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GEOSCIENCE & TECHNOLOGY EXPLAINED

GEOTOURISM
Aspen: Rocky Mountain High

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TECHNOLOGY EXPLAINED

The Future of Onshore Seismic

EXPLORATION
Awaiting Discovery? The US Atlantic Margin

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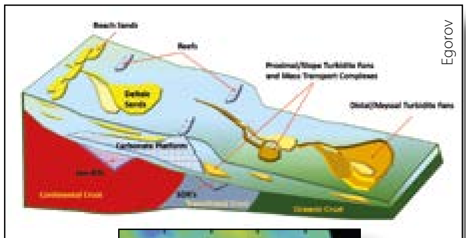

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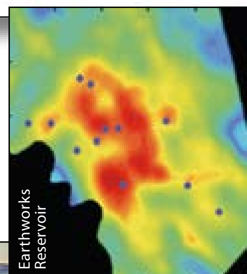

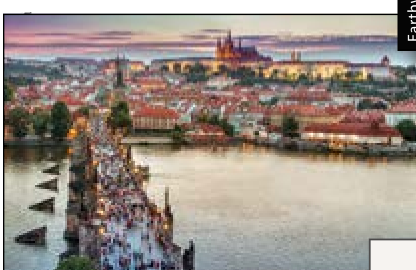

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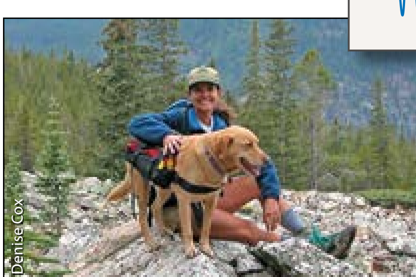

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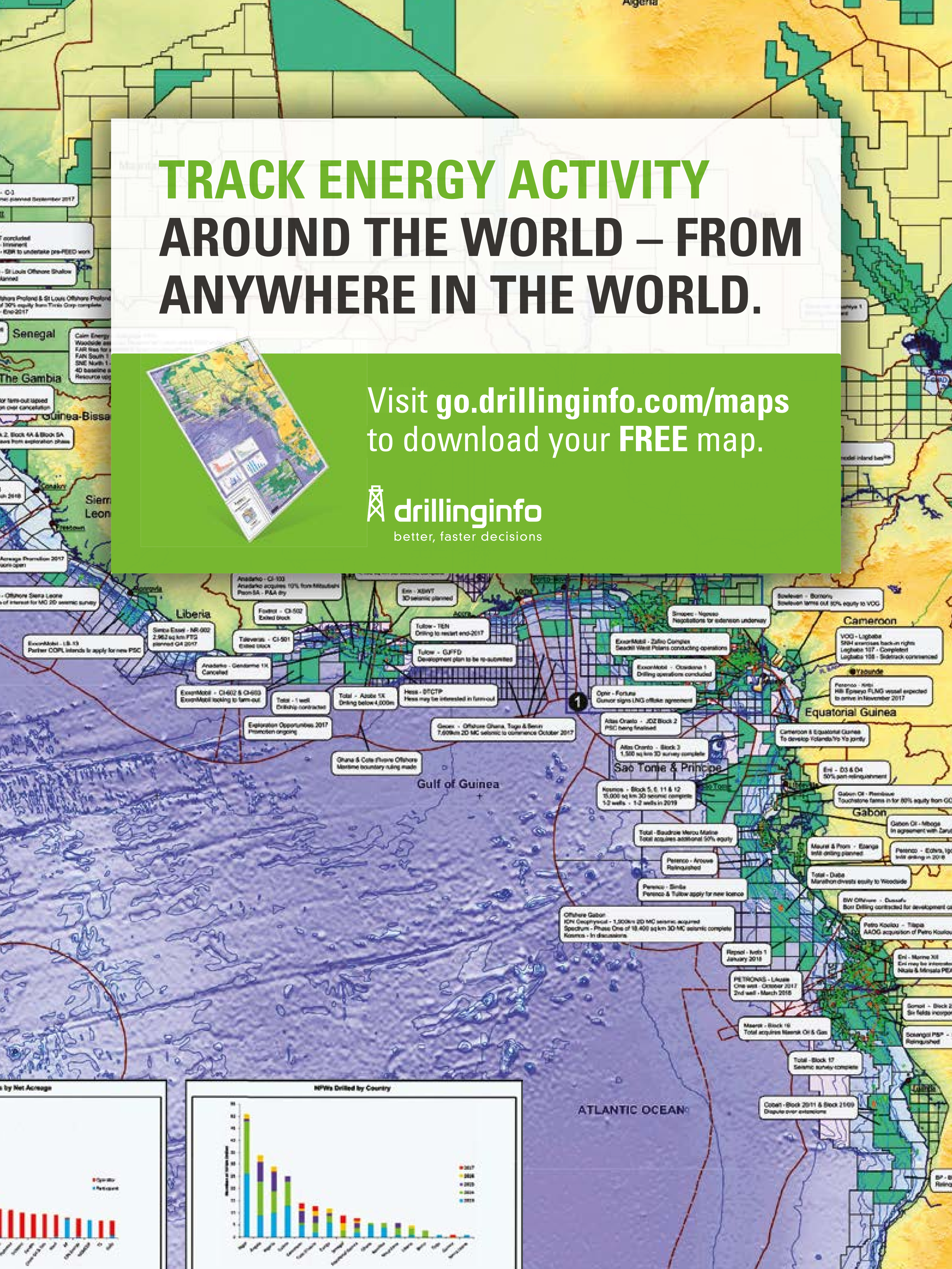
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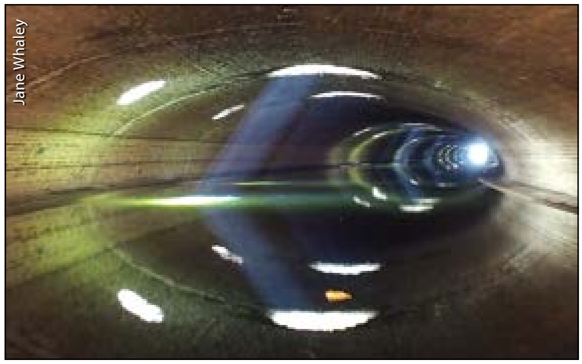
ATLANTIC OCEAN

Every Drop Counts



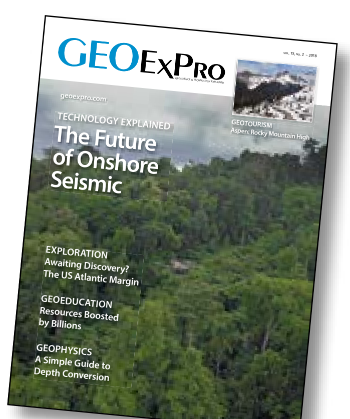
After a lot of doom and gloom, a glimmer of optimism is appearing in the exploration industry. Having been below $60 a barrel from mid 2015, since late 2017 the price of Brent crude has stayed above that level, even briefly hitting $70 earlier this year. A much-pared down industry is beginning to see light at the end of the tunnel. Job cuts have almost ceased, with increases in employment being evident in some areas, particularly the US. Total global proved oil reserves have been rising after stagnating for several years, and there has been a renewed interest in deepwater drilling.

This revived industry will be very different, however. For one thing, there seems to be less 'them and us' between service and exploration companies, with cooperation becoming the new norm. Take a look at the METIS project, our cover story: a fine example of the new spirit of collaboration, where supermajor Total and as many as 25 service companies are together creating a revolution in onshore seismic acquisition. Importantly, this project, like many in this new and exciting world, takes a holistic view of the issues involved, incorporating not just innovative technical solutions, but ensuring that health, safety, the environment and sustainability are all part of the program.

Working to get maximum production from every field has also become a priority in this new environment. Analyst Rystad Energy estimates that liquid resources from mature assets grew by 151 billion barrels over the last four years, driven by factors such as increased infill drilling, improved understanding of reservoirs, EOR projects and technology improvements. Looking ahead, every drop left behind will matter.

As Bob Dudley, BP Group Chief Executive, said in the recently released *BP Energy Outlook*: "Don't be fooled by the recent firming in oil prices: the focus on efficiency, reliability and capital discipline is here to stay." ■

Jane Whaley
Editor in Chief



DARTS AND DRONES: THE FUTURE OF ONSHORE SEISMIC

The dense rainforest of Papua New Guinea is the perfect testing ground for the METIS onshore seismic acquisition project, in which drones are used to drop biodegradable sensors through pre-identified gaps in the forest canopy.

Inset: The captivating scenery around Independence Pass in the Rocky Mountains is full of fascinating geological puzzles.

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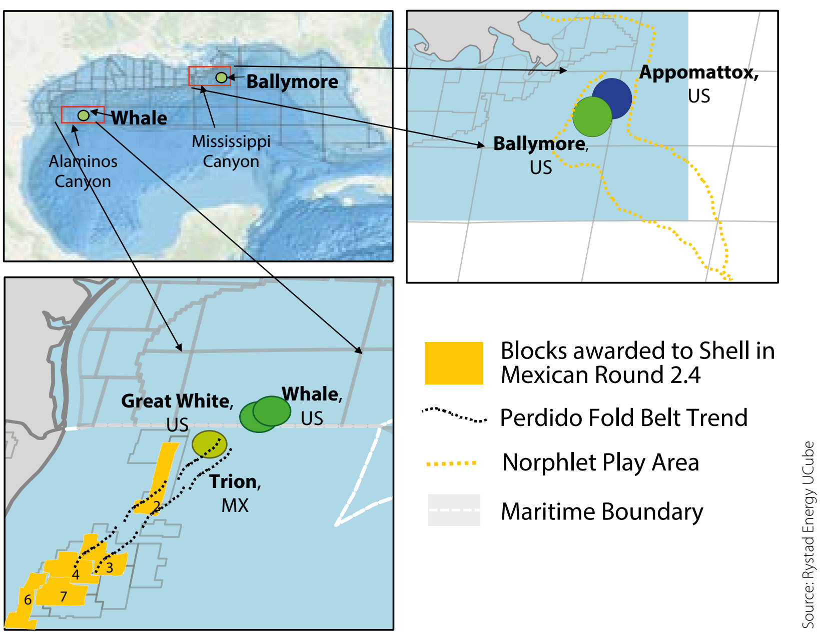
Ballymore and Whale

Key discoveries put US GoM back on the map

After a very disappointing 2017 in terms of oil and gas exploration worldwide, the US Gulf of Mexico is giving wildcatters reason to smile again as details were released in January of two significant discoveries by Chevron and Shell.

The most recent well is the Ballymore discovery, where operator Chevron and 40% partner Total found 670 ft (204m) net pay of high quality light oil in the sandstones of the Jurassic Norphlet Formation. This formation is fundamentally different from all other plays in the Gulf of Mexico. It lies at the base of the sedimentary package just above the Louann Salt and therefore this pay is charged by the overlying source rock, with nothing from an underlying source, as the salt layer is impermeable.

This also means the Norphlet Formation underwent the same pressure and temperature degeneration as its overlying source rocks. The reservoir quality at such depths could be questionable, as is also evident from the history of exploration in this play. Based on Rystad Energy analysis, we expect Ballymore to hold around 550 MMboe of resources, which could be developed as a tie-back to Shell's nearby Appomattox deepwater development project.



New oil discoveries in the US Gulf of Mexico.

Shell is a pioneer in exploring this play. It took the company around 10 years before it found thick Aeolian Norphlet sandstone in the Appomattox discovery well, at around 2,000 feet (610m). Prior to that, all wells drilled in the Norphlet play were either dry or uneconomical. Chevron's Ballymore discovery will add to the faith operators have in the Norphlet play, which extends into the eastern Gulf of Mexico and could be a potential target for future license awards.

The other big wildcatting news unveiled recently was Shell's Whale discovery, to the east of the Great White field and around 16 km from Shell's Perdido platform. The Whale probe encountered more than 1,400 feet (427m) of net oil-bearing pay, and Rystad Energy estimates around 400 MMboe of resources in the find.

This discovery lies in Alaminos Canyon and targeted the Wilcox Formation in the Perdido Fold Belt, which consists of north-east to south-west trending folded structures formed by gravity sliding. The Perdido Fold Belt extends farther south into Mexican waters, where Shell is now poised to make the most of its geological expertise in the play. Shell nabbed five blocks awarded in Mexico's recently-concluded Round 2.4, all of which appear to be directly aligned with the Perdido Fold Belt trend. ■

Aatisha Mahajan, Analyst, Rystad Energy

ABBREVIATIONS

Numbers (US and scientific community)

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

Liquids

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

Gas

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

Ma: Million years ago

LNG

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

NGL

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

Reserves and resources

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

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

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

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

Record-Breaking Round

Brazil's 15th Bidding Round received the largest signature bonus in history.

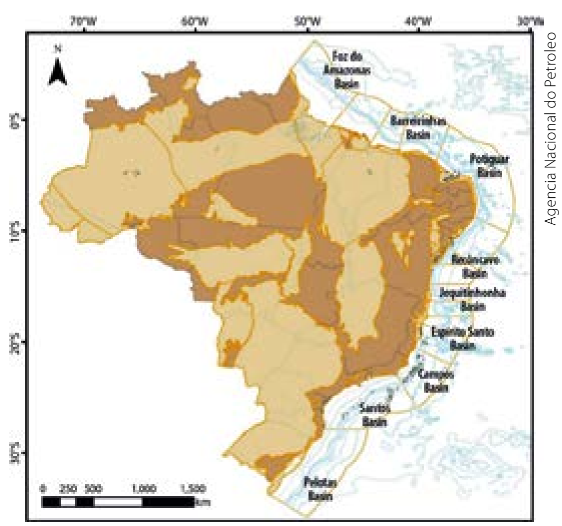
On March 29, 2018 Brazil's ANP (National Agency of Petroleum, Natural Gas and Biofuels) announced that its 15th Bidding Round had been a great success, particularly in the offshore area. A total of 68 blocks were offered, 47 in five offshore basins – Santos, Campos, Sergipe-Alagoas, Potiguar and Ceará – and the remaining 21 in the onshore Paraná and Parnaíba Basins.

Although none of the onshore blocks available received bids, there were offers for all the offshore basins, with 22 blocks being awarded, covering an area of 16,400 km^2 and raising a record-breaking 8 billion reais (US$2.42 billion) in signature bonuses, well above expectations.

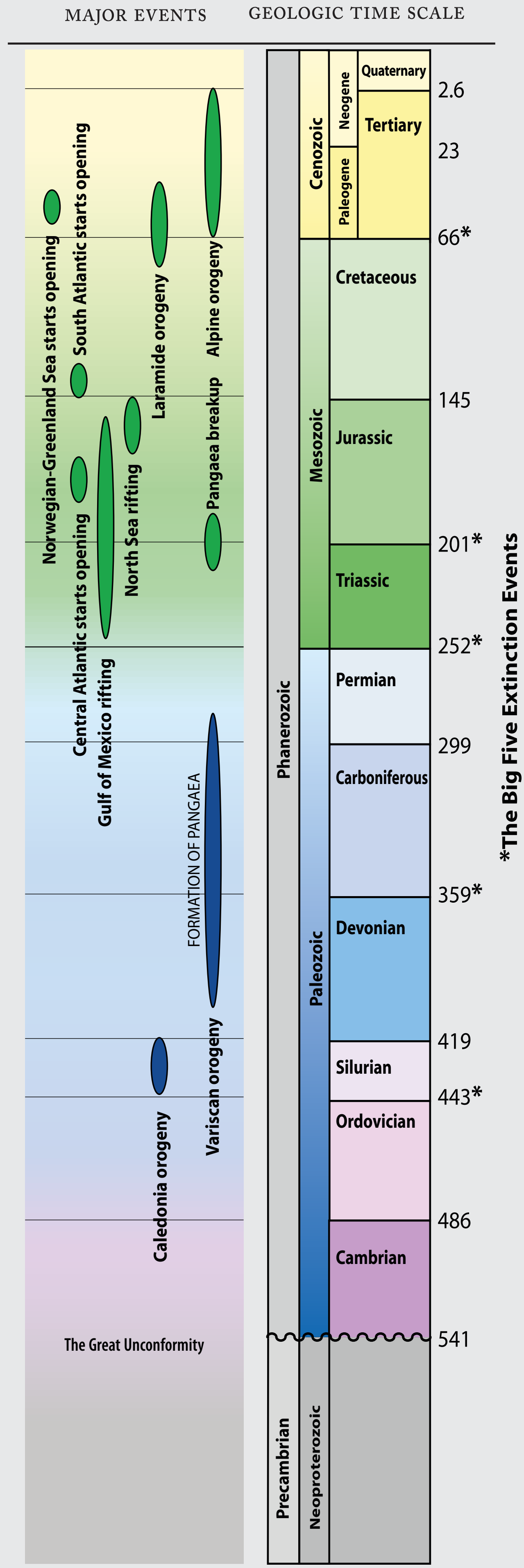
Deepwater Blocks

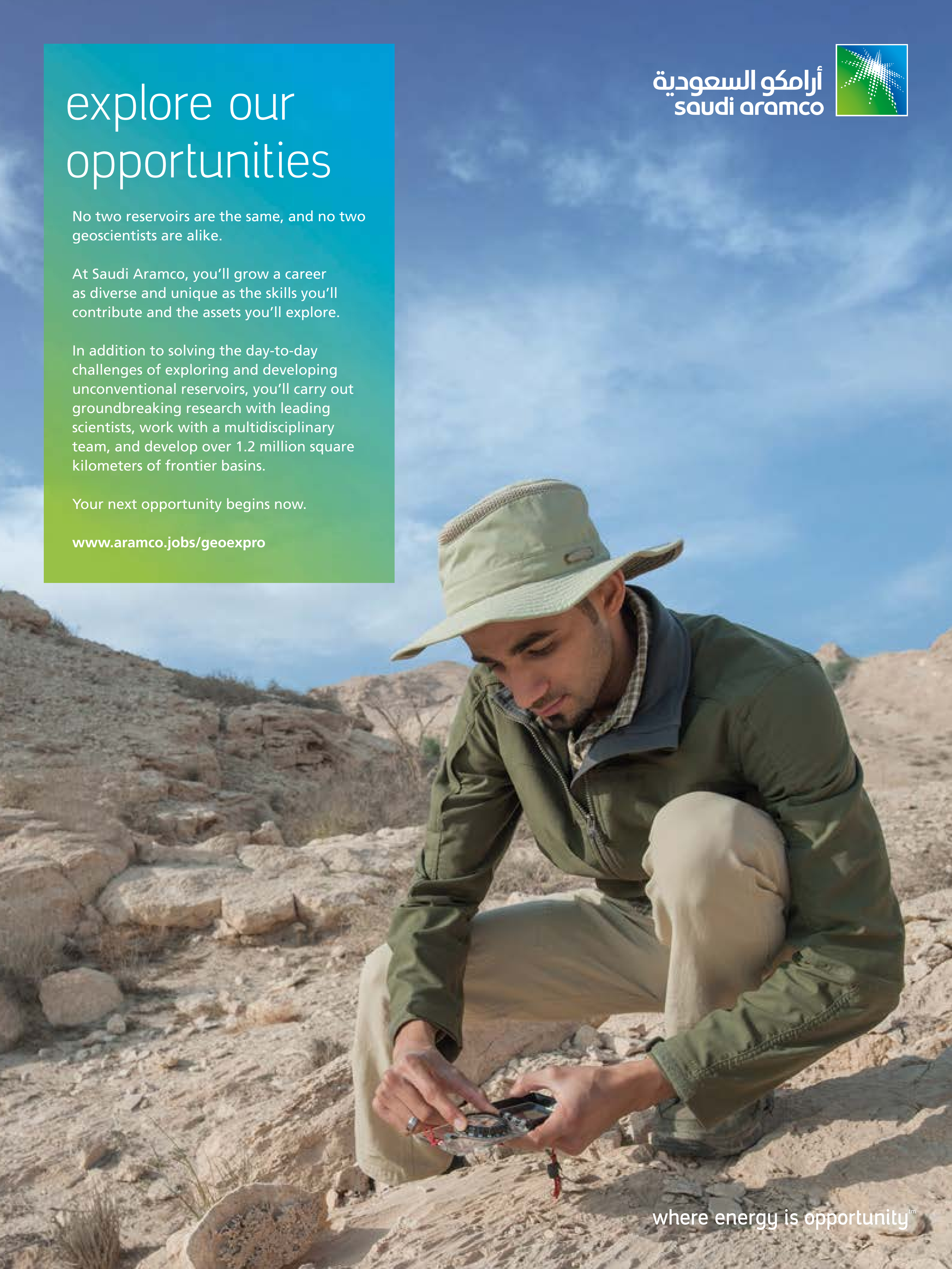
In all, 21 companies qualified, with 13 from 11 countries participating in the offshore section, all but one acquiring blocks. Petrobras, ExxonMobil, BP, Statoil, Shell, Qatar Petroleum, Chevron, Repsol and Wintershall all made significant additions to their Brazilian exploration portfolios, with ExxonMobil being particularly successful. The company acquired eight blocks in three different basins, bringing its holding in Brazil, a country it has been working in for over 100 years, to over 8,000 km^2 in a total of 24 basins. ExxonMobil and partners also paid the highest signature bonus of the round: 2,824,800,000 reais, or US$840 million, for Block SC-AP5-CM-789 in the Campos Basin. Competition was fiercest in this mature basin, with all nine blocks being awarded, while in the Santos Basin three of the six blocks offered were taken up. Out of the 13 available in the deepwater Potiguar Basin, seven were awarded, with strong competition between Wintershall and Petrobras, partnered by Shell and Petrogal. Wintershall has not been active in Brazil for over a decade, but returned with a flourish in this round, picking up seven blocks, four as operator. Three of these are in the Potiguar Basin, and it also acquired the only block awarded (out of 13 offered) in the deepwater Ceará Basin. The major Brazilian oil company Petrobras took seven blocks. Even the ultra-deepwater blocks in the Sergipe-Alagoas Basin were attractive, with ExxonMobil partnering with Queiroz Galvao E&P and Murphy Petroleum in this area.

The success of this round indicates that recent revisions to the regulations have paid off, and ANP are looking forward to the PSC Round in June. ■



Agencia Nacional do Petroleo

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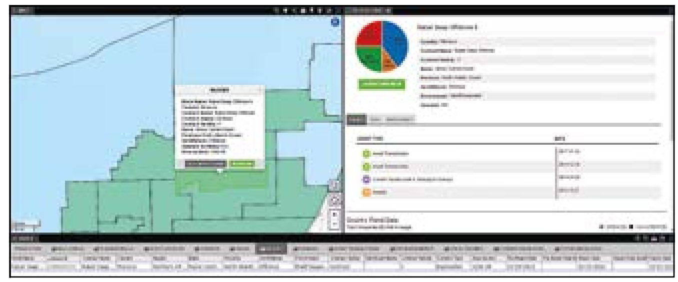
Whether for competitor intelligence, corporate evaluation or in a business development role, an accurate and up-to-date picture of **company ownership** across **E&P assets** is essential for O&G companies and the service and financial sectors. But how easy is it to gather and organize this content so it can be used for rapid worldwide querying and analysis?

Drillinginfo has 14 regional scouting teams gathering content from multiple sources. Identifying the local company subsidiaries participating in asset ownership along with % equity for over 23,000 licensed blocks worldwide is a fundamental part of each team's role. Tracking changes through individual farm-ins, local company deals and name changes, or international corporate transactions is essential in maintaining a current dataset.

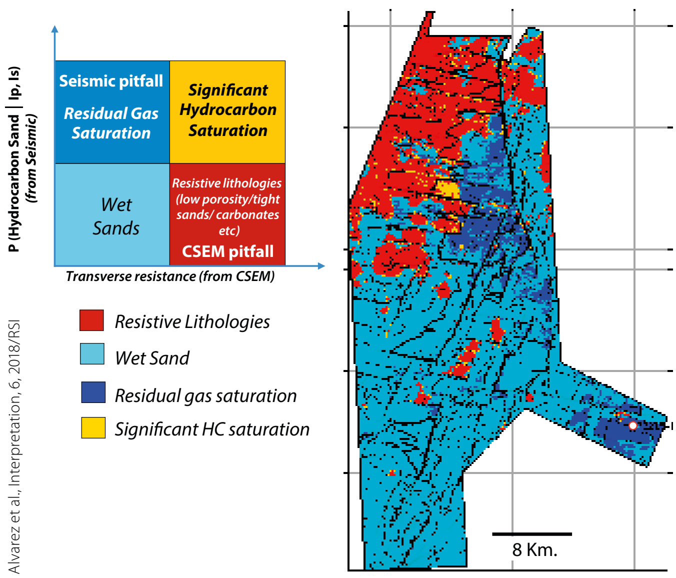
All this work comes together in a spatially accurate layer containing 5,900 local companies. These are linked to a set of 3,000 parent companies which are maintained through central tracking and research, providing a common international company name to query on. Organizing the data so consortia and their constituent companies can be queried in the same layer gives the product additional flexibility. International companies are also classified by type – IOC, NOC, Joint Stock Company, Service and Finance – allowing for deeper analysis of changing corporate environments. ■

Block card showing Rabat Deep Offshore II Block in Morocco from the Drillinginfo web app.



Multi-physics Reservoir Characterization

Geophysical data are widely used in **reservoir characterization** to determine the sub-surface lithology and fluid properties pre-drill. Such characterization processes must be built on a sound rock physics framework. However, even with the most careful analysis, results based on seismic alone can prove ambiguous. The widespread availability of controlled source electromagnetic (CSEM) data on the Norwegian Continental Shelf adds electrical resistivity to the analysis. **Multi-physics approaches**, where seismic and CSEM data are interpreted together, can dramatically increase the certainty with which reservoir properties are quantified. During a three-year R&D collaboration with Repsol, **RSI** have developed a variety of approaches to multi-physics analysis, ranging from integrated interpretation workflows to joint inversion algorithms. These can be deployed in tailored workflows to extract the full value from both seismic and non-seismic datasets.



An example from the Hoop area of the Barents Sea is shown here, where a multi-physics facies classification, calibrated using well log data, was used to de-risk prospects in the area. Only by integrating the seismic and CSEM data can the desired case (commercial oil saturation) be distinguished from the seismic pitfall case (residual gas saturation) and the CSEM pitfall case (resistive lithologies in the sub-surface). The results indicated that only residual hydrocarbon is present and the block was relinquished. ■

Asia Pacific Revisited: New Ideas, New Opportunities

Coming all the way from Singapore, **SEAPEX** is collaborating with **PESGB** to bring you the **Asia-Pacific E&P Conference** at **Olympia, London** on **June 27–28, 2018**. Like the highly successful SEAPEX conference, the event will feature an outstanding technical program with over 30 world-class speakers. The talks focus on future possibilities via new regional perspectives, highlighting exploration successes and opportunities on a country or play basis. Complementing the conference will be an extensive and lively exhibition floor with over 40 booths, including a dedicated farm-out zone.

There will be a wide range of social activities on offer to allow the 300 expected attendees to network, including an exclusive young professionals networking lunch, an ice-breaker reception, the conference evening and an affable pub crawl. A week of accompanying events will also be on offer, including a family-friendly Dorset field trip, an exploratory walk around London's historical streets and a 'Petroleum Geology of South East Asia' course delivered by Ian Longley.

Find out more and secure your place now at the PESGB website. ■

The Future of Geoscience and Engineering


Jane Whaley

The **80th EAGE Conference and Exhibition**, taking place **June 11–14** in **Copenhagen, Denmark**, offers the most cutting-edge, relevant and insightful papers chosen from the largest ever number of submissions received by EAGE. The topics cover geophysics, reservoir engineering, near surface and much more and will be complemented by a selection of fascinating papers on petroleum engineering from the Society of Petroleum Engineers. This will be the most impressive multi-disciplinary technical program ever. Every day will see 16 fascinating parallel oral and 11 e-Poster sessions, meaning that delegates will be able to choose from over 400 hours of talks, discussions and presentations.

This is also a fantastic opportunity to explore the latest technology, innovations and services on offer from over 350 of the most important companies in geoscience, engineering and energy production. At the exhibition you will meet the people behind the products and services that have defined the industry, as well as new companies seeking to pave the way to the future. An excellent opportunity to network with your peers from across the world, this exhibition is not to be missed! You can also learn new skills through intensive short courses and develop your professional profile with six broad-ranging workshops. ■

Missed Pay: Key to Future Success

'Missed pay' makes spectacular discoveries! Just think about Alta, Dvalin, Maria, Ivar Aasen and Cara on the **Norwegian Continental Shelf (NCS)** – all discoveries that were made fairly recently following previous dry wells 'ages ago'. The secret to success is detailed analyses of data from wells that were poorly sampled, or misinterpreted. In some cases, the presumed dry wells give indications of having drilled through reservoir rocks containing hydrocarbons or the presence of hydrocarbons up-dip. One of the key learnings is therefore that dry wells also need to have a full log-suite, including samples of fluids and pressure tests. These data could one day constitute the basis for a new and surprising discovery.

A special session will be devoted to the topic of missed pay during the **NCS Exploration – Recent Discoveries** conference, which will be held **May 23–24** at the **Scandi Fornebu, Oslo, Norway**. The session has been convened and will be chaired by Jon Halvard Pedersen, petroleum system analyst at Lundin Norway. The opening talk 'Oil Shows – a Hitchhiker's Guide' will give insight to what shows actually are. Several case studies will be given, which will hopefully encourage curious geologists to take another look at forgotten wells. ■

Registration Open for URTeC 2018

With a new boom in unconventional plays well underway, the timing of a meeting on unconventional resource technology could not be better. Registration is now open with early bird pricing for the sixth **Unconventional Resources Technology Conference**, to be held at the **George R. Brown Convention Center, July 23–25** in **Houston**. After the incredible success of the 2017 conference, **URTeC 2018** looks to push the boundaries and continue as the premier event focused on the latest science and technology applied to exploration, appraisal, analysis, and development of unconventional resources.

URTeC unites the disciplines by bringing the entire asset team together under one roof, concentrating on all things unconventional. URTeC is comprised of three sponsoring organizations: Society of Petroleum Engineers, American Association of Petroleum Geologists, and Society of Exploration Geophysicists plus nine endorsing organizations: American Rock Mechanics Association, American Institute of Chemical Engineers, Association for Iron and Steel Technology, American Society of Civil Engineers, American Society of Mechanical Engineers, Society for Mining, Metallurgy and Exploration, Society of Petroleum Evaluation Engineers, Society of Petrophysicists and Well Log Analysts, and the Minerals, and Metals and Materials Society. This multi-society collaborative platform brings depth to the technical base of the conference, providing cross-discipline information and innovation exchanges that sustain and propel the industry's ongoing success. ■

Globe: Earth's Evolution Unlocked for Better Exploration

Geoscientists working within oil and gas exploration and new ventures groups know that the judgements they make can have wide ranging repercussions. The pressure to make the *right* decisions means that all companies are looking for new, innovative ways of gaining a competitive edge. To meet this demand, the natural resource exploration experts at the **Getech Group** developed **Globe**; a product that delivers a unique view of the Earth's evolution over time and provides new insights into petroleum development in the world's oil and gas basins.

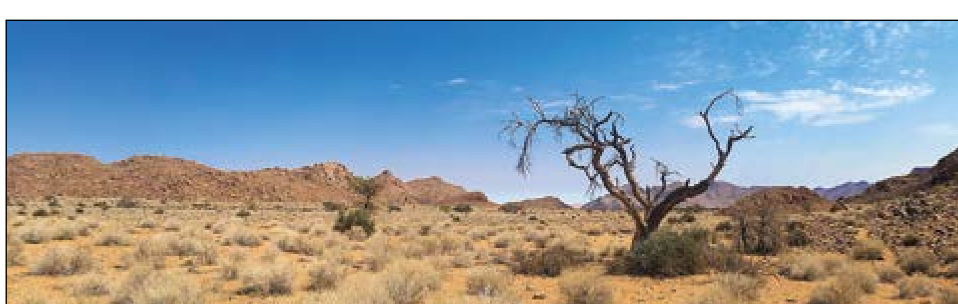
Globe is a comprehensive geoscience knowledge-base that provides petroleum geoscientists with a thorough understanding of the evolution of their area of interest and enables them to better understand the factors controlling hydrocarbon formation and preservation. By evaluating basins within a regional context and not simply in isolation, Globe delivers novel and distinctive insights into both emerging areas and the most explored basins of the world.

Importantly, Getech has understood that ease-of-use is also key to the successful deployment of any system, so Globe is delivered on Esri's industry-leading ArcGIS technology. Using this fully-featured and familiar GIS environment means that Globe is as simple to access as it is beneficial to use. ■

Big Continent and Big Opportunities

The **17th Annual Africa Conference** convened by the **Houston Geological Society** and the **Petroleum Exploration Society of Great Britain** will be held **September 12–13, 2018** at the **Norris Conference Centre, Houston**. The program's theme '**Big Continent, Big Ideas and Big Opportunities**' covers technical presentations on the petroleum opportunities highlighted by the recent discoveries in West Africa along the transform margin, salt basins and emerging areas of the Senegal and Mauritanian margins, as well as continued exploration in East Africa offshore and new play ideas on onshore rift basins. New play concepts/ideas in mature offshore areas of Libya and Egypt and the latest trends in the carbonate reefs similar to the Zohr discovery will also be discussed. The meeting will feature sessions on post-appraisal of discoveries in the past decade, highlighting initial estimates of major discoveries compared to ultimate field production. There will be panel discussions on Exploration in Africa – Past, Present and Future; Keys to Exploration Success; and Disaster Avoidance, all featuring senior management from major African players.

The program includes a seismic showcase where data from across Africa will be on display and there will be a series of expert mini-workshops focused on key ideas and exploration concepts in Africa. More information can be found at the HGS website. ■



DARTs and Drones: The Future of Onshore Seismic

The challenges associated with geophysical acquisition and 3D imaging in areas of complex topography and environmental sensitivity are being revolutionized by a multi-partner project spearheaded by Total.

JANE WHALEY

There is a long-held adage that two heads are better than one – so why not 25?

That was very much the approach taken by the R&D department at supermajor Total, when faced with the issue of acquiring high quality onshore seismic over difficult terrain with minimum environmental and societal impact. Conventional onshore acquisition systems tend to require many people on the ground, physically laying out lines of multiple sensors, which in mountainous terrain and poor weather conditions can be treacherous for the personnel. In rainforest and other highly vegetated areas, this also requires hacking paths through the undergrowth and disturbing wildlife and possibly indigenous communities, all very undesirable outcomes. A totally new approach was required.

Biodegradable Sensors

Back in 2015, Total began to consider innovative ways to tackle these issues and rapidly realized that finding a successful solution using only inhouse resources was not feasible. "We needed to access modern disruptive technologies to address many of the issues," explains Pierre-Olivier Lys, Innovative Acquisition Manager at Total E&P's Research and Development Center in Pau, southern France. "To do this we needed to go outside the company – and in some cases outside the industry." Thus, the Multiphysics Exploration Technology Integrated System (METIS) project was born, with the mission to 'improve the quality and speed of data acquisition through real-time quality control and processing, while at the same time slashing both the cost and HSE risks of operations'.

One of the first questions to address was how to put recording sensors in place without using personnel on the ground. For this task Total teamed up with Wireless Seismic, a leading innovator in real-time and cable-free seismic data acquisition systems for the oil and gas industry. Their unique technology allowed Total to develop a revolutionary system of receivers deployable through drones, transmitting data via a high-speed, real-time radio telemetry system. These recorders, known as DARTs (Downfall Air Receiver Technology) are, as the name implies, shaped like a dart and can impale themselves in the ground in an upright position. Each of the prototype wireless sensors weighs under 700g and is less than 50 cm long.

Total/RPS

Wireless Seismic/RPS/Total

The drones were designed by RPS to carry a number of DARTs simultaneously.

Ultimately, their size and weight will be decreased (300g and 25 cm long), and all components will be harmless to the environment. The body today is made of biodegradable polylactic acid (PLA), a type of plastic, and the research teams are already working with existing technologies to ensure that eventually every part of the DART, including the battery and sensors, will have a negligible environmental footprint. To this end additional partners in the project are battery specialist company SAFT, recently acquired by Total, and the multidisciplinary research organization VTT Technical Research Centre of Finland, which in this project is specializing in printed and hybrid electronics and biopolymer studies.

Once the DARTs are in place, Wireless Seismic provides the seismic recording infrastructure that allows the data to be transmitted from the sensors to intermediate antennas, which in turn send the information on to a central location using the radio telemetry system. This communication system is therefore providing real-time data, which can be analyzed to create preliminary images to monitor the quality of incoming data, so changes can be made

In the pilot project the DARTs successfully embedded themselves in the ground and transmitted data. They are designed to be biodegradable, leaving no trace after the survey is completed.

Total

Finding a location to drop the DARTs through the rainforest canopy can be challenging.

to acquisition parameters to ensure optimum results from the survey.

Flying Darts and Whales

The DARTs will ultimately be deployed by fleets of autonomous drones that undertake a multiphysics safety clearance check before releasing the sensors over prearranged optimized positions. These locations have to be chosen with care, particularly in dense forest, to ensure that the sensors can reach the ground through gaps in the foliage and will be able to penetrate the forest floor. Another collaborative partner, RPS, is responsible for designing and flying the drones and for the DART deployment, while satellite data, LiDAR and airborne electromagnetic and gravity companies provide the information needed to precisely model the surface before the sensors are dropped to ensure they can reach their target point through the canopy. They are released from about 20m above the trees, and multi-sensor cameras are used to check that the ground is free of people and animals before they are released.

"Late in 2017 we undertook a pilot study in Papua New Guinea, a country which presents some of the most challenging terrain for seismic in the world," Pierre-Olivier explains. "During this pilot we successfully deployed about 60 DARTs in only a few hours using a single drone, and we were able to recover seismic data live from these sensors, which proved that the method worked. For our next pilot, which we will undertake in 2019, we aim to deploy 4,000 sensors on a 50m grid from a number of drones flying in concert. Ultimately, we intend to use METIS in its first industrial application by 2021, before commercializing it a year or two after that."

To ensure that the footprint on the ground is as limited as possible in environmentally sensitive areas, Total have teamed up with aeronautical experts Flying Whales to create a multipurpose inflatable airship. This will transport all the equipment for the seismic sources, plus any material required to set up camps in the survey area. At the end of the project, all non-biodegradable material will be removed from the site using the airships and the area will be allowed to return to nature. "We consider the airship a very important aspect of the project," Pierre-Olivier adds.

Further Innovations

Another major partner in this project is the geophysical services company Geokinetics. As specialists in the acquisition and processing of seismic data in challenging environments worldwide, Geokinetics will ensure that all aspects of data production, from survey design and modeling to seismic processing and imaging, are integrated in order to provide the optimum solution. The company's expertise in logistics and project management as well as operation control and HSE will be vital to the successful outcome of the project.

"In the first pilot project we were primarily interested in the logistical aspects of how to convey the sensors to their chosen locations, and to recover seismic traces in real-time,

A simulation of the airship which will be used to transport equipment to and around the survey area.

thanks to the use of a relatively simple portable downhole airgun source," Pierre-Olivier explains. "One thing we discovered from the pilot was that the DART sensors do not all embed themselves vertically, which decreases the quality of the data submitted. As a result, we are investigating using multicomponent microelectromechanical sensors (MEMS) in the DARTs to replace the existing geophones, which will help eliminate that problem and also allow us to keep the DART environmental footprint to a minimum, as MEMS are considerably smaller. As a consequence, the DARTs will also be much lighter, which should assist deployment.

"Having successfully validated the deployment mechanism, we are now considering a variety of innovative source options, because the currently available source technologies are significantly more expensive and potentially more dangerous when used in these particularly challenging terrains. We are therefore in the process of finding even more partners for the project and are testing a range of new sources. Ultimately, we expect that more than 25 companies and organizations will be involved in this collaborative endeavor."

Cost Reductions

Bearing in mind the fact that all shothole drilling material must be flown to the base camp and then on to numerous source locations, the ability to deploy a large number of receivers – it is estimated that the drones could safely deploy about 4,000 receivers per day in harsh vegetated environments, and up to 40,000 per day in open environments – means that fewer sources will be required, which has advantageous safety and cost implications as well as being better for the environment.

Real-time processing and rapid subsurface image delivery allows the interpreters to drive the survey by assessing the quality of the data acquired and the illumination of the geological formations directly and locally. They will therefore be able to adjust and optimize the acquisition plan in real time based on results, if necessary adding or relocating sensors easily with the drones. This means that the time between completing the acquisition and finalizing the processing will be reduced and the value of the information significantly increased, leading to quicker and better decision making.

Real-time decision making is faster and involves fewer people, while drone deployment reduces personnel requirements on the ground as well, so there are significant financial savings in this aspect of projects undertaken through METIS. Further cost reductions are anticipated through the use of the purpose-built airships rather than helicopters and, by making the sensors biodegradable, there is no need to send survey teams out to recover them, which as well as being environmentally preferable, has financial and HSE advantages.

A Holistic Change

"At the beginning, it seemed like a crazy idea, and some people doubted it could be achieved – but in the team we knew it was possible," Pierre-Olivier says. "We did not initially anticipate that the project would be so big, with so many partners, but METIS has grown to encompass all aspects of an onshore survey and can be adapted to accommodate all geological data in the field, no matter how complex. It is ideal for resolving the challenges of 3D seismic acquisition and real-time processing in hard-to-access environments, such as foothills, but can also be adapted for deserts or areas crowded with infrastructure, or possibly in areas with unexploded ordnance, and for a variety of applications, from conventional 2D surveys to microseismic acquisition and seismic monitoring.

"METIS is revolutionary because it addresses an entire acquisition system holistically instead of one little piece at a time, in order to optimize HSE, quality, cost and turn-around time," he concludes. ■

Awaiting Discovery?
The US Atlantic Margin

Covering an area roughly the size of California and Texas combined, the US Atlantic margin is underexplored, but prospective basins along the margin may once again be open to exploration.

VSEVOLOD EGOROV, GeoExpera

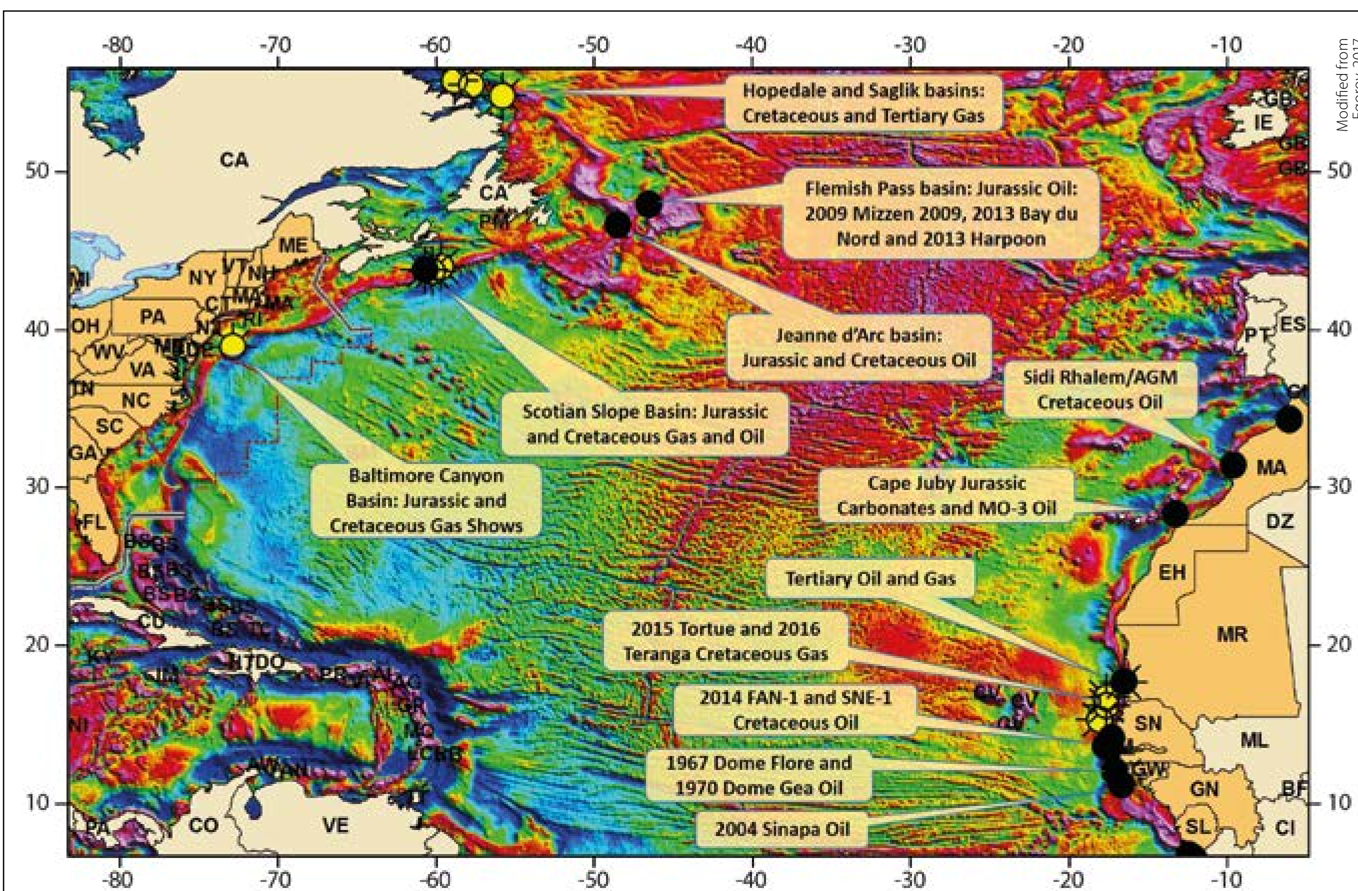
The US Atlantic margin is virtually unexplored. Ten lease sales were held in the Atlantic Outer Continental Shelf (OCS) between 1976 and 1983. The entire region has been penetrated by a total of only 51 wells, all drilled between 1975 and 1984. Of those, five were COST (Continental Offshore Stratigraphic Tests) wells and 46 industry exploration wells.

Along the adjacent and conjugate Atlantic margins of Canada, Ireland, and the central and northern African coast, extensive exploration activity has yielded numerous large oil and gas discoveries in strata similar to those found along the US Atlantic margin. Yet the US Atlantic OCS remains a true frontier for exploration companies and an area that could keep the country a top energy producer. In the latest assessment, the Bureau of Ocean Energy Management (BOEM, 2014/2016) estimated undiscovered technically recoverable resources and respective probabilities for the Atlantic OCS for oil to be between 1.150 (95%) and 9.185 (5%) Bb and gas to be 12.80 (95%) to 68.71 (5%) Tcf.

New Administration – New Direction

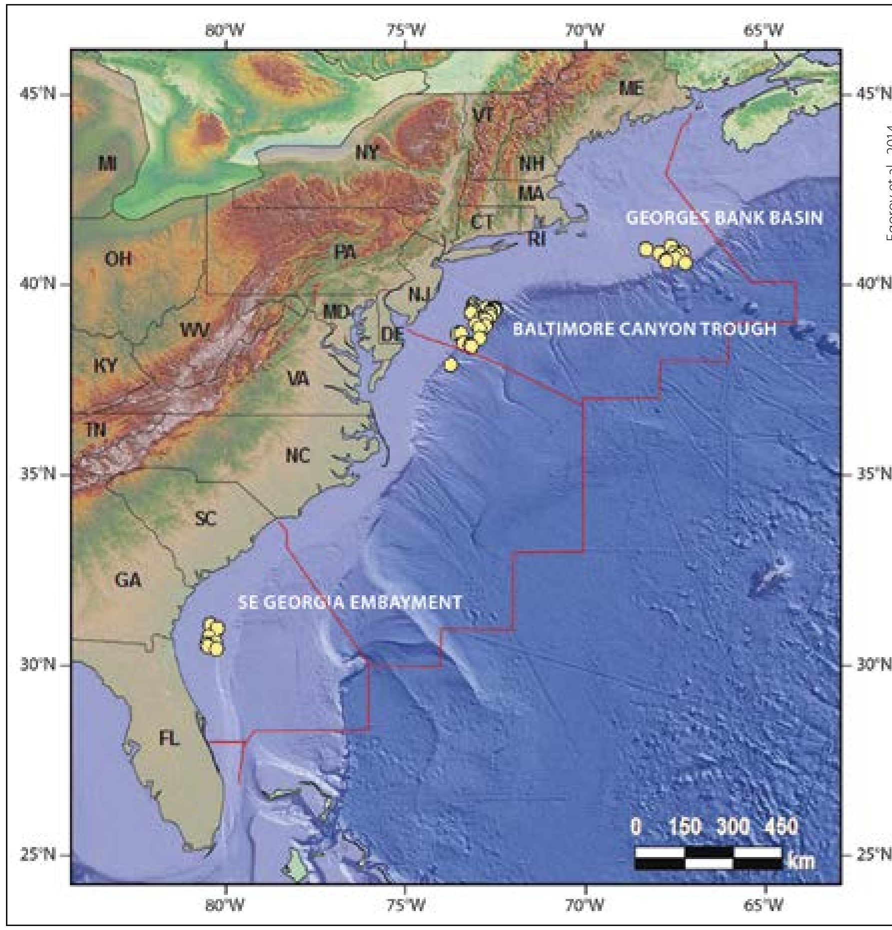
The current National Outer Continental Shelf Oil and Gas Leasing Program, adopted in 2016, includes ten lease sales for the Gulf of Mexico and one for Alaska, but

North Atlantic gravity map including key discoveries off Canada and north-west Africa. The prominent gravity high that trends south out of Nova Scotia and into the US portion of the Atlantic margin marks the extent of the shelf and closely follows the Mesozoic carbonate platform edge.



nothing off either the west or east coasts of the US. This current leasing program, which covers 2017–2022, puts 94% of the US OCS off limits to exploration. Encouraged by letters from members of both the US House of Representatives and the US Senate, Secretary of the Interior Ryan Zinke proposed a new National OCS Leasing Program for 2019–2024 that includes 47 potential lease sales in 25 of the 26 planning areas. If adopted as proposed, this Draft Proposed Program could result in over 90% of the total OCS acreage and 98% of the undiscovered, technically recoverable oil and gas resources in the federal OCS being made available for future exploration and development. Nine lease sales would occur in the Atlantic Region, with the first two, which would cover much of the US Atlantic margin, scheduled for 2020.

The new leasing program is currently in the development process, which includes stakeholder and public feedback, along with new scientific information to further refine the geographic scope of leasing areas. The 2017–2022 National OCS Program took about a year and a half to complete and will be in force until the new program is approved.



US Atlantic margin bathymetry map showing three areas drilled (Georges Bank Basin, Baltimore Canyon Trough, and SE Georgia Embayment) during a ten-year exploration period that ended in 1984. Only a few wells in the Baltimore Canyon tested non-commercial gas flows. The red line outlines the US OCS protraction area's boundary.

Available Data

Although no wells have been drilled since 1984 and no major geophysical surveys were conducted offshore US East Coast, there have definitely been some advances in both available data and research. Additional information can also be gleaned from exploration work and discoveries in other areas along the Atlantic margins.

Legacy seismic data have limitations in resolution and high-frequency content, but although overall not of up-to-date quality, they contain lots of useful information. According to BOEM (2014/2016), 239,000 line-miles (385,000 line-km) of 2D seismic were collected during the exploration activities from 1966 into the 1980s. Most of these data are publicly available. Additionally, a number of seismic companies undertook reprocessing, migration and depth-conversion of these legacy data, including Spectrum Geo, whose seismic depth-converted cross-sections are shown in this article..

Developments in space technologies have led to the emergence of satellite altimetry-derived gravity and continuous improvement of this worldwide offshore dataset. Various magnetic data were also compiled over the years. Both gravity and magnetics have proved valuable in the understanding of continental margins and petroleum exploration along these margins.

Geological Assessment

The closing of the Iapetus Ocean and the Laurentia-Gondwana collision in Carboniferous-Permian time led to the formation of the Appalachian fold and thrust belt. Following these events, the Late Triassic – Early Jurassic extension initiated the opening of the Atlantic between North America and Africa. The Appalachian orogen acted both as a source of sediments and a major zone of weakness. It partially accommodated Mesozoic extension by 'unbuckling' along pre-existing thrust faults and sutures. Triassic-Jurassic grabens and half-grabens are well documented onshore along the margin and propagate offshore in the northern part of the US margin. Detailed offshore distribution of these extensional structures requires additional studies. However, they are not as obvious and widespread as in many other parts of the Atlantic, indicating that a large portion of the offshore sediments was probably deposited during a passive (post-rift) margin regime.

The BOEM defined five major Jurassic-Cenozoic depocenters along the margin: the Georges Bank Basin, Baltimore Canyon Trough, Carolina Trough, South-East Georgia Embayment, and Blake Plateau Basin. Three of these areas were drilled, penetrating Cenozoic, Cretaceous, and in most cases Jurassic sediments. Few wells within the Georges Bank Basin and the South-East Georgia Embayment reached underlying Paleozoic metasediments. The deepest well was drilled in the Baltimore Canyon Trough and reached a depth of 6,584m.

Expanding on the mid-continent onshore success of discoveries associated with Paleozoic reefs, the majority of the offshore drilling efforts were focused on similar structures. Many interpreted pinnacle reefs within the Mesozoic carbonate platform were drilled but resulted in dry holes. These results were attributed to an absence of a hydrocarbon charging system, while some of the 'reefs' turned out to be volcanics. Yet another concept was brought into exploration from Gulf Coast and Gulf of Mexico salt basins. The early interpretation of seismic data from the Baltimore Canyon Trough indicated very prominent salt diapirs. However, drilling results, additional seismic data and later re-processing all demonstrated that salt diapirs do not exist in the Baltimore Canyon Trough and are absent along most parts of the margin, with the possible exception of the Carolina Trough area. A few wells tested deltaic deposits but found a disappointing dominance of shales and siltstones and an absence of good quality reservoir rocks. The only proven play with non-commercial gas discoveries was related to listric fault-controlled deltaic reservoirs within the inner shelf (Hudson Canyon 598 area).

Conjugate Analogs

While petroleum exploration off the US east coast practically stopped after the 1980s, it continued to the north in Canada and along the north-west African coast, the conjugate margin to the US Atlantic OCS. Studying analogs from conjugate margins has proved to be a great exploration approach, resulting in many major discoveries on both sides of the Atlantic. The subsalt discoveries offshore Brazil (Tupi and others) were followed by similar discoveries off Angola; the Jubilee turbidite play discovery offshore Ghana led to the discovery of analogous plays off Sierra-Leone and French Guiana. Studying these analogs is key to predicting US offshore plays and estimating hydrocarbon resources.

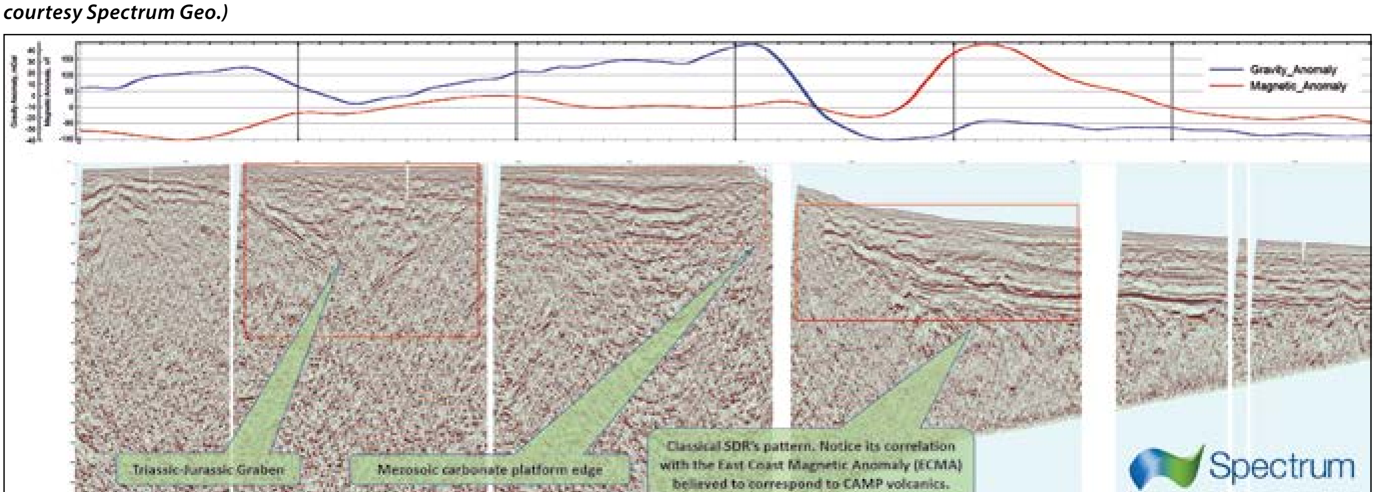
Recent exploration along the north-west African coast has led to several significant discoveries pertinent to exploration off the US east coast. The largest offshore discovery of 2014 was the SNE-1 field offshore Senegal. The hydrocarbon-bearing reservoir was defined by Cairn Energy as an Early Albian sandy pro-delta turbidite apron and delta-fed ramp. These deposits are within the extent of a Jurassic-Cretaceous carbonate platform. Following SNE-1, the FAN-1 discovery was made outboard of the platform within deepwater sediments comprising Albian contourites, gravity deposits and base of slope turbidite fans. In 2014 Kosmos announced the discovery of the Great Tortue gas field offshore Mauritania and Senegal with Cenomanian and Albian turbidite reservoirs. These deepwater plays also exist offshore US but are yet to be tested.

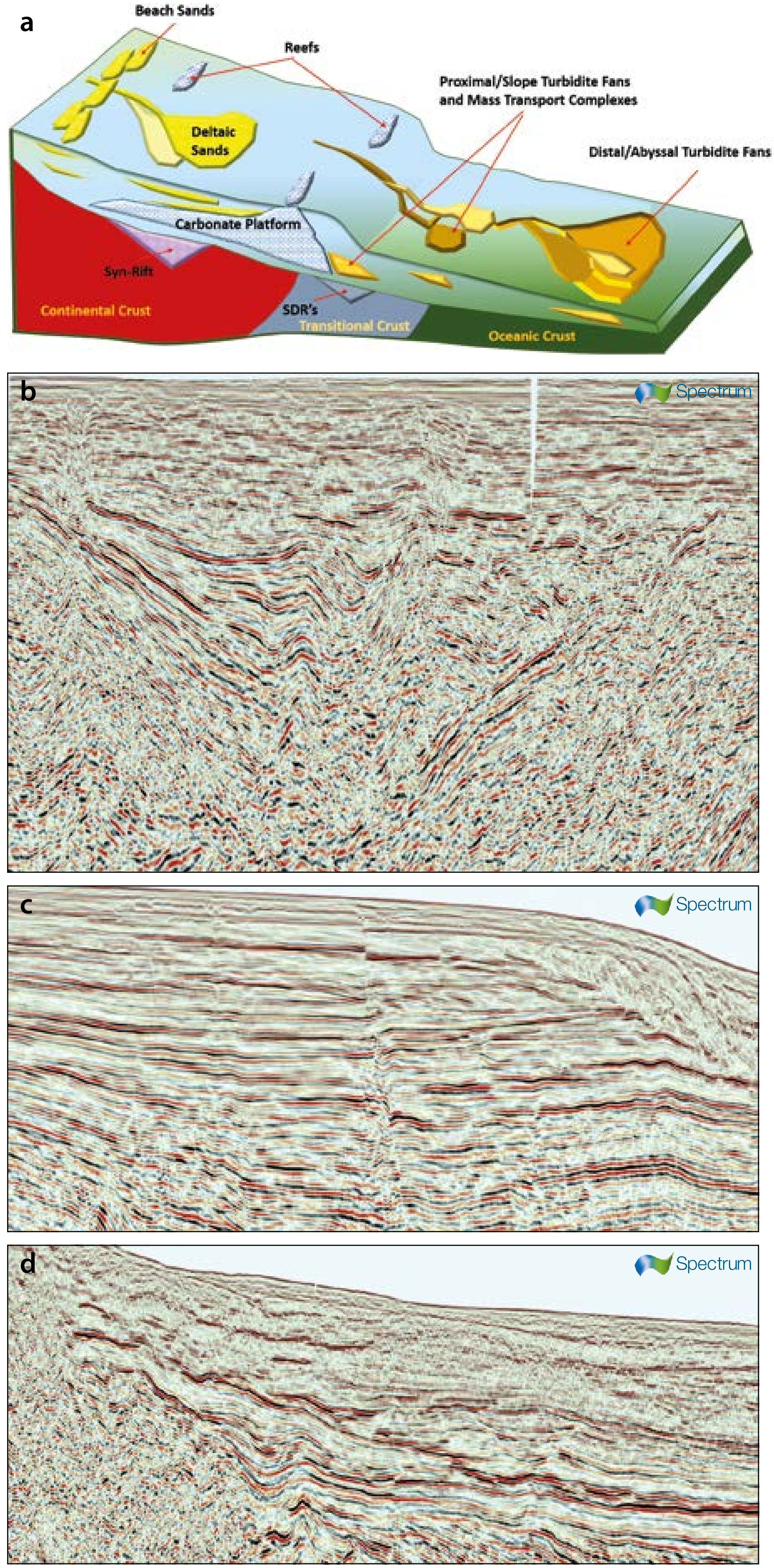
Canadian Plays Trending South

Exploration offshore Canada's east coast remains active. The Jeanne d'Arc basin off Newfoundland remains the only oil-producing province along the North American Atlantic margin. The Late Jurassic and Early Cretaceous sandstones produce nearly 35% of Canada's light crude, making Newfoundland and Labrador the second largest oil-producing province in Canada. Recent light oil discoveries in the deepwater Flemish Pass Basin are opening up a new oil and gas frontier offshore the province.

Natural gas fields discovered in the 1970s to 90s offshore Nova Scotia lie just north of the US east coast OCS. Reservoirs include Late Jurassic dolomitized carbonates and Late Jurassic to Early Cretaceous fluvial, deltaic, and shallow marine sandstones. More recently, oil companies have leased deepwater blocks, some in an area next to the Georges Bank just north of the border, and 3D wide azimuth seismic has been shot prior to drilling. Shell has drilled two wells in the deepwater Shelburne Basin and

West to east regional seismic section across the Georges Bank Basin showing major geologic features that include rift structures, the Mesozoic carbonate platform edge, and seaward dipping reflectors that indicate transitional crust. Corresponding gravity and magnetic profiles are presented across the top. Red boxes show approximate settings of the three plays shown in the figure on page 21. (Modified from Egorov, 2017. Seismic data courtesy Spectrum Geo.)





(a) Crustal types and some of the potential plays found along the Atlantic margins. Many of these plays depicted here have not been tested in the US Atlantic margin; (b) Intra-graben structures, stratigraphic pinch-outs towards structural highs, and hydrothermal dolomites; (c) Shelf shallow marine/deltaic sand reservoirs in the roll-over fault-controlled structural traps; (d) Deepwater channels and fans. (Egorov, 2017. Seismic Data courtesy Spectrum Geo.)

BP plans to drill a deepwater prospect approximately 300 km offshore Nova Scotia sometime this year. This is the only well expected in the area in 2018 and its results are highly anticipated.

Similar plays trend south and can be expected along the US Atlantic margin where they have either not been tested or tested only within three small areas. Meanwhile, an enormous portion of the OCS remains unexplored. Based on available data and analogs from continental margins, BOEM has identified ten potential offshore plays, including shallow and deepwater reservoirs both structurally and stratigraphically controlled.

Mature source rocks have yet to be identified along the US Atlantic margin. Non-commercial gas discoveries in the Baltimore Canyon Trough provide proof of a working petroleum system and suggest that mature source rocks are present off the eastern US coast. Wells have penetrated potential Cretaceous source rocks that were immature where drilled but could be mature seaward. Jurassic source rocks present in the productive basins off eastern Canada are expected to trend south along the US Atlantic margin.

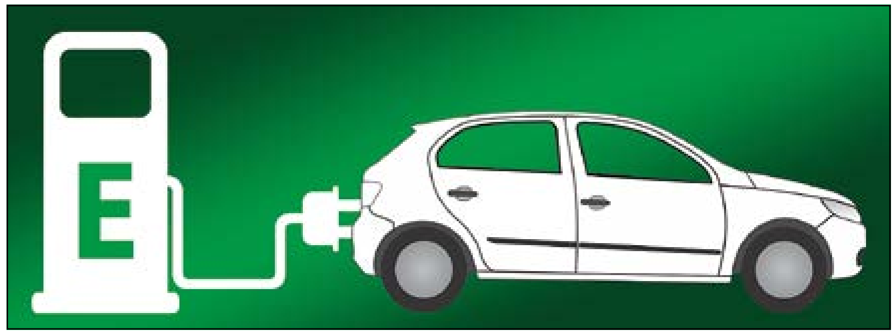
First Steps

It took years of intensive acquisition and analysis of geophysical and geological data and, eventually, exploratory drilling before success came to the basins adjacent and conjugate to the US Atlantic margin. Time will tell if any of the prospects and plays lining the US East Coast will be tested. First steps are starting to take shape in the form of proposed lease sales and new regulations governing oil and gas activity. Then it will be up to the oil and gas companies to obtain leases and explore the frontier basins lying just off the east coast of United States. ■

Mind the Gaps

Two serious gaps are looming in the industry: firstly between global production and demand, and secondly between experienced explorationists and the new generation of geologists and geophysicists who will be needed to find fresh reserves to fill the first gap.

MIKE LAKIN
Envoi Limited



How far into the future?

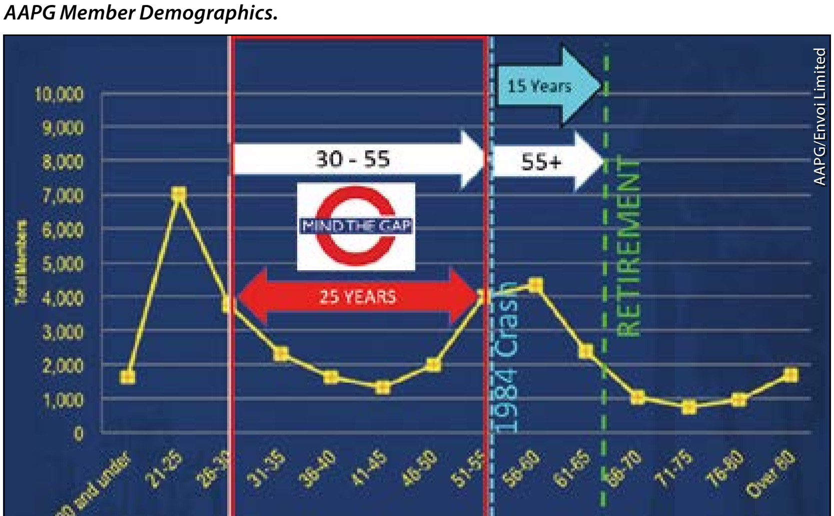
At most conferences and industry meetings so far this year, including the recent Global APPEX A&D Conference in London, much of the talk has been about a resurgence in oil price, an associated growth in upstream international deal making and a return to more buoyant E&P activities. The curtailment of production by OPEC and lower influence of US resource plays have kept the world adequately supplied and allowed the oil price to rebound – but is the future of oil and gas all rosy? I think not, but perhaps not for the reasons many might imagine.

Gap in Capability

Since the extended 1984–2003 price crash, when the oil price was between $10 and $27, the upstream E&P industry seems to have done little to properly prepare for the gap in exploration capability that has been evident for some years. This is the result of a missing generation of explorationists, primarily geologists and geophysicists, who were not hired in sufficient numbers in these years, and the effect of this will start 'hitting the buffers' soon. To be more specific, this means the loss of a significant proportion of the world's exploration experience – in other words, the only people who are qualified to define where hydrocarbons have been generated and where wells should be drilled to find it. Most of them are over the age of 55 and, having joined the industry at or before 1984, are reaching retirement age and don't need – or want – to work 9–5 each day for 48 weeks a year any more.

If the 55-year-old-and-over geologists and geophysicists – we'll call them the 1st generation – are allowed to retire without the industry harnessing their knowledge and hard-earned experience, and there is a 25-year gap between them and 3rd generation explorationists (with the 2nd generation missing), how can the younger explorationists be expected to decide where to drill and find new reserves of hydrocarbons as successfully as in the past, without the benefit of all those mentors and their experience? Unless we put into action some plans to fill that gap now and to find enough new hydrocarbons, the world's reserves and the ability to keep up with the demand for hydrocarbons could be severely affected.

AAPG Member Demographics.



Technology to the Rescue?

"Aa-ha," I hear you say, "technology will make the difference, making it easier to find hydrocarbons, so less G&G people will be needed – and anyway, we'll all be using electrical cars in 10 years so won't need more oil…"

Really? Can the current infrastructure be that easily upgraded all over the world to cater for seven times the electrical power this would demand, even if we were able to build the new power stations which will be needed to generate that massive increase in power? And what will be the source of that power? Nuclear? OK, perhaps not, so gas then – which, by the way, is found by explorationists in the E&P sector!

Also, it is suggested, any decline in conventional reserves production will simply be filled by fracking and unconventional production from the US anyway. There is no

doubt that the world's energy mix is changing and yes, there is also no doubt that in time oil will almost certainly become the new coal, but I think that will not be for 20 or maybe 30 years – probably more. For an example of just how long such transitions really take, just look at the years it took from the invention of the internal combustion engine (reportedly 1853, when a patent request was granted for 'Obtaining Motive Power by the Explosion of Gasses') to the first effective mass manufacture of the motor car in the 1920s and 30s; or the fact that diesel engines did not replace coal-fired steam engines until the mid-1960s, despite their existence long before then.

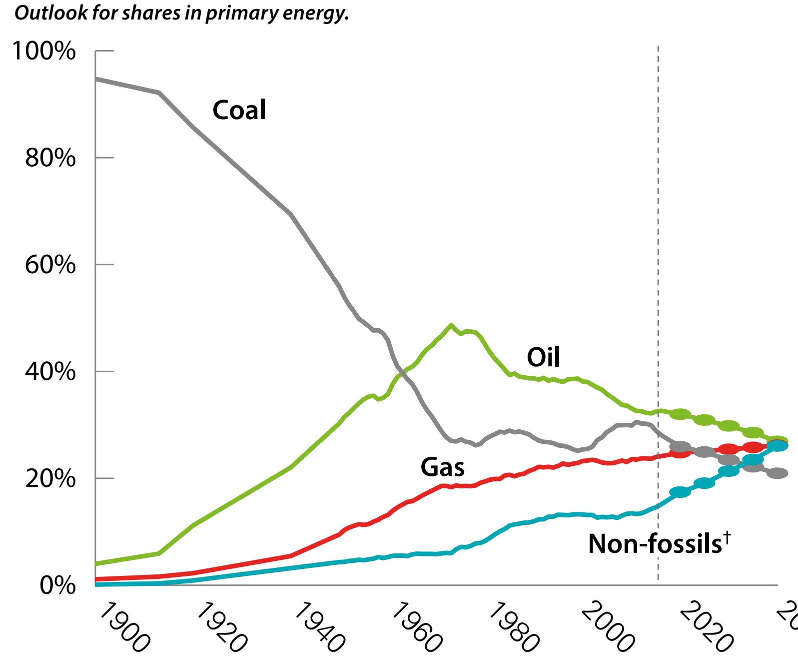
New Reserves Needed

There is also now concern as to when and if US resource plays will actually make enough money to live up to the recent hype and the massive investment that has gone into them. If they do, the noticeable lack of equal recent investment in conventional production, which is still responsible for more than 90% of the world's oil, will see a widening gap between global demand and the ability to source it.

The transition to new fuels and efficiency has started, but the oil business is far from finished. It will be needed for a good few years yet, but the possibility of a gap between global production and demand, together with the looming scarcity of experienced explorationists who will be needed to find new reserves to replace those produced over the next 20 years – before all the alternatives sources of energy are able to take up the slack and decrease the dependence and need for as much oil – should be a concern.

Two reasons perhaps to 'Mind the Gaps'! ■

Outlook for shares in primary energy.



2018 BP Energy Outlook

A Simple Guide to Depth Conversion: Part I

Continuing our series of 'simple guides' to aspects of geophysical processing, we look at the parameters involved in this important but complex subject.

ASHLEY FRANCIS, Earthworks Reservoir

Seismic reflection data records the two-way travel time (TWT) to a reflection event from the surface. Depth conversion is the process by which interpreted seismic horizons (and time domain seismic itself) are converted from the travel time domain to the depth domain. (Note that depth migration is a seismic imaging technique that improves reflector positioning. Depth migrated data is often converted back to time and then depth converted conventionally as this gives greater flexibility for testing alternative velocity models.)

Depth conversion can be simple or complex. Approaches to the technique vary all over the world and are dependent on the play scenario and geological overburden. Depth conversion is a big, technical topic for a short article, so we are going to try to make some general comments and highlight a few points that are perhaps less widely known.

When predictions of depth values are made at multiple regular points on a grid pattern then we tend to view the result as a depth surface. Smooth, best estimate predicted depth surfaces of this type are used for multiple purposes including drilling prognosis (well forecasts), in-place hydrocarbon volume estimation (surfaces) and reservoir modeling (surfaces).

The standard practice use of depth surfaces for making depth prognosis for well targeting purposes is entirely valid. However, the use of the same surfaces for in-place hydrocarbon volume estimation is not valid. A discussion of this and the role geostatistics plays in addressing this problem was given in a previous article 'A Simple Guide to Volumetrics' (*GEO ExPro* Vol. 12, No. 3)

Rock Velocity

To convert time reflections to a depth surface we need to know the velocity. The depth is then estimated from the simple geophysical relationship that depth = velocity x time.

The velocity of a rock is a fundamental physical property related to its hardness. As a simple rule of thumb, if you hit a rock with a geological hammer, fast rocks go 'ding' and slower rocks 'thud' (or even 'squelch'!).

For depth conversion, velocity varies with rock type, depth of burial and pore space factors such as porosity and the presence of microfractures. In general, the slowest velocity we encounter would be sea water, which is typically 1,500 m/s. The fastest velocities we commonly come across would be the matrix velocity of rocks such as sandstones, limestones and dolomites and igneous rocks, where the velocity reaches 6,000–6,500 m/s.

Sources of Velocity Measurements

Velocity measurements come from a variety of methods but the three most important sources for depth conversion are seismic processing velocities, sonic logs from well data, and checkshot and VSP surveys, also obtained from wells.

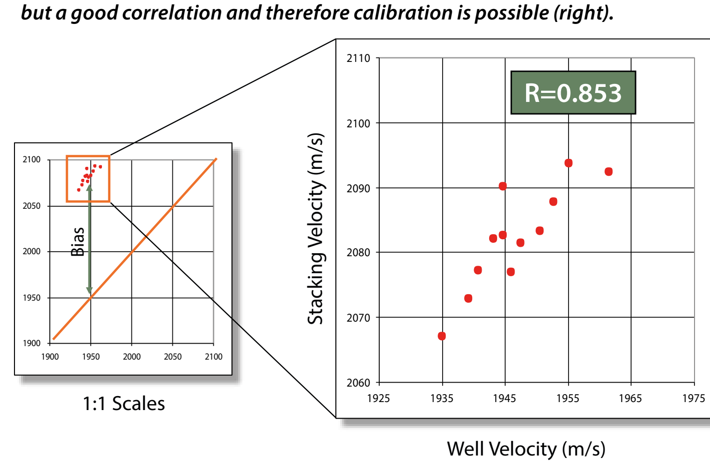
Seismic processing velocities in their most basic form are the so-called stacking velocities. Seismic processing requires curving events on gathers to be flattened using the NMO stretch correction before they can be stacked. The stretch factor is related to the RMS average velocity and so NMO correction gives an estimate of the velocity profile at each point it is picked in the dataset. The stretch factor is small for deep events and increases in magnitude for shallow events.

Wells give us depths to geological markers and by tying a well to the seismic using a synthetic seismogram the seismic time events that are interpreted can be related to the geology. A well depth and a seismic horizon time to the same event can be used to define a so-called pseudo-velocity and these are often used in depth conversion.

Well velocity information is obtained from both checkshot data (or better, from more detailed VSP survey first arrival times) and from sonic logs. Checkshot and VSP surveys give direct measures of both average and interval velocity by recording the travel times and depths from surface to a series of geophone locations along the length of the well.

Sonic logs are calibrated using checkshot data, resulting in the calibrated velocity log (CVL). The CVL is the best velocity information we have and combines the benefits of checkshots and sonic log data.

Figure 1: Well velocities compared to seismic velocities show bias (left panel) but a good correlation and therefore calibration is possible (right).



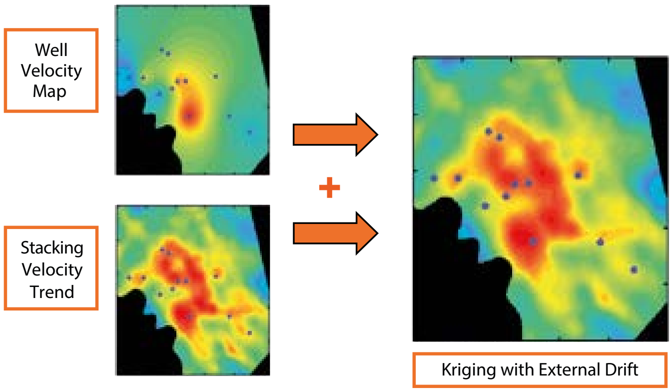


Figure 2: Combining well and seismic velocity data using geostatistics to obtain the advantages of both datasets.

Practical Depth Conversion

Seismic Velocities: Without well information the only source of velocity data is through the seismic processing accompanying seismic reflection data. Seismic velocities have some useful characteristics – for example, they cover the survey area with relatively dense sampling. Unfortunately, seismic velocities are potentially inaccurate, insensitive to velocity changes in deeper layers and noisy. Because of the noise, seismic velocities should be filtered or smoothed before use. Kriging using an explicit nugget (noise) model is a good choice for this task.

Seismic velocities can be used as an average velocity to a horizon for single layer depth conversion, or the Dix formula can be used to convert to interval velocities for use in a multi-layer depth conversion. Seismic velocities are inaccurate (biased) and can over- or underestimate the actual velocity by as much as 10–20%. Resultant depth prognosis will have similar error magnitudes, but the uncertainty in gross rock volume (GRV) is less affected by bias in the velocity field than it is by local variation and so the GRV uncertainty will be less affected.

If well data are also available, then seismic velocities can be calibrated and used to provide regional trends away from well control. This can be done geostatistically using methods such as kriging with external drift or collocated co-kriging. Alternatively, a simple linear regression calibration can be used. Figure 1 shows a comparison and calibration of seismic velocity to well data and Figure 2 shows the combination of both data types geostatistically.

The value of using seismic velocities diminishes quickly as the depth (or time) to targets increases due to poor velocity sensitivity to deeper reflections. The importance of seismic velocities also diminishes as more well control becomes available. Although useful, seismic velocities are the lowest quality source of velocity information for depth conversion.

Well Velocities: Well data are usually very sparse and cover very little area in a regional depth conversion. For this reason, well information is often used to define functions that relate the interval velocity behavior to the regional trends in the geology. There is a very rich family of functions available to choose from, but the most popular approaches are:

- Constant interval velocity
- Well velocity maps
- Depth/time functions
- Velocity/time functions
- Velocity acceleration functions

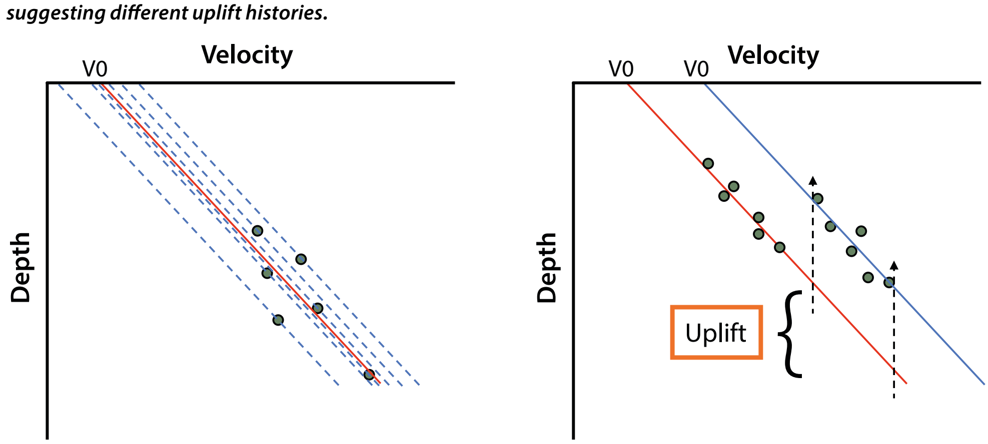
Some forms of velocity functions and, in particular, linear acceleration functions of the form V0+kZ (where V0 = reference velocity, k is the velocity gradient, and Z is depth) are very dear to the heart of many a geophysicist. There are sound reasons for their use, but some of the associated practices have become rather prescriptive and should be re-considered.

The first point to make about V0+kZ velocity functions is that they are strictly linear. This is both good and bad. Good because they avoid the bias of using average well velocities from the crest of a structure to depth convert a flank where the velocity might be expected to be higher due to compaction; bad because compaction effects are not linear and so velocity functions can become non-physical quite quickly outside of the depth range of the data from which the function was derived. For this reason, it is good practice to examine proportional horizon slices through the instantaneous velocity field at different levels within the layer to check the velocities are not physically too high or too low.

Another problem lies in a popular practice of (typically) calculating a global gradient k from a group of wells and then backing out an apparent V0 at each well. The V0 values are then over-interpreted by the geophysicist as a physical parameter whose spatial pattern represents differences in burial history (typically uplift). As well data are sparse and noisy this is almost certainly an over-interpretation and is usually just regression of noise. Only if groups of wells exhibited different V0 (for the same gradient k) might an uplift interpretation be justified (Figure 3). In general, V0 mapping methods are usually just error residual corrections in disguise and should be avoided.

In the next issue we will continue this article by discussing the key steps involved in the depth conversion process. ■

Figure 3: Two interpretations of V0. On the left the variation in V0 is simply the noise in the data extrapolated to datum. On the right, two different groups of wells are on the same gradient but different V0 at datum, suggesting different uplift histories.



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Renewed Excitement in Deepwater Gabon

Gabon has a long history of oil exploration on- and offshore. The last two decades saw production onshore and along the shelf dominated by Shell and Total, the Tullow JV, and juniors Vaalco, Perenco and M&P. Significantly, both Total and Shell sold the majority of their production in 2017, indicating their retreat from the mature onshore.

All eyes are on the big prize of world-class oil discoveries in deepwater, however. The most recent newsflash in support of this is Boudji-1, drilled by Petronas and Woodside, with reports of a 90m gross oil column pre-salt. Following poor results at Sputnik, and gas and condensate at Diaman and Leopard, this discovery of liquid hydrocarbons has galvanized the deepwater players.

The Play

The petroleum system is predominately the Lower Cretaceous play, with potentially large structural prospects in the pre-salt. Prospectivity certainly exists post-salt, in well-imaged marine clastic turbidites, channels and fans in the Upper Cretaceous and Oligo-Miocene. However, very large pre-rift faulted structures, with lower trap risk and larger prospective volumes, lie beneath the complex Aptian salt.

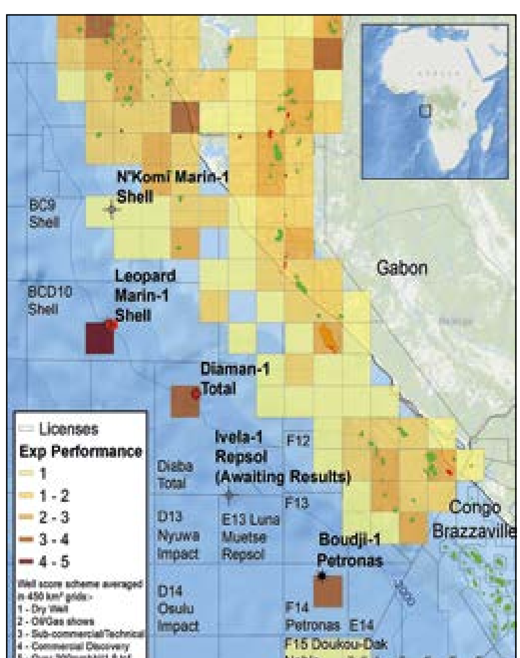
The Aptian Gamba reservoirs are proven onshore and nearshore, as are the Dentale sandstone formations. Both comprise high poroperm fluvio-deltaic syn-rift clastics, with lacustrine deltaic facies seen onshore.

Source rocks, perhaps lower risk post-Boudji, include Albian anoxic shales and Cenomanian and Turonian post-salt. Below the Albian, and underpinning this exciting new oil province are Apto-Barremian Melania lacustrine shales, with recorded 20% TOC Type I kerogen. The combination of this prolific source, thick Dentale sands in very large structural traps in rotated syn-rift fault blocks, sealed by late Apto-Albian transgressive marine shales and the Ezanga salt, provides all the ingredients for giant oil discoveries.

The risks are still high: the gas and gas condensate discoveries suggest other kerogen types or greater burial histories; at least one major inversion event affecting source, trapping and overall charge mechanism has been documented; charge retention is complicated by faulted salt seal; and the required juxtaposition of source and reservoir may not be present.

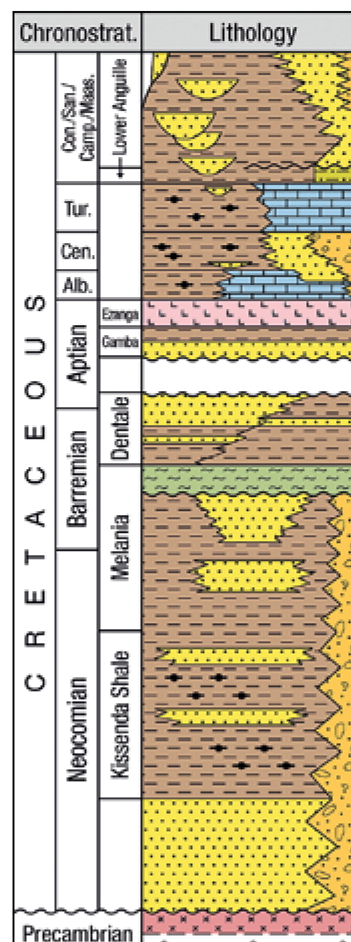
The Players

In addition to Shell and Total, Petronas have a commanding position in the region with blocks F14 (Boudji-1) and E13. Repsol will operate the next E13 well (Luna Muetse Ivela 1), Noble have a strong position in Block F15 (Douku Dak) and Woodside an excellent spread of interests from Diaba to F15, E13 and F14. Impact Oil & Gas, with a strong West African deepwater portfolio, hold blocks D13 and D14 in ultra-deepwater, with very large pre- and post-salt prospects based on high quality modern 3D. To the south-east in shallower water, Spectrum have acquired a large multiclient 3D survey in a similar pre-salt play in the Gryphon area, and Vaalco, Perenco and others are working up the shelf and shallow plays. Adjacent acreage in F12, F13, E14 is understood to be subject to negotiations in the Bid Round announced by DGH in 2016.



The Prize

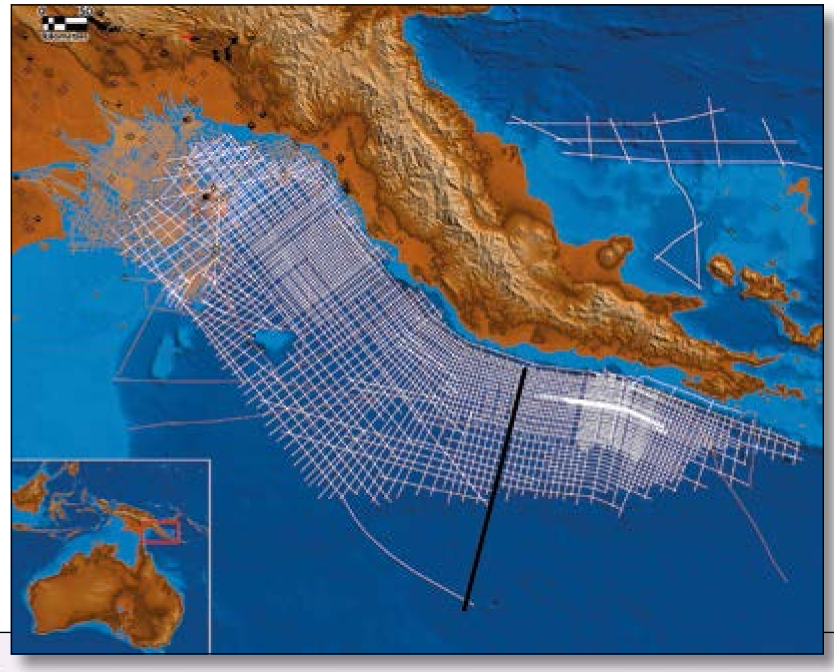
The development of this large oil play in deepwater pre-salt Gabon is significant for the industry in West Africa. A Cretaceous play, challenged by deep structural targets usually under salt, thus requiring the latest 3D processing and interpretation, this margin is yet to reveal a full-cycle success story as envisaged and proposed by avid Brazil-watchers. Kwanza has disappointed to date, but there are encouraging signs of a Lower Cretaceous-sourced petroleum system succeeding in the Mauritania/Senegal area, Gulf of Guinea and south-west Africa. The industry is determined to discover the truth behind the concept of vast oil volumes in pre-salt in West Africa near the limits of exploration technology. ■



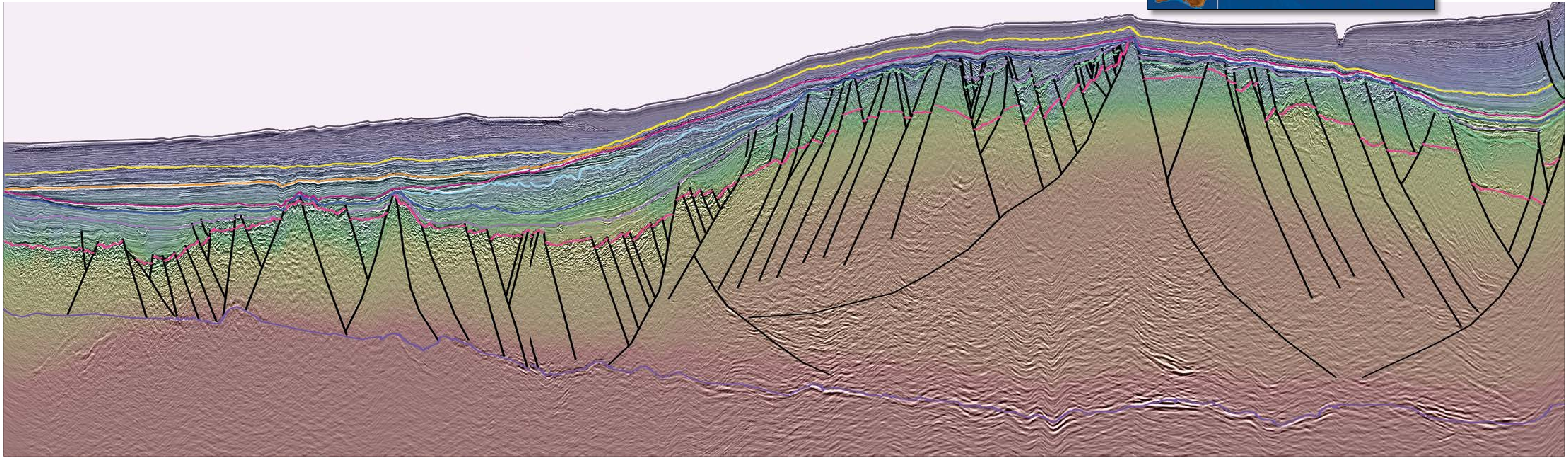
Exploring Papua New Guinea

Papua New Guinea has become one of the world's most exciting exploration regions, with significant petroleum potential in the Gulf of Papua. Searcher Seismic, in cooperation with the Department of Petroleum and Energy (DPE) and BGP, have acquired over 32,000 line-kilometers of long-offset, PSDM-processed 2D seismic in the Gulf of Papua. This dataset has revealed exciting new potential and has highlighted the prospectivity in the Gulf of Papua.

The interpreted line below is oriented south-west to north-east and shows a regional seismic line in the Gulf of Papua, where seismic stack data is blended with seismic interval velocity. Better seismic acquisition and imaging has allowed for a more confident identification of the Basement and Moho. The improved seismic quality also permits a robust definition of faults and structural style in the Gulf of Papua.



Map showing location of the new and reprocessed Searcher (in conjunction with Spectrum) 2D seismic data in the Gulf of Papua, with the location of the foldout line below highlighted in black.



Hydrocarbon Potential of the Gulf of Papua

Interpretation of new and reprocessed data reveals clear identification of promising plays.

SAID AMIRIBESHELI, DARIUSZ JABLONSKI and ANDREW WELLER, Searcher Seismic

The Gulf of Papua (GOP) has been acknowledged as a potential premier hydrocarbon region. Discoveries at Pasca, Pandora and nearshore Uramu have demonstrated the prolific charge presence analogous to other areas in south-east Asia (Jablonski et al., 2018). Exploration efforts in the deepwater GOP have been hampered by paucity of seismic data and some early models have suggested limited and geologically young sedimentation on top of the unknown age basement, most likely of oceanic origin (Struckmeyer, 1994).

Between 2015 and 2017 about 32,000 km of 2D long-offset, high-resolution, broadband seismic was acquired by Searcher Seismic, demonstrating the clearest picture yet of several depositional packages, often separated by tectonically significant unconformities. This is also supported by PSDM reprocessing of 12,972 km of the historical 2D data.

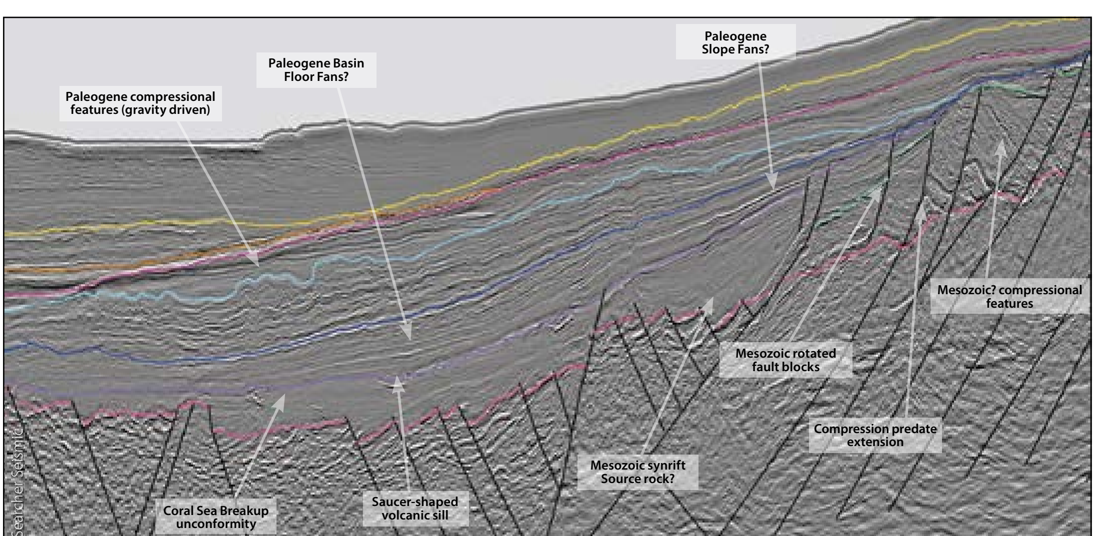
Several stratigraphic subdivisions have been proposed in the GOP. Whilst a Tertiary to Jurassic sequence is generally accepted, the older section is still poorly understood and limited by a lack of well information and poor legacy seismic imaging. Acquisition of new seismic data and reprocessing of historical data has led to the identification of several angular unconformities, each suggesting distinctive tectonic packages that have not been previously recognized, as described below:

1. Recent to Pliocene basins defined between the present-day sea floor and Woodlark Basin break-up unconformity.
2. Miocene to Paleocene basins bounded by an unconformity at the top and the Coral Sea break-up unconformity at the base, which corresponds to the C21 magnetic anomaly (5.2 Ma to 60 Ma).
3. Upper Cretaceous basins defined between the Coral Sea and Tasman Sea break-up unconformities (60 Ma or 79 Ma).
4. Lower Cretaceous to Upper Permian basins with the Middle Triassic and Permo-Carboniferous successions considered analogous to the Bowen and Galilee Basins located onshore Queensland in Australia.
5. Lower Permian to Upper Carboniferous basins are most likely economic basement.
6. Basement to Moho package allowing differentiation between continental, transitional and oceanic crust and consequently refinement of existing plate tectonic models.

With a more confident identification of a Basement and Moho marker, the interpretation of the shipborne gravity and magnetic data has allowed for a better understanding of the depth to basement and the composition of the crust, which is interpreted to be most likely of continental origin (non-oceanic; Lowe, 2016). These observations have been incorporated into a regional picture that connects geographically distant regions like onshore eastern Australia, PNG and New Zealand.

Synchronization of high quality seismic data and regional synthesis studies allow a more comprehensive play identification in the GOP. Several, often vertically stacked, plays have been identified in the GOP (Jablonski et al., 2018). These are summarised as:

- Middle Triassic to Upper Carboniferous reservoir/seal pairs analogous to the Bowen and Galilee Basins in Queensland;
- Lower Cretaceous to Upper Triassic reservoir/seal pairs – primary targets in onshore and offshore PNG exploration;
- Break-up structures of various ages;
- Miocene pinnacle structures analogous to the Pasca and Pandora gas discoveries;
- Pliocene detached basin floor fans;
- Compressional fold belt features, some up to 500 km long, not tested in deepwater. ■



Zoom-in of the regional line as shown in the foldout, illustrating the main geological features and structural elements.

The Malvinas Basin: Revisiting Prospectivity

New regional reprocessed 2D seismic reveals the prospectivity and hydrocarbon potential offshore Argentina.

DARIUSZ JABLONSKI, Searcher Seismic

Argentina, an area of world class petroleum potential, has experienced growing demand for high quality, regional datasets in advance of upcoming bid rounds. The Malvinas Basin, offshore Argentina, appears increasingly promising, as newly reprocessed 2D seismic reveals older play types and source rock potential. In this highly prospective region, all exploration play elements – structure, reservoir, seal, source rocks, maturity and timing – are in place. Both extensional and compressional structural styles exist with multiple stacked reservoir levels and world class oil-prone source rocks.

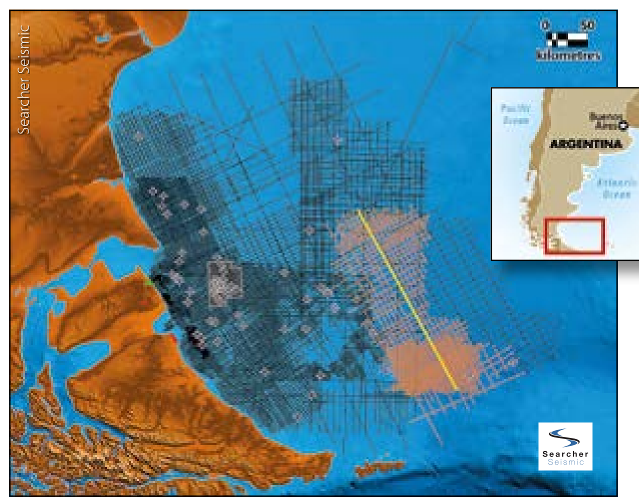
Several prospective play levels have been identified in the Malvinas and surrounding basins in this extensional and compressional setting, including (in order of exploration prospectivity):

- Valanginian to Albian lacustrine to shallow marine sandstones, Upper Eocene to Lower Miocene shallow marine to basin floor sandstones, Middle Miocene to Pliocene basin floor fan sandstones and Turonian shallow marine sandstones, all charged by up to six hydrocarbon systems;
- Lower to Middle Jurassic fluvio-deltaic sandstones that potentially contain age-equivalent Los Molles Formation source rocks that would provide in-situ charge (a new play in the Malvinas Basin);
- Upper Cretaceous reefs identified by Geleazzi (1998);
- Upper Jurassic break-up unconformity transgressive sandstones charged by Los Molles and Vaca Muerta sources;
- Basement highs that may be transgressed by mature Los Molles Formation.

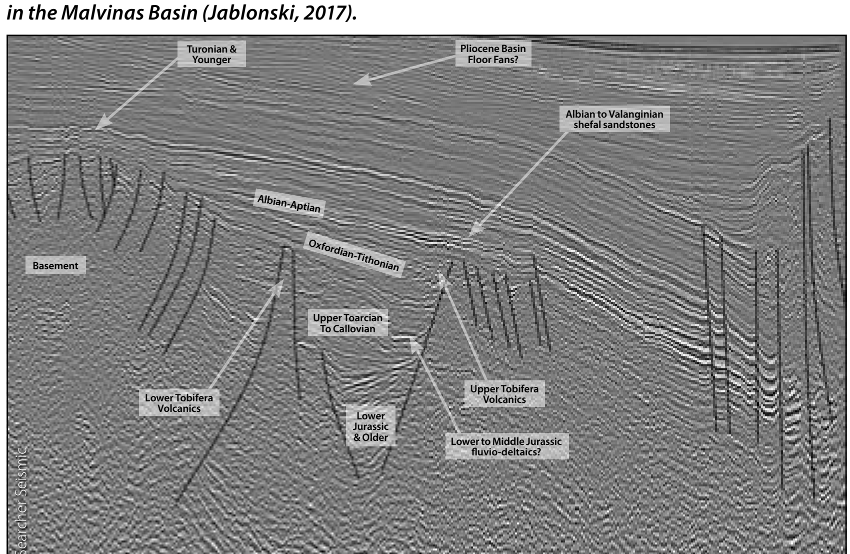
The Searcher Seismic 2018 broadband pre-stack time migration (PSTM) reprocessing flow allows for the identification of these plays. The seismic below demonstrates four different stratigraphically-aged rifts, each potentially with mature source rocks, as well as eight different plays including two new ones in Upper Jurassic break-up unconformity transgressive sandstones and Lower to Middle Jurassic fluvio-deltaics with in-situ migration from the Los Molles source rock equivalent. It is also possible to note clear differentiation between volcanics and sediments and between the Upper and Lower Tobifera Formations.

Within the Malvinas and surrounding on and offshore basins well density is highly variable. Onshore, basins such as San Jorge and Astral-Magallanes are covered by thousands of wells. However, offshore the well locations are sparse, with most of the exploration drilling completed in the 1980s. The North Malvinas and South Malvinas drilling was also relatively sporadic despite early success with the Sea Lion oil discovery. The 2016 Darwin-1 360 MMb condensate-rich discovery testifies to the high exploration potential in the region. Hydrocarbon occurrences in the area are widespread at various stratigraphic levels. A vigorous post-well analysis is currently being conducted by Searcher Seismic to further understand drilling outcomes within the region.

With the approaching bid rounds and the release of new data offshore Argentina, the future is exciting for exploration in this region. Searcher's newly reprocessed seismic will enable more confident identification of hydrocarbon occurrences and exploration plays, essential for petroleum exploration. ■



Searcher de-ghosted PSTM migration seismic line, illustrating stacked rifts and additional stratigraphic section of the Early Jurassic and older age, and some of the main plays present in the Malvinas Basin (Jablonski, 2017).



Czeching It Out:
The Potential of Central Europe

Central Europe has been not only at the forefront of the development of modern geology but has one of the oldest roots of the modern oil industry.

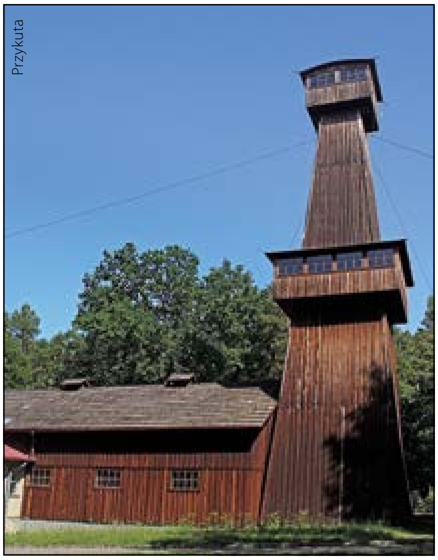
NEIL CARDY
Cogent Petroleum

There has been a long history of people exploiting hydrocarbon seeps throughout Central Europe since Roman times. Staszic's 1806 map (see *GEO ExPro*, Vol. 13, No. 6), for example, identified numerous oil seeps in the Northern Carpathians. During the 1850s the Polish pharmacist Igancy Lukasiewicz was experimenting with 'rock oil'. He was the first person to distil crude oil in Poland and developed the first paraffin lamp in 1853. In 1854 he opened the world's first 'oil mine' at Bóbrka in Poland, where the original wells were hand dug and about 1.2 x 1.2m in size. The early mines or wells were up to 15m deep, but eventually reached depths of 150m, and by 1868 there were 60 hand-dug wells around Bóbrka – two of them are still in use! The original site is now the Igancy Lukasiewicz Museum of the Petroleum Industry (see their website: www.openairmuseum.pl/skansen/bobrka). In 1856, Lukasiewicz opened the world's first industrial oil refinery (or oil distillery, to be accurate).

Oil from the Carpathians

From this simple beginning the oil and gas industry developed across Central and Eastern Europe, with discoveries from Austria in the west to Romania in the east centered around the Carpathians. By 1900, Romania was the largest oil producer in Europe and the third largest in the world, as well as the first country to export gasoline. However, following the Second World War, the region was isolated from the rest of the world's oil industry, which has led to it being relatively unknown today. This isolation has also resulted in the development of national, rather than international, names for stratigraphic and structural units which makes understanding the geology of the region more difficult, especially when looking at older maps and reports.

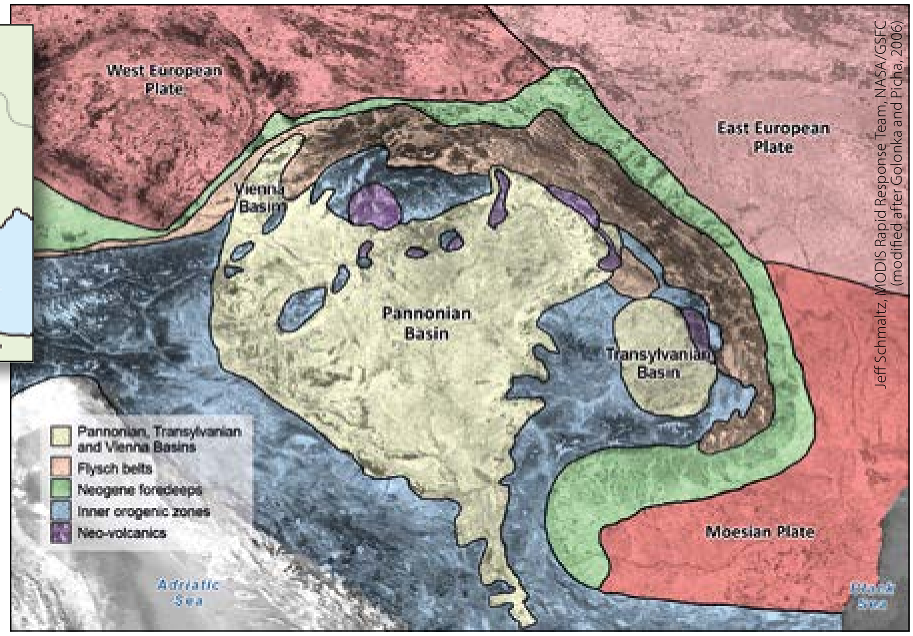
These hydrocarbon discoveries all fall within the Carpathians, which are the eastern extension of the European Alps. This mountainous region spreads across seven countries of Central and Eastern Europe and has a complex geological history. This article gives a simple overview of the geology and hydrocarbon-producing zones of the region – anything more is beyond the scope of even a series of articles.


Przykuta

An old rig at the Bóbrka petroleum museum in southern Poland.


Nicu Farcas

The Apuseni Mountains in Romania divide the Pannonian and Transylvanian Basins.



Jeff Schmaltz, MODIS Rapid Response Team, NASA/GSFC (modified after Golonka and Picha, 2006)

Simplified geological map of the Carpathians and surrounding area. The Carpathian mountain range can be seen to form an arc running from west to east through the Czech Republic, Poland, Slovakia, Hungary, Ukraine and Romania.

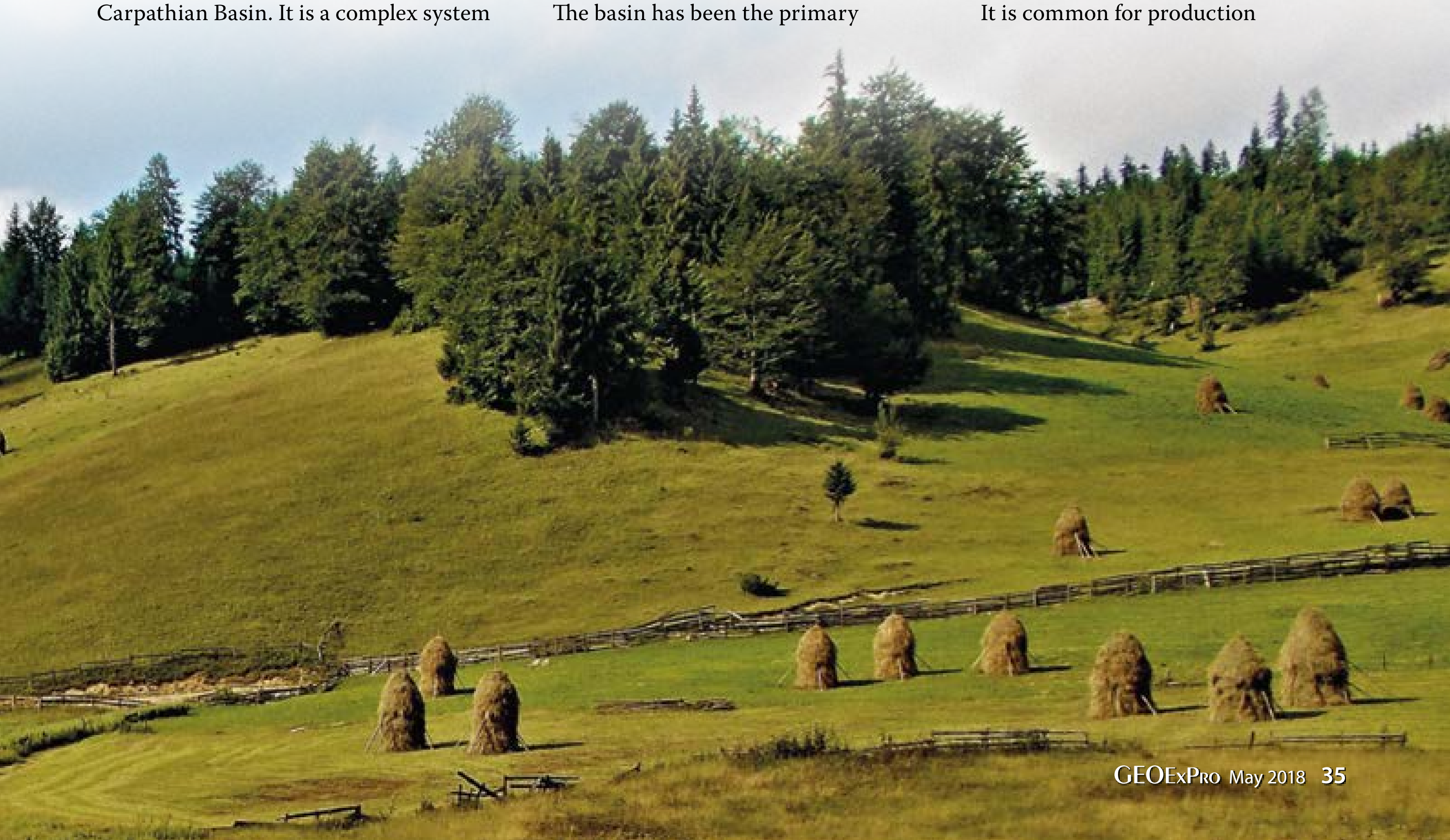
The Carpathians are typically composed of three lithological zones: the outer Flysch foldbelt of sandstone and shales, a central metamorphic belt (forming the highest peaks of over 2,500m), and an inner belt of volcanics. Within this arc are three basins: the Vienna Basin in Austria, Czech Republic and Slovakia; the large central Pannonian Basin centered in Hungary; and the Transylvanian Basin in Romania to the east. These three central basins, along with the outer Flysch zone of the Carpathians and associated thrust belt, make up the hydrocarbon provinces of the region.

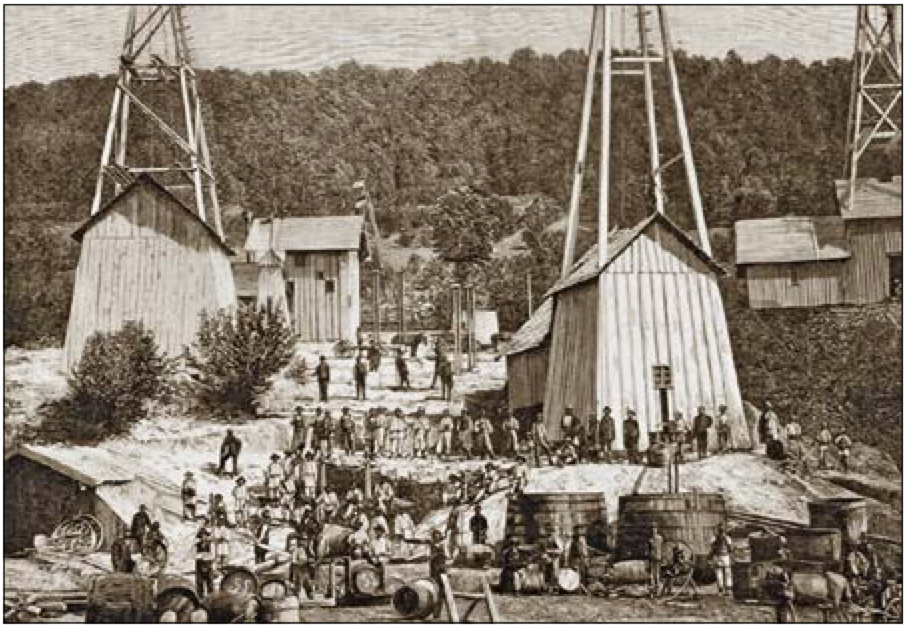
The Pannonian Basin

The name Pannonian comes from the Roman Province of Pannonia which partially overlapped the basin, although in Hungary it is referred to as the Carpathian Basin. It is a complex system of Neogene sediment-filled sub-basins which overlie deformed and faulted nappes of Mesozoic, Paleozoic and Precambrian rocks, extending some 600 km from east to west and 500 km from north to south. The structure of the region is the result of the convergence and collision of the European plate with smaller continental plates to the south during the Cretaceous and Miocene.

The basin has been the primary petroleum area of the region and the reservoir rocks reflect the complex geological history of the area. Around 62% of the region's oil production comes from Tertiary (Neogene and Paleogene) sediments and a further 24% from Mesozoic carbonates, with crystalline basement reservoirs making up a further 5%; 70% of natural gas production is from Tertiary reservoirs.

It is common for production





Drilling rigs in western Galicja in 1881. Now part of Poland, this region included the world's first 'oil mine' at Bóbrka.

to come from multiple zones. For example, the largest oil and gas field in Hungary, Algyö, produces from fractured Paleozoic metamorphics and Miocene conglomerate and sandstone. Elsewhere, there are wells which produce from weathered and fractured granites, quartz porphyria, mica and carbonate schists as well as Miocene conglomerates and sandstones.

Similarly, there are numerous source rocks, ranging from Triassic organic-rich shales and marls in the basement complex through to Cretaceous and Miocene formations. The Miocene shales and marls are thought to be the principal source of oil and gas in the region.

The Pannonian Basin has relatively high geothermal gradients, averaging 3.6°C/100m, so these organic-rich formations generate hydrocarbons at relatively shallow depths, with oil typically generated between 2,000 and 2,500m and gas below 5,000m. It appears that there is considerable migration both vertically and horizontally, with the reservoirs often being found in thermally immature rocks. Within the basin most oil reservoirs are between 500m and 2,500m deep and the gas reservoirs slightly deeper.

Since the first hand-dug wells in the 1850s the area has been extensively explored and about 500 fields have been discovered, with the first commercial gas field found in 1917 and the first commercial oil discovered in 1937. It is estimated that over 5,200 exploratory wells were drilled between 1935 and 1990 in Hungary alone. In 1994 Hungarian oil production reached an all-time high of 46,000 bopd, but since then it has shown a steady decline and currently averages around 14,000 bopd.

The Vienna Oil Basin

The Vienna Basin is the smallest of the basins within the Carpathians and extends through Austria, Czech Republic and Slovakia. As with the Pannonian Basin, production comes from a range of formations including fractured Triassic carbonates in the underlying nappes and multiple mid-Miocene sandstones.

In 1913 oil was discovered at the Egbell field in what is now Slovakia but was then the Austro-Hungarian empire. In the following years several more fields were found and in 1949 the largest oil field in Central Europe, Matzen, was discovered with total estimated reserves of 510 MMbo.

Transylvanian Basin

The Transylvanian Basin is the only one of these hydrocarbon-producing regions that lies within a single country, Romania. It is also the only region in the Carpathians that produces no oil, but it represents nearly 70% of Romania's natural gas resources. It is separated from the main Pannonian basin by the Apuseni Mountains to the west and is surrounded on all other sides by the Carpathians. The ranges were uplifted during the Pliocene to Holocene resulting in the shape of the basin.

Over 7,500m of sediments were deposited in the deepest parts of the basin near the center and along the north-eastern edge. The sediments have been disturbed by the movement of thick Miocene evaporites which have formed salt domes up to 15 km in diameter in

Pumps on the Matzen field in Austria in the Vienna Basin. Discovered in 1949, it is the largest field in Central Europe.

the central part of the basin and north-south diapiric folds along the perimeter.

Unlike the Vienna and Pannonian Basins, the Transylvanian Basin is the result of much more localized tectonic and sedimentary activity. The whole process of source rock and reservoir deposition, hydrocarbon generation, migration and accumulation occurred during the Miocene and Pliocene.

The source rocks are Miocene non-marine and brackish water shales and the gas appears to be generated from organic material that is dispersed throughout the formations rather than from a single rich source rock. The thick evaporites that underlie these sediments effectively separate the basin from any deeper hydrocarbons migrating from older formations. The reservoirs consist of Miocene to Pliocene marly sandstones forming hydrocarbon traps such as domes and anticlines through salt diaprism of the underlying Miocene evaporites.

The basin has been explored for more than a century, with the first natural gas being discovered in 1909 and Romania's largest natural gas field, Deleni, discovered in 1912. The length of exploration combined with the geological complexity is thought to limit the number of fields left to discover, although little work has been done on the geology below the evaporite layer at the base of the Neogene.

The Carpathian Outer Flysch

This is the outermost zone of the Carpathians and is 1,300 km long, stretching along the whole length of the mountain range. It is formed from Cretaceous and Paleogene sediments – the flysch which have been thrust onto the European foreland. As the name suggests, flysch is a sequence of repeated sedimentary rock layers which were deposited on the edge of an orogenic belt. They are typically formed by turbidity currents and the Carpathian Flysch was one of the areas where the concept of deepwater turbidites was developed in the 1950s.

The flysch basins were thrust over the stable European platforms during the Cretaceous and Miocene in a series of nappes which overrode the molasse deposits that were being deposited

The Carpathian National Park in Ukraine.

there. This has resulted in the molasse deposits being integrated into the flysch nappes, forming the complicated geological assemblage of the folded and thrusted flysch belt and the overlying Carpathian foredeep.

Several Petroleum Systems

A number of Total Petroleum Systems (TPS) have been identified over the region.

In the Northern Carpathians three separate systems have been identified. Moving from north to south and from young to old, these are: the Isotopically Light Gas TPS, the Mesozoic-Paleogene Composite TPS, and the Paleozoic Composite TPS.

The Isotopically Light Gas TPS is located within the undisturbed Miocene molasse of Austria, Poland and Ukraine and is predominately methane in structural or stratigraphic traps. The Mesozoic-Paleogene Composite TPS includes most of the Polish and Ukrainian oil fields that are found both in Paleogene and Cretaceous flysch nappes and in the Paleozoic-Mesozoic basement, with Miocene molasse deposits often providing the seal. The Paleozoic Composite TPS extends from the eastern Czech Republic along the Polish border into south-western Ukraine and consists of Paleozoic formations underlying the flysch and molasse, which act as a seal. This system is deeper and much less understood than the younger, shallower systems.

The eastern and southern part of the Carpathians borders the Transylvanian Basin in Romania. Again, there is a series of flysch deposits that have been thrust over older platforms. This region contains the world's second largest producing oil mine at Sarata Monteoru where the oil is produced from galleries 240–320m below the surface. Two petroleum systems have been identified: the Moesian Platform Composite TPS and the Dysodile Schist-Tertiary TPS. The former stretches from the edge of the flysch zone in the west to the Black Sea in the east. It contains most of Romania's oil reserves in Miocene reservoirs, as well as Triassic, Jurassic and Cretaceous reservoirs. The younger Dysodile Schist-Tertiary TPS includes Oligocene and Miocene flysch deposits.

Great Opportunities

As can be seen from this very brief overview of the region, there is a great diversity in the geological environments, as well as the types of hydrocarbons, both in their formation and preservation. Central Europe is one of the oldest developed oil and gas regions and despite the amount of exploration and production that has taken place in the last 164 years there are still fields to be found. The complexity of the geology of the region along with the exploration history suggests that there are still likely to be numerous small discoveries to be made. This may not attract the attention of the larger oil companies but could potentially offer smaller companies great opportunities. In addition, there are relatively unexplored areas such as below the evaporites in the Transylvanian Basin or the deep Paleozoic Composite TPS in the northern Carpathians which may offer new prospects. ■

Resources Boosted by Billions

Unconventional hydrocarbon volumes have taken the headlines recently – but how are these figures worked out and why are they so big?

TIM DALEY

In March 2016, a small UK independent oil company announced the results of flow tests from their Horse Hill-1 discovery well, 60 km south of London, sparking a fierce backlash against the vision of an American-style frack-fest across the rural idyll of the Weald (see *GEO ExPro* Vol. 13, No. 5). While stressing that no rocks had been fracked in the making of the oil flows, the press release outlined very promising oil rates from Jurassic strata: 323 bopd from an established Portland sandstone play and also 1,365 bopd from two Kimmeridgian intervals characterized as 'tight' reservoirs. The latter grabbed media headlines, as it was revealed that up to 124 Bbo could lie beneath the commuter belt of southern England. Press reports emphasized that this is an 'in-place' resource estimate of all the oil zones encountered and would need confirmation from future drilling results across the 3,266 km^2 evaluation area. Even so, how can such an enormous volume be justified by one well, when the latest government estimate (2017, UK Oil and Gas Resources as at end 2016, ogauthority.co.uk) attributes 'only' 43.5 Bboe produced to date from the whole of the UK North Sea?

Conventional Beginnings

When I started work as a seismic interpreter in the mid-1980s, there was only conventional oil and gas and it was vital that we learned how to assess for the ingredients and requirements for an economic oil or gas field, as understood then. A prerequisite is the presence of a source rock, often a black shale with a high organic content, which is gently heated as it is buried by sediments, transforming the plant or animal matter to hydrocarbons. Crucially, these escape the source rock and migrate across the strata, reaching porous layers, after which their buoyancy conveys them upwards, unless trapped by an impermeable layer. An anticline or a tilted fault block can form such a trap, filling until the fluids spill from a leak point into the next structure or onwards up-dip.

The direct result is that such oil and gas fields are discrete structures, with oil migration focused towards structural highs or fault blocks. For sure, exploration successes are usually grouped along structural trends that are close to and above the mature source 'kitchen', but otherwise, each is individually assessed. The in-place hydrocarbon volume of an undrilled prospect or discovery is essentially a simple calculation of structure volume, reduced by multiplication to reflect the proportion of net sand thickness and its porosity, accounting for water content and the compression factor related to its depth. Finally, the all-important recovery factor is applied to provide the reserves figure – those hydrocarbons that can be produced.

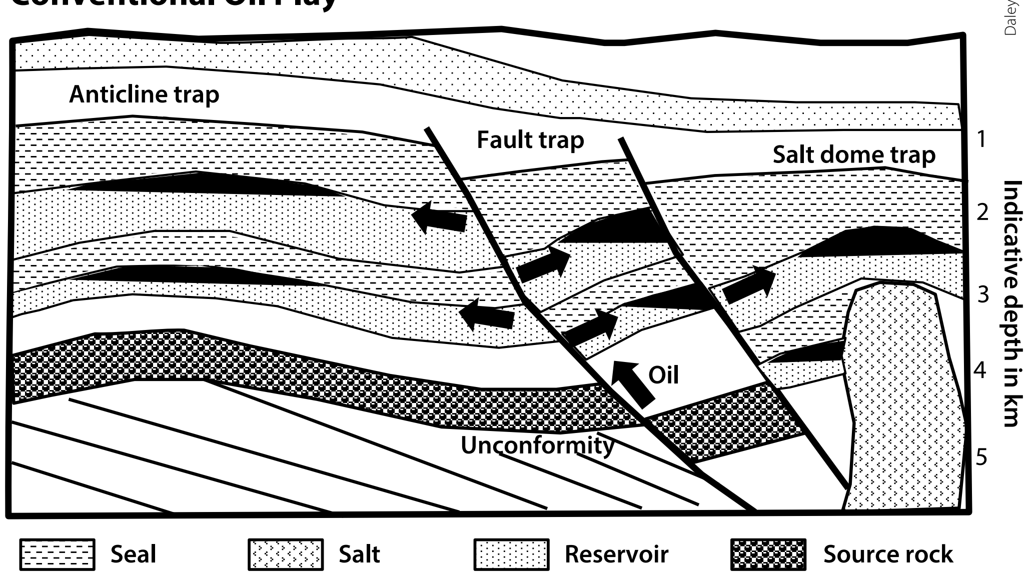
Brent: No Wild Goose Chase

If we view an oil field distribution map, using the East Shetland Platform of the northern North Sea as an example (right), we can see the trend of faults reflected by the blobs approximating the field outlines, indicating where Jurassic sands of the Brent Group, segmented by tilted fault blocks, are overlain by sealing shales. Take the mighty Brent Field, the oil giant whose discovery in 1971 set in motion the exploitation of a vast new hydrocarbon province (*GEO ExPro* Vol. 14, No. 2). During 40 years of production the field has produced almost 2 Bbo and 6 Tcfg, approximately half and three quarters respectively of the original estimated hydrocarbons in place. Today, this vast hydrocarbon factory is being decommissioned and the first of the giant platforms has arrived on Teeside, north-east England.

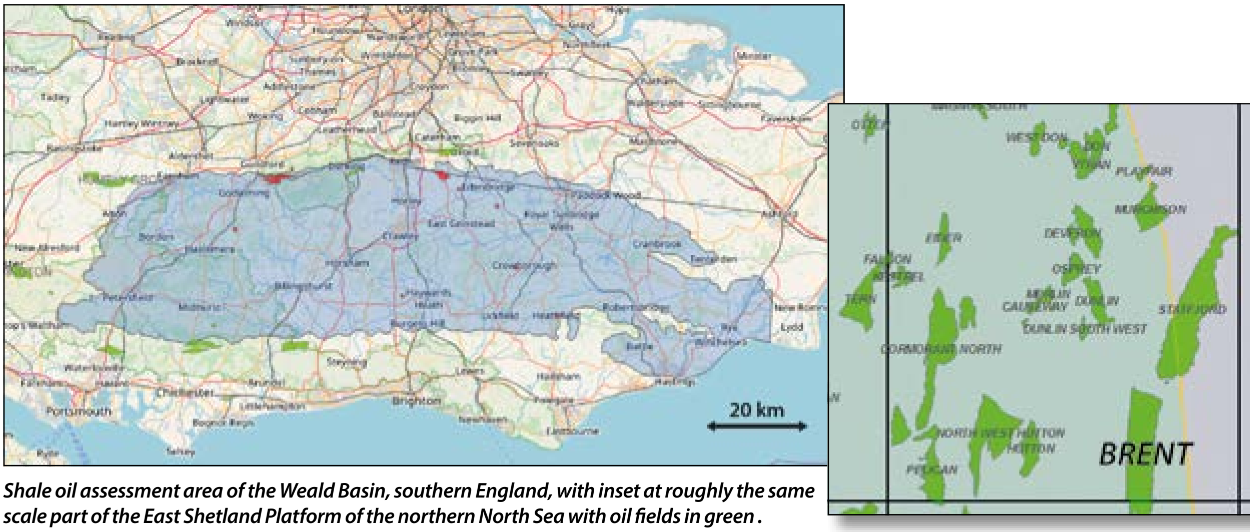
2P or Not 2P

Only now, near the end of Brent's life, we can be confident of exactly how much oil will be produced – but as geologists we are required to estimate the producible reserves throughout a field's life. According to the Society of

Conventional Oil Play



Oil volume in-place = volume of structure * % net reservoir * porosity * oil saturation



UK Oil & Gas Authority

Shale oil assessment area of the Weald Basin, southern England, with inset at roughly the same scale part of the East Shetland Platform of the northern North Sea with oil fields in green.

Petroleum Engineers (SPE), the industry declared arbiter of such assessments, to be classified as reserves, hydrocarbons must be discovered, recoverable, commercial and remaining. Proven reserves (1P) are often considered to be only those associated with the forecasted production (decline curves) from wells already on stream. Probable reserves (proven plus probable, hence 2P) could include new drilling or well interventions already approved and financed, while possible reserves (3P) include those assessed volumes for which there is not yet a development plan. During the life of a field, reserves initially classified as 2P and 3P are developed and re-categorized as 1P before being produced. Other discovered but undeveloped hydrocarbons are considered contingent while undrilled structures are indicated as prospective.

However, P also stands for probability and the market is often confused between 1P, 2P, 3P versus P90, P50, P10. This confusion arises from the exploration practice of assessing the range of volumes associated with an undrilled prospect. When minimum, most likely and maximum reservoir parameters were multiplied, it was realized that the minimum volume could be minutely small while the result of combining maximum values correspondingly huge. In a bid to rationalize results, Monte Carlo simulation is used, in which thousands of realizations sampled from the range of prospect parameters are plotted and the resulting probability curve has a 'most likely' or 'P50' result. The low case is associated with 'P90', for which there is a 90% chance that the actual reserves are higher. The range between P90 to P10 is routinely used to describe the range of possible reserves from the outcome of a successful exploration well.

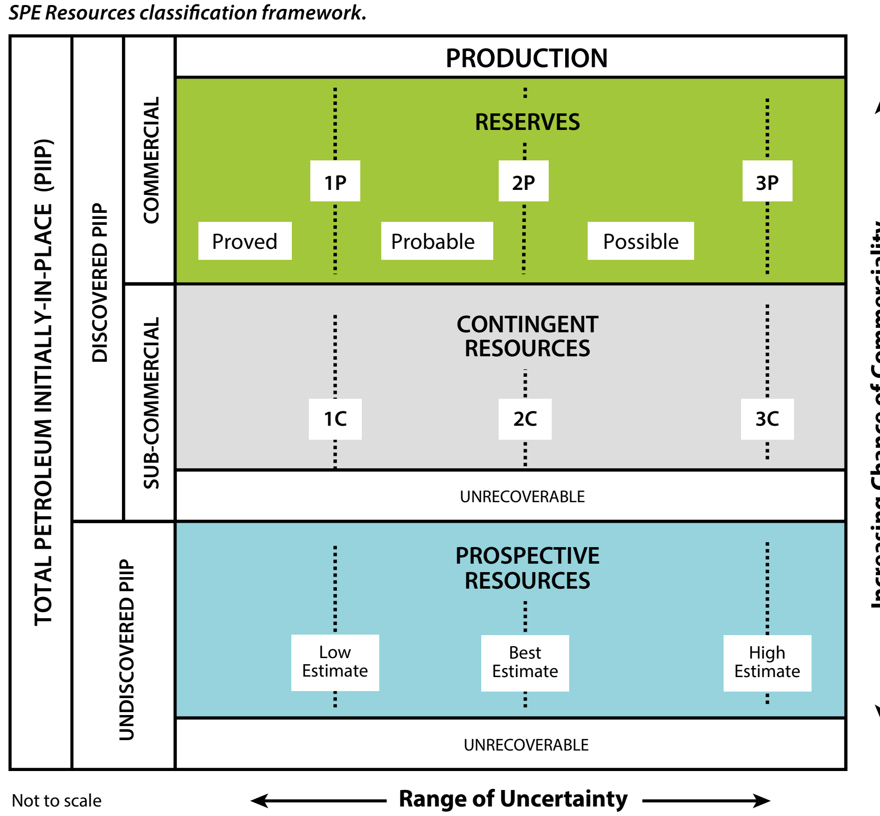
Confusion might arise with this usage in the production world. Even a proven oil reserve can have a low, most likely and high case depending on pessimistic or optimistic forecasts of production decline and could be referred to as P90, P50 or P10 cases.

Reservoirs Can be Tight

The Brent Field is an example of how a good reservoir with 20–25% porosity can be a prolific producer. Of course, some reservoirs disappoint; the oil may be there, but stored in smaller pores of low porosity sandstones which are poorly connected, inhibiting the flow of hydrocarbons, quantified by rock core measurements as permeability. Such reservoirs are dubbed 'tight'; a good reservoir would have permeabilities of tens to hundreds of millidarcys, a tight one would be a single millidarcy or less.

Tight reservoirs have long been

SPE Resources classification framework.

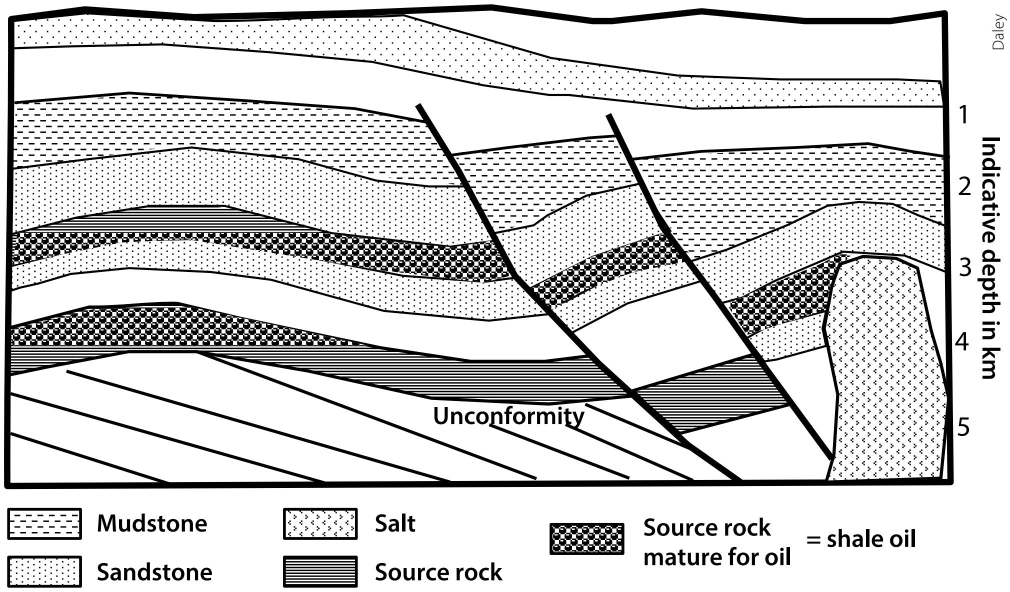


SPE

stimulated by hydraulic fracking, when water is pumped down the well at pressures high enough to fracture the reservoir by expanding and extending existing natural fractures, improving the permeability by the resulting network of interconnected flow paths. Outcomes can be further improved if the injection fluid is charged with proppant, like sand, which props open the cracks even after the pressure is relaxed. Such an operation can easily require 1.3 million litres of water, plus a hundred tonnes of proppant, propelled downhole at pressures of 10,000 psi or greater.

For many years fracking was limited by drilling technology to vertical or slanted wells, but since the turn of the century, the impact of this operation has been transformed by its deployment in horizontal wells. The ability to drill and frack multiple intervals along the target strata has enabled the development of hydrocarbons from previously unpromising reservoirs.

Unconventional Shale Oil Play



Shale oil volume in-place = thickness * area where mature * % of bound oil in source shale

Now Source is Reservoir

Although I had worked on numerous tight reservoirs through my career, never did I think that the source rock itself could become prospective. It seemed that, while highly organic shales could source oil, they are also the archetypal seal beds, being minutely grained and impermeable. But it has turned out that the right sort of shale, preferably brittle or riddled with fissures, can be exploited commercially when stimulated by hydraulic fracking. The hydrocarbons in such rocks are either stored within the micro-porosity or chemically bonded ('adsorbed') to the organic constituent of the source rock. In either case, they remain in-situ and do not flow, even when their confining pressure is liberated by the drill bit. Cue hydraulic fracking, which releases the hydrocarbons from along horizontal boreholes, and we have the basis of the unconventional shale resources.

To determine the amount of oil and gas in place for the prospective shale beds, we must estimate the proportions of free (but tightly held) and adsorbed hydrocarbons. The former is derived from bulk density on wireline logs and the latter by assessing the total organic content, preferably calibrated to measurements from rock core. Crucially, when estimating the volume potential for a shale play, the hydrocarbons are attached to the reservoir and not constrained to structural highs. Play areas are defined by mapping the distribution and thickness of the objective shales and outlining where they are both mature for hydrocarbon generation and have the required brittle property. The mapped area of each prospective interval is continuous across the fairway (in contrast to conventional oil fields) and characterized by barrels stored per unit area.

So, in the case of the Horse Hill-1 tight reservoirs, the prospective areas and parameters of the various target shales and tight limestones were mapped and aggregated beneath the Weald. The reported result gives an average of 38 MMb/km^2 across an area of 3,266 km^2 – hence 124 Bbo in place. It is by its nature a widespread resource and awaiting confirmation drilling, but the volumes certainly catch the headlines, particularly if fracking is to be employed.

Brent Delta being decommissioned at Teeside in October 2017.

Recovery Position

The oil industry of the USA has been transformed by shale and fracking; oil production has been boosted by over 4 MMbopd and unconventional plays are contributing half the gas currently produced by the country. The technology, however, requires intense operations; horizontal wells are sequentially fracked in 6 to 12 sections and 6 to 8 wells are typically drilled from each well pad, with some provinces drilling a thousand or more such wells a year. Individual well flows tend to decline quite rapidly, so continued new drilling is required to keep production rates at a plateau. And all this effort typically recovers 3–6% of oil or 15–25% of gas originally in place, much less than conventional reservoirs.

But how would reserves be assigned for such a widespread resource? The use of decline curves is still preferred to define proven reserves but they require careful calibration, as many producing wells experience a precipitous fall in flow before a stable, low rate is established. In 2011 the SPE updated their guidance for reserve estimates, suggesting that probable reserves for shale gas could include 2 or 3 drill locations beyond current production, as long as they lay within a contiguous and appraised region. Likewise, possible reserves could extend the probable area in a similar manner.

In Plain Sight

If I were to speculate that just the tight Kimmeridgian limestones that flowed in Horse Hill-1 were the primary interest, development of the cited 20 Bb in place across the region might recover a billion. An optimistic view of the average cumulative production per well of a million barrels would require 1,000 wells to be drilled from over a hundred well pads. While the drilling operation is time-limited compared to production, the public perception around water usage, gas leakage and induced earthquakes will provide fertile ground for a ferocious opposition, even before discussions against the continued development of fossil fuels. Today's estimates of what oil might be produced could only be considered as 'technically recoverable', as the economic and political factors will dominate any development plan.

Now that the Brent Delta platform is on view in Teeside, we can get a sense of the scale of development it took to produce the North Sea resources that were comfortably out of sight. The trouble with onshore developments is that they are always in someone's backyard; the scale required to develop shale plays in the UK will take some hiding.

Sources: UK Oil and Gas plc website, UK Oil and Gas Authority; SPE 2011: Guidelines for Application of the Petroleum Resources Management System. ■

Anti-fracking protest near the Horse Hill site in 2015 – despite assertions that fracking would not be used.

Rocky Mountain High: Aspen, Colorado

Aspen's superlative alpine scenery, the result of the region's fortuitous location during multiple orogenies, draws jet-setters from around the globe and presents geologists with a tantalizing puzzle to deduce when and why these beautiful mountains arose.

LON ABBOTT and TERRI COOK

In 1879, intrepid miners searching for gold and silver high in central Colorado's mountains braved the dangerous climb up and over the Continental Divide. As they descended the western slopes, the men discovered the Roaring Fork Valley, a region of soaring, crimson-colored peaks surrounded by lush, green vales incised by crystal-clear streams. The area's rich ores quickly attracted thousands of people. In just over a decade the main settlement, which was soon renamed Aspen, surged to nearly 12,000 people, and its silver production assumed global importance. Although the town's population plummeted after the price of silver crashed during the panic of 1893, the foundations had been laid for one of the Rockies' poshest and most celebrated resort towns.

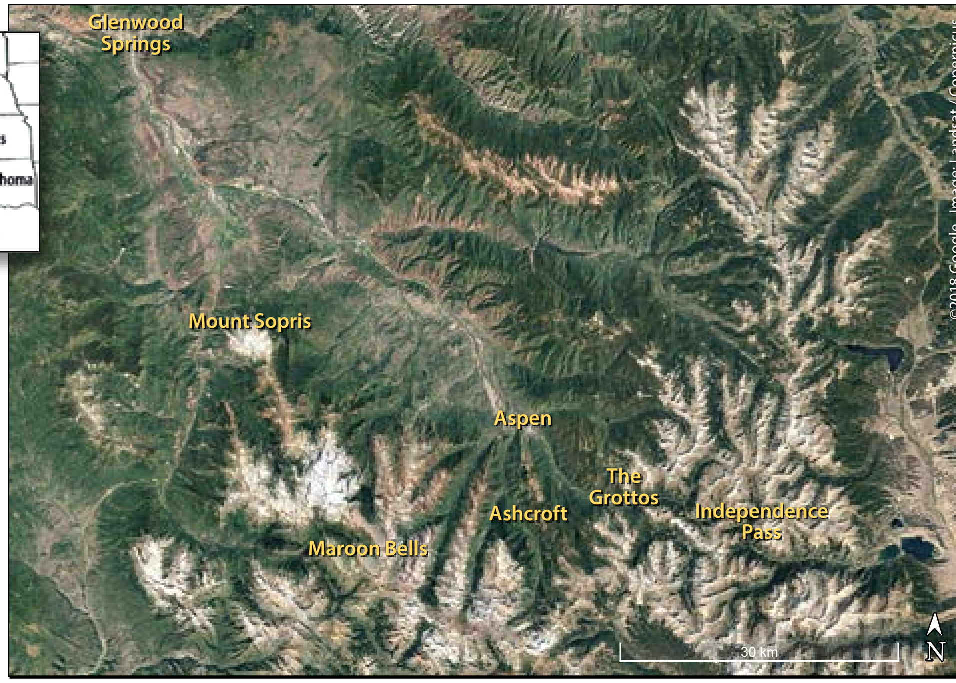
In 1950, just three years after Aspen Mountain opened its first ski lift, the town became the first site outside Europe to host the World Alpine Championships, an event that put this surprisingly laid-back town squarely on the jet-set map. Singer-songwriter John Denver, who made Aspen famous with 'Rocky Mountain High' and other tunes, and 'gonzo' journalist Hunter S. Thompson, whose run for sheriff in 1970 cemented the town's reputation as a countercultural mecca, were among its most famous residents.

Today the town continues to draw a steady stream of movie stars, musicians, and executives. Aspen is so popular, and buildable land so scarce, that its real estate is among the most expensive in the U.S., with a median house price of $2.6 million. Fortunately, you don't need to be a multi-millionaire to immerse yourself in the region's spectacular scenery. Several short excursions, including the highest paved crossing of North America's Continental Divide, bring visitors face to face with beautiful views and the chance to examine the geologic upheavals that have transpired during the last 300 million years to produce the town's historic mining wealth and its modern 'white gold' – powder skiing.

The Maroon Bells: Ancestral Rockies' Legacy

The gorgeous Maroon Bells, a pair of 14,000-foot-high (4,260m), bell-shaped peaks south-west of Aspen, are an icon

Aspen, one of the Rockies' most affluent resort towns, was originally founded by silver miners.



of Colorado's alpine grandeur. The sight of the bells' scarlet slopes mirrored in the still waters of Maroon Lake, especially during the fall when the valley's dense groves of aspen trees glow golden yellow and the summits are dusted with snow, is among North America's most photographed vistas. Maroon Lake is a 10 km shuttle-bus drive, bike ride, or cross-country ski jaunt up a beautiful glacial valley from the Aspen Highlands ski area.

The Maroon Bells, like many peaks in the Elk Range west of Aspen, have a distinctively different appearance compared to most Colorado peaks because they consist of layered sedimentary rocks rather than the more typical Precambrian granite and gneiss. The reasons for this difference relate to the geographies and tectonic styles during two different mountain-building episodes – the 300 Ma Ancestral Rockies Orogeny and the 70–40 Ma Laramide Orogeny, the seminal event that determined the location of today's mountains.

Transpressional faulting during the former raised two ranges — an eastern one located on the footprint of the modern Front Range, just west of the capital city of Denver, and a western one that ran from modern-day Grand Junction to Durango. Although the entire Paleozoic sedimentary section was eroded from both ranges to expose the Precambrian crystalline bedrock, these rocks were preserved in the intramontane lowland known as the Central Colorado Trough, in which Aspen lies. The synorogenic Maroon Formation was added on top, resulting in a five-km-thick sedimentary sequence in the Trough.

The next major tectonic event to affect Colorado, during the latest Cretaceous and early Tertiary, was the Laramide Orogeny. Most of the discrete ranges built during this event rose in approximately the same location as the earlier Ancestral ranges, so the Precambrian crystalline rocks underlay a notably thin sedimentary section that was quickly eroded, thereby producing Colorado's quintessential crystalline peaks. But in the Aspen area, the Laramide rise of the Elk Range inverted the Central Colorado Trough, whose layered rocks, most prominently the deep red Maroon Formation, comprise most of the range's spectacular peaks, including the Maroon Bells.

Independence Pass: Roof of the Rockies

The drive east of Aspen up to Independence Pass, the crest of the Sawatch Range, the largest and tallest of Colorado's Laramide ranges, ascends the highest paved crossing of North America's Continental Divide. Deep snow closes the pass each winter, but its snaking switchbacks, narrow pavement, and spectacular scenery make it a great summer driving or cycling adventure.

Unlike the crystalline peaks that comprise most of the Colorado Rockies, the Maroon Bells are carved from distinctive synorogenic sedimentary rocks deposited in a trough between two Ancestral Rocky Mountain ranges.

The drive over Independence Pass, the Continental Divide's highest paved crossing, offers tantalizing scenery and the chance to reconstruct key events that shaped the southern Rockies.

A trip over Independence Pass also provides an opportunity to track some of the key tectonic events that shaped today's southern Rockies. By the Jurassic, erosion had erased the last vestiges of the Ancestral Rockies topography, and subduction had commenced along the west coast of North America. That plate compression initiated the Sevier Orogeny, producing a series of fold-and-thrust belts that stretch from the Canadian Rockies in the north to western Arizona in the south. Colorado, by contrast, was a lowland traversed by sluggish, meandering rivers. After a Cretaceous rise in eustatic sea level flooded that lowland, Colorado became part of the Western Interior Seaway, in which more than two kilometers of marine shale accumulated. Those marine rocks host many of Colorado's most important oil and gas systems, including in the Denver Basin and the Piceance Basin west of Aspen.

One puzzling attribute of the Laramide Orogeny is the fact that deformation in Colorado occurred 1,000 km from the active tectonic boundary in California. Geologists explain this unusually large gap between trench and mountains by invoking nearly flat subduction of the Farallon Plate, which produced a compressional stress field unusually far to the east.

The Sawatch Range consists of a large anticlinal arch bounded on the west by the Castle Creek reverse fault that lies just west of Aspen. The Independence Pass road ascends the dome's western flank, with the drive affording sweeping alpine vistas of the range's Precambrian granites. The pass stands a lofty 12,095 ft (3,687m) above sea level. After you catch your breath, it's worth strolling along the gentle trail that traverses the wildflower-filled tundra south of the pass. After a kilometer the granite gives way to welded tuff as you cross the ring fracture of the 34 Ma Grizzly Peak Caldera, one of the numerous rhyolitic and andesitic volcanoes that erupted across the Colorado Rockies between 37–24 million years ago. The cause of this so-called 'Ignimbrite Flare-up' in the aftermath of the Laramide Orogeny is yet another tectonic puzzle.

Ashcroft: Ghosts of the Past

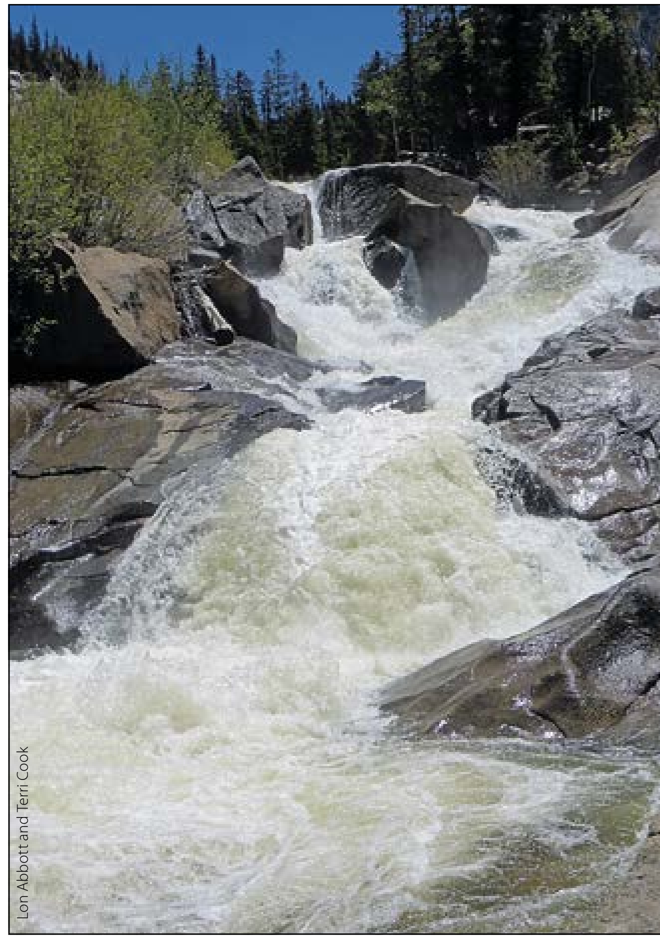
The ghost town of Ashcroft, located along the Castle Creek Road south of Aspen, is one of the best places to explore the Aspen area's rich mining legacy. The town was built during a two-week period in 1880 by a group of intrepid prospectors led by 'Crazy' Charles Culver and W.F. Coxhead. By 1883, the camp had a population of close to 2,000 and hosted a school, sawmills, and 20 saloons. Although Ashcroft's initial silver production was fantastic, the deposits were shallow, and big strikes in Aspen soon lured away most of the inhabitants. By the turn of the 20th century, only a handful of single men remained, and they reportedly spent most of their days in the local bar rather than working their claims. By 1939, all of the original inhabitants had passed away. Today, visitors can stroll past more than a dozen false-fronted buildings, labeled with interpretive signs, to learn more about the silver camp's history.

The rich silver lodes in Ashcroft, Aspen, and other nearby camps all formed when magma bodies and accompanying mineralized fluids intruded the crust during the Laramide Orogeny. They are part of a belt of Laramide-age plutons called the Colorado Mineral Belt. Although such magmatic belts commonly form during orogenies, they are usually oriented perpendicular to the subduction direction. Paradoxically, the Colorado Mineral Belt is oriented north-east – south-west, parallel to the direction of plate subduction. This unusual alignment presents yet another puzzle associated with the Laramide Orogeny that geologists continue to grapple with.

Fruits of a Hot Mantle

As puzzling as many Laramide characteristics are, these attributes form just part of the riddle that scientists have yet to solve to explain why Colorado even hosts mountains today. Several lines of evidence indicate the Colorado Rockies cannot be explained solely as the result of the Laramide Orogeny. There's no better locale to contemplate this puzzle than the world's largest hot springs pool at the historic Glenwood Hot Springs Resort, located adjacent to the Colorado River in Glenwood Springs, 65 km from Aspen.

The pool's water is derived from the Yampah Spring, which issues 8,500 liters per minute at a toasty 50°C. The mineral-rich water is then diluted to 34°C in the main pool. According to both heat flow and seismic data, these and many other hot springs scattered throughout the Colorado Rockies are the product of unusually warm mantle underlying this region. It is this warm, buoyant mantle that supports the state's high topography, not the typical crustal root that sustains most other compressional mountain ranges. Seismic data reveal the absence of a root beneath the Colorado Rockies, and structural studies document 10–20% crustal shortening during the Laramide. Isostatic calculations indicate that mountains produced by such modest crustal shortening and thickening would, on average, be only half as high as today's average 3,000m-high range.



The Roaring Fork River tumbles over Precambrian granite at The Grottos along the drive up Independence Pass, which climbs over the Laramide-age Sawatch anticline.

Although scientists generally agree that Colorado's mountains are supported by warm, buoyant mantle, they lack consensus regarding when that mantle heated up and the modern mountains rose. Mount Sopris, the summit that dominates the vista on the return drive to Aspen, illustrates the crux of this debate. It is one of several impressive Elk Range peaks that consist of light gray, 34-million-year-old granite. Those plutons likely formed in magma chambers that fed Ignimbrite Flare-up volcanoes similar to the Sawatch Range's Grizzly Peak Caldera. Many scientists argue that mid-Tertiary mantle heating is what produced the huge volume of magma that fed the Flare-up, as well as the rise of the modern Colorado Rockies due to associated thermal expansion. But other scientists who note that a vigorous cycle of erosion commenced across the region sometime between 5–10 million years ago argue that mountain uplift in response to mantle heating at that time is likely what triggered that erosion.

Contemplation of these tectonic puzzles provides geologists with an added incentive to relax in and enjoy Aspen's captivating alpine scenery. ■

The Aspen area's dramatic scenery is enhanced by the stark contrast between the Maroon Formation's vivid red sedimentary rocks and numerous light-gray middle Cenozoic intrusions, one of which is Mount Sopris, the peak on the left skyline.

Commercializing Bright Ideas

LAURA ROBERTS
PDS Group

How easy is it to translate academic research into a commercial business?

Oil company sponsorship of applied geosciences research is undergoing a renaissance after the past few years of drought and doubt. Given the competitive drivers of sponsoring companies, however, is this really effective in generating innovative technologies which can become robust commercial products, readily accessible by industry professionals from mainstream modeling platforms? E&P has a reputation as a sluggish adopter of new technologies – but there are some barriers to change. There's no lack of ideas, and anyone with professional geomodeling experience will admit to frustration with the status quo. The real challenge in translating good academic research into commercially viable offerings is that it requires sustained resource commitment and the skillful orchestration of multi-disciplinary teams with broad-ranging skills and expertise, including:

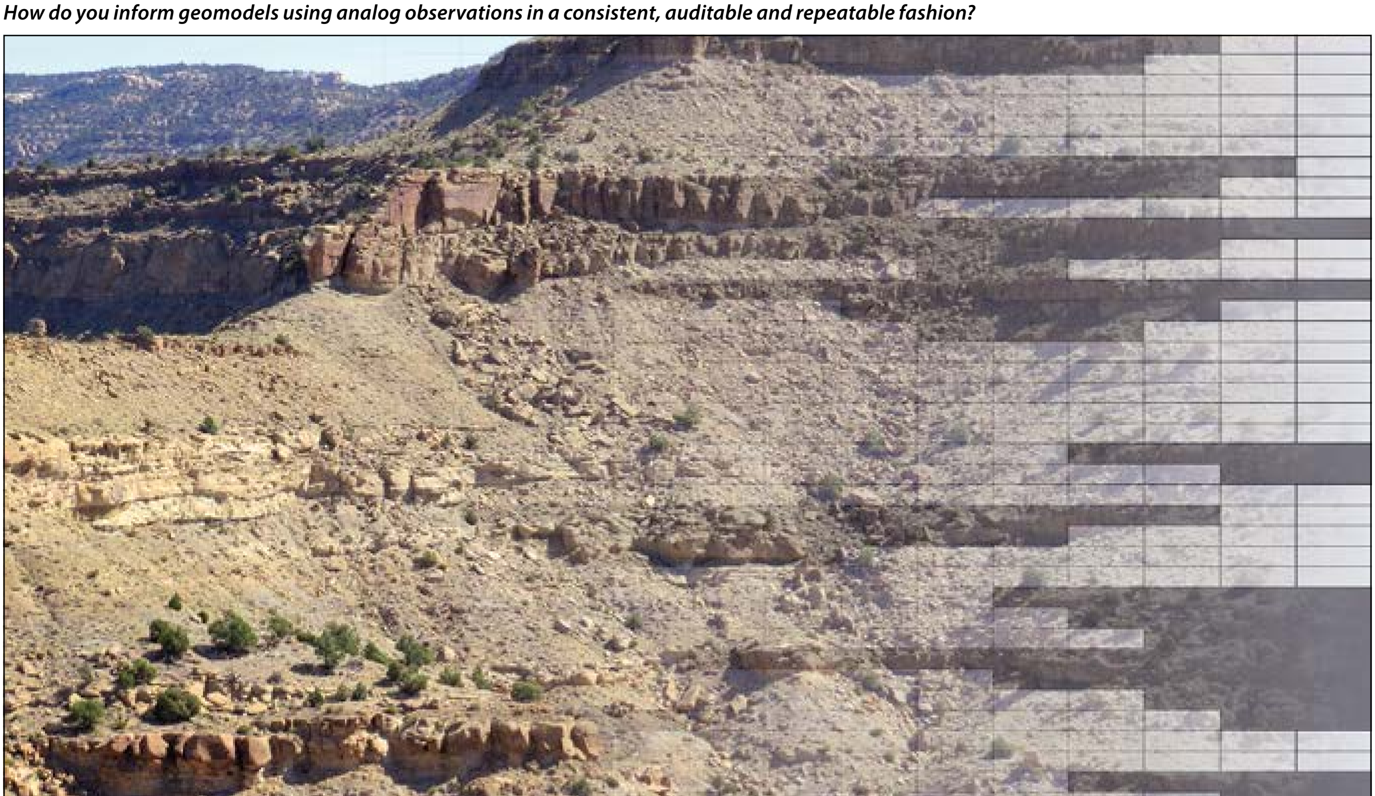
- In-depth commercial understanding of the petrotechnical software market, particularly in view of disruptive changes caused by cloud-hosting and next-generation data sciences platforms;
- Petrotechnical software R&D by teams with the experience and insight required to turn raw academic research into robust, affordable products;
- Commercial leadership able to execute effective marketing strategies and complex enterprise sales;
- Organizational maturity and financial resources sufficient to engage and support the global market.

So, how to take the first steps? Read the experience of a couple of geologists taking theirs!

Applying Clastic Analogs

Around the low point of the recent industry downturn, driven by a strong desire to improve the technologies used by geoscientists, especially in the reservoir modeling space, Viki O'Connor and Ben Meyer quit their day jobs and set about engaging with various groups looking to commercialize their R&D. To most of their colleagues (and a fairly large subset of their friends and families), their venture seemed foolhardy. But tapping into their network proved fruitful and they were surprised by the number of opportunities that presented themselves. One such opportunity was the chance to work with world-class researchers at the University of Leeds, who wanted to explore the commercial applications of the sedimentological databases they had developed, including the Fluvial Architecture Knowledge Transfer System (FAKTS), Shallow Marine Knowledge Store (SMAKS) and Deep Marine Knowledge Store (DMAKS).

How do you inform geomodels using analog observations in a consistent, auditable and repeatable fashion?



The laterally accreting macroform – a sedimentological feature on the architectural element scale. (a) Modern example – Rio Negro, Argentina; (b) Ancient example – Karoo Basin, South Africa. The geometries and statistics of the neighboring elements are stored within the University of Leeds databases.

During their previous careers, Ben and Viki's work had largely focused on identifying the weaknesses and limitations of existing geomodeling software and developing solutions, integrating them into existing mainstream platforms like Petrel™ (*Mark of Schlumberger). The opportunity to collaborate with the researchers was appealing because applied sedimentological research continues to have far-reaching implications for industries undertaking subsurface geological modeling; in particular, the improved definition of the uncertainty space through more realistic representation of sedimentary bodies can support more robust exploration and development decisions. They saw the potential of these databases for tackling some of the known pain-points of existing geomodeling tools, primarily the structured application of databases of clastic sedimentary analogs to directly inform both existing and potentially new facies modeling algorithms and approaches.

The initial product vision would allow them to target these well-known bottlenecks; however, the pair needed a commercial partner to bring the product concept to life.

Finding a Partner

"When we sat down together and sketched out our initial ideas for the Leeds researchers, we could see the potential of the opportunity, but needed help to tackle the four key challenges of commercialization," explains Ben, now Managing Director of PDS UK.

It was through their network that Ben and Viki were quickly able to find a suitable partner. PDS Group has a long-standing reputation for delivering software solutions for the oil and gas industry and their leadership team, headed up by Group Managing Director, Steve Daum, were supportive of their venture. The pair joined PDS in 2016 to work directly with their engineering, marketing and sales teams to turn the concept into a commercial product.

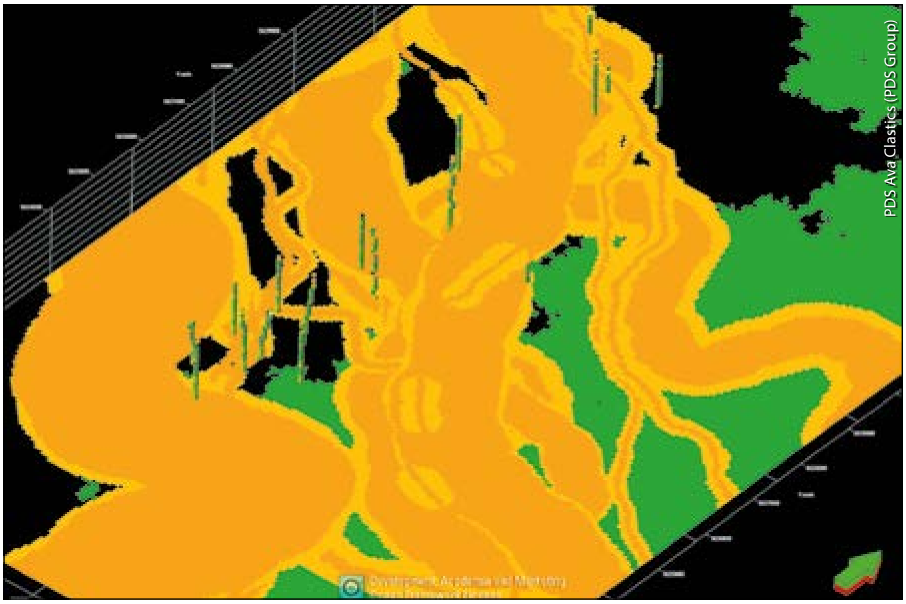
"Collaboration between academia and industry partners is vital for the acceleration of technology application in upstream E&P workflows, and we are very excited to represent Leeds' world-class clastic databases," explains Steve. "Augmenting and enhancing them with intuitive workflows will help E&P operators improve their ability to predict what lies between their wells, reducing uncertainty through geologically-grounded facies modeling."

Following an initial agreement with the University of Leeds researchers for the FAKTS database in 2016, PDS Group launched the product in April 2017 as Ava Clastics: a technology that facilitates the effective application of analog databases to reservoir models. "Users of Ava Clastics will have seamless access to a rich set of analogs, delivered via user-friendly, commercial software. This will enable them to interrogate the data intelligently, asking contingent 'what if' questions to improve geomodeling accuracy," says Professor Bill McCaffrey, Director of the Turbidites Research Group at the University of Leeds.

The University scientists then signed an extended agreement with PDS Group to commercialize the other two databases, which enabled the inclusion of SMAKS into Ava Clastics in late 2017, which will be followed later in 2018 by the addition of DMAKS, thus completing the original vision for the product.

"It is an exceptional achievement on the part of the academics that they've been able to align the interests

The team at the launch of Ava Clastics in Houston 2017.



Generating realistic sedimentary architectures within reservoir models. A result from Ava Clastics, shown in Petrel™ (Registered trademark of Schlumberger).

of different research groups to deliver these databases," says Viki, who is now Director – Geoscience International for PDS. "It also shows that a commercial company like PDS can work successfully with universities to incorporate their academically developed products into a compelling commercial business."

Successful Collaboration

"The joint-venture between researchers from the University of Leeds and PDS Group shows how a carefully balanced collaboration can result in the successful commercialization of world-class research," says Bill.

In the long term, the PDS team see many opportunities emerging from their ongoing partnership with the University of Leeds. Ben believes that "the next step should be to try and move beyond making representations of facies assemblages and make data-supported representations of depositional systems at different scales to inform many workflows, including intelligent upscaling and process-modeling. With their source-to-sink approach, the researchers will continue to produce an understanding of these systems in the rock record, which we can then tie into E&P workflows." From the university's perspective, Rachael Spraggs, Executive Director, Petroleum Leeds, says "we're excited about Ava in its own right, because its success will confirm Leeds as a place where world class research, innovation and impact coincide."

Bridging the Gap

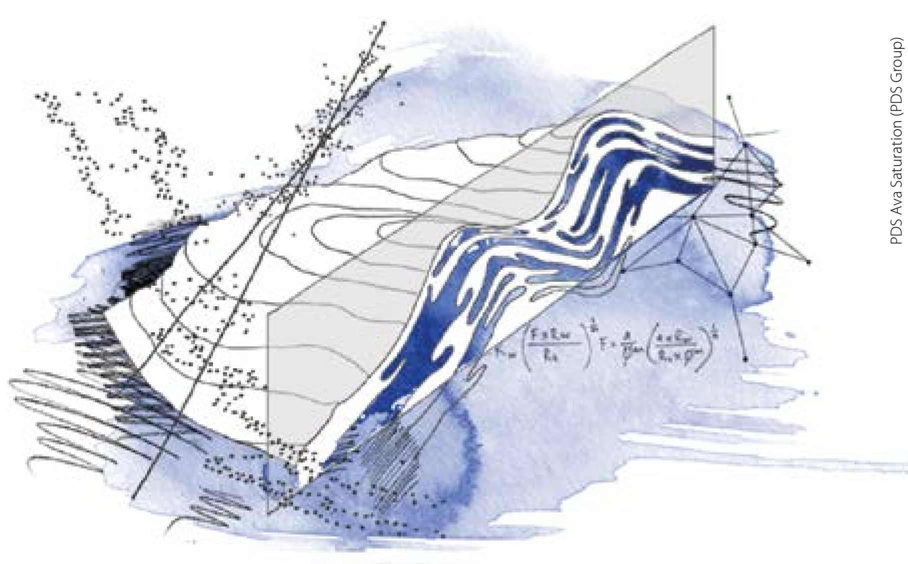
Following the launch of Ava Clastics in early 2017, PDS were approached by a number of groups and individuals interested in their ability to deliver high quality solutions to market quickly. One of these individuals, Matt Bowyer, had developed an idea for a product based around an underserved but critical reservoir modeling workflow, namely water saturation modeling. The derivation and application of saturation height functions is often left to the production geologist, with no clear audit trail linking the hard work done by the petrophysicist to the final results utilized by the reservoir engineer. Matt identified a gap in the market for a technology that would address this problem from the perspective of the geologist.

As a result, in May 2018 PDS will be launching Ava Saturation, realizing Matt's ambition to provide geologists with direct support for this critical part of the E&P workflow. Building on the experiences of the Ava Clastics team taking their product to market, Matt and his team are looking forward to the market response to their new technology.

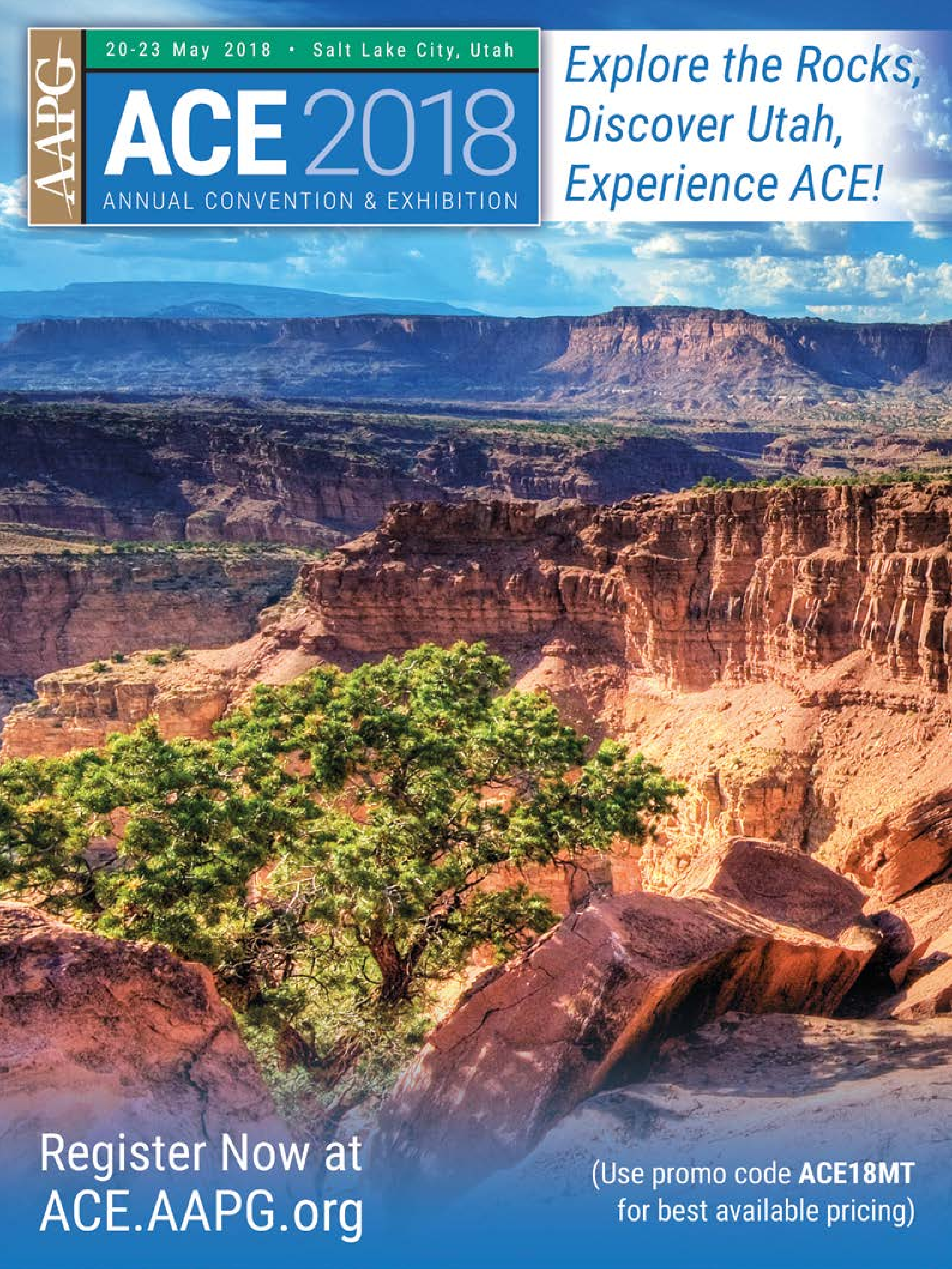
"As a geologist who has worked for many years for operators of all sizes, I became frustrated by the *ad hoc* and repetitive nature of saturation modeling workflows. I often asked myself if there was a better way than working with laborious spreadsheets or trying to use other software applications designed for users from other disciplines," Matt explains. "PDS has enabled me to develop my initial ideas and work with people with different skillsets to create an elegant solution which will appeal to geologists like me. I'm excited by the impending product launch!"

"We hope to continue broadening our footprint in the geomodeling space," adds Viki. "We really think that now is the perfect time to embrace emerging technologies, both within the domain and externally, blending these with expert geological insight to impact the bottom line. There are so many groups out there with great ideas and we look forward to collaborating with them in the years to come." ■

Structured incorporation of available log data can support efficient saturation modeling workflows.



PDS Ava Saturation (PDS Group)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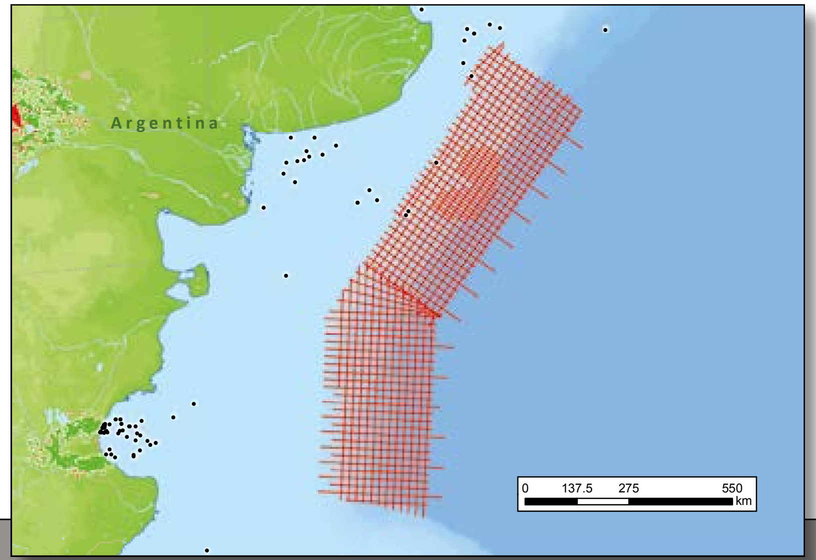
New Light on Northern Argentina

New seismic data offshore Argentina reveals extraordinary structures in an underexplored region.

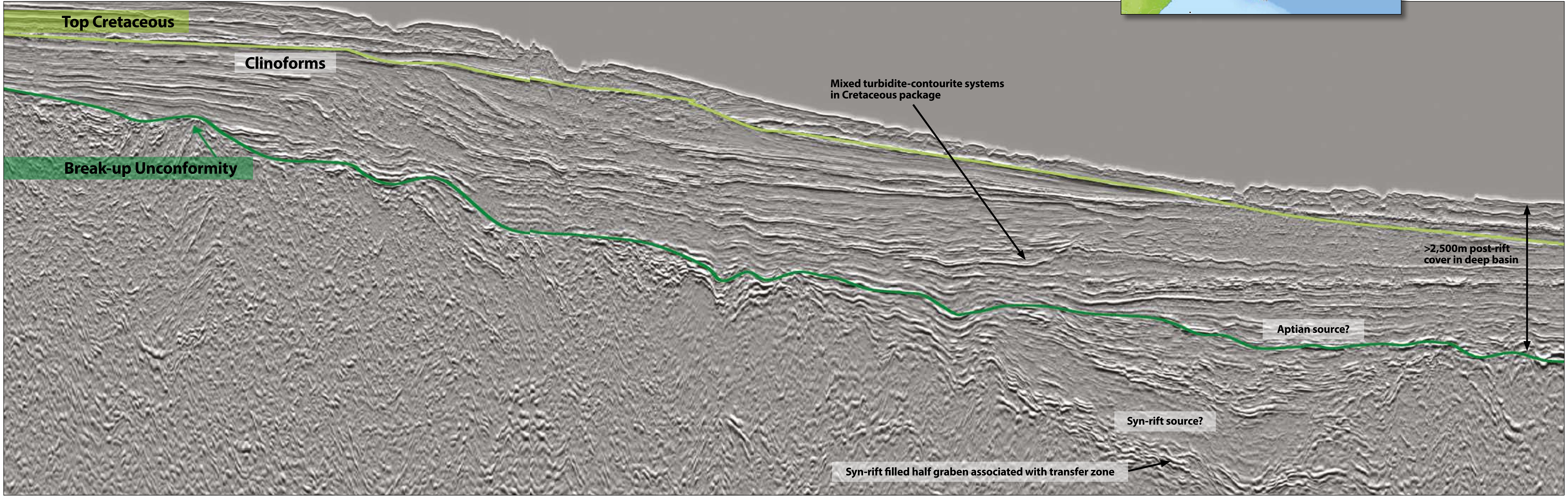
Offshore northern Argentina has attracted very little industry interest over the years. A lack of success in exploration campaigns in the late 1960s and mid-1990s can now be largely attributed to a lack of understanding of rift basin/rifted volcanic margin architecture and to inadequate acquisition and imaging technology. Recent billion barrel discoveries in analogous basins on the Atlantic margin, utilizing state-of-the-art seismic and drilling technology with current geological concepts on source rock and reservoir development, suggest this underexplored part of the world could be one of the last frontiers for both shallow and deepwater exploration.

A subset of 22 lines from a new long-offset 2D exploration survey acquired from 2017 to 2018 was used in this analysis, along with shipborne and regional satellite-derived gravity and magnetic data. The available seismic data was a mixture of conventional and broadband PSTM and PSDM processing offering greatly enhanced imaging, which is essential for future exploration on this margin. Acquisition of the full dataset was completed in April 2018, with final processing scheduled for delivery in late Q2 2018.



Map showing Argentina deepwater survey outline.

Spectrum



A Hibernating Giant?

The new long-offset data reveals insights into crustal architecture.

HANNAH KEARNS, KARYNA RODRIGUEZ and STEVE DEVITO, Spectrum

Northern Argentina has a continental volcanic rifted margin, segmented by major transfer zones which reflect the pre-existing Gondwanan structural fabric. The individual rift basins along this margin initially formed from intracratonic rifting within the paleo-continent of Gondwana during the middle Mesozoic, and evolved into a true passive margin following the separation of the South American plate from the African plate in the early Cretaceous. The evolution of the Argentine margin was far more complex than had been previously understood.

Only 26 exploration wells have been drilled on the northern margin (north of 47°S), with none in water depths greater than 100m and all located at least 15 km inboard from the continental shelf edge. The last offshore well in this area (Pejerrey x-1) was drilled by Shell in 1997. During the mid-1990s, a handful of wells were drilled, mostly by major oil companies, without any commercial success.

Recent academic work has focused on understanding the opening of the South Atlantic Ocean, rifted margins, and ocean basins. This work, combined with industry exploration in other deepwater, rifted passive margins around the world, has led to a much better perception of the Argentine margin for future exploration.

Seismic Observations

Crustal Architecture: Long-offset seismic data acquired with a 12 km cable has enhanced the Moho signature significantly. Interpretation of the Moho has allowed us to develop conclusions about the nature of the crust and the position of the continent ocean transition zone (COT). Seaward Dipping Reflector (SDR) zones are easy to distinguish on the high quality seismic dataset and the varying acoustic signature and thickness of different SDR packages allow us to make inferences about the volume of magmatism at the time of rifting. Transfer zones observed on strike lines cut by numerous strike-slip faults appear to correlate with thinning and offsetting of these volcanic SDR packages. The imaging at depth outboard in the deep basin is of high quality, allowing clear identification of SDRs quenched by first flooding and the onset of oceanic crust.

Pre-Rift Structuration – Shallow Water Potential: Pre-rift structuration is associated with orogenic events from the Neoproterozoic, Cambro-Ordovician and the Permian. Onshore, in the Sierras Australes, pre-rift rocks exhibit box fold structures which evidence these compressional events, and we can trace similar events in the seismic data extending into the offshore region. Many structures have been eroded at the break-up unconformity level but the forelimbs and backlimbs of the folds are still present. This truncated stratigraphic relationship as well as the uneroded anticlines may act as hydrocarbon traps sourced by Permian, Carboniferous, and Early Cretaceous syn-rift source rocks.

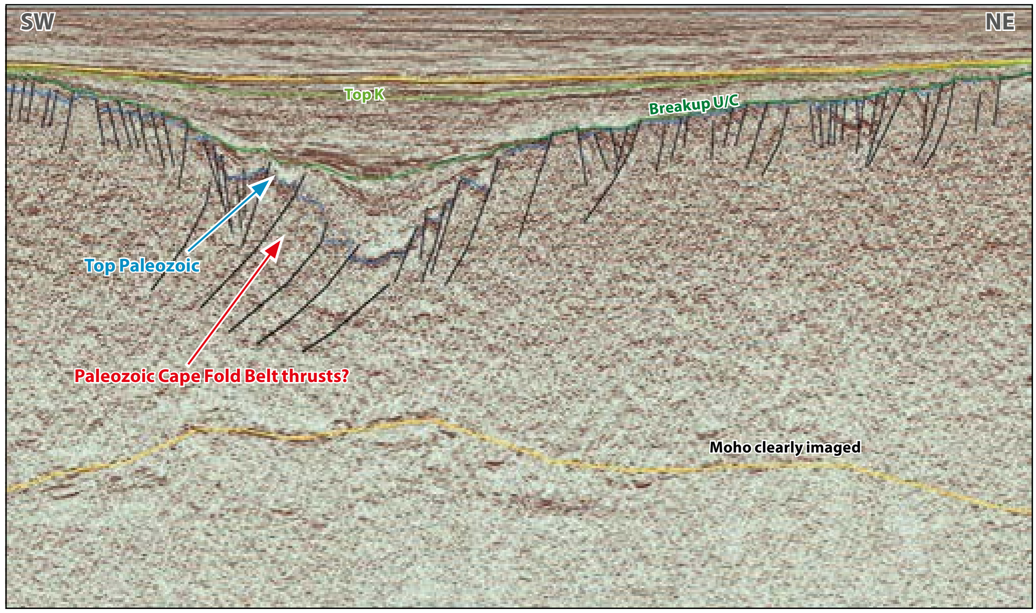
The Colorado and Salado Basins that formed following north-west to south-east extension prior to the east/west extension that resulted in the opening of the South Atlantic can be clearly seen superimposed on the predominantly compressional pre-rift architecture (see figure top of page 54). Multiple syn-rift packages within grabens are well imaged on these lines and have been recorded in wells.

License Round Information

In December 2017, the Argentine Ministerio de Energía y Minería previewed the first new offshore Argentina license round in more than 20 years. In 2018 two large areas will be opened to tender: the northern deepwater Argentina Basin and the offshore Austral and Malvinas Basins. This will be followed in 2019 by a license round covering the southern deepwater Argentina Basin.
For the northern deepwater Argentina Basin and the Austral and Malvinas Basins, the official opening is planned for July 2018, with bids due in late November 2018. Final regulations on qualification, block size, work programs and fiscal terms will be published with the official declaration.

MINEM license round preview, December 2017

Post-Rift Deposition – Deepwater Potential: Further offshore there is seismic evidence that tilted fault blocks are present inboard from the inner SDR packages, and a Kudu-type play may exist within continental sands interbedded with flood basalts, sourced by syn- or pre-rift organic-rich sediments. Just above the break-up unconformity we can identify a thin, acoustically opaque but laterally extensive package which bears a striking resemblance to the prolific Aptian-age source rock on the conjugate Namibian and South African margins (see main foldout line). Approximately 2,500m of post-rift cover is present in the deep basin, providing sufficient burial for source rocks to mature.



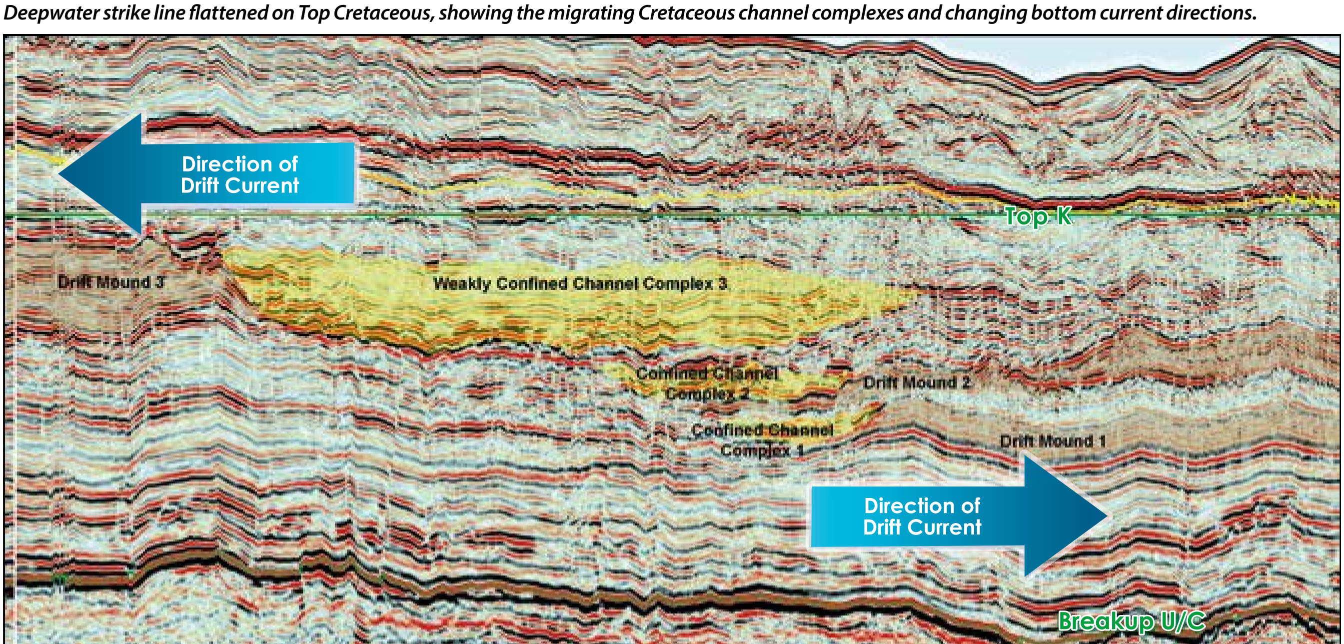
Strike line showing the Colorado Basin.

This presents a case for a high quality source rock with sufficient burial depth to generate hydrocarbons overlain by numerous stacked, mixed turbidite-contourite drift mounds and confined channel complexes throughout the Cretaceous and Cenozoic. These clearly demonstrate the alternating dominant bottom current directions at the time of deposition (see below). Drift mounds comprise predominantly muddy, fine-grained silty sediments, whereas the intervening confined channel complexes are likely to consist of coarse-grained well-sorted sands with high net:gross – ideal reservoirs for hydrocarbon accumulations. Acoustically opaque packages are also identifiable during periods where ocean currents were apparently much weaker in the Paleogene and Cenomanian-Turonian, when the depositional environment in the deepwater setting would have been ideal for source rock deposition.

Extraordinary Structures Revealed

Newly acquired long-offset seismic data offshore Argentina reveals extraordinary structures in a margin that has remained underexplored. The potential for deepwater source rocks is ever-present, and the data provides exciting insights into the pre-Cretaceous continuation of the Cape Fold belt from South Africa, with excellent images of rift grabens and large contourite deposits. The upcoming licensing round in May 2018 has the potential to make Argentina the new South American giant in oil and gas exploration. ■

Deepwater strike line flattened on Top Cretaceous, showing the migrating Cretaceous channel complexes and changing bottom current directions.



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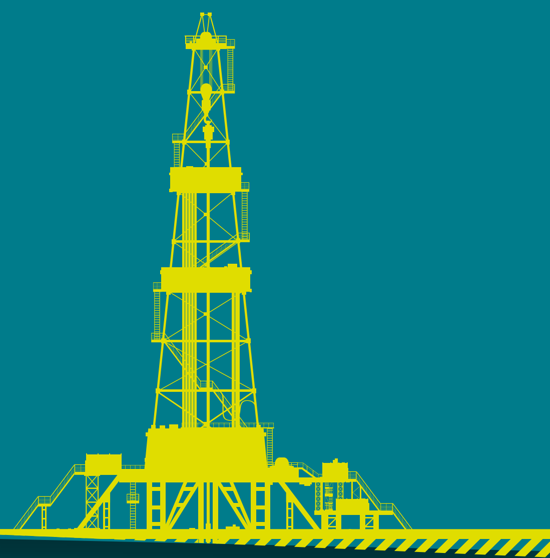

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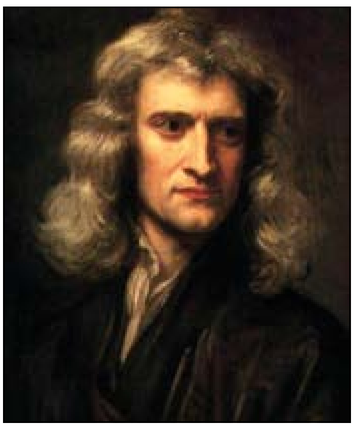
Finite Difference Modeling: Part I
Become Expert in Five Minutes

LASSE AMUNDSEN,
ØRJAN PEDERSEN, and
MARTIN LANDRØ

I recoil with dismay and horror at this lamentable plague of functions which do not have derivatives.

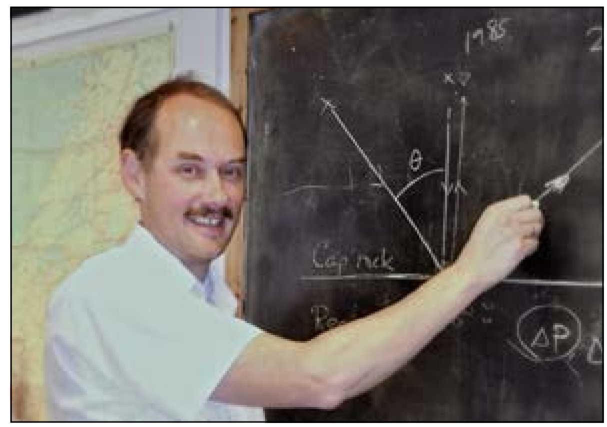
Letter to Dutch mathematician Thomas Joannes Stieltjes (1856–1894) from French mathematician Charles Hermite (1822–1901).

Newton, 1666:
"I've invented calculus!"



Leibniz, 1674:
"I've invented calculus!"

Landrø, 2014:
"Really? Sounds a little bit… derivative."



The history of calculus does not begin with the findings of the English mathematician and physicist Sir Isaac Newton (1642–1726) and the German philosopher and mathematician Gottfried Wilhelm Leibniz (1646–1716). Their calculus was the culmination of centuries of work by many mathematicians. Newton and Leibniz argued over who had first invented calculus: Newton made his discoveries in 1664–1666, but his findings were not published until 1693. Leibniz worked between 1672 and 1676, but published the results in 1684–1686, before Newton. In 1711, the controversy was taken to court. The Royal Society appointed a commission to investigate the charges, which found Leibniz guilty of plagiarism; perhaps not that surprising since Newton was the president of the Royal Society. Years after Leibniz's death, the mathematical community came to realize that Newton and Leibniz had made their discoveries independently.

In computational mathematics, finite-difference (FD) methods are numerical methods for solving differential equations by approximating them with difference equations, in which finite differences approximate the derivatives. Many outstanding texts have stimulated the development of the calculus of finite differences. One of the first, presented in a form suited to the needs of students and teachers, is that by the English mathematician George Boole (1815–1864), who published the *Treatise on Differential Equations* in 1859, followed in 1860 by the *Treatise on the Calculus of Finite Differences.*

In 1928, the German-born American mathematician Richard Courant (1888–1972) published the theoretical fundament for the solution of problems of mathematical physics by means of finite differences. Among other things, Courant and coworkers defined the FD approximation for the wave equation, and the famous Courant–Friedrichs–Lewy (CFL) condition – a necessary condition for convergence while solving partial differential equations numerically by the method of finite differences.

Considerable progress in FD methods was made during and after WWII, when practical applications became possible with the use of computers. John von Neumann (1903–1957), the Hungarian-American mathematician, physicist, and computer scientist, developed the von Neumann stability analysis, known as Fourier stability analysis, used to check the stability of finite difference schemes as applied to linear partial differential equations. In 1949 he worked with meteorologists Jule Charney (1917–1981) and Ragnar Fjørtoft (1913–1998) on numerical weather prediction, and von Neumann's Fourier method was given a rigorous treatment in their joint publication in the periodical Tellus (Charney et al., 1950).

For hyperbolic equations the FD method has played and is still playing a dominant role, starting with the work of, e.g., Friedrichs, Lax, and Wendroff in the 1950s and 1960s (Lax, 1954; Lax, 1961; Lax and Wendroff, 1964). Standard references on FD methods are the books of Forsythe and Wasow (1960) and Richtmyer and Morton (1967).

Today, FD methods are the dominant approach to numerical solutions of partial differential equations (Grossmann et al., 2007). For wave equations solved in seismics, the FD method is accurate and robust (Fornberg, 1988; Etgen et al., 2009; Robertsson and Blanch, 2011; Ikelle and Amundsen, 2018). We note that the FD method was introduced in 1966 by Yee to discretize the differential form of Maxwell's equations. Alterman and Karal (1968), Boore (1970, 1972), and Kelly et al. (1976) then applied the FD method applied to seismology and seismics. They used a displacement formulation with conventional grids, which yielded instability problems in models with high-velocity contrasts. Virieux (1984, 1986) introduced the stable staggered-grid velocity-stress FD schemes, following Madariaga (1976) who introduced the staggered-grid formulation for dynamic modeling of earthquake ruptures.

High School Math

Calculus (from Latin *calculus*, literally 'small pebble'; the small stone the ancient Romans used in counting and gambling) is the mathematical study of continuous change. One way to think of calculus is as the study of functions of time or of space. There are two different types of calculus, differential calculus and integral calculus. Differential calculus divides functions into different pieces and tells us how they change from one moment to the next. Integral calculus joins or integrates the small pieces together and tells us how much of something is made by a series of changes.

In high school, you learn that differential calculus is concerned with finding the instantaneous rate of change (i.e., derivative) of a function's value, with respect to changes within the function's arguments. The derivative of a function with respect to a variable is denoted, after Leibniz, by:

$$\frac{df}{dt},$$

where f represents the pressure field in acoustics and t the time. When a derivative is taken twice, the notation is:

$$\frac{d}{dt}\frac{df}{dt}=\frac{d^2f}{dt^2}.$$

When the function $f(t,x)$ depends on more than one variable, a partial derivative:

$$\frac{\partial f}{\partial t},\frac{\partial f}{\partial x}$$

is used to specify the derivative with respect to one (or more) of the variables.

In high school, you also learn that the derivative of the function f with respect to the variable t is defined as:

$$\frac{\partial f}{\partial t}=\lim_{\Delta t\to 0}\frac{f(t+\Delta t)-f(t)}{\Delta t}. \qquad (1)$$

If the first derivative exists, the second derivative may be defined as

$$\frac{\partial^2 f}{\partial t^2}=\lim_{\Delta t\to 0}\frac{f(t+\Delta t)-2f(t)+f(t-\Delta t)}{(\Delta t)^2}$$

For example, with the equation $f=t^3$ we know that if t=1, then f will be 1; if t=2, then f=8; if t=10, then f=1,000. The derivative of f most of us know is $3t^2$. By use of equation 1, one finds:

$$\frac{(t+\Delta t)^3-t^3}{\Delta t}=3t^2+3t\Delta t+(\Delta t)^2. \qquad (2)$$

In the limit we obtain the derivative:

$$\lim_{\Delta t\to 0}\frac{(t+\Delta t)^3-t^3}{\Delta t}=3t^2.$$

We can now reveal the inner secrets of finite-difference experts. The approach they take to solve differential equations is simply to approximate differential operators such as $\frac{\partial f}{\partial t}$ by a difference operator such as:

$$\frac{\partial f}{\partial t}\approx\frac{Df}{Dt}=\frac{f(t+\Delta t)-f(t)}{\Delta t}$$

for some small but finite Δt. Likewise, they approximate $\frac{\partial^2 f}{\partial t^2}$ by:

$$\frac{\partial^2 f}{\partial t^2}\approx\frac{D^2 f}{Dt^2}=\frac{f(t+\Delta t)-2f(t)+f(t+\Delta t)}{(\Delta t)^2}.$$

However, due to the discretization of the functions, the difference approximation makes an error. The error for the first derivative of $f=t^3$, as seen in equation 2, is $3t\Delta t+(\Delta t)^2$. We will return to these errors in Part II of the series.

The Wave Equation

The laws of physics are generally written down as differential equations, or relations involving rates at which things happen; that is, derivatives. A differential equation expresses a relationship between a function and its derivatives. If we know the function and its derivatives at a particular point or time, then this information, together with the differential equation, can be used to determine the function over its entire domain.

One example is the wave equation. It is a second-order linear partial differential equation which describes how waves, such as sound, light and water waves, travel. The French mathematician Jean le Rond d'Alembert (1717–1783) was the first to find and solve the 1D wave equation – now known as d'Alembert's solution in his honor. Ten years later, Leonhard Euler (1707–1783) solved the three-dimensional wave equation.

Here, we study the 1D equation for the acoustic pressure field :

$$\frac{\partial^2 u(t,x)}{\partial t^2}=c^2(x)\frac{\partial^2 u(t,x)}{\partial x^2}+s(t,x),$$

where c is the propagation speed of the pressure wave, and s is the source. In seismics, the source is an airgun that injects high-pressure air into the surrounding water.

The wave equation alone does not specify a physical solution; to obtain a unique solution we need to set initial and boundary conditions. Demonstrations may start with an initial profile of the pressure wave $u(t=0,x)=I(x)$, being at rest $\frac{\partial u(t=0,x)}{\partial t}=0$.

For seismic problems, we use $I(x)=0$ where there is no pressure wave before the source is activated. Boundary conditions fix the pressure at the start $x=-L$ and end $x=+L$ of the computational domain. The condition $u(t,\pm L)=0$, often

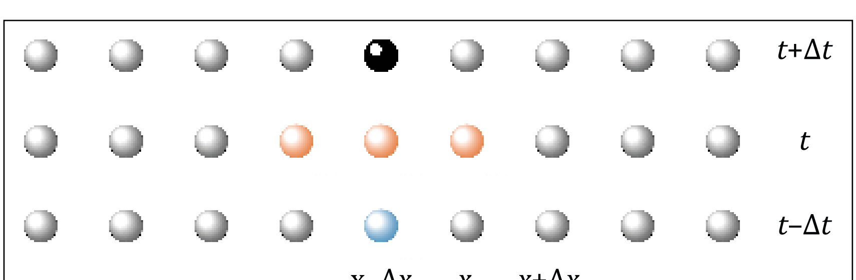


Figure 1: To compute the wave field u at time-space location $(t+\Delta t,x)$ (black dot) we use the wavefield at two previous times t and $t-\Delta t$ at three space locations $x-\Delta x$, x, $x+\Delta x$ (red and blue dots).

known as a homogeneous Dirichlet condition, will mirror the wave. It reflects the wave into the domain with opposite sign of amplitude. The condition $\frac{\partial u(t,\pm L)}{\partial x} = 0$ is known as a homogeneous Neumann condition. As the wave hits the boundary, it runs up to the double amplitude, and propagates back into the domain again.

Solving the wave equation means finding p in terms of t and x. It turns out that solving the wave equation, as most other differential equations, can be quite hard, and there is no general method that solves every differential equation. We will generally focus on finding a numerical solution to the wave equation by using computers.

Ready to Go

To solve the wave equation by computer, we discretize the time and space variables (see Figure 1), replace both second derivatives in the wave equation with finite differences, and obtain:

$$u(t+\Delta t,x) = u(t,x) - 2u(t-\Delta t,x) + \left(\frac{c(x)\Delta t}{\Delta x}\right)^2$$

$$* \ [u(t,x+\Delta x) - 2u(t,x) + u(t,x-\Delta x)] + s(t,x)\,.$$

This solution is a time marching scheme, where the next value of the wavefield at the discrete time $t+\Delta t$ is computed from current values known at time t and the previous time $t-\Delta t$. For every next time step, the source is activated with its current value.

The choice of time step Δt is dependent on the grid size Δx. It turns out that as we increase the time step while keeping the grid size fixed, the FD method eventually becomes unstable. Likewise, if we decrease the grid size while keeping the time step fixed, we run into stability problems. To know how to change the time step with changes in grid size in order to maintain stability, we revert to the famous CFL condition for stability, which for our wave equation has the form $\frac{c_{max}\Delta t}{\Delta x} \leq 1$ where c_{max} is the maximum velocity in the model.

There is little need to know much more at this point. You can now leap on the train to a job as a geophysicist in the oil industry with whistles and fanfare as you chug out of the station.

Solution for Constant Velocity

When the velocity is constant, and the source is a point monopole source, located say at $x=0$, the wave equation has the analytical solution of an outgoing wave from the source:

$$u(t,x) = S(|x| - ct)\,,$$

where S is the time integral of the source signature s in the wave equation. The pressure wave is not altered as distance x increases. (In 3D, however, the pressure wave decreases in amplitude with distance.)

Let's check if the FD solution to the wave equation reproduces the analytical solution. The source is located at $x=0$. It is given a time signature that is a time derivative of a Ricker signature, sometimes called the Mexican hat wavelet:

$$s(t-t_0) = \frac{\partial}{\partial t}\left(1 - 2\pi^2 f_M^2 t^2\right)\exp\left(-\pi^2 f_M^2 t^2\right),$$

where f_M is the peak frequency of the signal, and t_0 is time where the zero-phase Mexican hat has its maximum amplitude. Parameters are c_0=3,000 m/s, Δt=0.00058 s, Δx=2.5m, and f_M=10 Hz. The output is displayed in Figure 2 as time traces at four different recording locations from the source. Indeed, the waveform is the Mexican hat wavelet traveling outwards from the source without change.

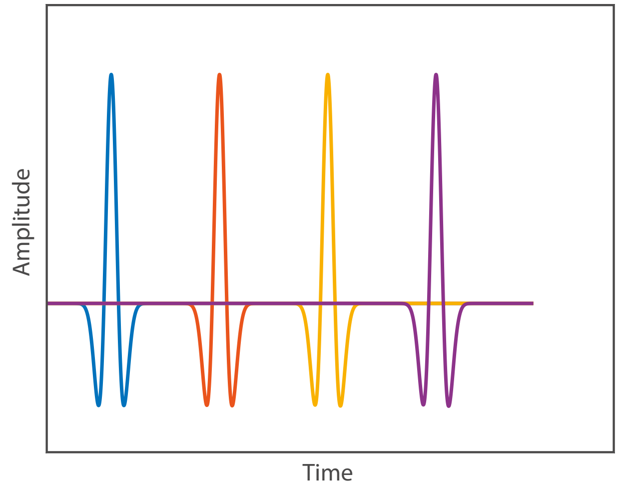


Figure 2: In a homogeneous 1D medium, the FD solution of the wave equation produces a wave that moves outwards from the source without change. The four Mexican hat signals are recorded at four different locations. This result agrees with d'Alembert's solution, discovered in 1746.

Solution for Non-Constant Velocity

We let the velocity take the form of the long-wavelength sine-model

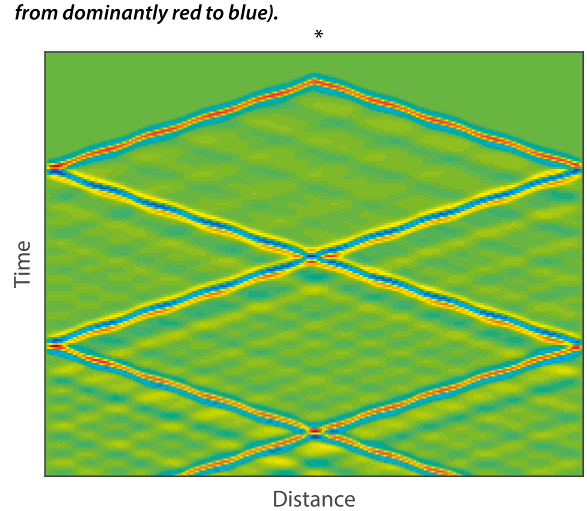
$$c(x) = c_0 + \Delta c \ \sin(2\pi x/\lambda)\,,$$

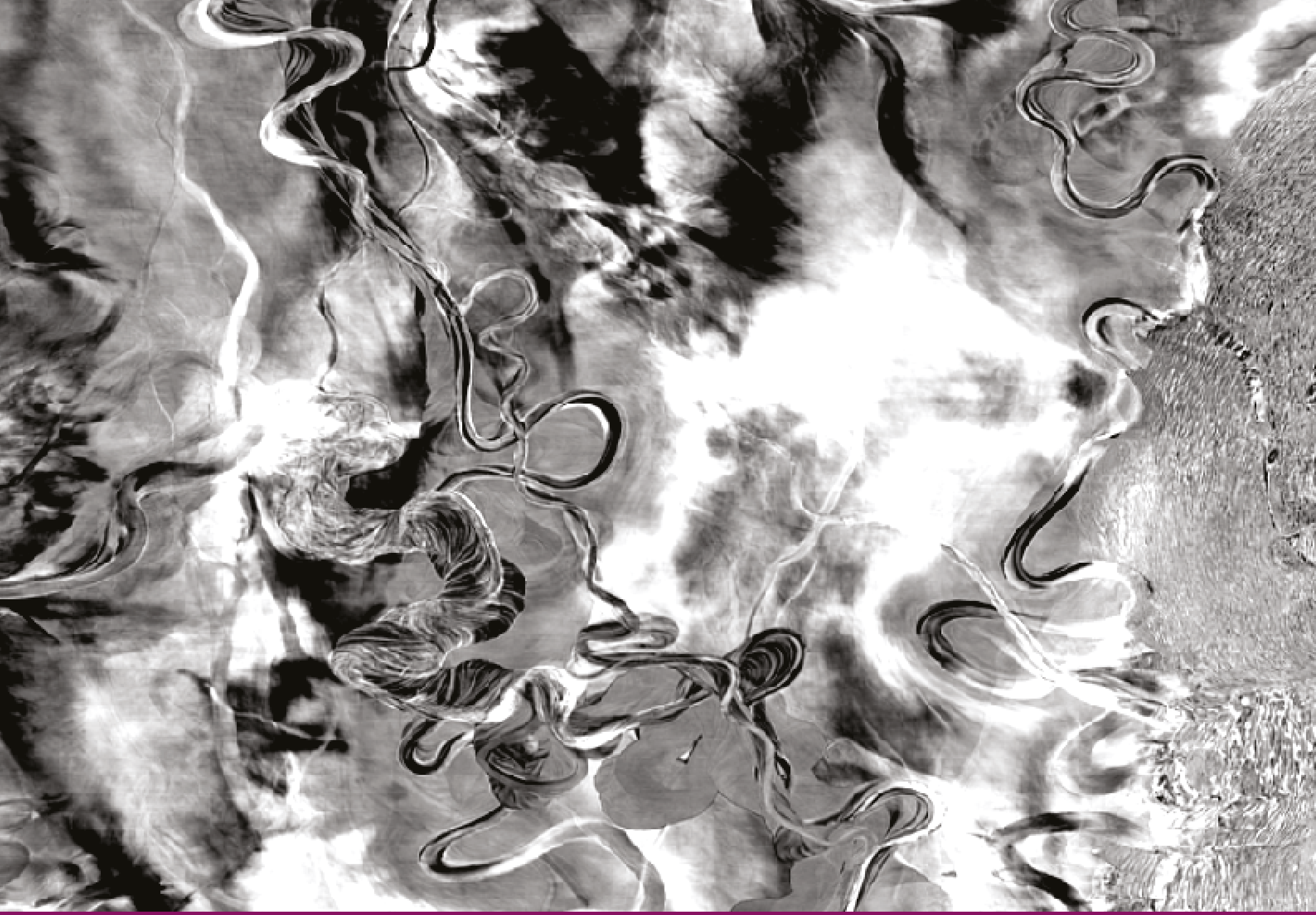
and run the FD scheme with velocities c_0=2,000 m/s, Δc=500 m/s and λ=250m. We set the pressure to zero at the end of the computational domain and display the pressure wavefield in Figure 3 as a 2D color plot over distance and time. Observe that the wave changes sign after hitting the pressure-free ends of the domain.

In Part 2 of this series, we will discuss the numerical errors that one can make in FD modeling and bring you the latest research on how to eliminate errors caused by the time-stepping of the wavefield.

References available online. ■

Figure 3: FD solution of the 1D wave equation in the long-wavelength sine model. The source is located at the center distance of the model (*), and the wavefield is recorded at all distances and times. At the endpoints of the model, the wavefield is fixed to zero, so that the wave is mirrored into the model domain with opposite sign in the amplitude (colors change from dominantly red to blue).





Making Connections

JANE WHALEY

Denise Cox, President of Storm Energy and President-Elect of the AAPG, loves geology and wants to let a global audience understand more about the role of geoscience in energy solutions.

Although she did not work it out for a while, Denise Mruk Cox was destined to be a geologist and world traveler. Geology was written in the stars for her: she was told by an astrologist while still at school, "You enjoy working with the Earth."

From mucking around in the mud in her backyard as a toddler in southern central New York, she rapidly progressed to hiking the tree-covered glacial hills around her home and to exploring the Devonian outcrops of the Finger Lakes region. When she wasn't outside she had her nose in a book, her other favorite pastime, exploring other continents and other times.

Intersection of Science and Art

Coming from what she describes as "very modest roots", Denise was of the first generation in her family to go to university. It was not until her second year at the State University of New York at Binghamton that she took a class in geology – and even then, it was only because in her first year she balanced the science and math subjects at which she excelled with an elective course in Arabic; it was her Arabic professor who recommended she tried geology. Almost immediately, she knew geology was what she wanted to do.

"I love that geology is the marriage of science and art," Denise explains. "You need creativity to see something on the Earth's surface and know how it looks in the subsurface, and science and math to support that vision. Geology is at that intersection – I believe in STEAM (Science, Technology, Engineering, Arts and Mathematics), not just STEM. Geological features and processes can be described equally by drawing a picture, or by using scientific and mathematical formulae. Interestingly, I find that many geologists have artistic skills, particularly music. The people in geology are also diverse and from such a range of backgrounds that they reflect the diversity of the subject itself."

Despite her late start in geology, Denise graduated with an Honors BS in the subject and was awarded the Glenn G. Bartle Award for excellence in geology. Her career began as a technician with the US Geological Survey in Denver, Colorado on a 9-well Uranium and Thorium coring project. She soon realized that to have a career as a geologist, she would need a further degree. She attended the University of Colorado, Boulder, a perfect choice of location given her interest in the outdoors, and took a masters in geology, which included courses in petroleum geology and a thesis on the diagenesis of the Permian Capitan Formation in West Texas. Whilst completing her research she was also working part time as a reservoir geologist at Marathon Oil's Denver Research Center (DRC), where she further developed her interest in carbonates. After graduation in 1985 this led to a full time offer of work at the DRC and ultimately a 20-year career with Marathon, in Denver and Midland and Houston, Texas where she specialized in the application of new technology to carbonate petroleum reservoirs and later the evaluation and development of unconventional reservoirs.

On location in West Texas and 'in the pink' with a new discovery, 2014.

Denise Cox

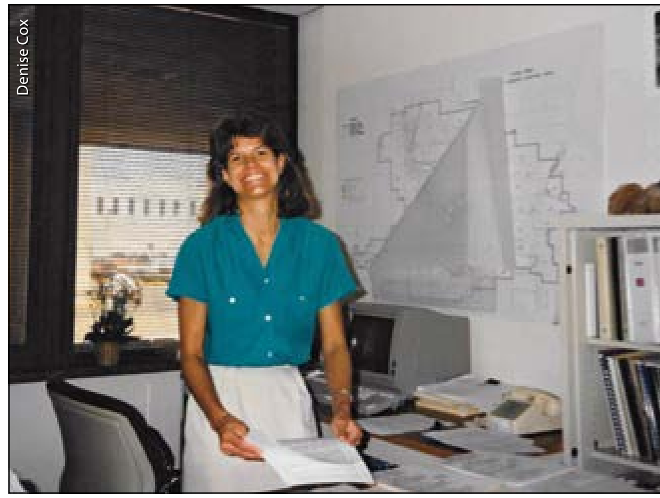
Connecting and Networking

The job with Marathon had initially come about through people Denise met during one of the industry-led seminars during her masters study. She is a great believer in networking and describes herself as a 'connector'. "I hear many ideas but when I make a connection on how it can be developed and implemented, I want to share it with the world."

Denise provided some insight on making connections at work. "When I started a new job I would do 'rounds', finding out what everyone's role was in the group and what were their processes – types of maps, cross-sections, analyses – for exploration or development. Because of this I knew what person A was doing and how it might help person B, if only C would provide the data." This proved very useful when the exploration industry began to introduce less rigid subject-led management structures, and probably resulted in Denise being chosen to lead one of Marathon's first multi-disciplinary teams.

"One of the best pieces of advice I can offer young and experienced people alike, is to network and make connections," she says. "When you're hired or transferred into a new group, talk to the people you work with and question them about what they are doing, and why. It helps you to understand their perspective and recognize how your knowledge and project contribute to the team's objectives. And when you find someone really passionate about their job, learn from them!"

What else would Denise suggest to young people starting out in the industry? "To those already working: don't be afraid to say, 'I don't understand'. Accept and learn from your mistakes – we all make them. I've drilled my share of dry holes; the important thing is to understand why, so the next well gets drilled and is a success.



Denise working in Marathon's office in Midland, Texas in 1988.

"Also, try to take all the experience and leadership opportunities offered to you. You may not feel you are ready for a transfer or management role, but if someone approaches you with one, it is because they've seen technical or leadership traits in you that mean you ARE ready.

"To undergraduate students I would suggest that they get the best fundamental geoscience education that they can at a college or university which has the best connections to the industry where they want to work. Good choices lead to good choices." Denise adds: "If possible, take courses in data analytics and geostatistics; these are really important to have on your resume in today's job market.

"For graduate studies, the best geoscientists are the ones who have seen the most rocks, so make sure you get out in the field and if possible do a field or core-based thesis."

Unplugged and hiking with Maggie in the Colorado mountains, 2002.

Career Choices

In 2004, Denise decided not to permanently relocate to Houston when Marathon consolidated their production offices there. She joined her husband, Kurt, also a geologist, as a technical consultant for Storm Energy, the company he built through an acquisition and successful prospects. They moved to Panama City and she now heads up the company, as Kurt has a new career as a writer.

"Storm Energy has what I think is a unique business model," she explains. "We started as a consultancy doing technical evaluations and then putting prospects together in the Gulf Coast and Permian Basin. This has evolved into working with expert partners – geophysicists, petrologists, engineers, and landmen – to undertake technical and economic evaluations of both conventional and unconventional US projects for acquisition or investment. We are able to secure partnerships for project operations and financing and have not yet used the traditional private equity route to secure funding. I think this partnership model should appeal to younger geologists with about 10 years' experience who have an idea they want to develop. Again, it's all about connecting with the right people to work together – and doing what we all love: exploration and maximizing recovery of reserves!" Denise likes to refer to herself as the 'spatula' of the oil business – she likes to get the last drop of oil out of existing oil fields.

"While I was happy in the corporate world, and had corporate management aspirations, there are a lot of advantages to my role as a small independent. I love the strategic side of the business, and the fact that we make our own policies – such as moving the office to Colorado for a couple of months every year, to unplug, go back-packing, and hunting for something other than oil." Among her many interests, Denise is also an avid wild mushroom collector.

Leadership Roles

Denise has always been active in professional societies such as the American Association of Petroleum Geologists (AAPG), Association for Women Geoscientists (AWG) and the West Texas Geological Society. She was President of AWG in 2014–15 and is at present President-Elect of AAPG, due to take up the presidency in July this year – only the third woman in the 100-year history of the society to have this role. I ask why she decided to stand for election to this prestigious post.

"Firstly, because I was asked, and as I said, my advice is not to turn down an opportunity to lead," she replies. "Also, I love what I do, so this role gives me a chance to communicate a global perspective of geoscience and the importance of the petroleum industry in energy solutions. The AAPG is US-based, but importantly has Regions in Africa, Asia-Pacific, Canada, Europe, Latin America and the Caribbean, and the Middle East; AAPG truly has a global reach. After all, geology crosses borders; it is a systems science, not a geographically-bound one. For example, there are Paleozoic geological systems throughout the world and we can benefit from the knowledge of petroleum systems say in the Permian of West Texas compared with the Southern Permian Basin in Europe.

"I also agreed to stand for AAPG President because I get to connect with current and future members," she continues. "It's great to realize how many people are working on energy solutions at any time, somewhere in the world! On a recent AAPG trip to the Middle East I was impressed by the talented and well-spoken men and women I met. They understand their crucial role as geoscientists in the petroleum industry and are passionate about providing new ideas to explore for and develop low cost, reliable energy. The women were particularly interested in career options, so they were pleased to see a woman in a prominent leadership position.

"I am also keen to use the role of AAPG President to work cooperatively with other professional organizations to talk about 'sustainability'. Geoscientists as well as petroleum companies have an important part to play in global energy solutions. With our subsurface knowledge and technical abilities, we can help address the economic, environmental, and social issues that face the petroleum industry and the next generation. To that end, I'm working with Max Brouwers from Shell on an AAPG Energy Transitions Forum – A New Era for Geoscience – to be held in Amsterdam later this year."

Making a Difference

"Like many people, I want to give something back," Denise says. "I was keen to participate in organizations like the AWG because I was the recipient of a Chrysalis Scholarship to help finish my masters, so I know how vital these funds are. As a past Chair of the AAPG Grants-in-Aid Committee, I also established a scholarship in my family's name, 'the Mruk Family Grant'. We need to make sure that scholarship funds are available so future geoscientists can answer some of the questions that we've yet to address.

"I know I'll never have enough time to do everything that interests me, but if I've made enough connections to have made a difference – then I'll know I've helped the next generation to 'go forth and make the world a better place'," she concludes. ■

Denise as AAPG Secretary, with Charles Sternbach, DPA President, connecting with students at AAPG's International Convention in Singapore 2012.

Denise Cox

A Play for Oil

A Play for Oil: The Stories Behind the Discovery and Development of Oil and Gas.
By Tim Daley. Springer, 2018.

JOE GREEN

This autobiography of a geoscientist is a very well-constructed and exciting review of the oil exploration industry over the past four decades.

It starts as it means to continue with descriptions of the fun involved in taking part in undergraduate field trips to undertake surface geological mapping in Spain. Thereafter, we are reminded that hydrocarbons are discovered by figuring out where the sedimentary reservoir rocks might be located, under land or ocean, together with their source rocks and the hydrocarbon trapping process. Enhancing these fundamental principles, however, Tim emphasizes the necessity of collecting and interpreting seismic data, in order to locate prospective reservoirs and drill them. Therefore, from this point early in the book, he always describes himself as a 'seismic interpreter'.

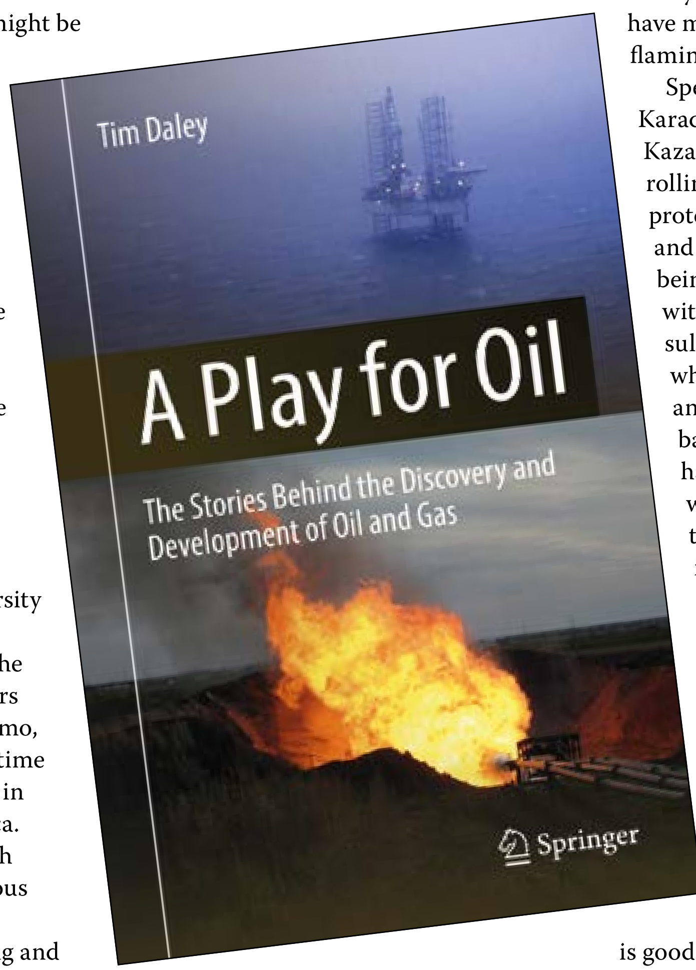
After Spain the author graduated from Oxford, progressed to a Masters in Geophysics at Durham University and started work with Esso in Esher in Surrey in the UK in the early 1980s. His later employers included UK independent Lasmo, as well as ENI and BG. Much time was spent in remote locations in Asia, Africa and Latin America.

The reader is presented with basic information on the various technologies involved in the process of prospecting, drilling and testing for oil and gas. Naturally, there are several pages describing the seismic acquisition process and, unsurprisingly, an entire chapter on seismic interpretation. However, this technical content is not too scary, with good simple diagrams to assist our understanding.

The transformation of technology from analog to digital is also emphasized, which not only made the move from 2D to 3D seismic possible, but also brought about the luxury of doing seismic interpretation on individual desktops. Do we have smartphone seismic yet?

Showing Humanity

However, the magic of this book is its humanity. The geophysics world can be a bit awesome with its mega-computing physics speak, its massive seismic boats and huge, all-terrain trucks, but related stories from Blackpool to Balikpapan keep our feet firmly grounded. The mysterious whisky bottle in the violin case, crossing the Danube to Romania; the all-terrain taxi in Ecuador; and the cocktail and beer parties in remote areas of Pakistan and Borneo all remind us that this serious business has its lighter moments.



In Chapter 8 our hydrocarbon 'seismic interpreter' reveals his concern for communities through his involvement in trying to establish whether high pressure fracking in Oklahoma and Lancashire is causing earthquakes. He wonders how 'nimbyism' can be satisfied when we have movies apparently showing flaming faucets?

Spending a summer in the Karachaganak field in Western Kazakhstan, he speculates that the rolling steppes are to a certain extent protected by the dangers of the oil and gas operation. The hydrocarbons being produced are contaminated with highly poisonous hydrogen sulfide gas, which means that the whole production area is treated as an exclusion zone. The resultant barring of the population at large has therefore created a protected wildlife habitat. It is at this point that this geoscientist reveals his interest in bird watching as well as rocks, and proves he is very knowledgeable on the topic.

The final chapter reminds us that the oil and gas industry exists because the world's population demands the luxury and convenience that hydrocarbons provide. We shall replace it with alternative energy sources given time, but until then it is good to be reminded of the work and effort undertaken in the search for oil throughout the world.

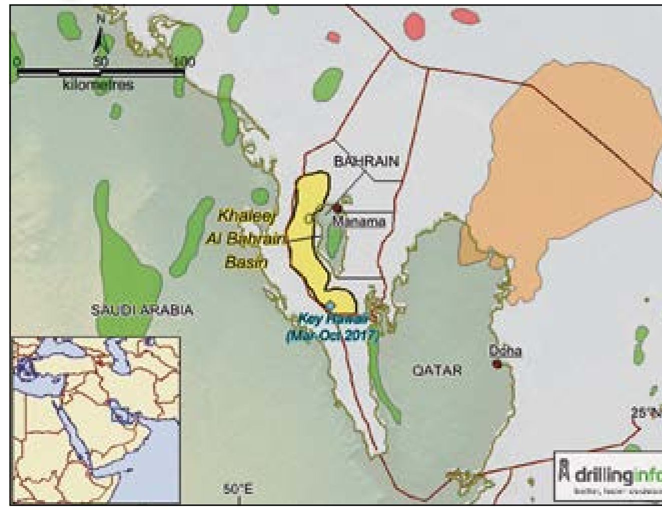
Tim should be proud of providing us with this honest, informative and exciting read, which I note has a Library of Congress reference. It should be in every library and we readers should also spread the word.

Read Tim's article on resource estimation on page 38.

Bahrain: Unconventional Discovery Dwarfs Reserves

In early **April 2018** Bahrain's Higher Committee for Natural Resources and Economic Security announced a 'highly significant' offshore discovery of tight oil and deep gas in the 2,000 km^2 **Khaleej Al Bahrain Basin**, which extends off the west and south-west coast of the island. The exact location has so far not been revealed; however, in 2016 operator **Bapco** let a turnkey contract to Schlumberger for the drilling and testing of two exploratory wells, and the Key Hawaii jack-up was operating in the extreme south of the Bahraini sector between mid-March and mid-October 2017.

The Oil Minister, Sheikh Mohammed bin Khalifa al-Khalifa, said that the discovery was estimated to have 80 Bb tight oil in-place, with 13.7 Tcf of associated gas, with deeper gas amounting to 10–20 Tcf in-place – figures which dwarf Bahrain's existing known reserves. The 80 Bb figure is reported to be a P50 estimate and is thought to apply to the entire resource play.



Bapco pointed out that the presence of a layer with moderate conventional reservoir properties on top of an organic-rich source rock creates a unique self-sourcing and trapping system, enhancing production and economic viability.

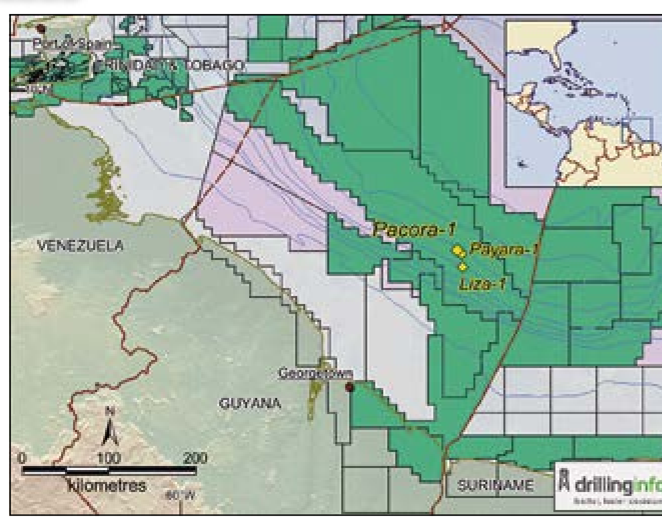
Earlier Bapco technical documents suggest the oil may be reservoired in Jurassic Hanifa-Tuwaiq Mountain Formations. In 2012, light oil (43° API) was recovered from the source rock interval in this formation, establishing the potential for unconventional plays. The deep gas is probably reservoired in the Paleozoic Jauf and Tawil Formations (Pre-Khuff), which are deeper levels than the Khuff gas identified in the onshore Bahrain field. The source rock for the Pre-Khuff gas is the geographically extensive Silurian Qusaiba Formation. Thermal history modeling suggests gas generation in the Oligocene-Miocene. Deep (Pre-Khuff) gas has long been an identified target under the Bahrain Field, and it is possible the figures for the current find conflate the offshore and onshore potential.

Two Halliburton-operated appraisal wells have been agreed for 2018 and Bapco is in discussions with IOCs and major service companies on partnerships to exploit the resources. To date, worldwide, no unconventional resources have been exploited offshore, but an optimistic production start date of 2022–2023 has been touted. The Minister added that they expected the resources to support production of 200,000 bopd and 1 Bcfgpd.

This discovery could provide a much-needed boost to the Bahraini economy, although with energy sales accounting for 87% of the government's total income (2016), Bahrain has been trying to diversify its economy. ■

Guyana: Another Stabroek Success

On February 28, 2018, **ExxonMobil** confirmed that the **Pacora-1 NFW** detected 20m of high-quality, oil-bearing sandstone in the offshore **Stabroek Block in Guyana**. The well spudded on January 29, 2018 with the *Stena Carron* drillship and was drilled to a TD of 5,597m in 2,067m of water. This latest **Guyana-Suriname Basin** well is located about 6.2 km north-west of the Payara discovery, in an area covered by 3D seismic, recently acquired by PGS. The Pacora resources will therefore be incorporated for development into those of the giant Payara field, which is planned as the third development offshore Guyana.



ExxonMobil and its partners have a multi-phase development plan for the Stabroek Block, which will help take Guyana's forecast petroleum production to more than 500,000 bopd in the coming years. The Payara discovery was announced in January 2017, with the discovery well encountering more than 29m of high-quality, oil-bearing sandstone reservoirs. Looking ahead, ExxonMobil has laid out a potential multi-FPSO development solution for its Stabroek Block. The company is progressing with selecting the floating production concept for the development of Pacora and Payara, which could be sanctioned by 2023–2024. This will follow the first project, Liza Phase 1, which is on track for March 2020, with development drilling beginning in 2018, and the second project, Liza Phase 2, planned for 2022 utilizing a multi-FPSO development solution. ExxonMobil operates the block with 45% WI, Hess with 30% and Nexen (CNOOC) with 25%. ■

Encouraging Partner Employment

Anyone in the exploration industry who has worked abroad would agree that it is important that all family members are happy with an expat posting, including ensuring a spouse or partner can find suitable employment. Françoise van Roosmalen explains how Permits Foundation can assist in this.

What is Permits Foundation?

Permits Foundation is an international non-profit initiative, established in 2001, which aims to encourage governments to improve work permit regulations to make it easier for spouses and partners of expatriate staff to gain employment during an international assignment. More than 40 major international companies have joined the Foundation because dual careers are such a key factor in employee diversity and mobility.

What prompted its start-up?

The founding companies recognized the needs of expatriate families and the growth of dual careers, so partners could continue working or, at least, have the choice to do so. It raised the idea of working together globally to address an issue that affects men and women of all nationalities all over the world and is essential for equal opportunity and diversity. It also creates a more attractive climate for international mobility; governments and companies realized that partner access to employment in the host country was a key factor in attracting and retaining talent.

The Foundation has grown rapidly, demonstrating the breadth of concern and quality of support for international dual careers in both the private and public sector.

How do you work with governments and employers?

Our goal is for recognized partners to be allowed to work on their 'dependent' pass, without further bureaucracy. Each country needs an individual approach, though there are common steps in planning every campaign. We start by checking the current status of family members in the country's immigration legislation and we meet with companies in the country to get a feel for the wider social, political and economic context and whether there is potential for change. If this is positive, we form a local network of our sponsor companies and others who can advise us on the legal aspects and government relations.

The next step is to identify key decision makers and other stakeholders and find whether the change needs an act of parliament or a ministerial decision. We gather local evidence and prepare a position paper, write letters and organize meetings with policy staff, members of parliament and ministers of state, as the local circumstances require.

We approach it constructively and diplomatically, sharing best practice from other countries and providing evidence from surveys of employers, expat employees and partners to show the importance of allowing partners to work. We cover the economic benefits of attracting highly qualified talent to support investment and growth, as well as the positive impacts on adjustment and integration, health, and well-being.

Policy changes do not happen overnight – we need to be patient and persistent. But with many countries now allowing spouses, partners and sometimes children to work, it is clear that working together through Permits Foundation creates a triple win for countries, employers and families!

What are your major successes to date?

Since we started, 30 countries now permit spouses or partners to work and there are clear signs of a growing trend to acknowledge family needs, including the recognition of unmarried and same-sex partners.

Currently, almost all European or EU countries allow family members of skilled foreign workers to work, either under national provisions or the EU Blue Card or Intra Corporate Directive (ICT) scheme. As an example, the ICT Directive proposal did not initially include a provision to enable direct access to work for spouses or partners of transferees, but thanks to our advocacy, this was included in the final Directive. We have been successful in influencing change in the USA, Hong Kong, Japan and more recently in Brazil, and are continuing to make headway in India, engaging further in South Africa and exploring opportunities in China.

Finally, faced with immigration challenges in the UK (Brexit) and US, we are working actively to prevent policy roll-back.

What can we do?

Now that you have learned about our global advocacy work and the positive impact it has on dual careers, we encourage you to raise awareness of Permits Foundation (www.permitsfoundation.com) within your organization and wider network. We are also interested in receiving feedback from anyone who has experience of applying for a work permit in any country that does not yet allow partners to work on their dependent permit. ■

Permits Foundation

Françoise looks after sponsor relations and accounts for Permits Foundation. Her colleagues include international advocacy advisor Helen Frew and and Foundation director Michiel van Campen .

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Oil Demand Still on the Rise

"As the world learns to do more with less, demand for energy will be met by the most diverse fuels mix we have ever seen."
Spencer Dale, BP group chief economist

2040: that is only 22 years from now (remember 1996?). BP is once again looking into the crystal ball, all the way up to 2040, with the results presented in their most recent Energy Outlook (2018 edition)*.

A prerequisite to understanding future energy demand is GDP (Gross Domestic Product) forecasts as a function of population growth. According to BP, world GDP will more than double during the next two decades, broadly in line with growth seen over the past 25 years. And, as the global population reaches 9.2 billion, more than 2.5 billion (500 times Norway's population!) will be lifted from low incomes.

BP therefore concludes that global energy demand will increase by about 35% as global prosperity increases. China and India will account for half of this demand. That figure is not controversial.

Forecasting the future energy mix is, however, always controversial. BP's view is that oil, gas, coal and non-fossil fuels (hydro, nuclear, renewables) will each contribute around 25% in 2040.

Renewables will constitute 14% in 2020, with an annual growth of 7%. This makes up 40% of the increase in energy supplies. Remember, with an annual growth of 7%, it takes ten years to double the production. Consequently, the world needs a much stronger growth in renewables if these sources are to replace fossil energy before 2040.

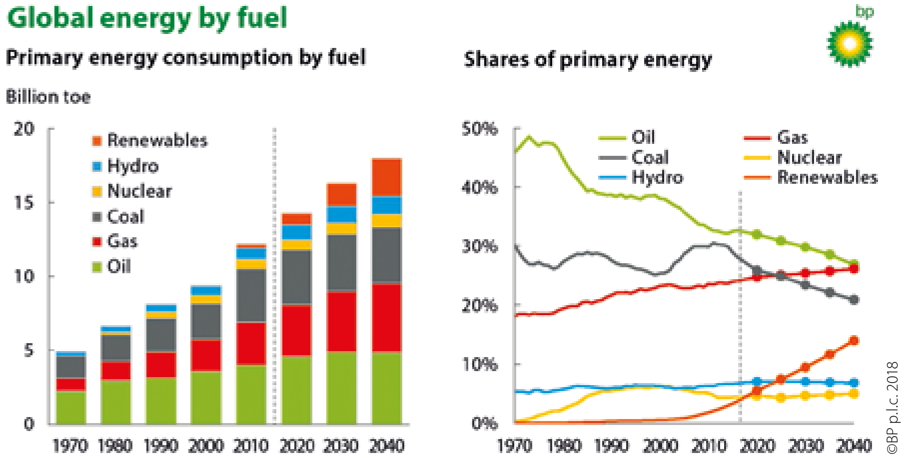
For the oil industry, it is comforting to read that BP believes that demand for oil will grow by 0.5% p.a. during the 2020s. However, demand is projected to plateau in the 2030s. Moreover, demand for natural gas will grow strongly at 1.6% p.a. and during the next 20 years it will overtake coal as the second largest source of energy.

> "The date at which oil demand will stop growing is highly uncertain and small changes in assumptions can lead to vastly different estimates."
> *BP Energy Outlook 2018*

The world is likely to demand large quantities of oil for many decades to come, BP concludes. ■

Halfdan Carstens

Global energy by fuel



* www.bp.com/en/global/corporate/energy-economics/energy-outlook.html

Conversion Factors

Crude oil
1 m³ = 6.29 barrels
1 barrel = 0.159 m³
1 tonne = 7.49 barrels

Natural gas
1 m³ = 35.3 ft³
1 ft³ = 0.028 m³

Energy
1000 m³ gas = 1 m³ o.e
1 tonne NGL = 1.9 m³ o.e.

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

Supergiant field
Recoverable reserves > 5 billion barrels (800 million Sm³) of oil equivalents

Giant field
Recoverable reserves > 500 million barrels (80 million Sm³) of oil equivalents

Major field
Recoverable reserves > 100 million barrels (16 million Sm³) of oil equivalents

Historic oil price