VOL. 14, NO. 6 – 2017

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

geoexpro.com

GEOTOURISM

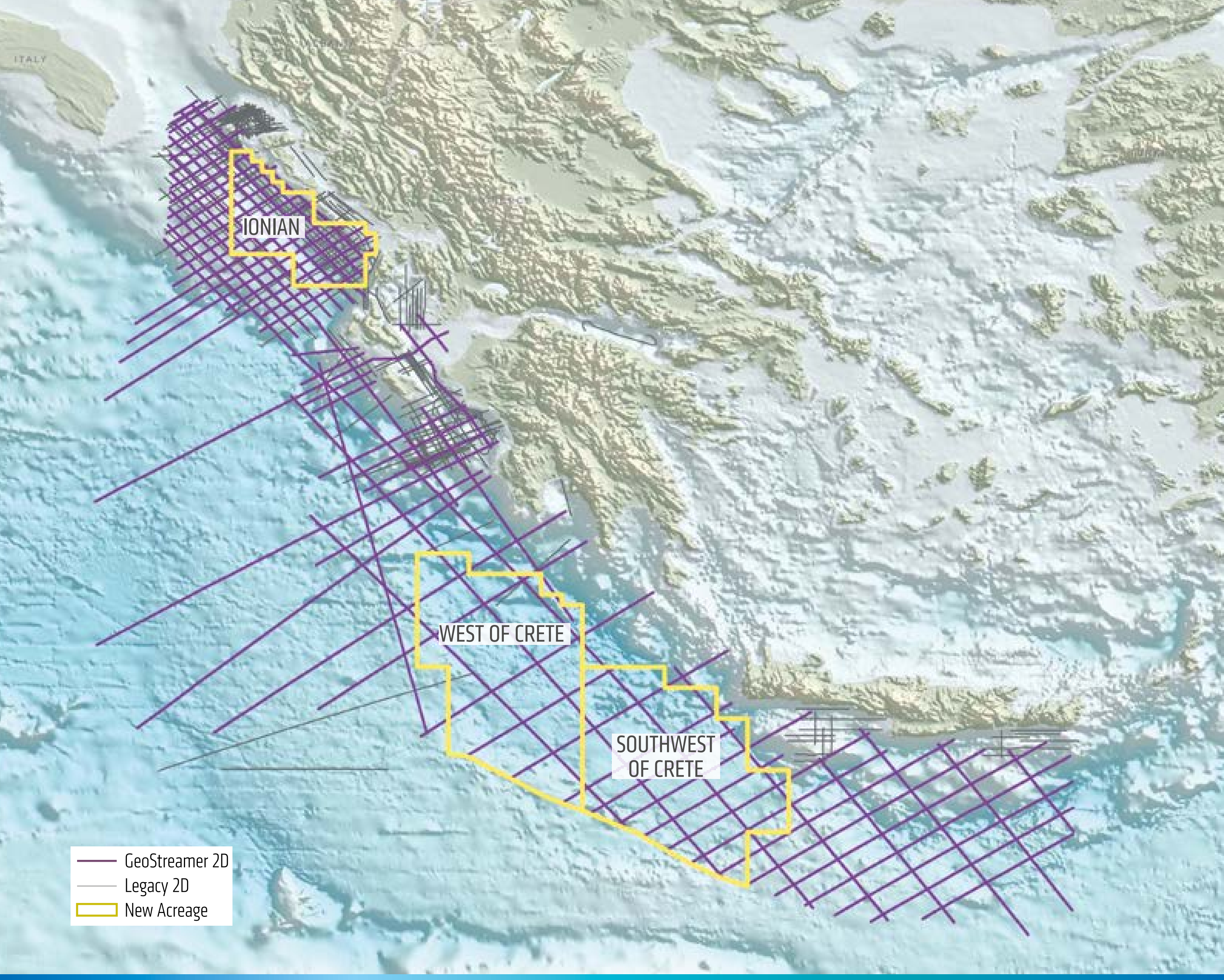
Faroe Islands: Europe's Best Kept Secret

HISTORY OF OIL: The Barnett Shale

INDUSTRY ISSUES
Managing Funding Risks in E&P

GEOPHYSICS
Imaging Shallow Reservoirs through Innovation

FRONTIER EXPLORATION
Tools for a New Era



Every Second Counts

Greece 2017 Offshore Tenders

Three huge new exploration blocks in Greece will open for tender in 2017. The 90-day window for applications will leave little time to spare when assessing these exciting opportunities. PGS have the data library and knowledge you need to begin today.

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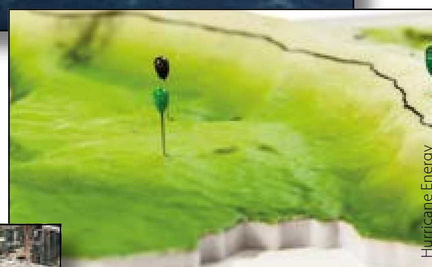
TopSeis is a radical new seismic acquisition and imaging system, where the source is towed above the middle of the streamer.



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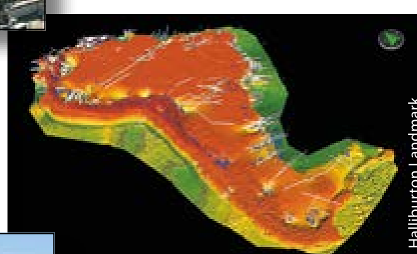

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This edition of *GEO ExPro* magazine focuses on North West Europe; Frontier Exploration; Seismic Imaging; and Managing Risk in E&P.

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Deepwater Renaissance

The Maersk Venturer, which in 2016 broke the world record for the deepest water depth for an offshore oil rig after spudding a well off Uruguay more than 3,500m below the sea surface.

When the oil price plummeted back in 2014, there were many who predicted it signalled the end of deepwater exploration: the economics just would not allow it, these expensive wells needed an oil price nearer $100 a barrel than $50, it was said. Attention turned to shales and to getting as much as possible from existing portfolios in rather more accessible locations.

But in the background, it seems there was a lot going on. About a year ago I heard a representative from one of the supermajors confidently asserting that they had refined their deepwater drilling through modern technologies, lower rig prices and increased efficiencies, and now believed they could make a profit on deepwater exploration with an oil price of $40 or less. All of a sudden, deepwater exploration was back in the picture. At the Africa Oil Week in October there were a number of talks focusing on the topic, including an entire session entitled 'Is there a future for deepwater exploration?' Several companies said they believed that deepwater drilling was now quite feasible with a breakeven full-cycle oil price of $30–$50 per barrel, making it competitive with shale oil. True, the lead time from discovery to first oil is a lot longer for a deepwater discovery, but the field life is longer too, without the steep decline rates common in unconventional wells.

A return to deepwater will not be that easy. Only the most competitive deepwater projects will move forward, but terms have improved over the last few years, with cheaper entry, more flexibility and easier access to funds, on top of major technological advances.

If any further evidence of this upsurge in interest in deepwater drilling was needed, it was given to us by the hugely increased level of interest in the recent Brazil pre-salt licensing round, the first where foreign companies were able to bid as operators since the vast oil reserves beneath the salt were discovered. Six of the eight well-contested, high potential deepwater blocks were awarded, with supermajors like Shell, ExxonMobil and Total among the winners. They obviously believe that deepwater exploration is back on the table. ■

Jane Whaley
Editor in Chief

THE FAROES: EUROPE'S BEST KEPT SECRET

Unspoiled, unexplored, unbelievable, as the Visit Faroes organisation says. Lake Sørvágsvatn on the island of Vágar seems to hang above the ocean, until it suddenly spills its contents into the sea via a steep, 30m-high waterfall. It is surrounded by glaciated cliffs and hills formed by continuous lava flows.

Inset: A well drilling into the Barnett shale in Texas.

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GEO ExPro

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

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

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North West Europe: Attractive Investment Arena

RYSTAD ENERGY

Oil production from shale formations and increased uncertainty around future demand for oil has created less visibility around the viability of long cycle offshore oil production and exploration projects. North West Europe, a predominantly offshore region, will also be impacted by these large macro trends. Three lenses can be used to examine how we can think, observe and assess the different supply segments of oil and how they compete for available capital and resources.

The first lens looks at how decision criteria has evolved from volume-based metrics like production targets and reserve replacement in the US$100/bo era to profitability indices, dividend protection and cash preservation in the downturn. Downturn behaviour penalises long cycle offshore projects, while upturn behaviour enhances emphasis on long cycle-friendly decision criteria. This means that frontier regions in North West Europe – the Barents Sea and West of Shetland – will suffer the most. The remaining areas in the North and Norwegian Seas are covered by infrastructure, a key enabler for short-term projects offshore such as infill drilling and tiebacks.

The second lens is resource availability, as not every company can access all available resources. The most profitable resources are locked behind national oil companies, while shale resources require a vastly different business model than conventional oil. We observe that transaction multiples have increased for shale resources and decreased for North West Europe resources, implying an overly high entry price to the North American shale world, locking out offshore-focused players without an established shale activity. These companies have a limited investment arena and North West Europe offers one of the few conventional OECD production sources.

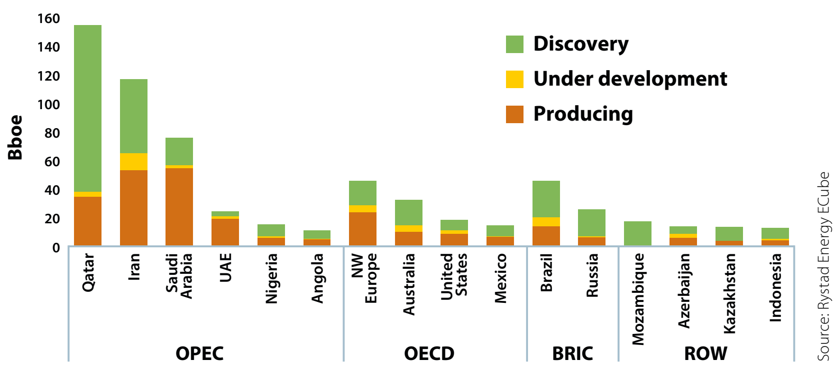
The third lens looks at transaction and portfolio opportunities. Only a subset of companies can allocate capital to a wide array of projects in all oil supply segments. Transaction history for majors and big international oil companies gives no clear indications that offshore is divested in favour of other segments, suggesting that it is still considered attractive despite the short cycle and payback time characteristics of shale oil. From a full cycle perspective, offshore projects can compete with equal or better breakeven levels. The only clear indication that transaction history reveals is divestment of oil sands.

These three lenses teach us that understanding capital allocation and its implications on offshore supply, transactions, field developments etc., is complicated. Observations made around the few companies able to work across all oil supply segments do not support any widespread move away from long cycle conventional offshore projects.

North West Europe, as one of the leading offshore regions globally and with OECD exposure, should therefore expect to see continued capital and resource allocation as long as projects are competitive. Given the wide array of commercially very robust projects in the region, the expectations suggest a new development boom. However, recent poor exploration results have not filled the project portfolio, potentially creating declining activity past 2020.

Simon Sjøthun, Project Manager, Rystad Energy

Countries or regions with remaining discovered offshore resources greater than 10 Bboe: North West Europe has the biggest OECD resource base.



ABBREVIATIONS

Numbers
(US and scientific community)

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

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

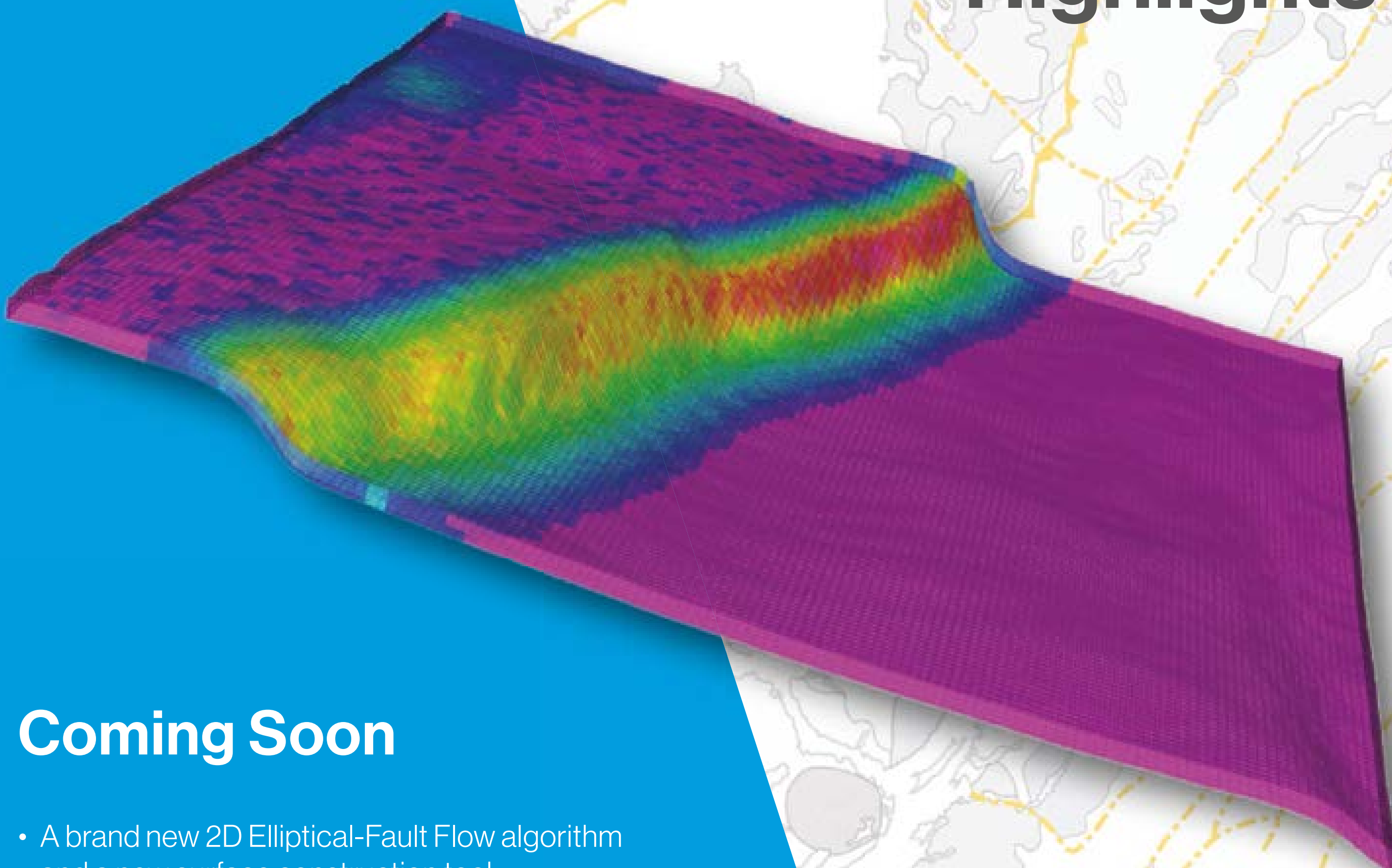
P2 reserves:
Quantity of hydrocarbons believed recoverable with a 50% probability

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

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

move™

Move2018
Highlights



Coming Soon

- A brand new 2D Elliptical-Fault Flow algorithm and a new surface construction tool.
- Developments and improved functionality within the horizon/fault extrusion and extension tools.
- Map View control of 3D data.
- Stochastic modelling in Fault Analysis and Monte Carlo Fracture Response in Fault Response Modelling.
- A new Attribute Query tool and 3D Seismic export capability.

mve.com/move-latest

midland valley

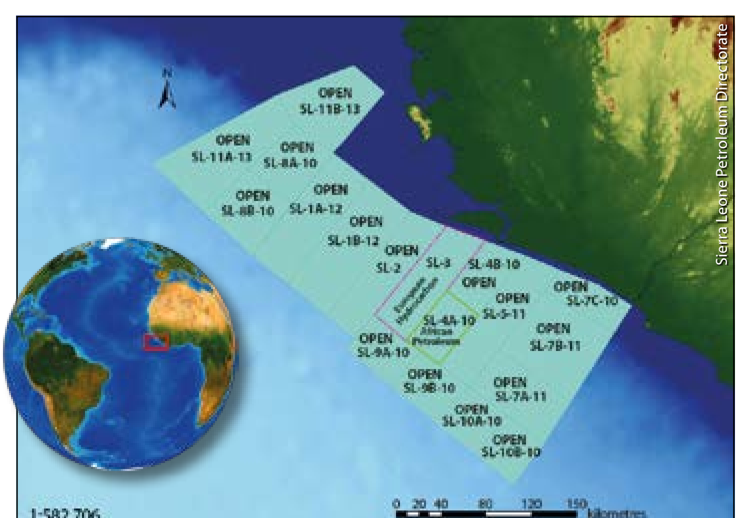
Opportunities on the West African Transform Margin

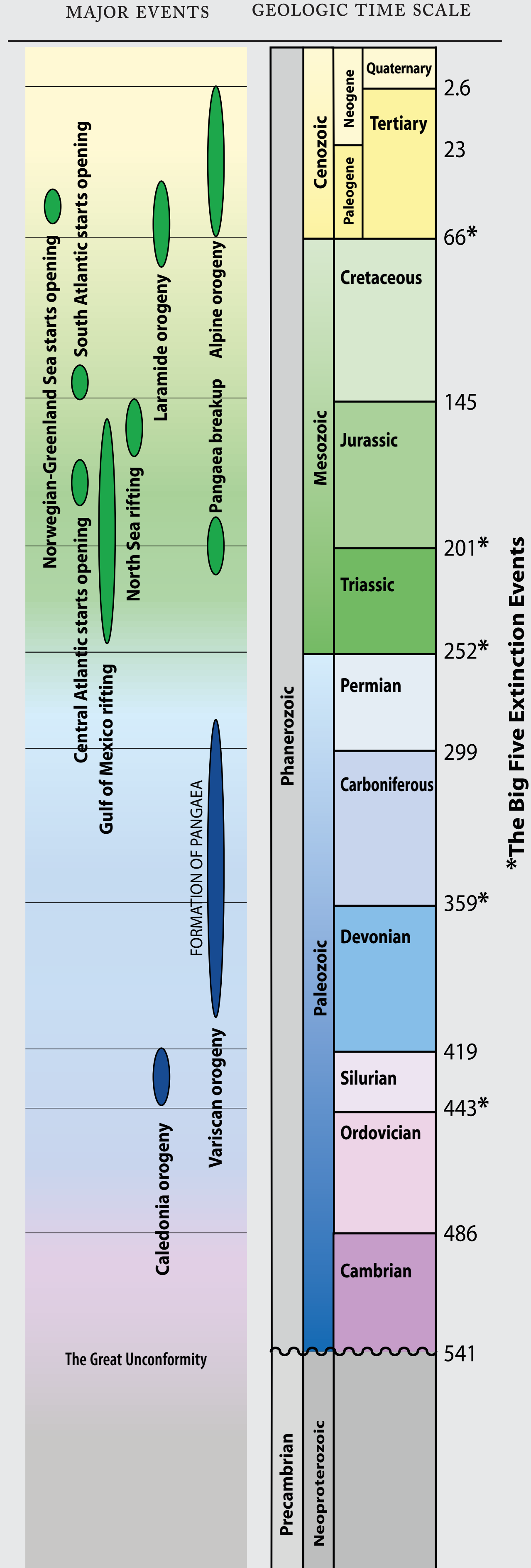
Sierra Leone Fourth Licensing Round Announced

Since the discovery of the giant Jubilee oil field off Ghana in 2007, interest in the transform margin sector of West Africa has been high, further encouraged by recent discoveries off Senegal and Mauritania and the belief that Sierra Leone's offshore waters may contain proven petroleum systems that are conjugate to major discoveries in South America. Considerable interest is therefore expected in Sierra Leone's fourth licensing round, which was announced in late October and which will take place between mid-January and the end of May, 2018. The round will be exclusively supported by the Getech Group through its wholly-owned subsidiary ERCL. The company will operate a data room containing 15,000 km^2 of 2D seismic, more than 10,000 km^2 of 3D seismic, including PSDM volumes, and all the wells from the 2009–2013 drilling campaigns, together with value-added products built by Getech using the government's released 3D seismic and well data.

Exploration for oil and gas in Sierra Leone started in the mid-1980s with two shallow water wildcats, which had oil shows but were plugged and abandoned, possibly because of the depressed state of the industry at the time. Fast-forward to 2002, and the opening of the first offshore bid round, which was backed up by improved understanding of the subsurface based on a 5,800 line-km 2D survey which had been undertaken by TGS in 2001. The second round followed in 2004–2005, when three blocks covering about 17,700 km^2 were offered, and in 2012 a third round offered eight blocks, some of which were oversubscribed. The areas to be explored are normally demarcated in blocks of at least 2,000 km^2 and offered for a period of 30 years. At present the acreage offshore Sierra Leone is divided into 18 blocks, only two of which are under licence at the moment.

The first discovery in Sierra Leone was Venus-1B, drilled in 2009 in 1,800m of water, followed by Mercury in 2010 and Jupiter in 2012, all found by Anadarko. Two further wells have been drilled offshore since then, one of which had shows, so the offshore area could correctly be described as underexplored. ■





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* Reservoir geophysics;
* Borehole seismic surveys and micro-seismic;
* Geophysical research and software development;
* GME and geo-chemical surveys;
* Geophysical equipment manufacturing;
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Africa Units

As Africa moves towards the commercialisation of its huge gas and oil reserves, the African oil industry met in October to discuss the potential and challenges it faces. Ministers from Côte d'Ivoire, Namibia, Nigeria, Ghana, Mali and South Africa attended, as did US Secretary for Energy Rick Perry. The event drew speakers from the highest echelons of government, operators, service providers, legal, advisory and research firms. The key themes discussed were the development of the continent's oil and gas resources, with a focus on exploration, regulatory frameworks and governance.

Identifying the way forward for the industry was a strong theme, as Africa competes for investment capital. It was agreed that there are big opportunities to use Africa's substantial gas resources to meet the constant and ever-growing need for power. This in turn will trigger economic growth, but for this to happen greater cooperation is needed in moving energy around the continent. African countries must also address regulatory and fiscal conditions in order to attract investment and reignite the development of identified deepwater assets and to exploit the substantial exploration potential of the continent.

African ministers at the Africa Oil Week.

Africa Oil Week next year was confirmed as **5–9 November 2018**, once again in **Cape Town, South Africa**. ■

Fijian PM for IP Week

The Prime Minister of Fiji, Hon. **Josaia V. (Frank) Bainimarama**, has been confirmed amongst an impressive line-up of speakers for **IP Week 2018**, hosted by the **Energy Institute**. Fresh from chairing the forthcoming UN Climate Change Conference in Bonn, Germany, Mr Bainimarama will update delegates at IP Week 2018 on the outcomes at COP 23 and reflect on the urgency of the transition to a low carbon future.

Fiji and neighbouring islands in the Pacific are highly vulnerable to climate change impacts, which it is estimated could displace up to 1.7 million people by 2050. It is expected Fiji will experience higher rates of disease as average temperatures rise, increasingly destructive storms as oceans become warmer and weather patterns more severe, and disruption to agriculture as saltwater intrudes onto farmland.

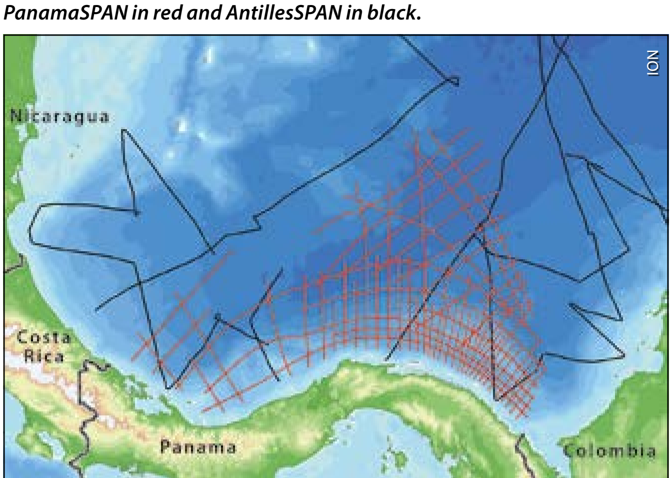
Mr Bainimarama will speak at IP Week alongside other senior figures including Dr Fatih Birol, Executive Director of the International Energy Agency; Eirik Wærness, Chief Economist at Statoil; and Dev Sanyal, Chief Executive, Alternative Energy and Executive Vice President, Regions at BP. More speakers will be announced in the coming weeks.

IP Week 2018 takes places on **20–22 February 2018** in **London**. The programme can be found on the IP Week website. ■

Extension to Panama Survey

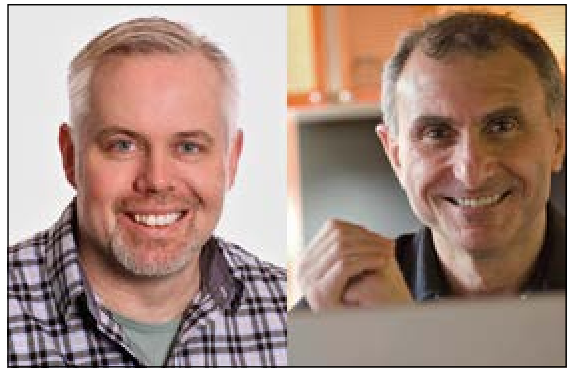
The first seismic survey acquired in the Caribbean offshore **Panama** in approximately 30 years, **ION's PanamaSPAN** 2D programme is designed to provide information on the hydrocarbon potential in this underexplored area ahead of an anticipated inaugural licence round. The project, which started in August this year, aims to create a well imaged, deep dataset to help understand the tectonic framework of the south-west Caribbean. It will also delineate the three distinct deformation elements of the North Panama Deformed Belt based upon their sediments and structural styles. To ensure the deep focus, 10,000m offsets are being used and the survey lines tie to wells and to AntillesSPAN, ION's reprocessing programme covering the entire Caribbean plate, thus ensuring full regional control.

PanamaSPAN in red and AntillesSPAN in black.



Due to strong client interest this industry-funded project has now been expanded by about 50% to cover 9,460 line-kilometres. The new extension will provide more detailed coverage that will allow E&P companies to evaluate blocks ahead of the expected licence round. Initial deliverables will be available in fourth-quarter 2017 and complete interpretation of the data by mid-2018. ■

QEye Growth Continues



Per Avseth (left) and Jack Dvorkin (right).

Qeye recently took a major step in developing its business further by entering into a collaboration agreement with two world leading rock physicists, Per Avseth and Jack Dvorkin, who will join Qeye in the capacity of Scientific Advisors.

Qeye is a geophysical technology company specialising in customised **quantitative interpretation (QI)**, which uses tailored workflows integrating a range of measurements and interpretations across disciplines and across different scales in order to better understand reservoirs. Various techniques can be employed, from AVO analysis and inversion to facies classification, pore pressure prediction, 4D (time-lapse) seismic analysis, and geomechanical analysis. The company has come a long way since its establishment almost six years ago, setting new standards for QI technologies and services and providing project-based consultancy using its proprietary and innovative QI software, all of which is developed in house. QEye solutions cover a variety of scenarios, from risk management to production monitoring and unconventional resources, using a range of technologies which include seismic data conditioning, well data analysis, seismic inversion and lithology and fluid prediction. ■

Future Geoscience Launches

Challenging circumstances in the oil and gas sector have required maximisation of data value, to quickly impact on interpretation and workflows. Whilst stratigraphic data interpretations have traditionally provided one of the backbones of subsurface interpretation, new methods of extracting value from integrated data is paramount for improving the predictive understanding of future subsurface interpreters.

PetroStrat, the largest commercial, global bio-stratigraphic group in the industry, and **Hafren Scientific**, developer of innovative technologies in elemental/chemostratigraphic data, have formed a joint venture company, **Future Geoscience Limited**, which combines the stratigraphic experience of over 60 experts, backed by two world-class accredited laboratories, to deliver novel integrated products based on their **combined chemo- and biostratigraphic skills**. This approach will maximise value of integrated datasets to de-risk plays and prospects.

According to industry trends and analysis, 'big data' products will provide the optimum solutions for oil and gas companies seeking to de-risk exploration and reservoir characterisation. The complementary high quality, quantitative datasets generated by both businesses and the new joint venture products will form the foundations of innovation in stratigraphic interpretation. ■

Combining chemo- and biostratigraphic skills.

Why the Name Zebra?

Because every dataset is different like the stripes on a zebra? Knew you wouldn't believe that, too pretentious. Because plenty of people start at the back of a magazine and it makes a change from aardvark? No, too silly! Because as a start-up, it is important to keep costs low and with Zebra, all stationery could very legitimately be black and white? That has a ring of authenticity.

Anyway, what does Zebra offer the industry?

The focus of **Zebra Geosciences** is borehole seismic data and its connectivity with surface seismic and well log data. Offering survey planning, data processing and reprocessing using the proprietary **Zebraseis**™ software suite, the goal is to deliver the greatest value and data integration. Zebra Geosciences celebrates 15 years of operation in December 2017.

In 2005 Zebra Data Sciences (ZDS) began providing specialised technical and marketing services based around the **EZDataRoom**® product line. This world-recognised platform for securely showcasing technical data online has been shown to aid the **data-to-deals** process within the O&G industry. Along with its renowned promotional and marketing brand, **HydrocarbonAssets**™, ZDS offers a cost-effective solution to identifying potential and viable partners with a better chance of a successful outcome at the negotiation table.

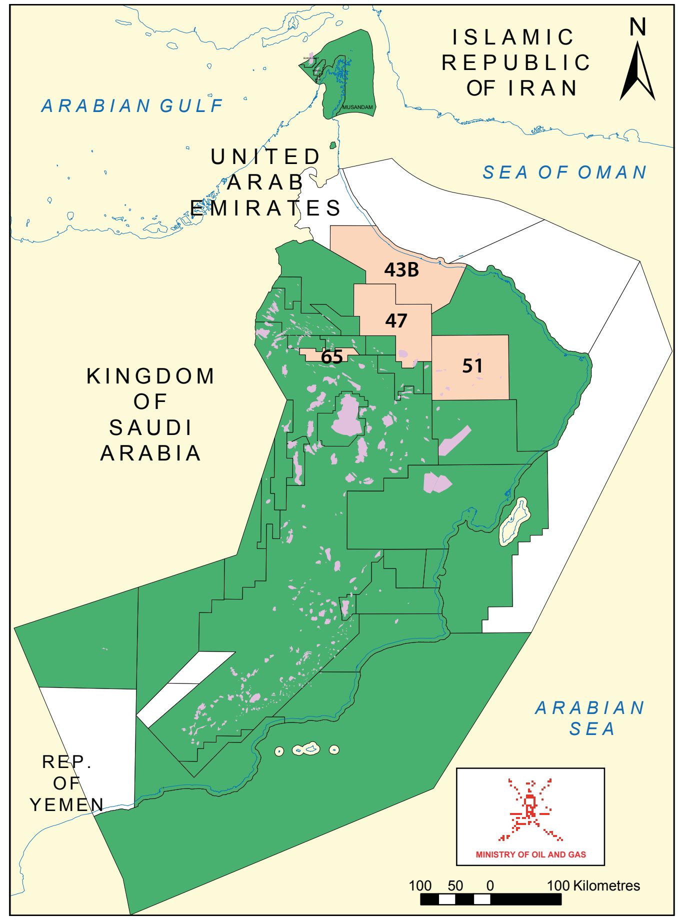
By the way, these Zebras also do colour now. ■

2017 Oman Bid Round

There are currently over 10 open blocks that will be tendered in **Oman** over the next few years, providing some excellent exploration opportunities. In the **2017 bid round**, four blocks will be offered: **Block 43B, Block 47, Block 51 and Block 65**. The bidding round closes 31 December 2017.

The online service at www.ldr.digitalenergycloud.com has been designed to provide a '**Living Data Room**' with online tools for browsing and visualising available block data with an easy-to-use web interface, offering the ability to access the data from any location world-wide.

As well as the high quality raw data, additional 'ready-to-use' interpretation projects are available to subscribers. These projects will save time and facilitate fast-track evaluations. ■



Sultanate of Oman concession boundaries

Deals for the Future

After the last few years of 'demand and supply' related low-price industry downturn, the evidence appears clear that the upstream sector may have turned the corner. The established E&P players, together with new start-ups replacing the many casualties of this last cycle's trough, are back taking on new technical staff and once more looking for new deals to restock their international upstream portfolios. Key equity markets also seem to have responded and money is now being raised, albeit it with a low risk focus on proven producing basins and new term production, but leading to renewed frontier and deepwater exploration.

As a result, the annual **APPEX Global A&D Conference** in London (**27 February to 1 March 2018**), promises to be a very exciting event, particularly if the steady rise in commodity price continues, and, like previous cycles, history repeats itself. This may be the perfect time to be doing the **best deals for the future**. New sources of oil and gas will be needed and if oversupply turns to undersupply the need for new exploration and production is guaranteed.

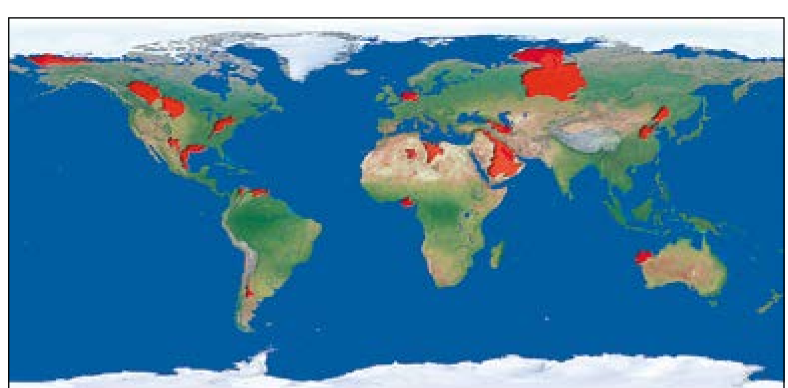
Come to APPEX 2018 to meet the right people, gauge market trends and enjoy the best chance annually of either selling or buying new upstream opportunities. ■

The World's Most Lucrative Basins

Whether you are an energy executive, investor, geoscientist or consultant, **AAPG's Global Super Basins Leadership Conference**, to be held **27–29 March 2018** in **Houston, Texas** will give you the information you need to be successful in the world's most significant basins. Co-hosted by IHS Markit, the event will feature regional experts who will share their unique first-hand knowledge of each of the globe's super basins.

So, what are super basins? They are the world's most richly endowed petroleum basins, each with at least 5 Bboe produced and more than that left to produce. With multiple source rocks and plays and well-established infrastructure, the top 25 global basins hold potential for hundreds of billions of barrels of future resources, thanks to ongoing technological innovations.

Giving you actionable intelligence to profit from the world's most lucrative basins, the topics covered will include: what makes each super basin unique; exploration/production history and the major plays' remaining potential; key innovations in each super basin; which basins will be a regional or global disrupter; critical geoscience elements that contribute to the success of these basins; and more. Learn about this exclusive conference at the AAPG Super Basins website. ■



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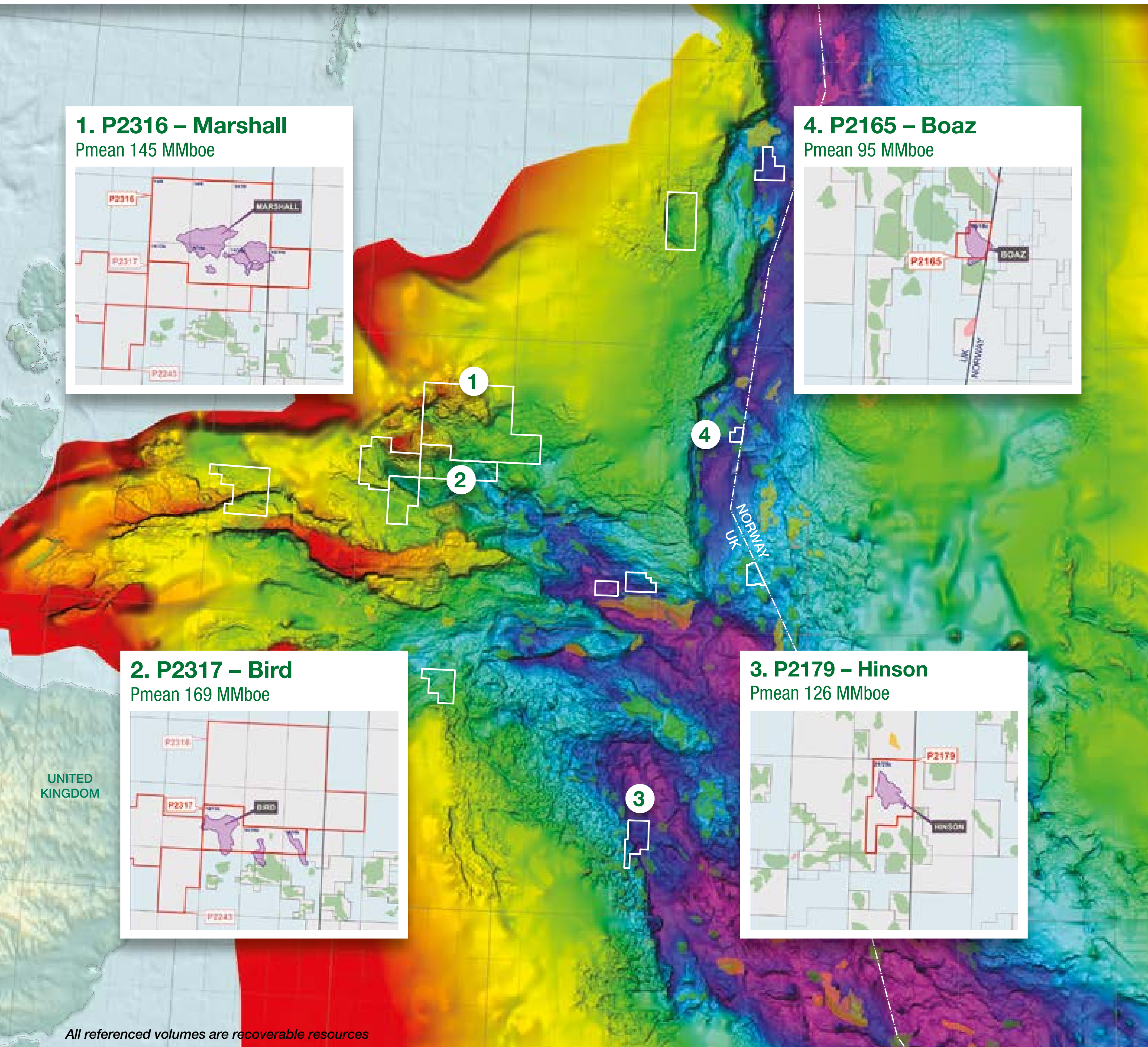

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Faroe Islands
Europe's Best Kept Secret

LIS MORTENSEN, Jardfeingi (Faroese Geological Survey)

Far away in the middle of nowhere in the North Atlantic Ocean you find the Faroe Islands: eighteen small, elongated islands towering above the sea, separated by narrow sounds.

There is a good reason why the Faroe Islands are called Europe's best kept secret. The islands, lying north of Scotland and west of Norway, are so small that they are all too often missing on world maps and even on regional maps of Europe. Yet it seems the rumour is spreading, and growing numbers of people are finding their way to the Faroe Islands to explore their scenic landscapes and unique culture.

The first challenge anyone who wants to hike in the Faroese hillsides and mountains has to overcome is the ever-changing weather. The islands are located where oceanic temperate and polar air meet, and this leads to constant passages of weather fronts bringing sun, rain, fog, snow, wind and calm weather. Sometimes it feels like you have all four seasons within a day, reminding you of Mark Twain: "If you don't like the weather now, just wait a few minutes." The sound advice before going on adventures in the Faroese hillsides is to take good account of the weather, bring clothes for rain and wind and be careful if you run into fog or any other unforeseen challenge.

Rich Landscape of Stories

The cultural heritage of the islands is rich and reflects close bonds with nature. You find that every place and even rock has its own name and, as mysterious tufts of fog crawl over the hillside, legends come alive. It is easy to listen to the stories which tell us that Fugloy is a floating island and the rocking boulders in Oyndarfjørður were pirate boats. The villages of

The fiord of Kollafjørður on the island of Streymoy is a classic glaciated valley, surrounded by flat layered basalts.

Eiði and Tjørnuvík treasure the legend about the two giant trolls who tried to move the Faroes to Iceland. They collected the islands and began to walk into the sea, whereupon the sun rose and turned the trolls into the two tall rock stacks that can be seen in the area today.

The islands were spared, but the legend brings us to the geological origin of the Faroe Islands, which began with the same rifting plates that are in the process of forming Iceland today.

The landscapes of the Faroe Islands, from the cliffs facing the ocean, to the mountains and valleys, tell geological stories spanning giant volcanism and the opening of an ocean, followed by glacial erosion in high arctic climates and a steady attrition by North Atlantic waves. The Faroe Islands are indeed a fascinating destination for geotourists interested in the stories that natural landscapes are able to tell.

Bernard Cooper

The two rock stacks north of Eysturoy – all that remains of two giant trolls.

Volcanoes, Forests and a New Ocean

The picturesque village of Fámjin is located on the western side of the southernmost island, Suðuroy. On the coast close to Fámjin is a high vertical cliff formed from the Beinisvørð Formation, which gives us a window into the early geological history of the Faroe Islands about 60 to 55 million years ago, when the opening of this part of the North Atlantic Ocean was in its infancy. At this time the land areas of what is now the Faroe Islands and eastern Greenland were still joined.

Volcanic eruptions developed along a long rift close to the present coast of east Greenland as the North American and

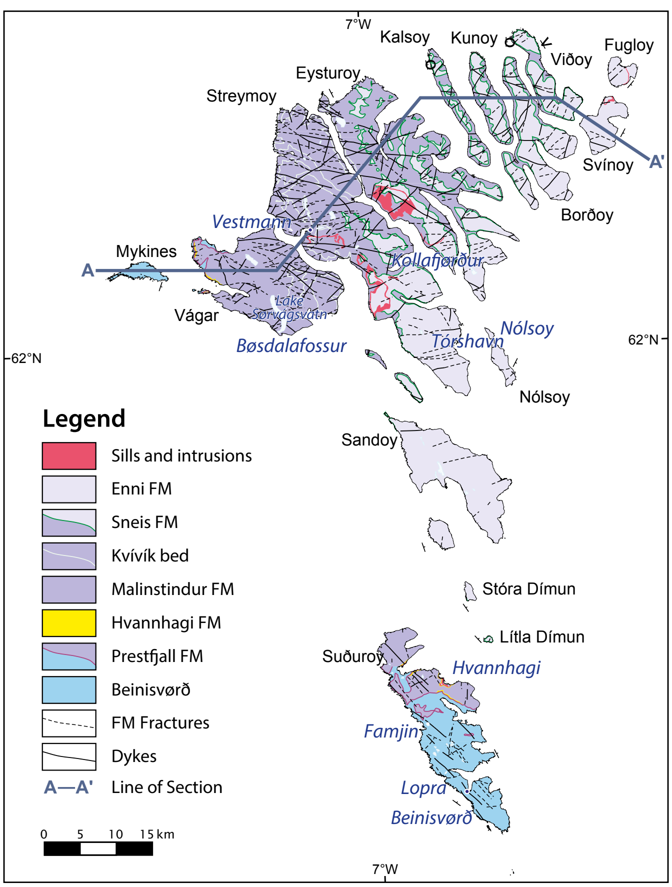
Øluva Eidesgaard

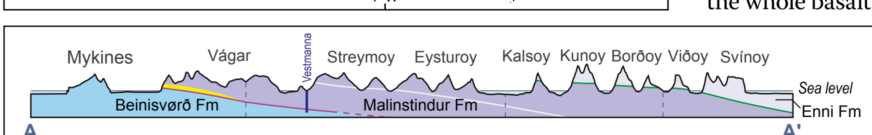
Eurasian plates began to drift apart. This type of volcanic activity is found all over the world where two tectonic plates move away from each other, but this time there was a difference. In one particular area along the new rift zone the flood basalt eruptions resulting from the volcanic activity reached an epic scale and huge amounts of basaltic magma poured out of volcanic rifts and flowed many tens of kilometres over the landscapes. The long parallel layers that we can see in the cliff at Fámjin are basaltic sheet flows, each horizon a former land surface showing how flat these vast volcanic fields were.

The cliff reveals the magnitude of the early basalt flow eruptions that formed the Faroe Islands. Basalt flows formed by volcanic eruptions during this late pre-breakup period elsehwere usually reach a thickness of 10 to 30m; the thickest basalt horizon found in the coastal cliff of Fámjin is 70m thick. Is it possible to even imagine the sheer scale of an eruption from a volcanic rift producing a lava stream of such magnitude which also covered a vast area of land?

The red sedimentary rock seen separating the basalt horizons in the cliffs at Fámjin shows that nature reverted to a subtropical climate during the pauses between volcanic eruptions. The barren lava fields were repeatedly transformed when soil developed in the ash-rich ground, and forests with metasequioa and other subtropical tree species colonised the flat landscapes. The cycle repeated itself with the next volcanic eruption when once again huge quantities of basaltic magma erupted from the rift zone and thick lava streams ran over the landscapes, burying the forests.

The majestic cliffs at Fámjin were built by a series of basalt flows in the Paleocene.





The Beinisvørð formation exemplified in the coastal cliff at Fámjin shows the character of the huge flood basalt eruptions in the period before the rift opened. After the opening there was a long pause in volcanic eruptions and the young Atlantic Ocean began flowing between Greenland and the Faroese land plateau. Subtropical forests took over the landscapes and thick layers of dead wood and other organic waste material built up in wet basins, eventually forming the coal of the Prestfjall Formation. Although the coal is not of the best quality, it was a valuable resource which was exploited for centuries and a coal mine is still open in Hvalba on Suðuroy today.

The Last Days of the Volcanoes

After a long pause, volcanic activity began again with a huge explosion, evidence for which can be observed in the Hvannhaga Formation, best seen in the beautiful valley of Hvannhagi, again on the island of Suðuroy. The volcanic eruptions continued with the build-up of the Malinstindur Formation, which comprises a continuous series of basalt eruptions with practically no breaks.

By this time the rift between Greenland and the Faroese land plateau had opened and a new mid ocean ridge began to take shape between the coasts of the two land areas. The twin landscapes of the Beinisvørð Formation in Greenland and the Faroese land plateau were separated forever.

Evidence of the effect of volcanic activity on the new low-lying land can be observed in the area around the village of Vestmanna on Streymoy, the largest of the northern group of islands. A boat ride to the majestic cliffs of Vestmannabjørgini on the west coast of Vestmanna allows a closer look at the volcanic eruptions which occurred in conjunction with the opening of a young world ocean. The eruptions were smaller than previously but much more frequent, with few pauses between them, so the whole basalt series of the Malinstindur Formation seems to be welded together without any weak sedimentary rock horizons.

The upper basalt series of the Faroe Islands is the Enni Formation, which was deposited when the volcanic eruptions once again changed character to somewhat larger flood basalt events. These basalt flows could reach a thickness of a few metres and are frequently separated by thin sedimentary rock horizons, which tells us that there were pauses between the volcanic events again, as the soil had time to develop and create the environment suitable for subtropical forests to colonise the flat landscapes.

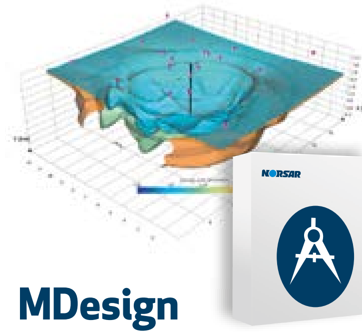
A good place to look at the last days of the volcanoes that built the Faroe Islands is on Nólsoy, a small island just to the east of the capital, Tórshavn. The basalt horizons are once again clearly visible, separated by soft reddish sedimentary rock horizons in the layered appearance of the mountains so characteristic of the Faroese landscape. East of the village of Nólsoy there is an interesting locality with a calling card from the subtropical forest: a horizontal hole in the shape of a large tree trunk, which is thought to have been caused when a tree was caught in a lava flow. Its foot would have caught fire so the whole tree fell and was consumed into the lava. The line of the tree probably points towards the flow (see photo following page).

Out of Fire, into Ice

The volcanic activity that built the Faroe Islands eventually died down as the part of the Eurasian plate with Faroese land area moved out of the active volcanic rift zone. Land construction was complete – and the destruction phase took over. At the same time the subtropical climate of the area gradually cooled over the next 40–50 million years, during of the Paleogene and Neogene Periods.

The waterfall at Bøsdalafossur, which drains Sørvágsvatn, seen on the front cover. For scale, note the people near the top of the waterfall.

Production enhancement



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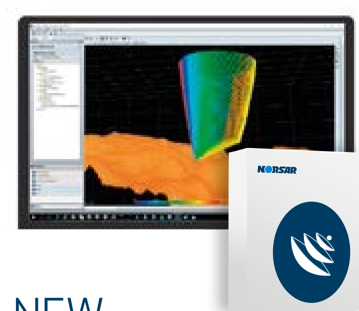

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The village of Nólsoy on the island of the same name.

The beginning of the Quaternary Period 2.6 million years ago brought severe climate fluctuations. The Earth experienced ice ages during which the middle to high latitudes were subjected to high arctic conditions, interspersed by shorter interglacial periods with warmer climates similar to those we are experiencing at the moment. In the Faroe Islands erosion during the ice ages completely transformed the scenery as the landscape of flat low relief suffered severe glacial erosion, which formed deep valleys, steep mountain slopes and narrow fjords and sounds.

A classic place to observe the severe transformation of the Faroese landscapes shaped by glacial erosion is along the high mountain road above Kollafjørður, about 20 km north of Tórshavn. Looking down the mountain slopes above the fjord we see the basalt layers on both sides of the fjord and, with some effort, we can pair the horizons across the fjord and realise how flat the landscape used to be. The glacial erosion during the quaternary period has irreversibly transformed the low relief area of Kollafjørður into a classic U-shaped valley with steep mountain slopes and a wide valley floor (see photo page 14).

Destruction by Ocean Breakers

Stories about gigantic volcanic eruptions and extensive glacial erosion are the geological heritage of the past. These are not active forces today, but are forever moulded into the landscapes of the Faroe Islands.

The most active force shaping the islands today is the ocean and the destruction of the coast by strong storm breakers. Every year the ocean eats into the land and the steep coastal cliffs facing the ocean pay the highest toll.

A breathtaking place to watch the erosion caused by the sea is near Bøsdalafossur waterfall at the end of Lake Sørvágsvatn on the western island of Vágar. The area around the lake is mild and friendly until the path brings you close to Bøsdalafossur, where the water suddenly drops into the sea via a 30m high waterfall. The whole area around the waterfall is a vertical cliff which is constantly shedding pieces of rock into the ocean below.

The Faroe Islands may not last forever and we can let a place like Bøsdalafossur remind us of the importance of enjoying and caring for nature as it steadily changes around us. ■

A hole in the basalt left after a tree caught in the lava flow burned away but cooled the hot lava so much that it solidified, leaving the shape of the burned tree forever frozen into the basalt. Note the layer of red sediment beneath the lava.

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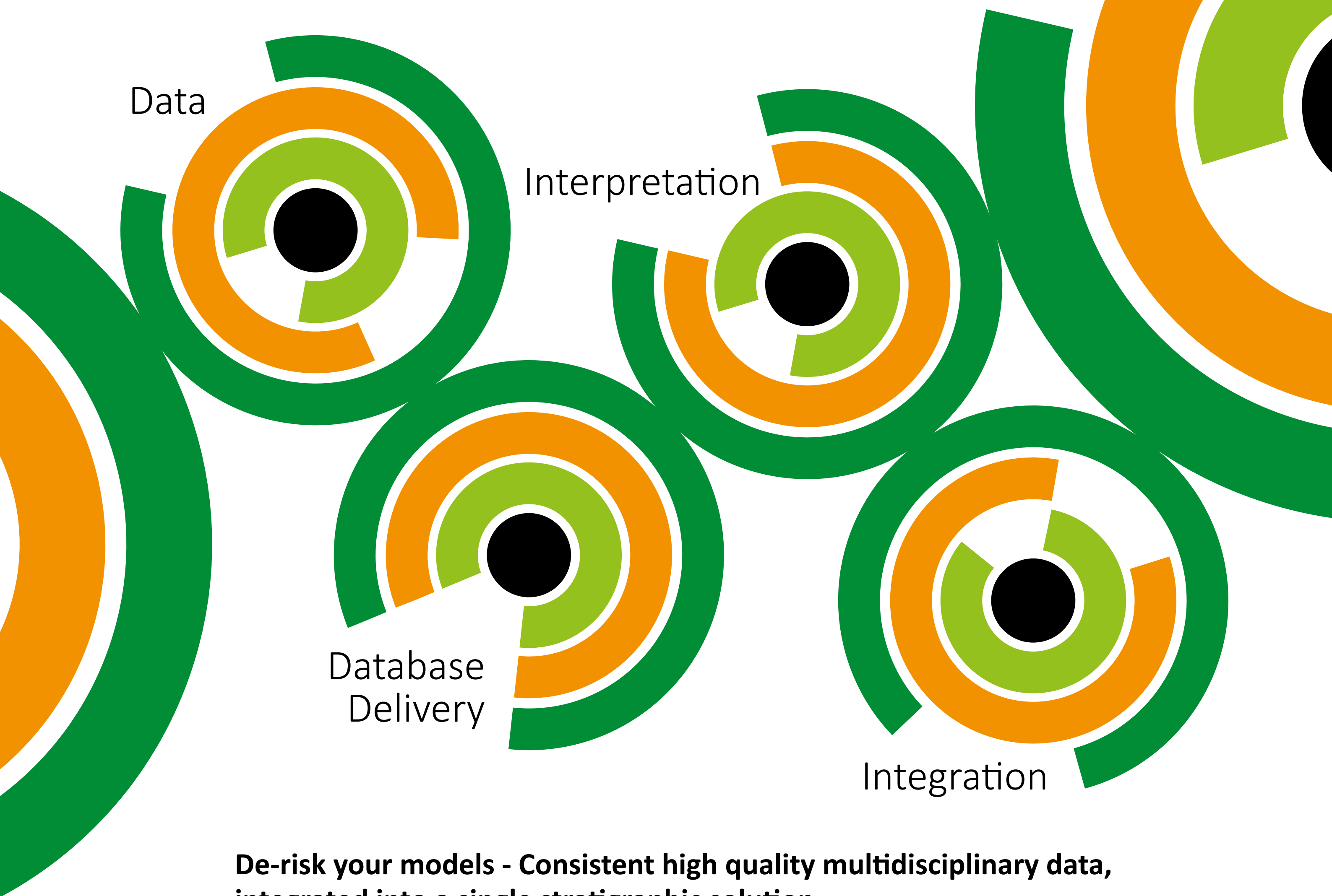

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Brazil is Back in the Game

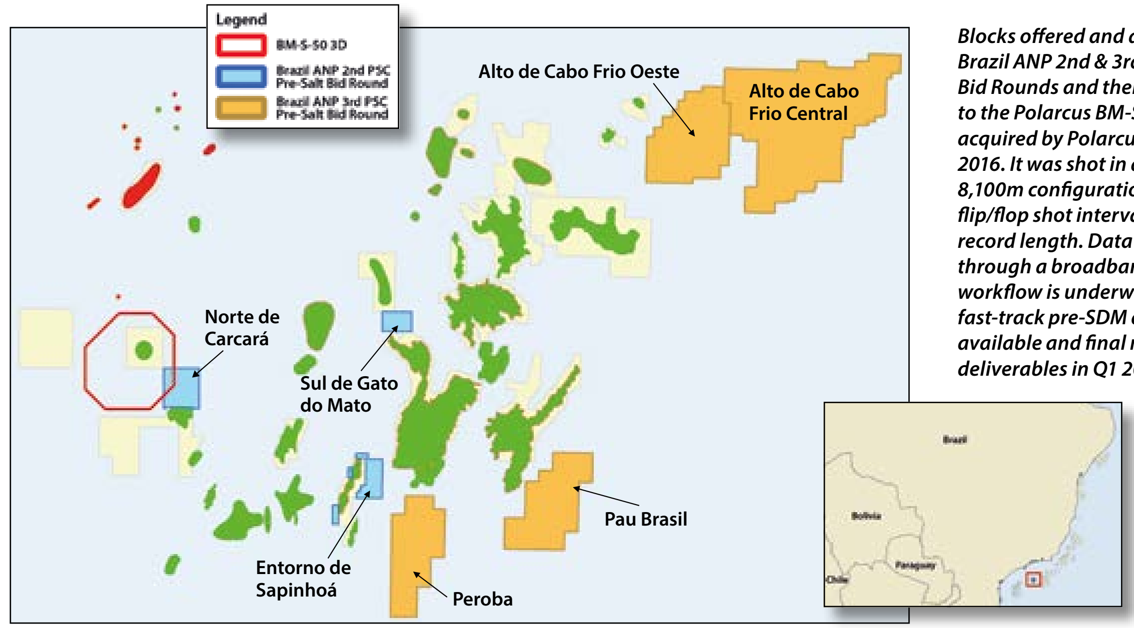
Polarcus brings innovative imaging to the pre-salt in Brazil.

Polarcus BM-S-50 3DMC multi-azimuth survey reveals detailed and complex faulting patterns of the pre-salt section – with direct implications on migration pathways, reservoir development and trapping mechanisms.

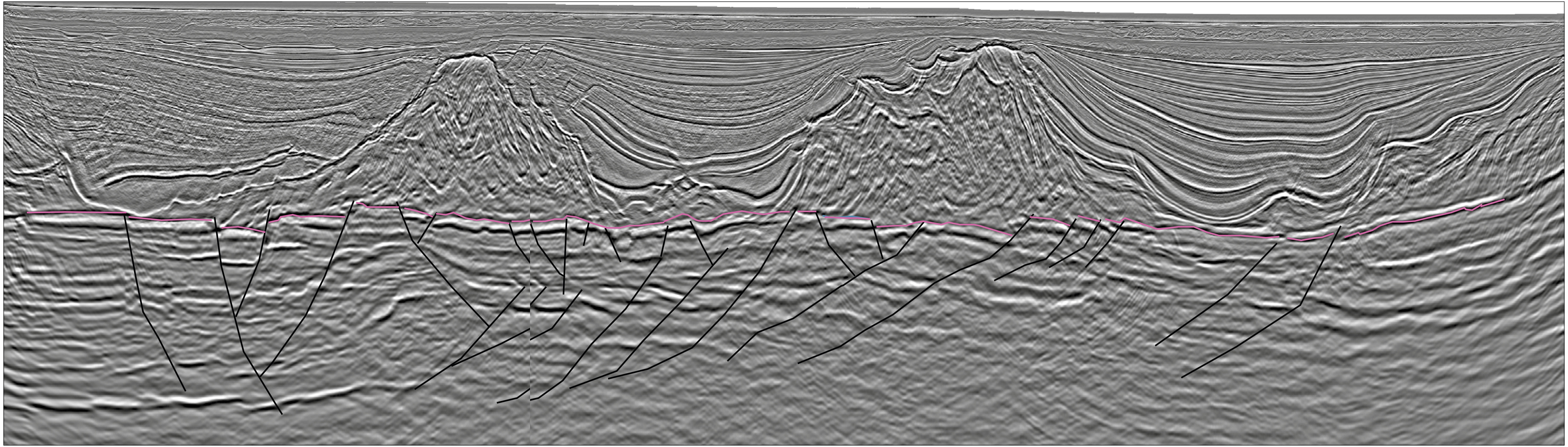
On Friday 27 of October, the results of the 2nd and 3rd Production Sharing Round (PSR) were announced, with six out of eight blocks on offer being awarded. The big winners in the 3rd PSR include CNOOC (20%) and BP (40%), who will join forces with the operator Petrobras (40%) in the Peroba Block. Alto de Cabo Frio Oeste will be operated by Shell (55%), with CNOOC (20%) and Qatar Petroleum (25%) as partners; whereas in the Alto de Cabo Frio Central Petrobras and BP will split a 50% stake. In the so-called Unitisation (2nd) Round, a consortium of Shell and Total obtained the Sul de Gato do Mato block, while Petrobras, Shell and Repsol Sinopec were awarded Entorno de Sapinhoá. The joint venture between Shell (40%), ExxonMobil (40%) and Petrogal (20%) obtained the very prospective Norte de Carcará block, which is in close proximity to the Polarcus BM-S-50 3D multi-client survey. The latter deal also includes the formal announcement of Exxon as a new partner in BM-S-8, where the Carcará discovery is located.

The Polarcus BM-S-50 survey will be able to provide clients with unique imaging of the pre-salt section, and enable seismic explorers to evaluate the hydrocarbon potential in this prolific but highly complex geological setting in the Santos Basin. With a multi-azimuth solution, Polarcus is now delivering high quality post- and pre-salt data with sharp fault definition in the pre-salt which is crucial to understand the petroleum system of both pre-rift and rifting sequences.

Polarcus®



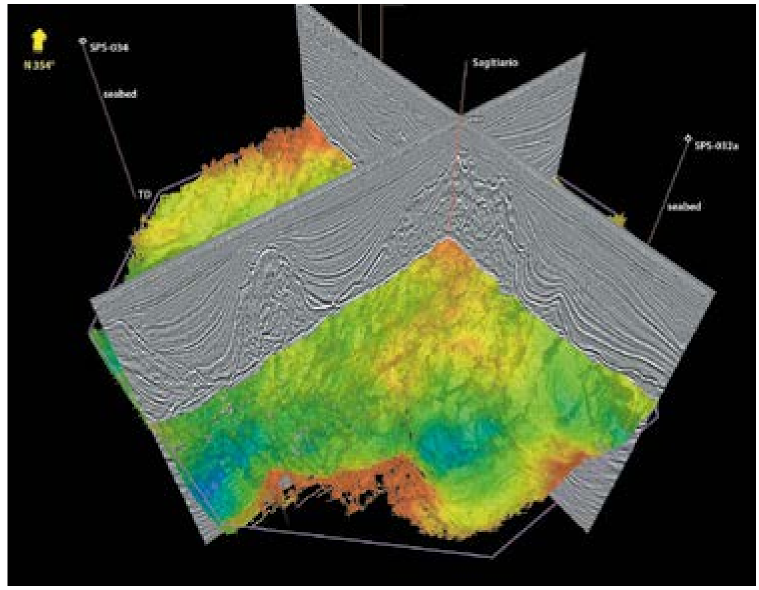
Blocks offered and awarded in the Brazil ANP 2nd & 3rd PSC Pre-Salt Bid Rounds and their proximity to the Polarcus BM-S-50 survey, acquired by Polarcus Adira in 2016. It was shot in a 12 x 75m x 8,100m configuration, with 25m flip/flop shot interval and 10.5s record length. Data processing through a broadband pre-SDM workflow is underway, with fast-track pre-SDM data already available and final multi-azimuth deliverables in Q1 2018.



New Lights on Santos

The prolific pre-salt province in the Santos Basin offshore Brazil is experiencing a renewed hydrocarbons boom. With recent regulatory changes, the ANP has managed to attract some of the heavyweights of the industry, this time to operate and cooperate with the Brazilian national oil company, Petrobras.

DAVID CONTRERAS DIAZ, Polarcus



3D visualisation of target Base of Salt within the BM-S-50 survey.

Geology Always Comes First

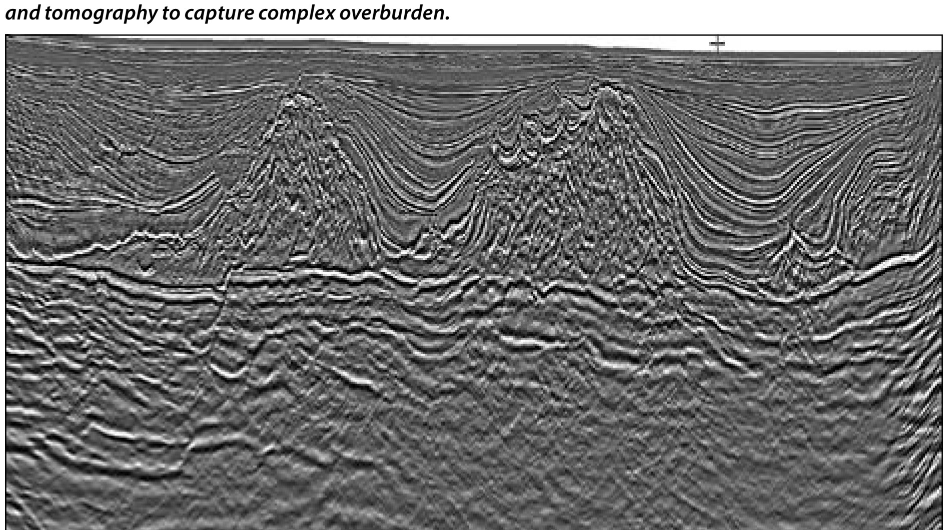
The Santos Basin needs no introduction. The prolific pre-salt carbonate reservoirs have been on the radar of seasoned seismic explorers around the world ever since Petrobras' discovery of the Tupi field in 2006 (now named Lula after the former Brazilian president). This is unsurprising given its risked recoverable resource of 50 Bboe and its impressive 1.5 MMbopd production reached during the summer of last year.

Optimising the region's potential, Polarcus is very pleased to offer its 1,600 km^2 BM-S-50 3DMC multi-azimuth survey for licence, which was acquired with a 12 x 75m x 8,100m configuration, 25m flip/flop shot interval and 10.5s record length. The survey is in the heart of the pre-salt, covering the block where Petrobras' 2013 Sagitario discovery well (1-SPS-98) found a 159m light oil (32° API) column in carbonate reservoirs with excellent poroperm properties. Besides the prolific microbialite carbonates in the Sagitario section, identified in large structural features, there is strong potential in the post-salt sequence, with structural carbonate prospects (Albian limestones) or deep-water clastic plays in the Upper Cretaceous to Lower Tertiary, with a possible combination of structural and stratigraphic trapping. Polarcus' pre-STM data is already available, enabling explorers to map the highly complex structural nature of the pre-salt in extensive detail. Pre-SDM deliverables will be available in Q1 2018.

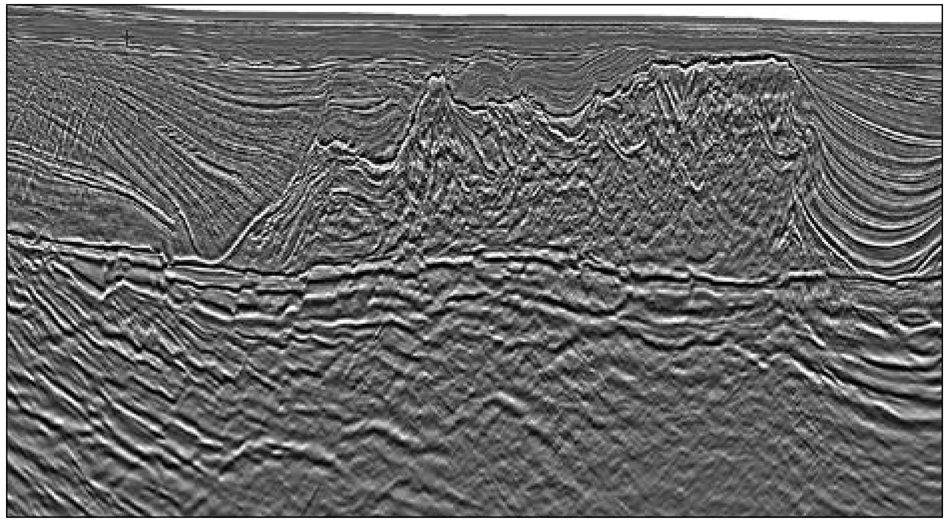
This survey is of particular interest because of its proximity to the nearby Carcará discovery in BM-S-8, where Statoil acquired operatorship from Petrobras through a $2.5 billion transaction for a 66% stake in the block. The Norwegian company paid half of the amount on completion of the transaction and the remaining half will be paid after certain milestones, mainly related to the unitisation of the Norte del Carcará extension of the discovery. In August 2017, Statoil increased its stake in BM-S-8 by acquiring 10% from Queiroz Galvão (QGEP) for $379 million. As a result, the remaining partners in the licence are Petrogal Brasil (14%) and Barra Energia (10%). More recently Statoil, joined by ExxonMobil and Petrogal, secured the Norte de Carcará area in the recent awards of the 3rd Pre-Salt Unitisation Round in the auction on 27 October.

Other companies have been working hard to

Complex halokynesis requires innovative geophysical solutions, multi-azimuth in the acquisition side and tomography to capture complex overburden.



secure both volumes and high productivity wells in key fields in the Santos Basin, confirming the resilience of deep water exploration in the world's key oil provinces.



Unique imaging in the Santos Basin resolves the complexities of the rift and pre-rift sections of the pre-salt.

Attracting Foreign Investment

Brazil has adapted quickly to the reality of the prolonged downturn. The country's National Petroleum Agency (ANP) has implemented regulatory changes such as the reduction of local content rules, which currently stand at 18% for exploration activities, as well as allowing foreign companies to operate in the pre-salt. It has an ambitious licence round schedule comprising up to ten bid rounds within the next three years. These changes offer attractive incentives to the oil industry, making it easier for offshore Brazil to compete for exploration dollars against the US unconventional market.

In addition, the ANP is establishing a direct negotiation licensing policy, whereby areas that have been relinquished (or previously approved by the CNPE) would be in permanent offer to the industry. The ANP estimates that hundreds of areas will be offered again to the market, starting in 2018.

The first test on the effectiveness of these changes came last September with the block awards of the highly anticipated 14th Brazilian Round. ExxonMobil, with Petrobras as partner in some of the blocks, committed $1.2 billion in signature bonuses to secure a cluster of blocks in the Campos and Espirito Santo Basins and also in the Sergipe Alagoas Basin, where the supermajor will be partnering with local explorer QGEP, together with American independent, Murphy, a newcomer to the Brazilian offshore.

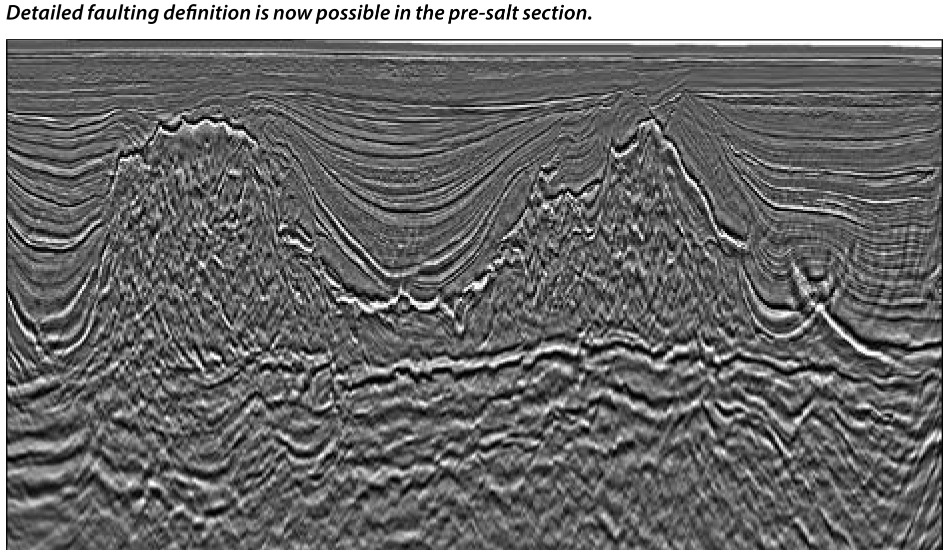
It is thus not surprising that the 2nd and 3rd Production Sharing Bidding Rounds were in the spotlight, with the pre-salt area in the Santos expected to be fully contested. The 2nd Production Sharing Round (also known as the 'Unitisation Round') offered the Gato do Mato, Carcará, Sapinhoá and Tartaruga Verde areas. This round was characterised by near-field exploration opportunities and nearby existing discoveries or production fields. The 3rd Production Sharing Round offered Peroba, Pau Brasil, Alto de Cabo Frio Oeste and Alto de Cabo Frio Central in areas of higher risk but also arguably higher potential reward. The round was an uncontested success, with ANP awarding six of the eight blocks on offer with a combined $1.88 billion in signature bonuses.

Unique Imaging of the Pre-Salt

Polarcus' BM-S-50 survey allows new ventures teams to assess the petroleum system and upside potential of the pre-salt, not only of the Sagitario discovery (pictured above) but also of the entire carbonate play fairway near the Carcará discovery. The complex faulting in this area is finally imaged properly by the multi-azimuth acquisition solution (see below). By rigorous velocity modelling of the post-salt (with six tomography passes), the interpretation of the main reservoir interval underneath the salt is highly enhanced, as shown in the pre-SDM figure on the facing page. Polarcus' dataset is an excellent tool to improve the regional understanding of this highly prospective area. To organise a data viewing, please email mc@polarcus.com.

Polarcus' multi-client team will continue to monitor the development of current and future rounds, and is busy putting together new surveys that will provide the industry with unique geophysical solutions to image the pre-salt in the prolific Santos Basin. Watch this space! ■

Detailed faulting definition is now possible in the pre-salt section.



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TopSeis is a radically new solution for seismic acquisition and imaging, developed through collaboration between an oil company and the service sector.

JANE WHALEY

"Good things can come out of a downturn, despite what you might expect. Sometimes it can encourage creative sparks that help solve a problem. I think TopSeis™ is a good example of this; we probably would not have had the time to develop this ground-breaking technology in the boom times."

Vetle Vinje is Principal Research Geophysicist at CGG Subsurface Imaging and the project he is talking about is an innovative new concept in seismic acquisition and imaging, the result of several years of collaboration between the geoscience company, CGG, and oil company, Lundin Norway AS.

"Lundin Norway has substantial acreage in the Barents Sea in the Norwegian Arctic. After a number of years exploring in the area it became apparent that there are serious issues with seismic imaging over some of the prospective areas in the region," Vetle explains. "The main reservoir rocks in the Loppa High, for example, are shallow karstified carbonates located between 400 and 1,600m below the seabed, which is itself unusually hard and reflective in this area. The result is poor imaging of these shallow reservoirs."

Source Over Streamer? Never!

Lundin Norway approached a number of seismic companies in an attempt to find a solution to this imaging challenge, and in 2015 began working on a detailed solution with CGG, with whom it had previously collaborated on several technology projects. The challenge was to improve imaging of shallow and intermediate-depth targets by overcoming the fact that conventional towed-streamer seismic lacks the near-offset data (the reflections recorded when the source and hydrophones are close together) which are crucial for illuminating such areas. Together, the companies came up with a revolutionary – and initially very controversial – new idea.

"As we all know, in conventional seismic acquisition a single vessel tows both the source and the streamer," Vetle

In the revolutionary TopSeis acquisition method the seismic sources are deployed over the streamer spread to make use of the full range of reflections. In this first full-scale acquisition in the Barents Sea, photographed using drone technology, the sources are positioned directly over the streamer spread, which is being towed by the streamer vessel several kilometres in front. The deep 'banana-shaped' configuration of the streamer ensures notch diversity, enabling robust processing-based deghosting.

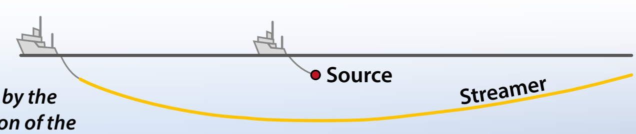
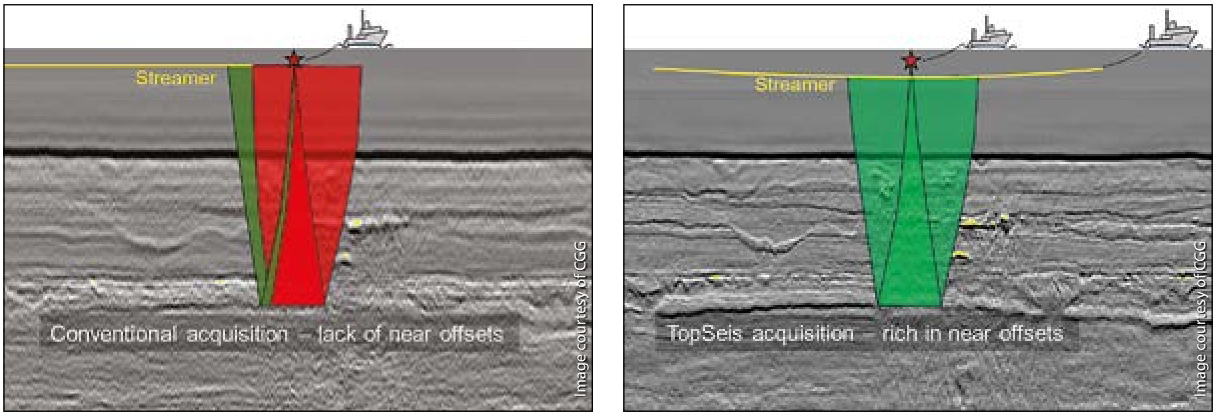


Image courtesy of CGG



Schematic comparison of conventional and TopSeis configuration.

explains. "This means that much of the source energy is directed forward and is not recorded. In addition, with shallow targets only the nearest offsets contribute to subsurface imaging as reflections soon approach the critical angle and are lost.

"To resolve this issue we proposed towing the sources from a second vessel positioned above the middle of the streamer spread, thus eliminating the near- and zero-offset problem and also reducing 'tug and flow' noise found on the hydrophones close to the streamer vessel. Of course, this idea was controversial; the potential risk to the source vessel if one of the streamers were to rise towards the surface and get entangled with it is not inconsiderable. But in CGG we have been perfecting the art of deep-towing our streamers for a number of years with our earlier step-change seismic acquisition solution, BroadSeis™, where the streamers, which come from the robust and proven Sercel Sentinel® solid streamer family, are towed up to 50m below the sea surface. We were confident that this would prove to be safe, but needed to show that the whole system worked and that we would see the required improvement in imaging."

Modelling and Field Testing

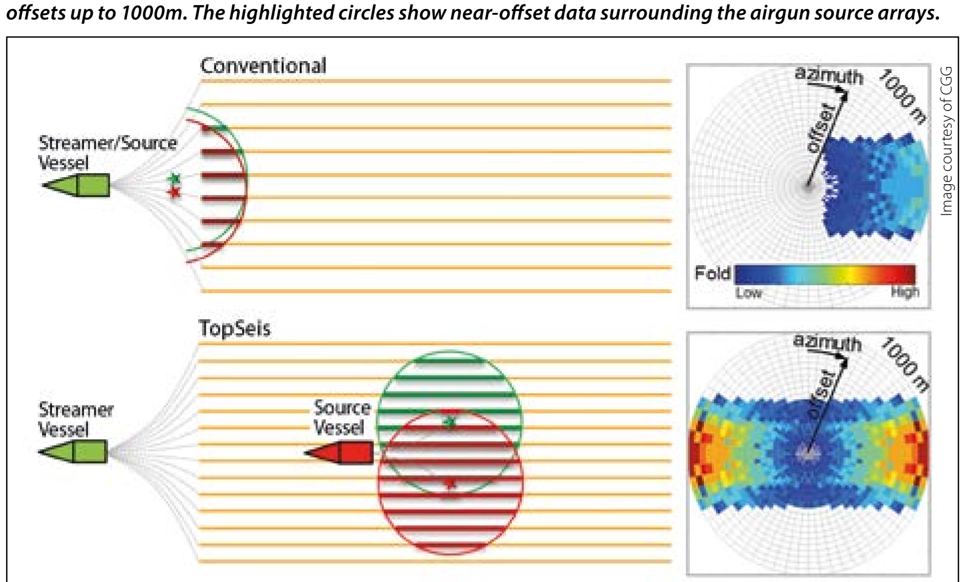
"First of all we undertook a lot of synthetic modelling to derive the optimum configurations for specific targets and to develop methods to deploy these configurations safely; this is why I got involved, as modelling and seismic processing are my areas of expertise," Vetle continues. "We spent two years working on the modelling, finding the best positions for the source vessel, how far apart the sources should be and the ideal horizontal streamer separation distance for specific targets. Synthetic seismic data from a series of acquisition designs with real noise added were fed into our 3D seismic processing and imaging workflows to determine the optimal processing criteria.

"Our modelling confirmed that by positioning the sources further apart than usual, to ensure more uniform shot spacing in the crossline direction, and several kilometres behind the streamer vessel, we could achieve zero offsets with a semi-wide azimuth coverage. In the models this led to enhanced resolution and improved signal to noise ratio owing to the superior illumination density when compared to conventionally acquired seismic, especially with shallow targets."

Having confirmed that in theory the new acquisition system would achieve the main objectives, by late 2015 the companies were ready to undertake field tests to ensure that all the practical aspects of the acquisition would work. These included, crucially, safety, to confirm that towing the source above the streamers posed no risk, and also navigation and vessel manoeuvring and equipment durability, as well as actual data processing and imaging. In March 2016 a single test line was shot off Gabon in West Africa, followed by a 3D test over the Frigg-Gamma structure in the North Sea in June the same year.

"The results from just the single line in Gabon immediately demonstrated a significant improvement in imaging when compared to a conventionally acquired broadband line shot over the same area," says Vetle. "The conventional shot gather contains offsets from 150 to 3,000m, while the split-spread TopSeis shot gather contains offsets between -3,000 to

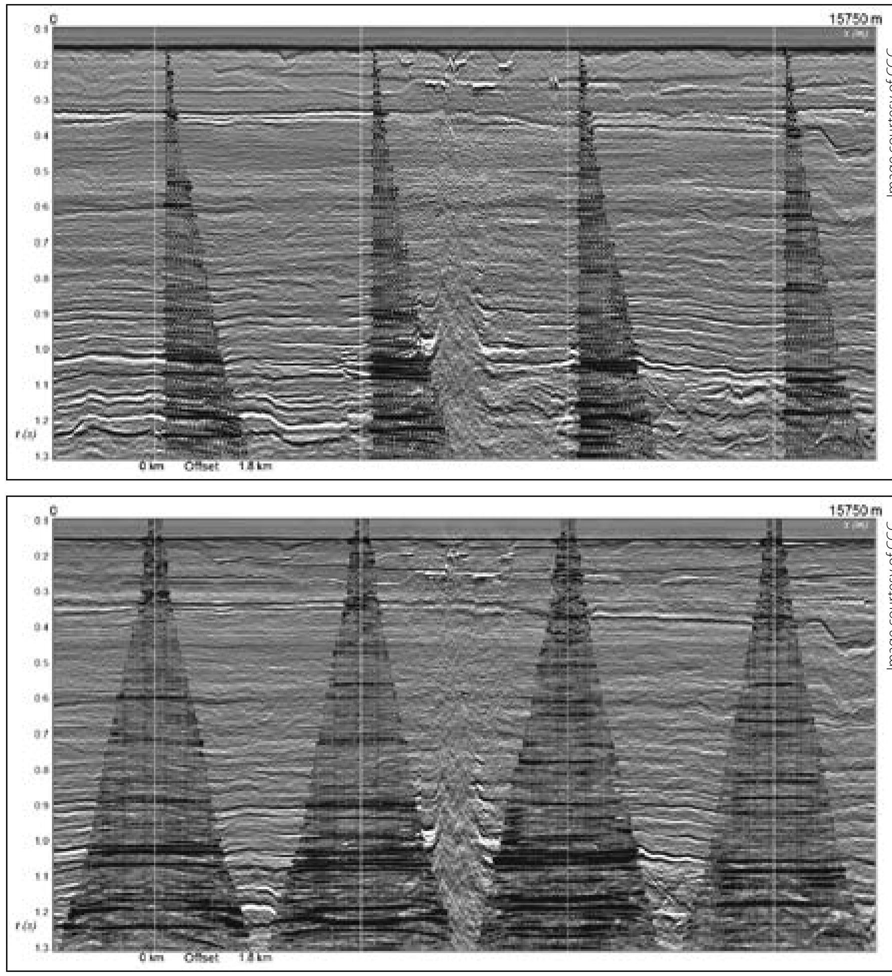
Conventional and TopSeis marine acquisition layouts with corresponding offset/azimuth rose plots with offsets up to 1000m. The highlighted circles show near-offset data surrounding the airgun source arrays.



3,000m; the presence of the zero and negative offsets is very useful in processing, particularly for removing multiples and imaging. We had been worried about the effect of the impact of the downgoing seismic waves hitting the cables, since they were closer than usual, but discovered that while the hydrophone recorded an immediate 'shock', it soon settled back, and we were able to develop the processing to eliminate this and associated ghost effects."

The Frigg area was chosen for the 3D trial because it is known to present imaging challenges due to the presence of leaked hydrocarbons in the shallowest 2,000m – plus a conventional 3D survey over the area was scheduled a month later as part of CGG's multi-client programme, so it would be possible to make comparisons between the two. The two datasets went through the same processing workflow, including basic denoising, source designature, receiver deghosting, demultiple, regularisation/binning and prestack time migration in a simple isotropic velocity model, with additional processing to eliminate direct wave and similar issues in the TopSeis data.

Vetle says, "The TopSeis results clearly showed much better imaging of subtle shallow features such as post-glacial channels and basins, gas pockets and pockmarks along the water bottom, as well as improved signal to noise ratio."



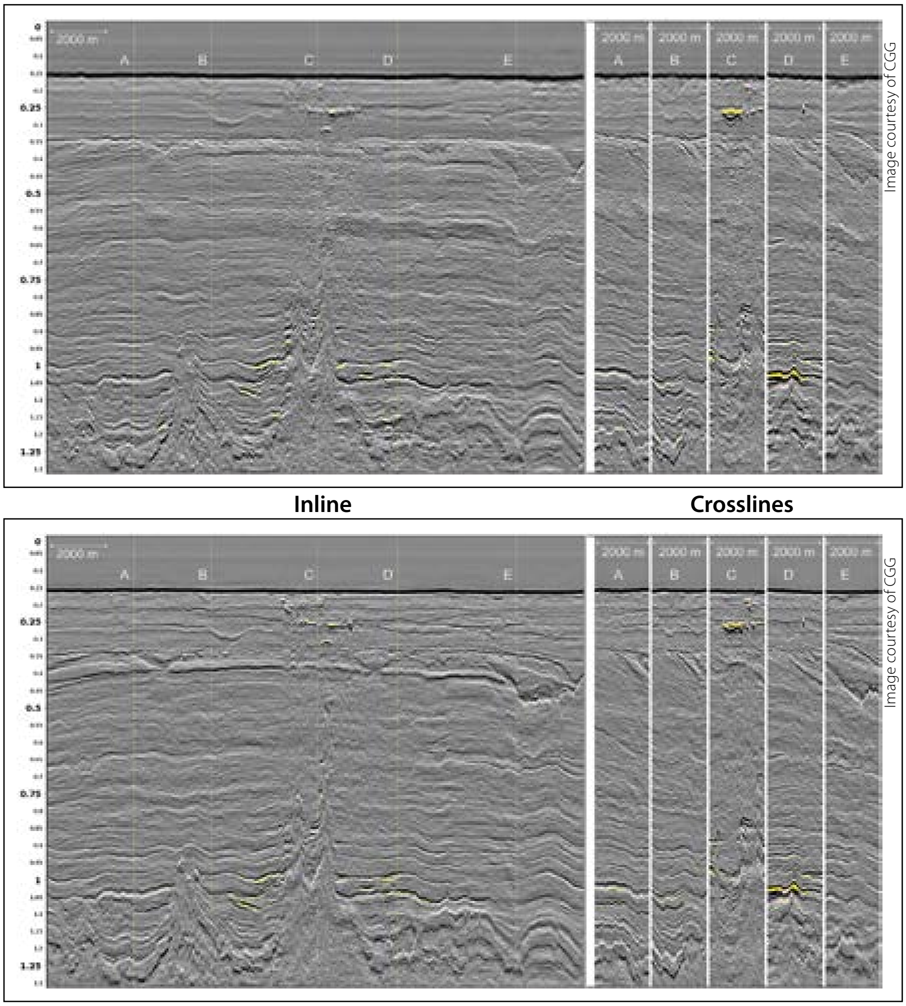
Comparison of stacks and four image gathers for conventional acquisition (top) and TopSeis (bottom), illustrating the considerably increased range of data available in the latter.

First Commercial Survey

Finally, having proved beyond doubt that this revolutionary new acquisition concept could enhance the imaging of shallow and intermediate reservoirs, Lundin Norway was ready to take it live with the first full-scale commercial TopSeis survey. With Lundin Norway's partners on the Barents Sea acreage, a 1,950 km^2 survey over the Alta Gohta discoveries on the Loppa High was undertaken between July and September this year. The final results are due in summer 2018 but already it is clear that the imaging issues, particularly with regard to the shallow carbonate reservoir in the Loppa High, have been successfully addressed.

"We were all very pleased with the early results," Vetle says. "Not only did the records demonstrate a step-change in the imaging of shallow to intermediate depth targets in comparison to conventional surveys in the area, but the water-bottom image was also very good, clearly showing the hard, iceberg-scoured nature of the seabed. These images were comparable to those normally obtained from

Lundin actively participated in the TopSeis development every step of the way. Their management team and key project contributors visited the Geo Coral during the TopSeis survey in the Barents Sea this summer. (Left to right): CEO of CGG Jean-Georges Malcor with the Lundin Norway delegation: Halvor Jahre (Exploration Manager), Jan Erik Lie (Chief Geophysicist), Kristin Færøvik (Managing Director), Per Eivind Dhelie (Senior Geophysicist) and Vidar Danielsen (Senior Geophysicist).



Dense and uniform crossline shot sampling is important for 3D seismic resolution within the shallow section. A comparison between the conventional (top) and TopSeis (bottom) records for an inline and five crosslines show significant improvement with the new method.

traditional multi-beam sonar.

“What’s more, less infill than usual was required and, because of the deep towed streamers, the system is more robust and tolerates higher sea states. The project came in on time and on budget, with hardly any technical downtime and no HSE incidents: an undoubted success.

“This means that, despite requiring two vessels, TopSeis is a very cost-effective seismic acquisition method, particularly when compared to an ocean-bottom survey, which is the only other way to acquire marine zero-offset data,” Vetle points out. “The technology is also ideal for areas other than the Barents Sea. Since the improved imaging and reservoir analysis is evident from about 3,000m depth right up to the seabed, it would be useful, for example, over much of the North Sea, since many of the fields are at about that level. It is also an ideal tool for identifying shallow gas pockets and other hazards.

“The huge improvement in data quality and quantitative depiction of the reservoirs is the ultimate prize; a dry well is very expensive, so anything which gives our clients increased knowledge of the subsurface is important.”

Significant Collaboration

Vetle is very keen to point out that this major development in seismic acquisition and imaging is the result of a significant and effective collaborative effort by the 100-strong multidisciplinary team from Lundin Norway and CGG. In the case of the latter this included CGG and Sercel experts in equipment, marine acquisition and geoscience based in Norway, France, the UK and the US. As he says: “This is the way ahead; oil companies with a challenge need service companies with skills and creativity so they can work together to find solutions. This requires a lot of trust between the parties, and it probably helped in this case that the Lundin Norway and CGG offices that were leading the research in Oslo were physically very close, so if we had a question or an idea, we could just pop round and see our colleagues in the other company. Having collaborated with Lundin Norway on a number of projects previously, we knew we could have a successful partnership.

“So much of this project required new thinking,” says Vetle, “from spec’ing to modelling; reviewing sources and how to tow them; navigation issues; HSE; even insurance questions. It was a huge collaborative effort. Now we are keeping our fingers crossed for the discovery which will reward all our work and belief in TopSeis.” ■

The TopSeis team won CGG’s inhouse technology award for 2017 for their work on TopSeis and celebrated by inviting everyone based in Oslo who had worked on the project to share the prize money with a meal out together.

3D Printing

A Dip Into an Evolving Technology

LAWRENCE PIDSLEY

> *"The whole nature of trade, the whole nature of supply chain, changes fundamentally. I do not need to ship goods from one part of the world to another, I print it."*
>
> *Dale Spencer, January 2017*

This vision of the effects of additive manufacturing – or 3D printing – was espoused by Dale Spencer, chief economist at BP, when speaking at the launch of the company's annual long-term forecast in January.

Dale has a vision which could be transformative for the oil industry, and in this article I would like to focus on how 3D printing may help upstream oil exploration. Sitting in front of our work stations, reviewing and interpreting data in three dimensions, may lull us into a false sense of security, because we are really only seeing it in two dimensions. Are we missing a visualisation tool which could aid comprehension and move a prospect from the screen to reality? I will discuss the process of cognition, and give examples in other disciplines, like architecture, medicine and design, where 3D printing has helped understanding, before finally hypothesising on how 3D printing may help in our field.

Cognition

The brain has evolved over millions of years to understand things in three dimensions. Our language also reflects the three-dimensional tactile nature of cognition; for example, the verb 'to grasp' is often used when understanding a concept, but it is normally used for an action on a tangible solid object. This concept, that the brain most easily understands three-dimensional images, has been recognised by model makers for centuries, as they convert terrain maps into models, which, although a labour intensive process, removes a

Mia Gonzales with a 3D-printed model of her heart.

Stratasys/Incus Media

major cognition process for the observer trying to visualise contours as terrain, and allows the brain to focus on processing the more subtle information displayed. An example of how 3D printing is helping to overcome this hurdle can be seen in the 3D model (right), which shows the fortifications in the Valais region of Switzerland. It was commissioned by the museum at Naters in Switzerland to illustrate how the defensive positions were chosen with great care to make use of the terrain, to not only be impregnable but also control access to trade routes.

3D model of fortifications in the Valais region of Switzerland, built at a scale of 1:45,000.

3D Printing in Action

Unsurprisingly, one of the first professions to embrace the process of 3D printing was architecture, and the advantages of converting virtual plans and images from the desk top to reality quickly became apparent. For example, 3D printing of the Victoria underground station refurbishment for Transport for London allowed the complex system of tunnels, escalators, utilities etc. to be visualised and shared with all the stakeholders in the project. Closer to home, a 1:100 scale model of the Ivar Aasen platform, over two metres in height, can be seen in the reception area of the Aker BP offices in Trondheim , Norway.

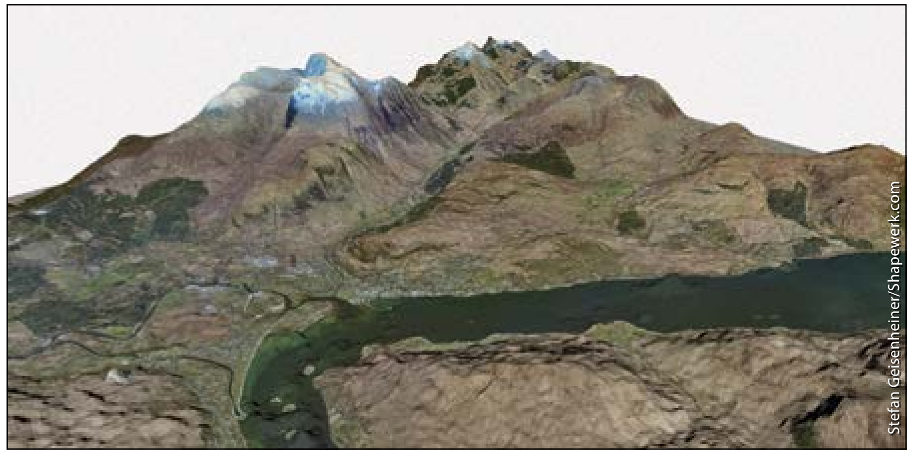
Another example where 3D printing is key in aiding cognition, and in fact acts as a life saver, is in medicine. Printing models of the heart before an operation allows the entire surgical procedure to be planned and reviewed before the operation, which can significantly reduce the time required to perform long and complicated surgery, and often eliminates unexpected complications and surprises. Five-year-old Mia Gonzales, seen in the opening photograph, suffered from a rare heart malformation: a double aortic arch, a condition in which a vascular ring wraps around either the trachea or oesophagus, restricting airflow, leaving her constantly tired and very sickly. The lead surgeon for Mia's operation, Dr Redmond Burke, said: "By making a 3D model of her very complex aortic arch vessels we were able to further visualise which part of her arch should be divided to achieve the best physiological result. … without the model, I would have been less certain about [operating on Mia] and that would have led me naturally to make a larger incision that

APWorks Light Rider motorcycle: 3D printed aluminium frame, 6 kw electric motor, total weight 35 kg.

Stratasys VeroFlex Rapid Prototyping Eyewear Solution.

could possibly cause more pain and a longer recovery time," adding: "using the model, there was no doubt, and surgeons hate doubt."

Before commencing production of any product, customer evaluation and engineering prototypes are needed in order to bring a product seen on a flat Computer Aided Design (CAD) screen to life. From glasses to motorbikes, 3D printed prototypes let one assess the look and feel of the product. The technique also permits rapid prototyping, allowing the functionality of a design to be tested, changed and re-tested in a short space of time and at much less expense when compared to traditional methods. An example of how revolutionary embracing 3D printing in design can be is a new civilian turboprop engine being developed by GE. The redesign reduces 855 separate parts down to just 12, with over a third of the engine 3D printed. The first test flight is scheduled for late 2018.



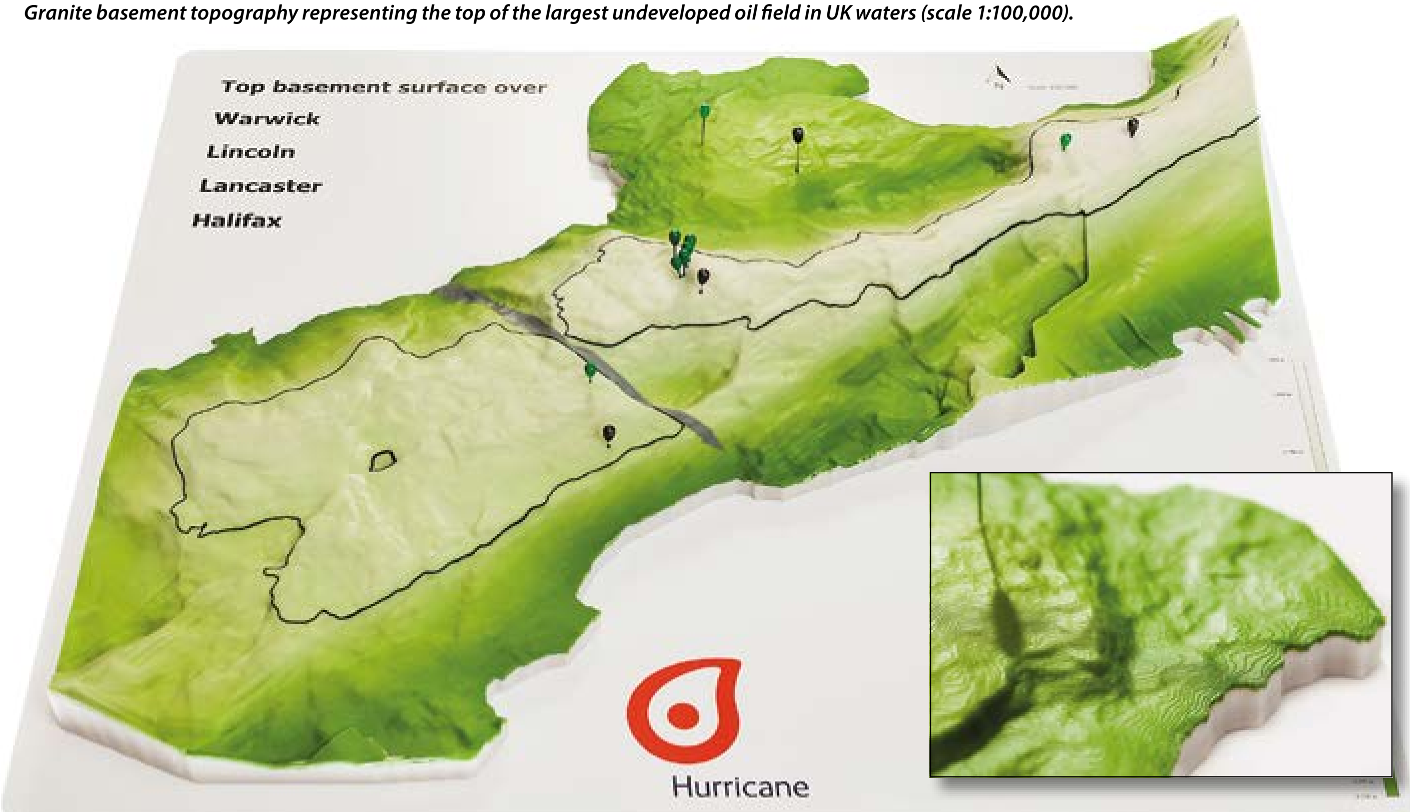
Screen capture of 3D rendered image from north-west Scotland, showing Loch Linnhe and Fort William with Aonach Mor, Ben Nevis and the Mamores in the background.

3D Printing and Oil Exploration

3D visualisation to aid comprehension of the subsurface is not new. In the late 1980s and 1990s visualisation centres with 3D glasses were all the rage in the exploration industry, and in more general use 3D films and televisions using similar technology took off in the noughties, but these failed to connect with the viewer and have faded. What has been missing is an emotional, tangible connection, so I have teamed up with a German company, Shapewerk, to see what can be offered. The company specialises in converting terrain data into 3D models with satellite imagery superimposed, and hence is well placed to expand into making geological models which require a similar skill set. To show what Shapewerk can do, have you a favourite mountain range, island or perhaps just your local area you would like to see as a 3D model? Shapewerk allows you to select on a 2D map any location on earth and within five minutes a fully rendered 3D image will be available to review on your computer, on top of which can be projected a satellite image, as in the example above. This process is free of charge, allowing exploration of any area of interest.

The first oil-focused 3D printed model using Shapewerk technology is a

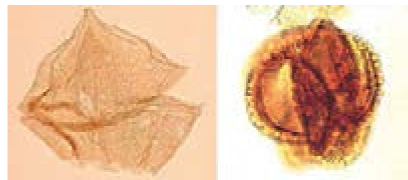
Granite basement topography representing the top of the largest undeveloped oil field in UK waters (scale 1:100,000).

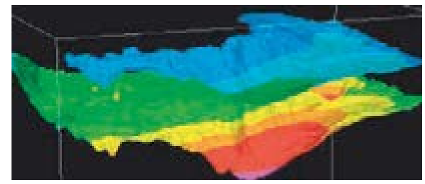


APPLIED PETROLEUM TECHNOLOGY

Our scientific staff cover a wide range of expertise gained from many parts of the globe, dealing with many and varied projects. The unique combination of in-house geological services and a staff boasting extensive offshore and oil company experience provides a competitive edge ito our services. We offer complete services within the disciplines of Petroleum Geochemistry, Biostratigraphy and Petroleum Systems Analysis, and our customers expect high standards of quality in both analysis and reporting.

High quality analyses and consulting services to the oil industry





Geochemistry services

In addition to providing a full range of geochemical analyses of unsurpassed quality analysis, APT also offers insightful and tailor-made interpretation, integrated data reporting, and basin modelling and consulting services. We pride ourselves on quality and flexibility, and perform analyses and report results to our clients' specifications.

Biostratigraphic analysis and services

APT delivers a full range of biostratigraphic services, ranging from single well reports and reviews of existing data to full-scale field or basin-wide evaluations. We take no established truths for granted, and we turn every stone in the attempt to bring the stratigraphic knowledge a few steps forward.

Petroleum systems analysis

APT has gained extensive experience in Petroleum Systems Analysis using the "PetroMod" suite of programs. Projects range from simple 1d modeling of a set of wells to complicated 3D models with maturation, kinetics, generation, expulsion, and migration and accumulation issues to be resolved or predicted.

Geochemistry services
- Analytical services
- Reporting
- Interpretation
- Exploration Solutions
- Petroleum consulting services

Biostratigraphy
- 24 hours Hot Shot analysis
- Routine biostratigraphy
- Well-site biostratigraphy

Petroleum System Analysis
- Analysis
- Interpretation
- Data Reporting
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www.aptec.no

APT Group- Head Office Norway
nm@aptec.no

APT (UK) Ltd
patrick.barnard@aptuk.co.uk

APT (Canada) Ltd
mf@aptec.ca

model of the top reservoir for Hurricane Oil's Warwick, Lincoln, Lancaster and Halifax fields, printed in full colour, showing the oil water contact (OWC), controlling fault and well locations. Clare Slightam, Hurricane's Subsurface Technical Director, was very pleased with the resulting model. She said, "We intend to use our 3D model at meetings involving non-technical people such as potential investors," adding, "for a non-geologist who is not used to working with maps on a regular basis, a 3D representation is a valuable way of helping to picture a geological setting." The model was printed to an accuracy of 0.1 x 0.1 x 0.1mm using an x, y, z input dataset on a 25 x 25 x 1m grid.

The ability to print in full colour is a new development in 3D printing and allows any attribute to be shown on a given surface – in the Hurricane image the colour scale was chosen as depth to top surface, but it could have been any other attribute. This ability, combined with the improved attribute quality available as a result of the advances of broadband acquisition and processing, allows a better understanding of the reservoir. We are now working on a model showing top reservoir with acoustic impedance overlay clearly delineating the OWC. More complex models can also be printed including features such as salt diapirs, reverse faults, multiple layers and reservoirs.

As discussed, other industries have embraced 3D printing to give a tangible dimension to designs produced on work stations, helping in understanding the product and allowing stakeholders to focus on the design. In oil exploration this advantage has not yet been adopted, but I believe there are several areas where a 3D printed model can help convert prospects to reality. Small oil companies spend a lot of time working up prospects before they can attempt to farm out a stake to allow the discovery to be developed. Time is spent at trade shows and data rooms trying to entice larger companies or investors to join them with, in general, low success rates. Differentiating a company from competitors, a 3D model of its prospect at a trade show would act as a focus for discussion of the depositional environment, burial history, oil migration paths and source rock, generating further interest. I also believe basin-wide 3D models of a given key surface – for example the Base Zechstein in the southern North Sea or BCU in the central North Sea – showing developed fields and prospects together with an attribute such as gravity, magnetic or isopach information to a deeper horizon may allow further insights. These basin-wide models may also be of use in areas of the world which are less mature. Built from 2D data, they would be a less accurate model, but would allow explanation of the regional geology and help to demonstrate the advantages of a multiclient survey location.

I hope this article has piqued your interest. If you want to learn more, and maybe even see one of your datasets in reality, I can be contacted on Lawrence.pidsley@gmail.com. ■

Spindletop Gladys City Boomtown Museum

Newark East Barnett Shale's Spindletop

The Barnett Shale gas discovery, like 'Spindletop' nearly 100 years prior, changed an industry by unlocking huge new volumes of oil and gas, this time from shales.

THOMAS SMITH

The spectacular blowout in 1901 at 'Spindletop' in south-eastern Texas ushered in the modern oil industry and greatly changed the world's energy mix. People realised the potential of oil to surpass coal as an energy source, leading to the discovery of huge deposits of conventional oil and gas around the world. While the Barnett Shale discovery started in a much quieter way, its impact is no less important and has transformed oil and gas exploration and exploitation.

A unique formation, a driven company leader, and a very committed team of geoscientists and engineers combined to break the code that unlocked vast new unconventional oil and gas deposits. This is their story…

Against the Odds

While the Spindletop and Barnett discoveries look very different on the outside, they share some interesting similarities, both beating the odds against them. These included:

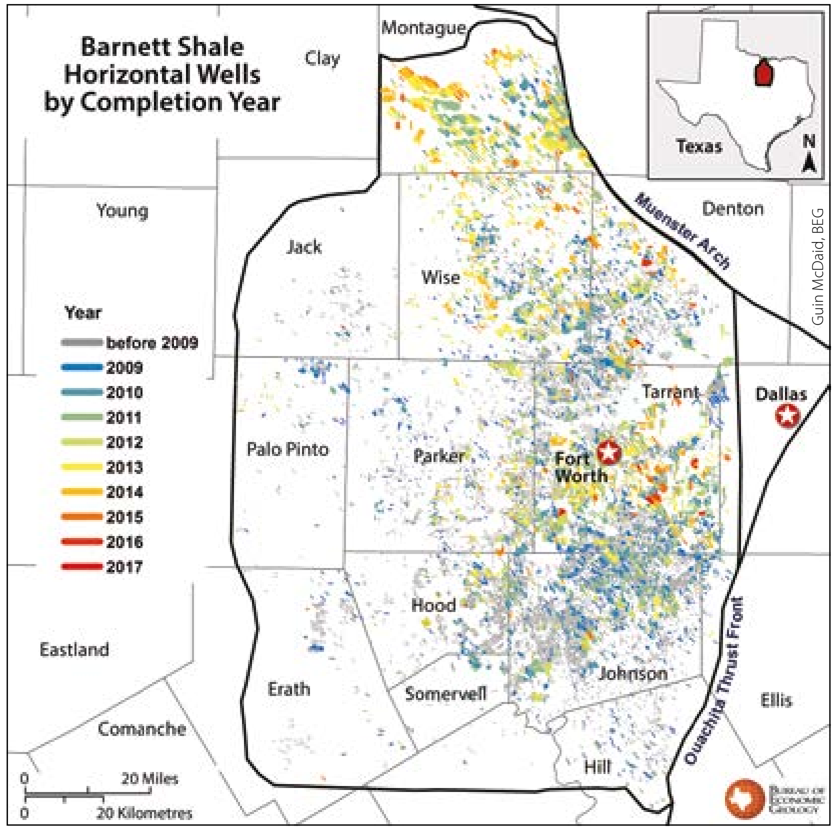
The companies: Each very small for their time without the large financial and research resources of a major.

Determined oil men: A self-taught geologist named Patillo Higgins tried to drill the salt dome at Spindletop for more than ten years. The first wells failed and Pennsylvania oil men Galey and Guffey were persuaded to finance another well. Similarly, George Mitchell, a Texas A&M educated geologist and petroleum engineer, spent millions drilling hundreds of wells over 17 years before finding economic success.

Sceptics and the unknown: Before the Spindletop discovery, most people in the petroleum geology business thought Higgins's ideas of finding oil in a salt dome were nonsense. Similarly, little was known about the potential of producing gas from shales. Mitchell's own board of directors were sceptical and considered his efforts in the Barnett a waste of money.

Innovation: While drilling the Spindletop discovery well, drilling difficulties and cave-ins forced the crew to pump mud instead of water down the hole to remove cuttings, a revolutionary idea at the time. The mud worked by coating the drill hole, allowing quick progress when the well had to be deepened. The Barnett discovery got its breakthrough when engineers switched from gel to water fracks. The change in fluids used made a major difference for both discoveries and those innovations are still used today.

Changing an industry's outlook and future: Spindletop blew oil nearly 50m into the sky and caused a stampede of drilling and new discoveries all over Texas and the world. Once Mitchell proved the economic success of the Barnett, the oil and gas industry's outlook on unconventional reservoirs greatly changed and prompted the drilling of thousands of new wells in shale basins across the US and other countries.



Drilling locations for the Newark East Barnett field over time. Most of the early Barnett development occurred in and around Wise County. Horizontal completions after 2009 greatly expanded the extent of the field.

Changing Time

In 1973 the Arab oil embargo prompted a great awakening across the US; our oil and gas supplies were dwindling and we could be vulnerable to supply disruptions. As a result, the Department of Energy (DOE) was formed in 1977, unifying energy planning within the federal government by putting a host of federal energy-related agencies and programmes into a single, presidential cabinet level department.

The government started to look to new sources of energy and unconventional gas was one of them. The US gas industry began back in 1821 near Fredonia, New York, where a gas well produced a few thousand cubic feet each day from Devonian shales continuously for 35 years. This seemed a natural place for the DOE to start to support research and development of unconventional resources. The Eastern Gas Shales Project (EGSP) was initiated in 1976, a year before the DOE existed, but soon became an integral part of the department's Unconventional Gas Recovery Program. The project promoted commercial gas development from Devonian shales in the Appalachian Basin, which could contain up to 900 Tcfg. They also studied advanced drilling technology such as directional drilling and advanced stimulation technology.

North Texas: the First Sixteen Years

While this was happening Mitchell Energy was busy drilling wells in North Texas. Mitchell's investment in the area was substantial and it needed a new gas source to reverse the company's declining gas production, so George Mitchell began thinking about the Barnett Shale. About this time Dan Steward joined Mitchell as part of a new team of geoscientists and engineers. Dan became the coordinator between the Barnett team members as "a lot of people in the company thought the Barnett was a waste of time and money and did not want to get their hands dirty on the project".

"In 1981, George had Slay No. 1 drilled to evaluate shallow conglomerates and the deeper Viola Limestone which lies below the Barnett," recalls Dan. "The Viola turned out tight and Mr. Mitchell had always wanted to test the Barnett. While drilling many previous wells, the Barnett section would give up good gas shows. We were not very optimistic at the time but went ahead with fracking and testing the Barnett. After stimulating with N_2 (no sand or water, based on the EGSP's work with Devonian shales), the well produced 120 Mcfpd. It

Barnett core bleeding gas, indicating a much higher gas content than studies had predicted.

was refracked the next year using CO_2 foam, which increased gas production to 274 Mcfpd." (Note: The Slay well has been fracked five times and is still producing.)

The next 40+ wells Mitchell fracked and tested in the Barnett would also test the company's fortitude. Dan Steward explained, "We started out with small fracks and poor results, finally going to much larger gel fracks consisting of 400,000 gallons of water and 1,250,000 pounds of sand. By 1991, Mitchell had a good position in the basin but we were still lacking a knowledge base. That was when George Mitchell said he was open to bringing in DOE and the Gas Research Institute (GRI). We started by evaluating Barnett core and then GRI sponsored a horizontal well in the Barnett." GRI's assessment of that horizontal well concluded, "The Barnett Shale drilling and completion economics favour hydraulic fracturing in vertical wells." Mitchell drilled two additional horizontal wells, but the bulk of their producers were vertical.

"From 1987 until 1997, 304 Barnett wells were all stimulated with these massive hydraulic gel fracks," Dan continues. "Most of these wells were deepened down to the Barnett from wells testing shallower objectives which really improved the economics and were also helped by gas contracts and federal tax credits for tight gas. We had wells that produced up to 1 Bcf ultimate recovery. It was near the end of this testing period when we realised we did not have open fractures in the rock."

"Geophysics had a pretty small part in the early development of the Barnett," says the project's geophysicist, Jon Huggins. "However, our mapping showed that as we got near faults, production would drop off. Initially we thought open fractures were needed to get results, but it turns out that was not necessary. We finally shot a small 3D survey and found the area much more complex than mapped from the older 2D surveys. It turns out, with the more recent switch to horizontal drilling in the play, detailed seismic mapping is necessary to accurately locate wells."

Success at Last

The massive gel-fracks were very expensive, most costing more than the actual drilling, but they got the job done. However, there were other problems besides the cost. Most of the reservoirs being fractured were either tight or at such low permeabilities that the formation was not able to 'clean-up', and the fractures had much shorter effective half lengths than designed.

Nick Steinsberger on a frack treatment in Texas.

The early Barnett team in 1986 (left to right): George Wilson, drilling superintendent; Paul Westbrook, drilling manager; Dan Steward, development geology manager; Loren Vogel, reservoir engineer manager; George Jackson, completion engineer manager; Bill Pyle, North Texas land manager.

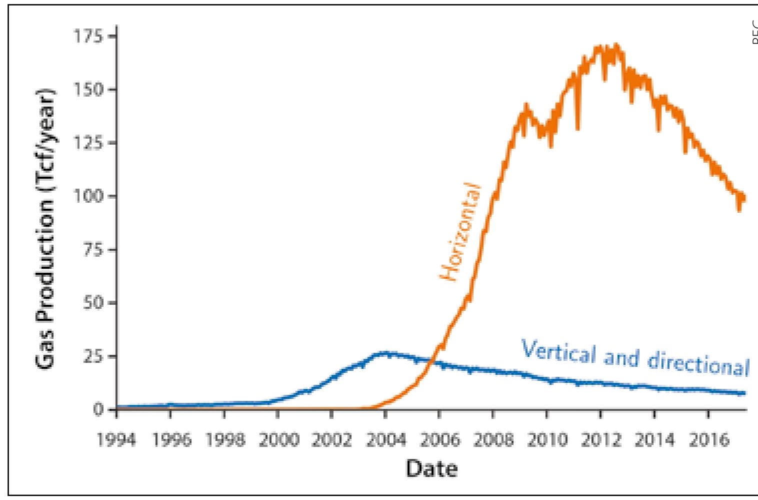
At this time, engineer Nick Steinsberger was running the fracking effort in the Barnett and experimenting with different liquids and gels to create pathways for the gas to escape. "I had been charged with cutting fracking costs to improve the economics of each well," says Nick. "With wells only producing 1 Bcf and the gel-fracks costing in excess of $375,000, something needed to be done. For a couple of years we kept experimenting with reducing the gel loads. On one well in 1997, I noticed the chemicals failed to create the normal viscous, jello-like fluid and they ended up pumping a much thinner fluid. The service company did not like it but we went ahead with the stimulation. The well turned out not all that bad and I thought I may be on to something."

His idea got a boost when he met Mike Mayerhofer, an engineer working at Union Pacific Resources, who had been successfully using mostly water for fracking operations in East Texas, although they added polymers to reduce the water's surface friction. This reminded Nick of his experience with the watery gel-frack, so to cut costs and hopefully increase production, the use of 'slick water' fracking was proposed to management.

"We got approval for the slick water fracks on three wells in spring 1997," recalls George Jackson, then heading up Mitchell's engineering effort. "Most of the folks involved were against it but we really needed to cut costs. The slick water fracks did not flow back very well at first. We were possibly overly cautious and restricted the wells on flowback thinking we could crush the resulting fractures. After a month, we opened up the wells again and they flowed gas at decent rates similar to the rates after a gel frack."

"During the winter of 1997–98, we were able to stimulate additional wells," says Nick. "However, instead of the Union Pacific Resources formula, we increased the frack size using greater volumes of water but lower concentrations of sand (now called light sand fracks) to create more micro-fractures. When the production from the S. H. Griffin No. 4 well was doing better than any well had ever done, I thought we had found the key." The production from this well was 1.3

MMcfpd gas after its first 90 days. No Barnett well had ever done that – and it kept going. Steinsberger, in an interview with *The Atlantic*, said, "This was the 'aha moment' for us, it was our best well ever in the Barnett, and it was a slick water frack. And it was my baby." Not only did slick water fracks work better, they only cost $85,000, saving nearly $300,000 per completion. George Mitchell was well on his way to his goal to replacing his gas source.



Barnett gas production took off after the first slick water treatments in 1998 and sky rocketed in 2004 with horizontal drilling. It peaked in 2012 but declined rapidly, with no active rigs reported in October 2017.

Yet There Was More!

Enter a new geologist: Kent Bowker had been working for Chevron on its unconventional gas acreage, south of where Mitchell was working, and drilled a Barnett test in 1997: a 60-foot (18m) conventional core taken in the middle of the formation. "We put the cores in rubber sleeves and I remember seeing the ends bulging with gas after a short time," says Kent. "My thoughts right then were that this formation had a whole lot more gas than previous studies indicated." Indeed, earlier absorption isotherm tests performed by GRI contractors were much lower than the later tests by Chevron and Mitchell. "The well proved to be a failure for Chevron," says Kent. "However, the results of the higher gas content convinced Mitchell to re-evaluate the gas content of its Newark East field.

"By 1999, with the higher gas content and much reduced completion costs, the Mitchell team started to complete the Upper Barnett and re-fracks on existing wells," Kent continues. "The Upper Barnett added an average of 250 MMcfg reserves per well and the re-stimulated wells that had been gel-fracked were adding 500 MMcfg additional reserves on an average per well basis. (The new stimulations created a much bigger fracture network than the older gel stimulations.) What makes the Barnett so prolific is the huge amount of gas in place, in an overpressured and fully-saturated state."

The George Mitchell Factor

While George Mitchell did not invent fracking, his interest in the Barnett and tight gas plays went back to the 1950s when he noticed a layer of impermeable rock in wells drilled north of Fort Worth, Texas. He thought this could contain a lot of natural gas and obtained leases in the area, drilling his first well there in 1951. The rock was tight sandstone with natural fractures. Many subsequent wells there were hydraulic fractured, a technique developed commercially only a few years earlier.

Mitchell kept his eye on the Barnett and prompted his team to test it in 1981. "George was a strong-minded, stay on top of it type of person," says Loren Steffy, Houston author and biographer for George Mitchell (book currently in review). "For the Barnett, he brought perseverance to the equation. He spent millions more than any other company over the 17 years it took for success. Once he was convinced he had a gas source, it did not matter how hard or long, he was going to see it through."

George Mitchell controlled about 70% of the company, allowing him to override his board and even his own engineers. Jon Huggins remembers, "He was difficult to work for at times and had his own ideas. Initially, engineers were sceptical of pursuing the Barnett, but over time became believers. The H. A. Smith well in Denton County, east of established production, was plugged when logs showed it did not meet the net porosity cut-off that had been established for the play. When George became aware of this, he made the decision to unplug and complete the well. He kept the group focused on the mission and on trying until we got it right."

Mitchell went on to prove up more acreage prior to selling the company to Devon, who with other companies took the lead in developing the field using horizontal drilling and multi-stage stimulations. Newark is now listed as the second largest gas field in the US, only surpassed by the Marcellus of Pennsylvania and West Virginia, another shale play that was developed initially using knowledge learned in the Barnett. ■

Left to right: Dan Steward, Nick Steinsberger, George Jackson, Jon Huggins and Kent Bowker receiving the 2013 Spirit of Engineering and Construction Community Award. More than 62 team members were involved with the Barnett project over 17 years. Special thanks to all the above for their help in writing this article.

Potential Risks from Outdated Technology

Embrace modern technologies to assure organisational and operational security.

SCOT RUDOLPH, Director of Business Development, RiskPoynt

Anyone who has been in the oil and gas sector for the last 20 years or so has seen vast improvements in the use of technology to advance operational efficiency and reliability. The improvements in assessing operational readiness of equipment and systems are one of the great stories of the 21st century. So why are we still using archaic risk assessment methodologies as attestation that we are 'safe to start' and 'safe to operate'? These outdated methods include static, manual, and 'just-in-time' risk assessments and registers.

Here is a short self-assessment on operational risk management:

- Is your organisation still dependent on spreadsheets, studies, dashboards, etc. that were done six months ago, or longer?
- Has anything changed within your plant, facility or operations since these studies or reports were completed?
- Are you dependent on risk management specialists, such as risk engineers, to evaluate and update your operational risk assessments to qualify barrier health?

If you answered, 'no' to the aforementioned questions, congratulations! From our interviews with prospective clients over the past ten years, we can say that you are in the extreme minority of oil and gas organisations. While many have embraced new hardware and software solutions to improve both the quality and quantity of data that is used for predictive analytics for preventative and reparative maintenance and operational efficiency, very few have invested in similar solutions to manage operational or process safety risks.

An Outdated, Inconsistent System

Enterprise software systems, such as those that are used to track training, competency and certification, are typically 'stand-alone' arrangements that are not integrated with the risk management process, and they certainly cannot transmit information back to a maintenance management system that says, "Hey, Joe just retired and the new guy has no experience with this equipment."

Similarly, distributed control systems (DCS) typically provide data on the operational efficiency and health of the equipment that it is part of. However, human factor data is not usually included in the data feed used to evaluate process safety risk and maintenance management systems, yet human error has largely been recognised as one of the key contributory causes of process safety incidents. The systems that we have created to manage operational efficiency, competency, and maintenance and training are not being used effectively to

predict and prevent process safety incidents.

Risk is a cumulative assessment process, yet we continue to use stand-alone, outdated processes to determine the safety to start or operate. Why is this?

Perhaps the drivers that influence updating our other systems focus more on optimisation of operational efficiency, i.e. our ability to maximise productivity, rather than evaluate the risk (severity x probability) for catastrophic failure due to a process safety incident. Almost certainly one of the factors is the plethora of methodologies and acronyms that are used across the oil and gas industry sector – bowties, HAZIDS, HAZOPS, ENVIDS, risk registers, pre-start up safety reviews (PSSR), project HSE and security reviews (PHSSER), human factors assessment tools (HFAT), process hazard analysis (PHA), to name just a few.

The Anacortes refinery in Washington state, where seven workers died in 2010 when a heat exchanger violently ruptured after a maintenance restart.

We have seen a wide spectrum of processes that are or are not being used in the oil and gas sector just like an 'a la carte' breakfast bar. It is my belief that this contributes to the confusion and lack of standardisation across the sector of risk management processes. The importance of this standardisation can possibly be best understood by looking at two major process safety incidents from 2010, including several key causal factors and recommendations that were provided by the United States Chemical Safety Board (US CSB).

Safety Incident #1 – Anacortes:
On 2 April 2010, the Tesoro Refining and Marketing Company, LLC petroleum refinery in Anacortes, Washington experienced a catastrophic rupture of a heat exchanger in the Catalytic Reformer/Naphtha Hydrotreater unit. The rupture fatally injured seven Tesoro employees who were working in the immediate vicinity of the heat exchanger at the time of the incident.

Causal factors identified by the US CSB included the following:

- The rupture of the E heat exchanger was the result of the carbon steel heat exchanger being severely weakened by a high temperature hydrogen attack (HTHA). This causes fissures and cracking and occurs when carbon steel equipment is exposed to hydrogen at high temperatures and pressures, which degrades the mechanical properties of the steel.
- Tesoro used an API (American Petroleum Institute) recommended practice (RP 941), which utilised a document that allowed Nelson Curves to predict the occurrence of HTHA based on previous equipment failure incidents, which are plotted based on self-reporting process conditions that were ill-defined and lacked consistency.
- The start-up of the heat exchangers was hazardous, non-routine work. Leaks routinely developed, presenting hazards to workers conducting the start-up activities. Process hazard analysis at the refinery repeatedly failed to ensure that these hazards were controlled and that the number of workers exposed to them was minimised.

Safety Incident #2 – Texas City:
At approximately 1.20 p.m. on 23 March 2005, a series of explosions occurred at the BP Texas City refinery during the restarting of a hydrocarbon isomerisation unit. Fifteen workers were killed and 180 others were injured. Many of the victims were in or around work trailers located near an atmospheric vent stack. The explosions occurred when a distillation tower flooded with hydrocarbons and was over-pressurised, causing a geyser-like release from the vent stack.

The recommendations that came out of the BP Texas City refinery investigation included the following:

- Improve operator training and, at a minimum, require face-to-face training on recognising and handling abnormal situations.
- Require knowledgeable supervisors or technically trained personnel to be present during hazardous operations phases such as unit start-up.
- Ensure that process start-up procedures are updated to reflect actual process conditions.

At the 10-year anniversary of the incident, the US CSB made the following statement: "The gaps in existing federal and state regulations were cited in recent CSB investigations, including the April 2, 2010 explosion at the Tesoro refinery

The aftermath of the Texas City refinery fire.

in Anacortes, Washington, and the August 6, 2012, fire at the Chevron refinery in Richmond, California. In both investigations, the CSB concluded warning signs regarding a potential accident were overlooked for years leading up to the catastrophic events. However, in both cases the CSB also found that federal and state process safety management regulations do not explicitly require the kinds of preventative measures that may have stopped the accidents from occurring.”

The safety message concludes with the following call by the CSB Chairperson, Moure-Eraso: “It’s been ten years since the terrible accident at the BP Texas City refinery. Industries and governments alike should increase their efforts to prevent process related disasters. Workers, the public and companies will benefit.”

Risk Assessment Matrix

Impact of Risk (Consequence)	Unlikely (0-33%)	Moderately Likely (33%-66%)	Highly Likely (66%-100%)
Major	Medium	High	Extreme
Moderate	Medium	Medium	High
Minor	Low	Medium	Medium
Seriousness of Risk = Probability x Impact	Probability of Risk (Likelihood)		

Risk assessment matrix.

Any Answers?

So, what are the answers to these dynamic and complex situations that are present in the industry?

First, the use of standardised tools to evaluate risk across the sector would be a good starting point. This includes the suite of tools recommended by API and the International Association of Oil and Gas Producers. Additionally, though, evaluation of process safety barriers using methodologies such as James Reason’s Barrier Model, frequently referred to as the ‘swiss cheese’ model, provide a standardised framework against which direct and contributory factors can be assessed using software applications.

Through the use of technology integration software, operators and producers can utilise risk assessment software that can accept millions of inputs, including static registers/studies, DCS, daily operational inputs, and maintenance and enterprise software systems. The amount of data provided is tremendous, but the output in the form of dashboards and registers is simplified so that the operation’s personnel can manage risk at the local level instead of needing a risk engineer to interpret the data.

The most sophisticated software applications are now cloud-based so that data can be accessed anywhere and at any time, as long as there is an internet connection. This enables front-line operation supervisors to objectively consult with senior level management because everyone is able to view the data together in real time from the cloud. Because inputs are continuous and based on actual operating conditions in the facility, risks can be viewed in real time and decisions can be made based on objective data versus subjective opinions.

RiskPoynt’s® safety software application is one such technology solution. While other software solutions exist, very few have designed their products to accept inputs that evaluate human factors, safety critical equipment, deferred maintenance, operational inputs, DCS, enterprise software feeds, and static risk data from risk registers, HAZIDS, HAZOPS, ENVIDS, PHAs and the rest. Based on conversations with major software and hardware developers, there is a consensus that we are currently in an augmented information technology (IT) space where humans make critical safety decisions based on the information provided through such systems.

But the evolution will undoubtedly evolve to the next generation of information technology, cognitive IT, where the software will make critical decisions, such as shutting down systems based on the data, without the need for human intervention. Before this can occur, though, the industry will need to evaluate the current standards, hardware and software that can provide the data, as well as the man-machine interface upon which critical decisions, either augmented or cognitive, are made. The first steps are to embrace the technology and improve on existing processes and systems utilising modern tools to view objective information for competent people to make the right decision. ■

Chemical Safety Board investigators inspect the aftermath of a refinery fire.

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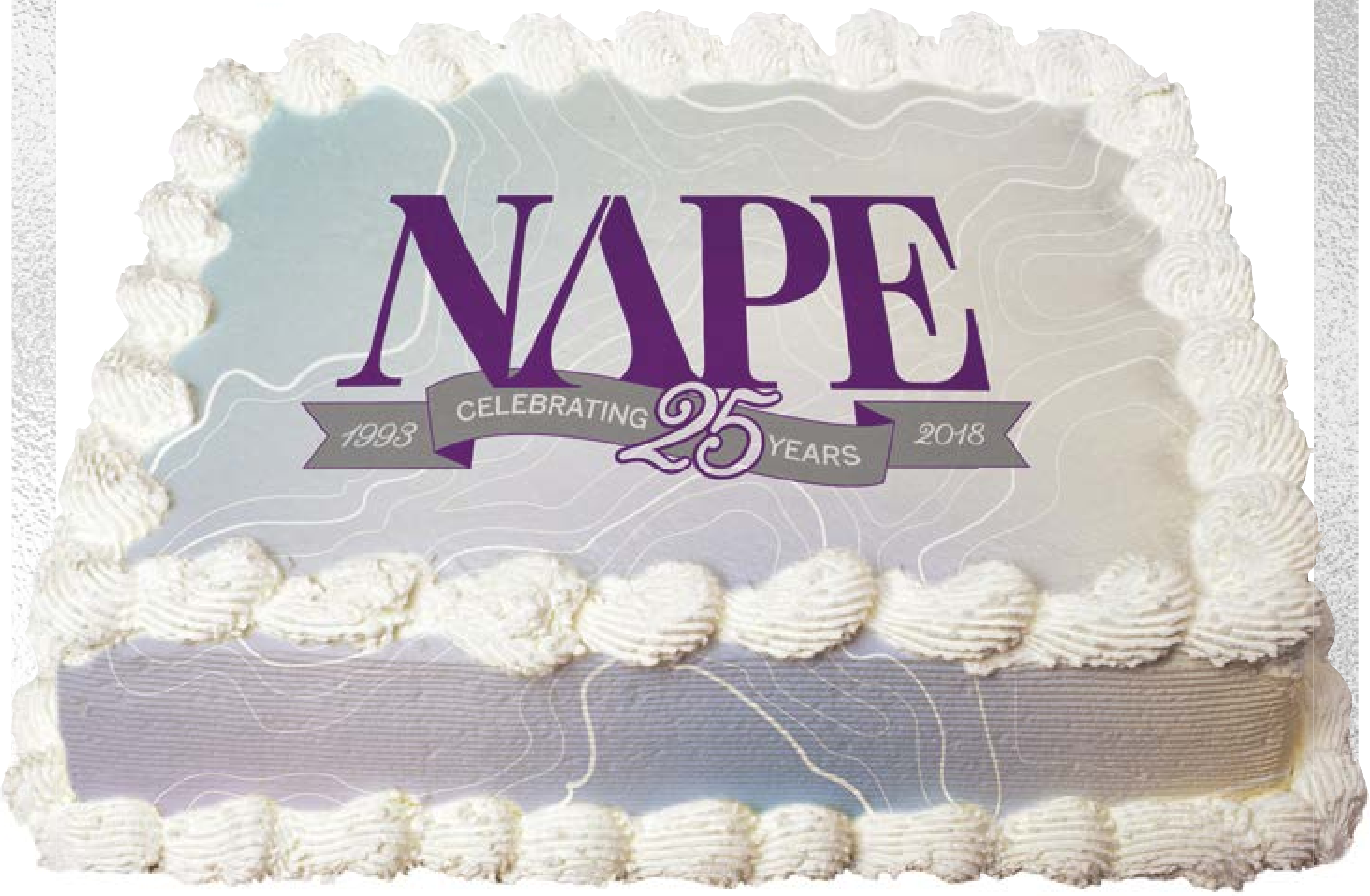

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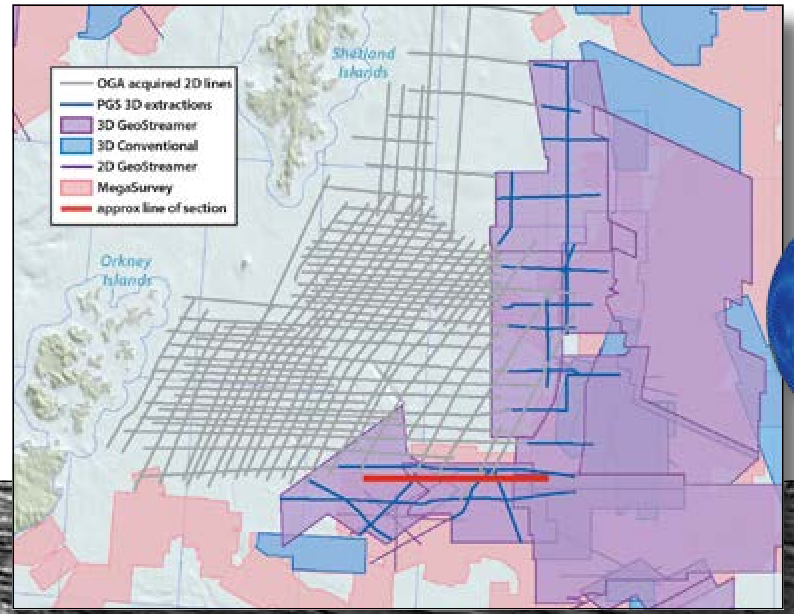
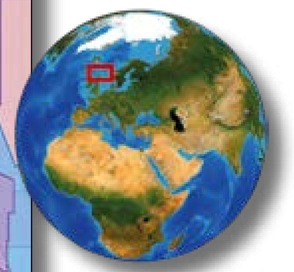
The East Shetland Platform

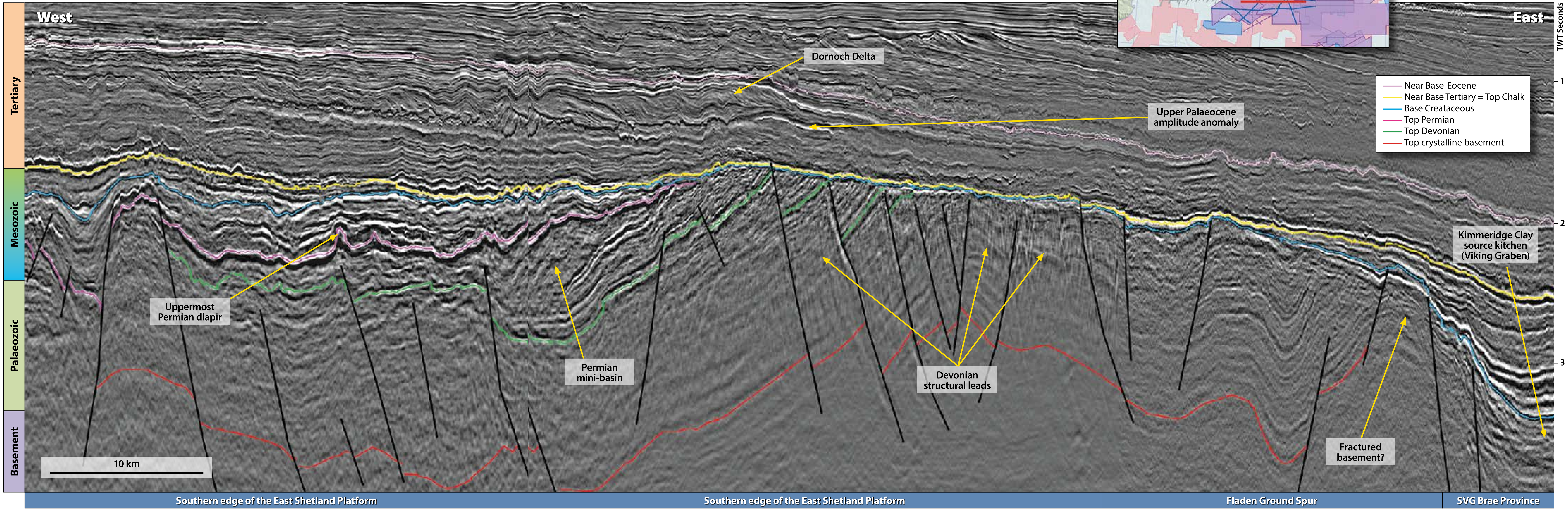
The next large frontier – on the periphery of a world-class mature basin.

With exploration focus shifting from the mature basins to frontier areas once again for the 31st UKCS offshore licensing round, the East Shetland Platform (ESP) is a key area situated at the periphery of the mature graben axes of the North Sea rift system. PGS multi-client 3D GeoStreamer data has imaged a number of large Palaeozoic structures with a prospective working petroleum system in this area.





PGS has provided a number of extractions from its 3D multi-client library on the ESP to provide well ties for the UK Oil and Gas Authority's recently acquired 2D lines, which will be made available ahead of the next licensing round.



The East Shetland Platform: Illuminating Sub-BCU

New 3D data allows the true geological story of the Palaeozoic of the East Shetland Basin to be unravelled.

STEFANO PATRUNO and CHRISTINE ROCHE, Petroleum Geoservices Ltd

Due to the limitations of legacy seismic and despite significant discoveries within Palaeogene-age reservoirs, the East Shetland Platform (ESP) has been historically conceived as a broad and flat high, with shallow basement and few visible structures. Mesozoic units are generally thin or absent whilst Palaeozoic reflectors were often interpreted as basement on legacy seismic. Several 3D multi-client GeoStreamer® dual-sensor broadband seismic surveys were acquired by PGS between 2011 and 2016 over a total area of 17,200 km² (UKCS Quadrants 3, 8–9, 14–16), and these have allowed for clearer imaging, which it is believed could open up a whole new era of exploration potential.

These new GeoStreamer surveys clearly illuminate sub-BCU (Base Cretaceous Unconformity) Palaeozoic structures and potential closures in areas where legacy 2D and 3D seismic mostly showed no discernible sub-BCU reflectors (see below). In other cases, the new seismic has helped make sense of old well results, including reported Devonian oil shows and source rock penetrations.

Petroleum System Summary

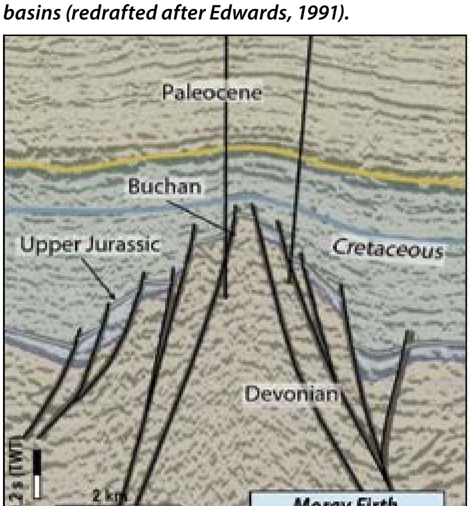
PGS has been studying the ESP for the past three years, and findings have been previously published in First Break (Patruno and Reid, 2016, 2017). These PGS studies show that the ESP petroleum system comprises multiple proven and potential reservoir and source intervals, with viable play fairways and possibly mature source rocks. The ESP comprises persistent basement highs and predominantly subsiding Permo-Triassic depocentres, which contain a nearly continuous Palaeozoic-Mesozoic succession (e.g., the newly-defined 'Crawford-Skipper Basin').

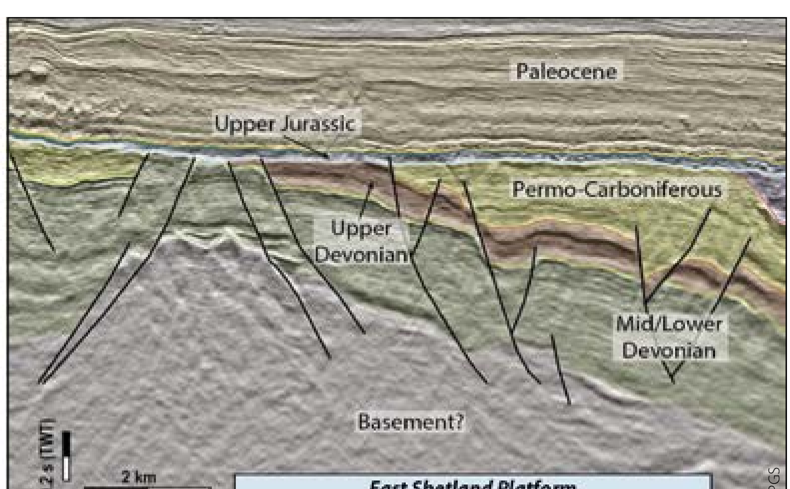
Existing hydrocarbon discoveries and shows on the ESP are in the vicinity (less than 7 km) of intra-platform Permo-Triassic basin margins. Exploration close to such basins is inherently less risky due to possible positive influences on deep-seated structures in the petroleum system. These influences include the formation of Meso-Cenozoic closures; the maturity of the Devonian source and the presence of simple fault-related migration pathways; and the viability of sub-Cretaceous reservoir-trap-seal configurations.

Fluid Escape Features

More recently, numerous vertical seismic amplitude anomalies have been observed within the Cenozoic succession of the ESP (top of facing page),which are interpreted to be a result of hydrofracturing associated with vertical fluid migration through the sedimentary rocks. Anomalies seen over the Greater ESP are for the most part clustered in association with the south-eastern edge of the Crawford-Skipper Basin and other Permo-Triassic fault-bounded depocentres. This additional evidence strengthens the suggestion that the preserved intra-platform Permo-Triassic basin fill plays a pivotal role in the maturation of the Devonian source rock and the upward and outward migration of hydrocarbons.

Devonian Buchan Field in the neighbouring Moray Firth showing similarities to undrilled structures in the Permo-Triassic intra-platform basins (redrafted after Edwards, 1991).





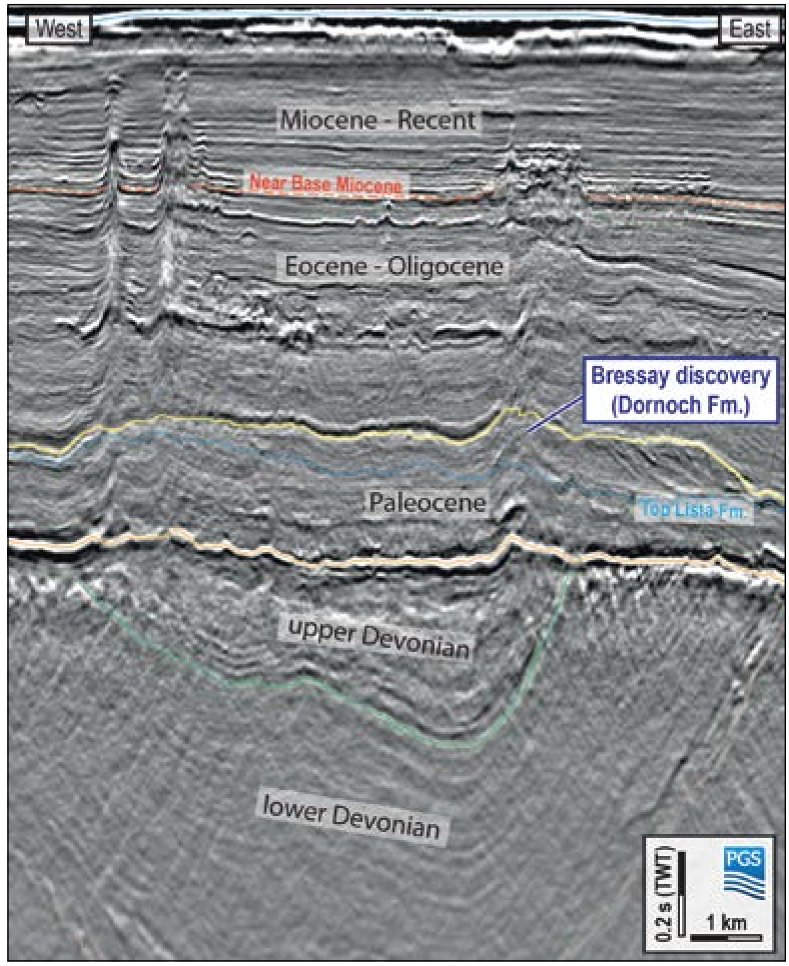
Quantitative Interpretation

A successful quantitative seismic interpretation of rocks as deep and as old as the Devonian was undertaken as part of the ongoing study of the area. This confirms that GeoStreamer dual-sensor broadband acquisition and processing enables geoscientists to derive reliable pre-stack information (acoustic impedance and Vp/Vs), even at depth. A very high correlation between the wells and seismic in the Palaeozoic section was observed and there were also clear indications that Upper Devonian rocks are characterised by surprisingly high effective porosities, up to 22% (below). Well analysis suggests that relative acoustic impedance for the upper Devonian is a proxy for effective porosity, as successfully tested on this broadband seismic data.

Greater Clarity

Due to the imaging limitations of vintage seismic data, the East Shetland Platform was once poorly understood. With the acquisition by PGS of several recent 3D multi-client dual-sensor broadband surveys there is now a unique opportunity to view the Palaeozoic reflectors with significantly more clarity than has been possible in the past, allowing the true geological story to be unravelled.

PGS has identified a number of sub-BCU targets and highlighted the presence of multiple reservoir intervals. A mature and working source might be present, as highlighted by direct well penetrations and indirect evidences (e.g., vertical amplitude anomalies and seep surveys). Intra-platform Permo-Triassic basins with a more complete stratigraphic succession are present, and represent inherently less risky exploration areas. Quantitative interpretation has been used to further de-risk Palaeozoic plays at reservoir scale. ■

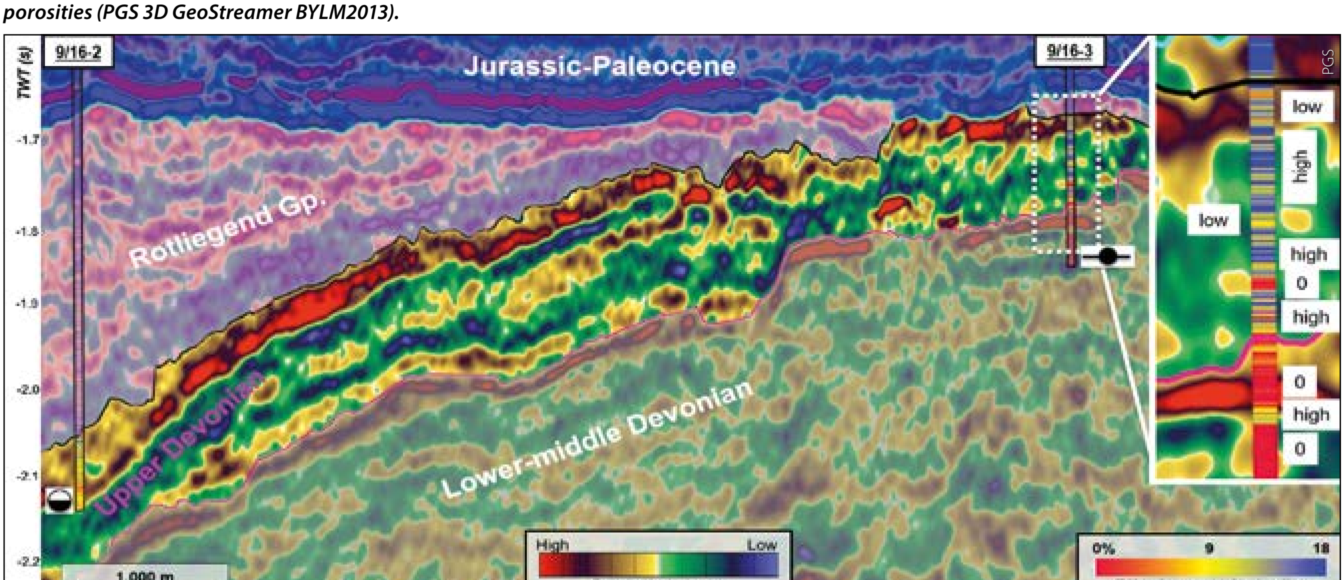


Two vertical seismic anomalies associated with vertical fluid migration (PGS 3D GeoStreamer PGS15010).

References:

Patruno, S. and Reid., W., Dec. 2016 and Jan. 2017. New plays on the Greater East Shetland Platform (UKCS Quadrants 3, 8–9, 14–16) (part 1 and 2). First Break, 34–35 .

Relative impedance can be used as a proxy for effective porosity. Hard impedances correspond to low porosities and soft impedances to high porosities (PGS 3D GeoStreamer BYLM2013).



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An Introduction to Deep Learning: Part II

LASSE AMUNDSEN, HONGBO ZHOU, Statoil, and **MARTIN LANDRØ**

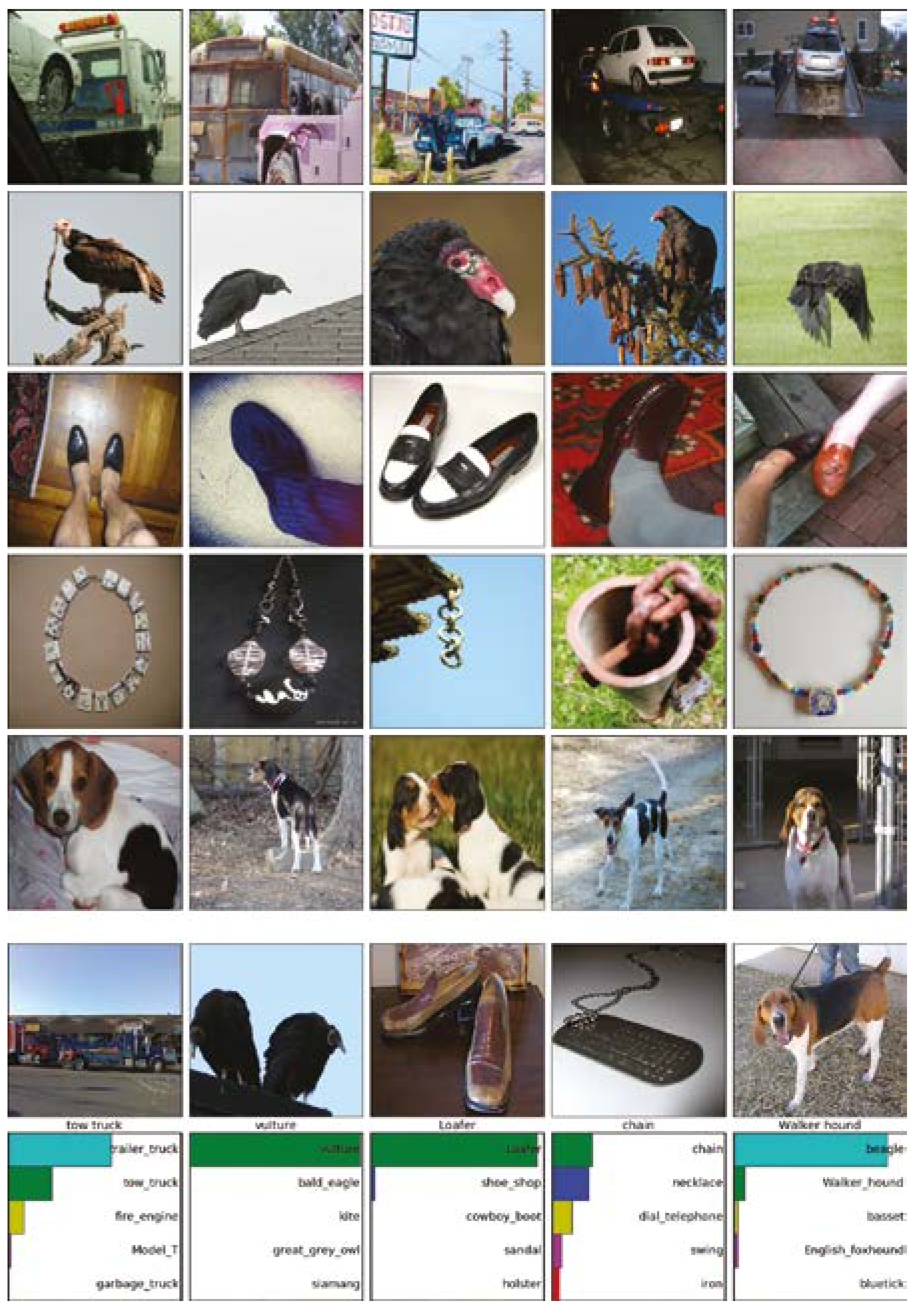
"We need to go deeper."

Leonardo DiCaprio, in the film Inception (2010). A thief, who steals corporate secrets through the use of dream-sharing technology, is given the inverse task of planting an idea into the mind of a CEO.

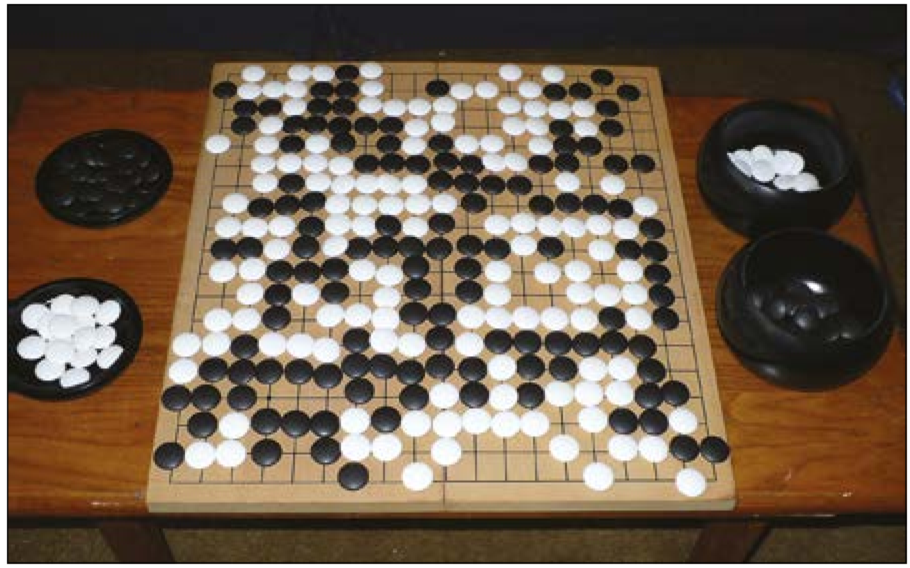
Well said, Leo. In Part II of this article, we deepen our discussion on deep learning – a tool for implementing modern machine learning.

Over the past few years, AI has accelerated. Factors that have helped renew progress in AI are faster, cheaper and more powerful computers. Progress came also with Big Data, with exponential growth, availability of data, and growing understanding of the potential value of such data – images, text, mapping data, and so on. With these computing breakthroughs, neural networks were revisited, and they could be made huge.

ImageNet Large Scale Visual Recognition Challenge (ILSVRC), set up to encourage computer-vision breakthroughs, is the world's top computer vision contest. To compare models, ImageNet examines how often the model fails to predict the correct answer in their top five guesses (the top-5 error rate), in descending order of confidence. ILSVRC 2012 brought a small research group led by Geoffrey Hinton at the University of Toronto to



The ImageNet dataset contains 15 million labelled images of objects in around 22,000 categories. ILSVRC, the 'Olympics of computer vision', is an annual competition which uses a subset of ImageNet – roughly 1,000 images in each of 1,000 categories.
The top five rows show five ILSVRC-2012 classes of images for network training and validation. The bottom two rows show the corresponding five test images and their top-5 labels considered most probable by using a variant of the AlexNet model (illustration made for the purposes of demonstration for this article). The correct label is written under each image. We see in the last column that the network found the walker hound incorrectly to be a beagle. The beagle and the walker hound however have similar 'tricolour' coloration. But the net indeed labelled it correctly at the second 'guess'.



Go is a strategy board game for two players, in which the aim is to surround more territory than the opponent. Go is played on a grid of black lines (usually 19×19). Game pieces, the black and white stones, are placed on the lines' intersections.

everyone's attention. The group had parallelised its convolutional neural network AlexNet on Nvidia GPUs, and won the contest by getting an error rate of 16.4% with the given data for the top-5 guesses, while the error rate of the second-best system was around 26%. ILSVRC 2012 marks the turning point for neural nets research, heralding the abandonment of feature engineering and the adoption of feature learning in the form of deep learning. Since then, remarkable progress has been made by the community and the pinnacle was reached by Microsoft in 2015 when it achieved a top-5 error rate of 3.57%.

Deep Learning

Deep learning is nothing but a rebranded name for a family of deep neural networks – complex mathematical systems that can learn tasks by analysing vast amounts of data. Deep learning thus is a class of learning procedures based on the neural network model. It has facilitated image recognition, object detection, video labelling, and activity recognition, and is making significant progress into other areas of perception, such as audio, speech, language translation and natural language processing (NLP). According to Schmidhuber (2015), Rina Dechter (1986) introduced the expression 'Deep Learning' to the machine learning community at the conference of the Association for the Advancement of Artificial Intelligence (AAAI). Later, it became widely accepted when Igor Aizenberg et al. (2000) introduced it to ANNs. (see Part 1).

Deep learning can circumvent the challenges of feature engineering that are critical for symbolic-based machine learning. The remarkable thing about deep learning is that no human is required to program a computer because the deep learning models are capable of learning the features automatically by themselves. Therefore, programmers just need to feed the computer a learning algorithm, expose it to terabytes of input data to train it, and then allow the computer to figure out itself how to recognise the desired objects. In short, such computers can now learn by themselves. This makes deep learning an extremely powerful tool for modern machine learning. Deep learning methods are beating traditional symbolic-based machine learning approaches on virtually every metric.

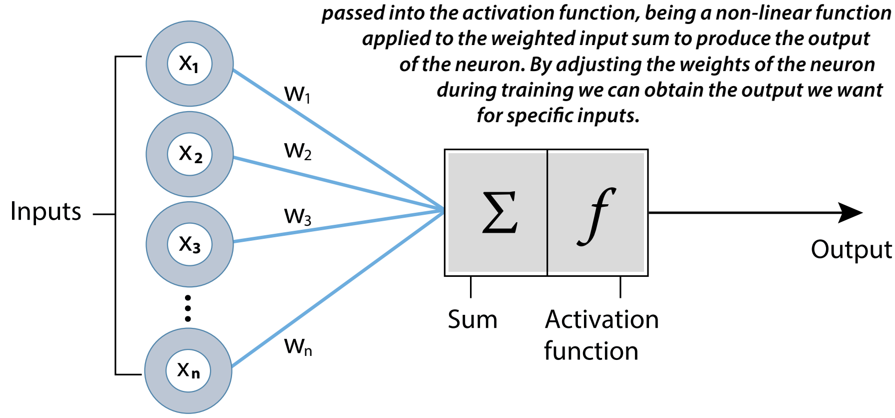
Further evidence that deep learning is on the rise is the amount of capital being invested, the number of people who are choosing it as their area of study, and the number of leading technology companies that are making AI the core of their strategic plans. It is revolutionising many areas of machine perception, with the potential to impact people's everyday experiences. Some even believe that AI could be used to mimic human common sense someday.

Great Achievements

One of the landmark achievements of deep learning is Google DeepMind's AlphaGo beating the world legendary Go champion Lee Sedol four games to one in 2016. The game of Go was invented in China more than 2,500 years ago and is believed to be the oldest board game still played today. Its simple rules and deep strategies have intrigued everyone from emperors to peasants for generations. The goal is to gain more territory than the opponent, but it is very complex and possesses more possibilities than the total number of atoms in the universe. The AlphaGo computer program uses deep neural networks, reinforcement learning and a Monte Carlo tree search to find its moves based on knowledge previously learned by an artificial neural network through extensive training, both from human and computer.

Deep learning can be trained with supervised learning, unsupervised

Model of an artificial neuron. Suppose that the neuron connects with n other neurons and so receives n-many inputs (x1, x2 ,… xn). The inputs are individually weighted, summed together and passed into the activation function, being a non-linear function applied to the weighted input sum to produce the output of the neuron. By adjusting the weights of the neuron during training we can obtain the output we want for specific inputs.

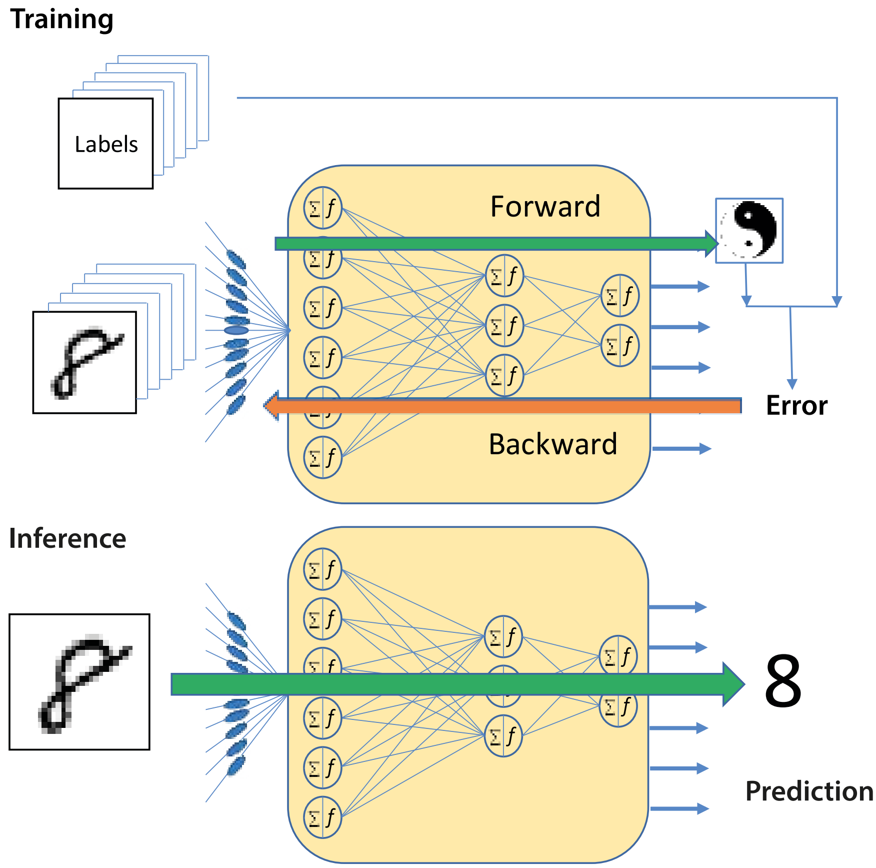


learning, or reinforcement learning. Unsupervised learning is the ultimate goal for the future and reinforcement learning is gaining more ground, especially in gaming and robotics. But supervised learning is the champion today: it works by showing the network a bunch of things with labels saying what they are, and getting the network to learn and classify future things without labels.

Deep neural networks generally work as a two-stage process. First, a neural network is trained with its parameters determined using labelled examples of inputs and desired output and then the network is deployed to run inference, using its previously trained parameters, to classify, recognise, and process new inputs. This is illustrated in deep forward neural nets on the right. When receiving an input image, the network translates it into a hierarchical level of features, and the neurons in each layer of the network are tuned to recognise certain patterns in the features. Low-level neurons recognise things like edges or basic shapes, then pass the data to the next layer. This layer of neurons does its own task, and passes processed data on. Neurons in high-level layers can 'see' objects – say, a cat or a dog. Each layer communicates forward with the one next to it, and as information travels down the network, some feature extraction processes take place automatically. At the end, the network comes up with an output – a prediction of what is in the image.

Return to the Wrong Way sign example in Part I: the image is split into a number of tiles that are inputted into the first layer of the neural network. The neurons examine each tile's attributes: for the Wrong Way sign, its rectangular shape, red colour, eight letters, and its size. Each neuron assigns a weighting to its input, where the weight tells how correct or incorrect it is relative to the task being performed. As data are passed forwards, the neural network's task is to predict with some probability, based on the total of the weightings, whether the sign is Wrong Way or not. Perhaps the network is 90% confident the image is a Wrong Way sign, 7% confident it is a Bicycle Wrong Way sign, and 2% confident it is a Danish flag on a flagpole, and so on.

While the neural network is being trained, the odds are in favour of it predicting incorrectly. Therefore, it needs lots of training, using millions of images, until the weightings of the neuron inputs are tuned so precisely that it gets the answer right almost every time. At that point the neural network has taught itself what a Wrong Way sign looks like.



Deep learning training and inference. In training (top), many inputs, often in large batches, are used to train a deep neural network. In inference (bottom), the trained network is used to discover information within new inputs that are fed through the network in smaller batches.

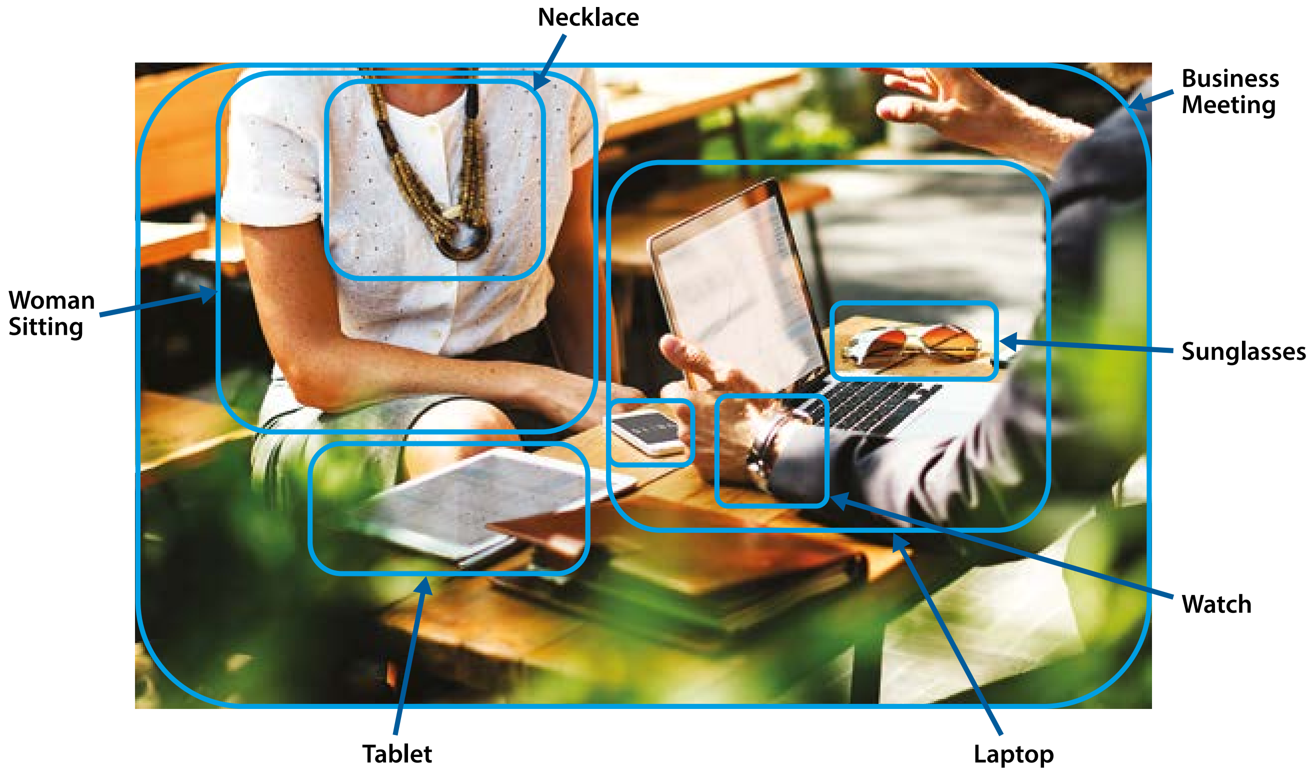
Classification, Localisation, Detection, and Segmentation

The examples in the introductory image address image classification, which is the task of taking an input image and outputting its class (cat, dog, etc.) or a probability of classes that best describes the image. It works well when the image contains only one object.

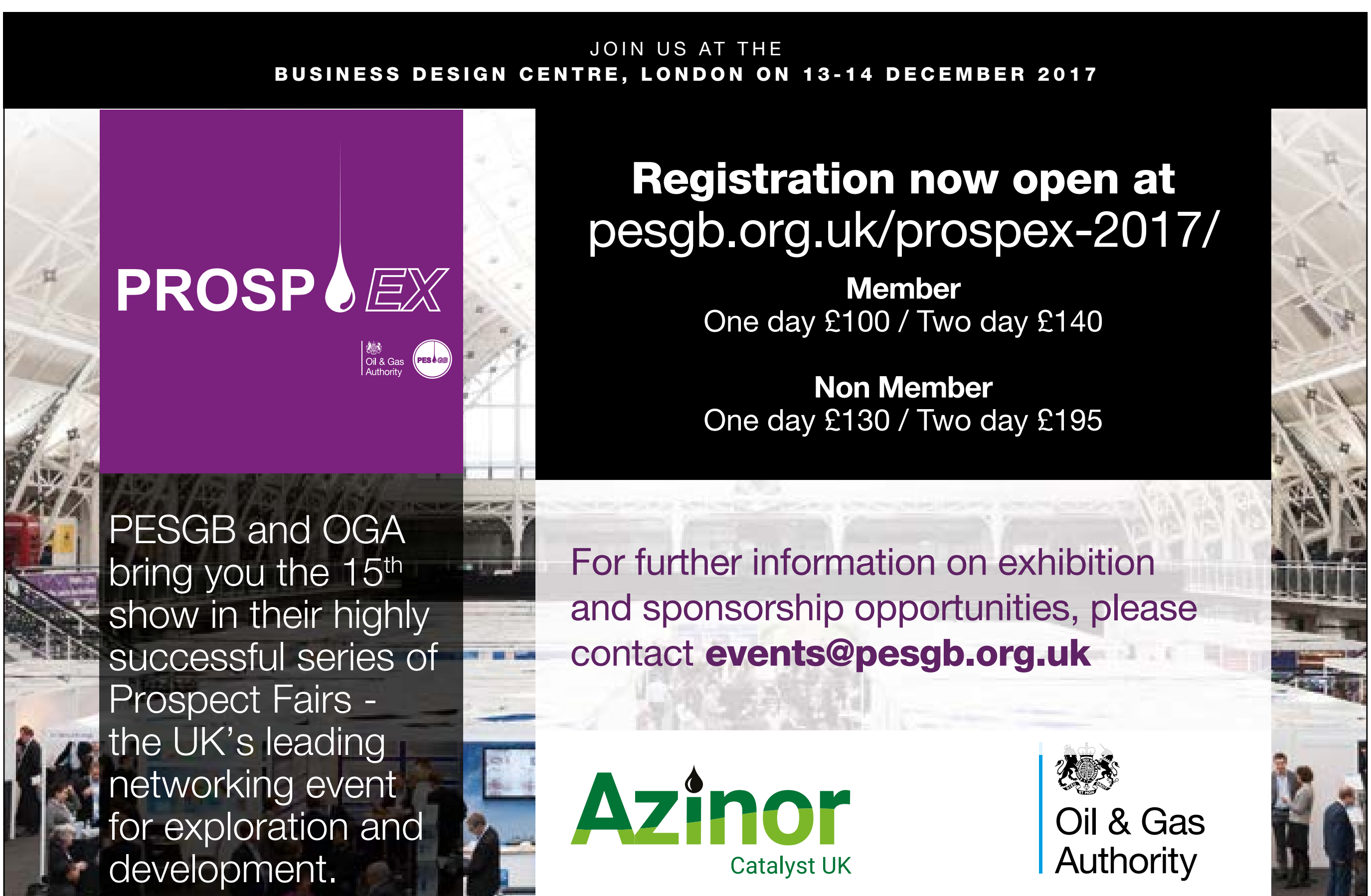
For humans, a quick glance at an image is sufficient to point out and describe an immense amount of details about the visual scene. When we look at an image we are immediately able to characterise the objects and give each a label. These skills at quickly recognising patterns, generalising from prior knowledge, and adapting to different image environments are ones that computers do not easily share with us. However, the success of the AlexNet in 2012 spurred research and great achievements in object localisation, detection and segmentation.

Object localisation not only produces a class label but also a bounding box that describes where the object is in the image. In the task of object detection, localisation needs to be done on all of the objects in the picture, resulting in multiple bounding boxes and multiple class labels. Finally, we also have object segmentation where the task is to output a class label as well as an outline of every object in the input image.

We end by referring the reader to Karpathy and Li (2015), who combine convolutional neural networks (CNNs) and bidirectional Recurrent Neural Networks (RNNs) to generate natural language descriptions of different image regions. Basically, their model is able to take in an image, and output a concept, as demonstrated in the image on the next page. ■



With conventional CNNs, a single label is associated with each image in the training data. Karpathy and Li (2015) presented a model that generates natural language descriptions of images and their regions. Their model has training examples that have a sentence associated with each image. This type of label is called a weak label, where segments of the sentence refer to (unknown) parts of the image. Using this training data, a deep neural network 'infers the latent alignment between segments of the sentences and the region that they describe'. Another neural net takes in the image as input and generates a description in text. The illustration above is a conceptual example of such an output.



Insights into Exploration: Tools for a New Era

KASPER STORRS, COLETTE LYLE, CHRISTINE YALLUP, JONATHAN WILSON and RICHARD JAMES
Halliburton Landmark

Streamlining the process of exploration to provide a better understanding of geological risk for frontier plays.

Despite a protracted low oil price, the number and geographical distribution of wildcat exploration wells scheduled throughout the coming year demonstrate that frontier exploration for new plays remains an important part of the hydrocarbon industry. While this trend partly reflects previous work commitments, it is also defined by the long-term necessity for operators to replace reserves and for governments to ensure energy security.

Delving into the Frontier

However, frontier exploration is not without considerable geological risk, as demonstrated by increasing finding costs across the industry. How can we streamline the process of exploration and provide a better understanding of geological risk, even for frontier plays where hard data are often scarce? Halliburton Landmark's approach uses an innovative suite of exploration tools that provide a mechanism for validating play concepts. These tools are built around the integration of multidiscipline datasets, resulting in a series of geological models ranging from plate tectonics, palaeogeography and palaeoclimate, to sequence stratigraphy and burial; combined, these models help ensure more informed predictions of the subsurface.

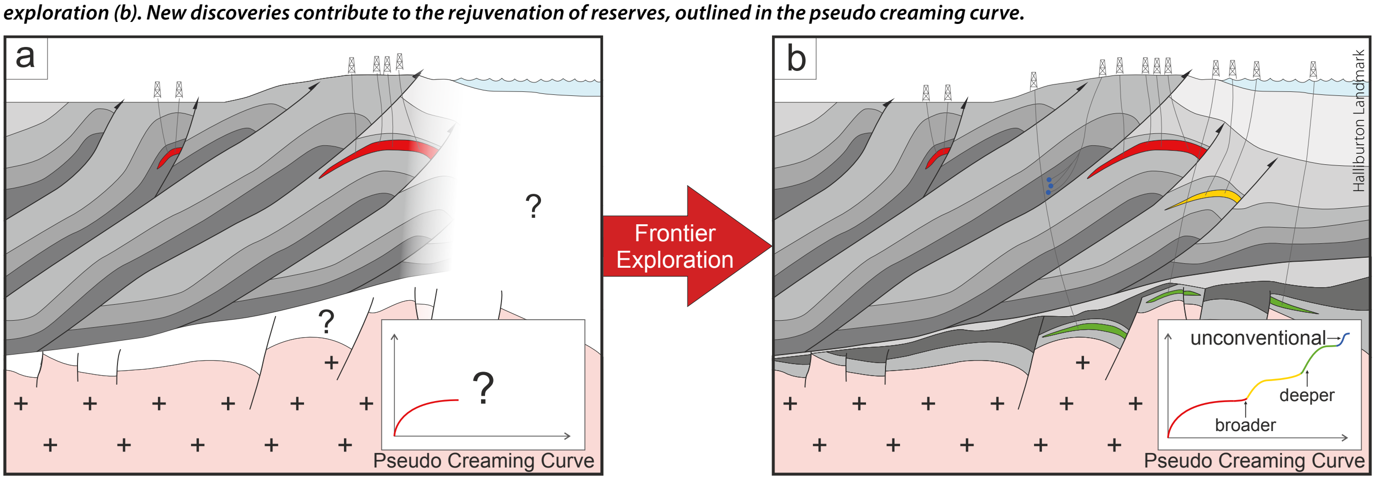
Frontier exploration not only describes the search for hydrocarbons in undrilled geographic areas (Figure 1a), but also underexplored stratigraphy in mature basins and the development of tight or unconventional plays (Figure 1b). Many basins therefore have frontier play potential that could yield considerable undiscovered hydrocarbon reserves. However, frontier exploration poses a higher risk of failure because of the paucity of data control compared to more mature or more accessible assets. Exploration geologists therefore need to mitigate such risks and create a well-reasoned conceptualisation of the subsurface, integrating interpretations from plate to pore scale. Here we show how exploration geologists can make informed predictions on a range of features within a basin, including its origin, likely stratigraphy, the quality and effectiveness of play elements, and, ultimately, likely hydrocarbon endowment.

Plate Reconstructions and Stratigraphic Heterogeneity

Plate tectonic models are powerful tools for characterising the geological history of a region (Figure 2) and are built using a range of datasets, including seismic, potential field, geochronology, biostratigraphy, and palaeoclimate information. By carefully integrating these data, plate tectonic models provide insight into the timing of regionally important geological events and therefore help establish a structural framework from which gross tectonostratigraphic units within a basin can be defined.

Plate tectonic models also allow data to be reconstructed into their original palaeogeographic positions, providing geological context for further analysis. Recent developments in cloud computing have transformed the accessibility and the speed at which these models can be manipulated, allowing all explorers to use them and make important inferences on basement rheology, stratigraphic setting, and likely source-to-sink relationships, which have implications

Figure 1. (a) Frontier exploration can occur in either unexplored areas or deeper stratigraphic intervals, leading to a broadening and deepening of exploration (b). New discoveries contribute to the rejuvenation of reserves, outlined in the pseudo creaming curve.



for predicting sedimentary infill. Such models therefore provide a foundation upon which play concepts can be tested and also provide crucial context to the structural and stratigraphic interpretations important for defining tectonic megasequences.

With a tectonostratigraphic framework established, the geoscientist is faced with creating a higher-resolution stratigraphic model that captures both vertical and lateral heterogeneity within the basin. Building such a framework can be challenging, particularly in frontier settings, where well data are likely to be minimal. Instead, an understanding of the factors controlling sedimentation and stratigraphic architecture is required.

The widely adopted principle of sequence stratigraphy provides such a framework, as it allows the likely response of depositional systems to changes in accommodation space to be understood (Figure 3). These changes occur as a result of the interplay between eustacy, tectonics, sediment supply, compaction or climate, and lead to the development of systems tracts: packages of sediments which are genetically related both temporally and spatially. An understanding of these stratal geometries, in combination with the application of Walthers Law (facies occurring in conformable vertical successions also occur in laterally adjacent environments, Figures 3a and 3b), allows facies to be predicted outside of direct well control (Figures 3c).

In frontier areas, prediction can also be driven by information on conjugate margins, well-understood analogues, or even outcrop data near the margins of the depocentre. In terms of exploration, one key outcome from the use of sequence stratigraphy is the prediction of likely play elements, including source rocks, reservoirs, seals, and stratigraphic traps.

Palaeoclimate Models and Source-to-Sink Relationships

Climate is one of the primary controls on present-day sedimentary systems, but extrapolating current observations back through geological time can be difficult. Complex palaeoclimate simulators built considering

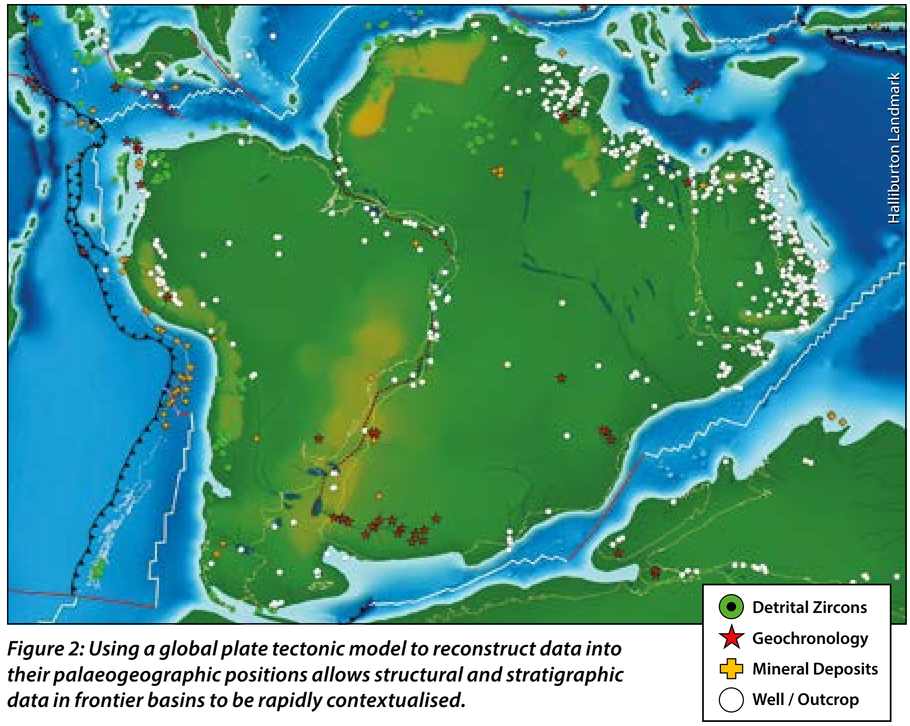


Figure 2: Using a global plate tectonic model to reconstruct data into their palaeogeographic positions allows structural and stratigraphic data in frontier basins to be rapidly contextualised.

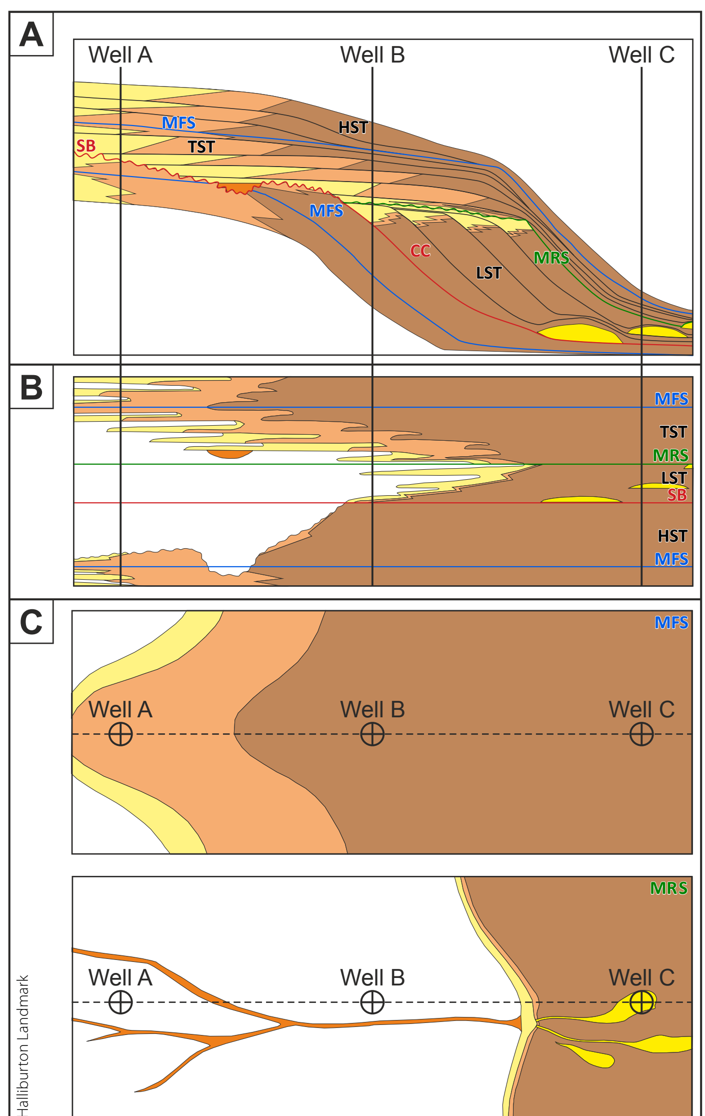


Figure 3: Sequence stratigraphic model of a clastic system in (a) cross-section view highlighting spatial relationships between strata; (b) chronostratigraphic view highlighting temporal relationships; and (c) plan view during both maximum flooding (MFS) and lowstand conditions (SB). Sequence stratigraphy groups strata into genetically related packages bound by stratal surfaces, which behave in a predictable manner to changes in relative sea level. These changes occur both geographically and stratigraphically. Understanding the principles of sequence stratigraphy allows the geoscientist to interpolate and predict the geology away from data control.

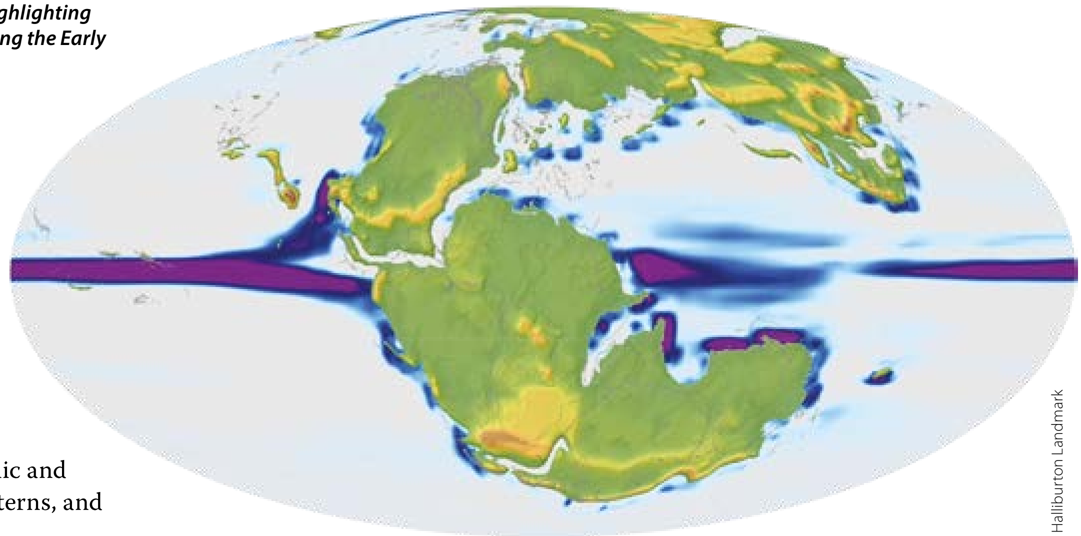


Figure 4: Palaeoclimate model highlighting areas of predicted upwelling during the Early Jurassic.

palaeogeography, palaeo-elevation and bathymetry can help, and are unique in that they provide a measured understanding of a broad range of spatial and temporal controls on sedimentation, all within a single realisation, synthesising information about river discharge, oceanic and atmospheric circulation patterns, and temperature through time.

With increasing accessibility to supercomputer processing capabilities, both the cost and time necessary to generate results are being reduced, making the use of palaeoclimate models more commonplace within the industry. In the following sections, the impacts of palaeoclimate models on predicting the nature of various play elements are discussed.

Source Rocks: The deposition of organic-rich sediments is a precursor to the formation of source rocks in the subsurface and hence the generation of hydrocarbons. It is therefore crucial to be able to accurately predict where organic-rich sediments are likely to have been deposited and preserved. The probable source of this organic matter also needs to be determined, as this has an important control on the phase of hydrocarbons ultimately generated during burial.

Sediments that form world-class source rocks tend to accumulate where the production and preservation of organic matter are elevated, or dilution of organic matter is inhibited, such as in low-energy basins, where restricted circulation leads to a depletion of oxygen in the water column and on the seabed. Other palaeogeographical phenomena that produce widespread organic enrichment include oceanic upwelling, particularly along the western margins of continents, where deep, nutrient-rich water moves toward the sea surface, driving high marine organic productivity. The accumulation of organic matter can also be assisted by rising sea level, which inhibits the dilution of organic matter by migrating clastic sources landwards. Therefore, models for predicting organic matter accumulation can be included in the sequence stratigraphic and palaeoclimate modelling stages (Figure 4).

To predict the occurrence of organic-rich sediments and kerogen type, the geoscientist needs to clearly understand the driving mechanisms behind their accumulation. In the geological record certain periods of time favour the accumulation of organic-rich sediments more than others. The most geographically widespread examples occur during oceanic anoxic events, which relate to the extensive development of low-oxygen conditions in the ocean or increased organic productivity, resulting in widespread, predictable source rock formation. Such events occurred throughout the Phanerozoic, with the best-known examples found during the Cretaceous.

Reservoirs: The quality of subsurface reservoirs is influenced by the original composition of the deposited sediment and any subsequent evolution of the porosity and permeability characteristics by burial and diagenesis. When clastic systems are considered, the composition of a reservoir rock can be influenced by depositional environment, the composition of the hinterland, the scale of the drainage basin, the ability of a system to store sediment within it, and the palaeoclimatic regimes operating across both the drainage and depositional basins (Figure 5). An integrated interpretation of depositional systems should consider all of these components and therefore is often referred to as source-to-sink analysis.

Within the drainage basin, the erosion of hinterland of differing lithologies significantly affects the compositional quality of the derived sediments (Figure 5). Source terranes with a predominant quartz-prone character are generally preferred because they produce sediment that is cleaner, contains fewer reactive minerals, and tends to maintain better porosity-permeability on burial. Although composition is a function of geodynamic setting rather than climate, the compositional and textural maturity of the sediment are influenced by the nature of the palaeodrainage system, where longer transport distance leads to improved compositional quality. Palaeoclimate plays an important role here, with the distribution of arid vs. humid climate zones influencing the size of the drainage system. Source-to-sink analysis allows parameters such as sediment flux and submarine fan size to be calculated by applying well-established power law scaling relationships or analytical models. Palaeoclimate models provide us with robust estimates of the factors needed to calculate these parameters, including catchment area, rainfall and temperature.

Play Element Evaluations

A plate-to-pore scale exploration workflow usually culminates with

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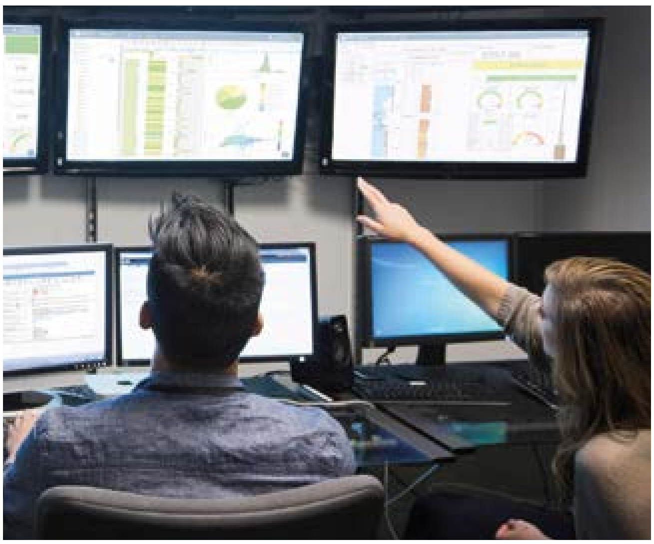

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assessment of the impact of burial on reservoir quality, source rock maturity and charge. Ideally, the models produced during this phase would be supported by empirical data, such as vitrinite reflectance or porosity and permeability depth trends. In frontier settings these data are typically lacking. However, several tools can be used that allow us to conduct meaningful assessments, despite this lack of data.

The advancement of computing and software capabilities combined with access to large amounts of data allows the generation of 3D depth frameworks at a size and scale impossible until recently (Figure 6). These can be generated using a range of data, including seismic datasets, well or outcrop information, structural cross-sections and surface geology maps. These subsurface representations identify key stratigraphic horizons within a basin and can be tied to tectonostratigraphic events identified through plate models. The depth frameworks can be populated with predicted or known petroleum system elements and their maturity or reservoir effectiveness can be modelled based on depth estimation, augmented by a knowledge of crustal heatflow and the response of this to different tectonic regimes predicted by the plate model, with surface heatflow provided by palaeoclimate models.

Another important source of information regarding the effectiveness of key petroleum system elements is found through the careful use of analogues, particularly valuable in frontier settings. Global analogue databases, such as Halliburton's Playfinder™ software, make the identification and comparison of relevant analogue data increasingly simple, with geological insight on equivalent stratigraphic horizons easy to identify and extract. Using carefully selected analogues, reliable porosity and permeability trends can be predicted in relation to the depth of likely play elements.

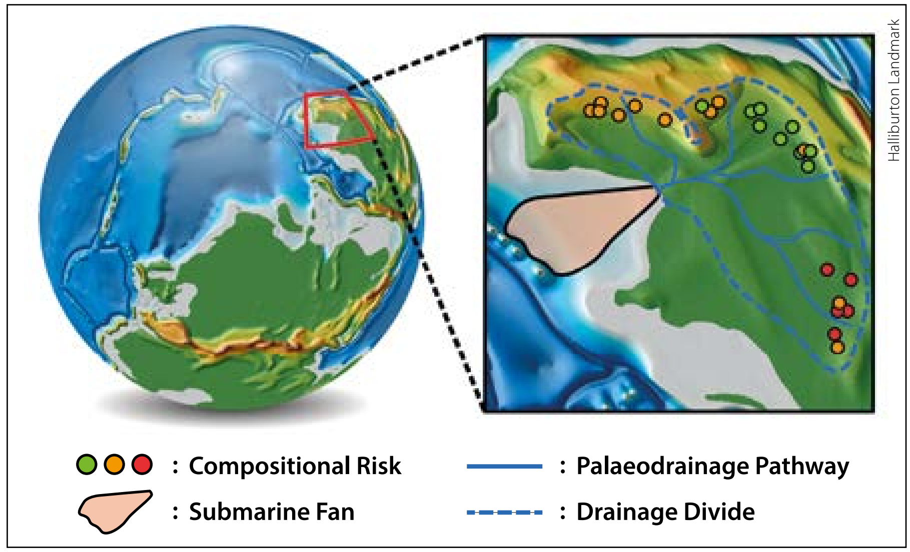


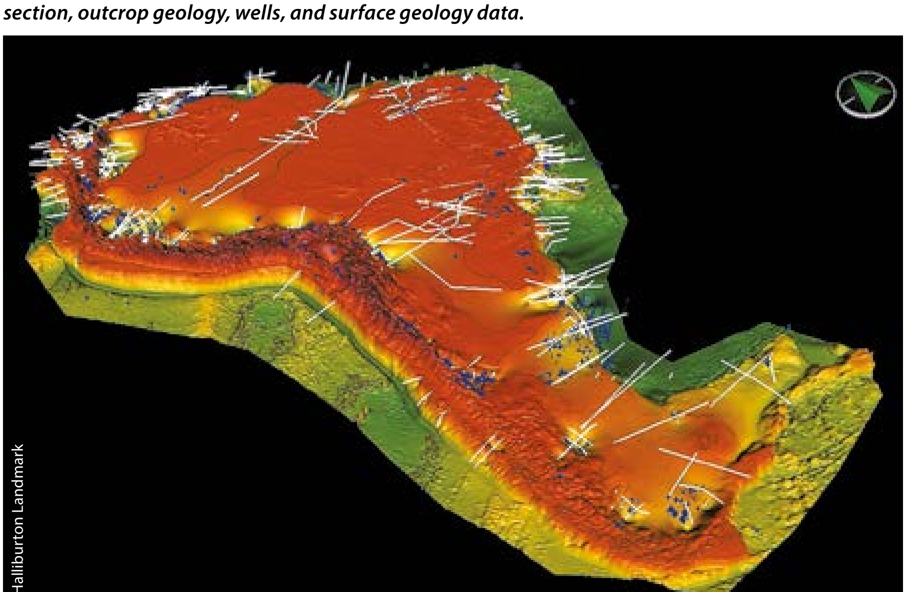
Figure 5: Tectonic models can help identify potential sediment source areas, while using palaeodigital elevation models, combined with an understanding of the hinterland composition, allows for indirect assessment of reservoir quality based on composition and textural maturity.

Integrating Models Brings Results

As we have demonstrated, even in areas with poor data control the integration of multiple reasoned geological models can provide a robust assessment of an area's petroleum potential, whether it represents a stratigraphical or geographical frontier. Such insight is possible through the adoption of an approach where a disparate range of powerful modelling tools is combined to construct a unified conceptual subsurface framework. The models used include those defining the evolution of tectonic plates, those defining changes in palaeogeography and palaeoclimate over time, and those that assess the burial of rocks.

To perform this effectively, a consistent, well-structured, and iterative workflow is necessary, providing the geoscientist with a platform from which to employ inductive and deductive scientific reasoning, test hypotheses, and rapidly update and adapt predictions in a dynamic manner. The result is a time-efficient and well-reasoned subsurface model that culminates in the identification and risking of play concepts.

Figure 6: South America regional depth framework highlighting data inputs, including lines of section, outcrop geology, wells, and surface geology data.



Acknowledgments:

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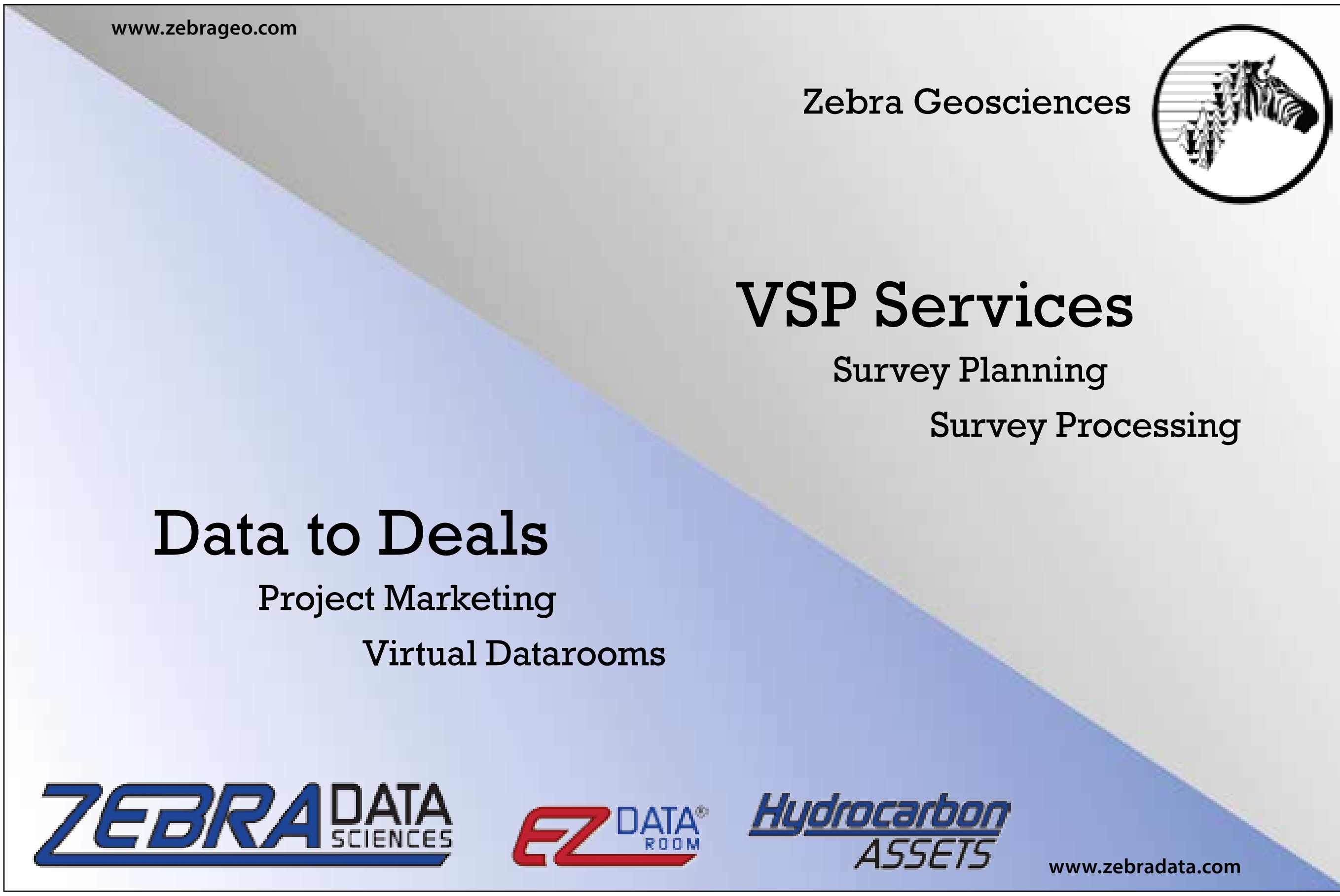

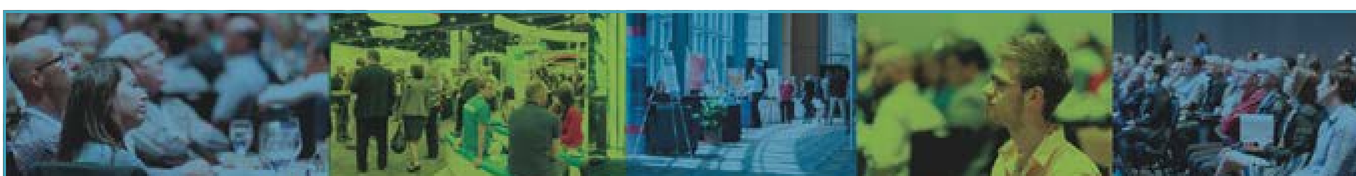

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Great Yarmouth: An Unlikely E&P Hub

Tucked away about as far to the east as you can get in the UK is a small fishing town that for over 50 years has played an important role in the exploration for oil and gas in the North Sea.

JANE WHALEY

Although for many people Aberdeen in Scotland is synonymous with the search for hydrocarbons in the UK, the rather smaller town of Great Yarmouth was the first place to experience the excitement of a North Sea 'black gold rush'. The first discoveries on the UKCS were gas, and they were all in the Southern North Sea Basin, off the coast of eastern England. With its long seafaring history, Yarmouth (as it is usually known) was an obvious choice as a base to service these fields.

The Silver Harvest

Great Yarmouth, which lies about 175 km north-east of London, is built on a 5 km-long spit of sand, which separates the sea from the river Yare and results in a safe protected natural harbour, the source of the town's prosperity since the Middle Ages, when it became the centre of the North Sea herring industry. For centuries huge shoals of these fish have migrated south from Scotland to arrive in the southern North Sea in the autumn, on their way to their breeding grounds off France – pursued by fishermen, and also by a large troop of shore-based, mostly female, packers and gutters, following the very lucrative 'silver darlings'. Yarmouth was the final stop: home to a large fleet of herring 'drifters' and the site of the largest annual herring fair, where smoked, pickled and salted fish were sold and despatched all over Europe.

As well as fishing and ship building, in medieval times Great Yarmouth was an important trading centre due to its relative proximity to Holland and the rest of Europe. In the 13th and 14th century the burgeoning population was housed in 'The Rows': an unusual form of urban development built as a series of narrow parallel passages with houses which had only one room up and down. When more space was needed, extra rooms were added at the back, and the houses ended up so close that special narrow carts, known as 'trolls', had to be used to move goods around them. Sadly, Yarmouth's position on the very eastern edge of England meant that it was heavily bombed in WWII, and all but a very few of these unique houses were destroyed, as were many merchant's houses and much of the centre of the town, the majority of which dated back to the beginning of the 16th century.

Beaches and Broads

A predominantly rural and relatively isolated area, the countryside around Great Yarmouth is very distinctive and picturesque. The flat landscape is dotted with windmills and church spires, with pretty flint and timbered cottages and quiet villages, and dominated by the wide expanses of the Broads – a network of navigable rivers and lakes formed by the flooding of medieval peat workings.

In Victorian times Yarmouth began to develop as a popular tourist seaside destination. The arrival of the railway in 1844 made it easy for people in the rapidly industrialising Midlands, 300 km to the west, to reach the town and enjoy sea bathing on

© Jack Harrison

Traditional herring drifters line the quay at Great Yarmouth in 1954.

A rather quieter view of the same quay in 2015 with the supply boats moored further down the river. The green vessel is the steam drifter Lydia Eva*, built in 1930.*

© Helen Hotson/Dreamstime

its very wide expanse of rather stoney beach. By the first half of the 20th century Yarmouth was in its holiday heyday, with its beach front hotels, lodging houses and, later, caravan parks full for most of the summer months. Two traditional piers were built and a range of seaside amusements and rides were constructed on the seafront for the entertainment of visitors.

By the 1960s the advent of cheap air travel made holidays in the – rather warmer – Mediterranean accessible to everyone, and the holiday industry in Yarmouth declined, although canal and sailing vacations on the Broads remain popular. But the future of the town was to turn out to still lie in the cold waters of the North Sea.

Boom Times

1913 was a record year for the herring industry in Yarmouth – 1,163 boats used the port and over 1,200 million fish were caught, with 6,000 seasonal workers staying in the town. But a combination of over-fishing, changing tastes and rising fuel prices meant that by the mid-1960s the once powerful industry was almost non-existent, with only a handful of fishing boats still eking out a living.

And then came oil and gas exploration. The first discovery in the UKCS, in 1965, was the West Sole field (see *GEO ExPro,* Vol. 14, No. 3) rapidly followed by others, including the giant Leman field, about 50 km north-east of Yarmouth, which was discovered in 1966 and came on production in 1968. The boom times were back: with supply ships, survey vessels, pilots and safety boats, the harbour at Great Yarmouth was soon buzzing again. Fabrication yards building platforms and rigs developed in the vicinity and a major gas terminal was built at Bacton, about 20 km north of Yarmouth. This quiet corner of England was for a short while the centre of the largest change to energy supply in the country for centuries, as power plants and homes were converted to North Sea gas.

Yarmouth became the main supply centre for the southern North Sea, and companies setting up there included drilling specialists, operations and maintenance service providers, logistics and safety experts and engineering firms. The boom lasted through the ’70s, but by the middle of the 1980s as the discoveries moved further north, so did many of the service companies, and Yarmouth slumped into relative obscurity and high levels of unemployment.

However, the turn of the century has seen a revival in the offshore industry in Great Yarmouth, fuelled not by fossil fuels, but by wind. Situated as it is on the edge of the very windy but relatively shallow North Sea, a number of windfarms have been built off Norfolk, including the UK’s first offshore wind farm at Scroby Sands, which began supplying power to the national grid in 2005. These are predominantly serviced from Yarmouth, while another growing industry revolves around the decommissioning of the offshore rigs and infrastructure built during the gas boom of the ’60s and ’70s. In 2015, 50 years after the first discovery of gas in the southern North Sea, more than 350 companies employing about 7,000 people in and around Great Yarmouth are still involved in the offshore industry. ■

Managing Funding Risks in E&P

Is being able to secure adequate funding a major risk for your corporate or asset activity? What is the position for energy companies seeking funds in 2018?

ROSEMARY JOHNSON SABINE, Gneiss Energy

Whether you work for a private or public company, large or small, and whether you are concerned with a specific asset project or a larger corporate transformation, you may need long- or shorter-term finance. This has been hard to come by of late for any fossil fuel exploration and production activity. Conversely there are bargains to be had in the sector if you can raise that vital finance.

The Challenges

Many companies are now working across the energy or natural resources spectrum to broaden their portfolio and, likewise, investment funds and advisory firms can cover this range. A few majors and relatively debt free contractors are able to finance their own projects. Many companies have had a couple of years since the 2014 oil price crash to restructure their debts one way or another. But since the oil price seems to be staying lower for longer it is becoming harder to convince investors currently why they should choose your project over the many others they may be offered.

Firstly, you need to choose your project wisely. Is gas the future? Where is your best market which will provide for future growth? A compelling profitable case in needed. Equally, have you been cautious? Have you correctly assessed your P90 case and does it work below an oil price of $60 a barrel? Or have you, as a company, got a well-balanced portfolio, with oil and gas, across the value chain, and geographically spread across various political regions?

Finally, are you planning to be fully aligned with your investors, sharing the risks and waiting for those profits?

Varied Solutions

You may be able to tap vendor finance or, in other words, raise investment, perhaps as work, from your contractors. For example, Transocean Rigs recently did an incentivised deal with Hurricane Energy – but investment for Hurricane Energy's development also came from Kerogen Capital, a private equity fund, as well as other institutional investors.

Private equity funds appear to have billions to invest but can afford to be choosy. They say they are prepared to invest in long-term projects but require transparent information sharing and updates along the way from aligned and experienced managements. Over the past year, the North Sea, for example, has experienced a large increase in private equity funding and spending (Figure 1).

A company that looks fundable in the future may tend towards a gas portfolio focus rather than one focused on oil; the acquisition deal that private energy backed Neptune Oil and Gas chose to make with French utility Engie's E&P business is one such example. An onshore location for your portfolio may provide the lower project costs that

again make an investment look more appealing. Working up a project along the value chain and then farming down your equity also raises money effectively.

For funding you may need to consider a corporate transaction; a strategic transformation may be needed as part of the preparation for raising funds from the capital markets, public and private. The UK North Sea has seen a significant increase in M&A (mergers and acquisitions) activity in 2017 after several years of downturn (Figure 2).

Consider your case for raising funds through equity versus debt or mezzanine routes. You will need to explore a wide range of relationships with various institutions, including hedge funds, family offices, private equity, sovereign wealth funds and commodity trading companies.

The equity markets remain relatively subdued outside of a few large raises. Excluding Tullow Oil's approximately £600 million rights issue and Hurricane Energy's £235 million follow-on, only about £285m has been raised in London in 2017. The IPO (the initial offering of a private company to the public) market remains particularly depressed, with the last IPO over £50 million in the industry being Seplat Petroleum's in 2014 (Figure 3).

As the RBL (reserve based lending) market has also remained subdued, commodity traders have

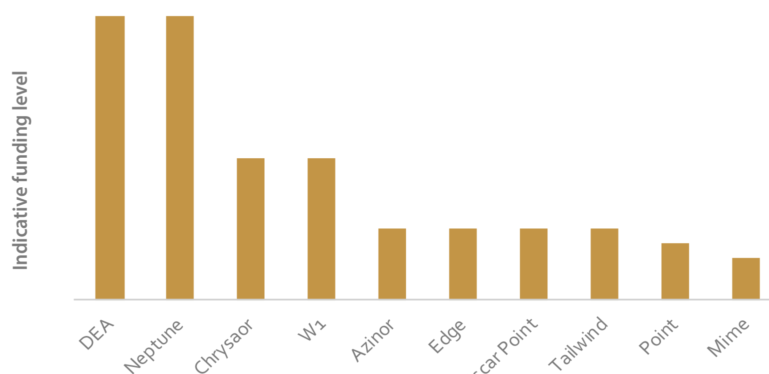

Figure 1: Private equity funding in the North Sea. (Source: Woodmackenzie)

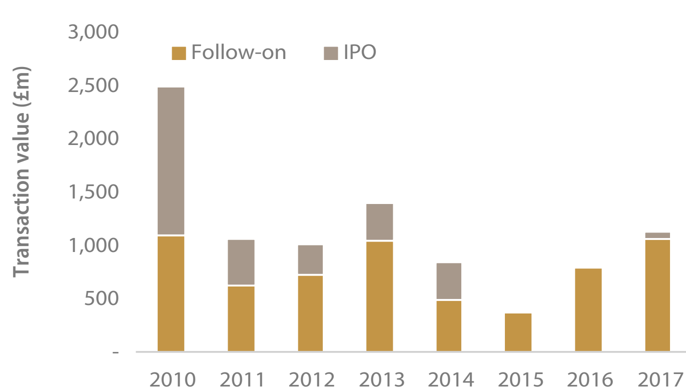

Figure 2: UK North Sea M&A. (Source: Company reports, I.H.S Herold)

increased lending to the sector in order to gain access to offtake. This lending can be structured in various ways, including providing prepays and buying Asian call options. A recent example is Mercuria Energy Trading's $75m prepay arrangement with TransGlobe Energy, who will use the money to refinance and restructure and which will be paid back through deliveries of oil to Mercuria.

If you are not a listed company, you might wish to consider listing via an IPO, but only if your project or portfolio looks compelling. You will also need commercial and legal advice and good marketing material. You will have to consider where you list; perhaps the London Stock Exchange has the best track record and initially you might consider the smaller friendlier AIM market there, but there are alternatives around the world with some experience of E&P companies that might suit your project better.

Whatever your route, you are also likely to need good technical advisers and an independent Competent Person's Report on the volumes, merits and risks associated with your project or across your portfolio. This report can then be quoted in your marketing material.

Happy Ending? If We Work Together

If there is no increase in the funding available for new oil and gas exploration and developments then many observers predict a shortage of production versus demand in the mid-term future, even when an increasing market share for alternative energies is included in the model. The much-acclaimed industry cost-cutting which has been so prevalent over the last few years has included a lack of investment at the start of the value chain (Figures 4 and 5).

The collapse in oil prices has led to a major short-term drop in investment in the oil industry, with global investment in production and exploration falling from $700 billion in 2014 to $550 billion in 2015, with spill-over to energy commodities. Sharp declines in investment in other commodity sectors have also contributed to overall slow global growth.

An increase in funding for worthy E&P projects is therefore a beneficial aim for all of us in 2018. ■

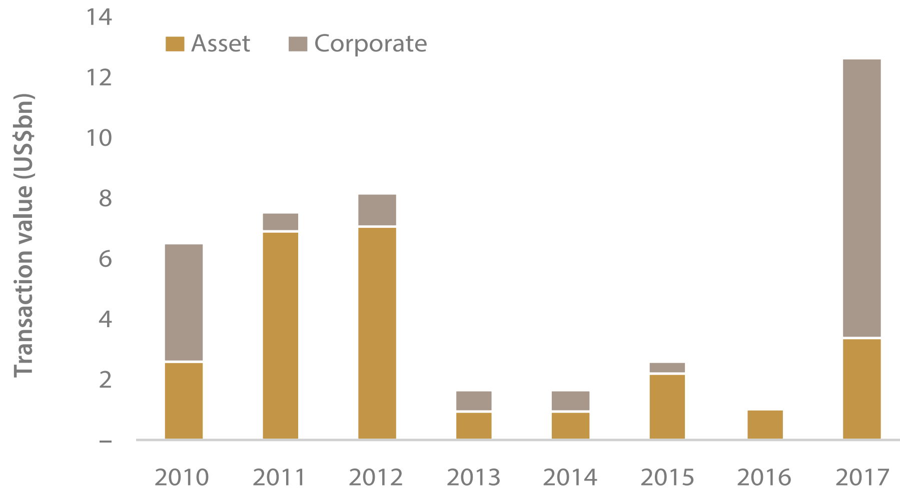

Figure 3: Equity raised in London for E&P companies. (Source: London Stock Exchange)

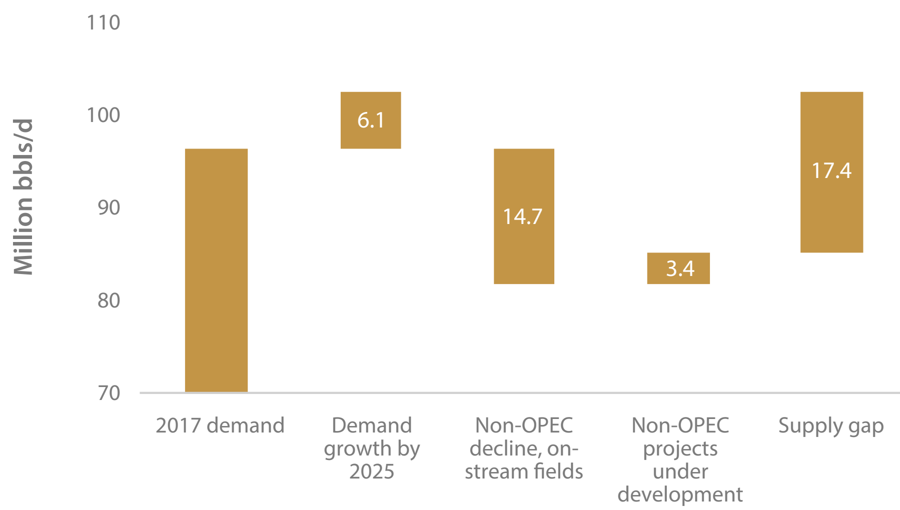

Figure 4: Supply gap to 2025. (Source: Woodmackenzie)

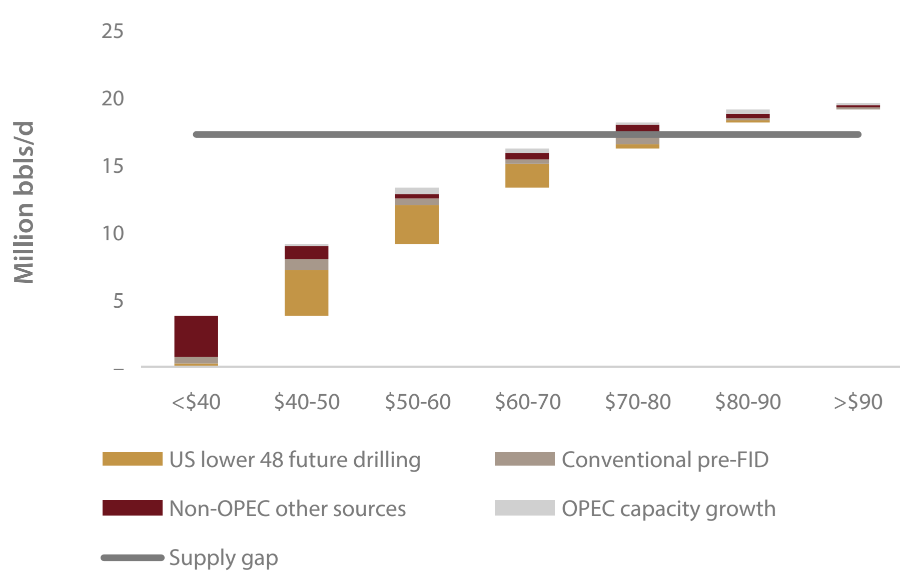

Figure 5: New supply required to fill the gap.

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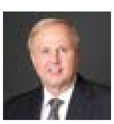
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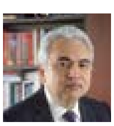
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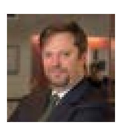
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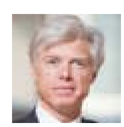
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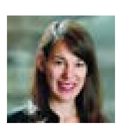
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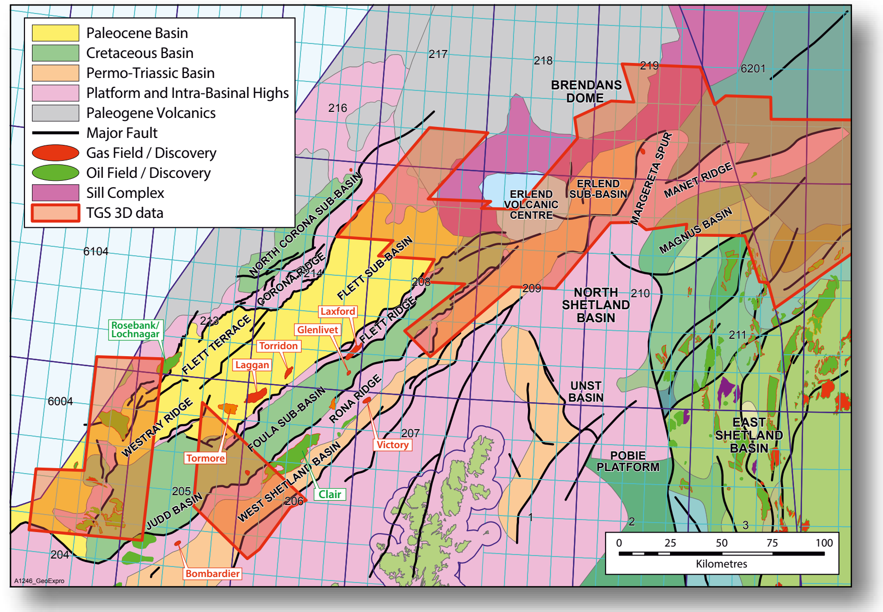
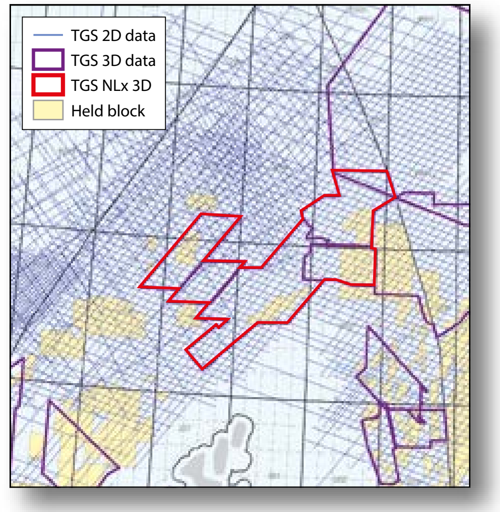
Exploring

West of Shetland:

The Northern Flett Sub-Basin

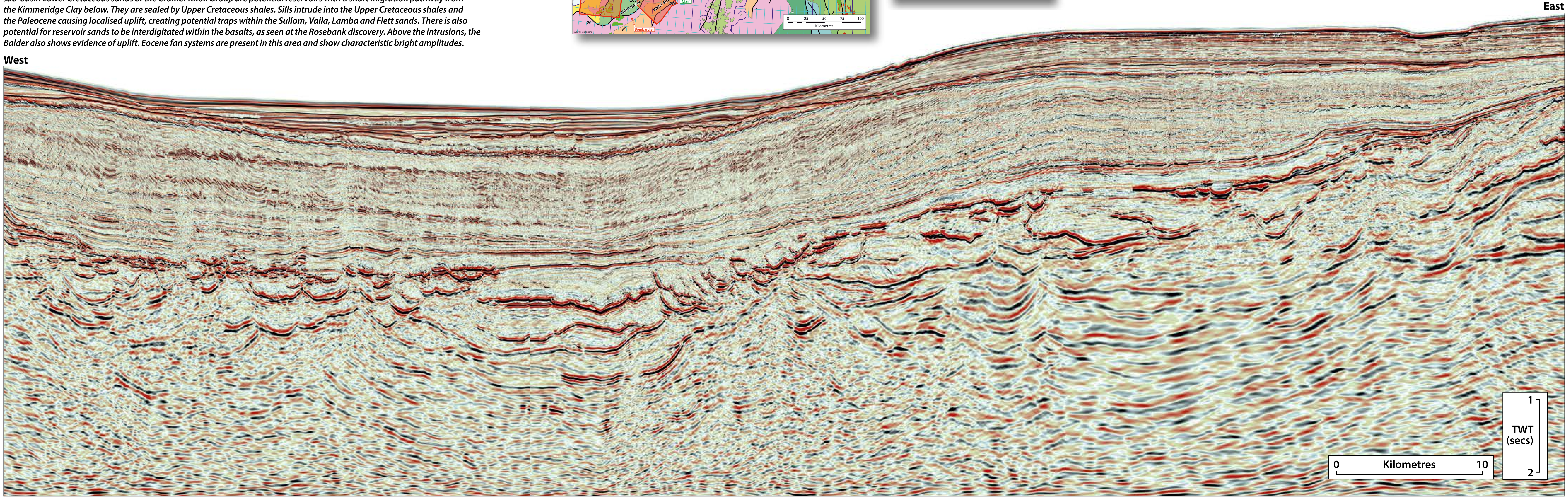
Below: Approximate west–east view through the Flett Sub-Basin on the TGS Northern Lights 3D seismic survey. There is a large central ridge formed by a tilted Jurassic fault block with extensive Cretaceous sub-basins either side. In the eastern sub-basin Lower Cretaceous sands of the Cromer Knoll Group are potential reservoirs with a short migration pathway from the Kimmeridge Clay below. They are sealed by Upper Cretaceous shales. Sills intrude into the Upper Cretaceous shales and the Paleocene causing localised uplift, creating potential traps within the Sullom, Vaila, Lamba and Flett sands. There is also potential for reservoir sands to be interdigitated within the basalts, as seen at the Rosebank discovery. Above the intrusions, the Balder also shows evidence of uplift. Eocene fan systems are present in this area and show characteristic bright amplitudes.





The TGS Northern Lights 3D seismic survey (NLx) comprises a merge of five high-quality broadband-processed 3D datasets of over 10,000 km² in the West of Shetland area. The original 3D surveys were acquired between 2012 and 2014 as a result of industry interest in the area following extensive long-offset 2D acquisition in previous years. The Northern Lights survey images a number of geological basins; this article aims to summarise the known play potential and identify areas of overlooked prospectivity in one of these: the Northern Flett Sub-Basin.

TGS



Prospectivity in the West of Shetland Region

Prospectivity redefined with recent 3D seismic in this underexplored region.

ALEX BIRCH-HAWKINS, ASHLEIGH HEWITT, JAMES CLARKE, Dr. JENNIFER HALLIDAY AND WILL BRADBURY; TGS

Since 1972, 151 exploration wells have been drilled West of Shetland and discoveries have been made in intervals from fractured Lewisian basement through to Eocene-aged sediments. Major oil discoveries, such as the Clair, Lancaster and Schiehallion fields, demonstrate the significant potential of the area. High-profile gas discoveries at Tobermory and Cragganmore have increased interest in the northern region, but the recent industry downturn has slowed exploration further to the north and east.

TGS have continued to show commitment to the West of Shetland region, acquiring multi-client seismic data in areas that we believe hold future potential, such as the extensive Northern Lights 3D covering the northern limits of the Flett, Foula and Erlend Sub-Basins.

The Flett Sub-Basin

The West of Shetland area is characterised by south-west – north-east trending sub-basins separated by Palaeozoic ridges. The Caledonian mountain-building orogeny caused uplift througout the area, and the Old Red Sandstone continental redbeds were deposited in intramontane basins, forming the dominant sediments associated with the older Palaeozoic highs. Mesozoic rifting formed the Flett Sub-Basin, resulting in deposition of thick Middle Jurassic to Paleocene sediments. In addition to this, the North Atlantic opening was heavily associated with volcanics and sills of Upper Cretaceous to Paleocene age, controlling and deforming the basinal sediments pre-, syn-, and post-depositionally.

The Jurassic Kimmeridge Clay is present throughout the Flett Sub-Basin and is proven to have reached thermal maturity, generating and expelling hydrocarbons encountered in the discoveries throughout the West of Shetland region. The intrusives form both trapping geometries (inflation anticlines) in structurally-shallower sediments and conduits for migration of hydrocarbons into the younger reservoirs. Here we examine three key play types in the Flett Sub-Basin: the Eocene fan play, the Paleocene play and the lower Cretaceous play.

Eocene Fan Play

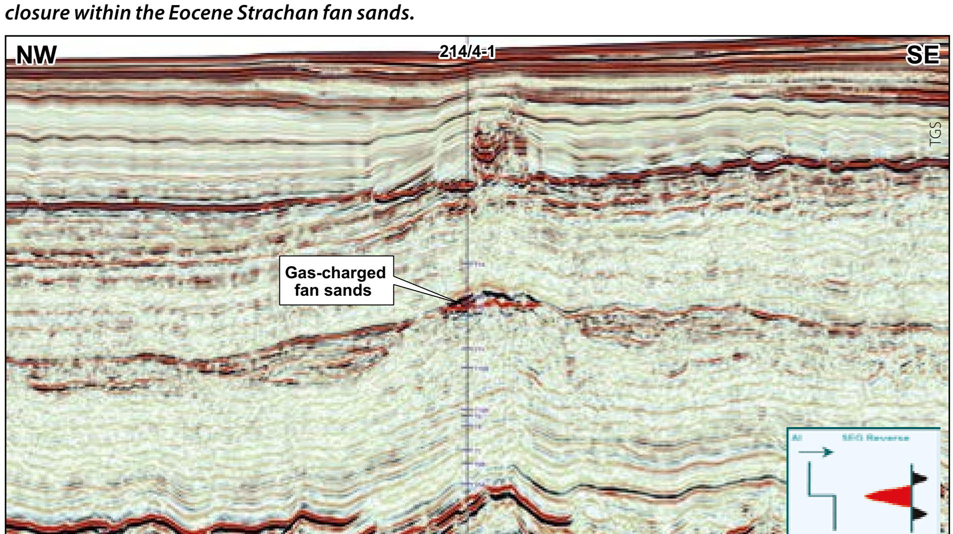
The extensive Eocene fan systems are present in the Flett Sub-Basin area and are the reservoir for the Tobermory gas discovery (Figure 1). The fan system contains several hundred metres of predominantly sandy Mid-Eocene fan deposits from the Flett High that are deposited within an Eocene to Oligocene section mostly comprised of mudstones. They exhibit a net to gross in excess of 80%, with porosities of around 30% reported at the Tobermory discovery. This discovery proves successful hydrocarbon charge from the deep-seated Kimmeridge Clay source, with the sills playing an important role by providing the jointing and fractures necessary to create migration pathways for the hydrocarbons, whilst the overlying claystones form an effective seal.

Numerous bright amplitudes are evident within the Eocene fan systems to the east of Tobermory into the Northern Lights 3D survey. The approximate extent of the fan system can be identified from 2D data; however, the generation of 3D seismic attributes in the Eocene can highlight areas of lower risk reservoir compartmentalisation and higher seal competency which are critical for hydrocarbon exploration.

Paleocene Play

The West of Shetland Paleocene play encompasses a number of reservoir intervals and trapping mechanisms, generally sourced by the Jurassic Kimmeridge Clay

Figure 1: 3D seismic profile through the Tobermory well: 34m column of gas discovered in a four-way dip closure within the Eocene Strachan fan sands.



shales. Sands within the Flett, Lamba, Vaila and Sullom Formations have all been proven through the exploration of the region. The reservoir intervals are heavily impacted by the presence of co-eval basaltic extrusives and intrusive sills. The existence of intrusives allows for the formation of the well-documented jack-up play: post-depositional uplift of Paleocene reservoirs by underlying intrusive sill complexes, such as the Danian-age Tulipan Discovery in the Møre Basin in 2006. This play type can be readily identified through structural mapping of the key reservoir formations, however, there is further potential to better predict reservoir distribution within the Paleocene by understanding timing of structural uplifts and depositional mechanisms.

The 3D data assists in building a geological model to better predict sand presence where seismic identification of Paleocene reservoir is challenging due to the existence of the basalts. Flett reservoir sands are known to interdigitate with basalts, as proven by the Rosebank and Bunnehaven discoveries, however, the strong acoustic impedance of the basalt masks the seismic expression of the sands in these locations. Elsewhere, there remains evidence for sandstone presence controlled by older intrusions. Figure 2 shows an example of Flett-aged sediments onlapping older Lamba/Vaila sediments due to the intrusion below. The onlap suggests these Flett sediments ponded around the Lamba/Vaila forced fold structure (A) formed by the intrusion. Furthermore, it appears that a later Balder-age intrusion has inverted the Flett (B), causing the ponded sediments to sit structurally shallower than the Lamba/Vaila structure that controlled their deposition. Further study of these sediments and their relationship with the multi-phase intrusions is required; however, this suggests that understanding the local structural timings and depositional mechanisms is critical in play concept development and prediction of lithologies.

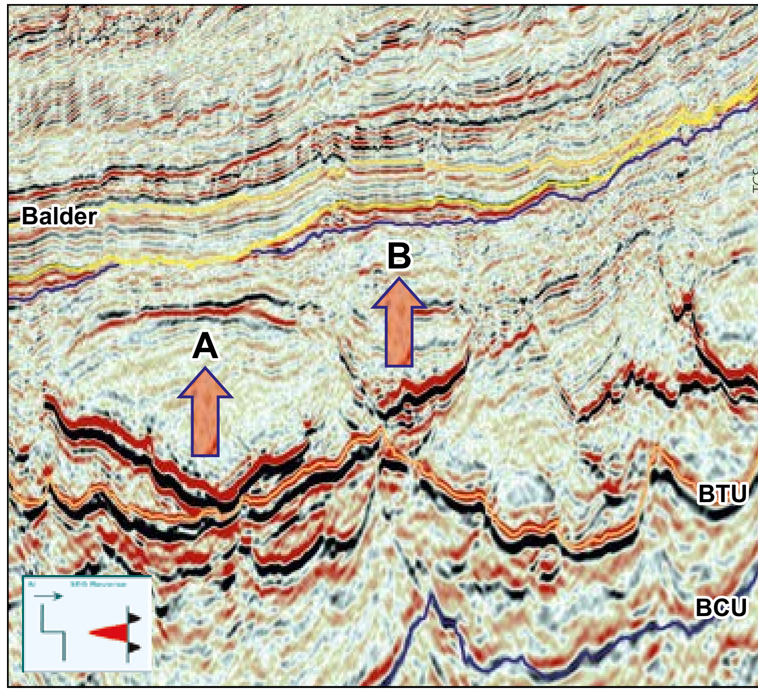


Figure 2: Evidence for inflation anticlines controlling Flett sediment deposition on 3D seismic data. Higher amplitude Flett sediments (between the yellow and blue horizons) onlapping an older inflation-related anticline (A). This is followed by a separate later inversion of the Flett sediments (B).

Lower Cretaceous Play

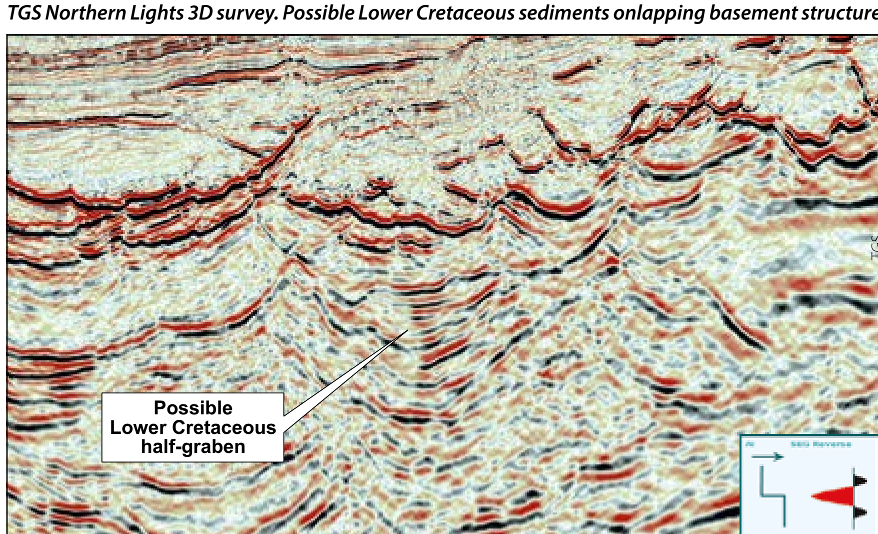
The Victory Formation forms the primary reservoir in this play, charged by the underlying Kimmeridge Clay. Areas where the Lower Cretaceous sediments onlap basement structures form the main targets in faulted combination structural-stratigraphic traps. The major discoveries in this proven play have been found along the West Shetland Platform and the north-east extensions of the Rona and Flett Ridges, however the 219/28-2Z discovery demonstrates the potential as far north as the Brendan Basin.

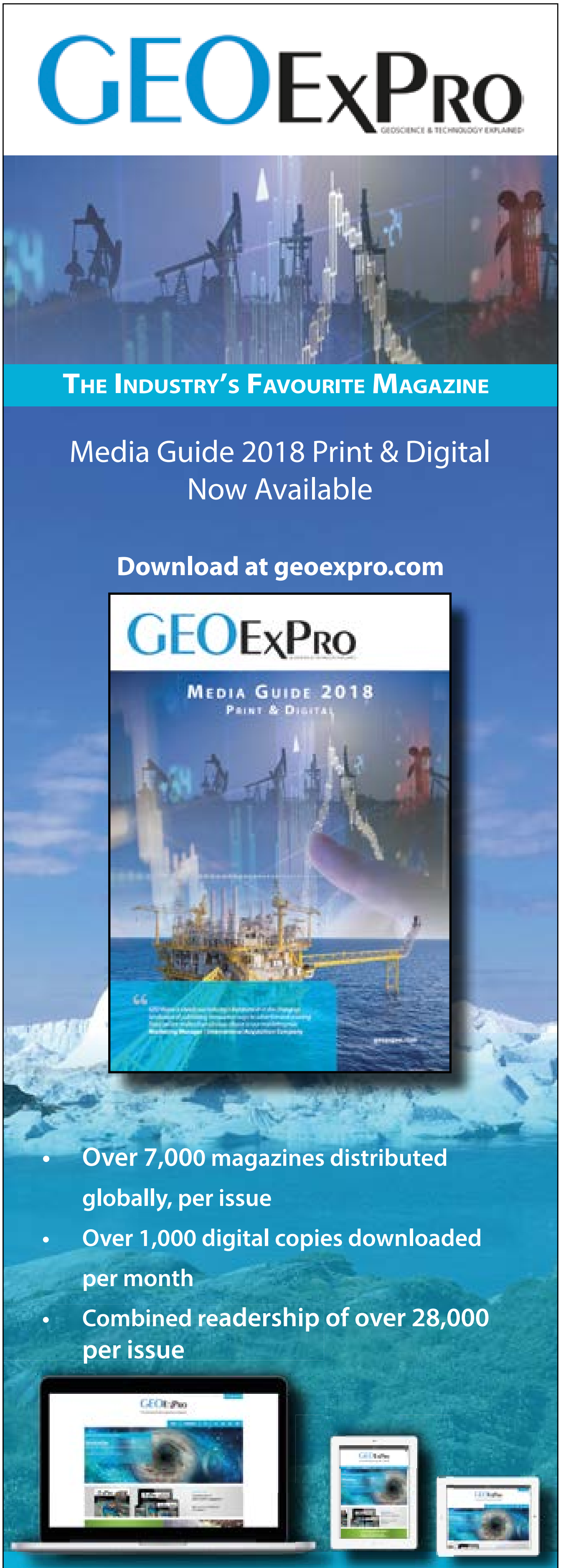
Figure 3 shows an example of a Lower Cretaceous half-graben consisting of sediments onlapping a possible basement structure beneath intrusives. Note the amplitude variation between half-grabens beneath the sills: these seismic facies changes could be mapped on 3D data in this area and potentially used to constrain gross depositional environment maps.

Improved imaging is contributing to a much greater understanding of the complexities that exist within this underexplored area and can help to realise the potential of this proven hydrocarbon region. Further refinement of play concepts will help to evaluate exploration targets, leading to potentially highly lucrative future discoveries.

References available online. ■

Figure 3: Evidence for imaging of Lower Cretaceous half-grabens beneath extensive intrusive sills on TGS Northern Lights 3D survey. Possible Lower Cretaceous sediments onlapping basement structure.

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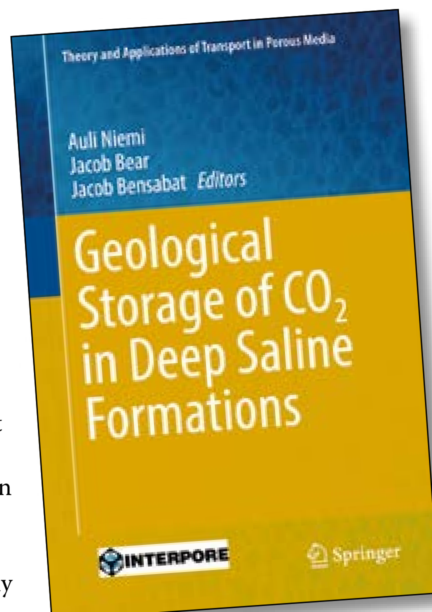
Geological Storage of CO_2 in Deep Saline Formations

PROF. JOHN GLUYAS

Volume 29 in Theory and Applications of Transport in Porous Media
Niemi, A., Bear, J., and Bensabat, J. (Eds). Springer, 2017. ISBN 978-94-024-0994-9

This new book on carbon capture and storage (CCS) might be perfectly timed to reach an eager audience. The storage of anthropogenic carbon dioxide emissions in deep saline formations and depleted petroleum fields is a transition technology to a low carbon (energy) future but one which has struggled to become established in any meaningful way. The problem is that first generation capture, compression and storage is expensive; not so much in the storage of CO_2 but rather the capture of dilute CO_2 in flue gases.

There have been thousands of studies and many trials and demonstration projects in North America, Europe and Australia, with less activity in Asia and South America. African nations have studied but not trialled CCS. Few governments have seized the opportunity to make CCS happen and demonstration projects have been cancelled at the eleventh hour, citing high costs. Norway alone has run a project for 20 years, at Sleipner in the North Sea. However, this parlous situation is changing. The global Oil and Gas Climate Initiative, created by 10 multinational and national petroleum companies, aims to ensure CCS is developed as part of the effort to maintain global temperature rise below 2°C. The early signs are that this organisation is making sufficient investments for CCS to take off properly. Within this setting, the information contained in this book will likely prove invaluable.



Ten Chapters

The book comprises 10 chapters. The first covers the concepts behind CCS including the impact of greenhouse gases on climate and likely consequences of climate change, while the second examines the processes involved in the geological storage of CO_2, with case histories. Chapter 3 is titled *Mathematical Modeling of CO_2 Storage in a Geological Formation* and Chapter 4 is similarly titled *Mathematical Modeling: Approaches for Model Solution*, a little misleading since both chapters cover the physics and reservoir engineering aspects of CO_2 storage, though Chapter 4 is rather more detailed, with three case histories apparently of real or proposed storage sites. However, it is not clear that the modelling work presented in any of these examples has been ground-truthed against measured information from real sites.

Chapter 5 addresses the perennial problem of upscaling from laboratory to field scale, with Chapter 6 called *Laboratory Experiments*. It is of course not a pre-requisite to read chapters in order but since several of the properties addressed in Chapter 6 are upscaled in Chapter 5, these two chapters might well have been presented the other way around.

Site Characterisation is covered in Chapter 7. Much of the first half of the chapter will be completely familiar to petroleum geoscientists and much of the second half to petroleum and reservoir engineers. Site characterisation is, of course, a critical component of any carbon storage development and this chapter gives the topic comprehensive treatment.

Chapter 8 is called *Field Injection Operations and Monitoring of the Injected CO_2*; while injection is mentioned frequently in the chapter it is in the context of monitoring during injection rather than as implied by the part title, 'injection operations'. Nonetheless, the coverage of monitoring techniques is good and there are real case histories of monitoring reported. I was puzzled why Chapter 9 was called *Natural Analogue Studies*. Half of the examples are CO_2 injection sites; great stories and important sections within the chapter but only a few of the cases presented are natural or mixed CO_2 petroleum accumulations.

Chapter 10 covers storage risks and risk management policy. At 20 pages it is not much more than a taster of what will happen if CCS becomes an established technology. This is a key topic for development along with new, continuous, passive monitoring technologies.

Comprehensive and Balanced

This is an intense book, heavy (necessarily) on equations and narrative but light on illustrations, some of which are not of the highest quality and difficult to read. A few would have been better bigger. The referencing is by chapter and fairly comprehensive. Given the explosion of articles on carbon storage the editors have a pretty reasonable balance from the main regions of contribution and expertise in the USA, Canada, Europe and Australia.

This book is more comprehensive and better balanced than preceding books on carbon storage (including my own). If carbon storage becomes a mainstream technology, then this book will become a classic and we can expect to see well-thumbed copies on the bookshelves of those charged with storing CO_2 in deep saline formations. ■

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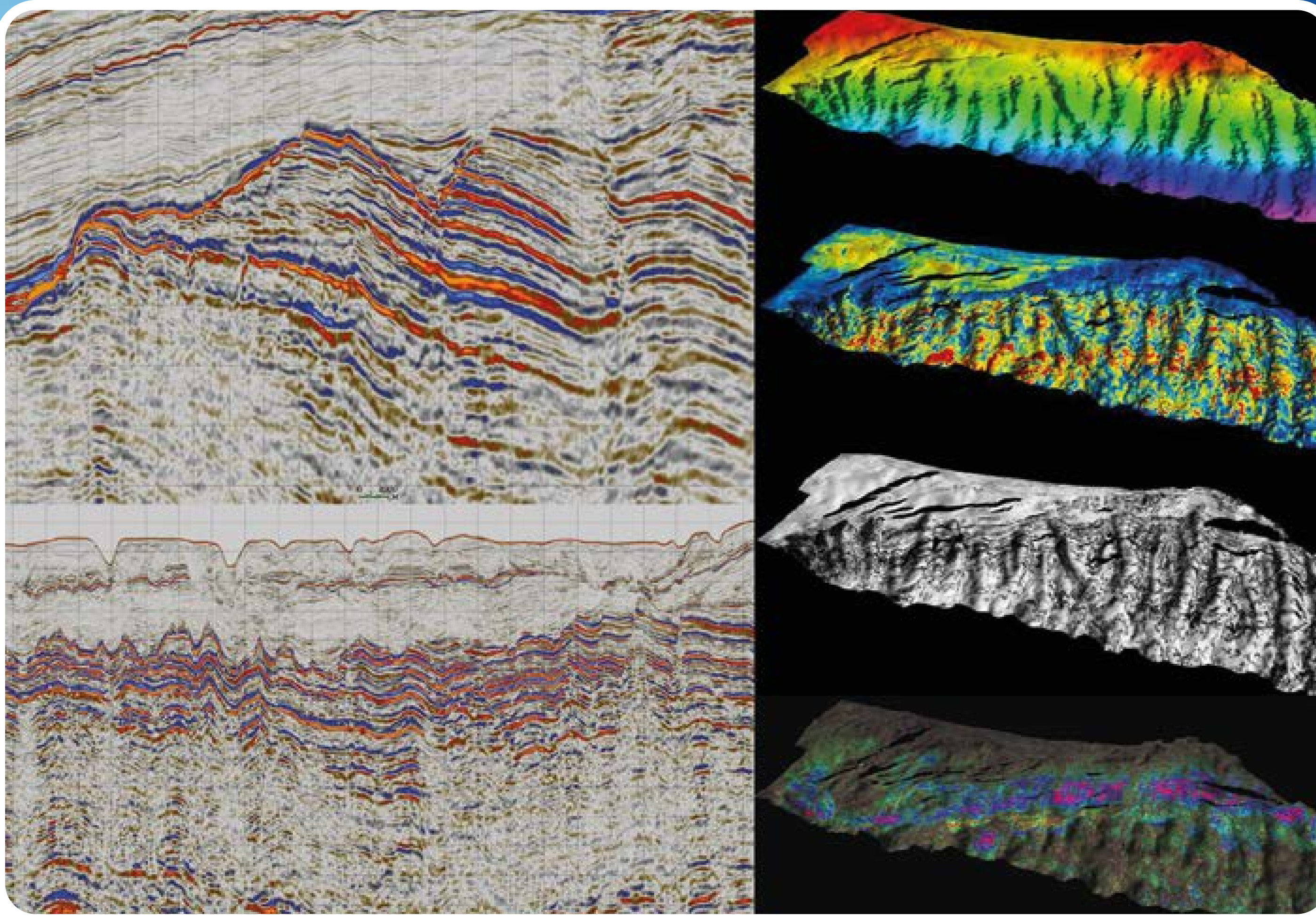

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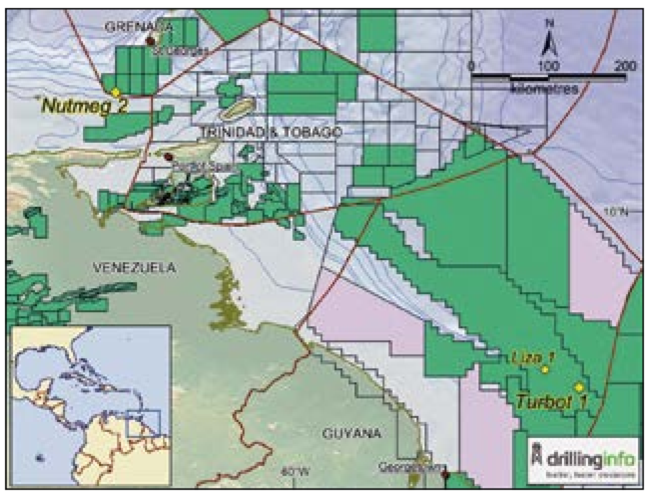
Grenada: First Discovery

In late October 2017 **Grenada's** Prime Minister, Keith Mitchell, cautiously confirmed the country's first discovery, saying that **Global Petroleum Group (GPG)** found indications of natural gas while drilling the **Nutmeg 2** new field wildcat in offshore **Block 8** in the Tobago Trough, about 100 km south-west of the island in 180m of water. However, Mitchell, who is also Energy Minister, added that further evaluation is needed before the Caribbean nation could claim its first commercial natural gas discovery.

Sources said the well was plugged and abandoned without testing, though GPG did run logs, reportedly in Miocene objectives at a depth of around 2,743m. The well also investigated a secondary Eocene objective below 3,000m. Sources said GPG found indications of gas whilst drilling, after the well was sidetracked because of technical problems. No other details were available on the sidetrack, and Nutmeg 2 reached TD at about 3,352m in late September 2017. GPG now plans to farm-out part of its 100% working interest in the block before it begins drilling a follow-up well. In all, GPG has 11 licences extending across 7,450 km^2.

If commercial, the discovery would bode well for the country. The underexplored Grenada Tobago Basin acreage is adjacent to the Venezuelan/Trinidadian Patao-Poinsettia gas trend, and Nutmeg was drilled close to Grenada's maritime border with Venezuela. Grenada recently passed a Hydrocarbon Exploration Incentive Bill 2017 to spur further exploration for oil and gas, successfully gaining more companies interested in the island. ■



Guyana: Additional Stabroek Find

ExxonMobil announced on 5 October 2017 that it had made its fifth discovery offshore **Guyana** with the **Turbot-1** new field wildcat. Located in the south-eastern portion of the **Stabroek Block** in the **Guyana-Suriname Basin**, the well, which was drilled to 5,622m in a water depth of 1,802m, encountered a 23m-thick reservoir of high-quality, oil-bearing sandstone in the primary objective.

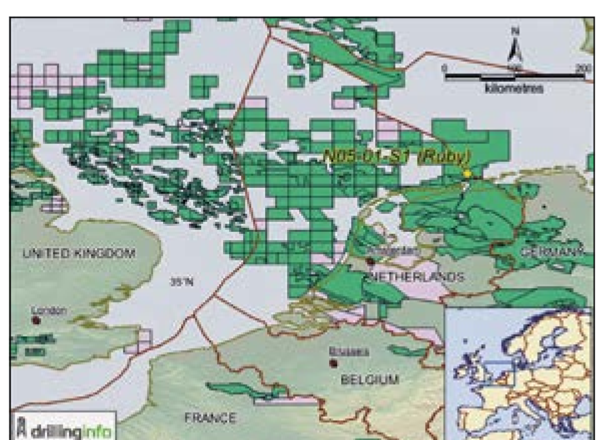
Turbot-1 is about 50 km south-east of the **Liza** field and was targeting a similar stratigraphic play type. It was spudded on 14 August 2017 and a follow-up well is now planned for next year. The discovery means that gross recoverable resources for the Stabroek Block, which includes the Liza, Liza Deep, Snoek and Payara discoveries, are likely to rise above the current estimate of 2.25–2.75 Bboe. ExxonMobil is currently undertaking a 3D/4D survey covering a broad swath of the Stabroek Block, which is due to be completed in early November 2017. It is expected that around 2,215 km^2 will be acquired, focused around and north-west of the Liza, Payara and Snoek discoveries. ■

Netherlands: Significant Discovery and Appraisal

Hansa Hydrocarbons confirmed on 26 September 2017 that its new field wildcat **N05-01-S1** in the Dutch **N05** block was a significant gas discovery in the Permian Lower Rotliegendes, with 24m net interval of high permeability sands, thought to be Findorf sands. A DST in the vertical well tested 53 MMcfgpd, although flow rates were limited by surface equipment. The discovery, known as **Ruby**, is the first well to be drilled targeting the basal Rotliegend sands; it is also the first in the area since the early 1990s and the first well to be drilled with the benefit of 3D seismic data.

The well spudded on 1 May 2017 but it was junked and sidetracked on 13 May. TNO, which oversees developments in the Dutch hydrocarbon industry, confirmed the well as a success. A down-dip sidetrack appraised the discovery, with operations concluding on 25 August 2017.

The block, which lies in 25–30m deep water, forms part of the **GEms** acreage, named for its location in the Ems estuary and which includes Dutch blocks N04, N05, N07c and N08 and extends into German waters. In January 2017 Hansa farmed out half its equity in the Dutch GEms licences to Oranje-Nassau, including operatorship of the N05 well. In addition to Hansa Hydrocarbons Ltd, which now holds 30%, the partners in N05 are Oranje-Nassau Energie BV with 30% and Energie Beheer Nederland with 40%. They have also identified prospects in the Dutch and German GEms acreage, with 2 Tcfg estimated mean in-place prospective resources across the licences. ■

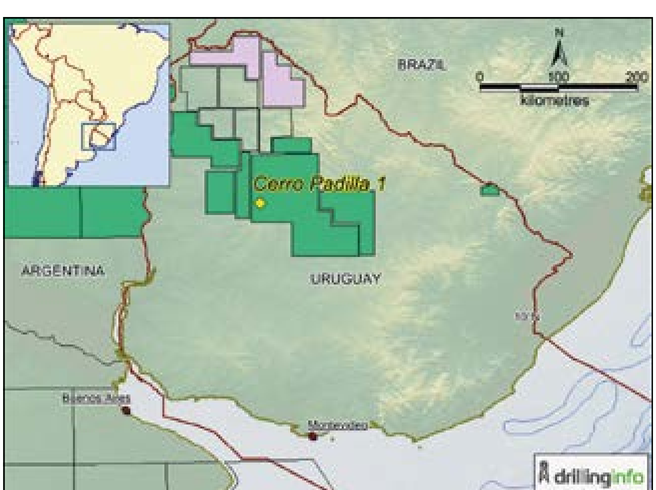


Uruguay:
First Technical Discovery

Hopes that Uruguay had made its first oil discovery were dashed when Australian operator, **Petrel Energy**, which has a 51% controlling interest in Uruguay oil and gas explorer **Schuepbach Energy**, said that testing of 2m oil-saturated sand from its **Cerro Padilla-1** exploration well on the onshore **Piedra Sola Block** was not considered a success. It did, however, mark the first time a well had been tested in Uruguay with oil being recovered to the surface, thus making it the first technical, if not commercial, discovery in the country. Petrel CEO David Casey attributed the lack of commercial success in the test to the well location being off structure at the base of a thin oil zone but said it bodes well for the rest of the drilling programme and especially the next well, which has multiple and much larger potential targets.

Cerro Padilla-1, which is located about 300 km due north of the capital, Montevideo, had a pre-drill P90 oil in-place estimate of 21 MMbo. It was spudded on 4 June 2017 with the aim of confirming the reservoir potential of the Permian Tres Islas Sand and the Permian source rock at a shallow depth. It is part of an ongoing four-well drilling programme on the Piedra Sola and Salto concessions and also targets structures that could hold oil and gas within the same stratigraphic sequence or updip of oil shows and weeping core samples. The previously drilled Cerro Padilla E-1 corehole found a 3m possible reservoir with fluorescence confirming a potential oil charge.

The rig is now mobilising to the Cerro de Chaga-1 and Panizza-1 wells in the Salto permit, which lies to the north-east of the Piedra Sola Block. The drilling programme and its geological model were developed from the reinterpretation of a 597 km 2D seismic programme completed in late 2014. Interpretation of additional seismic data, completed in early 2015, revealed an initial 20 conventional structural targets and others at shallow depths. It also confirmed the existence of a deeper sedimentary sequence in the Salto concession. Petrel said in the statement that one of the Salto wells will target a shallow AVO gas anomaly that has a certified prospective P50 resource estimate of 240 Bcfg. Schuepbach is currently seeking partners for the blocks. ■



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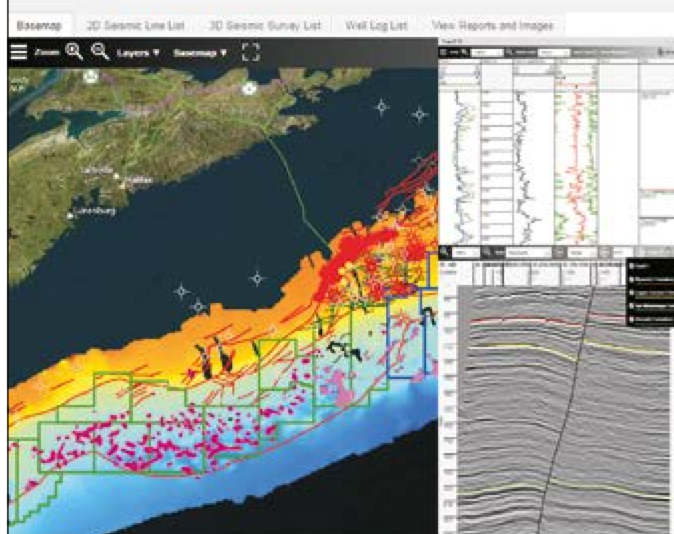

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Showcasing Women in the Energy Sector

"Diverse teams deliver the best decisions," explains Beverley Smith, Director of POWERful Women, an organisation which aims to advance the professional growth and leadership development of women across the UK's energy sector.

Can you tell us a bit about POWERful Women and its aims?

POWERful Women was launched by Baroness Verma and Laura Sandys in summer 2014, with Ruth Cairnie, former Executive Vice President for Shell, joining as industry chair in 2015. It is a UK-based professional initiative which aims to advance gender diversity within the energy sector in the country – hence the pun with the word POWER! Our target is for 40% of middle management and 30% of executive board positions to be held by females by 2030 and we record companies which pledge support for advancing the professional growth and leadership development of women in the UK's energy sector.

How will it achieve these targets?

We aim to deliver these targets in three ways. Firstly, by campaigning for recognition of the targets and reporting progress throughout the various power industries; secondly, by supporting women in their careers, through advice and mentoring; and thirdly with practical support through events and networking and also the provision of resources that help companies tackle gender diversity. On our website, for example, (www.powerfulwomen.org.uk) there is an expanding repository of resources which is free to use and includes signposts to toolkits, articles, case studies and a wealth of other reference material to support and inform positive action.

What attracted you to the organisation?

POWERful Women is a committed but friendly organisation determined to make a real difference. We have several events a year ranging from speed mentoring and networking through to the launch of our annual board statistics. Gender diversity makes clear business sense and I think this organisation understands that and is committed to enabling businesses to help themselves.

We've been talking about this for a long time: are we actually making progress?

Yes, we have reached a real turning point in the UK now, I think. The government is committed to change, and the Davies and Hampton-Alexander targets, which are aimed at increasing the numbers of women on boards and in the executive pipeline, are making a difference. The gender pay gap reporting which will be published in April 2018 will also enable us to look at the percentage of women in each salary quartile, at least for companies with more than 250 employees. It will be much more obvious then which companies are really working hard in this area.

What are the most important thing(s) the O&G industry can do to empower women?

Set gender diversity targets, report them and track them. Try to sponsor and support women because in general women tend to be less confident about putting themselves forward than men. Remove the unconscious bias that results in people recruiting in their own image.

And what can each of us do individually?

Everyone should ask what targets their company has and how they are tracked. Women should seek out mentors and sponsors to support them: the POWERful Connections section of our organisation supports senior women in reaching energy's 'top table' by linking them with some of the biggest names in the sector for several months of one to one mentoring. And don't be afraid to put yourself forward! ■

Beverley Smith is a chartered geologist with more than 25 years of expertise in the oil and gas industry, predominantly with BG Group. She was Exploration Manager for BG in Algeria and Exploration and Development Manager in China, and was Vice President Exploration and Growth (Europe) until the company's merger with Shell in 2016. She has been Director of POWERful Women since January this year.

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How Much Oil?

World oil output continues to increase – but if we experience a decline next year, it might be a consequence of lack of investments since 2014.

"The energy transition is taking place much faster than most people realise" is a commonly heard phrase. The backdrop here is that the old economy, fuelled largely by fossil fuels, is being replaced by one powered by renewables, in particular solar and wind energy. The reason, they say, is obvious: the cost of solar panels and windmills are falling fast in a growing number of electricity markets.

Have you heard this before? Is it correct? Or are the fortune-tellers being too optimistic about how fast the transition is moving?

Let's look at some numbers.

Using BP as a source it can be shown that the world's oil production has risen from 65,800 bpd in 1992 to 92,200 bpd in 2016. This is equivalent to an increase of 40%, or, to put it differently, an average increase of 1.35% annually. The largest annual increase in this 25-year period was experienced as recently as from 2014 to 2015, when the growth was almost 3,000 bopd. The last decline from one year to the next was from 2008 to 2009 (a percentage decrease of almost 1%). Those old enough will associate this with the financial crisis that hit the world in 2008; it had nothing to do with renewables.

Interestingly, oil production also increased last year, from 2015 to 2016, but the growth rate of 0.5% was less than the 25-year average.

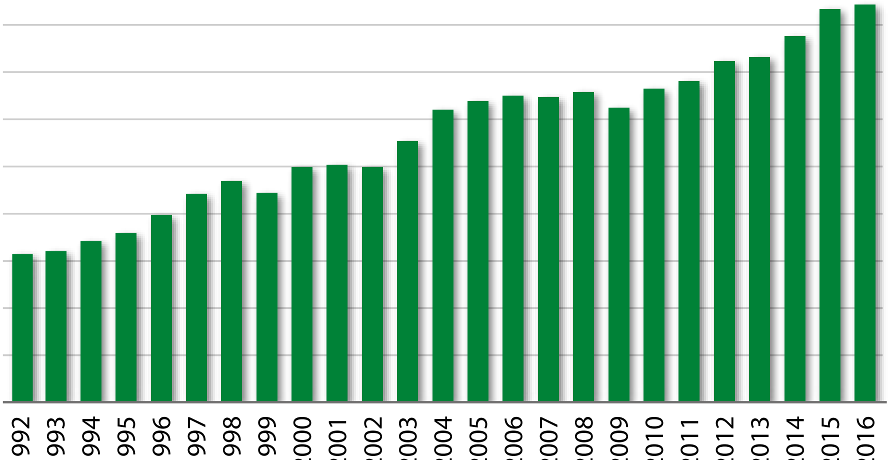
The graph below illustrates another important point. The growth is by no means even and in four of the years from 1992 to 2016 we experienced a decline. Predicting future production from this curve is therefore without value if we know nothing about investments in oil production. For example, while oil and gas companies have spent considerably less since the oil price went to rock bottom in 2014 (as we have all experienced), production has remained relatively stable since 2015. The explanation is straightforward: projects committed to at a high price – when it was too late to reverse decisions – have come into production. The situation is different for mature fields that need infill drilling to prevent declining production. Short-term investments are easy to postpone.

The lesson to be learnt is that if we see reduced production next year, the reason might be that oil is being replaced with renewables – or it may be the result of not enough investment in new projects following the 2014 disaster.

The graph below demonstrates that oil has (still) not been replaced by renewables. The next report from BP will be met with curiosity.

Halfdan Carstens

World-wide production of oil from 1992 to 2016 according to BP Statistical Review of World Energy. For clarity the baseline is 50,000 bopd.



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.

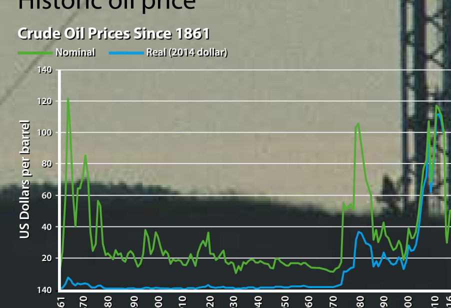
Numbers
Million = 1×10^6
Billion = 1×10^9
Trillion = 1×10^{12}

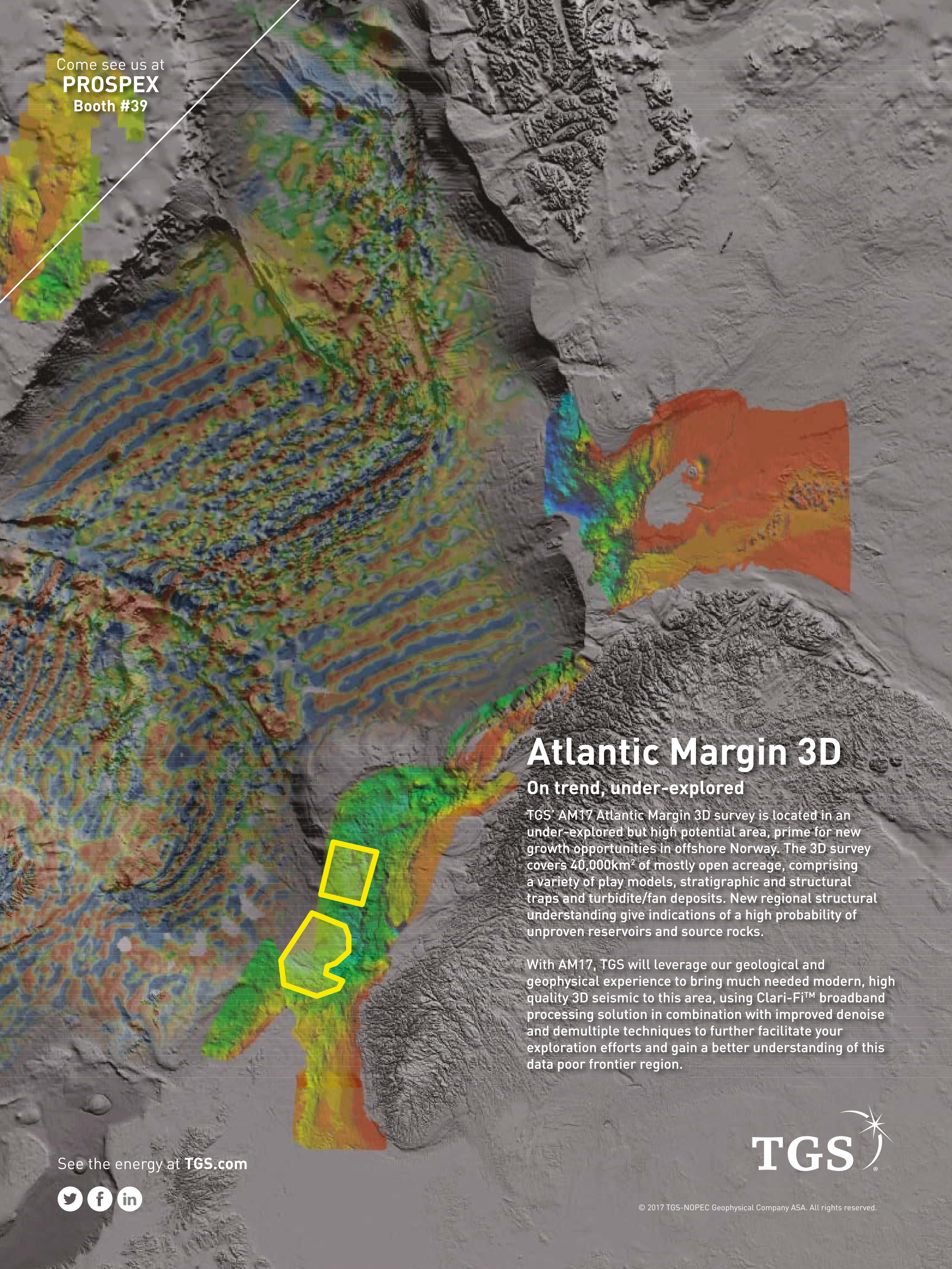
Supergiant field
Recoverable reserves > 5 billion barrels (800 million Sm^3) of oil equivalents

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




Come see us at
PROSPEX
Booth #39
Atlantic Margin 3D
On trend, under-explored
TGS' AM17 Atlantic Margin 3D survey is located in an under-explored but high potential area, prime for new growth opportunities in offshore Norway. The 3D survey covers 40,000km² of mostly open acreage, comprising a variety of play models, stratigraphic and structural traps and turbidite/fan deposits. New regional structural understanding give indications of a high probability of unproven reservoirs and source rocks.
With AM17, TGS will leverage our geological and geophysical experience to bring much needed modern, high quality 3D seismic to this area, using Clari-Fi™ broadband processing solution in combination with improved denoise and demultiple techniques to further facilitate your exploration efforts and gain a better understanding of this data poor frontier region.
TGS
See the energy at TGS.com
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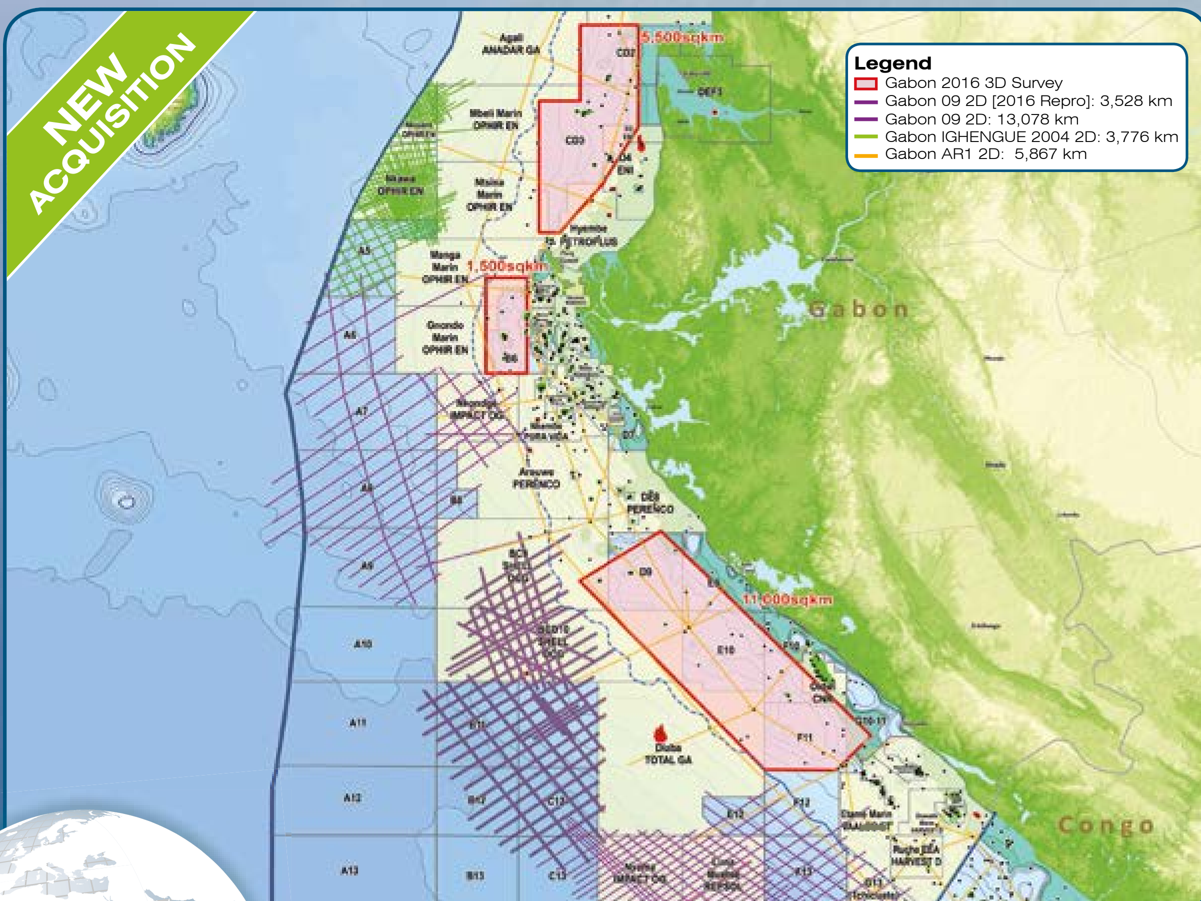
multi-client seismic

GABON

Offshore Gabon 3D

New Multi-Client 3D Seismic in Open Acreage + Regional 2D



Spectrum, in collaboration with the Direction Générale des Hydrocarbures (DGH), are undertaking a number of shallow water 3D seismic surveys in open blocks to provide the industry with state of the art 3D broadband data. A variety of plays are targeted to allow a new generation of oil exploration in these prolific basins.

The 11,500 km² southern survey, now complete, is the definitive dataset to image the pre-salt and, for the first time, intra syn-rift plays can be targeted. In the North, acquisition of a 5,500 km² 3D survey is due to begin imminently to image pre and post-salt targets. Further acquisition is planned in Central Gabon, at the western edge of the Ogooue Delta where the under-explored shallow water plays are post-salt, proven and close to existing infrastructure.

Data will be made available for future License Round evaluation facilitating immediate activity when the blocks are awarded.

spectrumgeo.com
mc-uk@spectrumgeo.com
+44 1483 730201

in association with

Spectrum