VOL. 13, NO. 2 – 2016

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED

GEO TOURISM:
Australia's 'Big Red' Centre

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ALTERNATIVE ENERGY

Iceland: Harnessing the Earth

EXPLORATION

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TECHNOLOGY EXPLAINED

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GEO ExPro
GEOSCIENCE & TECHNOLOGY EXPLAINED

Time to take another look at Portugal?

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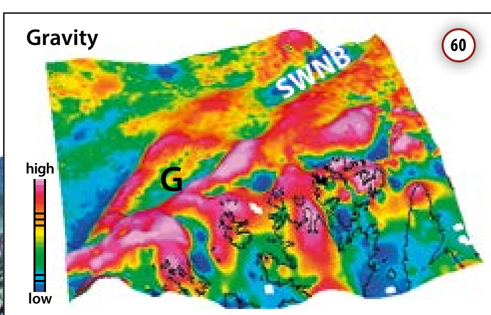

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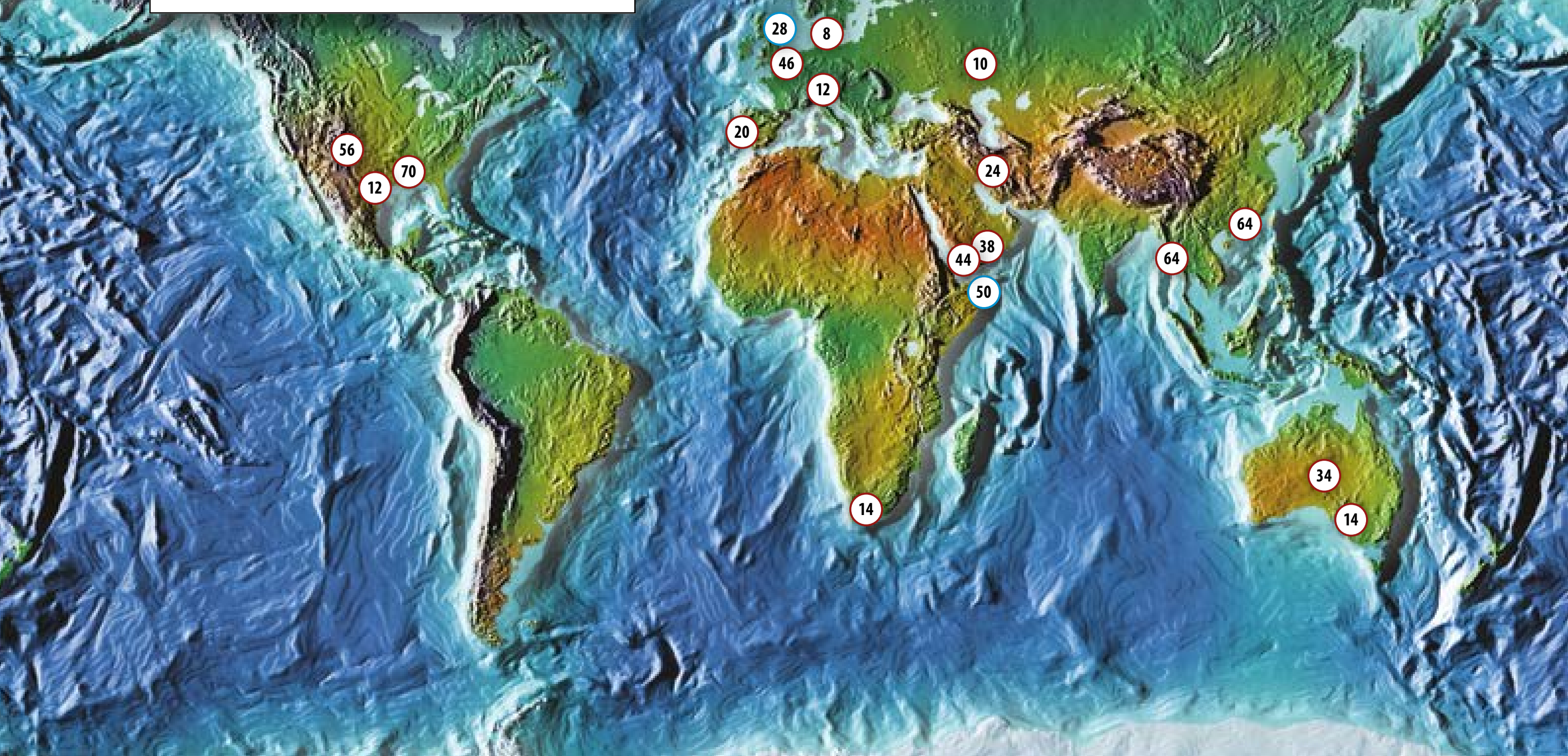

A BETTER WAY
OF FINDING YOUR WAY

WHAT IF YOU HAD THE ABILITY TO MORE ACCURATELY AND EASILY NAVIGATE YOUR OILFIELD PROSPECTS? WITH THE KNOWLEDGE PROVIDED BY THE DAKS™ SYSTEM, YOU CAN DO JUST THAT. GAIN DETAILED UNDERSTANDING OF WHAT HAS OR HASN'T WORKED, WHERE AND WHY, BEFORE YOU START. BECAUSE THERE'S NOTHING LIKE STARTING YOUR EXPLORATION WITH A SMART HEAD START.

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KNOWLEDGE IS OPPORTUNITY

C&C Reservoirs

Embracing Energy

Statoil's proposed floating windfarm.

The mood in the O&G industry is undoubtedly pessimistic. In a recent survey of 6,000 industry professionals (Warren Business Consulting), nearly 50% of respondents declared themselves to be 'not very optimistic about the industry', at least in the near term, although the same percentage believe that it will remain a significant force in the world for at least the next 20 years, albeit with reduced profitability.

One thing that everyone, not just participants in this survey, agrees on: it is time to 'look outside the box' and get innovative. After the price collapse of 1986 induced the industry to cut costs dramatically, many advanced technologies in seismic acquisition and drilling were developed, aided by the explosion in computing power and driven by the need to achieve more with less. It is time again for companies to seek out innovative technological solutions, and to invest in ones that have been identified but not yet developed.

Original thinking is also needed with regard to effective use of the human resource. It has been estimated that over a quarter of a million people have lost their jobs in the sector since the beginning of 2015, and more are announced daily. While cuts are inevitable at such a time, alternative ways of reducing costs, such as voluntary part-time options which do not impact on career prospects and incentivising personnel to develop economies in their own working environments, should be encouraged.

While being bound to promote hydrocarbons, do we in this industry, which is, after all, about energy, give sufficient consideration to alternative sources when they are appropriate and cost efficient? A number of companies are already involved in the alternative energy market: oil giant Total, for example, is affiliated to Sunpower, which has developed the most efficient solar panel in the world; while Statoil has a multimillion dollar venture capital fund dedicated to investing in ambitious growth companies in renewable energy and has recently invested in the world's first floating wind farm, in the North Sea not far from Aberdeen.

Maybe one way around the permanent cycle of boom and bust in the oil and gas industry is not just to *think* outside the box – but to *step* out outside the box and embrace the energy industry in all its manifestations. ■

Jane Whaley
Editor in Chief

HARNESSING ICELAND'S GEOTHERMAL ENERGY

As one of the most tectonically active places on earth, Iceland has a high geothermal gradient, and hot groundwater frequently escapes at the surface in the form of steam. The country has harnessed this energy and it now generates a quarter of Iceland's electricity and warms almost all its houses.

Inset: Australia's Red Centre is a major draw for global travellers seeking outstanding geotourism experiences in the country.

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What Chance a Production Freeze?

Saudi Arabia and Russia increase pressure on Iran

In February Russia and Saudi Arabia agreed to freeze oil production at the January 2016 level, but only if they are joined by other large producers too. The deal came as a big surprise and pushed oil prices lower, as many market players had hoped for a substantial cut that could help restore the balance in the market and push oil prices higher. This was the first coordinated move by oil producers to try to reduce the vast supply glut triggered by the OPEC strategy change announced on 27 November 2014.

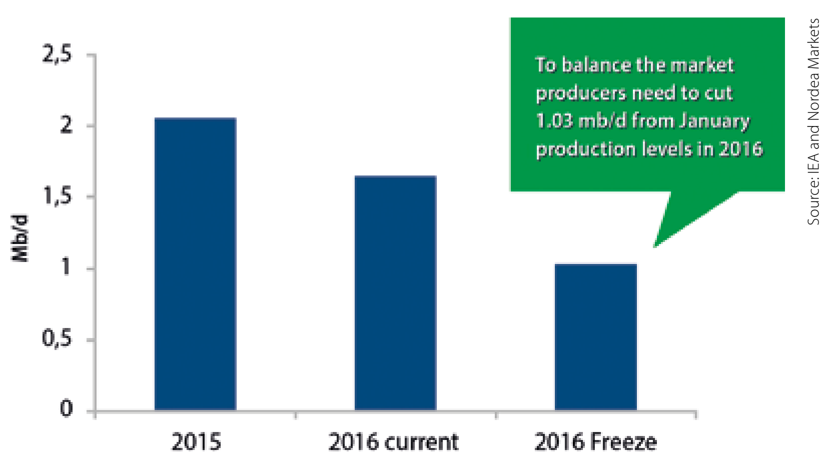
The deal was reached at a meeting in Doha, where OPEC members Venezuela and Qatar also joined the agreement. The effect of the deal is still uncertain, however, as vital players such as Iran and Iraq, which are seeking to ramp up production to improve their economic conditions, have yet to sign the accord, and are unlikely to do so. In fact, Iran is expected to increase production by around 700,000 to one million barrels a day this year and extend production capacity by another 2 MMbopd by 2020, as a result of the lifting of sanctions on the country's oil industry in January. Without support from Iran and Iraq the deal will have limited impact on the market.

What if all OPEC countries and Russia were to freeze their production at January's level: would oil prices increase sharply then?

Global oil supply reached 96.5 MMbopd in January, around 2 MMbopd higher than global oil demand – indicating the supply glut will continue to increase if nothing is done to slow oil output growth. In contrast, if all OPEC countries and Russia agreed to freeze crude oil production, global oil supply (IEA forecast 96.1 MMbopd) would still outbalance global oil demand in 2016 (IEA forecast 95.6 MMbopd), but only by 500 Mbopd. This could potentially push oil prices slightly, but not radically, higher as the market would still be oversupplied. If the producers are looking for a real bounce back in oil prices in the short term to a level some OPEC members have indicated would be an acceptable price – around US$60 a barrel – we need to see a real cut in oil production. A freeze would not be enough.

It is still uncertain whether the deal will gain wider acceptance from other vital oil producers. By suggesting a freeze to output at January's level Saudi Arabia and Russia are putting heavy pressure on Iran to limit output growth, as the country is the only producer apart from Saudi with a substantial production cushion to talk about and the ability to increase production markedly in 2016. If the deal is not accepted by other producers, oil prices are expected to remain at the current level of around US$ 33 per barrel in Q1, as it is hard to find drivers that can push prices significantly higher in the short term.

Thina Margrethe Saltvedt



ABBREVIATIONS

Numbers (US and scientific community)

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

Liquids

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

Gas

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

Ma: Million years ago

LNG

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

NGL

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

Reserves and resources

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

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

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

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

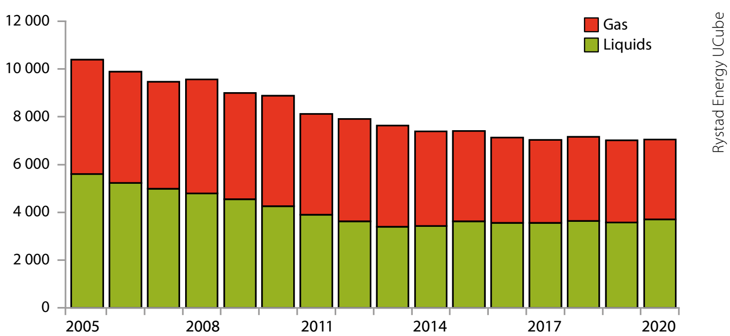
RYSTAD ENERGY

Western Europe:
Production Up – Exploration Down

Oil production in Western Europe increased for the first time this century.

Oil and gas production in Western Europe* was in decline from 2000 to 2014, with liquid production decreasing from 6.7 MMbopd to 3.4 MMbopd and gas dropping from 266 Bm^3 to 230 Bm^3. However, in 2015 liquid production increased by 200 Mbopd, the largest rise since 1996. This change in liquid production is due to a combination of things, including new project developments like Norway's Gudrun and the UK's Golden Eagle fields, the redevelopment of old producing fields such as Valhall and Ekofisk in the Norwegian North Sea, as well as less down time during the summer of 2015.

Gas, on the other hand, did not experience the same growth story, decreasing by 9.9 Bm^3 during 2015. This reduction was driven by the continued decline of the Groningen field in the Netherlands but was partly offset by an increase in production from the Norwegian gas fields. Total production for the year increased by 11% in the UK and 6% in Norway, but decreased in the Netherlands.



Total Western Europe production by liquids and gas (Mboepd).

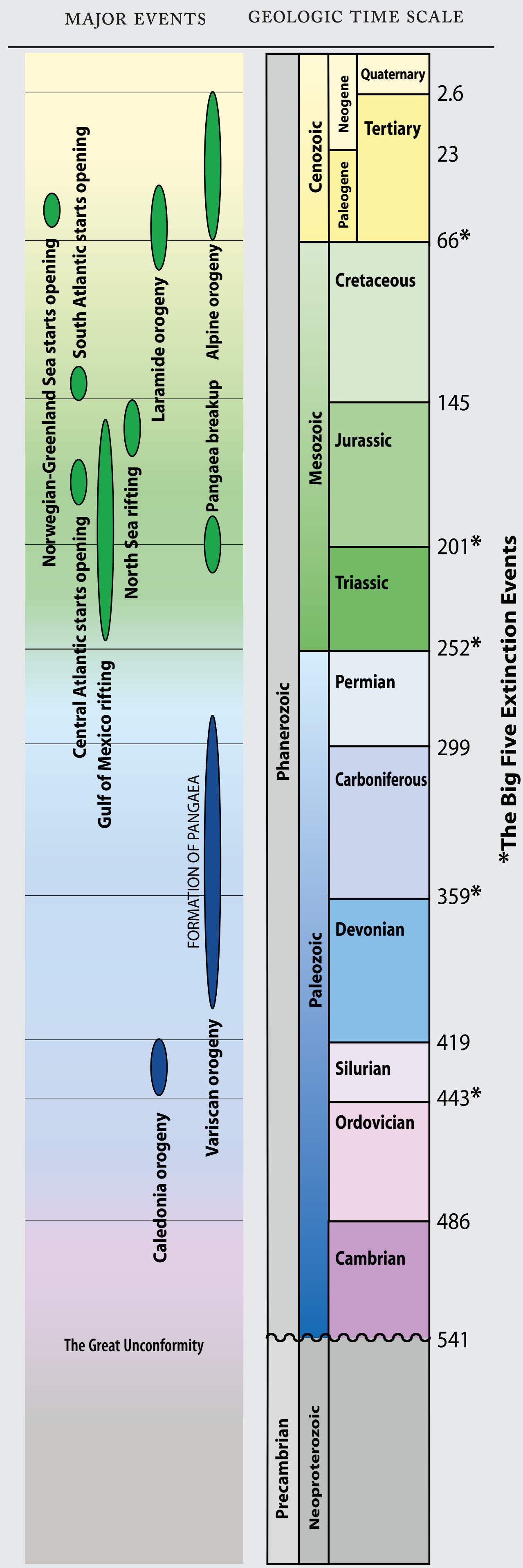
In terms of exploration, 2015 was a disappointing year, with only 430 MMboe of new volumes discovered, compared to production of 2,700 MMboe, implying a 16% resource replacement ratio. The largest discoveries last year were the ENGIE-operated Dalzier and Chrysaor's Mustard in the UK, and Norway's Julius and Snefried North fields, both operated by Statoil. The 2015 exploration results follow the declining trend in discovered resources of the last four years.

The overall level of activity was affected by lower commodity prices in 2015. Total E&P spending for Western Europe fell 25% in 2015 compared to 2014, ending the year at US$78 billion. The drop was a result of lower maintenance activity, coupled with a reduction in the prices that oilfield service organisations were able to charge the E&P companies and the weaker Norwegian krone. In 2016, spending is expected to fall another 10%, before gradually increasing in 2017.

Despite the reduction in short to medium term activity and the disappointing exploration results over the last year, Rystad Energy forecasts that liquid production from Western Europe will increase going forward due to the large projects that are currently being developed – quite an achievement considering the decline over the last 15 years. This does require a recovery in the oil price from the current low values, but 2015 has already shown that production from Western Europe is on its way back up. ■

Espen Erlingsen, VP Analysis, Rystad Energy

* Western Europe: Norway, UK, Netherlands, Denmark, Germany, France, Austria, Ireland



Johan Sverdrup Production Drilling

Development of **Johan Sverdrup**, one of the largest oil fields yet found on the Norwegian continental shelf, continues apace, with the announcement on 1 March, 2016 that production drilling had commenced. The rig *Deep Sea Atlantic* is working on the first of 35 wells, using a predrilling template installed on the field last year. Eight wells will be drilled through the template, use of which enables the production capacity on the field to be utilised as efficiently as possible when it comes on stream. The rig will then relocate to drill injection wells at three locations.

The permanent Johan Sverdrup drilling platform, which is under construction in Norway and Thailand, will be installed in 2018 and the eight predrilled wells will be hooked up from the predrilling template.

The field has estimated reserves of between 1.7 and 3 Bboe and peak production is expected to be equivalent to 25% of all Norwegian petroleum production. ■

A core sample from the original Johan Sverdrup (previously Aldous) exploration well.

Broadband Land Seismology

With exploration targets becoming smaller and more complex, the industry trend of increasing the use of broadband seismic acquisition in an attempt to identify important and detailed structural and stratigraphic features has shown no indications of flattening out.

For example, reef-flat carbonate reservoirs are the dominant facies developed along the eastern edge of the Pre-Caspian Basin. Due to the influences of salt domes, the pre-salt, stratigraphy-controlled traps cannot be clearly imaged with conventional sources, geometry, and processing methods. The boundary of the reef-shoal is not clear, and low resolution data fails to characterise thin carbonate reservoirs with strong heterogeneity. This has created a pressing need for broadband techniques that are compatible with the use of wide-azimuth and high-density acquisition.

BGP, one of the world's leading geophysical service companies, has developed a **specialised broadband vibrator, LFV3**, which enhances low frequency energy from 1.5 Hz. It has been deployed in a 3D land project in **Kazakhstan** to acquire a wide-azimuth, broadband, and high-density (**WBH**).

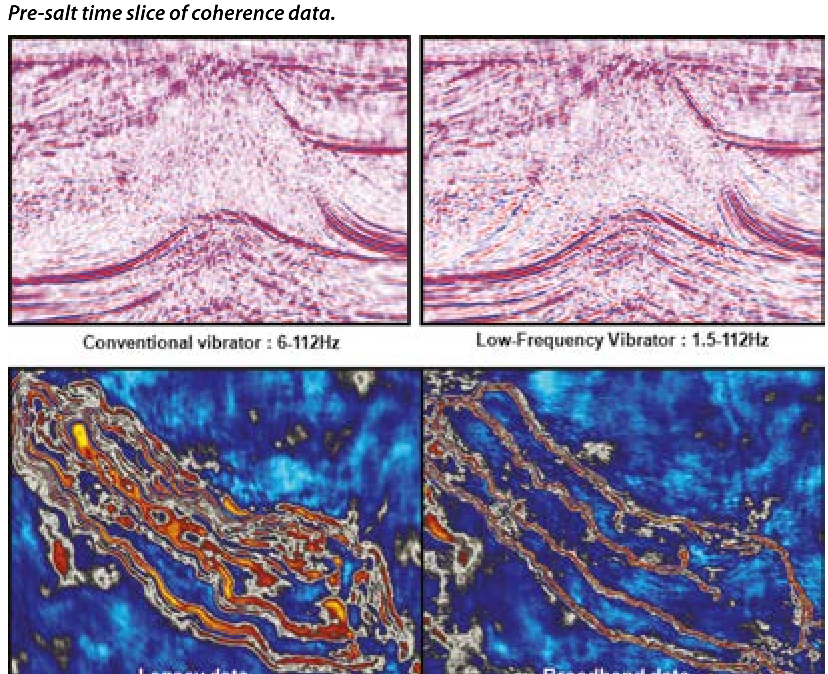
Using WBH Data

High-density data can be used to increase the spatial sampling density and reduce the impact of spatial aliasing, while data fidelity is improved through adaptive data-driven ground roll noise suppression methods, whilst maintaining low frequency components. When this data is combined with extensive near-surface uphole information, a more accurate near-surface model can be created, while the iterative process of the azimuthal velocity analysis and residual statics improves the accuracy of field statics.

Acquisition with the low-frequency vibrator means that abundant low frequency components can be obtained, so combining low-frequency recovery and high-frequency compensation techniques effectively widens the frequency band of seismic data. Wide-azimuth acquisition improves the illumination of targets, and wide-azimuth data processing in the COV (common offset vector) domain eliminates the effect of azimuth anisotropy and improves the imaging accuracy of targets.

Following the acquisition of this wide-azimuth, broadband, high-density data, a WBH processing and inversion flow was set up. The result was greatly improved imaging accuracy of the salt dome boundaries and pre-salt reflections, as well as increased resolution, leading to a more precise delineation of the geological features of the exploration targets. ■

Pre-salt time slice of coherence data.



From Morocco to Madagascar

From Morocco to Madagascar, from the eastern Mediterranean Sea to offshore Namibia, and across the greater expanse of Africa, industry activity is humming. Both on and offshore, major new reserves are proved almost monthly. Offshore East Africa continues to be the site for the discovery of thick gas-filled reservoirs; could similar deposits be found east of the Davie Fracture zone offshore Madagascar? Are there oil plays to be made in greater southern Africa, commonly thought to be dominated by gas? The onshore East African rifts are a developing oil province, with successes in Uganda and Kenya; rift plays in Chad, South Sudan, Ethiopia, Eritrea and Somalia beckon. The oil-rich, western flank of Africa is also a focus of discussion; much can be learned from the conjugate margins and regional studies of several West African basins indicate more possible shelf slope fan reservoirs.

These and many other issues will be on the agenda at the **15th annual Africa conference**, 12–14 September, in Houston, organised jointly by the **Houston Geological Society** and the **Petroleum Exploration Society of Great Britain** and held alternately in London and Houston.

Presentations and posters will address major questions about recent plays, successes and prospects, including the application of emerging technologies. See further details on the websites of the two societies. ■

Vienna Hosting EAGE's 2016 Annual Conference

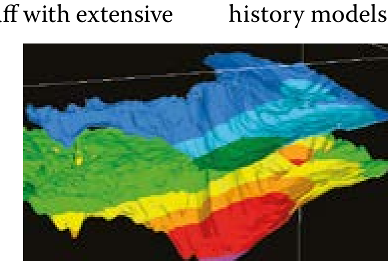
How do we face the most challenging period in the history of the oil and gas industry? Answering this question will be the top priority during the **78th EAGE Annual Conference and Exhibition 2016** (including SPE EUROPEC). It is the world's largest multi-disciplinary geoscience event, this year held in **Vienna**, Austria from 30 May to 2 June 2016 at Messe Wien Centre.

The main conference covers a wide variety of technical topics in parallel sessions, including oral and poster presentations. There are also numerous workshops to choose from as well as short courses and field trips. Following last year's success, several special sessions are on offer again, including the forum, executive sessions, and sessions for Young Professionals and Women in Geoscience and Engineering. Last but not least, the student programme, themed Perform & Peak, will provide a full programme with dedicated technical presentations, workshops, trial interviews and much more. In addition there is a large exhibition where around 350 companies are showcasing the latest technology and services.

Learn more about and register for the event in Vienna on www.eage.org/event/vienna-2016. ■

More Than Meets the Eye

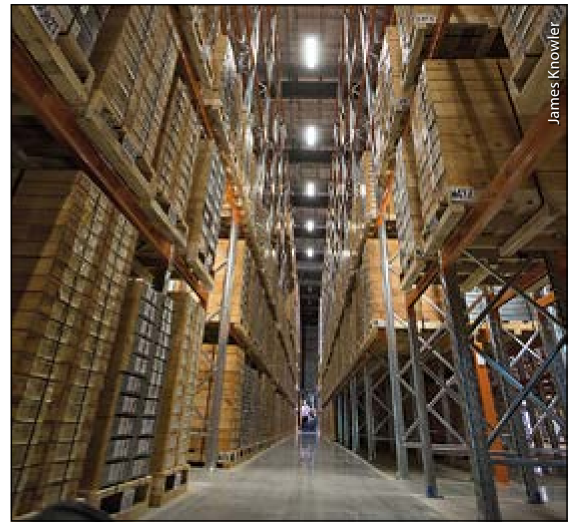
As the highly experienced geoscientists at **Applied Petroleum Technology (APT)** know, high quality geochemistry and biostratigraphy analyses are the ultimate support for important exploration decisions. APT, established in 2000, offers a wide range of interpretation and consulting services in the fields of **petroleum geochemistry**, **biostratigraphy** and **petroleum systems modelling**, using the expertise of staff with extensive experience acquired in oil and service companies, research organisations, and relevant fields outside the oil industry.



Services offered include petroleum geochemistry, encompassing routine lab analyses and microscopy, interpretation and integrated modelling, delivering data in easily usable formats. APT's routine well evaluation and offshore services include full biostratigraphic processing, analyses and interpretation using palynology and micropalaeontology, finalised in reports which emphasise the geological implications of the data and important aspects of the interpretation. The company also has extensive experience in petroleum system analyses, creating basin and thermal history models which provide quantitative understanding of the origin and evolution of petroleum systems through time and an assessment of extent and timing of hydrocarbon generation and expulsion within source rock systems.

Based just outside Oslo in Norway and with offices in the UK, Canada and Houston, APT is a company with plenty to offer. ■

Hi-Tech Drill Core Library



One of the world's most advanced drill core libraries, holding 130 years of samples, has opened in South Australia. The **South Australia Drill Core Reference Library** in Adelaide holds 7.5 million metres of drill core samples from across South Australia and can display up to 2 km of cores for inspection on a series of automated conveyor belts in the main viewing area. It also features a 3D viewing room, which uses virtual reality technology to give geologists a view of the geology and mineral deposits under the earth's surface.

Exploration companies in South Australia are required to provide samples of any core and cuttings taken to the State Development Department, which were previously held in at a number of separate drill core libraries across South Australia. The new library includes a massive eight story-high warehouse, with room for future samples for several decades.

The new South Australia core reference library

Get in the African Game!

Global Pacific & Partners with **ITE Group** will host the 23rd **Annual Africa Oil Week/Africa Upstream 2016 Conference** from 31 October to 4 November 2016, at the Cape Town International Convention Centre, South Africa. This event will again showcase the governments, NOCs, Licensin Agencies and corporate players shaping Africa's future. The 2016 conference highlights Africa's upstream world, involving independents engaged in Africa from around the globe, as well as those in the expanding Africa-wide gas-LNG and energy game and emerging unconventional ventures in shale and diverse hydrocarbons.

Top-level executives in the industry agree that the conference stands apart from all other events as the leading meeting in or on Africa, sitting at the top of the global O&G calendar, with 180 exhibitor companies and more than 1,250 senior executive delegates. These have unrivalled opportunities to meet with Africa's state oil officials and senior executives and to acquire insight and knowledge from an outstanding programme with 175 top-line speakers. They can discuss ventures with major oil/energy banking institutions, investors, multilaterals and transaction advisors and network with the growing service and supply industry operators found across Africa's oil and gas-LNG value chain.

You're only inside Africa's oil and gas game if you are at Africa Upstream 2016. ■

Enhancing Capabilities

Specialist geosciences company, **Bridgeporth**, was founded in 2011 by a small team of highly qualified geoscientists to provide specialist geoscientific services for a range of national and international operators in oil and gas exploration, mining, hazard mitigation, research and media industries. To ensure it can always offer the most appropriate service for its clients' needs, parent company **AustinBridgeporth** is collaborating with Lockheed-Martin to provide gravity gradiometry acquisition services. In addition to its conventional airborne gravity instrumentation, it will now be able to offer both **Full Tensor Gravity Gradiometry (FTG)** and state-of-the-art **Enhanced FTG (eFTG)** acquisition to its global client base. By adding to its land and marine potential field capabilities, AustinBridgeporth aims to offer a truly multi-disciplinary integrated approach to non-seismic exploration.

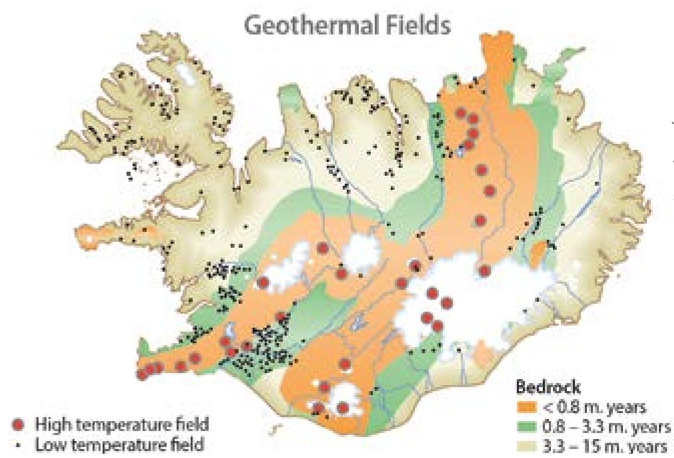
It chose Lockheed-Martin's FTG instrumentation because this has become the industry standard in high-end potential field imaging, which by measuring minute differences in the Earth's gravity field allows geoscientists to image subsurface structure and complexity in unprecedented detail. Lockheed-Martin's new eFTG system increases accuracy even further with a noise level three times lower than its predecessor, which translates into an increase in acquisition efficiency and ability to image subtler geological structures. ■

Iceland
Harnessing the Earth

Iceland is one of the pioneers in the use of geothermal energy, both for heating homes and generating electricity.

JANE WHALEY

Iceland is a country shaped by and reliant on its geology in a remarkable way. Not just because its resultant stunning scenery encourages ever-increasing numbers of foreign visitors – up 20% per year on average since 2010, with tourism responsible for nearly 30% of the country's export revenue – but because its geology means that the country's electricity is almost entirely generated from renewable energy sources. The majority comes from hydroelectricity, as the water disgorged from the central highlands and ice fields drops hundreds of metres through spectacular waterfalls, releasing enormous amounts of energy in the process. However, 24% of electricity in Iceland is generated by geothermal energy, and over 90% of buildings in the country now have it as their heat source.



Geothermal fields in Iceland. There are at least 20 high-temperature areas with underground temperatures reaching 250°C within 1,000m depth, all directly linked to the active volcanic systems. About 250 separate low-temperature areas (those not exceeding 150°C in the uppermost 1,000m) are found, most in the areas flanking the active zone.

Where Does Geothermal Heat Come From?

The heat in the earth is generated in the mantle and crust by the decay of uranium and thorium. Iceland, one of the most tectonically active places on earth, sits on the Mid-Atlantic Ridge dividing the North American and Eurasian plates, and this is the reason why it can access such large volumes of geothermal energy. It lies above a 'hot spot' where the molten deep mantle material wells up from depth and either emerges at the surface in the form of volcanoes or intrudes into the shallow geology, increasing the temperature of the surrounding rock and groundwater, which in turn makes its way to the surface in the form of hot springs and geysers. More than 600 springs with temperatures over 20°C have been located in the country.

Iceland's abnormally hot crust, warmed by rising magma, is the heat source for the water, but the extensive fracture system, exacerbated by ongoing tectonic activity, provides channels for the water to circulate and distribute the heat.

As can be seen from the map above, high-temperature

The Krafla geothermal power station in north-east Iceland was a pioneering development, which opened in 1978. It uses steam from 18 boreholes to drive two 30 MW turbines.

zones, where underground water can reach temperatures of 250°C within 1,000m of the surface, are primarily located within the active volcanic zones, mostly on high ground. The bedrock in these areas is less than 0.8 million years old and very permeable and the water table is deep. Under pressure, the water emerges through vents at the surface as steam, which contains high quantities of hydrogen sulphide. The highest recorded downhole temperature for groundwater in Iceland is 386°C.

Groundwater with lower temperatures – between 20 and 150°C – is found in older rocks, usually close to the edges of the main south-west to north-east trending volcanic zone. The groundwater is of meteoric origin, falling on the central highlands and percolating down until it meets the hotter bedrock, when it warms, resulting in a lower density, causing it to rise again, often reaching the surface as hot or boiling springs.

Steam rising from a hot pool at Geysir in south-west Iceland, from which the phenomenon gets its name. Hydrogen sulphide in the steam tends to be oxidised at the surface by atmospheric oxygen, either into elemental sulphur deposited around the vents, or into sulphuric acid, which leads to acid waters altering the soil and bedrock, as can be seen here.

Water from the low-temperature areas is primarily used to heat homes, while that from high-temperature areas, which is too mineralised and gas-rich for domestic use, is used to power turbines and thus generate electricity.

Steaming Bay

Iceland was first settled in the 9th century by Viking explorers, who arrived in the south-west and were so impressed by the visibly steaming thermal springs that they named their town Reykjavik, or 'Steaming Bay'. Icelanders have always enjoyed bathing in hot natural pools as well as using them to wash their clothes, with stories of bathing in naturally heated water going back to the 13th century.

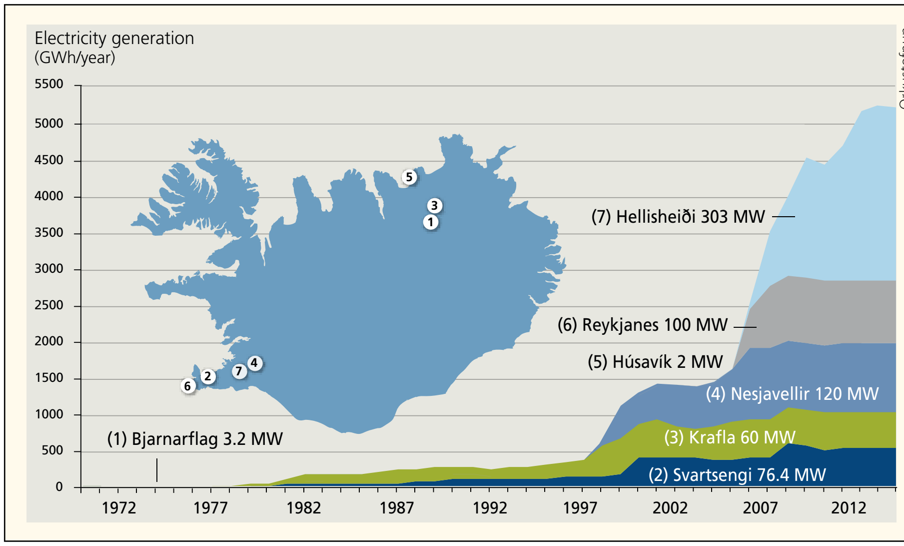
Geothermal water was not used domestically, however, until early in the 20th century, when water from nearby springs was piped into houses and also into greenhouses. These projects were all financed by individuals, but in the early 1930s official drilling into the hot reservoirs began, in the Laugardalur valley, in order to provide hot water and heating to local schools, hospitals, swimming pools and houses in Reykjavik. Initially, technology limited drilling to less than 250m, but the development of the steam rig in 1958 allowed wells to be drilled up to 3,000m, accessing the deeper groundwater reservoirs.

The beginning of the 1970s saw the introduction of steam to generate energy using turbines. The first power stations of this kind were built in the mid-1970s by the Icelandic government at Bjarnarflag and Krafla, in the Lake Mývatn area in north-east Iceland, although development at the latter was hampered by political feuds and technical complications as well as volcanic activity. A year after construction work began an eruption only 3 km away sent corrosive gas into the geothermal system, which destroyed the borehole linings. The tectonic activity did not calm down until 1984.

Svartsengi, the first geothermal power plant on the

Reykjanes Peninsula, was started in 1977, and the latest addition to it was constructed in 2008. Water which had been through the turbines and heat exchanger was collected in a mineral-rich man-made pool – now known as 'The Blue Lagoon', one of Iceland's premier tourist attractions, which draws hundreds of thousands of visitors a year.

There are now six geothermal power stations in Iceland, the biggest, and also the third largest on the world, being at Hellisheiði in the Hengill area in south-west Iceland. It was opened in 2006 and now has a capacity of 303 MW of electricity and 400 MW of hot water.



Geothermal power plants in Iceland, showing the capacity of each one.

Minimal Environmental Issues

Geothermal energy is considered a 'clean' fuel, as it does not burn fossil fuels, and most geothermal plants emit about a sixth of the carbon dioxide of a relatively clean natural-gas-fuelled power plant, while binary plants (see box below) emit none. And, unlike other renewable energy sources such as wind and solar power, it is always available, and it is also very safe. Although the initial outlay, particularly drilling wells, is costly, running a geothermal power plant is relatively inexpensive; savings from direct use are reported to be as much as 80% over fossil fuels.

However, the conversion efficiency of geothermal power developments is generally lower than that of conventional thermal power plants such as coal, natural gas, oil, and nuclear power stations. In addition, exhaust heat is often wasted, unless it can be used locally in greenhouses, timber mills and for district heating.

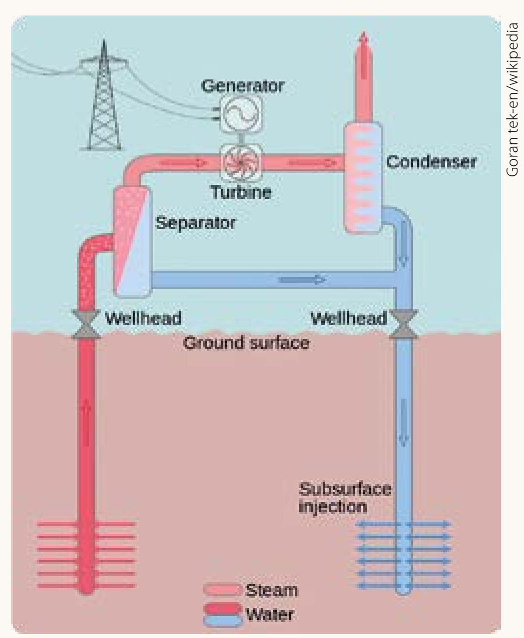
Although thought of as a 'green' source, geothermal energy does bring with it some environmental issues, particularly the release of hydrogen sulphide with its unpleasant smell, while the waste water may contain toxic elements such as arsenic and mercury, which are harmful if released into rivers or lakes instead of being reinjected.

It is a undoubtedly a renewable energy source that can be utilised in a sustainable manner, but the process of extracting geothermal fluids is thought to remove heat from natural reservoirs at over ten times their rate of replenishment, partially balanced by injecting waste fluids back into the system. There is also a danger that natural features such as hot springs, mud pools and geysers can be irreparably damaged by geothermal development. Excessive production from a geothermal field is therefore not sustainable, but in Iceland they use 'stepwise development', which takes into consideration the individual conditions of each geothermal system, looking at the production and response history of the

Generating Geothermal Electricity

To produce geothermal-generated electricity using the 'flash steam' method, wells up to 3 km deep are drilled into underground reservoirs to tap very hot water usually at a temperature of over 180°C, effectively using the earth as a fuel source. The fluids rise naturally and as the pressure decreases, some of the water boils into steam. On reaching the surface, the fluids goes through a separator, and then the steam component passes through a mist eliminator to make it as 'dry' as possible, before being used to drive the turbine of a generator, producing electricity. After going through the turbines, the steam passes through a heat exchanger or condenser, where it can be used to heat fresh cold water for household use, before being reinjected into the ground to return to the groundwater system, creating a simple, sustainable circuit.

The most recent development in geothermal energy is the binary cycle system, which has the advantage of being able to use water at a lower temperature, in the region of 60°C. This heats a secondary fluid which has a much lower boiling point than water, causing it to rapidly vapourise, and the force of the expanding vapour, like steam, turns the turbines that power the generators.



reservoir during the first development step to estimate the size of the next development step, thus minimising damage as well as long-term production costs.

Leading the Science

Icelanders have benefited hugely from the fortuitous geological siting of their island, where the energy current beneath it has been estimated to be about 30 GW. The development of geothermal resources has had a notable impact on social life; better space heating improves both comfort and health, while snow-melting in private and public spaces and sports arenas has increased safety and allowed people to enjoy outdoor sports in winter. Beautiful geothermal swimming pools have developed into social meeting places for all generations, while the type and variety of foods available in the country have improved through the heating of greenhouses.

Iceland is now one of the leading countries in geothermal science and technology, with a well-recognised community of scientists, engineers and academics whose advice is often sought by countries looking to develop their own resources. Cutting-edge research includes the Iceland Deep Drilling Project, a long-term study of high-temperature hydrothermal systems in Iceland.

The earth is a huge heat engine, and after 4.5 billion years we have about 85% remaining, so Icelanders should be able to keep themselves warm for some time yet!

Acknowledgement: Many thanks to Prof. Jon Gluyas for assistance with this article. ■

Although geothermal energy makes an important contribution, over 75% of Iceland's electricity comes from hydro plants.

Promising Portugal

Good sediment thickness; multiple trapping mechanisms; excellent energy-hungry markets nearby; and large areas available for leasing: time to take a look at underexplored Portugal.

UPEP/ENMC

Lying at the far south-western end of Europe, Portugal is associated with seafaring explorers, white beaches and sweet fortified wine – but not hydrocarbons. Yet though few wells have been drilled, the results were often encouraging, and the necessary ingredients for potentially economic accumulations – mature source rocks, sealed reservoirs and traps – are all present. No commercial production has yet been achieved, but with new moves to encourage further exploration, together with very favourable contractual and fiscal terms, this may change.

Thick Accumulations of Sediments

The western Iberian Peninsula suffered several distinct phases of extension, uplift, subsidence and inversion during rifting related to the North Atlantic opening and the closure of the Tethys Ocean in the Jurassic.

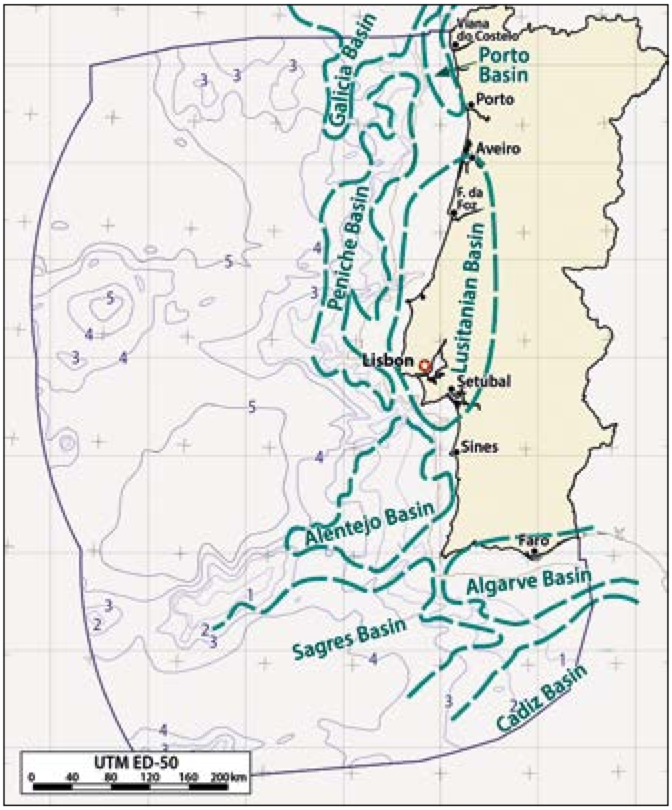
The earliest, syn-rift, sediments in Portugal are Late Triassic coarse red continental clastics, overlain by thick evaporite deposits mainly made up of Late Triassic–Early Jurassic salt and anhydrite, succeeded by Early Jurassic shallow marine carbonates. As regional subsidence continued through the Early and Middle Jurassic deeper marine carbonates were deposited in the north, with shallower carbonate platform deposition further south and west. Uplift in the mid–late Jurassic resulted in a regional unconformity over most of the basins, before rapid subsidence resumed during the Late Jurassic.

An abrupt influx of coarse continental clastics at the end of the Jurassic reflects the initiation of a second rifting phase, eventually leading to the separation of the Iberian and North American plates, with a shallow transgressive sea spreading over the area in the Late Cretaceous. Episodes of igneous activity and the emplacement of sub-volcanic massifs in the vicinity of present-day Lisbon at this time may be related to the opening of the Bay of Biscay.

During the Paleogene continental and shallow marine clastics and carbonates were deposited, before Neogene subsidence and marine transgression resulted in thick accumulations of shallow marine to terrestrial carbonates and clastics in all basins. Compression caused by the collision of the African and Eurasian plates led to basement shortening and inversion, especially in the northern and central basins. Most of the structuration resulting from these compressional episodes was controlled by pre-existing Hercynian basement faulting

Bruce Winslade

The tall cliffs and lighthouse of Cape St. Vincent, the south-westernmost point of Portugal, looking west into the Atlantic Ocean. For centuries this promontory has been a major landmark for seafarers heading for the entrance to the Mediterranaean. The lighthouse is amongst the most powerful in Europe – its power and height enable it to be seen for up to 60 km out to sea.



Portuguese Meso-Cenozoic basins: with an area of over 100,000 km² and only 175 wells, most basins are underexplored. (Bathymetry in kilometres.)

and often amplified by halokinesis, sometimes leading to the formation of diapirs that pierced the entire sedimentary cover.

Exploration History

Only 175 wells have been drilled in Portugal, a mere 27 offshore and only four in deeper waters, but 117 had oil or gas shows, including 16 offshore. The majority of exploration to date has been in the Lusitanian Basin just to the north of the capital, Lisbon, and the Porto and Algarve Basins, in the north and south of the country respectively. Onshore, 5,856 km of 2D and 580 km² 3D have been acquired, while offshore surveys have covered 67,000 km 2D and 9,752 km² 3D.

Hydrocarbon exploration in Portugal began in the early part of the 20th century, mostly near oil seeps in the Lusitanian Basin. The first exploration and production concession, covering the Lusitanian and Algarve Basins, was granted in 1938 and 78 wells were drilled in the Lusitanian Basin by 1969, most shallower than 500m. Many had strong shows and some achieved sub-commercial production. Gravity and magnetic data were also acquired, while the only exploration in the Algarve Basin was a gravity survey.

The prospective areas both on and offshore were then divided into blocks in a regular 5′Lat/6′Long grid and offered for bidding to the industry. In 1973 and 1974 30 contracts for offshore areas were signed. This led to the drilling of 22 offshore wells by 1979, two of which produced small amounts of oil on test, while several others had good shows. Interest then moved onshore and 1978–2004 saw the drilling of 28 wells, 23 in the onshore Lusitanian Basin. Again, many of these had good shows, mainly oil, but no production resulted.

In 2002, after a major offshore seismic campaign by TGS, Portugal launched a bidding round with 14 deep offshore blocks, two of which were taken up, followed in 2007 by a significant increase in interest with the signature of 12 new concession contracts, including seven in the deep offshore of the Alentejo and Peniche Basins, resulting in 2D seismic surveys in these deepwater areas. The first 3D seismic surveys in Portugal were acquired in 2010, and to date areas in the deep-offshore Peniche and Alentejo Basin, on- and offshore the Lusitanian Basin and the deepwater Algarve Basin have been surveyed.

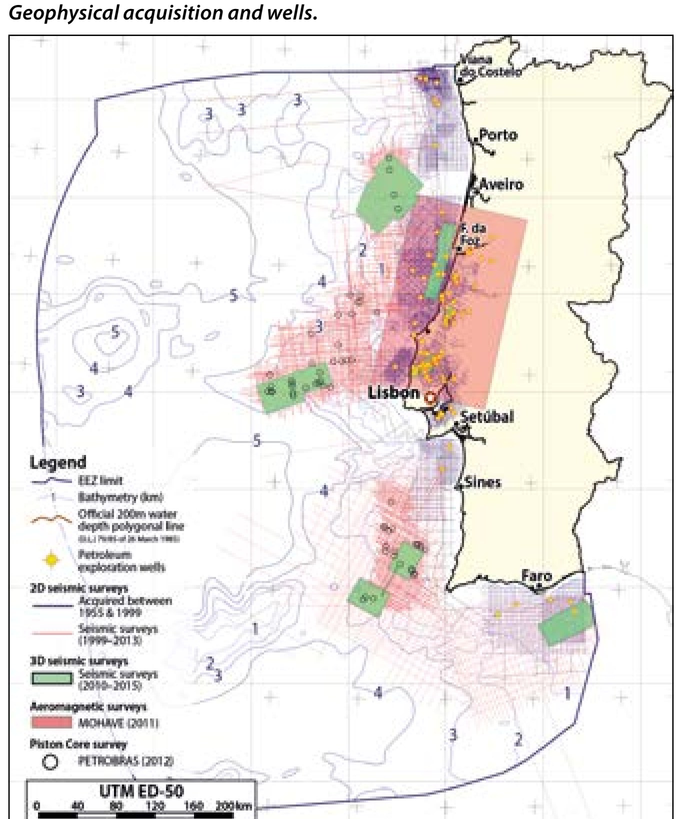
Underexplored Basins

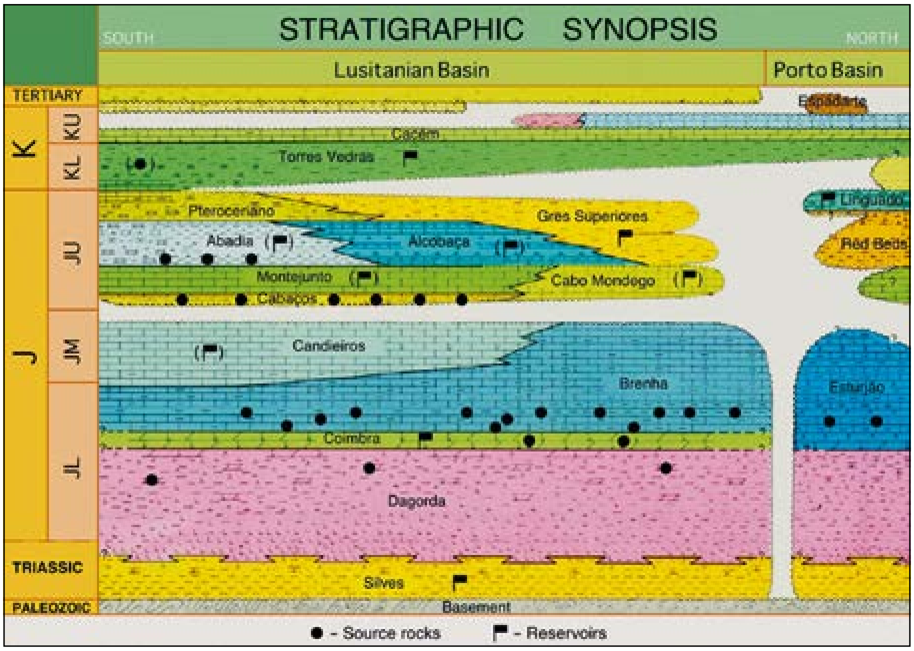
Three of the Meso-Cenozoic Portuguese sedimentary basins – Porto, Lusitanian and Algarve – lie in shallow waters offshore, sometimes extending onshore, while the remaining five are predominantly in over 1,000m of water. During the uplift, subsidence and inversion associated with plate movements significant quantities of hydrocarbons were generated, as evidenced by the numerous surface manifestations and well shows.

Porto Basin: This offshore basin extends northwards into Spain and westwards into waters over 2,000m deep. It contains up to 8 km of Late Triassic to Late Cretaceous sediments, overlain by a generally thin Cenozoic cover. The Triassic evaporitic sequence is less developed in this basin. The most promising reservoir rocks are probably shallow marine, deltaic sandstones within the Lower Cretaceous Torres Vedras Formation. Only eight wells have been drilled, four with oil or gas shows.

Lusitanian Basin: Lying south of the Porto Basin and extending onshore, the Lusitanian Basin shares the same tectonic environment, related to the evolution of the Palaeozoic

Geophysical acquisition and wells.





Stratigraphy of the Lusitanian and Porto Basins.

Basement. The sediment fill is also similar, with maximum sedimentary thickness of some 6 km, mostly Jurassic, and a thin Cenozoic cover. It is the most explored of the Portuguese Basins, with 162, predominantly shallow, wells, a number of which had shows or produced oil when tested.

Algarve Basin: The Algarve Basin lies in the very south of the country both on and offshore, extending eastwards into Spain as the Spanish Cadiz Basin. It was influenced tectonically both by Atlantic opening and by movement of the North African Pelagian Platform and contains at least 7 km of late Triassic to Recent sediments, with a greater thickness of Cenozoic, particularly Neogene, sediments than the other inner basins. It is largely unexplored, with only five wells, two with weak gas shows. Due to its geological similarities with the Gulf of Cadiz, gas-bearing reservoirs are expected. Basin modelling and multiple indirect indices suggest thermogenic hydrocarbon generation, expulsion and accumulations. A well is due to be drilled in the basin in the near future.

Outer Basins: The Galicia Interior, Peniche, Alentejo, Sagres, and Gulf of Cadiz Basins, lying to the west of the other basins in up to 3,000m of water, have never been drilled although 2D and 3D surveys have been undertaken in them. From these and from piston cores obtained by the concession holders, the basins are known to have thick sections of Triassic, Jurassic and Lower Cretaceous sediments and the petroleum systems evident in the inner basins are expected to be present. In addition, the Triassic evaporitic layer is thought to be particularly deep, with halokinetic structures playing an important part in the formation of structural traps. DHI's like brightspots and flatspots seen on seismic provide indications of a working hydrocarbon system and several mapped leads appear to be very large.

Plays and Petroleum Systems

Although not fully explored, it is thought that two main petroleum systems are present throughout the country, including offshore. The first is the **Palaeo-Mesozoic Petroleum System**, sourced by Palaeozoic black Silurian shales, which have total organic content (TOC) of 0.5–1.5 or more and vitrinite reflectance values of 0.7%, placing them in the oil window. Another potential source is the marine Carboniferous, which may be over-mature, but could produce dry gas. Reservoirs in this system are found in the Upper Triassic or younger, particularly the coarse red clastics of the Triassic Silves Formation, which show good reservoir characteristics on outcrop along the rims of the Lusitanian and Algarve Basins, although grain size and porosity decrease towards the centre of the basins. Porosity, though variable, can be up to 20%. The system has not been fully tested, although gas accumulations have been linked to it.

The second system is the **Meso-Cenozoic Petroleum System**, which has Mesozoic source rocks and Mesozoic and/or Cenozoic reservoirs and seals. In the main depocentres of the Lusitanian and Porto Basins there is evidence of significant thicknesses of oil-prone, deep marine shales of the Lower Jurassic Brenha Formation, which have TOC values of 0.2–5.8%. Rich source rocks have also been found in the southern Lusitanian Basin in Upper Jurassic bituminous

The Jurassic Brenha Formation is thought to be the source for the Meso-Cenozoic petroleum system.

limestones of the Cabaços Formation, which have TOC values up to 3% and maturation levels ranging from immature to over-mature.

The sands and conglomerates of the Triassic Silves Formation again make a potential reservoir in this system. In the Algarve Basin Middle Jurassic vuggy dolomites and limestones with porosities up to 11% have been observed in wells. These could potentially make good reservoirs, as could the Upper Jurassic reefs commonly found in the Lusitanian and Porto Basins. In the former, friable sands and conglomerates of the 300–400m thick Cretaceous Torres Vedras Formation with porosities of up to 35% potentially constitute an excellent reservoir. These rocks are sealed by Lower Jurassic or younger marls, shales and evaporites.

There are multiple trap types evident in Portuguese basins, but over 90% of the wells drilled to date in Portugal targeted structures, possibly because they are easier to identify on seismic, bearing in mind the fact that most wells were drilled in the 1970s and '80s. Structural traps include late inversion of Tertiary and Cretaceous reservoirs, while hydrocarbons could be trapped stratigraphically in Miocene channel fills, as in Mauritania, or in turbidites and basin floor fans of the same age. Salt diapirs and reefs are also potential drilling targets.

An as yet unexplored play present in all Mesozoic basins is the subsalt beneath the Lower Jurassic evaporitic Dagorda Formation. This could be sourced by Silurian graptolitic black shales of the Sazes and Vale da Ursa Formations, thought to have TOC values of 0.5–8%. The syn-rift Silves Formation is expected to be the primary reservoir, formed when regional scale drainage systems deposited mature siliciclastic sediments in the basins. In addition, the transitional carbonate and anhydrite beds at the base of the Dagorda evaporite sequence offer a primary target for the subsalt play. The seal would obviously be the Dagorda evaporites, which exhibit different thicknesses and lithologies but are found throughout the basins. The play is expected to be gas-prone.

Conjugate Margins

Interest in Portugal is increasing, aided by the relative accessibility of the country and attractive concession and fiscal systems, coupled with the low, intermittent level of exploration. There is plenty in the geology to encourage explorers, including the fact that, before rifting, several of the Portuguese basins were close to the Grand Banks-Newfoundland area, where a recent assessment suggested there are yet-to-find reserves of 12 Bbo. They show a common initial genesis and geological similarities to prolific Canadian basins like Jeanne D'Arc. Similarly, the southern Portuguese basins were close to the Morocco Variscan Belt, formed in a similar geological setting to that of the recent discoveries off Mauritania.

With only 175 wells drilled in an area of over 100,000 km^2 and promising, unexplored geological basins, it is definitely time to take another look at Portugal.

ENMC, E.P.E. (National Authority for the Fuel Market) is the agency of the Ministry of Economy responsible for handling matters concerning hydrocarbon E&P in Portugal. UPEP: Petroleum Exploration and Production Unit ■

Unlocking the Petroleum Potential of Iran

GIS databases are a powerful tool for minimising exploration risk in Iranian hydrocarbon basins through geospatial analysis.

JAN WITTE and Dr. OLAF SCHÖNICKE
Falcon Geoconsulting, Germany

Iran's enormous surface area stretches over 2,300 km in a north-west to south-easterly direction – almost the distance from London to Istanbul. Inside this extensive territory there are several highly prospective sedimentary basins, which host a number of world-class petroleum plays. Iran holds the fourth-largest proven crude oil reserves and the second-largest natural gas reserves in the world (EIA, 2015). In simple terms it can be described as an assemblage of rigid crustal blocks forming the centre of the country, surrounded by a number of mobile orogenic belts (Figure 1), with the Zagros foldbelt being the most prominent and most prolific of these basins. In this article we will demonstrate how modern GIS databases can help to conduct regional studies and how they support exploration teams in reducing drilling risks in established and frontier hydrocarbon basins.

GIS Databases: Workflows and Benefits

A comprehensive proprietary GIS database covering the Middle Eastern countries from Egypt to Oman is currently being built by Falcon Geoconsulting. To date, this database, which covers Iran, already contains more than 30,000 GIS-based features, including digital elevation data, newly interpreted sedimentary basin outlines, distribution of salt basins, tectonic provinces, re-interpreted structural elements, structural cross-sections, basement maps, individual categorised faults, fold axes, lineaments, seeps, hydrocarbon fields, wells, individual salt structures, undrilled prospects, stress data, structural play fairway maps, cultural data and many other elements. The data is incorporated from publicly available sources and it is consistently georeferenced and digitised, before being integrated and re-interpreted according to the latest geological concepts. The database specifically focuses on tectonic and structural data, such as different types of faults and lineaments, present-day stress data, fracture data, etc.

The benefits of such a database are twofold. Firstly,

Figure 2: Simplified stratigraphic chart of the Zagros Foldbelt. Key source rocks are of Palaeozoic, Jurassic and Cretaceous age; main production comes from Cretaceous and Tertiary reservoirs. Fundamental detachment levels are typically located in evaporites (modified after Alsharhan & Nairn, 2003; Jahani, 2008; Barzgar et al., 2015).

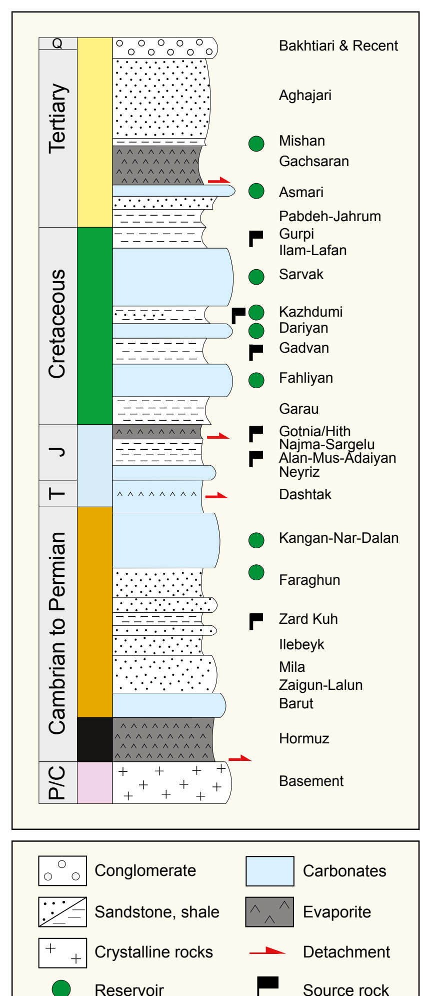
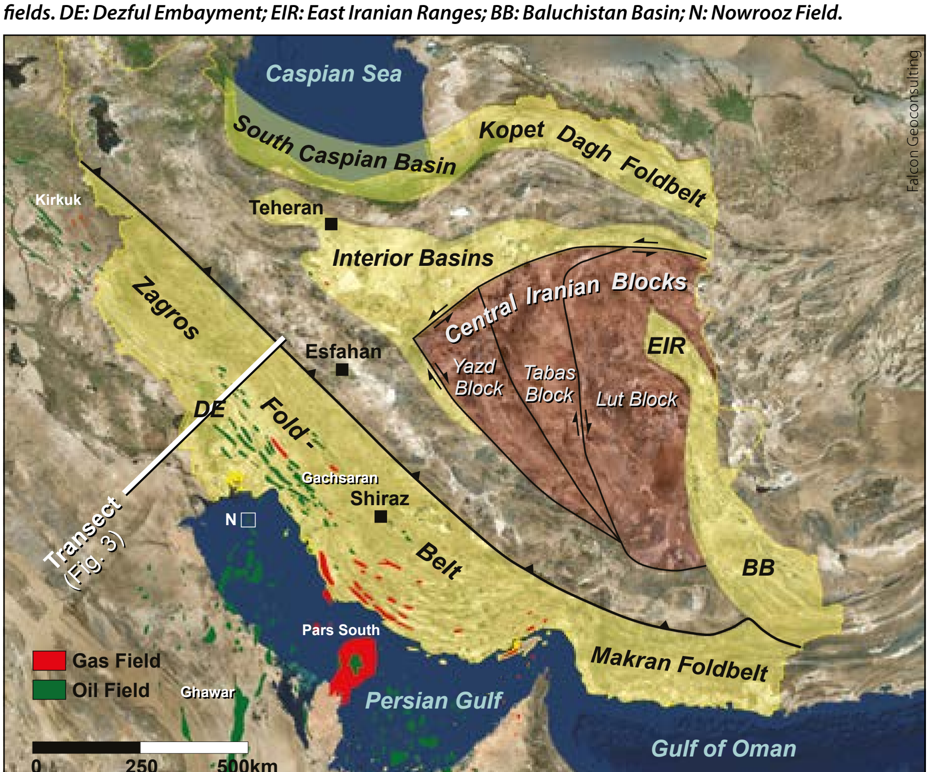


Figure 1: Schematic geotectonic map of Iran; showing major tectonic elements, basins and hydrocarbon fields. DE: Dezful Embayment; EIR: East Iranian Ranges; BB: Baluchistan Basin; N: Nowrooz Field.



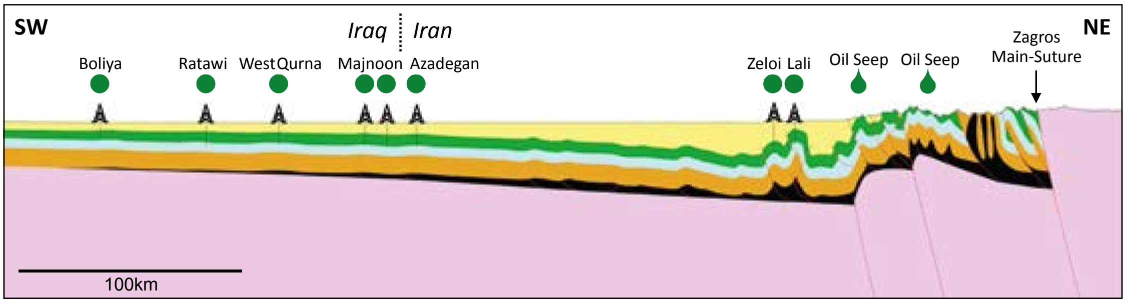


Figure 3: Schematic regional structural cross-section (2.5x vertical exaggeration); for stratigraphic colour code see Figure 2; for location see Figure 1.

statistical GIS data on petroleum basins is fundamental for regional evaluations, in order to understand how exploration-mature certain basins are and where upside potential is located. Whilst this data will help to de-risk existing plays, it can also be used to develop new ones. Secondly, local structural data, such as lineaments, categorised faults, fractures and stress data, will greatly help with projects at the prospect or field scale, supporting field development strategies and – ultimately – result in better recovery factors.

The data integration has already led to a detailed stratigraphic understanding of the different basins of Iran. Figure 2, detailing the Zagros zone, illustrates the way in which numerous highly prospective petroleum plays are stacked vertically above each other, explaining why the Zagros belt is such a prolific hydrocarbon province.

Data Integration and Regional Structural Analysis

Digital elevation, well, geochemical and remote sensing data, together with structural geology and other data sources, are integrated to build regional structural cross-sections. The transects can be restored incrementally to their pre-deformational state, with the aim of understanding the lateral distribution, relief, timing, migration routes, access to kitchens and charge risk of paleo-structures.

The transect in Figure 3 reveals how thin- and thick-skinned structural styles interact. Near the Zagros thrust front most of the relief is generated by deeply rooted thick-skinned structures, whilst a superimposed thin-skinned system adds additional relief (e.g. Kashfi, 1980; McQuarrie, 2004). The thickness of the Hormuz salt decreases significantly westward and so does the influence of the thick-skinned structures, meaning that the distal structures are much less pronounced than the proximal ones, located above thick salt. Distal structures such as Azadegan, Majnoon or Ratawi still accommodate shortening through salt-detachment, but the importance of evaporites is much lower there than at the mountain front. In the absence of Hormuz salt, salt-detached traps cannot form, an important observation when exploring for salt-related prospects.

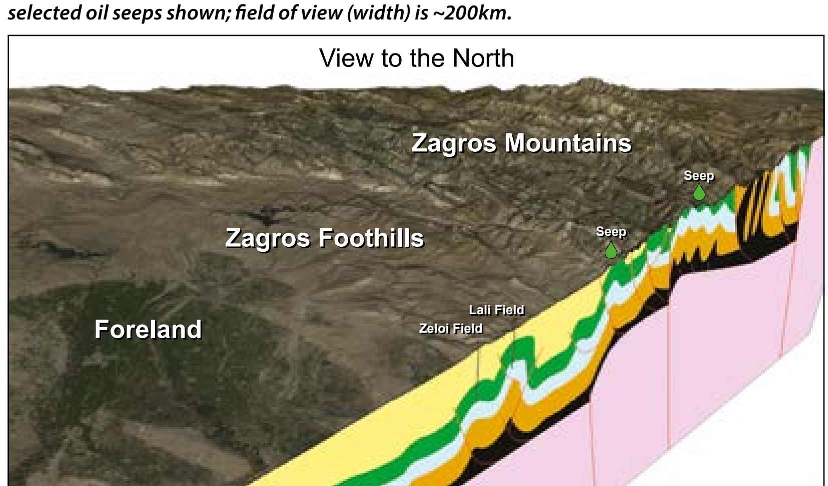
Known oil seepages are found mainly in highly deformed strata near the mountain front, where either hydrocarbons migrate to the surface via leaking faults or, alternatively, previously buried and impregnated reservoirs are currently being eroded at the land surface. 3D visualisations of satellite imagery and subsurface data help to assess the context of structural models and possible breaching risks of prospects (Figure 4).

Mitigating Exploration Risk in Iran's Petroleum Basins

A very valuable tool in exploration risk management is the integration of remote sensing data, surface geology and geochemical information from oil seeps. These must be very carefully assessed, as oil seeps or oil impregnations may be indicative of different scenarios. An oil seep above a trap may indicate that the structure is breached and is actively leaking hydrocarbons to the surface, while seeps located between the kitchen and the trap may mean that the migration has been inefficient and the trap may not be fully charged. Seeps located updip from the kitchen but beyond the prospect may indicate that migrating oil has reached the trap, filled it to spill and is migrating further updip towards the basin edge. Tectono-morphologic visualisations (see Figure 5), if part of an integrated workflow, significantly help to assess the spatial context of migration routes and breaching risks.

To fully explore the vast potential of the Iranian hydrocarbon resources, we believe that surface and subsurface data integration should be undertaken for all potentially prospective Iranian basins, utilising the latest technological and geological methods. A lot of data is available for the established Iranian basins, which have been explored for decades, where consistent GIS and structural data integration will contribute to the discovery of new reserves and to optimised recovery from existing fields. For Iran's frontier basins, such as the Central Iranian Basins, where only a few discoveries have been made to date, as well as the South Caspian Basin, the Amu-Darya Basin (hosting major gas-condensate fields) and the Kopet-Dagh

Figure 4: View from Zagros foreland towards the north, across the Zeloi and Lali oil fields; selected oil seeps shown; field of view (width) is ~200km.



belt, GIS analysis and structural assessment will lead to a better understanding of the prospectivity and will therefore help to uncover upside potential that has been overlooked so far.

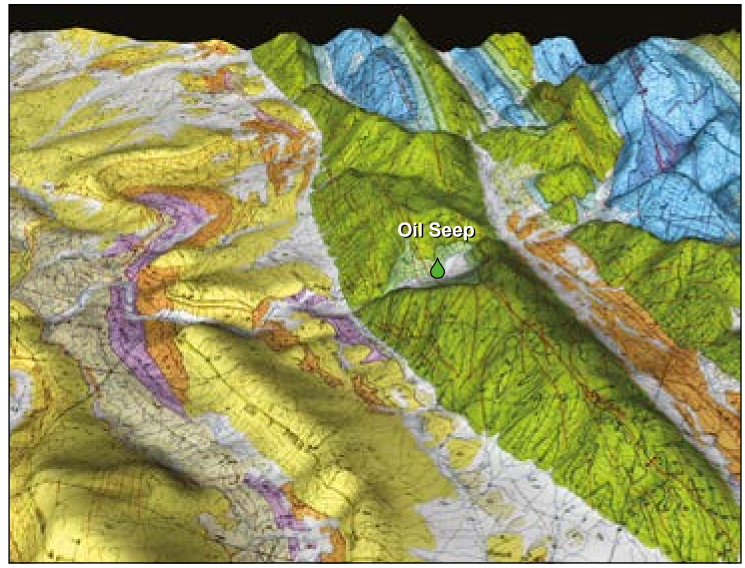


Figure 5: Oblique view of a 3D-model built from digital terrain data, surface geology (Perry & Setudehnia, 1967) and seep data, looking north along the Gurpi and Pabda anticlines, showing the oil seep in the erosional window of the Pabda anticline. Field of view ~26km. Green: Oligocene outcrop; blue: Cretaceous outcrop.

Prospect and Field Scale Assessment

In addition to giving a regional perspective, the integration of a statistically significant number of structural data elements (faults, anticlines, lineaments, domes, arches, etc.) at the prospect-scale allows for the detailed assessment of individual reservoirs and their associated production behaviour. The integration of present-day stress data, for example, directly mitigates operational risks, as it has implications for well planning, borehole stability, breakouts, induced fractures, the behaviour of open versus closed fractures, coring operations, production and injection behaviour.

For the assessment of fractured reservoirs (clastics or carbonates) it is necessary to build 3D reservoir models, based on seismic data, well logs, surface geology (if applicable), production data and core data. Once the static 3D structural model is finalised, kinematic structural modelling is conducted, which is needed for two reasons. Firstly, as a quality assurance tool it will quickly reveal geometric inconsistencies in the model; and secondly, kinematic modelling allows for strain analysis of the reservoirs and seals and can help to detect 'sweet spots' (areas of higher fracture intensity) in the reservoir and to map highly strained areas in the cap rock, possibly indicative of a damaged seal.

A structural 3D model of the Nowrooz Field, based on public data, reveals that its overall structure is a transpressional anticline, over 18 km long, dissected by two longitudinal faults (Figure 6). The main reservoir here, the Azadegan sandstone, belongs to the Early Cretaceous Kazhdumi Formation (Ghazban and Motiei, 2007). Curvature analysis was conducted and two anomalies of increased curvature have been mapped, one in the south-west quadrant and the other to the north-east. When displaying the oil water contact, present well locations and the curvature anomaly, it is easy to see undrilled and highly curved domains which could be potential targets for future infill drilling.

If detailed and localised fracture data from wells, cores, image logs and outcrops is available for a field, discrete fracture network models can be built and exported directly into reservoir simulation software. These models are a strong tool to better understand and optimise fluid flow inside the reservoir. Fracture analysis and fracture modelling will also improve extraction and injection strategies as well as permeability-enhancement of reservoirs. Hence, if applied correctly, these workflows may help to prevent early water breakthrough (or other reservoir damage) and enhance the ultimate recovery rates of fractured reservoirs.

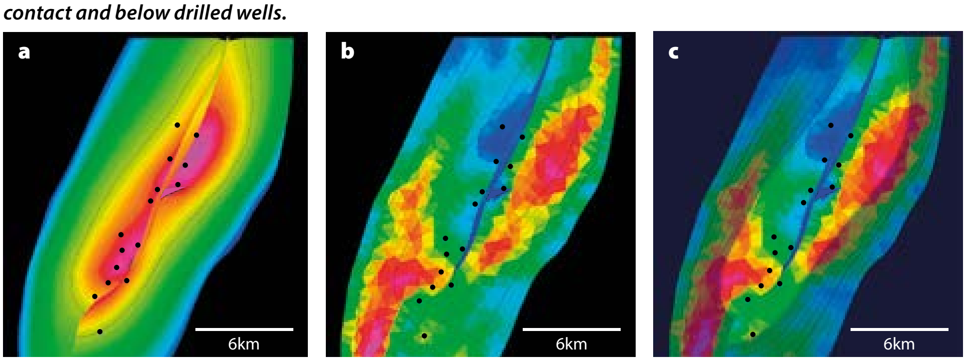
Outlook

This article gives an insight into how modern GIS database management can help optimise basin-scale or field-scale petroleum projects. For a robust workflow it is fundamental that the data be integrated with modern geological and structural concepts. In our experience, it is common for G&G staff to work on the prospect-scale without the regional context, which can lead to interpretation biases and consequently to dramatically wrong strategic and economic decisions. For both exploration and development projects, the regional context has a tremendous economic impact, a fact often overlooked by explorers and managers. We suggest the regional GIS approach should be used for any exploration or development project.

If the data is integrated consistently and according to modern concepts, GIS databases are a powerful tool to minimise exploration risks and to unlock new petroleum potential, in Iran or elsewhere.

References available online. ■

Figure 6: Different structural maps of the Nowrooz oil field (for location see Figure 1), extracted from a 3D reservoir model and shown in map view. (a) Structural map of the Nowrooz oil field; Azadegan sandstone reservoir, C.I. 10m. (b) Curvature map of the Azadegan sandstone reservoir; C.I. 10m. Warm colours show high curvature, cold colours show low curvature. Curvature can be used as an indicator for fractures. (c) As (b), but with oil water contact shown, which helps to determine highest curved areas above the oil water contact and below drilled wells.

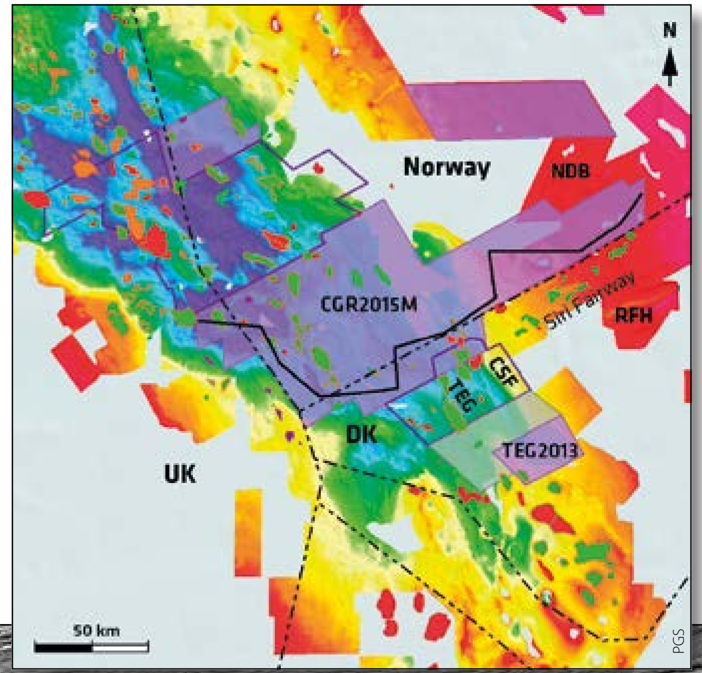


3D Broadband Seismic in the Southern Central Graben

Enabling an enhanced regional perspective and revealing new potential plays

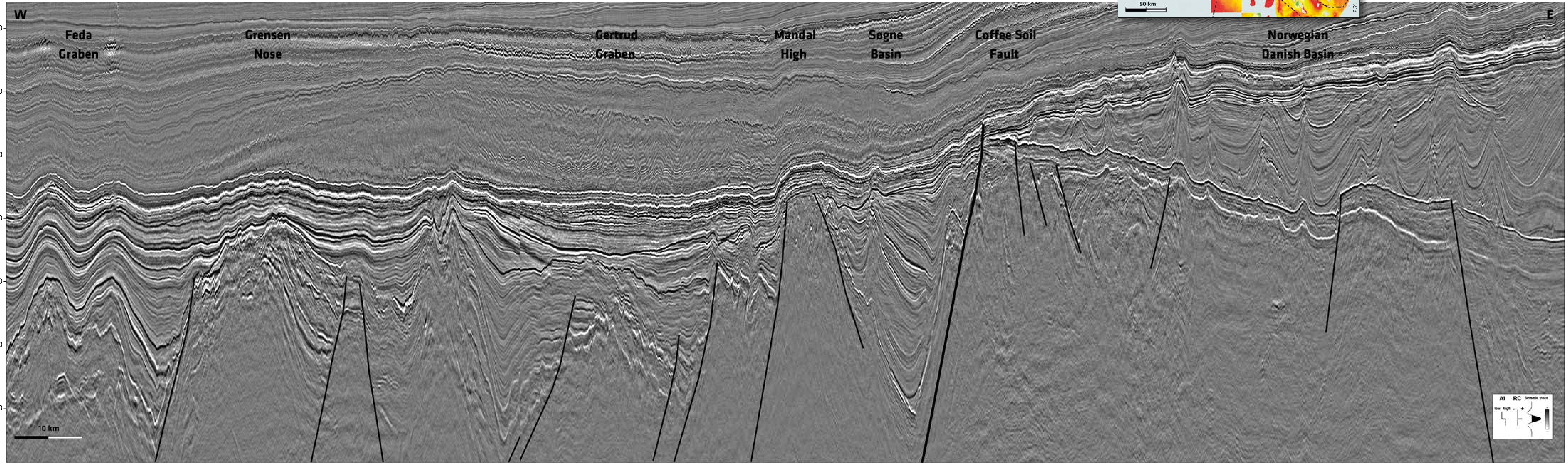
Regional west-east seismic section from the Feda Graben in UK waters, through part of the Gertrud Graben in the Danish sector and over the Mandal High and Coffee Soil Fault into the Norwegian Danish Basin. The section highlights the sharp imaging of structures and faults, particularly at depth, allowing for a better regional geological understanding of the complexity in the area.

The ongoing acquisition by PGS of true broadband seismic in the Southern Central Graben of the North Sea can help to develop established plays whilst generating new ideas to revitalise this mature province. Even after several decades of extensive exploration, development and production using conventional seismic, it remains an important hydrocarbon exploration province. Since 2010 PGS has acquired 3D GeoStreamer® data over a large proportion of the Southern Central Graben area. Several of these broadband dual-sensor surveys have been merged to form a large high quality regional dataset CGR2015M, seamlessly covering a significant part (approximately 9,000 km²) of the North Sea Graben Province across the Norwegian, Danish and UK sectors. During the 2015 season, PGS completed the acquisition of two further GeoStreamer surveys north-west and south of the existing coverage, providing an additional 6,000 km² of coverage over the Tail End Graben in the Danish sector and extending the GeoStreamer coverage towards the East and West Central Grabens to the north. This dataset with enhanced imaging enables an improved regional perspective and understanding whilst revealing the full exploration potential in the greatest detail. The new wave of regional GeoStreamer towed dual-sensor streamer surveys provide the explorationist with the tool to reveal more of the hidden potential within this area thanks to the imaging and Quantitative Interpretation possibilities in determining structural definition, lithology and fluids in both existing and potential plays.



PGS

PGS GeoStreamer coverage in the Central Graben, North Sea. The black line represents the foldout line. The purple outlines show the most recent area of acquisition (in processing), while the polygons with purple infill show existing coverage. The grey polygon shows planned acquisition. The horizon displayed is the TWT Base Cretaceous Unconformity (BCU), with dark blue/purple colours indicating the deeper parts. Fields are green (oil), red (gas) and orange (condensate). TEG: Tail End Graben; NDB: Norwegian Danish Basin; RFH: Ringkøbing-Fyn High: CSF: Coffee Soil Fault.



New Potential in the Southern Central Graben

JENS BEENFELDT and SIMON BAER, PGS

Is it possible to determine where the future hydrocarbon potential lies or to identify a new play that will ensure continued interest and growth in the Southern Central Graben of the North Sea?

The Southern Central Graben is a significant oil province and contains important plays at several stratigraphic levels, from the deltaic-shallow marine sandstones of the Middle-Late Jurassic to the Upper Cretaceous – Early Paleogene marine chalks and shallow marine-turbiditic sandstones.

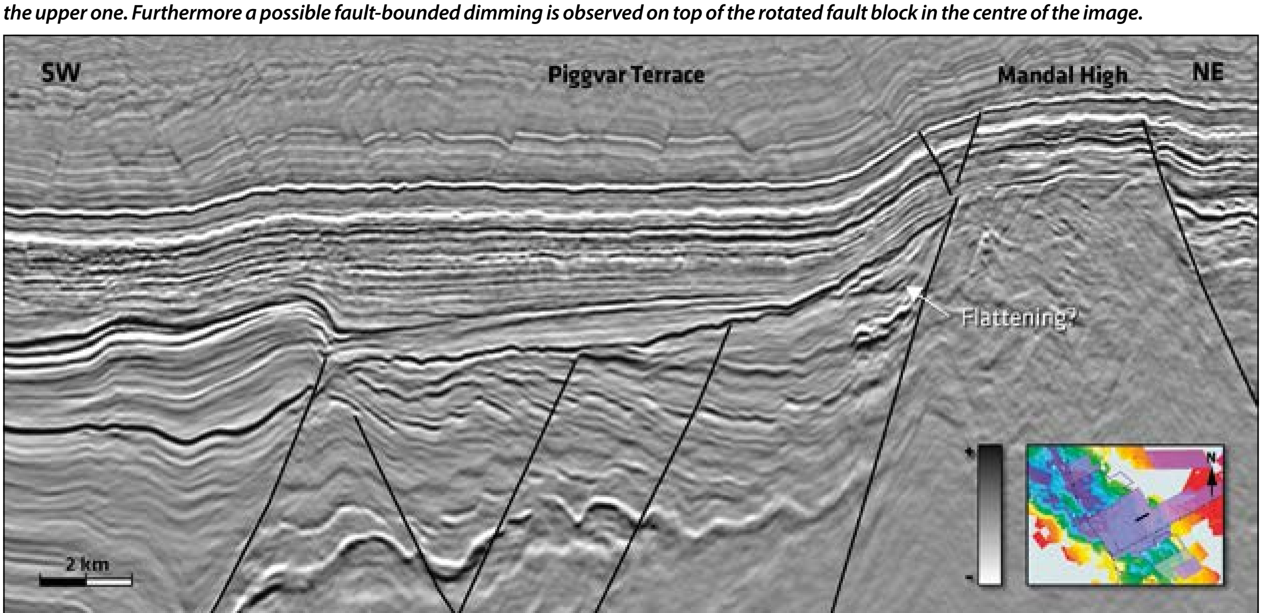
With more than 150 wells in the region, many of the large structures have been drilled and have yielded producing oil fields in the Norwegian sector, such as Valhall and the Ekofisk complex with estimated recoverable volumes of more than 1 Bboe and 6 Bbo respectively. In the Danish and UK sectors several fields, smaller but significant for the province, including South Arne (~269 MMbo), Harald (~204 MMbo) and Affleck (~20 MMbo), are producing.

Analogues to Johan Sverdrup

Often the key to a new play in an area is to seek analogues of a play concept that has been successful elsewhere. Arguably the most successful play on the Norwegian margin in the last decade has been in the Johan Sverdrup area. In that case, more than a dozen wells had previously been drilled to basement on the Utsira High and found only thin or absent Jurassic-Triassic successions with no hydrocarbons interpreted, and the prevailing industry view was that this large high 'platform' area was a barren basement high on the flanks of the main Mesozoic graben. A fresh regional examination of the integrated elements of a play combined with modern seismic imaging provided the keys to open up this now prolific play.

In 2014, the Norwegian exploration industry's attention was drawn to the South Central Graben area of the CGR2015M GeoStreamer dataset, where Det Norske sought to pursue the same play concept almost 300 km along the basin margin to the south. Well 2/9-5S, located on a terrace to the west of the Mandal High, targeted an Upper Jurassic play and a secondary 'pre-Jurassic' play in a rotated fault block on the margins of a large fractured basement high. Unfortunately, this new well was dry, with only thin minor sandstone intervals at both Jurassic and pre-Jurassic target levels. Although a disappointing result, the play concept of Middle-Upper Jurassic sandstones being distributed down flank from the Mandal High onto the Piggvar Terrace and possibly further on into the Gertrud Graben are still considered viable targets. Illuminating them, mapping their distribution and characterising potential stratigraphic or structural traps accurately becomes essential for evaluating and de-risking leads or prospects in the area. GeoStreamer's improved imaging and broader frequency spectrum, including more low frequencies, provides that opportunity and allows the interpreter to confidently map the structural complexity. The AVO/

Seismic section over the Mandal High and Piggvar Terrace showing a wedge-shaped geometry with possible syn-rift deposits of Jurassic age down flank from the high. Within this wedge, two amplitude brightenings can be observed towards the main fault of the high with a possible flattening in the upper one. Furthermore a possible fault-bounded dimming is observed on top of the rotated fault block in the centre of the image.



AVA capabilities of GeoStreamer data coupled with the well control in this mature area should allow the delineation of the lithology and fluids within reservoir intervals, thereby helping to de-risk the area with regards to the location of possible reservoirs, traps and seals.

The figure (left) shows several potential scenarios where hydrocarbons could accumulate around the Mandal High and within the Piggvar Terrace areas. The traps include rotated fault blocks, folding due to local inversion and stratigraphic traps on the flanks of the high.

In well 2/9-3, the Late Jurassic Kimmeridge Clay Formation was proven to be within the upper part of the oil window and wells in the area have also penetrated potential reservoir sandstones in the Middle to Upper Jurassic Bryne Ula Formations. In addition, the Mandal High shows fault/fracture patterns in the metamorphic basement that could act as migration pathways or as a fractured basement reservoir. All of this indicates that there is still remaining hydrocarbon potential in the main Central Graben area.

Illuminating Subtle Traps

Moving further east within the CGR2015M dataset, to where the Coffee Soil Fault separates the Danish Central Graben from the Ringkøbing-Fyn High and the Norwegian Danish Basin, the exploration focus changes from the Jurassic-Cretaceous within the Central Graben to the Paleocene (Siri Fairway) close to the Norwegian-Danish border. Evidence on the seismic data of chaotic geometries with thickness variations in the Paleocene, combined with a general lack of continuous reflectors in the CGR2015M survey, could potentially indicate a sand-rich system. These are interpreted to be related to the intra-Paleocene channel mounds of the Siri Fairway just to the south. The new CGR2015M survey could enable the stratigraphy and traps relating to the Siri Fairway on the platform that is proven in the Danish sector, to be mapped further to the north in the Norwegian sector and extend the exploration potential.

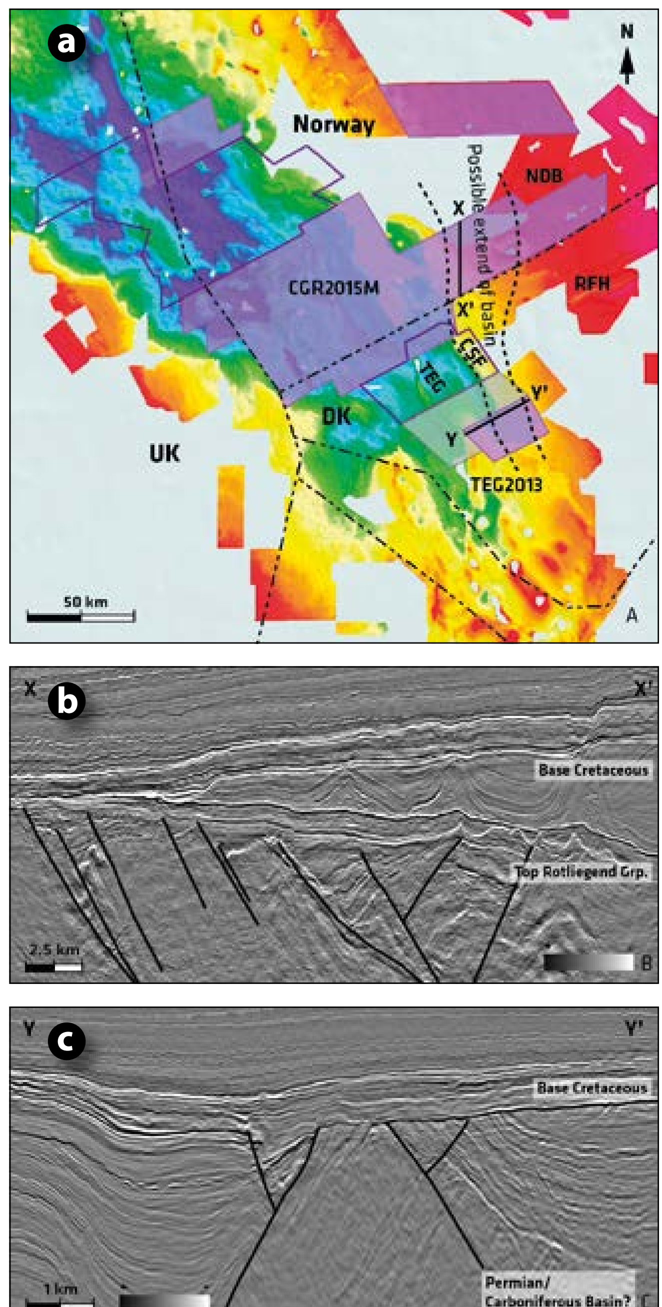
Additionally, a Permian-Carboniferous sub-basin in the Norwegian Danish Basin to the east of the Coffee Soil Fault can now be identified. This basin has been poorly understood using conventional seismic data, but GeoStreamer data has greatly improved the imaging of the deep structure, where rotated fault blocks can be observed, which could represent potential hydrocarbon traps for future exploration targets.

The Permian-Carboniferous basin continues to be exposed to the south in the TEG2013 survey, where the sediment infill is up to 750m thick towards the north (see figure right), truncated against a basement high to the south. The northwards dip of the basin within the TEG2013 survey and the similar geological setting of the basin to that of the CGR2015M survey indicates that it extends from the Tail End Graben along the east side of the Coffee Soil Fault, northwards to the Norwegian Danish Basin, as seen in the CGR2015M survey. Future surveys (see map on page 30) aim to provide the next piece of the puzzle towards unravelling the deep structure in this area.

Within the Permian-Carboniferous sub-basin in the TEG2013 area there is a change in dip and seismic character which could be associated with the permo-Carboniferous unconformity, providing geometries for stratigraphic and structural traps for hydrocarbons sourced from Carboniferous coals (see figure below.)

The combination of seamless broadband regional seismic combined with good well control will allow explorationists an opportunity to unravel more of the regional geology and unveil potential new plays across this already highly prolific region. Through illuminating the more subtle traps within this established area and exploring the edges, the Central Graben is still unveiling new potential. ■

(a): Base Cretaceous Unconformity (BCU) map in TWT with blue-purple colours representing the deeper areas. Overlaid is PGS's current GeoStreamer data coverage (filled purple), data recently acquired (purple polygons) and planned surveys in grey. A possible extension of a Permian-Carboniferous Basin is highlighted with dashed lines. Examples of this basin are shown in (b) for line X-X' and (c) for line Y-Y'.

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Australia's 'Big Red' Centre

'Big Red' country, encapsulated in Australia's first National Landscape – Australia's Red Centre is now being recognised as a major draw for global travellers seeking outstanding geotourism experiences in the country.

ANGUS M. ROBINSON and CHRISTINE EDGOOSE, Geological Society of Australia

To best experience Australia's Red Centre, a six- or seven-day tour is recommended, commencing at Uluṟu (also known as Ayers Rock) and following the famous 'Red Centre Way' in a continuous loop which travels across the landforms of Kings Canyon and the West MacDonnell Ranges through to the town of Alice Springs. The trip traverses many of the sedimentary sequences of the Amadeus Basin, where sedimentation spanned from the late Neoproterozoic to the Devonian, when deposition ceased around 350 million years ago in response to the intracratonic Alice Springs Orogeny. Since that time a long period of erosion has resulted in the distinctive landforms now forming the Red Centre landscape and a wide variety of evolved land systems, accentuated by the iron-rich red soil.

Uluṟu-Kata – Spiritual Home of the Anangu People

The first place to visit after arriving at the airport at Yulara is the Uluṟu Cultural Centre of the Uluṟu-Kata Tjuṯa National Park, to learn about the culture of the indigenous people (Anangu). This park is internationally recognised as a World Heritage Area, one of the few properties to be dual-listed by UNESCO for both outstanding natural and cultural values. The Cultural Centre explains the foundation of aboriginal culture, Tjukurpa – the traditional law that guides Anangu daily life. Visitors can also take an interpretative walk of the geology and indigenous culture around the base of Uluṟu (Ayers Rock) – the world-famous exposure of the early Cambrian Mutitjulu Arkose – before enjoying a classic Uluṟu sunset, as the vast inselberg slowly moves through a broad spectrum of colours.

To truly appreciate the colours, rise early to witness, from the Talinguru Nyakunytjaku lookout and interpretative walking trail, a spectacular Uluṟu sunrise, seeing its terracotta-coloured surface bathed in flaming red. In the distance Kata Tjuṯa can also be seen emerging under sunlight.

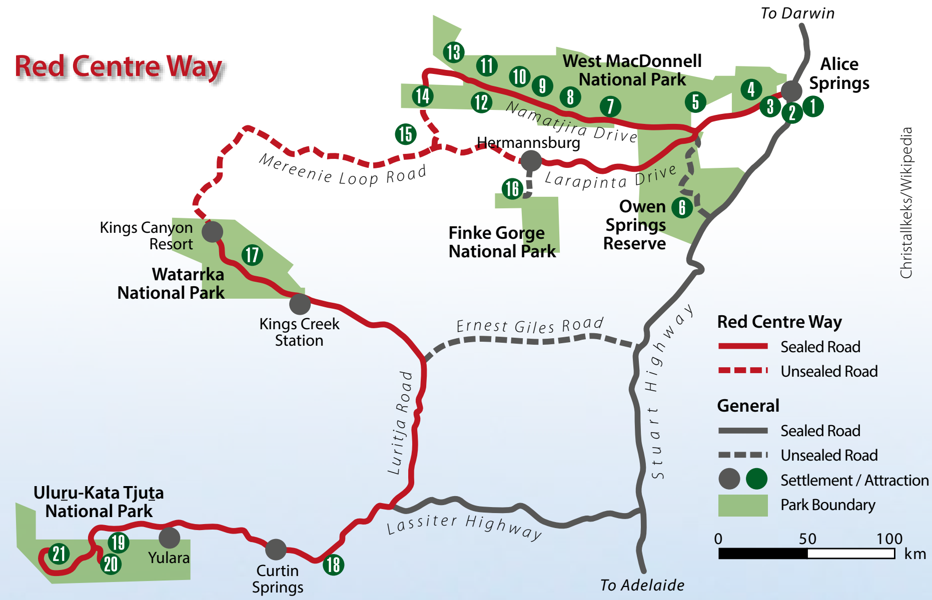
Kata Tjuṯa is some 50 km from Yulara, where you can enjoy outstanding walks at the Kata Tjuṯa Dune viewing area, the Valley of the

For world travellers, the large red inselberg of Uluṟu, in Uluṟu-Kata Tjuṯa National Park, instantly identifies the island continent of Australia, but Kata Tjuṯa in Uluṟu-Kata Tjuṯa National Park is similarly spectacular. The domes that make up Kata Tjuṯa are composed of early Cambrian conglomerate.

Parks Australia and Tourism Australia

Winds, and the Walpa Gorge. The 36 domes that make up Kata Tjuṯa cover an area of 21.8 km^2 and are composed of early Cambrian conglomerate, a sedimentary rock consisting of cobbles and boulders of varying rock types which include granite and basalt, cemented by a matrix of sandstone, deposited at the same time as the Mutitjulu Arkose at Uluṟu.

Leaving the Uluṟu-Kata Tjuṯa National Park and after traversing vast sand dune land systems and passing the Mount Conner mesa, you arrive at the Watarrka National Park, where a great place to stay is the fabulous Kings Canyon Wilderness Lodge – 'glamping' at its very best. Interpreting the geology exposed in the walls and along the rim of Kings Canyon (within the Watarrka National Park), composed of the Silurian-Devonian Meerenie Sandstone, as well as seeing the flora of Kings Canyon on either the rim walk, or the easier watercourse walk up through the Canyon, will occupy a whole afternoon – preferably followed by a gourmet Aussie barbecue and an interpretative astronomical tour of the brilliant, crystal-clear southern skies.



1 Araluen Cultural Precinct
2 Alice Springs Desert Park
3 Flynn's Grave
4 Simpsons Gap
5 Standley Chasm
6 Owen Springs
7 Ellery Creek Big Hole
8 Serpentine Gorge
9 Serpentine Chalet
10 Ochre Pits
11 Ormiston Gorge
12 Glen Helen Gorge
13 Redbank Gorge
14 Tylers Pass
15 Tnorala (Gosse Bluff)
16 Palm Valley – Finke Gorge
17 Watarrka (Kings Canyon)
18 Mount Conner
19 Vulara Visitor Centre
20 Uluṟu (Ayers Rock)
21 Kata Tjuṯa (The Olgas)

Mereenie Loop Drive – An Outback Experience

Travelling along the famous unsealed and rugged outback road known as the Meerenie Loop is an exciting journey, best done with a four-wheel drive vehicle. It passes through some dramatic Australian outback scenery and across several of the major formations of the Amadeus Basin, as well as through the Meerenie gas field. Along the way you pass the Gosse Bluff meteor impact crater of Cretaceous age, and then travel through some of Australia's finest Red Centre scenic landscapes, featuring outstanding River Red Gums and Ironwoods.

The beautiful Ormiston Gorge of the West MacDonnell Ranges.

The stunning and beautiful Ormiston Gorge introduces visitors to the spectacular geology and landforms of the West MacDonnell Ranges, where the geology is very complex, with much folding and overthrusting of the strata. Immediately past the entrance gates to Ormiston Gorge Park is an anticline outlined by the late Neoproterozoic Heavitree Quartzite, the oldest formation in the Amadeus Basin sequence. At the main waterhole, the Heavitree Quartzite in the base of the cliff is overlain by a repeated sequence of Heavitree Quartzite which has been thrust southwards from several kilometres to the north.

Ellery Creek flows southwards across the basin sequence, beginning at a gap in a ridge of Heavitree Quartzite at Ellery Big Hole. The trip along the creek covers the Neoproterozoic to Palaeozoic history of the Amadeus Basin, and finishes at exposures of the Devonian Brewer Conglomerate, deposited in response to the early stages of the Alice Springs Orogeny. On the way it cuts through the Ordovician source and reservoir rocks of the Mereenie and Palm Valley gas fields.

Also in the West MacDonnell Ranges is Standley Chasm. About 900 million years ago magma was introduced into fractures in much of the basement rock of the Arunta Region, which pre-dates the Amadeus Basin, west of Alice Springs. The fractures were vertical and extended north-south. This intrusion opened the fractures and the magma cooled and formed dolerite. At Standley Chasm the dolerite intruded the approximately 1,600 million-year-old Chewings Quartzite (now comprised of interlayered quartzite and mica schist). Dolerite is much less resistant to weathering and erosion than quartzite, and during the latest weathering cycle a south-flowing creek eroded out a dolerite dyke, leaving vertical quartzite walls at Standley Chasm, brilliantly illuminated by the rays of the sun around midday.

Closer to Alice Springs is Simpsons Gap, which features a ridge of Heavitree Quartzite down-faulted into older Arunta Region rocks.

'A Town Like Alice'

The historic Alice Springs Telegraph Station is worth a visit; the first site of European settlement in Alice Springs, it was in service for 60 years before becoming a school for indigenous children. The telegraph played a pivotal role in Australia's history and with 12 stations along the line, the Alice Springs Telegraph Station is the best preserved of them all.

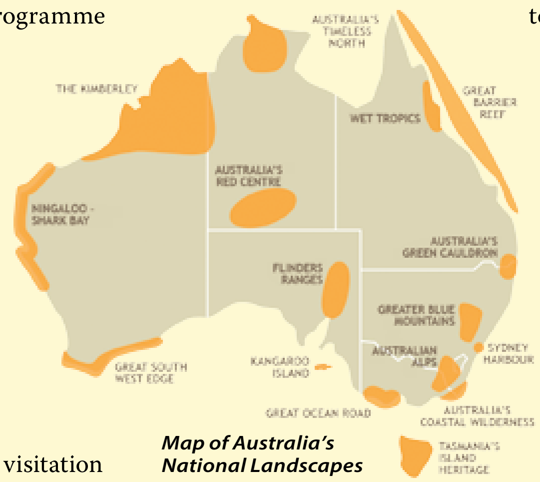
At the Alice Springs Desert Park visitors can enjoy an indigenous bush survival display, a truly outstanding flying bird demonstration, and the chance to meet and greet a variety of Australian inland animals such as the dingo and some nocturnal mammals, snakes and lizards, as well as the flightless emu, which with the red kangaroo forms a key part of the Australian coat of arms.

An enjoyable late afternoon experience is a guided sunset tour of the home of Brolga and his kangaroo family, as seen on 'Kangaroo Dundee' (BBC UK / Nat Geo USA / Animal Planet). The Kangaroo Sanctuary is a place to celebrate the beauty of the big red kangaroo – an Australian iconic species – but also to learn about how Brolga first established the baby kangaroo

The spectacular Standley Chasm bathed in sunlight at noon.

Australia's National Landscapes Programme

Australia's National Landscapes Programme was originally developed by the Australian government in collaboration with state and territory national park agencies, state and regional tourism organisations, local government and industry to highlight a collection of iconic places with great cultural, natural heritage and spiritual significance. The Programme aims to promote the conservation of Australia's natural assets while raising awareness and visitation to Australia's premier culture and nature-based destinations that deliver memorable holiday experiences to the international 'Experience Seeker' target market. It is now operating on an industry-owned model coordinated administratively by the peak industry association, Ecotourism Australia Ltd. As well as Australia's Red Centre, the Programme currently includes 15 other National Landscapes.



Map of Australia's National Landscapes

rescue centre and then went on to build his own wildlife sanctuary. (Bookings are essential.)

And for a change from all the geology and nature, visit the Araluen Cultural Precinct for a self-guided walking tour which provides a fascinating glimpse into the art, culture and heritage of Central Australia. The Precinct includes the Araluen Arts Centre, incorporating the Albert Namajira indigenous Australian Art Gallery, a natural history museum of Central Australia, the Strehlow Research Centre (indigenous culture), the Central Australian Aviation Museum, as well as craft galleries and shops.

A trip to the Red Centre must include a visit to the world-famous Royal Flying Doctor Service Tourist Facility, which includes a new theatrette, interactive information portals and a full scale replica of the fuselage of the Service's operational Pilatus PC 12 aircraft. Starting as the dream of a Presbyterian minister, the Reverend John Flynn, the Royal Flying Doctor Service is one of the largest and most comprehensive aeromedical organisations in the world, providing extensive primary health care and 24-hour emergency service to people over an area of some 7.25 million km^2.

A Holistic Environmental Experience

We hope that a journey through Australia's Red Centre will reveal for the visitor a breathtaking and awe-inspiring landscape of power. As the National Landscape Programme says: "Its Neolithic presence has stood firm against the winds of time, harbouring the secrets of the earth itself. It has whispered an unbroken narrative between man and earth, deeply influenced the earliest memories of the traditional custodians and awoken the spiritual depth of the European. An enigmatically surreal energy hangs in the air from Kings Canyon to Uluru and Alice Springs, inspiring some of the most iconic, artistic expressions by artists from Minnie Pwerle to Sidney Nolan and Namatjira."

From a geotourism perspective, a trip to Australia's Red Centre is a truly holistic environmental experience, which recognises the significant contribution of geology and landscape, while giving the visitor an engaging, informative and enjoyable trip.

Acknowledgements:

This geotour was originally designed for two international groups – in 2014, for Rotarians visiting Australia for the Rotary International Convention, and in 2015, with a customised geological focus, as a pre-conference tour of the AAPG International Conference in Melbourne. Both tours were led by Angus M. Robinson (Managing Partner of Leisure Solutions); and for the second tour, in his capacity as Chairman of the Geotourism Standing Committee of the Geological Society of Australia, ably assisted by Christine Edgoose who is both Manager, Basin Geoscience for the Northern Territory Geological Survey and a Councillor of the Geological Society of Australia. ■

'Roger', Australia's 'Big Red' kangaroo on display at the Kangaroo Sanctuary, Alice Springs. Australia is renowned for its unique wildlife, particularly the big red kangaroo, imagery of which is prominently displayed on all aircraft of Australia's flag carrier airline – Qantas, appropriately nicknamed 'The Flying Kangaroo'.

Kangaroo Sanctuary in Alice Springs

Petroleum Basins of Yemen

> "As we climbed, the vegetation grew denser, streams appeared in unexpected clefts, and now and again one of us would exclaim at some new discovery, a spider's web constructed on perfect Euclidean principles or a caterpillar in poster-paint colours… Near the crest, the vegetation thinned. Limestone gave way to naked granite."
>
> Tim Mackintosh-Smith in *Yemen: The Unknown Arabia* (2000)

Yemen, situated in the southern part of the Arabian Peninsula, was the last country in the Middle East to make a commercial oil discovery. Since that find in 1984 the country's petroleum industry has witnessed tremendous ups and downs. Yemen's petroleum resource base will be a critical part of reconstruction efforts once peace is restored, but this will require high-resolution exploration and development in both onshore producing basins and offshore frontier areas in the Gulf of Aden and the Red Sea.

MUSTAFA AS-SARURI, Ph.D. and **RASOUL SORKHABI**, Ph.D.

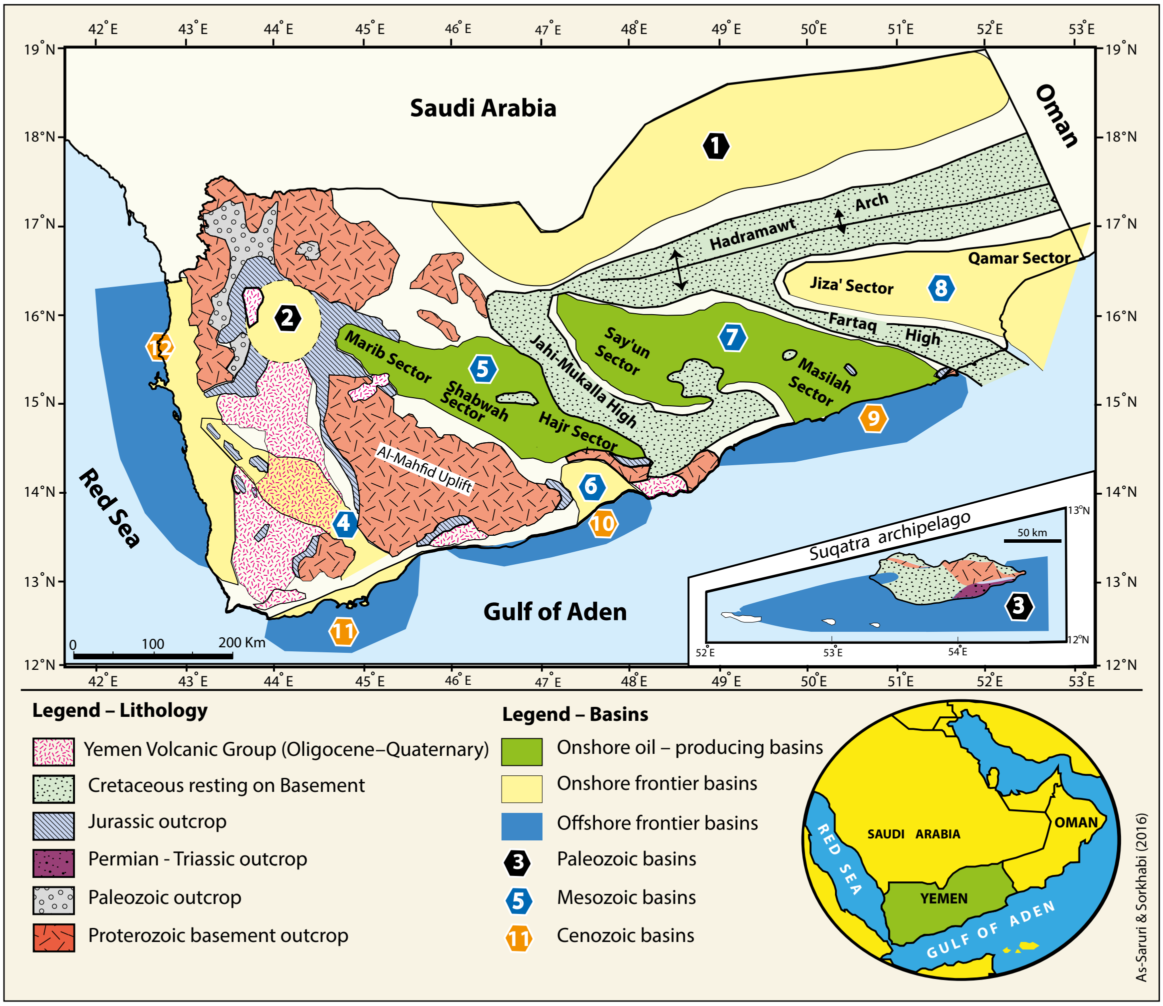
In recent years, Yemen has been engulfed in civil war, violence, and intrusion by religious militants and outside governments. Put this dark, unfortunate image aside, however, and Yemen is a jewel of history and nature on the Arabian Peninsula. Known as the land of the Queen of Sheba, its antiquities are millennia-old, while the high mountains and beaches along the Gulf of Aden and Red Sea present a charming contrast to the desert landscape found over so much of the region. The ancient Romans referred to Yemen as Arabia Felix: Happy or Blessed Arabia.

Plenty to Explore

Geological surveying and petroleum exploration in Yemen date back to the early decades of the 20th century (see 'Oil Exploration in Yemen,' *GEO ExPro*, Vol. 10, No. 3). From the 1930s–60s, the Iraq Petroleum Company conducted exploration in the Hadramawt and Mahrah areas in north-east Yemen, during which period Ziad Rafiq Beydoun (1924–1998) pioneered geological studies of the country. In 1962 and 1967, respectively, two separate states, pro-West North Yemen and pro-Soviet South Yemen, were formed.

Upper Jurassic Madbi Formation (major source rock) overlain by the Nayfa Formation, Wadi Al-Masilah, SE of Qal'ana, Hadramawt province.

M. As-Saruri



Sedimentary basins of Yemen and their classification according to the geologic era in which they formed.

Palaeozoic basins: (1) Rub' Al-Khali (the southern flank of a much larger basin extending into Saudi Arabia; (2) San'a; (3) Suqatra (an island in the Gulf of Aden).

Mesozoic basins: (4) Siham-Ad-Dali'; (5) Sab'atayn; (6) Say'un-Masilah; (7) Balhaf; (8) Jiza'-Qamar.

Cenozoic basins: (9) Mukalla-Sayhut; (10) Hawrah-Ahwar; (11) Aden-Abyan; (12) Tihamah.

During this time, Pan American Oil continued exploration in Hadramawt (in South Yemen) and drilled a number of wells, with the non-commercial discovery of several barrels of oil from the fractured carbonates of the Cretaceous Qishn Formation in Tarfayt-1. Drilling on the Tihamah Plain in the 1960s by US company John Mecom produced oil shows in Zaydiyah-1.

During the 1970s and 80s both North and South Yemen began offering concession blocks to a number of foreign oil companies. The first commercial discovery came in 1984 when the American company Hunt Oil drilled Alif-1 in the Marib sector of the onshore Sab'atayn Basin in North Yemen, penetrating a total depth at 4,182m and hitting oil (40.4° API) in the Alif Member of the Sab'atayn Formation (Middle–Upper Tithonian age) with an initial flow of 7,800 bopd. In 1986, the Russian company Techno-Export, which was operating in South Yemen, drilled West Ayad-1 in the Shabwah sector of the Sab'atayn Basin, encountering 35° API oil in the Jurassic. Petroleum exploration by Canadian company Occidental in another onshore Mesozoic basin, the Say'un-Masilah Basin, led to an oil discovery in 1991: Sunah-1 drilled to the total depth at 2,917m and discovered oil (36° API) in sandstones of the Lower Cretaceous Qishn Formation.

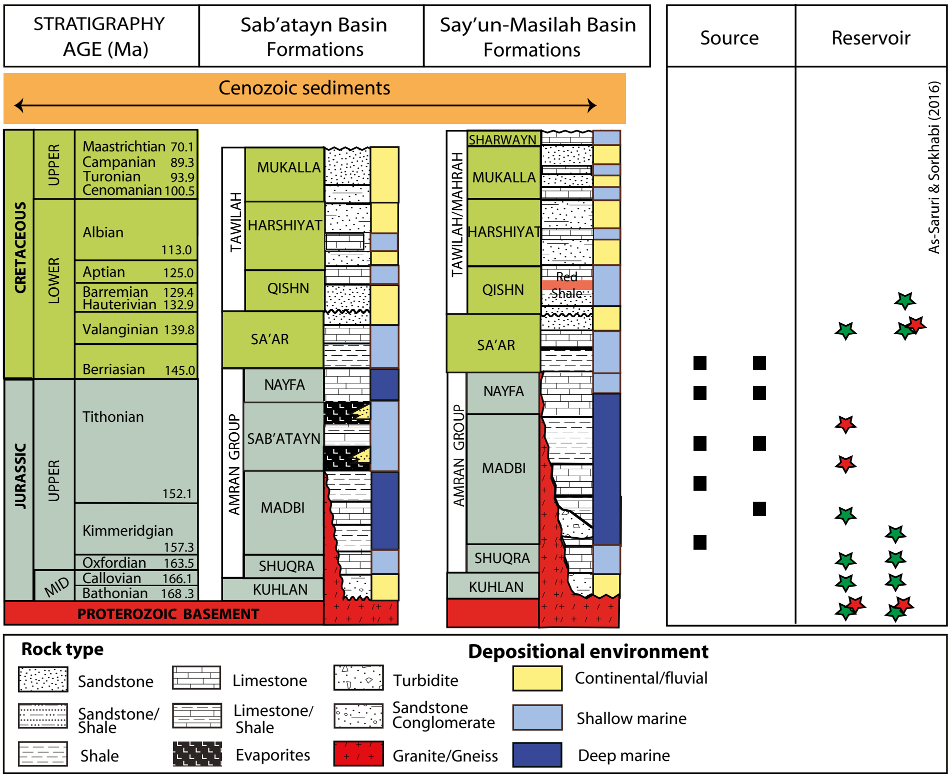
Oil production in Yemen began in the mid-1980s. In 1990, South Yemen and North Yemen were unified, and the new republic further opened Yemen to international markets and oil companies. The country enjoyed a successful period of oil and gas discovery and production during the 1990s until 2005, but Sab'atayn and Say'un-Masilah are still the only producing basins in Yemen.

Producing Mesozoic Basins

Twelve onshore and offshore sedimentary basins have been identified in Yemen, categorised into three groups based on the geological era in which they originated: Palaeozoic, Mesozoic and Cenozoic. Of these, only two, Sab'atayn and Say'un-Masilah, are well explored; the rest remain frontier basins.

Sab'atayn and Say'un-Masilah Basins: These two basins are parallel rift basins separated by the Jahi-Mukalla High. They developed in Late Jurassic to Early Cretaceous times during the fragmentation of Gondwana. The basins, filled with syn- and post-rift sediments, share many similarities including source and reservoir rocks of Late Jurassic-Early Cretaceous age. Both basins also contain fractured Precambrian granite reservoirs with 41°API oil, charged by downthrown Upper Jurassic shale.

The bituminous shale members of the Kimmerdgian-Tithonian Madbi Formation are the main source rock for the discovered oil fields in the Marib and Shabwah sectors of the Sab'atayn Basin. These rocks are characterised by Type II (dominant) and Type III kerogen; the total organic carbon



Mesozoic stratigraphy and petroleum systems of Sab'atayn and Say'un-Masilah Basins.

(TOC) values are generally 3–5%, but locally as high as 20%, with organic matter of mixed marine and terrestrial origin deposited in a moderately anoxic environment. The main source rock in the Say'un-Masilah Basin is also bituminous shale and carbonate within the Madbi Formation. These sediments are up to 450m thick and have TOCs as high as 18%. Immediately overlying the Madbi Formation, Upper Jurassic shale units in the Nayfa Formation have also been found to be a potential source rock with TOCs over 1% and vitrinite reflectance values in the range of 0.4–0.5% (for example in the exploratory wells Sunah-1 and Ghayl Bin Yamin-1).

One significant difference between these two basins is that Tithonian-age evaporite beds are absent in the Say'un-Masilah Basin while the intra-salt sandstones and sub-salt turbidites offer significant oil accumulations in the Sab'atayn Basin. Another difference is that the Lower Cretaceous sandstone of the Qishn Formation is an important reservoir in Say'un-Masilah, but not in Sab'atayn. The initial reservoir pressures in the latter are gas-driven, while those in the Say'un-Masilah Basin are water driven.

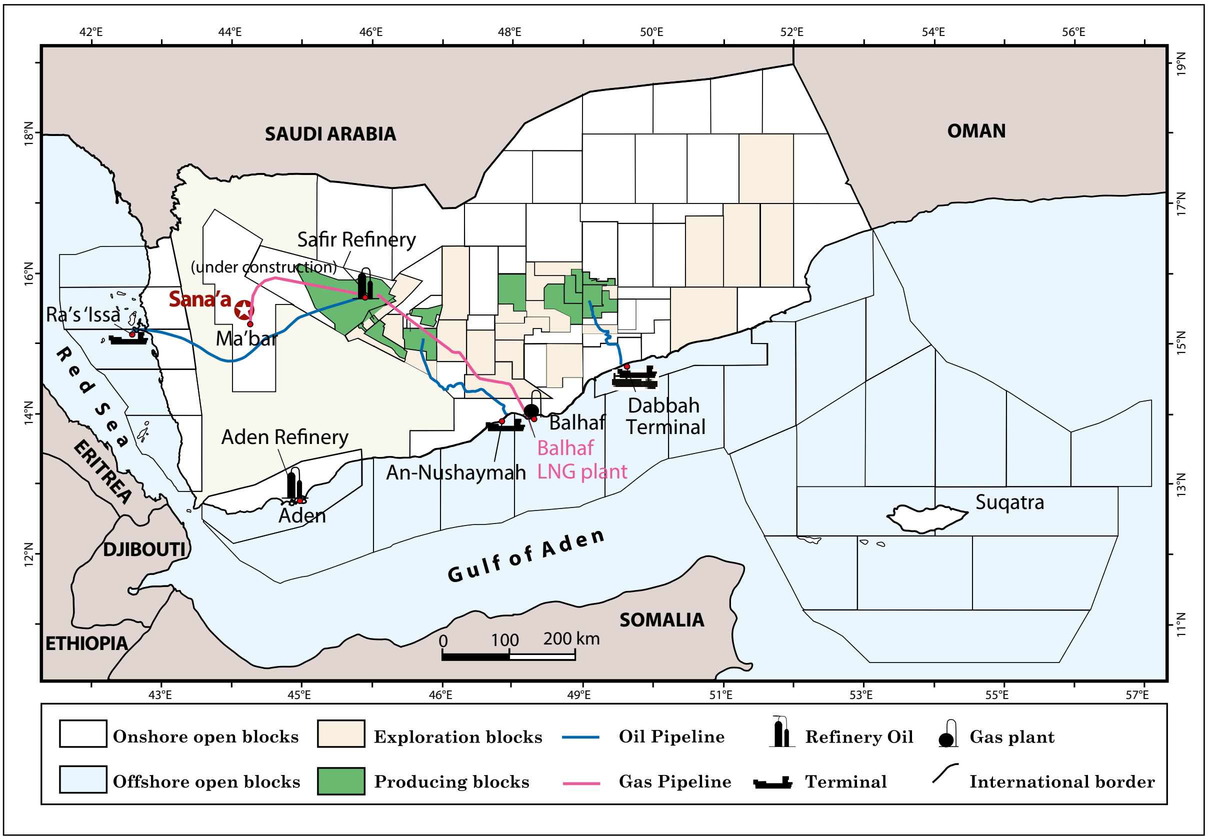
Mukalla-Sayhut Basin: The Mukalla-Sayhut Basin lies to the south of the Say'un-Masilah Basin and extends on- and offshore along the Gulf of Aden. It developed during the rifting of the Gulf of Aden in Oligocene-Quaternary times. Regionally, Upper Jurassic-Lower Cretaceous sediments are expected to be present in the Mukalla-Sayhut Basin; indeed, the offshore well Sarar-1 encountered Jurassic shale with TOCs of 1.3–2.5%. Cretaceous source rocks are also identified in the shales of the Mukalla Formation (Turonian to Campanian age) with TOC of 1.7%, and in the marl and limestone of the Fartaq Formation (Albian to Cenomanian age) with TOCs up to 4.41%. The organic matter is Type II. The mudstone of the Ghaydah Formation (Oligocene) has fair source potential in several exploratory wells, including Hami-1, Sarar-1, and Ra's Ghashwah-1, drilled from 1979 to 1981. The organic matter for these rocks is ype II, with TOCs up to 4.20%.

The pre-rift fractured carbonate rocks (Middle Eocene) and syn-rift sandstone layers (Upper Oligocene) are considered to be good reservoirs. The cap rock is represented by the evaporites of the Rus (Lower Eocene) and Ghaydah Formations as well as shale layers which occur at different levels in the stratigraphic succession. Hydrocarbon potential in this basin is supported by the non-commercial discovery of oil in the fractured limestone of the Middle Eocene Habshiyah Formation in 1982 in well Sharmah-1. This oil is different from the Jurassic oils in that it has a higher gravity (43°API), higher pristane/phytane ratios (between 2.02 and 2.92), and was probably charged from the Upper Cretaceous or Lower Eocene shale or marl.

The **Balhaf** and **Hawrah-Ahwar** Basins to the south of the Sab'atayn Basin and along the Gulf of Aden remain unexplored but are expected to have similar Mesozoic stratigraphy to Sab'atayn.

Jiza'-Qamar Basin: This is the easternmost basin in Yemen. It is separated from the Say'un-Masilha Basin by Fartaq High on the west, and from the Rub' Al-Khali Basin by Hadramawt Arc to the north. The Jiza'-Qamar Basin comprises a 6–8 km thick sedimentary succession with several horizons of good quality source and reservoir rocks. Ar-Rizq-1, drilled in this basin in 2008, encountered a high pressure zone of gas. Recent studies of Upper Cretaceous rocks from the basin by A. S. Alaug of Taiz University in Yemen show encouraging results. TOC values of 24% for mud-rich carbonates have been reported from the Turonian-Campanian Mukalla Formation, with kerogen Types of II and III. The overlying Dabut Formation (Campanian to Early Maastrichtian age) from the same basin yielded kerogen Type-III shale with TOC of 1%. Vitrinite reflectance values from these Upper Cretaceous shale units in well 16/U-1 range between 0.3 and 1.0%, indicating sufficient thermal maturity for oil generation in the onshore Qamar sector.

Tihamah Rift Basin: The Tihamah Basin includes both coastal plains and offshore sediments along the Yemeni Red Sea. It developed during the rifting of the Red Sea in Late Oligocene-Quaternary times, when syn-rift to post-rift sediments of Miocene-Quaternary age were superimposed on a thick succession of pre-rift sediments, including the Jurassic Amran Group (shallow and deep marine shale and carbonates), the



Map of concession blocks and midstream/ downstream petroleum industry in Yemen (as of 2012).

Cretaceous Tawilah Group (sandstone and shale deposited in fluvial and shallow marine environments), and the Paleocene-Lower Eocene Majzir Sandstone. The Late Eocene-Oligocene represents a major unconformity in the basin.

There are various lines of evidence of petroleum prospectivity in this basin. Oil seeps have been observed at As-Salif in western Yemen and several exploratory wells have encountered oil and gas shows (for example, in onshore wells Alpha-1 and Abbas-1). The offshore Tihamah exploratory wells have found mudstone source rocks in the Zaydiyah and Maqna Formations (Early to Middle Miocene age) with very high TOC contents: >20% in Antufash-1; 5% and >8% in two intervals in Kathib-1; and >4.76% in Al-Meethag-1. Thin black mudstone associated with salt layers in the Mid–Late Miocene Salif Formation have TOCs up to 4%, deposited in lacustrine and shallow marine environments.

Old Oil, New Oil

If Tihamah represents the youngest petroleum system in Yemen, there is also 'old' petroleum potential in the Rub Al-Khali Basin in the north-east, and in the San'a Basin in north-west Yemen. The Siluarian Qusiaba shale, so productive in Saudi Arabia, also extends into northern Yemen. Jurassic plays are other possibilities in these basins as well as in the offshore Suqatra Basin; Permian-Cretaceous rocks outcropped on Suqatra Island.

Proven conventional oil reserves of Yemen (as of 2010) are about 4.731 Bbo, and proven gas reserves are 18.6 Tcfg, and the country still retains good potential for further discoveries. Acquisition of new seismic will reveal better information on the structure and sedimentary succession of the onshore and offshore basins in Yemen. ■

Folding of the Upper Jurassic Nafay Formation (carbonates), Wadi Hajr Al-Farsh plain, Hadramawt province.

Yemen: The Issues

As we have read, Yemen has plenty of potential – but the country's war has significance far beyond its boundaries.

NIKKI JONES

Despite having known reserves and promising potential, as discussed in the preceding pages, the bombing of pipelines and the blockading of ports over the last year have repeatedly stopped all exports of hydrocarbons from Yemen. Oil production dropped to just 44,000 bopd in mid-2015, down from 421,000 bopd a decade ago, and exports of LNG, which only began in 2009, are similarly affected.

However, Yemen has significance for the global oil economy beyond its own production. Along with Djibouti and Eritrea, it controls the 30 km wide Bab al-Mandab strait between the Red Sea and the Gulf of Aden. If this channel were to become unsafe, shipping would have to make the long voyage around Africa to connect the Mediterranean with the Indian Ocean.

Complicating its role as guardian of a key shipping lane, the country has slid into an Afghan-style chaos and more foreign powers have become involved, culminating in Saudi Arabia claiming in December that it now leads a 34-country strong, Muslim, anti-terrorism alliance. Distant states such as Malaysia, Nigeria and Morocco are included and non-Muslim countries, notably the US and UK, are willing and active backers.

A Proxy War for Saudi-Iranian Rivalry?

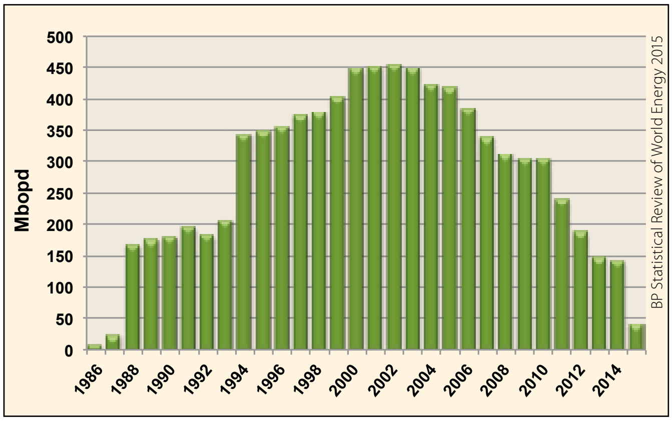
In January 2015, the Saudi-backed president installed in 2012 after the Arab Spring demonstrations, Hadi, was forced into exile. Although the Zaydi Houthis are doctrinally close to Sunni Islam, they consider themselves Shi'ite and their leadership has a high regard for Iranian-style politics. Their main objective, however, given that they are a third of Yemen's population, is to preserve their separate cultural identity. For this reason they are Hadi's main opponents. They have been backed by those loyal to the previous president, Saleh, and since March 2015 together they have controlled the western side of the country, including the capital, Sana'a, and the oil fields around Marib.

Saudi Arabia maintains that the Houthis are backed by their regional Shi'a enemy, Iran, although there is no clear evidence of this, and nor does it appear that western backers believe this to be so. Since the overthrow of Saddam Hussein and Iraq's change of leadership from Sunni to Shi'a, Saudi Arabia has become more nervous of perceived threats to its pre-eminence, and the nuclear peace deal with Iran has only exacerbated this. The fear of Shi'a encirclement appears to explain Saudi Arabia's extraordinarily violent campaign, although it is true that the Kingdom has a long and complicated relationship with its poor southern neighbour, inflamed by decades of colonialism and the cold war. (South Yemen was the only Marxist state in the Middle East.) In addition, two provinces within Saudi Arabia are ethnically and culturally Yemeni and this porous border has provided a smuggling route for drugs and arms into the Kingdom.

The war in Yemen is significant for another development: the Kingdom's new willingness to conduct an aggressive campaign abroad. This policy appears to be led by Prince Mohammed bin Salman, the thirty-year-old son of King Salman, who is second in line to the throne. At home he has been promoting the most conservative of clerics and strengthening the religious police, while in Yemen his campaign has been widely criticised for its bombing of civilians, including hospitals, far from Houthi positions, and for the use of cluster bombs that most of the world has declared illegal.

The question will be whether, in the medium term, the prince is strengthening or weakening the Saudi state. With oil prices low, the costs of war have increased the budget

Yemeni teenagers in traditional dresses with janbiya knives proudly pose with a Kalashnikov machine gun in the Hadramawt valley, Yemen.



Oil production in Yemen has plummeted in recent years.

deficit to $95 billion. The Saudis have found themselves in the unusual position of announcing austerity measures, including the phasing out of popular fuel subsidies, as well as issuing government bonds to raise money.

In July, the Houthis were ousted from the port of Aden but since then there has been a bloody stalemate. Approximately 6,000 people, including many civilians, are believed to have died in Saudi bombing raids, and the near-famine conditions, fuel shortages and dry water pumps are such that even Somali exiles have returned home. Almost 22 million of Yemen's 26 million population are now reliant on humanitarian aid.

Why Western Involvement?

Yemen's conflict may have even greater significance for exposing some of the fault-lines in the tangled political alliances between western and Middle Eastern powers. The US and UK have backed the bombing, and are reported to have military advisers in Riyadh supporting the campaign. Both states have continued to sell arms into a 'hot conflict', with apparent disregard for the international arms trade treaty they signed in 2014. US sales to Saudi Arabia are reported to have reached $24 billion since mid-2014.

The west's desire to support its long-time ally, Saudi Arabia, does not fully explain its involvement, and a military defeat of the Houthis has always been unlikely. It seems the west has Al Qaeda on the Arabian Peninsula (AQAP) and ISIS/Daesh in its sights, objectives that are not shared by their Middle Eastern partners. Both groups have gained control of significant areas of Yemen but, to the west's alarm, the coalition appears to be avoiding engagement with either. Across the Middle East, there have been no calls for the coalition to unite against ISIS, and the Gulf countries have not moved to support the Syrians and Iraqis who are fleeing them. This is despite the fact that ISIS threatens the Gulf monarchies that it believes are not true defenders of the faith.

Yemeni peace talks began again at the end of 2015, with the objective of finding a federal solution. But with al Qaeda and ISIS holding territory within Yemen it is not clear that there is any foundation for a lasting peace. The tectonic plates of diplomacy and power are shifting and Yemen, poor and unstable, is likely to be a catalyst for change far beyond its own boundaries. For the ordinary Yemeni people, it seems that many more years of disunity and conflict lie ahead. ■

A Passionate Geologist

Executive Vice President of Exploration for Shell, Ceri Powell, talks to us about her life and career – and how it felt to be described (in Fortune Magazine) as the 21st most powerful woman in the world.

JANE WHALEY

Growing up in Pembrokeshire in south-west Wales, a young Ceri Powell was inspired by the wonderful geology all around her. "It's an area of astonishing geology, some of the most diverse in the whole of Europe in such a small area," she explains. "Volcanics, clastics, carbonates – we have them all. And luckily for me, my school had geology on the curriculum, and an inspirational teacher." Add to that a father who was a manager at the huge refinery at nearby Milford Haven and also Chairman of the Pembrokeshire National Park Authority, demonstrating that industry and nature can go hand in hand: Ceri's future career as an oil industry geologist seemed inevitable.

Inversion Tectonics

"I studied for my undergraduate degree at the University of Liverpool, where I was primarily attracted to structural and igneous geology – I didn't have much interest in sediments in those days," she says. "The course included lots of fieldwork, which is so important."

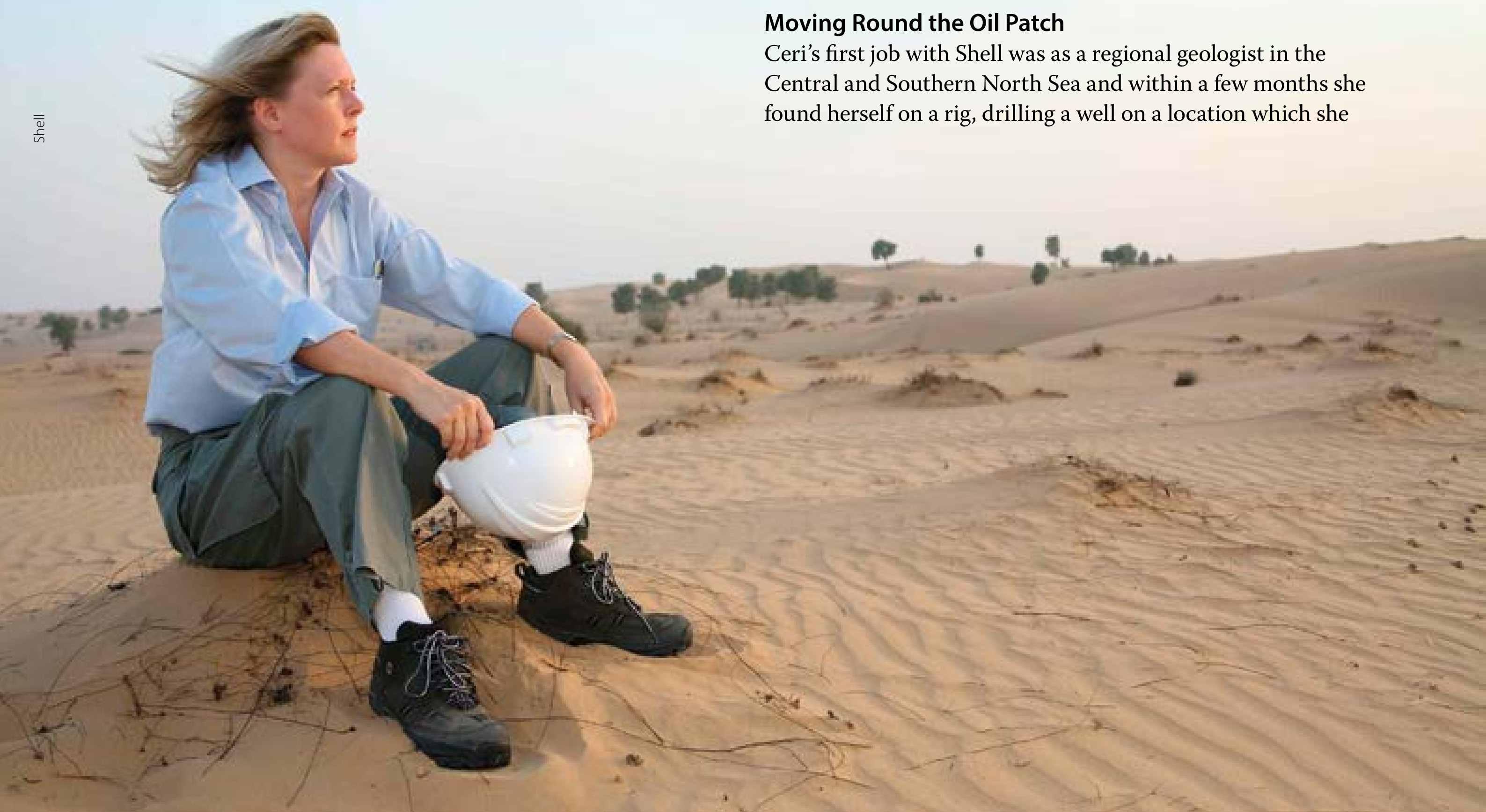
Ceri went on to do a Shell-sponsored Ph.D. at Cardiff University, studying inversion tectonics and the reactivation of faults as thrusts. As she says, this was ground-breaking work at the time. "It was a very new concept, and needed to be tested in many different places throughout the world, so my field research was in the Pyrenees, the Swiss Alps and the Rocky Mountains. It was an exciting time in structural geology, with a lot of new thinking around the subject. In parallel, the oil and gas industry was starting to realise that the Southern North Sea was a reactivated basin and its structure was not as simple as had originally been thought, so there was a link to my future career even then.

"Shell encouraging me in this project was typical of the broad and innovative approach the company still likes to take, and it is very important that the oil and gas industry funds this type of research," she continues. "Shell sponsors a number of Ph.D. students each year and we think it is an excellent training for future executives, as it teaches you how to manage a large scale project within a limited timeframe. You also need to be a self-starter, which is something we look for in an employee; we need to be able to send someone out to, say, Pakistan or Colombia and know that they will be able to run a project from scratch.

"When I finished my doctorate, I didn't have to work for Shell, even though they had agreed to offer me a job – but I had been interviewed by the company at undergraduate level and had liked what I saw. When I arrived for my first postgraduate interview with them, the interviewer turned out to be the renowned Dr Peter Zeigler and I spent the next four hours discussing the Moine Thrust with him. He was an inspirational man – I thought to myself 'if this is the level of technical excellence in the oil and gas world, then I want to be part of it'."

Moving Round the Oil Patch

Ceri's first job with Shell was as a regional geologist in the Central and Southern North Sea and within a few months she found herself on a rig, drilling a well on a location which she



Shell

Ceri Powell

Ceri loves Scotland, with the Isle of Skye being a particular favourite.

had worked up and proposed. "At Shell we believe that everyone should have a good knowledge of working in the field and a grounding in the range of skills that is required in exploration," she says. "Arriving at a rig which was drilling where I had identified a prospect so early in my career helped instill accountability – even though it turned out to be a dry hole!

"My next role was with the Angola team in The Hague," Ceri continues. "In Shell, small regional groups like these are like little companies, where everyone helps out at all tasks, and I learnt a lot from the experience, and especially as a contrast to the large North Sea team. You have to work well together and learn to take fast decisions, often collaborating with your partner companies. In some respects we are competitors, but we are also on the same team and we're all geologists with the same aim in the end. In Angola we had to focus strongly on health and safety, as there was little backup in Luanda if there had been an accident."

The next move was to Miri, in the Malaysian part of Borneo, a town at the time described by the Lonely Planet Guide as "full of oil industry expatriates and prostitutes"! Ceri was in charge of the technical and commercial team, looking to follow up on the success of Shell's large offshore gas discoveries. This turned out to be a very interesting experience, as Ceri explains. "Miri was a small town so I spent my weekends visiting my Malaysian colleagues and their families in traditional longhouses in the rain forest – amazing; I made life-long friends!"

New Challenges

In 2000 Ceri moved out of exploration and took up a new challenge in charge of Shell's Competitive Intelligence Team at the Head Office, which had been set up in the aftermath of the late 1990s downturn and the mergers of oil giants (like Exxon and Mobil) which accompanied it. "Our task was to try to identify what the industry would do next. What plays would the competition go after? What geology was 'hot'? We spotted very early on trends such as national oil companies moving into international exploration. Nowadays, all companies routinely do this research, but it was very radical at the time," she explains. "It's strange to think it now, but that was in the very first days of the internet, and I think there had been less 'worldwide thinking' in the world of work. It was very exciting. I had a very young team – all under 30 except me – and sometimes the result of our analysis meant that I had to inform the senior management that Shell's strategy was going wrong.

"I then spent a couple of years as business advisor to

Ceri and her husband Ajay (right), also a senior manager in Shell, on a site visit in Oman.

Shell

the Upstream CEO. These two strategic roles fitted in well, with Shell ensuring that I had a wide range of experience to advance my career confidently. This approach to employees' progress and welfare had been one of the things which had initially attracted me to the company.

"I really enjoyed being in Competitive Intelligence and 'bag-carrying' for a senior leader," Ceri says, "but I missed the technical rigour of practical exploration, so I was delighted to be invited back into it as VP for Exploration in the Middle East, Caspian and South Asia." This meant a move to Dubai and yet more interesting challenges, including being on the board of a joint venture in Saudi Arabia – the first woman in such a post – and having to give a talk to a room full of 1,000 men.

"The authorities in Saudi were very supportive as they are keen for more young women to take up careers in the industry and they thought that I would be a good example to young Saudis. I met many impressive young females in my five years in Dubai, and I found it very interesting talking to them, trying to understand the issues they were facing and to help them in their career. I think it is important for managers at VP level to foster the younger generation; it's a real opportunity to make a difference." One such woman mentored and advised by Ceri was Intisaar Al Kindy, who was profiled in *GEO ExPro* Vol. 12, No. 6.

"I have never been aware of a 'glass ceiling' in my career," Ceri continues, "even in the places where you would most expect it. I have always felt respect from colleagues, management, commercial partners and government representatives."

Asking the Right Questions

In 2008 the CEO of Shell asked Ceri to run the company's strategy department, covering a range of activities including refining and petrochemicals, a move designed to further broaden her skills as a leader. "I learnt how to ask the right question when I didn't know the precise science – a vital senior management skill," Ceri explains. "The right question, to the right people, at the right time, in order to move the business forward."

This has propelled Ceri ultimately into her present role, as Executive Vice President Exploration, with nearly a thousand staff, a multibillion-dollar annual budget and global accountability for exploration operations and new business opportunities worldwide. Since 2013 this role has also included being the Global Functional Head of Exploration. With this remit, Ceri has very clear ideas on ensuring that Shell is maximising the brain-power of the professionals available.

"We work in a very innovative and intelligent industry, with a high number of brain cells required to extract each barrel of oil. We must therefore attract and retain the best talent and make sure everyone is able to perform to the best of their ability," she says. "Sometimes that means looking at the life/work balance and offering flexible working – with modern communications, tailoring work to suit the individual is totally feasible for any size of company. I'm not just talking about people with families but also, for example, elite sportsmen and women, and older employees near the end of their careers – part time includes working for six weeks at a time then taking a month or two off to pursue other interests."


Ceri Powell

Ceri visiting the oil sands sites in Canada.

Sustainability and Success

"I also feel responsible for ensuring sustainability, recognising that we are part of the global community," Ceri continues. "Any energy company is responsible for extracting and producing hydrocarbons in the most sustainable way possible. I feel very fortunate to have been active on the Advisory Board of the United Nations Sustainable Energy for All initiative, chaired by the Secretary General of the UN. It's a facilitator for change and the UN's long-term view, looking ahead to 2040, fits in well with Shell's strategic viewpoint."

In 2013 and 2014, Ceri Powell appeared in Fortune Magazine's list of the 50 most powerful women in business – quite an accolade! How does she feel about that?

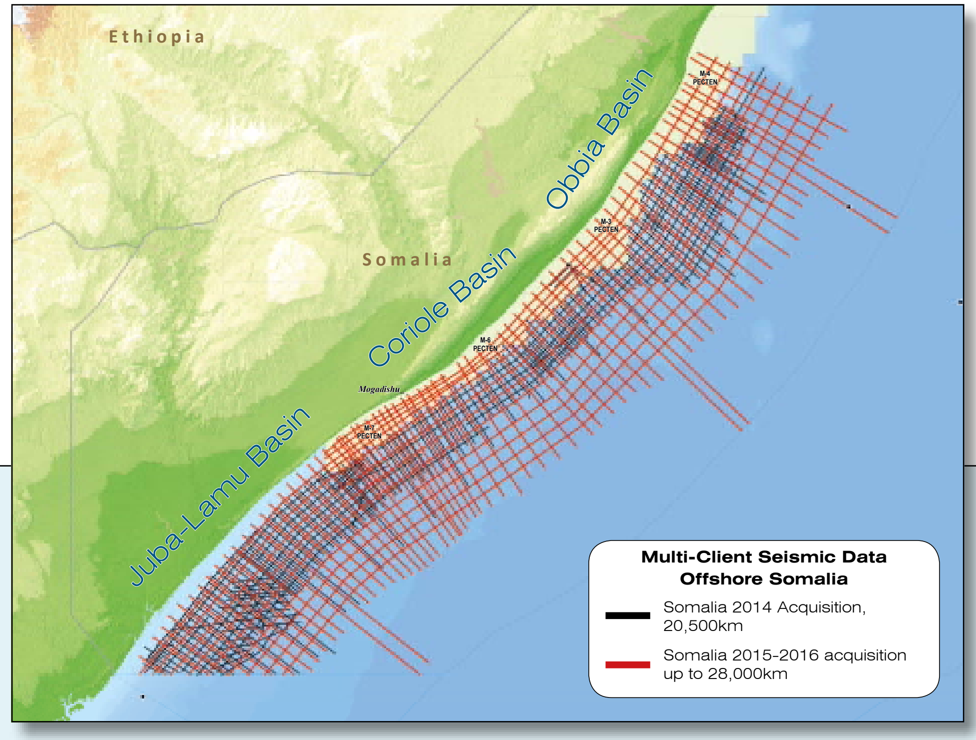
"Do I feel powerful? Well, I feel responsible – for the safety of all the people working for me, and for ensuring we deliver within our budget and produce good results. I feel more lucky than powerful; after 26 years in this industry, I am still excited by geology – by looking at cross-sections and maps, and at rocks in the field. I still make sure there is time for site visits, as I think it is very important that you 'keep your hand in' on the practical side to ensure you make the right decisions. Exploration is about gut feel as well as science, so it is important that I continue to hone my geological skill set.

"How do you define power or success?" Ceri concludes. " Knowing that I have inspired just one female to take up geology – that's what I consider success!" ■

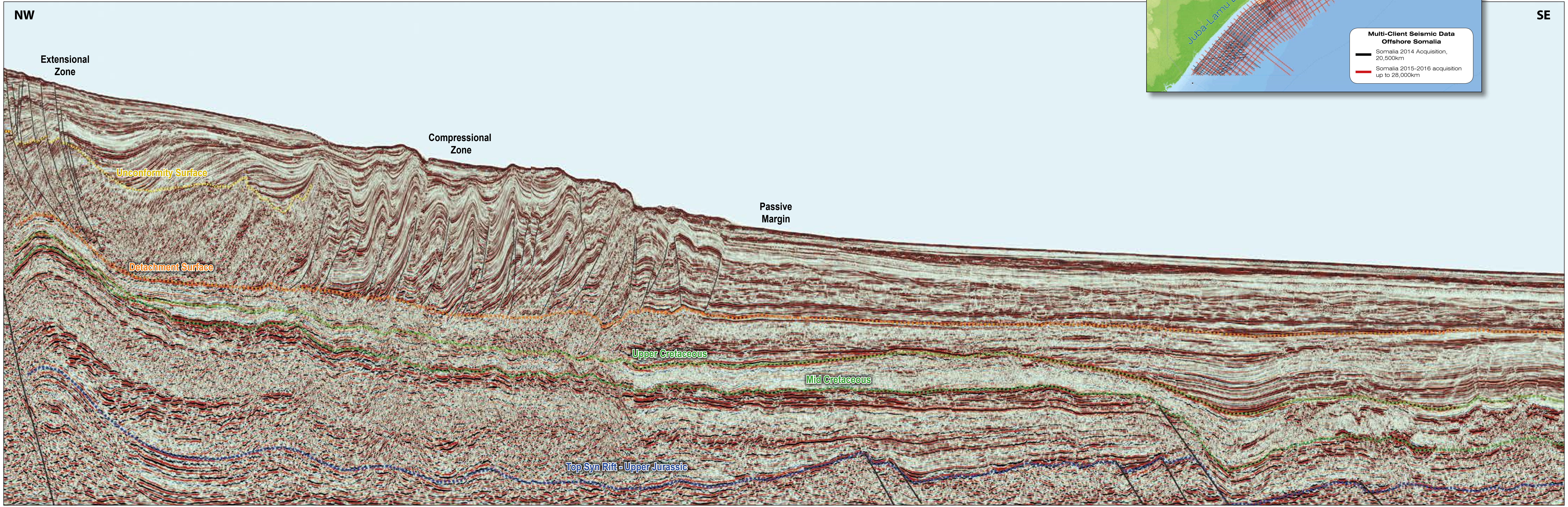
Offshore Somalia:
East Africa's Oil Frontier

Somalia's offshore hydrocarbon systems have been slowly maturing since the Jurassic period. Now, after ten years of relative political peace, Somalia is set to emerge as the new hot-spot for the industry, offering not only vast reserves to match the Rovuma Basin of Mozambique, but also the most elusive of prizes in East Africa – black oil.

Spectrum



North-west to south-east seismic line from the northern Juba-Lamu Basin. Line length = 170km



Somalia's Exploration Journey

HANNAH KEARNS, JAKE BERRYMAN, NEIL HODGSON and KARYNA RODRIGUEZ, Spectrum

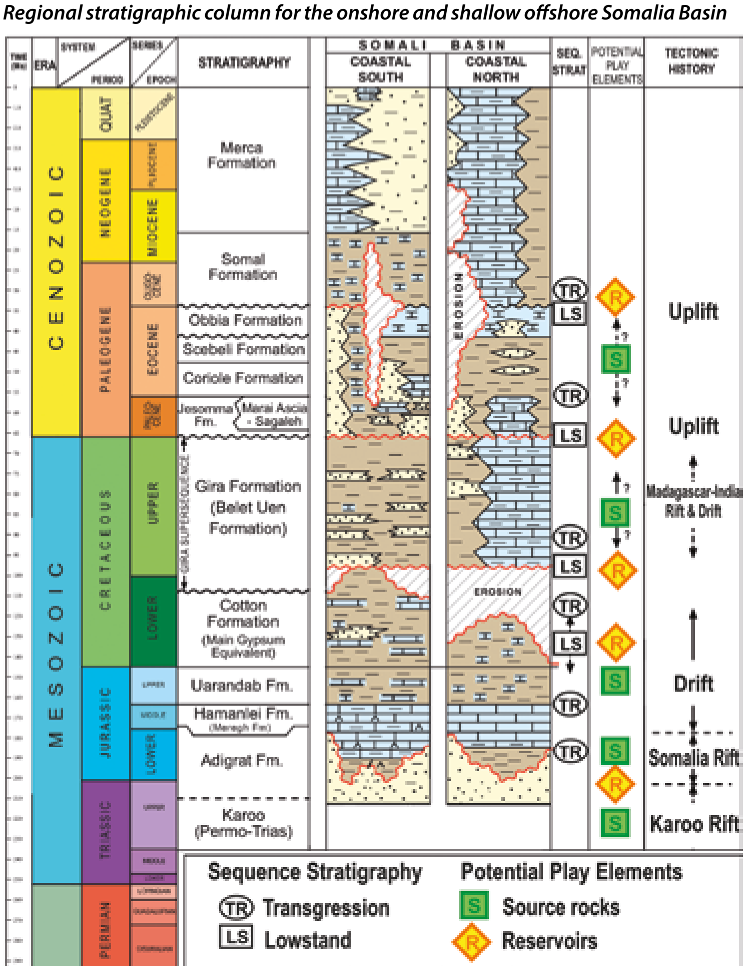
Peace is bringing hope, seismic exploration and evidence of exciting hydrocarbon-bearing structures offshore Somalia.

Exploration in Somalia began onshore in 1956 with the drilling of the Sagaleh-1 well, followed by a number of wells drilled mostly in the north of the country. These clearly established the presence of a working Jurassic hydrocarbon system, as illustrated by the 1959 Daga Shabel-1 discovery well. Following successes within the Yemeni Jurassic basins during the 1980s, a great deal of renewed interest was shown in the country. Tragically, the collapse of the government in 1991 ushered in a period where Somalia remained inaccessible to exploration companies for 25 years. During this time, the majority of Somalia's legacy geological and geophysical data were lost or destroyed.

However, since the inauguration of the Federal Government of Somalia in 2012, the country has made significant advances towards political stability. As a small illustration of this progress, the installation of the country's first ATM in Mogadishu in 2015 suggests that the country is finding stability and security and developing a new degree of civil society determined to bring peace, progress and foreign direct investment to the region.

Recent positive efforts by the government to boost hydrocarbon exploration activity have been made through allowing seismic companies to acquire new 2D seismic data. An offshore 2D acquisition programme for Soma Oil and Gas commenced in February 2014, and concluded in June 2014 with over 20,500 km of seismic data acquired across a 122,000 km² area, completed with no security or HSE incidents. Spectrum is to acquire a second offshore long offset 2D multi-client survey to complement and infill the existing Soma grid. The aim is to image to 15 seconds TWT to build up of a complete understanding of the rifted margin, as the record length of the existing Soma data is more limited and only captures the top of the syn-rift section in the deep offshore area (see foldout on previous page). Spectrum's analysis of the existing and new seismic datasets, integrated with regional gravity, potential field and satellite seep data, provides the basis for the following overview of the tectonostratigraphic history of offshore Somalia, highlighting potential play concepts and prospects.

Regional stratigraphic column for the onshore and shallow offshore Somalia Basin



Tectono-stratigraphic Evolution

The initial 'Karoo' rifting of the Gondwana super-continent began in the Late Carboniferous, and syn-tectonic deposition of the 'Karoo Supergroup' continued until the Early Jurassic. This Karoo event signalled the fragmentation of Gondwana, firstly through the separation of East Antarctica from East India, synchronous with the development of an oblique rift valley between Somalia and the Madagascar-Seychelles-India (MSI) block. The Karoo is synonymous with the deposition of a world-class source rock observed from Yemen to South Africa. Using existing well data, a moderate geothermal gradient is inferred for offshore Somalia, implying that some of the more deeply buried Karoo source rock is likely to be in the oil window.

The Jurassic commenced with the deposition of the Adigrat Formation, when further rifting and subsequent seafloor spreading between East Africa and the MSI block resulted in the separation of Somalia and Madagascar, which began to drift to the south-east. The Early Jurassic marine transgression from the north saw the regional deposition of syn-rift organic-rich marine sediments in a restricted embayment, where northerly transform faults may have created partial barriers to oceanic circulation.

Following the separation of East Africa and Madagascar, a period of uplift and erosion occurred during the Cretaceous as the Jurassic rift shoulders responded to unloading. Throughout the Cretaceous, Northern Somalia saw the deposition of a marly-mudstone sequence, distal to an aggradational carbonate platform, whilst the southerly basins saw increased coarse clastic input from the Jubba and Shabeelle Rivers in the Early Cretaceous, depositing a significant post-rift sequence. These Early Cretaceous pro-deltaic sediments provide a potential source rock interval in the south.

Cenozoic sediments on the north-east coast of Somalia are characterised by a thick aggradational passive margin carbonate platform sequence or pro-platform marly mudstones. To the south, a number of lignitic potential source rock intervals have been observed in onshore wells, including the Eocene Coriole and Scebeli Formations. In the south, the Palaeogene consists of predominantly deltaic clastics capped by thick marls, overlain by Miocene and younger deltaics and platform carbonates.

Regional Geology

Offshore Somalia, overlain by the current seismic grid, can be divided into three basins, each defined by their own individual structural regimes: Obbia Basin in the north, the central Coriole Basin, and the southerly Juba-Lamu Basin.

Obbia Basin: The post Early Cretaceous stratigraphy in this basin is primarily calcareous mudstone 1.5 to 3 km thick, which overlies very large Jurassic tilted fault block structures. In places these are crowned by carbonate build-ups, which may be comparable to the Sunbird discovery offshore Kenya. In the south, large antiformal Cretaceous to Early Cenozoic structures, interpreted as transpressional in origin, post-date dramatic Early Cretaceous gravitational slump structures, indicating that regional tectonics are significantly deforming the Cretaceous sequences. Karoo and Jurassic source rocks are a very likely source of oil for these potentially very large traps.

Coriole Basin: This basin is characterised by very large scale transpressional and transtensional flower structures, forming large anticlines related to the north-south strike-slip motion of transfer faults along the Davie Fracture Zone and southward movement and rotation of Madagascar. The Tertiary is represented by a thick siliciclastic section resulting from historic avulsion of the Shabeelle/Jubba/Tana river deltas. Using a moderate geothermal gradient it is reasonable to assume that structural and stratigraphic traps at Cretaceous and Tertiary levels are likely to have access to oil-rich hydrocarbons generated from Jurassic and Cretaceous source rocks.

Juba-Lamu Basin: The Juba-Lamu Basin has the thickest post-rift stratigraphy of the three basins, up to 12 km.

Oil slick from an active oil seep thought to be located directly over toe-thrust structures offshore Somalia.

The deepwater post-rift stratigraphy is characterised by siliciclastic deltaic sediments, sourced by the Shabeelle/Jubba/Tana river deltas. The Cenozoic section in the west is characterised by very large gravity slides on multiple décollement surfaces, which may be coincident with early mature organic-rich mudstones. These are the same mudstones that were reported by Pan Continental and partners as the main source for the oil in the Sunbird discovery. Additionally, these slides have created large, stacked toe-thrust structures downdip, analogous to the areas of significant success in the Rovuma Basin, offshore Mozambique (see foldout on previous page).

Beneath the décollement surfaces, thick Cretaceous clastic-rich sequences of apparent basin floor turbidite fans are draped over tilted fault blocks and stacked post-rift mass-transport system deposits. The similarity of this section to the outer regions of the Rovuma Basin east of the toe thrusts is striking. The main difference appears to be the lack of a Karimbas Graben equivalent down dip.

The potential for oil in this section will be critical to exploration interest. A significant observation from Spectrum's preliminary satellite seep studies is the identification of an active oil seep located directly over the toe-thrust structures where some of these features come close to seabed. The correlation of active seeps to subsurface geology is considered key to risk reduction and therefore these studies are continuing as new data are acquired.

Gigantic Structures

New seismic data from offshore Somalia are revealing extraordinary structures, in an oil-prone frontier province that has never been seen or explored before. The data correlate closely with the potential field results, and the most recent seismic is imaging gigantic structures that have never been mapped before.

Striking resemblance to the astonishingly successful plays in Kenya, Tanzania and Mozambique indicate that offshore Somalia is about to become the hottest area offshore East Africa, with not only the promise of huge hydrocarbon potential, but also a strong indication that this time the hunt is on for black oil. ■

Identifying Potential Oil Zones in Tight Reservoirs

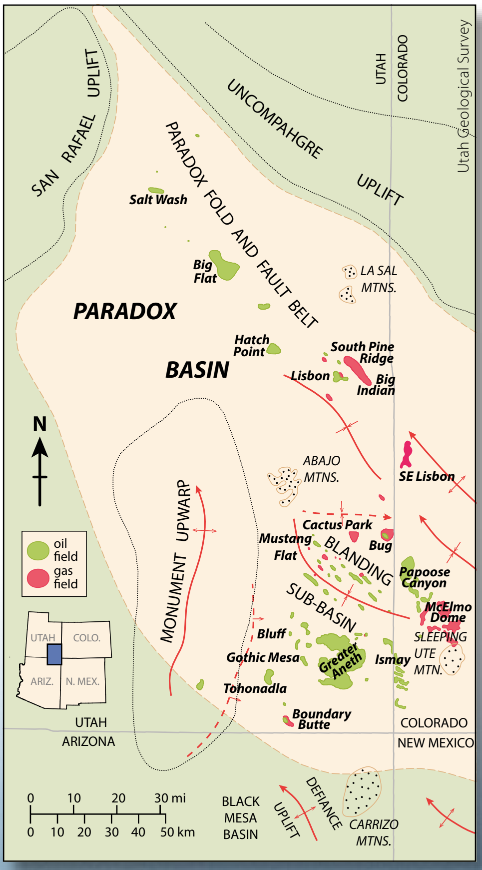
THOMAS SMITH

Low-cost epifluorescence microscope techniques have delineated a prospective, relatively untested oil-prone fairway in the Cane Creek shale play, Paradox Basin, Utah.

When it comes to liquid-rich shale production and potential, the Bakken in North Dakota, Eagle Ford, and the Permian Basin shales of Texas have grabbed all the attention. However, the Cane Creek shale in south-eastern Utah has huge overall potential and may, on a per well basis, outdo those well-known areas. The US Geological Survey says there is a 95% confidence that it holds at least 103 MMbo and a 50% confidence rate of at least 198 MMbo. As for well production, a Fidelity E&P well in the Big Flat field produced about 700,000 barrels of oil in its first year, free-flowing to the surface.

The Utah Geological Survey (UGS) has an ongoing basin-wide research project, part of a three-year US Department of Energy funded study. Their scientists are analysing the geological, geomechanical and geochemical properties of the Cane Creek shale across the Paradox Basin to provide improved reservoir characterisation. The goals of this research are to identify potential exploration areas outside the current Cane Creek unit and to improve drilling and production techniques. The epifluorescence (EF) study is part of that research; most of the operators in this area are small independents not in a position to undertake such an extensive regional study.

Location map for the Paradox Basin showing the Pennsylvanian oil fields.

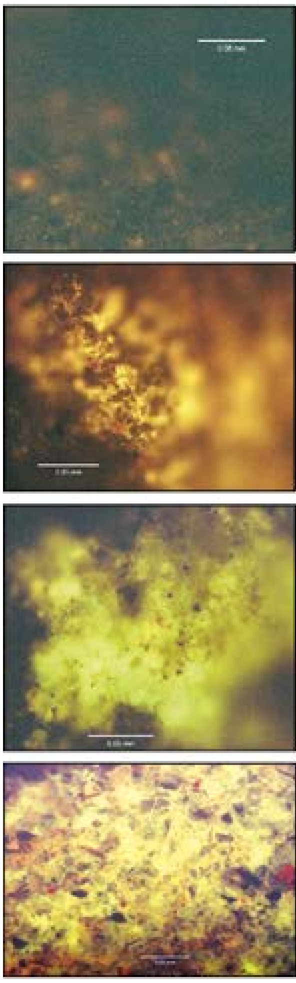


Paradox Basin

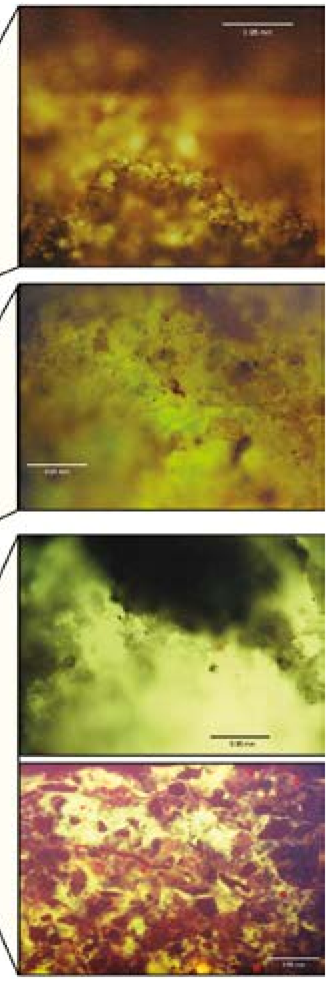
The ‘paradox’ originated in Paradox Valley in south-western Colorado. In 1875, geologist Albert Peale noted that the Dolores River had a “desire to perform strange and unexpected things”. Instead of flowing down the valley, the river emerges from a narrow gap, cuts perpendicularly across the centre of the valley and exits through another gap. This oddity or paradox was caused by the basin’s unique geology. The Paradox Valley occupies an eroded, salt-cored anticline and the river maintained its previously ancient course that was cut into the overlying bedrock.

The Cane Creek Anticline was the location of the first oil discovery in the Moab, Utah area in the 1920s. This feature is just one of many spectacular anticlines that extend for miles in the fold and fault belt portion of the Paradox Basin.

Craig D. Morgan, Utah Geological Survey



Key to Epifluorescence Qualitative Visual Rating Scale	
Rating	**Generalized Interpretation**
0 – 1.0	No Fluorescence: Not capable of oil production. May be wet, if not a gas-bearing interval.
1.0 – 1.5	Very Weak Fluorescence: An "oil" show. Indicative of minor oil in the system, but not capable of production. Some dull or weak fluorescence may exist in a wet zone (especially if there is "speckled" fluorescence) or in a mixed oil/water zone.
1.5 – 2.0	Weak/Spotty Fluorescence: A good "oil" show. Indicative of oil in the system, but probably not capable of production.
2.0 – 2.5	Moderate Fluorescence: A good indication of oil within this interval. Probably capable of some oil production if there is adequate porosity and permeability/fracturing.
2.5 – 3.0	Moderately Bright Fluorescence: A good to very good indication of movable oil within this interval. May be capable of some oil production if there is adequate porosity and permeability/fracturing.
3.0 – 3.5	Bright Fluorescence: A very good to excellent indication of oil within this interval. Should be capable of oil production if there is adequate porosity and permeability.
3.5 – 4.0	Very Bright, Intense Fluorescence: Also an excellent to the best indication of oil within this interval. However, some very bright fluorescence may indicate very tight oil-bearing rocks or mature oil-generating source rocks.



David E. Eby, Eby Petrography & Consulting, Inc.

Micrographs showing examples of visually rated epifluorescence in the Cane Creek shale zone.

Moab Valley (Spanish Valley) located to the west in Utah has a similar geological history and is bisected by the Colorado River.

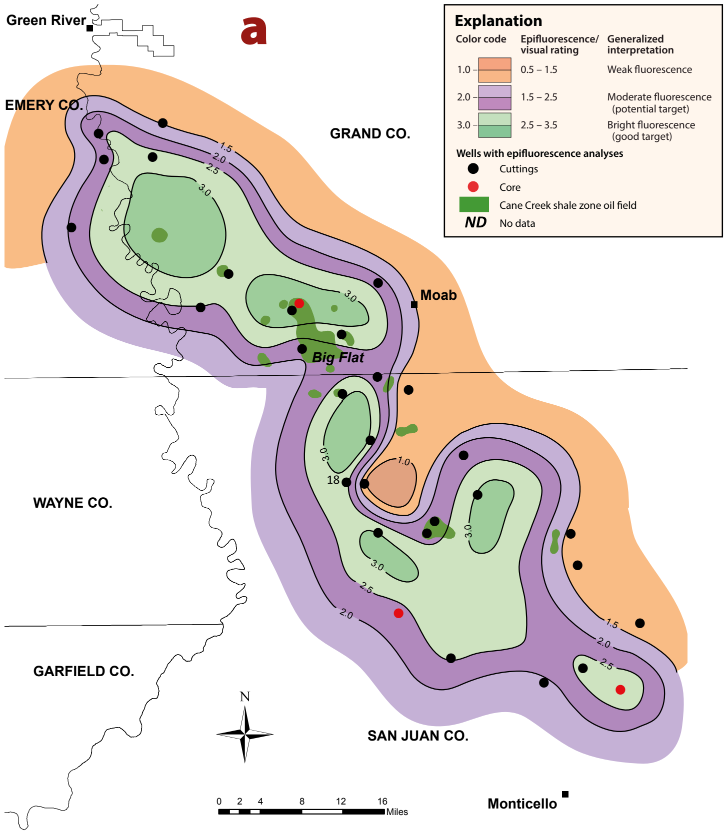
The Paradox Basin covers 85,470 km^2, primarily in south-east Utah and south-west Colorado, but extends into northern Arizona and New Mexico. The basin formed during Pennsylvanian (Late Carboniferous) time about 330 to 310 million years ago, when a series of fault-bounded uplifts and basins developed from Utah to Oklahoma as a result of continental collisions that formed the Ancestral Rockies. The Paradox Basin received a thick succession of cyclic carbonates, evaporites and organic-rich shales, now known as the Paradox Formation. The basin is divided into three areas: the fold and fault belt in the north, the Aneth platform in the south, and the Blanding sub-basin located between those two areas. Deposition in the northern portion of the basin (the Moab area) was in a highly restricted marine bay. Fluctuations in sea level left alternating thick deposits of halite and minor amounts of potassium and magnesium salts during low sea levels, while carbonates and siltstones with thin organic-rich shales were deposited during the high stands. There are 29 cycles in the Moab area; the Cane Creek shale was deposited in the highstand portion of cycle 21 in the lower Paradox Formation.

The first well in Utah was drilled in the northern end of the Paradox Basin near the town of Green River in 1891. Greater Aneth, Utah's largest oil field, is located in the southern end of the basin. Discovered in 1956, the field has produced over 470 MMbo.

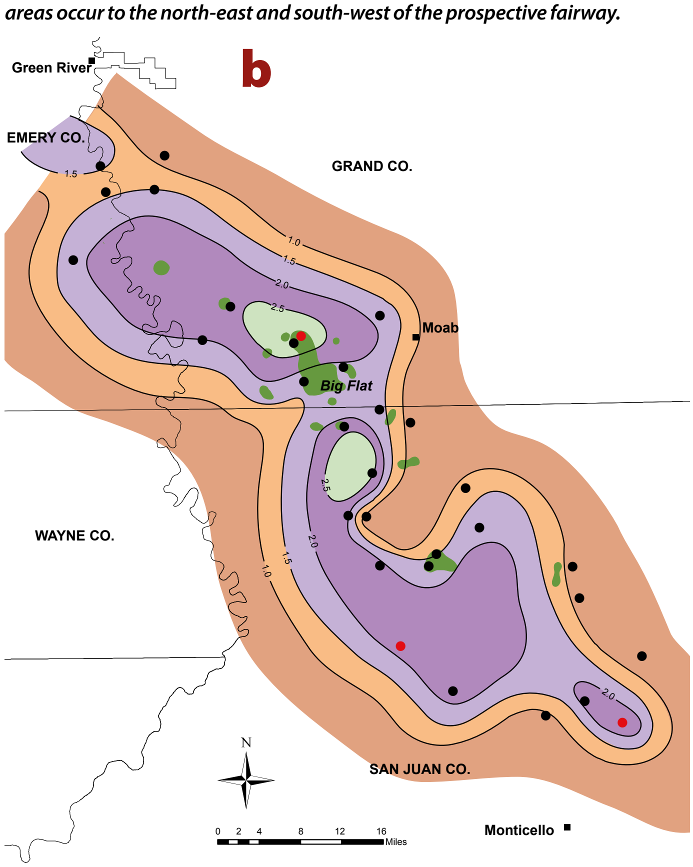
The Study

The first oil discoveries in the Pennsylvanian Cane Creek shale play occurred in the early 1960s. The most successful well drilled during this period was at Long Canyon field, which has produced over 1 MMbo, although most wells produced less than 70,000 bo before being plugged and abandoned. Exploration continued but significant success did not occur until Columbia Gas Development Corporation formed the Cane Creek Federal unit in 1991 and drilled a horizontal well, the first long-reach horizontal well in Utah. The company drilled six horizontal wells that have delivered over 1.4 MMbo and are still producing. Recently, Fidelity Exploration & Production Company took ownership of the field and has drilled 17 additional wells in the Cane Creek Federal unit. Now, with longer laterals and improved completions, well rates have dramatically increased and are expected to ultimately produce about 1.7 MMbo each.

The horizontal target is the B interval where the reservoir is primarily comprised of dolomite, sandstone and siltstone with both intercrystalline and microporosity. This interval is sandwiched by the A and C zones, consisting of organic-rich shale, anhydrite and silty dolomite which serve as both



Maps showing highest maximum epifluorescence (a) and highest average epifluorescence (b) for Cane Creek B interval. A well-defined fairway with ratings 2.0 and higher (purple and greens) follows the same general trend as the total Cane Creek shale highest rating. All existing Cane Creek fields lie within this trend. Very prospective, largely untested B interval sections are present in lobes to the north-west and south-east of the Big Flat field, indicating the interval may not have uniform prospectivity along the favourable fairway. High-risk, less prospective areas occur to the north-east and south-west of the prospective fairway.



Utah Geological Survey

the hydrocarbon source and as seals for the B interval. The entire Cane Creek interval is naturally fractured and overpressured. Production occurs in the fractured dolomites, sandstones and siltstones, usually on subtle subsidiary structural noses found associated with the major structures that trend south-east to north-west across the northern portion of the Paradox Basin. This area, known as the Paradox fold and fault belt, is crossed by large spectacular anticlines that are cored by salt.

Locating these subtle traps usually requires expensive, 3D seismic acquisition in often environmentally sensitive areas. To help high grade this large area outside the existing unit for lease acquisition and more detailed seismic mapping that could lead to exploratory drilling, UGS scientists working with Dr. David E. Eby, from Eby Petrography & Consulting, Inc., Denver, Colorado, have used the area's extensive collection of cuttings, core chips and a limited number of thin sections to conduct this study. EF microscope techniques gave them a low-cost, non-destructive way to characterise the reservoir properties and organic matter including live hydrocarbons.

"Approximately 2,650 cuttings samples and core chips from the collection at the Utah Core Research Centre were evaluated from 31 wells penetrating the Cane Creek shale, including several producers," explains Tom Chidsey, senior scientist at the UGS. "Cuttings were examined under a binocular microscope and representative samples were selected over the Cane Creek interval. Four to ten samples were analysed over each depth interval from each well. The cuttings or core chips were placed on Petrologs™, a small plastic, self-adhesive compartmentalised cuttings storage unit that made sample preparation quick and inexpensive for EF examination. All Petrologs used in this study are stored at the Utah Core Research Centre and are available to the public."

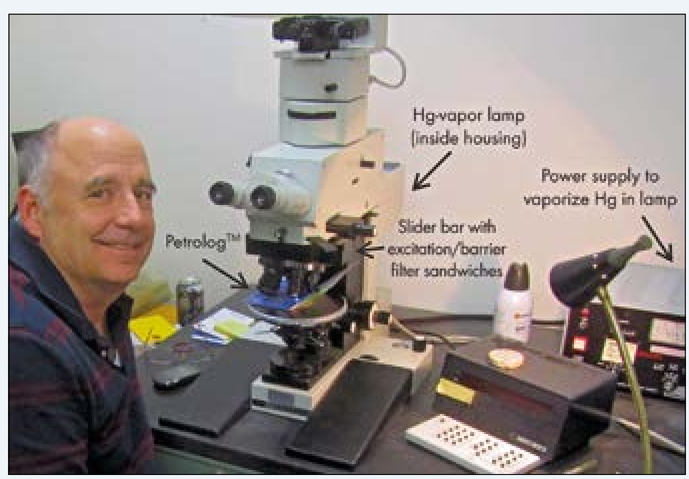
Qualitative Mapping

"EF petrography makes it possible to clearly identify hydrocarbon shows in the Cane Creek cuttings," says Chidsey. "The best images are obtained at relatively high magnifications (greater than 100x). A qualitative visual rating scale (a range and average) based on EF evaluation was applied to the group of cuttings or core chips. Using the qualitative visual rating scale, a variety of EF readings for each well were plotted and mapped. We mapped highest maximum and highest average for the total Cane Creek shale zone and then separated out the A, B, and C intervals. All the maps use the same ratings. Areas considered highly prospective for oil have ratings 2.0 or higher." As expected, the EF ratings for productive Cane Creek wells were generally highest and served as a baseline in identifying potential.

"The Cane Creek interval is a difficult reservoir to explore and develop," explains Chidsey. "Seismic mapping can identify potential drilling targets; however, identifying where good quality reservoirs exist is extremely difficult. Using low-cost EF analysis and

Epifluorescence Microscopy

EF microscopy enables better imaging of poorly preserved textures and grains in sandstone, siltstone and carbonate rocks, particularly the type of dolomites encountered in the Cane Creek play. Information on the diagenesis, pore types and organic matter (including 'live' hydrocarbons) within sedimentary rocks are gained using EF microscopy. Samples are analysed using a rapid and non-destructive procedure employing a petrographic microscope equipped with reflected-light capabilities, a high pressure mercury vapour lamp for EF evaluation, appropriate filtering and a film imaging system. For the Cane Creek samples, magnification ranges for examination and image-documentation were between 130 and 320x, and it was found that broad-band, blue-light EF was the most helpful in observational work on the dolomites. The greater depth of investigation into a sample by the reflected fluorescence technique over that provided by either polarised or other forms of reflected light makes it possible to resolve grain boundary and compositional features that are normally not appreciated in cuttings or thin-section petrography.



David E. Eby, Eby Petrography & Consulting, Inc.

mapping has identified a prospective north-west to south-east oriented fairway in the Cane Creek shale zone, whereas the north-eastern part of the Paradox fold and fault belt shows low EF values. The implication is that hydrocarbon migration in the Cane Creek dolomite beds was along regional north-west trending folds, faults and fracture zones, creating this relatively untested oil-prone area.

"EF analysis represents a low-cost method that can help quantify and delineate the 'sweet spots' and the potential areas in emerging tight oil plays around the world just as it has in the Cane Creek shale."

The UGS and Eby previously conducted a similar EF study on the Mississippian Leadville Limestone, also in the Paradox Basin, which also showed areas with untested potential. ■

Gravity for Hydrocarbon Exploration

Can an unexplored sedimentary basin be unravelled by gravity? How can gravity in cross-disciplinary workflows estimate the base of salt domes and gas saturation in shallow sedimentary traps ? Read on!

Gravity. It's not just a good idea. It's the Law.

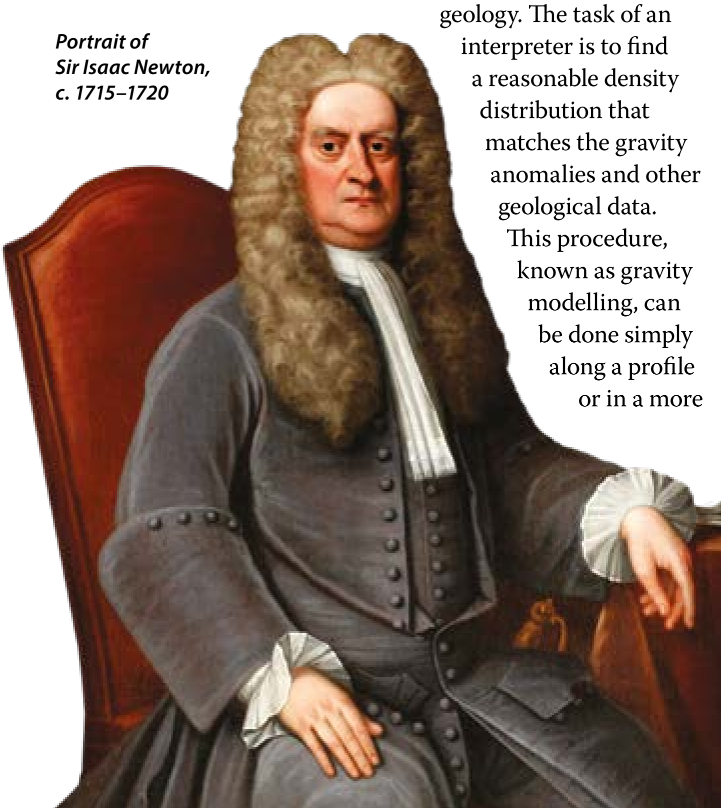
Gerry Mooney (1977)

Guest Contributor: CHRISTINE FICHLER; Column Editors: MARTIN LANDRØ and LASSE AMUNDSEN

Thanks to Newton's Law of universal gravitation, you are safely standing on earth and not flying off into space. The gravitational attraction between two masses increases as their mass expands and decreases as the distance between them grows. For you, this means that you are one mass and mother Earth is another mass – luckily a big one, which attracts you.

From the geological viewpoint, all subsurface rocks are part of the earth's mass. They cause an attraction on a test-mass, spring-mounted in a gravimeter, the instrument that measures gravity. Just the size of a car battery, it can be located on seismic vessels, aeroplanes or simply on the ground. Tiny deviations from the average gravity force caused by density variations in subsurface rocks are called gravity anomalies. The density of a rock relates to its mineral composition and pore space: sediments, for example, possess low densities, increasing with compaction towards crystalline rocks like granites. Higher on the density scale are mafic rocks like gabbros and basalts; and densest of all are ultramafic mantle rocks.

Gravity anomalies are a composite expression of all the subsurface densities and as such contain a clue to the subsurface geology. The task of an interpreter is to find a reasonable density distribution that matches the gravity anomalies and other geological data. This procedure, known as gravity modelling, can be done simply along a profile or in a more advanced fashion on gridded or triangulated surfaces or even using voxels. Once a basic subsurface geometry has been established and density ranges for the expected rocks are set, the fun begins: grab a body or a point in the model, move it with your cursor, see the immediate change in the gravity in your program and play this game towards a model that matches the gravity (Figure 1).



Portrait of Sir Isaac Newton, c. 1715–1720

Alternatively, you can let an inversion algorithm do the work, by telling the program which points it is allowed to move, or which density it can change, and it will find the solution with the best gravity match. This leads to a familiar concern regarding the inherent ambiguity in gravity interpretation, since both unrealistic and reasonable models can generate exactly the same gravity anomaly. The most important strategy to tame the 'beast' of ambiguity is to utilise constraints, such as the geometry of layers interpreted from seismic, densities from geological databases, or geological models or analogues. Gravity will always provide a solution space, hopefully narrow enough to provide the missing piece of the puzzle. It can be used to supplement seismic data and geological models with unknown quantities or to create an initial coarse structural model of an unexplored basin.

Let's look at three important tasks where gravity can make an impact in hydrocarbon exploration.

Basin Structure in Early Exploration

Early basin exploration suffers from a lack of geological information due to scarce seismic coverage. Gravity interpretation can address open questions of basin geometry, sedimentary thickness and direction of structural trends, as illustrated in the synthetic model in Figure 2, consisting of crystalline basement and sediments, where the clue is the contrasting density. Gravity anomalies and vertical gradients have been computed, the latter representing a highpass filtered gravity version, which enhances details of the shallow structure better than the gravity anomaly itself. The top basement is heavily faulted at all depths and its appearance on the gravity data illustrates the decaying resolution capability with increasing depths: all peaks forming the shallowest part of the basement high are clearly visible on the gravity gradient, which as such provides an excellent tool for top basement mapping. However, fault blocks in the deeper part of the basin (left section of the profile) are smeared together. The same loss of detail occurs when inverting the calculated gravity for top basement, solely based on the

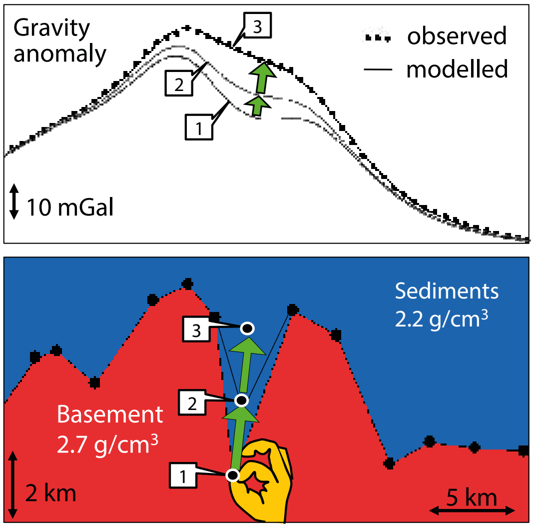


Figure 1: Gravity modelling in practice: The hand-hold pointer is at the boundary between top basement and sediments; move it upwards through positions 1 to 3 and the calculated gravity anomaly is changed. The aim is a match with the observed gravity.

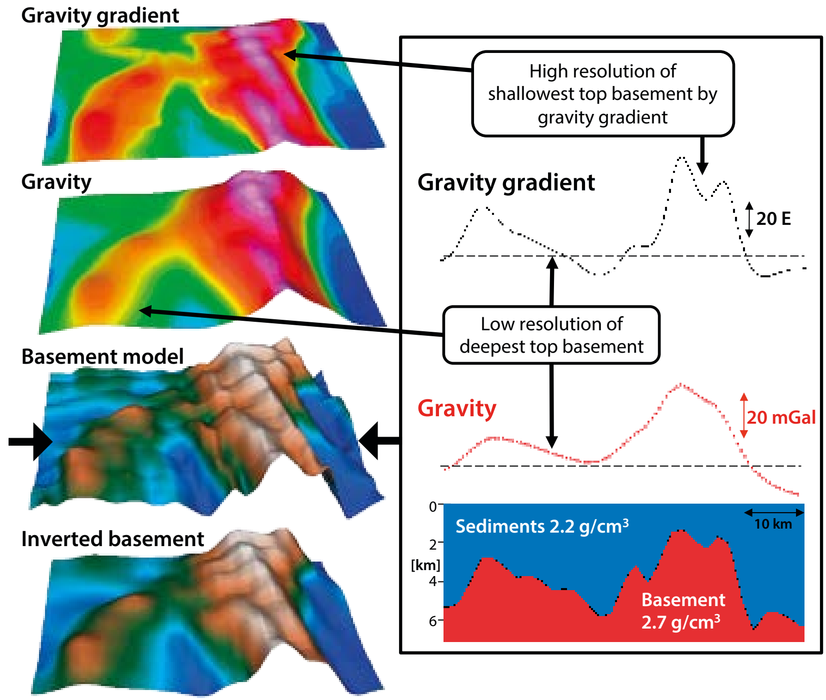


Figure 2: Synthetic model of a highly faulted basement in 3D and on a profile (location shown by large black arrows), with calculated gravity (Gz) and vertical gradient (Gzz). Inverted top basement obtained from inversion of calculated gravity Gz (Parker inversion; GEOSOFT Oasis Montaj).

pre-defined density contrast between sediments and basement. Nevertheless, the gravity data give a clear idea of the shallowest and deepest parts of the basin as well as the main structural trends, which are related to those of the overlying sedimentary strata. This is useful for 2D seismic survey planning, both ensuring a suitable angle of the lines to the structures and focusing on the most interesting parts of a basin.

The level of detail unravelled depends on the quality of the gravity data, as noise causes artificial anomalies to merge with real ones. For offshore areas, gravity data from satellite altimetry covering the entire world is freely available, or in enhanced quality from contractors. Onshore, the options are airborne or ground gravity data.

In well explored areas, better gravity data should be available, as shown in Figure 3 from the Gjesvær Low in the south-western Barents Sea. The almost triangular depression was identified as a prolongation of the salt-bearing Nordkapp Basin by gravity and only later confirmed by seismic.

Modelling of Complex Salt Structures

The development of a realistic model for some salt diapirs can be a hard nut to crack for seismic imaging, but gravity data can help to define the edge and base of the salt. Figure 4 gives an example from the 'Uranus' salt dome in the Norwegian Nordkapp Basin, which was interpreted by combined seismic and gravity gradiometry. The seismic profile illustrates the lack of reflectors at the base of the salt and presents minimum and maximum salt extension models from the pre-well interpretation. Well data proved the minimum model wrong and, after the acquisition of new gravity and gravity gradiometry data, the density model was developed using sedimentary boundaries and top salt from seismic interpretation and densities from wells. Salt forms a negative density contrast against surrounding rocks, thus generating a negative gravity anomaly. The vertical gravity gradient, Gzz, senses the shallowest part of the salt, as can be seen by the way the salt ridge lines up with the lowest values of Gzz (dark green

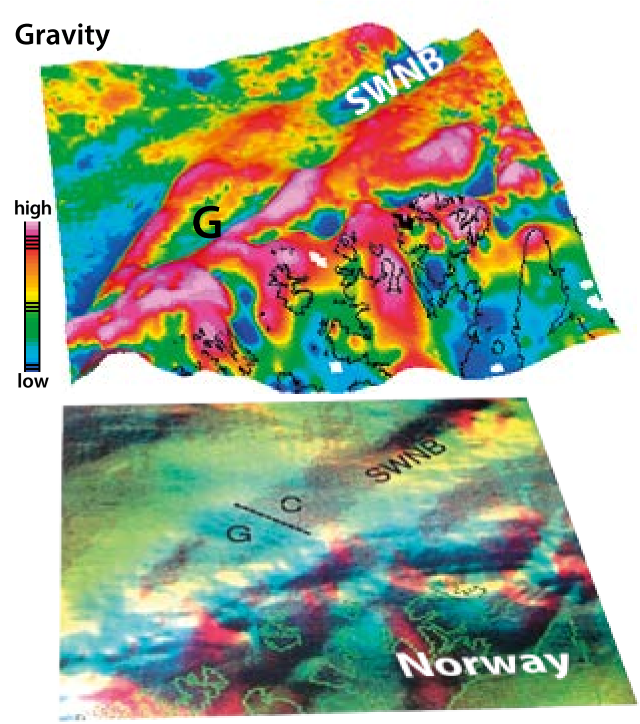


Figure 3: What was hard to see in 1994 is clearly identified on a modern composite data representation, when the small sedimentary basin Gjesvær Low (G) was found to be a continuation of the Nordkapp Basin (SWNB), south-western Barents Sea. Gravity anomalies from a 20-year-old survey are compared to recent results: (upper) modern data (Olesen et al.) in 3D shows vertical gravity gradient draped over the gravity anomalies (GEOSOFT Oasis Montaj); (lower) original display (modified from Johansen et al., 1994.

and blue). The gravity Gz is wider and smoother as it is also sensitive to the deeper parts of the salt body. This difference in sensitivity is used to address different depth regions during the inversion of Gz and Gzz in order to yield thickness estimates of cap rock, depth to base salt and thickness of mother salt. Modifications in density and salt thickness were used to span the solution space for the base salt, as shown on the seismic profile.

Imaging salt on seismic can benefit from gravity in different phases. Survey planning makes use of early gravity models for optimal orientation and the subsequent seismic processing for quality control of seismic velocities. The velocities can be converted to a density model, which should result in matching gravity anomalies. Finally, seismic interpretation can be improved in an interactive loop with gravity modelling and inversion, as shown in Figure 4.

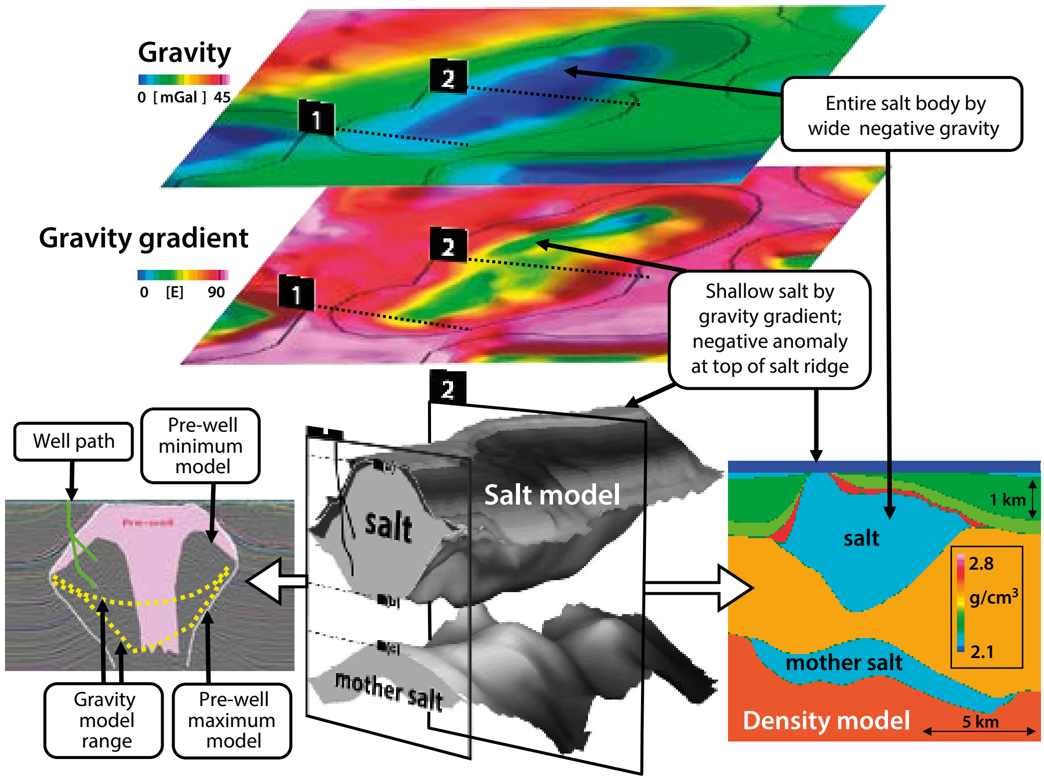


Figure 4: Salt model derived by integrated seismic and gravity interpretation (modified from Stadtler et al., 2014 and Hokstad et al., 2011).

Shallow Lithology and Gas Mapping

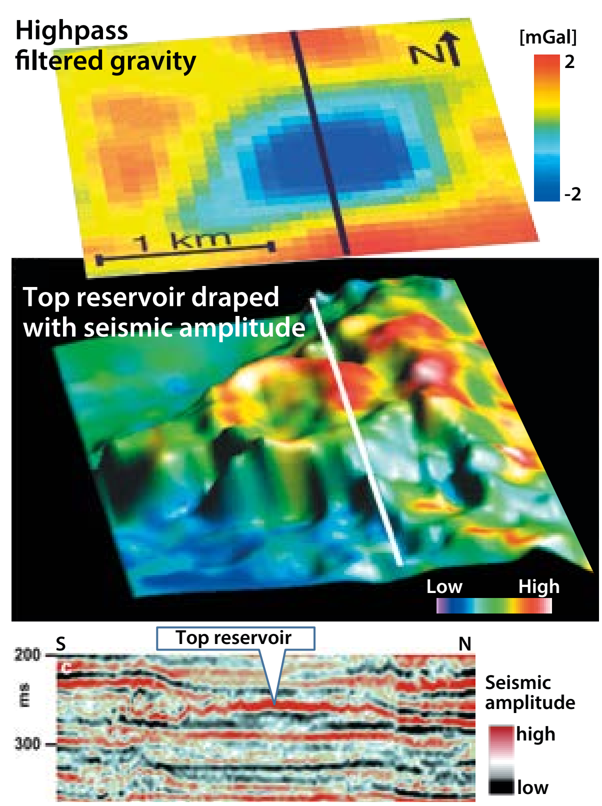
It is well known that reservoir monitoring can estimate alterations in gas saturation through density changes observed on repeat gravity surveys. The same effect can be used in exploration to estimate gas saturation in shallow targets, combining the interpretation of 3D seismic and high resolution gravity data.

On Figure 5 a distinct gravity low is seen at the same location as a small seismic closure topped by a seismic bright spot. A detailed density model was constructed from interpreted seismic surfaces and densities from wells, leaving the density of the reservoir as unknown. Gravity modelling was then used to estimate the density within the closure, resulting in values that could indicate either gas-filled sand or a lithology change. When the gas saturation changes, there will be a corresponding linear change in density, which can be combined with seismic to lead to a more precise prediction of gas saturation. This handy connection can only be applied to shallow targets as the resolution of gravity anomalies decays with depth. Furthermore, high quality gravity or gravity gradiometry data are a pre-requisite for such applications.

After this excursion into the world of gravity, hopefully you will feel tempted to include these data in some of your workflows. A final important argument for gravity data is its low cost. Satellite altimetry and country-scale data are often free of charge, and even high resolution gravity data cost only a minor percentage of a seismic budget. Wisely used, serious savings may be achieved with regard to optimally placed seismic surveys in early exploration, and, where applicable, a better constrained seismic interpretation.

References available online. ■

Figure 5: Negative gravity anomaly (blue) indicating a density deficit at a shallow seismic closure, possibly caused by shallow gas (modified after Bauer and Fichler, 2002).

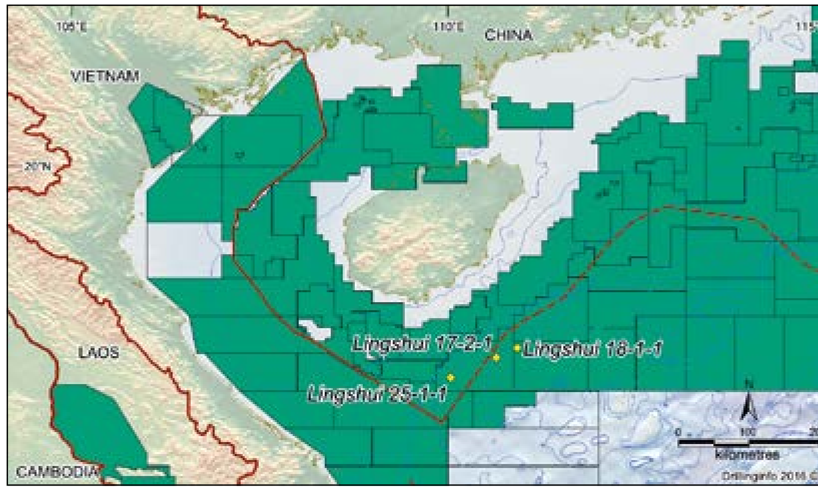


China: First Ultra-Deepwater Discovery

In late February 2016, **CNOOC** confirmed **Lingshui 18-1-1** as China's first ultra-deepwater natural gas discovery. Located in the Lingshui 18 Block in the Qiongdongnan Basin in the north-western part of the **South China Sea**, the well flowed gas to the surface upon testing in early December 2015 and although the test rate has not been disclosed, the discovery has been certified by the Ministry of Land & Resources.

The exploration well was spudded on 21 October 2015 using the *Haiyangshiyou 981* semi-submersible in 1,689m of water; an offshore well is considered ultradeep if it is drilled in waters over 1,500m deep. It reached a TD of 2,927m in mid-November 2015, and is thought to have been targeting the shaley sandstones of the Pliocene Yinggehai and Late Miocene Huangliu Formations. The gas flowing on test is believed to have come from the Second Member of the Yinggehai Formation.

Lingshui 18-1-1, operated by CNOOC, is located near another deep sea gas find, Lingshui 17-2, which has certified proven gas reserves exceeding 3.5 Tcf, as reported by the state media a year ago. This 2014 discovery well was drilled in 1,450m of water and reached a total depth of 3,510m, where it struck a 55m-thick reservoir. ■



Myanmar: New Play Opener

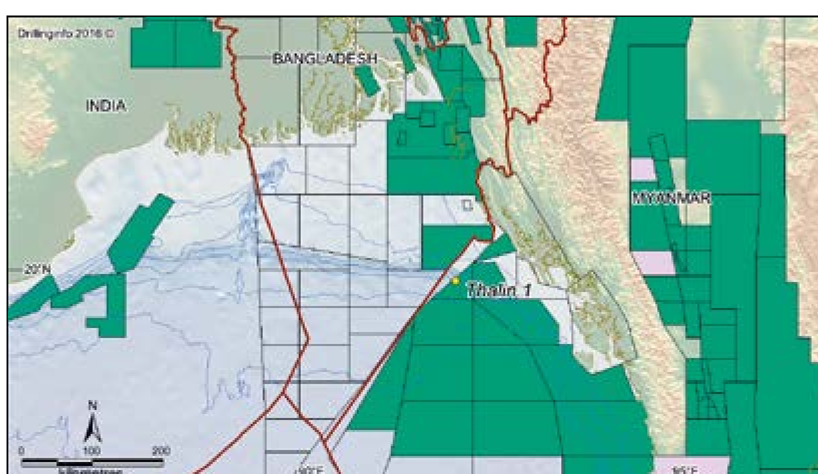
On 12 February 2016, **Woodside Energy (Myanmar) Pte Ltd** plugged and abandoned the **Thalin 1** (also known as Thalyn 1) gas discovery, located in the 1,646 km^2 Block AD-7 in 836m of water in the Bay of Bengal, about 100 km off the coast of Myanmar and less than 20 km from the maritime border with Bangladesh. The well encountered a 64m gross gas column, with 62m of net gas pay, interpreted to be within the primary objective, and it had been logged and pressure tested, confirming the presence of a gas column, before being abandoned.

Thalin 1, which is in the northern part of the **Rakhine Basin**, follows an earlier gas discovery by Woodside in the same basin at the Shwe Yee Htun-1 well in Block A-6, announced on 4 January this year. The two discoveries lie at opposite ends of the Rakhine Basin and the company believes that Thalin-1A had successfully confirmed a working petroleum system whilst also proving a play type different to that encountered at Shwe Yee Htun-1. It lies approximately 60 km west of the Daewoo-operated producing Shwe Field, which has onshore gas plant and pipeline gas export facilities.

The well was spudded on 22 January 2016 using the Transocean *Deepwater Millennium* and drilled to a total depth of 3,034m. It is part of a one plus one option well drilling programme, with the option well planned for 2017.

Equity in Block AD-7 is split between Daewoo International Corp (60%) and Woodside (40%) with Woodside as the operator with respect to the deepwater drilling activities and Daewoo in charge of all other operations. In March 2014 the consortium acquired a 1,349 km^2 3D seismic survey over the block, and after the block's area was recently expanded north to the Myanmar maritime boundary, the AD-7 Joint Venture has approved the acquisition of an additional 1,200 km^2 of 3D seismic data over this area, scheduled to commence in March 2016. This survey will facilitate further evaluation and expansion of the prospect portfolio.

Woodside is currently the largest acreage holder in the offshore Rakhine Basin, with interests in six blocks covering a total of about 47,000 km^2. ■



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Groundbreakers

A new book on the history of the upstream petroleum industry is itself a groundbreaker in a fascinating field.

Groundbreakers:
The Story of Oilfield Technology and the People Who Made It Happen
Mark Mau and Henry Edmundson, FastPrint Publishing, 2015.

JOE GREEN and RASOUL SORKHABI, Ph.D.

It is a delight to introduce this new book on the history of petroleum. The oil and gas industry is barely 150 years old and yet this book contains over 450 pages of fascinating facts about its technical development, from humble beginnings to the major influence it has for most people on the planet – and the innovators responsible for it. It is an amazing piece of research by the authors, who come from two different but complementary backgrounds: Dr. Mark Mau is a professional historian and Henry Edmundson worked for Schlumberger for over 45 years and was the founding editor of the company's popular journal, *Oilfield Review.*

There are already several books on the history of the petroleum industry, but many focus on economic and political history, and only a few deal with petroleum geoscience and engineering. *Groundbreakers* is a welcome addition to the literature. It combines the histories of geoscience as well as engineering, covering many recent developments in the field. It also offers first-hand information, as the book is primarily based on interviews with experts – over 130 interviews by the authors alone and 20 more from internet sources.

Turning the page to discover another familiar company or corporation name and the individuals who started it off, plus the discovery technology which got it going is really quite exciting and surprising. Did you know, for example, that the Soviet oil industry developed turbine drilling in order to achieve a solution to the poor quality of steel pipe, leading them to pioneer lateral drilling and completions, without which the US shale boom would never have happened?

Such is the mother of invention and significantly, much of the 'groundbreaking' described is about adaptation of existing technology. Sometimes this is from non-oilfield applications, such as applying knowledge from aerospace to new drilling systems and from military weapons to borehole perforation. It was also surprising to learn just how early some of the developments were, like Mr Solomon Dresser's well packer patent, granted in 1880.

Covering a Wide Field

The organisation of chapters and topics roughly reflects the chronological development of petroleum geoscience and engineering. The first two chapters are on the drilling of pioneering oil wells in Baku and Pennsylvania and applying the anticline theory as the earliest attempt to locate oil fields. Rotary drilling, seismic surveying, reservoir coring and characterisation, well-logging, controlled drilling and well perforating, artificial oil-lift methods, basin analysis, application of digital and computer technologies, offshore drilling, and exploration of non-Western countries are discussed in subsequent chapters.

More recent developments such as 3D and 4D seismic surveys, deepwater exploration and drilling, horizontal drilling, hydraulic fracturing, and the shale revolution are also discussed. In 'Looking Ahead', the final chapter, the authors touch on the potential of electromagnetic surveys, expandable casing, managed pressure drilling, ultradeep offshore drilling, and reservoir nanotechnology.

While the various elements of oil industry technologies are segregated into these chapters, the book does a good job of maintaining our focus on the objective of improving the discovery and production of hydrocarbons. The digital age has revolutionised geology and geophysics, reducing the risk of drilling dry wells considerably. But it is not just about economics – automated drilling rigs are much safer than yesterday's manual environments.

Over a hundred pages are taken up with a reference section listing timelines, interviewees and a bibliography, which is great fun. So you want to know if there was a Mr Halliburton and how he got started? Check it out in this book. Every rig site should have a copy in the recreation room library.

It is also beautifully illustrated (by Abigail Whitehead) in an understated manner, which just adds to the enjoyment.

Overall, *Groundbreakers* is a well written, fascinating book on the development of the petroleum industry. Well done to all who made it happen. ■

Meeting Society's Expectations

IPIECA is the global oil and gas industry association for environmental and social issues. Executive Director Brian Sullivan tells us about its aims and its importance to the industry and the wider world.

Can you tell us about the background and mission of IPIECA?
IPIECA is the only global association involving both the upstream and downstream oil and gas industry on climate and energy, environment and social issues. Our membership comprises oil and gas companies involved in the exploration, production and refining of oil and gas, along with national and international oil and gas industry associations. Altogether, IPIECA company members produce 60% of the world's oil and gas.

IPIECA was originally formed in 1974 to act as a liaison with the United Nations Environment Programme. Since then our remit has broadened to include other UN bodies such as the International Maritime Organization, international NGOs and other stakeholders, including academia and the investment community. IPIECA's work was primarily focused on specific environmental impacts such as oil spills or the particular local risks of pollution from operations, but over time our remit has broadened to reflect environmental, social, climate and energy issues. We have also extended our scope beyond the liaison role and spend most of our time convening working groups supported by over 500 member employees to develop and share knowledge and good practice on environmental and social issues. Our vision is an oil and gas industry that successfully improves its operations and products to meet society's expectations for environmental and social performance.

Does the industry know enough about IPIECA?
Given the specialist roles we fulfil for the industry, it is unlikely that people in other disciplines will know much about us. What is important is that the industry is aware of and understands the environmental and social context in which it operates and seeks to continuously improve in order to maintain its licence to operate. At IPIECA we can help the industry to achieve this through sharing knowledge, developing good practice and keeping stakeholders informed about industry progress.

Does the E&P industry care enough about environmental and social issues?
The industry places a very high priority on environmental and social issues. From our vantage point connected to 36 of the world's leading oil and gas companies, we see continued commitment to environmental and social responsibility despite the challenging economic environment. Companies appreciate the business case for responsible operations and products. They are also fully aware of the interests of their stakeholders. Many provide regular updates of progress through sustainability reports.

What do you think are the most pressing environmental issues?
Climate change is an important topic for the industry. It affects the political and social environment in which the industry operates and the risks present challenges to our markets, industry facilities and operations. Also, the industry can play a significant role in climate risk mitigation through the provision of gas as an alternative to coal and through actions to reduce emissions from our operations.

Air quality is another pressing environmental issue linked to energy usage. The industry, through IPIECA, has a long history of collaborating with our UN partners to improve the situation, most recently through the eradication of leaded gasoline. Other important environmental issues include biodiversity and ecosystem services, water management and oil spill preparedness and response.

And the most pressing social ones?
It's hard to separate environmental and social issues as they become increasingly interconnected. However, key areas in terms of social responsibility include business and human rights. The recent UN guiding principles for business and human rights provide a framework for business to understand and manage risks and issues arising from their activities. IPIECA has led the work of the industry in operationalising the guiding principles so that they are deliverable in the oil and gas sector.

What would success look like in 2040?
One thing is for certain, the world, its energy use and the oil and gas industry will look very different in 2040 compared to today. How different remains to be seen; however, scenarios published by the International Energy Agency and others, based on current knowledge, suggest that oil and gas will remain as significant sources of the world's energy. The industry must and will continue to improve its operations and products to mee stakeholders' ever-increasing expectations. Success in 2040 would be recognition that the industry is the leading sector in meeting these expectations and that IPIECA has played its part in enabling that. ■

IPIECA

IPIECA Executive Director Brian Sullivan joined the organisation in 2011 after 23 years in BP.

The Future is Shale

Shale oil and gas were considered rarities ten years ago. In the future these sources will constitute a sizable share of the market.

The 'shale shock' is very well illustrated by the fact that in its 2013 Energy Outlook BP projected US tight oil to reach 3.6 MMbopd by 2030. In fact, that level was surpassed in 2014.

Shale shocked the world.

In less than 10 years US oil production from tight shales has grown from virtually nothing to more than 5 MMbopd. And, according to Rystad Energy, US shale production may very well reach 8 MMbopd in 2020. Meanwhile, at the moment, tight oil *outside* North America totals less than 1 MMbopd.

By helping the US towards self-sufficiency in liquids, the boom will, of course, have large geopolitical impacts, as OPEC countries will have to gradually divert their exports from the US towards Asia.

BP agrees with this remarkable outlook. The 'shale revolution' will continue, the company says, fuelled by the technological innovations and productivity gains that have unlocked vast resources of both tight oil and shale gas. However, the BP forecast is somewhat different from that of Rystad Energy, as the company expects tight oil production to plateau in the 2030s at nearly 8 MMbopd. On a global level, BP believes that shale oil will reach 10 MMbopd in 2035, meaning that it will account for about 10% of worldwide oil production.

BP also expects a sharp increase in the global production of shale gas, expecting that in the US this will account for around three-quarters of total US gas production in 2035 – almost 20% of global output. "Globally, shale gas is expected to grow by 5.6% p.a. between 2014 and 2035, well in excess of the growth of total gas production. As a result, the share of shale gas in global gas production more than doubles from 11% in 2014 to 24% by 2035," BP reports in its Energy Outlook 2016. While the growth of shale gas supply is dominated by North American fields, production will continue to expand elsewhere, in particular in China.

No one predicted the extreme growth in shale oil and gas production that we have experienced in the last five years or so. It remains to be seen if today's forecast will turn out to be correct, 5, 10 or 20 years from now.

Halfdan Carstens

Onshore US oil is transported by trains.

Conversion Factors

Crude oil

1 m^3 = 6.29 barrels

1 barrel = 0.159 m^3

1 tonne = 7.49 barrels

Natural gas

1 m^3 = 35.3 ft^3

1 ft^3 = 0.028 m^3

Energy

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

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

Numbers

Million = 1×10^6

Billion = 1×10^9

Trillion = 1×10^{12}

Supergiant field

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

Giant field

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

Major field

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

Historic oil price