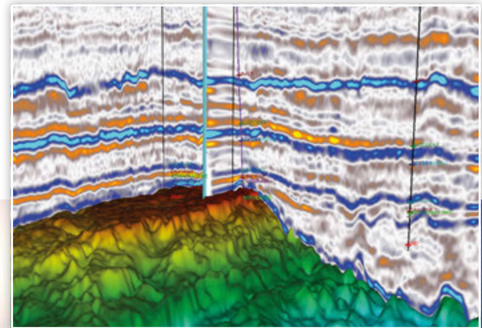
VOL. 17, NO. 4 – 2020

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



TECHNOLOGY EXPLAINED
Making Waves with Big Seismic Computing

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EXPLORATION
Chasing Plays Along the Rona Ridge

SEISMIC INTERPRETATION
Cinder Cone or Mud Volcano or …?

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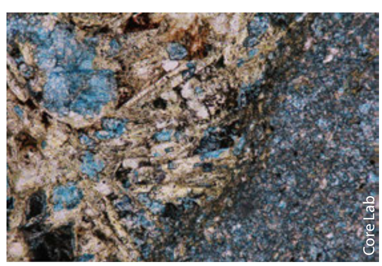

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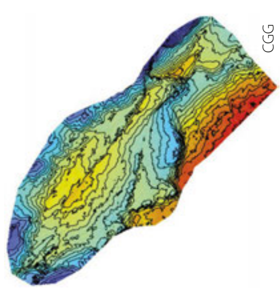

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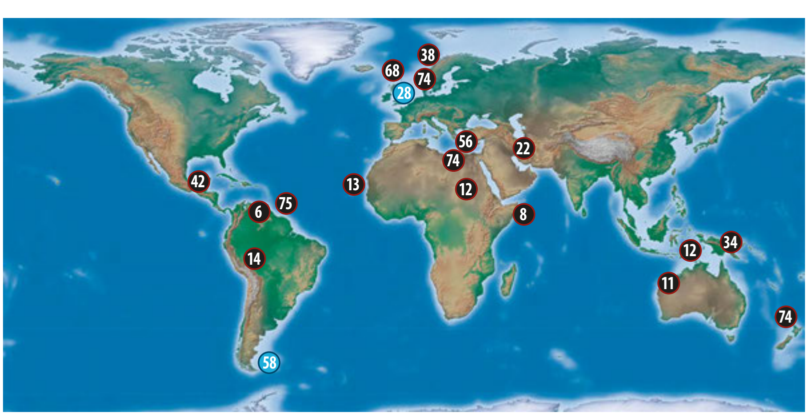

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This edition of *GEO ExPro* focuses on Europe and Latin America; Developments in Geophysics; and Using the Cloud.

Breaking Barriers


David Mark from Pixabay

An industry at the forefront of technology such as ours must always be breaking barriers. In this edition of *GEO ExPro* you can read a number of examples of innovations and technological breakthroughs in the oil and gas industry.

One of the focuses of this issue is 'Using the Cloud', a topic which by definition is about breaking barriers; moving into the theoretical ether and finding ever more uses for communal space and shared software, all driven by artificial intelligence and machine learning. Although some in the industry consider that we were slow to adopt the digital transition, we now seem to have well and truly jumped onto that fast-moving super-highway and are beginning to open up to the possibilities offered through such things as digital twins, undertaking pre-stack analysis on large multiclient 3D datasets, and accessing the vast quantity of data available to enable accurate real-time monitoring; all topics discussed within these pages.

Less obvious innovations have also been occurring in the industry, particularly in the realms of communication. I have now participated in a number of virtual seminars, conferences and webinars and found them interesting experiences. Having no real idea as to how many people are out there listening is daunting for a presenter, but at the same time, not having to make eye contact with the audience is strangely liberating. As an attendee, it is good to be able to dip in and out of talks as interest and other commitments dictate, and particularly useful to be able to listen to a presentation or discussion at a time which suits you, from the comfort of an armchair. One of the major advantages of the online conference is that because there are no traveling costs, they are accessible to many more people than usual and from a wider range of countries, so the educational aspects are being spread much more widely than usual. Of course, the all-important networking part of a meeting is missing, although there have been some very valiant efforts to simulate that aspect of a conference online.

In this issue we bring you another first: an article that captures a fascinating social media discussion on a seismic interpretation conundrum, which collates and discusses comments made by people from across the globe with a range of backgrounds and experience. A fine example of geoscience being both analytical and innovative. ■

Jane Whaley
Editor in Chief

THE BOLIVIAN ALTIPLANO

The glories of geology in the pristine but challenging environment of the Altiplano vast plateau in the middle of Bolivia can set the heart racing, as one gazes at the wonders of nature in complete and utter silence. A meditative experience.

Inset: A ground-breaking project to develop interactive software capable of quickly visualizing and processing pre-stack seismic data is the result of crowdfunding and R&D tax incentives.

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Latin America Leads the Way

South America's upcoming floater projects could help sustain yards.

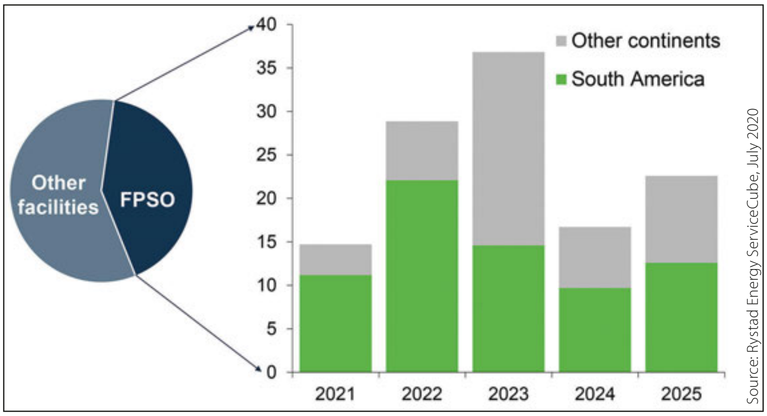
While the rest of the global oil industry copes with the consequences of the Covid-19 crisis, South America seems to be pulling through with announcements of major floating production, storage and offloading (FPSO) projects to be tendered. These projects should bring much-needed orders to fabrication yards that are struggling to keep their doors open. Approximately 40% of offshore deepwater and ultra-deepwater contracts to be signed in the next five years come from FPSO developments, driven by Brazil and Guyana, thanks to lower breakeven prices, thus promising major deals in the fabrication and subsea sectors.

Fabrication jobs for floaters destined for Latin America have become a significant source of revenue for many yards, both local and international. Last year was remarkable as five out of nine global projects came from this continent. Winning contractors including Modec, SBM Offshore and Yinson have carried these prizes across the globe, offering jobs to yards in Asia. The projects awarded last year have resulted in $2.3 billion in construction and installation contracts, $2.6 billion in equipment contracts and $4.9 billion in contracts for subsea equipment, umbilicals, risers and flowlines.

The industry's high expectations for 2020 were dashed by the double shock of faltering prices and demand, which has pushed many projects into the future. Major Latin American projects, including Equinor's Bacalhau and Petrobras's Mero in Brazil and ExxonMobil's Payara in Guyana have been postponed, leaving few orders to compete over. Contractors have also been pressured to cut prices on ongoing contracts, adding to the challenges brought on by the dearth of new contracts.

Bouncing Back

Such a low level of activity was also seen in 2016, when no new floater-related contracts were awarded. However, the market was quick to bounce back with 12 new awards over the next three years. History should repeat itself as another 12 new awards are now lined up in just the next two years, representing close to $8.8 billion in construction, installation and equipment contracts and $8.5 billion in subsea contracts. Petrobras is in talks to finalize FPSO lease contracts for Mero 3 and Parque das Baleias and has already hit the market for new floaters to be deployed in the next phases of the Mero and Buzios pre-salt developments. In the long term, the state-controlled player is looking to deploy around a dozen FPSOs under the fourth phase of its pre-salt development plan, remaining a key driver for the world's offshore sector.



Offshore deepwater and ultra-deepwater contract awards between 2021 and 2025.

While current orders will help yards stay afloat until the market settles down, South America will contribute significantly to the next wave of orders that will help these yards remain open in the future. Current low prices being offered in a very competitive environment should also incentivize operators to begin tendering processes and lock in these contracts before prices rebound.

Recent exploration awards in the Latin American region have also piqued the interest of the seismic and G&G (geological and geophysical) market, potentially attracting new surveys. However, activities are now moving at a cautious pace as many operators have cut back on exploration costs due to the downturn. This has not deterred seismic players like WesternGeco and CGG Veritas from planning multiclient surveys in Brazil's prolific plays, given that operators are bound to return and resume exploration activities. Brazil's National Petroleum Agency has also scheduled four licensing rounds in 2020 and 2021, indicating an improved environment for the seismic and G&G market in the coming years. ■

Chinmayi Teggi, 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

Licensing Update

Somalia: A Final Frontier Opens Up

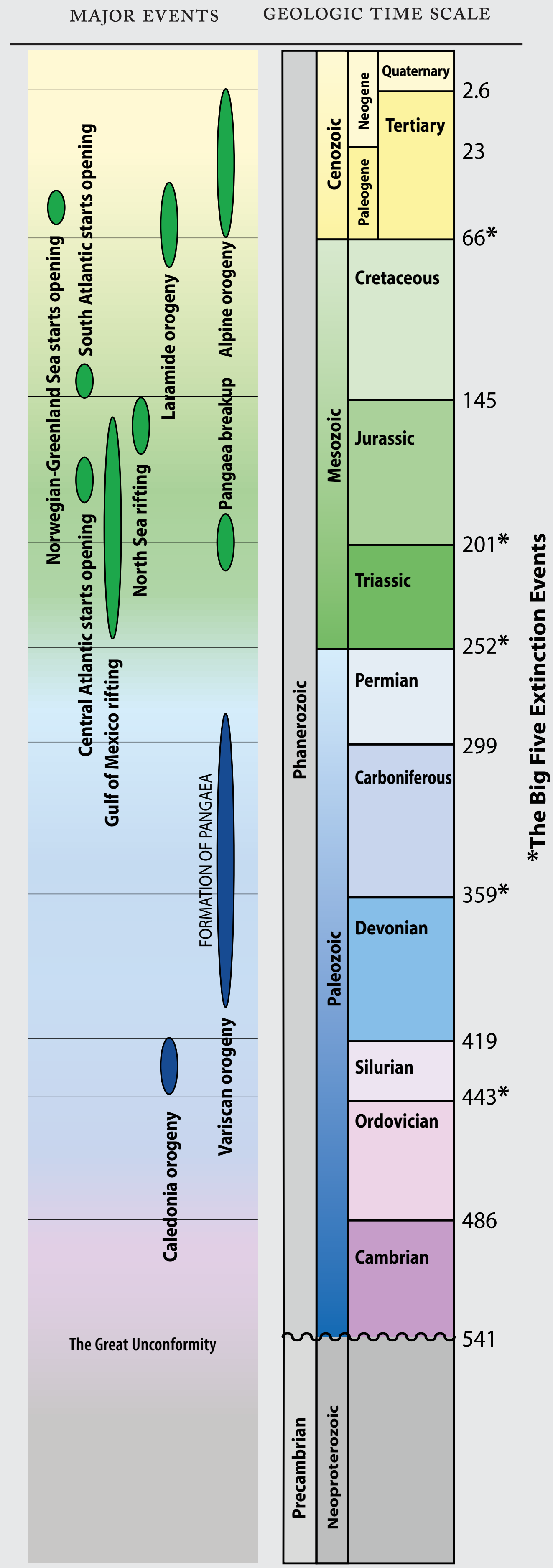
Offshore Somalia is one of the few remaining frontier areas in the world. Only one exploration well, Meregh-1, has been drilled along the country's entire 1,200 km-long margin. That was in 1982 and very little exploration has been undertaken in the country for at least 25 years, particularly the deeper waters, which have only been investigated by shallow-level Deep Sea Drilling Project wells.

In July 2020, the Ministry of Petroleum and Mineral Resources of the Federal Republic of Somalia established the Somali Petroleum Authority (SPA), paving the way for the announcement in early August of the first ever offshore licensing round – a milestone for the country. The round comprises seven blocks, numbered 152, 153, 164, 165, 177, 178 and 204, covering a total of 30,168 km^2. The Somali offshore can be divided into three basins: from north to south these are the Obbia Basin; the Coriole Basin, where six of the offered blocks are situated; and the Juba-Lamu Basin, containing the seventh block.

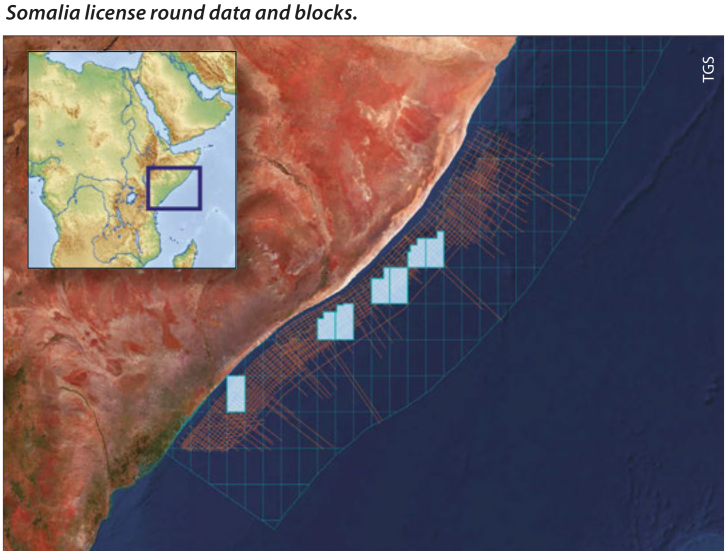
Using new long-offset 2D seismic data it acquired between 2014 and 2016, TGS has identified four source rock intervals that basin modeling indicates could be mature for hydrocarbon generation. These range from pre-rift Triassic Karoo and syn-rift Jurassic sources to post-rift Cretaceous and Early Tertiary source rocks. The data has also demonstrated a range of traps and reservoirs. In the north, Jurassic and Cretaceous limestone reefs, some up to 1,000 km^2, are expected to provide excellent reservoirs, as are tilted fault blocks of pre-rift Karoo sandstones, while further south, large, well-defined toe-thrust systems with flat spots are visible, again offering attractive potential. Sealing lithologies are expected throughout the area. Play types identified by TGS include sandstones and shales in pre-rift tilted fault blocks, syn-rift sandstone wedges, carbonate build-ups, structural closures and gravity slides and thrust-bound anticlines. One of the most exciting aspects of the seismic interpretation is that, unlike much of East Africa where gas discoveries are the norm, TGS believe that there is a strong possibility of oil-prone prospects offshore the whole length of the Somalian margin.

A revised Production Sharing Contract has been designed in parallel with the 2020 round to encourage exploration, with fiscal terms reflecting technical, economic, commercial, operational and political considerations.

The round opened on August 4, 2020, with bid applications to be submitted before the deadline of March 12, 2021. ■



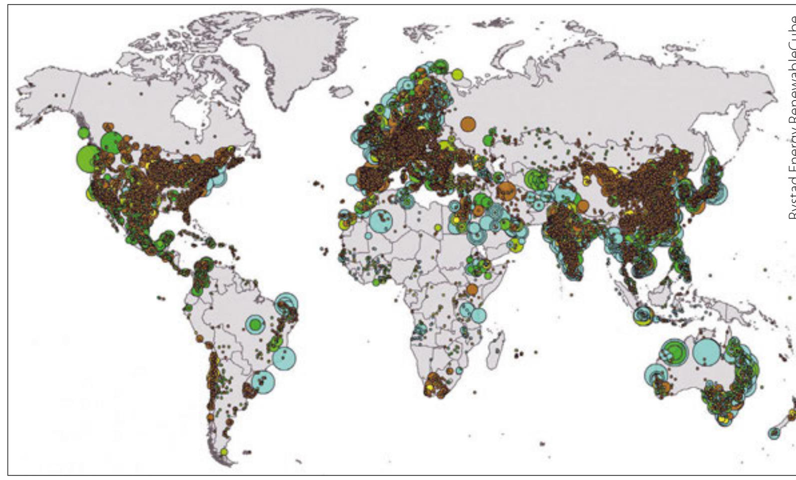
Somalia license round data and blocks.



Rystad Launches Renewables Solution

Renewable energy is a fundamental component of the **energy transition**, and the share of utility-scale renewable generation in the global power mix is poised to explode in the coming years, with planned projects around the world estimated to be worth several hundreds of billions of dollars. In order to monitor, track and analyze global data coming from this emerging industry, **Rystad Energy** recently announced the launch of its **Renewables Solution** data, analytics and advisory service.

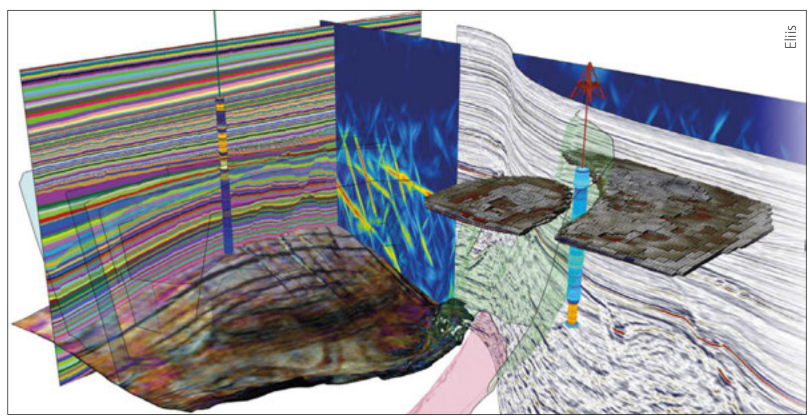
The new product will offer a unique set of easy to access global solar, wind and energy storage project data, ideal for making informed strategic decisions on benchmarking and deal screening. These make it possible to identify global trends in ownership, development stage, capacity, offtake, equipment, contractors, cost and location data for more than 60,000 renewable energy assets in 175 countries. In additional to the raw data points, covered assets and projects are also tracked and mapped in detail, with actionable insights offered through frequent reports and commentaries, as well as within dashboards and in frequent webinars. ■



Global utility-scale renewable energy projects by development status.

The PaleoScan™ Spirit

Are you looking for a disruptive interpretation software? For more than ten years, **PaleoScan**™ and the **Eliis** team has played its trump on flexibility and constant innovation, with an effort to cherish its users daily. This probably explains why PaleoScan has proven to be a vital piece of the interpretation puzzle in many areas and sedimentary basins worldwide. Its avant-garde semi-automatic interpretation method and its quick way to get comprehensive data insight yield an invaluable analytical capability in an intuitive and interactive interpretation environment.



A few months ago, the 2020 version of PaleoScan was released. A few of the exciting features to be found in this new version include:

- A way to consistently model the geology has been created that gets free of the seismic artefacts and is able to represent thrust structures.
- The automatic fault extraction workflow has been improved.
- In 2D, the automatic connection of reflector propagation between the lines makes the interpreter's life easier.

Discover more at the Eliis website. ■

SEG Celebrates 90 Years

For the past 90 years, the **Society of Exploration Geophysicists (SEG)** has engaged and served diverse global communities in order to advance applied geophysics for the benefit of humanity. In October, SEG will celebrate its **90-year history** virtually at its **Annual Meeting**. This year's technical program will feature over 750 presentations with nine special sessions. The Business of Applied Geophysics sessions will dive into four key strategic discussions: geophysical business climate in Africa; the value of near surface; the business climate of the oil and gas sector; and geophysics for CO_2 injection and storage, from reservoir characterization to long-term monitoring. The postconvention workshops will encompass 21 interactive educational sessions. For more information about the SEG20 online experience please visit the SEG website.

SEG has a new addition to its portfolio, **Energy in Data**, in partnership with the American Association of Petroleum Geologists and the **Society of Petroleum Engineers**. Energy in Data is a data conference exclusively designed for the energy sector, providing a unique experience for multidisciplinary teams to influence the direction of the industry through the digital transformation process. ■

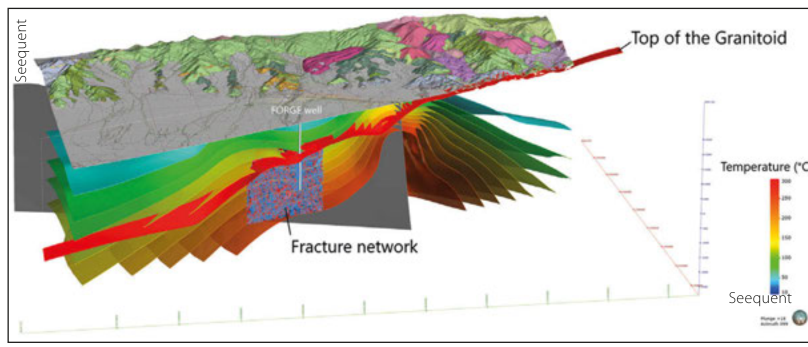
GSL Special Interest Energy Group

The **Petroleum Group** has been the **Geological Society of London's (GSL)** special interest group in Petroleum Geoscience for the last 40 years and has always endeavored to remain relevant to an ever-evolving industry and constantly changing geopolitical environment. No issue is so pressing for the human race, with the potential to disrupt our society on a fundamental level, as climate change. The Group has decided to take a proactive role in the wider energy transition and has therefore agreed to broaden its scientific remit and become the **Energy Group** of the GSL.

Going forward, the Energy Group will encompass all geoscience aspects of the full cycle delivery of energy to society including, but not limited to: petroleum, carbon capture, utilization and storage; radioactive waste disposal; geothermal energy; and the role of geoscience in renewable energy sources. To be able to support this transition, the Group is seeking nominations for committee members with knowledge and experience of non-hydrocarbon related energy geoscience. In order to develop a scientific program that represents its expanded scope as the Energy Group, they are encouraging the submission of technical conference proposals that showcase the role of geoscience in the energy transition, together with those that continue to lead the way in cutting-edge petroleum geoscience. ■

Cloud Solutions for a Pandemic

The Covid-19 pandemic has created many demands and operational challenges for organizations trying their best to continue 'business as usual'. One way to address this is to make greater use of 'the Cloud', and for this reason geoscience software company **Seequent** is accelerating the development of its cloud-based solution **Seequent Central**, enabling organizations to continue work on critical, large-scale, earth, environment and renewable energy projects from wherever they are located during the crisis. The software supports the company's geoscience analysis, modeling and collaborative technologies, including Oasis Montaj and Leapfrog, by allowing a range of stakeholders in any location to visualize, track and manage geological models created for infrastructure and critical services projects, in a centralized, auditable environment. These tools support exploration and development workflows within the hydrocarbon and geothermal industries globally.

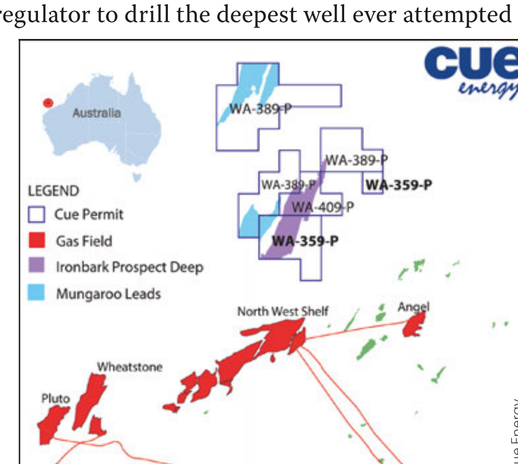


Temperature distribution and fracture network model at the FORGE Milford site visualized in Seequent Central..

One project which has benefited from Seequent Central is the FORGE project at the University of Utah, which is undertaking research on enhanced geothermal systems, using data coming from a lot of different datasets. Seequent Central is used to manage and visualize the team's geological data and models centrally, utilizing a web-based server that the entire team can look at, annotate and comment on, with everything visualized in a 3D volumetric space. ■

Australian Well to Break Records

Supermajor **BP** has been given permission by the **Australian** national oil and gas regulator to drill the deepest well ever attempted in Australian waters. The well, **Ironbark-1**, will be drilled on in Block WA-359-P in the prolific Carnarvon Basin, about 170 km offshore Karratha, in approximately 300m water depth. Drilling using Diamond Offshore's *Ocean Apex* drilling rig is expected to start in the third quarter of this year and will take up to 100 days, as the well is expected to extend to 5,500m.



According to partners Cue Energy, the Ironbark prospect is estimated to hold prospective reserves of 15 Tcf gas and the well will be targeting an exciting new play type with multiple targets in the Triassic Mungaroo Formation. The Mungaroo has already proved very successful in the region, as it is the reservoir formation in a number of nearby large fields, including Gordon, Lago Perseus and North Rankin.

Ironbark-1 is the first well drilled by BP as an operator in Australia for a number of years. It holds a 42.5% stake and its partners in the joint venture are Cue Energy (21.5%), Beach Energy (21%) and New Zealand Oil and Gas (15%). ■

AustinBridgeporth and TGS to Acquire eFTG

AustinBridgeporth CEO Dr Mark Davies outlines the eFTG program to an international audience at EGYPS2020.

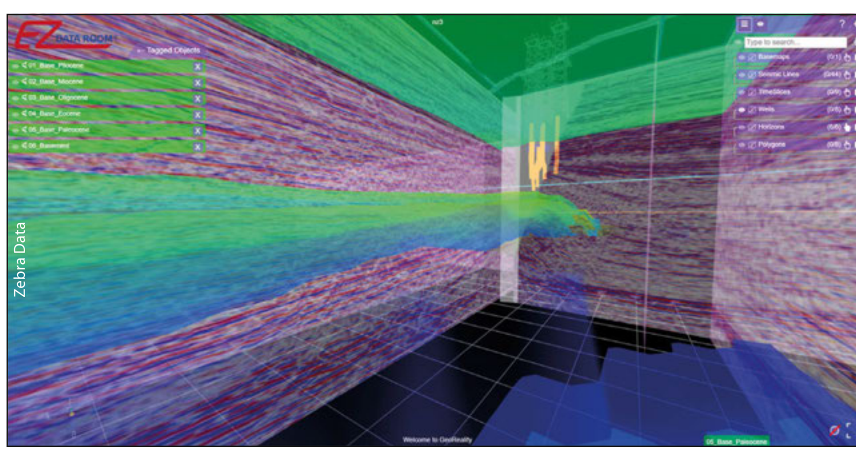
Gravity gradiometer technology measures minute differences in the earth's density to yield information on geologic structures underground and undersea. The data is acquired using either ships or aircraft and is very effective at identifying host geologies that are indicative of hydrocarbons or mineral ore bodies.

Multiclient geoscience data provider **TGS** and specialist geosciences company **AustinBridgeporth** recently announced a collaboration to undertake a regional airborne **Enhanced Full Tensor Gravity Gradiometry (eFTG)** multiclient survey over the Upper Egypt region. The survey will also obtain magnetic and LIDAR data and will be undertaken in a number of phases. The first phase, which has already commenced, will cover an area of approximately 120,000 km^2 and has been designed to provide unique, high-resolution imaging of the region with increased accuracy and higher spatial resolution to enhance exploration activities. It is expected that the survey will provide sufficient data on the geological structures and sedimentary basins in **Upper Egypt** to enable the Egyptian government to launch new international bid rounds for the area. The project is being undertaken for Egyptian company GANOPE, which is responsible for all oil exploration and exploitation activities carried out by contractors in the southern region of Egypt.

Full Tensor Gradiometry measures the rate of change of gravity in all directions of the field, caused by subsurface geology. The Lockheed Martin eFTG system used in this project is the world's most advanced moving-base gravity gradiometer, possessing a noise floor about four times lower than previous gradiometry systems and providing data with higher bandwidth, giving increased accuracy and higher spatial resolution. ■

New Technology for Timor-Leste

Autoridade Nacional do Petróleo e Minerais Timor-Leste (ANPM) launched the 2nd Timor-Leste Licensing Round in October 2019 and immediately invested in the latest technology to ensure the success of the both the license round and future exploration.



Example of GeoReality modeling.

ANPM engaged **Zebra Data Sciences** to build and manage their **EzDataRoom® Web Geotechnical Virtual Data Room (VDR)** filled with Timor-Leste seismic, well and other data. This permits interested investors unheeded access in order to assess the potential of the seven onshore and 11 offshore blocks from their offices – which turned out to be a very wise decision, considering the subsequent Covid-19 lockdowns across the world. Even if working from home, investors can still access the VDR with only a standard browser and internet access. ANPM included more hi-tech in the VDR with **GeoReality®** models covering the open blocks. See an example of this at georeality.com/TL2LR

In order to effectively promote the prospectivity of the onshore area, which has only airborne gravity and magnetic data, ANPM engaged **GeoProspect™**, a joint venture between Zebra Data and **Cambridge Geoconsultants (CGC)** to produce a Prospectivity Report of onshore Timor-Leste using CGC's unique Intelligent Geological Target Identification process, an AI/neural network-based algorithm. The findings of the report suggest that the onshore region of Timor-Leste is rich in both oil and gas reserves, with the depth of the reserves varying between 1.5 and 5 km. The report may be licensed from GeoProspect. ■

Mauritania 3D Program

In July **ION Geophysical Corporation** announced it would undertake the first **3D multiclient seismic program** in **Mauritania**. The project will initially involve the integration and reimaging of approximately 24,000 km^2 of 3D data held by the Mauritanian Ministry of Petroleum, Mines and Energy (MPME) and can be expanded to include a further 15,000 km of 2D data, pending industry support. The project includes legacy seismic surveys as well as data from relinquished areas and all open file well logs and covers a number of past oil and gas discoveries including Chinguetti, Tiof C-4-6, Merou-1 and Banda C. It aims to significantly enhance the data's resolution and subsurface insights by creating a continuous regional volume that will help reduce risk at play, prospect and reservoir scales. ION expects the program to commence in 2020 with final deliverables available in mid-2021.

Mauritania is part of the prolific MSGBC Basin in northwest Africa, where some of the most exciting discoveries of recent years have been made, such as Orca, Tortue Ahmeyim and SNE, and where large offshore gas reserves are being developed for LNG export to Europe and elsewhere. The area has a history of proven oil deposits. The project will support the efforts of the MPME to improve its exploration strategy on and onshore in the Taoudeni area in order to attract more investors to the country. ■

Africa Oil Week Launches AOW Virtual

AOW Virtual is a **two-day online conference** to be held **October 7-8, 2020** designed to reignite the African upstream after a period of intense upheaval. Though the oil and gas industry is still unable to unite in person, AOW Virtual is a chance for you to engage in dialog with leaders. Best of all, the content sessions are free to attend. They include:

- Operators' Strategic Outlook: Hear how supply and demand shocks have affected operators' African portfolios and learn what they plan to do next.
- West Africa Regional – New Ventures and Opportunities: What are the hottest new venture opportunities in West Africa? Watch these quickfire presentations to find out!
- Interactive Debate – Natural Gas vs Renewables: Is a leapfrog to renewables or an energy transition via natural gas the more sustainable and economically viable route for Africa?
- Somalia Licensing Round – Derisking Above Ground Factors: Run in partnership with TGS and the Somali Ministry of Petroleum and Mineral Resources, this session is your first opportunity to grill senior stakeholders, following the country's official bidding round announcement.

Somali Petroleum Minister Hon. Minister Abdirashid Mohamed Ahmed speaking at AOW 2019.

Interested? Register for free at the Africa Oil Week website. ■

The Bolivian Altiplano: The High Plateau in the Mountains

As they continued their epic cycle through South America, as described in several previous articles, Olivier and Caroline found crossing the high plateau of the Bolivian Altiplano to be a direct encounter with pristine and pure geology, in a meditative environment.

OLIVIER GALLAND and CAROLINE SASSIER

The temperature is -17°C in the tent! Altitude: 4,700m, the highest campsite of the journey. The early morning sunlight does not succeed in heating up the frozen air of Sur Lípez, the southernmost region of Bolivia. The last noticeable human presence was a tourist 4x4 vehicle yesterday afternoon. Since then, nothing; the whole desert of the high Altiplano was ours. For the first time, we experienced true silence: no running water, no moving plant, no insect or bird, and no wind. This vast emptiness was our anxiogenic sleeping cocoon, a pure feeling of isolation and solitude. After a tasteless oat-based breakfast, we extracted our creaking bodies out of the tent to embrace a stunning landscape: the Salar de Chalviri, nestled between mineral red-ochre and yellow snow-coated, eroded, volcanic edifices. The Bolivian Altiplano revealed in all its cruel beauty, so challenging to conquer. Ten exhausting days fighting against awful sandy and deep washboard tracks will be necessary to escape this hostile part of the world.

The Altiplano Plateau

The Altiplano is a high plateau that formed along with the tectonic uplift of the Andes mountains. Its average elevation is about 3,750m. It is located where the Andean range is the widest, bounded to the west by the peaks of the Western Cordillera, consisting of the modern volcanic arc, and to the east by the peaks of the Eastern Cordillera, of tectonic origin. This peculiar geological structural configuration makes the Altiplano an area of inland drainage (also called an endorheic basin), the lowest point of which is the Salar de Uyuni (see below). The basin has an approximate area of 154,000 km^2.

The existence of the plateau is the result of a gap in tectonic deformation in this segment of the Andes. Here, most of the tectonic shortening concentrates on the eastern boundary of the plateau, in the eastern Cordillera and the Sub-Andean ranges, whereas the plateau itself has not experienced much shortening since the Upper Miocene. The reason why the Altiplano Plateau is poorly affected by tectonic shortening is still debated. Its preservation as a high plateau is a result of the arid climate, since the very limited erosion did not erode the western and eastern boundaries of the endorheic basin enough to connect it to either the Pacific or the Atlantic.

Losing the track in the middle of the Altiplano Plateau. The flat scenery is similar to that seen in the middle of the low-altitude Pampas, but here we are at about 3,800m – higher than most European peaks!

Olivier Galland and Caroline Sassier

Natural Sculptures and Wonderful Lakes

Volcanic rocks make up most of the relief of the southern end of the Bolivian Altiplano. Among these, extensive sheets of ignimbrite deposits resulting from gigantic volcanic explosions almost entirely covered this part of the plateau during the Oligocene and Miocene. In such a dry and windy climate, ignimbrite exhibits peculiar weathering patterns due to the abrasive effect of sand transported by the ferocious winds. These aeolian processes have sculpted astonishing natural features, as can be seen on the next page, which evoke the surrealist paintings of Salvador Dalí, which is why it became known as the Salvador Dalí Desert.

The southern Altiplano Plateau hosts shallow lakes of wonderful colors, targets of photographers from all over the world. The southernmost of these lakes is the Laguna Verde ('green lake' in Spanish), close to the Chilean border. It nestles at the foot of Licancabur volcano, the shape of which is characteristic of Andean strato-volcanoes. Its green color is a result of mineral suspensions of arsenic and other minerals collected by the weathering of the neighboring volcanic rocks. Depending on the sediment input into the lake, the colors vary from turquoise to dark emerald green (see image overleaf).

The other famous and picturesque lagoon is the salty Laguna Colorada ('colored lagoon' in Spanish). Extending over more than 60 km^2 and less than one meter deep, the deep red 'blood-colored' waters spectacularly contrast with shining white borax islands, the deep blue sky of the high altitudes and the snowy peaks surrounding the lake. Suspension of red fine sediments and pigments of certain types of algae provide this unique color. Because it contains high amounts of plankton, Laguna Colorada is a special nesting place for three species of flamingos, including the extremely rare James' Flamingo.

Olivier Galland and Caroline Sassier

The Bolivian Antiplano is a vast flat area in the center of the Andes at altitudes of over 3,600m. The red line indicates Caroline and Olivier's 10,000-km journey, undertaken in 2015.

The Salar de Uyuni

The Salar de Uyuni is the world's largest salt flat, extending over an area of 10,000 km^2 at an elevation of 3,656m. It is the lowest point of the

Natural sculptures of the Salvador Dalí Desert.

endorheic Altiplano Basin and so collects all the running water. It is covered by a salt crust a few meters thick, although the salt deposit can locally reach up to 140m in places. This vast shining white plain is extraordinarily flat, with an average elevation change of less than one meter over its entire area.

Salars are the natural products of endorheic basins in an arid climate. Their formation results from a similar process to that of salt accumulation in the oceans. The rain falling on the endorheic basin reacts and weathers the exposed rocks, dissolving ions. These running waters collect into rivers, which converge toward the lowest point of the basin, in this case the Salar de Uyuni, where the dissolved salty elements transported by the rivers accumulate. The arid climate conditions then trigger water evaporation, leaving the salty elements behind. Continued inflow of water from rivers brings more salty elements, which again are deposited after water evaporation. This process continues through time and leads to high concentrations and large volumes of salts; the subsurface of the Salar de Uyuni hosts salt-saturated brines. The drained area which collects at the Salar de Uyuni is so vast that when, during the wet season, Lake Titicaca further north overflows and discharges into other lakes and salars, the waters eventually reach Salar de Uyuni. When flooded, the Salar de Uyuni can be described as the 'world's largest mirror'.

One of the salts contained in the brines of the Salar de Uyuni is subject to worldwide interest: lithium chloride (LiCl). The so-called 'white gold' is a key player in the industrial ▶

Laguna Verde, at the foot of Licancabur volcano, the southern tip of Bolivia.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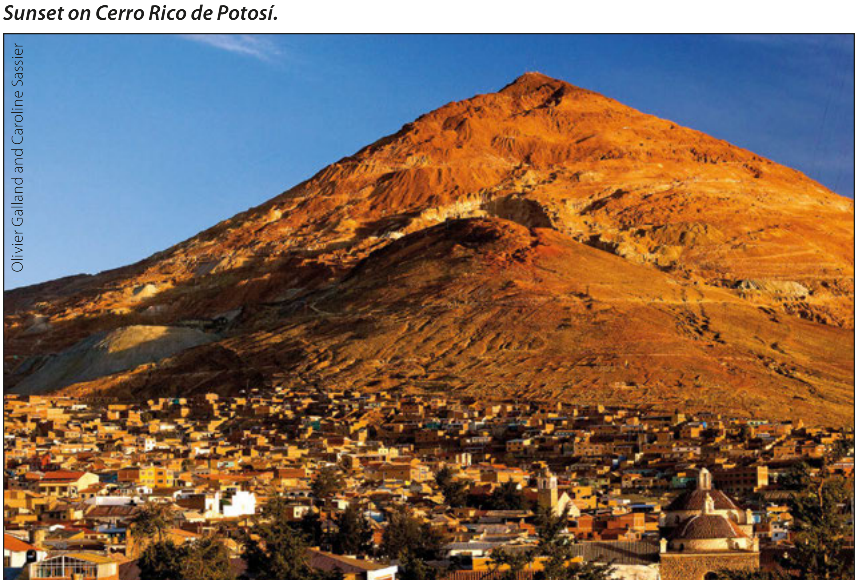
Photograph of polygonal fracture pattern of the Salar de Uyuni.

boom of electric car batteries, among others. Exploration campaigns estimate that the Salar de Uyuni hosts more than half of the world's reserves of lithium. Together with Chile and Argentina, Bolivia is part of the Lithium Triangle, which is believed to host 75% of the known lithium reserves! One reason for the high abundance of lithium in this part of the world is that the rocks surrounding the salars are young volcanics, containing significant amounts of the mineral.

The production of lithium consists of pumping out the subsurface brines, which are stored in large evaporation pools. In Uyuni, the lithium concentration in the brine is about 0.3%, i.e. almost ten times lower than in the Salar de Atacama. During the evaporation process, several salts successively precipitate, including halite ($NaCl$), sylvite (KCl), magnesium chloride ($MgCl_2$) and eventually lithium salt. However, because of the high altitude of the Salar de Uyuni, the relatively abundant precipitations, moderate temperatures and brine concentrations, the salt separation process from evaporation in Uyuni takes about six months, making the production costs high with respect to other deposits.

Sunset on Cerro Rico de Potosí.



Cerro Rico de Potosí

The Eldorado legend in South America probably takes its origin from the infamous Cerro Rico de Potosí. This mountain, in the Bolivian Eastern Cordillera, east of the Salar de Uyuni, hosts the world's largest silver deposit. The massive 4,782m-high red mountain dominates the incredible city of Potosí, which has many stunning Spanish imperial-style edifices. The Cerro Rico was the richest source of silver in the history of mankind.

The silver ore was known long before the Incas, but its mass production started with Spanish conquistadores, back in the mid-16th century, to fulfill their thirst for shiny metals. Their discovery of the silver deposit revolutionized this part of the Andes. In just 70 years, what used to be a high altitude, unpopulated Incan shepherd area became a city of 170,000 inhabitants, the fourth largest in the Christian world, bigger than London, Milan and Seville put together. The activity boom associated with the silver rush attracted artists, architects and intellectuals. However, the downside of this was the need for manual workers in the mines, so that thousands of native Peruvians and African slaves were deported to Potosí to extract the silver ore. Many of them perished in the mine, and the Cerro Rico became 'the mountain that eats men'. The mountain's silver production was so large that it changed the world forever, facilitating the exchange of slaves, fabrics, spices and other goods across the globe: it is considered that this initiated the premises of capitalism.

The Cerro Rico de Potosí ore deposit belongs to the Bolivian tin belt, which is a mineral-rich region in the Eastern Cordillera of Bolivia with voluminous tin, tungsten and silver deposits. The mineralizations of the belt formed as a result of fluids expelled from peraluminous magmas, which usually form by partial melting of the continental crust. The Cerro Rico itself is an extruded dacite volcanic dome, the age of which is estimated to be 13.8 ± 0.2 Ma. The intense hydrothermal alteration associated with the volcanic dome made the mountain red, recognizable far away from all over the area.

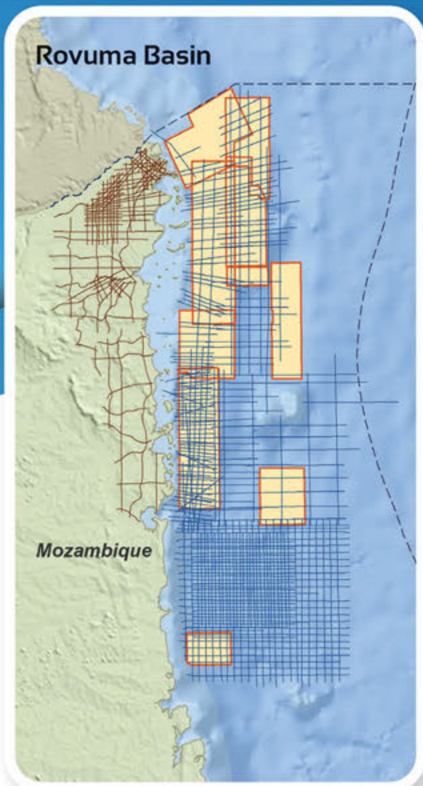
Today, small-scale artisanal mining activity remains, mostly to extract zinc and tin. The working conditions are worthy of Europe's 19th-century mining, and life expectation among the miners is about 40 years. It is possible to visit the miners in the galleries, after buying peculiar gifts for them at the local market: coca leaves, 96% alcohol, and dynamite sticks for half a euro. A real geological adventure! ■

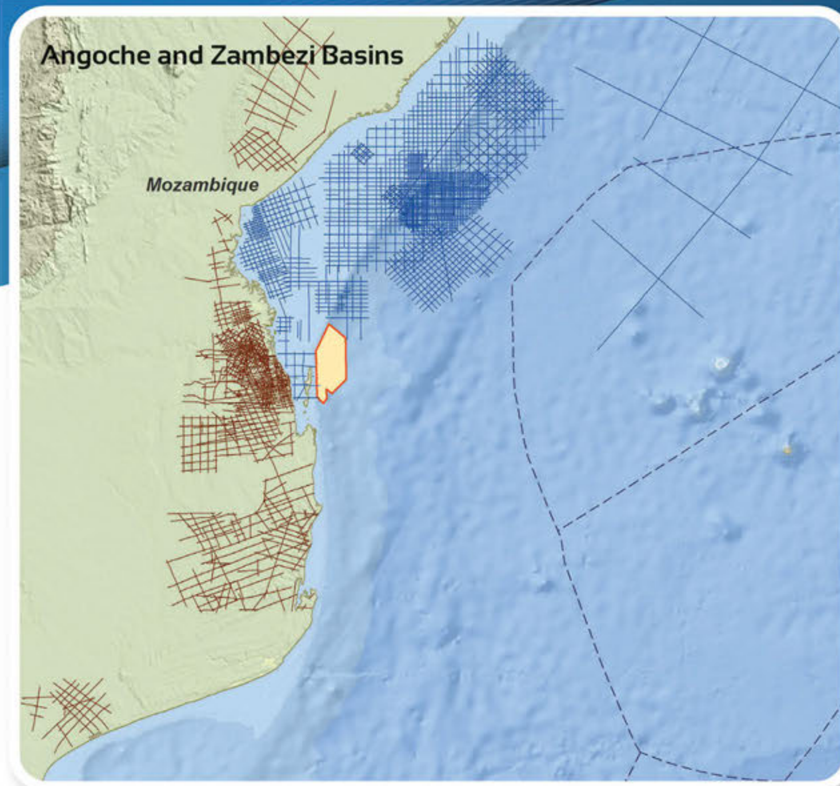
Multi-Client Seismic Africa • Mozambique

GeoPartners

Mozambique 6th Licence Round

Legacy Data Brokerage – 2D and 3D Seismic Surveys





In advance of the forthcoming 6th Licence Round, the Institute of National Petroleum (INP), on behalf of the Government of the Republic of Mozambique, is making available 2D and 3D seismic datasets for Multi-Client licensing.

These surveys cover both onshore and offshore areas in the prolific Rovuma, Angoche and Zambezi basins and consist of 21,223 sq.km of 3D seismic, 43,408 km of offshore 2D seismic and 18,735 km of onshore 2D seismic. These datasets will be included in the data packages to be licensed in advance of participation in the 6th Licence Round. INP have concluded the evaluation of nominated areas to be included in the round and will be shortly announcing the final block areas in each of the basins.

GeoPartners are providing technical assistance to INP for the Multi-Client licensing of these datasets and supporting the organisation of the 6th Licence Round to be announced later this year.

In addition to the seismic datasets, well data and

technical reports for all areas included in the round are available for licensing through INP, please contact the Data Manager at INP, http://www.inp.gov.mz.

For further information please contact Jim Gulland:
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A Bridge Between Two Worlds

The idea of the 'digital twin' is catching on in the oil and gas industry. But what exactly is it, and how can it help?

JANE WHALEY

A digital twin is a virtual representation of a physical object or process and it is important because it allows analysis of the data and systems involved in a new concept before they have even happened. It is a bridge between the physical and digital world. As described in *Network World*: "a digital twin is a computer program that takes real-world data about a physical object or system as inputs and produces as outputs predications or simulations of how that physical object or system will be affected by those inputs."

It is the advent of cloud computing together with machine learning algorithms and rapid computing power that has made the idea of integrating all data together a practical reality. 'Smart' components containing sensors are used to gather data about the real-time status, working condition and position of a physical item, such as an engine – or an offshore drilling rig. The data is sent to a cloud-based system, which stores and analyzes it, combining it with and comparing it to other relevant data, so the twin simulates the physical object. Additional information integrated with the sensor data into the twin includes engineering content, such as diagrams and specifications, as well as financial considerations and uncertainties like weather, customer demand and supply disruption. Updating is constant and in real time, so fast decisions can be made using all available information.

The concept has caught on rapidly. Global research and advisory company Gartner identified digital twins as one of the most important trends in 2018, and it is now being used in a range of industries, from transport to manufacturing and healthcare.

Digital Twins in O&G

As an industry at the forefront of technology that already works with dynamic software models, oil and gas is also taking advantage of this concept, both in ensuring efficient and safe ongoing operations and in designing new techniques and facilities. Independent risk management and quality assurance expert DNV GL has undertaken research that suggests that in the oil and gas industry "cloud computing, advanced simulation, virtual system testing, virtual/augmented reality and machine learning will all progressively merge into full digital twins which combine data analytics, real-time and near-real-time data on installations, subsurface geology, and reservoirs".

At the moment much of the oil industry work involving digital twins is being undertaken in the design of platforms and similar installations, with data on both existing and planned installations being constantly fed into the models. By using the cloud for storing datasets from all over the world, accurate and wide-ranging information is used to ensure a new design is both up to date and robustly tested. It requires a big investment in systems, sensors and analytics, but many companies believe it is worthwhile.

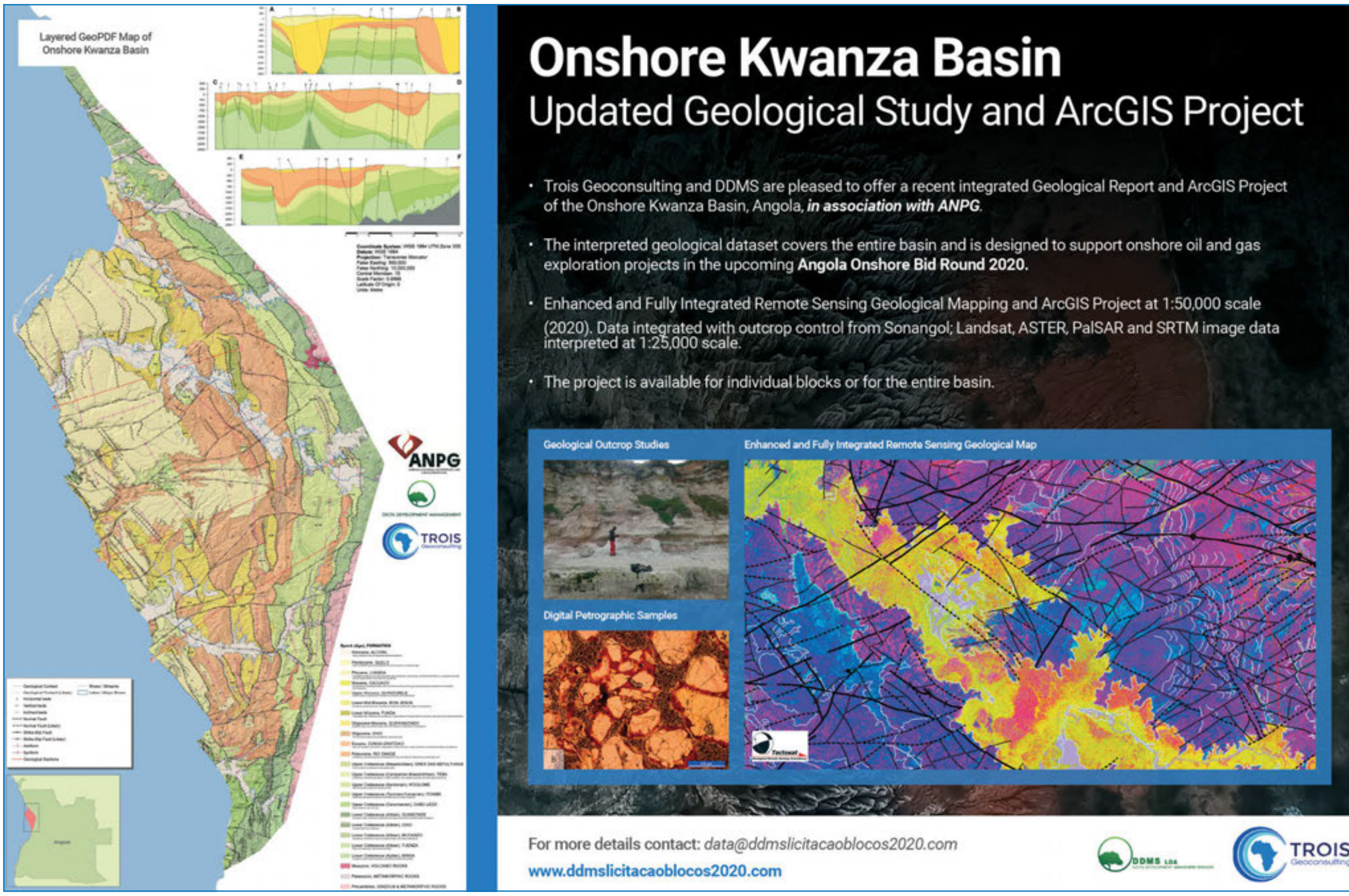
The concept is also in use in operations, where it can help inform decision-making around optimizing production and maintenance by assessing how actions or events affect a virtual model of an asset. Since it is possible to model not only existing conditions but to also simulate extreme circumstances, the digital twin enables the operator to evaluate the most appropriate procedures to ensure both optimal production and personnel safety.

Oil Majors Creating Twins

Equinor has developed a digital twin solution it calls Echo, which is used to access and visualize data from a range of its cloud-based databases. It is in place at ten assets so far, including the giant Johan Castberg field and the recent Mariner development.

One of the more innovative aspects of digital twin technology that Equinor has been investigating is the use of the 'digital field worker', whereby everyone in the field

Elnur Amikishiyev /123RF



can effectively bring the 'office' with them. Issues that previously had to be resolved onshore, with trips back to the office and many physical signatures, can now be carried out entirely in the field with digital tools. Equinor says that over 6,000 employees will adopt advanced digital solutions such as Echo during 2020, adding that "Everyone with access can enter the digital twin at any time, irrespective of whether they are onshore at the office, or offshore on the installation."

BP is using its own digital twin system, APEX, a production optimization tool that has created a virtual copy of all the company's production systems throughout the world. The company says APEX added 30,000 bopd to production in 2017 alone. It also considerably speeds up processes, with the company citing a systems optimization procedure that used to require about 24 hours now being done in a mere 20 minutes.

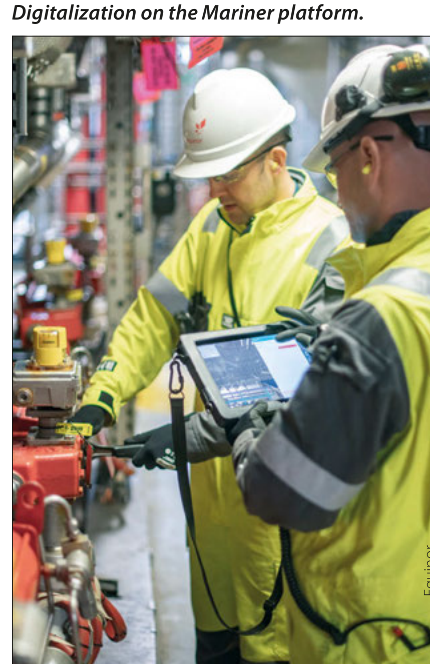
APEX is also a surveillance tool, capable of spotting issues in the field before they have had a chance to affect production. It can be used to test 'what if' scenarios; by pairing the model with the actual data, irregularities can quickly be detected and different procedures can be simulated, tweaking various components to ensure the optimum solution. As BP says: "virtually verifying before refining the reality."

In 2017, Shell was the first operator to participate in a Joint Industry Project initiative focused on advancing the structural integrity management of offshore assets using digital twins. It continues to roll out the concept over its assets, most recently collaborating with Kongsberg to create a fully realized dynamic digital twin of the Nyhamna facility, a gas processing and export hub for various fields in the Norwegian North Sea, including Shell's Ormen Lange project.

Embracing Twins

Digital twins are here to stay, throughout the E&P cycle, from subsurface modeling and the design of rigs to optimizing production, increasing safety and reducing field personnel, and in the installations required to process, refine and distribute hydrocarbons, continually evolving and maturing with the asset. The establishment of this sophisticated technology is complex and expensive but the evidence suggests the financial and practical rewards are worth the investment. ■

Digitalization on the Mariner platform.



The Khoshtaria Concessions: Oil and the Northern Provinces of Iran

MICHAEL QUENTIN MORTON

As ever, international interests were at the heart of the intrigue around the awarding and operating of concessions in the north of Iran.

The early history of oil in Iran (Persia) is overshadowed by events surrounding the Anglo-Persian Oil Company – known as Anglo-Iranian from 1935 and the forerunner of British Petroleum – which operated the D'Arcy concession for the south-western part of the country. However, there is a less familiar narrative around the provinces of northern Iran which, because of their proximity to the oil-rich southern Caucasus region, were considered promising. At the heart of this story is the mercurial figure of Akaki Khoshtaria, a Russian businessman from Georgia, who was instrumental in securing oil concessions for the area, while the competition over oil rights rekindled the nineteenth-century rivalry between Russia and Great Britain, only now with a new player in their midst: the United States.

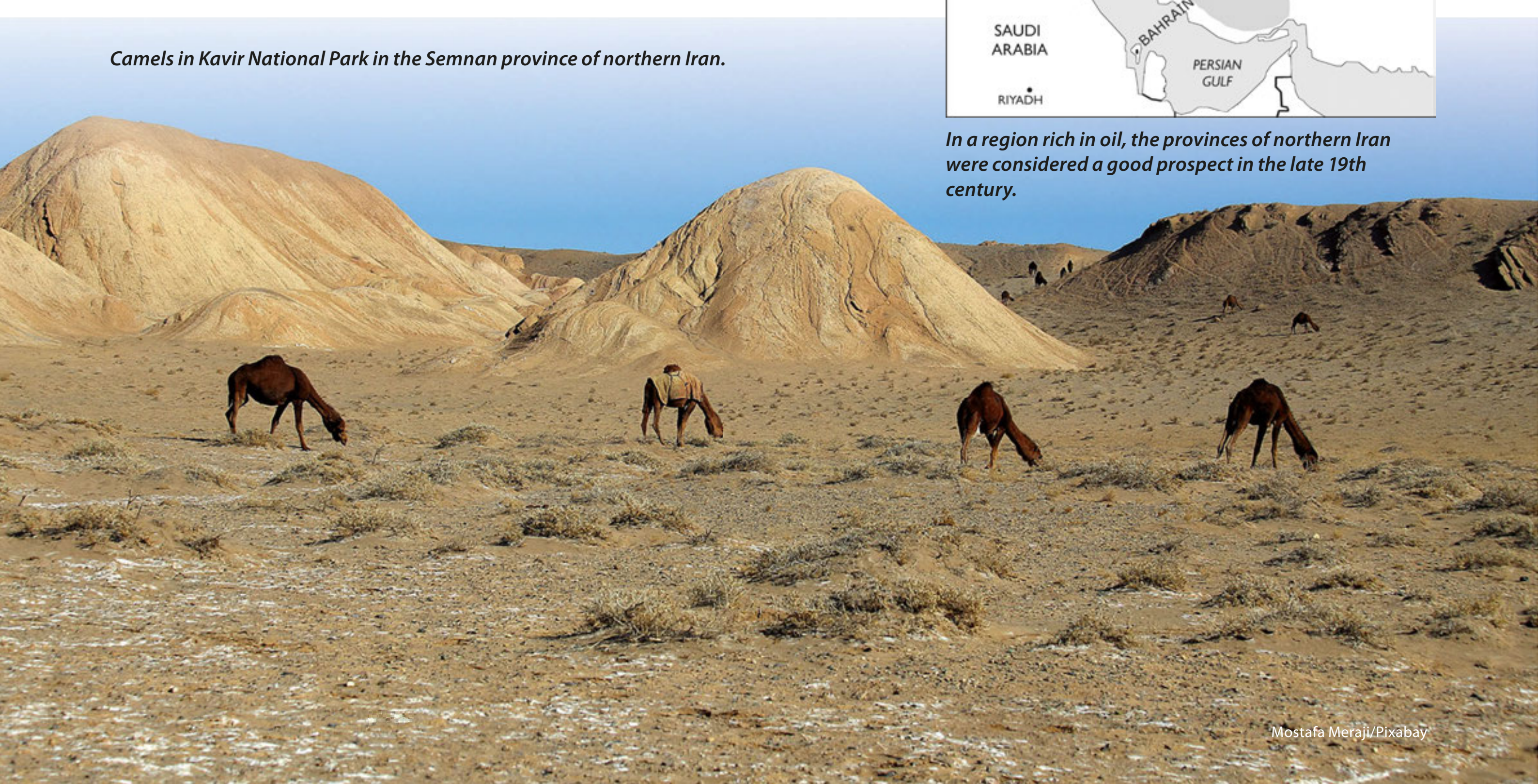
Origins of the Persian Oil Industry

In the late nineteenth century, the shahs of the Qajar dynasty who ruled Persia were on the look-out for new sources of income, and selling concessions was an easy method of raising extra funds. In 1879, Naser al-Din Shah granted a German-born British subject, Baron Julius de Reuter – founder of the famous news agency – a concession to prospect for minerals. Two wells were drilled in Fars and one on Qeshm Island, but without success.

In 1880 the Shah granted a firman (or royal decree) to Hajir Ali Akbar Amin, allowing him to look for minerals in Kavir-i-Khourian, a desert area to the south of the town of Semnan. Amin, described as the 'custodian of the mines', was a small-scale producer of sulfur, lead, copper and coal. Although the firman was for ten mines, and the Khourian fold was of some interest as an oil-producing area, production methods were rudimentary, with crude oil being collected from seepages on the ground.

The D'Arcy concession, granted in 1901, formed the basis of Anglo-

In a region rich in oil, the provinces of northern Iran were considered a good prospect in the late 19th century.



Camels in Kavir National Park in the Semnan province of northern Iran.

Mostafa Meraji/Pixabay

Naser al-Din Shah Qajar, 1831–1896.

Persian's operations in south-western Persia and specifically excluded five northern provinces – Azerbaijan, Gilan, Mazanderan, Astrabad and Khurasan. In 1908, when the company struck oil at Masjid-i-Suleiman in Khuzestan province, the future direction of Persia's oil industry was confirmed. Anglo-Persian built a refinery at Abadan and became a major supplier of fuel oil to the Royal Navy with the result that, in 1914, the British government took a 51% share in the company. In this way, British imperial interests were firmly tied to the future of Persian oil.

The Multi-Faceted Akaki Khoshtaria

Until then, the center of the petroleum world had been the southern Caucasus, where a number of entrepreneurs made fortunes in the oil industry. Among them was a Georgian businessman by the name of Akaki Khoshtaria, who mixed in the highest circles, counting Winston Churchill and Franklin D. Roosevelt as acquaintances and keeping close links with the ruling shahs and the Russians. He was described as 'an American-style businessman', though his start in the industry owed as much to luck as business acumen. One of his oil shipments was caught in a storm and diverted to Turkey, where he sold the cargo at a great profit and was able to invest the proceeds in equipment, thus entering the ranks of the oil producers of the time.

When the British spy, Reginald Teague-Jones, visited Tbilisi in 1922, he stayed at Khoshtaria's mansion, which was decorated with the heads of a leopard and an elephant ordered from a London taxidermist. Many claims have been made on Khoshtaria's behalf: that he set up the first railway in Iran, was first to export cars to Iran, owned a monopoly on soap and fish producing, was involved in the wool trade and founded the Georgian navy. He was also a philanthropist, patron of the arts and sponsored students to study abroad. However, it was in the realm of oil concessions that his name first came to the notice of the international oil companies.

In 1916 Khoshtaria was granted an oil concession for the provinces of Gilan, Mazanderan and Astrabad for a period of 70 years. This concession was partly based on a firman granted in 1896 and was generally known as the 'Khoshtaria concession'. In order to gain a foothold in the northern provinces, Anglo-Persian bought the concession for £200,000 (about £4.3m today) and formed North Persian Oils Limited with Khoshtaria as a shareholder. Although the Persian government canceled the concession, and a Treaty of Friendship between Persia and Russia in 1921 also cast doubt on its legality, Anglo-Persian stuck to its guns and insisted it was still valid.

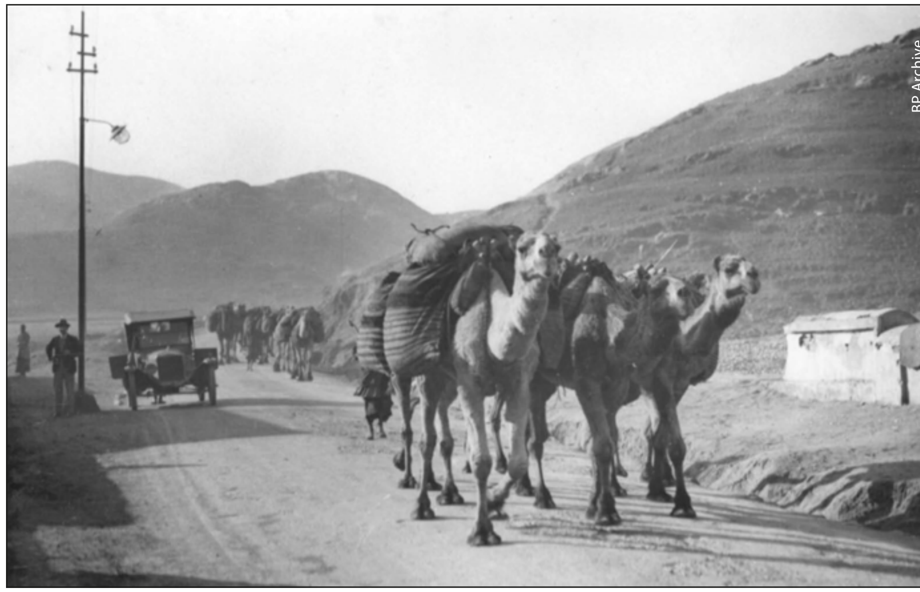
America Moves on the Northern Provinces

The early 1920s was marked by two American companies – Standard Oil of New Jersey and Sinclair Consolidated Oil Corporation – trying to gain a stake in Persian oil. Since the D'Arcy concession ruled them out of the south-west, their efforts focused on the northern provinces. This was a time of growing interest in overseas oil development, with US firms being encouraged by Secretary of State Hoover to seek new sources of petroleum around the globe in pursuit of the so-called 'Open Door' principle.

In August 1920 US firms were invited to apply for concessions in northern Persia. Standard took up the challenge and opened talks in Tehran, but problems soon emerged. Sinclair declared an interest, immediately presenting Standard with a rival bid and ensuring that the state department could not favor one firm over the other. That effectively neutralized Washington's support at a time when London was pushing the interests of its protégé, Anglo-Persian, which was using the Khoshtaria concession to block its rivals from the northern provinces.

Akaki Khoshtaria (1873–1932).

The Americans were enjoying a honeymoon period in Persia: they were a popular counterweight to the overweening influence of the British. In November 1921, the Persian government granted Standard the right to negotiate a 50-year concession, but the fact that Anglo-Persian controlled the pipe-laying rights and therefore the main oil outlet for crude oil was a major obstacle to their scheme. However, their bid coincided with a rapprochement with the British across the Middle East, with Standard Oil of New York (Socony) being allowed into Palestine (see *GEO ExPro* Vol. 17, No. 1). In December 1921 Standard New Jersey joined forces with Anglo-Persian in the northern provinces of Persia.

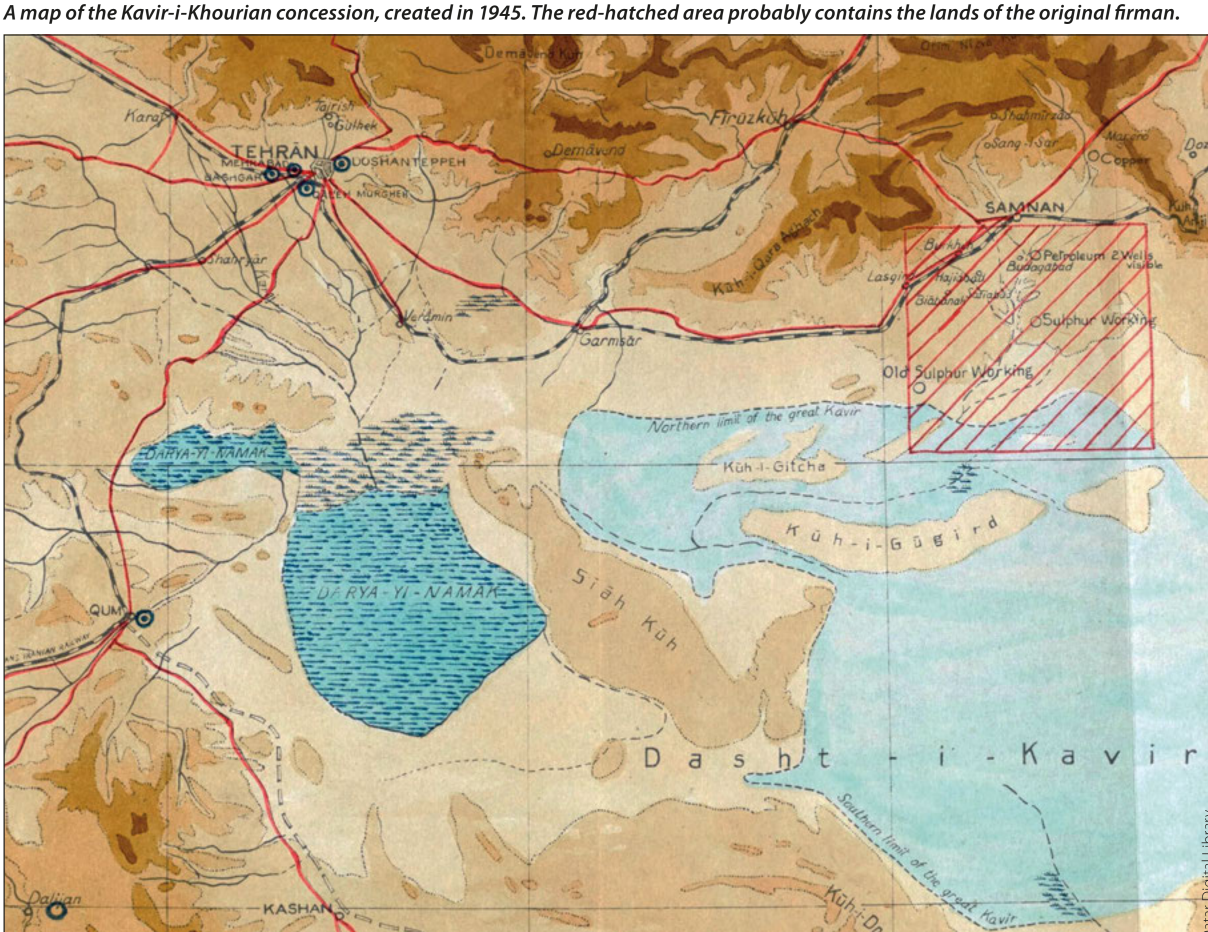


BP Archive

A road to the Persian oil fields, 1926.

Soon there was an added complication. In December 1923 the new prime minister, Reza Khan, approved the grant of a concession to Sinclair for four northern provinces. In order to get around the problem of exporting oil, the company planned to transport it across the Caucasus to the Black Sea – in view of its good relations with the Soviet government, the company believed that to be a viable option. However, after the Teapot Dome bribery scandal broke in the US, Sinclair struggled to raise the funds for a loan owed to the Persian government. In June 1924 two Americans were attacked at a Persian shrine, one of whom was rumored to be the Sinclair representative, Ralph Soper. Although Soper was unscathed, he took the hint and left the country soon afterwards. ▶

A map of the Kavir-i-Khourian concession, created in 1945. The red-hatched area probably contains the lands of the original firman.



Qatar Digital Library

After the Soviet government blocked the export of oil through its territory, the situation became impossible for Sinclair, and the company withdrew from the concession in 1925. Standard followed suit two years later, leaving the field clear for Anglo-Persian in the south-west, but the status of the northern provinces was still debatable. In 1937 the Amiranian Oil Company, a US firm based in Delaware, gained a 50-year concession for northern and eastern Iran, but withdrew two years later, citing political and logistical problems, while Anglo-Persian argued that the concession infringed the Khoshtaria concession.

Stalin, Roosevelt and Churchill at the Tehran Conference in 1943. Russia's reluctance to leave northern Iran at the end of the war was due in part to their interest in oil.

The Russian Connection

All the while, the Kavir-i-Khourian firman was in contention and, again, the hand of Akaki Khoshtaria was apparent. When Hajir Ali Akbar Amin died in the late 1890s, the rights under the firman had passed to his heirs, which presented Khoshtaria with an opportunity to buy them up and exploit the concession for his own ends. There were several heirs, and it is likely that Khoshtaria purchased most of their shares, visiting the town of Semnan to conclude his deals before a local mullah. As a British report observed, "It must be borne in mind that more than one of the co-heirs were people of little education who could no doubt be fairly easily persuaded to part with their share of the rights for a sum in cash down." However, Khoshtaria did not succeed to obtaining the original document, which was held by the principal heir.

At that time, the concession itself was unremarkable, having been operated in a primitive fashion for many years but, as rivalries in the petroleum world became more intense, it came under great scrutiny. Khoshtaria's dealings provoked much debate, especially since his name was already linked with the northern provinces. Perhaps more significant, and of some concern to the British looking on, were his connections with the Soviet leaders of Russia, and the Russian Bank. It is not clear whether Khoshtaria was acting on his own account or as agent for the Russians, but the thrust of his plans soon emerged.

In 1924, the *Majlis* decided to regularize various claims for oil rights throughout the country and, during the process that followed, only one out of 23 requests was registered – the Kavir-i-Khourian concession. It was, according to a British observer, an "extraordinary result" designed to bolster the legality of the 1880 firman and secure the original document; whatever the explanation, the ministry of public works sold the concession on to Khoshtaria, who transferred it to the Russians.

Despite protests from both the heirs to the original concession and Anglo-Persian, which regarded the area as within the D'Arcy concession, a syndicate of Iranian and Russian shareholders known as Kavir-Kurian was formed to develop the concession. Khoshtaria, who was on its board, was highly active on behalf of the new company and persuaded the Russian Bank to provide most of the capital. At one stage Calouste Gulbenkian (*GEO ExPro* Vol. 16, No. 1) engaged in talks about a joint venture with the Russians in northern Persia, and Khoshtaria offered a holding in the company to French and Italian interests, resulting in a party of geologists being sent to examine the concessionary area. Their report was unfavorable, although a prominent Soviet geologist took a different view. Between 1925 and 1932, two wells were drilled without any success and the concession remained unproductive at the outbreak of World War II

Overall, the concession suffered from a lack of funds, despite the fact that operations were funded in part by the proceeds from the sale of the original 'Khoshtaria concession' and with Russian money. Matters were complicated by the involvement of the court minister, Abdul Husayn Khan Timurtash, who fell out of favor with Reza Shah Pahlavi in 1930, and the untimely death of Khoshtaria in Paris two years later at the age of 59.

Postscript

Disputes over the Kavir-i-Khourian concession played out for many years. During World War II Semnan became a garrison town in the Russian zone, and the oil field was closed off. As the Russians had long regarded northern Persia to be within their sphere of influence, they expected to receive favorable treatment for oil concessions. However, despite a Russian minister, Sergey Kavtaradze, visiting Tehran in September 1944, their overtures were rebuffed. As it emerged that their move was part of a wider strategy to control the northern provinces, the deputies of the *Majlis* banned oil concessions being granted without their consent. This paved the way for the nationalization of the D'Arcy concession in 1951; and the architect of both reforms was none other than Anglo-Iranian's nemesis, Mohammad Mossadegh.

Quentin Morton's latest book Masters of the Pearl: A History of Qatar *is now available from all good booksellers.* ■

Artificial Intelligence: Revolutionizing Our Understanding

Structural seismic interpretation can be a complex and time-consuming task. In this case study, we have applied an Artificial Intelligence (AI) fault interpretation workflow to a 28-year-old dataset (1992) from the UK sector of the Southern North Sea.

The data focuses on the Dowsing Graben System (DGS), North Dogger Fault Zone. The complex, thin-skinned tectonics which define the graben feature are detached from the underlying Permian tectonics. These are responsible for the surrounding hydrocarbon fields such as Lancelot, Excalibur, Mordred, Guinevere and Galahad; however, recent studies illustrate the importance of the DGS on the petroleum system (Grant et al., 2019). Knowing that faults can influence the petroleum system, they all need defining clearly and concisely so a greater understanding of the subsurface can be achieved.

The clarity of the AI results ensures a rapid and detailed understanding of the structural regime. As would be expected from the application of AI, the results are available very quickly, the interpretation is free of any interpreter bias and delivers an indication of the confidence in the structural interpretation.

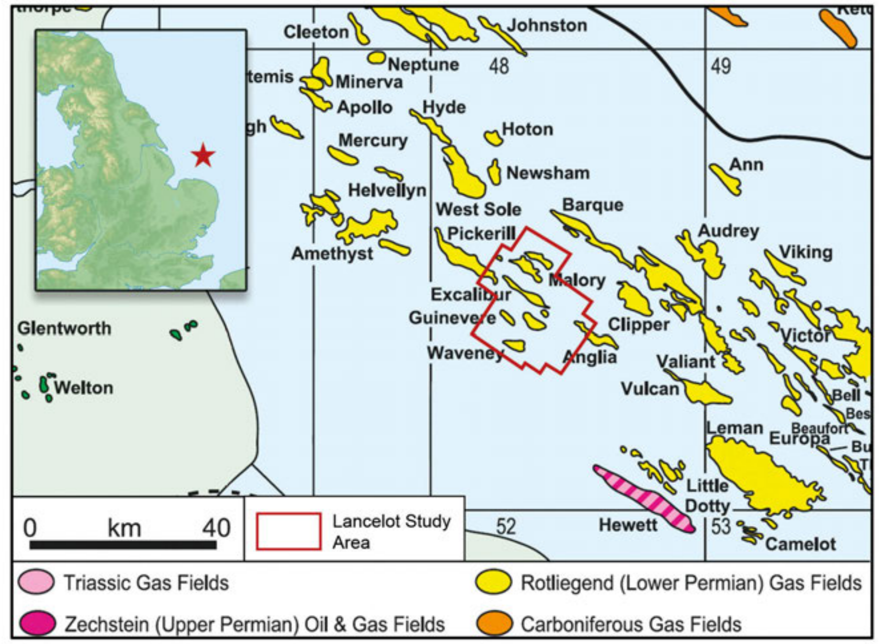
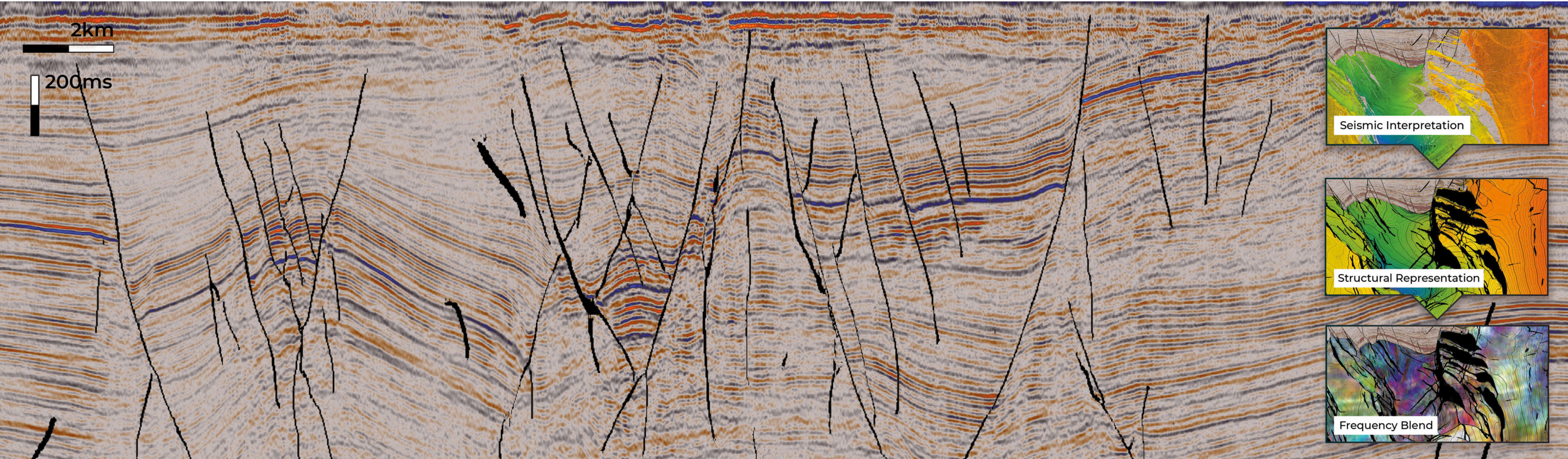


Figure 2: Map showing the location of the Lancelot Study Area (modified after Underhill, 2009).

geoteric

Figure 1: New tricks with old data: AI fault analysis of a 1992 dataset from the UK North Sea, revealing the structural complexity of the Dowsing Graben System.



AI Seismic Interpretation

See how cutting-edge AI technology is enabling a revolution in subsurface understanding.

MARK BROWNLESS, RYAN WILLIAMS and ABDULQADIR CADER; Geoteric

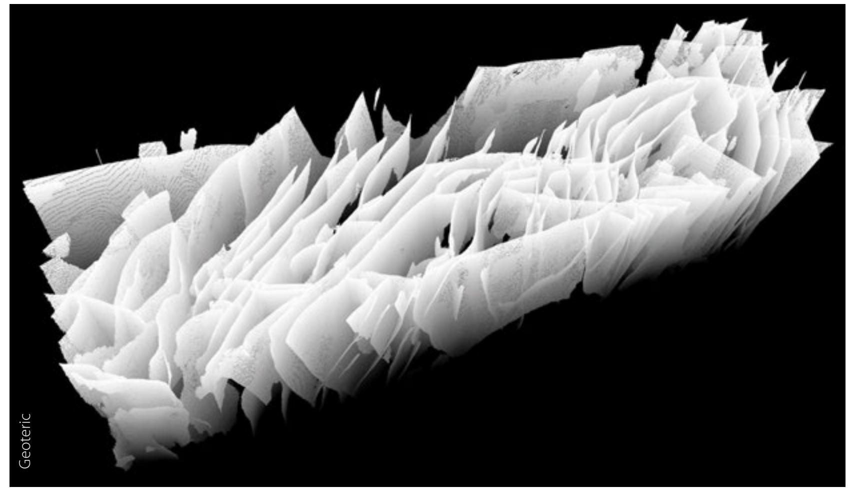
It is about time there was some delivery from the promise of AI to help and enhance the subsurface workflow. Pipes and pumps are one thing, but the subsurface is not so easy to measure directly. At Geoteric we have been engaged with the application of AI to data types of all quality, from around the world. We, and our clients, have seen that AI is now mature enough to provide insight and new understanding to datasets young and old. If you think the data quality needs to be perfect, think again (Han and Cader, 2020)! If you need a better understanding of the system you are working with at a development or exploration scale to inform investment decisions, AI is now proven to be the breakthrough you need. Even in noisy or poorly orientated datasets, AI is seen to deliver an informative 3D model of the subsurface.

The Big 3D Reveal

Effective structural analysis is critical to asset team decisions. The ability to reveal faulting and structural elements in 3D helps understanding of the subsurface, not just in the level of detail that can be obtained, but also the speed; time thus saved can be used to enable further understanding. Embedding AI fault results into the horizon interpretation process ensures the resulting horizon (Figure 1 – foldout on previous page, top right image) is interpreted understanding the location of AI-defined faults and allows for further accurate surface generation, tightly tying the faults. As the interpretation is bound by AI-detected faults, this in turn creates a pseudo-fault polygon representation on the horizon (Figure 1 – middle right image). It is well known that frequency decomposition can reveal stratigraphic features in great detail throughout seismic volumes. By combining this high-resolution stratigraphic analysis with the AI fault result (Figure 1 – bottom right image), an interpreter can gain a greater understanding of their volume and any potential interaction between stratigraphic features and structural events. Although the AI analysis attempts to find all faults in the data, the algorithm can miss one from time to time, as seen on the furthest left bounding graben fault, where a small antithetic fault is not identified (Figure 1). With the assistance of an interpreter, the algorithm can be further trained to identify features that were initially of low confidence. This augmented approach to AI interpretation not only ensures a quick turnaround in results but one determined to have the most accurate level of geological understanding.

Revealing the structural elements in 3D can be greatly beneficial to an interpreter, helping them visualize features that would otherwise remain unseen. Best practice for structural interpretation involves interpreting the structures perpendicular to the strike of the faults. However, nature does not always allow for this, with most seismic volumes containing faults of varying orientations. In the background image of Figure 1, several wide, low-angled fault responses are observed, which would normally be questioned instantly by an interpreter. After investigation, these responses are confirmed as faults, but they are (sub)parallel to the seismic section. Faults observed in this orientation often produce some very interesting shapes, which can be confirmed after QC (see section below). The identification of (sub)parallel faults can further assist in horizon interpretation and explain why there may be a break in an apparent continuous reflector, only to reappear shortly after. This allows an interpreter to work in a traditional 2D environment (in-line and cross-line interpretation), whilst having a strong appreciation for the 3D shapes of faults, often an issue which remains with traditional interpretation techniques.

Figure 3: 3D representation of the faults associated with the Dowsing Graben System. Faults with varying strikes are observed and illuminated in this 3D rendering of the AI fault detection.



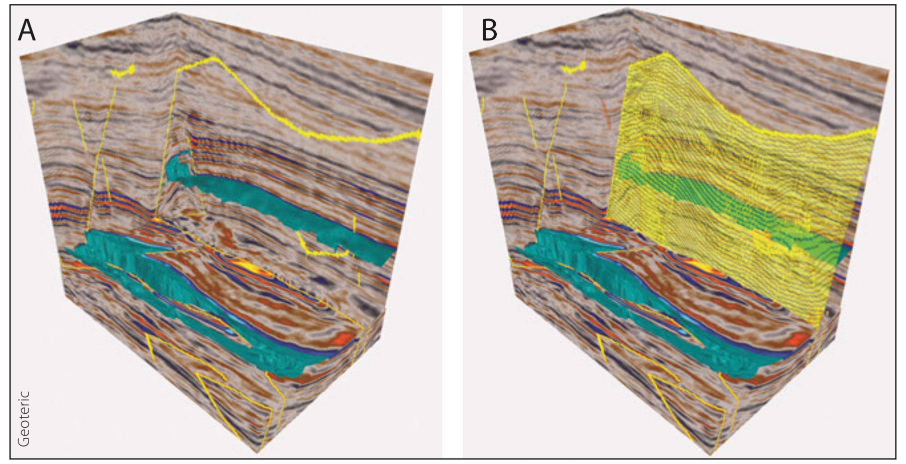


Figure 4: (A) fault representation on in-line and cross-line; (B) 3D rendering of fault. Sub/parallel faults often have strange shallow shapes (A) but when the 3D shape is taken into account and the fault plane visualized (B) the shallow response can be correctly confirmed as a structural lineament.

Illuminating Faults

The AI fault analysis of the Lancelot field illustrates exceptional results when visualized in 3D (Figure 3). The ability to see the distribution of faults in a lateral and vertical continuous manner gives the interpreter more confidence in the results and a deeper understanding of the system. Having the ability to analyze the complex Dowsing Graben System in 3D allows for unprecedented subsurface investigation – now the intricacies of the complex faulting system can be revealed. In this image the internal faulting of the graben system is illuminated with many cross-cutting and basin parallel faults. We have experienced in several projects that the Geoteric 3D visualized model of the structure delivered by the application of AI has explained multiple post-drill well failures. Had AI been available pre-drill, and had it been applied to the data, the well trajectories would likely have been changed before drilling. Bringing the drillers and development team together around the 3D AI structural model is a key to better, faster and safer projects.

Path to Success Is Rarely Straight

The images from the Lancelot dataset show a horizon that has been offset by a fault – nothing so unusual there. The depiction of the fault on the in-line is very unusual and is something of invaluable assistance when interpreting horizons (Figure 4). To aid understanding in the figure, the fault is shown as an interpreted line on an in-line and a cross-line (A), and a time slice. It is also shown as a 3D plane (B) with transparency. Whilst it may be unusual to see a fault interpreted as a sub-horizontal 'smile' breaking up a horizon, it is clear this result is logical, consistent and correct. If you have reservoir engineering or petroleum system questions involving flow-pathways, either in production or exploration, perhaps the answer can yet be found in your seismic data. The identification and interpretation of elements that are difficult to find is a key benefit of AI analysis of seismic datasets.

Old Fields, New Perspectives

The Lancaster Field on the Rona Ridge, UK Continental Shelf is a proven fractured basement play; however, the dataset is 25 years old (1995). Therefore, the signal-to-noise ratio is low, especially in the presence of multiples and general complexities associated with fractured basement reservoirs. Using AI we can delineate many faults and determine the associated confidence rating. Fault trends have been calculated directly on the AI faults indicating their lateral orientation or strike (Figure 5). Knowing the local stress field, the orientation of the faults which are most likely open can be determined and examined and the implications considered (Williams et al., 2020). The AI algorithm's ability to see through poor data to a more informative signal that is related to the fault structure has resulted in high-quality and reliable data which can be used to make a well-founded decision about the location and orientation of exploration or appraisal wells in good and poor data.

The work to produce the models of these fields can take just a day from receipt of uninterpreted data to the results seen here, with volume calculations.

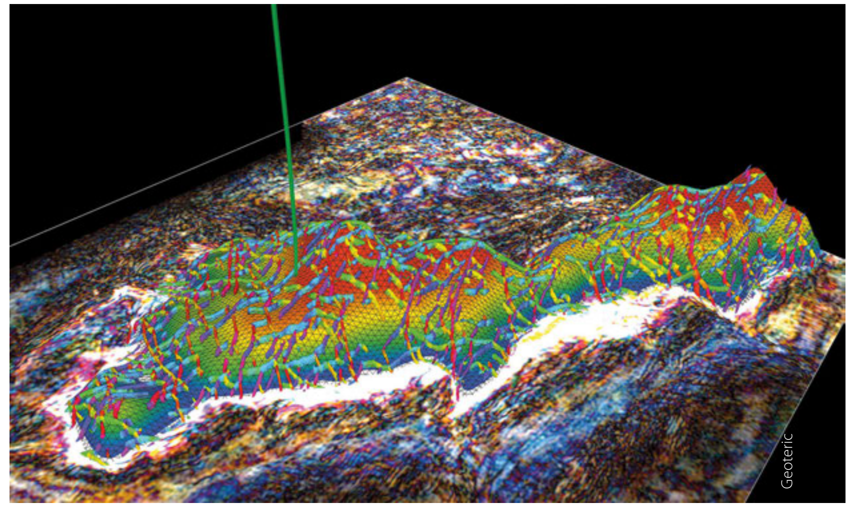
So, Is It All Hype?

At Geoteric we think it is right to leave that decision to you, but for what it is worth we have already run over 150 seismic volumes and multiple client projects from all over the world. This AI fault interpretation service is removing the hype from the machine learning and AI technology cycle and replacing it with delivery.

We believe that this as just the beginning of a deeper understanding of the Earth.

References available online. ■

Figure 5: AI fault trends rendered at top reservoir, highlighting the orientation/strike of lineaments, which are critical to the success of the fractured basement Lancaster Field.



Cinder Cone or Mud Volcano?

Experience Bias and Observation on the Papuan Plateau

NEIL HODGSON and KARYNA RODRIGUEZ; Searcher Seismic

My grandfather once said to me that "sometimes I sits and think, and sometimes I just sits." In the Covid Anthropause one might be forgiven for adopting the latter strategy – but the questioning mind of the geologist is built for puzzle solving, as demonstrated in a recent debate on LinkedIn about a curious geological puzzle.

The image below was recently posted on LinkedIn by Discover Geoscience (Searcher's G&G team). They asked: "*Cinder Cone or Mud Volcano? We discovered this bad boy lurking in Searcher's Hahonua Dataset while working on our regional Gulf of Papua Regional Study recently. What do you think it is?*

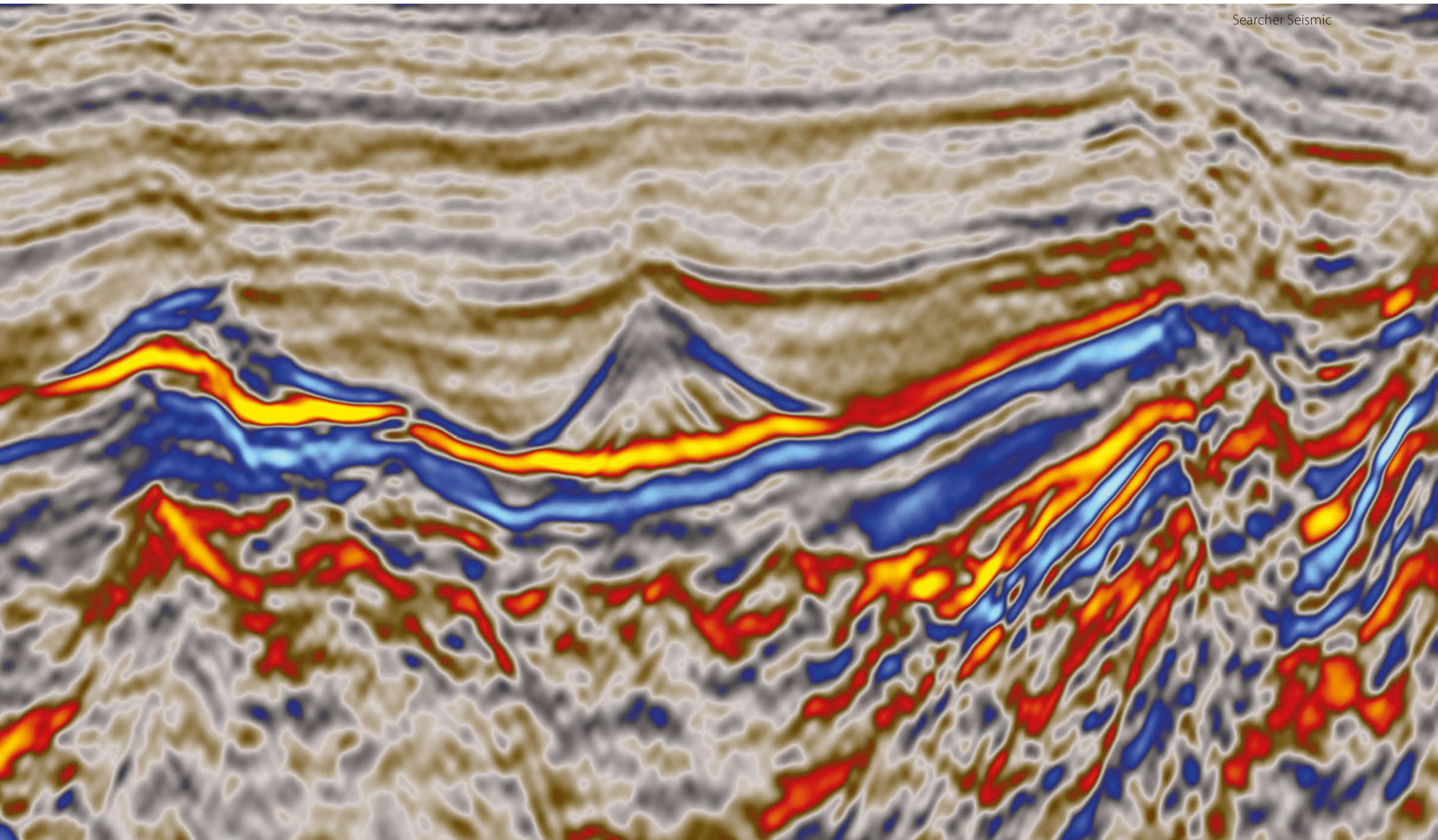
"It sits on a regional flooding surface above a small half graben with no obvious vertical feeder pipe below. It is 130m high by 1km wide and looks identical on the crossline. There are known volcanics at this time regionally, but the basin was also likely maturing for hydrocarbons at the time. Is it a gas escape feature or volcano?"

The "bad boy" in question is the beautifully-imaged nearly equilateral triangular structure at the center of the image below, which we will now call the 'feature'.

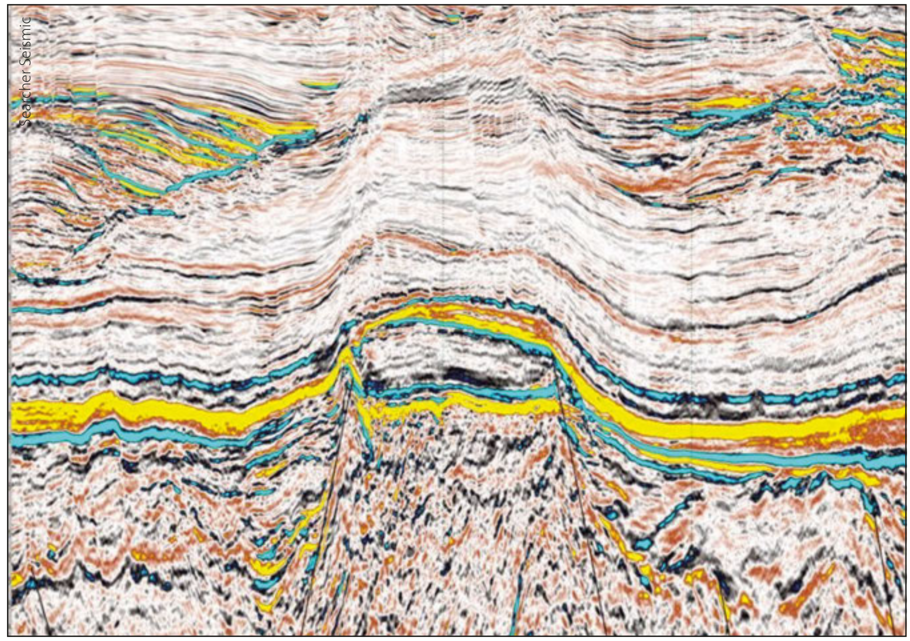
In the 21st century, this should be a simple question; a clear, modern seismic example of a distinctive feature, many of which have been described and seen before. But this is geoscience, and we look for both "what are we seeing?" and "how did it get there?" to tell us what it is made from and whether it has utility. This is deduced from a huge variety of potentially uncertain observations, with their alternatives and subtleties. Weighting of this information can and does create a diversity of interpretation. The debate on LinkedIn drew many responses, from all over the globe. Some geoscientists were obviously intimate with the area and some less familiar but had a great line in observational reasoning. However, given a binary question, what was interesting was the range of strongly held conclusions that were distilled from the available information.

Some responses were simply: "it's a cinder cone" or "it's a mud diapir";

The "bad boy" under discussion.



observations made from experiential analogy (aka "seen this before bias"), or perhaps based on the click-bait quick look. As Malcom Gladwell showed in his book *Blink*, reflex analyses can be helpful and insightful, but since as many jumped one way (igneous volcanic) as the other (fluidized sediment) by reflex, we needed a more reductive analysis to move ahead. So started the more observational analysis. Of course, before you can put a geologist in a box with only two sides, first you need some "but is it either?" suggestions.



An example of a carbonate build-up seen on Searcher's seismic from Papua New Guinea.

Carbonate Build-Up?

An alternative to seabed extrusion of one form or another is the suggestion that the feature is a carbonate build-up. Pinnacle reefs are well known in the Gulf of Papua, and Luis Carlos Carvajal made the excellent suggestion that we use the Burgess et al. (2013) 20-step observational ranking methodology to analyze the feature as an isolated carbonate build-up. In this system the feature scored 5 out of 20, suggesting that either the ranking system was not attuned to this type of carbonate build-up or it is not one.

A characteristic of a carbonate between overlying and underlying mudstones is a hard seismic kick in the acoustic impedance at the top of the feature, with a soft one at the base. Here, the blue dipping event of the flanks of the feature suggest the reverse, as the top is soft and the base hard. Just to its right, where 'post-feature' mudstone sits on syn-rift, the basal event is less strong, implying that the feature is even less dense than the surrounding mudstone. Several posters noted that shaped features had been drilled assuming they were pinnacle reefs in various other basins in the world from New Zealand to Turkey; anecdotes that usually ended ruefully in an old volcano. This may be evidence of sampling bias because fewer carbonate reefs are discovered by accident by a well targeting an igneous volcano.

Different Form of Extrudite?

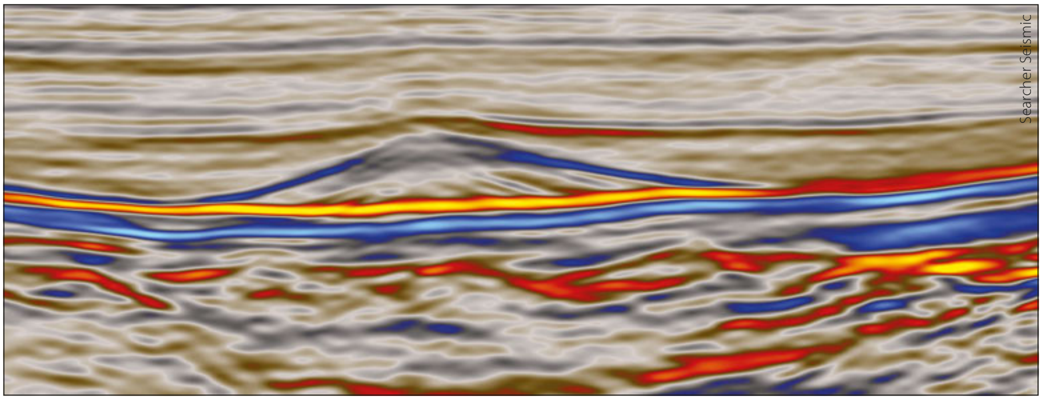
A non-mud or igneous extrudite model suggested that it could be an erosional remnant or even a prograding point bar. There were some quite detailed observations of the internal geometry of the feature; there appears faintly to be a series of internal reflectors parallel to the dipping flanks, again suggesting construction via eruption in some form from a central point. Some observers saw this as evidence of extrusion, but others did not think there was enough internal variation versus analog volcanics that they had seen, as they expected volcanics to be polyphased. The steeply dipping layers within the feature suggest a more central construction rather than an erosional remnant which could be expected to have base-parallel rather than flank-parallel internal bedding.

Another non-mud or igneous extrusion suggestion was a salt diapir, yet there is no stock connecting to the halofer and not enough disruption to make a diapir a candidate. However, salt could represent the body of the feature; it is similar to a remnant salt wall between two sediment pods, as seen in other salt provinces like Gabon or the UK Central Graben. The occurrence of salt walls with sediment pods between them could explain why the structure to the left of the feature is also soft topped, although rather less perfectly formed; could it be another volcano or relict salt wall? However, salt with a soft kick top (unlikely unless deeply buried or surrounded by carbonate), in a basin where salt is not recognized and most likely has a deepwater setting does not seem likely, so we will park that in case we run out of other models.

If we rule out the carbonate, relict and salt hypotheses in favor of an extrusive, the issue for the igneous model is the soft top. Glenn Lovitz suggested that cinder cones may be soft topped with a thick tuffaceous final or major late flow that is highly porous, i.e. low velocity (see webinar Abdulkader M. Afifi, 2020). A lower impedance compared to the bland shales above could be enhanced by subsequent clay diagenesis of the felsic component. Glenn notes that mapping the internal geometry can differentiate between a pinnacle reef and an extrusive, but the nature of the extrusion, be it magma or fluidized clastics, could perhaps generate the same constructional geomorphology.

Why No Feeder Pipe?

But a bigger problem awaits all the extrusive models. Several contributors noted that the feature has no feeder pipe or disturbance below the cone, at least not visible on this section. Some great seismic examples were posted showing drilled volcanoes that had very disturbed substrate. If it were a cinder cone or mud diapir then some material, either molten lava or fluidized mud, will be supplied from depth to the then sea floor, where the feature is built. Why can we not see a conduit of material beneath it?



The feature at 'true scale'.

Of course, absence of evidence is not evidence of absence per se. The feeders may have caused disruption below seismic resolution (especially if they were clastic injectites) or the line or feeder pipes need not have been central. Although you only get a pointed crest on a conic section if you go through the cone top, many cinder cones have pointed caldera-rim ridges that are offset from the vent center. Allan Scardina favored a volcanic cone subject to a better understanding of the paleo-bathymetry of the onlapping section; he felt a lack of feeders is not definitive evidence as they can be difficult to spot. It was exciting to see a post regarding the non-visibility of a possible feeder pipe, with an example from offshore New Zealand including different types of igneous seismic facies (Bischoff et al., 2019).

When Discover Geoscience posted the original image, they also noted the lack of obvious feeder pipes and also the aspect ratio (height to width 0.1) and the fact that the same geometry was present on the cross line, making it likely that we are looking at a conical feature, albeit rather more squashed flat than the image suggests. Several posters took the time to recreate the image in 'true scale' – a discipline that perhaps we should endorse more often as it allows our models to be informed more accurately by real-world observation. However, the aspect ratio is not uncommon in monogenetic submarine volcanoes composed of poorly consolidated tephra showing steep slopes and pointy or flat tops, often characterized by sub-vertical knolls (e.g. Cavallaro and Coltelli, 2019). Submarine extrusives are often not as delightfully pointy as this example because of the interplay between volcanic activity, wave and current erosion, mass-wasting and depositional processes, in relationship with sea-level change, acting in both subaerial and submarine environments. However, the mudstones overlying the feature are deepwater sediments, so presumably some of these processes may have had little chance to modify the geometry before the feature was buried.

The surrounding mudstones onlap the feature, do not seem to have eroded it, and appear to have compacted more than the feature itself (slightly arcuate downward on the flanks), suggesting that it is made of material that behaves differently to the depositional mudstones surrounding it; either mud in the feature is not de-watering on loading, or they comprise material that is not compacting. This fueled the reasoning that the feature comprises a hard (igneous by inference) material, more solid than the mudstones around it and perhaps not consistent with it being comprised of soft mud volcano extrusives. More solid but lower density with that soft seismic kick?

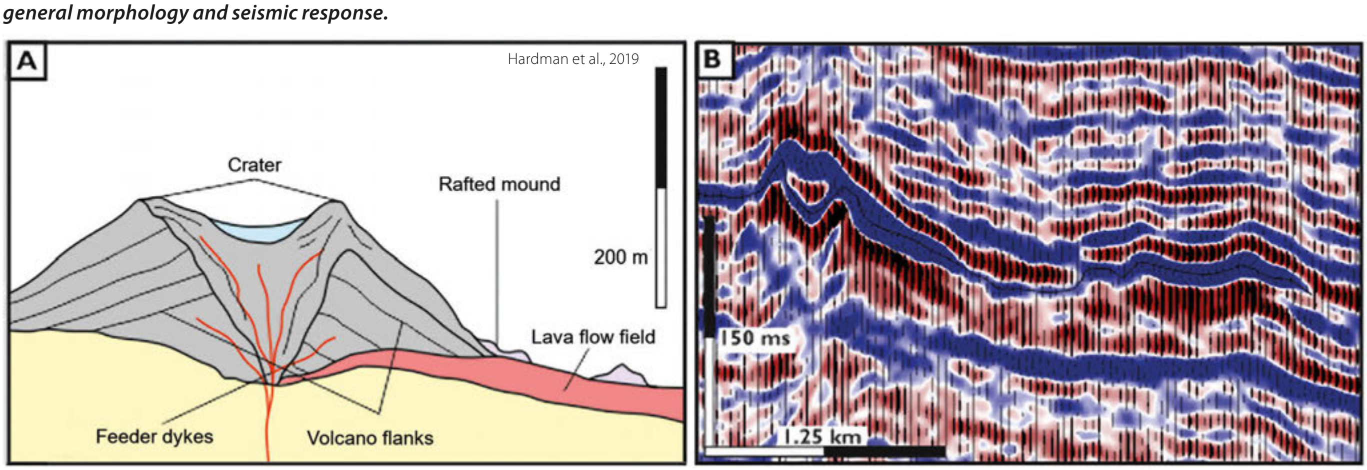
The presence or otherwise of distortion in the seismic above the crest of the feature drew attention. Some identified a gas escape distortion in the overlying strata, others unambiguously said there was no sign of gas escape, only faulting due to compaction. That fluid flow might continue through a system post-mud eruption and burial is not impossible, yet it is also not compulsory, nor probably limited only to clastics and could come from volcanics too.

Curiouser and Curiouser

So two parallel trains of argument were slugging it out in the LinkedIn feed: the volcanic cinder cone or the mud extrusive. The salt diapir, carbonate build-up and erosional remnant have all left the venue on stretchers with mild concussion.

But now comes a third boxer into the ring: Charlotta Luthje said: "I put my money on a sand volcano at that scale." This is

(A) Cross-section through a cinder cone, adapted from Németh and Kereszturi (2015). (B) Seismic line across a cinder cone and lava flow highlighting the general morphology and seismic response.



an awesome thought. Perhaps the sand was less compressible than mudstone so the compaction difference we see between the feature and the mud either side could be explained. Mads Huuse added into this line of thought by supplying an analog from the North Sea – a subsurface feature interpreted as a sand volcano (Andresen et al., 2009). He could not prove the analogy was a sand volcano – it was just an interpretation.

Hans Ladegaard pulled together a set of observations that seemed to establish this model as a firm candidate. He noted that the internal stratification suggests it is a build-up rather than an erosional remnant. The soft top and the brightening of the hard base shows that the body has lower AI than the surrounding rocks, ruling out salt, carbonate and possibly also a volcanic origin. There is some differential compaction of the surrounding strata which is difficult to reconcile with a pure mud volcano (although it could be a result of late movement), suggesting a sandy volcano, which may also explain the vague hints of fluid escape above the crest.

Well, although we have looked and cannot find any outcrops of sand volcanoes on this scale and geometry, at least our dancing around the various alternatives has generated a prospective model. Sand, sealed by shales but connected to the deep syn-rift by sand conduits for hydrocarbons to ooze up, a high net/gross sandstone target in a shape of a right cone, full of oil.

Geoscience at its Best

From a single seismic line and binary question we have had many firmly held alternative models discussed and dissected, which we have perhaps been biased enough to whittle down to the one with hydrocarbon prospectivity!

Perhaps the conclusion is that an interpretation is only as certain as the richness of the observations upon which it is based and the alternatives considered. Given a binary question in an increasingly polarized binary world, we are proud of the geoscience community for coming together and finding a third way. This is geoscience at its best.

References available online. ■

Cross-section through a sand volcano. County Clare, Ireland.

Making Waves with Big Seismic Computing

BILL SHEA, Sharp Reflections

In 2006, a 'moonshot' R&D project was launched: to develop interactive software to visualize and process pre-stack seismic data.

To reach this impressive goal, researchers from Equinor (then Statoil) and Germany's Fraunhofer Institute embraced new 'Big Data' compute technologies first developed for manufacturing. Pre-stack specialist company Sharp Reflections successfully commercialized the disruptive technology, and today is again working closely with Equinor to automate analysis of time-lapse seismic to monitor production in maturing fields.

Fostering Innovation

Research and development are crucial to the survival of the oil and gas sector. According to Norsk Petroleum, competitiveness mixed with innovation has driven the Norwegian oil and gas sector forward since its inception. Never has this been more important than now, as the world questions the role of oil and gas in the energy transition.

The support provided by the Norwegian authorities for R&D has also gone a long way towards fostering the innovative atmosphere that exists in Norway's oil and gas sector today. Joint Industry Projects (JIPs) have played a key role in fostering long-term collaboration between oil and technology companies alike, allowing oil companies to pool support for projects with ambitious goals. The sense of 'inventiveness' that is fostered also provides room for pivoting or changing the scope as results and testing take place. Should projects find new, more innovative solutions than were originally intended, this can be encouraged, funded and commercialized.

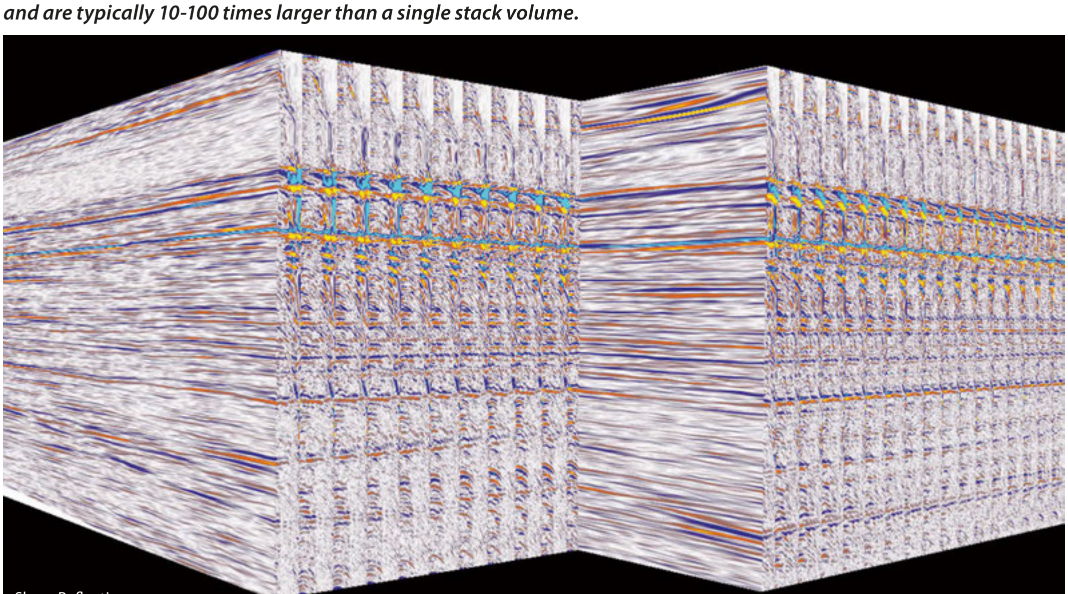
Crowd-Sourced R&D

The development of Sharp Reflection's commercial software *Pre-Stack Pro* provides a window through which it is possible to analyze how the innovative spirit of Norwegian oil and technology companies can be fostered to cultivate truly groundbreaking results. It was born out of an idea to explore potential oil and gas applications using the Fraunhofer Institute's High-Performance Computing (HPC) visualization technology. The adoption of new 3D seismic visualization technology powered by Silicon Graphics supercomputers was proven in the 90s, with entire 3D volumes being loaded directly to computer memory for interactive analysis. The new HPC technology had the potential to visualize much larger 3D datasets, using low-cost commodity computer servers.

Pre-stack gathers, which capture a complete high-fidelity image of the seismic amplitudes recorded by all geophones, looked like an obvious application for Big Data visualization. Depending on acquisition geometry, they are 10s to 100s of times larger than the equivalent full-stack volume: far too big to manipulate efficiently with standard desktop computers. As a result, pre-stack data were typically treated as an intermediate-stage processing byproduct, only rarely making it to the interpreter.

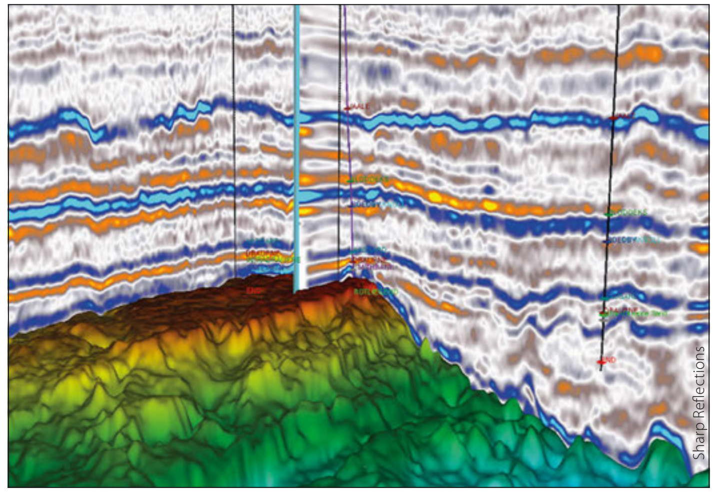
Seeing the potential of the project, the initial seed funds were provided by Statoil. In just a few months the team at the Fraunhofer Institute could import and load 1 TB of pre-stack gathers into memory and interactively roam through the entire data volume. Users could inspect the final processed gathers at any location in the entire survey and quickly assess data reliability. After just a few test projects, it was clear that the toolkit would benefit greatly by adding a small suite of high-value processing tools to improve data

3D pre-stack visualization of migrated seismic. Data can be viewed as angle or offset 'slices' or as traditional gathers, and are typically 10-100 times larger than a single stack volume.



quality. Seeing the long-term value of the research, Statoil launched a three-year strategic project to develop these tools.

Under the original scope, the R&D team delivered an advanced prototype with clear performance advantages. Stakeholders recognized that more effort and funding was required to develop a complete product and Sharp Reflections was launched. A JIP was formed to broaden the sponsor base, with Rock Solid Images (RSI) brought onboard as a development partner. RSI contributed a library of advanced geophysical algorithms that were adapted to the new compute engine, greatly accelerating the launch of the JIP's new commercial software, Pre-Stack Pro. This crowdfunding model established product-market fit and created a small core of early adopters committed to using the software on real datasets.



Today's 3D visualization canvas in Pre-Stack Pro. A nearly-unlimited number of 3D stack and attribute volumes can be loaded to memory on HPC clusters, and browsed interactively. Pre-stack gathers can also be accessed and displayed at specific locations. Data courtesy of Equinor.

True Interpretive Processing

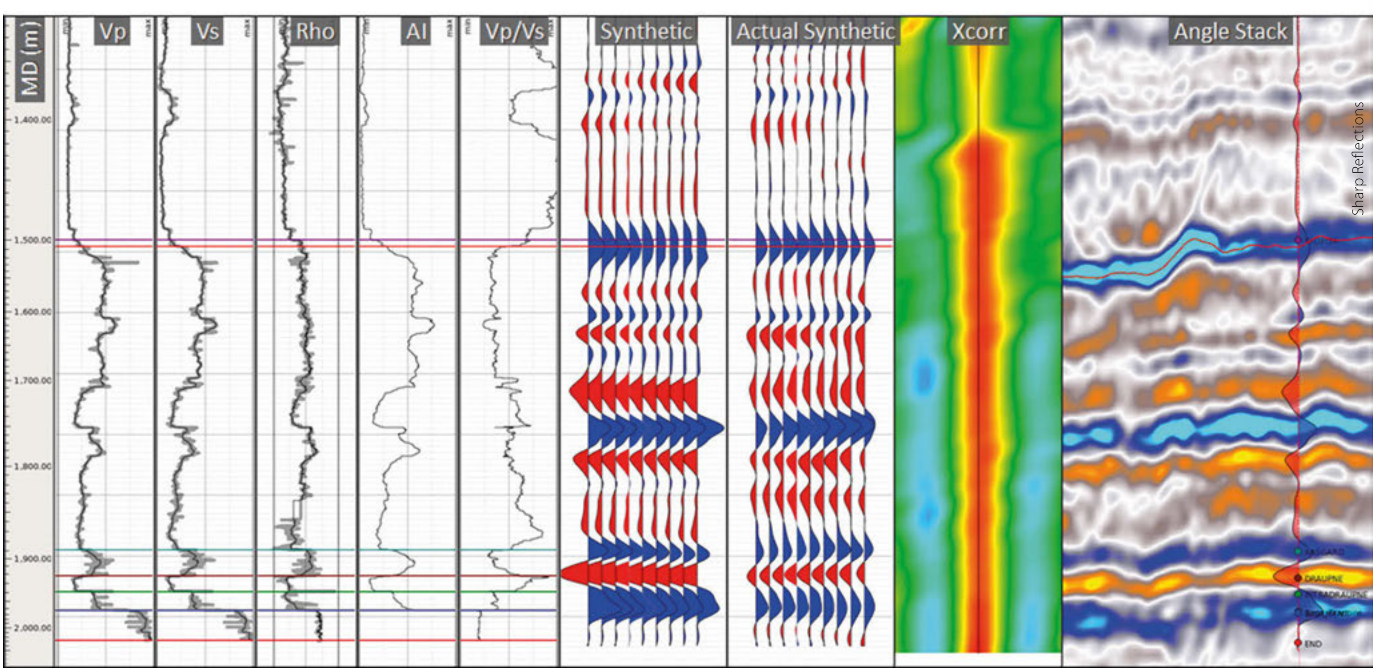
The technology quickly captured a small niche market among hard-core geophysicists seeking a 'light' seismic processing tool that could be used on multiclient 3D exploration surveys. Multiclient data typically require gather post-processing for AVO or pre-stack inversion studies, and Pre-Stack Pro provided a real-time, DIY solution. Many users had hands-on seismic processing experience, with the skills needed to tune processing workflows and optimize data quality for specific reservoir objectives. Through a series of funded foundation projects, these early oil company customers sponsored development of amplitude mapping, well calibration, and pre-stack seismic inversion tools to help de-risk prospects without switching applications. These developments began to blur the traditional boundaries between seismic processing and interpretation software, with a foot in both worlds.

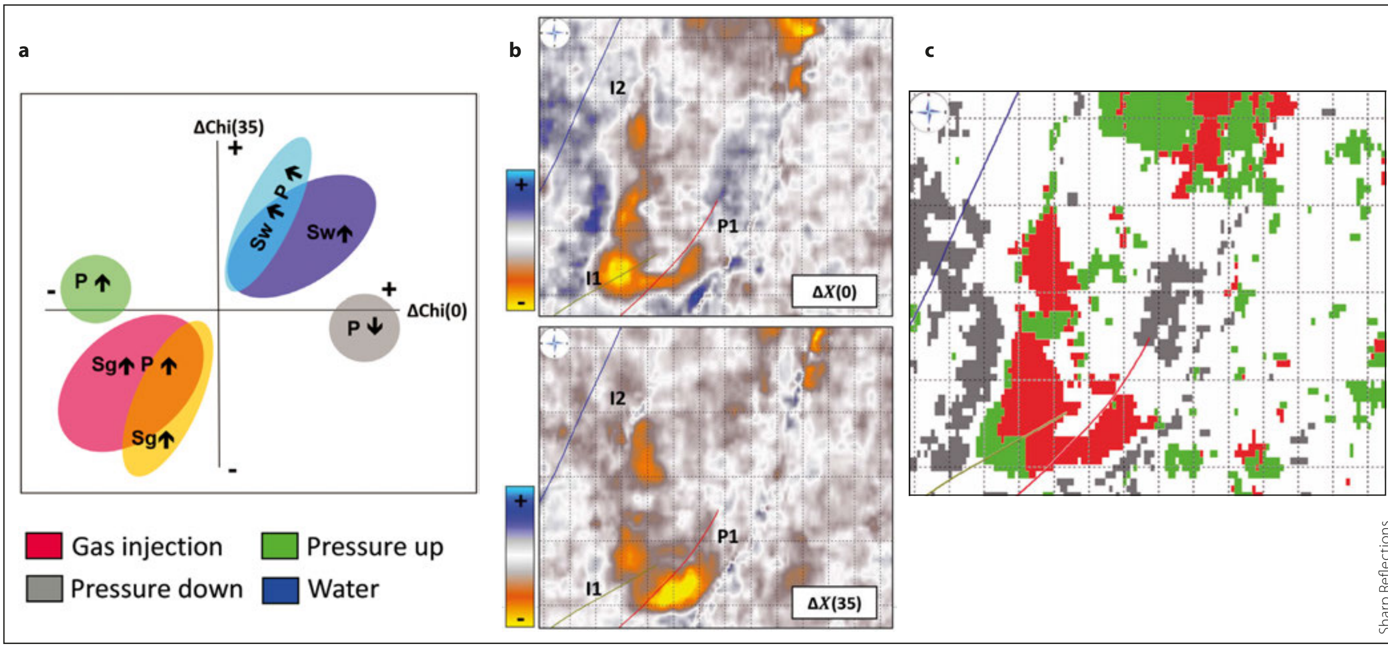
Recognizing the potential of the software beyond marine streamer acquisition, the pre-stack scope was extended. The Fraunhofer research team worked with Sharp Reflections to extend their pre-stack seismic data model, adding a second gather dimension to handle azimuthally-varying seismic data collected on land or with Ocean Bottom Node technology. This resulted in the development of new tools to automatically extract amplitude information from any angle of incidence and any azimuth direction and collect the results in a single five-dimensional seismic volume.

Best Practice Workflows, Brought to Life

Key advisors in Statoil's Production Subsurface Technology organization recognized that Pre-Stack Pro was increasingly

The new pre-stack well tie module. Actual and synthetic pre-stack traces are cross-correlated, providing quick visual feedback about the match quality. The tool eliminates the need to tie synthetics to each individual partial angle stack and simplifies calibration of seismic amplitudes in producing fields.





Quantitative analysis of pre-stack 4D amplitudes improve understanding of dynamic changes in producing reservoirs. (a) individual and combined pressure and saturation changes for water and gas each show a distinct 4D amplitude fingerprint on synthetic EEI models; (b) actual EEI differences for specific reservoir zones are calculated from pre-stack seismic; (c) EEI cross-plots are used to classify the changes according to the expected dynamic response. Data courtesy of Equinor.

used for routine seismic reservoir characterization tasks in producing fields. Nonetheless, critical 'feature gaps' remained. The companies signed a new exclusive R&D deal to plug these gaps and develop an efficient geophysical interpretation workflow stretching from seismic QC and data cleanup to full pre-stack inversion.

Major developments in the 'Efficient QI' (EQI) project included design of a new pre-stack well tie module and implementation of proprietary seismic inversion codes developed by Statoil and the Norwegian Computing Center (Norsk Regnesentral). This new solution had all the functionality required to design, build, run and calibrate the inversion, and to interrogate and extract maps from the 3D results. Statoil also facilitated IP transfer and encouraged the companies to establish a commercial partnership, which then secured Statoil's investment in advanced geophysical technology and a sustainable framework for future innovations.

Sonja Maultzsch, leading advisor for quantitative seismic analysis at Equinor, has already seen the R&D investment bear fruit. "The tools developed through the EQI project empower geophysicists throughout the organization to understand the quality of their pre-stack data and the associated AVO information, with the possibility of interactively evaluating quantitative interpretation products all the way through to pre-stack seismic inversion. This leads to a much more informed understanding of how quantitative interpretation can contribute to well planning or geomodeling projects for a given field and dataset. The threshold for working with quantitative analysis as part of interpretation workflows both in development projects and producing fields has been considerably lowered through the project."

Multidimensional Interpretation

Equinor users soon recognized that the new technology offers even greater benefits when applied to seismic reservoir monitoring, prompting the team to look again at the scope of the research. According to Sissel Grude Haug, R&D project manager for this project, which is still ongoing, small enhancements can make a big impact. "We see that minor improvements to the software can play an important role in analysis of time-lapse seismic data, both pre- and post-stack. By funding the development of these improvements, we ensure that our production geophysicists have the best tools at hand to properly understand and get the most out of their data."

Time-lapse 4D projects consist of a baseline survey and one or more monitoring surveys, generating multiple vintages of data that must be painstakingly acquired and processed to maximize repeatability, resulting in a veritable explosion in total data volumes. Full-angle and multiple partial angle stacks are produced for each vintage, and difference volumes are generated between each time-step and all previous vintages. Three monitoring surveys can create as many as 50 individual and difference volumes, which must be analyzed to yield a comprehensive picture of production-induced changes. Attributes and inversion results add further to the number of derived volumes.

Equinor researchers and 4D specialists now organize these time-lapse volumes into a 'pseudo' pre-stack data structure to create logical collections of volumes for each vintage. By exploiting the 5D data structure developed for multi-azimuth seismic, partial angle stacks for all seismic vintages can be grouped in a single, multidimensional volume. This greatly simplifies the organization of the seismic database and opens the door to more digital automation. Routine tasks, such as computing maps showing all 4D differences on a specific reservoir horizon, can now be automated with just a few mouse clicks, and quickly compared to production data.

This multidimensional seismic framework also leverages all of the existing pre-stack tools to automate the processing, analysis and interpretation of multiple vintages of 4D data. Automation has also facilitated strategies to boost 4D signal by more aggressively attacking random and coherent noise on each vintage, using exactly the same processing parameters on each survey. This 'parallel stream' reprocessing has proven to boost signal in unswept or partially swept areas of fields.

Today, Equinor is using the new toolkit to quantitatively prize out dynamic changes such as pressure and saturation variations in the reservoir. One technique is 4D Extended Elastic Impedance (4D EEI), which mines and condenses the pre-stack data into weighted stacks that show varying contributions from pore pressure and hydrocarbon saturation effects.

As part of the Snorre field project, 4D EEI was used to optimally separate mixed pressure-saturation (gas and water injection) effects from pure pressure changes in the time-lapse data. This provided valuable understanding on how the Water-alternating-Gas (WAG) injectors are behaving and whether nearby wells are receiving enough pressure support. Improved understanding of dynamic changes allows engineers to optimize placement of producer wells in unswept areas and to optimizing injection rates and fluids of current injectors. According to Ming Yi Wong, a senior reservoir geophysicist at Equinor, "this saves me a lot of time and speeds up the 4D interpretation process, giving me more time to tackle essential technical issues."

To the Cloud – and Beyond!

Bringing the software into the public cloud was the logical next step for realizing the platform's important role in the digital transformation. Pre-Stack Pro has been successfully deployed in two large public computing clouds (Amazon and Microsoft Azure), so clients can carry out pre-stack analysis on some of the largest multiclient 3D datasets in the world without investing in their own HPC hardware.

Looking to the future of the sector, a new multidimensional seismic data structure is also likely to be adopted as a new standard by the Open Subsurface Data Universe, a major industry initiative to develop a standard data platform. High-dimensional seismic data is also expected to play an increasingly important role in seismic artificial intelligence.

Without early stage research and development support, small startups like Sharp Reflections have no hope of undertaking 'moonshot' projects. Crowdfunding and R&D tax incentives can play a vital role in allowing researchers to launch a project, transition from interesting idea to commercial product, and execute fast pivots to discover new applications of the core technology. ■

Alfredo Guzmán: Making a Case for Mexico

HEATHER SAUCIER

Alfredo Guzmán is an untiring advocate for Mexico's oil and gas industry and its people. He tells GEO ExPro about his years exploring new geographic and technical frontiers in the country and his hopes for the future.

About 100 years ago, Mexico practically dominated the industry as the world's second largest oil producer, trailing only the United States, and as the world leader in oil exports. Its well-known Northern Golden Lane fields in the Tampico-Misantla Basin were pumping up to 300,000 barrels of oil a day. That era created a strong sense of pride for the country and has motivated some of Mexico's modern-day geologists to push for a renaissance.

Believing that Mexico has much more potential than recognized, Alfredo Guzmán, a former Vice President of Exploration at Pemex and charter Commissioner of Mexico's National Hydrocarbons Commission, is encouraging a renewal of exploration. Having worked in all eleven hydrocarbon-bearing basins of Mexico and been responsible for great surges in production, Guzmán knows the country is steeped in unrecovered resources that could bolster the struggling Mexican economy.

"Mexico is poorly explored and exploited because since 1938 the government has maintained a monopoly on the search and production of hydrocarbons. It is impossible to benefit from its huge endowment with only one oil company," Guzmán said. "Even if Mexico had an ecosystem of thousands of operating and service companies, that would still only make a dent in all that richness."

Guzmán, 72, also knows that the window for capitalizing on hydrocarbons is shrinking, as the world searches for reliable sources of sustainable energy. As a result, he has been championing efforts for Mexico to lift its current ban on hydraulic fracturing and unsuspend auctions for private investors and international operators.

The time for Mexico is now.

Alfredo Guzmán

Budding Geologist

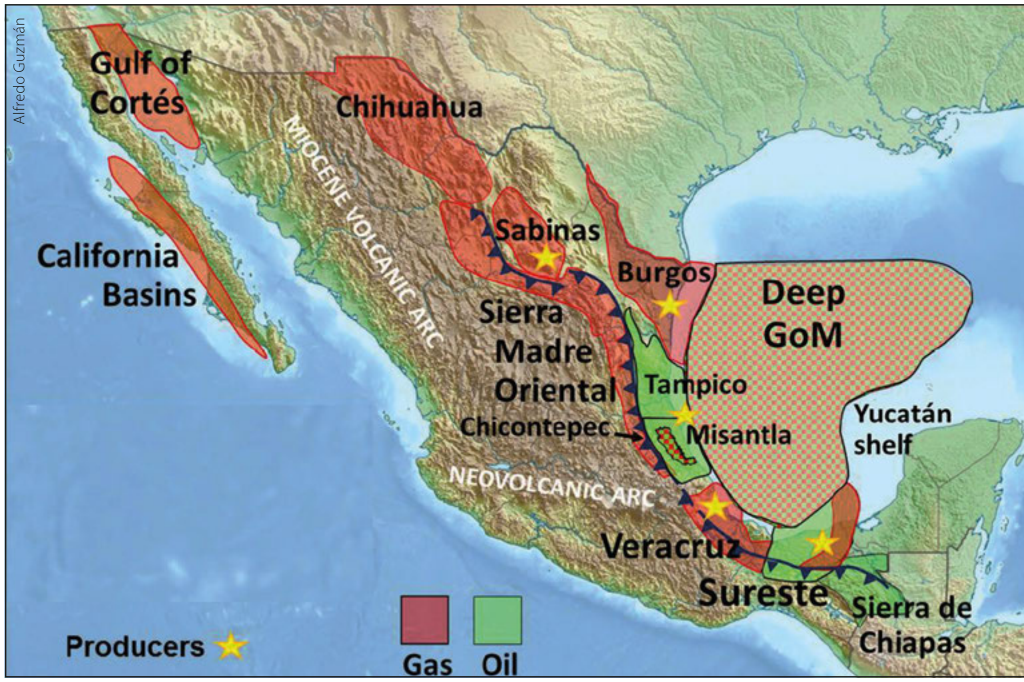
Although his father, the late Eduardo J. Guzmán, worked as a geologist for Pemex for 34 years, the young Alfredo initially opted to study chemistry at Texas Tech University, until a geology professor took him to Palo Duro Canyon State Park near Amarillo, Texas. Guzmán became mesmerized with the stories that rocks could tell about the earth and found himself following in his father's footsteps.

After earning bachelor's and master's degrees in geology, concentrating on carbonates, he declined offers to work at independent oil companies, enticed by the great potential of Mexico. As a young geologist with big dreams, Guzmán was especially attracted to the large carbonate fields discovered in the Tampico-Misantla Basin of North Central Mexico. He began his career at Pemex in 1974 as a field geologist. Just four years later those same carbonate fields gave rise to the Sureste Basin's Cantarell field, which became the world's largest offshore oil field in 2004, when it reached its peak production of 2.2 MMbopd.

Guzmán participated in the discovery of substantial gas fields in the Vizcaíno Desert and in the Gulf of

Cortés, but they could not compete with the oil-rich Sureste Basin and were not developed. "I was not frustrated about these discoveries not being economical to develop," Guzmán notes. "I was young and having fun."

In the early 1980s, he worked in the Chihuahua Basin in search of potential similar to the Permian Basin across the border in the US, but the difference between the geological conditions across the Rio Grande ended any hope of finding sweet spots there. He then focused on the Sierra Madre Oriental fold-and-thrust belt west of the Tampico-Misantla Basin, known for its oil potential, but a lack of high-resolution seismic data and the national pursuit of less complex basins prevented its exploration.



Petroleum basins of Mexico.

Over the next decade, Guzmán continued to explore the Tampico-Misantla, where substantial oil accumulations had been found in carbonates, and the Chicontepec Sub-basin, known for its tight oil. However, "exploration became a challenge, as most human resources, rigs and investments were transferred to the recently discovered fields in the Sureste Basin," Guzmán explains. "Pemex, being the only oil company in Mexico, abandoned for all practical purposes the exploration and development of the Tampico-Misantla Basin." The move made sense for a company, but not for a country.

A Wave of Success

In the early 1990s Guzmán was asked to move to northern Mexico to lead the rejuvenation of non-associated gas production in the Burgos and Sabinas Basins, which were experiencing significant declines. Having read about the success of multidisciplinary approaches in South Texas, he put together five such teams for the job and, harnessing the talent of this broad range of experts, Guzmán and the teams evaluated undeveloped discoveries and proposed leads, prospects and drilling locations based on 3D seismic data. Applying advanced technology, such as PDC bits, well completions with larger fractures, and the commingling of multiple sands, daily gas production increased from 180 MMcfg to more than 1.6 Bcfg.

In 1995, Guzmán became Exploration Manager of Pemex's North Region and oversaw the exploration of northern Mexico, including the deep waters in the Gulf of Mexico. Four years later, he became Vice President of Exploration and, with the help of Brett Edwards, an Australian international consultant, he implemented a process for the evaluation of exploration opportunities. Under Guzmán's guidance, the country's registry grew from roughly 50 drillable locations to more than 2,100 leads, prospects and identified drilling locations.

Guzmán was made Vice President of the North Region in 2001 by Pemex E&P CEO Luis Ramírez Corzo, becoming the first geologist in Mexico to hold such a position. His expertise was needed once more, as that region was responsible for all of the country's dry gas resources. He oversaw operations in the Veracruz Basin and applied 3D seismic technology across all producing areas, resulting in more than a dozen new discoveries. After researching the prolific gas wells in Trinidad and Tobago, he began implementing horizontal drilling completions with slotted casing, and within three years daily production jumped from 130 MMcfg to nearly 1 Bcfg.

"Alfredo has carefully studied the resource development in the US and other places in the world and realized how these lessons could be applied to Mexico's extraordinary opportunities," said Paul Weimer, professor at the University of Colorado in Boulder and Director of the Energy and Minerals Applied Research Center, who worked with Guzmán on a research project between Pemex and the university. "He is a fantastic geologist and a global ambassador of our profession and industry."

The Case for New Technology

DeGolyer and MacNaughton had certified in the 1960s that the Chicontepec Sub-basin contained 137 Bb oil and 60 Tcfg – yet the area of about 5,000 km^2 was producing only 3,000 bopd. "Although our marching orders were to explore for gas, this was too challenging to let it rest," Guzmán said. "This basin has reservoirs strikingly similar to the Spraberry Formation of the Permian Basin."

During a well recovery platform installation at the Carpa oil field, offshore Golden Lane, in 2005.

With a sliver of a budget, Guzmán and his team began testing reservoirs in 2002, raising output to 30,000 bopd and making the case for drilling 16,000 new wells. Yet additional investments were desperately needed, as Mexico's powerhouse, the Cantarell field, began declining in 2005, and Pemex had not really funded exploration since the mid-1980s. In 2006, it authorized the development of the Chicontepec and the Ku-Maloob-Zaap fields, but hit a snag when oil prices tumbled in 2013, rendering the Chicontepec project uneconomical.

When Mexico historically opened its borders to outside operators that same year, an air of hope penetrated the industry and the country, and Mexico waited for the price of oil to slowly rise. Developing new discoveries could be the gateway to renewed prosperity. Yet, as oil labored through a long comeback and reached levels high enough to make shale plays economical, Mexico became less welcoming to third parties and in 2018 announced a moratorium on hydraulic fracturing – dashing hopes for a new era.

"These are regretful decisions," Guzmán says. "Hydraulic fracturing is capital intensive. Due to Pemex's limited resources, independent parties could help the industry thrive."

More than 90% of the substantial resources in the Tampico-Misantla Basin are in tight rocks, which require horizontal wells with hydraulic fracturing for recovery. "The basin has the same amount of oil and similar reservoirs as the Permian Basin, which produces 4.8 MMbopd, a third of the US production," he adds.

Guzmán shared Mexico's plight at the American Association of Petroleum Geologists (AAPG) Global Super Basins seminar in 2019. AAPG Past President Charles Sternbach recalled that "Alfredo gave a brilliant assessment of Mexico's undercapitalization. He has been tireless in his work to help Mexico achieve its potential."

Guzmán has been lobbying for Mexico to encourage third parties to help bridge the technology gap and also adopt best practices in horizontal drilling and hydraulic fracturing, working to counter local environmentalists' radical rhetoric about risk, pollution and seismicity.

Waiting for Change

After 32 years with Pemex, Guzmán retired in 2007, affording him more time to dedicate to the AAPG, having served as President of the Latin American and the Caribbean Region, as Regions Vice President, a two-time candidate for AAPG President and recipient of the Michel T. Halbouty Outstanding Leadership Award. He also served

With wife Kitty at the Tajin Pyramid located a few miles from Poza Rica, where they moved to in 1993.

as President of the Mexican Association of Petroleum Geologists.

Just two years after retiring, Guzmán was asked to become a charter Commissioner for Mexico's National Hydrocarbons Commission (CNH). He strived to make known how Mexico's hydrocarbon endowment could benefit its people if resources could be monetized. And, he has been promoting the development of tight oil resources in the Tampico-Misantla Basin that could easily make up for the steady declines of the country's legacy fields.

However, his tenure at the CNH was short because of a health condition of his wife, Kitty. During his career, Guzmán had moved his wife and three daughters 18 times and to nine different states, and it was time to settle down.

Yet he continues to advocate for Mexico's oil and gas industry and its people.

"The age of oil will be over in 20 or 30 years. Countries such as Brazil, Guyana and Argentina that are ramping up their production will make a killing once the price of oil recovers," Guzmán says. "Mexico could easily produce an additional couple of million barrels a day in northern Veracruz if private companies and hydraulic fracturing were allowed. The income could solve in the short run all of the country's need for oil and benefit a lot of people in Mexico." ■

Playuela gas well blow-out, Veracruz Basin, 2004.

Alfredo Guzmán

From Arrhenius to CO_2 Storage

Part IX: How CO_2 Emits IR Photons

LASSE AMUNDSEN* and
MARTIN LANDRØ, Bivrost Geo/NTNU

"Thanks for the lonely night, for the hills, the rush of the darkness and the sea through my heart! This silence murmuring in my ears is the blood of all Nature seething; … the northern lights flare over the heavens to the north. By my immortal soul, I am full of thanks that it is I who am sitting here!"

From 'Pan' by Knut Hamsun (1859–1952), Norwegian winner of the Nobel Prize for Literature in 1920.

Skydive with us into the quantum world, where we provide to those unafraid of molecular energy transfer an answer to the question: what happens to Earth's radiated infrared (IR) photons *after* they are absorbed by IR active CO_2 molecules in the lower atmosphere? Part VIII (*GEO ExPro* Vol. 17, No. 3) showed how CO_2 molecules absorb Earth's IR radiation. Here, we show that the bulk background gases N_2 and O_2 are critical for the greenhouse effect because collisions of CO_2 (and other greenhouse gases) with N_2 or O_2 both take away and add energy to the CO_2 molecules. Every collision that adds energy gives the CO_2 molecule a chance to undergo radiative decay and emit a photon.

Two granite sculptures in the work 'Thoughts for Two', created by the Sami artist Annelise Josefsen. A boy and a girl, sitting under the Northern Lights in remote Tranøy Hamarøy, in northern Norway, where Knut Hamsun spent much of his childhood. The quote above is carved into the smooth rock slopes below them.

Ketil Kåsli

Crash Course in Molecular Energy Transfer

First, a brief review of the various mechanisms, definitions, and terms useful in understanding molecular energy transfer. Consider the bimolecular collision in which reactants A in quantum state i and B in quantum state j react to form products A in quantum state l and B in quantum state m,

$$A(i) + B(j) + \Delta E \underset{k_r}{\overset{k_f}{\rightleftarrows}} A(l) + B(m) \qquad (1)$$

Here ΔE is the exchanged energy during the collision process; quantum state 0 corresponds to the ground state. The forward process is described by the right arrow. An increase in the concentration [A(i)] or [B(j)] results in an increase in the rate of reaction. The concentration unit is measured in molecules per cubic centimeters per second. It stands to reason that the reaction rate is proportional to the increase in concentration, so rate = k_f[A(i)][B(j)]. The rate constant k_f is the proportionality constant relating the rate of the reaction to the concentrations of reactants.

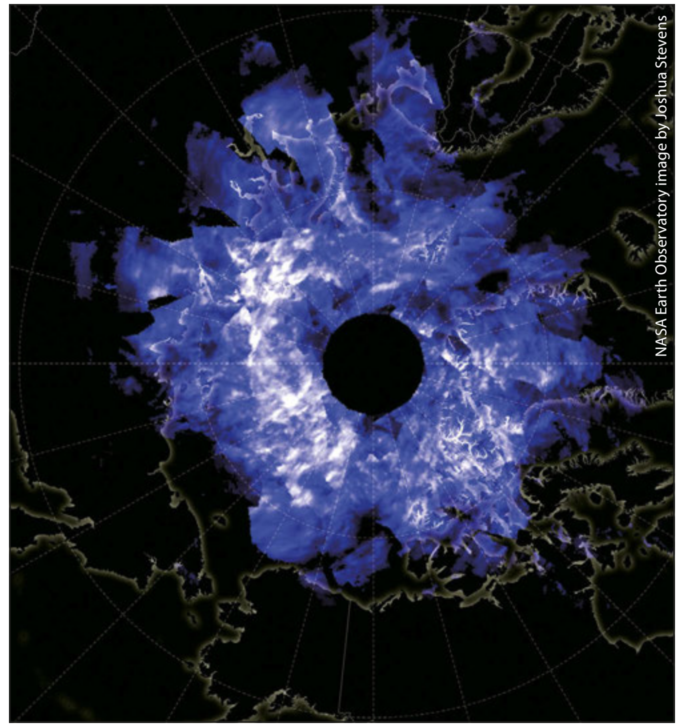
A large k_f means that the reaction is relatively fast, while a small value means that it is relatively slow. Raising the temperature of the reaction usually results in a higher rate of reaction; the particles move faster and faster, resulting in a greater frequency of collisions, so k_f is temperature dependent. The reaction in equation 1 can be shown to have exponential temporal behavior with a 'time constant' $\tau = 1/k[M]$), where M equals A or B and τ is referred to as the relaxation time for the process.

Corresponding to the forward process is the reverse process (left arrow) with rate constant k_r. When the rates of the forward and reverse reactions have become equal, the reaction has achieved a state of balance or equilibrium, k_f[A(i)][B(j)] = k_r[A(1)][B(m)], yielding the ratio (Denisov et al. 2003):

$$\frac{k_f}{k_r} = K = \frac{[A(l)]\ [B(m)]}{[A(i)]\ [B(j)]} = \frac{g(l)g(m)}{g(i)g(j)} \exp(-\Delta E/k_B T) \qquad (2)$$

where K is the equilibrium constant, g denotes the degeneracy of the molecular quantum state, and $k_B T$ is the product of the Boltzmann constant and the temperature. The term 'equilibrium' indicates that the different forms of energy (rotational and vibrational) are characterized by one temperature T (energy equilibrium).

There are two kinds of vibrational energy exchange processes during bimolecular collisions: vibration-translation (V-T) and vibration-vibration (V-V). Let us consider a vibrationally excited molecule, A*, where the asterisk denotes one quantum of vibrational excitation. A* collides with a species M, and the vibrational energy is transferred into translational motion. This process may be expressed by the transfer equation:



Satellite view of noctilucent or 'night shining' clouds centered on the North Pole on June 12, 2019. The clouds float 80–85 km high in the atmosphere so that they are still lit by sunlight even after the Sun has dropped below the horizon for people on the ground. As Earth's lower atmosphere warms with spring and summer, the upper atmosphere grows cooler. In the process, ice crystals collect on meteor dust and other particles, creating electric blue wisps on the edge of space.

$$A^* + M \underset{k_f^{VT}}{\overset{k_r^{VT}}{\rightleftarrows}} A + B + \Delta E \qquad (3)$$

where A represents the molecule in its ground state. Equation 3 is the special case of equation 1 when l=1, i=j=m=0, and B=M. In contrast to equation 1, here the left to right process is associated with the reverse rate constant, where the excited reactant A* undergoes vibrational deactivation. The V-T process results in energy transferring from molecular vibrational modes to molecular translation. One molecule loses one quantum while the vibrational state of the other molecule is unaltered. The process associated with the forward rate constant is that where the reactant A acquires enough energy to react by colliding with another molecule M. This process is called vibrational up-pumping.

How CO_2 Relaxes in the Lower Atmosphere

Part VIII told us that the terrestrial radiation follows a blackbody distribution of characteristic temperature of 288K, with 98% of radiative power emitted in the 5–80 μm range. There is only one CO_2 absorption band of importance in this range, at around 15 μm (667 cm^{-1}). This band almost coincides with the spectral maximum of terrestrial radiation and therefore to a large extent determines the interaction of CO_2 molecules with the radiation. CO_2 is responsible for a large gap in the transmissivity of Earth's IR radiation towards space, centered around 15 μm.

The process whereby a CO_2 molecule absorbs an infrared photon of energy 667 cm^{-1} and goes to the vibrationally excited state CO_2*(010) reads:

$$CO_2(000) + 667cm^{-1} \rightarrow CO_2^*(010) \qquad (4)$$

The photon transfers its energy to the IR active CO_2 molecule and is removed from the radiation field, while the photon energy raises the CO_2 molecule to a higher vibrational state. But since excited states are energetically unfavorable the molecule wants to return to the ground state by giving up energy. How? We provide the answer by following the respected physics tradition of 'back-of-the-envelope' calculations.

Finding the Winner

Vibrational energy can be transferred either radiatively by spontaneous or stimulated emission or non-radiatively by collision. Which process is the winner? To find out, one must compare the radiative lifetime of the excited level with the relaxation time of collisions. If the relaxation time is short compared with the average radiative lifetime of the excited level, then the collision process wins.

Radiative lifetime: The photon's energy causes the CO_2 molecule to elevate. The molecule releases this extra energy by emitting the photon, which is identical to the absorbed one, but emits in an arbitrary direction since it, like the drunken sailor, has no memory of its previous steps. Once the emitted photon has left, the molecule returns into its ground state. The radiative lifetime of the (010) molecular vibration is about 1.1s (Cheo, 1971). It is an eternity on a gas kinetic time scale.

Relaxation time by collisions: The collisional relaxation process occurs when the relaxation time can compete with the radiative lifetime of the excited energy levels. Even though the activated CO_2 molecule, at a CO_2 concentration of 400 ppm, is one among around 2,500 other molecules, it is moving very fast and it does not have to move far before it bumps into other molecules – usually N_2 or O_2 – and drops back into its ground state. The freed energy then adds speed to another molecule's motion. When many collisions take place simultaneously, the faster speed of the molecules being bumped into raises the temperature of the gases in the atmosphere, since temperature is proportional to the average kinetic energy of the gas. Since the photon is permanently lost from the radiation field, this is absorption of photons.

How fast does this happen? The collision process for CO_2 deactivation in the temperature range 300–140K against a number of gases has been studied by Siddles et al. (1994). Let M denote either the N_2 or O_2 molecule. The process of vibrational de-excitation from the 667 cm^{-1} level through collision with molecule M can be described by (see equation 3)

Illustration showing an astronaut on Mars, as viewed through the window of a spacecraft. The Martian atmosphere is 96% CO_2 but it is extremely thin (1% of Earth's atmosphere), very dry and located further away from the Sun. This combination makes Mars an incredibly cold place.

$$CO_2^*(010) + M \underset{k_f(v_B)}{\overset{k_r(v_B)}{\rightleftarrows}} CO_2(000) + M + 667cm^{-1} \qquad (5)$$

where $k_r(v_B)$ is the V-T rate constant for relaxation of CO_2(010) by M, where the vibrational energy ΔE resident in the CO_2 bending-mode is transferred to M as translational kinetic energy, which is reflected on the macroscopic scale as a temperature increase.

The speed of the process depends on the temperature where the process runs. We select the altitude 3,550m where temperature is 265K (-8°C). The number of molecules per cm^3 in dry air at this height is [M]=1.79 × 10^{19}, with 78% N_2 and 21% O_2. For N_2 and O_2 Siddles et al. (1994) give constants $k_r^{(N_2)} = 2.4 \cdot 10^{-15}$ and $k_r^{(O_2)} = 3.6 \cdot 10^{-15}$ cm^3(molecule s)$^{-1}$. The lifetime of collisional de-excitation for CO_2 (010) in the atmospheric gas bath can be deduced as

$$\tau = 1/(0.78\, k_r^{(N_2)} + 0.21\, k_r^{(O_2)})[M] \approx 21\ \mu s$$

The typical collision time through which a CO_2 (010) molecule can transfer its energy to another gas molecule is about 20 μs in the lower atmosphere at altitude 3.5 km. Collisions take place more often than re-radiation. Therefore, when a CO_2 molecule in air absorbs a photon, it is much more likely – on the order of 1s/20μs=0.5 × 10^5 times – to heat the surrounding air molecules with the energy it acquired from the absorbed photon than to re-radiate the photon. Statistically, the same CO_2 molecule re-emits the photon energy two out of 100,000 times; but 99,998 times out of 100,000 the excited CO_2 molecule is de-excited by collision. ▶

In physics, thermalization is the process of physical bodies (e.g., molecules) reaching thermal equilibrium through mutual interaction (e.g., collisions). In general, the natural tendency of a system, like the atmosphere, is towards a state of equipartition of energy and uniform temperature. Since the collisional step is fast (about 20 μs at 3.5 km), the photon energy involved at 667 cm^{-1} is rapidly spread out among the surrounding air molecules – or thermalized into the 'heat bath' of the atmospheric gas. CO_2 is then rapidly in thermal equilibrium with the rest of the gas molecules.

The Life Events of CO_2 Molecules

The atmospheric bath receives an inflow of energy from Earth's IR radiation where CO_2 absorbs photons in the 667 cm^{-1}-centered band but seemingly only negligibly emits photons. The gas bath increases its temperature, but a gas cannot easily increase its emissivity (Robitaille, 2014). As Earth continuously sends IR energy upwards, CO_2 photon absorption would make the air get really hot … unless there is a process that is able to pass the received energy on. The gas needs to cool, and the question is how? This process must involve the creation of additional photons that can become the energy carriers for radiation.

Of course, in steady state, under the assumption of local thermodynamic equilibrium, the reverse process to that we have considered is also ongoing, at equal rate, all the time (see equation 5). Therefore, collisions of ground-state CO_2 molecules with air molecules may excite the former and cause them to radiate. The rate constant $k_f(\nu_B)$ for vibrational up-pumping at gas temperature 265K, where $k_B T$ = 184.2 cm^{-1}, can be found from $k_f(\nu_B)$ by using equation 2:

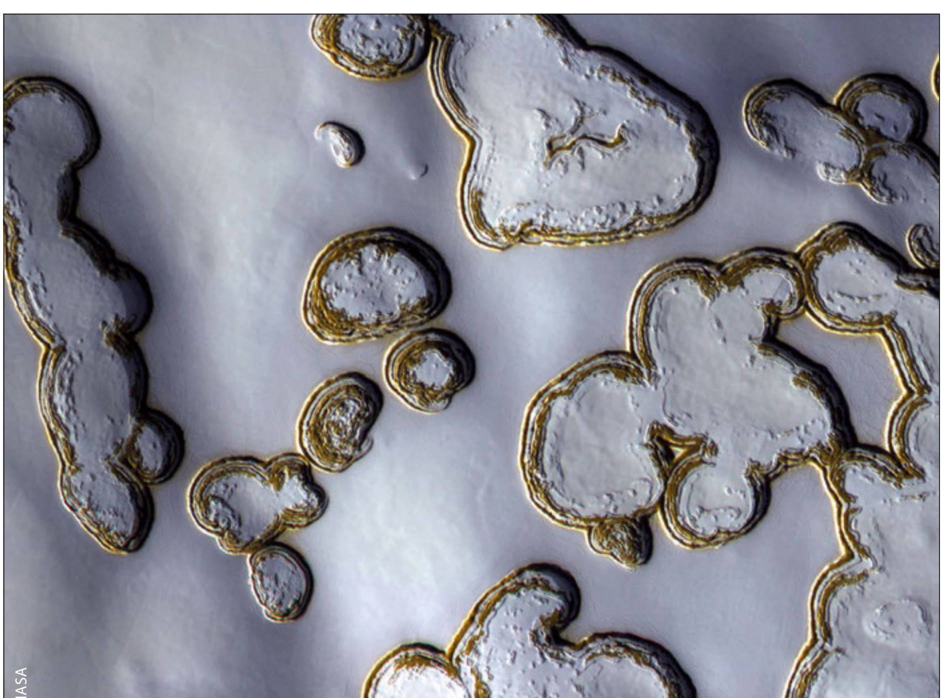
$$k_f/k_r = 2\ \exp(-667/184.2) = 0.0535$$

The number 2 in this equation arises because of CO_2 (010) being doubly degenerate; the two bending mode vibrations in CO_2 have equal energy. Repeating the calculations as above with a new rate constant, the relaxation time for the reaction is found to be around 20 μs/0.0535 or about 400 μs.

Recall that the radiative lifetime of CO_2 de-excitation is around 1.1s. Since the collisional processes are much faster, a CO_2*(010) molecule can de-excite in 20 μs and excite back to the (010) state in 400 μs. It is quite a pace! One trip back and forth takes 420 μs so that during 1.1s the number of possible trips is 1.1s/420 μs = 2,620. When 100,000 CO_2*(010) molecules are available for de-excitation, it is likely that two of these will be reserved for radiation of a photon; the remaining 99,998 are back after 420 μs to offer 2/100,000 of these to radiate a photon while the rest de-excites through collisions. During a time interval of 1.1s, a back-of-the-envelope calculation indicates that a little less than 2,620 x 2 = 5,240 CO_2*(010) are likely to participate in the photon radiation process. This is around 5% of the CO_2*(010) molecules. We may thus conclude that around 5% of the CO_2 molecules which absorb IR radiation from Earth's surface tend to radiate IR photons (at altitude 3.5 km). The rest are busily colliding with N_2 and O_2 molecules.

The process of photon absorption and emission can be defined as follows: The photons in the band around 667 cm^{-1} from Earth's surface are absorbed by CO_2 molecules. Only a very small percentage re-radiate photons in a random direction and the rest lose that energy to the surrounding bath of atmospheric molecules. In turn, the atmospheric molecules collide with CO_2 molecules so that they get excited to the (010) state. A very small percentage radiates new photons, again in a random direction, and the rest lose the energy by collision. It is a stressful life! The process repeats forth and back rapidly, so that in the timeframe of about a second, around 5% of the CO_2 molecules radiate. Close to the surface the percentage is slightly higher since the temperature is elevated, while higher in the troposphere it is slightly less since the temperature is lower.

On Mars it gets cold enough to freeze carbon dioxide out of the atmosphere during the winter. This slab of ice is a few meters thick and is penetrated by the flat-floored pits shown here. The quasi-circular pits in the center of the scene are about 60m across. The distinct color of the pit walls may be due to dust mixed into the ice.



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**Lasse Amundsen is a full-time employee of Equinor.*

References available online. ■


SHEARWATER
Monsoon
Bring the power of cloud to seismic.
shearwatergeo.com/monsoon

Pitfall Petrofacies

Using reservoir description and regional geology to recognize problematic non-reservoir facies in Equatorial and South Atlantic Margin Basins.

ANNE MCAFEE, SIMON GREENFIELD and JOSEPH WHITING; Core Laboratories UK

Despite the advances in seismic and log lithology interpretation techniques in recent decades, some wells still show major variations between predicted and actual lithologies; in some cases, absence of the prognosed reservoir facies has been the primary factor in well failure. Core Lab's rock-based approach to regional geological evaluation, which involves revisiting the exploration legacy of core and cuttings material stored in national archives, provides some interesting insights into the persistently problematic rock types – or 'pitfall petrofacies' – that have proven difficult, or indeed impossible, to characterize using lithology prediction methods, resulting in the recurring misinterpretation of sandstone and carbonate reservoir targets. In some cases the visual description of drill cuttings and sidewall core samples at the wellsite also fails to recognize the presence of these atypical lithologies.

Thus it appears that some non-reservoir facies can only be fully characterized through detailed integration of petrographic data, taken from sidewall cores and/or drill cuttings, with downhole logs. The reduced acquisition of conventional and sidewall core material in recent years has further exacerbated this issue, as turbo-drilled wells lacking good quality rock material are less likely to provide the detailed lithological information required to flag the raised reservoir risk associated with these complex lithologies prior to follow-on drilling.

Comparison of predicted lithologies and/or composite log data with rock-based petrographic information in multiple sedimentary basins across the Equatorial and South Atlantic margins reveals that the main categories of non-reservoir petrofacies that can be difficult to discriminate from reservoir rocks comprise low gamma siliceous mudstones and altered igneous or hydrothermally-influenced rock types. On a regional scale the lateral and vertical distribution of these petrofacies can be related to variations in intrabasinal topography, oceanic circulation patterns and/or degree of volcanic influence during successive phases of basin evolution.

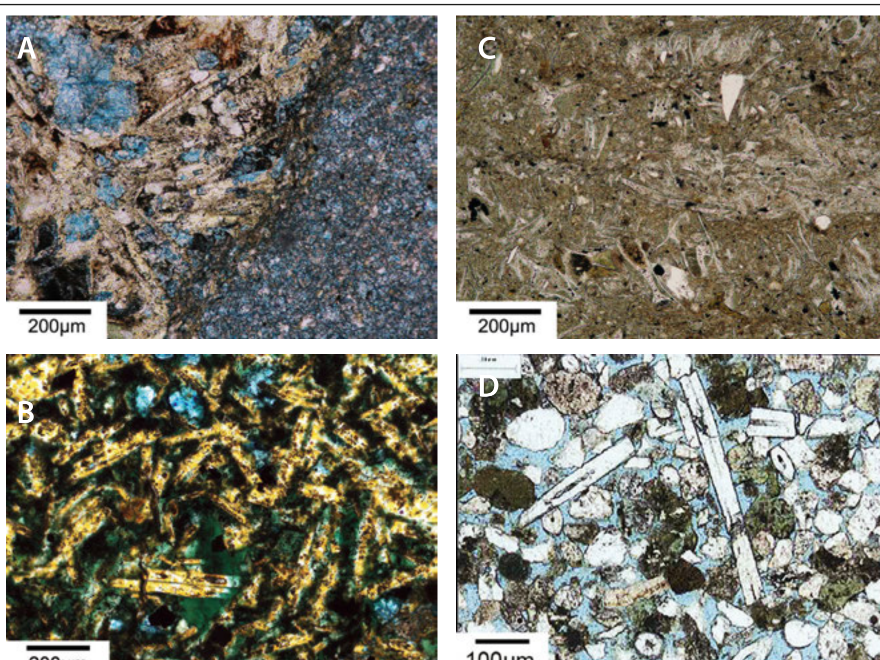
We discuss some examples of these in more detail below.

Volcanics vs Reservoir Facies

A variety of complex lithologies can develop in basins with igneous influence, particularly when the original intrusive and/or extrusive rocks are partly altered and replaced by authigenic clays, carbonates, zeolites and/or siliceous minerals, or when the host sediments, including both sandstone and carbonate reservoir targets, are altered by associated high-temperature fluids. Examples of volcanically-influenced problematic lithologies can be found at multiple stratigraphic levels in basins across the South Atlantic Margin.

Pre-Salt Carbonate Play: Angola and Brazil

Extensive industry and academic evaluation of core and sidewall core samples from wells drilled in pre-Salt carbonate reservoirs, offshore Brazil and Angola, has provided detailed classification of the diverse carbonate



Core Lab

Figure 1: Selected cuttings thin section photomicrographs illustrating problematic lithologies related to volcanic and hydrothermal influence in South Atlantic Margin basins. In the Kwanza Basin (Angola) original volcanics (A) when hydrothermally altered to carbonate (ferroan dolomite) can be difficult to discriminate from targeted pre-salt carbonate reservoir facies on seismic and logs. Some syn-rift volcanics, such as trachyte lavas (B) have a very high gamma ray signature due to presence of abundant K-feldspar, but trachytes have a much lower density than mafic igneous rocks and can therefore be difficult to discriminate on seismic. The Tertiary succession offshore Argentina includes vitric tuffs with highly microporous matrix (up to 30%, but depending on level of recrystallization) – this rock type shows a fairly low gamma ray response and relatively low bulk density (C). Some locations also show an unusual 'hybrid' rock type comprising glauconitic pellets, volcanic grains and sponge spicules with interconnected interparticle pores resulting in fairly high measured porosity and permeability values (D). This silica-rich petrofacies therefore represents a potential reservoir facies.

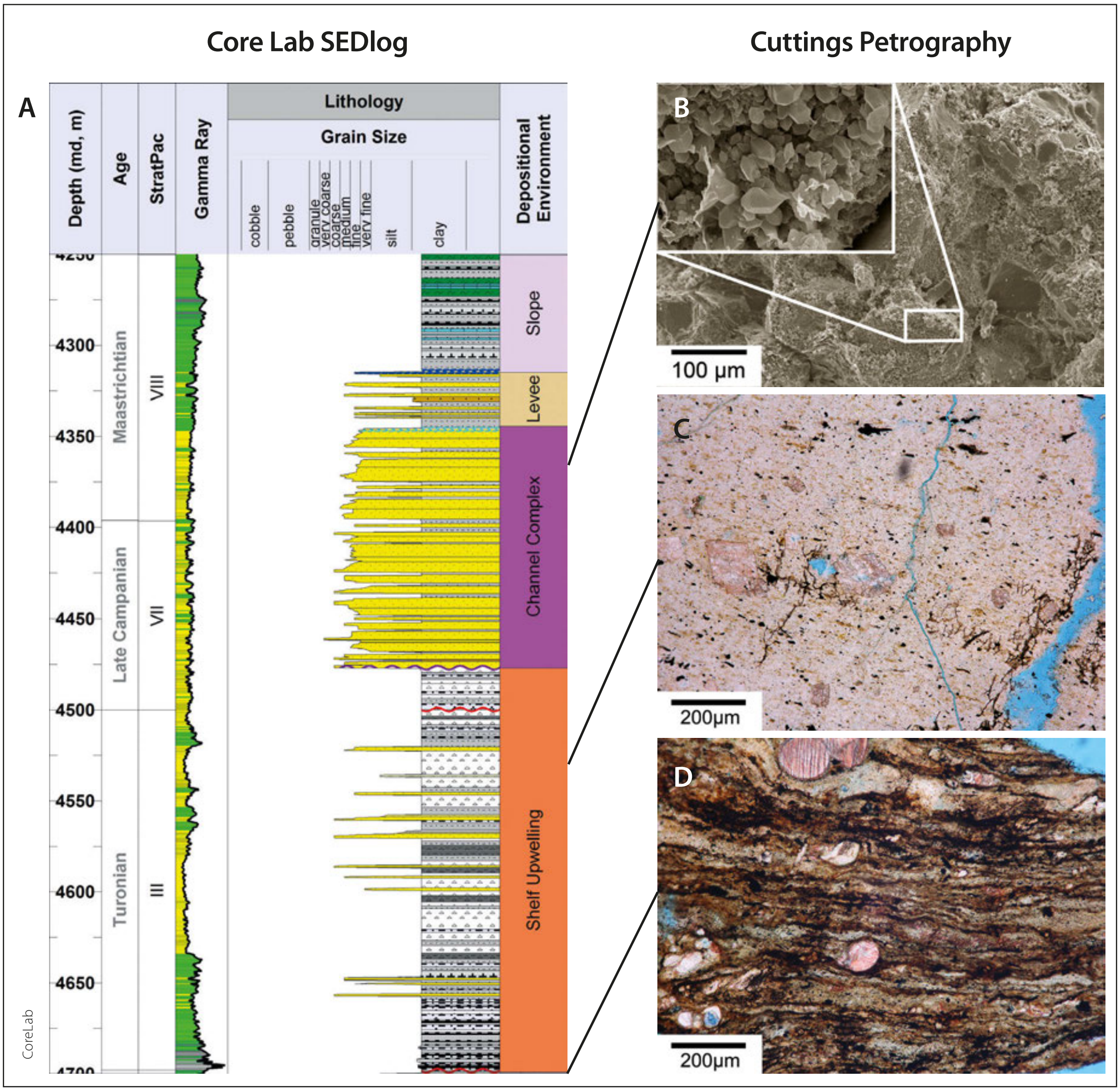


Figure 2: Simplified sedimentary log (A) and photomicrographs (B-D) illustrating silica-rich facies from a well offshore Suriname. The siliceous mudstones (C) show lower gamma ray response than the overlying feldspathic (channel) sandstones. These turbidite sandstones are prone to microquartz cementation as a result of the silica-rich fluids (B, SEM image). Organic-rich beds show suppressed 'hot shale' response due to siliceous mudstone interlayers (D).

facies encountered in these syn-rift and sag phase volcanically-influenced lacustrine basins. However, in areas with limited well or rock data it still remains a challenge to fully discriminate igneous rocks from carbonate facies on seismic, as illustrated by several deepwater wells in the Kwanza Basin which failed to encounter reservoir facies due to unexpected pervasive volcanic influence throughout the late syn-rift and sag succession (see Figure 1). Although seismic techniques are evolving in order to improve pre-drill recognition of the igneous rock types (Bonet et al., 2019), there is still a need for systematic calibration of downhole logs with rock material in order to map the lateral and vertical distribution of volcanic rocks and high temperature mineralization in relation to the underlying structural topography. Facies mapping suggests that deep-seated fault systems facilitated movement of ascending magmatic hydrothermal fluids and/or mantle gases through reservoir zones in this petroleum province.

Tuffs vs Reservoir Targets: Atlantic Argentina

Unlike the basaltic igneous provinces further north, the Argentina Atlantic Margin was influenced mainly by acid and intermediate volcanism. Syn-rift Jurassic volcanic tuffs here can show high porosity values due to the microporous nature of the microcrystalline matrix and, in the absence of core material, can be difficult to distinguish on logs from early post-rift alluvial fan reservoir facies with abundant reworked volcanic clasts. During Late Cretaceous – Tertiary periods of active andesitic magmatism on this margin, high volumes of volcanic glass were deposited in the marine environment, resulting in markedly increased

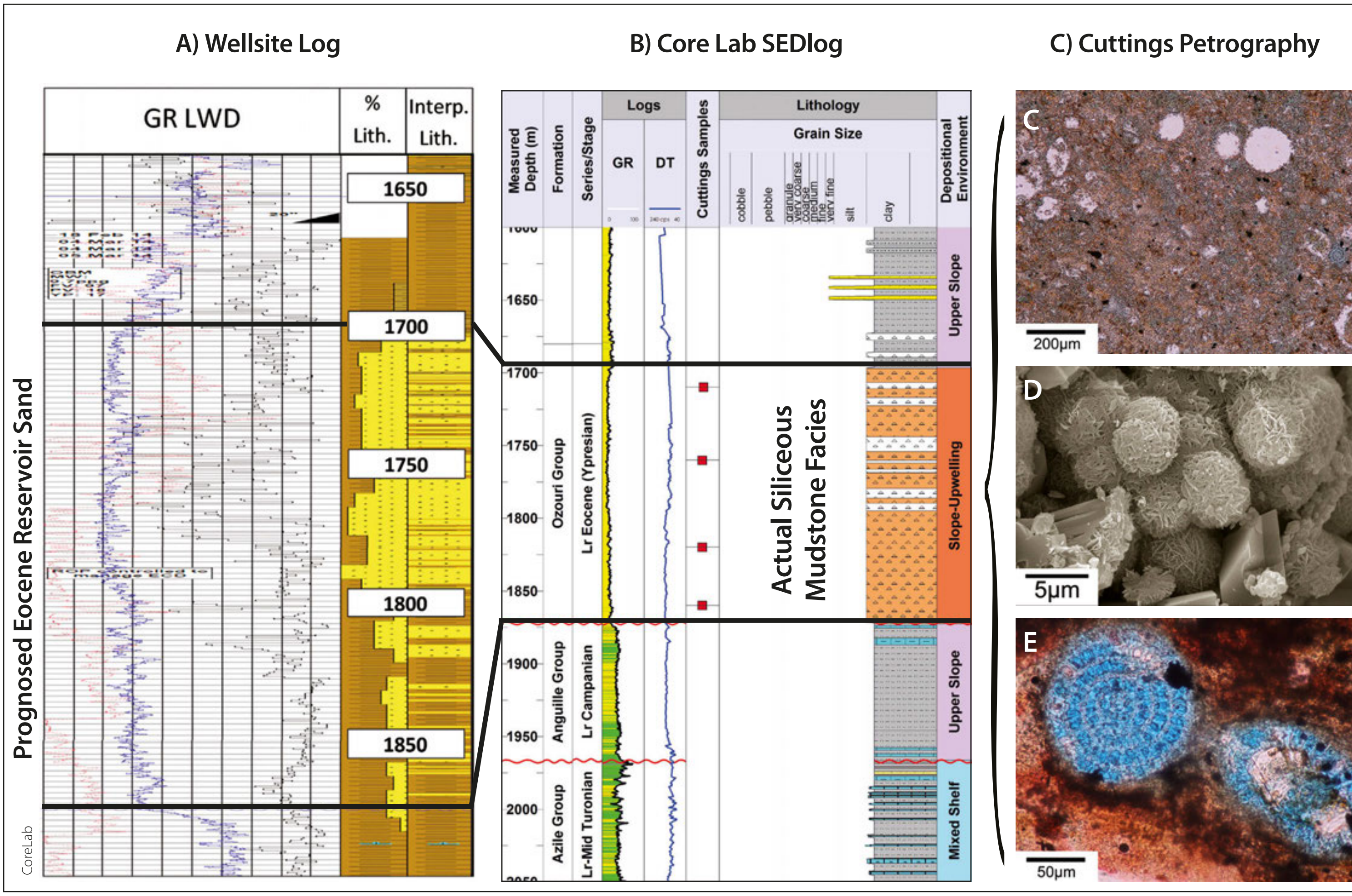


Figure 3: Gabon well illustrating how the Eocene sand-dominant interval on the wellsite lithology log (A: yellow lithology) was proven to comprise non-reservoir chert and porcellanite through petrographic evaluation of cuttings (B: white and orange lithologies on SEDlog). High magnification thin section (C) and SEM (D) images illustrate the highly microporous nature of the opal-CT porcellanites (lepispheric fabric), which locally show preservation of silica-rich microfossils (E: radiolarian tests). The volume of clay present in the matrix influences the rate of conversion of Opal-A to microquartz during burial diagenesis.

biogenic productivity of siliceous micro-organisms. Offshore exploration well data here reveals locally complex interbedding of volcanic rocks with diatomites, radiolarites, cherts and deepwater mudstones (Figure 1) that are difficult to differentiate on log signature, particularly in the absence of petrographic calibration. Although most of the observed siliceous rock types represent microporous non-reservoir facies, some Tertiary samples containing high proportions of leached sponge spicules show high measured permeability values and therefore represent legitimate reservoir targets.

Sandstones vs Siliceous Mudstones: Equatorial Transform

The pitfall potential of siliceous mudstones on the West African Equatorial Atlantic Margin has previously been highlighted by Anadarko Petroleum (Brown et al., 2015) in a review of the Campanian 'quartz claystone conundrum' that documented dramatic discrepancies between wireline log interpretations of "thick, high quality, quartz-rich deepwater sandstones with effective porosity up to 25%" and wellsite rock descriptions and subsequent laboratory tests that revealed non-reservoir, quartz-rich mudstone facies.

Core Lab's well-based mapping across this margin from Benin to Liberia reveals an increased prevalence of these silica-rich mudstones in the periods following regional-scale Albian and Santonian uplift events, suggesting that tectonic enhancement of intrabasinal topography may have played a role in the establishment of upwelling silica-rich currents along the paleo shelf-edge during the Late Cretaceous. Siliceous mudstones are less widely developed on the South American Equatorial Margin but similar nutrient-rich upwelling currents have been described from the Late Cretaceous succession along the flanks of the Demerara Plateau on the Suriname Margin (Elrich et al., 2003). Our well data from this region illustrates how interbedding of siliceous mudstones, thin turbidite sandstones and organic shales creates a complex gamma log response that requires systematic calibration against petrographic data (see Figure 2). The chert and porcellanite (siliceous mudstone) facies show lower gamma response than the overlying turbidite (sub-arkosic) sandstones, while, conversely, in the organic-rich mudstones the expected 'hot shale' response is suppressed by the presence of interlaminated microporous silica.

Sandstones vs Siliceous Mudstones: Post-Salt Gabon

The presence of chert beds in the Early Tertiary post-salt succession on the Gabon Margin (Ozouri Formation) has been well-documented through decades of drilling along the inboard parts of the margin, but more recent drilling has highlighted the pitfalls associated with distinguishing Eocene channel-fill slope sandstones from thick-bedded cherty mudstones in the deepwater domain. As illustrated in Figure 3, some wells show dramatic differences between the final well composite log based on wellsite visual cuttings description (showing stacked blocky sandstones) and our sedimentological log calibrated with petrographic description of cuttings revealing various porcellanite, radiolarite and chert lithologies. Although the high silica supply on this margin can be correlated with the establishment of South Atlantic upwelling bottom current cells during the Tertiary, there is evidence to suggest increased prevalence of these siliceous facies in the vicinity of volcanic features in the deepwater domain. Discriminating sand fairways from the background siliceous shelf and slope mudstones here requires detailed facies mapping using all available adjacent and inboard well data.

Preventing Pitfalls in Petrofacies Prediction

Our observations from multiple studies across the Equatorial and South Atlantic Margins suggest that some pitfalls in facies prediction can be prevented by applying in-depth knowledge gained from petrographic and sedimentological studies of legacy well cuttings and core material. Problematic low gamma siliceous mudstones appear to be more commonly developed in basins with volcanogenic silica input and basins with pronounced intrabasinal topography, particularly on narrow, fault-bounded continental shelf margins, prone to development of upwelling current systems. In these basins, where the primary exploration target involves slope channel sandstones, it is essential to perform detailed paleogeographic mapping, using rock-based sedimentological data from inboard and adjacent wells tied to intrabasinal structure, in order to define the (often narrow) sand fairways across the shelf. In addition to siliceous facies, volcanically-influenced basins can show a wide range of problematic carbonate and clay-rich lithologies, due to diagenetic alteration and/or hydrothermal mineralization of primary igneous rock types. These 'secondary lithologies' can often only be recognized through detailed petrographic analysis and therefore the value of post-drill rock calibration of downhole log lithologies cannot be overstated in terms of reducing reservoir risk for future drilling campaigns. ■

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NVENTURES

The Nile Delta

Dominating the scene in North Africa.

PETER ELLIOTT, NVentures Ltd

For minnow and supermajor alike, the various plays of the Nile Delta continue to attract investment for major exploration campaigns through the downturn. The government of Egypt, along with the parastatal operators Tharwa and EGAS, have managed over time to maintain sufficient interest in the exploration upside via reasonable investment terms and a vibrant operating environment. Since the beginning of 2019 around 15 wells have been drilled onshore and seven offshore, mostly wildcat or near-field exploration, and ten large exploration licenses have been awarded offshore.

Deepwater Campaign Disappoints

In the 2000s Shell (partly with Petronas) carried out a major wildcat campaign on what was then the NEMED block, with at least seven wells coming up dry or with very thin gas pay. Comparing the Nile Delta to other mega-river deltas with very thick sedimentary columns, the supermajors expected a bonanza to be delivered in the deep water, in a similar vein to the Niger and US Gulf of Mexico (GoM). The Oligo-Miocene play does, of course, continue – perhaps as far as southern Israel and into the waters of southern Cyprus – but the charge and seal mechanism too often fails, at least at the scale required for commercial discoveries. The major exception to this was the 2015 Zohr discovery, which proved that source was not the main issue; up to 30 Tcf gas was trapped in a major Miocene carbonate reef build-up.

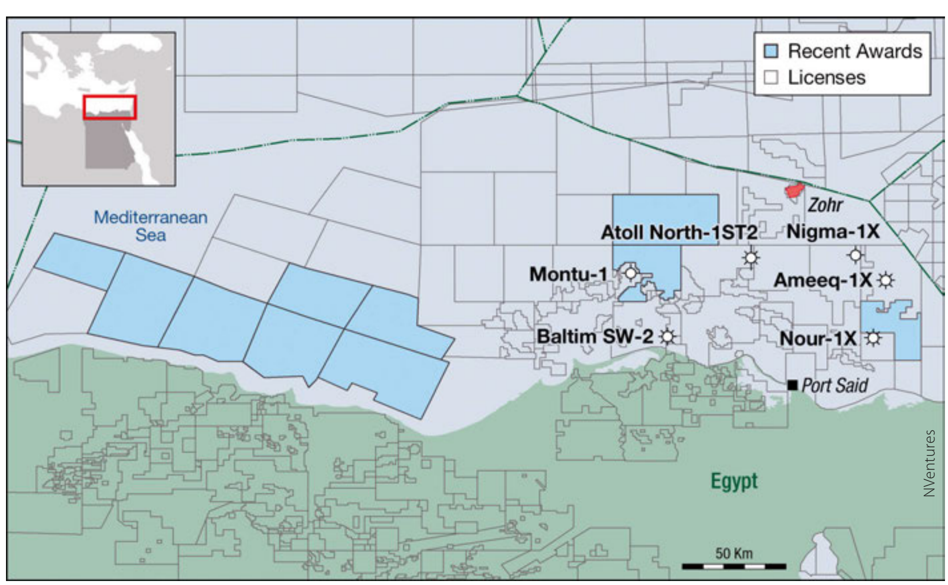
This discovery was enough to galvanize the large companies to remap the area for new leads. Interestingly, the acreage around Zohr – comprising the Shorouk Block (hosting Zohr itself) and the West and South Zohr Blocks – was not immediately drilled up. In fact, the North Port Fouad and Thekah concessions south-east of Zohr were ultimately relinquished. All of these blocks are yet to be evaluated with the drill bit, while carbonate reef build-up style traps have been tested, with mixed results, in Cypriot waters, namely, Glaucus and Delphyne (ExxonMobil), Onesiphorous (Total) and Calypso (Eni). This may be partly due to the high commercial value of the acreage post-Zohr, with new joint ventures taking too much time, but also the lessons from the NEMED campaign meant the non-reef play was still likely to disappoint.

Not to be put off, the supermajors did continue their efforts in 2019 and 2020 further east. At least three wells were drilled in the deepwater blocks, all failing to extend the deepwater distal delta play, perhaps stymied by a lack of major structuration there, although gentle compressional rollovers do exist. Similar size deltas have benefited from a major décollement surface, such as shale in the Niger Delta and salt in the GoM, creating many large structures. Energean's Ameeq well recovered some gas but Nigma (Eni) and Merak (Dana Gas) were dry. Dana Gas' next well, on the North El Arish block, will, however, test a large carbonate build-up: the Thuraya prospect.

Onshore and Shallow Water Win

Since these campaigns, the industry has firmly refocused on the onshore delta and the shallow water acreage in the offshore western Nile Delta. SDX Energy and Dana Gas have carried out successful campaigns onshore in the South Disouq and Balsam concessions respectively. Offshore, the 2019 Licensing Round finally delivered a huge payday for the government, with ten awards to the majors and supermajors. Winners include ExxonMobil, BP, Shell, Chevron/Noble and Apache.

Given the existing large gas developments nearshore at Temsah, Baltim, Nidoco, Rosetta, Burullus and North Alexandria, exploration companies are keen to extend the shallow water topset/proximal Oligo-Miocene delta play to the west. Recent reserves additions by Eni at Baltim SW and Bashrush (see page 74) serve to reinforce this strategy for low risk exploration adjacent to established developments in the shallow and onshore Nile Delta. ■



Offshore Argentina: Tertiary Play Potential in the Malvinas Basin

Whilst the Malvinas Basin is an exciting and widely recognized underexplored oil and gas-prone basin, traditionally the main target for explorers has been the Early Cretaceous transgressive sandstones of the Springhill Formation – a prolific reservoir in the Austral Basin to the east. However, reprocessed de-ghosted data has now revealed numerous Tertiary plays in the Malvinas Basin offering new and highly prospective play systems still to be explored.

In the reprocessed PSTM line below, a previously unimaged thick syn-rift section with postulated lacustrine source rock has been revealed. At this location, the base of the prograding sequence marks the 35 Ma unconformity associated with rifting of the Scotia Plate to the south. With the source rock modeled to be in the hydrocarbon window and migration pathways ascertained, the identified Tertiary plays are believed to be associated with significant prospectivity.

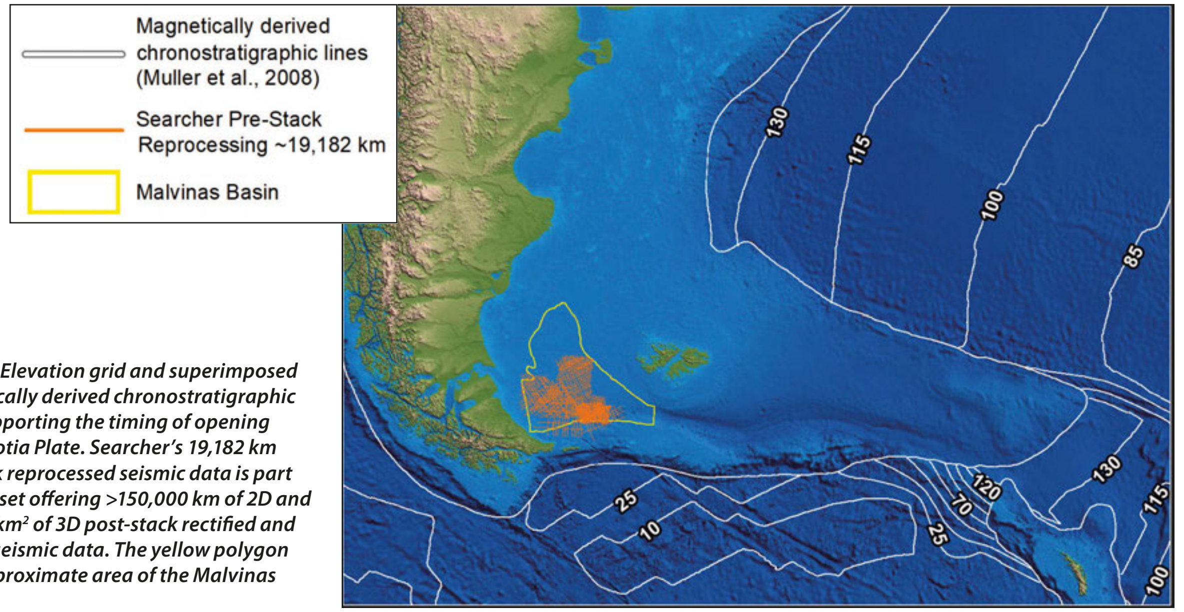
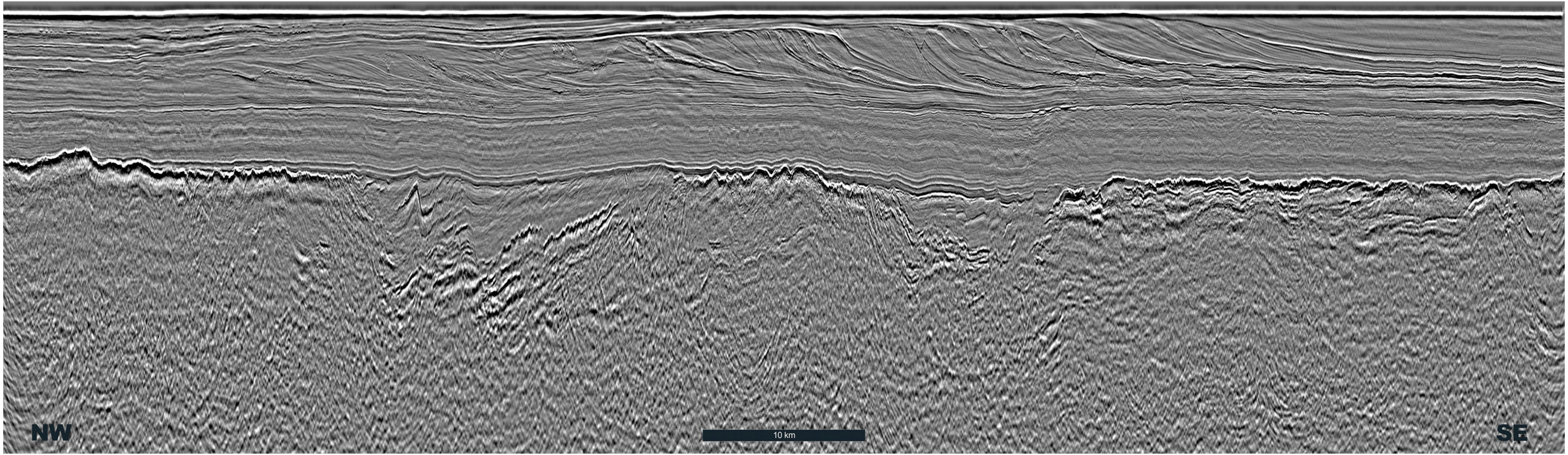


Figure 2: Elevation grid and superimposed magnetically derived chronostratigraphic lines, supporting the timing of opening of the Scotia Plate. Searcher's 19,182 km pre-stack reprocessed seismic data is part of a dataset offering >150,000 km of 2D and >12,000 km² of 3D post-stack rectified and merged seismic data. The yellow polygon is the approximate area of the Malvinas Basin.

Figure 1: Searcher's 2020 broadband reprocessed PSTM line in the Malvinas Basin.



Tertiary Prospectivity in the Malvinas Basin

Reprocessing of seismic data across the Malvinas Basin has aided in the definition of virtually unexplored Tertiary plays.

KRISTA DAVIES and PETER HOILES, Discover Geoscience; KARYNA RODRIGUEZ and NEIL HODGSON, Searcher Seismic

The Malvinas Basin is a large foreland sedimentary basin located entirely offshore on the Argentine Shelf of southern Patagonia. To the west the basin borders the Río Chico-Dungeness High, which separates it from the Magallanes Basin. The southern boundary is the Tierra del Fuego fold belt, formed by transpressive movement along the Scotia Plate boundary.

Setting the Scene

The Malvinas Basin sedimentary succession can be divided into four tectonostratigraphic units: Jurassic rift deposits; Late-Jurassic to Cretaceous sag deposits; latest Cretaceous to Eocene transitional marine deposits; and the late Eocene-Pliocene foredeep deposits.

As Gondwana began to fragment during the Jurassic, rifting commenced across the Malvinas Basin and between Antarctica and South America. Jurassic volcaniclastic sediments and potential lacustrine source rocks of the Tobifera Formation infilled the rifted topography in the Eastern Malvinas Basin.

Through the Cretaceous however, deconstruction of the supercontinent was relatively quiescent in this area. Lower Cretaceous post-rift sag deposits form a backstepping siliciclastic marine wedge that was fed mainly from the North (Biddle et al., 1986). At the base of the section is the prolific traditional Springhill Formation target, which incorporates known source rock and reservoir sections of the adjacent Magallanes Basin and is covered by a marly aggradational interval deposited in neritic to open marine conditions. Relative accommodation space continued to increase into the Late Cretaceous with thermal sag and the deposition of predominantly open marine sediments.

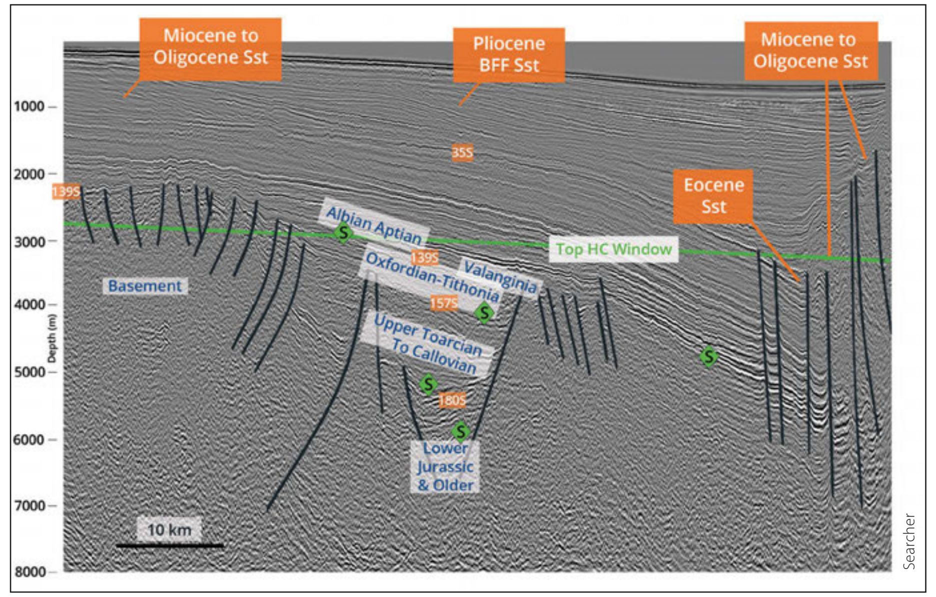
It was only when South America began to accelerate westwards relative to Antarctica, about 50 Ma, that rifting began again south of the Malvinas Basin, opening a shallow (<1,000m water depth) Drake Passage. The accelerated oceanic crust formation led to uplift in southern Patagonia and erosion and deposition of marine turbidite sandstones into the Malvinas Basin during the Eocene. By 26 Ma rifting entered a spreading phase and the Drake Passage opening deepened to depths greater than 2,000m (Livermore et al., 2005), creating the first oceanic crust (Figure 2). This drifting led to the formation of the oceanic Scotia Plate, which, interestingly, could potentially be used as an analog for the formation of the Caribbean Plate.

At the beginning of Scotia Plate drifting, the formation of new oceanic crust was the main driver for the onset of tectonic instability in the Malvinas Basin, controlling the development of depositional systems. Syn-rift sandstones were eroded during the uplift of localized areas, as the Scotia extensional plate developed, and transpression on the northern margin of the Scotia Plate compressed the southern edge of the Magallanes, Malvinas and South Malvinas Basins. The foredeep created by this compression was infilled by shallow marine to basin floor clastic deposition until the Late Miocene.

The 35 Ma sequence boundary marks the top of the hydrocarbon-bearing Eocene sandstones encountered in the Salmon-2 well and also corresponds to the base of Oligocene to Lower Miocene sandstones from which hydrocarbons were recovered in the Ciclon-1 well.

Searcher's 2017 and 2020 seismic reprocessing indicates several deltas rapidly prograding within

Figure 3: A north–south seismic line through the Malvinas Basin showing the Miocene to Pliocene prograding deltas, the 35S break-up unconformity, identified plays, and syn-rift geometries.



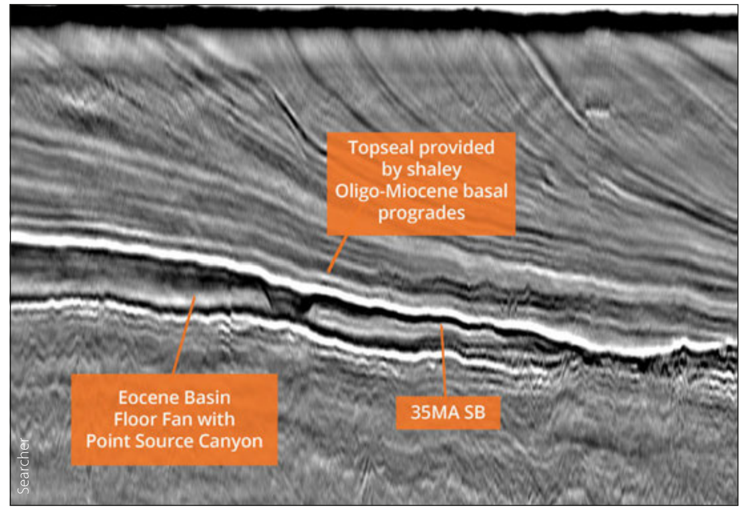


Figure 4: Eocene basin floor fan.

the Malvinas Basin (Figure 3). In places, these are sufficiently buried to offer exploration targets. Progradation of deltas continued during the Pliocene.

Prospective Tertiary Play Levels

Two key potential Tertiary play intervals are identified within the Malvinas Basin: Paleocene to Eocene deep marine turbidite deposits; and the retrogradational basin floor fan, slope canyons and slope fan deposits of Oligo-Miocene age.

Paleocene to Eocene-aged deep marine turbidite sandstones have been encountered in 23 wells within the Malvinas Basin ranging in thickness from 15m in Sirius X-1 to over 100m in Centauro X-1. Reservoirs are characterized by massive, amalgamated sandstones in the Paleocene and lower energy interbedded sandstones in the Eocene (Figure 4). Traps are generally stratigraphic or combination structural stratigraphic, with some relief provided by compressional topography, as seen on the foldout on the previous page. Top and lateral seals are provided by the transgressive and highstand Eocene deep marine shales or the progradational toes of the Oligo-Miocene deltas. Salmon X-1 produced oil and gas from excellent quality Paleocene sandstones proving the potential for this section as a viable exploration target in the Malvinas Basin.

The 35 Ma sequence boundary marks the base of Oligo-Miocene deltaic deposition. Progradation of the deltas occurs into the Malvinas Basin from north-west to south-east. Basin Floor Fans are observed on the reprocessed data, along with slope canyons and fans, and slope channel complexes, apparently influenced by contourite currents (Figure 5). Twenty-five wells have intersected reservoirs sandstones at this stratigraphic level, ranging in thickness from 20m in multiple wells to over 210m in Nerita X-1. Due to the retrogradational nature of deposition, sandstones in this section tend to be higher energy, thicker and more amalgamated than those deposited prior to the 35 Ma sequence boundary. Top seal is provided by the shaley progradational toes of subsequent deltas, and is therefore higher risk near shore, with the risk decreasing into the Malvinas Basin.

The sources for the hydrocarbon systems charging plays in the Malvinas Basin include lacustrine source rocks in the Jurassic Tobifera Formation, Early Cretaceous source rocks of the Springhill Formation and the Late Cretaceous Inoceramus Formation, and potentially additional prodeltaic source rocks in the Lower Tertiary.

Successful Exploration Anticipated

The tectonic influence of the rifting of the Scotia Plate from 50–35 Ma played a key role in the evolution of the Malvinas Basin and generated the right conditions for reservoir deposition and trap formation. Reprocessing of seismic data across the basin has aided in the definition of Tertiary plays which have been largely underexplored but partially proven by well results in the Malvinas Basin. Identification of shallow gas anomalies using deep machine learning has helped to de-risk the potential for Jurassic lacustrine source rocks to charge the Tertiary plays, suggesting that Tertiary play systems will underpin successful future exploration in the Malvinas Basin. ■

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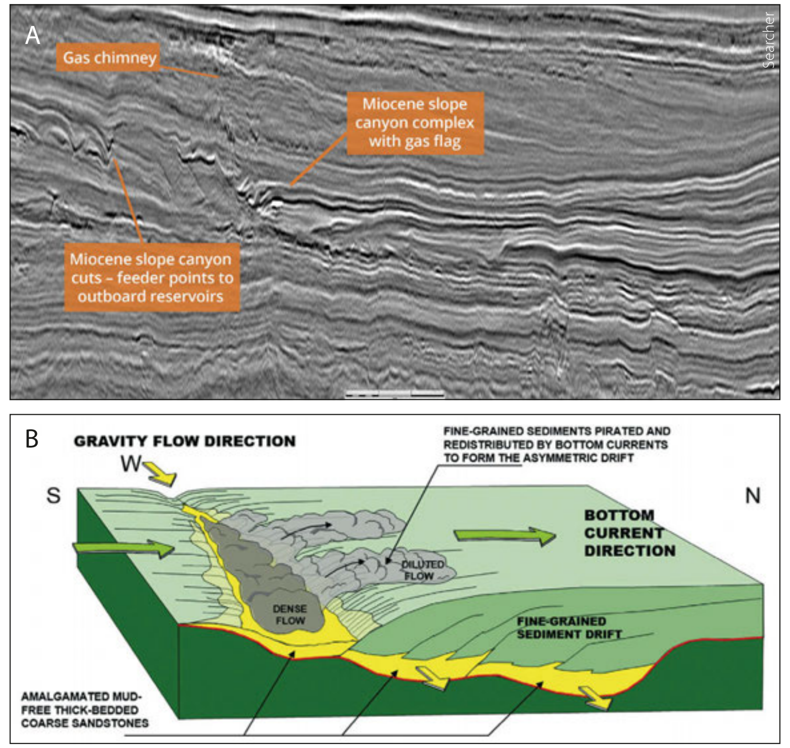
Figure 5: (A) Miocene slope canyon complex; (B) depositional model associated with the recent significant discoveries in east and west Africa (e.g. 80 Tcfg Mamba and Coral Fields, Mozambique, and Jubilee, Ghana, 600–1,800 MMboe). (Modified after Palermo et al., Insights into a new super-giant gas field-sedimentology and reservoir modeling of the Coral Reservoir Complex, Offshore Northern Mozambique. Offshore Technology Conference-Asia, 2014.)



No Longer a Dream

Dealing with large datasets has been always a challenge for the industry, keeping real-time monitoring and control of subsurface operations, until now, only a dream – but it is fast becoming a reality.

ALAN J. COHEN, HAMED SOROUSH and SALAH FAROUGHI; PETROLERN LLC

Why Real Time?

The upstream oil and gas industry collect huge amounts of data, yet very rarely analyzes more than a small fraction of it. In addition, some decisions need to be made not only smartly but swiftly, including those that are critical to safety and to minimizing the environmental impact of operations, as well as those needed to effectively manage wells and reservoirs. This has prompted a major effort in developing technologies for subsurface monitoring and decision-making in near real-time.

Real-time decision-making applicable for subsurface energy systems is a transformational goal that may take a decade to completely impact and revolutionize the oil industry. Regardless, several technologies are currently being developed that can have a significant impact near-term on enhanced decision-making. These include high resolution downhole tools including fiber optic sensors that measure temperature, strain, acoustic, electromagnetic and chemical properties, as well as improved computational platforms and algorithms, artificial intelligence and machine learning methods, and other differentiating technologies. These technologies can impact not only mainstream oil and gas exploration and production decisions and enhanced oil recovery, but also carbon storage and enhanced geothermal systems.

Workshop on Real-Time Decision-Making

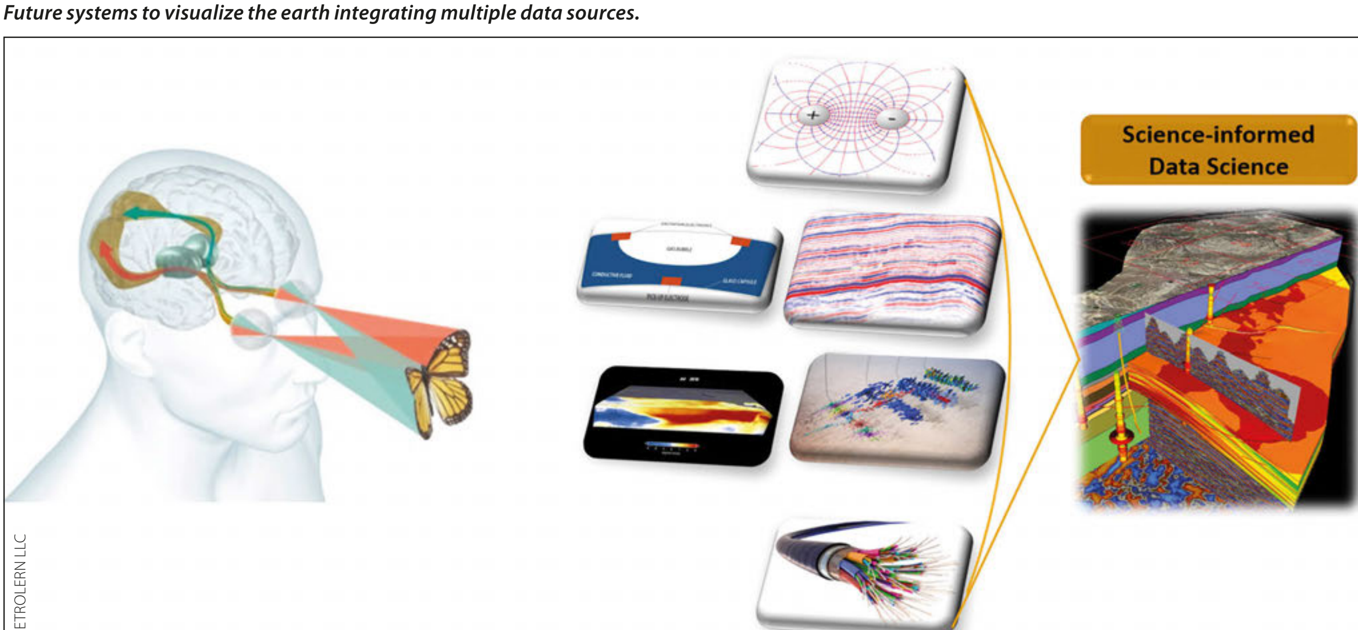
In 2018, a major workshop was held in the United States at Carnegie Mellon University, attended by about 70 representatives from industry, academia, national laboratories and the US Department of Energy (DOE). The primary focus was on unconventional oil and gas recovery and subsurface carbon storage. In June 2019, a report entitled *Real-Time Decision-Making for the Subsurface*, was generated, which summarized the findings and recommendations of the workshop. It is accessible online at the Carnegie Mellon University website: www.cmu.edu/energy/education-outreach/policymaker-outreach/documents/real-time-decision-making-for-the-subsurface-report.pdf.

The highest-value use cases considered at the workshop included:

(i) Safety: protecting workers, the environment and equipment from serious incidents using technologies that can provide an early warning for failures, and enable other decisions that must be made smartly and swiftly;

(ii) Drilling/geo-engineering: accelerating and improving the drilling process and improving well placement;

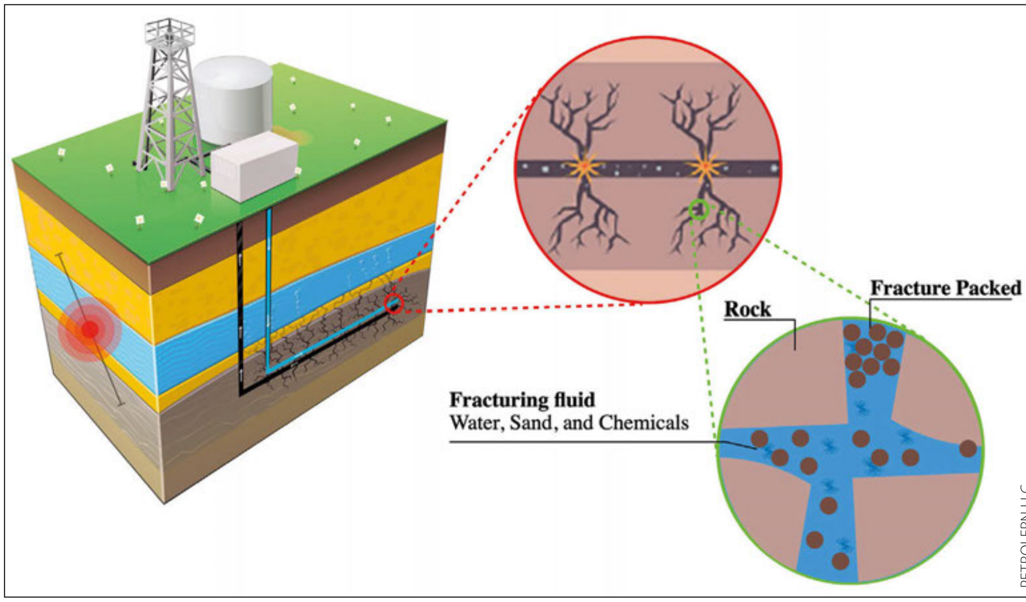
(iii) Management and operations: optimizing recovery and storage efficiencies through improved reservoir characterization, fluid injection and production, ensuring no leakage of resources beyond the reservoir, while



Future systems to visualize the earth integrating multiple data sources.

PETROLERN LLC

mitigating induced seismicity;
(iv) Completions and well operations optimization: including managing stress, and monitoring and controlling fracture formation and fracture growth.



Schematic of hydraulic fracturing. Swift real-time decision-making is vital for this technology.

The workshop also identified several challenges that can impede the development and use of real-time decision-making tools. These include missing or incomplete datasets; incompatibility between data formats; limitations on storing, transmitting and managing large data volumes; lack of appropriate or useful signals; and hesitance by decision makers in adopting and embracing new technologies.

Recent Technology Award

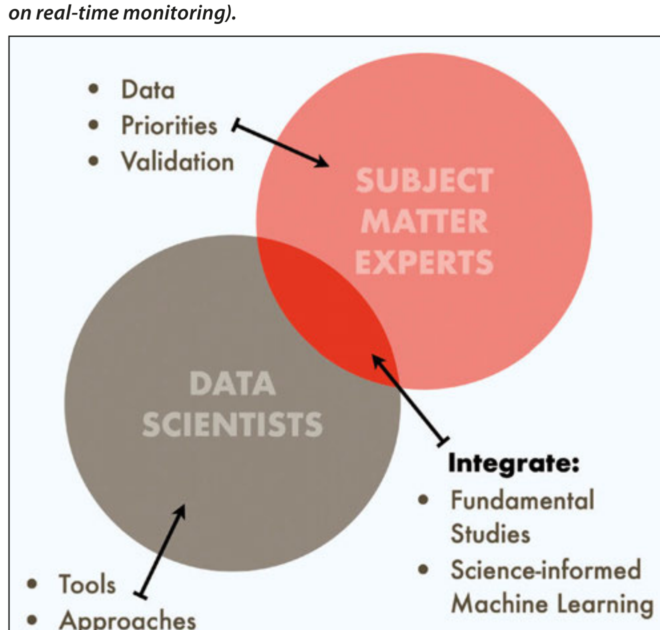
The US DOE recently awarded PETROLERN LLC, an Atlanta-based service and R&D company, a $1.2 million grant to advance real-time subsurface decision-making. The project primarily focuses on carbon storage but it could also have results that would be advantageous for oil and gas and geothermal applications. The technology directly addresses the challenges associated with transmitting and managing large data volumes and partly addresses the gap associated with signal enhancement. It develops hardware and software to acquire, compress, transmit, process and analyze large datasets from downhole and surface sensors (both fiber optic and others), using advanced signal processing and science-based machine learning methodologies. Much of the computing is done at the edge of the survey sensory network rather than solely in the cloud. The project is illustrated for carbon storage in the figure on the following page.

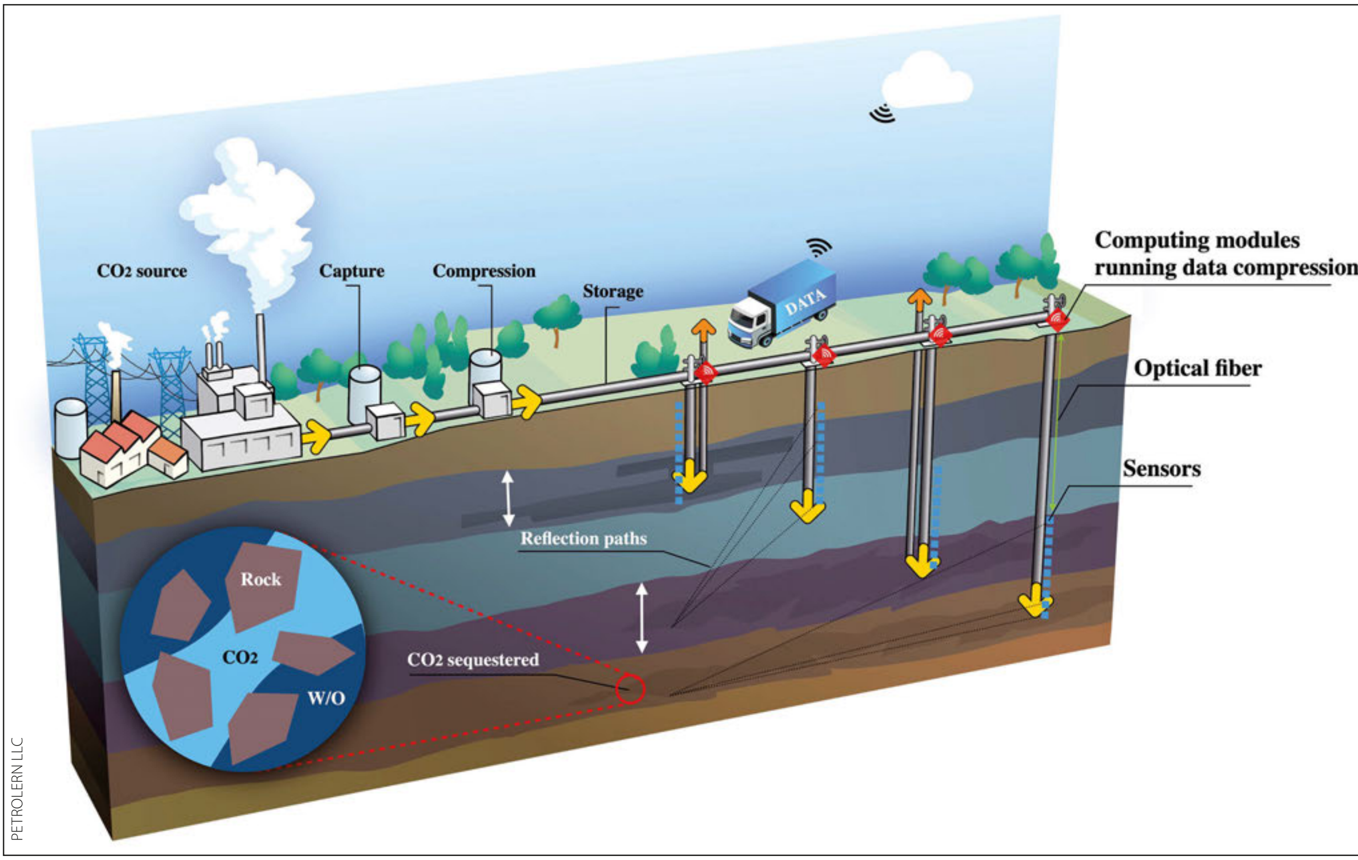
The company believes that this technology has the potential to completely change the way oil and gas fields and other resources are operated. It is also low cost and can drastically improve safety and project profitability. Although still under development in phase 2, it has already attracted the attention of several oil and gas operators, utility companies and fiber optic technology firms. It is the fifth such contract the US government and industry has awarded PETROLERN in the past two years, with the objective of pushing the current boundaries in monitoring and control of subsurface operations by adding real-time capabilities. One of the reasons this technology development has thus far been successful is the close working interaction between subsurface engineers, geoscientists and data scientists working on machine learning and artificial intelligence.

Solution to a Key Challenge

So, what specifically is different about this new technology? Over the past two decades, there has been a drastic advance in sensing technologies and data acquisition systems in different disciplines. Some of these technologies have been deployed in carbon capture and storage (CSS) for monitoring, verification and accounting (MVA) to confirm permanent storage of CO_2 in geological formations. MVA is a significant cost component of any carbon storage campaign and necessary for its success. Automated and low-cost MVA solutions can therefore advance CCS towards commercialization by providing a

Close integration of geoscientists and engineers (subject matter experts) and data scientists is a key to success (after Carnegie Mellon/DOE report on real-time monitoring).





Carbon storage operations using real-time downhole monitoring.

reliable and real-time control option over the reservoir, as well as reducing the associated costs.

For MVA, a complex network of surface and underground sensors is often installed, generating a large volume of intricate datasets that present a challenge in terms of transmission to the surface. These raw data also require swift, automated and affordable tools to be efficiently processed and analyzed to enable real-time decision-making. However, the conventional data collection and processing methods used are often rudimentary, and significant time is required to transmit the high-resolution data to the cloud, with the processing needing significant human intervention. Furthermore, the hardware platform has usually been designed and implemented for data acquisition and sampling, and the microcontroller architecture cannot provide any computational power to carry out the analytics at the sensor node. Therefore, the entire process is curbed by human aptitude, computational power and the available bandwidth. This introduces a huge challenge to collecting and processing large volumes of data in an efficient and cost-effective manner.

Bottlenecks in data management systems available at the moment include, but are not limited to, insufficient bandwidth, inadequate storage and limited connectivity, meaning it is important to find a solution which reduces the volume of the recorded data streamed on site. This is achieved by developing adaptive data acquisition techniques that enable data compression at the sensor locations. The vast amounts of data acquired in real-time require improved data compression methods that focus on recording changes in the data rather than recording and analyzing each sample – and this is what the new technology does. It provides a solution to a key challenge described in the DOE workshop report, specifically: "As the volume of data continues to grow exponentially, the computational tools required to store and transmit such data volumes in real-time have often not kept pace, such that some data that are currently collected are not used in a meaningful way. Methods for keeping track of data as it moves through a system that allows storage, backup, and analysis are lacking" [and are critically needed].

What's Next?

This new technology will be tested, commercialized and hopefully used routinely in the field in a few years. Subsurface real-time visualization and decision-making, however, is a huge puzzle, for which this new technology provides some of the critical components, but not all of them. Some other pieces that need to be resolved include more advanced sensors, high-resolution visualization tools to display and diagnose anomalies, better so-called 'reduced-order models' to reflect subsurface changes on the fly and with proper physics, and autonomous control systems that can take action when needed. In the near-term, there will be a human in the loop to make decisions when an alert sounds, but eventually the control system will be fully autonomous, and real-time subsurface monitoring and decision-making will no longer be a dream but will have become a reality. ■

Chasing Plays Along the Rona Ridge

Exploring the frontiers of the Faroe-Shetland Basin

MATTHEW DACK, CGG

The Faroe-Shetland Basin (FSB) west of the Shetland Islands is one of the least mature producing regions on the UK Continental Shelf (UKCS). Although the Central North Sea is considered by the Oil and Gas Authority, the UK Government industry regulator, to contain the largest yet-to-find potential on the UKCS, the West of Shetland area offers arguably the largest remaining opportunities for significant new finds (Austin, Cannon and Ellis, 2014).

Exploration activity in the basin began in 1972, with more than 30 wells drilled in the following decade. Initially, exploration focused on simple tilted fault block traps, analogous to the North Sea, in relatively shallow waters (<500m) along the south-east flank of the FSB. The first hydrocarbon discovery, although sub-economic, was made by Shell in 1980 at the 206/2-1 well, located close to the present day Greater Laggan Area. During this initial exploration phase the giant Clair (4 Bboe STOIIP) and Victory fields were discovered in Devono-Carboniferous and Lower Cretaceous sandstones respectively. Due to technological and commercial constraints, these fields lay undeveloped for many years. During the 1980s advances in deepwater drilling technologies shifted exploration activity into the deeper parts of the basin, such as the Flett Sub-basin, where sub-economic gas was found within the Paleocene. Further sub-economic discoveries were made until the discovery of the Foinaven and Schiehallion fields in the early 1990s. These discoveries were driven by advances in seismic technology, particularly amplitude-versus-offset (AVO) analysis, and led to the establishment of the Paleocene oil play with total reserves in excess of 1 Bboe.

Until recently, much of the focus has been on these post-rift plays. However, recent successes, including the development of the Clair field, the Glendronach gas discovery in Lower Cretaceous turbiditic sands and the Lancaster field, the UK's first fractured basement oil play, have renewed focus on these deeper and more challenging syn-rift and pre-rift plays (Figure 1).

Plays at Multiple Stratigraphic Levels

Over the more than 40 years of exploration in the FSB, plays have been identified at all tectono-stratigraphic levels (Figure 2), with hydrocarbons produced from reservoir intervals contained within structural and combination structural/stratigraphic traps.

Within the pre-rift, the deposition of thick sequences of non-marine clastics deposited in fluvial, aeolian and lacustrine environments constitutes the main reservoir intervals of the Devono-Carboniferous play, typified by the Clair field. More recently, the development of Precambrian, Lewisian metamorphic basement along the Rona Ridge has established a fractured basement play.

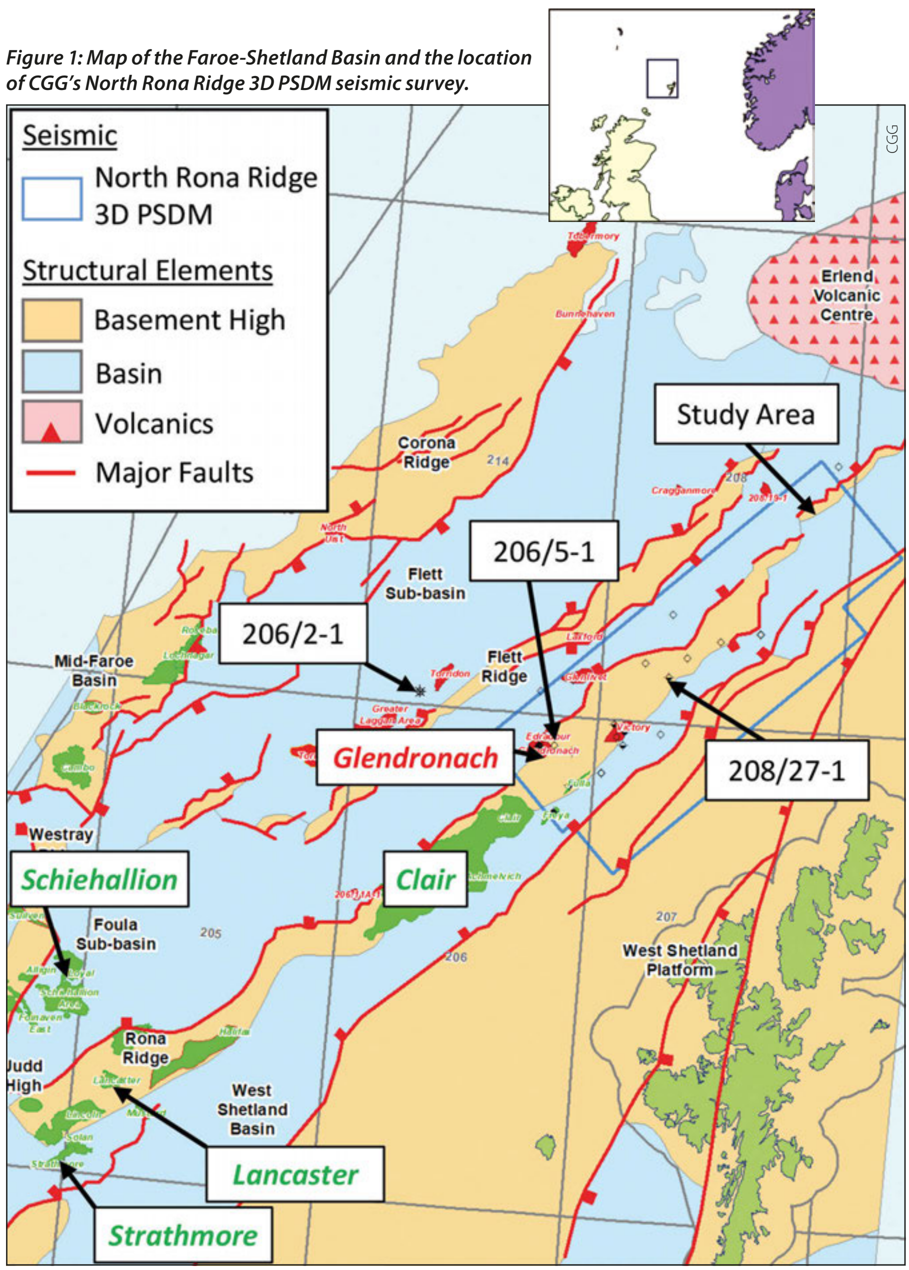


Figure 1: Map of the Faroe-Shetland Basin and the location of CGG's North Rona Ridge 3D PSDM seismic survey.

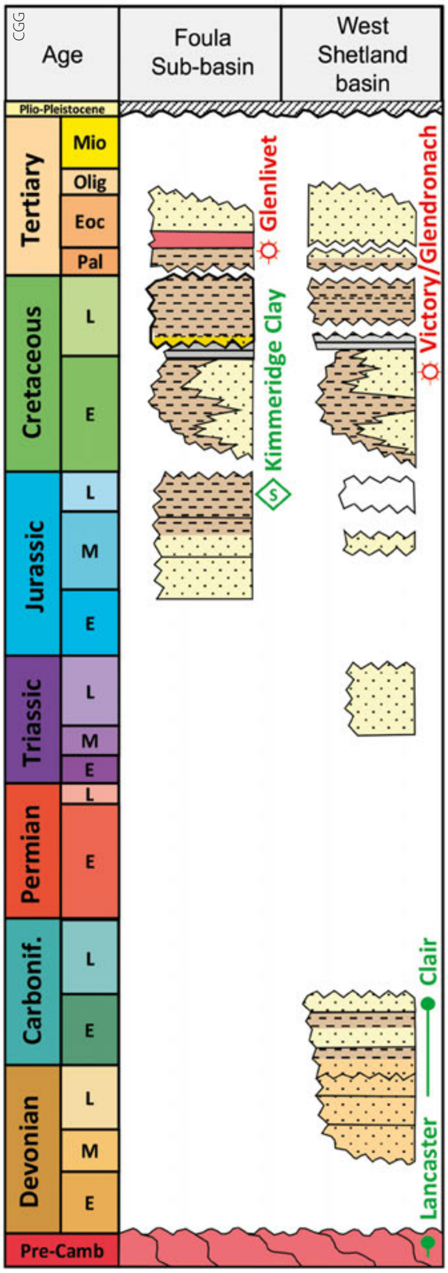


Figure 2: Chronostratigraphy of the study area showing key reservoir intervals.

A number of rift phases associated with the opening of the North Atlantic in the Triassic and Early Cretaceous led to the deposition of the main syn-rift plays in the basin. In the Triassic, continental sediments deposited in a series of extensional half-grabens constitute the reservoir intervals at the Strathmore discovery. In the Early Cretaceous, major extension led to the deposition of sandstone-dominated successions in marine conditions. The Lower Cretaceous succession in the West Shetland Basin includes fan delta and shallow marine sandstones deposited in narrow half-grabens east of the Rona Ridge (e.g. Victory Sandstone, Victory field). This succession also contains mass-flow sandstones and mudstones deposited on the basin-ward side of the platform-bounding fault system as seen in the Royal Sovereign Sandstone of the Glendronach field (Larsen, Rasmussen and Hjelm, 2010).

Within the post-rift sequence, by far the most dominant play is the Paleocene deep marine sandstones. It consists of amalgamated channel complexes derived from a sand-dominated shelf to the south-east and deposited in the Foinaven and Flett Sub-basins. The play is typified at the Foinaven and Schiehallion fields (Lamers and Carmichael, 1999). The majority of these plays are charged by Upper Jurassic-sourced hydrocarbons generated by the Kimmeridge Clay Formation, which was deposited in an open marine setting under anoxic ocean bottom conditions over most of the area during a widespread marine transgression. It tends to generate a low wax oil. There is also upside potential from Middle Jurassic shales deposited in more restricted marine/lagoonal settings that tend to produce a waxier oil grade. Both source intervals are penetrated by well 206/5-1 (Figure 1).

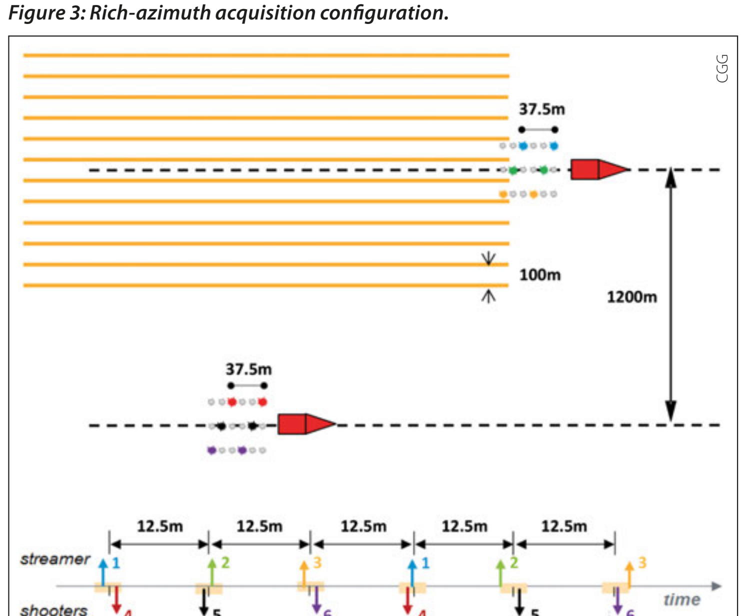
Post-rift deposition of thick, deep marine mudstones provides excellent seals for the deeper pre- and syn-rift plays, whilst tuffaceous units associated with Neogene volcanism (i.e. from the Icelandic Plume) provide regional seals for the shallower plays.

Overcoming Geological Challenges

To date, much of the exploration focus has been on the shallower, post-rift plays because of the known geological, geophysical and operational challenges for seismic imaging that have historically hampered the targeting of the deeper syn- and pre-rift plays in the FSB. These challenges are mostly associated with the presence of intrusive and extrusive volcanic rocks, emplaced around 55 Ma due to the impinging Icelandic Plume, the proximity of the basin to the Shetland Islands and strong along-strike currents. This has resulted in a lack of seismic signal penetration and poor illumination, particularly of dominant north-east–south-west basin-bounding faults.

In 2018/19 CGG undertook a multiclient 3D PSDM seismic survey covering 3,600 km^2 of the North Rona Ridge and adjacent Foula and West Shetland Basins. The data were acquired with a rich-azimuth acquisition configuration consisting of dual triple-source vessels with significant lateral offset, which, when combined with advanced imaging technology, offered enhanced illumination underneath the volcanic intrusions present in the area and increased dip-line sampling to improve fault imaging (Figure 3). The seismic interpretation of this data has allowed for a new assessment of the exploration potential of deeper syn- and pre-rift plays along the Rona Ridge.

Figure 3: Rich-azimuth acquisition configuration.



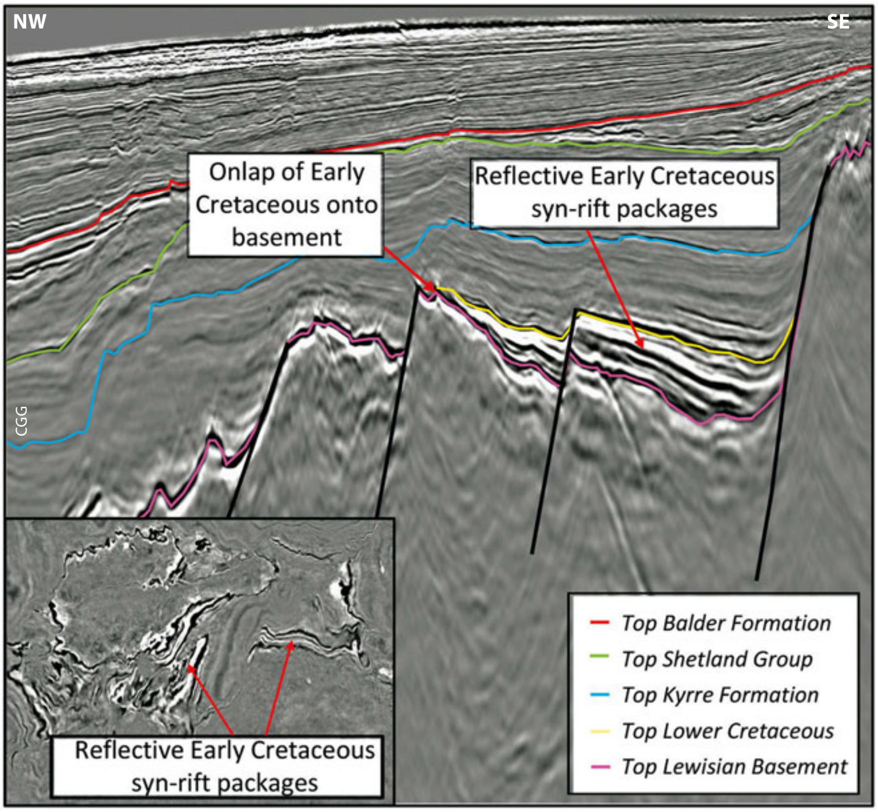


Figure 4: Potential Early Cretaceous syn-rift targets.

permeability, thickness and net-to-gross. This is demonstrated by the Victory wells (207/1-1, 2, 3 and 1a-5) where over 200m of Lower Cretaceous sand is penetrated with good reservoir properties. These syn-rift wedges form stratigraphic traps with top seal provided by the thick post-rift shales of the Shetland Group (Figure 4).

Elsewhere within the study area, the post-rift also shows potential with the presence of Paleocene turbidite sands. The structural interpretation of the Top Balder Formation and Top Shetland Group has been used to constrain RMS amplitude extractions of the Paleocene section with the results revealing information on the distribution of Paleocene reservoirs in the deeper Foula Sub-basin. As with many other Paleocene discoveries to the south, the Paleocene Vaila sands encountered at the Glenlivet field display characteristic amplitude brightening. The amplitude is indicative of fluid response and excellent reservoir properties, with 61m net sand thickness, net-to-gross of 94% and good porosity (Figure 5).

Chasing the Post- and Syn-Rift Plays

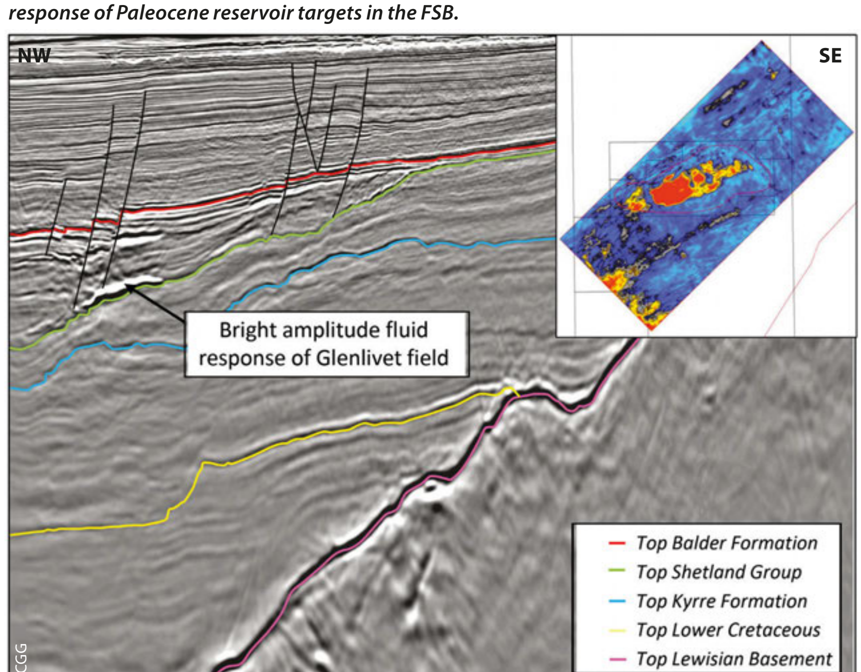
A full 3D seismic interpretation has revealed the geometry of several key stratigraphic horizons in the area, including the Top Lewisian Basement, Top Lower Cretaceous, Top Shetland Group and Top Balder Formation, with age calibration from several key wells. The structural interpretation has been complemented with attribute analysis to aid understanding of reservoir distribution in the study area.

For the prospective syn-rift interval, structural interpretation of the Top Lower Cretaceous marks the top of the prospective stratigraphic units identified at the Victory and Glendronach discoveries. The interpretation of this interval has been extended away from these areas to identify a more expansive network of Early Cretaceous syn-rift wedges towards the north-east. These are deposited on fault terraces on the eastern side of the Rona Ridge and onlap the Lewisian Basement. It has been interpreted that, unlike the deeper marine, turbidite-prone sand sedimentation to the west of the Rona Ridge, this more proximal setting provided conditions for the deposition of stacked fan delta-to-shoreface sandstones and inner shelf mudstones in a ponded, hanging wall, back-basin (Larsen, Rasmussen and Hjelm, 2010). This more proximal setting would be conducive to improved reservoir characteristics, such as higher porosity and

Further Fractured Basement Potential?

The northern Rona Ridge may also provide upside potential within the fractured Lewisian Basement to the north-east of the currently producing Lancaster field in the FSB (Figure 1). From the structural interpretation of the top basement horizon a number of structural closures can be identified. The seismic data reveal the presence of

Figure 5: Interpreted dip-line and RMS amplitude extraction (inset) showing the amplitude response of Paleocene reservoir targets in the FSB.



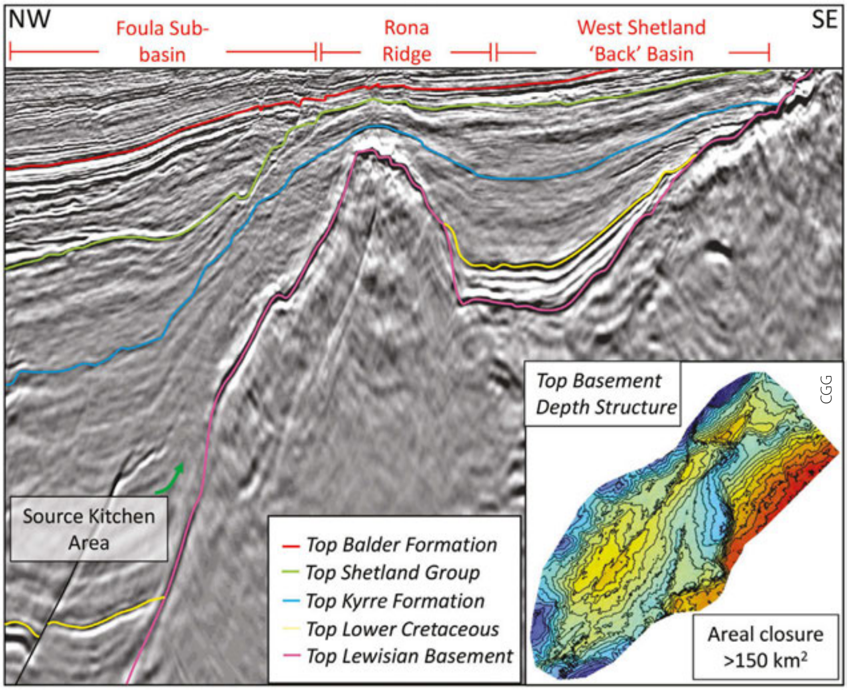


Figure 6: Interpreted dip-line showing potential Basement prospect forming large structural closure (inset).

numerous faults, which are likely to be associated with fracturing, within the basement itself. These fault and fracture zones provide the required porosity and permeability for good hydrocarbon production. The location of these closures, adjacent to the main basin-bounding fault, provide a direct pathway from the source kitchen in the deeper basin (Figure 6). A number of wells penetrating the basement in the study area encounter an upper 'weathered zone' consisting of a brecciated section with metasediment clasts. As elsewhere in the basin, the 208/27-1 well data, in particular, confirm the upside potential of a fractured basement play, with hydrocarbon shows within the basement itself.

Further 'Victory' Remains

Review of the new 3D seismic data in the FSB has revealed the new potential of the Early Cretaceous syn-rift and Precambrian fractured basement plays along the northern extent of the Rona Ridge. The configurations of these play fairways mirror those that have brought success to the south-west of the study area.

One question that remains, however, and is the focus of further work, concerns the migration of hydrocarbons from the deeper basin into the interior back-basin regions on the eastern flank of the Rona Ridge. Fault analysis and careful mapping of migration pathways are key elements to de-risk these plays further. ■

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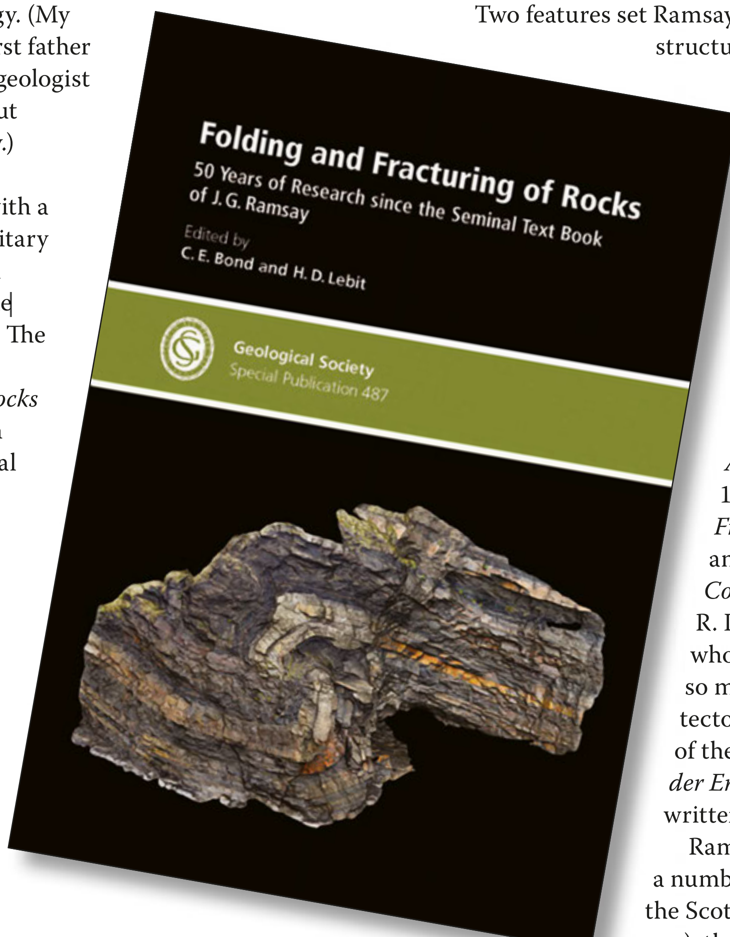
Celebrating Ramsay's Rock Folds and Fractures

RASOUL SORKHABI Ph.D.

Folding and Fracturing of Rocks: 50 Years of Research since the Seminal Textbook of J.G. Ramsay
Edited by C.E. Bond and H.D. Lebit
Geological Society, London, Special Publication 487, 2020)

Every branch of geology probably has two founders: the first one usually lived and worked in the 18th or 19th century and laid down the foundations while the second one pioneered the modern version of the discipline. John Graham Ramsay, born in 1931 in England, is the father of modern structural geology. (My favorite candidate for the first father in this field is the Austrian geologist Eduard Suess, 1831–1914, but opinions in this matter vary.)

Ramsay graduated from Imperial College, London with a Ph.D. in 1954 and, after military service, in 1957 he returned to Imperial College where he became a professor in 1966. The following year he published *Folding and Fracturing of Rocks* (McGraw-Hill, 1967), which to this day remains a seminal work in strain analysis of rocks and geologic formations. Ramsay left Imperial for Leeds in 1973 and then moved to ETH at Zurich in 1977, succeeding the legendary geologist Augusto Gansser (1910–2012). After retiring in 1992, Ramsay moved to France where he still resides and enjoys playing at cello concerts (he has talents in music and poetry as well).



Ramsay has been given a number of prestigious awards. In 2017, a special session was held at the European Geosciences Union in Vienna, honoring the 50 years since the publication of *Folding and Fracturing of Rocks*; Ramsay also attended the session. Contributions to this occasion resulted in the publication by the Geological Society, London of a new volume discussing the research undertaken since Ramsay's original publication, edited by the meeting's conveners Clare Bond (Aberdeen) and Hermann Lebit (Houston). The volume consists of 17 articles, including an introductory chapter by the editors.

Highly Original Work

Ramsay trained a large number of students; some of the most eminent structural geologists of our time were among them. Two of his students from the 1960s, Susan Treagus and Peter Hudleston, share their memories of being taught by him in Chapter 2 of the new volume. In Chapter 3, Richard Lisle, Fernando Bastida and Jesus Aller survey how Ramsay's 1967 book still tops the list of structural geology books published in the past five decades in terms of citation and influence. This book, in 568 pages, was reprinted in 2004 (Blackburn Press).

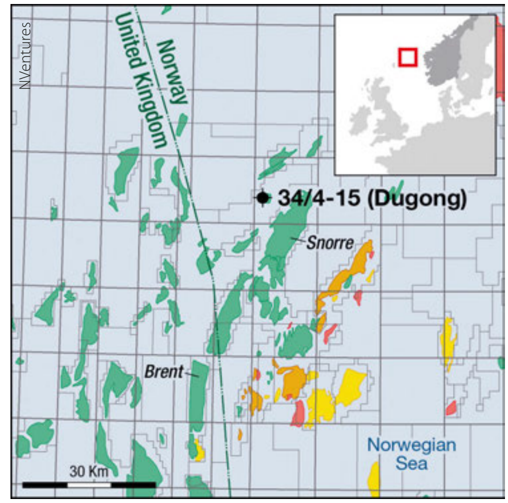
Two features set Ramsay's book apart from many other structural geology textbooks. Firstly, it applied mathematics to rock strain; and secondly, it was highly original, and not simply a synthesis of previous works.

Ramsay also wrote a three-volume textbook entitled *The Techniques of Modern Structural Geology* (Academic Press, now out of print), totaling 1,061 pages. It comprises Volume 1, *Strain Analysis* (with M. Huber, 1983); Volume 2, *Folds and Fractures* (1987, with M. Huber); and Volume 3, *Applications of Continuum Mechanics* (2000, with R. Lisle). The only other geologist who has synthesized and written so much in structural geology and tectonics was Eduard Suess, author of the four volumes of *Das Antlitz der Erde* (*The Face of the Earth*), written between 1885 and 1901.

Ramsay has conducted research in a number of mountain belts including the Scottish Highlands (his Ph.D. area), the Alps and the Himalayas. In fact, I first met Ramsay at a Himalayan conference in Switzerland in 1996, to which both Gansser and Ramsay attended and gave talks; both of them emphasized the importance of field work, observation and mapping in structural geology. I also learned that Ramsay has a talent for cooking!

This new volume, edited by Bond and Lebit, also offers 14 theoretical or field case studies related to rock folding, fracturing and strain. These field case studies mostly come from the UK and the USA, but there is also a paper each from Greece, the Dead Sea and China. ■

Norway: Neptune North Sea Success

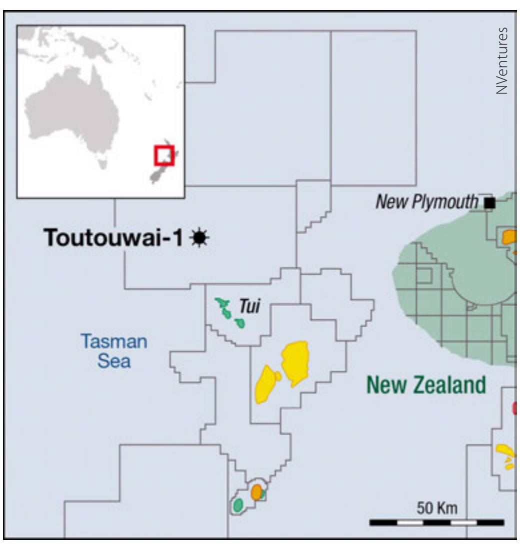


The international gas-weighted explorer **Neptune** continues to be successful in the North Sea, having recently reported a discovery offshore **Norway** with **Dugong 34/4-15**. The well proved oil between 3,250m and 3,500m in the Viking and Brent (Upper to Middle Jurassic) Groups after a sidetrack (34/4-15S) helped refine the expected recoverable volumes at the discovery to between 40 and 120 MMboe, compared to the pre-drill estimate of 86 MMboe. This represents the largest hydrocarbon discovery in Norway so far in 2020, and is the first exploration well in License 882. In addition, the Dugong discovery has significantly de-risked another prospect in the license, estimated by Neptune to hold 33 MMboe.

Dugong lies near the north-west margin of the Viking Graben of the Northern North Sea and north-west of the Snorre and Statfjord giant complex. Whilst this is conventionally considered a mature area Equinor and partners appear to be finding significant new volumes, enabling them to extend the life of existing facilities. They have also made a 20–60 MMboe Brent discovery near Huldra at 30/2-5 and are drilling 34/7-E-4 offsetting the Vigdis field.

Dugong was drilled by the *Deepsea Yantai* rig (Odfjell) in 330m of water. Along with Neptune (40%), Concedo, Petrolia and Idemitsu are partners. ■

New Zealand: A Beginning or the End?



In April **OMV**, with partners OMV Sapura and Mitsui, announced the success of the **Toutouwai-1** well in the **Taranaki Basin Block 60093** offshore **New Zealand's North Island**. The well reached 4,317m in April 2020, in 130m water depth and preliminary results are encouraging, with hydrocarbon pay measured in Cretaceous sandstones.

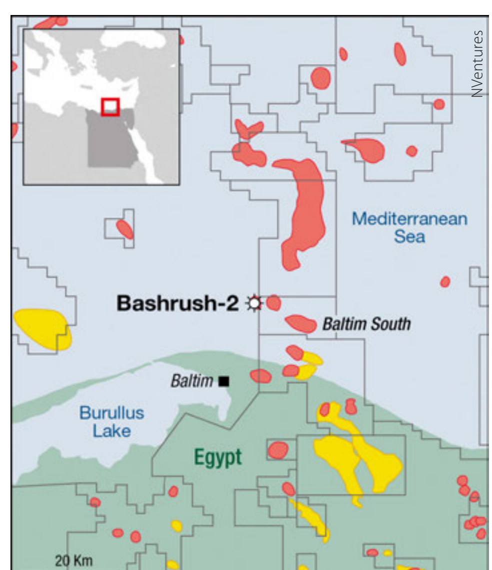
The well is north-west of the producing **Maui** gas field, where Cretaceous Rakopi Formation coal measures charge North Cape Formation sandstones. Both oil and gas are reported at Toutouwai-1, and the small Tui area fields nearby have light oil in the Upper Cretaceous and Paleocene Kapuni Formation, sourced by organic shales. It will be interesting to see if gas, oil or both will be tested at the Toutouwai-1 well.

The *COSL Prospector* was due to spud Maui-8 after Toutouwai-1. However, exploration drilling is classified as non-essential due to Covid-19 restrictions, so the rig is understood to have been stood down. Environmental campaigners are hailing this as the end of exploration offshore New Zealand, whilst the operating group will have plans to study development possibilities at the new discovery. ■

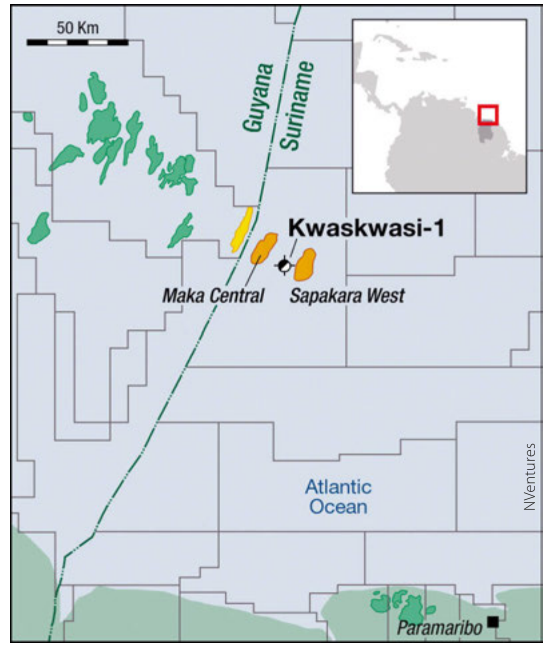
Egypt: Shallow Beats Deep Water

After a string of dry wells in the eastern deepwater **Nile Delta, Eni**, in partnership with BP and Total, have had success testing their recent shallow water **Bashrush** discovery, in the **North El Hammad** concession. Over the last two years, companies drilling beyond the proven Oligo-MioceneSalamat–Temsah–North Port Said trend in the deeper offshore area, east of Zohr, have all reported dry or disappointing wells. Focus in this play has now returned to the shallow Baltim–Rosetta trend for lower risk gas on the doorstep of existing gas development infrastructure.

The Bashrush well found 102m gas in Miocene Messinian Abu Madi gas sands in the north-eastern area of the North El Hammad offshore block, awarded to the Eni/BP/Total group in 2015. The well, drilled to 3,600m in May 2020, delivered 32 MMscfd of gas on test, limited by surface testing facilities, and the well deliverability could be as high as 100 MMcfgpd and 800 bcpd, according to the operator. The field is an extension of the **Baltim** group of fields and should be tied back relatively quickly. ■



Suriname: Perseverance Rewarded



After two high-profile, high-cost dry holes drilled on **Suriname's** Block 53 in 2015 and 2017, **Apache** have now hit their third consecutive major condensate-light oil discovery on **Block 58**, located between their dry holes and ExxonMobil's Stabroek discovery trend in neighboring Guyana. The **Kwaskwasi-1** well, which was targeting Campanian and Santonian deepwater sands, TD'd at 6,645m and encountered 278m net pay, the highest by far in the region to date. The Campanian section holds 86m net volatile oil and condensate plus 63m net light oil, and the Santonian has 129m net light oil. Samples from the Campanian show 34–43° API, with data still being analyzed from the lower interval.

This portion of the Guyana–Suriname trend, along with ExxonMobil's Haimara-1 just across the border, appears to be shaping up as a lighter oil-volatile oil-condensate and wet gas fairway, as opposed to the more purely light oil found in the heart of the Stabroek block in the Liza complex region, about 100 km to the west. Kwaskwasi-1 is also a record setter for overall net pay in the whole trend: Apache's Maka Central had 123m and their Sapakara West found 179m, while to the west the ExxonMobil wells have been averaging in the neighborhood of 50m net pay.

Following completion of Kwaskwasi-1, the *Noble Sam Croft* drillship will move about 25 km to the south-east to drill Keskesi East-1 with the same general objective interval. Total (50%), as agreed in their farm-in last December, will then take over operatorship and plan an appraisal and exploration campaign to begin in the first quarter of next year. Apache are in the process of submitting appraisal plans for the first two discoveries to the government, and the terms of the farm-in state that Apache will receive a $5 billion cash carry on their first $7.5 billion of appraisal and development work, and a 25% carry beyond; both companies will fund 50% of new exploration. No acreage relinquishments are required until mid-2026. ■

Taking Ownership of Your Career

How can professional organizations help young people in the industry? David Eastwell, Europe President of the American Association of Petroleum Geoscientists Young Professionals group (AAPG YP) talks about the advantages of membership, both professionally and personally.

When did you join the AAPG YP group and what prompted you to do so?

I was very fortunate early in my career to have been offered a chance to work in Perth, Australia. It was a brilliant opportunity but when I landed I didn't know a single person and I was working with quite a small team. I joined AAPG as well as several local societies and instantly had access to a network of peers who fast became a great group of friends. When I came back to the UK, I wanted to do my bit to help build a society to provide others with this same experience.

What has membership of AAPG YPs taught you, particularly in your leadership role?

We have so much talent and passion within the YP and student communities. People's willingness to engage with their job and professional community outside of working hours through networking, training and conferences is, I think, quite unique. It's a testament to how much people just really enjoy their subject that they will happily head into London after hours to talk about rocks. That energy is an underused commodity (if you will excuse the pun!)

How do you see the industry evolving?

I think the distinction between 'oil and gas' and 'renewables' is fast becoming blurred and the term 'energy provider' is increasingly relevant, with many traditional oil and gas companies moving into renewables. Wind turbines power production platforms, and hydrocarbons fill in the downtime in the renewables sector. Additionally, the application of carbon capture and storage (CCS) could potentially create thousands of highly skilled jobs and go a long way to reducing the carbon footprint of the industry. This integration is only going to increase and hopefully pave the way for more sustainable business driven by a diversified energy portfolio.

What could it do better?

We need to get better at how we market jobs to young professionals. We have relied on a network of peer-to-peer recommendations and recruiters that worked well whilst we still had a solid graduate scheme pipeline, but when the pipeline of graduate scheme opportunities dries up, as it has over the last eight years, we are left with a recruitment system heavily geared towards experienced professionals with an established contact network and work history. This system does not work well for younger members who will not have the same network to access when looking for a position. Many excellent graduate positions are available through the services and consulting companies; however, a lot of these company names are unfamiliar to someone who is not established in the industry. I think we need to get better at communicating these opportunities or making them much more publicly visible.

How has the AAPG responded to these changes?

I think AAPG Europe has worked hard to broaden the scope of its content. The Energy Transition Conferences have been a great initiative to give a platform to geoscientists and companies working across the spectrum of energy providers. The geotechnical workshops also now include subjects like CCS and geothermal. As for the YP teams, we have really started to try and push more in the careers support direction. We actively look for opportunities that will suit our members and publish them and put together more career-focused content. The recent young professional conferences in association with other societies have again been unique in that they are organized by and geared solely towards young professionals.

What advice have you for student or early career geoscientists?

The industry is constantly evolving, and now more than ever is in a state of change. The desired skills change rapidly, so what may have worked before isn't always the right thing now. Find what you enjoy – interpretation, coding, thin sections, or whatever – and do everything possible to be as good as you can be in that area. Take ownership over your training, find side projects to work on and training material to read and have fun getting really involved in your subject. If you are already in a company, find some data and see if you can work up a new story from it, for example. When the time comes that someone is looking for that skill you will immediately stand out from the crowd, plus along the way you will be doing something you enjoy. ■

Ikon Science

David is the current Europe President of the AAPG YP network, working with a team of volunteers to provide careers, training and networking opportunities for the AAPG's younger members. He works for Ikon Science as a geoscientist, specializing in rock physics and has also worked on designing and interpreting seismic surveys and hydrocarbon exploration projects around the globe with TGS.

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Changing the Traffic

Anyone who has driven in or out of Los Angeles during rush hour will understand what it means to be in the mother and father of all traffic jams. Bumper-to-bumper gridlock as fumes hang in the air like the aftermath of battle. Another form of lockdown: alone in a vehicle going nowhere fast and already late. This is a depressing scenario for any kind of automotive experience, whether petrol, diesel or electric. Too much traffic is a denial of the personal freedom people have supposedly purchased with their motorcar. Too much pollution, even for the most enthusiastic climate change activist, can be more difficult to quantify.

In Los Angeles there are moves to get people out of their single occupancy gas-guzzlers and onto trains and electric buses, providing of course they follow social distancing rules and wear a mask. LA Mayor Eric Garcetti wants to be part of a new Global Green New Deal and has announced what he calls the Transportation Electrification Partnership: an alliance of cities, carmakers, utilities, transit agencies and a clean tech incubator. A key target for the group is for zero emissions vehicles to constitute around a third of the total in the next eight years. That means around 80% of new car purchases will need to be fuel cell or electric by the deadline.

Oil and gas companies may not quake at this latest target as they grapple with more fundamental short-term transition issues. Recent results from Shell and BP suggest a continuation of the industry's slash and burn (pardon the pun) to control costs and present a more diversified face to the world. Shell, for one, has cut its dividend for the first time since the Second World War while BP wants to sell off its petrochemicals business, the bit that is doing well, growing fast and making 10 million tonnes of petrochem products a year. The name of the game for these and other oil and gas majors is to protect balance sheets at a time when transition needs to encompass everything from solar energy to investing in hydrogen.

In the meantime, there are those carbon targets that according to the Oil and Gas Climate Initiative (OGCI) mean cutting the carbon intensity of upstream operations by 13% of 2017 levels by 2025. Shell for one wants to reduce its net carbon footprint by 50% by 2050. This includes the 85% of emissions created by customers – the likes of all of us who have yet to go electric or board our local hydrogen bus. ■

Nick Cottam

Alexander Grishin/Pixabay

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.

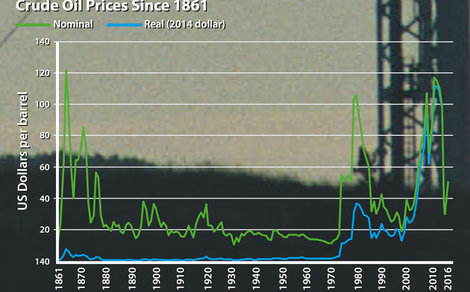
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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

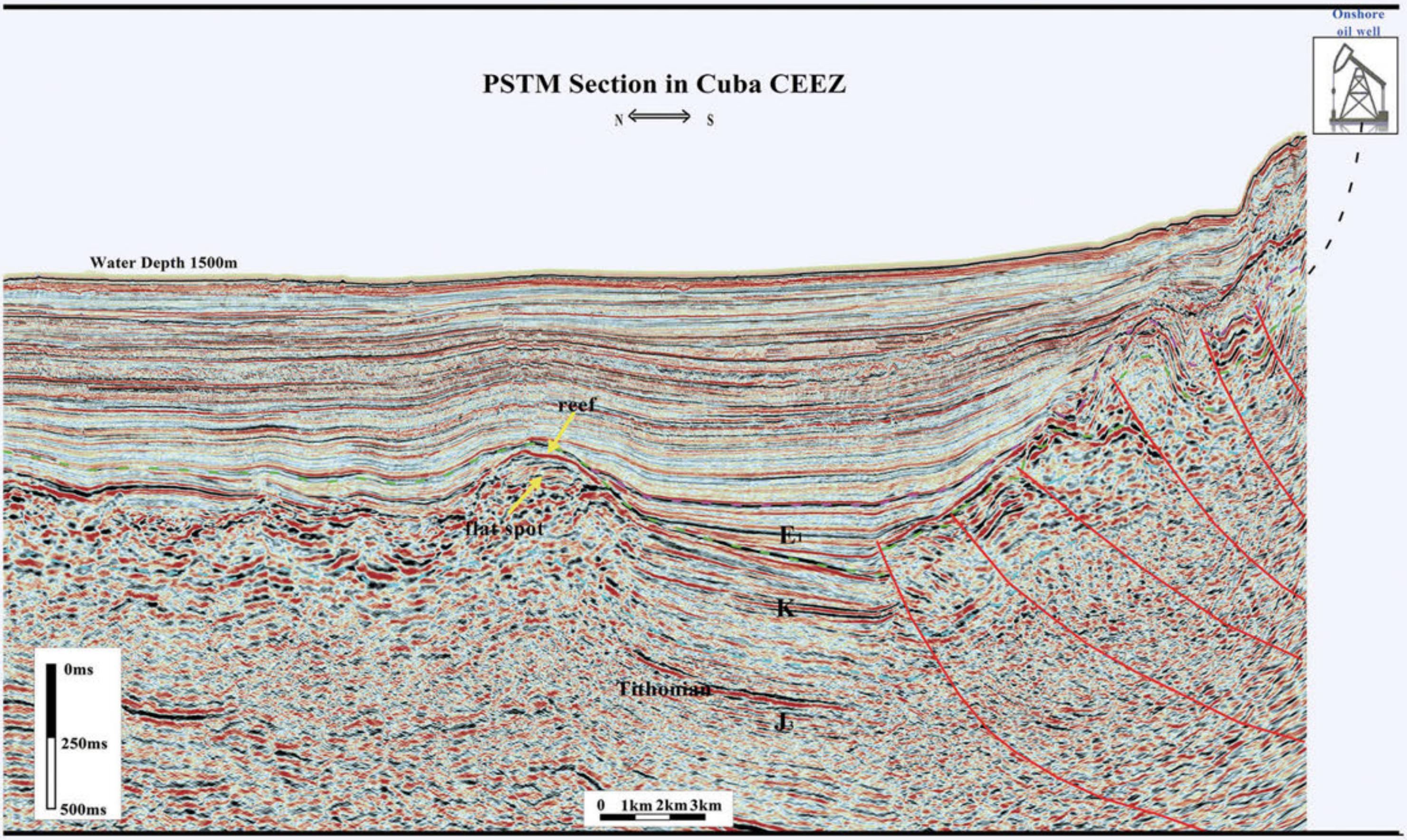
Major field
Recoverable reserves > 100 million barrels (16 million Sm^3) of oil equivalents

Historic oil price



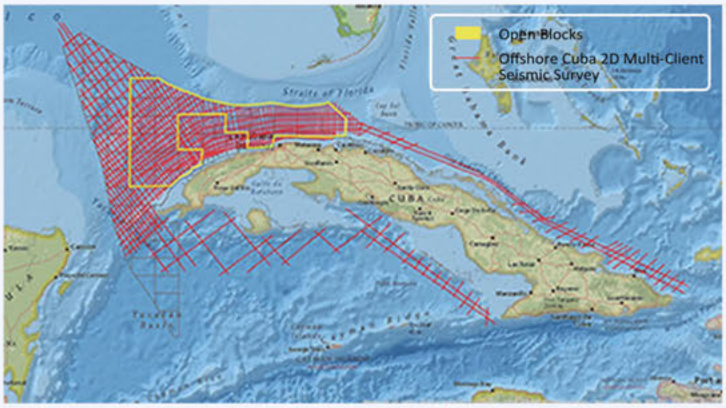
Cuba: Ongoing Licence Round

Multi-Client 2D Seismic for a New Exploration Journey



BGP has acquired 26,880 km of Multi-Client 2D seismic data in the Cuba offshore, with gravity and magnetic data. Pre-STM and Pre-SDM data set are 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, Besides the newly drilled oil well near this area has proved its potential. A group of reefs with flat spot reflection inside is quite clear 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.



Cuba is offering 24 blocks in the Cuban sector of the Gulf of Mexico. The bidding process will close on 5 March 2021.