VOL. 13, NO. 3 – 2016

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

HISTORY OF OIL:
Gulf of Mexico

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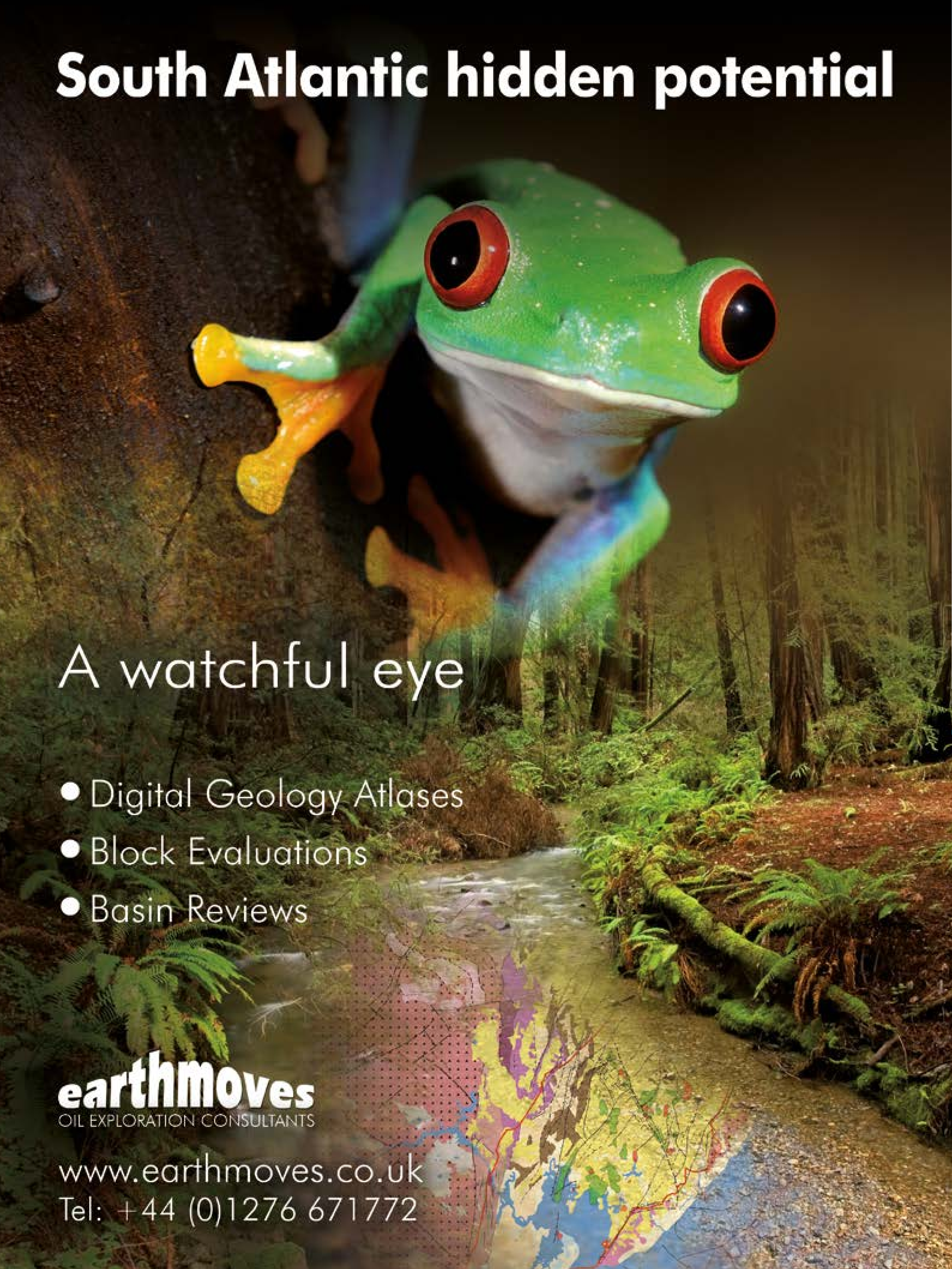
GEO TOURISM
Spectacular Swartberg

TECHNOLOGY EXPLAINED
A Cleaner Future for Heavy Oil

EXPLORATION
Unconventional Resources:
A World of Opportunity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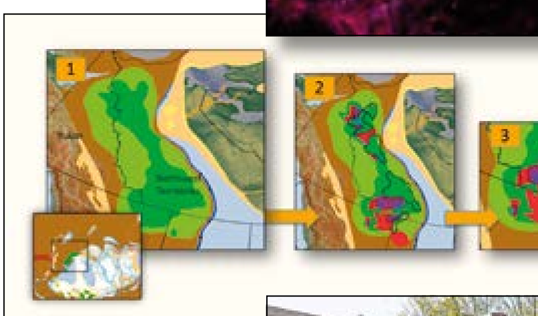

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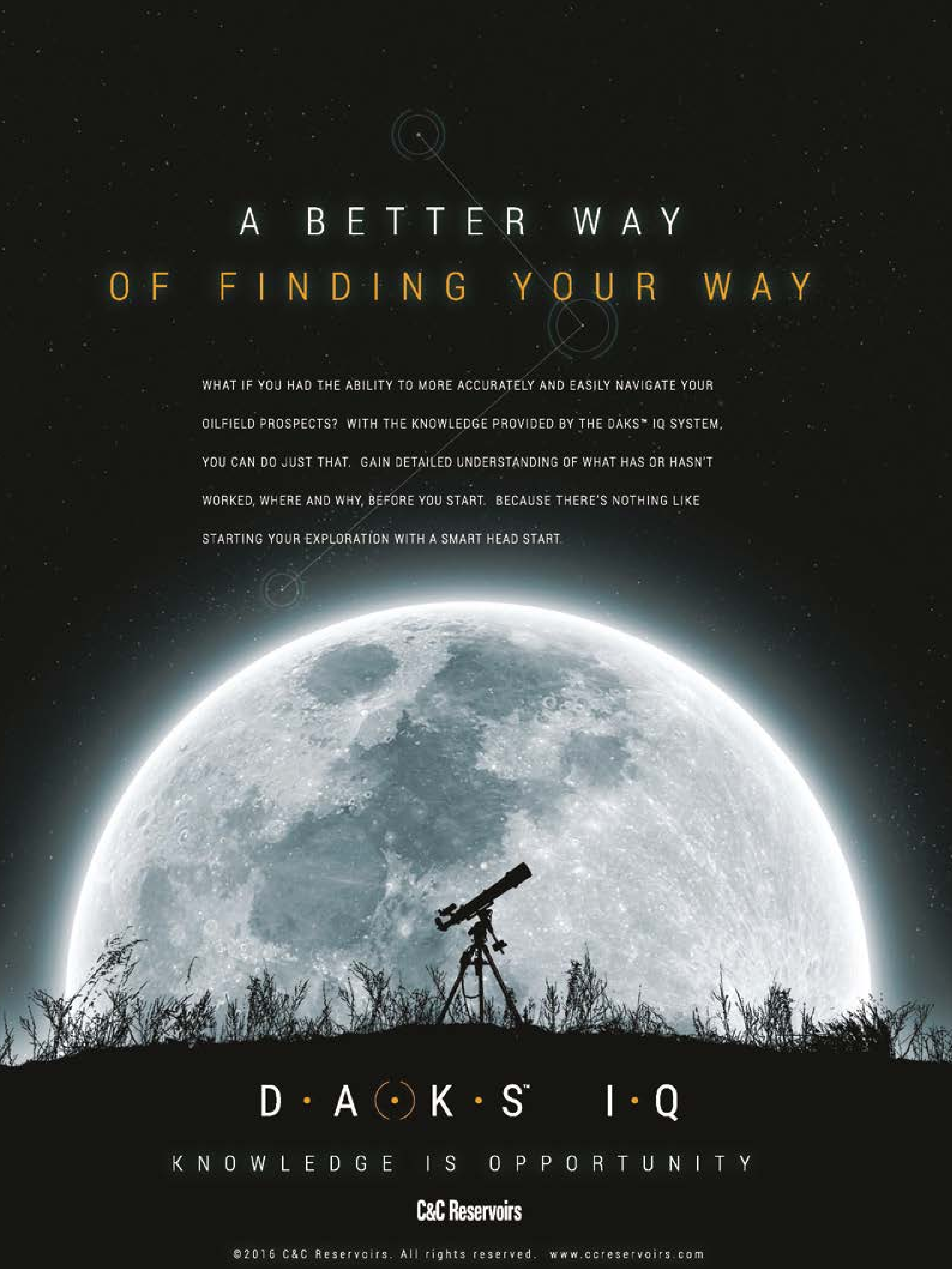
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A Dangerous Industry

Zukiman Mohamad

All 13 people on board a helicopter ferrying them to Bergen died when it crashed in April. In the Gulf of Mexico an offshore worker died on a rig in March and three workers were killed when fire broke out on an oil processing platform in February. A worker died in an explosion at field in Gabon in March; another fell to his death on the last day of 2015 when a huge wave hit a rig in the North Sea.

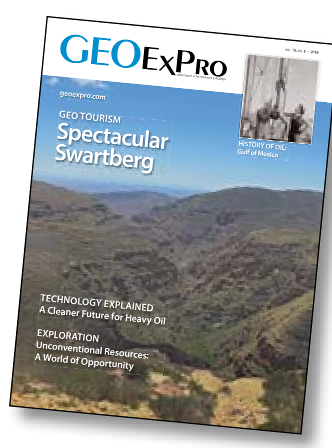
The list continues. Extracting oil and gas is a dangerous business, and E&P industry workers face some of the most difficult working conditions of any profession. In 2014 it was estimated that a US oil industry worker was about six times more likely to die at work than the average American.

Disasters like the 2010 Deepwater Horizon explosion grab headlines, but many work-related oil industry deaths result from transportation accidents – particularly helicopters. In the UK between 1995 and 2014, four fatal helicopter accidents claimed the lives of 38 offshore workers and crew, while 49 of 128 US fatalities during the years 2003 to 2010 had the same cause. In addition, the large trucks, cranes and heavy machinery common at oil fields account for a large number of deaths and injuries. According to a report from the International Association of Oil & Gas Producers, a third of fatalities reported to the organization in 2014 resulted from 'being struck', either by a vehicle or machinery, while 11% were the result of falls.

Other hazards at rig sites include exposure to deadly chemicals or to fire or explosions. In addition, many people in the industry work in regions where war and conflict add to the danger. A number of foreign oil workers were kidnapped in Libya last year and 39 oil workers held as hostages in Algeria were killed in 2013 when Algerian forces attempted to free them.

The E&P industry has very stringent safety rules, but it works in some of the most challenging environments in the world, from frozen Arctic wastes and searing deserts to mountainous seas, using heavy equipment in remote regions. We honor all those who have lost their lives serving this industry. May they rest in peace. ■

Jane Whaley
Editor in Chief



SPECTACULAR SWARTBERG

Looking down from the Swartberg Pass at a deep incised valley through the superbly folded rocks of the Paleozoic Cape Supergroup towards the vast expanse of the Karoo Plateau; the spectacular journey along this pass through the Swartberg Mountains is one no geologically minded visitor to South Africa should miss.

Inset: After the first onshore discoveries in the US, oil exploration moved rapidly offshore into the Gulf of Mexico.

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A Bumpy Road Ahead

The collapse of oil freeze talks reduces the chance of a change in OPEC's market share strategy.

Talks in Doha in April aimed at reaching the first extended production accord in 15 years between both OPEC and non-OPEC producers ended without an agreement to freeze oil output to stabilize prices. The failure to do so triggered another sharp oil price drop when the oil market opened, with Brent falling to about US $40/barrel. It has since risen to over US$ 48/barrel, but continues to fluctuate.

The outcome of the meeting is clearly a disappointment for the oil industry, which has been under severe pressure to cut costs and change its business models to increase profitability in the 'lower-for-longer' price era. Countries such as Venezuela and Ecuador have been especially hard hit by the collapse in oil prices since their peak in June 2014. The talks failed because Saudi Arabia insisted that Iran should sign up to the agreement. Neither Iran nor Libya were present at the meeting.

Saudi Arabia had actually indicated early this year after talks with Russia that it could comply with an output freeze even without Iran's involvement, but it has now decided it will not sign up without Iran. According to the media network Aljazeera the parties will try to meet again in June. The failure to reach an agreement in Doha clearly reduced the hope of any changes to the market share strategy or reintroduction of the quota system when the OPEC cartel meets on 2 June in Vienna.

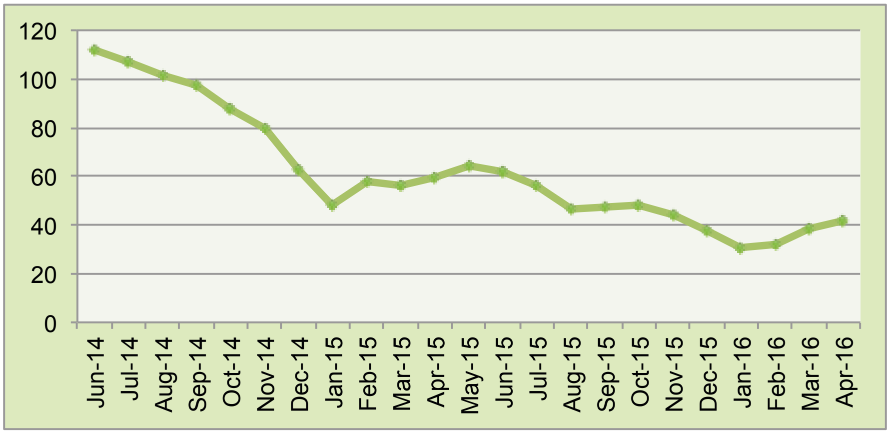
Drowning the Market

The outcome of the Doha meeting underlines the big controversies within OPEC, which had become evident when the group met in December. The cartel members could not manage to commit to a new production target in an attempt to reduce the vast supply glut and support oil prices. Saudi Arabia is clearly not ready to abandon the market share strategy launched at the OPEC meeting in November 2014 without the cooperation of Iran; in fact, in May Saudi Aramco chief executive Amin Nasser intimated that Saudi production will increase in 2016. Iran, meanwhile, will not sign up to any agreement to cap output before the country reaches pre-sanction levels of production.

This means that OPEC will continue drowning the market with cheap oil, trying to squeeze out the more costly producers such as the US, Russia and Norway, despite the fact that the process has been more painful and longer lasting than expected. This may also set off another round of price wars between Iran, Iraq, Russia and Saudi Arabia as competition is fierce to increase market share among clients in Asia and Europe.

Thina Margrethe Saltvedt

Brent Spot Price US$/barrel since the peak in June 2014. (Data source EIA)



ABBREVIATIONS

Numbers
(US and scientific community)

M: thousand = 1×10^3
MM: million = 1×10^6
B: billion = 1×10^9
T: trillion = 1×10^{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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* GME and geo-chemical surveys;
* Geophysical equipment manufacturing;
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EUR Per Well Heading Upwards

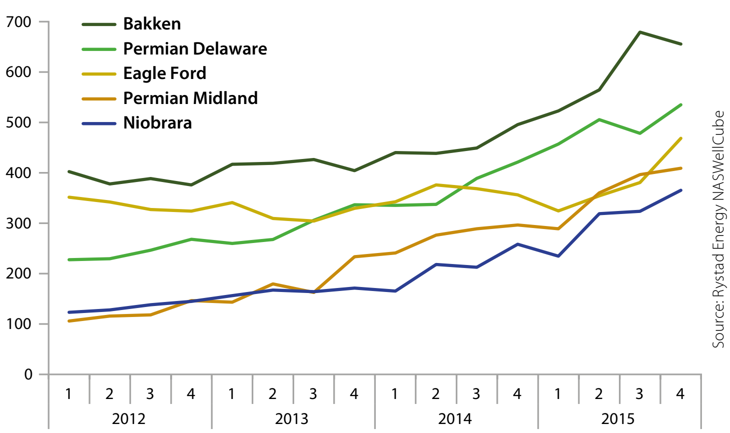
RYSTAD ENERGY

Well performance in North American shales has improved significantly.

The United States and Canada have been driving global shale production. Out of the 15.6 MMboepd produced from shale last year, 99% of the production came from North America. Shale production from this region has proven to be highly resistant to the low commodity prices.

One reason shale is surviving in the current price environment is because companies have shifted their exploration focus. When prices were high, shale producers actively explored for the next big play, mainly through drilling exploration wells on new acreages. As the oil price started to drop, producers returned to their core areas. The shift in focus then centered on improving completion techniques and increasing the recovery per well.

The impact of this activity is illustrated below. The chart shows the average estimated ultimate recovery (EUR) for oil per well for selected US shale plays split on the quarters the wells started up.



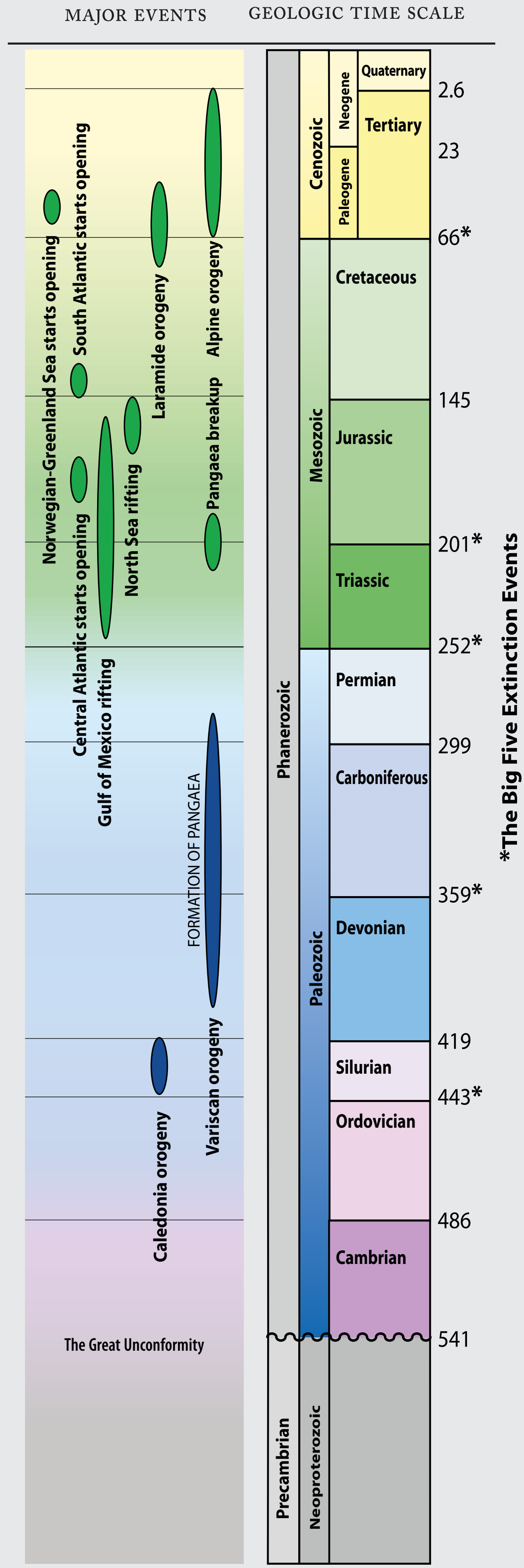
Average oil EUR per horizontal well. Thousand Boe.

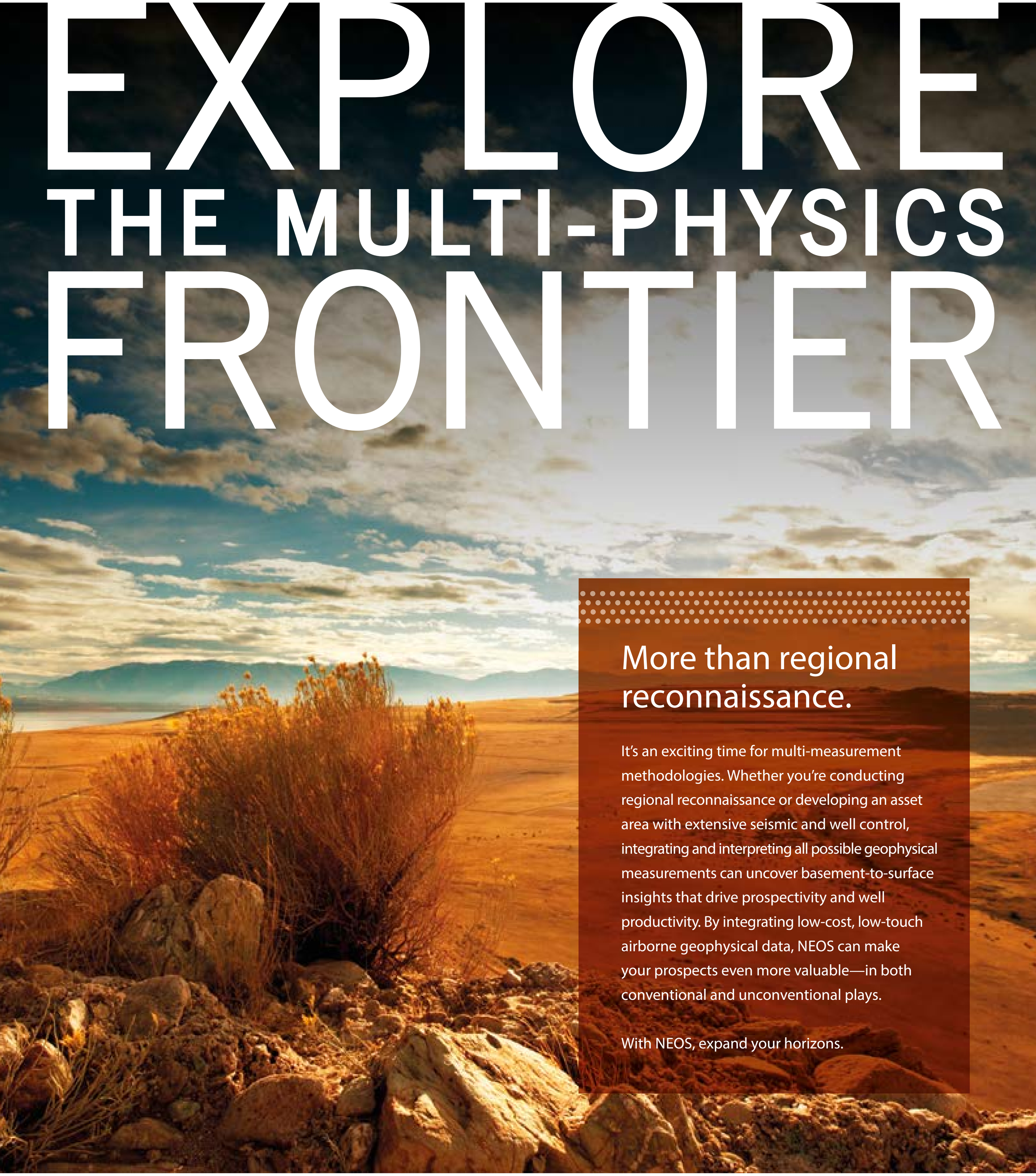
The chart shows considerable improvements in the production volumes per well, especially in 2015. On average the resource per well increased by 45% from the beginning of 2014 to the end of 2015. For Bakken, the play with the highest oil estimated ultimate recovery, the number increased from 400 Mboe to above 600 Mboe. Meanwhile, Niobrara's EUR more than doubled during the same period, from 150 Mboe to above 350 Mboe.

There are several reasons behind these increased well performances. Companies are targeting the best drilling locations, and are drilling wells with longer laterals and well flow optimization, which accounts for some of this increase. Improved microseismic has also enabled the drillers to perform more efficient well placement, while better completion techniques, such as slick water, have enhanced the fracking process.

While well performance improvement has been a key challenge for shale producers over recent years, it is a challenge they have delivered on. This knowledge will be vital when exploration of new acreage starts up again, and will help more basins to be commercial. ■

Espen Erlingsen, VP Analysis, Rystad Energy





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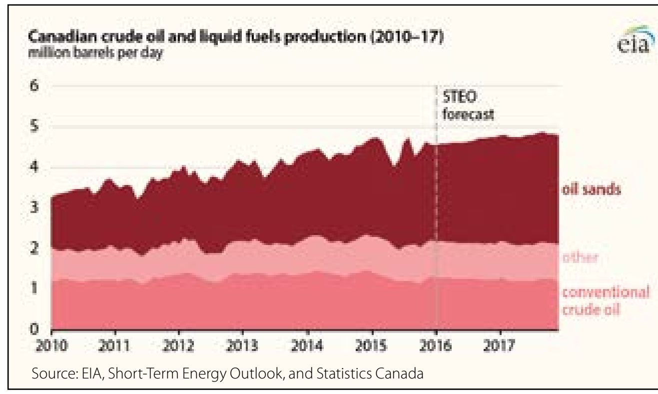
Canada's Production to Increase

Despite lower crude oil prices, the US Energy Information Administration (EIA) expects **Canadian oil production** to continue increasing through 2017, primarily driven by oil sands projects which were already under construction when prices began to fall in 2014. According to the **EIA's February Short-Term Energy Outlook**, production of petroleum and other liquids in Canada, which totaled 4.5 MMbopd in 2015, is expected to average 4.6 MMbopd in 2016 and 4.8 MMbopd in 2017. This increase is driven by growth in oil sands production of what is expected to be about 300,000 bopd by the end of 2017, although partially offset by a decline in conventional oil production.

Canadian heavy oil prices are linked to the Western Canadian Select benchmark. This has traded about US$15–20/barrel lower than US benchmark West Texas Intermediate crude oil since early 2014 because the Canadian oil has to be transported over longer distances to refineries and, due to its density and quality, it is more difficult to process. The average price for WCS in January 2016 was US$18.42/barrel, suggesting that many oil sands projects may be trading at a loss at the moment, but they are built to have a life span of over 30 years, and would hope to weather a short term downturn. New projects, however, have been slow to come onstream as operators wait for an improvement in prices. ■



Source: EIA, Short-Term Energy Outlook, and Statistics Canada

NEOS Expands

Exploration solutions provider **NEOS** recently announced its acquisition of **CGG's Multi-Physics and General Geophysics** Italy business lines which, once the transaction closes in a number of months, will make it the world's premier multi-physics company, delivering a full-scope offering that encompasses survey design, data acquisition, processing and analytic interpretation.

The combined company, which will continue to be called NEOS, will feature the world's largest fleet of geophysical acquisition aircraft; one of the largest multi-client Grav-Mag data libraries in the world; advanced multi-physics technologies, including AGG, EM, hyperspectral imaging and predictive analytics; and industry-leading capabilities in seismic data processing in complex geologic regimes, including subsalt, naturally fractured, and stacked-pay reservoirs. It will also increase the company's workforce to nearly 350 professionals around the world, including Perth, Johannesburg, Rio de Janeiro, Italy, Toronto, Denver and Houston.

NEOS accesses, acquires and analyzes a broad range of geological and geophysical data, including public domain information, client data, and data acquired using proprietary platforms, to produce a highly constrained 3D model of the subsurface. By applying the latest geostatistical and predictive analytics techniques, this can be used to determine the most prospective parts of a country or natural resource basin. ■

The Path to the Arctic

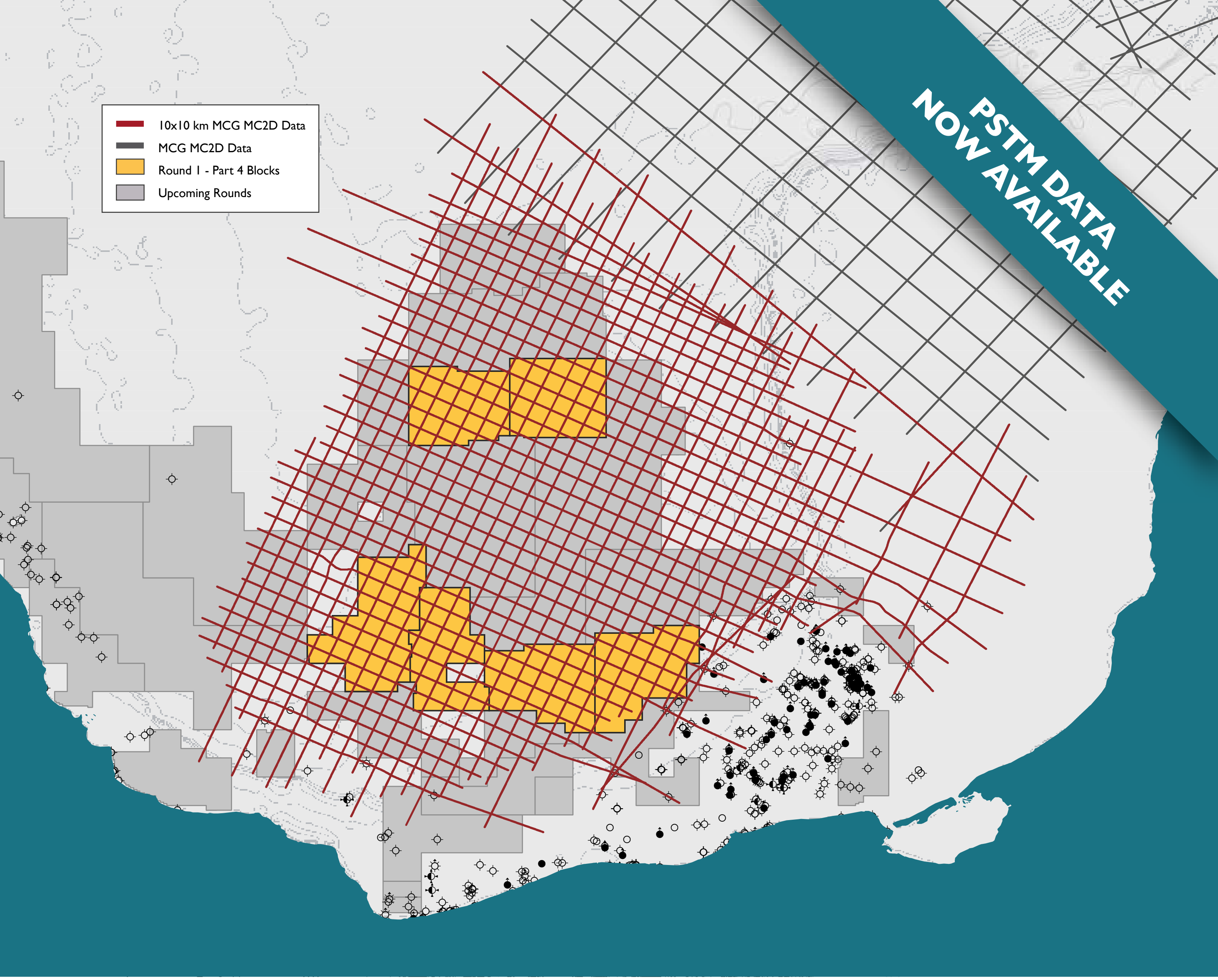
OTC's **Arctic Technology Conference** (ATC) is the only Arctic event backed by the combined reach and credibility of 14 of the world's top engineering and scientific organizations. Harnessing OTC's more than 45-year history of successful multi-disciplinary events, ATC is the world's most focused and comprehensive technical conference and exhibition for Arctic E&P professionals.

ATC will be held in St John's, Newfoundland, in October.


Riche Perez

Now in its fourth year and built with expertise representing every discipline, the conference has demonstrated its success by attracting industry professionals from 26 countries.

This year, the ATC will be held at the Convention Centre in **St John's**, capital of **Newfoundland and Labrador,** on **24–26 October**. St John's is well known as an ideal staging and proving ground for Arctic-related research and offers the global Arctic industry a strategic North Atlantic base for operations on international shipping lanes and northern sea routes. It is home to well-established infrastructure and with the development capacity to support a growing energy sector. It is also the site of world-class academic and training institutions prepared to respond to the demand for innovative technology solutions. ■



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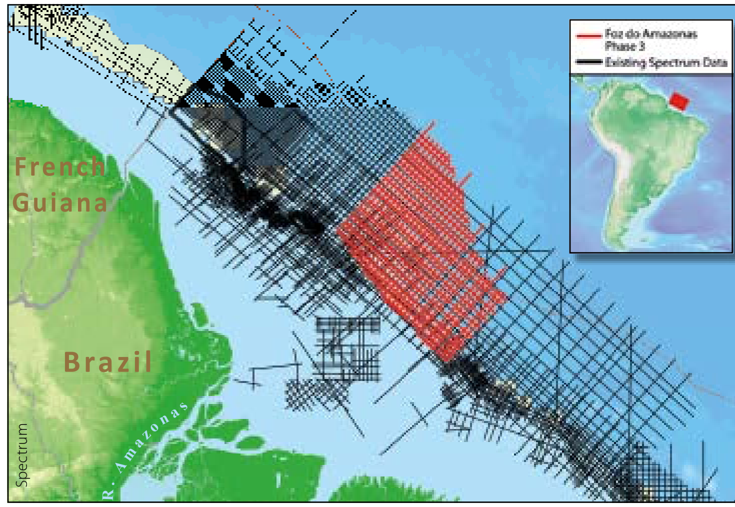
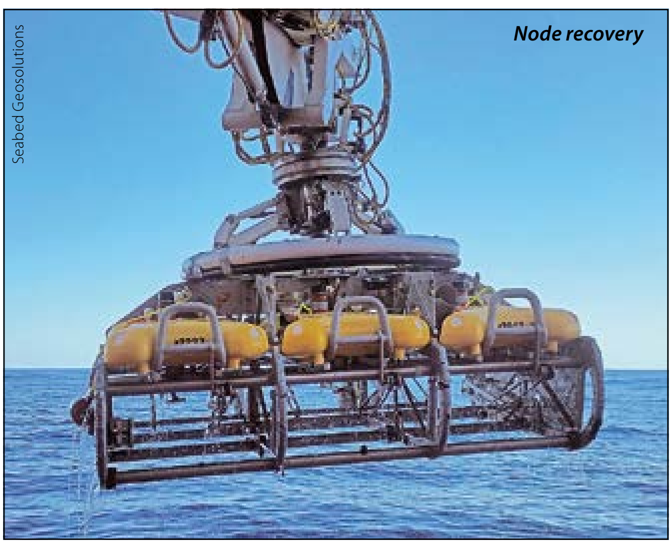
New MC Seismic Survey Offshore Brazil

Spectrum, in partnership with **BGP**, have recently commenced a 10,400 km multi-client long offset 2D survey in the **Amazonas and Para-Maranhao Basins** along the Equatorial Margin offshore **Brazil**. Data is being acquired with a 12,000m cable and will be processed in Spectrum's processing center in Houston, with PSTM, PSDM and broadband products expected to be available in Q4 2016.

The data will be merged with over 125,000 km of recently acquired and reprocessed data to provide the industry with a continuous dataset along the Brazilian Equatorial Margin from the French Guyana border through to the Potiguar Basin. Long offset acquisition has been used in order to help understand the basins' architecture as well as to better image the prospective zones in the mid and lower Cretaceous sections. A licensing round covering this area is expected in 2017. ■



Largest Ocean Bottom Node Survey



Node recovery

The world's largest – and **Australia's** first – **ocean bottom node survey (OBN)** has recently been completed by **Seabed Geosolutions**. The data were acquired offshore in the **North-West Shelf** area, and the two vessel operation deployed nodes on more than 3,000 receiver locations, achieving a failure rate of less than 0.5%. The shooting effort comprised almost 700,000 shots in dual source mode with an 18.75m shot interval. Initial client feedback indicates the quality of the data is very promising.

Stephan Midenet, Seabed Geosolutions' CEO, commented "Efficient operations and QHSE excellence led to the project being acquired ahead of schedule and under budget with an exceptional health, safety and environmental record."

OBN data offer unparalleled image quality due to the full azimuth/long offset survey geometry the technology allows and it has become the seismic technology of choice for 'development quality' data in deepwater areas worldwide. ■

Industry Technology for Research

The **British Antarctic Survey (BAS)** recently purchased two **Prion Mk3** drones from **UAVE Ltd.**, to be deployed at its science research station, Rothera, during the 2016/2017 summer work season in Antarctica. BAS's aim is to use the drones to make measurements that are not currently possible, such as airborne measurements in the Antarctic winter, and to undertake current airborne analyses in a more economical way.

The Prion Mk3 is the culmination of an oil industry-funded research project and was initially designed for work within that environment, but this new project diversifies the use of the aircraft for other scientific surveying purposes, which are anticipated to be many and varied across Antarctica.

The aircraft has applications in offshore wind farm operations, aeromagnetic surveys, and meteorological and air quality monitoring, as well as payload (humanitarian aid) delivery. The Prion Mk3 is highly versatile and can launch from a grass airstrip or otherwise via a compressed gas launcher where no airstrip is available. The long range flight endurance characteristic of the Prion is known to have been key to the decision process of BAS in awarding this contract to UAVE Limited. ■

Real-Time Downhole Flow Measurement

Fluid injection monitoring and placement often requires customers to reach conclusions through trial and error or time-consuming logging operations. To improve this situation, **Schlumberger** has developed a **real-time downhole flow measurement service** which delivers real-time injection diagnostics and treatment evaluation in just one run in a well. The **ACTive Q** service uses fiber-optic telemetry and calorimetric flow measurements so that engineers can evaluate the flow rate contribution to each interval, review the data in real time and adjust the pumping schedule as needed for diversion and subsequent stimulation stages.

As Amerino Gatti, president, Product Group, Schlumberger, says: "With the ability to measure pressure, temperature and fluid velocity in real time during interventions, the ACTive Q service improves our customers' understanding of downhole wellbore and reservoir behaviors while intervention is ongoing. This helps facilitate customers' decision-making and improve the effectiveness of treatment placement."

Schlumberger cite how the Kuwait Oil Company wanted to stimulate a water injector well which was suffering falling injection rates and an increase in wellhead injection pressure. Using this service enabled it to identify the sections that needed stimulation or diversion while avoiding additional logging runs. The accurate targeting of those sections with an adequate fluid treatment resulted in decreased wellhead injection pressure beyond project expectations and significant cost savings.

The ACTive Q service is part of the ACTive* family of real-time downhole coiled tubing services. ■

*Mark of Schlumberger

AAPG in Cancun

AAPG's 2016 International Conference and Exhibition (ICE) returns to Latin America – this time to beautiful **Cancun**. Hosted by the AAPG Latin America region, the Society of Exploration Geophysicists (SEG), the Mexican Association of Petroleum Geologists (AMGE), and the Mexican Association of Exploration Geophysicists (AMGE), this is the premier international geosciences event for information exchange, knowledge, networking and new business development opportunities, covering the topics most beneficial to your career.

Making headlines, **Mexico's** recent legislative changes aimed at increasing oil and gas production are opening up opportunities for the private sector. Global attention is now focused on the horizon of promise these changes may deliver. Industry partners and companies such as yours are essential in integrating all of the technology, product and service solutions necessary for prosperity. At this major event you will be able to collaborate with innovation leaders and technical experts, gain unmatched exposure and discover new opportunities.

With the downturn continuing in today's global market, Mexico's energy reform pushes forward on the fast track to success. As Mexico sticks to its plan and continues to increase access to new oil and gas prospects, now is the time for you to join this new horizon of E&P opportunities.

The conference will be held on 6–9 September at the Cancun Convention Center. Registration and sponsorship opportunities are also still available. ■

Spectacular Swartberg

JANE WHALEY

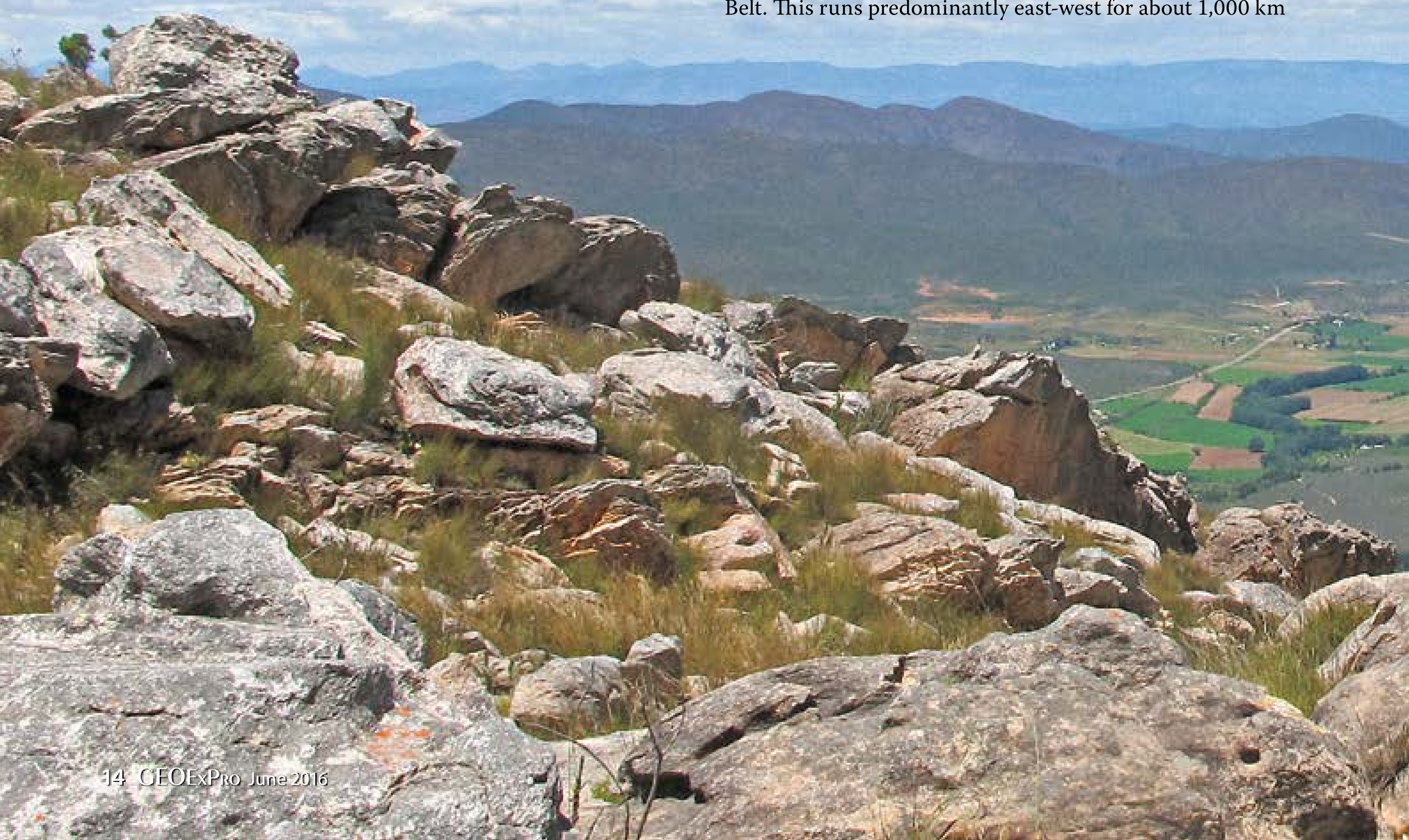
The Swartberg Mountains in the Western Cape province of South Africa are considered to be one of the finest exposed fold mountain chains in the world. Two dramatic passes afford the geologist unparalleled views of Paleozoic quarzitic sandstones folded spectacular fashion.

The Swartberg (Black Mountains in Afrikaans) range, part of the Cape Fold Belt, stretches from the town of Laingsburg, 200 km east of Cape Town, eastwards for 230 km, with the Klein Karoo to the south and the vast expanse of the Groot Karoo to the north. The easternmost end of the range rises over 2,000m and is traversed by two dramatic roads: the paved Meiringspoort Pass and unpaved Swartberg Pass. It is possible to drive a circular route encompassing both these passes – a round trip from the town of Oudtshoorn of about 170 km – in a day, allowing for frequent stops to gaze at the breathtaking views and the awe-inspiring rocks, and also the beautiful flowers, vegetation and bird life. Much of the Swartberg range is a UNESCO World Heritage site.

Folds and Thrusts

The geology of the Western Cape region is dominated by the Ordovician to Lower Devonian Cape Supergroup (CSG). This originally consisted of as much as 10,000m of layered sandstones and shales, deposited in a rift valley on a subsiding continental margin, and lying unconformably on top of Precambrian basement sandstones, siltstones and thick mudstones. These older rocks are mostly found in the vicinity of Cape Town and the far west of the Western Cape, but also outcrop at the foot of the Swartberg Mountains as the Cango Caves Group, and comprise limestones, turbidites and conglomerates..

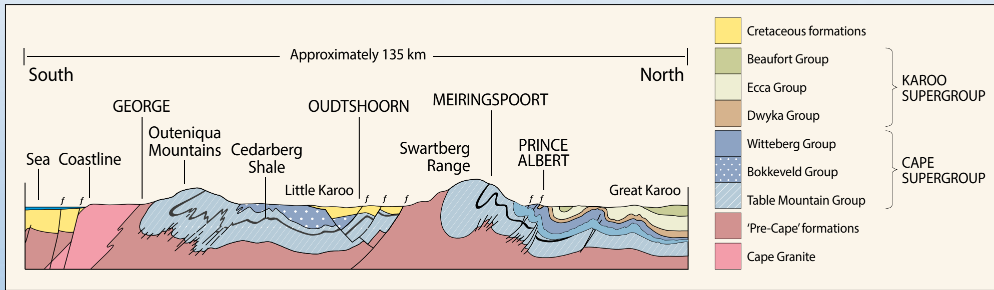
About 330 million years ago, as the continents collided to form the super continent of Pangea, a subduction zone formed in the south, causing the CSG to undergo uplift and compression, which deformed and folded the previously horizontal layers, forming a mountain range up to 7 km high. The weight of the buildup of these mountains caused subsidence, and a large basin formed to the north. Between the Late Carboniferous and the Early Jurassic this filled with the sediments partially derived from the CSG rocks to form the Karoo Supergroup, which as the Karoo Plateau now lies over much of the center of South Africa, stretching from the northern Cape area over 1,000 km to Johannesburg. The CSG rocks underwent extensive erosion during this period and were partially buried by Karoo sediments, but re-emerged during the tectonic upheavals which resulted from the breakup of Gondwana about 150 Ma to form the Cape Fold Belt. This runs predominantly east-west for about 1,000 km



Jane Whaley

The view from the 1,568m Swartberg Pass, looking south across the Oudtshoorn valley and the little Karoo to the Outeniqua Mountains in the far distance.

across the southern tip of present-day Africa, with the westernmost arm trending north-south parallel to the west coast. Some Cretaceous sedimentation occurred in the Western Cape area, but much has been eroded except in the Oudtshoorn Basin south of the Swartberg Mountains, although it is believed to be widespread offshore.



North-south geological cross-section through the southern Cape Fold Belt, from the southern Karoo to the complex of offshore basins formed during the breakup of Gondwana. In the center it crosses the arch of metamorphosed sediments that lie beneath the Cape Fold Mountains and the Cretaceous sediments around Oudtshoorn. (Vertical scale exaggerated.) Courtesy of Norman and Whitfield, 2006.

An extensive fault system runs through the Western Cape parallel to the Cape Fold Belt, with evidence of older faults being reactivated into thrusts due to compression. Along the southern edge of the Swartberg Mountains the Cango Fault, which extends for 320 km eastwards from Cape Town, forms the boundary between the Cretaceous sediments of the Uitenhage Group in the Oudtshoorn Basin and the uplifted older rocks of the Swartberg Mountains, with rocks of the Precambrian Cango Caves Group exposed at their base.

Traversing the Swartberg

The Swartberg Pass (the westernmost route through the mountains) is a national monument, honoring the amazing achievement of Thomas Bain, the engineer who (with help from convict labor and lots of gunpowder) created the 24 km-long road, which was opened in 1888. It travels up the southern side of the mountains, predominantly composed of massive quartzites of the lower Table Mountain Group (TMG), the oldest rocks of the CSG, which rise almost vertically over 1,000m from the valley floor. It then winds down through the crevasses and folds of younger TMG sediments, to Prince Albert and the Groot Karoo. The road is gravel, but unless there has been a lot of rain it does not require a four-wheel drive car.

Meiringspoort Pass is now traversed by the main N12 north-south road from Beaufort West to the coast, but the first, rather rough road through the pass opened in 1858. It is very different to the Swartberg Pass, as the route follows the path of the Groot River, which has eroded through the surrounding mountains to form a deep canyon. The soaring cliffs on either side show more fantastic exposures of folded and refolded TMG rocks. The route crosses the river 25 times, a fantastic feat of engineering – but this meant that the road was susceptible to flooding and eventually, to avoid this, the alternative western route was constructed.

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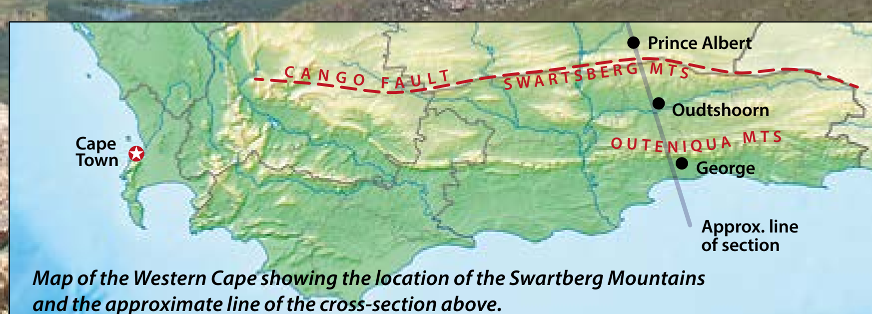


Map of the Western Cape showing the location of the Swartberg Mountains and the approximate line of the cross-section above.

Near the northern end of the pass you find vertically bedded quartzites of the Witteberg Group, some of the youngest rocks of the CSG.

The small picturesque town of Prince Albert, backed by the Swartberg Mountains, marks the beginning of the Groot Karoo. It is situated on sandstones and shales of the Carboniferous to Triassic Karoo supergroup, which underlies much of South Africa beyond the Cape region.

Spectacularly folded quartzites, again from the TMG, lie immediately above the thin Cedarberg shale layer, which acted as a plane of dislocation. This area is reputed to have some of the best exposures of folded mountain rocks in the world.

Looking back towards the top of the Swartberg Pass along the ridge of almost vertically bedded rocks of the Table Mountain Group.

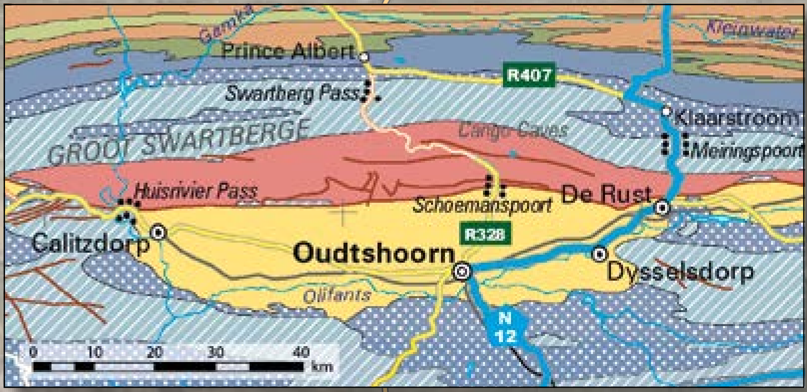
The views south from the top of the Swartberg Pass are spectacular, as can be seen on the photo on the previous page. They are also stunning looking north – see the front cover.

Between Schoemanshoek and the Cango Caves you cross the Cango Fault and move from the reddish brown conglomerates of the Enon Formation, part of the Cretaceous Uitenhage Group, into the much older slates and dark limestones of the Upper Precambrian Cango Group, the darker rocks. The cliffs of the TMG quartzite tower above them. Oudtshoorn is famous for ostrich farming.

Some of the many highlights to be seen during the fantastic 170 km round trip from Oudtshoorn through the Swartberg Pass to Prince Albert and back via the Meiringspoort Pass.

Background Topographics: Imagery ©2016 TerraMetrics, Map data © 2016 AfriGIS (Pty) Ltd, Google

Geology in the Swartberg Pass region. For legend see cross-section on page 15. Courtesy of Norman and Whitfield, 2006.



The paved road back to Oudtshoorn goes through the beautiful Meiringspoort Pass, very different in character to the Swartberg Pass, as it follows the river through a steep-sided valley through the Bokkeveld and Table Mountain Groups.

South African Tourism

The Cango Caves are a major tourist attraction in the area. The extensive system of caves and tunnels in the 1,200m thick Cango limestone covers about 4 km, although only a quarter is open to visitors. Cango is the local San word for water mountains, because of the number of streams rising here.

Heading south through Meiringspoort, stop at the information point at the picturesque 60m high waterfall and admire the steeply folded TMG rocks which form the steep sides of the valley in all directions.

1 *The Klein Karoo is a semi-arid valley between the Outeniqua Mountains (in the far distance) and the Swartberg range. In the Oudtshoorn region it is underlain by the relatively soft clastic sediments of the Jurassic-Cretaceous Uitenhage Group, a diverse group deposited in shallow marine environment.*

A Cleaner Future for Heavy Oil Extraction

JOE KUHACH
Nsolv

Climate change has raised questions about the future of carbon-intensive industries, including the development of unconventional oil reserves. But emerging technology from Canada is proving that heavy oil extraction can be made cleaner without imposing major costs on producers or the environment.

Global energy demand is projected to increase roughly 33% in the next 25 years, according to the International Energy Agency. How that demand will be met is a central question in the current debate around combatting climate change. In the wake of COP21, governments around the world have set their sights on a low-carbon future and a transition away from so-called 'dirty' fuel sources, like oil. The challenge is that oil is currently the most-used fuel source worldwide, so it is hard to imagine a near-term scenario where oil is phased out and energy demand is still met.

Despite this reality, governments have already begun pulling on policy levers like carbon taxes to discourage a reliance on oil. Such initiatives are particularly precarious to heavy oil development. Heavy oil is an unconventional liquid petroleum with less than 20° API gravity, and extra-heavy oil is even more dense and immobile at less than 10° API gravity. Because of their low viscosity these oils are more challenging and expensive to extract compared to conventional oil. They also impose a larger environmental footprint, including carbon emissions. Therefore, the impact of carbon taxes and low prices is more severe for heavy oil producers compared to conventional oil counterparts. This begs the question whether the future of the heavy oil industry is in jeopardy.

The status quo of heavy oil extraction may be under pressure, but new technology being developed in Canada is showing that unconventional reserves can be developed in a more sustainable and economic way. Nsolv, a clean energy company, has introduced a solvent-based extraction process that results in significantly fewer greenhouse gas emissions, uses no water and improves project economics compared to existing heavy oil recovery technologies.

A Global Picture of Heavy Oil

Some estimates have shown there is twice as much heavy oil left to be tapped

Solvent-based heavy oil extraction, shown here in northern Canada, is a potential solution to the environmental concerns around current production methods.

Close-up of NSolv's pilot project in the Canadian oil sands.

worldwide than there is conventional oil. The largest known reserves of heavy and extra-heavy oil are situated in Canada and Venezuela, with significant amounts also found in the Middle East, Russia and China. What makes oil 'heavy' is the fact that it is thick, sometimes immobile and often locked into a reservoir of sand underground. This leads to monikers like 'oil sands,' a term used to describe the natural extra-heavy oil or bitumen in northern Canada.

Several technologies have been developed over the years in order to mobilize the otherwise immobile fluid. In the Canadian oil sands, the industry incumbent is steam assisted gravity drainage (SAGD), a process that uses natural gas to heat vast amounts of water to create steam that is injected underground. When heated with steam at high temperature and pressure, the bitumen melts, allowing it to flow into a production well, which pumps it to the surface.

While effective, SAGD has environmental and economic consequences, which include high greenhouse gas emissions associated with steam generation, as well as high costs associated with handling, separating and purifying large amounts of water. This environmental reality reinforces the negative perception that oil is a dirty fuel source.

Solvent Not Steam

Both the environmental and economic challenges of SAGD are rooted in the consumption and handling of water to make steam. Calgary-based Nsolv is proving that when steam is removed from the equation, heavy oil extraction becomes a whole lot cleaner and cost efficient. The company has patented a process that replaces steam with a purified, warm solvent. Nsolv demonstrates that when a solvent, typically butane or propane, is vaporized and injected underground, it condenses and diffuses into heavy oil, decreasing the oil's viscosity and allowing it to flow. Injected solvent is produced with the oil and reused in the process.

This simplified process has major environmental and economic advantages over SAGD. There is no need for a continuous supply of water, and since the solvent only needs to be heated slightly, Nsolv uses a fraction of the energy required for SAGD. As a result, heavy oil can be extracted with only a quarter of the greenhouse gas emissions.

The lack of water and reduced energy use also result

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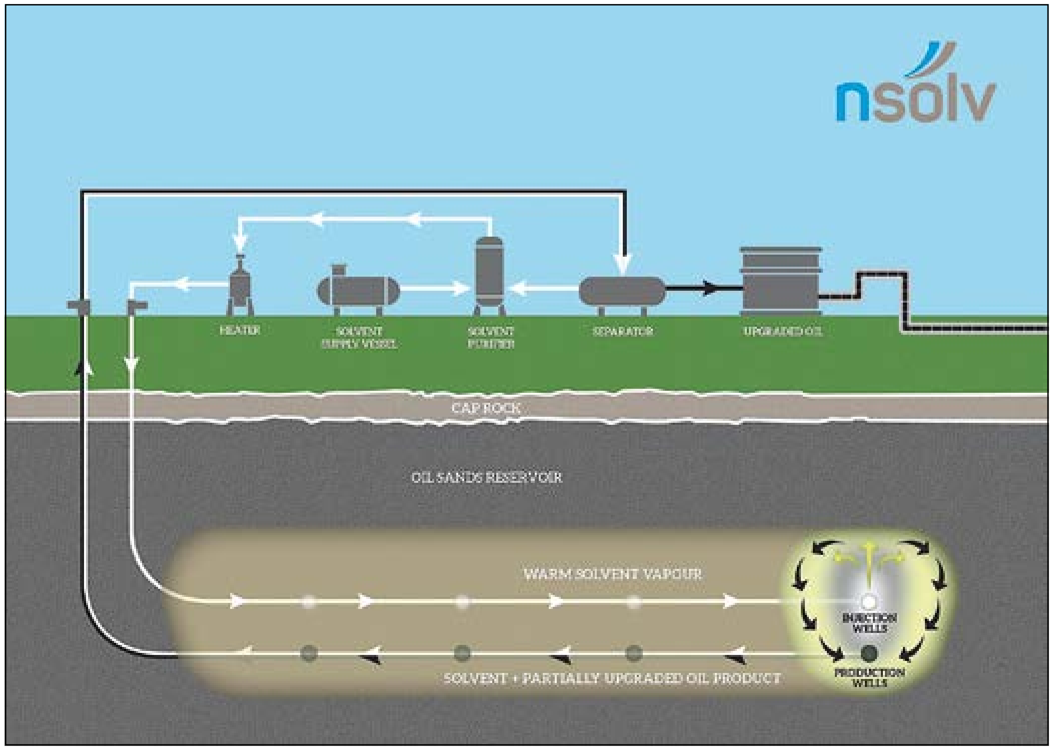
in significantly lower operating costs and about a 40% reduction in capital costs to the operator. In addition, the solvent-based process results in a partially upgraded, higher-value oil with less waste from the refining process, since the low-value, high-carbon asphaltenes, along with heavy metals, get left behind in the reservoir. The partial upgrading also means that very little diluent is needed to ship the oil via pipeline. In effect, more oil of better quality can be shipped through existing pipelines. When all the benefits are considered together, it means extraction with solvents is economically viable even in a low oil price environment.



The Nsolv process involves the use of solvent to produce heavy oil rather than steam, as is the case with steam assisted gravity drainage.

Evolution of Solvents

Nsolv's process dates back to the 1970s, when Emil Nenniger began researching methods to extract oil sands bitumen in-situ. One winter, while tapping maple trees at his family farm in Ontario, Mr Nenniger found inspiration in the consistency of the maple syrup after it was distilled from the thin tree sap. If only heavy oil could move like maple syrup, he thought, the problems of getting it out of the ground and to market would be solved.

Nenniger began to experiment in the lab to develop a process that would use solvent. He was testing his theory that by mixing the solvent with the heavy oil, the oil would become less viscous and movable. While the solvent idea worked, further testing showed that the process occurred too slowly for it to be economically viable.

Years later, John Nenniger would work with his father to finish the work Emil began. Through further testing, they showed that purifying and heating up the solvent just a little would make it diffuse into the heavy oil more quickly, drastically reducing the viscosity of the heavy oil and enabling it to flow into a production well. The solvent could also be recovered and reused throughout the process, only needing a small top-up. This seemingly simple idea is at the heart of Nsolv Corporation, which was formally founded in 2003 and shortly thereafter received financial backing from engineering and pipeline giants Hatch Ltd. and Enbridge as major long-term equity partners.

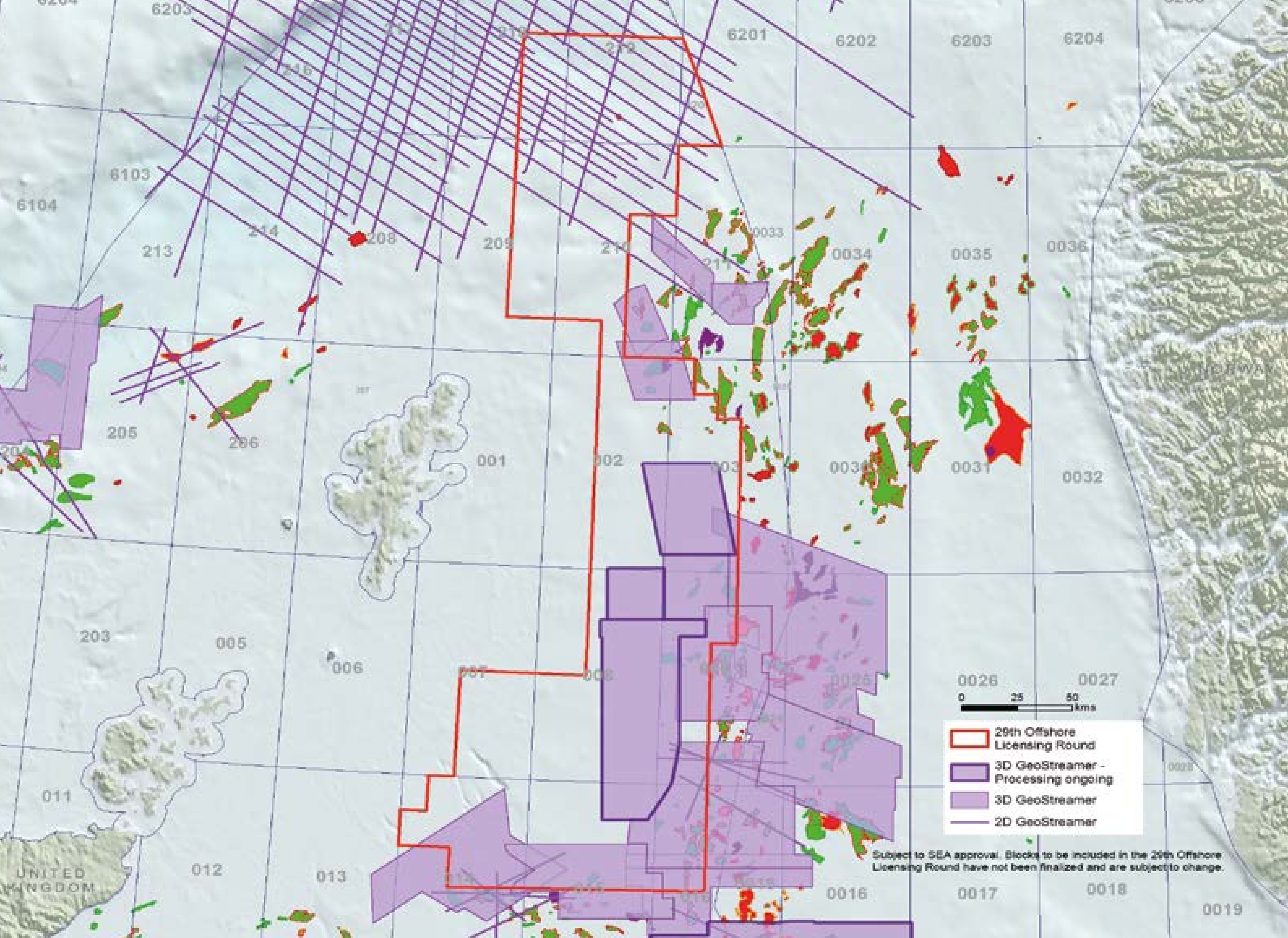
In 2012, Nsolv teamed up with one of Canada's largest energy companies, Suncor Energy, to put its technology to the test via a pilot project in the Alberta oil sands. With support from this partnership, and government funding from Sustainable Development Technology Canada and Alberta's Climate Change and Emissions Management Corporation, the Nsolv pilot plant was constructed.

After construction and commissioning, the pilot began producing in spring of 2014 and the plant recently produced its 90,000th barrel of oil, all the while meeting key performance indicators. The project has been pivotal to the company's evolution. Not only does it prove the technology's commercial potential – a requirement for any producer to even consider switching production methods – it provides a showcase for the technology's environmental and economic benefits.

Implementing Solvent Technology

Large-scale commercialization of solvent-based extraction will be the next big step in the technology's evolution. Despite the push toward renewable energy sources, the world will continue to rely on oil as a fuel source. Yet governments remain eager to find economic and environmentally sustainable energy technologies. With pressure mounting on producers to reinvent or adjust their extraction methods for both environmental and economic reasons, solvents offer a viable alternative. This presents great opportunities for technologies like Nsolv.

To date, this process has been applied strictly to the bitumen found in the Canadian oil sands; however, the technology has huge potential to unlock heavy oil resources worldwide. Heavy oil will continue to be in high demand until there are significant advancements in renewable energy generation and storage. With companies like Nsolv proving that heavy oil extraction can be done in a more sustainable fashion, at reduced cost, the future of heavy oil is looking brighter than one might expect. ■



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Predicting Reservoir Properties

Reservoir lithology and fluid properties can be characterized using seismic, CSEM and rock physics.

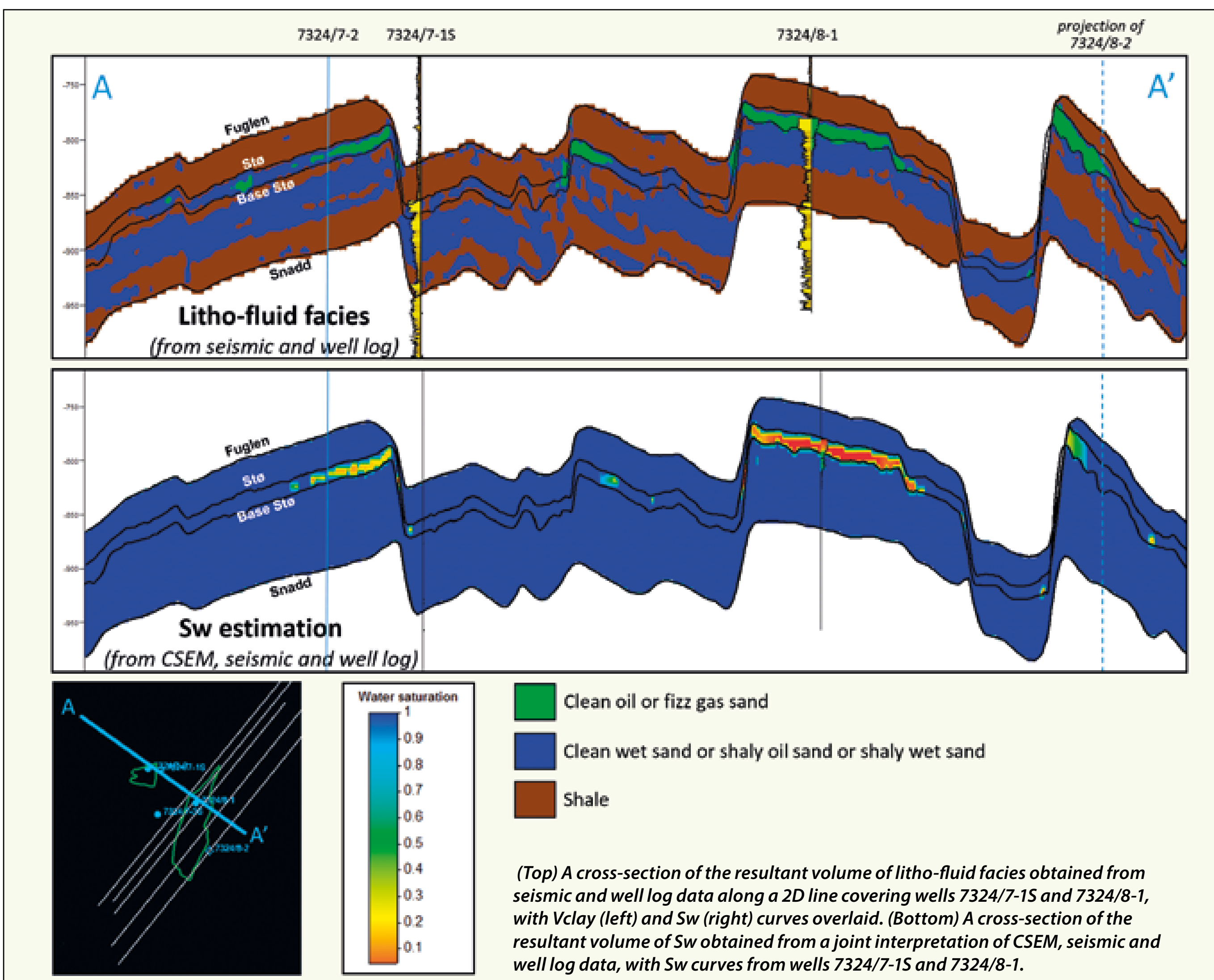
AMANDA ALVAREZ, PEDRO ALVAREZ and LUCY MACGREGOR, RSI

Surface measurements such as seismic and controlled source electromagnetic (CSEM) data are commonly used to estimate reservoir properties. Seismic data provide an excellent image of structure and stratigraphy, and can be inverted to provide a quantitative interpretation of porosity, lithology and litho-fluid facies. The CSEM method provides a surface measurement of electrical resistivity, which is an integral part of a petrophysical interpretation; however, the structural resolution is limited. CSEM data must be tightly integrated with available well and seismic data in order to provide a robust interpretation.

An Integrated Analysis

A dataset consisting of nine lines of 2D GeoStreamer® seismic and towed streamer CSEM data (695 km total) was acquired concurrently in 2015 by PGS in an area in the Hoop Fault Complex on the Bjarmeland Platform in the Barents Sea. This dataset covers the Wisting discovery in the south-west of the survey area, and extends to the area east of the Atlantis well in the north. Two public domain wells in the area provide calibration for the integrated analysis. Oil-bearing sands were encountered in the Realgrunnen interval at well 7324/8-1 (Wisting Central). Nearby well 7324/7-1S (Wisting Alternative) targeted the deeper Kobbe and Snadd intervals, where oil shows were encountered; however, water-bearing rocks were found in the Realgrunnen interval. Two additional wells have been drilled in the immediate vicinity; 7324/7-2 (Hanssen) yielded a small oil discovery, and 7324/8-2 (Bjaaland) was dry.

A significant response to the Wisting Central accumulation can be clearly seen in the CSEM data in a wide range of frequencies. The CSEM data for six frequencies were inverted using an Occam approach to derive anisotropic resistivity models. Appropriate seismic structural constraints were applied to help enhance the resolution of the CSEM



(Top) A cross-section of the resultant volume of litho-fluid facies obtained from seismic and well log data along a 2D line covering wells 7324/7-1S and 7324/8-1, with Vclay (left) and Sw (right) curves overlaid. (Bottom) A cross-section of the resultant volume of Sw obtained from a joint interpretation of CSEM, seismic and well log data, with Sw curves from wells 7324/7-1S and 7324/8-1.

results and allow the interpretation to be focused in the zone of interest. Fast track processed pre-stack seismic data were conditioned carefully to be optimal for inversion, and then inverted using a simultaneous elastic impedance inversion to derive P- and S- impedance values.

Rock property estimation from seismic data was carried out using the multi-attribute rotation scheme (MARS) described by Alvarez et al. (2015). This method is a hybrid rock physics/statistical approach designed to yield the optimum seismic inversion attribute correlation to target reservoir properties. MARS estimates a new attribute τ in the direction of maximum change of a target property in an n-dimensional Euclidean space formed by n-number of attributes. We search for the maximum correlation between the target property and all of the possible attributes that can be estimated via an axis rotation of the basis that forms the aforementioned space. This methodology uses well log data to evaluate the relationship between all possible elastic attribute spaces and a target petrophysical property using a similar correlation approach to the one used by Whitcombe et al. (2002) in the Extended Elastic Impedance methodology. For this case study, MARS was used to estimate total porosity, clay content and litho-fluid facies volumes from seismically derived volumes of P- and S-wave impedance. A cross-section of the resultant volume of litho-fluid facies along the Wisting Central and Alternative wells, with their Vclay (left) and Sw (right) curves, are shown in the top figure on page 22. The green-colored areas may be related to clean oil or fizz gas sand – the seismic data alone cannot distinguish between commercial and non-commercial hydrocarbon saturation.

The final stage in the analysis is therefore to invert the seismic and CSEM derived properties within a rock physics framework. The inclusion of the CSEM resistivity information within the inversion approach allows for the separation of these two possible scenarios.

Successful Predictions

Excellent correlation with known well results was achieved. The integration of seismic, CSEM, and well data predicts very high hydrocarbon saturations at Wisting Central, consistent with the findings of the well. The slightly lower saturation at Hanssen is related to 3D effects in the CSEM data, but the outcome of the well is predicted correctly. There is no significant saturation at Wisting Alternative, again consistent with the findings of the well. At Bjaaland, although the seismic indications are good (upper plot in figure), the integrated interpretation result again predicts correctly that this well was unsuccessful.

Acknowledgement: RSI would like to thank PGS for providing the towed streamer CSEM and GeoStreamer™ seismic data used in this study.

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Supercomputers for Beginners PART IV

Quantum Computers

> *God does not play dice with the universe.*
>
> ***Albert Einstein***

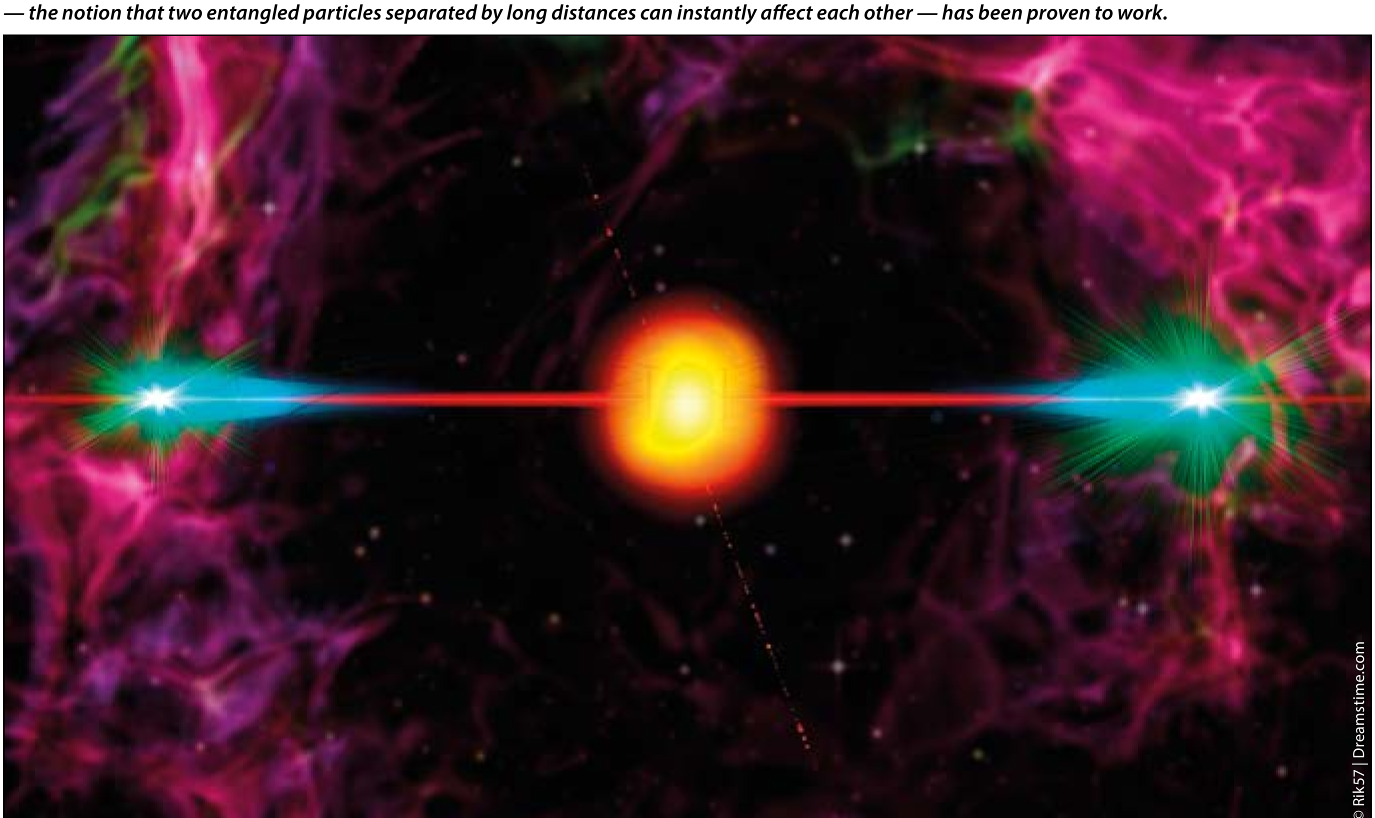
LASSE AMUNDSEN, Statoil
MARTIN LANDRØ and **BØRGE ARNTSEN**, NTNU Trondheim

The 2012 Nobel Prize in Physics was awarded to Serge Haroche and David Wineland for Quantum Entanglement, which is a phenomenon that enables the manipulation and measurement of individual quantum systems without destroying them. This may pave the way for superfast computers, called quantum computers. Some of the smartest physicists, mathematicians and information theorists today are driving this development. Quantum computers may find applications in inverse problems, like those which the industry is trying to solve in geophysics. Give it 20–30 years, and you will have quantum computer desktops.

Will we ever have the amount of computing power that we need or want? What is the next era of computing? If we agree with Moore's Law, the years 2020–2030 will find the circuits on a microprocessor measured on an atomic scale. The logical next step will be to develop quantum computers which tap directly into the field of quantum mechanics to speed computation. As of 2016, the development of quantum computers is still in its infancy, but experiments have been carried out in which quantum computational operations were executed on a very small number of quantum bits. Academic research labs and universities around the world and companies such as IBM, NASA, Google, Microsoft, and Lockheed Martin have been working on the basic building blocks of a quantum computer for some years. But most people, like us, do not really understand what quantum computing is and isn't. We will not even attempt to give a full explanation, but only an introduction.

Recall that a conventional computer stores information as

Sorry Albert, but it looks like the universe is one big dice game. Recent studies have confirmed that the 'spooky action at a distance' that so upset Einstein — the notion that two entangled particles separated by long distances can instantly affect each other — has been proven to work.



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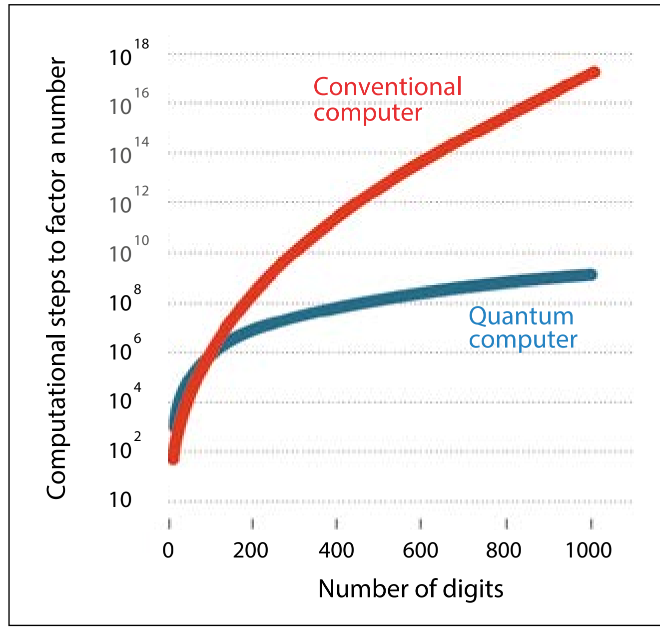
0s or 1s. Most real numbers are stored with a set of 64 zeroes or ones—i.e. *bits*. However, the quantum computer uses quantum bits, or *qubits* – which can be a 1 or a 0 or both *at the same time*, a condition known as a superposition. Qubits represent particles – atoms, ions, photons, or electrons – and their respective control devices work together to act as computer memory and a processor. Because qubits can exist in quantum superposition, or multiple states simultaneously, the quantum computer has the potential to be millions of times more powerful than today's most powerful supercomputers. But – of course – this real speedup remains to be demonstrated.

Quantum computing exploits two principles offered by the laws of quantum mechanics to perform operations on data: the principle of superposition of states and the concept of entanglement. Superposition is a one-particle property while entanglement is a phenomenon associated with two or more separated but connected particles.



The time needed to solve a problem increases with the problem's size. For a conventional computer the time needed to factor a number explodes almost exponentially with the number of digits. The idea behind quantum computing is that its compute time will grow much more slowly; for the factorization problem that time should grow as the number of digits cubed. This is a 'quantum speedup'. To date (May 2016), the largest number factored on a quantum device is 200,099. (The factors of a number are all those numbers that can divide evenly into the number with no remainder.)

Superposition

Superposition is essentially the ability of a quantum system to be in multiple states at the same time. A well-known example of a two-state system is the spin of a spin-1/2 particle such as an electron, where the spin can point in two opposite directions, say 'up' or 'down', and the spin states can be denoted as $|1\rangle$ and $|0\rangle$. By the laws of quantum mechanics, the electron can exist in a superposition of these two states, written as: $|f\rangle = a|0\rangle + b|1\rangle$, where a and b are related to the probability of finding the electron in state $|1\rangle$ and $|0\rangle$, respectively, satisfying $|a|^2 + |b|^2 = 1$. $|f\rangle$ is called a qubit. A single qubit thus can represent 1, 0, or *any* superposition of these two qubit states. As such, a qubit might seem to contain an infinite amount of information. But the information must be extracted by a measurement. When it is measured, quantum physics requires that the result is an ordinary bit – either $|1\rangle$ or $|0\rangle$.

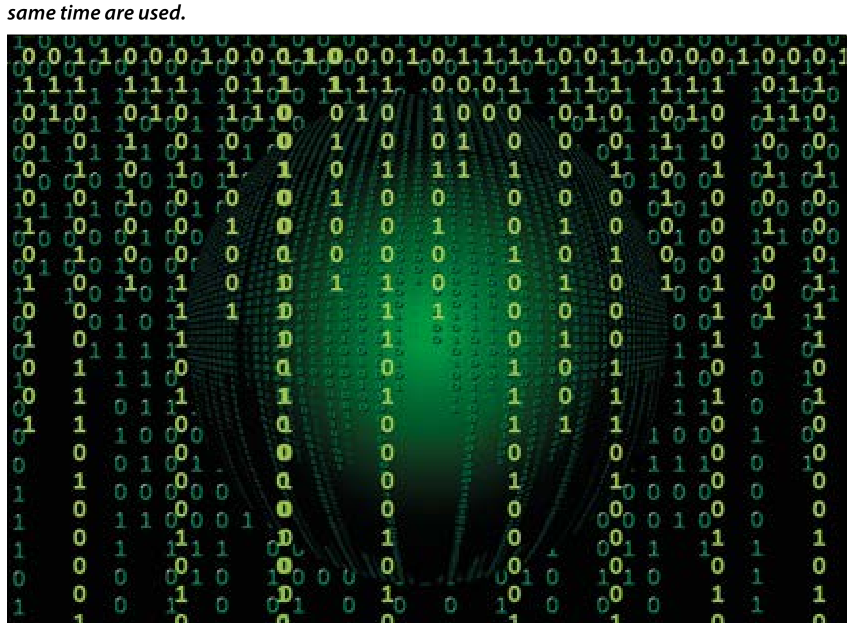
Entanglement

In quantum physics, entanglement is an extremely strong correlation that exists between quantum particles — so strong, in fact, that two or more quantum particles can 'dance' in instantaneous, perfect unison, even when placed at opposite ends of the universe. This seemingly impossible connection inspired Einstein to describe entanglement as *'spukhafte Fernwirkung'* or 'spooky action at a distance.' The quantum state of each particle cannot be described independently – instead, they are to be considered as a whole.

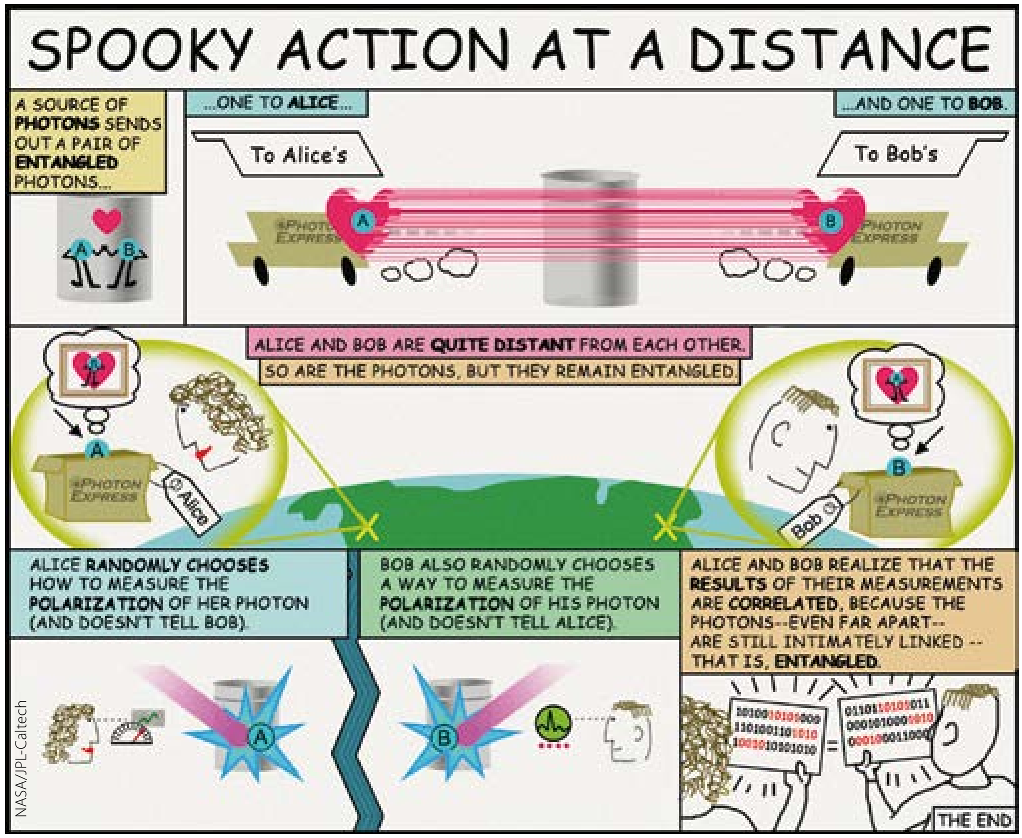
Consider two entangled electrons; the sum of their spins is null. When entangled, their spins are linked by photons acting as the messengers of the electron's spin. If entanglement had an analog in classical physics when you spin coins, then if you spun a coin in London clockwise, an entangled second coin in Trondheim would start to spin counter-clockwise.

Two spatially separated qubits can be in any superposition of 2^2=4 states: $|0\rangle|0\rangle$, $|0\rangle|1\rangle$, $|1\rangle|0\rangle$, $|1\rangle|1\rangle$. Of these, the four states $\frac{1}{\sqrt{2}}(|0\rangle|0\rangle \pm |1\rangle|1\rangle)$, $\frac{1}{\sqrt{2}}(|0\rangle|1\rangle \pm |1\rangle|0\rangle)$ are called the 'maximally entangled Bell states' (see https://quantiki.org/wiki/bell-state). They have the peculiar property that the

Computers require data to be encoded into binary digits (bits). A bit is the basic unit of information in computing and can have only one of two values: 0 and 1. A quantum computer exploits quantum mechanical phenomena, such as superposition and entanglement to perform operations. Instead of bits, quantum bits or qubits that can be zero and one at the same time are used.



particles always 'know' about each other, even if they are separated by large distances. Consider the first Bell state, and assume that the two separated qubits are held by Alice (A) and Bob (B). The state is $\frac{1}{\sqrt{2}}(|0\rangle_A|0\rangle_B + |1\rangle_A|1\rangle_B)$, meaning the qubit held by Alice can be 0 as well as 1. If Alice performs a measurement on her qubit the outcome would be perfectly random, either possibility having probability $\frac{1}{2}$. But now the fate of Bob's qubit is sealed; the outcome would be the same as the one Alice got. So, if Alice tells Bob the result of her measurement, Bob instantly knows what the result of measuring his qubit would be – he doesn't need to bother doing the actual measurement.



Cartoon helping to explain the idea of 'entangled particles.' Alice and Bob represent photon detectors.

You may say that this is nothing special: maybe, when the pair was created (before the qubits were separated), the two particles 'agreed' in advance which outcome they would show in case of a measurement. Following Einstein, Podolsky, and Rosen in 1935 in their famous 'EPR paper', there is something missing in the description of the qubit pair given above – namely this 'agreement', called more formally a hidden variable. Then, in another famous paper from 1964, John S. Bell showed by simple probability theory arguments that these correlations cannot be explained by the use of any 'pre-agreement' stored in some hidden variables – but that quantum mechanics predicts perfect correlations.

Entanglement such as this is a basic ingredient of quantum computing. Three qubits will be in any superposition of 2^3=8 states: 000, 001, 010, 011, 100, 101, 110, 111. Generally, n qubits can be in a superposition of 2^n states. In quantum one-way computers the computation is decomposed into a sequence of one-qubit measurements applied to a highly entangled initial or cluster state. The calculation ends with a measurement, collapsing the system of qubits into one of the 2^n pure states, where each qubit is zero or one. The outcome can therefore be at most n classical bits of information. Quantum algorithms are often non-deterministic, in that they provide the correct solution only with a certain known probability.

The Holy Grail

It is the quantum computer's advantage of using 1s, 0s and 'superpositions' of 1s and 0s that can make it outperform classic supercomputers. Its basic feature is its ability to operate simultaneously on a collection of states, thereby performing many operations in the time. Certain complex calculations can be done exponentially faster than a classical computer.

The difference between quantum computing and classical computing can be illustrated by the optimization problem of finding the lowest point in a landscape with mountains and valleys, like the waveform inversion problem that geophysicists have been working on for decades. Every possible altitude of the landscape at a point, or the 'energy" or 'cost' of the solution, is mapped to coordinates on the landscape. Classical computers running classical algorithms can only 'walk over the landscape'.Quantum computers can tunnel through the landscape thus making it faster to find the lowest point. Particularly for highly irregular (or non-smooth) surfaces, this type of tunneling might speed up the optimization process significantly.

But what more can quantum computers do than searching through a space of potential solutions for the best one? Quantum computers will be able to efficiently simulate quantum systems, which has been said to be a 'holy grail' of quantum computing: it will allow us to study, in great detail, the interactions between atoms and molecules. This could help design new drugs and new materials.

More creepy is the fact that quantum computers can learn from experience and do self-corrections. This concept is called machine learning. It is much more sophisticated than your Facebook news that feeds changes based on which posts you 'like'.

If you feel that quantum computers sound like witchcraft, you're not alone. The future uses are bound only by imagination. ■

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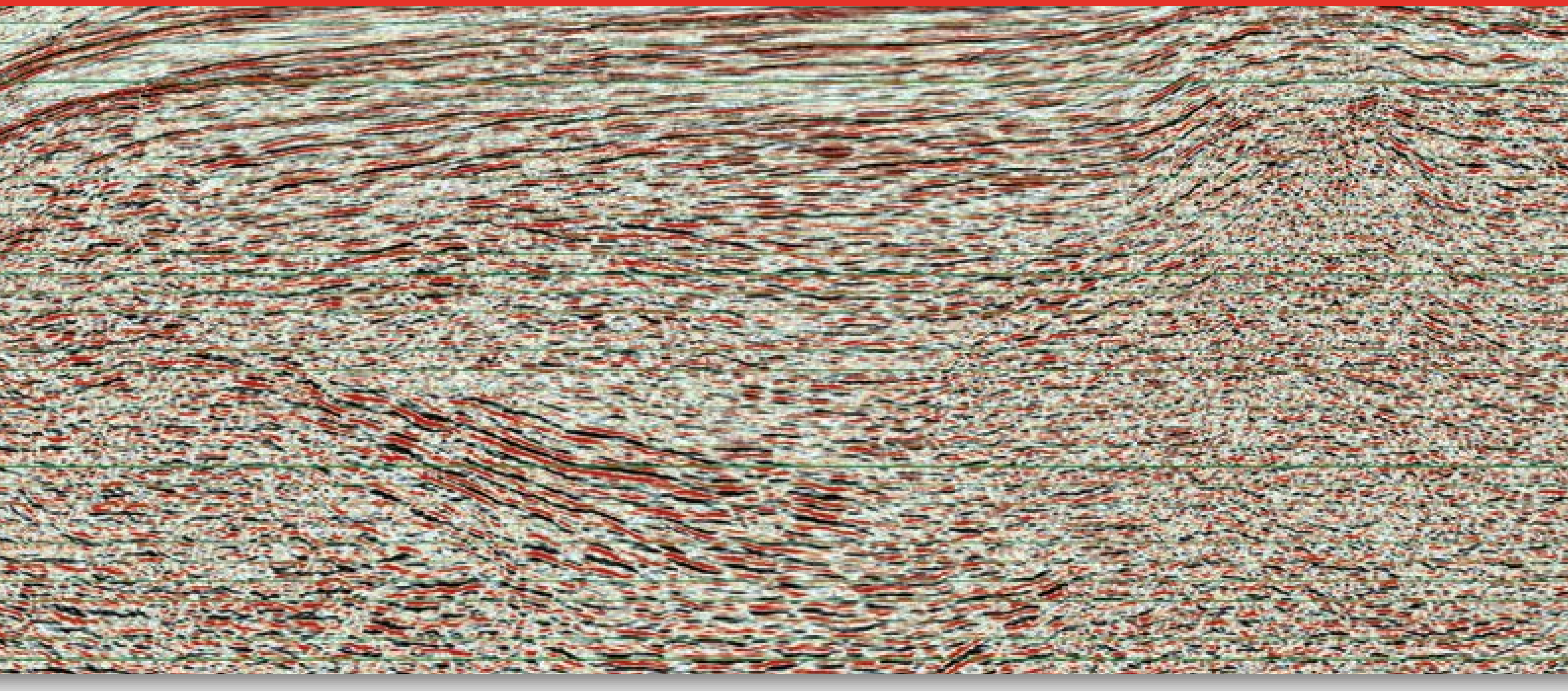

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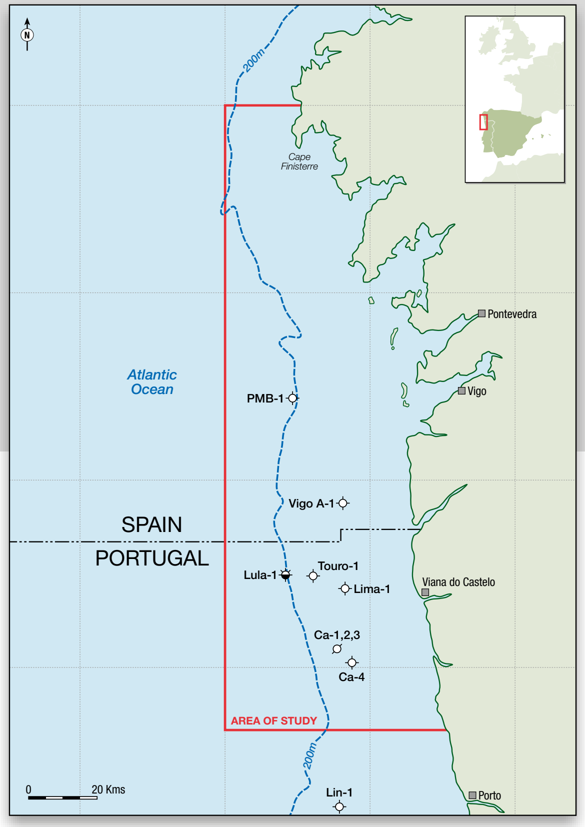

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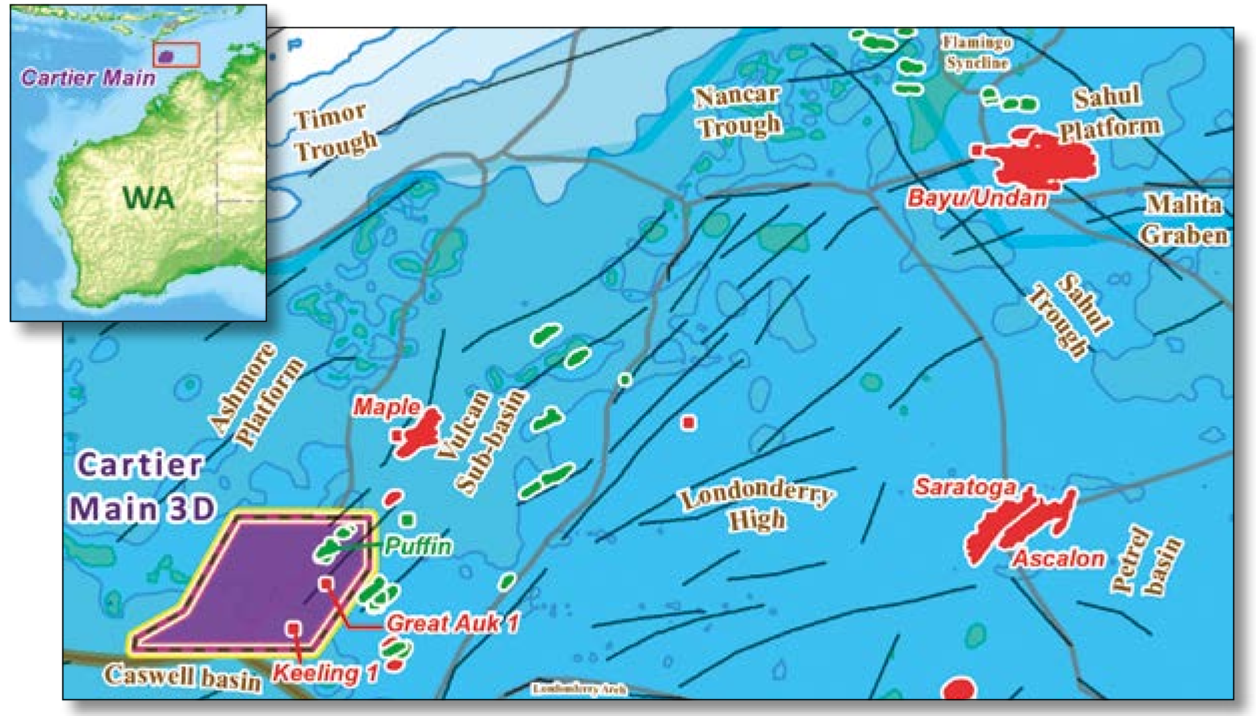
Beyond the Puffin:

Applying Modern Processing Workflows in the Vulcan Sub-Basin

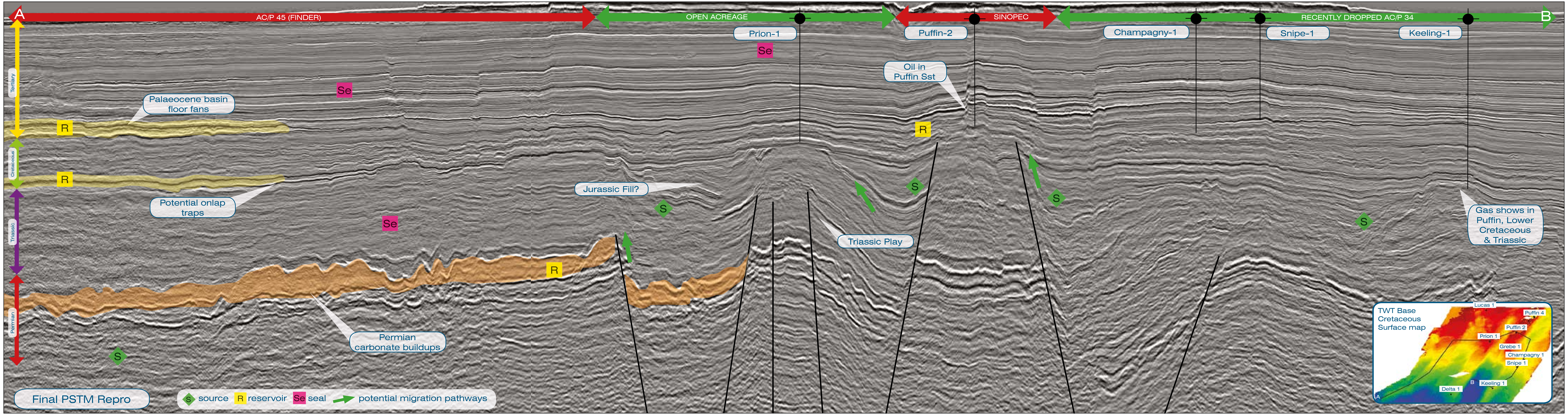
A deghosted pre-stack depth migration processing workflow has resulted in significant enhancement to the data at Puffin Formation level, as well as unprecedented imaging of Triassic structures and superb resolution and internal geometry definition at Permian level. Additionally, new play types such as potential onlap traps and Paleocene basin floor fans can be confidently mapped on the new dataset and far angle imaging has provided for the first time a tool for calibrated direct hydrocarbon detection.

Spectrum



Structural elements of the Bonaparte Basin showing the locations of the Puffin Field and the Cartier 3D Seismic Survey.

Arbitrary line through the reprocessed dataset illustrating the enhancement at Puffin Formation and Keeling-1 gas discovery levels as well as the new play types revealed by improved imaging.



A Game-Changing Tool

KARYNA RODRIGUEZ, PHIL COOK and DAVID EASTWELL, Spectrum

Improved seismic resolution has been key in reviving interest in the Vulcan sub-basin.

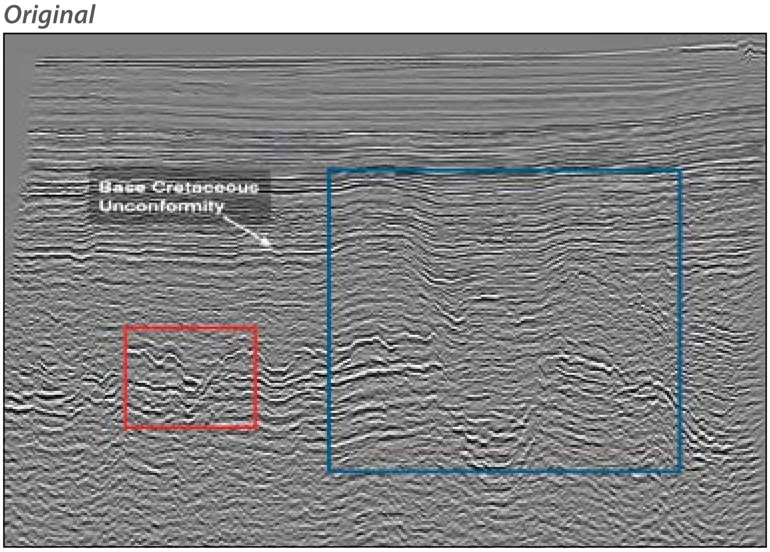
Exploration in the Vulcan sub-basin, located offshore Western Australia, has been relatively slow since the 1990s. However, a deghosted pre-stack depth migration processing workflow is proving to be essential in gaining a better understanding of the area and mitigating the main risks in trap definition, structural evolution and thin reservoir identification.

The Vulcan sub-basin is a north-east-trending Mesozoic extensional depocenter in the still largely frontier Bonaparte Basin. It comprises a series of horsts, grabens and terraces hosting a combination of structural and stratigraphic traps such as tilted fault blocks, horsts and lowstand basin floor fans. It is estimated that the Vulcan sub-basin contains reserves of 388 MMb of liquid hydrocarbons and 1.3 Tcf of gas.

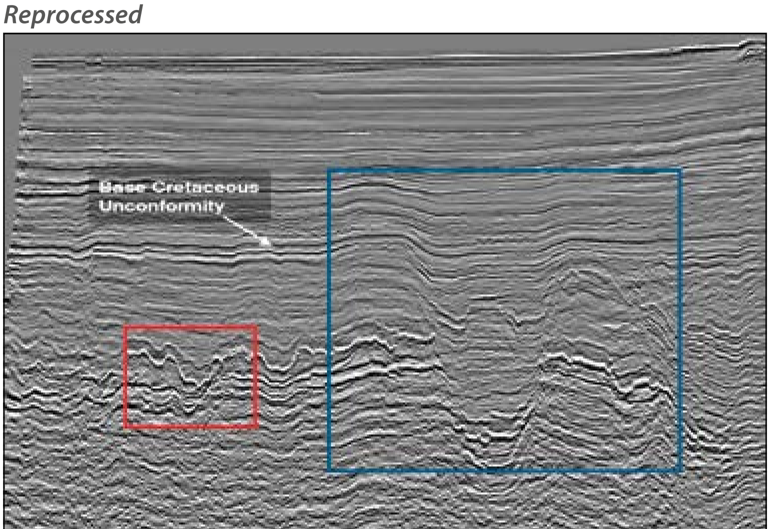
The Puffin Oil Field is situated in the Ashmore Cartier Exploration Permit area within this sub-basin (see map on preceding page). As it has produced light, sweet crude with an API of 43.8 degrees, it is no wonder that subsequent exploration in the Vulcan sub-basin primarily targeted similar structures in the Puffin Sandstone. In order to address the remaining exploration targets, Spectrum's 2,770 km² multi-client Cartier 3D survey was acquired in 2010, providing the framework required for a more detailed regional evaluation of the Upper Cretaceous submarine fan sandstones of the Puffin Formation and to evaluate the additional potential of possible deeper Triassic and Permian plays.

Original processing (top) and reprocessed dataset (bottom), showing clear improvements in horst and graben structures (blue rectangle) and Permian (red rectangle) intervals.

Original



Reprocessed



Reprocessing Methodology and Objectives

Due to the relatively complex geological and structural setting, even this relatively modern 2010 3D dataset did not sufficiently manage to address the main geological risks, such as seismic trap definition, retention of hydrocarbons in tectonically reactivated structures and identification of thin reservoirs. The survey was therefore reprocessed through a deghosted pre-stack depth migration workflow, achieving extremely significant imaging uplifts, which have subsequently increased the geological understanding of the area and are expected to have a game-changing impact on future exploration in this region.

The reprocessing had specific targets aimed at enhancing prospectivity at various objective levels. For the Upper Cretaceous Puffin basin floor fan sands play, improved demultiple and deghosting was designed to image individual sand packages, while depth migration was expected to improve poorly imaged structures affected by ray paths through faults and major velocity breaks across faulted sections. Also, with historically poor far angle imaging, the reprocessing focused on getting far angles flat and imaged correctly for possible hydrocarbon detection through calibrated AVA anomaly evaluation.

New Light on Triassic Prospectivity

Structures in the Triassic just below the Base Cretaceous Unconformity could be structurally mapped on the original dataset. However, Triassic faulting is complex and historically has been uninterpretable. The new demultiple and deghosting techniques employed here resulted in unprecedented improvements at Triassic level, as can be seen on the images on the opposite page. Detailed attention to velocity analysis also made a big difference in improving the stack response of critical reflectors.

Triassic targets have typically been explored based on the structural configuration at Base Cretaceous Unconformity level. The reprocessed example shows a Triassic horst (blue rectangle) not previously identified as it lies under a Base Cretaceous syncline. The improved image within the Triassic interval means not only that an intra-Triassic marker, appearing to be equivalent to the prospective Nome Formation, can now be mapped confidently, but also that possible Jurassic sections containing potential seals above these horsts can also be inferred. Several of the horst blocks also exhibit seismic amplitude anomalies confined to structural closures that could relate to the presence of hydrocarbons.

New Play Types Revealed

Even when the Top Permian horizon is reasonably clear, this potential play has been very poorly understood. Significant improvements at Permian level have been achieved predominantly through the recovery of low frequency as well as pre-stack depth migration where complex velocity boundaries and structural geometries have caused imaging issues in the previous pre-stack time migrated data. Top Permian character is clearer, more continuous and imaged with a greater bandwidth. Abundant potential structures can be seen from the mapping of the top Permian in 3D, many of which sit within 3,000–4,000m below sea level range. Further analysis of seismic attributes will determine the viability of these closures and potentially their porosity distribution, with a view to possible drilling.

Further Insights Obtained

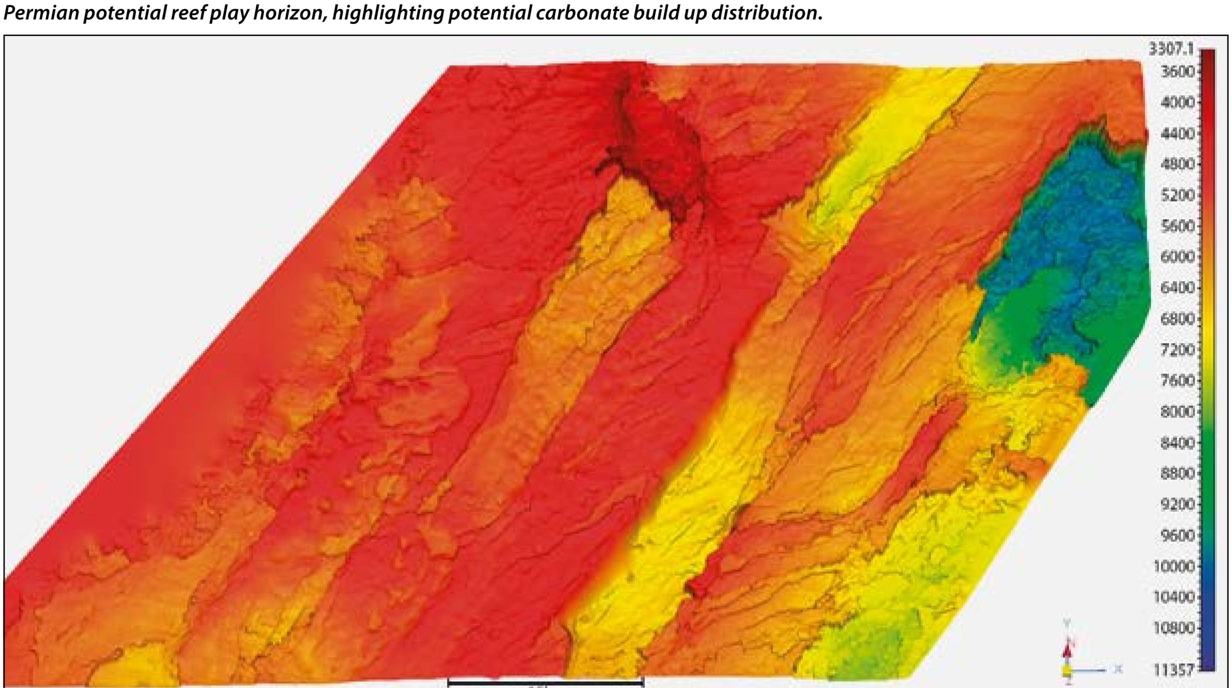
The reprocessing workflow employed not only had clear outcome objectives identified from the start, but also integrated all available data with a very strong understanding of the geological and structural challenges related to seismic imaging. By continuously tying interim tests to expected results, it was clear before the final results were obtained that the interpretation of the Puffin Formation was going to be greatly enhanced by improved multiple attenuation and detailed attention to velocities.

More advanced attribute work such as continuity attribute (similar to coherence) applied at Puffin sandstone level has revealed a series of channels and fan-like geometries explaining some negative well results. In addition, frequency decomposition applied at Puffin, Triassic, Paleocene fan and Permian carbonate levels, together with structural imaging blended with the frequency decomposition information, have all provided further insights into the data. At Puffin and Triassic levels, frequency responses expected of hydrocarbon accumulations, calibrated with wells in the area, have been observed; Paleocene fan geometry has been interpreted for a pinch-out play at Paleocene level; channel and karstic-like features have been mapped at Permian carbonate level and angle stack analysis has shown increase in positive amplitude value with angle at Puffin and Triassic levels.

This dataset will allow the area to be more fully understood by providing a reliable tool for post well analysis, prospect de-risking and high grading of new plays. So far it has already provided a true game-changing tool for exploration in this section of the Vulcan sub-basin.

References available online. ■

Permian potential reef play horizon, highlighting potential carbonate build up distribution.

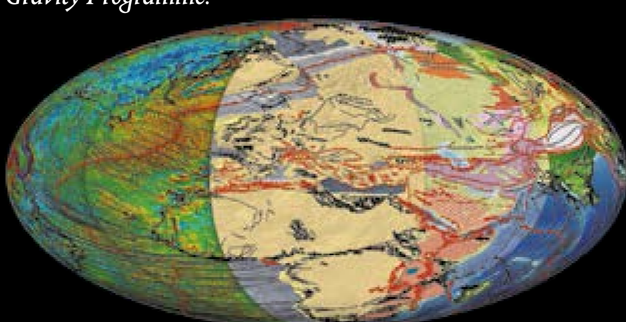


Getech's 30th Year

It's been 30 years since Getech began its work; so how did it all start, what have we achieved and how do we envisage our future?

We're often asked at Getech, "Why Leeds?" After all, the city is not commonly thought of as being part of the global oil patch, though we would argue that it is now! Getech began life as a research project at the University of Leeds back in 1986, compiling, for the first time, a continental-scale grid of gravity data for Africa. In the process, we uncovered a swathe of mega-regional structures never previously observed. These data continue to facilitate our understanding of the tectonic history of Africa.

Since that original project, we have grown from a niche gravity and magnetic (G&M) player with 8 researchers to an AIM listed company with over 100 staff based in 3 offices internationally. We've built and maintain the largest commercially available global library of G&M data (including the largest US onshore gravity database). We haven't rested on our laurels; instead we have used this incredible resource to build advanced G&M multiclient products, including our *Global Depth-to-Basement Study* and a global map of the Curie point isotherm – a mappable proxy for depth-to-Moho. We have also recently added new data to our global library with our *Multi-Satellite Altimeter Gravity Programme.*



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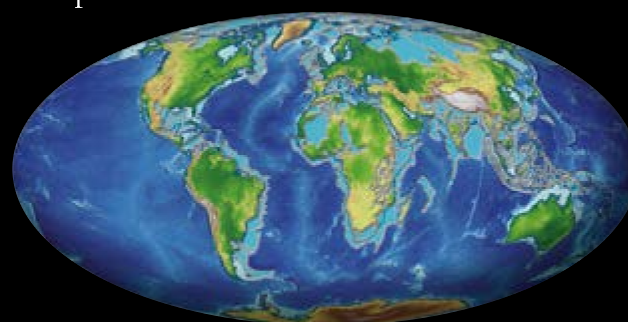

In 2015, the Getech group of companies grew with the acquisition of ERCL, who are based in Henley-on-Thames. ERCL's work with Mozambique's INP and ENH, assisting them in the promotion of license rounds and providing advanced exploration consultancy services, means that they have proven to be an excellent fit with Getech's style and approach.

So what does the future hold for Getech? It's certainly been a tough time for the industry recently, but Getech has demonstrated the robust nature of what we do and its value to the oil and gas exploration industry both in times of plenty and in times of famine. We will continue to look at expanding the range of our data, products and services, and we're always looking for complimentary companies to join the group. We attribute our success to our commitment to listening to our clients and what they want us to focus on, be that new layers in *Globe*, new *Regional Reports*, new data or new services.

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A World of Opportunity?

Regional screening for unconventional resources: geological techniques to locate new opportunities

MIKE SIMMONS, Landmark Exploration Insights

The success of shale gas and shale oil exploitation in North America in plays such as the Bakken, Eagle Ford and Marcellus (Figure 1), has ignited a global search for similar targets. There are several geologically distinctive aspects to North American resource plays, most notably their thickness, lateral continuity and relatively structurally undeformed nature; nonetheless, explorationists have begun looking for broadly analogous strata elsewhere. There are many areas of the world known to contain substantially thick and geographically extensive organic-rich mudrocks and carbonates in various onshore sedimentary basins. This poses a challenge: how can these potential plays be assessed quickly and ranked for more detailed examination? Additionally, how can individual parts of basins be high-graded as having the most likely potential?

Landmark Exploration Insights, a business line within Halliburton, has developed a variety of techniques for rapidly assessing the resource play potential of any basin. These include:

- Global mapping of gross depositional environments of precise stratigraphic intervals to identify basins likely to contain organic-rich sediments and the geographic distribution of these sediments within the basins;
- Evaluation of stratigraphically attributed geochemical data from organic-rich sediments worldwide. Screening workflows also consider thickness and depth of target horizon;
- Once an area has been high-graded, it can be further evaluated within the 3D geological interpretation platform of Landmark's DecisionSpace® software, which facilitates, among other things, regional evaluation of maturity.

Where and When?

The starting point for a global or regional assessment of resource play potential is to determine where and during which geological periods organically rich shales and carbonates were deposited. Organic enrichment of sediment occurs for a variety of reasons, but there were several times during geological history which were particularly prone to organic-rich sediment deposition, particularly those associated with Oceanic Anoxic Events (OAEs). These are intervals when large areas of the seafloor became anoxic, synchronous with (and perhaps related to) times of high organic productivity. This allowed the extensive preservation of organic carbon, typically in the form of black shale. The cause of OAEs has typically been attributed to pronounced climate change resulting from volcanogenic and/or methanogenic processes. The ensuing greenhouse world would have

Figure 1: Marcellus Shale at Seneca Stone Quarry, New York.

presumably been characterized by enhanced rainfall, increased nutrient delivery to the oceans, increased upwelling, and increased organic productivity. Classically, OAEs have been recognized during the Mesozoic Era; but, increasingly, Paleozoic 'black shale events' are being related to OAE-like conditions. In particular, such events are widely reported throughout much of the Devonian, the early Silurian, and Late Ordovician (Figure 2).

OAEs and other geological periods of widespread black shale deposition can be examined with regard to the global distribution of sedimentary facies at these times. A geodynamic plate model can be used to place sedimentary facies in their palinspastic context to develop a global paleogeographic map of how the Earth appeared at the time of deposition (simplified version in Figure 2). Sedimentary facies are mapped with stratigraphic precision by using a eustatically mediated sequence stratigraphic model to recognize precise time slices. This means that the precise interval of organic-rich sediment deposition can be mapped without compromising accuracy by selecting too broad an interval for mapping. Well, outcrop, geochemical, and seismic data can be related to the sequence stratigraphic model, which allows depositional facies distribution to be mapped for each time-slice when integrated with tectonic controls on deposition and an understanding of the stratigraphic evolution of a basin.

Figure 2: Paleogeographic extent of organic-rich sediments (green) during the latest Frasnian (Upper Kellwasser OAE). Simplified paleogeography is based on Landmark Exploration Insight's Geodynamic Model, while organic-rich sediment extent has been derived from the allied Gross Depositional Environment maps and Petroleum Systems Database.

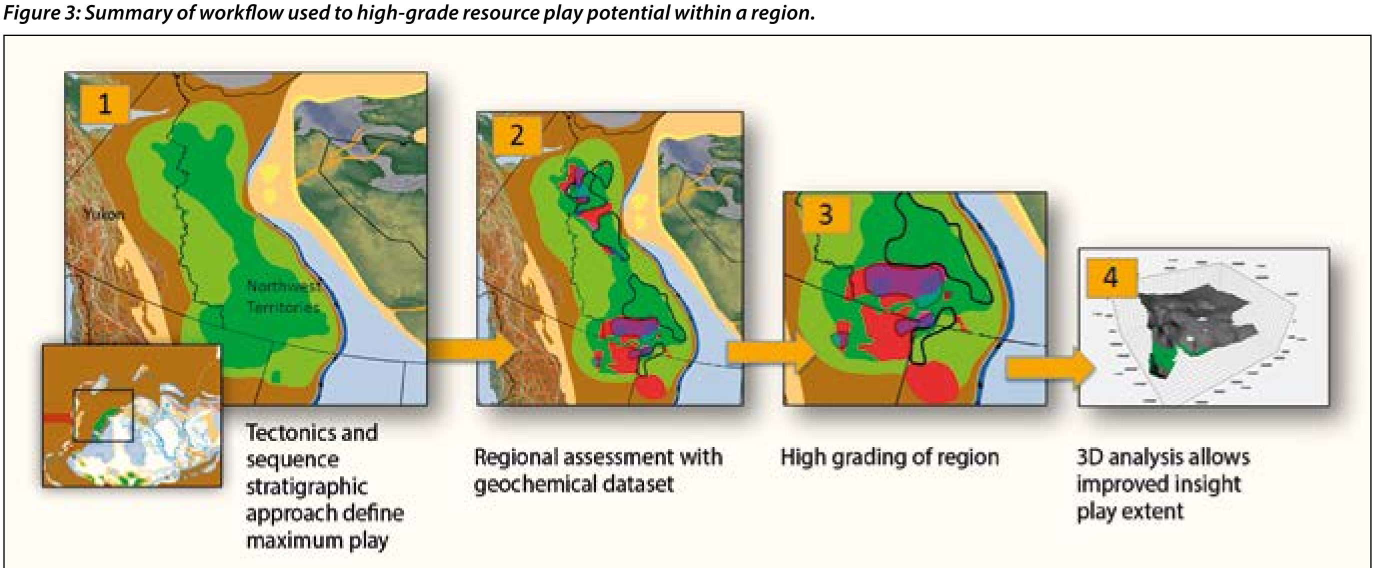
Because data distribution is variable at a global scale, the technique requires the prediction of sedimentary facies into regions lacking data. Sequence stratigraphy facilitates this; but other techniques, such as paleoclimatic modeling, can be used to predict areas prone to deposition and preservation of organic-rich facies. As an example, it is possible to predict where coastal upwelling occurred in the geological past, which led to nutrient-enriched waters and high productivity of phytoplankton, in turn leading to organic-enrichment of the associated sediments being deposited.

The lithology of potential resource play intervals is also critical. Ideally, the organic-rich intervals should be associated with high (>35%) quartz or carbonate content that leads to a brittle, frackable nature. Once again, regional paleogeography can be used to determine likely lithology, for example, by predicting the input points of quartz-rich sediment from granitic or quartz-sandstone dominated paleo-highs. This involves mapping paleo-drainage patterns using tectonics, paleoclimate, and well and outcrop data.

Examining the Goldilocks Window

Within an area of focus, the geochemical, thickness, and depth parameters can now be employed within the workflow to define the location of the highest potential for resource plays. A window of optimal conditions can be identified within geochemical data beginning with organic richness and

Figure 3: Summary of workflow used to high-grade resource play potential within a region.



kerogen type. A cutoff of 2 wt.% Total Organic Carbon (TOC) is commonly used to screen for resource plays. By examining a geochemical database of stratigraphically attributed past analyses, it is possible to define a sub-region where TOC is commonly above 2 wt.%. Precise stratigraphic attribution of the data is fundamental to aiding focus on the interval of interest and to disregarding other data.

The next step is to establish thermal maturity of the subregion of high organic carbon enrichment to screen out immature areas and highlight those within the present-day oil or gas window of hydrocarbon generation. Vitrinite Reflectance (Ro) can be used to define regions within the oil window (Ro = 0.6 – 1.35%) and within the gas window (Ro = 1.35 – 3%).

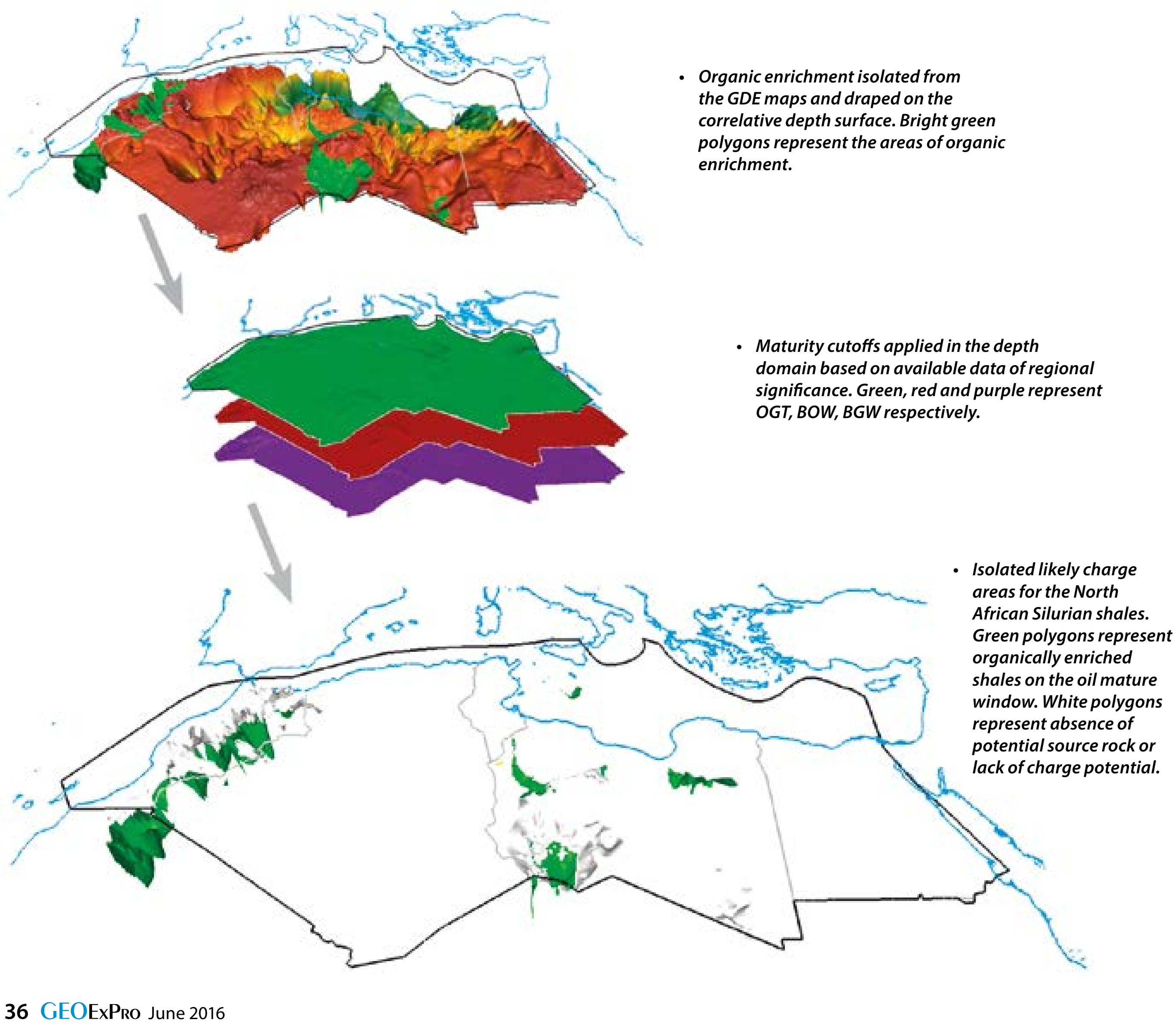
If shale oil is a desired target, then further geochemical screening can be performed by examining the Production Index (PI) values and the temperature at which the maximum amount of hydrocarbons are generated during pyrolysis (Tmax). The PI is the ratio of already generated hydrocarbon to potential hydrocarbon [S1/(S1 + S2)] derived from pyrolysis measurements. A cross-plot of PI and Tmax values high-grades locations where samples have a PI between 0.2 and 0.6 and Tmax values of 435 to 455°C.

Pyrolysis data, such as S1, is useful for determining if free oil is present within pore space. In such circumstances, S1 values will be greater than 2mg HC/g TOC.

Cutoffs for the thickness and present-day depth of organic-rich intervals can also be used during the screening process – a thickness greater than 30m is desirable, whilst depth cutoff will depend on local circumstances and the changing economics of drilling costs. However, 3,000 to 4,000m is typically considered a viable maximum.

The workflow for assessing a region, as summarized in Figure 3, can be accomplished in ArcGIS software or within the 3D software environment of DecisionSpace software. The latter has the advantage of the user being able to run multiple 'what if' scenarios by varying the cutoffs used in the screening parameters. It also facilitates the dynamic updating of the model as new data becomes available. This means

Figure 4: Simplified workflow summarizing the process to derive maturity maps for the Silurian shales of North Africa.



the screening workflow can be rerun in minutes or hours, not days or weeks.

Timing is Everything

Once an area has been high-graded, further assessment to locate a precise subregion with the highest potential is best facilitated in DecisionSpace software (Figure 4) by building a gridded depth model of key stratigraphic surfaces, draping facies maps on these surfaces, and evaluating maturity by integration with geothermal gradient information to define subsurface temperatures, or by integration with petroleum systems modeling tools, such as Permedia™ software. This will result in a precisely defined region for focused further study and, potentially, future exploitation.

In the example illustrated in Figure 4, a regional depth model for North Africa can be interrogated to assess the maturity of early Silurian source rocks. The Oil Generation Threshold (OGT) and the Base Oil Window (BOW) were defined as 80 and 130°C, respectively. Using geothermal data from a representative set of wells, we are able to ground truth an average geothermal gradient within key basins whilst applying a consistent continental scale value, which can be used in the workflow.

Assigning the relevant depth cutoffs to the model related to present-day subsurface temperatures, we can begin to assess the likely distribution of immature, mature, and overmature intervals against our gross depositional environment (GDE) maps. Where additional maturity data are available, such as vitrinite reflectance and detailed heatflow analysis, it is possible to further enhance screening and perform a superior assessment of regional hydrocarbon potential using a detailed basin-by-basin approach.

Resource Plays Beyond North America

There is no doubt that the global search for unconventional resources is firing the imagination of the international exploration geoscience community. At the recent Geo2016 conference on Middle East geology, a significant proportion of the presentations discussed resource plays. BP has recently entered into a joint venture to exploit a Chinese shale gas play. There are many exciting opportunities to be identified and exploited outside of North America, but it will require a sound understanding of regional geology, paleogeography, geochemistry and modeling to really identify where the best potential lies. Whilst deposition of organic-rich facies can extend across a huge area within a basin, when source rock quality, maturity, lithology, thickness and other filters are applied, the area of best potential is often greatly reduced, as in the North Africa example mentioned previously (not even considering sociopolitical and engineering factors).

As with conventional exploration, basin screening based on sound regional geoscience integrated with the technology to accelerate assessment will be a prerequisite to success.

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East Baghdad

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Super-Giant Field Under a Populated Area

The super-giant East Baghdad oil field lies in the heavily populated outskirts of Baghdad. Can it be successfully and safely exploited?

Prior to 1956, the eastern part of the Baghdad Governorate was separated from Baghdad City by an earth barrier called the Nadhim Pasha Dam, established in 1908 to protect the city from the annual floods of the Tigris River. Consequently, the area was underpopulated apart from isolated settlements, where peasants from southern Iraq built shanty houses to live and find work in the city. In 1956, however, the annual floods were permanently prevented by the construction of the Tharthar Dam, 100 km north-west of Baghdad, and the area east of the original city became available for building.

Sadr City now covers much of this eastern edge of Baghdad. It was built in 1959 by Prime Minister Abdul Karim Qassim and later unofficially renamed Sadr City (after Ayatollah Mohammad Mohammad Sadeq al-Sadr). A public housing project neglected for many

Satellite image of Baghdad showing the location of Sadr City on the eastern edge, and the area depicted in the 1944 map on the opposite page.

The teeming modern city of Baghdad is underlain in its eastern suburbs by by a super-giant oil field.

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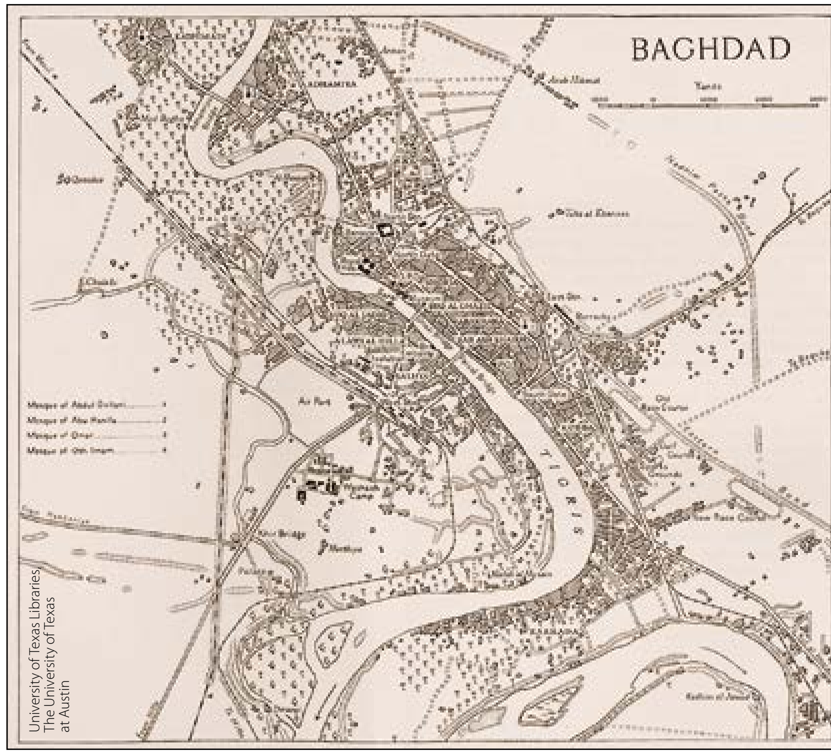
years under Saddam Hussein, Sadr City has a population of about a million residents, and the districts to the south-east and north-west of it are also heavily populated urban areas.

The super-giant East Baghdad oil field is situated directly to the east and south-east of Baghdad, underlying these heavily populated outskirts, and crossing both the Diyala and Tigris Rivers. It extends further north-westwards into the Salah ad-Din Governorate, where the area is densely covered with horticulture and fruit trees. Although initially discovered in the 1970s it remains very underdeveloped, primarily due to the political, practical and health and safety issues involved with exploiting an oil field in an urban area.



Baghdad in 1944. The Nadhim Pasha Dam can be seen running north-west – south-east and then due south in the top right quadrant of the map.

Exploring a Giant Field

Prior to 1960, early exploration work in the East Baghdad area was carried out by the Iraq Petroleum Co. group using gravity and seismic surveys, and in 1974, a Romanian land crew undertook further land seismic in the East Baghdad area for the Iraqi National Oil Co. During the implementation of seismic survey operations, there were some difficulties due to the fact that a large part of the survey area was within the urban suburbs of Baghdad city. Traffic is very heavy in the area, and to further complicate matters, some seismic lines passed through an intensively farmed agricultural zone to the north – problems which still exist. As a result, some seismic surveys had to be repeated for detailed acquisition, and further work was carried out in the northern area to delineate the field's extent.

The results indicated the presence of a number of faults, the most important of which trend north-west to south-east. The surveys indicated the existence of several structural closures and all the early drilling locations were based on these.

The first well, East Baghdad-1 (EB-1), was drilled to test the Cretaceous and Jurassic reservoirs. Located about 20 km east of the center of Baghdad City, it was spudded in June 1975 and completed in May 1976, reaching TD at 4,842m in the Lower Jurassic Adaiyah Formation. Testing carried out after drilling indicated some hydrocarbon shows in the lower horizons, but did not give encouraging results. The deepest unit to produce oil was the Khasib reservoir, which produced around 2,830 bopd. A slightly lower production rate was later obtained from the Tanuma reservoir and a long oil column was found in the Hartha reservoir, but its productivity was small at around 630 bopd. The produced oil was around 24° API on average from these units. Oil shows were tested in the Lower Miocene Jeribe Formation and the Upper Cretaceous Sa'di Formation. Lighter oil was tested in the Lower Cretaceous Zubair Formation, but other potential Cretaceous reservoirs tested water.

East Baghdad-2 (EB-2) was located about 20 km south of EB-1. During drilling, oil shows were found from the reservoirs mentioned above, but the Tanuma and Khasib reservoirs were poor quality and production levels were worse than in EB-1. However, oil was also found in the Zubair reservoir, producing around 13,824 bpd of 38° API oil. Exploration continued and EB-3 was drilled in 1978 in the central urban part of East Baghdad, with the main objective being the Zubair reservoir.

In the short time period between 1979 and 1981 a further 22 wells were drilled, covering an area of about 60 km^2. The first assessment and proposal for a development scheme was carried out between 1982 and 1983, when a geological model was prepared and an area for a Pilot Project to assess the performance of the different reservoirs was chosen, in preparation for a well-supported, phased development plan. The years 1983–1990 witnessed the delineation of the field to the north-west of the River Tigris, with a total of 85 wells. The drilling results showed a wide variation in the well rates with a range of 50 to 250 bopd recorded, due to field complexity and lithology changes.

The field needs further evaluation, particularly in the north-west, which will add a new phase of development to the existing scenarios.

Source Rocks, Maturation and Migration

Recent studies by Al-Ameri (2011) on the correlation between the oil from the Khasib and Tanuma reservoirs and the kerogen of the source rocks indicated the presence of mature source rocks in the uppermost Jurassic to lowermost Cretaceous (Tithonian-Berriasian) Chia Gara Formation, which consist of limestone and calcareous shales. The generation of petroleum in the Chia Gara Formation began in the Upper Cretaceous, and continued to the Lower Tertiary

(Late Eocene) time. This coincides with the formation of the Khasib and Tanuma structural fold closures in the East Baghdad structure at the Cretaceous/Tertiary time boundary event.

The second phase of trap formation was a result of the abrupt change in thermal subsidence during the Miocene, which coincided with the Alpine orogeny. This event is responsible for terminating Tertiary oil migration. The generated and expelled hydrocarbons migrated along faults and compression joints in the anticline crest and charged the Upper Cretaceous Khasib Formation and Tanuma Formations. Spilled-out oil migrated upwards to the younger Lower Miocene reservoirs below the Upper Miocene Lower Fars regional seal.

There are no studies available on the source of the lighter oils in the Zubair reservoir.

Cretaceous Reservoirs

The East Baghdad field extends for more than 100 km in a north-west to south-east direction, with a width of over 10 km in places. The field is characterized by a complex structure, which is connected to a central fault along the field, with transverse faults trapping oil. Oil production to-date has come mainly from the late Cretaceous Tanuma and fractured Khasib carbonates and from the early Cretaceous Zubair sandstone formation. Oil has been successfully tested in other Cretaceous reservoirs, including the Hartha carbonates, Mishrif/Rumaila carbonates, Nahr Umr clastics and Ratawi mixed clastics/carbonate, and there also have been good oil shows in other Cretaceous reservoirs. Overall, about 90% of the reserves are found in the Upper Cretaceous reservoirs and 10% in the Middle and Lower Cretaceous reservoirs.

The Upper Cretaceous Hartha, Khasib and Tanuma Formations consist of carbonate rocks with a chalky, variable nature, generally with high porosity and low permeability. In each of them the upper parts are more porous than the rest of the formation, while the middle parts are water-saturated. Average porosity and permeability are about 15–20% and 45 mD respectively. The Tanuma and Hartha Formations exhibit the same oil property variations from top to bottom throughout the reservoirs, whereas the Khasib reservoir shows a lot of variation in oil types over the formation as a result of compartmentalization due to transverse faults which trend almost perpendicular to the axial trend of the structure and which do not extend up into the younger horizons. Oil gravity ranges between 15° and 24° API, with an average of 20° API. The presence of a tar mat at the base of the Khasib reservoir may indicate the oil/water contact.

The Middle Cretaceous Nahr Umr sandstone reservoir, which occurs mainly in the northern part of the field, has potential but it has not been produced as yet.

The Lower Cretaceous Zubair Formation consists of alternating clean sandstone and shale with good porosity and permeability values and high productivity, with an oil gravity range of 32°–38° API, averaging 34° API. However, analysis of the results of the drilled wells showed this reservoir to be less important than originally considered as the accumulations in the formation appear to be located in non-continuous lenticular sandstone units. The Hartha Formation does not reservoir oil over the whole field, but is limited to certain areas.

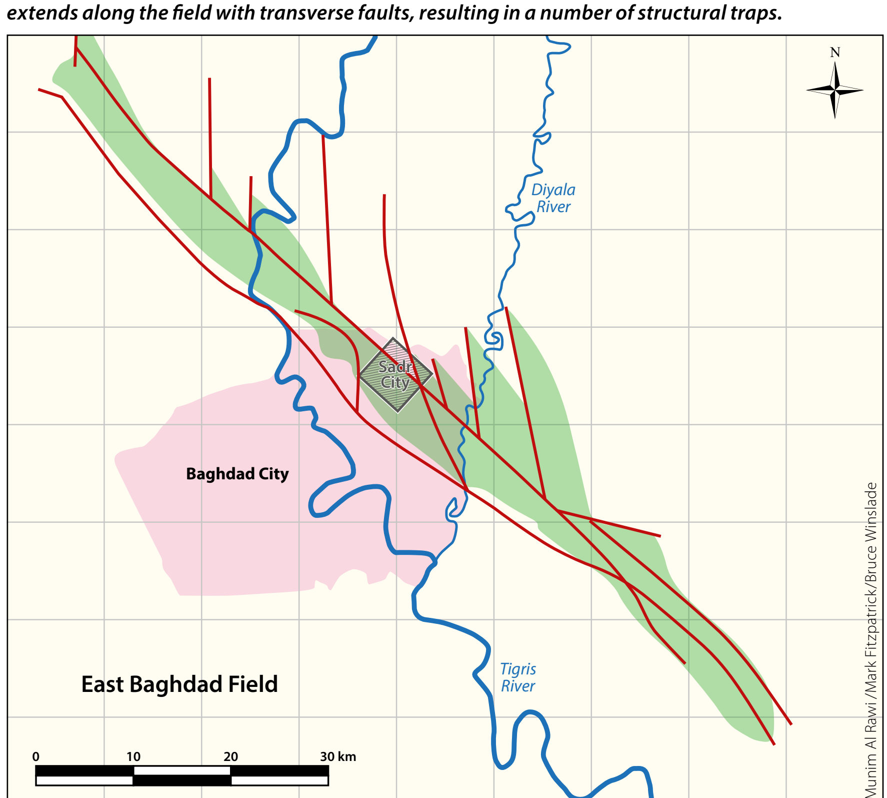
It would appear that the only continuous reservoirs are the Khasib and Tanuma units, which consequently became the main targets for development drilling.

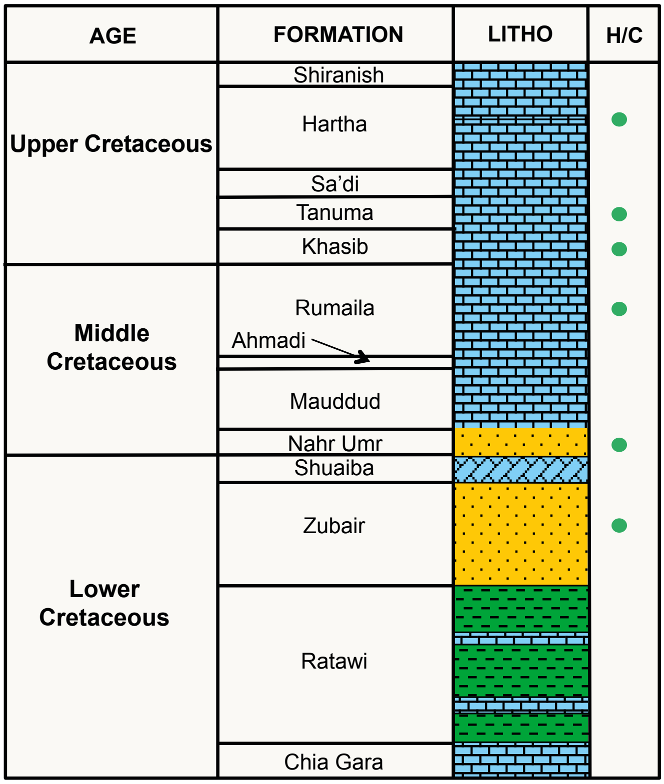
Limited Production

The East Baghdad field began production on April 1989 at an initial rate of 20,000 bopd and 14 MMcfgpd. Studies indicated that production would require pressure maintenance by water injection, as well as artificial lift in the producing wells, and gas lift was selected as the alternative option. Production stopped in both 1991 and 2003 due to conflict. Since 2009, the East Baghdad field has been producing 10,000 bopd of 20°–24° API from the Upper Cretaceous reservoirs, all of which is sent to the old Doura refinery in South Baghdad for local use.

Pre-2003 plans encompassed a phased development with an eventual plateau of 160,000–200,000 bopd in order to link development with utilization of the produced oil. The first phase of this development was to supply the central refinery, which was planned to have a capacity of 40,000 to 80,000

The East Baghdad field in relation to the city and also the suburb of Sadr City. The field is characterized by a complex structure, shown in red, which is connected to a central fault that extends along the field with transverse faults, resulting in a number of structural traps.





A simplified stratigraphy of the Cretaceous formations in the East Baghdad field.

bopd, but was never constructed. However, during Iraq's Second Petroleum Licensing Round in December 2009, the East Baghdad field was offered for development with a plateau production target of 30,000 bopd. The contract area for the offering was about 65 km long and 11 km wide, covering only the section of the East Baghdad field north-west of the Diyala river, but no bids were received.

Drilling Under a City?

The East Baghdad field oil and gas in-place reserves are reported to be 31 Bbo, with over 11.3 Tcf of associated gas, of which recoverable oil and gas reserves are 4.67 Bbo and 9.3 Tcfg. This makes it a super-giant field, but only a relatively small amount of it has been recovered so far.

The dilemma facing Iraq is how to exploit this resource without disturbing or endangering the multitudes who live and work above it. Since the East Baghdad field is situated within well-populated residential districts and a dense agricultural area, directional drilling was originally selected as the most appropriate way to drill most of the delineation wells. Some studies were also carried out to ensure population safety against any risk resulting from drilling and work-over operations.

It is suggested here, however, that the best way of fully developing this super-giant field may be by creating industrial zones between the residential suburbs of East Baghdad. Development of the field may also be a solution for the unemployment in the troubled East Baghdad districts. The high financial field development cost may well be a price worth paying. ■

References available online.

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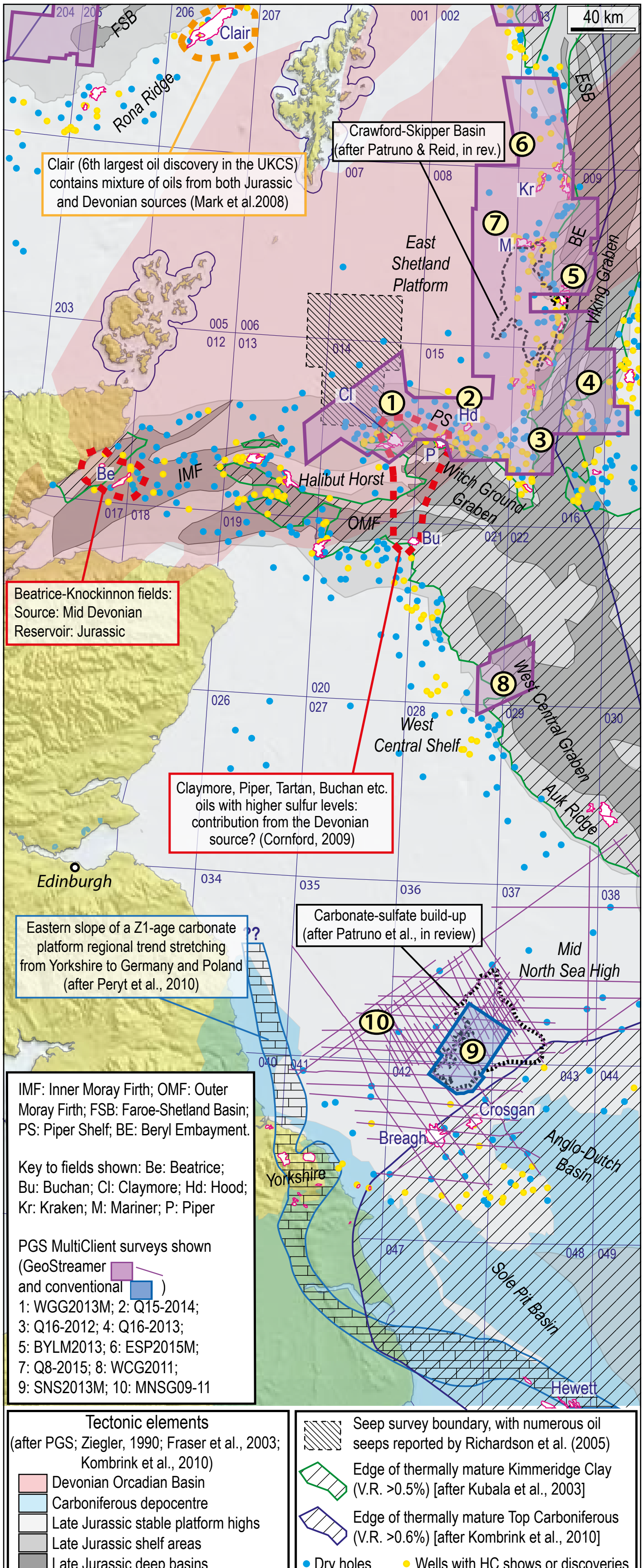

Figure 1: Structural elements, main fields and well results on the eastern UKCS. All the surveys shown, except MC3D-SNS2013M, are GeoStreamer, constituting >18,520 km² of modern (post-2010) 3D seismic and approximately 5,700 line-km of regional 2D (2009-2011).

The East Shetland Platform and Mid North Sea High

An introduction to the Devonian-Paleogene prospectivity of the key areas of interest for the UKCS 29th Frontier Licensing Round.

STEFANO PATRUNO and WILLIAM REID, PGS

The East Shetland Platform (ESP) and Mid North Sea High (MNSH) remain relatively underexplored platforms, with less than 10 wells per 1,000 km^2. Over Quadrants 3, 8–9, 14–16, 35–38, 41–43 (Figure 1), the clearer imaging of the modern broadband dual-sensor towed streamer surveys (GeoStreamer®) provides new insights into the geology and the petroleum systems of these frontier areas, which are proposed for inclusion in the upcoming UKCS 29th Frontier Licensing Round.

The following is a short summary introducing the main play concepts. A much more comprehensive description and discussion of these areas have formed several technical papers and presentations, some of which are referenced here.

Source Rocks

The majority of the hydrocarbons found in the Northern and Central North Sea are sourced from the oil-prone upper Jurassic Kimmeridge Clay. In contrast, in the Southern North Sea, the main source rocks are gas-prone Westphalian coals and shales. The source kitchens in both regions are restricted to basinal depocenters, with charge to the platform margins occurring via lateral migration (Figure 1). A deeper source rock is needed in order to extend prospectivity beyond these margins (Patruno & Reid, in review).

On the ESP, middle-Devonian lacustrine source rocks have been penetrated by numerous wells and oil seep data has revealed a working petroleum system up to 80 km away from the Jurassic source kitchen (Richardson et al., 2005). This Devonian source is proven to work in the Inner Moray Firth (Beatrice Field) and West of Shetlands (Clair Field) and may provide a secondary charge for large Witch Ground Graben fields (e.g., Claymore, Piper) (Mark et al., 2008; Cornford, 2009). 1D basin modeling supports the hypothesis of Cornford (2009) and suggests that the best-case scenario for the maturation of the middle-

Devonian source rock (i.e. post-Jurassic maturation) occurred over parts of the ESP (Patruno & Reid, in review).

On the MNSH, the Westphalian interval has been significantly eroded due to Varisican uplifting. Older source rocks (e.g., Carboniferous Scremerston Formation) could provide hydrocarbon charge beyond the platform margins. So far, all wells north of Quadrant 36 have been dry, suggesting that the central and northern MNSH may be affected by fundamental source/charge issues.

Reservoirs

Existing discoveries on the ESP and MNSH highlight the presence of multiple working reservoirs.

The ESP hosts predominantly Paleogene-age reservoirs (e.g., Mariner, Kraken) as well as Upper Jurassic sandstones (e.g., Hood, Claymore). Large Devonian-age discoveries are present in the West of Shetlands and Central North Sea (e.g., Buchan, Clair; Fig. 1). Clair, in particular, with >1,100 MMboe, is the sixth largest oil field in the UKCS.

The MNSH main reservoir intervals are Carboniferous in age (e.g., Breagh, Crosgan). Additional potential within the MNSH is located in the Zechstein Group, with Z2-age carbonates (Hauptdolomit Formation) being a proven reservoir in Crosgan, onshore Yorkshire and throughout the Southern Permian Basin (Figure 1; Patruno et al., in review). In addition, the Z1 carbonates also constitute a proven reservoir (e.g. giant Hewett gasfield).

Seals

Within the study area, hydrocarbon discoveries and potential traps are generally buried beneath 1 second (TWT) of sediment (Figures 2–3). In the ESP, most of the overburden is composed of Mesozoic-Tertiary mudstone-prone sealing lithologies (Patruno & Reid, in review). In contrast, in the MNSH, Zechstein evaporites constitute the top-seal for Carboniferous and intra-Zechstein reservoirs, and additional seals are provided by the overlying mudstone-rich Triassic-Tertiary units (Figure 3).

Traps and Unexploited Potential

The existing discoveries on the ESP rely predominantly on Paleogene-age traps, ranging from stratigraphic (e.g., Brae-West, Harding) to structural (e.g., Balmoral, Skipper). Upper Jurassic discoveries close to the Witch Ground Graben edges are structural (e.g., Claymore) or mixed stratigraphic-structural (e.g., Hood – Figure 2A). Fields with Paleozoic-Triassic reservoirs rely on structural, fault-block-related traps (e.g., Crawford, Stirling, Cairngorm) (Patruno & Reid, in review).

Additionally, several yet-undrilled traps and structures have been mapped throughout the ESP (e.g. Reid & Patruno, 2015). These include newly imaged Devonian-Jurassic fault systems, Devonian fault-blocks, anticlines, and intra-platform Permo-Triassic basins (e.g. the Crawford-Skipper Basin). The clear seismic imaging has also better defined the Mesozoic-Tertiary interval, identifying a number of potential exploration leads. These include Paleogene anticlines and pinchouts with amplitude anomalies; DHIs associated with Eocene-age clinoforms; and high-angle Eocene injectites (Figure

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Image must be high resolution, at least 300dpi
Multiple entries welcome but maximum 10 entries per category
Enter one or more categories
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Deadline September 30th 2016

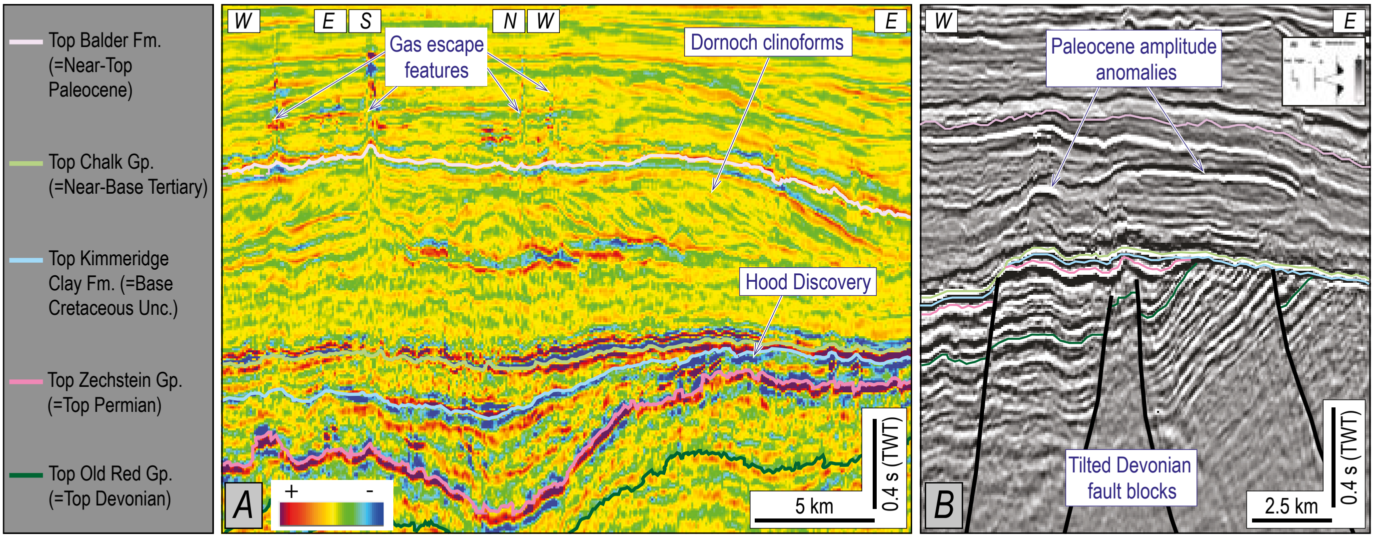


Figure 2: MC3D-Q15-2014 GeoStreamer from the East Shetland Platform. (A) Post-stack run-sum showing possible gas escape features; (B) Full-stack Paleocene amplitude anomalies and Devonian fault blocks.

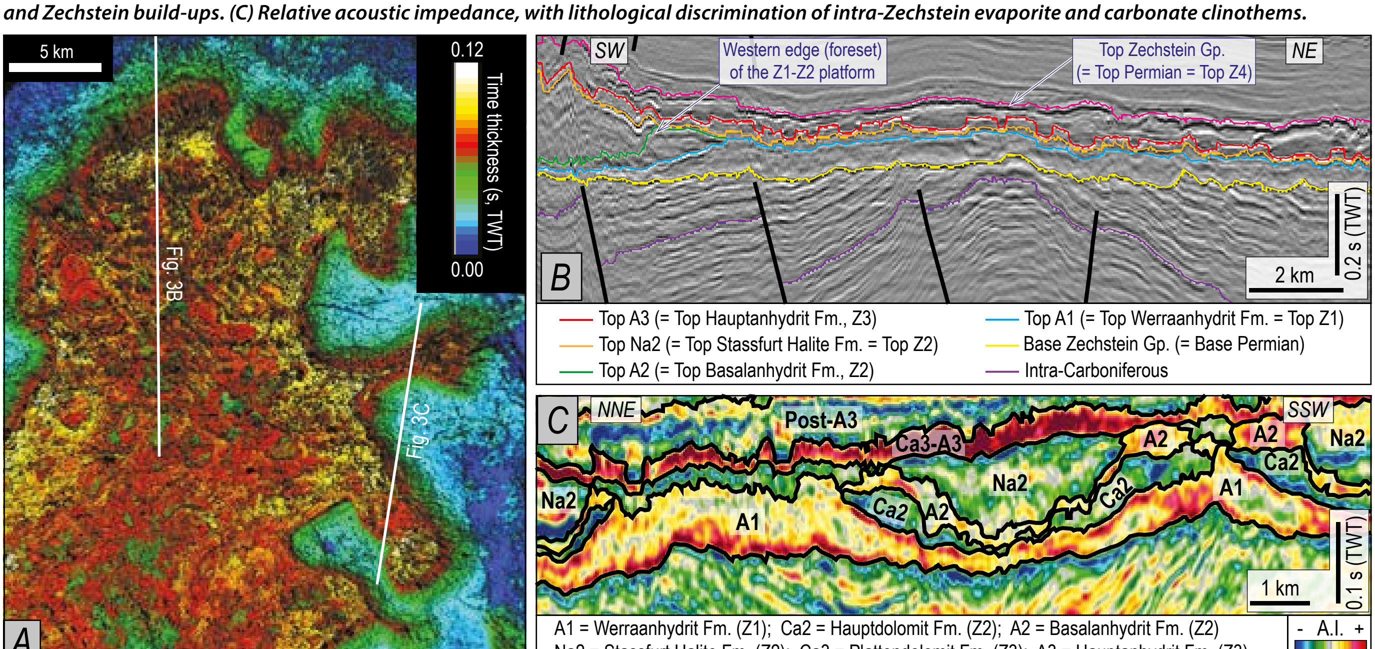
2). As with existing multi-reservoir discoveries (e.g., Claymore, Crawford), some newly-defined leads on the ESP comprise stacked targets, such as the Eocene clinoforms, Paleocene amplitude anomalies and Devonian fault blocks seen in Figure 2.

A relationship between the deep-seated Paleozoic-Mesozoic fault systems and the Tertiary leads and discoveries has now been documented (Figure 1; Patruno & Reid, in review), with existing hydrocarbon discoveries on the ESP clustering in the vicinity (<7 km) of intra-platform Permo-Triassic basin margins. Exploration near such basins is less risky due to possible positive influences of deep-seated structures on the petroleum system, such as the formation of Meso-Cenozoic closures via fault-inversion; Devonian source maturity; the presence of simple structural migration pathways, and the viability of sub-Jurassic reservoir-trap-seal configurations (Patruno & Reid, in review).

The southern MNSH hosts several trap types. These include Carboniferous-age 4-way dip closures resembling existing discoveries (e.g., Breagh; Figure 3B); Devonian Kyle Limestone fault blocks, mapped in 3D for the first time; and a 2,284 km^2, newly described sulfate-carbonate platform (Figures 1 and 3) (Patruno et al., in review). This sulfate-carbonate platform comprises a series of prograding-aggrading clinothems of lower Zechstein age (Z1-Z3), with some composed of anhydrite (high impedance) and others of carbonate (lower impedance) (Figure 3C). The Z2 carbonates form the most prospective clinothems, both regionally and locally (Patruno et al., in review). Although gas shows have been identified in at least 21 nearby wells which penetrated the tight Z2 bottomset carbonates, the thickest and most permeable part of these clinothems (i.e. foresets) has never been drilled in this area.

A full list of references is available online. ■

Figure 3: MC3D-SNS2013M (Mid North Sea High). (A) TWT-thickness map of a Z1-Z2 sulfate-carbonate platform. (B) Full-stack Carboniferous structures and Zechstein build-ups. (C) Relative acoustic impedance, with lithological discrimination of intra-Zechstein evaporite and carbonate clinothems.



AFRICA: What's Next?

Africa: What's Next?

The 15th HGS-PESGB Conference on African E&P

September 12-14, 2016

The Westin Houston, Memorial City, Houston Texas

Six of the IHS Top Ten discoveries of 2015 occurred on the African continent. This clearly illustrates why Africa is so important in the search for oil and gas. The annual HGS–PESGB Africa conference, alternating between Houston and London, has established itself as the premier technical E&P event on this fascinating, and frustrating continent. If you are currently exploring or are thinking about exploring the African continent you cannot afford to miss this conference! Scheduled speakers include the top explorers and researchers working Africa and its margins. A primary goal of the HGS during this difficult business climate is to provide inexpensive, quality training and networking opportunities for our membership and the greater geological community. We believe we have met this goal with the speakers, short courses, geophysical showcase and geological workshop we have assembled for this conference. Typical conference attendees include industry operators, consultants, governments, and academia.

The Second Annual Interactive Seismic Showcase and Geology Workshop will feature geophysical and geological vendor presentations highlighting their products and services. This proved to be a big attraction in London in 2015 and we are anticipating similar excitement at this year's event.

Short Courses

Two short courses will be held in conjunction with the conference

Duncan Macgregor – *Petroleum Basins and Recent Discoveries in North and East Africa*

Ian Davison – *South Atlantic Margins: Geology and Hydrocarbon Potential*

Conference Opening Evening Lecture

Prof. Andrew Nyblade (Penn State University) will present the conference opening lecture on *Imaging First-Order Structure of Large Karoo and Younger Basins in Central, Eastern and Southern Africa Using Passive Source Seismic Data*. The lecture will be held on the evening of Monday September 12th. This event has limited seating and requires a separate reservation. Details will be on the HGS webpage under "Events".

Conference

Early Bird registration April 1 through June 30, 2016 = $300
Regular registration July 1 through August 31 = $400
Late/onsite registration September 1 through September 14, 2016 = $450

Short Courses

Early Bird registration April 1 through June 30, 2016 = $200
Regular registration July 1 through August 31 = $250
Late/onsite registration September 1 through September 14, 2016 = $300

A $50 discount will be given to individuals that sign up for both the conference and a short course

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Taking a Holistic Approach

Low oil prices are triggering much-needed change through a holistic approach.

DAN JACKSON, io oil & gas consulting

Change in the oil and gas industry often comes slowly. However, as months of low oil price turn into years, it is necessary now. Oil producers have taken to cutting billions of dollars in expenditure, which has forced providers and contractors to slash rates, and delay and even cancel projects.

The upstream industry in particular needs to fundamentally transform the way it works to survive and thrive. While cost-cutting can be an effective plan in the short-term, the industry needs to take a longer-term focus and change the fundamentals of the way it operates. To compound matters, the days of triple-digit oil prices appear well and truly over, with the World Bank estimating that a barrel of oil will only rise to $60 by 2020.

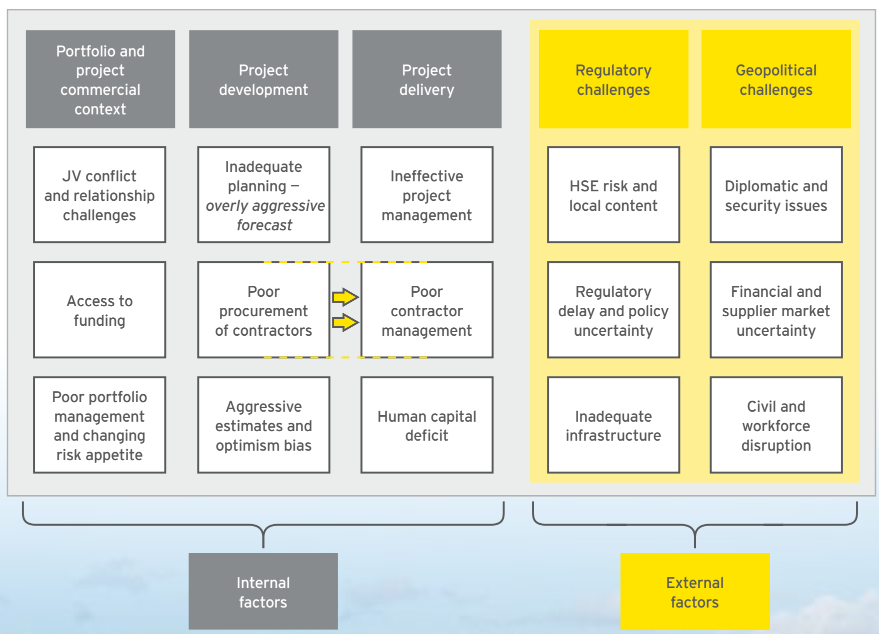
Regardless of the oil price, the sector needs to rethink established ways of working in order to better handle increasingly complex projects. The high crude price in recent years helped the industry gloss over inefficiencies and enjoy success in the short term. But the recent slump has fully exposed shortcomings, and shone a spotlight on the fact that the offshore industry was on an unsustainable path and in need of guidance to standardize processes to lead it through a turbulent time.

Piecemeal Model

Part of the reason why projects are not completed on time and on budget is the disconnect between operators and contractors. EY's 2014 report on oil and gas megaprojects showed that 21% of project failures were down to management processes and contracting and procurement strategies; 65% due to people, organization and governance; and 14% of failures due to external factors such as government intervention and environment-related mandates.

The existing model of contracting is piecemeal with specialist designers, contractors and projects managers coming on board one at a time, with no one group that

Factors responsible for cost overruns and delays. Source: Spotlight on oil and gas megaprojects, EY



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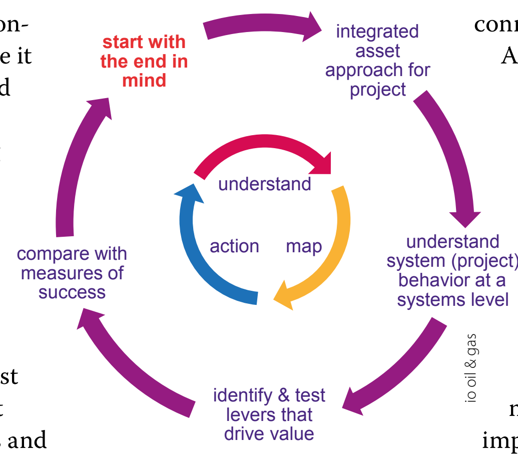
brings the whole project together at the front end to deliver efficiencies and control that should be standard in an ever-evolving offshore sector. Oil companies and contractors therefore need to work together to better understand the drivers and develop the best blueprint to take the project forward into execution with a common purpose.

The benefits of a holistic approach mean that all aspects of a project are taken into consideration from the beginning to ensure it can be delivered on time, on budget and with certainty.

An offshore project is only as strong as its weakest link and developments today contain significant complexity owing to competing technical, commercial and risk requirements. This means that altering one small variable can have a ripple effect on an entire operation. Failure to create robust and balanced synergies across a project can result in unintended consequences and uncertainty.



Start with the end in mind.

Integrated Asset Approach

Understanding these components and developing a process for option evaluation and selection is integral to creating maximum return on investment for an offshore project. With this in mind, recently formed consultancy io oil & gas has developed an integrated asset approach (IAA) specifically to tackle complex offshore jobs by being holistic and full field in nature and encompassing the plan, build and operate phases of a project. The approach uses rapid comparison of concept options to form a deep understanding of different project variables and their interdependencies. Rather than individual focus on each sector, this allows the spotlight to be on areas that have a genuinely significant impact on project commerciality, thus maximizing investment returns by balancing reservoir performance and project costs. It improves financial viability, identifies inefficiencies, removes risk, creates value for operators and, as the company says, 'delivers certainty in an uncertain world.'

The company believes it is crucial to work in partnership with clients to understand their specific needs and identify the innovative solutions necessary to deliver effective outcomes. Most projects are characterized by significant complexity around concept selection, owing to competing technical, commercial and risk requirements, as well as reservoir uncertainty, and altering one small variable can have big implications, potentially affecting an entire project. A system like IAA is crucial as it has been purposely developed to deliver optimum project value by factoring in the impact of trade-offs. By finding the common bonds between, for example, commercial and technical aspects, it is possible to reconcile the differences and begin to understand the high level interconnectedness of the components.

New Thinking

As well as the need for new ways of approaching projects, the industry knows that advancing technology holds the key to enhancing recovery of remaining reserves in this environment – but producing new tools, technologies and equipment and changing the accepted way of doing things can prove challenging. 'Big Data' is being touted as one of the secrets to the future of oil and gas, as it allows the uncovering of invisible patterns and connections by linking disparate data sets. As such, there is potential for operators to find efficiencies and improve the performance of components throughout their operations.

'Big Data' can also be used for sophisticated reservoir monitoring, allowing companies to optimize field depletion planning and maximize ROI. As more Cloud-based systems come online, management tools and remote working practices will become more commonplace, leading to safety improvements and cost reductions.

The status quo is failing too often and new powerful thinking is needed to deliver fresh engineering solutions for the next generation of offshore fields. One of the best things the industry can do when looking to embark on new projects is to start with the end in mind. This type of holistic thinking is going to prove invaluable to the industry and will ensure that projects have built-in contingency plans, guaranteeing that time and money are not wasted.

Though the price downturn has cast a shadow over the industry, it has also created an opportunity to change standard ways of working as well as taking advantage of the improvements technology like Big Data can provide. The industry needs consultancies that can manage the intricacies of each part of a project by blending the right people with broad experience and domain expertise and deep commercial knowledge. Having access to industry and specialist expertise with end-to-end systems thinking and organizational insight will make significant efficiency savings and instill confidence at an uncertain time for the offshore oil and gas industry.

Reference:

EY Spotlight on oil and gas megaprojects 2014 ■

Dan Jackson, CEO of io oil & gas.

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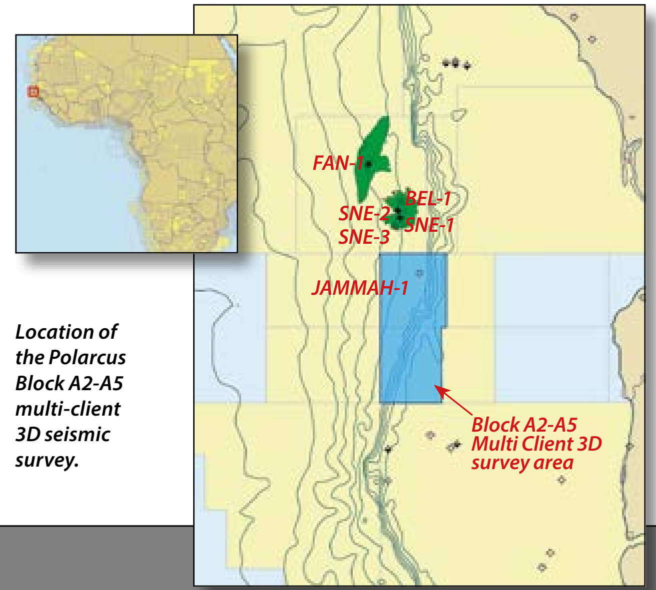
The Gambia: The Next Major Oil Play?

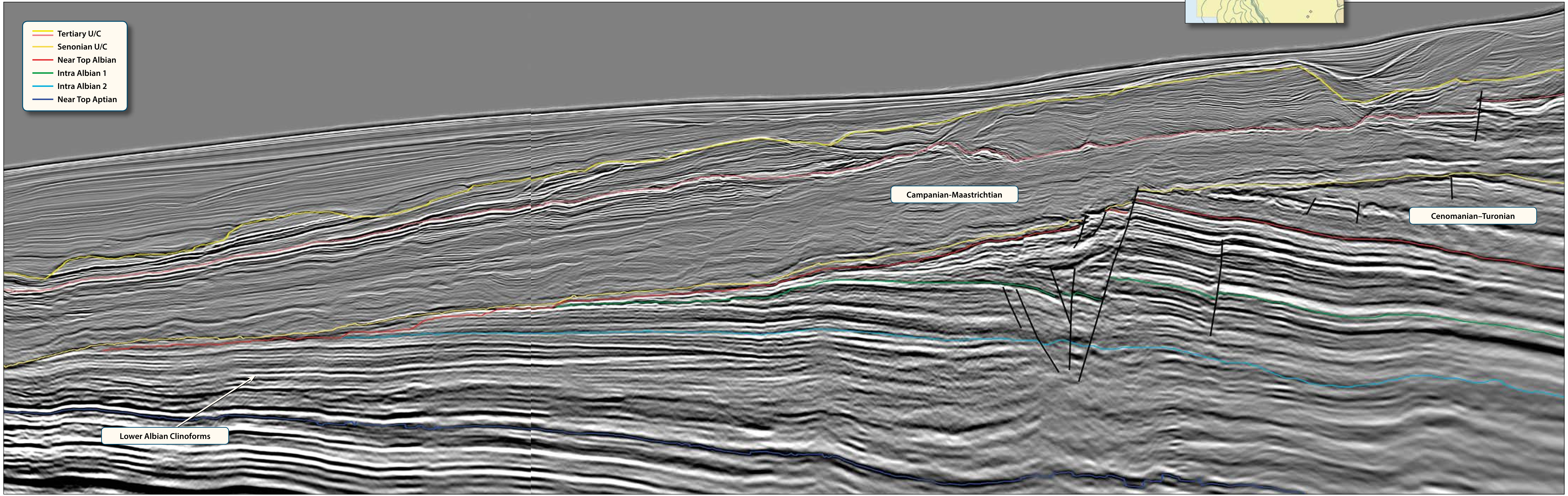
Polarcus, in collaboration with The Gambia's Ministry of Petroleum and GeoPartners, has recently completed a 1,504 km² RightBAND™ Multi-Client 3D seismic survey over Blocks A2 and A5, within the prolific MSGBC Basin offshore The Gambia. This modern broadband data volume lies in an area with no previous 3D seismic coverage, and where the commerciality of the SNE oil discovery in neighboring Senegal has recently been confirmed. Screening of the new 3D multi-client volume has identified a number of both structural and stratigraphic leads on trend with the Senegalese discoveries, confirming that the new deepwater clastic play concept extends into The Gambia. Polarcus' Block A2-A5 survey provides optimum imaging to allow evaluation of this highly prospective area.

The survey was acquired in this geologically complex area using the *Polarcus Alima* towing a 12 x 100m x 8,100m ultra-quiet Sentinel® solid-streamer spread with an 18.75m flip flop shot interval and a nine-second record length. The data has been processed by DownUnder GeoSolutions through broadband pre-stack time and depth migration workflows.



Location of the Polarcus Block A2-A5 multi-client 3D seismic survey.

Figure 1: Regional east-north-east to west-south-west seismic line. PSTM volume after a simple 1D conversion to depth.



Extension of a New Oil-Prone Fairway

The SNE and FAN discoveries in neighboring Senegal have opened up a new oil-prone fairway with multiple play types extending to the south into Gambian waters.

TONY PEDLEY, Polarcus

The Polarcus Block A2-A5 survey is located in The Gambia's offshore Casamance-Bissau sub-basin, located in the southern part of the greater Senegal Basin. The area has seen recent renewed industry focus due to three successive hydrocarbon discoveries on the adjacent Cairn-operated acreage in Senegalese waters to the north. The world class SNE-1 and FAN-1 oil discoveries in Albian-aged sandstones have opened up a new oil-prone fairway with multiple play types. Similar plays along the West Africa margin are already in development or production, and the adjacent acreage in The Gambia provides a number of leads and prospects on-trend to these exciting discoveries.

Exploration for hydrocarbons in The Gambia dates back to the 1950s, but none of the companies involved in the early exploration of the area progressed beyond initial studies apart from Chevron, who drilled Jammah-1 in 1979. This is located in Block A2 and to date is the only well drilled offshore The Gambia. It was plugged and abandoned with gas shows at a TD of 3,020m. It targeted an Albian shelf-edge carbonate feature slightly to the east of the axis of a large north-south trending anticline and encountered viable sandstone and carbonate reservoir horizons but only minor petroleum shows. The well was drilled on the basis of 2D seismic data and post-well studies suggested it was dry due to erosion of potential Turonian source rocks at the location, though analysis of the new seismic data acquired by Polarcus in 2015 suggests it did not test a valid structural closure.

Studies have reviewed the offshore exploration potential and a range of play types including fan and slope channel systems, karstified reef build-ups, 4-way closures and clastic deposits onlapping the shelf edge have been identified. No further drilling has taken place offshore The Gambia.

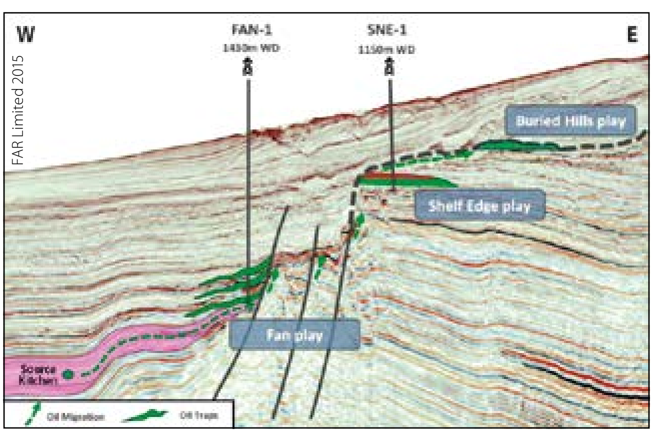
A New Oil Province

In 2014 Cairn drilled two deepwater exploration wells offshore Senegal, SNE-1 and FAN-1; both wells discovered oil, opening a new hydrocarbon basin on the Atlantic Margin. FAN-1, the first well drilled in deepwater offshore Senegal, is located in 1,427m of water in the Sangomar Deep Block. It encountered high quality light oil in multiple stacked deepwater Cretaceous clastic fan bodies with 29m of net oil-bearing reservoir located in a combined structural and stratigraphic trap. The second deepwater exploration well, SNE-1, located in 1,100m of water approximately 24 km from the FAN-1 discovery, targeted Albian sandstones overlying Aptian carbonates. A 95m gross oil column with a gas cap was encountered in excellent quality Albian reservoir sands with 36m of net oil pay. However, no hydrocarbons were encountered in the deeper carbonates.

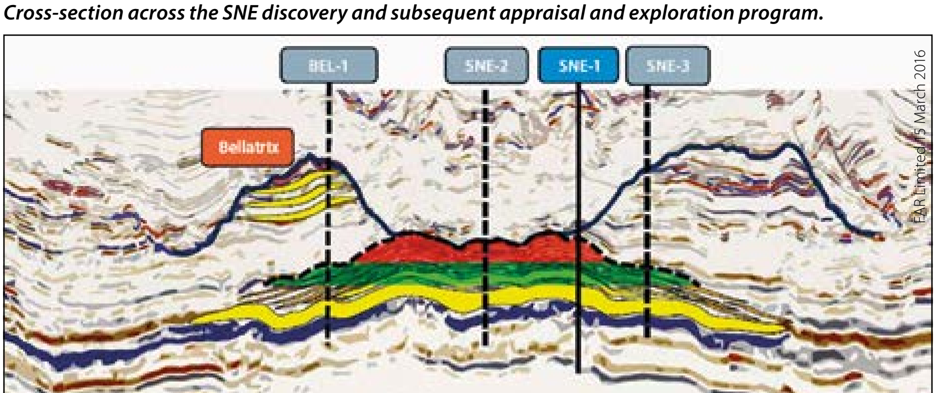
The SNE-1 discovery was appraised by the SNE-2 well which flowed up to 8,000 bopd on DST, confirming the high delivery of the principal reservoir unit and the connectivity of the principal reservoir with the discovery well. In March 2016 Cairn announced the results of further appraisal drilling with the successful testing of the SNE-3 well, which flowed at a maximum rate of 5,400 bopd on DST. The well confirmed similar reservoir quality and correlation of the principal reservoir units with SNE-1 and SNE-2, including similar oil-down-to and oil-up-to depths. Initial indications confirmed the same 32° API oil quality as seen in the previous wells.

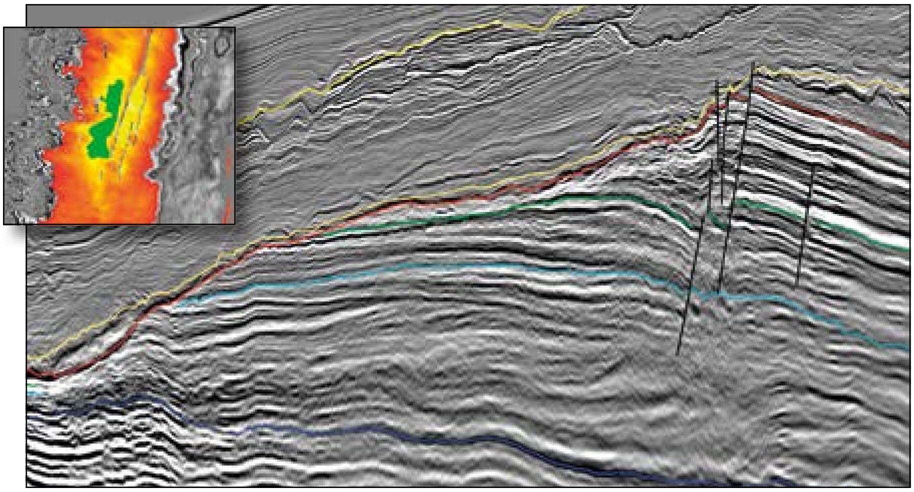
Further exploration followed with BEL-1, which drilled the Bellatrix Prospect and tested the Buried Hills play, discovering gas in two

Cross section across the FAN-1 and SNE-1 discoveries.



Cross-section across the SNE discovery and subsequent appraisal and exploration program.





Structural 3-way dip closure bounded to the east by a faulted margin. PSTM volume after a simple 1D conversion to depth. Inset shows a mapped Albian lead.

good quality Cenomanian sandstone reservoirs. The well was deepened to further appraise the SNE discovery and to progress towards proving a minimum economic field size. It also confirmed the extension of reservoirs and oil column on the northern flank of the discovery. Estimates by the operator Cairn, post the SNE-2 well, suggest contingent reserves of 385 MMbo and further analysis of the resource is underway as further appraisal drilling is ongoing.

Gambia: The Aptian-Albian Shelf

The Block A2-A5 area lies immediately to the south and along structural trend with the recent discoveries in neighboring Senegal. The Jurassic to Aptian carbonates are overlain by a series of Albian sequences displaying large scale clinoforms. These occur as a number of discrete stacked systems, each prograding from east toward the west. The clinoforms can be seen to be laterally extensive across the area, providing the potential for reservoir sandstones across the shelf. As well as providing reservoir sands into a number of structural play types, the evolution of the delta-to-slope systems provides possible stratigraphic components to plays within shelfal distributary systems, shelf edge clinoforms and more basin-ward down dip sand-bodies.

Uplift and rotation due to the withdrawal of Triassic salt led to erosion of the Aptian-Albian shelf and the overlying Upper Cretaceous sequence. This has provided a further series of prospective play types with structural components. Gambia Blocks A2-A5 contain all the necessary components of a successful petroleum system as seen immediately to the north in Senegal, with potential existing for source rocks in several Jurassic to Cretaceous sequences both outboard the shelf-slope break and across the shelf area.

Multiple Play Types

Interpretation of the newly acquired 3D multi-client volume has identified a number of play types across the shelf and shelf edge areas including: 4-way dip closures, fault bounded 3-way dip closures, Buried Hills plays, and slope fan and stratigraphic plays. A number of examples are presented herein.

Structural 4-Way Dip Closures: Initial interpretation of the final PSTM data volume after a simple 1D conversion to depth shows a number of 4-way dip closures affecting the Albian sequence all along the shelf edge area across Blocks A2-A5. Interpretation of the full PSDM data volume, due in the third quarter of 2016, will allow proper evaluation of this exciting series of leads.

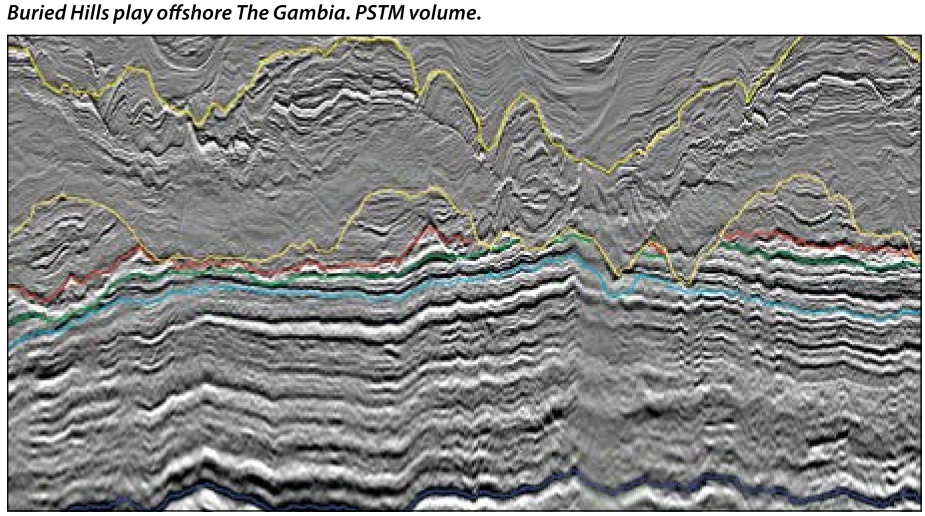
Structural Fault Bounded 3-Way Dip Closures: A series of rollovers into the prominent north-north-east to south-south-west trending faulting affecting the uppermost Albian sequence is observed. The 3D data reveals a number of closures at this stratigraphic level forming a series of leads along strike. Deeper within the sequence the Albian is less affected by this fault system and 4-way closures occur.

The Buried Hills Play

Analogs to the Cenomanian Buried Hills play as successfully drilled in the BEL-1 exploration well can be seen across the A2-A5 area. Erosion and incision of the Upper Cretaceous sequence has resulted in trapping of Cenomanian sand-bodies sealed by the overlying Tertiary and Cretaceous shales and claystones. The new 3D data enables interpretation of the depositional packages within the Cenomanian, allowing evaluation of a number of leads. The example below, which also displays a structural 4-way dip closure of the underlying Albian sequence, is analogous to the section across the SNE and BEL discoveries.

References available online. ■

Buried Hills play offshore The Gambia. PSTM volume.

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On Shaky Ground Induced Earthquakes

THOMAS SMITH

Over the last decade, certain oil and gas producing areas have come alive, experiencing an escalating number of felt earthquakes, some even large enough to cause property damage.

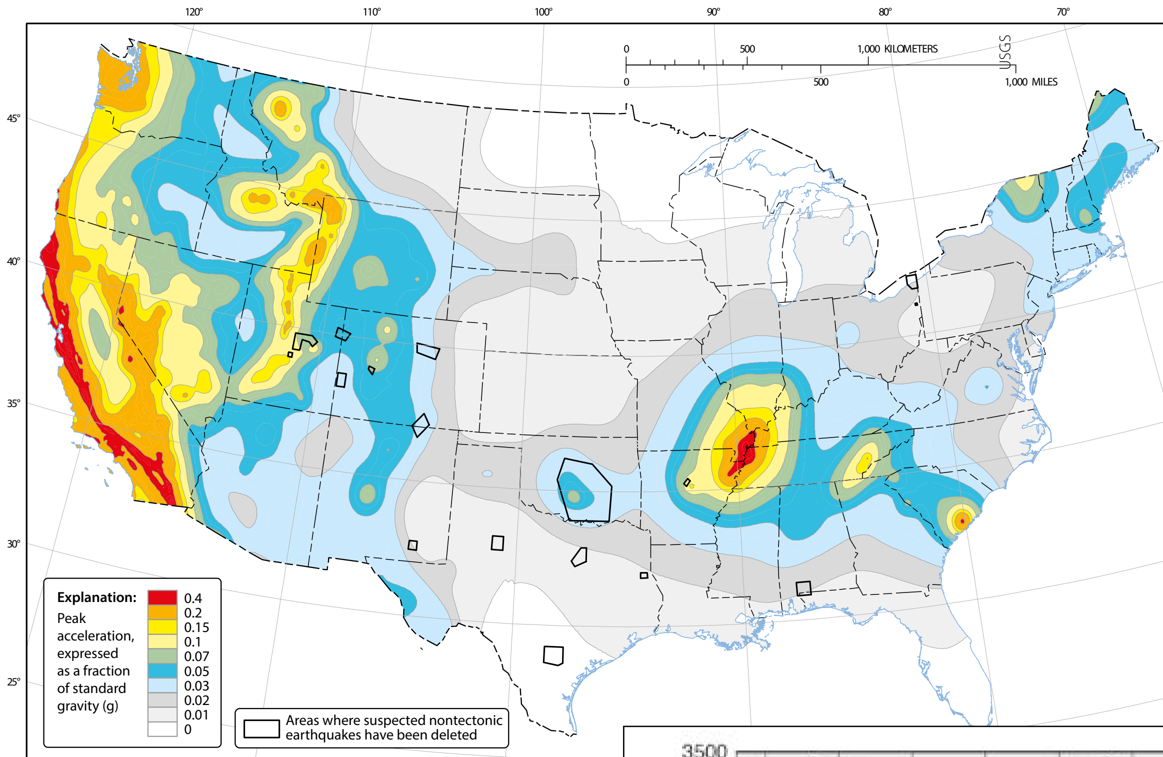
Most people consider California an area likely to be hit by frequent, and sometimes damaging, earthquakes. After all, the state lies within and along a tectonically active plate boundary where elastic strain energy accumulates in the Earth's crust and can be suddenly released, causing earthquakes. Move into the mid-continent area of the United States, far from the natural stresses of a boundary between moving continental plates, and, historically, earthquake activity has been considerably less.

In Oklahoma, for example, before 2000 on average one and a half earthquakes of magnitude 3 (M3) or greater occurred *each year*. In 2013, the Oklahoma Geological Survey (OGS) observed two >M3 earthquakes *each week* and by early 2015, they reported that an average of two and a half >M3 or greater earthquakes were occurring *each day*. In April, 2015 an OGS Statement on Oklahoma Seismicity by Richard D. Andrews, State Geologist and Dr. Austin Holland, then State Seismologist, now with the USGS, stated that, "The OGS considers it very likely that the majority of recent earthquakes, particularly those in central and north-central Oklahoma, are triggered by the injection of produced water in disposal wells."

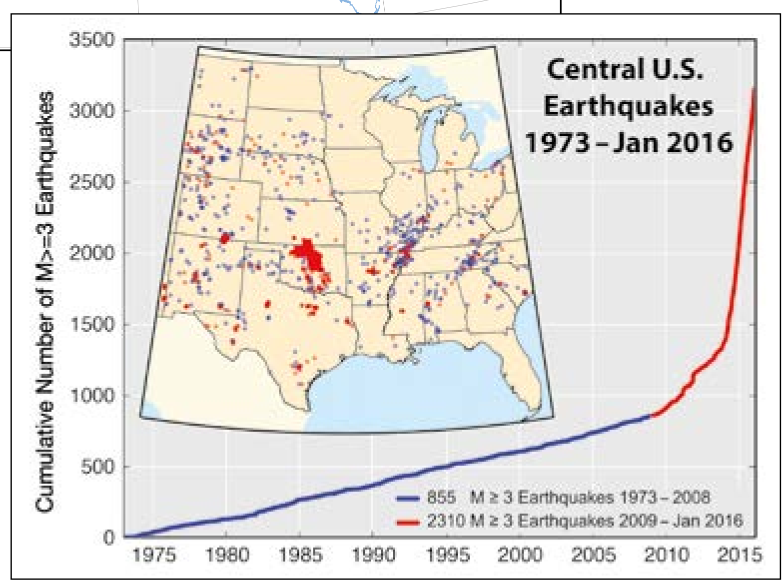
Out of hundreds of thousands of energy developments in the US, only a small fraction of those have caused detectable seismic activity noticeable to the public. Of the suspected induced seismic events, very few have been large enough to cause property damage. However, the increase in the seismic hazard associated with oil and gas activities both in North America and Europe has been attracting the attention of politicians, the public, the industry, and scientists seeking to understand the causes and solutions to mitigate the consequences.

Brian Sherrod, USGS

House damage in central Oklahoma from the M5.6 earthquake on November 6, 2011. Research conducted by USGS geophysicist Elizabeth Cochran and her university-based colleagues suggests that this earthquake was induced by injection into a deep disposal well in the Wilzetta North field.



2014 National Seismic Hazard Map for the US (not including Hawaii and Alaska) showing areas in red and orange as having the highest seismic risks (10% probability of exceedance in 50 years of peak ground acceleration). Notice the areas of suspected nontectonic (human-caused) earthquakes and compare this to the map below.



Graph and position of earthquakes which have occurred since 1973. Notice the increasing number of earthquakes since 2009, particularly the post-2009 earthquakes (red dots) in the south-western portion of the map in Oklahoma and Texas.

Measuring the Seismic Hazard

Most of the Earth's destructive natural earthquakes occur at or near convergent and transform plate boundaries along areas of active deformation. Earthquakes also happen along divergent plate boundaries and are generally associated with shallow earthquake activity from extensional forces stretching the lithosphere. Under the low temperature and pressure conditions of the upper lithosphere, silicate rock can build up huge amounts of elastic strain energy. The sudden release of this stored energy occurs through the rapid sliding of faults, causing earthquakes at a wide range of magnitudes. The released energy travels through the crust as waves of elastic energy, also called seismic waves, that can be measured and felt on the surface as earthquakes.

Because shear stress levels across continental plates are near the strength limit of the crust, there is also a potential for natural earthquakes to occur in interior continental areas far away from active deformation zones. As Dr. William Ellsworth, Professor at Stanford University in California, who has divided the central and eastern US into two equal sized areas, points out: "Most of the earthquakes for this large area have occurred along ancient basement faults at rates much lower than areas along the plate boundaries. Over most of the central and eastern US, the US Geological Survey (USGS) earthquake hazard model is derived by projecting the spatially smoothed historical earthquake rate, with aftershocks removed, forward in time. Therefore, these two areas should have a constant rate of earthquake occurrence. However, parts of the western area have experienced an upsurge in seismicity levels since 2000 that continues to increase."

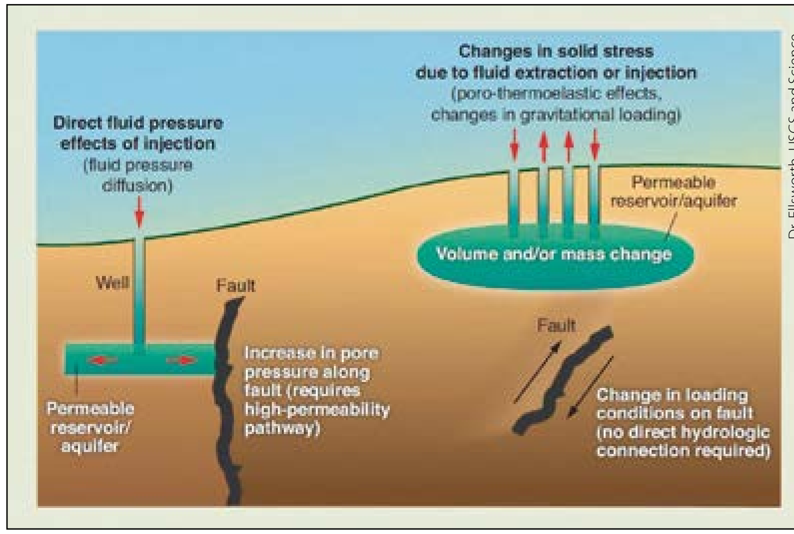
Looking to the Cause

"The cause of the recent observed changes in seismicity in parts of Oklahoma, Texas, and Colorado has become a rather contentious question in some circles," says Dr. Ellsworth. "There is always room for more research and better data, but an extensive and solid body of scientific investigations, theory, and even experiments document how earthquakes can be induced".

In fact, human-initiated earthquakes have been documented for over 100 years. Recognized causes include huge hydroelectric projects with large water reservoirs, mining activities, geothermal drilling, nuclear detonations, and extraction and injection of fluids and gas into subsurface formations.

One of the first links to induced earthquakes caused by underground wastewater storage was made at the Rocky Mountain Arsenal (RMA) near Denver, Colorado. A deep injection well was drilled in 1961 to dispose of hazardous chemicals stored at the facility. Several months after fluid injection started, earthquakes were felt and measured in the north-east Denver area. Before injection ceased in February, 1966, thirteen M4 or larger earthquakes were recorded. The three largest, including an M4.8 event in 1967 that caused minor damage, were logged after injection had stopped. Hydrologic modeling showed the migrating seismicity was tracking a critical pressure front. Although declining, seismicity continued occurring for 20 years up to 16 km from the injection site.

Another important step in understanding how fluid injection, and thus fluid pressure in a fault, could control earthquake activity occurred at the Chevron-operated Rangely oil field in north-western Colorado (see *GEO ExPro* Vol. 12, No. 6). Studies on the earthquakes at the RMA led scientists to believe that earthquakes could be controlled by modulating the fluid pressure in a fault. In 1969, the USGS conducted an experiment to test this theory. Chevron allowed the USGS to regulate the fluid pressure in a portion of the Rangely field that was known to be seismically active. After two cycles of fluid injection and withdrawal they found that the rate of seismicity could be controlled by adjusting the pore pressure at the depth where the earthquakes initiate.



Schematics (not to scale) of two mechanisms for inducing earthquakes related to oil and gas operations. An increase in the pore pressure along a fault is illustrated on the left, while the right side shows how load changes on the fault (either through extraction or injection) can induce movement.

An Excess of Earthquakes

The four areas in the central US that have seen more than their share of earthquakes in recent years are the Raton Basin on the Colorado-New Mexico border; through central Oklahoma; in the Dallas-Fort Worth, Texas area; and at the Cogdell oil field in western Texas. "These areas have been thoroughly investigated using available seismicity, well, and geologic data," says Dr. Ellsworth. "In most cases, the evidence points to wastewater disposal by injection as the cause." He cites at least eight recent papers covering this subject.

"These areas do not contain the extensive knowledge of the stress, pore pressure, and hydrologic conditions that made the Rangely experiments possible," Dr. Ellsworth adds. "Consequently, the studies rely on spatial and temporal correlations when assessing the involvement of industrial activity as the cause of the increased seismic activity, which leaves speculation about other possible causes." (Note that in most states, the industry currently holds the proprietary data on underground conditions, subsurface geology and fault locations which would allow a more rigorous scientific analysis such as was conducted at the Rangely field in Colorado.)

As other causes, Dr. Ellsworth cites hydraulic fracturing treatments, which have induced M4 earthquakes in Canada. No evidence has been found to support hypotheses such as the effects of the severe drought in Texas and Oklahoma or a natural tectonic event. Most of these other theories have been discounted. The 2015 OGS Statement of Oklahoma Seismicity says: "The primary suspected source of triggered seismicity is not from hydraulic fracturing, but from the injection/disposal of water associated with oil and gas production." They found that the earthquakes occur over a very large area, about 15% of the state, corresponding to a region "that has experienced significant increase in wastewater disposal volumes over the last several years."

Another interesting finding regarding the Oklahoma earthquakes is that most occur within crystalline basement well below most oil and gas operations. The OGS attributes this to reactivation of the basement faults from water injection and that the pressure from the water disposal sites can be transmitted several kilometers from the injection site.

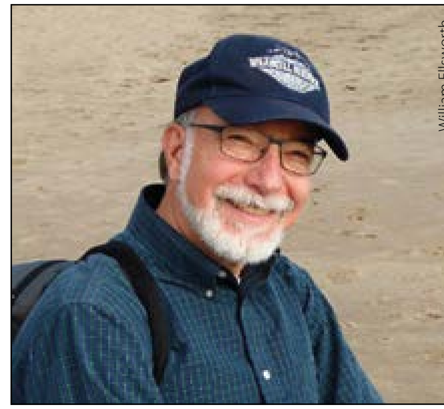
It should be noted that only a small fraction of the over 35,000 active wastewater disposal wells, 80,000 active enhanced oil-recovery wells, and tens of thousands of wells hydraulically fractured every year in the US have caused any increase in detectable seismic activity. For example, research by Dr Cliff Frohlich and others at the Institute for Geophysics and Bureau of Economic Geology (BEG), the University of Texas at Austin, shows that the Williston Basin, with the rapid Bakken development and greatly increased injection volumes since 2007, has resulted in no observable increase in earthquake activity. Generally, most of the induced earthquakes are small; only the 2011 M5.6 Prague, Oklahoma earthquake resulted in significant losses ($10 million insured). Two other earthquakes recorded in 2011, at Trinidad, Colorado and near Guy-Greenbrier, Arkansas, caused minor property damage.

The Next Step

A new study by the USGS (see map illustrated in box on next page) shows some areas in the US have up to a 1:8 chance of experiencing damaging ground motion within a single year, comparable to high hazard areas of California. To this end, government officials have taken note in preparing for this increase in seismicity and are starting to fund further studies.

The State of Oklahoma is now in the process of improving their earthquake monitoring, adding staff and working closely with the USGS and other researchers worldwide investigating induced seismicity. In his role as the State Geologist of Texas, Dr. Scott Tinker worked with State of Texas legislators, agency heads, industry and academics to establish the $4.47 million TexNet facility, which is managed by the BEG. TexNet will install 22 permanent and 36 portable seismometers around the state. The Center for Integrated Seismicity (CISR), comprising over 20 scientists and engineers and led by Dr. Peter Hennings and Dr. Ellen Rathje, is an academic-government-industry consortium established by the Bureau to work with TexNet data and conduct integrated seismologic-geologic-engineering research. Stanford University has its Center for Induced and Triggered Seismicity, in which Dr. Ellsworth and nine other professors are involved, addressing a wide variety of scientific and operational issues associated with managing the risk posed by induced and triggered earthquakes. Let's not forget the researchers at the USGS, through their Earthquake Hazards Program, who have been at the forefront of monitoring and assessing earthquake impacts and hazards, and continue their research into the causes and effects of both natural and induced earthquakes. The recent release of "2016 One-Year Seismic Hazard Forecast for the Central and Eastern United States from Induced and Natural Earthquakes" is already making an impact.

This awareness and new research is not just happening in the US. The Netherlands, for example, has been experiencing shaking from the long term production of gas from the Groningen field. The Dutch Petroleum Company (NAM) and the government are working closely to manage the hazard.



William Ellsworth

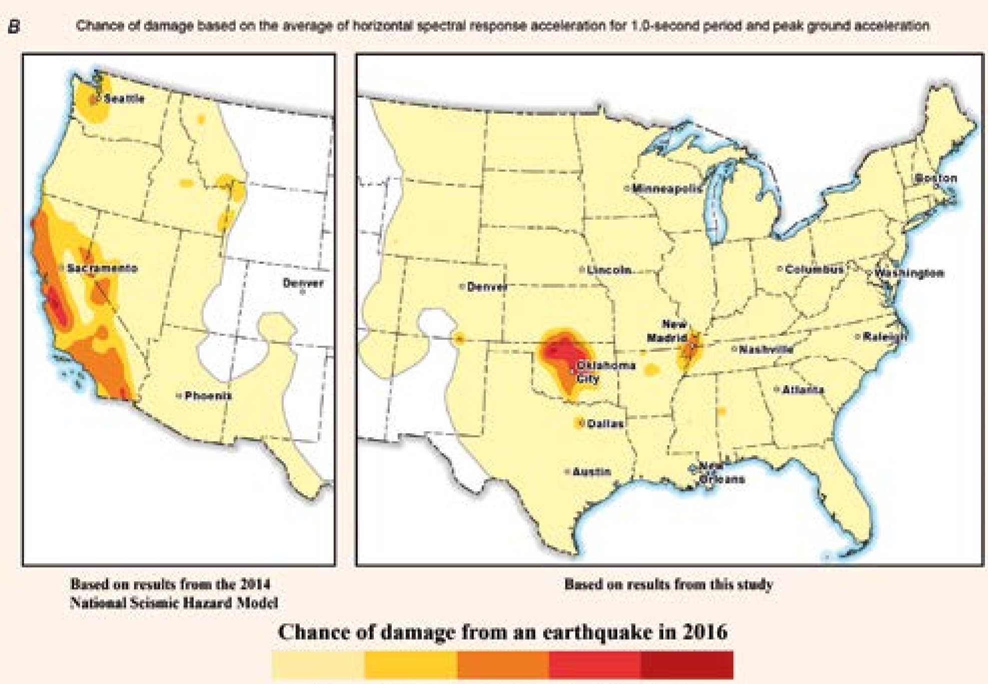
Dr. William Ellsworth is currently a professor at Stanford University where he co-directs the Stanford Center for Induced and Triggered Seismicity. Before joining Stanford, he was a research geophysicist at the USGS for over 40 years and served as Chief Scientist of the Earthquake Hazards Team.

USGS geophysicist and Director of the Induced Seismicity Project, Dr. Art McGarr, states that, "In contrast to natural earthquake hazard, over which humans have no control, the hazard from induced seismicity can be reduced. Improved seismic networks and public access to fluid injection data will allow us to detect induced earthquake problems at an early stage, when seismic events are typically very small, so as to avoid larger and potentially more damaging earthquakes later on."

Special thanks to Dr. Michael L. Blanpied, USGS for his review and suggestions. ■

USGS Addresses Induced Hazards

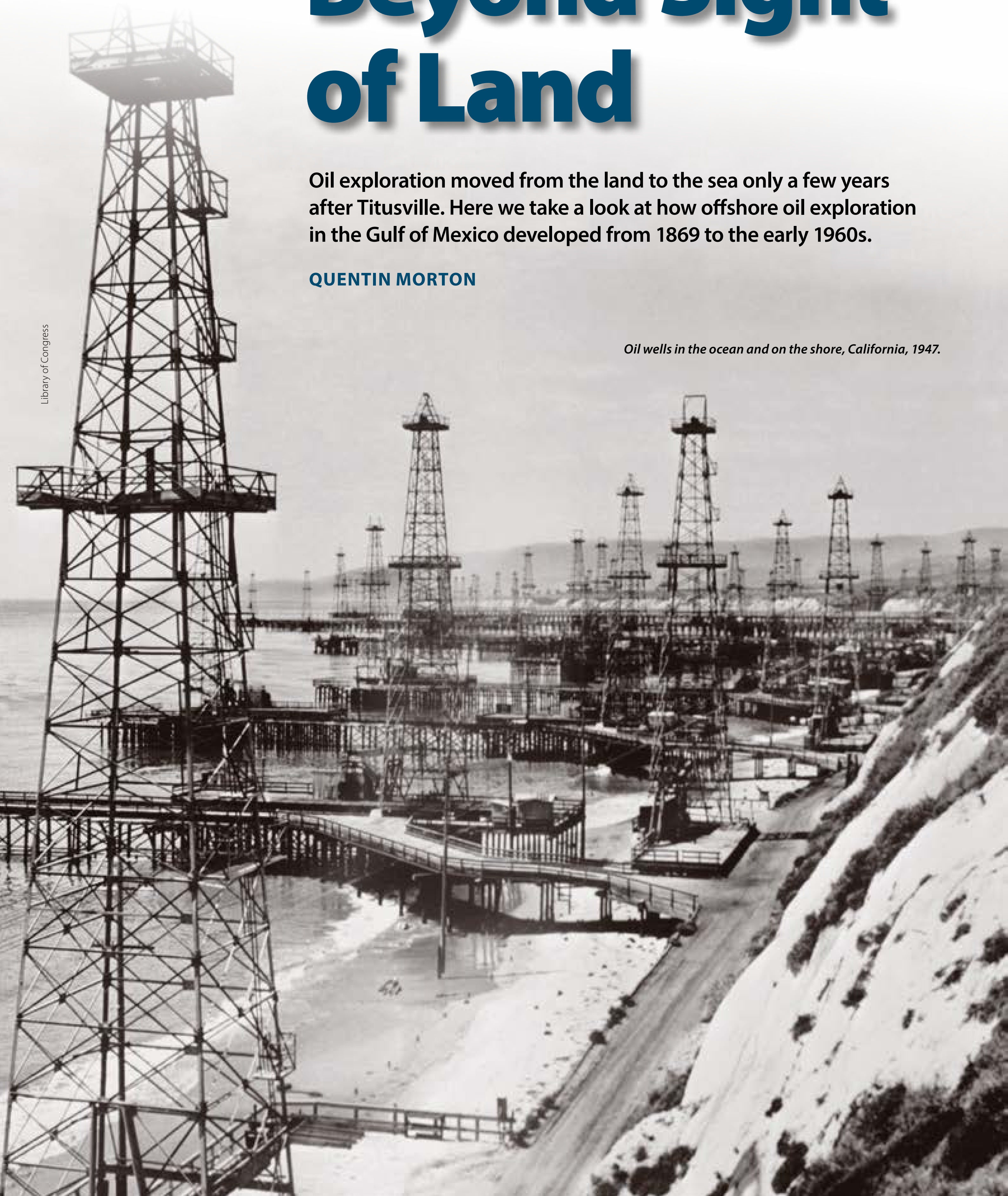
The US Geological Survey (USGS) has just released the first one-year seismic hazard forecast for 2016 that includes the potential for both induced and natural earthquakes in the Central and Eastern United States. Past seismic hazard models, including the 2014 United States National Seismic Hazard Model, had nontectonic events, such as those caused by wastewater injection or other human activities, removed from consideration for their hazard assessment. Their objective was to provide forecasts of locations, magnitudes, and rates of future natural earthquakes as well as estimates of long-term shaking hazard that are applied in building codes and other public policy applications. Therefore, induced earthquakes are not considered in the current building-code maps but do create a seismic hazard to structures in a very populated portion of the central US and other areas where they occur. This new forecast map shows that the chance for damage in north-central Oklahoma and southernmost Kansas is similar to that of high-hazard sites in California. (see www.geoexpro.com for a more detailed discussion on this map).



Beyond Sight of Land

Oil exploration moved from the land to the sea only a few years after Titusville. Here we take a look at how offshore oil exploration in the Gulf of Mexico developed from 1869 to the early 1960s.

QUENTIN MORTON



Library of Congress

Oil wells in the ocean and on the shore, California, 1947.

In the days before underwater probes and 3D imaging, the oil pioneer had to visualize how the oil-rich rock formations of the land extended under the sea. As E.W. Owen's *Trek of the Oil Finders* observed, "no evidence suggested that the present shoreline constituted the boundary of a separate structural province". But as the search for submarine oil in the United States moved from an exploration of its lakes and marshlands to its shorelines and shallow marine waters, and then beyond sight of land, so the risks increased accordingly – the sheltered bays and creeks of the coast were relatively benign when compared with the perils of open water.

Early Pioneers

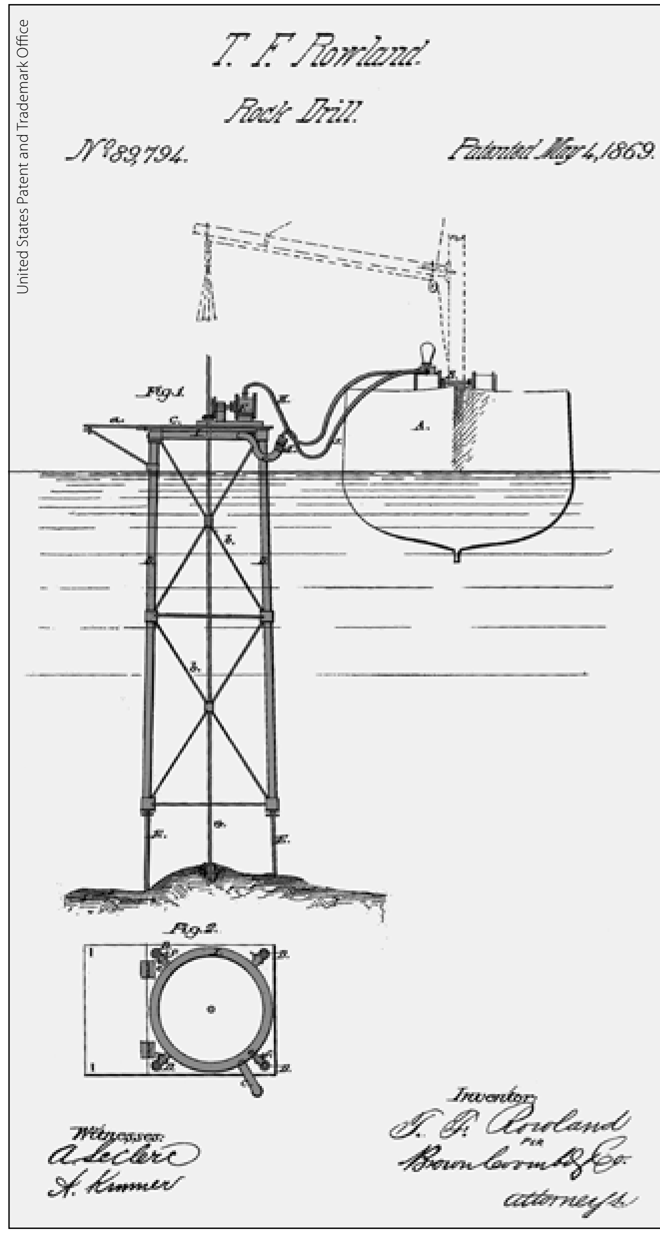
In 1869, only ten years after Col. Edwin Drake first struck oil at Titusville, Pennsylvania, Thomas Rowlands took oil well design a step further by adapting it for use at sea, obtaining a patent for what he called a 'submarine oil drill'. The rig was designed for drilling in shallow water, and its appearance – with four telescopic legs resting on the seabed – resembled a modern jack-up rig. Bearing in mind that offshore drilling would not become a serious commercial activity for many years to come, Rowlands' invention was remarkable indeed.

In 1891, following the discovery of oil in the Trenton limestone reservoirs, oilmen reached Grand Lake St. Marys, a shallow man-made lake in Ohio known locally as the Reservoir. A decision was made to drill on the lake but, while drilling wells on land was familiar practice, techniques for drilling in water were as yet unproven. In the event, pilings were driven into the bedrock under the lake to create 'cribs' on which cable-tool rigs were mounted. But it was in California that marine drilling truly began. In 1896 Henry L. Williams and his associates, having drilled three wells on the shore at Summerland, built a pier 90m out into the Pacific and placed a cable-tool rig on the end of it. There followed 400 wells, and the offshore field continued to produce oil for the next 25 years.

The system of piers, or trestles, first used at Summerfield, was still in evidence in the 1940s. In Baku, for example, extensive trestle systems were employed to extend drilling into the Caspian Sea. Elsewhere, there were many variations. On Lake Maracaibo in Venezuela, where oil had been apparent to Europeans since Spanish sailors arrived in the 16th century, attempts to use wooden structures as drilling platforms had been abandoned after marine termites bored into them, even when they were coated with creosote. They were replaced by concrete pilings, leading the operator, Creole Petroleum, to construct 106 drilling platforms on the lake. Drilling on Lake Caddo, on the border between Louisiana and Texas, had resulted in a spread of activity across the wetlands and bayous of Louisiana, with numerous refinements such as platforms made of oyster shells, sunken barges and timber-plank roads built over the water. However, the Great Depression of 1929 brought a worldwide slump and a decline in exploration.

Wind, Waves and Weather

The Gulf of Mexico was an intriguing prospect. For years, the Texas and Louisiana coastlands had yielded rich pickings for oil prospectors: its situation on the continental margin provided near-perfect conditions for the laying down of



Rowlands' 1869 patent for a 'submarine oil drill'.

oil-rich sediments over millions of years, and its salt plugs and anticlines provided ideal hydrocarbon traps. In 1938, an American company, Humble Oil, had built into the sea a mile-long wooden trestle with railway tracks and ending with a derrick, at McFadden Beach on the Gulf of Mexico, but in August 1938 a hurricane severely damaged the pier and drilling platform. The company bowed to the inevitable and abandoned the costly operation without finding commercial oil.

Meanwhile, in 1937 two independent firms, Superior Oil of California and Pure Oil, had built a large platform 2 km from the shore at a depth of 4m. With 300 piles of yellow pine driven into the seabed, it was designed to withstand hurricane-force winds. The platform was built 4.5m above the sea so that if very high waves should impact the rig, the platform would detach from the pilings, thus avoiding the loss of the whole structure. In fact, this happened in 1940 when a hurricane swept the deck and damaged piles, but workers were soon able to rebuild it. The fact that this, the Creole field, was successful vindicated the risk of the venture, but the disadvantages of having such large, fixed platforms remained. They were costly to build and, if the well proved dry, those costs were not recovered.

And yet the high cost of drilling at sea encouraged innovation, resulting in a number of new techniques that transformed offshore drilling. Drilling narrower ('slim') exploratory holes brought a switch from steam to diesel-electric rigs; and rather than drilling single wells vertically from a central platform, oil companies such as Pure and Superior embarked on directional drilling, which enabled several wells to be drilled from a single platform. A novel procedure at the time, it would become an industry standard in future years.

Kerr-McGee Oil Industries and Humble adopted a different approach, building smaller platforms which housed the drilling equipment, with the living quarters located on tenders – ex-World War II landing craft with their engines removed. If a well came in dry, the tender could simply be towed to another site, thus reducing the cost of each well. This configuration did bring its own problems, however. It was difficult for workers to climb onto the platform in rough weather – so much so that the bridge they crossed was christened the 'widow maker'. Shrimp-boat captains were often hired to bring crews from the shore only to find that the sea state was too rough to allow them to board the platform or the tender alongside. Even locating these platforms at sea could be challenging in adverse weather conditions without the benefit of modern navigational aids. And in harsh weather the tenders could break loose from their moorings and, having no engines, smash into the platforms.

Through a process of design and experiment, trial and error, the challenges of open water were largely overcome. Hurricanes remained a constant seasonal threat in the Gulf of Mexico, but structures were getting stronger. Lack of knowledge about weather was being remedied by a growing number of navigational aids and weather forecasting systems. The US Pioneers Corps had specialized in wind, tides and other weather forecasting for the seaborne landings of World War II, and this knowledge was transferred to the offshore oil industry in peacetime. The American Petroleum Institute also started collating information, giving the operators of marine rigs more tools to predict the weather and evacuate the rigs in the event of an impending storm.

A Shell Oil seismic vessel in the Gulf of Mexico, April 1951.

The Application of Science

Meanwhile, there were new developments on land. First magnetic surveys, then gravity and electrical methods were used to map the subsurface – but it was the advent of seismic techniques that transformed oil prospecting, both on land and sea. In 1938 Shell Oil started experimenting with seismic testing off the Louisiana coast, where a 'shooting' boat would drop a single stick of dynamite into the sea and measure the seismic waves with geophones on the seabed. Six years later, Superior Oil and Mobil followed their example in order to look for salt domes using much the same arrangements. Kerr-McGee used shooting boats that would circle the recording boat, setting off charges at regular intervals. By 1947, all the equipment – shooting and recording – was housed on a single boat.

After World War II, many of the independent oil companies that had been excluded from land-based exploration by leases granted to the oil majors took advantage of the new technology to extend their operations offshore in the Gulf of Mexico. The problem of drilling at depth remained. A number of different designs were tried: submerging a floating barge at the site to provide a base for a drilling rig, with a platform above the surface; small, fixed platforms without living quarters; and

Oil well drilling rig with supply boat, Kerr-McGee Oil Industries, off the coast of Louisiana, April 1949.

larger submersible platforms.

The new seismic techniques revealed many salt domes in the Gulf, prime objects for further investigation. Creeping towards deeper water continued. In 1946, Magnolia Petroleum demonstrated that it was possible to drill beyond the three nautical miles (5.5 km) of territorial waters. In October 1947, another milestone was reached when Kerr-McGee drilled the first discovery well out of sight of land, a fixed platform at a water depth of 5.5m, some 16 km from the shore. By 1948, 24 operations were taking place beyond the three-mile limit and, a year later, a mobile offshore rig was launched. In 1954 the first jack-up rig arrived – in time, this type of rig would be able to drill in water 90m deep.

Into Deeper Water

In 1945, after shortages of oil during the war, the US Congress investigated petroleum resources. On 28 September, President Truman proclaimed the United States' right to exploit its continental shelf, extending its jurisdiction well beyond the traditional three-mile territorial limit. He stated that the United States regarded as part of its jurisdiction the natural resources of the subsoil and seabed of its entire continental shelf (defined as the area up to a water depth of 180m).

In the Tidelands controversy, a series of legal proceedings arising from a dispute between the United States and Texas, the limits of state and federal ownership over the three-mile wide marginal sea was established. In 1953 the Submerged Lands Act was passed, recognizing state ownership of the minerals and resources of the marginal sea to their historic boundaries, with the remainder owned by the federal government. Legal challenges followed over many years, the last being settled in 1963.

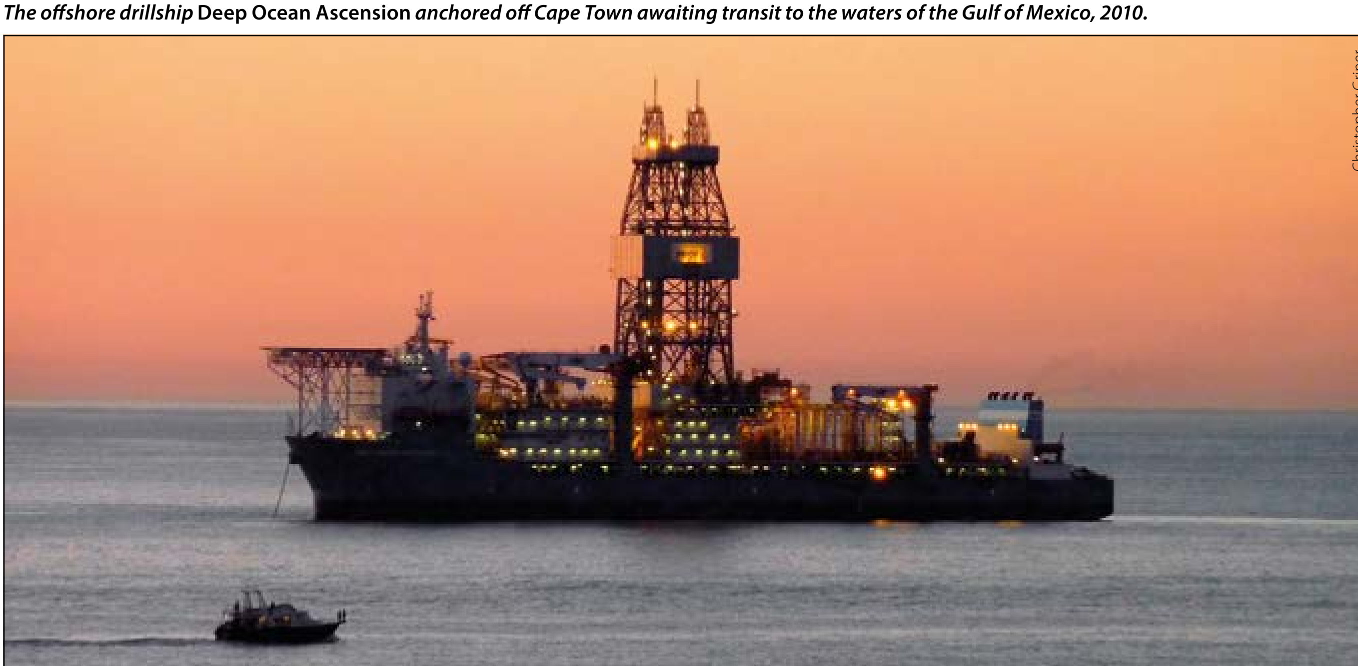
Today, offshore oil is a worldwide industry exploring to ever-increasing depths. The real breakthrough came in 1962 with Shell's semi-submersible rig, *Blue Water 1*, which was the first rig to be detached from the seabed, relying on a mooring system of eight anchors to keep it steady in the water. This, together with remote wellhead assembly on the sea floor, opened up the possibility of drilling and maintaining wells in deepwater. At present in the Gulf of Mexico there are 15 structures operating in water depths greater than 304m. In 2005, the *Discoverer Spirit* drillship drilled the Stones-2 well to a true vertical depth of 8,705m in a water depth of 2,919m, an achievement that would have surely amazed the early offshore pioneers.

DeGolyer Library, SMU

Workers guiding the bottom hole assembly with stabilizer and new rock drill bit on an offshore drilling platform, 1955.

Acknowledgement: *The author would like to thank Dr Alan Heward and Peter Morton for their kind assistance.* ■

The offshore drillship* Deep Ocean Ascension *anchored off Cape Town awaiting transit to the waters of the Gulf of Mexico, 2010.



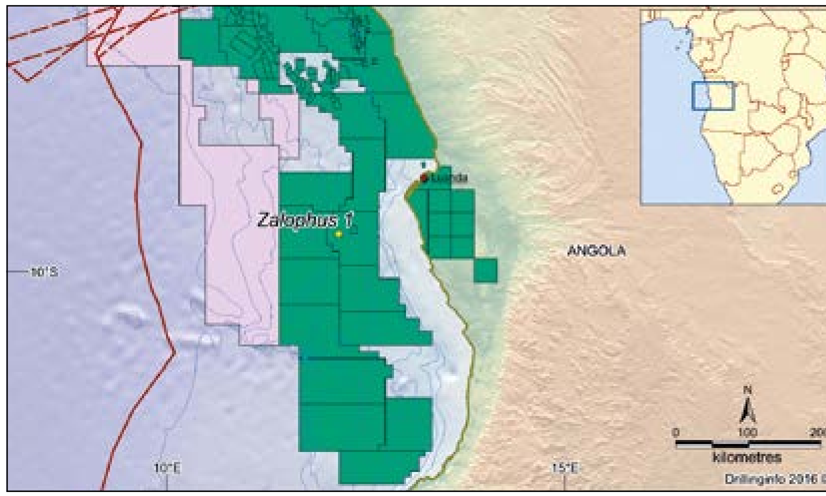
Christopher Griner

Angola: Pre-Salt Discovery

In the most significant non-Mauritania/Senegal well this year, and in fact the only West African discovery outside that area, **Cobalt** have announced a further pre-salt discovery on Block 20/11 offshore **Angola**. New field wildcat **Zalophus 1** encountered gas and condensate, and is Cobalt's sixth pre-salt discovery offshore Angola and also its third discovery on Block 20. The well, which had a TD of 5,170m, is located about 120 km south-west of Luanda in over 1,800m of water and is about 10 km south-west of Colbalt's 2013 Lontra discovery, which was reported to have resources estimated at between 700 MMboe and 1.1 Bboe.

Zalophus 1 was drilled by the Petroserv SA *SSV Catarina* semi-sub between January and March 2016. The rig then moved on to drill Golfinho 1, also on Block 20/11, the last exploration well commitment the company has on the block. Cobalt is considered by many to have opened up the Kwanza pre-salt play with its discovery in 2012 of the 300–500 MMbo Cameia field in Block 21, to the south of Block 20, and has had a successful string of discoveries in the play since then. The play has proved to have more gas than initially expected and is therefore not a direct analog to the pre-salt offshore Brazil, but substantial quantities of hydrocarbons have nonetheless been discovered.

Sonangol is acquiring Cobalt's 40% equity in Block 20/11 and Block 21/09 for a total cash consideration of US$ 1.75 billion and all costs going forward are being borne by Sonangol; however, Cobalt is still acting as operator at present. Once this transaction is formally completed, equity in Block 20/11 will be held by Sonangol, which will become the operator, with BP holding 30%. ■



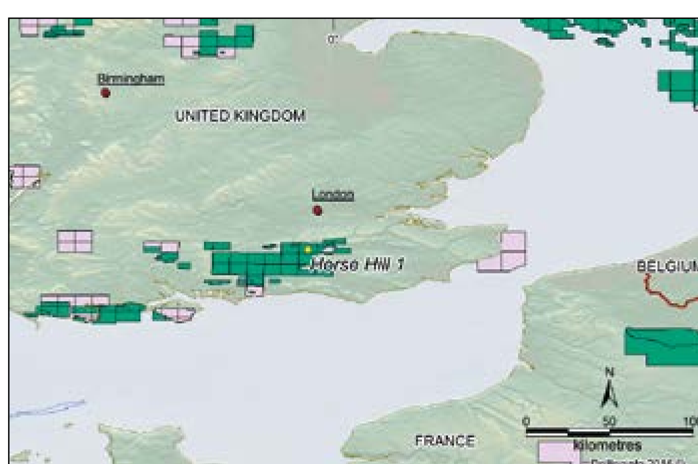
UK: Onshore Well Shows Potential

Successful onshore UK wells are relatively rare, so the **Horse Hill** discovery, located in onshore **UK block PEDL246** in the **Weald Basin**, about 50 km south of London, has created quite a stir. The well was drilled in late 2014, but testing has only recently been completed, and has proved Horse Hill to have considerable potential. In March 2016, the Horse Hill Development Ltd (HHDL) partners reported successful testing a 31.4m zone in the Late Jurassic Portland Sandstone, with 37° API oil flowing to surface at 323 bopd. The partners had previously reported successful testing from a 26.8m zone in the Late Jurassic Upper Kimmeridge Limestone and from the Late Jurassic Lower Kimmeridge Limestone, with 40° API oil recovered from both.

Log analysis of Horse Hill 1 had identified 156m net pay with potentially 277 MMbpkm^2 oil originally in place (OOIP) within the Kimmeridge clay, mostly in three reservoir sections comprising interbedded argillaceous limestone and mudstone. A further untested play is the Jurassic Oxford Clay and Middle Lias Formations, and the resource is believed to extend beyond HHDL's licenses, suggesting that the whole Weald Basin holds considerable potential. However, significant appraisal drilling will be required to satisfactorily evaluate the resource, with EOR techniques likely to feature. HHDL maintains that fracking will not be necessary but the experience of analogous plays in the US and Russia suggests that this cannot be ruled out. Since the area is relatively well populated and also part of the London 'Green Belt', any suggestion of fracking is likely to be very contentious.

These figures are in addition to conventional resources of 21 MMb OOIP (P50) within the Upper Jurassic Portland Sandstone, which the operator believes can be mapped across to the adjacent Collendean Farm structure 1.5 km to the north-west, which was drilled unsuccessfully by Esso in 1964.

PEDL 137 covers 99 km^2 over block TQ/24b, and was awarded in October 2004 as part of the 12th Landward Licensing Round. Equity partners are Horse Hill Developments Ltd with 65% and Magellan Petroleum Corp with 35%. ■

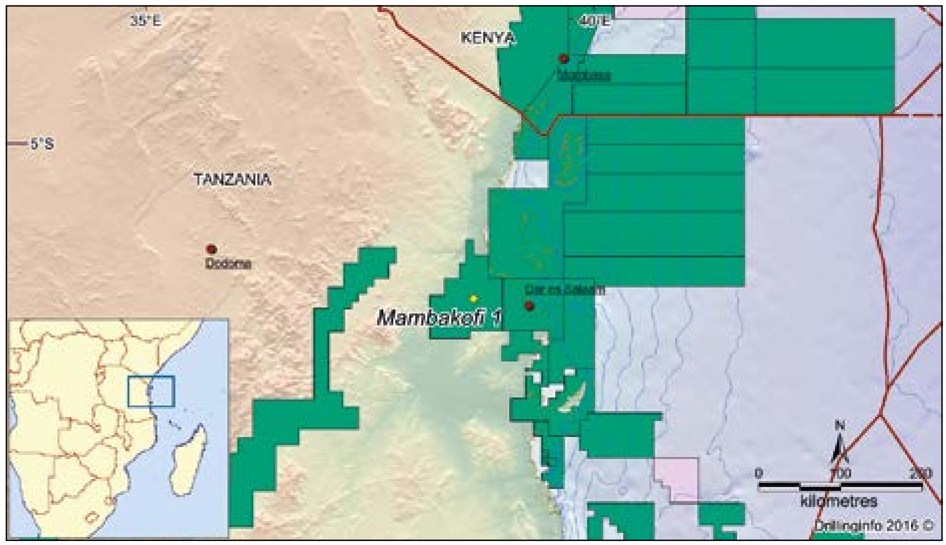


Tanzania: Largest Onshore Discovery

Although originally discovered in April 2015, recent investigations of the **Mambakofi 1** gas discovery in the onshore Ruvu Basin in **Tanzania** have shown it to be much larger than the 160 Bcfg initially announced. According to Dubai-based Dodsal, the operator, as a result of these tests prospective resources for the **Ruvu Basin** block, in which the well is located, are now put at 2.7 Tcfg, with a potential upside of 3.8 Tcf, making this the largest onshore discovery in the country. Further gas resources may be associated with Mtini 1, the second well to be drilled on the block, and the most recent one, Mbuyu 1, on the western side of the block, where a large, possibly tight, gas column was detected but not tested.

Mambakofi was drilled to a TD of 3,000m and bottom-holed in the Triassic. The gas is reservoired in the Upper Cretaceous, and a number of good reservoirs are understood to have been found between 800 and 1,500m. The source rock is thought to be Upper Jurassic. The Mbuyu well is believed to have hit a new Triassic play.

Unlike most of the other gas discoveries in Tanzania, which are offshore, these discoveries are only about 50 km from Dar es Salaam, which will make commercialization easier. It is reported that Dodsal has plans for "the implementation of an Early Production System to bring gas to market", hoping to produce the first gas from the field as early as 2018. The company owns 50% of the 15,300 km^2 license, which it obtained in 2007, with state-owned Tanzania Petroleum Development Corporation owning the other half. ■



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The History of Geotourism

Appreciating Physical Landscapes: Three Hundred Years of Geotourism,
edited by T. A. Hose
Geological Society, London, Special Publications 417

JANE WHALEY

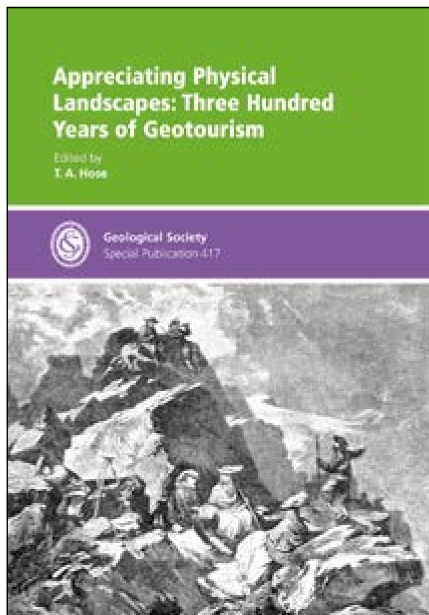
Having, with pleasure, both read and written many geotourism articles for the pages of *GEO ExPro Magazine*, it still came as a surprise to me that the topic is now a recognized strand of scientific study. Thanks to this Geological Society Special Publication, I am now much more knowledgeable both on the origins and history of geotourism and also on how the discipline has developed and been studied in recent years.

The book originates from a conference entitled **'Appreciating Physical Landscapes: Geotourism 1670–1970'**, convened at the Geological Society in London in October, 2012, and incorporates a number of the papers presented at that time, as well as several commissioned specifically for the publication.

Grand (Geo)tourists

Dr Thomas Hose of Bristol University, who both convened the meeting and edited the book, is one of the foremost proponents of the study of geotourism. In the first paper in the book he discusses the various definitions of the subject, which encompass interpretative and educational functions, basic tourism, geoconservation, geomorphology and ecotourism, as well as geology. He also points out the importance of distinguishing the difference between the 'casual' geotourist, who "occasionally visits geosites, mainly for recreation, pleasure and some limited intellectual stimulation" and the 'dedicated' one, who goes "for personal educational or intellectual improvement and enjoyment". Very interesting in this first chapter is the identification by Dr Hose that the original geotourists were those wealthy young Europeans of the mid-18th to mid-19th centuries for whom participation in the 'Grand Tour' was a vital part of their education, when appreciating and understanding physical landscapes played as important a role as visiting important cultural and archeological sites like Paris and Pompeii. They were encouraged to write and illustrate journals about their travels – not dissimilar to the plethora of travel blogs to be found now on the internet, and of equal variety in quality and artistic merit!

This leads to a theme common to a number of the following papers: the part played by art, and later photography, in the development of geotourism. One chapter is devoted to the development of various artistic movements in relation to a romantic fascination with the Scottish Highlands and how this changed the face of geotourism over several centuries, while another looks at how the work of 'tourist' artists was used by geologists to define as well as illustrate geological phenomena, particularly in (at the time) rarely visited places such as Australia. The use of photography is explored in several papers, including reference to how the observations and photos from 19th-century geotourists in Norway are a valuable resource for modern glaciologists as they chart changes in glacier extent and behavior in response to climate change.



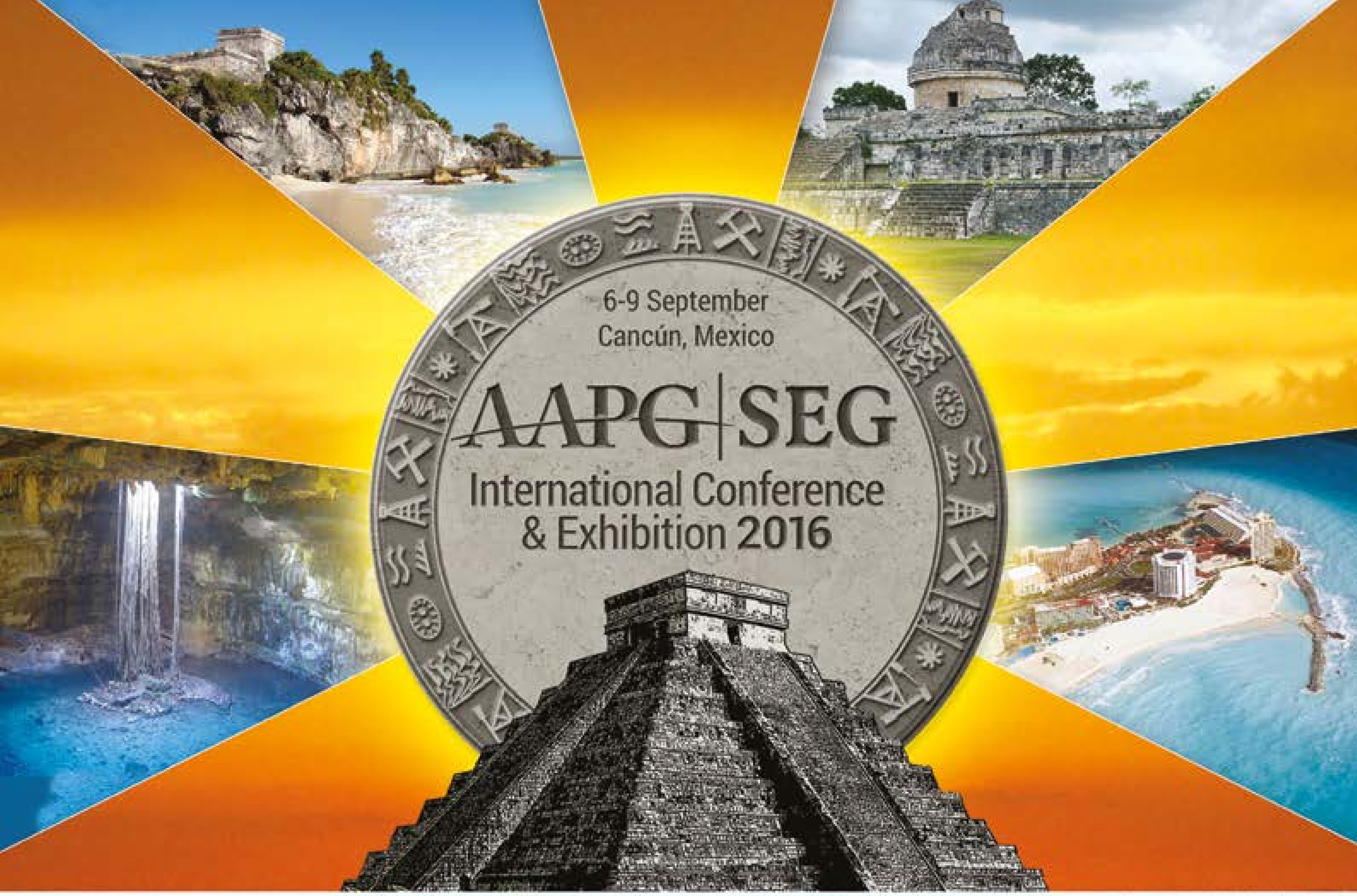
Another interesting paper discusses the crucial contribution the development of map-making made to the science of geology as well as to geotourism; in the 1800s it was difficult for many people to fully appreciate the physical landscape, but by the 1900s it was much easier, not just due to more accurate maps but also to the advent of mass transport systems. There are several papers devoted to the subject of caves, caverns and mines, many of which were popular destinations for both scientists and interested tourists from the early 18th century.

Education and Sustainability

Since this is a GSL publication, there is emphasis on the development of geotourism in north-west Europe and the UK in particular, but a number of papers discuss the changes in perception of geotourism over the centuries with special reference to locations elsewhere in Europe. These pay attention to how the popularity of a site can wax and wane, with some previously well-frequented locations now overgrown and deserted, and attempt to explain the rationale behind this.

An important theme throughout is that the modern approach to geotourism, in addition to providing the strong educational element which has always been evident, has a strong emphasis on maintaining 'geoheritage' and sustainability, ensuring that allowing access to interesting geosites does not bring with it any ecological or environmental drawbacks. The creation of the UNESCO Geoparks program progresses and popularizes the concept of geotourism a step further.

Since this book comprises a series of academic conference papers, it can be both repetitive and sometimes a little heavy, but is still an interesting read, putting our current needs and preoccupations into a historical context. However, I feel that a less learned and more publically accessible book on the history of geotourism is hiding in the pages, and if it ever appears it would promote the cause of modern geological travel and education. ■



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Do we need CCS?

Dr. Jon Gluyas is Professor in CCS and Geo-Energy at the University of Durham, UK. He explains the concept and importance of carbon capture and storage.

What is carbon capture and storage?
Carbon Capture and Storage (CCS) comprises three linked pieces of technology. The first is capturing carbon dioxide emissions from fossil fuel-fired power stations, cement production and other CO_2 emitting industries. The captured CO_2 is then compressed and transported to a disposal site (storage), via a dedicated pipeline or possibly by ship, injected deep into the earth and stored in underground reservoirs in much the same way that the Earth naturally stores petroleum. Storage sites are typically depleted oil and gas fields and deep saline aquifers. Disposal depth is over 1 km.

Do we really need CCS?
Yes! Emission of CO_2 from use of fossil fuels is driving climate change. We must lessen our use of coal, oil and gas but at present there is little prospect of that happening. The energy density in fossil fuels is so much greater than renewable energy that it is acutely difficult to wean humankind off using them. By capturing the emissions and storing them deep underground we can lessen the impact upon the climate. Moreover, as humankind does transition to renewables, we can continue to use CCS on biofuels. In this way we can go 'carbon negative'; something not possible with renewables alone.

After a 28-year career in the O&G industry, encompassing 15 years at BP and presidency of the PESGB, Jon Gluyas moved into academia, where he focuses upon the more complete use of resources and their byproducts.

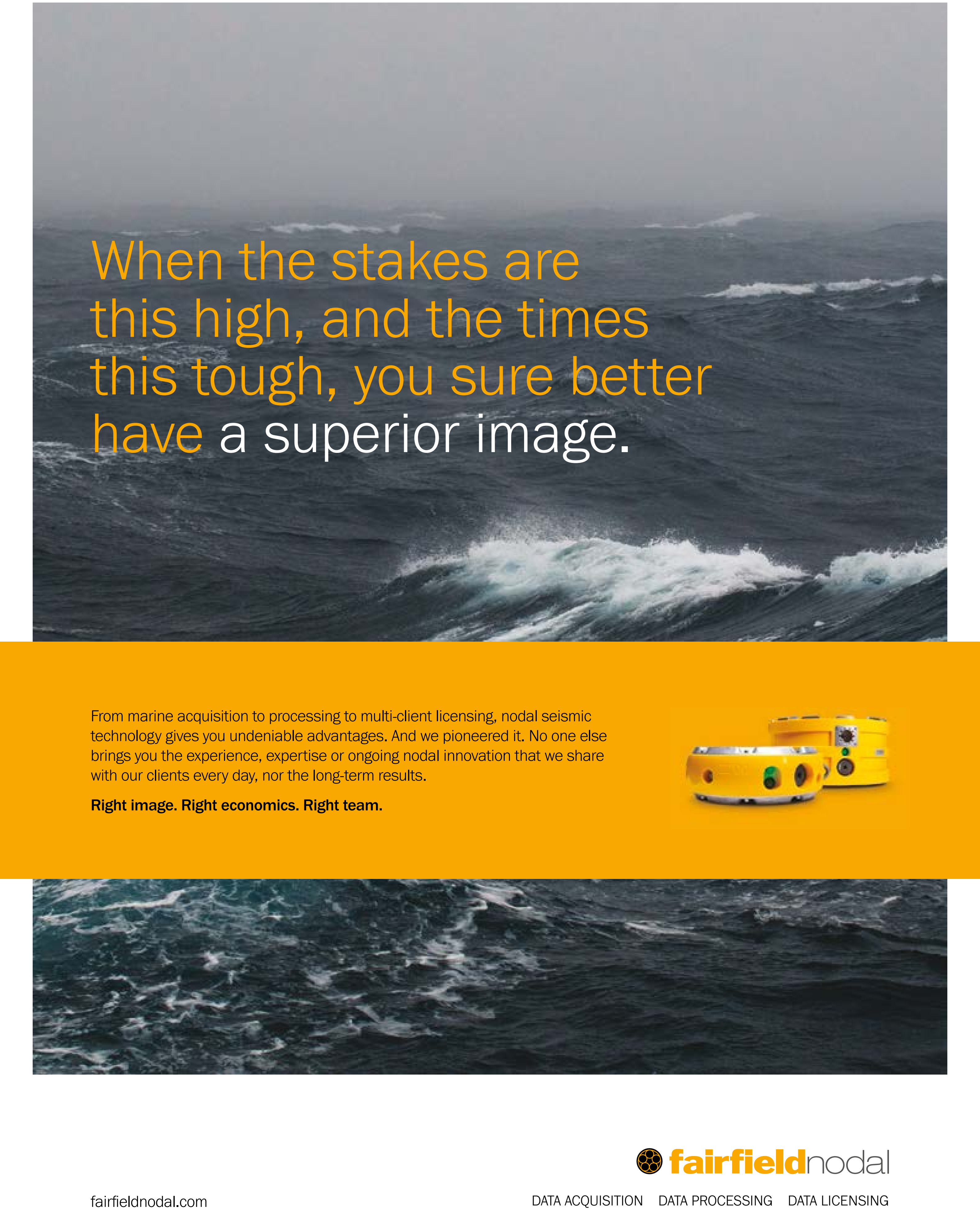
What attracted you to the topic?
I spent almost 30 years searching for and developing petroleum accumulations, indeed I still work on E&P, but what has become clear to me in the 10 years since I was introduced to CCS, and the past six years I have been working on it, is the realization that we need to tidy up after ourselves. Few would question the need for refuse collection or a working sewage system. The same would be true for nuclear power. It is accepted without question that emissions must be minimized – no one would want the surface of the Earth to be contaminated. I feel strongly that the same is true for CO_2 emissions. We need to reduce the impact on both the climate and the oceans.

Does CCS feature in the world of O&G?
Hardly at all. There are a couple of projects in which off-spec gas is stripped of CO_2 and this reinjected; Sleipner in the Norwegian North Sea is the best known and monitored. About 1 million tonnes has been injected at a depth of about 1 km beneath the sea bed and the process has run for almost 20 years without incident.

Can it be used for EOR?
CO_2 is a fantastic solvent and a great agent for enhanced oil recovery. First tried by the Hungarians in the 1950s, CO_2–EOR liberates two to five barrels of oil for each tonne of CO_2 injected. Work we recently completed suggests that CO_2-enhanced gas recovery looks really exciting and could dramatically improve the performance of pressure depleted gas fields. In both EOR and EGR, injection of CO_2 would essentially halve emissions and development of EOR using CO_2 would enable seamless transition to pure storage of CO_2.

What are the risks involved?
Pretty low. CO_2 is not flammable or explosive and although suffocation can occur through lack of oxygen, CO_2 itself is not very poisonous – it is, of course, what we exhale when breathing. Appropriate safety measures need to be applied at the capture and transportation stages but these are already used in the food industry (CO_2 is used to decaffeinate coffee) and dry cleaning where the solvent is CO_2. As for the storage end of the process, sites need to be secure long term which can be achieved by monitoring, using the same technologies as used in the E&P industry.

Who should pay for CCS?
All of us, for we all benefit from consumption of fossil fuels. That said, governments need to create the framework within which CCS will become as normal as paying taxes – something we all dislike but which we recognize is required for society to function effectively. The agreements reached by heads of governments in Paris last December were a huge breakthrough in terms of beginning to combat climate change. The next steps are even harder, for governments to put into practice their pledges on emissions reductions. In order to achieve those pledges, deployment of CCS on a large scale will be an imperative. ■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An Optimistic View

There are several good reasons to believe in a higher oil price than the current less than US$50 a barrel.

The Norwegian continental shelf is still a world-class petroleum province. This was one of several messages given by Eirik Wærness, chief economist with Statoil and editor of Statoil's yearly Energy Perspectives, to the attendees at the Recent Discoveries 2016 conference in Oslo in May.

Looking at conventional hydrocarbons discovered in the interval 2010–2015, Brazil ranks number one, far ahead of Mozambique in second place. The latter is, however, all about gas, while Brazil is predominantly rich in oil. Norway comes in at number six, just ahead of the US, and its increased reserves are dominated by oil. In fact, Norway, the US and Iraq have discovered approximately equal amounts of oil in the five-year period, with only Brazil adding larger oil reserves.

The reason for Norway's relatively strong position has to do with, firstly, government incentives to increase the level of exploration activity, resulting in lots of seismic and a high number of wildcats and, secondly, a lack of exploration success in other countries, resulting in a world-wide decline in discoveries.

The latter point was also mentioned by Nils-Henrik Bjurstrøm at Rystad Energy, referring to voluminous amounts of statistical data showing that the global oil industry is not able to replace reserves. There are simply too few sizable discoveries.

Wærness also pointed out that the low oil price will cause a substantial delay in a number of development projects around the globe, meaning that less oil will come to market in the years to come. Coupled with diminishing reserves, this may very well cause the oil price to rebound.

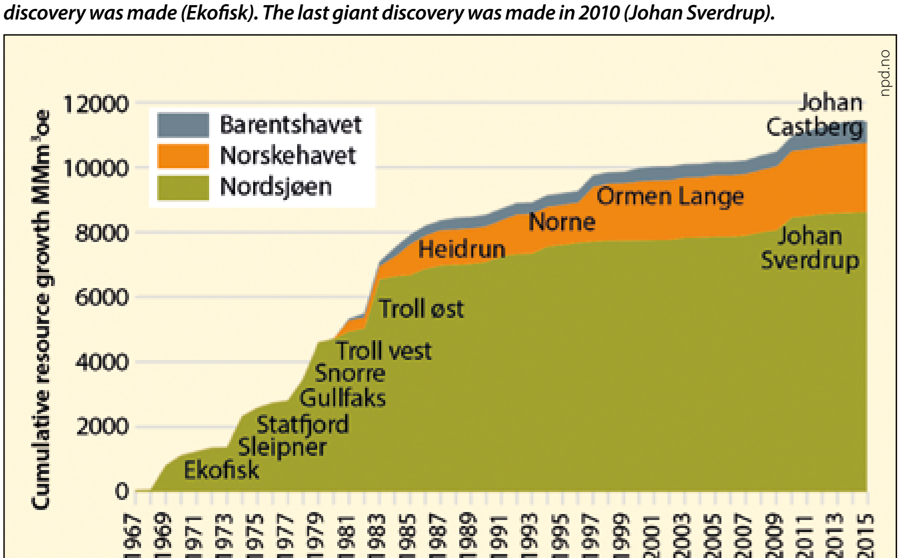
Jarand Rystad of Rystad Energy, who also gave a talk at the conference, gave a fairly bold prognosis, saying that the oil price may pass US$105 per barrel by 2020, the main reason being the low rate of new projects being sanctioned.

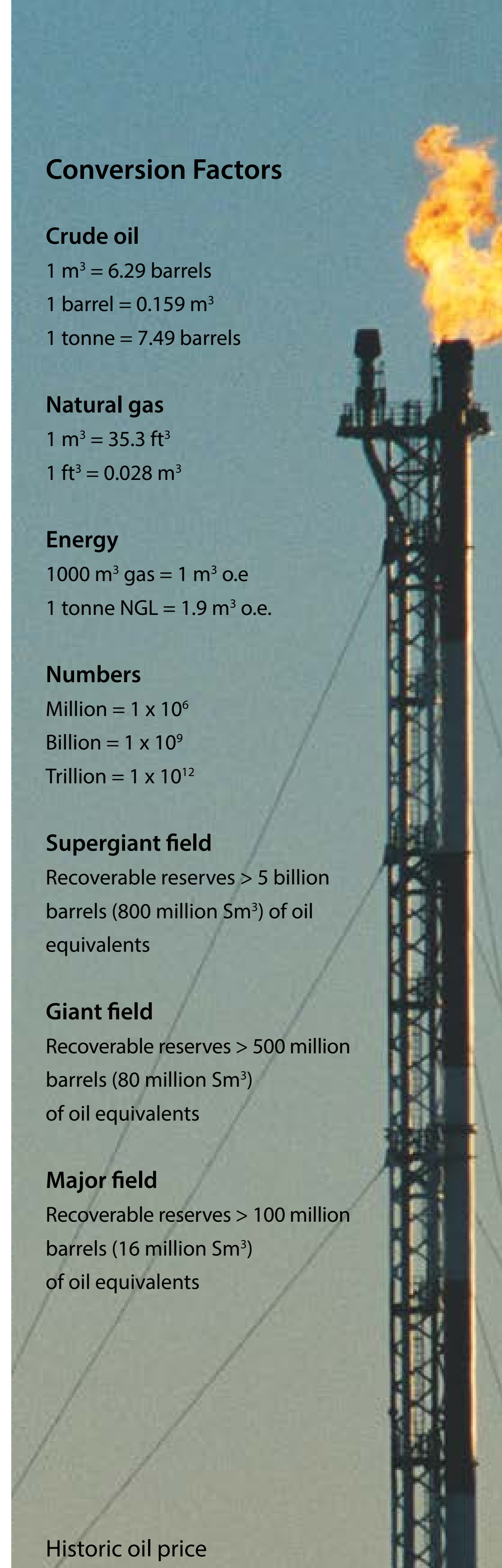
Rystad also bases his predictions on the development of shale oil production. He thinks it will not continue to grow as it has done the last five years and – maybe more importantly – he does not believe that geological provinces in other countries will turn out to be as prolific as the US sedimentary basins.

Overall, three of the speakers at the Recent Discoveries 2016 conference gave a very optimistic view of the future. Following the Paris agreement, they said there will be a strong demand for both of oil and gas, and, as Eirik Wærness concluded, "Oil is here to stay". ■

Halfdan Carstens

While the first technical discovery on the NCS was in 1967, it took another two years before a commercial discovery was made (Ekofisk). The last giant discovery was made in 2010 (Johan Sverdrup).





Conversion Factors

Crude oil

1 m³ = 6.29 barrels

1 barrel = 0.159 m³

1 tonne = 7.49 barrels

Natural gas

1 m³ = 35.3 ft³

1 ft³ = 0.028 m³

Energy

1000 m³ gas = 1 m³ o.e

1 tonne NGL = 1.9 m³ o.e.

Numbers

Million = 1 x 10^6

Billion = 1 x 10^9

Trillion = 1 x 10^{12}

Supergiant field

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

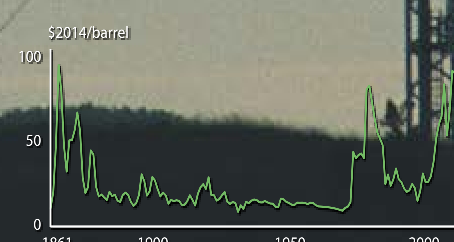
Giant field

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

Major field

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

Historic oil price



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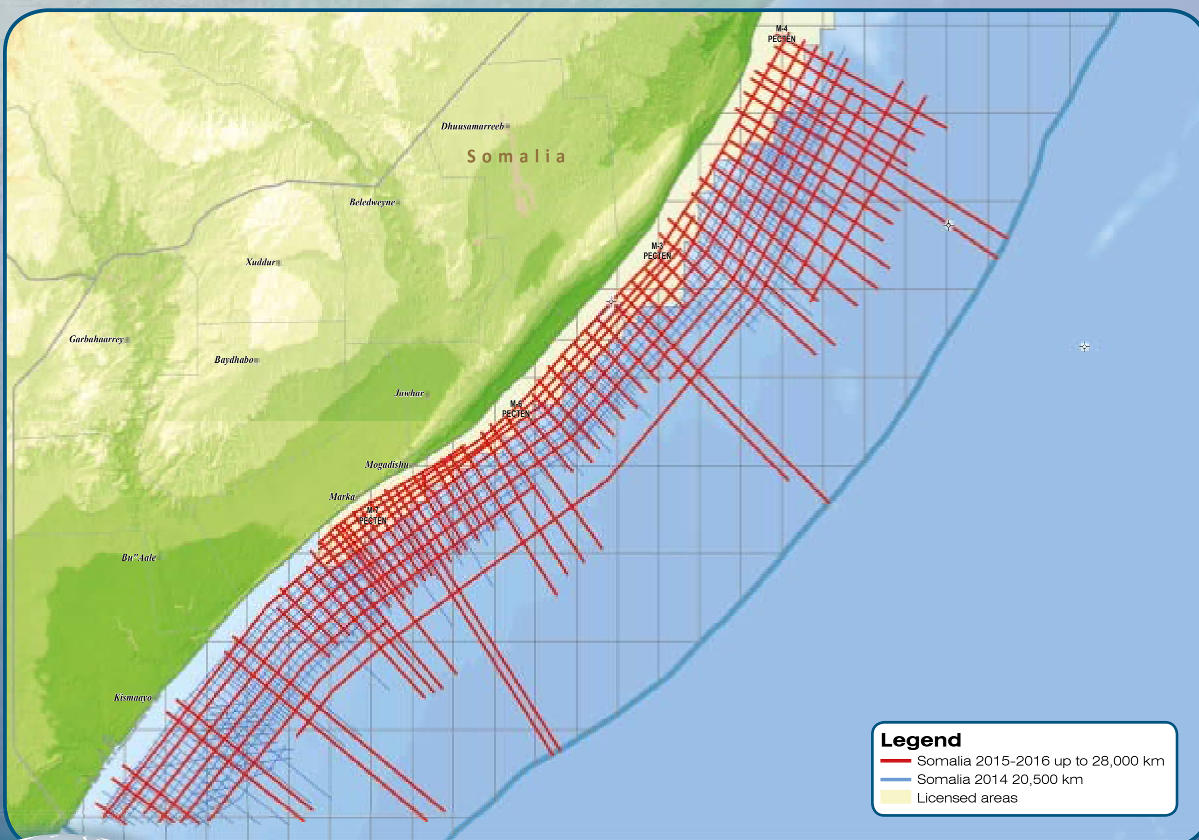

In preparation for future licensing rounds, Spectrum has now completed a majority of the unique 28,000 km 2D Multi-Client seismic acquisition program, offshore Somalia. This program complements 20,500 km of existing seismic data that was acquired in 2014.

The survey design, which covers water depths of 30 m to 4,000 m, has allowed for seismic coverage over the shelf, slope and basin floor with dip, strike and recording time intervals suitable for defining a range of leads and prospects. Streamer lengths of 10,050 m have been used in order to adequately record information at all offsets, further assisting imaging of the underlying syn–rift geometries.

Modern processing algorithms are being applied to the raw data to achieve optimal imaging of the steeply-dipping extensional and compressional features and illumination of subtle amplitude anomalies. Data is expected to become available from Mid 2016.

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