lee of the Korea Institute of Geoscience and Mineral Resources (KIGAM) told delegates to the 19th World Petroleum Congress in 2008, South Korea found gas hydrates in June 2007 when piston



Hydrate core studies underway onboard the *JOIDES Resolution* during India's offshore expedition in 2006.

cores were taken off its south-east coast. Seismic vessel *Tamhae 2* intercepted hydrates 100 kilometres south of Ulleung Island and 135 kilometres north-east of the industrial city of Pohang in the East Sea at a water depth of over 2,000 metres. A



Burning methane from a gas hydrate sample recovered by Korea's expedition in 2007.



Korea's 2010 expedition team pose for a group photo onboard the *Fugro Synergy*.

follow-up expedition was mounted later that year to drill wells at three different locations in the Ulleung Basin.

The expedition was carried out in two legs using REM Etive and was organised by the Korea National Oil Corporation (KNOC) and Korea Gas Corporation (KOGAS), while decisions directing the scientific aspects of the work were made by the Korea Gas Hydrate R&D Organisation and KIGAM.

Leg 1 investigated five locations in the Ulleung Basin, which had been selected as representative of the basin based on pre-expedition 3-D seismic evaluations. The results were used to select the three locations most likely to contain gas hydrates. The second leg entailed the drilling and coring of the three sites, where significant gas-hydrate-bearing reservoirs were documented up to 150 metres below the seabed and at water depths between 1,800 and 2,100 metres.

A further expedition was mounted from July to September 2010 using the *Fugro Synergy*. The primary objectives were to collect data in order to understand the distribution of hydrate-containing structures as required for the hydrate gas resource

assessment and to find promising candidate areas for a future offshore production test. Ten sites were selected and wells were drilled to depths of between 230 and 360 metres below the seabed. The water depths at the sites ranged from 910 to 2,160 metres.

A production test is planned for 2014 using the depressurisation method.

#### USA

In the USA, research projects have focused on Alaska and the Gulf of Mexico.

In 2001, the Department of Energy (DOE) commenced a joint industry project in the Gulf of Mexico with an international consortium led by Chevron. This initially focused on understanding the impact of hydrate-bearing sediments on conventional deepwater oil and gas drilling safety. Analysis of conventional seismic data defined prospects for a drilling, logging and coring expedition in the Gulf of Mexico in 2005. Five wells drilled at two deepwater locations demonstrated the ability to predict hydrate saturations in fine-grained sediments and safely drill through those hyd-

rate-bearing sediments that are most typical of the deepwater Gulf of Mexico.

The current phase of the project is focused on the identification of gas hydrate-bearing sand reservoirs. A drilling and logging expedition in April–May 2009 confirmed the presence of high hydrate saturations in reservoir-quality sandstones in multiple locations. A future expedition will use a new coring system designed to collect hydrate-bearing sands at reservoir pressure and transfer the samples at pressure to a variety of newly-constructed testing devices. These samples will enable the first measurements of a range of physical properties of marine gas hydrate sand reservoirs.

In Alaska in 2002, the DOE initiated a project with BP that was conducted in collaboration with the US Geological Survey. The project used existing seismic and well data to define 14 drilling prospects in the Milne Point area. In early 2007, the project drilled, cored and tested the Mt Elbert well. The well provided 31 metres of hydrate-bearing core with hydrate saturations as high as 75% of pore volume in predicted zones. A short-term downhole test confirmed the ability of the formation to release gas through depressurisation.

In 2008, the DOE initiated a project with ConocoPhillips and JOGMEC to test CO<sub>2</sub> injection

as a mechanism to produce methane from hydrate in Prudhoe Bay. This technology would have added benefits in storing CO<sub>2</sub> in the subsurface and preventing surface subsidence by maintaining the integrity of hydrate-cemented formations.

The Ignik Sikumi (Inupiaq for “fire in the ice”) well was drilled, tested and temporarily abandoned in March and early April 2011. Proof-of-concept testing was carried out between February and April 2012, when the team injected a mixture of CO<sub>2</sub> and nitrogen into the formation, and demonstrated that this mixture could promote the production of natural gas. Further analyses of the extensive datasets acquired at the field site will be needed to determine the efficiency of simultaneous CO<sub>2</sub> storage in the reservoirs.

### Work to be done

Research continues around the world and the results of the forthcoming production tests are eagerly awaited. However, there is still a lot of work to be done and commercial exploitation of methane hydrates is a long way off.

*Mark Blacklock is the Editor-in-Chief of International Systems and Communications.*



A successful production test using CO<sub>2</sub> injection was carried out at the Ignik Sikumi well in Alaska in 2012.

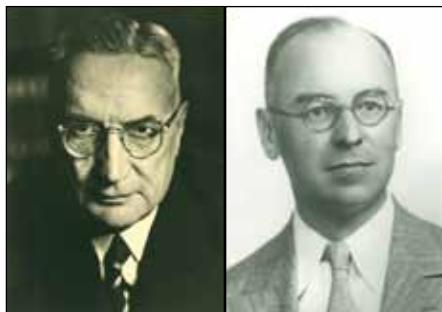


# Gas-to-liquids

By Mark Blacklock

The gas-to-liquids (GTL) process offers a means of extracting greater value from an important resource.

Today's GTL business draws on the pioneering work on synthetic fuels carried out by Franz Fischer and Hans Tropsch in Germany in the 1920s. They developed a process to turn gasified coal into liquids, and gave their names to the generic term Fischer-Tropsch (F-T) synthesis. However, Germany's synthetic fuel production during World War II (which reached a peak of 50% of consumption in 1943) was largely based on hydrogenation with F-T production accounting for about 8% at the peak. It was South Africa which took the lead in developing large-scale F-T liquefaction plants



Professor Franz Fischer (LEFT) and Dr Hans Tropsch carried out pioneering work on synthetic fuels.

after the war, initially using coal as a feedstock and later natural gas as well.

The original development of synthetic fuels was subsidised for strategic reasons; Germany and South Africa had large coal reserves but had to import oil. The challenge of subsequent R&D was to make synthetic fuel production commercially viable, and a number of proprietary technologies using F-T synthesis have been developed.

The basic process (see box) sees methane converted to carbon monoxide and hydrogen (syngas) for processing in a reactor to produce paraffinic waxes which can then be refined. The various proprietary technologies use different combinations of catalysts, reactor types and process conditions. The production phase of GTL uses more energy and thus entails higher emissions of greenhouse gases compared to a standard refinery, but the end products are cleaner.

The main product of a typical GTL plant is automotive diesel with virtually no sulphur or aromatics and a high cetane number. High-quality naphtha for petrochemical feedstock, kerosene for blending into jet fuel, normal paraffins and base oils for top-tier lubricants are also produced.

## Monetising gas

GTL is a means of monetising gas resources that are abundant, undervalued or wasted by flaring.

A barrel of oil has roughly six times the energy of a million Btu (mmBtu) of gas. Oil has traditionally traded at a premium to gas given the ease of refining it to produce a range of products, but this premium is increasing in some markets. At the time of the 19th World Petroleum Congress in 2008, for example, the oil price of \$147/b and the US Henry Hub price for gas of \$13/mmBtu meant the oil premium was about 100%. As delegates gathered for the 20th WPC in 2011, oil was trading at around \$104/b and the Henry Hub price for gas was just over \$3/mmBtu – giving an oil premium of 500%.

It is the flood of unconventional gas which has driven US prices down and is now driving interest in developing GTL plants. Sasol is working on a feasibility study for Westlake GTL in Louisiana and is also looking at a GTL plant in western Canada. Both would use shale gas as a feedstock. Other companies are considering projects.

For countries with abundant conventional gas resources, GTL is a way of providing high-quality products to the domestic market as well as extracting greater value from exports. Qatar Airways, for example, plans to fuel its aircraft with a 50:50 blend of locally-produced GTL kerosene and conventional jet fuel. The resulting GTL jet fuel is not only cleaner but has a higher concentration of energy and weighs less than conventional jet fuel.

Flaring gas associated with oil production is polluting and wasteful. Nigeria is one of the members of the World Bank-led Global Gas Flaring

Reduction (GGFR) public-private partnership, and the Escravos GTL plant being built by Chevron and the Nigerian National Petroleum Company will help the country eliminate flaring.

Brazil also wants to avoid flaring associated gas. For its offshore oil fields Petrobras is evaluating a project to include a small GTL plant on floating, production, storage and offloading (FPSO) vessels. This would produce a synthetic crude (syncrude) which would then be shipped with the main crude production to be refined elsewhere.

### GTL plants around the world

The first large-scale plants using gas as a feedstock were commissioned in 1992 by Mossgas (now part of Petro SA) in Mossel Bay, South Africa (using Sasol's advanced synthol process), and in 1993 by a Shell-led consortium in Bintulu, Malaysia (using Shell middle distillate synthesis – SMDS).

### Processing of natural gas

After raw natural gas has been treated, there are three main operations in a gas-to-liquids plant. Firstly, synthesis gas (syngas) is produced. This is typically a combination of hydrogen and carbon monoxide in a ratio of 2:1, and four alternative methods are used:

- Steam reforming of the feedstock in the presence of a catalyst.
- Partial oxidation – oxygen is separated from nitrogen in a cryogenic air separation unit (ASU) and burned with natural gas at high temperatures and pressures. Alternatively, air may be used instead of pure oxygen.
- Autothermal reforming, where partial oxidation is combined with steam reforming.
- Gas-heated reforming of natural gas with steam and oxygen.

Then Fischer-Tropsch synthesis converts syngas into paraffinic hydrocarbons, a waxy synthetic crude. There are three principal types of process:

- Fluidised bed processes, in which syngas is passed rapidly at high temperatures through a catalyst bed, such as the Sasol advanced synthol process. This uses an iron-based catalyst. It has been superseded by SPD in the international market.

- Slurry processes, in which syngas is reacted in a slurry with a catalyst and molten wax (produced in the reactor), such as the Sasol slurry phase distillate (SPD) low-temperature process. This uses a cobalt-based catalyst.

- Fixed bed processes, where the syngas flows through tubes containing catalyst, such as Shell middle distillate synthesis (SMDS). This uses a cobalt-based catalyst.

The synthetic crude is then converted into marketable petroleum products using conventional petrochemical upgrading processes, depending on the final slate of products required by the plant operator.



Petro SA's plant in Mossel Bay was the first to start volume GTL production.

The Malaysian plant suffered an explosion in its air separation unit in December 1997 and was closed until May 2000, but this was caused by an accumulation of air-borne contaminants from forest fires and was not related to the GTL technology.

Oryx in Ras Laffan, Qatar was the next GTL plant and uses the slurry phase distillate (SPD) process developed by Sasol at a test plant in Sasolburg. Oryx shipped its first product in April 2007 but a higher than design level of fine material in the paraffinic wax initially constrained output, and it took several years to resolve the problems and achieve full output. Oryx is now working on expanding capacity through debottlenecking.



The Oryx GTL plant in Qatar is expanding capacity.

Meanwhile, in Nigeria, the problems of building Escravos GTL in the Niger Delta caused long delays and cost over-runs. The plant was originally expected to cost \$1.7 billion and be in service by 2008. The cost is now \$8.4 billion and it is due to start operations in 2013. This is around six times the cost of the similarly-sized Oryx plant (which was built under a fixed-price contract signed before construction costs in the petroleum industry escalated) but it will still be profitable at current oil prices. Escravos will use SPD.

However, the largest GTL plant, Pearl in Ras Laffan, Qatar, was built on time and budget. The first product was shipped in June 2011 and full



SMDS was proved at the Bintulu GTL plant in Malaysia.



HH Sheikh Hamad bin Khalifa Al-Thani, Emir of Qatar (*second right*) inaugurated Pearl GTL in a ceremony on November 22, 2011, accompanied by HE Abdullah bin Hamad Al-Attiyah, Deputy Prime Minister (*left*), Peter Voser, CEO of Shell (*second left*) and HE Mohammed bin Saleh Al-Sada, Minister of Industry & Energy (*far right*).

output was achieved in mid-2012. Pearl is an integrated project and its \$19 billion cost covered the upstream as well as the downstream development. The project produces 120,000 b/d of upstream products (condensate, LPG and ethane), while the GTL plant has two 70,000 b/d trains and uses SMDS with improved catalysts based on experience from the Bintulu plant.

### GTL projects

Looking ahead, a GTL plant using SPD in Uzbekistan is at the front-end engineering and design (FEED) stage, while the Sasol projects in Canada and the USA for which feasibility studies are underway would also use SPD. And now that Pearl is in full operation Shell is evaluating its future GTL

options, including a plant on the US Gulf Coast.

SMDS and SPD are the two principal proprietary F-T technologies in commercial operation; others are on the verge of commercialisation.

One is GTL.F1, a low-temperature process using a cobalt-based catalyst in a slurry bubble column reactor. This was developed by Petro SA, Lurgi and Statoil in a 1,000 b/d semi-commercial unit (SCU) at Mossel Bay. Statoil has since withdrawn and the two remaining partners are looking at opportunities for GTL.F1 in North America.

Another has been developed by CompactGTL and is the technology being used by the Petrobras project in Brazil. It is for small, modular plants ranging in capacity from 200 to 5,000 b/d and does not require pure oxygen to convert the feedstock into



Escravos GTL is due to start up in 2013.

syngas, meaning there is no need for a separate oxygen plant and a GTL plant can be integrated on a vessel. The capacity of the plant can be adjusted to match the declining flow of associated gas throughout the life of an oilfield, with plant modules being shut down and removed for refurbishment and/or re-deployed elsewhere.

A modular unit has been tested at the Petrobras research site in Aracaju and it has been approved for commercial deployment.

Syntroleum's proprietary F-T process also uses air rather than oxygen and the company was evaluating a number of GTL projects to exploit associated and stranded gas but is currently concentrating on biomass-to-liquids ventures.

A Japanese consortium has developed a process that allows natural gas containing CO<sub>2</sub> to be used directly as a feedstock rather than having to be treated first. Japan GTL was successfully trialled at a 500 b/d demonstration plant in Niigata between April 2009 and December 2011 by Inpex, Nippon Oil & Energy, Japan Petroleum Exploration, Cosmo Oil, Nippon Steel Engineering and Chiyoda in cooperation with Japan Oil, Gas and Metals National Corporation (JOGMEC). Commercial opportunities are now being sought.

### Growing importance

By 2013, GTL production will be over 250,000 b/d. While this is still a small proportion of the overall market for refined petroleum products, a high oil price and premium over gas mean the sector is set to grow in importance.

*Mark Blacklock is the Editor-in-Chief of International Systems and Communications.*

### GTL plants in operation, under construction and in FEED

Name/Location	Partners	F-T Process	Capacity (b/d)	Status/Notes
Pearl, Ras Laffan, Qatar	Qatar Petroleum, Shell	Shell middle distillate synthesis	140,000	Operational
Oryx, Ras Laffan, Qatar	Qatar Petroleum, Sasol	Sasol slurry phase distillate	34,000	Operational, debottlenecking underway
Mossel Bay, South Africa	Petro SA	Sasol advanced synthol	22,000	Operational
Sasolburg, South Africa	Sasol	Sasol synthol	15,600	Converted from coal to gas feedstock in 2004
Bintulu, Malaysia	Shell, Diamond Gas (owned by Mitsubishi), Petronas, Sarawak govt.	Shell middle distillate synthesis	14,700	Operational
Escravos, Nigeria	Chevron Nigeria, Nigerian National Petroleum Co.	Sasol slurry phase distillate	32,400	Under construction, in service 2013
Shurtan, Uzbekistan	Uzbekneftegaz, Sasol, Petronas	Sasol slurry phase distillate	38,000	FEED underway, projected operations in 2018

**Note:** Sasol's Secunda plant in South Africa uses a mix of coal and gas feedstock.



## Three companies describe their proprietary processes

### CompactGTL

CompactGTL's small-scale modular GTL plant is designed with multiple reactors in parallel to accommodate gas feed variation and decline when converting associated gas into syncrude over the life of an oilfield.

### Process

The feed gas is first treated to remove contaminants. The gas stream is then heated by steam in a pre-reformer and the higher hydrocarbons are reacted to give methane, hydrogen and carbon monoxide. The methane-rich gas stream then undergoes two-stage steam methane reforming (SMR). By adjusting the fuel flow into the first and second stage of the reactors, independently, a useful degree of process control can be exercised as temperatures can be regulated for each stage; increasing process stability, enhancing catalyst life and reducing thermal stresses in the reactor blocks. The reforming process runs at high temperatures; the first stage at 650°C and the second at 780°C; the endothermic (i.e. heat absorbing) reaction converts the methane and steam into syngas. The steam reforming eliminates the need for an oxygen production plant making the process simpler and safer.



CompactGTL's commercial demonstration plant for Petrobras in Aracaju, Brazil.

After the second stage SMR reactor and prior to the two-stage F-T process the syngas is cooled from 780°C to 200°C; the steam which is generated is used to feed the pre-reformer. Following cooling the syngas is compressed to achieve the correct pressure for the F-T process and other impurities are also removed at this stage to further enhance the life of the FT catalysts.

The first stage of F-T converts about 50% of the syngas to F-T product and the remaining unreacted syngas then enters the second stage for conversion. As F-T synthesis occurs liquid hydrocarbon product is cooled and collected as syncrude. The F-T process is an exothermic (i.e. heat producing) reaction and efficient removal of heat is critical for the stability and efficiency of the process. Cooling is achieved by re-circulating pressurised water through the F-T catalysts.

F-T synthesis creates approximately one barrel of waste water for every barrel of syncrude product. The water produced in the F-T reaction can be treated to remove impurities and recycled back into the steam reforming process. The remaining unreacted syngas can either be recycled in the process or used to drive gas turbines which power the syngas compression unit, or a combination of both.

The CompactGTL reactor design is a variation of plate and fin technology widely used in a number of industries and the catalyst components are based on automotive mass manufacturing techniques. The close relationship between the SMR and F-T reactors in the CompactGTL process is a vital element in the efficient management of the overall system. The two reactions are tuned to work together to maximise efficiency and minimise waste streams depending upon the specific application and location of the plant.





### Three companies describe their proprietary processes (continued)



Sasol's SPD process is used at the Oryx GTL plant in Qatar (*pictured*) and will soon be in operation at Escravos GTL in Nigeria

#### Sasol

At the core of Sasol's GTL technology is the Sasol Slurry Phase Distillate (SPD) process. This three-stage process combines leading proprietary technologies that enable the production of cleaner synthetic products.

#### Natural gas reforming

In the first step natural gas is reacted with oxygen and steam over a catalyst to produce synthesis gas (syngas). Sasol uses autothermal reforming technology under licence for this step, a catalytic partial-oxidation process.

#### Hydrocarbon synthesis

In the next step, syngas is converted into longer-chain hydrocarbons in the Sasol slurry phase reactor. Synthesis gas is fed to the bottom of the reactor where it is distributed into the slurry consisting of wax and Sasol's proprietary cobalt catalyst. As the gas bubbles rise they diffuse into the catalyst and are converted into waxy syncrude. This product is separated from the slurry containing the catalyst particles in a proprietary process. The lighter fractions leave in a gas stream from the top of the reactor after which it is cooled to recover the lighter species and water.

Benefits of the slurry bubble column reactor over the tubular process include that it allows for greater scale of operation and efficiency, and has a lower pressure drop. The high heat transfer coefficient that can be achieved makes it suitable for the highly exothermic hydrocarbon synthesis reaction, offering more isothermal operation that enables easier control of selectivity. Comparatively smaller catalyst particles also result in high catalyst activity.

#### Product work-up

Following this step the broad range hydrocarbon streams are sent to the product work-up, a version of refinery hydroprocessing technology for upgrading into high-quality products, such as Sasol SPD diesel and naphtha. This synthetic diesel has better environmental and performance profiles than conventional diesels.

A GTL facility can be designed to also include other products such as high quality base oils, kerosene and various chemicals providing an opportunity for value uplift and diversification of the business under the right circumstances.

The strength of the Sasol SPD process is not simply the inherent quality of the three component technologies but also the way they are combined and further integrated to increase efficiency and optimise output. It is this fact, together with the energy integration and process simplification achieved by Sasol that has enabled an economic GTL process.

#### Shell

The Shell GTL process, Shell Middle Distillate Synthesis (SMDS) involves three key conversion steps.



### The Shell gasification process

In the first step of the GTL process, natural gas (methane) is converted into a mixture of carbon monoxide and hydrogen which is known as syngas. The natural gas is partially oxidised in a non-catalytic reaction with 99.8% pure oxygen. The reaction is conducted at temperatures around 1,300°C in a steel vessel clad with insulating material. The reaction has a high selectivity, meaning it achieves a greater than 95% conversion of the carbon in methane to carbon in carbon monoxide. Waste heat is used to make steam, which is then used to power equipment.

### Heavy paraffin synthesis

The syngas is then passed through proprietary multi-tubular fixed-bed synthesis reactors and converted into long-chained waxy hydrocarbon molecules with the aid of Shell's proprietary, cobalt-based F-T synthesis catalyst.

The multi-tubular fixed-bed reactor design (made up of tens of thousands of reactor tubes) is a robust, proven technology. It allows simple scale-up by adding more tubes. The design ensures that catalyst is distributed uniformly. It also enables complete separation between the products and the catalyst, eliminating the need for catalyst separation and filtration and ensuring minimal catalyst losses and product contamination. The reactor tubes are surrounded by boiling water to provide cooling for the highly exothermic synthesis process, recovering process heat as steam.

### Heavy paraffin conversion

In the third step, the long-chained waxy hydrocarbon molecules are converted into middle distillates in the heavy paraffin conversion unit followed by distillation. Heavy paraffin conversion uses selective catalytic hydrocracking – the long-chained waxy hydrocarbon molecules

are brought into contact with pure hydrogen at high temperature and high pressure in the presence of a proprietary catalyst, which facilitates the breakdown of the long paraffinic molecules into smaller ones.

The process also shapes the molecules to achieve desired GTL product properties. This process produces high-quality liquid fuels, including GTL gasoil and GTL kerosene as well as 100% paraffinic GTL naphtha.

Shell has developed further proprietary processes for the production of GTL normal paraffins (feedstock for the manufacture of biodegradable detergents) and GTL base oils, which are used to make high-quality lubricants.

GTL normal paraffin is produced by the distillation of the waxy hydrocarbon molecules from the heavy paraffin synthesis process to produce a fraction consisting of hydrocarbon molecules with 10 to 13 carbon atoms. This fraction is subsequently processed with hydrogen over a proprietary catalyst to remove all undesirable components. GTL base oils are produced by distillation under vacuum of a heavy stream from the heavy paraffin conversion unit to produce "waxy raffinate" that is subsequently processed with hydrogen over a proprietary catalyst to remove all traces of heavy waxy material.



Shell's GTL process, SMDS, is in operation at the Pearl GTL plant in Qatar (pictured) and Bintulu in Malaysia.



# Glossary

**Acidising** This technique is used in tight gas extraction and involves pumping acids into a well to dissolve the limestone, dolomite and calcite cement between the sediment grains of the reservoir rocks.

**Adsorbed gas** Natural gas that has accumulated on the surface of a solid forming a thin film.

## Advanced conversion technologies

These transform waste into energy and include technologies that use combined-cycle turbine systems or pyrolysis, or anaerobically generate biogas.

**Anaerobic digestion** The breakdown of organic matter by microorganisms in the absence of oxygen.

**Aquifer** An underground layer of gravel, sand, silt or permeable rock saturated with water. The two main types of aquifer are “confined” and “non-confined”.

**Biogas** Gas produced by anaerobic digestion.

**Biomass-based fuels** These include, but are not limited to wood, sawdust, grass cuttings, biodegradable domestic refuse, charcoal, agricultural waste, crops and dried manure.

**Bio-SNG** Bio-synthetic natural gas, which is produced by the gasification of cellulosic materials such as forestry residues and crops. After initial gasification, a gas conditioning step usually follows and then SNG synthesis and gas upgrading. It can also be converted to liquid biofuels.

**Black shale** Thinly bedded shale that is rich in carbon, sulphide and organic matter, formed by anaerobic decomposition.

**Brittleness index (BI)** A measure of the ability of rock to fracture.

**Btu** British thermal unit, a measure of the heat value (energy content) of fuels with 1 million Btu roughly equal to 1 million cubic feet (28.3 cubic

metres) of natural gas. Prices in the USA are denominated in dollars per million Btu.

**Carbon capture and storage (CCS)** A combination of technologies which can potentially play a major role in managing and reducing global CO<sub>2</sub> levels. The CCS process involves separating carbon dioxide from industrial and energy-related sources and isolating it from the atmosphere, mostly in geological traps, such as old oil and gas fields, or aquifers.

**Clathrate** A solid compound in which molecules of one substance are trapped in the crystal lattice of another; also known as hydrate.

**Cleat** A natural fracture in coal.

**Coal-bed methane (CBM)** Also called coal-seam gas, this is natural gas found in coal seams formed by the decomposition of organic matter in coal. The gas is adsorbed to the surface of the coal. Depending on the nature of the formation, the coal's cleats can also contain free gas. CBM is extracted from virgin coal seams; the gas from working mines is known as coal-mine methane (CMM) and that from closed mines as abandoned-mine methane (AMM).

**Combined-cycle gas turbine (CCGT)** This technology uses a gas turbine to generate electricity and then captures the resulting waste heat to create steam, which in turn drives a steam turbine. It has much greater thermal efficiency compared to single-cycle power plants.

**Dewatering** A process used in CBM extraction whereby water is pumped from a coal seam to lower the pressure, which causes the gas to desorb and flow via cleats into the well.

**Directional drilling** See horizontal drilling.

**Dry hole** A well that cannot produce oil or gas in sufficient quantities to warrant completion.

**Flowback** The return of fluid to the surface after the completion of a hydraulic fracture.

**Fluid-bed gasifier** A gasifier that converts biomass waste products into a raw synthesis gas (syngas) for subsequent processing with a

plasma converter. The material for the bed of the gasifier is sand, char or a combination of both.

**Fossil fuels** Hydrocarbon fuels such as coal, oil, and natural gas formed by the decomposition of prehistoric animals and plants.

**Fracking/fracking** An abbreviation for hydraulic fracturing. There are alternative spellings.

**Free gas** Natural gas contained in pores in rock.

**Gas hydrate** Gas hydrates can form under conditions of low temperature and high pressure in pipelines and block them. They are generally removed by reducing pressure, heating or using chemicals, such as methanol, to dissolve them. Methane hydrates also occur in great quantities in permafrost regions and subsea sediments and are a potentially vast energy resource.

**Gas-to-liquids (GTL)** A process that converts natural gas into higher-value products such as diesel, naphtha and kerosene. The basic process sees methane converted to carbon monoxide and hydrogen (syngas) for processing in a reactor to produce paraffinic waxes which can then be refined.

**Greenhouse gas (GHG)** Any of the atmospheric gases that contribute to the greenhouse effect by absorbing infrared radiation produced by the solar warming of the Earth's surface. Greenhouse gases include carbon dioxide, methane, nitrous oxide and water vapour. These gases can be naturally occurring or produced by human activity.

**Greenhouse effect** The phenomenon whereby thermal radiation from the Earth's surface is absorbed by atmospheric greenhouse gases and then re-radiated, causing the average surface temperature to rise.

**Horizontal drilling** Also known as directional or slant drilling, this is the practice of drilling through formations at an angle of up to 90 degrees from an initial vertical bore. It allows multiple sub-surface locations to be reached from a single pad, reducing costs and the surface footprint.

Hydraulic fracturing is the process of creating fractures in underground rock formations to extract natural gas (or oil). It involves pumping a mixture of water, chemicals and proppants (often sand) into a well under high pressure. The proppants keep the fractures open, allowing the gas to flow.

**Hydrocarbon** A naturally occurring organic compound comprising hydrogen and carbon. The most common hydrocarbons are natural gas, oil and coal.

**Inhibitor injection techniques** The injection of substances such as methanol to assist with the extraction of natural gas hydrates. Such an injection will dissolve the methane from the hydrate so the gas is released.

**In situ** Geological term meaning in the original location or position, such as an outcrop that has not been upset by faults.

**Liquefied natural gas (LNG)** In liquid form natural gas takes up 1/600 of its gaseous volume making it easier and cheaper to transport if pipelines are not available. The gas is liquefied by cooling to a temperature of -162°.

**Methane hydrate** A lattice of one molecule of methane surrounded by a "cage" of six frozen water molecules. Methane hydrates are only stable in a limited range of pressures and temperatures.

**Microseismic fracture mapping** Provides images of fractures by detecting microseisms or micro-earthquakes that are set off by shear slippage on bedding planes or natural fractures adjacent to hydraulic fractures.

**Multilateral drilling** Drilling techniques pertaining to wells where there is more than one branch radiating off the main borehole.

**Natural gas** Largely comprises methane ( $\text{CH}_4$ ) with some carbon dioxide and other impurities such as sulphur-based gases.

**Permeability** This measures the ability of fluids to flow through rock or other porous media.



**Plasma converter** This uses the intense ultra-violet light and heat from a plasma arc to crack the long chain and aromatic hydrocarbons in raw syngas. A pure, highly calorific, hydrogen-rich syngas is produced.

**Play** A group of fields with similar trap (see below) structures.

**Porosity** The ratio of the volume of space to the total volume of rock.

**Proppants** Small particles of sand or other materials such as ceramic or glass, which are used to hold open cracks in rocks produced by hydraulic fracturing.

**Pyrolysis** Chemical decomposition induced in organic materials by heat with little or no oxygen present. The process transforms hazardous organic materials into gaseous components, small quantities of liquid and coke. Pyrolysis of organic materials produces gases, including carbon monoxide, hydrogen, methane and other hydrocarbons. This is often carried out under pressure and at high temperatures (above 400°C).

**Recovery rate** The rate at which natural gas is removed from a reservoir.

**Reforming** The process of converting methane to hydrogen using a catalyst and steam.

**Seismic survey** This consists of emitting waves through the subsoil and recording their return using groups of sensors. Seismic is one of the basic and essential methods used in oil and gas exploration to generate information concerning the shape of the underground strata in the explored region.

**Shale** A fine-grained sedimentary rock composed of muds, flakes of clay minerals and tiny particles of other minerals such as quartz and calcite.

**Shale gas** Natural gas held in shale, rocks made up of thin layers of fine-grained sediments. Shale formations have very low permeability.

**Slant drilling** See horizontal drilling.

**Slick water fracturing** A method of hydraulic fracturing that adds chemicals to water to increase the fluid flow and increases the speed at

which the pressurised fluid can be pumped into the wellbore.

**Sweet spot** The area of a gas play with the best potential for commercial exploitation due to its higher porosity and permeability.

**Syngas** An abbreviation of "synthesis gas", a mixture of gases made as feedstock. It is produced by reacting steam, or steam and oxygen, with a heated carbon-containing material such as natural gas.

**Thermal maturity** The amount of heat to which a rock has been subjected. A thermally immature rock has not been subjected to sufficient heat to start the process of converting organic material into oil or gas.

**Thermogenic** Generated or formed by heat.

**Tight gas** Natural gas found in tiny pores in low-permeability rock formations which have to be stimulated before the gas will flow. As the rock is often sandstone, the term tight gas sands is also common.

**Trap** the geological structure in which hydrocarbons build up to form a gas or oil field.

**Total organic carbon (TOC)** The concentration of material derived from decaying vegetation, bacterial growth and metabolic activities of living organisms or chemicals found in source rocks.

**Unconventional resource** An umbrella term for oil and natural gas produced by means that do not fit the criteria for conventional production. The term is currently used to reference oil and gas resources whose porosity, permeability, fluid trapping mechanism or other characteristics differ from conventional sandstone and carbonate reservoirs.

**Ultrafiltration** A technique to separate suspended solids from waste water that results from oil and gas production. Ultrafiltration is not fundamentally different from other forms of filtration, such as microfiltration, nanofiltration or gas separation, except in terms of the size of the molecules it retains which are very small.

**Viscosity** A property of liquids that indicates their resistance to flow.

**Wellbore** A channel created by drilling.

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*CBM in Australia:* Santos (78, 81 & 82), Adrian Giddings/ISC (79), Origin Energy (80).

*Unconventional gas in Canada:* Encana Corporation (84 & 85), Apache Corporation (86), Devon Energy Corporation (88), District of Kitimat (89).

*Unconventional gas in China:* CNPC (90), Total (91), Adrian Giddings/ISC (92), Royal Dutch Shell (93 upper), China United CBM (93 lower), Andrew Wong/Getty Images/Rolls-Royce plc (94), CDX (95).

*Gas hydrate:* Natural Resources Canada & Aurora College (96), US Geological Survey (99 upper), KIGAM (99 lower), KIGAM, KNOC, KOGAS and GHDO (100), DOE (101).

*Gas-to-liquids:* Max Planck Institute of Coal Research (102), Petro SA (104 upper left), Oryx GTL (104 upper right & 108), Royal Dutch Shell (104 bottom, 105 & 109), Eudon Hickey/Escravos GTL (106), CompactGTL (107).



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