VOL. 9, NO. 3 – 2012

GEO ExPRO

GEOSCIENCE & TECHNOLOGY EXPLAINED

GEOTOURISM: Olympic London

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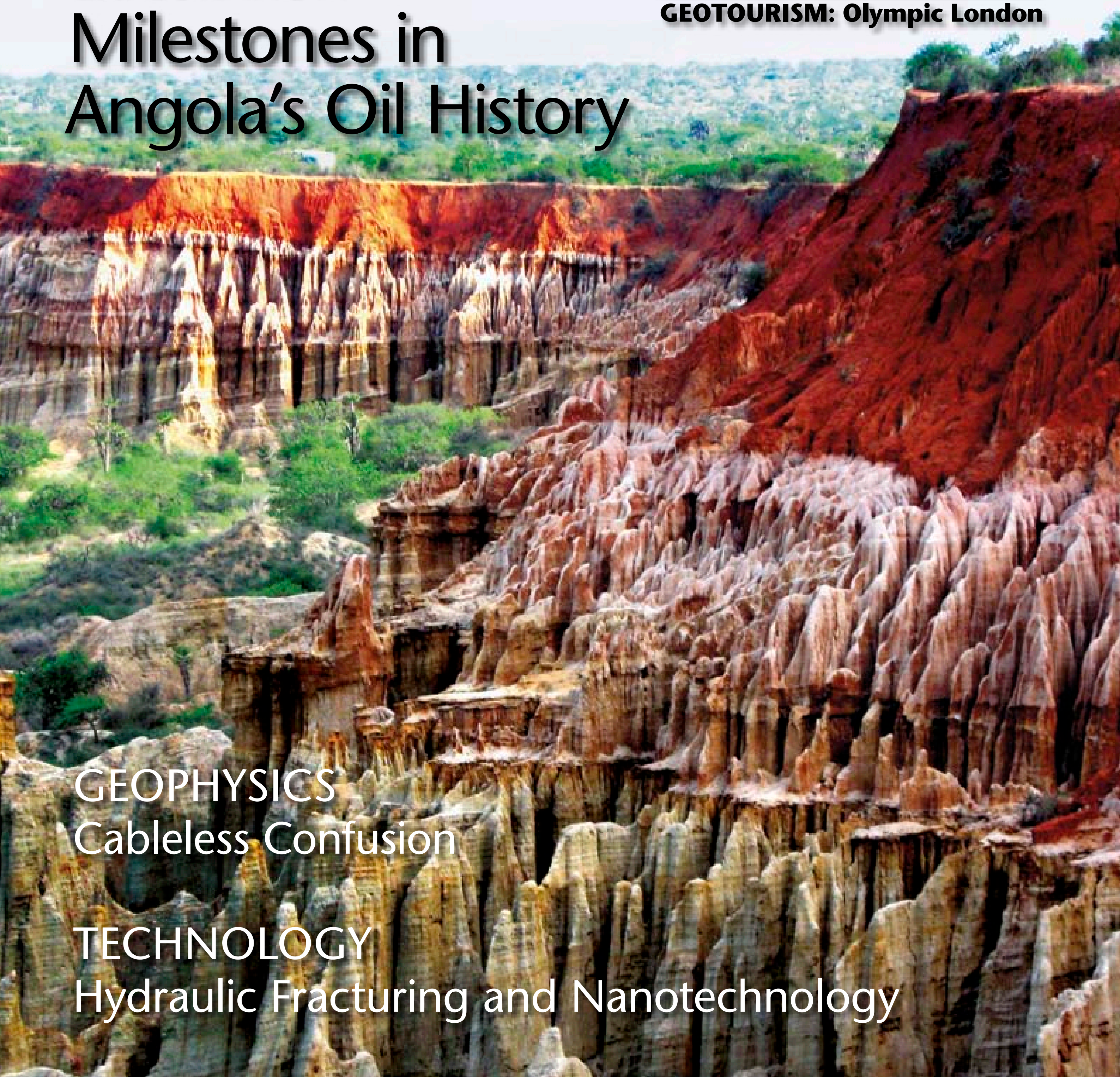


EXPLORATION

Milestones in Angola's Oil History

GEOPHYSICS

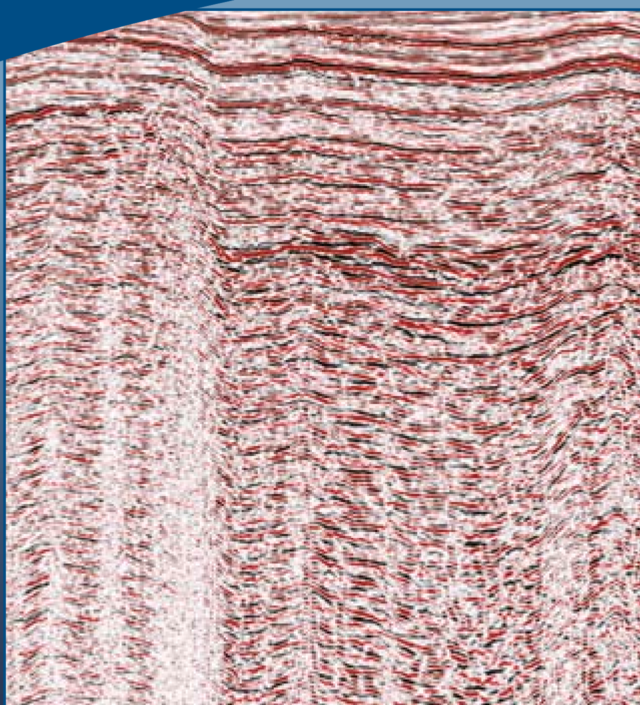
Cableless Confusion

TECHNOLOGY

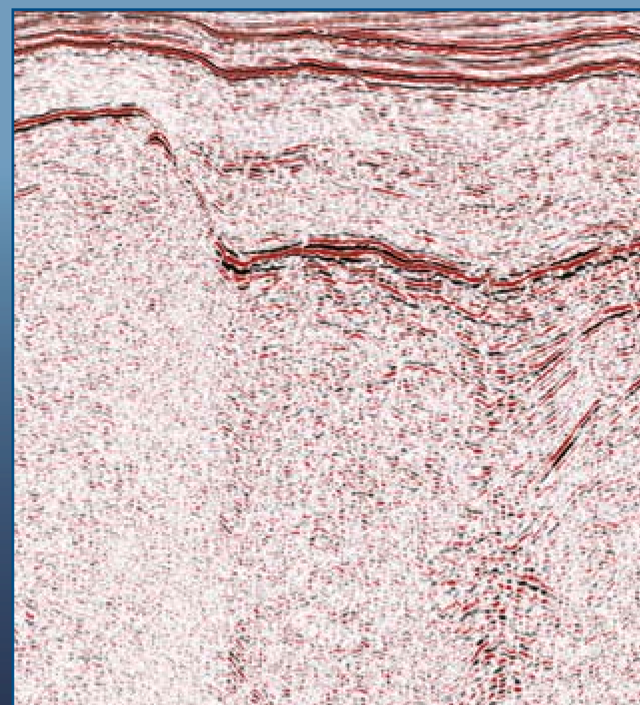
Hydraulic Fracturing and Nanotechnology

GEOLOGY GEOPHYSICS RESERVOIR MANAGEMENT

Introducing SMELT



Before SMELT - North Sea 2011



After SMELT - North Sea 2011

Stepwise Multiple Elimination using Linear Transforms (SMELT)

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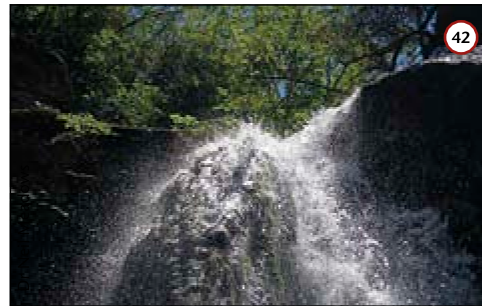

The use of nanotechnology with hydraulic fracturing promises to protect valuable water resources

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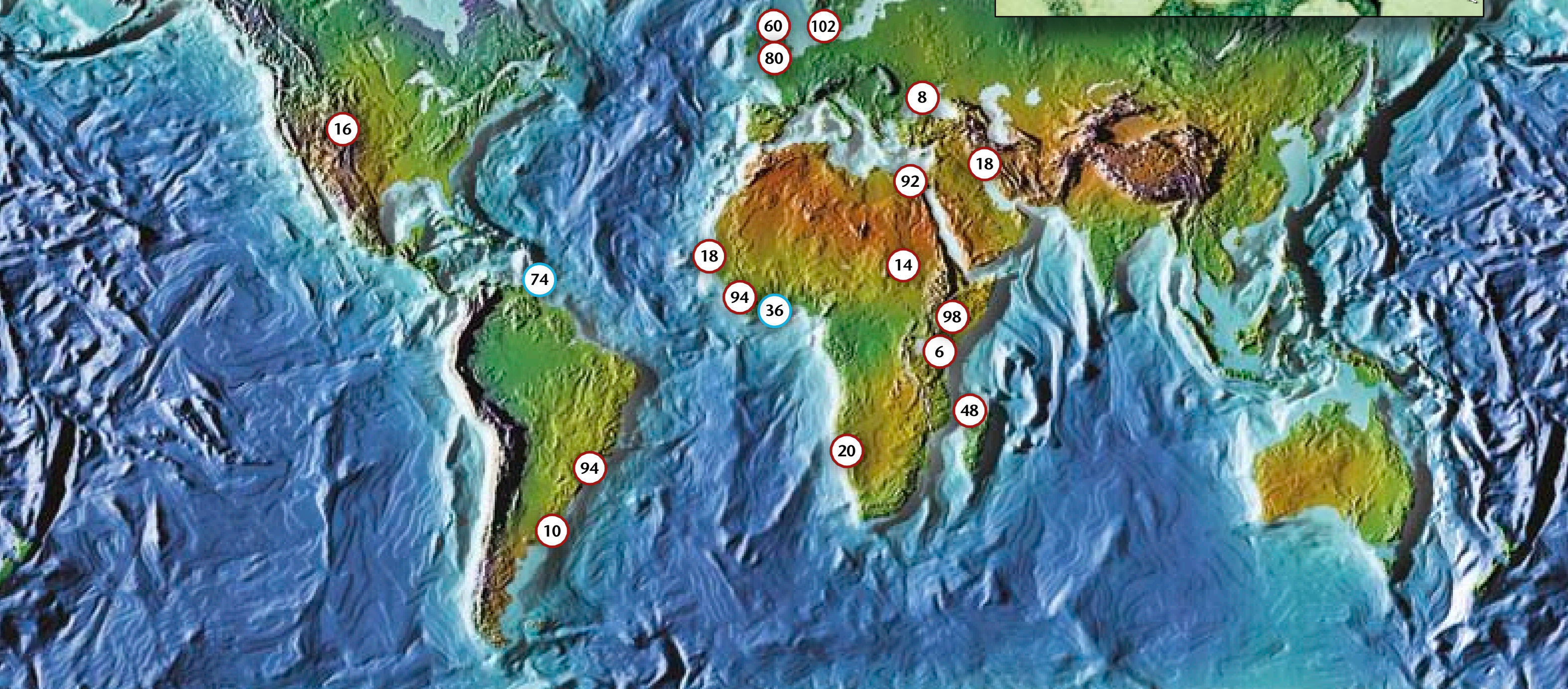


Africa and New Technologies

Ghanaian President John Evans Atta Mills opens the valve for First Oil on the Jubilee field in December 2010

Africa and new technologies: the focus of this edition of *GEO ExPro* magazine and a very appropriate juxtaposition of ideas. Many of the most exciting discoveries in the last decade have been in Africa – and technological developments have been key to a good number of them.

Back at the turn of the century there was a lot of talk about the gas potential of the deep waters of the Nile Delta in the Mediterranean Sea, an area that has since proved very prolific, with latest USGS estimates suggesting that there are still about 223 Tcf of gas to be found. One of the keys to unlocking this region was the use of multi-azimuth seismic, then in its infancy but now, along with wide-azimuth seismic, accepted as standard procedure for detailed prospect investigation.

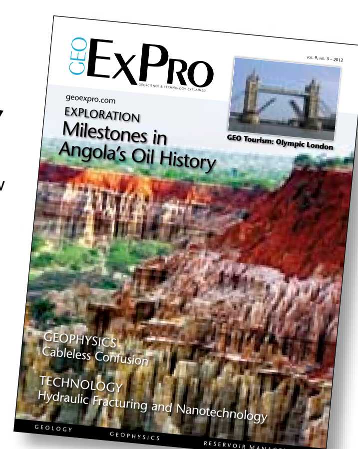
The excitement travelled westwards – initially to the deep waters off Ghana, and then following additional discoveries further to the west along the West African Transform Margin. Once more, improvements in seismic acquisition technology as well as in processing and imaging techniques, outlining, for example, significant AVO anomalies, made an important impact on these discoveries. Advances in drilling capabilities were also crucial to enable effective exploration in such deep waters, leading to time from discovery to first oil for the Jubilee field to be a mere three and a half years.

Interest has now moved to East Africa, where there have been major discoveries both offshore, particularly in Mozambique, and onshore in the Rift Valley areas of Uganda and Kenya. Recent technological developments in seismic acquisition and processing, as well as the introduction of non-seismic techniques such as full tensor graviometry, are believed to be partly responsible for these recent successes.

In this edition of *GEO ExPro* we look in more detail at some of these areas, but also at technological developments which could revolutionise exploration in parts of the world which have been stepped over in the search for hydrocarbons, as much of Africa had been a decade ago. New ways of viewing the subsurface, whether through innovative seismic imaging or using the next generation of facies modelling, will all have their part to play in helping to unlock and exploit much needed resources in the future.

JANE WHALEY
Editor in Chief

MILESTONES IN ANGOLA'S OIL HISTORY



Miradoura da Lua (Portuguese for 'Landscape of the Moon') on the Atlantic Ocean coastline, 30 km south of Luanda. The outcrops of Miocene-age shallow water marine sediments located seen here are stratigraphically equivalent to the Tertiary (Miocene and Oligocene) strata in the deepwater area of the Lower Congo Basin which contain the prolific turbidite reservoirs that produce about three-quarters of Angola's approximately 1.9 million barrels of oil per day. A thick layer of red lateritic clay overlies the Miocene sediments. Recent sub-salt discoveries in the deep waters of the South Atlantic promise to further revolutionise output from this well established petroleum-producing country.

Inset: With the Olympics upon us it is an appropriate time to reveal the geology of London for our visitors.

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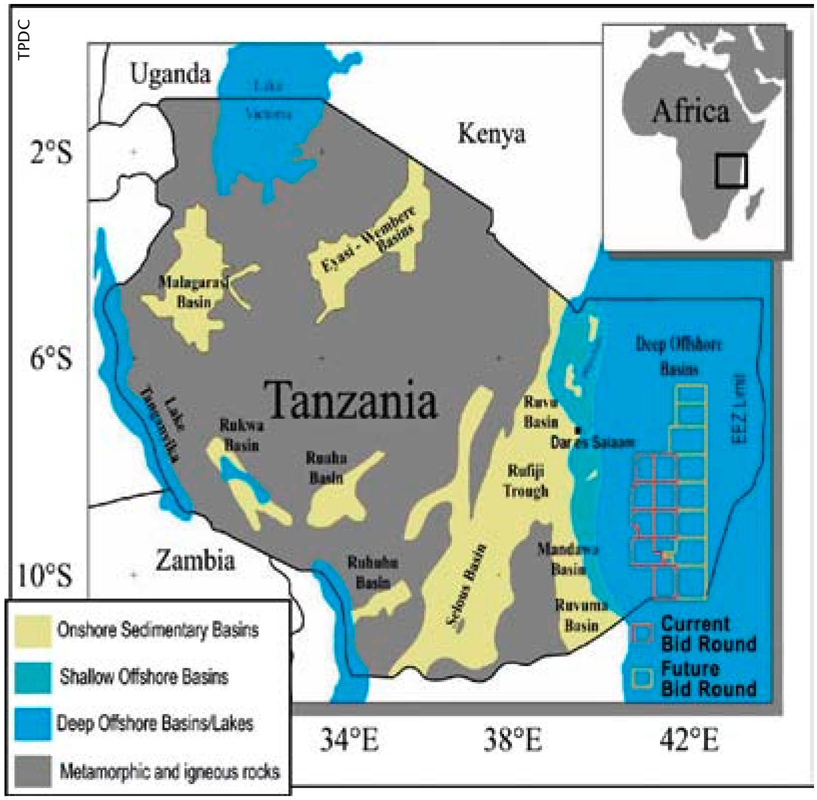
GEO ExPro is published bimonthly for a base subscription rate of GBP 60 a year (6 issues).
We encourage readers to alert us to news for possible publication and to submit articles for publication.

Cover Illustrations:
Main Image: Henriette Koning
Inset: Antony Slater

Layout: Bookcraft Ltd.
Print: NXT Oslo Reklamebyrå

issn 1744-8743

New Offshore Licensing Round for Tanzania



Four main categories of sedimentary basins are recognisable in Tanzania: inland rift basins, coastal basins, shelf and shallow offshore basins and deep offshore basins

With recent discoveries in East Africa dominating the news, the government of Tanzania is expected to get a lot of interest in its 4th Offshore Bid Round, due to be launched in September. The Round will cover eight offshore blocks in waters between 2,000m and 3,000m deep and which vary in size from 2,545 km^2 to over 3,600 km^2. They lie east of and close to areas which have already been found to be prospective, with estimated reserves of 5 Tcfg in Block 1, close to the southern border with Mozambique, and a similar volume in the adjacent Block 2, which includes the promising Zafarani discovery, made in February this year. Of the six wells drilled offshore in 2011–2012, five found commercial quantities of gas.

This will be the fourth offshore bid round for Tanzania. The first took place between June 2000 and April 2001, when only one of the six offered blocks was taken up, by Petrobras. Things improved in the 2nd Round, in July 2002, when four out of 11 blocks were awarded, all to Shell. A 3rd Round in 2005 resulted in take-up of three blocks, and two further blocks were directly awarded to Ophir Energy a year later. The remaining two blocks were awarded to Dominion Petroleum and Petrobras in 2007 and 2011 respectively. Since then, there have been a number of relinquishments and these, plus areas never offered before, are included in the new bid blocks.

A number of plays, both stratigraphic and structural, have been identified from seismic in the offshore area. Reservoirs ranging from Tertiary to Upper Cretaceous have been tested, with channels, fans and turbidite systems all expected to be present. Source rocks are thought to be Jurassic and Cretaceous, and there are ample supplies of shales and siltstones to act as cap rocks. To date, seven wells have been drilled in the deepwater offshore, resulting in five discoveries: Pweza, Chewa, Zafarani, Chaza and the most recent one, Jodari, found in March 2012. This last is considered to have recoverable reserves in the region of 5 Tcfg, and proved the viability of the outboard basin fan play, so productive in neighbouring Mozambique. None of these offshore fields are yet in production, but the cumulative discovered gas resource in Blocks 1, 2 and 4 is now about 10 Tcf, approaching the minimum required for a two-train LNG development.

With this in mind, Tanzania has been looking to improve its hydrocarbon infrastructure. The processing plant at Mnazi Bay, one of only two onshore producing fields in the country, near the Mozambique border, has been expanded to increase capacity from 10 MMcfgpd to 21 MMcfgpd. Mtwara Base Supply Port, close to the discoveries in south-eastern Tanzania, has also been upgraded as an oil and gas supply and logistics base. In addition, a 580 km long 36" gas pipeline from Mtwara to the capital, Dar es Salaam, the longest in the country, is currently under construction.

Plenty of Data Available

The Tanzania Petroleum Development Corporation (TPDC) is working with seismic company ION/GX Technology in preparing a data room for the duration of the Round, and data packages will be available to interested companies. In recent years ION/GXT has acquired and processed a significant amount of regional 2D seismic offshore Tanzania as part of its multiclient East AfricaSPAN project, which includes about 5,000 line kilometres across the offered area. In addition, ION are about to commence infill lines to help map leads, and a refraction survey is underway in order to attempt to delineate the limit of ocean crust. Piston coring of the seabed in the vicinity of known oil seeps will also be undertaken in the next few months. About 11,000 line km of good regional PSTM and PSDM 2D seismic dataset will also be available. The data is being re-processed from Post-Stack Time Migration to Pre-Stack Time and Depth Migration.

The 4th Tanzania Licensing Round will be officially launched on 13 September during the HGS/PESGB Africa Conference in Houston, which will be followed by road shows at AAPG ICE in Singapore, in London in October and at the East African EAPC conference in Arusha, Tanzania in March 2013. Further information can be obtained from TPDC website, www.tpdc-tz.com and on www.tz-licensing-round.com. ■

Effective Data Management Maximises Subsurface Asset Values

An Exploration and Production organisation generates vast amounts of data in order to define and value its subsurface assets. But ultimate value will only be maximised if critical business decisions are made correctly, based upon the knowledge and understanding that data can provide.

Effective data management is the key to correct and timely decision making. It provides the right information, to the right people, in the right place, at the right time, delivering the best outcomes based upon true insight. If the mistakes of the past, like bad drilling decisions or incorrect reserves estimates, can be avoided, the potential values of the future are more accurately assessed.

However, implementing consistent data management practices in an organisation is complex and challenging due to the sheer volume of data, the mixed vendor environment, and the multi-disciplinary and dispersed location of data users and keepers. A structured but flexible, vendor-neutral solution must be developed, based upon three fundamental processes. These are data discovery; organisation; and preservation.

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Data Discovery

The vastness of the data and the tendency of some users and applications to store data in diverse places can make it difficult to obtain a complete picture of an asset. Data can exist on user workstations, external hard drives and dedicated file stores. Discovering and understanding exactly what is available can be achieved by profiling file systems with a fine level of detail and application awareness. Utilising a combination of data points from applications, projects and file contents will enable inter-related data to be captured and correlated. This may also identify previously unknown data that can contribute to a better valuation of the asset. It is important that factors such as the frequency of data access, duplication and the relationship between dispersed data sets are considered within the discovery process.

Organisation

Efficiently structured data sets improve the management of assets by increasing the speed of access, improving accessibility and ensuring that complete projects can be relocated, perhaps for a divestment or portfolio re-organisation. When the full spectrum of data is identified and understood, it can then be organised appropriately. This should follow a logical structure that mirrors the taxonomy and processes of the business.

When performing any restructuring it is essential that the referential integrity of the data sets is maintained, capturing references to external data sources where possible. A highly effective approach for this is intelligent integration to the very applications that manage the data.

Preserve and Retrieve

Asset data, such as that captured during a seismic survey, collected from the well site or interpreted data, doesn't have a set expiry date beyond which it is no longer useful. Indeed data can evolve, changing hands and value many times, with factors such as fluctuations in oil price, regulation, compliance, acquisition or divestment all affecting its currency and relevance. Exactly what to preserve and for how long is a key business decision. Keeping everything is costly, but not keeping enough may be much more costly. The challenge is to define and keep the valuable data and enable decision makers to retrieve it quickly, efficiently and effectively.

Most asset data needs to be kept for a long time. Regulatory requirements can mandate retention of data for life of field plus seven years. Reserves estimation data should be quickly and easily reproducible on the demand of auditors within an alarmingly short period of time. However it is not always feasible to store all data online. Free space is at a premium but typically 80% of network attached storage has not been accessed for over six months. A structured archiving methodology can be adopted, to move infrequently used but still valuable data to more cost-effective disk or tape storage. Much of the data will be inter-related, yet it can securely reside across multiple file stores. Where data is managed by applications, a vendor neutral approach will ensure that consistent levels of detailed information about the data or 'metadata' is captured and complete referential integrity maintained. To allow everyone, not just data owners, fast location and retrieval of quality data with good provenance, it is crucial to catalogue the data logically and to capture high quality metadata during this process. This can be captured manually, including the wisdom only in people's heads, and automatically from the managing applications, complemented by a process of content indexing.

These sound data management practices, enabled by specific software and process solutions, drive long term oil and gas asset values. They deliver clarity and control of information along with knowledge of the past and present while being ready for the future. Critical decision making is enhanced and the enterprise is enabled to react more quickly to change and to compete more effectively in the marketplace. ■

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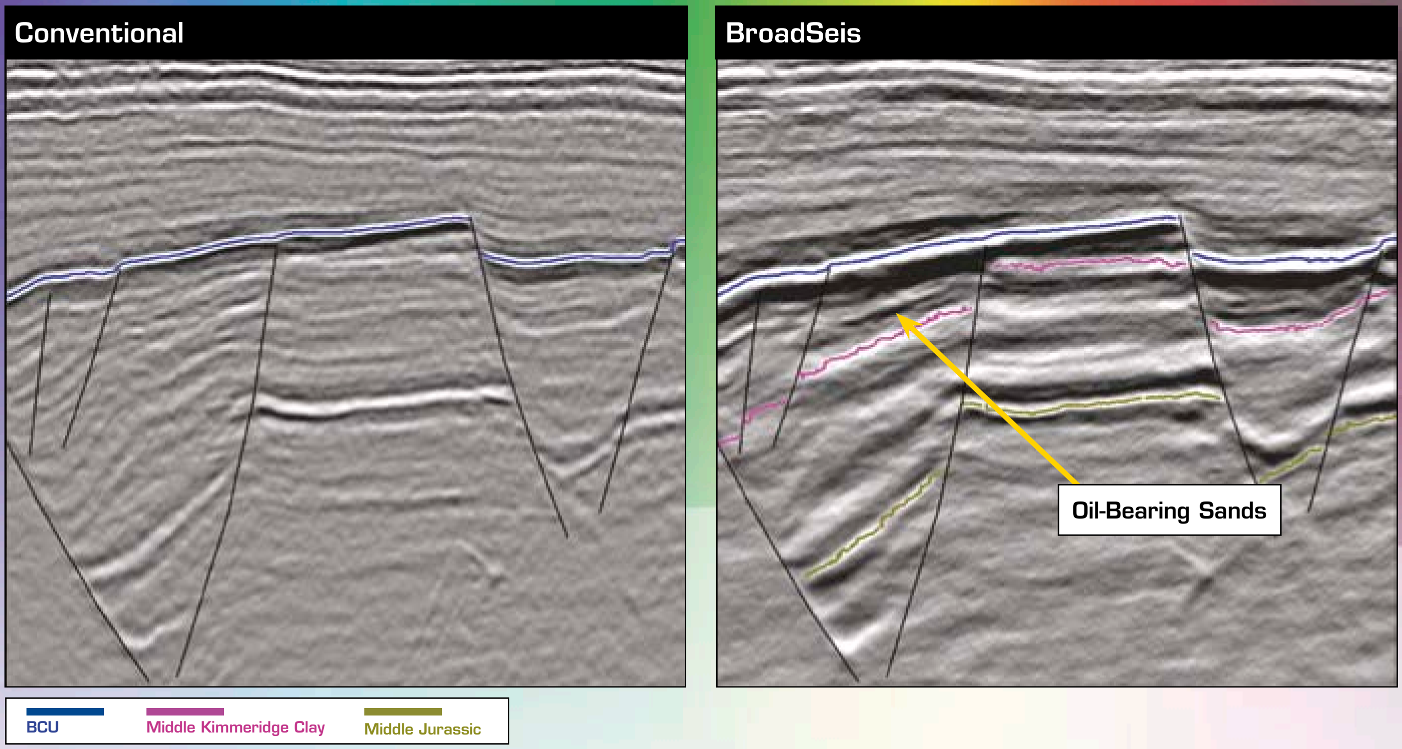
BroadSeis - Enhancing Interpretation



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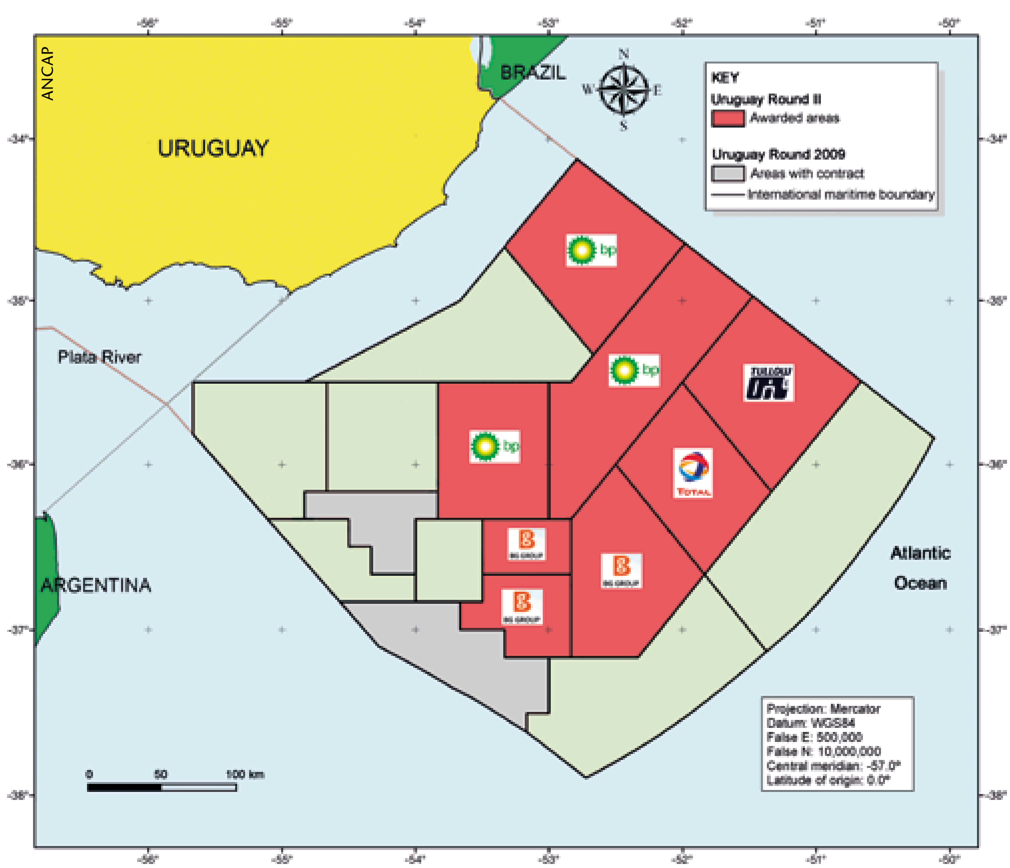
Uruguay Round II Awards Offshore Acreage

Uruguay's state oil company, ANCAP, has recently awarded offshore blocks in the Round II bidding to British companies BP and BG, French company Total, and Irish company Tullow Oil. These four organisations are all new players for the area and will add to work already being done by Petrobras, YPF and GALP on two offshore blocks previously awarded in 2009.

A total of 19 offers were received in 8 of the 15 blocks that were offered for exploration. ANCAP eventually received bids from 9 of the 11 oil companies that had qualified, with competition between three or more companies in five of the blocks. Blocks in all three Uruguayan offshore basins, Oriental del Plata, Punta del Este and Pelotas, were awarded. ANCAP will assess the successful bids and sign contracts with the winning companies by September 2012.

ANCAP retains between 22% to 35% interest in each block. The winning companies have a total exploration period of eight years, which is divided into three sub-periods. The Committed Exploratory Program that should be completed in the first three-year period includes 2D and 3D seismic surveys, electr omagnetism surveys, sea bed sampling, and additional seismic data processing. Only Total, on Block 14, has committed to the drilling of an exploratory well in the first period. The second and third sub-periods should include at least one exploratory well. The terms of the contract shall be 30 years and may be extended 10 additional years. ■

THOMAS SMITH



ABBREVIATIONS

Numbers
(US and scientific community)

M: thousand	= 1 x 10^3
MM: million	= 1 x 10^6
B: billion	= 1 x 10^9
T: trillion	= 1 x 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

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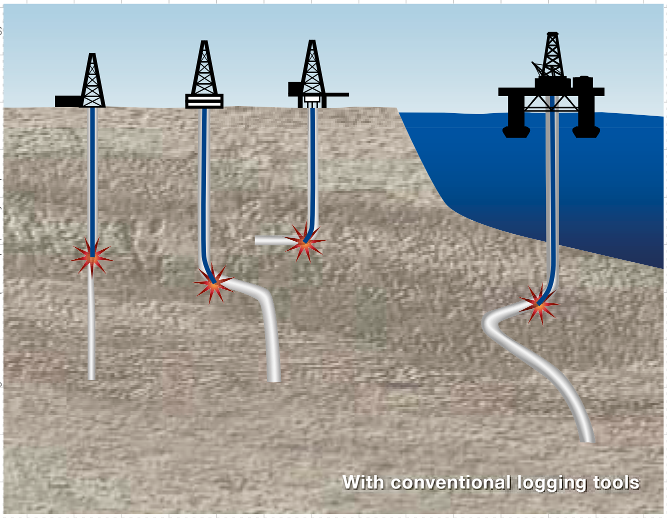

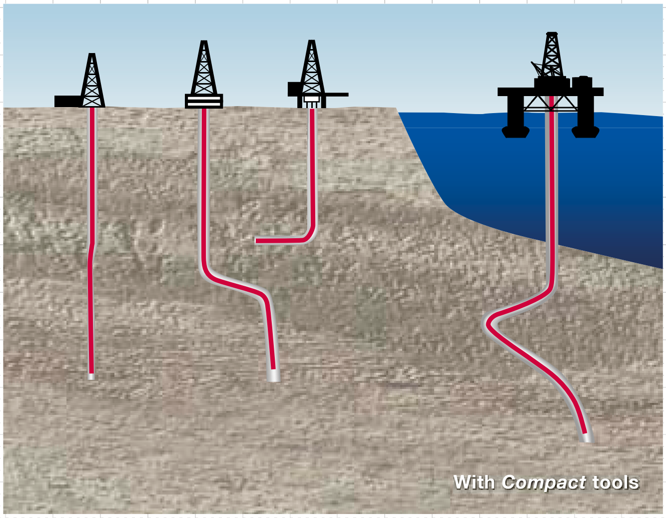

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Geology Without Limits!

Cross border co-operation leads to better geological understanding

As we all know, geology does not follow political boundaries. To undertake a wide-ranging geological study of a large region presents challenges, so finding a modern comprehensive review of an area such as the whole of the **Black Sea** is rare. To solve this issue, a number of scientific institutions and organisations have got together to form **Geology Without Limits**, in order to conduct international marine scientific programmes aimed at exploration and understanding of the geology of world basins and major geological elements of the Earth's crust.

As Eugene Petrov, Senior Geoscientist with Regional Geophysical Exploration Ltd. in Moscow, which is co-ordinating the programme, explained: "Much of the Black Sea is well studied already, by many people, but the different authors tend to be subjective, and may not be basing their conclusions on modern technology. In order to combine all the available information, it is necessary to build a new tectonic model of the area. Conducting regional investigations is a multi-layered and complex process."

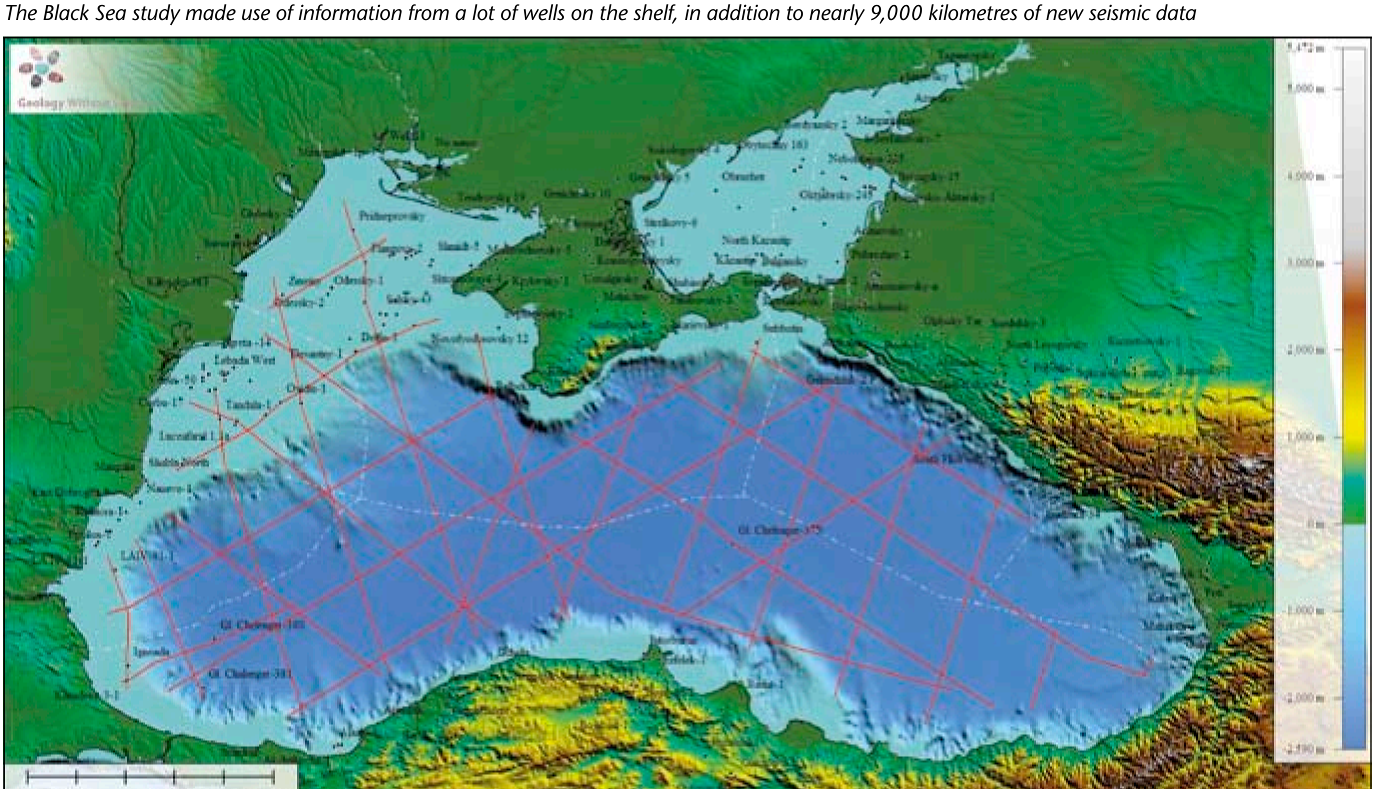
The institutes involved in the Black Sea study come from Russia, Bulgaria, Romania, Ukraine and Turkey. Between them they have provided large volumes of vintage data to the study, as well as plentiful well information, the latter primarily confined to the shallow shelfal areas, which does not reflect the geological composition of the whole structure of the region. This data is therefore being augmented by the acquisition of about 8,900 line kilometres of high quality modern long offset (10,200m) seismic with powerful and specially tuned sources, designed to increase penetration. In this way the study has been able to investigate the poorly studied lower part of the sedimentary cover over the Black Sea depression, with processing focussed on depth horizons not observed in earlier investigations, using new velocity models. The results produced images to a depth of 18 km, from the Lower Cenozoic to the Triassic and Palaeozoic, providing new information on the Cenozoic structure, geodynamics and history of the Black Sea region as well as insights into its pre-Cenozoic evolution. Data processing was completed in January 2011, and the research was finalised in November the same year. Results are being presented at the EAGE in Copenhagen.

A second phase of the Black Sea programme will extend the study with the use of seismic refraction and ocean bottom sampling, particularly in the vicinity of gas volcanoes and chimneys, to clarify understanding of the major structural elements of the basin and construct a merged, updated tectonic-geodynamic model of the platform domains of south-eastern Europe.

Further co-operative projects are being planned, with a regional study leading to a tecto-dynamic model of the Caspian Sea already under way, involving research organisations from Russia, Azerbaijan, Kazakhstan, Turkmenistan and Iran so far. The study is due to be completed by 2014. And further from home, Geology Without Limits is planning a study of the Caribbean Basin, in which the Russian institutes will co-operate with scientific organisations from more than 30 countries bordering that major region. This project will study interrelationships between continental and oceanic crust blocks, the role of strike-slip and thrust tectonics in regional structure and the distribution and structure of carbonate platforms, among other topics.

JANE WHALEY

The Black Sea study made use of information from a lot of wells on the shelf, in addition to nearly 9,000 kilometres of new seismic data

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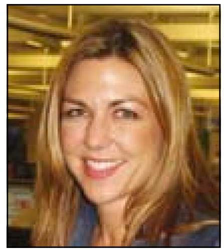
Sudan and South Sudan Conflict Increases Pressure on Oil Prices



THINA MARGARETHE SALTVELT, PH.D

On 9 July 2011 when South Sudan finally gained independence from Khartoum, we warned against the risk of increasing political tension as several critical issues had not been resolved before the separation. Unfortunately, we were too right in our warning. Disputes over oil fields near the border, citizenship and transit fees continue to undermine the transition, and many are now warning that a war may be closer than at any time since the 2005 peace deal that ended five decades of civil war.

According to the US Energy Information Administration Khartoum began to divert South Sudan's Nile blend crude to its Khartoum and el-Obeid refineries in December 2011, primarily as a result of the impasse on transit fees. South Sudan responded by shutting in 350 Mbopd of oil production until a fair deal was reached on transit fees, or an alternative pipeline was built. Border clashes between the two countries have damaged key installations at the Heglig oil field with 60,000 bpd of Sudan's output still shut in.

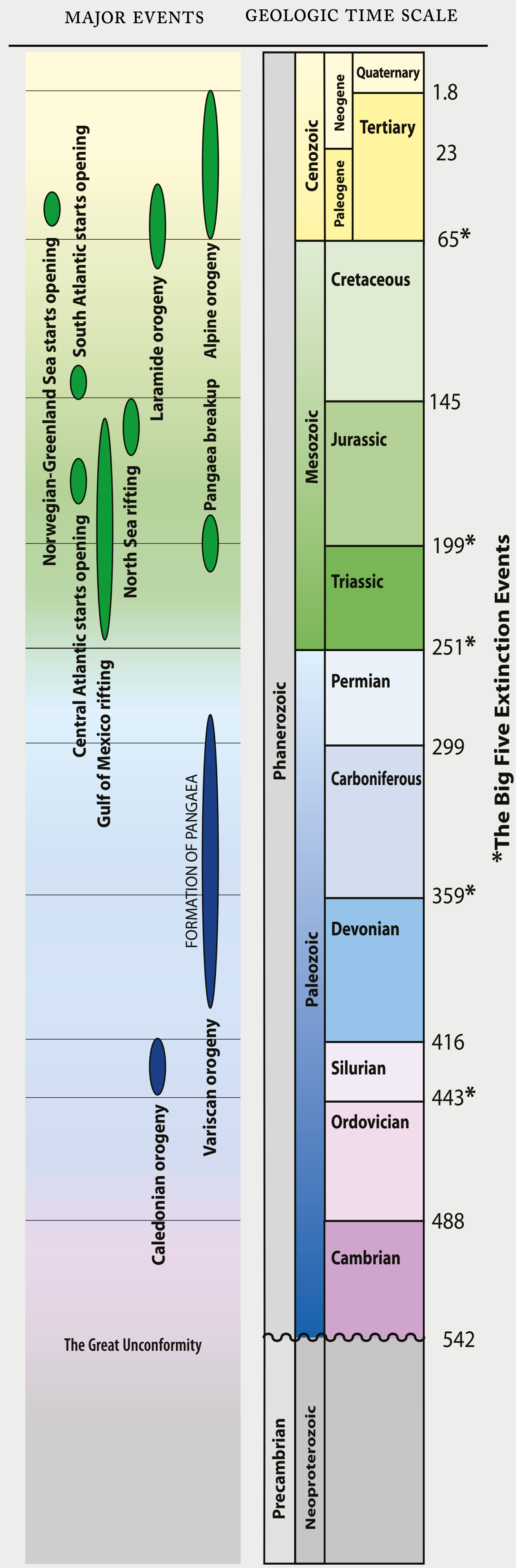
Although the two countries together account for only 0.6% of global oil production, the oil supply disruptions add to an already stretched OPEC spare capacity buffer as the sanctions against Iran, oil production outages in Yemen and Syria and the threat of a conflict in the Middle East have cut the buffer markedly since October last year. Sudan and South Sudan combined exports averaged 330 Mbopd in 2011 and went almost exclusively to Asian markets.

Sudan recently issued a resolution declaring a state of emergency in border districts in the south of the country. Without any near-term significant breakthrough in the negotiations, South Sudan's production outage may last until the end of the year and continue to support a higher risk premium and thereby higher oil prices. The more severe the damage made to oil installations on both sides of the border, the longer it will take to restart oil production and the more the oil production shut-ins will weigh on global spare capacity. A longer-lasting conflict will therefore push up the risk premium and thus prices for longer-dated oil contracts.

According to the *Financial Times*, South Sudan is one of the poorest countries in the world, and the dispute between the two countries has already halted nearly all oil production that underpins both economies. Oil represented over half of government revenue and 90% of export earnings for Sudan. For South Sudan, oil represented 98% of total revenues. The International Monetary Fund has projected that real GDP growth for Sudan will fall by 7.3% in 2012, the fiscal deficit will fall to 3.9% of GDP and the current account to -4.6% of GDP. Currency depreciation and non-food commodity shortages are expected to push inflation to 26% in 2012.

While about 75% of oil production originates from South Sudan, the export, pipeline and refining infrastructure is located entirely in Sudan. To become less dependent on its relationship with its northern neighbour, a 1,400 km pipeline to ship oil from South Sudan to a new port in Lamu in Kenya or to Ethiopia has been proposed. For the pipeline to be economically viable South Sudan needs a major boost to output. With neither political stability nor proper legal infrastructure expected in the near term, companies will likely remain reluctant to undertake major investments.

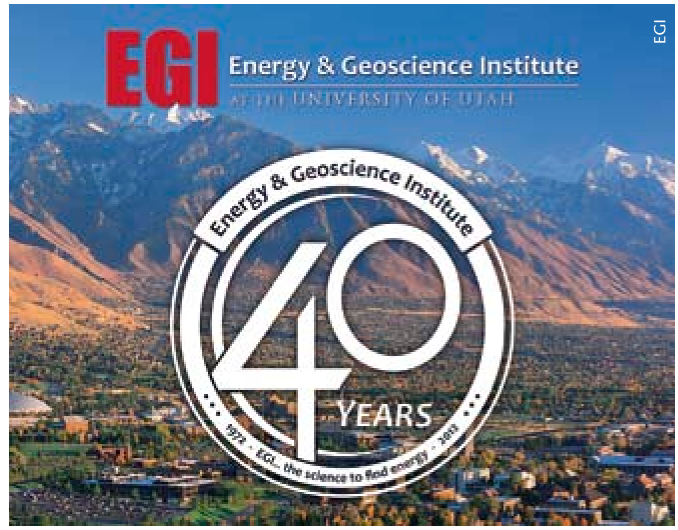
In a worst-case scenario South Sudan's oil production could decline markedly within the next five years unless the political climate changes, and longer-dated oil prices will increase to reflect a tighter supply side. ■



EGI: Celebrating 40 Years

EGI, the Energy & Geoscience Institute at the University of Utah, in Salt Lake City, is celebrating 40 years of global research and scientific collaboration. It is the world's largest university-based industry cost-shared upstream research programme, with more than 70 member companies from over 20 nations. EGI has over 100 scientists and staff, based in Utah, Slovakia, Canada, Australia and the UK but who hail from throughout the globe and speak a total of 24 languages.

The core research areas of the organisation are hydrocarbon resources, geothermal energy and carbon science and engineering. Over the years it has produced more than 750 reports, involving research from all the continents. Current hydrocarbon projects in progress include a study of liquids from shales and an analysis of the Mesozoic Facies of Ghana. The organisation boasts one of the strongest carbon science research groups at any university, and also the largest university-based geothermal research group in the United States. EGI scientists and researchers focus both on exploration for new geothermal resources and the appropriate development and management of discovered resources.



EGI also owns a huge database accessible by its **Corporate Associate Members**. This includes over 350,000 km of 2D seismic from 60 countries, and thousands of well locations and logs, as well as the projects and reports, delivered rapidly and securely online. ■

New App for GEO Expro

GEO Expro magazine is excited to announce that it has developed an application for tablets for the entertainment of all those avid readers who want to be able to access their favourite magazine wherever they are, taking advantage of the ground-breaking interactive possibilities that this format offers.

The initial issue, due out in early June, will contain all the most popular articles from the first three editions of 2012, but with additional material such as interactive videos, animations, maps and photographs to enhance the original stories. There will also be links to sites which will provide supplementary information to allow you to delve deeper into any subject which has caught your imagination. And with interactive advertisements as well as articles allowing you to pull up maps, wells and seismic lines, for example, simply by touching the screen, you will want to explore every page and facet of this amazing new product.

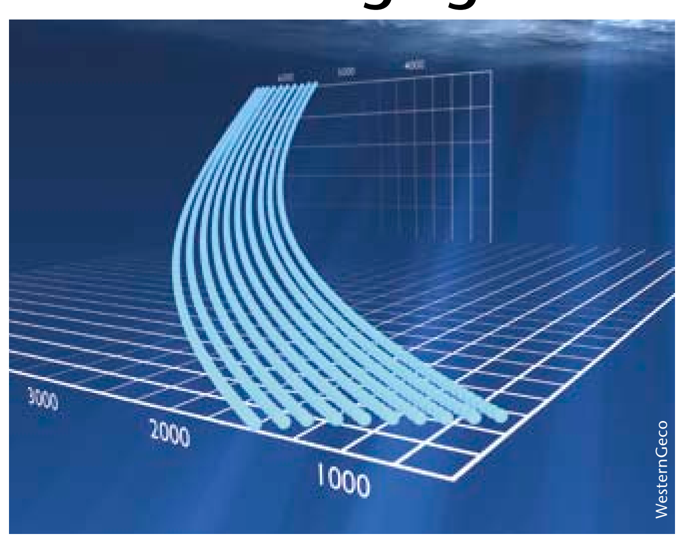
The new **GEO ExPro App** will be available as a download from the standard Newsstand. Don't have a tablet yet? Just come along to the **GEO Expro** booth (1006) at the EAGE in Copenhagen, pop your card in the collection box and you may find yourself the lucky owner of a brand new one. ■

ObliQ Technology Improves Seismic Imaging

In a marine geophysical survey, every attempt is made to maintain the streamer at a constant optimum depth. But there are issues involved in selecting that optimum depth; too shallow, and the record tends to be noisy; too deep, and a ghost notch appears in the useful bandwidth of the seismic signal.

WesternGeco has now introduced its **ObliQ** technology to help solve his problem through its unique sliding-notch broadband acquisition and imaging technique, which enhances low-frequency content of marine seismic data without compromising high frequencies. It achieves this by using a variable cable depth, which increases from the near offset to the farthest offset. The minimum and maximum cable depths can be determined in the survey design and selected to optimise the recorded bandwidth to meet the geophysical objectives of the survey. In surveys that use this technique, streamer depths range from 5m to 50m – a wider selection of depths than available in conventional acquisition.

The ObliQ technique de-ghosts data acquired with a variable streamer depth by using a workflow that improves the low-frequency content while maintaining the high-frequency content. This process minimises the effect of the receiver ghosts on the pre-stack data and so allows us to re-datum the cable to a constant depth and process the now de-ghosted data in a conventional fashion. ■



The ObliQ technique de-ghosts data acquired with a variable streamer depth.

Iraq Investment Set to Increase

The energy sector in **Iraq** is predicted to see investment of a minimum of **US$50 billion** over the next five years amidst a gradually improving security situation, according to a newly released comprehensive report. Iraq remains the largest and most underdeveloped oil nation in the world today, with fewer than ten wells drilled annually since 1980 and only 25% of the country comprehensively explored, according to EIC Consult, the market research and consultancy arm of the UK Energy Industries Council.

The report found that, despite continued concerns over security, political instability, and the lack of a settled investment environment, a proposed infrastructure overhaul and ambitious plans to increase oil and gas production present huge opportunities for service providers at every stage of the supply chain. It states that, as of 2011, Iraq had around 80 commercial oilfields and daily oil production of about 2.65 MMbopd, which the report believes will rise to between about six and eight MMbopd by the end of 2017. It stresses, however, the urgent need for a binding national hydrocarbon law, federal oil investment and revenue sharing agreements. The report concluded that there are few locations on a global scale that can offer the size and quality of hydrocarbon reserves as Iraq. ■

Extended North West African Margin Survey

Since May last year, **Dolphin Geophysical** has been acquiring long-offset, high specification, regional 2D data along the **North West African Atlantic Margin** (NWAAM). Initially covering Guinea, Guinea-Bissau, Gambia and the AGC zone shared between Guinea-Bissau and Senegal, in July 2011 the survey was extended into Senegalese waters.

In March this year the company announced that a further agreement had been made with the government of Mauritania to continue the survey to cover deepwater acreage off that country. These additional data will increase the total for the NWAAM project to around **26,000 line km**, encompassing over 1,600 km of coastline from northern Mauritania to southern Guinea Conakry. It provides the only continuous, conformable, long-offset, well-tie, regional dataset in this underexplored but potentially prospective area.

Dolphin has agreed with Petrosen, Senegal's National Oil Company, that it will also acquire, process and market a new 3D multi-client survey over deepwater acreage in the Senegalese offshore. These new long-offset data, totalling about 3,600 km^2, is due to be completed by mid-May. The survey is designed to image potential submarine turbidite fan plays and will complement the large 2D dataset of the NWAAM 2D Regional Survey.

This major project is a joint venture between Dolphin Geophysical and TGS. Data will be processed in the UK by the latter, and a regional interpretation study is already underway. Road shows are being scheduled in London and Houston later this year when representatives from each of the governments will be present to promote available acreage and hold private discussions with interested companies. ■


Dolphin Geophysical

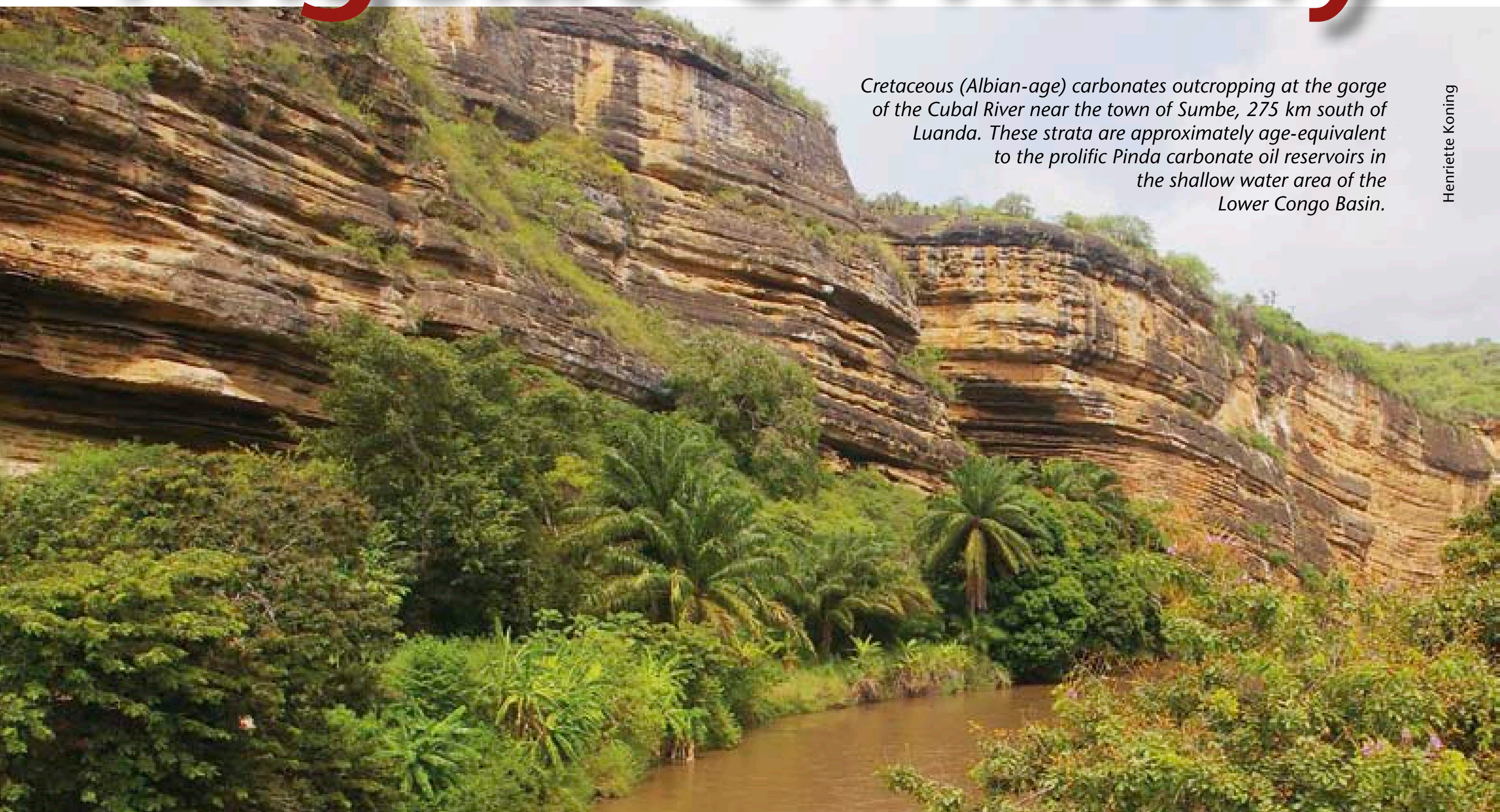
The NWAAM survey is being conducted by the seismic vessel, Polar Duke

ARKeX Goes Multi-Client

Within the hydrocarbon exploration industry, the market for gravity gradiometry has grown substantially over the past few years. **ARKeX**, which specialises in non-seismic geophysical imaging, has become one of the major players in this market through its proprietary surveys. It has therefore decided to launch a new business area which will focus on multi-client full tensor gravity gradiometry (FTG) surveys, making the technology available to a wider customer base and enabling more clients to benefit from the enhanced resolution of gravity gradiometry. One of the first multi-client projects planned is a 50,000 km^2 survey offshore Greenland in conjunction with ION Geophysical Corporation.

The multi-client data library, which includes gravity and magnetic data as well as gravity gradiometry, can be accessed via ARKeX's new website at www.arkex.com. ■

Milestones in Angola's Oil History



Cretaceous (Albian-age) carbonates outcropping at the gorge of the Cubal River near the town of Sumbe, 275 km south of Luanda. These strata are approximately age-equivalent to the prolific Pinda carbonate oil reservoirs in the shallow water area of the Lower Congo Basin.

Henriette Koning

TAKO KONING

Angola is set in the next decade to overtake Nigeria as the biggest oil producer in Africa.

We look at the milestones in the country's rapidly expanding oil and gas industry.

The oil and gas plays found in Angola range from the pre-salt to the post-salt and include Tertiary-age clastic turbidite reservoirs, salt-rafted Cretaceous age Pinda carbonates, and pre-salt microbalitic carbonates similar to Brazil's giant Tupi oil discovery. Many of these have only been identified since the turn of the new century, and these wide-ranging, high potential plays have led to a dramatic surge in Angola's oil production.

A decade ago, the country was producing approximately 750,000 bopd, while now production of almost 2 MMbopd has been achieved. Angola is already the second biggest oil producer in Africa after Nigeria (which is currently producing about 2.4 MMbopd), but its highly favourable petroleum geology means that within the next decade it is expected to replace that country as Africa's top oil producer.

Historic Milestones

The first milestone in Angola's petroleum industry occurred in the late 1700s when the Portuguese colonialists discovered oil seeps and asphalt deposits at Libongos, about 60 km north of Luanda, and shipped some of the oil to Lisbon and Rio de Janeiro to be used as caulking material to prevent water leakage into their ships. Libongos is located on the eastern edge of the Kwanza Basin, within half a kilometre of outcrops of Precambrian granites.

The year 1915 marked the next important milestone for Angola when the Portuguese oil company, Companhia de Pesquisias Mineras de Angola, carried out the first drilling for oil in the valley of the Dande River, near the coastal village of Barra do Dande, about 40 km north-east of Luanda. One of the wells, Dande-4, drilled in 1916, was tested at 6 bopd and

The author standing in front of the Libongos oil seeps near Caxito, 50 km north of Luanda in the north of Angola. These seeps have been known for several hundred years.

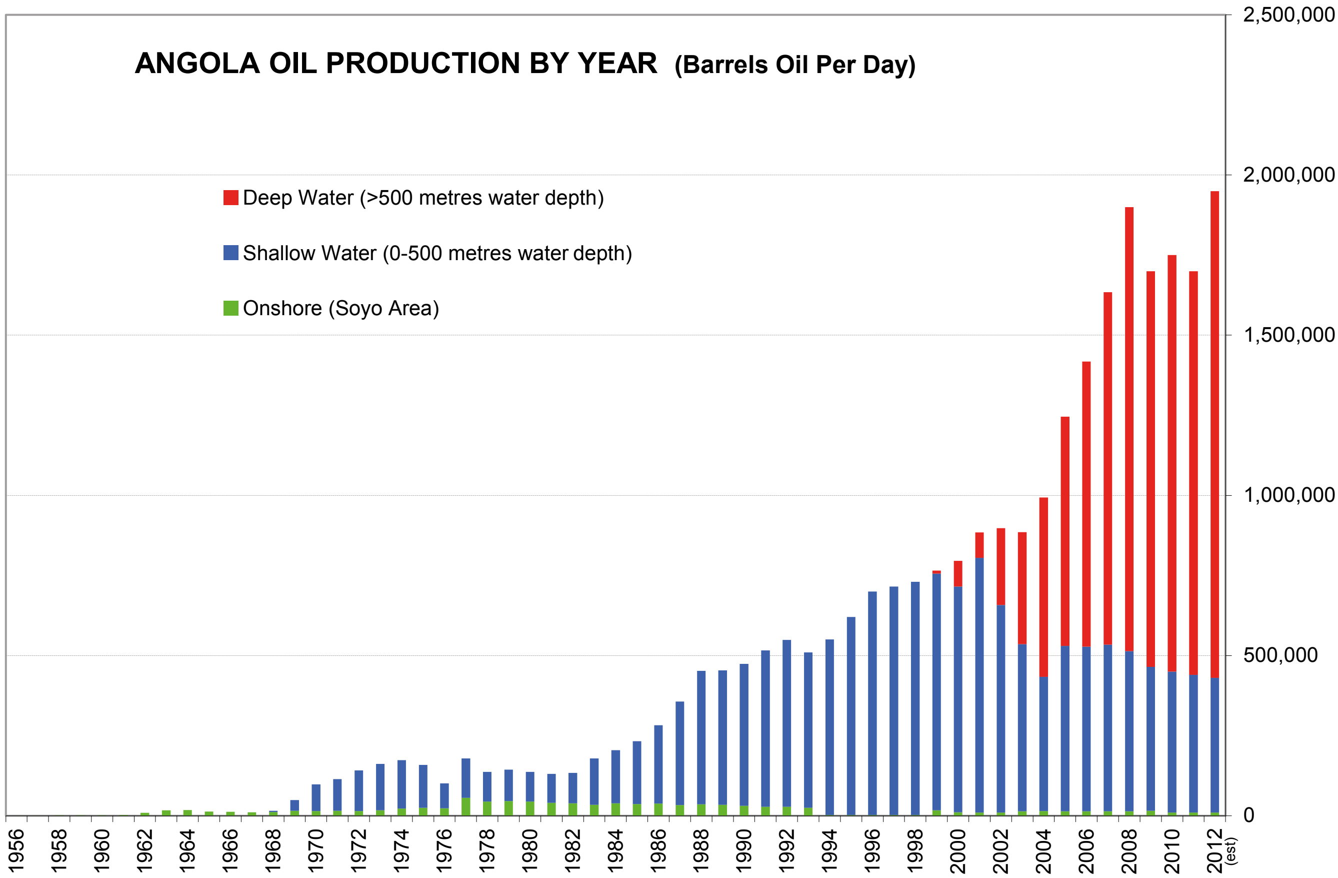
was subsequently abandoned, but it signified the first flow of oil in Angola.

Drilling for oil in the onshore Kwanza Basin continued sporadically for the next forty years but with no commercial success until 1955, when the Benfica-2 well just south of Luanda resulted in the first commercial oil discovery in Angola. The field went on production in 1956, representing the beginning of oil production in Angola. The first offshore oil field in Angola, Malongo, was discovered ten years later in 1968 in Cabinda by the American company, Cabinda Gulf Oil Company. Chevron bought Gulf Oil in the early 1980s and the company is still an operator, now producing approximately 500,000 bopd from just two blocks offshore Cabinda.

Angola's long-drawn-out civil war, which lasted from independence in 1975 until 2002, undoubtedly slowed down onshore exploration, so international companies concentrated on the offshore during these years. Angola was producing about 700,000 bopd by 1996 when another historic event happened: the French oil company Elf Petroleum discovered the Girassol oil field in Block 17 in deep waters (1,300m), about 140 km off the coast of Angola. This discovery stunned the oil industry, since finding oil so far from the coast and in a new geological formation was totally unexpected. Additional drilling by Elf proved Girassol to be a giant size field, with the oil-bearing reservoir located in Oligocene sandstones and conglomerates which had been deposited as turbidites. This led to many more such discoveries in the Oligocene and Miocene (15 Ma) in the deep waters off Angola, including by Chevron, Esso, Maersk, Total, BP and Sonangol P&P. As a result, about 75% of Angola's production now comes from such reservoirs. Had Girassol and the follow-up fields not been discovered, Angola would have remained merely a modest oil-producing country with production of only about 500,000 bopd – now it is an important one.

Looking Across the Atlantic

The discovery of the Tupi oil field on the other side of the southern Atlantic in Brazil in 2007 was an historic event for the oil industry. Tupi was drilled by Petrobras in the deepwater part of the Santos sedimentary basin in water depths of 2,100m. It was drilled to a depth of about 5,200m below the sea floor, giving a total drill depth of the well of 7,300m; it had many mechanical problems and the final cost was $240 million. But the costs were justified by the results. Tupi is estimated to hold eight billion barrels of recoverable oil reserves in a high pressure, high temperature environment beneath a massive salt sheet over 2,000m thick. Tupi (now renamed Lula after Brazil's ex-President Lula) proved to be the first of the now famous pre-salt oil



Angola's oil production was considerably boosted by the discovery of the deepwater fields, starting with Girassol, which began producing in 2000
Source: Sonangol Universo magazines, SPE Journal of Petroleum Technology (JPT), Energy Administration Agency (EIA), Oil & Gas Journal

and gas fields which have been found in the Santos Basin as well as in the more northerly Campos Basin in Brazil.

The Tupi discovery proved that a working petroleum system exists beneath the salt layer of the Santos Basin. The oil source rocks are the organically rich lake shales, the reservoirs are lake beach sands and porous limestones and dolomites known as microbalites, and the seal above the reservoirs which keeps the oil entrapped is the thick, impervious salt layer. Oil industry analysts such as Wood Mackenzie and IHS have estimated that the oil reserves in Brazil's pre-salt reservoirs could amount to some 20 to 30 Bbo recoverable, with ANP, Brazil's government oil industry regulatory agency, quoting recoverable reserves of up to 50 Bbo. The impact of these discoveries has been dramatic: Brazil's oil production is now at a record 2.2 MMbopd of which already about 150,000 bopd is from the pre-salt. Petrobras recently announced that output from the pre-salt reserves is expected to grow, bringing Brazil's per-day oil output to 6 MMbo, nearly triple current production.

When the conjugate margins of Angola and Brazil are juxtaposed or reconstructed to the time of the initial opening of the southern Atlantic, about 140 million years ago in the early Cretaceous, the Santos and Campos Basins are clearly located adjacent to Angola's Benguela and Kwanza Basins. Accordingly, the success in the pre-salt of Brazil could be repeated in Angola's deepwater areas, where drilling in the pre-salt was negligible before 2011.

> "If you are a petroleum geoscientist, you'll be challenged to find a country as interesting as Angola"

More History is Made

As a result of investigating the southern Atlantic conjugate margins, an historic event for the hydrocarbon industry in Angola occurred in 2011 when eleven deep to ultra-deepwater pre-salt blocks in the Kwanza and Benguela Basins were awarded by Sonangol to a number of operators. These included BP, Cobalt, Repsol, Total, Eni, ConocoPhillips and Statoil, the last obtaining the lion's share with two operated blocks and non-operated working interests in three others (see *GEO Expro*, Vol. 5, No. 4).

On 4 January this year Maersk and Sonangol announced that Azul-1 on deepwater Block 23 was the first well to penetrate pre-salt objectives in Angolan deepwater. The well was drilled in a water depth of 920m and reached a total depth of 5,330m. The press release stated that "the preliminary interpretation of the data indicated a potential flow capacity of greater than 3,000 bopd. We are encouraged by the results of our first pre-salt exploration well in this region, which was also the first ever deepwater well targeting pre-salt reservoirs in the Kwanza Basin".

Shortly afterwards, on 9 February 2012, Cobalt International Energy (CIE) announced the results of its Cameia-1 well, drilled in 1,680m of water in deepwater Block 21, again targeting the pre-salt section. Cobalt reported that the well confirmed the presence of 360m of gross continuous oil column with over a 75% net to gross pay estimate. No gas-oil or oil-water contact was evident on the wireline logs. An extended DST (drill stem

test) was performed on Cameia-1 which flowed at a sustained rate of 5,010 bpd of 44° API oil and 14.3 MMcfpd of associated gas, giving a total of approximately 7,400 boepd day with limited drawdown. Cobalt stated that it believes that the well has the potential to produce in excess of 20,000 bopd.

What Does the Future Hold?

Based on my 40 years of experience in the oil industry, I expect that the Angolan oil industry will remain vital for many more years. Already, two-thirds of Angola's production is from the deepwater and, unquestionably, more Oligocene and Miocene oil discoveries will be made in the ultra-deepwater areas seawards of Blocks 31, 32 and 33. Based on the drill results of Maersk's and Cobalt's wells, the pre-salt play suddenly looks very promising.

Could the dramatic increase in production seen in Brazil as a result of the discovery of the pre-salt oil fields happen to Angola? Based on the very recent successes by Maersk and Cobalt, it is possible, although, of course, much more drilling is needed.

Another milestone in Angola's petroleum industry will happen in June 2012 when the LNG plant at Soyo in northern Angola commences production at 5.2 MM tonnes per year. On an energy-equivalent basis, this amounts to about 200,000 barrels of oil per day. A strong demand exists for Angola's natural gas due to the increasing consumption of LNG in Asia and also as Europe seeks to reduce its reliance on gas from Russia. In addition, as gas becomes increasingly the preferred fuel of the future, there will be much focus on the gas potential in Angola, which to date has been only minimally explored. ▶

Spectacular outcrops near Bentiaba, southern Angola. The underlying reddish-brown unit consists of Lower Cretaceous terrestrial sediments which were deposited during the initial continental break-up of south-western Gondwana. These are unconformably overlain by Cretaceous Albian carbonates. The contact between these two sequences is the continental break-up unconformity.


Tako Koning

Angola's Petroleum Systems

Angola is made up of the Kwanza, Congo and Namibe sedimentary basins, but so far only the first two have yielded oil in commercial quantities. The southern Namibe Basin remains underexplored, although on the basis of limited vintage seismic data and regional geology many commentators consider that it has plenty of potential.

Angola's strong oil and gas production is intimately related to its working petroleum systems, which are primarily Lower Cretaceous and Tertiary in age. The geological evolution of these began during the Early Cretaceous with the continental break-up of Gondwana. Lacustrine rift basins developed in extensive north-south trending linear depocentres in the Lower Congo and Kwanza Basins. The now-famous major source rock, an organically rich lacustrine shale known as the Bucomazi Formation, fed oil into the recently-formed Kwanza Basin pre-salt traps as well as into the numerous Pinda carbonate oil fields in the Lower Congo Basin. The nature of the salt which was deposited in a narrow highly saline basin immediately before the two continents split apart varies across the Angolan offshore. In the deeper water parts of the Kwanza Basin, for example, it is thicker but at less depth than in the shallower areas, where thick diapirs appear to be more common. Extensional rift tectonics dominate in the pre-salt section, with a fault-induced relief that exhibits both tilted and folded sections.

The Tertiary-age Miocene and Oligocene oil fields in the deepwater part of the Lower Congo Basin are the result of a geological evolution separate and distinctive from the Bucomazi. Giant-sized oil fields (>0.5 Bbo) such as Girassol, Dalia, Great Plutonia and Kizomba, are reservoired in highly porous sands and conglomerates which flowed as turbidites seaward from the ancestral Congo River. The Congo, currently the second biggest river in the world after the Amazon, was also one of the world's largest rivers in Miocene and Oligocene time (5–35 million years ago), during which time it spewed an enormous amount of coarse-grained clastic sediment eroded from the vast African proto-continent into the Lower Congo Basin. Since tropical conditions with attendant thick and luxurious terrestrial vegetation existed at that time, these sediments also included vast amounts of organic material. The net effect was to provide the Lower Congo Basin with excellent, highly porous reservoirs as well as rich oil and gas source rocks.

The oil and gas source rocks of Angola have provided crude oil which is typically medium gravity, minimum wax and with almost no sulphur. These crudes are welcomed by refineries worldwide.

__Tako Koning__ is a long time resident of Angola. Born in Holland and raised in Canada, he is a geologist who started his career forty years ago working with Texaco in Canada, followed by assignments to a number of countries, including Indonesia and Nigeria. Since 1995 he has been living and working in Angola, where he combines being a consultant in Luanda for Gaffney, Cline and Associates with leading field trips in the country. He has published more than 100 papers and abstracts and in 2010 was awarded the AAPG's Public Service Award for a lifetime of mixing humanitarian aid with his science on a global basis. ■

Peter Moeller

Tako Koning runs many popular field trips in Angola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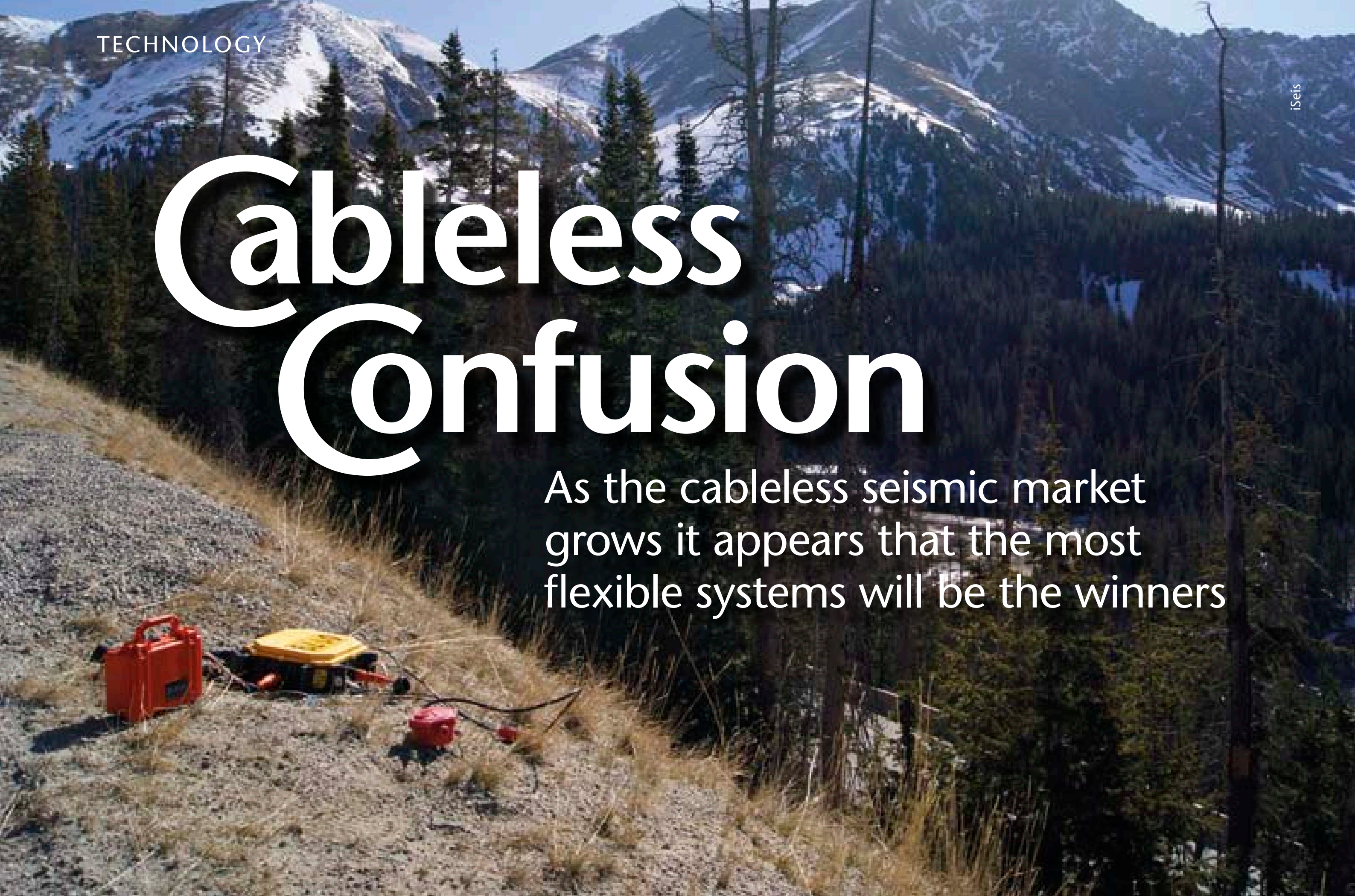


Cableless Confusion

As the cableless seismic market grows it appears that the most flexible systems will be the winners

ROBERT HEATH

After almost a decade of nearly taking off, this flexible new technology is finally making its mark. With around a quarter of a million cableless seismic channels sold in the last few years, and an ever-growing share of the land acquisition market, there is no doubt that such equipment is here to stay.

Nowadays, the industry accepts cableless with few questions, such is its desperation to get away from the disadvantages of cable. The main one of these was often said to be weight, and it was difficult to disagree. With the exception of some rather uncommon combinations of trace interval, sensor type and choice of cableless system, a cabled crew is always going to be heavier. (see "Weighing the role of cableless and cable-based systems in the future of land seismic acquisition", *First Break*, June 2010). But in these days of more complex acquisition, weight as the worst attribute of cable may be getting surpassed, as users find this old technology just too user-unfriendly to take on new types of exploration. Cable recorders were devised at a time when simple 2D or 3D CMP acquisition summed up the main types of survey being considered, so flexibility did not need to be this equipment's trademark. Today, inspired by the greater demands of this industry, novel geophysical techniques need recorders unrestricted in any way by hardware.

Despite this, cableless kit should come with a health warning for reasons which are not at first sight obvious. Just as there is little to choose between the different cable systems in terms of flexibility, so the way you might use them tends to vary little. But there is much more choice when it comes to systems which allow operations without cables and it is this variety which can cause problems. There are about ten cableless recorders available nowadays and they differ greatly from each other in features and functionality. So all of a sudden it is rather important to understand the pitfalls that each type may bring as this new way of doing acquisition moves out of adolescence.

Depending on GPS

Such pitfalls are best understood if we consider what is inherently different between a generic cable system and a cableless one, and the different ways this forces us to operate. Cables were there for a reason – three reasons in fact. The first was to emit timing to remote units, the next was to send out remote control commands and the third was to carry back along the cable QC and status information and lots of seismic data. Every cableless system manufacturer has had to consider whether to incorporate some wireless method to mimic these functions, or come up with a reason why it's no longer needed. Let's start with timing as it is the easiest, though not quite as clear cut as some would have you think.

There is a common belief that this problem is entirely solved by putting a GPS receiver inside each remote unit. Where and whenever you can pick up GPS signals – problem solved. But that is not everywhere. GPS receivers have become very sensitive – you can bury them some inches down and still pick up GPS as long as the dielectric properties of the ground permit. But a sudden rain storm can change good reception into intermittent or none at all, and GPS has also been reported lost for conditions ranging from freak weather to sand storms.

The lesson here is that the seismic environment can always find a way to outfox us, especially if hardware cuts too many corners. Making a system dependant on reliable GPS reception means you might end up with no useful data at all at times.

So, do we do nothing about this and hope for the best, or can some insurance be built in? The first thing to do is to incorporate a clock in each ground unit, which remains accurate even over long periods with no GPS signal. As this costs money and takes extra power, only a few systems bother. The next issue to cope with is when there is no GPS at all. A handful of products were devised to work without GPS timing, believing that some other form of radio-based synchronisation was always going to be a better bet. For example, a VHF frequency can naturally penetrate further through foliage than any GPS signal as it has longer wavelength and usually higher power. One system which has the best of all worlds uses GPS and a very accurate clock as the basic system, thus being able to cope with intermittency, and the option of VHF-based timing for when GPS is elusive. In all cases, given seismic data's dependence on very accurate timing, surely the most important thing is to be able to monitor when the ground units are getting no synchronisation signal. However, very strangely, few new products have made this available.

Choices in time-stamping: two Sigma units, which are receiving essential timing information via a VHF synchronisation system, used when GPS signals are unavailable.

Remote Control Commands

The next function performed by cable was sending out remote control commands. Some systems have decided not to bother with this, claiming it is not necessary to change any settings during acquisition. But this is to miss the point. Remote control in cableless recorders is to deal with power, or more strictly speaking, energy consumption. Whether batteries are a great advantage or a huge hindrance in cableless recording compared to cable depends on whether you can control how much power is used. Cabled systems come with the choice of using fewer but larger batteries which require changing rather regularly, or smaller batteries which are greater in number but last longer. Each method has pros and cons but in all cases cable systems allow users to switch off when power is not needed, and also to monitor remotely how much power remains in each battery.

To go cableless, requiring many more batteries than almost any cabled configuration, while not being able to control or monitor power, is asking for trouble. Some say the problem is made even worse by the use of lithium-based batteries. The extra power density of lithium is often cited as a way to overcome the power wastage if it is not possible to remotely switch off the ground unit, but reliance on this battery chemistry is risky, since it tends to be fussier about operating temperature and the way it is charged. It is also much more expensive, and there are reports of lithium batteries exploding, so some airfreight companies will not carry them. The worst of all worlds is probably the use of an internal lithium battery, which seems to be just asking for trouble given its predilection for erupting.

Sending Back Data

Next is the issue of sending back QC, noise, status and seismic data. In the cable world, this can be considered as more or less one function but it would be a mistake to think this when coming to cableless, because the amount of data involved in sending QC, noise and status back from the spread to the observer is tiny in comparison to seismic data volumes. This is an essential distinction because wireless technology handles low bandwidth rather well whereas even today, high bandwidth

Cableless systems offer greater flexibility

iSeis

A USB (bottom of picture) actively harvesting data from a Sigma unit

transmission in the seismic environment comes with many hurdles.

Nevertheless, some systems force the operator to live without any QC, status or data at all, so-called shoot-blind operations. This had some advantages when the deployment of such ground units was simpler than deploying those where some form of complex radio communication had to be established. But nowadays some manufacturers recommend that their shoot-blind units are buried to avoid theft, which removes any advantage of rapid deployment. Systems now exist with mesh radio networking technology built in, which are just as easy to deploy as any shoot-blind equipment, do not come with any recommendation to be buried and take away the risk of theft, and of recording bad data while not knowing about it. Such mesh radios can be used to send back all sorts of information including GPS reception strength, as well as have the benefit of allowing remote control of ground units, thus simultaneously solving the battery usage problem too.

When it comes to real-time transmission of seismic data, there are various approaches on offer, all of which have some level of drawback. Perhaps most capable is that demonstrated by iSeis's Sigma system which can be used for both passive and active recording. In fact, it is currently being used to provide real-time transmission from a passive spread of 750 km^2 for over two years, 24/7 – probably a world record.

But if you choose hardware which either does not offer real-time data return, or you use it in a non real-time way, then sooner or later you have to retrieve data from the ground units. Here, there are two broad choices: systems where the units must be collected and taken to a central location, where they are attached to some sort of rack and the data sucked out; or those where you go to the unit and copy the data while the box is still recording. Some obvious benefits of the latter approach are that it is much faster and that less equipment is needed. If you do not have to pick up boxes just to get your hands on the data they can stay doing the job they were purchased for.

'Harvesting' Data

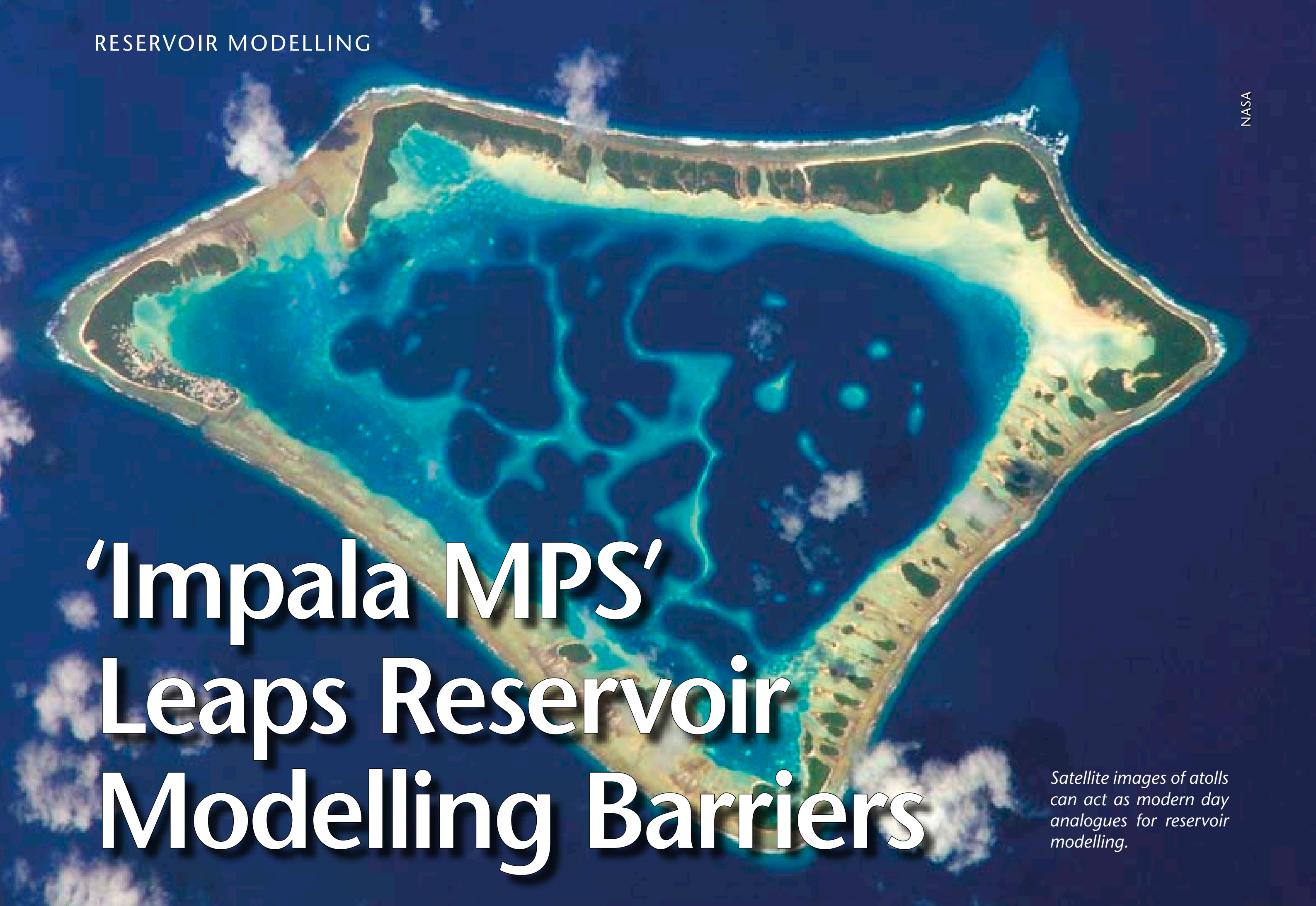
Then comes the issue of how to get the data out, something which is usually referred to as harvesting. As almost all cableless recorders are continuous record systems, it is useful to have the option only to take out data relating to reflection seismic files, and to ignore all the stuff in between. On impulsive crews, this saves a significant amount of harvesting time and so may affect the choice of technology used in actually transferring data from the internal memory of the ground unit.

So what is the ideal way to transfer data? The answer is that there is no single best way but to have only one method has been found to be a severe limitation when operating in different environments. A very useful option is the ability to record not just to internal memory but to some detachable external memory simultaneously. This enables data harvesting to be instant, which is especially useful when birddogs want to get their hands on data for QC, and it also overcomes the occasional problems of using Wi-Fi for harvesting. The iSeis company has just recently added this feature to its Sigma system.

As we see, there is great choice in cableless, with some manufacturers having decided to offer much more versatility than others. If the future of a seismic contractor is in being able to get the greatest use out of one set of equipment, it seems that the most flexible systems are going to be the winners. ■

Cableless seismic operations in Quito, Equador. 'Cableless' and 'cablefree' are not synonymous. The 'cable' refers to digital telemetry cable, which cableless systems do not have, but they all have other bits of cable, to connect batteries and geophones.

Dan Braden



NASA

'Impala MPS' Leaps Reservoir Modelling Barriers

Satellite images of atolls can act as modern day analogues for reservoir modelling.

PAUL WOOD

Oilfield services company Baker Hughes has introduced a next generation geological facies module into its JewelSuite™ reservoir modelling product.

Reservoir geologists in the hydrocarbon business today have to deal with great complexity. In many hydrocarbon fields, oil and gas are produced from rocks that have compositions and properties that vary rapidly. These rocks may be deposited by meandering river channel systems where the distribution patterns change character depending on the distance from the coastline, or as limestone atolls in which the porosity and permeability of the reservoirs varies in complex patterns. These may be related to depositional patterns and later processes such as the formation of fractures and cavities when the sea level dropped and the limestone platform was exposed.

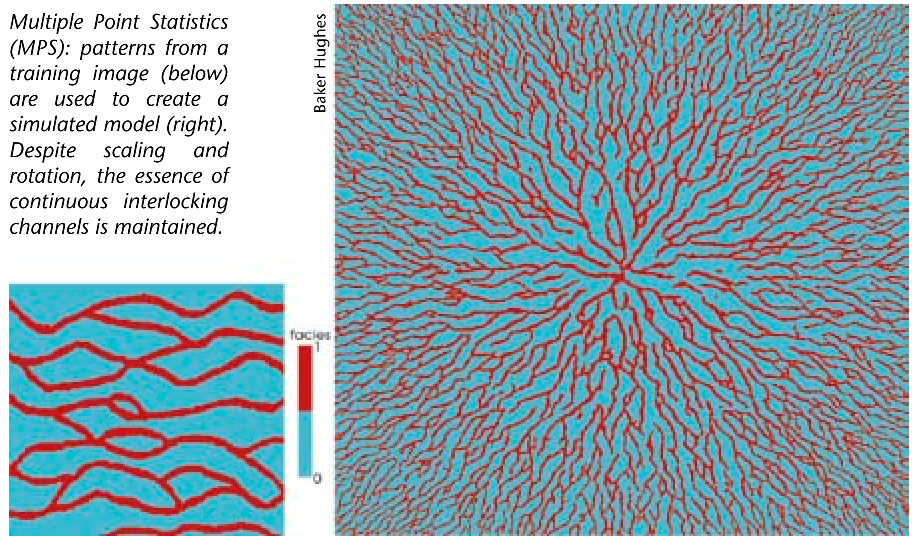
Whatever the geology, it is crucial that geologists can make the most accurate subsurface model of the field possible. The geological model must match the (often many) well penetrations and past hydrocarbon production in order to predict future production correctly and guide decisions that will lead to enhanced hydrocarbon recovery.

Creating Models

Some models are created by populating the space between wells directly with porosity and other reservoir properties. Greater complexity can, however, be addressed better if the rock types or 'facies' are first defined and models developed to show the patterns in which these facies would occur between wells; then the corresponding reservoir properties can be filled in. Traditional facies modelling has tended to use one of two methods for this: either two-point statistics or object-based methods. In two-point statistics, the statistical relation between two points in space is assessed and used to predict the unknown properties of intervening locations. Object-based modelling makes the prediction by placing entire objects like a river sand body into the model – in this case the dimensions and shape would be derived from ancient or modern analogues. The two-point method often does not produce geologically meaningful results, while object-based modelling can become very complex and computer intensive, especially when data from many wells must be honoured.

One way to get more realistic results from statistical modelling is to use Multiple Point Statistics or MPS. This method involves statistical analysis of 'training images', 2D or 3D analogue models, to create a library of geological patterns and then using these patterns to fill the space between wells.

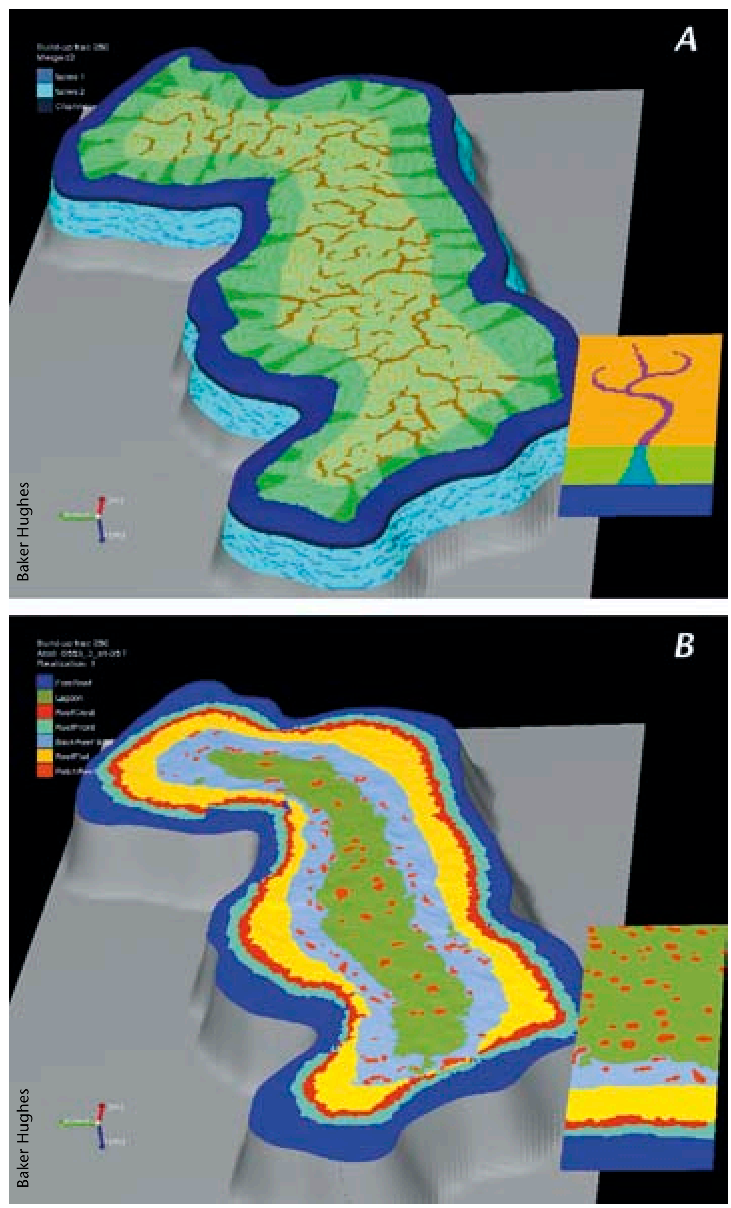
Multiple Point Statistics (MPS): patterns from a training image (below) are used to create a simulated model (right). Despite scaling and rotation, the essence of continuous interlocking channels is maintained.



The way MPS modelling works can best be shown by an example. A simple training image is created, representing a generic system with two distinct facies, in blue and red. This could be, for example, an interlocking channel system. The training image is input into the model, that also has to conform to external data. Control parameters such as rescaling and rotation can be imposed, so the simulated model might represent channels radiating off a dome and becoming more numerous and smaller the further they are from the centre.

MPS as a method has been around for a few years, but has not so far been adopted widely. Initial implementations in modelling packages were not very efficient, resulting in prohibitively long run times for more complex models. Training images, in particular 3D ones, were not readily available and, in order to satisfy the mathematics behind MPS, were required to be 'stationary' – that is free of any trends. Recently, these limitations have been overcome by smarter algorithms, parallel processing and the introduction of a concept called 'auxiliary variables'. These variables describe trends in training images and subsurface models. Their effect may be sketched as 'if you can describe the direction and magnitude of trends I will handle them for you'.

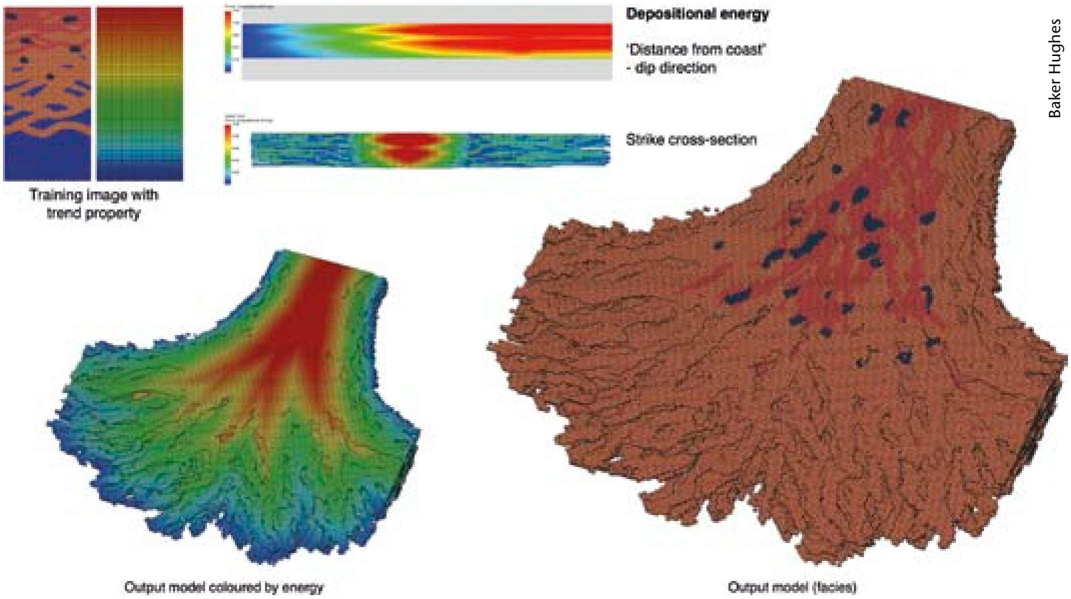
Impala facies modelling during sea level drop (A) and during sea level rise (B). The progression moves from an interior region (orange) through a tidal inlet region (green) to open marine conditions (blue).



Reservoir Modelling Software

As part of its reservoir management platform, oilfield services company Baker Hughes offers the reservoir modelling software JewelSuite™. This product line can use add-ins, software applications that may be developed by third parties. Baker Hughes saw the need to improve the way reservoir models were generated, so were looking for suitable add-in programmes. As Jonathan Zwaan of Baker Hughes' JewelSuite team says, "People want to build geologically realistic facies models, with shapes that they recognise, but where the modelling is done in a statistically sound way. We found this ability with the multiple point statistics software 'Impala MPS', produced by Swiss company Ephesia Consult. Impala has a unique performance with complex models and with the implementation of auxiliary variables. So we have incorporated it as a JewelSuite module".

An example of Impala facies modelling is shown for a carbonate platform, modelled during a sea level drop when erosive channels were cutting into the atoll. Typically, such channels differ in shape between the platform interior and the edge of the platform where they



Turbidite fan model with trend for depositional energy

become wider, showing a distinct trend. The modelling steps describe the trend from an interior region (orange) through a tidal inlet region (green) to open marine conditions (blue) and define the trend direction that points away from the central watershed of the platform.

A similar application of trend properties when superimposed on the same platform model during a sea level rise leads to another result containing details of different reef and lagoonal facies. In this case the properties were derived from a satellite image of a modern day atoll.

Many Depositional Environments

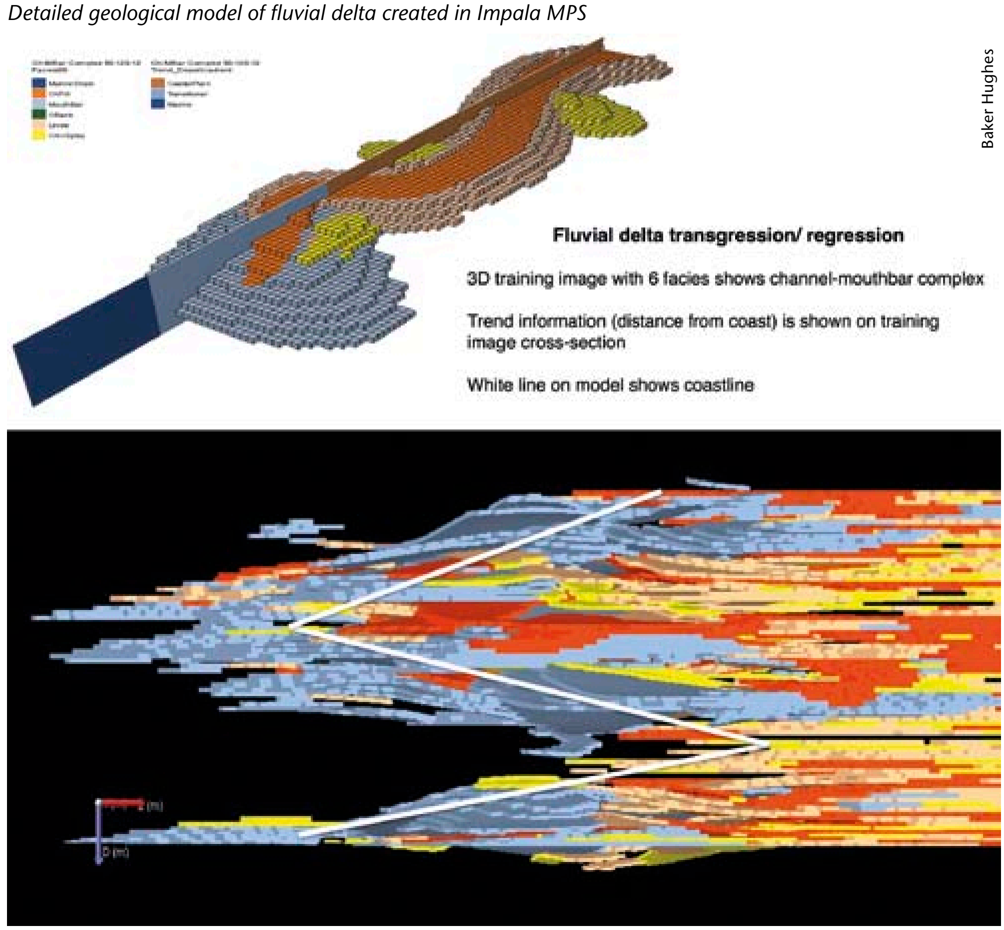
Christian Höcker, technical consultant at Baker Hughes, thinks that MPS is a very flexible method for facies modelling, capable of addressing many depositional environments and scales. He says, "The additional capability of Impala MPS regarding the use of trend properties is important as it greatly enhances ease of use. Other implementations require complex set-ups for laterally and vertically varying conditions, whereas with trend properties, I can use a single training image, covering a number of depositional settings, and be certain that the appropriate patterns are mapped into the respective locations in the simulation model."

This ability can also be seen in a model of a turbidite fan generated from a simple training image with only one trend property – 'depositional energy'.

A more complex 3D training image of a fluvial delta can be taken, by using simple trend properties, through a series of transgression/regression cycles, resulting in a realistic and highly detailed geological model.

Christian concludes, "The examples show that – if properly applied – very simple training images can address complex needs. We have recently added features that make trend description and rotation really easy. This means that once reservoir modellers have understood some basic principles of MPS and tried the specific features of the JewelSuite implementation they will have a tool for all cases at their fingertips. And I am most happy to share training images and modelling recipes for various settings." ■

Detailed geological model of fluvial delta created in Impala MPS

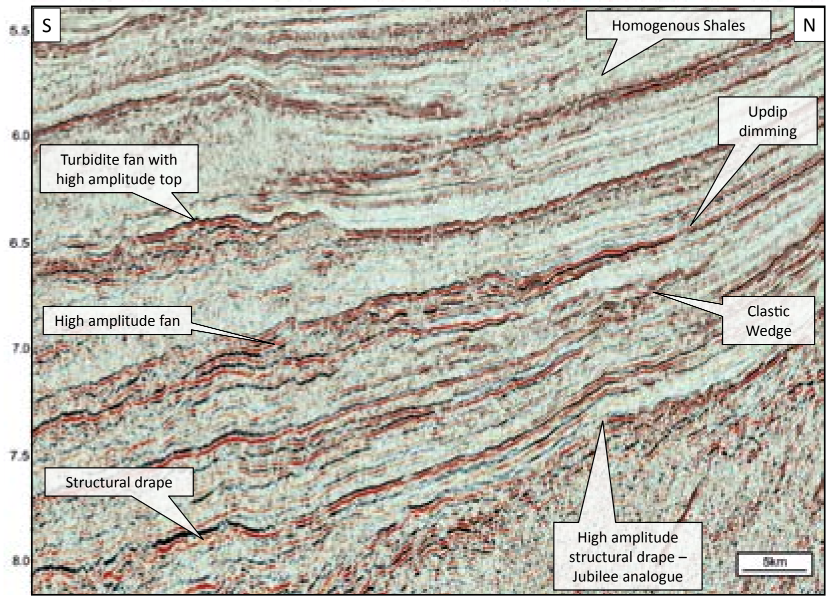


Offshore Côte d'Ivoire:

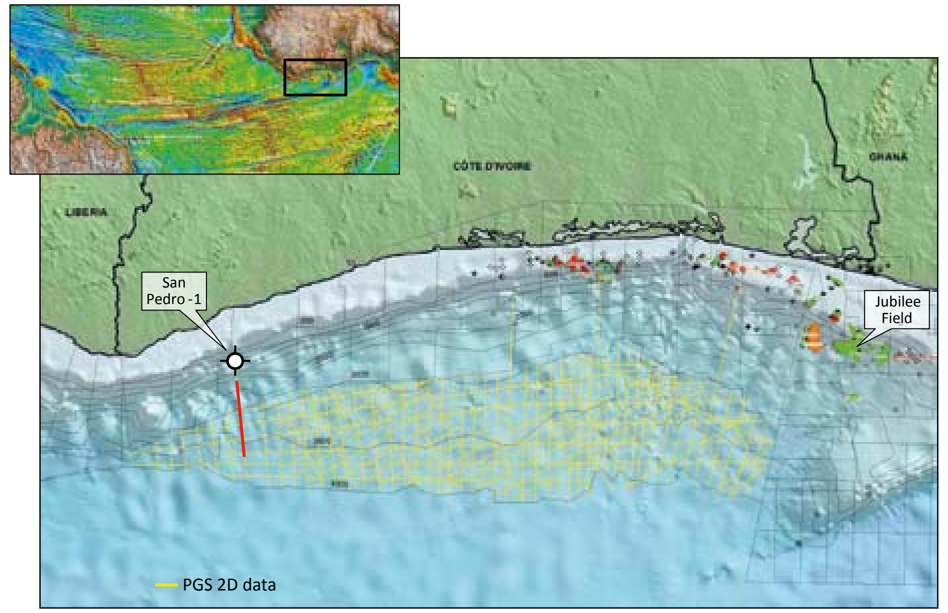
A Modern Exploration Frontier

Highlighting the remaining potential for undiscovered resources

The main foldout line shown illustrates the petroleum system elements offshore deepwater Côte d'Ivoire, including fault blocks and synrift sediment fill of Early Cretaceous age, lying beneath thick marine post-rift sequences. PGS holds 6,500 km of 2D data in the region, including new and reprocessed Geostreamer data, which has enabled a detailed interpretation and subsequent characterisation of regional prospectivity. The line shown covers about 50 km from south to north and 2.5 – 6.5 seconds two-way-time. Despite a lack of deepwater well control, a number of ties to wells on the shelf have made it possible to accurately define the offshore stratigraphy.

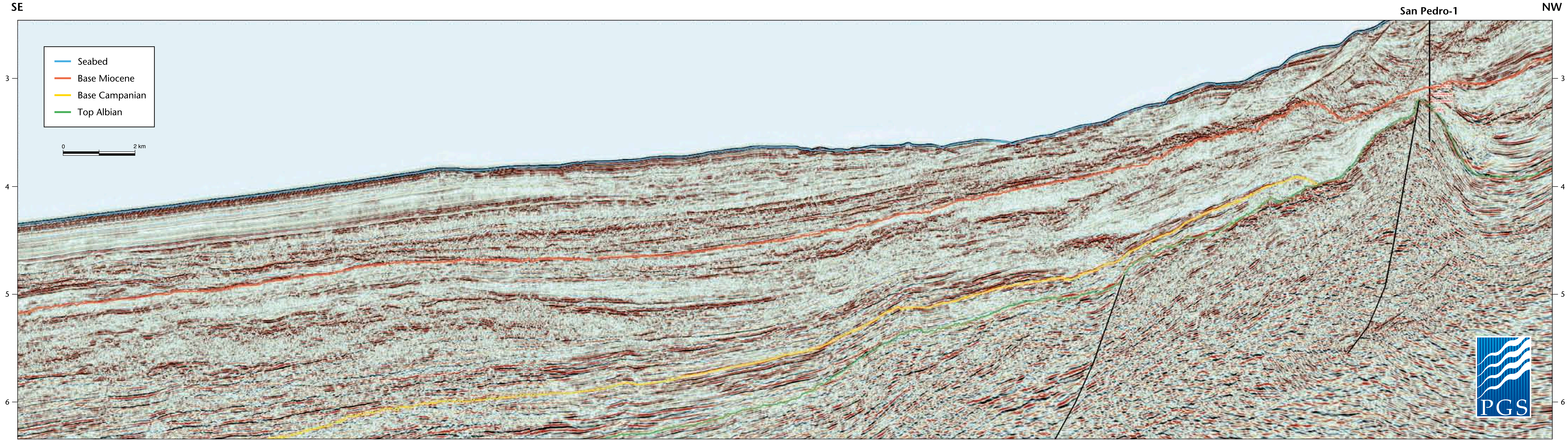


Section detail showing some of the key features identified in the area



Location map showing the offshore Côte d'Ivoire region, PGS 2D data coverage in yellow and approximate location of main image in red. Existing fields and wells drilled are visible on the shelf in the east (source: Petroview).

Inset: African and South American Equatorial margins free air gravity from satellite, showing conjugate tectonic elements (source: Nupetro, 2003.)



Deepwater Potential in Côte d'Ivoire

STEVE WELLS, MATT WARNER, JENNY GREENHALGH & RON BORSATO, Petroleum Geo-Services

Recent discoveries such as **Jubilee** (Ghana, 2007) and **Zaedyus** (French Guiana, 2011) have proven the significant remaining potential for hydrocarbons on the Equatorial Atlantic conjugate margins of West Africa and South America. Offshore Côte d'Ivoire is a major part of this tectonic province, with a huge offshore area of around 100,000 km^2 which contains all the geological attributes necessary for a prolific petroleum system. Despite this, the deepwater section is underexplored, with no wells drilled off the shelf break. Several oil discoveries on the shelf of eastern Côte d'Ivoire in shallow marine clastic systems support the potential for deepwater turbidite systems of a similar age further offshore.

The western part of the shelf is also remarkably underexplored. No discoveries have yet been made in the Western offshore, where only one well (San Pedro-1, 2005) has been drilled in an area of 35,000 km^2. However, recent discoveries in Sierra Leone and Liberia, such as the Mercury discovery, confirm the presence of effective source rocks along the margin to the west. Licensing activity has seen an increasing interest in the region, and where current explorers include Total, Anadarko, Lukoil and Tullow, although much acreage remains unlicensed. The water off the shelf is very deep, often between 2,000 and 4,000m, and the costs involved in drilling in such settings necessitate the requirement for high quality seismic data to accurately define exploration targets.

Petroleum Systems

Offshore Côte d'Ivoire is part of the Atlantic rift system, where rifting began to propagate northwards from the South Atlantic in the latest Jurassic. Crustal stretching along transform fracture zones led to complex linked regional-scale fault systems along the margin of Côte d'Ivoire, as shown by regional seismic and gravity and magnetic data. This structuration and subsequent basin sag created a predominantly marine depositional environment from the late Albian onwards, and a series of isolated sub-basins of various depths which contain potential for source rock generation.

The deep marine environment also dictates reservoir targets in many areas off the shelf, often deep-marine turbidite sands. Morrison *et al.* (2000) document three key play types in the Côte d'Ivoire offshore region, which can be applied across much of the margin. These are, firstly, a middle Albian terrestrial gas-prone source rock feeding Albian reservoirs; secondly a late Albian marine transgressive oil prone source rock feeding Albian reservoirs; and thirdly a Cenomanian-Turonian open marine oil-prone source rock feeding Albian and younger reservoirs. The quality of these source rocks probably increases towards deeper settings (MacGregor *et al.*, 2003), but potential here for the deposition of reservoir sands may be reduced.

Effective exploration in this area is a spatial balancing act between the juxtaposition of effective source rocks with sufficient sediment supply from the margin. Key controls on reservoir distribution and quality are likely to be sand provenance, avulsion of major supply channels, and the extent of sand input bypassing the shelf into the deeper waters. Major sediment supply routes are likely to follow regional transform structural elements, enabling detailed prediction of reservoir location and provenance. Palaeo-channel system reconstruction is a key task in order to define the location of probable deepwater reservoirs, and can only be achieved through interpretation of regional high quality seismic datasets.

Stratigraphy

The expected stratigraphy predominantly comprises clastic sands and shales. Transform rifting in the Late Jurassic / Early Cretaceous began in a continental setting, where deep strike-slip basins were filled with lacustrine shales and coarse continental clastics. These lacustrine shales form important source rocks similar in composition to the Bucomazi Formation of Angola. As rifting continued and the basins deepened, marginal marine environments began to dominate the stratigraphy, with interbedded carbonates, shallow marine clastics and shales of the mid-Cretaceous. These marine shales also form important source rocks. The end of the syn-rift stage on both the Brazilian and African margins is characterised by a major unconformity, above which rest the post-rift sediments. The stratigraphy of this section is almost entirely clastic, and shale-dominated after the Turonian when connection was made between the Atlantic and Tethys seaways.

In the early post-rift, sediment drape over the deeper rifted structures creates some of the most important deepwater reservoirs in the form of Upper Cretaceous turbidites. Basement highs are a key control on reservoir distribution and also form important trapping structures. A range of structural and stratigraphic trapping styles can be identified on deepwater seismic data, including syn-transform structural fault block traps associated with the Romanche Fracture Zone, and post-transform anticlinal traps analogous to the Belier Field. Many untested trapping mechanisms can also be recognised, including ponded stratigraphic turbidites and limestone units resting on syn-transform highs. Stratigraphic plays can be identified throughout the Upper Cretaceous and Paleogene sections. Burial history revealed by isopach mapping and heat flow in the basin are thought suitable for hydrocarbon generation from key source intervals of the mid-Cretaceous.

Existing Successes

The near-shelf **Espoir** and **Baobab** oilfields of eastern Côte d'Ivoire have reservoirs of porous Upper Albian marine sandstones with excellent production characteristics, containing approximately 320 MMbo in total. Other key discoveries in this region include **Tano**, **Panthère** and **Foxtrot**, all reservoired in Cenomanian or Albian sandstones. Significant sand input to the shelf at this time, as proven in these fields, indicates the potential for deeper turbidite, fan and channel sandstones in the offshore basins.

The Jubilee Field in Ghana is now an important deepwater analogue, as similar structuration and sedimentation regimes exist all along the Equatorial margin. Jubilee was discovered with the Mahogany-1 well in a series of turbidite fans and channels of Campanian to Turonian age, with excellent production characteristics, draped over a rifted high and pinching out up-dip. The field is located some 60 km offshore in 1,100m of water just off the shelf break to the east of the Côte d'Ivoire maritime boundary. Recoverable reserves are estimated at over 600 MMb of light oil up to 35° API. On the South American margin, Zaedyus was also discovered in stacked Upper Cretaceous turbidite fans, proving up the conjugate margin analogue, and potentially containing more recoverable oil than Jubilee in a larger fan system. It is possible to identify a range of similar prospective features on PGS data, along with additional potential in a range of untested plays.

Regional Insight

PGS Geostreamer and conventional data provides a crucial insight into the potential for new discoveries offshore Côte d'Ivoire, an area set for extensive deepwater exploration in the coming years. High quality imaging enables the successful characterisation of petroleum systems, in particular the ability to solve key regional issues such as deepwater reservoir deposition and timing of sediment supply. Tectonics also exerts a key control on the development of source rocks, and regional structural mapping is required to highlight generation potential. The offshore deepwater and western shelf of Côte d'Ivoire are underexplored, and will soon see an increase in exploration activity in the region as interest intensifies along both sides of the Equatorial conjugate margins of the Atlantic. ■

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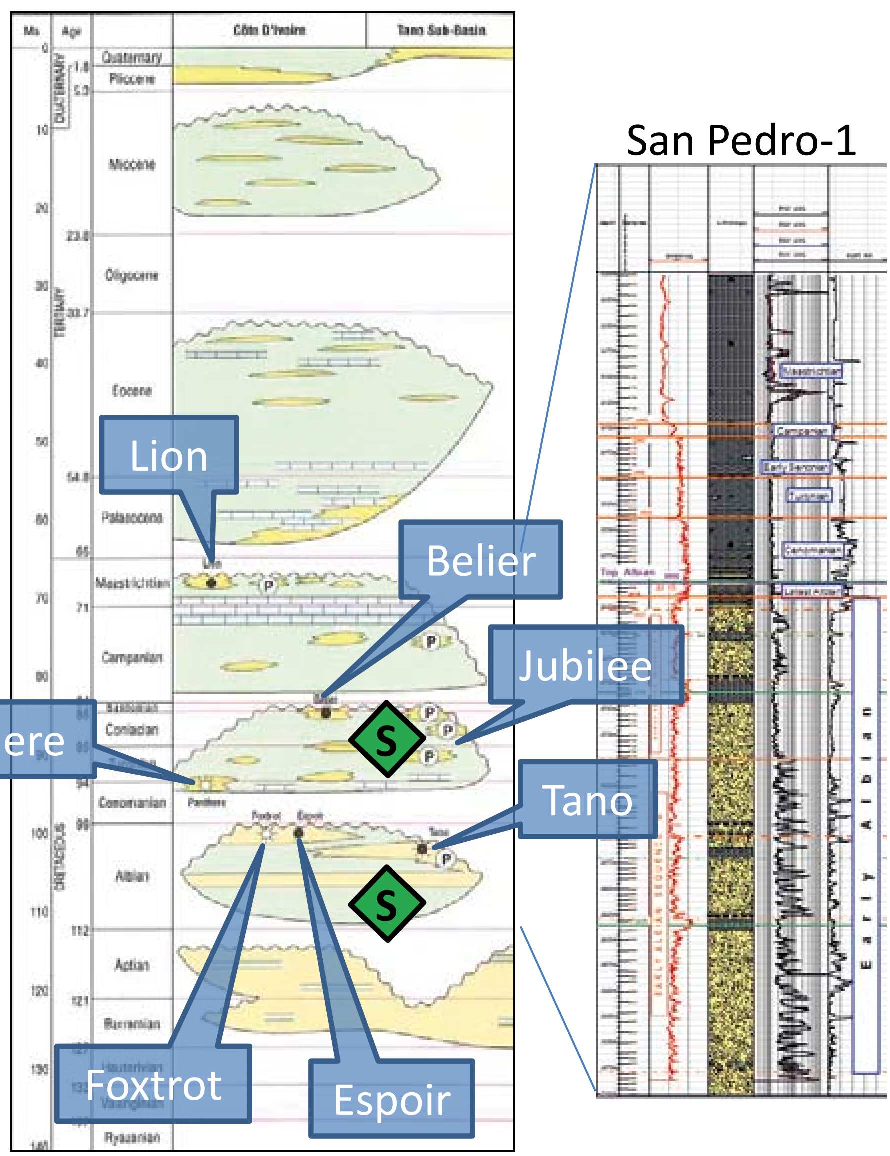
Côte d'Ivoire chronostratigraphy and Upper Cretaceous log of the San Pedro-1 well

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Solving Hydraulic Fracturing 'Controversies'

Hydraulic fracturing has unlocked a vast, new oil and gas resource from very tight rocks. Innovative developments in nanotechnology are poised to make hydraulic fracturing more efficient, accountable, and much safer for the environment.

THOMAS SMITH

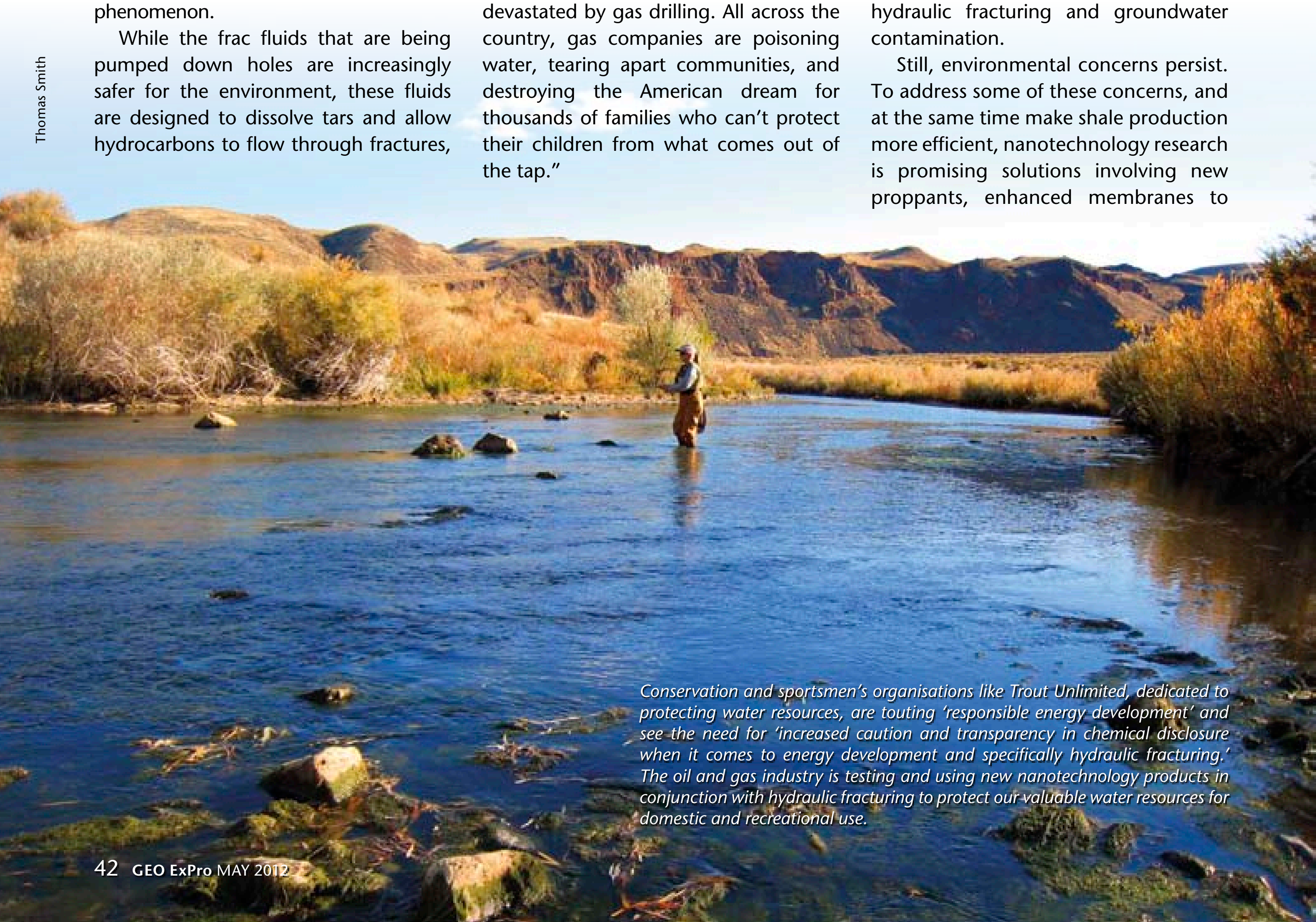
The production of shale and tight formation oil and gas has been increasing by leaps and bounds in the United States over the past few years. Just a decade ago, these same low permeable shale rocks were regarded as just source rocks for our conventional oil and gas fields. Thanks to horizontal well bores penetrating these very tight formations and multi-stage hydraulic fracturing of the shale in them, this resource is growing into a world-wide phenomenon.

While the frac fluids that are being pumped down holes are increasingly safer for the environment, these fluids are designed to dissolve tars and allow hydrocarbons to flow through fractures, enhancing recovery and making the produced water very dangerous to human health and the environment. The rapid increase in wells drilled, along with production, has led to mounting environmental concerns. There are numerous websites, such as Waterdefense.org, posting warnings such as:

"Natural Gas Exposed tells the stories of Americans whose lives have been devastated by gas drilling. All across the country, gas companies are poisoning water, tearing apart communities, and destroying the American dream for thousands of families who can't protect their children from what comes out of the tap."

Without hydraulic fracturing, the resource simply cannot be unlocked from these tight formations. Yet, governments continue to hold up development over this one issue even though reports of any problems are rare. In fact, a recent study funded by the Energy Institute at the University of Texas at Austin of shale gas development in the Barnett, Marcellus and Haynesville shales found no evidence of a direct link between hydraulic fracturing and groundwater contamination.

Still, environmental concerns persist. To address some of these concerns, and at the same time make shale production more efficient, nanotechnology research is promising solutions involving new proppants, enhanced membranes to



Thomas Smith

Conservation and sportsmen's organisations like Trout Unlimited, dedicated to protecting water resources, are touting 'responsible energy development' and see the need for 'increased caution and transparency in chemical disclosure when it comes to energy development and specifically hydraulic fracturing.' The oil and gas industry is testing and using new nanotechnology products in conjunction with hydraulic fracturing to protect our valuable water resources for domestic and recreational use.

Nanotechnology is the engineering of functional systems at the molecular scale. A human hair is about 50,000 nanometres (nm) in diameter. Engineers and scientists can arrange atoms into nanoparticles ranging from 1 to 100 nm in diameter that can be built to do specific tasks. This technology is offering better, longer lasting, safer, and smarter products, such as coatings on clothing to provide better UV radiation protection or bandages that use nanoparticles of silver that smother microbes, thus killing them. These are just two of the thousands of examples of nano-enhanced products being embraced by consumers and commonly used by businesses like the oil and gas industry.

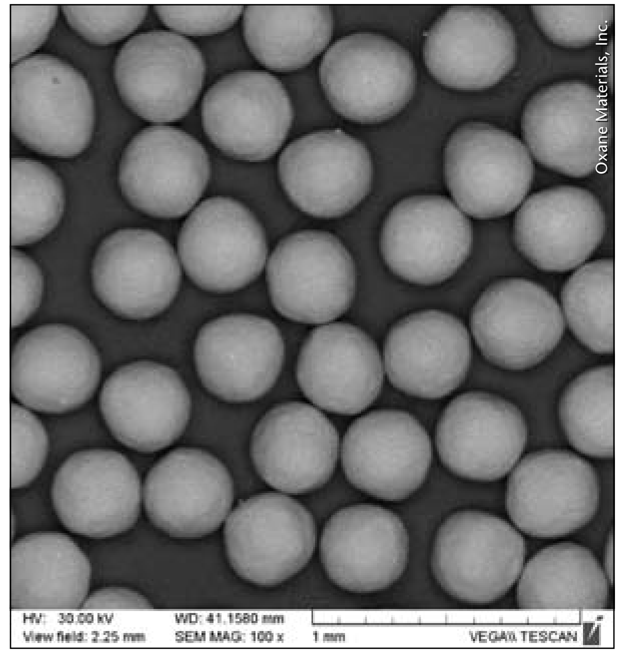
contain and treat fracture fluids, and unique, easily detectable tracers so that the movement of fracture fluids can be followed.

Proppants

Water is the main ingredient used for hydraulic fracturing. Well stimulations can use between 2 and 10 million gallons (8 and 38 million litres) delivered under very high pressures to create fractures in the producing horizon. A small percentage of chemicals are added to the water and vary from play to play. Some of the typical additives and their common uses include: diluted acid (hydrochloric or muriatic) that helps dissolve minerals and initiate cracks in the rock (also used as a swimming pool cleaner); friction reducers such as mineral oil or polycrylamide, that reduce friction between the fluid and the pipe and are also used for water treatment, laxatives and candy; crosslinkers (borate salts) to maintain fluid viscosity, also used in laundry detergents, hand soaps and cosmetics – and the list goes on. One of the companies heavily involved in the fraccing business, Halliburton, has a complete list of additives regionalised on their website.

One of the most critical components of the fraccing process is the proppant, or the component used to keep the fractures open. Commonly used proppants include plastic-ceramic beads, sand, lightweight ceramics and sintered bauxite. "These proppants are either hard and heavy or soft and light," says Dr. Andrew R. Barron, Welch Chair of Chemistry and Professor of Materials Science at Rice University, Houston, Texas. "The ideal proppant should be mono-dispersed, round, and high in strength with low fines to enhance flow through the fractures. It also needs to be light to optimise transportation.

"Fraccing with particles of different sizes, often the case when using sand as the proppant, can slow flowback," Dr. Barron continues. "Nanotechnology research at Rice has developed a proppant with particles consistently the same shape (round) as well as being stronger and lighter than previously used proppants. This new proppant, OxBall©, is being used in the Barnett, Haynesville and Eagle Ford shale plays and tests results have been excellent. All wells stimulated with the OxBall showed better than 25% increase in production."



The proppant developed at Rice University has the advantage of being lighter in weight and much more perfectly spherical than sand or ceramic beads. These characteristics allow for longer transport into the hydraulic fracture and at the same time require less frac water.

Water Containment

While there is no evidence that the downhole fracturing process has ever contaminated ground water, the same

Fracture fluids are often sprayed into visqueen-lined pits (left) that can leak. The poly-asphalt containment pit (right) may cost twice that of visqueen-lined pits but provides a containment system very resistant to wear and corrosion. This pit has a grid added above it to protect wildlife.

cannot be said for the large volumes of produced frac water. These waters have been dumped or spread over unprotected surface areas and allowed to evaporate. Containment in surface pits has been problematic. "Pits lined with visqueen can leak allowing liquids to percolate into the ground water," says Dr. Barron. "We have developed a felt and poly-asphalt system that has enhanced resistance to wear and corrosion using nano-alumina coatings on the frac fluid containing pits. Four pits have been constructed and proven a very effective containment system."

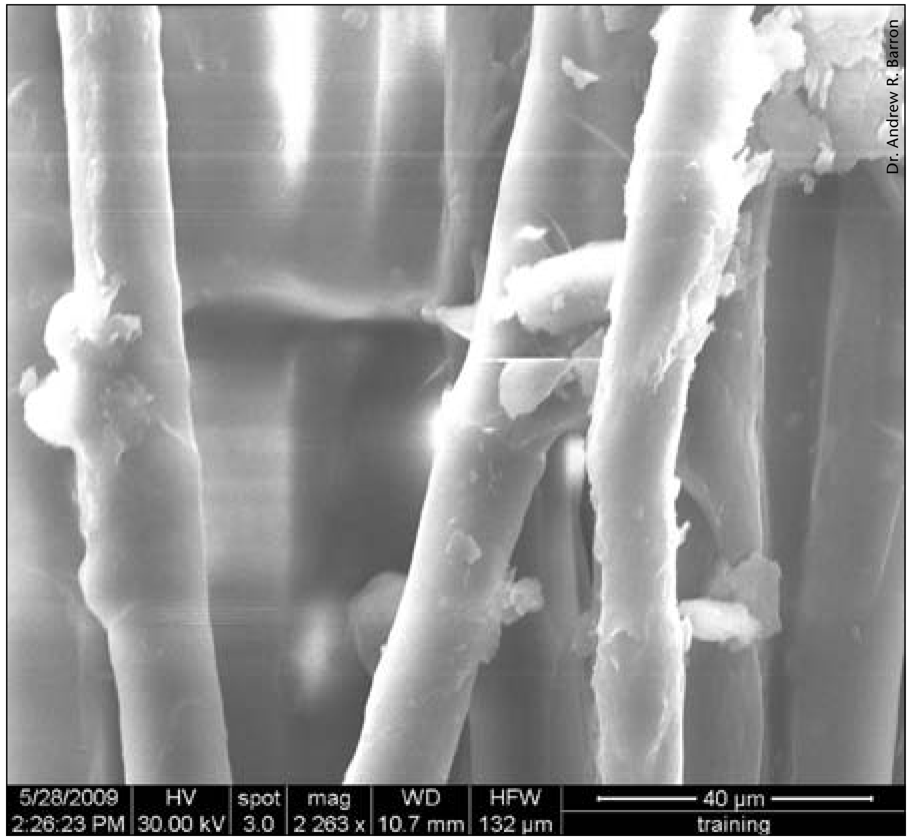


Photo of nomex coated with alumoxane nanoparticles that allow fine organics to be removed easily from produced water.

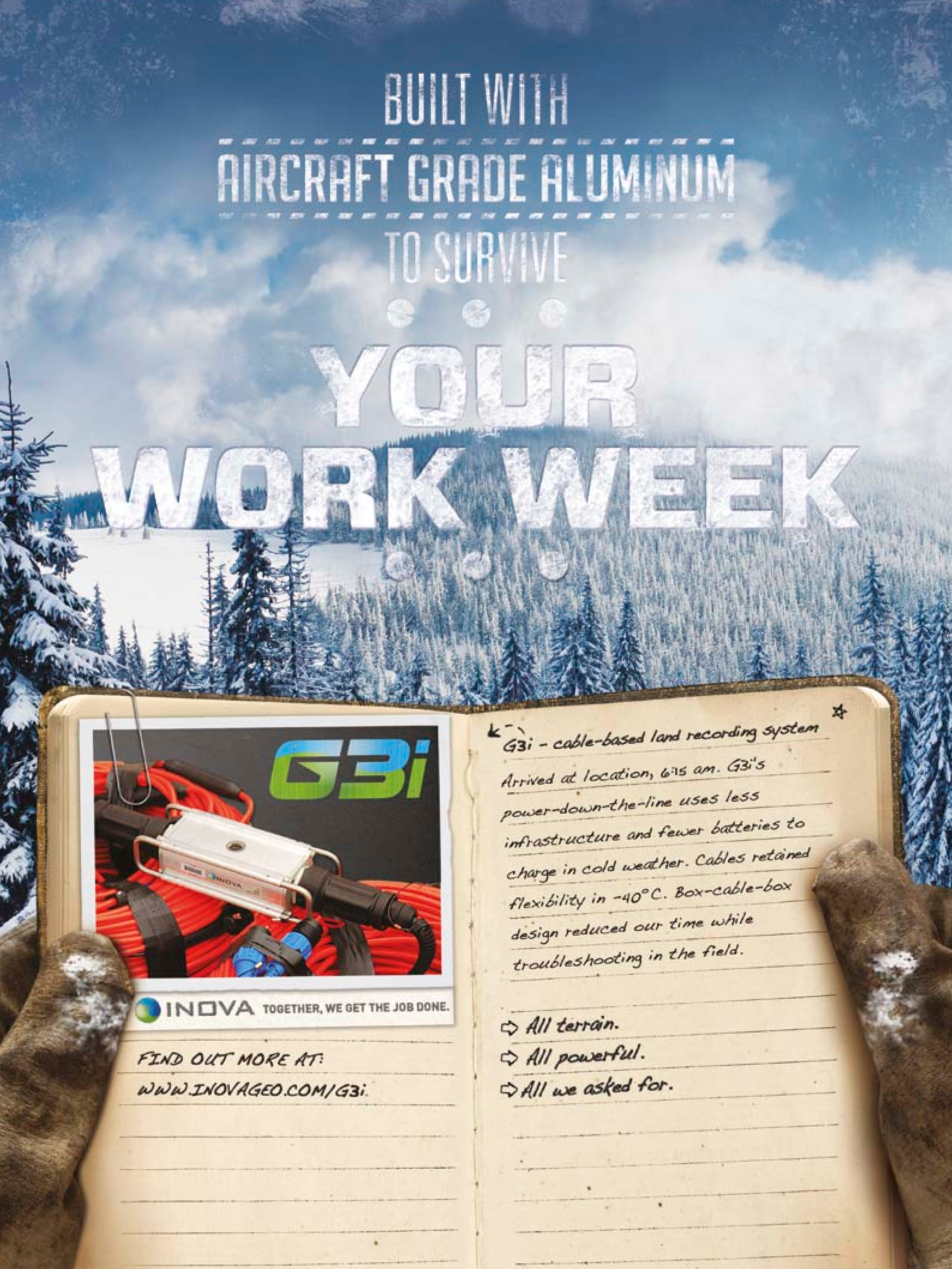
Water Clean-up and Tracers

Hydraulic fracturing fluids are getting much safer and less toxic. "However, 25 to over 40% of these fluids return to the surface and, in addition to the fraccing fluids, may contain formation and heavy metals, while all contain organics and hydrocarbons making these fluids very dangerous," according to Felipe Lembcke, CEO of Molecular Filtration, Inc. "This produced water needs to be treated on-site to reduce the carbon content to below the Environmental Protection Agency's (EPA) standards."

Waste water containing hydrocarbons can present a major pollution control problem to the industry. Filtration through traditional ceramic membranes that work on size exclusion requires a fairly high feed pressure of 4 to 8 bars and multiple layers that can become fouled by organics and cannot retain the small molecules such as xylene or benzene. "The nano-functionalised membrane (the first organophobic ceramic membrane) requires less than a 2 bar feed pressure that will not become fouled by organics or show decay," says Felipe. "The molecular forces in this membrane are so powerful that only water passes through. The cancer-causing small molecules like xylene and benzene are retained by the membrane along with all the other hydrocarbons, organics, bacteria and viruses. This is all accomplished without the use of chemicals."

Felipe Lembcke on location in Utah holding concentrate and the clean water after filtration that contains less than 6 ppm carbon (EPA standards require less than 9 ppm carbon) and no organics or bacteria. A portion of the truck-mounted field filtration unit is in the background which has operated continuously for 15 days with no fouling or loss of permeability of the membranes.

Fraccing has received much bad press about contaminating ground water and polluting drinking water. "One way to remove doubt from the public and government agencies is to introduce a unique tracer



BUILT WITH
AIRCRAFT GRADE ALUMINUM
TO SURVIVE
YOUR
WORK WEEK
G3i
INOVA TOGETHER, WE GET THE JOB DONE.
FIND OUT MORE AT:
WWW.INOVAGEO.COM/G3i
G3i - cable-based land recording system
Arrived at location, 6:15 am. G3i's
power-down-the-line uses less
infrastructure and fewer batteries to
charge in cold weather. Cables retained
flexibility in -40°C. Box-cable-box
design reduced our time while
troubleshooting in the field.
All terrain.
All powerful.
All we asked for.

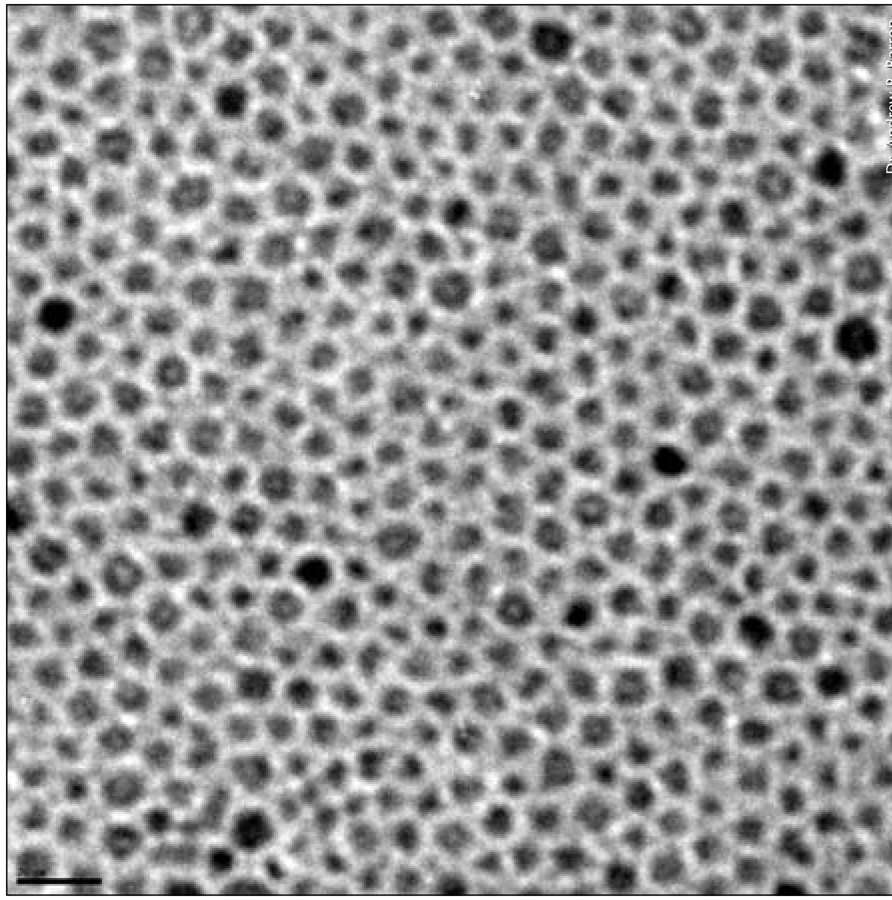
to your fraccing operation," says Dr. Barron. "We can control the composition and design magnetic properties at the nano scale to manufacture non-toxic tracers that are easily detectable in ultra-small quantities, water soluble, and not retained in the reservoir formation. The first customer field trials are in development and tests may soon begin in west Texas."

Fraccing's Future and Policies

Information and reports about hydraulic fracturing abound in the public domain; some are true and some are false. "In either case, the policy makers and regulators, both federal and state, must alleviate some of the fears, uncertainties and doubts of the communities in these shale regions being impacted by the way we produce hydrocarbons," says Emil Peña, former Deputy Assistant Secretary for Oil and Gas at the US Department of Energy, industry veteran, and Executive Director of the National Corrosion Center, Rice University. "They must also balance the industry's needs and rights to produce these natural resources in a safe and environmentally friendly manner.

"Water is our most precious resource and should never be wasted," Emil Peña continues. "The nano-based technologies covered in this article are only the tip of the iceberg and if these and others are implemented in a responsible manner, the public will begin to feel a better comfort level through transparency. The role of the policy maker and regulator is to ensure that these measures are taken and reported by the industry. The Federal government through various agencies has started their own requirements on federal lands. The State of Texas was the first to pass and implement frac transparency laws and other producing states have followed and are also beginning to coordinate their efforts towards transparency.

"The challenges before us are twofold," according to Emil. "Firstly, we must have common disclosure standards and not a patchwork of regulations that would impede industry progress. The second is a continuing and dynamic review of reporting requirements and technologies that are now being commercialised to better produce, while having minimal impact on the environment.



The tracers being developed at Rice, in collaboration with Dr. David Potter, Professor of Physics and Director of Integrated Petroleum Geosciences at the University of Alberta, consist of about 7nm doped (the process of changing properties by adding trace amounts of elements) nanoparticles. The doped ferrite nanoparticle has high permeability and controlled solubility qualities. Each non-toxic tracer can be made with a unique fingerprint and can be readily separated from large volumes of produced water.

"While laws and regulations are needed, the companies have the true incentive, in part driven by the insurance industry, to produce our resources in a responsible manner," says Emil. "When you are managing a producer's risk better through superior knowledge, techniques, and technologies, the impacts to the producing regions can be minimised, lowering insurance rates and allowing our communities to rest a little easier." ■

Nanotechnology Research

The Richard E. Smalley Institute for Nanoscale Science and Technology at Rice University, Houston, Texas was the world's first nanotechnology centre, founded by Professor Smalley in 1993 as the Center for Nanoscale Science and Technology (CNST).

Starting with Professor Smalley's vision, funds were quickly amassed to buy research equipment and laboratory space. The institute has now grown to include 151 faculty members in 21 departments and over 500 students researching societal and scientific arenas including energy, education, aerospace, ethics and human health.

The technologies and companies presented in this article are the outgrowth of research at Rice University and the goal is to bring this research into the public domain. It is up to individual faculty members to raise interest in the technology, start the company, and have the newly formed entity negotiate for a licence to use that technology.

Is There Oil Offshore East Africa?

There is definitely gas – but do the vast expanses of the Indian Ocean also hold promising oil reserves?

DAVID BAMFORD

The emergence of East Africa as a petroleum province has been spotted by the media, especially the UK press where a headline such as 'Improved technology helps to oil the wheels for East Africa' (*The Times*, 7th January 2012) is but one of many.

As a recent Finding Petroleum Forum revealed, it is certainly true that improved technology has had an impact, whether through satellite imagery, aero-magnetics, gravity gradiometry or plate tectonic modelling. The likelihood of oil, however, and where it may be located, as well as whether the gas that has been discovered is commercial, requires more careful thought.

If we go back let's say 10 years, East Africa was completely disregarded by petroleum explorers. Only a handful of wells had been drilled. There was not very much data but source rocks were generally believed to be absent or poor; the prevailing view was that there would only be small amounts of gas, if anything.

Actually, it appears that this was based on 'Myths, Myopia, Misinformation', as pointed out by Chris Matchette-Downes in *GeoExpro,* Vol. 4, No. 5. In particular, he identified evidence for contiguous source rocks, for example in the Early and Mid-Jurassic, which could be in the oil window offshore. And of course, persistent seeps were known both offshore and in the lakes of the East African Rift System.

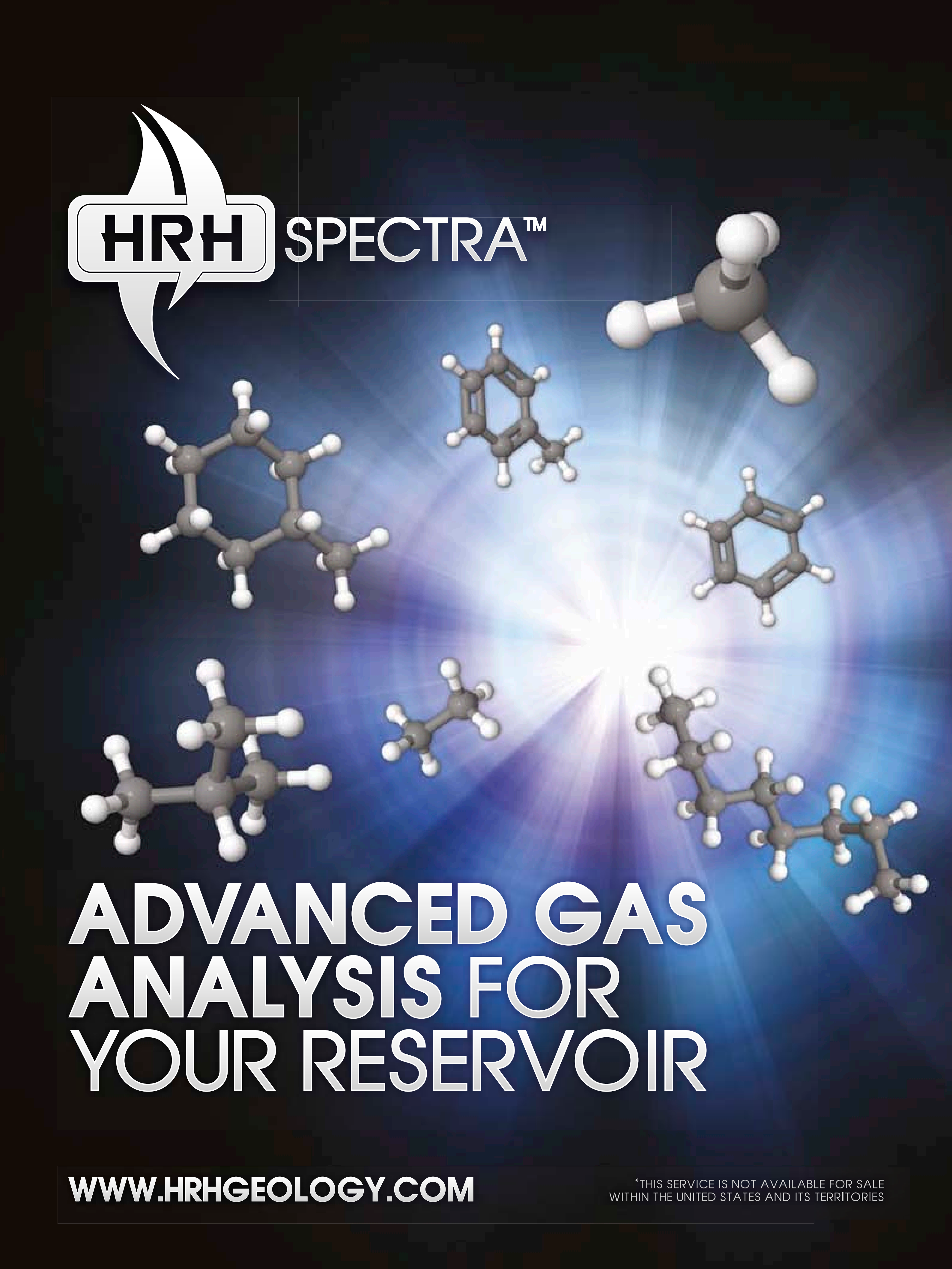
Since 2008, there has been significantly more exploration activity and new well results are being announced all the time, but the essence is still the same: oil has been discovered onshore in the Albertine Graben of Uganda and very recently in Kenya (see Hot Spot, page 98). Large amounts of gas have been discovered offshore – in both Mozambique and Tanzania – but no oil as yet.

Significant Gas Volumes

What has been proposed so far offshore is that the youngest source rock is an Early/Mid-Jurassic marine shale, and so one model suggests that this may have been buried under more sediment than previously anticipated and is now in the gas window. However, this source rock has not been sampled and an alternative explanation is that the gas derives from an area of this rock that has had high terrigenous input and so is gas prone.

The gas volumes discovered in both Mozambique and Tanzania are significant and as a distant observer one's immediate response is to think that they are both

Jane Whaley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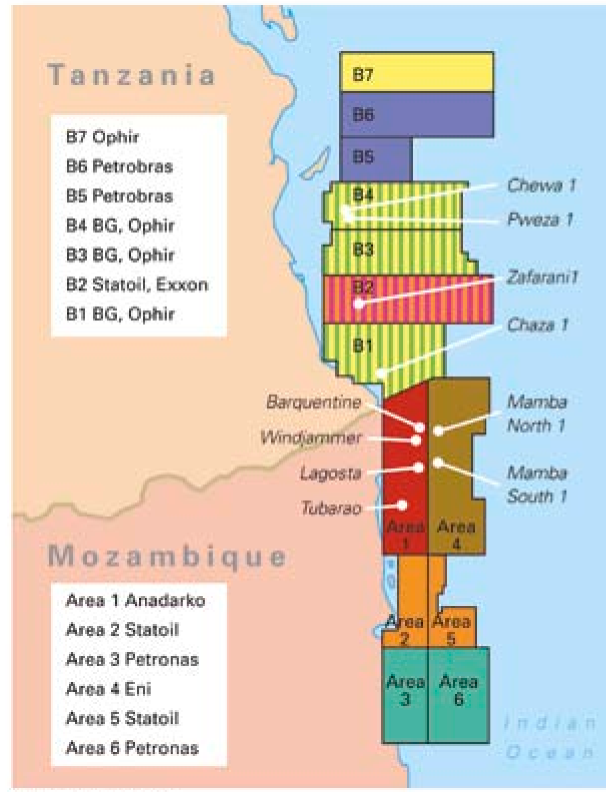
candidates for LNG schemes. However, as Monica Enfield of Energy Intelligence pointed out in her Finding Petroleum presentation[1], this perspective ignores the focus that both host governments will have on domestic issues, such as creating a local market and providing employment in the relatively short term.

As Bernstein Research has noted, a combination of successes – for example shale gas onshore in the USA, and conventional gas in the Eastern Mediterranean and on the North West Shelf of Australia – has led to there being a large number of global LNG opportunities for gas to be sent to fuel the markets of either Europe or South East Asia. This may mean that somewhat more costly East African LNG will have to wait its turn in the queue. Whilst the Majors may be content to 'bank' gas for the longer term, ready for the day the price rises and it is needed, this may not at all be in line with the hopes and expectations of the governments of Tanzania and Mozambique.

The attraction of oil offshore East Africa would be that the global price is probably going to remain high and that a discovery of a few hundred million barrels can be developed fairly rapidly with an FPSO and shuttle tankerage – indeed many tankers pass this way as they go around the Cape of Good Hope.

East African Gas Hot Spots



Source: Energy Intelligence

Where is the Oil?

So where might there be oil offshore? Explorers now have vast amounts of data – from satellites, airborne surveys, field geologists, seabed cores, national repositories, the huge number of wells drilled – over 200,000 'wild cats' alone since 1965 – and publications. They will need to sift through all of these to identify basins and plays which might work or, in the question I have just posed, might work in a particular way.

The ability of explorers to spot the next big play depends on their ability to deal with this veritable Niagara Falls of data, to solve what some have referred to as the 'Big Data'[2] problem – or, perhaps, opportunity is the better word?

Deploying a deep understanding of plate tectonics and chronostratigraphy – understanding what gets deposited where and when – is the key process by which this is achieved, whereby opportunity is accessed.

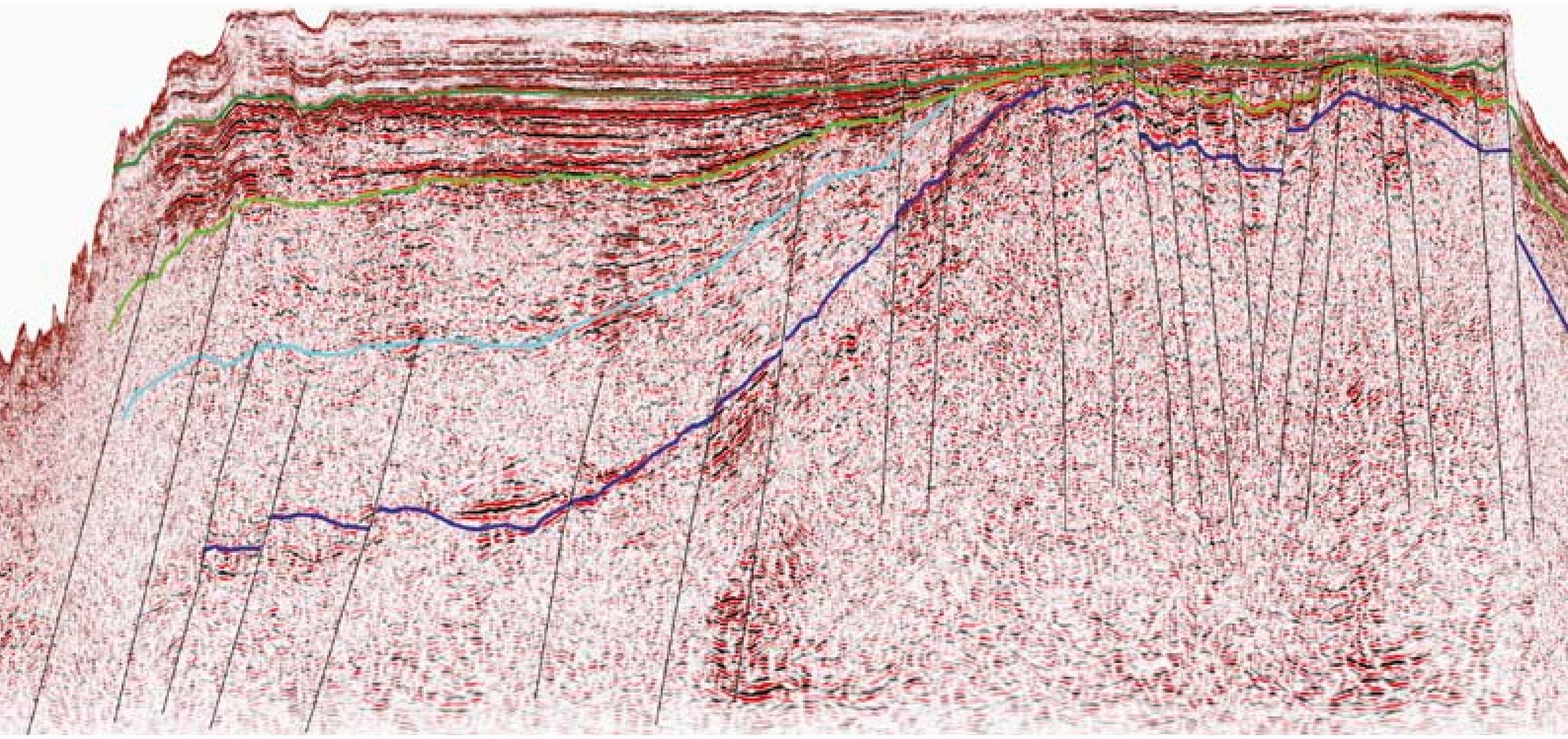
It is just my opinion but we explorers may be guilty of laziness, believing – or at least giving the impression of believing – that offshore exploration nowadays simply consists of dropping in a regional/exploration 3D seismic survey and then 'no dry holes' will result. This is far from the truth! ■

Acknowledgements:
I am grateful to Alastair Bee at Richmond Energy Partners, Chris Matchette-Downes at MDOil and Oswald Clint & Robert West at Bernstein Research for helping me summarise the current status.

References:
1. Finding Petroleum Forum, 17th April 2012
2. http://www.findingpetroleum.com/video/385.aspx

Apology:

GEO ExPro Magazine would like to apologise to Jon Gluyas, Jim Lorsong and Ian Phillips for inadvertently omitting to acknowledge their assistance with the article 'Enhanced Oil Recovery – Utilising Captured CO_2', published in Vol. 9, No.1



Energy and the Environment

The Rise and Rise of Corporate and Social Responsibility in the Energy Industry

Jardine Marine Consulting

The issues surrounding Corporate and Social Responsibility and Social Licence to Operate are nowhere better demonstrated than in the Arctic.

JOHN POTHECARY and JAMES BLANCHARD, RPS Energy

Petroleum operations have not always sat comfortably with concern for the environment or sustainability. However, over time this landscape has evolved, moving from the position that responsibility stopped with the applicable regulations, through an unwritten social contract into a more rigorous Social Licence to Operate (SLO). A genuine desire to safeguard people and the environment has become an increasingly formal and central part of the business process. This understanding now flows throughout the life of an asset encompassing strategic considerations, project funding and approval, stakeholder engagement, project management, and of course their relationship to technical expertise. These winds of change are blowing increasingly strongly through all sectors but particularly through the energy industry, with its potentially high impact from 'wide-area' operations.

There are a number of cultural, technological and commercial drivers for this change. The central components are a developing and more universal understanding of human rights coupled with a growing trend of nationalisation and a call for greater transparency for public companies. These are driven, at least in part, by an increasing number of vociferous stakeholders, emboldened by new communication technology, not least the internet.

Marry this with the inevitable push into more technically challenging, as well as more environmentally and culturally sensitive areas, and it is clear why the energy industry now has to develop and protect its SLO as it strives to deliver the type of programmes that are expected of it.

It is right and proper that a degree of power has shifted from those traditionally involved in exploration and production, such as landowners, technology providers and financiers, to a broader church of stakeholders. However, this shift means that there is now an additional level of complexity that must be managed, and managed well.

A Broad Canvas

Ten years ago this looming challenge was apparent to RPS and led to the decision to develop an Energy Practice, bringing energy and the environment together within a single company. This strategy has developed over the years both in the UK and elsewhere, building a consultancy that combines best-in-class technical and environmental expertise. Today, RPS has strong and diverse energy and environmental expertise in EAME, Australia/Asia Pacific and in North America. An important aspect of this development has been the recent incorporation of a strong training capability, partly driven by the desire to contribute to the increasingly important knowledge transfer aspect of SLO as an element of a company's broader corporate responsibility strategy. It is a core competency to be able to offer the training excellence expected by international operators to national energy companies and to help them manage their training and competency assessment and assurance needs.

Corporate and Social Responsibility (CSR) operates on a number of levels. At the lower end of the spectrum, good practice requires engagement with local communities to identify opportunities for assistance and to mitigate any adverse consequences. Thus companies contributing to local health care, supporting schools, providing local people with support and employment, whilst not being entirely altruistic, reflect a tacit understanding that the value of success to them is large and that a proper engagement of the community is both beneficial and welcome.

At the other end of the spectrum, an holistic approach to CSR can help mitigate the 'Paradox of Plenty', whereby resource-rich developing countries frequently do relatively less well in terms of social performance than countries with fewer resources. In this context, helpful CSR can include promoting transparency, strengthening institutions, providing guidance on social and environmental regulation, helping to provide environmentally clean investments, investing in proper knowledge transfer and in training of local staff. Between these two ends of the spectrum is a gradation of support that can provide appropriate input to communities and that engenders social and political support at home and in other countries. Whether rooted in altruism or not, the drivers encouraging companies down this road are undoubtedly beneficial to local populations and ultimately of benefit to the company and to society.

The Challenge

The upstream energy sector is not unique in needing to work to an 'energy and the environment' ethos. Such considerations are important to all industries that may have a material impact on the broader environment, whether directly or indirectly. Stakeholder engagement and support is also important throughout the lifecycle of an asset, and is as critical to infrastructure development and subsequent asset operations as it is to the earlier phases of resource exploration and extraction.

Indeed, the emplacement of infrastructure is often more problematic in its planning and implementation than exploration and appraisal, as it may spread the original footprint across a much broader area, potentially affecting much larger numbers of people. SLO concepts in this case extend to cover a whole new range of stakeholders, many of whom may not directly benefit from a gain to the local economy – thus the need to plan and mitigate social impacts becomes even more important and challenging.

These issues are nowhere better demonstrated than in the Arctic. With the eyes of the world on operations in this area, whether with environmental, cultural or political sensitivities in mind, operators are well aware of the need to work to strong SLO principles. Even for the largest operators, the sheer range of capabilities needed to ensure that all aspects are addressed is a

Rapidly Evolving Concepts

Corporate and Social Responsibility (CSR) and Social Licence to Operate (SLO), as concepts, have evolved rapidly over the last 10 years and are now integral to the operation of Energy and Resource companies.

Ten years ago, as these winds of change gathered momentum, RPS recognised their importance and actively pursued a strategy to meld traditional technical and operational skills with the environmental and social expertise needed for this new agenda. Now, this combination of expertise, the individual disciplines of which might previously have been thought strange bedfellows, has proved to be a useful resource for companies operating all over the world, both on and offshore.

CSR continues to develop and with it the range of skills required. The trend is towards putting in place the wherewithal to develop autonomously rather than providing a time-limited benefit. Training and institutional strengthening will play an increasing part and companies looking to operate sensitively will need to develop these skills internally or seek assistance from qualified third parties.

"Companies that are breaking the mold are moving beyond corporate social responsibility to social innovation. These companies are the vanguard of the new paradigm. They view community needs as opportunities to develop ideas and demonstrate business technologies, to find and serve new markets, and to solve longstanding business problems." – Rosabeth Moss Kanter, Harvard Business Review.

"Companies with their eye on their 'triple-bottom-line' outperform their less fastidious peers on the stock market" – The Economist


RPS

The search for unconventional hydrocarbons such as coal seam gas involves discussions with politically sophisticated stakeholders

Case History: Arctic Field Data Collection

The Central Beaufort Sea is a challenging area for potential offshore development. RPS provided experienced Arctic marine project management and HSE expertise, including the collection of environmental, oceanographic, meteorological, biophysical, geotechnical and geophysical data. RPS also offered advice on the planning and oversight of on-ice activities, polar bear and cetacean aerial surveys. Throughout the project RPS gave support through mentorship, coaching advice and field leadership for all stakeholders, including the scientific community, multiple federal government agencies and the first nation and aboriginal peoples of the North West Territories, who were involved in the planning and execution of the various projects.

challenge and is an area where companies like RPS have been very active. The need for a multidisciplinary response has resulted in our involvement in helping to balance the technical aspects of projects, such as seismic, site surveys, drilling and logistical operations, within an acceptable environmental framework. This is achieved through careful operational and preparedness planning, environmental impact assessment, metocean analysis and rare species monitoring. In part, this has been predicated by the regulatory framework but frequently these requirements have been exceeded by the desire to satisfy the company's various stakeholders.

The search for unconventional hydrocarbons, whether shale gas and oil in the USA or coal seam gas in eastern Australia, perhaps provides a counterpoint to the Arctic frontier. Whereas the previous example involves a wide audience concerned about a fragile and potentially shrinking environment, the latter requires engagement with politically sophisticated stakeholders in the context of comprehensive existing legislation and regulation. Operators trying to balance the positive message of important new reserves with the concerns and sometimes objections of others, all against a reputational risk backdrop, have a delicate challenge to address requiring a different, if overlapping, set of capabilities.

In both cases, the franchise of stakeholders includes staff, as it is increasingly important for both recruitment and retention that people feel proud of their company. Ultimately a low turnover of staff directly affects a company's ability to operate effectively and this aspect of CSR is as important as other more direct issues.

Gaining a proper SLO is a challenging task, and even if successfully gained can be very easy to lose. A multi-faceted approach to keep on top of all the challenges faced before, during and after an operation can be a task that stretches even the most experienced companies.

The Future

The drivers behind a much more environmental approach to both resource exploration and associated infrastructure are clear and have been recognised by most Western operators. However, the issues are complex and even well-resourced majors will struggle to find all, or even most, of the required resources in-house. Take this in conjunction with the slow but steady take-up of these ideas by non-traditional international operators such as NOCs both at home and abroad and it is clear that there is a going to be a significant demand for consultancy services such as those offered by RPS and others.

We expect an increasing take up of skills that are informed by a broad understanding of the wider CSR requirement. It seems likely that pressure from governments and NOCs will direct CSR efforts increasingly towards training of all sorts and also towards institutional strengthening. However, the narrower requirement for local support during operations will continue to be needed to manage local expectations and engagement.

The energy and the environment theme is a useful way of looking at the development of capability and one that will become increasingly important as resource industries try to keep up with global demand. ■

Kulusuk, south-east Greenland: due consideration for local populations will give them the incentive to engage with well-run operations to the benefit of all parties.

Finding BURIED Treasure!


BG Group

Geologist *Malcolm Brown* of BG Group is proud of a career spent in exploration throughout the world, and reflects on why he believes that the oil industry is all about 'making tomorrow better'.

JANE WHALEY

"What really gets me up in the morning is the thought of finding something new," says Malcolm Brown, Vice President, Exploration and Technology for BG Group, explaining why he still loves the career he commenced over 30 years ago. "Exploration is always a big gamble; you create your play, based on analogues, apply for acreage, but then you have to be brave and drill. It's like being a detective, trying to work out what happened sequentially a hundred million years or more ago. Obviously, there's a lot of high-tech science and software involved, and you have to overlay the commercial and competitive elements – we're competing with some pretty big companies out there. But ultimately it's about finding the code to unlock buried treasure. It often doesn't work out, but I still find it fun."

A Good Investment

Like many young geologists who graduated in the '70s, Malcolm did not necessarily envisage a career in the oil industry. "I decided to study geology because I was fascinated by plate tectonics, which was only just coming to the fore," he explains. "After my first degree at Kingston Polytechnic, there were not many jobs around except in the expanding oil industry, so I joined GibCo as a mudlogger – the lowest form of geological life! I worked in the Libyan desert; it was tough, but fun, and I formed some great friendships – we still have reunions. After a couple of years I moved to Saudi and worked in directional surveying; driving to rigs all over the desert, getting there and back and getting the job done, it seemed exciting work with a lot of responsibility for a young man."

Malcolm believes that such early, field-based experience gives young graduates a good grounding and introduction to the hydrocarbon industry, particularly if it is then cemented by a further qualification – in his case, a Masters degree in Petroleum Geology at Imperial College in London. "It was the best investment I ever made in myself," Malcolm says. "It gave me an excellent grounding in the basics of finding oil and gas, and BG Group still employ several people each year from that and similar courses. We find first degrees in Geology are too general and therefore tend to take on people with further degrees, either MScs or PhDs. We also like it if someone has basic industry experience as it makes them more focused and mature."

On leaving Imperial College, jobs in exploration were scarce, and Malcolm joined the nationalised UK company British Gas, which concentrating on selling and distributing gas, with a very small and totally UK-oriented E&P arm. He thought he'd stay just a short while; 30 years and several company transformations and name-changes later, he's still there.

Varied Roles

Malcolm takes up the story. "In 1986 British Gas was privatised, meaning that we were able to look overseas for exploration opportunities and expand back into oil. We bought the Houston-based oil company Tenneco International in 1988, which had a portfolio of ten countries. I spent from 1991 to 1994 there as Exploration Manager covering West Africa and latterly South America. When I returned home, the company was going through a period of considerable change, with the first of two demergers. The gas distribution arm eventually became owned by Centrica, and E&P and the international gas business was reincarnated as BG Group.

"This came with a great opportunity for me as I was appointed Exploration Director, although, unfortunately, my first job was to reduce my staff by 40% – a hard task. However, we were able to high grade the portfolio and, despite being small, we then enjoyed five very successful years, during which time we had major discoveries, such as West Delta Deep in Egypt, Kashagan in Kazakhstan, as well

as important finds in Indonesia, Bolivia and Trinidad."

Malcolm's next role, in 2000, was Asset General Manager running BG Group's Central North Sea fields, which included Armada, Everest and Lomond. He found the move into production interesting, but admits that he missed the excitement of exploration. "Production is often about looking back, fixing what has just broken, and I enjoy looking forward, so it didn't suit me so well.

"I then moved into a senior 'corporate' role, concentrating on HSSE," he continues. "This was also interesting, giving me some different and very valuable insights into the business – again, trying to make tomorrow better! However, it never replaced the exploration 'buzz' for me, so in 2005 I returned to lead Exploration, with a worldwide remit.

By this time BG Group had grown considerably and there was a lot to do in terms of refilling the portfolio. In 2006 it drilled its first deepwater subsalt well in the Santos Basin in Brazil with Petrobras. "It was long and difficult, but it unlocked the key and the second well we drilled was the giant Lula discovery. It was all a big gamble, but it paid off and it may all seem very obvious now, but it wasn't always at the time! For all the recent good plays, like sub-salt Brazil, offshore Ghana or now Tanzania, technological developments have been important, but so too has been the willingness to test accepted logic.

"I think a mixed range of assets is vital for successful growth," Malcolm adds. "Our portfolio has broadened; it still has a large proportion of gas, though the major oil reserves from Brazil will form an increasing percentage of our production. The key part of our unconventional portfolio is coal seam gas in Australia, which accesses international LNG prices. Market is crucial – companies must always be market driven".

Biggest Challenge

In common with many people, Malcolm believes the biggest challenge facing the industry is successfully bringing on the next generation of geoscientists and engineers. He is proud of the fact that BG Group has a 90% retention rate over 10 years for geology and geophysics recruits to its graduate scheme, which has been running for almost 20 years. "I think that while we are a growing company, which is fun and stimulating, we are still small and entrepreneurial enough for each person to feel they can make a difference," he says. "We employ 350 geologists and geophysicists in about 15 different countries and about half of these do not originate from the UK. We actively try to take graduates from the countries where we work, often sponsoring them through further degrees.

"My advice to young geoscientists is to go overseas and get experience in a range of branches of the industry. That's what we do to all our young graduates. The average geologist in an oil company doesn't spend enough time on rigs or with seismic crews, as it is important for them to see where the data comes from and the issues involved in its acquisition. They should also experience living and working in a foreign country."

Having worked for the company for a relatively long time, Malcolm enjoys seeing the fruits of this carefully planned graduate training system. "It's good to see people we took on as young graduates fifteen years ago now thriving as excellent exploration managers."

Transforming Lives

In 2011 Malcolm Brown was awarded the Silver Medal of the Petroleum Group of the Geological Society of London, which is a yearly award presented to individuals with a geoscience background who have made outstanding contributions to the petroleum industry. "I was very flattered to receive this," he says, "because a number of people for whom I have great respect, such as Bob Stoneley and Malcolm Pattinson, were previous recipients. Having been in the industry for a long time, it was an honour to follow in their footsteps."

Malcolm has also been an active member of the Geological Society Council, and is on the advisory board of the Energy and Geoscience Institute (EGI) at the University of Utah. "I enjoy broadening my remit and seeing how the geosciences work outside the oil industry," he explains. "I also find that extracurricular activities are useful both in learning more about the sciences and for networking. It helps you look at the world afresh. I think there are still whole chunks of it that need a change of paradigm; either the geology isn't what we had always assumed it to be, or a crucial market change will shed a completely new light on it.

"My whole career with BG Group has been a fantastic experience," he continues. "It's a very special company. I have worked with a group of loyal, dedicated people, with great camaraderie, and I like what we've done. I love being part of an industry which can make such a difference to people throughout the world. Brazil is a good example, where the major recent discoveries will bring economic benefits to the people and create a technological industry to invest in the future. And look at East Africa. For years it was a backwater; soon it will have a gas export industry, creating long term employment and major revenues for the host countries, transforming lives forever. It's hard to get that across to the media, which is partly our fault – we don't tend to present a coherent story and we need to address that, in order to encourage more young people into the industry.

"Making tomorrow better is what drives me, and that is what we do," Malcolm concludes. "I'm proud to be involved in this amazing industry." ■

In his spare time Malcolm Brown enjoys mountain-biking, running and travelling, and often takes his bike with him on his travels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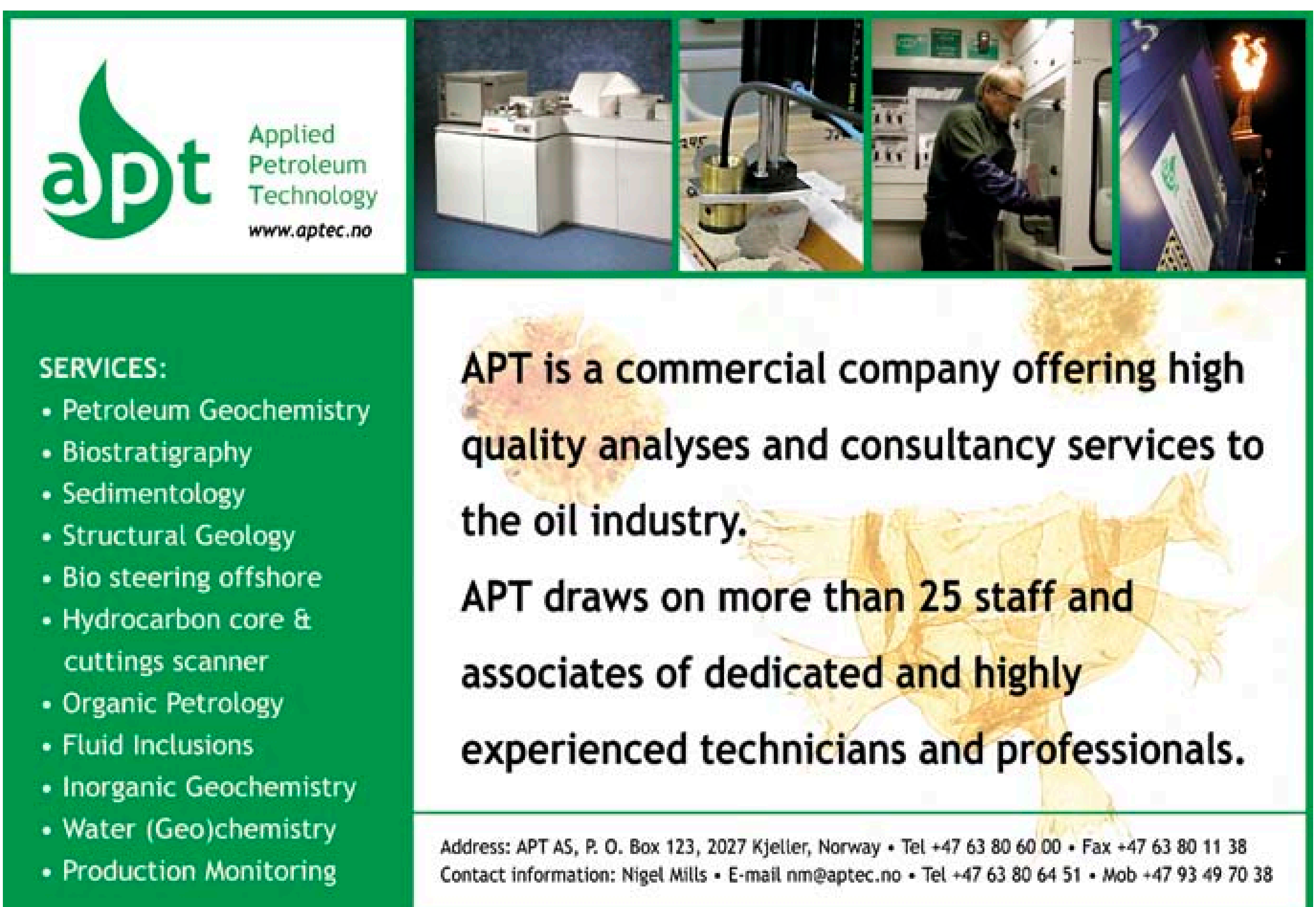
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Fertilising the Future

York Potash, a mining company based in north-east England, have discovered significant quantities of minerals for use as fertiliser, using technologies familiar to the oil and gas business.

The town of Whitby on the coast of north-east Yorkshire in the UK is known more for its associations with Dracula and the famous explorer Captain James Cook than as a centre of industry. Whitby has a long history, dating back to the year 656, when Whitby Abbey was founded. The ruined 13th-century abbey building, destroyed during the time of Henry VIII, still looms imposingly above the harbour where James Cook first learnt his seafaring skills. Later, author Bram Stoker was inspired by the Gothic ruins to write his novel about vampires.

Whitby does also have an industrial past, albeit not on a large scale. Much of that industry was a result of the local geology, such as the extraction of alum, dating from the 16th century, and the discovery of jet, from fossilised Jurassic conifers, which was used in jewellery. Iron-rich springs led to the development of a spa and hint at the ironstone mining and smelting that occurred in the locality and further inland in the 19th century.

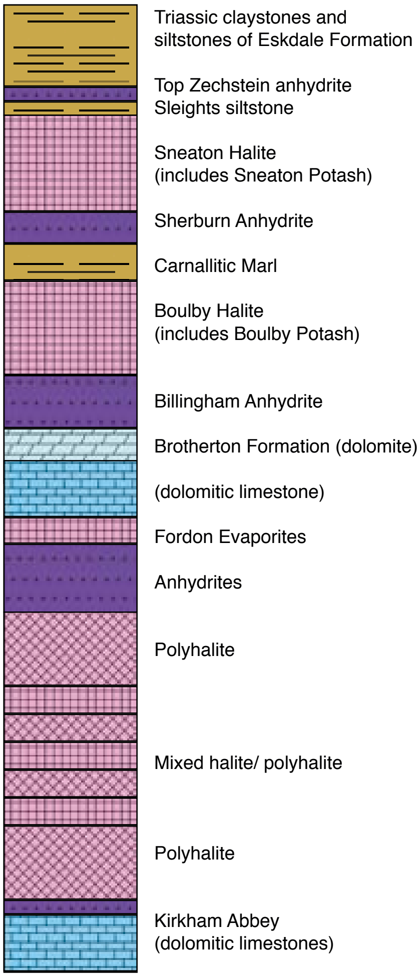
Deposits Linked to Hydrocarbon Geology

This relatively small scale industrial past is poised on the brink of a larger scale future thanks to the discovery of minerals that can be used to manufacture fertilisers, now a product much in demand in the face of a growing global population and the need to produce more and more crops in an efficient and cost-effective way.

These minerals are not visible in surface exposures but are located at depths of between 1,000m and about 1,600m below ground level. They were first discovered during petroleum exploration in the 1930s and are inextricably linked to the familiar oil and gas geology of the Southern North Sea, as they are found in the evaporite sequence of the mid and lower Zechstein Formations. Two main types of minerals have been found in quantity here, sylvite, or potassium chloride (KCl), and polyhalite, a complex hydrated sulphate ($K_2SO_4.MgSO_4.2CaSO_4.2H_2O$), either a product of evaporation or the alteration of minerals such as gypsum.

The deposits were not exploited until the 1960s, when three companies started investigations in the Whitby area. Only one of these resulted in a commercial project when, in 1973, Cleveland Potash Ltd. opened the Boulby mine, about 15 km north-west of Whitby. This mine has been in continuous production since opening, mining mainly sylvite from a seam in a halite sequence above the Billingham Anhydrite. A by-product has also been salt, which is used in the grit spread on the roads, much appreciated by UK motorists in the recent harsh winters!


Paul Wood



Schematic stratigraphy of Zechstein sequence in NE Yorkshire. Ca. 400m column (not to scale)

Polyhalite, however, is considered more economically attractive, as it is more effective as a fertiliser and can be processed into a wide variety of other high value potassium and magnesium minerals. Cleveland Potash started mining polyhalite, found deeper in the Zechstein, in 2011. These deposits are found offshore in the area of Boulby mine, but the zone of deposition moves inland further south, following the edge of the North Sea Zechstein Basin.

Using Legacy Data

In 2010, a new company, York Potash, was established to explore in this area, which comprises an onshore part following the coastal zone between Whitby and Scarborough and also further offshore. Mineral mining rights are not the same in the UK as those for hydrocarbons, so the company defined an area of interest in which mineral rights would be acquired.

York Potash engaged regional mining geological specialists, FWS Consultants of Spennymoor near Durham, to provide an initial evaluation of the expected resource based on the rights so far agreed. Based on a reasonably extensive suite of boreholes, some from the potash exploration of the 1960s and some from hydrocarbon exploration ranging from the 1930s to the 1990s, the evaluated resource proved more than sufficient for a commercial project and an exploration programme was embarked upon. Early in 2011, York Potash was acquired by the AIM-listed, potash exploration and development company, Sirius Minerals, giving the project further impetus.

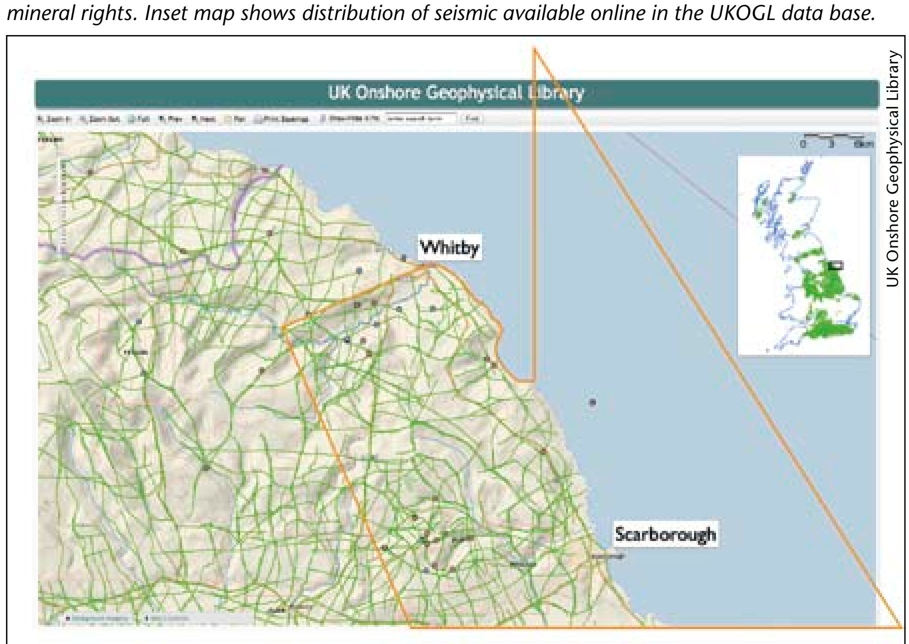
Coincidentally, FWS' investigations were in progress at the time the UK Onshore Geophysical Library (UKOGL) was launched by Lynx Information Systems (see also *Geo ExPro,* Vol. 8, No. 1). Rick Smith, lead consultant at FWS, says, "We realised that now there was a major resource available online, showing maps and cross sections of almost all of the legacy seismic data onshore UK. Because of past hydrocarbon exploration, north-east Yorkshire is particularly rich in such seismic. By browsing the data on the Internet, we could see that much of it, in particular Vibroseis lines from the 1980s, were of a good enough quality to use as mapping, connecting up the boreholes."

In order to make maps, however, the data needed to be obtained digitally and conditioned so that the various vintages and acquisition types matched up. York Potash engaged Spectrum ASA, well known in the hydrocarbon business as a provider of multi-client seismic data, to process the data. Spectrum also specialises in seismic imaging. Andy Billings of Hornet Geoconsulting was also contracted for the interpretation. Various data purchase options are available through UKOGL, either temporary or permanent licences, so it was possible to acquire the data in a cost-effective manner, with post-stack conditioning of the data providing a data set to be interpreted in parallel with the initial borehole programme. Processing tests indicated that some vintages were considerably enhanced by pre-stack time migration, so a second phase was directed towards processing the more 'modern' lines in order to connect the boreholes.

Essentially an Oilfield Operation

The similarities between this mining project and the oil and gas business does not stop with the geology and the seismic. The drilling programme is essentially an oilfield operation, with the difference that York Potash are trying not to find gas in the Zechstein! Oilfield geologists might be surprised (and perhaps jealous) of the amount of core that is cut – necessary in the mining business in order to get an accurate assay of the mineable seams. In the first well, over 500m of core were recovered,

Map of north-east Yorkshire from UKOGL database, showing legacy seismic lines (green) and boreholes (blue and red dots). Orange outline shows general area of interest where York Potash holds mineral rights. Inset map shows distribution of seismic available online in the UKOGL data base.



including the entire Zechstein sequence that was penetrated.

Another familiar hydrocarbon player, Schlumberger, also comes onto the scene to log the wells. The high grade potash and polyhalite seams are characterised by high and specific gamma ray readings, so gamma and density logs are also important. In order to tie to the seismic, as well as sonic and density for the synthetic seismic, VSP surveys are conducted.

Successful Results

So far, the results have been very successful. The initial assessment of resource volumes assumed a 5m thickness of 'ore grade' polyhalite. The first well found a 23m thick deposit, split across three seams and the second and third wells also found thick deposits. Chris Fraser, Managing Director and CEO of Sirius Minerals, said: "These are fantastic results that are a validation of the world-class status of the project. The first hole we have drilled has delivered one of the world's single thickest potash intersections ever reported."

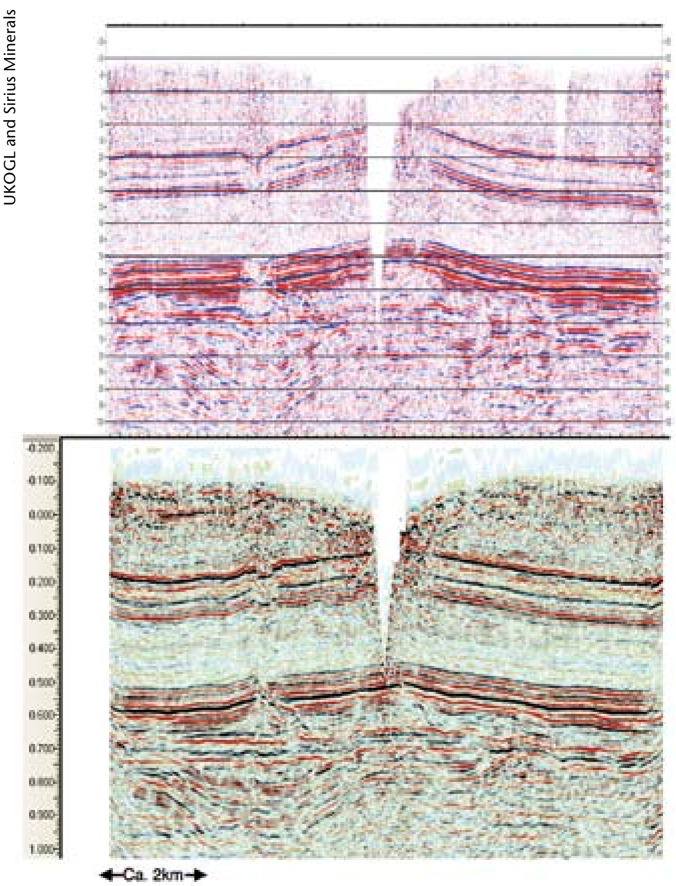
The project looks set to progress further and to develop into a mining operation that will provide a much needed boost to this region of the UK during a time of economic uncertainty. One thing York Potash and Sirius Minerals are very conscious of is that the mine site will most likely be within the North York Moors National Park (as indeed is Boulby Mine). But mining technology has moved on in 40 years and they aim to have as little impact on the environment as possible. The mine head will be designed for low visibility and it is the intention that the product be transported by buried pipeline – another link to the oil industry.

The industrial heritage of Whitby should now be revived, albeit in a high-tech way. What would the Victorian jet, alum and ironstone miners have thought of our ability to find and develop minerals at a depth of 1,500 metres? Even Dracula would want a stake in it! ■

York Potash drilling site near Whitby

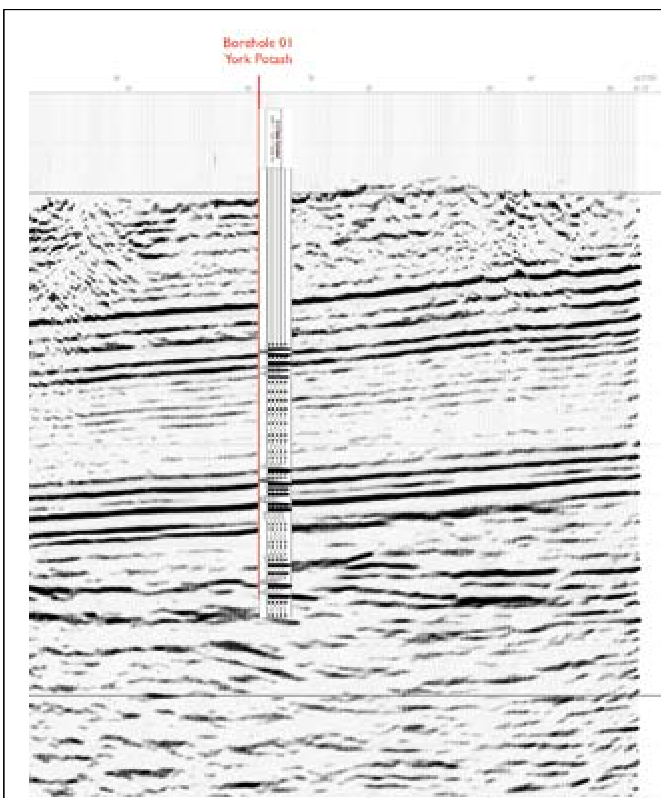
Paul Wood

UKOGL and Sirius Minerals



Seismic line within area of interest: (top) line from UKOGL data base; (bottom) pre-stack processing by Spectrum

Sirius Minerals



Tie between surface seismic and VSP

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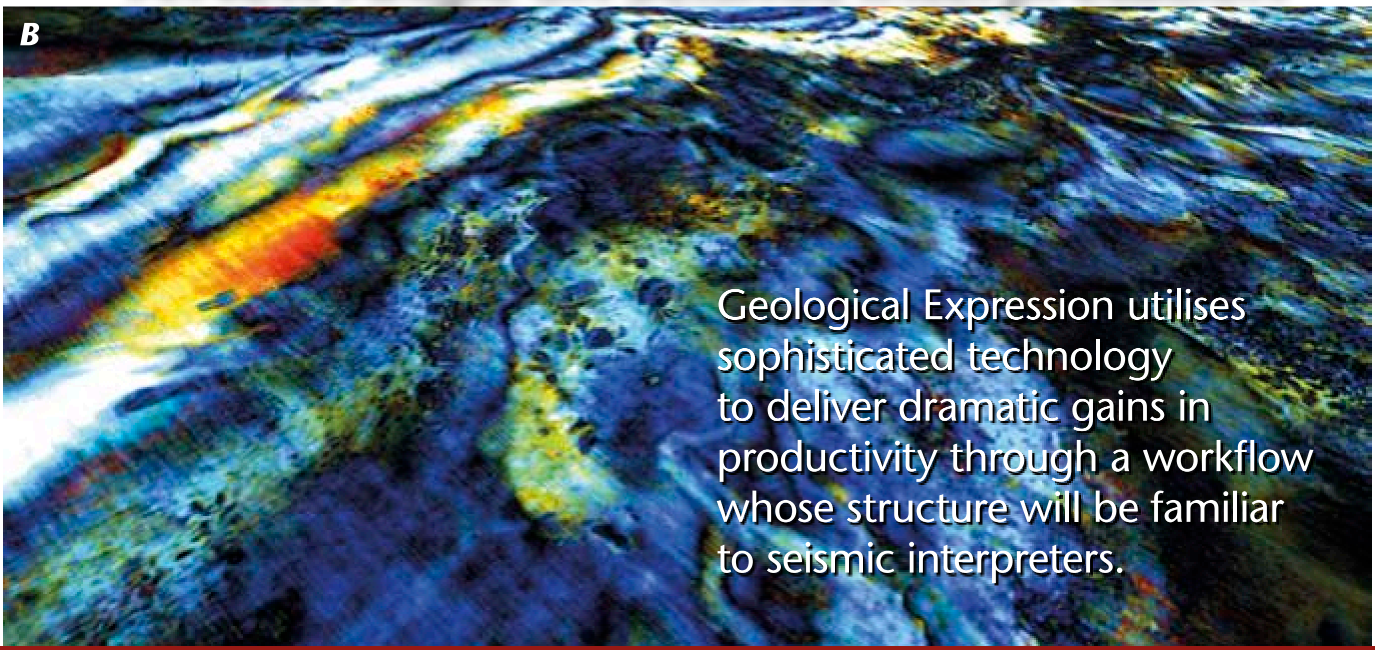
Geological Expression:

A New Angle on Seismic Interpretation



JONATHAN HENDERSON, ffA

Jonathan Henderson, Managing Director of ffA, brings us the first in a two part series on a new paradigm in understanding the geology of the subsurface and his vision for the future in seismic interpretation.

Understanding the Subsurface

It does not matter whether we are working in frontier exploration or on the development of existing discoveries – we are making decisions that are critical to economic success based on our understanding of subsurface geology.

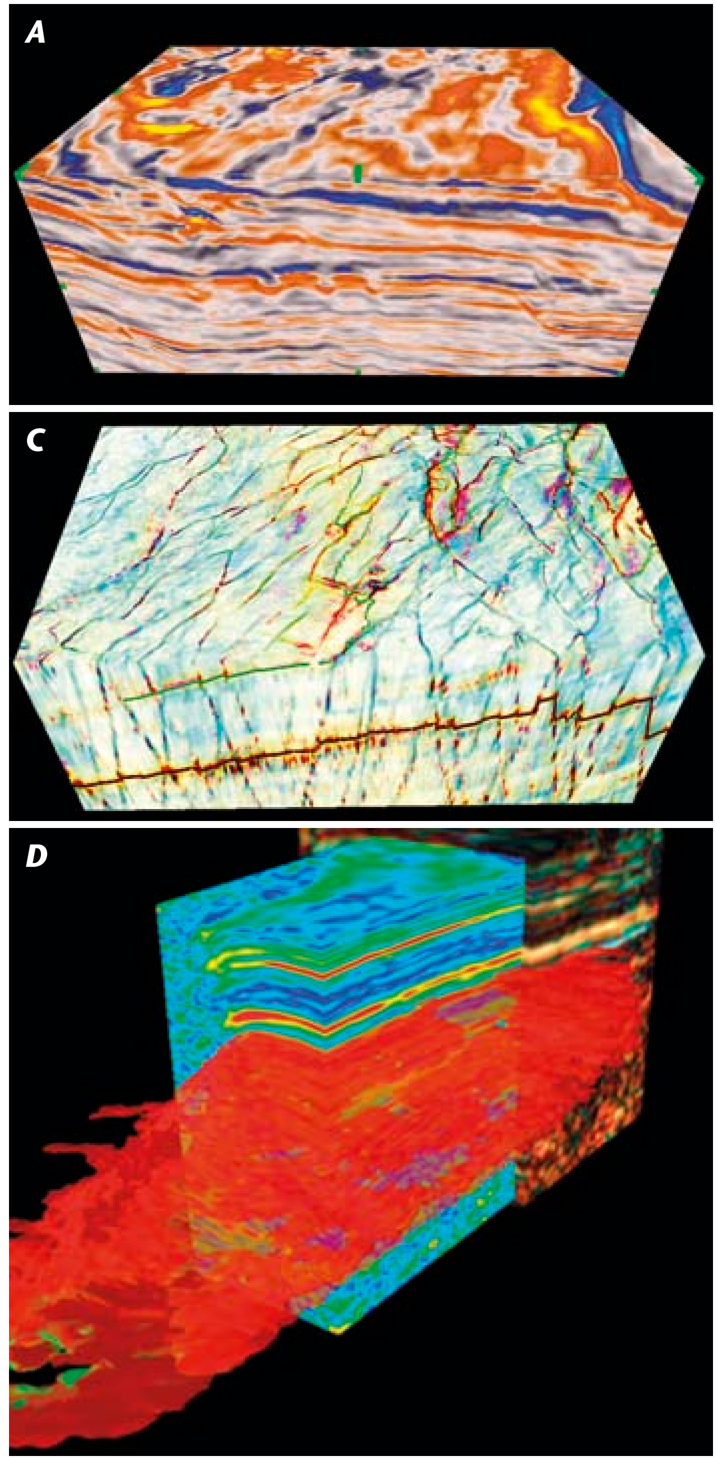
Geological understanding comes from access to information, and seismic data is the most important source of information that we have about the subsurface. Which is why, as an industry, we spent around US$8 billion on seismic acquisition and processing last year. The quantity of seismic data acquired is staggering. Virtually all of the 11.5 million km^2 of licensed offshore acreage has seismic coverage, a very large proportion of which is 3D and the same is true onshore. In many circumstances, the problem that we face is not the lack or quality of data, it is our inability to access the information contained and utilise it effectively to better understand the subsurface.

Seismic interpretation is the process of gaining an understanding of the imaged geology from seismic data. Although it is in many respects a sophisticated process, the way many aspects of seismic interpretation are approached is closely linked to paradigm structured methodologies developed for interpreting 2D paper sections. In some cases this is for the very good reason that these techniques work and we understand them. However, seismic interpretation needs to evolve, and evolve quickly, if we are to keep up with the amount of data that is being produced.

The data analysis issues that we face in seismic interpretation have arisen elsewhere and we can learn a lot from work that has been done outside our own environment. For example, in medical imaging, the rise of screening programmes, such as for breast cancer, gave radiologists and physicians a real dilemma in that there were insufficient experts to interpret all the images being generated using their conventional diagnostic workflow. At the same time they were placing even greater demands on their image data because they needed to reliably detect early stage tumours whose image characteristics were by definition very subtle. The problems of too much data, too few trained and experienced interpreters trying to get more accurate, detailed and subtle information from the data would resonate with most geophysicists and geologists. In the medical world an incomplete or inaccurate interpretation can have life or death consequences; in E&P it can result in millions of dollars of wasted expenditure or hundreds of millions of dollars of missed opportunity.

Adapting the Medical Imaging Paradigm

In medical imaging an enormous effort was put into trying to develop automated diagnosis based around computer analysis of images. What became apparent very quickly was that computers cannot replace clinicians. However, substantial improvements in diagnostic effectiveness and efficiency could be achieved when objective data analysis techniques could be combined interactively with clinical expertise. This resulted in development of CAD (computer-aided diagnosis) systems. Without CAD systems, *The Geological Expression Workflow supports a more efficient way of working in seismic interpretaions, bridging the gap between processing, interpretation and well planning. A Data Conditioning, B. Data Reconaissance C. Fault Imaging D. Horizon Interpretation (next page) E. Geobody Delineation F. Fault Interpretation and Analysis G. 3D Geological Modelling and Well Planning*



data overload would have made several health screening programmes impractical as there are just not enough trained clinicians to review all the data such programmes produce. A similar approach can be applied to seismic interpretation. Automated interpretation is an unrealistic and arguably an undesirable goal. What we need to be striving for is adapting the medical paradigm, which achieves huge efficiency and productivity gains through making objective analysis a central part of the workflow in an interactive data-driven/user (interpreter) guided process.

How would we utilise such an approach in seismic interpretation and what would it give us? This requires taking a look at what we are trying to achieve. As in medical CAD systems, the interactive data-driven/interpreter-guided process should bridge the gap between image formation (seismic acquisition and processing) and interpretation. Also, like medical systems it should enable features of interest to be delineated in a way that respects both the data and what is geologically (pathologically) reasonable based on expert judgement.

Definition of horizon and fault surfaces will be a necessary and important aspect of seismic interpretation for the foreseeable future although there may be more efficient ways of doing this. Where we can increase value immediately is in accessing the information contained in seismic data that is not reflected in horizon or fault surfaces. This information is achieved by analysing the different ways in which geology can be expressed in the data. It can be utilised to better understand the geological variations associated with horizons and faults and to delineate geological elements, such as channels, fan systems, salt bodies, gas chimneys, karsts, injectites etc. that cannot be adequately represented by planar surfaces.

The Geological Expression Workflow

We call the data-driven/interpreter-guided approach for understanding and defining the 3D morphology of the geological elements imaged within the seismic data the Geological Expression approach. As CAD supports a more efficient way of working in medical diagnosis, Geological Expression supports a more efficient way of working in seismic interpretation.

The Geological Expression workflow fully embraces seismic attributes, which have been available for some time, but integrates methods that make it much easier to identify what information is relevant to achieving our objectives and techniques that allow that information to produce 'tangible' representations of geological elements that can be taken into the next stages of the overall subsurface workflow.

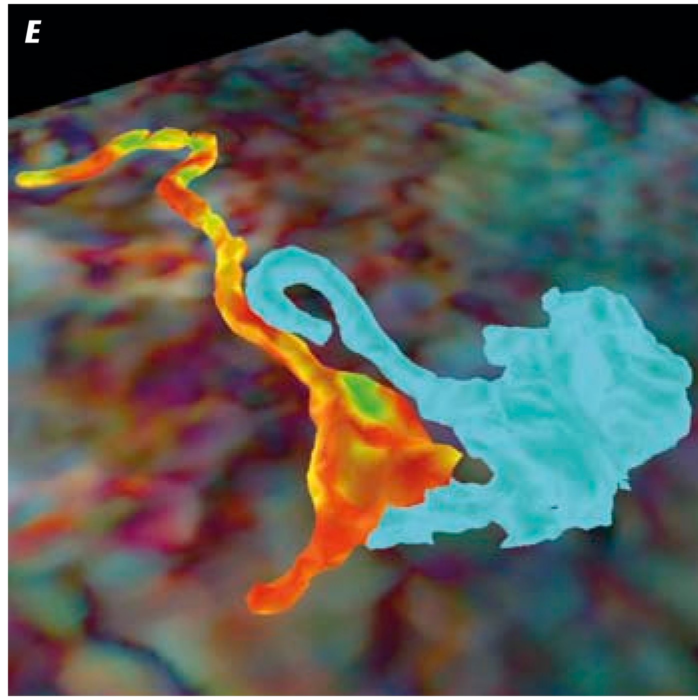
The keys to this are high resolution colour visualisation and lots of processing power. We have to thank the computer games industry for the fact that we now have access to both of these in standard desktop workstations and high-end laptops. Several years ago it was realised that a computer's graphics card could be used to process data as well as power the computer's display. This led to GPGPU or General Purpose Graphics Processor Unit computing. A modern CPU (central processing unit) may have up to sixteen cores giving some capacity for concurrent processing. In contrast, GPUs have hundreds of cores. This means that certain algorithms can run up to 40 times faster on a GPU than on a CPU. As a consequence of the improved performance of CPUs and then the availability of GPUs, at ffA we have seen compute times for volume attribute calculations on desktop hardware shrink by 99.9% in the last 10 years. As a result, processes that used to take a week to complete now run in a minute or two. The power of the GPU is also the reason that we can utilise full colour volumetric displays. Until recently, virtually all volume visualisation systems were limited to displaying at most 256 colours or shades of grey. This meant that data had to be compressed before it could be viewed volumetrically resulting in large information loss. We can now work with volumetric colour displays showing more than 16 million colours. The use of such high resolution colour displays is critical in understanding the subsurface from seismic data as it greatly increases our ability to see, compare and analyse subtle but important features in our data.

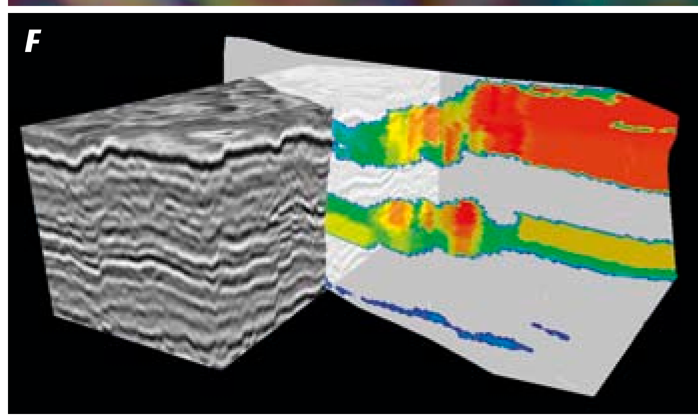
The Geological Expression workflow has several components in common with a conventional seismic interpretation workflow. The big difference is that at every stage the Geological Expression workflow allows the interpreter to interact seamlessly with information provided through an objective analysis of the geological expressions contained in the data.

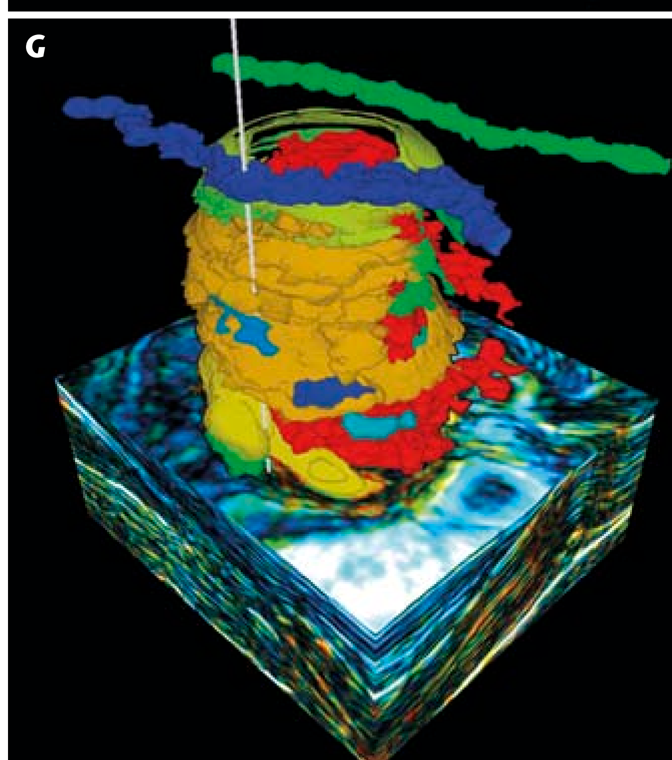
The Geological Expression workflow has to reconcile a number of conflicting requirements. One of these is that it should give the interpreter free reign to explore the data and to examine different scenarios and investigate new concepts. By designing the Geological Expression approach around geologically directed workflows, the interpreter can target their approach efficiently without reducing the scope of their investigation.

Bridging the Gap

Considering the here and now: a full Geological Expression workflow, such as embodied in ffA's GeoTeric™ software, can be realised today. The Geological Expression approach to seismic interpretation bridges the gap between processing and conventional interpretation and increases enormously the amount of data and the level of geological understanding that can be obtained from 3D seismic data. The interactive data-driven/interpreter-guided approach on which the Geological Expression workflow is based is fundamental to being able to deal with the immense and ever increasing volume of seismic data that the industry is investing so heavily in acquiring. ■







Netherlands TerraCube[Regrid] data, supplied by Fugro Data Services AG

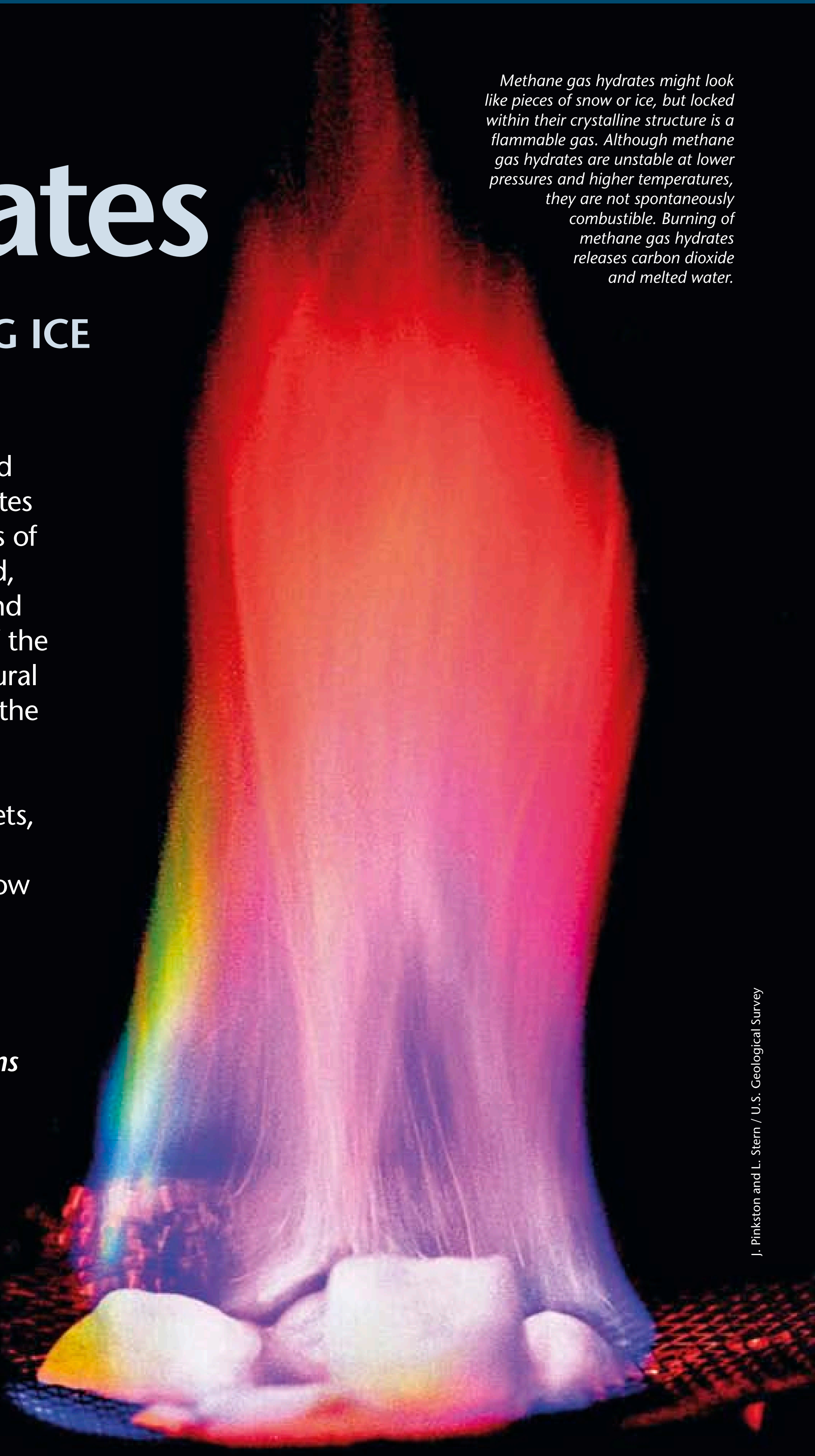
About the Author

ffA

***Jonathan Henderson** is a physicist with over 20 years of extensive experience in imaging and image analysis. His initial interests were in medical imaging, where he had worked on developing new methods for extracting and quantifying the information contained in x-rays and ultrasound scans. Since joining ffA in 2001, he has used his knowledge of medical image analysis to help the company develop unique seismic image analysis technologies. Jonathan has been Managing Director of ffA for six years, during which time the company, its global customer base and its software portfolio have all expanded substantially; the latest development being the launch of GeoTeric, the Geological Expression software.*

Gas Hydrates

PART I: BURNING ICE



Methane gas hydrates might look like pieces of snow or ice, but locked within their crystalline structure is a flammable gas. Although methane gas hydrates are unstable at lower pressures and higher temperatures, they are not spontaneously combustible. Burning of methane gas hydrates releases carbon dioxide and melted water.

J. Pinkston and L. Stern / U.S. Geological Survey

Scientists have known and studied natural gas hydrates for decades. Vast deposits of hydrates have been found, both in the permafrost and the continental shelves of the oceans of the world. Natural gas hydrates also exist in the universe. Hydrates have played an important role during formation of planets, and our atmosphere and hydrosphere. Want to know more? Read on!

"Curiosity is always the starting point for solutions to a problem."

Galileo Galilei (1564-1642)

LASSE AMUNDSEN AND MARTIN LANDRØ

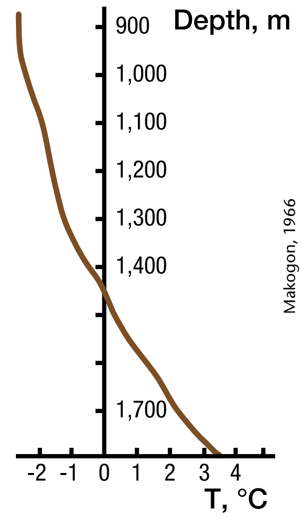
In a series of articles we will explain in a simple way what gas hydrates are, where they can be found in nature, and what their physical properties are. Natural gas hydrates are a potential source of energy and may play a role in climate change and geological hazards. A number of countries, including Japan, USA, India, China, Korea, Germany, and others, have national programmes for studying and industrial production of natural gas from hydrates.

Doubted by Experts

Yakutia, or the Sakha Republic, is a vast unexplored region of Siberia in the north-east of Russia. It is one of the rare places left on Earth where large expanses of wild nature – mountains, rivers, lakes, forests, tundra – are saved untouched by civilisation.

Yakutia is located in a permafrost zone, although the climate is continental, with summer temperatures in July in the city of Yakutsk reaching 40°C, as hot as Tokyo, while in winter it goes down to -50°C. Yakutia is where we find the Cold Pole, the coldest place in the northern hemisphere, where in 1924 the lowest ever temperature for our hemisphere, -71.2°C, was recorded. Here, beyond the Polar Circle, the night lasts all winter, and the day all summer.

It is 1963, and Yuri Makogon, then at the Moscow Oil-Gas Gubkin Institute with a fresh MSc degree in petroleum engineering (now recently retired from Texas A&M University), is staying in the north-western part of Yakutia. He participates in the drilling of the Markhinskaya well, down to 1,800m depth where the temperature is 3.8°C. The well reveals a section of rock at 0°C temperature at a depth of 1,450m, where permafrost ends at a depth of around 1,200m. Yuri recognises that this section of the rock matches hydrate formation conditions. He hypothesises the possibility that gas hydrates can exist and accumulate in such cold layers. His hydrate hypothesis is seriously doubted by the experts, and the idea needs experimental verification, so in 1965 Yuri experimentally proves that gas hydrates may accumulate as large natural deposits in porous rock. In 1969 this discovery is formally recognised and registered in the USSR. Yuri is today recognised as the first to discover that hydrates of natural gas can accumulate as deposits in nature.



Thermogram of the Markhinskaya No. 1 well

Easy Rapid Process

Monterey Canyon is a submarine canyon in Monterey Bay, California. It begins at the middle of the Monterey Bay, and extends 153 km into the Pacific Ocean where it terminates

The wild mountain landscape of Siberian taiga along the Lena River in Lenskie Stolby National Nature Park, Yakutia, Russia

A massive hydrate layer (left) obtained from fine-grained sediment recovered in a marine setting in the Gulf of Mexico, compared to (right) hydrate recovered in a coarse-grained gravel layer from an Arctic setting, the Mallik 2L-38 well, drilled in the Northwest Territories of northern Canada.

at the Monterey Canyon submarine fan, reaching depths of up to 3,600m below surface level at its deepest. The canyon's depth and nutrient availability due to the regular influx of nutrient-rich sediment provide a habitat suitable for many marine life forms.

In 1996, the remotely operated vehicle (ROV) Ventana comes to rest in the Monterey Bay Canyon at 910m depth where the temperature is 4°C. Operated by scientists from Monterey Bay Aquarium Research Institute, Stanford University, and the US Geological Survey, an amount of methane is injected into the water and bottom sediments. Within minutes, this mixture of gas and water forms into a solidified block, bright white and fluffy. The experiment shows not only that methane hydrate formation is possible in natural seawater but that the process is extremely easy and rapid, given that the pressure and temperature conditions are right. Prior calculations had shown that the local hydrographic conditions gave an upper limit of 525m for the pressure-temperature (P-T) boundary defining methane hydrate formation at this site, and thus the experiment takes place well within the stability range for this reaction to occur.

An Unusual Catch

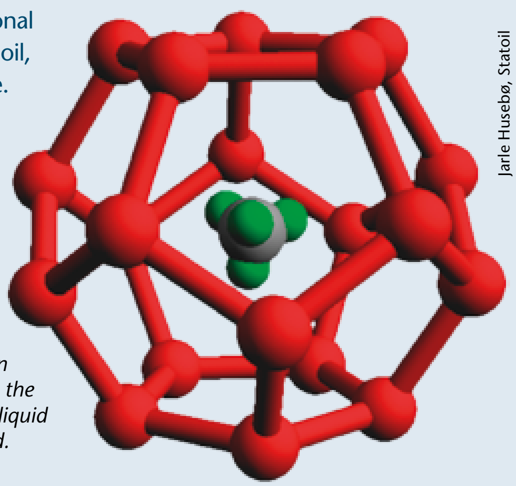
Barkley Canyon is located off Vancouver Island, Canada, on the northern Cascadia Margin accretionary prism. The Barkley Canyon drops down the continental slope toward the abyss. Canyons are

Gas Hydrates

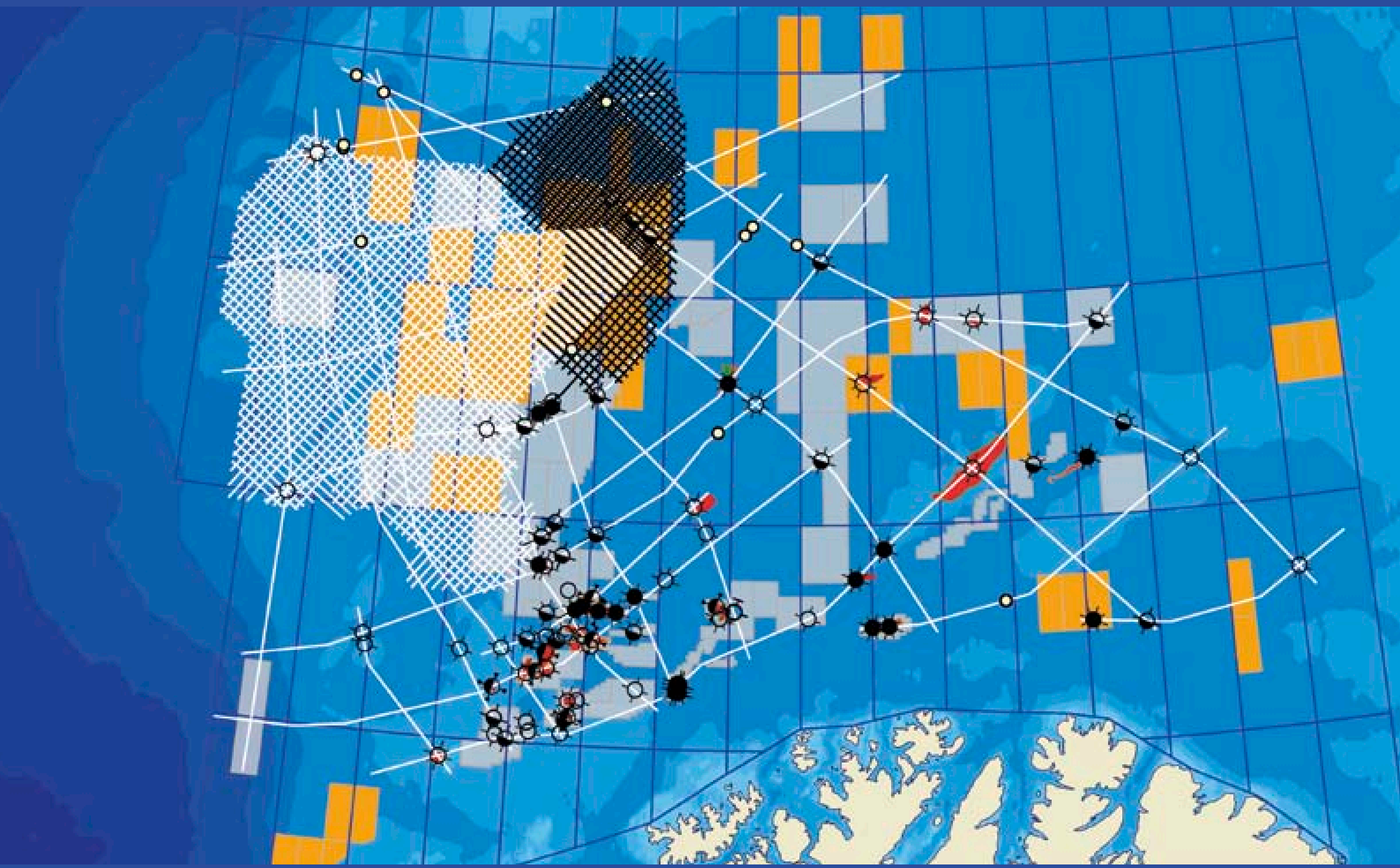
You are familiar with ice: it is cold, hard, slippery, and buoyant. You can find icebergs and ice floes on the surface of the ocean in polar regions. But there is another, higher-pressure form of ice trapped at and beneath the seafloor that is far less familiar. This ice, which is known as gas hydrate, is created by the reaction of gas – predominantly methane – with water at low temperature and high pressure to form a crystalline solid. Such compounds are a common occurrence buried in permafrost and continental slope sediments around the world ocean. For methane hydrate, the water and gas combine in a ratio of six molecules of water to one of gas. The gas draws in the water molecules to form a cage within which the methane molecule flutters in a strange molecular dance, feeling the attraction and pull of the hard ice walls of its prison, but without ever touching.

Most natural gas hydrate appears to be in this structure, with methane as the trapped guest molecule, although alternative structures have also been identified, with guest molecules such as isobutane and propane, as well as lighter hydrocarbons.

Gas hydrates provide an extremely effective way of storing natural gas or methane (CH_4). At standard atmospheric temperature (20°C) and pressure (1 atm) conditions, 1 m^3 of solid methane hydrate is equivalent to 160 m^3 of free gas. Although global estimates range widely by more than two orders of magnitude, the most cited value is that of Kvenvolden in 1988, at $2x10^{16}$ m^3 of gas, or 10,000 gigatons of carbon. In comparison, estimates for the known combined reserves of conventional hydrocarbons (natural gas, oil, coal) are about half of that value.



A model of methane hydrate's cage-like structure in which methane (the grey/green molecule) is enclosed inside a lattice of water (the red molecules). This 'unit cell' joins together with other unit cells by sharing faces to build the hydrate solid, even at temperatures well above the melting point of water ice. When gas hydrates dissociate (melt), the crystalline lattice breaks down into liquid water (or ice) and the gas is released.



typically sites of underwater landslides as well as movement of sediment, organic material and nutrients to the deep ocean. The upwelling of nutrients driving the region's rich biodiversity makes the upper slope a crucial study area for scientific and environmental policy purposes. It also makes it a popular region for commercial fishing.

One November day in 2000 the vessel Ocean Selector is trawling over the Barkley Canyon in an area of 800m water depth. (Trawls are fishing nets that are pulled along the bottom of the sea or in midwater at a specified depth). When the captain pulls up the net, the crew see the most unusual catch: over a ton of strange white solid that fizzes and crackles on the deck. They shovel it overboard, fortunately without harm. The crew has by accident discovered a large seafloor deposit of methane hydrate. If one of the seamen had lit his smoke it could had resulted in a disaster as the crackling actually released significant amounts of methane gas.

Methane is a fuel, and despite being trapped in an 'ice', it will readily burn. For this reason, methane hydrates are known as burning ice.

That day in November introduced the scientific community to a new, massive seafloor outcrop of gas hydrate on a 500m wide, 1 km long plateau perched 150m above the canyon floor. In 2004, Canadian scientists explored and verified the site, and the ROV revealed pinnacles cutting up through the seafloor. Massive outcrops are exposed in 1–2m high mounds covered by a thin veneer of sediment. A light yellow condensate fluid is present in the surrounding sediment and associated with the hydrate, causing yellow staining. With buoyant hydrate slabs on the seafloor reaching 7m in length and 3m in height and with only a thin sediment cover, the hydrate mass must continue deeper and be anchored below the surface.

Although methane hydrate is known to be stable at the sea floor for water depths greater than 500–600m at temperate latitudes, observed outcrops of hydrate at the sea floor are rare and somewhat poorly understood. ■

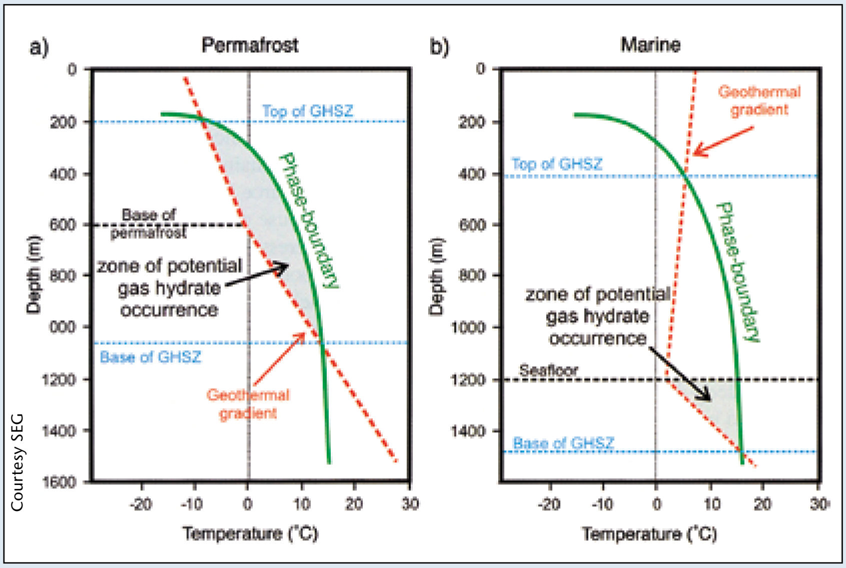
Gas Hydrate Stability Zone (GHSZ)

Gas hydrates are stable only under high-pressure and low-temperature conditions. The region where gas hydrates are stable – the gas hydrate stability zone (GHZS) – is defined by the intersection of the pressure-temperature phase boundary and the local geothermal gradient. Because of the nature of the conditions for stability, gas hydrates are usually found only in permafrost regions and on continental slopes where water depth exceeds 300–500m.

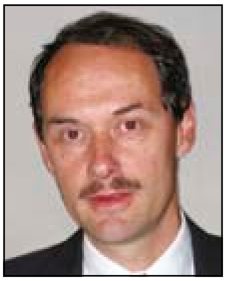
As shown in the figure for the marine setting, the top of the GHSZ occurs above the sea floor. However, the ocean water does not contain enough gas to stabilise hydrate and the top of the GHSZ is normally defined at the sea floor. Here, the temperature is normally 3–4°C. Going down into the sediment, the temperature slowly increases; the global average of the geothermal gradient is 0.02°C/m. While the pressure increases with depth, after 500–1,000m depth the temperature becomes too high for hydrates to remain stable. This is the base of the GHSZ.

In permafrost, the situation is similar. The top of the GHSZ is where the temperature line crosses the hydrate stability line, often beginning at 100–300m depth. The GHSZ typically extends for hundreds of meters. The depth of the GHSZ is also related to the base of the permafrost, which is at 0°C. The deeper the base of the permafrost the deeper the GHSZ becomes.

Methane gas hydrate stability zone (GHSZ) for permafrost (left) and marine (right) settings. The pressure-temperature phase boundary (idealised) is shown as a green curve, and the local thermal (assumed) gradients are in red. In permafrost, the GHSZ can begin at 100–300m depth and extend for hundreds of meters beneath the base of the permafrost (typically occurring at 150–600m depth). In marine sediments, the GHSZ typically begins below 300–600m and extends for hundreds of meters. The thickness of the marine GHSZ depends on sea floor water temperature (typically 3–4°C), salinity, geothermal gradient and depth.



Lasse Amundsen is Chief Scientist Exploration Technology in Statoil. He is adjunct professor at the Norwegian University of Science and Technology (NTNU) and at the University of Houston, Texas.



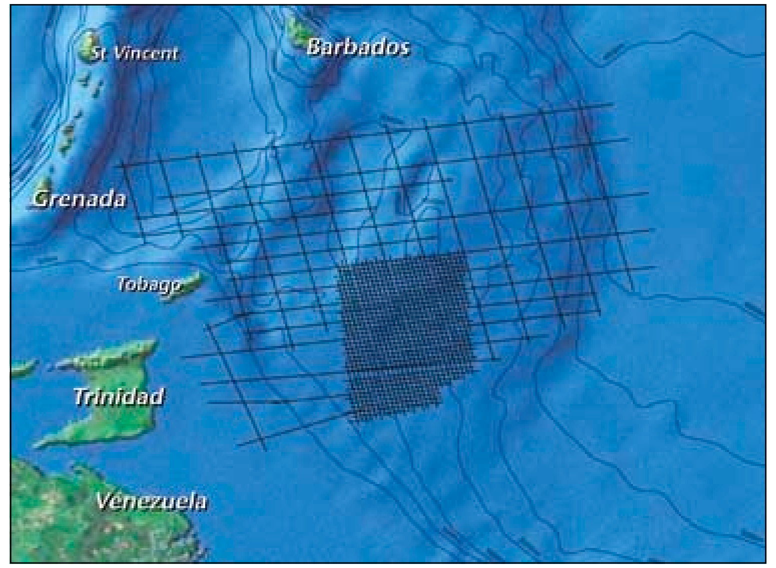
Martin Landrø is professor in Applied Geophysics at NTNU, Trondheim, Norway.

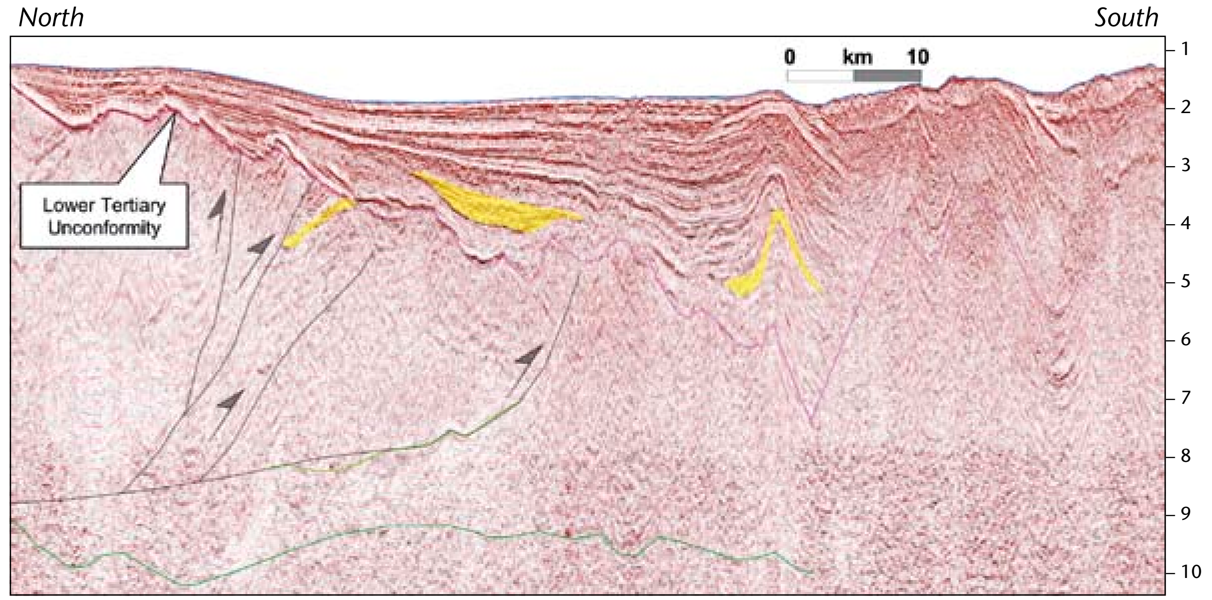
Exploration Potential of Deep Water offshore Trinidad, Tobago and Barbados

Re-imaged 2D regional seismic will lead to a better understanding of the Trinidad-Tobago and Barbados region and promising new opportunities in the search for hydrocarbons.

Improvements in image technology and seismic processing workflow design permit better constraints upon extrapolating shallow water exploration potential seaward towards the ultra-deep.

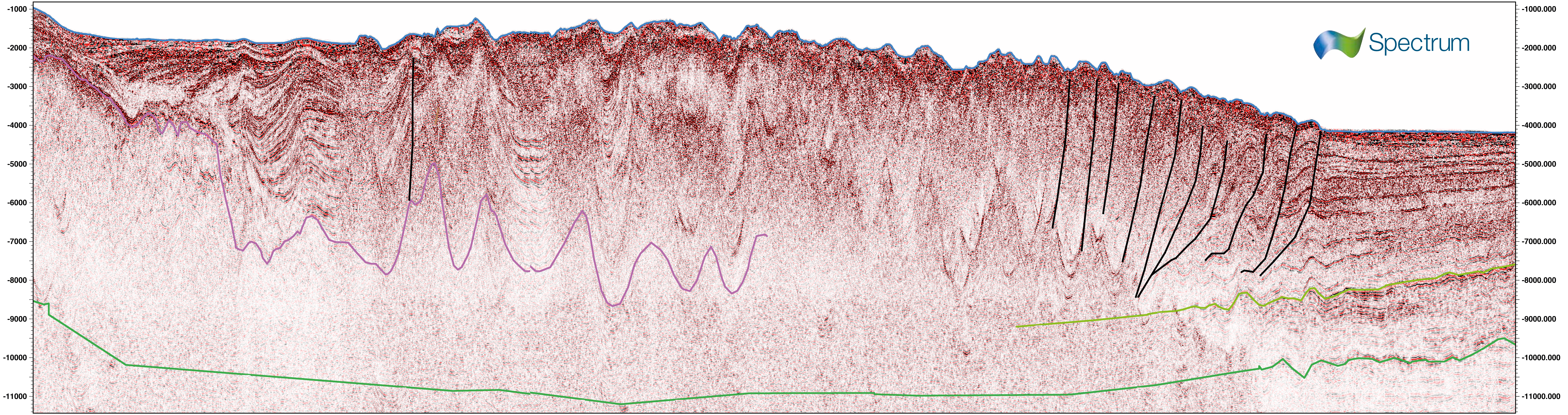
A recently reprocessed vintage data set acquired in the ultra-deep water of Trinidad and Tobago has improved the industry understanding of this hydrocarbon province.
Renewed understanding of the geologic opportunities now observed when combined with favorable government fiscal terms should encourage industry interest in this hydrocarbon province.





Thrusted Cretaceous to Oligocene stratigraphy below a Tertiary unconformity can be observed proximal west of the islands of Trinidad, Tobago, on the island of Barbados and in the Tobago Basin

Seismic line through the Trinidad, Tobago and Barbados Accretionary prism. The basal dark green line marks the basement. The light green marks the top of the Cretaceous. The purple marks the Oligocene unconformity.



The Deep Unexplored Waters off Trinidad, Tobago and Barbados

SCOTT BOWMAN Petrodynamics Inc., **TED STIEGLITZ** Spectrum Geo Inc.,
STEPHEN JAGDEO Ministry Of Energy and Energy Industries, Trinidad and Tobago

The deep and ultra-deep waters of offshore Trinidad, Tobago and Barbados have remained underexplored due to structural and stratigraphic complexity. Although nearly every well encountered some measure of hydrocarbons, exploration efforts in the deepwater region have been challenged by sub-economic accumulations, high pressures which restrict the drilling window, thin sands on the top of structures, complex pathways which may restrict charge, thin or unconsolidated seals which may not be effective enough to hold the oil or gas column, and shallow oil which has been biodegraded. Recently re-imaged 2D regional seismic data released by the Ministry of Energy and Energy Industries, Trinidad-Tobago and Barbados region, may lead to a better technical understanding of the region and new promising opportunities in the search for hydrocarbons.

The 2D Deep Atlantic Seismic Programme used in the analysis presented here was originally acquired in 2002. The SR/V New Venture (Veritas) used a 6,000m cable programmed for 240 channels at 25m group intervals with a record length of 9 seconds.

Plate Tectonic Setting

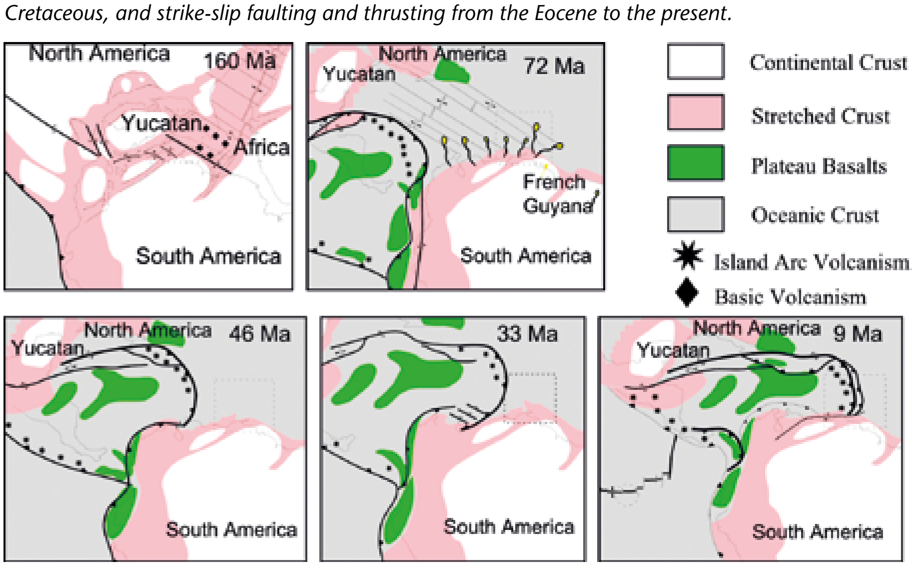
The basement of the Trinidad and Venezuela region initially formed during the rifting of North America and Africa in the Triassic. At this time, Cuba was located offshore Trinidad and eastern Venezuela. The northern margin of Trinidad was a strike-slip margin that accommodated the northward movement of North America and Cuba. Onshore, arkosic quartz arenites and conglomeratic limestones were deposited along the coast. Contemporaneously, 60m to 1,500m of shale was deposited offshore. During anoxic conditions thick source rocks formed during the Coniacian-Santonian (Gautier Fm.), Campanian (Naparima Hill Fm.) and Maastrichtian (Guayaguayare Fm.). Occasionally, during lowstands, the deep basin received continental-derived arkosic sandstones in the form of turbidite deposits shed off the South American craton in a similar fashion to those recently discovered in French Guyana and West Africa.

More than 1,500 km away in the Pacific, a westerly dipping subduction zone was forming on the eastern margin of the Caribbean Plate. The associated calc-alkaline volcanism formed the early stages of the Lesser Antilles (Tobago and Barbados) island arc system.

During the Late Paleocene-Eocene-Oligocene-Miocene east-west striking thrust faults developed in the Trinidad region as North America and South America began to converge. To the south of the Lesser Antilles arc system, South America was sliding past at approximately the margin of present day Colombia at a modest rate of 10 mm/yr. Erosion and sedimentation was relatively slow, developing a progradational shoreface with some carbonate bank development. By the late Miocene the region of Trinidad was passing by the southern end of the Lesser Antilles arc system.

About 10 million years ago the African plate became fixed with respect to the mantle when it collided with Europe. All of the spreading along the mid-Atlantic ridge had to be accommodated

The region experienced rifting in the Jurassic, passive margin subsidence throughout the Jurassic and Cretaceous, and strike-slip faulting and thrusting from the Eocene to the present.



along the Pacific/Nazca/Caribbean and North America/South America plate boundaries. A doubling of the westward velocity (to 20 mm/yr) of South America and North America forced the South American plate to ride on top of the Nazca Plate in the Pacific, causing the Andean mountain range to uplift.

The Caribbean Plate has been stationary with respect to the mantle. This plate is subducting into the mantle creating a tensional environment on the west side of the subduction zone. The southern boundary of the Caribbean Plate is in contact with the South American Plate and accommodates this motion by a system of dextral shear faults parallel to the Central Range Fault in Trinidad, and the El Pilar Fault in Venezuela.

By four million years ago an increase in siliciclastic sediment influx occurred in the Trinidad region as large volumes of sediment from the newly uplifted highlands in the Andes was transported down the Orinoco and Amazon Rivers. This created rapidly filling basins with overpressured shale, which may have been generated in part as the prolific Albian source rock (Gautier Formation in Trinidad, equivalent to the La Luna in Venezuela and Colombia) passed through the oil window and into the gas window. The overpressured shale became mobile, forming diapirs and mud volcanoes. This recent sediment influx has driven burial and maturation of the source rock in the region, leading to the recent expulsion and trapping of the majority of the 13 Tcfg and 600 MMbo discovered in the basin.

Exploration Potential

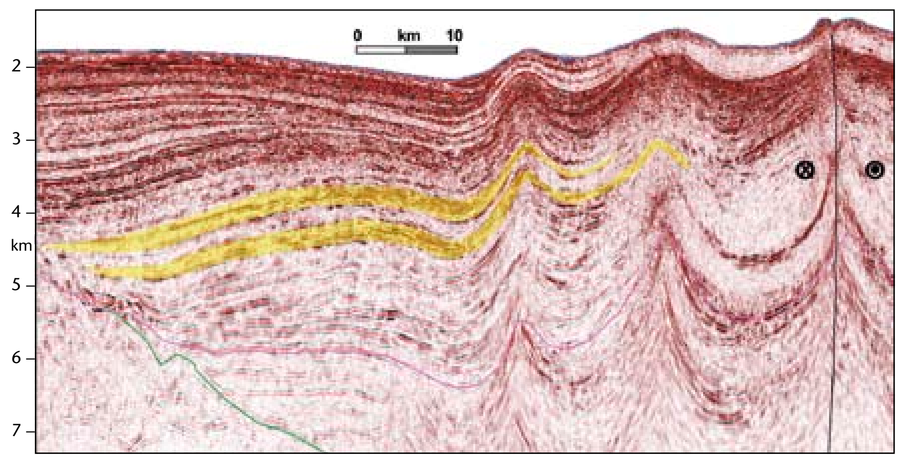
The principle plays that can be pursued in this environment include thrusts in Oligocene and older stratigraphy, Miocene and younger stratigraphy in shale diapirs and adjacent basins, and extensional structures in Miocene and older structures in the Columbus Basin.

Thrusted Cretaceous to Oligocene stratigraphy below a Miocene and older unconformity can be observed proximal west of the islands of Trinidad, Tobago and on the island of Barbados and in the Tobago Basin. The key challenges in pursuing this play are identifying valid traps defined by reservoir intervals which are deep enough to escape biodegradation but shallow enough to preserve liquids and porosity. BHPBilliton's Angostura Field is a good example of this play. This field is challenged by shallow depths that have led to biodegrading of the oils. The Woodbourne Field on the island of Barbados was discovered in the late 1950s and has produced 9 MMbo since 1966. The field is shallow and has API gravities that range from 11° to 32°.

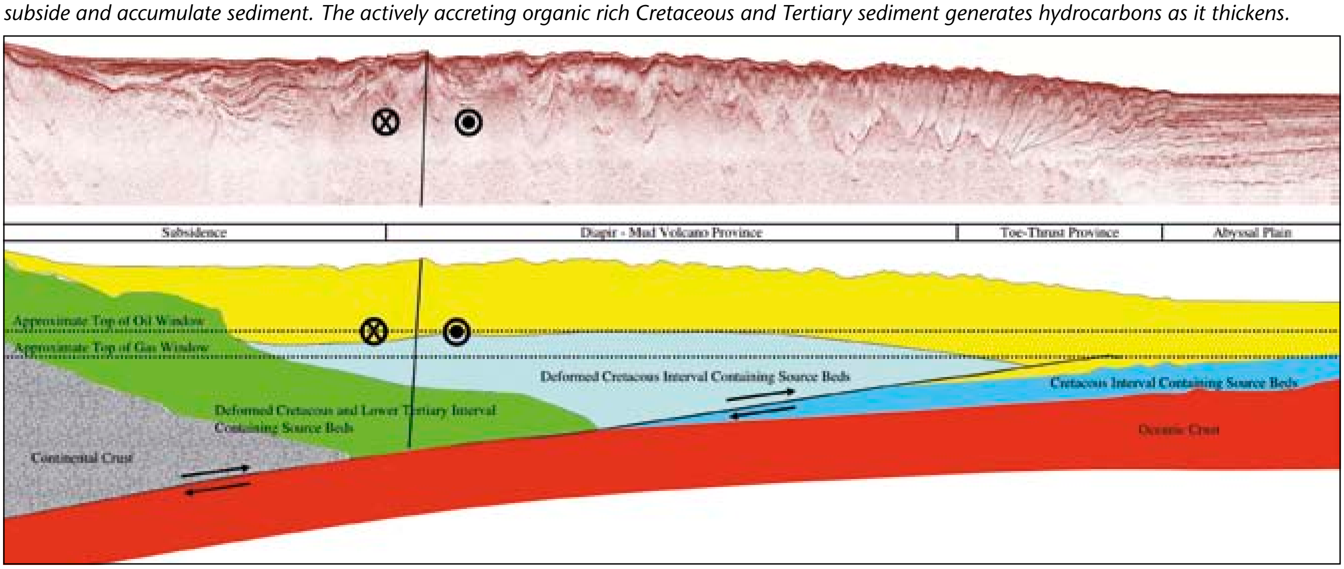
Structures and stratigraphic traps containing Miocene and younger stratigraphy are present throughout most of the region west of the islands of Trinidad and Tobago and Barbados. The core of the accretionary prism has the highest amount of shortening and deformation due to shale diapirism. The best defined structures and stratigraphic traps are on the margins of the Diapir Province near the islands. ■

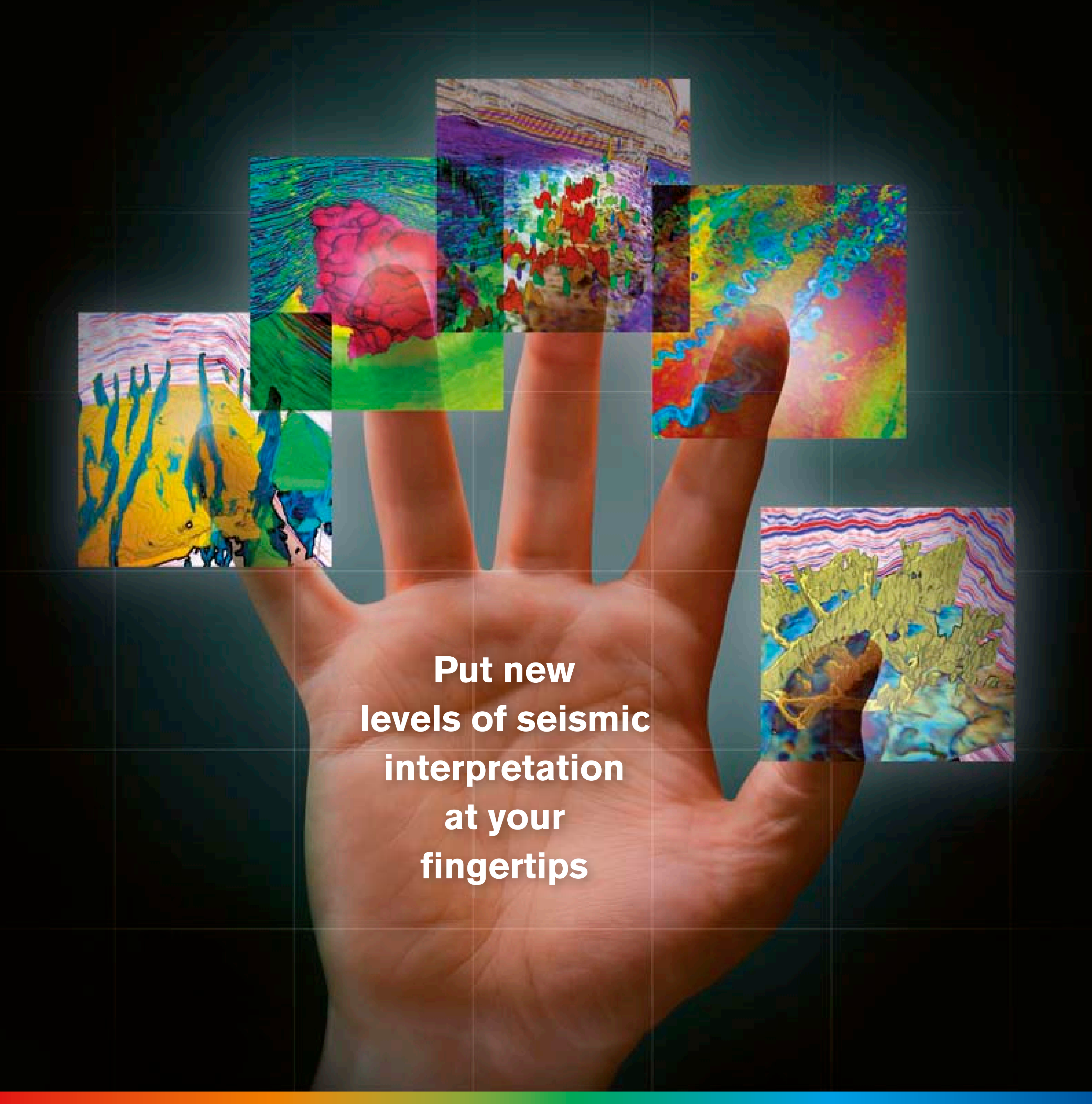
Acknowledgements:
The authors would like to thank Spectrum/GeoServe and the Government of Trinidad/Tobago for permission to show the seismic data.

Simple folds above continental crust offer attractive traps in Tertiary slope fan deposits.



The westward dipping slab of the Trinidad, Tobago and Barbados Accretionary prism creates a transtensional setting which allows the basin to subside and accumulate sediment. The actively accreting organic rich Cretaceous and Tertiary sediment generates hydrocarbons as it thickens.

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The Geology of London

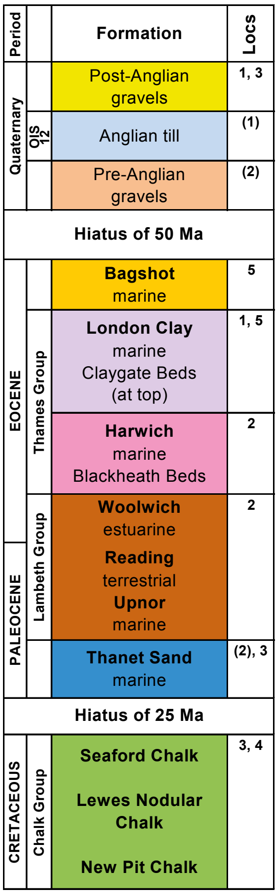
DIANA CLEMENTS

With the Olympics upon us it is an appropriate time to reveal the geology of London for our visitors. A brief introduction to the geology is followed by five itineraries that have been selected to give an overview of what can still be seen, despite a population of nearly eight million.

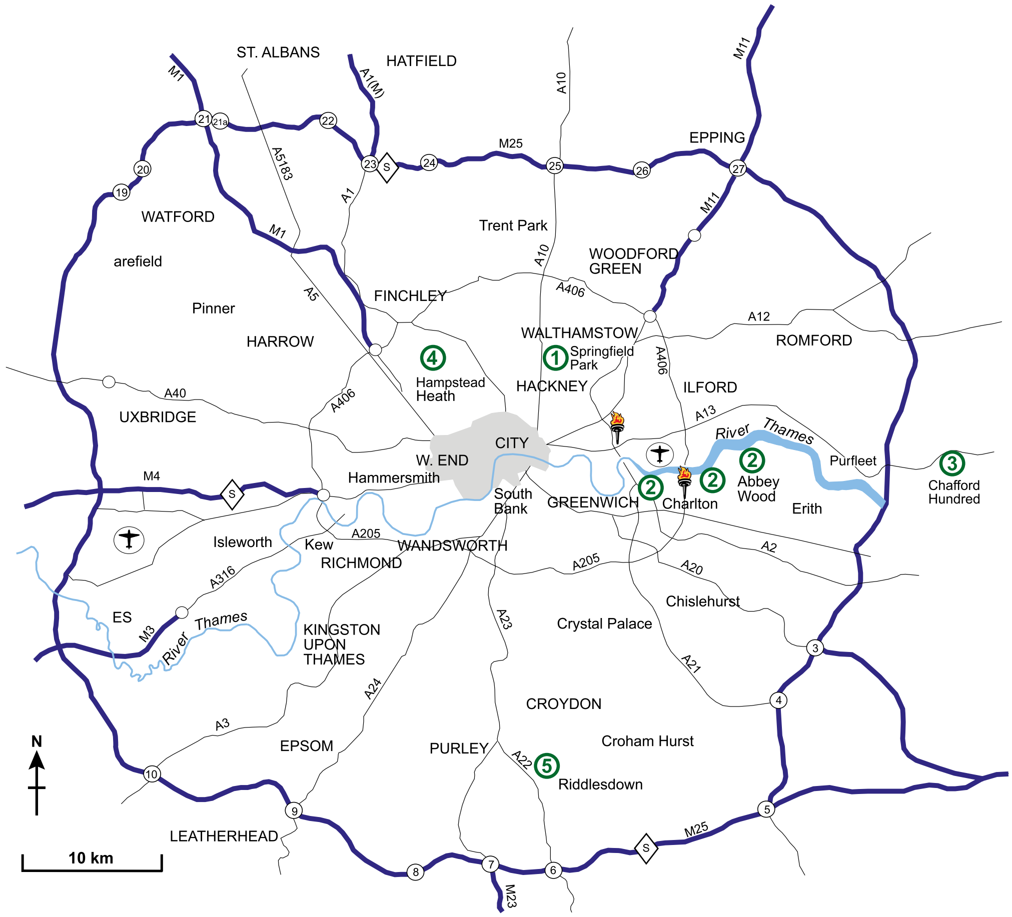
London sits within the London Basin formed as a distant downfold from the collision of Africa with Europe. The basin is bound by the 85 million-year-old chalk hills of the North Downs in the south-east and the Chiltern Hills to the north-west. Inwards from these hills early Tertiary sediments of Thanet Sands and the variable Lambeth Group and Harwich Formation are exposed at the surface. Not surprisingly, it is the London Clay that is the bedrock under most of London. This is topped by the Bagshot Sands, deposited about 50 Ma.

A long interval of over 45 Ma followed, during which folding took place and most of the Bagshot Sands and Claygate Beds were removed, leaving isolated hillocks today. Some are capped by ancient river gravels relating to the former course of the Thames and its tributaries, many of which are thought to have crossed the area from the Weald to the south to join the Thames on its earlier course further north.

The spreading of the Anglian ice age from the north just 450,000 years ago changed everything: the ice reached as far south as Finchley and Hornchurch in North London and, as the ice melted, large pro-glacial lakes formed. When these burst they altered the route of the Thames, pushing it south to its present position through what was to become the centre of London. Vast amounts of gravel were caught in the melting waters' bed load, which was spread over a wide area. Subsequent ice ages never again reached as far as London but each event provided fresh gravel deposits so that a series of terraces now remains either side of the



Geological strata in Greater London (not to scale).



M. Ridd, adapted with permission of the Geologists' Association from GA Guide 68 2010

Map of the London area showing locations of the itineraries selected.

Thames. Finally, in many areas, wind-blown loess was redeposited extensively over the gravels and has been a source of excellent brickearth.

All of the sedimentary rocks exposed have been extensively used for the building of London. During the 19th and early 20th centuries Greater London was peppered with quarries, and geologists were able to examine good exposures. Now it is only the Thames gravels in East London and up the Colne Valley that are still exploited. However, with the wealth of data collected during recent London-wide engineering projects, new discoveries, particularly about the structure, are still being made.

Where can the geology be seen? Here we give you a selection of interesting locations and geological walks in Greater London. You can find more in *The Geology of London* and *London's Foundations*, which both give a general introduction on the geology with maps and details on these and other sites. Grid references are given in the text to help pinpoint the locations.

Springfield Park, Hackney ①

Springfield Park *(grid ref: TQ345873)*, on the west bank of the River Lea, is the closest location to the main Olympic Stadium. Its name comes from the numerous springs that arise along the junction between the Hackney Gravel and the underlying London Clay. Brickearth overlies the gravel at the top of the park, which was designated a Geological Nature Reserve in 1997. Interpretation boards in the park and leaflets available at the Visitor Centre explain the geology, although there are not usually any actual exposures. The River Lea has eroded a substantial valley since the big Anglian glaciation. The ice was very close to the park and, as it melted, would have formed deposits characteristic of the braided channels seen during glacial melts around the globe today. By the time the Olympic Park is reached, about 4 km to the south, the Lea has eroded both the London Clay and the Harwich Formation and excavations for the new Stratford station revealed excellent temporary exposures of the Lambeth Group. The gravels deposited within the valley have been extensively quarried in the past and the flooded holes now serve as boating lakes and reservoirs.

View from Springfield Park across the River Lea to the Epping Forest Ridge on the far side

Green Chain Walk Geotrail ②

The Green Chain Walk Geotrail runs from the Thames Barrier *(grid ref: TQ415793)* in south-east London to Abbey Woods Station *(grid ref TQ473790)*, a distance of 11 km, which includes 12 geologically interesting stopping points. Dog Rocks in Plumstead, and two Sites of Special Scientific Interest (SSSI) at Gilbert's Pit, Charlton and the fossil bed in Lesnes Abbey Woods are described below. The Geotrail passes right through the Olympic venue of the Royal Artillery Barracks on Woolwich Common and a diversion will be in place at this point during the Games.

Gilbert's Pit was formerly one of several quarries in the area primarily exploiting the Thanet Sand, which was used as foundry sand at Woolwich Arsenal and for making bottles. The strata still exposed at the top of the quarry are the reason for the SSSI status. Here the sediments that make up the Lambeth Group and Harwich Formation are a valuable window into some of the most variable rocks that underlie London and the exposure is much visited by engineers. It is the type section of the estuarine Woolwich Formation. Beneath, a thin but important bed of mottled clay represents a period of high temperature during deposition of the terrestrial Reading Formation. This is underlain by marine Upnor Formation, mostly obscured by scree. At the top of the face the rounded black pebbles of the Blackheath Beds can be seen. These were laid down in marine conditions and are the local representative of the laterally variable Harwich Formation. Pebbles and occasional shells have rolled down the scree slope and can be picked up at the bottom. The Thanet Sand is now entirely covered by scree. Two faces can be examined from the bottom of the quarry. The main one is on the eastern face, where there is also an explanation board, and the other on the south-east face, but both are currently surrounded by a fence. Access can be obtained via Greenwich Council (tel: 0208 856 0100).

Dog Rocks, Plumstead Common, formed of cemented Blackheath Beds pebbles. The blocks are in the shrub bery opposite the entrance to the playground.

The Dog Rocks *(grid ref: TQ443779)* on Plumstead Common allow close examination of the Blackheath Beds. Here the black pebbles have been locally cemented and the large lumps that can be seen were probably dumped by the quarrymen from within the quarry that now forms part of Plumstead Common and houses the Adventure Playground.

The fossil bed at **Abbey Wood** shows a third variation of the Blackheath Beds. Marine shells were noticed in sand in rabbit holes and with further investigation rare bones and teeth of mammals were found. The site is now opened up annually and the sand is wet-sieved on site, the residue being removed for further examination. All the mammal remains are housed in the Natural History Museum and are providing a valuable insight into their evolution. It is for the mammals that the site is an SSSI, but there are plenty of marine and estuarine shells as well as sharks' teeth that come from the shell bed and some are abandoned when the dig is back-filled each year. It is not hard to find examples on the surface of the fossil enclosure.

For further details see:
www.greenchain.com/pdfs/Geologytrail.pdf

The Chalk Walk: Chafford Gorges Geotrail ③

This walk starts and finishes at the Visitor Centre, Chafford Hundred *(grid ref: TQ599793)*, East London, where a leaflet describing the Geotrail is available. Upfolding of the chalk in north-east London brings it to the surface in the Purfleet area close to the Dartford Bridge where it was exploited in large quarries until 1976. Now one of the quarries houses the Lakeside Shopping Centre while those to the east have become home to the new town of Chafford Hundred. The planners have created an interesting area of 'gorges' mostly left in their natural state with the housing around the top. Vegetation and lakes fill the centre but the white cliffs with their prominent flint bands and the contact with the overlying Thanet Sand are still well-displayed. Periglacial features can be seen in places and there is a locked quarry displaying an unstable cliff of Thanet Sand. The area contains an SSSI for the overlying Thames gravels where a rich Middle Palaeolithic site has been found. Some fine examples of sarsen stones have been left by quarrymen at the top of one of the quarries.

For further details see:
http://www.essexwt.org.uk/visitor_centres__nature_reserves/chafford_gorges

Dissolution hollow with Thanet sand piped down into Seaford Chalk, which can be seen from the ramp up the cliff face at Chafford Hundred. Bullhead Bed flints line the hollow.

Hampstead Heath between Hampstead and Highgate ④

From the top of Hampstead Heath there are fine views across London to Shooters Hill and Sydenham Hill on the other side of the Thames, with the North Downs beyond. It is an excellent location to understand the overall structure of the London Basin. Views to the north are now largely restricted by trees but in winter the Chilterns can be glimpsed in the distance. At 134m this is the highest point in London and is where the youngest of the solid geology can be seen or, at least, inferred. Bagshot Sand tops the hill and, in the 1860s, it was dug by hand and carted away for the construction of the St. Pancras railway, leaving an interesting terrain of hollows and mounds on Sandy Heath. An interpretation board has been erected in a small enclosure around two old trees which shows the sand pits being worked *(grid ref: TQ264869)*.

The Claygate beds beneath, at the top of the London Clay, were utilised for brick-making. The sandier texture was more suitable than the London Clay itself and former quarries have been noted right round the Heath. An interpretation board with a photograph of the brickfield operating in 1880 is placed beside the Viaduct *(grid ref: TQ269865)*. The scene looks very tranquil, far from the reality when firing was taking place and sulphurous smoke invaded the neighbourhood.

The junctions between the sand, silt and clay are marked by springlines. These can be seen around the Heath, identified by moisture-loving plants and often by gullies running away downhill. A small new pond has been created at one of these springs above the boating pond. An interpretation board placed here demonstrates how the geology dictates the locations of the springs. Ultimately the streamlets give rise to rivers, notably three of the 'lost rivers' of London: the Fleet, the Westbourne and the Tyburn, whose courses can still be traced underneath London's streets.

About the Author:

Diana Clements has worked part-time in the Department of Palaeontology at the Natural History Museum for over twenty years, first specialising in the geology of London in 1996 when she began research on Islington, culminating in an exhibition in 1997: 'Beneath our Feet: the Geology of Islington', aimed primarily at residents and visitors with little geological knowledge. Since then, her researches have extended to Greater London, gathering itineraries for the *Geologists' Association Guide No. 68: The Geology of London,* published in 2010. She is an active member of the London Geodiversity Partnership, whose aim is to identify, protect and promote London's geological heritage. She teaches and gives talks on London geology and leads walks and field trips around the capital.

Geological interpretation boards on Hampstead Heath. A, Bagshot Sands on Sandy Heath; B, Claygate Beds being used for brick-making at the viaduct; C, Springlines on the Heath above the Boating Lake

Riddlesdown Quarry ⑤ (Croydon area)

Riddlesdown Quarry *(grid ref: TQ336592)* is the best location for seeing chalk exposed in the London area. Quarrying ceased in the 1960s and this very large quarry in the North Downs is now owned by the City of London Corporation, who are conserving it as public open space. Steps up the spoil heap adjacent to one of the faces allow close examination of the chalk. In all, nearly 50m of chalk are displayed in the quarry from the top of the New Pit Chalk Formation in the south-east corner, through the entire Lewes Nodular Chalk Formation up into the base of the Seaford Chalk Formation at the top of the quarry. For engineers this quarry provides essential viewing to realise how variable the chalk under London can be. Access to the quarry is only permitted when accompanied by a ranger (tel: 01372 279083).

Open University Geological Society students examining the chalk from the steps up the face of Riddlesdown Quarry

Further information:

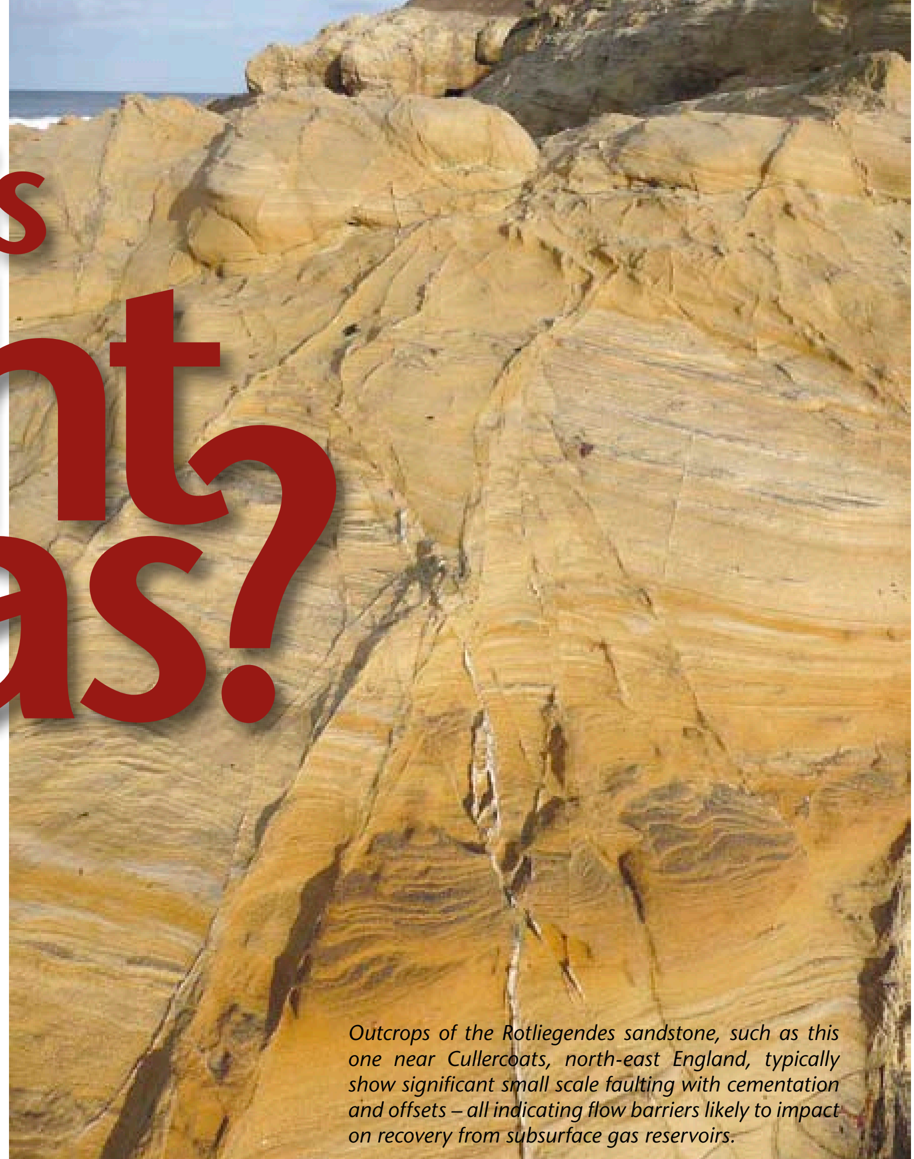
London's Foundations, 2012, GLA 1–59, pp. 119–249, GLA 43, 14, 8, 1, 42, 26 www.londongeopartnership.org.uk/Publications.html.

The Geology of London, 2010. Geologists' Association Guide 68.

Geological maps of the UK. The British Geological Survey has a free iPhone app so that the geology can be called up in the field. Also available on the internet: mapapps.bgs.ac.uk/geologyofbritain/home.html

Grid references can be put into www.streetmap.co.uk, which allows maps to be printed. ■

What is Tight Gas?



Dr. Tim Wright, Merlin Energy Resources

Outcrops of the Rotliegendes sandstone, such as this one near Cullercoats, north-east England, typically show significant small scale faulting with cementation and offsets – all indicating flow barriers likely to impact on recovery from subsurface gas reservoirs.

Since its production is tied to technological developments, well cost, and fraccing gas prices, tight gas is an economic issue

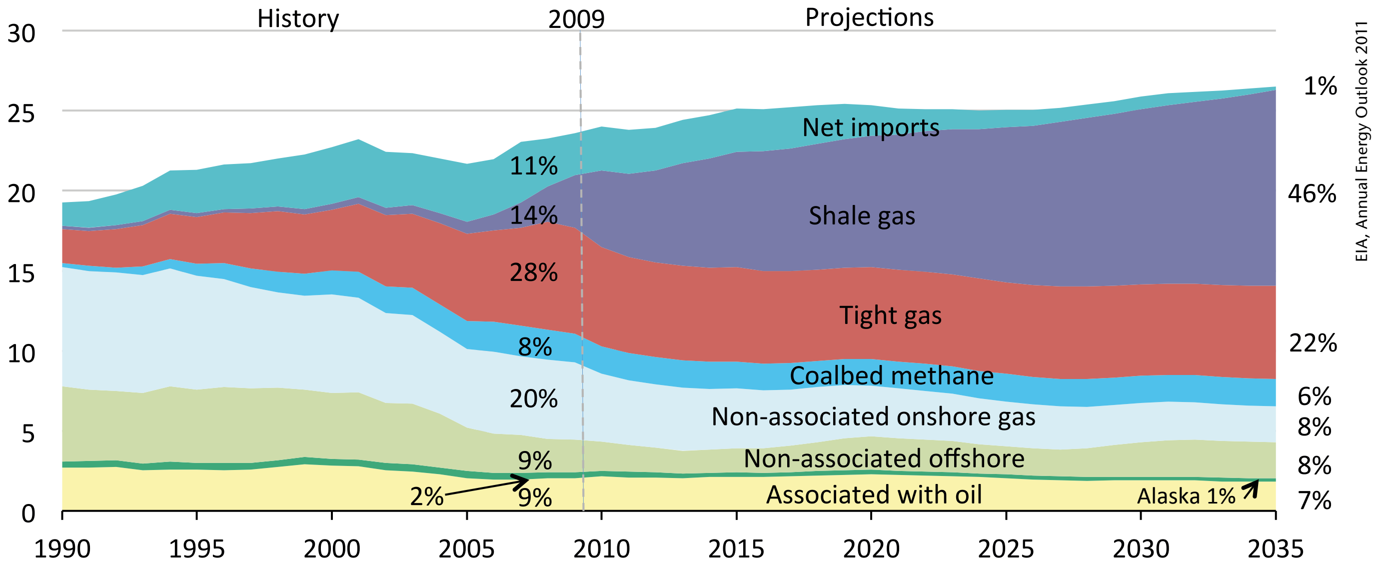
ROY HARTLEY

A practical definition of a tight gas field at present is one that can be made economic with a combination of horizontal wells and fracture stimulation. Production and permeability guidelines are relative to technology development, well cost, frac cost and current gas price. As technology has developed the permeability guideline, at least onshore, has changed from <0.1mD in the 1970s to <0.01mD today and arguably to <0.001mD in the US.

Comparing USA and Europe

A comparison between the US and Europe is instructive. The US was the largest volume producer in the world from the 1870s through to the 1960s. It had developed a large and competitive service industry, with over 2,000 active rigs and a countrywide natural gas pipeline grid by the time gas demand began to exceed supply in the 1970s. The shortages were addressed by deregulation of the gas price and by US government-funded R&D and tax incentives to create the technology required for tight gas development. It was in the 1970s that the United States government defined a tight gas reservoir as one in which the permeability to gas flow was less than 0.1 mD. This definition is now defunct but was used to allocate federal and state tax credits for producing gas from tight reservoirs. In addition, the National Energy Technology Laboratory (NETL), part of the US Department of Energy (DOE), invested significant funds in developing the essential science to characterise and produce tight gas and the Gas Research Institute and industry cooperated to launch the early technology demonstrations.

The results have been remarkable. Not only has tight gas grown from almost non-existent production levels in the early 1970s to account for close to 30% of current US production, but the technology was further developed to produce coal bed methane and then shale gas. In combination, these are now responsible for some 50% of US production and are all forecast to continue to grow. Gas price played a role. It stayed close to $2/Mcf through to the end of 1999 but then rose to peak above $10/Mcf in mid-2008. Inevitably, independents were encouraged to develop formerly marginal assets such as tight gas in Jonah, Pinedale and Bossier and coal bed methane in Powder River and San Juan. The real breakthrough came after 2002 when it was demonstrated in the Barnett and Fayetteville gas shales that high rates of gas production could be achieved by using intensively stimulated horizontal wells. Natural gas production



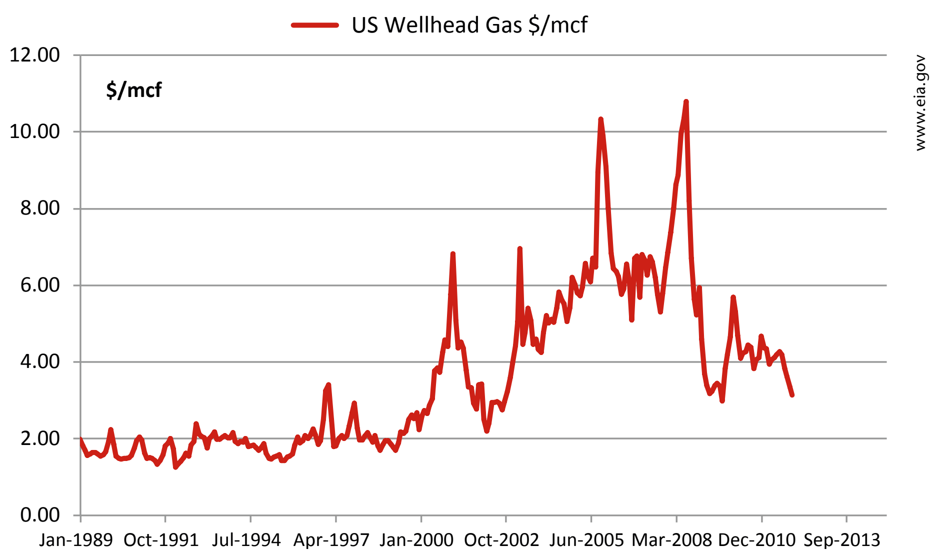
US dry natural gas production since 1990: tight gas now accounts for nearly 30% of production

from shallow, fractured shale formations in the Appalachian and Michigan basins of the US had existed for decades; the 'game changer' was the recognition that intensively stimulated horizontal wells could create a reservoir. Typical Barnett completions developed from 500m to 1,000m and the number of fracs from 5 to 12.

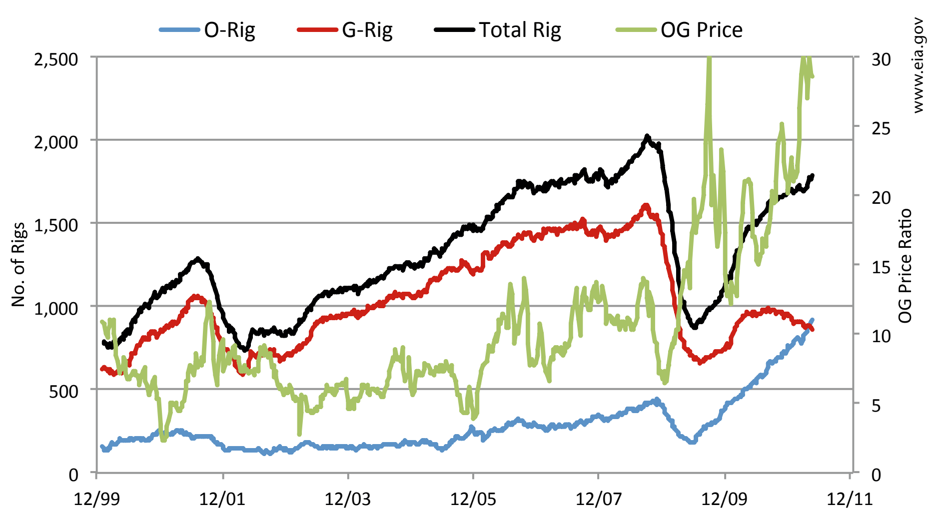
Gas development was so successful that by the end of 2008 there was an oversupply of about 5 Bcfpd, prices fell to circa $4/Mcf and the total rig count halved. By mid-2009, however, the rig count was again on the increase because higher relative crude prices encouraged operators to drill for crude oil and natural gas liquids. This shift can be clearly seen in the redistribution of the US rig fleet since mid-2009. Futures prices 3 years forward are now $25/barrel less than the market price, indicating that the current success with oil development is expected to continue.

Lessons to be Learned

The lessons to be learned are that the US gas market is very flexible and driven by price, technology, an efficient service industry and a lack of 'easy' import possibilities. The gas plays had been known for 50 years, but it took the combination of technology development, shortage of supply and the increase in gas price to make them commercial, and when oversupply made further development unattractive operators switched rapidly to oil and



US wellhead gas prices since 1989



Numbers of rigs allocated to oil and gas drilling in the US and the relationship to the ratio of the oil spot price to the gas spot price.

gas liquids. It is also significant that it was the small independents that developed the tight and shale gas plays, growing significantly as a result.

In Europe it is very different. A large scale gas market developed after the discovery of Rotliegendes gas in 1959. It has been sustained by the development of Groningen (Netherlands), Salzwedel (Germany) and very large North Sea fields, principally by state companies and majors, and the ready availability of gas from the FSU and North Africa. As a result, tight gas has not received the attention it has in the US. Recent interest has been sparked by the US shale gas boom and Poland in particular has seen an increase in shale activity.

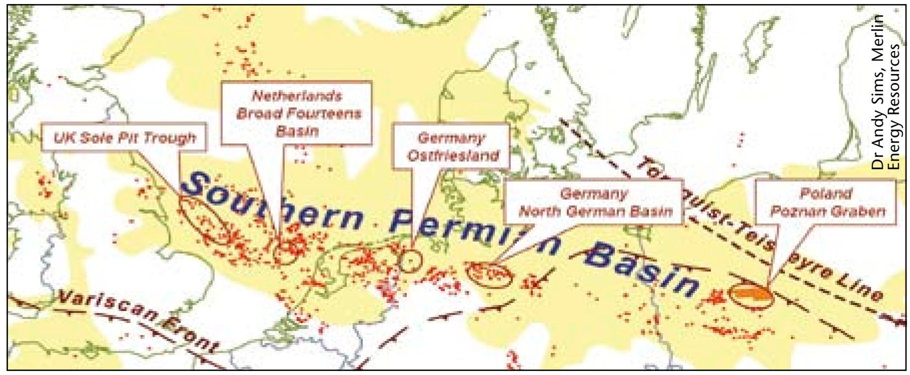
Cost is a barrier to successful tight gas development in Europe. Most European rig contractors have fewer than 10 rigs, are effectively unchallenged in their own geographical area because of language and other barriers to competition and rely on overseas work to keep going. There are currently about 30 land rigs working in Europe; 50 working is a peak, compared with close to 2,000 in the USA. At present 10 frac crews are available but not fully employed in Europe, while in the US more than 500 frac crews are busy. As a result of the limited capacity in Europe, costs for single wells are high but conversely the potential exists for large reductions for long term contracts. As an example, a 'factory' well drilled to 3,500m tvd (total vertical depth) and 1,200m horizontal with 14 frac stages can cost €6million in the US but as a single well project could cost €18million in Europe. Offshore, the same well could cost €58 million. Given a long drilling programme with repetition of the well design and a reduction in data requirements – pilot holes, cores, wireline logs – it is likely that Europe could get close to US costs onshore. Although US drilling is remarkably cost-effective, the efficiency and cost reduction in an extended field development comes from reducing data collection and cutting out inefficiencies. There is no reason why Europe cannot replicate the US experience if large scale development takes place.

Rotliegendes Tight Gas

So what is a typical tight gas reservoir? Most are sandstones where the original pore space has been reduced by lithifaction and diagenesis. A small percentage of production comes from fractured limestones, and natural fractures can play a role in production from tight sandstone reservoirs. A tight gas reservoir can be deep or shallow; high pressure or low pressure; high temperature or low temperature; blanket or lenticular; homogeneous or naturally fractured; and contain a single or multiple layers.

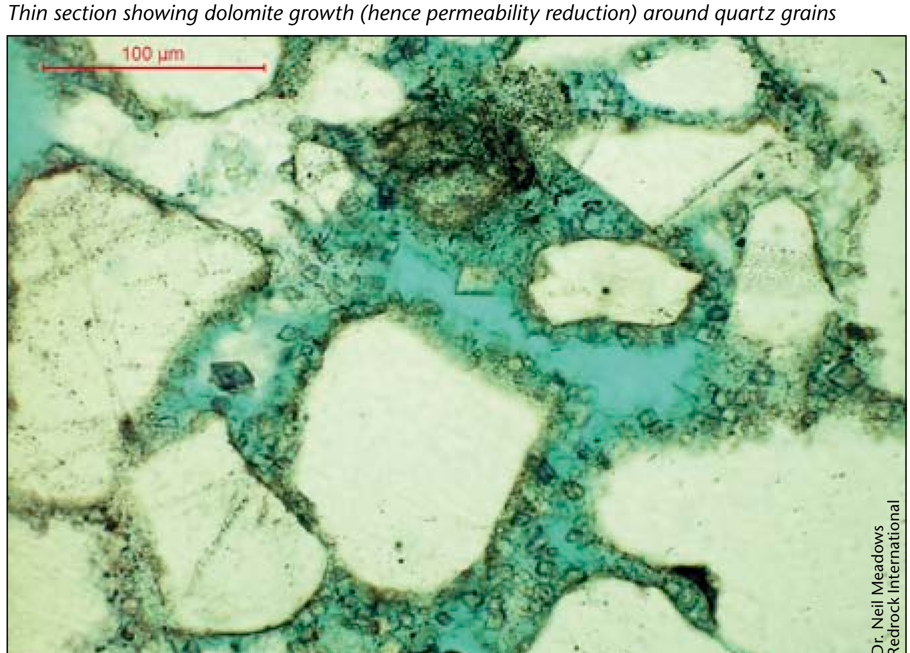
The major gas source in Europe is the Rotliegendes sandstones, a portion of which can be characterised as tight gas. Deposition occurred in a range of arid, terrestrial environments, wadi systems, aeolian deposits, desert-lake environments, and adjacent sabkhas. Compaction, pressure solution, and precipitation of diagenetic minerals all negatively impact the porosity and permeability of Rotliegendes reservoirs, but precipitation of fibrous illite is the most damaging diagenetic effect. Sandstones with the cleanest, best porosity at the time of deposition, and those sandstones deposited away from the water table tend to retain porosity and permeability. Fluviatile sandstones are commonly severely altered by diagenetic processes and tend to be those classified as tight. Small scale faulting with cementation and offsets are common in Rotliegendes outcrops and similar features are likely to act as subsurface flow barriers and further impact on recovery from gas reservoirs.

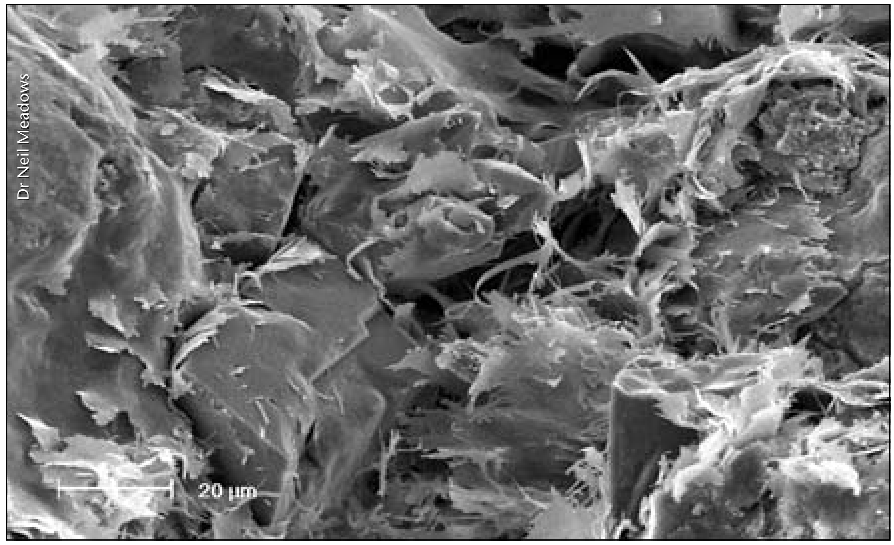
Development of Rotliegendes gas started in 1959 when Groningen was discovered onshore Holland (see *GEO Expro* Vol. 6, No. 4). In 1965 the discovery of West Sole proved that similar Rotliegendes sediments extended across the southern North Sea. Some 300 gas fields and 75 Tcf of recoverable natural gas have been discovered in the southern North Sea, and



Rotliegendes Basin and active tight gas areas

Thin section showing dolomite growth (hence permeability reduction) around quartz grains





SEM Rotliegendes core – fibrous illite with wisps and strands bridging the pore throats.

onshore in the Netherlands, Germany and Poland about 260 gas fields and 150 Tcf have been found. Unfortunately there is no equivalent of the EIA to record tight gas developments. A review of the technical literature, however, indicates that about 50 fields are described as tight, with over 300 slant and 100 horizontal wells drilled, amounting to reserves of around 7 Tcf. The potential is much greater; a joint industry/university study identified potential of 10 to 18 Tcf in tight Rotliegendes in the North German Basin alone.[1]

Fracture stimulation of individual tight Rotliegendes wells commenced in the 1970s and the first field development that relied on fracture stimulation was North West Leman in 1987. Fracture stimulation of slant wells proved generally successful but problems were encountered with fluid incompatibility, proppant back production and early water breakthrough due to fracturing into the water leg. During the early 1990s the emphasis moved to horizontal drilling[2], which proved particularly effective in the UK sector, where a number of fields had productive natural fracture systems or wells encountered sweet spots. The use of multiple propped fractures in horizontal wells followed. Underbalanced drilling was introduced in the late 1990s but faded when it became clear that the increase in productivity did not compensate for the additional cost.[3] The use of horizontal wells stimulated with multiple propped fractures is now the technology of choice for the development of tight gas.

Technology Transfer?

In conclusion, tight gas development is a large-scale day-to-day business in the US and the technology and resources (trained manpower, equipment, business environment) allowed the development of shale gas. Tight gas has barely been tried in the rest of the world. Europe and Poland in particular has now jumped directly to shale gas appraisal and development without the benefit of the infrastructure and business environment built on the back of a tight gas industry. Success requires the technology to be transferred from the US – but how easily that can happen while trying to build critical mass is an interesting question. ■

References

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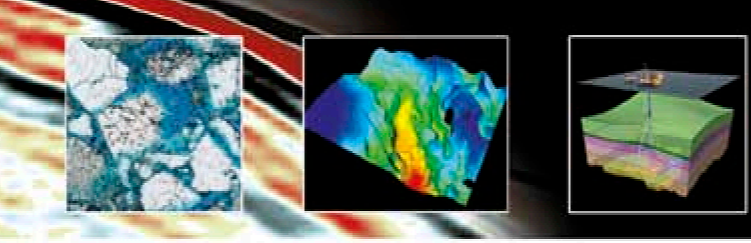
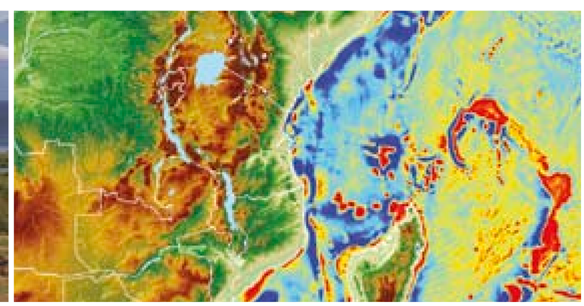
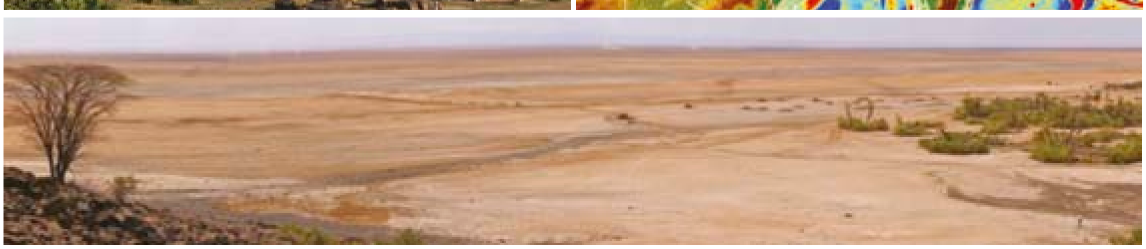
2. *Tehrani, A.D.H., 1992. An Overview of Horizontal Well Targets Recently Drilled in Europe, SPE 22390-MS.*
3. *Veeken, C.A.M. et al. Underbalanced Drilling and Completion of Sand-Prone Tight Gas Reservoirs in Southern North Sea, SPE 107673.*

About the Author:

***Roy Hartley** graduated as a petroleum engineer from Imperial College in 1969. He witnessed his first frac in the Rotliegendes in the same year. He is currently Chief Operating Officer for Aurelian Oil and Gas.*







Cairo: City of a Thousand Minarets

Built upon power struggles and commerce, and dominated by the magnificent River Nile, Cairo is one of the most exciting cities in the world.

SINÉAD ARCHER

If you have ever been to Egypt, you will probably have visited its eclectic and vibrant capital city. Cairo's stunning Islamic architecture has earned it the nickname 'the city of a thousand minarets', and as you wander the backstreets of the atmospheric souk, you are aware that the gentle spice scents and gleaming copper coffee pots have changed little in recent centuries. However, this is no city mired in the dark ages and never was this more apparent than during the pinnacle of the Arab spring – the Egyptian revolution of 2011. A modern revolution, the Egyptian uprising was masterminded through the use of the internet and social media and its largely peaceful demonstrations captured the attention of the world: Cairo appeared to be seeing its most dramatic period of history. However, this is a city with a dramatic past and 2011 was not the only year to see turbulence and power struggles.

The Victorious City

It may come as a surprise to some that despite Egypt's famous ancient heritage, Cairo is a relatively modern city. Although the epicentre of Ancient Egypt and the world-renowned pyramids are now just a short drive from modern-day Cairo, the city was only strongly established when the Romans conquered the region. With one of the few Nile crossings, the area had long been settled, and under Persian rule a fort had been built on the banks of the Nile, but it fell from any kind of importance during the Greek period. The Romans, recognising that both the Nile and the location of the Persian fort were of great strategic and economical use, soon established themselves there. Although largely persecuted by the Romans, it was during this time that a community of Coptic Christians also began to flourish, an influence still visible today in the old Coptic churches and the 'Coptic Cairo' region of the city.

Despite these 'false-starts' in the development of the major city that modern Cairo is today, its true establishment came with the arrival of the Arab Muslims in the 7th century. As well as introducing Islam to the region, which is still followed by the majority of Cairo's inhabitants today, the Arabs are credited with founding the city as it is now. In the 10th century the ruler, General Jawar, gave the city the name Al-Qahira – 'The Victorious' – and built the town into a walled city strong enough to survive the attack of any opposing armies. Which came in useful when a century or so later the Crusaders threatened to invade nearby Fustat, which had until then been the military and administrative capital of Egypt. The ruler at the time, Vizier Shawar, set fire to Fustat to deter the Crusaders and with immediate effect made the new Egyptian capital Al-Qahira, or, as it soon became known to the West, Cairo.

Cairo's trials and tribulations were far from over. Under the Mamaluks – an army of slave soldiers who revolted and took power in the 13th century – Cairo truly boomed, becoming a trading hub for multiple industries, but following the Ottoman invasion,

Anne Whaley Sousou

the city fell into a decline. It was not until the 'founder of Modern Egypt', Mohamed Ali Pasha, took control of Egypt in 1805 after several decades of power struggles between the Ottomans, the Mamaluks and the Albanians that Cairo became again the metropolitan hub it had once been. Ali Pasha can largely be credited with the introduction of cotton production to Egypt, starting an industry that refreshed the nation's economy and allowed Cairo to finally start to live up to its potential. Egypt underwent strong development under Ali Pasha and his successors and became one of the Arab world's leading economies. The British, always with an eye out for an opportunity, set their heart on this perfectly situated country, intersected by the fruitful Nile and with its thriving cotton revenue, and soon made it part of the ever-expanding British Empire.

2011 was not the first time that Cairo had seen large-scale demonstrations and uprisings. In the early 20th century, Egyptians became increasingly unhappy with the British Empire and public protests finally led to the country's independence in 1922. From this point onwards Cairo began its true expansion to become one of the most populous cities in the world today.

Cairo and Oil

Whilst oil production plays an important role in Egypt's economy, employing countless people and producing about 660,000 bopd barrels a year, down from a 1996 peak of about 935,000 bopd (EIA), there is one major reason why Cairo has risen to become a key city in the world of oil production.

Less than 160 km away from Cairo's buzzing streets lies the Suez Canal. At just 190 km long and 205 metres wide, the canal is an artificial waterway that since 1869 has allowed ships to pass from the Mediterranean Sea to the Red Sea without having to sail all the way round Africa. With roughly 1% of the world's oil production passing through the Suez Canal, it is a major revenue stream in Egypt's economy, with tolls set up to collect from every ship that passes along the waterway. Despite an international treaty from 1888 that states the Suez Canal can be used "in time of war as in time of peace, by every vessel of commerce or of war, without distinction of flag", through blockading and limiting access the canal has been used as a Egyptian power tool in the past, namely during the 1956 Suez Crisis and the Egypt-Israeli wars in the 1960s and 70s. The impact of such blockades on all of the oil industry has serious resonance. So important, in fact, that when the 2011 revolution threatened to disrupt the transportation of oil along the canal, the worldwide price per barrel shot up 4% overnight.

With Egypt's governance still currently in question, Cairo is unlikely to have seen the last of its drama, but with a population of 17 million and such a rich history, we may not have seen the city's true glory days just yet.... ■

JANE WHALEY

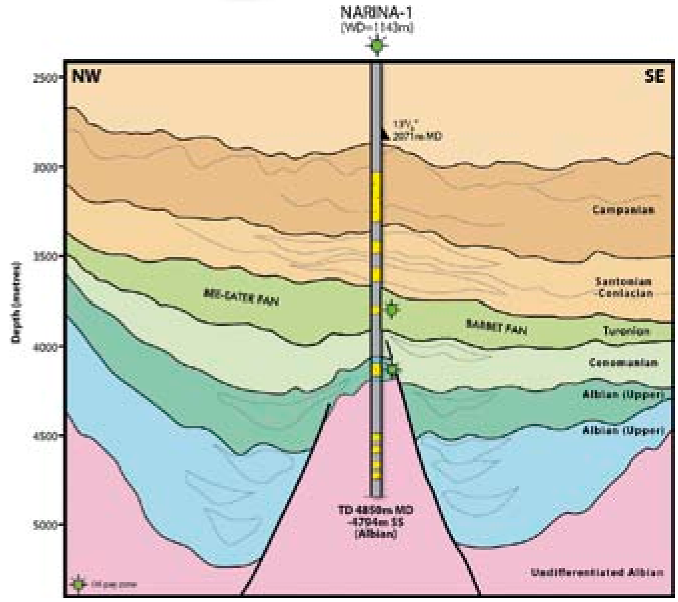
Liberia: Significant Oil Discovery

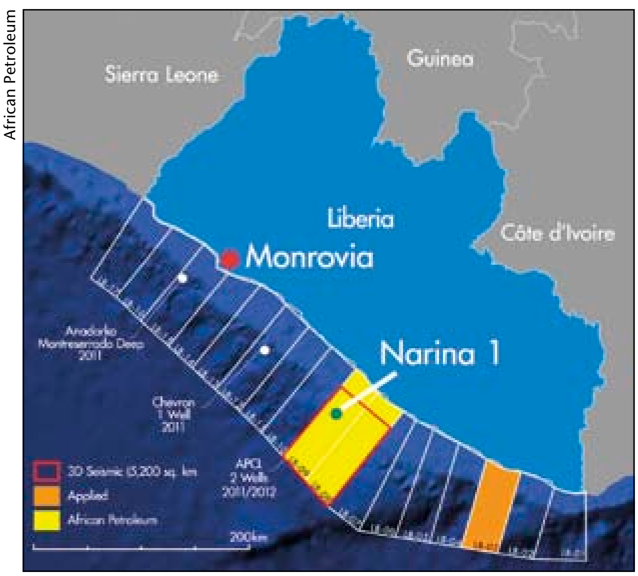
Liberia's race to join its West African neighbours Sierra Leone, Côte d'Ivoire and especially Ghana has moved an important step forward. In late February African Petroleum, which specialises in exploration in West Africa, announced what it described as a 'significant' discovery at its deepwater well, **Narina-1**, in Block LB-09, approximately 185 km south-east of the capital, Monrovia. The well was drilled to a total depth of 4,850m and is in waters 1,143m deep.

About 21m net pay of good quality 37° API oil was found in Turonian-aged rocks, part of a submarine fan system and shows were encountered over a total of 170m of this interval, with no oil water contact being found. The well also discovered 11m net pay of 44° API oil in the Albian, near to a very large Albian submarine fan prospect. In addition, over 200m of good quality thick sands were found in the shallower Campanian, Santonian and Coniacian horizons, which, although water-bearing, proved the presence of a good reservoir at this interval. This de-risks a number of other leads in the area, which, unlike the Narina prospect, have evidence of traps at this level.

African Petroleum is 100% owner and operator of Blocks LB08 and LB-09, covering a total of 7,135 km^2. Before drilling this well, African Petroleum acquired over 5,000 km^2 of 3D seismic over the two blocks and the company now plans an extensive drilling and appraisal programme later in 2012.

Although the shallow waters off Liberia have been explored previously, and six wells had oil shows, there has been very little exploration in the area since the 1980s, and until the drilling of Narina, no deepwater wells had targeted the Cretaceous sands which have proved so productive in Sierra Leone and Ghana. ■





African Petroleum

Brazil: Further Pre-Salt Discoveries

Offshore Brazil continues to prove that it is one of the most exciting and prolific exploration areas in the world, with four of the top discoveries so far this year having been made in the area, according to IHS. These include the successful **Päo de Açúcar** well, which in late February found two pre-salt accumulations with a total pay of 350m, and estimated 2P reserves of nearly 650 MMboe, with 330 MMb of oil and 1.9 Bcf of gas. The well is located in block BM-C-33 in the Campos Basin, which also contains the Seat and Gávea discoveries, 195 km offshore Rio de Janeiro State in 2,800m of water. Repsol Sinopec is operator with a 35% stake, while Statoil and Petrobras hold 35% and 30% respectively.

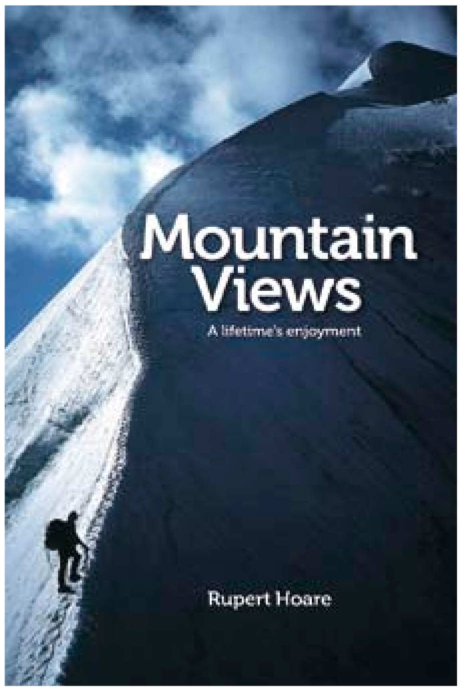
This was followed in early March by the **1-RJS-691A-RJS** well which found good quality 25° API oil at the Tupi Northeast prospect in the Santos Basin, a few kilometres from the giant Lula field (formally known as Tupi). Reserves here are thought to be in the region of 500 MMbo (2P), with a 290m oil column in the pre-salt reservoirs, where the targets were microbial and stromatolitic Aptian Barra Velha carbonates and the Itapema lacustrine limestone. Petrobras is operator and owner of the block. Two other discoveries of note occurred in the Santos Basin in January, with Shell's **1-SHELL-026-RJS** well finding 200 MMbo (2P) and OGX discovering 100 MMbo with **1-OGX-063A-SPS**.

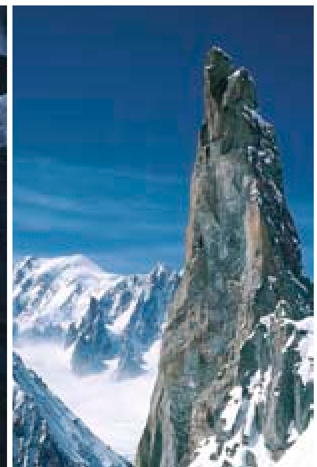
Petrobras also announced in late March the success of well **4-SPS-86B**, known unofficially as **Carcará**, 232 km off the coast of the state of São Paulo in water depths of 2,027m. Although no reserves estimates have been announced, the well is reported to have found good quantities of 31° API in reservoirs at a depth of 5,750m. ■

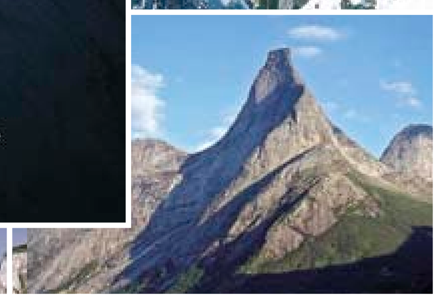
Rupert Hoare's Mountain Views

Rupert Hoare was widely known and respected in the E&P industry. What was not so widely known was that he was an extraordinarily accomplished rock climber, mountaineer and ski-mountaineer and a former President of the London Mountaineering Club and the Alpine Ski Club.

As a fellow skier, I am writing this article some 2,200m above sea level, high in the Alps, a place that Rupert felt most at home and one of the many places that he described and photographed in his book "Mountain Views – A lifetime's enjoyment", written in the final six months of his life. I understood Rupert's intense love for the mountains, although he disliked piste-skiing due to the ugliness of the associated lift systems. For Rupert, there was only one way to ascend a mountain – by walking, skiing and climbing to the very top. The extent of his climbing adventures ranged far and wide.







Rupert was a born explorer. After receiving a BSc in geology from the University of Exeter, he began his career in the E&P industry in 1977, joining Seismograph Service for what was advertised as 'a life of science and adventure'. Rupert was already destined for adventure from his early climbing days at Winchester College, visiting Arctic Norway with the British Schools Exploring Society, and then at Exeter University with further visits to Norway, Scotland and South Africa. His love of the outdoor life fitted well with oil exploration, with the associated periods of leave allowing him time to pursue his sport and visit a wide variety of climbing locations for weeks at a time.

In 1981 he joined Lasmo as an interpreter in London and then South-east Asia, finally returning to his seismic roots with Geco in London in 1995 and later in Aberdeen. Rupert's career in the industry placed him in many parts of the world, enabling him to climb in Japan, New Zealand, Tasmania, Nepal, Iran and closer to home in Greece, Corsica, Spain, the Alps, the Dolomites, the Pyrenees, Norway and Greenland.

The accounts of his exploits range from the humorous to the heroic and in some instances to the tragic, all supported by spectacular photographs, many of which he took himself. His attention to detail was legendary, with routes meticulously researched and planned weeks in advance. His pragmatic approach was typified in one instance, where, after falling from a ridge on Aonach Mor in Scotland during a 'white-out', he considered suing the Ordnance Survey for mispositioning a vital landmark he had used as a reference, but then decided that his efforts would be much better spent finding himself a new job, having recently parted company from Lasmo.

His underlying passion for the sport and the mountain environment that he cherished shines through on every page of his book, and as he himself said, if it encourages just one youngster to take up the sport, then he would have been more than satisfied.

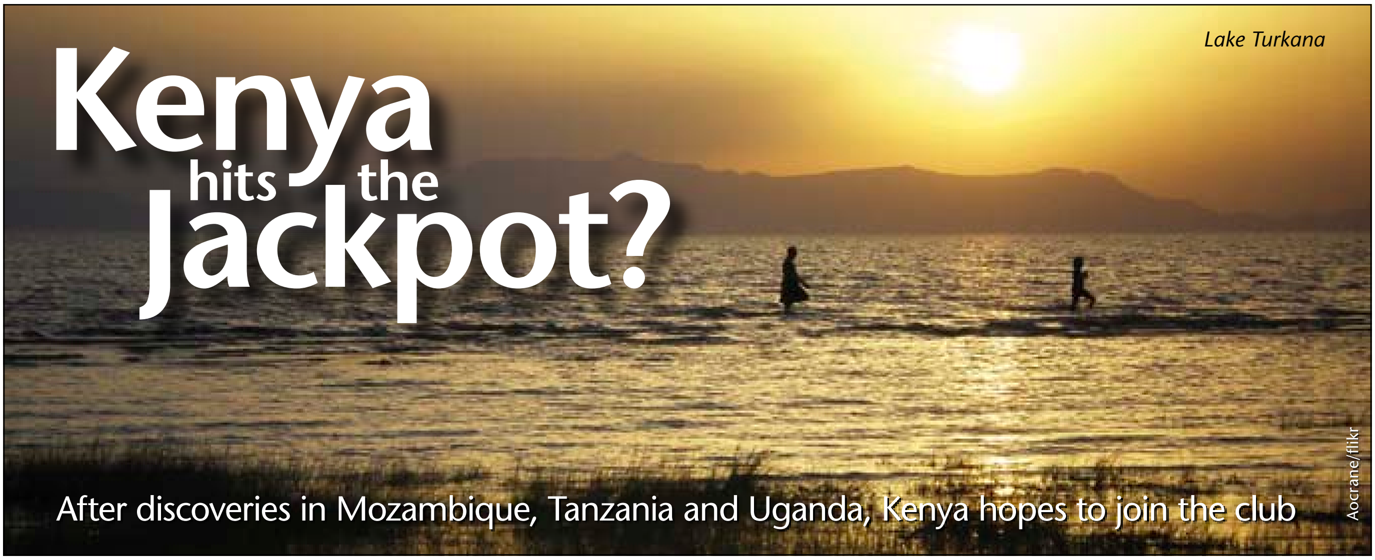
With only 16 out of the 283 Munros of Scotland left to climb and much to the shock of everyone who knew him, Rupert was diagnosed with inoperable pancreatic cancer in January 2011 and died in September 2011.

All profits from the sale of his book go to the Pancreatic Cancer Research Fund, which has also benefited from donations given in the memory of Rupert Hoare. ■

CHRIS WALMSLEY, WesternGeco

Mountain Views: A Lifetime's Enjoyment
by Rupert Hoare. Vertebrate Graphics Ltd, 2011

Kenya hits the Jackpot?



After discoveries in Mozambique, Tanzania and Uganda, Kenya hopes to join the club

For too long a backwater in hydrocarbon terms, dependent on imported oil and gas, East Africa is now well in the limelight. Following on from major gas finds offshore Mozambique, where recently discovered reserves amount to an estimated 50 Tcfg and still counting, Tanzania was the next to announce a major offshore gas find, with BG's Jodari-1 well bringing the total recoverable gas reserves for that country to about 8 Tcf. Meanwhile, in Uganda a number of companies had been exploring the Albertine Graben and other parts of the East Africa rift, and 2.5 Bboe have been discovered, much to the joy of the inhabitants of that impoverished country.

And now Kenya has joined the party. On 26 March Tullow Oil, together with partner Africa Oil, announced that the Ngamia 1 well in Block 10BB in the Lake Turkana area of north-west Kenya had encountered a 20m column of good quality 30° API oil, with similar properties to the light waxy crude discovered about 500 km to the north-east in Uganda. Shell drilled two wells in the Turkana area in 1992 and one, Loperot 1, found about 10m of waxy crude, but the company pulled out of the country. There was no further exploration in the area until 2007, when the block was awarded to a consortium before it eventually passed to the present owners, Africa Oil and Tullow, which drilled the discovery well about 25 km from the location of Loperot 1. Pre-drill P50 estimates were in the region of 45 MMbo, and the block contains a number of larger leads.

Kenya has four main exploration basins: Lamu, Anza, Mandera and the Tertiary Rift, with a combined surface area of about 500,000 km^2. The discovery is in the Lokichar Basin, part of the eastern branch of the East African Rift system, where several kilometres of Neogene sediments were deposited in a series of half-graben basins. Only 32 wells have been drilled onshore over the whole of Kenya since independence in 1963, meaning that the stratigraphy is poorly understood and many horizons and potential plays have yet to be investigated.

Increased Interest

Many leads and prospects similar to Ngamia have been identified in the area through recent seismic surveys, and this discovery has considerably improved the expectation of success.As a result, despite the fact that the operator, Tullow, has yet to declare the discovery to be commercial, interest in the surrounding blocks has intensified. It is reported that a number of companies have expressed interest in 13 of the remaining 16 unlicensed blocks, and 29 blocks, both on and offshore, have been licensed to foreign consortia from 14 different companies.

In addition to interest in the onshore potential, Kenya has earmarked eight large deepwater blocks for exploration and Total, Statoil, Apache, Petrobras and Tullow are among the companies reported to have expressed interest in these. The new areas all lie to the east of the 15 existing offshore blocks available, and are between 10,000 and 15,000 km^2 and up to 4,000m deep. They will bring the total number of exploration blocks in the country to 46. Plans are underway to drill an additional five oil wells between June 2012 and December 2013 in five blocks, two onshore and three offshore.

Raised Expectations?

The people of Kenya, an estimated 50% of the population of whom live below the poverty line[1], are desperately hoping that this discovery will prove commercial and be the first of many. However, they are looking at other countries, such as Nigeria, where the oil revenues benefit only a small minority of the population, and hope to learn from their experience and develop any reserves prudently. It will also take some time before infrastructure would be in place to exploit any discoveries, particularly since the Turkana area is remote, poor and susceptible to tribal clashes.

Any potentially large finds in Kenya will also alter expectations in Uganda, which had looked to its more populous but hydrocarbon-poor neighbour to provide a hungry market for its own recent discoveries. Plans to build a pipeline from the Albertine Graben fields to the ready market of Nairobi and further across Kenya for export from the Kenyan coast may be revised in the light of any local discoveries. Since South Sudan also has vast oil reserves, the neighbours will need to cooperate in order to avoid unnecessary competition and, in the worst scenario, conflict, so that they can all benefit from their hydrocarbon resources.

JANE WHALEY

[1] CIA World Factbook

Acknowledgement: Many thanks to Tiziana Luzzi of IHS for assistance with this article

What's Ahead for North West Europe?

We ask two analysts focused on this area, André Sharma and Elizabeth Lloyd from Petroleum Services at Deloitte, to give us their thoughts.

What are the latest drilling trends in the UK and NW Europe for 2012 so far?

During the first quarter of 2012 drilling activity across the UK and Norway has been at similar levels to those seen in Q1 2011. In the first quarter, a total of 25 exploration and appraisal (E&A) wells were drilled across north-west Europe, of which 11 were drilled in the UK and 10 in Norway. This represents a 4% increase across north-west Europe compared to the same quarter in 2011 where 24 E&A wells were drilled in total. For the UK this translates into a 22% increase while for Norway it reflects a 25% decrease. Both countries have shown a decrease in drilling when compared to levels seen in Q4 2011. Overall, drilling activity levels during the first quarter tend to be low, driven by adverse weather conditions affecting operations during the winter months.

What trends do we see in licensing and deal activity across north-west Europe?

Across north-west Europe the level of deal activity has been lower through the first quarter of 2012 compared to the fourth quarter 2011. However, the UK itself has seen an increase in activity and in Norway levels have remained consistent to previous quarters.

The relatively high numbers of farm-ins recorded in recent years, as companies sought partners to mitigate financial risk, is now being matched by a rise in the number of asset acquisitions as companies are keen to acquire development and producing assets in order to make the most of the sustained high oil price. Licensing activity is strong across the region, with the Awards in Predefined Areas (APA) 2011 in Norway and the recent announcements of the UK 27th Licensing Round and the Norwegian APA 2012.

What factors are affecting drilling and deal activity across north-west Europe?

The sustained high oil price has given companies confidence to pursue new field developments, incremental projects and near term production. This is also demonstrated by the number of farm-ins and asset acquisitions which have taken place during 2011 and 2012. Additionally, in the UK, the recent Budget announcement in March 2012 provides more certainty on tax relief for decommissioning costs and broadened the field allowance legislation to incentivise and encourage exploration and appraisal activity and field developments across the UKCS. However, the Eurozone debt crisis and the recession of 2008 still continue to impact the financial and credit markets which in turn affect levels of investment in E&A drilling across the region, while constraints on rig availability across the region also continue to be an issue.

What are the emerging frontier areas in North West Europe?

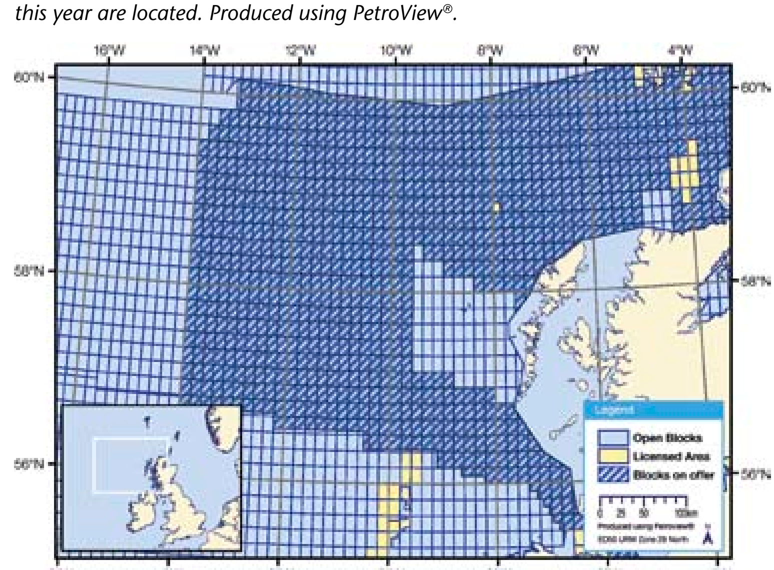
In the UK, the West of Shetlands has seen increased levels of E&A activity over the last five years. In 2011, 16% of wells spudded on the UKCS were located in the West of Shetlands and already in the first quarter of 2012, 18% of exploration and appraisal wells drilled are located in this area. Following the Budget announcement and the introduction of field allowances targeting deepwater fields to the West of Shetland, it is clear the government is keen to incentivise further investment in this region.

There has been some focus on recent activity in Greenland, with Cairn drilling nine wells in the past two years. No commercial discoveries have been made to date, although USGS estimates resources of up to 50 Bboe.

Iceland has had no exploration wells to date. owever, the 2nd Licensing Round opened in April 2012 where acreage is available to the south-west of the Jan Mayan Ridge. In the Faroe Islands there is an open door licensing policy to encourage exploration.

However, all these areas share common challenges with deepwater, extreme metocean conditions and new play concepts requiring cutting-edge technology and high commitment. ■

The UK 27th Licensing Round opened in February this year and included much of the West of Shetland area, where already 18% of exploration and appraisal wells drilled this year are located. Produced using PetroView®.



Relying on Chalk

Almost all Danish oil and gas comes from the Central Graben. Nevertheless, there is still some interest in other areas, including the onshore.

The first exploration licence in Denmark was granted in 1935. Following a series of failed attempts onshore, the first well in the Danish part of the North Sea discovered hydrocarbons in 1966. The discovery was also the first find in the North Sea, but it was not put on stream until 1996 (Kraka, with a cumulative production of more than 30 MMbo by the end of 2010). The first oil produced was from the Dan field, Denmark's largest field, which is still producing some 50 Mbopd and by end 2010 had delivered a total of almost 640 MMbo.

Since 1983, areas in the North Sea have been offered to interested oil companies in a system of rounds; six in all, the latest in 2005/2006. However, in 1997, an Open Door procedure was introduced for all unlicensed areas east of 6° 15′ E, i.e. the entire Danish onshore and offshore areas with the exception of the westernmost part of the North Sea. However, to date no commercial oil or gas discoveries have been made in the Open Door area.

Denmark has 19 producing fields, of which 15 are operated by Mærsk Olie og Gas, three by DONG E&P and one by Hess Denmark. All of them are in the offshore sector, and most of them are located in the Central Graben, with only four in the Norwegian Danish Basin. The oil is, however, generated in the Central Graben.

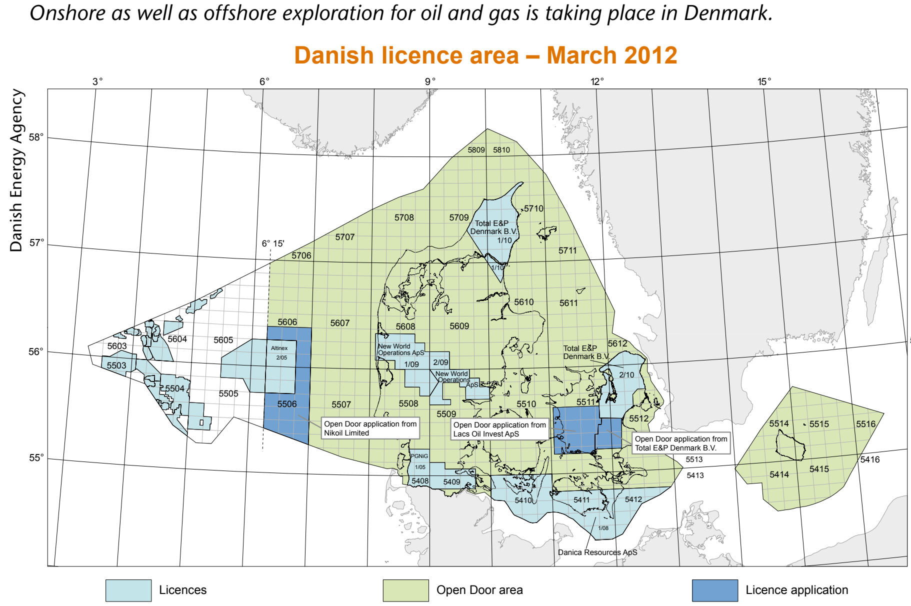
All but five of the fields are producing from Danian and Upper Cretaceous chalk. This includes the largest producers like Dan, Gorm, Halfdan, Skjold and Tyra. Other producing formations are Paleocene sandstones east of the Central Graben (Siri, Nini and Cecilie), Lower Cretaceous shaly chalk and sandstones (Valdemar), Jurassic sandstones (Lulita) and Permian carbonates (Dagmar).

As of 1 January 2011, it was estimated that some 1.2 Bbo is left in the ground, while 2.3 Bbo have already been produced over almost 40 years. In 2010 oil production in Denmark averaged 245,000 bopd. About 0.6 Bboe of recoverable gas reserves remain, while about 1 Bboe of gas had been produced by the end of 2010. The recovery factor from all Danish gas fields averages 26%, although from the larger fields, like Dan, Gorm and Skjold, an average recovery factor of 37% is anticipated.

This means that Denmark will be a net exporter of oil and natural gas until 2019 and 2012, respectively. ■

HALFDAN CARSTENS

Onshore as well as offshore exploration for oil and gas is taking place in Denmark.



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.

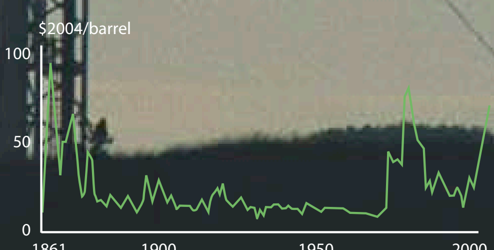
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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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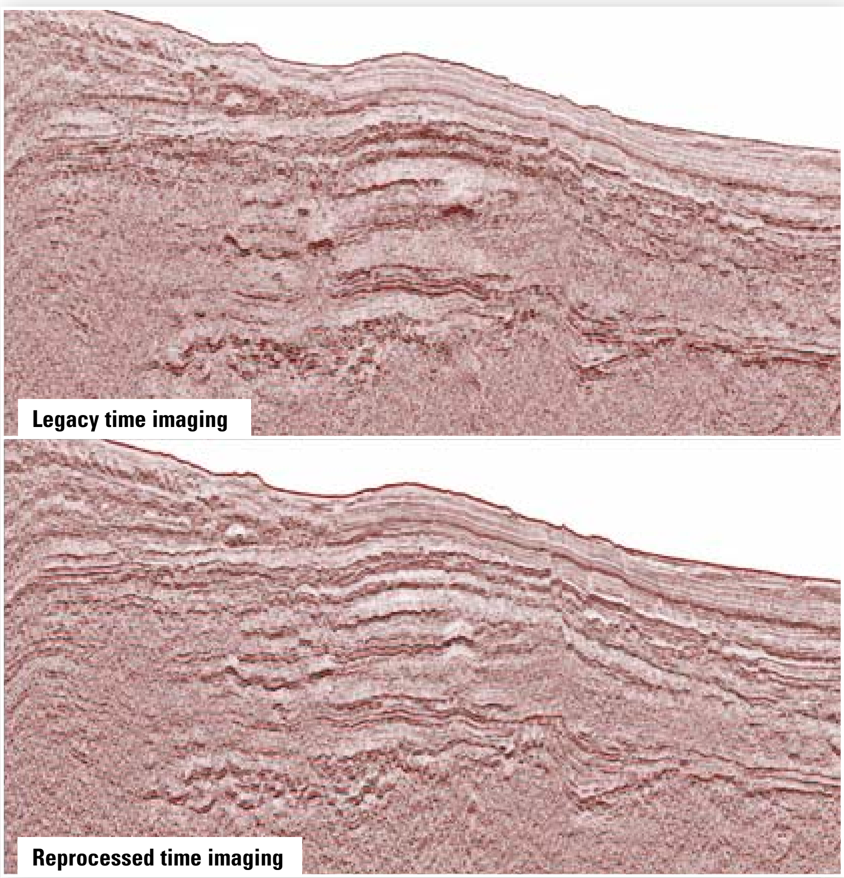

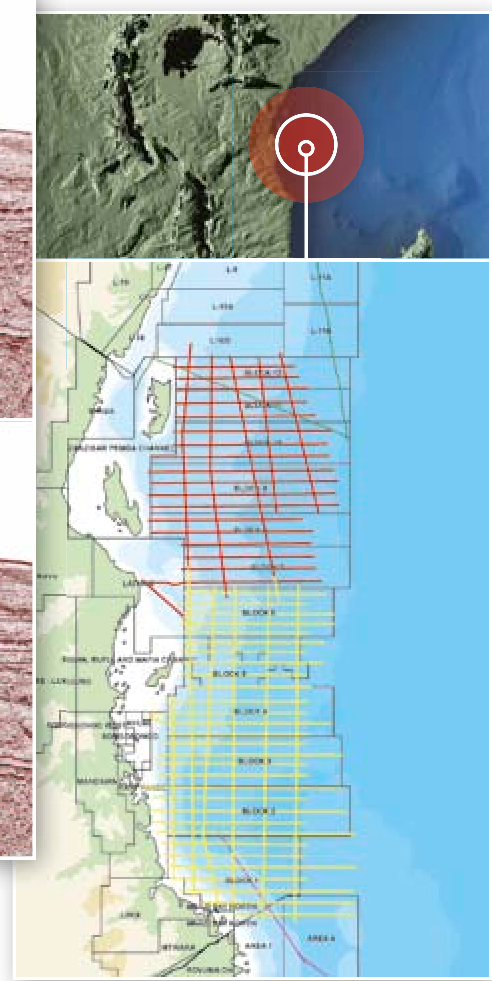

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■ 7,035 km PSTM and PSDM underway

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