VOL. 11, NO. 6 – 2014

GEO ExPro

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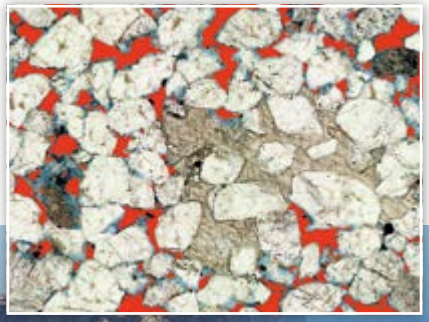

Technology Explained:
A New Approach to Cores

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The Great Australian Bight

GEOTOURISM

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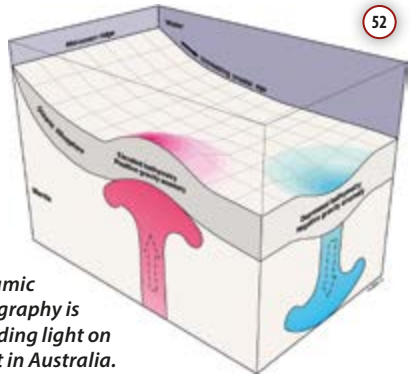

Dynamic topography is shedding light on uplift in Australia.

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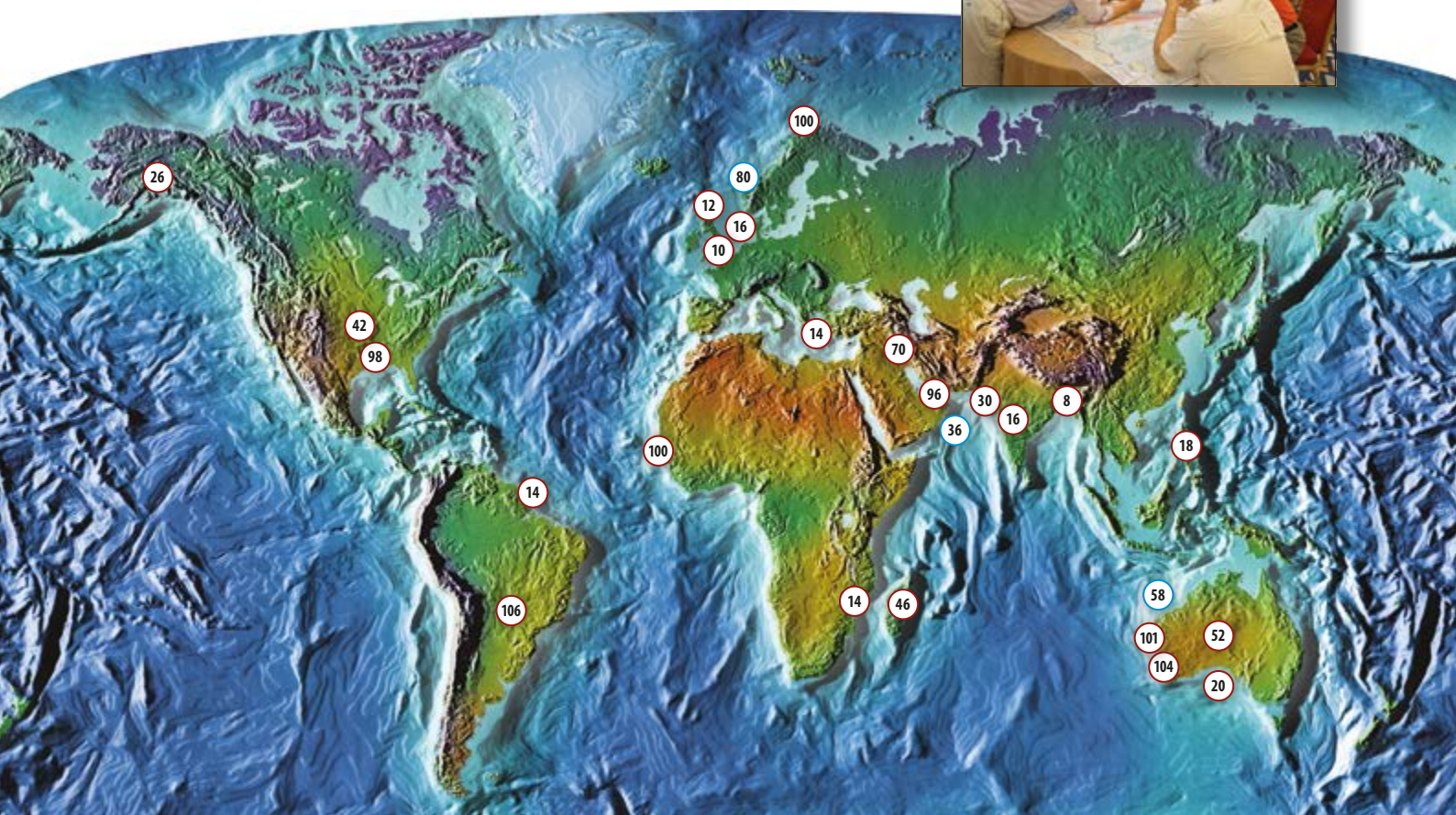
This edition of *GEO ExPro* Magazine focuses on Australasia, the Indian Subcontinent and New Technologies

COLUMNS

FEATURES

Rejuvenating thinking by connecting generations of explorers.



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Keep on Innovating

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Technological progress and innovation are key to the oil and gas industry. We may have found the 'easy' resources – although the geologists who explored for hydrocarbons with a compass and a hand-drawn map in the days before sat-nav and mobile phones may dispute our definition of easy – but we need to constantly innovate in order to locate and extract the remaining reserves.

Aided in recent years by consistently high oil prices, but also by the realisation of this need, the industry has been spending considerable capital on R&D in a wide range of fields – from automation and robotics to biotechnology, nanotechnology and data analytics – and in developing techniques like microseismic and multistage fracking. In addition, significant sums have been spent on technologies to enhance production from both new discoveries and more mature fields.

A recent worldwide survey of senior industry executives undertaken by Lloyds Register* attempts to assess innovation trends and drivers in the sector. While nearly 60% of the respondents said their company had increased R&D spend in the last two years, the report found that technologies to extend the life of current assets or improve efficiency get the greatest priority. Three-quarters of those questioned said that pressure to innovate has intensified, yet only 25% admitted to being 'early adopters' of technology; 20% preferred waiting until a technology was established before adopting it. Unsurprisingly, the survey found that cost was the biggest barrier to innovation, followed by uncertainty over returns, as well as worries about skills shortages.

The oil and gas industry is often considered conservative and inherently risk averse. This survey was undertaken before the recent plummet in the oil price; it would be interesting to know whether the 69% of respondents who said they would be increasing their R&D spend over the next two years would still say the same? What then do we need to do to continue developing technologically?

Collaboration may become an important factor, both between E&P and service companies and also with partners beyond the industry, as several articles in this edition describe. And we must continue to invest in training and development, encouraging young minds to tackle the issues of innovation in the future. No matter how clever a technology is, people are the key to its implementation and success.

** Lloyd's Register Energy: Oil And Gas Technology Radar* ■

Jane Whaley
Editor in Chief

THE GREAT AUSTRALIAN BIGHT

Dynamic uplift over the last 40 million years has exposed the vast South Australian Nullarbor Plain, which ends abruptly at a 200 km long line of cliffs. These look out over the expanse of the Great Australian Bight, where a new wave of exploration looks to produce exciting results from these pristine waters.

Inset: Digital archiving of core information affords the oil and gas industry an opportunity for rapid core evaluation.

GEOExPro

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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 Photograph:
Main Image: Neale Winter/South Australian Tourist Commission
Inset: PetroArc International

Layout: Bookcraft Ltd.
Print: NXT Oslo Reklamebyrå

issn 1744-8743

From Scarcity to Abundance

Supply glut and growth worries – a recipe for lower oil prices.

Oil prices dropped sharply over the summer and in October they really nose-dived. Prospects of surprisingly weak demand have oil industry people tearing out their hair, companies trembling at the knees and financial traders selling loads of paper barrels. Unfortunately, there is little hope of improvement any time soon.

The demand for oil has weakened sharply as a consequence of poorer outlook for economic growth in large oil-consuming countries such as China, Brazil, the Euro area and Russia. US economic growth indicators remain positive, but concern is mounting that weaker global growth will begin to be felt even there.

High oil prices earlier this year contributed to strong growth in shale oil production in the US and Canada – but this is not cheap to produce, so how much can oil prices fall before production slows down? The answer is complex, as production costs vary hugely. With today's technology it is possible to produce more oil per well, driving costs down, while lower oil prices mean equipment and rigs are hired on short-term contracts, helping drive down rental prices. The shale revolution has reduced the US's oil import requirement, so countries that previously exported light oil there must now look for other export markets.

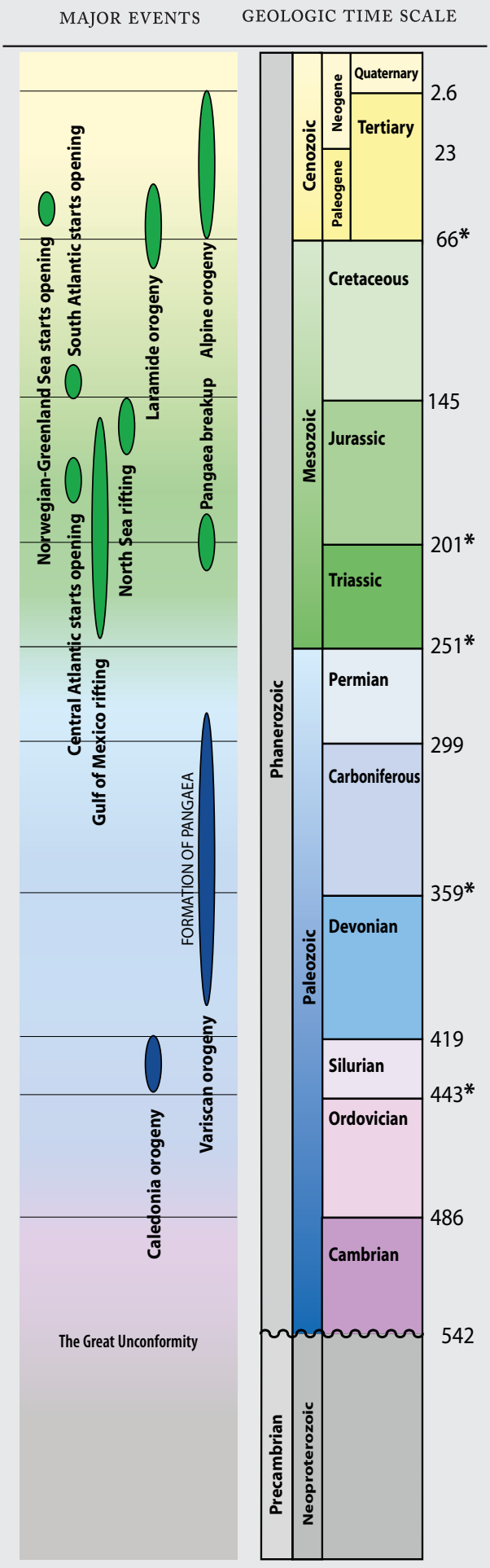
Will OPEC Cut Production?

Contrary to market expectations, the OPEC countries increased their production in September, rather than cutting production to defend their unofficial price target of US$ 100/barrel. There are many possible explanations for this move. The recent sharp increase in Libyan production, despite its political instability, was a surprise. Increased competition in the Asian market and a strategy focusing on maintaining market share are other possible explanations. The Saudi government can handle periods of lower oil prices and may have concluded that those benefiting the most from a production cut would be the US and Russia.

Lower forecasts of demand growth in 2015 and increased production by other producers mean that OPEC may have to reduce its total production and agree new country-specific quotas. With substantial political tensions inside the cartel and increased competition, Saudi Arabia may also hope that keeping the oil price low might encourage all members to abide by the agreed production volumes. Countries like Venezuela, Iran, Iraq and Nigeria need an oil price much higher than US$ 86/barrel to balance their budgets, so this strategy may work.

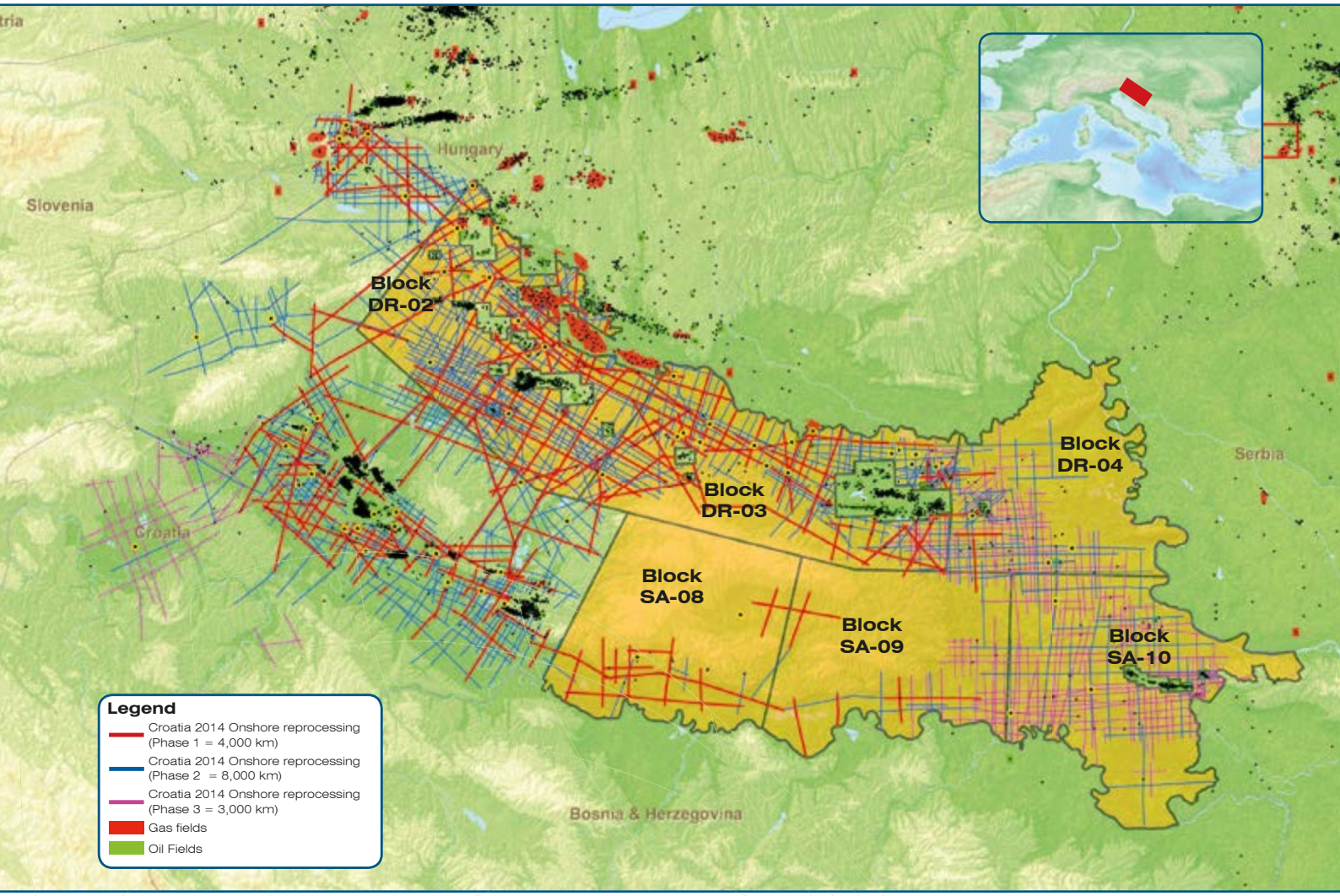
A factor contributing to the sharp drop in oil prices is increased concern in the financial markets about the direction of the world economy. After the 2011 euro crisis fluctuations in oil prices dropped to around 15% over the past year. But with speculation about growth, uncertainties and price fluctuations both rose, triggering a sell-off of more risky assets like oil, further intensifying the drop in oil prices. These will remain low for a while yet, increasing pressure on oil companies to trim costs and boost earnings. ■

Thina Margrethe Saltvedt



Onshore Croatia

Newly-Enhanced Seismic for 1st Onshore License Round



The first onshore licensing round in Croatia officially closes in February 2015. This is the first of three tenders for onshore tranches in the forthcoming period. The first license round comprises a total of 6 blocks with a total area of 14,600 km^2 in the Drava, Sava and Slavonija Basins, in the prolific southern Pannonian Basin.

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Spectrum

Bangladesh Offers New Exploration Arena

A ruling by the Permanent Court of Arbitration in The Hague on 7 July 2014 has delineated the maritime border between India and Bangladesh, with Bangladesh winning 19,467 km^2 of the 25,602 km^2 of disputed maritime area. This ruling means Bangladesh has finally, after 35 years of inconclusive negotiations, legally established its maritime boundaries, a separate maritime dispute with Myanmar having been settled in 2012. The peaceful settlement of the Bangladesh-India border dispute is a positive step forward in the broader context of gradually improving relations between the two countries and increasing energy interdependence.

New Round Coming Up

Following the ruling, which is binding on both parties, the chairman of state-owned Petrobangla, Hossain Monsur, indicated that Bangladesh will launch a new round of offshore oil and gas tenders in the Bay of Bengal in the near future; ten blocks are expected to be offered. However, the removal of uncertainty over maritime sovereignty will not of itself be sufficient to attract international investment in exploring the Bay of Bengal, as was amply demonstrated in Bangladesh's lacklustre 2012 offshore bidding round.

Various aspects of the offshore model PSC came to light when ConocoPhillips identified a large deep-sea oil and gas prospect in Block 11, but could not proceed towards drilling as it felt that the financial risk was too high. Learning a lesson from poor response to the two previous offshore oil and gas bid rounds in 2008 and 2012, the government is set to revise its model production sharing contract with better incentives. In addition, the government will shortly tender for a contractor to conduct a seismic survey in early 2015 in the Bay covering 10,000 line-kilometres in both deep and shallow waters to stimulate bidders' interest. At present, Bangladesh has no data about offshore prospects to attract oil companies, and the planned survey, estimated to be completed within eight months, would generate data to be available to interested bidders in an offshore bid round scheduled for 2016.

Bangladesh had a single producing field in the Bay of Bengal, the Sangu Field operated by Cairn Energy (Capricorn Energy), a subsidiary of Santos International, but operations were shut down due to lack of production in October 2013. Consequently the offshore remains a vastly underwexplored arena, with only 17 new field wildcats in an area covering 63,000 km^2. Cairn drilled two multi-Tcf prospects (Magnama 3.5 Tcf, Hatia 1.0 Tcf) near the Sangu Field in late 2007/ early 2008, but both were disappointing and require further appraisal. Magnama 1 encountered a number of thin, normally pressured gas bearing sands (20-40m) which may thicken on the flanks of the structure, while Hatia 1 found non-commercial volumes of hydrocarbons and was suspended pending possible re-entry after evaluating the up-dip potential.

Currently there is too little geological data on Bangladesh deepwater blocks to make a prediction on prospectivity or likely resources. Nevertheless, recent big gas discoveries off the Arakan coast of Myanmar are just about 100 km south of St Martin's Island in Bangladesh and these, along with those on the Indian side, have raised the interest of gas explorers to venture out into the Bay of Bengal. Only intensive exploration by companies with high-tech high-cost capabilities can actually offer a definitive answer.

Ken White

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

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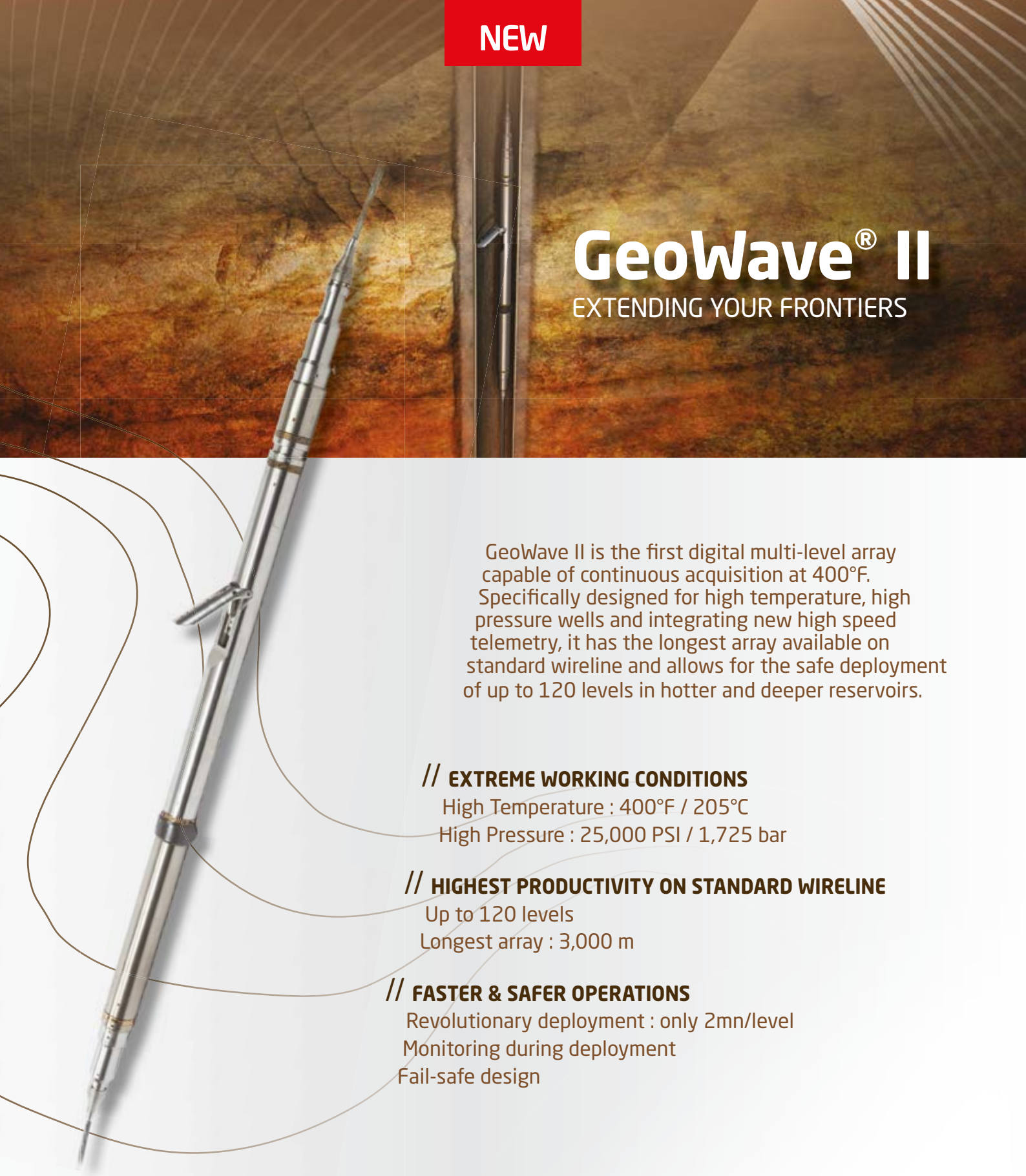

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The APPEX Effect!

MIKE LAKIN, APPEX 2015 Chairman

With the present state of the world's economy and the outlook for 2015, it's important to remember the 'four Rs' of the A&D process.

It is that time of year again when most of the upstream world's attention is tuned to the end of the year. As 2014 is rapidly running out, budgets for 2015 are being finalised, what remains of any budget for this year is being allocated to existing and new opportunities and the majority of the workforce is thinking about a short break around Christmas and the New Year.

The state of the world's economy obviously plays a key role in the financing of upstream deals and the ability of E&P companies to fund their international activities, which inevitably includes work programme obligations and commitments. With exploration ever more difficult to finance in the present climate, even where organisations have enough money to fund their obligations, reducing risk by farmout, strategic divestment of interest or even just a wish to find strategic partners with complimentary expertise, leads companies to undertake an A&D process.

To achieve this, it is essential to be mindful of what are sometimes referred to as the 'four Rs' when activating a divestment or farmout process:

- **R**IGHT Information
- **R**IGHT People
- **R**IGHT Way
- **R**IGHT Time

Essentially, providing the right information, in the right way, to enough of the right people and at the right time! Sounds simple, but many forget how long the process can take and rarely start it early enough. Independent global farmout statistics from around 3,000 transactions reviewed and tracked over 15 years clearly show that a farmout takes an average of over 12 months to complete, so planning and optimising a project marketing campaign for 2015 should have started by now for companies with obligations in 2015, and also for those with commitments in 2016.

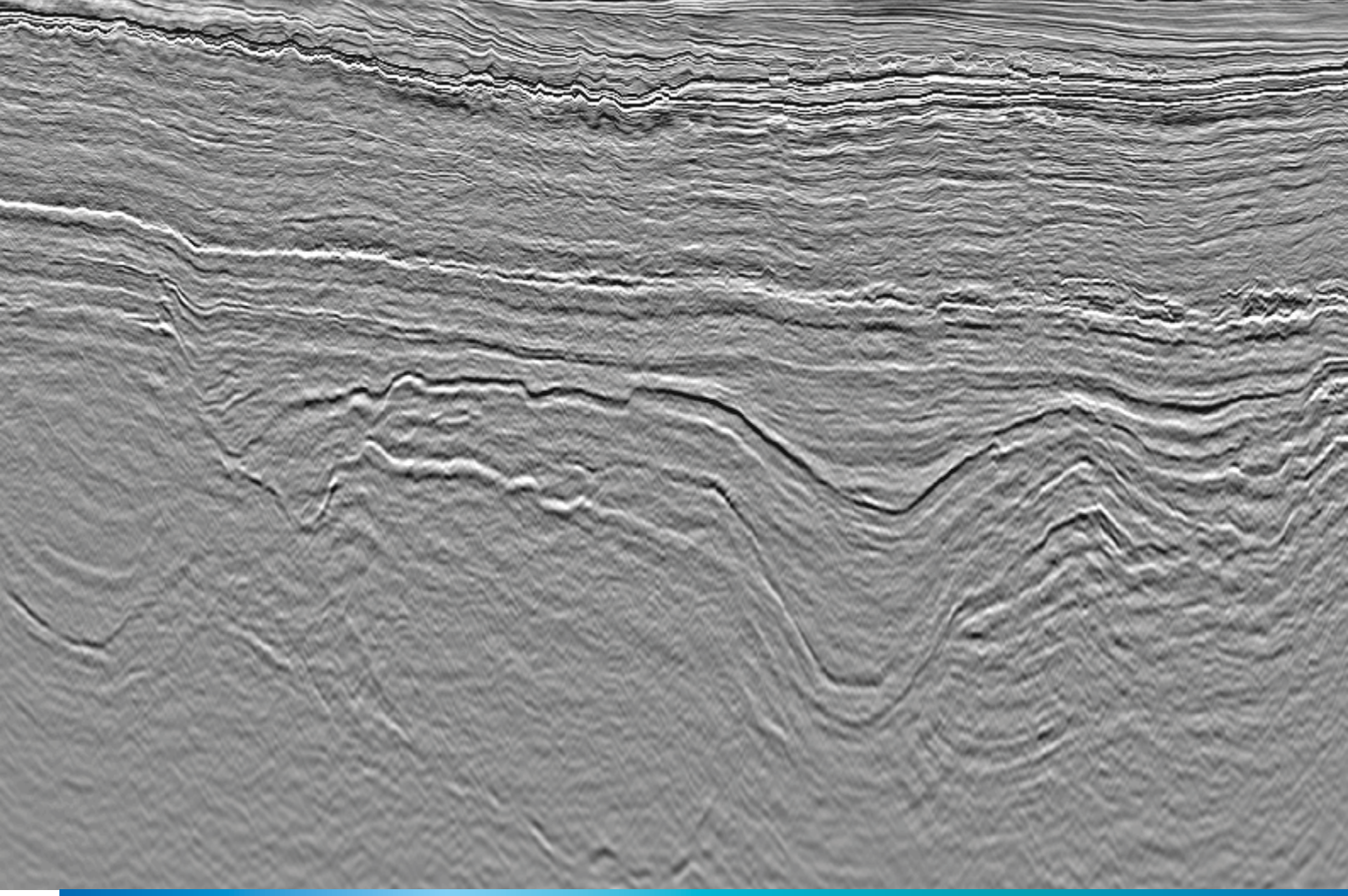
Global Meeting

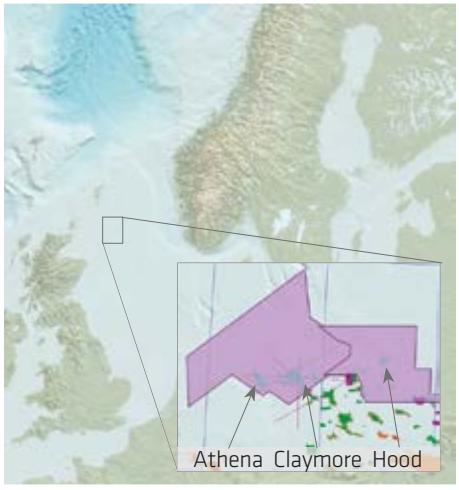
The annual Global APPEX, now in its 12th year, is just one of the key platforms where at least three of the Rs are available all under one roof. It will again be held during the first week in March at its traditional home in the Business Design Centre in Islington, North London, just a stone's throw from the centre of the city.

Year on year, attendance at this specialised international A&D event has grown and, based on the growth of the last few years, we can expect to see over 800 of the world's upstream decision-makers in London, either looking for new opportunities or themselves looking for partners. If you are one of these key people and are either looking to buy or sell E&P interests, then if you have not been before you should consider doing so in 2015, where early registration is advised, particularly if your company's plans involve exhibiting and presenting project opportunities. If you are planning a return visit, please reserve the first week in March 2015 and we look forward to welcoming you back. More often than not, we are told by attendees that APPEX in London is a must for any company involved in global upstream A&D. We look forward to seeing you there if you are one of those people!

(PS: Register before 2 January for the Early Bird rate and save up to 30%!) ■

APPEX 2014 attracted over 800 delegates.





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New Geoscience Hub for Scotland

A new research centre has been named after one of the founding fathers of geology.

Sir Charles Lyell (1797–1875) was one of the leading geologists of his day, author of the seminal work *Principles of Geology*, which popularised James Hutton's theory of uniformitarianism, and a close friend of Charles Darwin. He was also Scottish and married to the daughter of geologist Leonard Horner, founder of Heriot-Watt University in Edinburgh. So it is fitting that a new research centre at Heriot-Watt has been named after such an important figure in the history of geological study.

Promoting Synergies

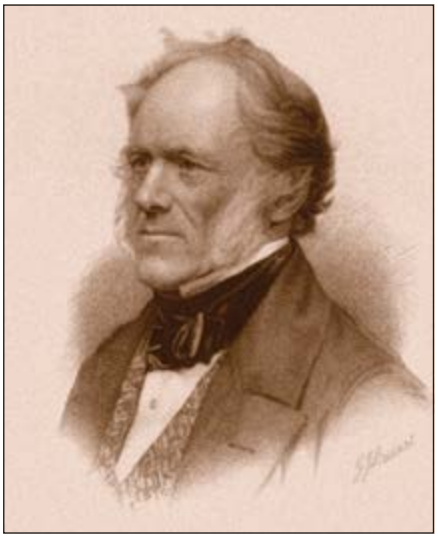
The Sir Charles Lyell Centre of Earth and Marine Science and Technology is the result of collaboration between the university and the British Geological Survey (BGS), which has long had a major presence in Edinburgh. By creating a new, purpose-built centre, jointly funded by NERC (the UK's Natural Environmental Research Council), the Scottish Funding Council and Heriot-Watt University, these two academic institutions intend to form a world-leading research hub in subsurface geoscience. Initially, the BGS was destined to move from Edinburgh due to funding cuts, but the establishment of this centre with an investment of £22m has turned a threat into an investment. Building work will commence in January and should be finished by spring 2016.

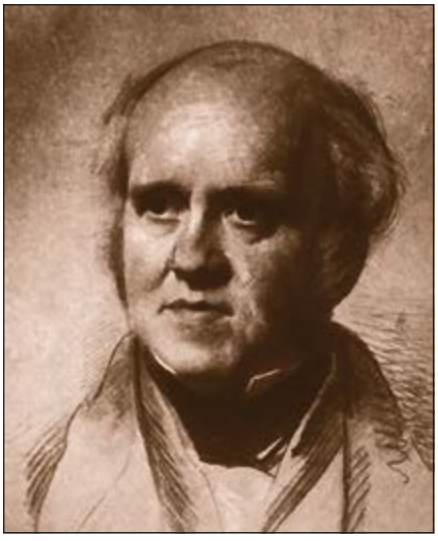
The centre will be the biggest applied geoscience institute in the UK and one of the largest in Europe, with more than 250 people based in it. A considerable number of these will be post-graduate and doctorate students studying through the newly formed School of Energy, Geoscience, Infrastructure and Society, which itself illustrates the way in which these disciplines are uniting and co-operating – a sure indication of the future way forward. With a strong petroleum geoscience involvement through the existing programmes in the university, including the new NERC Centre for Doctoral Training that Heriot-Watt and BGS are both core partners of (see *GEO ExPro* Vol. 11, no. 3), the Lyell Centre looks set to become a focus of excellence for the geosciences in the oil and gas industry. Heriot-Watt has the funding for fifteen new posts under their Global Platform Appointment for Research Leaders scheme and will be advertising the positions shortly.

In addition, BGS experts in marine geological studies, Earth observation, carbon capture and storage and shale gas investigation will all be based in the new establishment, encouraging synergies between the various branches of geoscience to enable them to tackle the major issues of natural resources, environmental impact, government regulation and energy supply in a responsible and sustainable way. This fusion of pure and applied scientific expertise will encourage the use of pioneering methods to create real world solutions in areas as varied but interconnected as earth processes, global change and ecosystems, seafloor-mapping using advanced robotic vehicles, earthquake and volcanic risk, monitoring and energy security.

Long Connection with Geology

Heriot-Watt University was founded by Leonard Horner and Robert Bryson in 1821 as the Edinburgh School of Arts. It was the world's first Mechanics Institute, designed to give ordinary people a specialist education in science and technology, and it started a worldwide education movement. Although Horner was by profession a linen merchant and Bryson a watchmaker, both men were very interested in geology and the natural sciences. Horner was one of the very earliest members of the Geological Society of London, joining it in 1808, a year after it was formed, and he was elected its President in 1846 and 1860, while Bryson was a Fellow of the Royal Society of Edinburgh, Scotland's national academy of science and letters. The institution became Heriot Watt College in 1885 – named after the famous Scottish inventor and mechanical engineer, James Watt, and George Heriot, an Elizabethan philanthropist – and was awarded university status in 1966.



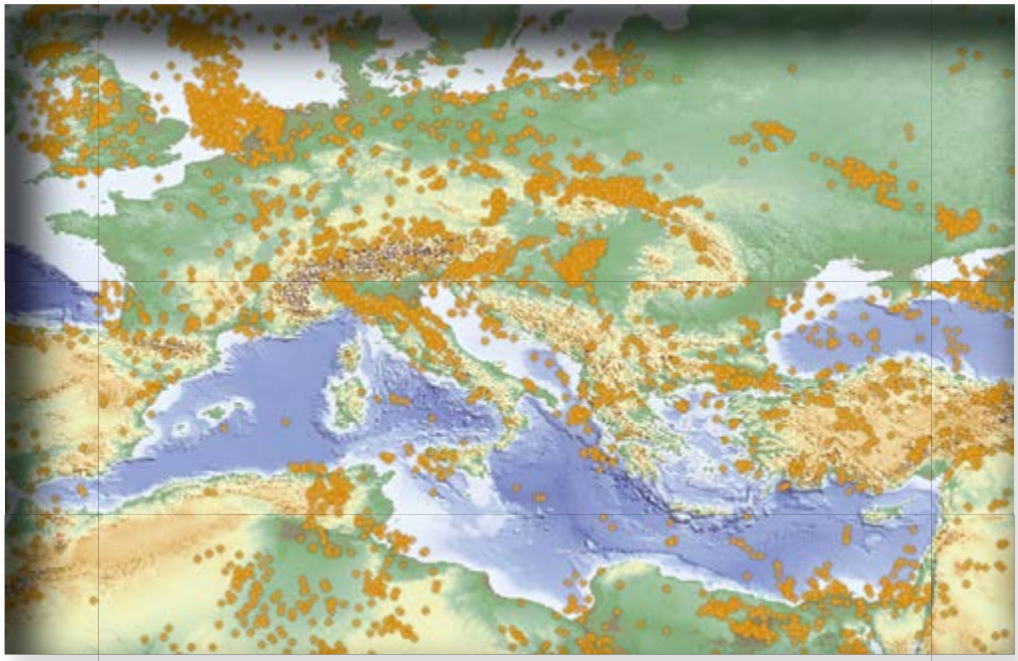


Sir Charles Lyell (top) and Leonard Horner.

A distinguished alumna of Heriot-Watt was Dame Maria Ogilvie Gordon, who went on to become the first woman fellow of the Geological Society, the first woman to be awarded a Ph.D by Munich University and the first female recipient of the Geological Society's Lyell Medal. She would surely have been very proud of this new centre.

Further details about the Lyell Centre can be obtained from Professor John Underhill, Heriot-Watt's Shell Chair of Exploration Geoscience, who is leading their Earth Science recruitment campaign (email: J.R.Underhill@hw.ac.uk) ■

Highlighting Hidden Value



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Prospective Frontier Acreage on Offer

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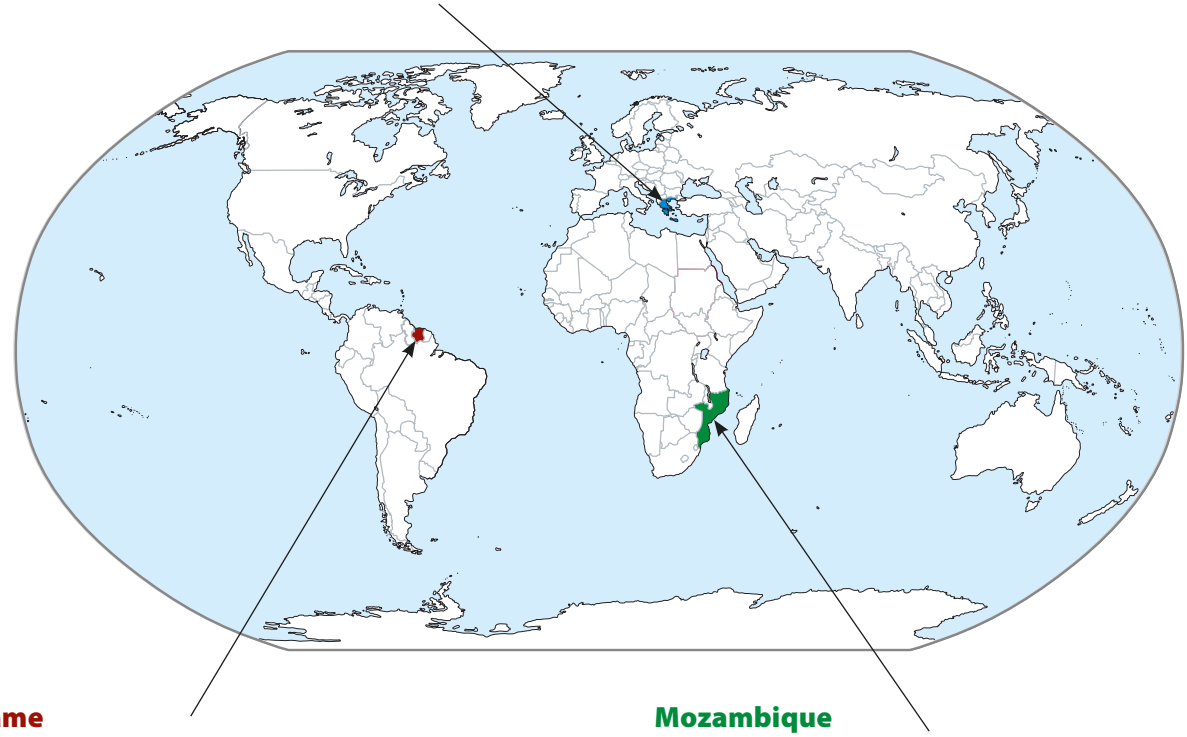
Greece

The offshore blocks offered in the country's Second International Licensing Round 2014 were published in the Official Journal of the European Union on 26 August 2014. The bid deadline is six months after this publication date; the bid evaluation will take three months and the lease agreement can be signed within another three months. The exploration term will be for eight years (3+3+2). The inventory includes a total of 20 blocks, ten of which are located offshore western Greece, one offshore southern Greece and nine offshore southern Crete. The size of the blocks range from 1,800 km^2 to 9,500 km^2; they are smaller in the Ionian Sea and larger offshore southern Crete. Water depth ranges from several hundred metres to 2,500m. New favourable fiscal terms are being implemented to encourage potential investors with tax rate cuts. Companies will be subject to a special income tax at a rate of 20% and a regional tax of 5%.

PGS acquired 12,431 km of 2D seismic data early in 2013; the interpretation report and the hydrocarbon potential assessment study is available to interested parties. ■



Suriname

Staatsolie is offering three offshore blocks (58, 59 and 60) in the Suriname-Guyana Basin through a competitive tender process, with two onshore blocks (Commewijne and Nickeris) available by way of direct negotiation to pre-qualified companies. The offer closes on 30 January 2015. Winning bidders bear sole exploration risk for the initial award period of seven years but Staatsolie can elect to participate in development and production operations with a maximum stake of 20%. Income tax of 36% is fixed for the term of the licence and a royalty of 6.25% is payable on gross production. Suriname is still a virtually unexplored territory, with only 25 offshore exploration wells drilled in an area of approximately 150,000 km^2, and is a frontier exploration play. Offshore exploration has so far failed to lead to commercially recoverable reserves, in part due to a lack of quality seismic data. Despite this, competitive bidding rounds were commenced in 2001, following a study conducted by the United States Geological Survey, which concluded that the Suriname-Guyana Basin may hold 15 Bbo of potentially recoverable reserves. Tullow Oil's discovery of hydrocarbons in neighbouring French Guiana in 2011 was seen as evidence of the extension across the Atlantic of the Jubilee play from Ghana. There is therefore a great deal of expectation within the industry that this current round will attract further interest from international players and that a major discovery is possible (see *GEO ExPro* Vol. 10, No. 4). ■

Mozambique

Hosting a presentation in London on 23 October 2014, the INP launched its 5th licensing round comprising 15 on and offshore blocks each of around 5,000 km^2, with the total area on offer amounting to 76,800 km^2. Application deadline will be 20 January 2015. The inventory comprises, offshore, three blocks in the Rovuma Basin, two in the Angoche area (Zambezi Delta), and six blocks east-north-east of Sasol acreage, also in the Zambezi Delta. Onshore blocks are offered in the Pande Temane region of the Mozambique Basin and in the Palmeira area, north-east of Maputo.

As the previous legislative framework for the oil and gas sector was unsuitable for such rapid developments in the sector (for example, it did not cover LNG processing) and did not provide protection to investments relating to the petroleum sector, the Mozambican Parliament approved a new Petroleum Law on 14 August 2014. This expressly provides for the security of both national and foreign direct investment in oil and gas in respect of the protection of property rights and undue and unfair expropriation. Unfortunately, the new law is lacking in detail, and many significant uncertainties remain concerning the rules governing the sector, while a number of its provisions may prove difficult for investors to navigate. ■

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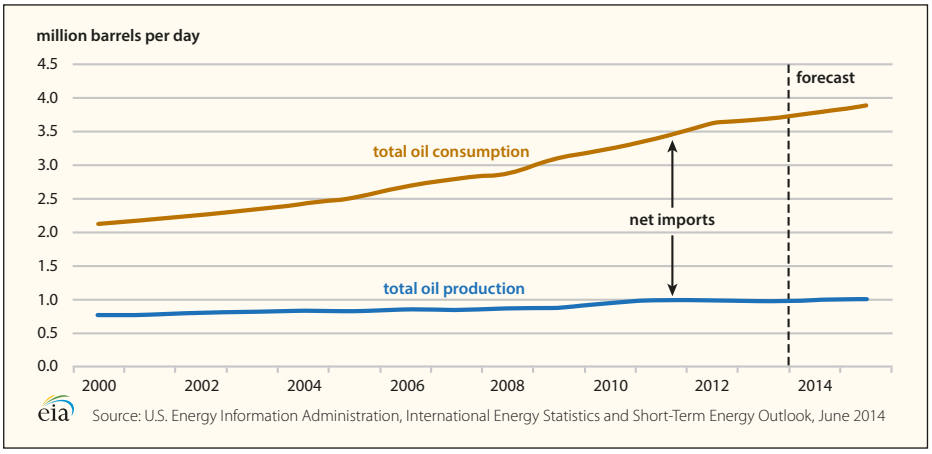
India Diversifying Supply

Despite having proved reserves of 5.7 Bbo and 47 Tcfg, Indian O&G production has not kept pace with rising demand in recent years, partly fuelled by highly regulated and subsidised consumer fuel prices. **India** was the fourth-largest consumer of oil and petroleum products after the US, China and Japan in 2013, and also the fourth-largest net importer of crude oil and petroleum products. There remains a severe shortage of energy for electricity generation, leading to blackouts, even though much of India's coal is used in this sector.



Indian petroleum and other liquids production remains relatively flat, while consumption increases.

Indian companies are searching further offshore into deeper water and purchasing stakes in overseas oil fields to try to bridge this gap and decrease the reliance on imports. They are also looking at enhanced oil recovery and marginal field development projects in the traditional producing basins in the west and north-east, which are becoming increasingly mature. Foreign investment in India has waned in recent years, both because of increased competition from domestic Indian companies and India's complex exploration and production laws. ■

UK 28th Round

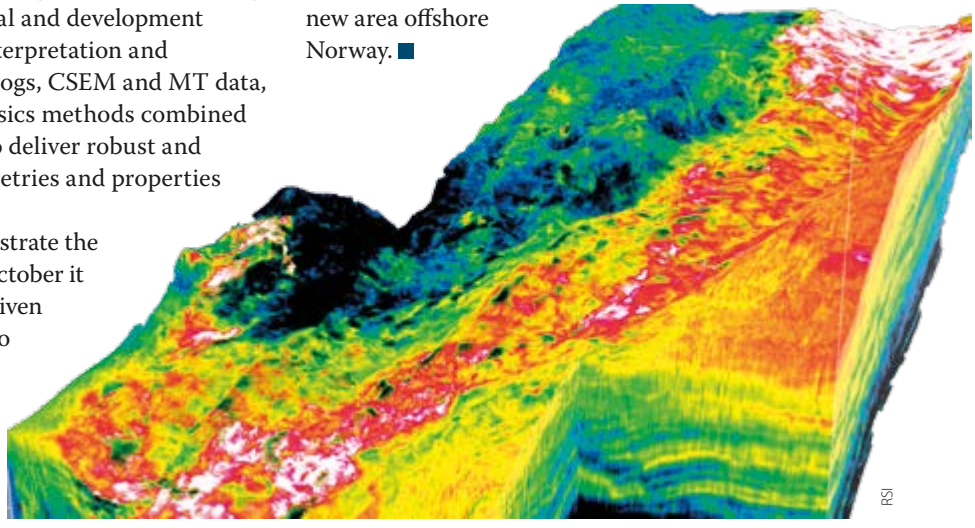
In early November the UK government announced that in the **28th UKCS Licensing Round** it had awarded 134 licences covering 252 blocks to over 80 companies. This was fewer than in the previous round, the most successful ever, and the number of wells committed, five firm and four contingent, was the lowest since the 22nd Round in 2004. UK Oil & Gas, the representative organisation for the UK offshore industry, pointed out that the disappointingly low number of wells "highlights the need to stimulate new plays through detailed technical work which requires measures to encourage more investment in the UKCS."

Other issues facing exploration in this already mature area include rising costs and an ageing infrastructure, which will require cooperation between producers to ensure that all remaining reserves can be efficiently produced. The industry is hoping that the government will soon announce fiscal incentives aimed at stimulating hydrocarbon exploration and a simplification of the present complicated tax regime. ■

RSI Seals Deals

Rock Solid Images (RSI) is an independent geoscience consulting firm offering quantitative reservoir characterisation with the goal of reducing exploration drilling risk and optimising reservoir appraisal and development plans. As an industry leader in the interpretation and integration of seismic data with well logs, CSEM and MT data, the company uses advanced rock physics methods combined with sophisticated geologic models to deliver robust and reliable predictions of reservoir geometries and properties to our customers.

Two recent contract awards demonstrate the range and value of RSI's services. In October it was chosen to provide rock physics-driven inversion and interpretation services to a Latin-American NOC in a contract worth in excess of $2 million; work will commence immediately and will be complete in the first half of 2015. And in November RSI agreed another US$2 million deal, this time with GDF Suez Norge, to provide quantitative geophysical services over a three-year period in a prospective new area offshore Norway. ■


RSI

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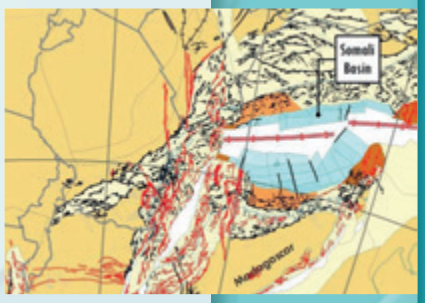

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Strategies for a Changing Landscape

With continuing political uncertainty around the world, it is apt that the theme of the **2015 International Petroleum (IP) Week** is '**Strategies for the changing oil and gas landscape**', as the role of oil and gas in sustaining society and economic growth has been brought closer to the fore and the need for the industry to meet future challenges is becoming ever more acute.

IP Week, which is organised by the UK Energy Institute, is a recognised forum where over 2,000 influential O&G industry figures and government officials can debate, discuss and share knowledge about the opportunities and challenges facing the sector today over three days of conferences, roundtables and breakout sessions. This year it includes a new focus on the US and Latin America, while the Middle East, Russia and the CIS, Africa and the Asia-Pacific regions remain key areas of interest. The guest of honour at the IP Week Dinner will be Ben Van Beurden, Chief Executive Officer,

Royal Dutch Shell, while Andrew Austin, CEO, IGas Energy will preside over the IP Week Lunch. ■

Research Consortium for ffA

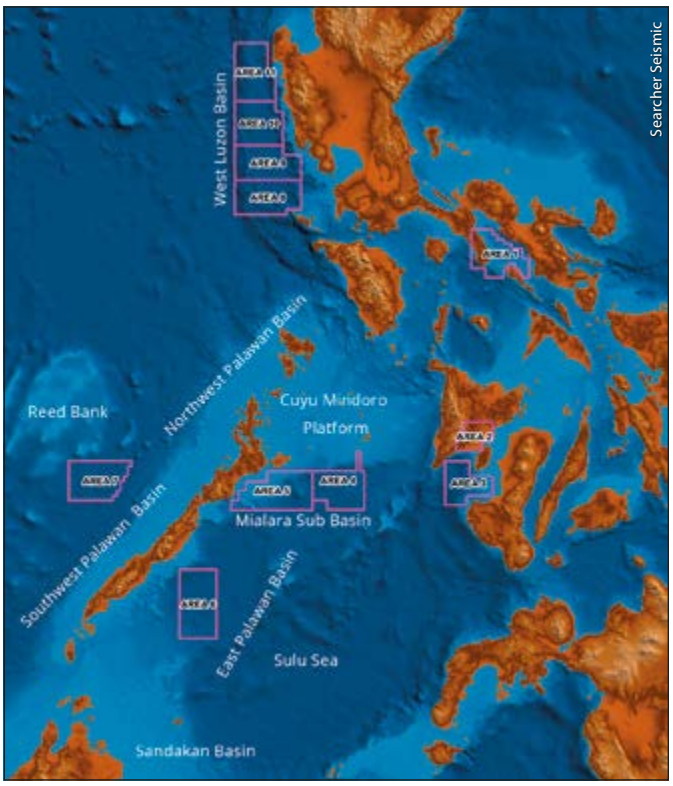
ffA's GeoTeric software is based around the Geological Expression approach to seismic interpretation, founded on a data-driven, interpreter-guided approach to using 3D seismic data for enhancing our understanding of the subsurface. Appreciating how geoscientists work and process data to gain a deeper understanding of the subsurface is an essential component of the software design, so ffA has formed a **GeoTeric Research and Development Consortium** to bring together technology focused E&P companies to guide the on-going development of the software.

The foundation members of the consortium include Centrica Energy Norway, Lundin Norge, VNG Norge and E.ON E&P. Centrica, for example, uses GeoTeric to visualise prospective depositional systems and other geological features to a degree that is beyond that obtainable through conventional interpretation tools, and it believes that this consortium will be the vehicle to take understanding of reservoirs to a new level of detail, through the combination of well data, modelling and focused spectral analysis, thus unlocking the potential for improved decision making. ■

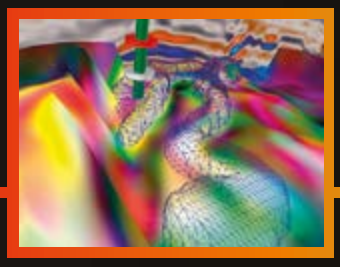
New Philippines Survey

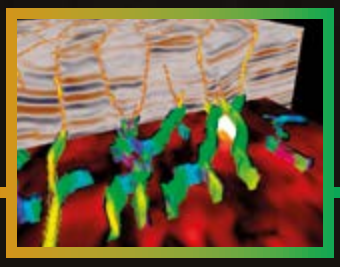
A new review of two basins in the Philippines, using recently acquired regional seismic data obtained by **Searcher Seismic**, suggests significant, previously unrecognised, hydrocarbon potential. The basins adjacent to the island of Palawan are the most prolific hydrocarbon producing areas in the Philippines. To date most of the exploration effort has been focused on north-west Palawan, but the review has identified significant depocentres in the **East Palawan Basin**, with the necessary ingredients for one or more proven petroleum systems, suggesting the area could have significant hydrocarbon potential.

The **West Luzon Basin**, which has four blocks offered as part of the PECR5 bid round, is a virtually unexplored deepwater basin that could have significant petroleum potential. It appears to have a similar Miocene history to the Mindoro Basin, where drilling results demonstrate the presence of a working petroleum system. Available data indicate the basin contains more than 4,000m of relatively undeformed sediments that are likely to be Miocene to Recent in age, and that this section may be underlain by an even greater thickness of older Tertiary sediments, which may also have petroleum potential. ■



Here for the boundary pushers, concept architects and restless minds.





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When a seismic interpretation project hits a problem it's new ideas and insights that get things back on track. GeoTeric gives you intuitive Geological Expression workflows that make it easy to explore multiple avenues in depth, and to put forward the most comprehensive range of scenarios available.

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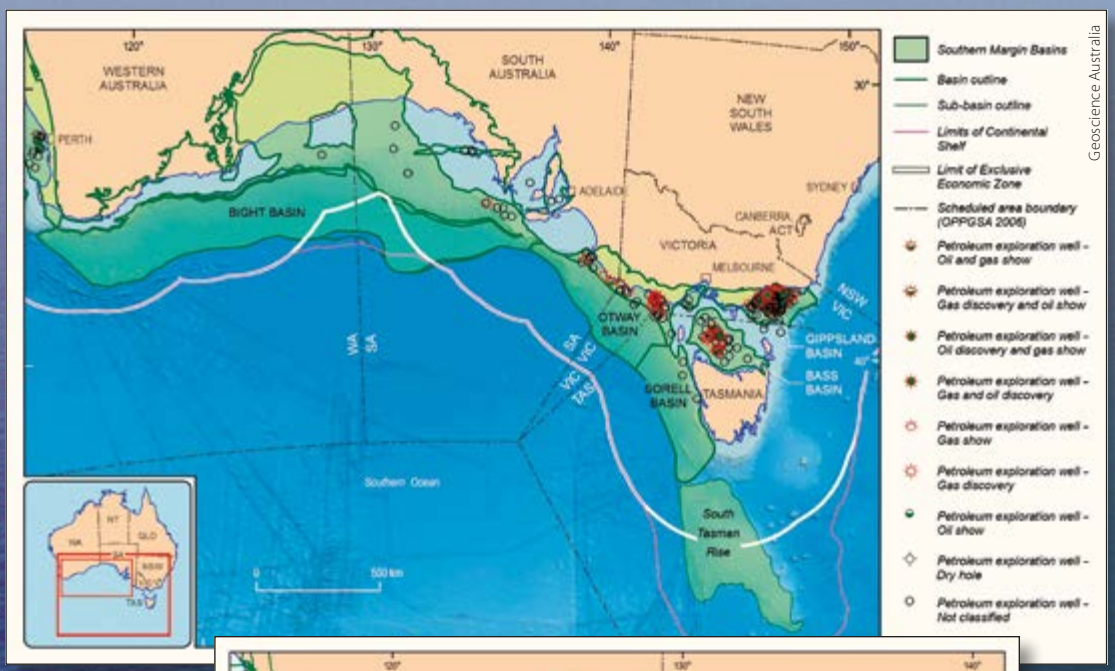
The Great Australian Bight

An Emerging Global Hotspot

Scale and ambition are accurate words to describe new oil exploration underway in the Great Australian Bight, but they do not quite do it justice.

DAVID UPTON



The Bight Basin is seriously underexplored.

Well symbol information from either 'open file' data from titleholders where this is publicly available as at 1 November 2013, or from other public sources.

To get a real sense of how this underexplored region is suddenly a hotspot, consider that six explorers —including half of the world's largest producers — are racing ahead with 3D seismic surveys over more than 40,000 km^2, an area the size of Switzerland. And that is even before the first well is drilled.

The Bight Basin is an almost continent-wide feature on Australia's southern margin, spanning 2,000 km from Albany in Western Australia to Port Lincoln on South Australia's Eyre Peninsula. This entire stretch of coastline is almost uninhabited and is best known as the location of the Nullarbor Plain and the world's longest stretch of railway without a single bend.

Unlike West Africa or the Gulf of Mexico, the Australian coastline today bears no sign of the giant river systems that once fed the Bight delta. A recent study of zircons in drill core by the Australian School of Petroleum suggested there might have been two river systems – an Amazon-like river with a catchment that spanned most of Australia in the Early Cretaceous, followed by a system of multiple, fast flowing rivers which coincided with rapid uplift in the last stages of rifting between Australia and Antarctica in the Late Cretaceous.

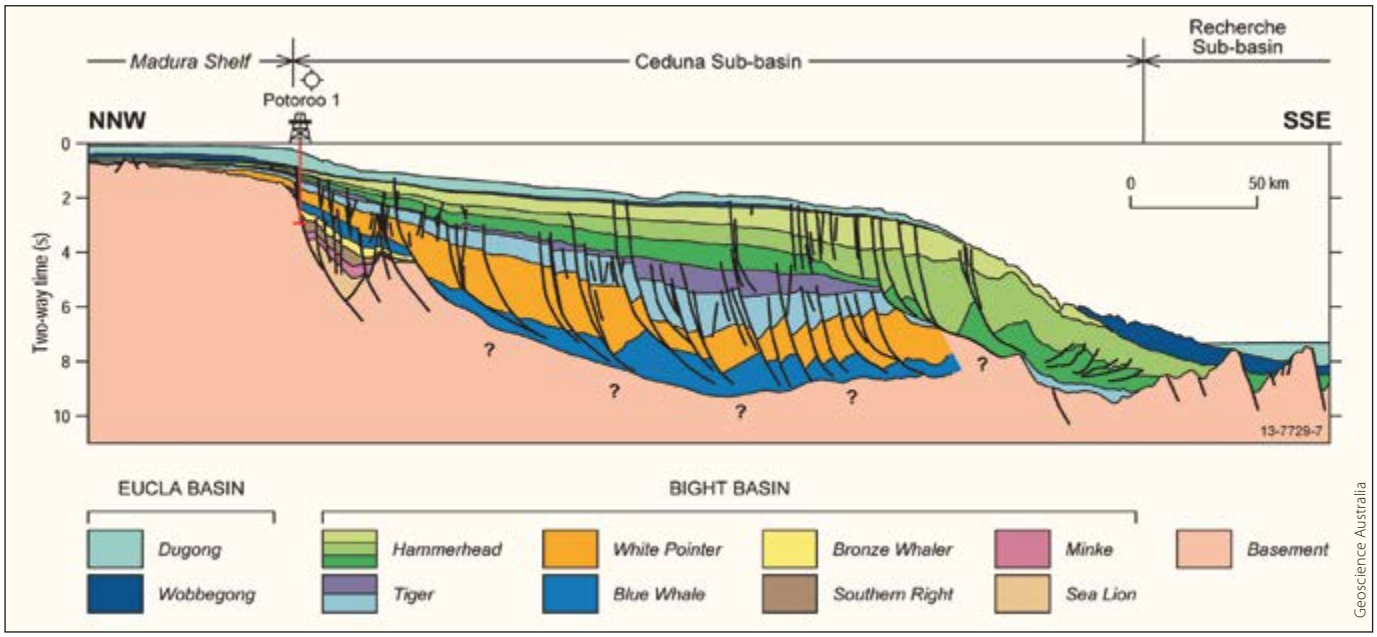
The Ceduna sub-basin, the target of most of the new exploration activity, is the largest of three major sub-basins and accounts for the obvious delta feature seen on bathymetry. To the west and east are the Eyre and Duntroon sub-basins respectively. These are older parts of the Bight basin that were generally not buried by the sedimentation in the Ceduna sub-basin. Earlier explorers targeted the Duntroon sub-basin in the 1980s and early 1990s.

Lack of Exploration

BP leads the new wave of exploration and has been uncharacteristically bullish in its public statements. Andy Holmes, President of BP Australasia, told *The Australian* newspaper in August that the Bight was most likely one of BP's top five prospects worldwide. "That territory could be something like the Niger Delta or Mississippi Delta, so it's of interest to the world, not just Australia and BP. We don't know yet, but it could be that big."

The Bight has always looked like a great target for oil explorers, who have been lured by the hope of discovering Australia's second great oil province (after the Bass Strait, which lies between the State of Victoria and Tasmania). Bathymetry shows a massive delta covering almost 130,000 km^2, while 2D seismic back in the 1970s and 1980s established more than 15 km of sediment thickness. But only 12 wells have been drilled since exploration began in the 1970s, the most recent more than a decade ago, when Woodside Petroleum drilled Gnarlyknots-1 in 2003. The well failed to reach its target zone in the deeper lobes of the delta because of fierce weather blowing straight up from Antarctica.

The remote location of the Bight, its deep water and the risk of violent storms for at least half of the year are major causes of the lack of historical exploration. However, the overriding reason was poor confidence in the presence of petroleum systems, and particularly source rocks. In 2007, the Australian government's agency for promoting offshore exploration, Geoscience Australia, planned to address the source rock risk with an ambitious seafloor dredging survey. Using historical 2D seismic and high-resolution swath bathymetry, the agency identified a number of locations where submarine canyons on the edge of the continental shelf should expose inferred source rock horizons.



Cross-section across the Ceduna Sub-basin showing inboard Jurassic half-graben and thick pre-breakup (Blue Whale to Tiger supersequences) and post-breakup (Hammerhead supersequence) deltaic-marine successions.

Sampling Canyons

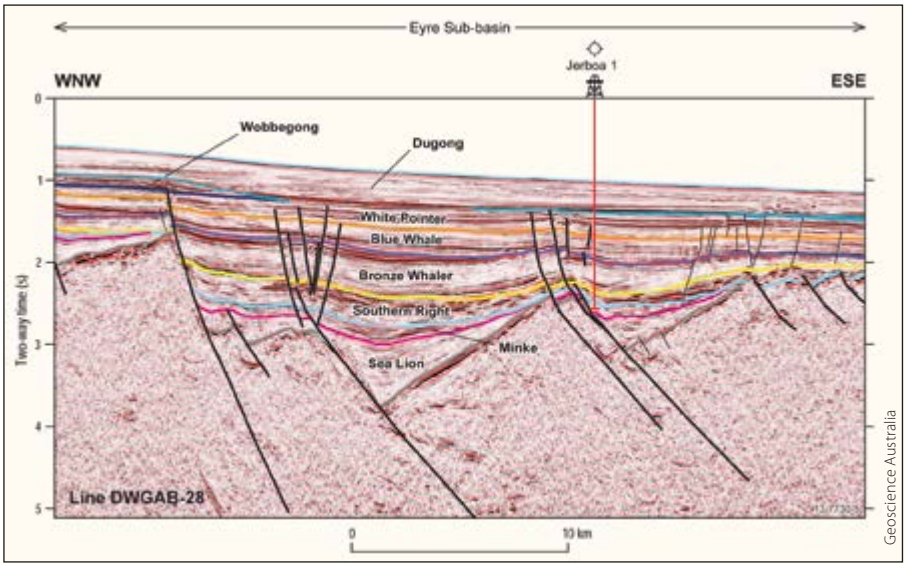
The practice of dredging the slopes of seafloor canyons had been developed and fine-tuned by Geoscience Australia over the previous 20 years. It had already been used successfully to generate a picture of the stratigraphy of the Bremer sub-basin at the western end of the Bight. The Bight dredging project was led by Geoscience Australia's senior geologist, Jennie Totterdell. After many months of planning, the difficult task of sampling the walls of submarine canyons at water depths in excess of 2,000m was executed without problems by a crew aboard the government-owned *RV Southern Surveyor*. It was not until preliminary analysis of the samples was completed six months later that Ms Totterdell knew they had hit the jackpot.

"In one particular canyon that had incised to a level where we could dredge samples of the right age rock, we obtained a suite of about 11 samples of mudstone that proved to be an organic-rich, liquids-prone source rock," she explained. "The more analyses we did, the better it looked. We soon established that these Cretaceous source rocks were right on the Cenomanian-Turonian boundary, which is one of the great anoxic events and a major global source rock. We no longer had to hypothesise about source rocks because there was one we could actually put our hands on. That made a big difference to how explorers perceived risk and prospectivity in the basin."

The results of the survey and Geoscience Australia's analyses were released as part of the Australian government's annual acreage release in June 2009 with the hope of reviving interest in the Bight, which had languished now for two years without a single exploration permit. The response was a dramatic vindication of the pre-competitive work, with BP announcing in January 2011 it had won four permits with a record-breaking six-year work programme worth $AUD1.41 billion. This included an 11,000 km^2 3D seismic survey, the biggest ever conducted in Australian waters. BP subsequently farmed out a 30% interest in its four areas to Statoil, laying off some of the risks and the costs of its commitment to a four-well deepwater drilling campaign that will begin in 2016, using a purpose-built deepwater rig.

Six months after the award of acreage to BP, Bight Petroleum, an unlisted junior explorer based in Adelaide, announced it had secured two permits at the eastern end of the Bight in the Duntroon sub-basin. The company had been working quietly to acquire permits since well before the 2010 acreage

Seismic line across Release Area W14-19 in the Eyre Sub-basin. Lacustrine source rocks in the Jurassic-Early Cretaceous rift section are interpreted to be the source of a palaeo-oil column in Jerboa 1.



release, based on the enthusiasm of a local consultant geophysicist, Dr Peter Boult.

Fifteen months after the award to BP, the revival of activity in the Bight had developed into an exploration rush, supported by new acreage released by the government. Chevron announced it had secured two areas by committing to spend at least $AUD486 million over the next three years, including 21,000 km^2 of 3D seismic and four exploration wells. In the same round of acreage approvals, Adelaide-based Santos and US independent Murphy Oil were granted a permit based on a $AUD50 million seismic programme of 2D and 3D seismic.

Bight 'Unique'

Ms Totterdell believes the Bight is unique both in Australia and globally, which is one of the reasons it has created such a high level of interest. "The age and the depositional environment of the source rocks have no good analogue anywhere in the world. In Australia, for example, the main source rocks we have identified in the Bight are marine in origin and of Albian and Cenomanian-Turonian age. That's unique for Australia. These rocks have no relationship with those in our most prolific petroleum provinces, the North West Shelf and the giant oil fields in the Bass Strait. At the eastern end of the southern margin, the offshore Gippsland Basin between Victoria and Tasmania has Late Cretaceous to Cenozoic source rocks that are entirely different to the Bight."

Looking further afield, analogues are still hard to find. "We know early Cretaceous marine source rocks account for a significant proportion of global oil production, but they are found in different depositional environments to the Bight. The analogies with the regions like the Niger Delta are only useful when you are looking at the structural geology. We only ever used the Niger Delta and Orange River basin as structural analogues. These are like the Bight Basin in that they are large prograding deltas, with big growth faults. Further outboard in the basin, the extensional movement of those faults is compensated by thrust faults, which creates a thrust belt at the edge of the basin. That's similar to the architecture on the Niger and many large Cenozoic delta systems in the world. But we are not talking about a Cenozoic system in the Bight, it's Cretaceous — a good 50 to 100 million years older. There was a greenhouse climate and different organic material contributed to source rocks, whether they are coal or marine algal material. So you can't compare them directly to something like the source rocks in the Niger Delta or the Gulf of Mexico or the Mackenzie Delta. The petroleum systems in the Bight are unique."

Ms Totterdell said that another reason for the level of interest in the Bight was the likelihood of a wide variety of source rocks. "In the Ceduna sub-basin you have 15 km or more of sediment that developed over 100 million years. You have everything from lacustrine source rocks in the Eyre sub-basin to the marine Albian and Cenomanian-Turonian source rocks in the Ceduna sub-basin. The big deltas that prograde out include coaly facies and associated mud rocks, which have source potential as well. It's just such a wide variety of potential petroleum systems."

The paucity of drilling, especially in the Ceduna sub-basin, means that while explorers are confident about source rocks, much more information remains to be gathered to understand the Bight's petroleum systems. "There are still questions about the distribution of reservoir rocks and seals, and the nature of the important facies for the petroleum systems. Many of these questions will not be answered until wells are drilled, although the level of knowledge is growing exponentially with the amount of 3D seismic being acquired. The amount of data that is available now compared to when we did our study is just stunning. And, unlike old campaigns where they were drilling poorly-imaged structures, today's 3D seismic is so much more sophisticated. Explorers can use a range of amazing geophysical techniques on that data to get a handle on the lithologies and understand the nature of reservoir and seal rocks," Ms Totterdell said.

Environmental Issues

Exploration in the pristine waters of the Bight has not been without controversy, with environmental groups mounting noisy anti-seismic and anti-drilling campaigns. BP was granted its acreage in the immediate aftermath of the Deepwater Horizon accident in the Gulf of Mexico and had higher-than-normal conditions placed on its permits. Activists were still not satisfied, but the Australian government and its new offshore drilling regulator, the National Offshore Petroleum Safety and Environmental Management Authority, have been meticulous in obtaining all possible safeguards and clearing a path for the first wells in 2016.

Ironically, the smallest player in the region, Bight Petroleum, has been hardest hit by environmental opposition. The company's acreage is located about 100 km from inhabited coastline, including the foodie and tourist haven of Kangaroo Island. In June, the company finally received environmental approval for a 3D survey, almost three years after it began consultation. The company is now seeking a joint venture partner to help fund its $AUD67 million work programme, and has no shortage of interested parties. More than 20 explorers have signed confidentiality agreements to evaluate a farm-in, including some of the world's major producers who are not already in the central part of the region.

Bight Petroleum's largest prospect, Price, is a four-way dip closure covering more than 130 km^2. Managing director, Matthew Philipchuk, said Price could hold more than 5 Bb of recoverable oil. "One of the advantages we have compared to where the majors are exploring in the central Bight Basin is we do have shallow water targets. We also believe we have the advantage of an overlying wedge of Tertiary sediments that is missing in the central Bight. We have some great evidence the source kitchen in our permits has been turned back on and that we are exploring a current-day petroleum system. That means we have fresh hydrocarbon charge and greater potential for oil accumulations, as well as sweeter oil than in the central Bight."

Opportunities

For explorers wanting to join the action in the Bight, there are still a number of opportunities aside from the least risky path of a joint venture with one of the existing players. A new area (W14-19) was released in May for work programme bidding, covering more than 30,000 km^2 of the Eyre sub-basin. Ms Totterdell said the area is centred on a Jurassic extensional depocentre and is a different play to the other permits in the Bight. However, there is evidence of a working petroleum system from Jerboa-1, the only well drilled in the permit. "Fluid inclusion studies by the CSIRO and Geoscience Australia did show that Jerboa-1 had drilled a breached accumulation, so we know that petroleum was generated and migrated into a trap that subsequently failed. We can also find these Jurassic depocentres beneath the Ceduna sub-basin, but they are more deeply buried there and in many cases the source rocks are likely to be overmature. In the Eyre sub-basin, the chances of success for the Jurassic play will be better."

In the context of the renewed exploration activity in the Bight Basin, the Australian government might consider the release of new acreage in coming years, but the least complex areas are certainly already taken. For most industry players, it might now be a case of wait and see what the first wells in 2016 bring. But if BP's confidence is validated, the entry terms are likely to be much more expensive. ■

Hundreds of kilometres of impenetrable cliffs help to make the Great Australian Bight a remote area for oil explorers.

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An Extraordinary, Unknown Career

Surviving the Great Alaska Earthquake was a historical achievement for American geologist Ruth A.M. Schmidt. Other feats were revealed only after her death.

HEATHER SAUCIER

Friends and colleagues have no trouble finding feisty adjectives to describe the late Ruth A.M. Schmidt, one of the United States' early female geologists. After all, it was Schmidt's frank and no-nonsense attitude that allowed her to step assuredly into a heavily male-dominated field in the 1930s and chart a historical career, much of which remained unknown until her death on 29 March this year at 97 years old.

At a celebration of life service in her honour last spring, many were surprised to learn how much the Brooklyn native cherished her privacy.

Schmidt was publicly noted for leading an inter-agency team of dozens of geologists and other earth scientists to remap the city of Anchorage at near record speed after the 1964 Great Alaska Earthquake, which she survived while working on a frozen Portage Lake. To date, it is the most powerful earthquake to strike North America, with a magnitude of 9.2.

In an article titled *Geology in a Hurry*, published in an October 1964 issue of the American Geological Institute's *Geotimes*, Schmidt described the controversial effort to identify geologic hazards in Anchorage for the purpose of mitigating future risks to development and the production of preliminary maps in a mere three weeks.

"No one likes to be told his house and business are on landslide areas, but if they are, how much better is it to know it?" Schmidt wrote, her resolute intentions permeating every word. "Geologists have done their part as citizens to see that everyone has been made aware of the hazards of building on landslides and similar weakened and unstable areas. Let us hope they can continue to guide the city and to help see that disasters do not recur."

Beneath the Surface

As revealed after her death, Schmidt's career proved to be as riveting as the quake itself. As friends and family began packing up her modest Anchorage home, which doubled as a library and laboratory for countless slides of ostracods and foraminifera, information emerged chronicling a career fit for history books.

"I was overwhelmed by what I didn't know about her," said Sally Gibert, a land planner, geographer and longtime friend of Schmidt. Gibert served as Schmidt's power of attorney when in 2005 signs of dementia began setting in. "She didn't hide things, but she didn't feel the need to talk about her accomplishments."

Ruth Schmidt was working for the USGS in Alaska when the 1964 earthquake struck. She was instrumental in helping the city of Anchorage document the extensive damages in an effort to mitigate future risks.

Dolores Roguskza

Gibert was charged with the responsibility of distributing donations to more than 20 charities, mostly Alaska-based, and seeing that Schmidt's coveted Alaskan art collection – including paintings by renowned geologist Marvin Mangus – was given to the Anchorage Museum of History and Art. She systematically emptied Schmidt's home – a process that included using a professional archivist from the University of Alaska, Anchorage.


Courtesy of Sally Gibert

Documents unexpectedly surfaced that placed Schmidt in the heart of World War II in 1943. She was one of few female geologists employed by the United States Geological Survey (USGS) to participate in a top secret Military Geology Unit in Washington, D.C. Schmidt mapped areas suitable for digging foxholes and building observation posts and pillboxes for the U.S. Army Corps of Engineers, in addition to finding the safest and most protected trails and terrain that could support bridges, and streams shallow enough to be forded.

The job spring-boarded Schmidt's geological career during a time when many women were openly discouraged from the field, according to Anne Pasch, who taught geology at Anchorage Community College with Schmidt and was told by a dean at the University of Wisconsin in 1950s that he would not sign her diploma if she majored in geology. "Geology was one of the last scientific disciplines that was cracked by women," Pasch said.

A micropalaeontologist by profession with master's and doctorate degrees in geology from Columbia University, Schmidt approached her work with a calculating, detailed eye. Registered as an X-Ray technician during her studies, Schmidt applied her knowledge of radiology to palaeontology – her work no doubt catching the eye of the Military Geology Unit.

Room for a Woman

Taking advantage of the shortage of scientists during the war, Schmidt left behind teaching assistant jobs at Columbia University and New York University to participate in an unprecedented effort.

"Prior to the establishment of the Unit, geologists the world over were studying rocks, mountains, plains and streams, without realising their military significance," stated a 7 October 1945 press release issued by the U.S. Department of the Interior. "It never occurred to them that their discoveries, important as some were to industry, might in any way be a primary factor in winning a war."

One can only imagine the mental whiplash of moving to Washington to join a team of draftsmen who were ordered to "Don't Think – Act."

"The Military Geology Unit went into high gear and stayed there," the press release stated. "They became the hardest and fastest working scientific group in history." For the first time, geologists became an integral part of the war effort, heavily relied upon to churn out maps as if part of an assembly line. "Geologic and topographical maps gave up the innermost secrets of enemy terrain," stated the press release. The maps "resulted in the saving of thousands of American and Allied troops."

Schmidt's employment with the USGS in Washington continued after the war. She worked for the Palaeontology and Stratigraphy Branch, the Organized Lexicon Project, the Palaeotectonic Map Project, and the Mineral Classification Branch.

Her professional strides made an impression on Hank Schmoll, a former co-worker of Schmidt who recently unearthed a USGS pamphlet circa 1947 that included a section titled 'Women in Geology'. It outlined their limited need in the field except during times of war and in laboratories. "All the good stuff was for men only," Schmoll said.

Included in the brochure was a staged photo of five women (see photo, above), one looking down a stereoscope, and others with maps in front of them. To the best of Schmoll's knowledge, only one stayed the course: "That was a young Ruth Schmidt, who was looking over the scene with a slightly critical expression on her face."

History: Part II

In the midst of her career in Washington, Schmidt unwittingly became part of history again – as the tables unexpectedly turned on her during the dark days of McCarthyism. Having joined the liberal, D.C.-based Washington Cooperative Bookshop, prompted by her interest in racial justice and a discount on books, Schmidt found herself the subject of investigation by the U.S. Department of the Interior's House Committee on Un-American Activities, as the bookshop was deemed a 'communist front' by the U.S. government, and its board members 'subversive'.

Not a communist and refusing to relinquish her innocuous, lifelong membership for which she paid $5, Schmidt remained a member and even served briefly on the bookshop's executive

board in 1947. She embraced the concepts of freedom and equality, which were promulgated by the bookshop through its advertisements, literature and guest speakers.

Two separate hearings, which took place in 1950 and 1954, forced Schmidt to hire attorneys, request 17 affidavits attesting to her loyalty toward her country from former professors, colleagues and friends, and subject herself to intense questioning to keep her job with the USGS. Each word of the hearing was recorded on carbon paper, which she kept filed in her home.

"She is extremely honest, frank and straightforward; a person of highest integrity in her dealings with other people, in her scientific thinking, and in her every-day living," wrote a Houston-based friend in 1950 on Schmidt's behalf. "At no time has she ever expressed sentiments of disloyalty to the United States Government."

In the end, Schmidt was cleared.

Alaska-bound

In 1956, the USGS chose Schmidt to establish an Alaska district in Anchorage. She accepted the assignment with the same unshakable self-confidence she had during the hearings with the federal government.

At an Alaskan Science Conference in 1957, Schmoll was introduced to Schmidt for the first time. "I have never forgotten Ruth's response: 'Hello. Now here's what I want you to do. These are the pages for the program book. They need to be stapled. Do it this way; don't do it that way. And when you are done bring them to me, and I'll tell you what to do next,'" Schmoll recalled. "Maybe that was a bit on the brusque side but… we've been friends ever since."

Once the Alaskan office was operational, Schmidt began what many say was her ultimate passion: teaching. As the first female geology professor and head of the Geology Department at Anchorage Community College in 1957, Schmidt's warm side appeared more regularly. She taught from the heart, especially encouraging young women to study the sciences. In her later years, she would establish several endowed scholarships to support those wanting to study science.

"She had a very strong interest in teaching and helping students. It was the joy of her life," Pasch recalled. "Geology has a problem because the general public doesn't understand it. She was able to cross that line between professional lingo and the vernacular."

In an August 1983 letter to the director of the science department, a female student wrote, "I can in all honesty say there is hardly a day that goes by that I do not look at the world differently and with more appreciation and understanding, armed with the knowledge acquired from Dr. Schmidt."

When the community college, which initially shared a building with a local high school, moved into its own campus in 1970, Schmidt took charge of building a laboratory that would be used for more than 25 years. She worked as a consulting geologist and a professor, retiring from the university in 1984, but she continued professional consulting until about 2000, when she was 84. During this time, she helped Anchorage recover from the '64 quake so it could rebuild its infrastructure with better knowledge about the lay of the land, and she served as an environmental officer on the Trans-Alaska oil pipeline in

One of Ruth Schmidt's greatest delights was mentoring young geologists.

1974. Her years of analysis of foraminifera helped scientists to conclude that the Bootlegger Cove Clay, which underlies parts of coastal Anchorage and tends to liquefy during earthquakes – is thousands of years younger than once thought.

A Softer Side

Even as dementia took an increasingly strong hold over her mind, the importance of education never left her thoughts. Forgetting that she had helped fund college for Gibert's two daughters, she often asked about their plans to attend a university and about their career goals.

"In hindsight, I realise she mentored me as well," Gibert said. "Her direct, cut-to-the-chase style was amazingly effective, and so outside the norm for women – especially in decades past. She commanded respect and was always respectful to others. I started out with a 'meek streak' and she showed me you don't have to play 'meek' as a woman to be accepted. She gave me courage and confidence without my ever knowing it was happening."

Schmidt may have had a thick outer shell, but – as any geologist might put it – it was highly porous. Many were drawn to her generous heart, her goodwill and her determination to do things right and well. Nearly 50 friends and former colleagues from Alaska and the 'Lower 48' attended her celebration of life last May. Representatives from nearly ten charities, serving a range of causes including science education, conservation, the arts and social justice, attended the service to thank her posthumously for her unexpected and generous bequests.

Feisty adjectives aside, Schmidt's legacy was a love for geology, the Earth and enabling the study of both, most especially for other women who love a good challenge. ■

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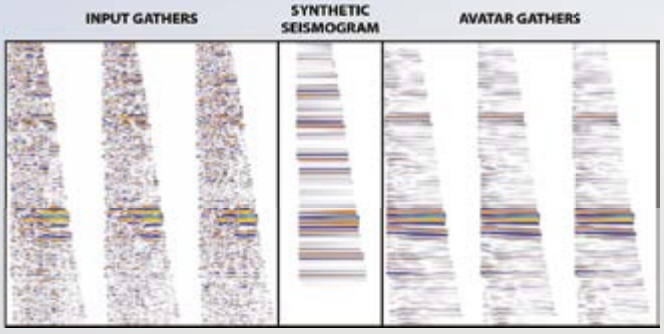

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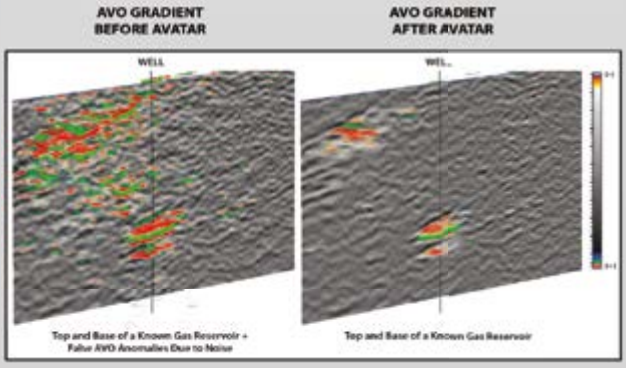

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The Kutch Basin of Western India

The fault blocks of the Kutch Basin in western India offer to the visitor a unique opportunity to observe the Jurassic-Cretaceous-Paleogene sediments rarely outcropping anywhere else on the Western Indian continental margin. A visit to Kutch also gives an opportunity to view and enjoy the rich cultural traditions and handicrafts of western India.

RASOUL SORKHABI, Ph.D.

The state of Gujarat has an area of 196,204 km^2 (sixth largest state in India) and a population of over 60 million. Although not as popular a tourist destination as Agra and Rajasthan, foreign visitors will find a great deal of history, culture and nature in Gujarat to enjoy. Mahatma Gandhi (1869-1948), India's independence movement leader, was from the state.

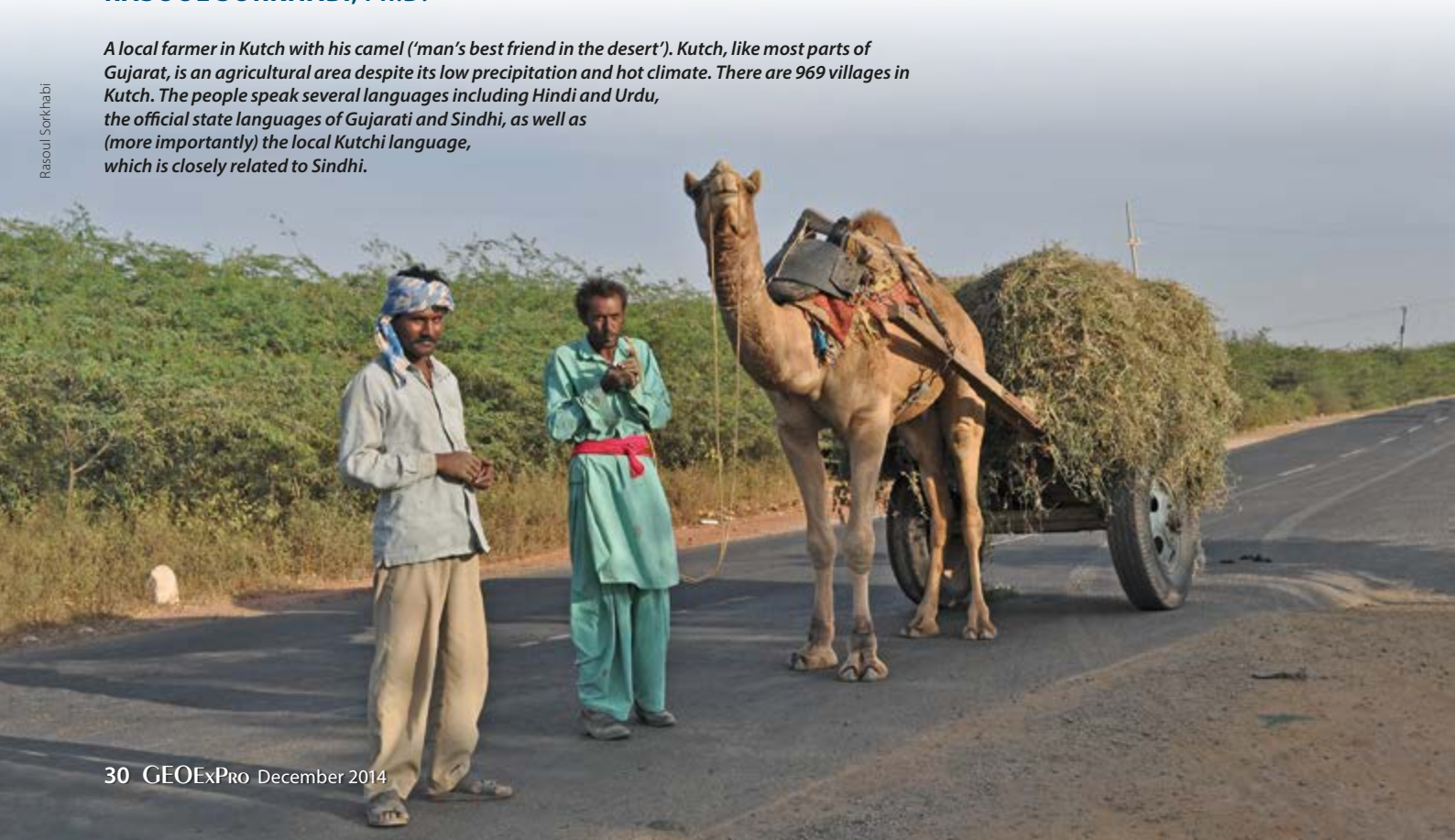
With a coastline of 1,600 km dotted by 41 ports, Gujarat faces the Arabian Sea and has enjoyed a long history of marine commerce and navigation. *The Periplus of the Erythraean Sea*, written in the first century by an unknown Greek sailor, mentions Gujarat. Geographically, Gujarat can be divided into mainland Gujarat in the east, with the Kutch Peninsula to the north-west, and the Saurashtra or Kathiawar Peninsula to the west. The Gulf of Kutch lies between the two peninsulas.

The Kutch Peninsula

Kutch (often spelt Kachchh) refers to both the Kutch Peninsula (which occupies about one-fourth of Gujarat State) and the Kutch District, which, with an area of 45,652 km^2, is the largest district in all India, although only two million people live in it.

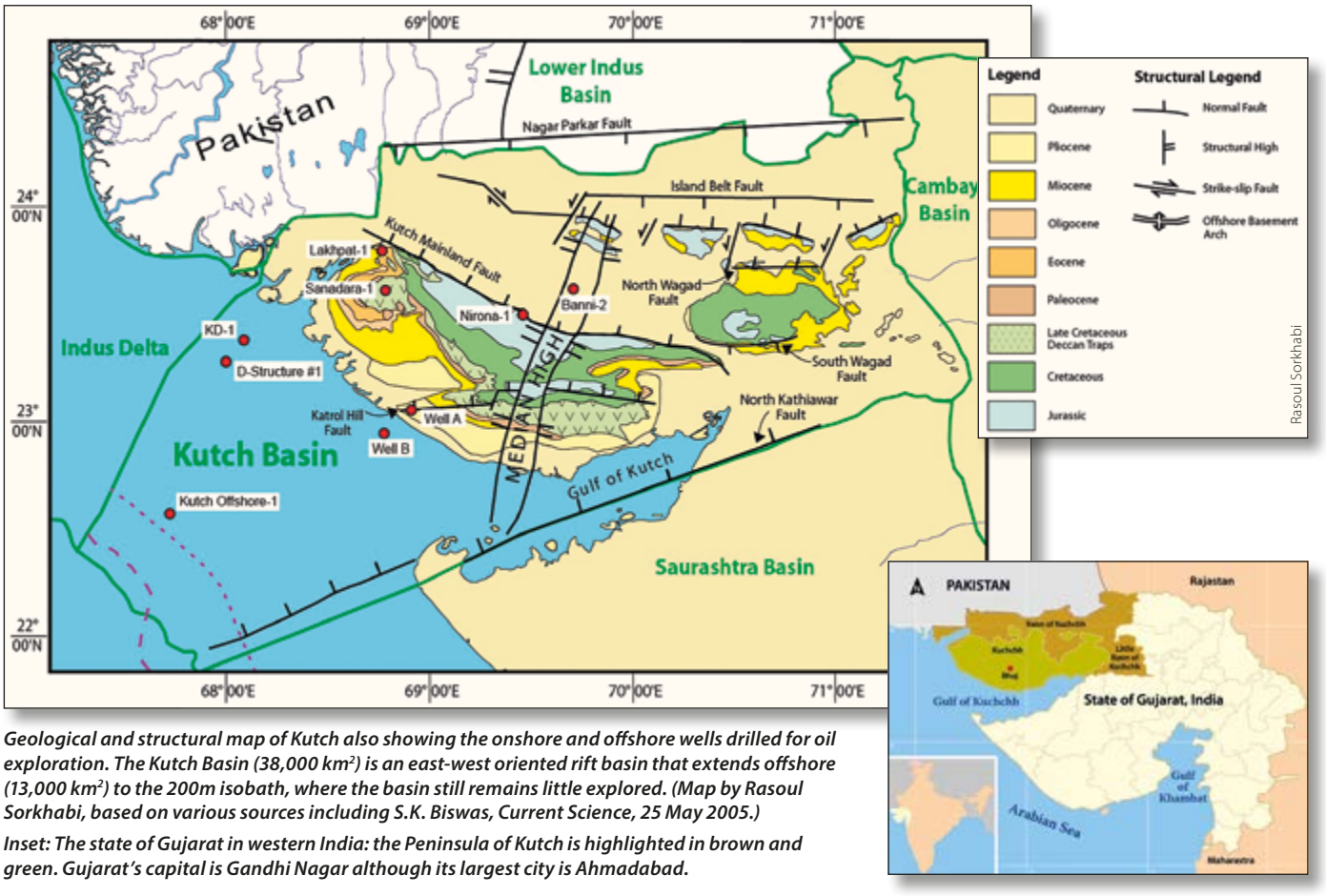
The Sanskrit word 'kachch' means a land which is intermittently wet and dry, referring to the normally dry and hot land of Kutch being drenched by summer-time monsoon rains. Average annual precipitation is about 380 mm, all of which comes from the south-west monsoon rains, peaking in July. There are 97 streams and rivers in Kutch, which eventually flow into the Arabian Sea. Dozens of small and large dams capture the monsoon runoff. The average temperature is around 30°C (90s°F) through most of the year except for the months of December to February when the temperatures are in the high 20s°C (80s°F).

Salt, cement, lignite and bauxite are the main mineral industries in Kutch. The area is famous for its textiles; fabrics, embroideries and cotton rugs are the major souvenirs that visitors purchase.



Rasoul Sorkhabi

A local farmer in Kutch with his camel ('man's best friend in the desert'). Kutch, like most parts of Gujarat, is an agricultural area despite its low precipitation and hot climate. There are 969 villages in Kutch. The people speak several languages including Hindi and Urdu, the official state languages of Gujarati and Sindhi, as well as (more importantly) the local Kutchi language, which is closely related to Sindhi.



Geological and structural map of Kutch also showing the onshore and offshore wells drilled for oil exploration. The Kutch Basin (38,000 km^2) is an east-west oriented rift basin that extends offshore (13,000 km^2) to the 200m isobath, where the basin still remains little explored. (Map by Rasoul Sorkhabi, based on various sources including S.K. Biswas, Current Science, 25 May 2005.)

Inset: The state of Gujarat in western India: the Peninsula of Kutch is highlighted in brown and green. Gujarat's capital is Gandhi Nagar although its largest city is Ahmadabad.

Kutch came to political prominence in the late 13th century as the Jadeja Rajputs founded a kingdom that lasted until India's independence in 1947, although it was a British protectorate called the Princely State of Cutch from 1815 to 1947. The city of Bhuj is the major municipality in Kutch. Founded in the early 16th century by a local ruler Rao Hamirji, it has retained its capital position in Kutch to this day. The city has a population of about 150,000 people and is home to Krantiguru Shyamji Krishna Verma Kachchh University (founded in 2003 and named after an Indian liberation activist), which has a geology department. The oldest school in the town is Alfred High School, founded in 1870 and named after Queen Victoria's second son, Prince Alfred.

Geology of Kutch

The Kutch Peninsula is essentially an east-west oriented rift basin bounded by the Saurashtra Horst (High) to the south and the Indus Plain to the north (in Pakistan). Within the Kutch Peninsula we find a diverse landscape of highlands or hills (uplifted fault blocks) and lowlands encompassing salt flats (Rann) to the north and east, grasslands (Banni) in the centre, and coastal plains to the south. The mud and salt flats include the Great Rann of Kutch in the north and the Little Rann of Kutch to the east of the peninsula, which are part of the much larger Thar Desert of north-west India and south-east Pakistan. These areas were submerged during marine incursions in the geological past but turned to desert as the sea transgressed and left behind Quaternary clay and evaporate sediments.

'Perhaps the most striking feature of the country is its sterility, naked rocky hills and sandy plains presenting in this respect a strong contrast to the more fertile portions of India; and yet parts of it are far from being unpicturesque, thought its barrenness is heightened by the scarcity of trees and general absence of anything that can be called jungle.'

A. B. Wynne, Memoirs on the Geology of Kutch (1872)

Geological outcrops found in the highlands are usually bounded by major normal faults. These outcrops attracted the attention of several British geologists during the 19th century as part of their mapping work for the Geological Survey of India based in Calcutta. Among these works, the most comprehensive and seminal contribution was the 294-page *Memoirs on the Geology of Kutch* written by A. B. Wynne in 1872 (reprinted by the Geological Survey of India in 2003). The colour geological map compiled by Wynne is still valuable.

Kutch represents a fossil rift basin (aulacogen) perpendicular to the strike of the West Indian margin. The oldest sediments in Kutch are late Triassic (Rhaetian) sands shed onto Precambrian basement rocks (these sediments were penetrated in the Banni-2 and Nirona-1 wells). The rifting was part

The Middle (silty sandstone) and Upper (sandstone) members of the Jhuran Formation are fluvial-deltaic sediments of Late Jurassic age, exposed here on the bank of Khari Nadi ('River') in Kutch, about 5 km north of Bhuj.

of an initial fragmentation within Gondwana, a southern supercontinent which encompassed the present tectonic plates of India, Africa, Antarctica, Australia and South America. As rifting progressed and Kutch became part of the passive continental margin of western India, shallow marine sediments were deposited during Early-Middle Jurassic times, as recorded by the limestone and shale sediments of the Early Jurassic Jhurio and Middle Jurassic Jumara Formations. These sediments are overlain by the deltaic sand and mud sediments of the Jhuran Formation (Late Jurassic) and fluvial sand-mud sediments of the Early Cretaceous Bhuji Formation. Mesozoic sediments have a total thickness of over 3 km.

Toward the end of the Cretaceous, at 66 Ma, continental flood basalts, the Deccan Traps, erupted and covered large tracts of central and western India. The thickness of these volcanic rocks in Kutch is not significant although there are outcrops of igneous intrusions which were possibly feeders to the Deccan Traps. The uplift and erosion at the beginning of the Cenozoic marks a major event in Kutch. The Paleocene rocks include laterites, bauxite and tuffaceous sediments (Madh Series). In the Early-Middle Eocene, marine transgression resulted in sedimentation of limestone, shale and marl (Berwal Series).

After a Late Eocene unconformity, shallow marine sediments (limestone, shale and siltstone) of the Bermoti (Oligocene) and Khari Series (Miocene) were deposited. Finally, Pliocene fluvial-deltaic sediments of the Sandhan (Kankawati) Formation as well as the Quaternary alluvial, coastal and evaporate sediments cap the Kutch basin.

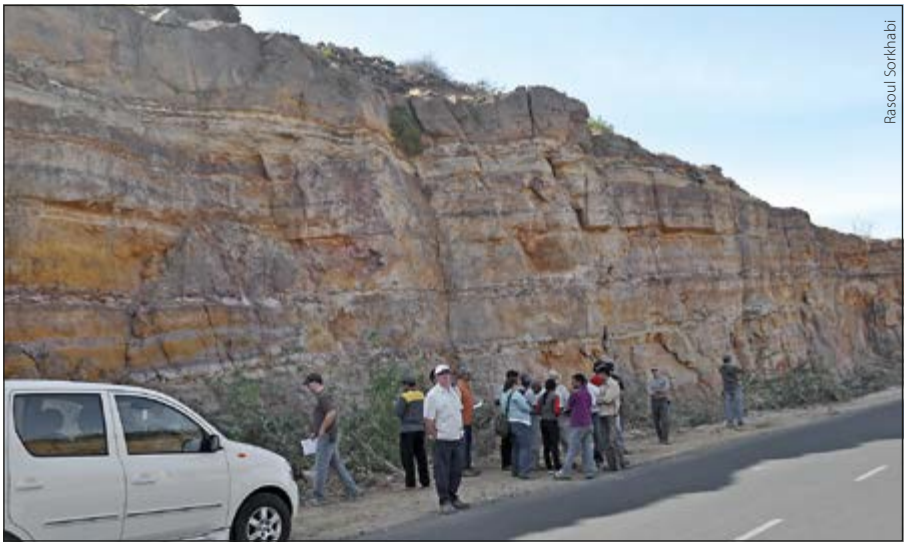
Kutch is a tectonically active region. The most recent and tragic earthquake in the region was the Bhuj earthquake (magnitude 7.6) of 26 January 2001 that killed over 20,000 people. Previous earthquakes on record include the 'Cutch' earthquake of 16 June 1819 (magnitude estimated to be 7.8) and Anjar earthquake of 21 July 1956 (with a magnitude of 6.1).

Geotourism and the Oil Industry

Kutch indeed is a land of unique geologic outcrops dating back to 250 million years ago. The Jurassic-Cretaceous rocks not only contain important fossils including those of dinosaurs but also provide reservoir-scale views of corresponding subsurface rocks currently offshore the Kutch Peninsula. Kutch, therefore, has great potential for designating national geoparks for geologists, students and ecotourists. This could contribute to Kutch's tourism industry and local economy as well as help preserve the precious geological outcrops which may be easily destroyed by mining and other human activities. This task, however, requires public education, government investment, better infrastructure, publicity as well as safety and security measures (both because of its arid conditions and being a border state with Pakistan).

For travellers (whether foreign or Indian) intending to see the geological features of Kutch, it is necessary to prepare well in advance and hire trusty

The city of Bhuj is situated on Cretaceous sedimentary rocks. The Early Cretaceous Bhuji Formation, mainly sandstone with some shale and conglomerate, is a typical sight in the city's road cuts.



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Gujarat is known for its remains of the Indus Valley Civilisation that flourished 3300–1300 BC. Two such archaeological sites in Gujarat are Lothal in east Saurashtra and Dholavira in north Kutch. The photo here shows a water reservoir at Dholavira. The site was discovered by Shri Jagatpati Joshi in 1967–68 and has been under excavation since 1989. Named after the nearby village of Dholavira, the site covers an area of over 250 acres (1 km^2). If you visit, take a reputable guided tour – make sure to see the museum as well.

guides, including a knowledgeable geologist who knows the landscape and geology of Kutch.

Although several onshore and offshore wells in Kutch have been drilled by India's Oil and Natural Gas Corporation (ONGC) in the past, the efforts have not been commercially successful yet. India's Directorate General of Hydrocarbons (DGH) has designated Kutch as a Category II basin, meaning that the basin is known for accumulation of oil or gas but there is no commercial production yet. ■

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Acknowledgement:
This article is based on a field trip to Kutch in December 2009. The author is grateful to **Dr S.K. Biswas** for leading the field trip and for discussions on the geology of Kutch.

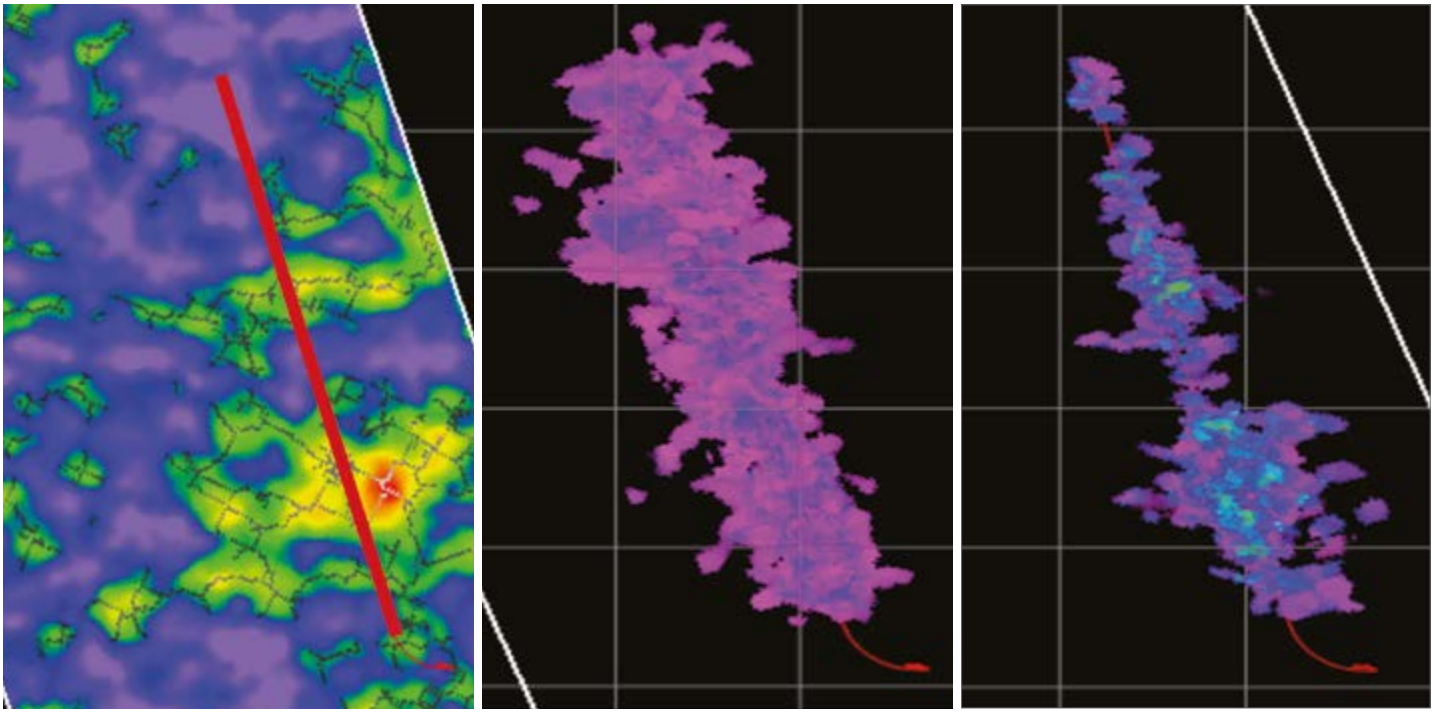
Dr Sanjib Kumar Biswas has pioneered the geology of the Kutch basin. Born in Kolkata (Calcutta), he studied geology at the University of Calcutta from 1949 to 1956 and obtained his Ph.D. in geology in 1979 from the same university. For nearly four decades, Dr Biswas worked as a geologist for ONGC, from 1986 to 1993 as director of the company's KDM Institute of Petroleum Exploration in Dehradun. Biswas has published extensively on the geology of Kutch since 1965. He has been awarded India's National Mineral Award (Ministry of Mines, 1972), L. Rama Rao Award (Geological Society of India, 1993) and Life Time Achievement Award (Association of Petroleum Geologists, India, 2011). He currently serves as a senior advisor for ONGC in Mumbai.

Additional references available online at www.geoexpro.com

Kala Dongar (Black Hill), at 485m above sea level, is the highest point in Kutch and provides a panoramic view of the mud and salt flats of the Great Rann of Kutch to the north. The author is seen in this photo.

Rasoul Sorkhabi

the ACOUSTIC VIEW



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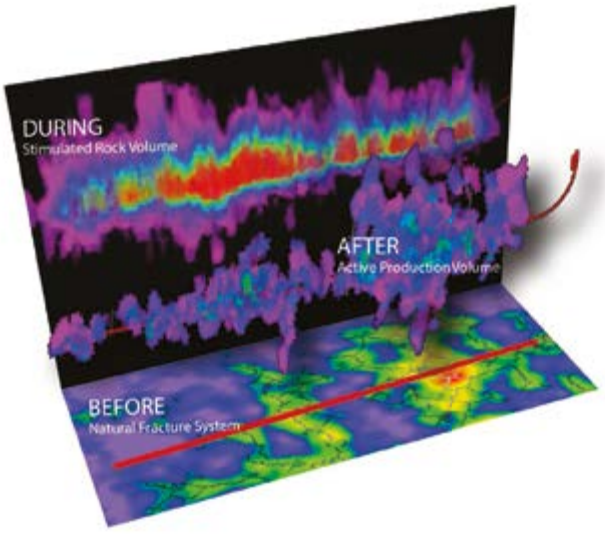

Before: Quiet Time recording before the frac images natural fractures and faults. **During:** Pumping time recording images the microseismically active volume during stimulation. **After**: Quiet time recording post-frac reveals the microseismically active production volume.

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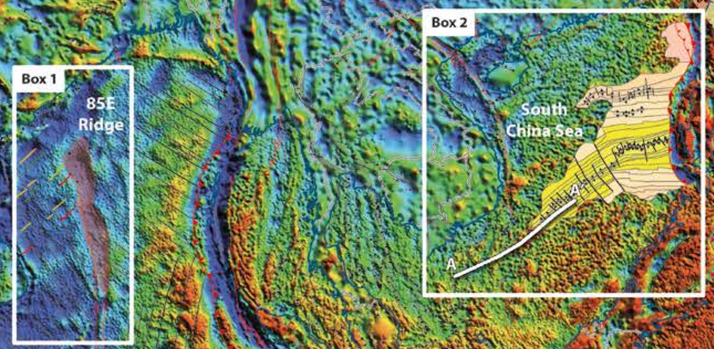
Global Plate Tectonic Modelling

Dirk Cuthbertson from Getech shares some insights from their global plate tectonic model, part of *Globe*, Getech's flagship new ventures platform.

Box 1 – The nature of the 85E Ridge and its impact on plate tectonic history

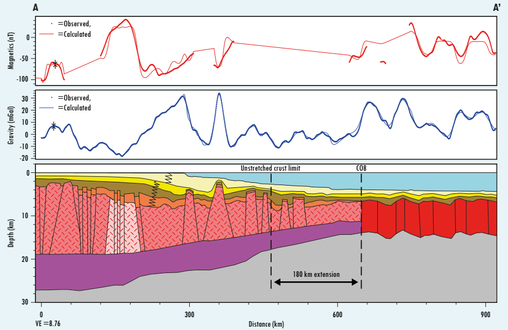
The 85E Ridge offshore eastern India manifests as a gravity low in Getech's *Trident* satellite gravity data, although very little is known for certain about its crustal nature. If it is a continental fragment, which is one hypothesis, then the prospective area for hydrocarbons is much expanded. Between the ridge and India, however, there is little evidence in gravity, magnetic or seismic data of a relict spreading centre, fracture zones are not of an orientation consistent with this movement, and isochron data (Ramana et al., 2001) show a younging to the south-east over any possible location for a spreading ridge. These isochrons are shown on the map below: orange is Chron M11 (136.29 Ma), green – Chron M10N, yellow – Chron M10, and red is Chron M8 (133.05 Ma).

A major challenge for the plate model that honours this data and a continental 85E Ridge is to provide enough space for the production of oceanic crust in the southern Bay of Bengal for the period 136–127 Ma whilst keeping other boundary conditions unchanged. To do this the Indian Plate must move 1,300 km northward relative to Madagascar during this time. Solutions for relatively small scale regional tectonic problems like this *must* be incorporated into the complete plate tectonic circuit in order to fully assess their impact.



Box 2 – Opening history of the South China Sea

Slab-pull or extrusion tectonics? What is the formative mechanism and timing of the opening of the South China Sea? Extrusion models, such as that of Leloup (1995), predict that in the south-western corner of the South China Sea, crustal north-east to south-west stretching can be no less than 250 km (more if the extension required to produce accommodation space in the Song Hong Basin is included). Getech's 2D gravity and magnetic modelling in this region (see profile A-A', below) shows that extension can be no more than 180 km. If a slab-pull mechanism (associated with subduction of a proto-South China Sea plate under present-day Borneo) is modelled, then this limit of stretching is not exceeded. An earlier opening – and thus rifting – history is implied, however, and this affects our understanding of the petroleum systems of this region, particularly the maturation history of any source rocks and the relative timing of changes to hinterland drainage and the impact on reservoir distribution.



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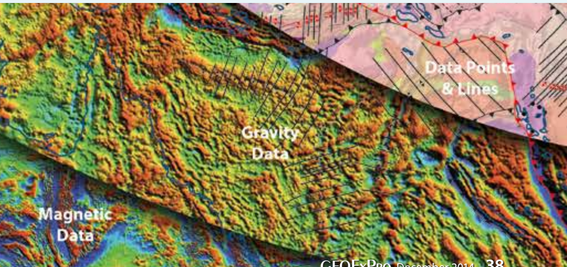

Legend

Structures

Active structures

Inactive structures

Offshore: Ocean crustal ages

Browns to yellows – Cenozoic
Greens – Cretaceous
Blues – Jurassic

Onshore: Crustal architecture

Colours differentiate various categories of continental and transitional crust.

Constrained By Data

Well and seismic data can be very sparse in frontier regions; however Getech's extensive global gravity and magnetic database, the largest commercially available dataset of its kind, covers almost all the sedimentary basins of the world. It is a superb resource for mapping the structural framework of the world, which helps us to better constrain our global plate tectonic model.

Our *Trident* satellite gravity data, derived from stacking three independent solutions of re-processed altimeter data from the ERS-1 and Geosat satellites, covers all of the ice-free continental shelves of the world with a minimum wavelength resolution of around 10 km. We are currently halfway through a three-year project to incorporate additional altimeter data from the CryoSat-2, Jason-1 and HY-2A satellites, which will generate a more accurate, reliable and coherent solution, particularly near coastlines.

The continental regions of the world are covered by both gravity and magnetic data from Getech's many continental-scale compilations, supplemented for many countries by higher resolution data including, for example, Tanzania, Mexico, Mongolia, the onshore US and eastern Europe. These datasets provide both detail at the block scale and insights into the regional context. The emergence of international unconventional hydrocarbon plays has also expanded the scope for using these data.

Published literature is a great resource for ideas, data and maps. Comparing published maps against our gravity and magnetic interpretations can often expose complexities and what appear to be relatively small inaccuracies, both of which have a big impact on our plate tectonic models.

We also incorporate other data to help constrain our plate modelling, including: published seismic and geological cross-sections, magnetic picks, well and outcrop data, digital elevation models, Landsat imagery, geological maps and apatite fission track data.

Uses of Plate Models

How do plate tectonic models help develop an exploration programme?

Firstly, a better understanding of the relative and temporal juxtaposition of hinterland elements to play elements within sedimentary basins can reveal new insights into their prospectivity. If your play models rely on, say, a granitic source for reservoir sediments during a particular stratigraphic stage, then our plate model can tell you if that is likely.

Secondly, rotating your data from their Present Day locations back in time can help you understand the palaeogeographic context of your exploration acreage. With *Globe*, Getech's flagship new ventures platform, we take this a little further. Our global plate model is the foundation for a series of 59 palaeogeographic maps and palaeolandscape models, one for each stratigraphic stage back to the Permian, one of which is shown below. These are used to generate palaeoclimatic, palaeoceanographic and palaeotidal models for each timeslice, each revealing new insights into the distribution, quality and preservation of the various elements of any petroleum system.

Conclusions

If well constrained by data, a global tectonic plate model can be built which takes account of small scale tectonic issues whilst ensuring that the integrity of the entire plate circuit is not compromised. This plate model then becomes a fundamental exploration tool, enabling a better understanding of hydrocarbon prospectivity by revealing the regional geological context for any element of the petroleum systems of a sedimentary basin.

With thanks to:

Many of my colleagues have contributed to the many years of effort which I have briefly summarised. Particular thanks go to Simon Campbell, Ben Franklin, Nicky Henshaw, Catherine Hill, Paul Markwick, Sheona Masterton, Stanislaw Mazur, David Sagi, Matthew Stewart, Peter Webb and Kerri Wilson.

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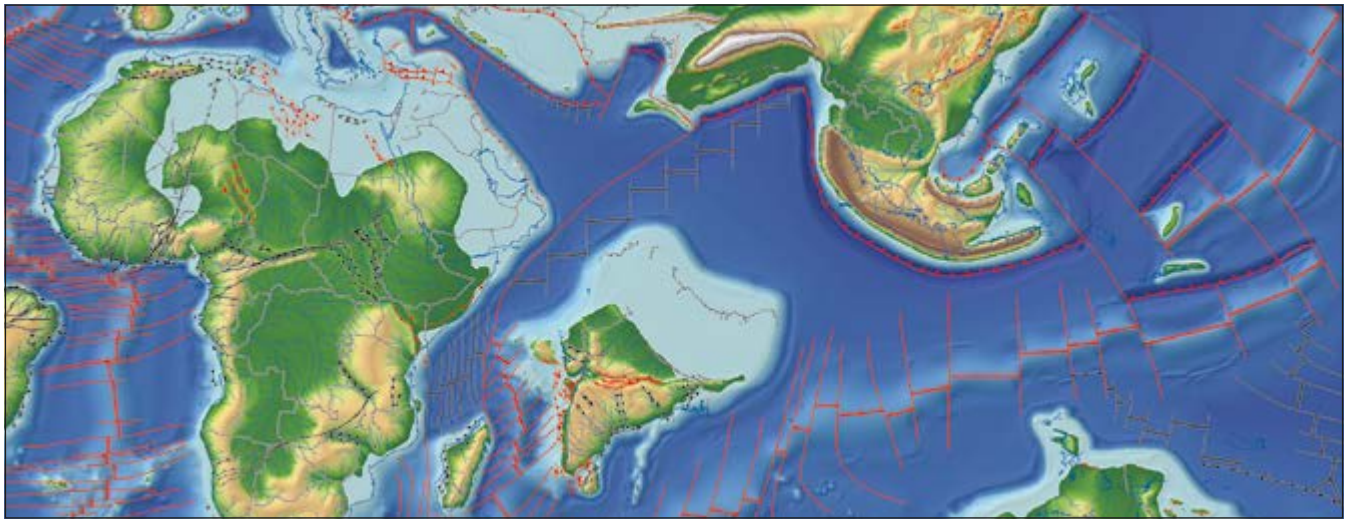

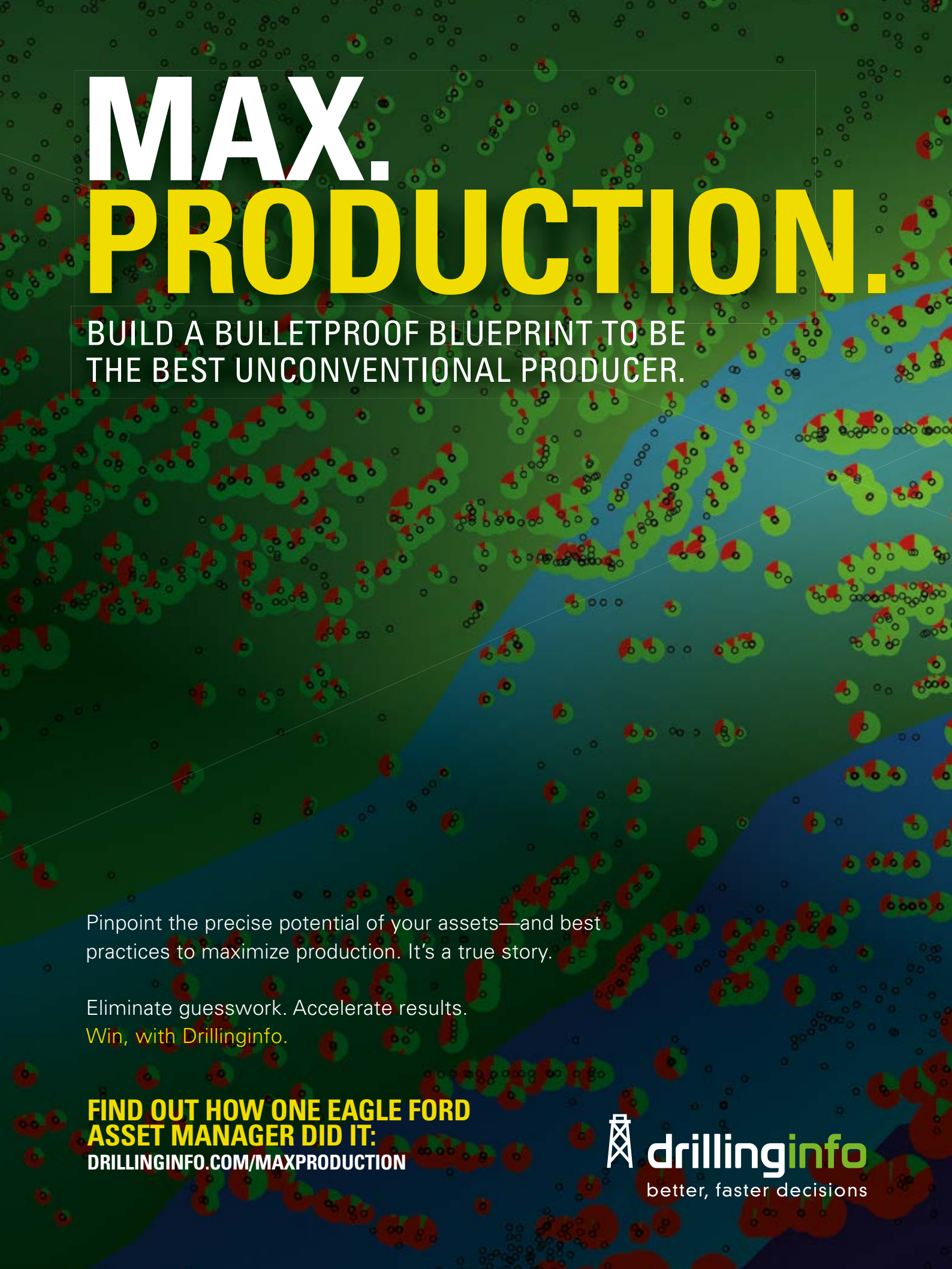
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A New Approach to Cores

Digital archiving of core information affords the oil and gas industry an opportunity for rapid evaluation of core.

CHRISTOPHER M. PRINCE PH.D
PetroArc International

The keys to the efficacy and value of cores in the oil and gas industry are accessibility and facility. Core description has always been done in lay-out rooms – and those lay-out rooms have always been travel destinations, no matter if they are halfway across town or halfway around the world. Once there, a geologist or two can evaluate the core using the tools they have always used: a 10x hand lens, a sand card, a ruler, protractor, a bottle of dilute hydrochloric acid, and a pad of paper. In most cases they will be the only people to examine the core and the only ones with the opportunity to do so. This limits the timely interchange of ideas vital within today's oil and gas industry.

Advantages of the Digital Archive

A digital archive of core imagery enables everyone to read from the same page no matter if they are in Williston, Denver, Luanda or London. When that core is imaged at the resolution of a 10x hand lens (or higher) it affords the opportunity for more scientists from all the interested working groups to evaluate it simultaneously. As more information arrives in the form of routine core analysis, well logs, thin sections, SCAL or written evaluations, a digital core archive must be able to accommodate the new information and make that accessible as well. This allows all of the interested parties to examine the core in the context of petrophysical response, and to examine laboratory results for their repeatability. More importantly, it permits the corporation or public organisation to centralise the data in order to forestall the inevitable 'data hunt' that accompanies any re-evaluation of the well.

Finally, there is facility. A digital core archive must enable the user to interact with the imagery to extract useful information. Most core is imaged, but the imagery is static; it is good for looking, but not good for doing. A high-resolution digital archiving system must contain tools for interacting with the imagery. These include methods for determining grain size, apparent dip, net pay, mineralic composition, colour and optical porosity, as well as tools for comparing the core with the logs.

PetroArc International, based in Houston, provides high-resolution imagery for the oil and gas business and believes it has found new ways to refine and centralise digital

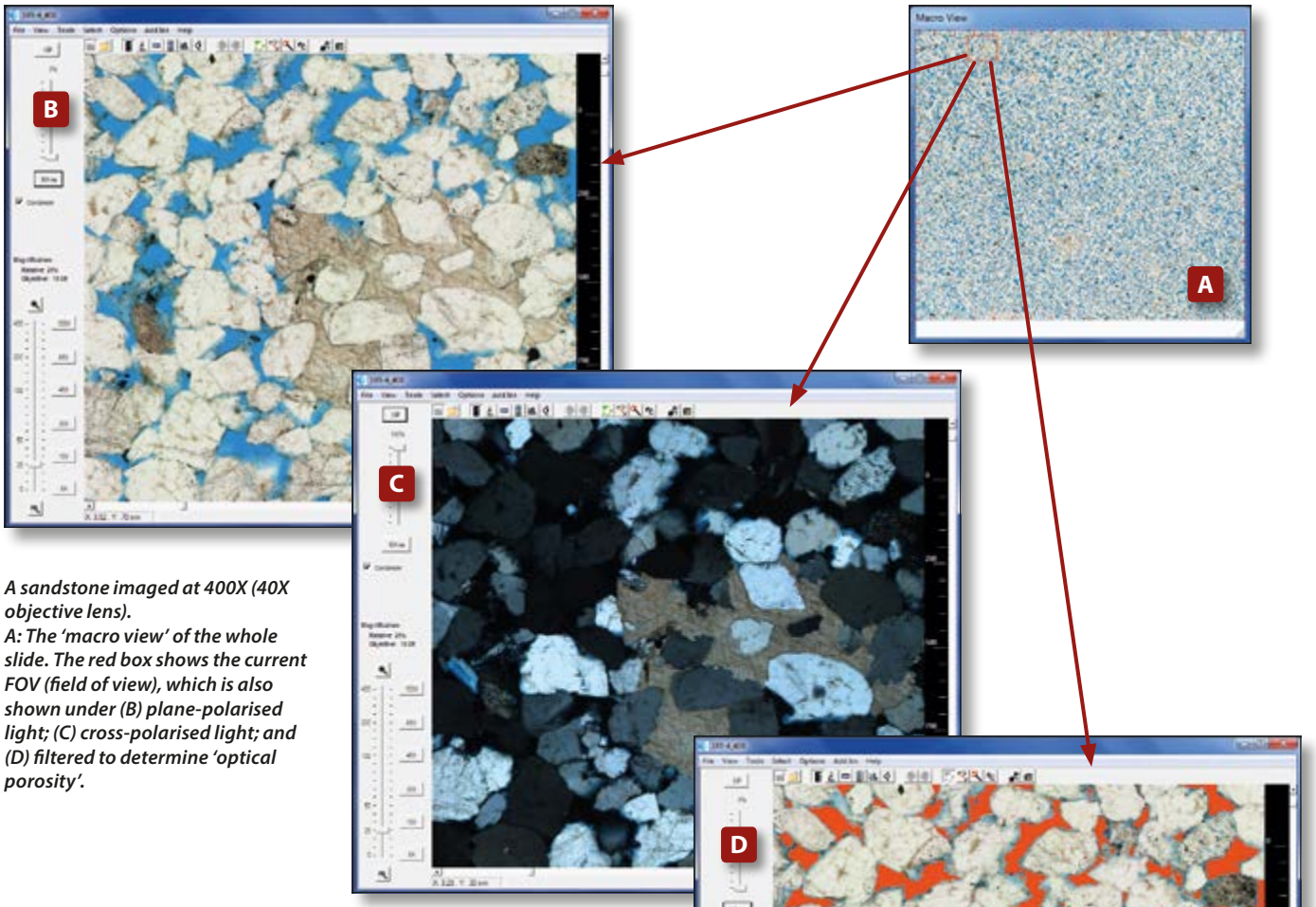
Standard 300 dpi 'high-resolution' imagery (top) compared to the 1,360 dpi resolution available using the TenEx imagery system (bottom).

information, making it available wherever in the world it is needed. Using its TenEx imagery system, core is digitised at the resolution of a 10x hand lens (or higher). The thin section 'MicroPics' can be imaged up to 1,000x magnification, the equivalent of a 100x objective lens. The company can also provide imagery of core plugs and cuttings, as well as biological samples for the medical profession.

This is not just simply taking digital photos of cores laid out on a bench! First, the cores are sanded and polished to a finish where all saw marks, roughness, dust and other obscuring matter are removed, allowing easy viewing of grains, fossils and porosity with the naked eye. This can take many hours or even weeks, depending on the composition of the core. Then a PetroArc digital imaging specialist scans the core, creating high resolution, depth-registered digital images which provide an easy-to-store visual record of the core that will not degrade over time and are easily duplicated and shared.

Virtual Microscope

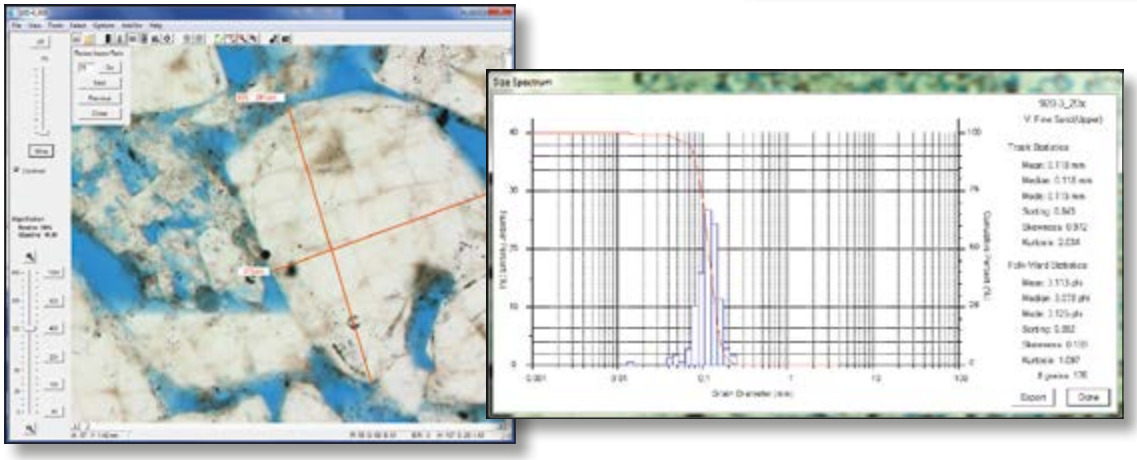
But this is only half the story. Most imagery is static; one can look at it, but that is all. To counter this, PetroArc International has developed virtual microscope technology which can interact with the imagery to perform analytical tasks, an example of which is a virtual petrographic microscope for thin sections. With this, the user can navigate throughout the slide, cross the polarisers, perform grain size, aspect ratio and



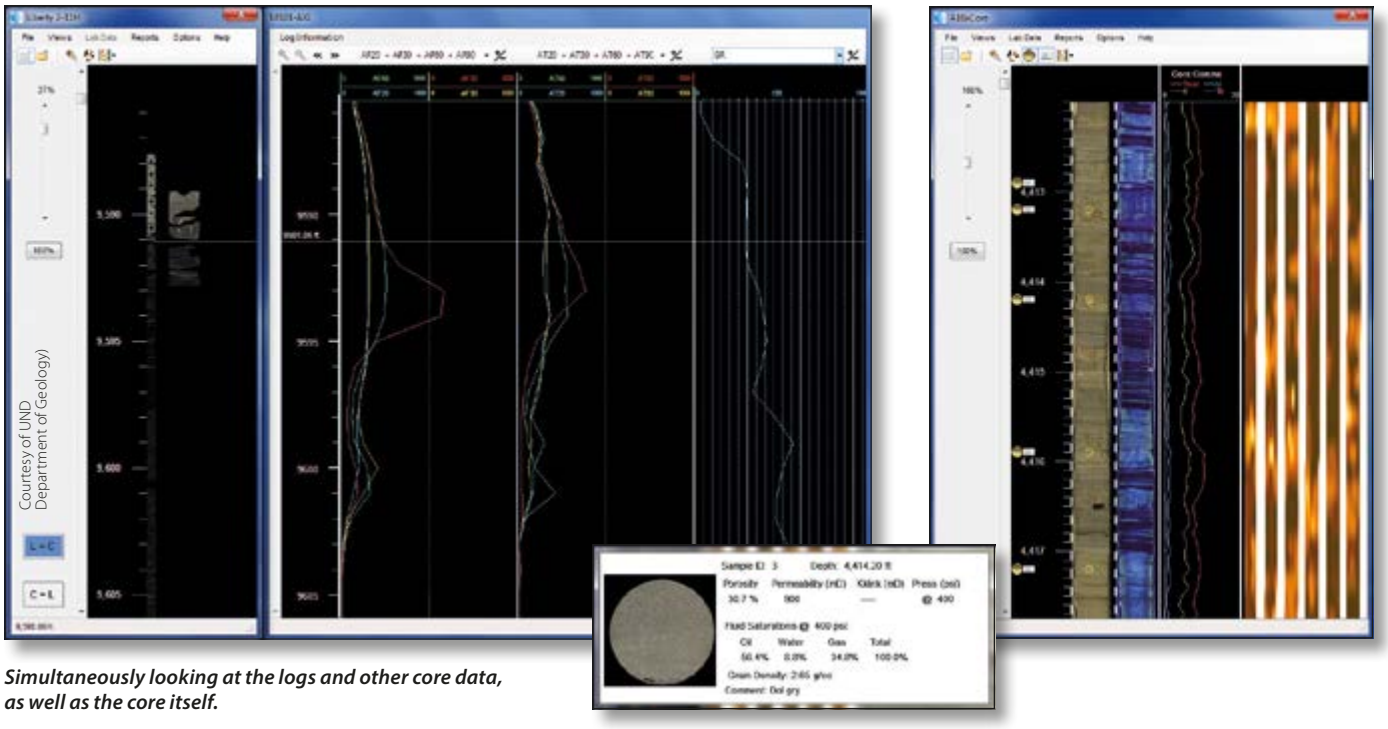
A sandstone imaged at 400X (40X objective lens).
A: The 'macro view' of the whole slide. The red box shows the current FOV (field of view), which is also shown under (B) plane-polarised light; (C) cross-polarised light; and (D) filtered to determine 'optical porosity'.

mineralogy point counts, and review them at any time.

The company has also designed software (CORSystem) which allows the user to examine the core, logs, lab reports and data, as well as analytical reports at the same time. At its centre is a virtual core microscope with tools to examine the core, measure apparent dip, as well as record the presence of index fossils, formation boundaries and a variety of other characteristics. CORSystem also contains innovative new tools for estimating grain size and cm-scale heterogeneity. All of the information is available to all the users, no matter where they are in the world.

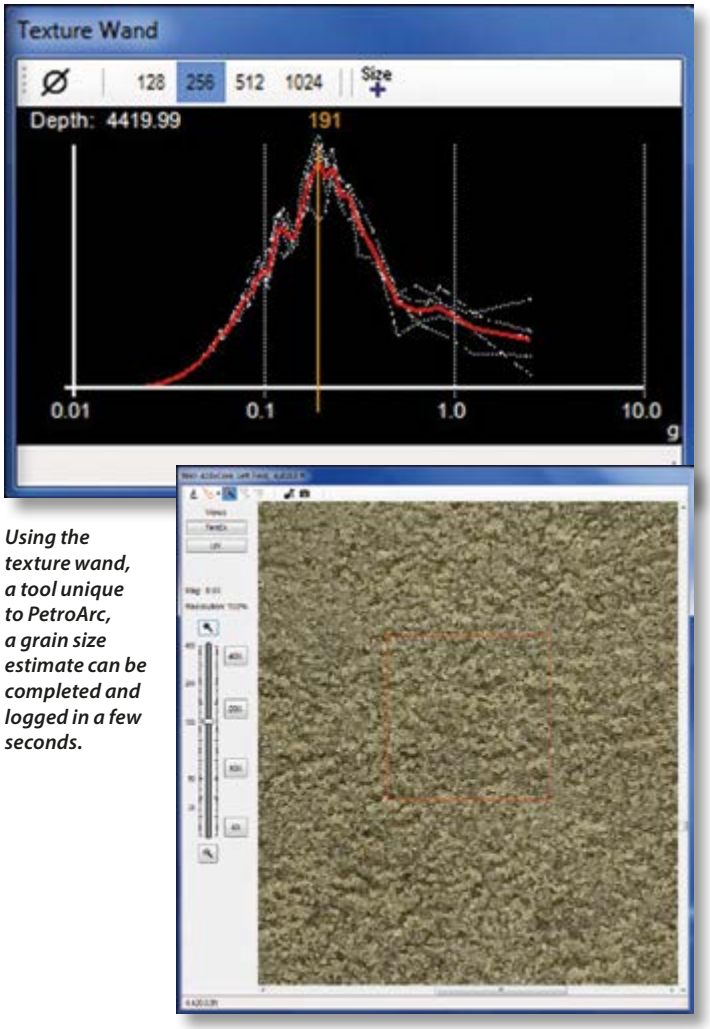


It is also possible to perform grain size analysis on the computer screen.



Simultaneously looking at the logs and other core data, as well as the core itself.

A high resolution digital core archive must be designed in such a way that the data is easily accessible, even data that arrives months or years after the core is imaged. It must also allow the users to perform routine analytical tasks from their desktops using the tools that are commonly used for evaluation. Such an archive has the potential to revolutionise the manner in which core is handled and evaluated, but only if the information is easily accessible and the access system has the facility for the users to get their work done. ■



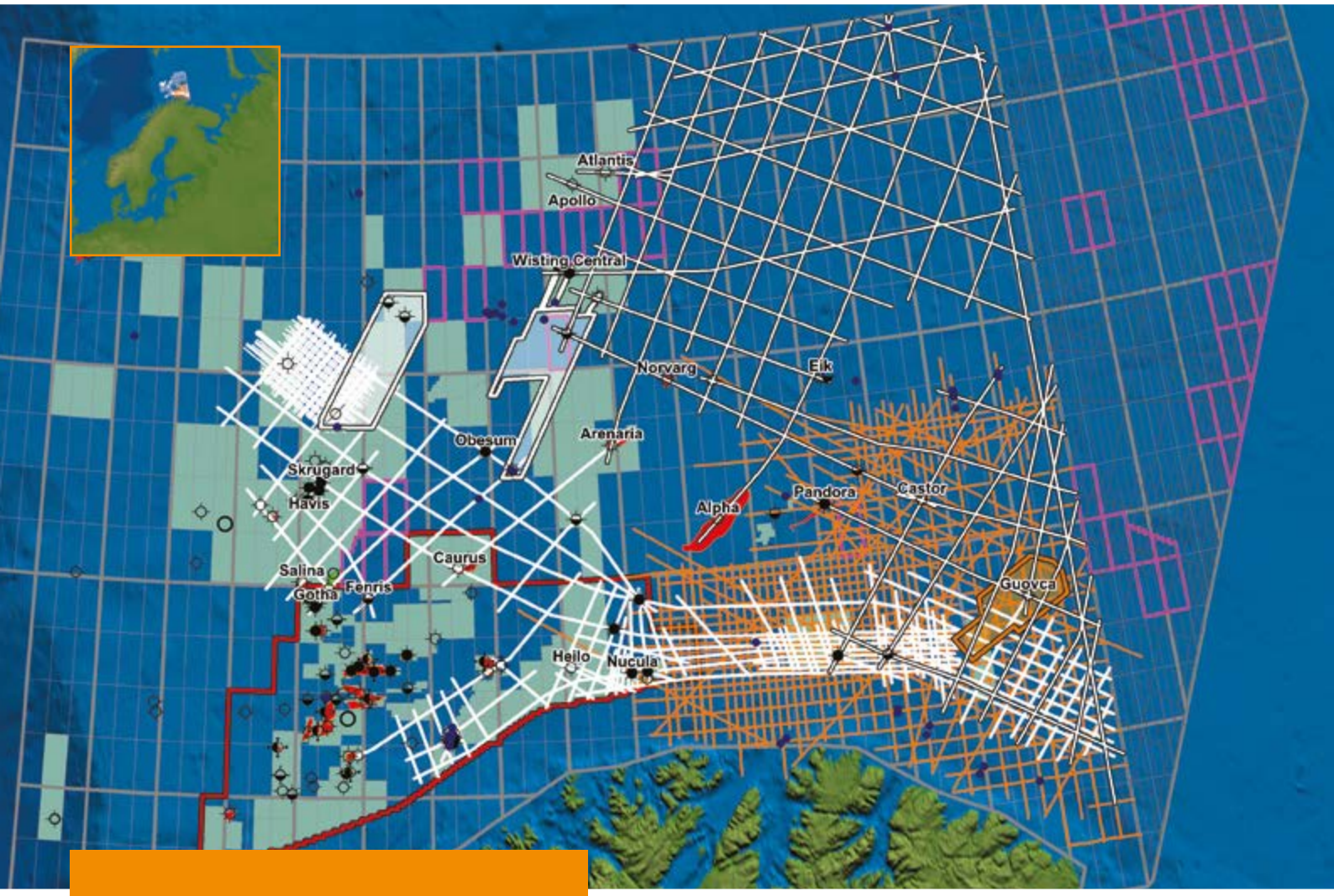
Using the texture wand, a tool unique to PetroArc, a grain size estimate can be completed and logged in a few seconds.

First University Core Library

The Wilson M. Laird Core Library at the University of North Dakota is an important resource for both students and the O&G industry in the state, but to access it researchers previously had to physically come to the library to study the cores. Recently, however, PetroArc International has begun digitising these cores and associated thin sections, plugs and drill cuttings in order to create the world's first high-resolution virtual core library. To date it has digitised over 2,000m of core and made it available for academic use with CORSystem 2.2, thanks to grants from Continental Petroleum and the State of North Dakota.

With the recent resurgence and rapid expansion of the oil industry in the western part of North Dakota, students and researchers, especially those studying in the Department of Petroleum Engineering at the university, will be able to use the software to manipulate the images of the cores and extract a lot more information. Lecturers can also use the core images as a teaching aid in class, not just in North Dakota, but throughout the world.

Barents Sea Seismic Projects



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Searcher Seismic

A New Oil Play in East Africa

Following the recent discoveries off Tanzania and Mozambique, a newly acquired 2D seismic data set (MAD13) which clearly illustrates the tectonic setting and prospectivity of offshore western Madagascar is set to revive interest in the region.

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Valentina Gabusi, Thinkstock

The offshore basins to the west of Madagascar are part of a large Gondwana break-up rift basin that formed during the early Mesozoic. The strike-slip rifting propagated southwards and includes several basins offshore Tanzania, Kenya and Mozambique. These basins make up a large prospective area that already has some significant discoveries, notably Sunbird offshore Kenya (oil) and Windjammer and Ironclad offshore Mozambique (gas). Due to the recent drilling successes, this trend has regained industry interest.

The deepwater Offshore Morondava Basin and Kerimbas Graben (also known as Lacerda Graben), which is the focus of this article, is undrilled and has licence blocks that are mostly open, with a planned competitive licensing round anticipated in 2015.

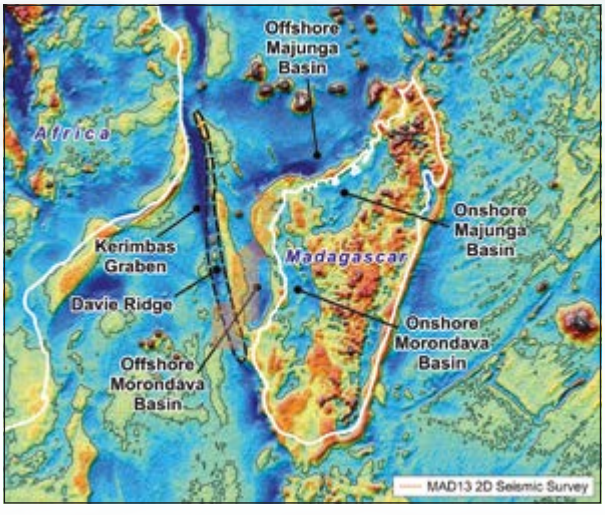
The TGS regional offshore geophysical data coverage in the region amounts to some 51,000 km of modern multi-client offshore 2D data. In addition the company have compiled logs and reports for 98 exploration wells in the adjacent shallow offshore and Onshore Morondava Basin.

Rifting Governs Geology

Onshore Madagascar, Tanzania and Kenya host failed Permo-Triassic rift basins. Permo-Triassic hydrocarbon deposits in the Onshore Morondava Basin have been known since 1842 and contain the Bemolanga and Tsimiroro oil fields.

The Offshore Morondava Basin and Kerimbas Graben to the west of

Satellite gravity map of the offshore Madagascar regions showing the major structural elements and the location of the MAD13 survey. Note the Davie Ridge that accommodates the right lateral strike-slip faulting (Satellite gravity backdrop from Scripps Institute of Oceanography, University of California).



Jurassic sandstone surrounds a natural swimming pool in Isalo National Park, Madagascar.

Madagascar formed in the Jurassic as a result of the separation of the Madagascar-Indian plate from the African plate. This break-up is likely to have followed or reactivated earlier Palaeozoic rift basins, with some evidence for these being interpreted within the Davie Ridge. Madagascar drifted south-eastwards away from the African plate throughout the Early Cretaceous along the Davie Fracture Zone, resulting in the transtensional and transpressive reactivation of existing fault systems. This rifting and transform movement resulted in the two major offshore basins: the Offshore Morondava Basin and the Kerimbas Graben, which are divided by the north-north-west to south-south-east oriented Davie Ridge.

In addition to the fault reactivation and deformation due to the right-lateral transform movement along the Davie Fracture Zone, the separation of the Indian plate from the Madagascan plate in Late Cretaceous times led to accelerated subsidence as well as compression and local inversion of the Jurassic rift basin. This break-up of the Madagascan and Indian plate was associated with igneous intrusion and volcanism. The volcanics form a regional stratigraphic marker of Cenomanian to Santonian age (Maloney et al, 2008).

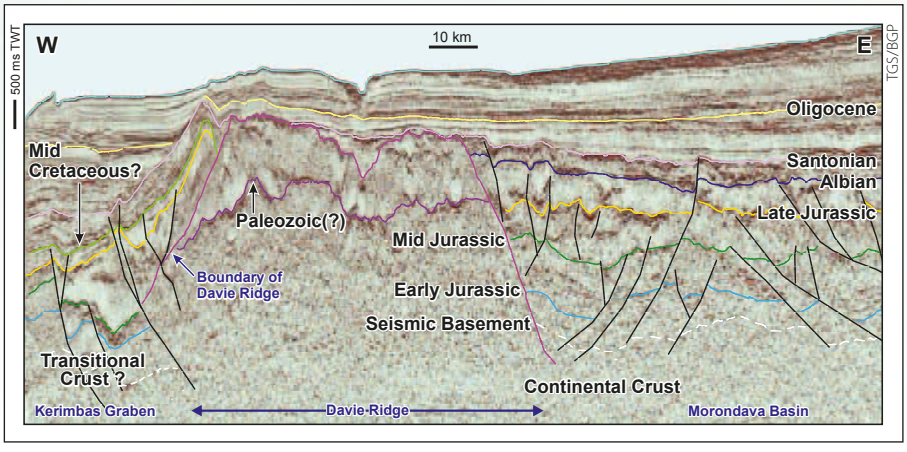
Interesting Structural Features

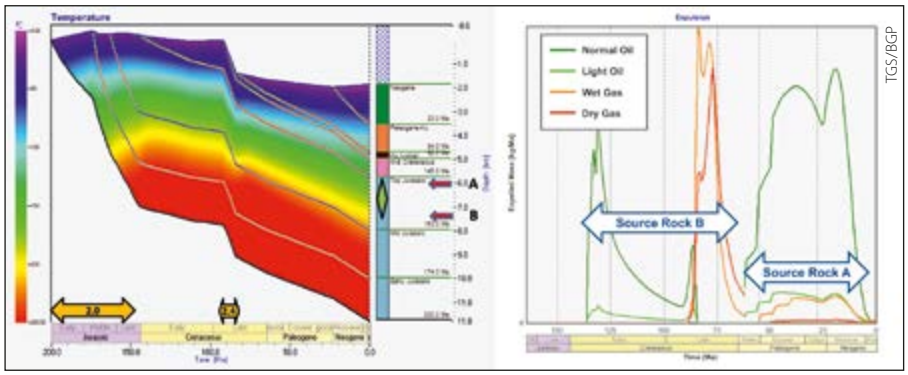
The Offshore Morondava Basin: The Permian shale source rock for the onshore Bemolanga Tar Sands may be present in the Offshore Morondava Basin, although it must be noted that there is as yet no direct evidence from drilling.

The original normal faults of the Offshore Morondava Basin and other rift basins to the north along trend have been re-activated by dextral strike-slip faulting. Major faults should have large throws with thick sediment piles developed in transtensional basins. The syn-rift sediments of this basin are Jurassic to possible Early Cretaceous in age (Rusk & Bertagne, 2003) and are likely to contain lacustrine or restricted marine source rocks together with alluvial and fluvial sheetflood sandstones, which can have excellent reservoir properties. The syn-rift sediments are interpreted to be present throughout the Offshore Morondava Basin.

A thick post-rift Cretaceous and Tertiary section overlies the syn-rift sediments and is interpreted to host reservoir and seal sequences comprising sand-rich turbidites, submarine channel and mass-flow

An example seismic line from the TGS-BGP MAD13 data set showing the two Mesozoic basins divided by the Davie Ridge. Note that the ages of the Kerimbas Graben stratigraphic surfaces are not constrained by any well data in this area.





Expulsion timing for source rocks at depths A (Type I: lacustrine) and B (Type III: coaly).

deposits. A Late Cretaceous regional volcanic event can provide a good seal over much of the area.

The Davie Ridge: The north-north-west to south-south-east trending Davie Ridge is bounded by right lateral strike-slip faults that extend from the coast of Kenya to south of Madagascar. It is interpreted to have developed on continental crust and its core is thought to contain Gondwana remnant material, which is likely to comprise a mix of sedimentary, metamorphic and volcanic lithologies. The Davie Ridge is characterised by a prominent asymmetric gravity anomaly, with the western part showing magnetic highs with gravity lows, while the eastern Davie Ridge shows magnetic lows with gravity highs. Additional modelling is required to explain this feature.

The Kerimbas Graben: To the west of the Davie Ridge is the Kerimbas Graben, which is part of a north-north-west to south-south-east trend of prospective grabens. This trend extends southward from offshore southern Somalia through offshore Kenya and Tanzania (where there is a proven petroleum system) to offshore Mozambique and Madagascar.

The Kerimbas Graben may contain Early to Late Jurassic syn-rift sediments. If present, as in the Offshore Morondava Basin, such rocks are likely to be lacustrine or restricted marine source rocks together with alluvial and fluvial sheetflood sandstones and mudstones, which could provide reservoirs and seals respectively.

The Source Rock Model

Early to Late Jurassic and Early Cretaceous oil-prone shales have been identified in the coastal wells and are likely to have been deposited within open marine, lacustrine, restricted shallow marine and lagoonal environments. They are also expected to be present westward and basinward into the Offshore Morondava Basin (Rusk, Bertagne and Associates, 2003; USGS, 2012) and may also be present in the Kerimbas Graben since source rocks of the same age are found in the basins of coastal Mozambique, the Mozambique Channel and Tanzania (USGS, 2012).

Initial Offshore Morondava Basin thermal modelling studies of Jurassic source rocks were undertaken at selected pseudo-well sites. Limited thermal and maturation data were available from the shelfal wells to assist in constraining the modelling. Beta factors of 2.0 and 2.4 were used for the Jurassic rifting and the Late Cretaceous stretching due to the break-up of India and Madagascar. Shallower depths of burial eastwards will lead to later oil expulsion events and the potential for older source rocks to contribute to the petroleum system.

The modelling indicates that the coaly source rocks expelled oil from Early to Late Cretaceous after which they passed into the gas window. The younger Late Jurassic lacustrine source rocks started expelling oil in the early Tertiary and this oil expulsion continued until the Pliocene. Early Cretaceous source rocks are likely to be in the oil expulsion window present day within the Offshore Morondava Basin.

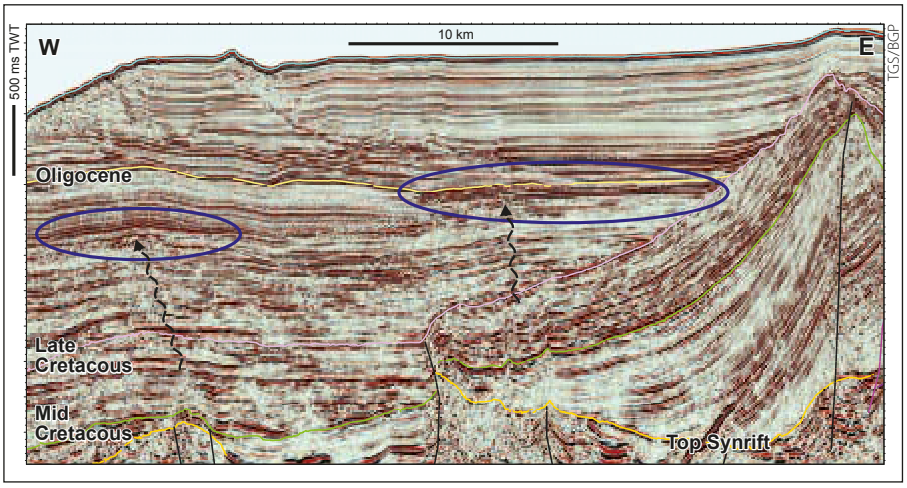
Numerous fluid conduits can be seen on the seismic sections emanating from the syn-rift sediments in both the Kerimbas Graben and Offshore Morondava Basin. These features may indicate possible vertical hydrocarbon migration pathways.

Highlights

Offshore Madagascar has the potential for widespread Jurassic to Early Cretaceous source rocks to be present, which are modelled as mature for oil within the study area. This indicates the presence of a new oil play in East Africa, where the received wisdom is that the area is likely to be another gas-prone province. Within the stacked reservoir sequences of the syn-rift and post-rift, there exists a variety of structural and combination trapping mechanisms which appear favourable for charge when the timing of late oil expulsion is modelled.

With a licence round to be announced in 2015, and the area covered by the MAD13 survey containing over 40 blocks of open acreage, this is an attractive undrilled frontier on which to focus. ▶

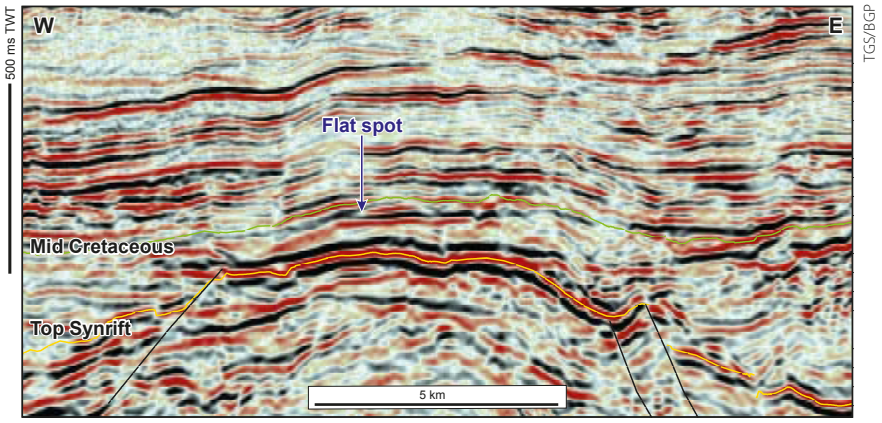
An example seismic line from the Kerimbas Graben showing fluid conduits indicating possible hydrocarbon migration. Blue polygons indicate brighter reflection features above the conduits.



Play Type Examples

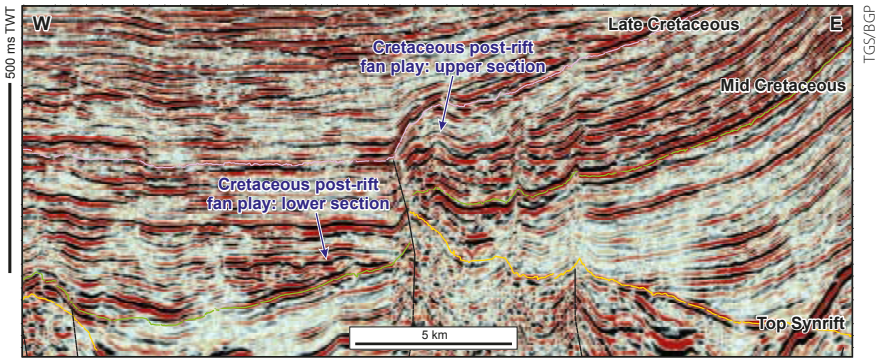
Play Type A: Mid Cretaceous post-rift play with flat spot – Kerimbas Graben

Play Type A is a post-rift sand-prone slope fan that displays a prominent flat spot. This is found just above the location of expected mature rocks in the Late Jurassic. The faulted syn-rift section below this also shows trapping potential.



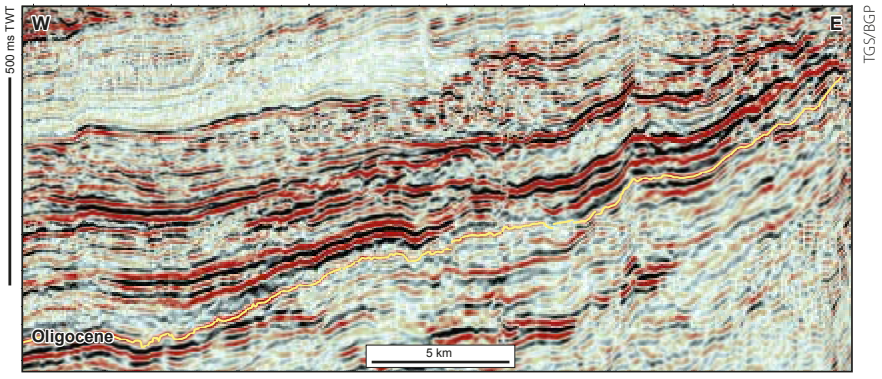
Play Type B: Cretaceous early post-rift play in sand-prone slope fan sandstones – Kerimbas Graben

Play Type B shows a post-rift slope fan with structural trap potential (upper section) and combination stratigraphic pinch-out with possible updip fault seal (lower section). This play is just above the location of expected mature source rocks.



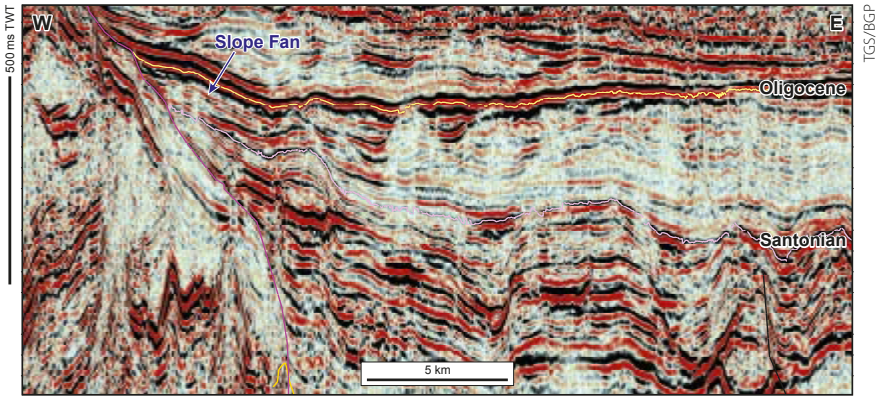
Play Type C: Sand-prone slope fan pinch-out – eastern flank Offshore Morondava Basin

Play Type C shows three sand-prone slope fans separated by deep water mud-prone facies. The sand fans display a hummocky facies character with generally good seismic continuity. The interbedded mudstones can act as intra-formational seals.



Play Type D: Offshore Morondava Basin sand-prone slope fan pinch-out against the Davie Ridge

Play Type D shows a Paleogene slope fan overlying a Cretaceous slope fan. The Paleogene fan pinches out against the Davie Ridge and shows brightening updip, which is a possible indication of hydrocarbon charge.



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Acknowledgements:

Simon Bowen, TGS-Africa, Mediterranean and Middle East; Mr Huang Weining, BGP; Ian Deighton, Erika Tibocha, Gavin Hudson, TGS.

With special thanks to Office des Mines Nationales et des Industries Stratégiques (OMNIS) for new data acquisition. ■

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Dynamic Topography Sheds New Light

The new field of dynamic topography is changing our understanding of the sedimentary record.

DAVID UPTON

Australia is at the centre of its own tectonic plate and a safe distance from the powerful and destructive forces of subduction in the Pacific Rim of Fire. Plate theory therefore says we can expect the Australian landmass, which has been unaffected by tectonic boundaries for 80 million years, to be flat and stable, with little or no vertical crust movement. But recent studies in the relatively new field of dynamic topography show that the Australian plate has been subjected to large vertical movements – up to one kilometre up or down – in the very recent geological past.

The new work is led by Geoscience Australia's Dr Karol Czarnota, who was sponsored by the Australian government geoscience agency to complete a doctorate in dynamic topography at Cambridge University in the UK. His conclusions challenge the view that in old and stable regions the stratigraphic record is a simple function of changes in global sea level. "The geoscience community is beginning to realise that many broad topographic and bathymetric features in intra-plate settings, such as Australia, are the surface expression of convective circulation within the Earth's mantle."

Implications for Petroleum Industry

Dr Czarnota and other dynamic topographers at Cambridge are turning upside down many of the previously accepted ideas developed from computer modelling of convection in the Earth's mantle. Their work is also relevant for climate change scientists and their models of sea level change.

For the petroleum industry, dynamic topography can mean quite dramatic changes in our understanding of the stratigraphic record and the way that petroleum systems were formed.

"Sequence stratigraphers have struggled to explain large unconformities in terms of rapid changes in sea level. These anomalies have been attributed to icecap melting, but that can only generate a maximum amplitude of about 120m. The sequence stratigraphic community has always had questions about what causes third order stratigraphic variations, and we think it is something to do with processes beneath the plate that are leading to dynamic topography," Dr Czarnota explained.

It has long been expected that above rising, hot and buoyant material within the mantle a broad topographic swell will develop. Conversely, the presence of sinking, cool and dense material within the mantle should lead to a wide topographic depression at the Earth's surface.

"These broad topographic features are expected to come and go as tectonic plates drift across an ever-changing pattern of convective circulation beneath them," he continued. "Until recently the significance and geological expression of this phenomenon, known as dynamic topography, has eluded the geoscience community because it has been difficult to measure its effects."

Dynamic Uplift and the Nullarbor Plain

The new field of dynamic topography addresses the problem by relying on a well-known relationship between the depth

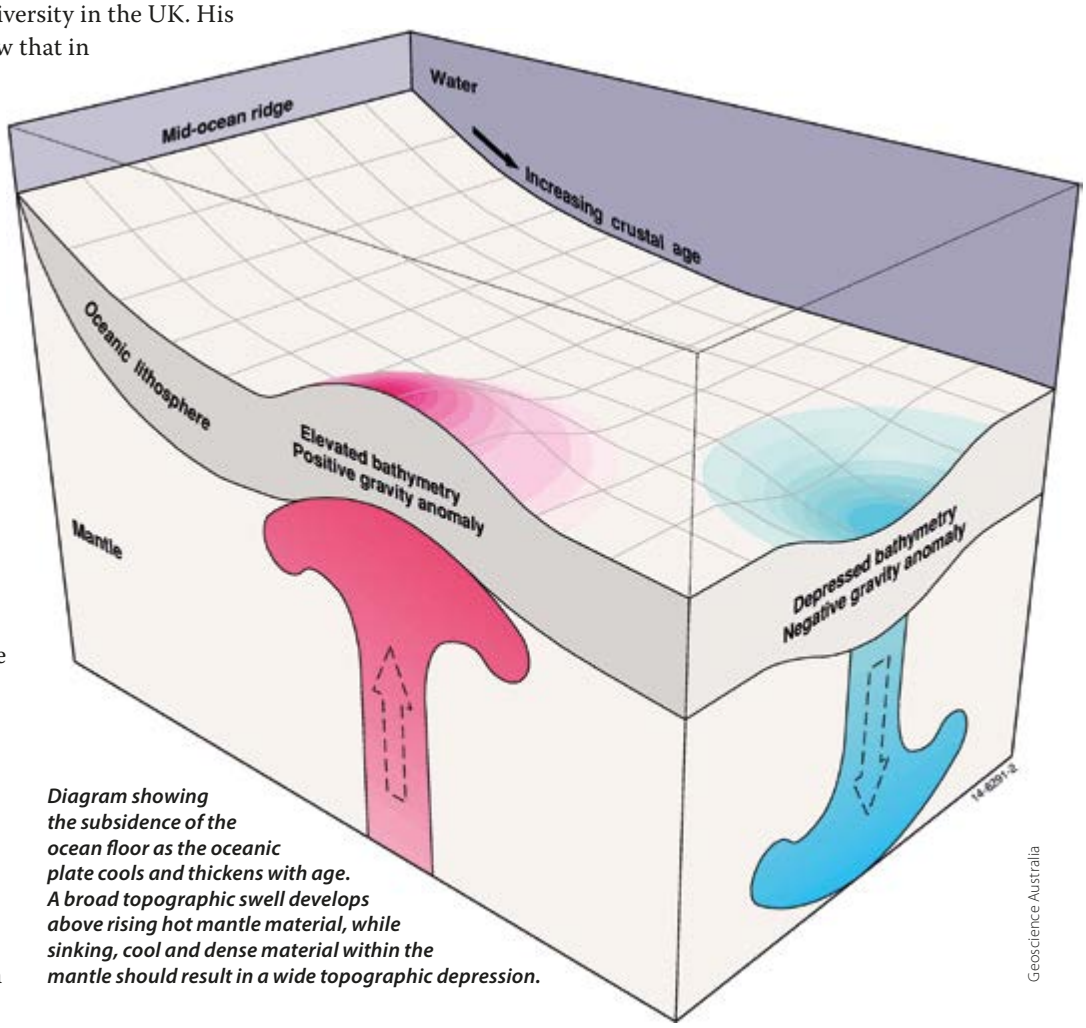


Diagram showing the subsidence of the ocean floor as the oceanic plate cools and thickens with age. A broad topographic swell develops above rising hot mantle material, while sinking, cool and dense material within the mantle should result in a wide topographic depression.

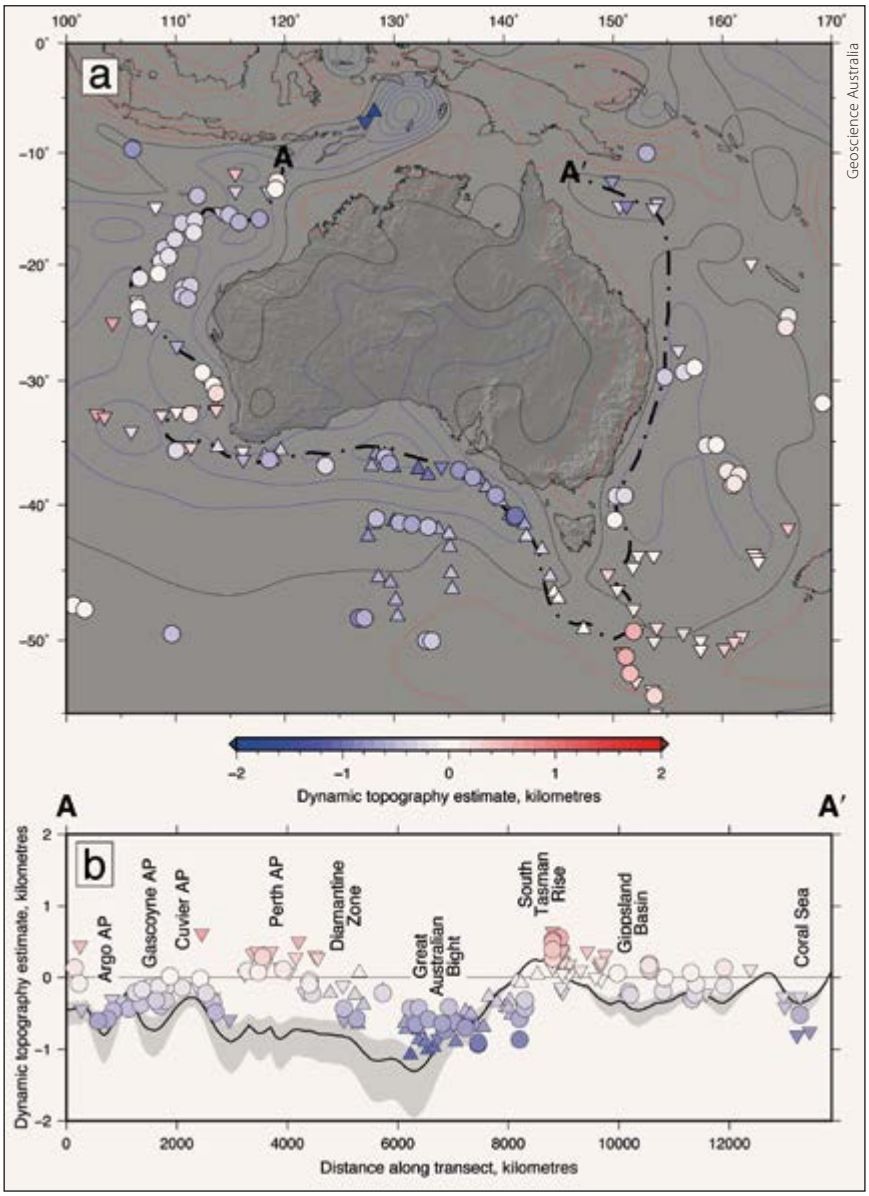
Geoscience Australia

and age of the world's oceans. On average, the oceanic floor is 2.6 km deep at mid-ocean ridges and subsides to 5.7 km as the plate cools and thickens with age. Dynamic topography measures the perturbations from that well-established age-depth trend.

Dr Czarnota said that a correction is applied to compensate for the actual thickness of the crust, which is possible from another well-established understanding of the change in topography due to thinning or thickening of the crust. Seismic surveys provide the data on crust thickness, and are in abundant supply on many parts of the Australian continental shelf.

The figure on the right shows the wide variation in expected bathymetry around the Australian land mass due to mantle convection. The most prominent feature is a large depression in the order of one kilometre in the Great Australian Bight. Towards the south-east of this, the depression gives way rapidly to an upwelling feature centred on the South Tasman Rise.

Dr Czarnota said the geological record on the Nullarbor Plain was of progressively younger shorelines towards the coast, and indicated the Bight was on its way up from an even deeper depression. This uplift was a consequence of the Australian plate drifting northwards out of the dynamic depression affecting the Bight and Southern Ocean. "In southern Australia, we have had 300m of dynamic uplift over the last 40 million years, which has exposed the Nullarbor Plain and formed spectacular cliffs along its southern edge." (See photo of the Nullarbor Plain on page 20.)



Oceanic dynamic topography estimates.

North West Shelf Puzzle

Dynamic topography is shedding new light on the way petroleum systems formed in some of Australia's most important basins, including the North West Shelf.

Dr Czarnota said the stratigraphic record along the North West Shelf revealed the onset of dynamic drawdown about 10 million years ago. Up to 700m of subsidence had occurred since then, which was seven times the amount that could be accommodated by global sea-level change.

"The rapid sinking of the North West Shelf was always puzzling to petroleum geologists because it happened in the Neogene, when evidence from around the world says this was actually a period of falling sea levels. Now we can understand the mechanism of this subsidence along the North West Shelf."

He said this was important because the rapid sinking was responsible for about 50% of the oil expelled from carbonate source rocks in the adjacent Browse Basin. If the Browse Basin had subsided as normal, the carbonate platform along the palaeo shoreline would have built out into the Indian Ocean. But sea levels rose instead, and carbonate reefs stacked up on top of each other, creating a high load of sediments that pushed the bottom of the stack into the maturation window.

In the Gippsland Basin, Dr Czarnota's work has also explained a large unconformity in the sedimentary sequence in a period of rapid Eocene uplift. "This unconformity has been linked to the arrival of mantle upwelling beneath south-eastern Australia and the formation of the Great Escarpment. The unconformity was infilled by reservoir rocks, a key component of one of the Gippsland Basin's petroleum systems."

Dr Czarnota said dynamic topography created important new insights, based on data rather than modelling, but the best results would come from working across many disciplines. "We need a very multi-disciplinary approach to get the most useful answers. That means input from modelling, from the data we collect, the geological record, the sequence stratigraphers and the basin analysts. Good exploration for hydrocarbons relies on good geology, and you make better decisions with the more information you have." ■

Communicating Naturally

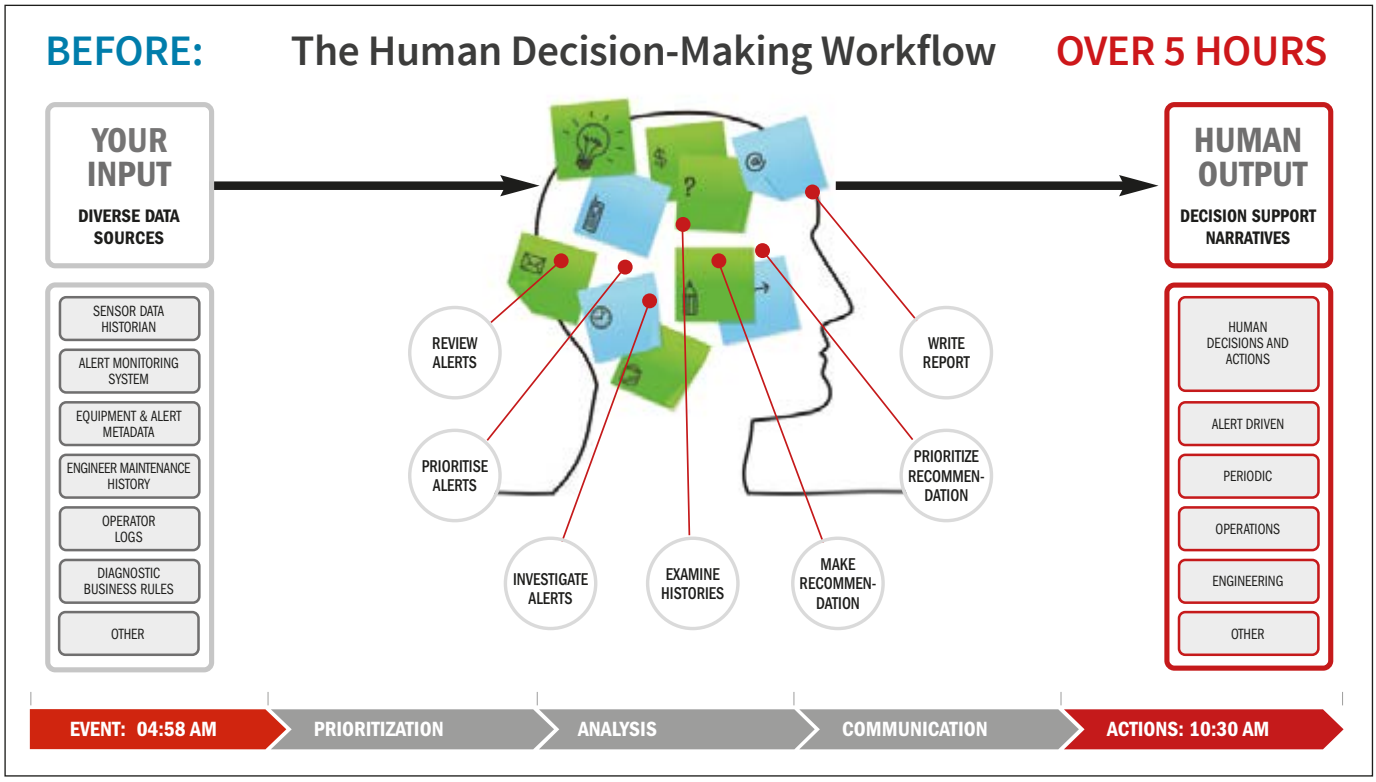
Critical decision making can be speeded up through Natural Language Generation software, a technique that originated in the medical world.

TRACEY DANCY

On the surface, you might not think that the oil industry would have much in common with the medical community. The mental image that most of us have of a rigger, dressed in coveralls and heavy boots, operating heavy machinery and braving extreme weather, is far removed from the sterile, white-coated figures who perform delicate surgery in climate-controlled operating theatres.

Dig a little deeper, however, and the two worlds overlap far more that you might imagine. Houston, Texas, for example, has two major industries – oil and gas, and medicine – and, via regular 'Pumps and Pipes' meetings, they have been exploring together the similarities in the technology they use and the challenges they face.

Professor Ehud Reiter agrees. He is Chief Scientist at Arria NLG plc, with 25 years' experience working on decision-support technologies across both these industries. His focus, and that of Arria NLG, is on using analytics to speed up mission critical decision-making with a technology called Natural Language Generation (NLG). He notes that both doctors and engineers "raise remarkably similar issues and concerns about decision-making, even though they work in very different contexts". This shouldn't come as a surprise, given that decision-making is fundamentally about the psychology of human reasoning, regardless of whether the reasoning concerns sick babies or malfunctioning generators.



Addressing Decision-Making Issues

Both engineers and physicians have a number of key complaints when it comes to decision-making:

1. It's too hard to find data: Fundamentally, humans are the same, regardless of what industry they are working in. They are good at making decisions if the key data is available, but finding the right data in a world where 'big data' has become a catchphrase can be like finding a needle in a haystack.
2. Expertise is a scarce resource: This can make a huge difference in decision-making confidence. In the oil and gas industry, in particular, we are losing experienced staff to retirement without bringing in new expertise at a basic level, with the consequent loss of knowledge and experience.
3. Key information is lost at handover: Handover time can be difficult. After a busy shift it is easy to forget details and omit to record every point. Forgetfulness is amplified by fatigue, compounding the issue.
4. Staff do not like computers telling them what to do: People want to be in control. Having their actions dictated by a machine can be difficult to accept – and there is often a lack of trust in the relevance and accuracy of the input.

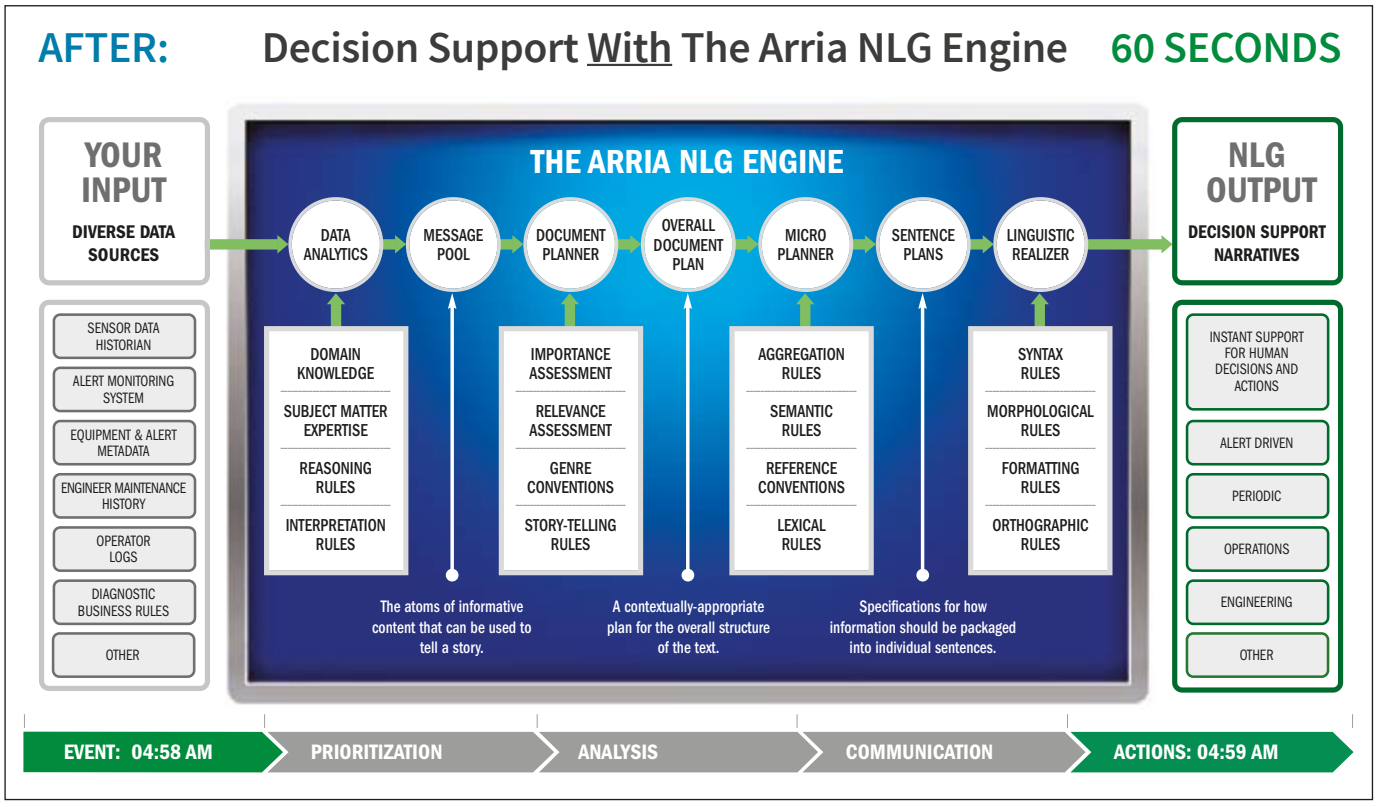
Natural Language Generation (NLG) is a technology that automatically generates textual narratives summarising complex data, providing a decision-support tool equally at home in both medicine and energy, and indeed in many other industries. NLG supports people, and in doing so, addresses the psychological issues outlined above in the following ways:

1. Finding Data: NLG pulls together the key facts from disparate data sources into a single, integrated narrative with supporting graphics.
2. Scarcer Expertise: NLG captures and 'bottles' domain knowledge. Once captured, it is always available to analyse which information is, and is not, important, and to draw conclusions from it.
3. Forgetfulness: NLG generates a reliable, comprehensive summary of key facts for shift handover.
4. Acceptance: NLG helps people do a better job by sharing information, not giving orders.

Tailored Reports

The BabyTalk system, an NLG application built by Professor Reiter's team for the Royal Infirmary in Edinburgh, generates summaries of clinical data about babies in neonatal intensive care. Data collected from a variety of sources, including the electronic patient record, goes through Arria's NLG Engine, producing a variety of reports tailored to the target recipient: the doctor, for whom the reports supply decision-making support; the nurse, for whom a detailed handover document is produced; and the parents, who receive a daily update on their child's condition and progress.

In the oil and gas industry, Arria is currently providing its technology for discrete equipment areas; specifically, an exception-based alert system for rotating equipment on platforms in the Gulf of Mexico. When an alert indicates a temperature or movement threshold has been breached, the



NLG system kicks into action. For any given alert, there are 77.6 million sensor data points that could be relevant, which the NLG Engine assesses, analyses and then feeds into a 500-word report, describing what's happening and why the situation has arisen, all generated in less than 90 seconds.

All this processing is performed on a standard desktop computer. The NLG Engine knows how to analyse the relevant data, including any data belonging to associated machinery, and how to decide what information is important and reportable. What is more, it also knows how to put together a story to explain the data, emphasising the most significant factors, and how to package information into sentences of the right size and complexity, using the correct grammar and appropriate terminology.

Further applications of the technology are planned in the Gulf of Mexico. Ultimately, Arria envisages a scenario where the NLG Engine could be used not just in discrete areas, but across entire platforms, enabling any level of report to be produced at the touch of a keyboard, ranging from specific equipment analysis to a performance summary for the entire platform, with each type of report being tailored to a specific audience.

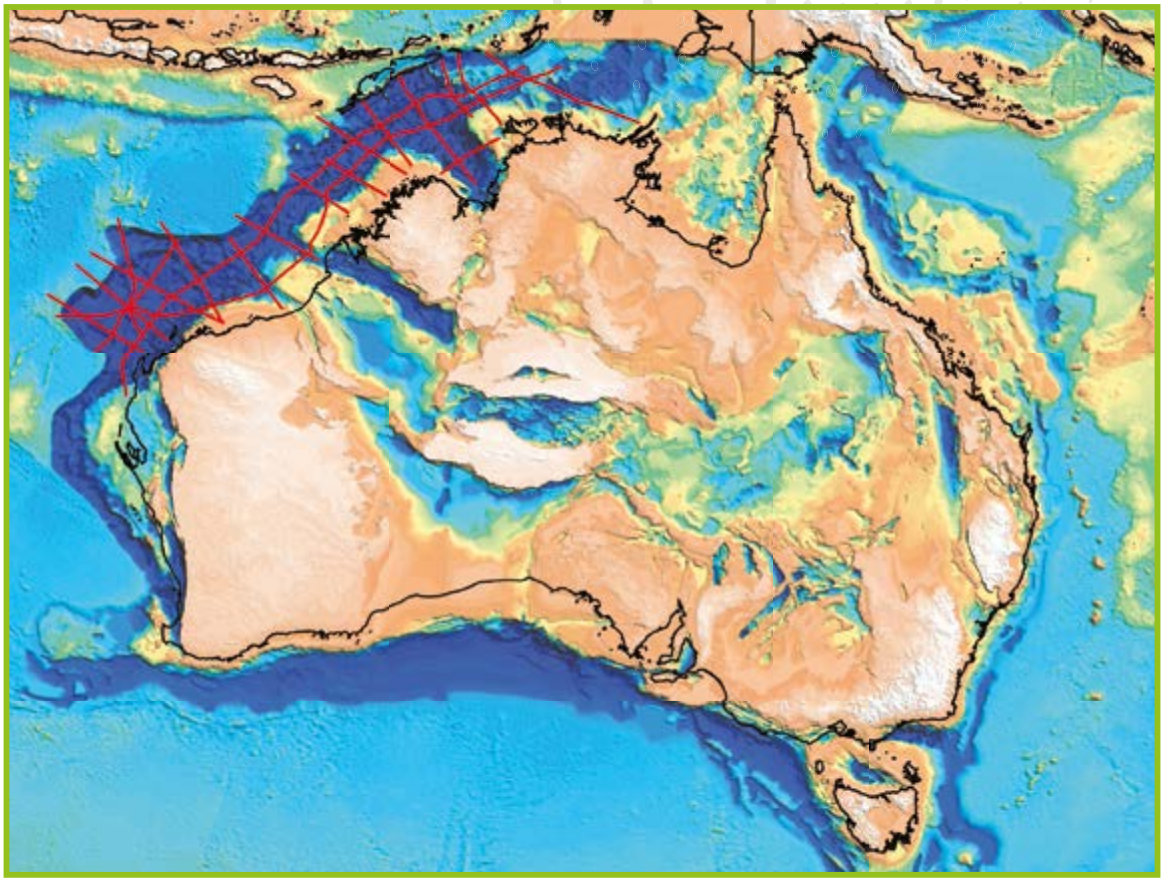
Arria's NLG core technology includes a sophisticated Data Science Framework. This rationalises the processes involved in analysing varied and complex data sets to make it quick and easy to configure analytics processing for new scenarios, and in particular to make it more straightforward to embed knowledge captured from domain experts into the NLG Engine.

The Articulate Oilfield

"Anywhere there's a lot of data that people struggle to deal with, is a place where this technology could be useful," says Dr Robert Dale, Chief Strategy Scientist and Chief Technology Officer at Arria NLG. "At the moment we're looking at electrical submersible pumps and drilling reports, an area that's generating a great deal of interest. We are starting with system components, but you can easily imagine how the information at that level can be aggregated, making it possible to report on chains of equipment all the way up to the entire platform, correlating and integrating that information for a complete report of the system – ultimately, creating what is really an articulate oil and gas field." ■

Arria's Chief Scientist Ehud Reiter is also Professor of Computing Science at the University of Aberdeen's School of Natural and Computing Sciences, and founder of the University's NLG research group. He also co-authored the book 'Building Natural Language Generation Systems' with Dr Robert Dale, published in 2000 by Cambridge University Press. Prof Reiter has a PhD from Harvard University.

WestraliaSPAN™: Redefining the Westralian Superbasin.



OZ SEEBASE™ Study 2005, Public Domain Report to Shell Development Australia by FROGTECH

WestraliaSPAN provides continuous coverage across the most prospective basins of Australia's North West Shelf. Acquired using ION's proven deep tow techniques and imaged by ION's GX Technology group using proprietary broadband processing, the survey includes more than 14,000 km of high-quality depth-processed data. The superior imaging of the WestraliaSPAN data has allowed for a step change in the understanding of the early tectonic history, in particular the interpretation of early rift structures, which originally formed the basins and sub-basins that comprise the Westralia Superbasin. To learn more, visit iongeo.com/WestraliaSPAN.

AREAS OF EXPERTISE

Unconventional Reservoirs

Challenging Environments

Complex Geologies

→ **Basin Exploration**

Reservoir Exploitation

The Australian North West Shelf: New insights from Deep Seismic

The North West Shelf of Australia is a diverse petroleum province that has remained enigmatic over a prolonged period of exploration. Offshore drilling started in the late 1960s with shelfal wells in the Carnarvon and Bonaparte Basins. More than 2,000 wells have since been drilled, resulting in discoveries of over 3 Bb of liquids and 100 Tcf of gas resources. In 2011, the USGS estimated a remaining undiscovered potential of 4.6 Bbo and 225 Tcfg for the basins from the North Carnarvon to the Bonaparte.

Figure 1. Map of the Australian North West Shelf showing the location of the main basins and the ION Westralia SPAN data. Lines from Figures 2–4 are highlighted.

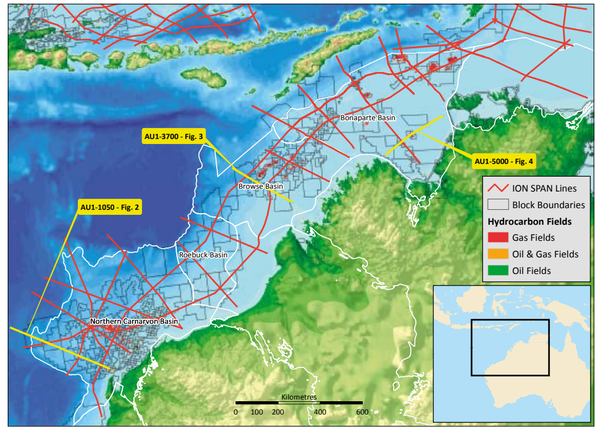


Figure 3. North-west to south-east section across the Browse Basin from the Leveque Shelf in the south-east across the Caswell and Barcoo sub-basins, both of which contain thick fluvio-deltaic (Carboniferous) to marine (Permian) sections. Transgression was accompanied by back-stepping and onlap onto the Leveque Shelf in the late Jurassic, continuing through the Early Cretaceous. Carbonate sedimentation commenced from the Turonian, interrupted in part by a pulse of siliciclastics in the Campanian to Middle Oligocene. The entire package is well imaged on this line. (See Figure 5 for horizon correlations.)

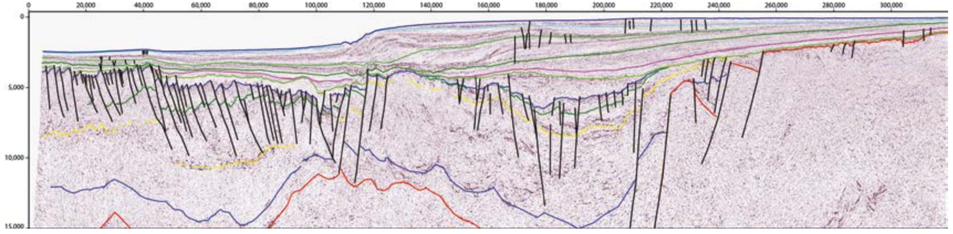
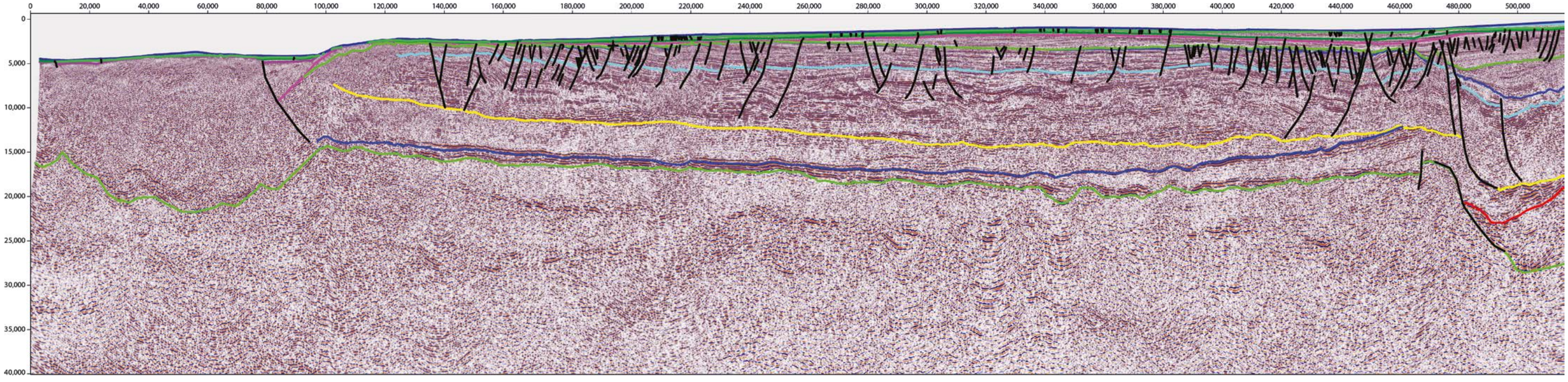


Figure 2. North-west to south-east line across the North Carnarvon Basin, imaging the full sedimentary section down to 20 km depth. The full Permo-Triassic Mungaroo delta is imaged with its small-scale extensional faulting, which appears to detach down onto the underlying Permo-Carboniferous strata. The majority of the section across the Exmouth Plateau is interpreted to be underlain by exhumed mantle. The inboard transition from continental crust to exhumed mantle is also the focal point for the later development of the Exmouth sub-basin at the south-east end of the line. The north-west end of the line records the eventual Jurassic break-up event with important volcanic and intrusive features diagnostic of a volcanic margin. (See Figure 5 for horizon correlations.)



A Developing Province

PAUL BELLINGHAM, KENNETH McDERMOTT, ION Geophysical

With an estimated remaining undiscovered potential of 4.6 Bbo and 225 Tcfg, there is still much to explore for in the North West Shelf of Australia.

The North West Shelf (NWS) can be divided into four major basin areas (Figure 1), each with a number of working petroleum plays from Permian to Cretaceous:

- The North Carnarvon Basin with its major gas plays on the Exmouth Plateau and oil plays in the Barrow/Dampier sub-basins. The area is characterised by the thick Permo-Triassic Mungaroo Delta section, thin or absent crust and Jurassic/Cretaceous deformation (Figure 2).
- The Roebuck Basin contains a thick Permo-Carboniferous section, reaching 15 km thickness in parts of the Rowley sub-basin. The overlying Triassic and Lower Jurassic systems provide good reservoirs and have recently been proven as a significant oil play with the Phoenix South discovery. These units thicken to the north-west only to be abruptly truncated at the margin.
- The Browse Basin deepens rapidly at a crustal necking zone at the edge of the Kimberley Craton (Figure 3) with the various sub-basins filled with thick fluvio-deltaic Carboniferous and marine Permian sediments as a record of the Westralia event (Figure 5). Carbonate dominated sedimentation started in the Turonian and continued through to the Oligocene.
- The Bonaparte Basin and Petrel sub-basin (Figure 4) contain over 20 km of fairly continuous stratigraphy from the Palaeozoic to the present day, largely uninterrupted by significant faulting since the Carboniferous. The thickening sediment section coincides with dramatic thinning of the crust to potential mantle exhumation.

The NWS and its constituent basins and sub-basins have been subjected to, and modified by, multiple tectonic events with different orientations and extents, each well defined in the ION WestraliaSPAN data (Figure 5).

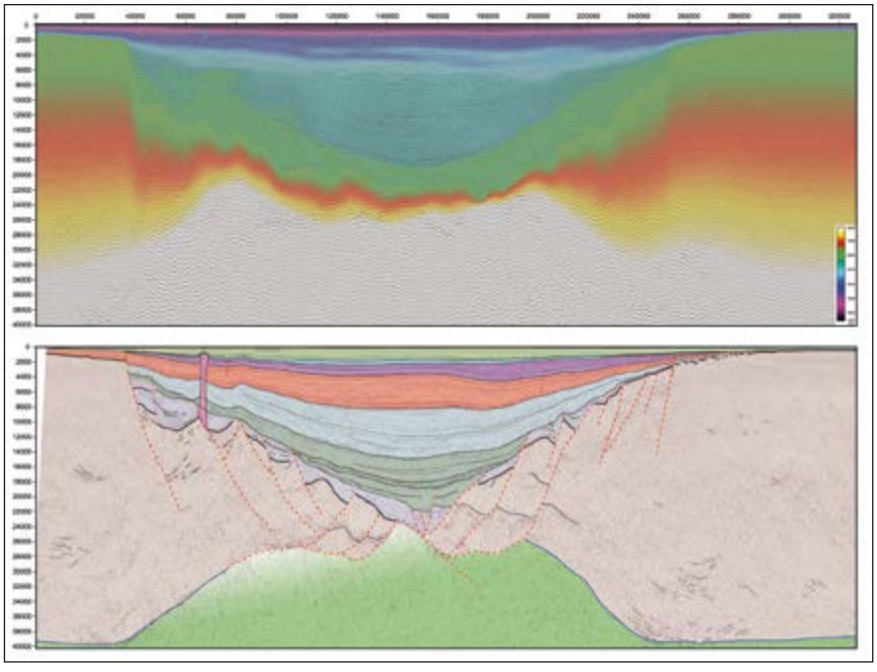
The Importance of Quality Data

Key to progressing our understanding of the NWS has been the availability of long-offset (10km), long-record (18s TWT), regional seismic data that have been pre-stack depth migrated (Figures 2–4). The WestraliaSPAN line layout includes true dip lines orientated so as to accurately image the structural grain of the NWS, while regional strike lines link the constituent basins of the Westralia Superbasin, providing regional links between the provinces of the NWS. This enables construction of regionally consistent models for the geological evolution of the NWS. Beyond careful planning and acquisition, the use of ION's latest imaging and velocity modelling capabilities are the basis for the results. Depth imaging enables complex structures to be viewed with true depth perspective, and permits the regional links between the different provinces to be calibrated. The improved imaging combined with better velocity modelling allows interpreters to see for the first time the full sedimentary section and underlying crustal architecture, distinguishing between what had previously been considered to be continental basement, and sediment.

Implications for Future Prospectivity

Both the North Carnarvon and Bonaparte Basins (Petrel sub-basin) are characterised by thick sediment accumulations, up to 20 km and 24 km respectively. Multiple rifting phases have resulted in hyper-extension of the crust and possibly extensive mantle exhumation in these basins. Sediment supply has generally kept pace

Figure 4. (a) North-west to south-east section across the Bonaparte Basin with the PSDM velocity model overlain. Demonstrates the high velocities attributed to the deep sediments interpreted at over 20 km depth. (b) Geoseismic interpretation of the same line. (See Figure 5 for horizon correlations.)



with the creation of accommodation space, with sediment having been deposited directly onto exhumed continental lithospheric mantle (Figures 2 and 3). A striking feature of the NWS is that it contains an almost complete record of sedimentation throughout the entire Phanerozoic (Figure 5). This is due to the protracted and polyphase nature of stretching events along the NWS, and the comparatively limited periods of uplift and erosion.

The thick sediment sections raise a number of questions and implications for the prospectivity of the basins. The anomalous sediment thicknesses are difficult to balance with traditional crustal extension and subsidence models. Models of hyper-extension and/or mantle exhumation are required to isostatically provide the accommodation space to allow for such deep basins. These models have significant uncertainties as the process of serpentinisation of the underlying lithospheric mantle is extremely difficult to constrain in terms of its extent and impact on density and heat flow. In general, serpentinisation will decrease density and thus suppress subsidence.

In addition, the process of multiphase extension with relatively long time periods between events (see Figure 5) means that the thermal effects of previous rift events will be largely dissipated by the time of the next event, and that both deep sediment and partially serpentinised lithospheric mantle from previous events may be acting essentially as continental crust in later events.

Finally, once the sediment pile reaches a certain thickness, progressively higher grade metamorphism will occur. We can see evidence for this on AU1-5000 (Figure 3) where reflections that appear to be characteristically sedimentary have seismic velocities in the region of 5.5 – >6 kms^{-1}. This increase in seismic velocity (and implicitly density) will serve to drive additional subsidence, creating accommodation space for further sediments. These competing factors driving the subsidence of the margin at different times and in different ways have implications for heat flow and thermal maturation of source rocks. Interpretation of the deep seismic data of the WestraliaSPAN survey provides an image of the architecture, allowing explorers to constrain the structural evolution and integrate existing heat flow and geochemical data to better understand petroleum system history.

Acknowledgement: *The authors would like to acknowledge the team at Frogtech for their interpretation work on the WestraliaSPAN project.*

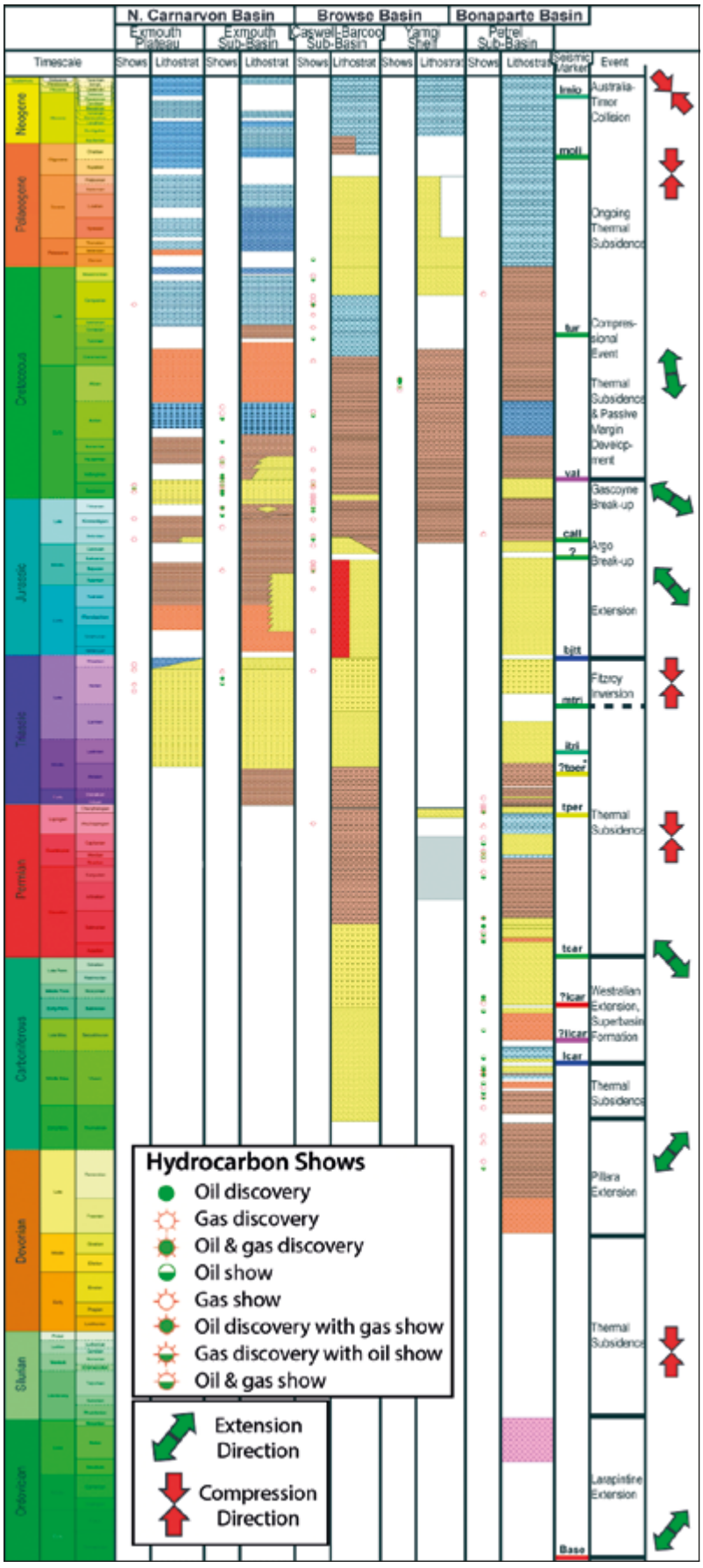
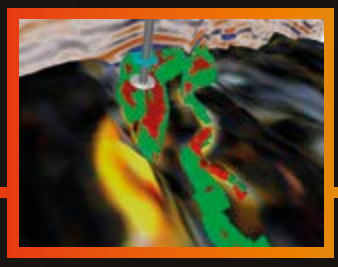


Figure 5: Tectonostratigraphy of the NWS basins discussed. Adapted from Geoscience Australia. Mapped horizons from the seismic sections (Figures 2–4) are shown along with the location of the main oil and gas plays in the basins.

Here for the energy hunters, risk investigators and decision makers.



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Gas Hydrates

PART V: The Resource Potential

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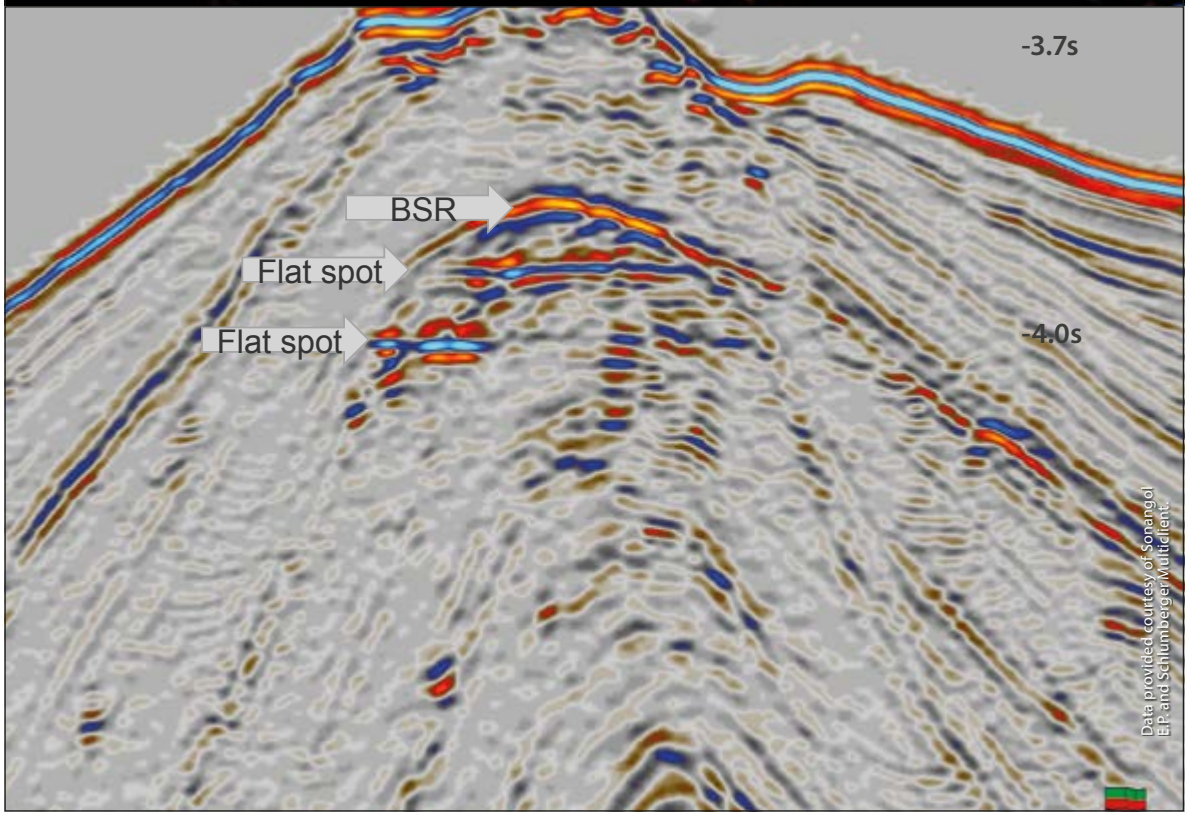
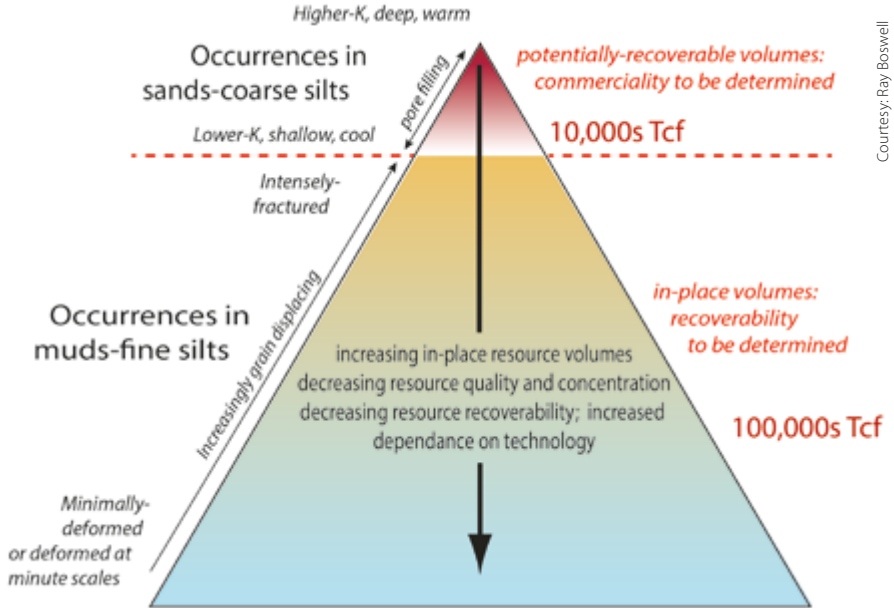
MARTIN LANDRØ, NTNU Trondheim

Seismic feature enhancement of BSR and two underlying flat spots. Courtesy Statoil.



Seismic example of marine gas hydrates above a double flat spot. The contrast between the high-velocity hydrate-bearing strata and the low-velocity gas-bearing strata beneath results in the bottom-simulating reflector (BSR). In this example, the gas hydrates act as seals for underlying hydrocarbon reservoirs. Courtesy: Statoil.

The gas hydrate resource is a function of host geology, technology, policy, and market conditions. The commercial resource and recovery potential of gas hydrate strongly depends on the type of gas hydrate accumulation. We continue our series on gas hydrates (*GEO ExPro*, Vol. 9, No. 3-6) by discussing the resource potential.



Courtesy: Ray Boswell

Gas hydrate resource pyramid: Gas hydrates exist in a variety of forms that pose different opportunities and challenges for energy resource exploration and production. The left axis displays lithology of the host sediment. The right axis shows associated estimates of natural gas resources. Gas hydrate-bearing sands are the most feasible initial targets for energy recovery. Other occurrences, such as gas hydrate-filled fractures in clay-dominated reservoirs, may become potential energy production targets in the long-term future.

Natural gas hydrate occurs worldwide: in oceanic sediments of continental slopes; in deepwater sediments of inland lakes and seas; and in both continental and continental shelf polar sediments. In oceanic sediments, where water depths exceed about 300m and bottom water temperatures approach 0°C, gas hydrate is found at the seafloor and down to sediment depths of about 1,100m. The typical depth range for hydrate stability lies 100–500m beneath the seafloor. In polar continental regions, gas hydrate can occur in sediments at depths ranging from 150 to 2,000m. Occurrences of hydrates within the gas hydrate stability zone (GHSZ) are affected by numerous additional factors, including availability of gas, water, and geological controls. About 98% of the gas hydrates are believed to be concentrated in oceanic sediments, while the other 2% are in polar landmasses.

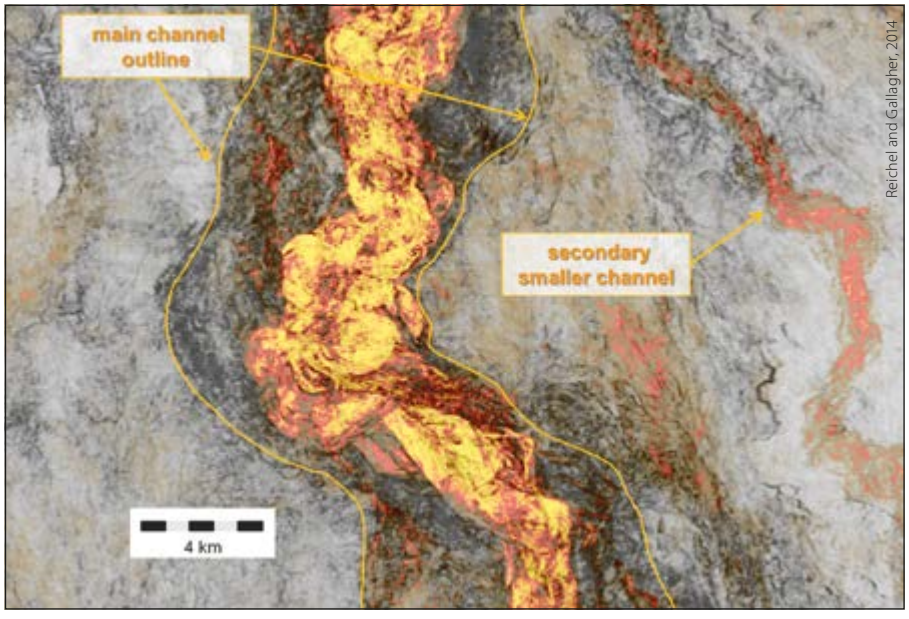
How Much Gas Hydrate Exists?

Gas volumes are often cited in units of trillion cubic feet (Tcf), and there are approximately 35.3 cubic feet in a cubic metre. It is estimated that resources of methane in natural hydrate reservoirs range anywhere from 10^5 to 2.8 x 10^6 Tcf, or around 2.8 x 10^{15} to 8 x 10^{15} m^3, indicating that more carbon is contained in methane hydrate than in all other organic carbon reservoirs on earth combined.

These estimates, however, include hydrate in low-grade shale deposits as well as in high-grade sand deposits. Only a fraction of the methane sequestered in global gas hydrate deposits is likely to be both concentrated and accessible enough to ever be considered a potential target for energy resource exploitation.

The relative amounts of gas hydrate in the global system can be illustrated by the hydrate resource pyramid, which captures the distribution of sequestered methane among the major types of global gas hydrate deposits. Only the hydrates at the top of the pyramid – a small subset of the hydrate deposits – are likely to be considered viable as a source of commercial quantities of natural gas.

Seismic attribute co-blend map (RMS amplitude/coherence) showing sand channels in excess of 150m thick. The bright yellow and orange colours highlight zones with high seismic amplitudes characteristic of sand channels. The displayed interval shows several generations of sand deposits within the gas hydrate stability zone. If charged with gas they could form prospective targets for gas hydrate exploration.



Reichel and Gallagher, 2014

Occurrences in Muds and Coarse Silt: At the top of the pyramid lie high permeability sediments in permafrost areas. The amount of gas hydrate in these settings globally is relatively small, but permafrost-associated gas hydrates might be the easiest to commercialise, particularly in areas with well-developed infrastructure from

conventional hydrocarbon production, such as the Alaskan North Slope.

Gas hydrate resources housed in marine sand reservoirs are also obvious major targets for any longer-term development of gas hydrates as a resource. Highly permeable marine sands with moderate to high gas hydrate saturations are considered the best targets for resource development. Recent logging-while-drilling in the Gulf of Mexico has identified geologic units with inferred hydrate saturations as high as 80%.

Reservoir quality is expected to increase with increasing grain size. However, the primary control of importance may be intrinsic permeability. Sediments of high intrinsic permeability may have the capability to host hydrate at high saturations (50–90% of pore space).

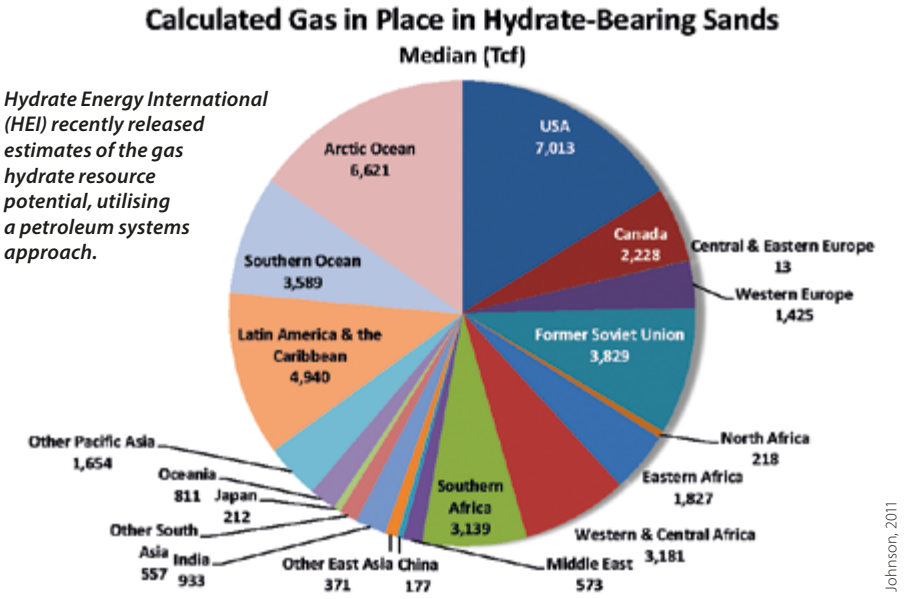
Occurrences in Muds and Fine Silt: Below marine sands in the gas hydrate resource pyramid is the category for muds and fine silt. Fractured muds are less permeable, usually smaller-grained sediments that may host gas hydrates in fracture-related permeability. Drilling on the Indian and Korean margins and in the Gulf of Mexico has found gas hydrate filling pervasive fractures within low permeability sediments (e.g., silts and clays). Such sediments may not have a high average saturation of gas hydrate, maybe around 20%, but targeted production from gas hydrates within the fractures could theoretically yield significant gas.

At the base of the resource pyramid lie gas hydrates in low permeability, undeformed fine-grained muds. Such sediments host most of the global gas in place in methane hydrates and are unlikely to become a target for commercial production of gas from methane hydrates. The saturation typically is only 5%.

Sea-floor mound deposits are small size and ephemeral. They are environmentally sensitive due to associated unique biological communities and thus unattractive as a resource target.

Potential Worldwide

In conventional petroleum systems analysis, the geological components and processes necessary to generate and store hydrocarbons are well established:



source, migration, reservoir, seal, and timing. To apply this petroleum system model to a methane hydrate resource system, one needs also to incorporate the parameters that determine methane hydrate stability conditions: formation temperature and pressure, pore water salinity, water availability, gas source, gas transport, gas concentration, and the time over which the system evolves.

Recently, Hydrate Energy International (HEI), as part of the Global Energy Assessment being conducted by the International Institute for Applied Systems Analysis (IIASA), released the results of a new evaluation of the gas hydrate resource potential, utilising a petroleum systems approach. Their median assessment is around 43,000 Tcf.

Geological Settings of Gas Hydrate

Gas hydrates occur in a wide variety of geologic settings and modes of occurrence. These include gas hydrate concentration, host lithology, distribution within the sediment matrix, burial depth, water depth, and many others. The major controlling factor on where gas hydrate forms is lithology and availability of methane.

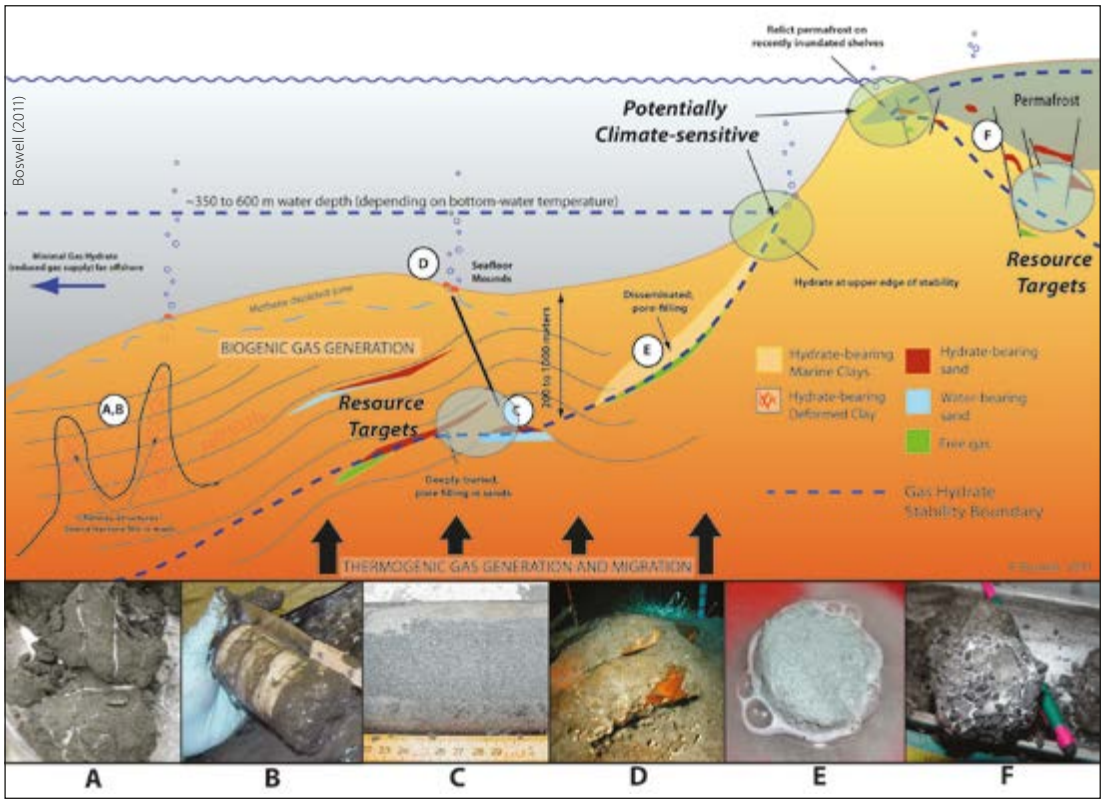
The illustration (next page) from Boswell (2011) gives a schematic depiction of the components of various methane hydrate systems. Examples A and B represent massive forms in hydrate-bearing marine clays. Example C shows a hydrate-bearing marine sand. Examples D and E represent sea-floor mounds (outcrops) and hydrate-bearing clays (finely dispersed).

Three dominant types of gas hydrate accumulations can be defined and distinguished based on the mode of fluid migration and gas hydrate concentration within the GHSZ (Milkov and Sassen, 2002). The end-members are structural and stratigraphic accumulations, but combination accumulations controlled both by structures and stratigraphy may occur.

Structural Accumulations: Structural gas hydrate accumulations occur in advective high fluid flux settings, where highly permeable fractured conduits like fault systems, mud volcanoes and other geological structures facilitate rapid fluid transport from depth into the GHSZ. The gas hydrate concentration in the sediments is relatively high. Gas hydrate deposits associated with active faults and craters of deepwater mud volcanoes usually present high gas hydrate concentrations, with 30–50% of the pore space filled by hydrates.

The shallow seafloor consists typically of non-consolidated silts and clays. Various types of gas hydrates may occur: layers of hydrates of thicknesses from millimetres to tens of centimetres, massive hydrate deposits, or hydrate outcrops (mounds) on the seafloor.

Bottom-simulating reflectors (BSRs) are not common in structural accumulations as they do not typically seal much gas below the gas hydrate layer. If present, they are patchy and displaced



A schematic depiction of the components of various methane hydrate systems. Typical methane hydrate reservoir morphologies include (A) networks of hydrate-filled veins; (B) massive hydrate lenses; (C) grain-filling methane hydrate in marine sands (Japan); (D) massive sea-floor mounds (Gulf of Mexico, USA); (E) grain-filling methane hydrate in marine clays; (F) grain-filling methane hydrate in onshore arctic sands/conglomerates. The general location of the most resource-relevant (blue circles) and most climate-relevant (green circles) methane hydrate occurrences are also shown. Other parts of the methane hydrate system as depicted include the relationship between microbial and thermogenic gas sources and gas migration controls.

and they do not parallel the seafloor.

Stratigraphic Accumulations: Stratigraphic gas hydrate accumulations generally occur in advective low fluid flux settings within passive margins in relatively coarse-grained sediments, from biogenic methane gas generated in situ, or gas which is slowly supplied from deeper in the subsurface.

In stratigraphic accumulations, gas hydrate tends to be highly dispersed through the GHSZ, and low hydrate concentrations are commonly measured; 1–12% of the pore space is filled by hydrates. The low hydrate concentration can be explained by the low permeability and porosity in clay-rich sediments, which hinder the mobility of both water and gas, necessary for hydrate formation. Most of the hydrate in clay-dominated sediments is present in a network of tiny fractures.

However, there are significant exceptions. Both the lithostatic pressure (depth) and the sediment type influence how the gas hydrate will occupy the sediment pore space. Deeper in the sediment column below the seafloor, the hydrate cannot overcome the lithostatic pressure between the sediment grains and must reside in the pore space or in fractures. For coarse-grained sediments, such as sands, hydrates can become highly saturated.

A well-known example is the Nankai Trough, where gas hydrate occupies up to 82% of pores in thin but very permeable sand units. The Nankai Trough is located beneath the Pacific Ocean off the south-east coast of Japan, and is known as an active subduction and earthquake zone. BSRs are commonly observed on the eastern Nankai margin. This is to date the only place where a successful gas hydrate production test has been performed.

Mapping of Gas Hydrate

Interpretation of seismic data provides the most important means for mapping and characterising the distribution of gas hydrates and possible underlying free gas. Shallow high-amplitude events can be generated by features other than gas hydrate – for example, carbonate-cemented zones, layered clays, the bases of mass transport complexes, and unconformities. However, the presence of seismic bottom-simulating reflectors is the most common indicator of the presence of gas hydrate. The BSR is often a strong, coherent reflector that lies at the base of the gas hydrate stability zone and is overlain by sediments containing gas hydrate and underlain by sediments containing free gas. The BSR has negative reflection amplitude caused by the difference in elastic impedance. The base of the free-gas zone is rarely evident in the seismic section and the concentration of free gas is thought to decrease gradually downward to water-saturated sediments. In rare cases we may observe a flat spot – in exceptional cases, as in the illustration on page 64, even two – beneath the BSR.

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Kirkuk
A Silent Giant Oilfield

The giant Kirkuk field, discovered in 1927, has had a very chequered history and requires imaginative reservoir engineering methods to return it to optimum productivity.

MUNIM AL-RAWI, Ph.D., Carta Design Ltd.

The Kirkuk oilfield is partly located in the Kirkuk Governorate in north-eastern Iraq and partly in the Erbil Governorate in Kurdistan Iraq. It was discovered by the Turkish Petroleum Company at Baba Gurgur in 1927 and was brought into production by the Iraq Petroleum Company (IPC) in 1934, which produced it until full nationalisation in 1972. From then it was operated by the Iraqi National Oil Company (INOC) until 1989 when the North Oil Company (NOC), a state-owned company, replaced INOC in the operation of the Kirkuk oilfield (see *GEO ExPro* Vol. 6 No. 2 for a fuller history of the discovery of the field). On 11 July 2014 Kurdistan Regional Government (KRG) forces seized control of the field, and it is reportedly pumping 120 Mbopd from Kirkuk and the nearby Bai Hassan field via the KRG export pipeline, which runs to the Turkish port of Ceyhan on the Sea.

This giant field, managed by different operators and at the centre of a very troubled and much fought over region, has silently suffered a great deal of reservoir damage.

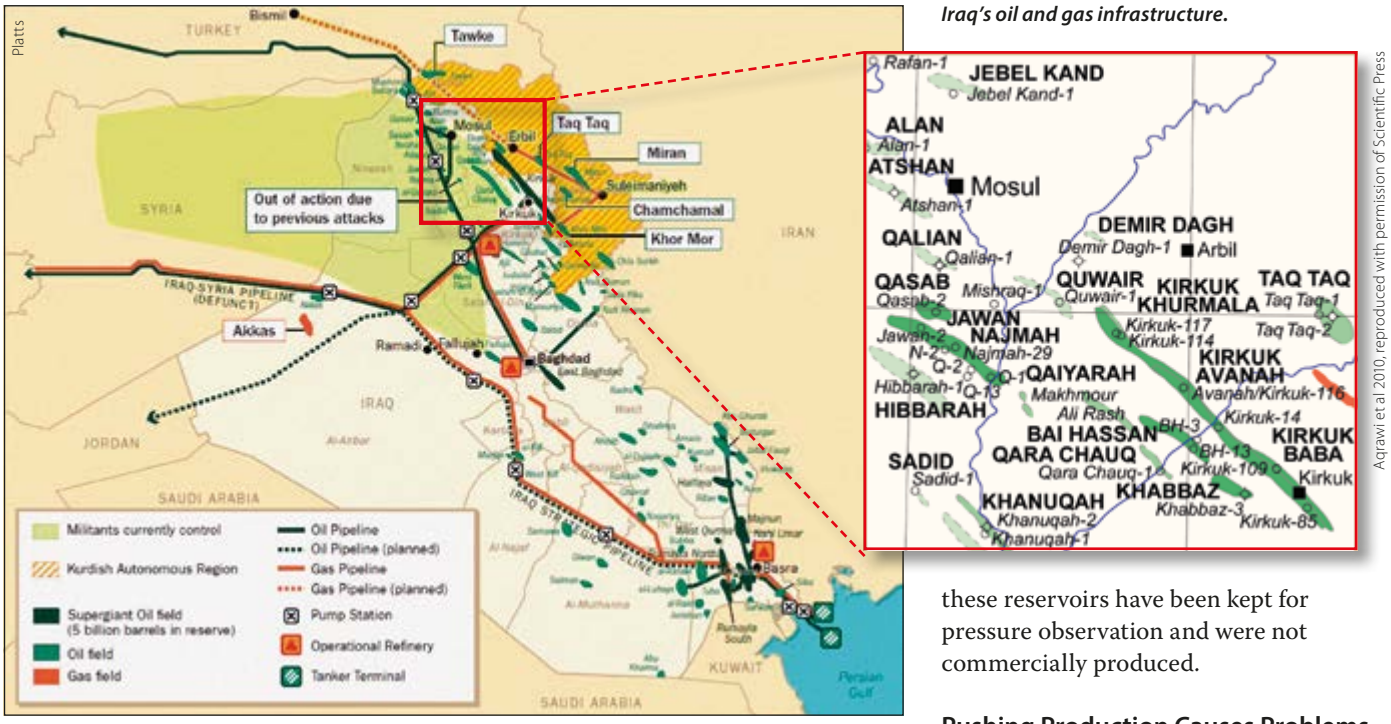
Kirkuk includes three pay zones. The first, the Kirkuk Tertiary Reservoir, is the largest producing reservoir in Kirkuk and comprises 98% of Kirkuk's recoverable reserves. The second and third pays in the Upper and Middle Cretaceous are small and non-producing.

The original oil in place reserves of Kirkuk were estimated at 38 Bbo. Since 1934, the field has remained the most important producer in northern Iraq, with over 8.9 Bbo proven remaining oil reserves in 2007. After eight decades in operation, and many reservoir problems, Kirkuk still produces 0.5 MMbopd.

In the subsurface, Kirkuk is an anticlinal structure trending north-west to south-east, 100 km long and 4 km wide at the original oil/water contact level in the Tertiary Reservoir. Structurally, it is composed of three domes, referred to, from south-east to north-west, as Baba, Avanah and Khurmala, which are separated by

Eternal fires (burning gas seeps on the Baba Dome at Kirkuk) with Kirkuk production facilities in the background (photo taken on a field visit by BP in 1988).

Photo courtesy Robin Cleverly/BP



Iraq's oil and gas infrastructure.

saddles, namely Amshe and Dibega. At the surface, however, it is a simple folded structure due to the Miocene salt flowage of the Lower Fars Formation.

Reservoir Geology

The Eocene-Oligocene Kirkuk Tertiary Reservoir is 365m (1,200 ft) thick and consists of a series of extensively fractured limestones, some porcelaneous and some dolomitised. These limestones were deposited in a variety of environments, including back-reef/lagoonal, fore-reef, and basinal, and have a wide range of porosity and permeability properties. The Oligocene Bajawan, Baba, Tarjil, and Palani Formations, which belong to the Kirkuk Group, are producing in Baba Dome, while the Eocene below, namely the Avanah and Jaddala Formations, are producing in the Avanah and Khurmala Domes.

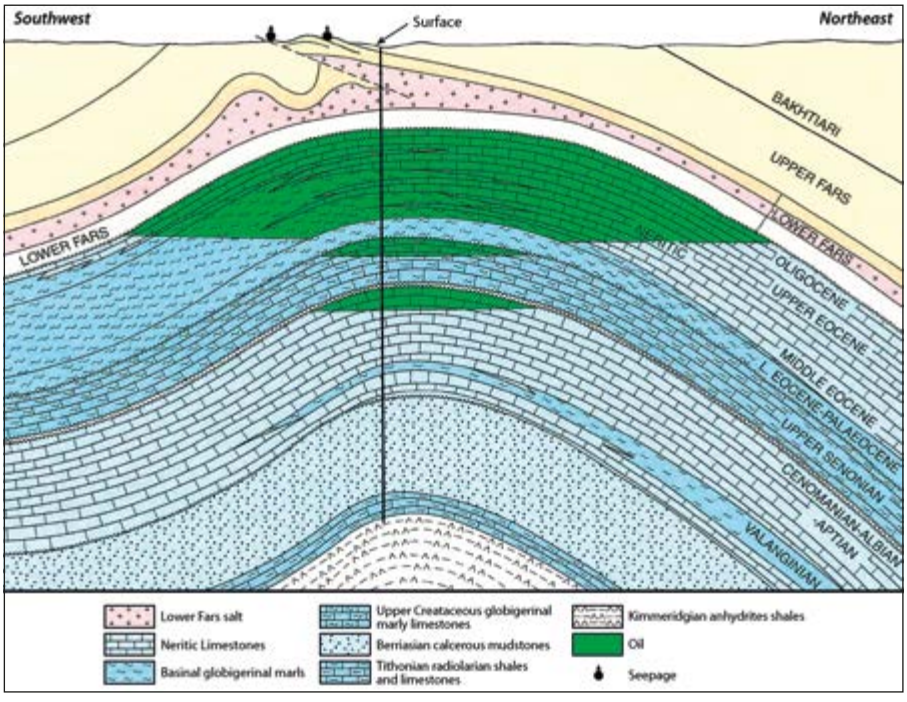
The oil is contained both in an extensive, extremely permeable but low-capacity fracture system and in a low-permeability but high-capacity, matrix-pore system. The porosity and permeability of the carbonates of the Kirkuk Group are usually good; some wells within the Baba Dome produced 100,000 bopd. The porosity ranges from 15 to 25% (averaging about 22%) and the average permeability is about 100 mD. The API gravity of oil ranges from 18° to 36° (average 30°) and was approximately 500 psi undersaturated at the original reservoir pressure of 1,100 psi. Sulphur content is 1.5–4%. The reservoir is underlain by a field-wide aquifer.

The other two reservoirs in the Kirkuk oilfield are the Upper Cretaceous Shiranish Formation and the Middle Cretaceous Upper Qamchuqa Formation. They are fractured carbonates, contain oil and gas, and are likely in communication with the first pay reservoirs. However, these reservoirs have been kept for pressure observation and were not commercially produced.

Pushing Production Causes Problems

As of January 1989, the original oil in place reserves of the Kirkuk oilfield were estimated at 38,045 MMbo, proven remaining oil reserves were 10,238 MMbo, and the cumulative oil production to end 1988 was 12,017 MMbo. Proven remaining oil reserves were reported as of January 2007 to be 8,973 MMbo, including estimated reserves for Khurmala Dome of 2,800 MMbo in place with 1,000 MMbo recoverable.

Schematic cross-section of Kirkuk Baba Dome; not to scale. Modified after Dunnington, 1958, Figure 17.



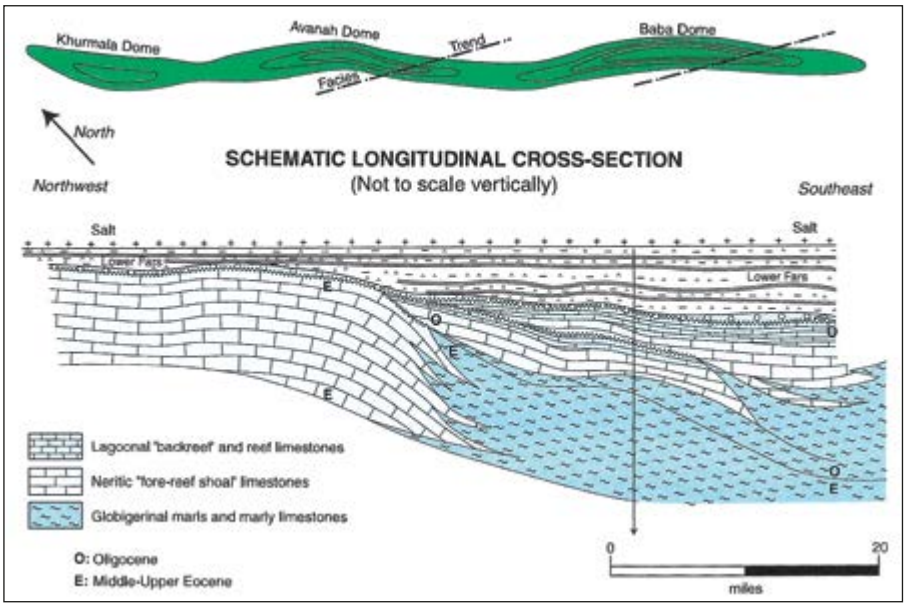
Production at Kirkuk started in 1934 from the Kirkuk Tertiary Reservoir in the Baba and Avanah Domes only, continuing at a low rate for the first twenty years of production. From 1951, however, there was a rapid five-fold increase in production over just three years. The reservoir is characterised by a density of fractures in the entire structure, but particularly in the structurally higher zones. This quick increase in production resulted in a rapid decline in reservoir pressure, and caused the creation of secondary gas caps in both Baba and Avanah Domes, since the water drive force is weak, as well as a small rise in the oil/water contact.

To maintain reservoir pressure, it was decided to use water injection, with, as a temporary measure until the start of water injection, gas from the nearby Bai Hassan being injected into Kirkuk from 1957 to 1961; 200 Bcfg was injected in total.

Water injection started in 1961 at Amshe Saddle. Despite the wide distribution of injected water in the Baba and Avanah Domes, it did not reach the south-east part of Baba Dome or the north-west part of Avanah Dome in equal amounts, which caused a rise of the oil/water contact in the producing regions of Baba and Avanah Domes, which in turn had a domal effect on the contact. In 1970 water injection commenced in the Tarjil area (south-east of Baba Dome), followed in 1978 by water injection in north-west Avanah Dome.

It is important to note that production of oil from the Kirkuk Tertiary Reservoir is done by the removal of oil from fractures, vugs and large pores through water swapping in a rapid or instantaneous manner, and also by imbibition, where water replaces oil in small pores, in a slow process that requires time. Assessment of the imbibition process and the rate of oil recovery and remaining oil in the flooded areas of the reservoir are the subject of ongoing reservoir engineering and laboratory studies.

A continuous increase in production rates requires the drilling of wells to replace those flooded by water because of the rising oil/water contact. The total numbers of wells drilled rose from 162 in 1964 to 230 by 1989.



Schematic longitudinal cross-section of Kirkuk field. Modified after Dunnington, 1958, Figure 18.

Unique Reservoir Needs Help

An analysis of this outstanding Kirkuk Tertiary Reservoir reveals a number of factors affecting reservoir behaviour. These include:

1. Calculating the actual percentage of fractures and vugs within the reservoir, which affects the oil reserves volume and recovery factor calculations of the original oil in place in rock matrix and fractures. Current estimates are that 95% of oil is in the matrix and 5% is in fractures.
2. Reservoir water salinity is low, dropping to 90,000 ppm. Measurements taken before the start of water injection indicate that it has changed in the three domes, which makes it difficult to calculate the original water saturation. Water injection has altered the salinity in the fracture areas.
3. Mud loss during well drilling in the highly fractured areas of the reservoir makes it difficult to measure reservoir resistivity and water saturation.
4. Due to the variation in the reservoir rock characteristics and fractures, it is also difficult to precisely simulate reservoir behaviour.
5. There are difficulties in evaluating the level of water saturation in flooded areas, and in estimating how much oil remains in the reservoir.
6. Declining crude oil qualities and increased 'water cut' (damaging intrusions of water into oil reservoirs) were probably the result of over pumping. Production from Kirkuk reached as high as 680,000 bpd, well above the field's estimated optimal production rate of 250,000 bpd. Iraq attempted to sell as much

Estimated reserves and production for the Kirkuk field.

Reservoirs	Kirkuk Tertiary (MMbo)	Cretaceous Shiranish & Qamchuqa (MMbo)
Original OIP	37,285	760
Recovery Factor %	60	36
Proven Recoverable 2P Reserves	22,255	275
Cumulative Production, End 1988	12,017	0
Proven Remaining Reserves, End 1988	10,238	275
Cumulative Production, End 2006	1,541	0
Remaining Reserves, End 2006	8,698	275
Total Kirkuk Remaining Reserves, End 2006	8,973	

oil as possible in the months leading up to the March/April 2003 war.

7. In addition, some analysts believe that poor reservoir management practices during the first Gulf war between 1981 and 1988, including the reinjection into the periphery of the Baba Dome of excess fuel oil (as much as 1.5 Bbo by one estimate), refinery residue and gas-stripped oil, may have seriously, even permanently, damaged the Kirkuk Tertiary producing reservoir. Among other problems, fuel oil reinjection has increased oil viscosity at Kirkuk, making it more difficult and expensive to get the oil out of the ground.

The unique Kirkuk Tertiary Reservoir has suffered a great deal from different management practices and will require imaginative reservoir engineering methods to put it back into good productive order. Some reappraisal has already been undertaken and will require full implementation on the ground to achieve results.

In September 2013, BP signed a letter of intent to help revive this ageing oilfield through a better understanding of the state of the Kirkuk reservoir. For BP, the agreement could be a first step toward clinching a longer-term development contract. Will the current political status in Iraq allow Kirkuk to be productive again?

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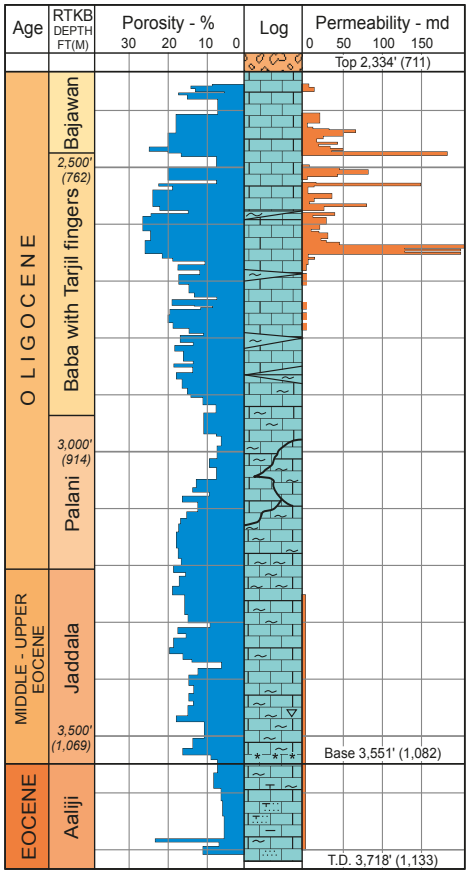


Kirkuk Tertiary Reservoir characteristics, Well K-115. Modified after INOC, 1987.

Decarbonising Energy

Scientists tells us that any rise in global temperatures needs to be limited to less than two degrees over pre-industrial times. Displacing coal is the primary focus. Does gas provide a useful stepping stone to a decarbonised future?

NIKKI JONES

The level of carbon dioxide in the atmosphere last year surged at its fastest rate in 30 years according to the UN Meteorological Organisation, possibly indicating that the world's oceans and forests are no longer able to store the gas as they have done in the past. Although the world is aiming at emission levels of 1 to 1.5 tons per head per year, we are currently close to 40bn tons annually across the globe and on track for a four degree warming by the end of the century, a temperature that will change both the human and physical geography of the planet.

Governments' options are varied but unpleasant – stopping deforestation, discouraging livestock farming (to curb methane production), reducing international travel and trade, cutting consumption generally. Faced with such unpopular choices governments are looking for substitutes to the fossil fuels that are the source of 87% of global human carbon dioxide emissions. Power production is the primary focus given the global move towards the electrification of heat and transport.

Coal-fired power generation is seen as the primary culprit as, at the power plant, it produces roughly twice the emissions of gas – as well as health damaging, smog-creating pollution. The low efficiency of most coal-fired plants – a global average of 33% – has helped focus the attention of governments.

However, according to the IEA, in 2014 coal was still the world's principal fuel for the generation of electrical power, a total of 1,700 gigawatts, 41% of global consumption. This has been fuelled by low prices as exports from the US have surged, following the shale boom, and there has been increased production from Australia, Indonesia, Colombia and South Africa. China's growth has fuelled this ramping up: the country now accounts for almost half of global coal consumption, a marked increase on its 25% share two decades ago.

There has been a fair amount of finger-pointing at China but, in fact, neither the US nor Europe have managed to wean themselves off coal. In Europe coal consumption began rising again in 2009, fuelled by the failure of the carbon pricing mechanism, as well as Germany's closure of nuclear plants. US consumption has been declining, but the Environment Protection Agency still anticipates coal will produce 30% of America's power in 2030. Creeping up on the inside, India accounted for 21% of global growth in 2013 and is set to overtake China as the world's biggest coal importer.

Tiananmen Square enveloped by heavy fog and haze in January 2013. Many of China's cities face serious air pollution and poor air quality.

axz65/123RF.com

Gas as a Substitute

The industry is pushing gas as a substitute, claiming that it is far cleaner than coal and can have the added advantage of relatively speedy reaction to fluctuations in grid demand. Instability in grids has been heightened by the switch towards intermittent renewables, now generating 22% of the world's electricity. In recent months Japan has announced that it is closing its grid to large-scale renewable generation because of this problem.

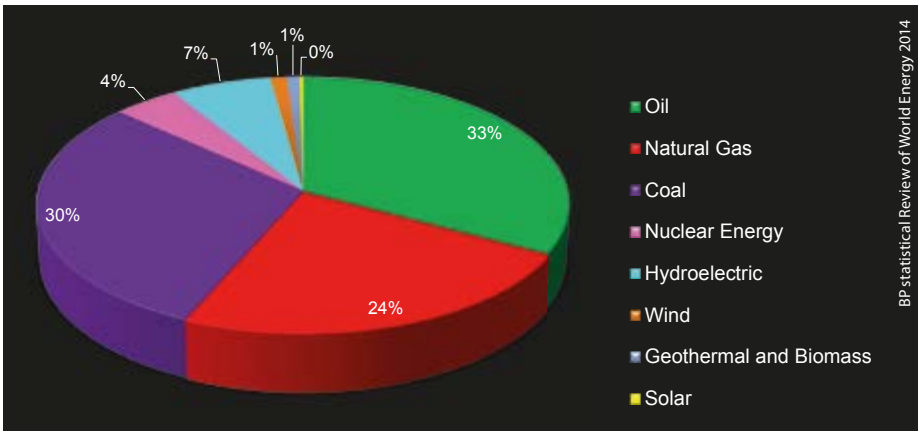
Backing up the argument for gas, manufacturers are now show-casing larger and more efficient turbines, capable of ramping up to full power within 30 minutes and with relatively low turn-down levels (40%).

However, both the industry and governments are asking searching questions, not only about the economics of a shift to gas but also security of supply and the actual claims of comparative cleanliness.

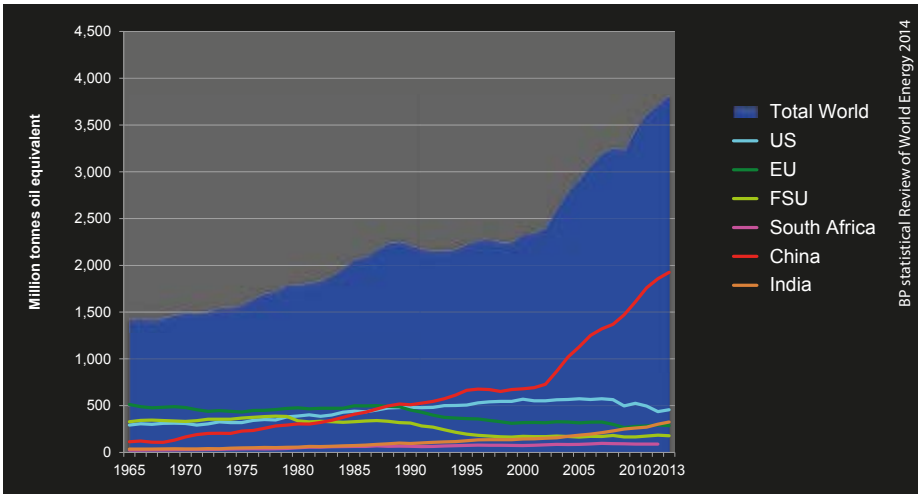
The argument for gas lies in the fact that it is twice as clean as coal *at the power plant*. However, there is real difficulty in comparing the two fuels when the whole production-fuel cycle is factored in, since each coal and gas field has its own production methods, processing requirements and different distances from markets. Emission levels will depend greatly on the CO_2 concentration in the raw gas, which can be as high as 14% mol, and processing and transport add substantially to the equation. LNG requires the super-cooling of gas to -162°C, ocean shipping in cryogenic sea vessels, regasification and pipeline distribution. There are wide variations in thermal efficiencies at liquefication and regasification stages dependent on the type of gas turbine used and the choice of process when reheating, and 85% of current carriers are fuelled by low efficiency (approximately 27%) heavy fuel il and boil-off gas. One estimate is that LNG, usually transported over distances of 3,000 km or more, consumes, on average, 25% of the energy transported.

Gas pipeline transmission has, to an extent, been below the radar, but a recent European Commission study found that over long distances (~7,500 km) pipeline greenhouse gas emissions are equal to those from LNG transport. These emissions are associated with the energy required to overcome frictional losses and also to maintain the pressure in the line.

Local leakages in distribution networks – almost 100% methane – are also a significant factor. In July this year the EPA reported that fugitive emissions from distribution pipelines in 2012 accounted for more than 13 million metric tons of carbon dioxide equivalent emissions, 10% of the total coming from the US natural gas industry.



Global energy consumption 2013.



Coal consumption in selected countries since 1965.

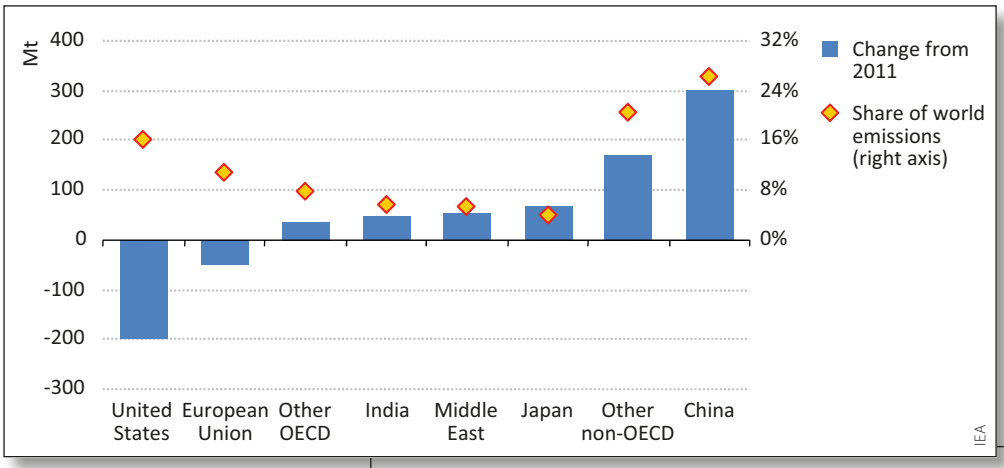
Emissions in Gas Production

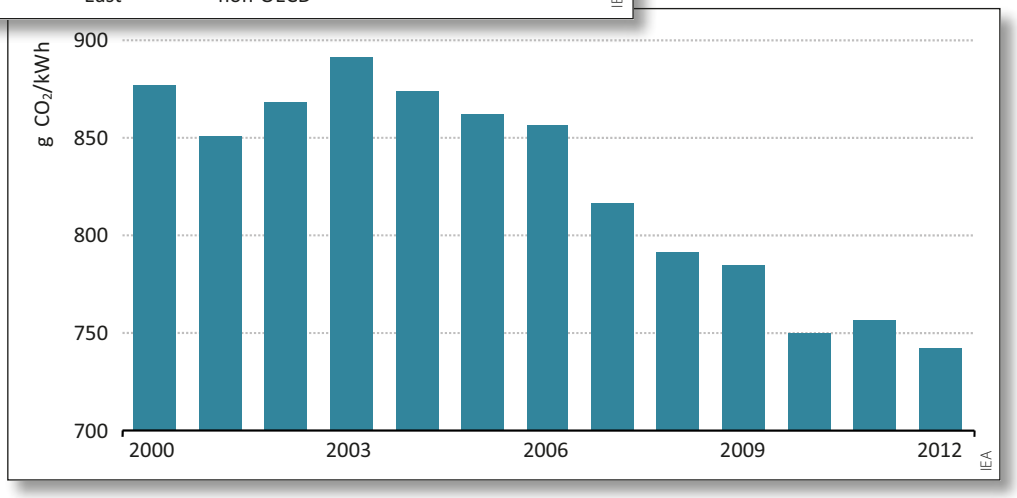
Emissions associated with conventional production (still the major source of gas) have also not been factored in to the 'cleanliness' argument. They depend on the energy used in dehydrating the gas, sending it to a treatment plant, guaranteeing the energy supply to the facilities and enhancing production with water injection, plus the characteristics of the gas produced. Analysts Altran Italia calculate that greenhouse gas emissions at this stage are typically between 0.95 and 1.5 kg/m mBtu, 15% of which are fugitive emissions and 5% flaring.

Emissions for shale gas, tight gas and coalbed methane are far higher than conventional gas sources. According to the IEA, this is partly because of the need for more wells and more hydraulic fracturing in order to maintain output – usually powered by diesel motors – and partly because of more flaring and venting during well completion. During the early flow-back period, when there is more fracking fluid than hydrocarbons, companies do not always separate and process the gas: at this stage it is mostly methane with a small fraction of volatile organic compounds. These emission levels are compounded by fugitive emissions plus incidents of ruptured equipment. There is also a need for local transportation, and there are emissions associated with water supply and waste water management.

Is Gas the Answer?

Despite these considerations, governments appear to have been





Left: CO_2 emissions trends in 2013. Below: CO_2 emissions per unit of electricity generation in China. While China made the largest contribution to the global increase in CO_2 emissions in 2012, this level of growth is one of the smallest in the past decade, reflecting China's efforts in installing low carbon generating capacity.

swayed towards the environmental benefits of gas – though they are more hesitant when considering the economics and the geo-strategic risks. Energy security has risen on the political agenda: in particular, the Ukrainian crisis has focused European minds on the continent's dependence on Russia, since approximately 30% of its gas comes from its neighbour.

If Europe is to pursue a new dash-for-gas, there are few economic, secure, politically acceptable sources of growth on offer. The most likely are Qatar, which already provides 10% of Europe's gas, and the Southern Gas Corridor through Azerbaijan, Georgia and Turkey, which is expected to supply 20% of Europe's needs by late 2018. Neither offer security of supply and the Caspian gas solution still requires another $28bn just to bring gas to the Georgian-Turkish border. Increased gas from Russia is unlikely given the current political climate. The South Stream pipeline, which would have brought Russian gas to Europe via Bulgaria, has been put on hold, and sanctions against Russia have effectively halted Russian shale and Arctic production.

China, like Europe, is heavily dependent on Russia, though this is less politically troublesome: approximately 40% of China's gas comes from central Asia and this year the government finally signed a $400bn deal with Gazprom.

At first glance the US gas glut offers a solution. Producers are begging to export as production in the Marcellus basin alone is up 800% over the last five years, and in September the local spot price plunged to a seemingly unviable low of $1.5686 per mBtu. Three LNG export projects have got the go-ahead to begin construction and 13 more have filed for approval, plus there are proposals for another 13 plants on the west coast of Canada.

However, the argument of energy security from the US falters if the US gas glut is not assured for decades ahead: even before the current oil price collapse, many were arguing that simply increasing the concentration of fracking wells was unsustainable and that production would stagnate in the early 2020s. Current prices have only exacerbated those fears. Nor is US shale gas a cheap solution when investments into liquefication, transport and regasification are added to the equation. In June this year the IEA warned that the high capital costs – an expected $735bn by 2035 – are likely to constrain the LNG industry.

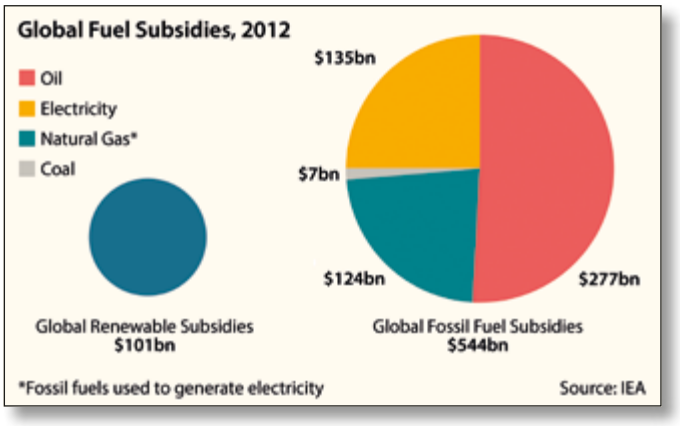
Is local unconventional exploration the answer? Germany has, this year, relaxed its opposition to fracking and the UK government has come off the fence and given full support to the industry. China has been issuing fracking licences for several years. But commercial viability remains unclear and given the generally higher environmental regulations and political objections in Europe, it seems unlikely that shale gas will make a serious, near-term impact on supply or price.

The Opportunity Cost

It appears that there is no clear win for gas on the three key criteria: cost, security of supply or even cleanliness. Its utility is as a back-up for the intermittency of renewables and some governments in Europe are now pursuing capacity mechanism strategies, paying producers for potential rather than actual output.

However, each dollar invested in gas locks the world further into a future of burning hydrocarbons that scientists tell us we cannot afford. Each dollar invested in gas is a dollar that isn't invested in more and diversified renewables, or the storage and transmissions research needed to overcome the intermittency problems. It has been likened to dieting on fat-free biscuits – i.e. not addressing the fundamental problem.

Although green investment is on the rise again after a few years of decline, mainly in China and Japan, the amounts spent – $56bn from China last year, $48bn in Europe and $36bn in the US – continue to be dwarfed by the $600bn given to the fossil fuel industry in subsidies. Now that many renewable sources appear to have achieved cost competitiveness with gas-fired power, scientists and environmentalists are arguing this investment needs to be diverted into energy conservation (which, according to the IEA, has already delivered a 5% cut in consumption across 18 OECD countries 2001–2011), interconnectors and inter-country markets. For Europe, that means geothermal from Iceland, solar from north Africa, wind from Spain; China and the US have similar opportunities with fewer political complications.



The Risks

Without really clear government direction, the risk is that coal will continue to win out on cost and security-of-supply concerns. In Europe a late October summit has delivered a target of 40% cuts to greenhouse gas emissions by 2030 (from 1990 levels) but following pressure from east European states that are heavily coal dependent, countries do not have targets for renewable generation. In the US a Clean Power Plan is targeting coal-fired power plants, but coal is still expected to supply 30% of the country's needs in 2030. A new wave of hydroelectric stations mean that no new coal fired plants will be built in China's industrialised east, but the country will remain heavily dependent on coal for the foreseeable future. The greatest threat to reducing coal consumption is the current glut and low price, not government decisiveness. It appears that governments are simply side-stepping the four degree problem. ■

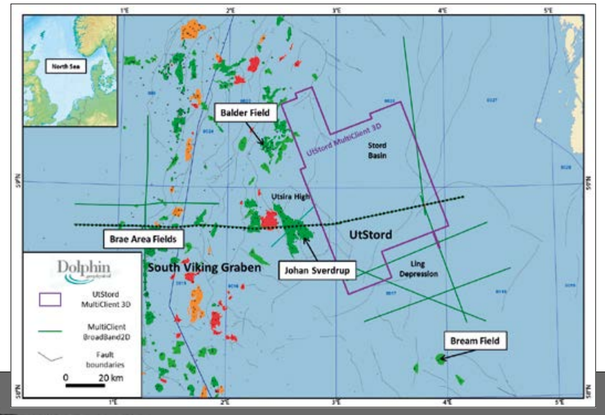
A coal-fired power plant adding its emissions to the atmosphere. Unfortunately carbon capture and storage is not the hoped-for solution. This year SaskPower in Canada launched the world's first large project but the problem of CO_2 leakage has not been overcome and the technology doubles capital outlays and reduces the amount of electricity to sell.

3D Seismic and SHarp Broadband 2D

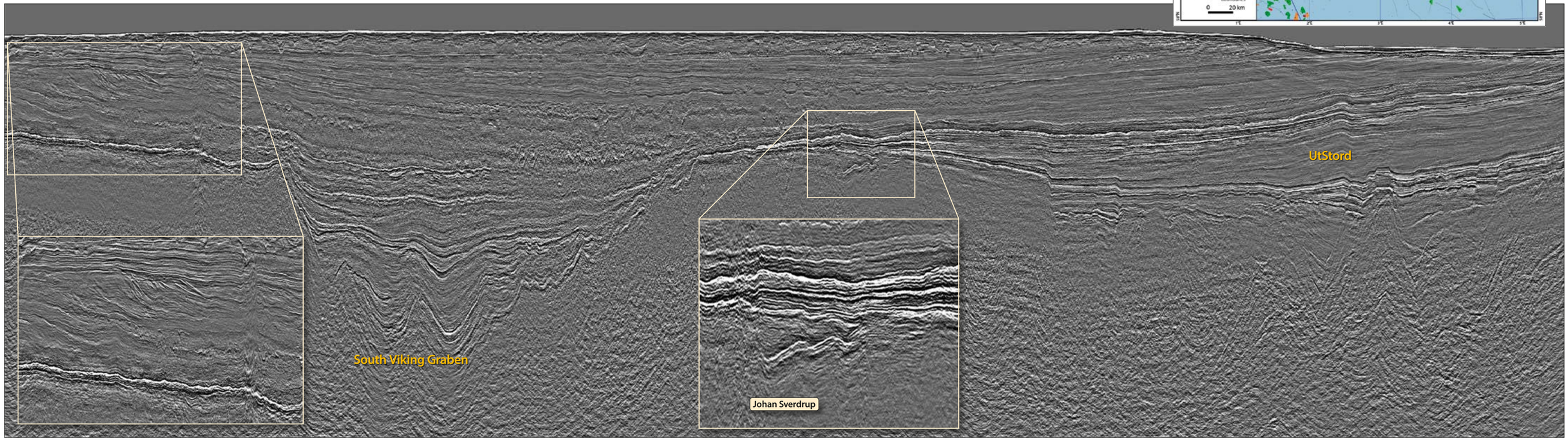
UtStord and South Viking Graben

3D seismic and SHarp Broadband 2D from the UtStord and South Viking Graben areas of the UK-Norwegian North Sea show improved imaging throughout the entire geological section.

In 2013 Dolphin Geophysical's *MV Polar Duchess* acquired a multi-client 3D seismic survey in the UtStord area of the Norwegian North Sea, covering 5,080 km^2. Also in 2013, Dolphin Geophysical's *MV Artemis Atlantic* acquired a multi-client 2D SHarp Broadband survey covering 1,050 km in total, extending across both UK and Norwegian waters over the UtStord and South Viking Graben areas. The 3D seismic survey extends over three main structural elements, namely the Utsira High, the southern part of the Stord Basin, and the northern part of the Ling Depression. The 2D SHarp Broadband seismic lines tie to key wells in the 3D area, extend across the Johan Sverdrup region, and link with a series of discoveries extending across both the UK and Norwegian sectors of the North Sea. The east–west regional coverage extends from the Brae area fields, which were discovered in the 1970s and started production in the 1980s, to the relatively recently discovered fields, such as Johan Sverdrup, situated in the Utsira High area.



Location of Dolphin Geophysical's UtStord 3D seismic and SHarp Broadband 2D lines in relation to key structural elements and discoveries.



Improved Imaging Throughout

NICOLAS HAND and DAVID JACKSON, Dolphin Geophysical

Examples demonstrate the tectonic styles and potential of the UtStord and South Viking Graben areas.

The Utsira High was initally explored by ExxonMobil, who were awarded the very first exploration licences on the Norwegian Continental Shelf in 1965. The first oil from the Norwegian Continental Shelf was produced from well 25/11-1, and the reservoir was of Tertiary Age. In more recent times the story of the major Johan Sverdrup discovery has made all the headlines. The oil and gas associated with the Johan Sverdrup area is reservoired in strata of Triassic to Mid-Upper Jurassic age.

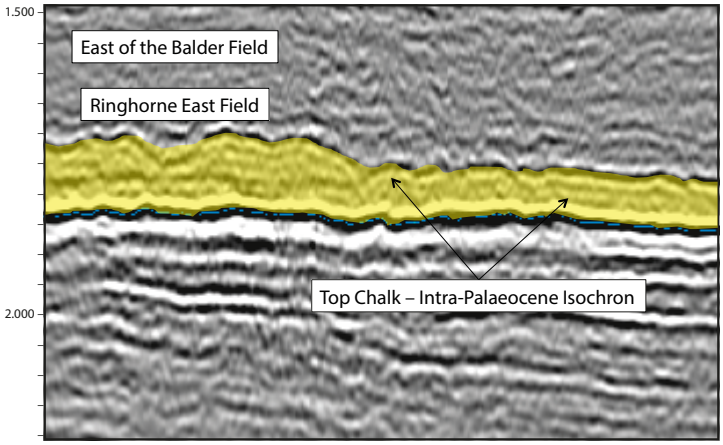


Figure 1: A sample of Dolphin UtStord 3D at the Top Chalk-Palaeocene level

Geological Overview

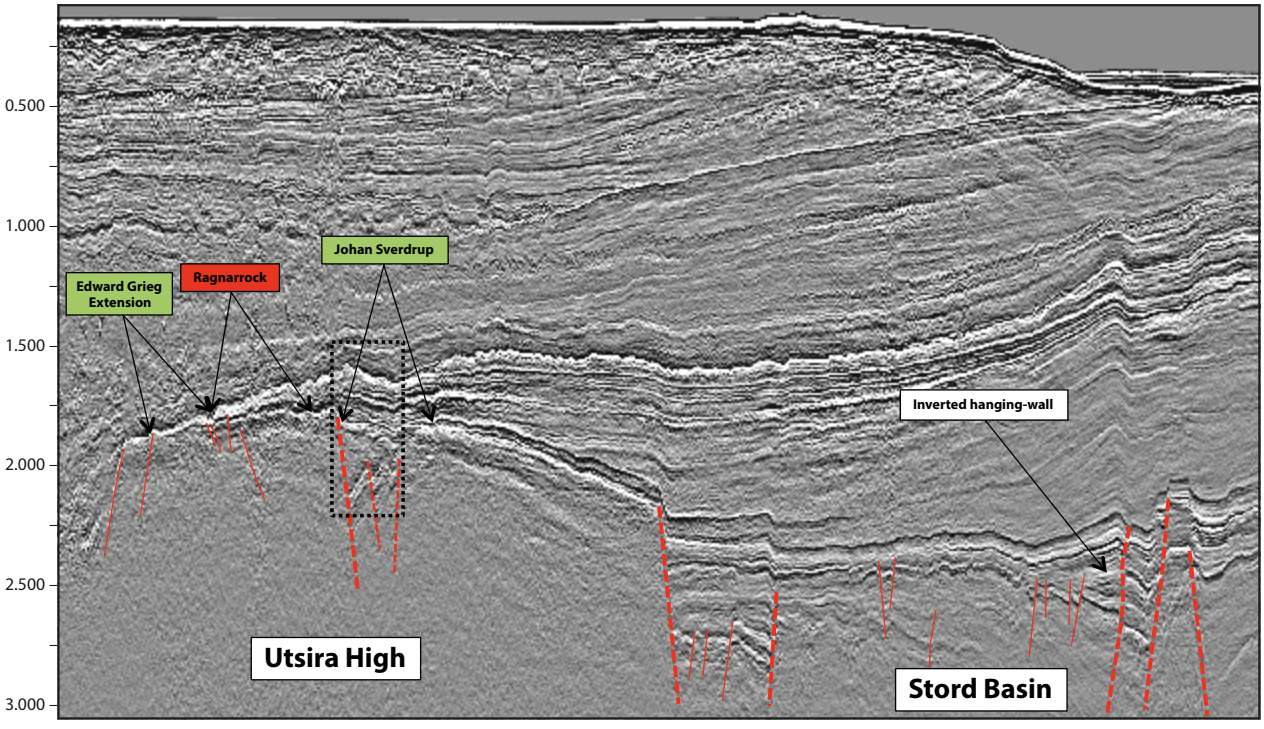
To the east of the Utsira High lies the Stord Basin, which was formed by multiple phases of extension which began in the Triassic, and continued with further pulses of extension during the Middle and Upper Jurassic. The faults are steeply dipping and planar in the shallower parts of the basin, but exhibit clear listric geometries at depth. Some of the faults have been reactivated in the Early Tertiary, which led to structural inversion geometries, such as hanging-wall folds, following the trends of these reactivated faults.

The Ling Depression lies to the south and east of the Utsira High, and the tectonics in this area indicate that rifting in the Carboniferous(?)-Permian has been overprinted by later Triassic-Jurassic rifting. The structuring in the area is a result of the interaction of multiple rifting events, salt withdrawal and subsidence.

To show the different tectonic styles across the area a series of selected seismic lines are displayed and discussed in this article.

Figure 1 shows a sample of the Dolphin Geophysical 3D seismic at the Top Chalk-Palaeocene level. The isochron of the Top Chalk-Intra-Palaeocene is highlighted in yellow. The isochron is almost twice

Figure 2: East–west regional line 2D SHarp Broadband.



the thickness where the seismic crosses the Ringhorne East discovery, reflecting the differential compaction associated with the Palaeocene where sand, which forms the reservoir, is present and where it is absent. The good imaging of the Top Chalk and Early Palaeocene means that channel geometries can be quickly highlighted by combining auto-tracked isochrons and draped amplitudes throughout the whole 3D volume.

Figure 2 shows a sample of the UtStord 2D SHarp Broadband, which extends from the Utsira High and part way across the Stord Basin. The left-hand side of the section crosses through the Edward Grieg extension, the Ragnarrock, and the Johan Sverdrup fields. Even at the regional scale the data clarity allows detailed fault-mapping at all levels within the section. The role of Early Tertiary tectonics and associated structural inversion is clearly indicated by the inverted hanging-wall geometries across the Stord Basin.

Figure 3 shows an enlarged view of the fault linkage underlying the Johan Sverdrup field, and also seismic geometries (in green) of the perceived Mid to Upper Jurassic part of the section, which form the main hydrocarbon-bearing strata in the area.

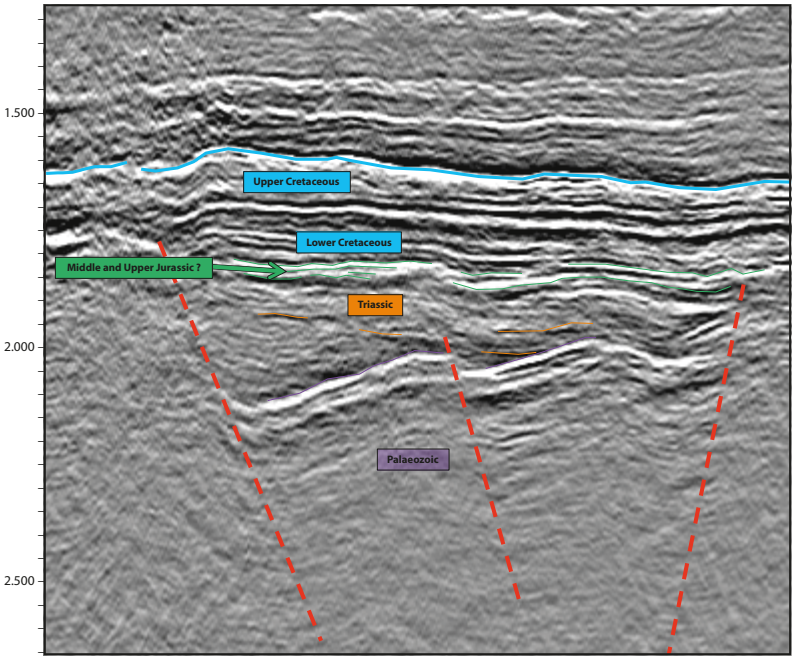


Figure 3: East–West regional line 2D SHarp Broadband : enlarged view of the fault linkage underlying the Johan Sverdrup field.

An east–west crossline from the 3D multi-client seismic is shown in Figure 4, with the Mid-Upper Jurassic intervals highlighted in green. Inset is a section of the Base Cretaceous TWT structure map, which shows fault-bounded closures (highlighted red) at the Base Cretaceous level. These are significant undrilled structures in the Utsira High area updip from the Stord Basin and Ling Depression.

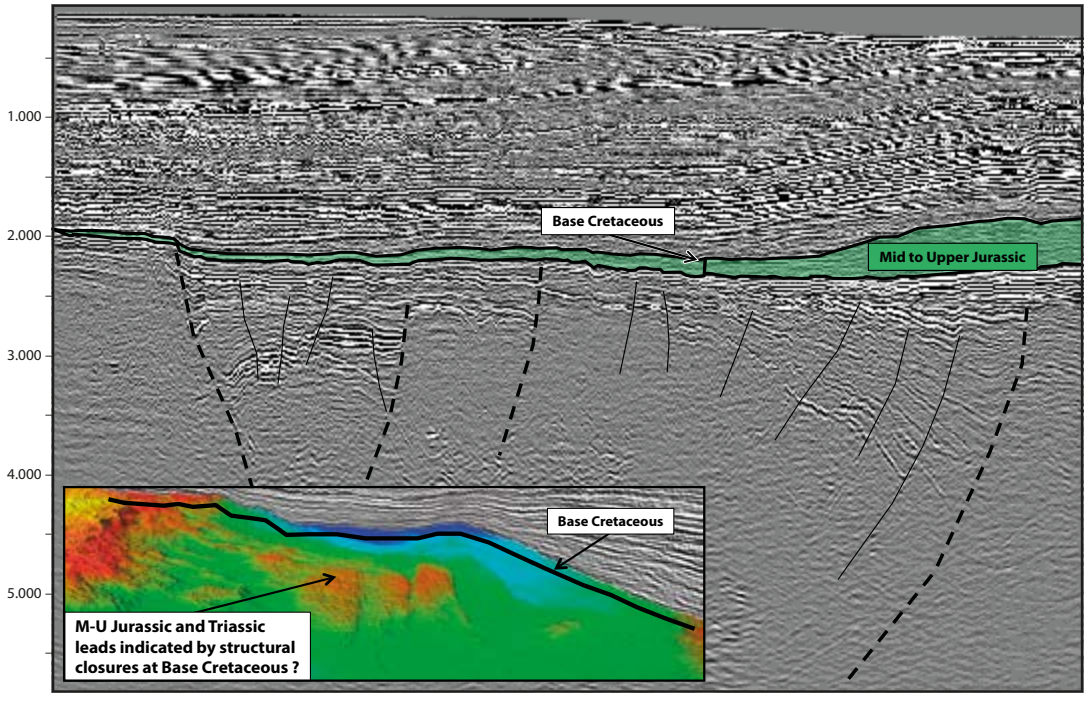
Processing Challenges

The main processing challenge with both the 2D and 3D data was the quite apparent presence of multiple content. Two passes of 2D SRME and Radon Demultiple generally worked well within these sections, and there was little evidence of residual water bottom or surface multiples.

The aim of the processing first of all was to improve on the fault definition, especially in areas of inverted hanging-walls, and to increase signal to noise ratio plus resolution within the main section. In general, the data is coherent, appropriately scaled and clean. Another main objective of the processing is to apply an AVO-friendly receiver side deghosting (also known commercially as SHarp deghosting), run pre-stack. We believe that this has been achieved alongside all benefits of SHarp deghosting, which includes greater bandwidth recovery and sharper, deghosted images of the final stacked lines.

For further information please contact:
Ian T. Edwards, Vice President, Global Multi-Client Surveys & New Ventures. Email ian.edwards@dolphingeo.com. Mobile: +44 (0)7920 713587

Figure 4: 3D seismic line showing deep fault linkage and the M-U Jurassic Interval with inset of TWT structure at Base Cretaceous



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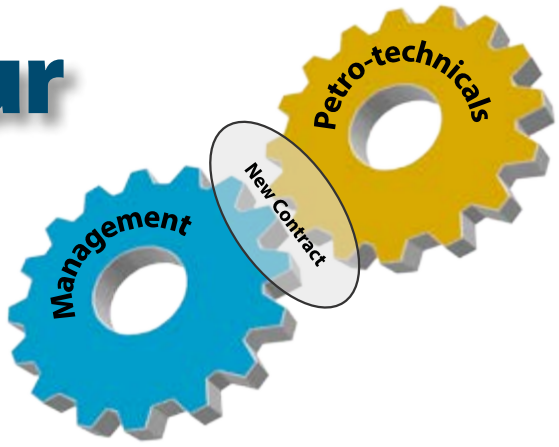


Oiling the machine with a new contract between management and the petrotechnical professional.

HENRY EDMUNDSON, R9 Energy Consultants, and **DAVID BAMFORD**, Petromall Ltd

The continued search for oil and gas relies in equal measure on good management and superior petrotechnical expertise. The key, though, is ensuring that the two worlds mesh smoothly and create a working environment that motivates both parties to succeed. This is more difficult to achieve than might be thought, for a number of factors.

First is the scarcity of top-quality petrotechnical professionals, covering everyone from geologists and geophysicists to drilling and petroleum engineers. This used to be blamed on the famous crew change, resulting from the paucity of recruits during the oil price crash of the 1980s. But things have now changed. The last few years have seen abundant recruiting by both operators and the service industry, and the crew-change problem has morphed into the different challenge of accelerating the development of thousands of young professionals to fill the still-prevalent mid-career gap. The result is an industry obsessed with accelerating employee development.

Second is the market force generated by the continued lack of mid-career petrotechnical professionals. These lucky individuals command a price in excess of their equivalent managers, and so do even the young aspirants joining their ranks, as there remains an extraordinary lack of competent geoscientists, drilling and petroleum engineers. And they know it. Never has it been so easy to jump ship, hoping for a better future.

Third is the meeting point between management and the petrotechnical expert. Both obviously aspire to business success, but beneath broad corporate goals lurk important differences. In companies of any reasonable size, managements must ensure that their machine to find and extract oil and gas is properly assembled, well lubricated, and working to maximum efficiency. Standards and discipline are important; within well-defined limits employees are expected to conform.

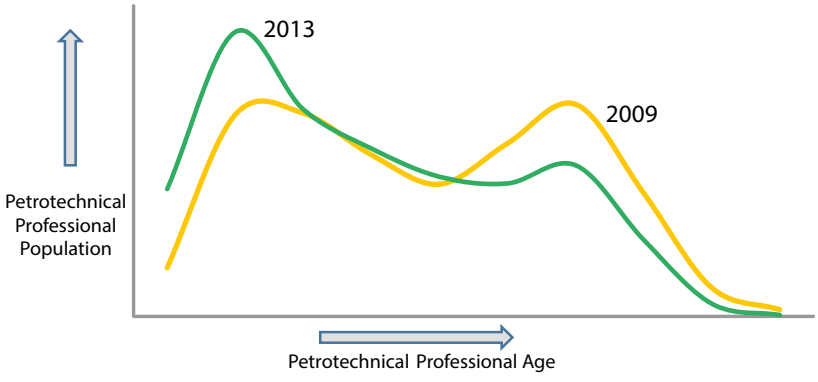
The petrotechnical expert, however, marches to a different tune, motivated by quite different criteria. When it comes to creativity and improving technical knowledge, petrotechnical professionals prefer less rather than more management, or even no management. The ideal state is being self-directed; satisfaction comes from solving tough technical problems. When it comes to their career, peer recognition and involvement is as important as management input. In short, and at risk of working an analogy beyond breaking point, the square peg that is the technical expert may not always fit the round holes of the smoothly running business machine. How to manage this less-than-exact fit requires some unusual strategies.

Let's start with two management imperatives, and then examine the details.

Firstly, in order to keep pace, managers need the brightest and best informed technical experts possible. This means ensuring technical employees have the right environment to develop new knowledge and skills, particularly in emerging technology areas – and not necessarily only junior employees. It also means that experts need free and easy exchange of knowledge and experience both from within and outside the company firewall.

The second imperative is that management needs to incentivise their technical experts so they are not tempted to leave for more enticing-looking employers. This can be achieved through a smorgasbord of options, including a total compensation package, a technical promotion system or ladder, and satisfying the development needs mentioned above. Above all, management must provide strong leadership and ensure a coherent and attractive company culture.

The crew-change challenge, with a peak population of older petrotechnicals as recently as 2009, had morphed by 2013 into the challenge of accelerating professional development due to the higher proportion of younger petrotechnicals.



Employee Development

Employee development is easy to wish for, harder to put into practice. There are several pitfalls. One is the traditional thinking that development is going on a week-long training course once a year. Courses have their place, but are only one component of a development programme. The other components include self-study – formerly done from books but now the internet – on-the-job training, just like apprentices used to do, and learning from colleagues. Each training mode has its memory retention factor, and research shows that the class-room setting, although key for getting basics across, does not feature highly, compared with self-study and repetitive hands-on practical application.

Whatever the mix, there are two management temptations that must be discouraged. The first is cutting employee training whenever business looks bleak. It is the easiest thing to cut since it never impacts the short-term bottom line, but the long-term is of course another matter. The second is believing that the return on investment of training and development can be measured and monitored. Training and development, by definition, is a long-term commitment, and it is as hard to quantify the benefits as it is to predict the success of R&D.

Dos

- Focus training on task at hand.
- Emphasise total package.
- Partner with petrotechnicals on technical ladder.
- Devolve large chunks of knowledge management to petrotechnicals.

Don'ts

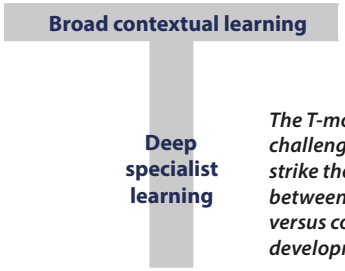
- Cut training to shore-up bottom line.
- Let competency-driven training get too big.
- Assume majority control of the technical ladder.
- Attempt to manage tacit knowledge inside the corporation.

Guidelines for management in the new contract.

What management can insist on, though, is focusing training and development on the job at hand, or at least what the employee is likely to be doing in the near future. Otherwise, training budgets quickly get eaten up providing employees with nice-to-know stuff rather than need-to-know essentials. The challenge is deciding what is truly necessary for the business. The oft-quoted T-model of training and development is a useful metaphor. The vertical of the T represents in-depth, specialist expertise, while the horizontal represents broad, contextual understanding. How a company trains its employees depends very much on the importance attached to each at various stages of the technical expert's career.

Companies wishing to realise immediate earning power from young employees will focus on the vertical, allowing the horizontal to develop once the employee matures. Other companies prefer more contextual development before forcing the vertical. It is a matter of strategy, but it needs to be thought through.

There are concomitant choices for managing the employee's development. The vertical is best managed through curriculum-based programmes, a linear progression of tasks and learnings to be ticked off. The horizontal is best managed using a competency management approach that maps selected



The T-model challenge: how to strike the balance between in-depth versus contextual development.

competencies and proficiencies to the job at hand. It risks becoming a large sledge hammer to crack the nut, but the idea does offer flexibility and the option to tailor training programmes to large numbers of diverse employees. However, competency management comes with a health warning. The systems quickly get heavy, they require employee assessments, and are difficult to maintain. The trick is to keep things simple.

Another training imperative is coaching, an idea handed us from ancient times when young people learned from a master. It has been unambiguously proven in recent studies that good coaching provides the most efficient catalyst for accelerating employee learning (see page 92). However, most companies struggle with the same basic conundrums. The coaching role needs careful definition, otherwise it ends up meaning whatever the participants decide. It is also expensive because valuable time is required from senior technical experts, and in today's world there are simply not enough of these to go round. Some companies contract retired experts to provide the role, but this risks diluting company culture. Coaching is worth every penny, but there are no cook-book recipes.

Knowledge Management

Knowledge is essential for any business, not least for satisfying a technical expert's ability to keep in touch with everything that's new. Technical knowledge in the business context can be divided between knowledge accessible from public sources and knowledge that is retained inside the firewall because it is deemed proprietary or confidential. Accessing the former is a purely mechanical task, revolutionised in the last decade by the internet.

Managing the latter is harder because the company itself must create the mechanisms. This management of internal technical knowledge divides into two main parts. One is explicit knowledge gained from company activities that must be validated, catalogued and made available internally. The other is so-called tacit knowledge that is in the heads of the technical experts and only gets shared in conversation, either in person or through the intranet. Sharing tacit knowledge is primarily a social activity. It works best when there is no interference from management; they would simply get in the way. The challenge for most companies is stretching the culture enough so employees can share their tacit knowledge with zero control. When it began, this type of activity was called communities of practice, but what it has become is just a typical social media activity like LinkedIn or Facebook, but restricted to inside the company.

Incentivisation and Careers

Given the continued shortfall in experienced petrotechnical professionals, both operators and the service industry are fighting for talent. For the professionals, the money offered can be tempting and occasionally extravagant, to the point where it is impossible for any given company to compete on an ongoing basis. What companies can do, however, is to ensure that their employees understand the total remuneration package, comprising salary, bonus, housing and travel benefits, pension and so on. The details are rarely understood by the employee or even enumerated by the employer. But the analysis is worth it, because it is the only way the employee can make a long-term comparison with offers on hand.

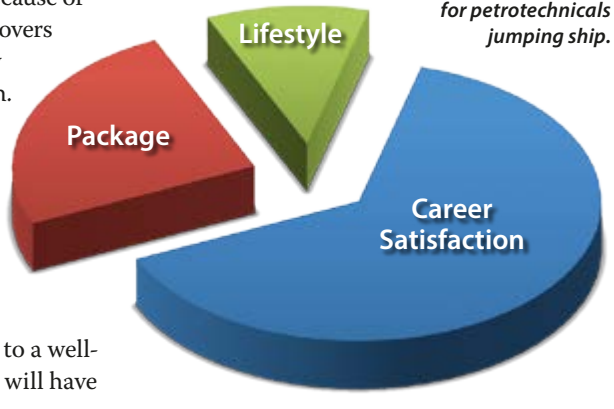
The best incentive for petrotechnical professionals, though, is a good career. Time and again, studies have shown that employees jump ship because of career dissatisfaction. This covers a multitude of sins, but a few basics cannot be argued with.

One is the need for status within the company. The company in which the management line remains the only path to the top risks losing its technical talent. The company with a secure technical ladder tied to a well-defined compensation scale will have no such worries. But given the number of failed attempts in our industry, how to create a technical ladder that both management and the petrotechnical professionals believe in? Two issues are key: the ladder must be jointly owned and managed by both management and the technical community, and the criteria for a technical promotion must address in equal part both business needs and technical requirements.

Another basic is the well-known fact that many employees quit because they can no longer tolerate their boss or some other irritant close by. This is hard for management to pick up on, but can be avoided through careful monitoring of employee dissatisfaction. In the last analysis, the employee is as responsible for his or her career as the employer is. Both make choices. The challenge is to create the best possible dialogue.

A New Contract

The oil and gas business continues on its technology journey and petrotechnical professionals provide the know-how. But they will remain in short supply for at least another decade. In the main, managers and technical professionals are cut from different cloth, so a company's prerogative is to ensure that their respective talents compliment rather than compromise each other. Contrary to traditional practice, an awful lot can be gained by an emphatic sharing of responsibility in key areas such as careers, training and development, knowledge management, and status for the technical professional. For the younger generation, especially, this is just plain common sense. For companies that have adopted this philosophy, it has paid huge dividends. ■



Typical reasons for petrotechnicals jumping ship.

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SNØSPURV HIGH RESOLUTION 2D 2013

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WEST OF HEBRIDES BROADBAND 2D 2013/2014

4,775 km Regional Long -Offset Porcupine Basin

In partnership with Geopartners

PORCUPINE BROADBAND 2D 2014

6,100 km Procupine Basin West of ireland

In partnership with Polarcus & Geopartners

SPIDERMAN WELL TIE 2D 2010

3,750 km of 2D long-offset Mid Norway Deep

In partnership with Spec Partners

VAMPIRE 2D 2011

7,000 km of 2D long-offset data Browse Basin, Western Australia.

In Partnership with Searcher Seismic

DUVALIA 2D 2012

3,300 blocks W12-10 and W12-11, NW Australia.

In Partnership with Searcher Seismic

ACHERON 2D 2009

2,678 km Geologically focused data in the Carnarvon Basin

In Partnership with Searcher Seismic

JDZ, SAO TOME & PRINCIPE 3D 2014

ST&P 1,500 km²
JDZ – 1100km²

In Partnership with Acorn

NAMIBIA 2D 2013

5,423km of long-offset 2D Blocks 2614A, 2614B, 2412B, 2413B, 2010B & 2912.

In Partnership Geopartners

PINATUBO BROADBAND 2D 2014

3,340 km Philippines West of Luzon, covering Areas 8 -11 to be launched in PECR5

In Partnership with Searcher Seismic

PALU SULU 2D 2011

6,202 km Long Offset 2D Sulu Sea, Philippines

In Partnership with Searcher Seismic

MIALARA BROADBAND 2D 2014

4,900 km* In The Philippines Covers Areas 4-6.

In Partnership with Searcher Seismic

*Planned

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DAS: Listening in Downhole

Distributed acoustic sensing is a breakthrough technology which can provide real benefits to the hydraulic fracturing process.

CHRIS SHANNON
Fotech Solutions

The oil and gas industry has continuously relied heavily on cutting edge technology in order to maximise the efficiency of extracting natural resources from deep underground. As a result, oil majors and operators always stand to benefit from new technological breakthroughs. For example, in the 1990s, the key technology was distributed temperature sensing (DTS). However, the breakthrough technology of this decade is distributed acoustic sensing (DAS).

Oil and gas exploration and production continues to gain in complexity as operators exploit more unconventional sources and deploy more complicated techniques. Downhole procedures such as hydraulic fracturing mean the challenge of gaining high quality real-time intelligence at every stage of the extraction process is increasing.

DAS technology can provide real benefits to the hydraulic fracturing process, which has been subject to criticism in terms of safety and efficiency. The process of drilling down into the earth before a high-pressure mixture of water, sand and chemicals is injected into the rock, allowing the gas to flow out to the head of the well, has been well established in several countries including the USA and Canada. However, concerns remain, with some high profile bans in countries such as France and Germany.

It is a method of extraction that still suffers from significant limitations in terms of monitoring and analysis of the drilling operation. To this day, the fact that engineers have almost no visibility of the fracturing process is one of the main causes for concern. As well as giving rise to safety and environmental issues, this lack of visibility is a major challenge for well operators as it limits their ability to achieve optimal recovery from wells.

Listening to the Well

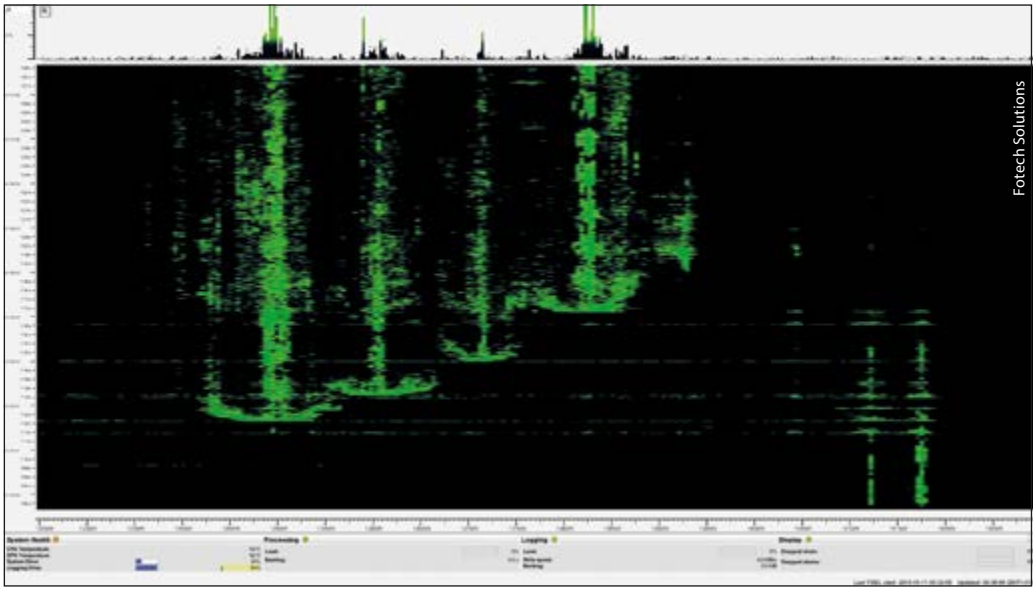
To date, even with tools such as DTS, optimising the fracturing process has only really been possible through labour-intensive and time-consuming trial and error testing. Clearly this is not an ideal situation and has resulted in significant uncertainty around key fracturing completion and production performance indicators such as fracture propagation and geometry, interference and deliverability.

DAS provides a tool to deliver a new dimension of knowledge that can be gained from each stage of the fracturing process and which enhances the production efficiency and safety of the procedure.

By using a fibre optic cable to detect acoustic vibrations, DAS allows engineers to 'visualise' and record what is going on downhole at every point of the well in real time. By listening at every point in the well and monitoring real-time downhole fluid flow during fracturing operations, the method can provide data and interpretative tools that have not been possible until now. This gives well engineers greater clarity than ever before and allows them to focus time and effort on value-adding activity that will ultimately increase recovery.

In the initial fracture stimulation phase DAS can give engineers a far greater understanding of fracture propagation and geometry. This includes building an understanding of the fracture operation itself, including ball seating, guns firing and perforation, before gaining visibility of the fracturing activity and propagation, potentially including the sensing of fluid flow in the active zone. This gives the engineer a real time log of the fracturing operation to an accuracy

The live DAS interface recording acoustic data from a downhole operation.



of one to two metres, providing an indication of fracture success in the exposed formation.

Optimising Hydraulic Fracturing

In a standard operation each potential production zone in the well is separately exposed to the fracturing fluid, conveyed at high pressure through perforations, open sleeves or other methods. Based on a lack of information, in a multi-zone hydraulic fracturing operation the assumption is made that every section of each zone will take the same volume of fluid equally, as though the formation was homogeneously permeable. In fact, great variation in relative permeabilities can occur even across a single zone, affecting future production rates.

DAS allows the engineer to determine, with documentary evidence, not only which areas are taking the fracture fluid in the first place, but also indicates how and where the permeability has been improved over the period of the fracturing operation. This information can indicate potential variations in production and which areas may underperform, increasing confidence in predicted production. The technique can also clearly identify which zones have not successfully fractured, ensuring that engineers do not fracture the whole well repeatedly. Instead, repeat fracturing efforts can be effectively targeted at only the zones that were not initially successful. Ultimately, this means that there is less subsurface disturbance, less fracturing fluid being used and ultimately less chance for issues to arise.

By installing the fibre downhole, DAS provides an additional benefit as it can be used not only to monitor the fracture zones, but also the cement casing of the wellbore itself. As a result, DAS can detect possible leaks and ensure that gas and fluid are not escaping from the well.

Post-fracture, DAS monitors the flow-back of the fluid from the formation to the well. A comparison of results from these two operations enables a great amount to be deduced and understood about the fractured formation. By monitoring this early production flow-back, engineers can look at correlations between fracture treatment and flow-back quantities and whether the back flow contribution profile changes over time.

A New Visibility

In essence, DAS is a cost-effective solution that allows the fracturing engineer to have vital information for the next well in the same formation or zone and ultimately reduces uncertainty and allows an optimised fracturing job to be delivered.

While it is a combination of these benefits that enables DAS to enhance the efficiency and safety of the fracturing process, it should not be seen as a replacement for existing monitoring tools. Instead it adds a powerful new element to the tools at the disposal of engineers. For example, when correlated with DTS and Surface Microseismic sensors, DAS creates a multi-dimensional, real-time dynamic profile of well conditions. Combining DAS with other existing technologies in this way can provide a comprehensive monitoring solution, delivering valuable insight into both completion and production issues. This will affect real time decision-making, improve overall efficiencies, increase safety and ultimately reduce assumptions in fracturing operations. ■

Chris Shannon has created a number of tech companies and led them to successful acquisition, including the Telecom division of Queensgate Instruments, Indigo Photonics and Ezurio. He became CEO of Fotech Solutions in 2011.

Rejuvenating Opportunities

Shell is leveraging hundreds of years of experience to search for new ideas in its traditional heartlands.

SHELL GLOBAL EXPLORATION COMMUNICATIONS TEAM

"If we don't invest in our people and the brainpower they bring to the table, we won't have a sustainable exploration business. And one way to invest in the brainpower is to more effectively connect generations of explorers. We leverage this connectivity in Shell Exploration by maximising our corporate knowledge, using a concept called Rejuvenate Opportunity Now workshops or RONs," said Ceri Powell, EVP of Global Exploration at Shell.

The concept of a RON workshop originated in late 2011 with the recognition of the importance of Shell's existing 'heartlands' in exploration delivery. These are countries or basins where the company has invested for many decades, established a strong and viable business with host governments and has a thorough geological knowledge of the sub-surface.

"Our belief in rejuvenating our heartlands is premised on the fact that the rich petroleum systems associated with our traditional areas, such as Oman, Malaysia and the North Sea, will continue to deliver new exploration discoveries. The limiting factor can be the need for an injection of new ideas and creative technical thinking rather than an absence of remaining potential," Ceri continued.

"It is clear that technology is key but it needs to be matched by innovative thinking – creativity, ingenuity and perseverance – and this is obviously about people and their geoscience capability."

Many Years of Diverse Experience

A RON brings together a diverse group of between 20 and 40 exploration-minded people with a mix of experience, from those working the basin today, to others from five, 20 and, in one case, more than 50 years ago. They all leverage their combined experience in diverse petroleum systems to generate new insights into the basin, identify additional opportunities within known or potential new plays and help to develop and prioritise forward plans to mature the opportunities. Participants comprise geoscientists with current knowledge of the basin or basins being

500 years of exploration experience gathered together in one room – and not a computer in sight!

Shell

Mike Foley, with over 30 years of experience in the O&G industry, leads the RON initiative.

Exploration Manager Mark Harvey is enthusiastic about the usefulness of the RON workshops in which he participated.

Ceri Powell, EVP of Global Exploration at Shell, is a great advocate of the Rejuvenate Opportunity Now (RON) workshops.

worked, legacy knowledge holders, functional expertise holders and invitees with an external perspective.

"So, imagine having up to 500 years of exploration experience gathered together in one room – with no computers! Instead, old-school tools – paper logs and 'mylar' – bring fresh challenges to dogmas and other biases that potentially hold back new thinking on known plays. Discussion, agreements and sometimes heated debate, all leaving the asset owners with a rejuvenated portfolio of concepts to turn into drill-worthy prospects," Powell said.

The RON Facilitator

Michael Foley has led the RON initiative since 2012.

"Since the inception of the RON approach to heartland rejuvenation we have benefitted greatly from the revitalisation of knowledge within current asset teams. Participants brainstorm new idea around plays and opportunities, with results ranked by technical attractiveness and 'doability', and follow-up plans are developed for further maturation by the team," says Foley.

"I very much enjoy working with asset teams to understand their objectives up front, help to design the workshop to meet those objectives and contribute to executing the RON to deliver them. My role during the workshop is primarily as a technical facilitator, but I do spend time working the geology, using my more than 32 years in the business, with the teams during the workshop and during the follow-up, when required," says Foley.

The RON Veteran

Professor John Underhill is the Shell Chair of Exploration Geoscience at Heriot-Watt University in Scotland and has been involved in four RONs so far.

"The first event that I took part in was the Central North Sea Rejuvenation Opportunity Workshop, which was held in Aberdeen, UK, in 2011. It involved a review of Shell's position in the Central North Sea. My role was to provide independent technical assurance to the process. My sense from speaking to many employees in attendance was that it was initially treated with some scepticism. However, the proof was in the positive outcomes. The event led to Shell applying for and being awarded licences in the subsequent licensing round, the first proactive bidding in the basin by the company in a decade. In November, Shell was awarded seven blocks in the Northern North Sea; this successful outcome was based on a RON conducted exactly a year ago.

"The second RON that I participated in took place in 2013 in Muscat, Oman and focused on identifying further exploration opportunities in existing play fairways in Petroleum Development Oman's acreage – the portfolio 'running room' as we call it – as well as completely new innovative play concepts which I typically refer to as 'blue sky exploration'. The event involved a balance between existing Oman-based staff and the wise heads of yesteryears, essentially people who have worked the basin previously from decades past and who returned to an old stomping ground. This proved to be a good challenge," said Underhill.

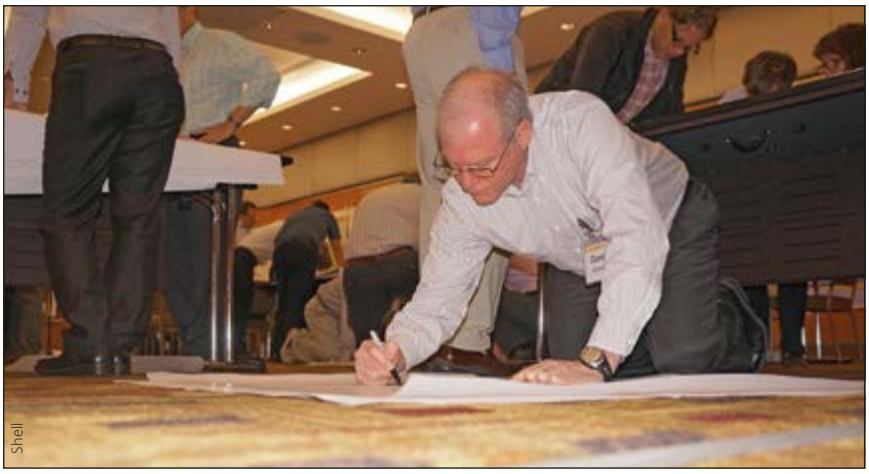
A key element stressed by Professor Underhill was the cross-border collaboration in the RON, which was a common theme across all the workshops. He referred to this as 'geology without borders', branded by him on his third RON, in Stavanger, Norway, which brought together the UK and Norwegian North Sea teams for a connected view of North Sea geology.

An Exploration Manager's Perspective

Exploration Manager in Malaysia, Mark Harvey, who has participated in RON workshops both in New Zealand and Malaysia, is enthusiastic about the real results he sees.

"The RON format is good because it makes people feel uncomfortable not knowing where the end may be, by starting from a bottom-up geological build and with no clear structure, yet leading to a deliverable at the end of day three. The RON involves geological experts, both past and present, thinking

broadly to help the business deliver a work plan focused on the geology with the best play potential. The workshop therefore ensured a grounding in geological play-based exploration work, enabling delivery of high quality play maps to help define where we want to be in this basin and why. In Malaysia, we can see the results helping to provide focus on where we think the business should be in Sabah and Sarawak," says Harvey.



Dave Steele shows that sometimes a little more space is all you need to find what you are looking for.

The RON for a Young Explorer

For Shell employee Ma Jing the experience of attending a RON was interesting in many ways, starting from preparing and participating and going forward to further action. She joined Shell two and a half years ago as an Exploration Geophysicist. Before that, she had been working for another IOC on the North China offshore basin for six years.

"It was a full three-day workshop aiming to arrive at a technical recommendation. Before that, our team spent about two months preparing the materials and documents used for the workshop, a large part of which was focused on de-archiving legacy data, digitising the maps and digesting the last two years of published papers, and books and play summaries," said Ma Jing.

"This is the first time I have been involved in such a big geology and geophysics event, able to work closely with so many experts with the same goal at the same time," she continued. "A big take-away for me was the 'ideas funnel' for further study. Essentially, this is set up during the three days and is a collection of good suggestions and technical recommendations: from conceptual ideas to ones supported by data and observations. I think participating in such a workshop is invaluable, especially for young explorers, as it allows you to learn from the experts and deepen your knowledge in the area."

Yielding Results

To date, eleven Shell Exploration RONs have been held around the world. They continue to yield results, directly contributing to improved technical assessments of targeted plays, supporting prioritisation and resourcing decisions for opportunities within a basin and providing a strong technical background that underpins decisions to enter, and in a few cases to exit, specific plays or basins.

"Generations of geoscientists, doing what they love best, and directly impacting the future of Shell Exploration. It doesn't get much more impactful than that!" summarises Ceri Powell. ■

Exploration Geophysicist Ma Jing attended her first RON workshop in June 2013 in China. She said: "Everyone shared their knowledge and gave their opinions freely. I got a great chance to listen to expert experience and be involved in the discussion in my capacity as a local basin knowledge holder." She is seen here on the left with Daniel Steffen (middle) and Jeroen Peters (right).

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The Chief Geophysicist

Phil Fontana is the Chief Geophysicist for seismic company Polarcus. He tells us about the career path which led to this role and what it entails – and why geophysics still excites him.

My undergraduate degree, at the University of Connecticut, was in geology, but I took a geophysics course in the final year and really enjoyed it, so I decided to do my Masters in the subject. I think what attracted me to the discipline is the mix of multiple sciences involved: physics, geology, technology – they are all needed, and it is very satisfying to see how they work together.

Influencing Technology

I learnt my craft after I left college by working as a geophysicist in a small geotechnical survey company in the US, where I had to do everything. I set up the equipment, ran it all, sorted out any problems and interpreted the results: a great learning experience!

I then moved on to the Applied Marine Technology Group at Western Geophysical, a much larger company, where I was working in research, which was very interesting. The geophysicists at Western actually decided what systems were needed and worked closely with the engineers in the group to make and test the prototypes, until we were happy with them, then they could be manufactured and supplied to the field crews. Back then the geophysicists had significant influence on the development of technology, with manufacturing virtually driven by what the geophysicists suggested. I think that is less true now, as many of the larger R&D facilities have been broken up.

After working in the research team I moved into management, with spells living in London and Houston. When Western merged with Geco I became the Chief Geophysicist for North and South America. However, I really prefer working in smaller companies where I feel more 'hands on', so in 2001 I joined Veritas, now part of CGG.

Finally, in late 2008 I was asked if I would like to be part of the newly-formed Polarcus. The opportunity to be in at the start-up of a new seismic company was very attractive, so I jumped at it, and have now been Chief Geophysicist for the company for six years. I am based in Dubai, which is a fascinating place to live. After all, it is probably the most modern city on the planet, so there is always something interesting to see or do.

Responsibilities

In an acquisition company like Polarcus many of the main responsibilities of the Chief Geophysicist revolve around developing and promoting the technical capabilities of the company. I need to assess how we use equipment both for operational efficiency and to ensure optimum geophysical quality. I also market our technical ideas and equipment internally to my colleagues and externally to our customers.

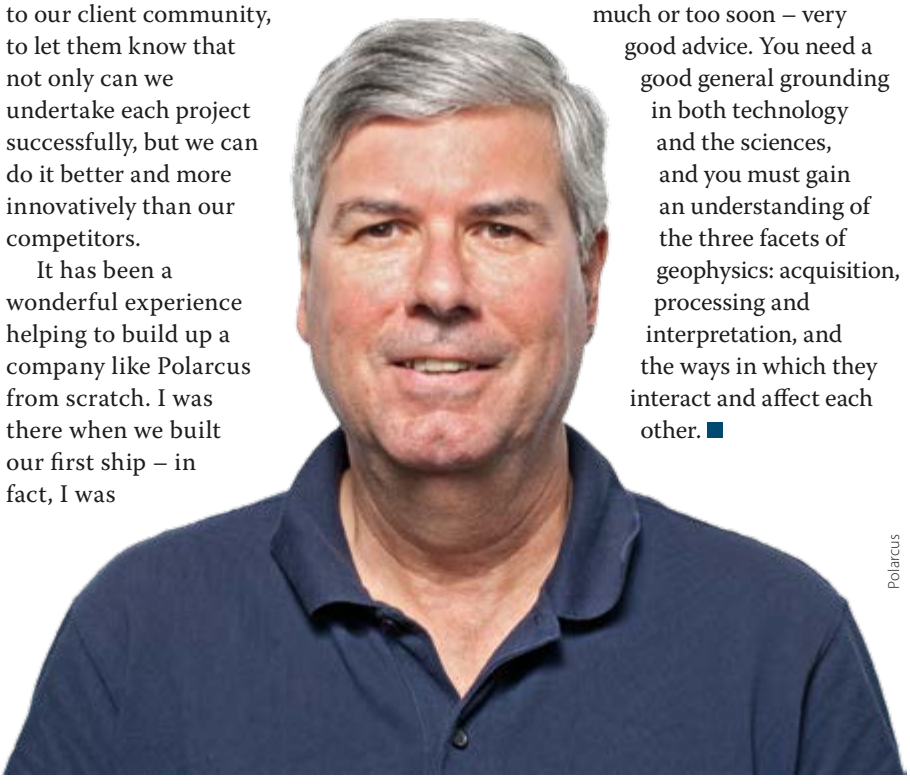
Talking and marketing to potential clients is an important aspect of my job. I need to be able to project the company's technical competence to our client community, to let them know that not only can we undertake each project successfully, but we can do it better and more innovatively than our competitors.

It has been a wonderful experience helping to build up a company like Polarcus from scratch. I was there when we built our first ship – in fact, I was marketing our services before she was even launched. I felt I was right there in the centre of the fray and it was so exciting.

And after all these years in the business, geophysics is still not boring, because there is always so much yet to learn. I continue to get involved with the subject, primarily as a result of the very innovative team I have around me in Polarcus, who are constantly coming up with new ideas and fresh ways of attacking problems and expanding our services and products. And I am also strongly involved in mentoring the next generation of geophysicists and managers so they will be well equipped to take over my roles in the future, and those of my managerial colleagues.

What Attributes are Needed?

What makes a good geophysicist, particularly one who aims for higher management level in a company? I was advised early on in my career to be a generalist and not to specialise too much or too soon – very good advice. You need a good general grounding in both technology and the sciences, and you must gain an understanding of the three facets of geophysics: acquisition, processing and interpretation, and the ways in which they interact and affect each other. ■



Polarcus

Midland, Texas:
Gateway to the Permian Basin

Starting out in 1881 as Midway Station, a railroad section house halfway between Dallas and El Paso, Midland is now the fastest growing metropolitan area in the US thanks to the 'Shale Revolution'.

THOMAS SMITH

If there is any city that deserves the title of 'Oil City', it would have to be Midland, sitting as it does atop one of the most prolific oil-producing areas of the US. Starting with a trickle (10bopd) in 1920 at the Westbrook Field, Midland's growth and fortunes are inseparably linked to the Permian Basin oil and gas developments.

Known as 'Midway Station' from the days of the Texas and Pacific Railway, the region's first permanent resident, Herman Garrett, moved here from California in 1882, along with his herd of sheep. Other ranchers soon followed and a post office was granted on 4 January 1884. In order to establish this, and as other towns in Texas were already called Midway, the site was renamed Midland. By 1885, an Ohio real estate firm had bought land and promoted the site, attracting 100 families to the area. Residents all used windmill pumps to obtain water and Midland became known as the 'Windmill Town'. By 1914, it was a thriving town of 2,500, the county seat with two banks, a cotton gin, lumber yards, four churches and an opera house. Extended droughts depressed the local economy and by 1920 the population had dropped to 1,795.

Then came the first of Midland's oil booms.

Oil and Midland's Ups and Downs

Three years after oil was discovered in the Permian Basin, the Santa Rita #1 blew out hitting oil and gas in dolomitic sands called the 'Big Lime'. It was the first of a long list of major discoveries in the 1920s that included the supergiant Yates Field in 1926. The Permian was now one of the world's great oil-producing basins, bringing thousands of oil field workers and investors to Midland.

By 1929, thirty-six oil companies had offices in Midland. Street and lighting improvements swept across the city and new, impressive structures such as the 12-storey Hogan Building were constructed. The county sold its old courthouse for one dollar to move into a new four-storey building. The city now boasted 5,484 residents with a new airport and luxury hotels. Shortly thereafter, the Great Depression brought dramatic changes to the area. The combination of a decrease in the nation's demand for oil and large, new oil discoveries in East Texas made for a glut of oil on the market, depressing oil prices. Many of Midland's oil businesses folded and by 1932, a third of the town's work force was unemployed. The local citizens showed the town's spirit

The 1923 Santa Rita oil discovery generated intense interest in the Permian Basin and kicked off Midland's first oil boom.

Courtesy Petroleum Museum

Downtown Midland rises out of the mesquite-covered West Texas plain as seen from the rooftop of the Petroleum Museum, a great place to begin a visit to the area. Some of the Museum's vast collection of antique oil drilling equipment (the world's largest) is pictured in the foreground.

Thomas Smith

Thomas Smith

by organising the Midland Community Welfare Association to distribute food and clothing to the needy.

This economic dip was short-lived, as the Texas Railroad Commission began to regulate oil production and the federal government placed a stiff tariff on foreign oil. Dozens of new Permian Basin oil fields began producing in the late 1930s and by 1940 Midland had almost doubled in size, nearing 10,000 residents. The town continued to prosper and grow during World War II, when there was increased demand for oil and more oil field workers arrived in the city. The army also established the Midland Army Air Force Base as one of the largest training bases in the world at that time. When the base was closed in 1946, it was converted to an excellent regional airport.

As goes the Permian Basin expansion, so goes Midland. Oil and gas production from the Permian Basin greatly increased through the late 1940s. It was the period when Midland attracted a huge influx of oil investors and workers, including two future US presidents (see photograph, below). By 1950, 215 oil companies had offices in Midland and the population had nearly doubled to about 22,000; by 1960, the population had nearly tripled that, to over 63,000. The small country town had become a city with a skyline that could be seen for 30 miles.

The next down period lasted over a decade, from 1960 into the early 1970s, even though Permian Basin production was increasing to its 1973 peak of 2.085 MMbopd. Competition from foreign fields had lowered oil prices and numerous companies left the area or trimmed their workforces. The 1973 Arab oil embargo led to increasing oil prices, relaxed federal regulations on the oil companies, and major conservation efforts. Midland boomed for the next nine years. New downtown high-rise offices were built; apartments and houses went up by the thousands, yet contractors could not keep up with the demand. By 1981, there were people living in tents, cars and trailers all around the city.

Then the sudden drop in oil prices in 1982 ended this boom period, leaving office buildings vacant and houses unsold. Even though Midland's economy had diversified, the primary source of prosperity for the area was the petroleum industry. With declining Permian Basin production and low oil prices, several large energy companies simply moved away, leaving their equipment to weather in the harsh Texas sun. Midland was in for a long downturn.

Enter Hydraulic Fracturing

In 2005, companies began drilling a few horizontal test wells and trying different hydraulic fracturing treatments on some of the Permian Basin's rich source beds. Most of these early experiments proved to be uneconomic. After trying a host of methods that included gels and CO_2 foams, the companies moved to slickwater completions and refined fracking methods to provide optimal rock breakage, thus increasing the surface area to be produced… the boom was on.

Midland just may be sitting on one of, if not *the* world's largest oil field, with companies targeting at least six shale intervals across the 400 km by 480 km Permian Basin. Early estimates are huge, well over 50 Bbo. Midland is resurging and, not unlike the other boom times, the city is feeling the growing pains. Housing is at a premium as rents have shot up rapidly; government and schools are overwhelmed; the roads are crowded; and new high-rise office buildings are proposed for the downtown. Most residents know that a slowdown will occur and that over-building and expensive city projects have come back to haunt them during slow periods in the past. As the former mayor, Wes Perry, notes: "We know it was there one day and can be gone again, so we better be careful." ■

A common site around Midland – small trailer parks and drilling rigs. The building of new homes and apartments is at a frenzied pace to accommodate the city's rapid growth.

Thomas Smith

George H. W. Bush first visited Midland in 1948, like so many others at that historic boom time, to get into the oil business. Midland was then known as the 'headquarters for the independent oil man'. George started out as a sales clerk but soon opened up his own independent oil company which he actively managed until 1966. He brought his family to Midland and bought this house in 1951. The house is unique in American history as it was the home of two US Presidents; George H. W. Bush, No. 41, and George W. Bush, No. 43, as well as two governors and a first lady.

Thomas Smith

KEN WHITE

Senegal: Cairn Has Substantial Find With First Well

The new discovery could hold nearly 1 Bb oil in place.

Hailed as the first major find for the company since it started divesting the proceeds from the sale of its Indian interests, **Cairn Energy** has made a "very substantial" discovery with its **FAN-1** wildcat in the **Sangomar Deep** block offshore Senegal, about 100 km south-south-west of the capital, Dakar. The well, located in 1,427m of water, reached a total depth of 4,927m targeting multiple stacked deepwater fans. Preliminary analysis showed distinct oil types ranging from 28° API up to 41° API. Cairn estimates in-place P50 resources of **950 MMbo**, broadly in line with pre-drill estimates. A preliminary analysis has indicated there is 29m of oil bearing reservoir in Cretaceous sandstones. No water contact was encountered in a gross oil bearing interval of more than 500m. There are no plans for immediate well testing but the news saw Cairn shares jump by more than 10%. The FAN-1 well, which was drilled using the semi-submersible drilling unit Cajun Express, is the company's first in Senegal.

Chief executive of Cairn Energy, Simon Thomson, said the discovery is an important event for Senegal and the joint venture as they have "encountered a very substantial oil bearing interval which may have significant potential as a standalone discovery." He added that "this result materially upgrades the prospectivity of the block with a proven petroleum system and a number of deep fan and shelf prospects established." The Cajun Express semi-sub has now moved to complete the second well, SNE-1, where the top hole has been drilled pending re-entry.

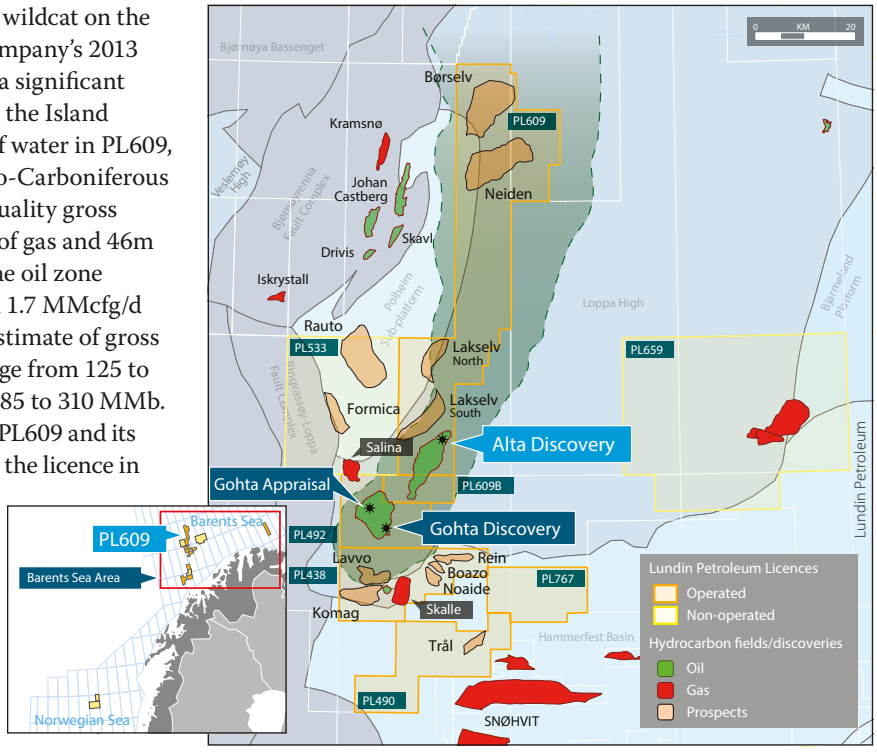
Cairn has a 40% working interest in the block, with ConocoPhillips holding 35%, FAR Ltd 15% and Petrosen, the national oil company of Senegal, 10%. The group hold two other blocks offshore Senegal (Sangomar Offshore and Rufisque), for which Cairn is also operator. The three blocks cover 7,490 km^2 and lie in the productive Mauritania-Senegal-Guinea-Bissau Basin. ■

Fishing boats in Dakar.

Norway: Lundin Considering Loppa High Infrastructure

Lundin Petroleum has described its 7220/11-1 wildcat on the **Alta** prospect, some 20 km north-east of the company's 2013 **Gohta** success in the southern **Barents Sea,** as a significant discovery testing both oil and gas. Drilled using the Island Innovator semi-sub, the well, located in 388m of water in PL609, reached a total depth of 2,221m targeting Permo-Carboniferous and Triassic objectives. It encountered a good quality gross hydrocarbon column of 57m consisting of 11m of gas and 46m of oil. Two drill stem tests were carried out in the oil zone producing at a maximum rate of 3,260 bo/d and 1.7 MMcfg/d through a 36/64" choke. Lundin's preliminary estimate of gross recoverable resources for the Alta structure range from 125 to 400 MMboe, with the oil resource estimated at 85 to 310 MMb.

The 7220/11-1 well is the first to be drilled on PL609 and its success has de-risked the remaining prospects in the licence in which both the Børselv and Neiden prospects are drill-ready. Alta is seen as another positive step towards proving up sufficient resources in the Loppa High area of the Barents Sea to enable the development of oil production infrastructure. Lundin has indicated it is likely to drill three or four appraisal/exploration wells in the Loppa High area in 2015. ■



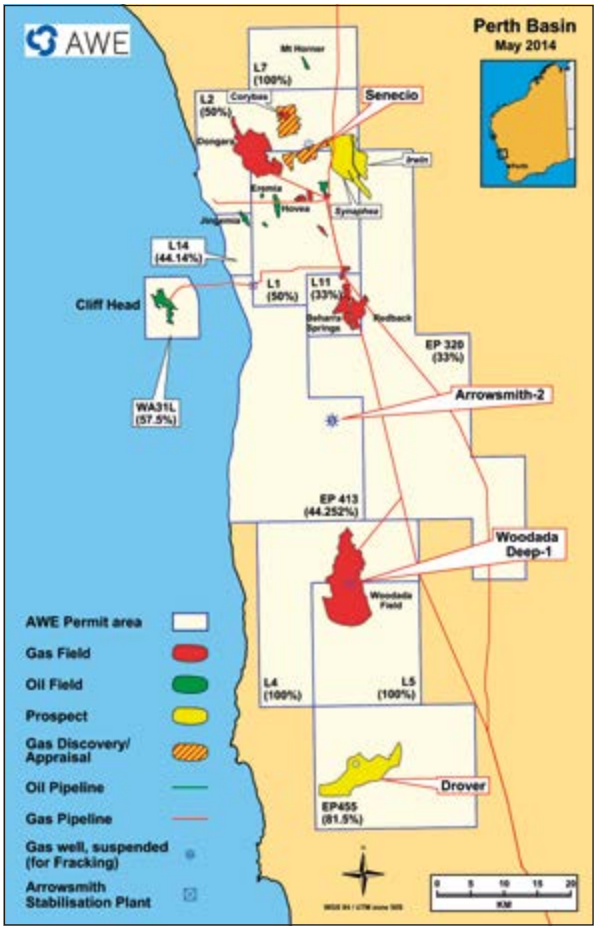
Australia: AWE Opens New Play in North Perth Basin

According to Australian exploration company **AWE**, its **Senecio-3** well in onshore blocks L1/L2, about 360 km north of Perth, has increased the development potential of the Senecio gas field and discovered the new **Waitsia** gas field in the underlying section. This has opened a new play with significant upside potential in the **North Perth Basin**.

Shale gas exploration in the North Perth Basin.

After initial analysis of data from the Senecio-3 well and the existing 3D seismic, AWE estimates that the Lower Permian Kingia/High Cliff Sandstone intervals in the Waitsia discovery (formerly Senecio Deep) have gross contingent resources (2C) of **290 Bcf**. The company is keen to undertake further appraisal work as the Kingia/High Cliff Sandstone interval has not been previously penetrated in this part of the basin. It believes it may have discovered what may be the largest onshore gas find since the discovery of the **Dongara** gas field in the 1960, which has been producing gas for 40 years but is nearing depletion of its reserves. The Senecio-3 appraisal well is located on agricultural land approximately 15 km east of the town of Dongara and 7 km from the AWE-operated Dongara gas plant.

AWE is also evaluating the gas-bearing intervals in the Lower Permian Irwin River Coal Measures and the overlying Caryniginia Shale, which could provide substantial additional unconventional resource potential. The company estimates that the Irwin River Coal Measures has gross prospective resources (P50) of 420 Bcfg, but further evaluation and appraisal would be required to establish whether reservoir productivity will be sufficient for commercial development. Prospective resources for the Caryniginia Shale have not yet been estimated for this location, but could be substantial. ■



The End of Country
Dispatches from the Frack Zone

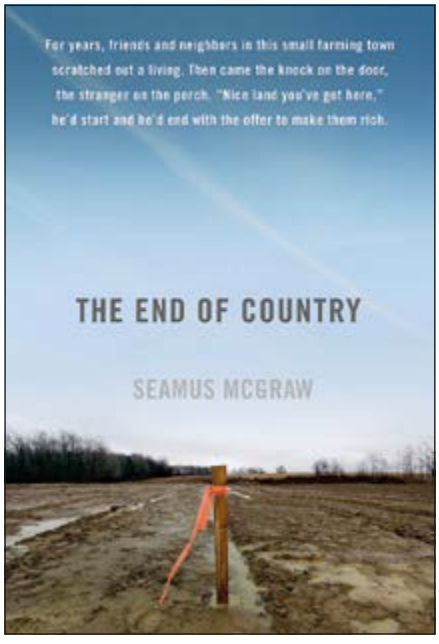
The End of Country: Dispatches from the Frack Zone
Author: Seamus McGraw
Hardcover: 2011
Paperback: Random House (2012)

This is a book that all those interested in the anti-fracking movement should find rewarding.

While helpfully descriptive in many areas, it is riddled with assumptions and technical misconceptions; and it is very forgiving of the foibles of the author's rural Pennsylvanian associates. That said, this is probably how many opponents of the shale revolution think. It came out in 2011, a long time ago in shale terms; but the issues faced are now being met all around the world.

Unstoppable Momentum

I picked up a copy in 2011 in Pittsburgh airport while returning from a DUG (Developing Unconventionals) East conference which had seethed with energy and new ideas. Most importantly, a Washington heavyweight had been the lead-off speaker (from the US Environmental Protection Agency, no less) and, exuding the quiet confidence of the truly powerful, intoned two or three times from a prepared speech that the shale revolution was in the 'national interest', vital to the 'national security' of the United States – but it had to be done right. Obama was on side; the applause was that of relief.



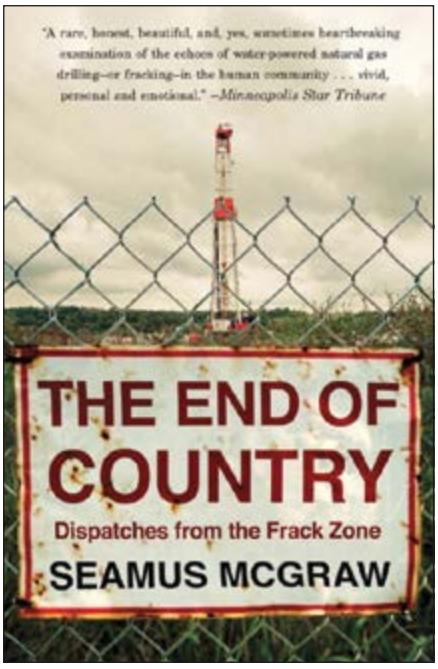
There seemed an unstoppable momentum – and in truth there is.

The shale revolution has drastically increased the world's economically recoverable hydrocarbon resource base. It will take time to spread but in the meantime, US production alone will bring radically lower oil and gas prices worldwide. 2011 was a heady time for those who had watched the evolution of the shale revolution.

But there was trouble brewing on the environmental side; *The End of Country* appeared just after the film *Gasland* came out. As Professor Terry Engelder of Penn State demonstrated in his AAPG Distinguished Lecturer series (see *GEO ExPro* Vol. 11 no. 4), *Gasland* is more fiction that fact. Nevertheless, it has still helped convince a sizeable part of the environmental movement to erect barriers to the use of shale gas, thus slowing the wholesale switch from coal to shale gas worldwide – which just happens to be the only way to make needed CO_2 reductions in the short time-frame that environmentalists, almost to a person, say is needed. This seems perverse.

Local Insights

The End of Country is important because very little has been written on fracking from the bottom looking up – the place where public opinion is formed. It helps fill this gap by presenting the facts as seen through the eyes of an 'everyman'. McGraw was a reporter of no great accomplishment or geoscience expertise, but he was a keen observer of fracking operations on the ground – and in the minds of his neighbours. He has strong memories of growing up in north-east Pennsylvania, an area where naturally occurring gas seeps are well known, and lived a few hills over from Dimock,



Pennsylvania, the depressed farming area brought to prominence by *Gasland*.

He is also a man with conflicted interests, who supports selling drilling rights on the family farm and at the same time has the "what will all this mean for us?" concerns of everyman.

Upon my re-reading, the book still exudes that same initial feeling of a story well told with somewhat forced balance, imbued with insights that only a local could provide. It describes the first wave of landmen coming to town with their usual sales talk, but fails to evoke more than mild disapproval of their mis-steps; it talks about misunderstandings turned to principle, then to revenge and acts of expensive nuisance; it speaks mostly of local motivations and fears, but it is clear that the preservation of the 'peace and quiet' of a very beautiful area conveniently located a mere 150 miles from New York City plays a bigger role.

It will evoke a peculiar mixture of admiration with a nagging feeling that nothing substantially threatening has been described – yet the anxiety and concern are palpable.

The End of Country tracks the transformation of the mundane into a powerful political force – one capable of setting back fracking policy in jurisdictions where political leadership is weak.

So, if you want or need to understand these forces, read this book. ■

Cabot Martin

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ALLWORLD EXHIBITIONS

Hard Work and Innovation

In just eleven years, DownUnder GeoSolutions (DUG) has grown from a few people working in a shed in a Perth garden, to a company employing 200 people with seven offices based all around the world. Dr. Matthew Lamont, who founded DUG in 2003 with Dr. Troy Thompson, explains why he decided to start his own geosciences company.

What led you to found DownUnder GeoSolutions?
I had always wanted to start my own business. Whilst working in Houston (for BHP Billiton) I had witnessed companies, similar to what we have now become, doing very well. After returning to Australia I realised that there weren't really any Australian companies of this type – that is, small service companies that approach G&G from a new and different angle. The time was right to try and fill this gap in the market.

A small number of my past colleagues believed in what we were trying to create and provided a modest amount of start-up capital and DownUnder GeoSolutions was born. Our first office was literally a shed that we built in my own backyard!

DUG has grown very rapidly: to what do you attribute your success?
I think there are a few things. We have worked very hard to get where we are today. We have been lucky enough to attract some fantastic (and very clever) people over the years who have helped us to grow and innovate. I think that our focus on research and development from day one has also been important. Our fleet-footedness, relatively low overheads and not being afraid to take an (educated) risk or two have served us very well. Our drive to be a successful company has certainly never waned.

Is there enough innovation in the 'geosolutions' field?
Yes, I believe there is. Every single project has its own unique set of challenges which need to be solved. I think this field will always strive to do things more effectively and efficiently. Innovation is certainly a big part of what we strive to do every day – be it on a technical project or a marketing strategy or an IT solution. As hardware for high performance computing continues to evolve it is essential that we keep our finger on that pulse too. For example we are embedding our processing and imaging system into our interpretation package, DUG Insight. Add this together with our new Intel Xeon Phi-powered desktops and we're now making interactive processing a reality on each of our geophysicist's individual computers. A testing regime that once took weeks can now be achieved in days. Innovation is a necessity if you want to stay near the front of the pack, I believe.

You are based in Perth, but where does the majority of DUG's work come from?
In the very early days a fair amount of our work came from the Gulf of Mexico. But even then we started getting projects from a variety of international locations. Expanding our presence in south-east Asia was the obvious first step out of Perth, and we opened offices in Kuala Lumpur and Jakarta in '07 and '08. Today we work in all corners of the globe with seven international offices including London and Houston.

How do you see the state of the E&P industry in Australia and South East Asia?
Things have flattened out a little at this moment in Australia. There is a lot of focus on a few mega-gas projects. That said, the recent Phoenix discovery (Canning Basin, offshore Western Australia) has been very exciting. Things are continuing to go well in the Cooper Basin too.

Do you think the big oil and services companies pay enough attention to Australia?
Yes I do. All of the majors have a presence in Australia. If you ask me, I think we actually have too many service companies!

You recently won the prestigious SEG Cecil Green Enterprise Award. What does this mean to you?
Our company will be eleven years old this year and we are proud of all of our achievements. But to be recognised by the SEG is certainly a great honour and it feels pretty good. There is no doubt that it will also help our international brand recognition, which will keep our business moving in the right direction! ■

Paraguay Draws Industry Attention

Two recent wildcats in the Paraguayan Chaco Basin lend substance to an estimated resource potential of over 27 Bboe for the country.

It is fashionable to identify deepwater regions, unconventional plays and the Arctic as the 'hot spots' in the current global exploration scene. In recent years, violence, tension with governments and power struggles with state-owned oil companies have weakened the allure of less-developed nations in North Africa and Central Asia, where lax regulations and cheap labour costs once promised hefty profits for oil companies. But with two wildcats proving the presence of thick Devonian source rocks which are actively generating liquid hydrocarbons, Paraguay has been brought to the industry's attention. These wells (Jacaranda x-1 in August 2014 and Lapacho x-1 in October), which are operated by President Energy, were the first to be drilled in the Pirity sub-basin of the Paraguayan Chaco for 30 years.

Lapacho x-1 in the Pirity Block, which borders Argentina where the same petroleum system in the Olmedo sub-basin is producing mostly 40-44° API crude, encountered significant shows of oil in the Devonian Icla Formation sandstones, with President Energy identifying 20m of net pay in two zones. Although the porosity is tight at 6%, extensive fracturing has been identified and the sidewall cores were bleeding light oil and condensate. Pre-drill gross mean unrisked prospective resource estimates for this well were over 1 Bboe. The company is now proceeding to its primary target, the Lower Devonian Santa Rosa Formation, and will then conduct cased hole flow testing, before returning to the Jacaranda x-1 to drill deeper to test the Icla and Santa Rosa Formations.

Plenty of Potential

This landlocked country, long a gaping hole in the hydrocarbons map of South America, currently has no production, despite being sandwiched between gas-rich Bolivia, hydrocarbons-producing Argentina and Brazil, with its vast offshore oilfields. In 2013 the first significant seismic surveys since 1997 were undertaken, including the first ever 3D seismic, which was acquired by President Energy and which led to the company's drilling success.

In July 2011 US geoscientists estimated Paraguay's undiscovered hydrocarbon resource potential to be 27.95 Bboe, of which 27.55 Bboe were estimated for the Palaeozoic and 400 MMboe for the Mesozoic. These estimates include unconventional resource potential in their calculations; Paraguay has an unconventional shale gas resource potential estimate of 62 Tcf.

The Chaco Basin is a large sedimentary basin located predominantly in north-western Paraguay and south-eastern Bolivia. The Paraguayan part, where recoverable potential has been estimated at more than 4 Bboe, remains one of the world's least explored onshore hydrocarbon areas. Several factors render the Paraguayan Chaco Basin attractive for oil and gas exploration and development. These include larger and growing markets for hydrocarbon products, significantly increased oil and gas prices, at least until recently, improved infrastructure in the Chaco and a positive change in the political climate. However, high operating costs pose a threat and it may prove difficult to convince the indigenous groups in the Chaco region that there is potential benefit to a well-managed petroleum industry. In addition, there are a number of stages to the contractual process and it can be time-consuming and lengthy.

A reliance on imports probably explains why the country offers one of the most benign fiscal regimes in the world of hydrocarbons. In April 2013, Horacio Cartes, a businessman first and foremost, won Paraguay's presidential elections. He has no resource nationalism tendencies, as has been apparent elsewhere in Latin America, and the general consensus is that he will govern from a pro-investment perspective that will benefit the oil and gas industry. Paraguay holds no bid rounds and all contracts in the country are dealt with by the MOPC (Ministry of Public Works and Communications) and its Direccion de Hidrocarburos, a subdivision of the Vice Ministry of Mines and Energy, through an open licensing system. Moves to create a dedicated ministry for energy mines and hydrocarbons were defeated in 2013 but are likely to be revived.

Ken White

Cleared seismic lines through the Chaco Basin; the results of the seismic survey guided the drilling success.

Ireland – South Porcupine Basin

Multi-Client 2D & 3D Data

Polarcus is pleased to announce the availability of a major new multi-client seismic program in the South Porcupine Basin, offshore south-west Ireland. The South Porcupine Basin is an underexplored rift basin with multiple exploration plays, and this summer Polarcus and its partners have acquired 4,300 sq. km of 3D data and 5,000 km of 2D data in this area. The 2D data provides a comprehensive regional database infilling the new PAD regional dataset and complementing ION's NE Atlantic SPAN data, whilst the 3D data provides coverage over the Drombeg exploration prospect and the attractive adjacent open acreage. These new data provide a better understanding of the basin and allow companies to review the prospective plays and structures for the forthcoming 2015 Atlantic Margin Oil and Gas Exploration Licensing Round.

These new *RightBAND*™ data are being processed by GX Technology through a WiBand™ Pre-STM processing flow and data are available for licensing now to allow companies to evaluate the multiple plays seen in this under explored basin.

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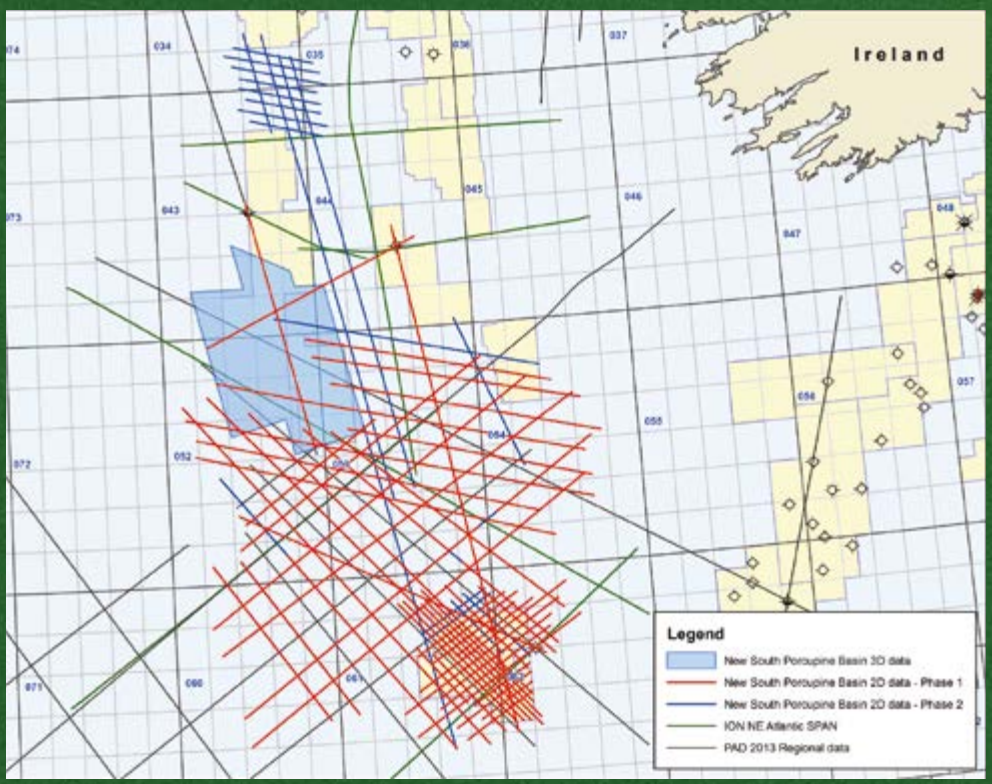

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Explaining US$85 per Barrel

The unexpected increase in tight oil production in the US explains why the oil price has plummeted from around US$110 per barrel in 2013 to roughly US$85 per barrel in recent months.

Nobody – absolutely nobody – was able to predict what was about to happen. In just three years, oil production from tight* reservoirs in the US tripled from 1 MMbopd in 2010 to more than 3 MMbopd in 2013. This year, production has increased to 4 MMbopd.

This dramatic increase from tight formations is all the more interesting when you take into account the fact that US oil production dropped to an all-time low of 6.8 MMbopd in 2008. By 2013, output was 10.0 MMbopd due to the technological revolution involving horizontal wells and fracking. The International Energy Agency (IEA) has made projections that suggest that US domestic crude oil production could increase to nearly 13 MMbopd before 2035. Such an optimistic view depends on both technical improvements and geological presumptions about oil resources.

Many analysts claim that this increased production from tight oil reservoirs in the US is to blame for the lowered oil price. How the predicted increase will affect the oil price remains to be seen.

Tight oil is also a viable option in many other countries, like Russia, Canada, China, Argentina and Mexico, all of which have unexploited resources. BP has made projections that production from such reservoirs may contribute up to 9% of total world oil production by 2030. In its *Energy Outlook 2030*, it says that "growing production from unconventional sources of oil – tight oil, oil sands and biofuels – is expected to provide all of the net growth in global oil supply to 2020, and over 70% of growth to 2030".

BP Group Chief Economist Christof Rühl is of the opinion that "vast unconventional… delivery has been made possible not only by the resources and technology, but also by 'above-ground' factors such as a strong and competitive service sector, land access facilitated by private ownership, liquid markets and favourable regulatory terms".

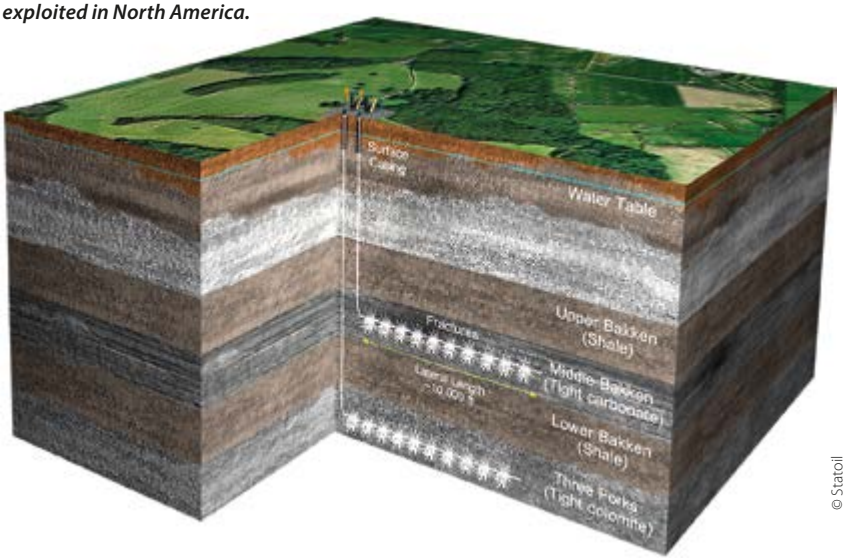
"No country outside the US and Canada has yet succeeded in combining these factors to support production growth," continues the economist.

North America will therefore still dominate production of tight oil in years to come.

**According to the IEA, "tight oil is an industry convention that generally refers to oil produced from very low-permeability shale, sandstone, and carbonate formations".*

Halfdan Carstens

Drilling for tight oil in the Bakken Formation in the Williston Basin, North Dakota. Horizontal wells and fracking explain why this previously inaccessible resource from low-permeability reservoirs is now exploited in North America.



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Conversion Factors

Crude oil
1 m^3 = 6.29 barrels
1 barrel = 0.159 m^3
1 tonne = 7.49 barrels

Natural gas
1 m^3 = 35.3 ft^3
1 ft^3 = 0.028 m^3

Energy
1000 m^3 gas = 1 m^3 o.e
1 tonne NGL = 1.9 m^3 o.e.

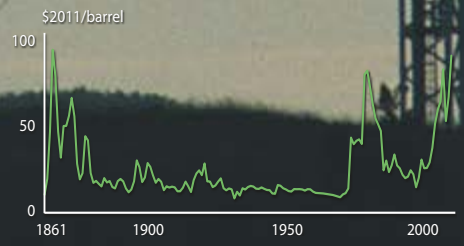
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

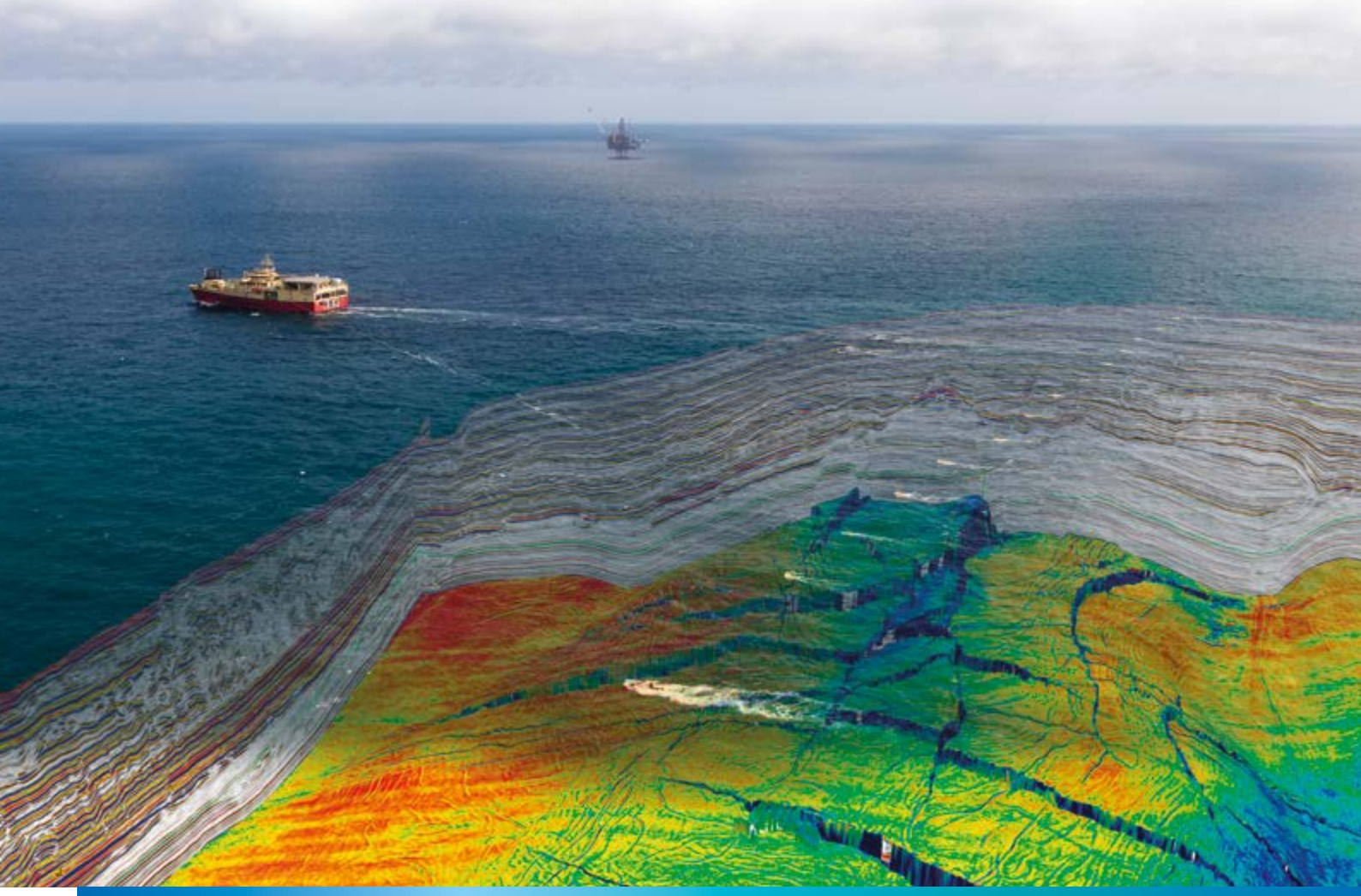
Supergiant field
Recoverable reserves > 5 billion barrels (800 million Sm^3) of oil equivalents

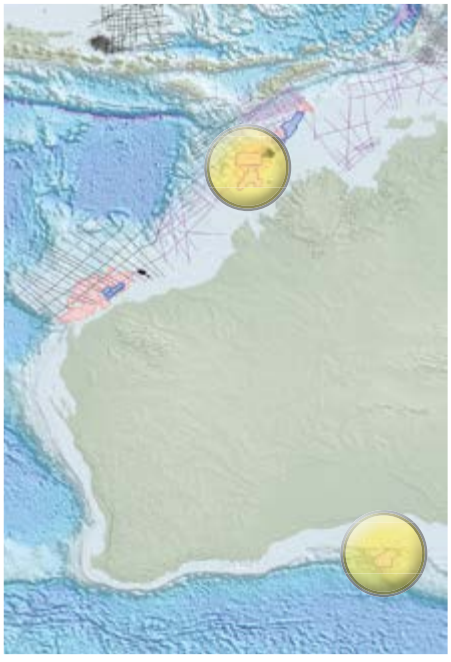
Giant field
Recoverable reserves > 500 million barrels (80 million Sm^3) of oil equivalents

Major field
Recoverable reserves > 100 million barrels (16 million Sm^3) of oil equivalents

Historic oil price







AUSTRALIAN HOTSPOTS

We've got them covered with GeoStreamer®

Browse Basin

PGS has acquired over 18,500 sq km of modern GeoStreamer® 3D data across the most prolific section of the Browse Basin. The new data sets reveal both new exploration potential and will also serve to de-risk future exploration and development strategies in this geologically complex area. Recent significant discoveries at Crown-1 and Lasseter-1, both within the survey area, have stimulated increased Industry interest in this part of the North West Shelf of Australia.

Great Australian Bight

Southern Australia has become a hot spot for exploration activity following recent acreage awards. The Ramform Sovereign will commence acquisition of the Springboard MC3D in November 2014. This survey will deliver 8,000 sq km of high quality true broadband GeoStreamer data over the Ceduna Sub-basin allowing lead identification and mapping of drillable locations.

To locate and evaluate prospects, head straight for the PGS MultiClient Data Library at **www.pgs.com/multiclient**

A Clearer Image

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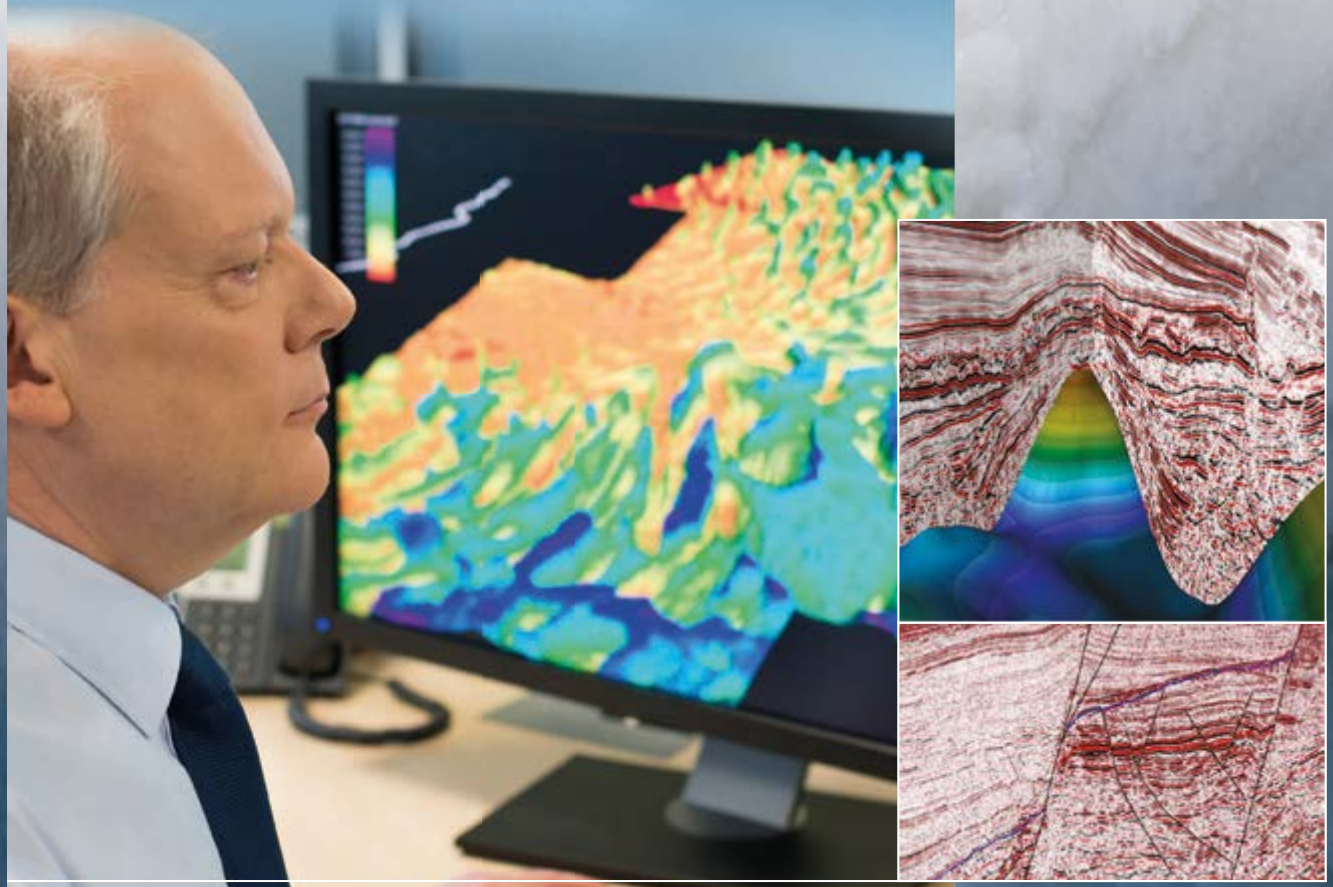
in the Barents Sea"

"SUCCESSFUL PRESALT WELL
offshore Angola"

"SIGNIFICANT OIL DISCOVERY
IN MOZAMBIQUE AND TANZANIA"

Multiclient



We make the data, you make the news.

Nobody knows where the next exploration success is going to be, but recent discoveries in the Barents Sea and the West Africa presalt Kwanza basin all have Schlumberger multiclient data at the heart of the story.

Decades of experience form the foundation of our multiclient team's petrotechnical knowledge. Together with the latest acquisition and processing technologies, our experts collaborate with you to identify the best opportunities in the most promising areas.

Write your own success story with our multiclient data:
multiclient.slb.com

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