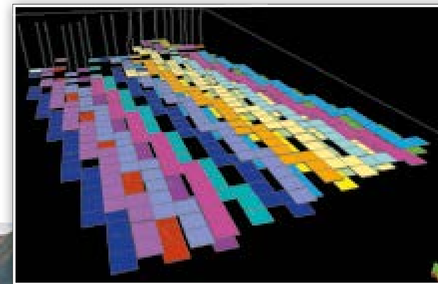
VOL. 14, NO. 3 – 2017

GEO ExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



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EXPLORATION:
Powerful Forecasting for Shale Reservoirs

GEO TOURISM
Playground of the Gods

GEO EDUCATION
Learning on the Rocks

EXPLORATION
Breaking Up Is Never Easy

INDUSTRY ISSUES
Resource Nationalism in the Caspian

GEO ExPro
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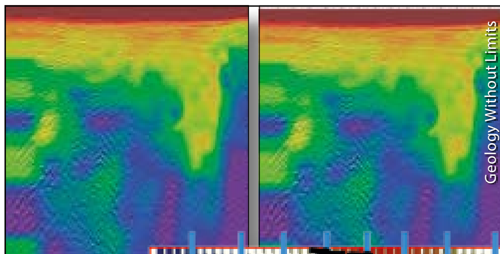

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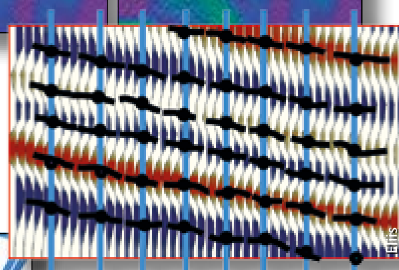

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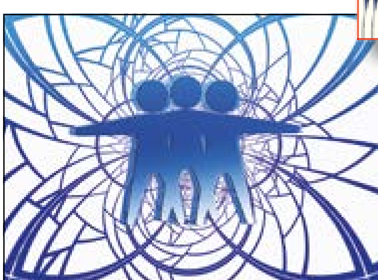

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This edition of *GEO ExPro* magazine focuses on Europe, Russia and the Near East; unconventional exploration; and collaboration and team building.

Fit for the Future

Two years into the downturn and still counting – but also still drilling and producing oil and gas. Since 2015 amazing strides have been made in efficiencies and technological advances, meaning that breakeven prices have dropped dramatically. It is reported that even traditionally high cost areas like deepwater sub-salt can now be made economic at an oil price of less than US $45 per barrel.

At the forefront of this productivity boom, of course, are the US tight oil plays, where increased and more efficient production has been spurred on by innovations in drilling, hydraulic fracturing and geosteering. As a result, production from the Permian Basin alone is up nearly 50% over the last three years.

This is an example of the very different industry which seems to be emerging from the price abyss; one that needs to be agile and dynamic to optimise its assets. The word that seems to epitomise this new thinking is 'collaboration'. Adversarial attitudes should be a thing of the past, it is suggested, particularly in mature provinces like the North Sea, where partnerships between the growing number of smaller companies in that arena will be key to extracting resources in the most efficient manner. More collaboration between companies also means looking at issues differently and moving out of the corporate mind set. It should result in different and innovative ways of doing business.

Building long-term relationships with, rather than squeezing, the supply chain is key. Everyone has a part to play in the future of this business. E&P companies will need to develop new work practices with the service industry, sharing data and information and creating partnerships for technological advancement and greater efficiencies. Ultimately, collaboration between operators and suppliers should not just result in efficiency improvements, but in reduced costs.

Most importantly, collaboration must become part of everyday practice, not just theory, with a substantial shift in thinking, particularly with regard to the supplier-operator relationship. This needs to be done to ensure that when the price environment starts to improve we are ready for it with a new, revitalised and streamlined industry. Otherwise we will just slip back into the old cycle of boom and bust. ■

Jane Whaley
Editor in Chief

PLAYGROUND OF THE GODS

The Highlands of North West Scotland boast a huge range of landscapes, from stunning, snow-capped mountains to clean sandy beaches and tranquil lakes like Loch Assynt, seen here. They are underpinned by the oldest rocks to be found anywhere in Europe, where thrust structures were first discovered and proved by pioneering Victorian geologists.

Inset: Detailed, integrated simulation models can accurately predict the reserves and production of shale reservoirs.

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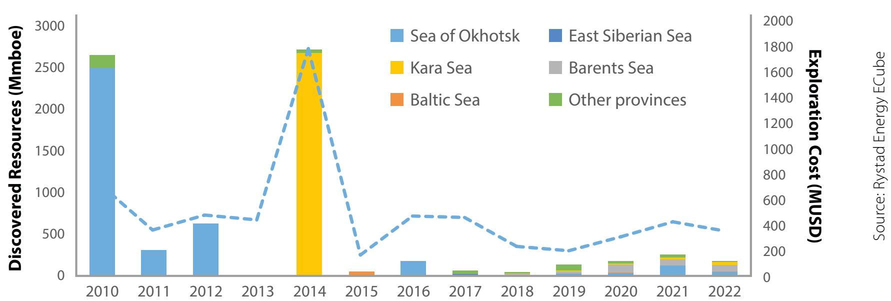
Russia: Fall in Offshore Exploration Investment

Scarce geological information and a reduction in exploration investments are a major hindrance to exploiting Russian Arctic Shelf potential.

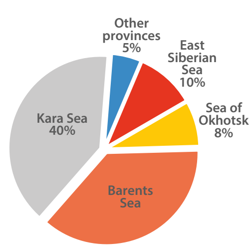
Since the 2014 discovery of Universitetskaya-1 in the Kara Sea, offshore exploration spending in Russia has fallen dramatically by 90%, dropping from US$1.8 billion in 2014 to around US$170 million in 2015, impacted by the fall in oil prices, sanctions, and rouble deflation. This decrease is also due to reduced activity on the western Russian shelf, i.e. the Kara Sea and the Barents Sea, where operation costs are very high. Offshore exploration was active in comparatively low-cost operational areas in the Baltic and Okhotsk Seas, but other than Universitetskaya-1, there have been no significant discoveries since 2011. New discoveries accounted for around 200 MMboe in total from 2015 and 2016.

Historically, the exploration trend in Russia has been switching from mature oil and gas areas to frontier provinces: first, it was the Volga-Urals, then Western Siberian. However, the current reserve growth in Western Siberian is mostly through enhanced oil recovery techniques rather than new discoveries, and the exploration focus now needs to shift further north towards the underexplored Arctic continental shelf, which holds unconstrained resources. This shift is in harmony with the global trend of a decline in 'easy' oil and a move to more expensive and geologically complex areas.

Rystad Energy estimates there are around 90 Bboe of undiscovered hydrocarbon resources in Russia, 40% of which lies in the Kara Sea and 37% in the Barents Sea. Both these regions have dense 2D seismic coverage and a working petroleum system, established by discoveries such as Shtokman and Prirazlomnoye. In addition, increasing activity in the Norwegian Barents Sea adds to the regional geological picture. However, the Eastern Siberian region, including the Chukchi and the Laptev Seas, have very poor data coverage in terms of both 2D seismic and wells, which is why Rystad Energy's yet-to-find estimates are heavily risked down and represent only 10 % of the total undiscovered potential. Despite high operational costs at the initial stage, the size of discoveries in these regions clearly indicates that the western Arctic shelf will play a crucial role in Russian hydrocarbon exploration in the near future.



Discovered resources and exploration costs.



Yet-to-find resources offshore Russia.

Reduced investment in exploration compels companies to consider more than the lure of high volumes, turning their focus to areas where government support and tax incentives increase the profitability of any discoveries made. Furthermore, under current Russian law private companies cannot have operating permits in Arctic waters, curbing the scope for investment in the Russian Arctic. After the easy discoveries of the mature Western Siberian Basin, this puts Russia in a fix as all frontier regions are offshore, underexplored and require high investment. With economic and legislative restrictions, it seems exploration CAPEX will remain low at least until 2019.

Aatisha Mahajan, Rystad Energy

ABBREVIATIONS

Numbers
(US and scientific community)

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

Liquids

barrel = bbl = 159 litre
boe: barrels of oil equivalent
bopd: barrels (bbls) of oil per day
bcpd: bbls of condensate per day
bwpd: bbls of water per day

Gas

MMscfg: million ft^3 gas
MMscmg: million m^3 gas
Tcfg: trillion cubic feet of gas

Ma: Million years ago

LNG

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

NGL

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

Reserves and resources

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

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

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

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

BGP Multi-Client New Acquisition in Offshore Cuba

~25,000 km multi-client seismic lines are to be acquired around offshore Cuba. The whole project will consist of lines in the economic zone of the GOM, lines in the south of the Bahamas Border, and lines in the southern sea of Cuba.

In-filled well-tie 2D seismic lines have been designed by BGP with the assistance of CUPET. These lines will help to improve seismic imaging in deep targets in offshore Cuba. The high density of seismic lines are designed in prospective GOM-CEEZ, where excellent levels of source rocks, reservoirs and leads have been identified in recent years.

The project will commence with three phases:

Phase I: ~20,000 km – Red lines

Phase II: ~2,500 km – Yellow lines

Phase III: ~2,800 km – Blue lines

BGP is one of the world's leading geophysical service companies, delivering a wide range of technologies, services and equipment to the oil and gas industry worldwide.

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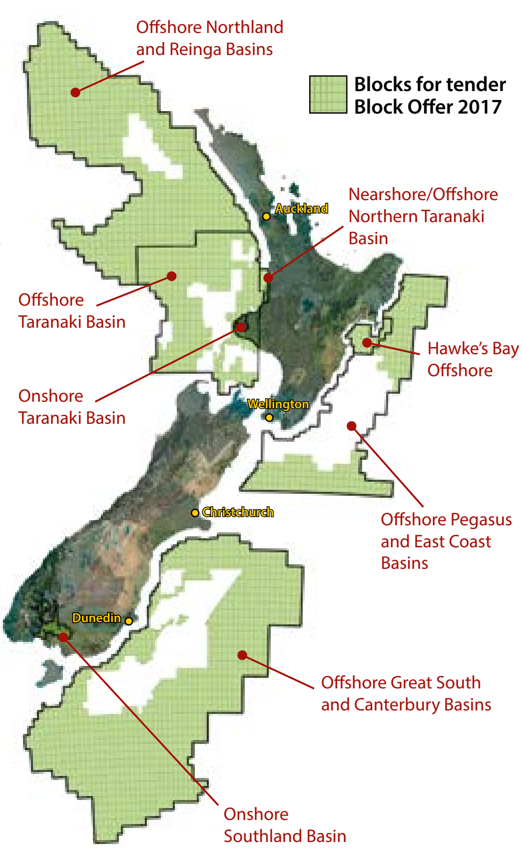
New Zealand: 2017 Block Offer

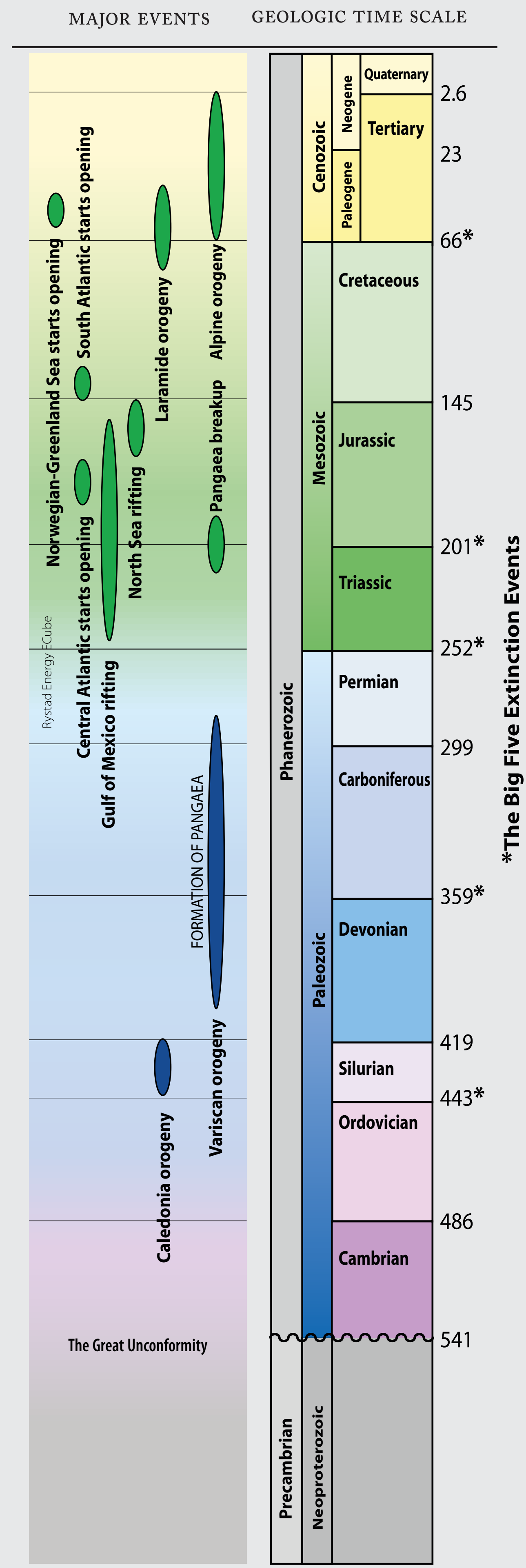
New Zealand has a long history of petroleum production, dating back to 1865, when the Alpha well was dug near seeps in Taranaki. This was followed by other wells in the area and the shallow Moturoa oil field was producing by the early 20th century. The modern era of exploration began in the 1950s with the discoveries of the onshore Kapuni gas-condensate field in Taranaki in 1959 and the large offshore Maui gas-condensate field in 1969, the latter making New Zealand self-sufficient in gas. New Zealand's EEZ and extended continental shelf covers over six million square kilometres and numerous play types have been identified in a range of petroleum systems in 10 petroleum basins. As of 2014, almost 6.7 Tcfg and 450 MMbo have been produced in the country, which is estimated to have 2P oil and condensate reserves of 240 MMb. New Zealand has a well-developed oil and gas infrastructure and a proactive globally-competitive oil and gas regime.

In March 2017 the New Zealand Energy and Resources Ministry (NZP&M) opened the Block Offer 2017 tender for petroleum exploration permits. This tender includes five offshore release areas, two onshore release areas, and one offshore/onshore area, totalling 481,735 km² and covering basins in the north-east, east and south-east of the country. Areas of importance to Māori, plus World Heritage Sites, national parks, nature reserves, wildlife sanctuaries and marine reserves are all excluded.

Currently all production in New Zealand comes from the Taranaki Basin and it is thought that exploration has not come close to realising New Zealand's true potential. Some of the offered areas, such as the Northland-Reinga and Pegasus and East Coast Basins, are relatively underexplored but have proven petroleum systems and are considered prospective for both oil and gas.

The assessment of bids for Block Offer 2017 considers the work the bidder proposes to undertake, their technical and financial capability to carry out that work, their compliance history, and their likely ability to meet New Zealand's health, safety and environmental requirements. The Invitation for Bids for Block Offer 2017 closes on 6 September 2017 and NZP&M expects to grant permits in December 2017. ■



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AAPG's 100th Anniversary Celebration

On 9 February 1917, geologists gathered in Tulsa, Oklahoma to start something special and enduring, which is still relevant today as the premier organisation for petroleum geologists.

I still remember my excitement after graduating in geology and being hired by an oil company to work in Alaska, America's 'last frontier'. Arriving on the job in Anchorage, I tackled the normal 'housekeeping' chores before getting down to a lot of training in that first year. However, one task still stands out, even after 44 years: becoming sponsored and applying for membership to the American Association of Petroleum Geologists – always known as the AAPG. It still rings as a proud moment that has stayed with me throughout my career. I had arrived and was determined to be the best geologist I could be. Attending the conference celebrating the first 100 years of this organisation has the same aura of excitement that will stay with us all and point the way forward.

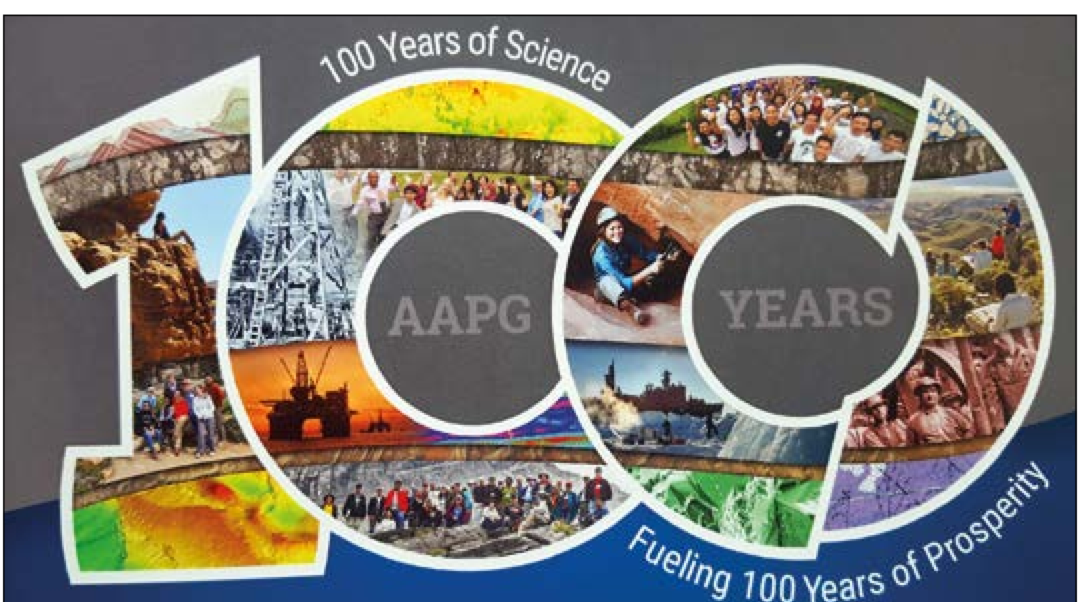
The thrill I felt just signing up for AAPG must have been pale compared to the meeting which took place in Tulsa early that February day in 1917. A great war was being waged in Europe and the US was just months from joining it. The industry was relatively young but with a promising future. The geologists that gathered that momentous day were drawn to this profession eager to see around the next corner or through the next doorway; possibly not much different from what I felt in heading to Alaska. The romance of this profession is still a draw and continues to excite.

I arrived in time to register and go upstairs to the George R. Brown Convention Center's Grand Ballroom in Houston, Texas, to attend the opening session and awards ceremony. Some of the honorees were geologists I have worked with, learned from, and admired. To get our attention, the ceremony opened with Richard Strauss's *Also Sprach Zarathustra*, probably better known as the theme tune from the movie *2001: A Space Odyssey*. After some introductory speeches, the honorees were introduced, given their plaques, and paraded to stage left. The last two, Edward D. Dolly, who received the Michel T. Halbouty Outstanding Leadership Award and Larry Meckel receiving the Sidney Powers Memorial Award, were both allowed to speak to this nearly full auditorium.

What they said would set the stage not just for this, the 100 Year AAPG Anniversary conference, but also into the next decades for this organisation. Edward Dolly commented that the educational opportunities and professional relationships offered to members of AAPG means a lot to all of us. "Be active, attend talks, network, keep learning" is a mantra that we all should use. Larry Meckel took this theme a step further, referring to his "resource pyramid" and paying tribute to the people that helped him develop a passion for geology. We all start with the many educators and mentors near the base, with people more important to our development further up the pyramid. Of those who inspire and lend him their unconditional support, the top spot for Larry goes to his wife Barbara – a sentiment that I am sure many of us will agree with in regard to our own lives and families.

From the opening ceremonies to my departure, the conference did not disappoint. It had something for everyone in the many themes that had been in the planning stages for about 10 years. I was encouraged to see so many excellent students and young professionals giving posters and talks, eager and ready to take the reins of AAPG and guide it into the next century. If they could see the organisation now, how it has grown and continues to expand our knowledge of this great field, I truly think those original organisers would be justifiably quite proud.

Thomas Smith



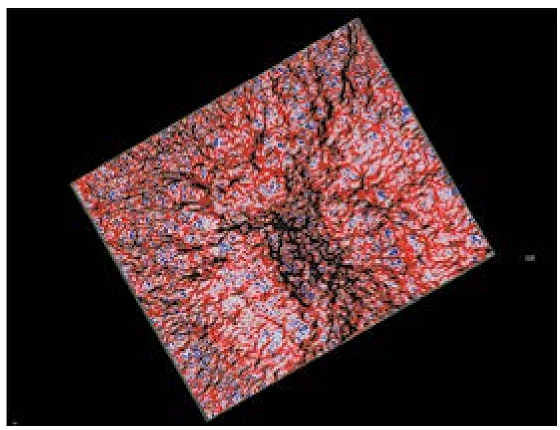
New Thinking, New Technology, New Hydrocarbons…

The annual **PESGB** and **HGS Conference on African E&P** provides the perfect opportunity for those with interests in the continent to come together. The conference has gone from strength to strength, establishing itself as a key event on African geology in the oil and gas calendar – and the 2017 conference promises to be bigger and better than ever. We will take the audience back to first principals and challenge pre-existing paradigms in Africa, highlighting new insights that will provide the foundations for the next generation of exploration, appraisal and development. Topics include the new geography of the distal domain; new insights into young rifts; and new technology for illuminating and defining reservoirs. Following the success of 2015, our seismic workshop will showcase recently acquired seismic surveys, with sessions from Ion, PGS, Spectrum and Western Geco. The conference promises a full programme of events and networking opportunities in the heart of London.

For a taster of what is to come, see page 58, for an article on exploration in the distal domain, written by Technical Chair Helen Doran and Key Note Gianreto Manatschal.

Registration is now open and includes admission to the exhibition and conference, all-day refreshments, lunch and a networking wine reception. The conference runs from **31 August** to **1 September 2017** at The Business Design Centre, **London**. ■

Applying Attribute Analysis



Increasingly, geoscientists are applying attribute analysis to extract more from seismic data. Analysing multiple attributes creates a Big Data problem – but can result in Big Returns when done correctly. The AASPI Consortium at The University of Oklahoma has led the industry in the theory and generation of seismic attributes. In October 2016 the AASPI Consortium and **Geophysical Insights** announced a partnership whereby Geophysical Insights would incorporate the library of AASPI attributes in the Paradise® multi-attribute analysis platform, which uses machine learning to help interpreters visualise patterns in their data.

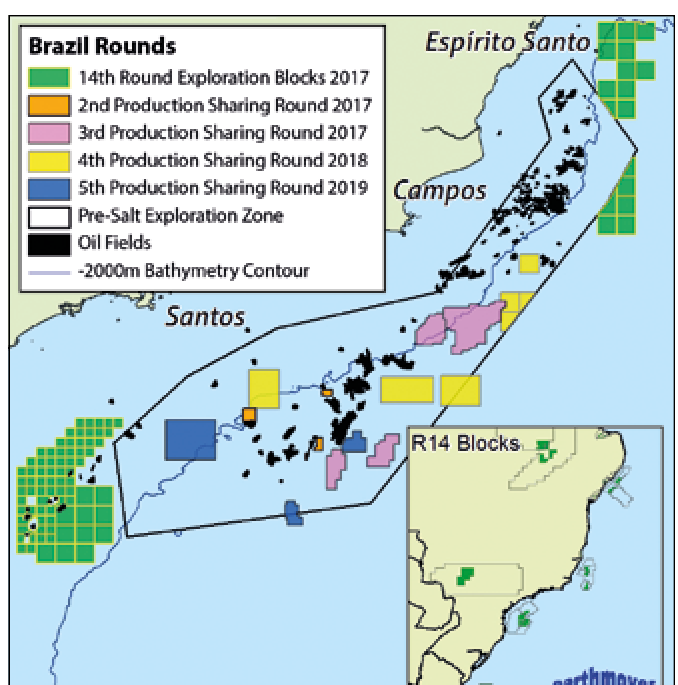
In April 2017 Geophysical Insights officially released the **Attribute Generator** in **Paradise**, leveraging the library of AASPI attributes in a guided Thought-Flow™. The new Attribute Generator offers over 100 attributes, spanning instantaneous, geometric and spectral decomposition types, with commercialised, off-the-shelf, easy-to-use software, effectively putting multi-attribute analysis in the hands of every interpreter. ■

New Brazil Licence Rounds

The **Brazilian Government** has recently confirmed the blocks to be offered in the **14th Exploration Round** and proposed areas for the **3rd Production Sharing (Pre-Salt) Round** in 2017. Four large attractive areas have been earmarked for this Production Sharing Round, where carbonate reservoirs are expected and large structural highs present. Further Pre-Salt Rounds are planned for 2018 and 2019.

The Round 14 offshore blocks are situated in the Pelotas, Santos, Campos, Espírito-Santo and Sergipe-Alagoas Basins. The Santos blocks are mainly located in the shelfal area, and several oil fields have recently been discovered nearby. The Pelotas blocks are frontier terrain with no wells drilled in this part of the basin. All the other deepwater(>2,000m) blocks are located downdip from major oilfields, where turbidite sandstone reservoirs can be expected in potential stratigraphic and structural traps.

The government has reduced the local exploration cost content to 50%, and Petrobras no longer has an exclusive right to participate in the Pre-Salt blocks. These highly significant legislative changes and the attractive array of offered blocks will surely lead to a resurgence in Brazilian exploration in the next three years. ■



SEG-Y Update

The Society of Exploration Geophysicists (SEG) has released a major update to the venerable **SEG-Y** workhorse seismic data exchange standard. SEG-Y is one of several standards developed by the SEG for storing geophysical data. It was originally developed to store single-line seismic reflection digital data on magnetic tape. First published in 1975, there has only been one major update, SEG-Y revision 1, which came out in 2002.

The result of more than two years of development and feedback from a large community of users, **SEG-Y Revision 2.0** provides high flexibility while maintaining a high degree of backward compatibility. It may be downloaded from the SEG Technical Standards web page. Notable new features include:

- Up to 65,535 additional 240-byte trace headers;
- The ability to unambiguously map trace-header contents;
- Capacity for traces to have up to $2^{32}-1$ samples and $2^{64}-1$ traces per line and ensemble;
- Sample intervals can be arbitrarily large or small;
- Support for little-endian and pair-wise byte swapping;
- Microsecond time-stamp accuracy;
- Higher-precision coordinates, depths and elevation;
- Depth, velocity, electromagnetic, gravity and rotational sensor data types;
- Optional XML-based Extended Textual File Headers. ■

Cutting-Edge Technical Insight

Registration is now open for the **SEG International Exposition** and 87th Annual Meeting at the George R. Brown Convention Center in **Houston, Texas**, on **24–29 September 2017**. This event will provide attendees with vast amounts of cutting-edge technical insight, high-level networking, and new business development opportunities across multiple geoscience disciplines. Thousands of geoscience professionals from more than 70 countries are expected to attend. SEG members save up to $150 on registration.

A record-breaking number of abstract submissions have been received, totalling 1,688, a significant increase on the 1,513 abstracts submitted for the 2016 Annual Meeting in Dallas, where an onsite survey revealed that 90% of attendees rated the quality and variety of exhibitors as good/exceptional, 85% attended the event to encounter new products/services and new technology, 82% rated the technical programme as good/excellent, and 83.4% said the event was important or very important for their job. ■

Shaping Africa's O&G Future

The **24th Africa Oil Week 2017** Conference and Exhibition on **23–27 October 2017 in Cape Town** brings together governments, national oil companies, corporate players, independents and financiers with service and supply operators shaping Africa's oil, gas and energy future. It is the longest-running and most prominent industry event held worldwide in and on the African continent and is renowned for its fast-growing oil, gas-LNG and energy industry news and business partnerships.

The conference involves five days of content-rich senior level executive insights, finance and investor outlook. It highlights Africa-wide state and private acreage opportunities, transactions and new venture assets and potential, exploration and production developments, and industry strategies, together with an overview of Africa's hydrocarbon future. The event is well-regarded for its high level participation, intimate networking and on-site deal-flow.

Annually, more than 1,250 corporate and influential leaders and thinkers from every continent attend Africa Oil Week, attracted by the content-driven programme, quality industry exhibition and five star networking opportunities. ■

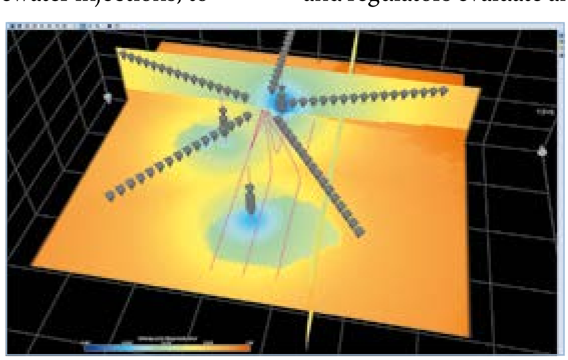
Important Geosciences Event

Don't miss the most important geosciences event this year! AAPG and SEG, the recognised global leaders in the dissemination of high-quality geoscience data and information, bring their **International Conference and Exhibition (ICE)** to ExCeL **London, 15–18 October 2017**. The 4th edition in the joint series, AAPG/SEG ICE London will gather geologists, geophysicists and other petroleum industry professionals from 60+ countries to build their knowledge and skills, discover technology innovations and network with peers. Attend ICE London and experience a multidisciplinary technical programme featuring over 350 oral presentations in 55 sessions and more than 220 poster presentations in 24 sessions. 2017 marks AAPG's 100th Anniversary Celebration so special programming will intensify the experience and create memories you will not soon forget.

If you want to become a leader or stay relevant in this constantly changing industry, you need access to the tools, content and contacts that will help you succeed. Through ICE, you will benefit from unmatched global, regional and local expertise, innovations and connections. The Societies' collective reach allows you to align yourself with some of the most credible geoscience information available. This focus on science and community unites the two societies in purpose and provides the cornerstone for both personal and business opportunities at the event. ■

Improving Microseismic Network Designs

The deployment of cost-effective network designs for either **microseismic** or **induced seismicity monitoring** is of increasing importance. From the benefits of providing stimulated reservoir volumes for hydraulic fracturing or ensuring caprock integrity during wastewater injections, to understanding and regulating potential seismic hazard, microseismic and induced seismicity monitoring can have a significant impact on NPV for the E&P industry. To ensure the greatest benefit, seismic networks must be carefully designed, so that seismicity can be detected in the desired magnitude range, and can be precisely located throughout a target region.



NORSAR already has a significant presence in developing microseismic research and delivering high quality microseismic services. To this it has added its first commercial microseismic software package, **Mdesign**, to help operators, service providers and regulators evaluate and optimise different seismic networks to ensure cost-effectiveness for a given project. Through three different workflows (detectability, location uncertainty and imaging-based focusing) the interactive software allows detailed comparisons to be made for proposed sensor network designs, while accounting for the effect of the velocity structure and noise levels. ■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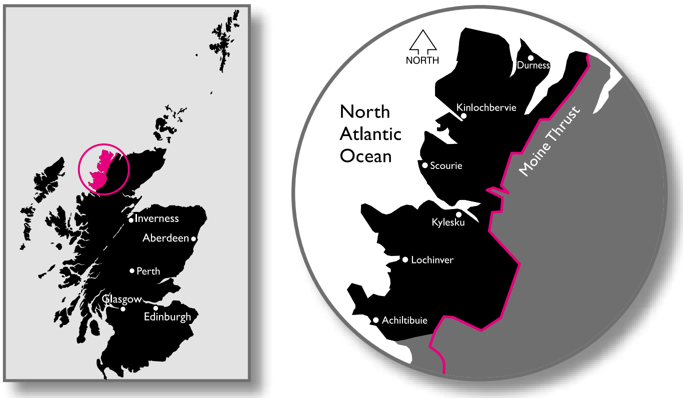
Playground of the Gods

Legend has it that the Scottish North West Highlands UNESCO Global Geopark is where the Norse gods practised their mountain building skills before they created Norway. In this case, there is a thread of truth to the legend, because the Caledonian-Appalachian Orogeny is the common shared geological heritage of Norway, Scotland, Greenland and North America.

Dr LAURA HAMLET, PETE HARRISON and MIKE GOODWIN, North West Highlands UNESCO Global Geopark

In the North West Highlands UNESCO Global Geopark you are surrounded by the Earth's early history, stretching from the Archaean to the Devonian, with an abundance of 'deep time' geological heritage. The low population density, late retreating glaciers, deforestation and slow plant colonisation have produced a perfect storm for viewing features from a huge range of geological time periods (see *GEO ExPro*, Vol. 14, No.1 for more information on UNESCO Geoparks).



Cradle of Geology

Travelling north-west past Inverness through the Scottish Highlands you enter the southern end of the North West Highlands Geopark near the busy ferry port and fishing town of Ullapool. The Geopark encompasses mountains, peat-land, beach and forest, as well as the coastlines of Wester Ross and West Sutherland and on to Scotland's north coast beyond the settlement of Durness and Loch Eriboll. Its eastern boundary follows the Moine Thrust Zone, the internationally significant geological structure that helped 19th-century geologists work out how the world's great mountain ranges were formed.

It cannot be a coincidence that Scotland was at the very forefront of pushing the boundaries of understanding during the Scottish Enlightenment of the late eighteenth century, just as the science of geology was established.

The main route through the Geopark is known as the Rock Route, now part of the North Coast 500, a route internationally renowned as one of the best drives in the world and Scotland's answer to Route 66. The 160 km Rock Route has 14 geo-stops along the way, and one not to miss is Knockan Crag National Nature Reserve, just 20 minutes'

Dr Laura Hamlet North West Highlands UNESCO Global Geopark drive north of Ullapool. Here you can see the Moine Thrust and touch the brittle fault between the Moine and the Cambro-Ordovician sedimentary rocks. The theory of this dramatic rock reversal was confirmed by Benjamin Peach and John Horne of the Geological Survey in 1907. There is family-friendly interpretation in the 'Rock Room' including touch screen computer systems, a Moine thrust machine and panoramic views of the mountains complete with narration to help you pronounce the Gaelic hill names.

Henry M. Cadell with his experimental 'squeeze box' at The Grange, Bo'ness in 1887. Cadell was one of several new recruits assigned to the Highland mapping programme that commenced in north-west Sutherland, stimulated by the discovery of the Moine Thrust. Courtesy BGS.

The Rock Route North

The unmanned open air visitor centre at Knockan Crag National Nature Reserve affords spectacular panoramic views over the Assynt landscape. For visitors with time to travel the full length of the Rock Route a leaflet provides a guide to all 14 localities, enabling visitors to interpret the landscape from the roadside. For those who want to dig a little deeper there are a series of Pebble Routes. These are shorter driving or cycling routes which guide you off the beaten track and into the story of the fascinating and interconnected geological heritage of the Northern Hemisphere as seen in the North West Highlands.

As you approach the halfway point of your journey north along the Rock Route you will descend past the peaks of Quinag to Loch Glencoul. Here you will find The Rock Stop, the UNESCO Geopark's own interactive Earth Science exhibition. The Rock Stop overlooks the Stac of Glencoul, where you can view the Ben More and Moine Thrusts at the same time. Glencoul has exceptional examples of thrust exposures and an unrivalled opportunity to view and understand the large-scale structure of thrust belts.

Visiting the Geopark

Many families in the Highlands are crofters. Crofting is a small-scale farming operation which is usually augmented by other sources of income. It is not unusual for a crofting family to also run bed and breakfast or self-catering accommodation. This is the traditional way to stay in the Geopark. There are several boutique hotels offering a warm welcome and delicious locally sourced cuisine. Unique and quirky independent hostels are also available or you can book a pitch on a serviced camp-site in an idyllic spot. If you wish to truly experience the wild landscape here it is legal to 'wild camp', but you must familiarise yourself with the outdoor access code first.

The closest major airport is Inverness, with flights directly from Amsterdam, London and Dublin. From Inverness you can drive to the Geopark in less than an hour and a half. Car hire is available at the airport and Inverness train station, and buses operate regularly in-between Inverness and Ullapool, the Geopark's gateway town. It is possible to catch a connecting bus on northwards, including the bike transfer bus.

Iain Sarjeant
The Sutherland Partnership

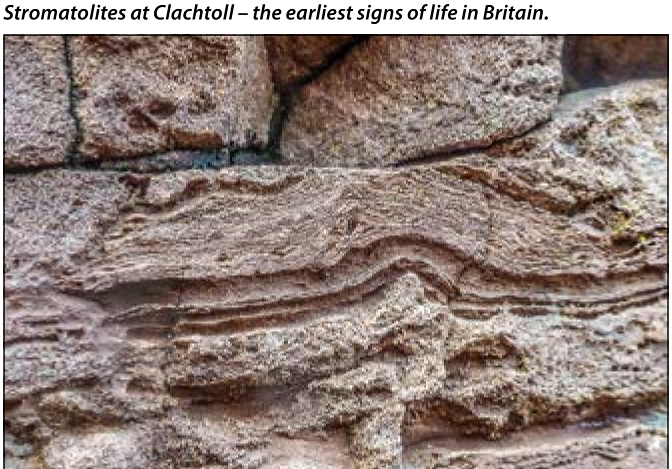
Walkers on Achmelvich, a few kilometres north-west of Lochinver.

Carved by ice, the inselbergs of Suilven and Canisp stand guard over the Assynt landscape.

Very Deep Time

North of Loch Glencoul and the Rock Stop we enter a landscape of rocks with their roots in very deep time. The Lewisian Gneiss which surrounds you is the oldest in Western Europe, dating up to 3,000 million years old, and as far we know it goes all the way down to the bottom of the crust. It formed over a long period of time, roughly one third of the age of the Earth. It started as magma, which cooled and crystallised to form igneous rock. This was then buried very deep in the crust (over 25 km) and suffered very high pressures and temperatures during several mountain-building episodes. It formed a very hard rock, which is coarsely layered, with alternating light and dark bands. There are places where you can see the bands have been bent and folded under the high pressures, before being split vertically and magma pushed up through it to crystallise and form dark igneous rock in sheets, which are called dykes.

Stromatolites at Clachtoll – the earliest signs of life in Britain.



Erosion, Life and a Meteorite

A very long period of erosion followed the formation of the Lewisian Gneiss, during which huge quantities were removed, perhaps as much as 35km. The lower parts of the Gneiss that we see at the surface now formed an irregular landscape upon which the Torridonian Sandstone was deposited from around 1,200 million years ago. The Torridonian is divided into several sub-divisions, with the most interesting of these being the one at the base, which is called the Stoer Group. It sits straight on the Lewisian Gneiss, but does not exist now over the whole Geopark area, as it was either not deposited everywhere or was eroded off before the rest of the Torridonian was deposited. It appears that it may have filled a rift valley which was formed as the continent started to break up and consists mostly of sandstone. The scree slopes that draped off the hills of Lewisian Gneiss can still be seen in places and the oldest signs of life in Britain are here in the form of cyanobacteria. These bacteria either formed mats spread out on the surface of damp mud or humped up into mounds of bacteria and mud called stromatolites, which are really bacterial reefs. Ripples and mud cracks can sometimes be seen preserved in the mudstone and sandstone.

Another fascinating layer of the Torridonian is called the Stac Fada. Originally thought to be a volcanic mudflow, emerging evidence is suggesting that it is material ejected from a meteorite impact. Research published at the end of 2015 strongly supported the asteroid impact theory. There is no doubt that extreme pressures and temperatures were generated and material flowed sideways with great force, with some being molten which cooled quickly whilst other material was blown high and rained down on the disrupted land surface in little balls that had accumulated as they fell. It has been proposed that the crater from the impact may

Spectacular outcrops of Lewisian Gneiss with igneous intrusions at Rock Route stop 11, known locally as the Multi-coloured Rock Stop. (inset) Lewisian Gneiss at Oldshoremore Beach, north-west Sutherland.

be to the east near Lairg as there is a low in the gravity map there and some of the indicators in the flow itself suggest flow from the east, but a lot has happened in the intervening 1,200 Ma to be sure of this.

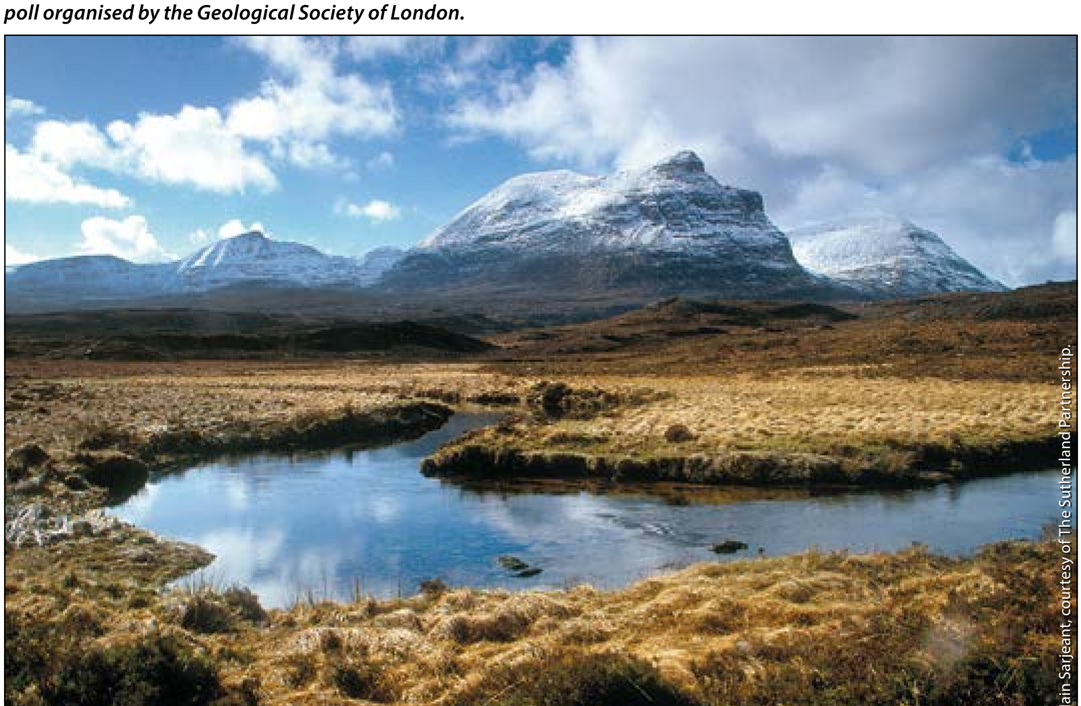
Fertile Oasis and a Viking Boatyard

The final leg of the Rock Route sees you descend a spectacular glaciated valley with the Cambrian Quartzite screes of Foinaven towering behind you. On reaching the Kyle of Durness you encounter a fertile grassy oasis in an area otherwise characterised by peat-land. The fertility of the land here and resultant agriculture is due to the underlying limestone.

Here, just a few hundred metres from the sea, is one of Britain's largest limestone cave systems. Smoo Cave, at the end of a long inlet from the sea, has been carved out through the interaction of coastal erosional and dissolution processes with a large karst drainage system. It is also an important archaeological site with evidence that Vikings hauled out their ships here for repair. Nowadays there is a family-friendly boat trip to explore the caverns before you continue east to Loch Eriboll, cross the Moine Thrust and the northern boundary of the North West Highlands Geopark. More ardent speleologists could join the Grampian team exploring the extensive underground network including a chamber as large as the Usher Hall in Edinburgh.

See http://www.nwhgeopark.com for more details on the North West Highlands Geopark. ■

The dramatic Y-shaped peaks which form Quinag are typical of Assynt, voted the UK's favourite landscape in a recent poll organised by the Geological Society of London.



Reflection or Refraction?

Reflection Refraction?

Taking advantage of joint acquisition and processing techniques: a case study in the Barents Sea Bjørnøya Basin.

ALEKSANDR NIKITIN, NIKOLAY AMELIN, SERGEI POKROVSKII and ANDREY LEKOMTSEV, Geology Without Limits

The Norwegian Sector of the Barents Sea is located in between the Norwegian mainland and Svalbard. As it developed it was affected by several tectonic events and now consists of a complex mosaic of platform areas and basins. It has significant commercial potential, making it a target for hydrocarbon exploration.

Although exploration activities in the Barents Sea have been ongoing for over 40 years, knowledge of the subsurface geology of the area is still limited, mainly due to its complex geological framework and the physical limits of contemporary methods of geophysical investigation.

Why Refractions?

Vast fault complexes, lithological heterogeneities, salt diapirism, steep dips and irregular bedding are all typical 'scenery' for a geological section of the Barents Sea area. These complexities mean that reliable data is hard to obtain using the most common survey technique – towed streamer reflection wave CDP seismic. Factors such as ray bending, scattering, diffractions, interference by adjacent reflections in high velocity formations are typical for reflected wave CDP surveys and these prevent geoscientists from acquiring reliable velocity models and final results in complex areas like the Barents Sea.

Geology Without Limits

Survey lines in the Barents Sea.

Geology Without Limits

Refracted waves are an alternative way to gain knowledge about velocity distribution in rocks They penetrate areas inaccessible to reflected waves as their different method of propagation means they are not influenced by diffractions at first break events and are also insensitive to absolute values of velocities and depth of transmission. Thus a refracted wave-based velocity model can be a better, more stable and reliable alternative for signal enhancement data processing, migration procedures and time to depth conversions.

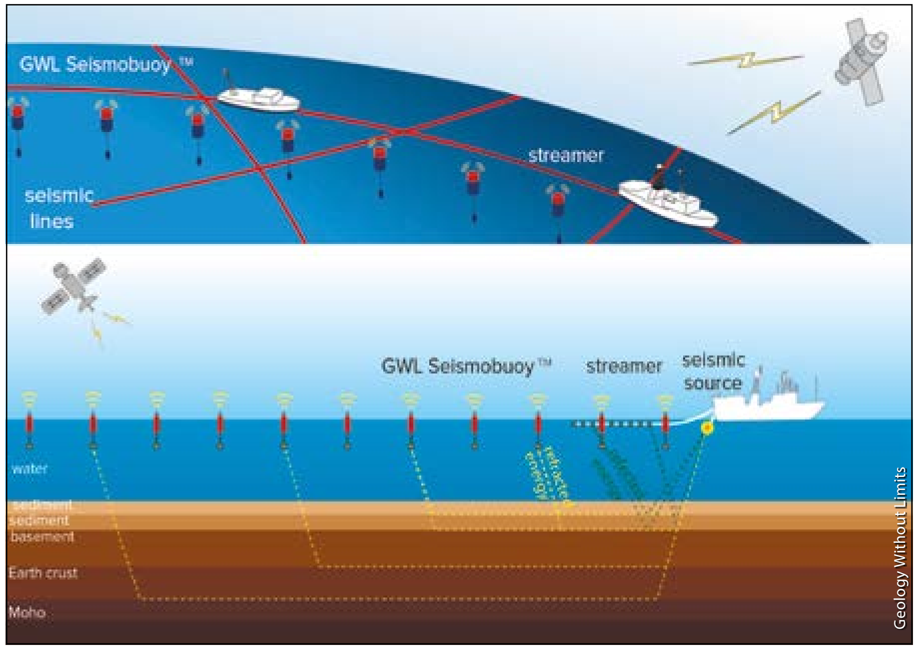


Figure 1: The newly-developed acquisition technique. Recording long-offset refraction data enables the creation of accurate velocity models, free of low-quality definition areas.

Recording Refractions

FloatSeis™ is a new marine seismic technology that enhances 2D/3D CDP reflection data with a velocity model derived from recorded ultra-long-offset refracted wave data. The main idea behind the technology is to make long-offset surveys much more affordable, especially important in a low oil price environment.

Several main factors in this method considerably reduce the total price of long-offset refracted wave seismic surveys. Firstly, 2D long-offset refracted seismic surveys can be conducted simultaneously with towed streamer CDP seismic data acquisition, so no additional seismic vessel with a high day rate is required (Figure 1). Moreover, the recording equipment can be deployed from the seismic vessel itself or from a boat associated with the seismic vessel, making long-offset refracted wave seismic surveys even more affordable.

Recording ultra-long-offset data is undertaken with the help of free-floating autonomous recording seismic units with a built-in online tracking system, which allows online monitoring of the position of all recording units at any place and at any time. In addition, it enables tracking of the status of the data recording process, the battery charge level and the readings of internal auxiliary sensors such as temperature, humidity and accelerometer. As a result equipment reliability, survey accuracy and marine operational safety are increased and considered equivalent to the highest industry standards.

Bjørnøya Basin Survey

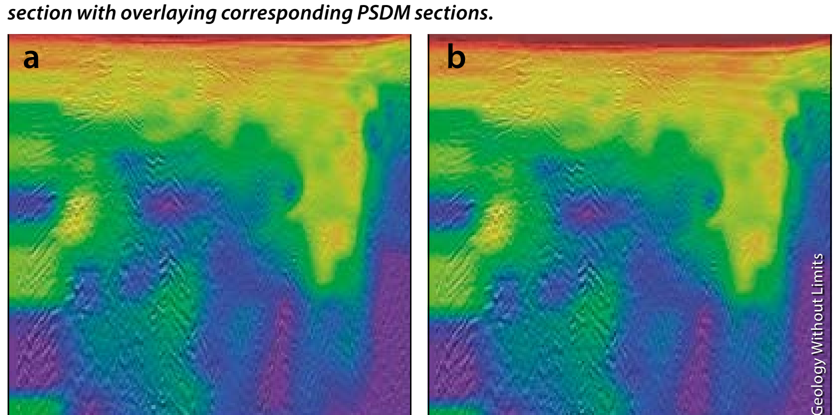
The Bjørnøya Basin's challenging geological framework appears to be a perfect environment for the application of FloatSeis technology, so a survey was undertaken in the basin in October 2016. The target depth of the survey was 5 km, the bottom of the Jurassic section containing a number of possible reservoir plays. Over 100 line-km of 2D long-offset refraction data was obtained during the survey. Recording units were deployed 3.5 km apart and shot point spacing was 37.5m, using a 6,100 cu. inch seismic source, and the 12 km-long towed seismic streamer simultaneously recorded 960 channels. Free-floating units recorded refracted waves on the offsets up to 30 km, which enabled the building of a reliable refracted wave velocity model up to 5.5 km depth.

Data processing was undertaken with two parallel routines. Before migration, streamer reflection data was processed in the standard manner used for marine surveys, the main procedures in the processing sequence being multiple suppression by wave-field modelling, linear events suppression by slant-stacking, ghost notch correction for shot and receiver and parabolic radon filtering. In addition, a grid depth-velocity model was built based on seismic reflection velocity analysis followed by iterative velocity update.

Processing FloatSeis refraction data involved picking first arrivals followed by tomography inversion of the picked traveltimes using an algorithm for maximum smoothness, which is most applicable for surface observations. The result of the tomography processing of the refraction data was an independent depth velocity model.

Finally, after undertaking pre-stack migration (Kirchhoff

Figure 2: Reflection (a) depth velocity section versus refraction (b) (tomography) velocity section with overlaying corresponding PSDM sections.



PSDM) with both velocity models it was possible to obtain two alternative versions of depth sections, shown in Figure 2, with the reflection and refraction velocity models overlaying the corresponding depth section. As can be seen, the refraction velocity section demonstrates better geological consistency and smoothness when compared to the reflection velocity section, which in its turn is less smooth and is muddied by distinctive anomalies that are not correlatable with geology.

A quality comparison of the depth migrated sections with the different velocity models derived from reflection and refraction seismic shows that refraction tomography velocity clearly improved both the focusing and positioning of the seismic images especially in the deeper part. Figure 3 displays the main zones where refraction velocities have allowed enhanced depth imaging results when compared to reflection velocities.

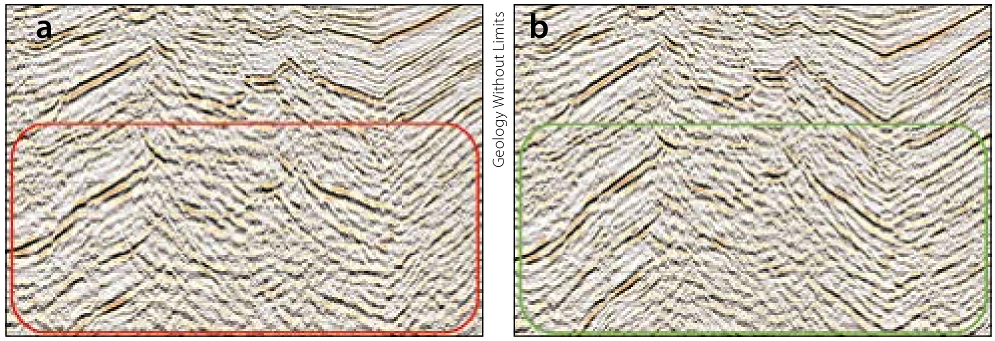


Figure 3: Reflection PSDM section (a) versus refraction PSDM section (b) with enhanced areas highlighted.

Quantitative Evaluation

To analyse the available seismic data, PSDM tomography-based and CDP-based seismic sections were converted to the time domain. The line crosses three wells – 7, 8 and 9 – and synthetic models for wells 8 and 9 are presented in Figures 4 and 5. Well 9 has sonic and density logs and check shot data, while well 8 has sonic and density logs. For seismic to well ties in both wells a check shot from well 9 was used. Both wells use a similar wavelet – Ormsby.

A comparison of the synthetic models (Figures 4, 5) demonstrates a higher correlation between the refraction tomography-based seismic and the synthetic model than CDP-based seismic and the model. Due to similar time processing flow parameters, the only difference that exists is in the velocity model, which can be explained by the refraction velocity model better fitting the real subsurface conditions than the CDP velocity model.

The models were not stretched or squeezed and are shown 'as found'. As can be seen, the correlation coefficient of PSTM tomography is higher than the PSTM CDP, evidence of the better fit of the tomography velocity model to the real velocity model.

Figure 4: Seismic to well tie for well 9.

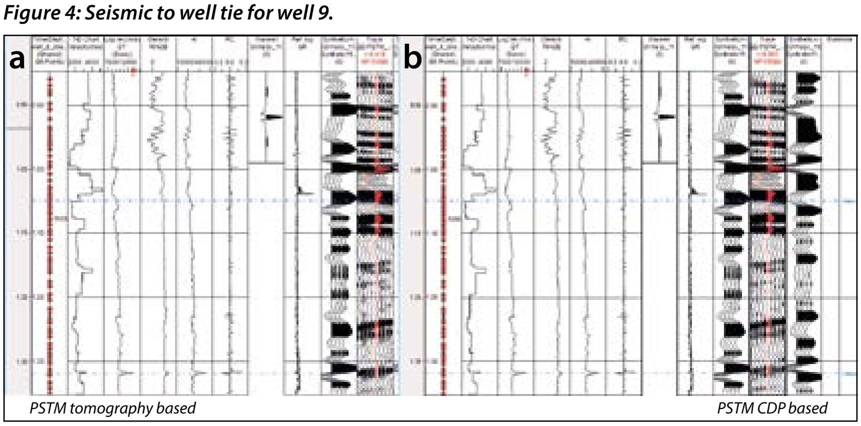
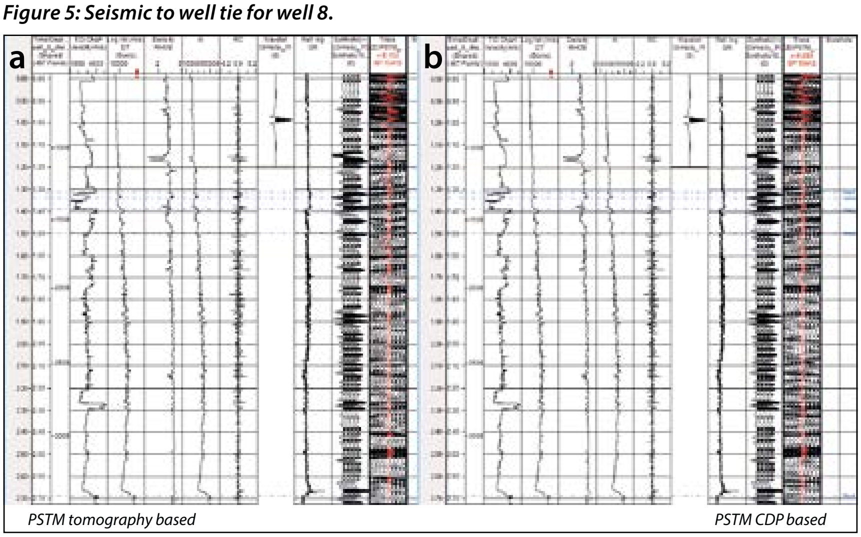


Figure 5: Seismic to well tie for well 8.



Revealing the Advantages

The Barents Sea Bjørnøya Basin case study shows that joint processing of refracted and reflected wave data helped to create an accurate velocity model free of low-quality definition areas. The final data reduces uncertainties in the velocity models, increases the level of confidence in the interpretation stage and helps build a detailed geological section with better well ties of the area under study.

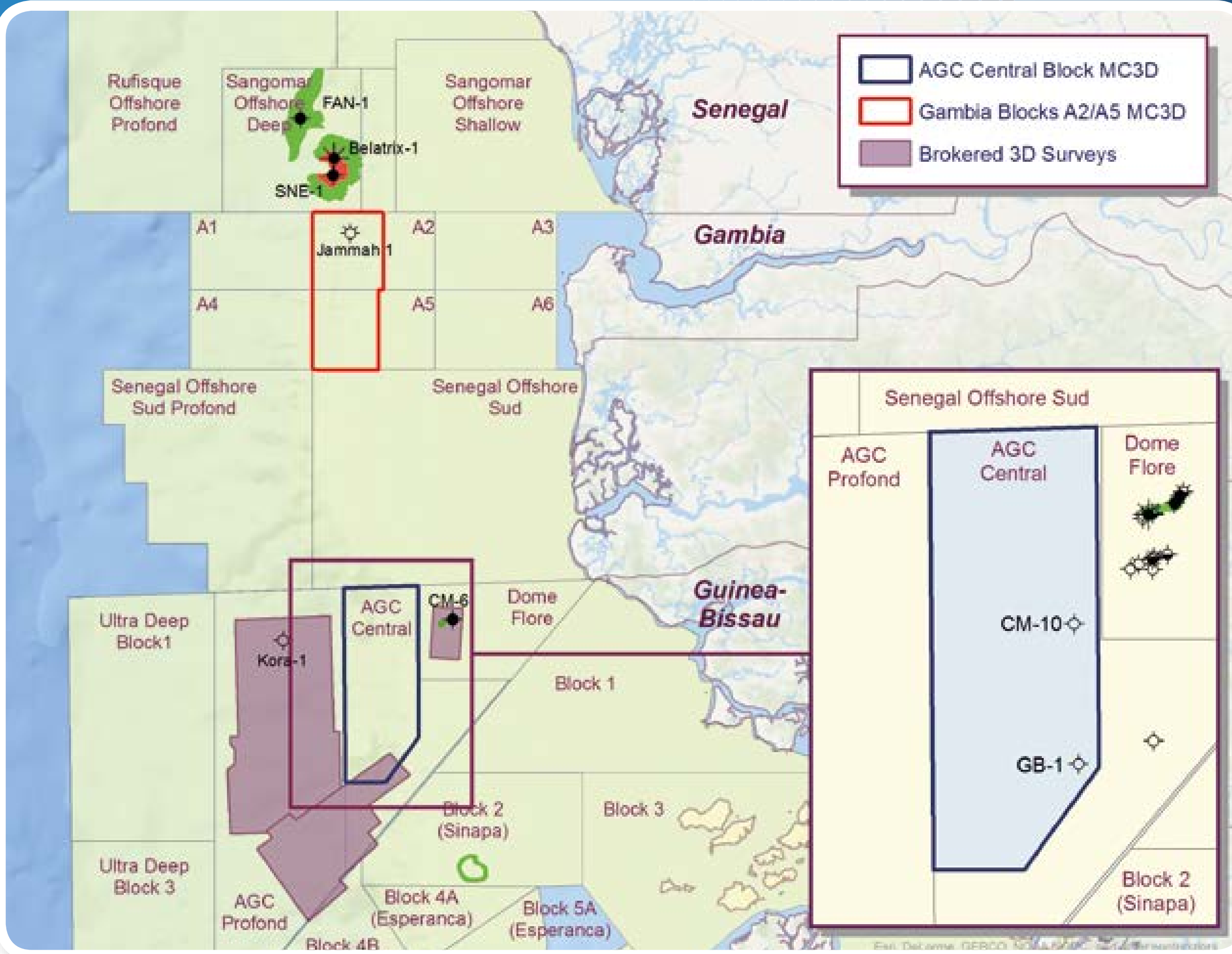
Moreover, in areas with a complex geological environment where reflections could result in controversial velocity models, the refraction tomography model can accommodate features such as lateral velocity changes, steep dips, high velocity formations and screening layers.

The maximum depth of refraction wave penetration can be roughly defined as 15–20% of the longest offset, meaning that a towed 12 km seismic streamer can only illuminate a 2.0–2.5 km depth range. FloatSeis technology extends the active marine spread, enabling a real depth of investigation of up to 7–8 km, as this case study has shown. ■

GeoPartners

AGC Central Block

New Broadband Multi-Client 3D Survey



In cooperation with the Agence de Gestion et de Coopération entre le Sénégal et la Guinée Bissau (AGC), GeoPartners are pleased to announce the acquisition of a new Broadband Multi-Client 3D survey on the Atlantic Margin of North West Africa. The survey covers 1921 km^2 of the AGC Central Block and was completed in January 2017 utilising the vessel BGP Prospector. The survey has been acquired in partnership with BGP Marine and DownUnder GeoSolutions.

The survey compliments the ongoing activities to provide the highest quality new 2D and 3D Multi-Client seismic in the MSGBC Basin, an area of heightened exploration interest following the world-class discoveries announced by Cairn Energy and Kosmos Energy in nearby Senegal.

The survey is currently being processed through a comprehensive Broadband sequence to produce both PreSTM and PreSDM final volumes. A Fast Track cube will be available for licensing early in April 2017.

Jim Gulland: jim.gulland@geopartnersltd.com • +44 (0)20 3178 5334

dug CNPC BGP

Powerful Forecasting for Shale Reservoirs

Integrating geology, engineering and economics into a detailed simulation model allows for the accurate prediction of shale oil and gas full-field reserves and their future production.

THOMAS SMITH

Key to economic and environmentally friendly development planning for an oil and gas field is to know how much of the resource can be recovered and by what means, and where the resource is located. For conventional fields, the process starts with exploration. Once an economic field has been found, the planning for that development takes place and can include well pads, pipelines and extraction facilities, culminating in proposals for the final abandonment of the site once the resources have been exhausted.

Shale or continuous reservoirs are more challenging to produce and pose a different and more difficult problem in assessing full-field reserves. This uncertainty makes the development planning process and the related impacts that policy-makers and the public must deal with problematic. However, accurate predictions are necessary and provide a common ground where industry, policy-makers and the public can come to terms with the complex issues related to development of a valuable resource.

New Approach

For the past seven years, the Bureau of Economic Geology's (BEG) scientists, engineers and economists at the University of Texas at Austin – led by physicist and economist Svetlana Ikonnikova, engineer John Browning and geologist Scott Tinker – have been using a new approach to answer questions on just how much, where, and when a shale field will produce through time. By assessing continuous (unconventional) reservoirs using a multi-disciplinary, bottom-up approach, they can make a simulated model of the entire field. This model, the most detailed publicly available in the industry, takes into account where each well is expected to be drilled and the number of future locations, how its completion would affect investment costs, and how all the produced elements, such as liquids, natural gas and water, will affect the revenue.

The team has completed studies on four shale gas and two shale oil basins to date. They have recently begun work in the Permian Basin Province located in west Texas and south-east New Mexico, led by Ikonnikova and engineer Mark Walsh. The 400 by 480 km area contains the Delaware Basin on the west side of the Central Basin platform and the Midland Basin to the east of that platform.

Permian Basin Province

The Permian Basin Province is one of the world's great oil-producing regions, delivering 17% of the US's total oil production (see *GEO ExPro*, Vol. 9, No. 6). Oil production has been steadily rising since 2008 to over 2 MMbopd (currently 20% of the US's daily oil production), matching the previous peak production mark achieved in 1973.

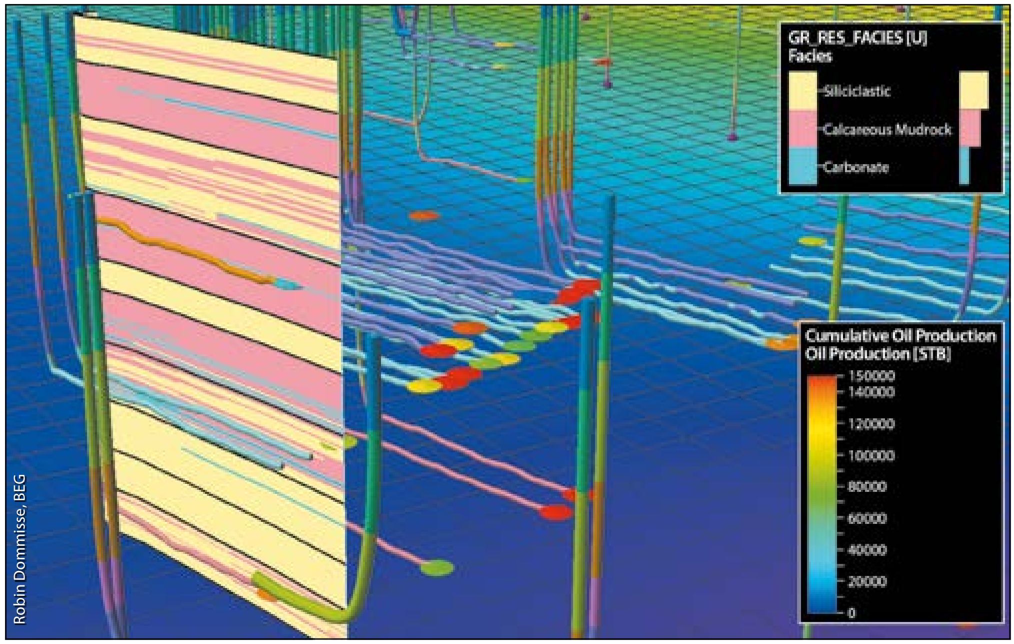
New wells being drilled to exploit shale resources stand alongside pump jacks bringing oil to the surface from conventional reservoirs in the Delaware Basin of west Texas. Innovative techniques using horizontal well bores and staged fracking will keep the Permian Basin Province a major US oil producer for many years to come.

Thomas Smith

Exploitation of the area's huge and varied unconventional plays has more than doubled daily production in less than a decade. These resources could make this one of the largest oil basins in the world.

The US Geological Survey (USGS) recently assessed just one horizon in the Midland Basin (the easternmost basin of the Permian Basin Province), the Wolfcamp Shale. Their technically recoverable mean resources of 20 Bbo and 16 Tcfg is the largest estimate of continuous oil ever assessed in the US.

BEG scientists are in the process of analysing the geology, engineering and economics that can be used in their detailed simulation model. Once completed, they will be able to accurately forecast production and recoverable hydrocarbons for this vast area containing multiple (seven for each basin) reservoir horizons. This task will take years to complete but will have far-reaching implications as to balance of trade, regulation and infrastructure planning, carbon and methane emissions, and energy security.



Shown are a collection of wells colour-coded by completion zone, with the end point coloured by total production to date. A distributed facies cross-section in the foreground was distributed from several hundred wells. This illustration shows the multiple shale targets that add complexity to the BEG study and huge oil reserves in the area.

The Barnett Study

The Barnett Shale play, located in north Texas west of Dallas, is the place where the 'shale revolution' got up and running, thanks to the efforts of Mitchell Energy in the early 1980s (see *GEO ExPro*, Vol. 4, No. 2). It is also the play in which BEG scientists first developed their methodology in determining full-field reserves and production forecasts for shale reservoirs.

This study, completed in 2013, provides a new benchmark with which to compare the more general, top-down approach to shale resources. The detailed, integrated study allows for scenario testing based on several technical and economic parameters. Their base case forecasts a cumulative 45 Tcf of economically recoverable reserves and they predict production will decline to about 900 Bcf/year by 2030 from a 2013 peak of 2 Tcf/year. This forecast falls in the mid- to higher end of other published predictions in suggesting that the Barnett will be a major gas producer for at least another 15 years.

This Barnett study offers several unique contributions to understanding how the play will be developed over time. For this model, they analysed 10 productivity tiers and determined detailed well economics, well attrition rates, quantification of well-drainage volumes, and recovery factors for each tier.

Methodology and Workflow

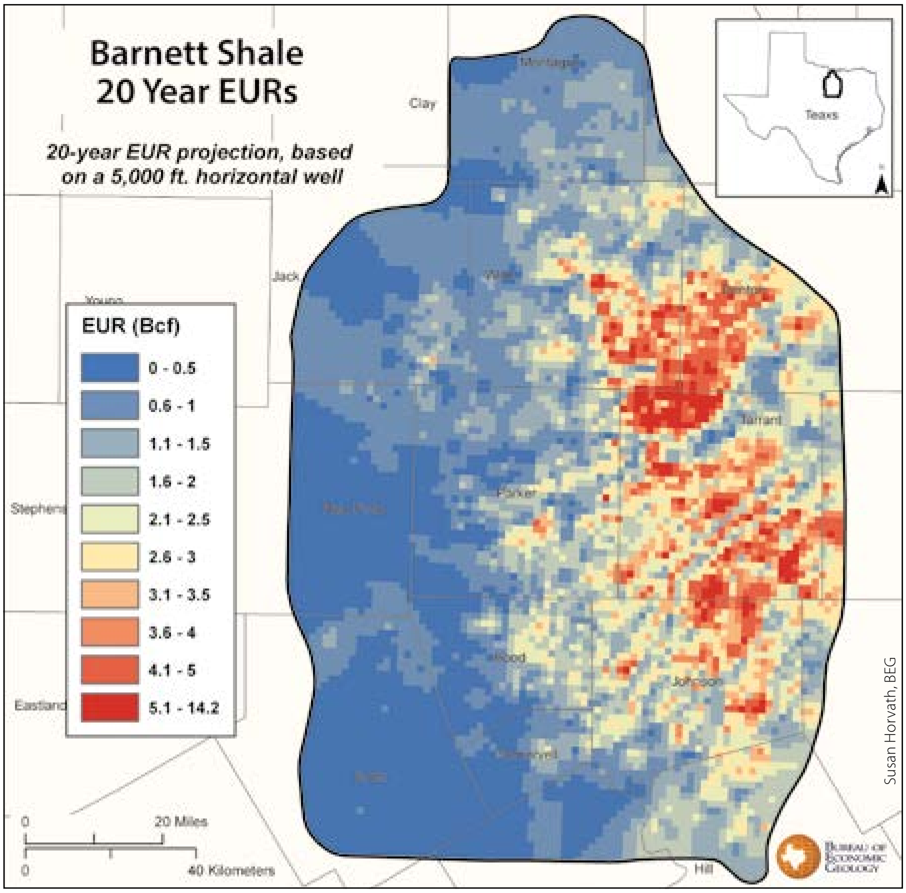
Underlying any play resource is the **geological characterisation** of that play. A stratigraphic framework is built from an extensive network of correlated well logs and put into a 3D geocellular model, where each geological layer in the Midland and Delaware Basins is represented. Using core analyses and petrophysical interpretations to understand the reservoirs, the **hydrocarbon pore volume** (HPV) is distributed in the 3D model. A **fluid**

Resource Assessments

Resource assessments are *estimates* that try to quantify something that cannot be accurately known until that resource has been depleted. Such assessments are based on the data, information and methodology currently available, making them subject to revisions over time as improvements in the data and assessment methods occur.

Resource estimates are prepared for many reasons and utilise a variety of methods. To make use of any estimate, and to compare them, it is necessary to understand the how and why it was prepared, the extent and reliability of the data on which the estimate is based, the expertise of the assessors, and the limitations of the methodology used. Adequate documentation must also be provided to allow users to evaluate the estimates and be able to compare different resource assessments.

Most resource assessments use a top-down approach to analyse plays and typically arrive at a probability range for the resources. BEG's bottom-up approach quantifies well-drainage volumes and recovery factors to obtain a numerical model that will predict full-field reserves and forecast production for a variety of economic scenarios.



Improving on other estimates, the BEG studies map the original gas-in-place for the play. In the Barnett Shale play map, the red colours represent the highest concentrations of free gas in place down to the lowest in blue.

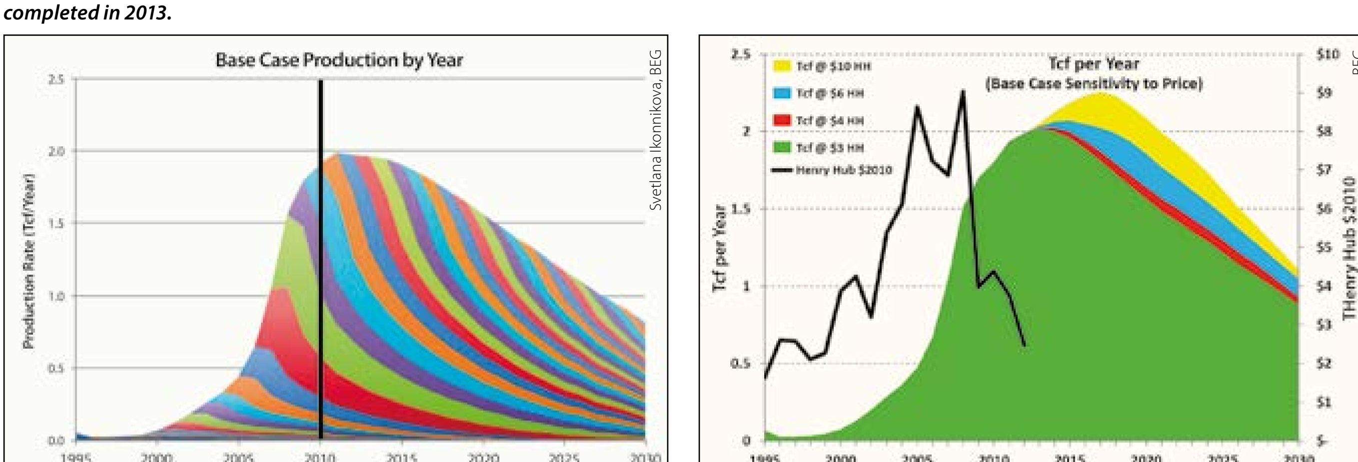
property model is then derived using pressure, volume and temperature (PVT) reports, oil gravity, pressure, and pressure gradient. Incorporating the HPV and fluid properties, the resource in-place can be estimated. This is all validated using the results of production analysis, particularly estimated individual well recovery factors, to identify areas that require additional data and analysis.

Concurrent with the geological analysis, BEG engineers are performing **decline analysis and reservoir engineering**. Using pressure, porosity, fluid viscosity and water saturation as input parameters into their physics-based model specifically designed for shale reservoirs, they can estimate future production from all existing wells. By understanding what existing wells will produce and drain, the BEG model is able to create rigorous scenarios for what remains to be produced from undrilled regions. Engineers also run full 3D reservoir simulations on representative window areas in the field to ensure accuracy and identify the most essential reservoir properties necessary to explain well production. From here, a decline model is developed. Expected future monthly production of oil, gas and water over the well's lifetime is predicted by this decline analysis. In combination with simulations, the analysis also allows the researcher to estimate effective stimulated rock volume and perform recovery factor studies. This becomes important in successive analyses of completions and expected future drilling patterns and their interrelation with *per well* expected production.

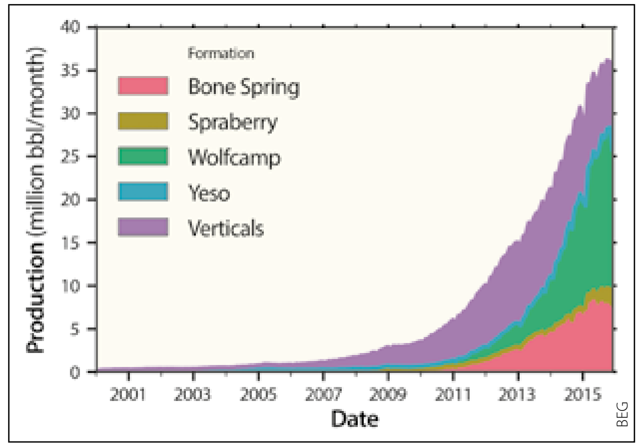
A **statistical analysis** is performed to identify the drivers of well productivity and to forecast productivity of future wells given a well's location. Particular attention is paid to well landing, completion date, and completion parameters. The expected productivity of wells combined with the projected number of wells left to be drilled in each square mile – given the thickness of each zone – are used to determine the technically recoverable resource with great granularity (level of detail). The inventory of future wells and their performance serve also to underlay further analysis of the possible future development of the basin as a whole, and within each zone.

To predict the path that future development will take, forecasts for the performance of existing and future wells will be input into a well **economic analysis**. The profitability of

The final products include production over time in each tier (on left) and production for different gas prices. Both graphs are from the Barnett Shale study completed in 2013.



existing wells and how wells of varying attractiveness have been drilled and completed over time is analysed to calibrate the expected drilling model. Based on expected profitability of future wells, a model is built projecting future drilling and how it is likely to change depending on technological progress, market parameters, infrastructure development, and costs associated with existing and future regulations. By answering the questions "where, when, and how will the wells be drilled?" the BEG team, guided by past play activity, can build much more accurate future production outlooks.



Unconventional resources are leading the production surge in the Permian Basin.

Using All Resources

Dr. Frank Male, BEG researcher, concludes, "To ensure that our assumptions are realistic and incorporate the major trends, we meet with key operators in each play. Supported by data on cost structures, drilling and completion approaches across the basin, and by understanding efficiency gains and areas subject to future improvements, we investigate the sensitivity of our projections. We run scenarios with varying assumptions on technology, economics, regulations, etc. The granular results are shared with state authorities, industry representatives, public, and research communities. Given the increasing share of shale gas and shale oil in the US energy supply, the related energy security benefits and environmental risks make the study valuable for the general public and policy makers.

"Our motivation for undertaking these detailed studies is to build the best, most robust, and transparent framework for discussing shale basins like the Permian," Dr. Male continues. "Once the framework is in place, we can start to tackle a wide range of questions important for the local, state, and US economy. Some of the issues include energy supply, security and sustainability of the supply, environmental impacts, infrastructure planning and management, and fiscal issues. For example, with water flowback, production, and completion analysis tied into field development scenarios, we can study how the water footprint of the Permian Basin evolves over time. These studies are designed to be of direct interest to stake-holders impacted by the field development." ■

Resource Nationalism in the Caspian

The proliferation of resource nationalism in the Caspian Sea littoral states is often perceived as a risk – but should it be considered an opportunity?

Dr. NADIR GOHARI, Global Risk Intelligence

The impact of globalisation has triggered increased interaction between members of the international system. This in turn has presented new areas for economic development and partnerships as well as provided numerous opportunities for potentially lucrative business ventures. In this aspect the natural resource sector has generated significant interest as it maintains connotations of substantial capital gains. However, associated issues that arise from the sales of natural resources include those of management, ownership and rights.

Consequences of Resource Nationalism

Resource nationalism has been used to engage such issues. Having no set definition, it has been described in a number of ways, most commonly simply as when governments and/or ethnic groups lay claim to natural resources located within their territory for the purposes of ownership and control (Overland, et al., 2010). It also frequently involves governments implementing policies and using private players in order to increase control over the natural resources.

Given such an understanding of resource nationalism, a number of fears have been generated by members of the international system, particularly over the uncertainty of what a host country would do with its natural resource sector when engaging investors. For example, would foreign investments in the extraction of natural resources be affected in a manner that would negatively influence operations; would there be revisions to pre-existing production sharing agreements (PSAs); or would the monetary return from the sale of natural resources generated from operations drop? Essentially, the exertion of a higher degree of control over natural resources by a host country in a situation where it was previously absent, or at least less rigorous, has created an environment that has come to be perceived as risky. Hence, resource nationalism has been ranked as one of the top risks of the system of internationalism.

Regardless of the perceived risks accompanying resource nationalism, the natural resource sector is still nonetheless a desirable area for business. Encountering ripe opportunities for the extraction and sale of natural resources can be found across the world, with an additional increase in accessible avenues following the collapse of the Soviet Union. Areas previously unavailable to the greater international system opened to an enormous client base demanding access to its resources. The close geographic proximity to Western Europe provided a prodigious set of mutually beneficial opportunities, providing reliable banking and legal infrastructure as well as the technology needed for extraction along with the ability to develop associated services for the sector. On a globalised level, opportunities and potential were further magnified with even greater access to international markets like the US.

Resource Nationalism in Azerbaijan

The Caspian Sea region in particular has generated worldwide attraction with its enticing abundance and diversity of natural resources such as metals, minerals and hydrocarbons. The Caspian Sea littoral states of Azerbaijan, Iran, Kazakhstan, Russia and Turkmenistan have all utilised resource nationalism to varying degrees and in different ways with regard to oil and gas.

A particularly fascinating case study is Azerbaijan. The

EIA estimates that in 2012 there were 48 Bbo and 292 Tcfg proved and probable reserves within the basins of the Caspian Sea and surrounding area.

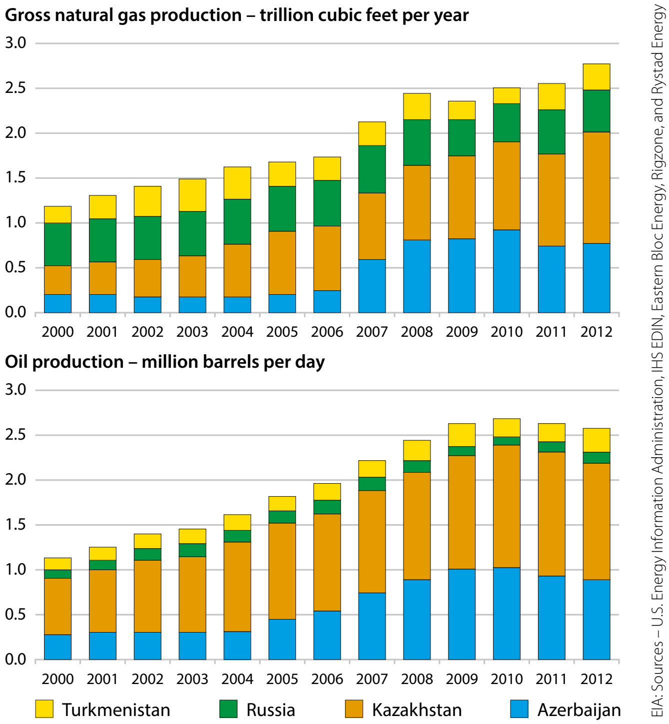
country has an extensive history of resource nationalism stretching over a century across various political systems. During Imperial Russian rule, oil was extracted in Baku and multiple pipelines were constructed linking the Caspian Sea city to the greater Caucasus region and the Black Sea (Akiner, 2004). By 1895, oil output from Baku accounted for nearly half of daily global production. Although Azeri and international oil magnates operated in Baku (see 'An Oil Pioneer', page 46), resource nationalism was personified by the Tsar and the materials were effectively his property, albeit with foreign investment having shares in operations and profits. Distribution of wealth and management of funds were through the Romanovs.

In 1918, the Azerbaijan Democratic Republic gained independence from the Russian Empire following the aftermath of World War I. By this time oil from the Caspian region, with Baku as one of the centres, had become increasingly coveted and was viewed as a means to generate funds as well as provide strategic energy supplies (Akiner, 2004). Independence was therefore short-lived as in 1920 the Red Army invasion of Azerbaijan succeeding in co-opting the area into the Soviet Union (Karagiannis, 2002). The Azerbaijani Soviet Socialist Republic fell under a socialist system in which all companies were nationalised, and all natural resources, including hydrocarbons, were property of the state.

However, following the dissolution of the Soviet Union, an independent Azerbaijan once again emerged, with a strikingly contrasting usage of resource nationalism to its former socialist model. Oil and gas matters of the country were now being represented through an NOC (Gojayev, 2010), the State Oil Company of Azerbaijan Republic (SOCAR).

Discussing hydrocarbon affairs in the state, Rauf Mammadov, a Resident Scholar on energy policy at the Middle East Institute in Washington, reflects that "Azerbaijan has been successful in realising outstanding upstream and midstream projects, and well-timed implementation of these projects was not dictated by the sheer desire of the state to hastily exploit the national

The modern oil industry in Azerbaijan started in the 1870s.



Caspian Sea region gross oil and gas production, 2000–2012.

resources, as we see for example in other 'petrostates' with symptoms of resource nationalism, but rather with prudence to revive the economy and to stabilise the socio-political situation in the country."

Preserving the Resource

This lack of haste in developing lucrative business ventures is a commonly observed behavioural trait exhibited by states utilising resource nationalism. The state perspective is that the materials over time will become more valuable, therefore an urgency to sign deals is not prioritised. This is particularly relevant when deals are perceived as benefiting foreign companies rather than domestic ones. Hence, states are more inclined to examine and initiate better deals for themselves rather than agree to or remain with deals perceived as imbalanced or unbeneficial to the host country.

In the hydrocarbon industry, NOCs are used to negotiate PSAs with international oil companies. In Azerbaijan, Mammadov observed, "Development of all the major upstream projects has been done through PSAs rather than risk service agreements or other governance frameworks specific to resource nationalism. The signing of the 'Contract of the Century' – the first PSA with a number of major oil companies – and adherence to the provisions of the signed documents by the state and SOCAR is a vivid example of the creation of a multinational partnership to extract the national resources of the country. More than 30 PSAs have been signed in Azerbaijan since 1994. All have been ratified by the parliament and have become the law of the country."

Other Caspian littoral states have similarly exercised resource nationalism with an omnipresent proliferation of the concept. One indicator is the presence of NOCs as a defining feature of resource nationalism. Iran maintains the National Iranian Oil Company, while Kazakhstan operates KazMunayGaz (Kennedy and Nurmakov, 2010). Russia sustains a different interpretation of resource nationalism that manifests as an oligarchical system of oil companies which, although privatised, share an intimate relationship with the state. Finally, Turkmenistan announced in early 2016 its intention to create its first NOC, and later in the year the Turkmen National Oil and Gas Company was formed.

Flourishing Future

It is important to note that none of the Caspian littoral countries possesses an identical model or interpretation of resource nationalism. Indeed, some countries have a longer history of experience and interaction with the concept than others. Moreover, while there have been economic successes in some countries due to implementation of the concept, the degree of economic benefits have varied (Kalyuzhnova, 2008) and did not occur simultaneously between states. Yet, despite the differences, every Caspian Sea littoral state has exploited resource nationalism.

Perceived obstacles and anxieties from the perspective of an IOC must be alleviated, though. While the landscape of the industry has changed when compared to earlier standardised dealings, every sector possesses its own relevant and associated risks. Resource nationalism should, in fact, be better received by IOCs, because the amorphous and adaptable nature of the concept can be adjusted to a mutually beneficial relationship. While monetary returns generated from petroleum windfalls may not be as high as before, significant gains are still possible. Moreover, related operations and diversification of investment portfolios present vast opportunities for the widening of economic interactions rather than being isolated to a single industry.

All the Caspian states have much to learn from each other and their proximity to the largest lake in the world in the advent of globalisation decreases distances, bringing the states even closer to one another. Resource nationalism is positioned to flourish into the future.

Bibliography available online. ■

The Shah Deniz platform in Azerbaijani waters.

Shaping the Future of Seismic Interpretation

A quicker way from seismic data to geomodel – or how seismic interpreters have finally come to the centre of the exploration workflow.

VIANNEY SAVAJOL, Eliis, Houston

From the advent of the first computer-aided interpretation methods in the 1980s, technological advances both in hardware and in algorithms have radically changed the work and the role of seismic interpreters. The downturn in the oil and gas industry has recently given another push for optimisation: workflows are being revisited and new technologies are being tested. In addition, over the last two decades 3D geological models, which represent a simplified version of the earth, have progressively become one of the major tools for exploration and production. These models, based on geo-cellular grids, where rock properties from well data are estimated for each cell, are used for reservoir simulation. To build these watertight geological models, geo-modellers generally use only a few horizons and faults provided by the seismic interpreters, but a new technique now allows us to compute watertight geological models directly from seismic data, using a dense horizon patch grid. Any change made on the stratigraphic or structural interpretation can then be directly applied to the watertight models. The role of seismic interpreters has hence become critical for keeping geo-modellers connected to the reality of the seismic data and allowing them to quickly create more accurate models.

Latest Innovations in Seismic Interpretation

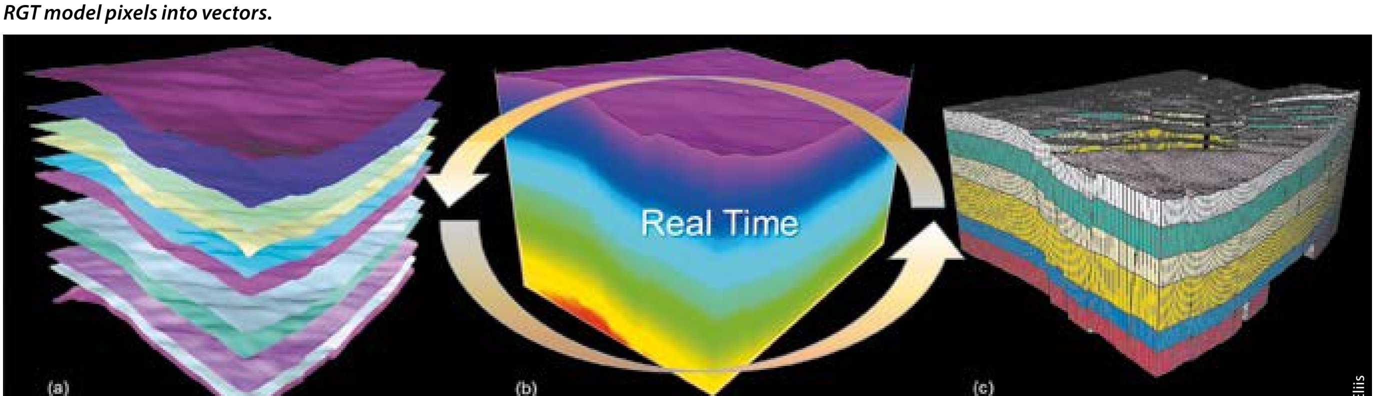
Over the last 15 years, new seismic interpretation techniques have been introduced that allow geoscientists to interpret seismic data faster and more accurately. Seismic interpretation is traditionally an intensive and time-consuming process based on manual picking or auto-tracking of single horizons within a seismic volume. The method where seeds are auto-tracked by correlation of wavelet amplitudes is often limited to regions showing clear seismic reflections and a relatively simple geology, compelling interpreters to make many assumptions. New approaches have been proposed that harness the three-dimensionality of the data and simultaneously track every surface throughout the volume. Some of these methods are based on the classification of reflectors extrema (Borgos et al., 2003), on phase unwrapping (Stark et al., 2004), on seismic flattening (Lomask, 2006), on horizon cubes (de Groot et al., 2010), on seismic DNA (Bakke e al., 2011), on chronostratigraphic models (Labrunye, 2013) and on horizon volumes with constraints (Wu and Hale, 2014).

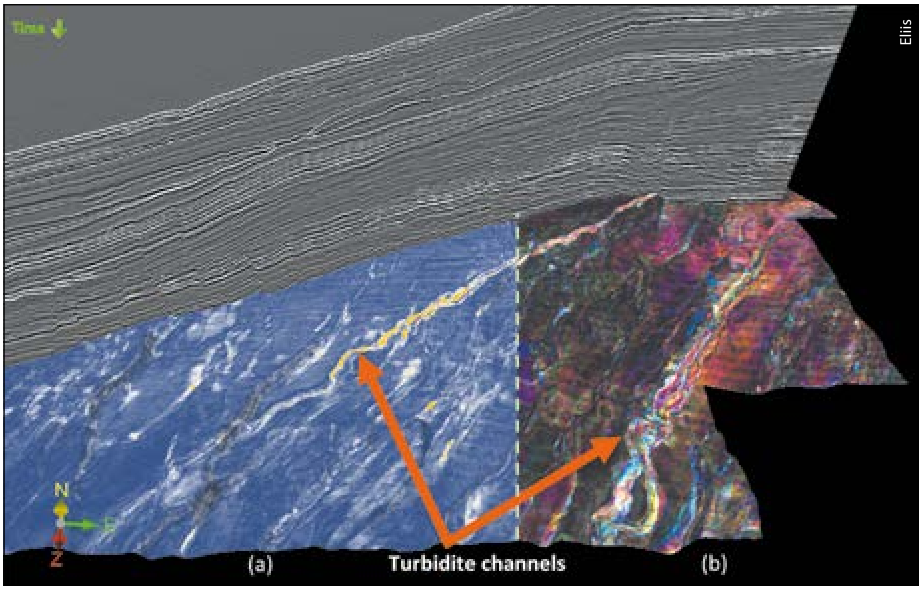
In 2009 Pauget et al. proposed a comprehensive approach to building a geological model while interpreting seismic data. The first step consists of computing a 3D grid of horizon patches from a seismic volume using the same methodology used to obtain a relative geological time (RGT) volume. Spatial resolution of the grid depends on the patch size, while the vertical resolution relies on the seismic trace extrema (peaks, troughs and zero crossings). The vertical links define the stratigraphic ordering whereas spatial links are built between patches based on their correlation and their distance. The same geological age is assigned to patches connected laterally, so horizons are thus chrono-stratigraphically sorted and never cross each other due to the uniqueness of the links.

Stratigraphic Analysis and Fault Imaging

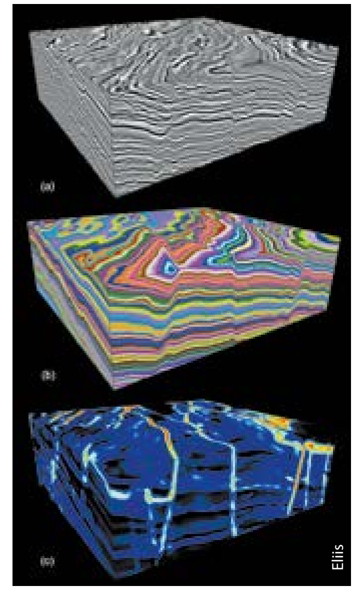
An unlimited number of horizons representing iso-geological ages are derived from the RGT model to interpret thin stratigraphic events at sub-seismic scale. Continuous surfaces can be computed anywhere inside a stratigraphic interval without being limited by seismic polarity changes, whereas other techniques are limited to 2D analysis and/or to a limited number of horizons. This method, combined with spectral

From seismic interpretation to reservoir modelling: (a) a high number of horizons are generated using a horizon patch grid; (b) relative geological time (RGT) model obtained by conversion of seismic voxels into relative geological times; (c) watertight model and cellular grid computed after converting RGT model pixels into vectors.





Horizon from the Exmouth sub-basin (North West Australia) showing (a) the envelope attribute and (b) the spectral decomposition of the signal mapped on it. Both are highlighting a channel spreading westwards in the Jurassic. The spectral decomposition shows a high-resolution image that helps understand better the internal structure.



Fault attributes derived from the RGT model: (a) seismic, (b) RGT model, (c) spatial gradient gradient model.

decomposition and colour-blending imaging, has been successfully used for reservoir detection in thin beds, for fault and fracture imaging and for reservoir characterisation.

Understanding the complexity of the structural network is usually a delicate task for seismic interpreters. Seismic attributes have been used extensively to image faults: dip-steered coherence analysis, such as variance, provides a significant image of the structural discontinuities but still depends on the seismic signal heterogeneities in the vicinity of the fault. Another technique consists of taking into account the RGT model as input for fault imaging complementary to seismic attributes: spatial derivatives of the relative ages show clearly the occurrence of faults and fractures even in areas of poor seismic signal quality. This technique provides a high-resolution fault image based on the geology.

From Seismic Data to Cellular Grid Geomodel

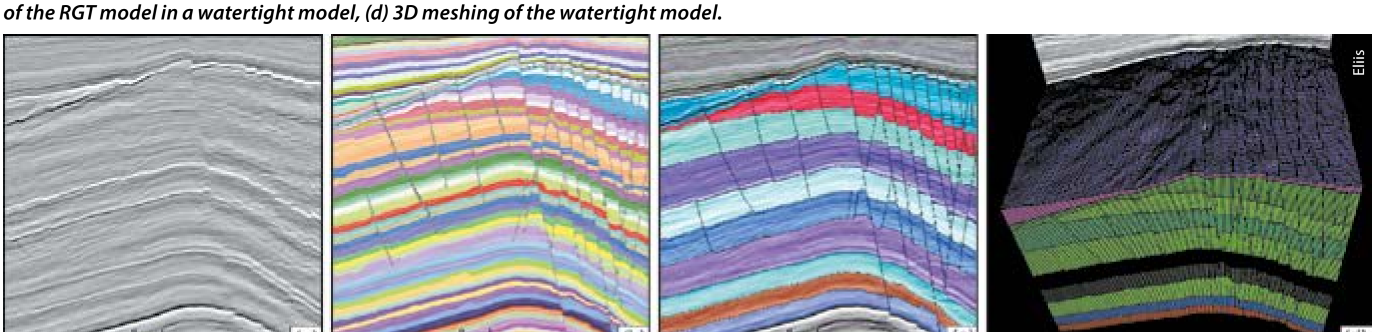
Fault planes are considered to be discontinuity constraints, as they remove links between patches of the original 3D grid without changing the chronological order. Therefore, a horizon will never cross a fault. By using that grid as proposed by Pauget et al. in 2016, watertight geological models are first computed in 2D on every in-line and cross line and then computed in 3D by synchronisation of the relative geological times. Whereas traditional techniques are limited to a couple of faults and horizons, this technique allows the creation of watertight geological models with higher level of information coming directly from the seismic data. Stratigraphic intervals can be defined at various scales without limitation. A triangular mesh of the model allows interpreters to generate watertight horizons and extract fault polygons. A geo-cellular grid could similarly be computed and populated with rock properties for reservoir simulation applications.

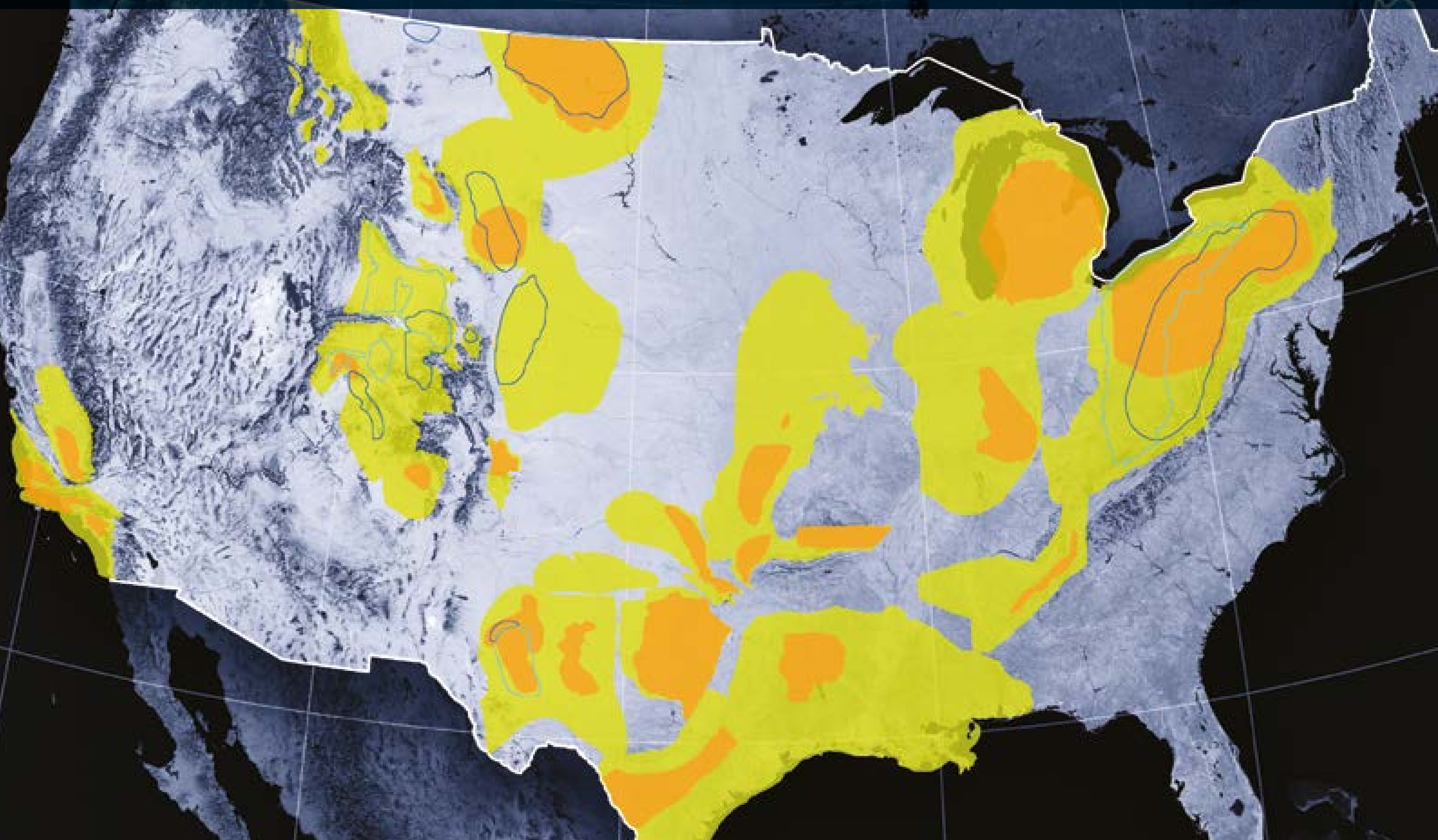
Interpreters are now equipped with unique software that has automated the formerly manual process of picking lines in seismic data. This has made seismic interpretation drastically more efficient, delivering to the geo-modellers in days rather than weeks not only high quality and high resolution horizons and faults but also a preliminary fully seismically consistent geomodel. The new workflows being developed around the software are accelerating the entire exploration cycle, thus shaping the seismic interpretation of the future.

Acknowledgements

The examples presented in this article were obtained using PaleoScan™, software developed by Eliis. The author would like to thank Geoscience Australia for their permission to publish the data from block HCA2000A (Exmouth), as well as TNO and the Dutch government for the authorisation to publish data from block F3. ■

Application of the watertight geological modelling to a North Sea dataset: (a) seismic section, (b) RGT model using the horizon patch grid, (c) conversion of the RGT model in a watertight model, (d) 3D meshing of the watertight model.





Sergipe Basin Undrilled Potential Surpasses Giant Offshore Discoveries

PSDM dip line showing syn- and post-rift targets as well as candidate Moho deep reflectors.

Evaluation of up to 16,000 km of modern, high quality, long-offset 2D seismic data, acquired by Spectrum in 2014 over the Sergipe Alagoas Basin (Figure 1), has confirmed the extension of a turbidite channel system into open acreage offered in the ongoing licensing Round 14. This channel system has been proven to contain several billion barrels of reserves from recent exploration programmes, including the Barra, Muriu and Farfan discoveries. Integration of derived seismic attributes and potential field data has resulted in a better understanding of the main elements of the petroleum system, allowing for the identification of multiple untested play types. This evaluation demonstrates that the undrilled potential offshore Sergipe may surpass the discovered resources to date.

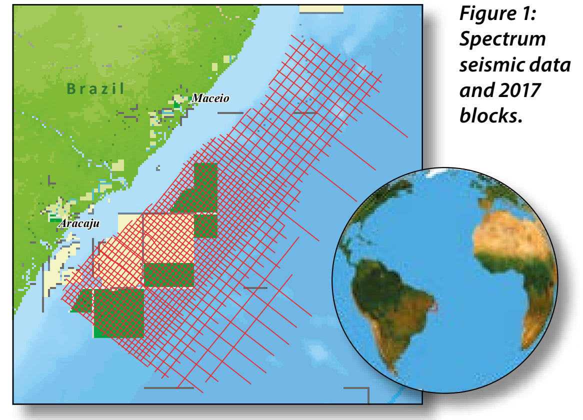


Figure 1: Spectrum seismic data and 2017 blocks.

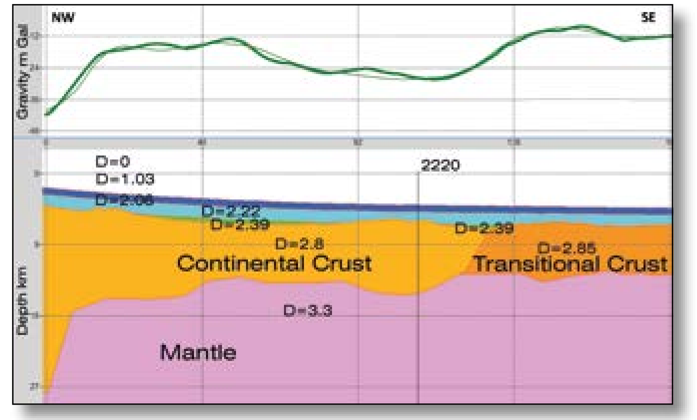


Figure 2: Constrained gravity model.

The long-offset 2D seismic data was processed through pre-stack time migration using conventional techniques, and through pre-stack depth migration using both conventional and broadband processing techniques. The application of these two technologies resulted in seismic data with a vertical resolution as fine as 5–10m (Saunders et al., *First Break*, 2015), allowing identification of additional levels of interest which are mostly beyond seismic resolution in the conventionally processed seismic data.

Additionally, AVO stacks and attributes have been generated over an area encompassing the Sergipe Sub-basin. A targeted pre-processing flow was used to produce conditioned-angle gathers, calibrated with existing well data, indicating numerous potential AVO anomalies (Saunders et al., *GEO ExPro*, Vol. 11, No. 5).

Ship-borne gravity data has also been integrated with the seismic interpretation of a relatively clear Moho reflection on the PSDM sections, to produce a series of density models (see Figure 2). This modelling exercise has resulted in a very clear interpretation of the crustal architecture. The outcome of the exercise will be a higher confidence in crustal architecture, leading to improved heat flow prediction and thermal maturity profiles.

Detailed evaluation of available seismic data indicates that the Sergipe deepwater plays extend further outboard to the east and south-east, where they have an added opportunity in a basin floor fan setting. To the north-east, primarily in Alagoas, channel fill sediment play, rifted basin fill, and faulted Palaeozoic sediments are all exploration targets. As part of the current licensing Round 14 and with strong indications of huge untapped potential, exploration activity, inclusive of drilling in this highly prospective area, is expected to yield continued success, with undrilled potential surpassing discovered resources.

Sergipe Basin Potential Revealed

Integration of seismic attributes and potential field data has resulted in a better understanding of the main elements of the petroleum system, allowing for the identification of multiple untested play types.

KARYNA RODRIGUEZ, MIKE SAUNDERS, NEIL HODGSON and **LAURIE GEIGER**, Spectrum

	Type	Reservoir	Primary Source	Seal
1	3-way with fault seal and 4-way dip closed structures	Early Cretaceous syn-rift fluvio deltaic and aluvial/aeolian sands	Early Cretaceous syn-rift lacustrine shales and juxtaposed Aptian marine shales	Intra formational shales
2	Unconformity truncation play	Early Cretaceous syn-rift fluvio deltaic and aluvial/aeolian sands	Early Cretaceous syn-rift lacustrine shales (and juxtaposed Aptian marine shales?)	Aptian shales, Intra formational shales
3	Still assisted closure?	Early Cretaceous syn-rift fluvio deltaic and aluvial/aeolian sands	Early Cretaceous syn-rift lacustrine shales	Sills and shales
4	Stratigraphic unconformity lag trap	Aptian/Barremian transgressive sands	Early Cretaceous syn-rift lacustrine shales and juxtaposed Aptian marine shales	Aptian shales
5	Stratigraphic seaward dipping	Aptian sands and lmsts	Aptian marine shales and lmst	Aptian shales
6	3 way dip closing against Seamount	Aptian sands and lmsts	Aptian marine shales and lmst	Aptian shales
7	Intrusive induced anticline	Aptian sands and lmsts	Aptian marine shales and lmst	Aptian shales
8	Fault controlled 3 way dip closure	Aptian lmst and clastics	Aptian/Albian marine shales and lmst	Albian and late Cretaceous shales
9	Intrusive induced anticline	Aptian lmst and clastics	Aptian/Albian marine shales and lmst	Late Cretaceous shales
10	Stratigraphic seaward dipping	Late Cretaceous Calumbi fm Slope apron and base of slope deep water turbidite sands	Aptian/Albian marine shales and lmst	Late Cretaceous shales
11	Fault controlled 3 way dip closure	Late Cretaceous Calumbi fm Slope apron and base of slope deep water turbidite sands	Aptian/Albian marine shales and lmst	Late Cretaceous shales
12	Intrusive induced anticline	Late Cretaceous Calumbi fm Slope apron and base of slope deep water turbidite sands	Aptian/Albian marine shales and lmst	Late Cretaceous shales
13	Stratigraphic landward dipping	Late Cretaceous Calumbi fm base of slope fan sands deep water turbidites	Aptian/Albian marine shales and lmst	Late Cretaceous shales
14	3 way dip closing against Seamount	Late Cretaceous Calumbi fm base of slope fan sands deep water turbidites	Aptian/Albian marine shales and lmst	Late Cretaceous shales

Related Closures: Structural; Intrusive; Stratigraphic; Unconformity. Geological period: Early Cretaceous Syn Rift; Aptian/Albian; Late Cretaceous and later

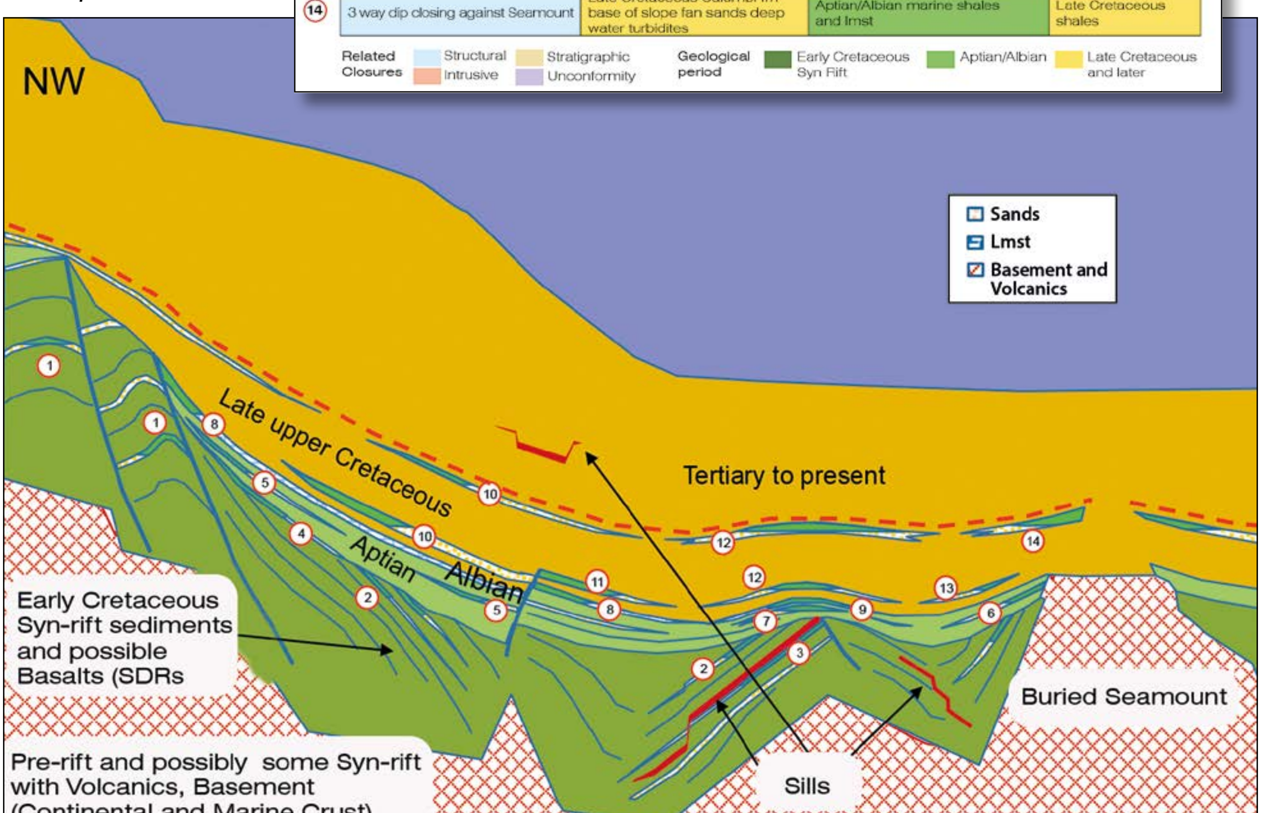


Figure 3: Play types offshore Sergipe Basin (see text page 42 for explanation).

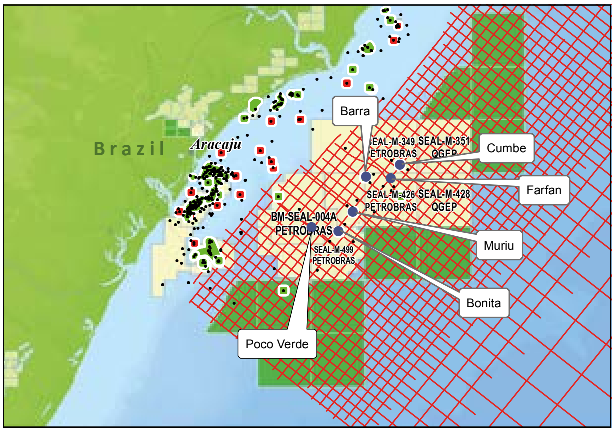


Figure 4: Sergipe deepwater discoveries.

The Sergipe Basin is located offshore north-east Brazil. It is divided into two sub-basins, Sergipe in the south and Alagoas in the north. With an offshore area of 35,000 km^2 and water depths up to 3,500m, it is classified as a passive margin / pull-apart basin with initial Early to Mid-Cretaceous rift basin development, followed by a passive margin drift phase from the Mid-Cretaceous to present, resulting from the separation of South America from Africa. The Alagoas Basin is dominated by a thick syn-rift succession and an abbreviated post-rift/drift sedimentary section. The Sergipe Basin is characterised by a major extensional rift phase and the presence of a fully developed post-rift sequence.

The onshore basin is mature, having experienced exploration activity for almost 100 years, although prior to the 1950s it was sporadic. In the '60s there was heightened drilling activity and the largest onshore field, Carmopolis, was discovered at this time. Offshore, significant seismic and drilling commenced in the 1970s and the 110 MMboe Caioba field was discovered. Exploration on the shelf continued through the '80s to late 2000s with moderate to small discoveries. In 2010 Petrobras made several significant Upper Cretaceous to Lower Tertiary, turbidite channel system discoveries in the deeper water of the Sergipe Basin. The company submitted eight appraisal evaluation plans to the ANP (National Agency of Petroleum) and drilling on the recent discoveries is continuing in order to commercially confirm some 3+ Bboe of reserves.

Undrilled Discovery Analogues

The Barra discovery well was drilled in September 2010, reaching a depth of 6,510m in 2,341m of water. Permeability and porosity conditions in the reservoir are excellent at well depths of approximately 4,650–4,750m, where drill stem tests indicate gas and condensate present in commercial quantities. The gross thickness of the zone of sandstones encountered in the Barra well is approximately 80m and well tests indicate a high porosity/ low density, gas-charged reservoir.

Two other discoveries in the deepwater area of this basin include the Muriu and Farfan finds, with estimates indicating 3 Bboip and rising due to other exploration successes, including the latest Poço Verde discovery (Figure 4). These discoveries are in turbidite channel systems of Mid to Late Cretaceous and Early Tertiary age. They are associated with clear amplitude anomalies as illustrated in both dip and strike seismic sections over the Barra discovery (Figure 5).

Using the angle stack attribute (Far-Near*Far) it was possible to identify multiple undrilled amplitude and AVA anomalies, with similar character to the Barra trend of discoveries and of similar and larger size. These can be seen extending into open acreage and blocks in the current licensing round.

Basin Floor Fan Play Fairway

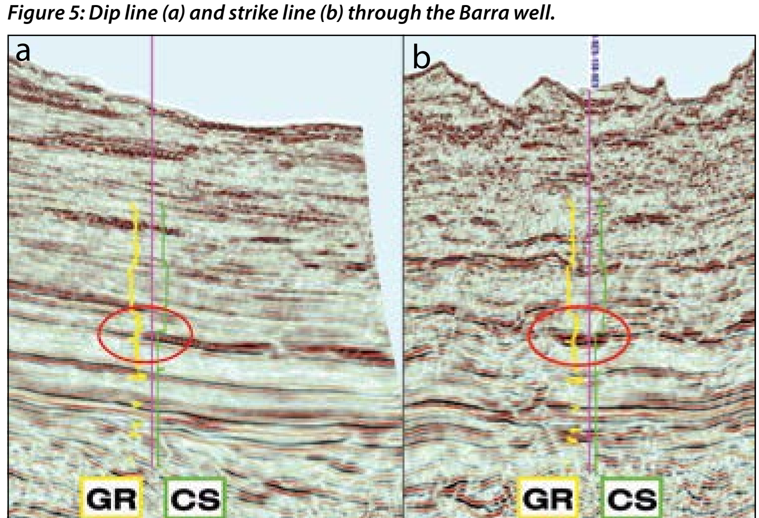
An extensive dataset of modern long-streamer 2D seismic along both sides of the South Atlantic margin has been used to identify a regional basin floor fan play fairway with a regional distribution of source rock and kitchen areas. At the same time, depth domain seismic profiles have revealed the true geometries of these basin floor fans. A deepwater basin floor fan play model (Figure 6) indicates a huge trapping geometry on seismic displays corrected for water depth, where it becomes apparent that the basin floor fans directly overlying mature Aptian source rock are in fact dipping landward or pinching out towards the mid-oceanic ridge, thereby eliminating the most dreaded up-dip seal trapping risk for this type of play.

This geometrical relationship is observed offshore Sergipe, outboard of the turbidite channel discoveries in the basin floor fan setting. Amplitude and AVA anomalies indicate that there could be significant hydrocarbon accumulations associated with extensive basin floor fans to the east of the channel discoveries and with a separate trap provided by 3-way dip closure and up-dip pinch-out to the east.

Proven and New Play Types

Integrating all available seismic tools, a schematic section

Figure 5: Dip line (a) and strike line (b) through the Barra well.



has been put together to illustrate the various play types identified in the Sergipe Basin (see Figure 3, beginning of article). Source rock, reservoir, seal and trap evaluation has been combined with amplitude and AVA anomaly analysis, resulting in up to 14 different potential targets in pre- to syn-rift and post-rift sequences which have been mapped and are potentially associated with hydrocarbon indicators. These play types include the proven stratigraphic seaward dipping Late Cretaceous Calumbi Formation slope apron and base of slope deepwater turbidites.

Many new untested play types include Early Cretaceous syn-rift 3-way dip closures with fault seal and 4-way dip closed structures with either fluvio-deltaic or aeolian sandstone reservoirs, Aptian source rock and intra formational shale seals. Also in the Early Cretaceous, syn-rift unconformity truncation plays similar to those associated with the successful Dentale play fairway in Gabon have been identified.

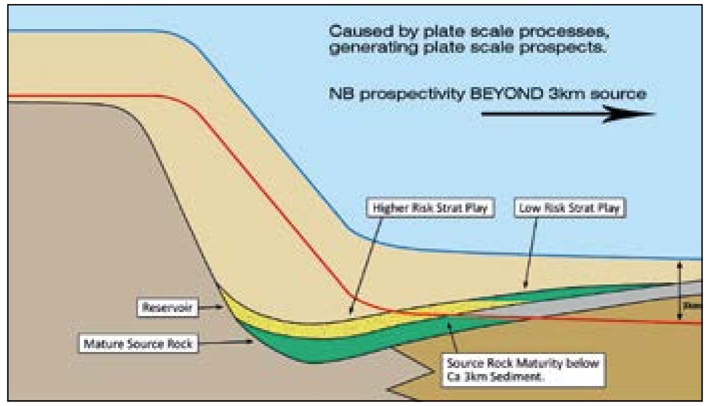


Figure 6: Atlantic margin basin floor fan play fairway model – note up-dip closure of apron fan.

Aptian/Albian plays could be sourced by either Aptian or Albian source rock and include Aptian/Barremian transgressive sands, sandstones and limestones in stratigraphic unconformity lag or seaward dipping traps, as well as 3-way dip closures against sea mounts or intrusive induced anticlines and fault controlled 3-way dip closures.

Late Cretaceous and younger rocks have similar traps to those mentioned above, with the Calumbi formation as the reservoir and either Aptian or Albian source rocks. The combined structural-stratigraphic landward-dipping basin floor fans are a significant untested play type with excellent amplitude and AVA seismic indicators. Figure 7 shows a dip seismic line in time, displaying the (Far-Near*Far) angle stack attribute. Yellow indicates a soft kick which brightens in the far angle stack (AVA anomaly). A zoomed-in panel of the dashed box shows a strong AVA anomaly with an associated basin floor fan geometry. The conventional seismic PSDM zoomed-in display, with water depth corrected, shows the true geometry of this basin floor fan.

Gravity Modelling

An accurate interpretation of the crystalline basement and the Moho discontinuity was made possible by the high quality PSDM imaging (see foldout). The interpreted horizons and interval velocity models were used to constrain modelled gravity profiles, from which were derived gridded maps of the base of sediment (top crystalline basement) and the Moho discontinuity.

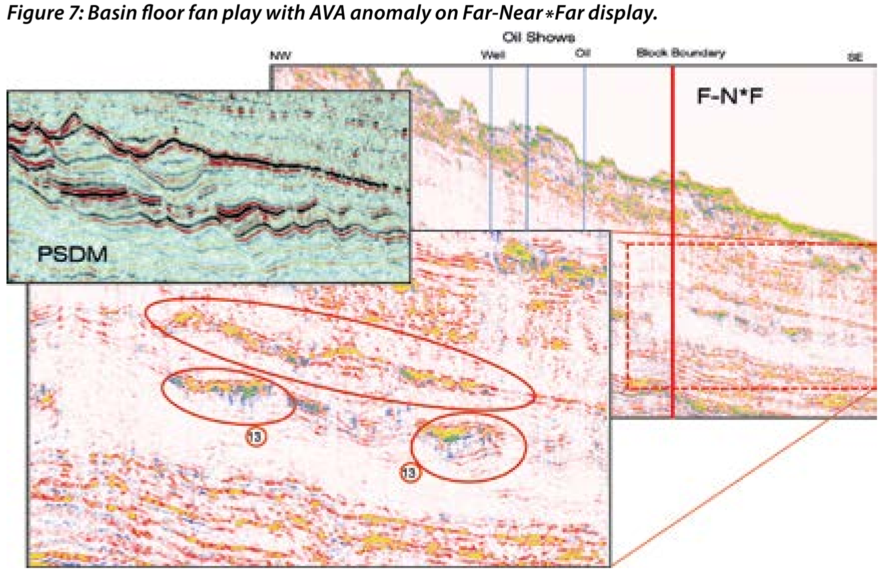
These modelled gravity inversions have led to an improved interpretation of the crustal geometry by augmenting the seismic imaging, resulting in a clearer picture of crustal architecture including the amount of stretching associated with rifting across the basin (Figure 2). The beta factors that are implied by this stretching help to constrain the modelling of heat flow and thermal maturation.

Sergipe Past, Present and Future

Evaluation of modern, high quality seismic data has led to the confirmation of the extension into open acreage of proven turbidite channel systems of Mid to Late Cretaceous and Early Tertiary age. Using an extensive long-offset seismic dataset spanning both sides of the Atlantic, a model has been put together showing basin floor fans dipping landward and pinching out towards the mid-oceanic ridge. In Sergipe these basin floor fans are associated with AVA anomalies similar to those of the discoveries. This play type is being tested by the Yakaar well offshore Senegal and is set to become the exploration target of the future due to its huge potential.

Integration of available seismic and potential field data has resulted in a greater understanding of the main elements of the petroleum system and, therefore, in the identification of multiple as yet untested play types in this basin. Again, with calibrated amplitude support and with pre- to syn-rift analogies in the successful targets in the conjugate Gabon margin, modern tools are available which confirm that the undrilled potential offshore Sergipe easily surpasses the discovered resources to date. ■

*Figure 7: Basin floor fan play with AVA anomaly on Far-Near*Far display.*



Adapting to a Changing Environment

The E&P industry is facing many challenges: collaborative thinking is key to improved systems and productivity.

JOHN PEARSON, Amec Foster Wheeler

The generally accepted understanding in the O&G industry seems to be 'lower for longer'; the days of US$100 a barrel oil are gone, and waiting for them to return will not move us forward. Hope is not a strategy – we need to think beyond the oil price. Operating in a more challenging environment, collaboration will prove to be key, and there are five vital collaborative elements that need to be addressed in order to adapt to this new situation.

Everyone in the industry needs to be aligned on **metrics**. If we all looked at what our customers measured, we could align with those metrics and help them deliver the things that matter. In the times of peak oil prices, we lost our focus on the end result. Since prices dropped in Q4 2014, capital and operating costs have fallen by 27% and 18% respectively, and although productivity has improved dramatically, we now need to get about 50% more out of the CAPEX and OPEX for each project. The productivity imperative for oil and gas is clear.

We need more collaboration across the whole **supply chain**. The current relationship between oil and gas companies and the service industry is not working; as the graph shows, this has been tough for everyone – and it is not sustainable for anyone. We must all learn to trust our collaborators. In 2016 operators spent US$600bn through external suppliers and there is huge potential for productivity gains in this area if everyone is working together.

Moving forward, there is a need to **change the culture** within companies; if you think you or your company are better than everyone else, you're wrong. Understand that you are part of the change and learn to constantly question how to create more value. Only the paranoid survive!

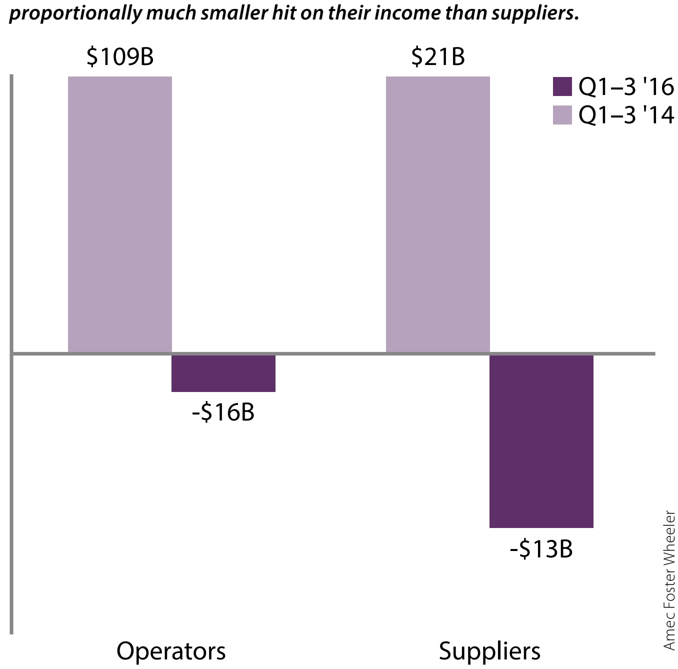
Everyone is aware of the need to be more **cost efficient**, but this has to be combined with a more **agile** approach. Delayering, removing duplication and reducing overheads must all be undertaken, without compromising on safety, but look at the issues from all angles, making it a collaborative operation.

Now is the time to bring in **digital, process and commercial innovations**. The scaled deployment of new business models, new technologies and value engineering will bring rewards. We can learn a lot from other industries – for example, if our digital delivery mechanisms had moved at the pace that Amazon's did, we would be in a very different place now. Process innovation means doing more for less – always talked about, but often not really examined closely until we have to, as now. Lower prices have revealed inefficiencies. One company recently realised it could safely and easily replace a US$350,000 titanium valve with a plastic one costing US$25,000, something they did not consider when oil prices were buoyant. There are innovative processes we can consider in the commercial field to increase trust, sharing and partnerships, so that by creating more value through collaboration there is more to share out between the partners.

The industry is already moving in these directions and there are great things happening – but is it enough? I fear it may not be, because the changes are not momentous enough yet. Nothing has happened which would be equivalent, for example, to the revolution we have seen in the retail industry with the move to online selling, and I believe we need to be changing at that scale.

We must not waste this crisis. If we review our collaborative working practices we will get something out of it and end up with an improved industry. ■

Total net income, top 60 O&G operators and suppliers. The current financial performance is not sustainable, with operators taking a proportionally much smaller hit on their income than suppliers.



Arthur Beeby-Thompson Oil Pioneer

PAUL C. LOGAN, Chase Geoscience

In 1873, 14 years after the world's first commercial oil well at Titusville, a boy was born in Northampton, England, who was to become known throughout the fledgling oil industry, simply as 'Beeby-Thompson'. His achievements were such that the foreword to his autobiography was written by none other than Herbert Hoover, 31st President of the US.

Arthur Beeby Thompson was the son of Beeby Thompson, Headmaster at Northampton Science School, who, unusually for those times, specialised in teaching geology and physics, and who took his son on fossil-hunting expeditions to "nurture his inquisitive nature and powers of observation". Leaving school at 16, he was articled for five years to a local engineering firm, and so began his long and distinguished career as an engineer. He first worked in the machine shop, graduating to the drawing office, where he learnt to make accurate plans and drawings.

On completing his apprenticeship he joined a firm of waterworks contractors as a draughtsman, where he also learnt about well boring and shaft sinking. In 1896 he became a water engineer in government service on the Gold Coast (now Ghana) in West Africa.

After eight months of sinking water wells, and having survived several bouts of malaria, he returned to the UK on leave, taking up a temporary post as surveyor on a London reservoir project. Having added the skills of a field surveyor to his growing list of accomplishments, he readily returned to the Gold Coast to join a survey team working in the uplands, surveying potential water sources.

Drilling in Baku

Beeby-Thompson returned to England in 1897, but felt that his "inclinations… lay elsewhere in foreign fields". In 1898 he joined the European Petroleum Company in Baku as a water engineer, although his duties soon involved more oil than water. In the last years of the 19th century, the Baku oilfields covered an area of about 10 km^2 and by 1900 were producing 75 MMbo a year from 1,700 wells – more than 50% of the world's output.

Soon after his arrival a severe recurrence of malaria brought him close to death, not helped by daily injections of quinine and arsenic! Having been "reduced to a skeleton", the doctors pronounced him ready for his funeral rites, at which point he refused all further treatment and began to recover. While convalescing he made himself familiar with the techniques employed in oil drilling. Most wells were drilled with the 'free-fall' percussion method, dropping a heavy bit and sinker bar into the well-bore. Average penetration rates were a little over 2m a day and wells took several months to drill. Numerous tool failures resulted in long, costly 'fishing' jobs, 'gushers' were frequent, and sand entrained in the gas and oil would cut through a 30 cm thick steel plate in days.

In 1900, he was appointed Chief

Mechanical Engineer, and he began experimenting with new techniques, including cable-drilling, screw-threaded (rather than riveted) casing and the replacement of steam power with internal combustion engines. After the initial 'gusher' phase most wells at the time were produced by bailing, with large diameter boreholes; Beeby-Thompson introduced an air-lift system, increasing production five-fold. He also unravelled the mystery of 'oil-dirt' – a curdled mixture of oil and water that would not separate, and was burnt or run off. Such colloids were little understood, but he found a way to separate them, enabling the oil to be used. He also entered the field of reservoir geology, making microscopic examinations of rocks, seeking clues to the origins of oil generation and compositional variations – knowledge which would stand him in good stead in later years.

Life in the Baku oilfields was not without danger. The wooden derricks were frequently soaked in oil, oil was stored in adjacent open vats and no-smoking regulations were generally ignored, resulting in many damaging conflagrations. Robbery and murder were common, with professional assassins available to settle political and business disputes! Beeby-Thompson's own official 'shadow', a promising young Russian engineer, was himself murdered on the road for the sake of the few roubles he was carrying. Crime took other forms like unauthorised tapping-into or diversion of pipelines and consequent theft of oil.

While in Baku Beeby-Thompson spent his spare time studying the geology of the region, which was to aid him greatly in his later career as he turned his hand to petroleum geology, field mapping and surveying in diverse continents. He also began work on the book for which he was to become best known, *The Oilfields of Russia and the Russian Petroleum Industry.*

In 1901, he married London-born Christina, and in 1904, with two daughters and worried by increasing political unrest, he left Baku for London, having resolved to set up shop as a consulting petroleum engineer. A third daughter arrived shortly after their return to London.

A village group in Ghana, 1896, with the author standing on left behind the chief.

More Foreign Adventures

He formed a partnership with another former Baku engineer, Campbell Hunter, and they duly awaited their first client, having been warned by family, friends and businessmen alike of their poor prospects!

After a brief contract in Baku, cut short by severe inter-communal violence between Armenians and Tartars, Beeby-Thompson and Hunter were commissioned to go to Peru to appraise an oil property which their clients had owned for some time, but which they professed to know very little. In 1905, Beeby-Thomson was offered a post in Persia by William Knox D'Arcy, founder of the Anglo-Persian Oil Co., which he declined, preferring London to the "rough living conditions and trying climate" that the new post would entail – somewhat ironic, given the conditions he was to experience later in his career. He was elected as a Fellow of the Geological Society of London in December 1906.

The firm grew and the partners were, for the times, enlightened employers: "Our staff were treated as colleagues, rather than as employees, and they knew that there was no need to invent sick or deceased relatives as reasons

Baku oil fields early in the 20th century could be dangerous places.

Tekniska museet

US President Herbert Hoover was both a friend and work associate of Beeby-Thompson.

for absence, when important football matches or the Wimbledon finals were in progress"!

Between 1906 and 1914 the London investment market underwent an oil boom, with many new mining companies and numerous flotations and speculative ventures, and the firm of Thompson and Hunter found themselves at its heart. Among their achievements was persuading British companies to start building oilfield equipment, which hitherto had generally only been available in the US, thus opening up new markets for these firms.

In 1908, he began his long association with Herbert Hoover, who had asked for assistance in securing interests in Trinidad and Peru. Over the ensuing years, Beeby-Thompson was to advise Hoover in a number of ventures and the two became firm friends. More foreign adventures followed and between 1905 and 1914 Beeby-Thompson worked on projects in some 30 countries. Given that this was before the advent of air travel, it is perhaps unsurprising that from 1905 to 1939, he spent only two Christmases at home with his family!

In 1914, with the beginning of the First World War, Beeby-Thompson turned his attention to water supply security, initially for London. Though repeatedly refused an army commission due to his age, in 1915 the War Office asked him to travel to Gallipoli with a hand-picked team to ensure a water supply for the allied troops there. After the evacuation of Gallipoli, he returned to his civilian occupation and in 1916, travelled extensively in North America in pursuit of his oil business interests, sailing home from New York on New Year's Day, 1917.

1918 found him back on war service, looking for water supplies in Sudan, Egypt, Somalia and Palestine, where he met Colonel T.E. Lawrence – 'Lawrence of Arabia'.

Opening Iraq

After the war, Beeby-Thompson made several visits to America, meeting many of the leading figures in the burgeoning oil industry. He had a reputation as a skilled and knowledgeable 'oil man' and often found himself feted and hosted at the very best hotels, a far cry from the privations of his earlier expeditions.

From 1921 Beeby-Thompson began his involvement with oil exploration in Mesopotamia, especially the Mosul area. The discovery of oil at Kirkuk in 1927 spurred efforts by interested parties to secure further concessions in Iraq, with Beeby-Thompson in the thick of it. His firm was commissioned by the Iraq Petroleum Company to begin drilling near Mosul and he made several trips to Iraq, including one when he seems to have visited most of the country, travelling through Kurdistan, noting the profusion of natural oil occurrences and seeps.

Beeby-Thompson when serving in the Middle East during the 1914–1918 war.

In Baghdad he met King Feisal, who sought his help in improving the country's water supplies.

In 1934 he noted the problem of "the poisonous character of the gases" encountered in drilling operations in Iraq, saying that "one whiff of the gas [hydrogen sulphide] was enough to cause instantaneous unconsciousness and muscular paralysis". In cable drilling, it was impossible to avoid the gas escapes and so, true to his engineering origins, Beeby-Thompson designed a system of fans and extractors to remove and blow the gas to one side, removing a major threat to the health and safety of the drilling crew.

Rounding the western (Syrian) end of Jebel Sinjar, Iraq, in 1932.

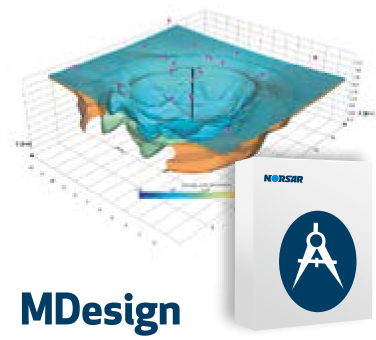
A Pivotal Role

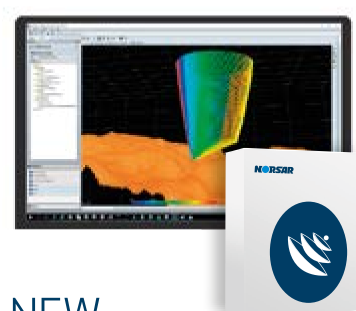
In his autobiography, Beeby-Thompson says nothing of his activities during WWII, so we assume that, by then in his late sixties, he passed the war at home in England, tending to his business interests as best he could. Sadly, his wife Christina passed away in 1941 at the age of 68, having spent much of her married life apart from her husband. In 1946, in what was almost a post-script, he formally changed his surname to 'Beeby-Thompson', the name by which he had been known throughout his working life.

After the war he resumed his international career and in 1947 travelled to Bahrain, where oil had been discovered in 1932. Air travel now established, he flew from Bahrain to Cairo, and observed that he had seen "more geology in a few minutes than [he] could have in months of ground work". In 1948, at the age of 75, Beeby-Thompson again travelled widely in the United States, renewing his acquaintance with Herbert Hoover, who had served as President from 1929 to 1933. The final act of his career was to publish his autobiography *Oil Pioneer*, in 1961. He died in London in 1968, at the grand old age of 95, despite having suffered from recurrent attacks of malaria, dysentery and typhoid during his earlier adventures.

Although now largely forgotten, Beeby-Thompson played a pivotal role in the early development of the global oil industry. He travelled hundreds of thousands of miles, criss-crossing the globe on journeys that took weeks and months. His travels took him to the heart of the developing oil industry and he certainly met many of the leading figures of the age. He was an engineer and scientist and perhaps most of all, an innovator. One cannot help but wonder what he would have made of today's advances in petroleum geology and engineering with its 3D seismic and reservoir models, large, powerful drilling rigs and modern drilling methods, and what more he might have achieved, had they been available to him.

A longer version of this article is available online. ■





Learning on the Rocks

JON NOAD
Sedimental Services

How can non-geologists gain a better understanding of the various aspects of reservoir geology? By physically exposing them to outcrops, in multidisciplinary teams with geological guides on hand.

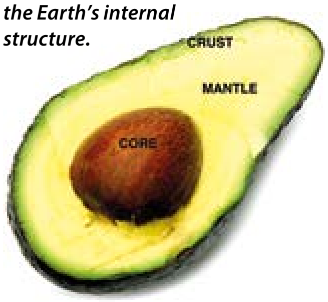
Understanding the geology of a potential or producing field is a key component in calculating its potential volumes, and in planning its successful development. Yet it is often difficult for the geologists in integrated teams to explain concepts such as the interpreted depositional setting in which the reservoir formed, inter-well correlation, sand body connectivity and reservoir heterogeneities to their colleagues, or how these will affect the production of the resource. One of the biggest challenges is trying to get an appreciation of the scale of the reservoir and its component elements such as sand bodies and fractures. How can non-geologists such as geophysicists, reservoir engineers, petrophysicists and petroleum engineers really get to grips with the rocks?

Sedimentary, My Dear Watson

All is not lost. One of the most enjoyable aspects of geology is its accessibility to the layman, primarily because it is based on careful observation and interpretation, rather than complicated equations. Geology is full of 'wow moments', with dinosaurs, mammoths, volcanoes, earthquakes and tsunamis giving it an almost lurid appeal.

However, many of the aspects of sedimentary geology are far more mundane, such as looking at rivers and shallow seas, and the deposits that they generate. They are also readily available to view in outcrops all over the world. Elements such as sedimentary structures and trace fossils, once explained, are easily comprehended.

Over the last 20 years I have set up several 'Geology for Non-Geologists' (G4NG) courses for various oil companies, in diverse locations and spanning four continents. Ideally the course is divided up into a single day in the classroom followed by two days spent in the field. Everyone recognises that there is a lot to learn, and rather than wallow in the complexities of sedimentary structures and strain ellipses, the classroom lectures are kept short and entertaining. They are interspersed with practical exercises designed to teach geological concepts through the application of simple principles.



An avocado demonstrating the Earth's internal structure.

A G4NG field trip looking at limestone outcrops in the Rockies, close to Exshaw, Alberta, Canada, which will help appreciate reservoir scale.

Jon Noad

The world-class seal and source rock outcrop at Kimmeridge Bay, Dorset, UK.

A good example is a short lecture that uses food to explain concepts such as folding and fracturing, by gradually bending cheddar cheese until it cracks. An avocado can be used to show the Earth's crust and mantle, and we ask the students to use sliced bread to create geological cross-sections. Another exercise has them designing organisms to live in different settings, and then imagining what sort of structures they would create as they burrow through the sediment. Geological themes covered include sedimentology, palaeontology, structural geology, oil genesis and migration, exploration and production, and basin evolution, all attacked from novel perspectives.

Location, Location, Location

Of course, the key learnings take place on the rocks. When selecting the field location, ideally the outcrops should offer the widest possible range of depositional settings within a relatively small area, in order to minimise driving time. In addition, the presence of a working petroleum system in the area adds an extra element of relevance to the fieldwork. Dorset in southern England has proved to be an outstanding location for a G4NG course: an area of natural beauty and a World Heritage Site, with a wide variety of sedimentary rocks exposed along the coast, in addition to oil production.

Oil is being produced from both the Kimmeridge and Wytch Farm oil fields, the latter being Britain's largest onshore oil field with a STOIIP of some 900 MMbo. The main reservoir rocks, the Sherwood Sandstone and Bridport Sands, are exposed at Ladram Bay and Bridport respectively, and a world-class seal and source rock outcrop at Kimmeridge Bay (above). Another source rock at Lyme Regis is chock-a-block with giant ammonites. Depositional settings range from rivers to deserts, alluvial fans, lagoons, beaches and shallow seas. The same structures that trap oil at Wytch Farm are strikingly exposed at Lulworth Cove, where a huge fault drags the

Fossil tree trunk exposed in the Jurassic Fernie Formation at the Banff Traffic Circle, Alberta.

sedimentary rocks until they dip near vertically. There is even an oil seep on the beach at Osmington!

Another classic location for a G4NG field trip is around Canmore and Banff, in the Canadian Rocky Mountains of Alberta. Also a World Heritage Site, the region offers a breath-taking backdrop. A field trip run over one day includes two clastic outcrops, one exposing shallow marine mudstones and sandstone beds with some striking trace fossils. The second has a continuous succession shallowing up from turbidite deposits, through shoreface sandstone beds with fossilised tree trunks, and up into fluvial channel deposits. The attendees walk it out, imagining that they are swimming up the palaeoslope and clambering onto the beach.

G4NG participants working on the logging exercise in Bowes Quarry, Isle of Portland, Dorset.

There are also two limestone outcrops, which provide the chance to talk about depositional cycles and sea level change. Bedding planes expose several fracture sets, which are utilised in a fascinating exercise on producibility. An ash bed, deposited in the same eruption that created Mono Lake, leads to a lesson on catastrophic events, and there is an obligatory structural stop to look at thrusts, illustrated with a folded field guide. As in Dorset, there is a working petroleum system in the vicinity to provide a strong link to the hydrocarbon industry.

Getting Back to the Rocks

In terms of overall logistics, a safety briefing and short introductory lecture set the scene the evening before the field trip begins, and multi-disciplinary teams of four are assigned. Everyone gets a field guide, packed with information and diagrams, as well as a basic geological glossary, because geologists have an inordinate fondness for acronyms and obscure terminology. For example, one man's *sea level rise* is a geologist's *transgression*.

The following morning we head into the field. I like to start each outcrop with a short story, which helps to embed the basic geology in the participants' heads. For example, when looking at deep water sedimentary deposits, they learn about the 1929 earthquake in Grand Banks, Newfoundland. This triggered landslides that sent turbidity currents racing downslope at up to 130 km/hour, breaking transatlantic cables in at least 23 places. The resulting tsunami reached Portugal, while the cable breaks allowed scientists to prove the existence of turbidites for the first time. Hopefully the next time someone mentions turbidites in the office, they will think of sediment-laden plumes careering through submarine canyons.

Getting close to the rocks.

The next thing is to set the participants loose. At every outcrop they are given a simple exercise, usually a combination of observations, followed by interpretations. An example would be to sketch an outcrop and then to try to pick out the different sediment packages. Once completed, they have to pick out the potential reservoirs, and decide how to drill them. Each exercise is carefully designed to build upon the ones preceding it, developing the confidence of the students by not introducing too many new concepts in too short a space of time. Two field trip leaders, both experienced geologists, move between the teams to help them whenever necessary.

After completing an exercise, a team will be chosen at random (to keep them all on their toes) to present their findings, which leads to a facilitated discussion. There are no wrong answers. The field trip leader will draw their attention to some of the aspects that help to determine the answer to each exercise. Any specialists on the trip may be asked to contribute, for example the geophysicist may be asked whether a particular bed or structure would be visible on a seismic line. A white board is an invaluable aid for everything from explanations of depositional settings and structures to sketching what the participants should be focusing on.

A highlight of every G4NG field trip is when the non-geologists get to log a short (5- to 10-metre) section of outcrop. Each section has been carefully selected to expose a variety of facies and sedimentary structures, and hopefully a small fault or two. Another unforgettable activity is on the second evening, before dinner. Each team is assigned a fun topic, such as using trace fossils, designed to make them pull together observations from more than one outcrop seen during the field trip. They then put together a ten-minute presentation, delivered to all the attendees, without recourse to slides, often in a convivial setting in the hotel. It is incredible to watch how far they have come in three short days, and the geological discussion continues over dinner.

The Gift That Keeps On Giving

While it is obviously not possible to 'create' a geologist from an engineer over the course of a few days, the G4NG courses provide an awareness of basic geological concepts that can then be directly applied back in the workplace, while ensuring that geologists and their counterparts are now 'speaking the same language'.

Choosing the right field localities ensures that there are plenty of highlights to keep the newly acquired skills fresh, while an email, sent to the participants as an *aide memoire* shortly after the field trip, details everything they have learned in 15 concise bullet points. Successful exploration and production rely on working efficiently in integrated teams.

The best way to build cooperation and understanding is by learning from one another and sharing ideas. What better place to do that than on a stunning outcrop in the sunshine? ■

Outcrop of parasequences at Woodside Canyon in Utah, overlain with seismic wiggles.

Time-Lapse Refraction Seismic I
A Complementary Monitoring Method?

MARTIN LANDRØ and LASSE AMUNDSEN

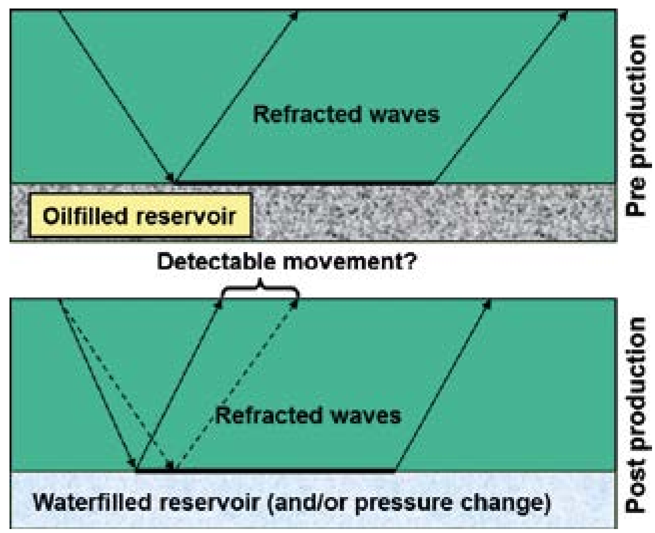
Would you like me to give you a formula for… success? It's quite simple, really. Double your rate of failure… You can be discouraged by failure – or you can learn from it. So go ahead and make mistakes. Because, remember that's where you'll find success. On the far side.

Thomas John Watson, Sr. (1874–1956), Chairman and CEO of IBM

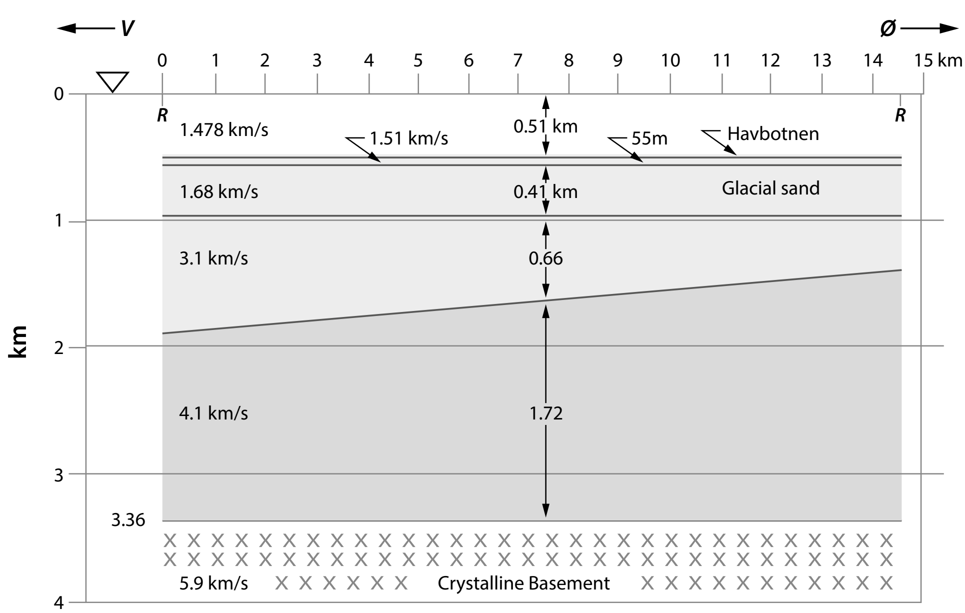
In 1962 Markvard Sellevoll at the University of Bergen, together with the Universities of Copenhagen and Hamburg, acquired a refraction seismic survey in Skagerak, south of Norway. The aim of the survey was to prove the existence of sediments in the area. The seismic refraction data clearly showed a low velocity layer approximately 0.4 km in thickness with low seismic velocities confirming sedimentary layers (see figure below).

The Basic Idea

In the early history of exploration geophysics, the seismic refraction method was commonly used, but gradually reflection seismic, as we know it today, demonstrated its usefulness and its ability to create precise 3D images of the subsurface. Hence, the use of refraction seismic – by which we mean looking for waves that have predominantly travelled horizontally when compared to reflected waves – decreased. Here we discuss and show evidence that, although the most accurate 4D seismic results are obtained by repeated 3D reflection seismic surveys, there might be a small niche market for time-lapse refraction seismic. Landrø *et al.* first suggested this monitoring technique at the SEG meeting in 2004. The figure top right, taken from this presentation, shows the basic principle: if the oil that originally filled a reservoir is replaced with water, the velocity in the reservoir layer will change, and hence the refraction angle (and the traveltime) for the refracted wave will also change.

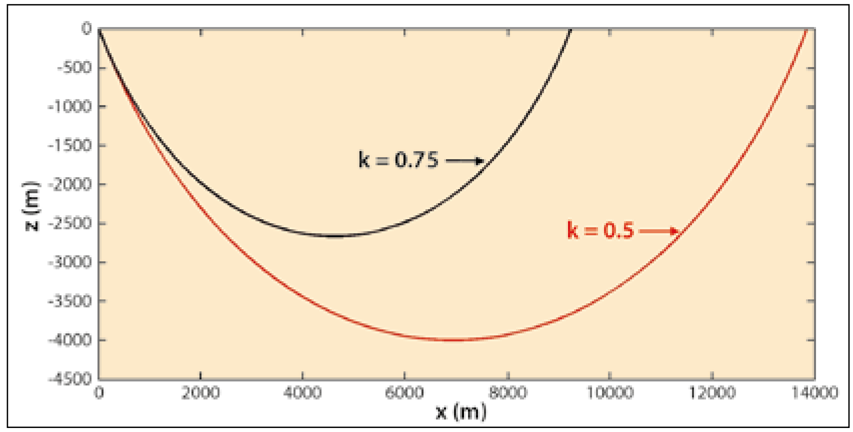


Example showing how refracted waves can be used to monitor an oil reservoir that is gradually getting more and more water-saturated. Velocity changes caused by pressure changes may also be detected this way.



The end result of the refraction seismic survey from Skagerak in 1962. Sellevoll interpreted the first low velocity layer below the seabed as a glacial sand layer. The velocity of this layer was estimated to 1,680 m/s.

It should be noted that the term refraction, or maybe one should say the way the word is used within geophysics, is not precise. The basic meaning is that if a wave changes direction obeying Snell's law ($sin\ \theta_1/v_1 = sin\ \theta_2/v_2$) across an interface, the wave is refracted. The portions of the initially downgoing energy refracted along the boundary interface are called critically refracted waves. In this case, θ_2 is 90°, implying that the incident angle θ_1 must be greater than the critical angle $sin\ \theta_c = v_1/v_2$ for waves to travel along the interface. As the critically refracted wave propagates along the interface, energy is sent back to the surface at the critical angle. We call this returning energy refracted waves or refractions. They are also called head waves since they arrive ahead of the direct wave at large source-receiver distances. When we use the term time-lapse refraction here, we mean that we exploit head waves and in general post-critical or diving waves.



Raypaths for two diving waves in a medium where the velocity increases linearly with depth. V_0 = 2,000 m/s and two different k-values are used. The take-off angle with respect to the vertical axis is 30° for both cases.

Diving Waves

Diving waves are waves that are not head waves but, due to a gradual increase in velocity with depth, they dive into the subsurface and then turn back again, without a clear reflection event.

A diving wave occurs when the velocity (v) increases linearly with depth (z): $v = v_0 + kz$, where k is the velocity gradient. Using Snell's law again ($sin\ \theta_1/v_1 = sin\ \theta_2/v_2$), it is possible to show that the ray path will be given as a circle with a radius (R):

$$R = \frac{1}{pk} = \frac{v_0}{k \cdot sin\theta_i}$$

where p is the ray parameter

$$(p = \frac{sin\theta_i}{v_0}),$$

and θ_i is the take-off angle with respect to the vertical axis for the ray.

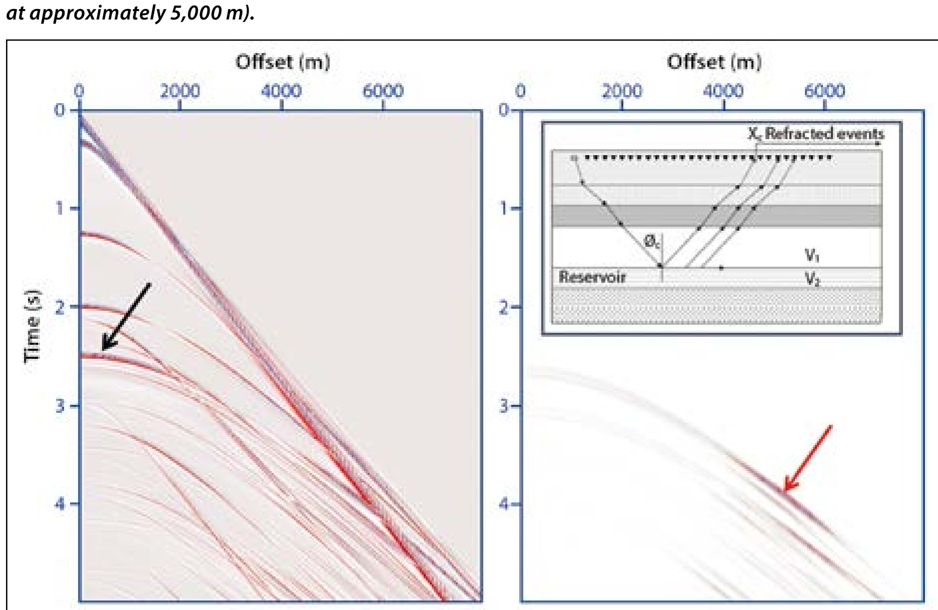
The figure above shows two examples where the solid black line ($k=0.75\ s^{-1}$) represents a velocity model where the velocity increases more rapidly with depth than the solid red curve ($k=0.5\ s^{-1}$). We observe that in a model with higher velocity gradient, the ray prefers to turn around earlier, so the offset where this ray is observed is shorter. This is exploited in Full Waveform Inversion to determine the low frequency velocity model. We clearly see that diving waves occur at large offsets. A linear velocity model is of course an idealisation, but due to compaction, it is not a bad first order approximation for a setting where the subsurface consists of sedimentary layers.

Complementary to Reflection

Both head waves and diving waves need large offsets to be detected, and therefore we often put them into the same category, although they are different wave types. It is also challenging to discriminate between diving waves and head waves in field data, so it is often convenient to put them into the same basket.

From the equation defining the critical angle, we see that to generate a head wave or refracted wave the velocity of the second layer must be greater than that of the first layer or overburden. This is the first of several practical disadvantages in the time-lapse refraction method. Another disadvantage is that the horizontal extension of the 4D anomaly needs to be large enough to be detected by the method. A long, thin anomaly is ideal. In this way, it is clear that the refraction method is complementary to conventional 4D seismic. ■

A synthetic seismic shot gather showing baseline data (left). The P-wave velocity of the reservoir layer is changing from 2,500 m/s to 2,450 m/s, and the shot gather on the right shows the difference between the base and monitor shot. The black arrow shows the top reservoir event, and the red arrow on the right plot shows that the strongest 4D signal actually occurs close to the critical offset (which is at approximately 5,000 m).



Breaking Up Is Never Easy

The Complexities That Create Opportunities in the Distal Domain

HELEN DORAN, Ophir Energy plc, and **GIANRETO MANATSCHAL**, Université de Strasbourg

For the past two decades our understanding of the evolution of passive margins has been greatly enhanced. Research by academic consortiums and petroleum companies, using field studies and a wealth of new well and seismic data, has yielded a much clearer understanding of crustal architecture and the rifting mechanics of many of our continental margins. In unravelling the complexities of the enigmatic area between oceanic and continental crust and revealing the processes relating to extreme crustal thinning and breakup, a new exploration domain has been created, increasing the global footprint for future exploration.

While the observations made by the industry and academia have been around for decades, exploration has been slow to act on these insights. With the exception of the brave few, adoption of these learnings into play-based exploration workflows and capturing acreage has been measured. However, times are changing. In the industry we are now witnessing a wider acceptance of these insights. More and more companies are positioning themselves in the distal domains of passive margins with large acreage grabs poised to unlock new plays (Figure 2).

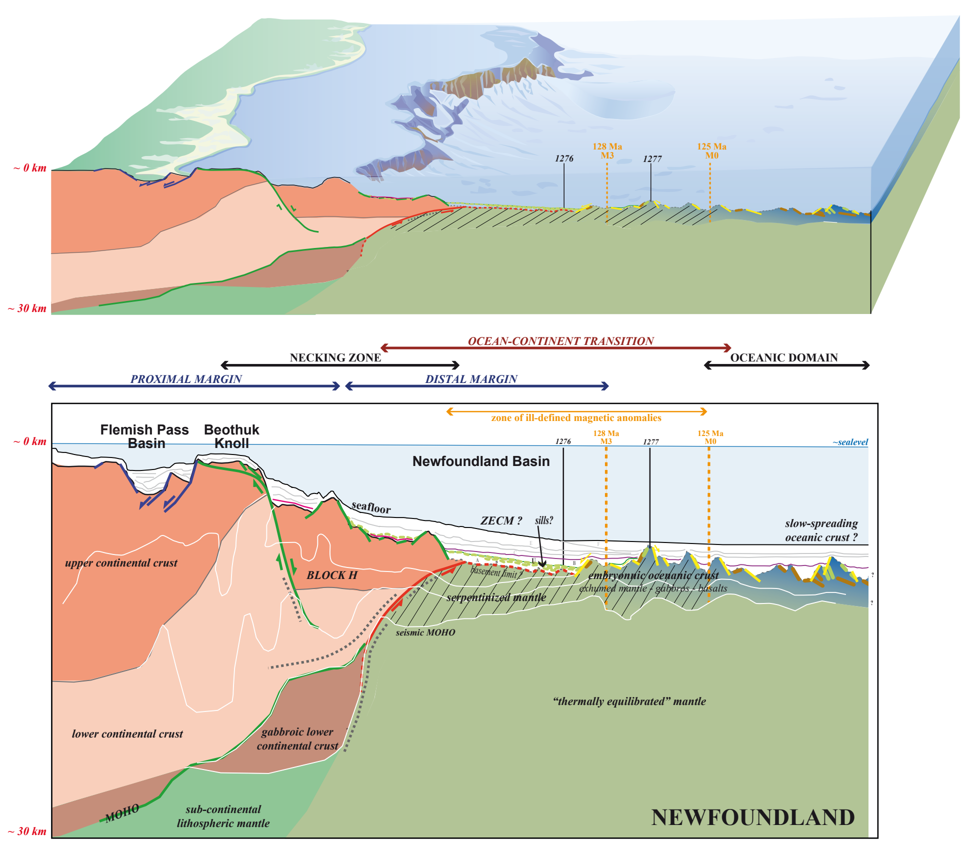
This article will highlight some of the key learnings from the latest research, the implications for play-based exploration and how we can move forward to become predictive to unlock the prize.

Old vs New

Determining subsidence history and paleo heat flux is critical to unlocking the remaining plays of our continental margins. The only way to successfully achieve this is to understand the mechanisms and timing of rifting. In the past we have made relatively simple assumptions. One of those assumptions dictated that rifting is of the same age across a margin and that breakup can be defined by the breakup unconformity. A simple yet profound consequence of this assumption was to incorrectly project observations made at proximal margins into the distal domain.

Holding a model on margin evolution is critical for play-based exploration. Historic rifting models often invoked systematic thinning of the continental crust towards the ocean continental boundary, which generally increased perceived risk moving from proximal to distal domains. In particular the risk associated with source rock maturity was often a barrier to exploring the distal domain. The assumption was that the primary source of heat flux is from radiogenic minerals present in the continental crust and sediment pile. Thinning in the distal domain and thus reducing radiogenic heat production introduced a significant perceived risk on source maturation.

It is now known that historic views of a margin development are overly simplistic and are not supported by observations. Rather than systematically thinning from the proximal to distal domain, crustal thickness has been observed to vary greatly along continental margins. Interpretation of seismic data has highlighted many occurrences of thick basement highs



formed by mantle, continental crust or magmatic additions, found far outboard of the limit of stretched and thinned continental crust (Figure 1). The zone between thinned continental and oceanic crust is now widely accepted to be extremely variable and complex in nature along both strike and dip directions. The zone can be associated with extreme crustal thinning, thick zones of exhumed and extruded mantle, proto-oceanic crust and true oceanic crust. We define this zone as 'the distal domain'. The subsidence and paleo heat flux of this domain varies greatly and the extent of the variation is in many ways dictated by the magmatic budget available during rifting and its presence after rifting. These insights challenge much of our preconceived ideas on potential plays in the distal domain and prompt us to rethink the prize.

Distal Exploration

Recognising that the distal domain is complex and accepting these complexities as opportunities offers additional real estate along our passive margins. We now understand that basement highs can exist in the distal domain. These highs are surrounded by stretched and thinned continental crust (e.g. Santos/Sao Paulo plateau; outer Campos high; Padouck High – see Figure 3). In addition to observing these on deep seismic reflection lines and from gravity data, we are slowly building a global well database on the subsidence and heat flux history of these highs.

Such basement highs are often attractive exploration targets. To unravel their potential, care needs to be taken to place these distal highs in relation to the proximal domain, the necking zone and the amount of stretching and thinning surrounding the high. In doing so we can unravel crustal composition, timing of rifting, and available magmatic budget during and after rifting, which allows us to be predictive on paleo heat flux, subsidence history and reservoir quality. Fluids associated with the magma may play an important role in early diagenetic evolution of the sediments and must be considered when determining reservoir play risk. The integration of regional and high resolution magnetic and gravity data coupled with deep seismic data is critical. Offset well data needs to be

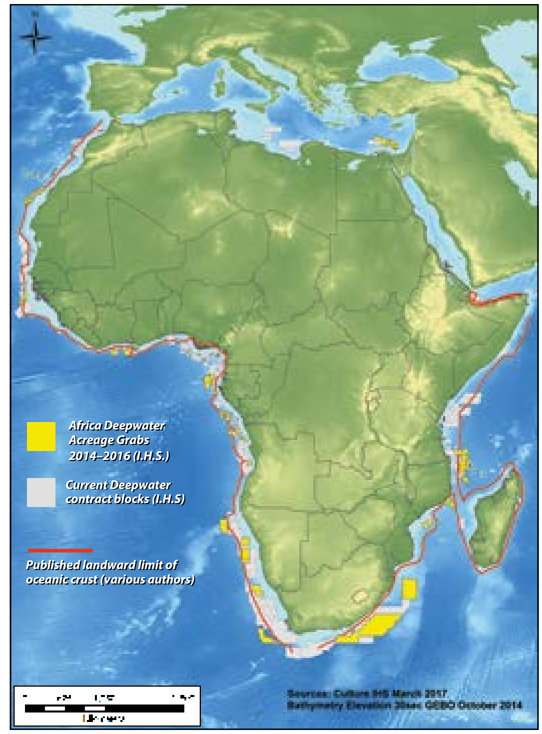


Figure 2: Map of Africa's deepwater acreage demonstrating a recent move by the industry into the distal domain.

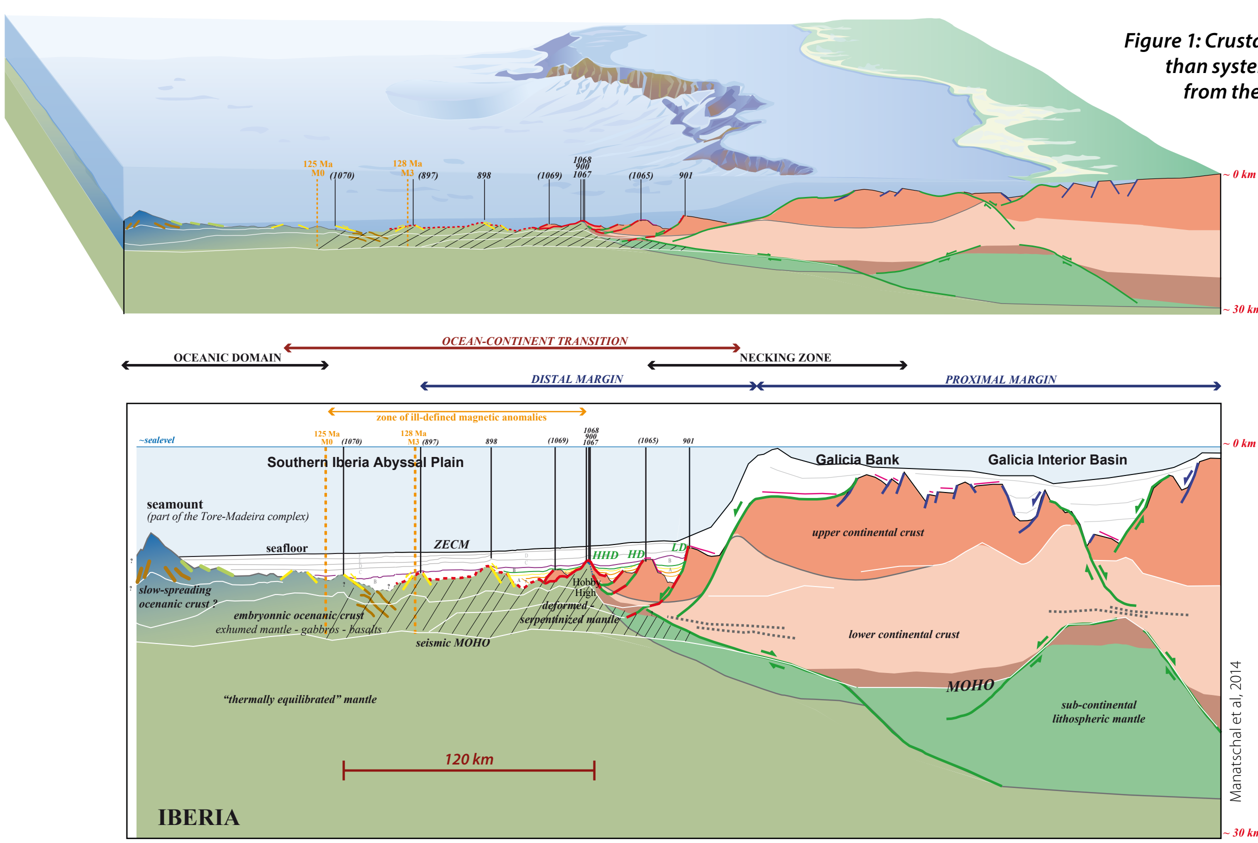
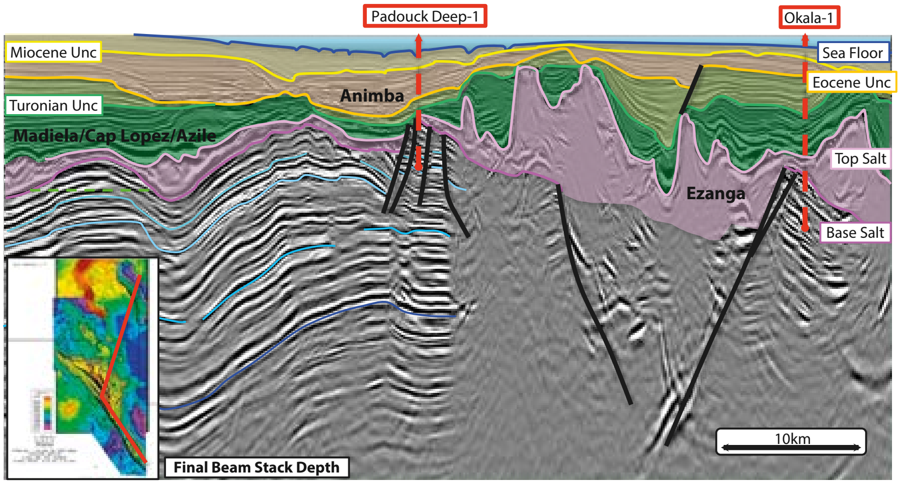
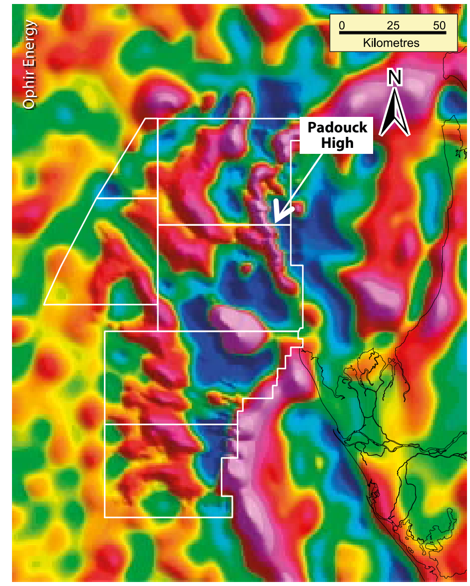


Figure 1: Crustal thickness, rather than systematically thinning from the proximal to distal domain, has been observed to vary greatly across margins.

Figure 3: The Padouck High (Gabon) is an example of a basement high positioned in the distal domain.





carefully evaluated to determine if it bears any relation to the stratigraphy to be tested. High-level observations regarding the character of these highs on gravity, seismic and from well data can then be made (Table 1).

The fundamental lessons learnt when drilling a basement high is that the subsidence and heat flux is very different to that of the surrounding basin, with the paleo heat flux often higher and the subsidence less. The basement thickness of these fragments dictates that they remained relatively buoyant throughout much of their post-rift history and therefore post-rift sediment cover is thin and condensed due to non-deposition and erosion. In play-based exploration, where previous exploration wells can influence the perception of play risk, particular care should be taken when using wells drilled on distal basement highs, as they often do not represent the stratigraphy, subsidence and heat flux of the surrounding basins. Likewise, a well drilled on very attenuated crust does not preclude the presence of an outboard thicker continental fragment.

Magma Budgets

A discussion on exploring in the distal domain would not be complete without a note on magmatic budgets. The magmatic budget available for rifting can be very variable and is not directly related to 'ß values', as often assumed in classical models. There are many occurrences in the literature which

Table 1: Observations from drilling a basement high

Data Type	Observation	Observations from drilling a Basement High
Potential Fields	Gravity response	Strong positive gravity anomaly (Figure 3).
Potential Fields	Position in margin	In excess of 100 km from the Hinge Zone surrounded by thinned continental crust.
Seismic	Elevated topography	Erosion off high/onlap onto high. Multiple unconformities observed in seismic. Thin overburden relative to surrounding flanks.
Seismic	Lack of evidence of syn-kinematic growth	No growth packages observed on seismic, the implication is that syn-kinematic sediments are not present.
Wells	Stratigraphy	Missing/condensed stratigraphy.
Wells	Environment of deposition	Prolonged sub-aerial to shallow marine conditions.
Wells	Maturation of sediments	Marked change in maturation of sediments between overburden and those drilled into the basement high.
Wells	Maturation of fluids	Marked change in maturity of fluids encountered in overburden and the sediments drilled into the basement high.
Wells	Diagenesis	High level of cementation present may relate to hydrothermal fluids related to magma.

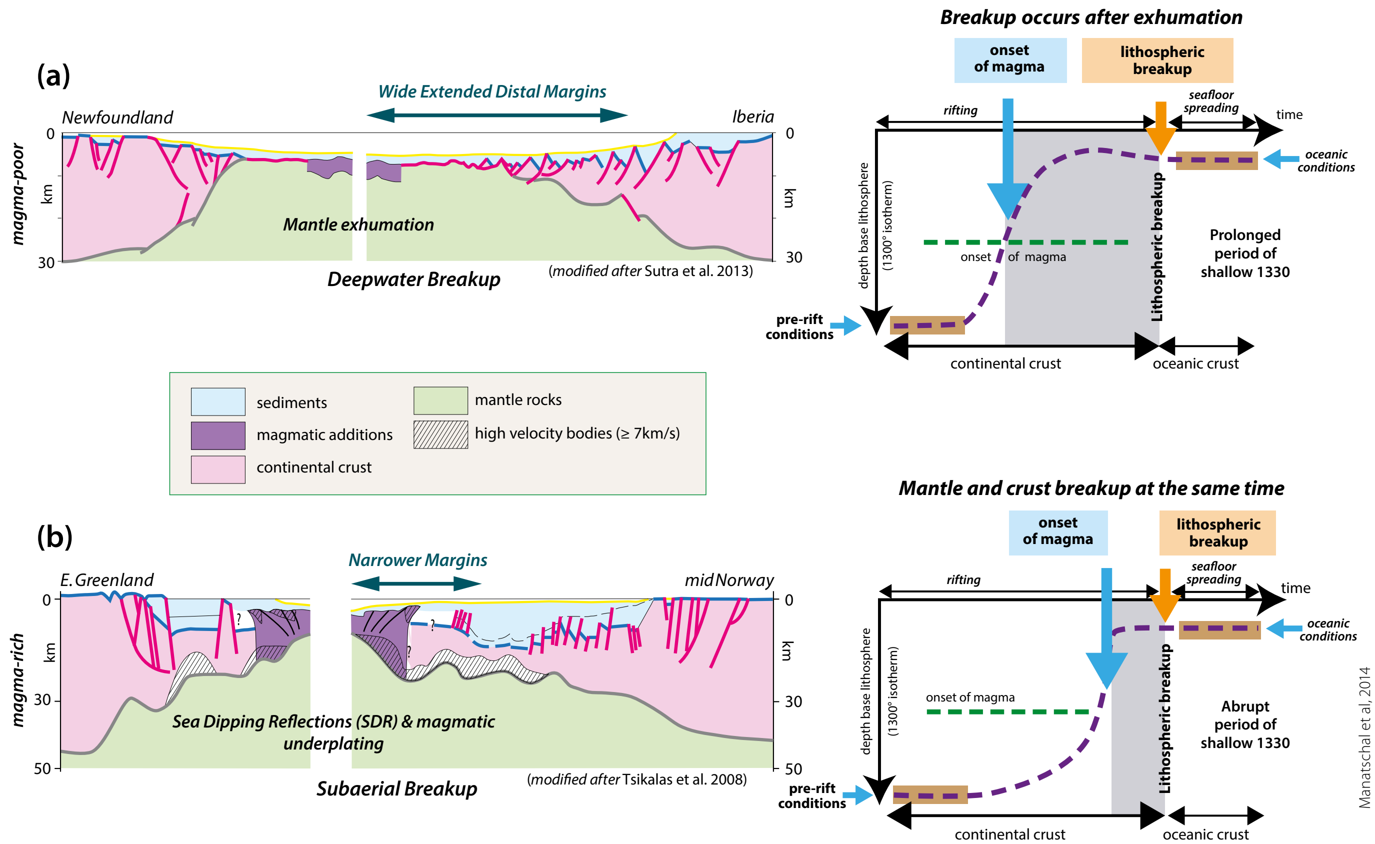


Figure 4: Variations in subsidence and heat flux in relation to magmatic budget: (a) magma poor; (b) magma rich.

describe magma-poor and magma-rich zones. However, these are end-member models. The industry now accepts that the available budget can be very variable as, for example, many margins globally exhibit magma-poor rifting in the proximal domain but magma-rich rifting in the distal domain.

The magmatic budget fundamentally dictates the thermal and subsidence history of the sedimentary section. In a magma-poor rift, breakup occurs in a deepwater environment resulting in deepwater sediments. In magma-rich margins breakup is often subaerial to shallow marine and subsequently the sediments represent this paleo environment. To complicate matters, in a hybrid margin exhibiting both magma-rich and magma-poor rifting, the volume of magma appears to change rapidly across transform faults and the subsidence history can show extreme variations within a few kilometres. The magmatic additions (intrusives plus extrusives) can also thicken the crust and can be mistaken for 'original' continental crust, leading to incorrect estimates of radiogenic heat flux and estimates of heat flow.

The volume of magma is dictated by the position of the asthenosphere under the sediment pile and the duration of its perturbation. In areas of hyperextended crust, heat flux from the mantle becomes a more important contributor than heat flux from radiogenic elements present in the crust and sediment pile. A shallow asthenosphere for a prolonged period of time has the ability to introduce high paleo heat fluxes into the overlying sediment pile. Recent wells drilled on hyperextended continental crust demonstrate that paleo heat flow here can be high. The data also shows that heat flow does not decay but remains high long after the period of rifting even to the present day. This is a more surprising and complex observation and is the subject of ongoing research. Several wells drilled along the distal domain of the Atlantic margin record present-day geothermal gradients in excess of 40° C/km. These elevated paleo and present day temperatures create an environment for maturation of both rift and drift related source rock facies in the distal domain. This is in stark contrast to our perception of immature source rocks inherited from the simplistic rifting model.

How do we Unlock the Distal Frontier?

As an industry we need to understand that collaboration will be the key to innovation. A perfect work programme utilises the bigger industry brain. Maximising the information from the experience of others, coupled with new data from potential fields, wells and seismic, will be required to unlock the prize.

We now recognise the complexities of the distal domains and no longer perceive these as risks but rather as opportunities for frontier exploration. The most fundamental lesson we can take going forward in exploring this new frontier is that we cannot simply project the lessons learnt in the proximal domain into the distal, but treat it as a new and distinct play fairway.

With special thanks to D. Burnett, A. Carr, S. Henry-Stogdon, J. Hull, W. Parsons, E. Pettinotti, O. Quinn and J. Smart from Ophir Energy and Nick Kusznir, OCTek. ■

Induced or Triggered Seismicity? A Long Term Approach

WILLIAM WILLS , Avalon Sciences Ltd.

The challenge of linking seismicity with human activity is not new; seismic recording systems were used to monitor induced earthquakes related to coal mining back in the 1900s. Real time seismic monitoring using highly sensitive downhole 3-component sensors, coupled with advanced downhole digital electronics and telemetry systems, have delivered a paradigm shift in spatially locating increasingly smaller earthquake foci in a 3D or 4D space. Real time monitoring and location of such 'microseismic' activity is common practice during unconventional hydrocarbon reservoir injection and depletion, where triggered events can be correlated with the spatial distribution of hydraulically fractured pathways and so indicate and optimise total stimulated reservoir volume and integrity.

Only recently have legal and regulatory bodies begun to formalise the process for instrumenting, monitoring and characterising *all* significant seismic activity related to reservoir activity. The economic incentive for operators and service companies to focus primarily on the very small microseismic events has yet to be extended to the practice of precisely monitoring and defining larger scale activity, especially *after* unconventional operations are completed.

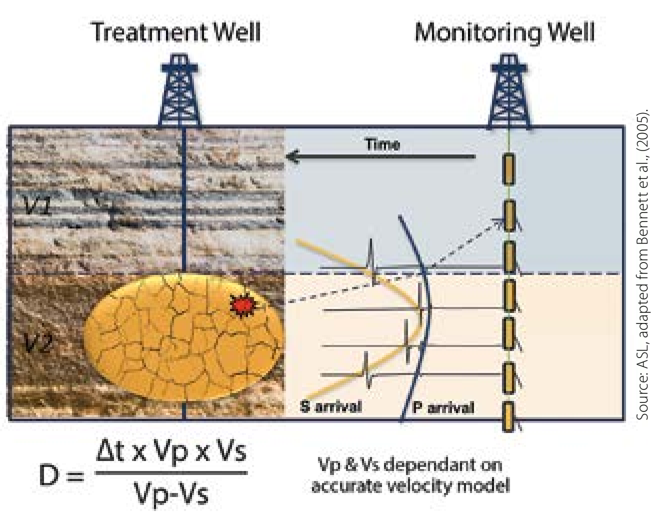
Induced or Triggered?

Recent unconventional operations associated with any 'felt' human-induced seismicity, especially in north-west Europe, have resulted in lengthy disputes between industry, seismologists and an increasingly sceptical public, convoluted further by the lack of any commonly accepted rules for discriminating between induced seismicity and triggered events.

Various workers have attempted to refine these terms, suggesting induced seismicity is related to volume change in the Earth, probably by human action during reservoir depletion. In such cases vertical shear stress is expected to be at a maximum at the edge of the expanding reservoir, leading to dip-slip events. Triggered events, on the other hand, are associated with the release of natural tectonic stress, although microseismicity associated with injecting proppant along a fracture plane can also be said to be triggered, as the effective stress changes trigger shear movement along/across the fracture network.

To differentiate seismic events recorded during reservoir operations by these terms, the spatial and temporal distributions of the foci need to be precisely and reliably resolved. The question of how close a seismic event has to be to the operation to be assumed related remains subjective, particularly in tectonically active regions with frequent natural earthquakes. Seismologists argue that we should integrate the recorded 4D foci distribution, the physical failure mechanisms and the modelled geomechanical regime, to help qualify a triggered/induced probability value for an event.

The methodology of acquiring such data is becoming firmly rooted in the practice of permanent/semi-permanent passive monitoring. Continuously recording events before, during and after injection provides a more stable background seismicity model, especially if combined with a known fault map, but this can add significant cost to the process.



Schematic of a borehole microseismic monitoring system.

Collaboration is Key

Standardising integrated 'big data' into a legal framework presents broad challenges. In Europe, monitoring is mainly a risk management rather than a production task. Demands from insurers and regulators are fragmented and require applied research and specialised niches. Perhaps peak ground velocity/max acceleration would be a more appropriate measurable variable and proportionate to 'felt' seismicity.

Unconventional extraction in Europe can no longer be justified with US analogues. Recent events in the USA, mostly associated with seismicity linked to waste water disposal, has given much unwanted publicity and pressure to hydraulic fracturing and its management. US and European regulatory authorities are watching each other to see what actions will have the first positive perceived impact.

A European network is required to defragment and standardise the operator, regulator and academic regulations, with criteria appropriate for the background seismicity of a region. Permanent monitoring will help constrain uncertainty and protect operators whilst bolstering the seismic recording market. By encouraging bodies to take a multi-disciplinary approach across better regulated industries like geothermal and mining, we will see the beginnings of quantitative, testable rules for the probabilistic discrimination of human-induced, human-triggered and natural earthquakes. ■

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Triumph and Tragedy

Kevin Topham has experienced both the excitement and tragedy of exploring for oil and gas. He was on the *Sea Gem* when it made the first commercial discovery in the UK North Sea in December 1965 – and also when it collapsed a few weeks later, with the death of 13 men. He tells us his story.

JANE WHALEY

Kevin Topham has had an eventful life. Born in Retford, Nottinghamshire, in the English East Midlands, he joined the RAF when still in his teens to fight in WWII. His four brothers were also all in the services and miraculously all survived.

Kevin remained in the RAF until the early 1950s, working for much of that time as a bomb disposal expert. When I asked him what drew him to a line of work the thought of which terrifies most of us, he simply says, "I was 17; you think you're invincible at that age. I was quite mechanically minded, and if the RAF decided you did something, you didn't have much choice!"

First UKCS Discovery

On leaving the RAF Kevin joined Kirklington Hall, BP's research station at Eakring in Nottinghamshire as a mechanical engineer. "I worked all over England and Scotland, drilling wells and finding oil and gas. I was even involved in drilling the first well at Wytch Farm, although it wasn't successful that time," Kevin says. "And we fracked all our wells! People seem to think fracking – or, as I prefer, hydraulic fracturing – is a modern process, but we've been doing it for years."

By the 1960s oil companies had begun to look seriously at the UK North Sea, and BP was no exception. "All of us based out of Eakring were experienced drillers, so when the company decided to start exploring the southern North Sea, they transferred us onto the project."

BP had converted a barge, the *Sea Gem*, for use as a drillship by welding on 10 steel legs and adding a helipad, living quarters, radio shack, drilling tower and associated structures. "I helped construct and test the derrick in Eakring before we transferred it to the *Sea Gem*," Kevin explains. "The whole thing was quite hastily put together – there was a lot of pressure to get a British rig working in the North Sea. Three wells had been drilled by American rigs, the first in December 1964, but they'd all been dry."

Kevin Topham at the Dukes Wood Oil Museum, recently relocated to Kelham Hall, Nottinghamshire. He is holding a sample of the first core taken on West Sole, the first UKCS hydrocarbon discovery.

Jane Whaley

In May 1965 the *Sea Gem* was towed out of Middlesbrough docks. The crew, including Kevin, flew out by helicopter to join her and by early June they were drilling about 65 km east of the English coast. "We were guinea pigs," he says. "Although some of the team had worked offshore Saudi, no one had experience of drilling in the North Sea. There was very little safety gear and no protective clothing. I travelled out with my RAF greatcoat to keep me warm."

On 17th September there were signs of gas and the drilling fluid returning from the bottom of the well was frothing: the *Sea Gem* had made the first discovery of hydrocarbons in the UK sector of the North Sea – the West Sole field. "To be honest, there wasn't that much excitement," Kevin recalls. "After all, we were experienced drillers and we'd found oil and gas before – it was just normal work for us. We also didn't know what they would do with gas, whether they would be able to pipe it to shore. And we knew that a show didn't necessarily mean a major discovery – in fact that first evidence of gas at 2,500m wasn't commercial."

The team continued drilling to over 3,000m and in December 1965 BP and the UK government announced that testing had shown that there was sufficient gas in the field to justify building a pipeline to bring it ashore.

Disaster at Sea

Having completed testing, the plan was to move the *Sea Gem* to a new drill site. Working a 10-day rota, Kevin expected to remain on board over Christmas 1965 – but a message came through on Christmas Eve saying that 12 personnel would be allowed home for Christmas, on standby for moving the rig when the weather permitted. Kevin continues the story.

"We talked among ourselves and those who wanted to have New Year off – mostly the Scots – stayed on board and the rest of us were delighted to be flown home to spend Christmas with our families. But on Boxing Day [26th December] there was a knock on the door and the BP driver told me I'd been recalled to move the rig and he'd pick me up early the next morning. Nine of us flew out to the rig on 27th December, looking a bit cheesed off at being recalled; four never returned.

"We arrived in time for an excellent late Christmas dinner, and then went to our cabins to change into working clothes. The rig was in the process of being 'jacked down' [when the hull is lowered down the legs until it is floating, before the legs are raised from the seafloor]. I wasn't due on shift until we began the move later that night, so I sat on my bed and picked up a magazine. Suddenly, there was a sharp judder throughout the barge, and I felt like I was going down in a lift. The shelf came off the wall behind me and hit me on the head and as I made for the door there was a terrible lurch and the floor tilted to about 45°. Dashing outside, I realised that two of the legs had collapsed and the rig was rapidly going over. The derrick had disappeared and so had the radio shack – there had been no time to send out a mayday call. We grabbed our lifejackets and ran; I was just wearing a shirt and trousers and my slippers.

"Initially I went to the highest point on the rig, the heli-deck, along with a number of other men, but spotting the empty lifeboat, which had been set adrift by the rig lurching, I determined to swim out to it, so went back down to the deck with Colin Grey, a radio operator, who had flown out with me earlier that day. By now the lifeboat was maybe over

The* Sea Gem*, a drillship converted from a barge.

100m away, and the sea was very rough with waves over 6m high, and I didn't think I'd manage to reach it, but Colin was a champion swimmer, so he dived in and I saw him reach the lifeboat and clamber in.

"The deck was now under water and we knew we had to get off fast. A couple of us tried to launch a Carley life-float – the thing that looks a bit like a white torpedo; you pull a rip cord and it inflates into a dinghy. We didn't think to tie it to the hand rail though, and as it inflated the rig made a further lurch and it went scuttling away over the waves, empty. We crept along the top of the hand rail like tightrope walkers to the next one and managed to get that afloat and three of us climbed in, soon followed by another 10 men. We were about to cut the rope to get away from the rig before she turned over when we saw Bert Cooper, the fitter, appear. He had been in the workshop below decks and broke several ribs when the rig lurched, but had somehow managed to climb in pitch darkness up to the deck. We turned back for him and then started paddling as fast as possible away from the rig. We could see a cluster of men still on the heli-deck, but the rig suddenly turned over and they went down with it."

One of the many articles about the disaster.

Rescued by Cargo Ship

Although the *Sea Gem* had not been able to send out a distress call, a passing cargo ship, the *Baltrover*, saw the disaster unfold and had immediately radioed for assistance. By the time the rescue helicopters arrived there was nothing to be seen of the *Sea Gem* but one of the broken legs sticking out of the water, a mass of debris – and empty life-rafts.

Meanwhile, the *Baltrover* had steamed towards the stricken rig and with great difficulty picked up the men in Kevin's overloaded life-raft, which by this time was shipping water fast. "One man was wearing Wellington boots and we used them to bale out the raft, which possibly saved our lives. Now another danger faced us, as the waves were pushing us towards the *Baltrover* and we were at risk of being crushed against it. We paddled round to the lee of the ship, where the crew threw ropes down to us. One man, Ken Forsythe, grabbed a rope and hung on to it, acting as an anchor to the raft so we could clamber up the rope ladder onto the ship. I still don't know how he managed it in those huge seas. We also had to help the injured up those swinging ladders; in some ways it was the worst part of the whole experience."

Thirteen men were lost in the disaster, including Colin Grey, who despite swimming to the lifeboat had died of exposure before he could be rescued. "He was only 19 years old," adds Kevin, sadly. "Two days later Dean Sutherland, the American specialist who had been in charge of the move, had a stroke and died. I think he blamed himself for the disaster, but it wasn't his fault. The enquiry into it found that the legs had suffered catastrophic metal fatigue, probably because of the cold water, and had literally snapped."

Sea Gem's Legacy

Kevin and the 18 other survivors, some badly injured, returned to shore and were taken to hospital, where he was kept overnight as he had injured his leg, before being sent home. "I arrived back 36 hours after I left home – but my offshore career was over, as my leg was never the same again, and I was off work for six months."

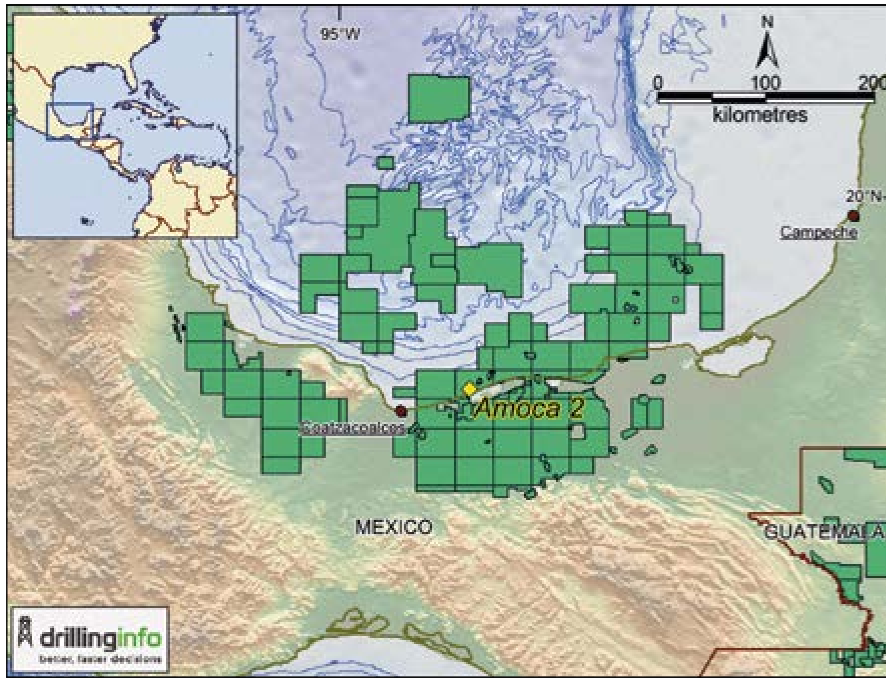
Kevin stayed with BP, working in maintenance at Eakring, before moving to the Central Generating Board, where for 25 years he specialised in safety matters. In his retirement he became a co-founder and curator of the Dukes Wood Oil Museum in Eakring, which celebrates 'Churchill's best-kept wartime secret': the Dukes Wood oil field which kept the ships and planes working during WWII (see *GEO ExPro,* Vol. 13, No. 5 for the story of Dukes Wood).

The *Sea Gem* disaster left a legacy to the UK offshore oil industry, as many new rules for operating were made as a result of the tragedy. These included more and better safety equipment, the requirement for an Offshore Installation Manager in overall charge, and a permanent standby vessel close to each rig or platform.

The men who survived the disaster continue to meet regularly, the last meeting being in February 2016, when they commemorated the 50th anniversary of the tragedy, although there are now only three of them left. Kevin says, "It is important that those of us who survived get together to remember the men who died and pay tribute to those who saved us.

"Eh, it was a hell of a day," he sighs. "Boxing Day and all. I still don't like Boxing Day, or Christmas much – but, anyway, life has to go on. Have you seen this?" And he hands me a mounted core from the well where Kevin Topham and the men of the *Sea Gem* found the first commercial hydrocarbons in the UK North Sea. A piece of history. ■

Mexico: First Foreign Discovery



Italian oil company **Eni** is the first major IOC to make an offshore oil discovery in **Mexico** since energy sector reforms were enacted in 2013. **Amoca 2**, which is situated in the Contract 1 area in the shallow waters of Campeche Bay, about 200 km west of Ciudad del Carmen and only a few kilometres offshore, was spudded in early January 2017 using Seadrill's *'West Castor'* jack-up.

The well, in 25m of water, reached a total depth of approximately 3,500m. It discovered about 110m of net oil pay from several good quality Pliocene reservoir sandstones, of which 65m were found in a deeper, previously undrilled horizon. The well confirmed the presence of 18° API oil in the shallower formations, while the newly discovered deeper sandstones contain high quality light oil.

On 1 December 2015, Eni reported that it signed a Production Sharing Contract with the Mexican authority CNH for the Contract 1 area covering the **Amoca**, **Mizton** and **Tecoalli** fields, which it had won in Mexico's Round 1.2. According to the official estimates from the CNH, the combined volumes in place for the three fields amount to approximately 800 MMbo and 480 Bcf of associated gas, and this discovery indicates a meaningful upside to the original estimates of recoverable resources. Eni is already evaluating options for a fast-track phased development of the fields.

Having made this discovery, Eni, which has not previously operated in Mexico, is moving ahead rapidly with its multi-well drilling campaign offshore Mexico, with Amoca-3 lined up to follow next, probably again using the *'West Castor'* rig. Eni is believed to have more wells planned in this shallow water block, including the Mizton-2 and Tecoalli-2 delineation wells. They will be drilled in 2017 to help the company better understand Mizton 1 and Tecoalli 1 and to target new undrilled pools. These discoveries were made by Pemex in 2012, before the international industry was invited to participate in exploration in Mexico.

Eni holds a 100% stake in the Area 1 Production Sharing Agreement. ■

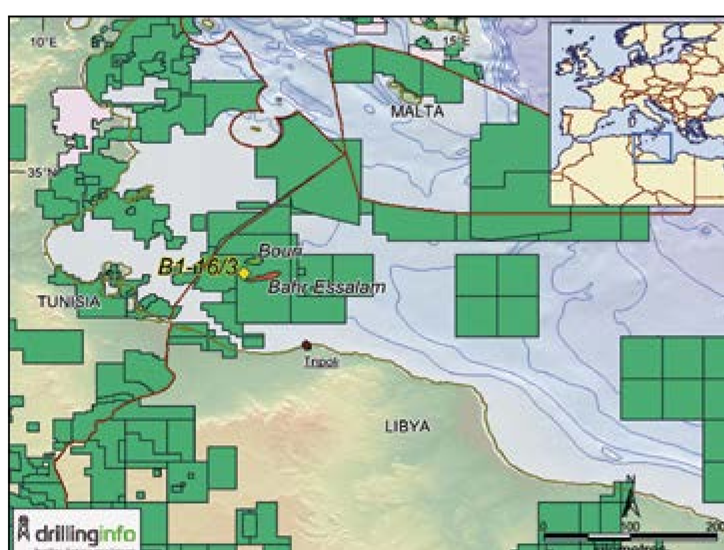
Libya: First Offshore NFW of 2017

Eni has made a gas and condensate discovery with the **B1-16/3** NFW **Gamma prospect** located on the offshore Area D concession, 50 km from the Tunisian border and about 140 km north-west of Tripoli. The well was spudded on 4 January 2017, utilising the *ENSCO 5004* jack-up, and was drilled in 150m of water, reaching a TD of 2,981m in March 2017.

B1-16/3 lies just 5 km north of the Bahr Essalam field and 15 km south-west of Eni's well established Bouri field. The well targeted Eocene Metlaoui carbonates, which were successfully tested in two intervals. This is the first offshore discovery in the country since Eni's A1-1/1 well in May 2015, which also encountered gas and condensate in Metlaoui carbonates. The company believes that the Gamma well could produce 7,000 boepd.

The drilling of the Gamma prospect is part of Eni's 'near field' exploration strategy, targeting opportunities that, if successful, can exploit existing infrastructures, thus reducing the time to market and providing additional gas to the local market and export.

Eni operates the Area 'D' with 50% equity, in partnership with the NOC (50%, carried). ■

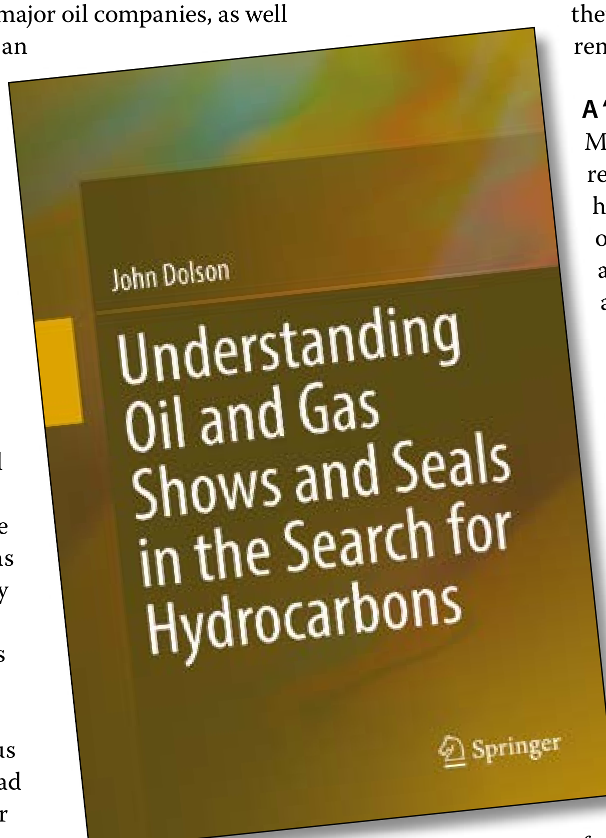


A Long-Overdue Book!

Understanding Oil and Gas Shows and Seals in the Search for Hydrocarbons
John Dolson
Springer, 2016

DAVID BLANCHARD, DB Global Energy Consultants

Let me start with my conclusion: Mr. Dolson's book is a long-overdue work, filling a critical knowledge gap that has spanned decades of exploration and has resulted in billions of dollars spent on dry holes. It is not that the information contained in Mr. Dolson's book was not or is not available, but his approach to pulling it together and explaining the subject in a refreshingly straightforward manner is easy to digest and grasp. His years of experience with major oil companies, as well as teaching and consulting, provide an exceptional perspective on this critically important subject.



Why So Many Dry Holes?

Whatever source you reference the message is consistent: most dry holes are a result of seal failure and/or breached traps. I've read that the staggering figure of up to 70% of dry holes industry-wide result from a failure to understand and properly risk seal capacity and trap integrity. I recall my early, and not so early, days at a major oil and gas company where the in-house training emphasis was on reservoir, sequence stratigraphy and structure, including glorious field trips to see reservoir outcrops and magnificent structures in the Rocky Mountains. Other than my own graduate work on a Cretaceous organic shale, which included a read of Schowalter's 1979 seminal paper on secondary migration, I found that traps and, in particular, seals were only given a skin-deep mention; almost as a side thought.

In the 1980s and early 1990s the emergence of a probabilistic risk approach to exploration, coupled with 3D seismic becoming more commonly available, led to the expectation that successful exploration would be commonplace and dry holes reduced to a minimum. This was a step change in the way geoscientists and engineers approached risk. But once again, the pitfall was the focus on reservoir, facies and structure risk with an attempt to model source and migration, but only basic seal analysis considered. Seal capacity was largely glossed over – in part, or perhaps mostly, because of the inherent complication of identifying and quantifying shale, or other cap rock, sealing capacity. Team meetings and peer risk review groups spent countless hours debating a $<2\%$ difference in the probability of reservoir presence while blissfully assigning a blanket 95 or 100% chance of seal capacity and integrity success with little or no discussion.

Residual and marginal shows from mud logs and core were seldom given serious analysis or significance especially if they conflicted with electric logs, and although production geologists and engineers were certainly keen to know what they meant, our tools to document remigration were limited.

A 'Must-Read'

Mr. Dolson analyses the risk relationships of seal, trap and hydrodynamics within the context of a basin-wide perspective while addressing the detailed operational aspects to determining subtle mud log shows and approximating capillary pressures and column height.

Successful companies today employ a rigorous process that includes a comprehensive approach to basin modelling and incorporates an understanding of hydrodynamics and petroleum fluid flow. Mr. Dolson provides examples and discussion of migration modelling at all levels by using 3D modelling programs that are capable of the interactive modelling of migration with open and closed faults, timing variations and fluid or gas type. Nothing is risk-free but a clear-eyed analysis of all available data in this context will most certainly reduce risk. As Mr. Dolson quotes, all subsurface maps are wrong, it's just understanding how wrong.

So, this book is an absolute 'must-read and keep' for explorationists at all levels as well as managers and engineers. No more hardcopy textbooks are allowed in my house so I have the e-version on my iPad, making it easy to access and refer to. It serves as a refresher for those more experienced geoscientists and engineers and importantly provides a clear process-oriented approach for entry-level professionals and emerging leaders in the petroleum industry. His early chapters are pretty basic oil and gas stuff but hidden gems and personal stories make it an engaging read and they should not be skipped.

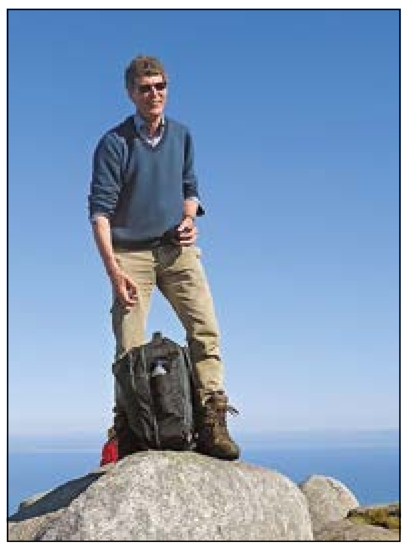
In short, this book is highly recommended. ■

Collaboration, the Underground and the Resistance

Having spent many years as a geologist in the E&P industry, Dr Bruce Levell is now Visiting Professor in Earth Sciences at Oxford University, and therefore well placed to discuss the need for collaboration between government, academia and the industry.

• Why is industry-government-academia collaboration important?
The hydrocarbon industry collects stunning data from the subsurface: high quality seismic, well data and fluid and rock samples. However, due to chronic time pressure, the industry often cannot use all their data, and sometimes is not aware of newly-developed or refined techniques to extract even more information from it. Conversely, due to confidentiality, academics are frequently not aware of industry data; they are idea-rich and data-poor. In my view there is therefore a great opportunity to simultaneously increase the efficiency of hydrocarbon exploration and development and the efficiency of scientific research by bringing these two communities closer together. This happens all the time; the challenge is to make it more structured, rather than the current reliance on personal networks and chance contacts. I feel that the professional societies could play a bigger role in extending the interface with academia to less traditional subject areas and to university departments that have not previously worked with the industry.

For me the role of government in this process is to increase the public availability of data. This would increase the development and testing of exploration ideas and force more collaboration, as companies will seek to take advantage of their limited confidentiality periods.


Prof. Bruce Levell in the field in Scotland.

• Is there enough collaboration between countries and regions?
In the interest of efficient exploration and development more data-sharing across borders is always better. This unfortunately already goes wrong at very basic levels – ask anyone who has tried to export rock or fluid samples. The answer is education of the officials. I'm not a fan of research consortia with large numbers of international players; the number of necessary relationships increases factorially.

• Should governments take the lead more?
In forcing industry collaboration with academia – no. Good research normally comes from a good science question – governments are not the best equipped to provide those. However, they can be important enablers, especially if open to the idea that sharing data and ideas is better for the national economy than keeping it secret. A government's choice of reward structure for academics is also relevant. Industry people read articles to find resources, not to quote. The impact of economic geology papers on economic activity may be very high, but that may not help an academic career.

• Do we need a deeper level of collaboration?
Yes. In my view the hydrocarbon industry will remain an important source of energy for several decades as we collectively work our way through the twin problems of overhauling the world energy system, replacing hydrocarbons with renewables; and building the infrastructure to deal with whatever climate change is coming our way.

However, the role of the industry is simply not accepted by a large influential slice of public opinion. It needs to be more transparent in order to engender a degree of trust in its honesty with respect to, for example, emissions, leaks or induced seismicity. In my opinion the industry needs to openly collect data on its own activities, which could be shared with sceptical independent academics – such as, for emissions, atmospheric scientists. This could reassure the public that industry claims such as "our operations are safe and secure" are verified. I believe it is to the industry's advantage to volunteer such collaboration before it is regulated.

• During a downturn, is collaboration relevant and cost-effective?
Collaborations and partnerships are long term and should ride through commodity price cycles if possible. A commitment to fund a PhD for four years can't be dropped because of a price crash. Better a lower but stable level of funding than a cyclical one.

• You called a conference presentation 'Collaboration, the Underground and the Resistance'. Why?
I'm glad you noticed the title! Well, the session was called the 'Collaboration Workshop' and it struck me that the word collaboration can be negative: collaboration with the enemy. Also, many in academia, taken across all subjects, would currently see working with the oil industry as 'collaboration with the enemy'. I wanted to highlight this, as a backdrop to the proposal to widen collaboration on the monitoring of assets and operations, as mentioned above, which I think would help reduce the number of people who saw collaboration as a bad thing. The 'Underground' stands for the subsurface – our main activity area. And the 'Resistance' are the blockers to collaboration, some of which we have discussed. The title as a whole is a bit contrived but it did allow me to start the presentation with a picture from the comedy series *'Allo 'Allo*, set in wartime France, which was widely shown across Europe – and perhaps helped people remember the talk. ■

Hunting the Silver Bullet

Prospect high grading does have an effect – an increased commercial success ratio as demonstrated by the Norwegian continental shelf.

In 1978 – that is, almost 40 years ago – Exxon decided not to apply for the acreage that later was revealed to host the largest oil and gas field in the entire North Sea. We now know that originally recoverable reserves in the Troll field were 11 Bboe. According to an unauthorised source, the supermajor did a detailed de-risking of the prospect. The local exploration team had identified a structural trap associated with an extensive flat spot that crosscut stratigraphy. Using a 'silver bullet' procedure, the overall rock volume was considered by the headquarters to be too large to be "believable". The prospect was thus downgraded.

It is now safe to conclude that the silver bullet procedure showed a fatal flaw. The lesson learned is that silver bullets can misfire. Nevertheless, on the Norwegian continental shelf (NCS) we continue to drill dry wells more often than previously.

In the NCS Exploration conference in Oslo in May, Westwood Global Energy Group presented data showing that commercial success rates (CSR) averaged 34% from 2008 to 2011, but from 2012 onwards CSR rates have averaged only 24%. Pre-tax drilling finding costs increased from US$ 4.93 to US$ 6.06/boe from the first to the second period. This is bad news and may reduce value for the oil companies. 2015 was particularly bad, with CSR reaching a low of 9%.

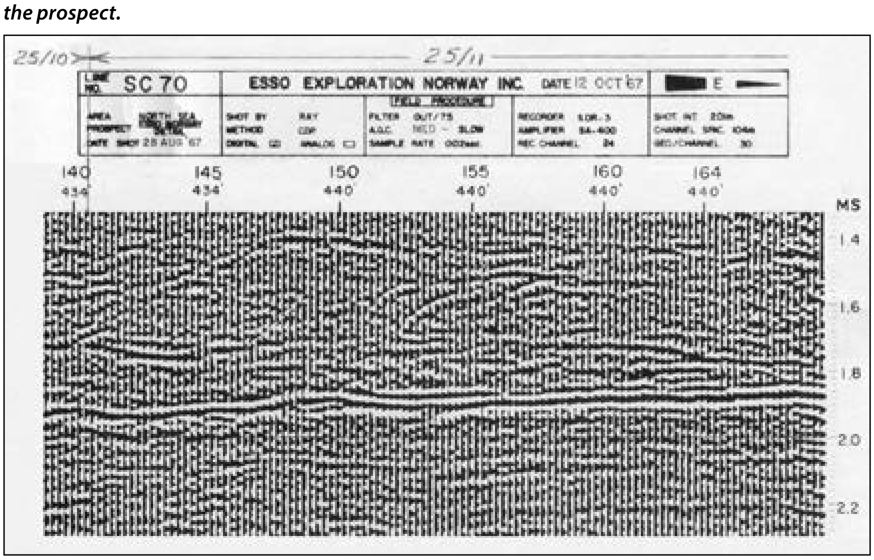
Also, certain lower risk plays, such as the Jurassic plays in the Northern North Sea and the Norwegian Sea that had been delivering commercial success rates in the 34–50% range, were found to have significantly underperformed, with average commercial success rates of only 24%.

This is happening in spite of significant improvements in imaging and the introduction and improvements of several 'revolutionary' de-risking tools, some of which were expected to be silver bullets, as well as increased geological understanding.

With a significantly lower well count in 2016, however, success rates improved across all pre-drill risk categories in 2016, meaning – Westwood says – that prospect high grading has been having an effect. This does not mean that the silver bullet has been found. Rather, it is tempting to conclude that risk awareness has increased with a lower oil price. ■

Halfdan Carstens

The very first oil discovery on the Norwegian continental shelf was made exactly 50 years ago. On 24 May 1967, Exxon found oil in Palaeocene sandstones, later to be recognised as turbidites and injectites. As indicated by this seismic line, there was certainly no silver bullet involved in targeting the prospect.



Conversion Factors

Crude oil

1 m^3 = 6.29 barrels

1 barrel = 0.159 m^3

1 tonne = 7.49 barrels

Natural gas

1 m^3 = 35.3 ft^3

1 ft^3 = 0.028 m^3

Energy

1000 m^3 gas = 1 m^3 o.e

1 tonne NGL = 1.9 m^3 o.e.

Numbers

Million = 1 x 10^6

Billion = 1 x 10^9

Trillion = 1 x 10^{12}

Supergiant field

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

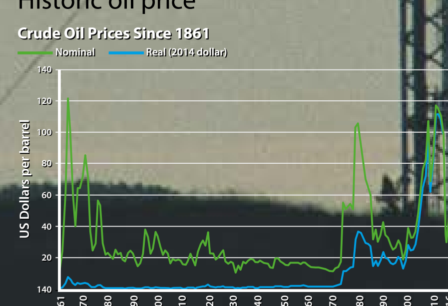
Giant field

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

Major field

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

Historic oil price



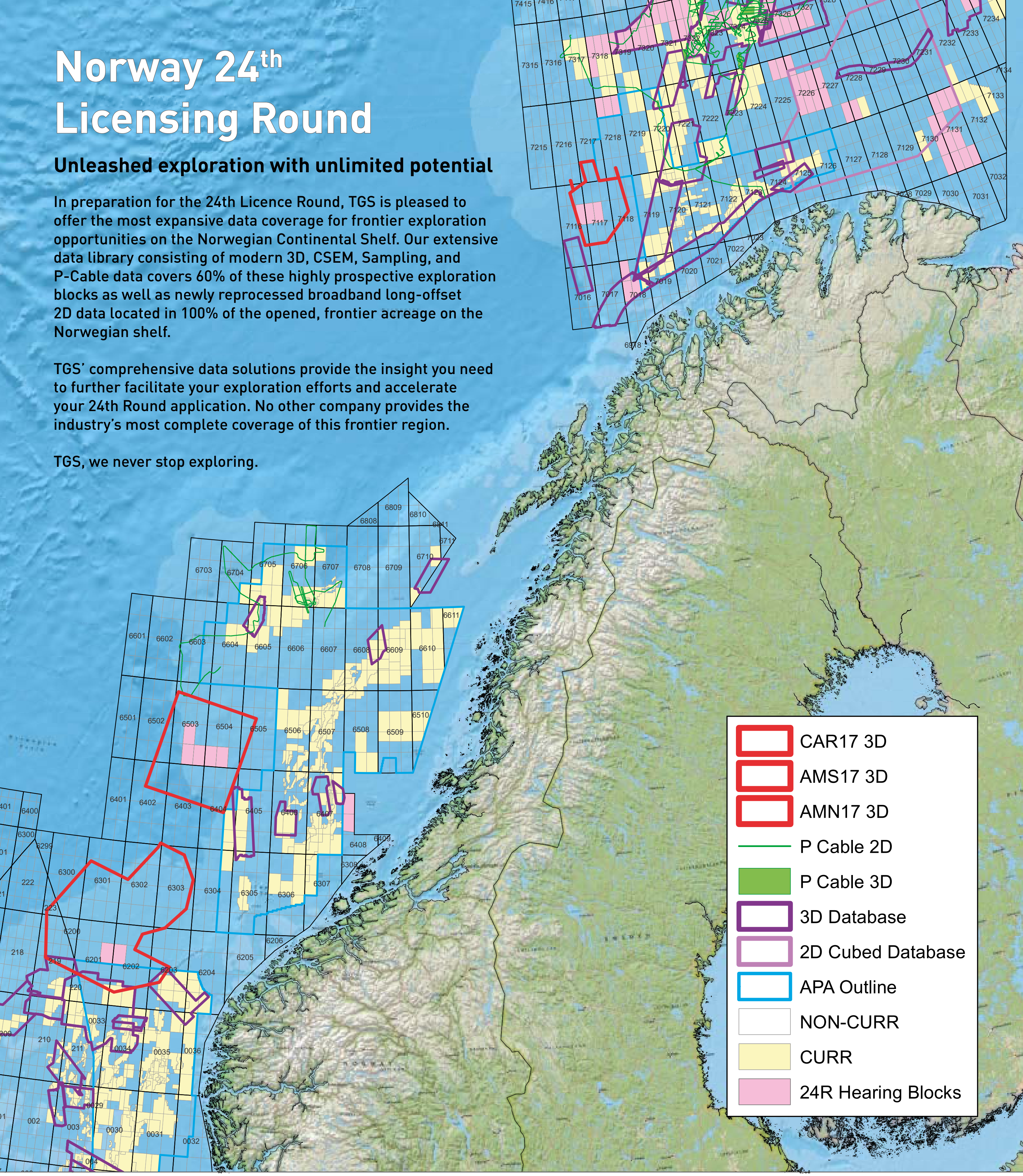
Norway 24th Licensing Round

Unleashed exploration with unlimited potential

In preparation for the 24th Licence Round, TGS is pleased to offer the most expansive data coverage for frontier exploration opportunities on the Norwegian Continental Shelf. Our extensive data library consisting of modern 3D, CSEM, Sampling, and P-Cable data covers 60% of these highly prospective exploration blocks as well as newly reprocessed broadband long-offset 2D data located in 100% of the opened, frontier acreage on the Norwegian shelf.

TGS' comprehensive data solutions provide the insight you need to further facilitate your exploration efforts and accelerate your 24th Round application. No other company provides the industry's most complete coverage of this frontier region.

TGS, we never stop exploring.



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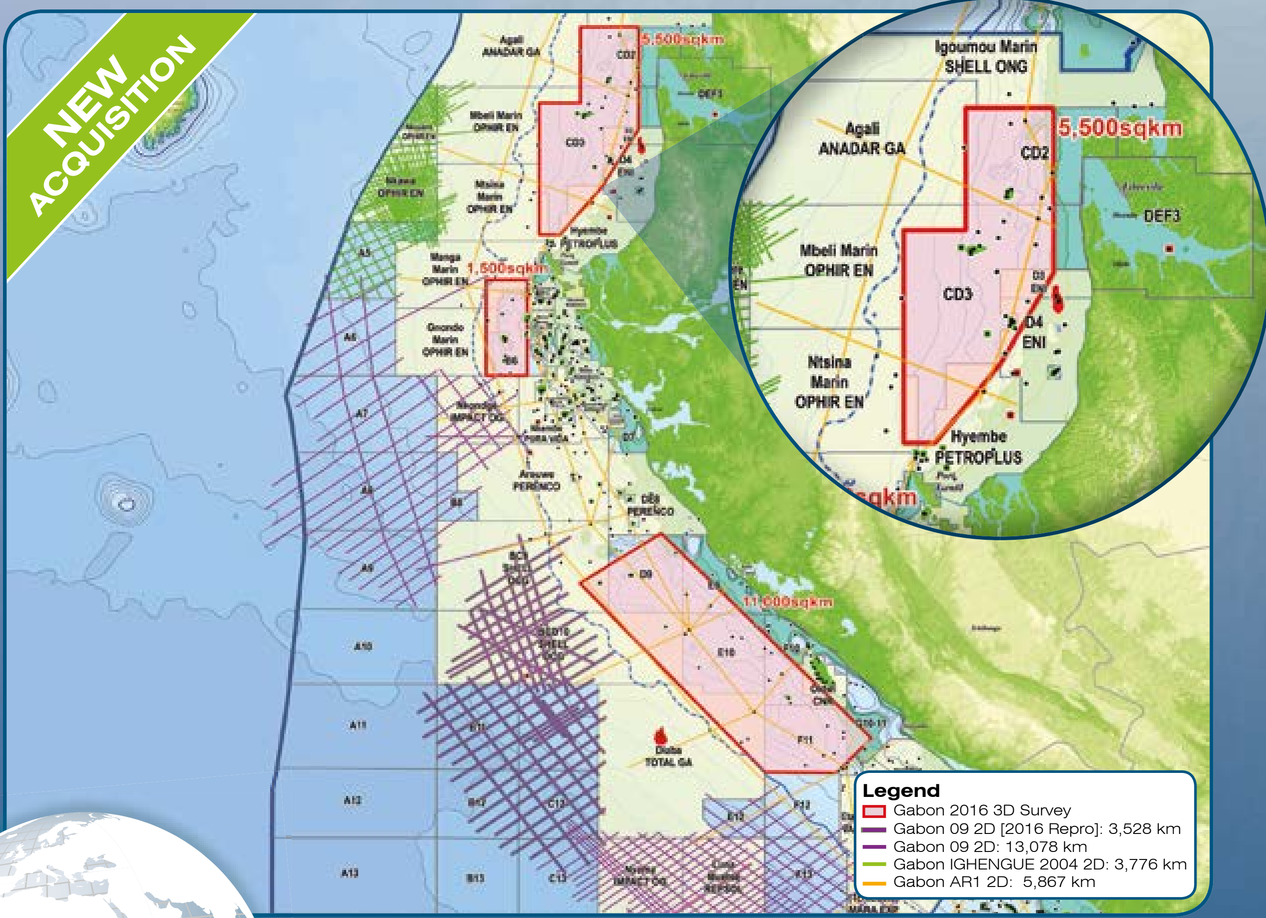

Spectrum, in collaboration with the Direction Générale des Hydrocarbures (DGH), is undertaking a series of 3D Multi-Client seismic acquisition programmes offshore Gabon. These programmes, located in under-explored shallow water open blocks, have already secured significant industry support and will offer the most up-to-date 3D imaging in the area. To accelerate exploration, data will be made available for future license round evaluation, facilitating immediate activity when the blocks are awarded.

The 10,000 km² Gryphon 3D survey in southern Gabon is currently underway. In addition, acquisition of a 5,500 km² 3D survey over open acreage in Northern Gabon is due to begin Q2 2017.

Data is expected to start becoming available toward the end of 2017 ahead of anticipated future licensing rounds.

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