VOL. 16, NO. 3 – 2019

GEO ExPro

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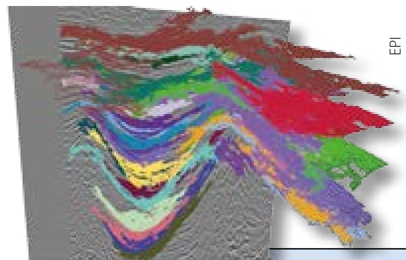
Leveraging the power of AI-driven software enables the rapid evaluation of complex areas.



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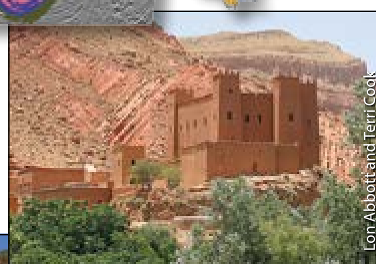

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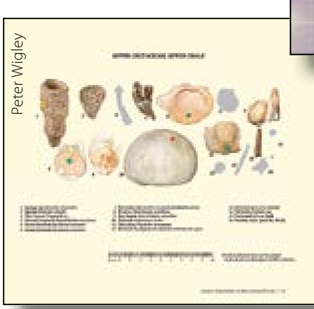

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A new book matching William Smith's fossils and illustrations is a testament to his genius.

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This edition of *GEO ExPro* focuses on the Circum-Mediterranean; Russia and the FSU; Unconventional Resources; and Seismic Sources

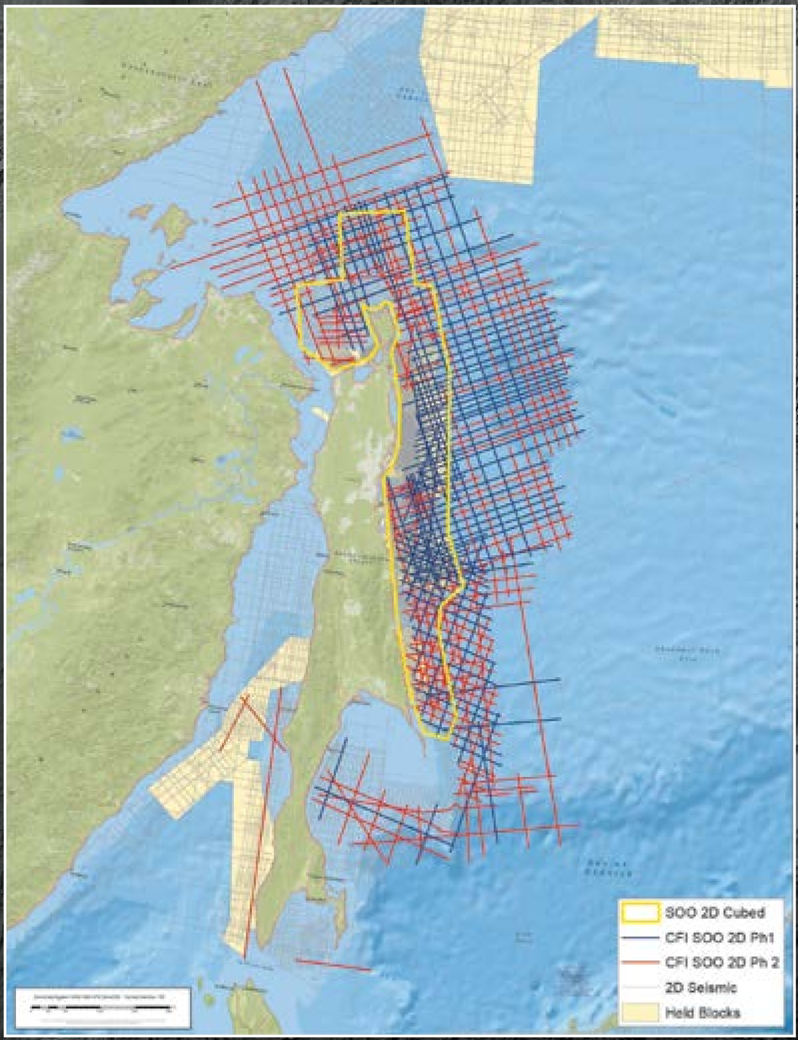
TGS expands its multi-client offering to the Sea of Okhotsk

TGS is pleased to announce an expansion of its Russian Sea of Okhotsk multi-client database. The new expansion provides high quality data for E&Ps, resulting in improved exploration decision-making.

New 2019 projects include:

- The creation of a 2D data Cube (70,000km²); and
- An expansion of the original 2D Phase 1 Clari-Fi broadband reprocessing of an 18,970km grid with a further 21,560 km

From seismic to well data, TGS has the largest library of geoscience and engineering data in the industry. Contact us today and discover how we can help you see your seismic data needs more clearly.



TGS

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Following the Shale Gale

A drill rig in the Fayetteville shale gas play, Arkansas.

We all know about the revolution in oil and gas production in the United States that has come from extracting hydrocarbons from shale, and the resulting upheavals in the markets for these commodities. In 2018 US oil production showed the biggest yearly increase in output since records began in 1859 and America has moved from being a net importer to an exporter of energy. From being one of the most expensive sources of new oil in 2015, Rystad Energy say that reduced costs mean tight oil is now the second cheapest source of new oil volumes globally; its breakeven price is only a few dollars less than that of the giant Middle East onshore fields.

According to the British Geological Survey, shale makes up 35% of the world's surface rocks – so why is the rest of the world not following the 'Shale Gale'? The answers are many and varied.

Geology is a major factor. Not many parts of the world have the huge swathes of relatively undisturbed homogenous layers that characterise the great US shale basins. And if the geology is satisfactory, few places have the access and ownership situation prevalent in the US – not to mention the political will. There are bans on fracking in several countries in Europe, and the idea produces considerable public disquiet in many others.

With plentiful proven untapped conventional resources, countries like China, Saudi Arabia and those in the Former Soviet Union have little motivation to exploit shale. Russia, for example, has as much as 24,000 Tcfg of unconventional resources, according to Gazprom, but it also holds vast conventional reserves and is using techniques developed in the US shale patch, like horizontal drilling and hydraulic fracturing, to unlock these.

As discussed on page 72, there is a similar scenario in Latin America. Even in areas with comparable geology to the US shale basins, there are plentiful conventional resources to be exploited. With limited infrastructure, the improved cost implications noted by Rystad will not be as pertinent.

After the USA, Russia has the second largest shale oil reserves in the world, with China in third place. Should these two countries begin to actively exploit their shale resources, a very different balance in the oil market might emerge.

Jane Whaley
Editor in Chief

ALGERIA: A NEW TECTONIC FRAMEWORK

The north flank of the Calcareous Range in Djurdjura with the Grande Kabylie in the foreground. Reinterpretation of tectonic movements in this area has led to new ideas on hydrocarbon traps and prospects.

Inset: Can the E&P industry still innovate?

GEO ExPro

www.geoexpro.com

GeoPublishing Ltd
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
+44 20 7937 2224

Managing Director
Tore Karlsson

Editor in Chief
Jane Whaley
jane.whaley@geoexpro.com

Editorial enquiries
GeoPublishing
Jane Whaley
+44 7812 137161
jane.whaley@geoexpro.com
www.geoexpro.com

Sales and Marketing Director
Kirsti Karlsson
+44 79 0991 5513
kirsti.karlsson@geoexpro.com

Subscription
GeoPublishing Ltd
+44 20 7937 2224
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
kirsti.karlsson@geoexpro.com

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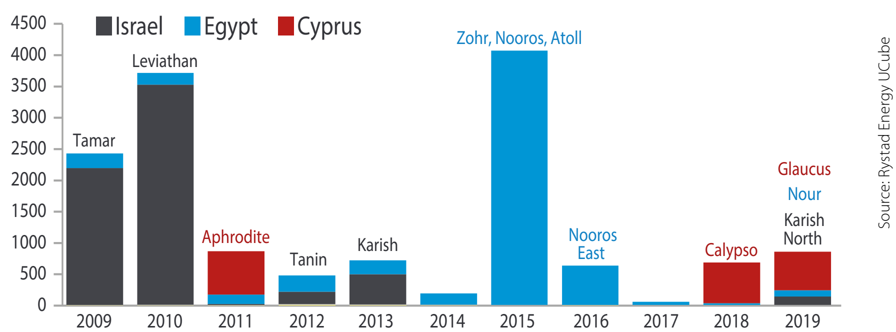
Fun in the Sun for Club Med Upstream Operators

The past 15 months has been a golden period for operators in the East Mediterranean Sea basin. In total, E&P operators have been able to unearth over 1.5 Bboe offshore gas resources in this region, including Glaucus and Calypso in Cyprus, Nour in Egypt, and Karish North in Israel.

Calypso 1 is a promising gas discovery which confirms the extension of the 'Zohr-like' play into the Cyprus Exclusive Economic Zone. Eni reported approximately 6 to 8 Tcfg in place. Rystad Energy estimates the field has around 600 to 700 MMboe of recoverable resources. ExxonMobil's **Glaucus** natural gas discovery is the third noteworthy find in Cypriot waters in recent years, following Calypso and Aphrodite. The discovery, in Block 10, encountered 133m of gas-bearing reservoir, with in-place resources of approximately 5 to 8 Tcfg, Rystad estimating the field could hold around 600 to 700 MMboe.

Eni-operated **Nour** 1 found a ~90m gas column in the North Sinai Concession and the operator plans to accelerate the development with existing facilities. Rystad Energy estimates the recoverable resources to be around 120 to 150 MMboe. The **Karish North** discovery has a gross hydrocarbon column of nearly 250m with in-place gas resources of approximately 1–1.5 Tcf. Rystad Energy estimates the recoverable resources at 100 to 150 MMboe. Operator Energean plans to develop this through a tie-back to a FPSO unit currently under construction.



Discovered conventional gas resources in the East Mediterranean region (MMboe).

Export Options

Cyprus has the lowest gas discovery cost at $0.20 per boe, which improves future exploration prospects in the vicinity, but the development of these finds faces the challenge of limited infrastructure. With low domestic demand, Cyprus currently has two options to accelerate development: either to use Egyptian LNG terminals, or to develop domestic floating LNG capacity.

Egypt's Damietta and Idku are the only LNG terminals in the region that can funnel gas reserves to the global market, with a combined export capacity of 1.75 Bcfpd of LNG export capacity. From 2019, Eni is expected to send gas from Zohr to Damietta, when the facility will be running at capacity. Idku will continue to operate at 20 to 25% of capacity. Cyprus received permission from the EU to construct a subsea pipeline to Idku, and has signed a contract with Egypt for the export of Cyprian gas to European markets. These developments brightened the Aphrodite gas field development prospects via Idku LNG, as Shell is a stakeholder in both projects. Aphrodite, discovered back in 2011, is a cautionary tale of the delays big discoveries in the region face if development is not actively streamlined.

With Egyptian LNG terminals running at almost full capacity, little spare processing capability exists to accommodate recent and future discoveries in Cyprus. However, with 12.5 Tcf of discovered recoverable resources already available, future discoveries could make a future FLNG in Cypriot waters commercially viable. ■

Aditya Saraswat, Analyst, Upstream Research, Rystad Energy

ABBREVIATIONS

Numbers
(US and scientific community)

M: thousand = 1 x 10^3
MM: million = 1 x 10^6
B: billion = 1 x 10^9
T: trillion = 1 x 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

Croatia: Third Onshore Bidding Round

An opportunity to enter an underexplored European frontier region.

Croatia's third onshore bidding round, which opened in February 2019, is focused on the Dinarides belt, which runs parallel to the coast along much of the country. The area is considered an underexplored frontier region, with only nine exploration wells drilled in the four blocks on offer. These recorded oil and gas shows but no discoveries. Around 545 km of 2D seismic is available, but it is sparse, old and of poor quality. Widespread seep occurrences hold out promise of discoveries yet to be made.

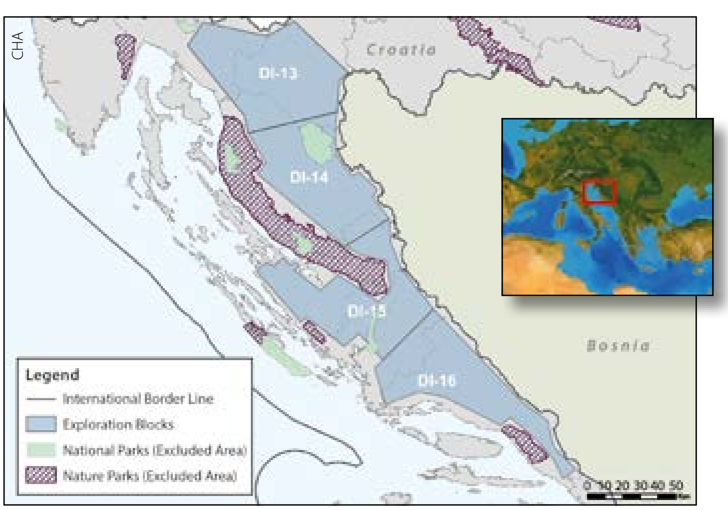
The Dinarides are a wide north-west to south-east fold-and-thrust belt stretching from south-western Slovenia to Montenegro along the Adriatic coast. They formed when the European and Adriatic plates collided, causing Meso-Cenozoic carbonate rocks of the Dinaric platform to over-ride the Adriatic Jurassic and Triassic rocks.

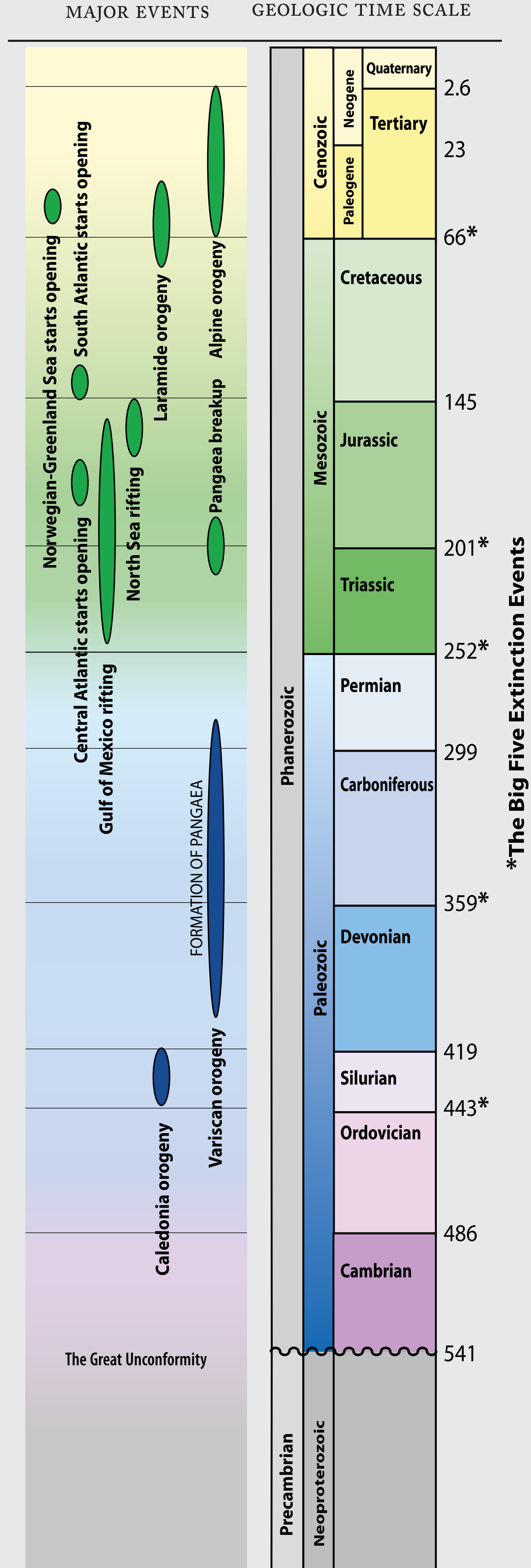
A number of petroleum systems have been identified, although drilling has not yet reached the deeper sediments, so there is still much to learn. Source rocks ranging from mid-Triassic through Upper Jurassic to Upper Cretaceous sediments have been found to have kerogen Type 1 and are considered very promising. Potential reservoirs are expected in horizons from Permian siliclastics to Cretaceous limestones and dolomites, while evaporites and clastics of various ages could form seals. However, the rough terrain and structural complexity mean that the geology is poorly understood, and it is thought that modern survey methods such as airborne gravimetry/magnetometry, as well as new seismic, will be able to shed light on the geology. There also appear to be close correlations with the prolific Apennine hydrocarbon province in Italy.

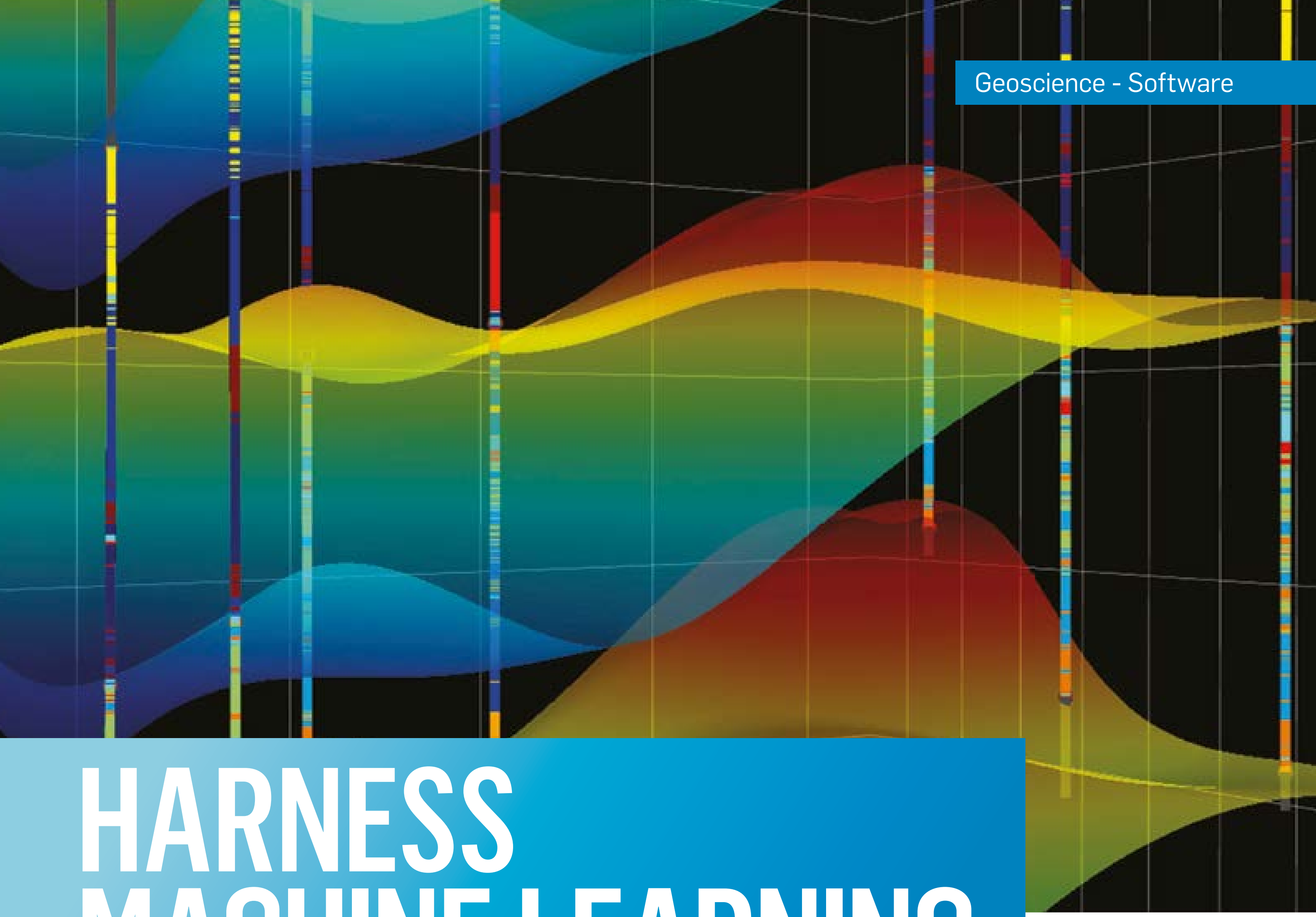
The exploration period consists of a first phase of three years (exit option) for seismic and other surveys to take place, followed by a second phase for further survey work and the first exploration wells to be drilled. Extensions may be available for up to two more years.

The round ends on 10 September 2019 and awards are expected to be announced in December.

(See www.geoexpro.com for information about Croatia's 2nd Onshore Round) ■







Seismic Data as a Service

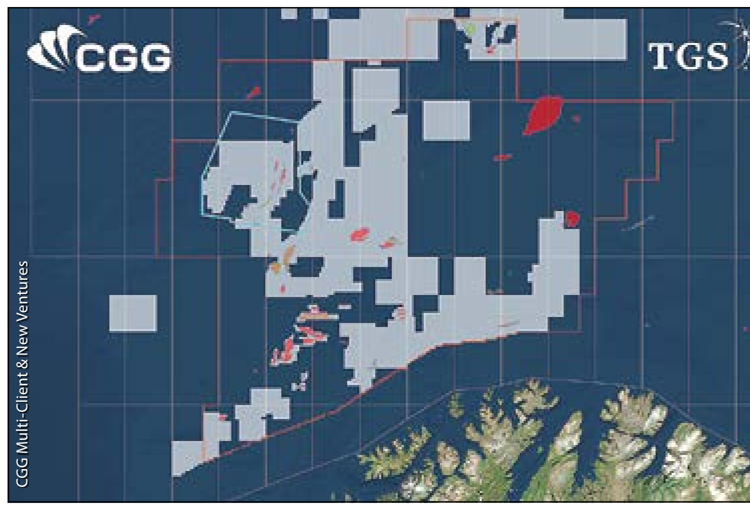
As machine learning becomes commonplace in the oil and gas industry the need for organised data with known provenance and usage rights has never been greater. The majority of currently available seismic data is fraught with challenges, from legacy file formats and inconsistent metadata to dynamic range problems. To address this issue, **Searcher Seismic** have recently launched **Saismic**™, a cloud-based service that provides **global seismic data on-demand** with native support for deep learning and advanced analytics. This transformative product offers the E&P industry an innovative and smarter way to interact with seismic data on the premise that it should be adaptive, flexible and compatible with today's big-data tools.

Saismic initially started out as a project to improve Searcher's internal data management and to streamline the delivery of seismic data, but seeing the potential, it developed rapidly to a platform that holds millions of kilometres of 2D and hundreds of thousands of square kilometres of 3D seismic. This global library of data has been deconstructed from the rigid flat file format traditionally associated with seismic and transformed into a distributed, scalable, big data store, allowing for rapid access, complex queries and efficient use of compute power. ■

Advanced Imaging in the Barents Sea

CGG, in partnership with **TGS**, will acquire a 5,000 km^2 multi-client 3D survey in the **Barents Sea** this summer. The survey will use the latest developments of CGG's **TopSeis** technology, combining an innovative **source-over-spread** acquisition configuration with advanced imaging to enable delineation of shallow-to-intermediate depth targets in the Barents Sea, not resolvable by conventional methods.

The next-generation TopSeis configuration deploys five sources on the source vessel, shooting over the centre of the streamer spread. An additional source on the streamer vessel provides long-offset data for Full Waveform Inversion and deep imaging. Previous TopSeis surveys in the Barents Sea delivered superior data for imaging and AVO due to the rich near-offset coverage, high trace density and low noise.



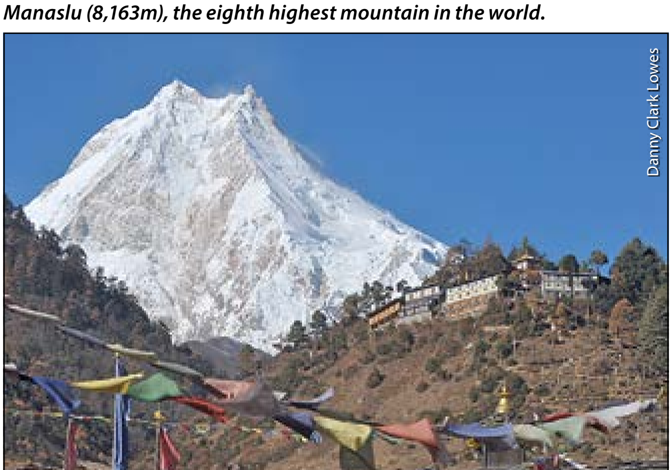
Location of TopSeis survey to be acquired over the Greater Castberg area of the Barents Sea.

The survey will include the prospective Greater Castberg area, covering existing and newly awarded licences as well as open acreage with several play models in multiple geological layers. Fast-track PSDM data will be available in December 2019 and final data in Q4 2020. ■

How the Earth Moved Beneath Manaslu

Following the devastating **Gorkha** earthquake that shook **Nepal** in 2015 there has been an intensification of earthquake research. The sudden and catastrophic brittle fracture at the hypocentre of the Gorkha quake involved movement on the **Main Himalayan Thrust**. This important low angle fault deepens northwards beneath **Mount Manaslu** and on beneath Tibet. Lateral displacement on it is estimated to have been 3m or slightly more at a depth of between 8 and 15 kms within the crust.

Manaslu (8,163m), the eighth highest mountain in the world.



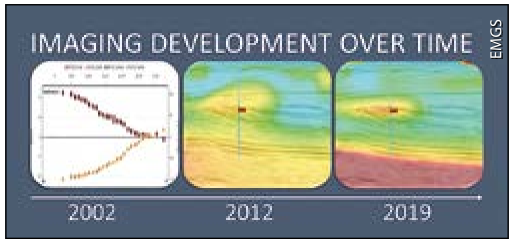
Other research has shown that adjacent to a branch of the Main Himalayan Thrust, called the Main Central Thrust, not only was there fault movement but, in the past, melting and mobilisation of the crust. This partial and total melting saw the development of migmatites and leucogranites which cooled and crystallised as, responding to horizontal compressive forces, they 'flowed' laterally southwards and upwards to what is now the surface. One of the most spectacular exposures of this white tourmaline-rich leucogranite is a 3,000m-high cliff at Manaslu.

Thanks in large part to the efforts of international charities, much of the 2015 damage to villages in the region has now been repaired, though further aid is still required. ■

A Strong Start to 2019

EMGS has to date acquired 950 surveys in 36 countries and territories, from Spitsbergen to New Zealand. The list of customers includes six major IOCs, seven major NOCs and a number of international independents. Currently 12 national authorities/regulators are including **CSEM services** in licence work programmes.

The company was hit by the recent downturn, but has now emerged out of it and has maintained a motivated and competent staff. Together with key customers Equinor and Shell, EMGS has used the tough years to invest in R&D, leading to significantly improved technology with the latest generation **Deep Blue** acquisition system and the **Gauss-Newton** full 3D inversion software. The results are technically great, allowing the imaging of targets down to 4,000m. Although not a silver bullet, key customers on both sides of the Atlantic have reported a prediction strength of 80% and above. Results are also visible on the commercial side, with the recent closing of contracts, and the company is now well positioned to benefit from the upswing in exploration activity and is ready to provide key data that will improve exploration results. ■



The Hottest Geophysical Event!

Join more than 7,000 colleagues in **San Antonio, Texas** for the **2019 Society of Exploration Geophysicists International Exposition and 89th Annual Meeting** – the hottest geophysical event of the year! Taking place **15–20 September, SEG19** will be multidisciplinary and integrated, featuring the hot plays of the Permian and Latin America, as well as the latest advances in data acquisition, the increasing value of AI and big data to the geophysical community, and much more.

Business of Applied Geophysics Plenary Sessions are included with registration this year, featuring sessions such as 'Challenges and Solutions in Developing Resource Plays' and 'Digital Transformation in Petroleum Geophysics: What Impacts Are We Seeing?'

This year marks the return of the SEG Golf Tournament, as well as the Presidential Jam, featuring SEG President Rob Stewart and past SEG presidents. Seven fascinating tours and field trips are planned, including to the Eagle Ford Formation, Cave Without a Name, and Natural Bridge Caves. Stay up to date on SEG19 with the SEG Events mobile app – search SEG Events on Google Play or the Apple App Store. Register for SEG19 by 30 July and save! ■

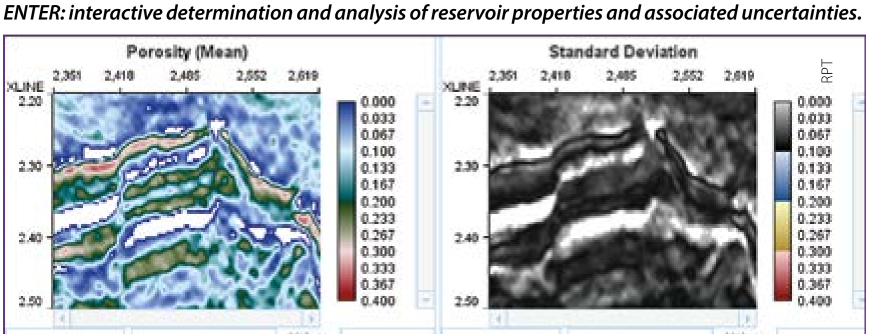
Take a field trip to the Natural Bridge Caves.

Rock Physics-Driven Quantitative Interpretation

Geoscience software company **Rock Physics Technology AS (RPT)** has taken the next step in reservoir characterisation by integrating its own innovative **Inverse Rock Physics Modelling (IRPM)** method with industry recognised workflows to perform rock physics-driven quantitative seismic interpretation using its **ENTER**™ software solution. RPT is now bringing the software behind the method and the applications to the international market.

ENTER enables the whole geoscience team to perform rock physics-driven subsurface characterisation, rapidly delivering predictions of rock properties and geological insight of the subsurface. The software includes access to advanced methods and tools to perform rock physics-driven analyses in all lithologies, from clean sandstones to complex carbonates. It can be used in all phases of the G&G workflow from exploration through to appraisal, development and production, enabling safe identification and extraction of hydrocarbons.

Founded in 2015 with the aim of commercialising exciting new ideas researched and developed at the University of Bergen, RPT has demonstrated the value of its acclaimed IRPM method through a number of projects carried out in Norway. Innovative workflows and in-house software position RPT as a global provider of quantitative seismic interpretation software and consultancy services. ■

ENTER: interactive determination and analysis of reservoir properties and associated uncertainties.


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Algeria

A New Tectonic Framework

A proposed new tectonic model for the northern Algerian Alpine Region based on studies of the Internal Zone rejects the previous model and suggests ideas for new hydrocarbon traps and prospects.

Dr. A. SAADALLAH
Consultant, Saadgeo

Tectonically, Algeria comprises two domains. In the north is the Northern Algerian or Maghrebian Belt, part of the Alpine Belt running from Gibraltar to Calabria, which is a result of Cretaceous–Miocene Alpine events. The Saharan Platform, unaffected by these major Alpine upheavals, encompasses southern Algeria. They are separated by the major Middle–Upper Eocene South Atlasic Fault.

Studies from parts of the Maghrebian Belt, including the Internal Zone and parts of the South Atlas range, have revealed the importance of major tectonic transpressive faulting and movement. This has caused the Belt to be split into three main segments or blocks (Western, Central and Eastern, see Figure 1) by two major fault zones, the dextral strike-slip Ténès–Bousaada fault and the sinistral strike-slip Tigzirt–Djebel Onk fault, which are separated by a large block that has moved south-eastward. This has resulted in a gap in the South Atlas mountain range, and has caused the External Zone of the Maghrebian Belt to outcrop at the Mediterranean coast to the east.

Since the previous understanding of the geology of the Maghrebian Belt was based on the mid-20th century theory of geosynclinal belt-building, with a dominant west–east continuity, this new interpretation requires a reconsideration of the whole strategy of hydrocarbon exploration and the style of major plays in North Algeria. To further this analysis, we look at the important features of the Maghrebian Belt: the three blocks and the two major faults zones separating them.

Two Major Fault Zones

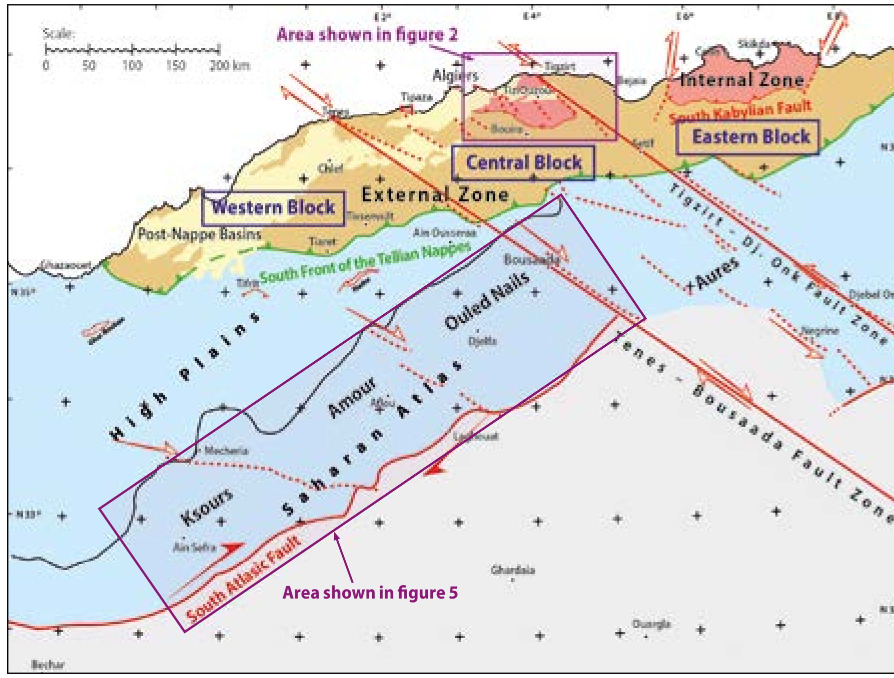
The eastern fault zone runs north-west to south-east, from Tigzirt on the Mediterranean coast to Djebel Onk at the southern limit of South Atlas range. It was first identified within the Metamorphic Core Complex (MCC) of the Internal Zone, where it was defined as the Souama shear zone, which bounds the metamorphic formations of the Grande Kabylie area (see Figure 2). Its major effect was to move the MCC up, down-throwing the Eastern Block of the Maghrebian Belt, acting as a sinistral strike-slip fault. The scale of the displacement is a few kilometres vertically but several tens of kilometres in the horizontal direction. The Oligocene–Miocene molassic formation (flysch) lies unconformably on the metamorphic rocks at the eastern edge of the MCC in Grande Kabylie and marks the base of the Cretaceous turbidites (see Figure 2a).

The Tigzirt–Djebel Onk Fault Zone is also seen in the

SofieLayla Thal, Pixabay

Looking north to Cap Carbon, near Bedjaia, where Jurassic carbonates of the External Zone outcrop at the Mediterranean coast.

Figure 1: The main structural features of the Maghrebian Belt. The Internal Zone, also called the Kabylian Domain (red), the most deformed part, includes metamorphic formations and is thought to have been located further north before tectonic activity. In contrast, the External Zone (brown) is considered to have been close to the relatively stable continental margin prior to tectonic events. Yellow represents the extensional post-tectonic basins that formed at the same time as the Mediterranean Sea (Miocene to 10 Ma). The Foreland Atlas Domain, comprising the High Plains and Saharan Atlas (blue), is considered to be the margin of the Saharan Platform (grey), part of the African Continent. The Maghrebian Belt has been split into three main blocks by two major fault zones: Ténès–Bousaada and Tigzirt–Djebel Onk. After Saadallah (2013).



Djurdjura mountains, cutting the Calcareous Range where it outcrops at Col de Chellata. This important Alpine feature then disappears, reappearing over 100 km further east, south of Collo. The previous interpretations based on the geosynclinal concept assumed the Calcareous Range underlaid this area at depth, but its absence is simply the result of the north-westerly displacement resulting from the sinistral strike-slip movement.

The Calcareous Range (see cover photo) is a flower structure resulting from the Eocene west–east transcurrent tectonic movement along the Djurdjura mountains (Saadallah et al., 1996). The axis of the flower structure plunges about 70° westwards, so all the formations involved, from Palaeozoic to early Eocene, disappeared under the post-tectonic Eocene–Miocene molasse cover in the area east of Kouriet. These factors suggest that the Calcareous Range at Col de Chellata was thrown up rather than down, as well as to the north-west.

The External Zone's 'Tellien de Dellys', Cretaceous marls with the specific signature of 'boules du Sénonien', is only found within the Eastern Block of the Maghrebian Belt (the brown area around Tigzirt-sur-Mer, Figure 2). This again suggests strike-slip motion in the fault zone, bringing the External Zone northwards to outcrop at the Mediterranean coast.

Further south-east, several north-west to south-east-striking faults can be seen in Figure 1, shifting the southern boundary of the Saharan Atlas range far to the south-east.

The major Ténès–Bousaada fault zone also trends north-west to south-east and forms the western boundary of the Central Block, which it displaces several kilometres to the south-east. It is a dextral strike-slip fault, and results in Internal Zone sediments outcropping at the Mediterranean coast, as several en echelon segments of the fault zone shifted segments of the Internal Zone south-east from west to east, i.e. from Ténès, Algiers, Lakhdaria and finally to the eastern edge of

Figure 2: Structural scheme of the Grande Kabylie outlining the two main fault zones, Souama and Tizi Ghenif. After Saadallah 1992, 2013, based on several sources and satellite imagery from Google Earth.

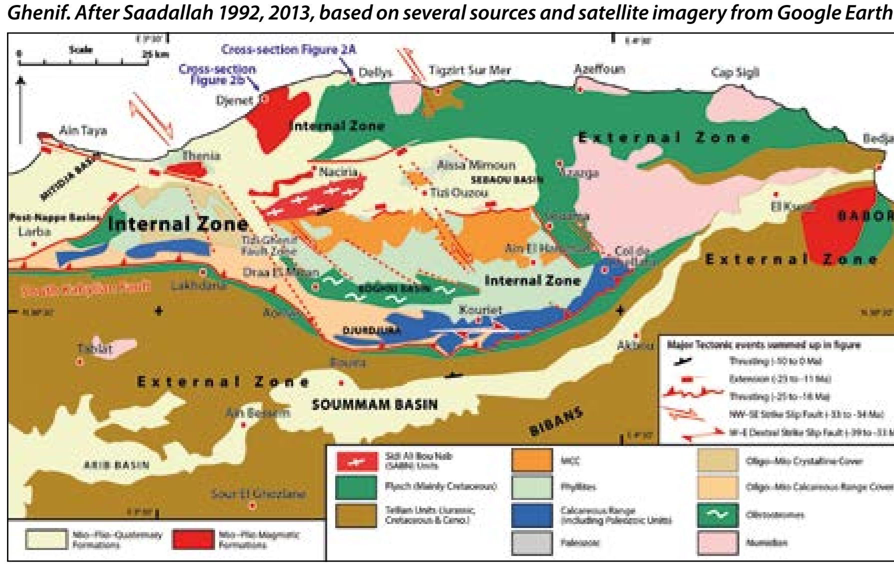


Figure 2a: Cross-section Dellys–Djurdjura.

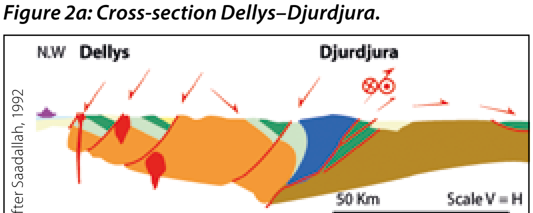
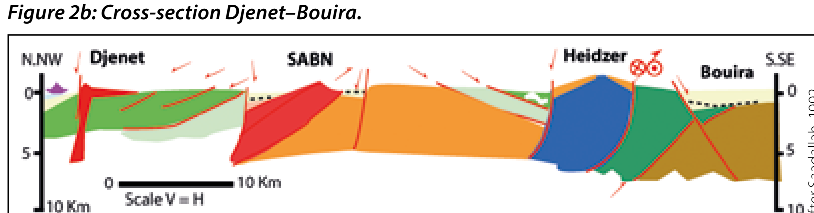


Figure 2b: Cross-section Djenet–Bouira.



the MCC in Grande Kabylie, at the Tizi Ghenif Fault zone (Figure 2). The Western Block was probably overprinted by the major thrust of the Tellian Nappes, the South Front of the Tellian in the area of Ain Oussera, north of Ouled Nails Mountains (Figure 1). The Ténès–Bousaada fault also affected the Saharan Atlas, downthrowing it and pushing it south-eastwards horizontally.

Movement of the Central Block

The Central Block of the Maghrebian Belt is used to define the Internal, External and Foreland Zones including the MCC, the Calcareous Range, the Tellian Nappes and the Atlas Domain. Most of the northern part of the Block was intensively deformed by distension during the opening of the Mediterranean Sea during the Miocene–Pliocene.

The Central Block pushed the Saharan Platform south-eastward and, as it moved, it appears to have tugged the northern edge upward and the southern edge downward (Figure 3). In addition, in the north the eastern edge was pulled upwards while the western side plunged downward, so the MCC and Calcareous Range rocks all dip westwards.

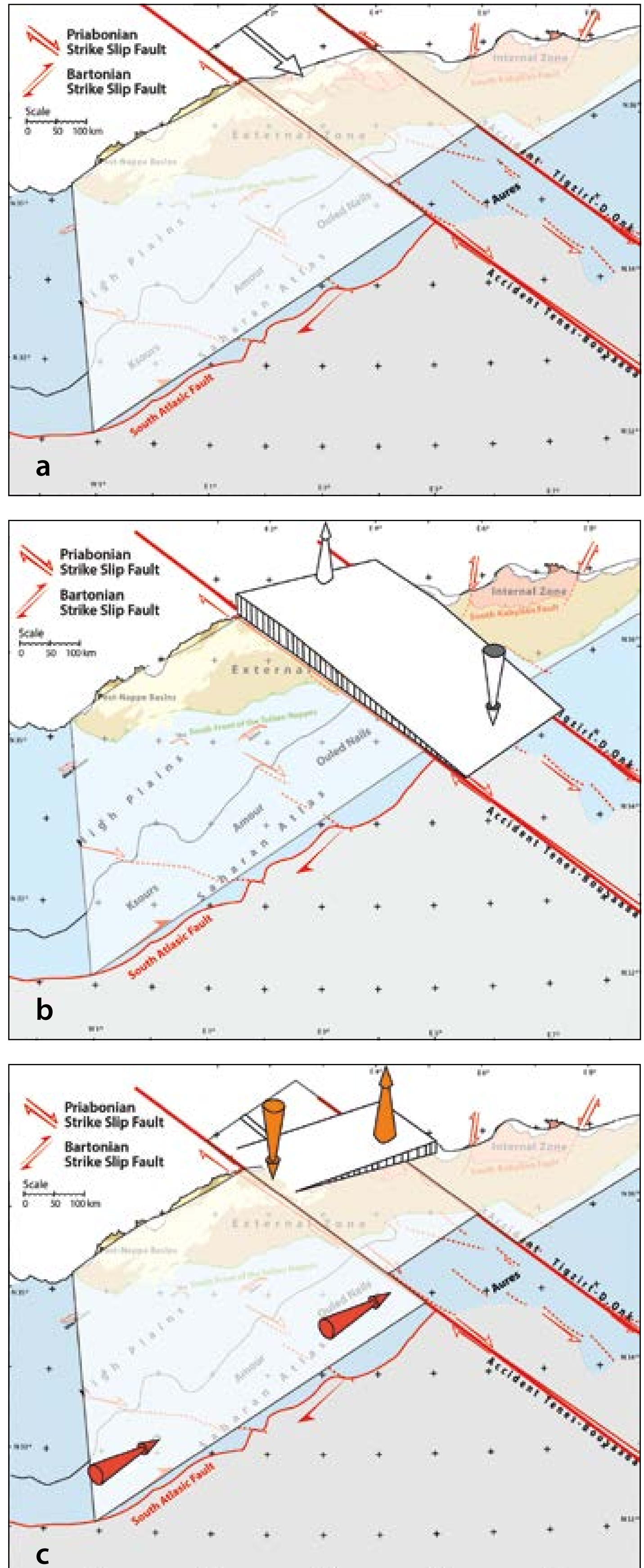
The section of the Maghrebian Belt west of the Ténès–Bousaada fault zone is characterised by the absence of the Internal Zone, the existence of a large External Zone and the presence of the Foreland or Atlas Domain, a wide flat platform forming the sub-horizontal High Plains. The apparently horizontal non-deformed High Plains display some ‘pop-up’ compressive structures revealing basement formations within horst and flower structures, as seen at the mountains of Ghar Rouban, Tifrit and Nador.

The Saharan Atlas

South of the Plains lies a broad section of the Saharan Atlas range with obvious en echelon structural features. The Atlas Domain is composed of Mesozoic formations, predominately Jurassic carbonates and Cretaceous sands, overlying Palaeozoic basement. Triassic evaporites (gypsiferous shales with salt) played a major tectonic role as a décollement horizon. The Saharan Atlas in northern Algeria is composed of four major mountain ranges: the Ksours, Amour, Ouled Nails and Aures mountains. The first three are separated by minor dextral north-west to south-east strike-slip faults, while the Aures range is isolated from the rest of the Saharan Atlas by the major dextral north-west to south-east shift of the Ténès–Bousaada fault zone.

The Saharan Atlas is known for narrow ‘anticlines’, separated by wide ‘synclines’ with flat bases. In fact, these ‘anticlines’ are actually antiformal structures generated by strike-slip shear faults, often with a reverse component, while the ‘synclines’ are large undeformed sigmoidal lenses, bounded by shear zones, in the classic pattern often found in large sheared areas. Most of the features indicate the dextral character of the transpressive shearing tectonics. The structure of the Saharan Atlas is therefore the result of transpressive dextral tectonics as the Algerian Alpine zone sutured to the Saharan Platform along the major shear faulting zone, the South Atlasic Fault. The High Plains remained predominantly outside the shear zone.

Figure 3: Schematic illustration of the shift south-westward of the Central Block (a) and the simultaneous dragging of its northern part upwards and southern edge downward (b). The Saharan Atlas dips north-eastwards while overall the Internal Zone of the central block dips westwards (c).



This transpressive north-east to south-west dextrally-striking tectonic event is dated Middle–Upper Eocene (39–33 Ma), with the movement terminated during the Upper Bartonian (34–33 Ma) by north-west to south-east striking dextral faults, probably at the same time as the Central Block of the Maghrebian Belt shifted south-eastward.

Overall, the Saharan Atlas dips north-east, so the Jurassic formations usually outcrop in the south-western part of the Saharan Atlas, while the Cretaceous and Cenozoic sediments are found along the north-eastern edge (Figure 4). This is contrary to the westerly dip of the Internal Zone, as explained previously.

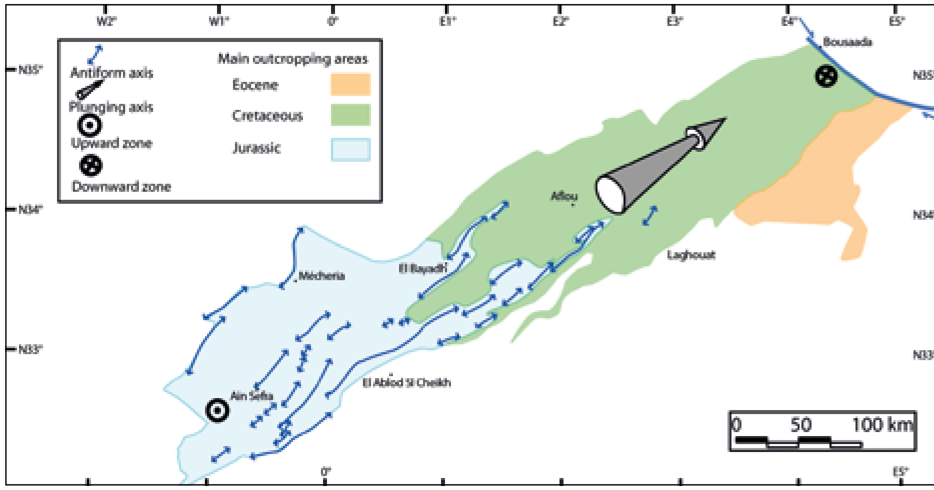


Figure 4: Map illustrating the overall structure of the Saharan Atlas dipping north-eastwards.

The Eastern Block of the Maghrebian Belt has to be reviewed carefully in the light of these new analyses, but this is beyond the remit of this article.

Impact on Hydrocarbon Exploration

This new tectonic interpretation highlights major impacts on hydrocarbon exploration. The effect of the suture of Alpine northern Algeria to the Saharan Platform, followed by the southerly movement of the Central Block during the Eocene, raises questions related to the migration of hydrocarbons northwards from Saharan formations after the Eocene. The fact that the southern part of the Central Maghrebian Belt has been pushed south-eastwards should allow for potential migration from the Platform, and probably also along the multiple north-west to south-east trending faults, which are sealed by the molasses and other deposits resulting from post-Eocene events. What potential paths could they use, and into which structures?

When considering the effect of this new analysis on the hydrocarbon potential of the Saharan Atlas area, two major features need to be kept in mind: firstly, the overall north-eastward dip of the Saharan Atlas; and secondly, which formations should be targeted? The sub-Triassic may have potential, with Triassic evaporites forming a good seal for any potential underlying reservoirs. For these targets, it is thought that the western edge of the Saharan Atlas could be the most prospective area, while its eastern edge could be a better location to look at the Cretaceous and Mesozoic formations.

The Next Step

From the little information I have had the opportunity to access, it is clear that the tectonic setting of Northern Algeria has to be reconsidered through the interpretation of large amounts of data. There are about 20 wells, only in the Foreland Atlas domain, plus 15,000 km of 2D and 3D seismic, many geologic maps and several cross-sections and reports, with roughly eight source rocks, from Devonian to Cretaceous, and four potential reservoirs ranging from Devonian to Jurassic. These all need to be studied carefully, with the collaboration and permission of Sonatrach.

These analyses and interpretations need to be reinforced by further studies incorporating subsurface data from oil companies. The model also needs to consider the eastern section of the Maghrebian Belt, into Tunisia. This work is in progress, including the compilation of published data, but is not yet ready to be published.

We know that 'oil is first found in the brain of the geoscientist' – but the proof still lies in the drilling results, so the next step should be an exploration programme based on interpretation of the existing data held by interested oil companies. This programme could include vertical drilling on the western edge of the Saharan Atlas targeting the sub-Triassic formations, and in the eastern Saharan Atlas to investigate the Cretaceous–Cenozoic formations – avoiding those false anticlines! Also interesting would be a deviated (horizontal) west-east well intersecting the Ténès–Bousaada fault zone in the Central Block, as these faults may act as drainage features for the hydrocarbons.

Acknowledgements:
The author would like to thank Sonatrach for inviting him to the JST11 (11th Journées Scientifiques et Techniques) in Oran (Algeria) in April 2018

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Diving deeper to reveal hydrocarbon potential in the Barents Sea

The south-western Barents Sea is characterised by a complex geological regime with a heterogeneous overburden. A key challenge in producing an accurate image of the subsurface lies in creating a velocity model which describes the recorded data well. Refraction-based Full Waveform Inversion (FWI) has become the standard tool for high resolution velocity model building in the Barents Sea. Nevertheless, due to the lack of recorded long offsets, model depths have been limited to the shallow overburden in the past.

In 2018 PGS and TGS utilised a novel acquisition setup for acquiring an ultra high density 3D seismic dataset in the Barents Sea, covering parts of the Hammerfest Basin and Finnmark Platform. In addition to 16 densely spaced streamers, three streamers were extended from 7 km to 10 km length, allowing the recording of deeper diving waves (refractions) and thereby enabling FWI to produce velocity updates to greater depths.

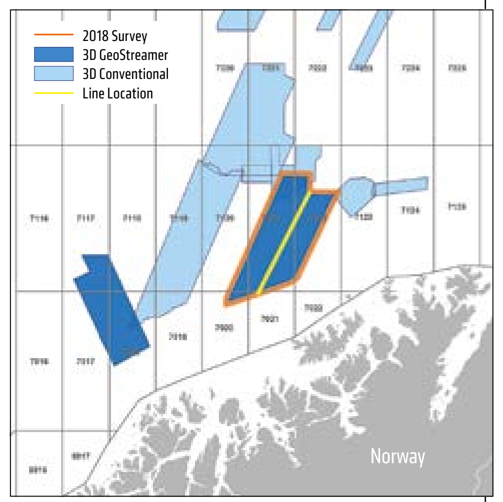
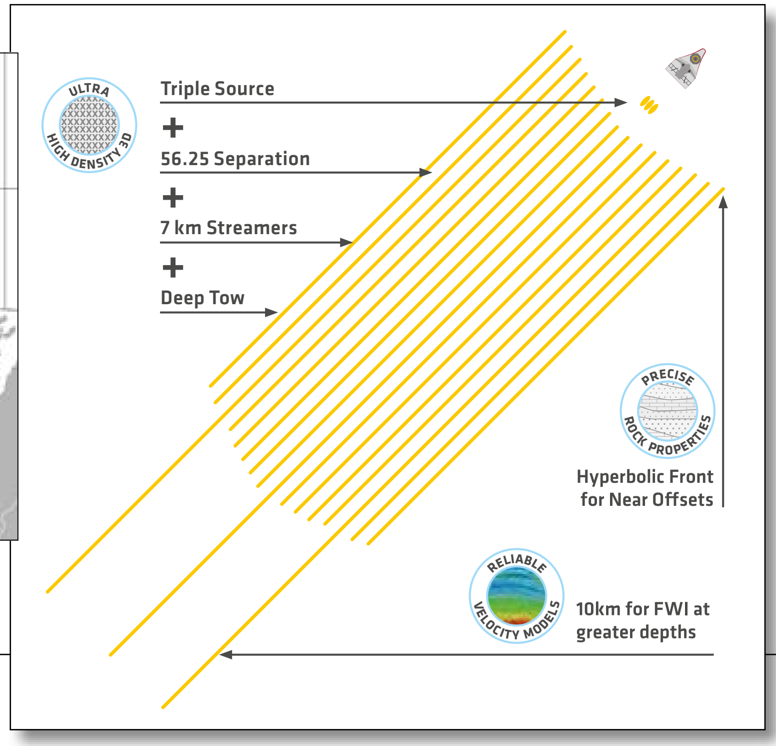
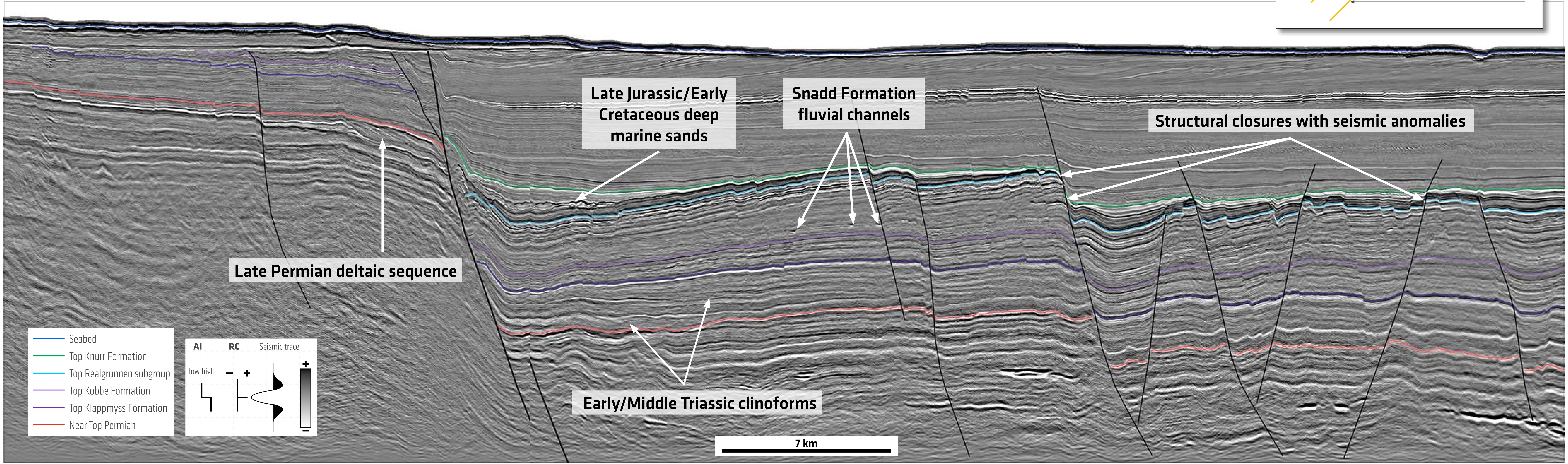


Figure1: Survey area



Seismic section (initial fast track Kirchhoff prestack depth migration) extending from the Finnmark Platform in the south-west into the Hammerfest Basin in the north-east. The initial depth migrated fast track data shows clear improvements in resolution and structural imaging compared to vintage data available in this complex area.



A Novel Solution Tailored for the Barents Sea

SÖREN NAUMANN and RUNE SAKARIASSEN, PGS

An unusual acquisition configuration resolves the challenges of the Barents Sea through an innovative combination of streamer setup and advanced imaging technologies.

The Barents Sea is one of the remaining frontier exploration areas on the Norwegian Continental Shelf (NCS); it accounts for around half of the undiscovered resources on the NCS, according to the Norwegian Petroleum Directorate. In order to fully exploit the exploration potential and to understand these frontier areas, high quality seismic data are required. PGS has added a unique ultra-high density 3D seismic dataset to their Barents Sea data library, utilising an innovative acquisition solution to enable FWI and high resolution imaging of this complex area.

The GeoStreamer survey was acquired during the summer season of 2018 and combined a high-density 16 x 56.25m streamer spread with a triple-source configuration. This resulted in a nominal acquisition bin size of 6.25 x 9.375m, allowing accurate imaging of frequencies as high as 200 Hz. For velocity model building using FWI, three out of the 16 streamers were extended from 7 km to 10 km, which allowed the recording of refracted energy generated from deeper geological layers. The survey covers an area of approximately 4,100 km^2 including parts of the Finnmark Platform and the Hammerfest Basin (Figure 1).

Great Potential

The Finnmark Platform is delineated from the Hammerfest Basin by the heavily displaced Troms-Finnmark Fault Complex, giving rise to large lateral velocity changes. On the Finnmark Platform a thick succession of Late Permian Tempelfjorden Group was deposited, consisting of alternating beds of sandstone/siltstone/claystone (Ørret Formation) and cherty limestone (Røye Formation). On the southern margin of the Hammerfest Basin there is evidence of a continuation of this Late Permian succession pinching out further north into the basin where a more carbonate-rich depositional environment is evident. Early and Middle Triassic clinoform beds and Late Triassic fluvial channel deposition are present, along with shallow marine sandstones of the Early to Middle Jurassic. There are also potential Late Jurassic and Early Cretaceous deep marine sandstones deposited along the margin of the Hammerfest Basin.

The stratigraphic units that have been identified as the key target areas for hydrocarbon plays are the shallow Kapp Toscana Group sandstones, and the deeper, potentially karstified, carbonates of Carboniferous/Permian age. Proven discoveries made in both geological regimes show the great potential of this area in the south-western Barents Sea. Nevertheless, a complex, heterogeneous geology and different target depths demand an appropriate acquisition solution. In order to produce an accurate, high-resolution image of the subsurface which reveals small-scale geological features and improves understanding of the geology, an accurate velocity model for pre-stack depth migration is required.

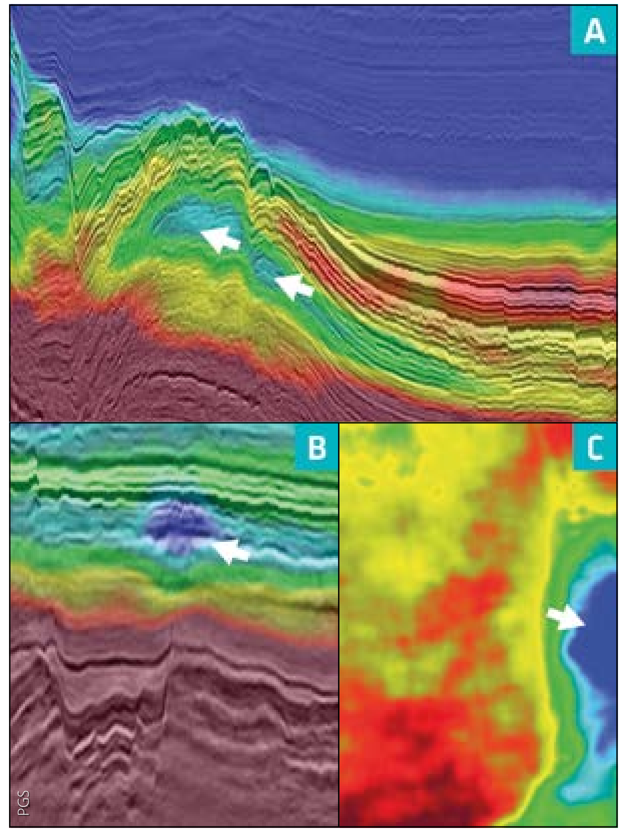


Figure 2: Fast track KPSTM stack with FWI velocity overlay through the Goliat reservoir (A) and the corresponding gas cloud (B). Velocity depth slice that shows a clear delineation of the overlain gas cloud (C). The high-resolution depth velocity model ensures accurate imaging of the subsurface, free from distortion effects caused by the heterogeneous overburden.

Refraction FWI for Detailed Velocity Models

In the Barents Sea, the combination of relatively shallow water depths and a hard, rugose sea floor creates a tremendous amount of noise. This complicates the use of reflections in FWI for velocity updates. On the other hand, this geological setting generates particularly strong and stable refractions (diving waves) and refraction-based FWI has been widely used to create detailed velocity models in the Barents Sea. However, model updates were limited to shallow depths due to the lack of recorded long offsets. With the unique, long offset streamer configuration deployed for this survey, a sufficient number of diving waves from deeper geological layers were recorded, which resulted in an extension of the model update depth from approximately 2.5 to 4 km depth. With a maximum frequency of 15 Hz for the FWI, a large amount of detail is included in the velocity model.

An example of the FWI velocity model around the Goliat oil field is shown in Figure 2. At the reservoir level, the model shows a clear low velocity anomaly, potentially indicating a porous and hydrocarbon-filled sand body. In the shallow overburden above the reservoir, a gas cloud can be clearly identified in the velocity model correlating well with an amplitude brightening on the underlying stack. On the velocity depth slice, it is obvious how FWI clearly delineates the actual extent of the gas cloud above parts of the Goliat field. The details and large velocity contrasts captured in the depth velocity model allow accurate imaging of the subsurface without being biased by distortion effects caused by the shallow heterogeneous overburden. Both the velocities and the resulting imaging provide further insight into the reservoir.

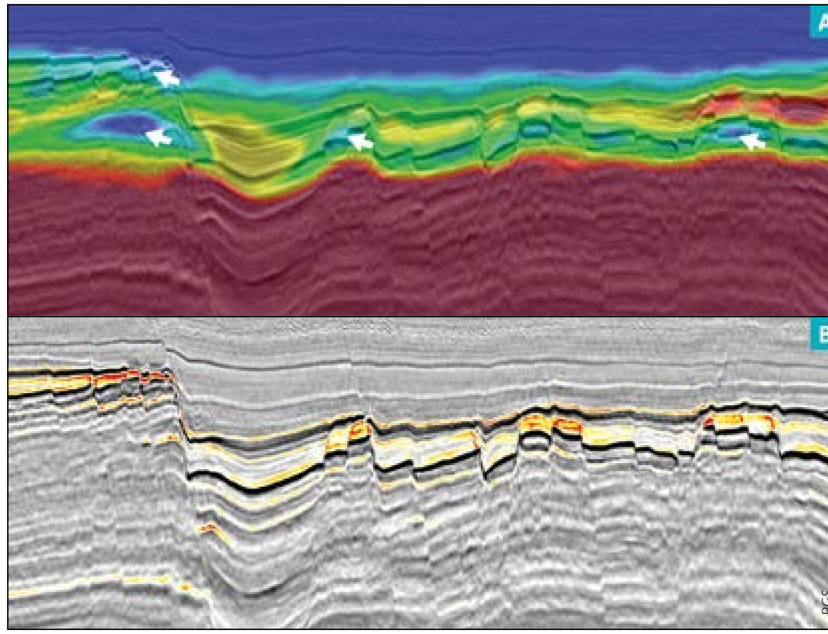


Figure 3: (A) FWI velocity model overlaid on a KPSDM stack and (B) KPSDM stack showing corresponding amplitude anomalies within the fault block complex. Both amplitude and velocity anomalies correlate well and this can be an indication of increased fluid accumulations at the structural highs.

Detecting Potential Hydrocarbon Plays

FWI velocity updates do not just provide a migration velocity model to enable accurate imaging of the subsurface; the results around the Goliat field demonstrate the ability of FWI to capture small scale velocity anomalies which are potentially associated with hydrocarbon accumulations. Figure 3 highlights a section around Top Realgrunnen at a depth of around 2.5 km (zoom of foldout line on previous pages). Within each fault block, low velocity zones are present at the top of the structure. These anomalous velocities correlate well with the seismic amplitude brightening and highlight areas of a potential increase in fluid accumulation.

Figure 4 shows velocity extractions at different stratigraphic units, including Top Kolmule and Top Realgrunnen. These velocity attribute maps highlight the spatial velocity distribution and, in combination with the topographic relief, several areas of anomalous low velocity zones can be identified which correlate well with potential structural closures. The detail the FWI velocity model provides can assist in identifying new hydrocarbon plays. Thanks to the additional long offset streamers and therefore increased model depth, detailed attribute maps can be extracted for both shallow and deep target horizons.

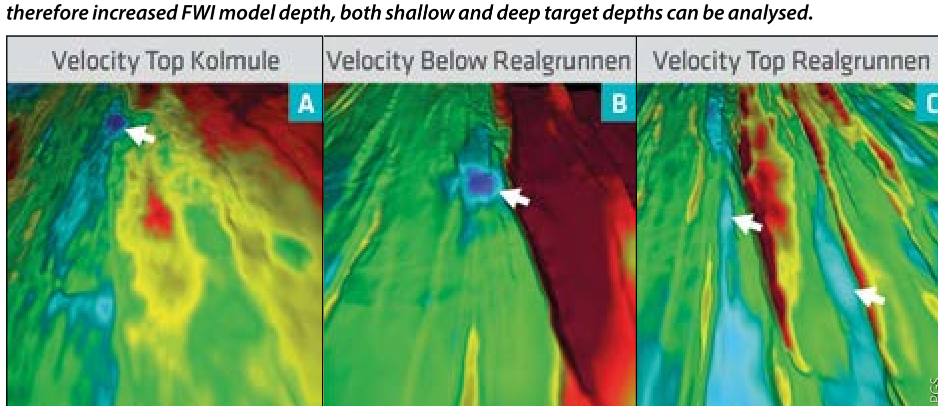
Deriving Attributes from FWI Velocities

To improve the understanding of a potential reservoir, the FWI results can be incorporated into a quantitative interpretation (QI) workflow. In the absence of any direct well information, the detailed FWI velocity model can be utilised as a low frequency model within a seismic acoustic inversion scheme. The long tails in the acquisition configuration enable deeper refraction FWI, filling the gap between 0 Hz and the lowest frequencies provided by conventional seismic, and allows the performance of absolute acoustic impedance inversion.

Furthermore, the velocities derived from FWI include valuable information in terms of reservoir characterisation. Low velocities can be an indication for porous sands, karstified carbonates, hydrocarbons or high porosity areas in general.

PGS considered imaging needs when designing this acquisition configuration so that the best solution was provided to resolve the challenges of the Barents Sea using an innovative combination of streamer setup and advanced imaging technologies. ■

Figure 4: Velocity attribute map extracted below Top Kolmule (A) and Top Realgrunnen level (B, C). Several clear low velocity anomalies can be observed, which correlate well with potential structural closures. These velocity attributes can help in identifying new hydrocarbon plays. Thanks to the additional long offsets and therefore increased FWI model depth, both shallow and deep target depths can be analysed.



The Death of Wiggle Picking

Geophysics must change – but it must also remain meaningful.

GEHRIG SCHULTZ, CHRIS TUCKER and KIRSTY SIMPSON; EPI

"Geophysical data are a part of everything that we do," Stephen Greenlee, president of ExxonMobil Exploration Co., told a roomful of people gathered for the opening session of the Society of Exploration Geophysicists International Annual Meeting. Whether we are picking a spot to explore, drill or bid on a block, deciding whether to continue an infill drilling programme or sanction a project, as he says: "It all relies on geophysical data."

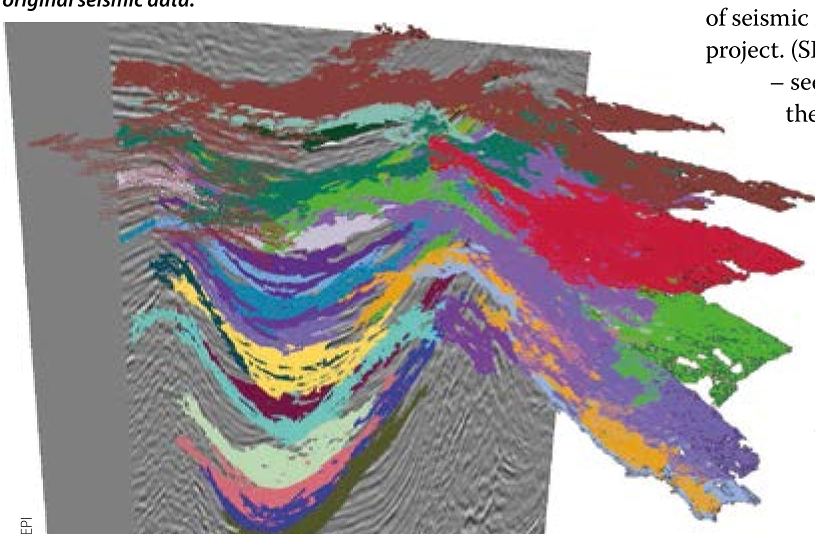
The amount of data collected from land and marine seismic surveys has grown considerably in recent years. A land seismic survey conducted in 2005 had 400,000 traces per km^2; by 2009, that number had reached 36 million. In 2018, an ultra-dense survey, with 72 million traces per km^2, was acquired onshore in Egypt. Between 2005 to 2009, the average volume of data gathered on an eight-hour shift grew from 100 gigabytes to more than 2 terabytes.

The problem that many companies are facing is that as the volume of data has increased exponentially, the timelines for delivering results has compressed.

Running Hard but Falling Behind

In an industry requiring ever more rapid decision-making, six to eight months interpretation time can no longer cut it. It has become clear that it is not just a matter of running faster or working harder; the key to success is working smarter and more effectively. Today's oil patch often demands almost instant opinions and interpretations of new data – how can geoscience feedback be provided whilst remaining an accurate and reliable answer?

Figure 1: Selected GeoPopulations™ generated within 24 hours from the original seismic data.



Machine learning and artificial intelligence (AI) are being leveraged to tackle the big data issue successfully in many industries, including oil and gas. This new technology is now being utilised to enhance interpretation workflows, enabling rapid, unbiased and comprehensive understanding of prospectivity.

Genetic Sequencing to the Rescue

Case studies and experience show that an interpreter may spend up to 60% of their time picking horizons and the remaining 40% actually thinking about the geological significance of the result. Seisnetics is an AI-driven software that addresses this issue by applying genetic segmentation and gene sequencing techniques, pre-interpretation, to analyse single or multiple seismic data volumes, significantly accelerating the interpretation workflow. The software selects random waveforms as seed points within the 3D volume to initiate unbiased processing, resulting in the generation of geopopulations (groupings of genetically similar waveforms) for virtually every peak and trough in the volume (Figure 1). The resulting spatial database is fully queryable and can be visualised either within the software's specialist 3D viewer or the interpretation software of your choice.

With the mechanics of picking horizons fully automated, the interpreter has much more time to focus on the geological and geophysical significance of the horizons. This methodology empowers the interpreter throughout the E&P cycle, from rapid new ventures screening of large datasets and prospect identification, through to the optimisation of well locations and modelling of existing fields.

The power of Seisnetics for fast and accurate identification of seismic features was tested on the Depth SEAM SEG GoM project. (SEAM Phase I addressed challenges of subsalt imaging – see *GEO ExPro* Vol. 15, No. 4 for more information on the project.) It took 20 minutes to download the data, 11 minutes to run the software, and just a single minute to find the hidden 'surface' of the SEG logo below the salt.

The process facilitates strategic data mining and integration of other relevant information such as well and production data. This enables much larger volumes of geophysical and geological information to be integrated into the decision-making process, quickly creating value, as the following case study demonstrates.

Case Study: Eastern Niger Delta

The case study is located in the Rio del Rey Basin of

Cameroon, a sub-basin of the Eastern Niger Delta system. The area is a mature petroleum system with over 1 billion barrels produced to date, mainly from shallow deltaic reservoirs, with exploration focused on structural traps over the crests of diapirs and toe fold structures.

The case study area was previously operated by supermajors, who made several marginal discoveries in shallow reservoirs. The area is characterised by challenging seismic data and complex structures, such as mud diapirs, multiple phases of faulting and the previously mentioned toe folds, as well as complicated stratigraphy, including shallow water deltaic reservoirs, incised valley fill and deeper water turbidites.

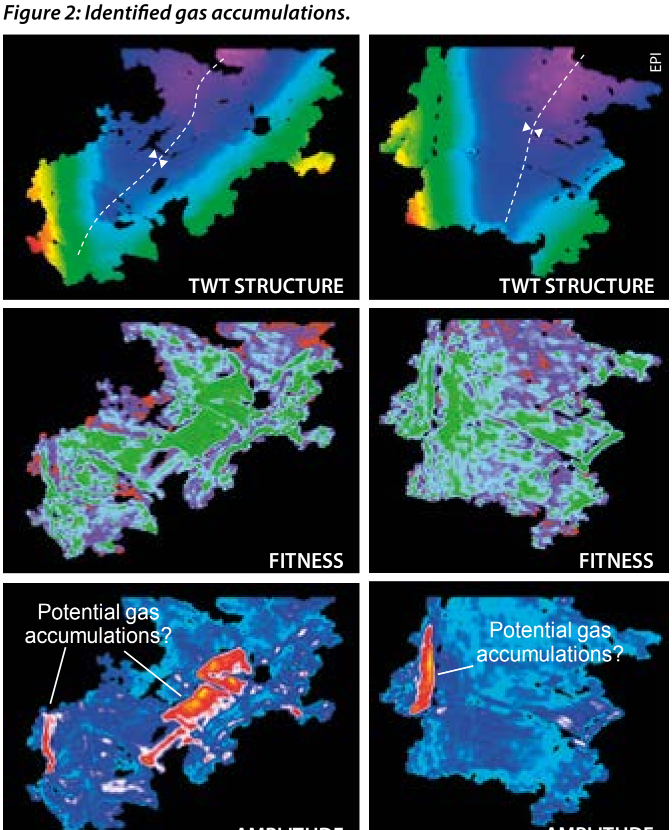
The current operator is planning to drill a new exploration well in 2019. The aim of this study was to leverage the power of Seisnetics to rapidly identify potential follow-on targets for subsequent drilling programmes.

The initial pre-interpretation processing of about 200 km^2 of 3D seismic was completed in less than 24 hours. The first data QC highlighted a number of stratigraphic features (channels and fans) which represent reservoir targets and possible structural and stratigraphic trapping configurations, as well as multiple potential gas accumulations.

The software enabled rapid identification and visualisation of potential satellite drilling targets around the flanks of an existing discovery. Figure 3 shows a 3D view of a regionally extensive erosional surface overlain by a seismic amplitude extraction highlighting the presence of sands.

This type of erosional feature, related to gravity-driven collapse and subsequent fill, is common throughout the Eastern Niger Delta and often controls the distribution of high quality reservoirs (e.g. Qua Iboe). The seismic attributes

Figure 2: Identified gas accumulations.



indicate the presence of sandy slumps/debris flows and channel features feeding fans near the base of slope, suggesting that the software has enabled the identification of a play in the study area which is similar to fields like Edop in Nigeria.

New Exploration Plays

Deeper turbidites are prolific reservoirs in Nigeria and Equatorial Guinea (e.g. Alba), as well as in other basins around the world like the Gulf of Mexico, but are largely untested in Cameroon. Interrogation of the database in the Seisnetics 3D viewer enabled the easy identification of higher amplitude features which resemble stacked and ponded turbidite fans. Figure 4 shows these features, which pinch-out towards the adjacent diapir and toe fold highs. The case study highlights that the distribution of turbidite reservoirs becomes progressively more restricted within the younger stratigraphy. Deeper turbidites are more extensive, locally pinching-out onto developing highs, while younger turbidites are more restricted, deposited in 'mini-basins' between emerging toe fold and diapiric highs. The AI-driven interpretation has therefore highlighted the presence of stacked targets.

The integration of existing well data into the workflow helped delineate the geometries and extent of known gas accumulations, extrapolation of which identified a number of undrilled gas prospects and enabled the evaluation of potential oil rims.

Adding Value

Leveraging the power of AI-driven software like Seisnetics allows the rapid evaluation and visualisation of new prospectivity in an area of complex geology. In particular, it has enabled the interpreters to focus on adding value rather than 'wiggle picking'.

References available online.

Acknowledgement: The authors would like to thank Tower Resources for providing the data for the case study and also GeoIntel, their partners in Seisnetics.

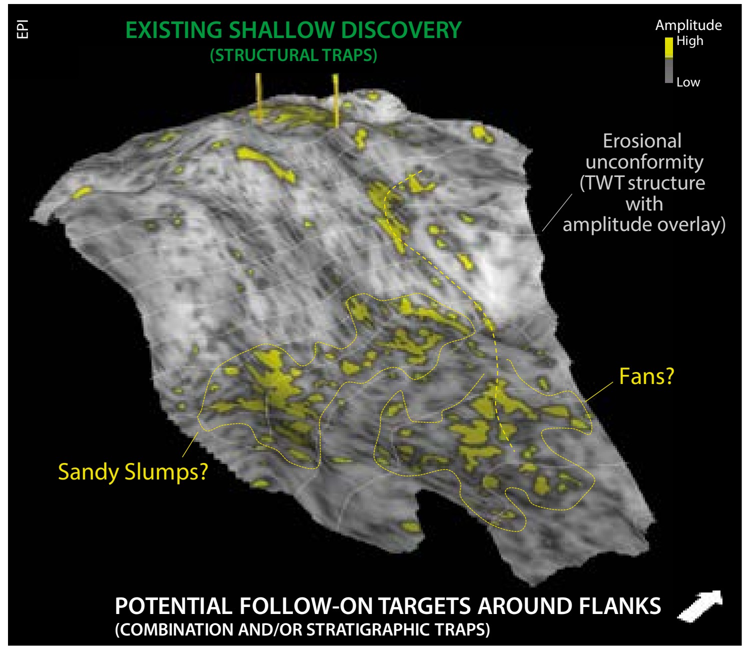
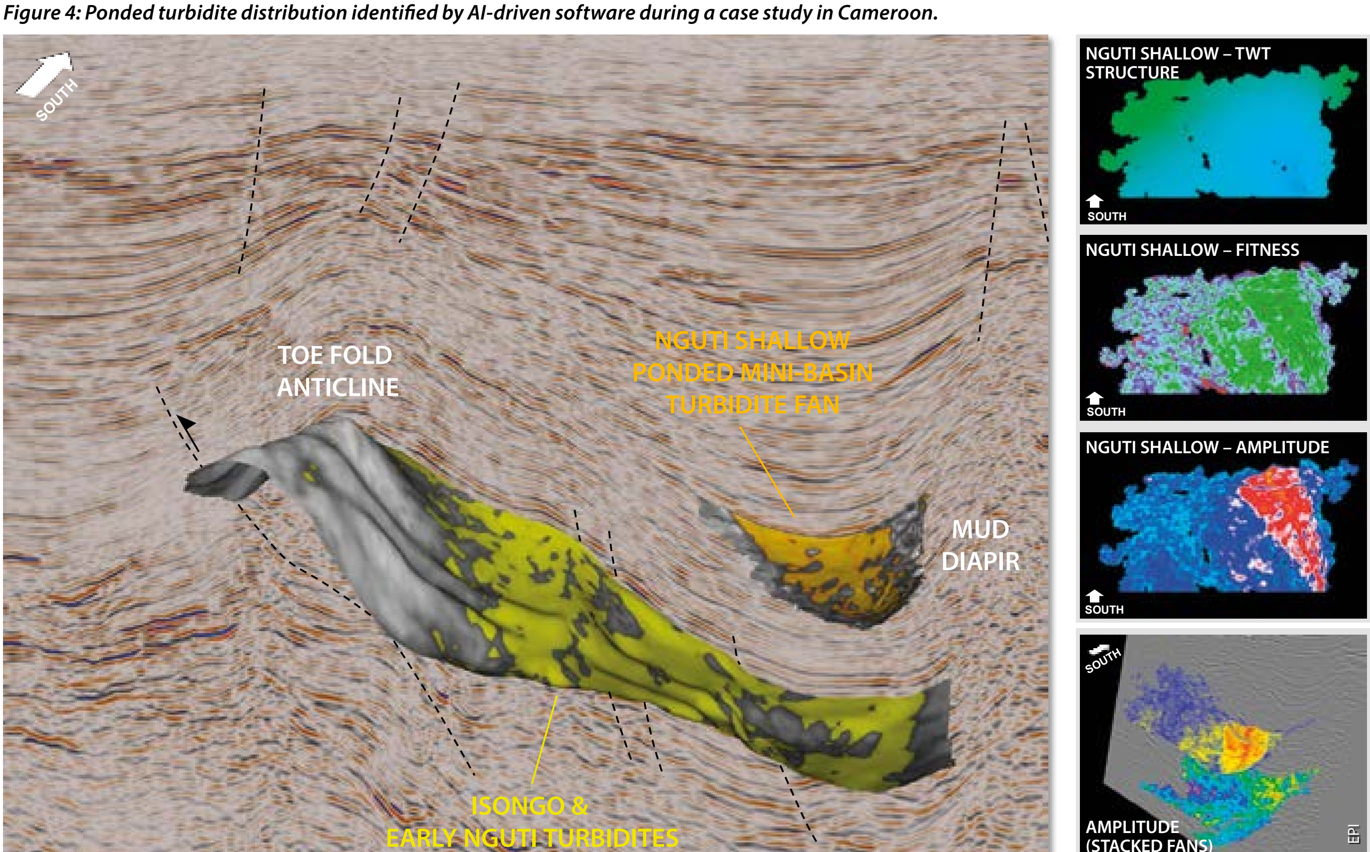


Figure 3: Potential satellite targets identified by the case study.

Figure 4: Ponded turbidite distribution identified by AI-driven software during a case study in Cameroon.



Morocco's Atlas Range

The Atlas Mountains, with their folded sedimentary rocks and thick-skinned faulting, soar above dramatic gorges, lush palm oases, crumbling kasbahs, and the exotic souk in Marrakesh.

Exotic Mountains in an Exotic Land

LON ABBOTT and TERRI COOK

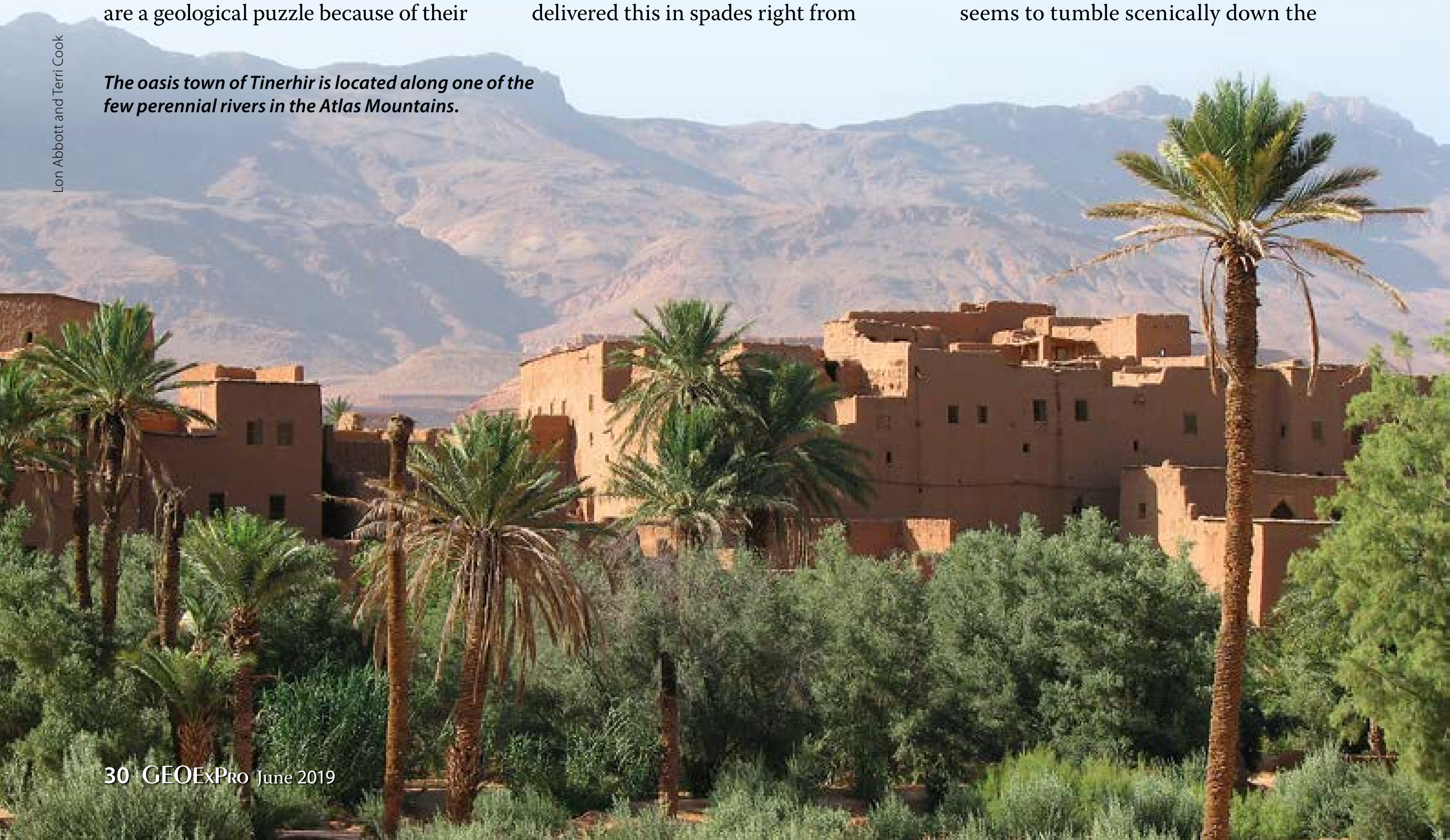
As connoisseurs of mountain scenery who enjoy exploring the world's high places while also immersing ourselves in foreign cultures, we jumped at the chance, while touring southern Spain, to ride a ferry across the famed Strait of Gibraltar to visit mountainous Morocco. The ferry docks in Tangier at the foot of the rugged Rif Mountains, which rise along the convergent Eurasian-African plate boundary precisely where plate tectonic theory teaches us to expect a mountain range. Although we'd heard many stories about the Rif's wonderful scenery and cultural delights, we chose instead to head inland to explore the Atlas, a much higher and more geologically exotic range.

The Atlas, which rise to 4,167m, 1,700m higher than the Rif's tallest peak, are a geological puzzle because of their location at the edge of the West African Craton, comparatively far from the active plate boundary, and because their lofty elevation greatly exceeds what is expected for an isostatically compensated range that is supported by a crustal root. By violating the plate tectonics 'rules' that neatly explain why most mountain ranges exist where they do, the Atlas epitomise the increasing number of exceptions that geoscientists are recognising. As such, the range is both an alluring geotourism destination and a natural laboratory in which to test new tectonic explanations.

Volcanoes and Roman Ruins

We came to Morocco seeking an experience different from that which Europe has to offer. The country delivered this in spades right from our very first stop: the Roman ruins at Volubilis, an impressive UNESCO World Heritage Site located at the foot of an isolated mountain named Jebel Zerhoun. Unlike many other ancient ruins, Volubilis is not a major tourist attraction surrounded by pricey snack bars and kitschy curio shops. It instead rises from a vacant field, to all appearances completely forgotten by history. The serene setting and excellent preservation make it easy to contemplate the city's heyday as a far-flung outpost on the edge of the once-mighty Roman Empire, as well as the site's later role as the seat of Idris I, founder of the region's first Islamic empire.

Just south-east of Volubilis, the town of Moulay Idris, where Idris I is buried, seems to tumble scenically down the



Lon Abbott and Terri Cook

The oasis town of Tinerhir is located along one of the few perennial rivers in the Atlas Mountains.

flank of Jebel Zerhoun. From here the N13 highway passes through the city of Meknes, one of Morocco's four former imperial capitals, and then climbs up and over the rolling, 1,200 to 2,000m-high upland of the Middle Atlas, the northernmost of the Atlas chain's several sub-ranges. Near the town of Azrou the road passes through a forest of stately cedar trees. Several intact Quaternary cinder cones and alkalic basalt flows belonging to Morocco's youngest and most voluminous Cenozoic volcanic field are visible from the highway. These features offer mute testimony to the presence of thin lithosphere, and hence unusually shallow asthenosphere, beneath the Atlas region. Most geoscientists attribute the Atlas' abnormal height to thermal expansion resulting from the replacement of colder lithosphere with this warmer asthenosphere.

But explanations for why the lithosphere beneath the Atlas is so unusually thin vary. Ideas include a 'baby' hotspot plume that taps material from the larger Canary Islands hotspot to the west; lithospheric delamination; a 'lithospheric drip' (known more formally as a Rayleigh-Taylor instability); or small-scale convection driven by edge effects at the interface between the West African Craton's thick lithosphere and the much thinner and younger lithosphere that underlies the Mediterranean Sea. Although research papers on these topics are coming out in droves, no single hypothesis has emerged as the clear leader.

Google Earth map of Morocco showing places mentioned in the text.

An Inverted Rift

We continued south on the N13 road through a small intermontane basin and over the High Atlas, the tallest of the chain's sub-ranges, via a 1,900m-high pass. The road then descends through the Jurassic limestone walls that line the Ziz River gorge, ushering drivers out of the mountains into the increasingly arid landscape of the Ouarzazate foreland basin, which marks the northern edge of the vast Sahara Desert.

We then turned west, traversing the foreland basin. This basin is unusually shallow, hosting a mere 1,200m of Neogene alluvial and lacustrine fill, likely due to a combination of modest amounts of crustal shortening (estimated at 26 km, or about 24% at the Ziz Gorge) and a relatively strong underlying lithosphere, which limits the basin's flexural subsidence in response to whatever thrust sheet loading has occurred.

The closer we got to our next destination, the oasis town of Tinerhir, the taller and more dramatic the mountains became. Tinerhir is located at the mouth of the spectacular Todra Gorge. The gorge's steep limestone walls shelter one of the range's precious perennial streams, whose life-sustaining waters create a stark juxtaposition of verdant green fields and palm orchards nestled within a barren, brown landscape almost completely devoid of vegetation.

Although most geoscientists agree that the hot mantle beneath the High

Inversion of a Jurassic rift produced the tightly folded limestone walls of the impressive Todra Gorge.

Atlas has raised the range higher than it would otherwise be, textbook plate tectonics has played an equally important role in the Atlas uplift story. The range was raised primarily by slip along a series of high-angle, basement-involved reverse faults – north-vergent ones on the range's northern flank and south-vergent ones on its southern side.

These high-angle faults were born as normal faults during the break-up of Pangaea, when the area that is today occupied by the Atlas was a rift that linked a young Atlantic spreading centre to the Tethys Sea. Throughout the Triassic and Jurassic, five to six kilometres of redbeds followed by open marine limestones gradually filled this rift. Dramatic differences in the thickness of these units testify to the activity of these faults, with thicker sections on the hanging walls and thinner ones across the footwalls of the parallel faults. In contrast, the Cretaceous section consists of limestone whose thickness is uniform across the area, suggesting that rifting had ceased by that time. During the Cenozoic, when the region's stress field switched to one of compression with the advent of the Alpine Orogeny, these normal faults were reactivated as reverse faults to form today's thick-skinned mountain belt.

Despite the predominance of thick-skinned processes in the modern Atlas, the range's southern flank displays a classic thin-skinned fold-and-thrust belt whose tight folds in competent Jurassic limestone are magnificently displayed as you wend your way up the 20-km-long Todra Gorge. Triassic evaporites serve as a decollement along which the Mesozoic cover has detached from the basement, in the process thrusting the sedimentary rift fill up and over the foreland's younger rocks.

The Dades River carved this spectacular slot through a section of tectonically thickened Jurassic limestone.

Spectacular Slot Canyons

About 53 km west of Tinerhir, the Dades, Morocco's longest river, flows across the High Atlas' frontal thrust and into the Ouarzazate foreland basin at the oasis town of Boumalne du Dades. The 5 km Dades Gorge, which begins about 15 km north of Boumalne du Dades, is a memorable sight. It is a true slot canyon that measures more than 200m deep and, in spots, just 20m wide. Because the road has to climb up and around the canyon, it offers breathtaking vistas into the slot both up and downstream. From this high perch, it's easy to see that the Dades flows down the axis of an asymmetric syncline. The gorge is carved through competent lower Jurassic marine limestone of the Jebl Choucht Formation. Thrusting here has nearly doubled the formation's thickness, probably playing an important role in forcing the river to carve a deep gorge instead of tracing an easier route through the less competent units that under- and overlie this resistant limestone.

A few kilometres further upstream, both the river and the road squeeze through another narrow canyon, the 150m-deep, 20 to 50m-wide Tarhia n'Dades Gorge. Geomorphologists have deduced that the Tarhia n'Dades marks the spot of a stream capture event that shifted the course of the ancestral Dades River. The gorge used to lie on a tributary that flowed down the limestone face of the syncline limb. The tributary had sufficient stream power to cut down through a comparatively thin portion of the Jebl Chouht limestone, which exposed the much softer, underlying Ouchbis mudstones to rapid erosion, triggering the capture event. The Tarhia n'Dades Gorge provides a dramatic location from which to contemplate the dynamic landscape of the Atlas.

Kasbahs and the Marrakesh Souk

After marvelling at the Dades Gorge, we continued our trek westwards through the Ouarzazate foreland basin to the scenic kasbah (fortress) of Ait Benhaddou. This UNESCO World Heritage Site's popularity has skyrocketed since it stood in for the fictional cities of 'Yunkai' and 'Pentos' on the television series *Game of Thrones*. From our comfortable lodge situated nearby in the Asif Iminni valley, we also explored the much smaller Tiseldei kasbah, whose abandoned remains guard the valley from a perch high on the adjacent slope. Both kasbahs are built on Jurassic redbeds intruded by dolerite sills, further evidence of the Mesozoic rift event.

The road to Marrakesh climbs over the High Atlas at the 2,260m Tise-n-Tichka Pass about 50 km east of Toubkal, the range's highest peak. Here at the western end of the High Atlas, where the mountains are highest, the amount of crustal shortening is, paradoxically, far less than it is farther east: a mere 13 km (15%) here. Given that crustal shortening is the mechanism that builds the crustal root, the Atlas are clearly not supported solely by such a root. Instead, the lithosphere is thinnest here where the mountains are highest, reinforcing the idea that mantle heat is what supports these high mountains.

The peaks surrounding the pass consist of mildly metamorphosed Palaeozoic and Precambrian basement rocks. For years geologists have used this fact to argue that the Atlas near Marrakesh stood as a palaeo-high in the Mesozoic rift, thereby limiting the thickness of rift fill and thus explaining the basement exposure here. Recent zircon (U-Th)/He thermochronology, however, has shown that the rift fill here was 5–6 km thick, comparable to what is present farther east. So it therefore appears that the exposure of basement rock here in the highest mountains of the Atlas is due not to thinner rift fill, but rather to deeper erosion.

The descent from Tise-n-Tichka Pass is executed in a series of tight switchbacks with sweeping views across the rugged range. The road crosses the northern bounding fault and exits the Atlas a mere 30 km from Marrakesh, a bustling city of a million people that was founded in 1071 as the capital of the Almoravid Empire. Its fascinating old quarter is surrounded by imposing walls of rammed red clay, built as a protective fortification during the 12th century.

But Marrakesh's main allure for travellers is the chance to wander through its traditional markets, known as 'souks'. The city's main souk, which is among the most famous in the Arab world, is a bustling and colourful scene. From watching snake charmers ply their trade in the large public square to getting lost in the warren of narrow alleyways lined with shops selling colourful spices, cloth, jewellery, and kitchenware, a visit to a Marrakesh souk is an unforgettable experience.

For us it was a fitting finale to a trip that delivered all of the exotic culture, equally exotic geology, and rugged mountain and canyon scenery we had come to Morocco to experience. ■

Shopping in Marrakesh's bustling souk is a colorful experience.

Making Waves

Seismic Data Collection Using Vibroseis Technology

Most people see a vibroseis as a big, loud, and even dirty machine that shakes the ground. In reality, the modern vibroseis is a complex, delicately tuned machine that just happens to be big, loud, and sometimes dirty. The shaking gets translated into seismic data to provide insights into the subsurface.

C. JASON CRISS, INOVA Geophysical

The process of defining a sweep, testing a vibroseis, and ultimately deciding on shooting parameters for seismic, is more complex than most people think. Designing a vibroseis, building it, and keeping it working is just as complex. In this article we discuss the key pieces in these intricate processes: sweep design; the controller; mechanics and hydraulics; and important specifications.

Designing Sweep

Sweeps have three key characteristics: a starting frequency, an ending frequency and a sweep rate. When a geophysicist designs a sweep, what they are really doing is telling the earth how they want it to respond. For this they need to find a balance between frequencies. Higher frequencies yield more seismic details, while lower frequencies tend to propagate further and improve the fidelity of the response.

Aside from the frequency range, the sweep rate is probably the most important feature. If it is too slow – something below 0.5 Hz/sec – the hydraulic system of the vibroseis struggles to reproduce the sweep; if it is too fast, the mechanical side of the machine simply cannot respond quickly enough, and will generate noise or limited force. Most of the sweeps in oil and gas exploration will begin at 1–2 Hz and end in the 85–90 Hz range, with a duration of 8–20 seconds. This is primarily because the earth simply will not respond, seismically speaking, to higher frequencies. Sweeping at frequencies lower than 2Hz can still be regarded as research. The length of the sweep, however, is guided by more practical forces: time and money. There are some regions of the world where higher frequencies are possible, but they tend to be less common.

Testing is a critical phase because the effectiveness of the vibroseis' ability to reproduce the designed sweep is a complex interaction between the hydraulics and mechanics of the vibroseis and the portion of the near surface of the earth that is captured by the baseplate of the machine. The variability of the near surface can be daunting and every effort should be made to optimise the result. Nevertheless, testing factors such as sweep length and force settings create predictable results, so the time spent with this type of parameter testing is often not needed.

In recent years, sweeps have been adapted in an attempt to enhance low frequencies, and are referred to as low dwell sweeps. These frequencies are generally in the range where the vibroseis cannot sweep at full force due to limitations in the hydraulic system or the mechanics. The force output of this sweep is designed to match the performance profile of the particular vibroseis. This low dwell sweep has

An 80,000 lb vibroseis working in the desert.

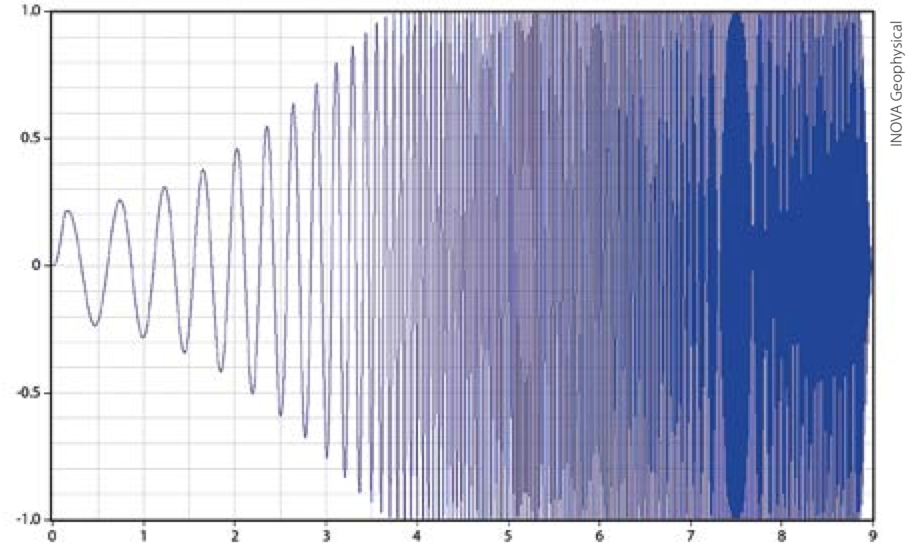
INOVA Geophysical

gained more attention due to its success at enhancing frequencies in the 1–5 Hz range in several regions.

The Vibroseis Brain

The task of the controller is to take the designed sweep and translate it into work for the vibroseis. It has been said that vibroseis technology does not get enough energy into the ground, but this often-repeated statement is fundamentally wrong. A basic idea of physics says that energy is the potential to do work. What people should really be saying is that the vibroseis is not doing enough work, because work is defined as the interaction of force and displacement. For this purpose the controller uses a sophisticated feedback loop to manage the pilot valve, a small hydraulic valve that is the first stage in the hydraulic system and is ultimately translated into bigger forces. The pilot valve controls the mainstage valve, which controls the main piston, and the main piston drives the mass. Feedback comes from accelerometers on the mass and the baseplate. The controller tells the vibroseis what to do, then measures its response and adapts the control in an attempt to match the vibroseis' output to the sweep as closely as possible.

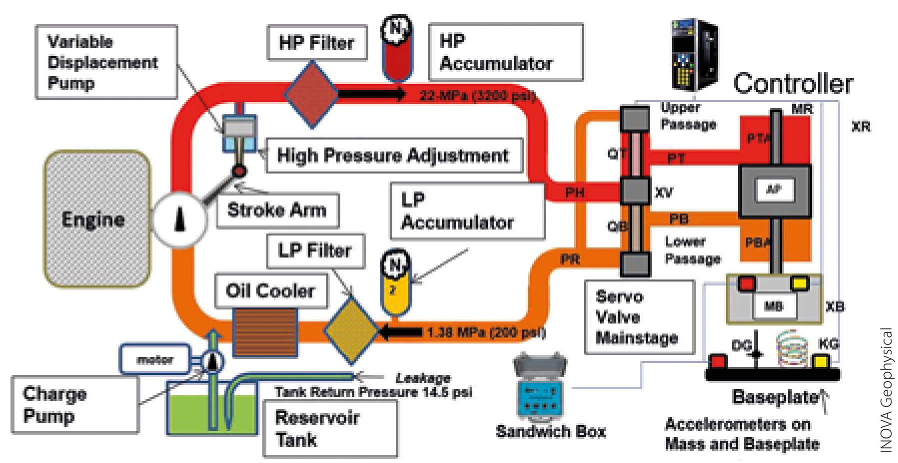
It is an imperfect machine, but the real measure of success is the consistency of the radiated sweep from one source point to another; consistency over variable ground means that the source signature is constant and predictable. This improves the final seismic result by eliminating spatial variables from processing and the final interpretation.



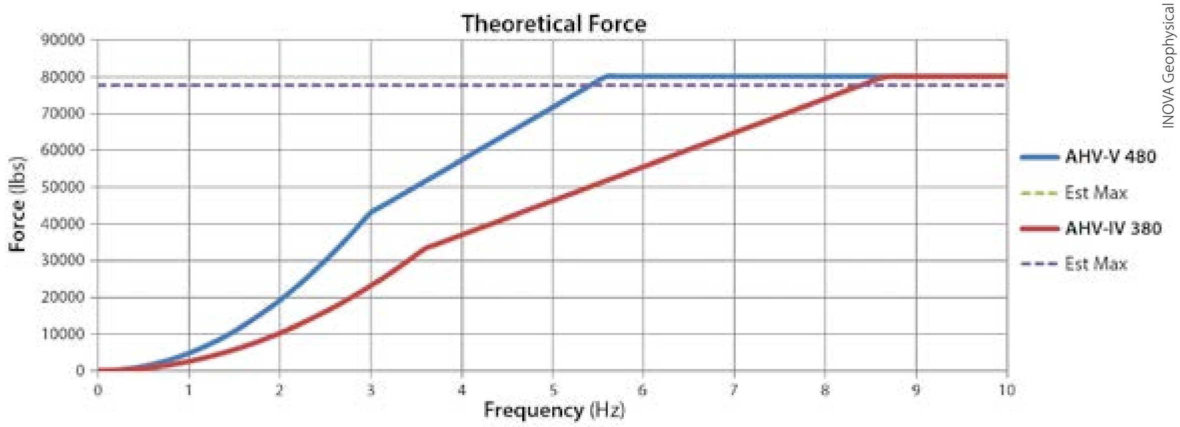
A low dwell sweep, typical of the type utilised today. There is a slower sweep rate from 0–3.5 seconds in the lower frequencies followed by a transition to a linear portion from 3.5–9 seconds. The amplitude of the sweep in the low frequency portion is proportional to the limitations of the vibroseis.

Controllers have also been enhanced in recent years to include features such as harmonic distortion reduction. Harmonic distortion is the noise that is always present when sweeping with a vibroseis that also steals some of the desirable radiated force from a sweep. If harmonics can be reduced, then the fundamental force of the vibroseis can be increased. The controller is

This diagram shows a schematic of the critical, mechanical, and hydraulic components of a vibroseis. The controller manages the full system with feedback from the accelerometers on the mass and baseplate.



Theoretical force profiles for two different 80,000 lb vibroseis. The blue curve shows the dramatic improvement that is possible with design feature changes such as a longer stroke and greater hydraulic flow.



the brain of the vibroseis but like the human brain, the body cannot always do what the brain says. Some of the sweeps that are proposed, such as random sweeps, simply cannot be reproduced mechanically in a reliable and consistent way.

Designers and Mechanics

Vibroseis experts come in two forms: the individuals that design vibroseis and the mechanics that build and maintain them. If you distil what a vibroseis does, it is really just an exercise in basic physics. The machine is designed to hold everything stationary, then oscillate a very heavy mass. Ideally, the oscillations will match the sweep profile. The hold-down weight of the vibroseis keeps the oscillating mass coupled to the ground so that the majority of the work performed is translated into radiated seismic waves. This work is accomplished through a surprisingly complex system of hydraulics and mechanics; this is where the real experts ply their trade.

Ideally, the hydraulic fluid will drive the mass up and down in a way that matches the designed sweep. While this sounds simple, the mass can weigh as much as 6,100 kg (13,448 lbs), so making it oscillate at over 100 cycles per second in a precise way is harder than it seems. Careful adjustments and calibrations are done to get the vibroseis to repeat oscillation reliably. The designers make certain that the physics is correct, while the mechanics build the units and keep them working correctly. A poorly maintained or adjusted vibroseis will generate a substantial amount of unnecessary noise, which will contaminate the result. In recent years, many improvements have been made to the vibroseis as a complete system, which have enhanced the performance of the unit when compared to those built in the late 1990s. Overall, maintenance and setup are still the major components to optimal performance.

Important Specifications

Low Frequency Performance: There have been many publications on this topic recently, but the critical factors to understand are the usable stroke of the vibroseis and the hydraulic flow rate. Some manufacturers publish the full force frequency, which provides an insight into the low frequency performance, but has limited value in predicting force output in the 1–4 Hz range of any vibroseis. A longer, usable stroke will result in a substantial increase in low frequency force. To date, the longest stroke production vibroseis available has a usable mass stroke of 17.78 cm (7”), while most older models are limited to about half that. With a long stroke, an 80,000 lb (~35,000 kg) vibroseis can produce only about 4,800 lbs (2,177 kg) of force at 1 Hz.

Peak Force: This term is generally thought of as the hold-down weight of the vibrator. It makes sense that the vibrator cannot output more force than the total weight of the unit; however, a more accurate measure is related to the hydraulic pressure and area of the mass piston. The operating high pressure multiplied by the area of the piston head is equal to the actual maximum force the vibrator can exert. By design, this force is generally very close to the hold-down weight of the unit, but it is based on parameters that are often not specified in marketing material. The complexity increases with the need to subtract the low side pressure from the equation. Nothing related to vibroseis technology is as straightforward as it initially appears!

Frequency Range: Most manufacturers will publish the frequency range that the vibroseis is able to reproduce; the caveat here is the force. High frequency sweep generation is almost always limited to something less than the published maximum force of the vibroseis. With large 60,000–80,000 lb vibrators, the maximum frequency is generally in the 130–140 Hz range – above those frequencies the vibrator sweeps with less force and will also generate more noise. With smaller vibroseis (25,000–35,000 lb), much higher frequencies (200–300 Hz) are possible, but often come with the same restrictions for lower force output.

There are other specifications that can be important and could impact operations and other detailed aspects of the vibroseis, but the ones discussed here are generally the most critical for geophysical considerations.

Complex and Precise Instrument

Vibroseis has become the common source for seismic data collection globally. Many improvements have taken place in recent years to make it a better, more consistent seismic source in all types of terrains. Understanding that the vibroseis is a highly complex and precise instrument, rather than just a large, brute force machine, is a key to its long-term success. ■

Exhumed Portuguese Oil Field Suggests Conjugate Potential

An exhumed oil field is exposed in the central Lusitanian Basin, now biodegraded to a tar-sandstone deposit. This is the only known outcrop of an oilfield trapped on a salt diapir flank, and the first to be described in this basin. This discovery significantly enhances the hydrocarbon potential of the Lusitanian and Peniche Basins and the conjugate Carson-Bonnition Basin in Newfoundland.

IAN DAVISON, Earthmoves Ltd, UK and **PEDRO BARRETO**, Partex Oil and Gas, Portugal

The Lusitanian Basin is part of the Central Atlantic rifting system which started opening between Late Triassic and Early Jurassic times. Hettangian-age salt was deposited during the rifting event, salt diapirs initiated soon afterwards. Salt diapir growth continued thoughout the Jurassic and Cretaceous. Alpine compression from Late Cretaceous to the present day caused squeezing of the diapirs and produced folding of the adjacent overburden.

The Lusitanian Basin has been extensively explored for hydrocarbons over the past 80 years, with 135 exploration wells drilled, predominantly onshore, yet no commercial oil has been discovered, and it has been questioned whether a viable petroleum system exists.

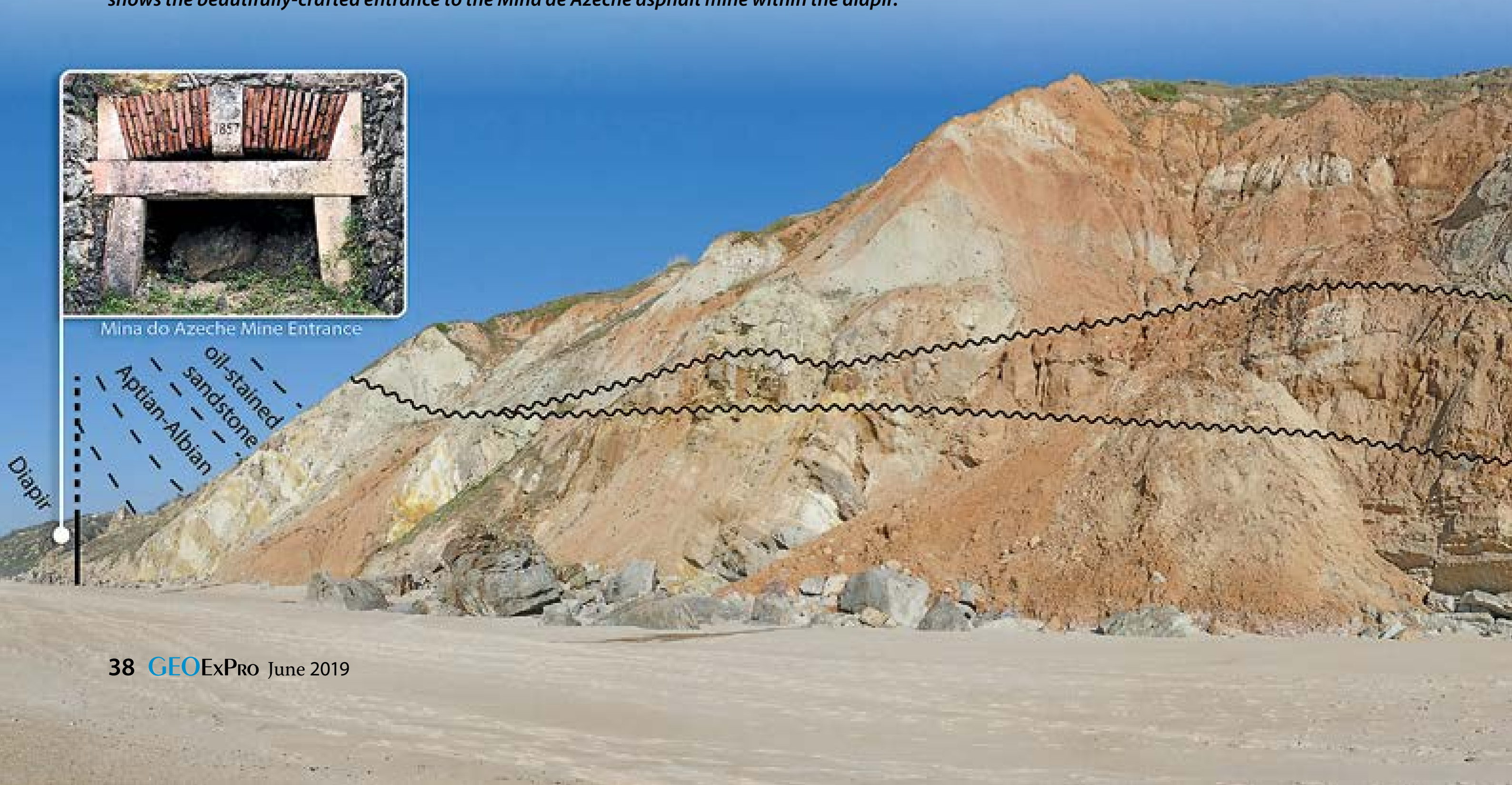
São Pedro de Moel Oilfield

Recent field work at Praia de Paredes de Vitória and Pedras Negras (black rocks) has revealed the existence of an important exhumed oil field, that has now biodegraded to bitumen. These two key outcrops occur at both ends of the oil field, which is trapped against an elongate salt diapir. Unfortunately, the inland area has very little outcrop and is now inaccessible following an extensive forest fire in October 2017, which left many tall tree trunks standing precariously, making it a 'no-go' danger area. Nonetheless, the information collected from vintage geological survey maps, together with exploration well data available around the diapir, provide a good control of the diapir's lateral extent, eastward and westward.

The Azeche Mine at Praia de Paredes de Vitória was exploited for tar from the 1840s into the early 20th century. At least 507 tonnes of bitumen were mined here (Rodrigues, 1934). The tar sands and dolomites from this mine were used to surface the first asphalted roads in Lisbon and paved railway stations across the country. The mine lies on the southern contact of the São Pedro de Moel salt diapir and the location is therefore well known as an oil seep – but it is of much greater significant than this.

As can be seen in the image below, the sea cliffs at Praia de Paredes de Vitória expose a 50m vertical column of

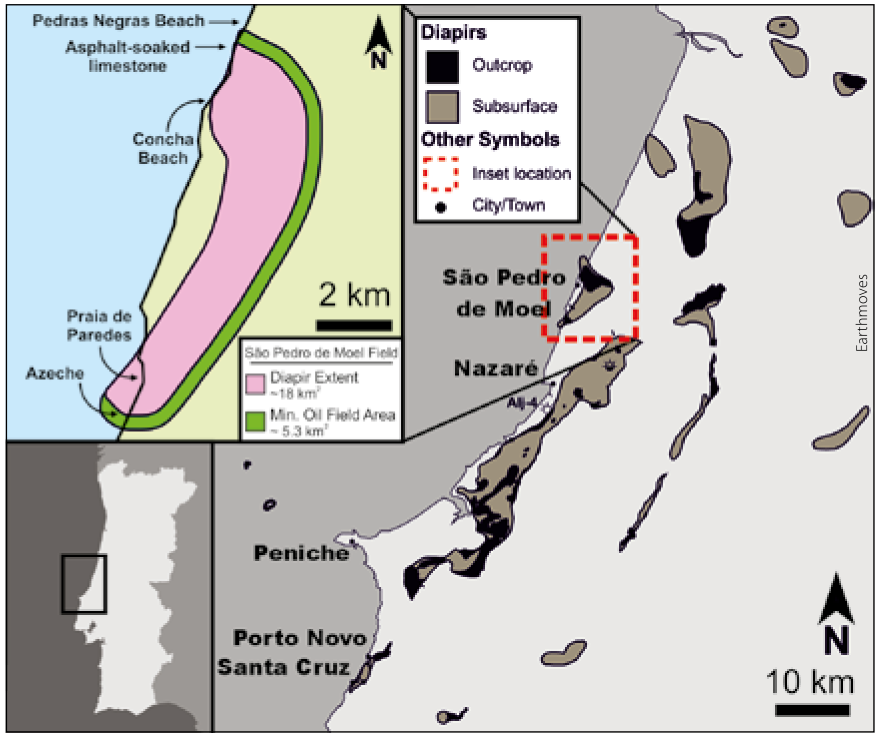
Panorama of the Praia de Paredes de Vitória outcrop with stratigraphic units and unconformities highlighted. This whole cliff face is impregnated with oil below the Eocene unconformity. Inset photo shows the beautifully-crafted entrance to the Mina de Azeche asphalt mine within the diapir.



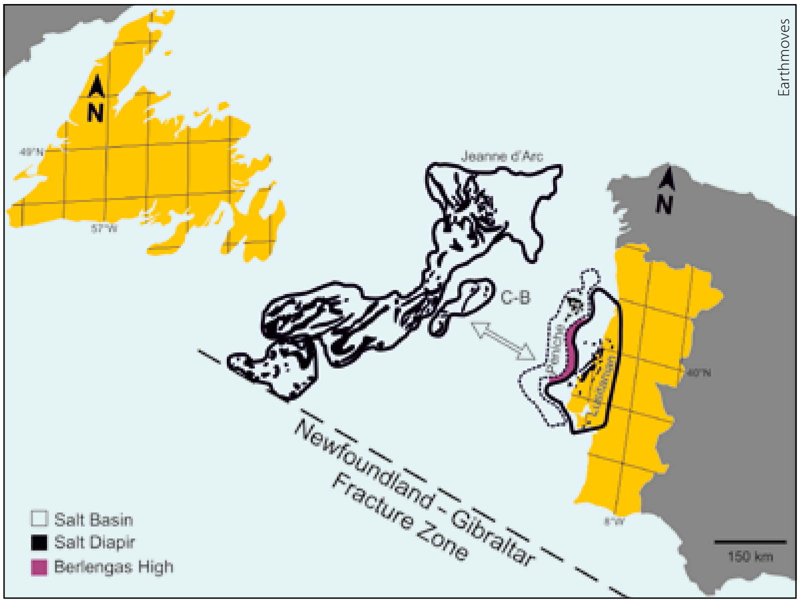
tar-saturated sandstones. The upturned hydrocarbon reservoirs extend for at least 350m southwards away from the east-west trending, vertical diapir wall before plunging below beach level. A minimum net reservoir thickness of 15m is present at the highest point adjacent to the diapir, and the sandstone units thicken downdip. The sandstone reservoirs weather to a white colour, but are black on fresh surfaces. Intervening tar-soaked shales are greenish-yellow on weathered surfaces due to growth of native sulphur, which is a by-product of oil biodegradation, giving a striking stripy appearance to the outcrop.

Two unconformities are exposed adjacent to the diapir (see photo below). The lowermost unconformity is probably Cenomanian in age and is caused by uplift of the salt diapir and subsequent erosion. Steeply-dipping (>70°) Aptian to Albian sandstones and Cenomanian limestones and conglomerates are overlain by shallow-dipping (<20°) Turonian-age, shallow marine sandstones. The age of the unconformity indicates that the diapir was growing at this time, which was well before the Alpine compression initiated. Seismic and field data also indicate the diapirs were growing during Jurassic sedimentation. The upper unconformity is more regional, where Eocene-age red and grey marls and claystones overlie older Maastrichtian to possibly Palaeocene sandstones with little or no angular unconformity. These Eocene rocks act as the top seal to the oil reservoirs, indicating that active oil migration must have occurred in post-Eocene times. Oil probably migrated up and along the diapir contact and then backfilled downward and outward into the adjacent reservoir sandstones.

The small quarries at the northern end of the salt diapir at Pedras Negras beach expose black tar-saturated highly-sheared dolomitic and gypsiferous shales, which form part



Location map for the central Lusitanian Basin showing the São Pedro de Moel diapir location. The dark grey areas show salt structures and the black areas are outcrops of evaporites. Coloured map shows the São Pedro de Moel oilfield (green) wrapped around the salt diapir (pink).



Approximate fit (adapted from Alan Smith, Cambridge University) between Portugal and Newfoundland during rifting showing the Lusitanian Basin was conjugate to the Carson-Bonnition (C-B) Basin. Salt basin outlines and individual salt structures shown in black. The Berlengas Horst (pink) separates the Peniche Basin from the Lusitanian Basin.

of the main diapir. These are overlain by tar-impregnated Jurassic marls. It is not clear whether these lie within the diapir or in the immediate overburden. However, it is apparent that this exposure is situated within the main hydrocarbon migration pathway along the diapir contact.

The proposed mapped outline of the diapir relies on outcrop information from the Geological Survey of Portugal and our own mapping. Based on the closure area we calculate that the field contains a minimum of 85 MMb of biodegraded oil, and probably significantly more, as deeper buried reservoirs are likely to exist below sea level. Furthermore, the upper part of the oil field may have been removed by the significant Alpine erosion in this area.

The syn-rift Sinemurian- to Pleinsbachian-age shales are the most likely source of the oil. These are particularly rich in the adjacent withdrawal synclines on the flanks of the São Pedro de Moel diapir, and reach up to 15% total organic carbon content. At least three different organic-rich intervals, with a gross thickness of 80m, are present at outcrop (Duarte et al., 2010).

However, the most productive gallery in the Azeche Mine was driven into dolomitic bituminous shales (Hettangian Dagorda or Sinemurian Coimbra Formation) within the diapir near the southern contact, where there is a well preserved mine entrance dated 1857 (Rodrigues, 1934; Morais, 1936). This suggests that source rocks are also present in the Dagorda Evaporites. BEICIP-FRANLAB (1996) reports up to 3.25% TOC within Dagorda marls from data collected both from outcrops and well data (both onshore and offshore).

Implications for Newfoundland and the Peniche Basin

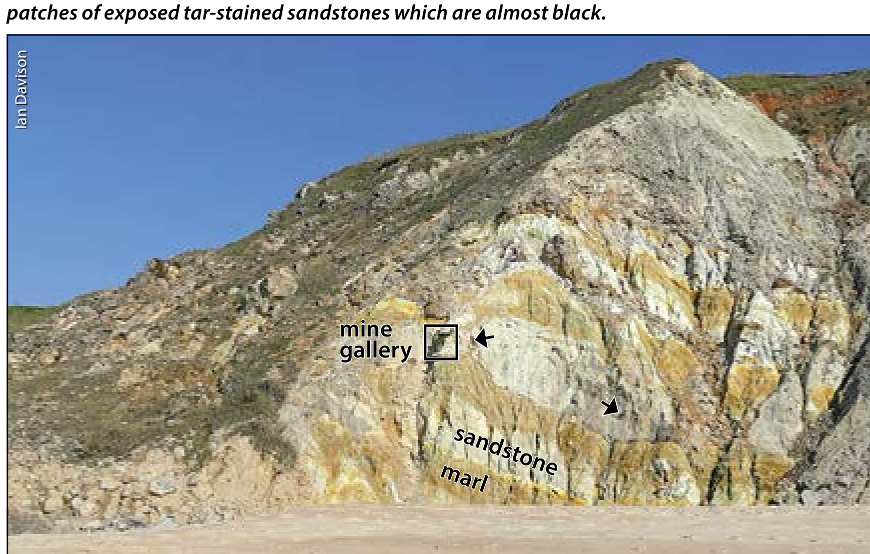
The conjugate Carson-Bonnition Basin in Newfoundland is approximately 160 km long and is a deep Early Jurassic salt basin with up to 7 km of mainly Mesozoic sediment fill. Three wells have drilled down to the Upper to Middle Jurassic strata on the shallow shelf, but no source rocks were encountered (Wielens et al., 2006). No wells have been drilled in the deeper, more prospective parts of the basin where better source potential can be expected in the Jurassic-age withdrawal synclines in between the large salt structures. This has left a large question mark regarding the source rock potential of this underexplored basin, despite the fact that it lies only some 100 km south-west of the prolific Jeanne D'Arc Basin (see figure left). This is a similar situation to the deepwater Portuguese Peniche Basin which is still undrilled, although recent 3D broadband seismic data coverage indicates the presence of many salt structures with a similar structural style, and consequently there are many potential leads.

The Lusitanian and Carson-Bonnition Basins were in close juxtaposition during the Early Jurassic, when viable source rocks, now proven, were deposited in the Lusitanian Basin. The discovery of a significant oil field in the Lusitanian Basin greatly enhances the hydrocarbon potential of the Peniche and Carson-Bonnition Basins. ExxonMobil recently acquired a large block in this basin. On 3 April 2019, the Newfoundland and Labrador Offshore Petroleum Board announced a Call for Bids, offering nine parcels covering most of the remaining prospective acreage, with applications due on 6 November 2019.

A very timely offering considering this recent discovery on the conjugate margin!

References available online. ■

Detail of the upturned Albian and Aptian interbedded sandstones and marls trapped against the diapir. One of the Mina de Azeche galleries is indicated by a rectangle. The arrows indicate fresh patches of exposed tar-stained sandstones which are almost black.

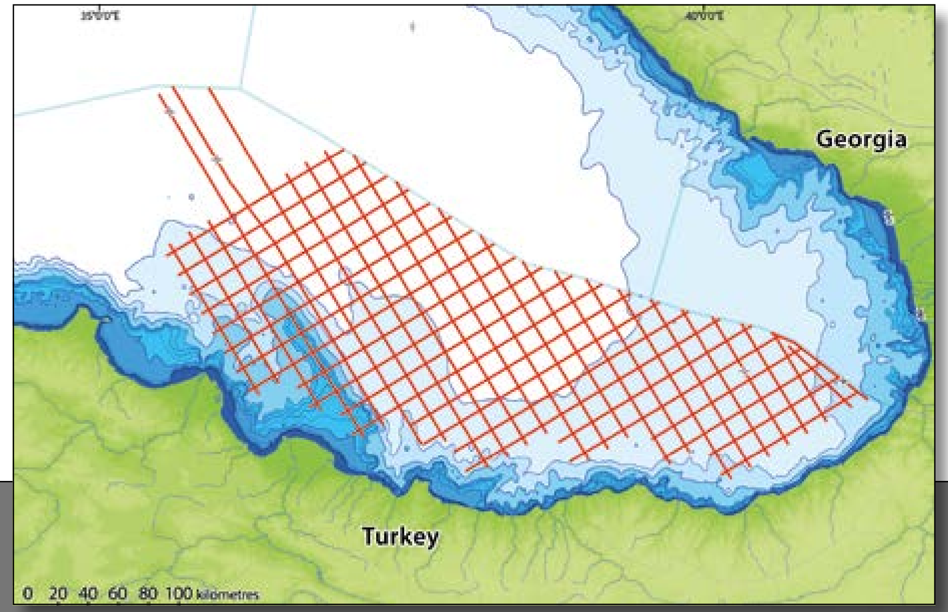


De-risking a Turkish Delight

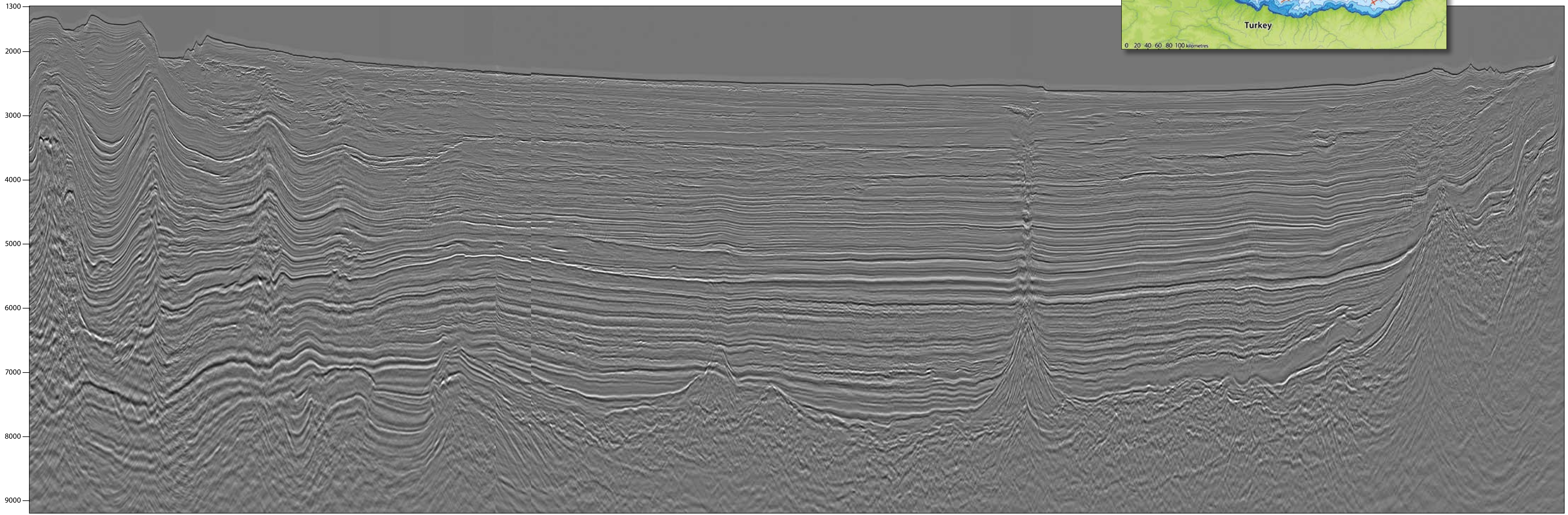
2018 East Black Sea Basin long offset 2D composite seismic section in TWT. Undrilled 4-way dip structural closures with AVO supported amplitude anomalies and seismic character within the Maykop indicating the presence of good reservoir quality sandstones in potential stratigraphic traps can all be observed.

Frontier exploration in an underexplored basin should always start with a single demand: "Show me the source rock". In the double foredeep of the eastern Black Sea the first dense grid of multi-client data available in Turkish waters reveals the world-class Maykop source rock, up to 2,000m thick: an AVO type 4 TOC-rich shale buried perfectly to be at peak oil. These new data also reveal untested analogues to the East Black Sea Basin Polshkov-1 oil discovery, with oil trapped in large structural and stratigraphic closures, in reservoirs provenanced from the quartz-rich sand sources of the Russian Caucasus.

Spectrum



Spectrum's Black Sea MC 2D data.



An Extraordinary Underexplored Basin

New data reveals the potential for a new super basin – an accessible oil play lying within the world-class Maykop oil source.

NEIL HODGSON, ANONGPORN INTAWONG and KARYNA RODRIGUEZ; Spectrum Geo Ltd

We all sense the verisimilitude of PK Dickie's warning against looking for new oil in old places with old ideas, which gives us two clear courses of action: either we can bring new ideas to old basins, or we can bring tried and tested ideas to new basins. Although truly new exploration plays are as rare as hen's teeth (mostly old ideas in new basins), new ideas stream out of new seismic data as we learn how much of "what we know for sure that just ain't so" (*The Big Short*, 2015). Whilst exploration geology has remained sitting on the sofa watching episodes of *Friends* on endless repeat, the advances in seismic imaging over the last 15 years, removing noise and multiples, are astonishing. So modern, long streamer, deghosted seismic data provides explorers worldwide with a practical idea-engine for old basins.

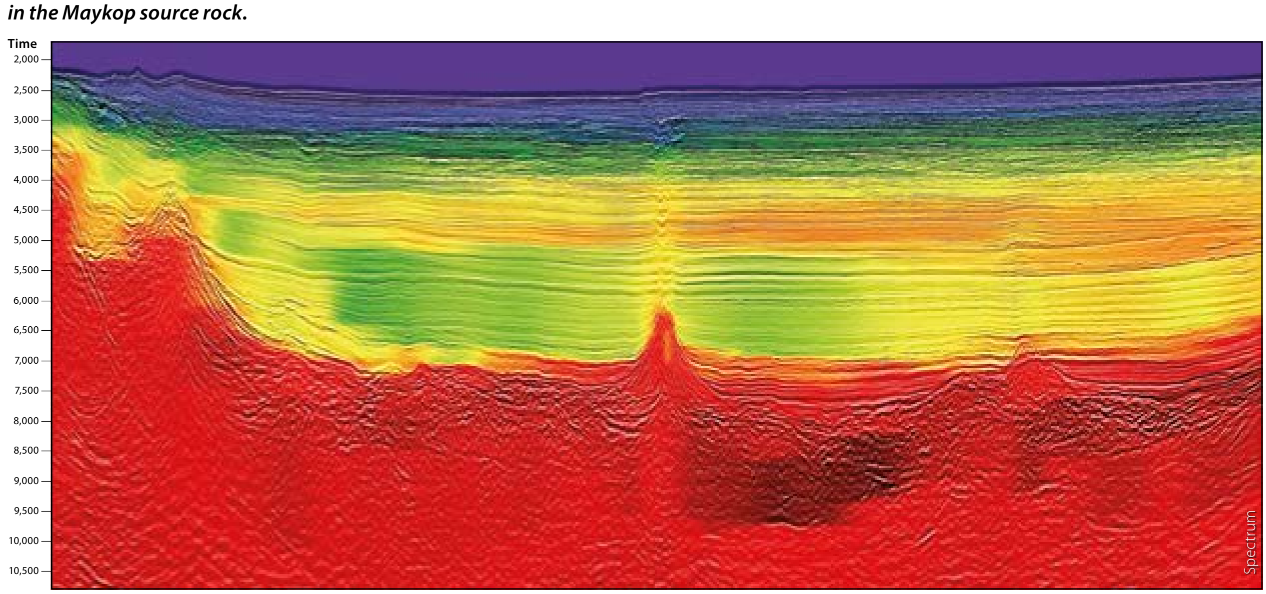
Maykop Proven Source

Yet how underexplored can a basin be in 2019? In the Turkish sector of the East Black Sea Basin, a basin half the size of the Gulf of Mexico, there are only three exploration wells. Period. In this Early Cretaceous foredeep basin trapped between the Pontide thrust belt to the south and the Caucasus to the north, the basin fill is Late Cretaceous to Tertiary in age. Yet the first two wells barely escaped the Pliocene, drilling carbonate build-ups that proved not to be build-ups (Sinop-1) and a Pliocene sequence dominated by immature sands sourced from the Rioni Delta offshore Georgia to the east (Hopa-1). The third well (Surmene-1, 1RE) reached only to the Middle Miocene, drilling off-structure at target depth. It is indeed rare to find a large deep basin with 8–10 km of sediment fill that is so underexplored, but the astonishing fact of the East Black Sea Basin is that it has 1–2 km of world-class Maykop source rock (2–5% TOC), sitting in the oil window and generating oil today over the entire basin. This is unparalleled in frontier basins on planet Earth.

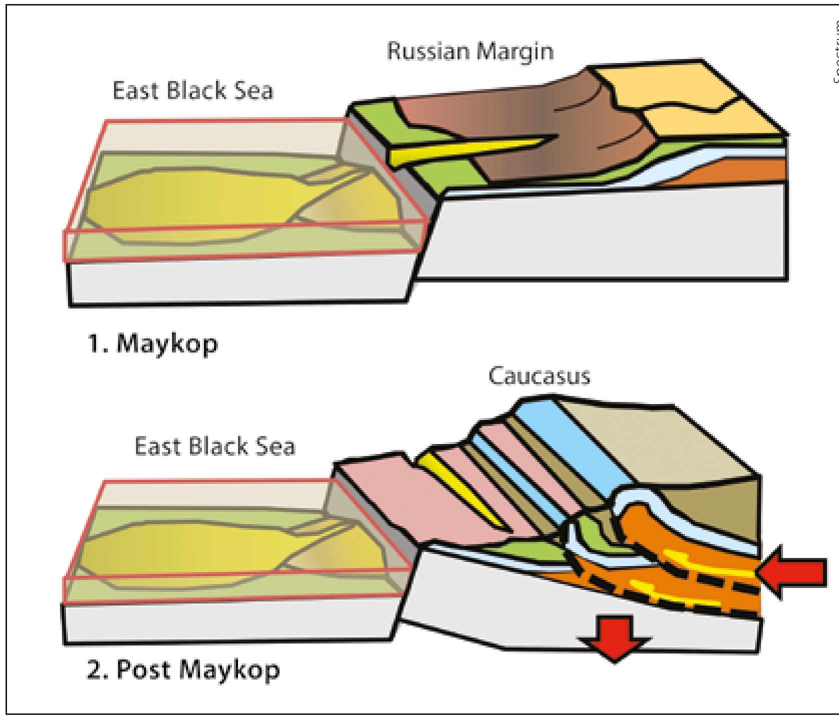
The Miocene Maykop Formation makes the East Black Sea Basin singularly different as, deposited across the extensive central Paratethys, the Maykop is the source for successful drilling in offset basins such as the southern Caspian Sea and western Black Sea (Tari and Simmons, 2018), and is also well studied in outcrop around the basin in the collisional Pontides/Caucasus. Petroleum system modelling of the Maykop in the East Black Sea demonstrates that the Maykop is currently in the oil window under geotherm scenarios controlled by available well and seismic data (Minshull, 2010), consistent with prolific repeating oil slicks visible via optical and radar satellite data, which have been sampled and found to have been generated from a thermogenic source. The two wells drilled in the east reportedly penetrated oil-bearing and Maykop-age (Mid to Early Miocene) Pliocene sands. Seismic correlation shows that these sediments are present across the whole basin, displaying a Type 4 AVA anomaly – a characteristic of identification of source rocks on seismic (Loseth et al., 2011).

Crucially, the Maykop displays seismic velocities

Velocity overlay on 2018 seismic from the eastern Black Sea showing a strong velocity inversion with depth due to hydrocarbon generation in the Maykop source rock.



that indicate that this interval, where the Maykop basin-floor sands are observed, is generating hydrocarbons. In a normally pressured system velocities extracted from seismic data will show a progressive increase with depth as lithologies compress due to loading. The exceptions to this are if there is a change in lithology type such as, for example, a carbonate shelf sitting above a shale, or if a unit is under-compacted due to either a failure to de-water or the in-situ generation of hydrocarbons. It is the latter expression we interpret from the velocities extracted from the new seismic in the eastern Black Sea, where a strong velocity reversal (decrease in velocity with increased depth) is clear at Maykop depth. A nuanced finesse of this phenomena is seen on the figure below left around the clear fluid escape feature (which leads incidentally to a recurring oil slick location observed on satellite data), showing hydrocarbon maturation-generated overpressure maybe locally decreased due to fluid migration.



Model for late formation of the Shatsky Ridge – post-Maykop sand delivery from the Russian north-west margin of the Black Sea.

Exploration Imminent?

So at this point, one might reasonably ask why, with these excellent indicators of a hydrocarbon system, is the East Black Sea Basin not explored more? Firstly, water depths in the main basin exceed 1,000m, so the area has had to wait until this century before exploration began. In addition, the first three wells were drilled on plays that did not work out, and whilst subsequently the Polshkov-1 well drilled offshore Bulgaria has proven the 'oil in Maykop sands' play in the Western Black Sea, this has simply not been attempted yet in the east. This then takes us to today, where the first densely shot multi-client data is available to chase Maykop sands in the eastern Black Sea, as well as new plays.

However, there is arguably one last test to pass for the East Black Sea Basin – that of sand quality. The Hopa-1 and Surmene-1 wells found tight, oil-bearing sands in the Pliocene and Miocene, and this poor reservoir quality is ascribed to compositionally immature sands rich in volcanoclastic fragments. These volcanoclastic lithic fragments are provenanced from outcrops in the fetch of the Rioni delta to the east (the source of the Pliocene sands); however, sand sources to the west are likely to be more quartz-rich (Vincent et al., 2013). As their distribution shows, the Maykop and pre-Maykop sequences were deposited before the collision of the Pontides and Caucasus, i.e. before the Rioni delta formed. Therefore, sands within and below the Maykop are likely to have been derived from river systems to the north-west in Russia and/or from a palaeo-Don/Volga (Kuban Fan) system. The new de-ghosted long streamer seismic data, designed to bring out sedimentological detail in the Maykop, has been mapped to show that the Intra-Maykop sand systems are indeed coming in from the north. These basin floor sands are onlapping the southern margin or draping four-way structures in the basin centre. The Shatsky Ridge to the north did not provide a barrier to sand entry as it, like the Rioni, only formed in the late Miocene–Pliocene, developing its dip-to-the-north geometry through Caucasus–Pontides compression.

Another new revelation from the 2018 dataset is the imaging of the Pontides fold and thrust belt at the edge of the foredeep basin. Here, large four-way closed structures are mapped in contact with the thick Maykop source sequence, and in places onlapped by basin floor fans that could provide charge focus systems. Although unexplored to date, the Pontides sedimentary sections are thick, folded, well bedded units likely to be composed of both carbonates and clastics, and it is this style of play that has many giant oil field analogues in foredeep collisional basins around the world.

New Potential Revealed

As has been described, this new long streamer de-ghosted 2D data is re-imaging the Turkish eastern Black Sea to reveal an extraordinary underexplored basin. Here, quartz-rich sands derived from Russia are ponding against the southern compressional margin of the Black Sea foredeep basin, or are draped over mid basin four-way structures. Previously inaccessible to drilling and un-imaged on seismic, these new data reveal the potential for a new super basin that is unique on planet Earth – an accessible oil play lying within the world-class Maykop oil source.

References available online. ■

From Arrhenius to CO_2 Storage

Part II: Arrhenius and Blackbody Radiation

"Humanity stands ... before a great problem of finding new raw materials and new sources of energy that shall never become exhausted. In the meantime we must not waste what we have, but must leave as much as possible for coming generations."

Svante Arrhenius (1859–1927)

Svante Arrhenius is often mentioned as one of the first scientists to couple atmospheric CO_2 to the Earth's temperature. Following on from Part I, where we introduced blackbody radiation and Milankovich cycles, here we look at Arrhenius' seminal 1896 paper and see how it relates to blackbody radiation and absorption of infrared radiation by the atmosphere. It is surprising to see how close his 1896 predictions are to today's advanced climate models.

MARTIN LANDRØ and LASSE AMUNDSEN, NTNU/Bivrost Geo

Svante August Arrhenius was born in Vik Castle close to Uppsala in 1859. He is best known for his theory of electrolytic dissociation and his model of the greenhouse effect. In 1903 Arrhenius was awarded the Nobel Prize for Chemistry. He learned to read at the age of 3, and at 8 he entered 5th grade at the local cathedral school. In 1884 he delivered his PhD thesis on conductivities of electrolytes, 150 pages, to the University of Uppsala. The thesis was not well received by his professors, and he got a fourth-class degree that was later re-classified to third-class. Part of the work in his PhD turned out to be the basis for the Nobel Prize for Chemistry. Around 1900 Arrhenius was involved in setting up the Nobel prizes, and he was a member of the Swedish Nobel committee for physics and chemistry for the rest of his life. He was elected a member of the Swedish scientific academy in 1901, against heavy protests because it was thought he was using his position on the Nobel committee to promote friends and stop enemies from receiving the award.

Radiation from Blackbodies: 1870–1910

When Svante Arrhenius wrote his famous 1896 paper *On the influence of carbonic acid in the air upon the temperature of the ground*, he was using knowledge and input from colleagues related to infrared radiation from blackbodies. (A blackbody is an idealised physical body that absorbs all incident electromagnetic radiation, regardless of frequency or angle of incidence – see Part I in *GEO ExPro* Vol. 16, No. 2.)

The empirical radiation law derived by Stefan and Boltzmann, stating that the total energy radiated per unit surface area of a blackbody in unit time, or the radiated energy flux, is proportional to the body temperature (measured in Kelvin; $273.15\ K = 0\ °C$) into the fourth power, was known:

$$U = \sigma T^4\ [Wm^{-2}] \quad (1)$$

where $\sigma = 5.67 \times 10^{-8}\ Wm^{-2}K^{-4}$ is Stefan-Boltzmann's constant. This means that if you double an object's temperature, the amount of energy it releases increases by a factor of 16. Energy flux has dimensions of energy per time per area, and the SI units to measure it are joules per second per square metre, watts per square metre. The radiated energy flux is also known as the blackbody irradiance. To find the total absolute power of energy radiated for the blackbody object we multiply by the surface area A; then $P = AU$.

Josef Stefan derived this law in 1879 based on experimental data obtained by John Tyndall. In 1884 Stefan's student, Ludwig Boltzmann, showed that this fourth order power

Figure 1: Thermal photo of a hand, exploiting blackbody radiation to determine the temperature of the various parts of the body.

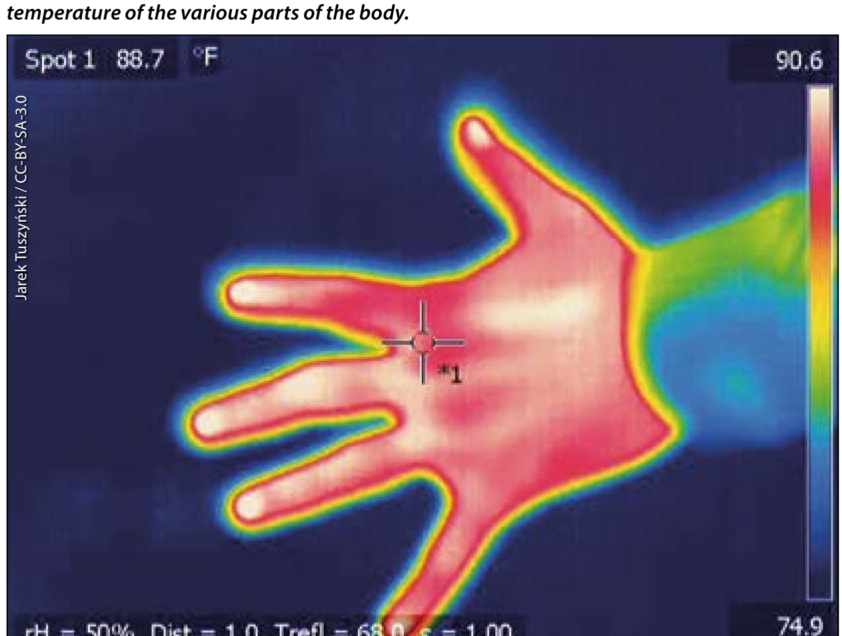


Figure 2: Svante Arrhenius.

Figure 3: Ludwig Boltzmann (at the table) with co-workers in 1887. Svante Arrhenius is standing on his left.

law can be derived directly from thermodynamics. Svante Arrhenius had regular contacts with Boltzmann and his co-workers in Austria, meaning that blackbody radiation and the physics behind this was well understood by Arrhenius when he wrote his 1896 paper. When we use the term 'light' in this context we mean the whole electromagnetic spectrum (see Part I).

However, the direct coupling between Stefan-Boltzmann's law and quantum mechanics was not revealed until Max Planck formulated his radiation law in 1900. Planck showed that the power emitted per unit projected area of a blackbody at temperature *T*, into a unit solid angle, per wavelength λ , is

$$B_\lambda = \frac{2hc^2}{\lambda^5}\frac{1}{e^{\frac{hc}{\lambda kT}}-1}\left[\frac{W}{steradian\ m^2\ m}\right] \quad (2a)$$

Here, c is the speed of light, h is Planck's constant, and k is Boltzmann's constant. The quantity B_λ is referred to as the spectral radiance. Its dimension includes the steradian unit. It is simply a unit solid angle (see Part I).

Radiance is the power emitted (or received) by a given surface, per unit solid angle per unit area. To find the radiance, one integrates the Planck equation (2) over all wave numbers,

$$B = \int_0^\infty B_\lambda\, d\lambda = \frac{2\pi^4 k^4}{15h^3c^2}T^4\left[\frac{W}{steradian\ m^2}\right] \quad (2b)$$

The total radiated power per unit area, called the radiant exitance or irradiance, with symbol *U*, is found by further integrating *B* with respect to a solid angle over the hemisphere into which the surface radiates. Since blackbody radiance is independent of the direction of emission, irradiance emitted by a blackbody is:

$$U = \pi B = \frac{2\pi^5 k^4}{15h^3c^2}T^4\left[\frac{W}{m^2}\right]$$

The pile of constants in front of the temperature is Stefan-Boltzmann's constant.

If we multiply the radiant exitance by the entire surface area of the body, we can find the total amount of power given off.

The empirical equation derived in 1879 was found to be of a much more fundamental nature 21 years later, as a result of the work of Max Planck, including quantum mechanics. Max Planck received the Nobel Prize for Physics in 1918. Equations 1 and 2 above contain a lot of information and represent a giant step in physics. By introducing quantum theory, Planck showed that it is possible to predict the 'colour' (or wavelength) distribution if we know the temperature of the blackbody, and vice versa. Furthermore, he showed that there is this fundamental relation between thermodynamics and quantum theory and that the apparent empirical Stefan-Boltzmann's constant is directly related to quantum theory (Planck's constant).

Radiating Blackbodies

A blackbody object radiates at all wavelengths. The wavelength that corresponds to the peak of spectral irradiance for a given temperature is found by taking the derivative of the irradiance with respect to wavelength, and setting the resulting expression to zero. Trust us: the solution gives the Wien displacement law:

$$\lambda_{peak} = \frac{b}{T}$$

where $b = 0.0029$. This relation makes it possible to compute the temperature of a blackbody by measuring the wavelength of peak spectral radiance. If $\lambda_{peak} = 0.5 \times 10^{-6} m$ *(500 nm)*, then $T = 5{,}800K$. This corresponds to green light in the middle of the visible spectrum.

An example of blackbody radiation from earth and moon is shown in the graph in Figure 4, where we have also included the most relevant absorption band for CO_2, ranging from approximately 12 to 18 μm. Water vapour has more extensive and slightly different absorption bands.

Anything that heats up on Earth will release long wavelength (infrared) radiation. The graph shows blackbody radiation from a person (310.15 K), the Earth (288 K) and the moon (255 K), using Planck's radiation law. On Earth,

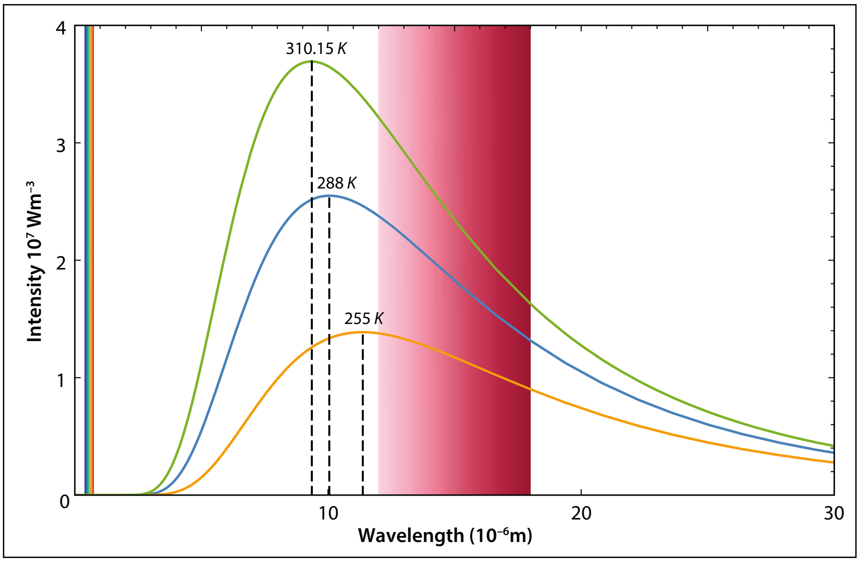


Figure 4: Blackbody radiation curves, showing at which wavelength bodies of a certain temperature emit their maximum intensity.

part of the incoming sunlight is reflected by the atmosphere and the surface. Most of the sunlight, however, is absorbed by the surface, which is warmed. Infrared radiation is then emitted from the surface. Visible light ranges from 0.4–0.7 μm (bars on the left of the graph, Figure 4), and the infrared range is between 0.7 and 1,000 μm, hence the dominant radiation from the Earth and the moon is within the infrared band. The typical absorption band for CO_2 is indicated by the Valentine colour band, ranging from approximately 12 to 18 μm. There is also a CO_2 absorption band between 4 and 4.5 μm.

A human body temperature of 310.15 Kelvin corresponds to a blackbody radiation wavelength of about 9.3 μm, which is in the infrared part of the spectrum. This infrared radiation of human bodies is the principle behind 'night vision' goggles: they convert infrared light to visible light, allowing the wearer to see warm bodies glowing in infrared light.

Arrhenius and Climate Change

In relation to climate research Arrhenius is known for the following equation, often referred to as the Arrhenius forcing law:

$$\Delta F = \alpha \ln(C/C_0)$$

where C_0 is the concentration of CO_2 at a reference time, and C the current concentration of CO_2 in the atmosphere, α is a constant and ΔF is the radiative forcing, which is related to the temperature increase, $\Delta T \sim \Delta F$. The general rule from Arrhenius' model is that if the quantity of CO_2 increases or decreases, then temperature will increase or decrease. He predicted that a doubling of CO_2 in the atmosphere would lead to temperature increases of 3 to 4°C.

In his 1896 paper, Arrhenius uses radiation data obtained by Langley on atmospherical absorption. The first sentence in this paper reads: "A great deal has been written on the influence of the absorption of the atmosphere upon the climate. Tyndall in particular has pointed out the enormous importance of this question." Langley had published a paper in 1890 entitled *The Temperature of the Moon* where he had estimated the average temperature of the moon to be about 45°C. Today we know that it is significantly lower, close to 247 K (-20 °C).

Arrhenius' idea was to use the absorption data obtained by Langley's measurements of the radiation from the moon to estimate the influence of CO_2 (denoted by K in his paper) and water vapour (denoted by W) on the Earth's surface temperature. Arrhenius roughly divided the observations into four groups, where K = 1.21; 0.36; 2.21 and 0.86 and W = 1.33; 1.18; 2.22 and 2.34. Based on this, he made a table (Figure 5) in which he estimates temperature changes as a function of latitude for both increase and decrease of CO_2. Although the actual numbers and the assumptions made are not regarded as valid today, it is interesting to observe that his simplified analysis predicts that the warming increases with latitude, and that a doubling of atmospheric CO_2 leads to 5–6 degrees of warming – not far from the estimates of modern climate models.

In the paper, there is a separate section discussing geological consequences. He mentioned the lively discussions at the Physical Society of Stockholm on potential causes for the ice ages, and proposed that variation in CO_2 level might be one cause. ■

Figure 5: Table VII in Arrhenius' paper from 1896. He estimated changes in the Earth's temperature for a doubling of CO_2 (middle column) and for a reduction to 67% of the present value in 1896 (left column) as a function of latitude. From the middle column we observe a temperature increase of 4–5°C at the equator and up to 6° closer to the poles. In this paper he does not suggest that burning fossil fuels will cause global warming, although he does suggest this in later work.

TABLE VII.—*Variation of Temperature caused by a given Variation of Carbonic Acid.*

Latitude.	Carbonic Acid=0·67.					Carbonic Acid=1·5.					Carbonic Acid=2·0.					Carbonic Acid=2·5.					Carbonic Acid=3·0.				
	Dec.–Feb.	March–May.	June–Aug.	Sept.–Nov.	Mean of the year.	Dec.–Feb.	March–May.	June–Aug.	Sept.–Nov.	Mean of the year.	Dec.–Feb.	March–May.	June–Aug.	Sept.–Nov.	Mean of the year.	Dec.–Feb.	March–May.	June–Aug.	Sept.–Nov.	Mean of the year.	Dec.–Feb.	March–May.	June–Aug.	Sept.–Nov.	Mean of the year.
70 to 60	−2·9	−3·0	−3·4	−3·1	−3·1	3·3	3·4	3·8	3·6	3·52	6·0	6·1	6·0	6·1	6·05	7·9	8·0	7·9	8·0	7·95	9·1	9·3	9·4	9·4	9·3
60 to 50	−3·0	−3·2	−3·4	−3·3	−3·22	3·4	3·7	3·6	3·8	3·62	6·1	6·1	5·8	6·1	6·02	8·0	8·0	7·6	7·9	7·87	9·3	9·5	8·9	9·5	9·3
50 to 40	−3·2	−3·3	−3·3	−3·4	−3·3	3·7	3·8	3·4	3·7	3·65	6·1	6·1	5·5	6·0	5·92	8·0	7·9	7·0	7·9	7·7	9·5	9·4	8·6	9·2	9·17
40 to 30	−3·4	−3·4	−3·2	−3·3	−3·32	3·7	3·6	3·3	3·5	3·52	6·0	5·8	5·4	5·6	5·7	7·9	7·6	6·9	7·3	7·42	9·3	9·0	8·2	8·8	8·82
30 to 20	−3·3	−3·2	−3·1	−3·1	−3·17	3·5	3·3	3·2	3·5	3·47	5·6	5·4	5·0	5·2	5·3	7·2	7·0	6·6	6·7	6·85	8·7	8·3	7·5	7·9	8·1
20 to 10	−3·1	−3·1	−3·0	−3·1	−3·07	3·5	3·2	3·1	3·2	3·25	5·2	5·0	4·9	5·0	5·02	6·7	6·6	6·3	6·6	6·52	7·9	7·5	7·2	7·5	7·52
10 to 0	−3·1	−3·0	−3·0	−3·0	−3·02	3·2	3·2	3·1	3·1	3·15	5·0	5·0	4·9	4·9	4·95	6·6	6·4	6·3	6·4	6·42	7·4	7·3	7·2	7·3	7·3
0 to −10	−3·0	−3·0	−3·1	−3·0	−3·02	3·1	3·1	3·2	3·2	3·15	4·9	4·9	5·0	5·0	4·95	6·4	6·4	6·6	6·6	6·5	7·3	7·3	7·4	7·4	7·35
−10 to −20	−3·1	−3·1	−3·2	−3·1	−3·12	3·2	3·2	3·2	3·2	3·2	5·0	5·0	5·2	5·1	5·07	6·6	6·6	6·7	6·7	6·65	7·4	7·5	8·0	7·6	7·62
−20 to −30	−3·1	−3·2	−3·3	−3·2	−3·2	3·2	3·2	3·4	3·3	3·27	5·2	5·3	5·5	5·4	5·35	6·7	6·8	7·0	7·0	6·87	7·9	8·1	8·6	8·3	8·22
−30 to −40	−3·3	−3·3	−3·4	−3·4	−3·35	3·4	3·5	3·7	3·5	3·52	5·5	5·6	5·8	5·6	5·62	7·0	7·2	7·7	7·4	7·32	8·6	8·7	9·1	8·8	8·8
−40 to −50	−3·4	−3·4	−3·3	−3·4	−3·37	3·6	3·7	3·8	3·7	3·7	5·8	6·0	6·0	6·0	5·95	7·7	7·9	7·9	7·9	7·85	9·1	9·2	9·4	9·3	9·25
−50 to −60	−3·2	−3·3	—	—	—	3·8	3·7	—	—	—	6·0	6·1	—	—	—	7·9	8·0	—	—	—	9·4	9·5	—	—	—

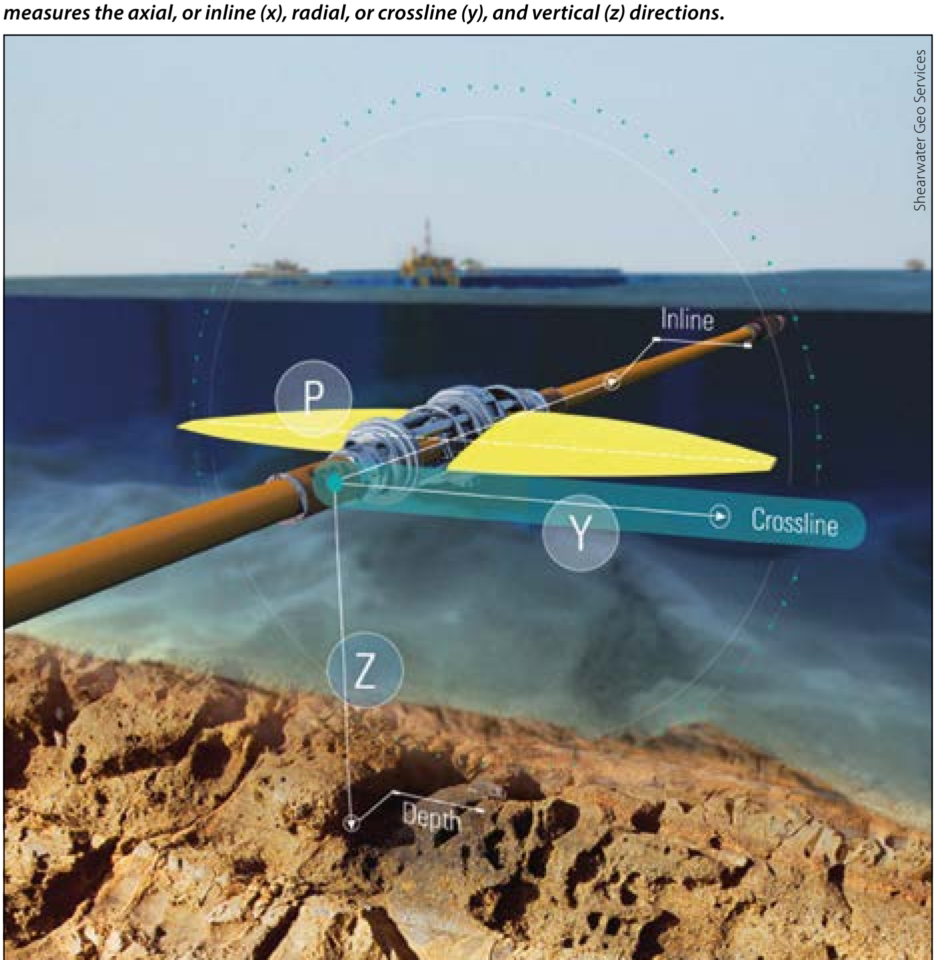

UNLEASH YOUR DATA'S POTENTIAL℠

From Sensor to Image

A new focus on innovation, technology and collaboration is developing.

TOM HAY, MEHUL SUPAWALA and TIM BRICE; Shearwater GeoServices

An example of innovation: one element in the Isometrix streamer system combines a hydrophone measuring pressure with a calibrated, triaxial microelectromechanical (MEM) accelerometer that measures the axial, or inline (x), radial, or crossline (y), and vertical (z) directions.



Can Our Industry Still Innovate?

The story of marine seismic is one of constant innovation, facilitated by, and equally frustrated by, dramatic cyclical fluctuations in the oil price. As we emerge from the momentous industrial fire of the recent contraction, we find that certain treasures have been retained and others lost. The structure of the industry has changed dramatically, with companies divesting fleets, committing to multiclient models, removing high capacity vessels, and developing the ocean bottom acquisition sector.

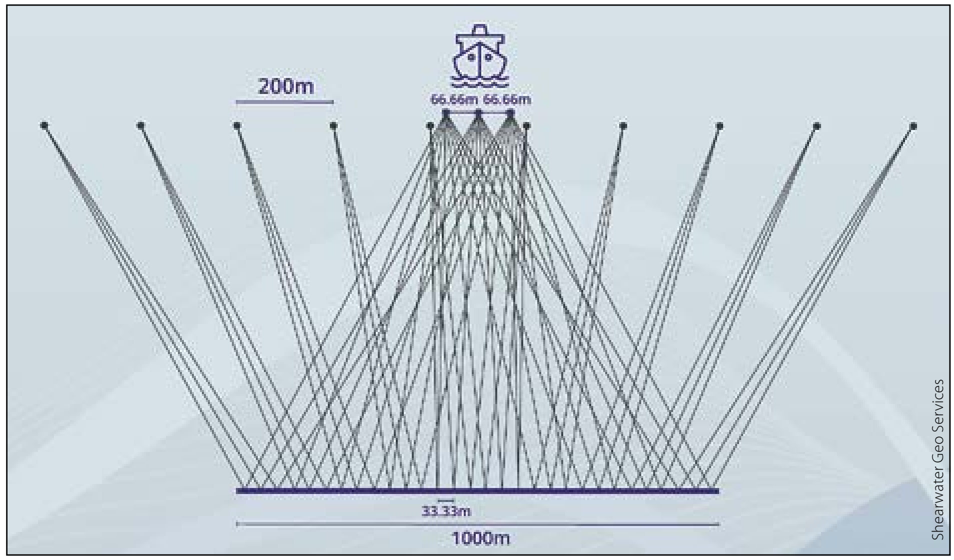
Much attention has been given to the move away from integrated multiclient and vessel-owning companies, with emphasis on who is 'asset heavy' or 'asset light'. There is, however, a challenging and pressing question for the transformed industry that is often neglected: have we preserved our industry's capability to innovate and can we do it in a new and sustainable way?

Shearwater GeoServices was founded in 2016 through a visionary partnership of GC Rieber Shipping and RASMUSSENGRUPPEN AS to build a new marine seismic company, taking advantage of the opportunities made available during the industry downturn. That transaction brought with it a processing and imaging services and software business but was limited to four vessels until the acquisition of the Schlumberger marine seismic acquisition business last year. As well as the fleet and equipment, with that deal came intellectual property, the industry's leading marine acquisition research and engineering centre (based in Oslo), and a modern manufacturing facility located in Malaysia. An important part of the industry's capability to innovate and manufacture leading edge technology was preserved and is now part of a dedicated marine seismic company. The interest is in how that capability can be used to collaborate on the next generation of technology innovation.

The Source of Recent Success

For a long time it was clear that marine source technology had become relatively static, dependent upon the classic dual airgun source – a good reliable, economic and technologically simple approach. Through the downturn the industry has had to reinvent itself to a lower cost position. As larger spreads became possible, the challenge has been how to combine fine sub-surface sampling with large subsurface coverage. One cost-efficient method has been found to be simultaneous source technology, for example Shearwater's FlexiSource. This has allowed wide streamer spacing, while retaining dense subsurface coverage, based on of multi-source capability and industry acceptance of shot deblending techniques.

The success of simultaneous sources in answering the demand for high quality dense subsurface coverage, at dramatically lower costs per square kilometre, has been striking. Early implementations of this method were developed through industry collaboration and focused on clear technical and economic objectives. The technology was developed rapidly, and at low cost, and is now one of the most common modes of marine acquisition. This collaborative and focused approach, both on technical and cost objectives, led to a transformation of towed streamer acquisition efficiency.

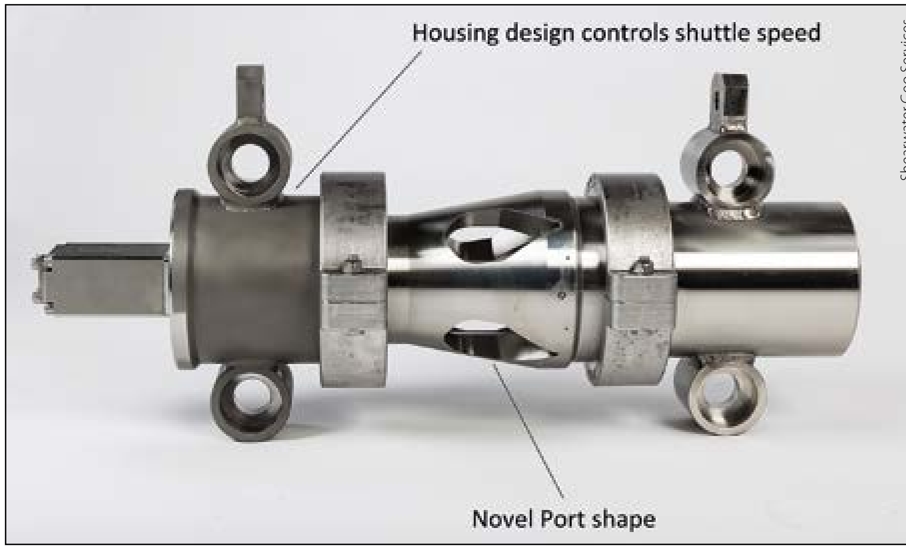


Example of a FlexiSource setup with 10 streamers and 200m crossline spacing together with triple sources.

Advances in signal processing have led to further inventions in deblending methods. One of these is the apparition method, which involves the use of modulated codes instead of random time dithers, facilitating improved separation when processing the data. Such technology further pushes the envelope of what is achievable with airgun sources in marine seismic data acquisition, improving both productivity and the quality of the data acquired using existing equipment on the vessels.

A Peaceful Future

Airgun impulsive sources have remained as the preferred choice of marine seismic source, although at the same time the potential impact of impulsive sources on marine life remains a discussion point for the industry. In the early part of the decade, with the oil price well over $100 per barrel and the marine seismic industry going strong, several initiatives were launched to ensure sustainability and continuity from a regulatory point of view. These included the formation of the E&P Sound and Marine Life Programme to improve the understanding of the effect of oil and gas exploration and production activity sound on marine life; the joint industry project on developing a non-impulsive marine vibratory source; and the joint initiative to develop a bandwidth-controlled airgun source, now known as eSource.



Bandwidth-controlled airgun with a port shape that enables gradual release of air.

eSource is a drop-in replacement airgun which reduces the amount of unwanted high frequency energy as this may potentially be harmful to marine life. It does this by reducing the rate at which the air is released from the airgun, resulting in a lower peak that limits the high frequency energy while still preserving the low frequency energy crucial for seismic imaging.

Despite the downturn, the industry has managed to introduce the eSource and successfully deployed it on commercial surveys, while the joint industry marine vibrator project, although not deployed, continues to make progress. Furthermore, recent inventions around the use of marine vibratory sources to improve productivity and reduce acquisition time and costs have generated renewed interest in this technology.

Reduced-scale marine vibrator prototype undergoing testing at Seneca Lake in 2013.

Marine vibratory sources offer significant environmental benefits over airguns, even if the vibrator array emits exactly the same energy spectrum as the corresponding airgun array. In addition to the environmental benefit, marine vibrators allow control of the phase of the emitted waveform. Imaginative use of this freedom to specify the phase, combined with new developments in wavefield reconstruction, could make marine seismic surveying with vibrators dramatically more efficient than it is with airguns. (See *GEO ExPro* Vol. 15 Nos. 3 and 5 for more on this topic.)

Are You Receiving?

Nearly two decades ago Q technologies became available to the market, firstly with the Qmarine tower streamer system. The innovation that fed into Qmarine stretched for a decade before that and much of that legacy remains embedded in Shearwater's Oslo technology and innovation centre.

Obtaining good seismic images requires a chain of factors: a good acquisition system, a good survey geometry and good processing algorithms and workflows. The Qmarine system arose from a programme that aimed to move from conventional seismic acquisition to discrete sensor technology. The technology included improvements in receiver sensitivity, signal to noise ratio, positioning accuracy, steerable streamers, greater source control and point-receiver acquisition which records traces from individual receivers to provide repeatable, high-quality data.

Later additions included source steering, dynamic spread control to facilitate techniques such as coil shooting, and continuous line acquisition. The system has become the leader in towed streamer 4D with a long, unparalleled reputation for quality acquisition and producing data ready for time-lapse studies.

The next generation technology, Isometrix, evolved from Qmarine and took the measurements to the next level, using very dense hydrophones, and accelerometer sensors to fully measure the seismic wavefield. These new measurements

– the crossline and vertical gradients, or variations with distance, of a pressure wavefield – enable true 3D deghosting and the ability to reconstruct the wavefield between the streamers with unprecedented accuracy. This not only enabled geophysicists to achieve broad spatial and temporal bandwidth but also allows data from a seismic shot to be processed as a full 3D wavefield rather than a collection of 2D profiles (as for standard 3D surveys). This presents us with the opportunity to reprocess data with finer spatial sampling as we move from the exploration to appraisal and development stages without the need to revisit the survey area and reshoot. It is often undesirable to return to an area for dense appraisal surveys for cost, environmental or societal reasons; isometric multicomponent surveys make this unnecessary.

Shearwater's Reveal seismic data processing software was created with seismic processors in mind. Many seismic data processing software packages, still in use, have the old punch card computers of the 1970s in their DNA. A software wholly written in the 21st century, built around ease of use, extensibility and flexibility, has enabled a new generation of geophysicists to get to work. Increasingly, turnaround time of the entire seismic project cycle is a key focus for E&Ps. This, coupled with the interdependency of acquisition and processing innovations, makes a modern processing software essential.

A New Collaborative Basis

What is common amongst these innovations in seismic acquisition and processing is that success comes from collaboration between services company and client – the relationship between the two is symbiotic. When companies

The Qmarine system combines point-receiver measurements, high positioning accuracy, source calibration and streamer steering.

innovate in isolation there is a risk that the innovation will not meet the market's need. When clients fail to invest and support innovation in their supply chain it is less likely they will see technology that achieves their goals – either in terms of quality or efficiency. The costs of innovation and risks of failure are significant enough to prevent companies investing in technology projects in isolation. The new generation of innovation will need to be based on shared investment and collaboration.

In answer to the question at the beginning of this article: yes, we have managed to preserve the industry's capability to innovate. However, if the story of innovation in marine seismic is to continue it will have to be on a new collaborative basis – from sensor to image. ■

Reveal, a modern processing software, is built directly for clients, on a collaborative model.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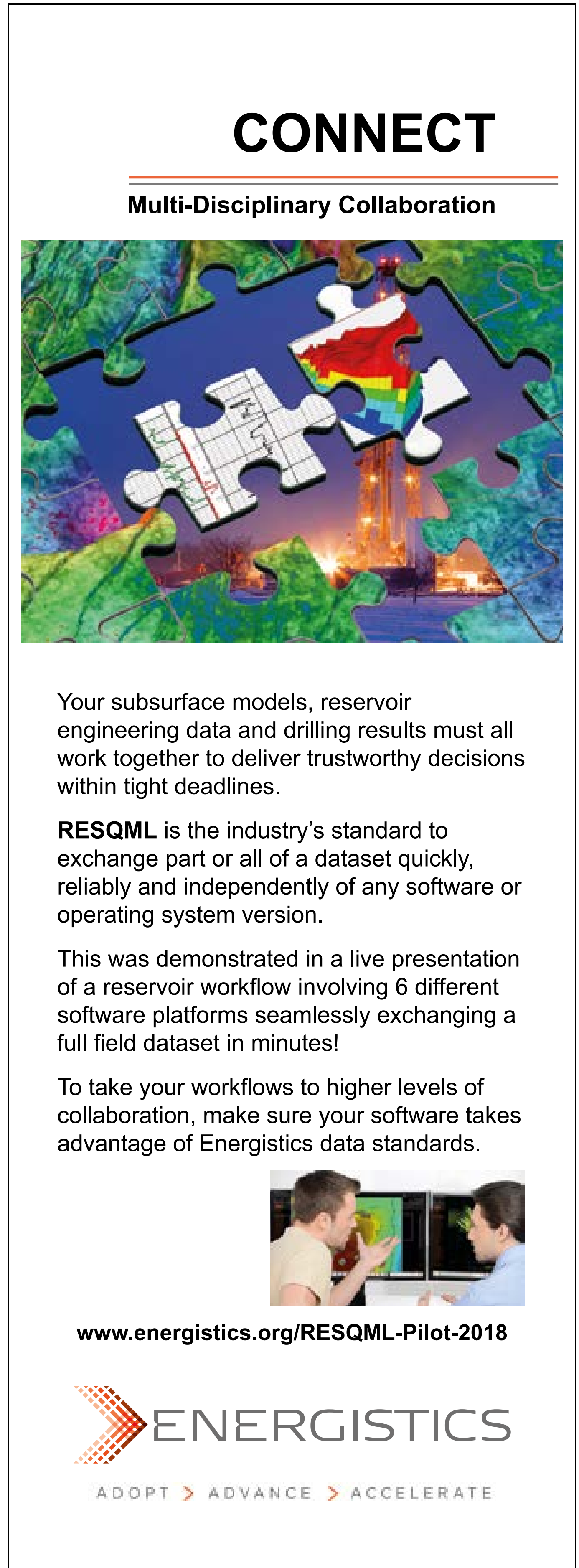
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Digital Transformation to Hike Production

In the upstream oil and gas industry, digital transformation is changing how companies do business. According to Booz Allen Hamilton (December 2018), digital transformation of E&P proprietary data could save the industry as much as $1 billion each year while boosting production by up to 8%.

PATRICK MERONEY, Katalyst Data Management

E&P data acquired over decades on various media technologies is commonly stored in warehouses and cannot be accessed on today's platforms, and that means missed opportunities. Geophysical companies are sitting on a wealth of information, and how they use subsurface data can make the difference between having to tolerate production plateaus instead of using new technology to wrest fresh income-generating insights from historical data.

Yesterday's thinking about the value of E&P data is why, according to Teradata, upstream companies can lose as much as $8 bn per year in non-productive work as their geoscientists, petroleum engineers and data managers spend up to 70% of their time poring over mountains of well data (cores, logs, scans, samples) and seismic data (2D and 3D time and depth sections in digital and hardcopy). To make matters more complicated, the subsurface data is contained in myriad current and legacy software applications, databases, data recording sensors, paper and tape records. Storing, managing and organising massive volumes of hard-copy proprietary records and media archives, and then trying to locate and access the specific data needed for analysis, interpretation and processing, is a cumbersome, challenging and inefficient process.

It is so inefficient that a McKinsey Report (CNBC 20154; 2015) says the oil and gas industry currently generates value from only one percent of all the data it creates.

Getting Value from the Other 99%

MIT's Sloan School and Deloitte rank the digital transformation maturity of the oil and gas industry among the lowest, at 4.68 on a scale of 1 to 10.

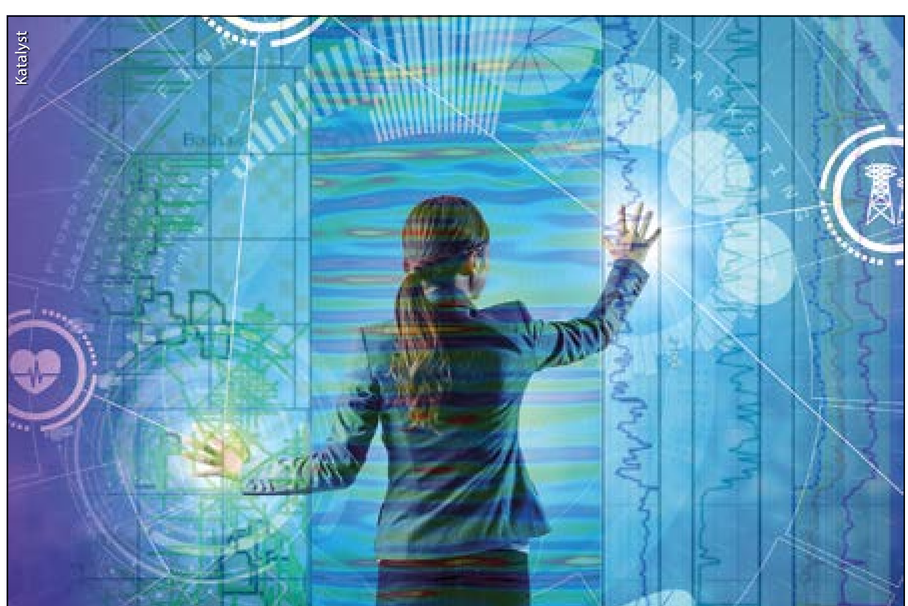
Before pinpointing the exact reasons for low maturity in digital transformation, consider the challenges confronting today's geoscientists, petroleum engineers and data managers:

- How to quickly find, access and make sense of all the proprietary subsurface data and metadata held within their company's information stores and department silos?
- How to consolidate, manage and access all that information in order to then analyse and aggregate it into meaningful decisions?
- How to extract actionable knowledge about, and mine fresh insights into, potential subsurface hazards and opportunities, given all the current and legacy records that exist?

These challenges are the reality for many companies who need to focus on how digital transformation of E&P data can optimise operations and create new value from old seismic data.

Enter the power of data digitisation, data migration and digital transformation for E&P data. Simply by conducting daily operations, operators have amassed and stored a virtual goldmine of subsurface data – several petabytes by Deloitte's estimation – of bankable geophysical information. When oil and gas companies digitise and transform these priceless libraries of paper records, recordings, 2D and 3D and other analogue information into secure cloud-based digital data records, decades of valuable E&P information become easily accessible to geoscientists and data managers to use whenever and wherever they need it. It is stored securely and privately in the cloud, where it is safe, protected and accessible.

With powerful data analytics, the secure treasure trove of digitised geoscience data can be instantly read, indexed, interpreted, manipulated, verified and accessed with smart-tool technologies that incorporate artificial intelligence (AI) and machine-learning.


Katalyst

Companies can mine historical, current and future data to find new patterns contained within that accumulated wisdom to ask better questions and make faster and better decisions.

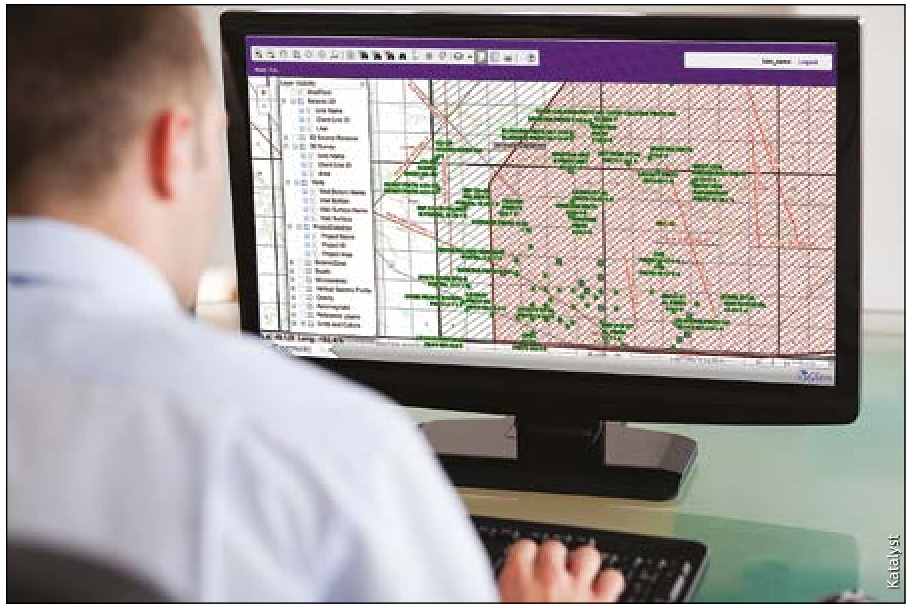
Big Data = Big Rewards

Many people think the term Big Data simply means having to deal with vast amounts of data. That is true, but it also means focusing on how to grow the business by effectively integrating all aspects of the data that have been accumulated over the decades to solve new problems and challenges. Big Data means breaking the barriers between departmental data silos, and increasing visibility throughout operations. It means creating the company's own E&P Internet of Things (IoT) for geoscientists and data managers to harvest at will, making new discoveries with old data, reducing the costs of new discoveries, improving well success rate and increasing profitability.

In a recent GE/Accenture report, surveys show that 81% of senior executives believe that Big Data analytics is one of the top three corporate priorities for the oil and gas industry.

In E&P operations, Big Data can be used to uncover non-productive time and activities, highlighting not-so-obvious operational losses and oppressive sunk costs. It can identify opportunities to boost production from existing assets and extract financial value from all available operations, no matter where the subsurface data originated or where it currently resides.

Digital transformation of E&P data creates an open data culture with full governance and good analytical accessibility within a protected environment. Instead of just connecting the dots, Big Data connects the datasets by mining libraries of digitised seismic data to quickly access information and extract additional intelligence, pinpoint the most valuable assets, derive new patterns of strategic planning, and create new avenues of thinking about how to increase efficiency and escalate profits. Because of the vigorous process involved in digital transformation, digital assets have become more secure and of higher quality, which promotes greater confidence in decision-making.



Seismic and well data that formerly resided in boxes can now be indexed, quality-checked and accessed via an online map portal by both geoscientists and data scientists.

But where does the vital E&P IoT data reside in the cloud? Where should it reside?

Clouds, Hybrid Clouds and Multi-Clouds

Cloud computing brings the benefits of digital transformation and data analytics to the local network – as well as a network of remote internet-hosted servers – to store, manage, process and manipulate through an online interface. Cloud computing allows companies to analyse a wealth of data quickly at a reduced cost, and provides an on-demand off-premise environment for disaster recovery solutions.

Beyond the cloud, oil and gas companies have expanded choices for visualising and mining seismic data, depending on dataset sizes, needs and budget. For example, a hybrid-cloud computing environment uses a mix of on-premises, private cloud and third-party services, with orchestration between. By allowing workloads to move between them as computing needs and costs change, hybrid cloud gives greater flexibility and more subsurface data deployment options. By comparison, a multi-cloud environment refers to the ability to leverage two or more cloud computing platforms but not necessarily requiring connectivity or orchestration between them.

E&P companies should choose the digitised-data storage method that fits their needs now, but keep an eye on the future. After all, the industry is growing.

Reasons to Get Started

Upstream companies can benefit from digital transformation of E&P data by:

- Generating value from the 9% of subsurface data estimated to be unutilised in paper records, recordings and other legacy media;
- Increasing annual production from existing assets by as much as 8%;
- Saving up to $1 bn per year by reducing non-productive activity by geoscientists, petroleum engineers, and data managers;
- Creating a cloud-based E&P IoT – an open data culture in a protected environment with full governance and analytical accessibility.

To get started, oil and gas companies should consider partnering with a subsurface data management service provider that has plenty of experience handling geoscience data and the media on which it has been recorded over the years. With over 40 years in the industry and 40 petabytes of data managed, Katalyst Data Management provides integrated, end-to-end data management and consulting services designed to help companies implement digital transformation of E&P data from every major basin worldwide. ■

A Quantum Leap in Water Recycling

NANCY SLATTER,
Cabral Technology

At the heart of the 'Shale Boom' in the US is the increased use of water for hydraulic fracturing of oil and gas wells – but how do we safely reuse or dispose of the waste water?

The race to increase production in some of the most prolific oil and gas basins in the United States, such as the Permian Basin in West Texas, the Barnett in West Central Texas, the Marcellus in West Virginia and Pennsylvania, and the Haynesville in Louisiana, have contributed to escalating water use for hydraulic fracturing.

In the early 2000s, the combination of multi-stage fracking in horizontal wells, beginning with the Barnett shale gas followed by the tight oil in the Bakken and Eagle Ford, around 2008 and 2009 respectively, helped ramp up the production of oil and gas in the United States. Oil production profiles show that 23,000 completed and fracked wells produced approximately 102,000 bopd in 2000, in comparison to 4.3 MMbopd from 300,000 completed wells by 2015, when 51% of oil produced in the US was primarily derived from hydraulically fractured wells (Figure 1).

Oil and dry shale gas production grew rapidly from mid-2005, increasing significantly in 2011, as shown in Figure 2, and with improved performance from hydraulically fractured wells in shale basins across the country, the 'Shale Boom' has made the US an exporter rather than an importer of oil and gas.

Hydraulic Fracking Fluids

While the efficiency and performance of fracked shale wells continues to improve, the high volumes of water usage have also increased; in 2019, for example, an estimated 7,000 drilled but not completed wells will undergo hydraulic fracturing by Q3. The median volume of water used (barrel) per well for hyfraulic fracturing was approximately 35,000 barrels (1.5 million gallons) between 2011 and 2013 as reported in FracFocus 1.0 by states (Figure 3). There was a great variation between the 10th and 90th percentile water used; 1,762 barrels/well (74K gallons/well) and 143,857 barrels/well (6 million gallons/well), respectively. Variations were attributed to several factors such as fracking design, different shale and well types, and fluid types. As a result, water management through disposal, reuse and recycling have become a priority for operators in the US.

Figure 1: Oil production in the US (2000-2015) in MMbopd). Current estimates from EIA indicate more than half the crude oil produced today is from hydraulically fractured wells. EIA, US Energy Information Administration (March 15, 2016); EIA, completion and production data from Drilling Info and IHS.

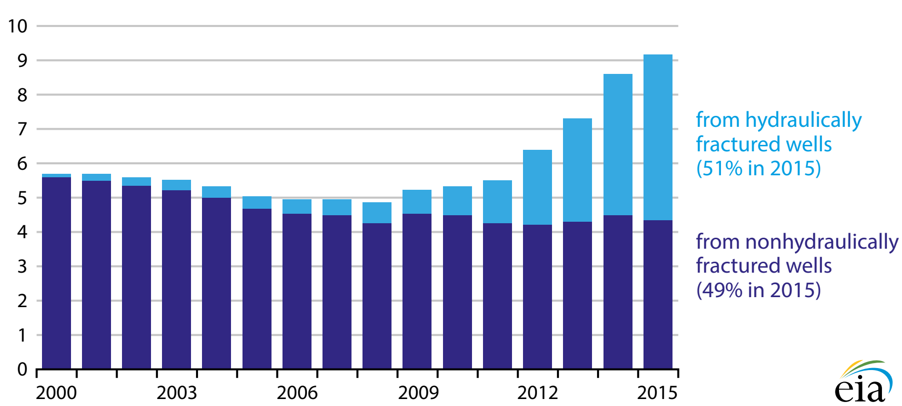
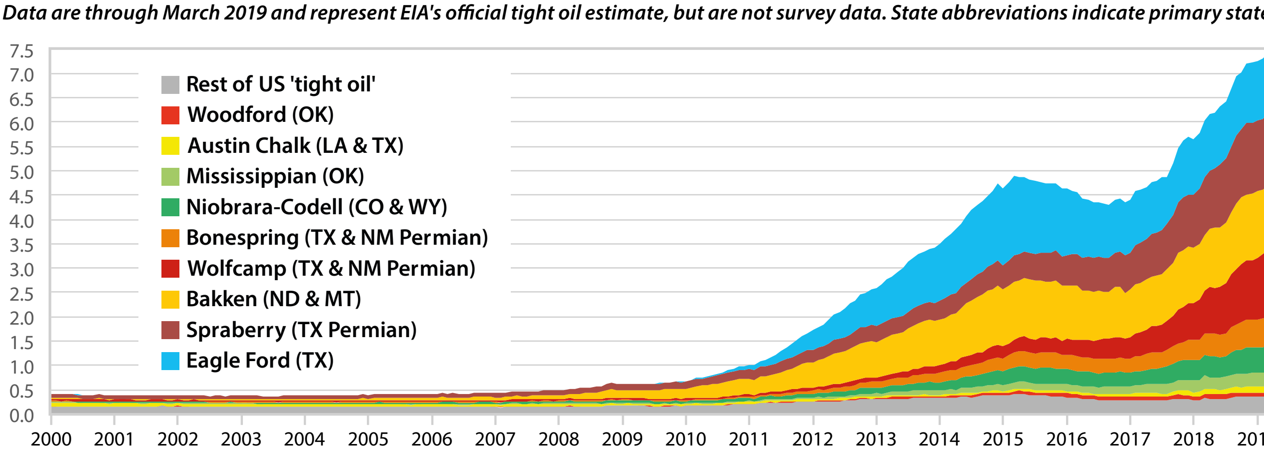


Figure 2: US tight oil production on selected onshore plays (MMbopd). Sources: EIA derived from state administrative data collected by Drilling Info Inc. Data are through March 2019 and represent EIA's official tight oil estimate, but are not survey data. State abbreviations indicate primary state(s).



Although the composition of hydraulic fracking fluids (Figure 4) varies depending on the type of shale, hydraulic fluids are primarily water and sand or proppant, with water making up 90–99% of the total volume injected into the well – hence the increasing need for water. Various chemicals or additives for slick water and energised fluid may contain biocides, corrosion inhibitors, foam, friction reducer, iron control, surfactants and gels, at different concentrations depending on the shale rock type in a specific basin in a particular play type.

Chemical mixing of additives is normally performed at the well site in storage trucks and tankers for the base fluids, with slick water or energised fluids making up the majority of the hydraulic fracturing mixture. The proppant or sand comprises the second highest component of the fracking fluids. An important aspect of chemical usage in the fracking fluid is characterising the type of chemicals and their migration and transformation throughout the whole cycle and process.

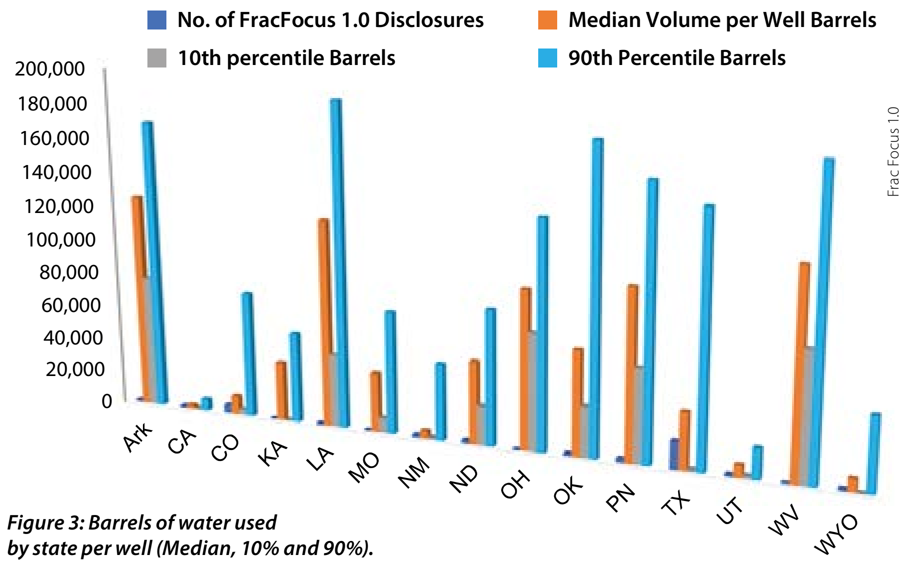


Figure 3: Barrels of water used by state per well (Median, 10% and 90%).

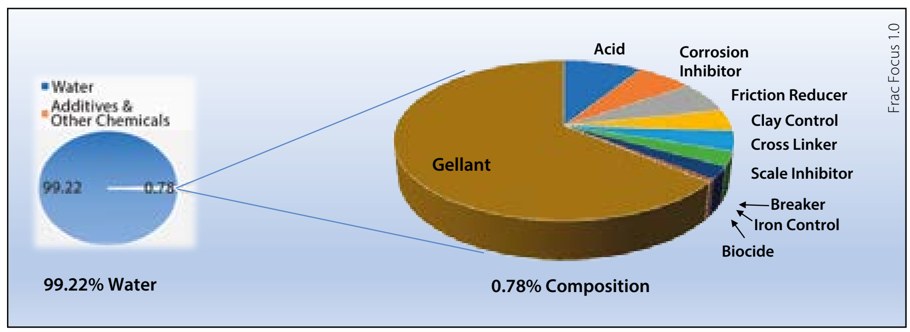


Figure 4: A generalised composition of hydraulic fracking fluid.

Access to Water

The full cycle of hydraulic fracturing operations requires a high degree of planning from the logistical point of view, from sourcing materials through to the development and production stages of a well. As part of this process, different operators have adapted several ways of sourcing water as well as dealing with produced and flowback water. A generalised cycle for hydraulic fracking operations is shown in Figure 5.

Water is obtained mainly from surface and groundwater sources but water sourcing differs between different states based on availability, climate and government regulations. In eastern states where it is more humid, surface water is used more extensively, while more groundwater is used in arid to semi-arid regions. Figure 6 demonstrates the difference between sources of water in the Marcellus Shale (Pennsylvania) – primarily surface water – and in the Barnett Shale (west central Texas), where an equal amount of surface and ground waters are used.

It is interesting to note that when water usage for primary hydraulic fracturing in unconventional oil production is compared to water consumption for injection in conventional oil wells, the unconventional wells use much less water than used in all the conventional stages (Figure 7).

Waste Water: Reuse, Recycle or Dispose?

Produced water is a byproduct of hydrocarbon production. It originates in the formation and flows through the producing well to the surface, where it is separated from the oil and typically is stored and/or treated by the operator. Initially, water produced by hydraulic fracturing contains some of the returned hydraulic fluids but with time the produced water is coming from the production in the formation. The

Pumping water from a lake for hydraulic fracturing in the Fayetteville Shale of Arkansas.

composition of produced water varies between different shales but typically includes salts, metals, dissolved organic compounds, and the returned hydraulic fluids.

Injection of produced water to a disposal well is a common practice with operators but it is costly and often not available due to limited capacity. Other management best practices are employed, such as water treatment in facilities for reuse for the next operation or recycled using different processes. Handling of produced water is very sensitive and care for handling is very important.

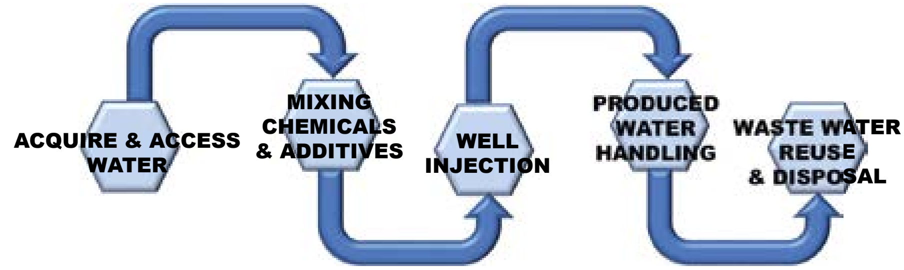


Figure 5: A generalised cycle of hydraulic fracking operations.

The escalating amount of water used for hydraulic fracturing to produce oil and gas is projected to increase even higher in the next few years. With the increased consumption of fresh water, the need for reusing and recycling produced and flowback water is even more important in the oil fields; some service companies have even transformed their strategies to focus on water. The challenge of sourcing, ensuring availability, moving, treating, and measuring water has become big business in drilling shale plays and from the standpoint of an environmentally conscious company, recycling and reusing treated water makes a lot of sense. The 7,000 wells already drilled that will be completed in late 2019 using hydraulic fracturing will create a bottleneck of large volumes of produced and flowback water that will need to be processed for treatment or reinjection.

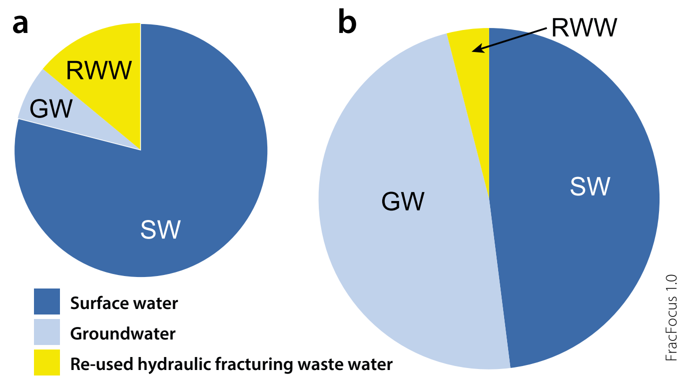


Figure 6: Comparison of sourcing water used for hydraulic fracking between (a) Marcellus shale (Pennsylvania, 2008–2013) and (b) Barnett Shale, Central Texas (2011 and 2013).

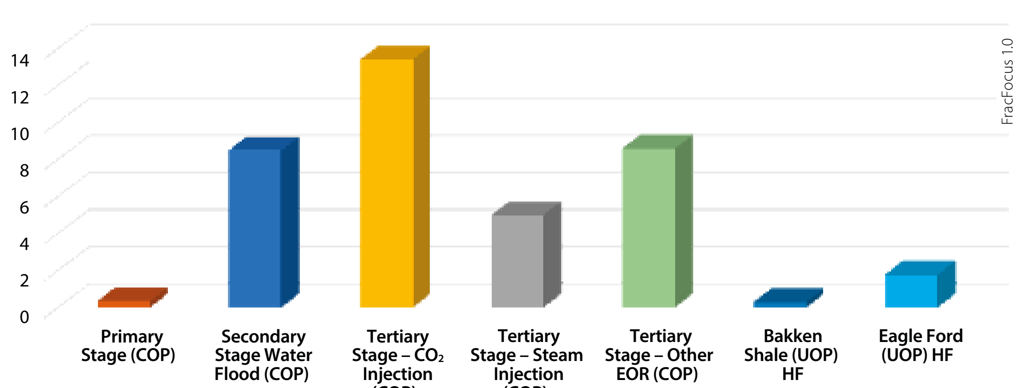
Portable Closed System Solution

Houston-based Cabral Technology has been developing ways to clean water used in fracking operations by combining geo- and bioengineering technologies. Produced and flowback water can be cleaned and recycled for reuse after salts, residues and chemicals are removed. Cabral uses a portable closed system for water recycling and, unlike other water processing units, storage tanks, pipelines, facilities and water well injections are not needed. The system allows for readily available water for the next fracking operation as well as easy transportation away from the site. This recycling process prevents the spillage which happens when large amounts of produced water are temporarily stored in surface pits, and avoids water evaporation from open pits, which can affect local air quality. It also means that water is not reinjected into disposal wells, which can have potentially detrimental effects on groundwater quality and which may pressurise sufficiently to cause local earthquakes. Reinjection into disposal wells has been common practice, but migration of the produced water into permeable layers is unproven, and there is not enough data to determine the long-term effects on groundwater.

The oil and gas industry faces an increasing problem with regard to sourcing, moving, and handling large volumes of water. Hydraulic fracturing has created yet another logistical problem on the roads, with trucks carrying sand, chemicals and water moving in and out of drilling sites. Cabral Technology combines an innovative water technology with solving the logistics problem by utilising machine learning and AI technologies to mitigate the risks of accidents on the roads while decreasing the costs to operators. The software monitors the roads and current operations in real-time using satellite, lidar, real-time road construction and flow stream data to execute and deliver equipment on site in portable systems that can handle and manage the fluids which need to be recycled and reused.

Cabral Technology is a service company in the O&G industry.

Figure 7: A comparison of water consumption for conventional (COP) vs. unconventional oil production (UOP).



Atlantic Offshore Morocco

New Data, New Insights

Geoex acquired 8,474 km of high-resolution 2D seismic data in the **2018 Morocco Atlantic Margin Well Tie MC2D Survey.** Potential field data were acquired jointly with the seismic. Additionally, 1,191 km of legacy seismic data have been reprocessed to form part of an integrated dataset.

The data provide a new view of the regional structural and stratigraphic relationships and deep crustal structure across the passive margin of Atlantic Morocco. In this way they provide a new framework for petroleum systems analysis in guiding future exploration in the region. The seismic data also tie key exploration wells and DSDP sites, allowing the extrapolation of stratigraphy and source rocks across the margin. In a supplementary study, the **Eastern Atlantic Oceanic Crust Project**, Subsurface Resource Consulting/Integrated Geochemical Interpretation (SRC/IGI) have re-evaluated the biostratigraphy and organic geochemistry of DSDP sites 136, 137, 369, 370, 415, 416, 545 and 547, offshore Morocco.

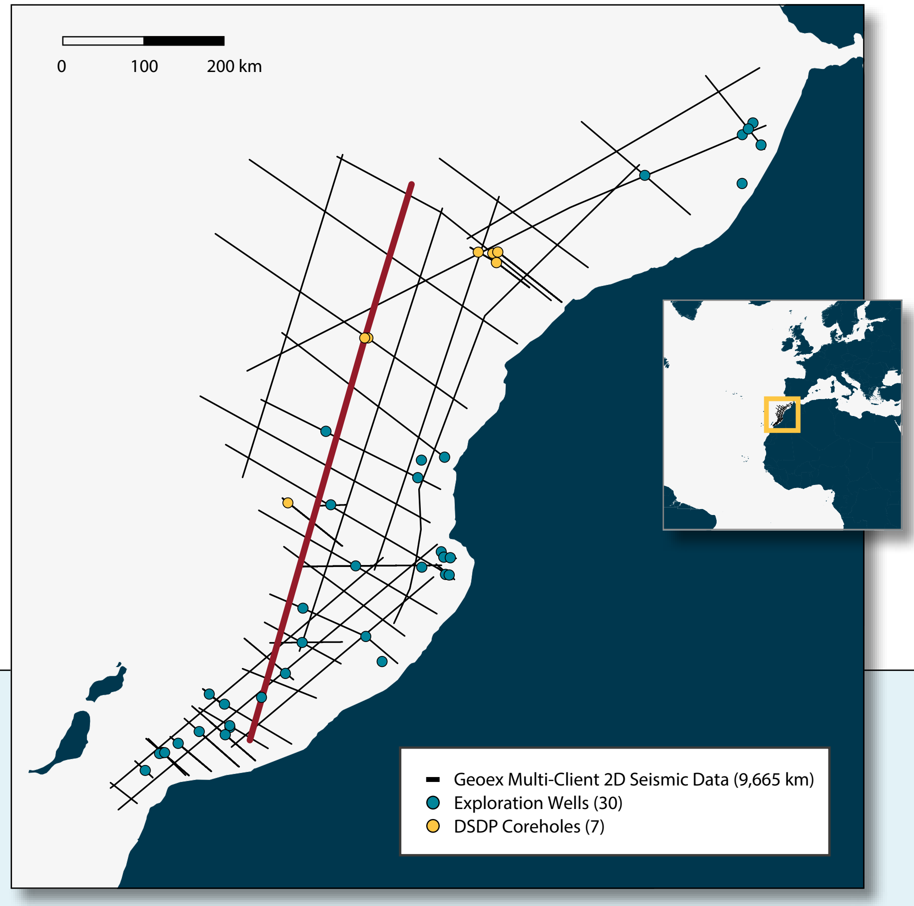
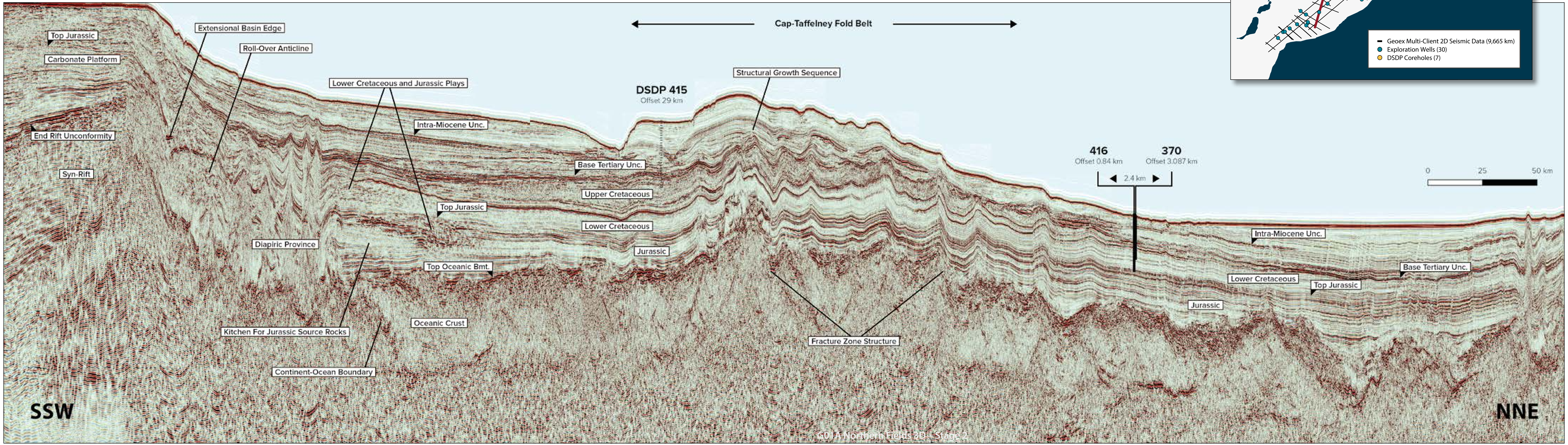


Figure 1: Seismic line extending from the basin margin in the south across the deep basin with its diapiric salt and onto oceanic crust. It shows the Jurassic carbonate platform with underlying syn-rift section, Cretaceous extensional hinge-line, extent of mobile salt, oceanic crustal deformation of the Cape Tafelney Foldbelt, the regional Base Tertiary Unconformity and key DSDP control points.



Regional Geology Key to New Understanding

Seismic data provide new clues to crustal architecture and deformation history.

STEVE LAWRENCE; Subsurface Resource Consulting

A Late Cretaceous 'Atlantis'

The 2018 Morocco Atlantic Margin Well Tie MC2D Survey data allow new insights into the Late Cretaceous-Tertiary crustal deformational history of the margin extending between continental and oceanic crust. Neumaier et al.'s (2016) Base Tertiary Unconformity (BTU) is clearly seen on the new seismic data (Figure 1). DSDP borehole control (415, 416 and 370, all drilled on oceanic crust, see Figure 2) show that the oldest sediments overlying the unconformity are Paleocene in age. The time gap of 30 to 40 million years (Paleocene to Mid-Late Cretaceous) has been attributed to a depositional hiatus by Neumaier et al. but the unconformity's truncational nature on seismic (seen strongly down-cutting to the north on Figure 1) attests to a period of widespread uplift and erosion (Figure 3). Vitrinite reflectance data from DSDP 397 (also drilled on oceanic crust) indicates that there could be kilometres of missing section at this unconformity, which is why we have labelled the BTU the 'Atlantis Unconformity' (see Figure 3).

The Late Cretaceous timing corresponds to the first shortening in the Atlas system in response to the onset of convergence between Africa and Eurasia. This was attributed to large-scale buckling of the lithosphere by Frizon de Lamotte et al. (2010) and on this evidence lithospheric deformation has affected both continental and oceanic crust. It also corresponds to a phase of Late Cretaceous-Paleocene 'passive' uplift and shallowing/emergence on the oceanic islands of Fuerteventura (Canary Islands) and Maio (Cape Verde Islands) (see Patriat and Labails, 2006).

Oceanic Crust Deformation

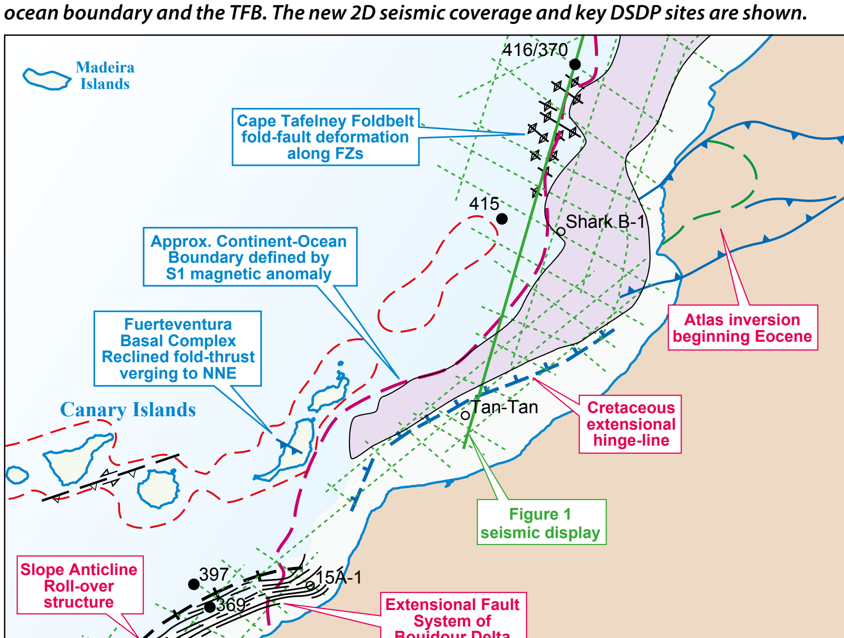
The new seismic data confirm that the Cape Tafelney Foldbelt (TFB) (see Figures 1 and 2) is a product of oceanic crust deformation (OCD). The structural fabric of oceanic crust consisting of spreading-ridge 'rift' faulting and the 'ridge-and-furrow' geometry of fracture-zones is imaged on the new data. The data show that the TFB was formed by compressional reactivation of fracture-zone structures deforming the overlying sediments in short-wavelength reverse fault-fold structures and also in long-wavelength folds or buckles. DSDP core-hole ties indicate that the main deformation occurred between the BTU and the Miocene but the effect of late broad folding can also be seen at seabed. Neumaier et al.'s north-to-south diachroneity of the folding is not apparent on the new data.

Oceanic crust deformation is also seen on Fuerteventura Island where an overturned Jurassic-Cretaceous sequence lying on oceanic crust forms the limb of a north-north-east-verging overturned fold (Figures 2 and 3). Timing of the deformation is reported to be Oligocene (Gutierrez et al., 2006) and was therefore temporally coincident with TFB deformation and with the main Atlas inversion. The new seismic data confirm that there is no direct tectonic link between the Atlas and the OCD of Fuerteventura and TFB, indicating that oceanic crust has deformed independently of continental crust during this phase of Africa-Eurasia convergence.

Deep Petroleum Systems

Over the last 20 years exploration wells have unsuccessfully drilled Upper Cretaceous-Tertiary, Lower Cretaceous and Jurassic reservoir targets offshore Moroccan Atlantic. The latest phase of exploration (~10 years) has seen wells drilling deep targets in Lower Cretaceous clastics and Jurassic carbonates. For this exploration, reservoirs with trapping potential were identified on seismic data (often de-risked by AVO/amplitude anomalies) and potentially charged by known Mid Cretaceous source rocks. The lack of significant

Figure 2: The main structural and crustal elements of the Central Segment of the Moroccan Atlantic Margin including the Cretaceous extensional hinge-line, salt province, continent-ocean boundary and the TFB. The new 2D seismic coverage and key DSDP sites are shown.



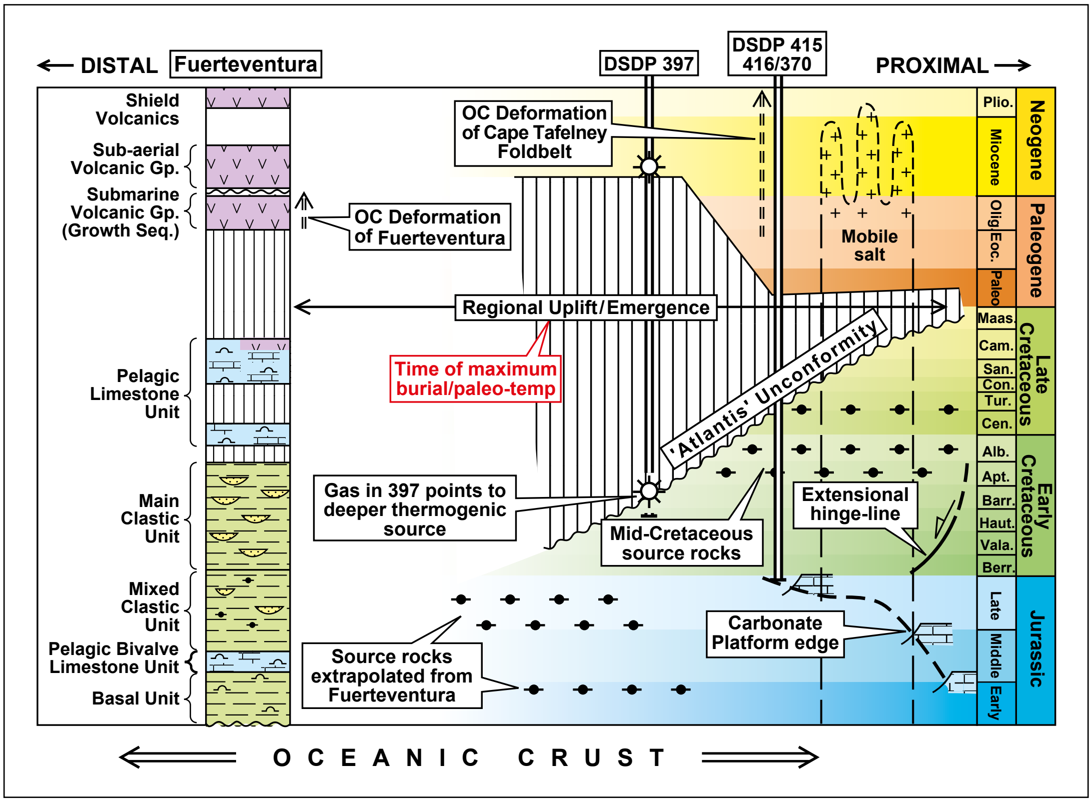


Figure 3: Chrono-stratigraphic chart illustrating the key tectonic and depositional events in the geological history of the Moroccan Atlantic margin. Note the regionally significant Base Tertiary ('Atlantis') Unconformity and the timing of oceanic crustal deformation of Fuerteventura and Cape Tafelney Foldbelt.

exploration success begs questions about the effectiveness of the petroleum system(s) associated with these source rocks. Time therefore for a re-assessment of the exploration potential in the context of a new regional geological understanding.

Direct evidence for source rocks in the 'deep' section of the distal domain comes from DSDP information (which can be extrapolated with the new seismic data) and the outcropping Mesozoic section in the Basal Complex of Fuerteventura, Canary Islands. SRC/IGI have analysed sediments for geochemistry from Fuerteventura and shown that there was an original source-level organic content and richness in the Middle/Upper Jurassic sediments.

Evidence for petroleum systems associated with Jurassic and Lower Cretaceous source rocks is provided by the hydrocarbons encountered in Jurassic carbonates along the Tarfaya margin and by DSDP drilling. DSDP Site 397, offshore Boujdour, encountered unusually high quantities of thermogenic gas and gasolines. Compositional and isotopic trends are consistent with diffusional migration from a deeper mature source rock or top-seal leakage from an oil/condensate accumulation. Either way, 'deep' Lower Cretaceous or Jurassic source rocks are implicated in the petroleum system.

Well CB-1, drilled southern offshore Boujdour in 2015, encountered gas and liquid hydrocarbons in a roll-over structure, demonstrating that kitchens for Jurassic and/or Lower Cretaceous source rocks have formed on oceanic crust. This scenario is also recognised on the new seismic data (see Figure 1) where Lower Cretaceous and Upper Jurassic play leads are depicted overlying a source kitchen on oceanic crust.

Plays and New Concepts

With the magnitude of erosion (missing section) indicated at the Atlantis Unconformity, the Late Cretaceous represents the time of maximum burial/palaeo-temperature for Jurassic and Cretaceous source rocks and therefore the end of the main phase of hydrocarbon generation. The recognised Mid Cretaceous source rocks are either missing due to erosion or, if preserved, would not have become mature enough for hydrocarbon generation pre-erosion. Therefore, for future exploration the focus should be on Jurassic and Lower Cretaceous source rocks but understanding their maturity history and expulsion timing becomes critical.

Future exploration targeting Lower Cretaceous and Jurassic reservoir plays should identify early-formed traps that maintain their geometrical integrity following Late Cretaceous deformation. Lower Cretaceous sandstones deposited by two major delta systems, Tan Tan and Boujdour, can be seen occupying structural traps associated with extensional growth faulting and roll-over structures. As well CB-1 shows, these reservoirs suitably trapped have the potential to retain their hydrocarbons following Late Cretaceous uplift.

Another aspect of petroleum system timing is that Tertiary reservoirs are more likely to be charged by hydrocarbons migrating from deeper accumulations and the evidence of DSDP 397 is that this process is actively working. Seismic evidence suggests that hydrocarbons are seeping across the BTU on a widespread scale and charging available Tertiary reservoirs. In this way, a new Paleogene play has been identified along parts of the margin where large 'drift-like' carbonate accumulations display strong amplitude anomalies.

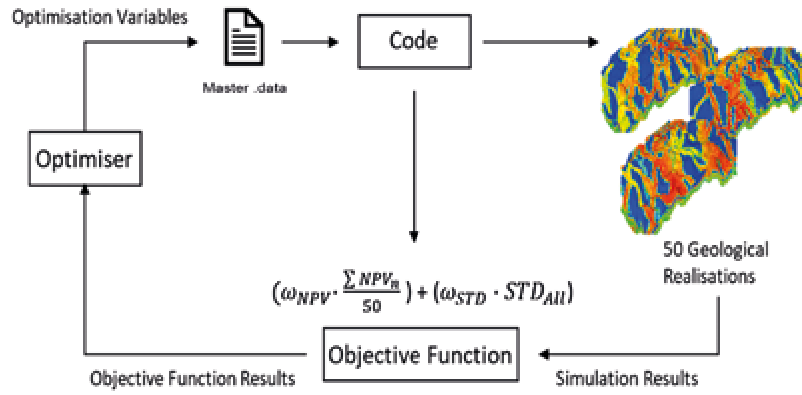
References available online. ■

Olympus Challenge

With Great Power Comes Great Responsibility

ALBERTO DIAZ, ALEXANDRA KIDD, ANDREY VOLKOV and DMITRY EYDINOV; Rock Flow Dynamics

The oil and gas industry is strongly associated with big investments and huge risks; therefore, everyone involved is looking to maximise revenue and minimise risks. Studies show that underestimation of uncertainties – for example, geological uncertainties – can result in unreliable reservoir predictions (Vink et al., 2015). However, modelling uncertainty is very challenging; it requires the generation of multiple models to account for multiple uncertainties, both static and dynamic, which is computationally expensive. Another challenge is the consideration of multiple field development scenarios to optimise field production performance while accounting for multiple geological uncertainties.



Ringrose and Bentley (2015)

Schematic representation of the workflow.

The study discussed here looks at well control optimisation under geological uncertainty for a synthetic reservoir model, using the OLYMPUS Field Development Optimisation Challenge data (see box).

To account for geological uncertainties, an ensemble of 50 geological realisations generated by altering the random seed is used (Fonseca et al., 2017). This study looks at how to handle the main limitations of working and handling ensembles of models that are related to workflows, technologies and integration, as well as analysing the enormous quantities of data produced.

Method and Workflow Characteristics

The main limitations of working and handling ensembles are often thought to be related to workflows, technologies and integration (Ringrose and Bentley, 2015). The common practice to overcome them is to create a very detailed high-resolution geological model that is anchored to a preferred 'base case', and this model is then upscaled to be suitable for simulation in a reasonable time. After that, an uncertainty range could be added, either as a percentage factor in terms of the model output (e.g. a percentage of the base case volume in-place) or as separate low and high cases flanking the base case (Ringrose and Bentley, 2015).

The Olympus Well Control Optimisation Challenge presented fifty equally probable geological realisations, the task being to select a single development plan which will be optimal for all 50 realisations. The limitations mentioned above are addressed in this study through a new integrated automated workflow using innovative technologies for model simulations (see figure above). An oil rate (liquid) control for each production well is used, varying from 0 to 900 m^3/day, and each injection well is controlled by a surface flow rate target with values from 0 to 1,600 m^3/day, which allows the optimiser to decide if a producer or injector should be shut at any given point in time. Well bottom-hole pressures and maximum liquid production rate specified in the exercise description were also included as group constraints.

To perform the well control optimisation study, 360 variables for each ensemble run were defined. Particle Swarm Optimisation (PSO), a stochastic optimiser that explores the parameter space by a population of particles searching for an optimum solution (Eberhart et al., 2001), was used as the optimisation algorithm. It was chosen because it has a small number of parameters to adjust, making it simple in both formulation and computer implementation (Mohamed, 2011). PSO searches for the parameter combinations to maximise the objective function. Net present value (NPV) was set up as the objective function. The following expression was used to calculate NPV:

$$NPV = \sum_{i=1}^{N_t} \frac{R(t_i)}{(1+d)^{t_i/\tau}}$$

where

$$R(t_i) = Q_{op}(t_i)\cdot r_{op} - Q_{wp}(t_i)\cdot r_{wp} - Q_{wi}(t_i)\cdot r_{wi}$$

$Q_{op}(t_i), Q_{wp}(t_i)$ and $Q_{wi}(t_i)$ are total oil production, water

What is the Olympus Challenge?

The OLYMPUS Field Development Optimisation Challenge was developed by TNO together with ENI, Petrobras, Equinor and Delft University of Technology within the framework of the ISAPP2 (Integrated Systems Approach for Petroleum Production) research consortium, and was launched in early 2017. This challenge is based on the realistic yet fictitious OLYMPUS oil reservoir and consists of three exercises on optimisation under uncertainty: one on well control optimisation, one on well placement optimisation, and one on joint optimisation of well placement and control.

production and water injection volumes over the time interval *Δti*, respectively.

A separate piece of code was developed to allow the running of all 50 geological realisations with the same schedule, launched from a so-called Master.data file. NPV is calculated for each simulation and after the 50 simulations, the mean NPV is calculated, as well as the standard deviation of the ensemble. These figures are used to calculate the objective function value, which is fed to the optimisation part of the workflow, allowing the optimisation algorithm to choose the optimised variables and continue the optimisation loop.

Innovative Technologies

In this study, several innovative technologies have been combined to maximise the efficiency of the proposed workflow.

Firstly, optimisation is carried out in the graphical user interface, where a user can select an optimisation algorithm, specify the number of variables and set up the range of each one. Automatic or manual weighting of the objective function can be performed, allowing the user to search and optimise the ensemble in relation to maximising mean NPV or minimising standard deviation (STD), or a combination of both.

Secondly, a link between an ensemble of geological realisations and a schedule file with 360 variables for each simulation run has been created using coding. This both launches the iterations and calculates the objective function of the ensemble. Coding brings in the flexibility; the same code could be altered and used for a different problem set up in a similar manner.

The third innovative technology in this study is cloud computing, used to facilitate computations, as ensemble optimisation requires huge computational power and cloud computing is very efficient at performing such tasks cost-effectively, using powerful external IT resources. Cloud computing is gaining popularity across a variety of industries but the oil and gas industry is showing resistance to this technology due to concerns such as data breach or loss. These concerns can be addressed and minimised by properly researching a cloud provider service, reviewing their security history and references, implementing end-to-end encryption and so on (Parms, 2016).

Unbiased Analysis

Once the limitations related to workflows, technologies and integration have been overcome, the next challenge is how to understand and analyse the enormous quantities of data produced. The main question is: which and how are models selected? How to judge which model is 'the best'? Working with ensembles might bring the personal preferences or bias of the engineer into the process of analysing results and picking the realisations.

For example, in this study, if the engineer focuses only on maximising mean NPV, it is quite probable that the standard deviation of the ensemble will also increase. STD can be translated as risk, with higher SD meaning higher risk. If only one result is provided, then an engineer is taking a corporate decision which involves personal preference. It cannot be forgotten that with great power comes great responsibility. To avoid this, the workflow focuses on the generation of an NPV vs STD plot, in which a Pareto front (a set of Pareto optimal solutions, i.e. those that are not dominated by any other feasible solutions) can be identified (see figure below). This can help to assess the multiple solutions against each other and to evaluate the associated risks. Such graphical representation of the results could be included in a project report for management to help them decide how much risk they, as a company, are willing to take for a possible NPV reward.

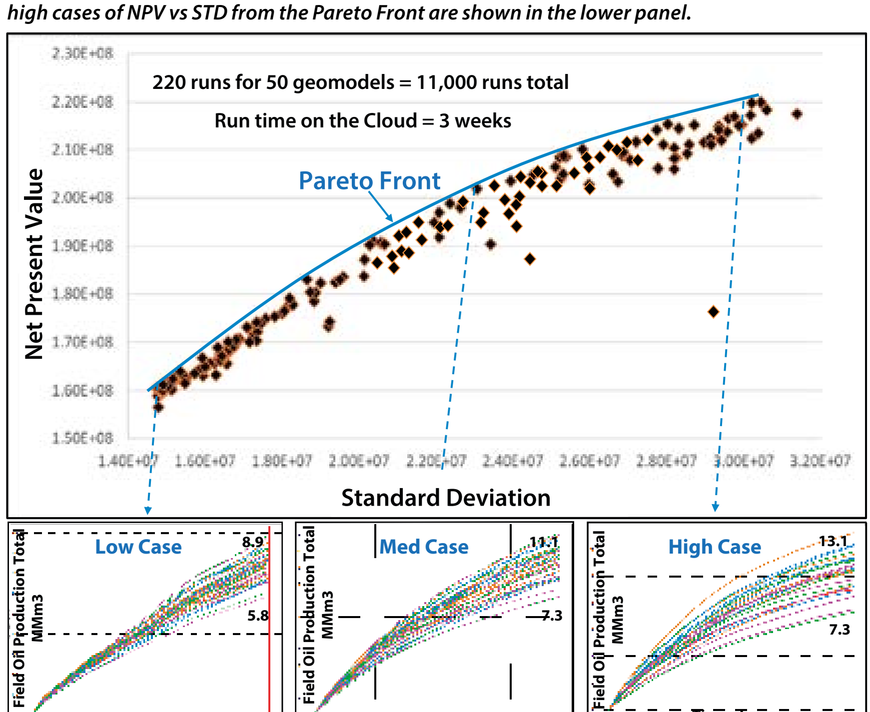
The spread of total field oil production for the low, medium and high cases of NPV vs STD from the Pareto Front are shown in the figure below, illustrating the impact of uncertainty in the 50 model realisations for three possible scenarios from the Pareto Front.

A Powerful Tool

An integrated automated workflow coupled with innovative technologies is a powerful way to perform extensive optimisation tasks whilst accounting for geological uncertainties. The workflow produces an optimised development plan which is ideal for multiple geological realisations. This approach, therefore, can help to undertake a better evaluation of optimal field operating strategies and helps to create an unbiased analysis of the results, taking into consideration risk-reward trade-off.

References available online. ■

Net Present Value vs Standard Deviation plot; a Pareto front is identified for optimisation of study results. Total field oil production for all 50 model realisations for the low, medium and high cases of NPV vs STD from the Pareto Front are shown in the lower panel.



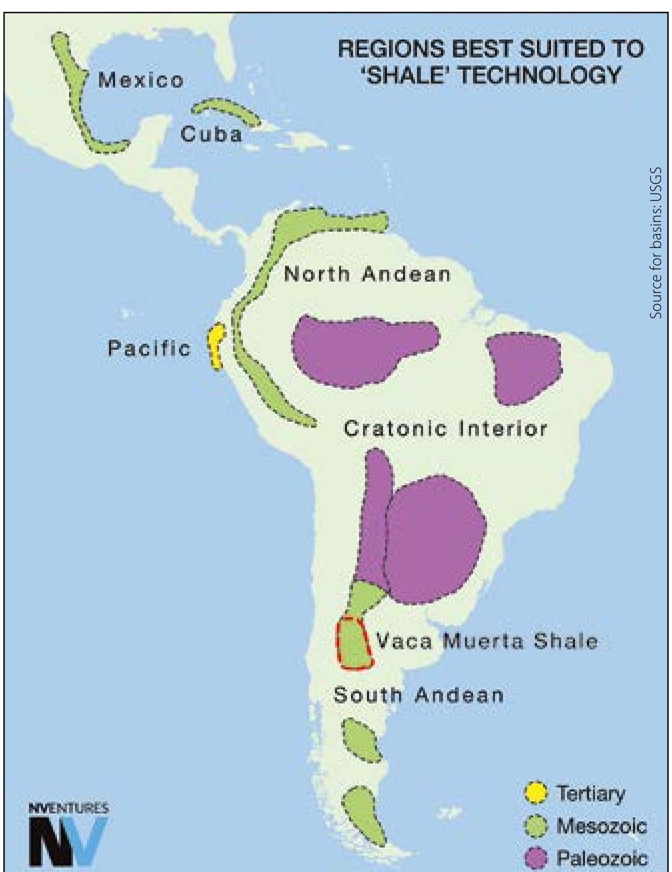
The Future of Unconventionals in Latin America

Latin America has the great geology to emulate the North American saga, but other factors are determining a different path.

ROG HARDY, Editor, NVentures Latin America Exploration Report

As the 'shale craze' of North America transforms oil and gas economics globally, where will the next boom be? One region under scrutiny is just to the south in Latin America, from Mexico to Argentina. Intense activity in the Permian, Williston and Appalachian Basins has not been matched, however, in this region, despite so many shared attributes. Why? Is it the geology, or something else? And will there be breakthroughs in the foreseeable future?

Part of the answer lies in the well-known story of how the 'shale craze' spread in North America's onshore. Everyone is familiar with the way a few pioneering geologists and engineers tackled the challenges of the Barnett Shale, and how they and colleagues eagerly tried the new technologies of laterals and multi-stage fracking in other brittle organic zones in nearby basins. They soon learned, however, that cookie-cutter approaches do not work so well, and every basin and area requires tailored technology plus some trial and error – or, as they say, an element of 'pump and pray'. This has met with varying degrees of success from region to region, with an expansion of the general technology and growth of oil and gas shale production from Pennsylvania to California and from Alabama to British Columbia. In addition to favourable geology, the pumping and praying pioneers in North America enjoyed one common denominator – an advantageous above-ground mix of topography and vegetation, regulations, service industry, land ownership and pipelines.



Source for basins: USGS

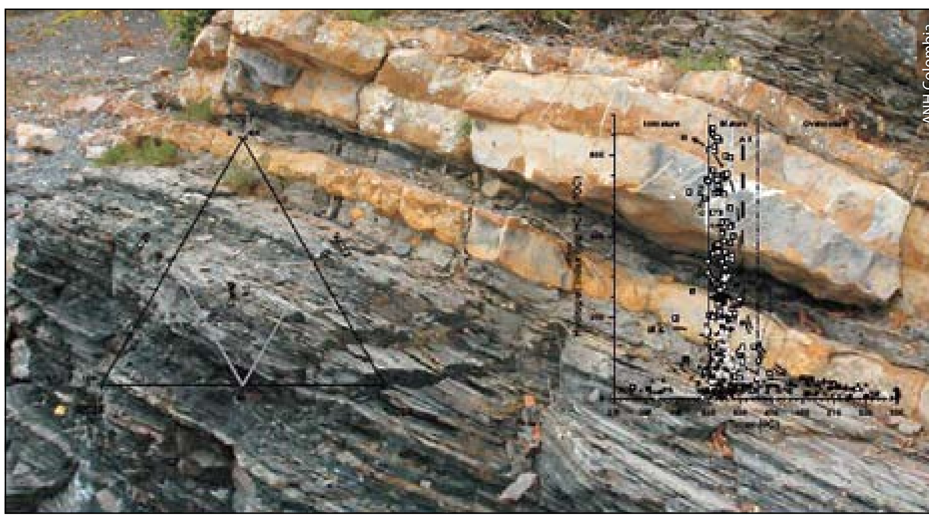
Impediments to a Boom

Latin America has great geology too, with the Eagle Ford bookend, La Luna and its equivalents, occurring across a broad swath of the North Andean realm from Trinidad to Peru, and the thick, rich, brittle Vaca Muerta Formation occupying a large basin complex in Argentina. The above-ground conditions are very different in Latin America, however. Few regions from Mexico to Argentina have much of a paved road network, let alone railroads or pipeline networks to support the massive drilling campaigns and gorilla industry needed for the multistage fracking or high water cut production associated with shale development. Much of Latin America is associated with high-volume rivers and heavy vegetation. Additionally, the local population have put up varying degrees of resistance and host government legislation often fails to cater for the intense drilling operations demanded by shale's modest per-well IPs and EURs.

Another, less recognised impediment exists to a 'shale boom' in the countries of Latin America: competition with remaining potential from onshore conventional production. Well density and technology in most of onshore Latin American is well behind that of North America and conventional exploration will vie for investment capital with any North America-like pure shale plays in most basins for the foreseeable future. In addition, with the significant exception of the Vaca Muerta, a shale boom will not happen soon because of very high remaining conventional gas potential.

These issues do not preclude the region from benefiting from the technological advances of North America shale. Many of the great organic-rich brittle rocks in Latin America have been subjected to major transpressional forces, especially in the North Andean realm. This has resulted in natural fracturing similar to the Monterey in California and giant fields have already yielded billions of barrels out of these brittle shales, most notably the La Paz-Mara complex on the north side of the Maracaibo Basin in Venezuela. Other large structures have been vertically drilled in a number of

countries with less well-developed natural fractures and are ripe candidates for laterals or high-angle wells coupled with completion techniques adapted from the latest North American practices. A few enlightened operators are starting this trend, albeit modestly.



The Eagle Ford in Texas (top) and the La Luna in Colombia.

Potential in Latin America

Let's take a look at some of the basins in Latin America where activity is most likely to be positively affected by applications of recent 'shale' drilling and completion technology.

The Eagle Ford trends into Mexico, but any sustained commercial activity there will have to compete with the incredible remaining onshore conventional potential further south in the Tampico-Misantla, Veracruz, and Sureste Basins. There is ripe opportunity here for shale technology to substantively enhance production in marginally fractured reservoirs, that have only seen vertical wells and decades-old completion techniques. With the recent 'opening' of Mexico, international operators are just starting this trend, but it will take a number of years to ramp up.

The afore-mentioned greater North Andean belt from Trinidad through Venezuela to Colombia, Ecuador and Peru harbours major potential for focused action with new techniques to open up historically stubborn rocks to supplement the high permeability sand reservoirs that have yielded most of the production to date. Progress will be very different from country to country, of course, as the above-ground considerations discussed above come into play.

An outlier of Tertiary rocks with shale gas potential in the Pacific realm's Talara Basin awaits a critical mass of activity.

Farther south we have seen a perfect storm of factors combine to create a major emerging shale producing region, the Neuquen Basin's Vaca Muerta. These include the world's thickest prospective zone; a relatively mature infrastructure from decades of conventional production; a flat, semi-arid, lightly-populated terrain similar to west Texas; a strong gas price; and a receptive provincial government. Success here could easily spill out to the nearby Northwest Basin and south to the San Jorge and Austral Basins, as long as provincial governments are receptive.

Also in the southern sub-Andean foldbelt realm in Bolivia, Argentina and Chile high angle or lateral wells with tailored completions might enhance gas production from naturally fractured Palaeozoics.

The interior of South America harbours broad swaths of Palaeozoic shales of varying degrees of potential for shale technology, with predominantly robust gas markets, but a variety of above ground factors such as competition with other markets, remoteness with poor infrastructure and dense vegetation probably preclude this resource from the current boom.

Dead Cow?

So, to sum up, there will not be any 'shale boom' in Latin America outside of the Neuquen Basin any time soon, but an educated application of tailored technology from North America's shale basins could sustain and grow oil and gas production in certain settings for decades to come. It is up to a collaboration of enlightened operators and collaborative local and national governments. ■

The Yamal Peninsula

The use of innovative new technologies opens up huge volumes of remote resources in Russia.

JANE WHALEY

The largest gas discovery of 2018 was Novatek's North Obskoye field in the shallow waters of Ob Bay in the northern Russian Yamal Peninsula. The discovery is reported to have over 11 Tcf of gas, and Rystad Energy estimate that it holds recoverable resources of around 960 MMboe.

This highlights the fact that that the Yamal Peninsula is one of the best resourced but little known oil and gas provinces in the world and the location of Russia's largest known untapped gas reserves.

Complex and Challenging

The bleak, cold Yamal Peninsula in north-west Siberia juts 700 km out into the Kara Sea north of the Arctic Circle. It is 240 km wide and rises no more than 90m above sea level, and it is home to a small human population – and over 200,000 reindeer. It is also 2,230 km as the crow flies from Moscow, the permafrost is up to 300m deep, there are complex geological and hydrological conditions and it is dark for many months of the year – so commercialising oil and gas reserves is challenging.

Hydrocarbons were first identified in Yamal back in the 1960s, but active exploitation of the resources did not commence until the second decade of the 21st century. With over 170 Tcfg initial reserves, Bovanenkovskoye is the largest field in the peninsula. When it and several other major gas fields were discovered in the west-central sector of the Yamal Peninsula between 1978 and 82, Russia began making plans to exploit these resources. After merely two years, however, the challenges involved in commercially extracting and exporting the gas, as well as environmental concerns and cultural issues with the local populace, meant that these plans were suspended. The field finally began producing commercially in 2012, with gas being exported 1,200 km to Ukhta and thence into Russia's Unified Gas Supply System. The gas is transported at 120 atm – a record high for onshore gas pipelines – and the pipeline crosses part of the Kara Sea, which is covered with ice most of the year: another major technical challenge.

It is a similar story for oil. Novoportovskoye, the largest oil field on the peninsula with over 1,650 MMbo, was discovered in 1972, but it was left undeveloped for 50 years until GazProm's pilot project began in 2011. With low permeability reservoirs and a complex structural setting in addition to the above ground challenges, this has been a difficult project, but extracting the oil has been achieved using many of the techniques more commonly associated with unconventional exploration, such as horizontal and multilateral wells and multistage fracking. The field is 700 km from the nearest oil infrastructure, so oil is exported to northern Europe by sea all year round by special tankers able to get through ice up to 1.8m thick, supported by nuclear icebreakers. The first oil left Yamal in 2016 and over 40 MMbo was exported in 2017.

LNG is also now being sent from Yamal by sea from a hub in the north-east of the peninsula close to the 32.7 Tcf (2P) South Tambey field, which the new discovery at North Obskoye will be able to tap into. This is a giant integrated project involving a number of operators and service companies. It required the construction of sea and airports and three liquefaction trains, each with a capacity of 5.5 million metric tons, as well as the use of specially built LNG ice-breaker tankers sailing to markets in Asia and Europe.

Huge Volumes

When you look at the potential of the Yamal Peninsula, the figures involved are staggering. More than 30 fields have been discovered so far and, according to GazProm, the total reserves and resources of the Peninsula are 936 Tcfg, 11 Bboe of gas condensate and 2.2 Bb of oil. In 2017 alone Yamal produced nearly 3 Tcf of gas and it is thought that there is potential for this figure to rise to over 12 Tcfg a year.

The Yamal Peninsula could be supplying Europe for decades. ■

The 'Arctic Gateway' terminal at Novoportovskoye is designed for year-round operation under extreme climatic conditions, with temperatures below -50°.

William Smith's Fossils Reunited!

An exquisitely produced new book celebrates and completes William Smith's seminal unfinished work, *Strata Identified by Organized Fossils*.

JANE WHALEY

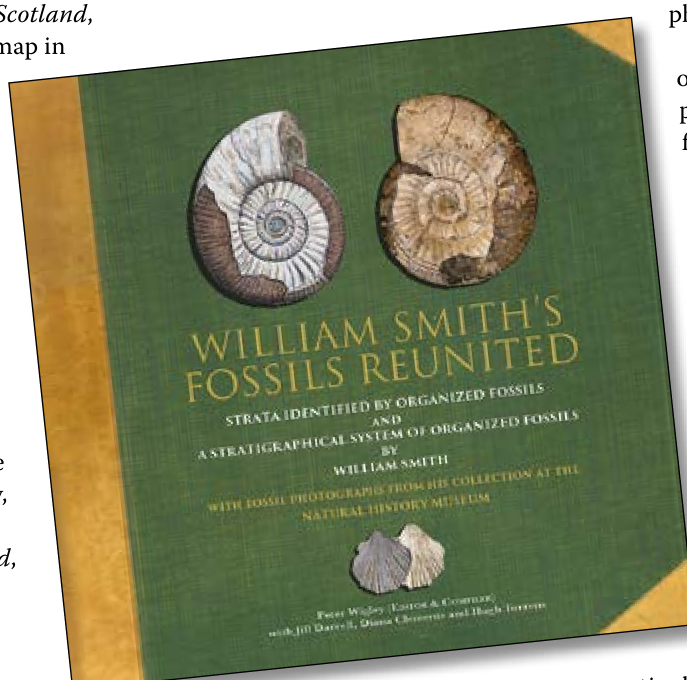
In the early 19th century the newly formed Geological Society of London did not treat William Smith, aka 'The Father of English Geology', kindly. Unlike most of the founders of the world's oldest geological society, Smith was not a gentleman, and the snobbish members took some time to realise the significance of his crowning achievement: his 1815 *Geological Map of England, Wales and Parts of Scotland*, the first nationwide geological map in the world.

The Society has been trying to rectify its mistake ever since. In 1831, it awarded Smith the first Wollaston Medal – its highest honour – and now annually presents the William Smith Medal. An original copy of his famous map hangs in pride of place on the Society's walls.

And in March 2019, the Society held a party to celebrate William Smith's 250th birthday, where a beautiful new book, *William Smith's Fossils Reunited*, was unveiled, bringing together the original fossils Smith used to delineate the strata on his map and the illustrations of these fossils prepared for his books and pamphlets explaining these ideas.

Seminal Publications

Through his work as a surveyor and his geological research, Smith travelled the length and breadth of England and Wales, gathering, describing and collating fossils. In 1816 he began *Strata Identified by Organized Fossils*, a book to be published as a series of pamphlets that explained the rocks of England and Wales from youngest to oldest. They were illustrated with exquisitely engraved images of the fossils found in each layer, drawn by renowned naturalist, mineralogist and illustrator, James Sowerby, from specimens provided by Smith. This was an important breakthrough: the first time anyone had tried to categorise strata through the use of fossils. Unfortunately, Smith never completed the project. Poor business decisions forced him into bankruptcy and in 1818 he sold his treasured collection of over 2,680 fossils to the newly formed British Museum, providing them with a catalogue of his specimens, *A Stratigraphical System of Organized Fossils.*



Dr Peter Wigley was involved with the Geological Society's celebrations of the bicentennial of the map back in 2015, and was instrumental in the creation of the *www.strata-smith.com* website. While researching that project, Peter was given copies of Smith's publications and had produced cleaned-up digitised versions of the illustrations for the website. After meeting Jill Darrell, Curator of the William Smith collection at London's Natural History Museum, the idea of matching the fossils in the books with the originals in the museum began to take shape.

Beautiful Book

Peter and his team of enthusiastic helpers digitised all the text of the unfinished book and of his fossil catalogue. They scanned the plates of illustrations and located and digitised notes for the unpublished part of the book, along with further original material, including comments and edits in Smith's own hand. They then matched the illustrations to the original fossils in the Museum's collection and photographed them.

The book shows a scan of each page of the original publication on one side, with facing it the reconstruction of the same page with high resolution photos of the fossils. Each page of Smith's original book was colour-coded to agree with the strata colours he used in his map and this scheme has been followed in the book. It also includes copies of Smith's maps annotated with the original locations of the fossils, which Smith had meticulously recorded.

Congratulations to the team who put together this superb book, and particularly to Peter Wigley, who conceived the idea and was the driving force behind it. It is not only beautiful to look at and a wonderful adornment to any coffee table, it should be of great interest to palaeontologists and to students of the history of geology. It is also a testament to the extraordinary skill of early 19th-century engravers and map makers – and to the genius of William Smith.

A longer version of this article and an interview with Peter Wigley is available online. ■

William Smith's Fossils Reunited
Peter Wigley (ed) with Jill Darrell, Diana Clements and Hugh Torrens
Halsgrove, March 2019.
Available through the Geological Society website.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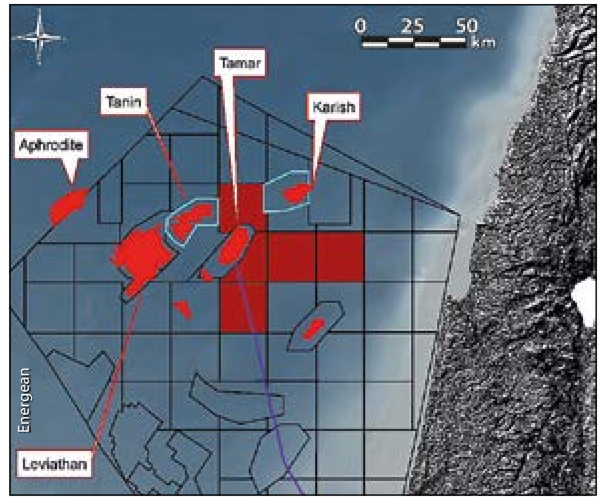
Israel: Significant Gas Discovery

The recent run of large gas discoveries in the eastern Mediterranean continues, the latest being **Energean's** successful well offshore **Israel** at **Karish North**, about 80 km north-west of Haifa and a few kilometres south of the maritime border with Lebanon. Initial in-place estimates are between 1 and 1.5 Tcf gas, reservoired in high quality sands, with a gross hydrocarbon column of 249m. Karish North was spudded on 15 March 2019 in waters over 1,700m deep. Further evaluation will be undertaken to refine the resource potential and determine the liquids content of the discovery.

Karish North lies only a few kilometres north of the **Karish** field, discovered in 2013, which contains more than 280 MMboe 2P reserves, and 40 km from the 2.2 Tcfg **Tanin** field. Plans for the joint development of these two fields using a Floating Production Storage and Offloading unit are already underway, so it will be easy to exploit the new discovery in conjunction with the two previous finds.

Israel's offshore lies within the Levantine Basin, which contains up to 10,000m of Mesozoic and Cenozoic rocks above a rifted Triassic-Lower Jurassic terrain. Energean's discoveries are all in the prolific Early Miocene submarine fan deposits of the Tamar Sands.

Energean Israel is the operator of the Karish and Tanin leases with a 100% working interest. ■



USA: Deepwater GoM Discovery

In April 2019 **Shell** announced an oil discovery in the deepwater western **Gulf of Mexico Alaminos Canyon Block 380** in the **Perdido** thrust belt. Drilling at the **Blacktip** well is still ongoing, but to date the well has found over 120m net oil pay with good reservoir and fluid characteristics.

The discovery is in the Palaeogene Wilcox Formation and is drilled in about 1,900m water, approximately 50 km from the Whale discovery and the Perdido platform, the world's deepest floating oil platform. It will allow Shell to augment existing production in the Perdido area where the **Great White**, **Silvertip** and **Tobago** fields are already producing.

Blacktip is less than 100 km from the Mexico maritime border with the US and the Perdido play is thought to extend into Mexico, adding to the significance of this discovery.

Alaminos Canyon Block 380 is operated by Shell with a 52.375% share, on behalf of partners Chevron U.S.A. Inc. (20%), Equinor Gulf of Mexico LLC (19.125%), and Repsol E&P USA Inc. (8.5%). ■

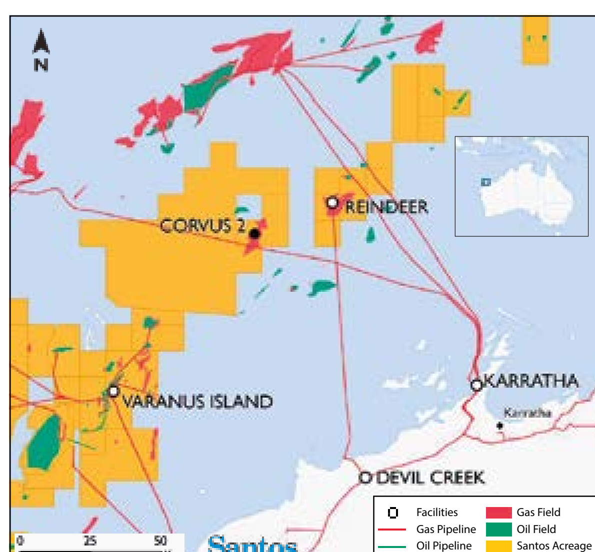
Australia: Large Gas Column

Santos recently announced what is thought to be the largest gas discovery for ten years in the **Carnarvon Basin**, offshore north-west **Australia**. The **Corvus-2** appraisal well in block **WA-45-R**, approximately 90 km north-west of Dampier, intersected a gross hydrocarbon interval of 638m, one of the largest columns ever discovered across the North West Shelf. Wireline logging confirmed 245m of net pay across the target reservoirs in the North Rankin and Mungaroo Formations, at depths between 3,360 and 3,998m.

Initial samples suggest that Corvus-2 shows a considerably higher condensate gas ratio than in Corvus-1, which was drilled several years ago and came into the Santos portfolio through the acquisition of Quadrant Energy. The company believes that the discovery has opened up a number of additional exploration opportunities in the region.

According to Wood Mackenzie, initial resource estimates are in the region of 2.5 Tcfg and 25 MMb condensate, making this the largest gas discovery in the basin since the Satyr-4 exploration well, drilled by Chevron in 2009.

Corvus, which lies in 63m water depth, is just 28 km from the Santos-owned Reindeer platform, which delivers gas to the Devil Creek domestic gas plant near Karratha, and about 62 km from a Varanus Island tie-in point, also owned by Santos, so commercialising this asset should be relatively easy. ■



Diversity is a Key to Success

Mme Teresa Goma is the Director General of Hydrocarbons for the Republic of Congo, sub-Saharan Africa's third-largest oil producer. She is responsible for the 2018–2019 Congo Licence Round Phase II, which involves both on and offshore areas. These include the underexplored onshore Cuvette Basin and the Coastal Basin, which covers onshore and shallow water blocks, as well as exciting deep and ultra-deepwater blocks.

Where do you think is the best potential for exploration in the Republic of Congo?
Both basins are very prospective, the only difference is that the Coastal Basin is better known than the Cuvette Basin. Our very deep and ultra-deep offshore areas are underexplored; the potential there is still at its maximum.

This is Phase II of the Congo Licence round; how successful was Phase I?
Three blocks were awarded in Phase I: Marine XX, Marine XXI and Marine XXVII. Although two of the licensees, Total and Perenco, are already in Congo, we have had the opportunity to have a new actor, the American company Kosmos, who will operate our ultra-deepest block. We are happy with the Phase I licence round results.

How did you decide which blocks were to be offered in each phase?
Phase I was primarily deepwater blocks. Actually, most of the blocks offered but not awarded under the 1st round were put back into the Round II. The criterion is simple: we have a map of our basins and all the free blocks are available for bidding.

Can you tell me about SNPC's regional 3D seismic project and your plans to encourage companies to support it?
Our partner PGS and the Congolese national oil company SNPC are currently working together, with the support of the Ministry of Hydrocarbons, to determine the best way to encourage companies to participate in this very productive, cost-saving project, which will involve a new broadband depth-imaged 3D survey. I can't tell you more about it for now, as we are considering a few leads, but I will be happy to come back and share with you the final decision.

How many companies have shown interest so far and when does this phase end?
Over 30 companies have shown interest so far; we are very excited by this enthusiasm. There are currently several bid rounds ongoing in the region and the world, but we really hope that our current and future partners will see the benefits of coming to Congo. We are, of course, very pleased to talk to potential partners and always available to clarify any concerns or questions they might have. The bid round deadline is June 30th; we hope that by Q4 2019, we will be able to announce the results.

What is your own role in the Licence Round process?
As the Director General of Hydrocarbons, I make the final calls on the entire bid round process, timing, data to be made available. I make sure that we all comply with the laws and regulations. And I try to assure our partners that Congo is a very welcoming country, where doing business, especially investing in the oil and gas industry, is always a win-win deal.

What are your hopes for this round?
I would like to diversify our oil and gas family, with small, medium and large size companies and new nationalities. As I said previously, we are happy to have a new operator from the USA in the country and my hope is having additional new nationalities. Diversity is one of the keys to success. ■

Mme Goma making a presentation at Africa Oil Week 2018. Teresa Goma has 18 years experience in the oil and gas industry, from both the services sector and with an operating company, Oryx Petroleum.

FlowBack is our new back-page column by industry specialist **Nick Cottam**.

The Generation Z Factor

How can we attract the next generation into the oil and gas industry?

In my early youth joining the oil and gas industry was very much a slick career choice (pardon the expression). Two acquaintances joined two different super majors and they seemed set for life – front line drama, travel, promotion and a pension to die for. What about today's click generation? How are they weighing up a career in oil and gas when faced with the strictures of the climate change lobby and the idea, however misplaced, that fossil fuel-based energy is living on borrowed time.

According to a recent poll of US consumers and oil and gas executives by the consultancy firm EY there are plenty of workforce challenges facing the sector. In the short term at least – certainly in the first half of 2019 – jobs may be on the rise thanks to a more bullish oil price but the EY poll suggests that young people are more sceptical than ever about making a career in the sector.

The survey quizzed millennials, those in the 20–35 age group, and the so-called 'Generation Z', the 16–19 year olds, many of whom are still looking at a higher education choice which leads to a worthwhile career. Graduates in disciplines such as geology, engineering and science subjects should be well qualified to walk into one of the big oil and gas companies when they are hiring. By the same token they could go and work for an NGO or become environmental consultants.

The point which keeps getting aired at industry conferences is that young people want job satisfaction and a reasonable reward but they are also becoming more idealistic about what they do. "Perhaps most concerning," notes the EY survey, is that "more than two out of every three teens believe the oil and gas industry causes problems rather than solves them." And teens and millennials are far less likely than older consumers to agree that oil and gas are "good for society".

So, the message that a career in oil and gas is not only technically (and intellectually) challenging but also matters in a modern, forward-looking sort of way needs to come across loud and clear. So too, as many of the majors are now proclaiming, is the notion that fossil fuels continue to play an important role in lifting people out of poverty. The lion's share of future growth comes from the emerging economies, and the need for cost-effective, available sources of energy will keep oil and gas motoring for many years to come. ■

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Conversion Factors

Crude oil
1 m^3 = 6.29 barrels
1 barrel = 0.159 m^3
1 tonne = 7.49 barrels

Natural gas
1 m^3 = 35.3 ft^3
1 ft^3 = 0.028 m^3

Energy
1000 m^3 gas = 1 m^3 o.e
1 tonne NGL = 1.9 m^3 o.e.

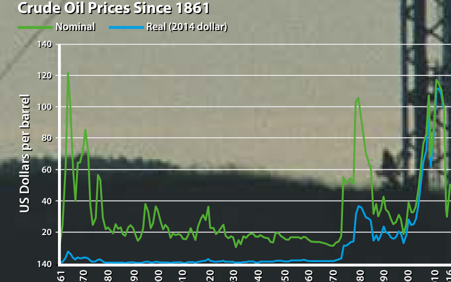
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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

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

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

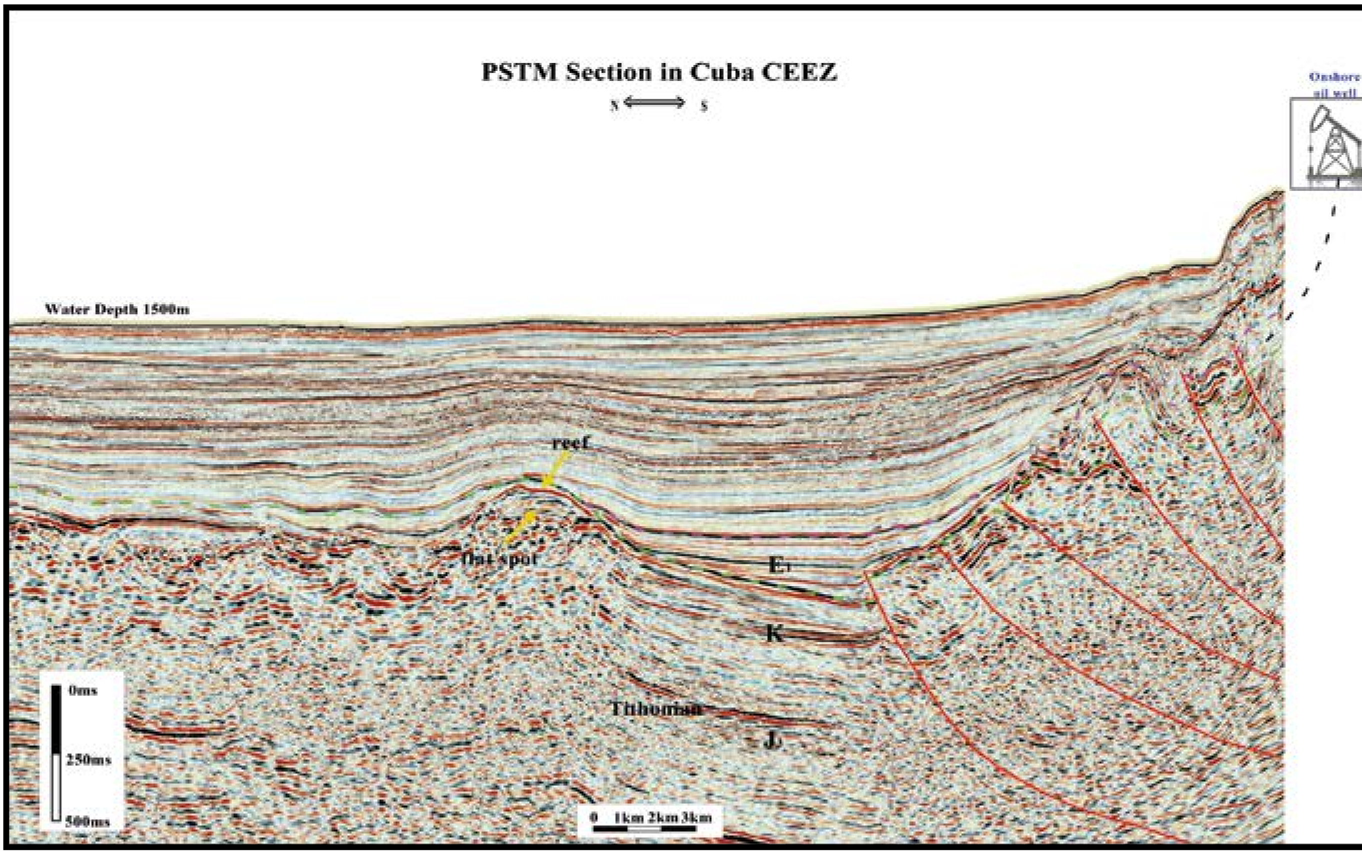
Historic oil price



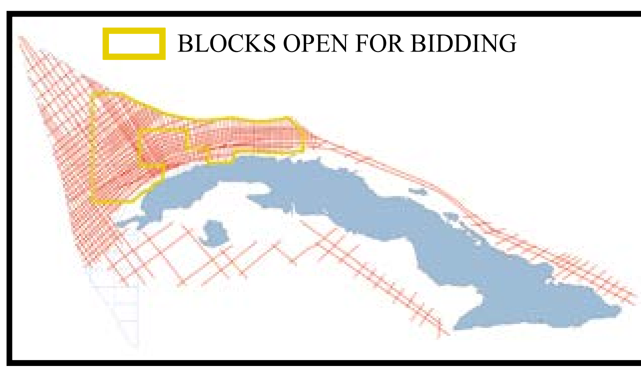
Cuba Re-launches Offshore Oil Exploration

Multi-Client 2D Seismic for a New Exploration Journey

A fresh look at a clear image



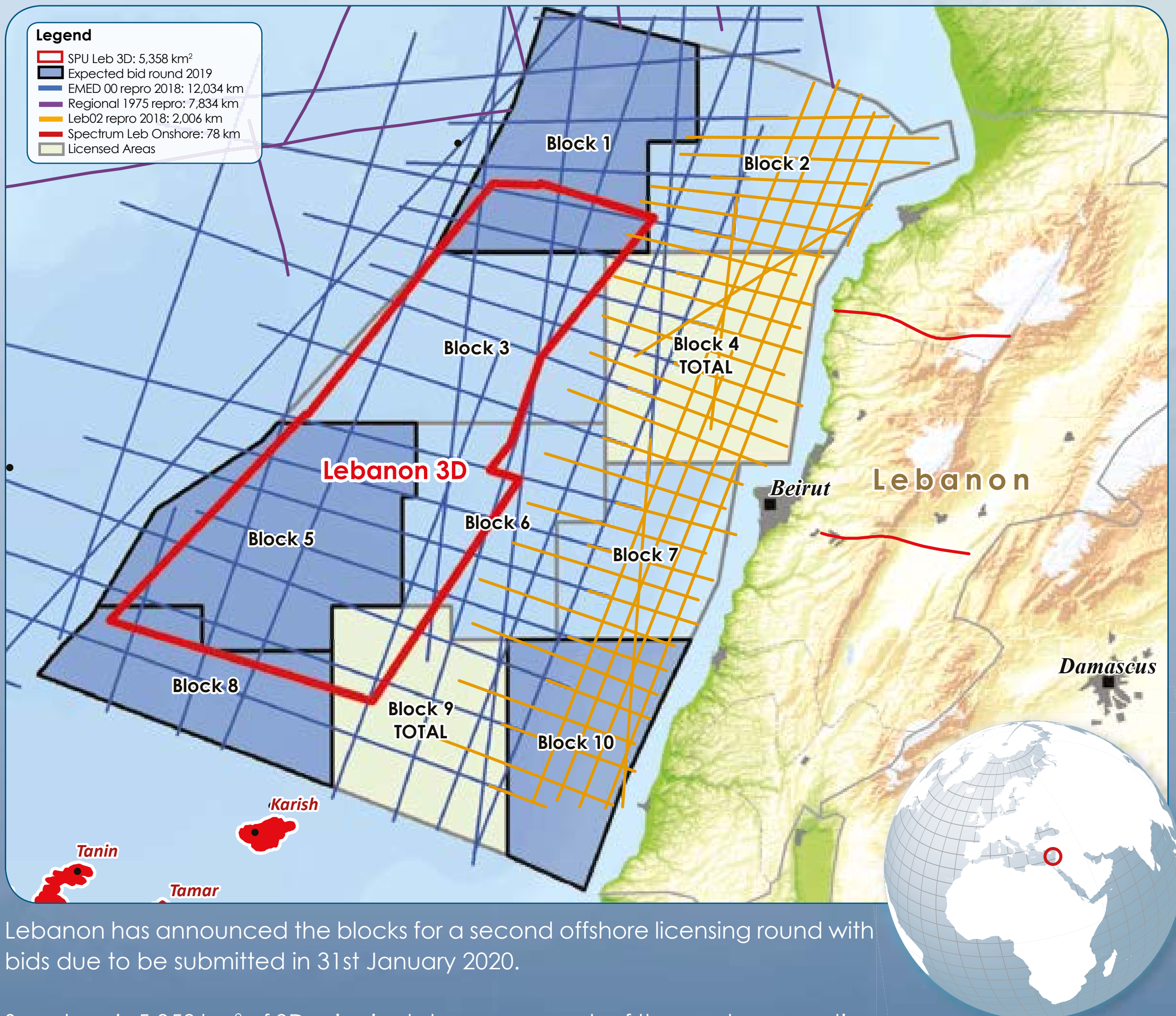
BGP has acquired 26,880 km of multi-client 2D seismic data in the offshore Cuba, as well as gravity and magnetic. PreSTM and PreSDM data set is available now. The new data reveal significant exploration potential of the Cuba Exclusive Economic Zone (CEEZ). The above section shows a series of structural traps in the thrust belt of CEEZ, which have favorable reservoir and seal assemblage, and the newly drilled oil well near this area has proved its potential. A reflection of reef is quite clear, and there is also a flat spot reflection in this section, which probably indicates the existence of hydrocarbon.
With these new understandings and discoveries in this area, it is time to take a fresh look at CEEZ.



The first Offshore License Round will be launched in June, 2019.

Republic of Lebanon

Essential 3D & 2D Multi-Client Seismic for 2019 License Round



Lebanon has announced the blocks for a second offshore licensing round with bids due to be submitted in 31st January 2020.

Spectrum's 5,358 km² of 3D seismic data covers much of the most prospective areas of the Levantine Basin. In addition Spectrum's comprehensive suite of East Mediterranean products includes 22,645 km of high quality 2D seismic.

The large structures, and folds are generally assumed to be filled by dry biogenic gas like the adjacent Leviathan and Zohr discoveries, however a credible oil play from an oil-prone source rock directly underneath the reservoir suggests this undrilled acreage could make Lebanon the East Mediterranean's oil capital.

data
for the
journey