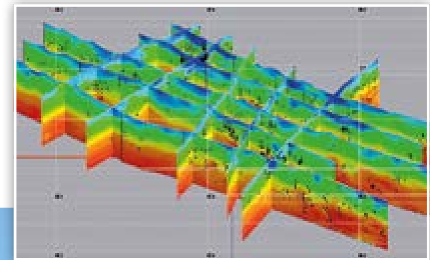
VOL. 15, NO. 1 – 2018

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



GEOPHYSICS:
Passive Seismic: Thinking Differently

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GEOTOURISM

Oman's Spectacular Geology

INDUSTRY ISSUES
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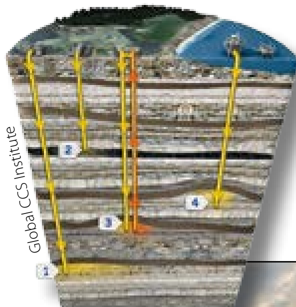

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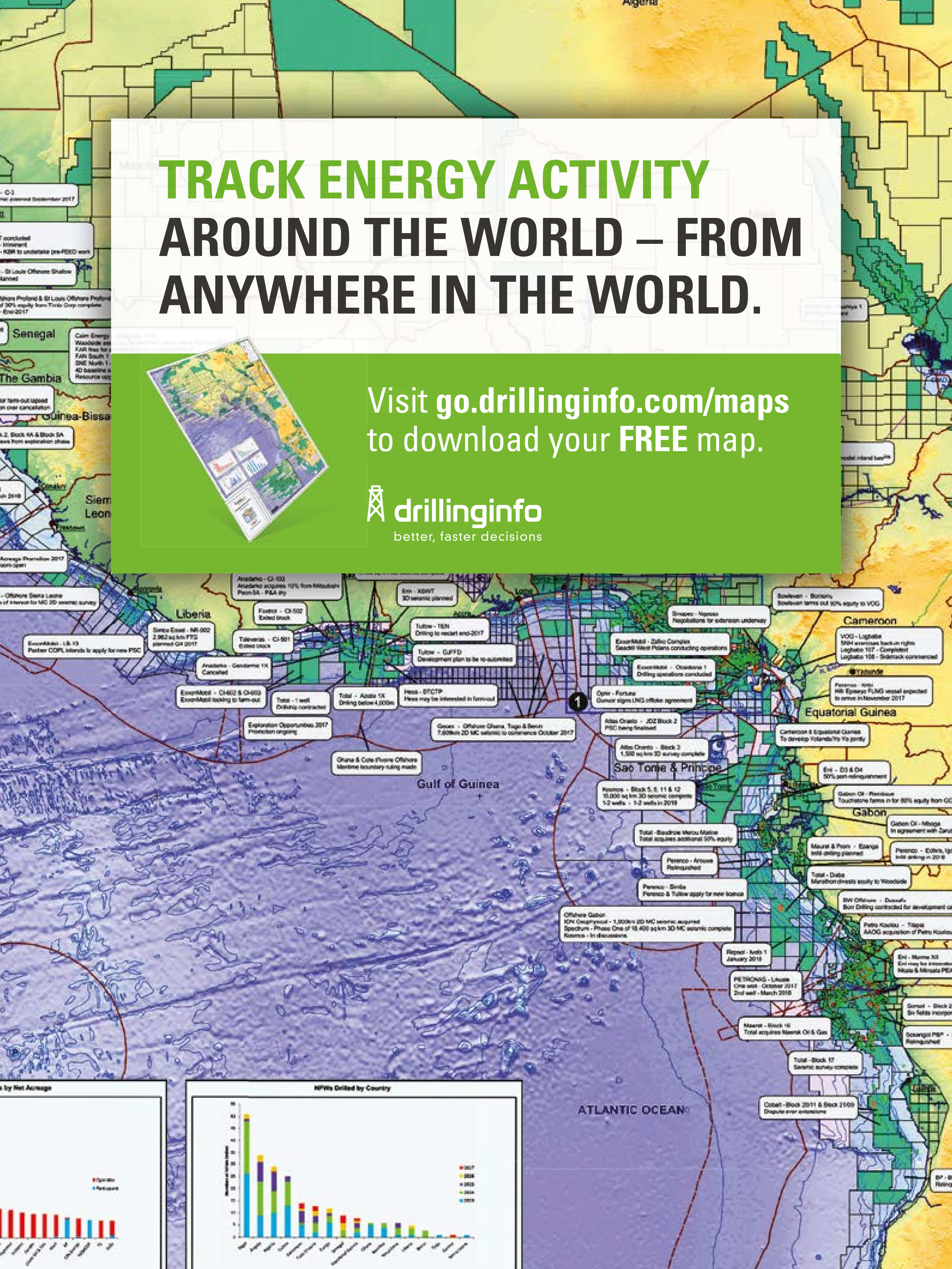
This edition of *GEO ExPro* focuses on the Middle East, Land Seismic and Carbon Capture and Storage.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Gabon
Gulf of Guinea
ATLANTIC OCEAN
NFWs Drilled by Country

Leading the Way

A CO_2 injection well (left) at the Weyburn field in Saskatchewan, Canada, where 31 MT of CO_2 is currently injected for EOR.

The idea of capturing carbon dioxide (CO_2) has a surprisingly long history – nearly 100 years, in fact, since technology was developed to remove CO_2 from natural gas before it could be sold. However, the concept of pumping CO_2 into reservoirs to boost oil field recovery was not considered until 50 years later, when CO_2 from a gas processing facility in Texas was piped to a nearby oil field and successfully injected, subsequently proving to have increased production by 5 up to 15%. Since then this process, known as CO_2 EOR, has been used extensively throughout the world, and we have learnt how to technically manage the process and how it affects reservoirs – and also the economic benefits to be gleaned. The technique is not appropriate everywhere; its effectiveness is dependent on the reservoir characteristics, the chemical composition of the oil, and field history and location.

Most CO_2 EOR projects use naturally occurring CO_2 extracted specifically for this purpose. There is now a lot of pressure to take this a step further and use the technique proactively as a mechanism for ensuring less CO_2 is released into the atmosphere, by using waste CO_2 from sources such as power plants for EOR and then storing it underground after production ceases. This is more expensive than traditional CO_2 EOR as it requires additional monitoring, measuring and verification. It will need to be catered for in the design stage, as well as during and after injection, to ensure that neither the geological formations nor any abandoned wellbores leak. This is all well within the industry's areas of expertise.

A study of 47 large oilfields in six basins spread over the world (Godec et al., 2011) estimated that the application of CO_2 EOR could result in the recovery of an additional 1,070 Bbo, with associated CO_2 storage potential of 320 Gt. These are significant volumes.

As has been discussed frequently, the oil and gas industry suffers from an image problem: providing a vital commodity, but considered by many to be contributing to pollution and climate change. By more actively harnessing our specialist knowledge and expertise to use waste CO_2 to increase recovery while storing the gas away from the atmosphere, we would be showing the world we are listening. ■

Jane Whaley
Editor in Chief

OMAN'S SPECTACULAR GEOLOGY

The village of Bilad Sayt, in the Al Hajar Mountains in northern Oman, can only be accessed by walking through a narrow canyon or driving down a very steep, winding road - exciting either way! The rocks towering around it are primarily the Hajar Supergroup, which are also exposed in the nearby Wadi Nakhr, commonly known as the Grand Canyon of the Middle East.

Inset: Passive seismic technology is used primarily as a production and monitoring tool, but in recent years more people have discovered its use in exploration.

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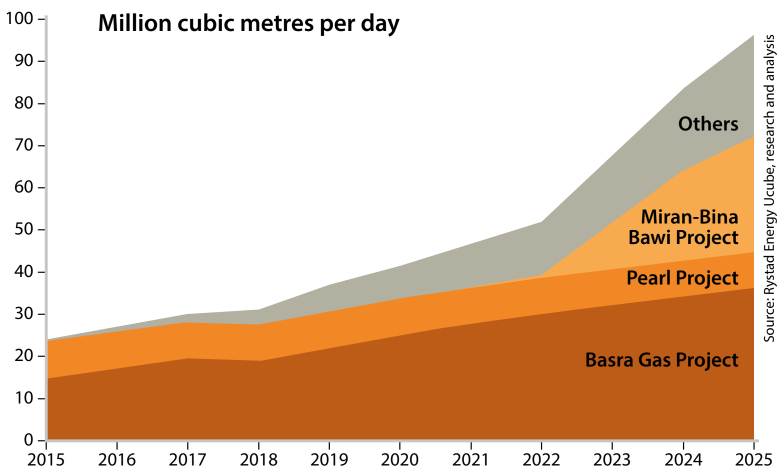
Iraq to Double Gas Production by 2023

The development of gas gathering and processing infrastructure in Iraq is picking up as the country focuses on boosting natural gas output by cutting flaring volumes. Iraq is nurturing partnerships with IOCs to achieve its gas production goals and reverse recent trends that have seen the process derailed by sanctions, geopolitical conflicts and a lack of incentives for international operators.

An increase in Iraq's gas production of 23 MMcm (812 MMcf) per day is expected from the start of 2018 to year-end 2022, with the additional output to be used primarily for domestic fuel and power consumption. After 2022 the output is expected to grow even more as the giant Miran-Bina Bawi project ramps up.



Iraq gas production, split by major projects.

Iraq produces just 31.2 MMcmpd (1.1 Bcfpd) of gas but has close to 3.1 Tcm (109.5 Tcf) of proved gas reserves, giving it the 11th largest reserve base in the world. A majority of this is associated gas and, due to insufficient infrastructure, most produced gas is currently flared. The recent spike in gas flaring volumes – from 40 MMcm (1.4 Bcm) per day in 2014 to 50 MMcm (1.8 Bcf) day in 2016 – mirrors the pronounced rise in oil production from 3.4 MMbopd in 2014 to the current 4.5 MMbopd.

Among recent developments, on 8 January 2018, Sonatrach and Orion both agreed with the Iraqi government to invest in developing Iraqi gas and processing infrastructure. Orion and the government have reached an initial agreement on boosting gas output from the Nahr Bin Umar field, which currently produces close to 40,000 bopd and 700,000 cmgpd (24.7 MMcfgpd). Sonatrach's investment is expected in the Basra province, where two-thirds of the country's oil output is currently produced.

Additionally, Gazprom brought online a 1.6 Bcm (56 Bcm) gas processing plant at the Badra field last month. It can provide enough fuel to produce a total of 123.5 MW of power.

In another move, Iraq recently announced that associated gas from the North Rumaila field will be exported to Kuwait by Basra Gas Company (BGC). BGC also processes gas from the West Qurna-1 and Zubair oilfields at the North Rumaila NGL plant (see page 34) and the Khor Al Zubair NGL and LPG plant. These facilities have nameplate capacities of 19.25 and 19.82 MMcmpd (680m and 700 MMcfpd), respectively. The plants require extensive repairs after the 2003 conflict, but work has been stalled of late by the economic downturn. This in turn limited production to just 19 MMcm (670 MMcf) per day. Repair work could be accelerated by Shell's recent decision to shift its investment focus in Iraq away from its own upstream business in order to prioritise its 44% stake in BGC. The state-run South Gas Company holds 51% and Mitsubishi the remaining 5%.

Aditya Saraswat, Analyst, 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

Looking to Revive Past Glories

Indonesia, South East Asia's biggest economy, was once a member of the exclusive oil producers club OPEC but in 2010, with its oil and gas industry stagnating, it left the organisation. Twenty years ago the country was producing about 1.5 MMbopd, but that has dropped steadily to its present average of about 800 Mbopd, valued at just 3% of Indonesia's gross domestic product. According to Bloomberg, a decade ago the oil and gas sector accounted for a quarter of Indonesia's state revenue. At the same time, internal demand has been growing rapidly, and Indonesia is now a net importer of oil and will probably become a net importer of gas early in the next decade.

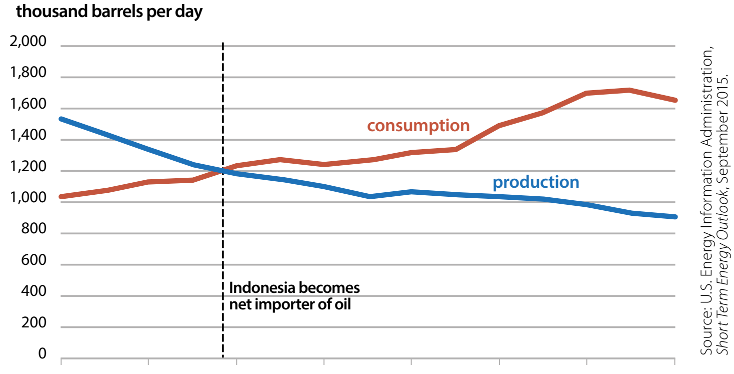
In an attempt to reverse this trend, in May 2017, the Indonesian Ministry of Energy and Mineral Resources offered ten conventional and five unconventional oil and gas blocks, or 'Working Areas' as it terms them, to potential bidders under revised production sharing rules. Despite extending the deadline to the end of December 2017, these appear to have received limited interest, with five eventually being awarded. Five of the working areas did not attract any interest at all from bidders.

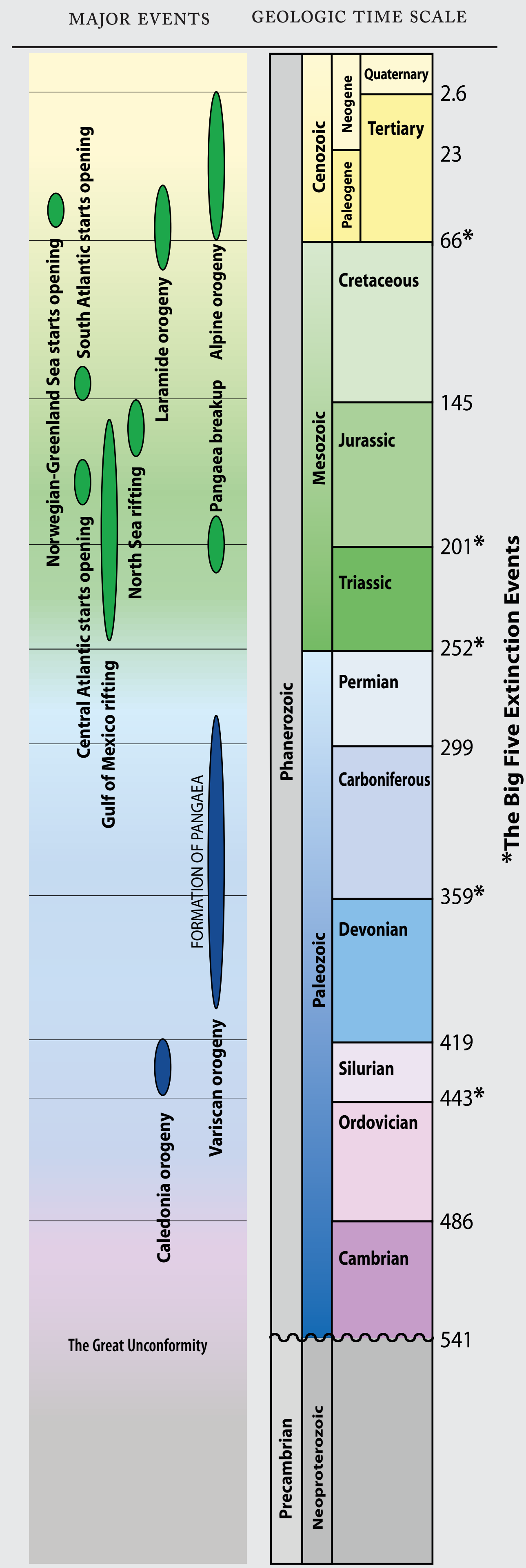
The ministry will auction 43 Working Areas in 2018, which will include new blocks as well as 32 which did not receive bids in the 2015–2017 auctions. Three of the Working Areas offer unconventional resources. The areas will be offered under the new PSC gross split scheme, which requires investors to pay exploration and production costs instead of relying on the government's reimbursement as under the former cost recovery scheme. Further details of the auction will be announced in March.

Whether this will help halt the decline remains to be seen, since the international industry seems to view Indonesia warily (see page 70). Frequent changes to contracts, lack of infrastructure and a perception that Indonesia is not an easy place to do business have not helped in the fight for scarce exploration funds in the present straitened times. A lack of drilling success has compounded this reduced interest.

Indonesia currently has 255 oil and gas Working Areas, covering both conventional and non-conventional oil and gas. Of these, 73 are in the production phase, 14 in development and 168 are under exploration. ■

Petroleum and other liquids supply and consumption in Indonesia, 2000–2014.





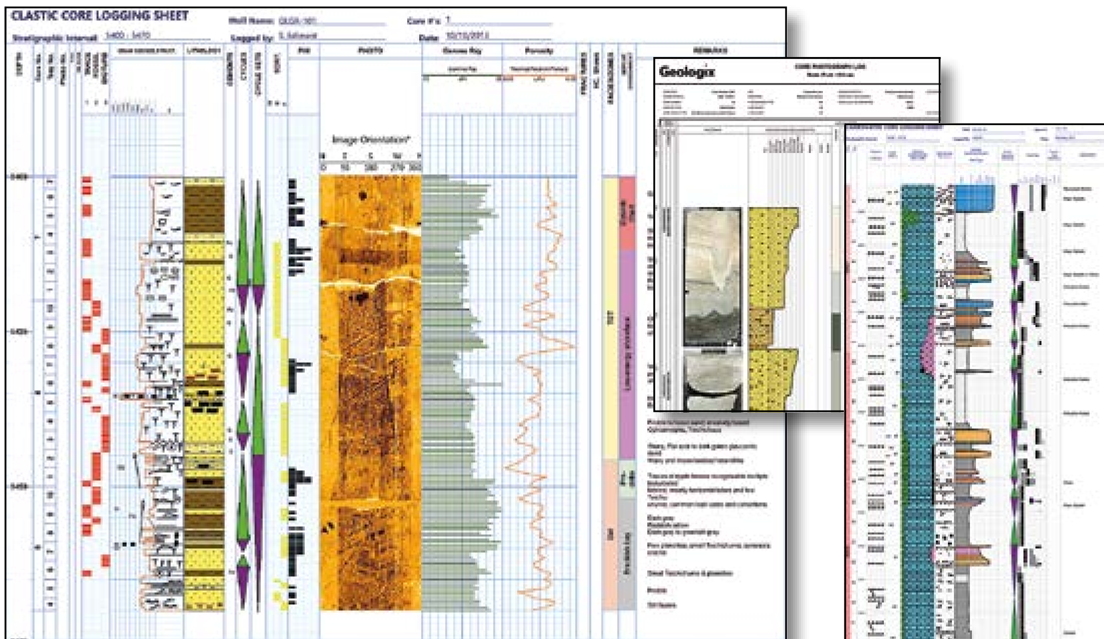
It's Not About the Rocks

Describing core to extract valuable hard data is key to the process of **reliable reservoir characterisation**, aiding field development and maximising recovery. Generating a digital interpretation of the core along with **routine core analysis (RCA)** data is not a new idea, since the data is always integrated and interpreted alongside other larger scale recordings from the well. If we assume the cut core quality is sufficiently good, and the interpretation quality is high, then the real prize is this information being delivered quickly to the reservoir team.

What is new now is the utilisation of core log software on tablet devices in the lab itself, replacing the pencil and paper grid typically used. RCA data can be loaded immediately into the software at the correct measured depth, and the core description can take place, using a stylus. Standardised core log templates include a scaled grid structure and a comprehensive core library that drives an efficient 'quick-start' experience, and short-shifts the digital data creation.

Once fully logged, all the data available in the application can be exported with one click and made immediately available to engineers waiting to add the latest data sets to calibrate a reservoir model. ■

Core description logs created using GEOSUITE by Geologix.



Bridging Fundamentals and Innovation

The American Association of Petroleum Geologists (AAPG) 2018 Annual Convention and Exhibition – ACE 101: Bridging Fundamentals and Innovation – is headed to **Salt Lake City, Utah,** on **20–23 May 2018**. Hosted by the **Utah Geological Association**, ACE 101 will provide an opportunity to return to the rocks and to remember the importance of fundamental geologic concepts, but also to look to the future, and to harness and embrace new technology and innovation.

Perhaps the most geologically interesting state in America, Utah will be the perfect host for this year's ACE. Salt Lake City's proximity to a number of pre- and post-show field trips will be a significant draw for geoscientists from around the world. With easy access to some of the most extraordinary rocks in the world, Salt Lake City is the ideal location to combine fundamental geology with emerging innovation and technologies.

Attendees will be exposed to 400 oral presentations, 600 poster presentations, 13 field trips, 16 short courses, 3,000 feet of core samples, luncheons, special sessions, social and networking activities, a packed exhibit hall, and several other events to help build skills and knowledge.

For over 100 years AAPG has been the core of the petroleum geoscience world. Entering its second century, AAPG is proud to once again bring together the best geoscientists on the planet to see the latest science and technology, both in the programme and exhibition halls at ACE 2018. ■

Zion National Park, one of the many exciting field trip destinations.

The Africa E&P Summit

The **Africa E&P Summit**, to be held on **23–24 May 2018** at the **IET London**, brings together Africa's upstream industry at a world-class venue in London for a unique event, shaped for companies active in Africa's oil and gas game to provide insight into the continent's fast-changing exploration horizon. Hear directly from key players and decision-makers, from corporate players active in Africa through to fast-moving independents, finance, legal and service and supply companies, as well as African governments and NOCs seeking investors.

Highlights include two days of world-class speakers and high-level networking; the Africa Petroleum Club World Upstream Reception with guest speaker; a showcase of African governments and NOCs; and a fascinating panel discussion on the risks, challenges and opportunities in Africa's upstream industry.

Confirmed speakers include Keith Hill, President and CEO, Africa Oil Corp.; Tracey Henderson, Senior VP Exploration, Kosmos Energy; Cath Norman, FAR Ltd.; Eric Hathon, Exploration Director, Cairn Energy; and Austin Avuru, CEO, Seplat Petroleum, among many others. ■

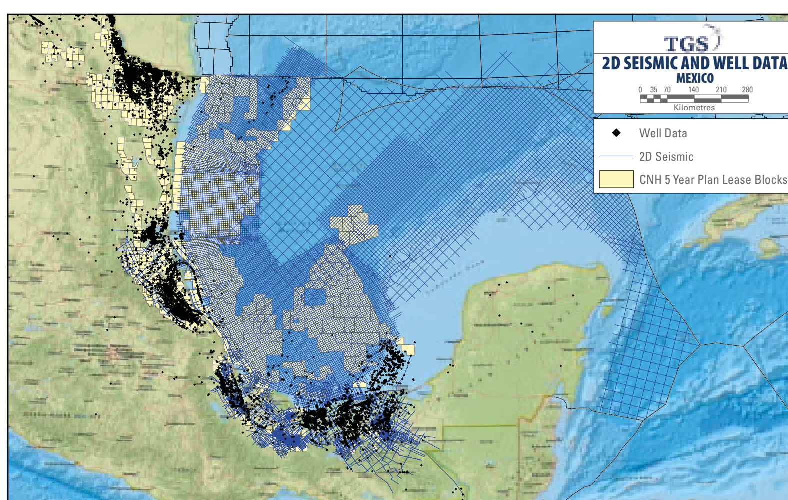
Successful High Density Seismic Survey

Ardiseis, a subsidiary of **ARGAS**, and its technology partner, **CGG**, have announced the successful completion of the **highest density broadband seismic survey** they have ever acquired, either on or offshore. The ultra-high density of the data recorded on the **West Kalabsha** permit on behalf of **Apache Corp**. heralds a step-change in the quality of seismic that can be economically acquired in Egypt's Western Desert – and a quantum leap in imaging for the Middle East and North Africa region.

The survey covered an area of 2,000 km^2 with a grid of 72 million traces per km^2 – denser than any survey acquired to date worldwide by CGG. To achieve this broadband seismic acquisition at a comparable pace and cost to conventional land acquisition, Ardiseis deployed CGG's proprietary **unconstrained blended acquisition** technology for the first time in Egypt. This uses a large fleet of vibrators operating simultaneously and independently non-stop, while a variety of CGG proprietary software was used to acquire the required low-frequency-rich broadband data (starting from 1.5Hz), which is free of harmonic noise contamination.

Apache were reported to be encouraged by the survey's preliminary results and plan to acquire more high density seismic in the region. ■

TGS to Process Mexican Well Library



Mexican regulator CNH has awarded multi-client seismic company **TGS** authorisation to access its entire library of more than **30,000 wells** in order to deliver high-quality, high-value well data products to companies exploring on- and offshore **Mexico**. Packages of subsurface data will include digitised well logs in LAS+ format, SmartRasters, and Validated Well Headers, with optional Directional Survey Plus, Checkshot Plus, Mud LAS and Lithology LAS. All data products come with full coverage of the wellbore system from surface to total depth, and quality control will ensure attributes such as depth, direction, height and elevation meet the most stringent accuracy guidelines.

Initially, processing will focus on all onshore and offshore exploration and appraisal wells, including those in the Perdido Fold Belt and Salina Basin and in the Sureste and Veracruz areas, where recent discoveries have received industry-wide attention, as well as Tampico-Misantla, with dense coverage across Chicontepec. Key development wells for bid rounds will be included.

This project will complement TGS' Gigante regional offshore 2D seismic survey and recently reprocessed onshore Mexico 2D seismic dataset, allowing E&P companies to evaluate petroleum potential throughout the country, including conventional and unconventional plays. ■

New Insights from GII's Microseismic Monitoring

The **long-term geological storage of CO_2** is increasingly accepted thanks to the development of microseismic techniques. **Microseismic monitoring** of CO_2 injection allows operators and regulators to verify the safe containment and actual location of CO_2 underground. Thanks to the development of new sensor layouts and processing techniques, very weak microseismic events can be monitored (see page 20) and thus provide information on permeability, fluid pathways, fault stability and especially the identification of potential leaks and stress field changes, helping operators mitigate potential risks. Microseismicity is monitored at several CO_2 storage sites around the world, including In Salah (Algeria), Decatur (Illinois, U.S.), and Longyearbyen CO_2Lab (Svalbard). In most cases the CO_2 injection induced very weak seismic events, only detectable by shallow-buried near-surface or downhole sensors. Microseismic monitoring helps assess the potential for induced seismicity that may affect local infrastructure and communities near the site.

CO_2 injection at In Salah.

In addition to 2D and 3D onshore seismic acquisition and processing, **The Geophysical Institute of Israel** is developing methods to detect microseismic events using near-surface sensors, thus reducing the cost of microseismic monitoring while preserving the required regulatory insight and providing additional information for the operators. ■

GeoConvention 2018: Building Strong Foundations

The oil and gas industry has been completely reshaped over the past three years. Although the worst of the budget cuts, layoffs and bankruptcies appear to be over, there is a lingering worry about long-term commodity prices, market access for production, and burdensome regulatory environments. Budgets will continue to be spent cautiously and geoscientists must live within these constraints while continuing to find and develop the resources necessary to power our economy. These issues have been front of mind for the committee for **GeoConvention 2018**, which runs from **7–9 May** in **Calgary, Canada**.

The GeoConvention 2018 technical content has been retooled into a new format, distilling the sessions into more impactful themes, including building strong foundations; new horizons; novel technological tools and advancements; advancing understanding and profitability of unconventional plays; challenges and opportunities for the energy industry, and several more. The high quality and relevant technical content makes the value of attending GeoConvention 2018 self-evident.

GeoConvention 2018 is an opportunity for delegates and exhibitors to benefit from and give back to the technical community, through topical, integrated technical sessions, the showcase stage and the exhibition floor. ■

Atlantic Margin Analogues

The **Atlantic Province** is a large, heterogeneous and prolific group of margins and basins. At the same time, it is one of the most eloquent examples of present-day rift-related continental margins. Looking globally, the Atlantic margins give us precious insights on the Western European margins, from Iberia in the South to the Arctic regions in the North. This insight may also be extended to similar past situations, like the peri-Tethyan margins, nowadays affected by the alpine collisional evolution. Such analogies are established by the recognition of similarities between objects or situations, and in **May 2018, AAPG Europe** is inviting you to find, discover, debate and discuss all the global analogues existing for the Atlantic Margin.

With more than 100 abstracts submitted, the conference chairs invite you to join the AAPG on this two-day conference in fascinating **Lisbon**, a dramatic city sitting next to the Atlantic, and network with oil industry exploration professionals and academic and independent researchers, to discuss how to approach the Atlantic Margins using global analogues. Registration now open – see the AAPG website for further details. ■

Leading Subsurface Conference

Leading subsurface conference DEVEX 2018 has released its technical programme and this year the conference promises to address the full cycle of reservoir discovery, evaluation, development and recovery in the UK. '**Working Together from Pore Space to Pipeline**', the conference will share subsurface technical knowledge, innovation and lessons learned and will feature case histories from operators, industry leaders, academia and the regulator. In addition to the strong technical programme, there will be core displays, with expert-led workshops taking place on both days.

There is a diverse exhibition and a variety of networking and training opportunities for all levels of experience, including the Young Professionals event, a networking reception and a field trip. The conference takes place on **8–9 May** at the **Aberdeen Exhibition and Conference Centre**.

With the generous support of conference partners and sponsors, DEVEX 2018 has continued to allow the first 300 delegates registered to attend free of charge. There is also a limited number of 'at cost' places available so delegates can take advantage of this fantastic low-cost training opportunity. ■

The field trip will take in the Hopeman Sandstones near Elgin.

Emerson and Paradigm Join Forces

Late in 2017 it was announced that global technology and engineering company, **Emerson**, had acquired **Paradigm**, a leading oil and gas software provider known for its array of tools that enable customers to gain deeper insight into the subsurface, reduce uncertainty and support responsible asset management. Having previously purchased reservoir management and production optimisation specialist **Roxar**, this latest acquisition has expanded Emerson's software and solutions capabilities across the oil and gas value chain. Paradigm's strengths lie in the upstream exploration and development side of the industry with its seismic processing and imaging solutions, while Roxar's software concentrates on reservoir modelling and production issues. Emerson already has a strong presence in the mid and downstream segments, so the combination of Roxar and Paradigm into a single unit, called **Emerson Exploration and Production Software**, allows Emerson to offer a complete E&P software portfolio, elevating the company's position as a strategic partner for both subsurface software and surface systems and solutions to the oil and gas industry. ■

The Grand Canyon of the Middle East

In a country of spectacular scenery and geological superlatives, Wadi Nakhr – Oman's Grand Canyon – can still take your breath away.

JANE WHALEY

Oman is often described as a geologist's paradise – with good reason. Boasting a huge diversity of rocks ranging in age from Late Proterozoic basement to Quaternary sands, well exposed in scenic vistas, and cut over millennia into wonderful landforms, there is always something fascinating to look at. From the jagged peaks of the Al Hajar Mountains and the deep inlets of the Musandam Peninsular to the wide Wahiba sand sea and the sabkhas of the Empty Quarter: there are thousands of geotourism stories in a single country. Its geological situation between the converging African and Asian land masses means that Oman has been subject to extremes of rock evolution, resulting in the assemblage of some of the most unique geological features to be found in the world, including the Earth's largest mass of exposed ancient oceanic crust, the Samail Ophiolite.

Here we take a look at just one of the country's many geological wonders: Wadi Nakhr, in the Al Hajar Mountains.

The Al Hajar Mountains

The Al Hajar stretch 700 km across the north of the country, majestically dominating the scenery as they rise abruptly to over 3,000m from the coastal plain. The sediments at the core of the range were mainly laid down during the Late Permian to Late Cretaceous in the Neotethys ocean basin that had resulted from the break-up of Gondwana. As the Arabian

platform slowly submerged, almost 3,000m of predominantly shallow marine limestones, with occasional clastic pulses, were deposited. This formed the Hajar Supergroup, which provides many of the best reservoir and source rocks throughout the Arabian Peninsula , including in the supergiant

Jane Whaley

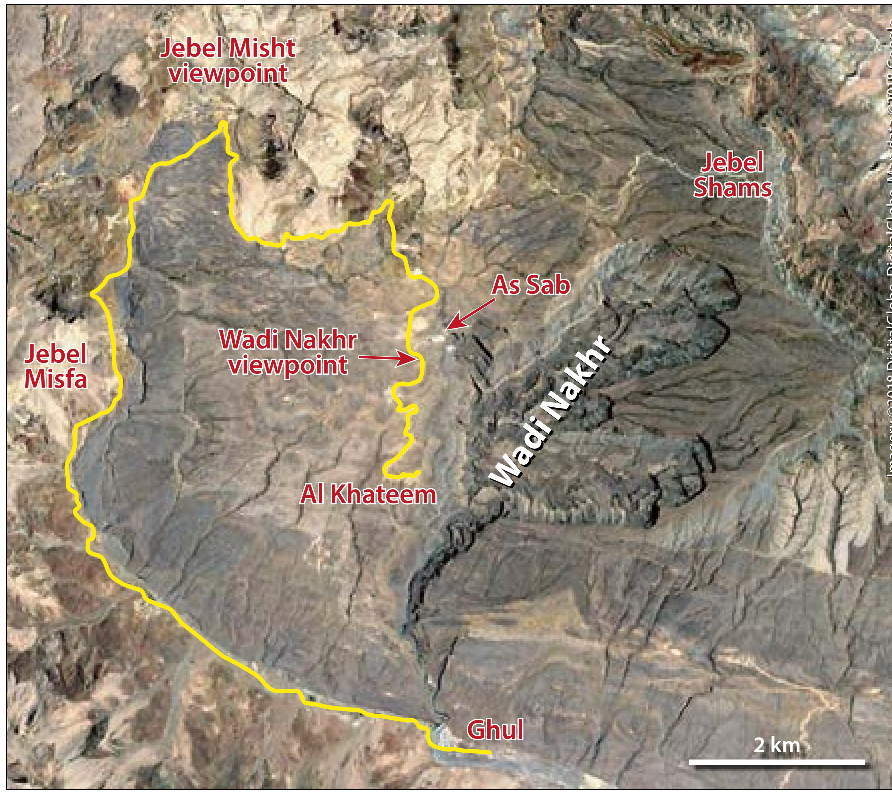
The trek known as 'The Balcony Walk' clings to the western edge of Wadi Nakhr. It can be seen as a thin white line running roughly parallel to the bedding in the centre of the photo.

Rumaila-West Qurna field (see page 34).

As the subduction of the Arabian Plate below the Eurasian Plate continued and partial closure of the Tethys basin commenced, the carbonate sequence was uplifted and compressed, and oceanic crust was pushed from the north over the continental crust to form the ophiolite complex which makes up the majority of the Al Hajar range. The carbonate platform sediments were folded during these movements, resulting in the westward-dipping anticlinal structure of the Jebel al Akhdar structure, which is one of only a couple of places where the underlying carbonates outcrop in the mountains. The highest point of Jebel al Akhdar is Jebel Shams, which at 3,010m is also the highest mountain in Oman.

The flanks of Jebel Shams are cut by a number of deep valleys, known in Arabic as wadis, running perpendicular to the strike of the anticline. The deepest of these is the 12 km-long Wadi Nakhr, which cuts down through over 1,500m of sediment, thus providing one of the best exposures of these important Cretaceous reservoir horizons.

The road to Jebel Shams gives a snapshot of some of the varied geology that this fascinating country offers the geo-tourist – before the final corner is turned and a deep crevice in the earth drops down into the hazy depths of Wadi Nakhr.



Satellite images of Oman clearly delineate the geology. The dark grey area, into which Wadi Nakhr is carved, is the Hajar Supergroup. The light areas are either Oman 'exotics' or Hawasina rocks, while the brown represents volcanics or the syntectonic Muti Formation.

Exotics and Supergroups

The road starts in the small town of Al Hamra, about 30 km north-west of the tourist centre of Nizwa, and a couple of hours drive from the capital, Muscat. The road runs alongside a wadi; for much of the year the river bed is dry, but the water table is high enough for there to be plenty of vegetation along the valley, helped by the highly effective 'falaj' system of irrigation found throughout Oman.

The valley is quite wide to begin with, with sides which rise steeply from 700m on the valley floor to over 1,600m. On the right (northern) side of the road are the gently-dipping layered limestones of the Hajar Supergroup, while on the southern side things look quite different. The road here closely follows the contact between the autochthonous Hajar Group rocks and the allochthonous rocks of the Hawasina complex, which comprise deep marine and continental slope sediments deposited in the ocean basin on the southern margin of the Neotethys ocean. During the Upper Cretaceous, the obduction of the Semail ophiolitic complex led to these

The entrance to Wadi Nakhr, where beds of the highly fractured Natih Formation limestone rise above the abandoned old village of Ghul (meaning ghost!).

A few kilometres beyond Ghul, Jebel Misfa, part of the Hawasina complex, looms ahead, with chaotic beds of the syntectonic Muti Formation in the foreground.

deep sea Hawasina sediments being thrust over the Hajar Supergroup.

Towering over the valley a few kilometres away to the south is Jebel Kawr, 35 km long and at 2,960m nearly as high as Jebel Shams. This is an example of the 'Oman exotics' – so-called because their lithology cannot be matched laterally to any of the adjacent rocks. It is composed primarily of Late Triassic limestones overlain by Jurassic pelagic limestone and overlies Triassic volcanics. It is believed to have been formed in an ocean island tectonic setting before being thrust over the Hawasina complex and folded by the tectonic movements which created the Jebel al Akhdar dome. The thick carbonate unit contains shallow marine fossils such as corals, crinoids and stromatolites. The volcanics underlying the limestone can be clearly seen along the southern side of the road from Al Hamra, both as basalt and as a volcanic breccia.

About 10 km from Al Hamra is the village of Ghul, which lies at the southern entrance of Wadi Nakhr. As is common in Oman, there is a picturesque but abandoned and crumbling old village, which lies on one side of the wadi mouth, with the modern village surrounded by date palms and irrigated gardens on the opposite bank.

It is possible to trek up Wadi Nakhr from here; a strenuous hike, but one which exhibits the full sequence of the Hajar Group. At the entrance to the wadi there is the massive limestone of the Natih Formation, conformably overlying the shaley Nahr Umr Formation, which together form the Mid Cretaceous Wasia Group. They are underlain by limestones and marls of the Lower Cretaceous Kahmah Group. Moving northwards further along the wadi floor, the southerly dip of the rocks mean that the canyon has eroded down to expose the Jurassic Sahtan Group, with oolitic black limestone underlain by rust brown shaley units deposited in a shallow marine environment.

Spectacular Views

Beyond Ghul the road begins to climb more steadily and the valley sides become even steeper. It runs along another geological contact, this time between the Natih Formation and the overlying syntectonic Cretaceous Muti Formation. This is a complex mix of sediments with conglomerates, mega breccias and irregularly sorted deposits including yellow siltstones with a chaotic structure, often with large blocks of the Natih Formation embedded within the conglomerate. It records the transition from a passive margin to a foreland basin during subduction.

About 16 km from Ghul, after a steep and winding climb, the road begins to flatten out at a height of about 1,500m and runs across a polished limestone pavement for several kilometres. This is the top of the Natih Formation, marking the cessation of marine deposition. A few kilometres further, and there is a spectacular viewpoint. In the distance is the sharp outline of Jebel Misht, the most spectacular of the Oman 'exotics', its dramatic white limestone cliffs rising

1,000m above the surrounding hills.

By this stage the road is no longer paved, and a 4x4 is required to continue – but it is well worth the effort. At the most northerly point of the drive, the track climbs along the edge of the steep white cliffs of another limestone exotic, with volcanics outcropping underneath. Vegetation is sparse at this height, so the long-haired goats, for which the area is famed, can be seen climbing trees in their search for food. The road now closely follows the unconformable contact between the Natih and the overlying, sometimes tightly folded shales of the Muti Formation.

The track levels out at a height of about 2,000m and heads southwards across the limestone plateau for a few kilometres – and a yawning chasm begins to be revealed. Finally, 40 km and a couple of hours since leaving the village of Ghul – now only 6 km south as the crow flies – there is the most spectacular viewpoint: the Grand Canyon of Oman.

The canyon cuts through over 1,000m of predominantly Cretaceous rocks.

The Balcony Walk

The canyon is over a kilometre wide here, and to the north it can be seen cutting deeply into the flanks of Jebel Shams. At the viewpoint there is an almost sheer drop to the canyon

In the far distance to the right is the Jebel Misht limestone 'exotic', probably originally an ocean atoll. On the left in the distance is Jebel Kawr, also an exotic, whilst the high cliff in front of that is Jebel Misfa. The Hawasina deep oceanic sediments of the Hamrat Duru Group form the intervening dark low hills, with the top Natih Formation limestone pavement in the foreground.

floor over 1,000m below, where at the very bottom a few patches of greenery can be seen, following the stream bed through the wadi. The deep ravine of Wadi Nakhr probably formed during the uplift of the Jebel al Akhdar dome, enhanced by successive wadi floods, with some speculation that the collapse of underground caverns may have added to its development. The entire sequence of the Hajar Supergroup is exposed on the wadi sides, with the massive limestone beds forming near vertical cliffs, interspersed by weaker, shaley horizons. Although not as huge as the American Grand Canyon, it is still an awe-inspiring sight!

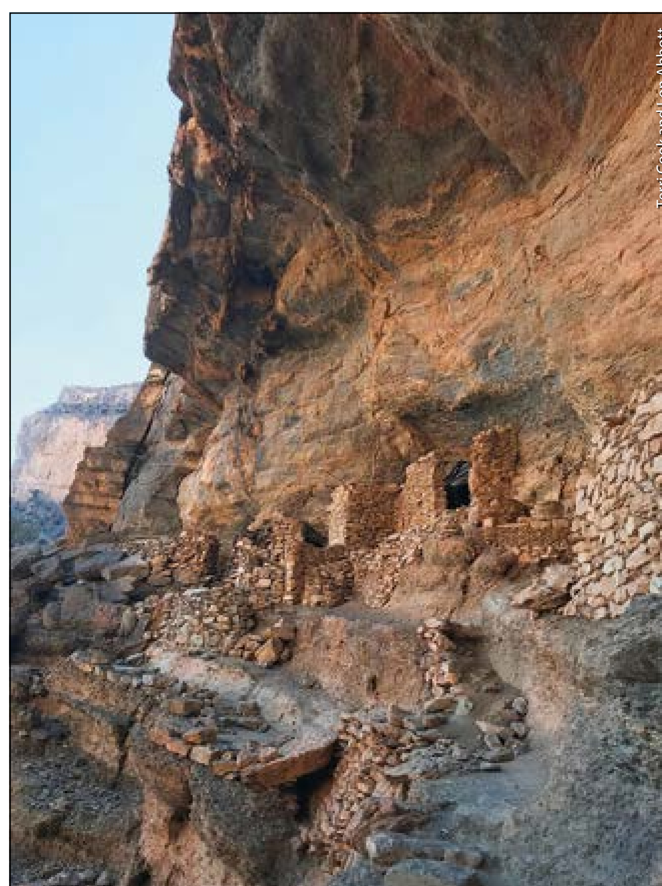
The journey is not yet over. A few kilometres further south, and the road finally ends in the windswept village of Al Khateem, sitting precariously on the edge of the canyon. Although the sides of the ravine look impenetrable, at this point it is possible to pick up a trail which travels inside the western rim of the canyon. Aptly known as 'The Balcony Walk', this old donkey path roughly follows the bedding, with occasional scrambles to a lower horizon. It affords tremendous views into the silence of the canyon, and of its geology – but with drops of hundreds of metres to one side in places, it is not for the faint-hearted.

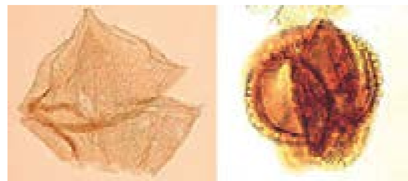
Extreme as this environment seems, the Balcony Walk eventually reaches the ruins of a small village, As Sab, about a 2-hour trek from Al Khateem, which was inhabited until not long ago. It is perched on the cliff side with rough-hewn terraces clinging to the rock beside it – and a drop of 800m below. A spring at the base of the limestone wall above the village provided the water for the terraced gardens, and many of the houses are still standing as they are protected from the elements by overhanging rocks.

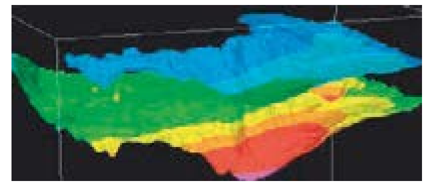
Heading back up the trail, the lucky walker may catch a glimpse of the distinctive black and white Egyptian vulture hovering on the thermals rising up from the valley; or even, as we did, an intrepid paraglider, 1,000m above us, silently circling over the canyon. Surely, that paraglider had one of the best views in the world!

References available online. ■

The abandoned village of As Sab, perched halfway up the sides of Wadi Nakhr.







Passive Seismic: Thinking Differently

Low-frequency seismic signals: are they really that hard to exploit in exploration – or do we just have to think differently?

KATERINA POLYCHRONOPOULOU, Seismotech S.A.

Over the last few years there has been a long debate on the exploitation of low frequencies in seismic exploration. Their value being undisputable, especially in the case of deep target exploration, how is it that they have always been troubling to those involved in the quest for information hidden inside active seismic signals?

People involved in seismic exploration have long been trying to record and exploit low frequencies. However, both the delicate nature of low frequencies, which makes them easily contaminated by noise, and the fact that their production and recording may dramatically increase the cost of a seismic survey, have limited their use to frequencies above approximately 10Hz.

Why are we Struggling?

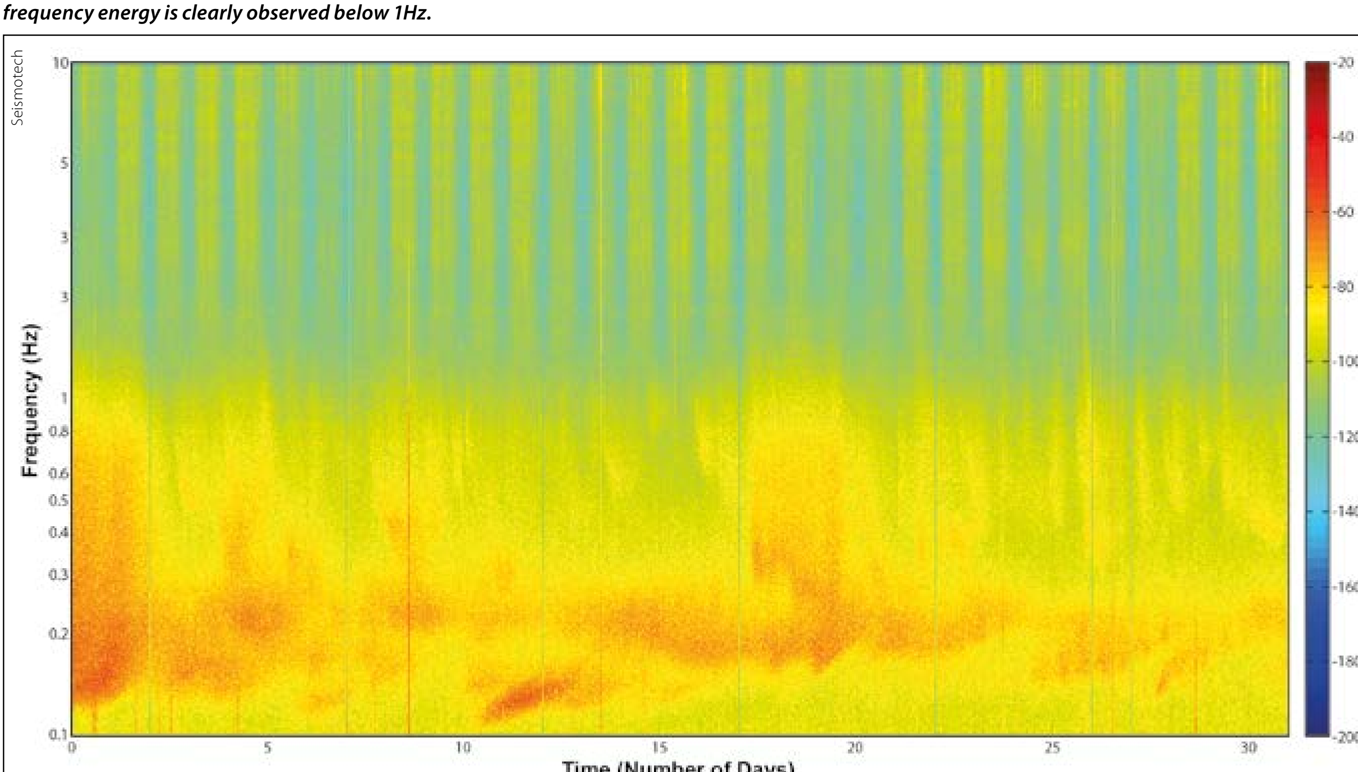
Producing low frequencies in seismic can be a nightmare. Explosive sources are known to produce a relatively broad bandwidth signal. However, the relationship between the frequency content of the produced signal and the parameters of the explosion (such as type of explosive, charge, depth) is not very clear, mostly relying on rules of thumb and field experience. Moreover, even in cases where low frequencies are successfully emitted, they tend to be mainly concentrated in the surface noise (ground-roll) and are missing from the reflected signal. As for vibrators, even though the emitted energy and the bandwidth are both controlled, the generation of very low frequencies is usually avoided, as it can result in severe structural damages.

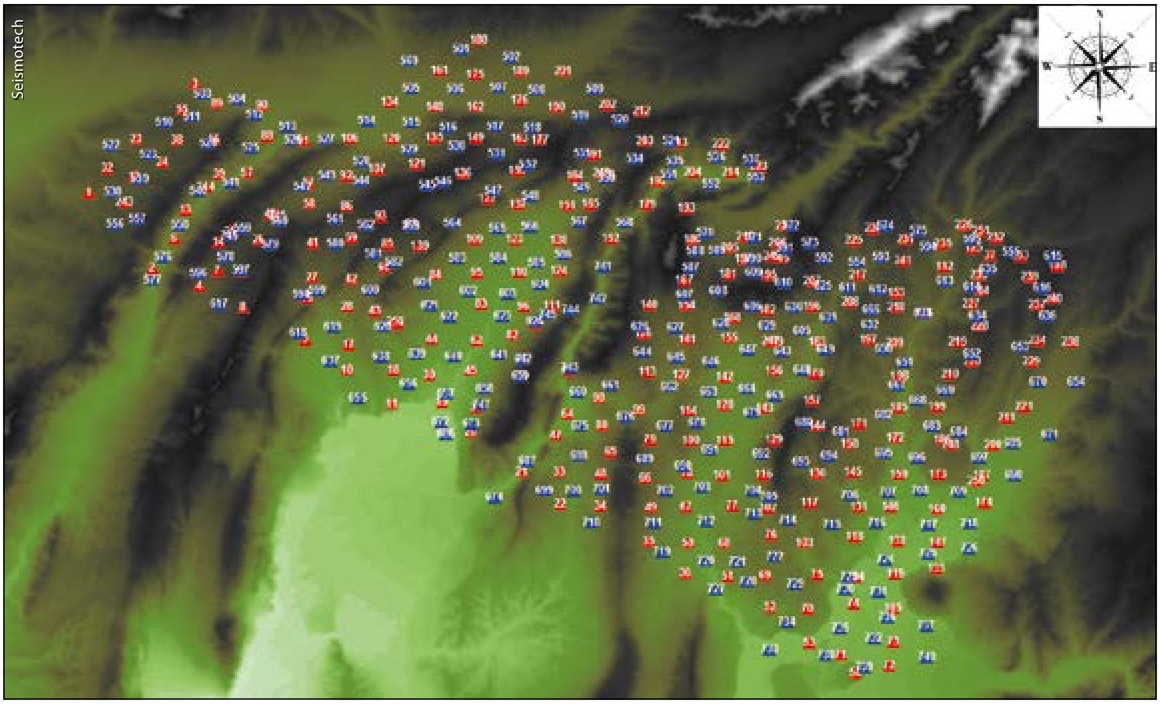
Recording low frequencies can also be a hard task. Commonly used seismic equipment is not designed to sense very low frequencies, since that would result in a substantial increase in costs, while the benefit to the survey of the acquisition of low frequencies would be highly questionable, as they are usually the first to be attenuated by high-velocity layers or contaminated with noise and might be easily lost.

On the other hand, passive seismic has for a long time exploited low frequencies (below 15Hz) for exploration purposes. These frequencies exist in abundance in nature, for example in the frequency content of earthquakes and seismic noise. Various passive seismic methodologies, exploiting different parts of a passive seismic signal, have been developed to extract information hidden in the frequency range of 0.1 up to 15Hz.

So why are we struggling to produce these frequencies ourselves when low-frequency passive seismic signals are constantly travelling through every spot of the earth's subsurface? The

Spectrogram visualising the temporal variation of the frequency content of the signal recorded by a broadband station during a 30-day period. The low-frequency energy is clearly observed below 1Hz.





A passive seismic network (480 short-period stations) installed in an area where a 2D active seismic survey is taking place.

challenge is rather how to record them and extract the information they carry in the subsurface. And while this could be extremely difficult in the case of an active seismic survey, consider how much easier it would be in a scenario where the low-frequency 'source' lies below the target zone and one-way travel is all that is needed in order for it to be recorded at a seismic station.

How Does it Work?

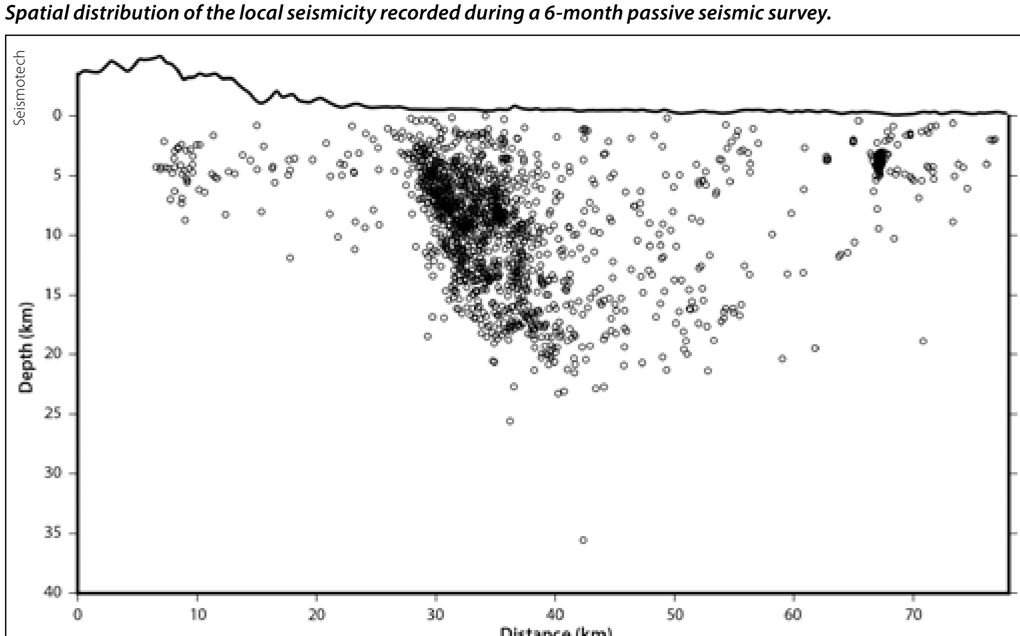
In order to acquire passive seismic, one has to install a passive seismic network, which consists of a number of stand-alone three-component stations, spread across the area of interest. These stations can be equipped with broadband or short-period sensors, or even simple geophone nodes, depending on the scope of work. Experience shows that for oil and gas applications, the most cost-efficient option is to use short-period equipment, which has the capacity to record lower frequencies at the geophones, for approximately the same cost.

These stand-alone stations will record for a specified period of time, like a few months, and the continuous record acquired is the passive seismic dataset, containing all types of passive seismic signal such as ambient noise and local or distant earthquakes. A number of passive seismic methodologies, including Local Earthquake Tomography, Ambient Noise Tomography and Surface-wave Tomography, which exploit different parts of the acquired signal and thus different frequency bands, can therefore be applied, using a single dataset.

This diverse dataset is then analysed and the 'useful' signal, as defined by each methodology, is isolated and extracted from the continuous records.

In the case of Local Earthquake Tomography, local earthquakes of low magnitude, occurring during the recording period within or around the area of interest, are the passive seismic 'sources'. These are detected in the continuous records; the first arrivals both of P- and S-waves at each station are picked up and the events' location

Spatial distribution of the local seismicity recorded during a 6-month passive seismic survey.

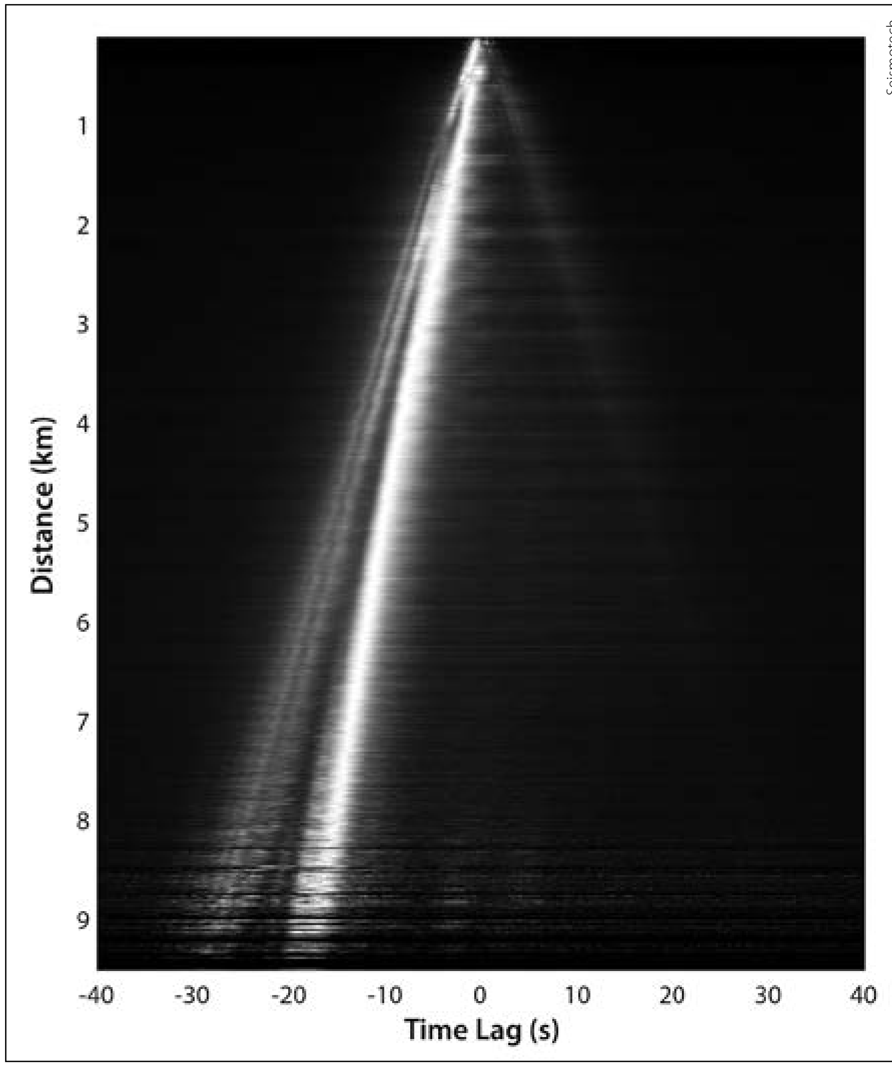


and time of origin are estimated, using sophisticated analytical tools like Seismotech's EQLab. Once the 'sources' have been located in both space and time, traveltimes to the seismic stations are inverted, in order to obtain the P- and S-wave velocity distributions below the study area. These models usually extend from the surface to the maximum depth of local seismicity (usually deeper than 15 km), which – in most cases– lie far below the average exploration target zone.

However, this methodology strongly depends on the spatial distribution of local seismicity, which might not be uniform or adequate to provide a satisfactory coverage of the totality of the area of interest. This is the reason why alternative passive seismic methodologies, independent of this parameter, are employed to complement the acquired information.

Ambient Noise Tomography exploits the frequency content of pure ambient seismic noise. In this case, therefore, there is no need to extract any part of the signal and the totality of the continuous records are used to calculate cross-correlations between station pairs. After frequency-time analysis, the mean Rayleigh-wave group and phase velocities are measured as a function of period, and dispersion curves are estimated for each cross-correlation. Inversion of these dispersion curves results in the construction of 2D group and phase velocity models, and consequently leads to the estimation of local group and phase dispersion curves. These are then jointly inverted to estimate a 3D S-wave velocity distribution below the area of interest, from the surface to a depth defined by the highest period (i.e. lowest frequency) recorded.

Surface-wave Tomography, by contrast, exploits distant earthquakes, evidence of which is extracted from the continuous records. A multi-channel cross-correlation technique is applied and phase velocity measurements are performed at various periods. These measurements are inverted and 2D phase velocity models for each period are constructed. Inversion of the local dispersion curves, calculated by the phase velocity models, results



Surface-wave energy clearly emerges from the cross-correlations calculated in the context of an Ambient Noise Tomography survey.

in a pseudo-3D shear-wave velocity distribution below the area of interest. Since this methodology exploits the lowest part of the passive seismic signal's frequency content (i.e. frequencies below 1Hz), the calculated model illuminates the deepest parts of the investigated space.

Why Passive Seismic?

Passive seismic provides an excellent exploration solution that could ideally complement any active seismic survey. It can be run simultaneously with a conventional survey, by setting up a passive seismic network in the area of interest, and, since the fieldwork involved is quite simple, it would not significantly affect the cost of the exploration programme.

Implementation of a passive seismic survey requires the installation of a number of seismic stations, which will be continuously recording during the acquisition period. Access to the station points is facilitated by the stand-alone concept, while the only action that has to be taken is periodic data gathering and battery changes at each station. Moreover, the absence of active sources, such as heavy vibrators and/or explosives, from the passive seismic procedure makes it ideal for environmentally sensitive areas, requiring minimum HSE control and leaving no environmental footprint.

In addition to all this, the velocity models acquired can provide an image of the subsurface, undoubtedly coarser, but significantly deeper, than that provided by active seismic, due to the nature of the low frequencies exploited. The passive seismic 'sources' lie within or below the target zone and the associated one-way travel-paths minimise the loss of energy, making it easy for the low-frequency seismic signal to reach the surface and be recorded by the seismic stations. This is very important, especially in areas where the existence of high-velocity areas close to the surface mask the image below (e.g. complex geotectonic regimes, such as thrust-belt zones), which is often the case in land seismic surveys.

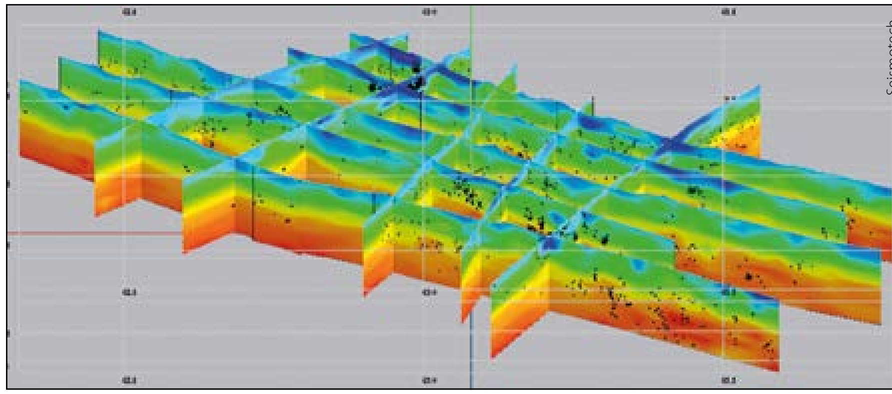
Moreover, the coarse models acquired by passive seismic methodologies can provide a robust 3D model that can be used to process or reprocess active seismic data. These models, apart from being better than a 1D velocity model based on geological information on the study area, might prove to be particularly valuable in cases where little information is available, such as the deeper parts of a survey area where well data are usually either unavailable or extremely sparse.

Last, but not least, the shear-wave velocity information acquired by passive seismic provides an additional insight into the explored subsurface volume, permitting the extraction of valuable lithological information from the recorded seismic signal.

Get Active… Choose Passive

Passive seismic has long been considered by the oil and gas industry as a methodology mainly applied during the production phase, in the form of microseismic monitoring, leaving its exploration potential on the edges of the industry's exploration methodologies' toolbox. However, during the last few years, more and more people have been discovering the value of applying passive seismic for exploration purposes. Successful case studies worldwide and intense scientific testing have changed the view of the oil and gas community on passive seismic.

Even though launching a passive seismic survey in parallel with land active seismic surveys is not yet common practice, this might well be the road ahead, as passive seismic can undoubtedly complement the seismic information acquired in a robust and cost-effective manner. ■



P-wave velocity distribution along the 2D profiles of an active land seismic survey. The vertical cross-sections are extracted from the 3D velocity model that was calculated using passive seismic methodologies.

CCS: Clean Growth, EOR and Sushi

Dr NICK RILEY MBE
Carboniferous Ltd

Is carbon capture, storage and utilisation essential to achieve the world's greenhouse gas reduction targets – and what part can the oil and gas industry play?

Carbon dioxide capture and storage (CCS) is a large-scale industrial process involving the capture of carbon dioxide (CO_2) from large point source emitters, such as fossil fuel and biomass/biogas burning power plants, petrochemical facilities, or steel and cement plants, with the intention of storing the captured CO_2 away from the atmosphere and ocean indefinitely. It is a technology that mitigates the adverse impacts of these emissions such as climate change and global warming, and with respect to the ocean, not just warming, but also acidification and sea level rise.

The main storage options are geological and achieved by deep injection (>800m) into depleted oil and gas fields and large saline aquifers. At these depths the CO_2 is in a dense phase where it behaves like a liquid and yet it is still a gas. Over time it is immobilised in the geological environment by several processes such as dissolution into saline water, mineral reactions with the rock minerals and brine waters and pore trapping via capillary mechanisms. Even in its dense phase CO_2 is buoyant relative to brine, so escape to the surface must be prevented by ensuring that there are effective geological barriers, usually clay or shale layers, known as cap rocks. These seal the CO_2 underground in the same way that oil and gas are trapped in natural systems for millions of years.

EOR, Coffee and Sushi!

The term carbon capture, storage and utilisation (CCSU) is applied to captured CO_2 that is then used in an industrial process. By far the largest volume use is in enhanced oil recovery (EOR), where CO_2 is injected into depleting oil fields to stimulate further oil production. There are 13 CO_2 EOR operations in the world, spanning from North and South America to the Middle East, all of which are supplied with CO_2 captured from industrial point sources. A further six CO_2 EOR projects, including three in China, are expected to come on stream over the next four years.

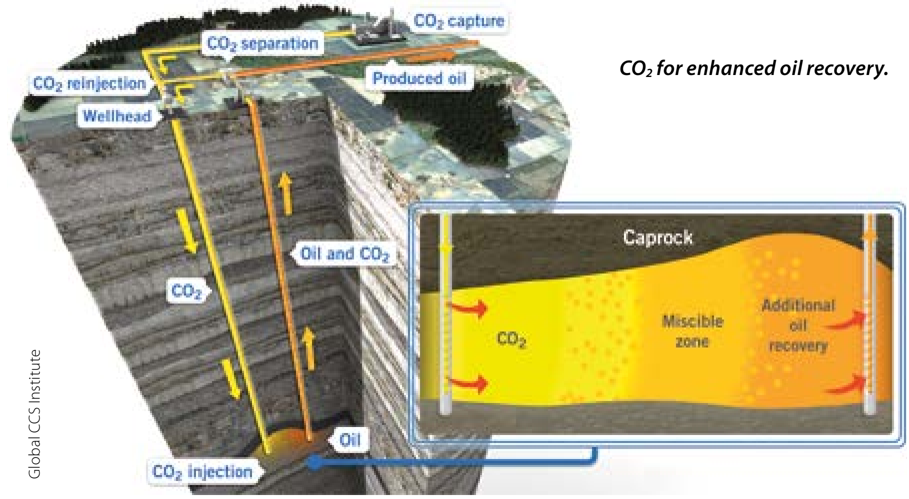
In CO_2 EOR the injected gas reacts with the trapped oil, reducing viscosity and selectively dissolving light oils and gases, which enables the hydrocarbons to flow toward the production wells. Oil and gas produced in this way reduces lifecycle emissions, as some CO_2 is passively stored in the depleted field, as a result of the same physical and chemical subsurface processes as in a saline aquifer. For example, over 31 MT of CO_2 have been stored through its use in EOR at the Weyburn oil field in Saskatchewan, Canada since 2000. Weyburn receives CO_2 via pipeline from a coal gasification plant over the USA border in North Dakota and from a coal burning power

The Dakota Gasification Company synfuels plant in North Dakota was built in the 1970s oil crisis. It has 13 gasifiers and makes synthetic natural gas, hydrogen and fertilisers from coal. All the CO_2 is captured and piped across the border to Canada, where it is used for CO_2 enhanced oil recovery. It is also capable of making synthetic petrol, diesel, and aviation fuel.

© Nick Riley

plant at Boundary Dam in Saskatchewan.

There are smaller volume niche uses of CO_2, such as fertilising fruit and vegetables in commercial greenhouses, as is done in the Netherlands. Microchip manufacture requires the gas as a cleaning solvent, while chilled food packaging often has CO_2 as a preserving atmosphere and it is an important solvent for decaffeinating tea and coffee. In Japan the world's first gas-fired power station to capture CO_2 (Kansai Electric Company) provides dry ice (frozen CO_2) to the fishing and sushi industries to keep fish fresh and chilled. Perhaps the most familiar use of CO_2 is in the drinks industry where it is injected into drinks to make them fizzy (carbonated); and CO_2 fire extinguishers are vital for dealing with electrical fires.



Global CCS Institute

CO_2 for enhanced oil recovery.

Dedicated Geological Solution

The main problem with CCSU is that in most uses, apart from EOR and emerging mineral capture technologies, the captured CO_2 still passes into the atmosphere and thence to the ocean. Nevertheless, CCSU is an important revenue stream that can finance the building of capture and supply infrastructure, which could eventually be used to send the gas to dedicated geological situations for permanent storage. The inability of such dedicated storage to cover its costs under present commercial conditions explains why there will be only five large saline aquifer storage sites in the world operating this year – in Norway, North America and Australia.

Statoil started the world's first project for geological storage under the North Sea in a saline aquifer in 1996, by capturing and injecting approximately 0.8 MT/annum of CO_2 from its offshore Sleipner gas production platform, just east of the Shetland Islands. This project makes commercial sense because the Norwegian government imposes a CO_2 emission tax on oil and gas production.

The legal situation for storing CO_2 underground depends on the methods used and the jurisdiction hosting such sites. If the gas is used as a working fluid in oil and gas production, such as CO_2 EOR, it is covered by long established petroleum production legislation. However, if the CO_2 is injected for dedicated geological storage, on a world scale legislation is more patchy. The European Union has a directive which ensures that member states (and associated states, such as Norway) wishing to conduct dedicated geological storage comply with strict criteria for site selection, injection operations, monitoring and verification, and final closure procedures, to ensure effective permanent storage, safety and environmental protection.

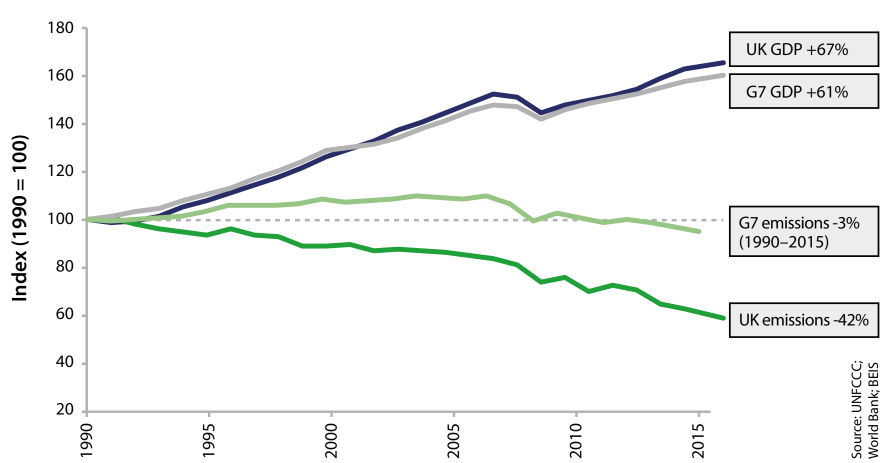
CCS and CCSU in the UK

Geological mapping of the subsurface with a view to identifying and predicting the amount of storage space (geocapacity) available in the UK began in 1991, led by the British Geological Survey, with European co-funding. Over the following 20 years methodologies were developed, refined and standardised through several projects, in collaboration with industry, government and EU funding. This work also matched CO_2 sources to potential storage sites.

In 2005 a Task Force was set up jointly by the UK and Norwegian governments to look at possibilities for collaborating on building a CCS infrastructure to receive CO_2 from countries surrounding the North Sea. This culminated in a study, *One North Sea*, published in 2010, which summarised geocapacities under the North Sea and potential supply routes, via ship and/or pipeline. Meanwhile, the UK government initiated competitions for industry to bid for government support of up to £1bn to fund full scale demonstrations of CCS from up to three UK power plants.

As a result, by 2015 the UK was on track to deliver the world's first full scale gas-fuelled power station fitted with CO_2 capture, transport and geological storage of the gas under the North Sea. In 2015 the UK government then withdrew the £1bn capital grant set aside for funding such projects, leading to their cancellation, even though £168m

UK and G7 economic growth and emissions reductions.



UK Clean Growth Strategy Report

of government money had already been spent in supporting the bids. The main excuse given by Government was that CCS was too expensive and costs needed to be reduced. This surprising decision has seriously delayed CCS deployment in the UK by at least 10 years.

A Clean Growth Strategy

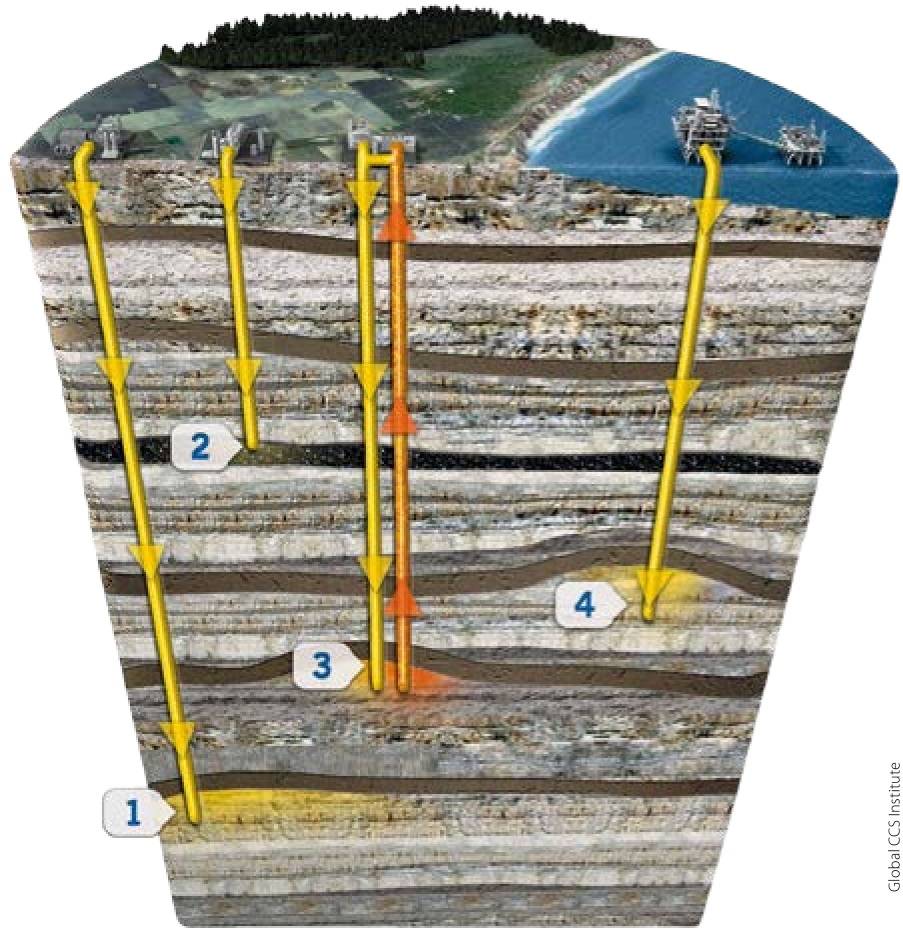
In October 2017 the UK government published its Clean Growth Strategy, which set out a road map of the research, innovation and deployment of low carbon technologies needed to enable the UK to meet its greenhouse gas reduction targets out to the period 2028–2032. These are legally binding targets, independently assessed and verified by the Committee on Climate Change, a body of experts to whom the UK government is accountable. In the strategy, gas becomes the most important fossil fuel as coal is phased out, leaving gas, renewables and nuclear as the main sources for heat and power.

The ambition is to have 85% of the UK's electricity generation from low carbon emission sources in place by 2032 – a major challenge! This requires CCS to be deployed in the 2030s, with emphasis on CCSU. Decarbonising the transport network, which accounts for 24% of UK emissions, will require more electric and/or hydrogen powered vehicles. Either way gas will be important as a source of hydrogen as well as electricity. Natural gas is currently the main source of hydrogen, through a long-established process known as 'steam reforming', in which methane mixed with steam is converted over a catalyst into hydrogen and carbon monoxide. Hydrogen can then be converted to electricity and heat either by burning it in a gas turbine or by generating heat and power via a fuel cell. The carbon monoxide can be oxidised and captured as CO_2.

Clearly there is a need to decarbonise gas use, otherwise the full benefits and deployment of low carbon electrification, hydrogen and heat will not be achieved. It is a 'no regret' part of the strategy which complements renewables and nuclear.

CCS Essential to Meet Targets

The UK Clean Growth Strategy set out three possible pathways out to 2050, one of which does not involve CCS.



Schematic of CCS storage options: 1. Saline formations; 2. Injection into deep unmineable coal seams or coalbed methane; 3. EOR; 4. Depleted oil and gas reservoirs.

However, the independent analysis of the strategy published by the Committee on Climate Change in January this year made it clear that it considered that CCS will be essential to meet the 2050 target, let alone the even more stringent Paris Agreement commitments that the UK has signed up to. The Committee points out that CCS may be needed as a greenhouse gas removal technology – for instance, by capturing CO_2 from biomass to avoid it entering the atmosphere – long after fossil fuel dependency. It advises that the 'Development Pathway' due to be published this year "must set out the Government's proposals for the delivery model for CO_2 transport and storage infrastructure, the funding mechanism for industrial CCS, and the allocation of risks between Government and developers, especially relating to long-term storage liabilities. Several promising projects exist in strategic cluster locations that could be in operation by 2025. If a decision on the future of the gas grid by 2025 is to be credible, then progress on demonstrating the business model for CCS will be needed before then."

Furthermore, the Committee criticises the £100m allocation for early stage R&D support for CCS as inadequate, compared to the £1bn previously committed and withdrawn in 2015. It implores the Government to be more ambitious in the funding and timing of CCS deployment by setting out plans this year to 'kick-start' a UK CCS industry in the 2020s.

The UK, in partnership with countries that surround the North Sea, especially Norway, is exceptionally well placed to deploy CCS now whilst it has the offshore oil and gas skill sets and infrastructures in place. Procrastination is no longer an option, and yet more 'studies' will not help the rapid deployment of CCS.

The O&G industry too needs to be more ambitious: if oil and gas use is not decarbonised the rising public concern about the fossil fuel industry and diminishing investor support will accelerate. ■

Norwegian Barents Sea: The Norsel High

Modern 3D seismic offers the opportunity to generate new hydrocarbon prospects at the heart of the Norwegian Barents Sea, in a strategic position for existing infrastructure and potential future development.

The 3D seismic consists of 3,600 km^2, acquired in 2012 and 2017, which has been processed with a modern broadband sequence.

Spectrum

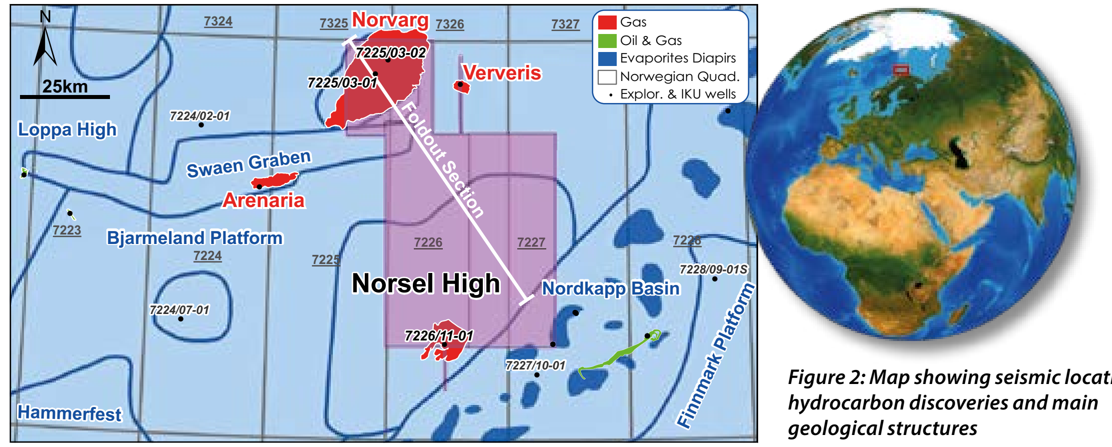
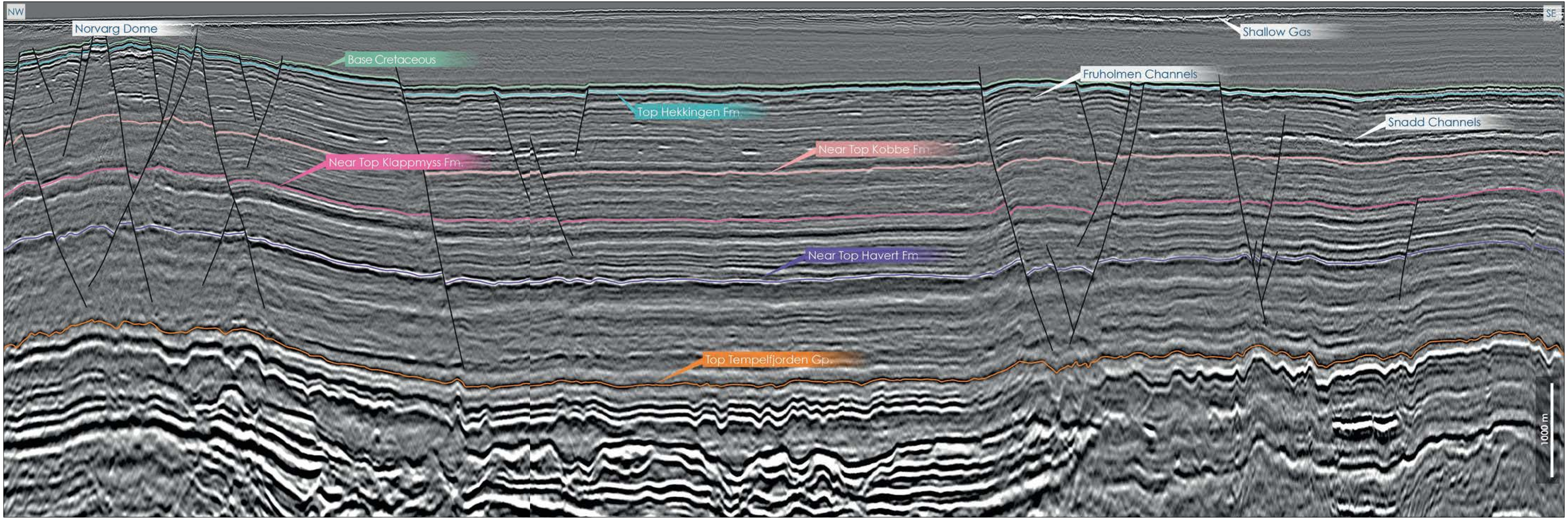


Figure 2: Map showing seismic location, hydrocarbon discoveries and main geological structures

Figure 1: Depth converted 3D seismic (Fast Track PSTM).



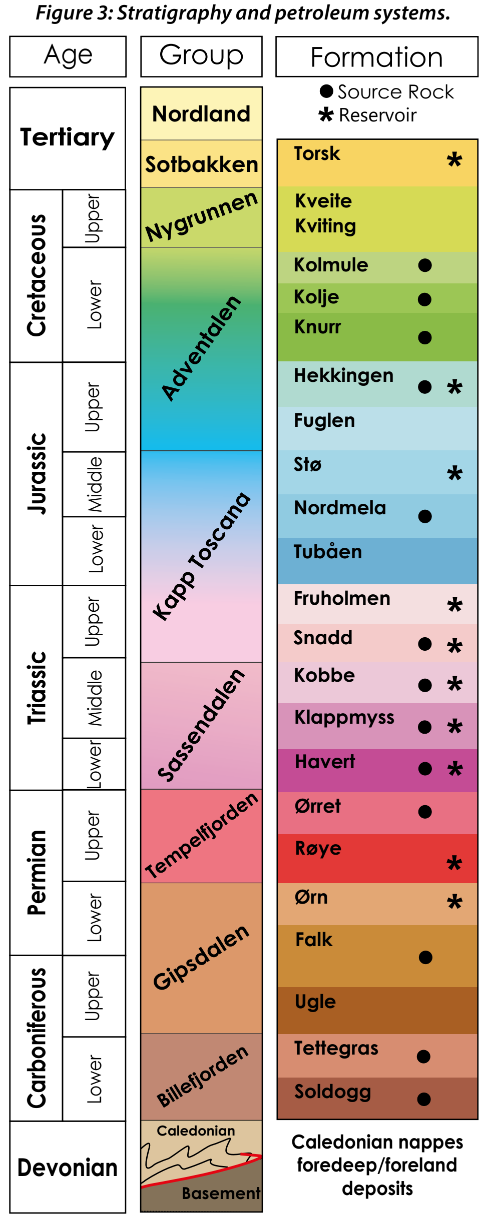
New Prospects Generated in the Norsel High

The new-found prospectivity in the Norsel High rejuvenates the established oil and gas plays of the Norwegian Barents Sea.

PAOLO ESESTIME, Spectrum

Following the drilling of the first well on the Norsel High (7226/11-01) in the 1980s, this area has been overlooked for more than two decades, despite the discovery of gas in the Havert Formation. Over twenty years later, wells 7225/03-01 and -02 found multiple gas zones at the top of the Norvarg Dome, in the Stø, Snadd and Kobbe Formations (Figure 1). The drilling campaigns did not resolve the full extent of these accumulations. Discoveries in the surrounding area include the Ververis and Arenaria wells, where Ververis proved gas in Middle Triassic sandstone, although the gas-water contact was never found.

Figure 3: Stratigraphy and petroleum systems.



Geological Evolution

That first well on the Norsel High (7226/11-01; see Figure 2 for location) penetrated the deep stratigraphic section of the Barents Sea, into the Permian-Carboniferous limestones and evaporites (see Figure 3). A basement high was confirmed to have been present since the Devonian, which had maintained its relief during the Carniferous and the Permian, allowing several carbonate sequences to develop as build-ups. These eventually grew laterally as carbonate platforms, and are now horizontally juxtaposed against salt deposits and diapirs, such as those observed in the adjacent basin (e.g. Nordkapp to the east). Carbonate platform growth continued into the Triassic, when they were replaced by deposition of up to 2,500m of clastic sequences.

Depth conversion and isopach generation from 3D seismic suggests that differential compaction in the Lower Triassic shale (Havert Formation) preserved the gentle positive topography of the Norsel High during the Lower and Middle Triassic, before it was finally overlain by a few tens of metres of Jurassic and 1,000–1,500m of Lower Cretaceous sediment.

During the Upper Cretaceous to Paleogene, tectonics reactivated the pre-existing fault-boundary with the Nordkapp Basin and inverted the pelagic area to the north, forming the Norvarg Dome.

Source Rocks and Maturity

The Norsel High exhibits proven hydrocarbon systems, regionally present in the Barents Sea and distributed at multiple stratigraphic levels from the Permian-Carboniferous to the Triassic and the Jurassic.

Oil and gas prone sources have been mapped in the Gipsdalend and Tempelfjorden Groups, which are particularly thick in Nordkapp and under the Norvarg Dome. These source rocks have been buried below 3,000m since the Jurassic and are likely to be in the gas window since the Cretaceous (Henriksen, 2012) (Figure 1).

Numerous proven source rocks are present in the Triassic, characterised by shale and coal beds. As well as being demonstrated to be gas-prone, these have also been proved to be oil-prone source rocks, and have gained even more interest since the discovery of oil in the area of Wisting to the north. Triassic source rocks are present at various depths (Figure 1), and these have different maturities (Ostanin et al., 2017). The point of expulsion is complex to model, as oil and gas windows may have moved upward through

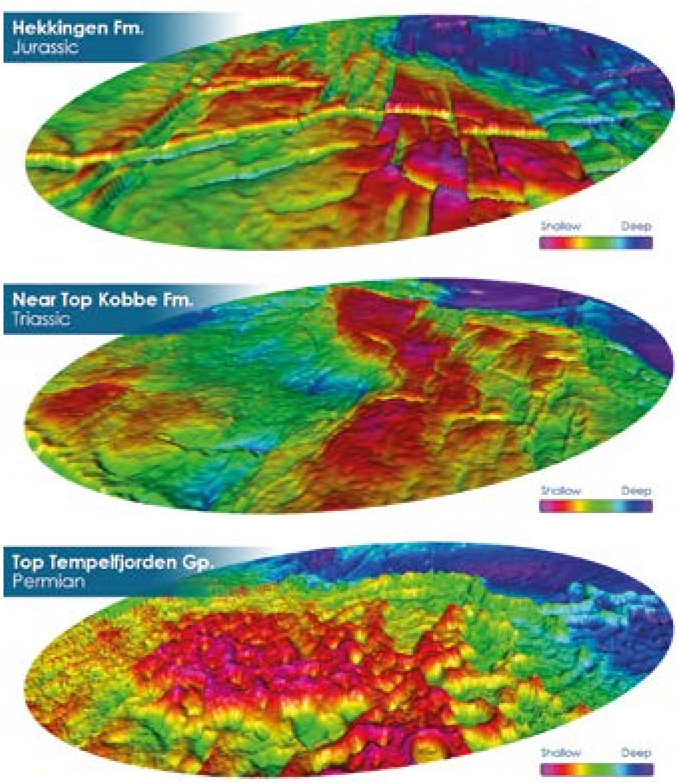


Figure 4: Structural closures mapped in TWT and related hydrocarbon prospects identified.

time, despite the lack of subsidence in the Jurassic and the limited Cretaceous-Paleogene uplift. For this reason oil may have migrated to plays and traps at several different times.

Reservoirs and Prospectivity

The new 3D seismic has allowed the generation of a number of hydrocarbon prospects in various structural traps in both Jurassic and Triassic targets (see Figure 4). The broadband imaging was vital to jointly map the channels and the structural closures. The prospects generated measure tens of square kilometres and have been confirmed by depth conversion.

Additional closures are still well preserved at the Top Permian and at the boundaries of the carbonate sequences. These deeper structures may have hosted the earliest hydrocarbons generated, which eventually re-migrated into younger prospects nearby (Figures 4 and 5).

The Jurassic and Triassic sandstones have been confirmed as the main targets for exploration. Channels and stratigraphic patterns are less faulted and easier to map on the Norsel High when compared to the Norvarg Dome, giving better control on reservoir distribution. Meandering channels have been mapped in the Snadd and Fruholmen Formations (see Figure 5), the channels being approximately 100–150m in thickness and demonstrating a clear meandering geometry.

Regional seals are provided at Top Jurassic by the Hekkingen Formation, while Triassic reservoirs can rely on a number of intra-formational shales for trap seal.

Reassessment of Resources

Spectrum's 3D seismic, broadband processed, enables

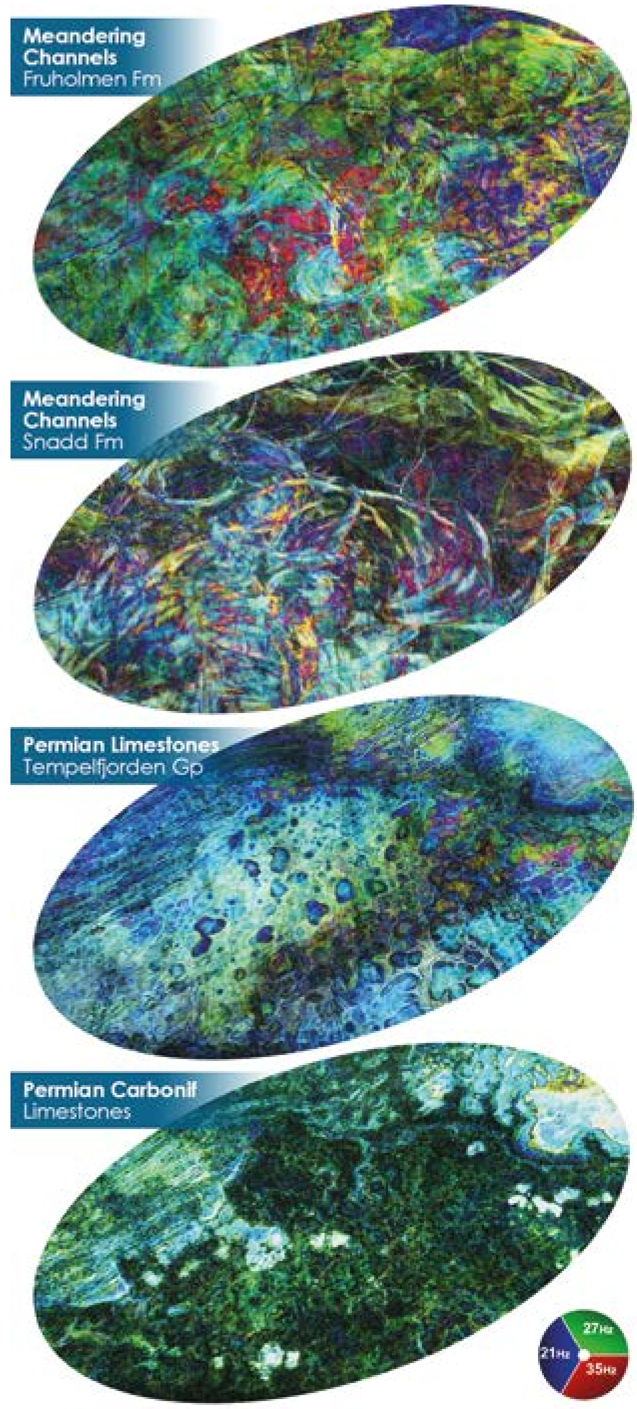


Figure 5: Spectral decomposition and RGB blend of the seismic envelope, extracted at different frequencies and flattened at the main targets (Hekkingen Formation, Kobbe Formation and Top Tempelfjorden Group).

the imaging of reservoir distribution and reservoir connectivity, and allows the reassessment of the hydrocarbon resources, both oil and gas, in the Norsel High area. New prospects have been generated, potentially charged by liquid hydrocarbons from multiple phases of expulsion and migration. Oil legs below gas are considered likely either due to incomplete flushing of early oil or remigration from older deeper structures. *References available online.* ■

Rumaila–West Qurna
A Unique Supergiant Field

Rumaila–West Qurna is one of the world's greatest supergiant oilfields. Having produced for over 60 years, it is believed to still contain 40 Bb of recoverable oil.

MUNIM AL-RAWI PhD, Carta Design Ltd

A supergiant field is one that contains over a billion barrels of recoverable oil. With initial 2P recoverable reserves of 44.4 Bbo and 13.8 Tcfg in multiple stacked reservoirs, the Rumaila–West Qurna field, 50 km west of Basra in southern Iraq definitely falls into that classification. Encompassing an area of 2,400 km^2 and extending 120 km from north to south and up to 20 km across, it is the largest oil and gas field in Iraq and one of the greatest fields in the world.

Multiple Reservoirs Discovered

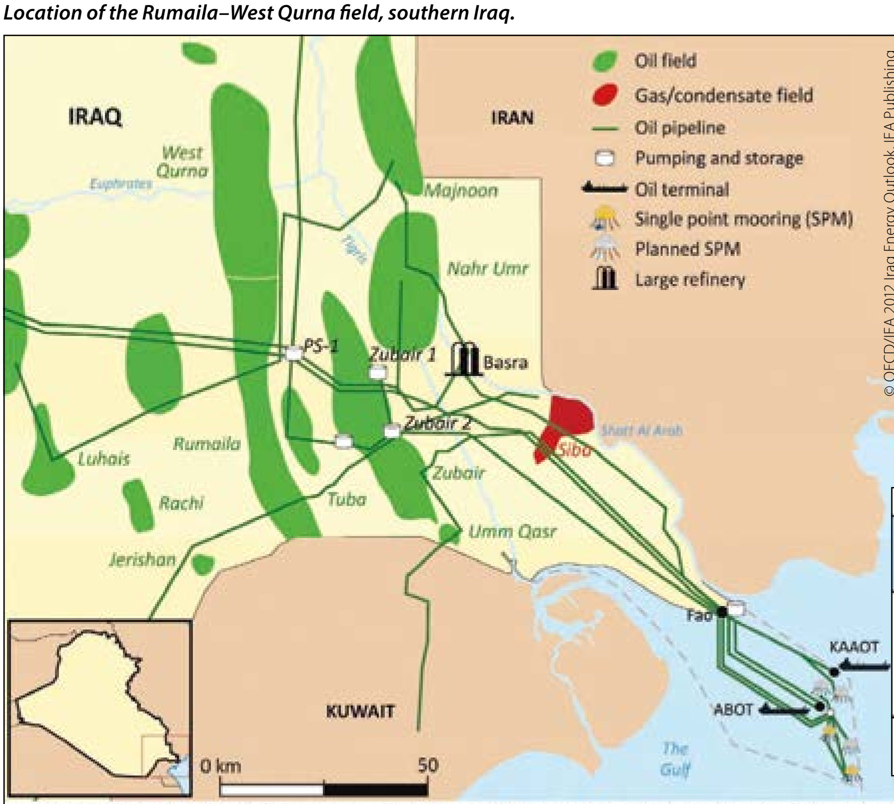
Structurally, this field is an anticline consisting of three domes named, from south to north, South Rumaila, North Rumaila and West Qurna. Most geological structures in southern Iraq were delineated between 1947 and 1949 by seismic surveys carried out by the Basra Petroleum Co. (BPC), part of Iraq Petroleum Company (IPC). The South Rumaila field structure was drilled by BPC in August 1953. Oil flowed from the Lower Cretaceous Zubair sandstone reservoir, (the 'Main Pay'), which had been previously discovered in the neighbouring Zubair field. BPC put South Rumaila into production in 1954.

The North Rumaila structure was drilled in June 1959 as a northern step-out on the Rumaila axis, with the intention of delineating the northern plunge and exploring the extent of the Middle Cretaceous Mishrif carbonate prospects, as well as investigating the Zubair sandstones below the Main Pay. However, this reservoir was found at a higher level than expected; the Mishrif contained a productive oil reservoir; and while the Main Pay was productive, the sandstones below were waterlogged.

BPC drilled another five wells on the structure before suspending drilling at the end of 1961, after the enforcement of Iraq's infamous Law No. 80, whereby the government expropriated 95% of IPC's concessions, temporarily putting a stop to exploration. In 1973 IPC was nationalised and the Iraqi National Oil Company (INOC) took over operations in the Rumaila fields.

In the early '70s a seismic survey confirmed the existence of a third dome on the Rumaila anticlinal axis, separated from North Rumaila by a shallow saddle. This northernmost dome, named West Qurna, was drilled by INOC in October 1973, and major reserves in the Middle Cretaceous Mishrif and Lower Cretaceous Yamama carbonate reservoirs were found. INOC began a deep drilling programme to look at the Yamama and the Jurassic Najmah carbonate reservoirs in the combined field and discovered the Ratawi/Yamama reservoir in 1976, the small Sulaiy reservoir in 1977 and the deeper Najmah reservoir in 1980.

Location of the Rumaila–West Qurna field, southern Iraq.



Additional seismic between 1981 and 1983, and further deep drilling in 1980 and 1983 by INOC confirmed the extension of the Yamama and Najmah reservoirs into the West Qurna field.

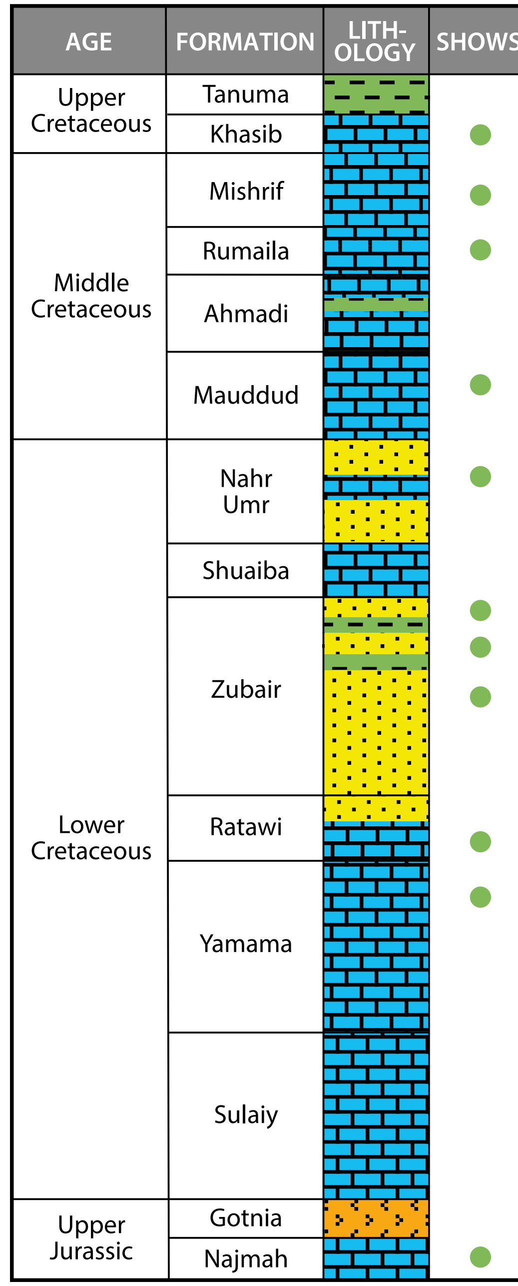
During the years of exploration and delineation from 1953 to 1983, over ten petroleum oil and gas reservoirs , ranging in age from Miocene to Jurassic, were discovered in Rumaila–West Qurna, containing proven oil and gas in place reserves of 125 Bbo and 17 Tcfg.

Anticlinal Structure

The three main domes of the supergiant field are separated by shallow saddles and the structure is tilted gently northwards. West Qurna and North Rumaila trend north-south, while the southern South Rumaila section trends north-north-west – south-south-east and extends southwards into Kuwait as the Ratqa field, where it is producing heavy oil from the Miocene Lower Fars reservoir. The flanks of the anticline dip at 1.5°–5° and are steepest on the western flank of West Qurna and North Rumaila and the eastern flank of South Rumaila. It is tighter at deeper structural levels, dipping 1.5°–3° in the Mishrif and 2.5°–5° in the Yamama Formations.

The crest of the Mishrif reservoir at the three main culminations is at 2,190m (bsl) in West Qurna, 2,130m in North Rumaila and 2,150m in South Rumaila, while the Zubair reservoir is shallowest in South Rumaila at 2,940m, as compared to 2,975m in North Rumaila and 3,070m in West Qurna. At this level the saddle between South Rumaila and North Rumaila has up to 100m of structural relief, but the one between North Rumaila and West Qurna is less pronounced with about 25m relief.

The Yamama reservoir in West Qurna has a crest at 3,515m bsl and the oil column is 46 m thick, with a lowest known oil depth of 3,980m. The shallowest well penetrations of the Yamama in North Rumaila and South Rumaila domes are 3,490m and 3,665m respectively. The reservoir is bottom-sealed by the tight limestones and shales of the Sulaiy Formation. At the top of the Yamama reservoir, the West Qurna Field covers an area of 735 km².



Generalised stratigraphy of the Rumaila–West Qurna field.

Prolific Reservoirs

Only the Mishrif, Zubair and Yamama reservoirs are currently being developed or are producing in the Rumaila–West Qurna field.

Zubair Reservoir: Two reservoir units are present in the Zubair Formation at South Rumaila. The Main Pay (Upper Zubair Sandstone), regarded as one of the most important reservoirs in southern Iraq, came on production at South Rumaila in 1954 and is still producing. It consists of three main sandstone units – AB, DT and LN – which have porosity around 20% and permeability about 600, 1,000 and 850 mD for the three units respectively. They are separated by shale and the net thickness of this reservoir is over 100m of mainly porous sand containing oil with 34° API and a sulphur content of 2 wt%. The hydrocarbons do not contain hydrogen sulphide.

The Upper Zubair Shale Reservoir occurs above the Main Pay where the sandstone units in the upper shale part of the formation have good to moderate reservoir properties, deteriorating northwards where they are replaced by shale in the West Qurna field. The net thickness of this reservoir is 25m, with estimated porosity around 15%. It is not present in North Rumaila.

Mishrif Reservoir: In the North and South Rumaila fields, the Mishrif reservoir is known as the Second Pay and it is regarded as one of the main producing reservoirs in southern Iraq due to its huge reserves. It started producing in South Rumaila in 1975. The Mishrif consists of complex carbonate rocks composed in two units, MA and MB (the main unit), with porosity around 22%. The net reservoir thickness is 25m. There is not enough drive energy in the water aquifer on the flanks of the field, so water injection is required. The oil has 27.8° API and sulphur content is 3.8 wt%. The associated gas contains hydrogen sulphide.

At North Rumaila, Second Pay production started in 1976. In this field the two main units are separated by a barrier unit. The oil is mainly found in unit MB, where porosity is ~16% and permeability 45 mD. This reservoir is regarded as continuous with the South Rumaila field, although with improved reservoir characteristics, particularly towards the north. Oil gravity is 26.3° API and sulphur content is 3.8 wt%, with associated gas containing some hydrogen sulphide. This crude is mixed with the oil in unit LN of the Main Reservoir to form Basra Medium Crude.

Workers at the Rumaila field.

Yamama Reservoir: This formation comprises at least seven recognised units of alternating limestone, each representing a depositional cycle. The upper unit, a thick porous permeable oolitic-peloidal limestone, is the most prolific, although the other units have sporadic oil saturation, while the lowest unit contains heavy tarry oil. The thickness of the limestone unit containing oil is about 77m, with porosity around 14% and water saturation of 40%. Oil gravity is 37° API.The formation passes downward into organic rich black fissile shale (Sulaiy Formation).

The Mishrif reservoir is believed to have held 48 Bbo in place, with 18.2 Bb initial recoverable reserves across the supergiant field, while Zubair had 40.2 Bbo in place and 16.4 Bb initial recoverable reserves. The Yamama reservoir holds 20 Bb of original oil and 5.9 Bb initial recoverable reserves in the North Rumaila and West Qurna fields only.

Field Development and Production

Separate operators were involved in the initial development of the Rumaila–West Qurna fields, resulting in varied production rates.

BPC began producing from both the Mishrif and Zubair reservoirs in Rumaila North and South in 1954 and by early 1962 it had drilled 33 wells in South Rumaila and six in North Rumaila. INOC took over the field operations after full nationalisation in 1973, starting production from West Qurna in 1976. By 1989 it had drilled a total of 221 wells in South Rumaila, 466 in North Rumaila and 266 in the West Qurna field, bringing the total in the whole supergiant field to 1,155. INOC operated the three fields until late 1987 when the Ministry of Oil re-organised it into several specialist operating companies, with Rumaila–West Qurna operated by the South Oil Company (SOC). A further re-organisation in 2017 meant that Rumaila–West Qurna is now operated by the new Basra Oil Company (BOC), in co-operation with international companies.

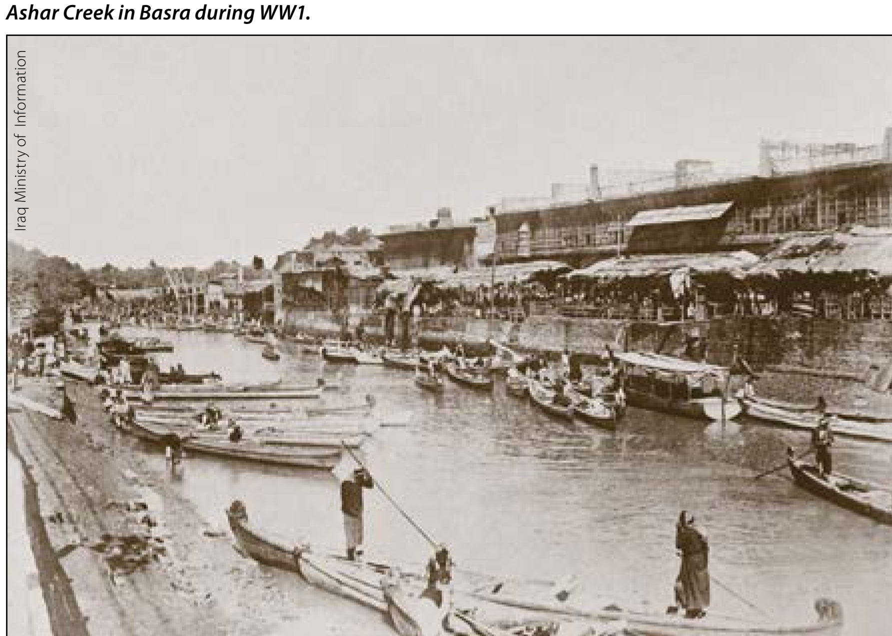
Operations were temporarily halted several times; between 1981 and 1984 during the Iraq-Iran war; from 1991 to 1995 during the conflict and sanctions due to the occupation of Kuwait; and finally in 2003 after the Allied invasion of Iraq.

Although field rehabilitation had resumed, serious development of the huge potential of this unique supergiant field was only realised in 2009 with the award of service contracts during Iraq's First Petroleum Licensing Round. Two licences on the supergiant field were offered in this bidding round, splitting it into Rumaila (North and South) and West Qurna. These called for the development of the producing Mishrif, Zubair and Yamama reservoirs, as well as of other discovered but undeveloped reservoirs, while also exploring for undiscovered potential reservoirs in the licences. In December 2009, West Qurna was divided into West Qurna 1, covering the area of the field north of the Euphrates River, and West Qurna 2 encompassing the area south of the river.

Rumaila Operating Organisation (ROO), composed of BP, PetroChina and BOC, which operates the Rumaila (North and South) licence, reported in December 2016 that oil production at Rumaila is now at its highest rate in 27 years, producing over 1.45 MMbopd, up from 1 MMopd in 2009. Remaining contracted reserves are 17 Bbo.

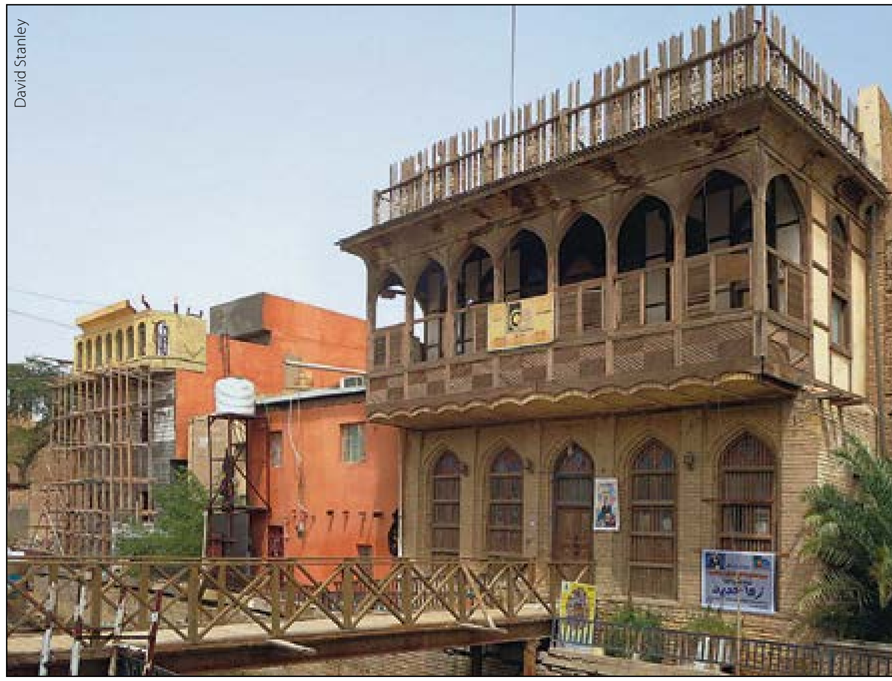
In November 2009 West Qurna 1 was granted to an ExxonMobil-led

Ashar Creek in Basra during WW1.



consortium. The field has contracted recoverable reserves of 8.7 Bbo and currently produces around 405,000 bopd. The West Qurna 2 licence lies in the Hammar marshes area, which was extensively mined with explosives during the three military conflicts between 1989 to 2003. It was granted to a Lukoil-led consortium in 2009. It has contracted recoverable reserves of 14 Bbo and is currently producing around 545,000 bopd.

In 2014 a multibillion-dollar water-injection project to help maintain pressure in the producing reservoirs in fields in southern Iraq, including Rumaila–West Qurna, was awarded to an ExxonMobil-led consortium. The project includes construction of a plant which will help six major oilfield development projects by producing 10–12 MMb (1.6–1.9 MMcm) of water per day.

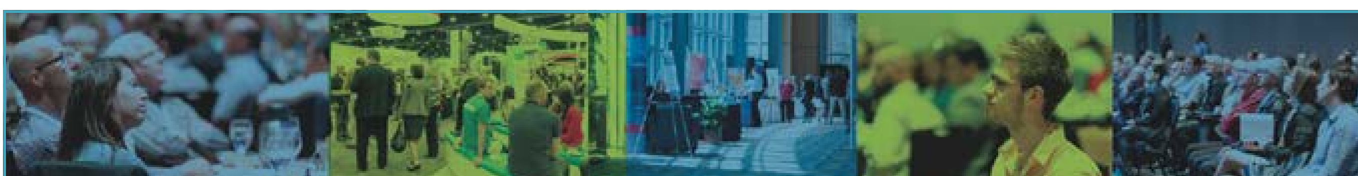

David Stanley

Rumaila – West Qurna is 50 km west of Basra, once regarded as the 'Venice of the East' because of its canals and houses with beautiful wooden balconies, known as Shanasheel.

Plenty of Life Left

Despite having been on stream for over 60 years, it is believed that the Rumaila–West Qurna field still holds around 40 Bb of remaining recoverable reserves in both developed and undeveloped reservoirs. With the lifting of sanctions and the entry of international companies into operating this supergiant, it should be producing for many years yet. That is good news for the economy of Iraq and will hopefully bring thousands of jobs to this underdeveloped region.

References available online. ■



Ichnofabrics: An Invaluable Tool for Sedimentary Geologists

Trace fossils can compensate for a lack of preserved sedimentary structures in core and outcrop studies.

JEAN GÉRARD, Sed-Trace

Bioturbation of sediments is synonymous with bad news for many geologists when they are describing new cores and outcrops, as sedimentary structures can be partly or even completely disrupted by biogenic activity. Nevertheless, trace fossils can provide invaluable information on the environmental conditions that prevailed during or shortly after sediment deposition. As such, recognition and interpretation of trace fossils and their associations, together with analysis of sedimentary and diagenetic structures, can be usefully integrated into modern advanced sedimentological core and outcrop studies.

Like most laboratory or field techniques, ichnology – the study of trace fossils – should not be thought of as a standalone tool, but is best used in the full context of the sedimentary framework. Only then can ichnology provide detailed environmental information that can be related to depositional processes, relative palaeobathymetry and sequence stratigraphy – all essential data for correlating surfaces, sequences and associated reservoirs in industry projects.

Ichnofacies: The Concept

The early successful use of trace fossils was greatly advanced by Adolf Seilacher in the 1960s, who introduced the concept of 'ichnofacies' as a way to split the marine realm into four main zones covering nearshore environments to the deep basin. Additional ichnofacies have since been defined for marine, non-marine and continental environments, producing a refined and comprehensive system.

In the 1970s sequence stratigraphy concepts, first developed on seismic data calibrated by biostratigraphy and core facies analysis, were spreading in both industry and academia. These ideas subsequently promoted the integration of data arising from all techniques, including trace fossil analysis complementary to sedimentology.

The use of ichnofabrics has increased steadily since the concept was first developed in 1984 by Bromley and Ekdale, who defined it as: *"all aspects of the texture and internal structure of a sediment that result from bioturbation at all scales."*

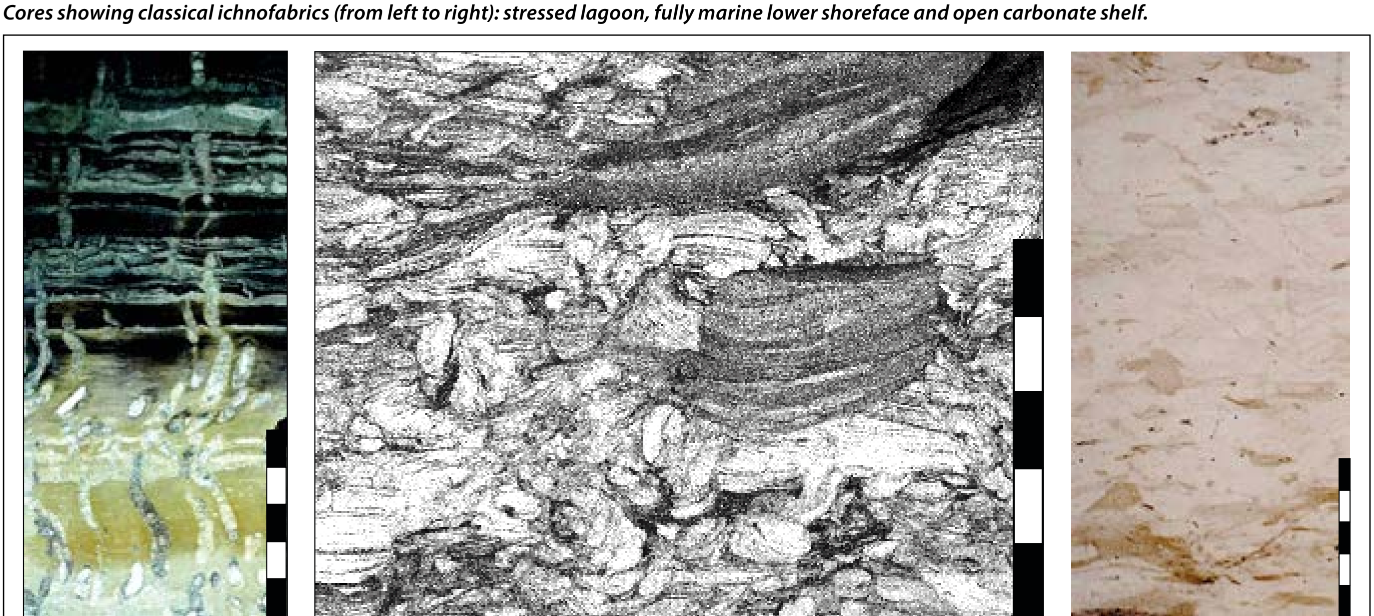
In 1991, the first International Ichnofabric Workshop was hosted by Norsk Hydro in Bergen in Norway. Since then, meetings have been organised every second year to demonstrate applications of ichnofabrics and present case studies to ichnologists, sedimentologists and geologists from both academia and industry.

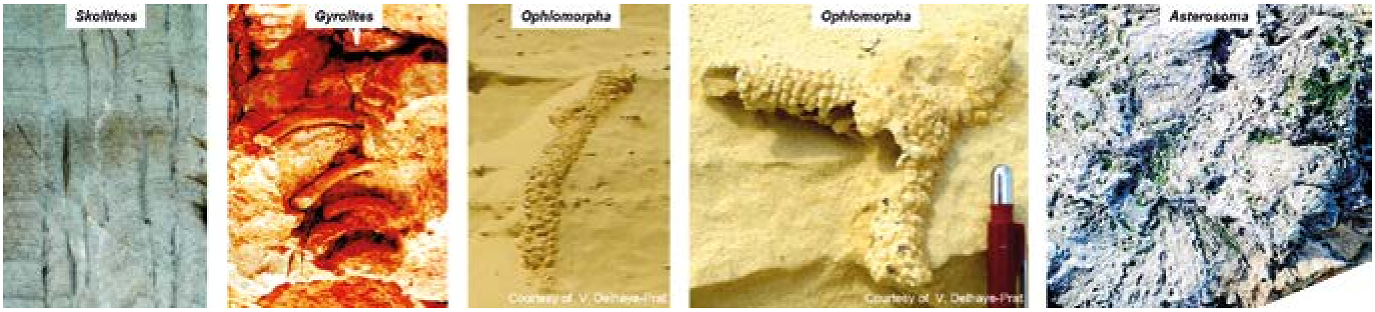
Ichnofabrics in Reservoir Studies

Combining the broader ichnofacies system with detailed ichnofabric analysis has been found to yield a better result than employing the systems separately. Ichnofabrics provide a finer resolution than ichnofacies but neglect the broader picture; they allow not only large third-order cycle recognition but are imperative for the identification of higher frequency cycles (parasequences) by comparing ichnofabric cycles and their vertical stacking.

Ichnofabric techniques involve the identification of trace fossils, the analysis of their cross-cut relationships and their grouping in recurring cycles

Cores showing classical ichnofabrics (from left to right): stressed lagoon, fully marine lower shoreface and open carbonate shelf.





Example of trace fossils from outcrops: a) vertical; b) helical, passive fill; c) vertical, pellet-walled; d) horizontal, branched, pellet-walled; e) rosette-shaped, active fill.

which classically represent either shallowing-upward or deepening-upward trends. This information, which is complementary to classical sedimentary attributes – grain size, sorting, texture, bedding – supply reliable constraints to aid the clearer identification of significant geological surfaces and sequences when correlating wells.

The level of resolution supplied by ichnofabrics is therefore compatible with and comparable to that needed for reservoir characterisation. From a reservoir viewpoint, the impact of bioturbation on early diagenetic fluid flow is being increasingly emphasised, as it may ultimately control micro-scale heterogeneity by enhancing (leaching) or deteriorating (mixing mud and sand or cementing) the reservoir quality of the sediment during burial history.

Trace Fossil Identification

Each trace fossil has a series of characteristics which have been accepted by the International Commission on Zoological Nomenclature. Most of this work, including description, identification and classification (ichnotaxonomy) is based upon analysis of specimens coming from outcrops, although sediment boxes and cores provide additional data.

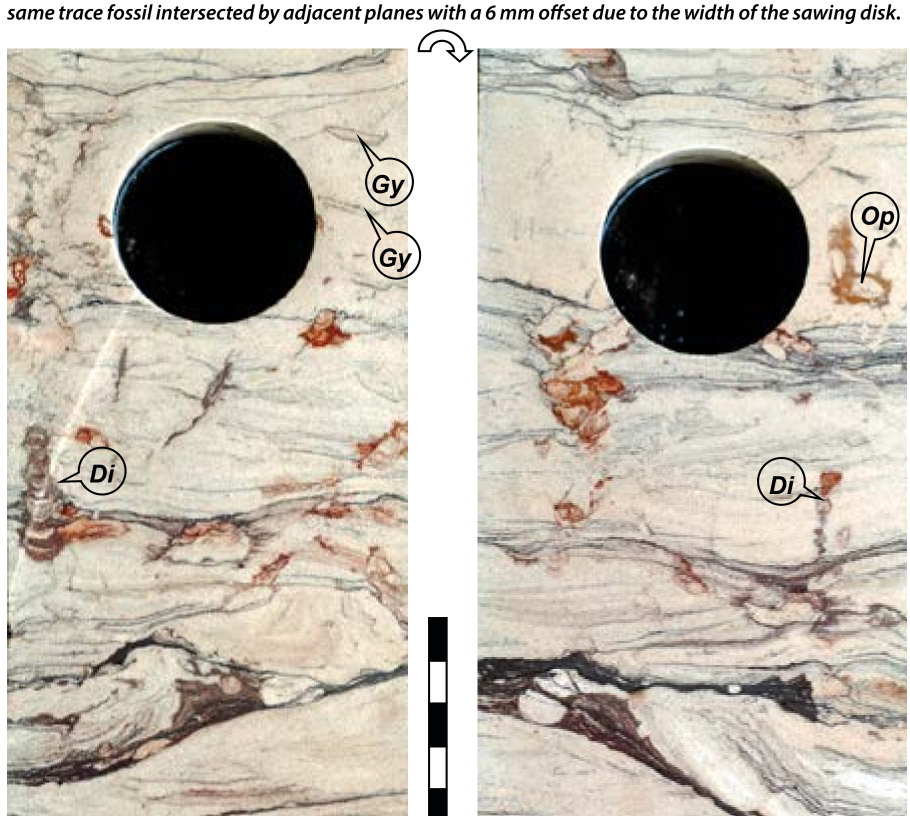
In fully bioturbated rocks, trace fossil identification is more difficult and even impossible, as the burrows cross-cut each other giving rise to all sorts of comments in core rooms when geologists try to describe bioturbated cores: “the sediment is churned, the funny stuff again, the rock is a mess…”

Published diagnostic criteria (see ‘About the Author’) can help sedimentologists in identifying many important burrows common in the rock record. The diagnosis must be established and supported by description (shape and size), substrate and behaviour, the most common depositional environments, ichnofabrics occurrence, ichnofacies and the age for each trace fossil. Forms and structures of the burrows vary in response to the type of substrate, which induces changes in the behaviour of the trace makers. Each type of trace fossil shows a few classical sections – although uncommon views of the burrows might just reflect an increasing complexity, such as branching, meandering or twisting.

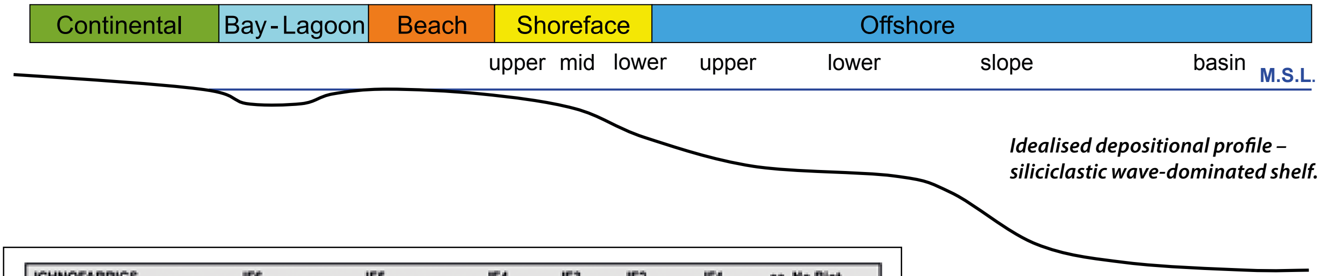
Ichnofabrics for Depositional Environment Interpretation

Identification of trace fossils and their grouping into different trace fossil associations or ichnofabrics can be distinguished on the basis of cross-cutting relationships between the ichnotaxa within each trace fossil association, which reveals the tiering pattern and thereby the tiered structure of the endobenthic community. Ichnofabrics from similar depositional settings generally show recurring patterns, which can be related to specific depositional environments, spanning from the continental realm to deep seas.

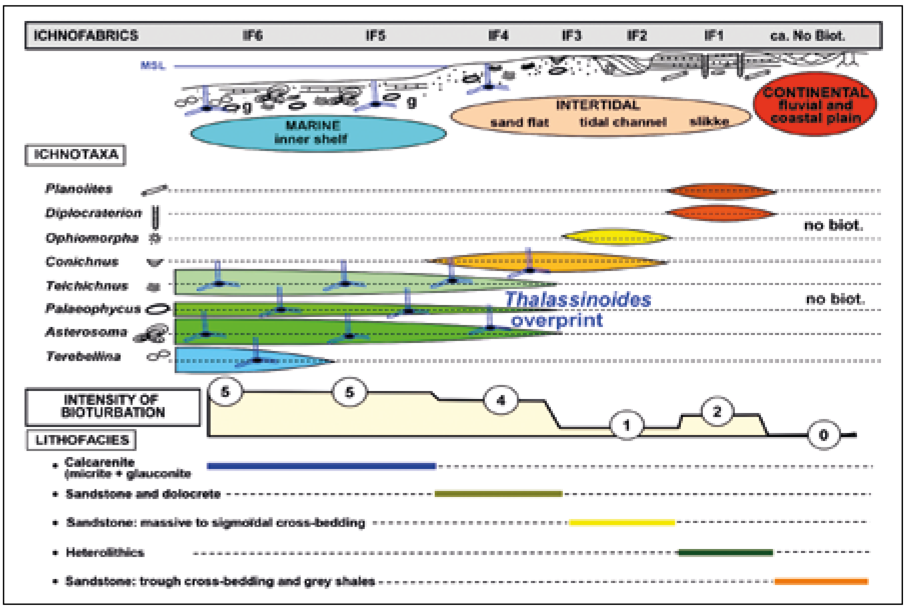
A series of classic ichnofabrics ranging from the terrestrial zone to deep water has been identified, although complications arise when



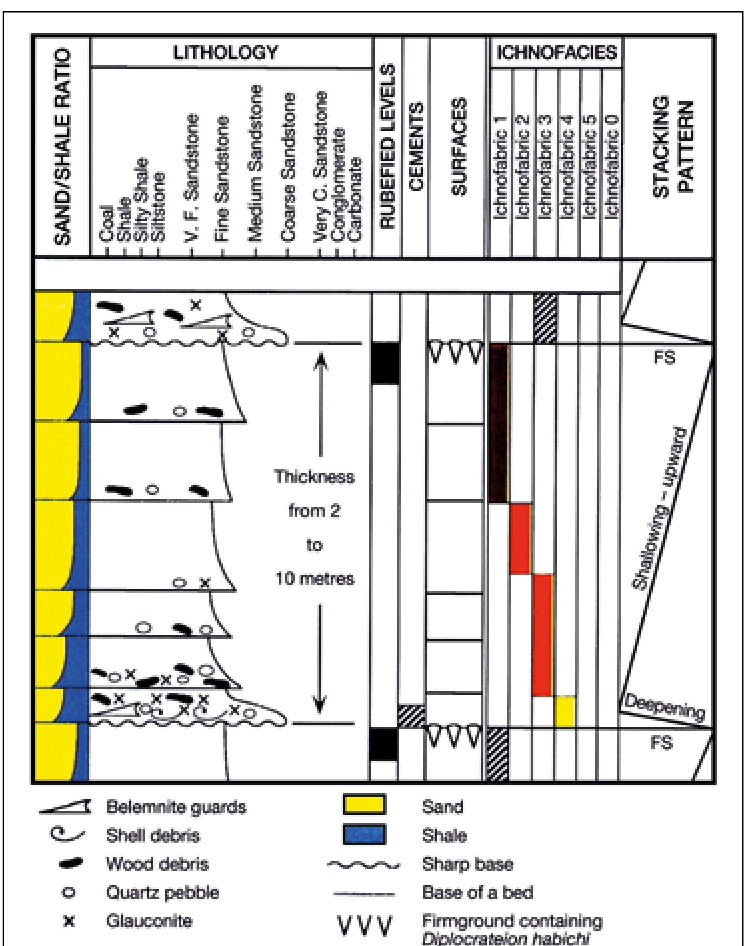
Trace fossils are physical structures that can display highly variable images when intersected by planes or cylindrical surfaces. These two surfaces from a slabbed core show very different surfaces for the same trace fossil intersected by adjacent planes with a 6 mm offset due to the width of the sawing disk.



Idealised depositional profile – siliciclastic wave-dominated shelf.



Summary diagram showing the depositional profile and ichnotaxa occurrence.



An example of a genetic sequence.

directly comparing Palaeozoic with Cenozoic ichnofabrics, as tracemakers have evolved through geological times. Nevertheless, the animal and vegetal communities adapt to physical processes such as currents, tides, waves and storms. Chemical, oxygen and redox conditions, for instance, affect the distribution of animals and algae in the different realms of the earth. Species occurrence grades from absent, where conditions are hostile, to present and even abundant if conditions allow blooming of the community. Community diversity may be very low and eventually limited to a monospecific colonisation if stressed and hostile conditions favour the development of only one type of animal and prevent other species from occupying the biotope. On the other hand, diverse ichnofabrics indicate steady environmental conditions which provide equilibrium to the community.

Distribution and Depositional Profile Interpretation

A case study from the Late Jurassic is an example of interpretation of the depositional profile based upon the relationship between ichnotaxa, bioturbation index and lithofacies. The summary diagram clearly indicates that ichnofabric examination is a building block in the sedimentary analysis. Lithofacies must be analysed first: grain size, sorting, texture and sedimentary structures. Intensity of bioturbation must be quantified, followed by the identification of burrows and their grouping into recurring ichnofabrics.

Compilation of all the analytical data supports the reconstruction of the depositional profile as it passes from non-bioturbated continental deposits to intertidal domain to marine open shelf. Transgressive surfaces are highlighted by colonisation of the back-stepping seafloor by crustaceans during transgressive pulses at the base of each parasequence (flooding surface).

Identification of a Genetic Depositional Sequence

In a large correlation project with abundant core data recurring ichnofabrics were observed and compared between twenty wells. Sequences show stacked decimetre to metre scale fining-upward beds bounded by a sharp base, although bioturbation sometimes make the identification of the contact difficult. The facies succession within a bed shows a cleaning-upward pattern associated with an upward dilution of the glauconite grains, coarse quartz grains and wood debris. At the base of the beds, shell debris may also be found.

Common coarsening-upward beds with mud drapes are interpreted as sigmoidal cross-bedded sediments from sub-tidal bars. Coarsening-upward cycles, based on the analysis of both facies succession and ichnofabrics, are interpreted as the genetic depositional sequences. The ichnofabrics evolution from base to top shows which can be interpreted as shallowing-upward cycles. Abundant deep burrows, *Diplocraterion habichi*, commonly occur at the top of these cycles and are interpreted to be indicative of firm ground colonisation.

The cycles are frequently bounded by early-diagenetic siderite-cemented horizons or 'rubified levels' that are indicative of early precipitation of iron in the upper part of the sediment, recording a depositional break.

Another Useful Tool

Sedimentological core studies dedicated to reservoir description, characterisation and correlation are better achieved when combined with other techniques, including ichnofabric techniques, particularly when sedimentary rocks lack diagnostic sedimentary structures as a result of intense bioturbation. Nevertheless, ichnology should not be used as a standalone technique, but as another tool available to sedimentologists who need to use it to describe complicated bioturbated sections rather than avoiding them.

No need for "the funny stuff again, the rock is a mess" anymore; there is information in there! ■

About the Author

Jean Gérard is a predictive stratigraphy specialist based in Madrid, Spain. This article includes selected examples from the atlas he wrote with Richard Bromley: *Ichnofabrics in clastic sediments. Applications to sedimentological core studies. A practical guide.* Published in 2008, the atlas is dedicated to the practical use of trace fossils and ichnofabrics for both sedimentological and sequence analysis purposes and provides guidelines to MSc and PhD students, researchers and industry geologists keen to broaden their skills and discover and apply ichnofabric techniques. The authors have collected and published outstanding core photos and sedimentological and reservoir case studies. The atlas has been translated into Chinese.

Students and new professionals are showing a growing interest in trace fossil applications and ichnofabric techniques. In 2015, the British Sedimentological Research Group organised a 2-day workshop hosted by the University of Manchester, attended by a group of nearly thirty PhD students, post-docs and young professionals. A combination of lectures and hands-on core exercises gave participants the opportunity to apply ichnofabrics to core description.

Jean Gérard

An Introduction to Deep Learning: Part III

LASSE AMUNDSEN, HONGBO ZHOU and MARTIN LANDRØ

There's this idea that ideas in science are a bit like epidemics of viruses. There are apparently five or six basic strains of flu viruses, and apparently each one comes back with a period of around 25 years. People get infected, and they develop an immune response, and so they don't get infected for the next 25 years. And then there is a new generation that is ready to be infected by the same strain of virus. In science, people fall in love with an idea, get excited about it, hammer it to death, and then get immunized – they get tired of it. So ideas should have the same kind of periodicity.

Tomaso Armando Poggio (1947–), Professor of MIT Brain and Cognitive Sciences, and Director of The Center for Brains, Minds and Machines.

We learn by doing, Aristotle (384–322 BC) told us. Today, experiential learning does not apply just to children; computers and robots are increasingly able to act and adapt based on experience. Most successes so far in deep learning have been based on supervised learning. The holy grail, however, is unsupervised learning, as illustrated here by five-year-old girls figuring out how to row a boat. In the unsupervised approach, the computer program figures out what the data means on its own. It may detect characteristics that humans cannot see.

Lasse Amundsen

Previously in this series we showed that deep learning is nothing other than neural networks – an approach to artificial intelligence (AI) which has been going in and out of fashion since the 1950s. Deep learning is a 'strain of virus', and since 2012 it has returned with great excitement and speed, accelerated by the increased processing power of graphics chips – as well as Big Data (all the images, videos, emails, driving patterns, phrases, objects and so on that are used to train the networks).

Examples of AI systems utilising deep learning range from speech recognisers on smartphones and automatic translators, to the technology behind driverless cars, enabling them to identify a stop sign or to distinguish a pedestrian from a lamppost. Current automated driving development requires millions of images and thousands of hours of video to train the neural network. Many automakers have announced plans to offer fully automated cars in the future. The driverless car is coming, but will we actually want to cede control?

Part II of this series mentioned a deep learning computer model that learns to perform classification tasks directly from images. The one that started it all was the 2012 publication 'ImageNet Classification with Deep Convolutional Networks' by Krizhevsky, Sutskever and Hinton, which discussed the architecture of the network, called AlexNet. They used a relatively simple layout, compared to modern architectures. The network was made up of only eight layers, where the first five were convolutional layers followed by fully connected layers.

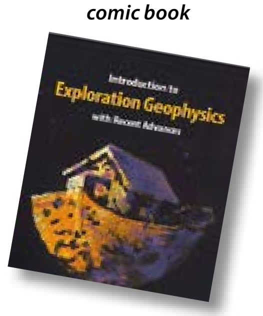
Deep Learning with MATLAB

Here, we show that you can apply deep learning with MATLAB using AlexNet: it is not perfect, but it is fun. MATLAB is a numerical computing environment with over 2 million users across industry and academia. One of MATLAB's developers has made a demonstration of how to apply deep learning in just 11 lines of code, which sets up your web camera to perform object recognition. First, the camera acquires images, then AlexNet takes the image as input and provides a label for the object in the image. All you need to do is to download the webcam support package and the AlexNet support package into MATLAB.

Let us experiment with objects in our surroundings to see how accurate AlexNet is. The first object that we let the webcam see is a pile of bananas. It is easily recognised by AlexNet. In the second example, we put a Powerpoint-made page of the cover of the book *Introduction to Exploration Geophysics with Recent Advances* in front of the webcam. AlexNet now suggests "comic book". The authors of the book are amazed that AlexNet recognises this is a book. Perhaps it is comic, too? It is up to the readers to judge.

bananas

comic book




```
clear

camera = webcam; % Connect to the camera
nnet = alexnet;  % Load the neural net

while true
   picture = camera.snapshot;                % Take a picture
   picture = imresize(picture,[227,227]);    % Resize the picture

   label = classify(nnet,picture);           % Classify the picture

   image(picture);      % Show the picture
   title(char(label));  % Show the label
   drawnow;
end
```

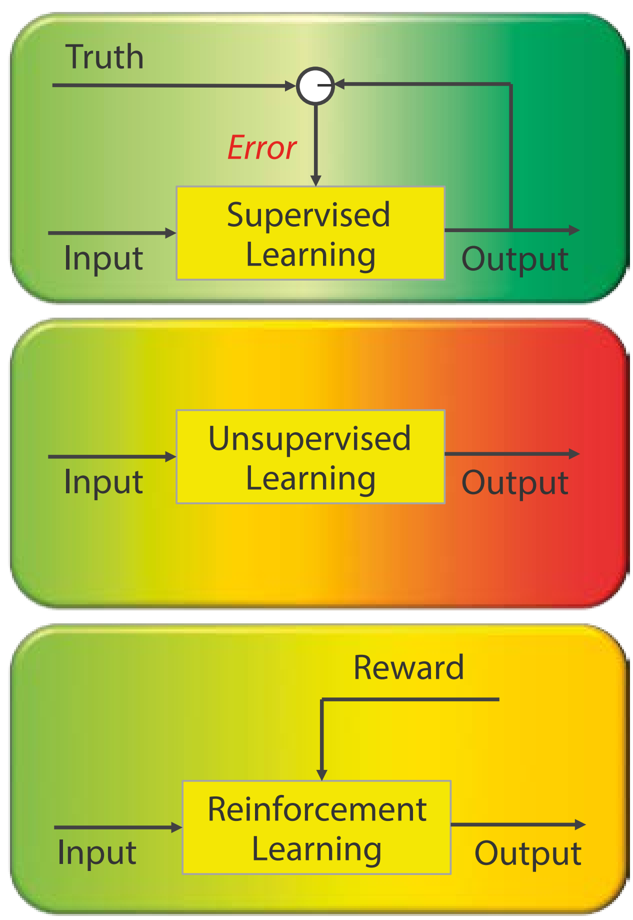
Deep learning in 11 lines of MATLAB code. All you need is MATLAB, a simple webcam, and a deep neural network – AlexNet – to identify objects in your surroundings (Hicklin, 2017). A few years ago, this example would have been considered science fiction.

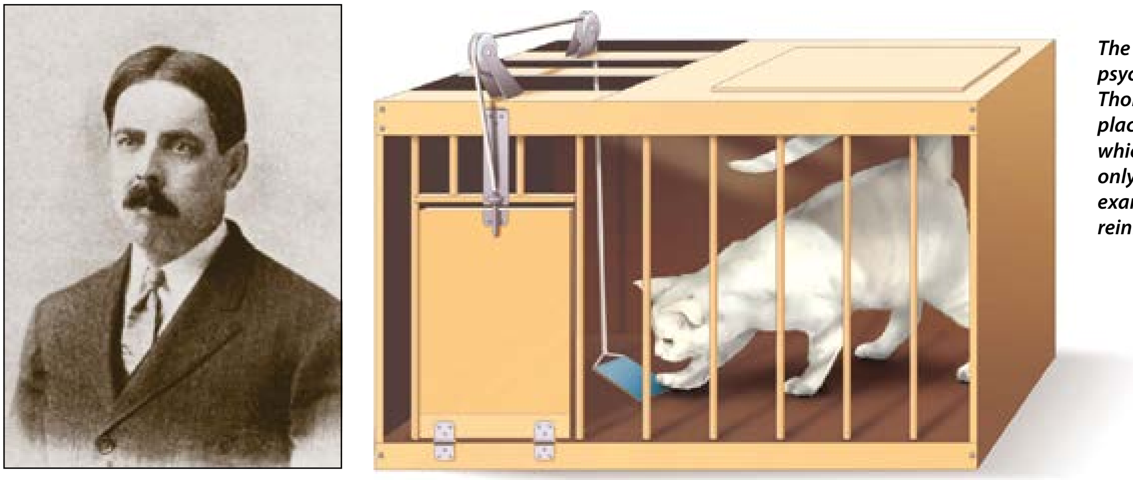
Supervised Learning

In Part II, we briefly discussed how deep learning can be used in supervised learning, in reinforcement learning, and in unsupervised learning.

In supervised learning, during training, data are fed to the network but have been painstakingly labelled in advance. This process can be thought of as a 'teacher' supervising the learning process. The teacher knows the correct answers, the algorithm iteratively makes predictions on the training

Supervised learning relies on data where the true class of the data (truth) is given. Unsupervised learning means that the deep learning algorithm does not have any labels attached to supervise the learning. Reinforcement learning focuses on the end outcome to learn. A reward function is provided that tells how 'good' certain states are.





The American behaviourist psychologist, Edward Lee Thorndike (1874–1949), placed cats inside boxes from which they could escape only by pressing a lever, to examine the phenomenon of reinforcement in learning.

data and is corrected by the teacher. Learning stops when the algorithm achieves an acceptable level of performance. For example, to train a neural network to identify pictures of bananas, it needs to be fed images that are labelled bananas. The network finds what all pictures labelled banana have in common, so they can eventually use those recognised patterns to more accurately predict what they are seeing in new images. The more labelled pictures the network sees, the better it can refine the accuracy of its predictions.

Supervised learning has shown impressive results for image recognition. For instance, Facebook's deep learning software is able to match two images of an unfamiliar person at the same level of accuracy as a human. Researchers from Stanford University in January 2017 published a deep learning algorithm that recognises skin cancer in photos as well as dermatologists do. It was built on the architecture of the GoogleNet Inception v3, a convolutional neural network algorithm, and trained on a set of nearly 130,000 images of skin lesions from more than 2,000 diseases. In the future, might you test skin anomalies with your smart phone?

Astrophysicists search the galactic sky for exoplanets (planets outside our own solar system) by analysing large amounts of data from NASA's Kepler Space Telescope with both automated software and manual analysis. Kepler observed about 200,000 stars for four years, taking one picture every 30 minutes, creating about 14 billion data points. The data points essentially are light readings – the minuscule change in brightness captured when a planet passed in front of a star.

Researchers from Google and University of Texas at Austin announced in December 2017 that a deep learning algorithm had discovered two new planets, Kepler 80g and Kepler 90i. The algorithm was trained on 15,000 signals from potential planets in the Kepler database. When the scientists tested their model on signals it had never seen before, it correctly identified which signals were planets and which signals were not planets 96% of the time. Then, the scientists took the trained system and set it to hunt for new planets on data from 670 stars that were already known to have multiple planets, as they considered those to be the most likely hiding places. Interestingly, the planet Kepler 90i is the eighth planet discovered orbiting the Kepler-90 star, making it the first known eight-planet system outside our own solar system.

Maximising Rewards

Reinforcement learning is the problem of getting the computer program to act so as to maximise its rewards. This learning copies a simple principle from nature. The American psychologist Edward Lee Thorndike (1874–1949) placed cats inside boxes from which they could escape only by pressing a lever. After wandering around restlessly and meowing, the cat would eventually step on the lever by chance. After it learned to associate this behaviour with the desired outcome – open door and food outside – it eventually escaped with increasing speed. Thorndike put forward the 'law of effect', stating that rewards for appropriate behaviour always substantially strengthened associations (connections), whereas punishments for inappropriate responses only slightly weakened the association between the stimulus and the wrong response. We can use a similar method to train computers to do many tasks.

DeepMind's AlphaGo computer program that astonishingly beat the world Go champion in 2016 (see Part II) was largely based on reinforcement learning and Monte Carlo tree search. Recently, a descendant of AlphaGo, dubbed AlphaGo Zero (now AlphaZero) because it didn't need any human input, achieved tabula rasa superhuman performance in the game of Go, by representing Go knowledge using deep convolutional neural networks, trained

AlphaGo Zero can beat all opponents in the game of Go, trained solely by reinforcement learning from games of self-play.

solely by reinforcement learning from games of self-play. In December 2017, starting from random play, and given no domain knowledge except the game rules, researchers from DeepMind reported that AlphaZero crushed the current world champion chess-playing program, Stockfish 8. In 100 games AlphaZero scored 25 wins and 25 draws with White, while with Black it scored 3 wins and 47 draws. The chess world was shaken.

Reinforcement learning will soon be applicable to more than games. In addition to improving self-driving cars, the technology can now get a robot to grasp objects it has never seen before. But there are challenges to overcome. This learning approach requires huge amounts of data. Successes have come when the computer was able to practise relentlessly in simulations.

Unsupervised Learning

In unsupervised learning, there are no correct answers and no teacher. Algorithms are left to their own devices to dive into the data to discover alone, looking for patterns and connections, and structures in the data. An example of unsupervised learning is: we have lots of photos of N people. There is no information who is in which photo. We want to divide this dataset into N piles, each with photos of one individual.

In 2012, Google demonstrated a deep learning network that was able to decipher cats, faces and other objects from a giant pile of unlabelled images. Unfortunately, so far, unsupervised learning cannot compete or match the accuracy and effectiveness of supervised training. The new buzz word that seems to replace unsupervised learning is 'predictive learning'. Predictive learning is like the astrophysicist's dark matter. Dark matter does not emit or absorb light. We know it is there, but we just do not know how to see it directly.

The Future

Deep learning has had many impressive successes, primarily in image and text recognition, and board gaming. But deep learning is only a small part of machine learning, which is a small part of artificial intelligence. The future of AI may explore ways beyond deep learning. Most of the important learning we do as humans is experiential – and unsupervised. Just think about it. Or look at the picture of the two girls rowing. You teach your children plenty, but after all, their most important learning is unsupervised. Just like humans, we expect that computers and robots will continue to improve as they learn… unsupervised… by doing. When we say that neural networks mimic the brain, that is true at the level of loose inspiration. To build true AI, computer scientists need a better model of how the biological brain works.

References available online.

Download the webcam support package from here: https://www.mathworks.com/matlabcentral/fileexchange/45182-matlab-support-package-for-usb-webcams

Download the AlexNet support package from here: https://www.mathworks.com/matlabcentral/fileexchange/59133-neural-network-toolbox-tm--model-for-alexnet-network ■

Donald Rusk:
Adventures in Exploration

JANE WHALEY

Geologist Donald Rusk has analysed petroleum prospects from over 170 basins in an amazing 67 countries, in the process helping to discover 18 commercial oil or gas fields. He tells about his 60-year career in exploration.

It is probably easier to ask Don Rusk where in the world he hasn't looked for hydrocarbons than to ask him to list all the countries he has worked in during an oil industry career which has spanned six and a half decades. They circle the globe, from Greenland to Madagascar and from Morocco to Sumatra. Yet, perhaps surprisingly, geology wasn't his first choice of career when he completed his national service in the US Navy in 1948.

"I wanted to be an architect. So I enrolled in the prestigious Illinois Institute of Technology, but although I liked the artistic aspect, I wasn't sure it was the right job for me," Don explains. "I considered engineering – and then I discovered the mystery of rocks, and the range of disciplines involved in studying them, and the opportunities for travel. So geology it was!"

Jungle, Mountains and Desert

Travel was always one of Don's ambitions, so after obtaining his degree from the University of Colorado in Boulder, he decided against further study and took a job in Venezuela with Creole Petroleum, part of Standard Oil New Jersey (now Exxon). "I spent a lot of time in the jungle looking for outcrops; a difficult task, since most exposures were at the edge of streams or on the stream bed. Also, I 'sat' wells, logging the lithology of drill cuttings and oil shows," he adds. "It was not only very good experience for a young geologist, it was essential preparation for my career; I was constantly learning new things. I worked a rota of seven weeks in the field, followed by a week in Caracas, where, of course, I had a wonderful time."

Bitten by the travel bug, after three years in Venezuela Don resigned and headed for Europe, where he spent the next three years travelling from country to country – and skiing in the Alps. "I had a small job selling books and hiring people to sell them at US Army bases. This was consistent with my desire to travel and ongoing study of Europe (I speak a useful amount of Italian, French and Spanish). There wasn't much money in book sales, but it enabled me to stay in Europe. Finally, after more than three years there, I decided it was time to go back to geology."

Because he had voluntarily quit his job in Venezuela he could not go back to work for Exxon. However, Exxon Exploration V.P. Bill Wallis suggested he contact Chris

Jane Whaley

Dome, who was setting up a new international oil company, affiliated with Standard Oil Indiana (Amoco). Don went to see him, explained his work experience in Venezuela, and was offered the job. "I considered the offer for a week and then said yes; and the next thing I knew, I was on my way to Libya and the desert! Chris Dome was exceptional at leasing highly prospective concessions, including, for example, in Egypt, Iran, Trinidad and the UK North Sea. When BP bought Amoco in 1998 about 90% of Amoco production, at that time, came from fields which had been discovered under Dome's watch.

"Libya was a wonderful, flourishing place in 1958," he continues. "King Idris was in charge, but the influence of the Italians, who had colonised the country, was also evident. It was a very open society and Tripoli was especially welcoming, with a wide range of nationalities living there. I spent six years in Libya and enjoyed life a lot, even though I was spending most of my time on well sites. In Tripoli there were several expat clubs along the beautiful coast, where I played tennis. If I had enough days off, I would fly to Rome."

Challenging Exploration

Don's Libya assignment was followed by a transfer to Aden, Yemen, which was not as much fun! "At that time Yemen was a British Protectorate and there was active anti-British terrorism," he explains. "Mostly, we were doing geological and geophysical analysis for well recommendations. In the desert we often had to explain to well-armed tribesmen what we were doing and why! On a couple of occasions, the Amoco staff were invited to desert banquets by Yemeni Sheikhs and their guards, along with several Saudi princes. After 13 months in Yemen, in late 1965, I was quite pleased to be transferred to Sumatra, Indonesia."

It was back to the jungle, "but this time with elephants and monkeys. And each month, after 20 days in the large jungle camp, all Amoco staff had ten days of quality living in fascinating Singapore." Don enjoyed his work in Sumatra, although it was very challenging, as he explains: "There were no outcrops, and in addition moving seismic equipment and drilling rigs was extremely difficult. On the other hand, our camp was very good: adequate living, eating and working facilities for all expatriate and local staff.

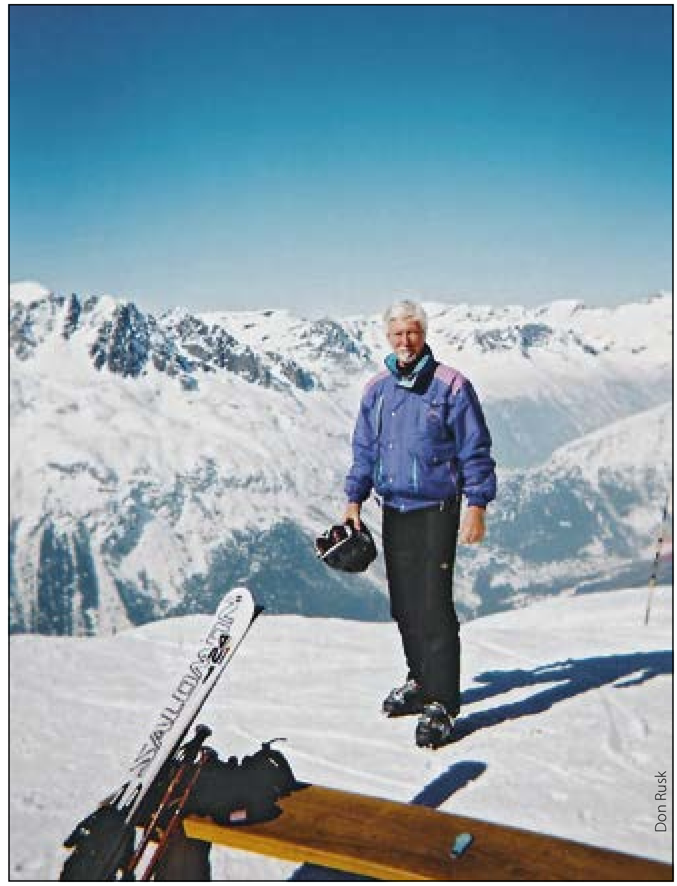
"Our database for mapping prospects was basically regional maps and well data. Fortunately, we were able trade for many Caltex wells, because Caltex concessions, with six or seven oil fields, surrounded the Amoco blocks. However, after five dry holes, Amoco left Sumatra. It turned out to be too soon; within several years, four oil field discoveries were made in the area we left.

"One of the best things about this posting was access to travel throughout South East Asia: I visited Cambodia, Hong Kong, Malaysia and Thailand."

After Sumatra, in early 1967, Don was transferred to London.

Worldwide New Ventures

Having spent a year in London working on North Sea block evaluations and gas field reservoir studies, Don finally returned to the US, as a senior staff geologist in Amoco's



An enthusiastic skier since his student days, Don was actively skiing until well into his eighties.

Chicago office. But the urge to travel had not disappeared, and by 1975 Don was back in London, heading up a New Ventures team, "this time with a wife and two babies in tow!" In this role he planned and managed exploration operations, projects, and new ventures in seven countries, covering large licences. He was supervising a professional staff of 16 geoscientists. "We successfully doubled Amoco's activity in the region in two years, moving into low key but ultimately successful areas like Ireland, Greenland and Italy. But there was still time for enjoyment; every year we went skiing in Austria, always meeting old friends."

Don continued working in New Ventures when he returned to Chicago in mid-1978. In 1981, he and the rest of the New Ventures team were transferred to Houston, which is still his home. "This was an exciting time to be in New Ventures," he tells me. "Amoco assembled a number of top, experienced geologists for the team and together we worked on some interesting projects, usually at the request of the Amoco Board of Directors. One project the Board requested was: 'What country, with excellent oil potential and where we can acquire licences, will give us good returns over a number of years?' Our answer was Libya, since a previous project had been to rank all the countries and the basins of the world, and Libya and Russia had come up top. I also led a team which produced a major report on the petroleum geology and plate reconstruction of the Western Tethys."

By the late 1980s, however, the industry was going through a bad time. "The first layoffs were in 1986, and it was

Don working with geological maps in his home office.

unfortunate," Don says. "Often it seemed that the quiet people who did their jobs without making much fuss were the ones who were laid off." Finally, in Dec.1989, after 31 years with Amoco – and with an offer to supervise a major petroleum study on Libya – Don decided to "take the package and retire."

Libya Expert

Masera Corp., an established producer of petroleum reports, funded the Libya report and provided Don and his staff with access to a huge amount of data. The study, published in 1992, included a comprehensive text and more than 200 enclosures, charts and appendices. It was very successful, selling about 35 copies (at $95,000 each!) and is still considered by many to be the definitive study on the petroleum potential of Libya.

"This gave me a reputation as a Libya expert." He explains, "I returned to the country a number of times up until 2005, as a consultant on exploration projects, evaluations and block selection for several companies. I am fond of Libya, and it is so sad to see the state it is in now. I am sure in time things will improve, but it will take years."

Having been a consultant now for nearly 28 years, Don has worked on E&P projects in many countries in addition to Libya, including Algeria, Ecuador, France, Hungary, Jordan, Liberia, Malta, Mozambique, Morocco, Sierra Leone, Syria and Turkey. He has also undertaken general studies of Africa and the Circum-Mediterranean, including co-authoring a major evaluation and regional study of the nine basins offshore southern Tanzania, Madagascar, Mozambique and Comoros; a region he has visited several times since his first trip there in the '80s. "I appreciate the way they do business there – it's similar to the Arab 'style'," he explains. "The first time you meet, there is no business talk; you just chat about the country and pass the time of day, and that can happen for a few meetings, before you get down to business."

A Few Tips

So with this wealth of experience in the industry, what tips would Don like to pass on?

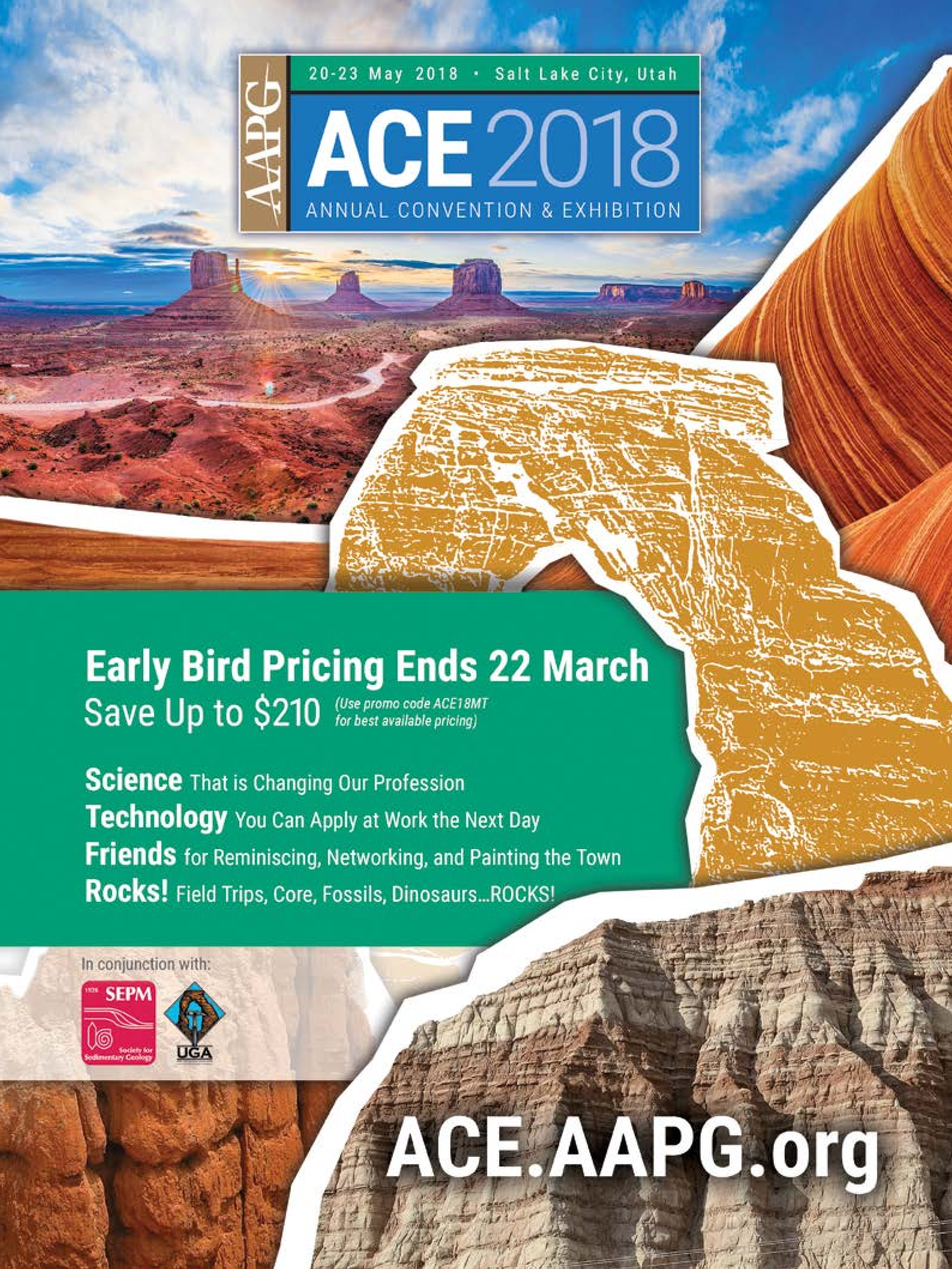
He says, "I think the industry is going in several different directions at the moment; there is a need to keep in a prepared mode; any given change may be an opportunity."

Also, he says that good middle management appears limited in many oil companies; often, they are just not getting the best out of their staff; probably a communication problem.

"Another thing I like to stress to all geologists is, when evaluating an area, do not ignore anything about the project that you are working on; everything must be looked into, including 20-year-old reports and old seismic," he says. "Also, find out who else has worked on this data and see what they had to say. I am also a believer in field work wherever possible. Younger people will say to me 'We've got great 3D seismic over that area, why do we need field work?' But to successfully evaluate a new ventures area, you must use all the data and options available.

"Finally, consider what you may be doing in the future, and where; be prepared!" ■

Don with his wife, Dayle, and Larry Luebke, geologist; a longtime friend at Amoco in the early '80s.



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Deepwater West African 3D Seismic Data

There is renewed exploration interest in the prospective offshore Equatorial Guinea area.

Multiple 3D data volumes are available which have been designed to explore Equatorial Guinea's distal hydrocarbon systems down-dip of proven hydrocarbons (oil and gas) in both the Lower Miocene and Upper Cretaceous-Paleogene plays. Geoex's 3D multi-client surveys cover over 8,400 km² and shed further light on the prospectivity of this fascinating region.

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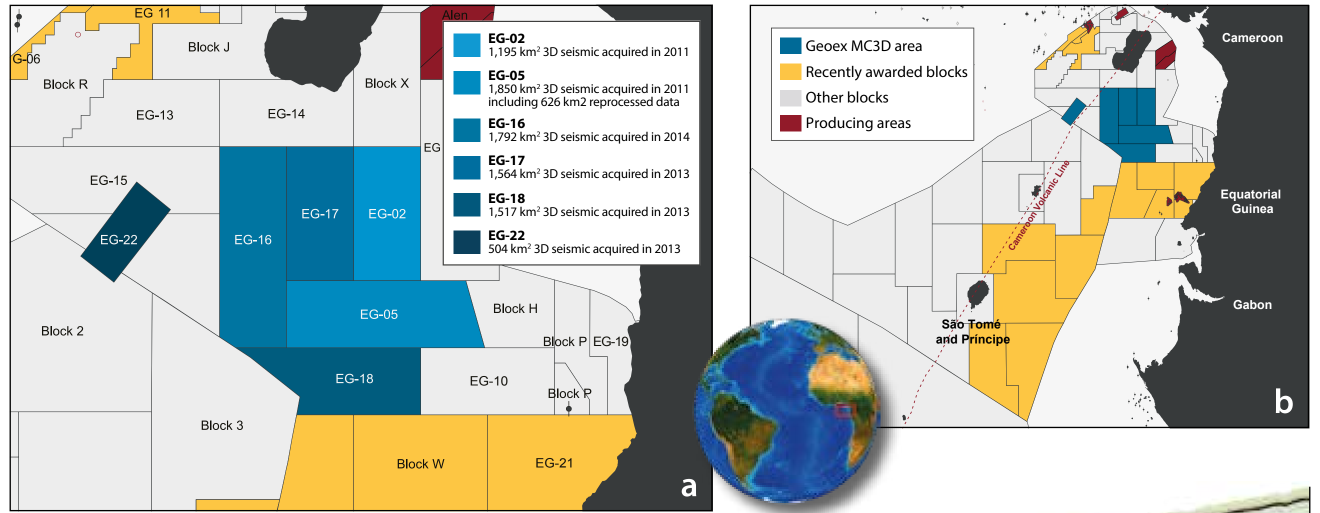
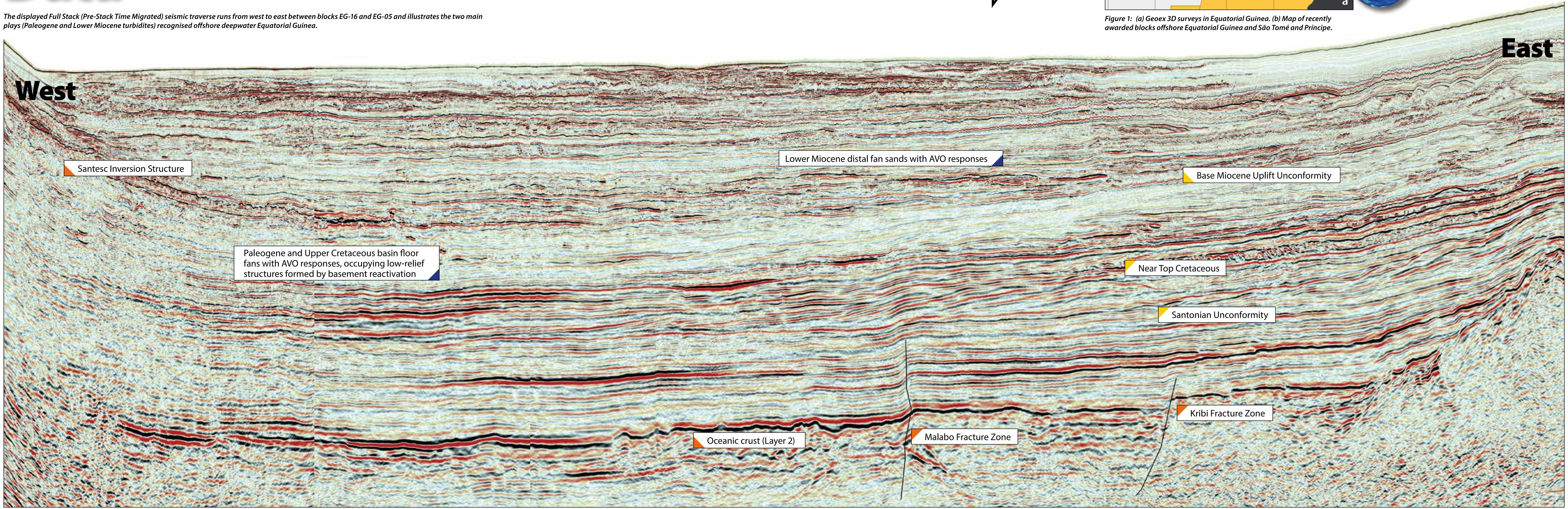


Figure 1: (a) Geoex 3D surveys in Equatorial Guinea. (b) Map of recently awarded blocks offshore Equatorial Guinea and São Tomé and Príncipe.

The displayed Full Stack (Pre-Stack Time Migrated) seismic traverse runs from west to east between blocks EG-16 and EG-05 and illustrates the two main plays (Paleogene and Lower Miocene turbidites) recognised offshore deepwater Equatorial Guinea.



Exploring Equatorial Guinea's Distal Hydrocarbon Systems

New 3D surveys, covering over 8,400 km², have identified a large number of new prospects in this fascinating region.

CHRIS IRONS and RICHARD BRAY, SAER Ltd; PETER ABRAHAMSON, Geoex Ltd

Several licences have recently been awarded to international operators in areas offshore São Tomé and Príncipe, Gabon and Equatorial Guinea, as illustrated in Figure 1 on the previous page. The exploration potential of this region is considered to be very high and interest from oil companies has risen dramatically, as demonstrated through new bidding activity in these three countries.

Geoex Ltd, which has acquired several multi-client 3D surveys in Equatorial Guinea, has already shown these surveys to a number of operators during 2017. The data packages will be available for viewing at the Geoex offices in Epsom, UK throughout 2018.

Seismic Data and AVO Analysis

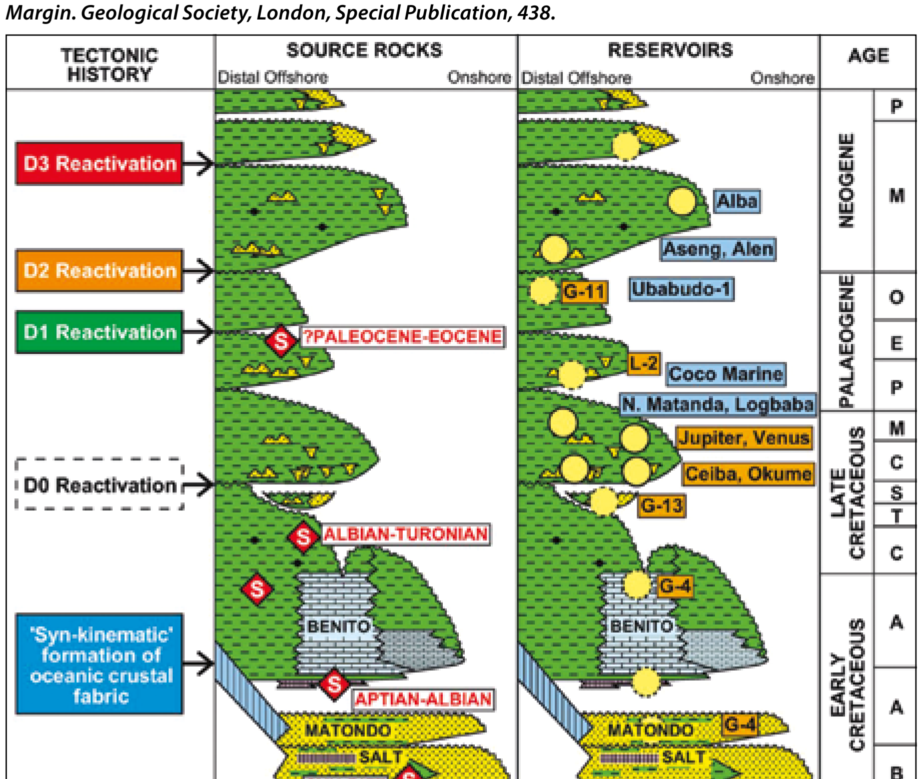
Equatorial Guinea's deepwater basin is highly prospective for oil and gas but remains largely unexplored by drilling. A series of five near-contiguous speculative 3D seismic surveys were carried out between 2011 and 2014 by Geoex, in conjunction with SAER Ltd., for the Ministry of Mines and Hydrocarbons, Equatorial Guinea (MMH) in order to promote exploration in this area. Together these surveys extend over an area of approximately 8,400 km², covering blocks EG-02, EG-05, EG-16, EG-17, EG-18 and EG-22 (see Figure 1a). A scoping interpretation of these data provides new insights into the regional geology and petroleum prospectivity of this deepwater basin. AVO-supported prospects are recognised in channel/fan systems in both Upper Cretaceous-Paleogene and Lower Miocene plays and the data illustrate the importance of the structural control imparted by reactivation of the oceanic crustal fabric.

Geological Evolution

Geologically the area overlies the distal parts of the Douala and Rio Muni Basins situated on oceanic crust, here referred to as the Douala-Rio Muni margin. This region developed as an 'oblique margin' where oceanic crust is strongly offset continent-wards by oceanic transforms into relatively shallow water. Several gas-condensate and oil discoveries have already been made in upper/middle fan reservoirs overlying oceanic crust. Source rocks for the recognised petroleum systems have been identified geochemically in the Upper Cretaceous and Paleogene section, while 'live' oil encountered in Tertiary sandstone cores from the Ubabudo-1 well drilled on the volcanic island of São Tomé has been geochemically linked to Middle-Upper Cretaceous source rocks (Figure 2).

The new Geoex 3D seismic data provide a near-continuous coverage over the region between the islands

Figure 2: Stratigraphy and petroleum geology of the Douala-Rio Muni margin. From Lawrence et al. (2016) Deformation of oceanic crust in the eastern Gulf of Guinea: role in the evolution of the Cameroon Volcanic Line and influence on the petroleum endowment of the Douala-Rio Muni Basin. In: Sabato Ceraldi, T., Hodgkinson, R. A. & Backe, G. (eds) Petroleum Geoscience of the West Africa Margin. Geological Society, London, Special Publication, 438.



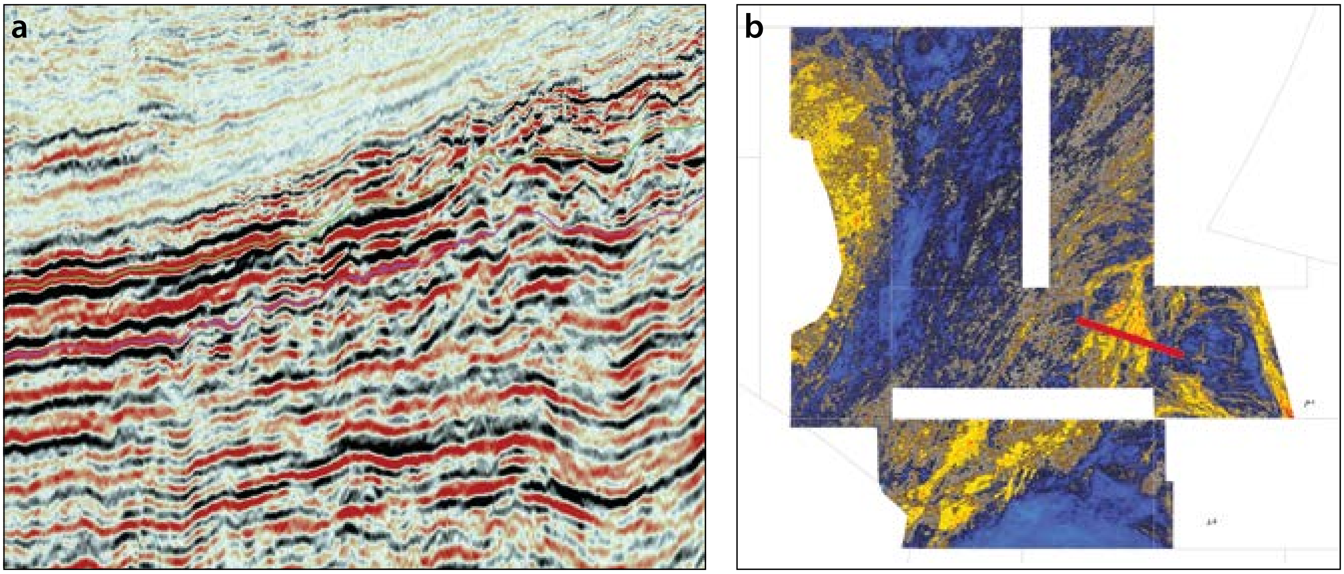


Figure 3: Amplitude response of an Aquitanian turbidite fan. Line of section shown in red on Figure 3b.

and seamounts of the Cameroon Volcanic Line and the Douala-Rio Muni margin (see Figure 1b). The data have imaged Miocene sand systems working southwards along the axis of the Douala Basin and Cretaceous-Paleogene sand systems migrating westwards out from the Rio Muni continental margin (Figures 3 and 4). The data also show basement structure reflecting the syn-kinematic fabric of oceanic crust in the form of spreading-ridge structures and oceanic fracture zones. Significant deformation of the overlying sedimentary section is observed, related to re-activation of basement structure during several tectonic episodes (Figure 2). This includes strong crustal uplift along fracture zones during the early Miocene which played a role in the formation of the volcanic islands and seamounts of the Cameroon Volcanic Line.

Many Prospects Delineated

The combination of underlying structure and basin-floor fan systems has contributed to enhanced trapping possibilities in the 3D area. Prospects have been delineated by combining structural mapping with the application of Amplitude Versus Offset/Angle (AVO/AVA) techniques. Type II/III AVO anomalies (low acoustic impedance, high porosity hydrocarbon-filled sands) characterise several prospects which have been identified on the Geoex 3D data. Similar Type II/III AVO anomalies have proven successful in every discovery to date in the Douala Basin blocks O & I (Lower Miocene play) and in the Ceiba and Okume fields of the Rio Muni Basin (Upper Cretaceous play).

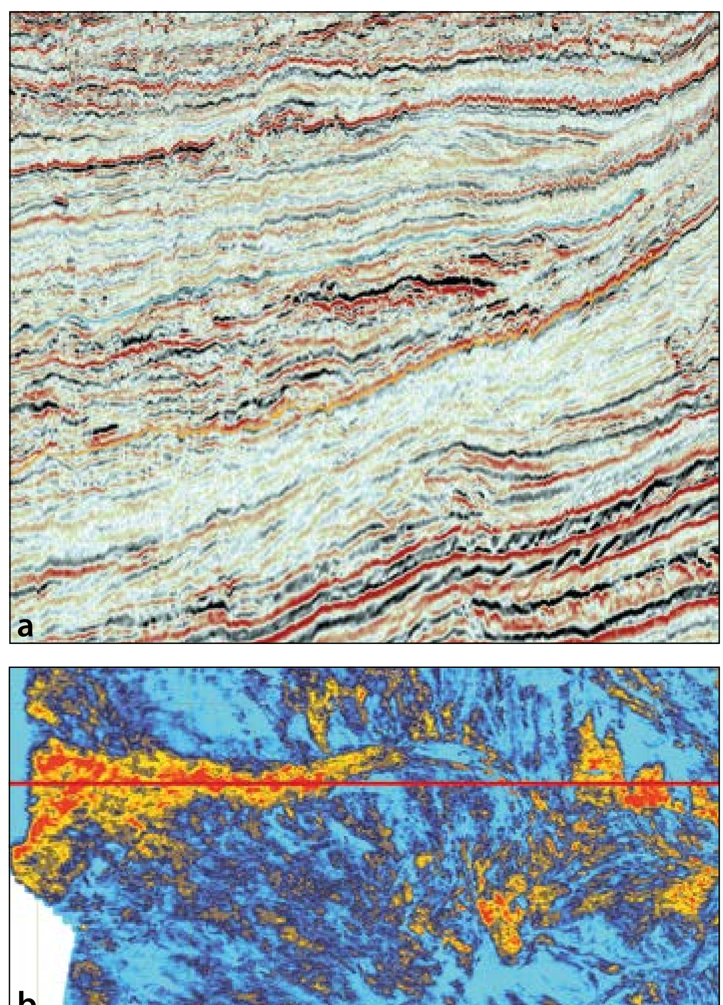
Figures 3 and 4 show examples of amplitude extractions on Lower Miocene and Upper Cretaceous-Paleogene systems, which both exhibit AVO responses.

SAER Ltd have produced five interpretation reports in cooperation with Geoex Ltd covering the blocks EG-02, EG-05, EG-16, EG-17 and EG-18 using the discussed 3D data. Scoping hydrocarbon volumes for 26 possible oil and gas prospects have been calculated in these reports.

Acknowledgement

Geoex Ltd would like to thank Ministry of Mines and Hydrocarbons for their continued support during all stages of the multi-client 3D projects offshore Equatorial Guinea. ■

Figure 4: Far trace amplitude response of a distal Upper Cretaceous basin floor turbidite fan. Line of section shown in red on Figure 4b.

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Can Oil and Gas Save CCS in Europe?

Carbon pricing and the transition to carbon capture and storage is inextricably linked to the oil and gas industry.

GAVIN WARD and **MARTIN WILKES**, RISC Advisory; **CONOR WARD**, University of Edinburgh

In the last decade, European leaders have faced a balance of payments shortfall from falling fossil fuel revenues and rising costs of new nuclear solutions. During this time, prices of carbon dioxide (CO_2) experienced uncertainty both as a tax liability and as a potentially tradeable commodity known as European Union Allowances (EUAs). However, taxation of CO_2 emissions from all industries, not just the fossil fuel industry, may fill the gap in the future.

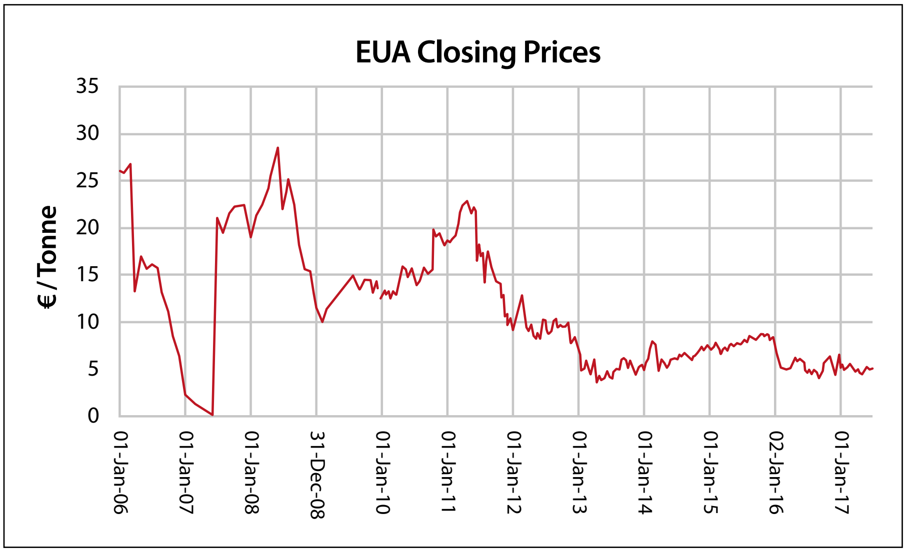
Using CO_2 for enhanced oil and gas recovery (EOR/EGR) begins to put a value on the commodity, so the relatively new European carbon credit market is something all oil executives should keep an eye on, just as much as the oil price. However, CO_2 can only transition from being solely a liability for emitters and into an asset for an emerging carbon capture and storage (CCS) industry as part of the value chain in EOR/EGR if costs reduce dramatically, or if product prices rise. So, what is going to happen to CCS and carbon prices now?

Value of Carbon Credits

Carbon pricing has been as volatile as oil prices over the last decade and still contains significant uncertainty. It is a commodity but not traded as widely or in the volume that oil is traded, as it is treated with scepticism by many. Nevertheless, since it is traded, evidence suggests prices will grow, either through free market forces or government intervention to tackle world emissions targets. Some would say that the introduction of a carbon floor price in the UK of £18 ($25) per tonne/$CO_2$ (approximately £1 per 1,000 cfg), which is well above the European carbon price, was the start of serious carbon taxation and revenue generation for the UK Treasury, since approximately £2.2 billion ($3.1 billion) is expected to be raised in taxation between 2017 and 2018 from the Climate Change Levy.

One way for finance ministers to maximise their revenue may be through the integration of carbon taxation as fossil fuel volumes decline. The astute among us will recognise that when the volume of emissions declines, any linked carbon tax will also decline. Therefore, it should be noted that the careful introduction of carbon capture or carbon capture and storage schemes, allied with carbon credits, may enable countries to have a new carbon capture industry effectively subsidised by the fossil fuel industry, which will be looking to delay or avoid field decommissioning costs or improve hydrocarbon recovery.

CCS can be used to reduce emissions.



European Union Allowance (EUA) for carbon prices (Euros/tonne). Each EUA represents one tonne of CO_2 that the holder is allowed to emit. Allowance units are freely allocated or auctioned to members of the EU Emissions Trading Scheme and can then be sold or purchased through the carbon market.

CCS Growth

In 2017, Richard Owen, ExxonMobil Australia Chairman, told a conference that organisations which claimed gas is a transitional fuel overstate the capacity of renewable energy and underestimate the future role of fossil fuels: "We often hear of gas as a transitional fuel and a bridge between coal and renewables, but we also know that everyone's forecast is that gas continues to grow." However, whether gas is transitional or not, CCS might just be needed as a new transitional industry in many countries to take us from the emissions levels the world is at now, to a time when energy can be stored in adequate quantities and emission technology has advanced to the point when coal and oil are as clean as gas.

Many European countries have seen the closure of coal-fired power stations, the reduction in the rate of growth of offshore wind and ballooning costs of new nuclear. Electricity tends to grab the headlines, but actually gas provides double the amount of energy that electricity does in Britain every single year. Like many European countries, the UK is now reliant on imported gas to meet its energy needs and as Nicola Pitts, Head of Gas Market Change at National Grid power distributor, recently said "… gas is a really critical part of our security of energy supplies… in the absence of some fairly robust policy drivers from [government] either at the national or the local level, we can anticipate that people will still be relying on [it for] heating in their homes. So, it's a really important factor for us to think about, with security of supply."

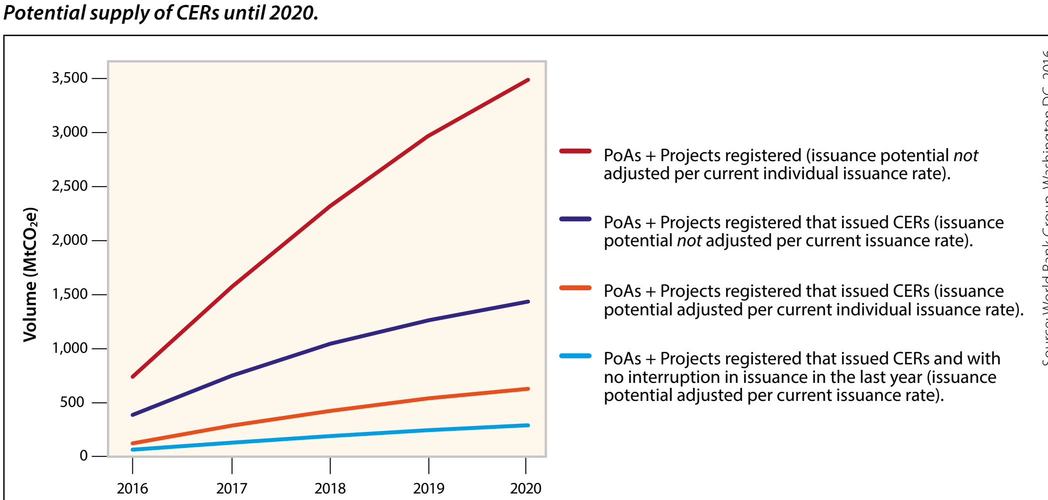
The Future

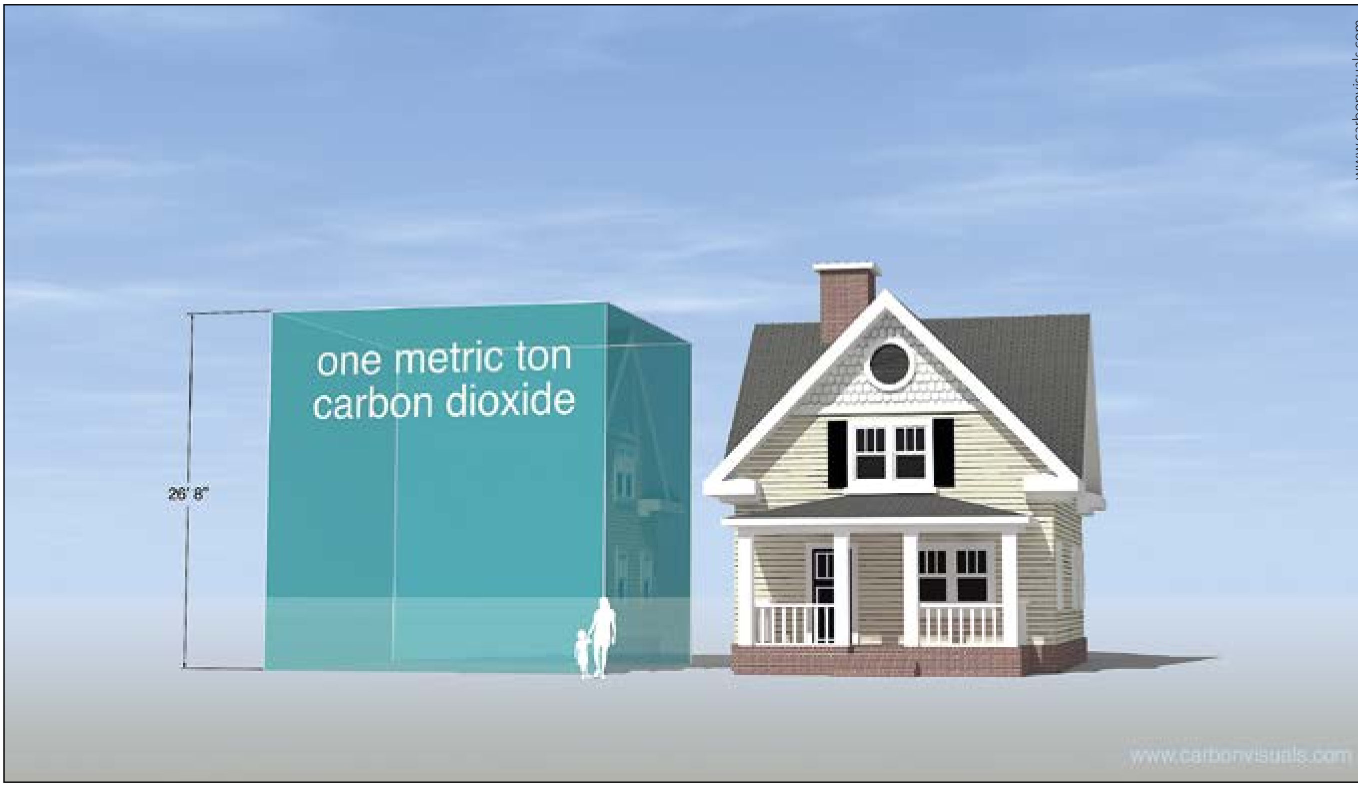
All countries face an energy trilemma, simultaneously satisfying three imperatives: affordability, volume of supply, and security of supply. Decarbonisation should be part of this formula but satisfying the current balance of three imperatives is complex enough without adding a fourth parameter.

Affordable new-build houses are not energy self-sufficient and many parts of Europe are full of housing built without much heat insulation or powered air conditioning, so energy will continue to be needed to both cool and heat homes. Renewables cannot replace the hydrocarbons used as feed stocks for our petrochemical and plastics industries, which manufacture a wide range of products such as medical equipment and computers. Even products used in renewables, such as the polycarbonate on solar cells and about 40% of all turbine blades in wind farms, are made from oil-derived products.

For CCS to work financially, one extremely important issue which needs to be solved is the carbon credit scheme. Currently, the European Union emissions funding scheme awards carbon credits to each country and each country in turn allocates them to industries. The flaw is that too many credits exist in the system, which means that high CO_2 emitters like hydrocarbon processing or cement plants may never run out of credits. This would seem to have a negative effect on national economies. These emitters do not need to buy credits to offset their emissions and therefore there is little penalty paid or revenue received by finance ministers for emissions not covered by carbon credits.

Potential supply of CERs until 2020.





One metric tonne (2,205 lb) of carbon dioxide gas occupies 534.8 m³ (117,631 US gallons). It would fill a cube 8.12m high (26' 8") or a sphere 10.07m (33ft) across. 1 million tonnes in weight of carbon dioxide is approximately equivalent to a volume of 19 Bcfg.

The European Union's Emissions Trading System was intended to reduce CO_2 emissions by setting a market price. The system, designed to cover three time periods, requires polluters to acquire credits to offset their emissions but oversupply of credits combined with lower demand because of weak economies is an issue. It has driven down the value of the carbon market and resulted in poor economics for CCS projects. Europe's carbon market was set up to regulate greenhouse gases by trading emissions permits but is struggling to stay credible. Despite the obvious trouble in the market and glut of European Union Allowance credits and Certified Emissions Reductions (CERs) (see figure on previous page), the European parliament voted down the proposed reduction in the number of credits in 2013 – and prices dropped 50% in five minutes. Consequently, declining value in the market has sapped liquidity and added too much uncertainty to CCS projects.

Emissions Taxation Helps O&G Industry

The fundamental driver of CCS has been the cost/price difference between two factors: the relatively high costs to implement a scheme and the relatively low costs of emitting the carbon. Current economics suggest that a carbon price well above €30/tonne (without grants, tax breaks or subsidies) is required to make CCS projects viable with current cost estimates. However, the price is a result of an artificial construct – the EUA. This is one of the key reasons why carbon pricing is treated with some scepticism since a change of government can also change taxation policy, as it has done twice in the case of Australia. Therefore, CCS in Europe has no foreseeable future if the European Parliament continues to make the same decisions on issuing EUAs as it did in 2013.

However, if the leading economies in the European Union can divorce themselves from EUAs then they will be able to restore some control over revenue from CO_2 taxation. The carbon market may then start to show some signs of stability and CCS may resurface as an economically viable alternative to buying EUAs or paying emissions tax.

This future scenario is not without some foundation, since the UK published a CO_2 target price in 2010 of £75/tonne ($105/tonne) by 2030, in response to the European Union's climate change target of reducing emissions by 40% compared to 2005 levels by 2030. The floor price was later capped at £18 ($25) per tonne of CO_2, to keep UK industry competitive, but although the target trajectory of £75/tonne is unlikely to be met, there is political desire to reach the 2030 emissions target and carbon floor pricing is one of the methods to achieve this.

Therefore, it is fair to conclude that emissions taxation will help keep the oil and gas industry alive.

References:

State and Trends of Carbon Pricing, World Bank Group, Washington DC, 2016.

Certified Emission Reductions (CERs) are a type of emissions unit (or carbon credits) issued by the Clean Development Mechanism (CDM) Executive Board for emission reductions achieved by CDM projects and verified by a DOE (Designated Operational Entity) under the rules of the Kyoto Protocol.

New York Times, Energy & Environment, Europe's carbon market is sputtering as prices dive, 21 April 2013. ■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Max Steineke and the Structure Drill

A breakthrough in the search for Arabian oil: how structure drilling revolutionised exploration in the Middle East.

MICHAEL QUENTIN MORTON

In 1933, Standard Oil of California (SoCal) was awarded an oil concession for the province of Al-Hasa in Saudi Arabia. Exploration commenced in the autumn but, as its geologists surveyed the terrain by motor car and aeroplane, the amount of information they could obtain about the geological substructure was limited. Traditionally, geologists had relied on surface pointers in the search for oil, such as anticlines, exposed rock formations and seepages, but these features were largely absent from the desert wastes. New methods such as seismic and gravity/magnetic surveys enhanced exploration, but it was the introduction of structure drilling that made the greatest difference at this stage. This entailed drilling shallow holes in order to determine the underlying geological structure, a technique that had been used elsewhere but never before in Saudi Arabia.

One American geologist, Max Steineke, played a leading part in introducing this technique to the area, just as hopes were fading of ever finding any oil on the Arabian mainland.

The Core Solution

In the mining industry, shallow holes were drilled for placing dynamite in a rock face, or for determining the thickness of coal beds, avoiding the time and expense of driving exploratory tunnels into the earth. In 1917 George Burton, assistant director of the Oklahoma Geological Survey, recommended that diamond core drills be used in order to locate structures. As the practice transferred across to the oil industry, core drilling was carried out in regular patterns – usually to depths of less than 600 ft (180m) – in order to make an accurate assessment of the substructure.

Whereas earlier drills had bored holes through a succession of blows, diamond drills allowed the rock core to remain intact. A barrel was screwed on to the bottom of the drill stem and then closed after drilling so that a core could be extracted. Royal Dutch Shell had applied this technique in the East Indies, used a double barrel in Holland and then brought it to California. Other designs were introduced, but, no matter what type of device, the objective was the same: to produce rock cores that could be examined by geologists in the field and by analysts in the laboratory. In 1922, E.W. Marland used diamond core drills to outline the northern extension and limits of an oilfield at Tonkawa, Oklahoma, and his success brought their widespread use across the industry.

In the 1920s, when even a basic steam-powered exploration rig could take a week to erect, a new type of portable rotary rig was used. Carried on a truck, it drew its power from the truck's engine or from a separate tractor engine mounted on the vehicle. These mobile rigs could drill ten 50 ft (15m) holes in a day, and were used for obtaining cores and planting

A wildcat well at Ain Haradh, al-Hasa, 1948.

DeGolyer Library, Southern Methodist University

Saudi Aramco

An early structure drill rig.

explosives in the ground. In this way, the modern technique of structure drilling evolved.

Geologists at Large

Thirty-six-year-old Max Steineke arrived in Saudi Arabia in September 1934 and went into the field, quickly adding to his reputation as an energetic and perceptive geologist. But it was a thankless task; from sand-blown plateaus to rubble-strewn plains, salt flats and wadis, there was little indication of subsurface structure. Although geophysical methods could assist, they were not always reliable at this time. However, could the portable drill be used to identify anticlinal structures where oil might be found at greater depth?

While it was widely known, structure drilling had never been attempted in Arabia. In the course of his earlier career with SoCal, Steineke had worked at home and abroad, so was familiar with the technique. In 1936, when he was appointed chief geologist for the California-Arabian Standard Oil Company (Casoc), which operated the Hasa concession, Steineke suggested a programme of structural drilling to map the subsurface geology and gather information about the pre-Neogene. This began later in the year with small portable rigs being introduced to the al-Qatif al-'Alah area.

These rigs drilled holes of small diameter and a few hundred feet deep in order to determine from one point to another the depth and elevation of important subsurface strata. A few holes were then sunk to greater depth in order to determine whether the rocks in certain areas were favourable to oil accumulation. Seismic data, ground surveys and, later, gravity-magnetic surveys, were used, but structure drilling was tailor-made for Saudi geology, because of the regional uniformity and continuity in rock units and their fauna. Aramco geologist R.W. 'Brock' Powers described it thus: "If you drill 1,000 to 2,000 feet deep, you pretty much reflect the same structure you're going to see at depth. In other words, if you've got a hump like this at 1,000 or 2,000 feet, it just persists on down to 8,000 and 10,000 feet, which is where the oil-bearing layers are."

From Prospect to Discovery

In 1938, exploration was spurred on by the discovery of commercial oil at Dammam. A new intake of geologists arrived from the United States. Among them was Nestor Sander, whose duties included logging and mapping the sequence of the Eocene at a place known as Abqaiq – "Father of Sand Flies" – south-west of the Dammam dome.

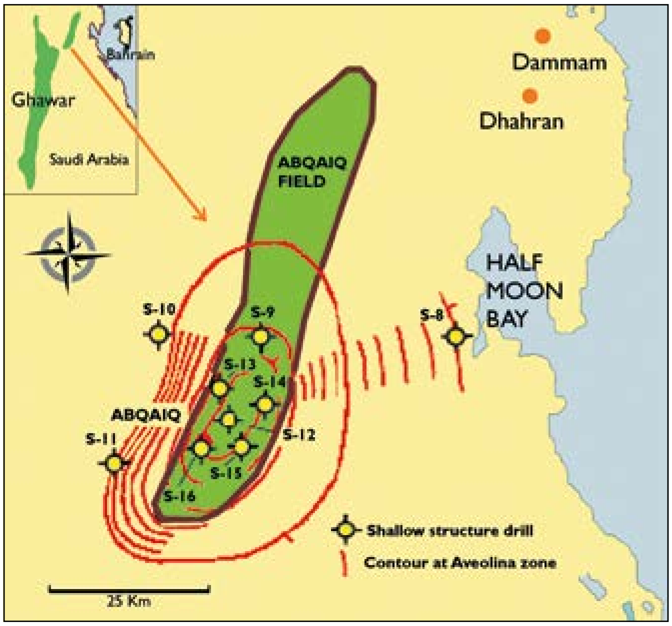
Abqaiq was Steineke's hunch. Since there were few surface features such as salt flats, Tertiary outcrops and the alignment of dunes to suggest underground structure, it was hoped structure drilling would provide more clues about the substructure. In his article *Early Exploration: The Structure Drill*, Sander described how the subsequent programme of structural drilling proceeded around Abqaiq. After placing the first well, S-8, in the *sabkha* to the east, he sited the next one on what he believed was the axis of the north-south trending anticlinal feature. Three fossils were used as markers, with drilling ceasing at *Lockhartia tipperi* in the uppermost Umm er Radhuma Formation.

After S-10 revealed thicker rock units lower in elevation, Sander made some crucial discoveries:

"The next well, S-11, was the critical one, sited some twenty kilometres south of S-10 in the same valley. If it found Eocene markers structurally low, a closed feature in strata of Eocene

Casoc geologists (left to right) Tom Barger, Walt Hoag, Max Steineke and Jerry Harriss, Saudi Arabia, 1937.

T.C. Barger Collection



The structure drilling programme at Abqaiq showing the approximate positions of drill sites S-9 to S-16. (Adapted from Nestor Sander/courtesy of AramcoExpats.)

age could be postulated because regional dip was to the east. They were low, so I completed the survey by sitting S-12 on what I thought to be the highest elevation on the feature. I could see clearly a slight downward slope to S-11 from there. To ice the cake I sited S-13 to S-16 in the quadrants around S-12 and found all four to be lower than S-12. So I wrote my report, made a map and submitted them to management in the early summer of 1939. My map showed limiting closure of 800 feet (it is more than 3,000 feet at the Arab-D)."

Abqaiq No.1 well commenced in February 1940 and struck oil in the porous Arab Formation carbonates; this was one of many discoveries that would follow in the Arabian desert. While the well was being drilled, another geologist named Ernie Berg was mapping the surrounding area and noted that Wadi Sahba took a sharp turn in its easterly direction. He concluded that this must have been caused by an anticline blocking the natural course of the dried-up watercourse. After discussions with Steineke, it was agreed that structural drilling should be carried out on the En Nala anticline, which proved to be the southern end of what would emerge as the north-south trending Ghawar giant oilfield.

Long-Term Results

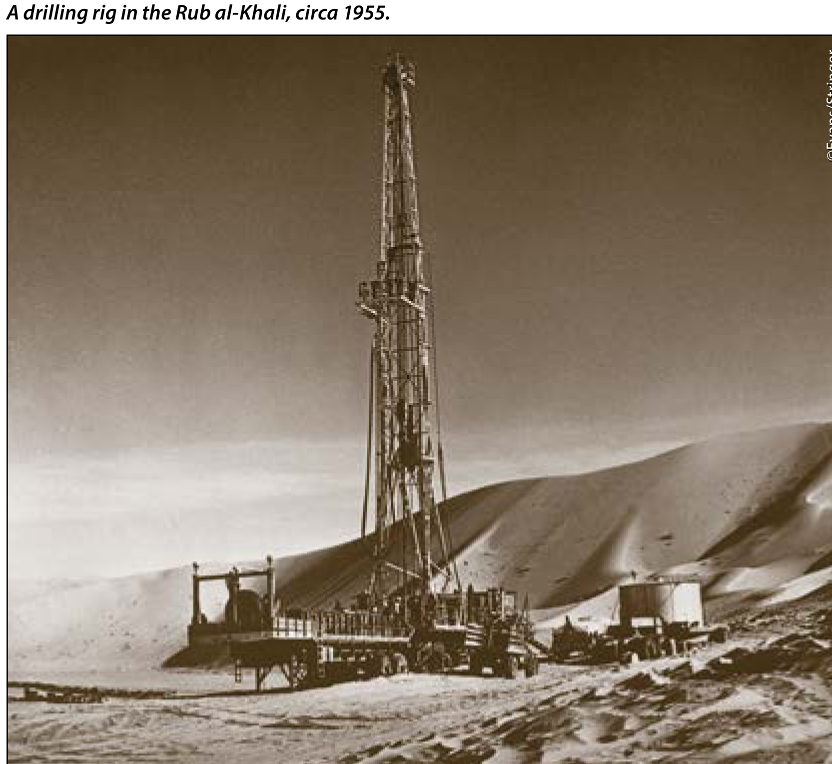
According to the *Aramco Handbook* (1960), when this work was suspended in the early 1940s "the geologists had covered 175,000 square miles by preliminary reconnaissance and about 50,000 square miles by detailed mapping. Much smaller, although considerable, areas had been covered by gravity meter, seismograph and structure drill surveys." After the war, the results of structure drilling on the northern end of the Ghawar structure yielded enough information for the geologists to recommend drilling wildcat wells along the anticline without relying on complex seismic methods, and oil was struck in 1948. Five years later, a series of wells had confirmed Ghawar as the largest oilfield in the world. Structure drilling was applied to marine areas, too: the Safaniya field, for example – the world's largest offshore field – was discovered by structure drill methods in 1951.

Exploration crews were soon penetrating the great southern desert, the Rub al-Khali, taking structure drills with them. It made financial sense because, as Brock Powers put it, "you can drill a 1,000- to 2,000-ft hole for almost nothing, compared to drilling the 8,000- to 10,000-ft hole. So we drilled hundreds and hundreds of those structure drill holes throughout Saudi Arabia." For several years, three structure drilling parties were in the field. Michael Cheney, in *Big Oil Man in Arabia*, wrote about the great Aramco convoys that used to trundle out of Dhahran each autumn on their way to survey the sands:

"The most impressive equipment belongs to the structure-drill parties, which go out with portable drilling rigs ready-mounted on trucks. The derricks fold down like jack-knife blades when travelling, then are stood upright for drilling. They drill for samples rather than for oil. The hollow drill string brings up long, round cores of each layer it drills through, and segments of each are sent to laboratories for analysis. Some of the material comes up semi-liquid, some solid. I still carry around a heavy six-inch length of such a core sample. Beautifully polished, it looks and feels like fine marble; but the interweaving black lines, I'm told, are oil."

In 1953, one of these structure drilling parties ran into a British-led patrol in the south-west desert, in an area where the political boundaries were ill defined. After a brief confrontation, the crew abandoned their equipment and

A drilling rig in the Rub al-Khali, circa 1955.



An Aramco structure drill abandoned in the Arabian desert in 1953.

returned to Dhahran.

Over the next decade, shallow-penetration structure drills were gradually phased out, to be replaced by deep stratigraphic drilling, with wells between 5,000 and 10,000 ft sunk around the edges of the concession area and throughout the interior.

Honoured Geologist

In 1951, the American Association of Petroleum Geologists awarded Max Steineke the Sidney Power Gold Medal, one of the greatest honours that can be bestowed on a petroleum geologist. In the citation read to association members at St Louis, it was said:

'[Max Steineke] suggested the structural drilling method which was so widely applied later in Saudi Arabia and has resulted in the discovery of so much oil. The methods he developed in the area probably resulted in the discovery of greater reserves than the work of any other single geologist.'

Aramco asserted that "far more oil has been found in Saudi Arabia by structure drilling than by any other method", a tribute indeed. Sadly, Steineke passed away at the relatively young age of 54, but his name lives on as one of the great geologists of petroleum exploration.

Acknowledgements: *The author would like to thank Hans Krause, Tim Barger and Peter Morton for their kind assistance.*

Quentin Morton's latest book, 'Empires and Anarchies: A History of Oil in the Middle East', is available from Reaktion Books and all good booksellers. ■

An Enjoyable Textbook!

Basic Geophysics by Enders A. Robinson and Dean Clark.

Dr KARL BERTEUSSEN, Prof. Emeritus

Published by Society of Exploration Geophysicists, 2017. ISBN: 9781560803454

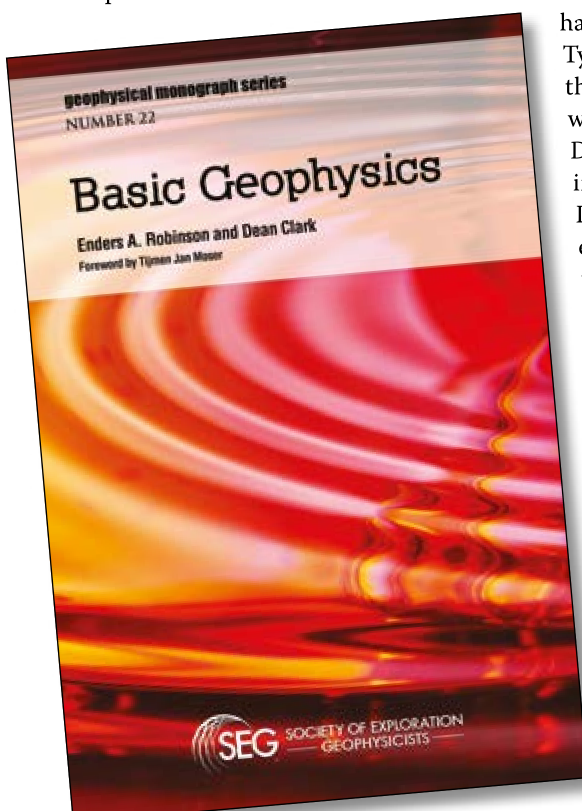
I received this book on December 28 – excellent timing. More or less finished with the easy Christmas reading, I was ready for something more substantial and I have never enjoyed reading a textbook as much as this. I have some concerns, but the overall impression is that this is a book every serious geophysicist should get. It is an unusual textbook and if you do not read it all, at least scan through it; I guarantee you will learn a lot of stuff you did not know, whichever theoretical level you are on.

Chapters 1 to 4 are composed of articles published by the authors in the SEG Journal *The Leading Edge*, while the rest is taken from their unpublished manuscript ‘Waves of Discovery’.

The Preface says “The intent is to cogently present the body of seismic theory that underlies modern exploration seismology in a format that transfers understanding to the audience.” And “If each reader can find an insight or two that were not previously appreciated, this book will accomplish its purpose.” I guarantee, whichever level you are on in seismic wave theory, you will definitely find just that.

Two more statements from the Preface: “An important mode of thinking is visual thinking” and “The figures in this book will help you see and understand seismic signals better”. I fully agree with this. Except for the front page, there are no fancy colour slides in the book, which is unusual for a text about seismic these days. There are, however, a large number of black and white drawings. At first glance they look simple, but it is obvious that the authors must have spent a lot of time making them. They are very clear and insightful and would be very helpful for anybody teaching seismic theory.

In addition to the theoretical stuff itself, the authors offer plenty of background information, explaining how what we all learned at university draws on earlier work by giants like Pythagoras, all the way up to Newton, Huygens and Fresnel, to mention a few. Chapter 2, for example, starts with Pythagoras, while later in the chapter you will find a section that has the heading “The eikonal equation and Pythagoras” followed by the section “Michael Faraday and the eikonal equation”.



Who’s It For?

An obvious question is: who should buy this book? As a retired professor I ask myself, how would I have used it if I were still teaching? And here I have an issue; the title of this book – *Basic Geophysics* – is misleading. The discipline of geophysics covers a lot more that just seismic theory; it includes practical measurement, gravity, magnetics, etc. None of these topics is covered, so if I was back at a university I could not use it for the typical basic ‘Introduction to Geophysics’ course. However, some geoscience students at Bachelor level still elect to focus on exploration seismic; for them the book would be very relevant. For students taking a Master’s degree in seismic it could also be important.

However, I encourage everybody who is teaching geophysics to read it. I know from my own experience that with tired students it is good to have something extra to talk about. Typically, that would be discussing how this “boring” subject is used in the real world, but illustrating how giants like Descartes or Euclid or Newton have influenced it would be interesting. It helps, when introducing eikonal equations, to be able to connect them to Pythagoras, and then be able to say that the Egyptians building the Great Pyramid knew about Pythagoras’s equation many years before Pythagoras. So, I am sure, if I were back in a professor position again, I would somehow find room for this book in the curriculum; it offers the reader that little extra that few other books give.

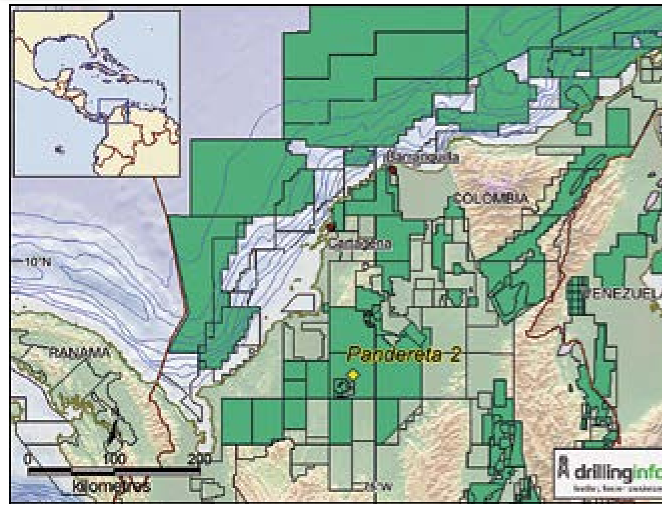
Who else should buy it? The excellent foreword by Tijmen Jan Moser says: “Scientists who know the foundation of their subject are better equipped to tackle new problems”. He is right: this is a well-written and fun book to read, and if you are a geophysicist or seismologist it will definitely help you to understand the foundations of your subject.

And finally, since this is written shortly after Christmas and I am still in the ‘Christmas gift spirit’, if you are a manager and have geophysicists in your organisation you could use it as a company gift to your staff at any time. I believe it would be a good investment, but be prepared – they might come back with ideas and questions you did not think about, so read it yourself first! ■

Colombia: Successful Gas Appraisal

In mid-January 2018, **Canacol** announced that its **Pandereta 2** appraisal well **in Colombia's Lower Magdalena Basin VIM-5 Block** intersected twice as much net gas pay in the **Ciénaga de Oro** (CDO) Formation as the Pandereta 1 discovery well had done. The appraisal well found 39.6m of net gas pay with average porosity of 23% in the upper part of the target Oligocene CDO sandstone reservoir, compared to 19.5m in the discovery well, which lies around 1 km east. Spudded on 3 December 2017, the well reached a TD of 2,938m in mid-December. Pandereta1 encountered 45.3m of total gas pay in the Ciénaga de Oro, Lower Tubara and fractured basement reservoirs.

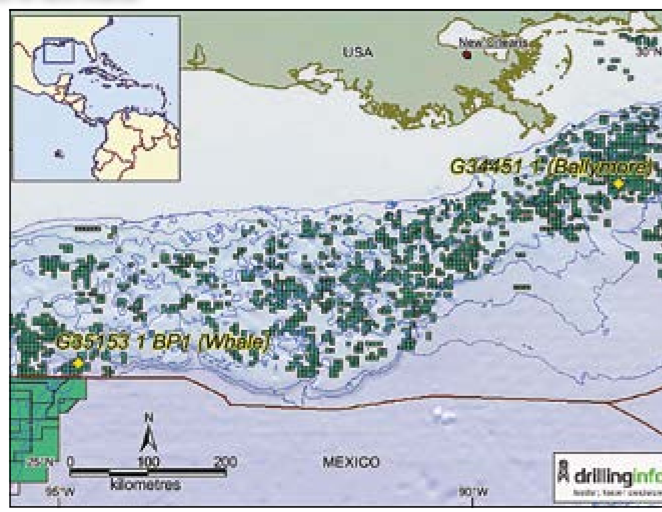
Canacol is currently drilling the Pandereta 3 development well about 1.5 km north-east of Pandereta 2, which will be followed by the Gaiteros 1 exploration well on the same block, also targeting the CDO reservoir. The company owns the block 100%. ■



United States: Two Major Discoveries

Chevron's G34451 1 (Ballymore) well in the deepwater (1,988m) **Mississippi Canyon 607 block** in the **Gulf of Mexico** encountered 205m of net oil pay, in a high quality Norphlet reservoir. The well, about 5 km from Chevron's Blind Faith platform and 80 km from the Louisiana coast, spudded in July 2017 and reached a final TD of 8,898m. A sidetrack well is currently being drilled to further assess the discovery and begin to define development options. Equity in MC 607 is shared between Chevron USA (60%) and Total (40%).

Another Gulf of Mexico success story came at the end of January 2018, when **Shell** reported that it had encountered over 427m net oil-bearing pay in its **Whale 1** NFW in **Alaminos Canyon Block AC 772**, near the ultra-deep **Perdido** spar, about 322 km off south-east Texas. The discovery lies up-dip of the Tobago and Silvertip fields. Block 772 is shared between operator Shell Offshore (60%) and Chevron USA (40%). The Perdido Field complex is one of the deepest and most remote developments in the world, spurring a string of similar discoveries in recent years to the south in Mexican waters. ■

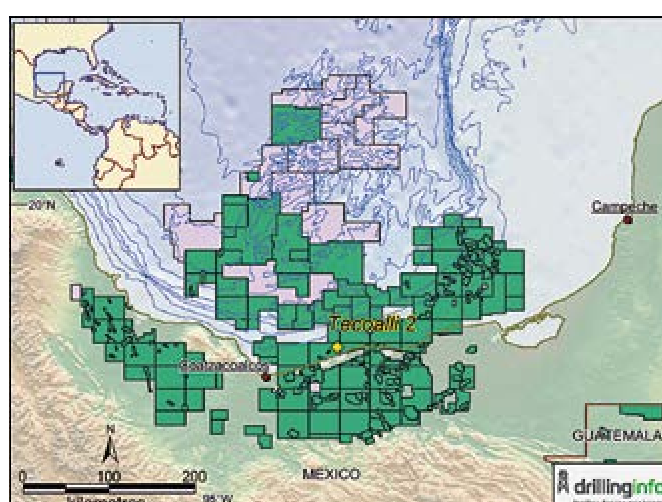


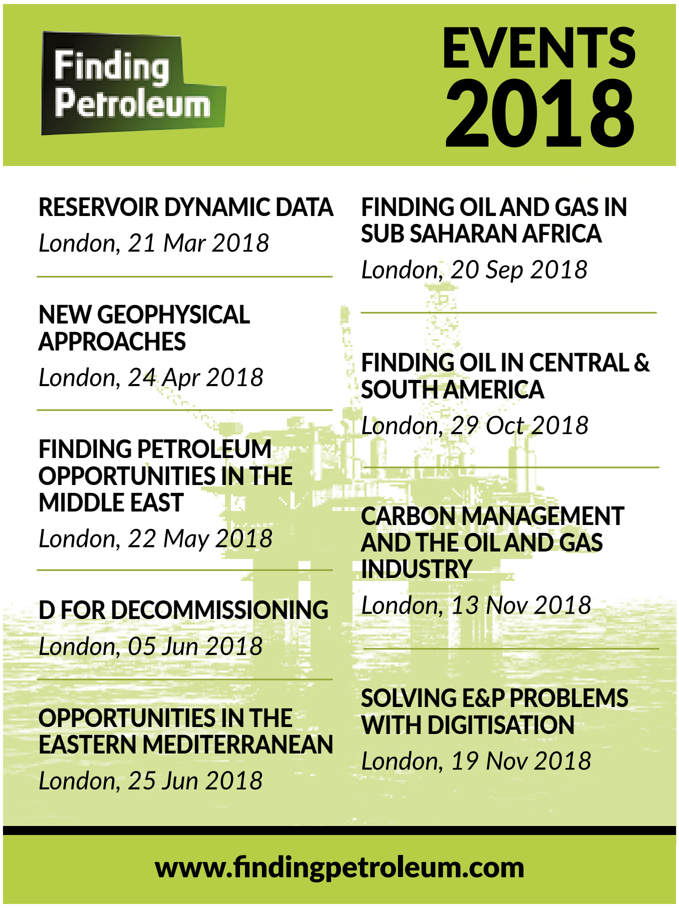
Mexico: Upgraded Reserves

Results of appraisal well **Tecoalli 2** and revised reservoir models of neighbouring Amoca and Miztón fields mean that **Eni** has upgraded its hydrocarbon in-place estimate for its shallow water **Area 1 (CNH-R01-L02-A1/2015) PSC** in the **Mexican Salina del Istmo Basin** from 1.4 to 2.0 Bboe, predominantly oil. In December 2017, **Eni** reported that it had found 40m net oil pay in Middle Pliocene Orca Formation sandstones and 27m in the Cinco Presidentes Formation. Tecoalli 2 reached a final TD of 4,420m in early December after being spudded in October 2017, having tested 7,000 bopd 30° API from the Orca Formation.

Eni was recently granted a one-year extension from the CNH for this Bay of Campeche block and will submit a Plan of Development for Area 1 before making a Final Investment Decision to sanction the development. Production start-up is planned for the first half of 2019.

Tecoalli sits around 24 km from the Amoca field and 13 km from Miztón. Eni has 100% working interest in Area 1. ■

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The Conference will also feature in-depth workshops, Core will be on display and there will be plenty of networking opportunities along with an exhibition. Supported by 13 of the Operators, this conference is not to be missed!
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Land-Based Seismic: Looking Ahead

INOVA Geophysical is a joint venture between BGP Inc. and ION Geophysical Corporation which specialises in technology for land seismic acquisition. Jason Criss and Andy Bull from INOVA consider the challenges ahead for land-based seismic.

Looking at future needs for land-based seismic acquisition, what fundamental changes in technology can we expect in the next five years?

Oil companies and their exploration teams are continually striving for a better understanding of the subsurface but at a cost and scale aligned to the commercial realities of today's energy market. Improved receiver sampling along with high productivity and a very wide broadband signal in the source domain are the geophysical drivers for acquisition technology today, which means a constant drive towards smaller, lighter and less power-hungry equipment, while also increasing channel counts without sacrificing system fidelity. Systems with channel counts exceeding 200,000 are commercially available today, allowing acquisition specialists to sample the subsurface in unprecedented ways. In addition, broadband source technology is progressing towards viable high force-energy penetration at frequencies as low as 1Hz.

With increasing volumes of data being recorded in the field we expect to see some novel solutions emerging which deal with data management, automation and remote analysis. Beyond the geophysical domain we should also expect to see technologies like the Internet of Things migrating into our industry to help address the challenges associated with deploying a complex operation of personnel, vehicles and equipment in remote locations.

What fundamental changes in land-based operations are coming in the next five years?

Crews will continue to become nimbler and more productive, with a much-reduced footprint. Areas that have proved difficult for seismic in the past will become accessible. The result will be smaller crews capable of handling nearly any project efficiently, meaning operational efficiencies, improved imaging and a lower 'social cost'. Nodal seismic systems have already had a profound impact on the efficiency of crew operations in North America and this technology will eventually see global acceptance. The introduction of increasingly viable technologies such as remote monitoring and predictive maintenance will impact the cost-effectiveness of operations and improve visibility.

What is the least understood technical aspect of land seismic acquisition?

Perhaps surprisingly, one of the least understood technical issues is related to the seismic source and the understanding of the source signature actually transmitted into the earth. While vibroseis technology has advanced dramatically, there are still many aspects of sweep generation and the transmission of that energy into the earth that need to be researched further and resolved.

What challenges does the Middle East environment bring to land-based seismic acquisition?

The Middle East has always been a challenge for seismic acquisition because of the remoteness and scale of the projects but it is now firmly established as the hub for most of the technological improvements in our industry. The scale of systems and crews which can be deployed is unmatched anywhere else in the world and the constant push for improved efficiency and quality has resulted in some remarkable breakthroughs in system design and operational methodology. Historically, the area has called for very large crews living in mobile camps in desert areas but an emerging sentiment amongst operators is that crew sizes may have reached their practical limits. The greatest challenge technically and operationally is to continue to increase the productivity of these crews while reducing or maintaining the headcount and improving the quality of the data acquired. These apparently conflicting drivers will undoubtedly lead to more breakthroughs.

What does the future hold for land seismic exploration?

In an era of lower price oil and growth in gas demand, onshore exploration should continue to have a reasonable future. Onshore operations are generally at the lower end of the cost equation when compared with, for example, deepwater operations, so we should expect spending decisions in general to be skewed in favour of onshore work should the current economic climate prevail. However, the relentless push for improved technology and lower costs creates pressures on equipment manufacturers struggling after several lean years. Collaboration amongst competing manufacturers and external technology providers, together with a deep understanding of oil company and seismic contractor requirements, seem like obvious solutions to combat some of these pressures. We have already seen evidence that manufacturers who have embarked on such strategies are slowly beginning to reap the rewards. ■

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Where to Invest!

Despite a lack of sizable discoveries, Norway and the UK are still considered attractive places to invest in petroleum exploration and exploitation, according to a recent survey.

Size matters. That is certainly true for conditions summarised by the **Policy Perception Index**. This index gives an indication of where in the world petroleum industry executives and managers find it attractive to invest in oil and gas exploration and production.

From a recent survey carried out by the Canadian Fraser Institute, which produces the Index, it is apparent that oil companies are more willing to invest their funds in countries (or jurisdictions, as the world is divided into by the Fraser Institute) if large petroleum reserves are coupled with an advantageous political and economic infrastructure.

With reserves of 28 Bboe, Texas ranks as the most attractive jurisdiction to invest in for petroleum industry executives and managers. Spindletop was the site of a spectacular blowout in 1901 that gushed 100,000 bopd for nine days before it was killed.

This is why **Texas**, **United Arab Emirates**, **Alberta**, **Kuwait** and **Egypt** are ranked as the most attractive. Likewise, the five least attractive of the large-reserve jurisdictions for investment on the basis of their Policy Perception Index scores are **Venezuela**, **Libya**, **Iraq**, **Indonesia** and **Nigeria**. It is not hard to understand why Venezuela, Libya and Iraq are 'black-listed'.

Amongst the 12 European jurisdictions that were evaluated, Norway and the UK have the highest scores on the Index. Noteworthy, Norway's acreage outside the North Sea, ranked highest in Europe, is considered more attractive than that within the North Sea. This is presumably related to the high expectations for the Barents Sea as communicated by the Norwegian Petroleum Directorate, according to which 65% of the remaining undiscovered resources in the country are to be found in Arctic waters. Coupled with a stable political regime and attractive tax incentives, it is no wonder that senior executives in the upstream oil and gas sector regard the Barents Sea as favourable for investments. Questions they responded to were on the subjects of fiscal terms, taxation, environmental regulations, regulatory enforcement, quality of infrastructure, quality of geological databases, political stability and security. Comments on the survey included these: "Norway has a consistent policy environment that is a model for other jurisdictions," and "exploration refunds are seen as exemplary policy. Such fiscal policies are an encouraging step that shows the government is willing to share the risk associated with oil and gas exploration."

France, having decided to abandon oil and gas production by 2040, is – no surprise – the least attractive country in Europe.

A total of 333 respondents participated in the survey last year, providing – according to the Fraser Institute – sufficient data to evaluate 97 jurisdictions that together hold 52% of proved global oil and gas reserves and account for 66% of global oil and gas production. ■

Halfdan Carstens

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.

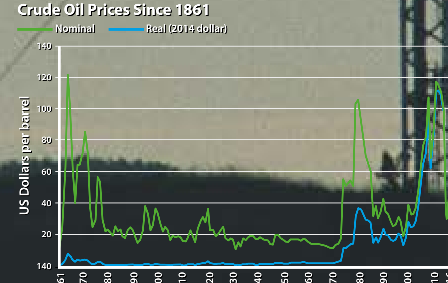
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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



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The Missing Piece

TGS has been authorized by the National Hydrocarbons Commission (CNH) to process and deliver high-quality, high-value well data products to companies exploring in offshore and onshore Mexico.

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The packages provide key coverage of all basins including exploration/appraisal and development wells and are complemented by TGS' existing Gigante offshore 2D survey and reprocessed Mexico onshore 2D seismic dataset with plans to build interpretive products.

Processing has already commenced with first delivery expected in February 2018. Evaluate your petroleum potential from deep water to conventional and unconventional onshore plays across Mexico with TGS's well data packages.

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