VOL. 16, NO. 5 – 2019

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

GEOLOGY
Are Carbonates Difficult?

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Namibia in the Spotlight Again

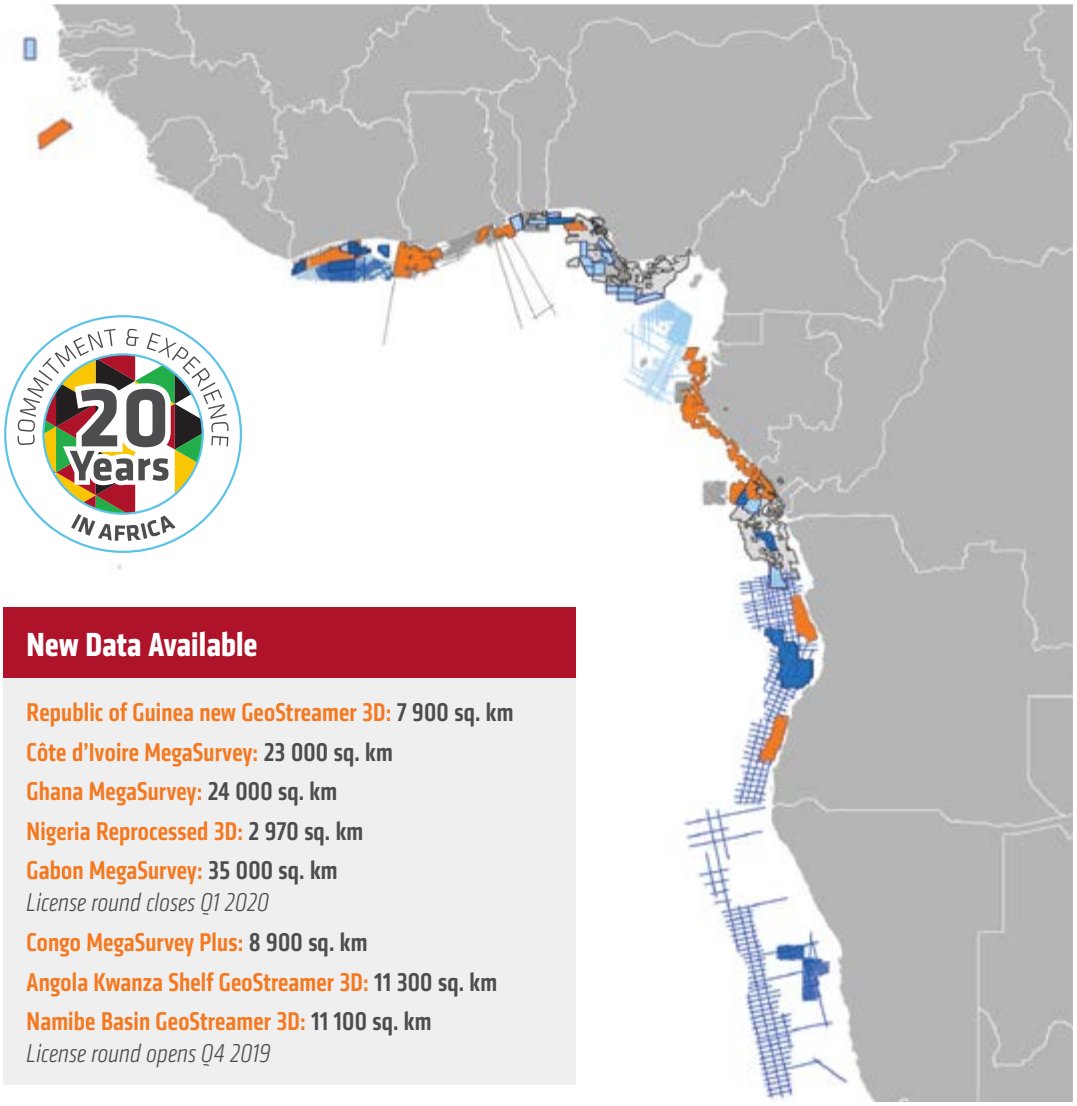
TECHNOLOGY
Look Under a Different Rock!

GEOTOURISM
The Dead Sea Transform

EXPLORATION
Shale Plays of the Middle East

Make Better Decisions

on Africa Exploration Opportunities



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Ghana MegaSurvey: 24 000 sq. km

Nigeria Reprocessed 3D: 2 970 sq. km

Gabon MegaSurvey: 35 000 sq. km
License round closes Q1 2020

Congo MegaSurvey Plus: 8 900 sq. km

Angola Kwanza Shelf GeoStreamer 3D: 11 300 sq. km

Namibe Basin GeoStreamer 3D: 11 100 sq. km
License round opens Q4 2019

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GEOSCIENCE & TECHNOLOGY EXPLAINED

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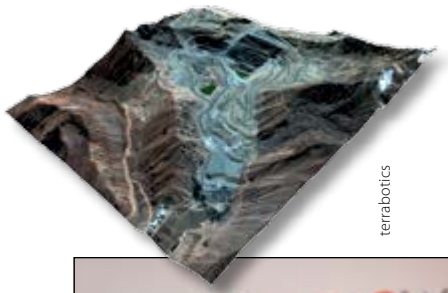
The O&G industry is benefitting from new data analytics technologies that make sense of the huge volumes of data and imagery coming from established satellite and drone capabilities.



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Namibia's Petroleum Commissioner, Maggy Shino, is passionate about finding and utilising oil and gas in her country.

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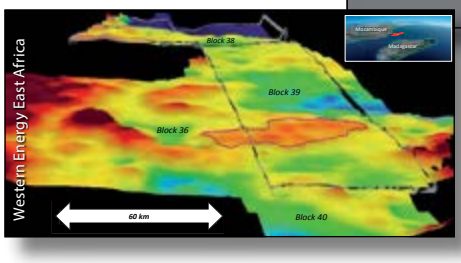
Super basins: finding oil in old places with new ideas.



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There is potential in the Comoros Islands for oil in similar plays to the ones holding giant gas fields off Mozambique.

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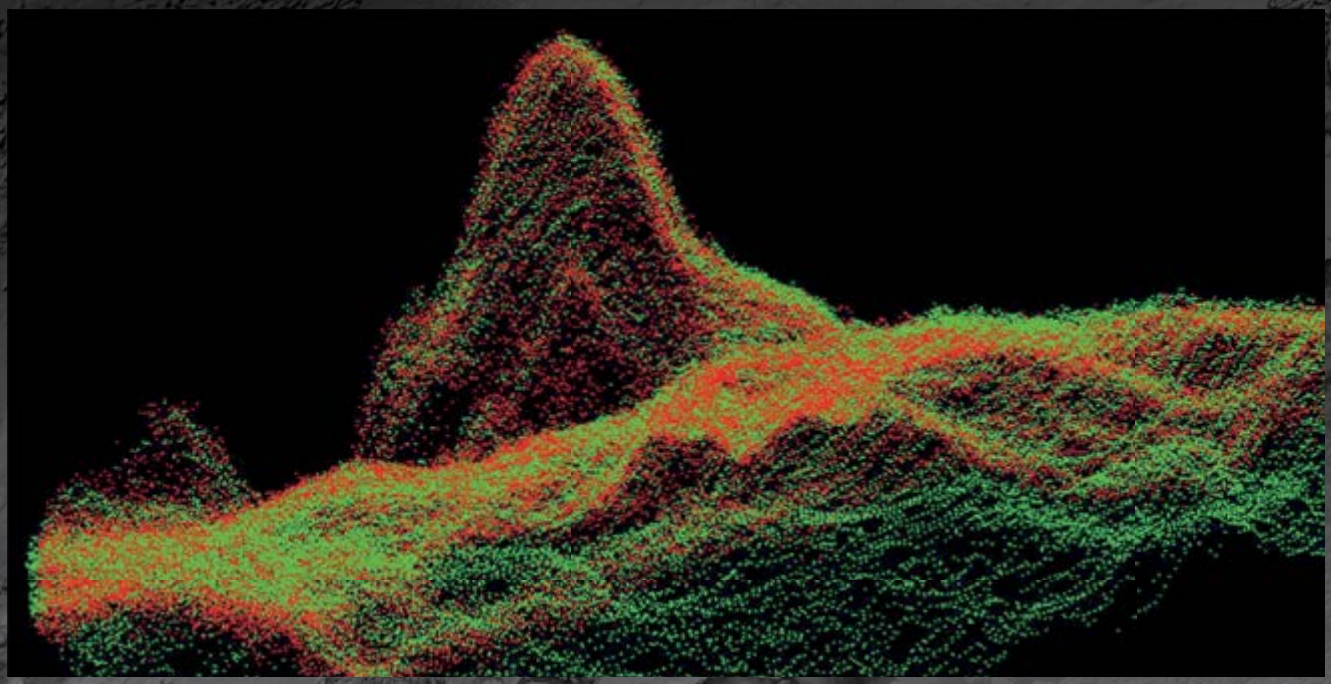
Come see us at AOW, booth #E50



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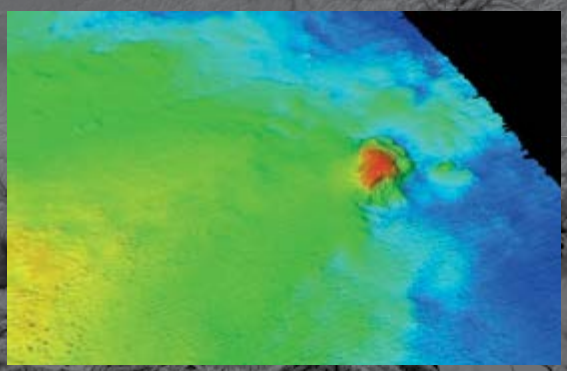

We are currently developing a comprehensive program of regional surveys to be acquired in 2019 and beyond that will deliver:

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The Key to Transformative Change

LNG train in Nigeria.

The world's first commercial LNG liquefaction plant was built in Africa – in Arzew, Algeria – in 1964. Although demand for the product took a while to develop, Africa is now the 'go-to' continent for LNG investment, with nearly one-third of total greenfield LNG investment going there this year. Mozambique is leading the charge and the sanctioning of the country's Area 1 project in June 2019 is predicted to transform Mozambique into a major LNG exporter.

And that raises an interesting question, one of many discussed in the book by NJ Ayuk reviewed in our GEO Media section. How much of the continent's total proved remaining gas reserves – a figure of nearly 510 Tcf, according to the *BP Statistical Review of World Energy* – should be exported and how much used at home? Why is it that some countries are net exporters of gas, but import expensive diesel from the US or Europe to run generators to light homes? Positive moves are afoot in the continent to ensure more gas is used domestically, to help electrification and industrialisation, diversify economies and create jobs. For countries that do not have plentiful gas reserves, importing gas for power generation from luckier neighbours, rather than have it exported to other continents, should be an obvious and easy option.

It was a great pleasure to interview Maggy Shino for the GEO Profile in this issue. As Petroleum Commissioner at the Namibian Ministry of Mines and Energy, she is very aware of the energy challenges facing her large but sparsely populated country and is a passionate advocate for searching for domestic energy resources that can be used to bring electrification, industrialisation and wealth to Namibia. In a country where many people still use firewood for cooking, a large gas discovery would be transformative.

To almost quote the catchphrase of a president from a different continent: 'Africa First'! ■

Jane Whaley
Editor in Chief

NAMIBIA IN THE SPOTLIGHT AGAIN

The Waterberg Plateau cliffs expose the Jurassic Etjo sandstone formation, part of the Karoo supergroup, which is one of several potential unexplored hydrocarbon targets in Namibia. Just underneath the cliff is the site where Namibia's first dinosaur, the *Masospondylus,* was discovered.

Inset: Carbonate reservoirs are often considered to be 'difficult', but maybe they just need a different knowledge base.

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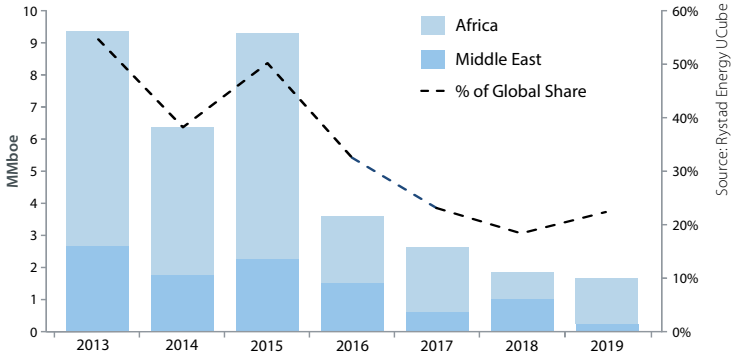
Reversing the Discovery Slump

RYSTAD ENERGY

Activity from upstream operators is starting to pick up from the post-2014 oil slump, and more money is being thrown at exploration, resulting in a gradual recovery in global discovered volumes. Despite major advances, however, these still lag far behind where they stood before the oil price bottomed out.

To analyse this, Rystad Energy benchmarked the discovered volumes between 2013 and 2018 by continent. The data shows that the Middle East and Africa decreased their share of global discoveries from 9.3 Bboe in 2013 to 1.6 Bboe in 2018; a reduction from 55% to 18% of global discovered volumes, with the Middle East contributing a mere 16% in 2013 and 10% in 2018.



Discovered volumes in Africa and the Middle East 2013–2019.

Between 2013 and 2018 discoveries amounting to 25 Bboe are reported in Africa, while the Middle East is way behind with only about 10 Bboe discovered. Major discoveries in Africa include Zohr (Egypt), Orca and Espadarte (Mozambique), Yakaar (Senegal) and Ahmeyim (Mauritania). Major Middle Eastern discoveries were made in Oman, Saudi Arabia and Kuwait.

With continuous hiccups in the oil price and easy-to-extract oil already explored, E&P companies looking to minimise risk are turning to locations with significantly high chances of success. With this strategy, the future of oil and gas exploration could be focused on the following:

- **Frontier areas:** Not an easy nut to crack, as areas are classified as frontier and remain underexplored for a reason. Therefore, it will be important to identify the basin depocentre(s) and the hydrocarbon kitchen to increase the success rates for exploration wells drilled and bring down discovery costs.
- **Underexplored deeper plays:** An example would be the Palaeozoic in the Middle East and the Oligocene deltaic sequence in the Niger Delta, e.g. the recently-discovered Obiafu Deep in the Obiafu-Obrikom fields.
- **Improving recovery technology while reducing operational costs:** Oman has developed a strategy to use solar-generated steam for enhanced oil recovery to reduce natural gas consumption and free up domestic hydrocarbon resources for export, while reducing reliance on costly LNG imports or diesel to power oil production and domestic power generation.
- **Unconventional resources:** This may be less attractive now, but cannot be ruled out as a potential future resource in the Middle East. Studies have proved that the region's stratigraphy contains excellent Palaeozoic and Mesozoic self-sourced shale reservoirs. Before diving into exploration, a detailed unconventional play study must be undertaken.
- **Political stability:** Nigeria, Libya and Somalia (to name a few) are examples of hydrocarbon-rich hotspots that have extraordinary potential, but have yet to create a stable enough political environment to lure in exploration companies.
- **Portfolio expansion:** Many Middle-East producers only focus on their immediate region, but national oil companies expanding beyond their comfort zones into foreign investments could be a future scenario. Qatar Petroleum is an example of a company that uses this strategy and now holds assets in various African countries. ■

Palzor Thendup, Rystad Energy

ABBREVIATIONS

Numbers
(US and scientific community)

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

Liquids
barrel = bbl = 159 litre

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

Gas

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

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

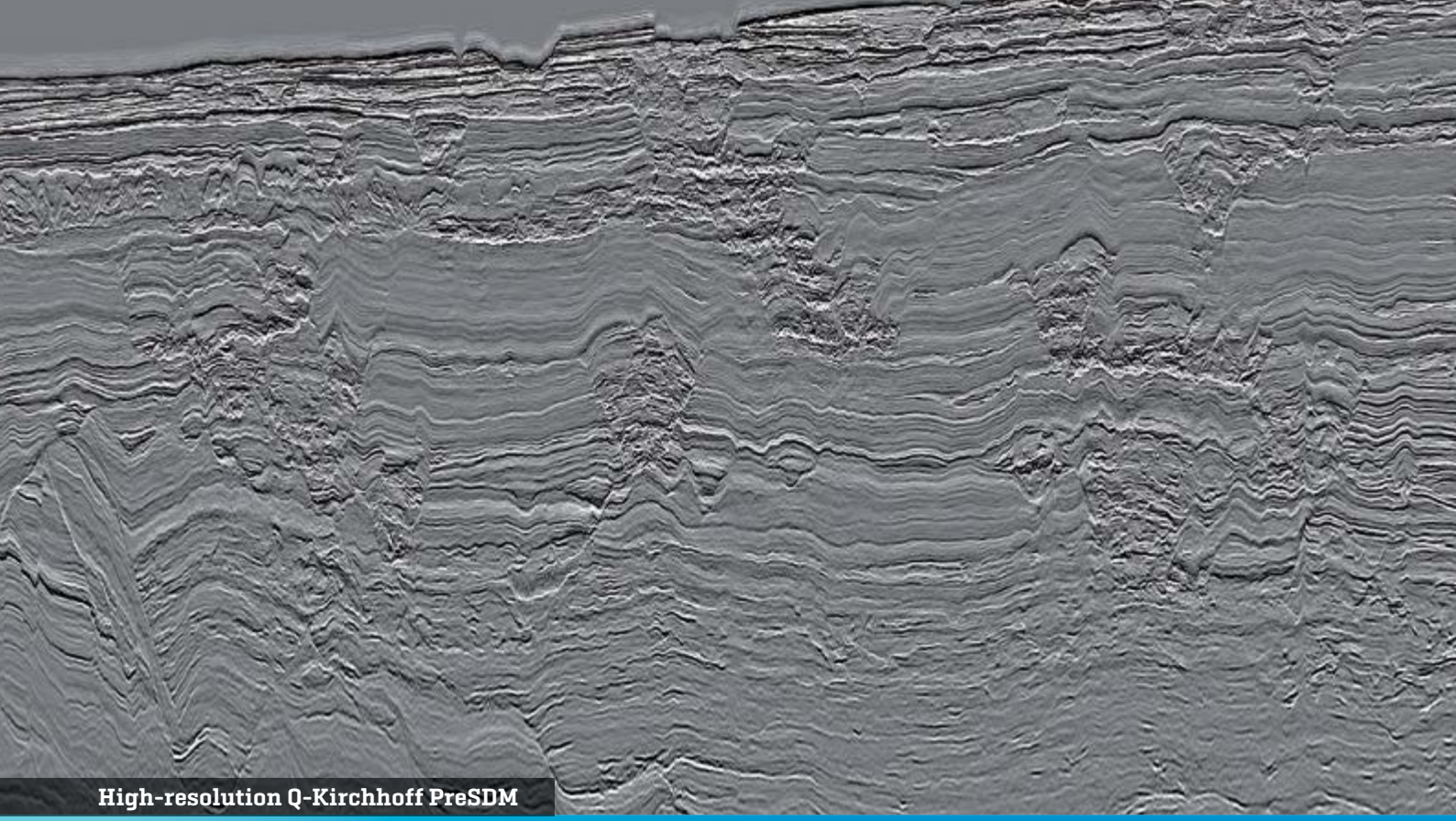
NGL
Natural gas liquids (NGL) include propane, butane, pentane, hexane and heptane, but not methane and ethane.

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

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

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

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



High-resolution Q-Kirchhoff PreSDM

ZAMBEZI DELTA 3D SURVEY

High-resolution reconnaissance PreSDM data available now

CGG has completed the imaging of a high-resolution volume as part of the Zambezi Delta 3D multi-client project. A **JumpStart**™ integrated package, incorporating gravity, magnetic, well and geological information, is being prepared to accelerate understanding of the petroleum systems in the area.

The high-resolution reconnaissance PreSDM data (sampled at 2 ms) and Fast-Track PreSTM data are available now and the final PreSDM data set will be completed in Q4 2019.

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Cuba: Ongoing Licence Round

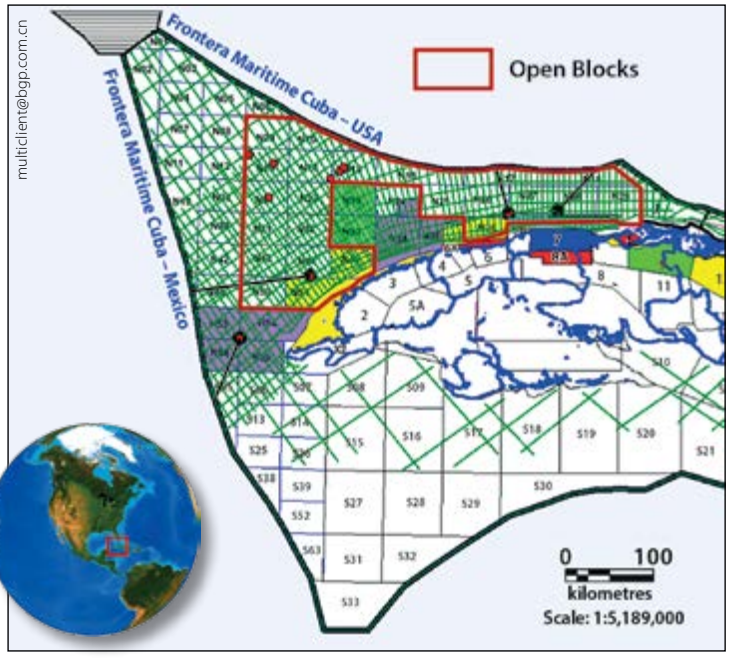
Underexplored area with plenty of open acreage.

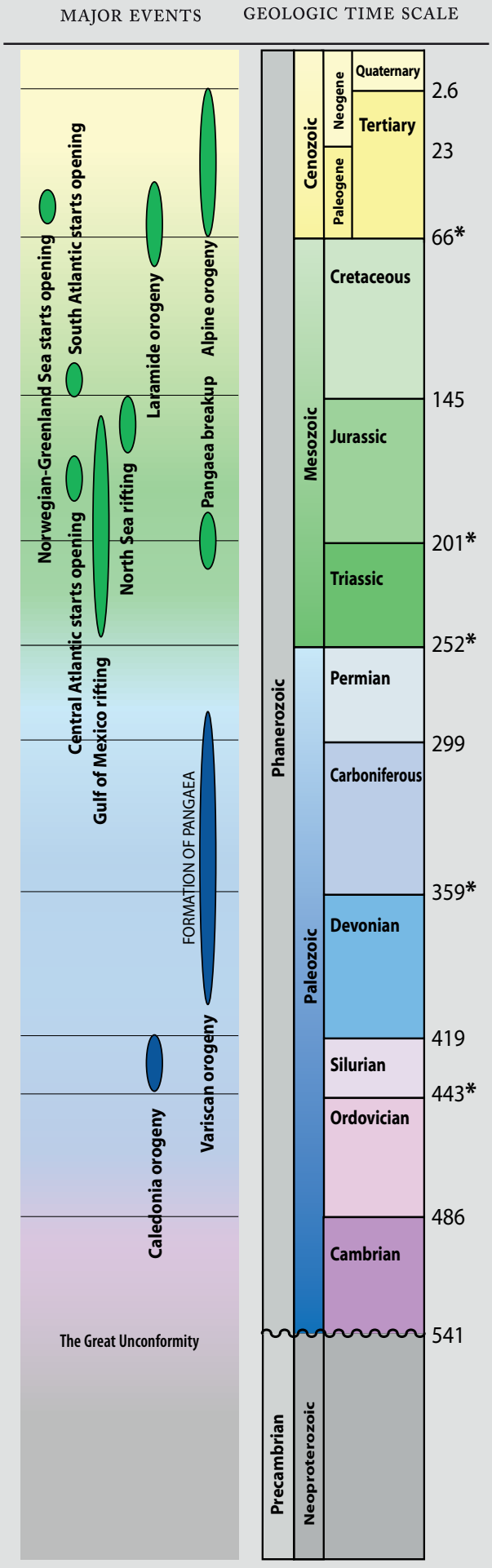
In June Cuba announced the opening of its first licensing round, with 24 blocks available, all of which lie offshore to the north and west of the country in water depths of between 500 and 3,000m. Cuba-Petroleo Company (CUPET) has now confirmed that the last stop of the roadshow it is undertaking to promote these blocks will take place in Havana on 27 November as part of the Cuba Energy, Oil and Gas Conference 2019, and the bidding process will close on 29 May 2020, with the award of licences being announced on 1 July 2020.

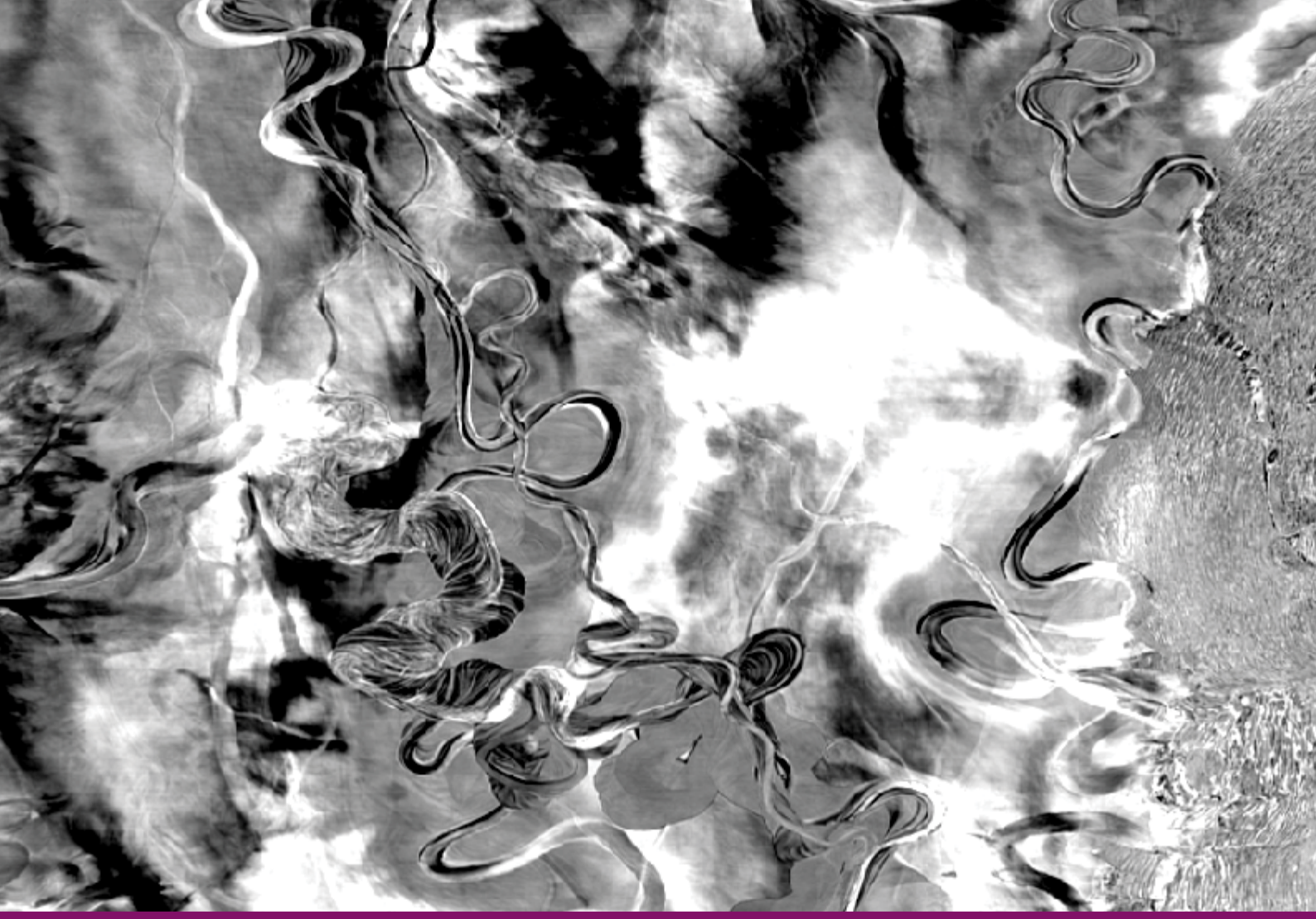
Two oil-bearing provinces have been identified in Cuba. The blocks on offer all lie within the Northern Cuban Province, which is about 1,000 km long and up to 100 km wide with over 10 km of sedimentary fill and includes the highly faulted and folded overthrust belt along the northern Gulf of Mexico. South of this is the Southem Cuban Province, which includes a number of Cretaceous–Tertiary basins.

Cuba produces about 50,000 boepd, mostly from fields along its northern coast in the overthrust belt, including the large Boca de Jaruco and Varadero fields. Some of these fields lie offshore and are accessed by drilling extended-reach wells from onshore into the Gulf of Mexico. Targets are Late Jurassic–Cretaceous fractured carbonates sourced from Jurassic deepwater clayey carbonate facies and sealed by Tertiary shales. In 2012, three deepwater exploration wells were drilled in the area covered by the licence round, but did not find commercial quantities of oil, although they all had oil shows, which according to biomarkers originated in Late Jurassic source rocks.

To assist in understanding the complex geology of the deepwater offshore north-west of Cuba, in 2017 BGP undertook a multiclient survey and acquired 25,000 km of 2D long-offset, high resolution, broadband seismic and gravity data. With data having been obtained to a depth of 10–12 km, this has provided valuable information concerning basement depth and sedimentary thickness and will help with a regional interpretation of the area. BGP mapped a number of leads and the results suggest considerable potential, with an estimate of possibly more than 10 Bbo recoverable. ■







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Geognostics Develops GEM+SEEBASE® 4D GIS

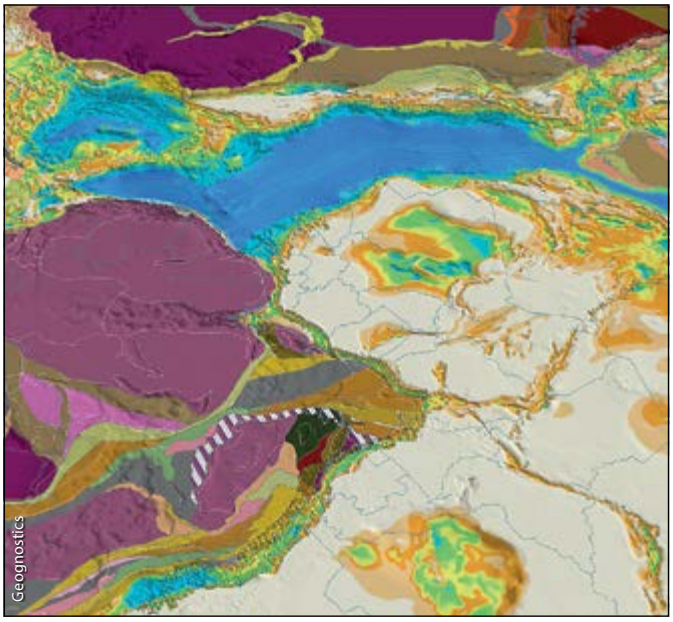
Geognostics, exclusive provider of the Geognostics Earth Model (**GEM**), has announced the expansion of its technical library and service delivery, including the recent acquisition of Frogtech Geoscience's IP assets. Geognostics now holds exclusive worldwide rights to the **SEEBASE**® technology and licensing rights to a portfolio of regional studies, databases and technologies.

GEM is the most detailed **global plate model** available, while SEEBASE is a dynamic **depth-to-basement interpretation** applying the company's global geoscientific experience to the integration of basement geology, structure and stratigraphy with all available constraining datasets. Together, these capabilities provide a one-stop shop to gain holistic, cutting-edge insights into continent to prospect-scale basin systems and their resource potential.

By combining GEM and SEEBASE in a 4D GIS environment, Geognostics has produced a series of margin-scale, time-slice-based plate reconstructions. These palinspastic maps include SEEBASE®, basement terranes, basin outlines, sediment thickness and tectonic event maps, delivered in GIS format. They provide key quantitative inputs for basin models and support a palaeogeographic interpretation of source kitchens, reservoir sweet spots, subsidence phases and trap development.

Geognostics' services are available as client-tailored studies, or through licensed multi-client products, including reduced-price bundles of Frogtech Geoscience SEEBASE studies. ■

Example of Geognostics GEM+SEEBASE 4D GIS (Late Jurassic).



Bid Rounds and Blocks

Looking for the latest **licensing round bid block perimeters**? The upstream data services company **Lynx Information Systems** provides free shapefile downloads for the public directly from a dedicated 'Bid Rounds and Blocks' page on its website.

The facility taps into a backend database of scouting information that Lynx harvests and utilises in its global portfolio of Exploration Adviser GIS studies for new ventures. These hydrocarbon assessment studies are play-based compilations put together by Lynx and its partners, which have a focus on Africa, the Middle East, Latin America and other international regions which often suffer from a paucity of readily organised data.

The page includes an interactive web map plus options to feed the map services directly to a client desktop mapping application. See the licensing rounds page on the Lynx website for more information. ■

Big Five Awards 2019

The **Big Five Board Awards** offer an unrivalled evening of networking for **Africa's** leading oil and gas companies and senior executives in a reception-style event for these long-respected annual accolades. Awarded since 1997 and with over 100 recipients to date, the Big Five Board Awards enter an incredible 23rd year. The event supports the plight of African wildlife and aims to raise funds for various conservation projects on the African continent with a charity auction.

The Big Five Awards ceremony 2019 will be held on Thursday 21 November 2019 at the Geological Society in Piccadilly, London. This year the guest speaker is Ade Adeola, Managing Director, Energy & Natural Resources, Standard Chartered Bank plc, who will be speaking on the challenges and excitement involved in building Africa's oil and gas future. ■

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AAPG Women's Network Repurposed

It is more than a new name and logo. The **AAPG Women's Network** is ready to move forward with a new mission and a new purpose – for everyone.

The AAPG Women's Network (AAPGWN), which was formally known as PROWESS, is a special interest group made up of men and women who are dedicated to promoting the technical and professional prowess of AAPG's women members. Its mission is to make a positive difference, provide guidance, support, increase participation and promote the advancement of women in geosciences and the energy industry. The emphasis will be on education, outreach, support, leadership development, and ultimately, retention and engagement. The AAPGWN will interact with men and women in geoscience, their peers and employers, educational institutions, and professional societies to accomplish this mission.

Current activities include hosting networking events and short courses at ACE and ICE conferences, nominating women for AAPG awards, partnering with sister organisations, and creating media materials to highlight the careers of women geoscientists and more. It is an opportunity to continue the discussion on gender balance in the industry and to share professional, technical and social interests with like-minded female geoscientists. ■

GII Steps Up its Game

With increased development of urban environments and the need to protect our natural habitat, hydrocarbon exploration operators are seeking **high-precision onshore seismic**. Acquisition surveys are required to be extremely low footprint and not to interfere with the local communities' daily life or impact the environmental balance. The **GII**, a leading global seismic acquisition provider based out of Israel, has purchased a brand new silenced mini-Vibrator fleet from INOVA Geophysical and coupled it with the Quantum nodal receiver system.

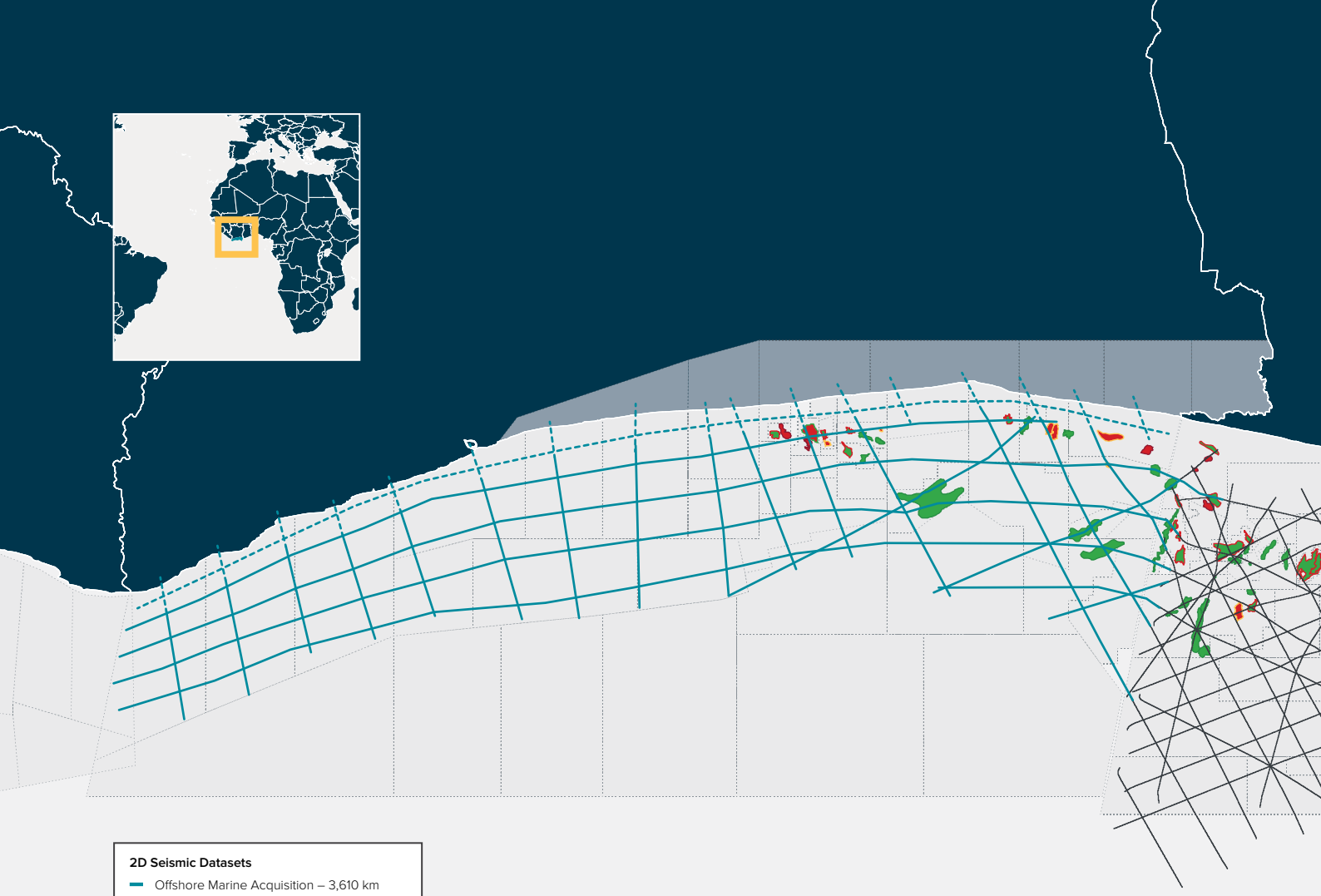
Recently deployed in Europe, the GII's **low-impact crew** is now executing a 3D survey which includes very narrow streets and bridges, a protected nature reserve and numerous agricultural lands. Permitting, involving thousands of land-owners, was streamlined by demonstrating the mini-Vib fleet and nodal operations to authorities. Expat and local employees are being trained in community relations and conflict resolution as these soft skills have been shown to contribute much more to speed and accuracy than an aggressive continue-at-all-costs approach. On top of this, local content percentages are expected to be high. The GII has invested in timing operations out of rush-hour and keeping lines away from main transit routes. In times of increased sensitivity towards onshore hydrocarbon exploration, specialist geophysical service providers are stepping up their game. ■

From Prospects to Production

PESGB Conferences Ltd and the **Oil & Gas Authority** are pleased to bring you **PROSPEX 2019**, the UK's leading networking event for exploration and development. PROSPEX 2019 will be held at **London's** iconic **Business Design Centre** on **11–12 December 2019**. PROSPEX 2019 will provide a venue for announced Promote licensees, oil and gas companies and governments to market their prospects and meet with potential investors to facilitate the deal-making process.

It offers a contextual overview of licensing activities and related topics for the UK continental shelf, the onshore and surrounding areas and creates a 'hot spot' by bringing together interested players to help advance the value chain from 'Prospects to Production'. As in previous years, there will be a full speaker programme incorporating the popular "Prospects to Go" sessions.

In 2018, PROSPEX was attended by over 800 delegates, had more than 30 prospectors promoting in excess of 50 prospects, with over a quarter of attendees being directors, C-level executives or VPs. PROSPEX 2019 is already shaping up to be larger than last year, with spaces selling fast and registrations coming in quicker than ever! ■



IVORY COAST REGIONAL DEEP IMAGING

Geoex & MCG are pleased to announce the commencement of the Ivory Coast Regional Deep Imaging 2D survey, currently open to companies for pre-commitment.

The program will consist of 3,610 km of multi-client 2D seismic data, in continuation to Ghana's regional dataset in partnership with ION, and is designed for a potential 813 km extension into the transition zone.

Acquisition is scheduled to start in Q1 2020. Data will be processed in time and depth with the integration of gravity, magnetic and well data for velocity calibration.

Please contact Jean-Philippe Rossi to learn more:
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Namibia in the Spotlight Again

Namibia's onshore has plenty of hydrocarbon potential just waiting for adventurous explorers.

ANSGAR WANKE, University of Namibia / Upstream Exploration Services Namibia

This year Namibia has again moved into the spotlight as major oil companies increased their presence along the Namibian margin. ExxonMobil acquired acreage in the Namibe Basin and Total announced it plans to test the giant Venus prospect in the deepwater offshore Orange Basin. Over the last five decades exploration offshore Namibia has been through cycles of consecutive rig activity, with high hopes and excitement alternating with prolonged phases of dormancy, the latter partly relating to the political complexity in southern Africa prior to Namibia's independence in 1990.

View of the front of the Naukluft Nappe delineating the Nama Basin to the north. In the foreground are tilted shales and carbonates of the Nama Basin.

A Century of Onshore Exploration

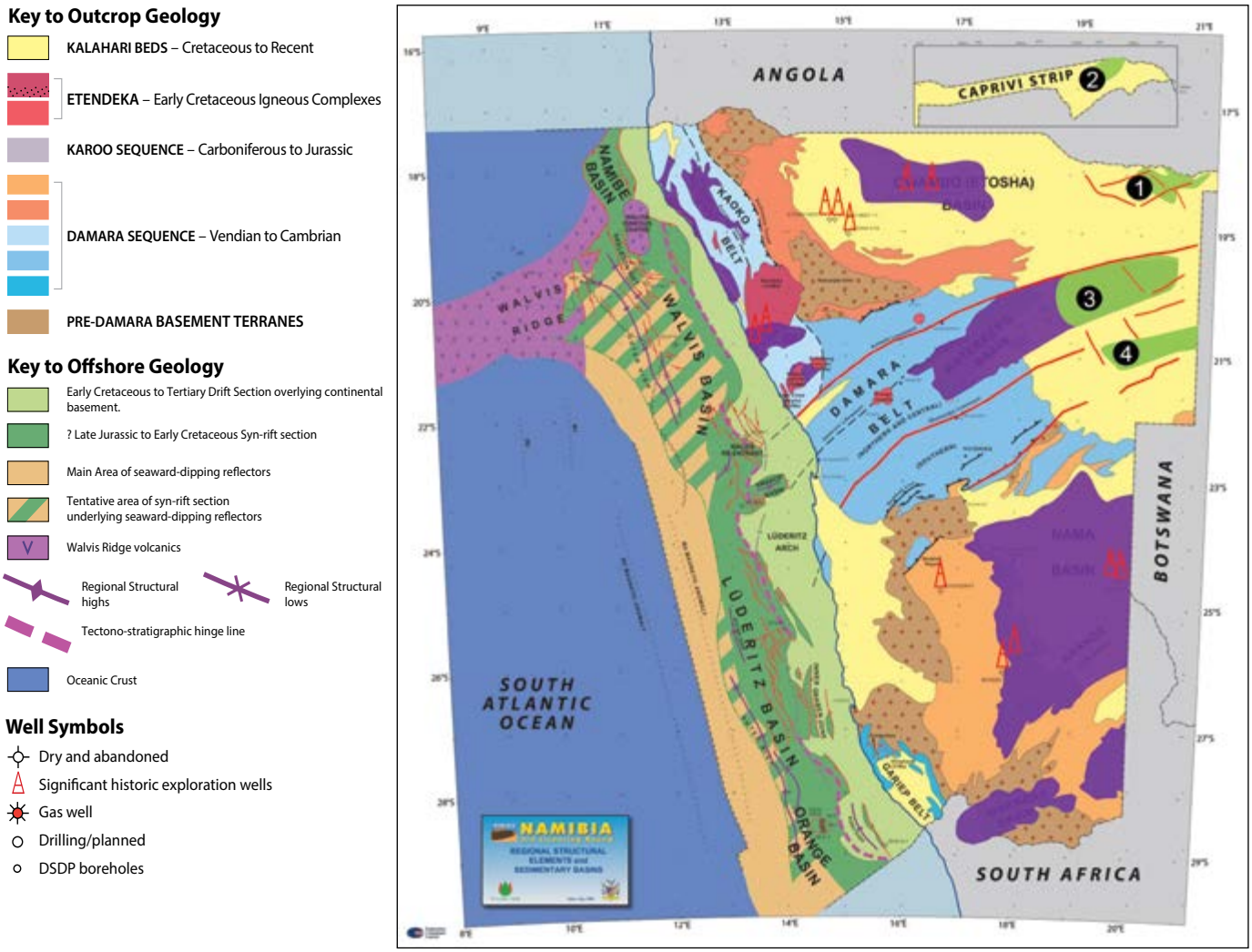
In a similar but less well known fashion, Namibia's onshore potential has received the attention of various explorers for now almost a century.

The first onshore exploration well, Berseba-1, was drilled by South West Africa Petroleum Corporation in southern Namibia in 1928. This was 46 years prior to the drilling of the first offshore exploration well, Chevron-Texaco's Kudu 9A-1 in the Orange Basin. Initially Kudu-1 targeted a Tertiary / Upper Cretaceous prospect that turned out to be dry, but then the well continued as a 'stratigraphic well' down into the Lower Cretaceous, leading to the discovery of the Kudu gas field in 1974.

Berseba-1 in 1928 was similarly experimental, and though a gas blow-out was reported at shallow depth during drilling operations, the well did not yield a discovery when it reached TD. Therefore, scepticism about Namibia's onshore potential may have played a role in explaining why only 12, mostly shallow, exploration wells have been drilled to date, thus hardly testing the country's full onshore potential.

Two Vast Basins

Namibia's onshore basins cover over 60% of the country. Two vast Neoproterozoic/Early Cambrian Basins, the Owambo-Etosha Basin in the country's northern part and the Nama Basin in the south, have been receiving most of the attention from exploration companies. These basins cover over 470,000 km^2 and both are flanked by early Cambrian pan-African orogenic belts. Both basins share the prominent Damara Belt, which forms the southern margin of the Owambo-Etosha



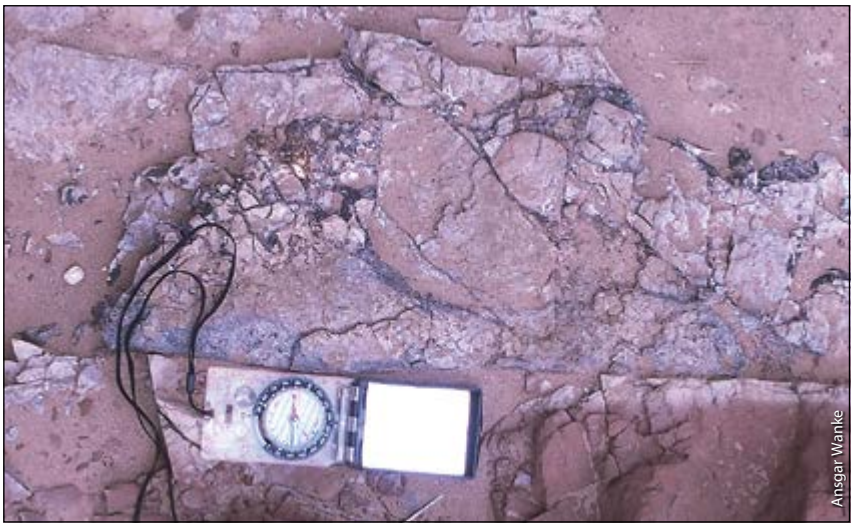
A geological map of Namibia displaying onshore and offshore sedimentary basins. The Owambo-Etosha Basin is located north of the Damara Belt, while the Nama Basin is situated south of it. Purplish overlays show proven Karoo Basins, green areas show postulated basins under Cenozoic cover: (1) Kavango Basin, (2) East Caprivi, (3) Waterberg East, and (4) Eiseb-Omatako.

Basin while delimitating the Nama Basin to its north. To the west the north-north-west trending Gariep Belt and its northern extension, the Kaoko Belt, form the western margins of the two basins. This means that each basin is flanked by two almost contemporaneous orogens leading to complex foreland basin architectures and the associated high probability for structural traps.

Migration is predicted to have started in the Cambrian following the Damara orogeny. Post-orogenic deformation events are minor, and therefore there is a good chance that Cambrian hydrocarbon accumulations remained preserved. Predicted deep depocentres and several source and reservoir lithologies observed in core and outcrops have attracted explorers, from small independents to majors. In fact, the exposed orogenic basin margin gives an excellent example of a fossil petroleum system with abundant graphite occurring in metamorphosed rocks originating from hydrocarbon-generating Neoproterozoic syn-rift shales.

The location of the first well in 1928 in the Nama Basin was solely chosen on field geology studies including the observation of bitumen veins in outcrops. So far, the source for these shows remains speculative; some may relate to matured Neoproterozoic source intervals, while others may rather derive from local hydrocarbon generation caused by basaltic intrusions in Karoo shales (Summons et al., 2008).

In 1968 DeBeers with Shell/BP acquired a concession and conducted the first 2D reconnaissance survey. This was followed by the drilling of Tses-1, which, with a TD of 2,225m, is so far the deepest test well in the basin. A second 2D survey covering 500 km was conducted much later in 2007/08 by Hungarian company INA Industrija Nafte d.d. This provided the first subsurface imaging of reasonably good quality, allowing more detailed structural and stratigraphic interpretations. However, INA did not test its prospects and current explorers will need to be prepared to shoot more seismic and drill new wells.



Bitumen-cemented fault breccia within sandstones of the Fish River Subgroup. Such outcrops motivated early explorers to drill the first oil exploration well almost a century ago.

Exploration in the Owambo-Etosha Basin is more advanced: seismic acquired includes vintage 2D surveys conducted between 1969 and 1995, and a more recent 120 km 2D survey carried out by CGG for Angolan AGREP in 2017. All 2D seismic surveys are widely spaced, and as expected in foreland basins, they reveal more structural elements at the basin margins, while flat reflectors rather characterise the basin interior. In addition, airborne geophysical surveys, soil geochemistry, remote sensing and micro-tremor studies have been carried out during the current decade and preparations for more surveys of this kind are underway.

Between 1964 and 1991 five exploration wells with TDs between 700 and 2,509m were drilled. Only the deepest of these wells penetrated a potential reservoir zone and a minor oil show has been reported. Otherwise the Owambo-Etosha Basin lacks the obvious outcrop hydrocarbon shows of the Nama Basin, probably due to the thick Cenozoic cover of semi-consolidated sediments. Encouraging elements are soil gas geochemistry, remote sensing and micro-tremors studies, as well as the abundant structural elements along the basin margins.

Petroleum basins with Neoproterozoic source rocks, such as in Oman, the Lena-Tunguska Basin in Siberia and others, have been the motivator for keeping exploration in Namibia's two Neoproterozoic/Cambrian basins going. But what have been lacking are more aggressive exploration campaigns with wells down to basement and well-placed denser seismic surveys. Fortunately, recent exploration activities have gained a new momentum, geological concepts have been refined, and now the scene is ready to design new determined exploration programmes.

Stromatolitic Otavi Group carbonates provide excellent high poroperm reservoir lithologies.

Karoo Basins: New Petroleum Target

Karoo-aged basins hosting late Palaeozoic to Mesozoic strata form another set of basins. In the '80s the Karoo basins were the target for coal exploration, and only more recently have they been considered as a hydrocarbon exploration target.

Continental sediments prevail in the Namibian Karoo basins with marine influence only having been demonstrated in the uppermost Carboniferous. The Permian strata contains not only coal seams, but also extensive organic shales. Perfectly preserved Mesosaurus fossils, a nektonic crocodile-resembling reptile, are described from those shales in Namibia. With Mesosaurus as an index fossil the Namibian black shales correlate well with similar shales

across Gondwana, known as the Whitehill Formation in South Africa and as the Irati Shales in South America. Sedimentology and isotopic signatures indicate restricted environments with repeated algal blooms: the perfect conditions for the deposition of oil-prone source rocks.

The Karoo in Namibia covers large areas in Namibia, with outcrops occurring particularly in southern, mid-northern central and coastal north-western Namibia. Outcropping Karoo strata form distinct landscape features such as the Weissrand Escarpment in southern Namibia or the Waterberg Plateau, the latter being a well-known scenic tourist destination.

In most areas the Karoo forms a veneer of horizontal strata less than a kilometre thick, and this has probably been the reason why hydrocarbons, apart from coal bed methane (CBM), have not been considered as a resource. Exploration wells for CBM were drilled in the Aranos Basin in 2008 and in the Huab Basin in 2012, but the gas contents have not proved economic.

Highly friable Upper Carboniferous black shale exposed at the banks of the Fish River in southern Namibia. Those shales may also occur in deeper depocentres and fuel Karoo-aged petroleum systems.

Depocentres are aligned along south-west to north-east trending fault systems that essentially follow the pan-African basement grain and are seen as part of the wider Southern Trans-African Rift and Shear System (Granath and Dickson, 2018). The prominent cliffs at the Waterberg and Mt. Etjo are erosive remnants of the top sequence deposited in such a depocentre. Geophysical modelling of magnetic and gravity data promotes the presence of deep Karoo basins exceeding 5 kms of sediment in the north and east of the country, where the terrain is essentially flat and rocky outcrops are very sparse due to the extensive Cenozoic Kalahari sequence cover. The locations of the predicted Karoo depocentres match the extrapolation of known major fault systems. Releasing-bent pull-apart extension is predicted, which would promote the presence of steeply flanked deep basins. In such a scenario episodes of anoxic lacustrine deposition would have probably occurred not only during the Permian, but possibly also higher in the stratigraphy. Given enough overburden, both conventional and unconventional petroleum systems have been hypothesised. The recently proposed Kavango Basin in the north-eastern part of the country relies on this concept and preparations for test wells have commenced.

Revealing Namibia Onshore Potential

The deeper parts of both the Neoproterozoic/Cambrian and the Karoo basins are believed to occur under essentially flat terrain with few surface clues indicating what is happening in the subsurface. This allows explorers to think laterally and, as is vital in frontier exploration, to ponder opportunities. The little subsurface data available is truly encouraging and moreover, Namibia offers an essentially friendly environment for exploration.

Now, 91 years after the first onshore well was drilled, explorers have a modern exploration toolbox at hand that will make it much easier to reveal Namibia's real onshore potential. ■

Southerly trending folded Neoproterozoic turbidites in the Kaoko Belt, which is the pan-African Belt that flanks the Owambo-Etosha Basin to its west.

Oil Bonanza in Guyana

But with notes of caution for the neighbours.

PETER ELLIOTT and ROG HARDY, NVentures Ltd

Exploration can rarely said to be 'hot' when expensive wildcats routinely come up dry. But after more than 25 dry wells in 'the Guyanas' over the last two decades, 14 oil discoveries adding up to an estimated six billion barrels of recoverable oil over the last two years in just one block (Stabroek) offshore Guyana is proving blistering. The legacy of bleak dry holes in ever deeper water and well costs that compete with Britain's Premier League football for eye-watering numbers are now being offset by world-class success in a classic deepwater exploration campaign that both galvanises and challenges explorationists in equal measure.

The Stabroek cluster, challenging the scale of Brazil's pre-salt and the reliability of Angola's Lower Congo Basin, may light up all of Guyana and Suriname, and perhaps motivate a return of oil companies to French Guiana. Or, does this super-cluster preface a Jubilee-style race to a string of dusters in adjacent basins? Suriname especially has so far proven that being next door to Stabroek does not guarantee an invite to the party. Big names such as Murphy, Noble, Chevron, Apache, Tullow and Kosmos have all fallen short in major drilling campaigns offshore Suriname, while the appraisal of Zaeydeus in French Guiana is a painful memory for Tullow, Total and Shell.

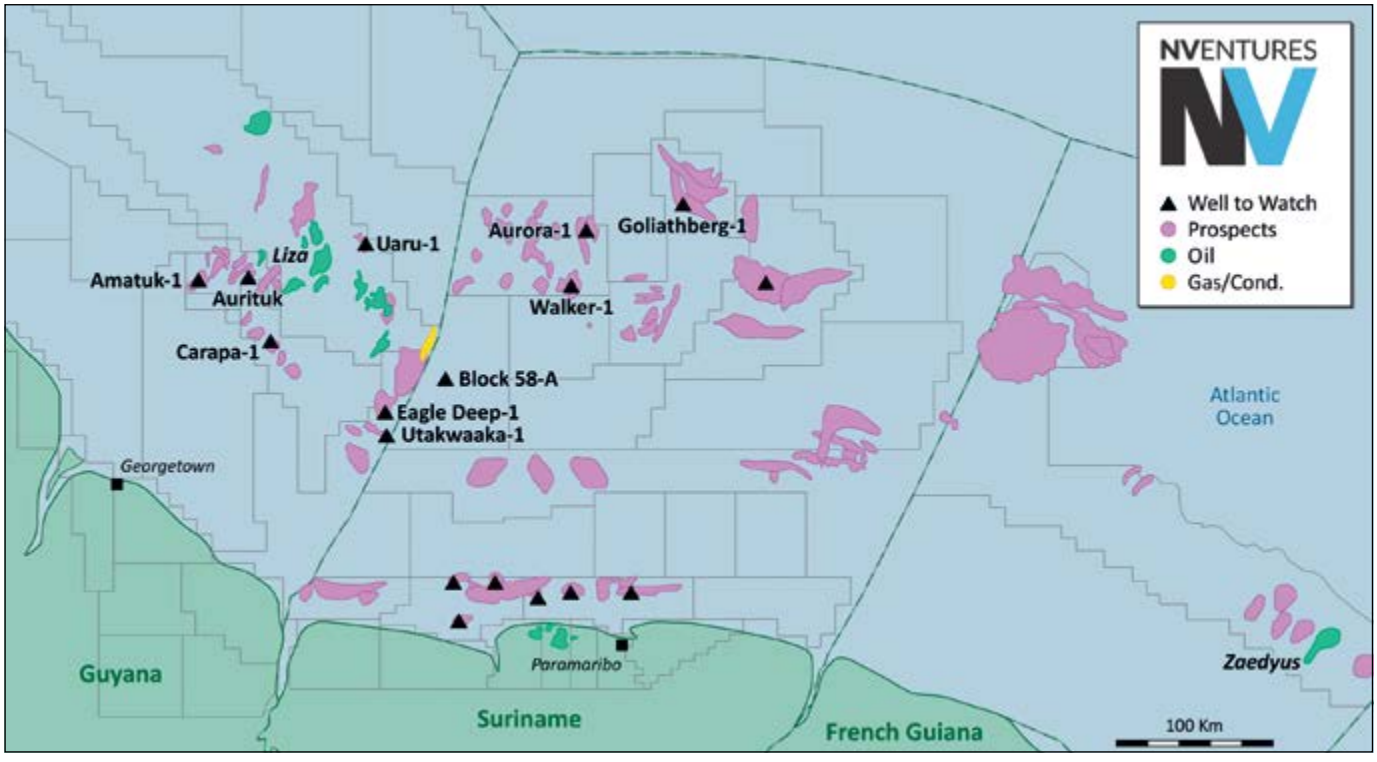
Drilling Will Reveal All

And now, while the Exxon/Hess/CNOOC group notch up sizable reserves additions in Stabroek, the savvy Tullow/Eco/Total group in the immediately updip Orinduik Block are soaking up the glory, batting two for two with oil discoveries at Jethro and Joe. Their Tertiary play is said to 'light up' on 3D in this basin, but the same effect is rarely repeated with any consistency in the Cretaceous elsewhere, especially in the conjugate basins of the South Atlantic. Industry observers have pointed out the Tertiary play in the Orinduik Block was already de-risked by Hammerhead, and their Cretaceous play, yet to be tested, whilst it has far more to offer, has far higher risks.

Looking ahead, the drill bit will help decide what's hot and what's not. In Suriname, Apache will spud a well (or two) in Block 58 this month; Kosmos, with Chevron and Hess, have Aurora and Walker planned in Block 42, while Tullow, with Ratio and Pluspetrol, are targeting Goliathberg in Block 47 and Tullow may test Block 54. In addition, back in Guyana, CGX have at least one well planned in the Corentyne Block and Repsol, with Tullow and Total, will drill the Kanuku Block Carapa 1. Tullow is forging ahead with the drill bit, announcing three wells in 2020 on the Orinduik Block – and of course ExxonMobil is flat out on Stabroek, with three drillships operating, as the Liza FPSO gets into position as the first of five such vessels planned on the Stabroek Block, which is targeting 750 Mbopd by 2025.

So, numerous exploration teams are positioning to chase the Tertiary and challenge the Cretaceous nearby. Stay tuned! ■

Future wells to watch in the Guyanas.



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North Gabon:

Lightning strikes connect the Gulf of Mexico subsalt trend to North Gabon

PSDM line extracted from the TGS North Gabon 3D dataset acquired by Spectrum in 2018. Unprecedented salt flank imaging reveals subsalt and salt flank opportunities in the post-salt while large pre-salt structures are also unveiled. Pockmarks observed at the seabed towards the centre of the section are interpreted as evidence of an active petroleum system.

In the early 1990s petroleum industry analysts had begun to refer to the Gulf of Mexico as the Dead Sea, claiming that there were no more large undiscovered resources left (*Offshore Magazine*, 1997). Exploration was re-animated in 1993 by the lightning strike of the Mahogany subsalt discovery, reflecting huge improvements in seismic imaging. This was followed in 1998 by the Tanzanite and Hickory subsalt discoveries, breathing new life into exploration in the shallow water Gulf of Mexico (Offshore Magazine, 1999). Until now, the salt basin of North Gabon has also been considered to have limited major undrilled potential, and once more this is just a false impression from available seismic imaging under detached salt canopies and overhangs.

The lightning has struck again: 3D seismic data acquired in 2018 has yielded unprecedented subsalt imaging, revealing the future Mahoganies, Hickories, Tanzanites and Mad Dogs of West Africa.

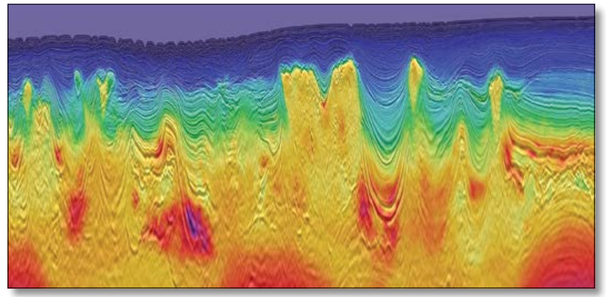
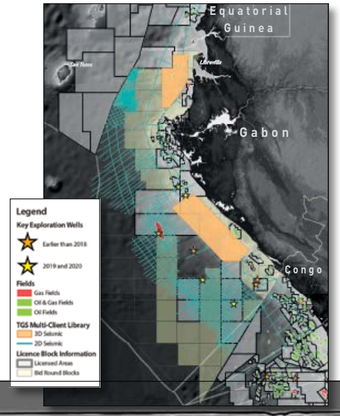
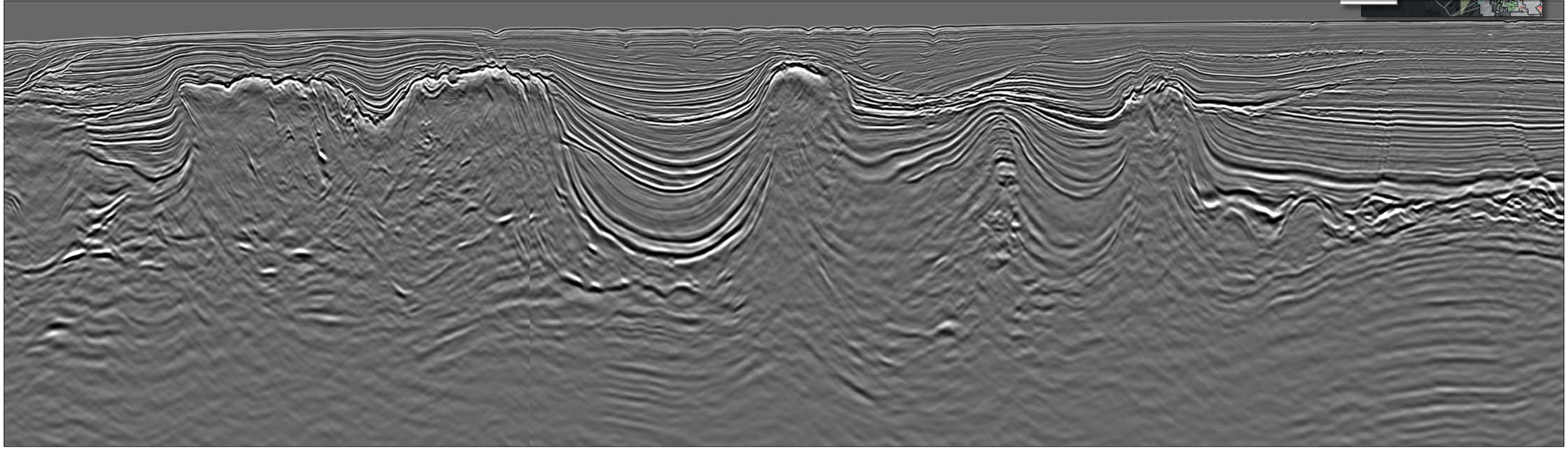


Figure 1: Final Velocity model (TVDSS). Detached salt bodies and well-defined salt flanks resulting from several iterations of manually picked salt bodies provided to constrain the tomographic updates.





The Tanzanites, Hickories, Mahoganies and Mad Dogs of West Africa

Stacked depth conformant amplitude anomalies indicating huge hydrocarbon potential similar to the Gulf of Mexico.

KARYNA RODRIGUEZ, NEIL HODGSON, HOWARD NICHOLLS and PAOLO ESESTIME, TGS

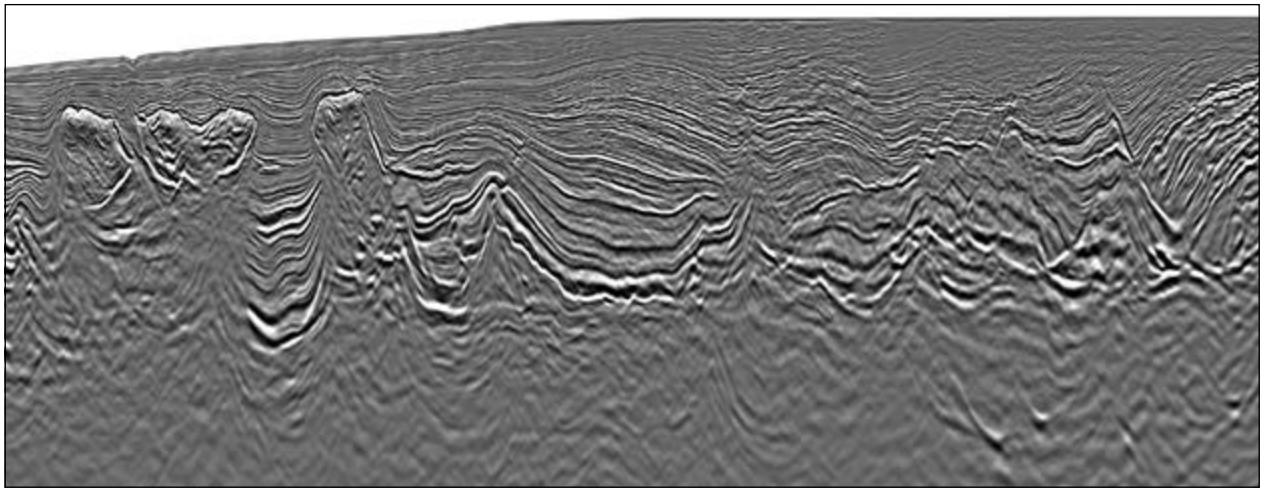


Figure 2: Final Kirchhoff PreSDM stack (TVDSS) illustrating the heterogeneous nature of salt distribution, showing thinner salt to the east becoming much more complex towards the west.

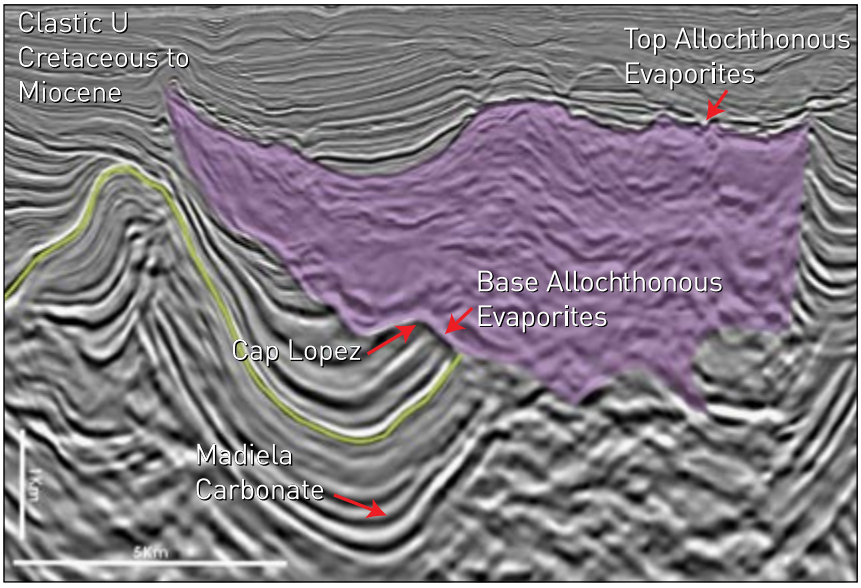
Heterogeneous Salt Distribution

Traditionally, two separate systems are considered in North Gabon. The deeper of the two is a pre-salt hydrocarbon system comprising the lacustrine Melania and Kissenda source rocks charging both syn-rift Dentale fluvio-deltaic sands and the early post-rift transgressive Gamba sandstone formation. An additional potential source rock, the restricted marine Vembo shale, is ubiquitously encountered sitting above the transgressive Gamba sandstone.

A shallower post-salt hydrocarbon system comprises a number of potential source rocks and a series of deltaic clastic reservoirs such as the Ewongue, Anguille, and Cap-Lopez Formations, in drapes, turtle structures and stratigraphic traps generated by salt topology. As confirmed by the 2018 3D seismic data, the distribution of salt is heterogeneous across the area (Figure 2). In the east, salt has mobilised into vertical diapirs leaving a very thin layer between the pre- and post-salt sections. The salt mobilisation reflects both extension of the section as it gently slides down-dip under gravity, and loading from sediment deposited on top. Like pastry in front of a rolling pin, a prograding delta pushes salt in front of it so that, to the west, the salt is still present in extraordinary amounts. Here the salt appears as complex salt walls, domes, canopies and diapirs. This heterogeneous distribution is crucial for exploration.

3D seismic data acquired in 2017–2018 with long 8,000m offset and processed through modern broadband and depth imaging algorithms has successfully targeted the post-rift, as well as the pre-evaporitic syn-rift sequences. More significantly for North Gabon, an unprecedented image of the salt flanks and detached salt bodies has been obtained, largely due to a very carefully

Figure 3: Imaging of top and base of allochthonous evaporites reveals subsalt traps. This prospect has been named 'Rhino' as the shape of the allochthonous body resembles a rhinoceros.



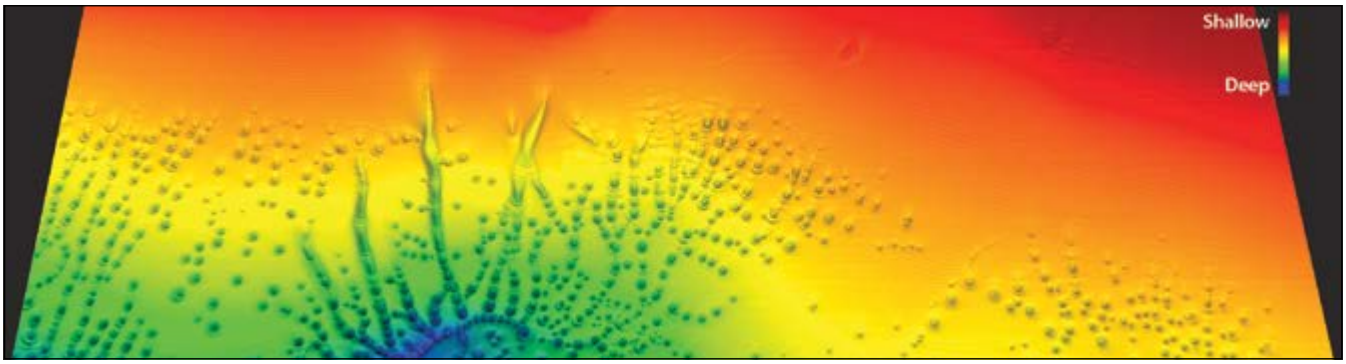


Figure 4: Seabed grid from the 2018 3D seismic dataset showing an impressive array of pockmarks observed to be related to shallow amplitude anomalies, indicating active hydrocarbon migration.

derived velocity model (Figure 1). High velocities, which are common in the Lower Madiela, were found in the lower section of the mini-basins. A slow overburden of 2,000-3,000 m/s was juxtaposed on allochthonous salt bodies.

GoM-Like Subsalt Prospectivity Revealed

Excellent imaging of salt flanks and top and base of allochthonous salt bodies (Figure 3) has allowed the extent of the clastic basins sitting between salt walls (called 'mini-basins') to be mapped over the entire shallow water North Gabon area for the first time. Over 20 mini-basins with areas up to 370 km^2 have been mapped. These provide a staggering total 1,500 km^2 area of closure against salt.

Subsalt success in the Gulf of Mexico is largely associated with amplitude anomalies and direct hydrocarbon indicators (DHIs). Having looked at hundreds of amplitude and DHI-supported prospects associated with salt in the Gulf of Mexico, the authors of this paper can confirm that amplitude depth conformance is the one factor which can be correlated to the highest success rate. Amplitude stacking has also resulted in some of the most commercial discoveries made in this type of environment.

In North Gabon we have observed several DHI types including high amplitude anomalies which stand out strongly against the background, dip inflection points and excitingly, the most wanted prize, stacked depth conformant amplitude anomalies.

Added Prospectivity Revealed

In the west of the area, where the post-salt mini-basins are thickest, an impressive array of pockmarks has been mapped at the seabed (Figure 4). These are associated with thick post-salt sections, suggesting a post-salt source is working, and also with apparent salt welds connecting pre- and post-salt sections. Faults connect salt welds up to the surface, and soft kick amplitude anomalies are observed in the passage way of fluid pipes, as well as salt flank amplitude anomalies in post-salt thick sections.

Very early results obtained for recent least squares Reverse Time Migration (RTM) tests, carried out by DUG (DownUnder GeoSolutions) over a selected area of the 3D, have improved salt imaging even further and have revealed additional prospectivity. There is a clear resemblance to the Mad Dog structure in the GoM (Figure 5).

With the area being open acreage in the ongoing licence round, new commercial terms having recently been passed by government, and the imaging for the first time of the sub-salt clastic plays that have provided such a rich harvest in the Gulf of Mexico, North Gabon offers an unparalleled opportunity for lightning to strike again. Modern seismic has brought the prolific GoM subsalt trend to North Gabon, re-energising exploration and welcoming in an era of discovery of the West African Tanzanites, Hickories, Mahoganies and Mad Dogs which have now been revealed. ■

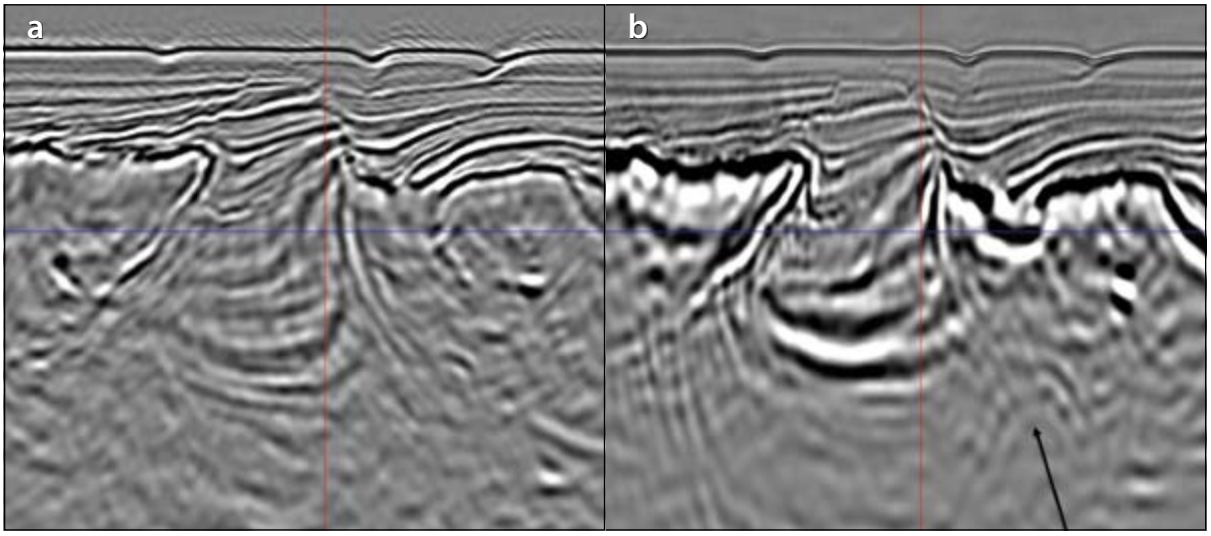


Figure 5: (a) Before Least Squares RTM Test. (b) After test. A significant anticline similar to Mad Dog in the Gulf of Mexico has been revealed.

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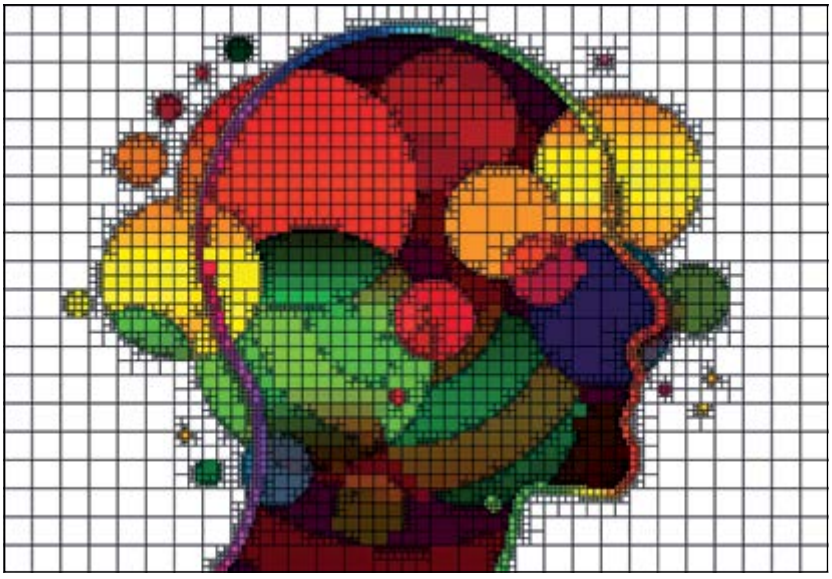
Jobs? Better Operations? Look Under a Different Rock!

The development of new technology is transforming the energy industry.

SUSAN SMITH NASH, PhD; AAPG



We have witnessed a tremendous transformation in the oil industry in the last few years, beginning with the adoption of the new techniques of 'factory drilling' of horizontal wells, with multi-stage hydraulic fracturing, and then with the digitalisation of all aspects of exploration and production. It has happened so quickly that many may not be aware of how the new technologies came to be developed and implemented so fast.

In the past, most technological development occurred either in company-owned R&D branches, or in various consortia, often located in universities. While those approaches are effective, a dramatic shift has occurred due to the availability of infrastructure, cloud computing and capital, which make it possible for companies to develop and launch products quickly and then be acquired by a larger organisation for further development and commercialisation.

In many ways, the approaches have emulated the technology start-ups and incubators of Silicon Valley, but with a few significant differences. Firstly, the applications tend to be much more specialised, so the development requires a team of technical experts as well as data scientists. Secondly, the nature of oil and gas production requires a great deal of attention to safety, the environment, and a complex web of infrastructure, which makes it necessary to proceed with caution, with redundancies and fail-safes in the process.

The author; behind her a participant is pitching an idea at AAPG's U-Pitch.

Organisations such as the American Association of Petroleum Geologists (AAPG) are working to attract capital, promote adoption, and boost commercialisation for new technologies. As a not-for-profit professional society dedicated to the advancement of science and technology, AAPG seeks ways to help its members equip themselves for changing times. Its U-Pitch Showcases are a prime example, which take place in conjunction with AAPG's major event.

Sources of Capital

A crucial requirement for a successful new technological development is access to funding. Several options are available.

Self-funding: Many start-ups are self-financed, particularly if they are expanding a current technology. Companies that undertake analytics and reservoir modelling often start by offering services, and then develop a platform or customised set of applications, taking advantage of general cloud provision offered by Google, AWS and Microsoft, before developing a custom platform. Other start-ups may create sensors, equipment, water processing technology, or oil field chemicals, offering a service that incorporates their unique technology. The advantages of self-funding is that there is no dilution of ownership and there is also the opportunity to develop technology for real-world situations, and to modify it in response to real-world settings. The downside is that

they may be undercapitalised, lacking sufficient funds or time for marketing or new business development. Furthermore, they may not be aggressive enough in the truly innovative aspects of the product development or have enough time or in-house expertise to build a working prototype for the next generation of their product. Finally, the key personnel may be poached by a company that can offer a higher salary or benefits.

Angel Investors: Angel investors tend to offer capital in exchange for a percentage of the company, assuming it will either eventually seek to be acquired by another organisation for a large return on investment, or it will generate profits that will result in ongoing cash flow and revenue. Angel investors are less risk-averse than companies that deal with a more established product or market. The downside is that the start-ups give up a relatively large percentage of the company, which may make finding a commercialisation partner more difficult later. The benefit of having a silent partner is that it allows the company to develop the product more quickly, but having an investor who does not know the business could lead to disagreements about the strategy for advancement, or to the company being acquired before the full potential of the product has been explored.

Technology Ventures Divisions: Despite the fact that major oil companies have been investing in new technologies for many years, their efforts are not always recognised in the overall development of game-changing technologies. Chevron, Shell and Equinor, among others, have divisions or subsidiaries that actively seek new technologies that can be used to improve their operations and business processes. They also invest in technology that will protect the environment, provide safe working conditions, and increase security. The majors often purchase a non-majority interest in a company or award a development grant and then provide technical and strategic guidance to the technology start-up. National oil companies may form a subsidiary to develop technologies in-house in addition to investing in technology start-ups, while large independent producers may not invest directly but will work with a new company and allow their operations to be used as a living laboratory to test out the equipment, process, or chemical.

Commercialisation Partners: Commercialisation partners are very important and have been in many ways responsible for the adoption of the break-through technologies of the last five to ten years. A commercialisation partner is a company that specialises in business development and marketing, and which may also wish to offer services to the industry. For example, a start-up may be developing a new approach for converting unstructured data to structured. The algorithm is sufficiently unique that it can process data faster and more accurately than others, and so could be an essential tool or component in an overall solution or platform. Companies such as Enverus (formerly DrillingInfo) actively seek such partnerships in order to develop a larger analytics solution, either purchasing the company and technology, or licensing it and paying royalties.

An example of new technology: SeekOps develops and fields advanced sensor technology for the energy sector to detect, localise, and quantify gas emissions through drone-based systems.

The Pain Points

There are innumerable start-ups with new technologies, but which ones succeed? In the world of shale plays and deepwater, sub-salt and pre-salt reservoirs, the costs are still very high and there is a great deal of uncertainty, not only with respect to the true commercial extent of the reservoir but also in other important technological and environmental factors.

Let's look at a few of the pain points and how they are being addressed.

Data Nightmares: Most companies have a great deal of information, and they have systems for accessing it, but the major problem is that it is not actually usable in its current form, as it is in many different formats and in different repositories, some cloud-based, some not. In some cases, the information exists in two or three separate divisions of the company that rarely communicate with each other, resulting in silos not only of data but also of expertise. Companies often limp along with their existing legacy information systems because to change or convert it would be too expensive and too slow, but in order to improve operations as well as comply with regulations, it is necessary to have a way to access, transform and standardise data.

Start-ups and more established, very agile, companies have been addressing the data problem, first with data management, and later for specific analytics-based tasks. According to Philip Neri, spokesperson for Energistics, which develops oil and gas data standards protocols, the need for data standardisation is immense, not only in order to make it possible to share repositories and for service companies to develop a product that all clients can easily use, but also to make mergers and acquisitions seamless with respect to merging legacy data.

Leaks and Spills: Quickly detecting leaks and spills and then dealing with them is vital, and technology is moving this area forward fast, with new technologies that can detect pipeline leaks with pinpoint precision. Some of these are sensor-based systems, while other leak detection systems use satellite imagery, which can be used for monitoring and measuring spills, as well as determining the extent of storm damage and human activities. Drones-based systems use hyperspectral / IR sensors to detect surface leaks and spills by means of the change in heat or colour signature from foliage and water. The data can also be used for assessing damage from floods, security breaches, and more.

Water Issues: Both sourcing and disposing of water are major issues in unconventional fields and it is an area ripe for new technologies. One of the most talked-about technologies in U-Pitch in 2018 was Katzwater, which has developed a patented proprietary water purification system which is both low-cost and easy to install. The company attracted technology venture capital and is now working on providing services, and in expansion.

The Decline Curve Problem: A number of start-ups tackle this issue using different technologies. One option is using geochemistry to determine shales that are preferentially enriched and which are likely to produce, and also identifying which drilling and completion methods and chemicals will be most effective. For example, one new technology uses a wettability alteration solution that works in mature conventional reservoirs as well as shales to improve ultimate recovery, while in another, pulsed electrical reservoir stimulation is working as a kind of waterless hydraulic fracturing.

Drilling and Completion Efficiencies: Time is money, so many new technologies are looking at improving the efficiency of drilling and completion techniques, by, for example, using smart processing algorithms to save hours of completion time – and millions of dollars. AI can also be used to automate field development, geomechanical characterisation, fault interpretation, and the prediction of core physical properties.

Safety and the Environment: An example of the use of new technologies for safety is a system that automatically detects and extinguishes fires. The environment is not forgotten, with one innovative start-up developing the use of recycled plastic and environmentally friendly, biodegradable materials to design, build and repair roads, pads and walkways.

The Future

It is tempting to look at technology as an instant solution which appears magically on the scene and solves a stubborn problem. What is often not recognised is the enormous amount of effort, persistence and creativity required to develop effective solutions. It is also necessary to have deep levels of subject matter and domain knowledge. For that reason geoscientists and engineers who feel frustrated as they look for employment in large companies in traditional positions should take a moment and explore the world of new technologies and innovation. There are opportunities at all levels, both in the start-up and conception phase and in marketing and commercialisation. ■

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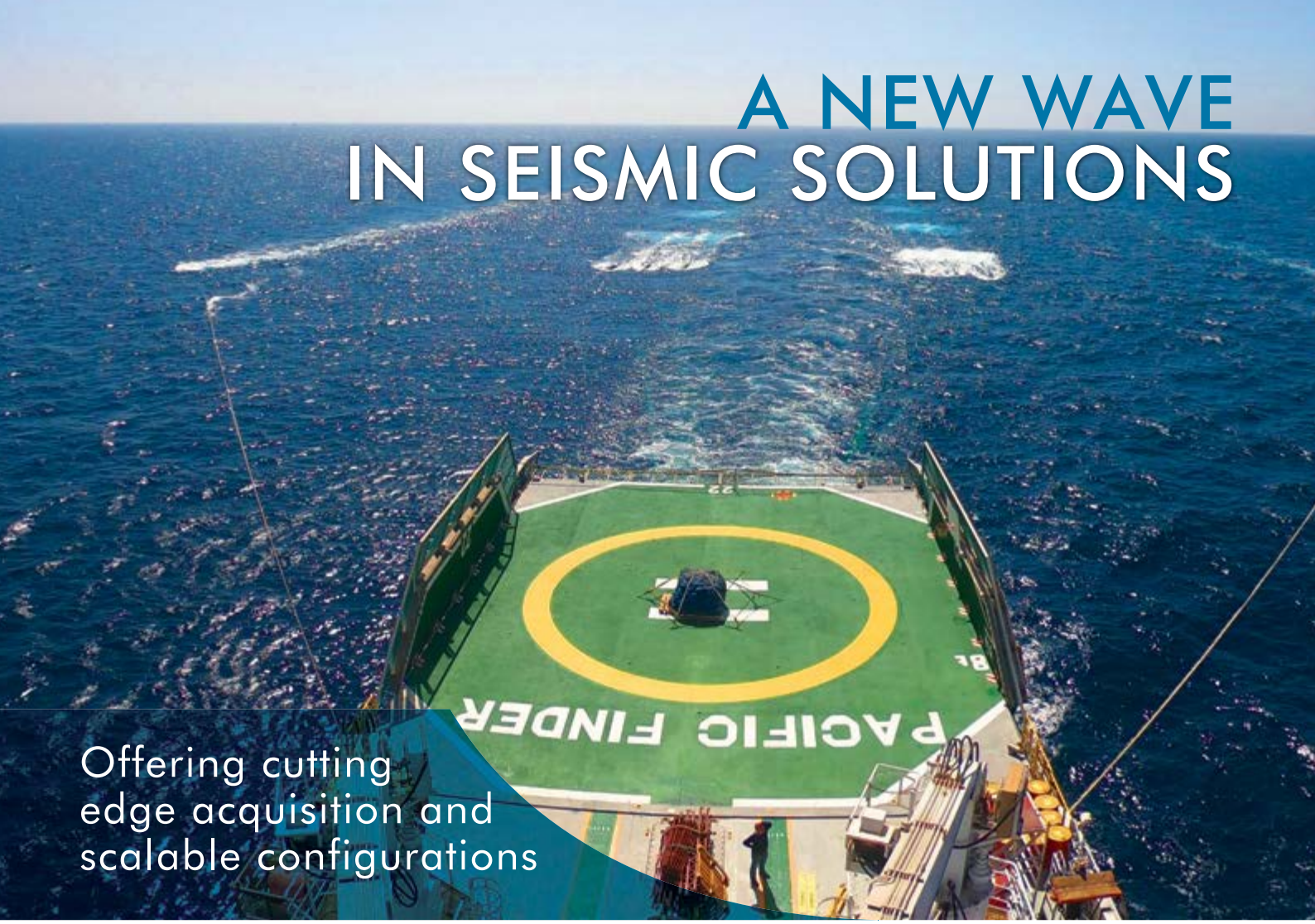

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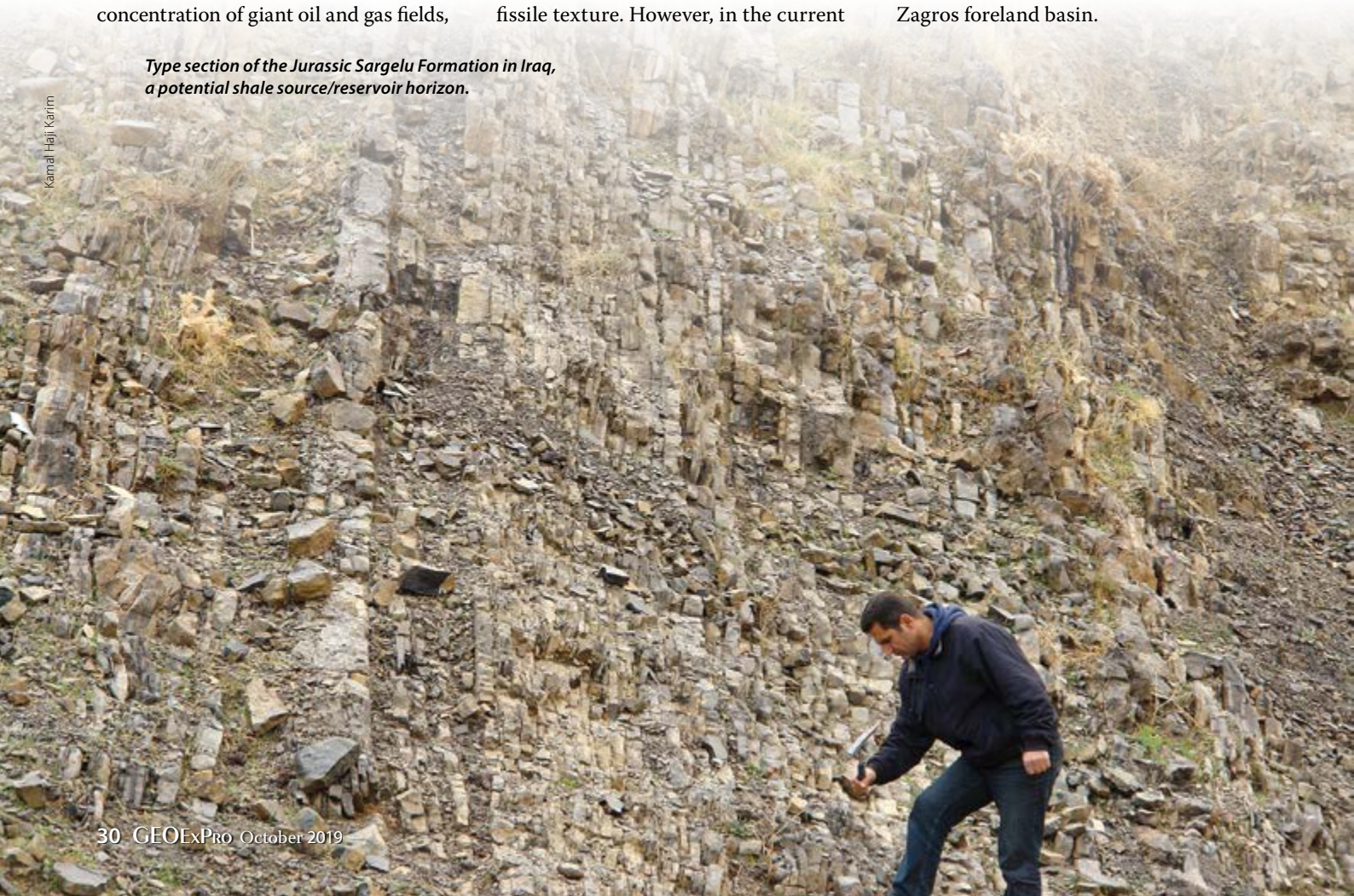
Shale Plays of the Middle East

The Middle East is best known for its conventional oil and gas reserves, which have been a critical part of the world's supply for nearly a century. Could the US shale revolution be transferred to the Middle East? Maybe – but geology is not the only factor in the shale revolution.

RASOUL SORKHABI, Ph.D.

The shale revolution in the USA has been phenomenal. Thanks to horizontal drilling and hydraulic fracturing technologies, shale has doubled US oil production from nearly 5 MMbopd in 2008 to 11 MMbopd in 2018. In the same decade, US annual natural gas production increased from 21.1 Tcf to 32.7 Tcf. The shale revolution has been limited so far to a few basins and plays in the US: the Permian, Barnet and Eagle Ford in Texas, the Bakken in North Dakota, and the Marcellus in the Appalachian east. However, all conventional petroleum basins around the world also contain large volumes of organic-rich shale formations. Since the Middle East has the largest concentration of giant oil and gas fields, its prolific source rock formations should offer enormous opportunities for stimulation and production. The Palaeozoic to Cenozoic sediments constitute a 12 km-thick volume of sediments on the Arabian platform and Zagros foreland basin, and almost every stratigraphic period contains at least one shale formation over a hundred metres thick, either distributed regionally or concentrated in specific countries. These shale plays remain unexploited.

The term 'shale' in geology specifically refers to a laminated (fissile), indurated, fine-grained sedimentary rock in which clay-sized minerals predominate. Shale is essentially mudstone but with a fissile texture. However, in the current petroleum industry 'shale' has been used in a too broad sense, including any fine-grained, low-permeability sedimentary rock – mudstone, shale, siltstone, marl and chalk – that requires hydraulic fracturing to produce oil and gas. Here I reluctantly adopt this current industry use but exclude the purely limestone and dolomite formations which occur so abundantly in the Middle East stratigraphy. What follows is a general outline of the Middle East shale horizons; local variations in depositional environment, unconformity, thermal maturity, and organic richness are plentiful. Overall, the formations become deeper from the western Arabian platform toward the Zagros foreland basin.



Type section of the Jurassic Sargelu Formation in Iraq, a potential shale source/reservoir horizon.

Kamal Haji Karim

Geologic Framework

The Middle East has prolific oil fields because it has inherited a unique set of geological conditions that favour the generation and accumulation of large oil reserves on the Afro-Arabian platform of Gondwana (see *Why So Much Oil in the Middle East*, *GEO ExPro*, Vol. 7, No. 1). During Palaeozoic-Mesozoic times, for nearly 500 million years, the Middle East was a vast, stable continental shelf facing the east-west running Tethys Ocean. The continental shelf was 2,000–3,000 km wide and at least 6,000 km long. During Cenozoic times, foreland basins formed by the collision of the Arabian-Asian plates and uplift of the Zagros-Taurus mountains and filled with 3,000m thick sediments, were superimposed onto the shelf sediments. In this manner, the shelf sediments, including organic-rich shales, were deeply buried and preserved.

Regionally distributed shale formations in the Middle East cluster in three stratigraphic groups: Ordovician–Silurian, Jurassic–Cretaceous, and Paleocene–Eocene. Early Palaeozoic periods were characterised by rapid radiation of life forms as well as a global rise in sea levels. During warm Jurassic–Cretaceous times, the Tethys Ocean was at its highest level and located in plankton-rich equatorial latitudes, which favoured deposition of organic-rich, anoxic deepwater shale sediments. A third group of shale formations belonging to the Paleocene–Eocene periods were deposited in foreland basins atop the shelf sediments.

A regional tectonic map of the Middle East.

Infra-Cambrian and Deep Palaeozoic Shales

The Huqf Group of Oman contains the best known Infra-Cambrian source rocks to have generated oil, stored not only in Permo-Carboniferous reservoirs but also within the Huqf Group itself ('Q' reservoir as encountered in Runib Field in southern Oman). The group consists of alternating carbonates, siliciclastics, and evaporates deposited in a deep, restricted and anoxic basin. The calcareous mudstone of the Shuram Formation (up to 600m thick) and the dolomite and shale sediments of the Ara Formation (up to 1,700m) are the major organic-rich source rocks. In many fields, the Ara Shale (with kerogen type II possibly of cyanobacterial origin) is still within the oil and gas windows; it is capped by Ara Salt, equivalent of the regional Hormuz Salt (beneath the Cambrian sediments) in the Persian Gulf.

Lower Palaeozoic formations in the Middle East greatly vary in thermal maturity depending on their burial depth; in the Zagros foreland basin, for example, they have been often metamorphosed to micaceous quartzite level. Upper Palaeozoic source rock formations are not continuous across the Middle East due to sea-level fall and tectonic disturbance toward the end of the Palaeozoic.

Notable Cambrian shale formations

Palaeozoic shale plays of the Middle East (compiled by Rasoul Sorkhabi).

	SE TURKEY	SYRIA	IRAQ	SAUDI ARABIA	KUWAIT	SW IRAN	QATAR	UAE	OMAN
PERMIAN	Gomani-ibrik Harzo			Khuf	Khuf	Dalan	Khuf	Khuf	Khuf
CARBONIFEROUS		Sawanet							
DEVONIAN	Koprulu			Jauf					Misfar
SILURIAN	Handof Dadas	Tanf	Mudaw-wara	Qusaiba		Gahkum	Shawara		Safiq
ORDOVICIAN	Bedinan	Sawab		Hanadir					Safiq
CAMBRIAN	Sosnik			Pre-Saq					Miqrat
INFRACAMBRIAN									Ara Shuram

deposited in fluvial to marginal marine environments in the Middle East include the Pre-Saq Formation (Lower Cambrian) in Saudi Arabia, Lower Haima (Miqrat) in southern Oman which has charged oil and gas in the Upper Haima clastic sediments, and the 1,000m-thick Middle Cambrian Sosnik Shale in south-eastern Turkey.

Ordovician shale formations were deposited in continental to marginal marine environments and have different stratigraphic names: Hiswa (Jordan), Bedinan (Turkey), Sawab (Syria), Hanadir (Saudi Arabia), and Safiq Shale in Oman (which extends into the Lower Silurian).

	SE TURKEY	SYRIA	IRAQ	SAUDI ARABIA	KUWAIT	SW IRAN	QATAR	UAE	OMAN
EOCENE		Jaddala	Jaddala			Pabdeh			Andhur
PALEOCENE	Sinan	Aaliji	Aaliji			Pabdeh			
UPPER CRETACEOUS	Kastel-Germav Kiradag	Shiranish Soukhne	Shiranish Sarmord		Mishfir Mauddud Burgan	Gupi Ilam Sarvak	Mishfir Khatiyah Mauddud	Khatiyah Mauddud	Natih
LOWER CRETACEOUS	Karababa Derdere	Qam-chuaqa Rubtah	Zubair Ratawi Garau	Sulaiy	Zubair Ratawi Minagish	Kazhdumi Gadvan	Shuaiba Ratawi	Shuaiba	Shuaiba
UPPER JURASSIC			Chia Gara Naokele-kan	Hanifa Twaiq	Najmah		Hanifa	Dukhan	Diyab
LOWER-MIDDLE JURASSIC		Sargelu	Sargelu	Dhurma Marrat	Sargelu Marrat	Surmeh	Izhara		
TRIASSIC	Aril?	Kurra Chine Amanus	Kurra Chine Beduah	Minjur Jilh					Jilh

Mesozoic-Paleocene shale plays of the Middle East (compiled by Rasoul Sorkhabi).

The Silurian is marked by a major petroleum source rock that was widely deposited in an open marine environment in the Middle East and North Africa. This marine 'hot shale' (as characterised by high gamma logs) is also named differently in various countries: Tanezzuft (Libya), Kohla (Egypt), Qusaiba (Saudi Arabia), Mudawwara (Jordan), Tanf (Syria), Akkas (western Iraq desert), and so forth. The Silurian shale has been well studied as it has generated gas as well as light crude, stored in Mid-Upper Palaeozoic reservoirs. The Qusaiba hot shale in Saudi Arabia ranges in thickness from 250m in outcrop to over 1,000m in the basin and has an average TOC of 4–5% (Cole et al., 1994).

A few organic-rich Devonian shales exist locally, such as Koprulu in south-east Turkey, Jauf in Saudi Arabia, and Misfar in Oman. The Permian-age Khuf Formation (and its equivalents), consisting of limestone, dolomite, shale and anhydrite, was widely deposited under tidal and shallow marine conditions in the Middle East. The formation often acts both as a reservoir and source rock.

Mesozoic Shales

Triassic source-rock formations, notably Kurra Chine in Syria and Iraq and Jilh in Saudi Arabia and UAE, consist of dolomite, shale and anhydrite, and were deposited in a shallow marine environment.

The richest and thickest petroleum source rocks in the Middle East belong to the Jurassic and Cretaceous periods. In some fields, multiple Jurassic and Cretaceous deepwater shale horizons, highly organic with kerogen type II, are present. These Mesozoic formations may be the most feasible shale plays to develop, although they are predominantly marlstone and bituminous limestone, and their calcareous nature may respond differently to fracking than siliceous shales such as Barnet. The Jurassic sediments are capped by evaporate rocks.

Chemical studies of the Jurassic Sargelu Formation in northern Iraq by Roger Abdula (2010) show that Sargelu has a rather uniform lithology with variable thickness from 25 to 485m and that its richest horizon has TOC values of 11%. The same formation in Iran has given TOC values of 3–4% (Bordenave and Bruwood, 1990).

Above the uppermost Jurassic evaporate deposits, several source rock formations of Cretaceous age are regionally present and are known by different stratigraphic names. These source rocks, mainly black shale and argillaceous limestone, have generated light crude stored in multiple Cretaceous carbonate reservoirs. The stratigraphic thickness and organic richness of these Cretaceous sources are remarkable: the Kazhdumi black shale in the Zagros Basin of Iran, for instance, reaches up to 450m and has TOC values of 3–12%.

Paleogene Foreland Shale

With the subduction of the Tethys Ocean beneath the Asian continent, the tectonic regime on the Arabian platform changed to the continental collision, uplift and foreland sedimentation that has characterised Middle East geology for the past 50 million years. The shallow marine shale formations of Paleocene age in the foreland basins have proved to be effective petroleum source rocks. These are known by different stratigraphic names: Taqiya (Jordan), Aaliji (Syria and norther Iraq), Pabdeh (Iran), and Um Er Radhuma (southern Iraq, UAE and Qatar). The Sinan Formation of Maastrichtian-Paleocene age in south-east Turkey consists of dark-grey limestone and marl and has proved to be a source/reservoir rock in both the Selmo and Selmo West fields.

Some Eocene shale horizons are also potential source rocks, such as the Jaddala Formation in Syria and northern Iraq, Andhur in Oman, and Jeza in Yemen. In many parts of the Middle East the Paleocene–Eocene rocks are capped by evaporates, thus preserving these petroleum systems.

Shale Gas

For Iran and Qatar, respectively the second and third largest repositories of natural gas in the world (Russia being number one), shale gas may not be of a high priority. However, for some Middle Eastern countries, especially Saudi Arabia and UAE, which are in dire need of natural gas for electric power and residential use, the prospect of shale gas produced from their own fields is enormously attractive. Ahmad Kenawi, Halliburton's vice-president for the Middle East and North Africa, recently reported that the national oil companies of Saudi Arabia, Oman, Bahrain and

Kuwait are seriously looking into how they can develop their shale gas resources. Saudi Arabia started its first commercial production of shale gas from the North Arabia field in May 2018 and supplied 55 Mcfgpd to a power plant in Wa'adi Al Shamal in the north of the country.

Shale gas reserves in Saudi Arabia are estimated to be more than 600 Tcf – twice the amount of conventional natural gas in the country. Saudi Aramco has focused on three specific areas for development of shale gas. These are the Ghawar field, which is the world's largest oil field; the Jafurah Basin, located close to Ghawar and expected to be the Eagle Ford of Saudi Arabia; and the vast Rub al-Kahli Basin in the south of the country.

Challenges to Development

Despite the widespread occurrence of shale formations in the Middle East, there are several important obstacles to the development of these plays. Currently, production from conventional carbonate reservoirs is more economic for Middle Eastern petroleum companies. Decades of drilling and production have provided ample information about these reservoirs, while production from the shale formations will require new data on reservoirs and oil quality in addition to deep drilling and the necessary infrastructure and strategies, all of which will require major financial investment. As long as oil prices remain at the current level, the Middle Eastern companies will have little commercial incentive to develop their shale plays; indeed, production from these new plays may even reduce oil prices further.

Moreover, developing shale plays requires huge amounts of fresh water for hydraulic fracturing (several millions gallons of water per horizontal well as in the US), but there is an acute shortage of fresh water in the Middle East, with low precipitation and a largely arid climate. This climatic constraint will persist on a long-term basis. Dry (gas) fracking, when developed fully, can provide a workable solution. Fluid-induced seismicity associated with shale stimulation is another major obstacle in those parts of the Middle East criss-crossed by active faults of various sizes.

While the shale geology is highly promising in the Middle East, the region faces economic and technological challenges to develop these resources. As in the US, the shale revolution in the Middle East will perhaps be triggered by shale gas in certain fields.

References available online. ■

Wadi Nahkr in Oman comprises primarily the Upper Cretaceous Natih Formation, a potential shale play.

From Arrhenius to CO_2 Storage

Part IV: Challenges and Some Practical Issues

MARTIN LANDRØ, LASSE AMUNDSEN and PHILIP RINGROSE

> *"If you really could take the CO_2, when you burn hydrocarbons – coal, for example – if you could really capture the carbon and sequester it – they call it CCS – if the extra capital cost, energy cost, and storage costs over time didn't make it super expensive, then that's another path that you could go down."*
>
> *Bill Gates, February 2016*

The basic idea behind CCS (Carbon Capture and Storage) is simple: put the unwanted CO_2 back into the ground again, like fishermen put leftover fish parts into the ocean. At the moment there are about 20 projects worldwide focusing on practical and economic issues related to this ambitious plan. Given the public interest in climate change related to CO_2 emissions, this number is surprisingly low. Is this due to economic constraints, technological challenges or long-term risk? We will briefly discuss the technological needs for CCS and focus more specifically on the storage part, although both capture and transportation are key bottlenecks for future CCS.

Diverse Views

Views on CCS are many and diverse. In an article in the *Financial Times* from 2015, Pilita Clark summarised different views and several important issues, the most important of which are, firstly, how to capture CO_2 from power plants, gas reservoirs, cement factories and the like, and secondly, how to transport and store it without leakage to the atmosphere.

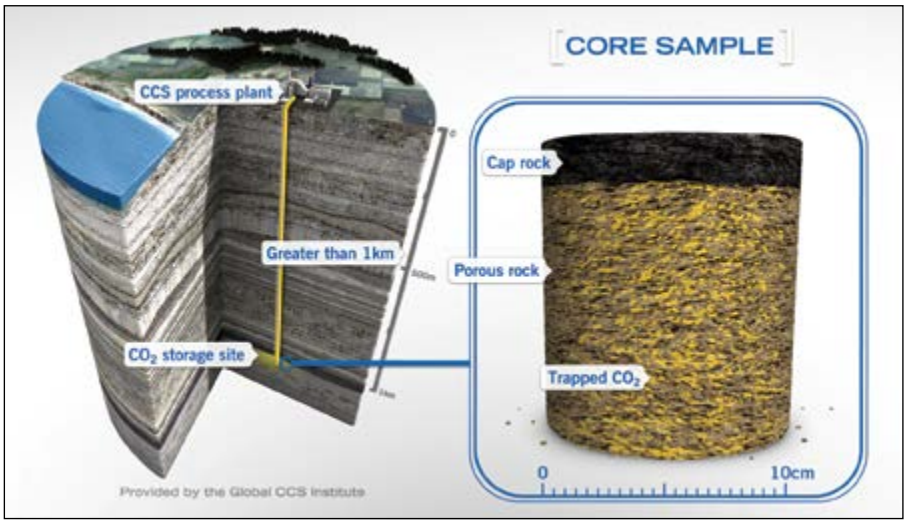
Arguments are often a mixture of economics, technological challenges, risk assessment and concerns that CCS might serve as a dangerous extension of the hydrocarbon era. On one hand fossil fuels accounted for over 80% of total energy demand, a level that has remained stable for more than three decades. All forecasts report this dependency will continue, as alternative energy sources will take many years to replace hydrocarbons

Since 1996, Norway's Sleipner field has been used as a facility for carbon capture and storage and about 1 million tonnes of CO_2 is captured and stored each year. This is the longest ongoing CO_2 storage project in the world.

Øyvind_Hagen/Equinor

– so taking responsibility for the emissions resulting from them is important. But many people believe that pushing CO_2 underground only creates further problems, lowers energy efficiency, and prolongs the use of fossil fuels.

This article does not intend to discuss these views in detail; the major point is that CCS is a political issue, and the politicians are facing a tremendous dilemma, driven by the enormous costs of engaging in climate action and a growing public clamour for action. Whether CCS becomes a significant technology to reduce atmospheric CO_2 within the next two or three decades remains to be seen. However, here we want to discuss how geoscience and various other disciplines might interact to ensure that if CCS is undertaken it is done in a responsible manner.



Where to Store CO_2?

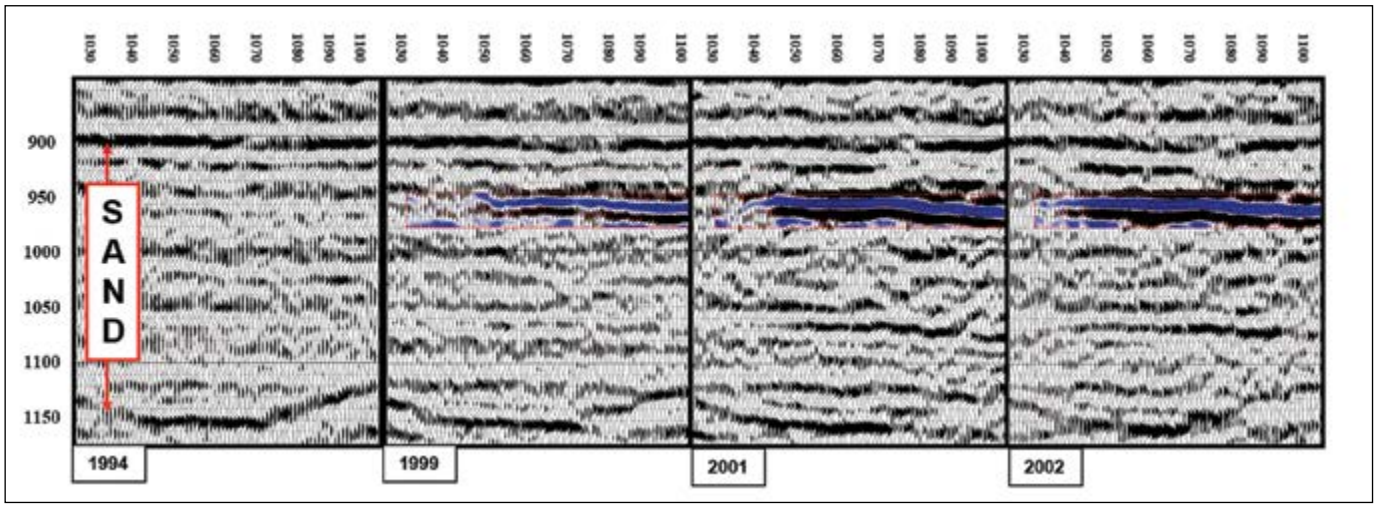
Several proposals have been made over the past decades on where to store large amounts (megatons to gigatons) of CO_2. The ocean was initially suggested as a potential storage possibility, but this is no longer regarded as a safe or environmentally friendly choice. The most realistic option today is subsurface storage in shallow aquifers or mature hydrocarbon fields. Furthermore, public concerns about possible risks associated with subsidence and damage to buildings generally excludes subsurface storage volumes below densely populated areas. Hence a more realistic option is to store CO_2 offshore. The Norwegian Petroleum Directorate has investigated this potential in depth and estimated that roughly 60–70 Gtons of CO_2 can be stored offshore Norway. (This study will be further discussed in the next issue.) At the moment, there seems to be an agreement that storage of CO_2 should preferably be offshore, or in remote onshore areas where subsidence risk is easy to control and handle.

Kiran Sathaye et al. published an interesting article in 2014, in which they estimate that 1.3 Gigatons of CO_2 is at present stored at the Bravo Dome in New Mexico – and furthermore, they show that the CO_2 has been there for approximately 1.3 million years. The reservoir is the Permian Tubb sandstone at a depth of 700m and is sealed by an overlying anhydrite layer. Reservoir porosities vary between 10 and 20%, and permeabilities between 1 and 100 mDarcy. The reservoir pressure measured in 1981 was found to vary from 2 to 14 MPa for different locations in the field. Production started in 1981, and the extent of the field is gigantic: 3,600 km^2. The Bravo Dome contains 99.8% CO_2 and it is estimated that approximately 10% of the CO_2 was dissolved during its emplacement, and another 10% was dissolved into the underlaying aquifer. Sathaye et al. concluded that "1.3 Gt of CO_2 have been safely contained at Bravo Dome at 700m depth for more than 1 million years without detectable leakage to the surface".

Earthquake Risks

There are several risks a regulator or operator of a CO_2 storage site needs to consider, including injectivity, storage capacity, effectiveness of sealing units, well integrity and the risk of induced earthquakes. In 2012, Zoback and Gorelick created a stir with a publication about induced earthquakes, in which they stated: "There is a high probability that earthquakes will be triggered by

A CCS project in Alberta, Canada.



Time-lapse seismic data showing monitoring of the CO_2 injection at Sleipner. The strong amplitude increase (shown in blue) is interpreted as a thin CO_2 layer. The dashed red lines indicate top and base of the Utsira sand layer (figure modified from Ghaderi and Landro, 2009).

injection of large volumes of CO_2 into the brittle rocks commonly found in continental interiors." They went on to question the feasibility and value of CCS as a strategy for significantly reducing greenhouse gas emissions. There were many responses to this paper, most notably the response by Vilarrasa and Carrera (2015), who argued that: "Geologic carbon storage is unlikely to trigger large earthquakes and reactivate faults through which CO_2 could leak."

The discussion concerns whether or not storage units are critically stressed, the degree to which injection pressure can be managed, the role of capillary forces and the rates of CO_2 dissolution in the water phase. Several industrial-scale storage projects have now monitored induced micro-seismicity. For example, at the Weyburn-Midale Carbon Dioxide Project in Saskatchewan Canada (Verdon et al., 2013) showed that the long history of the field had led to a complicated pattern of micro-seismicity, with most events related to production wells and not CO_2 injection. Risks related to CO_2 injection will no doubt continue to be aired, but the 'proof of the pudding' will likely emerge from real projects.

One of these is the Quest carbon capture and storage facility, near Edmonton, which has now been in operation for four years and has injected 4 million tonnes of CO_2 so far. Not only does this project add new experience to the earlier Norwegian projects like Sleipner, the world's first project for geological storage, but these recent projects were able to make use of more advanced monitoring and listening tools, like digital temperature sensing and distributed acoustic sensing to monitor the plume more cheaply and for recording seismic events (Mateeva et al., 2014). The demonstrated ability to use time-lapse vertical seismic profiling as a means of cost-effectively monitoring plume growth is particularly interesting.

The 'Northern Lights project' is the transport and storage part of the ambitious new plans for a Norwegian full-scale CCS project. It is led by the state enterprise Gassnova, who are charged with finding solutions to ensure that technology for capture and storage of CO_2 can be implemented as an effective climate measure. The oil/energy majors (Equinor, Shell and Total) have been tasked with executing this project, which is currently in the design phase and leading up to an investment decision in 2020. In describing the project, Furre et al. (2019) explain how experience from the previous Sleipner and Snøhvit CO_2 injection projects has been vital in reducing uncertainties for the new venture. Both the Sleipner and Snøhvit schemes encountered early surprises on injectivity and plume growth, which were handled using standard (but expensive) offshore well operations, guided by time-lapse seismic. Arguably, it was actually the power and precision of time-lapse seismic imaging, which allowed site operators to see 'where the CO_2 was going' that ultimately enabled these projects to proceed successfully.

So is it Expensive?

It really depends on how you look at this question. Large-scale CCS projects do cost in the order of $1 billion – they are sizeable infrastructure developments. When you break the projects down into capture costs and storage costs per tonne of CO_2 then we are talking of around $50–150 per tonne for capture but only $10–20 a tonne for storage. However, once large CCS infrastructure projects are in place, the cost of adding additional volumes starts to drop significantly. The current Norwegian CO_2 emissions tax of around 50 Euro/tonne makes some projects, like Sleipner, economically viable. But the price of emitting CO_2 to the atmosphere would need to rise to around 100 Euro/tonne before widespread CCS deployment could become economically viable. In the meantime, governments will need to stimulate CCS infrastructure (as they currently are doing in Norway, Canada and the USA) if they wish to accelerate CO_2 disposal technology.

The ideal scenario is that the costs of deploying CCS technology gradually fall as the penalty for emitting greenhouse gases to the atmosphere rises. That may turn out to be too idealistic. It then becomes a societal question – how much do we really want to reduce CO_2 emissions? The younger generation seems to be saying 'by a lot' and 'as soon as possible'.

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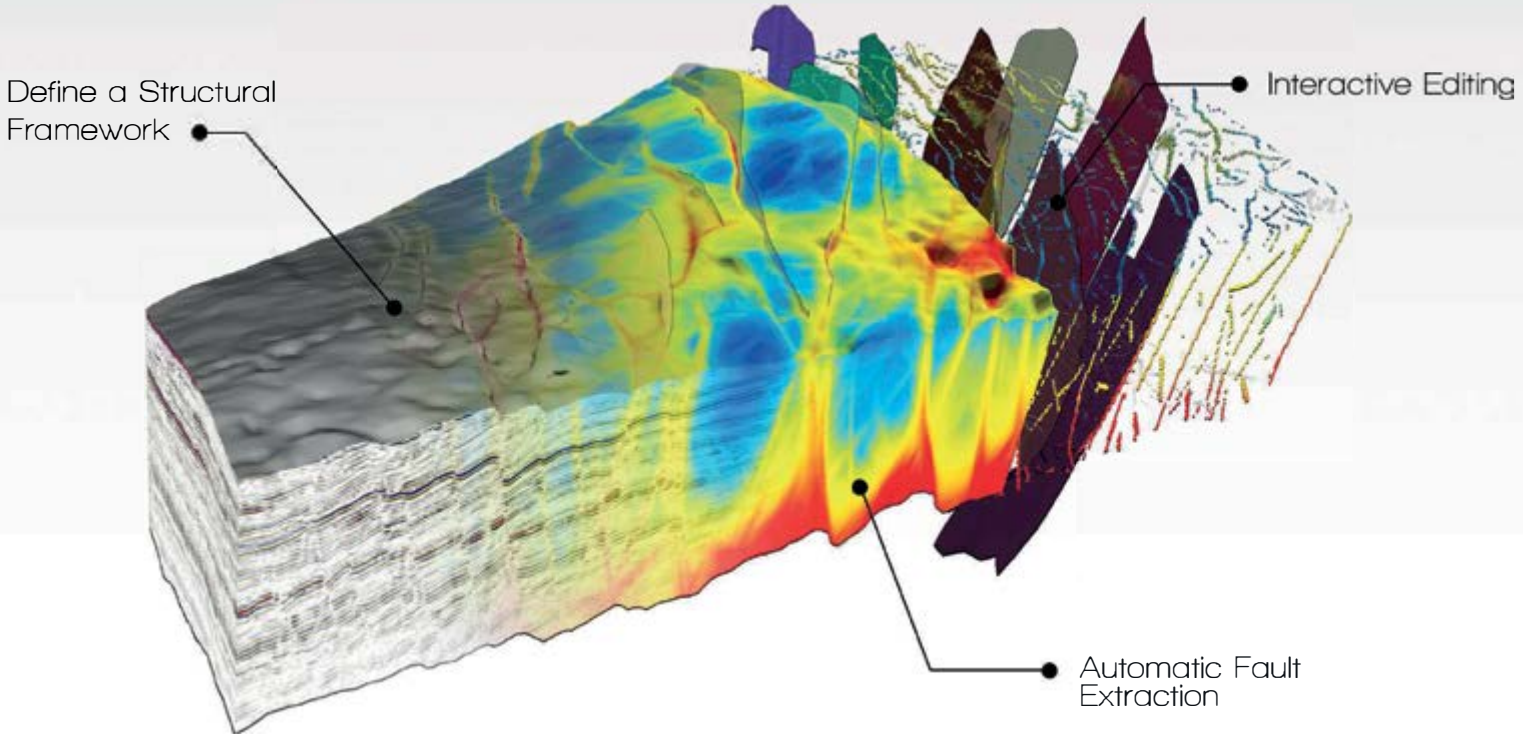

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Maggy Shino: Championing Namibia

JANE WHALEY

Maggy Shino is Petroleum Commissioner at the Namibian Ministry of Mines and Energy. An environmental scientist and petroleum geochemist, she is passionate about finding and utilising the resources that will help her country progress.

Maggy Shino describes herself as an inquisitive child who was drawn to science, a subject she excelled at in school. Therefore, it was no surprise that at the University of Namibia in Windhoek she chose to study environmental biology and chemistry; the surprise came later when she made a conscious decision to move into geology.

"My first job was as an energy researcher in the Ministry of Mines and Energy, which entailed trying to find alternative sources of energy and seeing if they were suitable to be included in the energy mix for Namibia," Maggy says. "I was mostly focused on renewable energies, identifying which would be most appropriate for the country. Of course, we have excellent exposure to solar energy – one of the best in the world – but we also have plentiful wind resources, especially in the southern part of the country. In addition, we use biomass for energy and one of my roles was to ensure it was used in the most efficient and sustainable manner. And one of the oldest sources of energy for power in Namibia is hydropower."

Change of Direction

After a year as an energy researcher, observing the challenges and limitations of renewable energy technologies, Maggy made a conscious decision to explore alternative ways in which she could advance her country's energy needs.

"When I joined the Ministry, my division had two sub-divisions: electricity generation and petroleum," she explains. "I observed that the upstream section of the petroleum directorate was quite inactive and that was because, at that time, there were virtually no qualified petroleum geoscientists in Namibia able to work in those roles. I developed a professional interest in that side of the energy spectrum and through personal research on Namibian geology, two thoughts kept lingering in my mind. The first was that, with one gas discovery already made, surely it is impossible for Namibia not to have oil, and secondly, why can't the discovered natural gas be utilised as an additional energy resource for Namibia?" And so she decided to enter the sector by studying for a master's degree in petroleum geochemistry at Newcastle University in the UK.

This was a big change, but Maggy settled in quickly and enjoyed her year there. "It was the first time I had lived outside my country, but Newcastle is a nice city, and in terms of its set-up and environment I found it quite similar to Windhoek. It's not as overcrowded as many European cities and the people are very friendly, so it was easy to settle. All the international students lived close to one another, so it was easy to meet people. There were fellow students from Ghana, Nigeria, Zimbabwe and Greece in my residence and I was exposed to many different cultures. We were all away from home and we all had different expectations and experience, so we could learn from each other; the year went by very fast. Because I didn't have geology in my first degree I had to have some assistance to bridge the gaps in that subject; it was a lot of work but I enjoyed it."

Hands-On Training

"When I went away to study geoscience, there were only two licences in Namibia, but since then interest has picked up and more companies have seen potential in the country, so we are getting a lot more interest and activity," Maggy continues. "Five petroleum geoscientists now work in the department, monitoring the work programmes to ensure the agreements of the awarded licences are followed. They also make G&G contributions and give guidance and provide technical advice for the work programme.

"For me and the other Namibian geoscientists it has been

Maggy speaking on a panel at Africa Oil Week 2018. She will also be speaking at the 2019 event.

very useful to have inhouse training through the companies working in Namibia. The ministry arranges these opportunities with the licensees through the petroleum agreements, to give us good exposure to hands-on geological training and to allow us to work on projects in the field environment and on courses tailor-made for the industry. For example, after completing my masters I gained a diploma in upstream management of petroleum development and operations – a bit like a mini MBA for the petroleum sector – at the PETRAD institution in Stavanger.

"Namibian geoscientists also shadow counterparts in the industry to get them fully up to speed on all aspects of exploration. I was attached to projects where I was able to work in the field in an operational way, including drilling the Kuneme 1 well, where I was 100% part of the crew, logging the well and gaining from the experience of the operator. In this way I was able to practise the theoretical work I had learnt and come up to speed on the project management side of the job."

While you can now undertake a basic geoscience degree and a petroleum geology MSc in Namibia, geoscientists still go abroad to train in specialist subjects, using scholarships provided through Petrofund, which licensees pay into as part of their capacity building obligation.

An Exciting Role

With her petroleum geochemistry degree successfully completed, Maggy returned to the ministry as a petroleum inspector in the energy sector, ensuring regulations with regard to HSE were complied with. She then moved into a role as a petroleum geoscientist and rapidly climbed the professional ladder to her present position as Petroleum Commissioner at the Namibian Ministry of Mines and Energy, a position she has held since 2015.

"The Petroleum Commissioner is a very exciting position. I am responsible for the exploration activities searching for oil and gas on the Namibian continental shelf, while ensuring that we minimise the negative impact of petroleum resources exploitation on the environment and contribute to value creation for society from petroleum activities," Maggy explains. "It is really a project management role, requiring a broad spectrum of knowledge. I need to understand the relevant administrative aspects, as well as have industry understanding. I am involved throughout the process, from attracting investment right through to spearheading negotiations with potential operating partners and monitoring the execution of petroleum agreements.

"I'm very aware that we are in competition for exploration investment funds with many other countries," she adds. "One of my roles is to provide input so that as a frontier petroleum nation we make policies that will attract the right investors. It is important that companies looking at Namibia have access to the information that they need to make these decisions, so we provide technical advice and manage data rooms so the information is available for them. We now have a huge technical knowledge in-house as well as large quantities of data and we want to make sure


Rosalind Julia

Maggy Shino's contribution to the industry as a woman was recognised in 2017 when she was awarded the Global Women Petroleum & Energy Club Award for Africa. She considers that receiving this award, which she is seen holding here, was a great honour.

that potential licence holders are aware of and make use of this; we don't want anyone 'reinventing the wheel'! We also talk to potential service providers to enter into collaboration and assistance to advance our technical knowledge through, for example, multiclient seismic acquisition and technical studies. All data belongs to the Namibian government, and we work with our national oil company to make certain that this data is managed in an efficient and easy-to-access manner.

"Hopefully, this can have a meaningful impact on the decisions that companies make and on their work programmes and ultimately lead to discoveries," she concludes.

Energy Mix Needed

Did Maggy ever imagine when she decided to study geoscience that she would end up as Petroleum Commissioner?

"No, not at all!" she laughs. "My dream when I got this urge to study petroleum upstream was to help Namibia. I saw the limits of energy availability and of what we could do with the energy resources we were using. We were a net importer of electricity; I saw how limited our capabilities for electricity storage from solar power were; how women in the rural villages were still cooking with firewood; how their lives were limited by the amount of time they spend collecting wood and by lack of electricity in the evening – and I thought 'there has to be another source of energy out there that Namibia could have access to'. I felt strongly that if there is oil in Namibia, we needed to discover it, and my dream was to contribute however I could to this.

"I would like to see Namibia using the full mix of energy resources, from renewables to petroleum products – but the former can't fill the gap fast enough. If we have oil and gas in our subsurface we need to look for it, locate it and bring it to the surface. Accessing that natural resource would not only help cover the energy needs of our country but would also provide huge economic benefit to the people of Namibia, bringing in much needed revenue and helping us move towards self-sufficiency. I strongly believe that a significant discovery will be a game-changer for the country.

"Technically we have advanced very far in recent years," she adds. "We have the Kudu gas field, an uncommercial discovery in the offshore Walvis Basin, and a number of other wells with shows on and offshore, so we know there are active petroleum systems in several basins – but we are still searching for all the required elements to come together to give us a significant commercial discovery. I think the chances of that happening soon are quite high. The next drilling campaign will look at a deepwater play we haven't tested before; we hope the operator, Total, will duplicate its recent South African success. In addition, Maurel et Prom and partners are planning on testing a diversity of plays with upcoming wells in the Walvis Basin.

Unchanging Ambition

Maggy and her husband were both born and brought up in the rural north of Namibia, and while they live and work in the capital, they both enjoy returning to their roots whenever possible. "In the north the lifestyle is much simpler," Maggy explains. "We are subsistence farmers who still tend animals and grow and eat our produce, and family is very important. Our two children, (a daughter and a son, aged 6 and 3), spend a lot of time there with their grandparents and love it. This double life is part of Namibian culture; many people return to the simple village life when they retire.

"Until recently, whether in the field or round the negotiating table, I have been the only woman, but I haven't found that this male-dominated environment has inhibited me," Maggy adds. "In fact, I think it has been character-building and toughened me up! I've always told myself that whatever a man can do, I can do better! Because of that I have progressed well. Also, Namibia as a country has developed policies to encourage equal opportunities for women in the workplace and I think that has enabled me to get the support I needed. I am pleased to see quite a lot of young Namibian women now making a career in the oil industry.

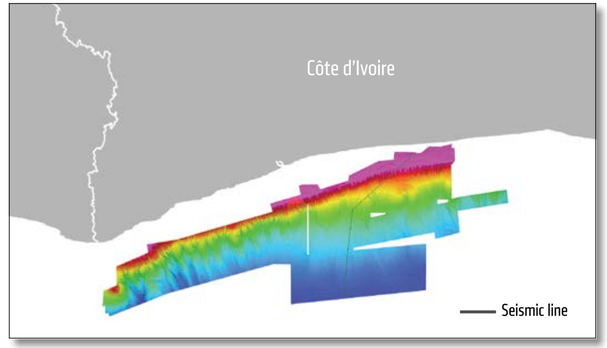
"I love the fact that in this job there are always new challenges and experiences; nothing stays the same. I've been to many different places and met and worked with interesting people across a wide spectrum of cultures, which is one of the most interesting aspects of my role. Relationships really determine whether a deal will work or not.

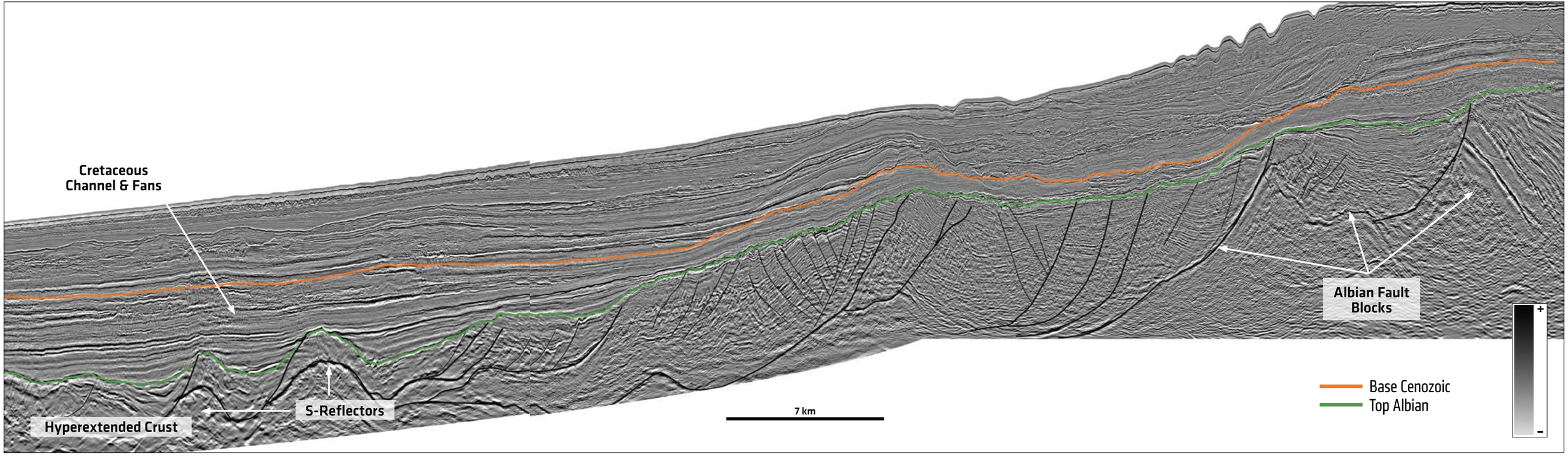
"I still have the ambition that I started with," she adds. "I want to make the discovery that will make a difference to my country. But I also want to ensure Namibia is ready as a nation so that discovery will be a blessing to everyone. My ambition is to see that through as far as I can – that would be my life achievement." ■

Côte d'Ivoire

Regional Understanding to Unlock Potential

Offshore Côte d'Ivoire is a well-established petroleum province, particularly in the eastern areas. Exploration is now moving into the more frontier region of the western Côte d'Ivoire Basin. To support these efforts PGS, in partnership with Petroci and Direction Générale des Hydrocarbures, has created a fully matched and merged contiguous dataset comprising full stack GeoStreamer 3D, conventional 3D and accompanying 2D across 23,000 km² offshore Côte d'Ivoire. The PGS Côte d'Ivoire MegaSurvey now allows exploration and detailed regional evaluation for the first time, allowing plays to be effectively developed and risked.





Extending Exploration Potential to Western Côte d'Ivoire

Regional seismic data allows plays to be interpreted in full for the first time across the Côte d'Ivoire.

WILLIAM POWELL and AVRIL BURRELL, PGS; IBRAHIMA DIABY and MARCELLE GAULY, Petroci

Exploration in Côte d'Ivoire has historically been focused on the central and eastern areas where numerous hydrocarbon discoveries have been made. These include a trend of gas discoveries in Upper Cretaceous stratigraphic traps (Foxtrot, Panthere and Marlin fields) and oil discoveries in Lower Cretaceous structural traps (Lion, Espoir, Acajou, Baobab and Kossipo fields). The Capitaine East-1X (Lukoil) and Paon (Anadarko) discoveries have proven the prospectivity of Upper Cretaceous oil-bearing stratigraphic plays in the deep water.

These exploration successes have encouraged explorers to look further afield in tectonically complex areas of the western transform area controlled by the St. Paul's Fracture Zone. The Morue-1X well (Anadarko and Total) and Saphir-1X well (Total) have shown a working hydrocarbon system in the previously underexplored western portion of the basin.

Development of the Ivorian Transform Margin

Côte d'Ivoire is part of the West African transform margin, a large tectonically constrained area bounded by a series of major fracture zones which formed during the separation of the African and American continents in the late Jurassic to Cretaceous.

An overview of the tectonic framework using Bouguer corrected Smith and Sandwell gravity data (right) outlines the key structural features of the Côte d'Ivoire Basin. The development of the Ivorian embayment was controlled by a segment of the Atlantic rift delineated by the St. Paul's fracture zone in the north and the Romanche fracture zone to the south. From east to west the crust transits from continental material with a low gravity response into increasingly dense oceanic crust. Along the northern margin this transition occurs more rapidly due to the area's proximity to the transform fracture zone. Using the PGS Côte d'Ivoire MegaSurvey seismic data, hyperextended crust can be delineated in the transitional area, providing potential for new play concepts and increased understanding of basin development.

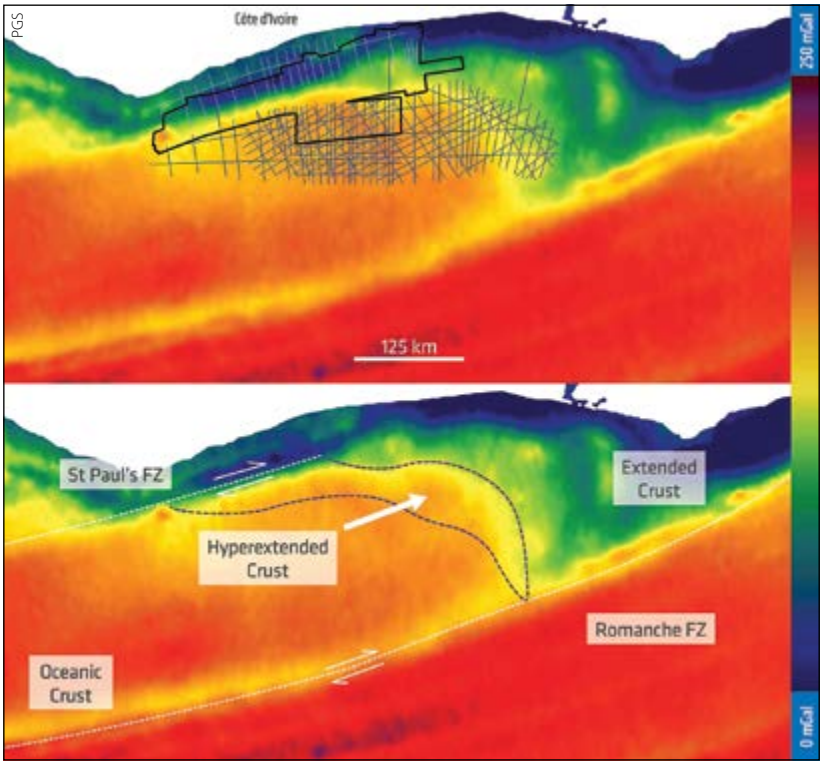
The western area of the Côte d'Ivoire Basin developed as a typically steep transform shelf margin characterised by transtensional faulting with local transpressional features likely to be controlled by pre-existing structure. Using the merged seismic data, the development of the margin can be broken into three fundamental periods of tectonic activity:

Pre-transform – Untapped Deep Potential: The pre-transform stage has not been penetrated by drilling in the central Côte d'Ivoire Basin, although outcrops of rocks from Precambrian to Triassic age do exist in the Tano Basin to the east in Ghana. Pre-transform Jurassic rocks have also been found in the neighbouring Tano Basin. These consist of conglomerates and shales deposited in a continental setting.

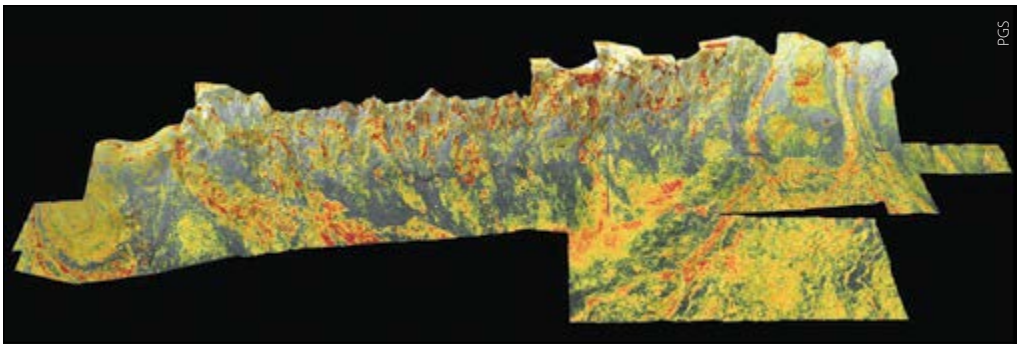
The pre-transform stratigraphy has been deformed and tilted by subsequent transform faulting, creating excellent trapping geometries.

Syn-transform – Development of Petroleum System Elements: During the syn-transform stage (Berriasian

Bouguer gravity maps across the offshore Ivorian Basin with the MegaSurvey data coverage overlayed (top) and a tectonic interpretation (bottom) showing the tectonic setting in which the MegaSurvey sits.



to Albian), sediments were deposited in a continental and marginal marine setting in the Côte d'Ivoire Basin (Chierici, 1996), allowing for the accumulation of Middle Aptian source rocks. The environment became progressively marine during the Albian as rifting continued, leading to the deposition of sands, shales, calcareous deposits and conglomerates.



RMS amplitude extraction of Cretaceous turbidites (yellow/red) using the Base Cenozoic horizon (see foldout), illustrating the distribution of channels and fans across the transform area extending the play from the east (view to north).

Inboard, the faulting associated with the transform superficially shows the appearance of typical rift normal faulting; however, secondary fault patterns and the tectonic setting indicate dextral oblique movements. Outboard there is clear evidence of hyperextended crust demonstrated by classic S-reflector (very low angle detachment faults) geometries.

This period corresponds to the syn-rift phase discussed in the literature covering the eastern passive margin setting of the Côte d'Ivoire Basin (Scarselli et. al., 2018).

Post-transform – Stratigraphic Trapping Potential: The end of oblique transform movement was superseded by thermal subsidence in the post-transform stage (Cenomanian–Holocene). This phase almost entirely comprises clastic marine sandstones and shale deposition, with minor carbonate sediments. Potential reservoir rocks include ponded and channelised turbidite systems and basin floor channel and fan systems. The organic rich black shales deposited within topographic lows provide source rock potential.

Regional Data Allows Broad Assessment

The key to evaluating a relatively underexplored region (with respect to the rest of the offshore Côte d'Ivoire) such as the Ivorian Transform Margin is the availability of regional datasets. The PGS Côte d'Ivoire MegaSurvey offers a regional perspective of the tectonic activity and basin development, leading to a greater understanding of existing and potential petroleum systems. This covers both existing discoveries and open blocks available for licensing, so analogues can be drawn and a regional evaluation of existing successes and failures can be made.

In the following sections some key examples show the advantage that a regional dataset can have in understanding the geology and its implications for further exploration.

Hyperextended Crust Exploration Opportunity

The foldout seismic section shows that the crust dramatically thins towards the offshore with evidence of hyperextension and S-reflectors across the base of the syn-kinematic packages providing potential for increased heat flux and source rock maturation. Distal areas are often dismissed as unprospective due to the limited maturation of source rocks through low levels of heat flux from radiogenic elements within remaining continental rocks (Doran and Manatschal, 2017). However, given recent advances in the understanding of margin development from seismic data and well results, it is becoming clear that this assumption is increasingly invalid (Doran and Manatschal, 2017). In magma-poor environments where the crust is able to extend significantly, the shallowing of the mantle controls increased heat flux. This can prolong the extension and drift phase of increased heat flux allowing for source rock maturation.

These distal areas of the Côte d'Ivoire could be productive with syn-kinematic stratigraphy being charged from a mature Aptian source. Another possible scenario is for a prevalent Cenomanian source rock to be matured allowing for the charge of the deepwater Cretaceous fan sandstones.

Results from the Kosmos exploration campaign across this terrain (deepwater part of the foldout) will provide valuable insight into the potential of these plays.

Regional Mapping of Cretaceous Turbidite Plays

The successful Cretaceous turbidite play is ubiquitous across the Côte d'Ivoire Basin. The regional nature of the PGS MegaSurvey 3D data provides an unprecedented ability to understand the distribution of the turbiditic sands. RMS amplitudes extracted through an interval of Cretaceous turbidite deposits clearly delineate the drilled channel systems to the east of the MegaSurvey and highlight that sediments were also sourced from the west. Basin-wide understanding provided by MegaSurvey seismic data allows for reliable regional depositional models to be built both spatially and temporally through geological time, allowing for the best potential targets to be identified for future exploration.

A Promising Area

The Ivorian Transform Margin is an exciting prospective area that now can be evaluated in detail in a regional context using the MegaSurvey. The initial results presented from this study show that plays in the well-established areas of the Côte d'Ivoire extend west, with new play potential also present. This opens the opportunity for operators to extend existing plays such as the Cretaceous turbiditic sandstones and to develop new plays in open acreage utilising new thinking of heat flux over hyperextended crust to exploit new potential source kitchens.

References available online. ■

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Bringing the Outcrop to Your Desk

PETRONAS and PetroEDGE have embarked on a project to bring favourite field trip locations to a wider audience.

SANDEEP KUMAR CHANDOLA and TENGKU MOHD SYAZWAN BIN TENGKU HASSAN, Petronas; and
CAROL HOPKINS, PetroEDGE

Staff who may not normally have the opportunity to visit the field will be introduced to field trips through interactive Virtual Reality training. The outcrops selected for this pilot project represent the well-known Miri and Lambir Formations, and provide insight into the reservoir properties of PETRONAS fields offshore.

Conventional geological field trips are invaluable but can be time-consuming, costly and present health and safety issues. As a result, industry is leveraging technology to adopt efficient and cost-effective alternatives to the conventional field trip. Another incentive to find alternatives is the degradation of outcrops caused by rapid urbanisation, vegetation and weathering. Virtual Reality (VR) field trips are an innovative way of delivering an immersive experience for studying and preserving the scientific value of geological outcrops.

This motivated PETRONAS to embark on a pilot VR outcrop programme in 2019 in collaboration with PetroEDGE. The pilot programme covers about 3,600 m^2 across three outcrops in Malaysia, encompassing diverse depositional environments and sedimentary features. The final pilot models are planned for delivery by the end of the year. The VR outcrops are constructed using high-resolution photogrammetry and photospheric imagery, and will include field guides and 'hotspots' containing subsurface G&G data and sedimentological analysis. PETRONAS intends to use the VR product for capability development of its geoscientists, by adopting a blended learning approach using a combination of classroom training and VR field trips. Such an approach will be particularly beneficial to young geoscientists and also to experienced professionals with limited exposure to geology. Based on the success of the VR pilot, the study could be extended to other outcrops in Malaysia with the potential of collaborating with other oil companies and academia to expand the knowledge base internationally. The field guide and hotspot content will have different versions, adapted to various audiences, such as geoscientists, engineers and non-technical staff.

Virtual reality view of the Miri Formation outcrop.

This course is used as part of blended learning with classroom training and workshops to ensure that the geoscientists and engineers would be able to relate outcrop-scale observations to seismic and reservoir scales. Many of the field trip outcrops that have been visited in the past are no longer available, and mostly overgrown or developed. Future generations may not have the opportunity to access and learn from this invaluable geological heritage of Malaysia. With VR, PETRONAS would be able to continue to include outcrop observations into its blended internal training. Trainees will continue to be able to develop field observation skills and experience many of the learning opportunities gained from the field environment, without having to travel or be restricted by weather conditions and safety.

Acknowledgements

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Virtual reality outcrop of the Lambir Formation.

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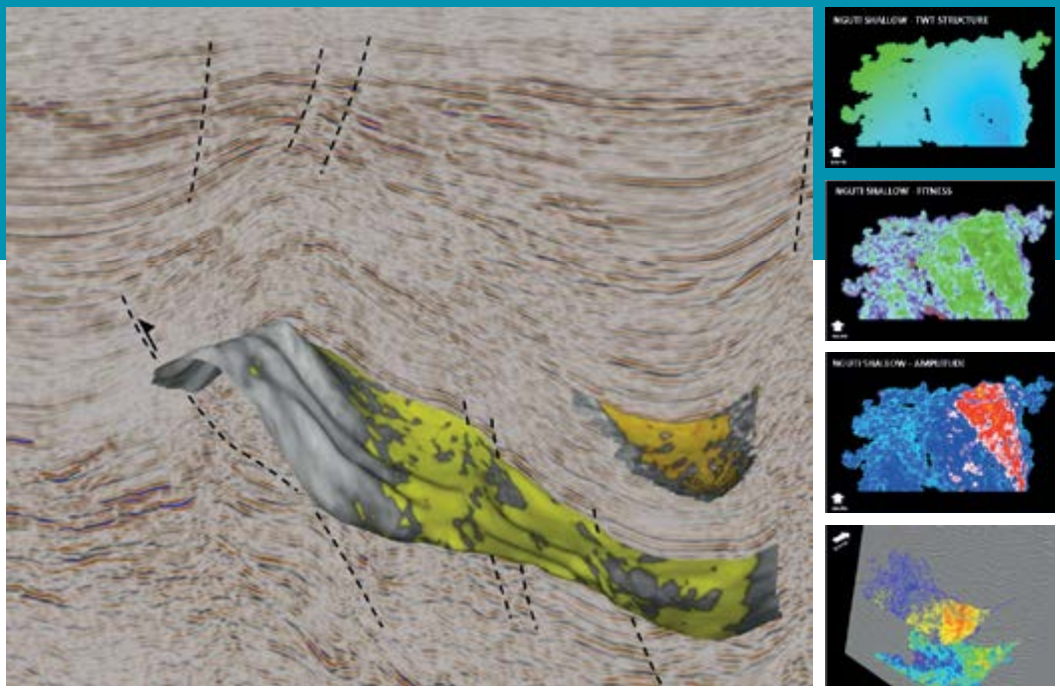

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Are Carbonates 'Difficult'?

Up to 60% of the world's conventional petroleum is reservoired in carbonate rocks – but they are often regarded with apprehension by the industry.

TREVOR BURCHETTE, Carbonate Reservoir Geoconsulting Ltd and Royal Holloway, University of London

Despite their reputation, carbonate reservoirs are often no more 'difficult' than their siliciclastic counterparts – but they are very different, and require an alternative knowledge base in order to effectively find, interpret and characterise them. The main challenges in developing carbonate reservoirs result from their often heterogeneous nature, which undermines our ability to predict reservoir quality, particularly at interwell scales, and to overcome often low recovery factors. Since carbonate reservoirs host a major proportion of the Earth's remaining conventional petroleum resources, it is clearly crucial that we fully understand them.

Variations in carbonate reservoir stratigraphy, diagenesis and rock-fabric all influence development costs and ultimate recovery and so have significant economic impact. While progress has been made on both stratigraphic and pore-scale aspects of carbonate reservoir characterisation over the last few decades, major hurdles still exist with respect to understanding and dealing with the uncertainties that derive from carbonate reservoir heterogeneity. New technologies and workflows based around petrophysics and digital modelling are helping provide solutions, but we still need to increase our understanding of the composition, diagenesis and depositional origins of carbonates.

Diverse Reservoir Types

For many in the industry, a typical list of petroleum reservoir types might include deepwater, fluvial, paralic (deltaic), shallow marine, aeolian, lacustrine – and 'carbonates'. While a clear distinction is generally made between the different siliciclastic depositional systems, it seems there is little recognition of the equal diversity of carbonate depositional systems.

Each carbonate depositional system has its own distinctive architecture and reservoir quality distribution resulting from the nature of its organic (or inorganic) 'factory' and stratigraphic and diagenetic context. These differences are not immediately obvious, in the way that a desert sediment is clearly different from a deep marine fan. A more realistic range of carbonate reservoirs should therefore cover environments such as mounds, isolated build-ups, shoals, reefs of various kinds, shelf, pelagic muds and lakes, and also include diagenetically highly modified rocks such as dolomites, evaporites, and karst terrains.

Recognising this diversity is not only a key aspect of locating carbonate reservoirs during exploration, but also of carbonate reservoir description. This understanding, sometimes guided by outcrop studies, ultimately allows the construction of realistic static reservoir frameworks populated with facies and rock types, which leads in turn to the optimal placement of development wells.

There are many parallels between the architectures of siliciclastic depositional systems from similar environments

A prograding Lower Cretaceous carbonate platform, Vercors, France. Studies of field outcrops such as this can guide us towards building more realistic models of carbonate reservoir architectures.

Claude Alleva/Pixabay

through geological time; were this not the case, our ability to interpret ancient siliciclastic depositional systems would be very different. While carbonate platforms also show superficially similar geometries through time, the detailed internal facies characteristics, early mineralogy, and subsequently diagenesis between platforms of different ages can be markedly different, not least because the constructing organisms have periodically changed. Prediction of this in a petroleum geology context requires specialist stratigraphic knowledge.

Complex depositional facies mosaics on Australia's Great Barrier Reef; environmental variability is responsible for much of the heterogeneity seen in carbonate reservoirs. Very few modern carbonate depositional systems can match the scale of the extensive carbonate platforms of the past.

Carbonate Reservoir Issues

There are some features unique to carbonate reservoirs that materially affect their development and commerciality, but remain challenging to resolve.

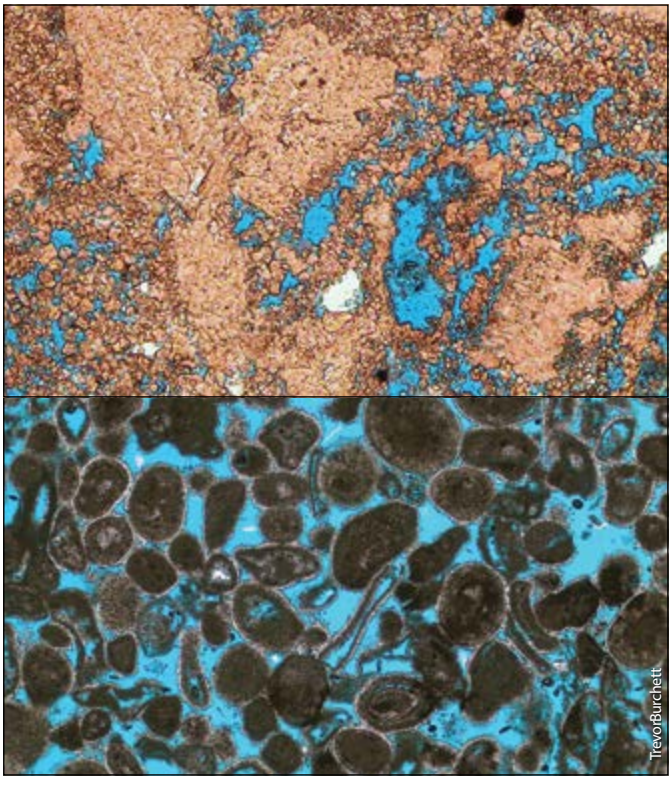
One issue is **rock-typing**, a categorisation of reservoir rocks into dynamic 'bins', generally derived from studies of depositional and diagenetic textures and other measured physical parameters. Most current carbonate rock-typing methods unfortunately include an inbuilt, uncontrolled upscaling process. For example, a single thin section from a routine poroperm core plug is often used to identify the rock type for a much larger volume – yet several petrographic rock types can often be found in close proximity within a carbonate core sample, particularly in vuggy or bioturbated lithologies. Further complications arise from the fact that many carbonate successions consist of vertically heterogeneous but laterally persistent layers.

In addition, friable or vuggy carbonates can seldom be effectively sampled using conventional plugs, or may not even be recovered in core, so the geologist may completely overlook such lithologies, particularly as they often have no unique wireline log characters. Such rocks, which are potentially problematic in a development context, are then even less likely to be identified in uncored wells. Yet friable, porous lithologies are also often the most permeable, so small, plug-scale samples clearly often do not represent the porosity, permeability and potential of coarser carbonate rocks.

Pore systems in carbonate rocks can vary widely, with diverse, complex pore shapes and sizes and a high probability of multimodal pore-size distribution within a single sample. This often leads to large ranges in permeability, even for a single rock type, something which makes estimation of dynamic behaviour challenging. Particular problems are encountered when trying to extrapolate rock types from cores to uncored wells using wireline logs, or later in history-matching reservoir performance. Determining the relationship between the micro- and macro-pore networks in a carbonate reservoir is thus critical and requires detailed understanding of microporosity generation, its distribution, and its role in fluid flow. Important in an exploration context, loss of porosity with depth is less well quantified in carbonate rocks than in siliciclastic rocks. It is interesting to note, however, that dolomites are often structurally more competent than limestones and their resistance to chemical compaction means that they may retain porosity more effectively at depth.

Permeability prediction is a major issue in carbonate reservoir characterisation. The variable pore systems can frequently lead to dual permeability properties which may

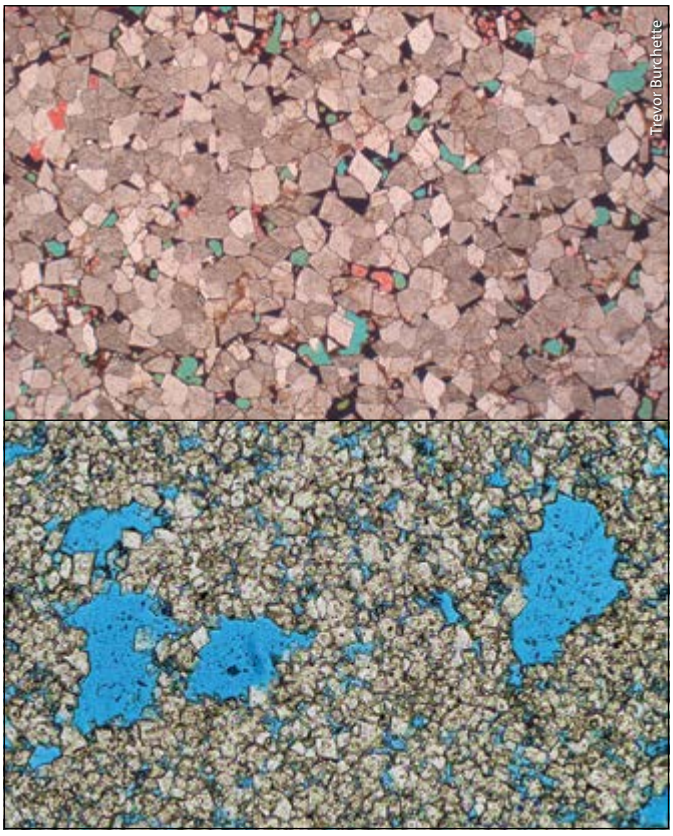
Thin sections of two very different carbonate reservoirs which illustrate pore-scale heterogeneity: (top) a leached bioclastic grainstone with mostly mouldic porosity; (bottom) an oolitic grainstone with intergranular porosity and microporosity within the grains. Field of view in both about 5 mm.



facilitate rapid breakthrough of injection fluids (e.g. water or gas) or 'low-resistivity pay', most markedly where there are connected vugs. Poor lateral but good vertical spatial correlation in reservoir permeability, often obscured by wide well spacing, also complicates the characterisation and development of many carbonate reservoirs. Geoscientists thus need to understand in some detail how permeability distribution can be tied to stratigraphy, structural evolution and diagenetic processes within reservoir architectures.

Fractures can play a crucial role in carbonate reservoir performance, so an understanding of their distribution and dynamic behaviour over time is essential. Moreover, faults which juxtapose carbonate against carbonate seldom effectively seal, so that intra-reservoir faults are more likely to act as conduits in carbonate than in siliciclastic reservoirs, making exploration for fault-sealed traps less attractive in carbonate-dominated fairways, unless a reservoir abutting a known seal can be clearly identified on seismic. As they grow, carbonate platform margins can become steep and unstable, leading to the development of syn-sedimentary faults and fractures, particularly where compaction occurs over softer slope and basinal sediments. Permeable faults and fractures also strongly influence burial dissolution and other diagenetic processes like dolomitisation.

All these factors must be considered when characterising a carbonate reservoir, whilst maintaining an awareness of the distinctive carbonate stratigraphic architectures that control the distribution of these features.



Photomicrographs of dolomites from two reservoirs. Porosity in both is mostly intercrystalline (oil stained in top image) but the bottom sample has retained some original texture as moulds after bioclasts. Field of view in both about 5 mm.

Fractures and Stylolites

These are often perceived as playing a significant role in carbonate reservoir performance, but the dynamic impact of both is difficult to quantify without expensive in-reservoir tests. Moreover, where the well stock consists predominantly of vertical wells, dynamically important fractures and faults may not be effectively sampled, increasing uncertainty around fracture permeability.

The mechanical stratigraphies of carbonate successions can be markedly different from those of siliciclastic successions, and this influences fracture distribution; massive reefal or early-cemented platform margins have no counterparts in siliciclastic environments, for example. In other settings, interbedded lithologies create numerous permutations of mechanical layering, such as thin-bedded limestones with shaly partings or inter-bedded limestones and dolomites. These are distributed, often cyclically, within stratigraphic frameworks with changing bed thicknesses and styles and can strongly influence fracture density, distribution and character. Shales that facilitate bedding-parallel shear are abundant in siliciclastic successions, but are rare in carbonate ones. However, evaporite intercalations occur within some arid carbonate platform interior successions and may influence fracture distribution in a similar fashion.

In carbonate reservoirs the effects of fractures can be difficult to distinguish from those of thin high-permeability layers or of conduits that originate through karst dissolution beneath major sequence boundaries. Extremely heterogeneous reservoirs like these are among the most problematic of all to characterise, develop and manage, regardless of matrix reservoir quality, not least because it is difficult to isolate the dynamic impact of any single feature; if there is one area in which carbonate reservoirs can be said to be more 'difficult' than siliciclastic reservoirs, it is here.

Progress Made

It is important to distinguish between reservoir issues that can be addressed through improving our knowledge of the geology of carbonate rocks, and those that represent reservoir problems which can be overcome through the application of generic tools and technologies to allow better physical resolution or imaging. In the latter context, improvements in computational technologies, reservoir modelling and simulation methods, as well as 'smart-well' technologies, can mitigate the dynamic impacts of the heterogeneities typical of carbonate reservoirs. Improvements in seismic resolution and attribute analysis are goals for the geophysical community with an ultimate (but possibly unrealistic?) prize of *in situ* measurement of reservoir porosity and permeability and real-time imaging of flood fronts.

Major advances are being made towards a better understanding of carbonate diagenesis, many aspects of which, such as dolomitisation, have remained enigmatic for decades. Modelling that can account for the fluid and chemical fluxes responsible for various carbonate diagenetic processes may provide greater insight into the ways in which carbonate rocks transform during burial. A combination of new technologies with petroleum systems modelling can provide a route towards a

better understanding of carbonate diagenesis on a regional scale.

On the positive side, the relationship between carbonate sediments and antecedent structural topography and their variations with time and relative sea level are now well enough understood, so that, in an exploration context, generating maps of gross depositional environments is no longer a major issue, providing there is access to good data. The routine application of sequence and seismic stratigraphic principles allows us to interpret the detailed evolution of carbonate platforms on seismic and to develop new plays with meaningful depositional environments and conceptual reservoir potential.

However, predicting reservoir *quality* for carbonate plays remains as large a problem as it ever was, particularly in underexplored basins. Discoveries in the South Atlantic of unexpectedly large, excellent pre-salt oil reservoirs in unusual lacustrine facies have shown just how limiting preconceptions or complacency in such matters can be.

The study of carbonate geology remains challenging but fascinating, and enthusiastic carbonate geologists will always be needed in oil and gas. Without a doubt, the geologists who are best able to provide knowledgeable input to the exploration for and development of carbonate reservoirs are those who have a first-hand, in-depth understanding of the rocks, and this can only be achieved by taking every opportunity to experience them, in core, in thin-section and in the field. ■

Reference:

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Poroperm heterogeneity in carbonate reservoirs is due to many factors, but one major contributor is subaerial exposure during sea-level lowstands, leading to leaching and karstification illustrated here in the Bahamas.

The Master Sculptor
The Dead Sea Transform

Strike-slip motion – with a dash of divergence – along this transform fault has created a rugged landscape of arid, cliff-girt plateaus towering above the Dead Sea, the lowest exposed point on Earth.

LON ABBOTT and TERRI COOK

The history of the world's three great monotheistic religions – Judaism, Christianity and Islam – has unfolded in the so-called Holy Land, a starkly rugged landscape that stretches from the highlands in Jordan to the Mediterranean and Red Seas. This terrain has been largely shaped by the Dead Sea Transform, a major fault system that forms part of the complex boundary between the African and Arabian plates.

This left-lateral strike-slip system runs from the Maras Triple Junction in southern Turkey to the northern end of the Red Sea. South of Lebanon it consists of a series of left-stepping, en-echelon faults; motion along these independent strands has produced 105 km of left-lateral displacement plus a smidge of extension, thereby creating a series of pull-apart basins. These lie well below sea level because they are on the hanging walls of normal faults that accommodate the small component of divergence produced in the gaps between the left-stepping strike-slip faults. By contrast, a combination of mantle heat and isostatic flexure has raised the blocks on the adjacent normal fault footwalls to elevations of 700–1,200m above sea level, creating a relatively moister climate that sustains much of the population in both Jordan and Israel. The transtensional nature of the transform's southern portion, where the fault system runs through the centre of the Dead Sea, creates the area's rift-like horst-and-graben landscape.

As a result of the region's active tectonism, the Holy Land is filled with distinctive geological and geographic features that govern the events related in many memorable stories contained in the holy literature of all three religious traditions. Mohammad, the founder of Islam, grew up in Mecca, a sacred city nestled in the hills that comprise the uplifted eastern flank of the Red Sea Rift, the more purely extensional portion of the plate boundary that lies south of the Dead Sea Transform. The waters that fill the Sea of Galilee, the world's lowest-elevation freshwater lake, and the site where Jesus, Christianity's prophet and founder, miraculously walked on water,

The ruins of Masada overlooking the Dead Sea at sunrise.

Lon Abbott and Terri Cook

come from the moisture that falls on the elevated plateaus. Jerusalem, the Holy Land's beating heart, stands on the western plateau. The Jordan River flows southward along the axis of the Dead Sea Transform, conveying water from the Sea of Galilee to the Dead Sea, the hypersaline lake whose -429m shoreline comprises the planet's lowest exposed land.

Given the Dead Sea Transform's role as the Holy Land's master sculptor, we decided to complete a circuit around its southern half to see its artwork for ourselves. Our trip began in Amman, Jordan's bustling capital, which is located at 1,000m elevation on the Dead Sea pull-apart's uplifted eastern flank, and ended in Jerusalem, 700m above sea level on its west flank.

Wadi Mujib.

The King's Highway

The first part of our journey led southward along the King's Highway, the modern asphalt rendition of an ancient trade route that ran along the spine of the Dead Sea Transform's eastern plateau, a terrain steeped in history. In the small city of Madaba, St. George's Church houses a 6th-century mosaic map of the Holy Land, believed to be the oldest such map in existence. Nearby Mount Nebo is the place where Moses, after leading the Israelites north from Egypt, caught his first – and only – glimpse of the Promised Land before he died. Today this popular attraction offers panoramic views of the Dead Sea nestled in the pull-apart basin 1,100m below.

35 km south of Madaba lie the ruins of Machaerus, Herod the Great's hilltop fortress, which was built atop a horst block surrounded by deep ravines. It was here that Herod II's daughter Salome danced for her father, extracting John the Baptist's beheading as her price. The hilltop and adjacent plateau surface are composed of Cretaceous to Eocene limestone deposited in the Neo-Tethys Sea.

This same limestone is also on display in Wadi Mujib, the impressive 600m-deep 'Grand Canyon of Jordan' that dissects the plateau 52 km further south; the wadi's walls consist of cream-coloured limestone from top to bottom. A few hills of black basalt that rise to the south-east testify to the crustal thinning and heating the area experienced during the formation of the Dead Sea pull-apart basin.

The King's Highway was a primary battleground during the 12th-century religious wars between Christian Crusaders and Saladin's Muslim armies. The Crusaders used the area's limestone to build the impressive strongholds of Karak and Shobak to defend themselves during their raids. Both castles make worthwhile stops along the drive.

The King's Highway's undisputed highlight, however, is the magnificent ancient city of Petra (*GEO ExPro* Vol. 10, No. 4). In contrast to the Neo-Tethyan limestone that underlies the gateway town of Wadi Musa, the up-flexed rift flank to the west consists of Cambrian arkosic sandstone belonging to the underlying Ram Group. The Nabateans, a semi-nomadic Arab tribe that controlled the region's lucrative incense trade, carved the grand city from this rose-coloured rock between the 4th century BCE and the 2nd century CE.

Reaching Petra entails a walk or horse-drawn carriage ride through the dramatic Siq slot canyon, which in places is a mere 3m wide, before it opens up to a breath-taking view of the Treasury, one of Petra's most impressive (and, thanks to Harrison Ford, one of its most famous) rock-hewn monuments.

Petra's other signature structure is the Monastery, a temple dedicated to King Obodas I, who reigned in the 1st century BCE. Unlike most Petra structures, which are tucked into shady canyons, the Monastery is dramatically perched at the edge of the flanking escarpment. The nearby 'Grand Canyon Overlook' boasts a stunning panoramic vista of the pull-apart basin 800m below. The escarpment comprises Ram Group sandstone underlain, across the Great Unconformity, by dark Precambrian basement. This basement consists of volcanic

The 12th-century Crusader castle at Karak.

Precambrian granite crossed by black diabase dykes along the King' s Highway heading to Aqaba.

rock erupted 550 million years ago on the floor of an earlier pull-apart basin, nearly identical to the modern one visible below.

Coral Reefs and Salt Domes

South of Petra the highway descends from the plateau, weaving its way through a basin-and-range landscape to the coastal city of Aqaba. Due to the hyper-arid climate, the area is nearly devoid of vegetation; each range consists of naked white granite intruded by criss-crossing black diabase dykes that collectively comprise Jordan's Late Precambrian foundation. The city of Aqaba lies at the head of the Gulf of Aqaba, a narrow arm of the Red Sea that has flooded the Dead Sea Transform's three southernmost pull-apart basins.

Jordan's 26-km-long stretch of Red Sea coastline is an important tourist attraction thanks to the luxuriant coral reefs that thrive in the exceptionally clear, warm water. Stunning reefs lie just metres off the beach, making the area an easily accessible snorkelling and diving locale.

After snorkelling, we crossed the international border to Eilat in Israel and headed north along the Dead Sea Transform's western side through the desiccated Arava Valley. Along the way, we stopped to see Mount Sodom, an 11-km-long salt dome that shares its name with the biblical city that God destroyed using fire and brimstone. The city probably flourished thanks to the local sulphur-rich asphalt, which was highly prized for its role in mummification.

Ancient Earthquakes and Salty Soaks

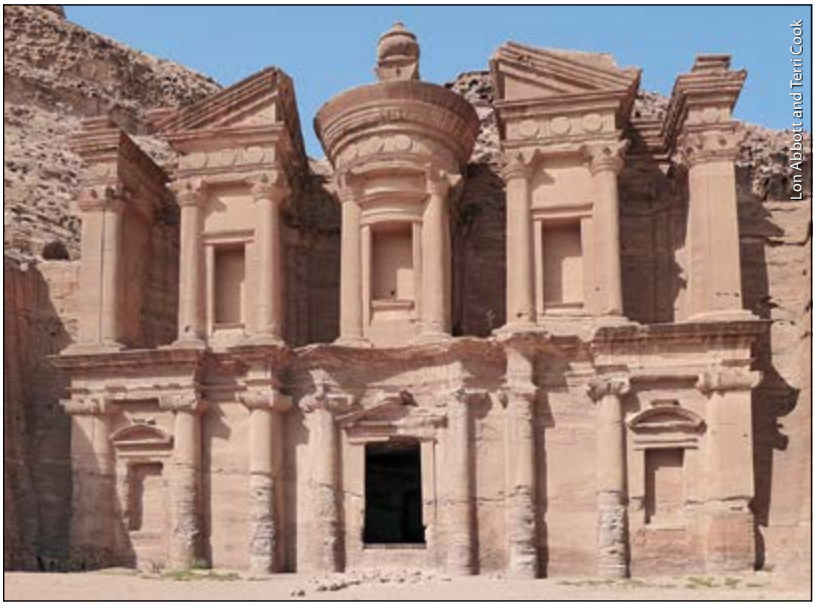
The last leg of our journey continued northward along the transform's western flank to the holy city of Jerusalem. Along the way, we stopped to soak in the Dead Sea, whose buoyant waters have a dissolved mineral concentration nine times greater than the ocean. Water diversions from the Jordan River have caused the Dead Sea's surface height to drop 39m since 1930 and triggered the opening of thousands of sinkholes due to dissolution of the lake's salt substrate. Together, these phenomena have made it increasingly difficult to reach the shoreline, so bathers flock to the resort area of Ein Bokek to float in evaporation ponds owned by Dead Sea Works, one of the world's largest producers of evaporite minerals.

Another of Israel's biggest tourist attractions, the ancient fortress of Masada, is perched atop a horst block 17 km north of Ein Bokek. It is another of Herod the Great's fortresses, built between 37 and 31 BCE, that Jewish zealots seized in 67 CE during the first Jewish-Roman war. The Romans patiently constructed a siege ramp atop a small bedrock spur that links Masada to the nearby Judean Plateau. Six years later, they rolled a battering ram up this ramp and used it to breach the fortress walls.

The Masada horst is ringed by 100m-high cliffs, only breached by two hiking trails. The Roman Ramp trail entails a moderate 15-minute walk from the Judean Plateau to the west; the much more strenuous Snake Path ascends 270m from the Dead Sea basin to the east. Snake Path climbers traditionally opt for a pre-dawn ascent to beat the heat and enjoy the commanding sunrise view.

We were excited to explore the sedimentary evidence of ancient earthquakes hidden in obscure arroyos cut through the Lisan Formation below the mountain. This formation consists of varves deposited between 70,000 and 12,000 years ago in Lake Lisan, a larger version of the Dead Sea that also encompassed today's Sea of Galilee. Identical millimetre-thick varve couplets accumulate on the floor of today's Dead Sea, composed of clastic detritus that washes into the lake during winter storms, alternating with aragonite that precipitates during intense summer

The Monastery – one of Petra's most impressive monuments



A 'seismite' interrupts the varves of the Lisan Formation.

evaporation. In places the Lisan Formation's varves are interbedded with fractured and folded beds that record sediment liquefaction and slumping that occurred during an ancient earthquake. Scientists have used these 'seismites' to construct a 50,000-year earthquake record for the Dead Sea Transform, the longest continuous such record on Earth.

Human and Geological Monuments

The lush oasis of Ein Gedi is perched on the banks of the Dead Sea 21 km north of Masada. Here two fault-controlled canyons carved by spring-fed streams crease the Judean Plateau. The streams tumble down beautiful, travertine-encrusted waterfalls and sustain local wildlife, including hyrax and Nubian ibex, in the otherwise harsh and unforgiving landscape.

From the oasis it is an 83-km trip to Jerusalem, the heart of the Holy Land and one of the world's most historic cities. Its main attractions are associated with stories from all three major religions; most famous is the Temple Mount, whose iconic Dome of the Rock was constructed by Muslim caliph Abd al-Malik between 688 and 691 CE. The dome was built atop the site where, according to Jewish tradition, Abraham prepared to sacrifice his son and where Herod's Second Temple once stood. According to Muslim tradition Mohammed also ascended to heaven from this same spot. Christian pilgrims retrace Jesus' path to his crucifixion, beginning just outside the Temple Mount's north wall.

Historic Jerusalem, and the rest of the landscape upon which the Holy Land's unparalleled history has unfolded, is a monument to human as well as geologic history. ■

A waterfall at Ein Gedi.

Lon Abbott and Terri Cook

New Technologies Through Collaboration

New nodal systems for both land and marine deployment demonstrate that it is important that companies keep innovating.

When discussing new technologies in the oil and gas industry, one can get the impression that most of the innovative developments are coming from bright new start-up companies, working with new ideas related to cloud computing and artificial intelligence. While it is true that there are many exciting young entrepreneurial ventures out there, a number of the longer-established companies in the industry still regularly push technology forward in new ways, often harnessing the digital revolution.

Building on Success

One such company is Sercel, a leading designer and manufacturer of seismic equipment and reservoir monitoring instruments and part of the CGG group. In March 2014 the company unveiled a highly sensitive single sensor with an ultra-quiet performance (below 15ng/√Hz across the frequencies of interest to the seismic industry), which was designed to detect even the weakest signals at extreme temperatures and in adverse conditions. The resulting digital signal provides a much higher fidelity representation of ground motion than that provided by analogue geophones.

Building on the success of this technology, known as QuietSeis®, the company has recently developed two new products which are anchored on the proven high performance of this highly efficient broadband digital sensor technology.

For land-based exploration, Sercel announced the launch of WiNG, a fully integrated wireless nodal acquisition system, which has the QuietSeis sensors at its heart and uses advanced vibroseis solutions to source the energy. The node is compact and light, designed to minimise transportation and storage costs, making it easy to deploy in a variety of environments, and can record data for up to 50 days. The data management system collects and processes of all survey information, from both sources and receivers, and the data is continuously monitored and quality controlled remotely in real time. In this manner, the accurate acquisition of high quality data can be combined with optimum field operational efficiency to provide improved imagery of the subsurface in a land environment.

Offshore Collaboration

Moving offshore, the company has been working on a new ocean-bottom node (OBN) that also harnesses QuietSeis' broadband digital sensor technology. The node is called GPR and features an integrated all-in-one compact design that holds both the sensors and the hydrophone that continuously record the data. Each node has an optional integrated acoustic positioning system to optimise operations. As with many offshore OBN systems, it can be deployed either by a remotely-operated underwater vehicle or using the 'node-on-a-rope' system, in which autonomous nodes are attached to passive ropes under water. Sea trials have been undertaken and the company believes that the results demonstrate that the GPR node can collect superior data for accurate seismic imaging in comparison to data collected by conventional sensors.

An interesting aspect of the development of the new node is that it it is the result of a collaboration between Sercel and BGP, a fact which demonstrates the innovative ways in which service companies in the oil industry have been working together in recent years. The two companies have a longstanding partnership and have used what they see as their complementary expertise to design and develop the new product. They believe that by collaborating together, harnessing Sercel's state-of-the-art technology and manufacturing expertise and BGP's long experience of operating OBN systems in the field, the two companies have been able to deliver a superior product. It is likely that partnerships like these will become more common and will thrive in the oil industry of the future. ■

The new WiNG fully integrated wireless nodal acquisition system.

What is a Super Basin?

JANE WHALEY

There is a trend away from frontier exploration towards finding more in less risky proven basins, fuelled by learning gleaned from studying the most successful basins in the world.

We are all familiar with Parke A. Dickey's quote about finding oil, the central part of which is "… sometimes, we find oil in an old place with a new idea" – and that just about sums up the reason we need to study super basins: the most important and prolific basins in the world.

The term 'super basin' was coined by Bob Fryklund and Pete Stark of IHS Markit in 2016. They defined such a basin as an established producer with at least 5 Bboe produced and at least the same volume of recoverable remaining reserves; two or more petroleum systems or source rocks; stacked reservoirs; existing infrastructure and oil field services; and good access to markets. This is definitely all about old places and new ideas – primarily, but not exclusively, technological ones.

Out of a total of about 870 petroleum-bearing basins in the world, there are technically about 100 of such richly endowed basins, spanning every continent. Of these, the top 30 super basins (48 contiguous sub-basins) contain about 57% of the world's giant oil fields. "This means that the world's richest super basins contain ten times the number of giant fields (the ultimate exploration prize) relative to all petroleum-bearing basins. In addition, it is thought that the top 25 super basins have the remaining potential to deliver many billions of oil and gas and are therefore key to our future energy mix," says Charles A. Sternbach, President, Star Creek Energy.

The study and understanding of these super producers is important as they give us insights into other basins. Because many super basins have undergone an energy renaissance within the last ten years resulting from recent technological innovations, their study can help us identify areas which, with similar treatment, could also move into the super basin bracket. To facilitate locating them, Charles instituted the AAPG Global Super Basin Leadership Conference when he was AAPG President in 2018, because, as he says, "Basin masters compare global geoscience architectures for actionable intelligence. These insights fuel abundant and affordable energy."

World-Class Petroleum Systems

What geological elements define a super basin?

"Well, firstly, it must have a world-class petroleum system," Charles observes. "A rich source rock buried by a thick sedimentary section is a prerequisite; in fact many super basins contain more than one great source rock that has attained peak oil and gas thermal maturity. The US Permian Basin, in many ways the archetypal super basin, actually has four source zones. Source rocks often occur in the toe of slope distal facies clinoforms, as, for example, the Utica shale in the US Appalachian Basin and the Vaca Muerta shale in the Neuquén Basin in Argentina. The petroleum systems must be capped by a regional seal, which is often an evaporite, or by a series of seals. Due to hydrocarbon generation and effective trapping, super basins may have components of high pressure in all or in parts of the basin."

Super basins are found in several structural settings. The stacked reservoirs needed for a giant field are a classic feature of the foreland basin, and sure enough, a number of super basins,

A West Texas pump in the Permian super basin.

searnstrong/123rf.com

including the West Canadian Sedimentary, Iraq and the Neuquén Basins, fall within this category, but super basins are also found in a range of other settings. The Algerian Illizi Basin and the West Siberian Basin, for example, are intracratonic, the latter in a gentle down-warp associated with a tectonically active fold and thrust belt, while the Zagros is a classic thrust belt and the North Sea a rift basin. Super basins are also found in the passive margin settings of the Gulf of Mexico and the Arabian Platform, characterised by thick sedimentary accumulations.

Technology as Game Changer

Many super basins have experienced a major renaissance in recent years, almost always as a result of technological innovations. The offshore areas of the Gulf of Mexico and Brazil, for example, have both been revolutionised by improvements in seismic imaging, enabling the visualisation and exploitation of the massive pre-salt resources which lie below the shallow, well-explored post-salt plays. Enhanced imaging has also improved understanding in the North Sea around basement highs.

Onshore, hydraulic fracturing has similarly revolutionised the Permian and a number of other US basins, allowing the exploitation of unconventional reservoirs in a truly game-changing manner, both for the basins and the country, and pushing some previously relatively small producing basins into super basin status. A resurgence in the gas and LNG industry enhanced by technology has also been seen in the Carnarvon super basin in Australia.

Charles notes: "It could be said that super basins are well known basins where technology has proved the game changer. Some of this may be due to the fact that they are large basins, with the scale and infrastructure to innovate and develop new technology, but the results will be appropriate to basins of all sizes – another reason for their importance and value. The Permian Basin, for example, offers hard-won lessons learned over more than a decade that include addressing needs for transport, water sources and disposal, sand shortages and issues around gas-oil ratios. Building on this experience, other basins and multiple companies can leapfrog ahead."

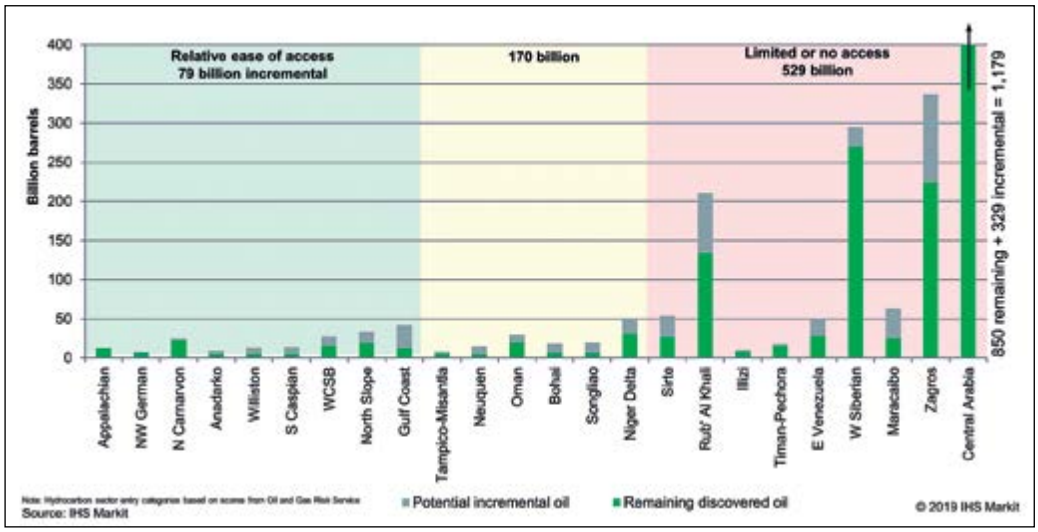
Thinking Differently

Bob Fryklund believes that developing the concept of the super basin is important, as it requires us to think about things and explore in a different way. "The old way of exploring," he explains, "was play based, reservoir by reservoir. It involved broad portfolios and lots of assets, in possibly hundreds of different basins, chasing short-term objectives. Technology was an enhancer, but didn't have the significant input into production it has in a super basin.

"In contrast, the super basin way of thinking is to view the basin as an ecosystem, considering where the demand is coming from as well as how to produce efficiently," he says. "Thinking differently means thinking in 3D rather than concentrating on individual single layers, because it is important to fully understand the volumetric richness of the multiple stacked plays that characterise a super basin like the Permian. Importantly, these stacked plays can be both conventional and unconventional, as is seen in many US super basins. In addition, commerciality is in the driving seat in the super basin, integrated with the geoscience. This is giving rise to the single basin specialist company, instead of the multi-basin broad portfolios which typified the 'old' way of exploring," Bob adds.

Technology is used as a driver in the super basin; for example, just the simple

The Zagros Mountains, one of the world's great super basins, has over 200 Bbo remaining.



Super basins (excluding Permian) remaining and incremental oil resources, sorted by hydrocarbon sector entry category and potential incremental oil.

use of horizontal wells can enable recovery from a previously disregarded conventional play, particularly when there is access to the infrastructure resulting from the much larger levels of production from the basin. The adoption of hydraulic stimulation, new completion and drilling techniques, and innovative seismic imaging technologies have all helped to unlock potential and push a basin into super basin status.

Another feature of a primary super basin is that it can be seen as a regional or even global disrupter. As discussed in a recent issue of *GEO ExPro*, the great South American super basin, the Neuquén, having been a conventional producer for 100 years, has had a completely new lease of life in the last decade by becoming a commercial unconventional producer – the first outside the USA – which means that Argentina is now an oil exporter: definitely a disrupter.

Incredible Potential

A characteristic of the super basin is its incredible richness, measured as the total volume of hydrocarbons per square kilometre; the Central Arabian Basin, for example, holds nearly 2 MMbo/km^2. The potential still locked in these basins is considerable. IHS Markit estimates that total uplift in the top 24 super basins is in the region of 779 Bbo, 42% of which comes from the Central Arabian Basin. However, two-thirds of this – 529 Bbo – is located in basins where for political, developmental or geographic reasons it is, at the moment at least, hard to access, such as East Venezuela, Zagros and West Siberia. Bearing in mind that recently we have been discovering a mere 8 Bbo a year from new ventures, this is a massive resource, even if we only look at the 79 Bbo which IHS classifies as 'relatively easy to access'.

So where is the next Permian Basin to be found? By studying super basins and comparing them to analogous areas, new prospect and play ideas will arise which may propel an as yet unknown basin towards this favoured status.

Acknowledgement:
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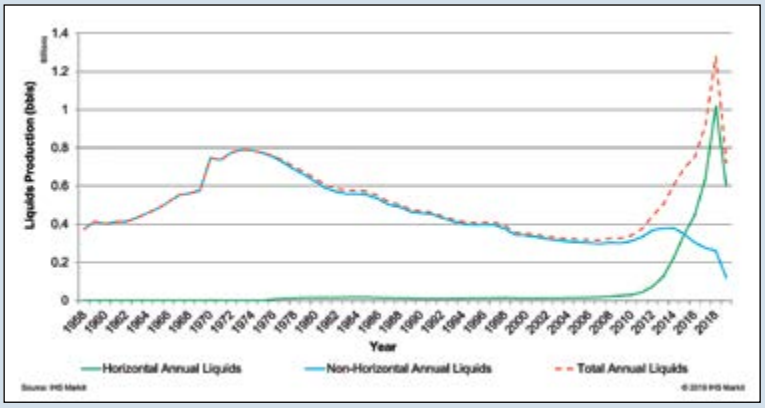
The Archetypal Super Basin

The US Permian Basin, located in west Texas and New Mexico, is in many ways the archetypal onshore super basin. It has the key geological fundamentals of source(s), stacked reservoir and excellent seal, plus it possesses critical factors for technological innovation such as private mineral ownership, a strongly networked community, service company partnerships, and immediate rewards for risk taking. It has shown a remarkable renaissance in the last ten years, driven by technology and innovative thinking, and its production curve shows the notable double peak that is symptomatic of the successful super basin; at least eight other super basins have similar peaks.

The basin has been producing for almost 100 years, with a total of 33.4 Bbo and 118 Tcfg produced by September 2018 (EIA). As can be seen from the graph below, it was considered to have reached its peak in 1974, and production declined gradually until 2006, when the implementation of hydraulic fracturing, horizontal drilling, and completion technology advances dramatically reversed this decline, and the basin has now exceeded its previous production peak. In 2017, it accounted for 20% of the total U.S. crude oil production. There is plenty that can be learnt from this super basin alone.

Permian super basin oil production.



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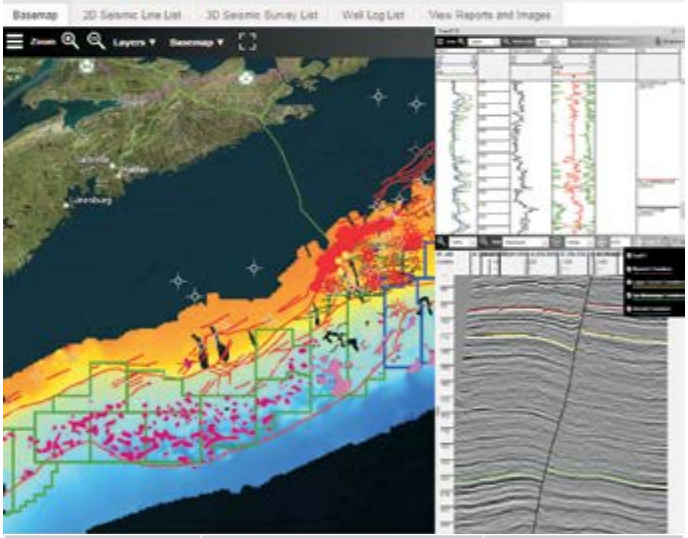

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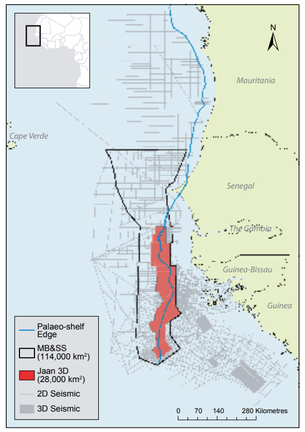
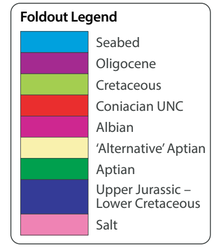
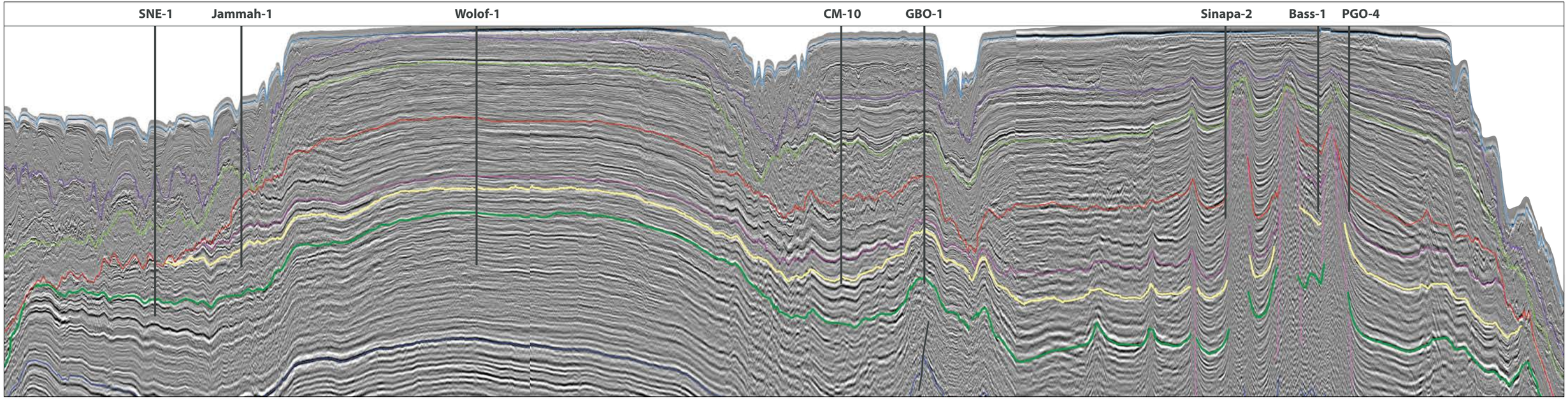
TGS in the MSGBC Basin

Aiding the next steps in exploration

The Mauritania, Senegal, Gambia, Guinea-Bissau and Guinea Conakry (MSGBC) Basin is home to several recent high-profile oil and gas discoveries, both on and off the shelf. The palaeo-shelf edge carbonate trend extending south of the SNE field and the expanse of prospective area outboard of this to the north and south have led many explorers to the region. TGS has recently completed the acquisition of its 3D Jaan survey, which, following completion of the processing, will have a depth migrated volume of over 28,000 km². To complement this – and gain vital information on the petroleum system(s) in a cost-effective manner – TGS is undertaking a multi-beam and seafloor sampling (MB&SS) project. It will cover an area of approximately 114,000 km² and will incorporate approximately 230 targeted cores with state-of-the-art geochemistry to follow. These data will be crucial to the understanding and de-risking of the basin, which is an area of active and planned exploration.







MSGBC Basin: An Integrated Approach to New Exploration

TGS

The MSGBC Basin, located on the North West Africa Atlantic Margin (NWAAM), comprises a collection of sub-basins within Mauritania, Senegal, The Gambia, Guinea-Bissau and Guinea Conakry (Republic of Guinea). Offshore exploration began in the 1960s in southern Senegal and AGC, the maritime zone established in 1993 between Senegal and Guinea-Bissau. Up to a billion barrels of bio-degraded heavy oil was found in Dome Flore (1967) and Dome Gea (1971), while others – namely CM-7 (1967) and CM-10 (1970) – showed excellent total organic carbon (TOC) and hydrogen index (HI) values. Crucially for exploration potential in the region, in 1975, DSDP-367 was drilled in ultra-deepwater (4,768m) on the Senegal-AGC border. It contained an excellent quality source interval from Upper Aptian/Lower Albian to Turonian over 100m thick, described in the official report as "a black, carbonaceous shale, which burns when ignited" and with TOCs of up to 28%.

Despite these early signs pointing towards a prospective hydrocarbon province, it took a further 50 years before the first major commercial discovery. In 2014, Cairn (along with ConocoPhilips, FAR and Petrosen) drilled FAN-1, 110 km south-west of Dakar in Senegal, and discovered oil in stacked Albian slope fan sandstones. The same consortium quickly announced the nearby SNE-1 oil discovery, an Albian sandstone shelf-edge play and the world's largest oil discovery of 2014. Further appraisal wells put the 'SNE development' 2C contingent oil resource at 563 MMb.

In 2015, Kosmos made the industry's second largest discovery of the year with the Tortue-1 gas well just across the northern border of Senegal in Mauritania. With the addition of Guembeul-1 and Ahmeyim-2 in 2016, the Greater Tortue Complex, spanning the Senegal-Mauritania border, stands at 25 Tcf. Two further gas discoveries were made by Kosmos in Senegal, roughly 80 km north-west of Dakar. Teranga-1 (2016) and Yakaar-1 (2017), reported to be the largest gas discovery of 2017 at 15 Tcf, tested the basin floor fan fairways outboard of the proven slope channel trend of the Greater Tortue Complex.

2D and 3D Seismic

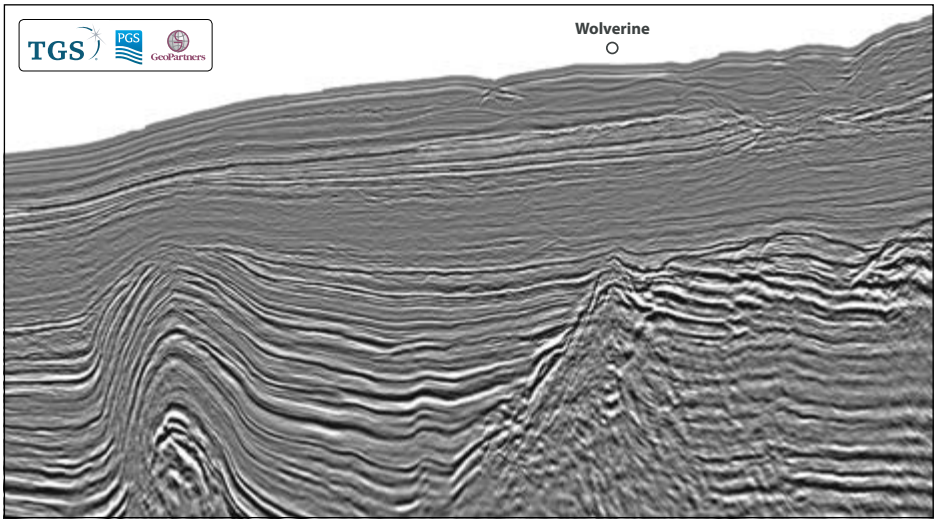
The SNE development is an instantly recognisable play of sand reservoirs sitting on a carbonate platform margin, while off-shelf, slope floor fans provide the FAN play. South of the SNE and FAN discoveries, the palaeo-shelf edge carbonate trend stretches over 550 km before meeting the Guinea Transform Fault and has attracted many exploration companies to the area as they chase similar plays.

The TGS 2D seismic library in the MSGBC Basin has been instrumental in many of the discoveries and comprises over 52,000 km in time and depth, acquired in two phases in 2012 and 2017. A further 20,000 km has been added to this library through TGS' recent acquisition of Spectrum. TGS has been present in the basin since 2010, when it acquired a 3D dataset in The Gambia. This survey now forms part of the recently completed Jaan 3D, which comprises 11,135 km² of new acquisition, complemented by the reprocessing and full pre-stack merging of existing multi-client 3D. The final depth-migrated volume will be over 28,000 km² and will completely capture the prospective palaeo-shelf edge carbonate trend, and therefore over 550 km of potential SNE and FAN plays. Fast track processing is ongoing and final deliverables will be available early 2020.

MB&SS Project

TGS has extensive experience of multi-beam, coring and geochemical analysis programmes, including projects in the Gulf of Mexico, Brazil and Indonesia. With acquisition running in parallel to the Jaan 3D, TGS have been undertaking a Multi-beam and Seafloor Sampling (MB&SS) project in the MSGBC Basin which, when complete, will cover an area of approximately 114,000 km² and incorporate around 230 cores. The footprint covers the entire Jaan 3D and continues north from SNE to the Senegal-Mauritania border, south to the Guinea

Figure 1: Planned well location of CNOOC International carbonate platform edge 'Wolverine' prospect.



Transform Fault and outboard to water depths up to 3,500m. MB&SS studies enable the mapping of hydrocarbon occurrences on the seabed and, through geochemical analysis of the cores, offer detailed information about the maturity and source of petroleum system(s).

The initial stage is a multi-beam survey to identify targets (as well as providing detailed bathymetry and information on seabed geo-hazards). It is conducted quickly over vast areas and proves to be an extremely cost-effective method to gain information on a regional scale. Targets for coring are identified as 'hard' seafloor features from the backscatter (the strength of the returned pings). Backscatter anomalies can be due to hydrocarbons migrating naturally to the seabed, which feed chemo-synthetic bacteria and consequently provide nutrition for other larger organisms, with other seabed structures forming as a result.

As of end of August 2019, a total of 105,234 km^2 of multi-beam bathymetry had been acquired in addition to 23 jumbo piston cores (20-metre barrels), 23 heat flow measurements and 71 anomaly-targeted six-metre cores, which are currently being analysed in the TDI Brooks laboratory in College Station, Texas. Oil samples have been recovered which are yielding exciting results. The integrated application of seismic surveys and MB&SS is a major benefit to future exploration in such a large area where there is a lack of modern wells and information about petroleum systems.

Jaan 3D and MB&SS Applications

The MSGBC Basin is an area of active exploration where two high-profile wells have recently been drilled within the area covered by the MB&SS. Samo-1 (2018), set ~30 km south of and on the same geological trend as the SNE field, and Jamm-1XB (2019), an off-shelf wildcat ~80 km north-west of the SNE field, both proved to have non-commercial oil shows. As operators release more information, it looks likely that several wells will be spudded in 2020. FAR stated in late 2018 (before the Samo-1 disappointment) that the "Samo-1 well result will not effect [sic] CoS for Soloo", a prospect situated between Samo and SNE in The Gambia. In July 2019 FAR stated the "Atum and Anchova (Greater Atum) were high-graded for follow-up drilling". These Albian prospects sit on the shelf edge ~250 km south of the SNE field in the AGC zone. Should they be drilled, the completed Jaan 3D survey will prove useful for further evaluation of migration routes, as the supposed source pinches out against shelf edge. Covered by the Jaan 3D within the AGC zone ~60 km north-west of the Atum prospect lies the recently published CNOOC International 'Wolverine' carbonate platform edge prospect (Figure 1), which may be drilled in 2020.

Another application of the final 28,000 km^2 3D depth-migrated volume, over and above prospect and lead mapping, will be the regional interpretation of the margin, since it will tie many of the on-shelf wells. There are several factors which make the on-shelf interpretation difficult. These include: lack of existing wells and shallow penetration depths (particularly below Albian), sparse legacy data from older wells, i.e. checkshots and reliable palaeo-data, and the fact that many wells were drilled into the flanks of salt diapirs. TGS performed an interpretation using the entire 2D dataset south of the Senegal-Mauritania border, integrating all available well information, press releases and publications. Despite the excellent coverage and large amount of well information available, the TGS Aptian interpretation was particularly troublesome since the wells in the north of the Jaan 3D (SNE-1, Jammah-1 and Wolof-1) did not tie with those in the south (CM-10, GBO-1, Bass-1 and PGO-4). This issue may affect the new wells in the area with regard to mapping of reservoir and source.

The foldout seismic image shows the official TGS interpretation of the Aptian (dark green) and the shallower Alternative Aptian (lemon yellow), highlighting the discrepancy. TGS believe the shallower Aptian, tying the southern wells, may have been picked on regional massive limestones without supporting palaeo-data. However, interpretation of the final 3D volume will shed light on this, if one of the upcoming wells doesn't first! ■

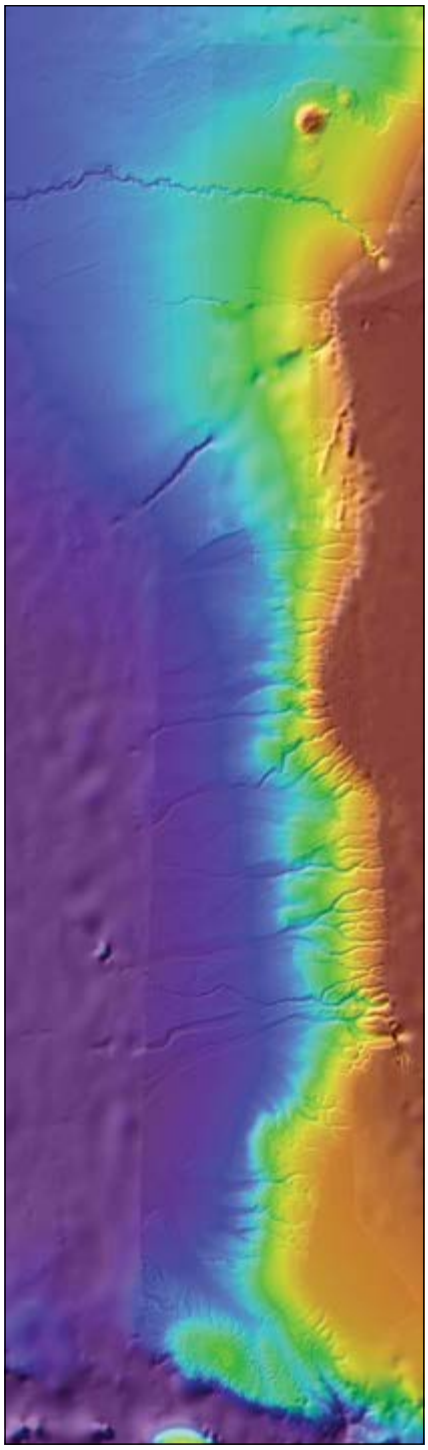


Figure 2: Recently acquired bathymetry, merged with existing public data (SRTM Ver 3), showing the seabed in unprecedented detail.

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Comoros Islands

Multi-Billion Barrel Deepwater Prospect Potential

CURTIS COHEN and
STEVEN MARSHALL
Western Energy
East Africa Ltd.

The scent of a new fragrance is in the air in the Perfume Islands. Hopes are high for an exciting new frontier, with multi-billion barrel oil prospects in the same plays that have found giant gas fields in Mozambique.

In the 18th century, the Comoros were known as the 'Perfume Islands' due to their fragrant flowers, like the yellow ylang-ylang, used in perfumes. Originally imported and cultivated by French colonialists, the ylang-ylang flower provided perfume makers with an exotic source of essential oils, while the 1,862 km^2 island archipelago provided France with a strategic base, port and harbour location midway between Arabia, the Indies and East Africa. Independence came late to the volcanic archipelago, in 1975, and since then the island colonies of Grande Comore (Ngazidja), Mohéli (Mwali), and Anjouan (Nzwani) which make up the young Comoros nation have grown to a population of 800,000, with a GDP around $650m and an annual per capita GDP of $850.

Neighbouring Discoveries Spark Interest

So when Comoros witnessed billions of dollars in major new investments being made over the past decade in the Mozambique Channel only 300 km away, which led to world-class gas discoveries totalling 200 Tcfg reserves in Mozambique and Tanzania, interest in the Comoros began

Large prospects have been mapped in ultra-deepwater depths of 3,000m off the Comoros Islands.

to stir. This is, after all, more gas than has been found in total in the US offshore Gulf of Mexico or Nigeria. These are among the world's largest gas finds of the past two decades and include the discoveries made by Anadarko (now Oxy), including Prosperidade, Orca, Lagosta, Atum, Golfinho and Tubarã discoveries in Mozambique Area 1; Coral, Mamba and Prosperidade, found by Eni in Mozambique Area 4 ; and BG (now Shell) and Equinor's Zafarini, Nzia, Jodari, Chewa, Pweza and Papa fields in Tanzania. With 375 Tcfg potential, development plans now underway and first liquid natural gas planned for 2023, the finish line is within sight in neighbouring Mozambique – in plain view of the Comoros.

This success by key international oil players, like Anadarko, Eni, CNPC, ONGC and more recently ExxonMobil, Oxy and Total, has emboldened smaller, independent entrants to wade into deep water and to prospect for new giant oil resources down-dip from the gas discovered earlier. Today, the Comoros archipelago is abuzz with talk of new deep sea riches potentially lurking below in waters up to 3,000m deep, just waiting to be discovered.

The ylang ylang tree in flower. More commonly known as Cananga odorata, the fragrant yellow flowers are native to the tropics in East Asia, especially in India, Malaysia, Philippines and North Australia.

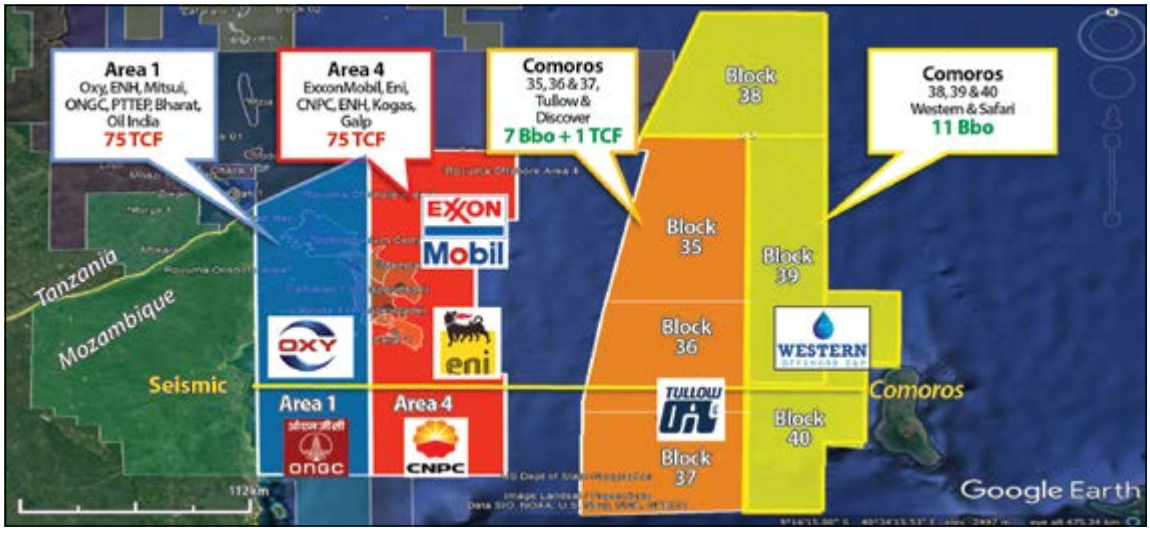
Following publication of a new petroleum law in Comoros in 2012, new players including Bahari Resources, Discover Exploration and Western Energy East Africa Ltd joined the hunt. Discover was founded by the Cove Energy management that in 2012 had created almost two billion dollars in shareholder value via a sale to PTTEP of its stake in Mozambique Area 1, while Western Energy is famed for its earlier successes in unconventional oil shale plays in Colorado and California.

Thus a new era of modern seismic surveying was kicked off in the Comoros, with a grid of some 8,500 line-km 2D seismic data shot in 2014. This was tied to 20,000 line-km of Ion's regional SPAN surveys, which had been shot in 2011 in East Africa over and surrounding several giant discoveries. The Bahari-Discover team licensed 2,330 km of the new Comoros 2014 infill 2D seismic over their 16,063 km^2 three block area (Comoros 35, 36 and 37), while Western Energy East Africa licensed 744 line km of 2011 vintage and 3,134 km of 2014 data. The company holds the three blocks (38, 39 and 40) east of Tullow (formerly Bahari) / Discover's area and currently operates 14,178 km^2.

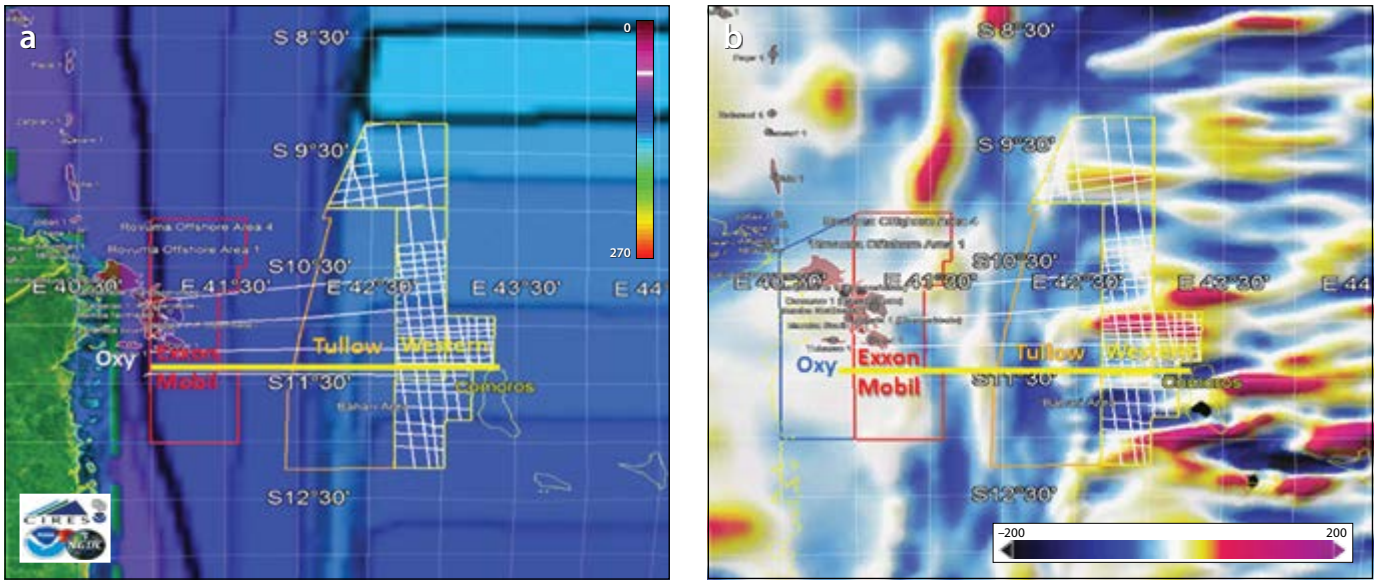
The bar was raised even further when superstar explorer Tullow Oil joined the party last year, fresh from earlier African successes in Uganda, Ghana, and Kenya and after extending its petroleum geology grasp further, into Guyana and Surinam in South America. Tullow took a 35% stake from Bahari and now operates for Discover.

Interesting Magnetic Anomalies

This is the first survey in the Comoros since Ion's pioneering regional SPAN work in 2011 and the 2014 infill, which built upon earlier 1980s seismic reflection and refraction studies conducted on cruises aboard R/V *Vema* and *Conrad* by Columbia University's Lamont-Doherty Geological



The Comoros Islands rise to the surface as atolls from water 3,000m deep, 300 km east of Mozambique. Oxy's Area 1 (blue) and ExxonMobil's Area 4 (red) in Mozambique each have 75 Tcf gas reserves west of Tullow Petroleum's (orange) and Western Energy East Africa's (yellow) Comoros blocks. Yellow line shows location of seismic overleaf.



Oceanic crust in Somali Basin is Lower Cretaceous age and youngs northward beneath blocks 38, 39 and 40. Basement beneath the western Comoros is composed of north–south trending ocean fracture zones, while under the eastern blocks it shows east–west magnetically striped ocean floor. Seismic basement mapping confirms magnetic basement structure here. Yellow line shows location of seismic on page opposite. Base map: GoogleMaps.

Observatory. These, together with DSDP and ODP core-hole programmes, proved that the Somali Basin floor, on which the Comoros volcanic island archipelago grew, was made of thin ocean crust, and not continental crust as at Mozambique Area 1, which lies west of the Davie Fracture Zone. The ocean floor formed during seafloor spreading in the Late Jurassic to Aptian, as Madagascar and India moved 2,000 km southwards, away from East Africa, meaning that the oldest sediments on the ocean floor in the Comoros are Lower Cretaceous.

As a result, it can be seen that Area 1 in Mozambique is on continental crust and Area 4 straddles the Davie Fracture Zone, but everything east of that is oceanic crust. This is clearly demonstrated by lower frequency magnetic anomalies over continents compared with oceanic crust, and by gravity and refraction seismic survey results showing thin, shallow gabbro with 7 km/s velocity that are about ~10 km thick. Seismic reflection and refraction data show a shallow Moho with 8 km/s velocity below the thin ocean crust, fracture zones and transform faults.

The basement below blocks 38, 39 and 40 is Lower Cretaceous ocean crust, with alternating east–west magnetic anomalies or 'stripes' in the ocean floor (see figure above), while the basement of the blocks to the west (35, 36 and 37) is the same but with the presence of well-developed transforms faults and fracture zones, some with as much as 2.5 km relief. New seismic (see figure opposite) shows ocean fracture zones bounding the first sediments to be deposited on the ocean floor, presumed to be of Lower Cretaceous age. Maps of seismic basement independently correlate directly with maps of magnetic basement. These Lower Cretaceous units are inferred to be restricted marine Type II source rocks and burial history plots show these today to be in the oil window in all the blocks. This offers a valid basis for Comorians' hopes for offshore oil.

High Hopes

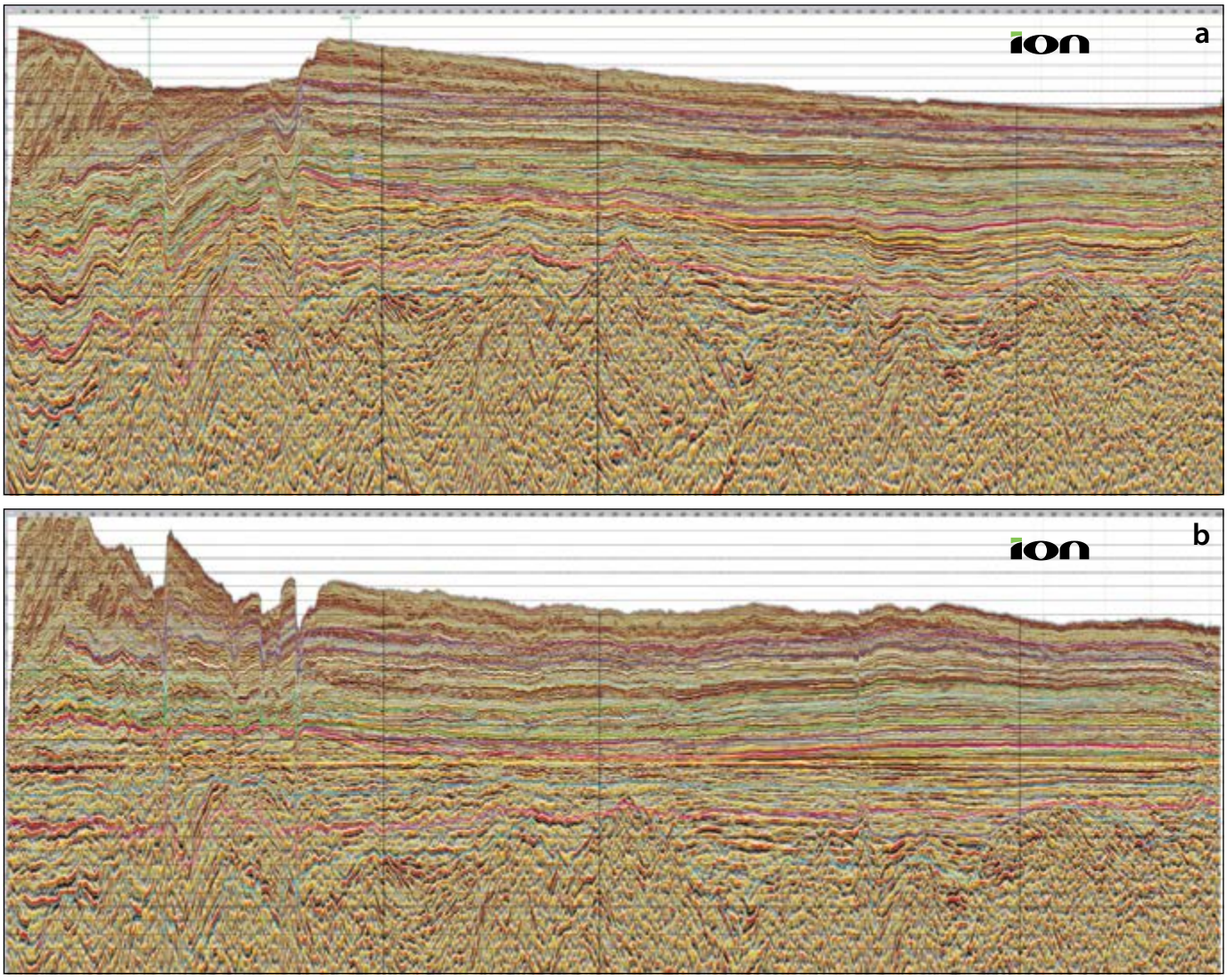
The igneous rocks in the Comoros Islands and surrounding seas are aged Miocene to present, which coincides with the onset of the East Africa Rift System, when asymmetric onshore rifts hosting deep anoxic lakes with Type I source rocks began developing. This is a modern analogue for Late Jurassic rifting of Gondwana, when similar lakes formed in Somalia, Mozambique and the Weddell Sea Basin. These later became restricted marine basins after Lower Cretaceous sea floor spreading, with Type II source rocks deposited during anoxic events. Sea floor spreading ceased in the Aptian, with a third post-spreading anoxic event possibly occurring in the Maastrichtian (Cohen et al., 2019).

Comoros mapped prospects range in size up to 700 km^2 (see figure opposite) and clearly straddle the boundary between blocks 36 and 39, showing similar trends and geology in deepwater Tertiary turbidite fans above the Lower Cretaceous oceanic basement. Many of these are associated with surface oil seeps detected by satellite synthetic aperture radar. In August 2019, Tullow began 3D surveying with the PGS vessel *Apollo*, and Western Energy East Africa have a 3D survey scheduled for 2020 that will cover 3,000 km^2 – an area that is bigger than the cities of Delhi or Bangkok.

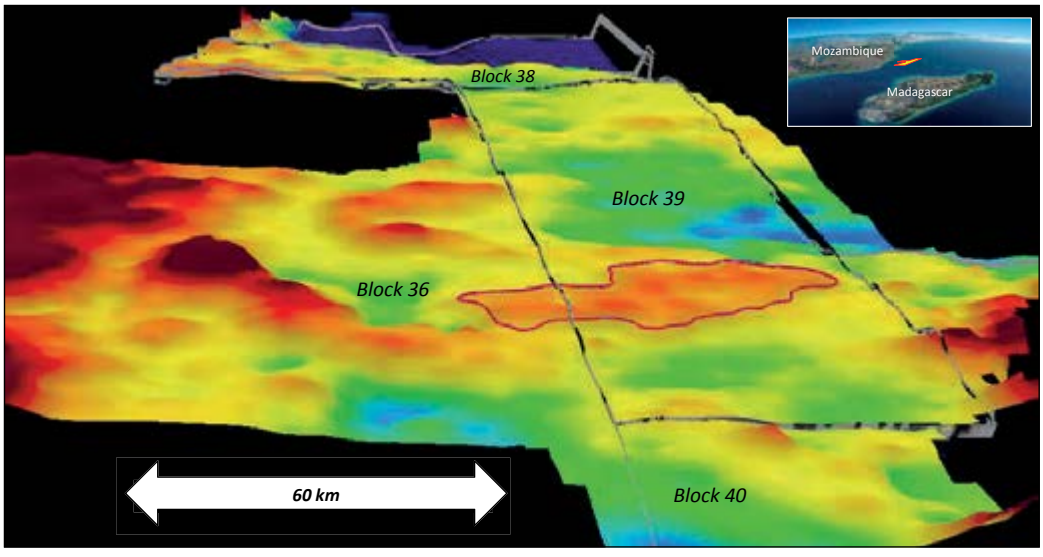
There appears to be considerable potential in these waters. A Competent Person's Report produced on Tullow's blocks 35, 36 and 37 estimated more than 7 Bbo and 1 Tcf of non-associated gas was recoverable; Western estimates it has 11 Bb of recoverable oil reserves on its blocks. Taking Tullow's and Western's mid-case assessment together, this amounts to half the oil equivalent of the 200 Tcfg found to date in the offshore Rovuma Delta.

Today, Comorians' hopes are high, as independent operators, seismic companies, news press and government have smelt the scent of the Perfume Islands and are on the hunt now for another essential oil: Texas tea, aka crude petroleum. The potential impact of any new-found wealth on the island's society could obviously be huge.

References available online. ■



(a) Seismic line Mz1-8400 crosses west to east from Mozambique Area 1 and 4 (left) through the active Kerimbas Graben and the Dugongo dry hole into Tullow's Block 36 and Western's Block 39 (right). The Kerimbas Graben is the site of the former Davie Fracture Zone, along which Madagascar translated south 2,000 km between Late Jurassic and Aptian time. It was reactivated in the Miocene by the East Africa Rift System which is both volcanically and seismically active in east–west extension today. (b) The same line is shown datumed near top Cretaceous (yellow) horizon. The line crosses deepwater toe thrusts (top left), through the active Kerimbas Graben with thicker Mio-Pliocene section and the Dugongo dry hole with excellent Palaeocene rock properties, into thinned Palaeocene and Eocene units in Block 36. The thick Palaeocene deepwater turbidite lobe can be seen in Western's Block 39 (right). Lower Cretaceous fracture zones in basement are well developed and present several avenues for mature oil prone Type II source rocks to vertically charge, beginning in the younger deep sea fans plays in Tertiary structures.



Depth structure map from Ion of new 2014 Comoros SPAN 2D PSDM data showing the presence of giant structures with capacity for multi-billion barrels. The outlined prospect has an area of 700 km², the size of Bahrain. Scale bar is 60 km.

Exploring the Last Frontier: Offshore South Gabon

JAKE BERRYMAN and GREGOR DUVAL, CGG

A new seismic survey and integrated study reveals potential in the ultra-deep offshore petroleum systems.

Historically, the focus of exploration in Gabon has been on the pre-salt plays of the interior sub-basin and the pre- and post-salt plays of the north and south sub-basins on the continental shelf. However, with these areas considered mature, and given the recent Ivela-1 and Boudji-1 discoveries, the announcement of Gabon's 12th licensing round, low drilling costs and more favourable production-sharing contract terms, explorationists are now looking further offshore.

In 2015 CGG acquired 25,168 km^2 of high-quality BroadSeis™ broadband 3D seismic, gravity and magnetic data in the Gabon South Basin and conducted an extensive two-year geological study for the Direction Générale des Hydrocarbures. State-of-the-art seismic imaging applied to this huge survey revealed the deepwater and pre-salt geology in unprecedented detail, and indicated the considerable potential of the basin, as well as that of the ultra-deep water.

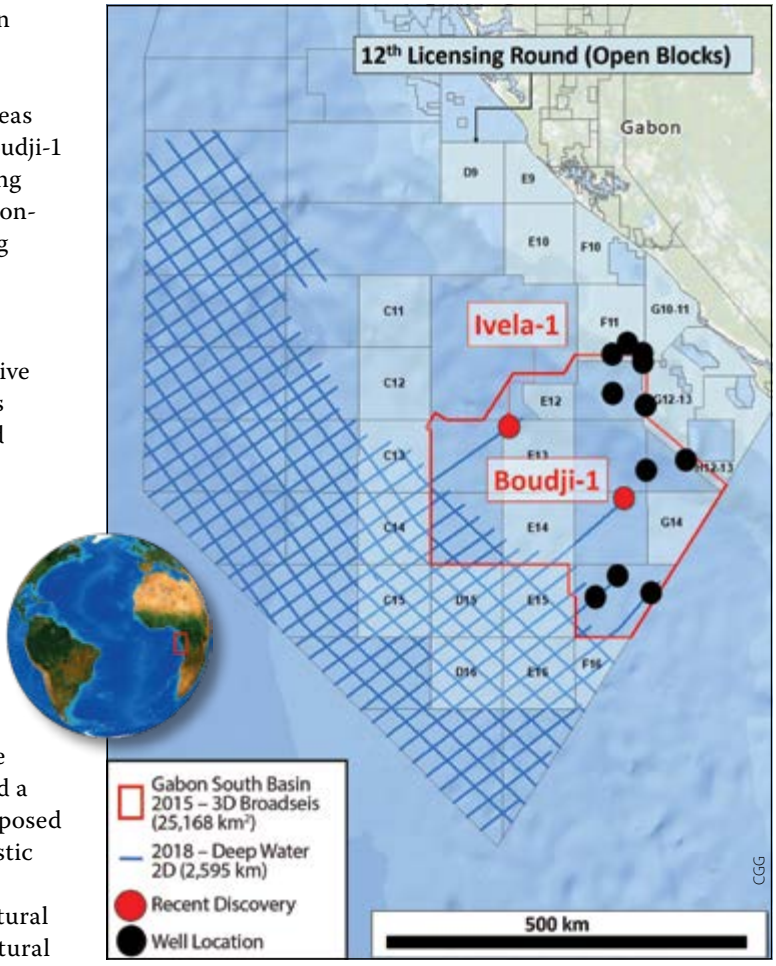


Figure 1: Map of South Gabon showing seismic coverage, locations of wells mentioned in the text and open blocks available in the 12th licensing round.

Active Petroleum Systems

The offshore Gabon basins have sedimentary fill typical of a passive margin setting, starting with syn-rift continental clastic deposits from Berriasian to Middle Aptian, a sag sequence made of transgressive Middle-Upper Aptian sands, shales and evaporates, and a post-rift series of Upper Aptian to Pleistocene age composed of shallow-water carbonates followed by deepwater clastic rocks, as illustrated in Figure 2.

Explorers have traditionally targeted combined structural and stratigraphic traps in the post-rift section and structural traps in the syn-rift and sag section in the offshore Gabon basins, as shown in Figure 3. In the Gabon North Basin, including the Ogooué Delta, the post-rift traps have been shown to be charged by a series of source rocks ranging from syn-rift lacustrine deposits to post-rift marine and deltaic deposits. In the Gabon South Basin, however, the only proven source rocks exist in the syn-rift lacustrine deposits of the Melania and Kissenda Formations, as illustrated in Figure 2, while there are questions over the distribution and maturity of post-rift source rocks.

It is thought that three post-rift source rock intervals may be found in the Gabon South Basin blocks offered in the 12th licensing round:

- A potential Turonian source rock (Azile Formation), which is proven to generate hydrocarbons in the offshore Gabon North Basin and has been drilled by several wells in the shallow waters of the Gabon South Basin. This source rock interval is the result of a deep marine anoxic event during the early Turonian (see Figures 2 and 4).
- A possible Cenomanian source rock (Cap Lopez Formation) from another global sea level high stand and deep marine anoxic event (see Figures 2 and 4).
- A potential Albian source rock (distal Madiela Formation) which has been shown to generate hydrocarbons and charge fields in the Lower Congo Basin to the south-east of the Gabon South Basin (see Figure 2).

Highlights from 2015 Data

Based on previous studies, the Gabon South Basin area is interpreted to include continental, transitional and oceanic crustal domains, as illustrated in Figure 5. Understanding the crustal types is important because they have different heat flows that can have an impact on source rock maturity.

In the early seismic images, the oceanic crust is jagged in nature and is displayed by a high-amplitude increase in

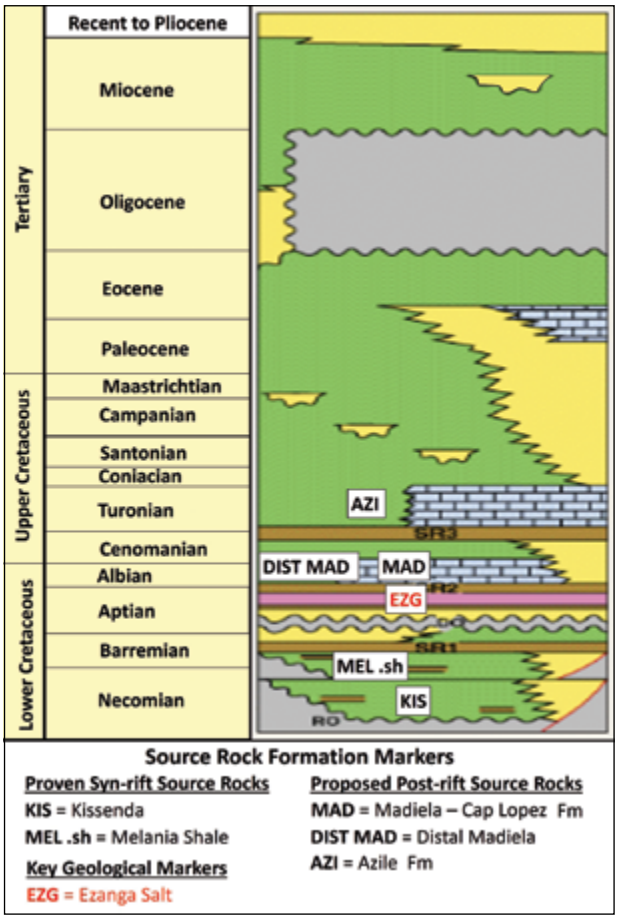


Figure 2: Chronostratigraphic chart of southern Gabon, modified from Bray and Lawrence, 1999.

acoustic impedance throughout.

Directly overlying the oceanic crust are a series of continuous, opaque, undulating parallel marine sediment beds that on-lap against a prominent unconformity surface. Drawing from previous studies in the area, from the stratigraphic relationship of this package with the surrounding sediments and from correlation of the seismic to the nearby wells that drilled through the Cenomanian-Turonian section, it is concluded that this is the interval where the post-rift source rocks are found.

Further up in the section, the seismic reflectors are regularly interrupted by bright amplitude patches, which indicate the presence of numerous sand-filled turbidite channels. From previous studies, it is thought that these are fed from the Congo Delta to the south-east and that they form good-quality reservoir targets (Figure 5). This turbiditic system has been active and depositing silici-clastic reservoir facies in the area since the Oligocene (Figure 6) when the West Africa plate margin was tilted by major tectonic events. These turbidites may interact with the Ogooué Delta input from the north-east. The Ogooué Delta is older than the Congo Delta, with onset of turbidite deposits in the Late Cretaceous, which have provided good reservoirs for most of the fields in the Ogooué Delta Basin.

On the images from the 2015 3D broadband data (Figure 5), the shallow subsurface is marked by a prominent seismic reflector that crosses the sedimentary structures at about 600 ms TWT below the seabed and mimics the bathymetry throughout the area of interest. This Bottom Simulating Reflector (BSR) is an indicator of the presence of large quantities of gas in the shallow sediments. At those depths, near the seabed, so-called gas hydrates can form. As the temperature increases again below the seabed, there is a point where the gas returns to its free state. The BSR observed on seismic data represents the boundary

Figure 4: Sea level curve highlighting high stands related to the Cenomanian to Turonian anoxic event, modified from Haq et al., 1987.

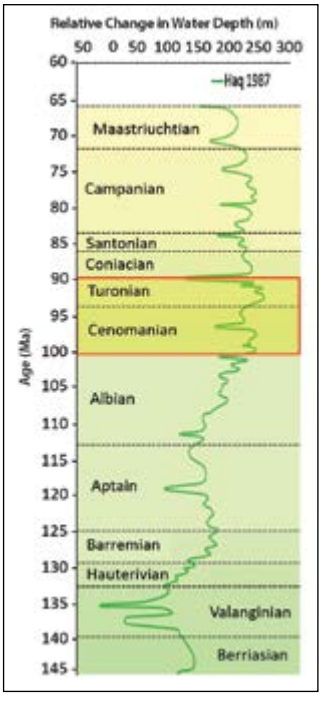
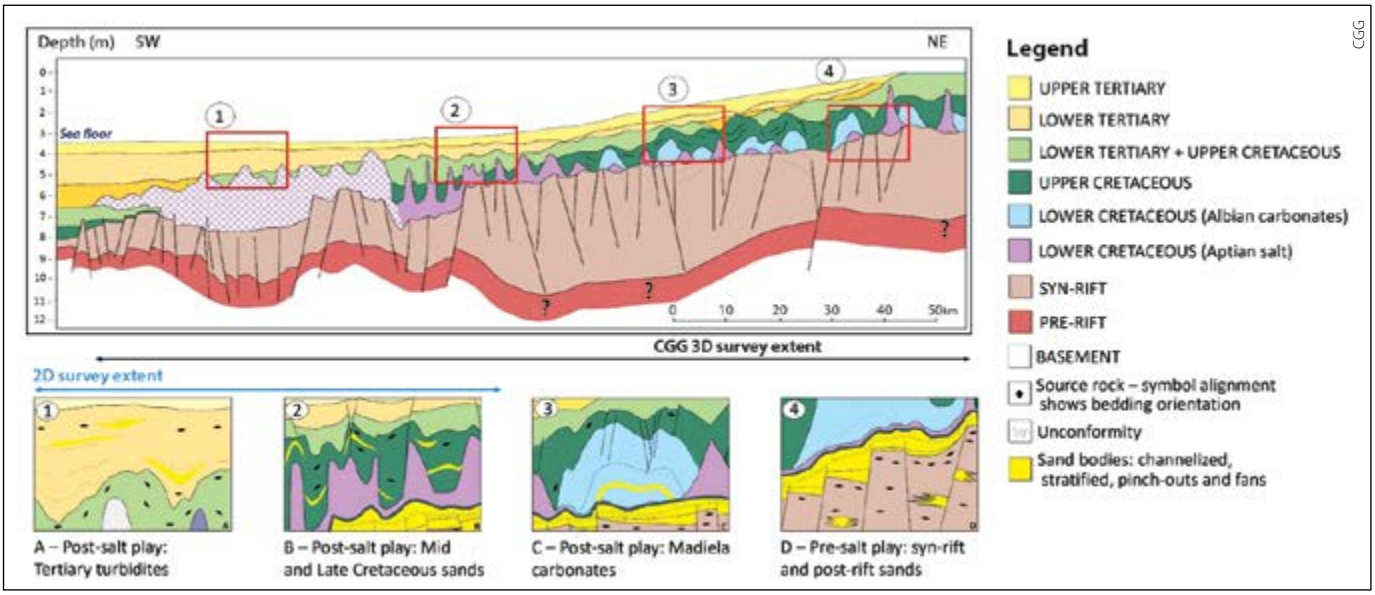


Figure 3: Simplified cross-section highlighting the play types offshore south Gabon.



between gas hydrates above and free gas below. Understanding the depth at which the BSR appears below the seabed is important because it provides an indirect measurement of the geothermal gradient and heat flow from the underlying crust, and hence provides information about the potential maturity of the hydrocarbon source rock. In fact, the potential gas chimney observed in the central part of the seismic section and connected to a deeper migration focal point is an interesting observation to support the maturity of Albian-Turonian source rocks.

On the north-east side of the seismic section in Figure 5, we observe the presence of the Aptian evaporates (i.e. Ezanga Salt Formation) and syn-rift fault blocks.

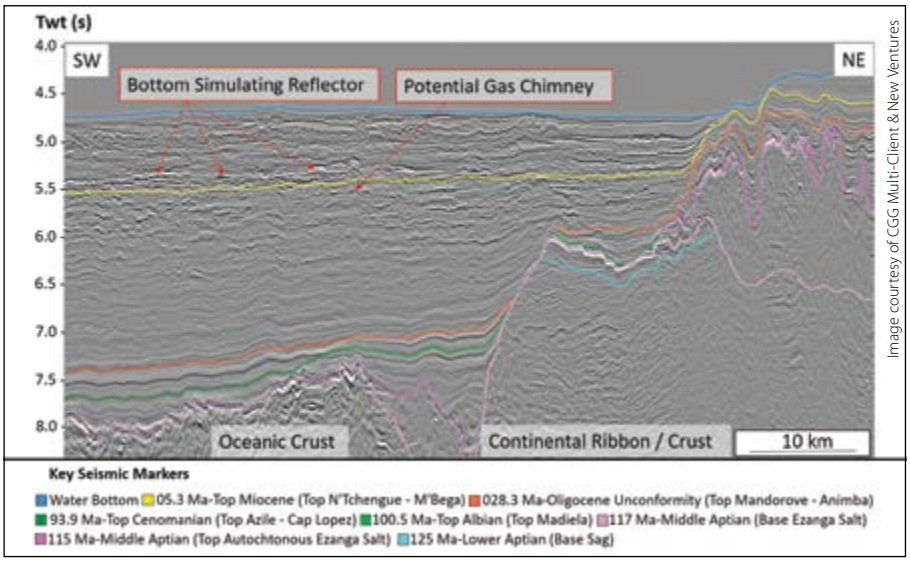


Figure 5: Seismic line highlighting key stratigraphic relationships, in the deepwater Gabon South Basin.

New Integrated Survey

As a consequence of the considerable potential revealed by the 2015 survey, CGG acquired a further 9,595 km of high-resolution 2D seismic data during 2018. This new 2D seismic covers the open blocks available in the upcoming licensing round (Figure 1) and is tied in to the 2015 3D broadband survey, the recent Ivela-1 and Boudi-1 discoveries, and the Judy-1, Genny-1 and Renee-1 exploration wells drilled in 2001. In addition, the westernmost extent of the survey covers new areas that have not previously benefitted from seismic data coverage. The survey was acquired in water depths between 2,000 and 4,140m using a 12-km streamer to provide ultra-long-offsets for deep imaging and velocity model building. It was towed at a depth of 12m in order to provide the wide seismic bandwidth necessary for optimum imaging throughout the entire seismic section, from water bottom to basement.

The new survey and an integrated study are looking at whether the source rock intervals outlined above can be mature in the ultra-deep offshore area where they have the benefit of a much thicker overburden, up to 4.5 km in places. They should also help us to understand how far the Congo Delta turbidite systems extend to the north and also how they interact with the Ogooué Delta input from the north-east, which may extend into the northern part of the new survey area.

A major objective of the new survey is to help understand how far the pre-salt petroleum systems may extend over the ultra-deepwater acreage of the Gabon South Basin. This is a successful exploration theme that has been proven by the recent Boudji-1 and Ivela-1 wells.

Deepwater Potential

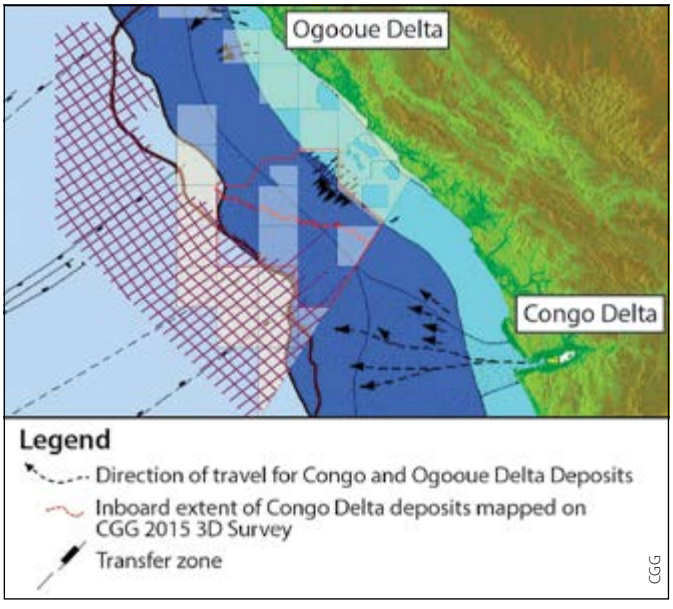
The deepwater potential of Gabon has been established with a comprehensive geological study of the Gabon South Basin, backed by recent discoveries. To test how far into the ultra-deep water this proven play extends, the new 2D survey and integrated study that have been acquired and commissioned will address the key questions about the ultra-deep offshore petroleum systems, including reservoir distribution in the area and source rock maturity.

The main play anticipated for the ultra-deepwater Congo South Basin is within stratigraphic traps or combined low-relief structural traps formed within the Tertiary turbidites originating from the Congo Delta slope and possibly the Cretaceous-Tertiary turbidites from the Ogooué Delta slope to the north, which have both proved to be good reservoirs. These turbidite reservoirs are interpreted to be sealed by impermeable marine mudstone interbedded with sandstone, which have been encountered in all the wells drilled through the Cretaceous-Tertiary sections.

The new survey will help to de-risk this extensive play whilst also investigating the potential of the transform faults to form huge structural and stratigraphic closures within the subsurface.

References available online. ■

Figure 6: Simple GDE map highlighting the inboard extent of the Congo and Ogooué Delta turbidite deposits and the cross-cutting transfer zones/faults.



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- What is the exploration/production history, and what are the major plays with remaining potential—conventional, unconventional, and field growth?
- What are key innovations in each super basin, these include: adoption of horizontal drilling, hydraulic stimulation, completion and drilling techniques, and seismic imaging that helped unlock the potential and what is needed to grow it further?
- How do "above ground" issues like politics, access, mineral ownership, and geography influence realizing the full resource potential of each super basin?
- Will the basin be a regional or global disrupter?
- Organized by AAPG Past President Charles Sternbach and a team of global experts

"Excellent diversity of talks. I really appreciated the consistent approach to communicating the geology – past, present, and future of each basin. Each presenter had a different approach that brought something unique about each basin forward."

– Past Super Basins Attendee

Join AAPG for the 2020 Super Basins conference at SuperBasins.AAPG.org

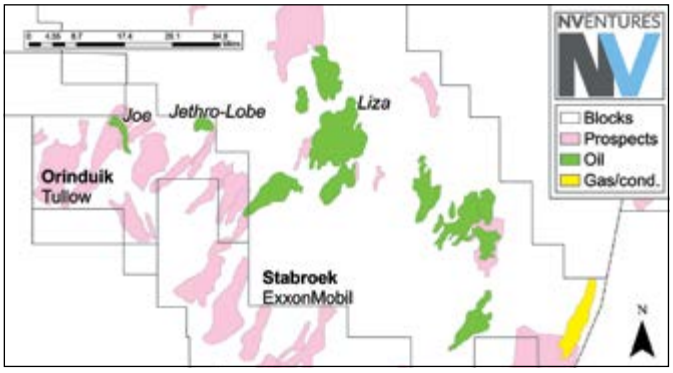
Guyana: Two Oil Discoveries

Two discoveries in **Guyana** were announced on 16 September 2019, further progressing the exciting story of oil in that country (see page 18).

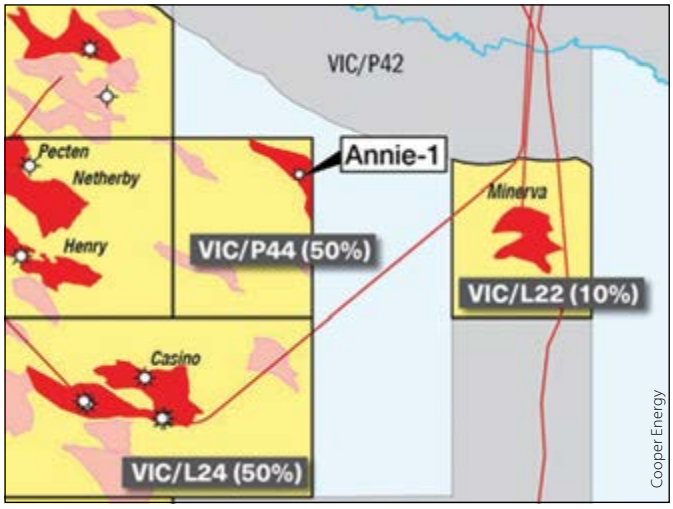
ExxonMobil's announcement of the success of its **Tripletail-1** well added to the previously stated estimated recoverable resource of more than 6 Bboe found in the 26,800 km^2 **Stabroek Block**. The well, drilled in over 2,000m of water, found 33m of high quality, oil-bearing sandstone in the south-eastern end of the block, about 5 km north-east of the Longtail well, which discovered 78m of good sandstone reservoir in June 2018, and close to the 2017 Turbot discovery. It is also approximately 50 km from the first major discovery on the block, **Liza**, which is in development, with first oil expected by early 2020.

Tripletail is the 14th discovery since 2015 on the Stabroek Block, which ExxonMobil operate with 45% interest, withHess Guyana Exploration on 30% and CNOOC Petroleum Guyana, 25%.

The second discovery announced on 16 September was on the **Tullow**-operated **Orinduik Block. Joe-1** encountered 14m of net oil pay in high-quality oil-bearing Upper Tertiary sandstone reservoirs, which is the first oil discovery in rocks of that age. The well was drilled in a water depth of 780m and lies about 50 km west of the Liza field and 75m north-north-west of Tripletoe. Tullow has 60% of the block, while Total E&P Guyana holds 25% and Eco (Atlantic) Guyana 15%. ■



Australia: Otway Basin Discovery



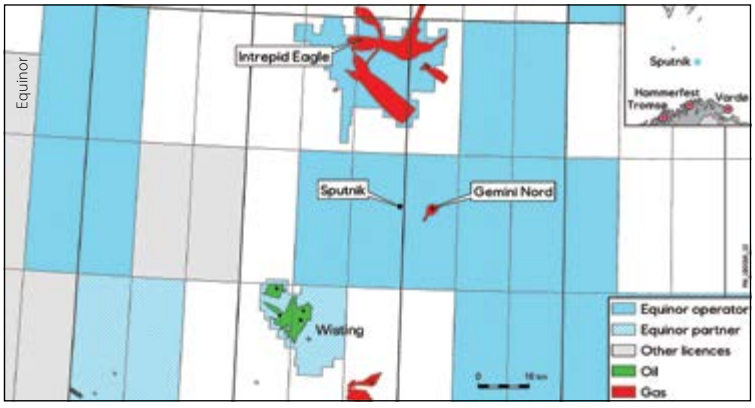
Cooper Energy have made a discovery in the large Late Jurassic–Cenozoic **Otway Basin**, on the southern Australian passive margin, the first discovery in the basin for eleven years. The well, **Annie-1**, in **Block VIC/P44**, is located about 9 km from the coast of Victoria in 58m of water and found a net gas pay 62m thick in the Waarre C sandstone formation at about 2,241m depth, although the deeper Waarre A target proved to be water wet.

Cooper Energy is operator, holding the block equally with Mitsui E & P Australia. This is the first offshore gas exploration well the company has drilled in Australia and the first of an AUS$80 million drill campaign by the joint venture this year to find new gas supplies for south-east Australia. It is located about 15 km east of the producing Netherby and Henry gas fields, which are also operated by Cooper Energy. ■

Norway: Barents Sea Find

A discovery in the **Barents Sea**, announced in late August, has found light oil in licence **PL855**, about 350 km north of the Norwegian town of Hammerfest in water depths of about 450m. The well, **Sputnik-1**, about 30 km to the north-east of the **Wisting** oil field, was primarily targeting the Late Triassic Snadd Formation.

Although the quantities discovered at Sputnik are relatively small, with estimates of between 20 and 60 MMbo recoverable, the well proves the presence of oil in the blocks north of the Wisting field, which itself has an estimate recoverable resource of 440 MMbo. The geology of Barents Sea area is very complex, meaning that each well drilled adds valuable information about a region which could hold up to 17.6 Bboe in the Norwegian sector alone. ■



Billions at Play

Oil and gas in Africa – resource curse or blessing?

KIERAN ARCHER

The phrase 'resource curse' is widely used in political economy to describe the situation where natural resources such as petroleum, diamonds or precious metals are exploited by foreign investors, usually to the benefit of a small number of native overlords and with damaging consequences for local communities or the environment. Also known as the 'paradox of plenty', it has been identified in many African countries, where hugely valuable oil and gas resources have created large profits for oil companies, with local wealth-creation being limited to a few indigenous chiefs and politicians. In contrast to the enrichment of the offshore bank accounts of a select few, the damaging impacts on many more people in the local communities have been severe, ranging from health and environmental implications of pollution and gas-flaring, and to war and political upheaval, to competitive consequences for traditional employment sectors such as fishing and farming.

This broad-ranging new book from NJ Ayuk addresses the future of African oil and asks whether it is fated to always be a resource curse or if it can be managed in such a manner as to become a blessing for many African citizens. Mr Ayuk is a Cameroon-born, American-educated lawyer who is CEO of a Pan-African law group and has spent a lifetime negotiating resource extraction deals between international oil companies and a variety of African states. He analyses the history to date of petroleum exploitation across the continent and cites a litany of greed, corruption and ineptitude in countries such as Nigeria, Angola and Libya, as well as amongst some of the major players in the industry. He does not pull his punches and is direct in allocating blame to the rent-seeking few for the sufferings of the impoverished many.

Optimism and Ideas

However, the book is not defeatist and Mr Ayuk's optimism for alternative means of managing resources in the future shines through. He focuses on many initiatives which could be harnessed to ensure that energy resources are employed for transforming the lives of millions of Africans. These vary from the invaluable role which women could play in managing the benefits of oil and gas,

to the need for local companies to gain access to marginal fields development programmes, and to minimising the wastage of natural gas through flaring. He uses examples of innovative deals being negotiated by countries such as Senegal, Mauritania, Uganda and Equatorial Guinea, who will be the new generation of petroleum-producing nations in Africa, to optimise the benefits of energy resources for their local communities and national economies.

Ayuk roams widely over a number of issues which are linked to the future of African oil. These include the need for oil companies to purchase local content and to demonstrate their corporate social responsibility agendas through support for indigenous communities. He also focuses on the critical deficiencies in African state electricity suppliers, citing the lack of reliable electricity in many African countries as a key reason behind developmental failings. He argues convincingly for a strategy of 'gas to power' as a multi-headed approach to reducing energy wastage, reducing external expenditure on unnecessary imports and supporting technological development which depends on reliable power supplies.

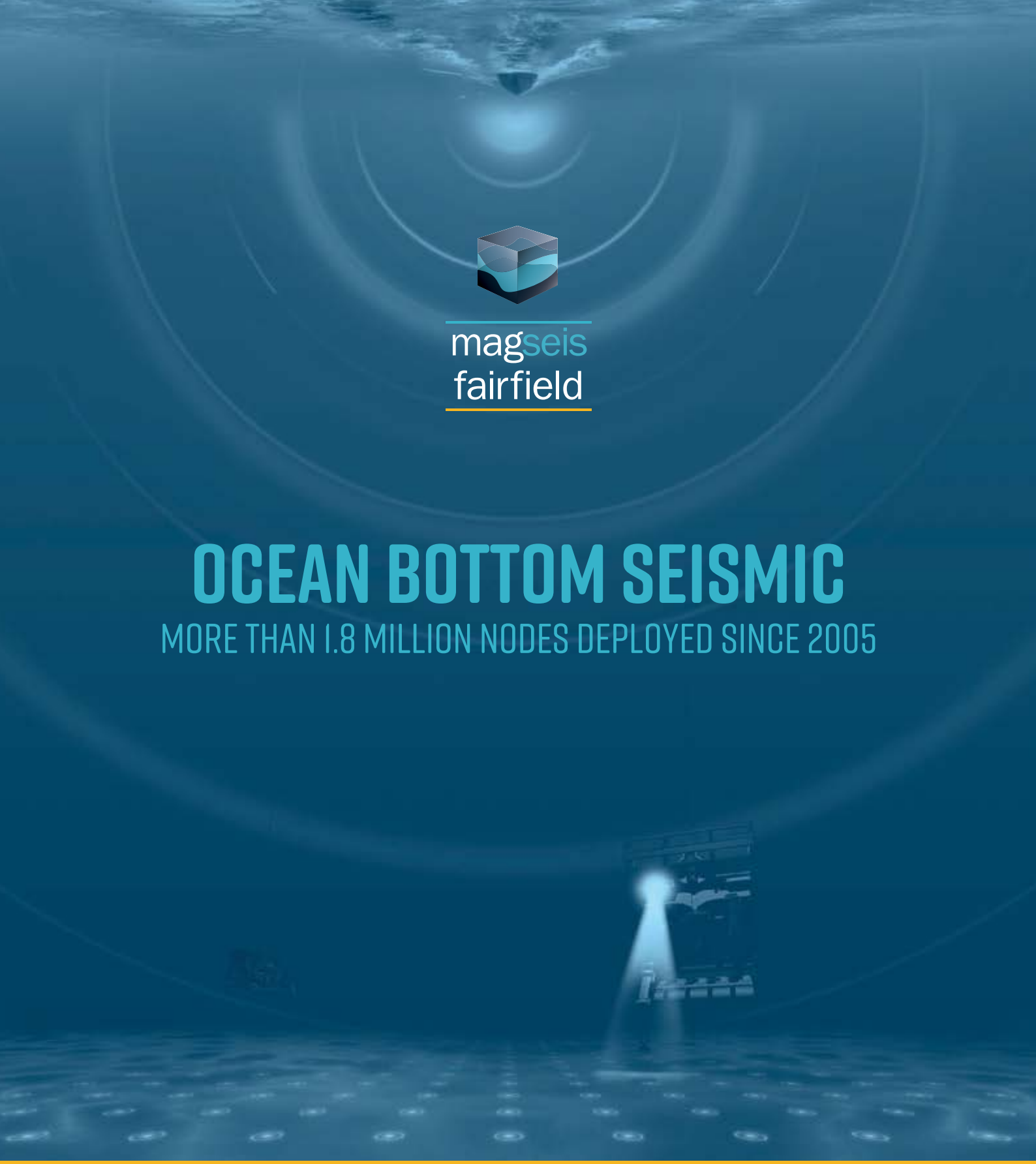
Although not an academic treatise, this book is comprehensive and well-researched, with copious sources across multiple disciplines. It is eminently readable and would be of interest to anybody with an interest in the political economy of emerging nations. It would be particularly instructive to oil industry professionals who are keen to understand some of the dynamics of development in contemporary Africa. Deal-makers seeking a manual for negotiations over oil revenues might be somewhat disappointed that the sub-title of the book ('The Future of African Oil and Doing Deals') is not realised very fully. The section on deal-making is limited to about 14 pages, but it does contain some passionately-held views, which Ayuk imparts to the new generations of deal-makers in Africa: *"Each one of us has a mandate to use our education to impact communities and to promote economic growth and empowerment... Use your skills to make sure that every day Africans receive their fair share of the benefits the continent's natural resources can provide."*

Billions at Play
By NJ Ayuk
Clink Street Publishing, 2019 ■

magseis fairfield

OCEAN BOTTOM SEISMIC

MORE THAN 1.8 MILLION NODES DEPLOYED SINCE 2005



INDUSTRY LEADING NODAL TECHNOLOGY

AUTOMATED HANDLING SYSTEMS AND FLEXIBLE DEPLOYMENT SOLUTIONS

NEXT GENERATION SOURCE TECHNOLOGY

Developments in the Marine Seismic Business

Earlier this year a merger was announced between TGS-Nopec and Spectrum, both companies which specialise in the acquisition, processing and interpretation of multi-client marine seismic data. Kristian Johansen, CEO of TGS and now of the merged company, talks to us about trends in the marine seismic business and the thinking behind this merger.

What are the important current trends in the marine seismic field?

The obvious one is the separation of marine seismic companies into those concentrating on multi-client and those more focused on acquisition, along with general consolidation in the industry on both sides. Another notable feature is the technological development that is taking place on the processing side of the business, driven by clients' needs to get the data sooner.

Will the trend away from seismic companies owning vessels continue?

Well, someone has to own the vessels, so we will end up with some companies concentrating on the seismic acquisition, and others which are specialists in the shipping aspects of the business, including production efficiency and HSE. I'm very happy that companies like Shearwater and Polarcus have a very clear strategy in that regard.

Do you expect further consolidation in the marine seismic business and would that be a positive move for the E&P industry?

A lot has already been done, so there aren't so many obvious transactions or consolidation opportunities out there. I think that the whole industry is going to benefit from this, because the way it's been over the last few years has not really been very sustainable, with a number of companies going through Chapter 11 or refinancing. This hasn't been ideal for either the seismic industry or the oil companies, so I don't think that consolidation is necessarily a negative thing for our clients. It is important that we keep a healthy seismic industry.

What do you see as the major commercial challenges to the marine seismic business in the next decade?

The biggest challenge is that seismic spending has been cut hugely: from around $9.2 billion in 2014 to $3.7 billion in 2017. It's now up slightly to about $4 billion, but that's still a big change from $9.2 billion. Oil companies have become very disciplined and efficient, especially in their procurement business, and there has also been considerable consolidation, so there are fewer companies out there. For example, I think there were 82 companies bidding in the US Gulf of Mexico licensing round in 2009; in recent times there are maybe between ten and 20 companies active in that region, which is a significant change. We have pretty much the same number of seismic companies as a decade ago, but we are chasing far fewer clients. That is probably the greatest challenge we anticipate looking ahead; we need to see more oil companies emerge or we will see further consolidation in the seismic industry.

How will the new merged company address this challenge?

Firstly, the merger means that we are a bigger company, particularly in the areas where we are seeing growth in the

TGS

Kristian Johansen has experience from executive positions in the construction, banking and oil business. He joined TGS as Chief Financial Officer in 2010 and became Chief Operating Officer in March 2016, before being appointed as Chief Executive Officer in 2016.

E&P business, like the South Atlantic, where we now have a much bigger footprint on both sides. There are also some cost benefits from the synergies, which will obviously make us more competitive. The two data libraries are extremely complementary; they have data where we haven't and vice versa; it is a very balanced transaction in that respect. In addition, it has given us access to a lot of good people.

The second thing is that the two companies have a very similar culture. The integration process, although it has only just started, is going really well because we are actually quite similar in our mindsets, so that's really helpful, because sometimes these things can be very complicated.

What changes are you seeing in the commercial side of the seismic business?

I don't see any really significant changes. The really hot topic in the industry is, of course, all about the use of the cloud for high performance computing and for data storage. It is now much easier to access data and download it from anywhere, and from any seismic company, which is making a huge difference. All the investment at the moment is going into compute power, data lakes and ease of access. This might mean that we'll see some changes in business methods, such as moving from direct sales to subscription models.

Do you envisage innovative business models in the seismic world?

I think a lot has been developed and will continue to develop around machine learning and AI. We've already seen companies like Google, Amazon and Microsoft moving into oil and gas, and that's because it's an extremely data-rich market. These sorts of companies are really good at developing machine learning algorithms, but they need a lot of data in order to train them, and that's why they have so much interest in the oil industry, including in seismic. So I think that there will be some changes and opportunities for our industry around that. Rather than just providing data, we will be able to use machine learning algorithms to get extra information out of that data, and adding value in that way will provide different business models in the future.

We will never reach the point where seismic companies tell oil companies where to drill, but by providing information as well as data we are getting nearer the decision-making process. The key to that will be using artificial intelligence and machine learning that we have developed ourselves based on the massive amount of data we have. As an example of this, TGS have just acquired a company called Lassar, which provides historical and monthly oil and gas data. It's a small company, but it has a lot of production data in the Permian, and by combining that with the completion and well log data that we already have, we will be able to predict production, which is obviously a very hot topic. This is a small acquisition, but a very important strategic one. To be a seismic company that can provide analysis and prediction – that's a very big step for us and a very positive one. We want to be seen not just as a seismic company, but more as a data and information company. ■

The Carbon Capture Conundrum

Deep, dark and turbulent are three adjectives which could be used to describe the often hostile waters of the North Sea. Here is a part of the world where oil and gas exploration and production has had to show long-term resilience and where the end of life decommissioning of facilities has reached new levels of complexity.

Given that hostile environments take no prisoners, it is perhaps appropriate that the North Sea should be a testing ground for the still-emerging solution of Carbon Capture Utilisation and Storage (CCUS). Capture carbon emissions, runs the thinking, and plunge them into a secure space where they can no longer make a contribution to global warming. While CCUS is both complex and costly it is increasingly seen as an essential element in efforts to meet emissions reduction targets.

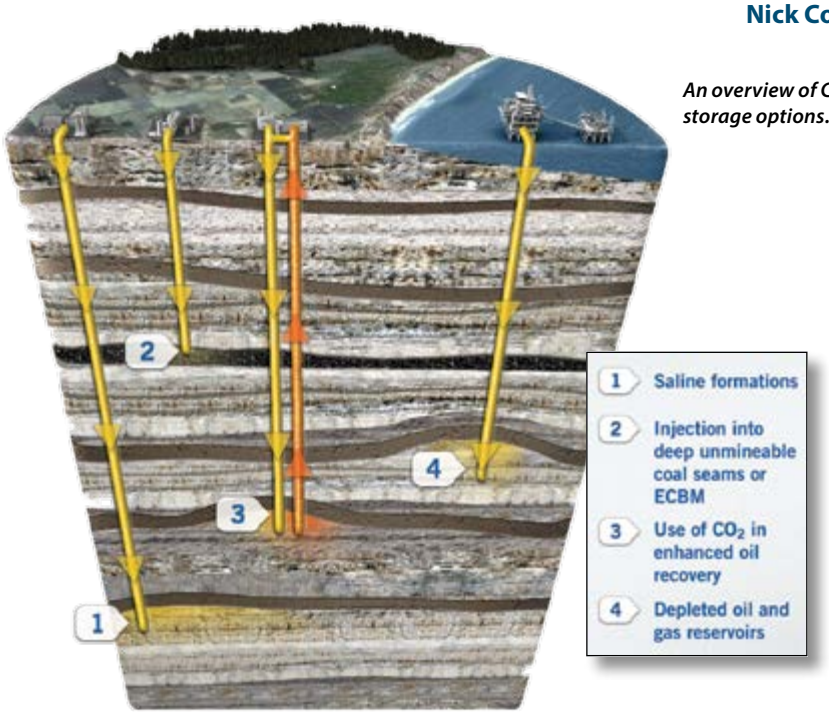
"CCUS will be vital to reach the global climate goals of the Paris agreement," says Eldar Sætre, President and CEO of Equinor, which is partnering Shell and Total to explore CCUS opportunities as part of the Northern Lights project (see page 34). Sætre makes the point that CCUS needs co-operation between companies and governments. Costs have to be shared and CCUS needs to be accepted as part of the solution.

Centred on looking at options for developing CO_2 storage on the Norwegian continental shelf, Northern Lights, like other CCUS projects around the world, is all about making CCUS commercially viable. Clearly it helps to have three oil majors involved, along with the backing of a wealthy Norwegian government, but these projects have to earn their keep.

By the end of 2018 there were 43 carbon capture projects globally, the majority of these in the US, where it is used predominantly for Enhanced Oil Recovery (EOR). This involves using carbon to push out more oil from a well which is nearing the end of its life. The carbon eventually fills the redundant well which is sealed for safe storage. The most recent incentive to push forward with EOR in the US has been to raise carbon tax credits from as little as $10 a ton to as much as $50 a ton for carbon captured and stored in geological storage. The consultancy firm Wood MacKenzie estimates that the carbon price would have to rise to $60 to make these projects viable in the long term.

The conclusion is that CCUS will continue to need a kick-start, from the chilly depths of the North Sea to the heat of Texas. Ultimately capturing carbon will have to be cheaper than not capturing it. ■

Nick Cottam



An overview of CO_2 storage options.

Provided by the Global CCS Institute

Conversion Factors

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

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

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

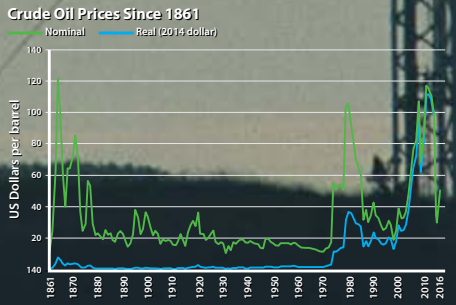
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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

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

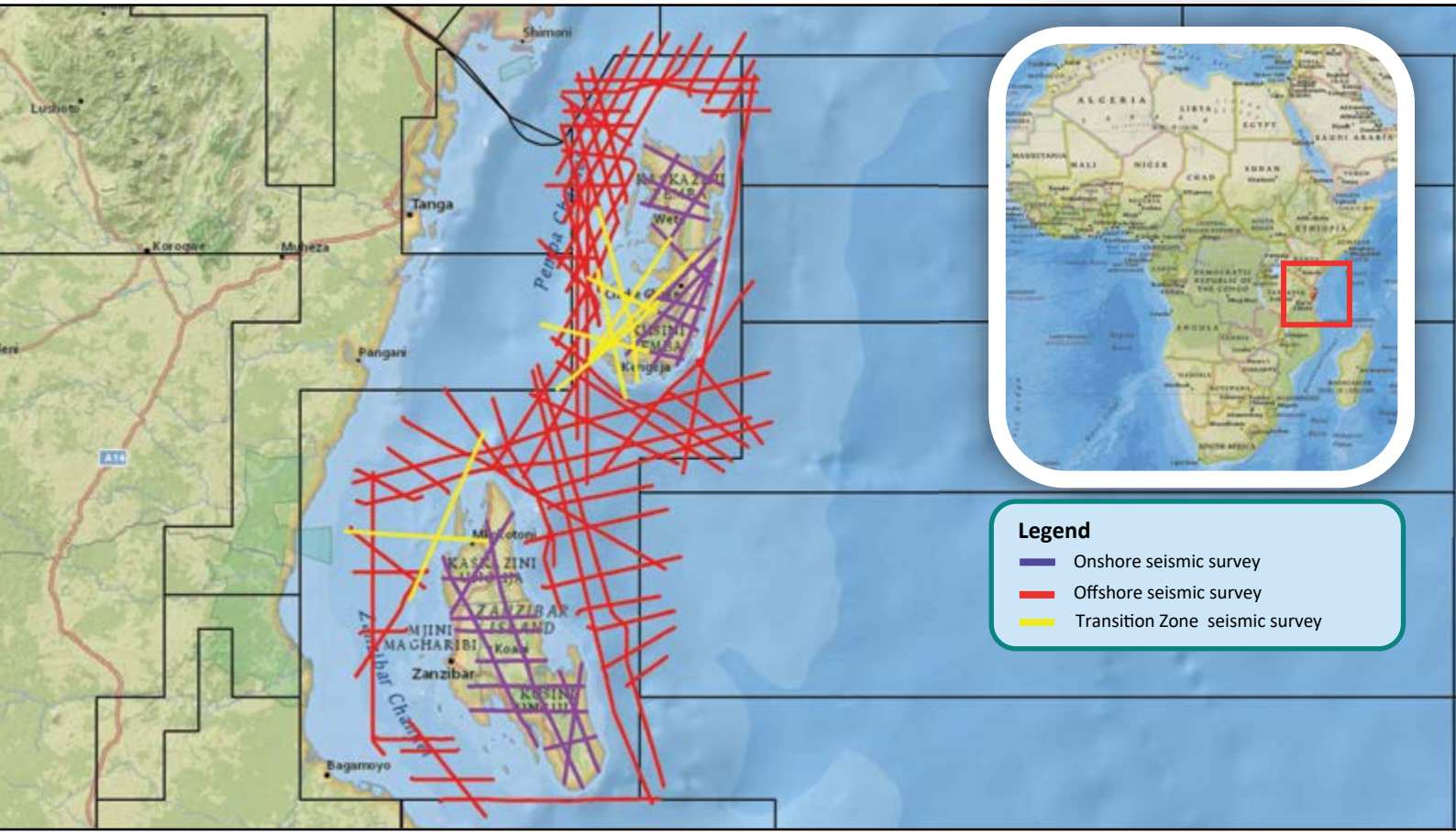
Major field
Recoverable reserves > 100 million barrels (16 million Sm^3) of oil equivalents

Historic oil price



Pemba-Zanzibar, Tanzania

New Multi-Client 2D Survey for a New Exploration Journey



BGP has acquired 3780 line km of 2D multi-client seismic survey in Pemba-Zanzibar, onshore/offshore Tanzania. The survey covering complex terrain aiming to assess the hydrocarbon potential of the Pemba-Zanzibar islands. Much of the area covered by the survey were comprised of onshore and offshore and shallow water transition zone environments where seismic operations are challenging.

Favorable geological settings are indicated by rich gas discoveries in onshore and offshore Tanzania basin. Active petroleum system are confirmed in Pemba-Zanzibar Block by three sources (J-K-E) confirmed by wells and oil seep with several reservoir sets penetrated by well and existence of Lower Cretaceous, Paleocene, Eocene, Oligocene reservoir supported by new seismic data. These new data will provide explorers with a better insight into the identification of prospective structural and future detailed seismic survey designs. Final PSTM and PSDM deliverables will be available in Q3 2019.

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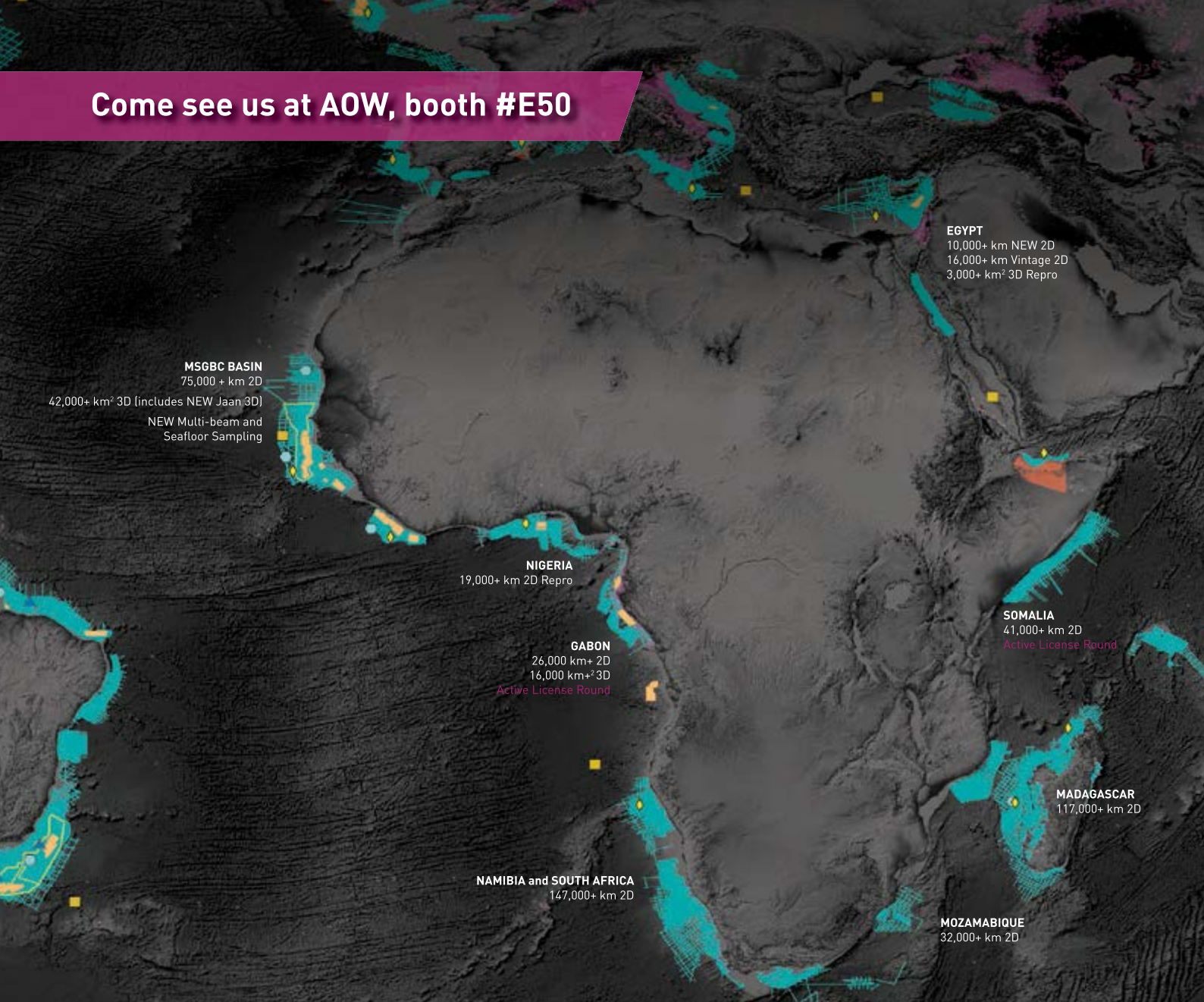
Come see us at AOW, booth #E50



The world's leading geoscience and multi-client data provider just got better.

TGS has completed the acquisition of Spectrum, holder of the world's largest 2D seismic library, along with 3D data and geological expertise in key global basins. Our new organization provides industry-leading seismic and geological data, as well as interpretation products and services. All are delivered through an innovative mix of technologies and unmatched imaging capabilities to energy companies globally.

Our combined extensive regional data coverage, coupled with in-depth geological knowledge, has been critical in supporting licensing rounds in several countries and numerous acreage farm-outs. This experience positions TGS as the multi-client company of choice in the region.

TGS, the gateway to subsurface intelligence.

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