VOL. 15, NO. 5 – 2018

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

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GEOPHYSICS

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EXPLORATION
Ireland's Porcupine Basin: Drilling Time?

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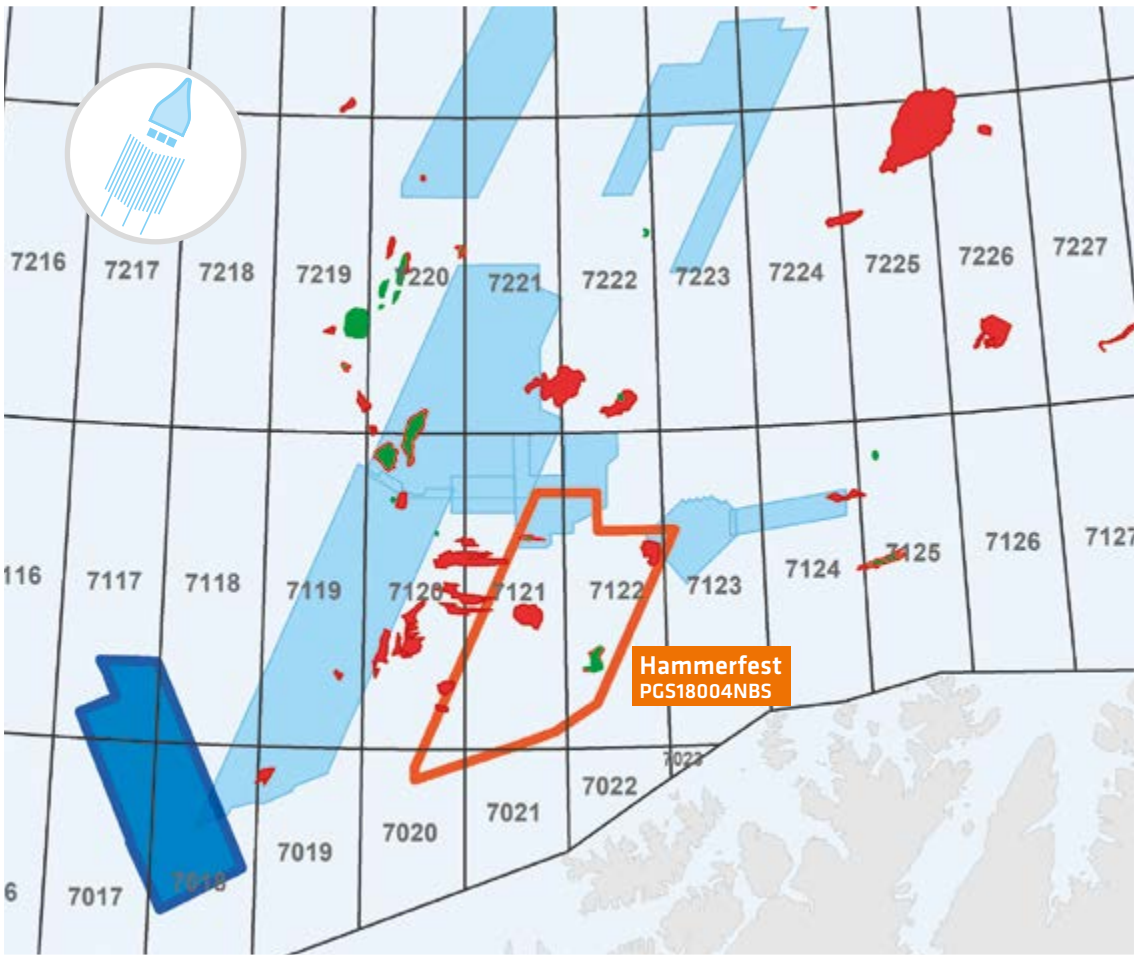
Make Better Decisions with Hammerfest Ultra HD3D



Barents Sea – GeoStreamer Ultra HD3D – 4 500 sq. km

This high density survey was completed with an innovative acquisition design that will maximize use of the full wavefield. Ultra-long streamers facilitate PGS FWI to even greater depths and Separated Wavefield Imaging (SWIM) provides increased illumination. The final data will deliver detailed stratigraphy at all depths and reliable AVO attributes for reservoir characterization.

PSTM data due June 2019. PSDM data due September 2019.

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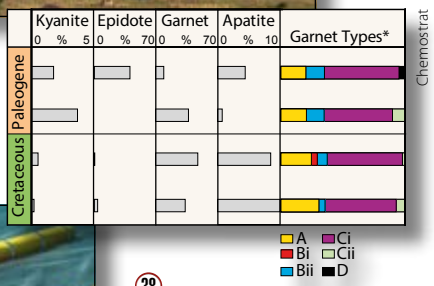

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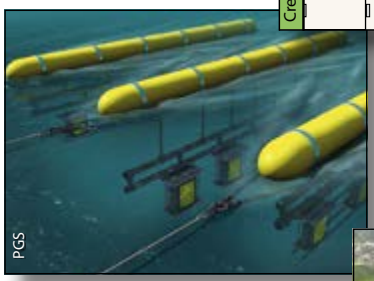

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Time to excite the public about how our Earth works and where our resources come from.

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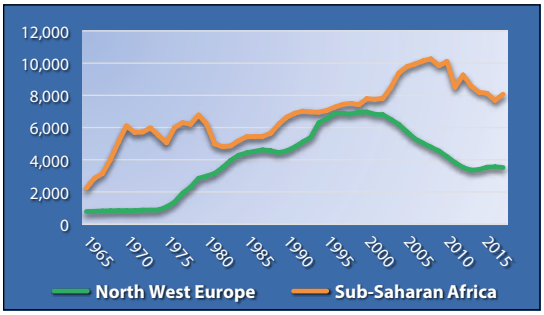
They Keep On Surprising Us

Sub-Saharan Africa and North West Europe: both have experienced oil and gas exploration for over a hundred years – and both still keep surprising us.

One of the first oil wells in the world was sunk in Wietze in northern Germany in 1858, leading to the discovery of over 70 fields, while in Scotland they were extracting oil from shales from the 1850s, for use as candles and lubricating lamps as well as for burning. Oil exploration in sub-Saharan Africa also started early in the 20th century – as far back as 1907 in Nigeria and 1915 in Angola, for example. The East African industry began with an Anglo-American expedition to Abyssinia (now Ethiopia) in 1920, with early efforts concentrating on Uganda and the Eritrean Red Sea.



BP Statistical Review 2018

Oil production from main producing countries in North West Europe and sub-Saharan Africa (Mbopd).

Once drilling moved offshore, both these regions found their feet. The first well was drilled off Nigeria in 1963, with the first offshore field there, Warri, discovered by Shell in 1965. Angola followed suit with Malongo in 1968. Once the first commercial discoveries in the North Sea had been made – the UK West Sole field in 1965 and Norway's Ekofisk in 1969 – there was no looking back for North West Europe, either.

Until, that is, the late 1990s, when 'peak oil' reared its head. Production in North West Europe took a steep dive – but, against all expectations, in 2013 it steadied, and since then there has been a slight upwards trend. This was largely driven by Norway, with discoveries such as the 2.1–3.1 Bbo giant, Johan Sverdrup – but also by explorers looking at different types of reservoirs, like the basement discoveries West of Shetland.

Production was buoyant for longer in Africa, before dropping back in about 2012. That has also been reversed, and is likely to continue positively, as areas once considered barren, like the MSGBC Basin or Lake Albert in Uganda – both discussed in this edition – have been turned around by exciting discoveries (and perseverance) and are now fast approaching production.

Crucial, however, has been the drive to extract every last drop from the reservoirs, both by the use of new techniques and by a willingness to think imaginatively and come up with new ideas about the geology and the plays. This will become increasingly important for both regions in the future. ■

Jane Whaley
Editor in Chief

DOES LIGHTNING STRIKE TWICE?

There is a commonly held view that lightning never strikes the same place twice – but it does! Can it therefore be used as a safe, environmentally clean and cost-effective source to look for oil and gas?

Inset: The Murchison Falls on the Victoria Nile is formed at the intersection of the Tertiary-age Lake Albert rift and Pan African Basement and has eroded back several hundred metres from the original fault scarp. The river is one of the input points for the fluvio-deltaic reservoirs of the Victoria Nile delta play discovered in 2008.

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GEOExPro

www.geoexpro.com

GeoPublishing Ltd
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
+44 20 7937 2224

Managing Director
Tore Karlsson

Editor in Chief
Jane Whaley
jane.whaley@geoexpro.com

Editorial enquiries
GeoPublishing
Jane Whaley
+44 7812 137161
jane.whaley@geoexpro.com
www.geoexpro.com

Sales and Marketing Director
Kirsti Karlsson
+44 79 0991 5513
kirsti.karlsson@geoexpro.com

Subscription
GeoPublishing Ltd
+44 20 7937 2224
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
kirsti.karlsson@geoexpro.com

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

Cover Photograph:
Main Image:
©www.123rf.com/ Romolo Tavani
Inset: Tullow Oil

Layout: Winslade Graphics
Print: Stephens & George, UK

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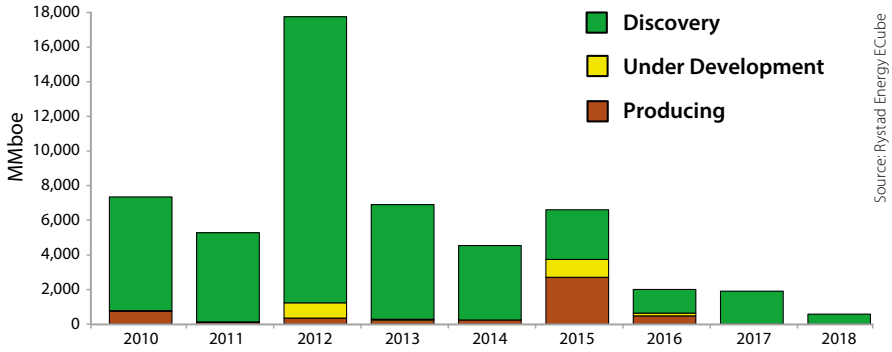
Discoveries Will Shape the Future

Africa is struggling to convert discoveries into producing fields.

Africa has been one of the less active exploration zones in recent years, especially after the crude oil price crash. Within Africa, the hotspots in the past three to four years have been the Senegal-Mauritania maritime border and Egypt, where there has been a considerable amount of exploration, resulting in some high profile discoveries. These include the giant Zohr gas field and the Atoll discovery offshore Egypt, the Ahmeyim-Teranga-Yakaar discoveries offshore Mauritania and Senegal, and the Nooros find onshore Egypt. However, as the graph below illustrates, overall exploration success has fallen considerably from 2016 onwards, compared to the levels from 2011 to 2015.



Total discovered volumes (oil and gas) in Africa by year and current life cycles of the discoveries.

One reason for the drop in the discovered volumes is the level of success of high impact wells drilled since the beginning of 2016. A total of 14 wells drilled since the beginning of 2016 were classified as high impact, either because they were a play opener or the focus for the operator, or based on large volumes of prospective resources reported. Only four resulted in a commercially successful discovery, whereas another four showed small or uncommercial volumes of hydrocarbons and the rest were declared dry.

However, the rest of 2018 and 2019 seem encouraging, with as many as 15 such high impact wells planned. Their locations vary from onshore Egypt, Morocco and Tanzania to deepwater Gambia, Namibia, South Africa, Ghana, Mauritania and Angola. The participation of supermajors like Total and ExxonMobil, Norwegian Equinor and British independent Tullow, as well as Kosmos and FAR, who have already seen success in Mauritania/Senegal waters, shows encouraging signs for near-term future exploration activity in Africa. In the rest of 2018 alone, ten such high impact wells, including Total's Tarif prospect onshore Egypt, Tullow's Cormorant prospect offshore Namibia, and FAR's Samo prospect offshore Gambia, are expected to be drilled. Also, the recent success seen by the independent Savannah Petroleum onshore Niger with the Amdigh, Bushiya and Kunama discoveries, has opened up a whole new prospective area in the continent.

Although Africa has tasted a reasonable amount of success in terms of discovered volumes since 2011, sanctioning and development of these reserves is an entirely different story. A paltry 17% of the overall discovered volumes have been sanctioned till now. The sanctioned volume would have been much lower if not for the high profile Zohr gas field, Nooros and Atoll projects in Egypt, and Coral FLNG offshore Mozambique, all of which were sanctioned in 2016–2017. Many of the recent discoveries are located in new immature basins, like Mozambique, Tanzania and Mauritania, which will require large investment commitments, so it will take time to mature and develop them. That said, the recent African discoveries will play an important role in shaping the future of a continent that is highly dependent on its hydrocarbon output.

Siva Prasad, Senior Analyst, 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

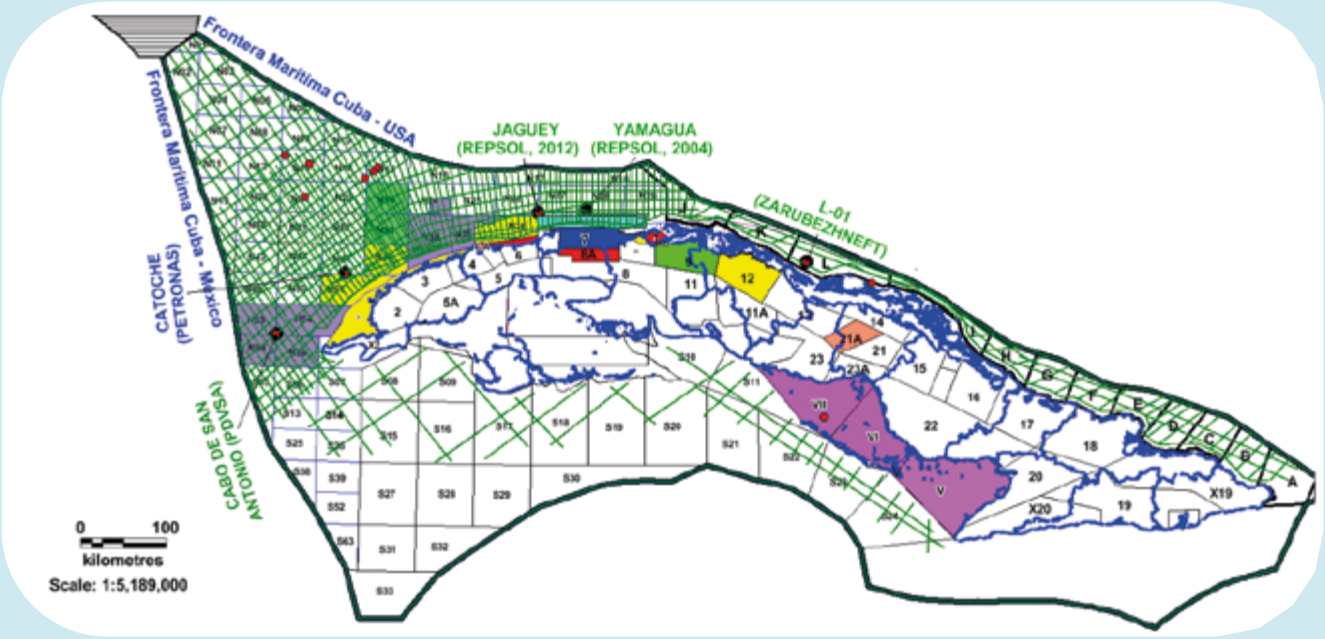
P2 reserves:
Quantity of hydrocarbons believed recoverable with a 50% probability

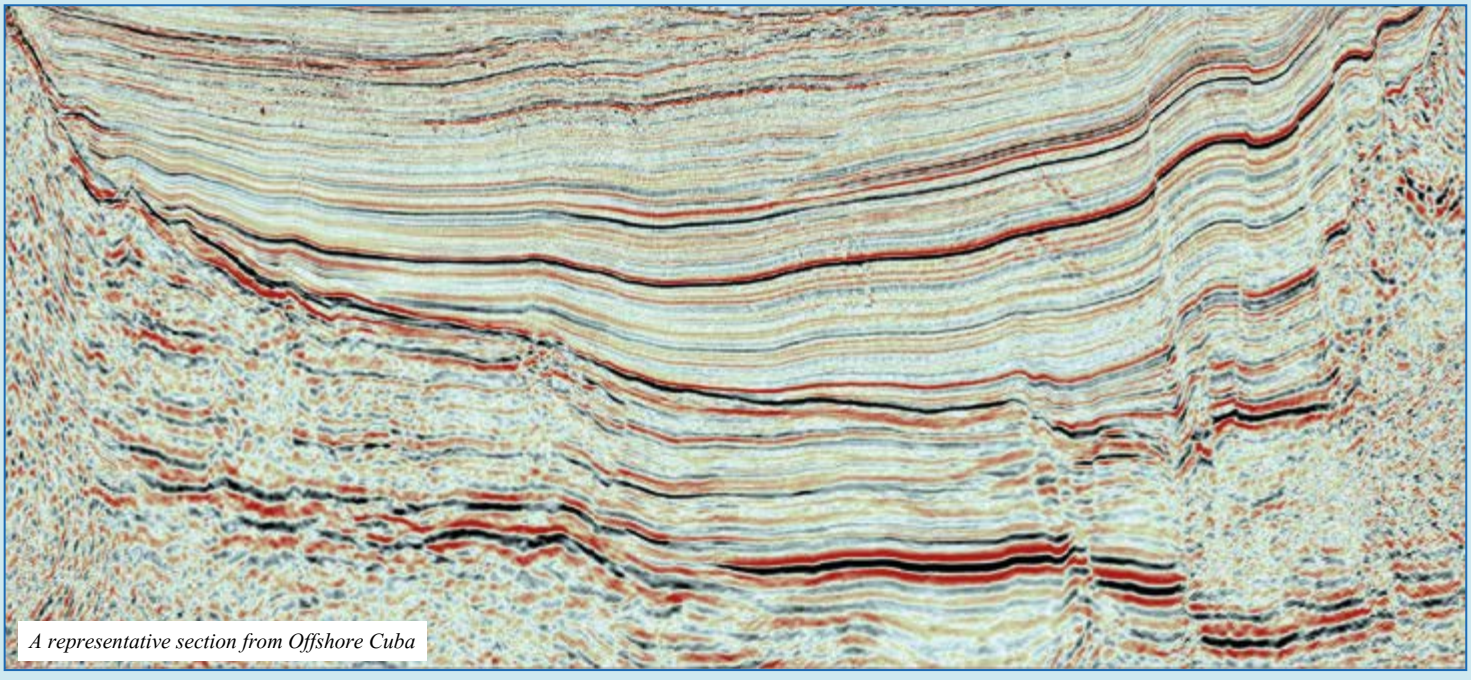
P3 reserves:
Quantity of hydrocarbons believed recoverable with a 10% probability

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

CUBA PRE-ANNOUNCEMENT FOR INTERNATIONAL BID ROUND, 2018

The Cuban national oil company Cuba-PetrÓleo (CUPET) is coming out with a plan to launch a formal bid round at the Cuba Oil & Gas Summit in December, 2018. The round will run from Q4, 2018 until Q2, 2019. It will focus on around 50 exploration blocks in the Cuban sector of the Gulf of Mexico. BGP has acquired a 2D Multi-Client survey in offshore Cuba after being awarded a contract by Cupet as shown in following map. Newly released 26,880km of 2D PSTM & PSDM data are available to license from BGP.





A representative section from Offshore Cuba

Tel: +53-7-2049051 Email:business@cupetsa.co.cu Web: www.cupet.cu
Tel: +86-22-66225097 Email: multiclient@bgp.com.cn Web: www.bgp.com.cn

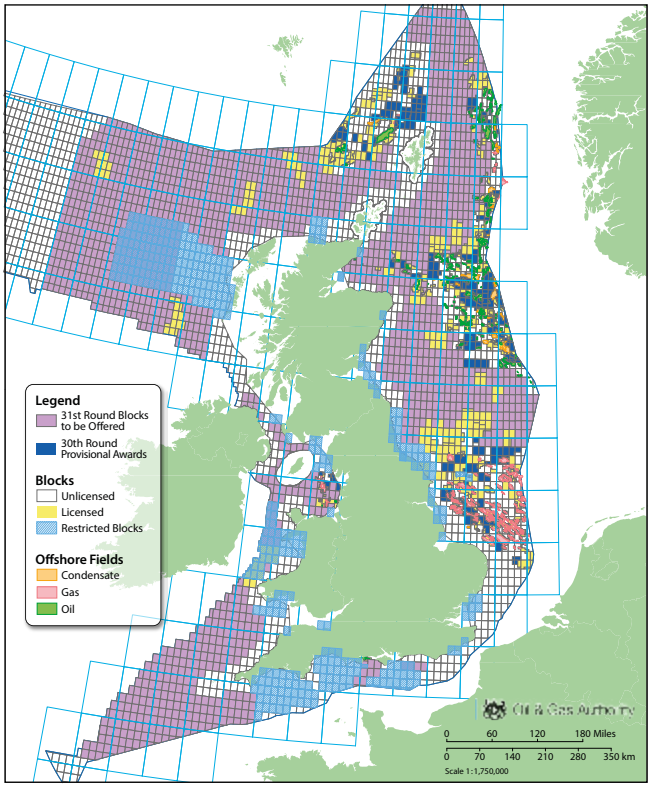
UK: 31st Offshore Round

The UK's 31st Offshore Licensing Round is due to close on 7 November 2018, with companies expected to find out if their bid is successful early in 2019. The round, which opened in July, focuses on frontier and underexplored regions in the UK Continental Shelf.

The UK Oil and Gas Authority (OGA) is offering a total of 1,766 blocks (370,000 km^2) across the West of Scotland, the East Shetland Platform, the Mid North Sea High, South West Britain and parts of the English Channel, which are covered by over 80,000 km of high-quality, publicly-available seismic data generated through the 2015 and 2016 government seismic programmes. The seismic, along with supporting datasets and reports, regional geological maps and other products, were released in advance of the round and can be downloaded from the OGA Data Centre.

The 32nd Offshore Licensing Round is planned to open in the summer of 2019, and will focus on mature areas of the UKCS. ■

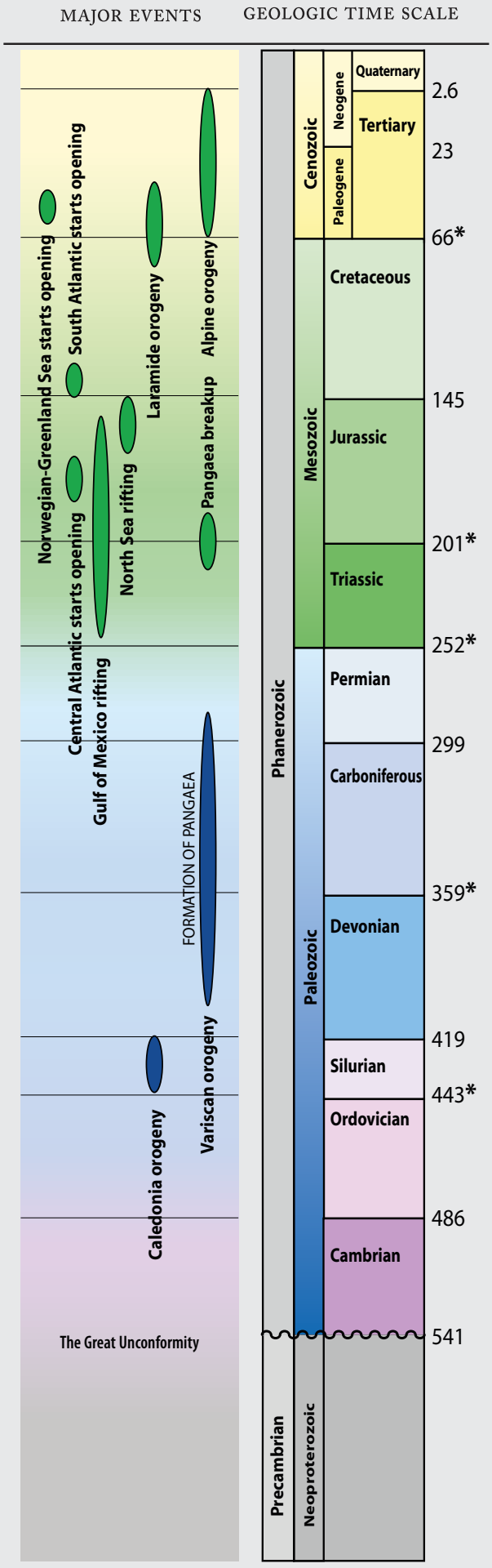
UK Continental Shelf 31st Licensing Round.



Sierra Leone: Round Suspended

In mid-September the Sierra Leone Petroleum Directorate announced a temporary suspension of the country's ongoing Fourth Licensing Round. This followed the appointment of Timothy Kabba as the new Director General of the Directorate and the decision to enter a period of industry consultation for six months. The offshore waters of Sierra Leone contain proven petroleum systems and the licensing round is reported to have generated significant levels of interest.

The round, which was announced at the 2017 Africa Oil Week, opened in January 2018 and was due to end in May. Both 2D and 3D data is available through datarooms in Freetown, Sierra Leone, and in London, where the round is supported by ERCL, part of the Getech Group. ■



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Big Five Awards

The Africa Petroleum Club's **'Big Five' Board Awards** have played a major role in presenting and highlighting personal and corporate achievements in the petroleum sector. These prestigious awards are now entering an incredible 22nd year.

Join us in **London** in November for 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 and annual awards, presented since 1997 and with over 100 recipients to date. The event will be at the Royal Institution in Mayfair and is held on **22 November 2018**. Contact Gayle at **Frontier Communications** for further details.

As part of the fundraising effort, proceeds of sales of fine art animal prints like this purchased through the Wild Earth Fine Art website (www.wildearthfineart.com) quoting 'Poached Rhino' will be donated to the 'Poached Rhino' charity (Registered Charity Number 1153221).

The event also supports the plight of African wildlife and aims to raise funds for various conservation projects on the African continent with a charity auction, held at the evening reception, which was a resounding success last year. ■

ExxonMobil Join OGCI

The **Oil and Gas Climate Initiative (OGCI)** is a CEO-led voluntary initiative representing some of the world's largest oil and gas producers working collaboratively toward solutions to mitigate the risks of climate change. It focuses on developing practical solutions in areas like carbon capture and storage, methane emissions reductions and energy and transportation efficiency, and was established following the 2014 World Economic Forum and formally launched at the United Nations Climate Summit the same year. In November 2016, the organisation launched a billion-dollar investment vehicle, Climate Investments, to invest in technologies that have the potential to significantly reduce greenhouse gas emissions, and that are economically viable through a global network of partners and co-investors to achieve speed and scale.

The twelve members – **BP, Chevron, CNPC, Eni, Equinor, ExxonMobil, Occidental Petroleum, Pemex, Petrobras, Repsol, Royal Dutch Shell, Saudi Aramco** and **Total** – were joined in September by **ExxonMobil**, which has already invested billions of dollars in researching and developing lower-emission solutions, including carbon capture and storage technology, next-generation biofuels, cogeneration and more efficient manufacturing processes. Earlier this year, ExxonMobil announced initiatives to lower greenhouse gas emissions associated with its operations by 2020, including reducing methane emissions by 15% and flaring by 25%. ■

PETEX 2018 – A New Optimism

Following the success of PETEX 2016, this biennial conference, the largest subsurface-focused global E&P conference and exhibition in the UK, will be returning in November, bringing together the industry's leading professionals, academics and exhibitors to discuss and support the future of our industry. With a technical programme highlighting the latest developments in exploration, development, production and subsurface technology, **PETEX 2018** will hope to challenge existing paradigms and, in turn, will ask questions to provoke lively debate and thought-provoking discussion.

PETEX 2018: a great networking opportunity.

PETEX is a meeting point for the industry: a chance to build contacts, grow professional relationships and forge connections across the breadth of a truly international industry. With over 70 exhibitors already confirmed, a full four-stream oral timetable and an expected attendance of over 3,500 delegates from over 40 different countries, why wouldn't you attend PETEX 2018?

PETEX runs from **27–29 November 2018** at **Olympia, London**. Head to the website for more details and to register for the conference, and don't forget to use the code: **GEOExProReader** at the checkout to receive £5 discount from the cost of your ticket. ■

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The Ultimate Multiclient Near-Field Exploration Tool

When exploring in mature basins you need the best possible seismic image to unlock the full reservoir potential. Over the last ten years most well-explored basins have been covered by broadband streamer seismic, which has revealed new potential. The next standard for near-field exploration, however, is **Ocean-Bottom Node (OBN)** seismic, as it provides **superior data quality** and **operational flexibility**. Until recently OBS was mainly used for reservoir monitoring but with the recent step change in cost-efficiency, OBN is now becoming the new standard for near-field exploration. Several supermajors now allocate more budgets to OBN than to streamer seismic.

This trend has been picked up by **Magseis**, a pioneer in OBN seismic. Having deployed over 200,000 successful node locations, it is now dedicating more resources to develop large scale **OBN multiclient** surveys. ■

Magseis Multi-client manager, Per Helge Semb, and Eivind Frømyr, chief geophysicist, with the miniaturised MASS 3 Sensor with 150 days battery time.

New Online Activity Service Launched

All the information you need is out there somewhere – but the problem is often seeing the wood from the trees. To borrow the title of a Beatles song, what you are searching for is 'Here, There and Everywhere'. To address this problem, **Keyfacts Energy** have developed an online database that takes you straight to the information you need, providing access to the key oil and gas companies in a chosen country and capturing an instant review of operational activity, capital expenditure, work programmes, farm-in opportunities, outlook, latest news, people and global office locations.

Keyfacts' **Oil & Gas Country Review** service provides a concise, 'one-stop' guide to global energy activity, featuring 144 countries, over 2,200 companies and more than 3,000 key personnel. Each report provides an overview of historic, current and future energy activity and can be purchased by individual country, region or as a global set.

Companies who choose a global subscription can nominate a university of their choice. This academic institution will be offered full complimentary access to the Oil & Gas Country Review package, providing a valuable inhouse 'non-technical' resource for the next generation of geoscientists and engineers, with high profile acknowledgement to the sponsoring company. ■

PROSPEX 2018: Come and Network!

The **Petroleum Exploration Society of Great Britain** and **UK Oil and Gas Authority** bring you the 16th show in their highly successful series of Prospect Fairs – the UK's leading networking event for exploration and development. This year's two-day exhibition, with a parallel speaker programme, is the perfect forum for prospectors and attendees to meet in an informal setting.

The show has gone from strength to strength; in 2017 we saw over 75 exhibitors and more than 850 attendees. The event allows attendees the opportunity to not only make business deals, but also to network, build professional relationships and look closely at prospector opportunities. There is also a full two-day programme of 'Prospects to Go' talks, overviews from government and presentations by explorers and consultants.

Don't just take our word for it: here are what some past attendees and exhibitors have said about PROSPEX:

"PROSPEX is the industry benchmark conference, where you meet all the right people."

"This show always has a buoyant and optimistic mood."

"The exhibition was a constant hum of activity!"

"A yardstick for activity within a region."

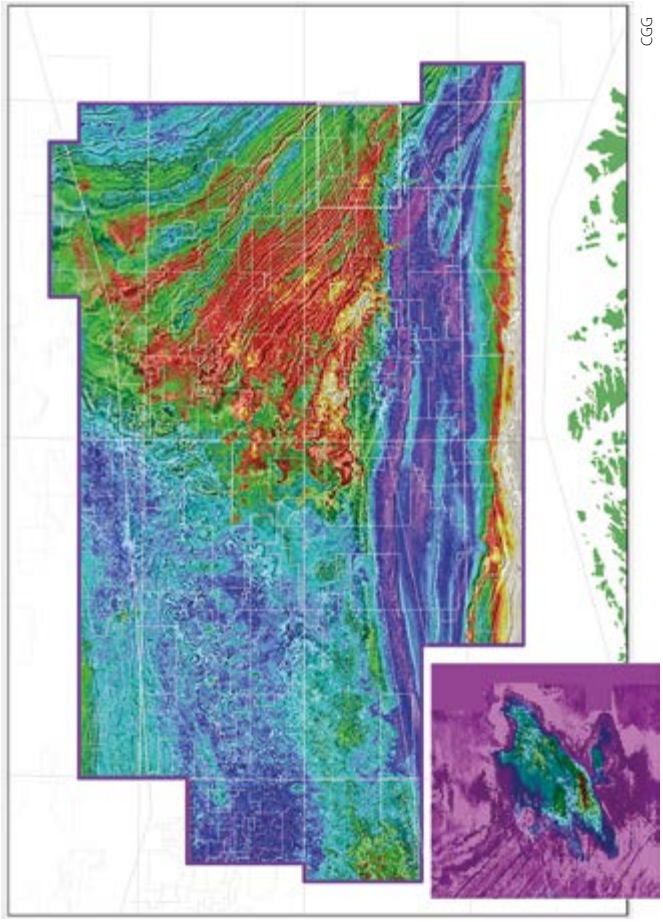
PROSPEX 2018 runs on **12–13 December 2018** at **Business Design Centre, Islington, London**. Registration is now open. ■

Large-scale Q-FWI and Imaging

CGG has just completed the depth-imaging of the entire **Northern Viking Graben** survey, using the latest velocity modelling and imaging technology to create a contiguous data volume of over 35,000 km^2 in the Northern North Sea. Processing has been tailored to address a wide range of local geological complexities, including large absorbing bodies and shallow gas. Model-building benefited from **Q-Tomo**, **Q-FWI**, and **Q-RTM** to define these anomalies, as well as advanced tomography and both refraction and reflection FWI to derive the velocities and anisotropic parameters. Imaging using Q-Kirchhoff algorithms has produced outstanding results, clearly highlighting near-surface features such as the Peon gas field, as well as providing clear images of the deep structures.

The dataset is complemented by a well study of 100 reinterpreted wells that have been integrated with the results of the seismic survey. An extension of 8,000 km^2 is currently being acquired to the south, which will also be processed through the same advanced sequence. A similar Q-processing sequence is currently being applied to CGG's 35,000km^2 Central North Sea Cornerstone dataset, with new high-resolution images of the Forties channels already having been achieved. ■

800m depth slice with FWI velocity overlay, with 595m Q-depth slice over the Peon field inset.



Does Lightning Strike Twice?

Lightning analysis provides a new geophysical technique, which is safe and cost-effective and has the potential to spark a step change in the geophysical exploration for oil and gas and minerals.

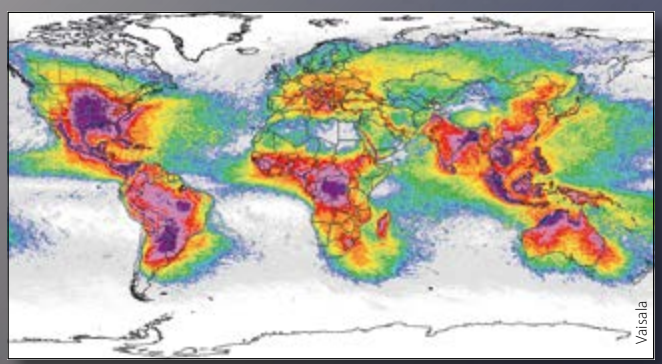
H. ROICE NELSON Jr., LES R. DENHAM, Dr. JIM SIEBERT and KATHLEEN S. HAGGAR; Dynamic Measurement LLC

Near Death Experiences

Benjamin and William Franklin risked their lives when conducting their famous lightning experiment in Philadelphia in 1752. A simple silk kite was sent aloft in a storm. A wire at the top served as a lightning rod. The kite was connected to a hemp string – which when wet would conduct any electrical charge from the storm down to a metal key. As the hemp line became wet, they noticed loose threads of the hemp string standing erect. Benjamin touched the key, and as the negative charges in the metal were attracted to the positive charges in his hand, he felt a spark. This experiment did not discover electricity, but it clearly demonstrated the connection between lightning and electricity.

Dynamic Measurement's path to discovery similarly took a path less travelled. Joe Roberts accidently put his life on the line while hunting ducks on his property on the edge of the Hockley Salt Dome in southern Texas, when a lightning strike hit very close to him, terrifying him. The same thing happened a year later, in exactly the same place. He drove round to his friend Roice Nelson, geophysicist and co-founder of Landmark Graphics Corporation, and asked, "Does lightning strike twice in the same place; if it does, does it mean I have oil on my property?" Roice asked Dr. Jim Siebert, Chief Meteorologist at Fox News in Houston, the same questions. Discussions with other experienced geophysicists,

Stroke density map: lightning is a worldwide source. Pink-purple = 16->32 strokes/km² per year. Green-blue = <2 strokes/km² per year.



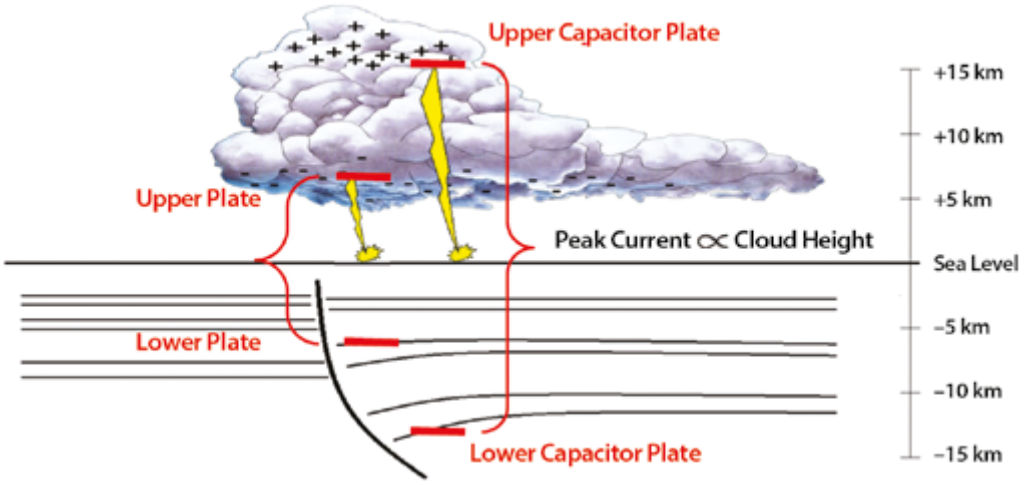


Figure 1: A model of how lightning strikes jump across a natural capacitor, created by currents in the atmospheric and lithospheric electrical half-spaces.

including Les Denham, resulted in the formation of Dynamic Measurement LLC.

We have now conclusively demonstrated that lightning does strike the same place twice. In fact, lightning strikes cluster, and these clusters are somewhat consistent over time. Dynamic Measurement continues to discover relationships between lightning strikes and resistive natural resources like aquifers, geothermal deposits, oil and gas reserves, as well as conductive materials like copper, gold, sulphides, clays and brines. Neither repetitive strike locations nor the presence of resistive/conductive actors under them are random.

For clarity: the entire lightning path is generally referred to as a stroke, while the location the stroke hits the ground is the strike.

Lightning Strikes

On a clear day the earth's surface acts as an equipotential surface, with equipotential lines parallel to the topography. Electrons cluster at a point, like an antenna – or Benjamin Franklin's kite. We are connected to the earth's electrical circuit, and the equipotential lines go up around us or the lightning rod. The electric field lines are always perpendicular to these equipotential lines.

As charge builds up in the atmosphere in an electrical storm, at the micro-scale close to the earth static electricity moves along field lines and bleeds into the earth. At the macro scale, ice and dust particle collisions within the clouds at 600–900m above the earth's surface generate electrical charges. Cloud-to-cloud (C2C) strikes result when opposite electrical charge build-ups in the clouds exceeds the dielectric, the electrical insolation of the air.

A basic assumption is that this build-up of charge interacts with telluric (earth) currents, at depths proportional to the height of the clouds where the charge originates. The atmospheric electromagnetic half-space mirrors the earth's electromagnetic half space (Figure 1). As the static charge builds up in the clouds, it interacts with and induces telluric currents. A signal with a period of 24 Hz is generally believed to have a skin depth of 600–800 km. Lightning strikes are understood to have a skin depth of a few metres. We know lightning strikes are a major source for charging telluric currents, all the way to the Mohorovičić discontinuity, at the base of the crust at a depth of 10–90 km, and everything below it is believed to be molten, and therefore a good conductor. Lightning storms build up over hours, lightning strikes over milliseconds, and this build-up of static electricity in the atmosphere is what charges telluric currents, and what interacts with these currents to guide lightning strike locations.

Figure 2: Lightning strokes occur when there is a sufficient static charge build-up for electrical currents to jump to an area with an opposite charge, either as a C2C or C2G stroke.

Geophysicists have known atmospheric static currents charge telluric currents since the 1950s, with the invention of magnetotellurics as a geophysical exploration technique. The build-up to a lightning strike takes up to 500 ms and can be derived by summing the time for related Cloud-to-Cloud (C2C) and Cloud-to-Ground (C2G) strikes. This build-up of atmospheric charge identifies an area of opposite charge in the subsurface of the earth. Lightning stroke pathways are largely determined by the field lines connecting these two 'capacitor plates' (Figure 2).

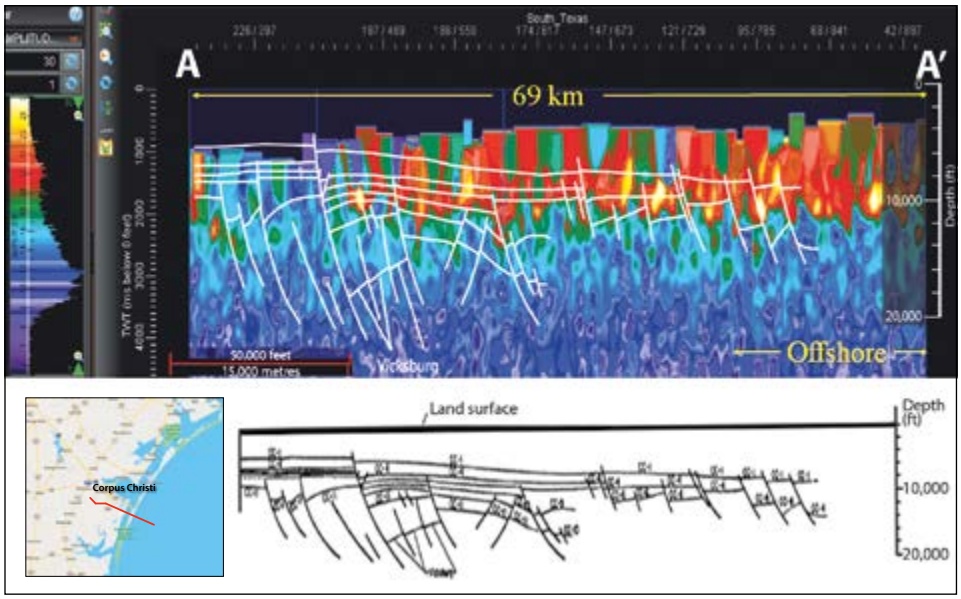


Figure 3: Comparing 2017 lightning-derived apparent resistivity cross-section with the equivalent 1986 interpretation by Tom Ewing (BEG) based on seismic and log data demonstrates how well the 1986 interpretation matched patterns in the apparent resistivity cross-sections.

Earth as Capacitor

Meteorologists have studied atmospheric electrical currents for decades, although the fluid nature of the atmosphere makes measuring electric fields and equipotential surfaces in and around clouds difficult. The electrical conductivity of air is 0.3–0.8 x 10^{-14} Siemens per metre, considerably lower than the earth's: assuming a typical sedimentary rock has 5% porosity, the electrical conductivity is 5.0 x 10^{-4} Siemens per metre, or about 10^{10} times the conductivity of air.

Treating the atmosphere and the earth as a capacitor, the charged thunder cloud is one plate, while the other is the earth underlying the cloud. The dielectric is the insulating medium between the capacitor plates that transmits electrical force without conduction; namely the air and the earth, between the atmospheric static charge build-up and the interacting and oppositely charged currents in a different part of the thunderclouds (C2C strokes) or telluric currents at depth (C2G strokes), as in Figure 1. Dynamic makes two assumptions: firstly, lightning occurs when there is sufficient charge to bridge the capacitor; and secondly, lightning is affected by geology to a depth proportional to the cloud height, as estimated from the Peak Current of the stroke. We recognise it is hard to accurately measure the height of a lightning stroke, and that the lightning strike itself, lasting microseconds, is a small part of the electrical interaction between the atmosphere and the lithosphere.

Lightning is like a current along a wire, inducing a magnetic field, which interacts with telluric currents deep in the subsurface. These telluric currents have more impact on lightning strike locations than vegetation, infrastructure, or topography.

The North American Lightning Detection Network, containing 20 years of data from the US and Canada, is the most extensive lightning database available, with records of location, time, Peak Current, Peak-to-Zero Time, recording quality, and other attributes. Most strikes in the US are recorded by 10–25 sensors, each within about 1,000 km of the strike location. These data are collected and stored for insurance, safety, and meteorological reasons, but Dynamic Measurement's exclusive data licence for natural resource exploration highlights new uses for them.

To illustrate how lightning analysis can be used in hydrocarbon exploration, let's look at an example from the Corpus Christi area of South Texas.

Lightning Maps for Exploration

Figures 3 and 4 compare regional lightning analysis results with geological ground truth, using work by Tom Ewing at the Bureau of Economic Geology (BEG). Dynamic Measurement has patented a method of calculating apparent resistivity from the lightning databases as a direct calculation, not an inversion process. The mathematical model is based on a relaxation oscillator (a neon light tube), where a capacitor is in series with a resistor and in parallel with a spark gap. As an input voltage is built up on the capacitor, it creates a spark across the gap, causing the inert gas to fluoresce. With a lightning strike, there is an additional resistor between the capacitor and the spark gap: namely the apparent resistivity of the earth between the strike location and where the telluric currents form the base plate of the capacitor.

Lightning occurs when the voltage across the atmospheric capacitor exceeds the dielectric strength of the air. As lightning leaders come down from the clouds, opposite charged electricity at the surface of collects and moves upward as a streamer of the opposite charge, and the up-going streamer and the down-going lightning stroke meet, the path is ionised and there is almost no resistance. The resistance in the subsurface is approximately constant over long periods of time, so even though each storm is unique and atmospheric factors vary with each stroke, with millions of strikes the consistent geological electrical properties result in strikes and attributes clustering.

Estimating the top capacitor 'cloud height' from Peak Current provides an estimate of the base capacitor depth. Placing the calculated apparent resistivity (or other lightning attributes) at these depths and doing a 3D interpolation allows

the creation of an apparent resistivity (or other lightning attribute) volume. These volumes can be interpolated to provide a trace for each bin in an existing or planned 3D seismic survey or each grid point in an aeromagnetic survey, and can be loaded into a geological, engineering, or seismic interpretation workstation. Binning and averaging all resistivity or other lightning attribute values for a specific area creates a map of the sum of the specific lightning attribute or rock property being evaluated.

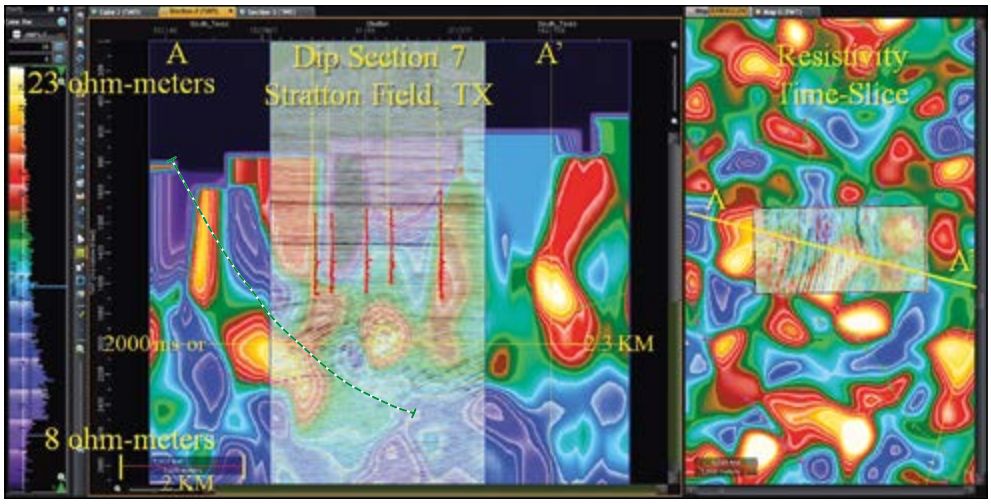


Figure 4: Apparent resistivity cross-section through the BEG's Stratton 3D seismic survey.

These volumes or maps, created anywhere there is Rise-Time, Peak Current, and Peak-to-Zero lightning strike data, can fill the gap between existing seismic and geophysical control. In the case of apparent resistivity, measurements are not limited to a few inches from the well bore, as with well resistivity logs.

A cross-section and a horizontal slice through the Stratton Field are shown in Figure 4, about 30 km west of section A–A' in Figure 3. In this display the seismic data, released by the BEG, is semi-transparent, revealing the apparent resistivity underneath. A Vicksburg expansion fault (dashed green line) is easy to see on the seismic data: note how well the resistivity volume maps this fault out from the seismic control. The fault can also be seen on the 2,000 ms time-slice on the right.

An apparent resistivity cross-section from south-south-west to north-north-east cutting the south-east corner of the Stratton 3D seismic survey is shown in Figure 5. This cross-section connects two deep resistivity logs, demonstrating how well the 20 ohm-metres recorded on the well log matches the 23 ohm-metres shown on the apparent resistivity colour scale on the left.

A New Geophysical Data Type

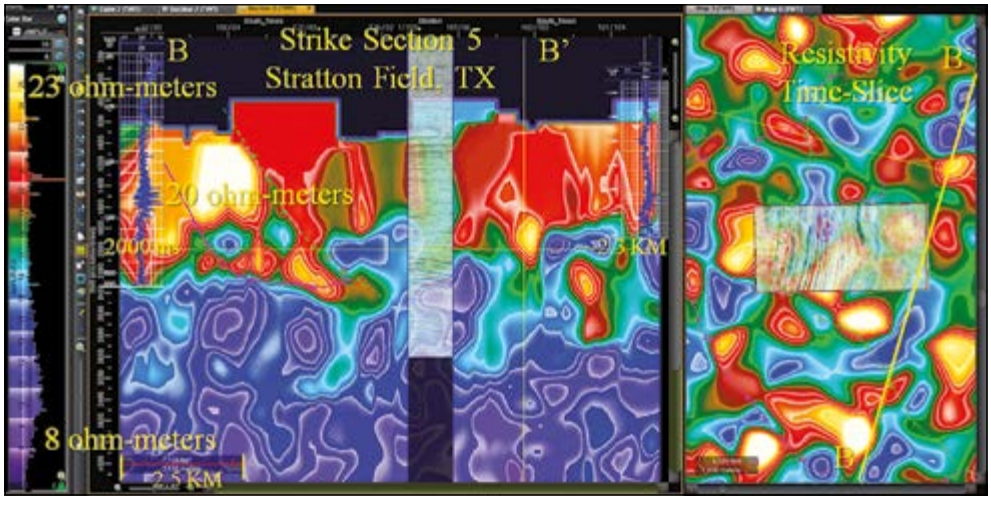
Dynamic Measurement has been developing this new branch in the geophysical services industry for ten years. As with any new geophysical data type, we regularly find further strengths and correlations. The approach has provided results which tie lightning analysis to seismic, air mag, and other geophysical and geological control, in areas ranging from the deserts of southern California to the swamps of Florida, and from South Texas to North Dakota. Each lightning analysis project Dynamic has done so far has shown similar correlations between the lightning derived maps and volumes and available geological and geophysical control.

Geology does not change over the timeframe of building the lightning database. Unlike other potential field methods, where sources and receivers are deployed to collect data, this approach is passive and non-invasive. The source is natural: no lightning strikes, no data. The receivers are in place for other reasons, so instead of thousands of receivers and sources, there are a few receivers collecting data from millions of lightning strikes, using the most powerful electromagnetic source on earth and creating consistent and useful data. Lightning analysis projects are quicker, safer and less expensive than any other geophysical data type: no permitting, no notifications, no need for any rights-of-entry, and no boots on the ground. Results are provided in workstation-friendly formats for easy integration with other geophysical or geological data.

Lightning analysis provides a new geophysical data type. Like new geophysical data types before, this innovative branch in the geophysical services industry has the potential to spark a step change in new revenues and cost avoidance for oil and gas, geothermal, aquifer, mineral, and other natural resource exploration companies.

An extended version of this article and references are available on geoexpro.com ■

Figure 5: Apparent resistivity cross-section through two deeper wells, with resistivity logs for calibrating apparent resistivity.



Exploration in Australia

After several low years, it looks as though drilling activity is picking up.

PETER ELLIOTT and MATT FITTALL, NVentures

At the beginning of 2018 exploration spend offshore Australia was at its lowest levels since 2004, with only a single wildcat exploration well drilled offshore in 2017 and four offshore in 2018 to date. An energy 'crisis' on the east coast of Australia, where domestic gas prices have doubled in the last two years, has been insufficient to stimulate the search for new gas resources in the offshore eastern Australian basins so far.

Nevertheless, the seeds for renewed exploration are being sown. Activity is picking up in the Gippsland (Baldfish-1) and Otway Basins offshore south-eastern Australia. Exploration drilling activity has resumed in the west, and the 2018 offshore acreage release is wide ranging, and includes several interesting opportunities. The Dorado and Ferrand discoveries in the North West Shelf are particularly welcome against these low levels of reserves replacement.

New, independent unconventional exploration in the onshore basins is also emerging as an important potential source of new gas supply for the eastern Australia market.

Exploration Bright Spots

Looking forward, where might the exploration recovery come from?

The Gippsland Basin in Bass Strait is historically Australia's premier oil province. The basin has lain fallow for the last decade or more without systematic exploration outside the heartland of the Central Deep and production licences. Exploration attention is increasingly turning to the deeper Golden Beach and Emperor sub-groups in the basin and moving towards the basin margins.

Drilling activity is picking up, with ExxonMobil spudding Baldfish-1, outboard of the Dory gas discovery and Blackback oil field. Development of the Sole gas field is currently being executed by Cooper Energy. The Gippsland could undergo a rebirth and has the potential to turn up a surprise, since it has been overlooked for some time and has a prolific history.

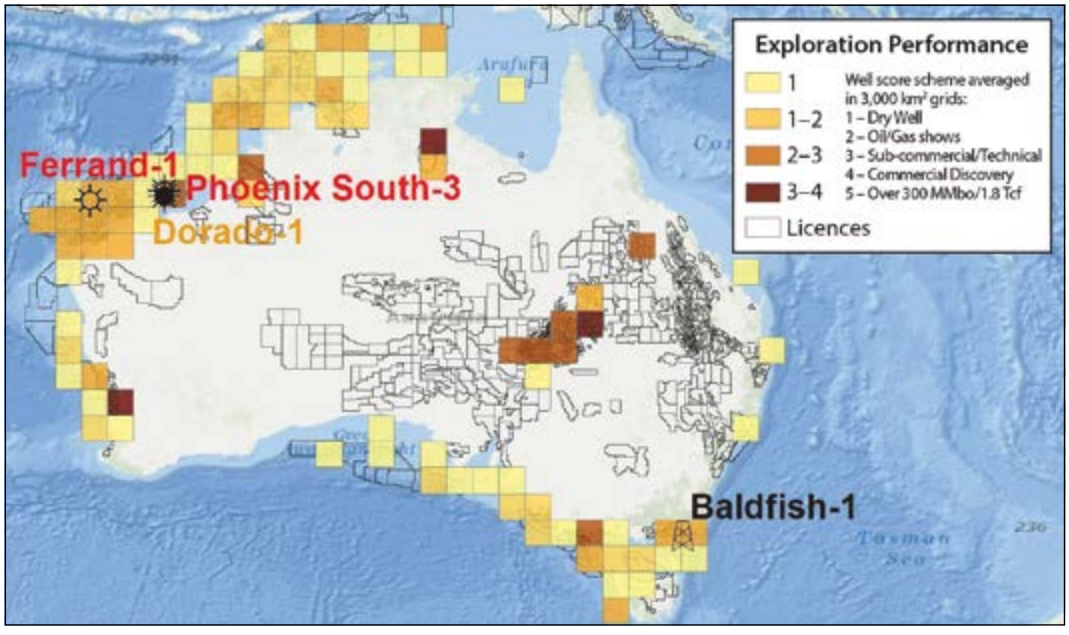
Exploration in the Otway Basin is also coming back into focus. This is an area where chasing amplitude anomalies on 3D seismic has been very successful. Three areas have been released for bidding this year and Spectrum is undertaking a basin-wide PSDM and broadband reprocessing of the 3D seismic surveys in the basin.

Following on from recent discoveries, exploration drilling by Quadrant/Carnarvon is currently delivering success in the Roebuck Basin on the North West Shelf, with the Phoenix South-3 well intersecting 131m gas. A well on the large Dorado prospect, up-trend from the Roc discovery and relying on lateral seal against a large canyon fill, revealed a total of 132m oil pay in the Triassic, the largest liquids discovery for a long time in this region. The discovery has spurred Santos into making an offer to buy Quadrant. Woodside have added gas reserves (69m pay) north of Gorgon at the Ferrand discovery well, and also in the Carnarvon Basin. A four-well exploration programme is firming up in the Canning to follow up the Ungani success by Buru.

In the onshore Perth Basin independent operators are planning at least two wells to further test the Waitsia concept and a follow-up well is being planned for the Xanadu oil prospect.

Key Wells Planned

The turnaround is underway in Australia. The eastern Australia gas supply shortfall is providing the impetus for significant unconventional exploration efforts in Queensland and the Northern Territory, and a rebirth of conventional exploration activity in the offshore Gippsland and Otway. Over in the west, new discoveries on the North West Shelf, and follow-up from recent play opening successes are the key drivers for drilling activity, with several key wells being drilled in the next year or two in the offshore Roebuck and the Canning onshore Basins. ■

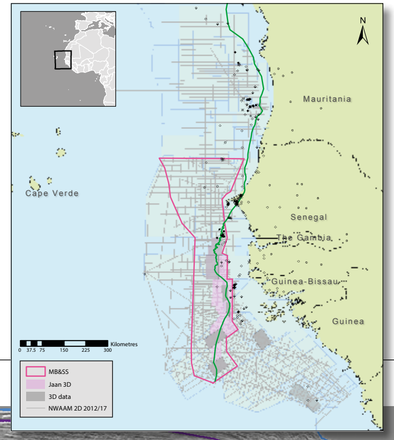


MSGBC:
Where is the Next Success?

The key to successful analogue hunting.

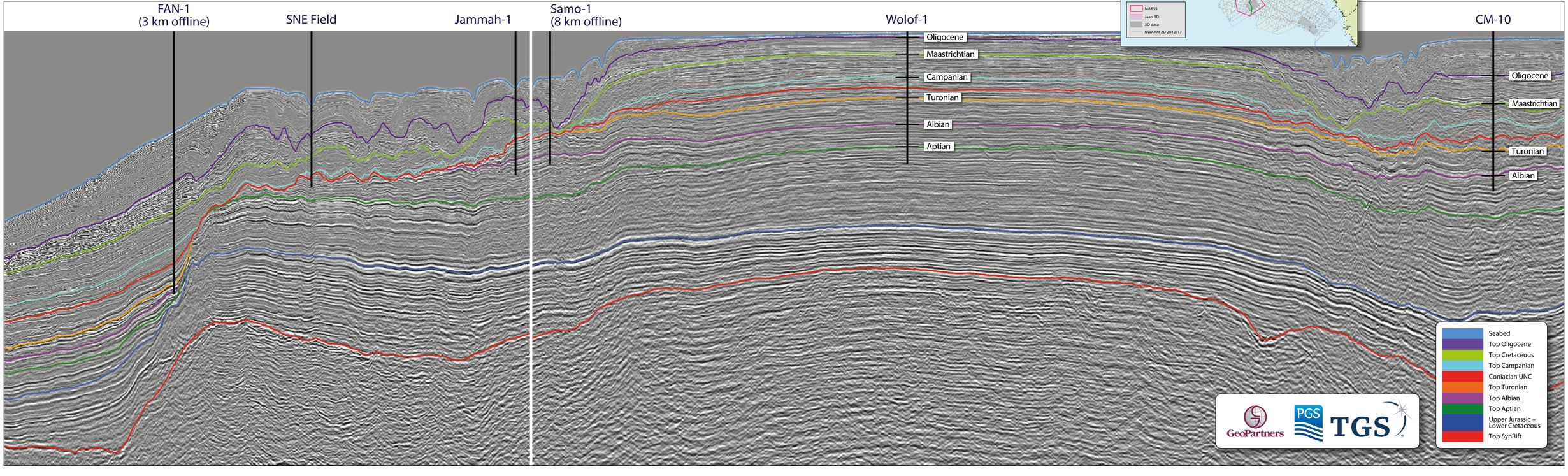
The MSGBC Basin has been the shining light of African exploration through the recent darkness that the industry has endured. That light, or rather floodlight, was cast upon the region through the recent world-class discoveries in Senegal and Mauritania. The MSGBC Basin is named after the acronym of the countries in which the basin (or more accurately a collection of mini sub-basins) resides, namely Mauritania, Senegal, Gambia, Guinea-Bissau and Guinea-Conakry. Also, just for completeness, the basin includes the AGC joint maritime zone, which sits between Guinea-Bissau and Senegal following a collaboration agreement between the governments. The location of the Basin is shown on the map (right).

The benefit of a regional dataset can be seen on the seismic foldout. This arbitrary 2D composite line spans from Senegal through The Gambia and back into Senegal concluding in AGC. It passes very close by FAN-1, the SNE field, close to Jammah-1 and the Samo-1 well location in The Gambia, as well as tying to Wolof-1 in Senegal, before finally tying CM-10 in AGC. The variation in the structural style and ability to interpret regionally is obvious.



TGS database in the MSGBC Basin.

Seismic section showing the wells named in the text.



Why MSGBC?

BEN SAYERS and RICHARD COOKE, TGS

The MSGBC Basin is ready for something new to help analogue-chasing the next SNE.

Prior to 2014, with doubts over the actual commercial success of Chinguetti in Mauritania, there was only sub-commercial success in the MSGBC Basin, proving the working petroleum system but not providing evidence that commercial quantities of hydrocarbons could be produced. Then FAR, an Australian exploration company, came along and rewrote the basin in the annals of history when they successfully farmed out their Sangomar Deep licence to ConocoPhillips and Cairn.

FAR had acquired 3D data and worked up a beautiful story with supporting seismic evidence of a prospect, Lupa Lupa, which had pre-drill P50 estimates of 154 MMbo. The name translates as 'butterfly' in the local Wolof language – which only built on the vision sold to the industry. Upon drilling, the prospect did indeed metamorphose into the largest discovery of 2014 – the SNE field. Subsequent appraisal drilling has now yielded 2C contingent resource of over 641 MMbo, according to a recent FAR investor presentation. Just before drilling SNE, the exploration team had drilled the FAN prospect, located basinwards, downslope and outboard of the palaeoshelf location of SNE (see Figure 1 and foldout overleaf).

Whilst the Cairn Group were having success south of Dakar with the SNE and FAN oil discoveries and subsequent appraisals, Kosmos were having their own triumphs farther north in Senegal and Mauritania. Tortue-1 (French for turtle) was the largest global thermogenic discovery in 2015, intensifying the light thrown on the region by the earlier drilling. The success of the Tortue Complex (which straddles the international boundary between Mauritania and Senegal) was attributed to the huge 3D seismic volume that Kosmos had acquired and interpreted. 'Postage stamp' 3D is good for working up drill-ready prospects but regional 3D enables a more holistic understanding of the complete petroleum system and hydrocarbon potential. After appraising, the P-mean gross resource estimate for the Greater Tortue Complex is now more than 25 Tcf.

Following the giant success of Kosmos, BP joined their party and became operator in December 2016. The group continued to build upon previous drilling, and leveraging the large 'exploration' 3D that Kosmos had had the foresight to acquire led to the world's largest discovery of 2017: Yakaar-1 in northern Senegal, with current resource estimates of 15 Tcf.

The next eagerly-awaited well is Samo-1 in The Gambia, the first to chase the SNE play beyond the Sangomar Deep Block, the location of which is shown in Figure 3. The success of this well could really open up the basin for more SNE hunting. It is operated by FAR with financial funding from Petronas, another large partner in the basin.

What Data?

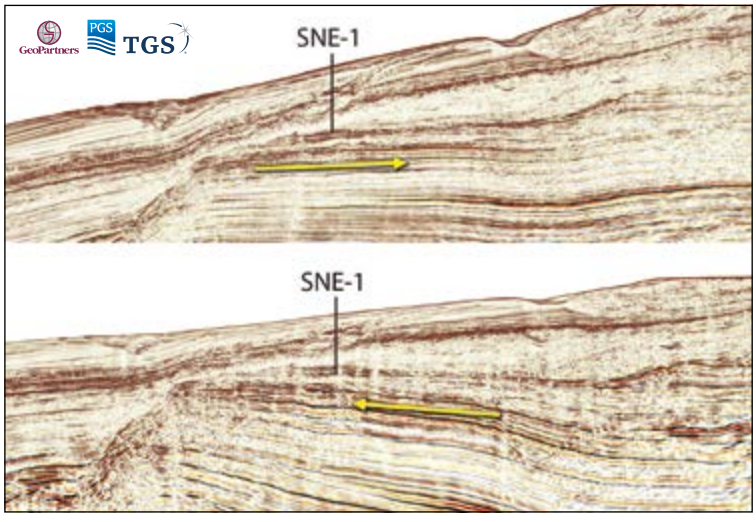
TGS have been present in the basin since 2010, when they acquired a 3D dataset in The Gambia. After seeing the structures in the subsurface, a commitment to acquiring a regional 2D seismic dataset over the MSGBC Basin on the North West African Atlantic Margin (NWAAM) was easy to make. This 28,000 km NWAAM2012 2D seismic programme was a regular regional grid that tied the entire basin from Mauritania to the Republic of Guinea. The success of the sales profile has been largely attributed to three main factors: the cross-border connectivity which enables regional trends to be followed; the tying of the majority of previous drill locations, which provides empirical knowledge to interpretations; and finally, the current success the basin is experiencing. All three elements combine to make the MSGBC Basin a focus area for future TGS investment.

During the recent industry downturn, TGS, with key geological knowledge and a strong balance sheet, acquired 3D assets from distressed partners, quickly taking a prime position along the palaeoshelf-edge trend (PSET), ready for future pursuit of the next SNE.

The NWAAM2012 survey was one of the last 2D surveys that TGS acquired in a standard acquisition set-up, as broadband deep-tow technology was not yet mainstream or accepted by industry partners at the time. This provided an excellent opportunity to infill the survey, decreasing the line spacing to roughly 7 x 10 km grid separation, with the NWAAM2017 broadband 2D survey, which has been processed to PSTM and PSDM, allowing subtle trapping angles to be seen across the basin.

The SNE play comprises Albian sands sitting on top

Figure 1: The importance of an accurate depth migration is clear. Top: PSTM line through SNE-1. Bottom: PSDM line through SNE-1.



of a carbonate shelf incised by paleo-canyons and below present-day seabed canyons, creating a very complex and rugose terrain to image through. The reservoirs are charged by an early Albian source which produces 32° API oil that migrates basinwards to fill the structures. The migration path and trapping angle of the reservoir is subtle along the PSET, so an accurate depth velocity model needs to be produced to support future exploration potential. Figure 1 shows the SNE play from a dip perspective in both time and depth domain. This subtle rotation effect highlights the need for the depth processing.

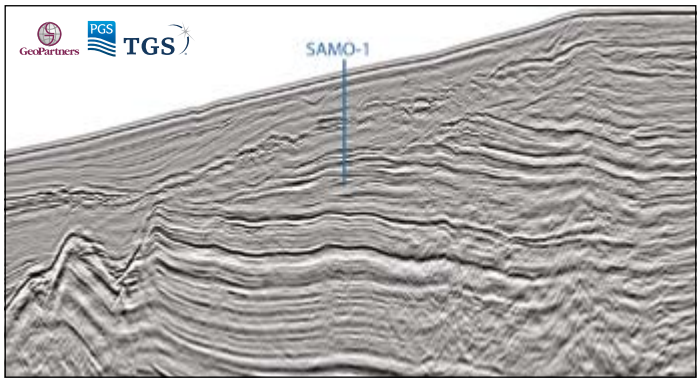


Figure 2: PSDM line from the NWAAM2017 survey showing the location of the FAR/Petronas Samo-1 prospect.

Chasing the Snake

Learning from the giant discoveries and cross-border exploration success, whilst acknowledging the benefit that 3D brought to BP-Kosmos, TGS, in partnership with PGS and GeoPartners, have created a new dataset. The 28,000 km² Jaan 3D project will fill the gaps along the PSET where there is no current 3D seismic data and then process and harmoniously merge the new and existing data to create a fully phase, amplitude, time and depth-migrated 3D exploration volume to unlock the next SNE.

When Jubilee was first discovered in Ghana in 2006 we saw the rush for analogue hunting. The industry chased 'the next Jubilee' for almost a decade with few positive results. By acquiring and processing Jaan, TGS hope to prevent such failures and ensure more astute exploration of analogous prospects.

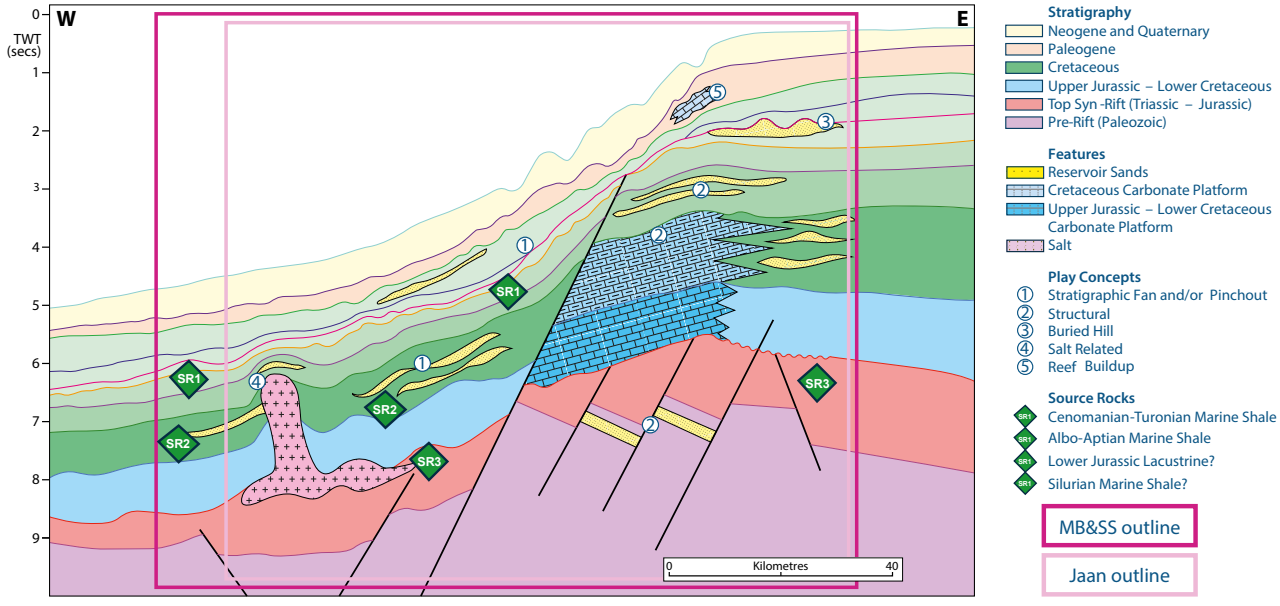
Jaan also has a Wolof name, in homage to FAR for their excellent efforts in persevering in backwater Senegal after 26 years of zero activity. It means Snake, as the PSET resembles a snake slithering down the NWAAM through the MSGBC Basin. TGS hope that by chasing the snake, future drilling can be located using regional 3D exploration seismic data underpinned by over 50,000 km of regional 2D seismic to provide basinwide ties.

Jaan is being marketed as a low fee licensing model so that exploration 3D is affordable and great geoscience is not restricted by budgetary restraints. By working with four administrative bodies, Jaan will enable the geology to be fully understood and to allow better decisions to be made, unrestricted by international boundaries.

To mitigate as much pre-drill risk as possible, TGS have recently funded a regional Multibeam and SeaSeep (MSGBC MB&SS) project covering the centre of the basin from northern Senegal to Guinea-Bissau. MB&SS has gained real technological ground in recent years with the advancements of MB tuning and backscatter analysis, which can now more accurately pinpoint seafloor sampling locations. In parallel with the refinement of backscatter anomaly mapping, coring location technology has also led to a paradigm shift forward. Seafloor samples can be cored successfully, with locations in water depths of up to 4,000m being retrieved from within 8m of the centre of the target zone.

Source presence has been highlighted as one of the greatest play risk-elements perceived in the MSGBC basin by some exploration companies. TGS have performed basin modelling that produces positive answers based upon the previous drilling results and the basinwide interpretation. However, nothing can beat having real, physical evidence of geochemical analysis of samples retrieved from the seafloor. With new data being collected in this emerging frontier, TGS look forward to assisting in bringing future exploration success to the MSGBC Basin. ■

Figure 3: Geoseismic section showing the various play types that will be covered by Jaan and the MB&SS programmes.



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Uganda
Identifying the Golden Thread

With over 1.4 Bbo of resources discovered in Uganda in recent years, including several giant fields, we look at the history of recent exploration in the country and its progress to first oil.

IAN CLOKE, SHANE COWLEY and ROBIN RINDFUSS, Tullow Oil

The East African Rift System became an exploration hotspot following prolific exploration success in the Lake Albert Rift Basin from 2006 to the present day. Conventional wisdom and paradigms have been challenged and overcome by the discoveries in this basin and the question now asked by many explorationists is 'where is the next Lake Albert?' In 2012 the Lokichar Basin was opened in the eastern arm of the East Africa Rift System in Kenya – but that's another story.

Exploration in the East Africa Rift System is not new, with oil seeps known for at least 100 years around Lake Albert and Lake Tanganyika and sampled by early field geologists mapping the African continent. The Tertiary rifts were tested by shallow wells in the 1930s (Waki-1; Lake Albert) and 1940s but interest then waned until the 1980s and '90s when these areas were re-licensed following Chevron's success in the Cretaceous rift basins of Sudan. Amoco was an early pioneer and jointly with Shell drilled a number of wildcats, though with little success. These included Loperot-1 and Eliye Springs-1 in Lake Turkana, Ruzizi-1 and Buringa-1 in Lake Tanganyika and Galula-1 and Ivuna-1 in the Rukwa rift. It was only in the early 21st century that interest returned to the rifts, with Lake Albert in particular being a focus for Tullow Oil, as well as Heritage Oil, Energy

Drilling Ngassa-2 in the central Lake Albert region in 2009.

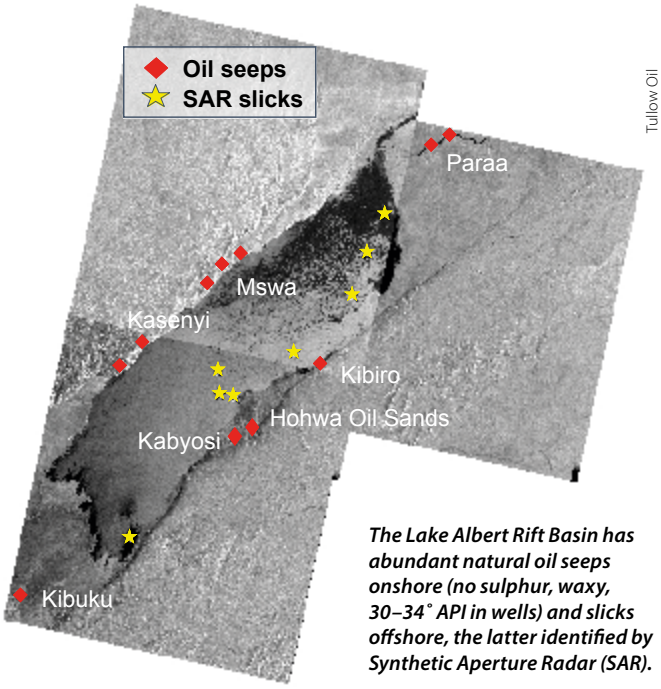
Tullow Oil

Africa and Hardman, subsequently all acquired by Tullow Oil and then sold on partially to Total and CNOOC.

Lake Albert Opens

In Lake Albert over 20 separate discoveries have been made and the play types to date have been syn-rift dominated. Rift-flank extensional folds form just over 25% of the discoveries, including Mputa, Waraga, Nzizi and Kingfisher, whilst the remainder, to date, are intra-rift tilted fault blocks in the northern end of the basin, identified as part of the Victoria Nile Delta play (e.g. Kasamene, Ngiri and Jobi-Rii). A prolific lacustrine Miocene-age Type I/II lacustrine source rock is a key component of the basin's success and, as the excellent Darcy quality Pliocene-Miocene reservoir sequences are intercalated with the source rock, hydrocarbon migration has been rapid and recent. Indeed, the frequent extensional faults to surface and outcrop expressions of tilted fault blocks and rift flank folds all require extremely recent charging of the traps. A high geothermal gradient in the north allows waxy crude to be mobile as shallow as 250m below the surface.

The first seismic in the area was recorded by Heritage Oil and Energy Africa in 2001 in the Semeliki flats at the southern end of Lake Albert. The location was chosen due to its proximity to the Kibuku oil seep. Wells Turacao-1, 2 and 3 were drilled here but no oil was discovered, only carbon dioxide. Interest then moved northwards and to Lake Albert itself, where 2D seismic data was acquired. Interpretation of this data identified the amplitude-supported Ngassa structure and the Kingfisher structure. Further 2D seismic data was acquired over the Kaiso Tonya area onshore to identify a location where the petroleum system could be tested at a low cost and in 2005 a light rig (the *Eagle Drill*) was mobilised in containers to the basin. The rift flank fold play was finally opened in 2006 with the discovery of oil at Mputa-1 (10m net oil pay). The Waraga-1 (26.7m net oil pay), Nzizi-1 and then Kingfisher-1 (40m net oil pay) discoveries followed. The hydrocarbons discovered at all these locations was sweet 30° oil but it was waxy, with a pour point of 36–39°. At surface temperature the oil was solid like that from Sudan or Chad. The discoveries were all tested in 2006, with Waraga-1 flowing over 12,000 bopd from three zones, Mputa-1 more than 1,100 bpd from two zones and Kingfisher-1 flowing over 9,700 bpd, again from three zones. Porosities and permeabilities were good to excellent.

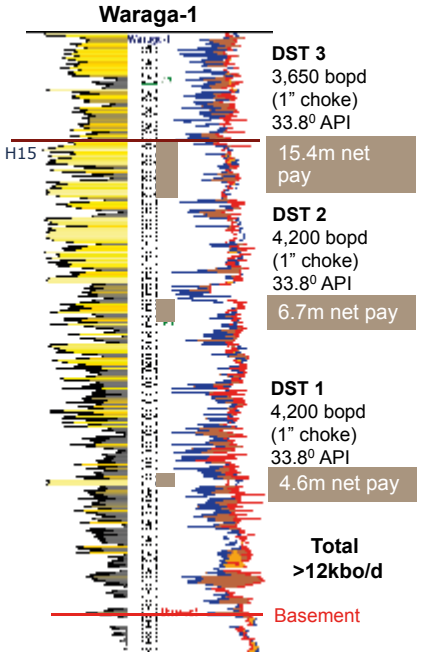


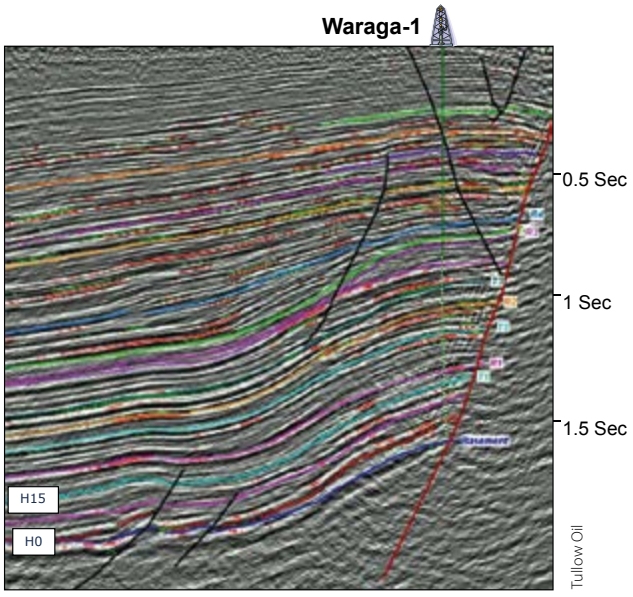
The Lake Albert Rift Basin has abundant natural oil seeps onshore (no sulphur, waxy, 30–34° API in wells) and slicks offshore, the latter identified by Synthetic Aperture Radar (SAR).

In 2007 Tullow Oil set about appraising the Mputa and Nzizi fields and a further minor gas discovery was made at Ngassa onshore. Throughout 2007 2D seismic was acquired across the northern area of the basin, as well as 3D seismic (380 km^2) over the Kingfisher discovery and on the Kaiso-Tonya–Ngassa structures (585 km^2).

The Victoria Nile Play

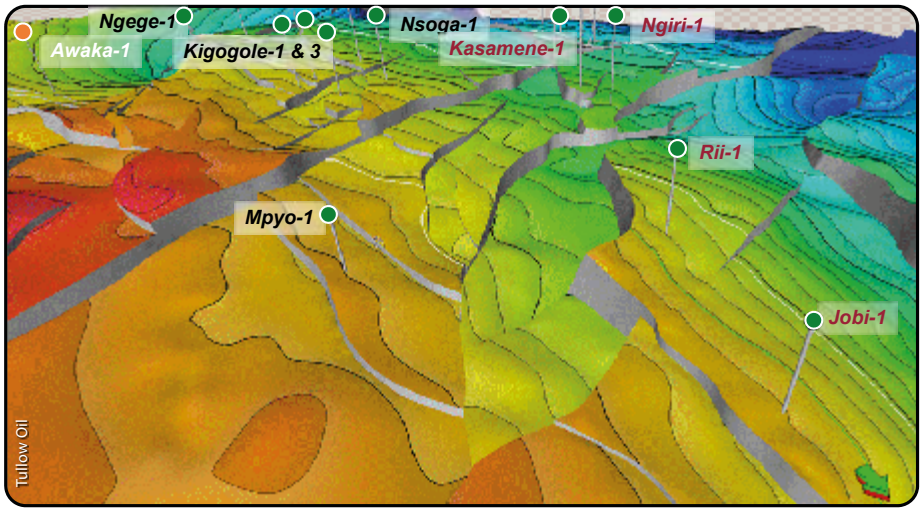
The 2D seismic data acquired in the north of Lake Albert was near the active 'Paraa' oil seep and was around and in the





Waraga-1 test commenced 22nd June 2006 and flowed at a combined rate in excess of 12, 000 bopd. This was the first flow of oil to surface in Uganda and East Africa.

environmentally sensitive Murchison Fall's National Park. Interpretation of the 2D seismic showed a combination of extensional rift flank folds in the east similar to those drilled in the south and also a new play similar to that of the Brent province of the Northern North Sea, with intra-rift tilted fault blocks. In addition there were frequent high amplitudes at the crest of tilted fault blocks, as well as amplitude phase reversals and common amplitude terminations. However, the amplitudes were anywhere from 300m below the surface to 900m and a concern was whether these could be oil, gas or carbon dioxide.



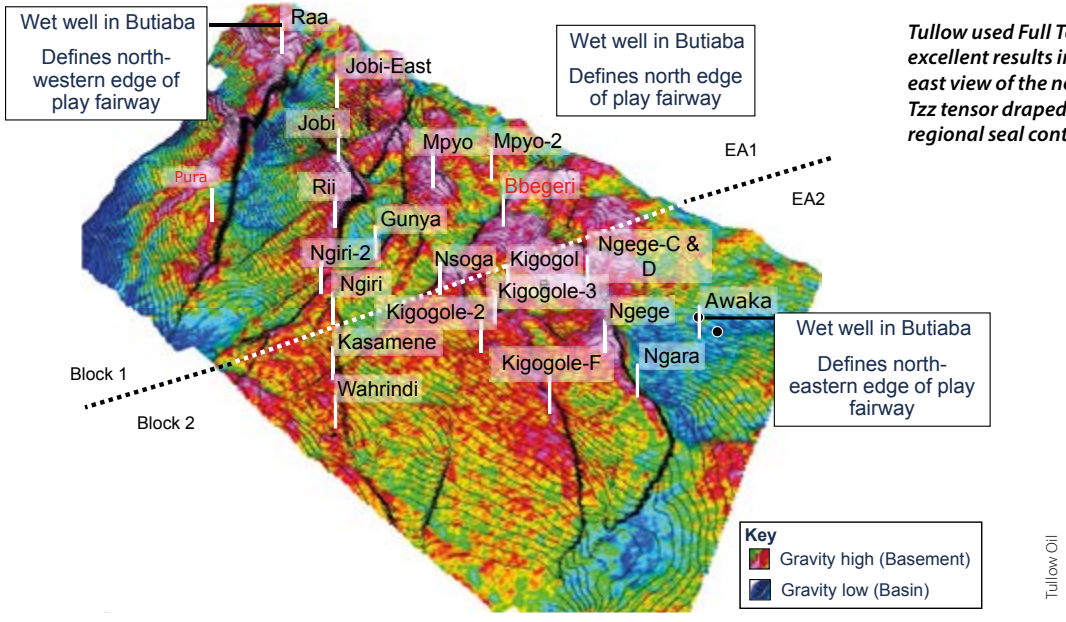
Structure map at Top Pliocene Reservoir looking south to Lake Albert. The Victoria Nile play is characterised by thick fluvial reservoirs sealed by lacustrine shale within simple tilted fault blocks.

In 2008 Tullow moved the *OGEC 750* light rig into the Butiaba area in the north of the Lake Albert Basin and an oil and gas discovery was made at Taitai (5m gas and 8m net oil pay), over 70 km from the nearest oil discovery. This was followed by the Ngege discovery (5m oil and 9m gas pay) in an intra-rift fault block with amplitude support. A subsequent minor oil discovery was made at Karuka-1 before the play opening Kasamene-1 oil and gas discovery (31m net oil pay and 6m net gas pay).

Kasamene-1 was the key discovery in the north and confirmed the existence of excellent quality reservoir units with porosities of over 30%, permeabilities in the multi-darcies and excellent seal units. It de-risked multiple other discoveries around it in Block 1 and 2 with similar amplitude characteristics. The oil in all the northern Lake Albert discoveries, although shallow, was high quality sweet crude, mobile and at 30–33° API. Despite the shallowness of the reservoirs, a high geothermal gradient of 6–7° per 100m allowed the oil to remain mobile.

A further discovery was made at Kigogole (10m net pay) in swift succession before the rig moved to the then Heritage-operated Block 1 at the very northern end of the lake. In October 2008 the Ngiri-1 discovery was made (31m net oil and 15m net gas pay) and then Jobi-1 (28m net oil and 15m net gas pay). This was the shallowest discovery in the basin, at 400m below the surface. Oil was still mobile but had a pore point ranging from 15–24°. The wildcat Rii-1 drilled in January 2009 encountered 38m of net oil pay in pressure communication with Jobi-1 and confirmed a major oil discovery of between 300 and 800 MMbo. By this stage, over a billion barrels of oil had been discovered in Uganda and commercialisation had become a reality. All these discoveries had been made on 2D seismic data.

Kasamene-1 was flow tested at 3,600 bopd with no depletion identified and the permeabilities extrapolated were in excess of 10 Darcy. Build-up data indicated a vast connected reservoir; the deliverability of the Victoria Nile play had been established. Subsequent oil discoveries were made at Nsoga, Wahrindi, Ngassa offshore, Ngara, Mpyo, Jobi East, Gunya and Lyec. 3D seismic data was acquired across the north of the basin and from 2010 through to 2014 appraisal wells delineated the discoveries made. The last appraisal drilled in Lake Albert was in 2014. This was the Waraga-3 well which discovered over 120m of net oil



Tullow used Full Tensor Gravity Gradiometry with excellent results in the Tertiary rifts. This north-east view of the northern end of Lake Albert shows Tzz tensor draped on top of Tz residual, with base regional seal contours superimposed on top.

pay, demonstrating that significant potential still exists within the basin for those who know where the prize is.

It was not all success: dry wells were drilled at Awaka-1 in 2009, testing the eastern limit of the Victoria Nile play; at Raa-1, Til-1, Riwa-1, Ondyek-1, testing the western limit of the play; and at Mpoyo-2, which tested the northern limit. In the south the Kanywataba-1 well also failed, testing an onshore structure south of Kingfisher.

Significant Prospective Resources

Tullow has been a pioneer of many high-end geophysical technologies as it has built its rift tool kit which it routinely deploys in the search for oil elsewhere in Africa, such as Kenya, Ethiopia, Zambia and Côte d'Ivoire. The company was the first to deploy Full Tensor Gravity Gradiometry in a large way in the Tertiary rifts in 2009 where it was used to provide a high resolution subsurface image in the Butiaba area prior to the acquisition of 3D. It deployed accelerated weight drop technology to acquire 3D seismic in a light touch manner in 2010 and used nodular technology for the acquisition of the onshore 3D acquisitions in northern Lake Albert.

Since appraisal finished, work has continued on the commercialisation of the discoveries. In excess of 1.4 Bbo (2C) has now been found in the Lake Albert Basin area, with the 478 MMbo Jobi-Rii discovery in 2008–2009 being the largest discovery onshore sub-Saharan Africa for over 20 years. A 24" pipeline with a capacity of over 200,000 bpd is planned through Uganda and Tanzania to the port of Tanga, which will be the longest heated oil pipeline in the world. The final investment decision is expected in the near future. In addition, an appropriately-sized refinery is planned in Uganda.

Kasamene-1, the 3,600 bopd Victoria Nile Play opener, Uganda in 2009

Significant prospective resources still exist, with potential to double or triple the discovered basin resource estimate. Big fields get bigger and with water injection and polymer floods planned for the future, the current 2C and 3C resources will surely increase further. Analogues are the South Viking Graben in the North Sea, where over 5 Bbo has been produced.

The record of 75 successes out of 83 drilled wells has highlighted the significant hydrocarbon potential of the East Africa Rifts, if the golden thread linking source, reservoir, seal and trap can be identified. Ultimately, the pioneering exploration performed by everyone from the PEPD in Uganda and the independents of Hardman, Energy Africa, Heritage and Tullow Oil to the major oil companies of CNOOC and Total will result in the delivery of Uganda crude to the world market as soon as possible, bringing major investment for Uganda and changing the lives of ordinary Ugandans. ■

A New Wave in Seismic

RICK DUNLOP and
BRIAN TAYLOR
Axxis Geo Solutions

Ocean-bottom acquisition is encroaching on the traditional marine streamer market by offering unique, scalable and efficient solutions for exploration and development.

Ocean-bottom nodal (OBN) seismic is riding something of a wave of success in the seismic acquisition market that, contrarily, has been hard hit over recent years. This was highlighted in 2017 when it was reported there were more seismic vessels deployed on seafloor or ocean-bottom (OB) surveys than in traditional marine streamer.

This has opened an opportunity for new companies, including Axxis Geo Solutions AS, to enter the market during this downturn, where more traditional marine streamer stalwarts appear to be exiting. There is a lot of speculation as to why OB, and particularly OBN, have been able to ride this wave despite the downturn; much of the market's success can be attributed to several key factors.

Acceptance Achieved

Over the past decade, we have seen widespread acceptance of what is perceived as 'blind' recording, both on and offshore. Broadly speaking, most nodal systems acquire data internally, and therefore do not provide the visibility to data on a real time basis, as is enabled by heritage cable, and in some cases, radio-based networked systems. This acceptance was possibly first driven by the high density source, high density receiver spreads deployed on land surveys, demonstrating the value of the very high quality data that can be acquired in this manner, and by the ability of processing to remove strong noise trains in the data without an impact of seismic data quality (in simultaneous source acquisition, for example).

Ocean-bottom surveys, by their very nature, decouple the source from the receivers, thereby allowing far greater flexibility in the way surveys are designed and executed. Better illumination is achieved through long offsets and WAZ (wide azimuth), as well as high signal to noise through dense sampling and high fold, multicomponent receivers and super vector fidelity. It is also clear that 4D FAZ (full azimuth) and WAZ designs are more easily achieved with nodal technology.

Another benefit of OBN is that it addresses two of the major limiting factors of Full Wave Inversion, i.e. restricted offsets and bandwidth, especially in the low frequencies.

Geo Caspian – 108m multi-purpose seismic vessel capable of seismic source, streamer and high speed nodal deployment and recovery.

Flexible and Efficient

OBN acquisition is much more forgiving in areas of infrastructure. Surveys can be designed to optimise receiver positions in relation to oil field infrastructure, limiting the impact of the infrastructure on the data. Hybrid surveys are becoming more frequent, where nodal patches are used to complement a marine streamer survey, filling in the areas that are normally not accessible to marine streamer and therefore creating a more contiguous data set. OBN offers the ability to create unique designs and is a highly scalable solution, unhindered by the conventional constraints in both the inline and crossline directions.

Efficiency is probably one of the most significant areas that has helped the uptake of ocean-bottom acquisition. Simply put, efficiency drives cost. New entrants into the market have focused on improvements in the speed of deployment and recovery of the nodes. Complementing this is the ability to deploy multiple sources that can operate independently and simultaneously (sim source), enabled by improved processing techniques that can quickly and effectively de-blend the data.

Footprint

A good deal of the benefits described above are due to the increasing size of the deployed spread, with a 10,000 node operation now being deployed today, compared to a little over a decade ago, when a 1,500 node survey was considered ground-breaking.

Despite a typical modern OBN 3D spread having a large physical footprint, the use of acoustic pop-up buoys makes it invisible to surface traffic and activities, enabling acquisition through heavy traffic areas that would otherwise be substantially disrupted by a marine streamer operation.

OBN provides all the elements of a good 3D seismic survey: fold density, spatial sampling, offsets and azimuths. Higher, properly designed, fold improves the ability to process seismic data; longer offsets provide good multiple attenuation and undershoot imaging; and increased azimuthal distribution improves the ability to image and resolve complex structures. This was observed in a study published in 2010 which stated, "The processed data from conventional towed-streamer seismic surveys over the Andrew satellite fields in the Central North Sea are of poor quality because of anomalously fast sand-filled channels in the Eocene overburden. The channels attenuate the primary energy and produce strong multiples. A step change in data quality has been achieved by acquiring a wide azimuth seismic survey using ocean-bottom cables and a high shot density. The new data have much higher signal-to-noise ratio and better resolution." (Daniel Davies, 2010.)

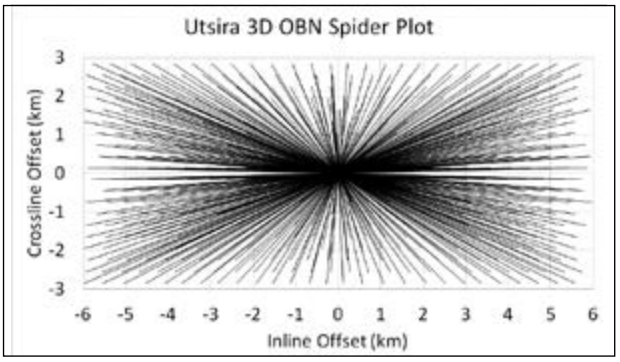
A modern quality OBN design can typically deliver 1,000x the data of a streamer survey, vastly superior

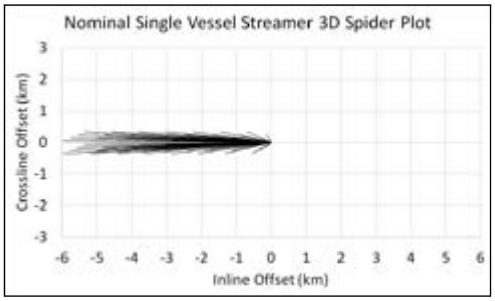
azimuthal distribution and is now more cost effective through higher productivity enabled by simultaneous source acquisition and refinements in the node handling domain.

Financial Sense

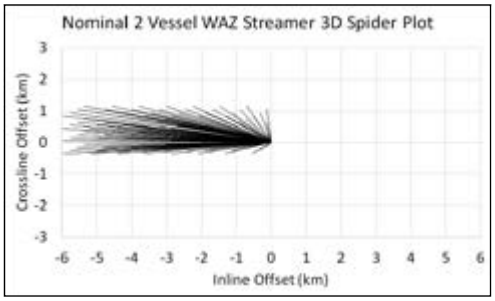
Driven by decreasing relative cost to marine streamer and increased oil recovery focus, financial analysts and industry experts are expecting the OBS market to deliver an annual turnover of around $1 billion in 2018. Further growth expectations towards 2021, it has been suggested, could be as high as $2 billion in annual turnover. It makes financial sense. NPV hit of a misplaced well (with a well cost of ~$10MM dry hole cost) in an onshore development is commonly over $40 million, and for offshore well costs and order of magnitude, higher NPV impact is significantly greater. Poor illumination and poor imaging of structures and faults all increase the risk of misplaced wells. *Reference online.* ■

Offset distribution of an OBN survey in the North Sea.

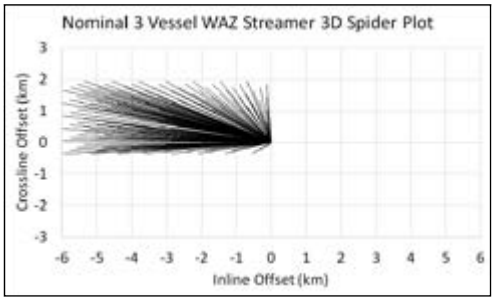




Offset distribution of a modern conventional streamer with a single vessel.



Azimuthal offset: marine streamer WAZ using two vessels.



Azimuthal offset: marine streamer WAZ using three vessels.

Unearthing the Source

Integration of sediment provenance analytical techniques is yielding critical new insights for hydrocarbon explorers around the world.

MARTA BARBARANO, Chemostrat

However far the stream flows, it never forgets its source.
– Nigerian Proverb

Sediment provenance analysis has become increasingly popular in the last decade due to the many applications it has for hydrocarbon exploration and production. Examples of these applications include tying reservoir sediment sources to specific terranes in order to better understand how sediment source-to-sink relationships have evolved over the period of reservoir deposition; improved understanding of sediment pathways, reservoir geometries and sand-on-sand contacts; and as a constraint on gross depositional environment maps. It also provides insights into reservoir quality, which is partially a product of sediment provenance. High amounts of K-feldspar, the dissolution of which can dramatically enhance sediment porosity, or of olivine, pyroxene and amphibole, which can provide the elements necessary for pore-choking chlorite formation, are related to the erosion of specific sediment source lithologies.

Chemostrat has successfully applied detrital zircon U-Pb geochronology and/or Raman heavy mineral analysis (a technique named after the Indian physicist and 1930 Nobel Prize for Physics winner, Sir Chandrasekhara Venkata Raman, who carried out ground-breaking work in the field of light scattering) on cuttings and core samples from sedimentary successions in a number of different geological settings and geographical areas. In each case the technique revealed new insights into the sediment provenance.

Southern North Sea Basin

A provenance switch is clearly documented in the Southern North Sea Basin, where zircon geochronology, in conjunction with a review of published source terrane ages, indicates that Carboniferous sandstones are derived from multiple basement terranes. A northerly Scandinavian hinterland is recognised as the sediment source for the Caister and Lower Ketch Formations, with (see Figure 1) sediments containing zircon grains from the Idefjorden Terrane in south-eastern Norway and south-western Sweden (c. 1,650–1,600 Ma), Mesoproterozoic to Neoproterozoic terranes in southern Norway (c. 970–920 Ma) and the Caledonian Belt (c. 450–400 Ma).

Derivation from the Bohemian Massif of northern Germany, which is a source of late Neoproterozoic zircon grains related to the Cadomian Orogeny (c. 650–550 Ma), and from the Variscan Front (c. 380–280 Ma) is evident for the Upper Ketch, De Lutte and Boulton Formations. Zircon age populations equivalent to those of the Cadomian and Variscan Orogenies are not identified in Scandinavia, clearly suggesting these formations have a different, southerly provenance compared with that of the Lower Ketch and Caister Formations.

Additionally, a provenance change between the Lower Ketch sandstones and the Upper Ketch sandstones can be suggested due to the different zircon age populations recognised (Figure 1B). The Lower Ketch sandstones have a similar provenance to that of the Caister Formation, whereas the Upper Ketch sandstones have an equivalent provenance to the Cleaver Formation. The Westoe Formation has a unique provenance signal.

Grand Banks Multi-Disciplinary Approach

In the North Sea example, clear evidence of provenance was detected using a single provenance technique (zircon geochronology); however, in most instances successful provenance studies require a multi-disciplinary approach. In the Grand Banks, offshore eastern Canada, Chemostrat has compiled a large, unprecedented dataset of both heavy mineral analysis, performed via Raman spectroscopy, and detrital zircon U-Pb geochronology.

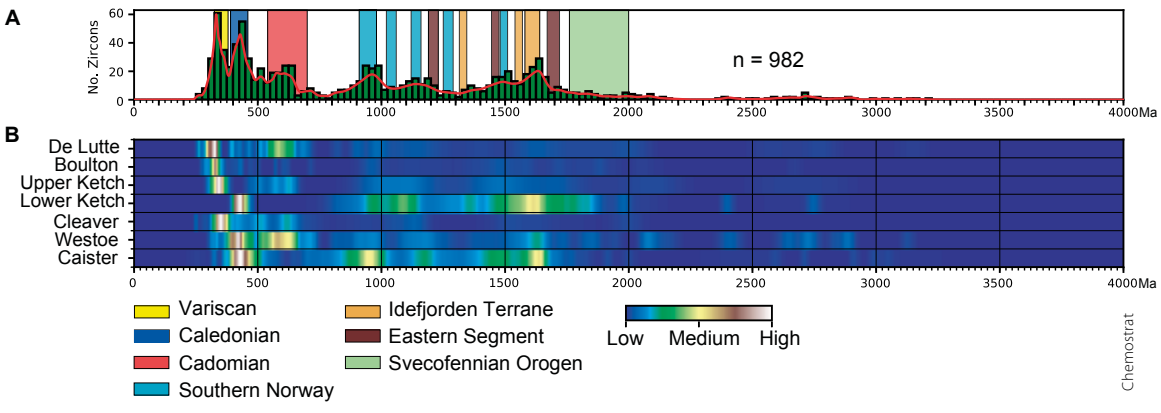


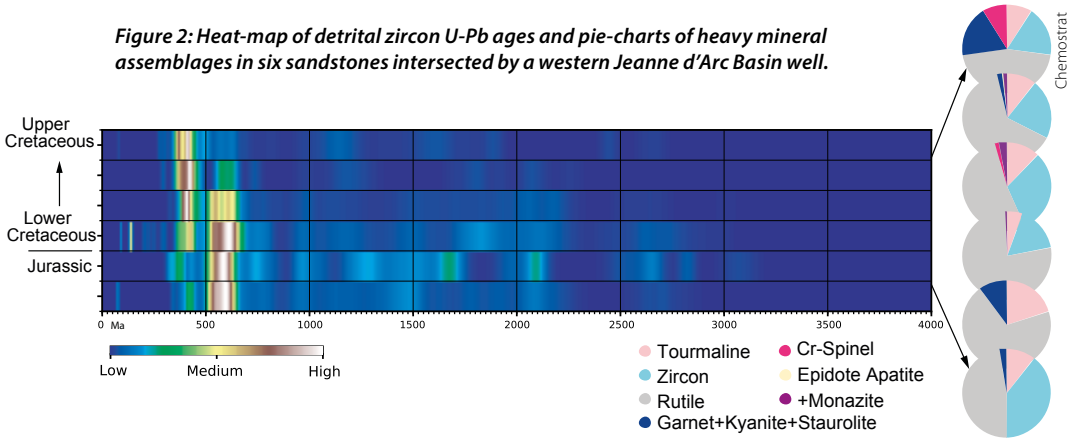
Figure 1: U-Pb ages of zircon grains of Carboniferous sandstones of the Southern North Sea Basin. A) probability density plot for all analysed grains, with source terrane ages. B) heat-maps of each analysed formation.

From this we have been able to demonstrate the value of the integration of the two techniques to determine the sediment provenance for the Jurassic to Cretaceous succession in the Grand Banks.

For example, in the western Jeanne d'Arc Basin, a shift in detrital zircon ages from predominantly Neoproterozoic (in Jurassic to Lower Cretaceous sandstones) to predominantly Devonian-Silurian (in younger sandstones) is observed (heat-map in Figure 2). Neoproterozoic zircon ages can be associated either with provenance from the sedimentary succession of the Avalon Zone of eastern Newfoundland, or with provenance from felsic igneous rocks. The first hypothesis is supported by the heavy mineral assemblages of Jurassic to Lower Cretaceous sandstones, which are enriched in ultrastable minerals that can survive sediment recycling, such as zircon, tourmaline and rutile (pie-charts in Figure 2). Additionally, an input of 'first-cycle' sediment derived from metamorphic units occurred in the shallowest analysed Jurassic sandstones, which contain metamorphic minerals (pie-charts in Figure 2).

The Devonian-Silurian felsic igneous rocks that provided zircon grains cannot be the only source of sediment during the Late Cretaceous. Additional sources must have been present, which provided the observed c. 10% Cr-spinel and c.20% high-grade metamorphic minerals, probably derived from the metamorphic basement and the associated ophiolites of western Newfoundland. Derivation from these terranes would have been missed if only detrital zircon geochronology was applied.

Figure 2: Heat-map of detrital zircon U-Pb ages and pie-charts of heavy mineral assemblages in six sandstones intersected by a western Jeanne d'Arc Basin well.



Onshore Tanzania

A multi-disciplinary sediment provenance study has also been performed for the sedimentary succession of onshore Tanzania, showing an important provenance change occurring at the Mesozoic/Cenozoic boundary. Raman heavy minerals analysis demonstrates a predominance of garnet and apatite versus kyanite and epidote in Cretaceous sandstones, but not in Paleogene sandstones (Figure 3A).

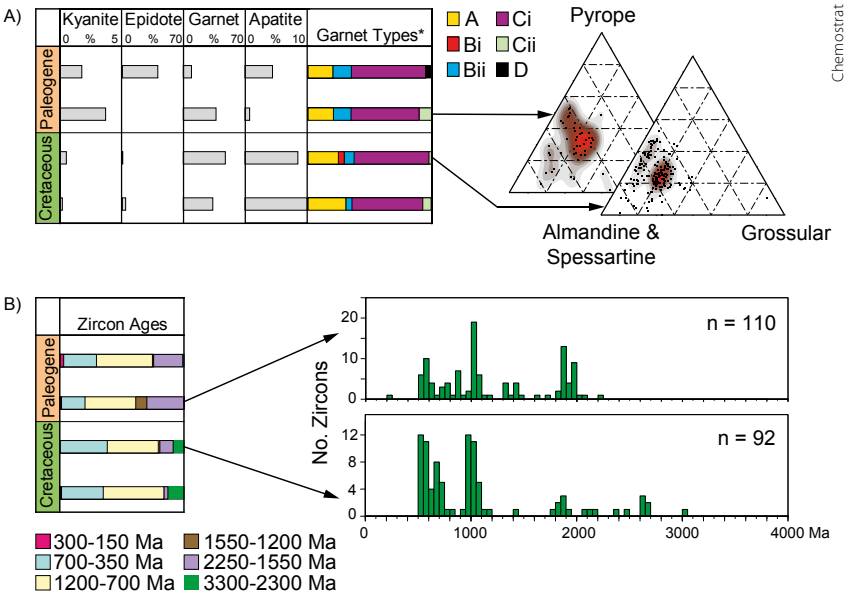
Raman spectroscopy allows the determination of different proportions of garnet end-members; results can be processed following Mange and Morton (2007) to relate different garnet 'types' with the lithologies the garnet grains are derived from. Provenance from high-grade granulite-facies metasedimentary rocks ('type A' garnet grains) are seen to be more prevalent in Cretaceous than in Paleogene sandstones, whereas provenance from low-grade metabasic rocks ('type D' garnets) is only documented for the youngest analysed sandstones. These sandstones also contain around 40% epidote in their heavy mineral assemblages, a mineral typically derived from greenschist-facies metamorphic rocks, and which has also been found in high concentrations in Eocene to Oligocene sandstones onshore Tanzania (Nerbraten, 2014). At the Mesozoic/Cenozoic boundary the detrital zircon age populations also change (Figure 3B), supporting the results of heavy mineral analysis.

Exciting New Insights

These case studies demonstrate that Raman heavy mineral analysis and detrital zircon U-Pb geochronology, when combined, provide hydrocarbon explorers with exciting new insights into the sediment provenance story for their region. Understanding the impact of sediment provenance on the quality of any reservoir can clearly be enhanced through application of this technique.

References available online.

Figure 3: Results of Raman heavy mineral analysis (A) and detrital zircon U-Pb geochronology (B) performed on sandstones from onshore Tanzania. Data from McCabe (in prep.) *Garnet Types after Mange and Morton (2007).



Thinking Outside the Play

How to rejuvenate exploration in prolific but tired petroleum systems.

GUY LOFTUS, ALLAN SCARDINA, PETER BURGESS and SIMON NEAL

It is never easy to let go of the assets which formed the backbone of your organisation's balance sheet for many years, even as the end of productive life approaches. Incremental volumes add significant value to tired settings with high exploration maturity, partly because the extra production can flow through existing infrastructure. Just as valuable to operators are the incremental savings in 'money of the day' brought about by delaying decommissioning of the same infrastructure. Despite the fact that all extractive resources are finite, it seems that prolific systems, whether located in the North Sea, the Gulf of Mexico or Indonesia, just keep giving, as technology, technique or just happy accidents extend productive life.

These 'super basins' seem to have generated more hydrocarbons than there are reservoirs to contain them, so the surprises tend to be around unexpected reservoirs or sub-seismic traps. So long as they keep delivering there remain opportunities, but the downside is that they also prevent anyone from being able to generate a meaningful 'yet-to-find'.

Understanding White Space

There are four components to 'white space' in petroleum exploration: physical white space (gaps in data); technical white space (gaps in data quality); intellectual white space (gaps in play-based thinking); and organisational white space (gaps in business focus) – see image top of opposite page. Each is associated with varying degrees in exploration maturity but the key to unlocking what remains of prolific but tired petroleum systems is intellectual white space. This exists because we have become so focused on extracting value with diminishing returns from bread-and-butter plays, that we have become perceptually blind to new play opportunities. In effect, we have forgotten how to think outside the play. We know this is true because these petroleum systems continue to deliver surprises in areas that were thought to have been well picked over including, for example, Johan Sverdrup in the North Sea, the Norphlet play in the Gulf of Mexico and Badik and Parang in the Tarakan Basin. It could be argued that ignorance is scope in frontier basins, but it erodes value in basins with high levels of exploration maturity. Many of these basins have no shortage of connected data but they are often short of connected thinking.

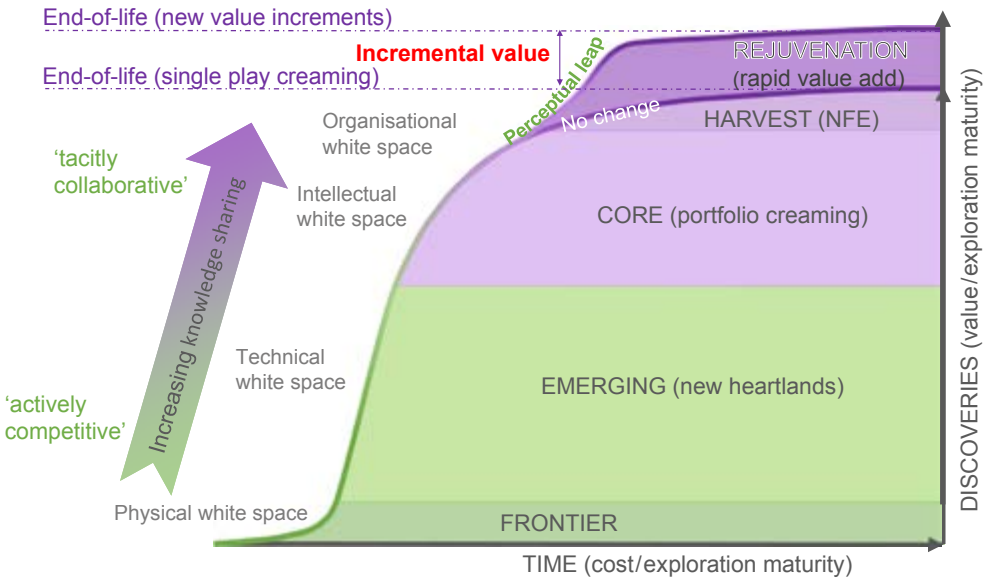
Understanding which component of white space needs to be overcome to add value in exploration materially changes how you deploy resources to achieve it.

Collaboration is an integral part of day-to-day petroleum exploration which works, but only if it does not compromise enterprise confidentiality. Collaboration through data exchanges or infrastructure sharing are tightly controlled as much by perceived quid pro quo enterprise transactions as by avoiding perceived anti-trust behaviours. Exploration risk can also be traded through collaborative equity exchanges to obviate exposure through risk optimisation, which may involve a minimum amount of knowledge sharing. Such transactions are all closed forms of collaboration between carefully selected organisations, with clear value of information controls to protect intellectual property. Open collaboration, however, whether through an exchange of data or knowledge, is a completely different transaction and one that challenges conventional views of enterprise driven dynamics (see *GEO ExPro* online exclusive article in September, 2018).

There is no question that enterprise driven principles are key to unlocking frontier, emerging and core basins, providing the engine for essential

Decommissioning is an expensive option.

investment and value creation. But when the petroleum system approaches its perceived 'end-of-life', jumps in value require leaps in perception rather than data. Value-adding perceptions may be geological, such as the existence of a seal in aeolian deposits of the Haima in Oman; engineering, like analysing what constitutes the deepwater limit for oil production; or commercial – for example, redefining what is meant by 'stranded gas' in the North West Shelf of Australia. This is when collaboration through a more open exchange of knowledge (not necessarily information) potentially becomes a new value driver, but it requires a conscious shift in enterprise dynamics which are currently purely opportunity driven.



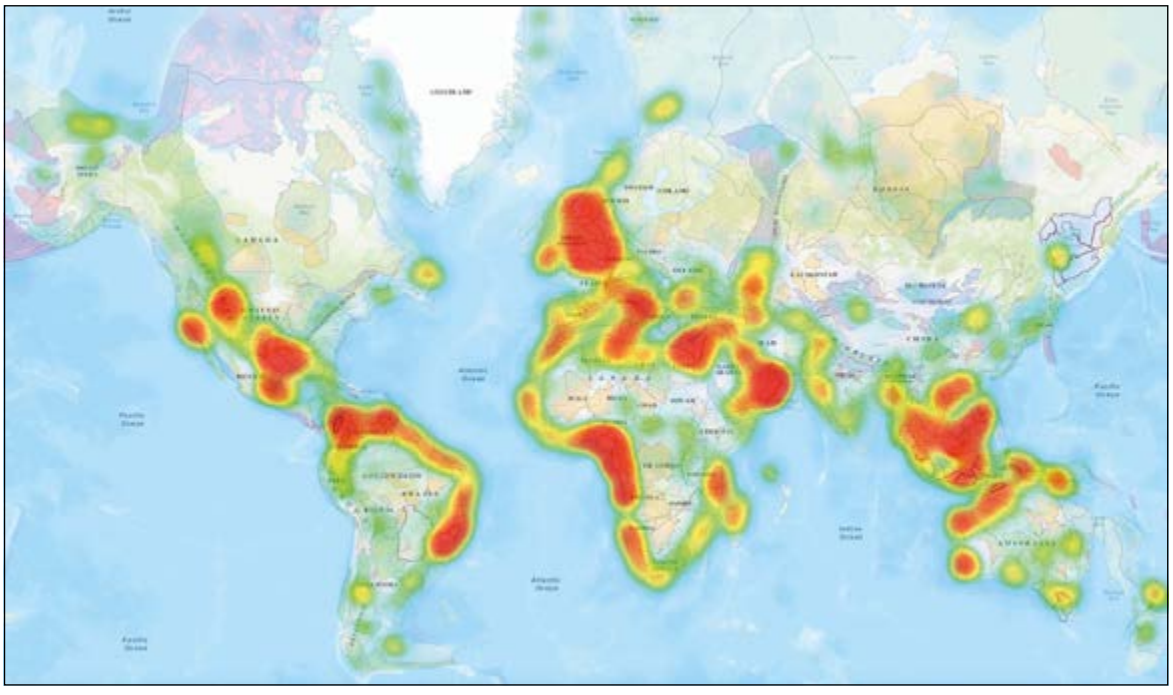
Finite resource creaming as an expression of exploration maturity over 20–120 years (and counting).

Rejuvenation Process

Rejuvenation of tired petroleum systems depends on geology, data, knowledge holders and – crucially – the backing of the regulator for the relevant segment of the petroleum system. The process outlined in steps below takes open collaboration to an unprecedented level and provides the means to achieve it using freely available crowd-sourcing tools. Each stage has been ground-truthed in other initiatives, public and proprietary, so we know that they work, but the simplified process discussed requires critical mass of opinion to be effective, which we believe can only be achieved if the initiative is supported and sponsored by a combination of the regulator and academia.

Step 1. Knowledge sharing: The first step is to find out who knows what, where and when, not just in the area of interest but globally. One way of doing this is through the freely accessible Knowledge PinMap™, which allows a crustal view to be established to help build meaningful analogues later in the process. Participants are invited to build their personal 'SpatialCV™', which will remain anonymous, through which they can identify plays where they have developed expertise.

Step 2. Play break-out: Regulator-appointed agents then create inventories of both bread-and-butter plays and potential plays with analogue content. This stage requires a unified play terminology recognised by all knowledge holders for a specific petroleum system and involves what can be an extended period of



Who knows what, where? A 'knowledge heat map' of the world, based on 2,500 contributions by 180 knowledge holders, is very useful (knowledge from SpatialCV™, basin outlines from Tellus).

convergence if play definitions have not been previously agreed.

Step 3. Play kracqing: Regulator-appointed agents will crowd-source scores for each play using an observational matrix provided by the KRACQS™ metadatabase, which was designed as part of an experiment conducted on knowledge stacking (Loftus et al., 2018).

Step 4. Play ranking: A panel of experts for each play is appointed to screen plays and to invite new concept thinking in plenary sessions. The agents can then rank the play potentials using regulator weighted metrics and establish globally calibrated yet-to-find values through play analogues.

Step 5. Publish: Distribute the results and ensure they remain evergreen by crowd-sourcing the continuously evolving opinion of participants as they react to changing circumstances.

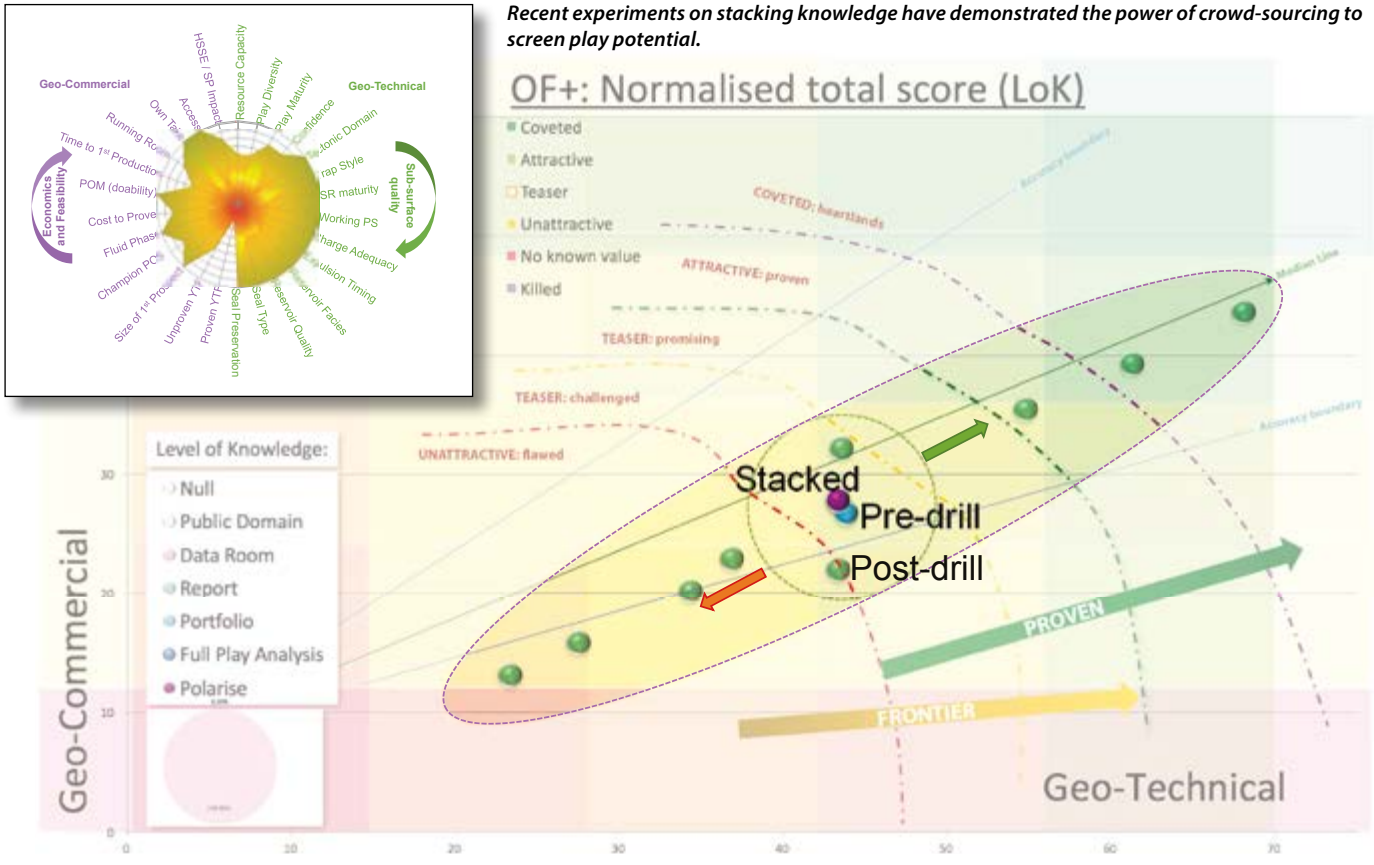
The authors described in the online *GEO ExPro* article how two-way crowd-sourcing opens up a whole new reference frame by consulting a broad college of opinion. Applying value-driven observational scores to targeted participants using free online facilities can be achieved through open collaboration without compromising enterprise confidentiality if participants have been granted formal clearance from their respective enterprises, even if their entries remain anonymous. Industry-wide opinion can then be associated with a compiled inventory of play potential across mature basins entirely through crowd-sourcing to deliver a common understanding of yet-to-find and value to each enterprise before decisions can be made whether to invest in or divest assets. Soliciting industry-wide knowledge has not been attempted before in the oil and gas sector and could play a key role in rejuvenating tired petroleum systems.

A Common Understanding

No isolated enterprise, however dominant in its understanding of an area or its access to data, can ever see the entire picture of a petroleum system that has been picked over by many operators for years, however robust their method of future potential assessment. Advisors to the industry have repeatedly stressed that collaboration is essential for unlocking the remaining potential in mature basins. The method described here not only demonstrates how to do it but provides the means to achieve it as well. The method requires careful management by the regulator (or its appointees), as they must determine how to pool knowledge in a way that all participants can potentially win by the integration of local geology with cost exposure, infrastructure maturity and legal framework. However knowledge pooling is achieved, the collaboration of industry with the regulator would form a powerful partnership in defining how to rejuvenate each basin. By crowd-sourcing opinion and shaping that in to a commonly agreed inventory of play-based value, the rejuvenation process invades intellectual white space, connecting knowledge by sharing knowledge in order to achieve a common understanding of value through open collaboration.

Authenticated knowledge can be shared anonymously without compromising enterprise competitive advantage.

References available online. ■



Recent experiments on stacking knowledge have demonstrated the power of crowd-sourcing to screen play potential.

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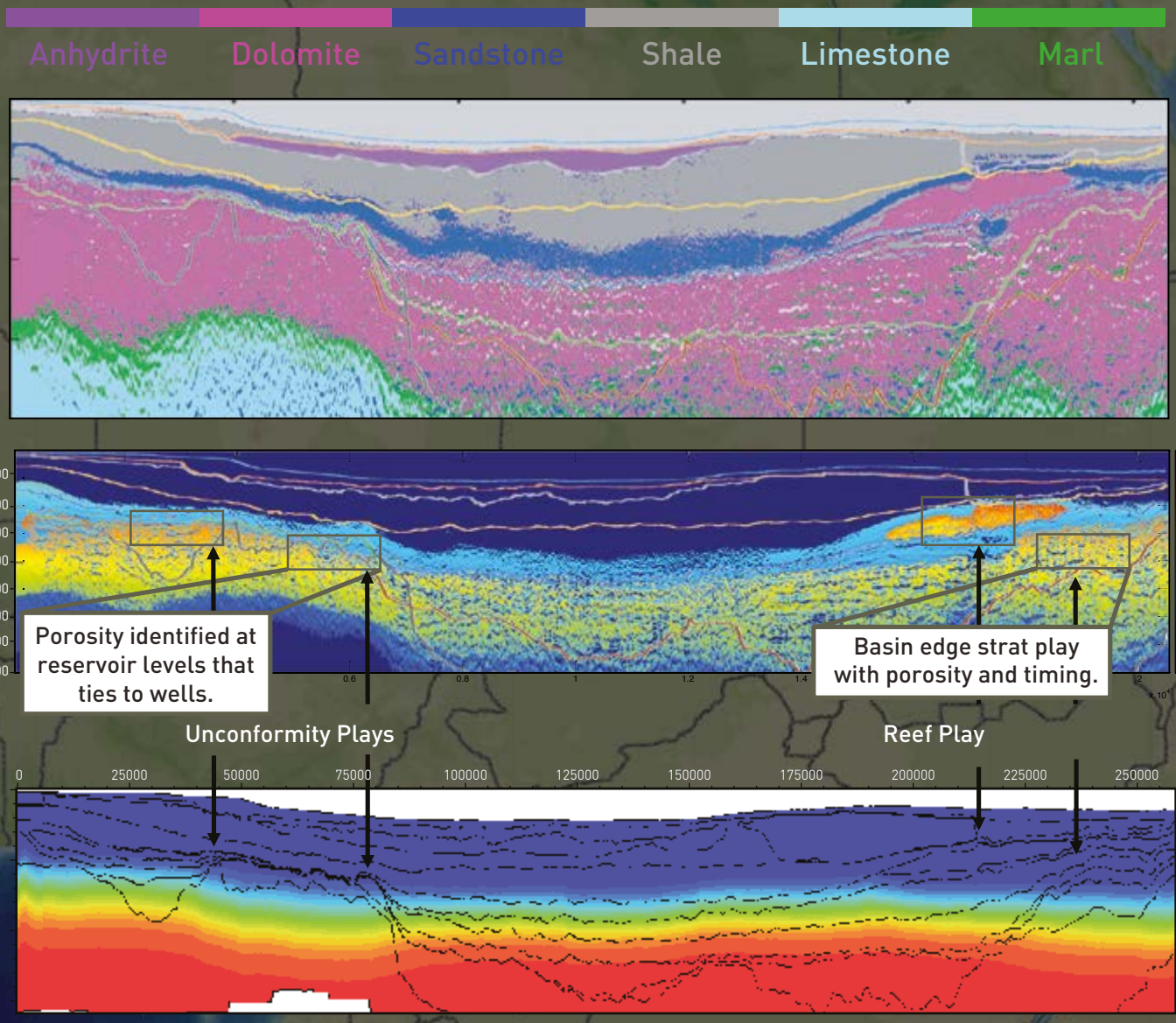

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"Once you know what you want in life... like a magnet you attract the resources necessary to manifest the world you desire."

Melissa Mojo Hunter, Pretty Poems to Ponder

Following on from Part I of our series on Marine Vibrators (GEO ExPro, Vol. 15, No. 3), we look at developments made in this technology by PGS.

Guest contributor: RUNE TENGHAMN, PGS
MARTIN LANDRØ and LASSE AMUNDSEN, NTNU and Bivrost Geo

Two years after Petroleum GeoServices (PGS) was founded in 1991, the company started to look into alternatives to marine airgun arrays. A huge marine vibrator based on flextensional principles equipped with an electric motor drive was developed and tested at the Norsk Hydro operated Oseberg field in 1995. In the period from 1996 to 2001 this prototype was further developed and the motor was exchanged for an electromagnetic drive, which was tested in the Gulf of Mexico between 1999 and 2001.

A major challenge for marine vibrators has always been to compose a broadband source spectrum, and to generate sufficient low frequency energy is especially challenging. This issue forces the size of the marine vibrator so it is significantly larger than an airgun.

In 2007 PGS started to use Terfenol as the driving mechanism. The use of Terfenol-D was actually launched in a development project financed by Saga Petroleum in the early '90s and the initial results were presented at the 1991 SEG meeting (Ursin-Holm et al., 1991). The Swedish company ABB had also performed experiments using Terfenol-D in 1983.

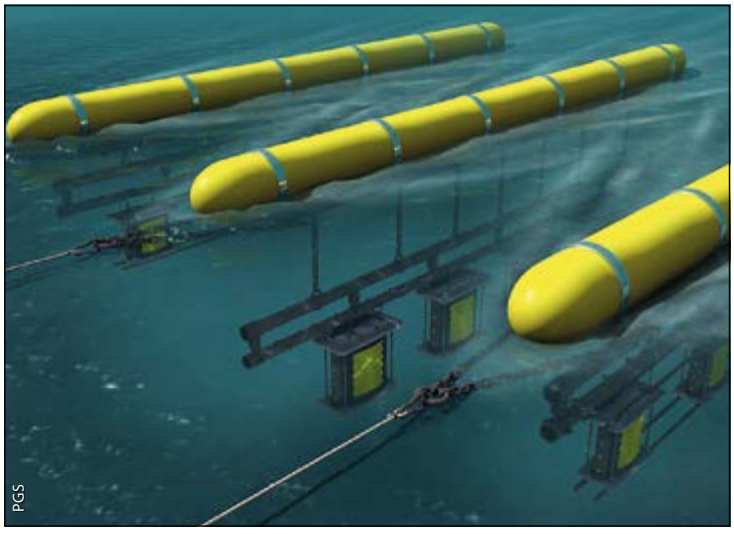
In the 1991 paper by Ursin-Holm et al. the main focus was to develop a source that could be used for site surveys and imaging of shallow marine sediments, with a source spectrum covering the bandwidth from 100 to 800 Hz. The nice feature of the Terfenol-D alloy is that a relatively small displacement along the major axis is converted to a much larger displacement along the minor axis. Typically, the Terfenol-D rod is surrounded by a flextensional shell. The 1991 test showed that this prototype source had a moderately flat spectrum with two major peaks (140 and 640 Hz), and an average peak output of approximately 1.2 bar-m. This signal strength is comparable to a small airgun (20 cubic inches). The 2007 version of the flextensional marine vibrator was tested in shallow water in 2012. Geokinetics has since used this source for several field trials, and denoted the source AquaVib.

In 2013, a new electromagnetic drive was developed which improved the low frequency response significantly, so that the new vibrator now provides a good bandwidth between 5 and 100 Hz.

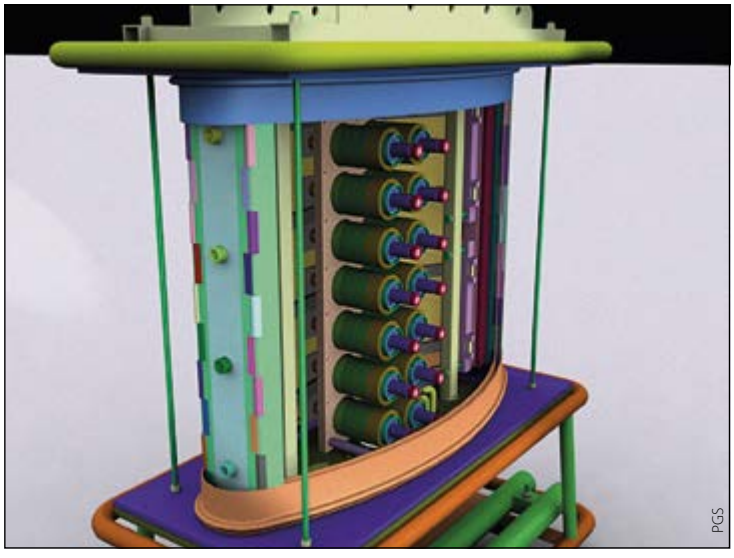
Improving Low Frequency Response

Conventional marine seismic vibrators (the early hydraulically driven marine vibrators) typically have a poor signal strength below 30 Hz, especially when compared to

Sketch showing how the marine vibrator is towed behind the seismic vessel.

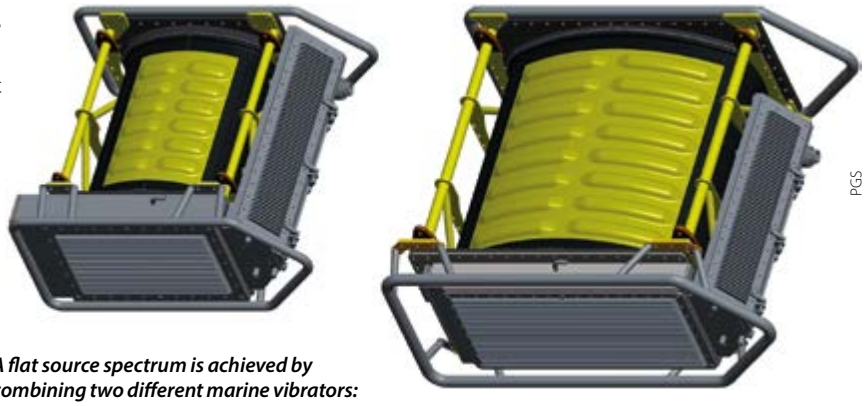


Flextensional marine vibrator equipped with an electromagnetic drive. Each source unit is the size of a man.



conventional airgun arrays. The reason for this is that these types of sources have a very poor efficiency at low frequency. The only way to get good efficiency at low frequencies is to have a resonance in the lower frequency range. The resonances for the hydraulic sources were above the seismic band, so in the period from 2013 to 2017 one of the main challenges that the PGS marine vibrator team faced was to improve this response.

By combining two sources, Triton M and the Subtone M (the M denotes a PGS source with the new electromagnetic driver), the source strength is improved significantly, especially for low frequencies. The clue to getting a good acoustic output was that each of the sources has two resonances, one in the low frequency end and one in the upper frequency range. The resonance in the low frequency range end is a result of the shell interacting with the surrounding water, while the second resonance is from the driver mechanism in the source itself. This type of system is the only known concept that can create a rather flat frequency response over a wide range of frequencies, making it a unique source for seismic applications. The two resonances for each source not only improve the acoustic output but also improve the efficiency, which in turn makes the sources more controllable, enabling them to use arbitrary signals with 'high acoustic fidelity'. From a field test it has been found that the output for the new vibrator array (consisting of 4 Subtone elements and 8 Triton elements) would meet the requirement of 190 dB re 1 microPa/Hz@1m for 5–10 Hz and 200 dB for 10–100 Hz for a 5 second-long sweep. This is comparable to a 1,000 cubic inch airgun, although this comparison is not straightforward since the marine vibrator will be repeatable and have less self-generated noise.



PGS

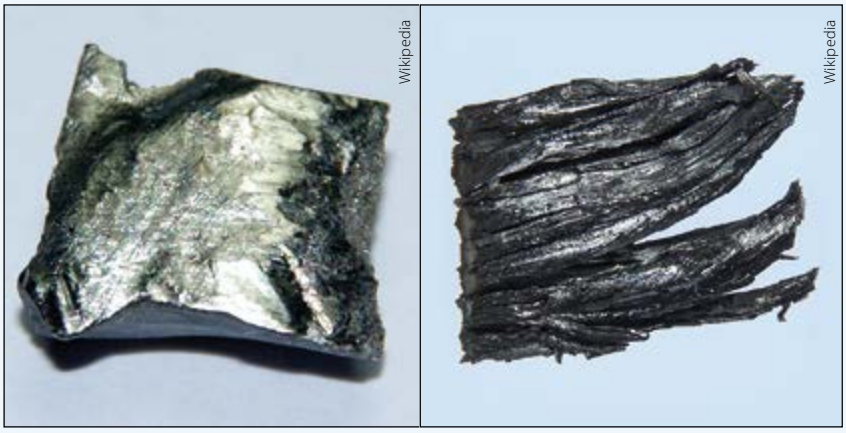
A flat source spectrum is achieved by combining two different marine vibrators: a Triton M source (left) and a Subtone M (right). The two sources are shown at the same relative scale.

The next step in this development is to build a full seismic array and test it in the field. Unfortunately, due to the major decline in the seismic market from 2013 to date, this project has been put on hold. The interest in marine vibrators, however, is increasing, and with an improving seismic market at the same time as the industry is facing more regulations, particularly related to impulsive sources, one may expect new opportunities for marine vibrator technology. ▶

Terfenol-D

According to Wikipedia, Terfenol-D is an alloy material composed of terbium (Tb), dysprosium (Dy) and iron (Fe). It is magnetostrictive, which means that it will change shape when exposed to a magnetic field. This property is exploited to generate the vibrations for the marine Terfenol-D-based device that was developed between 1991 and 2007. The acronym Terfenol comes from **Te**rbium, Iron (**Fe**) and **N**aval **O**rdnance **L**aboratory (where it was developed). The last letter (D) refers to **D**ysprosium. Both terbium and dysprosium are rare earth materials.

Snodgrass and McMasters (1997) states that Terfenol-D offers the highest strain of any magnetostrictive material at room temperature using practical driving fields; typically, up to 1.2 millistrain is achieved for a driving magnetic field of 100 kA/m. However, strains as high as 3.6 millistrain are possible if the Terfenol-D alloy is driven at mechanical resonance (Dapino, 2004). These strains are typically three orders of magnitude larger than, for instance, those of nickel.



Terbium (left) and Dysprosium (right).

Terbium is number 65 in the periodic table, and was discovered by Carl Gustav Mosander in 1843. The top three producers of this rare earth metal are China, Russia and Malaysia. In addition to Terfenol-D, terbium is used in several solid-state devices, low-energy lightbulbs, X-ray machines and laser devices. As a laser, it emits coherent light with a wavelength of 546 nm. Terbium is a soft material that can be cut by a knife.

Dysprosium is element number 66 in the periodic table and is also one of the rare earth metals. It was discovered by Paul-Emile Lecoq de Boisbaudran in 1886. The name is Greek and means 'hard to get'! Today, dysprosium is used to produce permanent magnets that are used in electric vehicles, among other things. In 2011 electric vehicles contributed to 20% of the dysprosium market. The demand for the mineral has increased over the last decades and according to Hoenderdaal et al., 2013, 99% of it is mined in China. Since it takes several years to establish new mines it is not unlikely that there might be a shortage of dysprosium within a few years.

Flexible System

The final stage of marine vibrator development, which was put on hold in 2016, showed that the required output of 5–100 Hz can be met. The developed marine vibrator array can be used in a towed mode (as shown below) or in a stationary mode for shallow waters or transition zones. The sweep length can vary from 5 to 40 seconds, and the depth range is from 2 to 30m. In the future it would also be possible to place units on unmanned surface vessels which would improve the flexibility further. New signal schemes together with continuous recording may also reduce the number of sources needed. ■

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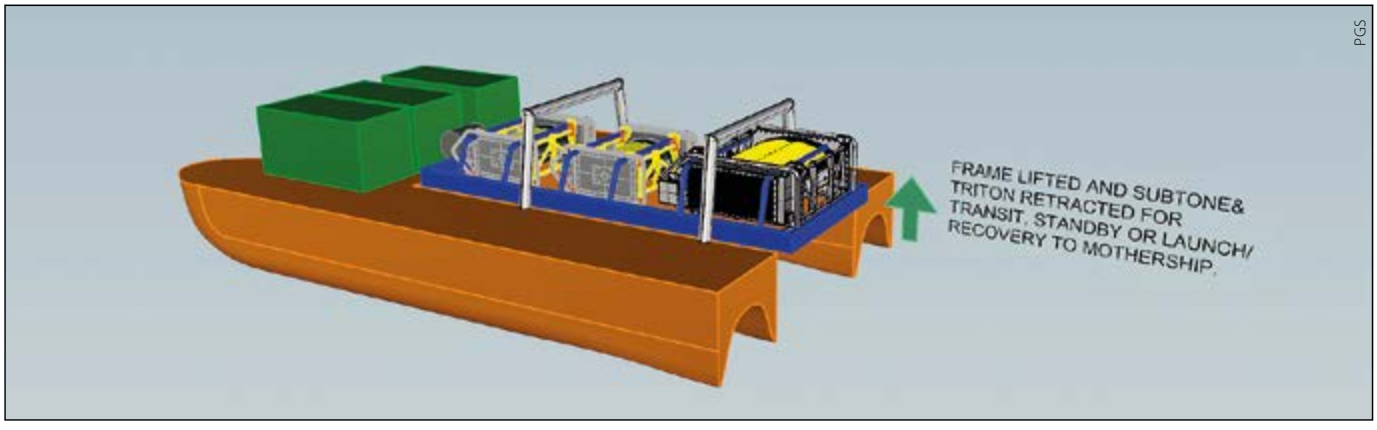
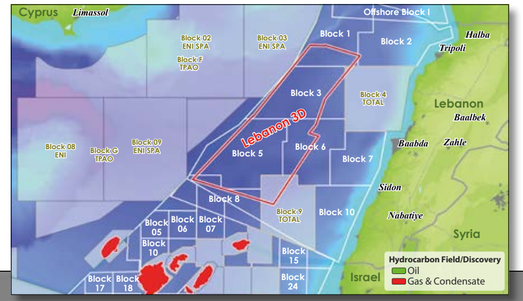


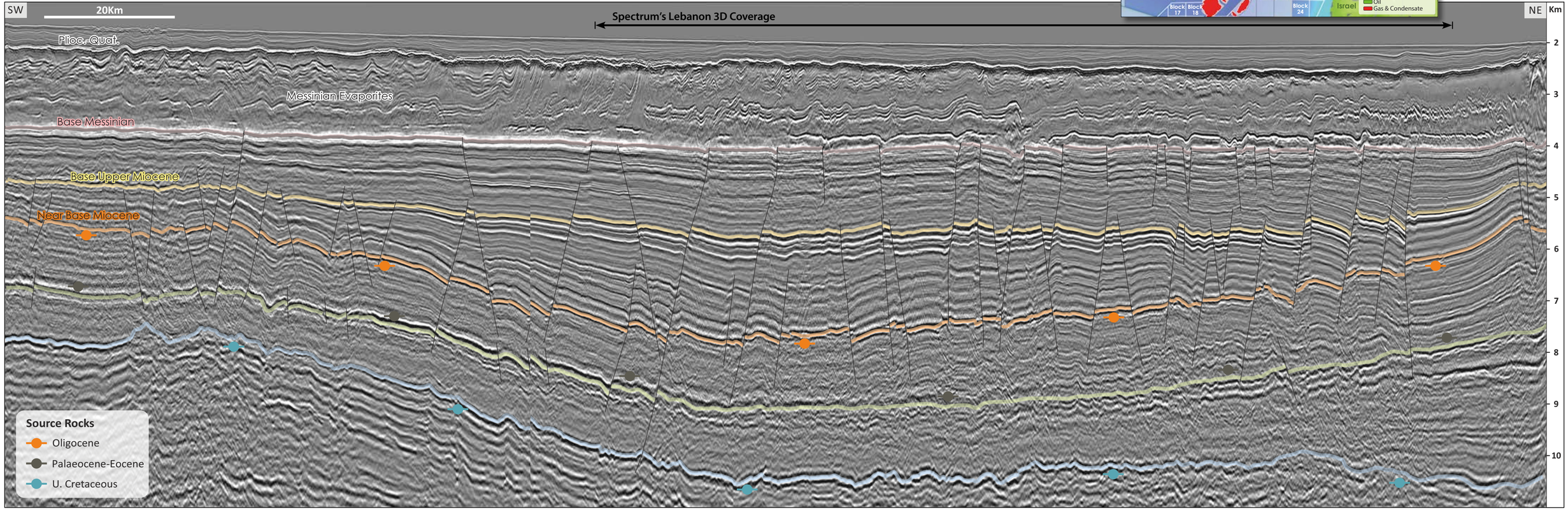
Offshore Lebanon:
Solving the Eastern Mediterranean's Oil Mystery

Lebanon's imminent second offshore licence round will offer blocks with extraordinary potential. Blocks in the west display large, simple 3-way dip and 1-way fault closed structures on modern 3D seismic, where blind planar east–west faults cut long north–south folds. These features, with 400–500m of closure, enclose 1,000m of Nile-derived deepwater fan, high quality sandstone in very large traps. Whilst these are generally assumed to be filled by dry biogenic gas like the adjacent Leviathan and Zohr discoveries, actually a credible oil play from an oil-prone source rock directly underneath the reservoir suggests this undrilled acreage could make Lebanon the East Mediterranean's oil capital.

Spectrum



A 2017 broadband reprocessed Kirchhoff PSDM 2D seismic line extending from the shallow basement of the South Levant Platform (LHS) into the Northern Levant Basin offshore Lebanon (RHS). Vertical axis Depth in Km. Horizons: Light Brown - Mid Miocene, Dark Brown - Oligocene, Green - Eocene, Blue - Cretaceous.



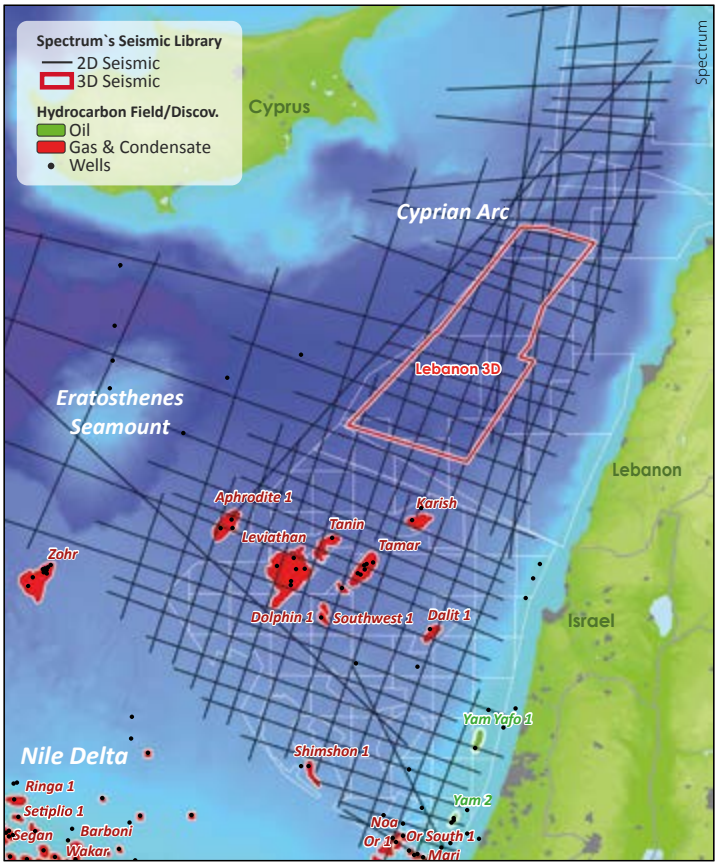
Extraordinary Potential Offshore Lebanon

As Jane Austen might have said: "It is a truth universally acknowledged, that exploration companies possessing acreage in the Eastern Mediterranean must be in want of biogenic gas."

NEIL HODGSON, KARYNA RODRIGUEZ and PAOLO ESESTIME, Spectrum Geo

Or so it would seem with the spate of giant biogenic gas discoveries in the Levant basin in Early Miocene sandstones and Early Cretaceous carbonate reefs over the last ten years.

Yet there is a deeper mystery here, as the Jurassic, Late Cretaceous and Lower Tertiary of the Eastern Mediterranean 'Levant' basins all display credible oil source rocks – so why has this not been the dominant hydrocarbon phase encountered? The answer to this puzzle is pointing explorers in a most remarkable direction: away from the Southern Levant and Eratosthenes platforms and the thick Tertiary Nile Delta cone and into the Northern Levant Basin offshore Lebanon. Here, a 'Goldilocks window' for generation puts the primary Lower Tertiary and Upper Cretaceous source rocks squarely in the oil window, where they sit directly beneath 1 km of Early Miocene Nile-derived basin floor sandstone fans in numerous significant simple structural traps.



Map of Spectrum data and the discoveries in the area.

Levant Basin Structure and Reservoir

The Eastern Mediterranean has a complex geological history. The eastern Levant is likely to be comprised of hyper-extended continental crust, and true ocean crust is probably not found east of the Eratosthenes platform, nor south of Cyprus.

Of the post-Jurassic basin fill, the Cretaceous is dominated by the growth of carbonate platforms such as the isolated Eratosthenes Platform and along the margins of what is now Lebanon, Israel and Egypt.

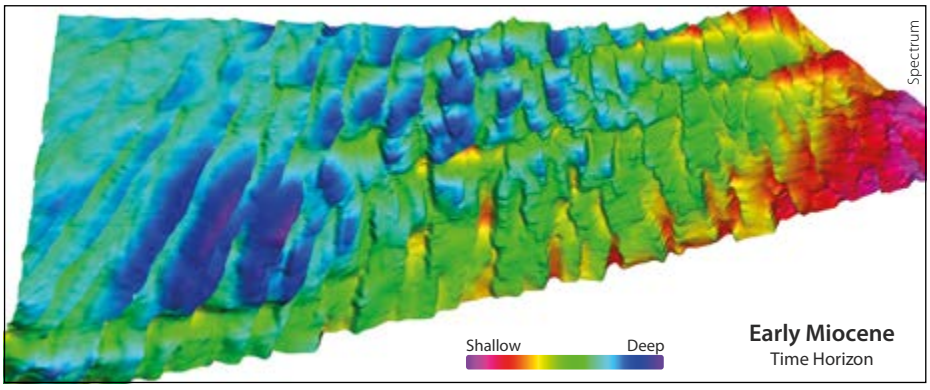
We believe that in the Late Cretaceous, a negative dynamic topographic event occurred in the Eastern Mediterranean, due to either new mantle convection cell creation or plate movement over a fixed short wavelength cell fabric. This allowed the Nile Delta, which had been draining into the proto-Niger, to begin to flow north and to bring clastics for the first time into the Mediterranean, drowning carbonate production on the margins. Oligocene coarse clastics were deposited to the south and west of the present Nile Delta, whilst Oligocene source rocks were deposited to the east; indeed, the Oligocene is a major oil source rock contributor in the Nile Delta. In the Early Miocene, thick deepwater turbidite fan complexes prograded east out across the Southern Levant platform. These mature, medium to fine grained and very high net-to-gross sands provide the reservoirs of the Israeli Tamar, Leviathan, Tannin and Kerish discoveries. With open seaway between the Mediterranean and the Persian Gulf, we expect that strong anti-clockwise contourite currents on the Mediterranean margin would have de-silted the turbidite flows.

However, just north of Kerish (see map) lies the Levant Ramp, down which Early Miocene sands would have continued to prograde into the Northern Levant Basin; in fact, it is possible to demonstrate that the 250–300m Early Miocene sand sequence on the Southern Levant platform thickens to over 1 km in the Northern Levant Basin (see foldout on previous page). This is interpreted from seismic facies analysis to be a largely deepwater basin floor fan sandstone complex. Unsurprisingly, the turbidites are thickest at the basin centre and thin out toward the basin margins, so that sands are very thin in the eastern pinchout where Onasagoras-1 and Amathusa-1 were drilled in Cyprus during 2013/4.

Towards the end of the Early Miocene the anti-clockwise rotating African plate collided with the Turkish fold and thrust belt, closing the seaway to the Persian Gulf and allowing the Nile Delta to re-adjust its depocentre into a more westerly loci. This ended coarse clastic supply to the Northern Levant Basin, which subsequently saw mainly mudstone deposition until the Messinian event.

In the Northern Levant Basin two structural styles

developed almost simultaneously during the Late Miocene prior to the Messinian. Long, planar and blind east–west extensional faults formed showing no listric rotation and terminating upwards either in the upper Miocene or the base Messinian and downwards in the Oligocene/Eocene. These faults are spaced 5–8 km apart (fault density is considerably less than seen in the Tamar field to the south) and hade either north or south (see image top right). As the post Early Miocene sequence comprises shale or marl, cross fault seal is extremely robust. There is no expression of these faults at Cretaceous level, indicating that the Oligocene/Eocene unit is ductile, with the timing of development of ductility being of particular importance.



3D image of the top Early Miocene reservoir.

At the same time, simple compressional folds developed on a north–south axis orthogonal to the extension. Again no expression is seen at Cretaceous level, indicating that line shortening is decolled in the ductile Oligocene–Eocene. Developed 40–50 km apart, these are not flower structures related to underlying fault systems, but simple folds developed under compression. The combination of east–west faults across the north–south folds creates a string of structures, three-way dip closed and one-way fault closed, along the axis of the folds. They range in area from 20 to 50 km^2.

The antiformal structure of Tamar (9 Tcfg) appears similar in size and scale to the Northern Levant structures except that Tamar is more highly faulted.

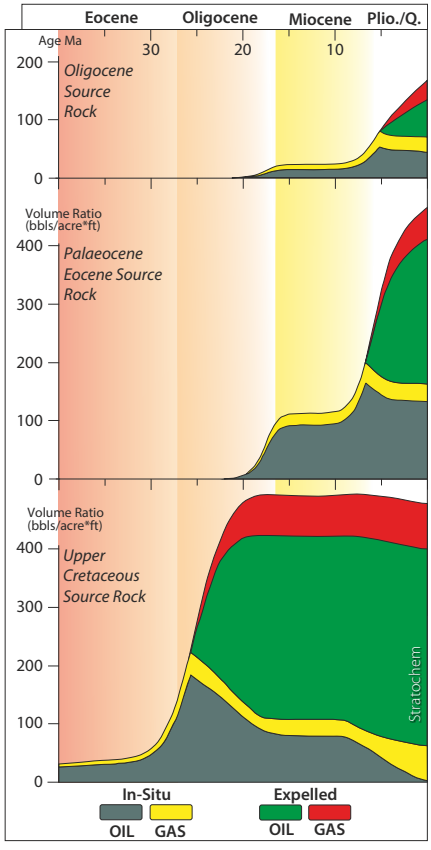
The Oil Play in Lebanon

The Early Miocene play in Lebanon is presented as big simple structures, with 1,000m of Early Miocene sandstone sealed by thick Late Miocene mudstones. But what of hydrocarbon charge? The adjacent discoveries in Southern Levant have generally low liquid content and light carbon isotope signature, supporting a biogenic origin. However, Tannin and Kerish fields are reported to have a higher liquid/gas ratio, suggesting at least in part a thermogenic source.

On the southern Levant margin, the geothermal gradient is now known to be low, at about 20°C/km. As biogenic gas is produced by bacteria active over a specific temperature range (20–60°C), this has led to Oligocene material being attacked by bacteria for a very long period of time, providing the gas found in the Early Miocene fields. Only recently have these cultures been killed off, but the Oligocene, Eocene and Palaeocene sequence is not yet hot enough to enter the oil window in South Levant, except perhaps under Kerish. Underlying source rocks in the Late Cretaceous and Jurassic have generated oil, as encountered in the Mesozoic section in wells such as Yam-2, but it is prevented from migrating into the Early Miocene section by thick Lower Tertiary shales.

To the east in Cyprus and northern Egypt, Early Cretaceous carbonate reef discoveries between 2014 and 2018 include Zohr (30 Tcf), and Calypso (6 Tcf). Prodigious volumes of biogenic gas have been sourced from the Oligocene under slow burial with low geothermal gradient. However, in the Northern Levant Basin where (assuming it displays the same geothermal gradient as seen in the Southern Levant Basin) the Oligocene and Eocene-Palaeocene sequences are in the oil generation window.

A simple graphic representation of the phase and timing of hydrocarbon charge for the three candidate oil source rocks.



To investigate this, a 3D project was undertaken by Stratochem to model the known and expected source rock hydrocarbon histories of the Oligocene, Eocene-Palaeocene and Late Cretaceous source rocks in the Southern and Northern Levant Basins. A large number of wells and Spectrum's 2D seismic interpretation were used to constrain the model.

The 3D basin model shows that, post the Messinian event, oil has been generated from the Oligocene/Eocene interval, charging overlying Early Miocene sands in structures which formed pre-Messinian.

Indeed, the high liquid content of Kerish and the presence of oil slicks observed on SAR radar tell us that this basin is generating oil at present. The peculiarities of copious biogenic gas flushing and immature source below structures in the surrounding basins suggest that perhaps the only place to find huge oil fields in the Eastern Mediterranean may actually be the last place to be explored – in the Northern Levant Basin offshore Lebanon. ■

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Integrating technologies for basin analysis improves geological and geophysical models.

Typically, seismic data processing employs a limited consideration for the geologic interpretation of structure, lithology and fabric. It is also a common belief that sequence stratigraphic interpretation is the only reliable method of determining sediment lithology, depositional environment and stratal geometry on regional seismic data. And, in most instances, basin analysis uses only information from the applied geological model. This workflow is common in the methods of basin analysis; however, modern seismic data contain more information than just reflectivity and geometry for interpreting structure and identifying sediment sequences. In many cases, the velocity model used to process the seismic data contains information that provides a robust constraint on the sediment type and is useful for building regional geological models. In the case of subsalt imaging, an insightful geological model employing an understanding of salt kinematics can create a velocity model with a seismic image superior to one obtained by tomography alone. In these cases, iterating on the subsalt geological model and the seismic image improves both the image and the mode itself.

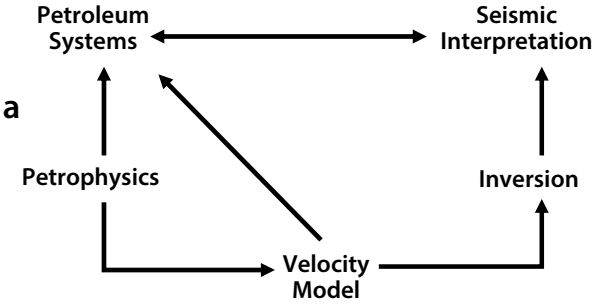
With this in mind, ION has recently introduced the iSPAN™ toolkit as a methodology for integrating technologies, resulting in data-constrained geological and geophysical models, better basin scale images and more accurate geologic models (Figure 1). Interpretation of the data using the workflow is faster than traditional basin analysis workflows, first creating a geophysical model, then structural and stratigraphic geological models, and finally a petroleum systems model. The toolkit allows geologists, geophysicists and petrophysicists to work together to create consistent geological and geophysical models encompassing the entire petroleum system from source, reservoir, trap and seal.

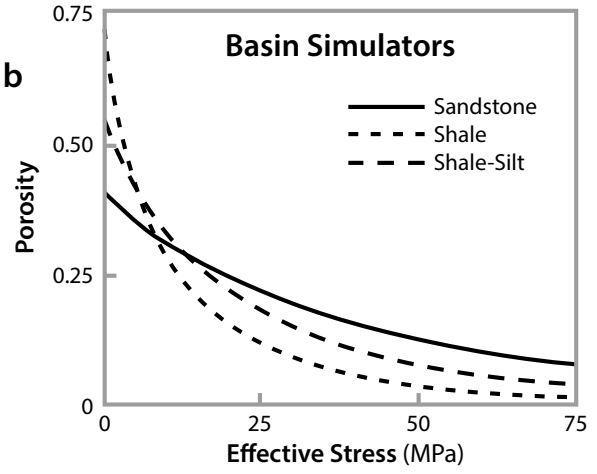
A New Workflow

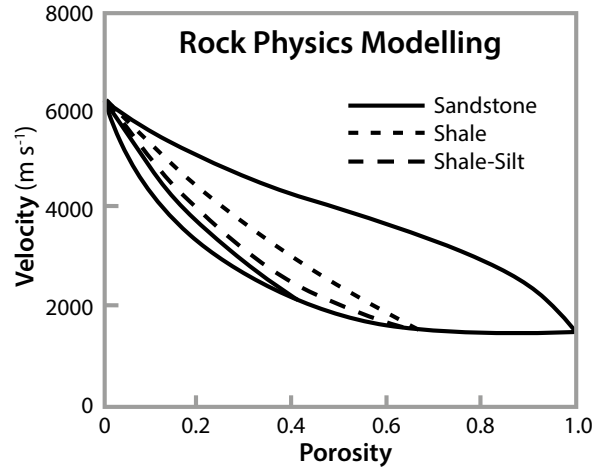
The physically based petrophysical model for the basin relies on well data and is the anchor of the iSPAN methodology because it relates the velocity of p-wave and s-wave data to the porosity of the sediments. The primary state variable in a basin simulator is porosity, which is related to the mean stress through the compaction law. Integrating the petrophysical rock physics model with the basin model constrains the sediment type from porosity and velocity.

The importance of physical models is critical, as they are bounded and the porosity-stress relation is based on a constitutive law between changes in stress and changes in porosity (strain). Similarly, for the basin model, the rock physics model satisfies Voigt-Reuss bounds, ensuring bounded values for the velocity to porosity relations shown.

Figure 1: The iSPAN toolkit connects technologies to reduce both exploration risk and the time it takes to develop regional play concepts. (a): The velocity model and inversion products are connected to the seismic interpretation; (b) shows how the compaction law used in the basin simulator relates to the velocity of different types of sediments. The compaction law and the rock physics models are bounded and well constrained by data. Inversion products further define the sediment properties and, in many cases, this leads to a quantifiable estimate of reservoir properties. The toolkit uses these advanced interpretation technologies early in the exploration cycle to develop quantifiable interpretations and inconsistencies that occur when technologies are applied as standalone products.







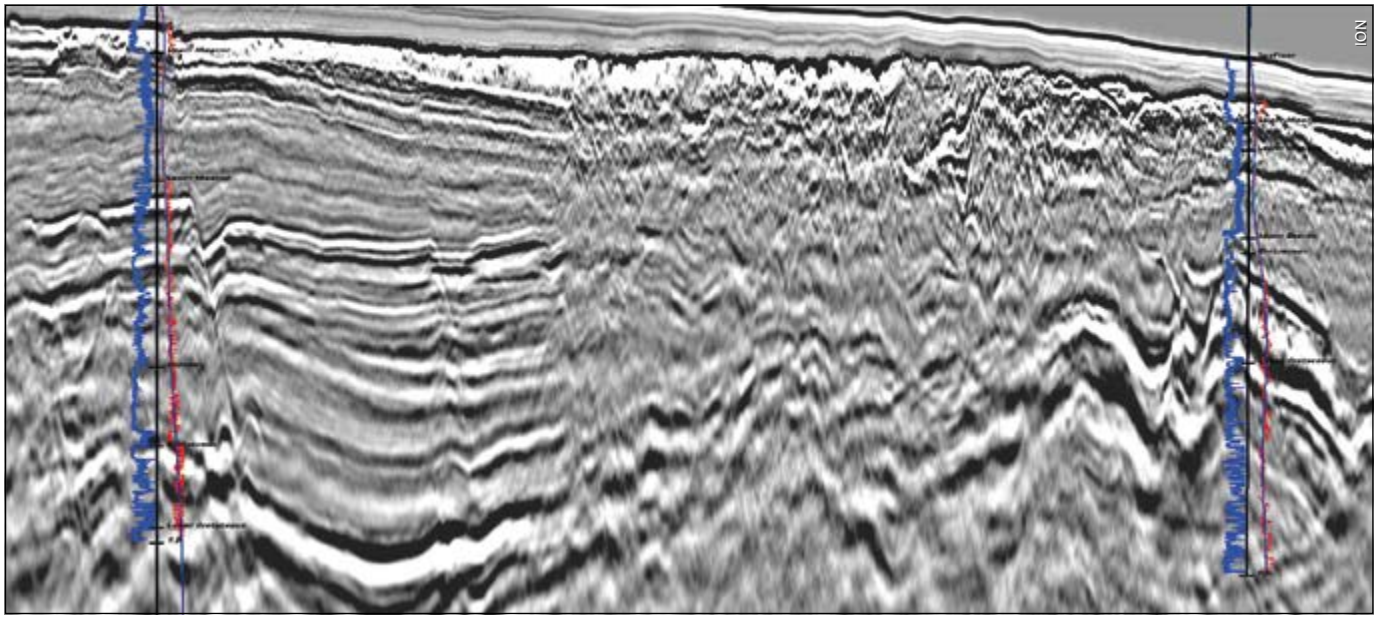


Figure 2: Anisotropic migration ensures seismic ties wells across three basins using the newly developed anisotropy derived from velocity model building methods.

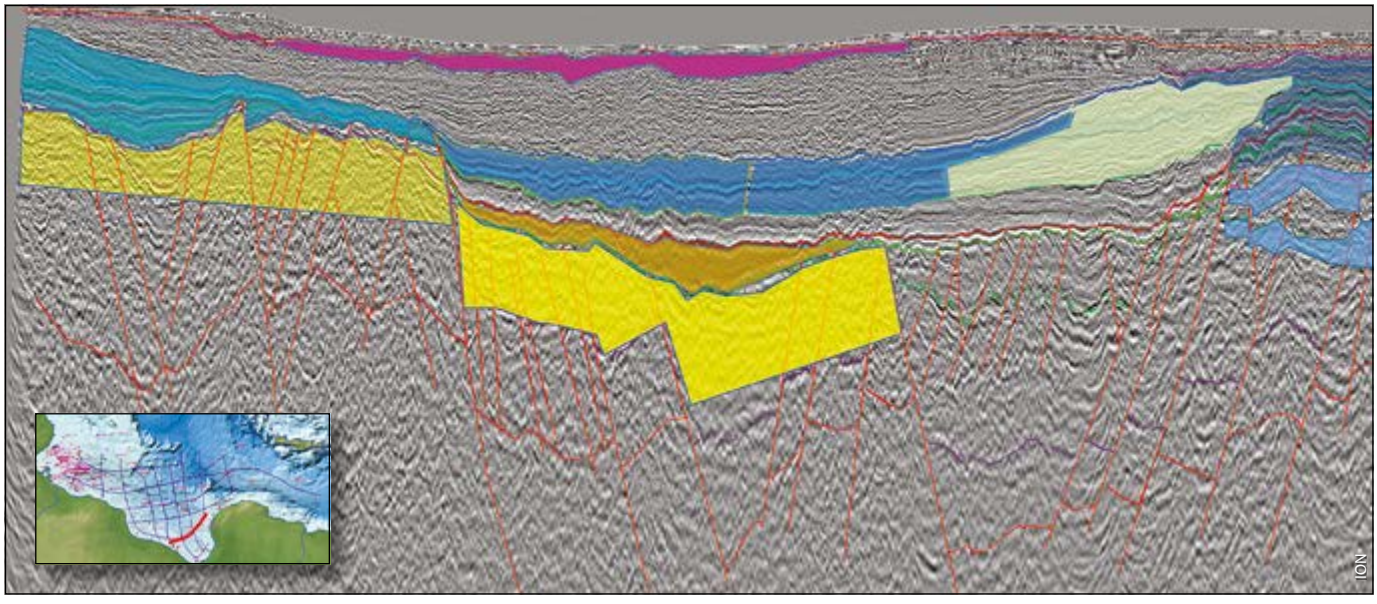
The use of physical laws instead of correlations means that the model result can quickly be compared to data to find parameters not included in models. For example, the waves typically travel much faster in carbonates than clastics, so a rock physics model without clastics is immediately identified because of the mismatch between model and data.

Anisotropy is an important iSPAN feature. The seismic data will always tie to the well data with the appropriate choice of Thomsen parameters (Figure 2). The traditional approach for building an anisotropic model is to use checkshot or sonic log data and isotropic seismic NMO velocity to calculate anisotropic parameters and propagate the anisotropy along seismic horizons. This traditional approach works reasonably well for relatively uniform geology but is a challenge for basin-scale anisotropic velocity models and seismic data that potentially cover multiple (sub) basins, resulting in changes in anisotropy across the lines or basin. Similarly, special consideration is required to ensure velocity models tie at all line intersections, so this workflow employs a data analytic approach to integrate well, seismic amplitude, high order RMO residuals and geologic interpretation. The newly derived anisotropic parameters ensure high quality seismic well ties that honour the geology over the entire basin range. Anisotropic migration also provides better seismic gathers for more reliable rock property inversion from seismic data.

A carefully calibrated rock physics model for the sediments, plus a seismic data set that ties to the well control, is the basis for the seismic inversion. Inverting the seismic data for lithology provides a level of detail that cannot be obtained with the rock physics models alone.

The rock physics workflow for inverting the seismic data to assign lithology includes rock physics diagnostics (RPD),

Figure 3: LibyaSPAN regional seismic line with inset location map. This line includes the southern portion of the Sirte Basin and shows major structural elements and sediment packages. The line is approximately 400 km in length. The western flanks of the basin have been tested with wells but the well data lacks modern logs.



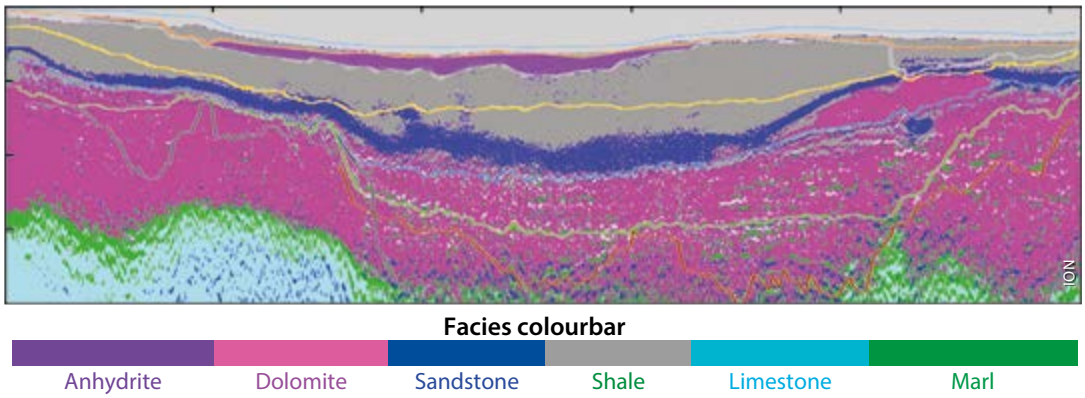


Figure 4: The same Libya seismic line showing probabilistic facies predictions from pre-stack seismic inversion using statistical rock physics workflow. The seismic interpretation overlays this facies model. This inversion identifies dolomitised carbonates in a reef (upper right) and in deeper parts of the section including the Palaeozoic sediment.

a rock physics template (RPT) and statistical rock physics (SRP). On a wireline log scale the RPD discriminates between reservoir and non-reservoir zones, while lithofacies in the seismic data are identified with the RPT. Uncertainty in the lithofacies estimates is reduced through the use of SRP.

Application to Basinwide Interpretation

Figure 3 is a seismic line from the LibyaSPAN™ 2D regional seismic grid in the Sirte Basin. The grid was designed to provide a regional framework for understanding how the offshore Sirte Basin is related to the onshore Sirte Basin oil and gas fields. Figure 4 is the same line of inverted seismic data, which enables us to identify dolomitised carbonates in the section, including a reef and deeper Palaeozoic strata. Separate inversions identify the variability of the overburden and show different prograding geometries stepping into the basin.

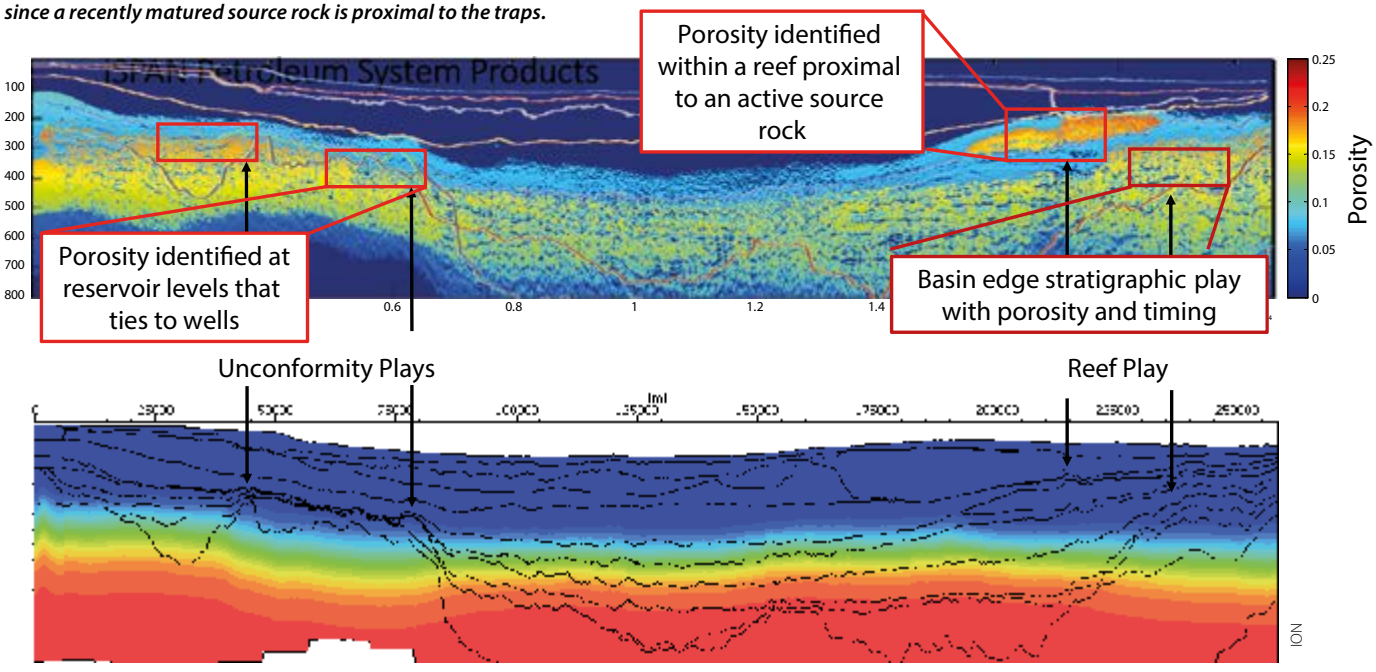
Combining these observations into an integrated basin simulator leads to a petroleum system view of the play on a regional scale (Figure 5). Without the iSPAN rock physics model and the inversion products, sediment type is identified only with sequence stratigraphy, leading to larger uncertainty in the elements of the petroleum system.

Putting it All Together

Regional 2D seismic data provide the framework for identifying new ideas and developing, extending and refining regional exploration plays. The iSPAN toolkit creates a better regional understanding of sediment type and identifies reservoirs and seals to extend the regional exploration evaluation within an integrated petroleum system model. In the example presented here, carbonate reefs are easily recognised and integrated technologies identify the presence of reservoirs beneath draping seals proximal to matured source intervals. Regional play concepts can be quickly and more accurately identified, thus shortening the cycle time between play concepts to a prospect.

This kind of analysis can be extended across any 2D dataset in order to provide a cohesive and comprehensive view of each petroleum system within a basin or basins, integrated with the regional framework of geophysical attributes such as velocity and porosity and the geological attributes that underpin structural and stratigraphic models. This type of basin analysis is faster than traditional workflows and provides insight by using integrated geophysical, geological and petrophysical models. ■

Figure 5: The same Libya seismic data: the upper panel shows the porosity of the dolomitised carbonates and the lower panel shows present-day source rock maturity for an oil prone source rock. These results indicate that all of the petroleum system elements are present, including the timing risk element, since a recently matured source rock is proximal to the traps.



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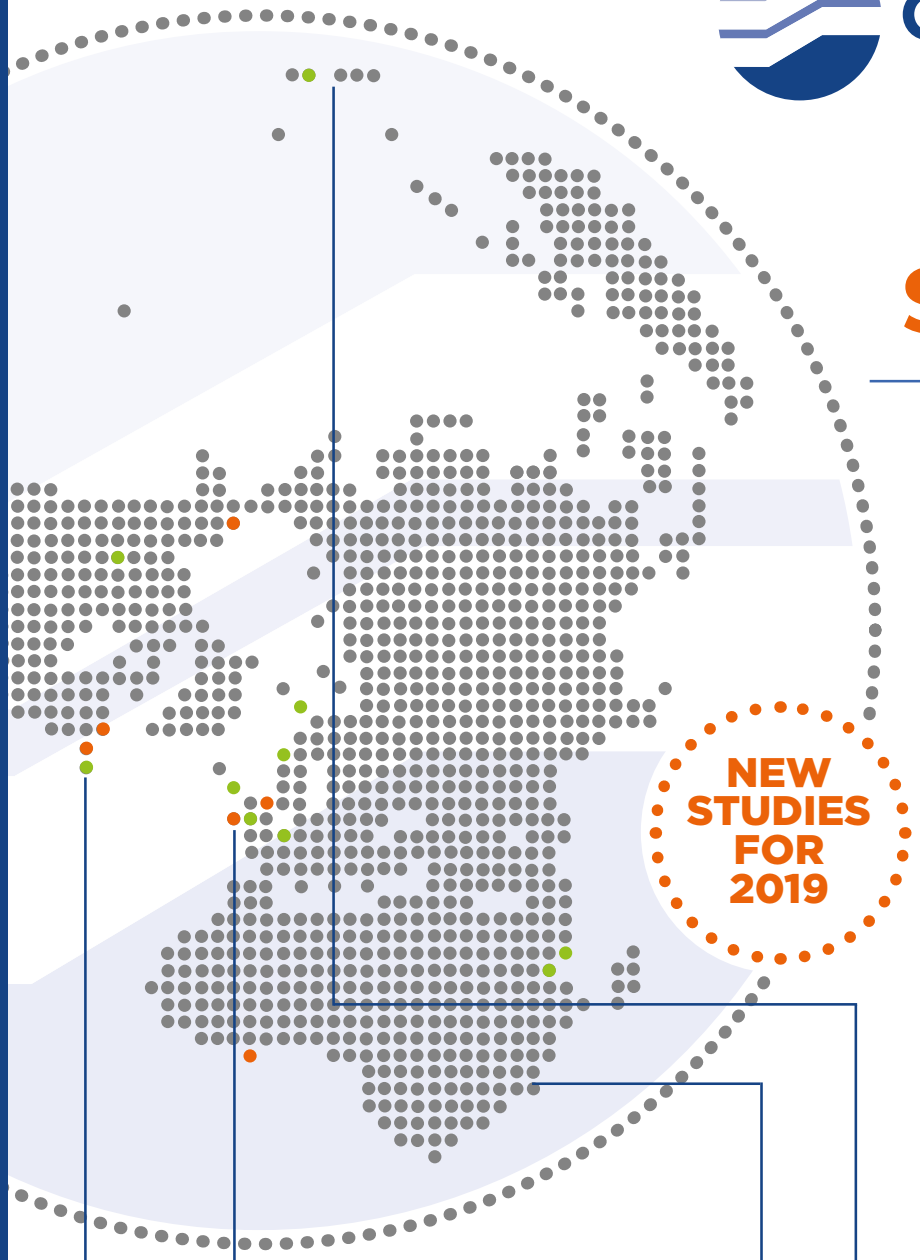

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- West of Shetland
- West of Hebrides
- Barents Sea
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Victoria Falls
The Smoke that Thunders

LON ABBOTT and TERRI COOK

With an annual average of 1,100 cubic metres of water plunging down its 108m-high face each second, Victoria Falls is unquestionably one of the world's greatest natural wonders.

In the local Tsonga language, the name for Victoria Falls is Mosi-oa-Tunya: 'the smoke that thunders'. As you approach the cataract, it's easy to appreciate this evocative name: the sheer power unleashed by the enormous volume of water colliding with rock after its 108m freefall makes a visit to Victoria Falls a multi-sensory experience. The falls' deafening roar is so intense that you do not just hear it; you also feel its vibrations in your chest. The clouds of spray released by the impact, which rise far above the lip of the falls, coat you in a chilly mist and impart a sweet 'rain' smell that mixes in your nostrils with the pungent organic odours released by the region's tropical vegetation.

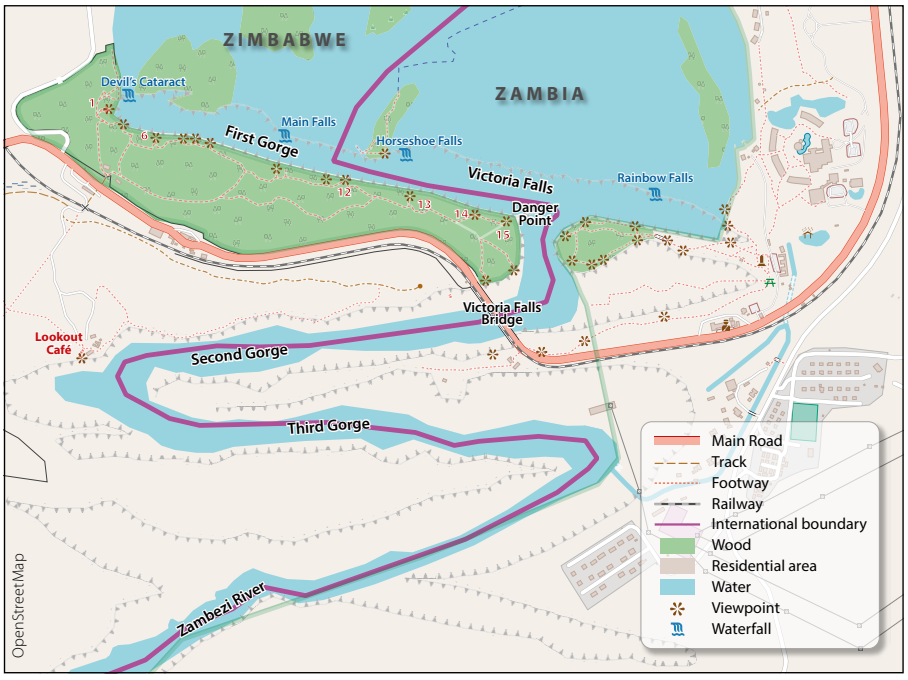
The geological recipe for creating this superlative natural spectacle calls for two primary ingredients: lots of water and sufficient local relief. The lush rainforests of southern Angola supply ample water to the Zambezi River, on which the falls are located. And two geological events, which are most likely related to one another, have provided the relief: elevation of the so-called 'African Superswell', the vast, low-relief plateau that comprises most of southern Africa, and the eruption of the erosion-resistant Batoka Basalt, which is part of the approximately 180 million-year-old Karoo Large Igneous Province (LIP).

Swamps Above the Falls: Chobe National Park

The Botswanan town of Kasane provides an excellent base from which to visit Victoria Falls, as well as Chobe National Park, a world-class game reserve best known for its large herds of elephants

Lon Abbott and Terri Cook

The Zambezi River plunges over Victoria Falls along the Zambia-Zimbabwe border.



and the prides of lions that prey on them. Kasane sits on the south bank of the Chobe River, a major tributary that joins the Zambezi 50 km upstream of Victoria Falls. Near Kasane, both rivers meander through fertile swampland that offers ideal habitat for many iconic African animal species. The national park is vast, so visitors often embark on multi-day wilderness game drives from Kasane. But if your time is short, outstanding wildlife viewing can be had on even a half-day to day-long game drive or boat cruise.

Because Kasane is tropical, days there are hot and muggy, but the nights cool off nicely, thanks to the city's 1,003m elevation. This is due to its position astride the African Superswell. Most geoscientists attribute the Superswell's 1,000–3,000m elevation range to the buoyancy provided by unusually warm material in the underlying mantle below 1,500 km depth – an anomaly that geophysicists refer to as the 'African Superplume'.

Although the Superplume's presence is evident in seismic tomographic images, these geophysical data don't reveal *when* the lower mantle beneath southern Africa first became warm enough to elevate the plateau. Two competing schools of thought are that the heating is either geologically recent or that it occurred about 180 million years ago, during the break-up of Pangaea. Support for the recent uplift hypothesis comes from the remnants of several peneplains: a series of widespread and relatively flat elevated surfaces first identified by geoscientists in the early 1900s. These surfaces have been interpreted as evidence that southern Africa has experienced repeated episodes of subsidence and uplift, with the last uplift episode having occurred recently. According to this theory, each time the land subsided, erosion graded a new peneplain to sea level; later, as the land again rose, these surfaces were raised to higher and higher elevations.

But the 180 Ma uplift hypothesis has recently been gaining favour for several reasons, including the observation that low-relief surfaces need not necessarily form at low elevation. Because the last time southern Africa was demonstrably at sea level was during Karoo Supergroup deposition between about 300–180 million years ago, this timing makes it less likely that the peneplains formed at sea level. In addition, recent studies employing apatite fission track and (U-Th)/He low-temperature thermochronometers have revealed that kilometre-scale erosion occurred in this region between 180–90 million years ago, suggesting the plateau rose following Supergroup deposition. Geodynamic models that reconstruct the changes in mantle convection produced by the break-up of Pangaea agree with these results, providing additional evidence that the African Superplume formed during that same 180–90 Ma time window and has been stable ever since.

An Unsurpassed Spectacle

The 85 km drive from Kasane to the town of Victoria Falls in Zimbabwe traverses a flat and nearly featureless plain that is capped by resistant Batoka Basalt. This 180 Ma-year-old rock is part of the Karoo-Farrar LIP, which erupted an estimated 2.5 million km^3 of lava across a wide area of Gondwana just prior to the rifting that sundered India, Australia and Antarctica from Africa. These Karoo flood basalts crop out extensively across southern Africa, whereas their counterparts, the Farrar flood basalts, are exposed in Antarctica and Tasmania. Eruption of the Karoo-Farrar LIP probably accompanied the

Boat cruises along the Chobe River are one of the easiest ways to glimpse the abundant wildlife in Chobe National Park.

A brief helicopter ride above the falls offers a fabulous view of the narrow joint into which the water plunges.

uplift and erosion of southern Africa's vast plateau region, as indicated by the thermochronologic studies.

Above Victoria Falls, the Zambezi River wanders lazily across the flat, basalt-capped plain, trending eastward before bending to the south just upstream of the spectacle. What little topography exists on this section of the plateau consists of a series of linear gullies that have been eroded along the families of east-north-east- and east-south-east-trending joints that crease the basalt. These joints provide a chink in the basalt's tough armour that the river could exploit to incise beneath the basalt cap — and form Victoria Falls.

Even at the entrance station to Victoria Falls National Park, you can hear the roar of the falls, but the cataract is still hidden by the dense vegetation. A 200m walk along a cobblestone path quickly brings you to a statue of colonial explorer David Livingstone and, just beyond, to your first, incredible view. To the north the Zambezi River flows towards you in a shallow channel a full 1.7 km wide. Suddenly, the river plunges 108m down into a chasm less than 120m wide, which is carved along an east-north-east trending joint crossing the river's path.

This first viewpoint is located at the falls' western end along the trend of the joint. From here you can gaze east along the length of the mist-filled chasm, which is called the First Gorge. If you arrive during the March to June high water season, you'll barely be able to see the curtain of plunging water through the prodigious mist. During lower water seasons, you'll spy dozens of ribbons of cascading water separated by slight bedrock rises along the waterfall's lip.

From this vantage point the path heads west, traversing a basalt peninsula perched high above First Gorge and connecting 15 viewpoints, each of which offers a unique and up-close perspective of the waterfall's wide expanse. You will get a thorough soaking at viewpoints 6–12, which are especially close to the Main Falls, the section where the greatest volume of water tumbles over the precipice. Viewpoints 13 and 14 offer drier viewing of the elegant tendrils that comprise the Horseshoe Falls segment, whereas the next section, which runs between viewpoints 14 and 15 (aka Danger Point due to the lack of any protective railings!), is known as Rainbow Falls because of the mist-produced rainbows that form here on sunny afternoons.

Danger Point is a particularly good place to examine outcrops of Batoka Basalt. The Zambezi River, which forms the international border between Zimbabwe and Zambia, exits First Gorge through a narrow canyon west of this point. An additional viewpoint on the opposite side of the peninsula from the falls offers an impressive view of the Victoria Falls Bridge. A true engineering marvel when it was completed in 1905, this bridge now serves as a major road link between Zimbabwe and Zambia, as well as a popular bungee-jumping location for shrieking tourists hurling themselves into the narrow gorge below.

The Zig-Zagging Batoka Gorge

The fundamental importance of the basalt's joint network for the formation and evolution of Victoria Falls is graphically illustrated below the cataract by the course of the river through Batoka Gorge, as it zig-zags up to 150° from one joint to the next. This convoluted path is immediately

apparent if you splurge on a scenic helicopter ride or drink in the amazing view from the Lookout Café.

After tumbling over Victoria Falls, the Zambezi's water flows east-south-east down First Gorge's joint-controlled slot, then rounds the promontory below Danger Point before abruptly turning west-south-west to flow through Second Gorge along an intersecting joint. Lookout Café is perched on the rim above the point where the river executes another impressive turn to head east-south-east through joint-controlled Third Gorge. The river then abruptly changes course several more times, passing through a series of 1–2 km-long linear reaches known as Fourth, Fifth, and Sixth gorges, each of which is controlled by a joint or fault.

The geomorphological work done by the Zambezi's plunging water constantly undercuts the base of the falls, a process that eventually causes the entire cliff to collapse. By this mechanism, Victoria Falls migrates inexorably upstream. The northern walls of gorges Two through Five have all been polished and abraded by flowing water, revealing that each was once the former site of a paleo-Victoria Falls. But just how long ago were the falls plunging at each of these locations?

The first piece of evidence to answer this question comes from a terrace containing the ancient river gravel that overlies the basalt above the Batoka Gorge rim for a distance of 20 km downstream from the modern falls. Clearly, this section of the gorge was cut *after* the river deposited these gravels, which means that Victoria Falls stood 20 km downstream of its present position at that time. Dating river gravels can be tricky, but fortunately these gravels contain stone artefacts that archaeologists have linked to the Middle Stone Age Lupemban culture, which thrived between 250,000 and 300,000 years ago. Twenty kilometres of retreat over that interval yields an average upstream retreat rate of 0.067–0.080m a year.

Another constraint is offered by deposits of Kalahari sand that overlie these gravels downstream of Third Gorge. The sand hosts artefacts belonging to the late Middle Stone Age Tshangulan culture, which archaeologists date at 71,000–57,000 years. Because this sand is absent between the modern falls and Third Gorge, a distance of almost 3 km, scientists have reasoned that during the late Middle Stone Age the paleo-Victoria Falls stood at the downstream end of Third Gorge, a conclusion that implies it has retreated at an average rate of 0.042–0.052m a year since that time.

In addition to fascinating geology, Batoka Gorge offers a variety of adventure activities, including whitewater rafting around these sharp river bends, zip-lining, and bungee jumping off the historic Victoria Falls Bridge (top left).

The Demise of the Falls

If the falls keep retreating upstream at this rate, within the next million or so years the river will pass beyond the western limit of the Batoka Basalt flows near Kasane. Once deprived of this resistant caprock, the river will quickly and efficiently erode the underlying rocks, and Victoria Falls will cease to exist. Fortunately, the geologic wonder of the smoke that thunders still graces the landscape during our time. ■

Visiting Victoria Falls, one of the world's great natural wonders, is a multi-sensory experience.

Ireland's Porcupine Basin: Drilling Time?

NEIL PARKINSON, ROWLAND THOMAS and HUGH MACKAY
Europa Oil & Gas

30,000 km² of 3D seismic data acquired offshore western Ireland since 2013 have yielded numerous prospects in a range of plays. Is it time the industry started to test these ideas with the drill bit?

The Porcupine Basin is a Late Jurassic rift off the west coast of Ireland, roughly congruent with the bathymetric deep (Figure 1). In simple terms it may be divided into a low-stretch, low-subsidence north section and a high-stretch, high-subsidence south. These two areas of broadly west-north-west – east-south-east extension are likely separated by transfer elements, sometimes informally referred to as the 'Dunquin Transfer Zone'.

Porcupine Exploration

A total of 26 exploration wells were drilled in the North Porcupine between 1977 and 2001, resulting in three non-commercial oil discoveries (Connemara, Spanish Point and Burren).

Only four wells have been drilled in the South Porcupine. The first (Esso 62/7-1, 1982) is not actually in the Porcupine Basin at all, but on the Goban Spur, the relative bathymetric shallow which extends south-west from the Celtic Sea, underlain by a labyrinth of small Mesozoic sub-basins and intra-basinal highs. Well 62/7-1, on one of these highs, was an extraordinary well for its time. Drilled in nearly 1,000m of water, 230 km from the Irish mainland, it had minor oil shows in a very thin Middle Jurassic sandstone. However, its main relevance to the Porcupine story is in proving that the thick and locally source-prone Lower Jurassic ('Lias') of southern England and the Celtic Sea extended at least this far west prior to Upper Jurassic rifting.

The first well in the South Porcupine proper was BP 43/13-1 (1988), which reached a TD of 5,128m MD, targeting a North Sea-style tilted fault block. Modern seismic and biostratigraphy shows that it did not exit the thick Kimmeridgian sequence, let alone penetrate the pre-Oxfordian stratigraphy that we would now call 'pre-rift'. It did, however, establish the presence of Kimmeridgian and Tithonian source rocks in the South Porcupine, and had intriguing shows in thin Kimmeridgian sandstone stringers which can be typed to a slightly more mature version of the source rocks found in the well.

Renewed Interest

The latest wave of interest in the South Porcupine began with the 2011 Licensing Round. This was led by junior oil companies, mostly chasing post-rift submarine fan stratigraphic traps in the excitement following analogue discoveries in the South Atlantic (e.g. Jubilee, offshore Ghana). Almost 14,000 km² of 3D was shot on this acreage, delivering amazing images of submarine fan development – although in most

The Porcupine Basin lies about 200 km south-west of the Beara Peninsula in the far south-west of Ireland.

Jane Whaley

cases not where the fans had been predicted on the legacy 2D!

The next licensing round, in 2015, saw the arrival of the majors. In the main, they seem to have been less excited by the fans than by the analogy between the Porcupine Basin and its conjugate: Flemish Pass, offshore Newfoundland. Statoil had made a series of discoveries in late syn-rift structures here, notably Bay du Nord (2013). Cash bids totalling about $1.9 bn were placed in the 2015 Flemish Pass Round and Irish bidding was similarly competitive, with many successful applicants proposing the immediate acquisition of large 3D surveys. Licensing Options over almost all of the basin margin open acreage were awarded at this stage, and by 2017 the total modern 3D seismic coverage had risen to some 30,000 km^2.

Drilling continued to be much more circumspect. ExxonMobil proved once again willing to place a big bet on an unusual concept. Its 2013 well, 44/23-1 (Dunquin) tested a Cretaceous atoll, possibly perched atop a volcano extruded from the transfer lineament between the North and South Porcupine. The trap appears to have been breached, but they found a significant residual oil column, providing yet more evidence of a working source rock in the basin. It is notable that, despite withdrawing from the Dunquin licence, Exxon made significant new applications in the 2015 licensing round, demonstrating continuing faith in the South Porcupine.

In 2017 Providence Resources became the first company to drill into the heart of the basin and test one of the key plays. The company had two targets: Druid, a Palaeocene fan, and Drombeg, a mid-Cretaceous fan. Both fans proved dry, though Providence reports signs of bitumen from Drombeg. Were they drilling too distally? Was up-dip seal adequate? The basin continues to tantalise.

A Diversity of Plays

Successive rounds of licensing, huge amounts of 3D seismic, but very few wells (Figure 2) mean that companies are now carrying untested plays and prospects representing billions of barrels of potential resources – as well as representing the changing enthusiasms of explorers over decades.

No pre-rift tilted fault block has been penetrated south of the Dunquin Transform, though large and spectacular blocks (e.g. Figure 3) occur on both sides of the basin. Fault blocks in the North Porcupine have

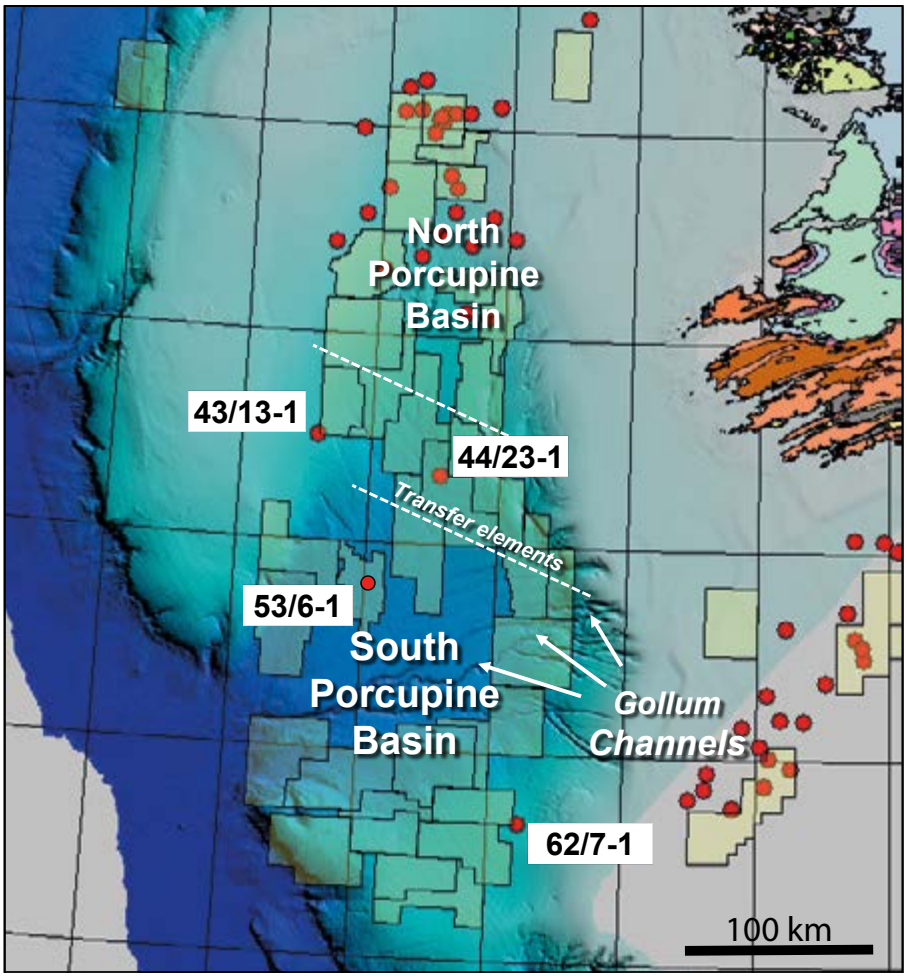
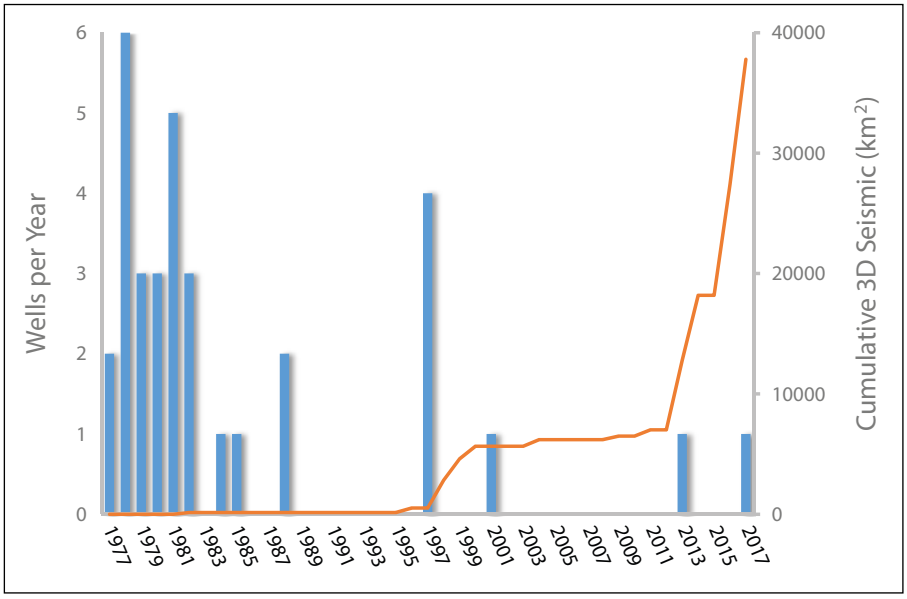


Figure 1: Offshore south-west Ireland: bathymetry, wells and current authorisations. Named wells are discussed in text. (Bathymetry from INFOMAR, onshore geology from Geological Survey of Ireland.)

Figure 2: Drilling and 3D seismic acquisition history. (Based on Irish DCCAE published data.)



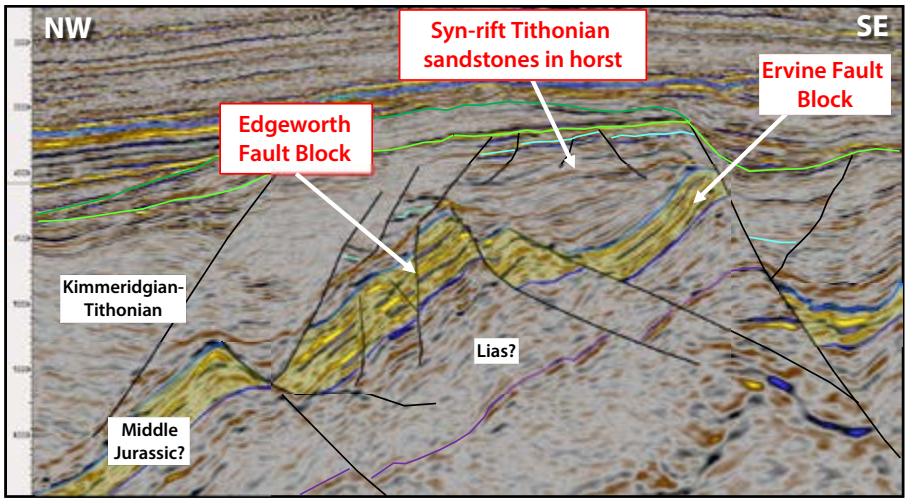


Figure 3: Pre-rift tilted fault blocks and syn-rift horst, SE Porcupine Basin. (Europa 2017 PSDM, Full Stack).

proved oil-bearing, but a combination of modest overall oil-in-place and poor quality, largely non-marine, reservoirs mean that no discovery has yet proved commercial. That said, we do not know if shallow marine reservoirs are present in the south. The Porcupine Basin is some 400 km long and a Middle-Upper Jurassic marine connection to the south is likely. Middle-Upper Jurassic well control is available only over the most proximal 100 km. The Porcupine Basin is comparable in size to the North Viking Graben of the North Sea, and there is plenty of room to put the Brent Province (which occupies little more than a Quad in total) into the more distal undrilled blocks (Figure 1).

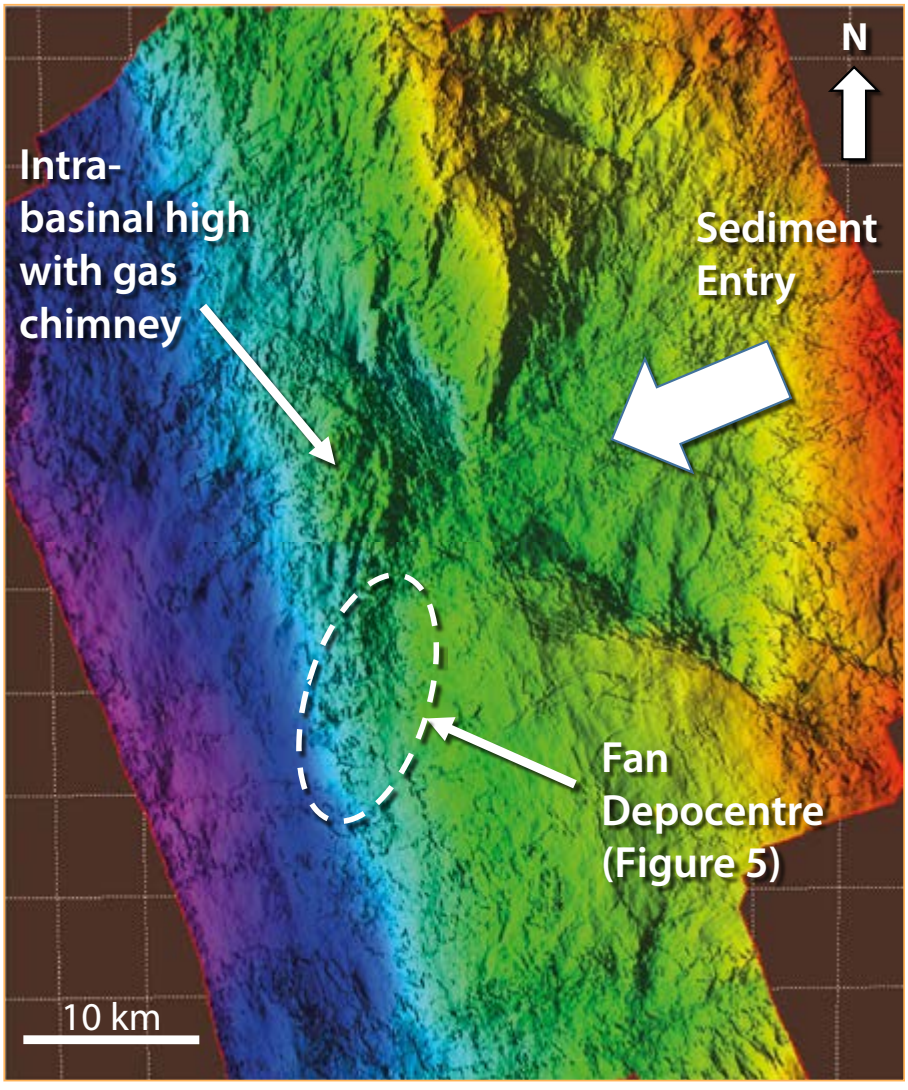
Success in the Flemish Pass came not from pre-rift blocks, but from younger traps in the Tithonian-Berriasian shallow marine sandstones of the late syn-rift. Again, sandstones of comparable age have yielded oil in the North Porcupine (Spanish Point discovery). Seismic character suggests these sandstones are also present in the South Porcupine and potential trapping configurations have been mapped (Figure 3).

Various deepwater systems are revealed by the 3D data in the post-rift. In the north-east 'corner' of the South Porcupine there is a canyon entry point set up by Jurassic rifting (Figure 4) which persists through the Lower Cretaceous and, indeed, can be thought of as the ancestor of the Gollum Channel system which feeds sediment off the south-west Irish Shelf and into the Atlantic Abyss today (Figure 1). At the mouth of this entry point we see structurally restricted fans of lowermost Cretaceous – perhaps Hauterivian – age (Figure 5). At broadly the same time, on the opposite side of the basin, we have slope-apron deposits.

In later Cretaceous (Aptian-Albian) times, possibly associated with the regional lowstands, we have less well-confined fans on both sides of the basin. Those in the west (such as Providence's Drombeg, mentioned above) are commonly fed by long sinuous slope channel systems. Those in the east are at the foot of steeper slopes and therefore may be better candidates for detachment. More fans occur in the Palaeocene, now broadly fed from the north rather than from the east and west flanks of the basin.

Finally, there is Dunquin South: the more southerly twin of the Cretaceous atoll referred to above, but this time without a gas chimney, so hopefully sealed. This is a tremendous prospect for the ENI-led partnership in Frontier Exploration Licence 3/04.

Figure 4: Base Cretaceous structural interpretation in the south-east Porcupine showing sediment entry point and submarine fan depocentre. (Europa interpretation from proprietary PSDM data.)



Easy to Procrastinate

In the last two Porcupine Rounds, concessions have been first granted as two-year Licensing Options which may subsequently be converted to Frontier Exploration Licences ('FELs'). A FEL lasts for 15 years, typically in four phases: a Phase 1 of three years and three subsequent Phases each of four years. A well commitment is not required until Phase 2. Most of the licences in the South Porcupine (Figure 1) entered FEL Phase 1 this year, so a commitment to drill will not be required until 2021 and the well need not be drilled until 2025: though clearly this would leave little scope for well evaluation and for planning the next move.

High (sometimes 100%) equities are an issue, in that many licencees will seek a farminee before drilling. We know that this can be a long process in the current commercial climate. Given the exposed Atlantic setting, most operators will also seek to drill between May and August, which means a maximum of two wells per rig per season.

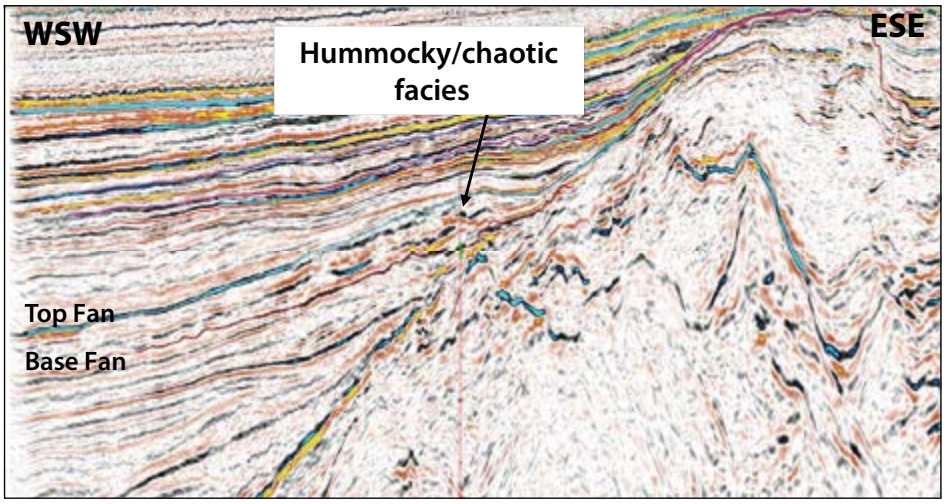


Figure 5: Lowermost Cretaceous submarine fan on the east side of the South Porcupine. (Europa proprietary PSDM data.)

These equity and practical issues, together with limited overall exploration budgets, make it all too easy to procrastinate. Yet rates for appropriate deepwater drilling units are uniquely low and there are few genuine frontier basins which offer such strong evidence for working hydrocarbon systems, combined with such attractive tax terms in a politically stable environment.

To date, only Nexen has acquired a site survey for a planned 2019 spud. Providence has also acquired a survey, but for a prospect on the Goban Spur. So, it seems that most Porcupine drilling will happen in the window 2020–2024. Does a major hydrocarbon province lie beneath the South Porcupine? We still await the critical exploration wells which will really give us the answer. ■

Seep Hunting!

Reducing costs and risks of deepwater exploration: the benefits and technology of seep hunting and surface geochemical campaigns.

STEPHANIE INGLE and JIM GHARIB, Fugro

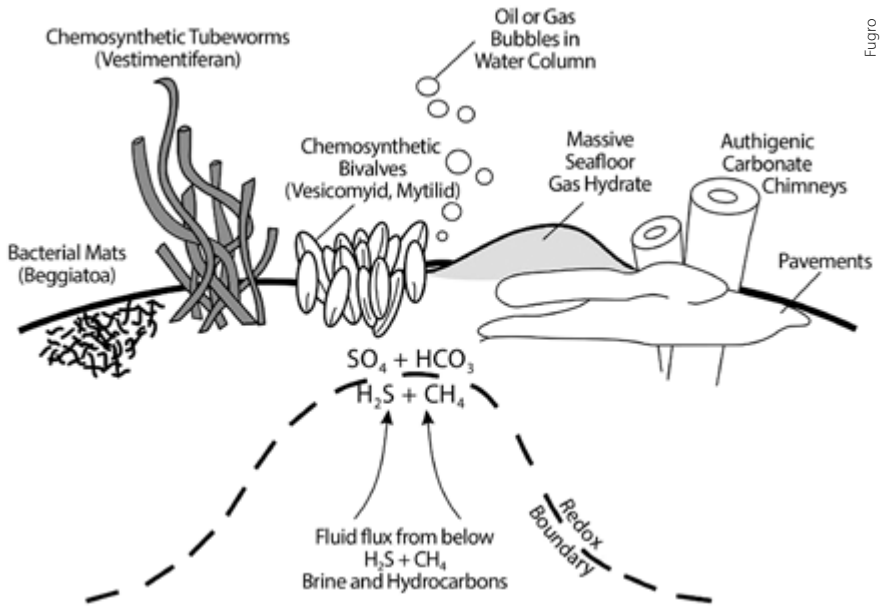
A seep hunting and geochemical campaign can provide economic and cost-saving benefits to most exploration programmes, especially in frontier, unproven regions. Seeps bring hydrocarbon-rich fluids from the deep subsurface to the seabed where they can be accessed for geochemical sampling. The resulting analyses can provide a wealth of information on the type and contents of a reservoir at depth. In a well-designed programme, gas, condensate and oil signatures may be distinguished from each other and used to refine and reduce the scope of further exploration work, make final investment decisions, farm-in or farm-out, and guide preliminary production design. Cost savings can be in the order of tens of millions of dollars (e.g., in reducing a 3D exploration seismic programme footprint) or much more – even avoiding a dry exploration well. The technology used to find offshore seeps (and the experience of scientists who employ that technology) is rapidly evolving, making seep hunting an exploration technique that continually improves.

How are Seeps Expressed on the Seafloor?

Onshore hydrocarbon seeps are easily identified visually and have been used for exploration purposes for more than a century. Finding offshore hydrocarbon seeps – in the absence of prolific oil seepage that leads to formation of sea surface slicks such as in the Cantarell Field in the southern Gulf of Mexico – is much more challenging. However, over the last few decades, technology has advanced significantly to allow for detection of both active and inactive seeps, even in deepwater. The driver of that technology has been the multibeam echo sounder, the rapid recent advances in that technology, and the skill of scientists in exploiting the resulting data for maximum utility.

Chemically-reduced seep fluids rise from depth and encounter oxygenating fluids near the seafloor surface. The chemical reactions that occur can lead to the precipitation of minerals in place (such as authigenic carbonates) as well as mineral-rich fluids capable of supporting life, from sulphur-consuming microbes to the molluscs and clams that come to dine on them. These chemosynthetic communities are typically discrete and focused around the channelised seeping pathway (e.g., fault, mud volcano). They also differ significantly from the surrounding seafloor in that they are hard surfaces and thus acoustically highly reflective. Enter the use of the multibeam echo sounder to acquire data enabling us to find them.

A schematic of a typical seafloor chemosynthetic community at the surface seep location. Note the steep geochemical gradient depicted below the community – if the sample is not properly located, the good geochemistry will not be obtained, and the results will most likely be inconclusive.



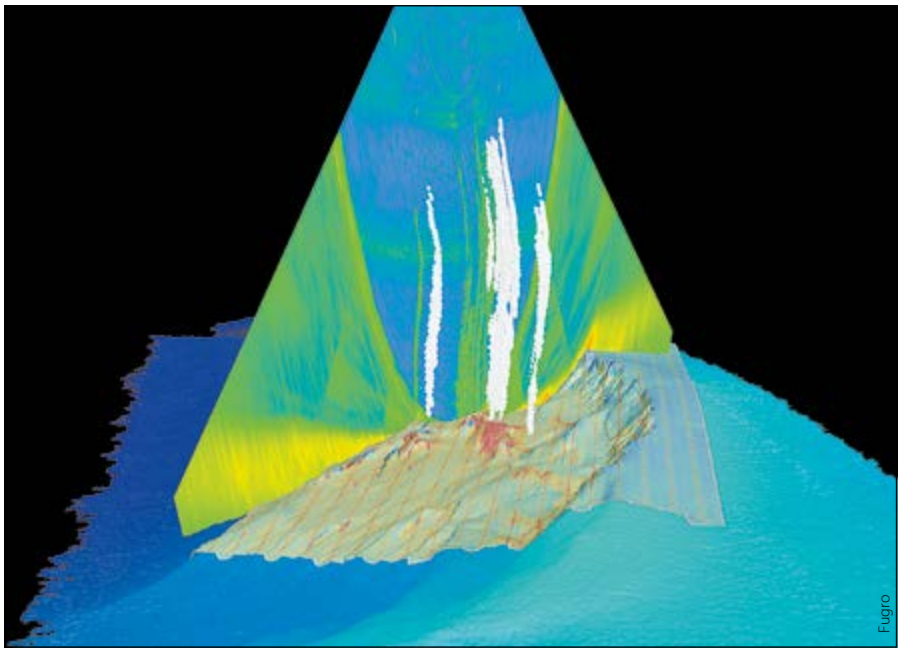
Fugro

The Technology of Seep Hunting

The primary technological driver allowing surface geochemical surveys to advance into the modern age, and to proliferate – despite the recent sizable market downturn – has been the evolution of multibeam echosounders (MBES), which are used to accurately map swaths of seafloor by acoustic signals (pinging) from fast survey vessels.

MBES technology is still rapidly evolving, with each new generation being much improved over previous models, and with constantly improving software/processing capabilities too. The most recent systems measure nearly five times the sounding data compared to the previous generation and can dual ping and acquire data in the water column as well as the seabed. The technology continues to improve as MBES manufacturers like Kongsberg attempt to meet and exceed the technical challenges imposed by operators such as Fugro, who are actively pushing the envelope in the survey and the seep worlds.

The datasets generated and interpreted by experienced MBES users have significantly improved the success



When present, water column anomalies (in white) can be extracted from the MBES dataset.

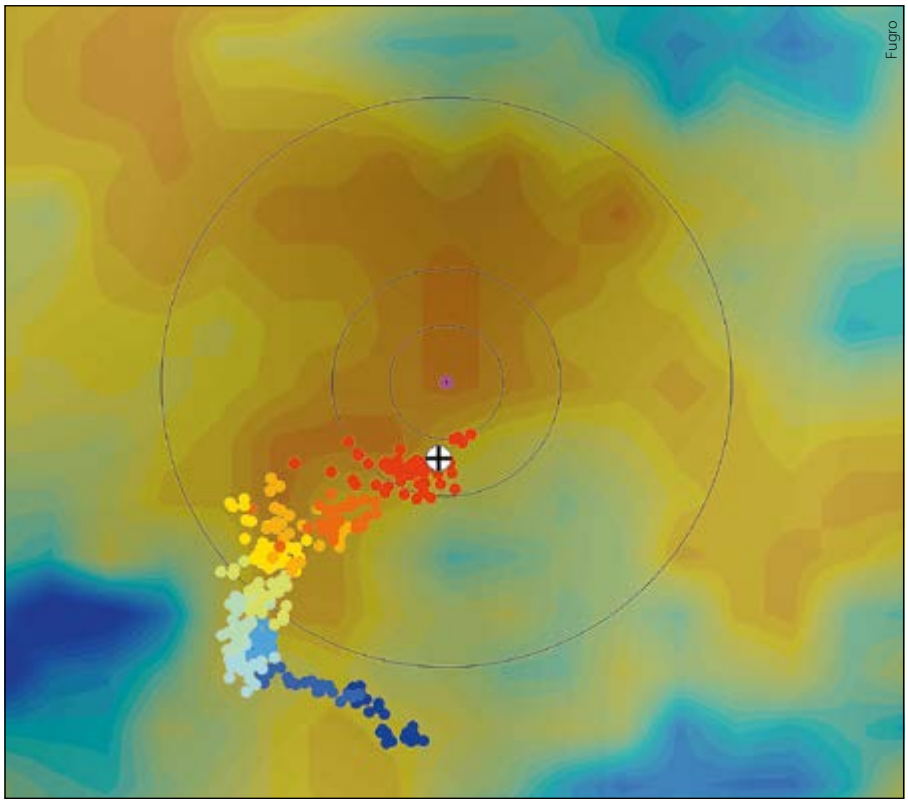
of surface geochemical surveys. This is what Fugro calls 'Seep Hunting': skilled geoscientists using MBES data to interpret seabed geomorphology and hardness/rugosity (using backscatter) and to detect gas bubbles in the water column (see image above). Trained, specialised geoscientists can now identify metre-scale hydrocarbon seeps in thousands of metres of water as the vessel is surveying over the feature. Significant attention must be applied to properly calibrate the MBES as the data are crucial for remote seep detection (e.g., Mitchell et al., 2016).

Older geochemistry programmes with no multibeam data were often considered scientifically inconclusive before quality MBES mapping and interpretation. However, recent industry exploration projects now routinely adopt this methodology and gain meaningful data to successfully drive their exploration strategies.

Adaptive Seep Hunting Campaigns

Skilled interpretive geoscientists on board are key to an optimal programme. They control not only QA/QC of MBES acquisition and processing but can make judgement calls as to whether an area warrants another pass for improved data quality. Seabed seep features are ephemeral, small, discrete, and hard to sample, so shipboard geoscientists continuously refine targets and use ultra-short baseline (USBL) navigation to guide a piston core so it may be sampled precisely (see image overleaf). When they examine core samples, they can again make decisions in the moment as to whether another core would be advisable. They also can quickly select key portions of the core for further laboratory geochemical analysis, minimise the chance of sample contamination, and maximise the preservation of the more volatile hydrocarbons. Case studies demonstrate how this type of approach – compared to historic industry success rates – can double the likelihood of recovering samples bearing evidence of migrated liquid petroleum and thermogenic gas (Bernard et al., 2008; Orange et al., 2008; Gharib, 2009).

Shipboard geochemical screening analyses, such as that currently conducted by Fugro, include gas chromatography for C_1–C_5 and total scanning fluorescence for aromatic hydrocarbons. Samples with evidence of thermogenic hydrocarbons are then selected for additional analyses (in shore-based labs) which includes C_{15+}, followed by advanced analyses including stable isotope compositions and biomarkers. There are many advantages in conducting screening analyses offshore, in addition to near-immediate availability of geochemical results. Optimising locations to return to in order to undertake additional coring



Real-time monitoring of a USBL-navigation beacon attached to the piston-coring assembly. The trace of the core's descent from sea surface (dark blue) to seafloor (red) is superimposed over the backscatter map.

while the vessel is still deployed can save millions of dollars in mobilisation fees. Furthermore, the samples for additional testing are identified before the vessel returns to port, meaning they can be shipped immediately to a lab for advanced tests, rather than waiting for shore-based screening results.

Accelerating Industry Adoption

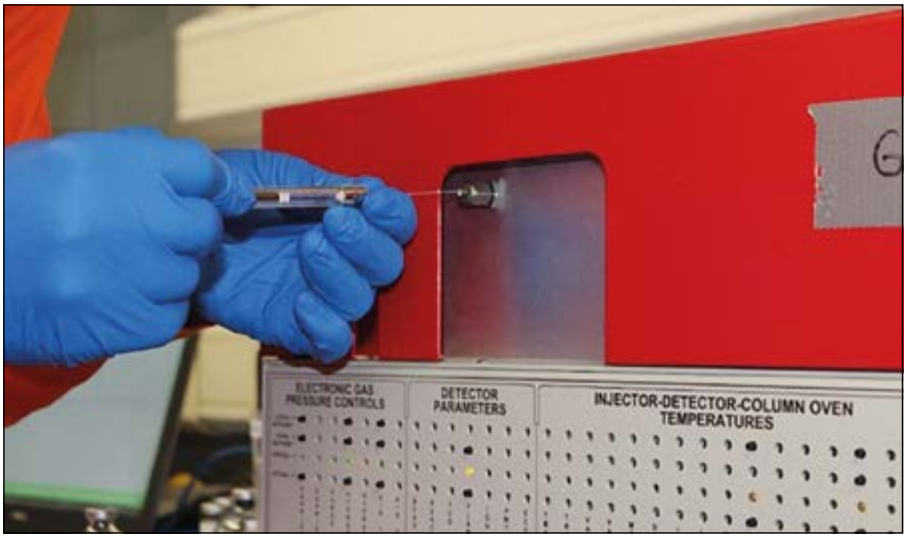
During the last 15 years, Fugro has performed over 100 seep hunting surveys and geochemical campaigns covering over 2,000,000 km^2 and acquiring thousands of cores and heat flow measurements. Fugro's seep hunting business has grown 14% year on year for the past 15 years; more notably, the business has grown 30% each year since 2010, including the years since the 2014 downturn. The industry clearly recognises the value for money in carrying out seep hunting and geochemical campaigns. In addition to high-grading future exploration activity by specifying a smaller area to carry out additional, more expensive, exploration work, the high-quality bathymetric data are useful for shallow hazard assessments and development planning.

Executing a seep hunting campaign in a frontier, prospective location also provides data that companies can use to attract farm-in (cost-sharing) partners or make confident decisions on acquisition or divestiture of lease blocks: decisions with major impacts on their future financial health. Furthermore, seep hunting surveys can easily be combined with other early-field work such as an environmental baseline or metocean studies, leading to reduced total vessel time and fewer mobilisations and demobilisations, yielding even higher value to cost ratios for energy industry stakeholders.

The technology of MBES and interpretive tools for its data continue to improve, making it likely these will be the primary tools for seep hunting for some time. That said, exciting new technologies are emerging that will complement and expand our current capabilities. Underwater cameras can directly image seeps, while chemical sensors, such as mass spectrometers and fluorometers, are capable of 'sniffing out' specific compounds in the water (e.g., Villanova, 2009; van Graas et al., 2018). MBES systems mounted on autonomous underwater vehicles have already been applied to deep seafloor surface geochemistry (e.g., Wynn et al., 2014). Ultimately, miniaturisation of MBES systems, allowing for their integration with smaller, unmanned surface vehicles and/or gliders, will allow seep hunting to occur in locations previously inaccessible or where hull-mounted seep hunting would be inefficient, like very shallow water. Relative to other methods such as 3D seismic, seep hunting is an economically-sensitive method for hydrocarbon exploration. The benefits of its results will continue to illuminate the resources and diversity of the seafloor for decades to come.

References available online. ■

Within a few hours of sample recovery, headspace gas can be extracted and analysed on a gas chromatograph for preliminary geochemical results, which help guide additional sampling. Here, headspace gas is being injected by a trained geochemist.



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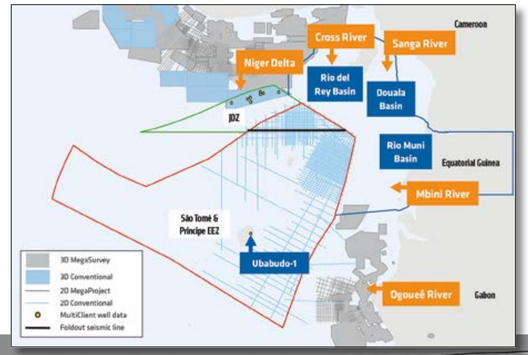
São Tomé and Príncipe

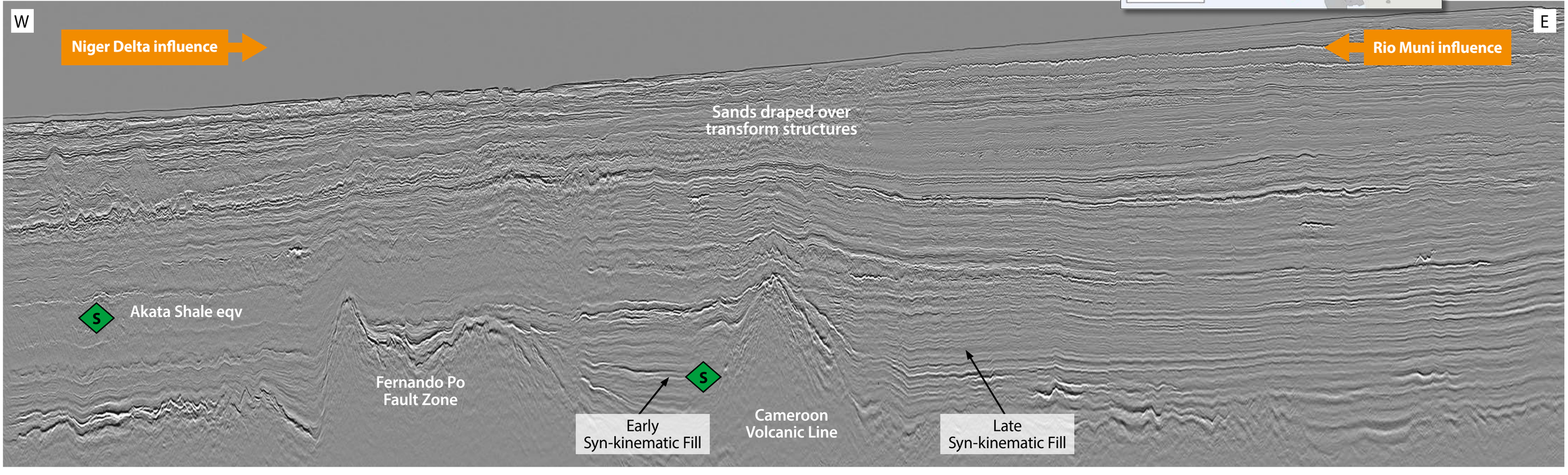
In recent years, the São Tomé and Príncipe Exclusive Economic Zone (STP-EEZ) has been the subject of significant attention from major oil companies, resulting in applications for exploration licences and farm-in activities over nine blocks. PGS reprocessed its MultiClient library data using modern processing techniques and conducted a basin analysis study to help understand the recent interest.

The study shows that all the elements of a working petroleum system are present in the waters of the STP-EEZ. Continental and transitional crust provide structures and source rocks and PGS basin modelling reveals that these sediments are mature for oil and gas. Long-lived fluvial systems provide quality reservoirs fed from numerous sedimentary catchment areas.



Base map showing the territorial waters of the STP-EEZ together with neighbouring countries. The PGS MultiClient seismic and well datasets are shown together with annotations showing the major fluvial input points (orange arrows).

PSTM seismic section from 2001 acquisition (reprocessed in 2014) showing tectonic zones, differing phases of syn-kinematic fill and evidence of sands draping over structural highs.



STP-EEZ: Four Key Reasons to be Excited

MATT TYRRELL, JOSHUA MAY and ERIC MUELLER, PGS
ORLANDO PONTES, ANP-STP

Modern reprocessing and new basin studies reveal potential in the São Tomé and Príncipe EEZ.

The São Tomé and Príncipe Exclusive Economic Zone (STP-EEZ) lies within the heart of a tripartite petroleum neighbourhood dominated by long-lived fluvial sedimentary basins: the Niger Delta to the north, the Rio del Rey and Douala Basins to the north-east and the Rio Muni Basin to the east.

A Brief History of Exploration

In 1997, the STP-EEZ that extends 200 miles (321 km) from the coastline of the islands was ratified by the UN Convention on the Law of the Sea. This enabled Louisiana-based company ERHC, together with the South African company Procura Financial Consultants, to sign an exploration agreement resulting in the award of Blocks 4 and 11 in 2001.

1998 to 2001 – offshore seismic and technical evaluation: In September 1998, ExxonMobil and STPetro signed an agreement to technically assist with 22 recently drawn offshore blocks. The first activities under the agreement saw PGS acquire 2,723 line kilometres of 2D seismic data followed in 2001 and 2005 by the acquisition of a further 11,277 line kilometres of speculative 2D seismic data with associated gravity and magnetic data.

2001 to 2012: A decade of exploration quiescence which resulted in little if any exploration activity.

2012 to 2015 – renewed optimism and licence awards: In 2012, Equator signed a PSC for Blocks 5 and 12 and later in the same year Oranto Petroleum agreed a PSC for Block 3 with a work commitment to acquire 1,500 km^2 of 3D data (which has now been fulfilled). In 2013, Sinoangol, a joint venture between China and Angola's state-owned oil companies, agreed to license Block 2 before farming-out to Sonangol.

2015 to present day – continued awards and revived exploration: This is the most exciting period of exploration for the STP-EEZ, initiated by the award of Block 6 to Galp Energia in 2015, an agreement that included a 45% stake for Kosmos Energy, who earlier that year had farmed-in to Equator Explorations Block 12. Kosmos Energy then expanded its block licence footprint in 2017 by farming-in to Block 5, taking over the operatorship from Equator Exploration, followed a year later by their farm-in to Block 11, to take over all licence rights from ERHC. The latter agreement saw Kosmos partner with Galp Energia, with whom they already held a partnership in neighbouring Block 6. In 2018 Kosmos Energy completed its most recent activities by licensing, together with BP, Blocks 10 and 13 before the acquisition of extensive 3D seismic surveys with a focus over the eastern blocks.

Why São Tomé and Príncipe is a Hot Exploration Area

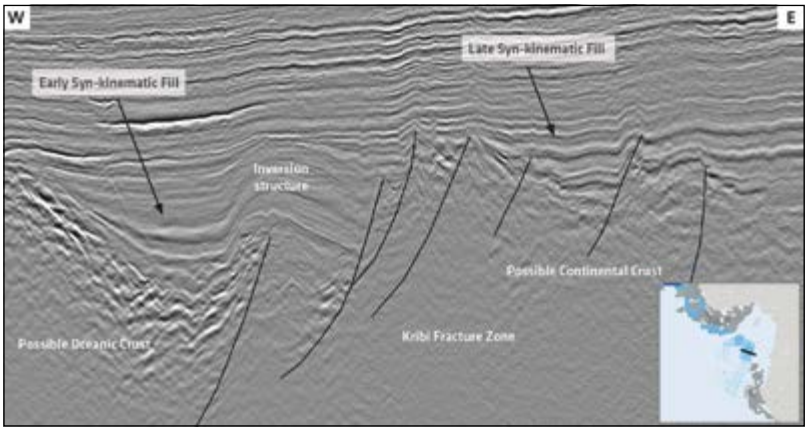
The PGS MultiClient data library over the region now includes the 2D survey acquired for ExxonMobil in 1999, together with the later 2D seismic, gravity and magnetic surveys acquired by PGS in 2001 and 2005. These three surveys have recently been reprocessed as a coherent dataset to allow seamless interpretation. In addition, the PGS MultiClient library contains the well data from Ubabudo-1 together with the eight exploration wells and one appraisal well drilled in the JDZ waters.

The interpretation of these data along with industry feedback have indicated that there are four key reasons for the recent interest in the area.

Reason 1: Continental and transitional crust provides source and structure

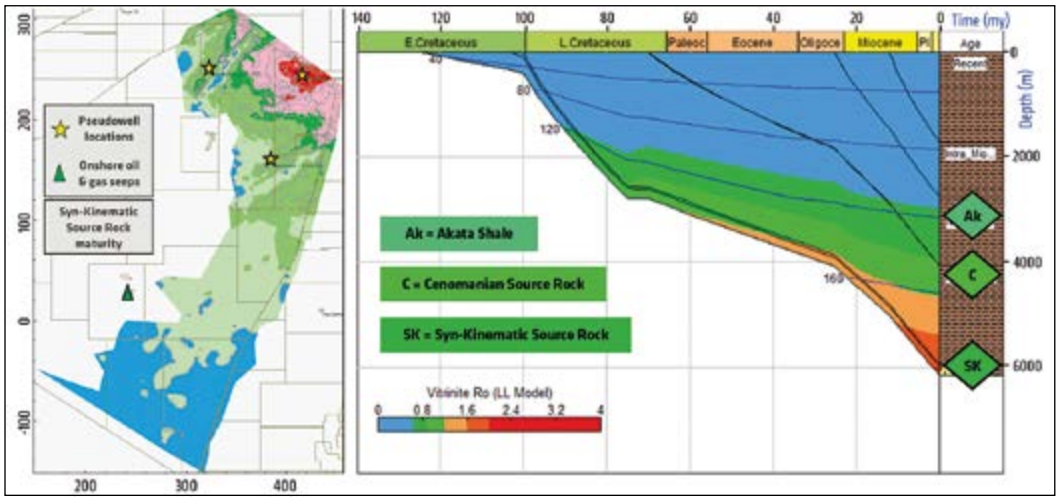
Historic geological interpretations predicted that the waters of the southern Gulf of Guinea, including the Niger Delta, were underpinned by oceanic crust. Revised crustal observations and models now suggest these areas instead contain a mélange of continental, transitional and oceanic crustal types controlled by extensional then compressional transform fracture zones. These revised crustal models have highlighted the potential for syn-kinematic sediments deposited in restricted marine conditions that can provide source rock deposits and accompanying structural plays.

2002-acquired 2D seismic line through the Kribi Fracture Zone showing a possible boundary between oceanic and continental crusts, transform fault surfaces, early syn-kinematic sediments that have undergone inversion and then later syn-kinematic sediments.



Reason 2: PGS basin modelling suggests Cretaceous sediment fill mature for oil

PGS have recently conducted a basin modelling study based on these revised continental and transitional crustal models. Temperature and source rock data from wells within the JDZ and offshore Gabon were also included. The study modelled three pseudowell locations in STP-EEZ to test the maturities of both the early post-kinematic sediments (Cenomanian-Turonian) and syn-kinematic source rocks. The results show that both potential source rocks are mature for oil and gas and are able to have charged the multiple sandstone reservoirs of the thick Cretaceous and Tertiary clastic successions. These results appear complementary to the presence of oil seeps onshore northern São Tomé at Uba Budo that have been typed to a Cretaceous source rock (ANP-STP).



Source rock basin modelling results showing vitrinite reflectance, indicating source rock maturity.

Reason 3: Long-lived fluvial systems provide thick clastic reservoir-quality successions

The Gulf of Guinea forms the sink for numerous fluvial systems: to the north lies the Niger Delta whilst to the north-east the Cross and Sanga River systems feed the Douala and Rio del Rey basins of Cameroon. To the south-east lies the Rio Muni Basin fed by the Mbini River of Equatorial Guinea and the Ogooué River of north Gabon. These rivers are believed to be long-lived, evident from Cretaceous sections interpreted on seismic data. The influence of these fluvial systems is witnessed by the preservation of unusually thick successions of distal fluvial outflow sediments with differing provenances and varying points of sediment input.

Reason 4: New Sub-Akata Shale plays in the distal parts of the Niger Delta

The prolific plays of the Niger Delta are encountered in Tertiary siliciclastic reservoirs that are charged by the Eocene Akata Shale source rock. An exciting new play concept, which has captured the recent attention of operators and explorers, lies beneath the Akata sedimentary succession of the distal or outboard parts of the Niger Delta. Here, a thinned Tertiary succession lies atop continental or transitional crusts. This play, as yet untested, predicts that the syn-kinematic source rocks are mature for oil and charge clastic reservoirs beneath the Akata Shale that acts as a seal rock.

This new Niger Delta play is interpreted to continue southwards into the outboard Gulf of Guinea, including the STP-EEZ and the deep waters of Gabon.

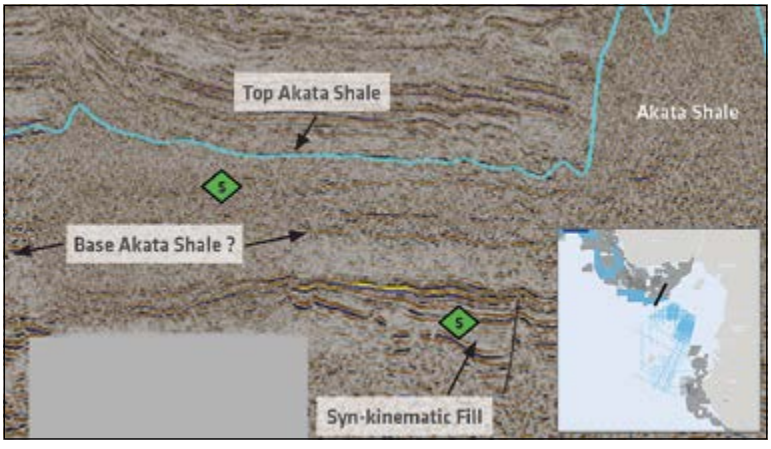
Potential Revealed

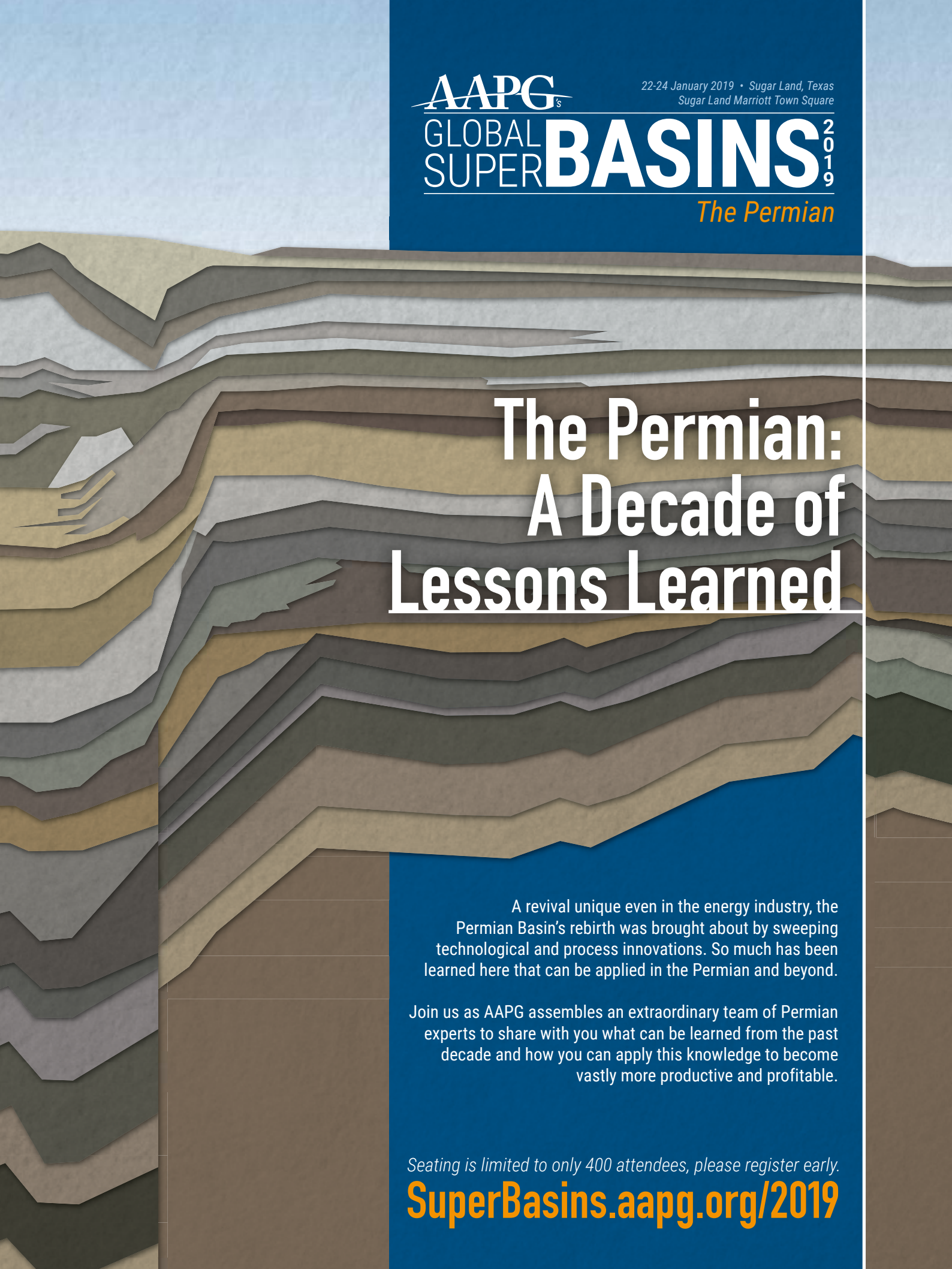
The surge in activity would appear to be a consequence of changes in geological understanding rather than for socio-political reasons. Modern processing of vintage seismic has provided compelling evidence that the crust beneath the STP-EEZ is a mélange of continental, transitional and oceanic types influenced by transform tectonism. The overlying sedimentary wedges that fill the associated kinematic basins have the appearance of isolated basins. When these syn-kinematic sediments are applied to basin models, the results suggest that they are mature for oil and gas, results that are supported by the presence of hydrocarbon seeps onshore São Tomé Island. The post-kinematic stratigraphy is dominated by multiple long-lived fluvial systems that likely provide reservoir quality sand bodies that onlap and drape the transform structures providing structural and stratigraphic traps.

All the elements of a working petroleum system appear to be present in the waters of the STP-EEZ. As exploration advances and wells are planned, it may only be a matter of time before we see the fruits that these new play concepts may bear.

Reference available online. ■

An arbitrary line through Nigeria and the JDZ showing the sub-Akata Shale syn-kinematic structure and stratigraphy. The potential for a sub-Akata petroleum system has excited Niger Delta explorers and operators.





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Talking Rocks

TIM DALEY

Communicating geoscience: building public interest and promoting inclusive dialogue.

Dumber than a box of rocks; that was on the T-shirt my Dad bought for me way back. Amusing. Ironic. Upsetting. Does anybody want to know about anything other than dinosaurs and disasters? When geo-controversies hit the headlines, why are geoscientists woefully unprepared to engage with a public who have no clue what we do, but who can be manipulated by social media into a highly motivated opposition? Geologists like being seen as slightly eccentric, outdoor-loving scientists who understand the Earth, and yet we are portrayed as bringing forward the end of the world. *GEO ExPro* has been following these themes for some years, but the controversies just keep coming back.

In September I attended the latest gathering to focus on how geological ideas could be conveyed across society: a Geological Society Petroleum Group event in London entitled *Communicating Geoscience: Building Public Interest and Promoting Inclusive Dialogue*. A broad topic – but unsurprisingly several of the talks and discussions returned to familiar defensive themes. We heard from Equinor how factions opposing fossil fuels want to legislate against exploration in the Norwegian Arctic and how the British Geological Survey (BGS) were caught out in 2011 by a minor earthquake in Lancashire and were overtaken by the frenzy of anti-frackers before they could mount an informed response. From Radioactive Waste Management we learnt that this is likely to be the next big topic to provoke the ugly side of protest. All three organisations feel that credibly presented science, operational excellence and demonstrating the importance of these activities should win the day.

The result of communicating sometimes complex concepts to the general public is hard to measure. Some polls suggest that science makes little difference to changing the mindset of an uninterested majority or stubborn opposition groups. ReFINE, an international research consortium set up by two UK universities specifically to impartially investigate the effects of fracking, is not immune from criticism. Presenting unbiased results of study does not necessarily facilitate universal acceptance, if the science itself has become politicised. Despite this, I think most geologists would not want to duck the responsibility for presenting the right science.

Consistent Messages

So what was suggested by presenters? Emphasise the bottom line: how will this affect you or why should I care? What is the role of this energy or these resources? Listen and take account of concerns. Show how these operations are to be executed and monitored so you can be trusted to take care of anxieties. Start public consultation earlier, bigger and better. The chances of a more positive outcome will be improved by a combination of consistently phrased messages whose presentations reach all the way to individuals in the community.

There is a consensus that geoscientists should be more visible to the public and take advantage of any interesting news opportunities that promote our science. John Underhill reminded us of the cases of the southern North Sea Silver Pit meteorite crater (or not) and the possible identity of Homer's Island of Ithaca in ancient Greece, which hit the press and TV several years ago. These were non-threatening dilemmas that caught the public interest but also were opportunities for geologists to explain our data and how they are used, whether seismic, satellite, outcrop or wells.

I was surprised by the relatively low attendance at the event, many of them already active disciples, although the conference was live-streamed with at least three mini-conferences across the country. There was also a session called 'Tools for Engagement' – the blogging-YouTube-Twitter-Instagram world. We should embrace with open arms the latest geo-generation sharing with the world their interest and studies.

There is good progress in the reporting and monitoring of environmental consequences of energy provision, but widespread acceptance of these studies is hard, given the perceived prejudices of many. So while industry cannot escape the requirement to tell the story effectively, the unbiased status of bodies such as the Geological Society and BGS should be conserved to allow public access to independent data and opinion.

We should not curb our natural enthusiasm to promote our science and to excite the public on how our Earth works and where our resources come from. And if they don't get it or are not excited, get a smarter box of rocks. ■

Panel discussion on 'Communicating Geoscience': (L to R) Clive Mitchell, Hazel Gibson, Philip Essl, Anna Szolucha and Jen Roberts.

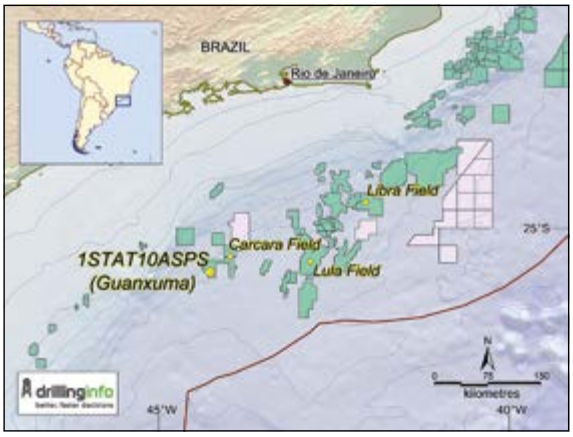
Kirstie Wright, Heriot-Watt University

Brazil: Promising Deepwater Find

In July 2018, **Equinor** announced the **1STAT10ASPS** NFW on the pre-salt **BM-S-8** Block in the **Santos Basin** had discovered hydrocarbons, calling the discovery "promising". The well on the **Guanxuma** prospect spudded on 29 April and was drilled to 6,600m with Seadrill's *West Saturn* in 1,990m water depth. It is assumed to be suspended as a potential oil discovery, since the rig began drilling a geologic sidetrack on 30 July, followed by a third well from the same surface location with the same planned total depth, indicating potential problems with the first sidetrack.

Guanxuma had a pre-drill estimate of 700 MMbo to 1.3 Bboe in recoverable reserves and is located on the same block as the pre-salt **Carcará** Field on BM-S-8, which is already estimated to have 2 Bboe recoverable. Equinor operates the block with 36.5%, with partners ExxonMobil (36.5%), Petrogal (17%) and Barra Energia (10%). As part of a plan to unitise the Carcará Field with the Norte de Carcará area, both Equinor and ExxonMobil are expected to raise their stakes to 40% before 2019, while Petrogal's interest will climb to 20% and Barra Energia will leave.

Equinor received a licence to drill up to five wells on the Norte de Carcará Block in early September, in addition to the seven it has in Carcará. Equinor's first well in Norte de Carcará spudded on 13 September with the Carcará West outpost, making it the first to be drilled by any company other than Petrobras, under the PSC regime in Brazil. ■



Guyana: Ninth Discovery

ExxonMobil on 30 August 2018 announced its ninth discovery on the **Stabroek Block** in Guyana after the Hammerhead-1 NFW encountered 60m of what it described as high-quality oil-bearing sandstone reservoir. The wildcat spud on 27 July 2018 with the *Stena Carron* drillship and was drilled to a TD of 4,225m. The well is located in waters of 1,150m, some 21 km south-west of **Liza-1**, where ExxonMobil (45%) and partners Hess (30%) and the CNOOC-subsidiary Nexen Petroleum (25%) made the first discovery in the block in 2015 in Late Cretaceous turbidite sandstones. Hammerhead, however, is updip of previous discoveries Liza, Liza Deep, Payara, Snoek, Turbot, Ranger, Pacora and Longtail and found oil in a Tertiary clastic reservoir.

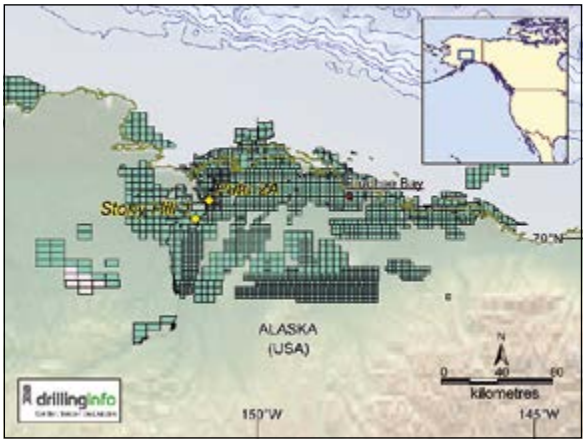
Total recoverable resource of over **four Bboe** has been estimated by ExxonMobil for the Stabroek Block, with the potential for up to five floating production, storage and offloading (FPSO) vessels producing more than 750,000 bopd by 2025. ■

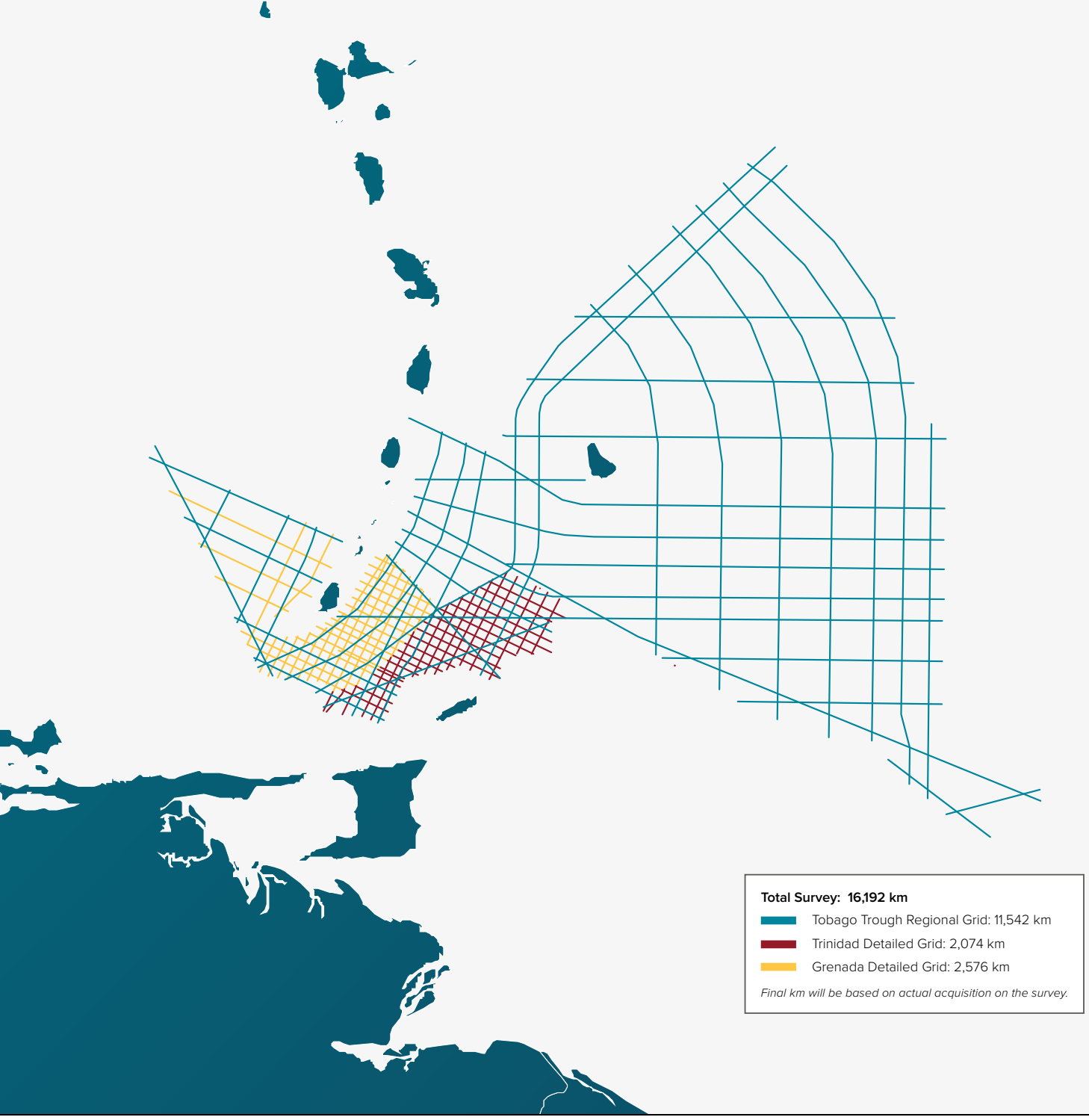
US: Alaska Narwhal Trend Discoveries

ConocoPhillips indicated in July that earlier in 2018 it had successfully drilled, cored and flow-tested both the **Stony Hill-1** NFW, in **North Slope** lease **AA093131**, and **Putu-2A** NFW, in lease **ADL 390674**. Stony Hill-1 reached a final TD of 3,376m and Putu-2A was drilled to 1,537m. Both wells were targeting the Nanushuk Formation, which underlies the recent Armstrong Oil & Gas discoveries at **Pikka**.

Both wells are sited on the **Narwhal Trend** and ConocoPhillips estimates that the current resource for the Trend is now 100–350 MMboe. Both discoveries, originally identified via seismic amplitude mapping, will require additional appraisal work, expected to take place in 2019. Putu-2A was capped and buried 2.4m below the tundra and directional drilling will be used if there is further development. Putu-1 was due to be drilled last winter but was postponed pending discussions with the local community.

ConocoPhillips stated in July 2018 that it has secured 0.5–1.1 Bboe of additional gross discovered resource associated with the exploration programme in Alaska since 2016, with 75% of the play yet to be drilled. The cost of supply of the new resource is estimated to be less than US$ 40/barrel. ConocoPhillips Alaska is the sole interest-holder and operator in both leases. ■





TOBAGO TROUGH MC2D

MCG is pleased to announce the Tobago Trough MC2D survey.

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Is the UK North Sea Finished?

Neil Hodgson directs a team of geoscientists at Spectrum working on placing new seismic programmes in the most prospective areas globally. With his extensive experience of the North Sea, we asked him this important question.

So, is the North Sea finished?
Far from it; actually there is a specific window of real opportunity just now in the North Sea, to use state of the art seismic acquisition to reveal the next generation of fields that will add another 30 years to the productive life of the North Sea. We need both ocean-bottom node (OBN) acquisition in areas where conventional data has been pushed to its limits and found wanting, and the acquisition of new data to chase both new and old plays in previously overlooked areas.

Are there any underexplored plays to work or new plays left to find?
Ask any geoscientist working the basin: there is still plenty we don't fully understand about the plays we are working. Often the remaining problems are due to seismic resolution – for example, the Jurassic–Triassic pods and diapir flank plays of the Central Graben, beneath the salt walls in the Southern North Sea or at any scale in the sub-salt of the western margins. Big questions also remain around little tested stratigraphic plays in the Northern North Sea (Triassic, and intra-Jurassic) and Southern North Sea (Lower Carboniferous and Permian).

Generations of inspired and super-competent geoscientists have been forced to draw conclusions (models or interpretations) from data that was not a complete vision, but all they had. The truly curious understand that what we know and what we just think we know are separated by a gap where exploration genius and big new plays have been found.

This year has seen record low drilling activity. Why?
The low oil price of 2014–2016 hit North Sea activity hard. However, stability at a moderate to good level has meant that funding for acreage acquisition is back, pre-staging a resurgence of drilling activity in the next few years. However, before activity can get going, we must change the game with new information, which has got to be up to the task. It is fortuitous that 3D acquisition over the more frontier plays, and OBN seismic in the mature basins, are now affordable.

What is needed technically to rejuvenate the area?
The North Sea creaming curve, or more correctly, the multiple play creaming curves inside that, are now limited by the available information. Whilst well data slowly gets released and becomes available as the creative feedstock for seismic interpretation, seismic only improves with reprocessing, or new acquisition by methods that deal with previous barriers to imaging. New information, targeted on old tired 'mopping-up' plays, will not shift the creaming needle. However, targeting repeatable, material-sized plays with next-generation technology has every chance to re-invent the North Sea.

How can investment be encouraged?
Where there is infrastructure there is opportunity. So here's the thing – there is a clock ticking on the longevity of facilities, both platforms and pipelines, and in time they will start to disappear. Yet the quality and availability of seismic data in the North Sea is only now able to solve the hardest problems – looking deep, looking more sophisticatedly and looking where data has been scant or misunderstood.

The problem we have to solve isn't funding new drilling – it's funding the new seismic data that will de-risk drilling. This is the low hanging 'elephant in the room' and the sooner the industry confronts this, the sooner we can stop the ticking clock and drill the juicy bones.

What can the UK government do to help?
It's already done it. In establishing the Oil and Gas Authority, it has unleashed a creative, integrated and professional organisation that is passionate about promoting and facilitating future exploration in the North Sea. This is the perfect platform. Whilst the Norwegian government's solution to stimulate exploration may not be open to the UK, creative minds ought to be looking at the huge abandonment costs ahead of the industry, vs a cash neutral risk-play on future exploration upside that is open to government, industry or new private funding.

Every generation has a mission and the current generation must think not what the North Sea can't do for them, but what new data can do to unlock the future of this great basin. ■

Spectrum

Dr Hodgson joined Spectrum in 2012 having previously worked for BP, BG and Premier Oil in a number of exploration and development roles over a 33-year career. His last role prior to joining Spectrum was Exploration Director for Matra Petroleum. Neil is AAPG Europe President Elect.

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Brazil: Emerging as Top Player

The pre-salt play in the Campos and Santos Basins offshore Brazil may contain as much as 100 Bb of recoverable oil, Equinor's EVP Exploration Tim Dodson said recently. That is as much oil and gas that is expected to be found offshore Norway, in total.

Equinor is producing 40,000 bopd from the Peregrino field, has a huge stake in a two billion barrel discovery named Carcará and Carcará North, and is also involved in several other discoveries. By 2030, Equinor expects to produce between 300,000 and 500,000 boepd.

The prolific play occurs in ultra-deep water, at a depth of 5–7 km beneath sea level, under a layer of salt up to 2 km thick. It comprises a sequence of sedimentary rocks formed during the separation of the current American and African continents about 150 million years ago. Heterogeneous layered carbonates make accurate reservoir characterisation a serious challenge. Also, it is reported that drilling exploration wells has proved extremely difficult, with low penetration rates.

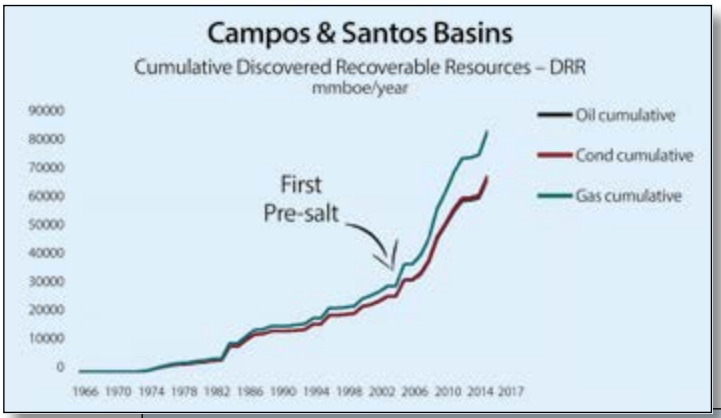
Brazil has turned out to be one of the top players in the world both with respect to oil production and reserves. Averaging 2.7 MMbopd in 2017, the country ranked as ninth amongst the top producers.

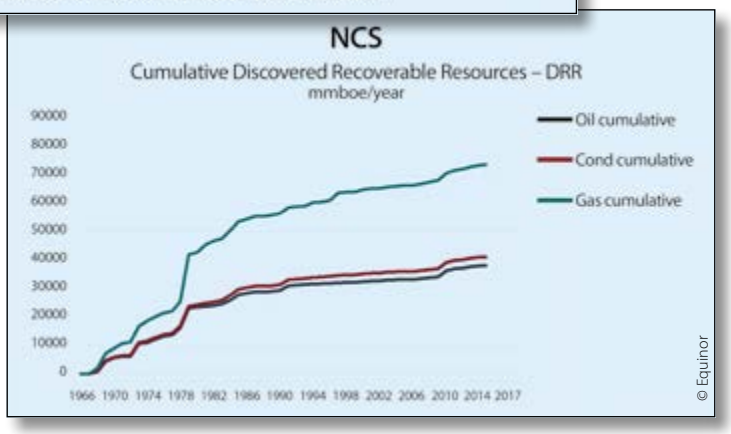
The pre-salt play in Brazil has been very successful. Further north, in Guyana, ExxonMobil has had tremendous success with – so far – nine discoveries in ultra-deep water and estimates that it has discovered more than four billion barrels of recoverable oil equivalent in the region. The potential, however, is a lot bigger. Some 10 Bbo may remain to be discovered. By 2025 production may reach 750,000 bopd and up to five floating production, storage and offloading vessels will be required. The first development, called Liza Phase 1, is expected to begin producing oil by early 2020.

South America is hot! ■

Halfdan Carstens

Comparison of creaming curves for the same time periods in the Campos/Santos Basins and the Norwegian continental shelf. While Norway's discovery rates are tapering off, Brazil is moving forward and it is evident that the pre-salt play has made a huge difference.





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

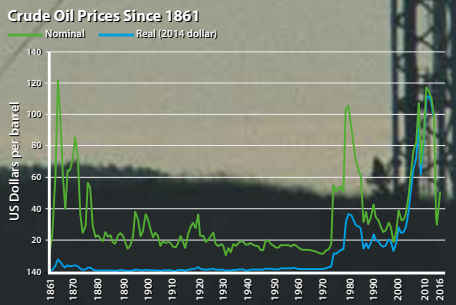
Giant field

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

Major field

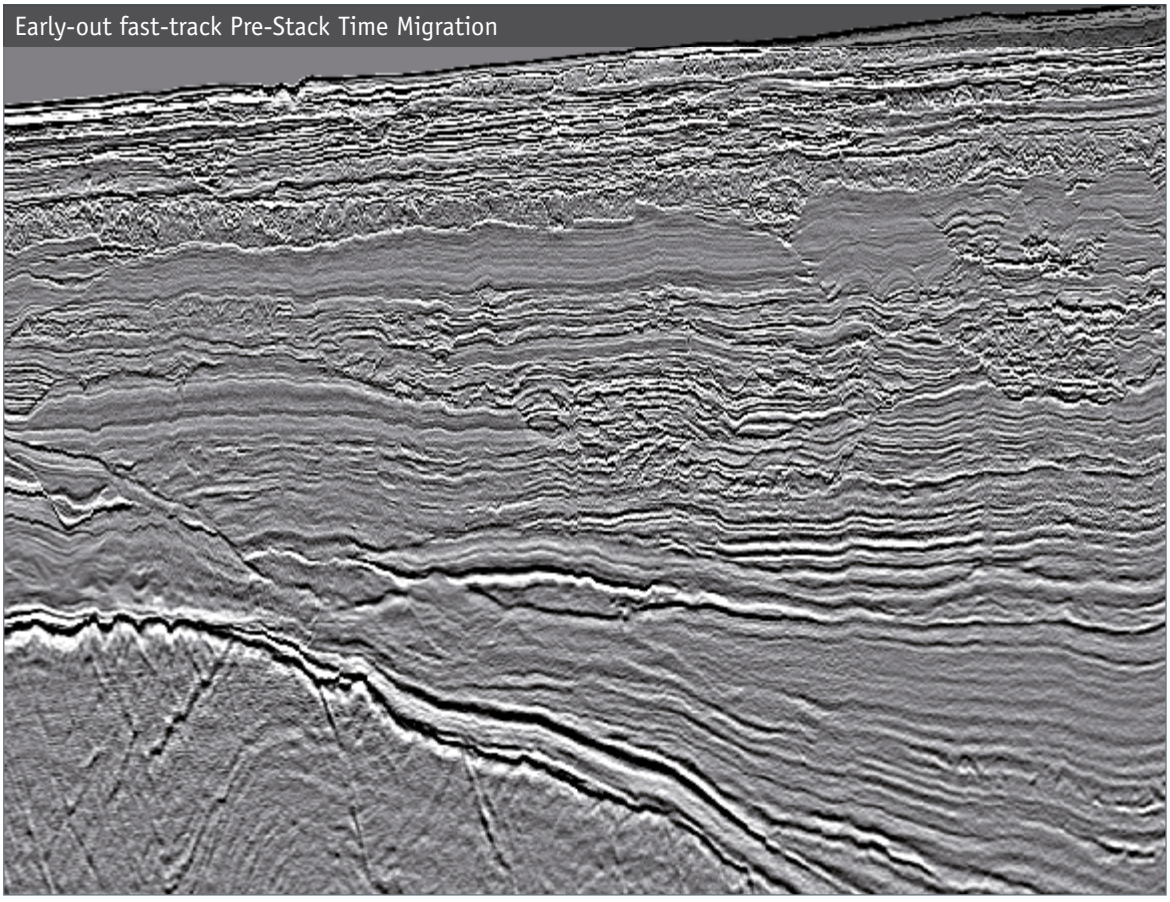
Recoverable reserves > 100 million barrels (16 million Sm^3) of oil equivalents

Historic oil price



PRIME PROSPECT

Zambezi Delta 3D Survey, Mozambique
Fast-Track PreSTM Data Available Now



CGG has acquired 15,400 km² of multi-client 3D seismic data in the outer Zambezi Delta, west of the Beira High. This is the first phase of a **JumpStart**™ integrated geoscience package, incorporating gravity, magnetic, well and geological information, and designed to accelerate understanding of the petroleum systems in the area.

Fast-track PreSTM data is available now and the final PreSDM data set will be completed in Q4 2019.

The right data, in the right place, at the right time

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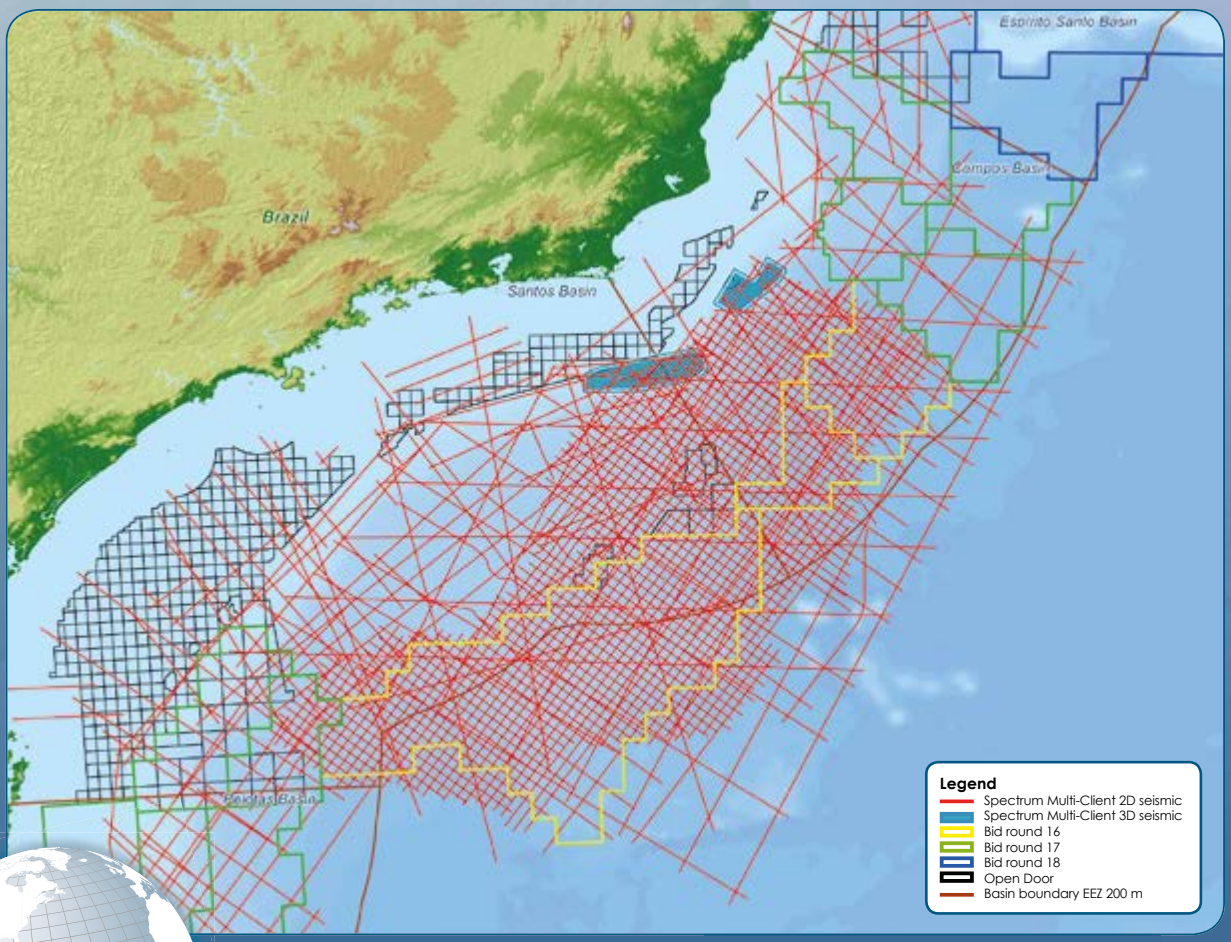
CGG
Passion for Geoscience

Brazil: Santos Campos 2D

Multi-Client 2D Seismic for the Exploration Journey to Giant Oil



Spectrum holds more than 38,000 km of long offset 2D seismic data in the Santos-Campos basin over some of the most exciting open exploration acreage in the world. These surveys, acquired between 2012 to 2018, have now been de-ghosted and are available in both Pre-Stack Time and Depth Migration (Kirchoff & RTM).

This seismic covers a vast area where the prolific pre-salt play is confirmed to extend out from giant discoveries into the16th Round Sector area. The 2D data, acquired in a 10 km x 10 km grid, allows crustal structure to be defined, thereby enhancing thermal maturity modelling and imaging of base salt and syn-rift source rock sequences. The prolific Barra Velha sequence is now mappable from Tupi, Jupiter and Libra into open acreage.

Multiple giant structures with billion barrel low-risk oil potential are mapped within Brazil's 16th Round Sector. This regional seismic data allows prioritization of the main play fairways, structural trends and oil prone areas, as well as deep crustal fault distribution mapping for CO_2 risk mitigation. Yet-to-find analysis of the area covered by this dataset exceeds the 60 billion barrel potential resource already discovered in the pre-salt play.

spectrum**geo**.com
mc-uk@spectrum**geo**.com
+44 1483 730201

Spectrum