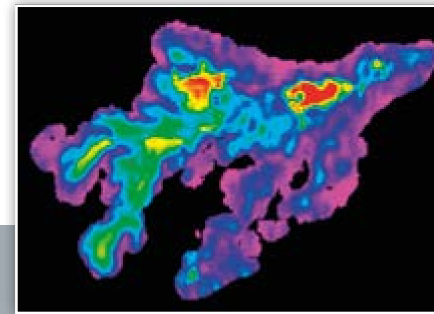
VOL. 12, NO. 5 – 2015

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



GEOPHYSICS:
A Simple Guide to Seismic Amplitudes

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Southern Chile's Ring of Fire

INDUSTRY ISSUES
Africa's Oil and Gas Future

RESERVOIR MANAGEMENT
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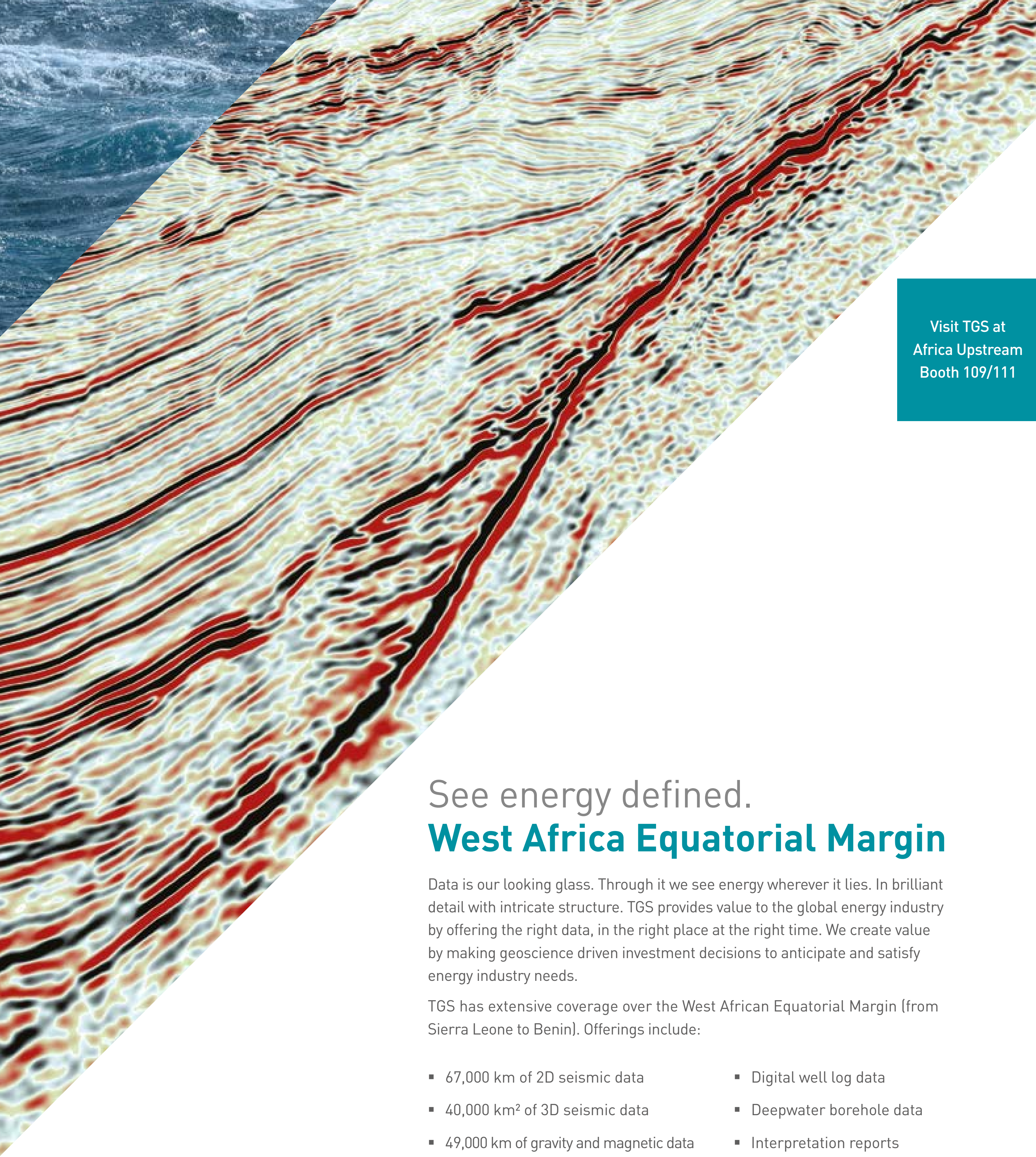
Uruguay: Small Country, Big Opportunities



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GEO ExPro
GEOSCIENCE & TECHNOLOGY EXPLAINED

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This edition of *GEO ExPro* magazine focuses on Africa, South America and Geophysics

Ghana and the 'oil curse'; why is oil a political football in much of Africa?

COLUMNS

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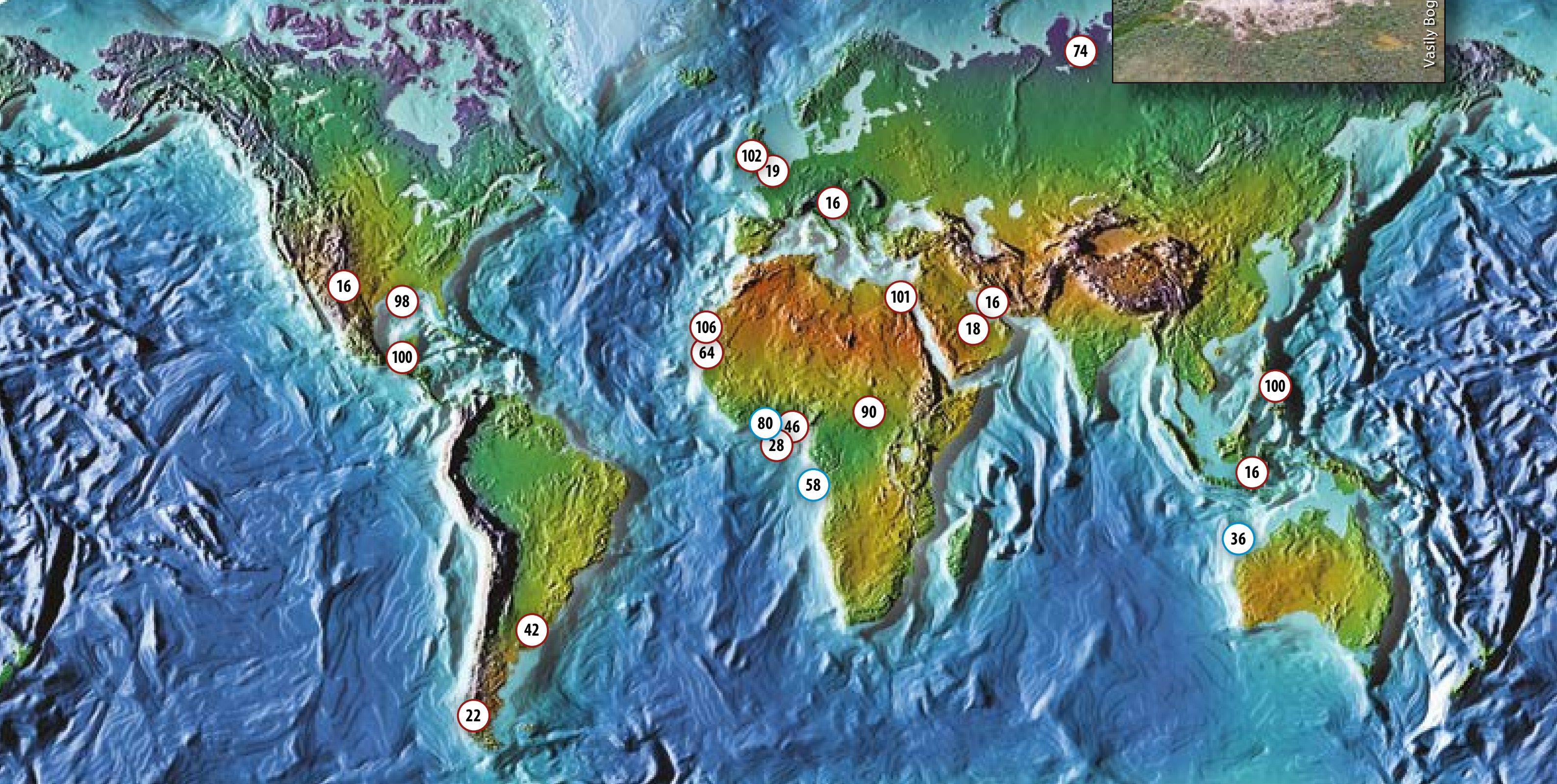
Why are large craters forming in the permafrost zone of northern Russia?



Bountiful Continents

Peru: a long history.

Long before Columbus sailed the Atlantic in 1492, the inhabitants of South America were aware of the bounty of hydrocarbons in their lands. They collected oil from seeps and used it for illumination and caulking canoes, and for medicine – very good for gout, apparently. Exploration for hydrocarbons in the modern sense has been underway for over 150 years and the first discovery in South America, the Zorritos Field in Peru, was made in 1869. Similarly, seeps throughout Africa have been known and exploited for centuries, and the first oil discovery in Egypt was made in 1869. According to the BP Statistical Review of World Energy, Africa and South America together contributed nearly 20% of the world's total oil production in 2013.

So both these continents have a proud history in the oil industry and continue to surprise us. In the early days of exploration who would have imagined that the sediments below the deep waters of both sides of the South Atlantic held immense riches under the salt; possibly 176 Bbo still to be discovered off Brazil alone. On the other side of the ocean, the North West African Atlantic Margin was long ignored, but is now holding out promise of great riches, as discussed in this edition of *GEO ExPro*.

How will these continents fair in today's straightened times? President Obama in his recent visit to Alaska said that he believed that the US should rely on domestic production rather than on foreign imports, but not all countries have that option. It is important that the technological advances that have already meant that US shale oil and gas is being produced much more efficiently than it was just a couple of years ago are transferred throughout the world for the benefit of all.

However, technology is not the reason why many companies find working in Africa and South America difficult. Many of the nations of these continents are caught up in the oft-cited 'oil curse', with impenetrable bureaucracy, behemothic state oil companies and impractical legal and profit sharing requirements. When there are many opportunities for oil companies to spend their much-reduced exploration budgets, it is easy to see why these scarce dollars may move away from 'difficult' countries to ones where there are fewer bureaucratic obstacles. ■

Jane Whaley
Editor in Chief

SOUTHERN CHILE'S RING OF FIRE
Climbing the glacier at the summit of Villarrica, which is Chile's most active volcano. It is a classic stratovolcano, typically found in subduction geodynamic settings.

Inset: A tuning wedge model from a thinning soft sand reservoir.

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A Scramble for Market Share

The world is drowning in oil, and no rise in prices is expected for some time.

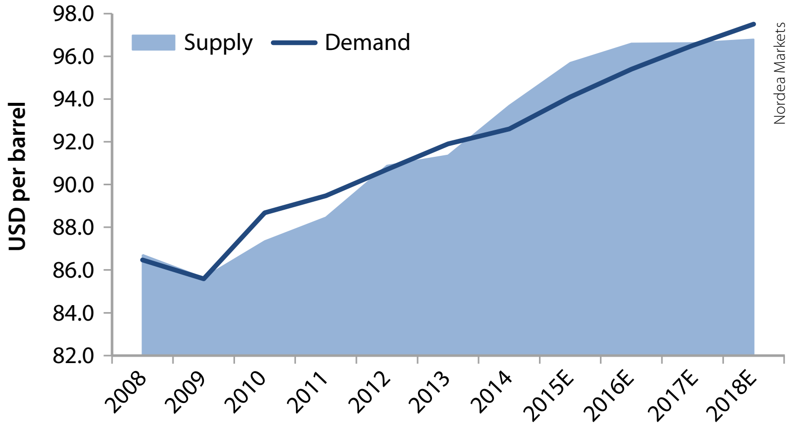
Oil prices are back to the January lows after regaining strength in Q2, and only a modest pick-up in oil prices is foreseen in the near future. A sharp upswing in OPEC production and no clear signs yet of contraction in non-OPEC supply have left the market awash with cheap oil. Until we see a sufficient contraction in supply, oil prices will remain elevated.

OPEC's surprise move in November last year to transform itself from being a market-dominating cartel to one focusing on market share has changed the price-setting dynamics of the oil market completely. For the first time since the early 1970s the role of being swing producers has moved back from Saudi Arabian to US drillers. The US tight/shale oil production has been more resilient to lower prices than expected as improving techniques have increased drilling efficiency. But with oil prices at levels last seen during the 2008–09 financial crisis, we expect a major decline in US shale production. Saudi Arabia does not yet seem ready to give up its strategy to regain market share. The Kingdom is expected to continue to produce at near-record levels until its goal is accomplished. This means that more of the high-cost oil production from Canada, Russia and Norway and US shale oil are squeezed out of the market. Add to this the historic agreement on Iran's nuclear programme, which is expected to bring back 700 bpd to the market next year. Low oil prices and massive investment cuts of US$ 180 billion in 2015 according to the IEA will eventually ease the supply glut. The supply overhang is expected to persist well into 2017. The more capacity the low-cost Middle East producers are able to build, the lower the demand for high-cost oil such as deepwater, Arctic, oil sand and tight oil will be going forward. Production is redirected from high-cost to low-cost areas.

Oil demand growth is expected to rise markedly this year as low petrol prices have made motorists in China and the US rush to the pumps and stocks are building worldwide. The momentum is expected to ease next year as efficiency gains, fuel subsidy cuts and a stronger US dollar offset the effect of lower oil prices. China will continue to be an important driver, but oil demand growth in the rest of Asia, especially India, is picking up pace. Rebalancing the Chinese economy to more consumption-driven growth is expected to curb oil demand growth. A hard landing for China is a clear and mounting threat to future oil demand growth, while lower commodity prices and tighter external financial conditions are expected to dampen it in Latin America and the Middle East. Energy markets will follow closely the progress of the UN Climate conference in Paris as the outcome could potentially have a big impact on future energy trends.

Thina Margrethe Saltvedt

Global balance – drowning in oil.



ABBREVIATIONS

Numbers
(US and scientific community)

M: thousand	$= 1 \times 10^3$
MM: million	$= 1 \times 10^6$
B: billion	$= 1 \times 10^9$
T: trillion	$= 1 \times 10^{12}$

Liquids

barrel = bbl = 159 litre

boe:	barrels of oil equivalent
bopd:	barrels (bbls) of oil per day
bcpd:	bbls of condensate per day
bwpd:	bbls of water per day

Gas

MMscfg:	million ft^3 gas
MMscmg:	million m^3 gas
Tcfg:	trillion cubic feet of gas
Ma:	Million years ago

LNG

Liquified Natural Gas (LNG) is natural gas (primarily methane) cooled to a temperature of approximately -260 °C.

NGL

Natural gas liquids (NGL) include propane, butane, pentane, hexane and heptane, but not methane and ethane.

Reserves and resources

P1 reserves:
Quantity of hydrocarbons believed recoverable with a 90% probability

P2 reserves:
Quantity of hydrocarbons believed recoverable with a 50% probability

P3 reserves:
Quantity of hydrocarbons believed recoverable with a 10% probability

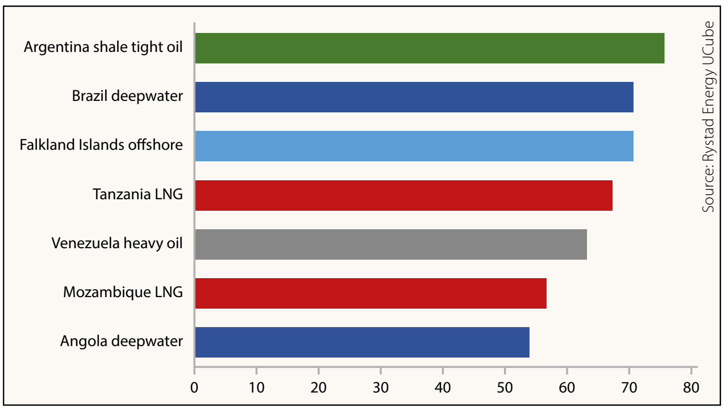
Oilfield glossary:
www.glossary.oilfield.slb.com

Converting Discoveries Into Production

A key challenge for the E&P industry over the few next years will be to mature the discoveries made during the last five years in South America and Africa, and convert them into commercial fields.

The two regions with the largest exploration success over the last decade are South America and Africa. The sub-salt discoveries in Brazil and the gas discoveries in offshore Mozambique and Tanzania were the key drivers for this success. At the time of their discovery, these finds were commercial and expected to generate high activity and production growth in the medium term.

Average Brent real breakeven oil price for different sources of new production.



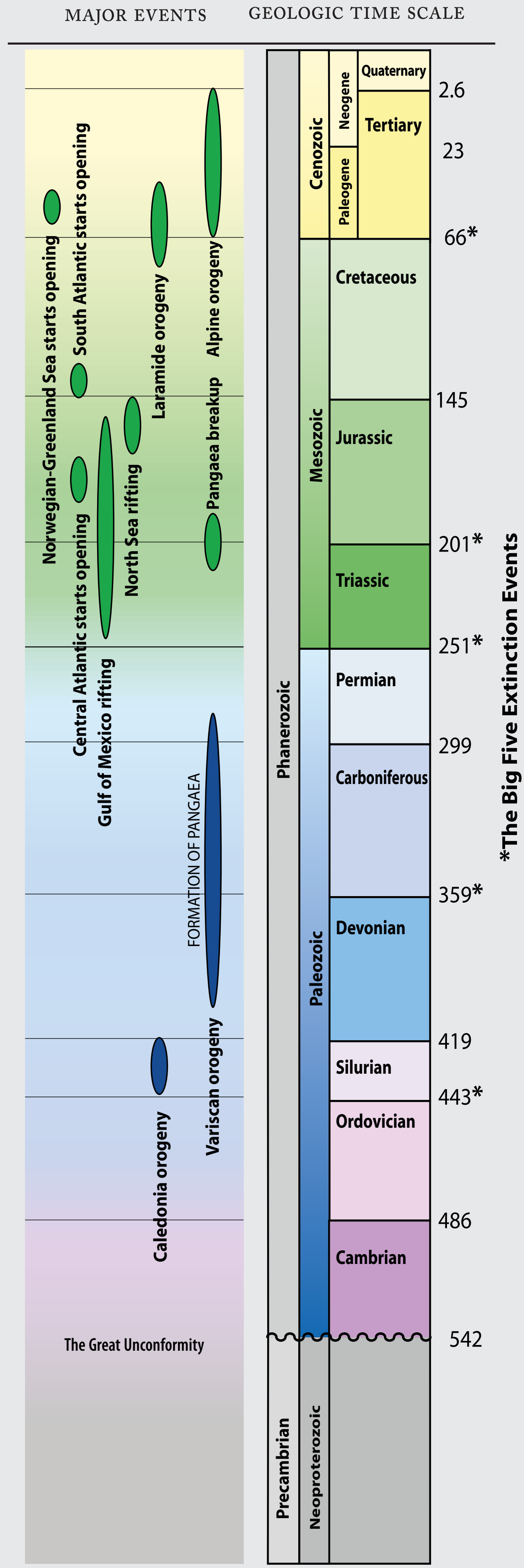
The figure shows the average real Brent breakeven oil price for different sources of new production. The breakeven price is the oil price that gives a net present value of zero when all future costs and governments' take are included. By looking at the chart, few of the resources are commercial with an oil price lower than US$50–60 per barrel. To improve the economics of the discoveries, both the E&P and oilfield service companies will have to try to be more efficient and come up with new technology.

In addition to the economics of the discoveries, other factors are making it difficult to develop the new volumes. In Brazil the combination of strict local content requirements, scarcity of human capital, cost inflation, corruption, and the fact that Petrobras is the sole operator for 'strategic' assets has limited the development. This problem became visible when Petrobras recently revised down its 2020 production goal by 1.5 MMbopd.

The development of LNG projects in East Africa has also slowed down; here new fiscal regimes in Tanzania have contributed to uncertainty around the projects, and in Mozambique operators are struggling to come up with joint development solutions.

With the current low commodity prices, the sanctioning of new projects in Africa and South America will be challenging. The focus will be on cost saving and efficiency gain to make these fields more attractive. Rystad Energy believes that in the long term commodity prices have to come up. When they do these regions will be well positioned to grow due to the recent exploration success. ■

Espen Erlingsen, Rystad Energy



Patience in the Time of Collaboration

'Wisdom comes to us when it can no longer do any good.'

Gabriel García Márquez, *Love in the Time of Cholera*

As I made my way across a bright but autumnal London to the annual **PESGB/HGS Africa Conference** I wondered what sort of event we would have this year. With the industry adjusting to the new price regime and news of reduced exploration budgets and layoffs filling the business pages, I was preparing to find the atmosphere at the Islington Business Design Centre (the venue for this year's event) subdued. Imagine my surprise then when I found that the usual buzz was there and for the 600+ attendees it was seemingly 'business as usual'.

There was, of course, acknowledgment of the current downturn, but as has been remarked upon many times before, explorationists are optimistic types and while topside issues continue to challenge, the geology remains the same; unlike capital markets, geological understanding tends to move in one direction only – upwards!

A common theme from many of the speakers at this year's event was a call for greater **collaboration** – a recurring theme in *GEO ExPro*'s pages also – and more **patience**.

Greater collaboration is to be welcomed but as the Q&A sessions at conferences demonstrate, we have a way to go before we can be clear when something is shareable and when it is 'competitive advantage'. A recent conversation with a colleague on the subject of proprietary technologies provided me with some insight: "Oil companies should explore for and exploit oil and gas accumulations and not create and patent technologies," he argued. "Let the service companies carry out the business of R&D and deployment of new technologies." I have some sympathy with the notion. Oil companies should compete for the best acreage, unquestionably; they should compete to provide the best service, indisputably; but competing on a technological level can create barriers to collaboration on a technical level.

Lessons From History

On the theme of patience I recommend the excellent history of the North Sea oil industry, *Tales from Early UK Oil Exploration 1960–1979**, where Richard Moreton has recorded the thoughts of some of the key players of an earlier era and has provided us with a snapshot of time when the industry was undergoing a period of adjustment, in a similar, if not exactly anomalous way to today. As he said at the time of publication (1995): "Our business today is leaner, meaner and probably fitter… than ever before, but at what cost (in human terms)… the process of slimming down and streamlining by a number of our major companies has simultaneously opened up new opportunities elsewhere – particularly in the field of high technology, geoscience consultancies – but a gap still remains… between jobs lost and jobs created."

Sounds familiar?

Maybe we have a little way to go before our patience is fully tested. Again from Richard Moreton's wonderful book, here are the words of Dr. Colin Campbell, from a special lecture to the PESGB (*The End of an Era – What Now?*) in 1994.

"In a long historical perspective the oil age is a fleeting one when Mankind burns up the world's recoverable resources formed over eons of geological time. The span of the oil age is now becoming known with virtually all prolific provinces already found. It falls into three epochs: a Period of Growth from its birth to 1970; a Period of Transition from 1970 to 2000; and a Period of Decline from 2000 to its end…

"… The days of the fat cat frontier explorer are almost over, but more pedestrian productionists can expect to earn a modest living worldwide much like mining geologists do.

"Advice: stay technical, shun promotion, be accommodating and don't turn down any good offers in banking."

Maybe you survived the '90s 'massacre' but do you have the patience to continue now? After all, we know what happened to bankers, don't we… ■

Will Thornton, Digital Editor, *GEO ExPro*

** Tales from Early UK Oil Exploration 1960–1979, compiled and edited by Richard Moreton. PESGB 30th Anniversary Book, 1995.*

Patience is a virtue – but how long will we have to wait?

Just Like the Real Thing

3D printing offers a novel non-destructive method of petrophysical rock analysis

Understanding the petrophysics of a reservoir rock, defined as the study of the physical and chemical properties of rocks and their contained fluids, has long been an integral part of efficient and successful production of oil and gas in the petroleum industry. To fully understand the petrophysical properties of reservoir rocks, pore-scale imaging and 3D digital modelling are used as routine methods to investigate rock characteristics that influence flow. The analytical process often requires multiple samples and some of the processes can destroy the original sample.

"Making copies of the natural rocks using 3D printing techniques offers the petroleum industry an additional way to analyse core samples," says Sergey Ishutov, PhD candidate, and Franek Hasiuk, Assistant Professor in the Department of Geological and Atmospheric Sciences at Iowa State University. "It is important to preserve limited or even rare core samples from destructive analysis. Analysing a 'copy' will allow different tests to be performed on an identical pore network. These models can be printed in multiple materials to control for geometrical effects on properties from the pore network. In addition, when flow properties are calculated on a digital pore network model with computational methods, we can 3D print that digital pore network and test it in the lab."

3D Printing

3D printing got started in the 1980s with what was called Rapid Prototyping technologies. The original process was conceived as a fast and cost-effective method for creating prototypes for product development. The first patent was issued in 1986 to Charles Hull for a stereolithography apparatus. Mr. Hull went on to co-found 3D Systems Corporation, one of the largest in the 3D printing business today. In the early 1990s, researchers at Massachusetts Institute of Technology (MIT) developed their trademarked 3DP and MIT remains an innovative leader in the industry.

Advance ahead 30 years, and 3D printing has become commercially available in just about all sectors of the economy. It has become much cheaper, faster, uses a wide variety of materials and is available in many sizes and capabilities. Amazingly, 3D printing can now create human tissue, prosthetics, car parts, rocket parts, guns, food, and the list goes on and on.

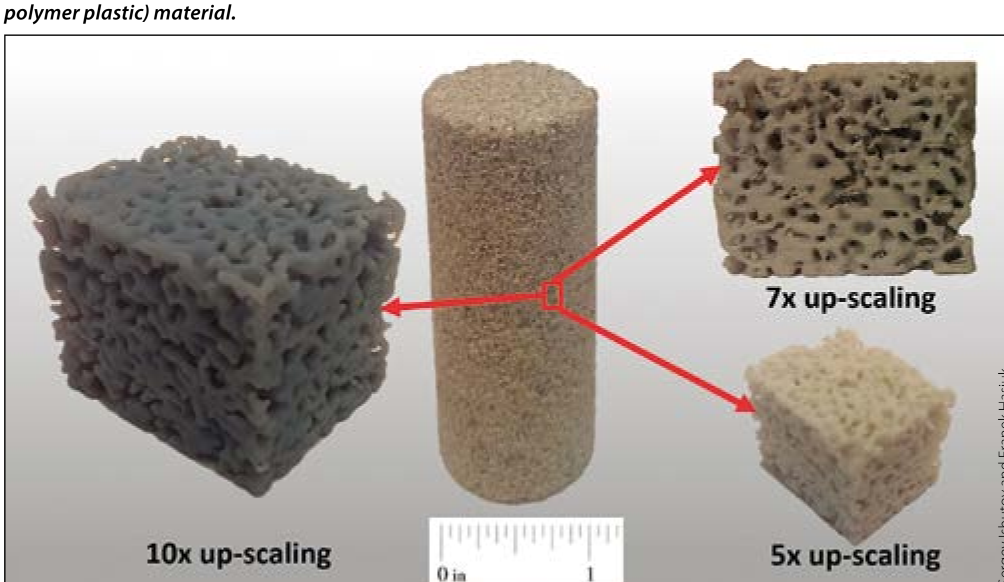
Making the Copy

Natural rocks contain a variety of different grain sizes, types, and shapes cemented together. Among the grains and cement, a typical reservoir rock will also have pore space containing fluids and connections (pore throats) through which the fluids can be extracted. "To manufacture porosity models of a sandstone, we use computed tomography (CT) scans and petrographic data from the natural sample," say Sergey and Franek. "The first step is an acquisition of two-dimensional (2D) CT images that are subsequently reconstructed into a 3D digital rock model composed of voxels (a 'volume element' similar to a pixel in 2D images), which are assigned a grayscale value based on x-ray attenuation during CT. The second step is to segment the volume into grains and pores. The third step is to 3D print the surface representing the boundary between the grains and pores. The materials we can print include plastic as well as powder-based gypsum and silica. The fourth step in the workflow, where it gets fun, is a comparison of petrophysical properties of natural rocks with their 3D printed copies (for example, via mercury porosimetry).

"3D printing offers a novel and non-destructive method of petrophysical rock analysis (preserving original rock samples), using destructive lab techniques to obtain rock properties that can then be compared directly with measurements from original rock samples, estimated from computational methods, or culled from the literature data. Repeatability in manufacturing, the flexibility in up-scaling and down-scaling digital models, and variability of 3D printing materials are the main directions where 3D printing can be advanced with a high potential to improve our ability to copy natural reservoir rocks." ■

Thomas Smith

3D printed samples from the core plug of Idaho grey sandstone. Models are manufactured in PLA (Polylactic Acid polymer plastic) material.



Little and Large

Seismic supply companies are helping operators face the downturn by providing cost-effective enhancements to existing product portfolios.

A Nomad 90 Neo operating in Oman.

With the oil price for this year staying at the low levels seen during late 2014, the seismic market in 2015 is understandably somewhat depressed. Many seismic supply companies are therefore turning to extensions of existing technologies to ensure the most cost-efficient solutions for operators. An example is seismic acquisition equipment specialist Sercel, which demonstrated at the June EAGE Annual Meeting in Madrid that it is committed to providing economic and effective enhancements for operators on its existing large product portfolio, despite the increasingly challenging environments faced by its customers.

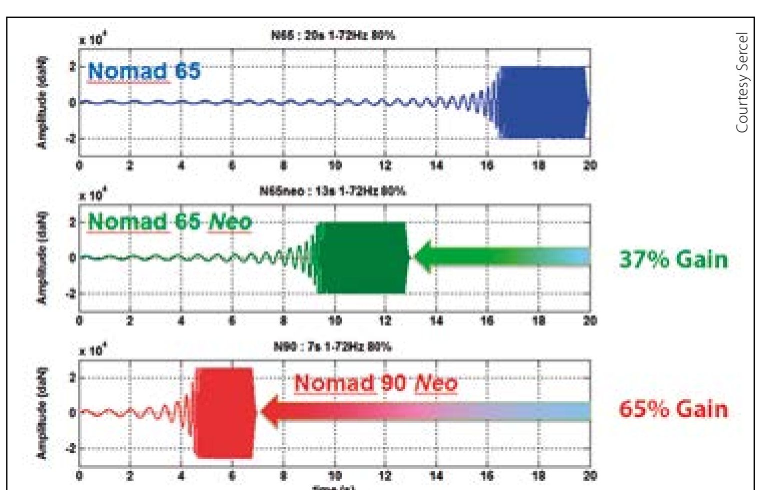
The company sees a reduction in land seismic activity of some 25% at present, with the overall market sustained by 'mega-crews', mainly in the Middle East. Seismic crews and their clients are looking for continuous improvements in speed of coverage and also the ability to input more broadband energy for better imaging. The mega-crews often work in desert terrain where obstructions are not a significant issue and the key is productivity.

With this in mind, Sercel has added the broadband, super-heavy Nomad 90 *Neo* vibrator to its seismic fleet. This 90,000 lbf (400 kN) peak force vibrator specialises in low frequencies, with full output (80,000 lbf/355 kN) reached at 5 Hz. Compared to 'conventional' vibrators, the Nomad 90 *Neo* can spend a significantly lower period in the time-consuming low-frequency end of the sweep but still output the same energy. The diagram (right) shows gains made by these vibrators for a sweep starting at 1 Hz. The Nomad 90 *Neo* has a high frequency performance with rated frequency up to 250 Hz, and an ultra-stiff baseplate that improves the fidelity of the high frequencies.

The Nomad 90 *Neo* joins the other vibrators in the Sercel fleet, with the Nomad 65 *Neo* (also a broadband performer, with a 62,400 lbf/280 kN peak force achievable from 5.4 Hz) as the workhorse, and the light Nomad 15 (17,300 lbf/77 kN) as the baby of the bunch. The Nomad 15 offers great flexibility for operators needing to work in challenging areas such as cities and forests or in places with restricted access, as well as in environmentally sensitive zones. It has a frequency range up to 400 Hz, with full drive reached from 7 Hz, and is highly manoeuverable thanks to its weight of only 9 tonnes and its four-directional wheels which offer various directional modes. All vibrators in the fleet are compatible with the Intelligent Power Management option that limits noise levels and reduces fuel consumption by up to 15% when compared with a vibrator without this option.

Another Sercel development highlighted at the EAGE meeting was the GeoWave® II downhole seismic array tool. As the frontiers of hydrocarbon exploration are pushed to ever deeper and hotter environments, there is more demand for wireline tools that can withstand higher temperatures and pressures. In 2014, Sercel launched the GeoWave II VSP digital tool, with a designed specification of 400°F (205°C) and with no requirement for active cooling. In June 2015, the company announced that in a field trial in France it had deployed the new tool in a 5,000m deep well. Temperatures of 362°F (183°C) had been reached during 23 continuous hours of testing, with a total exposure to 347°F (175°C) for 39 hours. In the trial a 16-level GeoWave II system recorded multiple VSP shots in open and cased holes successfully. It also recorded high frequency micro-seismic events at sample rates including 0.25ms. The pressure rating of the tool is up to 25,000psi (1,725bar), with a maximum wireline deployment of 120 levels and 3,000m length array.

Paul Wood



Sweep times needed to give the same energy output for various Nomad options (1-72 Hz sweep).

Iran at the Centre of Emerging Acreage

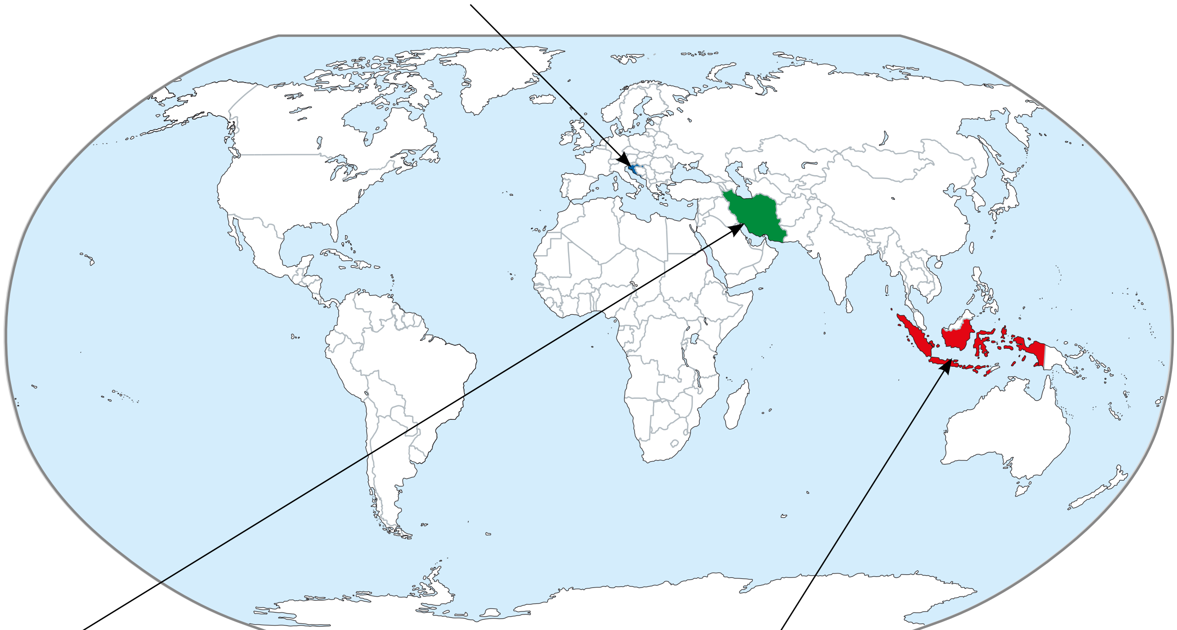
KEN WHITE

Croatia

Nearly all open acreage to be offered

Croatian Hydrocarbon Agency president Barbara Doric stated on 29 July her agency's plans to launch a second phase of both onshore and offshore licensing rounds in September 2015. The offshore round will consist of 25 blocks, while the onshore round will cover almost all of the open continental territory, excluding the islands. In January 2015, five companies were awarded licences covering 10 exploration blocks in the Adriatic Sea in Croatia's first licensing round, which had offered 29 blocks in the eastern Adriatic Sea covering a total of 36,822 km^2. The round was Croatia's first offshore bid round, following the establishment of the country's first hydrocarbon law in July 2013.

Offshore Croatia is underexplored, with known plays including the Pliocene gas plays of the northern and central Adriatic, and pre-Tertiary oil plays of the southern Adriatic. Croatia's potential reserves could prove significant both for the country and a wider region that is belatedly coming to terms with the importance of energy diversification in the wake of the Ukraine crisis. The situation undermined the case for Gazprom's South Stream Pipeline and elevated Croatia's position at the centre of countries that South Stream would have supplied. On the downside, there is a rising chorus of concern about the potential damage that exploration could do to the country's tourism sector, which generated revenues in excess of 7 billion euros in 2013. ■



Iran

Preparing for post-sanctions offering

The removal of crippling sanctions following mid-July's nuclear agreement with world powers has paved the way for the rejuvenation of the Iranian oil and gas sector and the industry is primed to capitalise on the country's wealth of resources. It all begins in London at the first Iran Oil & Gas Post Sanctions Summit, to be held 14–16 December, promoted as 'the event of the year in the energy calendar'. As the regime moves to repair its battered economy and improve the Islamic Republic's relations with the western world, it is believed that up to 45 oil and gas opportunities, both development and exploration projects, will be showcased at the event. In addition to extensive discussion on the opportunities that will be open to foreign companies, new contract terms will be unveiled by Seyed Mehdi Hosseini, Chairman of the Oil Contract Restructuring Committee. It is understood investors will not be allowed to claim ownership of the country's energy reserves but instead will be offered a 'risk service contract', which will offer payback in the form of cash or oil allocation.

Iran has the world's fourth-largest proved national reserves of oil, most of it cheap to produce at between US$ 8 to 10 per barrel – and is home to the biggest proved reserves of natural gas, 18% of the global total. The renewed energy drive ultimately aims to double current oil production levels of around 2.85 MMbpd. ■

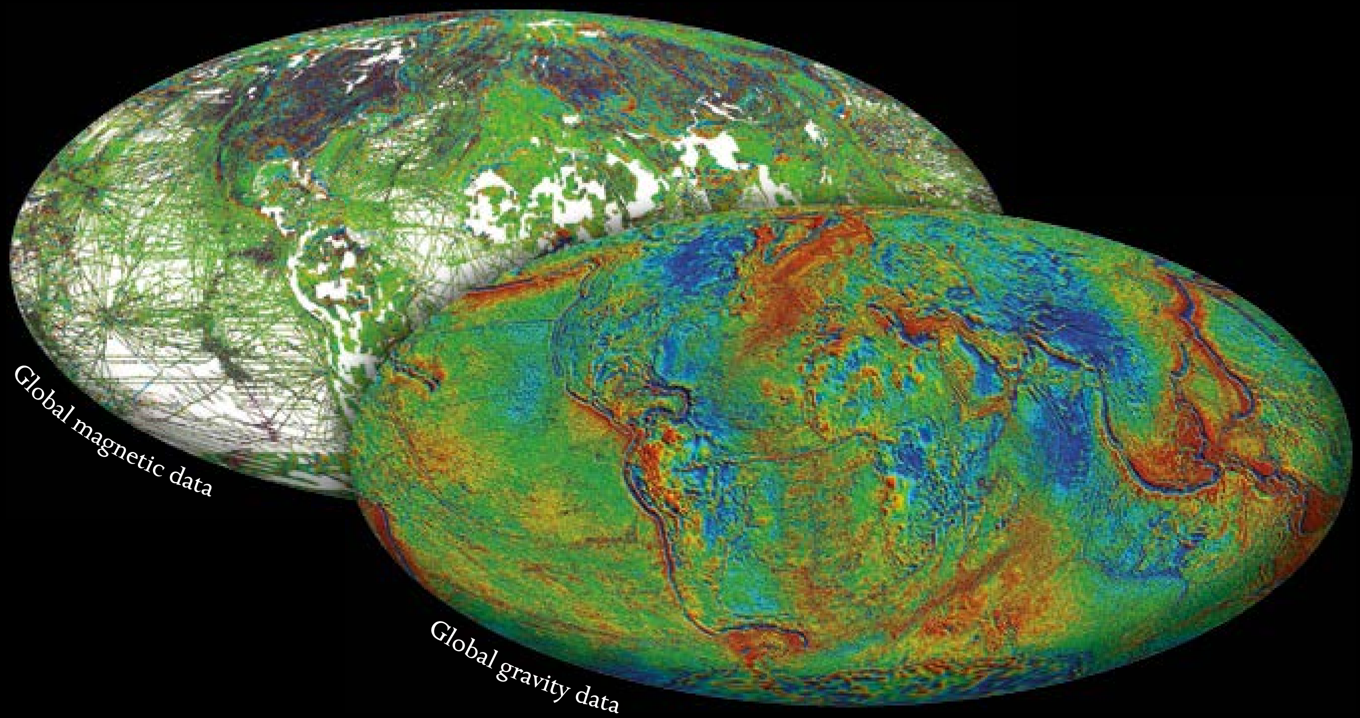
Indonesia

Continuing drive for foreign investment

The Indonesian Energy and Mineral Resources Ministry will shortly tender 11 oil and gas blocks in a new bidding round to supplement new working contracts secured earlier this year in an attempt to increase output. This is despite a waning investment appetite in the oil and gas sector due to persistent low global oil prices that have squeezed profit margins. In addition, exploration efforts are often hampered by bureaucratic issues. The blocks, spread across the archipelago, comprise three conventional blocks to be tendered through open bidding, another five under a direct appointment scheme to oil and gas contractors that have performed studies in respective areas, and three unconventional shale blocks.

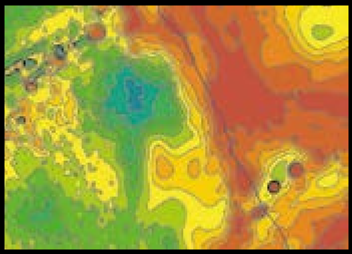
Domestic crude oil production rose in March 2015 when the Bukit Tua oil field (part of the Ketapang block in East Java operated by Petronas Carigali) came online, while output at the Cepu Block, also located in East Java, increased and is expected to reach its peak production (around 165,000 bpd) by October 2015. Expected higher oil output is also a reason why Indonesia has gained enough confidence to rejoin OPEC after a seven-year hiatus. Energy and Mineral Resources Minister Sudirman Said recently announced that the country will rejoin the organisation in November 2015 after all the cartel's members approved Indonesia's application. But to achieve sustained production targets, large-scale investments, supported by a transparent and secured regulatory framework, are needed. If these are not forthcoming, rising production levels will be considered temporary. ■

Getech's global gravity and magnetic data are the most extensive available. Wherever you are exploring in the world, we can provide the data and expertise you need to underpin your frontier and New Ventures exploration.



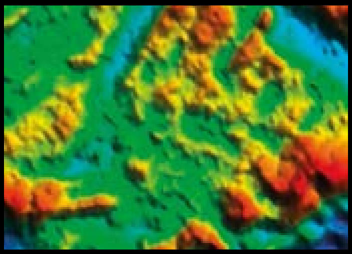
Our latest projects

Global Depth-to-Basement Study



This ambitious global project uses gravity and magnetic data to generate a depth-to-basement map for every continental margin and onshore basin in the world.

Multi-Satellite Altimeter Gravity Programme



This three-year programme delivers the most accurate, reliable and highest-resolution satellite-derived gravity data set over all of the continental margins of the world.

Visit us in October at SEG 2015 in New Orleans (booth 1916) and during Africa Oil Week in Cape Town (booth 87).

Getech's Global Gravity and Magnetic Data

Our gravity and magnetic data fuel our *Regional Reports* and *Globe*, our flagship New Ventures platform. These products provide cost-effective solutions for plate-to-prospect exploration.

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PROSPEX 2015: Network!

PESGB and the **Oil and Gas Authority** bring you the 13th show in their highly successful series of Prospect Fairs – the UK's leading networking event for exploration and development. The show has gone from strength to strength. In 2014 we saw over 90 exhibitors and 947 attendees, in addition to a full two-day programme of 'prospects to go', overviews from government and presentations by explorers and consultants. Despite the downturn, this year we are expecting a similar number of visitors and exhibitors.

But don't just take our word for it, see what attendees and exhibitors said last year: "PROSPEX is the industry benchmark conference, where you meet all the right people"; "This show always has a buoyant and optimistic mood"; "The exhibition was a constant hum of activity!"; "A yardstick for activity within a region".

If you want to see what all the talk is about, registration is now open and includes admission to the exhibition and conference, all-day refreshments, luncheon and a networking wine reception – head to www.pesgb.org.uk for more details. **PROSPEX 2015** takes place on 9–10 December 2015 at Business Design Centre, Islington, London. ■

PESGB/Karim Merie

Meet Decision Makers

The annual **Denver NAPE** expo is a networking event that brings together all the players necessary to forge, facilitate and close deals, offering prospects, producers and purchasers a unique chance to connect, reconnect, and make deals. More intimate than the annual NAPE Summit, this show is a 'must attend' event for those who want to network with those with first-hand knowledge of the opportunities and prospects throughout the area.

NAPE Denver kicks off with the highly informative Business Conference, where leading executives, experts and speakers examine E&P trends, legislative and regulatory challenges, technical advances and other topics of interest. Next, participants make their way to the expo floor where an estimated 2,500 attendees and 250 exhibitors gather for two days to listen to Prospect Previews and talk business, during which they expect to see the industry's latest and greatest prospects, ideas, products and services. The Icebreaker rounds out the first day and allows attendees and exhibitors an opportunity to mingle at NAPE's renowned networking event, as thousands of oil and gas professionals unwind from a day of deal making.

If you compete in the upstream oil and gas business, NAPE offers you an unparalleled opportunity to meet decision makers in an environment that is fun, energetic and, most of all, very serious about getting business done. ■

Present Climate Ideal for FTG

The industry has reacted to the substantially reduced oil price with, among other things, a huge reduction in exploration spend. By far the greatest cost in exploration is seismic acquisition, but technologies are available to substantially reduce costs, enabling operators to make better use of seismic budgets. One such is **Full Tensor Gravity Gradiometry** (FTG), supplied by **Bell Geospace**, world leaders in Gravity Gradiometry™.

Successful exploration is rarely dependent on a single source of information, and FTG has been adopted by dozens of established exploration companies globally, in conjunction with other geophysical techniques. It is a non-seismic geophysical technique recognised as a critical step in all stages of the exploration workflow; quicker, easier, more adaptable, non-invasive and cheaper to acquire, process and interpret than seismic, in a very short time FTG can identify promising targets for further investigation, at which stage a seismic programme can be designed over a smaller, more focused area.

Simply put, and to quote Tullow Oil's Annual Report, "sparse 2D seismic combined with FTG will provide 90% of the value of a full 3D seismic survey for 5% of the cost". For this reason alone, FTG is a valuable tool in a challenging economic environment. ■

Bell have recently been awarded a contract for an FTG survey in Mongolia.

Bell Geospace

New Standard for Ocean Bottom Seismic

Magseis has established itself as one of the leading providers of ocean bottom seismic acquisition by introducing innovative leading-edge technology to the market, proven through successful completion of a wide range of very challenging surveys. This impressive track record encompasses the most complicated reservoir seismic acquisition in the North Sea, challenging acquisition in the Barents Sea, and deepwater deployment in the Red Sea.

The company has developed a proprietary ocean bottom system (**MASS**) based on compact design and advanced electronics. Sensors are deployed in a robust and efficient cable with high positioning accuracy, or by ROV when required, which is particularly useful when acquiring reservoir seismic on congested producing fields, where complete uniform coverage can be obtained with one sensor system. ROV-assisted deployment was recently technically qualified on a high definition reservoir survey on the UK sector in the North Sea, and is now commercially available as a stand-alone service or in combination with regular cable acquisition.

Magseis is introducing the next generation MASS node to give enhanced battery lifetime and a better ability to increase the size of the seismic spreads, aiming to handle 300 km of cable in 2016. And the company sees no reason to stop at that, and believes that its next vessel should carry at least 1,000 km of cable and 10,000 MASS nodes. Ocean Bottom Seismic is a high quality, cost effective solution and an affordable alternative to towed streamer seismic in many areas. ■

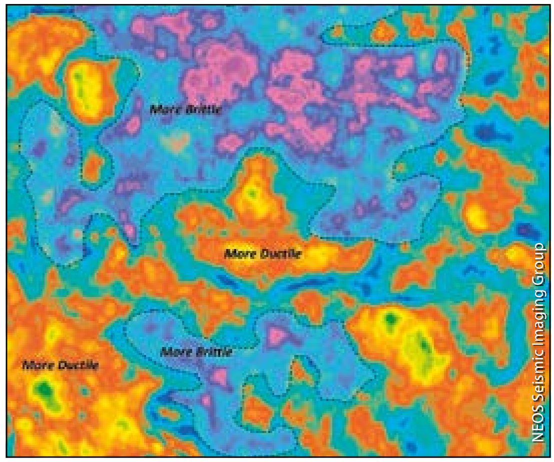

Magseis

Providing More Solutions

Explorations solutions provider **NEOS** accesses, acquires and analyses a broad range of geological and geophysical data – including data available in the public domain, owned by clients, or newly acquired – to help E&P operators all over the world gain new insights into the subsurface. The aim is to marry the latest sensor, computing and data analysis techniques from Silicon Valley with the extensive world-class experience of NEOS's team of geoscientists, mathematicians and engineers.

Since start-up in 2011, the company has gone from strength to strength. Its abilities were recently further advanced by the acquisition of **ION Geophysical Corporation**'s Denver land seismic data processing operation, which specialises in 'hard rock' processing in structurally complex geologic environments ranging from Bolivia to the North Slope of Alaska. As Jim Hollis, President and CEO of NEOS, commented, "We'll now have the capability to process, integrate and simultaneously interpret both seismic and non-seismic geo-datasets to render the most complete 'basement-to-surface' images in the industry."

Brittleness indicator derived from seismic inversion.



The Denver seismic data processing business had its roots as 'AXIS Geophysics,' which ION acquired in 2002. AXIS commercialised the technologies and workflows the E&P industry needed to undertake anisotropic and azimuthal processing, which subsequently found great utility in fracture detection and sweet spot imaging in tight, unconventional shale, and source-rock reservoirs. ■

IPTC Returns to Qatar

The **9th International Petroleum Technology Conference** (IPTC), an annual event rotating between Asia Pacific and the Middle East, is set to return to **Doha, Qatar**, on 6–9 December 2015. The scope of the conference programme and associated industry activities address technology and relevant industry issues that challenge industry professionals and management around the world.

The IPTC is a collaborative effort among the American Association of Petroleum Geologists; the European Association of Geoscientists and Engineers; the Society of Exploration Geophysicists; and the Society of Petroleum Engineers. The synergy of these four leading, individual member-driven societies provides the most comprehensive opportunity to form multi-disciplinary committees and an outstanding technical programme.

Regional oil ministers, industry leaders and governmental representatives will discuss and share their views on timely industry topics and trends, exchange expertise and experience, present state-of-the-art technology and innovation, and stimulate further research of technical and business activities. In addition, awards and recognition will be given for organisations' efforts in technical and business contributions to the industry. There will also be a range of integrated social activities to encourage networking and off-line discussion. For more information, please visit www.iptcnet.org/2015/doha/. ■

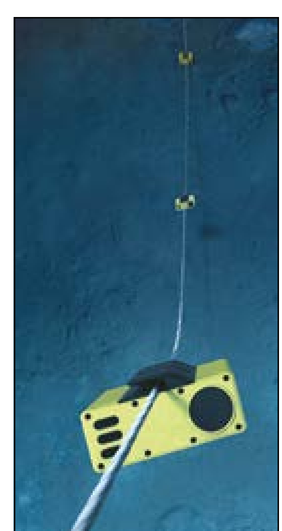
Next Generation Node-Based Seismic

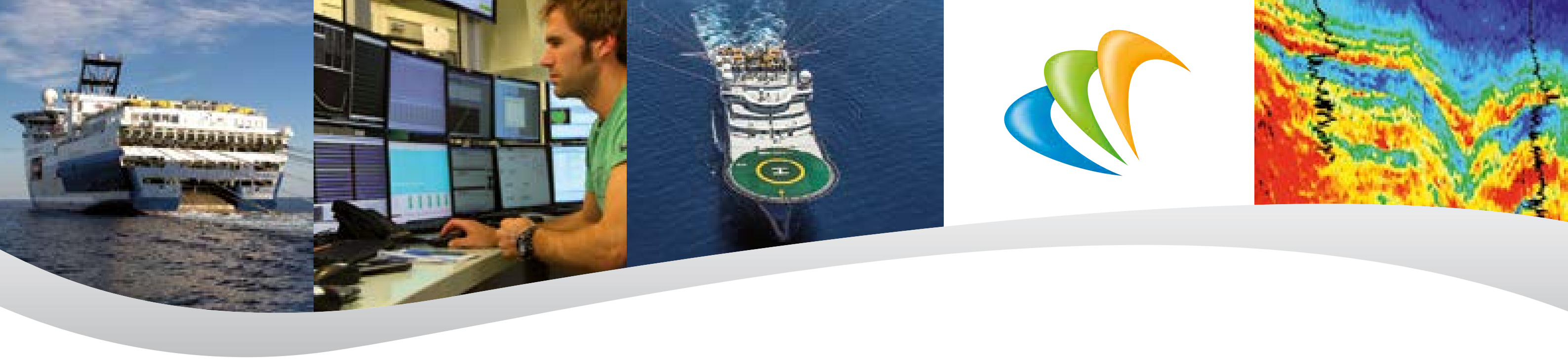
A transformation in the cost, efficiency and application of **node-based seabed seismic acquisition** systems takes another major step forward in November. This is when **inApril**, the emerging Norwegian seismic equipment supplier, carries out the first in-water tests of the novel launch and recovery features being introduced in its Venator fully integrated ocean bottom node (**OBN**) system.

Venator offers a step change in cost and efficiency, and intends to meet industry demand for a robust and easy-to-operate, modular OBN system. The same basic set-up is applicable to operations in water depths up to 3,000m, and can be readily installed on seismic vessels for proprietary or multi-client surveys.

Major improvements to conventional node-on-a-rope systems include longer battery life, built-in positioning transponder, a high degree of automation, including hands-free launch and recovery, and new sophistication in data management software. More than 10,000 nodes can be deployed and recovered from a single vessel at speeds in excess of three knots, thereby increasing the potential size and/or density of coverage of OBN surveys.

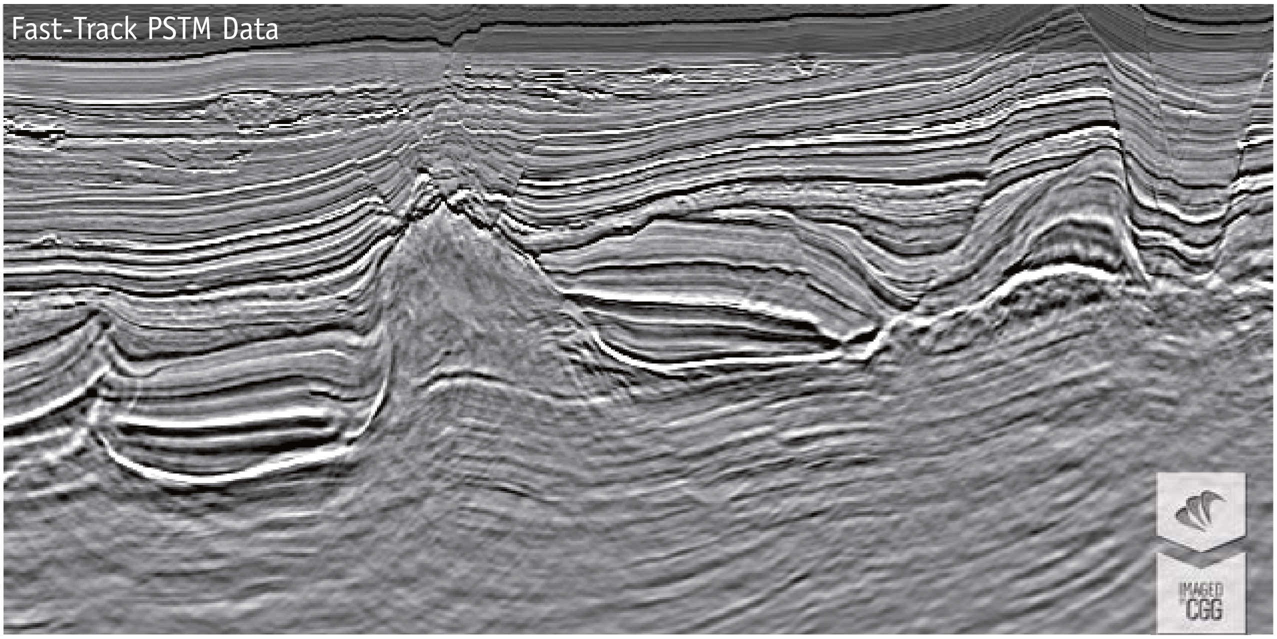
Vidar Hovland, CEO of inApril, said: "The industry has been waiting some time for a truly cost effective OBN tool to exploit the proven benefits of the higher resolution, quality data possible from seabed seismic imaging. Venator can deliver this with a solution that will challenge conventional towed streamer acquisition technology, particularly in exploration of geologically complex targets." ■



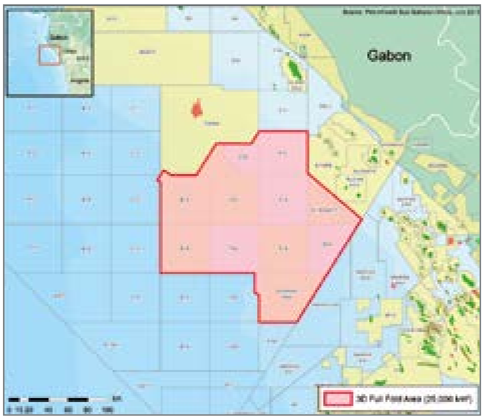


Gabon South Basin

25,000 km^2 of new **BroadSeis** data available now



BroadSeis fast-track PSTM data from our deepwater Gabon South Basin multi-client survey, showing clear faulting both pre- and post-salt as well as definition of the internal structure of Madiela carbonates.



CGG's fast-track 3D seismic data from our advanced **BroadSeis**™ survey over the deepwater Gabon South Basin are available now. This survey is optimally designed for the region's complex salt structures and is imaged with the latest technology. The final PSDM data will be available in Q3 2016.

CGG's **BroadSeis** data and advanced subsurface solutions offer unique opportunities for success in Gabon's emerging pre-salt story.

For more details, please contact:

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CGG
Passion for Geoscience

Southern Chile's Ring of Fire

OLIVIER GALLAND, University of Oslo, and **CAROLINE SASSIER**

Southern Chile is the setting for the dramatic snow-covered volcanoes of the Pacific Ring of Fire. This stunning volcanic range is the surface expression of the subduction of the Pacific seafloor under the western margin of South America. The southern Chilean Andes offer a fantastic playground for those who want to experience volcanoes – either peacefully or loaded with adrenaline!

In *GEO ExPro*, Vol. 12, No. 1, Olivier and Caroline described travelling through the dramatic Torres del Paine, in Patagonia, at the start of their 10,000 km epic cycle trip exploring the geological highlights of the Andes. Here they describe another leg of their exciting journey.

At the rim of Villarrica's crater.

Olivier Galland, Géoputé

Two months after the start of our journey, we were heading north along Chile's Road 7, the famous Carretera Austral, which spectacularly meanders between snow-covered peaks and glaciers. The dirt road cut through walls of pristine cold jungle, where hummingbirds were gathering nectar from colourful flowers. Contrasting with this peaceful natural paradise, travellers heading south consistently reported scenes of destruction and desolation from what used to be the peaceful spa town of Chaitén.

Fifty kilometres before reaching Chaitén, a covering of grey ash could be seen toning down the usually sparkling glaciers. Many trees were dead on the slopes of the mountain. The river beds were filled with ash, as were the sides of the road. When we reached Chaitén, an unforgettable scene hit us in the stomach: Chaitén was a partially destroyed, abandoned town, buried under a gloomy grey ash, and dominated by a monstrous volcano that continuously vomited a gigantic gas cloud.

Satellite image of Chile's southern volcanic zone (above) with our itinerary (right). White names locate the main volcanoes, with last eruption year in parentheses.

Chaitén: an Unexpected Eruption

Early in the morning of 2 May 2008, the Chaitén volcano exploded. Numerous earthquakes had shaken the area for several days before the eruption, warning the authorities and the population of the small coastal town, but because the volcano had no reported historical activity and did not show any recent signs of unrest, the authorities expected that it was the massive volcano Michinmahuida, 25 km east of the town, which was preparing an eruption. What a terrible surprise the inhabitants of Chaitén had, therefore, when a gigantic explosion occurred just 10 km away in the hills overshadowing the city.

As soon as the eruption started, the local population was evacuated. At its climax, the eruption produced an impressive Plinian ash column, 30 km high. Miraculously, this did not devastate the immediate surroundings, as the dominant west winds pushed the ash cloud across South America, eventually reaching Buenos Aires and the Atlantic. The ash also settled in the vicinity of the volcano, covering the area with a fine grey blanket, which rainfall then turned into the characteristic volcanic mudflows known as 'lahars'. Even though the eruption had not succeeded in destroying the town, the lahars obliterated numerous buildings and split the town in two with a wide, grey area of no-man's-land. Fortunately, by this time Chaitén had been emptied of people.

We camped on what used to be the seashore. The volume of ash carried by the lahars was such that a new, vast ash delta now filled the bay, moving the coast more than a kilometre seaward. Instead of the dark blue waters of the Pacific Ocean, a monotonous grey landscape spread in front of us. Partly buried boats and houses, including the former tourist information office, protruded from the deposits, breaking the monotony of the delta.

But the most impressive feature of this surreal scenery was the volcano. Only 10 km away, it dominated the bay and the valley. We could not forget it for a single second: it was visible from everywhere in the town – a chaotic, reddish volcanic dome that constantly exhaled dark gases and vapours. The summit was gradually growing, and from time to time unstable sections collapsed and produced small ash clouds. The volcanic dome had formed because the lava erupted by Chaitén was very viscous, and consequently could not flow downslope as in Hawaii but accumulated at the vent. In Chaitén, numerous blocks of porous, light pumice ejected by the volcano covered the ground. It is noticeable that the erupted magma was of rhyolitic composition, making this the first major rhyolitic eruption in nearly a century (the last one occurred at Novarupta, Alaska, in 1912). The 2008 eruption of the Chaitén volcano is thus a natural laboratory for such eruptions.

Because the road was partly destroyed further north, we left Chaitén by boat, travelling to the small fishing harbour of Hornopiren, before heading to Puerto Montt. Less than ten days later, Chaitén's volcanic dome collapsed, producing pyroclatic flows that ran furiously down the slopes of the volcano. They miraculously stopped at the gate of the town,

Desolate and deserted Chaitén with, in the background, the volcano and its rhyolite dome spewing gas.

but after this the Chilean authorities abandoned Chaitén.

A String of Stratovolcanoes

After a few days' rest at Puerto Montt, we cycled north through Chile's Lake District, where during the ride we could often identify the characteristic topography of the volcanic arc.

The most majestic of the volcanoes is Osorno, a perfect ice-capped, steeply pointed cone. This shape is characteristic of stratovolcanoes, which are typically found in active margins, i.e. in subduction geodynamic settings. Other famous examples of stratovolcanoes are Mount Fuji, Japan, and the almost perfect Mayon Volcano in the Philippines. They form as a result of successive effusive and explosive eruptions of basaltic, andesitic to dacitic magmas, producing stratified competent lava flows and loose tuff layers, respectively. The southern volcanic zone of Chile hosts many volcanoes that recently hit the headlines after large eruptions, including Puyehue-Cordón Caulle (2011) and Calbuco (2015).

The road approaching the volcano of Villarrica.

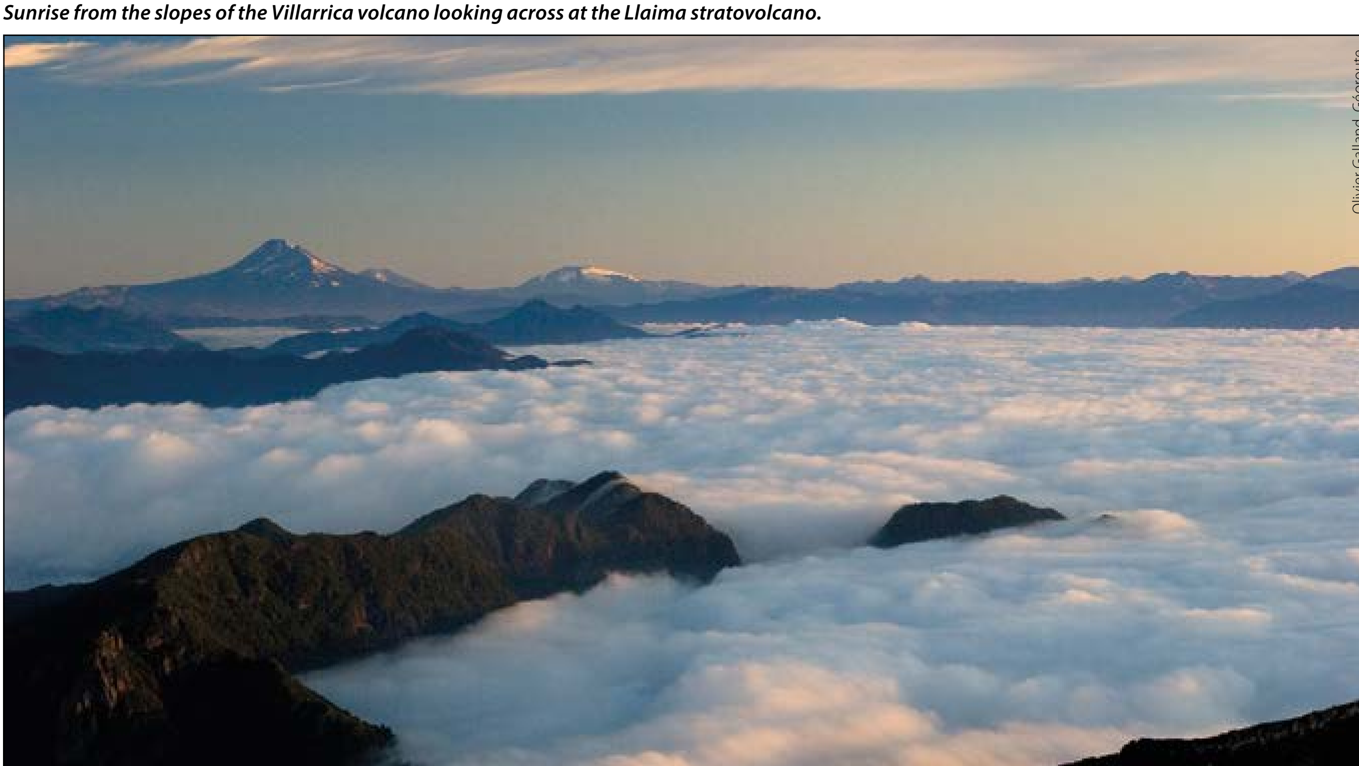
Climbing Villarrica

Villarrica, rising 2,847m above sea level, is a characteristic stratovolcano with an almost perfect conical shape. Its volcanic output primarily comprises compact basaltic lava flows, andesitic lava and pumice layers. Some locals like to claim that it is the most beautiful volcano in the world, and its majesty is enhanced by the 40 km^2 of glaciers that crown its summit, they may well be right.

It is not usually possible to climb Villarrica without a guide, but we obtained special permission directly from the director of the Villarrica National Park, don Jorge Paredes, to climb it alone. In return, we promised to visit him after the climb to report our observations. But he warned us not to have too many expectations: there was currently no lava in the crater…

We started our ascent at 4am in full darkness under the stars, which was really enjoyable. After an hour's walk through the forest, we reached the end of the national park road at the very foot of the volcano and of the base of the Villarrica ski resort. Even in the darkness, the almost perfect conical shape of the volcano was clearly visible. Suddenly, a

Sunrise from the slopes of the Villarrica volcano looking across at the Llaima stratovolcano.



pale red glow issued from the crater: did you say "No lava", Mr. Paredes?

As we climbed the steep slope of the volcano, the stunning sunrise revealed wonderfully memorable scenery, with the volcano Llaima to the north and the triangular shadow of Villarrica stretching in front of us. After several hours' climbing we stopped for a short break and looked down at the vehicles of the guided groups of tourists far below our promontory. We were much higher than them, and we were amused by their late start, sure that they could not catch up with us. But we were much less amused when we realised that their vehicles had clustered at the start of a ski lift, that this lift was working and that it exited… only 50m below us! We quickly packed and went on, but a few minutes later, the lift liberated hordes of fresh, loud visitors, who were almost running up the mountain. Tired after our early morning climb, we could not keep up and, as we looked on miserably, they overtook us on the glacier, a few hundred metres before the summit.

Luckily, the guided groups only stayed a very short time at the summit before returning to the valley, so after a while, we had the volcano to ourselves. We were sitting on the rim of the enormous crater, which was so deep that its bottom was invisible; it really made us feel we were looking into the mouth of the Earth. Sulphur gas was exhaling from every pore of the ground, comfortably heating up the area we were sitting on. Periodically, we noticed that gas burst out of the centre of the crater, accompanied by rumbling and subtle vibrations in the ground. There was no doubt: lava was venting at the bottom of the crater, which explained the glowing red light we had seen in the darkness. Our observations were confirmed in subsequent months, as the crater filled with lava and the vents became visible from the crater rim.

Chile's Most Active Volcano

The long descent down the volcano was very enjoyable. The ground was made of loose volcanic lapilli that allowed us to run comfortably without hurting our knees. When we got back down to Pucón, the tourist town at the foot of Villarrica, we reported our observations to Mr. Paredes, who was really excited that there was lava in the crater, as it is good for the tourist industry. However, at the same time he said that he regretted that people, and especially the locals, tended to forget that Villarrica is Chile's most active volcano and that Pucón and its surroundings are built on the pyroclastic deposits of the volcano. He clearly remembered the frightening 1971 eruption, which melted the snow and part of the glacier, liberating massive lahars that destroyed villages at the foot of the volcano. The landscape still exhibits prominent scars of these lahars on the volcano flanks.

To make tourists aware of the volcanic hazards, Pucón has designed an original warning system based on green, orange and red lights, very similar to traffic lights. Since 1971 this volcanic hazard alert system has remained in the 'green' level, the system becoming more part of the tourist attraction package than an educational and hazard communication medium. The year 2015 interrupted this long quiescent period, as Villarrica started a new eruptive cycle, which resulted in loud explosions and evacuation of the population in the nearby communities. This new eruption has been going on for several months already.

Acknowledgments:

The Andean Geotrail project was endorsed by the International Year of Planet Earth. The authors acknowledge financial support from the grant SPB-Guilde Européenne du Raid, the Conseil Régional Rhône-Alpes, the Conseil Municipal de Bourg-en-Bresse, the French Ministère de la Jeunesse et des Sports, and material support from Decathlon. ■

Olivier Galland, Géoroute

On the summit glacier of the volcano of Villarrica. At the bottom of the slope the lahars of the 1971 eruption can be seen as prominent scars through the forest.

What Lies Beneath the Deepwater Tano Basin?

Hunting for Jubilee-like prospects in Côte d'Ivoire

JAVIER MARTIN, GREGOR DUVAL and LUCIE LAMOURETTE, CGG

Boosted by recent discoveries, Côte d'Ivoire has seen renewed interest in its deepwater offshore basin over the last few years. Up until 2011, not a single well had been drilled beyond the 2,000m water depth line of Côte d'Ivoire, but ten wells have been drilled over the last three years. Several technical discoveries, which are not necessarily commercial for the time being, were made, including Saphir in Block CI-514, Morue in Block CI-516, Buffalo in Block CI-205, Paon/Autruche in Block CI-103, Ivoire in Block CI-100 and Capitaine East in Block CI-101 (Figure 2).

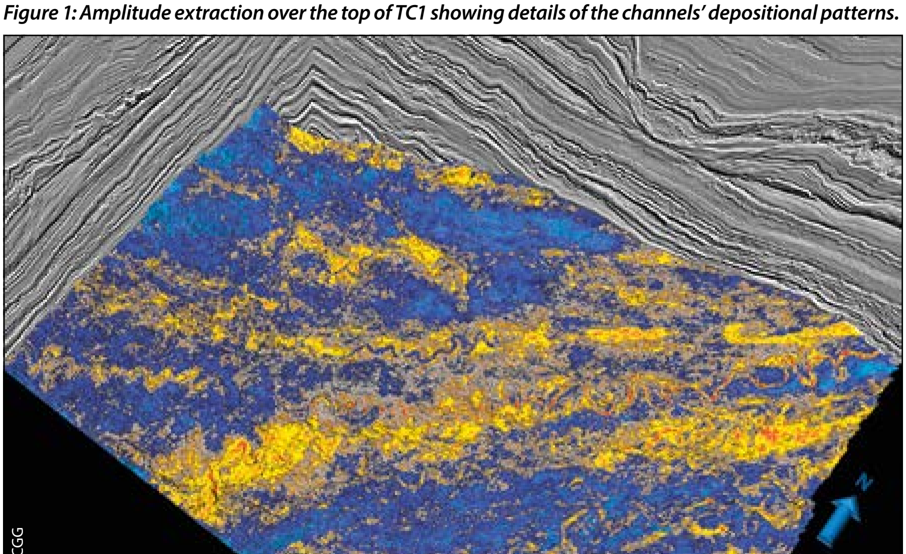
Nearer shore, the basin has been explored since 1972 when the first offshore well IVCO-1 was drilled. Subsequent discoveries were made that highlighted the presence of a working hydrocarbon system in the Lower Cretaceous syn-rift/transition sequence, but it was not until the new play-opener Jubilee discovery in 2007, found in Upper Cretaceous turbidite sands in the adjacent deepwater Tano Basin in Ghana, that deep offshore exploration started to take off. Soon after, two other Ghanaian oil discoveries were made: Tweneboa (one of the top 10 discoveries in 2009, according to IHS) and Enyenra (a top five discovery in Africa in 2010) in the vicinity of Jubilee. The oil was typically found in stacked turbidite channels, levees and splays. Exploration then shifted westwards into Côte d'Ivoire when the first ultra-deepwater well was drilled in 2011.

Two Working Petroleum Systems

The two main exploration phases that have taken place in Côte d'Ivoire (from shallow to deep water) have highlighted the existence of two major working petroleum systems. These are, firstly, a Lower Cretaceous syn-Atlantic rift system, which has been mainly explored and developed near shore so far. This petroleum system includes Aptian to lower Albian continental reservoir sands and source facies of similar age deposited in lacustrine to swamp settings, with mainly structural trap styles (i.e. fault blocks and compactional drapes). The second is a Late Cretaceous petroleum system found in the deepwater acreage, fed by a prolific Cenomanian-Turonian marine type II source rock with predominantly Turonian to Maastrichtian turbiditic reservoir sands, where a significant component of the trapping mechanism is stratigraphic in nature (i.e. pinch-out traps and local facies variations).

This article focuses on an area of 4,400 km^2 covering blocks CI-527, CI-528, CI-529 and CI-530 in the Ivorian part of the Tano Basin where no drilling has yet taken place (Figure 2). In 2014 CGG undertook a multi-client BroadSeis™ 3D seismic survey to cover this unexplored area, which has provided the basis for a geological review.

Figure 1: Amplitude extraction over the top of TC1 showing details of the channels' depositional patterns.



Stacked Turbidite Systems

A full 3D seismic interpretation was carried out to reveal the geometry of several key stratigraphic horizons in the area, namely Top syn-rift, Late Albian, Mid Cenomanian, Late Cenomanian, Top Turonian, Top Coniacian, Top Campanian, Top Paleocene, Oligocene unconformity and the seabed. Calibration of the age of these horizons was carried out by tying nearby well data with other CGG multi-client 2D and 3D seismic data in the area. This interpretation includes top and base of three main turbidite complexes (TC1, TC2 and TC3) identified through the Upper Cretaceous section, ranging from Santonian to Late Campanian age (Figure 3). Although younger than the Turonian-aged Jubilee-type reservoirs also found in Tweneboa, Enyenra and Autruche, these turbidite deposits are interpreted as analogous in terms of depositional environment: proximal slope channels and levee deposits with similar reservoir properties. This has been interpreted on seismic data using amplitude extraction methods, as illustrated in Figure 4. The interpretation of the three Upper Cretaceous turbidite complexes clearly shows a north-east to south-west orientation with sediments feeding from Ghanaian and Ivorian coasts into the deep Tano Basin. These sediment-rich turbidites flowed southwards until they reached the Côte d'Ivoire-Ghana Ridge (CIGR), which then diverted the flow towards the south-west. The CIGR forms the north-eastern tip of the 2,000-km-long Romanche tectonic transform lineament which ties to the Mid Atlantic Ocean Ridge, delineating the southern limit of the Tano Basin.

The deepest turbidite complex (TC1) represents an outer slope fan lobe, deposited in a lenticular down-dip geometry that is seen pinching-out towards the palaeo-slope. Internally, this body shows onlapping reflector geometries with a number of small-scale slump features. In Figure 1, a maximum amplitude attribute extraction performed over the top of TC1 shows a multi-phased system of meandering sand channels of Santonian age. Similar turbiditic sand deposits found at Jubilee in Ghana have shown good porosities averaging 17–22% and permeabilities of 100–3,000 mD (D. Hanley et al., 2009).

TC2 and TC3 represent two large turbiditic systems dominated by multiple lateral channel incisions, vertical channel migrations and associated levees. The internal architecture of the sand bodies shows widely developed pinch-outs onlapping towards the near-Santonian and Campanian palaeo-slopes.

These three turbidite complexes are each separated by thick intervals of aggradational deposition of sediments, suggesting mud-dominated depositional facies. Furthermore, the seismic interpretation reveals the presence of potential internal seal units within each turbidite complex (Figures 3 and 4) with local deposition of marine mud layers

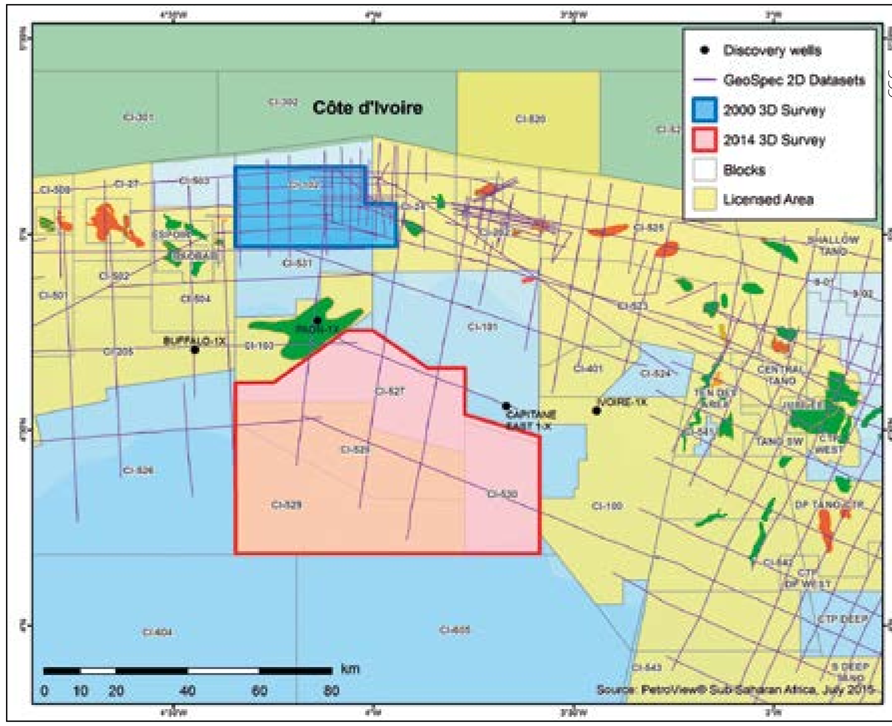


Figure 2: Location map of the deepwater Tano Basin and coverage of the 3D CGG seismic data. The deepwater oil discovery wells are also highlighted as black dots.

at times when the turbiditic system was starved of sands.

In terms of hydrocarbon trapping mechanisms, TC1 would be described as a pure stratigraphic pinch-out trap, whereas structural mapping of top TC2 and TC3 shows the potential of combined stratigraphic and structural trap styles (Figure 4).

The Influence of Volcanic Activity

At depth below the Upper Cretaceous turbidite systems, the seismic interpretation has revealed the presence of volcanic mounds surrounded by multiple sills and dykes (Figure 5). These intrusive volcanic complexes are exceptionally clear based on the combination of the broad bandwidth and advanced imaging: low frequencies penetrate deep below the sedimentary overburden and help reduce spurious sidelobes of the main seismic reflections, which in turn allow a clear pick of top and base of individual bodies of volcanic intrusions. Three main volcanic centres have been identified, aligned on a south-west to north-east trend parallel to the CIGR trend. In addition, when comparing the shallowest intrusions with the age of the encasing sediments, it is estimated that the relative age of the volcanic activity is Albian to Cenomanian. These combined observations suggest that the volcanic activity was related to the beginning of the drifting phase of the Atlantic Equatorial Margin. Although

Figure 3: Interpreted seismic section highlighting the three major turbiditic complexes TC1, TC2 and TC3. NB: The purple horizon represents Top Albian.

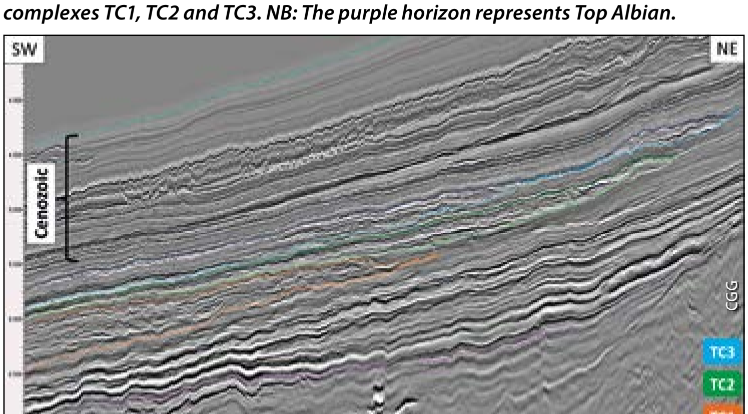
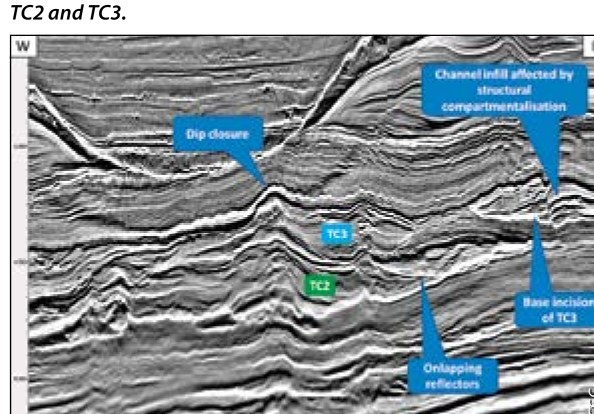


Figure 4: Details of the internal architecture and stratigraphy of TC2 and TC3.



the subject of speculation, volcanic rocks of that age had never been recognised in the basin before the acquisition of this new 3D seismic survey. The nearby Saltpond Basin in Ghana does show evidence of Jurassic volcanism (USGS Bulletin 2207-C, 2006) which could be related to the onset of block faulting, but nothing in the Albian-Cenomanian.

The presence of volcanism in the area and its age and distribution may have an impact on different elements of the petroleum systems, including seal and reservoir quality, trapping mechanism, heat flow distribution and local source rock maturation. One clear impact on hydrocarbon prospectivity is that these volcanic mounds can provide structural traps by compactional draping of the overlying layers of sediments, including Upper Cretaceous turbidites, as illustrated in Figure 5. Another more speculative impact could be the increased heat flow produced by prolonged igneous activity: this may have potentially altered the local maturation of both the Apto-Albian continental and the Cenomano-Turonian marine source rocks by bringing them into higher-maturity temperature windows.

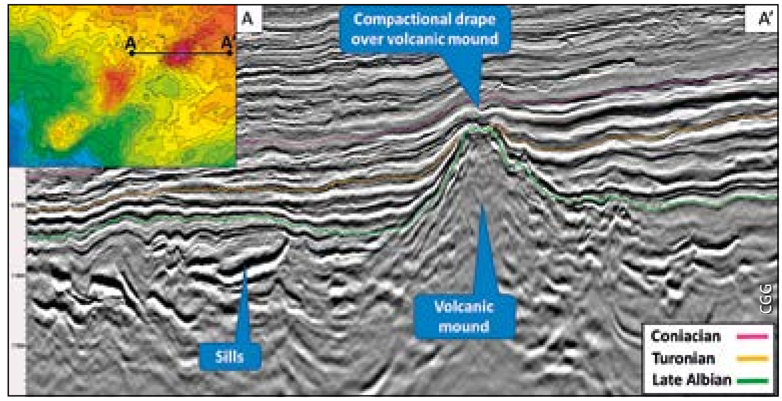


Figure 5: Details of a volcanic complex developed during the Albian-Cenomanian age.

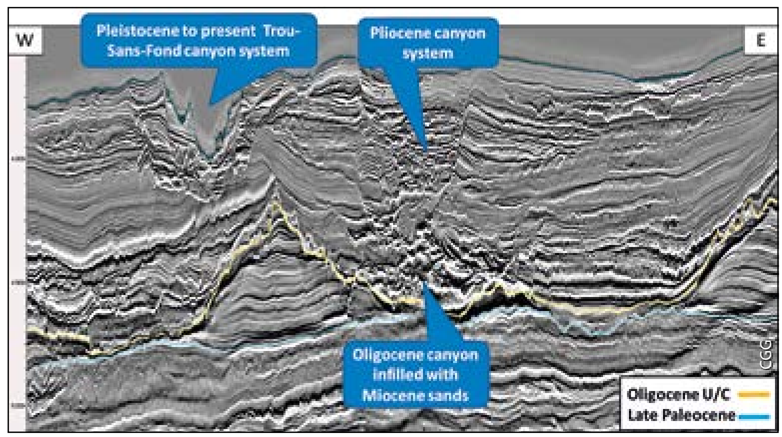


Figure 6: Detail of the widely developed Paleogene canyon systems.

Large Buried Canyons Revealed

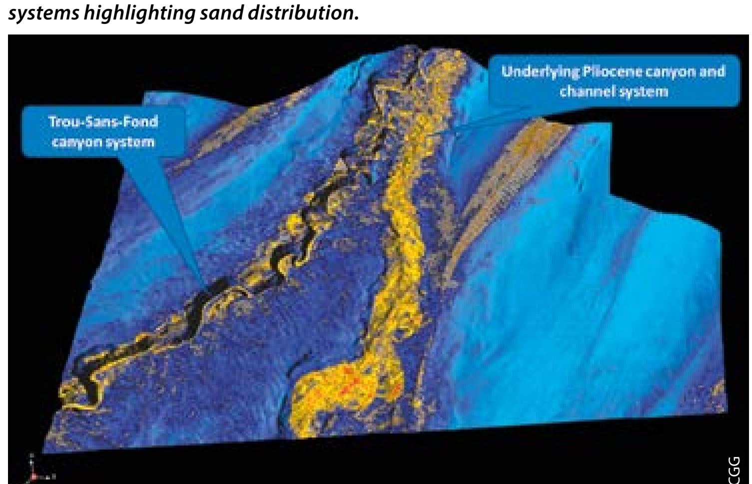
The 3D seismic data show high-resolution details of the shallow subsurface where deeply incised canyons with sand-filled channels can be observed. Our analysis reveals the existence of three major canyon system successions: the oldest being of Miocene age, the middle one interpreted to be of Pliocene age, while the youngest was initiated in Pleistocene times and is still active today (Figure 6). Its topographic relief is noticeable on present-day bathymetry with dimensions of over 500 metres in depth, several hundred to 1,000 metres in width, and a length of several tens of kilometres. This large deepwater canyon appears to be on trend with the well-documented Trou-Sans-Fond submarine canyon present on the Ivorian continental shelf (Figure 7). The intrusive volcanic complexes are exceptionally clear based on the combination of the broad bandwidth and advanced imaging. This is proof of its extension further into the ultra-deepwater of the Atlantic Ocean, several hundred kilometres from the coast.

As illustrated in Figure 7, these shallow palaeo-canyon systems are filled with high seismic amplitude channel sands, which can be easily mapped with Acoustic Impedance or RMS amplitude attribute extractions. The broad frequency bandwidth of the seismic data highlights details of the complex stacking patterns, truncations and internal geometries of these channels. Mapping of these anomalies is not only important for the identification of potential prospective features in the Tertiary section; it also brings high-value information to plan a drilling site and avoid geological hazards which may conceal a deeper exploration target.

Hunting Jubilee-like Prospects

Reviewing this new 3D seismic volume in the Ivorian deepwater Tano Basin has brought to light the presence of well-developed Upper Cretaceous turbiditic systems, up-dip of the main source rocks in the area, which are similar to the Turonian sands found at Jubilee and surrounding fields. The trapping mechanism is expected to be mainly stratigraphic with a partial structural component. This study has also highlighted the presence of Albian-Cenomanian volcanic intrusions and mounds underlying the potential reservoir sands, which emphasises the structural component of the trapping mechanism. Ongoing work now focuses on the analysis of Amplitude Versus Offset signature in order to ascertain the presence of trapped hydrocarbons and increase the chance of success on potential prospects. ■

Figure 7: 3D view and amplitude extraction of the Paleogene canyon and channel systems highlighting sand distribution.



A New Global Sediment Thickness Map of the World

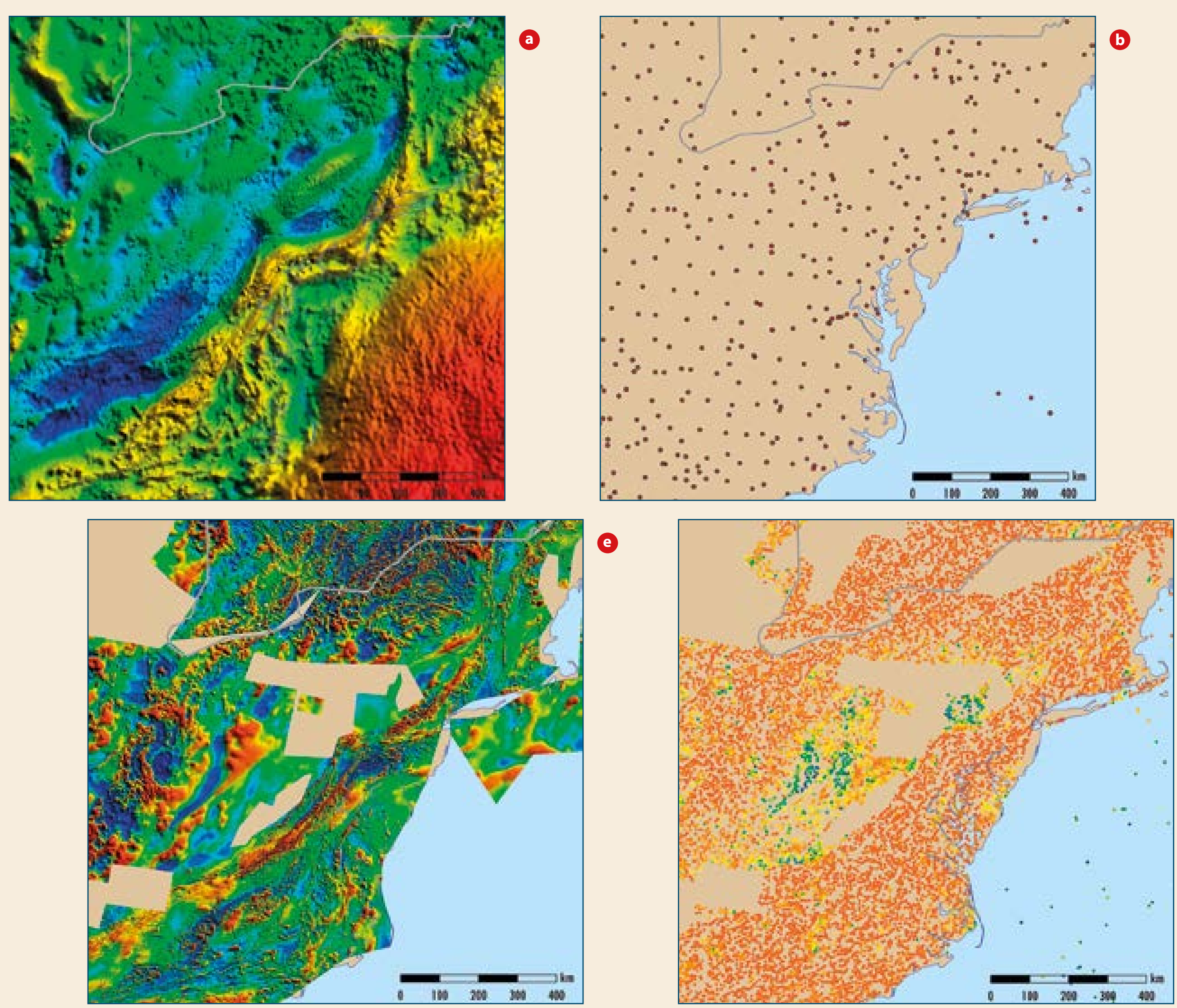
Sam Cheyney, Simon Campbell and Ian Somerton from Getech have been addressing the challenge of deriving a globally consistent depth-to-basement map and have devised an approach which accounts for the obstacles of variable data resolution and types, irregular constraints and different geological settings.

Finding new or under-explored sedimentary basins is a key aim for many frontier exploration groups, and using gravity and magnetic data is a very cost-effective method of identifying and mapping their extents.

Sediment thickness estimates are important for the New Ventures explorationist to identify potentially productive sedimentary basins and to map their extent. These maps provide a vital constraint for source rock maturity modelling and for understanding the local thermal regime in both conventional and unconventional exploration settings.

Getech has developed an integrated approach to map sedimentary thickness on a global scale using the best global compilations of gravity and magnetic data. The approach uses the relative merits of each of the data sets and

Figure 1: Example from north-eastern USA illustrating the integrated workflow. The Bouguer gravity anomaly (a) is compared against predicted gravity response from the Moho constraint (b) and is low-pass filtered until the maximum cross correlation is achieved (c). This is then inverted for depth-to-Moho (d), which is incorporated as a finite depth constraint when the magnetic data (e) is used for derivation of discrete magnetic depth estimates (f). The high confidence magnetic estimates are used in conjunction with independent constraints (g), before 3D inversions of magnetic (pseudogravity) and gravity data to produce the final integrated depth-to-basement map (h).



recent advanced methodology in depth-to-source estimation.

Potential Fields

Gravity and magnetic data have long been tools for mapping depth-to-basement given that density and/or susceptibility contrasts at the basement-sediment boundary should yield an anomaly that can be interpreted in terms of depth. These data generally offer a relatively quick and cost-effective evaluation of large areas. On a global scale, the availability and resolution of data are inevitably variable, and therefore this workflow has focused on an integrated approach that uses the relative merits of each of the data sets together with recent advances in depth-to-source interpretation methodologies.

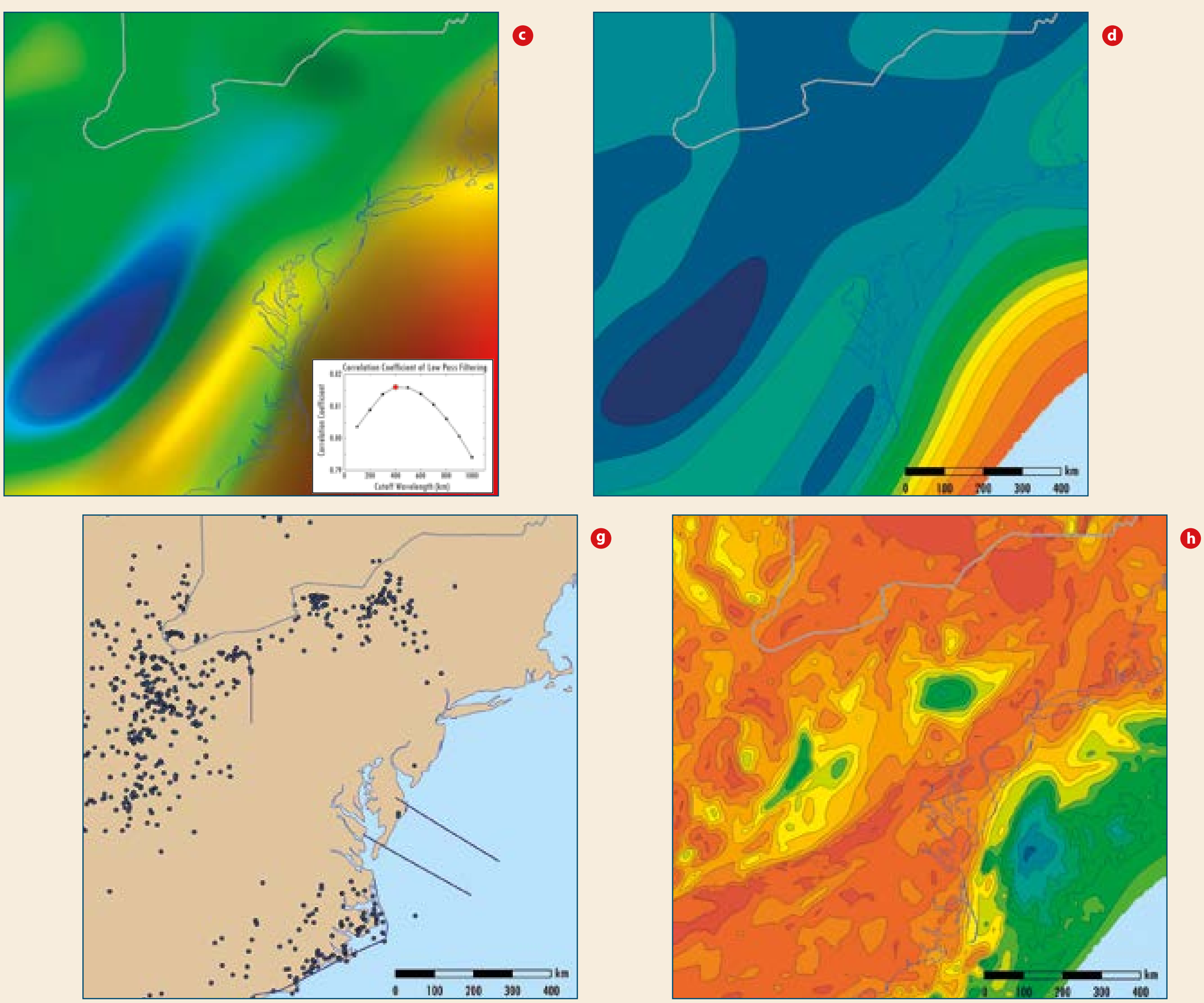
In the absence of large volcanic provinces, magnetic data is generally a more robust tool for depth-to-basement estimation. This is due to the fact that the basement rocks usually have a distinctive magnetic susceptibility contrast with respect to overlying sedimentary rocks. In general, sediments have a very low susceptibility, and for interpretation purposes can often be considered to be non-magnetic. Basement rocks have a much higher susceptibility; therefore, recordings of the magnetic field at the surface can generally be considered to be derived from the basement.

Where a density contrast at the basement exists, gravity data may also be used to invert for basement depths. However, density variations within the sediments can produce a significant contribution to the observed gravity data, which adds complexity. A significant density contrast is also likely to exist at the Moho, and hence play an important contributory part of the gravity anomaly. A good estimate of the depth-to-Moho is therefore an important part of Getech's workflow, as described on page 34.

Global Data Compilations

The fundamental data sets used are global compilations of gravity and magnetic data. These have been generated by merging thousands of individual land, marine, airborne and satellite surveys in a consistent manner into global 2 km (gravity) and 1 km (magnetic) grids.

Data coverage of the two data types is highly variable, and choosing which to use in different areas depends on



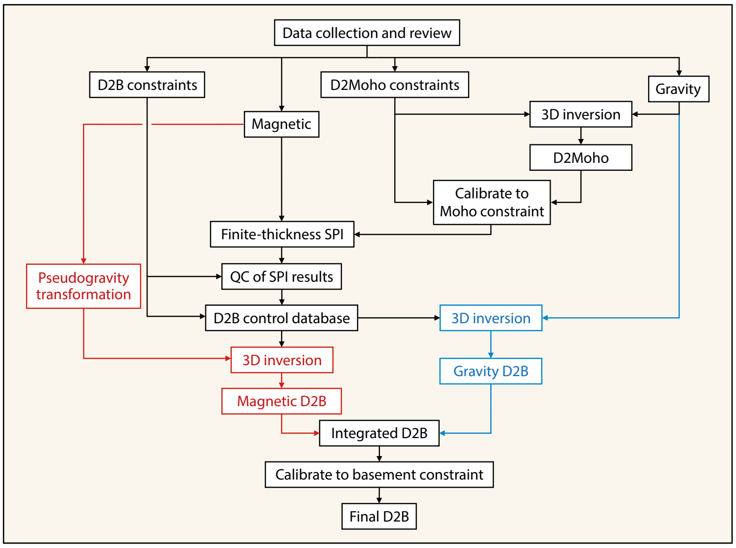


***Figure 2:** Depth-to-basement workflow showing the integration of the magnetic methods (in red to the left) and the gravity methods (in blue to the right) to produce a final composite depth-to-basement map.*

coverage, geological terrain and data resolution. For example, in the offshore continental margins there are a number of good magnetic surveys, but these are generally in small localised areas. Conversely, the gravity data in the offshore margin areas are of a very consistent quality and coverage owing to the availability of the latest satellite altimeter derived data. A workflow to incorporate both the patchy magnetic data (which allows a more direct estimation of basement depth) and the gravity data (which offers good coverage, but may depict basement more indirectly) is therefore the first challenge.

Integrating Additional Resources

The workflow Getech has developed is demonstrated by a walk-through of an example area from north-eastern USA in Figure 1 and is shown in chart form in Figure 2.

A key aspect of the workflow involves the building and validation of a database of individual depth-to-basement measurements, which is used as a control on the final interpretation. These points derive from published depth-to-basement values from literature (e.g. from seismic data), well data, outcrop information and depth-to-magnetic source estimates calculated directly from magnetic data where there is a high confidence. This depth-to-basement database is then used to identify large-scale regional variations across the area so that these can be incorporated into a final 3D inversion from either the magnetic or the gravity data. The global scope of the work means that the magnetic and gravity coverage will vary from area to area, and the final map will comprise elements from both the magnetic and gravity interpretations.

Recent Research

Getech's analysis of the magnetic data incorporates two important elements:

Finite depth extent: This takes into account the fact that the thickness of the magnetised layer will be depth limited and governed by the Curie point, the temperature at which magnetic minerals become non-magnetic. In certain geological settings, for example stretched continental margins, the thickness might be very small compared to the depth-to-magnetic source, and hence will have a significant effect on the depth results, causing them to be underestimated (Flanagan and Bain, 2013; Lee et al., 2010; Salem et al., 2014a). In this project the finite local wavenumber method has been used (Salem et al., 2014a), which requires information about the depth to Curie isotherm. In the absence of computed Curie depths, Getech has used the depth-to-Moho as a proxy for the base of the magnetic layer and has implemented this into its depth-to-magnetic source calculations, a significant improvement over a prior assumption of source geometry.

3D magnetic inversion using pseudogravity: Most magnetic depth methods that estimate solutions at discrete points are often biased towards the top edges of structures. When sampled onto a grid the resultant map often shows a shallower solution, missing deeper intra-basin details. Getech uses high confidence discrete magnetic depths (and other independent control data) to constrain a full 3D inversion to produce the basement surface using the pseudogravity approach (Salem et al., 2014b). This approach has an additional advantage in that the pseudogravity transformation converts a grid of magnetic data so that the resulting grid has the same simple relationship to magnetic susceptibility as the relationship between the gravity data and density, and hence a more straightforward inversion problem.

Crustal Architecture

Using these methodologies it has been possible to map the crustal architecture and produce positive results in a number of geological settings around the world. The results from both the gravity and magnetic data have been integrated with independent constraints to build a global depth-to-basement map. The approach is both technically robust and has allowed implementation in a practical and self-consistent manner. There will inevitably be limitations due to some over-simplification when applied at the global scale; however, at a regional scale, Getech views this as a valuable tool for first-pass basin screening.

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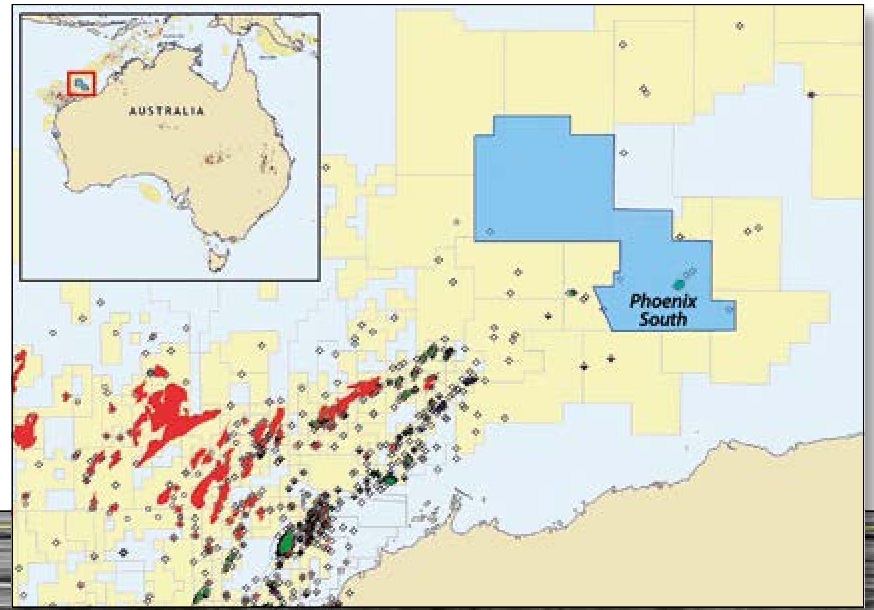
Western Australia:
North Carnarvon-Roebuck Basins

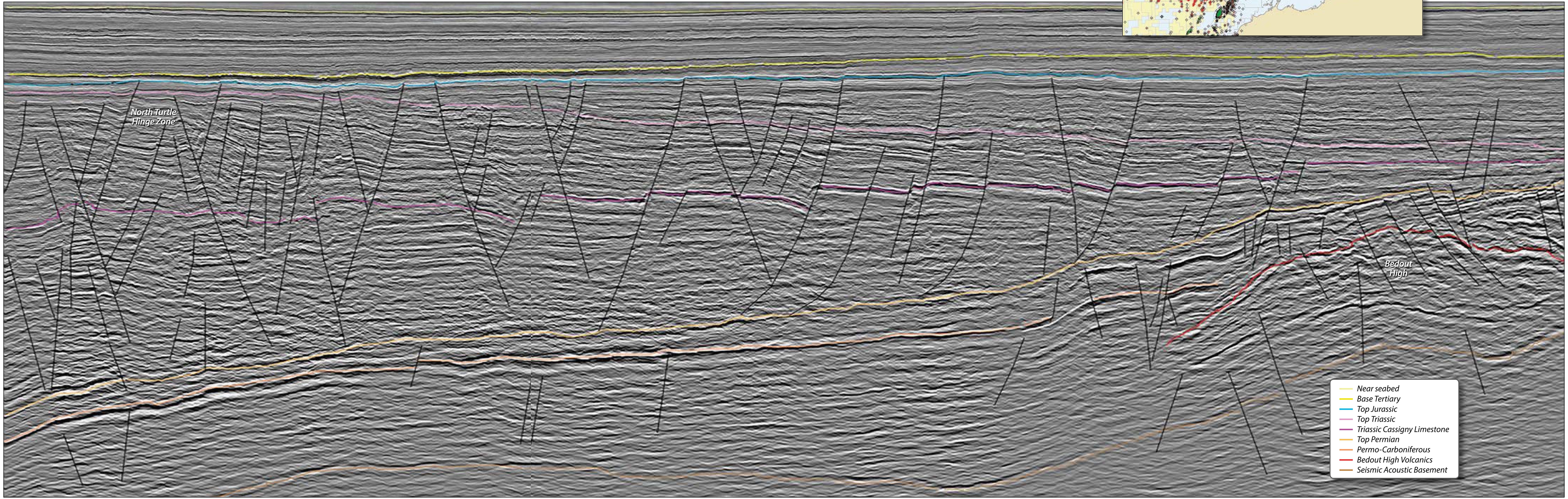
The 2014 Phoenix South-1 well drilled offshore Western Australia has confirmed at least four discrete oil columns in the Triassic Lower Keraudren Formation. The discovery of exceptionally good quality light oil with a high API gravity and favourable mobility represents one of the most significant developments in the region in recent times. The discovery, made whilst searching for the extension of discovered gas, represents a new oil province for Australia.

Polarcus' Capreolus multi-client 3D survey offshore Western Australia covers an area of 22,130 km^2, the largest single 3D survey ever acquired off Australia. The new data spans parts of the North Carnarvon and Roebuck Basins, providing exploration companies with an extensive regional high quality broadband 3D seismic dataset over this underexplored frontier. The Phoenix South discovery opens up the potential for a new oil province across an area historically only considered prospective for gas, with the oils derived from a Lower Triassic source interval clearly imaged on the new seismic. The new 3D data covers the Phoenix structure and allows investigation of the extent of the new oil province across the region.

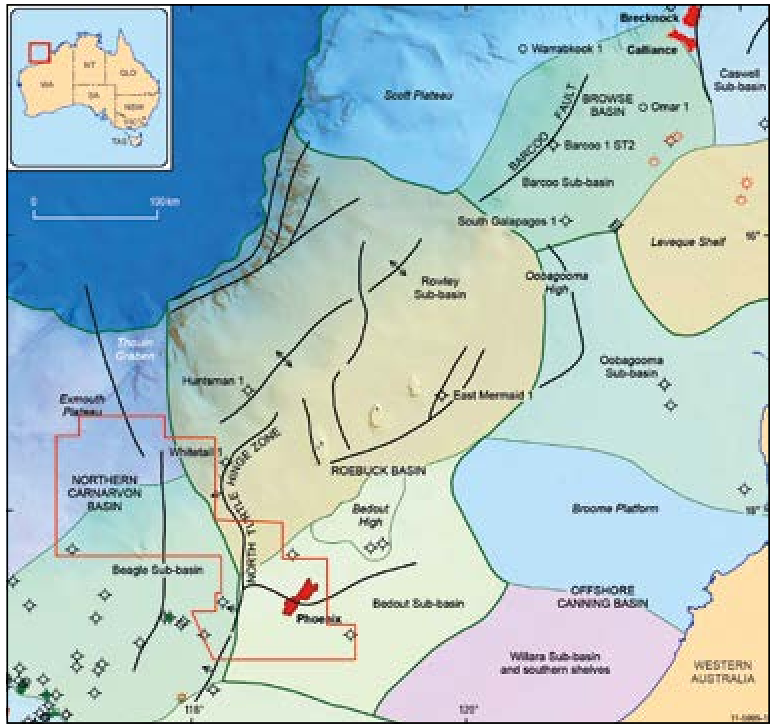
Polarcus®



Fast track PSTM data example across the Bedout Sub-basin.



A New Oil Province Offshore the North West Shelf



TONY PEDLEY, IAN COLLINS and JAI PANDYA, Polarcus

The Australian North West Shelf is comprised of four areas, namely the Carnarvon, Roebuck/Offshore Canning, Browse and Bonaparte Basins. These are filled with a thick sequence of late Palaeozoic, Mesozoic and Cenozoic successions. The area formed part of the Gondwana Supercontinent during the Palaeozoic, but by the Permian rift development had initiated in response to regional extension. Continental break-up began in the early Jurassic, resulting in deposition of syn and post-rift Jurassic to Cenozoic successions.

Northern Carnarvon Basin

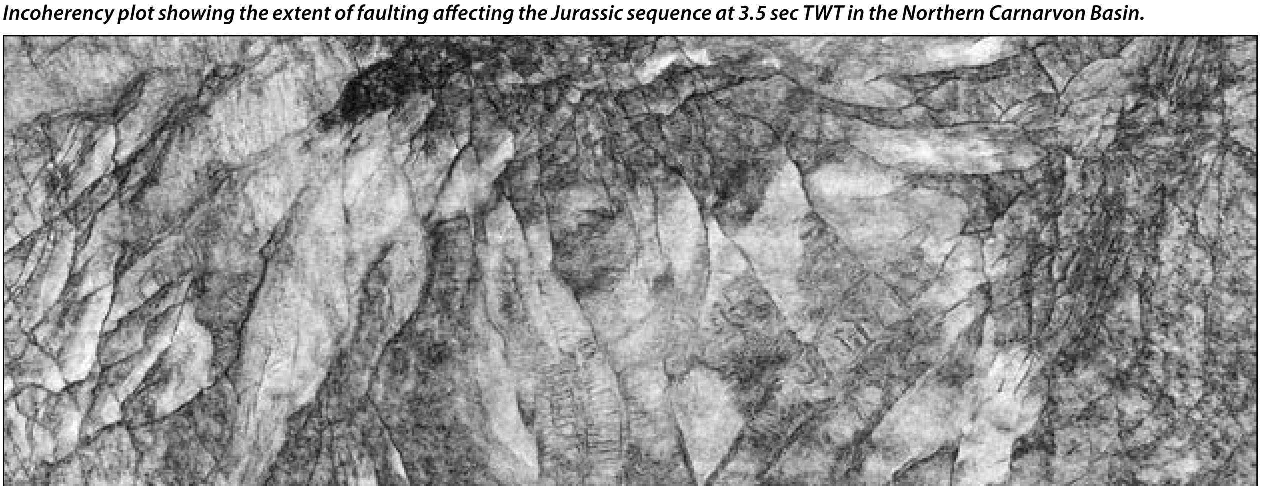
The northernmost part of this basin consists of the Beagle Sub-basin and the Exmouth Plateau. Depositional environments consisted of siliciclastic deltaic to marine sequences throughout the Triassic to the Cretaceous. Early to Middle Jurassic rifting occurred followed by deposition of Late Cretaceous to Cenozoic carbonates during post-rift thermal sag.

The main exploration targets in the basin are Upper Triassic, Jurassic and Lower Cretaceous sandstones, with both structural and stratigraphic plays identified, including up-dip pinch-outs beneath the regional Early Cretaceous seal. Jurassic organic rich claystones and the Triassic Locker Shale provide effective source rocks. The area has been extensively faulted by a series of approximately north-north-west to south-south-east and north-north-east to south-south-west high angle extensional faults that can be seen to heavily compartmentalise the potential reservoir intervals.

Roebuck Basin

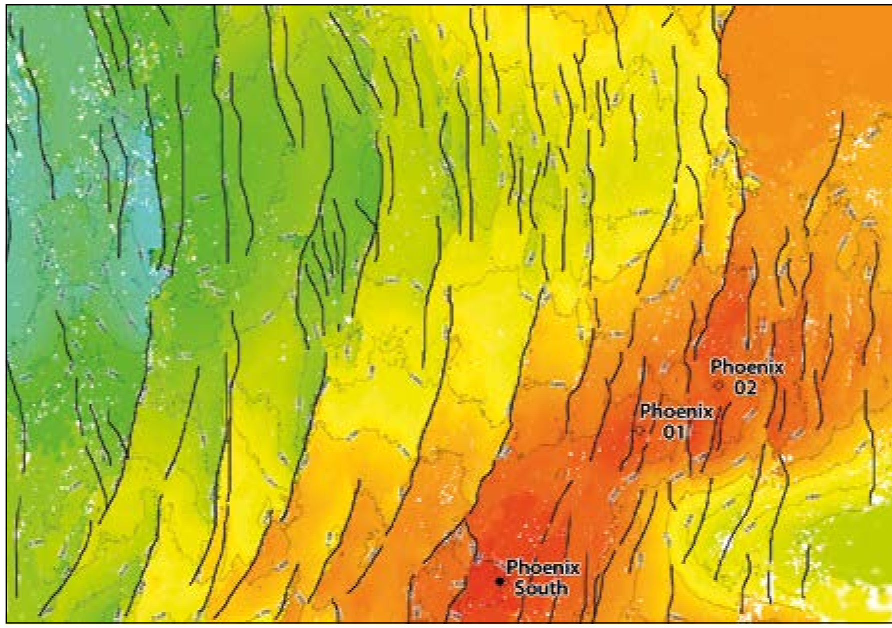
The Roebuck Basin consists of the Rowley and Bedout Sub-basins. The Mesozoic geology of the Roebuck Basin is similar to that of the adjoining Northern Carnarvon Basin, from which it is separated in part by the North Turtle Hinge Zone. The Roebuck Basin is one of the least explored regions of the North West Shelf. It was initiated by extension in the Late Carboniferous to Early Permian followed by regional uplift and faulting in the late Permian associated with volcanism. Subsequent

Incoherency plot showing the extent of faulting affecting the Jurassic sequence at 3.5 sec TWT in the Northern Carnarvon Basin.



thermal sag in the Triassic led to the deposition of a thick sequence of transgressive marine and deltaic deposits, followed by a series of transpressional events terminating in Early Jurassic extension. Lower and Middle Jurassic sediments were deposited in fluvial and deltaic environments followed by Upper Jurassic regional uplift and erosion. Upper Jurassic to Cretaceous sediments were then deposited, overlain by a thick section of prograding Cenozoic carbonates.

In the Bedout Sub-basin the Jurassic-Triassic sequence can be seen to be strongly affected by a number of extensional faults. In the area south and west of the Bedout High the normal faulting displays a high angle with little rotation of the affected stratigraphy. This can be seen in the area of the Phoenix discoveries where the wells tested the broad structural closure as defined by mapping of the overlying Cassigny Limestone. Toward the west, away from the high, the faults develop a listric character due to decollement within the Lower Triassic shales. This has led to rotation of the stratigraphy within the individual fault blocks, developing a number of potential structural traps to the west of the Phoenix discovery wells.



TWT structure map of the Cassigny Limestone in the Bedout Sub-basin. The Phoenix discoveries occur in the Lower Keraudren Formation beneath this shore-face to marine carbonate unit. A number of untested tilted fault blocks can be observed toward the west of the historic discoveries.

The volcanic build-up seen on the data at the margin of the Bedout High has influenced sedimentation of the overlying Triassic sediments, in places leading to complex on-lapping geometries. Beneath the Triassic, the new data also illustrates the complexity of depositional architecture in the Permian across the volcanic high. Reefal carbonates with build-ups atop the high can be seen to grade laterally into fore-reef-slope deposits, in some cases displaying down-lap as the bed-forms prograded basinward.

The main exploration targets in the basin are Lower to Middle Jurassic fluvio-deltaic sandstones; however the basin lacks the Upper Jurassic marine source rocks that are found in the Northern Carnarvon Basin and the presence of adequate source rocks has, to date, been considered a major risk. The Phoenix South oil discovery, sourced from Lower Triassic shales, therefore represents a milestone in the exploration of the basin.

Phoenix South Discovery

The Phoenix structure was originally drilled in 1980 by the Phoenix 1 well, followed in 1982 by Phoenix 2, both operated by BP Australia. Both wells encountered extensive gas columns within low porosity Triassic reservoirs. The Phoenix South well was drilled in 2014 by Apache Corporation with Partners Carnarvon Petroleum, Finder Exploration and JX Nippon. The target was the Triassic Lower Keraudren Formation, which pre-drill was expected to contain an estimated 5.5 Tcf of gas with associated volumes of liquids. The well was, however, plugged and abandoned as an oil well, with at least four discrete oil columns ranging in thickness between 26 to 46m being recognised. Evaluation of the discovery is under way, but the oil and reservoir quality encountered point to a commercial discovery. The area also includes a number of large and shallower, untested structures which include the nearby Roc-1 Prospect, scheduled to be drilled later in 2015.

Capreolus 3D Multi-Client Survey

Polarcus is acquiring this RightFlow™ multi-client survey using the Polarcus *Asima, Amani* and *Naila*, towing a 12 x 100m x 8,100–9,000m, ultra-quiet Sentinel® solid streamer spread and a 12.5m flip/flop shot interval, delivering 180 fold data and processed with a 12-second record length. Fast Track PSTM data is available now (see foldout line on previous page) with a PSDM data volume available early 2016. Deeper stratigraphic surfaces can be seen on the fast-track PSTM data volume, and a number of lines across the survey are being processed to 20 sec TWT to allow investigation of the basin-wide tectonic evolution of the area.

New Hydrocarbon Province

The Phoenix South oil discovery has illustrated the potential for a major new hydrocarbon province, which can now be fully evaluated using the newly available data. The Capreolus survey allows a comprehensive understanding of the Triassic and Jurassic reservoirs in both structural and stratigraphic traps across a number of basins, allowing investigation of the spatial relationships of individual mapped stratigraphic horizons and the understanding of the timing of observed events. The data provides a new understanding of the paleogeography, sedimentology and charge history within the individual seismically defined packages. ■

References available online.

Uruguay
Small Country, Big Opportunities

Uruguay welcomes you with new opportunities offshore.

FERRO SANTIAGO, PABLO GRISTO, BRUNO CONTI, CECILIA ROMEU and HÉCTOR DE SANTA ANA, ANCAP

Uruguay is located in South America between Brazil and Argentina and on the edge of the Atlantic Ocean. It is the second-smallest nation in South America, with a land surface area of 176,215 km^2 and a total area of 318,413 km^2, including rivers and territorial waters. The population is slightly more than 3,285,000, 40% of whom live in Montevideo, the capital city.

There are no remarkable topographic features; most of the country's landscape consists of rolling plains and low hills ranging with fertile coastal lowland – but the country does boast 660 km of stunning coastline with beautiful beaches. The weather and topographic features make Uruguay especially suitable for agriculture, forest and livestock production, which together represent the main sources of gross domestic product within the country. Uruguay has long-standing traditions of democracy and legal and social stability, and has a solid financial and legal framework which makes it attractive to foreign investors looking for business ventures in the region.

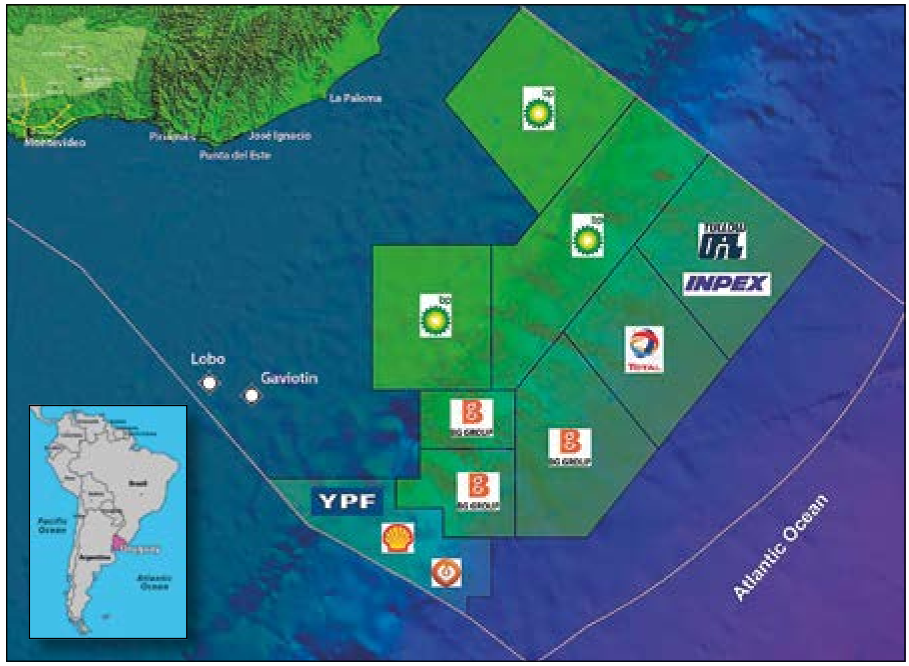
Reviving Exploration

Offshore exploration history in Uruguay has been very discontinuous and limited. The 1970s saw the acquisition of about 12,000 line km of seismic, mainly focused in the Punta del Este Basin, followed by the drilling of two shallow water exploratory wells by Chevron in 1976. Two further 2D seismic surveys of 1,400 km and 1,800 km were carried out in 1982 and 2002, respectively, while between 2007 and 2008 a regional 2D seismic survey of 10,000 km shed some light on the almost unknown provinces of the Pelotas and Oriental del Plata Basins.

Following the 2007–2008 seismic acquisition, offshore bidding rounds constituted the favoured approach for ANCAP (the national oil company of Uruguay) to attract investment by international companies. The first bidding round took place in 2009, in which two exploration and production contracts were awarded to a consortium formed by Petrobras, YPF and GLP. The second bidding round in 2012 was even more successful, and as a result of it, eight blocks were awarded, three of them to BP, three to BG, one to Total and one to Tullow Oil.

As a result of the committed exploratory work carried out by the operators, together with other surveys undertaken by ANCAP, Uruguayan offshore basins are now covered by more than 39,100 km^2 of 3D seismic (16,300 km^2 of multi-client and 22,800 km^2 of exclusive surveys), 13,000 km^2 of 3D electromagnetic surveys and 40,000 km of 2D seismic, 35,000 km of which is multiclient. After 40 years without any wells drilled offshore Uruguay, Total will soon drill the first exploratory well in ultra-deep waters in the Pelotas Basin.

Uruguay is dominated by a rolling plateau with ranges of small hills and is ideally suited to cattle and sheep ranches.



Blocks awarded in the second bidding round in 2012.

Three Offshore Basins…

Three basins are recognised offshore Uruguay: the Punta del Este Basin in the west, the Pelotas Basin to the east and the Oriental del Plata Basin to the south in ultra-deep waters.

The genesis of these basins is related to the break-up of the supercontinent Gondwana and the opening of the South Atlantic Ocean in the Late Jurassic-Early Cretaceous. The offshore basins have a total extent, up to the 200 nautical-mile limit, of more than 85,000 km^2, and a maximum volcano-sedimentary fill of 8,000m, based on seismic data. The water depths range from less than 20m to more than 4,000m.

The only two exploratory wells drilled in the offshore were located close to each other in the Punta del Este Basin in very shallow waters between 40 and 50m. These were Gaviotín-1 and Lobo-1, with total depths of 3,631m and 2,713m respectively. Both were declared dry, and they did not find significant source rock intervals, although fluid inclusions of light oil (36° API) and gas were shown to be present throughout the sedimentary column. The main reason for not finding source rocks in these wells appears to be related to their proximal situation regarding the basin.

The Punta del Este Basin is a funnel-shaped aulacogen which is separated from the Pelotas Basin to the east by the Polonio High.

The Pelotas Basin, which corresponds to the flexural border of a precursor syn-rift structure and developed on continental, transitional and oceanic crust, extends from the Polonio High up to the Florianópolis Fracture Zone in Brazil, close to the edge of the Santos Basin.

The ultra-deepwater Oriental del Plata Basin developed over transitional and oceanic crust. Its sedimentary fill reaches 5,000m and comprises Cretaceous and Cenozoic marine sequences.

… And Three Mega-Sequences

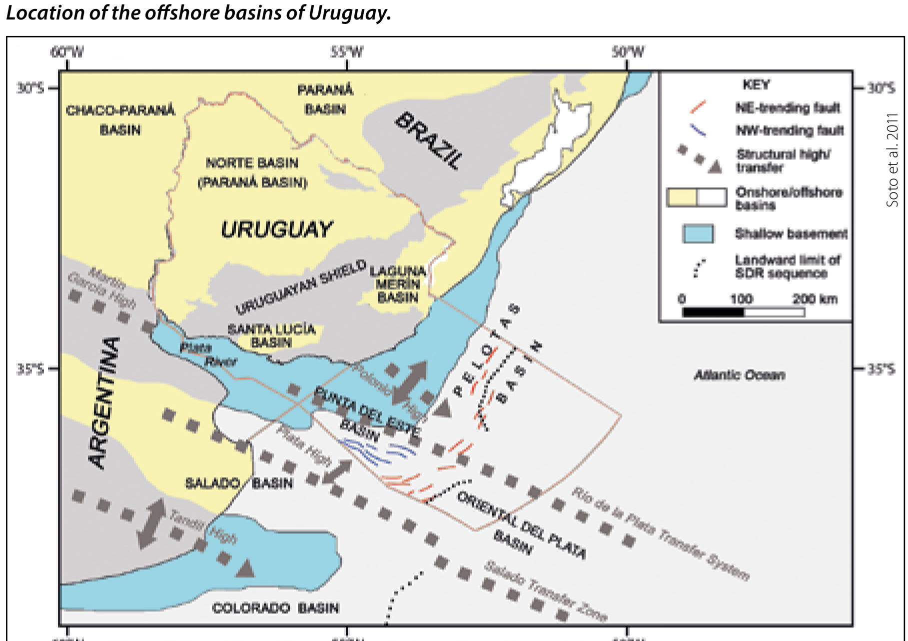
Three main mega-sequences are recognised in the offshore basins: they are pre-rift, syn-rift and post-rift.

The pre-rift mega-sequence corresponds to units preserved from an older basin that developed in the proximal segment of the Punta del Este and Pelotas Basins and is known through Permian sedimentary sequences found in the Gaviotín well at between 3,492 and 3,631m. These can be correlated with the Permian units of the onshore Palaeozoic-Mesozoic Parana Basin.

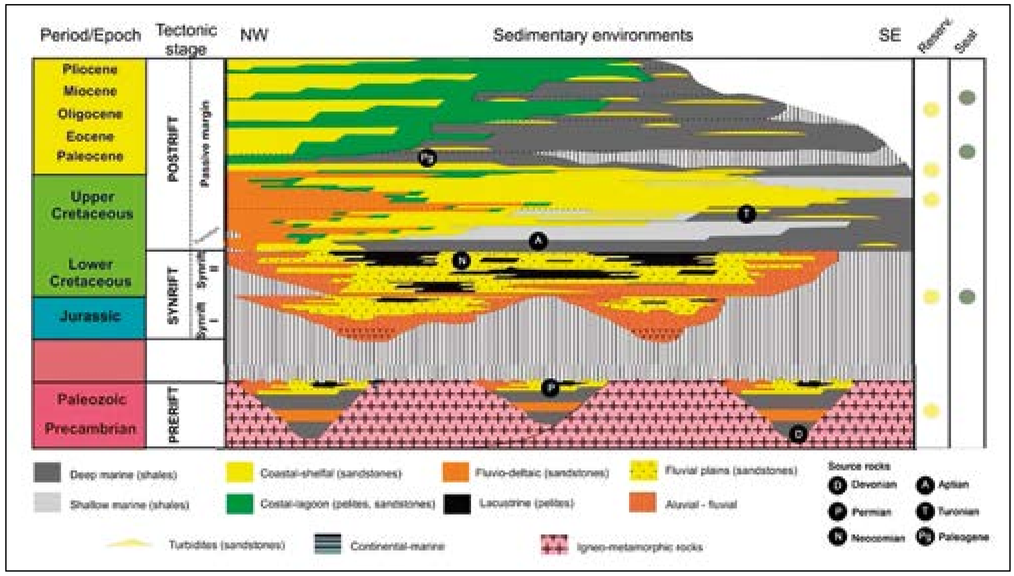
The syn-rift mega-sequence is represented by volcanic and sedimentary units deposited during the rifting of the supercontinent Gondwana. It includes alluvial-fluvial and lacustrine deposits interbedded with volcanic and volcaniclastic rocks, which fill a series of deep asymmetric hemigrabens developed in the proximal segment of the Punta del Este and Pelotas Basins. The syn-rift is also represented in the distal part by seaward dipping reflectors.

Two sequences can be identified in the post-rift mega-sequence: transition and drift. The transition sequence is recognised in the Punta del Este Basin, and includes fluvial-deltaic systems and distally marine systems. It was deposited during a period of thermal subsidence after the end of the rift mega-sequence (marked by the break-up unconformity). The

Location of the offshore basins of Uruguay.



drift sequence, which can be divided into a Cretaceous early drift and Cenozoic late drift segment, has a maximum total thickness of 5,500m based on seismic data and is characterised by several sequences of minor order associated with transgressions and regressions of the sea level. These sea level changes resulted in the deposition of several marine source rocks of good quality during the transgression periods, and in times of regression reservoir rocks of continental and marine origin such as channels, deltaic prograding fronts and turbidites were deposited.



Petroleum system model showing source, reservoir and seal rocks offshore Uruguay.

Proven Petroleum Systems

The main potential source rocks are related to the three mega-sequences identified. In the pre-rift, a lower Permian source rock has been proven in the Brazilian part of the Pelotas Basin. This was deposited in a restricted marine environment represented by marine oil shales with TOC levels up to 13.5%. Within the syn-rift sequence thick lacustrine source rocks have been interpreted on seismic, most importantly in the Punta del Este Basin.

The base of the post-rift sequence shows a clear transgressive character with the deposition of marine Aptian source rocks. These correspond to the first oceanic anoxic event of the Cretaceous, represented in several productive South Atlantic basins by black organic-rich shales. A second marine transgression during the Cenomanian-Turonian resulted in the deposition of a source rock that is also found in the Pelotas Basin in Brazil. Finally, there was a third important marine transgression of Late Maastrichtian-Middle Eocene age, which not only provides a regional seal but includes potential source rock levels, in spite of the fact that they probably only reached the oil window distally.

Proven high-quality reservoir rocks were encountered in the two wells, with porosity values between 18 and 25%, increased by fracturing and dissolution processes.

Different structural, stratigraphic and combined leads and prospects can be seen on the seismic sections in variable water depths, from shallow through to ultra-deep waters.

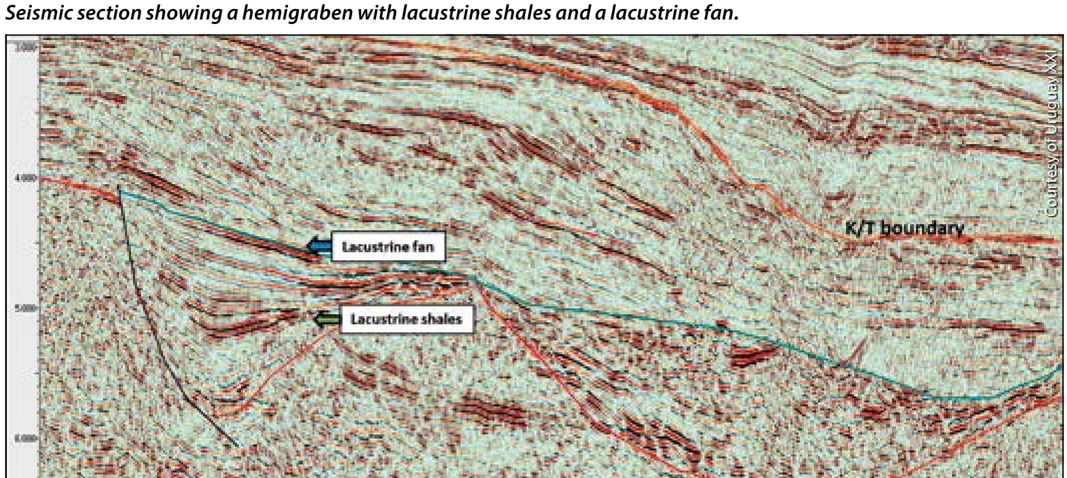
Plays in the pre-rift and syn-rift sequences include gentle anticline structures related to basement highs, rotated blocks, compaction synclines, lacustrine fans and pinch-outs against basement highs. Plays in the post-rift sequence include pinch-outs, channel complexes, and most notably turbiditic and basin floor fan systems.

New Opportunities

New areas offshore Uruguay in shallow, deep and ultra-deep waters will be offered to the industry in 2016 when the third bidding process, Uruguay Round 3, is released. The contract model, which will have similar characteristics to those signed in Uruguay Round 2, is a typical production sharing agreement, in which the contractor assumes all risks, costs and responsibilities for the activity. Offers for the available blocks will be compared taking into consideration the exploratory programme proposed over the minimum stipulations required, the percentage of profit split and the percentage of ANCAP's association in the case of a commercial discovery.

Come and visit Uruguay, a wonderful place to do business, and with promising geology and fair contract terms. ■

Seismic section showing a hemigraben with lacustrine shales and a lacustrine fan.



Ghana

From African Star to IMF Bail-out

Despite the government's protestations that oil revenues would be managed transparently, corruption, debt and economic mismanagement are now creating tension, as Ghana succumbs to the resource curse.

NIKKI JONES

In 2007 Kosmos Energy discovered the 1.2 Bbo deepwater Jubilee field off Ghana's coast. First oil was achieved in a remarkable three and a half years and since 2009, further discoveries of commercially viable gas, gas condensate and oil have been made in two other blocks. Production is expected to reach 190,000 bopd by 2016, plus another 80,000 boepd by 2019.

Ghana is, of course, accustomed to living on commodity wealth: gold is still its major revenue source, and the country is the second largest cocoa producer in the world. Despite this wealth, Ghana remains 138th on the Human Development Index, with more than 30% of its population living on less than $1.25 a day.

The discovery of oil inevitably prompted a huge, popular wave of optimism. Hopes were high that the government would be able to deliver more basic services – including energy – to its 26 million population, and move towards industrialisation, the 'holy grail' of every developing country.

Booming Economy

The big fear was the 'resource curse' – the seemingly inevitable fanning of corruption, conflict and increased poverty from an oil-fuelled exchange rate. However, hopes were high for Ghana, one of the continent's foremost 'rising democratic stars'. Since the early 1990s, politics have been stable and since 2001, elections have delivered relatively peaceful changes of government. Indeed, the government itself appeared to embrace the clamour of demands for transparency, accountability and public consultation. There was an immediate flurry of legislative activity, including a Revenue Management Act, a local content framework, and the establishment of two, key regulatory bodies. As early as 2010, Ghana was recognised as EITI (Extractive Industries Transparency Initiative) compliant.

Gold and cocoa prices were already

The glass walls of the Bank of Ghana building rise up above a slum in Accra.

Nikki Jones

The new presidential palace in Accra.

are weak. The national oil company, GNPC, was supposed to be removed from all contract negotiations, so that the NOC stopped being both referee and player, but in practice this has not happened. GNPC is still involved in the negotiation and reviewing of all petroleum agreements and although Ghana has belatedly published some of these contracts, publication is still not mandatory.

The suspicion is, of course, that certain members of the political elite are behind these unknown Ghanaian companies, and that under the guise of 'local content', they are either getting privileged access to high value blocks from which they hope to make fortunes, or they are operating simply as 'front' companies 'greasing the wheels' on behalf of larger IOCs.

Most cases are below the public radar but in 2014 one local company overstepped the mark. The unknown Ghanaian company Miura Petroleum International, only founded in 2013, was in exclusive negotiations with the Ministry and so confident of getting its contract for a block just 30 km from Jubilee that it forged the signature of the Minister for Energy and attempted to sell its stake to Canadian listed Gondwana Oil Corp. This only became public when Gondwana then went to the stock exchange to raise funds for its exploratory work.

As part of the initial flurry of protective legislation, a Right to Information Bill was first drafted in 2007 but it has still not been passed into law.

rising, and oil helped push GDP growth as high as 25% in 2012. Infrastructure projects were launched across the country and Ghana set about meeting its 2015 poverty reduction target. It seemed that it might just fulfil President Kufuor's dream of becoming an 'African tiger' and in 2010, the country was upgraded to Lower Middle Income Country status, ranking it alongside India, Indonesia and Ukraine.

Down on the ground, however, some of the realities were less encouraging. Accra suddenly became a boom town for prestige apartments and government department buildings – epitomised by the president's $40–50 million golden palace and the magnificent Petroleum Commission headquarters. Roads became clogged with SUVs, young people flocked to the cities, rents in strategic areas began to rocket and land-grabs (where no formal deeds were held) became commonplace. The reality for the majority remained subsistence-level, insecure petty trading with limited public services.

No Transparency in Block Allocation

Clearly, many of the worst features of the resource curse have arrived. Most worryingly, 17 of Ghana's off-shore blocks have now been licensed, but none by competitive tender. Several scandals have already emerged, almost all involving the granting of licences to small, unknown Ghanaian companies where the 'beneficial ownership' is hidden. Many are high value blocks close to the Jubilee field. In theory, all Petroleum Agreements are ratified by parliament but in several cases they have been introduced to parliament under 'certificates of urgency', with two 'approved' in less than six hours. According to the Africa Centre for Energy Policy (ACEP), the rush has been explicitly to get licences through before the long-awaited Exploration and Production Bill is passed.

A Petroleum Commission able to negotiate contracts was established in 2011 but its powers and its independence

Fishing provides an income for 10% of Ghana's population, but offshore exploration is having a detrimental effect on fish stocks.

Revenue Management

Similarly, it has been a battle to remove the Minister of Finance's power to withhold information on oil revenues. A Revenue Management Act, finally enacted a year after first oil, has brought some transparency. Revenues are now paid into a single fund before they are divided, roughly 50-50, between the government's budget and GNPC. Funds are then distributed into four agreed areas of national development, and two sovereign wealth funds.

Although the legislation is clear, and parliament is supposed to have oversight of all expenditure, Ghana's government, Auditor General, the Bank of Ghana and Ghana's Revenue Authority have all failed on key reporting and publishing requirements. The management of the sovereign wealth funds is beyond scrutiny and a particular cause for concern. There has been a reported 65 million Cedi (about US$20 million) allocation to the Office of the President – more than the allocation to agriculture. The amount claimed by the GNPC for production and administration costs is beyond scrutiny.

Regional and International Concerns

The 'resource curse' recognises that oil is not only a fuel for corruption, but can often bring regional conflict. There has been a noticeable increase in tension along the coastal strip where the UK's development agency has calculated that, because of oil, 60% of the 40,000 fishermen and 90,000 farmers in the region will have lost their jobs by 2020.

The northern regions, where two thirds live below the poverty line, are also a recognised 'hot-spot'. Inter-ethnic violence occurs on a recognisable ten-year cycle and although many have been lifted out of absolute poverty in the south, there has been an increase in the north. Agriculture, which employs 55% of the country, is a recognised priority, but the small percentage it receives is spread too thinly to make a difference.

In Accra, there have been demonstrations against power cuts and in June, the destruction of a slum, home to an estimated 50,000 mainly northern migrants, brought angry demonstrations, with some slum dwellers holding signs predicting the imminent arrival of Boko Haram. The clearance has left the 50,000 homeless, and the demonstrations were met by police using tear gas. It seems the oil-fuelled rush to modernise may be generating serious longer-term problems.

A further concern is a potential conflict with its neighbour, Ivory Coast. Like many African countries, Ghana has the artificial boundaries left from colonial days, including a thin finger of coast below its neighbour's territory which enabled Ghana to claim an extended, valuable offshore acreage. Last March, both countries took their dispute to the International Tribunal for the Law of the Sea, which ruled that although work on the TEN field (Tweneboa-Enyenra-Ntomme) could continue, there should be no further exploration in the area. Outright hostilities seem unlikely but the two-year wait for a legal ruling will severely disrupt Ghana's oil exploration.

The Biggest Threat – Debt

In 2014, debt brought Ghana down from the giddy heights of being one of Africa's shining stars to requesting an IMF bail-out, despite the fact that only as recently as 2004 Ghana had most of its external debt written off in the World Bank's Heavily Indebted Poor Country (HIPC) initiative. The Revenue Management Act allows the government to use 70% of oil revenues as collateral, and it appears to have taken full advantage.

By 2015, debt had climbed to 60% of GDP as successive governments have run large budget deficits. Foreign investors had rushed to provide loans while interest rates were so attractive. The confidence of the government was so high, that in 2007 Ghana became the first sub-Saharan country to issue a bond in US dollars. Now, as investors pull out, the Cedi has fallen. In 2014 it lost almost 40% of its value – the world's worst performing currency – and it has fallen a further 25% this year. This has been exacerbated by the drop in gold prices that began in 2013, and the drop in oil prices is estimated to have added a further 2% to the budget deficit.

Ghana has also been hit by the rising dollar. Not only are most of its imports – particularly food – purchased in dollars, bringing inflation to 17% in 2014, but its dollar-denominated bonds have had to be serviced.

The result is a billion dollar loan from the IMF, conditional upon measures that include a new 17% petroleum tax (for domestic consumers) and a freeze on public sector employment. For ordinary people who have seen no benefit from oil production, the currency crisis is a national disaster.

Access to electricity is not universal – and often neither safe nor legal.


Nikki Jones

Food and Energy Imports

This is particularly true because, despite its agricultural base and its oil wealth, Ghana is increasingly dependent on imported food and energy. Agriculture still employs 55% of the population and contributes 40% of GDP, but both domestic food production and cocoa, Ghana's lucrative export, have struggled for investment.

Energy is Ghana's other big import bill. Currently, 65% of Ghanaians have access to electricity but over the last few years, supply has become increasingly intermittent. President Mahama is popularly known as Mr Dumsor, Mr Off-On. The unpredictability has meant that many industries and wealthier homes have come to rely on diesel generators, which adds to the country's import bill.

The government's aim is to generate 5,000 MW by 2016, firstly by importing gas from Nigeria through the offshore West Africa Gas Pipeline; secondly, using its own gas; and thirdly – a more recent development – importing LNG. Delays in the first two projects have resulted in enormous costs for the country. Two thermal plants have been run on imported light crude, costing $3m a day, and free gas from the Jubilee field has not only not been used, but has been re-injected, reducing oil output. This gas finally came onstream at the end of 2014.

Although some of the delays have been outside Ghana's control, it is clear that corruption and mismanagement have also been factors.. Without open tendering, Sinopec was given the contract to build both the pipeline from Jubilee and the gas processing plant that Ghana is dependent upon. The deal was withheld from parliament and repeated delays have, according to the Africa Centre for Energy Policy, cost the country an estimated $2.2bn since 2011.

Fancy apartment buildings have sprung up all over Accra, while 30% of Ghana's population live below the poverty line.

Nikki Jones

Managing Expectations

Ever since oil was discovered, the mantra of government has been the 'management of people's expectations'. This has always seemed unjust given that the majority are still waiting to feel the benefits of more than a century's concerted mineral exploitation. It seems that Ghana's government is fulfilling the world's worst fears: it has not managed its own expectations. ■

Supercomputers for Beginners PART I

LASSE AMUNDSEN, Statoil,
MARTIN LANDRØ and **BØRGE ARNTSEN**, NTNU Trondheim

> *'f u cn rd ths, u cn gt a gd jb n cmptr prgrmmng.'*
>
> *Anonymous*

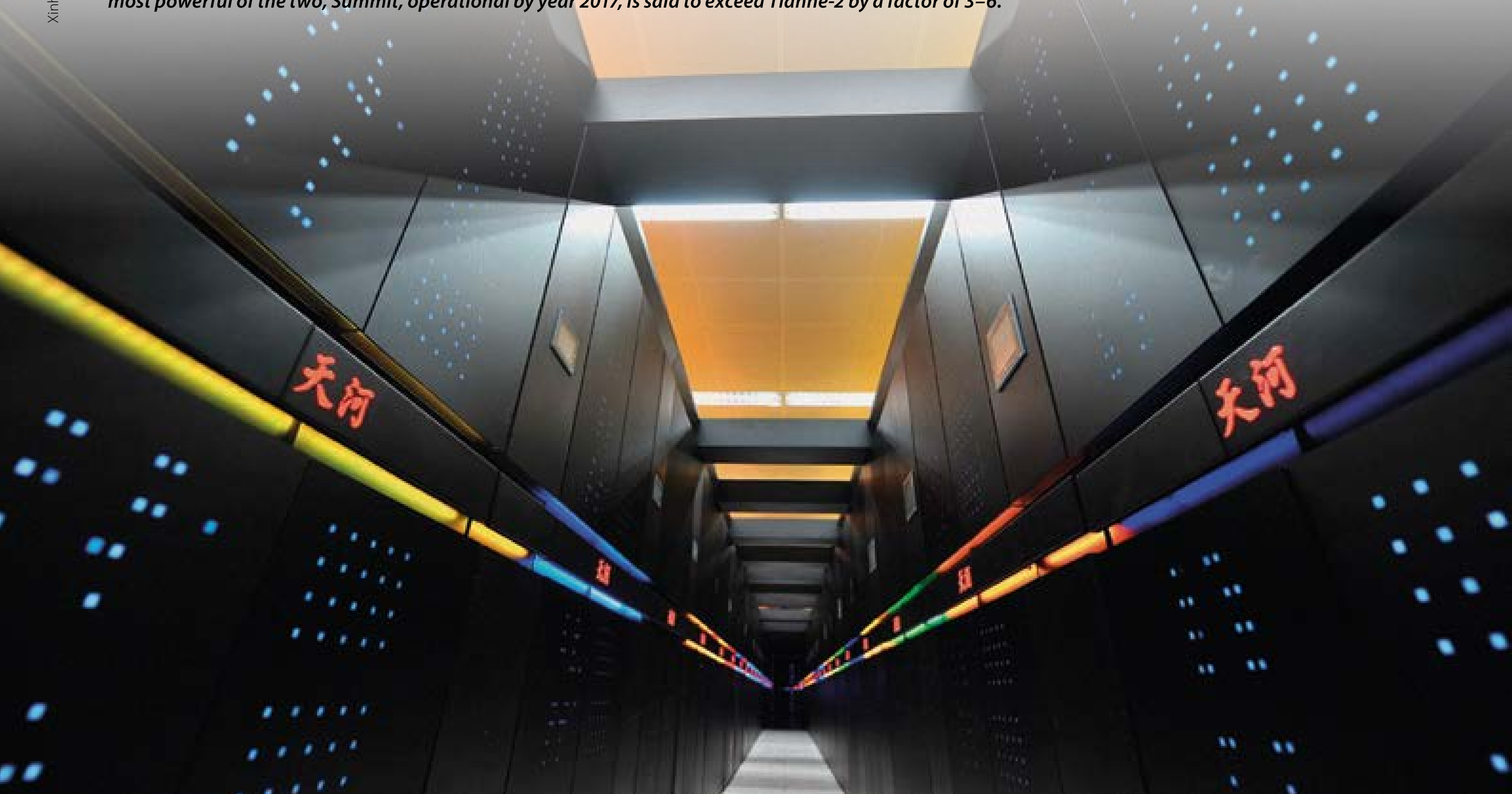
Supercomputers help geophysicists to analyse vast amounts of seismic data faster and more accurately in their search for oil and gas. Seismic surveying is a merger of big data and big computing, and the seismic industry is expected to be an early adopter of new and fast computing technologies. Majors like Eni, Total and BP have rolled out mega-supercomputing centres for seismic imaging. In March 2015, PGS installed a five-petaflop supercomputer, the most powerful in the seismic industry. By 2020 we will have exaflop computers doing a quintillion (10^{18}) calculations per second. This article is an introduction to supercomputers using high-level explanations.

Cutting-edge research and development (R&D) is a competitive differentiator for many organisations, allowing them to attract leading talent and solve some of the world's largest challenges. Supercomputing is revolutionising the types of problems we are able to solve in all branches of the physical sciences. Almost every university and major E&P company host some kind of supercomputing architecture. The primary application of supercomputing in E&P is seismic imaging, while secondary applications are reservoir simulation and basin simulation. The availability of computing resources is only going to increase in the future and as a result it is important to know the primary concepts behind supercomputing.

What is a Supercomputer?

The official definition of a supercomputer is a computer that leads the world in terms of processing capacity – speed of calculation – at the time of its introduction. It is an extremely fast computer whose number-crunching power at present is measured in hundreds of billions of floating point operations. Today's supercomputer is

The #1 system since June 2013 is Tianhe-2 (which means Milky Way-2), a supercomputer developed by China's National University of Defense Technology at a cost of 2.4 billion yuan ($390 million). Its performance of 33.86 petaflops (quadrillions of calculations per second) is used for simulation, analysis, and government security applications. It has 125 cabinets housing 16,000 computer nodes with a total of 3,120,000 compute cores, and each of those nodes possesses 88 gigabytes of memory. Powerful computers also use more electricity; at peak power consumption, it draws 17.6 megawatts (MW) of power, with the water cooling system bringing that up to 24 MW. The electricity bill for Tianhe-2 runs at 400,000–600,000 yuan ($65,000–$100,000) a day. The computer complex occupies 720m² of space. In November 2014, it was announced that the United States is developing two new supercomputers to dethrone Tianhe-2. The most powerful of the two, Summit, operational by year 2017, is said to exceed Tianhe-2 by a factor of 3–6.



Xinhua/Sipa USA

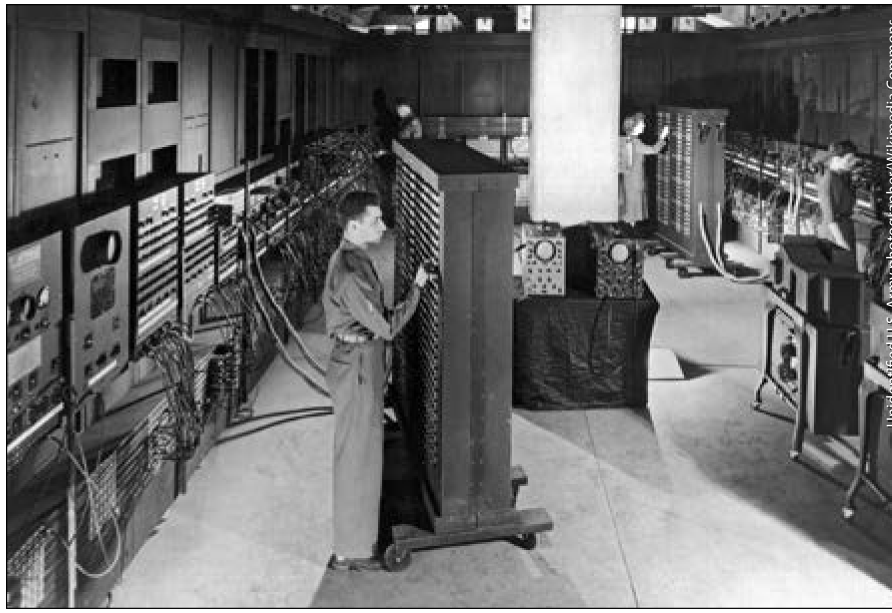
destined to become tomorrow's 'regular' computer. For many, a better definition of supercomputer may be any computer that is only one generation behind what you really need!

Supercomputers are made up of many smaller computers – sometimes thousands of them – connected via fast local network connections. Those smaller computers work as an 'army of ants' to solve difficult scientific or engineering calculations very fast. Supercomputers are built for very specific purposes. To fully exploit their computational capabilities, computer scientists have to spend months, if not years, writing or rewriting software codes to train the machine to do the job efficiently.

Supercomputers are expensive, with the top 100 or so machines in the world costing upwards of US$20 million each.

The terms supercomputing and high-performance computing (HPC) are sometimes used interchangeably. HPC is the use of supercomputers and parallel processing techniques for solving complex computational problems.

Today's #1 supercomputer is Tianhe-2. The first scientific supercomputer was ENIAC (Electronic Numerical Integrator and Computer), constructed at the University of Pennsylvania in 1945 (see above). It was about 25m long and weighed 30 tons. Two famous recent supercomputers are IBM's Deep Blue machine from 1997, which was built specifically to play chess (against Russian grand master Garry Kasparov), and IBM's Watson machine (named for IBM's founder, Thomas Watson, and his son), engineered to play the game Jeopardy.



Unidentified U.S. Army photographer/Wikimedia Commons

Installed in 1945 at the Moore School of Electrical Engineering, University of Pennsylvania, USA, ENIAC contained more than 100,000 components and weighed approximately 30 tons. It was the first programmable general-purpose electronic digital computer. The first test problem run consisted of computations for the hydrogen bomb.

Computer Speed

The definition of a supercomputer is defined by processing speed. Computer speed is measured in FLoating Point Operations Per Second (FLOPS). Floating point is a way to represent real numbers (not integers) in a computer. A floating point operation is any mathematical operation (addition, subtraction, multiplication, division, etc.) between floating point numbers.

To see the current computing leaders, check out the website: http://www.top500.org, which lists computers ranked by their performance. It lists as of June 2015 PGS' supercomputer, named Abel after the famous Norwegian mathematician Niels Henrik Abel (1802–1829), at #12 with a peak performance of 5.4 petaflops and with 145,920 cores – more than five thousand trillion (or quadrillions) calculations per second! Eni E&P's HPC2 supercomputer is #17 with a peak performance of 4.6 petaflops and with 72,000 cores. Total E&P's machine Pangea is ranked at #29 with peak performance of 2.3 petaflops, and boasts 110,000 processor cores, 442 terabytes of memory, and 7 petabytes of disk storage.

Entry onto the TOP500 list is voluntary, and some companies intentionally do not participate to keep information about their computing capacity hidden from competitors. As a result, it is difficult to know which really are the biggest supercomputers in the E&P industry. BP is known to be in the forefront of supercomputer technology with a total processing power of 2.2 petaflops, 1,000 terabytes of memory, and 23.5 petabytes of disk space. Exxon Mobil has also touted its supercomputer in an in-house magazine, saying that its calculating abilities are in the 'next-generation' quadrillions per second.

We can see from the graph, on a logarithmic scale, quite a linear progression in computing speed which implies exponential growth. This result is a basic outcome of Moore's Law. In 1964, the engineer Gordon Moore noticed that the number of transistors per computer chip seemed to be doubling approximately every two years. The law extends to the speed of our computers as well. Computers of the early 1970s ran in the kilohertz range, machines of the mid-1980s ran in the megahertz range, computers in the early 2000s ran in the gigahertz range, and in the early 2010s computers are running in the terahertz range: a thousand-fold speed-up every 10 years, and a billion-

IBM's Watson computer system competed against Jeopardy's two most successful and celebrated contestants – Ken Jennings and Brad Rutter – in 2011. What made it possible for Watson to win was not just its processing power, but its ability to learn from natural language.

©IBM

fold speed-up in the course of 40 years.

In his 2005 book *The Lifebox, the Seashell, and the Soul: What Gnarly Computation Taught Me About Ultimate Reality, the Meaning of Life, and How to be Happy*, Rudy Rucker (1946–), an American mathematician, computer scientist, science fiction author and philosopher, made an interesting drawing of what may happen if this trend continues (see above right).

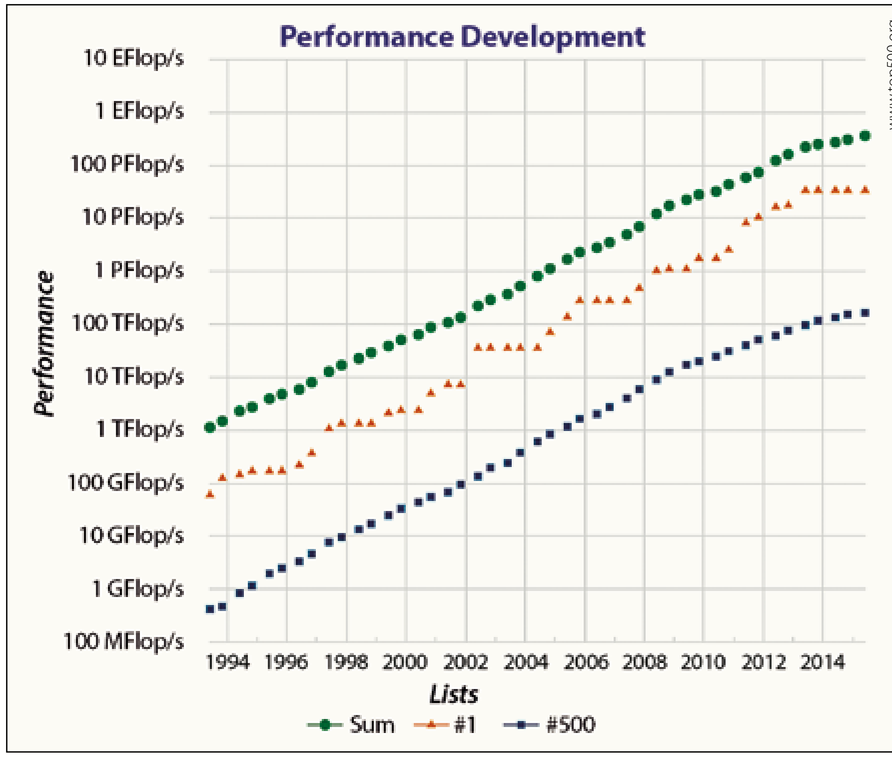
Energy Usage and Heat Management

The biggest supercomputers consume egregious amounts of electrical power and produce so much heat that cooling facilities must be constructed to ensure proper operation. Tianhe-2, for example, consumes 24 MW of electricity. Global power consumption is approximately 16 terrawatts, which means that Tianhe-2 uses 0.00015% of the world's energy consumption. The cost to power and cool the system is significant, e.g. 24 MW at $0.10/kWh is $2,400 an hour or about $14 million per year. The list Green500 (www.green500.org) provides a ranking of the most energy-efficient supercomputers in the world.

On the June 2015 Green500 list, the Shoubu supercomputer from RIKEN (Institute of Physical and Chemical Research in Japan) earned the top spot as the most energy-efficient (or greenest) supercomputer in the world, surpassing seven gigaflops/watt (seven billions of operations per second per watt). Assuming that Shoubu's energy efficiency could be scaled linearly to an exaflop supercomputing system, one that can perform one trillion floating-point operations per second, such a system would consume in the order of 135 MW. Shoubu is ranked #160 on the June 2015 edition of the TOP500 list.

Computer performance

Name	FLOPS
yottaFLOPS	10^{24}
zettaFLOPS	10^{21}
exaFLOPS	10^{18}
petaFLOPS	10^{15}
teraFLOPS	10^{12}
gigaFLOPS	10^{9}
megaFLOPS	10^{6}



The increase in supercomputer performance from the 1990s up to today has been amazing. The #1 supercomputer (June 2015) has a performance of 34 PFlops.

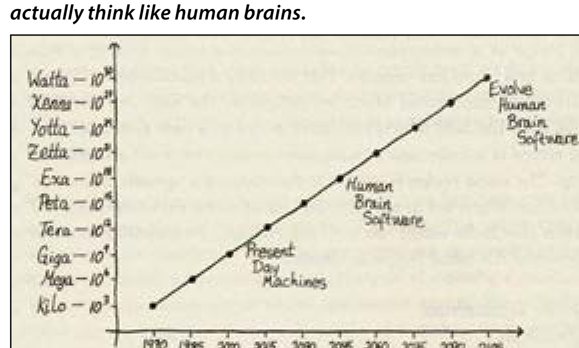
Supercomputers are either air-cooled (with fans) or liquid-cooled (with a coolant circulated in a similar way to refrigeration). Either way, cooling translates into very high energy use and expensive electricity bills. The water cooling system for Tianhe-2 draws 6 MW of power.

Parallel Processing

An ordinary computer is a general-purpose machine that inputs data, stores and processes it, and then generates output. A supercomputer works in an entirely different way, typically by using parallel processing instead of the serial processing that an ordinary computer uses. Instead of doing one thing at a time, it does many things at once. Most supercomputers are multiple computers that perform parallel processing, where the problem is divided up among a number of processors. Since the processors are working in parallel, the problem is usually solved more quickly even if the processors work at the same speed as the one in a serial system.

In the next article on supercomputing, we will elaborate on parallel processing, CPUs (central processing units), and GPUs (graphics processing units). GPU developments were primarily driven by the demand for more awesome video games. Now, in order to support the needs of physical simulations, GPUs have advanced significantly to do mathematical computations. If you think of your computer as an army, CPUs would be the generals – highly capable and extremely efficient at command and control. GPUs would be the foot soldiers, massive numbers of production units but not as capable at decision-making. ■

Rudy Rucker in his 2005 book plotted a trend whereby computers get a thousand times as fast every 15 years. We get machines with speeds comparable to the exaflop human brain in 2045, and in 2105 we get wattaflop machines powerful enough to evolve the software needed to make the exaflop machines actually think like human brains.

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Psychology of Exploration

Setting out to explore for hydrocarbons, Noble Energy's Susan Cunningham found herself on a journey of self-exploration, which led to a host of discoveries beyond her wildest imagination.

HEATHER SAUCIER

She has spent practically her entire career as a passionate explorer, taking the earth apart as if it were a puzzle to find oil and natural gas in places often missed by others.

Yet it wasn't until Susan Cunningham – a geologist and executive vice president of Exploration, New Ventures, Geoscience, EHSR and Business Innovation at Noble Energy – moved up the professional ladder that she realised the value of self-exploration and its unexpected connection to finding hydrocarbons.

As a woman in the industry, Cunningham once believed she needed to 'act like a man' to be competitive. After some heartfelt introspection, that idea is long gone. Relying on her finely honed skills as a geologist, an ability to build solid, interdisciplinary teams, and a strong intuition, Cunningham has created a corporate culture that insists on creativity and unconventional ideas. She has revamped exploration at Noble, which has evolved into a high-quality global exploration company. And, she is not afraid to admit that the process involved a bit of emotion.

Exploring the Earth

Cunningham's curiosity about the earth began as a child in Toronto, Ontario, Canada, where she often asked her mother why a mountain rose to awesome heights in a particular place. Her interest in landforms continued into college, prompting a counsellor to suggest that she study geology.

After accepting a job with Amoco Corporation in the United States in 1981, she requested extra time to drive from Calgary to Houston to take in the majestic landscapes of Yosemite National Park, the Grand Canyon and Carlsbad Caverns. While at Amoco, Cunningham began breaking barriers by becoming the company's first female country manager as well as its first female domestic exploration manager in the deepwater Gulf of Mexico. After 17 years, she joined Statoil, and a short time later, Texaco, as a vice president of Exploration.

In 2001, Noble Energy approached her, with big ideas in mind.

"When she joined, people at Noble thought they knew how exploration worked, but our track record told a different story," says Charles D. Davidson, former chairman, president and CEO of the company, explaining that he recruited Cunningham for her passion, creativity, visualisation, determination and desire to help people. "She doesn't accept 'good enough' when she knows 'outstanding' can make a big difference. She defends her position and sometimes it's against high odds."

Looking Inward

Starting at Noble Energy as senior vice president of exploration, Cunningham knew her ability to be assertive and speak her mind helped get her there.

"When you're first starting out and you're trying to find your way, you adapt to the environment you're in," Cunningham says. "That meant – to me – very specifically that I had to be one of the guys. It meant 'for God's sake, don't be emotional.'"

While those traits served as assets on her climb up, she quickly realised they became liabilities for a leader. In her quest to ramp up Noble's exploration programme, which at the time consisted mostly of single-well prospects, Cunningham believed she could raise the bar to unprecedented heights. "But something was in the way," she recalls. "It was like the glass ceiling." For Cunningham, that glass ceiling was the demeanour she brought into her new role. "It started out as this fight to get your way, but who wants that? I didn't feel like people heard my thoughts to the degree that I wanted them to when I thought I had value to add."

Concerned, she hired a life coach who encouraged her to look inward, be herself, and make genuine connections with people.

"That assertive and demanding person – that's not leadership. That's the stick," Cunningham learned. "In leadership, it's not about me getting it done. It's about the organisation getting done what needs to be done. That meant I had to be authentic and connect with myself – as a person and as a leader – in order to really connect with other people. And because I'm female, that had to be a part of it."

She tested that newly found advice by calling an important meeting about five years after joining the company. At the time, Noble was spending exploration dollars to drill small wells along the Shelf and Gulf Coast to keep production flowing. "I wanted to do something dramatically different," Cunningham says. "I had a vision, and I wanted to enroll everyone in it."

She wanted to discover 1 billion barrels of oil equivalent in five years.

"That was one of the scariest times leading a meeting that I'd ever had. Basically, I said we all had to go for it. I believed everyone wanted to make a big difference. No one really wants to muddle along," Cunningham recalls. "I was taking a huge risk. I became so emotional, I just let the tears out." The room fell silent, all eyes fixed on Cunningham. Her first thought: "OK, I'm connecting."

A New Era for Exploration

By 2012, Noble Energy had found more than 2 Bboe – essentially doubling Cunningham's initial goal. She credits the success with the connection she began making with her colleagues, and the hard, determined and inspiring work of the organisation that followed. "People connect with people who are really committed to something and who are vulnerable in it," she says. "One of the leaders came up to me and said, 'I really thought I was committed, but I can tell I've got to up my game big time.' That's when I learned not to hold back."

With the reins in her hands, Cunningham took Noble into material exploration prospects around the globe – all with significant running room, according to Dave Stover, chairman, president and CEO of Noble. "She was really breaking out new plays," he says. "It had a huge impact on the company's growth and resources."

The company broadened its base as it moved into the deep waters of the Gulf of Mexico and expanded its limited presence into Equatorial Guinea and Israel, and later into other countries that many operators avoided.

Cunningham took a 'big picture' view of exploration and advised the leasing of multiple blocks at a time to take advantage of low entry costs. If a prospect proved successful, then a powerful play had the potential to open up rather quickly. "You can't just look at one prospect in one country," she says. "You need to ask, 'What are the other opportunities for success if this one prospect works out?'" She applied that thinking in Equatorial Guinea, Cameroon, Israel, Cyprus, Gabon, the Gulf of Mexico and, most recently, in the Falkland Islands.

Although the company made a modest natural gas discovery off the coast of Israel in 2000, an opportunity to move into deeper waters came in 2007. The New Ventures team had passed on the prospect, but Cunningham had another hunch. After she learned about the opportunity, she challenged Noble's Gulf of Mexico deepwater experts to take a closer look. "It ended up being a string of the largest natural gas discoveries

Susan Cunningham (sitting) poses for a photo with Noble Energy leaders (from left to right) Amy Jolley, Lee Robison and Cathy Molitoriss for an ad to support the Women's Energy Network.


Noble Energy

we've made as a company," Davidson says of the Tamar field, with 10 Tcfg, and the Leviathan field, with 22 Tcfg. Today, natural gas from Tamar fuels more than 50% of Israel's electricity generation.

Similarly, when an opportunity to enter the Falkland Islands came in 2011, many believed the harsh climate and politics made the prospect too risky. After three weeks of reflection, Cunningham called a meeting to revisit the idea. "She took a strong stand and sold it to the executive team and then sold it to the board of directors," Davidson recalls. "This had a place in the portfolio." Results from the company's first exploration well are expected in the third quarter of 2015.

Starting her career as a petroleum geologist, Susan Cunningham performed field work in Tanzania in the East African Rift Valley in the 1980s.

Breakthrough Thinking

Noble Energy has upped its number of successful plays in large part because of processes used by Cunningham's organisation called 'Exploration Excellence and New Ventures Excellence', which was recently nominated for the Noble Energy CEO Award for Business Innovation. One of those processes is 'breakthrough thinking'.

Before going into a new country, Cunningham builds strong interdisciplinary teams and challenges team members to explore prospects with a macrocosmic view – tearing the geology apart and setting all biases aside. All issues and risks – geological, economical and political – are assessed so 'thoughtful' decisions can be made. Perhaps most importantly, Cunningham encourages her teams to toss every idea around the conference room – no matter how outlandish some might seem.

"It's about getting the genius out of each other," Davidson says. "It's about being able to take risks and feeling comfortable to speak out. When everyone says, 'That's impossible,' it forces you to think creatively. What would it take to achieve a real breakthrough?"

For many years, Noble operated in the Niobrara Formation of the DJ Basin in Colorado, drilling vertical wells. Initially unable to make horizontal drilling work, the company engaged in the breakthrough thinking process, and a slew of highly productive horizontal wells came on line. Today, sales volumes from the DJ Basin represent more than a third of the company's total sales volumes.

"Susan is good at looking at things from a different angle," Davidson says. "She's demanding, but she gives others the time and space to figure it out."

Breakthrough thinking became infectious – even during the 2010 Deepwater Horizon incident, which prompted the federal government to suspend all drilling in the Gulf's deep waters. Leaving behind a 'woe is me' mentality, Noble's drilling team met with the government's Minerals Management Service to discuss how permitting and well design should be revised, Davidson says. Subsequently, the company was given the first permit to return to the Gulf and resume drilling operations.

Looking Outward

Around 2008, as Cunningham's connection with her colleagues grew, she began looking outward at the people in Equatorial Guinea and other countries where Noble Energy operated. She planted the seed of bringing Corporate Social Responsibility (CSR) to the company's operations.

"Sometimes we forget in the industry that we have no right to be anywhere. We are leasing from people, and they have to want you there," Cunningham says. "Part of being wanted is connecting with people, understanding what their issues are and how you can help besides making a difference with dollars."

Noble has since built a global CSR programme, with its most notable activities taking place in West Africa. Achievements include participation in a partnership that launched an anti-malaria campaign, which has reduced the malaria parasite by 70% in children under 15 since 2004, as well as underwriting a programme to develop a vaccine for malaria that is currently in a trial period. It has also funded programmes to train health care workers in Equatorial Guinea, Cameroon and Sierra Leone to prevent, identify, control and treat the Ebola virus. In addition, Noble has provided an 18-month course abroad to train local people to operate oil and natural gas facilities.

Cunningham's concern for people also extends into the realm of the environment, health and safety – especially during a time when the practice of hydraulic fracturing in the United States is often misunderstood. "At Noble Energy we focus on people, making sure they are safe and that the environment they live in is healthy, that the air they breathe is clean, and that their drinking water is safe," she says.

In fact, Noble – working with other operators and the Environmental Defense Fund – helped develop the country's first methane emission regulations in Colorado.

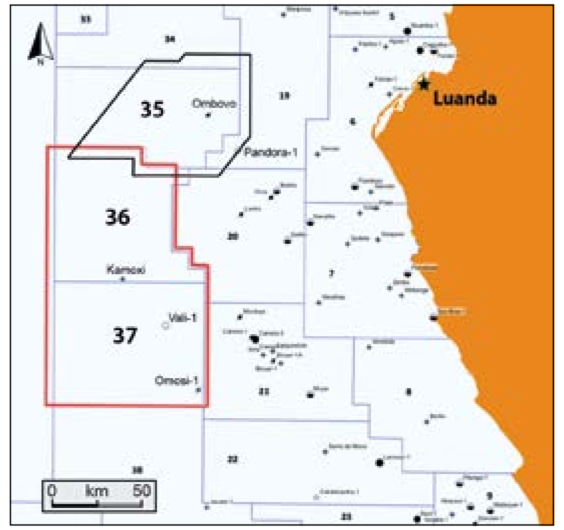
With raw emotion in her voice, Cunningham explains that she believes that caring for people should be a natural extension of the industry – as the industry is, after all, run by human beings.

"In the end," Cunningham says, "as I've been learning through this leadership journey, it's all about people." ■

Deepwater Kwanza Basin

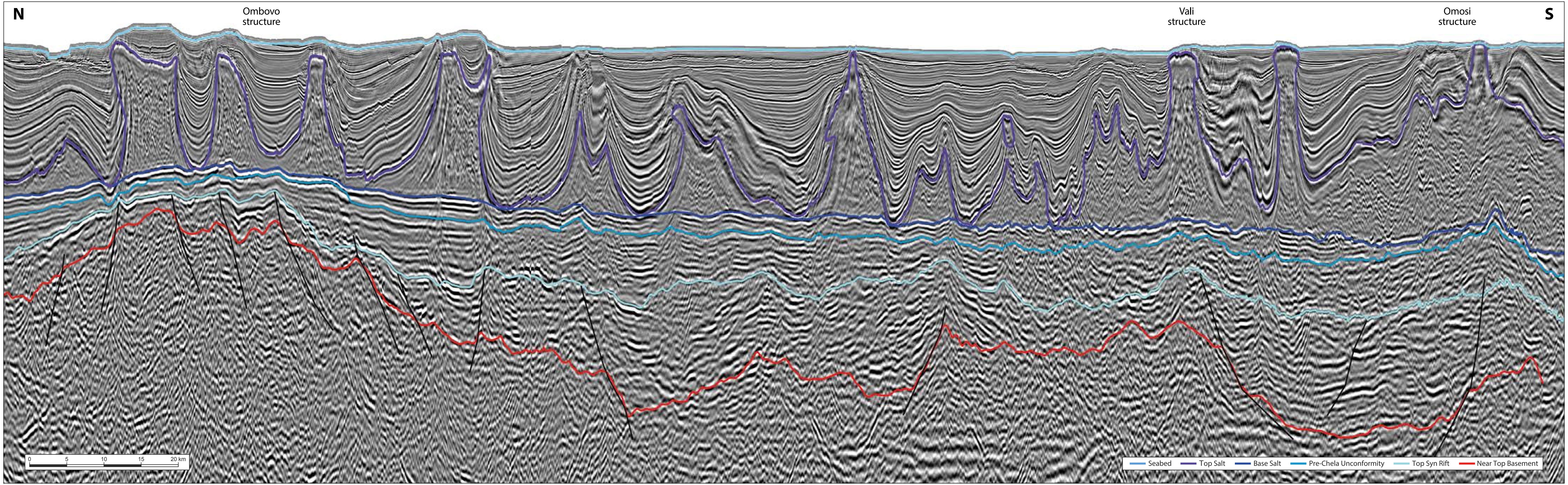
A Prospective Pre-Salt Province?

TGS acquired a high resolution multi-client 3D seismic survey over Blocks 35, 36 and 37 in the Kwanza Basin offshore Angola. A 3D Kirchhoff and Reverse Time Migration (RTM) Pre-Stack Depth Migration (PSDM) was undertaken to produce a more accurate velocity model, enhance event placement and improve salt boundaries and sub-salt imaging. As the first exploration period (January 2012 – December 2016) nears its end, we look at progress so far and consider a possible future exploration strategy.



Location map of Blocks 35-36-37 in the offshore Kwanza Basin.

Interpreted well tie line (PSDM-RTM) through some recently drilled structures in the Kwanza Basin, illustrating structural geometries, thick pre-salt syn-rift and sag phase sequences, salt diapirs and welds and post-salt raft tectonics.



Comparing the Brazilian and Angolan Conjugate Margin

Comparisons with Brazilian analogues can help with pre-salt exploration in the Kwanza Basin

CIAN O'REILLY, DARIO CHISARI, JAMES CLARKE, SADIQAH MUSA, Dr. JENNIFER HALLIDAY, IAN DEIGHTON, ERIKA TIBOCHA and PAUL CHANDLER, TGS

Brazilian pre-salt exploration success prompted enthusiasm for the conjugate Kwanza Basin. Eleven licence blocks were offered in 2011, with commitments to 3D seismic surveys and two pre-salt wells in each block before end-2016. As the first exploration period nears its end, we look at progress so far and consider a possible future exploration strategy.

Regional Setting and Well Results

Africa and South America were part of Gondwana until separated by Late Jurassic-Neocomian rifting, when horst and graben structures developed in trends roughly perpendicular to current coastlines. In both Brazil and Angola a transition is seen from proximal fluvial-alluvial clastic-dominated facies to widespread deposition of lacustrine facies. Carbonate reservoirs developed locally on or around horsts, whilst coeval organic-rich shales (associated source rocks) accumulated in the grabens. The end of major rifting is marked by a regional angular unconformity, with carbonates and shales infilling the late syn-rift to sag basins. Aptian microbialite (lacustrine carbonates) is the main pre-salt reservoir. Late Barremian to Early Aptian lacustrine bioclastic limestones (analogues to the Brazilian Coqueiros Formation) are the secondary reservoir. Increasing salinity of the lacustrine environment culminated in deposition of thick salt, which ended with the start of seafloor spreading and the resulting opening up of the restricted rift basin. Late Aptian-Albian shallow marine carbonates were deposited on the salt. Platform carbonates and their deepwater equivalents dominate the Albian–Cenomanian. The Upper Cretaceous to Tertiary is mainly characterised by siliciclastic deposition.

Angola has reserves of 8.4 Bbo (OPEC, 2015). Production peaked in 2008 at 1.85 MMbopd and declined to 1.65 MMbopd by 2014. Initial discoveries in Blocks 20 and 21 raised hopes that the Kwanza Basin pre-salt would be as oil-rich as the pre-salt of the Campos and Santos basins of Brazil. However, recent pre-salt well tests suggest that success is not a simple matter of drilling large four-way dip closures (4WDC).

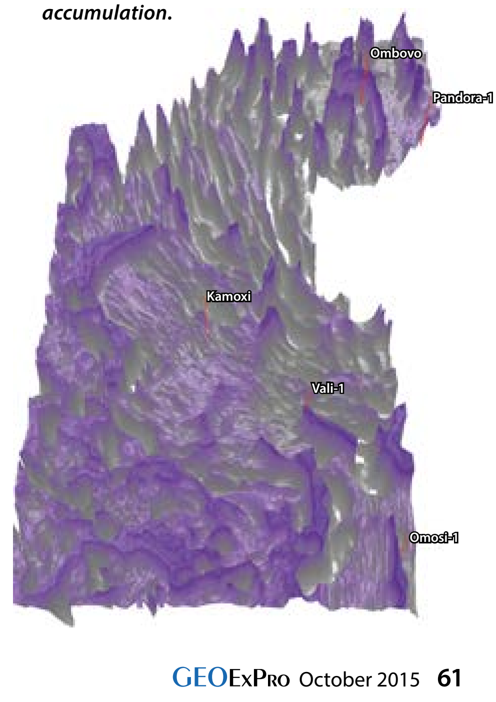
Four recent wells have been drilled in Blocks 35, 36 and 37. Ombovo-1 (ENI), drilled in 2014 in Block 35, was presented as an oil discovery (Adams, 2015). Kamoxi-1 in Block 36 (ConocoPhillips) tested a large 4WDC but was dry; the operator reported that "basically the reservoir wasn't developed there… the porosity just wasn't developed" (ConocoPhillips, 2015a). Omosi-1 (ConocoPhillips) in Block 37 tested a large 4WDC with a 160m gas column and the operator reported good reservoir facies and porosity at the well location (ConocoPhillips, 2015a). Vali-1 (ConocoPhillips) tested a 4WDC with a larger area at the Coqueiros level than at the microbialite, but the operator reported that the "well was plugged and abandoned as a dry hole" (ConocoPhillips, 2015b). Pandora-1 (BP), drilled in Block 19, just within the Block 35 seismic volume, in order to test the pre-salt microbialite and Coqueiros levels, was presented as an oil and gas discovery (Adams, 2015).

Comparisons with Brazilian Structures

Our research in the offshore southern Brazil basins and the Kwanza Basin indicates that the combination of modern pre-salt seismic depth imaging, Play Fairway Analyses and basin modelling studies have the potential to assist with hydrocarbon exploration. These methods allow us to increase our understanding of rift basin development and the timing of the source rock expulsion in relation to other 'sweetspot' petroleum system components (reservoir and seal presence).

Comparison of the seismic data at the structures tested in Blocks 35-36-37 with analogous structures in the pre-salt discoveries of the Espirito Santo, Campos and Santos Basins offshore Brazil is one way of assessing the chance of success in the Kwanza Basin. In particular, the Santos Basin pre-salt fields (on which much data has been published) and the Campos Basin Block BM-C-33 fields (Seat, Gavea and Pão de

Figure 1: Salt model for the study area, with grey depocentres and violet diapir crests. Regional tectonism and halokinesis are major controls on post-salt sediment deposition and accumulation.



Açúcar) may be useful analogues for the Block 35-36-37 area with its thick salt cover. For many of these Brazilian fields, the primary reservoir was a high porosity and permeability microbialite carbonate facies (Macabu Formation) sealed by the overlying salt. The deeper Coqueiros Formation bioclastic limestones, at the top of the major rift phase and in the lower part of the sag basin, are a secondary carbonate reservoir. In the Kwanza Basin, the microbialite is reported to be the main reservoir for the Cameia, Lontra, Orca and other discoveries in the Cobalt-operated Kwanza Basin Blocks 20 and 21, (Cazier et al., 2014), which adjoin Blocks 36 and 37 to the east. A deeper syn-rift bioclastic carbonate reservoir (Coqueiros equivalent) was tested by Cobalt and found to bear light oil in the Bicuar and Orca discoveries.

Our Santos Basin seismic facies and Play Fairway Analysis, calibrated against 20 pre-salt wells (TGS, 2013a), shows a high correlation between the development of a specific seismic facies and pre-salt fields/discoveries. This facies (high amplitude, good to moderate continuity, parallel to sub-parallel reflectors, locally with some progrades) is shown by the well data to be high porosity microbialite carbonate. This is the main pre-salt reservoir lithology in the Santos Basin. Most of the known pre-salt fields in Santos (Buzios, Libra, Florim, Iara, Tupi/Lula) occur on large 4WDCs within the area of this seismic facies (Figure 2a). A very similar seismic facies is observed at the Ombovo structure. It seems poorly developed at the Vali structure and absent at the Kamoxi structure (Figure 2b). This observation may be an indicator as to regional seismic prediction of presence (if not quality) of the main pre-salt microbialite reservoir.

The base of the microbialite succession is defined by a major sequence boundary that is known as the Pre-Alagoas unconformity in Brazil and the Pre-Chela unconformity in Gabon and Angola. The underlying section contains the coqueiros/coquinas successions and has been an oil-producing reservoir in the Campos Basin since the discovery of the Badejo and Linguado fields in the 1970s.

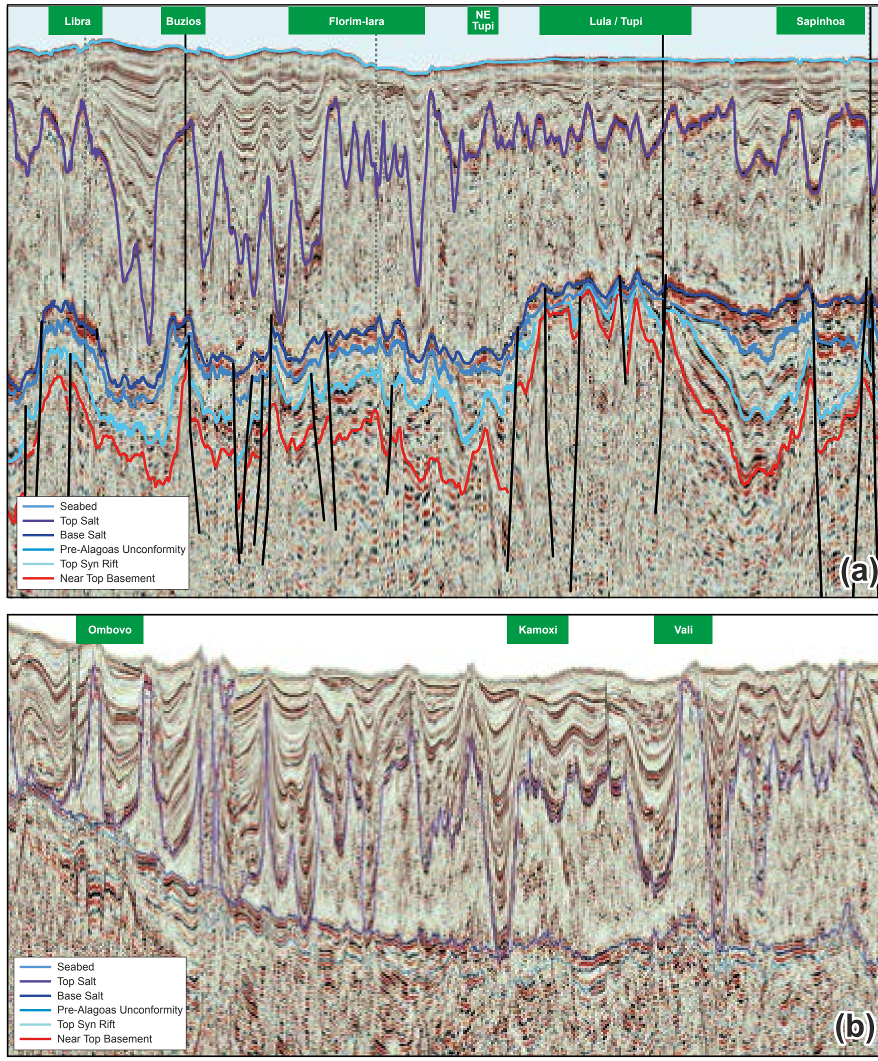


Figure 2: A distinctive high amplitude seismic facies is associated with extensive development of the prolific, high porosity 'microbialite' carbonate reservoir in the Santos Basin, Brazil (a). This same seismic facies is seen to be developed at some but not all of the tested prospects in the Kwanza Basin (b). The association of this seismic facies with large four-way dip closures is a primary test for lead development. High resolution pre-salt imaging is a pre-requisite for definition of the pre-salt seismic facies.

They are typically present as stacked banks of reworked shelly fragments deposited along lake margins and are found in deep to shallow lacustrine environments. The corresponding seismic facies is moderate to good amplitude, moderate continuity, parallel to sub-parallel (TGS, 2013b). Coqueiros reservoirs have been reported as oil-bearing at Seat and Pão de Açúcar in the Campos Basin, in the Libra, Buzios and Lula fields in the Santos Basin (Figure 2a). Such facies can also be seen at the Ombovo and Vali structures, but not at Kamoxi (Figure 2b).

Conclusions

Carbonate reservoirs are complex, with rock heterogeneities at all scales and variations in porosity and permeability that are difficult to predict. High resolution PSDM is a pre-requisite to exploration for pre-salt targets underneath thick salt cover but may not be sufficient on its own. Several crucial factors are at play in making the petroleum system work as oil or gas prone: the timing and amount of local syn-rift stretching and continental margin collapse, local and sub-regional heatflow, salt thickness and halokinetic effects. Seismic facies analysis (calibrated against well data) and Play Fairway Studies, such as those that TGS have conducted in Brazil, can help to further reduce the risk in screening pre-salt structural leads.

References available online ■

That's Not a Very Prospective Basin…

Time was when industry interest in the MSGBC Basin was lukewarm to say the least: not any more. The recent world-class oil discoveries by Cairn-FAR-Conoco-Phillips offshore Senegal and by Kosmos offshore southern Mauritania have shone a very bright light on the region's hydrocarbon potential.

GERRY SHEEHAN, T5 Oil and Gas

Sporadic Exploration

A potted history of oil and gas exploration in Senegal and in the wider Mauritania-Senegal-Gambia-Bissau-Conarky (MSGBC) Basin is one of periods of active exploration, followed by interludes with little or no drilling activity.

Throughout the 1950s and '60s companies such as Société Africaine de Pétroles undertook gravity and magnetic surveys, geological mapping and refraction seismic, culminating in regional drilling programmes. The results delineated the onshore sedimentary basin and provided the first positive indications of a working hydrocarbon system. Minor production of both oil and condensates was established on the Dakar peninsula at Diam Niadio and Kabor. Offshore 2D seismic in the '60s and '70s elucidated the classic West African margin geology and encouraged further exploratory drilling. A salt basin with spectacular diapirs in southern Senegal and Guinea Bissau waters was initially targeted. The surprise find was the billion barrel oil accumulation located over Dome Flore in 1967, but unfortunately its shallow depth and proximity to the seabed allowed severe biodegradation with oil gravity of 11° API. The results, disappointing as they were, proved that a rich source was present and had generated significant volumes of oil. Even more enigmatic was the presence of light oil in close proximity to the salt dome – clearly a basin with a complex hydrocarbon plumbing system. The oil industry, in our customary wisdom, decided that there were easier pickings to be had elsewhere in West Africa and exploration was directed at the emerging and ultimately prolific provinces of Gabon, Nigeria, Côte d'Ivoire and Cameroon.

In the mid-1980s newly formed Tullow Oil acquired rights to redevelop the modest-sized oil and gas finds on the Dakar peninsula. Some of the old '60s wells were nurtured back to life, high resolution 2D seismic was shot, new wells were drilled, pipelines were refurbished and an innovative gas storage facility was constructed. This storage facility allowed reservoirs to be produced with a very gentle touch; the gas accumulated in storage during the day could be released rapidly in reasonable volumes to fuel peak-time power generation. Tullow's personnel were on the ground from well-head to power-station, ensuring a highly efficient gas to power project; quite a few Senegalese power engineers to this day speak English with a lilting Irish accent.

It soon became apparent that the limiting factor for these Maastrichtian reservoir accumulations was the particular trap dimensions – small, low amplitude and fault controlled.

The Île de Gorée, off Dakar, was an important trading post for a variety of commodities, including slaves, and is now a popular destination for day trippers.

Jane Whaley

Deeper wells both onshore and later offshore targeted the older section with some penetrations to the Jurassic. The most recent onshore success is at the Gadiaga complex (1996), developed by Fortesa-Petrosen. The group produces gas at modest volumes from Campanian/Santonian-age reservoirs in a combination trap setting. The way forward for onshore exploration of the Mesozoic requires more focus on stratigraphic trap potential. Given the presence of good Cenomanian-Turonian and possibly Albian source rocks, there is potential for larger volume accumulations – most likely for gas. These will require denser grids of high quality seismic to delineate subtle traps with confidence.

Two Out of Two Ain't Bad

Tullow Oil's 2007 discovery of the Jubilee oilfield in Ghana sparked a scramble for lookalike submarine fans and channel systems along the entire Atlantic margin. First Australian Resources (FAR) held a significant acreage footprint offshore Senegal – with compelling indications of shelf edge and fan features. The acreage proved sufficiently interesting to encourage a new country entry by Cairn Energy and a return to West Africa by Conoco-Phillips. Petrosen, long familiar with this ground, co-ventured with 10% equity. Fortune has favoured the brave.

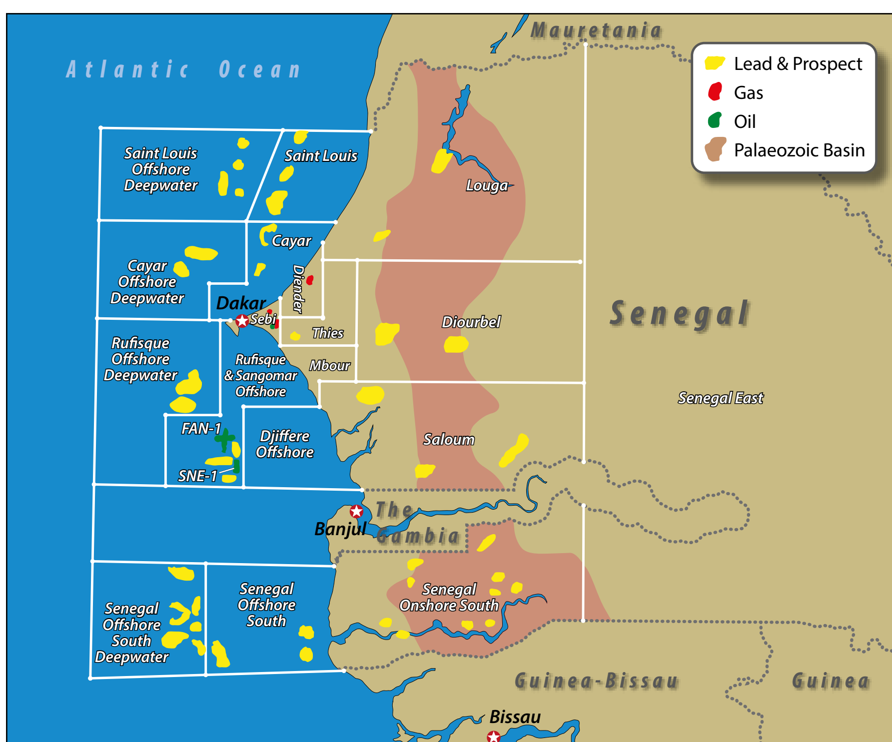
Well FAN-1 (2014) found good quality oil in a large Cretaceous-age fan accumulation. Current estimates of oil volumes in the accumulation are a P50 STOOIP of 950 MMbo. The second well in this consortium's programme, SNE-1, targeted a prominent shelf-edge structural high with closures defined at Cretaceous and Jurassic level. The well encountered an oil column in Albian clastic reservoirs and resource estimates for SNE are a P50 of 350 MMbo. The old explorer's maxim springs to mind: it's all about the source rock, the rest is just detail. These two wells are indeed testament to a rich oil kitchen.

The joint venture is now proceeding apace with their appraisal of these discoveries. Whereas the current oil price casts something of a shadow for investment in large scale offshore developments, there is the advantage that appraisal drilling and ancillary services are now less expensive. Oil companies by their nature will be innovative in developing large volume resources in benign operating and fiscal environments. A dynamic energy policy is at the core of Senegalese strategic development and, in conjunction with an enlightened state representative in Petrosen, should underpin an early development of these resources.

The Gadiaga field, about 60 km north-east of Dakar, was discovered in 1996 and came on stream in 2001.

Offshore – New Era, New Challenges

Senegalese and MSGBC waters remain considerably underexplored. It is worth remembering that Woodside's Chinguetti field (2001) was the first oil discovery in the whole area between Western Europe and Côte d'Ivoire! The greater MSGBC Basin extends over five countries with an area of about 1,000,000 km², about 450,000 km² of which is Senegalese territory.



The offshore offers multiple plays, primarily structural and stratigraphic plays in the thick clastic Cretaceous wedge, salt-related plays in the southern basin, and structural plays in the north-south trending Jurassic carbonate platform. The Cairn-led joint-venture has confirmed a prospect-rich shelf and slope setting; the recent Kosmos success with the Tortue well in southern Mauritania proves that this offshore petroleum system is viable over a very wide area. Within the MSGBC there is great scope for exploration in deeper Senegalese and Mauritanian waters and in the virgin acreage of Guinea Bissau and Guinea Conakry. With oil prices temporarily depressed, exploration managers inevitably face a close interrogation when asking their boards to commit funds to exploration. The very positive results, achieved in difficult times in a previously unloved basin, should make that task just a little easier for new projects in the MSGBC.

Putting in Sound Foundations

The nascent hydrocarbon sector in Senegal was blessed from the 1980s with a dedicated professional body – Petrosen. The company is imbued with a strong oil field technical culture and a hands-on attitude to oil and gas projects. The President of Senegal H.E. Macky Sall is himself a petroleum engineer. His appointment of Mamadou Faye as Director General of Petrosen ensured that the tradition of a technically driven organisation familiar with and embracing of industry best practice prevailed. In recognition of the need to encourage exploration, Senegalese Production Sharing Contract terms are considered fair and reasonable by the industry. The Ministry of Energy further complements this with a robust and transparent licensing regime – factors which give confidence to international investors.

PETROSEN

Onshore, Nobody Expected the Palaeozoic…

No doubt there is more oil and gas to be found onshore Senegal; the Jurassic carbonate platform remains compelling and untested. Stratigraphic or combination traps in the Cretaceous will be elucidated by high quality 3D seismic. On the basis that 'old data is old gold', the results of two stratigraphic test wells drilled more than 50 years ago in the Casamance region also merit a curious eye. Kolda-1 (1955) and Diana Malari-1 (1961) both encountered Silurian black shales with good organic content. The wells also penetrated a thick section of fractured Ordovician sandstone – these could act as good reservoirs.

This Palaeozoic sequence outcrops in the Bove Basin, where it is estimated that some 3,500m of alternating sandstone and shale are developed pre-rift, dating back to the Infra-Cambrian in age. The Silurian-Ordovician combination is a prolific producer in the Illizi (Algeria) and Murzuk (Libya) basins and hosts giant oil and gas fields. Gravity, magnetic and seismic reprocessing work by Petrosen and T5 Oil and Gas in northern Senegal (Louga Block) indicates a discrete Palaeozoic basin, and the old seismic data also indicates the presence of very large thrust anticlines related to the Hercynian Orogeny. It is worth remembering that in the Klemme et al. classic paper on source rock, it was estimated that some 9% of the world's hydrocarbons were derived from Silurian-age source rocks. There is credible evidence for an untested Silurian source Palaeozoic play at drillable depths onshore Senegal. Most likely this would be gas generative; a TCF-sized find of onshore gas would be transformational for Senegal.

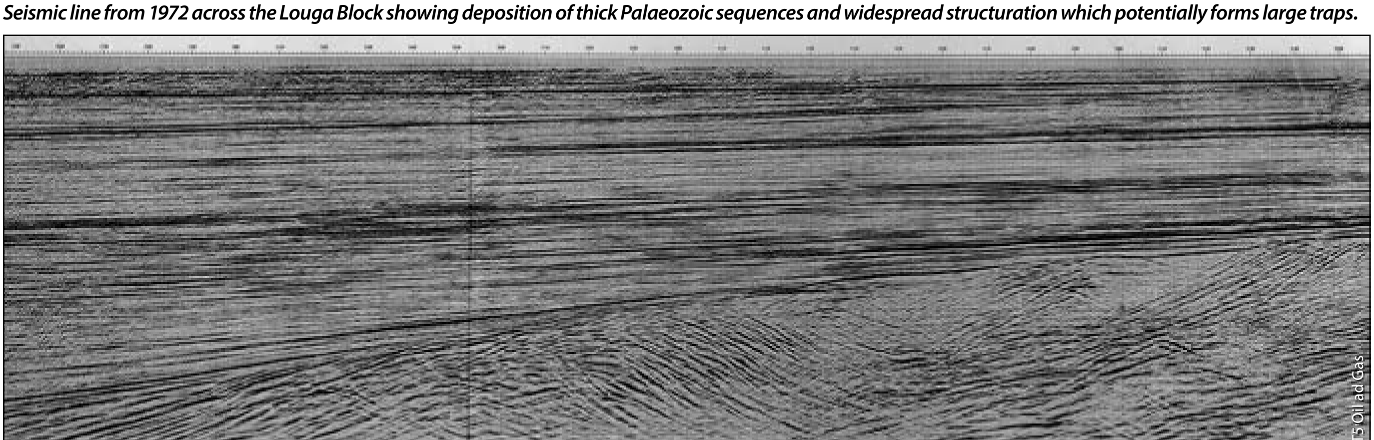
Petit à Petit L'Oiseau Fait Son Nid

This Senegalese proverb ('little by little, the bird builds its nest') is apposite for the slow but steady evolution of hydrocarbon exploration in Senegal. Early efforts provided enough encouragement for further exploration of the onshore and offshore basins. Petrosen quietly but efficiently put the technical and commercial framework in place to encourage investment, and successfully maintained a profile even in lean times. The bigger prize, however, proved frustratingly elusive for decades. And then in 2014 the picture changed dramatically with two major oil finds in the offshore.

Considerable potential remains: the offshore may yield additional fan/channel accumulations and the onshore Palaeozoic certainly looks capable of hosting large volumes of hydrocarbons. In the oil patch success tends to breed success. ■

See GEO ExPro, Vol. 7, No. 4 for more information about Senegal.

Seismic line from 1972 across the Louga Block showing deposition of thick Palaeozoic sequences and widespread structuration which potentially forms large traps.



A Simple Guide to Seismic Amplitudes and Detuning

ASHLEY FRANCIS
Earthworks Reservoir

Seismic Amplitudes

In a seismic survey, seismic amplitude is a measure of the contrast in properties between two layers. If the data are converted to relative impedance then seismic data observe the relative change of the rock property impedance (= hardness) as we move from one layer to the next. Note that seismic cannot tell us about the absolute change, only about *relative* changes.

The rock property contrast between a sand and shale varies with factors such as depth of burial, compaction, porosity and lithological composition. The amplitude response could be positive, negative or negligible depending on the relative hardness of the sands to the encasing shales. If we have an extensive reservoir sand, perhaps a sheet flood, beneath a shale, then the amplitude might vary laterally due to porosity variation or changes in reservoir quality by as much as 10–20% and these amplitude changes may be interpretable in terms of property changes. In a soft sand, the presence of gas will lower the impedance significantly, making a negative amplitude even more negative and therefore brighter (Figure 1). We can consider this in terms of reflection amplitude (for conventional seismic data) or relative impedance (from inverted data). Seismic inversion was discussed in *GEO ExPro*, Vol. 10, No. 2, 'A Simple Guide to Seismic Inversion'. Amplitude effects can be interpreted more easily on relative impedance data as the inversion process converts the reflection contrast to a local rock property.

For a picked horizon, if we extract amplitudes and present them as a map, the pattern of amplitudes may tell us something about the geology. In order of magnitude from strongest to weakest, physical property changes that might result in amplitude effects that we might see and interpret on seismic are typically lithology, porosity, gas fluids and oil fluids.

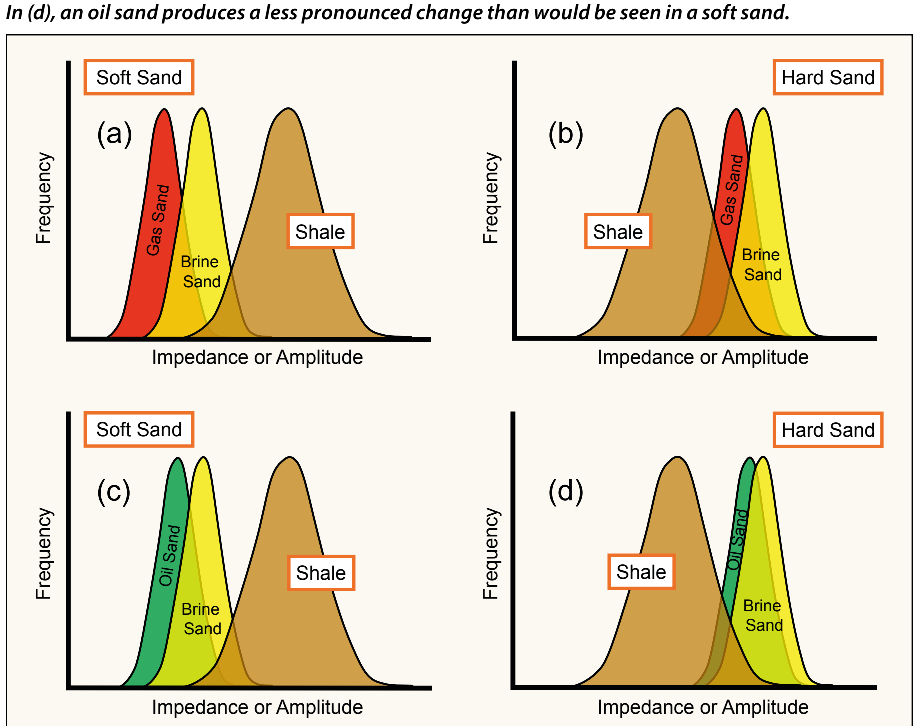
A common application of amplitude maps is to compare amplitudes to structure, as conformance of an amplitude anomaly with structure may indicate a direct hydrocarbon indicator, or DHI. This is usually assessed visually.

Saturation and pressure (time lapse effects) due to production may also be observed in seismic. These effects are much smaller and require repeat seismic surveys to be acquired and compared to each other over time, hence time-lapse surveys.

Tuning Effects

The earth is comprised of many geological layers superimposed on each other. Seismic data records only a limited range of frequencies (bandwidth), typically 10–60 Hz. (In terms of music, you feel rather than hear sounds at the lowest of these frequencies, the lowest note on a 4-string bass guitar being about 41 Hz). Consider a single layer: as it thins, the seismic reflection from the top and the bottom of the layer get closer together until eventually they begin to overlap, which results in interference. If we compute the relevant impedance for, say, a blocky sand, where the sand properties are fixed and only the thickness changes, we find that the seismic amplitude varies significantly with the thickness. As the layer thins, the amplitude brightens due to constructive

Figure 1: Representative histograms of seismic impedance for hard and soft sands with brine, oil or gas. Left: sands softer than shales; right: sands harder than shales. (a) gas sand has larger separation to low impedance than oil sand in (c). In hard sands, hydrocarbon effects move the response towards shale properties in (b) while gas sand shifts to lower impedance but starts to overlap shale properties. In (d), an oil sand produces a less pronounced change than would be seen in a soft sand.



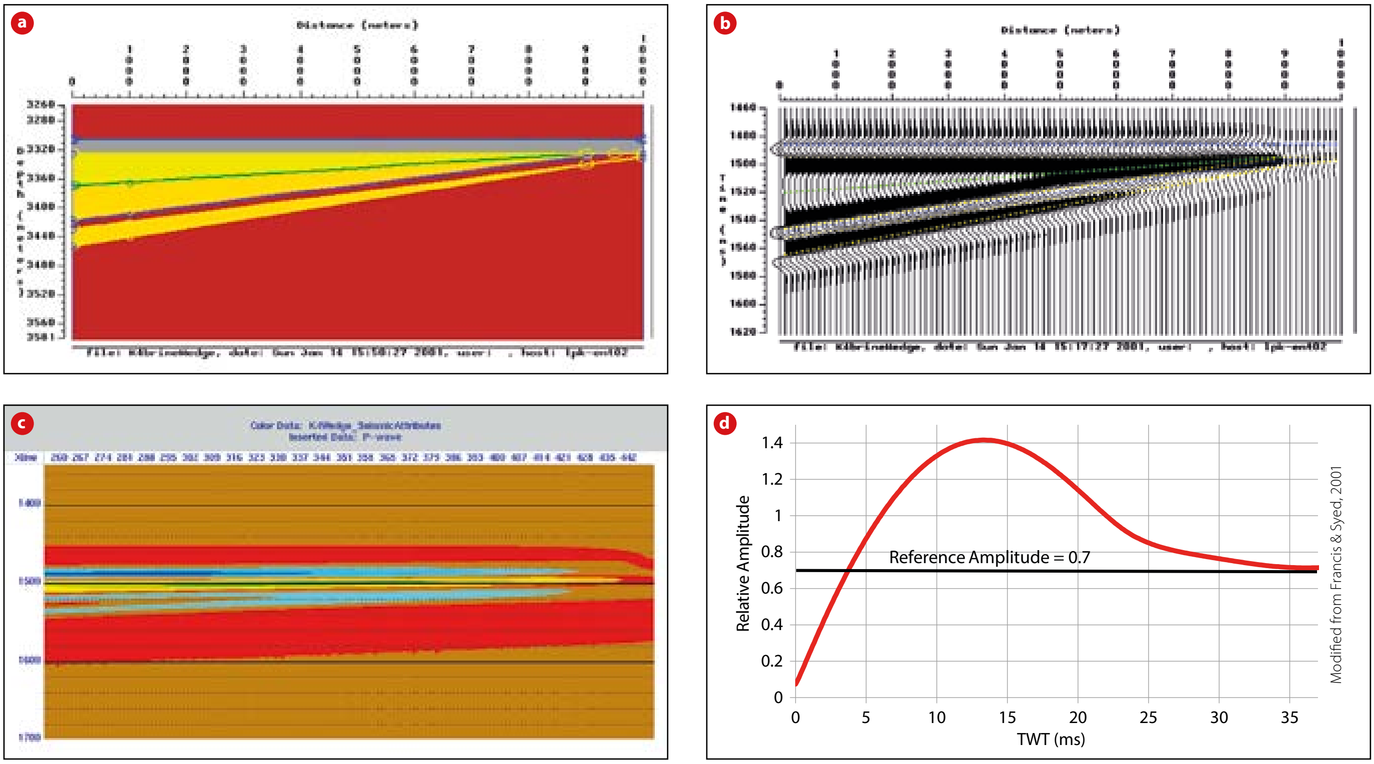


Figure 2: Example of a tuning wedge model from a thinning soft sand reservoir in the Kadanwari Field, Pakistan.

interference, reaches a peak and then declines due to destructive interference when the layer becomes very thin. This brightening due to constructive interference is thickness dependent tuning – usually just called tuning.

Geophysicists show the effect of tuning using a constant property wedge model. An example of this type of model of a thinning reservoir is shown in Figure 2. Image 2a is the wedge model for brine saturated sand, where all the layers in the model have constant properties: only the thicknesses are changing, thinning from left to right. In Figure 2b we see what this model would look like as seismic reflection data, where the black events merge into a single event on the right-hand side. Figure 2c shows the resultant relative impedance, where the reservoir interval appears as the yellow and green coloured (low impedance) layers. The actual modelled interval (2a) has constant impedance within each layer, but the relative impedance from the seismic model response is clearly brighter (greener) in the centre and reduces in amplitude (yellower) as the interval gets thicker or thinner.

Figure 2d shows a plot of amplitude (from the yellow-green sand in 2c) versus time thickness of the wedge. Note how the amplitude reaches a maximum around 13 ms and then falls off to about half the peak amplitude at around 35 ms. This doubling of the amplitude as a function of thickness is the tuning effect.

Modelling of the effect of gas in the same field demonstrated that a gas-filled reservoir sand would have about a 25% brighter amplitude than a brine-filled sand. From Figure 2d, the effect of changing reservoir thickness from 36 to 13 ms (corresponding to a thickness change from 60 to about 20m) would be to *double* the maximum amplitude of the seismic reflection, clearly demonstrating that thickness-related tuning effects are potentially much larger than lateral amplitude variations due to geological changes, including lithology or hydrocarbon fluid effects.

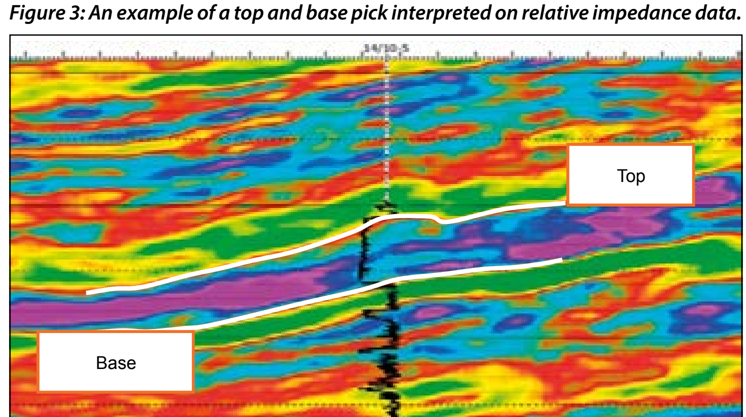
Tuning Effects and Amplitude Maps

Tuning effects are very predominant in seismic amplitude responses and tend to be the most significant factor affecting amplitude maps. Meaningful interpretation of amplitudes in terms of lateral property changes therefore requires us to first remove the effects of tuning.

To extract amplitude maps from seismic data we need a consistent approach. Fortunately, if we interpret on relative impedance data, there is a natural choice of how to pick and extract amplitudes – by picking zero crossings (Figure 3).

To correct amplitude maps for tuning, we need to first define the tuning curve as in Figure 2d, either by modelling or empirically from seismic picks (as discussed below). On

Figure 3: An example of a top and base pick interpreted on relative impedance data.



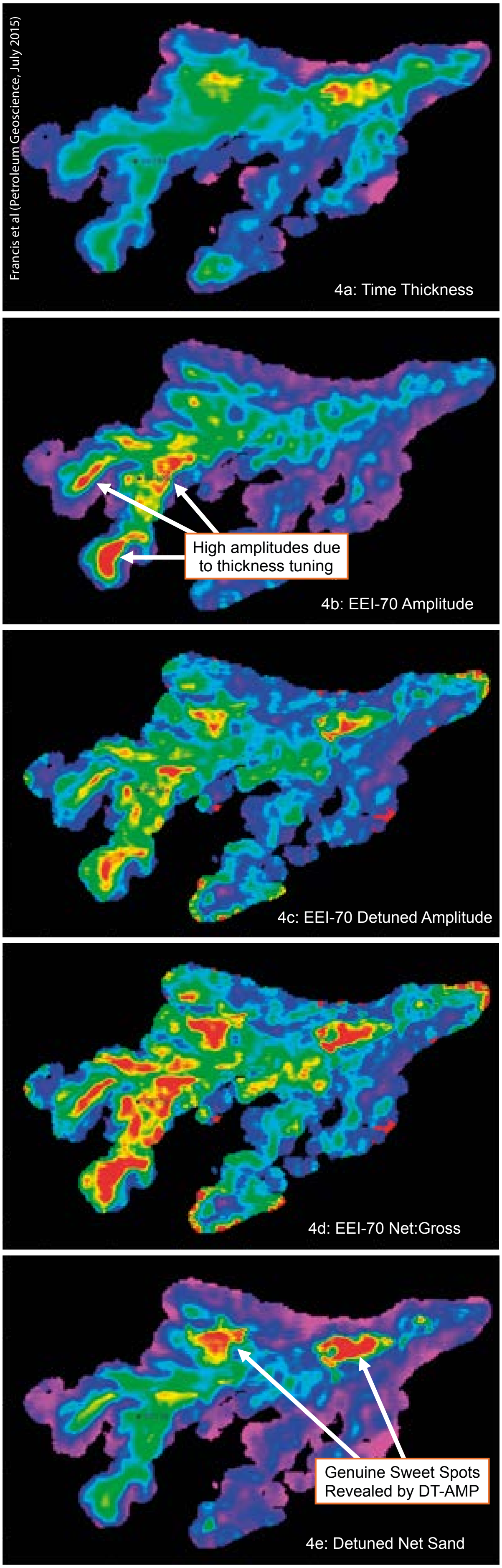


***Figure 4:** Detuning a hard sand turbidite (the Sea Lion fan, North Falkland Basin). (a) Time thickness map picked on top and base zero crossings from 3D seismic. (b) Average amplitude map between picks from (a). The bright amplitudes in the south-west area of the fan are the result of tuning. Using the thickness and tuning curve information (Figure 6), results in the detuned amplitude map (c); the prominent bright features are relatively suppressed and larger areas of the fan now show similar amplitudes. (d) shows the amplitude map of (c) calibrated to N:G using the method of Connolly (2007). (e) shows a net sand map, obtained by multiplying N:G from (d) by the time thickness of (a) and also by the sand velocity to obtain a net reservoir thickness estimate.*

the tuning curve, we arbitrarily define a reference for the seismic response. This is often convenient if set to be about half the peak tuning amplitude, or 0.7 in the example in Figure 2d. If our target interval had no property variation we would expect the seismic amplitude to be constant at all thicknesses if we remove the effect of tuning. So at any thickness we multiply the seismic amplitude by a factor which is the ratio of the reference amplitude to the tuning curve value at that thickness to correct the value on the orange curve to the reference value. As this is just a ratio, the scaling is arbitrary; if we know the shape of the tuning curve as a function of thickness we can detune amplitude data.

Figure 4 shows an example of amplitude detuning of a hard sand turbidite. The picked time thickness for the fan is shown in Figure 4a and the corresponding amplitude map in 4b. Note the bright amplitudes in the distal (south-west) end of the fan, associated with thinner intervals in the time thickness map; these are the result of tuning. Using the thickness and tuning curve information, detuning results in the amplitude map, 4c, where, after detuning, the prominent bright features are relatively suppressed and larger areas of the fan now show similar amplitudes.

Tuning Curves and Net Sand

Having interpreted the top and base zero crossings for the selected seismic event, we can cross-plot the average amplitude versus TWT interval thickness for every interpreted trace. Using the data from Figure 4a and 4b, an example of a tuning curve crossplot is shown in Figure 5. The orange line shows the expected amplitude versus TWT thickness relationship for a clean sand – this curve was used for detuning the data and obtaining the result in Figure 4c.

Inspection of Figure 5 shows that for real data sets there is a cloud of points rather than a simple curve relating amplitude to thickness. For every thickness there is a wide range of observed amplitudes. Why is this?

In 2007 Pat Connolly published a paper in *The Leading Edge* describing how the spread of amplitudes at a given thickness can be related to a change in reservoir properties, notably reservoir quality or net:gross (N:G). The argument is that if the 'reservoir' interval had the same properties as a shale above or below, then there would be no amplitude because there would be no contrast. An amplitude close to zero would be 0% N:G and would plot at the bottom edge of the graph. At the top of the graph, the orange curve represents the sand line where the N:G would be 100%. The position of any sample vertically can then be interpreted in terms of reservoir quality, so a point at half amplitude would be 50% N:G. For a given time thickness, the ratio of the observed amplitude to the tuning curve (100% sand) is then both a rock quality measure (N:G) and, because it also takes into account the shape of the tuning curve, is also detuned (Figure 4d). Figure 4e shows a net sand map, obtained by multiplying the N:G map of 4d by the time thickness of 4a and

also multiplying by the sand velocity to obtain a net reservoir thickness estimate in metres.

3D Seismic Detuning

So far detuning has been described here in terms of corrections applied to 2D maps, but it would have far more application if it could be applied to 3D seismic. In *A Simple Guide to Seismic Inversion* it was noted that seismic inversion output is potentially attractive as a constraint in reservoir modelling, but the effects of tuning must be removed from a relative (coloured) or deterministic inversion before use, so it would be of great value if a 3D reservoir model included detuned 3D seismic data.

Figure 6a shows a seismic section through a coloured impedance volume for the hard sands. At the well in the centre of the section the sand is close to 100% N:G. Bright amplitudes are developing downdip to the left, sustained all the way to the second well, and the reservoir is also thinning downdip. The downdip well has a lower N:G having some shalier intervals, so why are these amplitudes brighter downdip than at the thicker sands in the well at the centre of the section? The answer is, of course, tuning!

Figure 6b is the same seismic cross-section after the application of a new method of 3D seismic detuning called DT-AMP. The output is called the detuned modulated amplitude (DMAMP). After detuning, the bright amplitudes downdip are clearly removed and the change of amplitude now reflects the seismic interpretation of the rock properties: downdip there is a deterioration in reservoir quality.

In fact, I should come clean. All the amplitude and thickness displays shown here were generated by detuning the 3D seismic directly. The intermediate output products of this method allow very rapid, automated picking of the time thickness, average, detuned and N:G amplitudes. Manually picking the top/base zero crossing for the multiple fans in this survey originally took around six weeks; using 3D seismic detuning, a fan can be reliably picked and mapped in less than a day. And the 3D seismic is detuned in situ – so now where's my reservoir model? ■

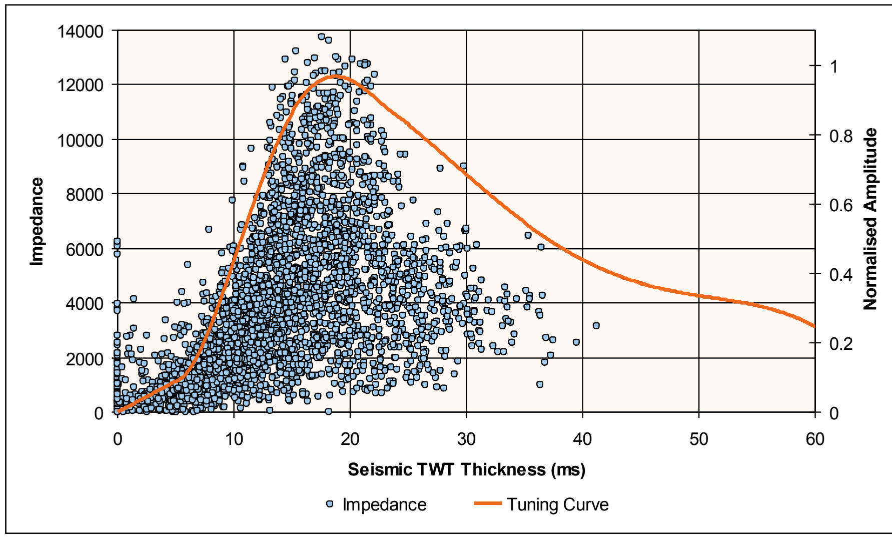
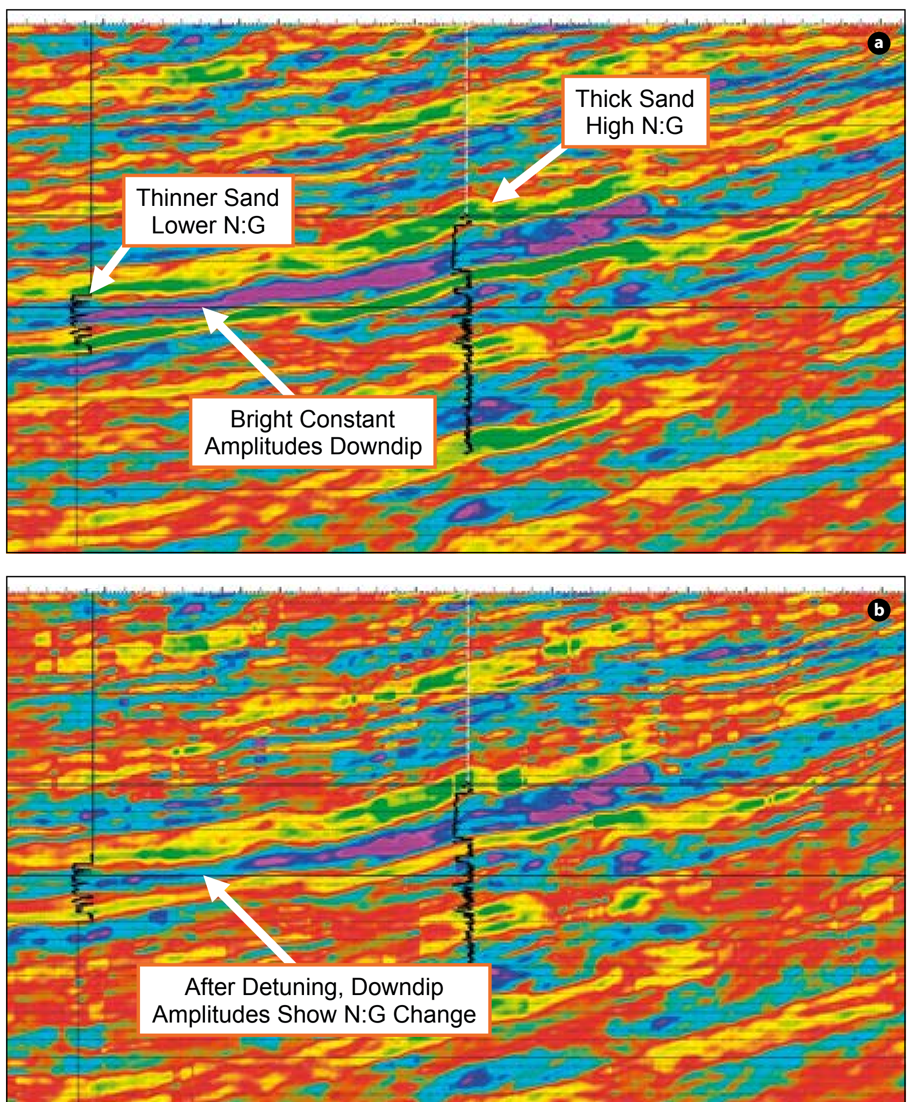


Figure 5: Crossplot of average amplitude against time thickness with modelled tuning curve superimposed.

Figure 6: Seismic relative impedance for a hard sand turbidite from the Sea Lion field. (a) original relative impedance seismic response, where hard sands show as the strong blue/purple response. (b) Relative impedance after 3D seismic detuning using DT-AMP to remove tuning effects. Downdip brightening due to thickness-related tuning is now suppressed and the amplitude better represents the lateral change to lower N:G in the downdip well.



Gas Blowouts
on the Yamal and Gydan Peninsulas

Last year a giant crater was discovered on the Yamal Peninsula south of the Kara Sea in the Russian Arctic, just 30 km south of the Bovanenkovo oil and gas condensate field. It rapidly became world famous as the Yamal crater, holding secrets to the degasification of the Earth's core.

Professor VASILY BOGOYAVLENSKY, Member of Russian Academy of Sciences

The region south of the Kara Sea is part of the Yamal-Nenets Autonomous District (YaNAO), and the crater has attracted great attention partly because of its proximity (only 3.5 km) to the Bovanenkovo-Ukhta high pressure gas pipeline – and also its size: the average diameter of the crater and the parapet are 26 and 37m respectively, while its depth is about 50m (Figure 1). It soon became clear that the Yamal crater (C1 on Figure 2) is similar to a number of other objects discovered on the Yamal and Gydan Peninsulas.

Several hypotheses have been suggested to explain the formation of these craters, including a hit by a meteorite or a UFO, or the collapse of an underground gas facility. All the craters look like the results of huge explosions (Figure 1).

Pockmarks and Pingos

As soon as information about the Yamal crater appeared on the internet, the Russian Arctic Development Centre (RADC), a nonprofit partnership of

Figure 1: Gas blowout crater C1 on the Yamal Peninsula on 8 July 2015, photographed from a helicopter, with (inset) the author standing beside the same crater on 25 August 2014.

scientific organisations, including the Oil and Gas Research Institute of Russian Academy of Sciences (OGRI RAS), started investigations. RADC was established in 2014 in Salekhard (the capital of YaNAO, located on the Arctic Circle) on the orders of President Vladimir Putin and YaNAO Governor Dmitriy Kobylkin. Since then the Centre has sent seven expeditions to different parts of the Yamal Peninsula, and I was able to participate in four of them. In spite of modern airports at Bovanenkovo and Sabetta, expensive helicopters remain the primary transport mode for the expeditions, so we use satellite imagery to investigate the landscape and to help them understand what took place in the crater areas before the unknown 'explosions'.

One of my main scientific work themes for many years has been the investigation of underwater fault zones, mud volcanoes, gas pockets, pockmarks, gas-hydrates and other examples of heterogeneities from the upper subsea section, especially in the Arctic seas. Because of the close nature of sea and land concepts in geology, I proposed that the mechanism forming these craters was the same as that which created pockmarks generated by gas blowouts offshore, except that in Yamal and Gydan the onshore gas comes from thermokarst caverns and other collectors under and inside the permafrost layers, which are about 200–400m thick.

The Cenomanian Upper Cretaceous sand, which is a regional gas reservoir, is very shallow (500–1,200m) and the biggest gas fields, including Bovanenkovo, Urengoy, Yamburg and Zapolyarnoye were discovered in this horizon. Gas rising to the surface through the systems of faults and cracks causes overpressure in the palaeo-permafrost clay layers and breaks through the weakened parts of it, forming the gas springs and blowout craters. There are lots of relict gas craters – pockmarks – in different parts of the World Ocean. Gas under high pressure destroys melted permafrost (taliks) in deep lakes, rivers and even thin layers of frozen rocks like those on frost mounds at the bottom of former lakes. Additionally, gas inflows could

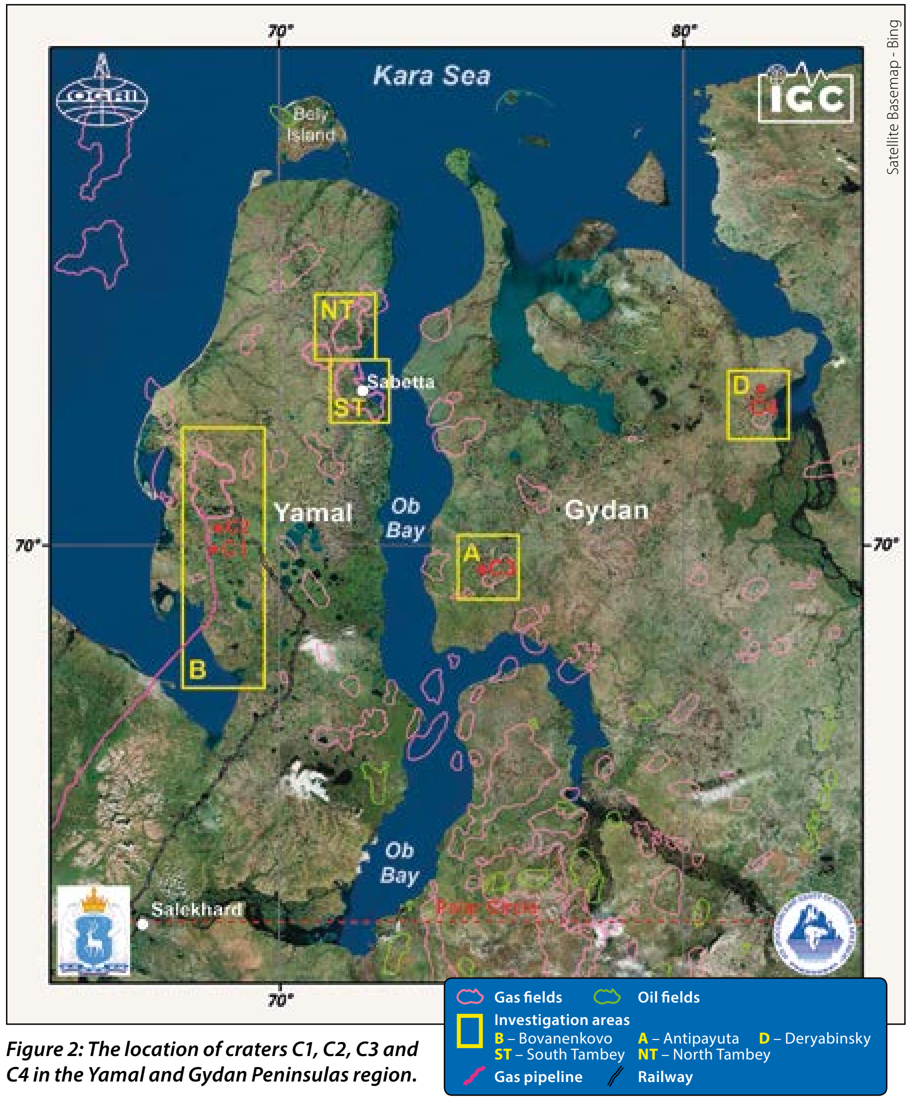


Figure 2: The location of craters C1, C2, C3 and C4 in the Yamal and Gydan Peninsulas region.

come from dissociation of gas hydrate detected in the Bovanenkovo field area.

Frost mounds, called bulgunnyakhs (Yakut language) in Russia and pingos (little hill in Inuit) in other countries, geologically appear as hydrolaccolites with ice cores formed from frozen ground water under high pressure. Figure 3 shows a typical pingo 100m in diameter, which is situated in the

Figure 3: A typical pingo to the south of Bovanenkovo field, July 2015.

Figure 4: Satelite images before (a) and after (b) the formation of C4 crater on Deryabinsky area.

southern part of the Bovanenkovo area. About 1,350 similar pingos have been discovered on the Tuktoyaktuk Peninsula in Canada (*GEO ExPro,* Vol. 10, No. 1). Basically, after a long period of growth the upper part of the pingo (the soil covering the ice core) cracks and the ice core melts, forming a round lake. It is known that sometimes these ice mounds explode under excessive ice pressure.

We suggest that in some cases frost mounds can be formed not only by the growing ice core, but also by the pressure of underlying gas deposits.

Exploring the Craters

The locations of the Canadian pingos are well known, but in Russia less attention has been paid to the issue. Pingos are of interest not only for scientific study, but also to ensure the safe functioning of oil and gas infrastructure and domestic and industrial buildings.

On 8 November 2014 the director of RADC, Vladimir Pushkarev, and four other specialists were the first in the world to descend into the gas blowout crater C1 (Figure 5). During the examination samples of rock which formed the walls of the crater were taken, eventually showing that they are made entirely from ice up to 30m thick. Ground-penetrating radar studies inside the crater proved the presence of sub-vertical channels of gas migration (supposedly a fault), which had caused the explosion of the frost mound.

An expedition in July 2015 found C1 almost filled with water (Figure 1), confirming our hypothesis that in a short period of time (2–3 years) the craters turn into lakes like thousands of others on the Yamal Peninsula. Our analysis of the satellite images taken in 2014 put the time of the blowout to be between September 2013 and June 2014. We suggest that conclusions published in 2015 (A. Kizyakov et al.) dating the crater formation to between 9 October and 1 November 2013 are erroneous, preferring the dates of 21 February to 3 April 2014 proposed by O. Sizov.

Complex retrospective analysis of satellite images and data from expeditions shows the presence of frost mounds at the location of every crater studied (C1–C4), confirmed by the ice rocks seen bursting out of all four craters. These frost mounds did not exhibit the large cracks seen on pingos (Figure 3). The 'Sever-Press' news agency reported an explosion with fire and smoke and an earthquake experienced by locals on 27 September 2013 near the site of C3 in the Antipayuta area of the Gydan Peninsula. Caverns, thought to possibly be the channels of gas inflow, were seen at the bottom of C1 and C3 before they filled with water, which had happened by the end of August 2015.

On 4 April 2013 deer-breeder S. Yaptune was the first man to see crater C4, after the locals heard an explosion in the tundra during March. From photos and the description given by S. Yaptune, the crater was about 4m across and over 60m deep. Fragments of rocks ejected from the crater were found up to 900m away, proving that the explosion was caused by gas combustion. According to QuickBird satellite data, by 19 June, 2013 the average diameter of the crater and parapet were approximately 16 and 33m (Figure 4). It is hard to imagine that the crater could expand to more than four times its original diameter in only four months, three of which were freezing, so the only rational explanation is repeated gas blowouts.

There are probably several craters in the Deryabinsky area, but we know the coordinates of only one, C4, recorded in 2014 by V. Epifanov, the first geologist to study this crater. We have information about more than ten surface craters, but we still do not know the detailed location of some of them.

Figure 5: Ice sampling in crater C1, looking up from the bottom of the crater, November 2014.

Evidence of Gas Blowouts

One of the main targets of the expedition in July, 2015 was the first investigation of the unique crater C2. This is situated 20 km to the north of C1 and 10 km south of the Bovanenkovo field. Satellite image analysis revealed that before the crater formed there was a frost mound, as there had been for C1, C3 and C4. I have concluded that several gas blowouts of different power were involved to form one large (100 x 50m) lake and more than 35 smaller ones. By looking at satellite images we think that the blowout occurred between 17 July and 23 October 2012. The photo of C2 in Figure 6 proves the presence of lots of little ponds around the big irregularly shaped lake. It is obvious that the lake has expanded substantially and changed its shape mainly because of the strong thermal denudation.

Large rock fragments are scattered up to 350m around the crater. According to the satellite image and ground observations we believe there was a mud blowout or fountain, which changed much of the land around the crater. Moreover, there are well preserved parapets around the smaller lakes, 0.5–1.5m deep and up to 8m across (Figure 6). There are other possible causes for parapet formation, such as frozen rock pressure or hard parts of ice soil falling from the frost mound during the blowout.

The horseshoe-shaped northern side of C2's lake has steep, 7.5m high sides, formed from the remnant of the former pingo, in the lower part of which ice with numerous cracks is clearly seen. The ice is thickest in the middle of the horseshoe, the top of it lying 1–3m below ground level, while the lower border is below the water surface, as evidenced by the ice caps which formed as the underwater ice melted rapidly in relatively warm water (about 8–9°C). The western end of the steep shore is cut by a narrow ravine with vertical walls about 2.5m high, possibly the surface appearance of a deeper fault, the presence of which was confirmed by regional geophysical surveys. Furthermore, craters C1 and C2 are situated in the anomalously high Earth's heat flow zone, which can provide more intense gas migration and even gas emissions or blowouts through the permafrost on the bottom of lakes, rivers and former lakes.

Some of the round lakes investigated during the 2014–2015 expeditions proved to be just the remnants of former pingos formed while the ice cores melted. Some of the lakes, however, have banks covered with light rocks, in contrast to the surrounding vegetation. These are thought to be material, possibly loam, formed by pneumatic pingo explosions.

Satellite image analysis and visual observation from the helicopter revealed lots of round underwater depressions (pockmarks, gas springs) in many lakes of all sizes, suggesting they are a result of degasification. In one of the lakes in the North Tambey area hundreds of pockmark-like craters with parapets around them can be seen (Figure 7). Several articles about pockmarks are given in the reference list, including I. Kuzin (1992), who concluded that the isotopic composition of helium and carbon in methane in the lakes proves that the gas originates at significant depths, probably from 1 to 3 km. We, however, believe that in many cases the released gas is biogenic, or formed as a result of dissociation of gas hydrate.

Figure 6: Horseshoe-shaped C2 crater, July 2015.

Further Study Required

Through research on these craters we have concluded that there is no doubt that gas blowouts from the interior of the earth form ground and underwater craters and pockmarks as seen in the study area and many other Arctic regions. These are not unusual phenomena, but they have yet to be studied properly.

We expect that many more of these and other unique natural objects formed by degasification will be discovered shortly as research intensifies in the Arctic and there is a need to undertake wider geophysical surveys to prove the natural occurrence of these objects.

It has also been observed that these blowout craters can be transformed into common lakes in a short period of time (probably just two to three years), which complicates their detection.

The local Arctic seismic monitoring network will help to determine low amplitude earthquakes connected to large gas blowouts. We hope that stations transmitting this data in real time to the Geophysical Centre of the Russian Academy of Sciences will soon appear in the YaNAO region, which will help to better study the Arctic region.

References available online.

Postscript:

In early September, after this article was prepared, a new expedition in Yamal took place, and one more crater (C9) has been confirmed to the south of the Bovanenkovo field.

Acknowledgements:

The author would like to thank Vladimir Pushkarev, Igor Bogoyavlensky, Roman Nikonov for help on the expedition and data preparation for this article. ■

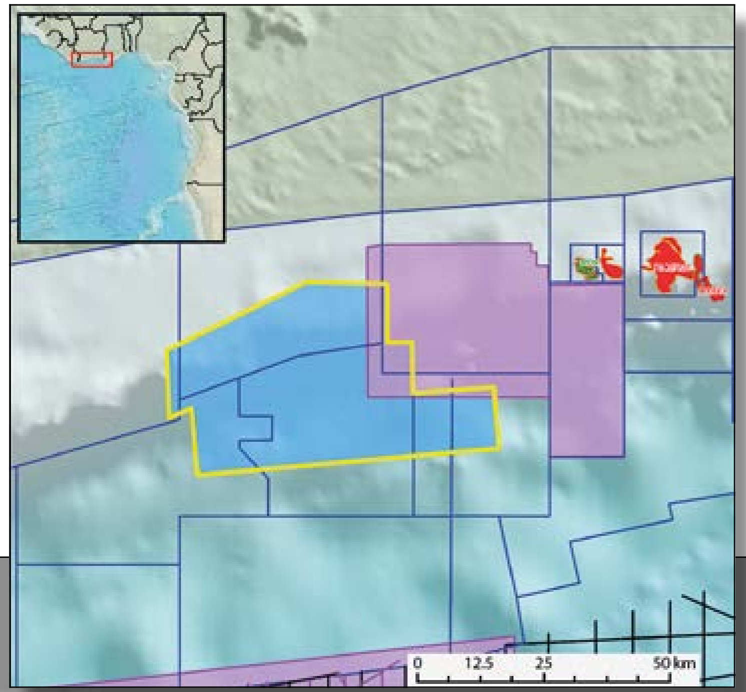
Figure 7: The lake in the North Tambey area showing gas blowout craters.

Ivory Coast

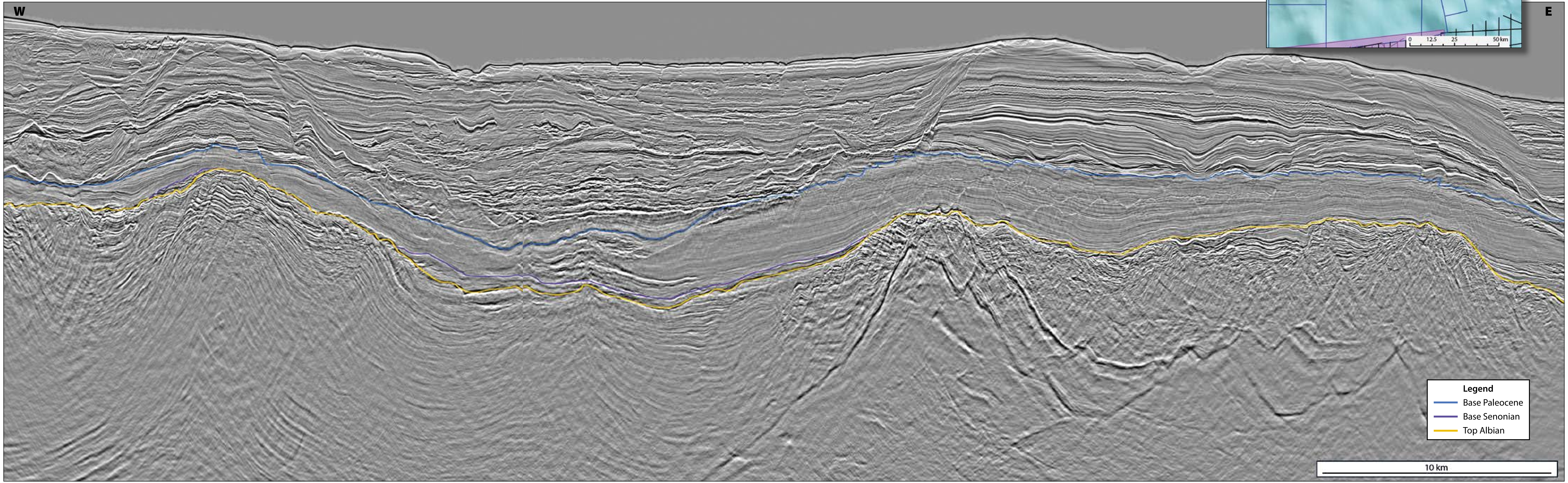
Exploration in the Transform Margin

The African Transform Margin is now well established as a petroleum province, with a well-defined syn- and post-rift play that has had much success over the past decade. In order to further exploration along this margin, Petroleum Geo-Services reprocessed a 1,600 km² 3D seismic dataset over an area of open acreage offshore Ivory Coast. The reprocessing project has revealed a much more extensive syn-rift system, and added clarity to post-rift channel systems migrating throughout the area.

Survey areas of the reprocessed 1996 data (yellow outline) and 2014 GeoStreamer® data (purple)



Strike section of Pre-Stack Time Migration (PSTM) reprocessed data from Blocks CI 104, CI-515, CI-115 and CI-116.



Offshore Ivory Coast: Reducing Exploration Risk

PATRICK COOLE, MATTHEW TYRRELL and CHRISTINE ROCHE
Petroleum Geo-Services

In 1996 PGS acquired a 1,600 km^2 3D survey over blocks CI-104, 515, 115 and 116. This survey has now been through reprocessing using a broadband processing workflow and reinterpreted by PGS. Here we present an introduction to the petroleum geology of Ivory Coast and discuss the results of the interpretation project.

Offshore Ivory Coast is part of the West African Transform Margin (WATM), a large tectonically constrained area bound by a series of major fracture zones formed during the separation of the African and American continents during the late Jurassic to Cretaceous. The margin, which has approximately 2,200 km of coastline, extends from Liberia in the west to the edge of the Niger Delta in the east.

Exploration in Ivory Coast has historically been focused on the central and eastern basins where numerous hydrocarbon discoveries have been made, including a trend of gas discoveries in Upper Cretaceous-age stratigraphic traps (Foxtrot, Panthere and Marlin fields) and oil discoveries in Lower Cretaceous structural traps (Lion, Espoir, Acajou, Baobab and Kossipo fields).

This success has motivated explorers to look further afield, extrapolating known play trends whilst hunting new opportunities. The Morue-1X well (Anadarko and Total) and Saphir-1X well (Total) have proven a working hydrocarbon system in the previously underexplored western portion of the basin, whilst the recent Capitane East-1X (Lukoil) and Paon (Anadarko) discoveries have also proven the prospectivity of Upper Cretaceous oil-bearing stratigraphic plays in the deeper waters.

To address this increased exploration activity in the central portion of the offshore Ivory Coast Basin, PGS have been actively acquiring new data whilst also reprocessing the existing library. Part of this reprocessing effort has focused on a 1,600 km^2 multi-client 3D seismic survey originally acquired in 1996 using conventional streamers, located in the central part of the Ivory Coast Basin adjacent to recent discoveries. The survey covers four blocks – CI-104, 515, 115 and 116 – three of which are currently open acreage. By applying a modern broadband time processing workflow (and thus broadening the seismic frequency post-acquisition and trying to remove the source and receiver ghost), PGS have been able to image the deeper syn-transform and early post-transform sections with much greater fidelity. In addition, PGS has two GeoStreamer® 3D datasets, to the west in CI-506 and 507 (currently open acreage), and to the east in CI-12 and 501.

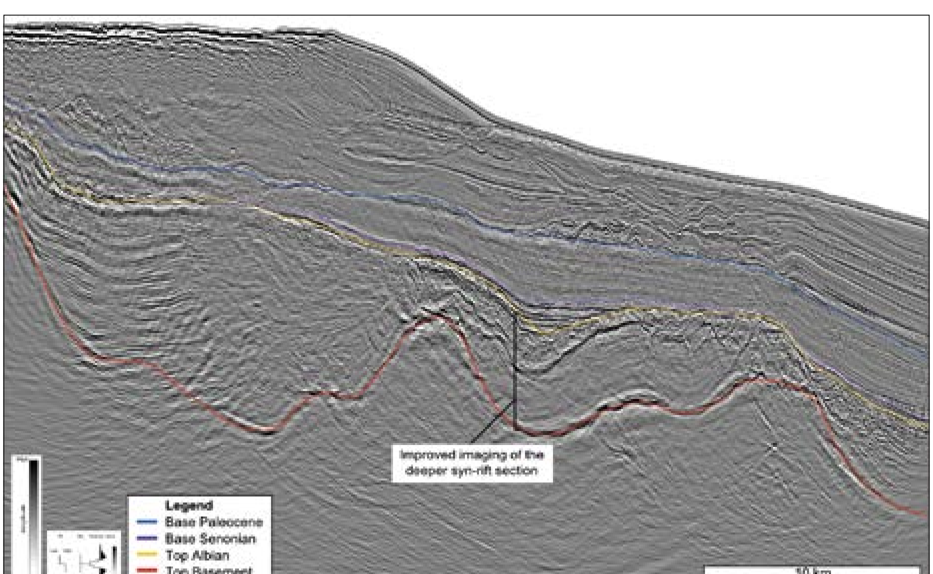
Stratigraphy Offshore Ivory Coast

Interpretation work carried out by PGS in the region has identified three distinct tectonic phases, each of which plays an important role in the petroleum system story:

- The syn-rift phase, characterised by pull-apart rifting that formed a horst and graben topography.
- The syn-transform phase, characterised by strike-slip movement that resulted in the inversion of many of the syn-rift structures.
- The post-transform phase, characterised by sediment fill of the post-inversion topography.

The pre-rift stage has not been penetrated by drilling in the central Ivory Coast Basin, although outcrops of rocks of Precambrian to Triassic age do exist east in the Volta and Tano Basins. Pre-rift Jurassic-aged rocks have also been found in the Ivory Coast Basin, which comprise conglomerates and shales deposited in a continental setting.

During the syn-rift stage (Berriasian to Middle Aptian), approximately 5,000m of sediments were deposited in a continental and marginal marine setting in the Ivory Coast Basin (Chierici, 1996), allowing the accumulation of Middle Aptian source



rocks. The environment became progressively marine during the Albian as rifting continued, leading to the deposition of sands, shales, calcareous deposits and conglomerates. The onset of a major phase of inversion occurred during the syn-transform and is marked by a significant unconformity in the Cenomanian that is apparent both in the African and Brazilian margins.

The end of transform movement and inversion was superceded by thermal subsidence in the post-transform stage (Cenomanian–Holocene). This phase almost entirely comprises clastic marine interbeds of varying thickness of sandstones, shales and minor carbonate sediments. Potential reservoir rocks include ponded and channelised turbidite systems and basin floor fans, whilst the organic rich black shales deposited within geographical lows provide potential source rocks.

Petroleum Geology

Within the waters offshore Ivory Coast, hydrocarbon discoveries have demonstrated the presence of working petroleum systems within the syn-rift (affected by syn-transform inversion) and post-transform tectonic phases. Future exploration targets can therefore focus on three key plays: Aptian–Albian syn-rift structural plays and early post-transform structural plays, both charged by hydrocarbons from syn-rift lacustrine or shallow marine source rocks, and post-transform channel and fan stratigraphic plays charged by hydrocarbons from a Cenomanian–Turonian source rock.

Successful exploration along the WATM is determined by a number of factors. In the syn-rift, the timing of expulsion related to tectonic phases is an important consideration, whilst in the post-transform, the up-dip pinch-outs of the numerous stacked channels and fans play a key role. The maturity windows of the two source rocks must also be determined to understand the charge of these reservoirs.

New Insights from Broadband Reprocessing

By analysing the amplitude extractions of the broadband reprocessed seismic data, PGS are able to gain effective insight into the distribution and reservoir characteristic of both the post-transform channel systems and the numerous syn-rift structures. This analysis has highlighted a number of untested leads within the region, many with similar characteristics to nearby discoveries.

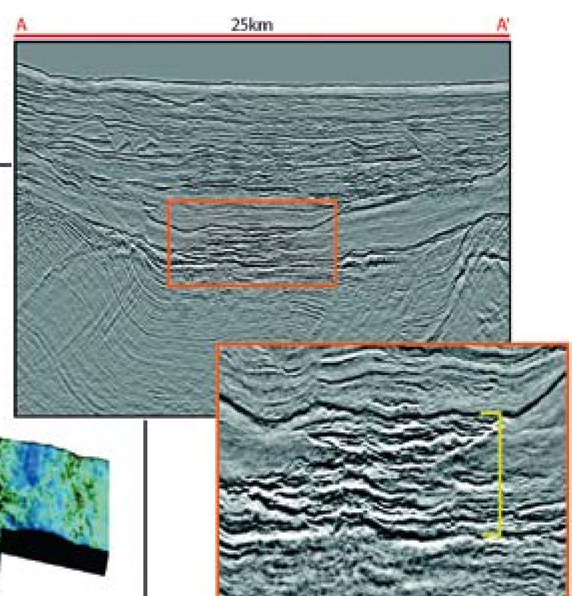
Further to this, by broadening the seismic frequency post-acquisition and trying to remove the source and receiver ghost during the reprocessing efforts, PGS have been able to improve imaging of the basement nature as well as deeper syn-transform and syn-rift sections. This insight has opened up the potential for new play concepts and the recognition of an untested Jurassic play system within the earliest syn-rift. This play is modelled to have potential lacustrine source rocks and shallow marine reservoirs.

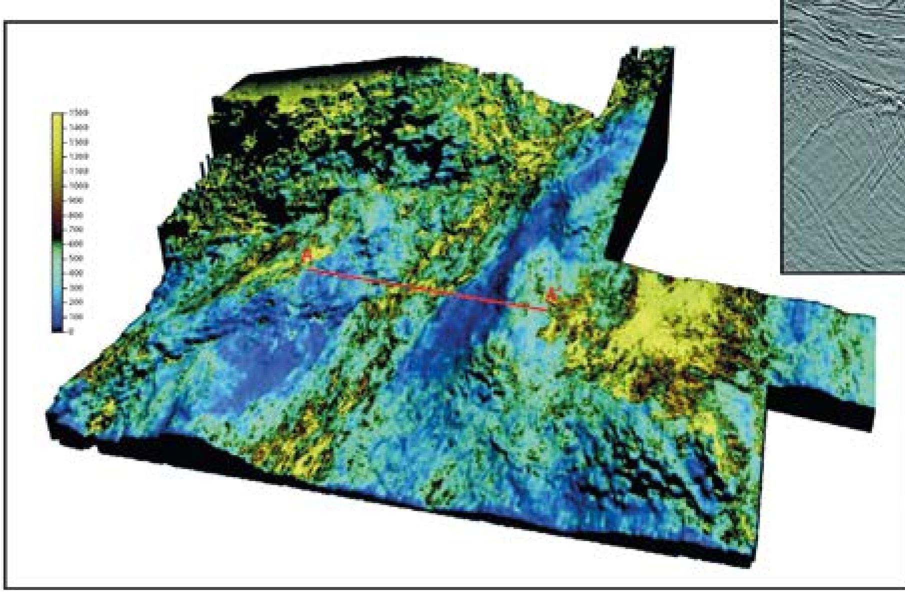
The Future for Exploration

Discoveries made by wells such as Saphir-1X, Morue-1X and Capitane East-1X together with the decision by Exxon in 2014 to license new acreage has shown a commitment to continued deepwater exploration in the area where hydrocarbon potential remains.

PGS have a comprehensive, modern-day multi-client seismic data library across the WATM and are actively acquiring new data in both the deepwater and shallow shelf areas to match the exploration requirements of the industry. The data library contains both GeoStreamer acquisition data and conventional acquisition data, much of which has been reprocessed using a broadband workflow.In Ivory Coast the reprocessed data over blocks CI-104, 515, 115 and 116 gives greater insight into the deeper syn-transform sections and greater clarity within the post-transform channel and fan sequences and thus reduces some of the exploration risk.

References available online ■





Stacked channel systems deposited within the post-transform depocentres.

Water Matters!

Water occurs virtually everywhere in oil and gas fields – yet it is often ignored. But the composition of today´s formation water is the result of multiple hydrogeochemical processes, and a primary source of valuable information.

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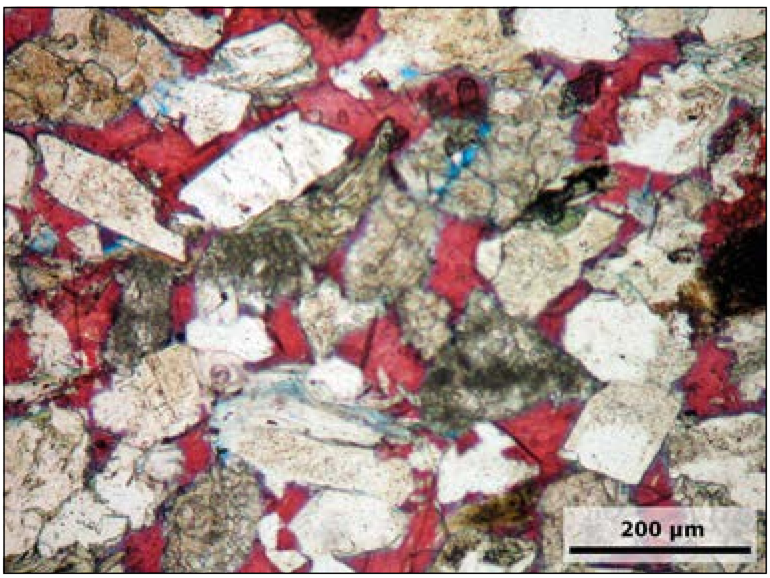
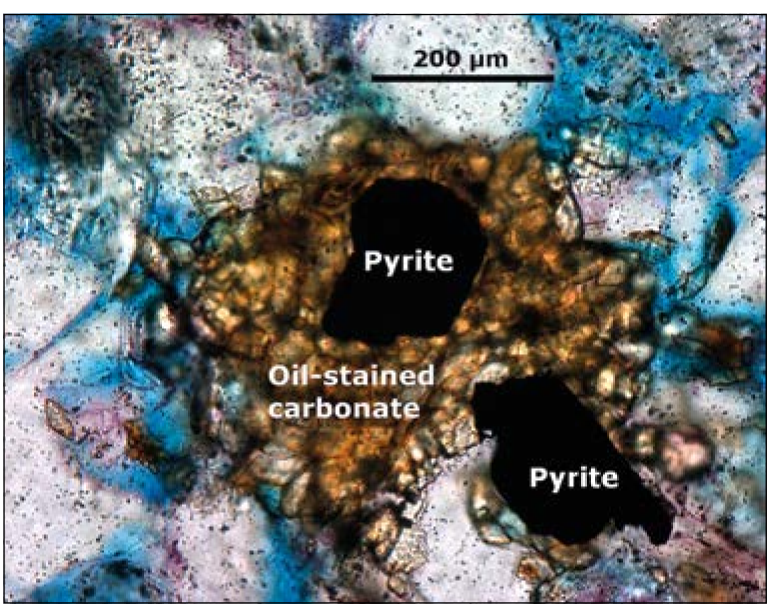


Organic-inorganic interactions in pore water – early diagenesis. Sandstone with calcite cement due to organic-inorganic interactions during early diagenesis when organic matter was converted. Anaerobic organic matter degradation released soluble CO_2, which precipitated as carbonate cement from pore water.



Organic-inorganic interactions in pore water – late diagenesis. Reservoir sandstone filled with pyrite and carbonate cement. Anaerobic oil degradation released soluble CO_2, which precipitated as carbonate cement thereby incorporating oil. Pore water sulphate was reduced to sulphide, and, together with dissolved Fe^{2+}, precipitated as pyrite.

The actual matrix for geochemical processes in sediments is water, which is ubiquitous in sedimentary basins where hydrocarbons form and accumulate. Water occurs as a free aqueous solution in rock pores and fractures, as a surface-coating water film around mineral grains (so-called irreducible water), as part of multi-component gases, or bound to/into hydrated minerals. As such, the aqueous microsphere in the subsurface is the reactor in which a seemingly limitless number of geochemical processes may take place, either microbially-mediated or abiotically, at all temperatures. Geochemical processes involved in hydrocarbon systems are predominantly *hydro*geochemical reactions because water is either a reactant or a reaction product in most of them. This includes biogenic methane generation during early diagenesis; oil formation and its degradation; porosity creation in carbonate reservoir rocks by corrosive fluids; thermochemical sulphate reduction; and scale formation resulting from seawater injection. Moreover, aqueous solutions in sediments are the matrix for diffusive and/or advective mass transport.

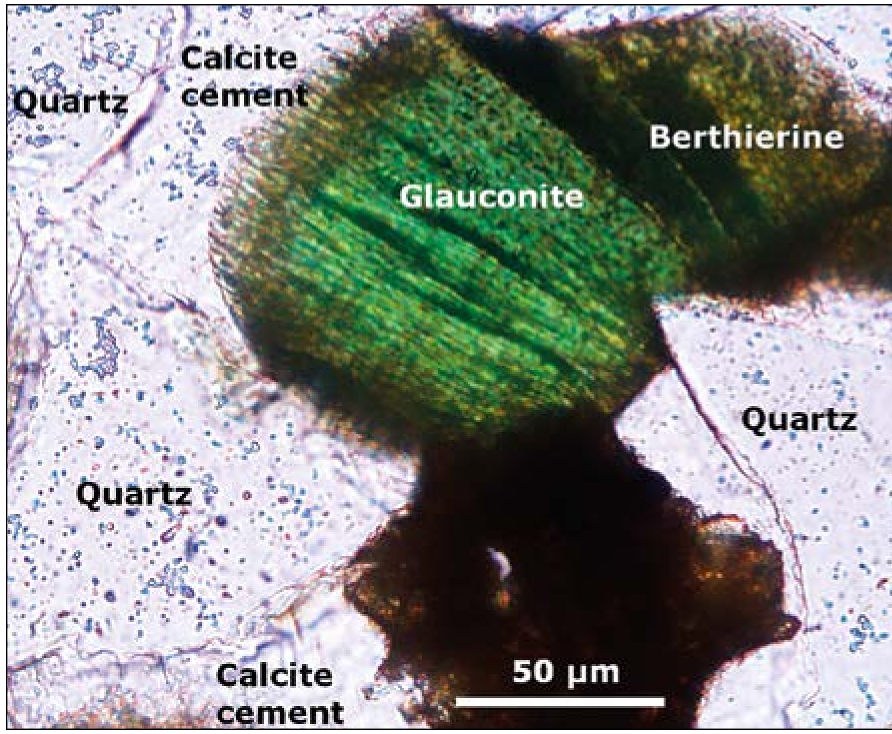
Appropriate computerised calculations (numerical simulations of reactive mass transport) are needed to make quantitative statements about the 'where, when, and how much' of water-rock-gas interactions and their effects on reservoir properties. However, traditional dogma about (hydro)geochemical processes in sedimentary basins still dominates; the focus is on isolated, selected reactions, such as abiotic sulphate reduction at high temperatures. Less attention is paid to the significance of water-rock-gas interactions as a complex web and of their coupling with mass transport processes, ranging from the micro to the macro scale in time and space. It is therefore mandatory to describe and to quantify the interacting hydrogeochemical reactions and the concurrent in-reservoir mass transport processes in four dimensions.

Basic Component in Hydrocarbon Systems

In hydrocarbon-bearing or other sedimentary systems rich in organic carbon, the driving force of complex organic-inorganic interactions is the conversion of thermodynamically labile organic compounds into reactive inorganic components (e.g., CO_2, H^+). Such interactions are widely known; they occur from shallow to great depth, in siliciclastics or in carbonate rocks, in a variety of sedimentary basin settings and also in subduction zones – and crustal Martian rocks. In petroleum systems water is an essential and basic reactive component in process chains during the generation of hydrocarbons, and its presence controls migration patterns. Additionally, it is a matrix for complex, interrelated hydrogeochemical reactions not just during geological alteration, but also in oil production.

However, such processes are dependent on a number of other controls. Temperature and pressure are exemplary basic physical parameters. The composition of the mineral phase assemblage, the type of water (e.g., the content of total dissolved solids, pH, E_H) and of co-existing gases (e.g., CO_2 partial pressure), and the type and the amount of soluble hydrocarbons, are all further important controls.

Several by-products formed during these interrelated processes are of great importance for reservoir studies. Changes in the mineral matrix may affect reservoir properties of oil and gas fields due to dissolution of unstable minerals directly coupled with precipitation of new and stable minerals, or to swelling of expandable clay minerals. This is often linked to lower API grades of oil, and also to changing gas:oil ratio and gas composition. Numerical simulations enable us to quantitatively describe the results of such reactive mass transport processes; for example to predict a potential hydrogen sulphide (H_2S) and carbon dioxide (CO_2) risk ahead of drilling. There are additional topics which relate to such conceptual approaches, such as seawater and CO_2 injection for EOR or sequestration.



Organic-inorganic interactions in pore water – high CO_2 partial pressure. Berthierine formation at the OWC in a glauconitic reservoir sandstone (Siri oilfield, Danish North Sea) is the result of anaerobic oil degradation, suggesting that water-rock-gas interactions can potentially lead to high CO_2 partial pressure.

Organic-Inorganic Interactions: From Shallow to Deep

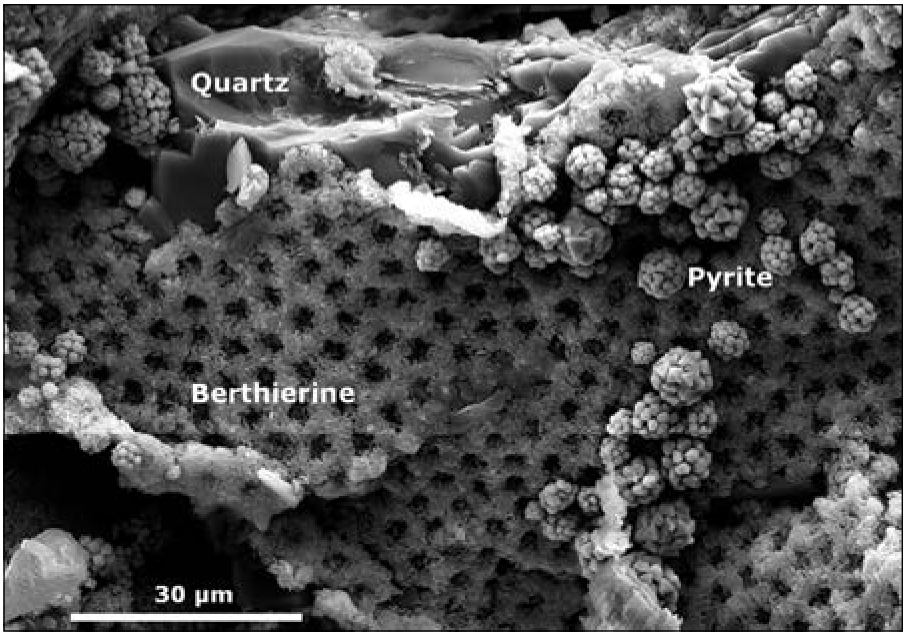
During sedimentation, degradable compounds of the sedimentary organic matter are converted to water-soluble reaction products like methane, carbon dioxide, molecular hydrogen and acetic acid (plus further low-molecular carboxylic acids). At low-temperature conditions in most marine sedimentary systems, early biogenic methane may be dissolved in the pore water until saturation; subsequently, a free multi-component, methane-bearing gas forms which, at suitable temperature/depth conditions, may be converted into solid methane hydrate. At greater depth, with a temperature of 40°C, a second peak of biogenic methane generation occurs. Again, numerical simulations enable us to quantitatively describe the results of such reactive mass transport processes evolving in dynamic systems like growing sediment columns.

Such basic processes are driven by the thermodynamically labile character of organic compounds and their understanding may be used to also understand processes at greater depth. In general, due to thermodynamic constraints, all organic-inorganic interactions, and thereby induced water-rock-gas interactions, are more or less similar from shallow to great depths. Water acts as the solvent for organic and inorganic reactants, and, notably, it may also be produced or consumed by such interactions. The chemical composition of aqueous solutions and the composition of coexisting multi-component gases and mineral assemblages change as inevitable consequences of chemical thermodynamics: the involved inorganic reactions tend to reach stable, thermodynamically-defined equilibrium conditions. In contrast, the degradation processes of organic matter proceed as irreversible, kinetically controlled reactions. The reactive inorganic products of such organic matter degradation (e.g., CO_2, H^+) drive new inorganic balances.

At greater depths, sedimentary organic matter can be converted to kerogen and release crude oil and natural gas. On both the micro and macro scale there are abundant interfaces in oil and gas reservoirs at greater depth where organic-inorganic interactions may lead to CO_2 and H_2S formation. These are the oil-water transition zone (OWTZ) or the reservoir-seal contact; if anhydrite forms the seal, reactive interfaces may occur inside anhydrite-bearing carbonate reservoirs.

How to Predict CO_2?

The OWTZ is the main interface where oil degradation and coupled organic-inorganic interactions take place. However, water-wet, oil-stained



Organic-inorganic interactions in pore water – late diagenesis. A net-like structure made up of berthierine (Fe-rich silicate) and pyrite framboids at an OWTZ due to anaerobic oil degradation in a glauconite-bearing sandstone and diffusive mass transport of aqueous components.

reservoir intervals also represent microspheres for such reactions, together with intervals where irreducible water mainly occurs around mineral grains. As a result, CO_2 as a main degradation product (besides methane) is being released into the formation water and can change the hydrogeochemical conditions. Such changes are strongly related to the rock matrix, and sensitive minerals like feldspar, carbonate or glauconite control the fate and behaviour of CO_2 by, for example, determining whether dissolved CO_2 may be trapped as carbonate minerals or not. Glauconite may dissolve as result of oil degradation, and minerals like berthierine can form.

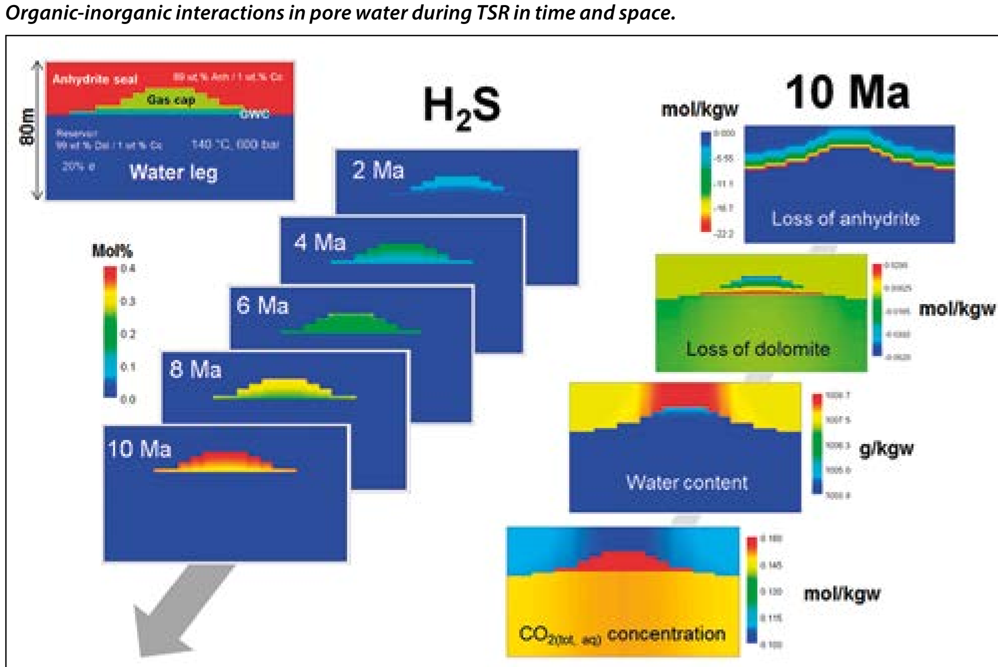
In addition, the feldspar composition and content in a reservoir rock mineral assemblage determine further reactions related to CO_2, including whether newly formed kaolinite decreases porosity and permeability. Under conditions of intense oil degradation, anorthite and albite are the least stable feldspars; their dissolution may lead to the formation of calcite or other carbonates, and additional sodium-bearing carbonates may form. However, if the CO_2-buffering capacity of the reservoir rock matrix and reservoir fluid is exhausted, CO_2 may occur as a gas and pollute the reservoir gas. To investigate the relation between the CO_2 behaviour and different minerals, appropriate numerical simulation approaches have been successfully tested for North Sea oil fields.

H_2S in Your Play?

H_2S is toxic, corrosive and lowers hydrocarbon value. For example, production from deep anhydrite-sealed carbonate reservoirs exposed to higher temperature and pressure conditions will face more aggressive corrosion environments, inevitably increasing risks and costs resulting from thermochemical sulphate reduction (TSR). But under which conditions does H_2S actually form in a reservoir, if it is not sourced from deeper horizons such as deep magmatic rocks? And which are the basic considerations for numerical 3D simulations with temporal resolution? Again, an interface is the reactive site for a complex reaction web.

Besides the OWTZ, the reservoir/(anhydrite) seal contact is an interface where aqueous components such as sulphate, methane and/or other short-chained hydrocarbons react in a complex and self-reinforcing reaction web. As only small amounts of water (e.g., irreducible water) are needed to dissolve anhydrite, hydrocarbons from the gas cap interact with dissolved, anhydrite-derived sulphate and trigger H_2S formation. This process resembles, in principle, H_2S formation during early diagenesis, but is an abiotic sulphate reduction at high temperatures (>100°C). However, this basic reaction is only a fragment of a broader reaction web, which also includes formation of elemental sulphur, pyrite, and calcite as mineralised by-products. Important,

Organic-inorganic interactions in pore water during TSR in time and space.



Organic-inorganic interactions in pore water – TSR. Solid TSR products are composed of calcite and elemental sulphur, both formed by aqueous dissolution of anhydrite.

PhreeqC and Phast

There are two, freely accessible, computer codes which enable one to undertake calculations of reactive fluid flow. These are PhreeqC and Phast, both developed and provided by the USGS (Department of the Interior). Whereas PhreeqC can be used to perform a wide variety of aqueous geochemical calculations including 1D reactive transport modelling, Phast, which is based on PhreeqC, simulates 3D multi-component, reactive transport and pore water flow systems. Although designed to investigate hydrogeochemical processes developing in near-surface aquifers, its broader application for hydrocarbon geology is both demonstrated and recommended. Processes at elevated levels of temperature, pressure and ionic strength are integrated in the software, allowing calculations for deep subsurface environments.

but often underestimated, is that one net product within the TSR reaction web – water, which is the actual matrix of all interrelated reactions building this integrated TSR web. Furthermore, mass transport of dissolved reactants in the reservoir plays a crucial role in TSR. A new approach to resolve H_2S formation as one of the TSR products in time and space was recently presented by Fu and co-authors, which enables the prediction of this process in frontier regions.

Cutting-edge Concepts

Water is everywhere in the subsurface. Its hydrogeochemical composition stores information about the basin history and its manifold geochemical processes. Interdisciplinary concepts help to improve long-established methods and to analyse past processes, but also to forecast consequences, such as those induced by reservoir engineering. Analysing and retracing geological processes will help us to plan technical measures better, including storing CO_2.

In short: by coupling petroleum geology with hydrogeochemistry we are able to enhance traditional methods with cutting-edge concepts.

References available online. ■

Building Africa's Oil & Gas Future

Commercial and organisational reforms together with sound advice and networks are needed to move Africa forward in the present challenging environment.

DUNCAN CLARKE
Global Pacific & Partners

Africa's continental oil and gas game flourished on long-term trend from the 1970s onwards, bar some cyclical down-shifts. 2008 was one such crisis, as the world financial meltdown impacted all, and, more significantly so far, 2014–15, as crude prices halved and most companies plus governments encountered fierce headwinds.

In the last decade-plus, Africa's governments, with few exceptions, indulged in a flurry of ill-advised resource nationalism initiatives. Many countries now find their E&P landscapes, structures, fiscal terms, investor contracts, capital tax levies and tax/subsidy regimes out-of-sync with crude cyclical realities that may yet last for several more years.

Crude Realities

Africa's E&P world today faces a plethora of problems. These include low crude prices, squeezed operating margins, companies in stress, some corporate takeovers and failures, survival issues for many independents and most minnows, constraints on new equity raisings, need for portfolio slimming, excess supply and fewer buyers in farm-out markets, large project delays and venture cancellations, asset and corporate divestments, lesser FDI inflows, and lower upstream capex commitments. There are difficulties to market old or new open acreage and retain global oil investors, tougher competition from the rest of the world, especially Iran, Latin America and Asia, with a shift in portfolio realignment towards the less risky onshore and shelf, leaving richer deepwater prospects fewer or untended, as well as stalling shale gas/oil developments.

Many governments remain stuck in old ideologies unsuited to market conditions, aligned to the past milieu of high crude oil prices and once-easier upstream markets for seeking and retaining corporate oil players.

In the state-controlled oil world and for Africa's national oil companies, multiple dilemmas have come to the fore, which compound these issues. All this makes for tougher forward conditions, if unaddressed, and might yet delay upstream recovery with rebalancing

Cape Town is the epitome of modern Africa: wonderful scenery, a contemporary vibrant city – and smog hanging over the townships on the outskirts.

Jane Whaley

needed for countries and state players to return to the upward long-term inbound oil and gas investment trends found in the recent past.

Indeed, Africa's contemporary state of play appears less propitious than even one year ago, following this coalescence of macro and country shifts that have combined in detriment with the latest crude market downslide. Libya has imploded; the Sahel is riskier; Central African Republic is off-limits to most; South Sudan is a de facto write-off but for the bravest; Nigeria remains without stable contract conditions, as the PIB is stuck in the political mud; South Africa is yet to resolve its legal framework for the offshore and in mandated state equity provisions – to cite but a few.

Many governments face oil-induced cash crises; penal-styled terms or residual resource nationalism 'stickiness' continues to deter cautious investors; more countries have retained and some enhanced capital gains taxes on primary market acreage transactions (DRC, the latest); uncompetitive 'state take' levels remain high and belie the likelihood of maximising near-term foreign company inflows; onerous local content obligations, often malformed, add costs and deter corporate entries and in-place players; and so on. Africa's state oil companies – with few exceptions – are mostly trapped in this web of complex and unwelcomed market conditions, even while new state oil and gas entities are being formed and brought into play (Uganda's the latest).

Unresolved problems abound. South Africa's PetroSA has incurred huge financial losses and awaits new leadership, while the Nigerian NNPC is yet to be reformed, and may be split up. Ghana's state gas entity was formed, then soon disposed of after heavy losses. Many state firms retain non-commercial aims, baggage from a past long-gone; few have been suitably restructured for stand-alone survival, let alone global competitivity. Many of them still have weak balance sheets, some no control over budgets or investments, and most play an

unhealthy role in managing extraneous non-commercial objectives with too few independent licensing agencies found, while several newly formed state oil entities are yet to fully launch off the runway.

Platforms and Networks

In the boom times, it might have been easier for the continent, countries and state oil players, with their ministerial oil officials, as well as the corporate world, to float along on the rising tide: no longer. Even then, the longer-term players and enlightened used platforms and networks like those of Global Pacific to engage with wider industry audiences. It enabled them to solicit new investment partners, plus benefit from the targeted interfaces provided, and shape competitive strategies along the lines of research and seasoned advice that had long been provided.

The African Institute of Petroleum, established 1996, is one of these enduring entities: it has long provided mechanisms for connecting key players one to another, counselled and advocated for countries to retain suitable terms and conditions that are always best to be struck in the top-quartile, and competitive within Africa and with the rest-of-world. The PetroAfricanus Club (established 2004) has brought over 6,000 state and private oil companies together to facilitate deal-flow, and showcase both to the benefit of all. More efforts will follow here, to stimulate corporate entries into Africa and encourage investment maximisation and best-practice. The International Licensing Association, formed in 2006, not just for Africa, has encouraged open and independent, world-class acreage and asset licensing, with knowledge to facilitate world-scale roadshows and marketing. This mode is essential in a market replete with multiple competitors – well over 150 countries are seeking scarce exploration dollars.

For targeted and specific talent-niches, the Global Women & Petroleum Club, established in 2001 and led by Global Pacific & Partners Chief Executive Babette van Gessel, has pioneered research, skills formation and special events to enable state and corporate players to recognise and enhance the role of women inside Africa and in the global oil industry.

Global Pacific & Partners is

enhancing these platforms and networks to serve the industry in Africa better in future, while adding to this with its landmark Africa Oil Week, now in joint-venture, and by continuing efforts on research and strategy briefings dedicated to Africa (on corporate players and state oil firms), including in-depth knowledge-banks on Africa's upstream, all accessible online. It also provides critical information to thousands of individuals daily across Africa and amidst the fourth estate, often much-neglected, by building communications for the industry in Africa via related oil and gas endeavours.

Shaping Africa's Future

The much-changed 'big picture' paradigm should guide current and future strategies for governments, national oil companies and private players – the last are already mostly very responsive, through sheer brutal necessity.

Costly state financing of subsidies to non-oil energy sources, companies and investments – renewables, and the like – should be cut or preferably eliminated, and level-playing fields in energy made the operating norm. Subsidised fuel too is an expensive game, to be best reduced and excised in time. Open investor landscapes for corporate oil and gas entry and flexible operation need maximal encouragement. Preferences for state oil players can often only be sustained at cost to slower rates of economic growth and the reduced level and rate of unlocking-in natural capital for productive investment.

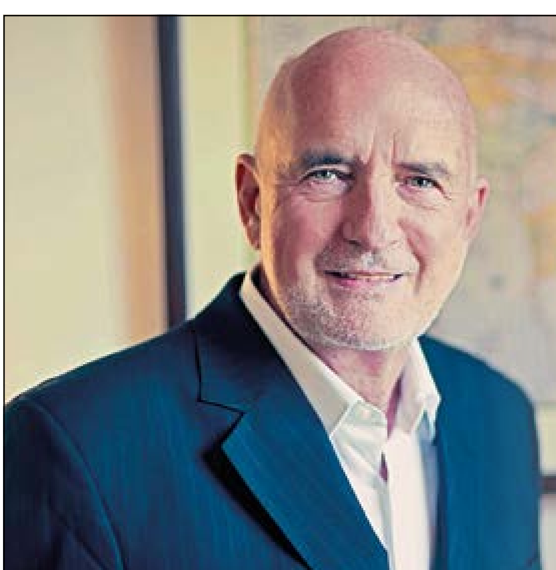
The politically seductive tilting of the playing fields for 'locals' usually only comes at hidden net costs to long-term capex inflows and maximal hydrocarbon development. The ideology of state-driven mandated local content – beloved by many – falls into this category, with short-term benefits typically gained only at higher long-run operating cost.

Multiple zones within and around Africa's nation-state boundaries reflect social fractures and potentially balkanising entities, some with long histories of irredentism, others seeking autonomy, with separatists established out of the remnants of failing or failed states. The potential for fragmentation remains significant; the nation-states only recently constructed on top of old socio-economic realities.

African national oil companies – a large and growing complex, managed and operated at less than world-class level – could be greatly reformed or restructured, and some partially privatised, to secure public and social benefit, with added net economic welfare. The lessons of the past and present tell of the necessity to reduce over-dimensioned state-protected behemoths; to shed non-commercial aims, preferably to ministries; and to reshape state oil firms' portfolios to offload unviable or non-performing assets. It would be better to privatise what cannot work or pay its way, or lacks the rubric of a 'public good', often found in ventures that are non-core, or accumulated from inherited history, including peripheral subsidiaries. Governments would be best served by divesting acreage licensing to professional autonomous entities.

None of this is rocket science: but too little of these reforms have been executed. Without deep reform many countries and their state oil entities might yet be drowned in the on-going tidal onslaught. There are numerous industry platforms dedicated to Africa and several beneficial networks that could be more rigorously employed by governments and state oil players to move ahead of this current cycle of crisis.

Sound advice, reforms and commercial platforms and networks could move Africa forward and upstream, to avoid sliding down the crude backtracks leading to the unenviable position of second-best or also-rans in this de facto hyper-competitive world. ■



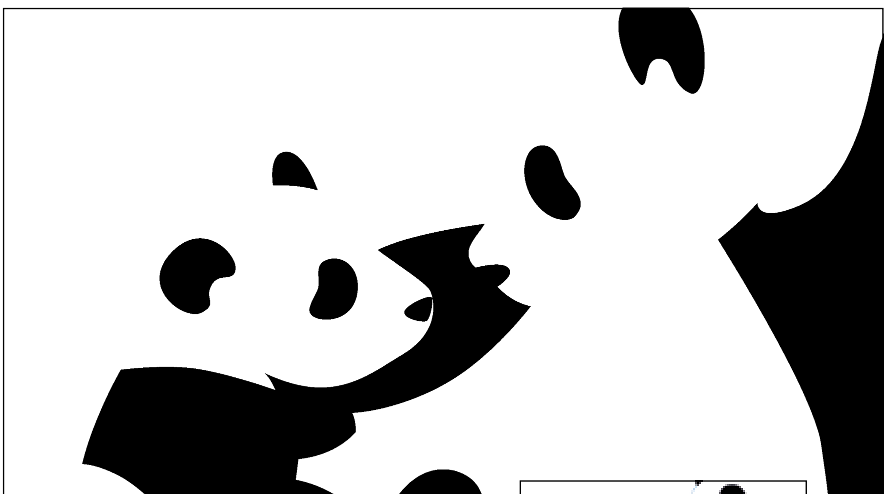
About the Author

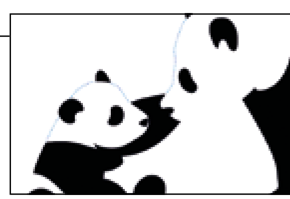
Duncan Clarke, based in London, is Chairman, Global Pacific & Partners, and author of *Africa: Crude Continent: The Struggle for Africa's Oil Prize* (Profile Books, London, 2010), and *Africa's Future: Darkness to Destiny* (Profile, 2012).

Cognitive Interpretation

Human vision and cognition have evolved over millions of years into an incredibly powerful system that enables us to actively seek the information we need to make sense of and interact with all aspects of the world around us. Despite the complexity and sophistication of the processes involved, vision and cognition are processes that we carry out quickly, continuously and with no conscious effort.

JONATHAN HENDERSON, CEO, GeoTeric





Human visual cognition can recognise this picture as representing a panda and her cub even though there are no 'panda shaped' elements in it. We can go further and make a reasonable estimate of the outline of the pandas' heads, again despite there being no boundary to track.

Whilst computer systems have been developed that can beat any human at chess, no computer can come close to humans when it comes to visual cognition. Why this is so becomes clear when we realise that around 50% of the cortex of the brain is devoted to vision, 40% to the other senses and controlling motion, leaving less than 10% for all other processes such as conscious thought, including playing chess. Attempts to improve the efficiency of interpretative tasks through automation deliberately ignore or sideline the enormous processing power within the human brain.

Revealing Geology First

This is of immense importance to the seismic interpretation segment of the E & P workflow, where we are currently both drowning in data and going through a major demographic shift. The latter means that in a very small number of years the industry will be reliant on a new generation of interpreters with expectations of computer technology which are simply not met by standard interpretation platforms. At the same time the imperative to get more from the major investment that has been made in 3D seismic data to better understand and characterise risk, develop new plays and improve recovery from existing fields has never been greater. What this means is that we need technologies that empower our geoscientists to work through the 'Data, Information, Knowledge' hierarchy and, therefore, be able to contribute to decision-making processes much more efficiently.

In the 1990s a number of 3D visualisation systems came to the market with the intent of replacing the traditional 2D seismic 'wiggle picking'. These systems represented a great leap forward in the tools that were available for understanding seismic data, but essentially they were 'just' visualisation systems. It is now recognised that a new, cognition-based approach to seismic interpretation is needed. Hence Cognitive Interpretation – the bringing together of advanced interpretative processing techniques and the power of human visual cognition.

Whilst being complementary to conventional interpretation, Cognitive Interpretation turns the interpretation process on its head. Conventional interpretation is centred on picking horizons and faults to reveal the imaged geology, whereas Cognitive Interpretation is based on revealing the geology ahead of defining the important structural and stratigraphic elements. This process reversal makes a significant contribution to the productivity gains that can be achieved with this method.

Many Disciplines

Creating a Cognitive Interpretation system is fundamentally different to the traditional visualisation systems and is non-trivial, as it requires the design of the system to be determined by human rather than technological factors. This includes an understanding of when it is most effective to rely on the human visual system, when to pass control to the computer and how the two components should interact. Cognitive Interpretation is only achieved in a system that combines high resolution, multi-component visualisation, advanced seismic attributes, interactive 3D object delineation and manipulation and interactive multi-attribute data analysis tools in exactly the right way.

To achieve this, Cognitive Interpretation must draw on research from many disciplines, including

Expertise and experience allow us to make stronger inferences from images. A geologist will recognise both these pictures as showing geological faults despite the vast difference in the properties of the images (scale, colour, orientation etc.). In addition, they would almost instantly be able to make inferences on how the faults were formed and the nature of the rocks that have been faulted, information which is not explicitly present in the image data itself.

anatomy, biology, ergonomics, neurophysiology, ophthalmology, physics and psychology, some of which are rarely if ever considered in the design of oil and gas technology, and connect this with expertise in mathematics, geophysics, geology and software engineering.

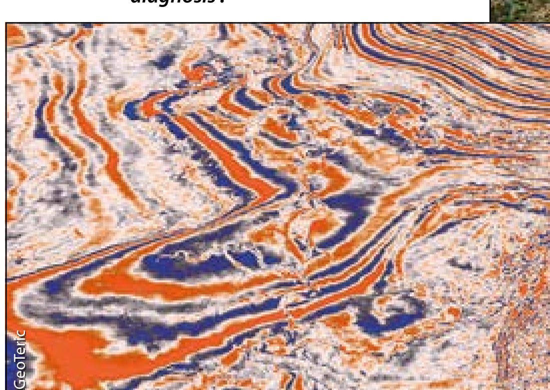
A very important consideration for Cognitive Interpretation is that the human visual system is much more sensitive to temporal or spatial change than the absolute intensity of an image. This manifests itself in how strongly the eye is drawn to motion, but we also see a much greater neural response when the eye travels over an edge in an image than when we look at areas of constant intensity. However, we cannot assimilate information in a scene if things change too quickly – but we also lose the ability to assess change if there are significant time delays between being presented with different scenes. In addition, our visual attention can be distracted by having to look elsewhere, e.g. at a computer keyboard or GUI item. What this means is that information needs to be presented to the interpreter at the speed at which they think and it must be possible for the interpreter to interact with the data in ways that minimise upsetting their thought process. It must also be possible to create and review multiple realisations at each stage of the workflow. The ideal Cognitive Interpretation system is one in which '… one is ignorant of the working of most of the parts – the better they work the less we are conscious of them…' (Kenneth Craik; *The Nature of Explanation*, 1943).

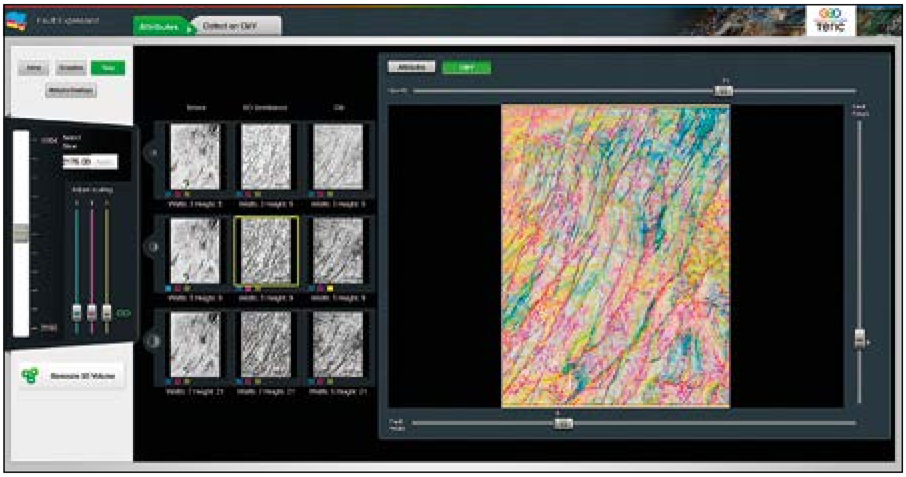
Colour Blending

A major step towards making Cognitive Interpretation possible is the use of Red-Green-Blue (RGB) colour blending of seismic attributes. This technique can convert 3D volumes of seismic 'wiggles' into geological images extremely quickly. RGB colour blending is effective because it reflects the way our visual system works and therefore allows information to be presented to the human visual system in a cognitively intuitive way. We perceive colour because we have three types of cone cells, which have their maximum response in (approximately) the red, green and blue segments of the electromagnetic spectrum. If we just had one type of cone cell all we would perceive are shades of grey no matter what wavelength of light the cell was most sensitive to. This would be very limiting as we can perceive around 10,000,000 colours but only 500 shades of grey.

The use of full colour RGB images (or their inverse Cyan-Magenta-Yellow), based on a palette containing thousands of colours, is at the heart of Cognitive Interpretation. Used correctly, full colour displays allow us to encode and comprehend much more information from a single image than using grey-scale, spectrum or other 1D colour palettes. As a consequence, and perhaps counter-intuitively, images become easier to comprehend when we use RGB-based 'Explicit Encoding' to increase the

When we see geological features in nature we make many inferences based on our training and experience, which give us an understanding beyond what can be obtained from the information explicitly captured in the image. Seismic data is an abstract representation of the geology, which complicates the process of making expert inferences and leads to greater uncertainty in our geological 'diagnosis'.





Using tools that are designed in a cognitively intuitive manner increase the efficiency of your work and enable you to harness your cognitive capabilities for a more focused interpretation.

amount of information in an image.

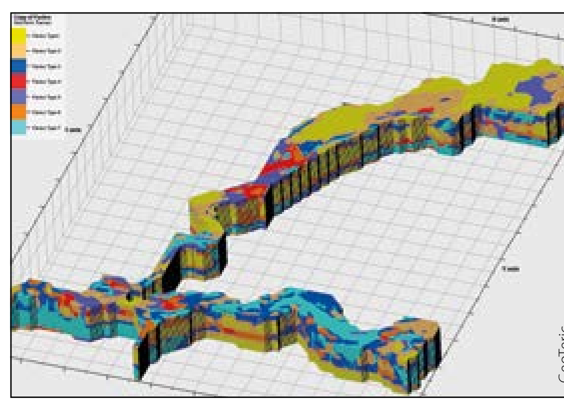
Knowledge and insight arise from understanding relationships between different pieces of information more than from examining pieces of information in isolation. In addition to explicit encoding, there are two other data comparison methods important to Cognitive Interpretation: superposition and juxtaposition. With an understanding of vision it is possible to select when to use these techniques, and very importantly, how they are implemented, so that we are always presenting information in a cognitively intuitive manner. At the heart of GeoTeric is a (patent pending) 'Example Driven Framework'. This uses superposition, juxtaposition and explicit encoding to support a set of interactive, cognitively intuitive workflows, which allow the interpreter to optimise results and examine different data analysis options in an order of magnitude more quickly than was possible previously.

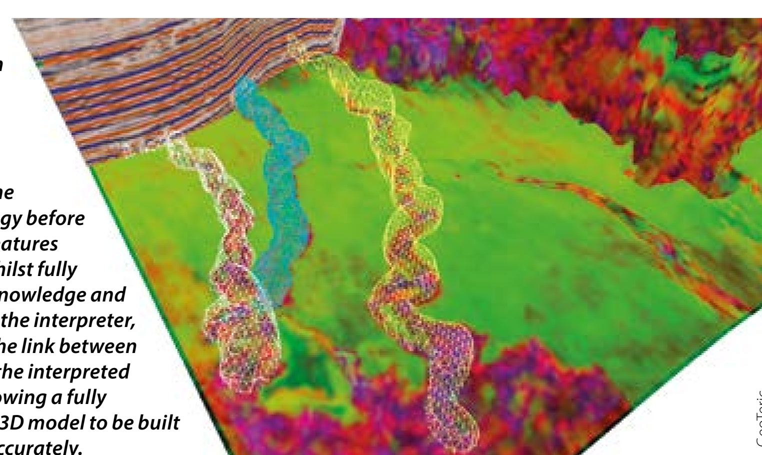
Win-Win Solution

Speed is only one of the benefits of Cognitive Interpretation. The full upside from leveraging cognition in seismic interpretation arises from the ability of the human visual system to recognise and classify features from incomplete and ambiguous data. Vision is an inherently multi-scale process, which automatically bases local inferences on a whole scene context and links these with world-knowledge and heuristics. For example, we can easily recognise something as a house even if it is largely obscured by trees and we have never seen that particular house before. This is hugely important for oil and gas exploration and production due to the immense geological variability and complexity that need to be understood when using a primary data source (3D seismic) which gives a non-unique and incomplete view of the subsurface.

The way that the human visual system recognises and reconstructs objects is still very poorly understood, but human observers will outperform any computer system when it comes to recognising and classifying objects that we have never seen before, even when they are obscured, poorly illuminated or distorted. At the same time, the human observer performs very poorly when it comes to comparing absolute values in an image and we see enormous inter-observer differences for tasks involving definition of the boundaries in images. However, the human observer can construct a reasonable representation of an object even where there are enormous gaps in the image representation of that object. So again, Cognitive Interpretation systems must be configured to create an optimal balance between the data-driven and expert-guided aspects of the interpretation process.

Cognitive Interpretation solves a major problem faced by the industry today with a win-win solution. It enables a more thorough examination of the information obtained in the available seismic data by more effectively utilising the skills of geologists involved in seismic interpretation. This increases the likelihood that a seismic interpretation is an accurate reflection of the imaged geology and allows a deterministic assessment of reservoir heterogeneity to be built into 3D geological models. The end result of Cognitive Interpretation is a huge increase in interpretation productivity, which allows improved volumetric estimation, better informed well planning and therefore a more confident assessment of field economics. ■





Cognitive Interpretation is based on revealing the information required to understand the imaged geology before delineating features of interest. Whilst fully utilising the knowledge and experience of the interpreter, it maintains the link between the data and the interpreted elements, allowing a fully deterministic 3D model to be built quickly and accurately.

Vibrant, Exciting

New Orleans

Unique New Orleans, one of the oldest cities in the United States. Renowned for music, architecture, street parades and cuisine, it also had its time in the oil industry spotlight.

JANE WHALEY

New Orleans was founded in 1718 as a French trading centre in the Mississippi Delta and was named after the Duke of Orléans, regent for young King Louis XV.

The new city lay on a slight rise in the land on a bend in the Mississippi River about 160 km from its mouth, with the large, shallow Lake Pontchartrain – strictly speaking an estuary connected to the Gulf of Mexico – lying to its north. In a taste of things to come, it was almost completely destroyed by a hurricane in 1722, after which it was rebuilt in the grid pattern which still survives. Contributing to its mix of cultures and heritage, in the 1760s it was ceded to Spain and remained a Spanish city for 40 years, during which time most of the distinctive architecture of the French Quarter, or Vieux Carré, was built.

In 1803 French Louisiana, which stretched west to the Rockies and north to Canada and included New Orleans, reverted from Spain to the French, who promptly sold it on to the fledging United States, thereby nearly doubling the size of that country.

Turbulent Times

New Orleans grew rapidly, becoming the wealthiest city in the United States, partly as a result of its port, through which large quantities of cotton and sugar were exported down the Mississippi River to the northern States and western Europe. It also played a major role in the Atlantic slave trade, as access to slaves was vital to the success of these industries. At the same time New Orleans had the largest and most prosperous community of 'free persons of colour' in the nation, often educated, middle-class property owners.

In 1830 the majority in New Orleans still spoke French, with the large Creole population (people descended from the colonial settlers of Louisiana, especially those with French, Spanish, African or Native American ancestry) joined by immigrants from France, the Caribbean and Canada (the original Cajuns, or Arcadians), as well as the French-speaking slave community. As the city got richer the French speakers were gradually outnumbered by English-speaking arrivals, so that nowadays the legacy of the language is mostly confined to place names and food.

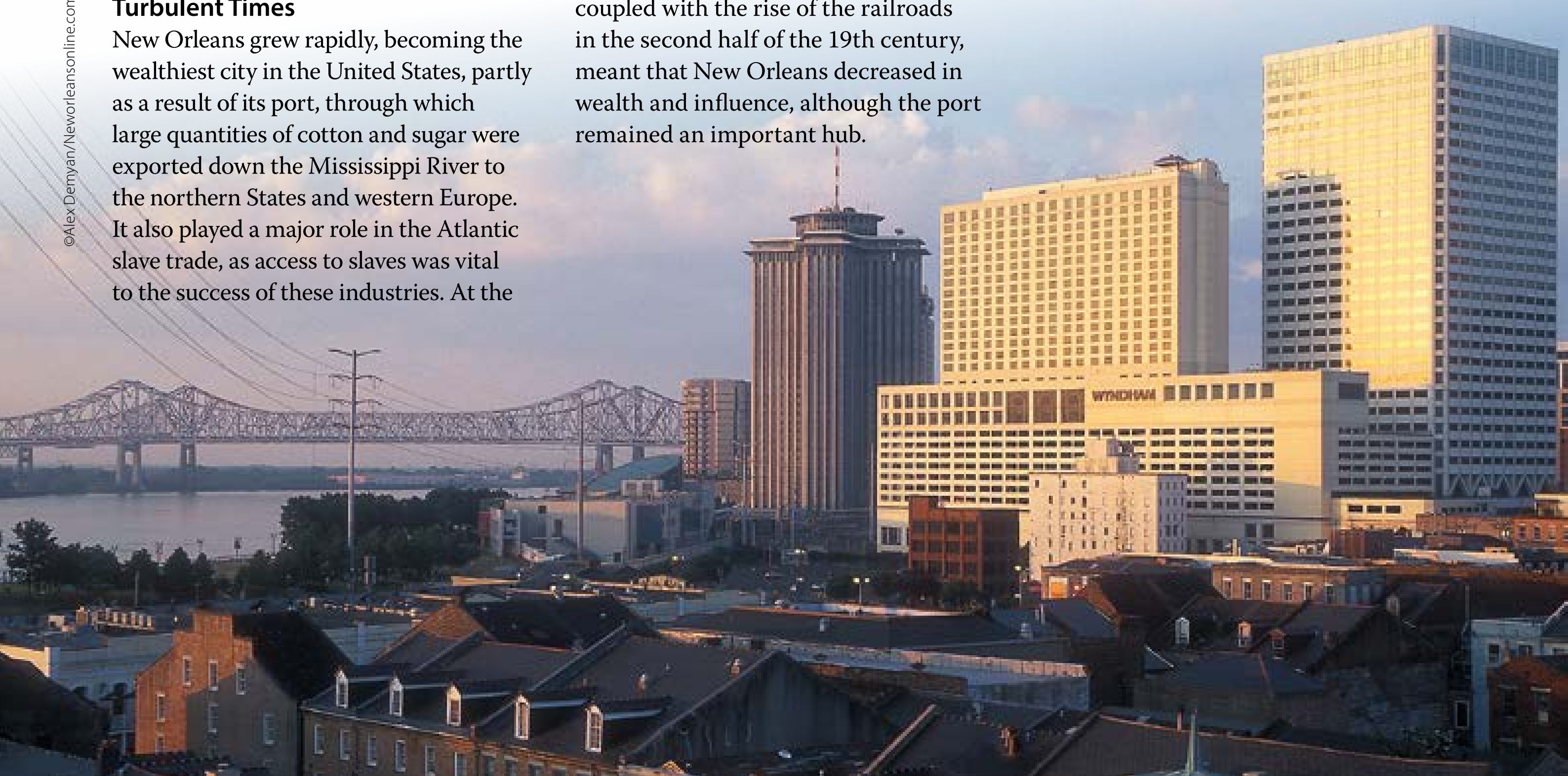
New Orleans was captured by Union troops in the Civil War. During the post-war reconstruction era, race became a potent political force, as emancipated slaves and free people of colour were brought into the political process, before the 1870s rise of the White League and the Ku Klux Klan forced them out of it. These upheavals, coupled with the rise of the railroads in the second half of the 19th century, meant that New Orleans decreased in wealth and influence, although the port remained an important hub.

Oil Comes to Town

By the beginning of the 20th century, the city was once more on the up, with major modernisation at the port and significant drainage works being undertaken to counteract the gradual subsidence the city was undergoing, as well as investments in water distribution, transportation and electrification, encouraging a burgeoning manufacturing sector. The new sound of New Orleans jazz was all the rage in the city and beyond.

Louisiana had also now entered the world of hydrocarbons. Encouraged by the spectacular 1901 oil gusher at Spindletop, some businessmen had leased land centred on gas seeps near the small town of Jennings, 250 km west of New Orleans. Having engaged the services of oil man W. Scott Heyward, who had been involved in the Spindletop drilling , they drilled to 450m – deeper than the Texas wells – without success. Working on a hunch, Heyward insisted they continued drilling – and at 550m they found a reservoir which gushed oil over 30m into the air. Louisiana now ranks third in gas-producing and ninth in oil-producing states in the US, and holds nearly 20% of the country's reserves of natural gas, much of it offshore in the Gulf of Mexico.

During WWII New Orleans boomed through ship-building and armaments. Post-war decline was averted by oil- and gas-related petrochemical processing plants which sprung up along the coast



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Carnival in Bourbon Street in the French Quarter.

and river, making the port one of the busiest in America.

The late 1970s and early ’80s were boom times for the New Orleans hydrocarbon industry, and the skyline of the city reflected it. Dilapidated 19th century-buildings in the Poydras Avenue area, including banks and the cotton and sugar exchanges, were replaced by tall glass structures such as the Exxon Building, at 1555 Poydras St. As so often happens, bust followed boom, and with the collapse of the oil price in the mid-1980s many companies failed or left town, and New Orleans entered a severe economic recession.

Hurricanes and Carnival

Built almost surrounded by water on swampy land barely above sea-level, slowly sinking, and right in the centre of the summer hurricane pathway, New Orleans has always been at the mercy of the elements. The first artificial levees and canals were built to protect it back in early colonial times, but it remains a problem. Between 1896 and 1915 a world-class drainage system was installed to remove runoff and groundwater in low-lying areas, and the levees are constantly revised and additional pumps installed, but hurricane damage and floods continued to threaten the city, culminating in Hurricane Katrina in 2005. The city was evacuated as the winds tore away roofs and drove a storm surge that breached levees, flooding 80% of the city. Hundreds were killed in the flooding and thousands were trapped for days.

The city is not yet back to its pre-Katrina levels of population or prosperity, and large areas are still in the process of regeneration. It remains, however, one of the most exciting and vibrant cities in the world to visit, reflecting its diverse history. The famous Mardi Gras parades are just one example of the carnival traditions which have centuries-old roots in French and Spanish Catholicism, as well as in African and Native American customs. There is an unrivalled music scene covering all genres, with fantastic live music on every street corner in the city centre, while the mixed European and Caribbean heritage is clearly found in the spicy Creole cuisine and distinctive architecture – best appreciated through a ride on the oldest surviving streetcar in the US along St. Charles Street from the French Quarter through to the Victorian mansions of Garden Town and Carolton. ■

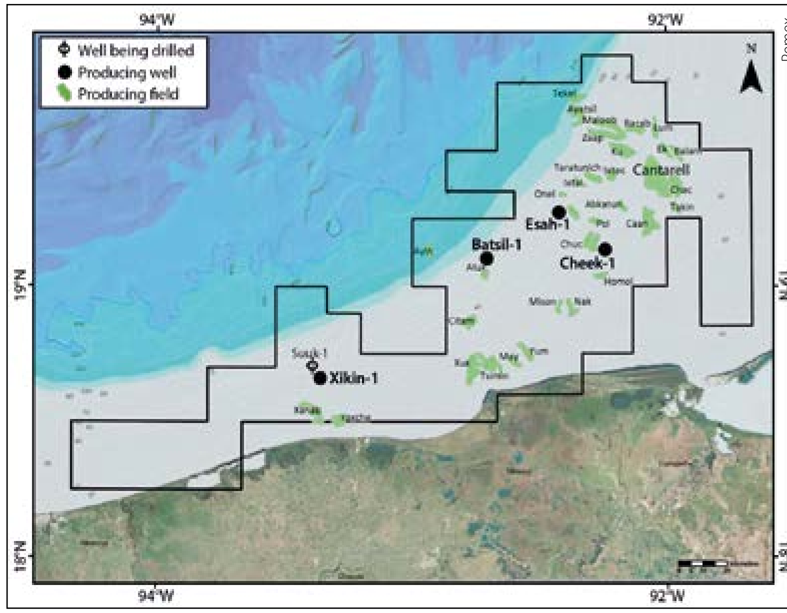
Street musicians on every corner.

KEN WHITE

Mexico: Light Oil Fields in GoM

On the eve of the deadline for bids to explore 14 shallow water blocks, the first package to be offered in the country´s inaugural licensing round, Pemex announced it has discovered one of the most profuse groups of light oil fields in the Gulf of Mexico. This accumulation of four discoveries is ranked as the largest in five years and marks the first significant exploration results for the company following Mexico's Energy Reform approval by President Enrique Peña Nieto in 2014. The four fields, three located off the Tabasco coast and one off Campeche, have estimated reserves that may be as high as 350 MMboe and could produce as much as 200,000 bopd, according to the company's chief executive officer, Emilio Lozoya. José Antonio Escalera, Pemex's Director of Exploration, said that it would take about three years for the fields to reach their full production potential and that half of the expected output of 200,000 bopd and 90 Mcfpd of gas will come from the three oil fields off Campeche, known as Cheek-1, Batsil-1, and Esah-1. Industry observers believe these figures are optimistic given that Esah is heavy oil. The remaining oil output and 95 MMcfpd will come from the Campeche field, Xikin-1-1.

While the company has discovered some reservoirs greater than 500 MMboe, the possibility of finding similar super-giant reservoirs is low and this appears to have impacted industry interest in the first bid round. Despite the exploration success, its best record since 2008, Pemex, along with four other prequalified companies that were part of separate consortia, withdrew from the bid process. Only two of the 14 blocks on offer were awarded. ■

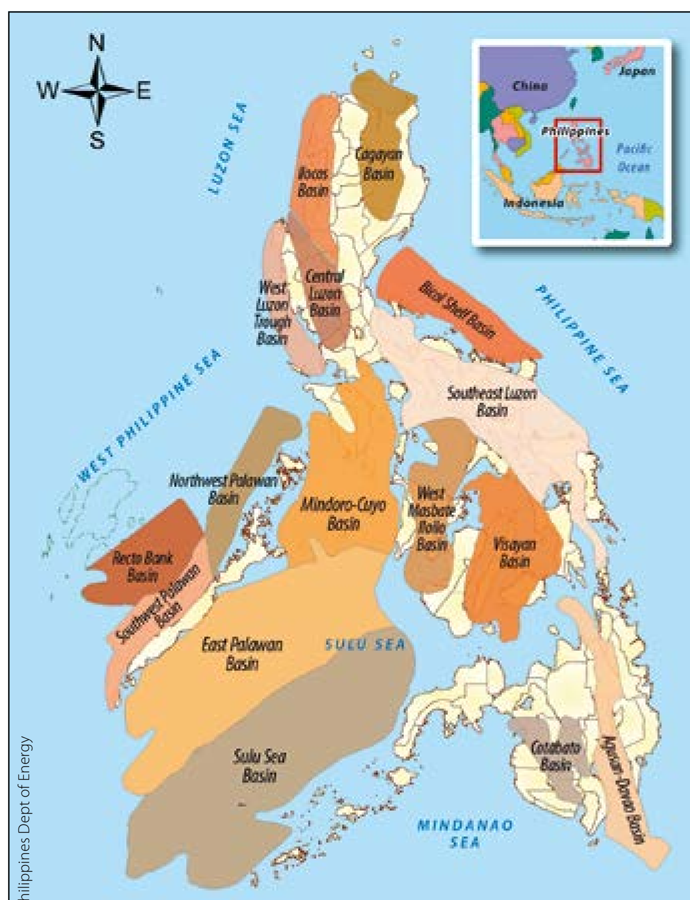


Pemex

Philippines: Mangosteen Gas Discovery

According to the Department of Energy (DOE), PNOC Exploration Corp. (PNOC-EC) needs to conduct more tests at the Mangosteen-1 well in service contract (SC) 37 onshore the Cagayan Basin to determine the commercial viability of the gas discovery. The PNOC-EC conducted drill stem tests on two zones between 2,216–2,236m and 2,243–2,250m in the Middle Miocene Sicalao Limestone, to ascertain if the zones of interest are capable of flowing gas in commercial quantity. Testing yielded gas but not in "commercial volumes due to the restricted flow of gas from the formation," the DOE said. Nonetheless the company's study showed the Mangosteen prospect has an estimated post-drill recoverable resource potential of about 24 Bcf, which could complement the Malampaya gas-to-power project offshore Palawan. The structure also has a higher resource potential compared with PNOC-EC's San Antonio gas field, which is also located in the Cagayan Basin and which operated commercially from July 1994 for 14 years.

The Cagayan Basin is one of 16 sedimentary basins in the Philippines, with a potential unmapped resource of 1.9 Tcf of gas and 26 Bbo, based on the Philippine Petroleum Resource Assessment. PNOC-EC continues to seek a partner to take up to a maximum stake of 70% in SC 70. ■



Philippines Dept of Energy

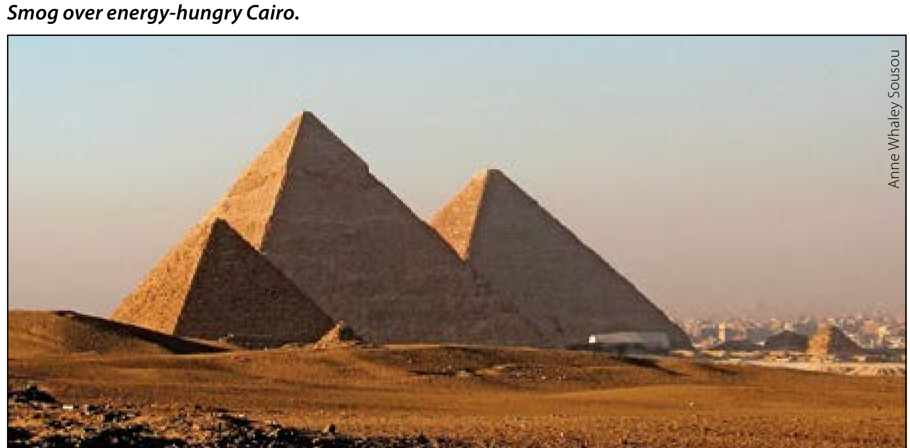
Egypt: Eni Claims Supergiant Gas Find

Eni has stunned the industry by declaring its Zohr 1 wildcat in Shorouk Block 9 in the deep waters of the eastern Mediterranean as the biggest-ever in this body of water and the world's 20th largest gas discovery.

Holding a 100% interest in the licence, the company describes the find as a world-class supergiant gas discovery with a field size of around 100 km^2 and the potential for 30 Tcf of gas in place, figures that could change the energy scenario in Egypt. The Zohr 1 discovery is located in 1,450m of water in a licence that was only awarded in April 2013. It was drilled to a total depth of 4,131m, encountering a 630m hydrocarbon column (400m net) in a carbonate sequence of Miocene age with excellent reservoir characteristics. The structure also has a deeper Cretaceous upside that will be targeted in the future with a dedicated well. Eni will immediately appraise the field with the aim of accelerating a fast track development, estimating that full development costs will be about US$ 7 billion, and the company has hinted that some 30% may be available to a partner(s) in the future.

The Shorouk block is part of the relinquished NEMED concession previously operated by Shell and this find is understood to be just a few kilometres from the maritime boundary with Cyprus. It follows other significant gas discoveries in the eastern Mediterranean in recent years, including off Egypt, Israel and Cyprus, offering projects that are seen as a means of lowering Europe's dependence on Russian gas imports. If appraisal work bears out the initial prognosis, Zohr jeopardises lucrative deals being negotiated between Israeli companies and their Western counterparts operating in Egypt, which may now no longer need to import. The discovery at Zohr is a true game-changer, firmly establishing the eastern Mediterranean as the new frontier in oil and gas production. ■

Smog over energy-hungry Cairo.



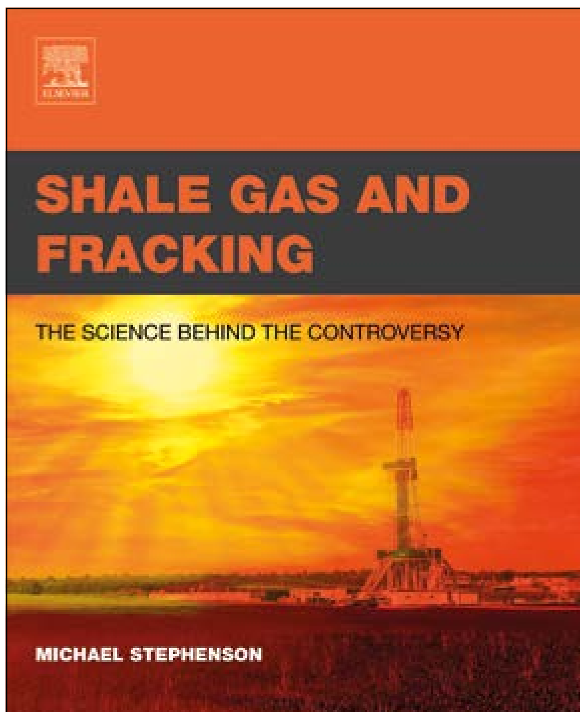
Nailing the Truth

Shale Gas and Fracking: The Science Behind The Controversy
Michael Stevenson. Elsevier, 2015

JOE GREEN

Published in 2015, this 150-page book is an up-to-date review of this new energy source from a UK perspective.

With very little drilling for shale gas having happened in the UK, the author, an expert geoscientist with the British Geological Survey, assesses the past ten years' explosive activity in North American shale exploration, drilling and production in order to try to define how the shale gas industry might progress on the other side of the Atlantic and elsewhere in the world.



Refreshingly written in plain English, we visit all the major points of interest, from environment of deposition to 'flaming faucets' and on to earthquakes, carbon emissions and social licence. All subjects are dealt with in such a balanced, even-handed fashion that it begs the question as to who the intended audience is – until the realisation hits that the author is trying to nail the truth in an industry renowned for its subterfuge.

This book is very reader-friendly, with each chapter having a list of contents, a synopsis, a number of key words and a bibliography.

Issues to be Resolved

Research using peer-reviewed scientific publications is a major source of the book's information. The claim and counterclaim are dealt with honestly, but it is obvious that there are issues that are yet to be satisfactorily resolved, and the author implies that some of the current scientific answers may change with further studies. There is, for example, the highly publicised, methane-in-tap-water issue, where methane gas contamination has been scientifically measured to be six times higher within a kilometre of fracking operations in the state of Pennsylvania – but not in Arkansas. This topic remains open and merits further investigation.

The fact that methane in water faucets is most prevalent in areas closest to fracked wells only in Pennsylvania is fascinating, but if it is caused by irresponsible cementing of casing, is this a state regulation problem rather than a drilling one? And should those famous tremors really be described as earthquakes?

Obviously new sources of hydrocarbons should not be discussed without consideration of the CO_2 emissions resulting from their combustion, and the book dedicates a chapter to this. The question of whether shale gas is a lower polluter than coal gas is not straightforward when the holistic science is applied. And should shale gas be left in the ground or is it definitely an opportunity wedge in the CO_2 stabilisation triangle? Another area for discussion.

Revisions to this first edition might emphasise that microseismic boreholes are shallow and therefore unlikely to cause permanent damage to the landscape and that methane emissions to the atmosphere during 'flowback' can be inexpensively cured with proven old-fashioned 'separator' equipment. Furthermore, the point that prolific gas potential in the Bowland shale under Manchester and Sheffield is unlikely to ever be exploited could be contrasted with the possibility of exploration in the more lightly populated areas between these two cities.

Environmental Questions

On the environmental front, the author talks of his experiences in Alberta where he describes the noise generated by fracking diesel pumps as 'skull battering.' But could that be considered as sort of okay in the middle of an unpopulated forest area, even if it goes on for days? And while modern soundproofed, electric powered drilling rigs can be quiet these days, can there ever be quiet high pressure pumps?

UK legislators recently ruled against shale exploration in areas of natural beauty and National Parks – but if not there then where could it be undertaken in an overcrowded country like the UK? This will be a massive challenge.

'Social licence' (a new term to this reviewer) describes the fact that despite the establishment of regulators to protect environments and the fact that exploration permits have been issued to explorers, people power has so far prevented any exploration drilling for shale gas in the UK in the past two years. The major task of changing public opinion is not dealt with in this book and probably requires a separate publication.

This honest attempt at describing the shale gas opportunity/threat scientifically should be read by all – and especially those living in cold climates who like to be warm in winter and those who like to be cool and dry when the heat and monsoon rains come along in summer. ■

Applying Innovations in Geophysics to the Hydrocarbon Industry

Regular *GEO ExPro* contributor Martin Landrø is Professor of Applied Geophysics at the Department of Petroleum Engineering and Applied Geophysics at the Norwegian University of Science and Technology in Trondheim, Norway. Here he discusses some of the more important innovations in the science of geophysics when applied to the hydrocarbon industry.

What first drew you to geophysics?

My wife! I had signed up for a research position at the Niels Bohr institute in Copenhagen, without telling my wife, and when I let her know about this golden opportunity in Denmark, she was not prepared for Copenhagen, and after a long discussion I applied for a position within geophysics in Norway, accepted, and turned down the Danish offer.

What geophysical innovations or technologies have had the greatest impact on the hydrocarbon industry?

In recent years, I would say that 3D seismic has significantly changed the way the industry works, both for exploration and for reservoir characterisation. For marine geophysics, I think that the introduction of four-component seabed seismic has been a game changer, while within reservoir geophysics I think 4D seismic has been a major step forward. Offshore Norway there are now four fields being monitored by permanent receivers (PRM) that have been entrenched into the seabed. The Norwegian government has already decided that the new giant Johan Sverdrup field will be monitored by a PRM system.

I would also say that the growth of controlled source electromagnetic methods (CSEM) has been an innovation step that has definitely changed the industry.

Do the most useful geophysical innovations come from academia or the industry?

They come from the industry in most cases. However, if you search you will often find academic traces in such innovations as early stage research initiatives. All the examples that I gave above were the result of research carried out by the industry, simply because big money is usually needed, in addition to great ideas.

Is the oil industry always ready to adopt new geophysical technologies?

No – I think that it is always a question of cost and benefit. When the oil price is low, innovations related to efficiency are very attractive. However, when the oil price is high, there is more room for new ways to detect oil and gas.

Is a downturn like the present one likely to slow down or encourage new technologies?

In general it will slow down new technologies simply because of lower research budgets. There will however, be an increased focus on those innovations looking at cost reduction and increased efficiency.

Are we producing enough qualified geophysicists and are we training appropriately?

At the moment, we produce more geophysicists than the market is capable of absorbing. Taking a long term perspective, the universities must plan for an average number that does not follow the fluctuations in the oil price.

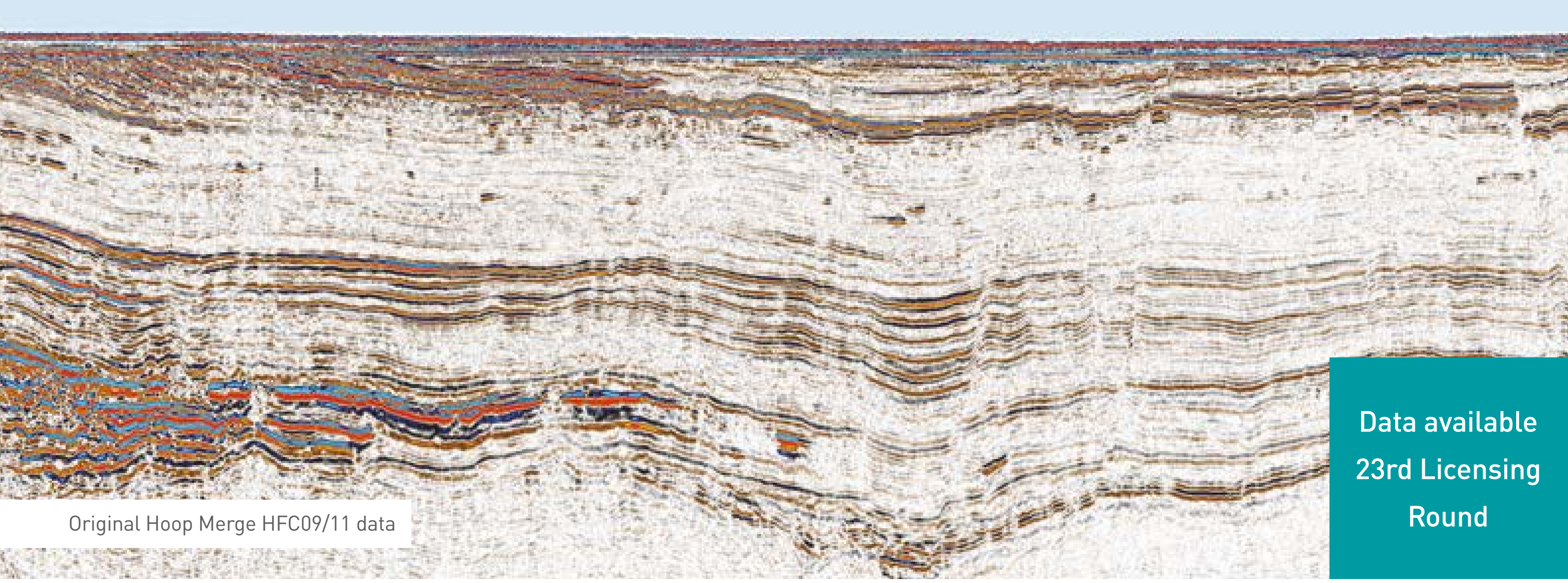
It is a crucial and important question to ask if the training we give the students is sufficient. I think it is important to focus on giving them the right toolbox that enables them to take jobs in a broad geophysical job market. The next wave of retirements in the hydrocarbon business is now the 55+ age group, and despite the current industry downturn we will require an influx of young brains with new ideas in the future.

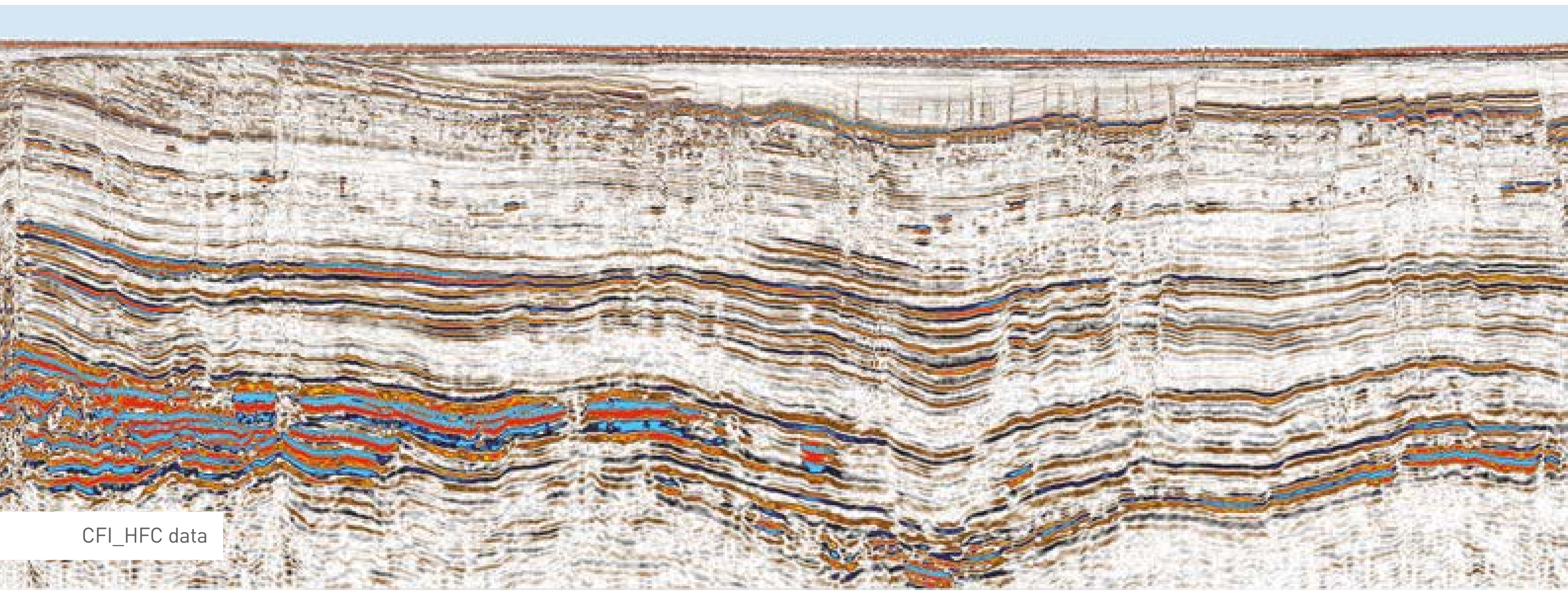
What geophysical breakthroughs do you hope to see in the next 10 years?

I hope to see an enormous growth in the number of data traces that go into a seismic acquisition – my dream is to tow a dense carpet of receivers behind the vessel for marine seismic acquisition. I also hope that we will be able to extend the broadband seismic bandwidth below 2 Hz in the future.

I foresee a breakthrough related to new innovative ways of combining key geophysical methods that we use today: seismic, electromagnetic and gravity methods. ■

Martin Landrø held research positions with SERES (86-89), SINTEF Petroleum (89-93) and Statoil (96-98), and was section manager at SINTEF Petroleum from 93-96. He is an EAGE distinguished lecturer and, among many other awards, was recipient of the prestigious ENI award in 2011 for the development and application of the 4D seismic analysis. (See GEO ExPro, Vol. 8, No. 4)





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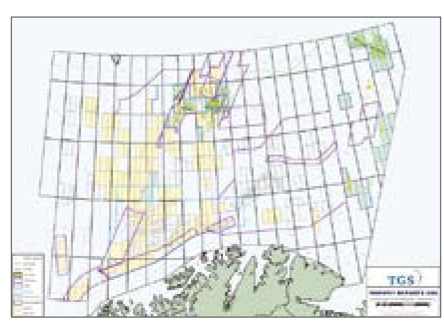

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Mauritania Offshore Hints at Significant Reserves

KEN WHITE

A new deepwater discovery revives the idea that Mauritania could become a global energy player.

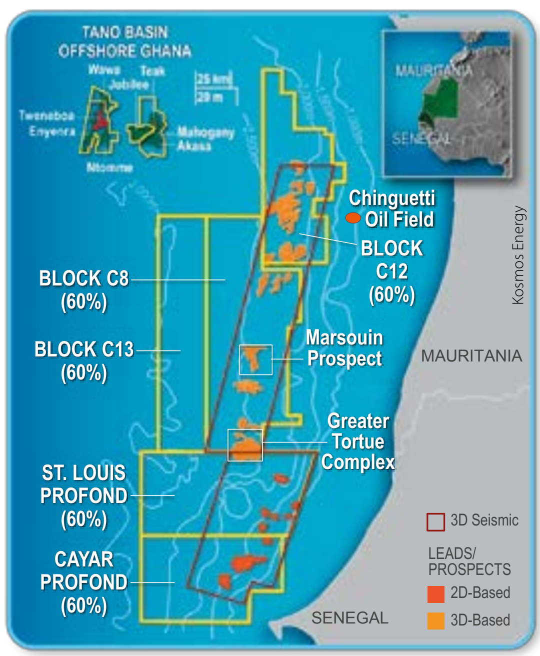
As the surge of oil and gas exploration activity on the African continent continues apace, a clutch of countries, including Mauritania, are emerging as particular hot-spots on a continent filled with resource potential. The offshore Chinguetti oil discovery in 2001, and the subsequent Banda, Tiof and Tevet Miocene discoveries, all made in the period to 2003, raised the country's hopes for oil wealth, paving the way for the creation of a favourable environment for rapid offshore oil development and the creation of an offshore oil boom. Fiscal changes, however, have yet to be realised and production has failed to meet initial expectations. Similarly, after nearly four decades of inactivity, exploration of the Taoudeni Basin in the innermost part of the country has yet to spark industry interest, and consequently large portions of onshore acreage remain unexplored.

However, hopes have been very much revived, particularly offshore, by Kosmos's recent gas discovery in deepwater Block C8, again hinting that Mauritania could become a global energy player.

Emerging Deepwater Potential

The country is a hydrocarbon wildcard in the truest sense, as little is known about its real potential either on or offshore and there is a poorly established international industry presence. Chinguetti was an important milestone, but having started up in 2006, it is still the country's only producing project. Unspecified technical issues led to a drastic decline in production rates, tumbling from an initial 60,000 bopd to just 20,000 bopd within 10 months, and further slides have brought rates down to less than 9,000 bopd more recently. Similarly, the field's proven and probable reserves have been consistently revised downwards from the original estimate of 120 MMb to just 34 MMb.

Problems aside, Chinguetti elevated the deepwater portion of the Mauritania-Senegal-Gambia-Bissau-Conarky Basin from its former rank wildcat virgin frontier status, putting it on the map as an exciting potential new deepwater province and opening up much of the north-west quarter of the continent. Despite Chinguetti's disappointing performance and chequered history, Mauritania's unexplored expanses leave plenty of room for lucrative new discoveries.



While the majority of the offshore, nearly 116,000 km^2, remains unlicensed, two companies, Tullow Oil and Kosmos Energy, head up a handful of companies exploring there. As with most extensive frontier exploration projects, Tullow encountered disappointments; the much-anticipated Fregate-1 wildcat in Block 7, while confirming the potential of the Late Cretaceous turbidite reservoirs, was not commercial but again teased at the potential of large offshore reserves. The company planned an aggressive four-well exploration campaign but with the falling oil price, corporate focus is now shifting to lower cost exploration in East Africa and Norway.

Tullow operated the 1 Tcf Banda gas field, the development of which forms part of the larger Banda Gas to Power project, which envisaged supplying electricity within Mauritania and to Senegal and Mali, with the Banda field contributing 65 MMcfgpd for 20 years. However, the project, which was to have produced first gas mid-2016, appears to be another casualty of the low oil price environment, with the government struggling to revive interest following Tullow's withdrawal.

Kosmos currently holds the exploration baton, the company's chairman and CEO Andrew Inglis claiming "our Tortue 1 gas discovery in Block C8 is the industry's largest offshore find so far this year." The company holds three contiguous deepwater blocks that include the outboard fairway of the underexplored Upper Cretaceous stratigraphic play concept, the company's core exploration theme. Kosmos estimates that the field, renamed Ahmeyin, has a mean resource of 8 Tcf subject to an appraisal programme, which will get underway after the Marsouin 1 wildcat in the central part of Block C8, which is expected to spud shortly.

High Risk – High Reward

The potential for commercial hydrocarbons is significant, but risks from poor infrastructure, a changeable political landscape and significant technical/financial challenges make it far from a sure bet. Nevertheless, companies investing in Mauritania's nascent offshore sector are confident that the finds will come, and their success could bring energy independence and accelerated economic development to a country whose population desperately needs it. ■

A New Classification

We need to classify resources irrespective of the energy source in question, which is why a UN committee has introduced a new system. The ambition is to implement it worldwide.

The classification of geological resources has (too) long lacked a common reference system that both industry and government can relate to in order to take proper industrial and political decisions. Now this is about to change. The idea is that we should have a common international standard for classifying resources. Geoscientists and engineers should be able to use the same system whether they are talking about oil, gas, coal, minerals, uranium or renewable resources.

"The advantage of such a system would be that everyone speaks the same language and that we will then be able to discuss figures and compare resources at several levels," says Sigurd Heiberg, member of a UN-appointed committee with a clear mandate to prepare a simple and user-friendly classification system for geological resources.

Classifying on Three Categories

Classification of natural resources such as petroleum, coal and minerals is obviously far from new. The first systems occurred in the early 1900s, after the industrial revolution forced the large-scale exploration and exploitation of energy and mineral resources. But no attempt was made to impose a standard for individual resources, let alone for more than one resource.

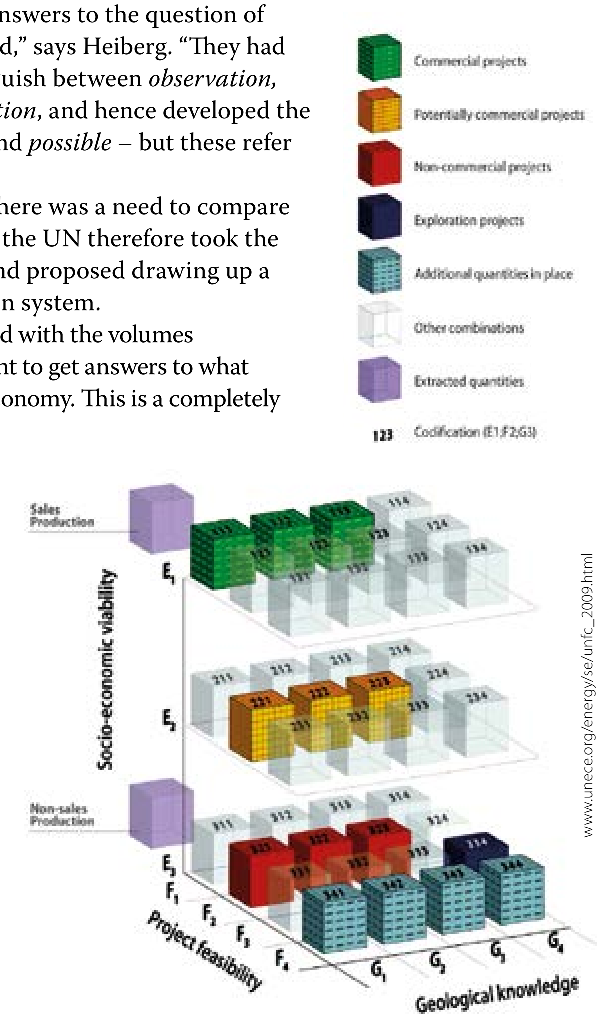
"Geologists were only concerned about the volume of rocks above or below the ground, thereby providing answers to the question of what actually had been found," says Heiberg. "They had strict instructions to distinguish between *observation, interpolation* and *extrapolation*, and hence developed the concepts *proved, probable* and *possible* – but these refer to rock volumes."

With a global economy, there was a need to compare resources across borders, so the UN therefore took the initiative in the late 1990s and proposed drawing up a new and unified classification system.

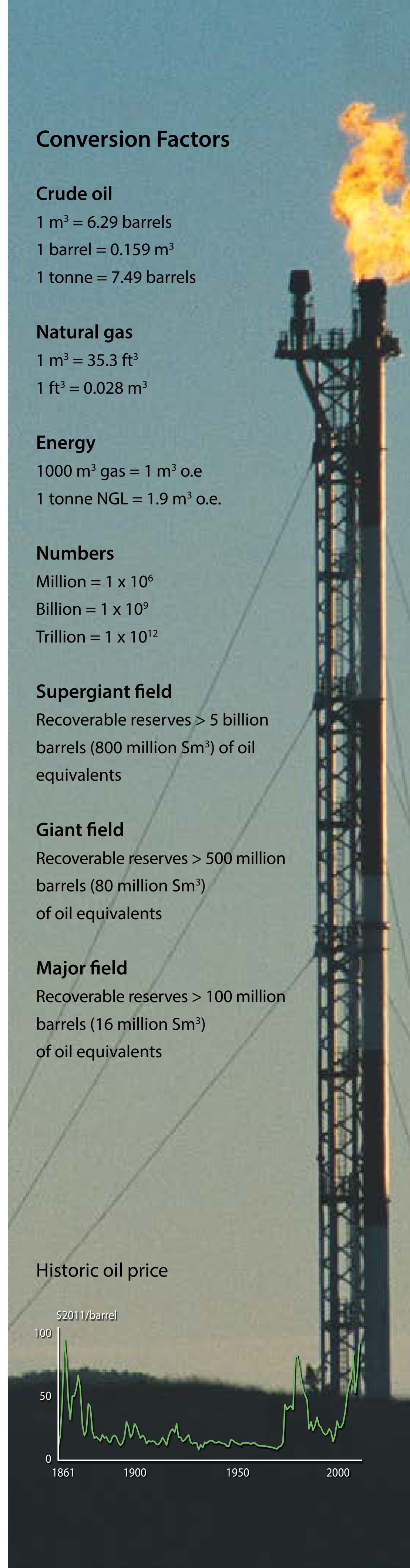
"Now we are less concerned with the volumes underground. Instead, we want to get answers to what resources we can get in the economy. This is a completely different way of thinking, as what we are classifying are the projects," explains Heiberg.

The classification system UNFC-2009 is based on three categories. The **first** – geological knowledge and uncertainties – and **second** – technological feasibility – are similar to those that the Society of Petroleum Engineers, among others, recommends. The difference comes with the **third**, which relates to socio-economic factors. This makes the system three-dimensional.

Halfdan Carstens



www.unece.org/energy/se/unfc_2009.html



Conversion Factors

Crude oil
1 m³ = 6.29 barrels
1 barrel = 0.159 m³
1 tonne = 7.49 barrels

Natural gas
1 m³ = 35.3 ft³
1 ft³ = 0.028 m³

Energy
1000 m³ gas = 1 m³ o.e
1 tonne NGL = 1.9 m³ o.e.

Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

Supergiant field
Recoverable reserves > 5 billion barrels (800 million Sm³) of oil equivalents

Giant field
Recoverable reserves > 500 million barrels (80 million Sm³) of oil equivalents

Major field
Recoverable reserves > 100 million barrels (16 million Sm³) of oil equivalents

Historic oil price

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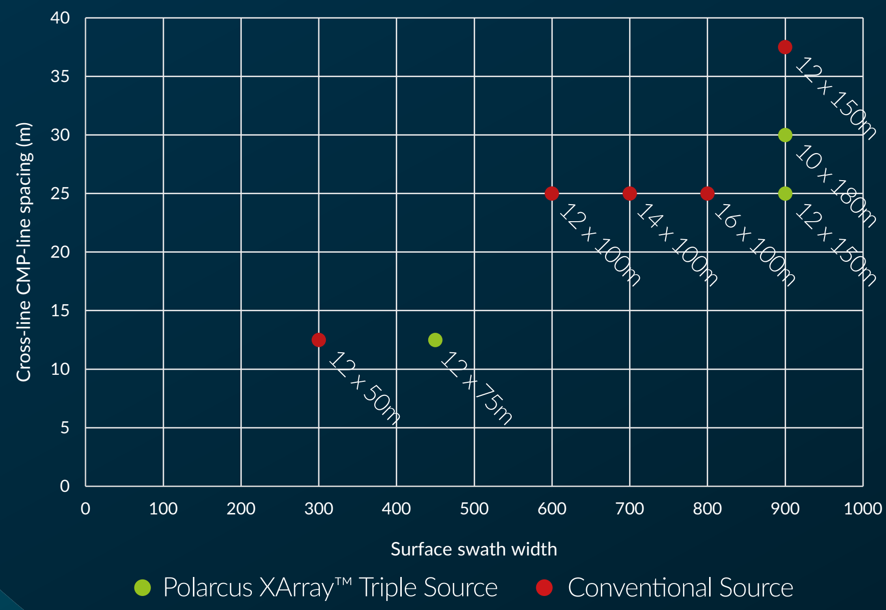

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