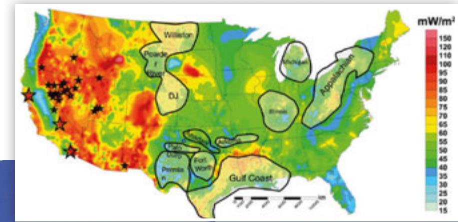
VOL. 18, NO. 4 – 2021

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



ENERGY TRANSITION
New Life for Old Wells

GEO TOURISM

Cliffs, Kayaks and Krabi

GEOLOGY
What Drives Continents Apart?

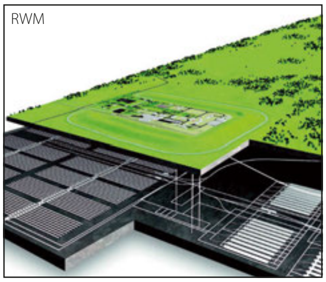
EXPLORATION
Suriname's Demerara

NEW TECHNOLOGY
AI: a Game Changer in Seismic Acquisition and Processing

geoexpro.com

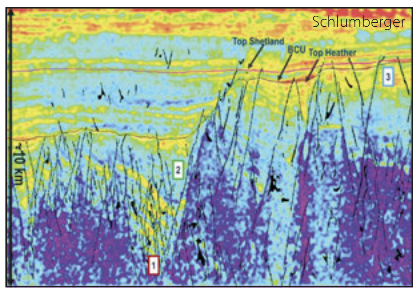
Previous issues: www.geoexpro.com

GEO ExPro
GEOSCIENCE & TECHNOLOGY EXPLAINED



14

The United Kingdom government has decided that the safest and most responsible way to dispose of its higher-activity radioactive waste is by deep geological disposal. Many of the investigative methods Radioactive Waste Management (RWM) intend to use are the bread and butter of any oil and gas geoscientist, even if applied slightly differently.



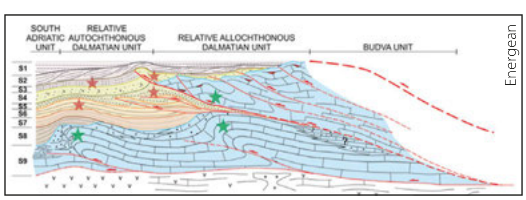
38

The approach to generate the best inputs to E&P workflows from seismic are automated interpretation solutions adaptable to any size of seismic surveys. This seismic fault interpretation workflow integrates geological knowledge, machine learning and deterministic techniques aimed at mapping and characterizing a fault framework with geological consistency.

Illustrated London News

52

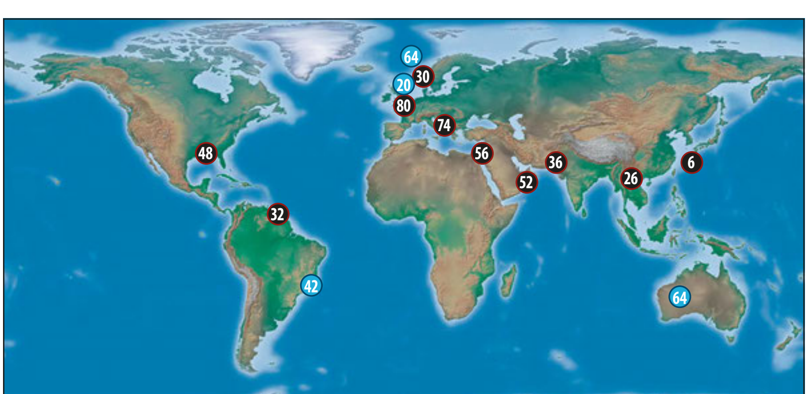
The twentieth-century American explorer Dr Wendell Phillips is best known for his colorful exploits in archaeology, which included surveys in Africa and Arabia. He was also an independent oilman who broke into the Middle East at a time when it was dominated by the major international oil companies.



Energean

74

The Dalmatian platform offshore Montenegro has the potential to have equivalent carbonate plays conjugate to the Apulian platform. New geochemical information reveals the presence of an oil-prone Late Jurassic–Early Cretaceous source rock, in addition to the well established Late Triassic Burano Formation.



Contents

Vol. 18 No. 4

This issue of *GEO ExPro* focuses on the Middle East and Asia; Geophysics, Machine Learning and AI.

5 Editorial

6 Regional Update: When Will We See Confidence in Asian M&A Activity?

8 Licencing Update: Pandemic Affects Licensing Plans

10 A Minute to Read

14 Geology: Secure Geological Disposal of Radioactive Waste

20 Seismic Foldout: Countdown to CCS

26 GEO Tourism: Cliffs, Kayaks and Krabi

30 Energy Transition Update: The Power of Data

32 Exploration: Suriname's Demerara

36 HotSpot: Progress in Pakistan

38 New Technology: How Machine Learning is Helping Seismic Structural Interpreters in The Age of Big Data

42 Seismic Foldout: Can Sparse OBN Equal Savings and Data Quality?

48 Energy Transition: New Life for Old Wells

52 GEO History: Adventures in Middle Eastern Oil

56 Exploration: A Journey of a Thousand Miles

60 New Technology: AI: a Game Changer in Seismic Acquisition and Processing

64 Seismic Foldout: AI Seismic Interpretation for a Better, More Sustainable Tomorrow

70 Geology: What Drives Continents Apart?

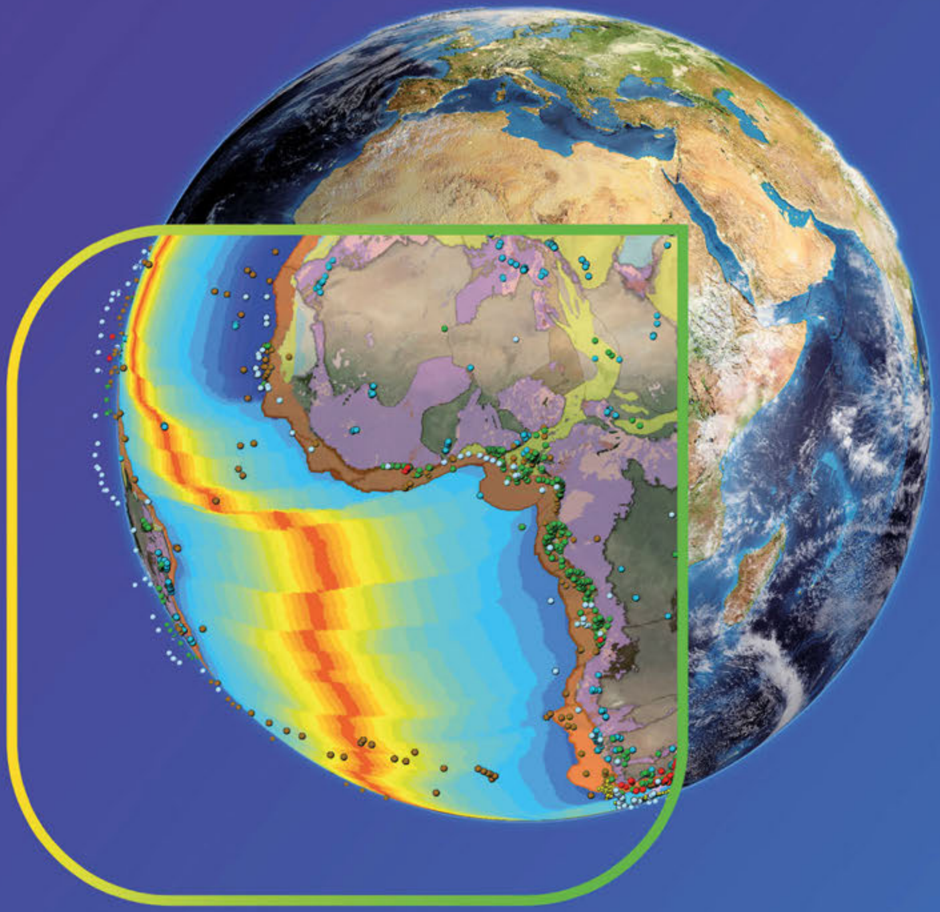
74 Geochemistry: Hot Enough in the South-East Adriatic?

78 Exploration Update

80 Industry Issues: Representing Geoscience for Over 200 Years

82 Q&A: Kirsti Karlsson: 2,000 GEO ExPro Articles and Counting

84 FlowBack: No Transition Without Offsets



AI and Code Red for Humanity

Mayflower unmanned underwater vehicle

The fifth of the UK Royal Navy's Astute-class submarines slid into the water at BAE's yard in Barrow-in-Furness during May this year. On the same day, 260 miles away in Plymouth, a much smaller submarine made its debut. A minnow compared to the 7,000+ tonne HMS Anson, this secretive nine-tonne craft may have greater implications for the future of the navy than its nuclear 'big brother'.

MSubs, a specialist in autonomous technology, has built an unmanned underwater vehicle called the Mayflower, capable of operating up to 3,000 miles from home for three months. The big innovation here is the autonomy. The submarine's movements and actions will be governed entirely by Artificial Intelligence (AI).

As the AI will be working in complete isolation from human contact, the principle of machine learning showing an AI program examples of how a task should be performed until it has embedded the right actions in its repertoire is used. The advantages for such a working system are obvious, removing risk for submariners and cost being the two most obvious.

There are synergies in the offshore exploration arena where such 'intelligent' autonomous vehicles could in principle survey large areas of the seabed and subsurface and whilst this is some way off, the extractive industries are already using the same technologies to improve and speed up seismic processing and interpretation as described in two of this issue's stories.

Moving from the world of nuclear submarines to radioactive waste disposal, Kirsty Simpson's article on deep geological disposal highlights that many of the key investigative methods required in this endeavor are the bread and butter of any oil and gas geoscientist, even if applied slightly differently. Although the UK does not appear to include significant expansion of its nuclear energy capability in its strategy to achieve its net zero commitments, this remains one way to reduce CO_2 emissions (though it clearly brings other challenges).

This brings me to a personal bugbear. The focus ahead of COP26 later this year is principally on mitigating climate change by reducing CO_2 emissions largely through transition to clean energy sources. Whilst this is undoubtedly of critical importance, perhaps as a species, we need to focus more on simply using less, as this for me at least, is really at the heart of the problem.

With the IPCC's August climate change report described as a 'code red for humanity' by UN Secretary-General, António Guterres, there was a glimmer of hope that deep cuts in emissions of greenhouse gases could stabilize rising temperatures, but consensus appears to be the damage is irreversible. Could AI provide a much-needed boost to the science and technology developments needed to mitigate climate change? One can only hope. ■

Iain Brown
Editor in Chief

CLIFFS, KAYAKS AND KRABI

Vegetation-clad limestone cliffs tower over the beach at Railay, near Krabi in the centre of the Thai Peninsular. Such karst outcrops dominate the scenery in this area, attracting the tourists who love to explore the caves, coves and hidden lagoons that are a result of the erosion of the Permian Ratburi Formation.

Inset: Major sedimentary basins overlaid on the heat flow map of the United States (Blackwell et al., 2011b).

GEO ExPro

www.geoexpro.com

GeoPublishing Ltd
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
+ 44 (0) 7909 915513

Managing Director
Tore Karlsson

Editor in Chief
Iain Brown
iain.brown@geoexpro.com
Editorial enquiries
GeoPublishing
Iain Brown

+44 (0) 7767 770265
iain.brown@geoexpro.com
www.geoexpro.com

Sales and Marketing Director
Kirsti Karlsson
+ 44 (0) 7909 915513
kirsti.karlsson@geoexpro.com

Subscription
GeoPublishing Ltd
+ 44 (0) 7909 915513
15 Palace Place Mansion
Kensington Court
London W8 5BB, UK
kirsti.karlsson@geoexpro.com

GEO ExPro is published bimonthly for a base subscription rate of GBP 60 a year (6 issues).
We encourage readers to alert us to news for possible publication and to submit articles for publication.

Cover Photograph:
Main Image: Donovan Richards
Inset: Petrolern (modified from Blackwell et al., 2011)

Layout: Mach 3 Solutions Ltd
Print: Stephens & George, UK

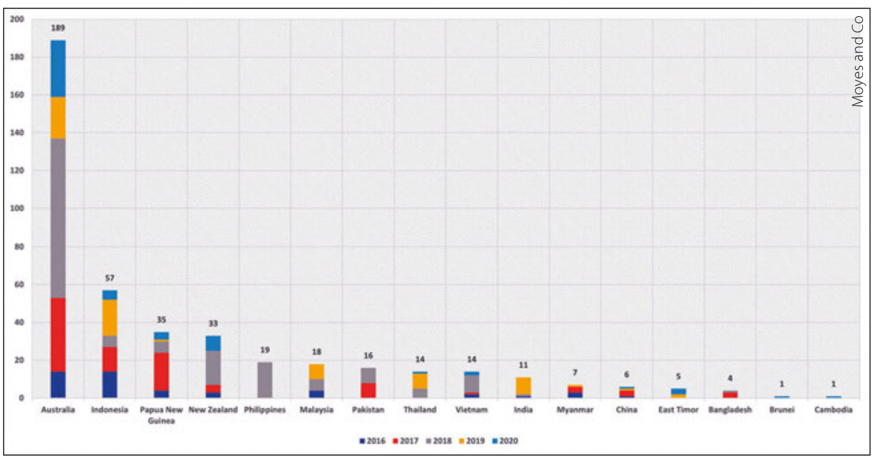
issn 1744-8743

Regional Update

When Will We See Confidence in Asian M&A Activity?

So far, the increase in oil price has not brought back the level of confidence to M&A activity that was expected, which is very apparent when looking at exploration opportunities. The industry has been and remains very cautious, but we expect with more robust 2022 budgets being set in the final quarter of 2021, that next year will be livelier. Meanwhile, the recovery in oil price has brought buyers and sellers closer in terms of deal value, after disconnected expectations in recent years. After a quiet 2020, the jury remains out as to whether the region is turning a corner, and, as analysts suggest, if 2021 will in fact be the 'bumper year' they predict.

The graph below shows how Australia dominates the Asia-Pacific region, presenting the number of transactions Moyes has captured by block and not the dollar value between 2016 and 2020. It should be noted that deals completed in the likes of New Zealand and the Philippines tend to be relatively small in value with the threat of field abandonment costs driving value down. Despite 2020 being seen as poor in terms of deals done, the Moyes data shows it was in fact a better year than 2016. The busiest year in this period was 2018, thanks to over 80 permits being the subject of M&A activity in Australia. Transaction activity remains strong in Australia with its excellent fiscal framework, transparency, and ability to conclude deals quickly. Asian countries should take note of this if they wish to attract investment.



Asia-Pacific transactions: 2016–2020.

With a lack of reliable data points in the region, it is hard to put a value on the opportunities available in the vast Asia-Pacific region. Estimates in the media range between US$10 to US$20 billion, with the opportunity of more significant packages being added notably by the major oil and gas companies. The ongoing divestment processes include ExxonMobil in Malaysia, Chevron in Indonesia and Australia, Shell in Malaysia and Indonesia, and ConocoPhillips in Indonesia. Lack of industry appetite has resulted in packages being taken off the table, and this includes ExxonMobil's Bass Strait, offshore south-east Australia.

With such a large number of deals available, the question is who are the potential buyers? The majors are eliminating themselves as they are largely in retreat to 'best-in-class' with the odd exception. Private Equity has had its fingers burnt in the region, and we are not seeing the level of interest that these firms have in places like the UK offshore, which offer reserves and production in stable regimes. Special Purpose Acquisition Companies, or SPACs, which were launched as far back as 2011 in Malaysia with mixed success, could be new buyers in the market. The Asian National Oil Companies (NOCs) are potential players as they have pulled back their horns in the region after some have suffered disappointments 'overseas', and we may see more NOC partnerships develop. The local companies often struggle to find the funds required for bigger deals and to continue operations if these do not go to plan. Some of the more successful in securing deals are the 'late life specialists', as they are known. These include Jadestone Energy and Hibiscus Petroleum, and it will not be a surprise to see other niche players join them in the hunt for assets, particularly in the South East Asia part of the region. ■

Ian Cross, Moyes & Co

ABBREVIATIONS

Numbers
(US and scientific community)

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

Liquids

barrel = bbl = 159 litre

boe:	barrels of oil equivalent
bopd:	barrels (bbls) of oil per day
bcpd:	bbls of condensate per day
bwpd:	bbls of water per day
stoiip:	stock-tank oil initially in place

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

Multi-Client Seismic Africa • Mozambique

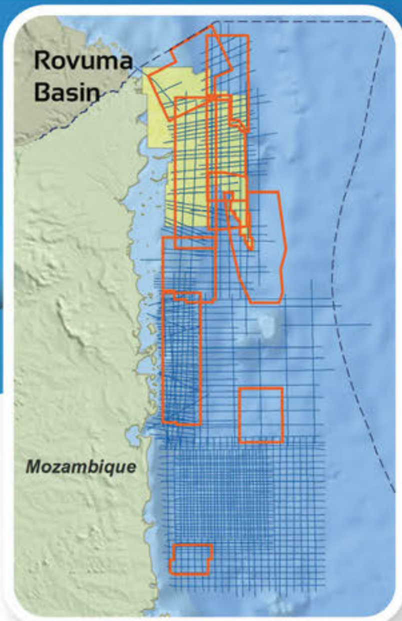
GeoPartners

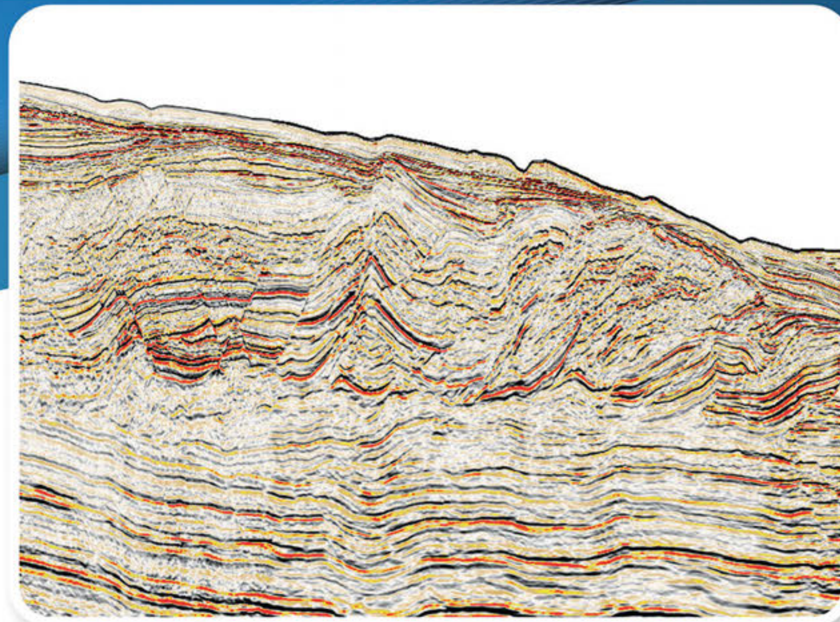
MOZAMBIQUE 6TH LICENSING ROUND

ROVUMA BASIN OFFSHORE – Legacy Seismic Data

RovumaMerge21 – 2D & 3D Data Reconditioning

inp





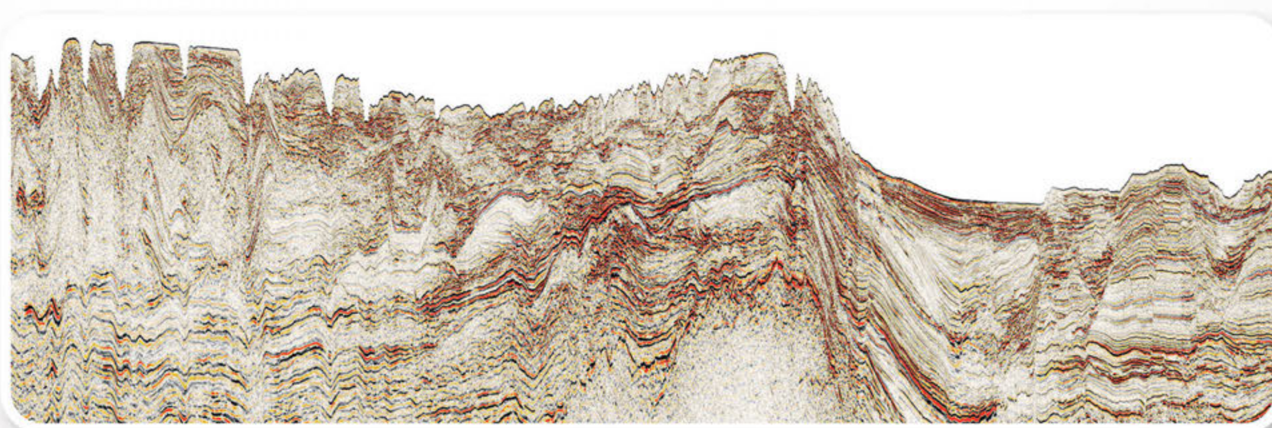
In advance of the forthcoming 6th Licence Round, the Institute of National Petroleum (INP), on behalf of the Government of the Republic of Mozambique, is making available 2D and 3D legacy seismic datasets for Multi-Client licensing.

GeoPartners are providing technical assistance to INP for the Multi-Client licensing of these datasets and has an exclusive agreement to license these datasets to interested companies and provide support to the organisation of the 6th Licence Round to be announced later this year.

In order to provide a regionally consistent data volume across the whole of the offshore Rovuma Basin area, GeoPartners has merged and reconditioned the existing 2D and 3D seismic surveys into a single matched data volume. This volume comprises over 20,000 sq. km of 3D seismic and over 16,000 km of 2D seismic. Full offset and angle stacks are available over an area of over 45,000 sq. km.

In addition to the merged seismic dataset, well data and technical reports for the area are available for licensing through INP; please contact the Data Manager at: INP, http://www.inp.gov.mz.

To arrange a viewing of this new and exclusive data volume, please contact either Jim Gulland, GeoPartners or Alessandro Colla, Trois Geoconsulting.



For further information please contact:
Jim Gulland, GeoPartners • jim.gulland@geopartnersltd.com • +44 (0) 20 3178 5334
Alessandro Colla, Trois Geoconsulting • alessandro.colla@trois-geo.com • +31 621143173

Pandemic Affects Licensing Plans

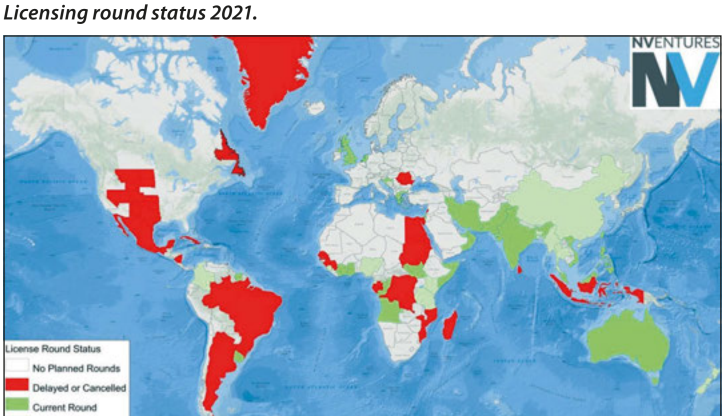
A worldwide pandemic impacts all aspects of life and over the last 18 months the oil and gas business, as well as all other industries, has had to adapt. The upstream part of the industry has been particularly disrupted with the global impact of Covid-19 massively reducing the demand for oil and gas during 2020. The resultant fall in the oil price has produced an almost unprecedented collapse in exploration activities globally. Although we are now seeing a rebound in prices due to OPEC+ production limits and drawdown of stored oil supplies, hydrocarbon licensing – the ground-floor driver of exploration for new reserves – remains disrupted, if not stalled.

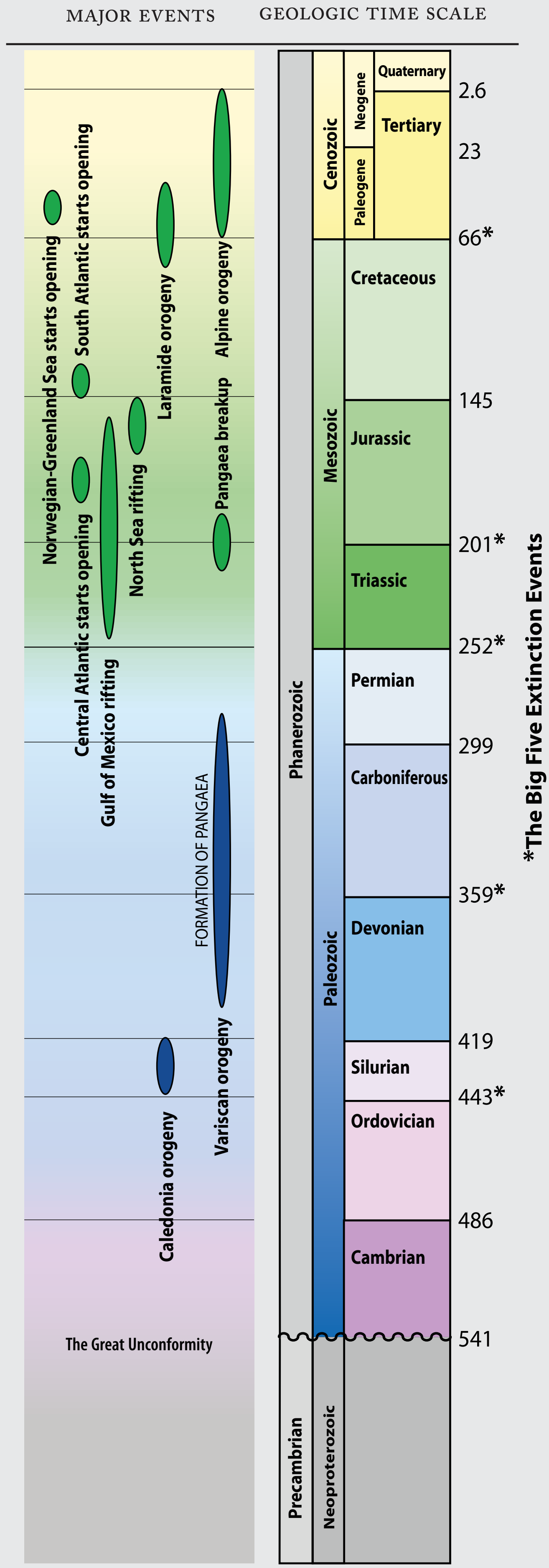
Governments use considerable human resources and capital to organize licensing rounds, whether it be in mature or frontier basins. Data packages which underpin these licensing activities include expensive items such as 2D and 3D seismic and other datasets and crucially the timing of the announcement of the round must be at the optimal moment to maximize the likelihood of sufficient bidding interest.

Predicably during the pandemic, we have witnessed a decline in the number of licensing rounds and delays in several already announced. If we look at the countries which have delayed or rescheduled rounds, we note nations such as Senegal or Brazil which have prospective, but deepwater environments or others like Sudan and Lebanon, which remain relatively underexplored. In all cases, the potential exploration opportunities in these areas are attractive but expensive, and it is not surprising that governments have delayed deadlines in the hope of a market recovery. Overprinting all of this uncertainty is an accelerating energy transition, which means, for example, that some IOCs (or IECs) have mandated no new exploration in countries where they do not already have a footprint.

As we navigate our way out of the current crisis, it is highly probable that we will witness fewer rounds with smaller acreages on offer, requiring higher investments and some countries may see a switch from competitive bidding to direct negotiations. For 2021, rounds that will be important as barometers of exploration interest will include Malaysia and Egypt. Another major event will be Brazil's 17th offshore licensing round, scheduled for October 7. ■

Licensing round status 2021.





Carbon Capture and Storage Surges


Pixabay

Recently, Carbon Capture Utilization and Storage (CCUS) has been getting a lot of attention. It is a centerpiece of the oil and gas industry's strategy for continued production of hydrocarbons and the US and European governments include it as a significant part of their climate agendas.

According to Wood Mackenzie, operational capture capacity grew from 41.9 to 47.1 Mtpa in 2020, with 19 projects added to the announced project pipeline with three major projects brought online in the past 14 month, adding a combined 7.8 Mtpa to the global operating capture capacity.

In an interesting development, in July this year, seismic companies CGG and PGS signed a Memorandum of Understanding (MoU) to develop multiclient data collaboration for CO_2 storage – similar in some ways to an earlier collaborative joint data marketing initiative, which also included TGS, for sale of seismic data agreed in 2020.

This MoU is intended to allow the combining of their seismic multiclient products and technical capabilities applied to the CCUS industry. The ambition is to jointly unlock the value of existing seismic data for carbon storage evaluation. Together, the companies intend to explore, conceptualize and create new derivative data products using existing seismic data to facilitate screening and evaluation of carbon storage sites.

CGG has 15 years of experience in CCUS projects and has a dedicated CCS & Energy Storage group, with capabilities in storage evaluation, reservoir characterization, engineering, instrumentation and monitoring. PGS believe their comprehensive worldwide multiclient data library and geophysical competence will be valuable resources and by joining forces with CGG will be able to help operators significantly accelerate their activities. ■

23rd WPC Attracts Key Industry Speakers

The 23rd World Petroleum Congress (WPC) continues to build participation from key global energy leaders with the recent announcement of plenary speakers **Bernard Looney**, CEO, BP, **Amin H. Nasser**, President and CEO, Saudi Aramco, **Anders Opedal**, President and CEO, Equinor, and **Meg O'Neill**, Acting CEO, Woodside Energy. They are the latest additions to a growing list of renowned leaders who will share their perspectives at the global conference, December 5–9, 2021, in Houston, USA.

WPC

Leading through purposeful dialogs and cross-industry collaboration, the **23rd WPC** will feature an extensive technical program that will take a deep-dive into topics impacting the industry, including E&P technologies, seismic data, digitalization, and more. Meanwhile on the engaging exhibition floor, delegates will experience various special features including the **Innovation Zone** by **ConocoPhillips**, which will give innovators and organizations the opportunity to present their cutting-edge solutions to a global audience.

To learn more, visit the **World Petroleum Congress website.** ■

Digital Twins and AI Reduce Carbon Footprint

New technologies, such as digital twins and artificial intelligence, can help companies to develop efficiency, quality and flexibility in an unprecedented way. A digital twin is a digital representation that simulates, virtually, a real-life object, process or system. Ideally, digital design tools can integrate into the real-world control of the production facility or the product or prototype in question. This allows testing of different production scenarios and validating the changes before advancing the new features into production.

The first benefit of a digital twin is the ability to produce simulated data. A virtual environment can theoretically iterate an infinite number of repetitions and scenarios. The simulated data produced can then be used to train an AI model. This way the AI system can be taught potential real-world conditions, that might otherwise be very rare, or still in the testing phase. Another benefit is the ability to plan and test new features. The digital twin should represent reality, but it can also enable you to virtually create future scenarios and test them. These iterations can be modified and rerun as many times as necessary to help find the optimal solution. Finally, adding machine learning to any industrial process will make the process more intelligent by enabling more accurate data and predictions, and understanding visual and unstructured data.

In the Dutch, Norwegian and UK North Sea, for example, **Neptune Energy** has announced the digitization of five of its operated offshore platforms. This will enable approx. 90 site inspections each year to be carried out from onshore, accelerating work schedules, reducing costs and cutting carbon emissions associated with offshore travel.

Working with the platforms' digital counterparts, engineers and integrity specialists will be able to carry out an estimated 4,100 hours of work from onshore locations, without the additional time and costs associated with flying offshore by helicopter. ■

Geoscience is the Key to Unlocking Africa's Hydrocarbon Resources

Despite the ongoing pandemic and the challenges in the global oil and gas industry, African producing countries remain undeterred about the prospects of the industry, which has become the economic lifeblood and engine of growth for their countries. This optimism is captured by their continued commitment to put substantial acreage up for bidding.

Across Africa, most of the producing countries over the past two years have either launched, or are planning to launch, or have recently concluded bidding rounds. This is despite the current uncertainties and low-price regimes that have dampened investments in the international oil and gas market. At the heart of these licensing rounds is the availability of up-to-date and accurate seismic data, which is keeping the geoscience companies operating in the region busy.

Africa Oil Week and the **International Association of Geophysical Contractors** have developed the 'Exploration Sector Best Practice Blueprint' to support African governments in defining global standards to drive the level of deal flow in the continent's upstream. This Blueprint will be made available to governments, regulators, NOCs, and concessionaires to assist them in fully engaging with the international private sector to advance their upstream licensing and business objectives. ■

Mozambique: Africa's Leading Exploration Light

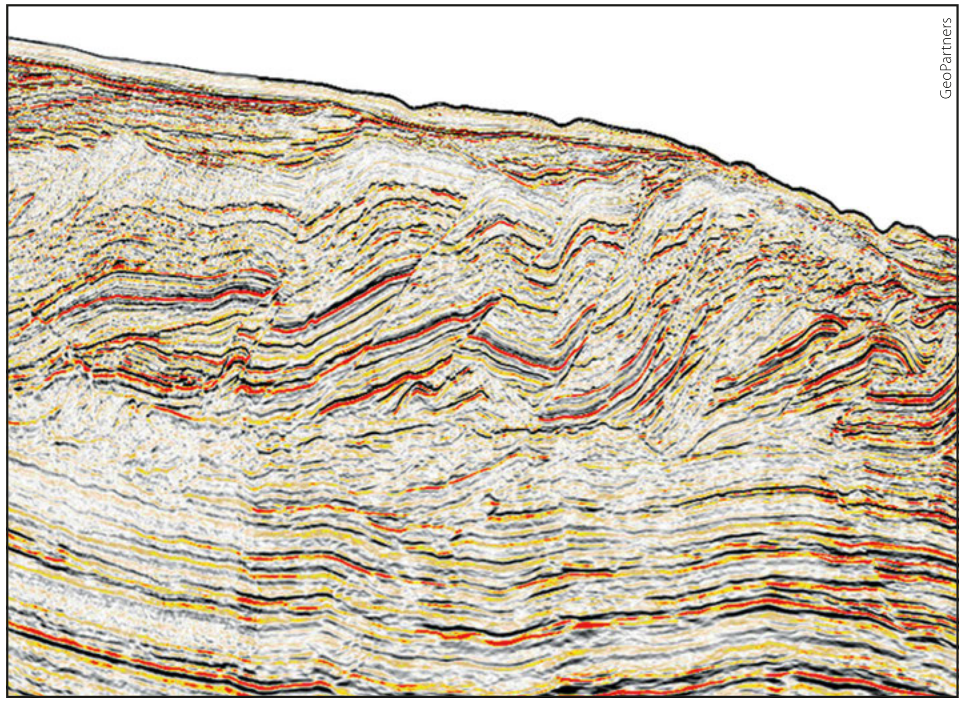


Image from the recently processed Rovuma Merge 21 3D volume.

Mozambique has passed legislation paving the way for the **6th License Round** to be opened later this year, bringing with it compelling reasons why Mozambique should be a priority when looking for new exploration acreage in Africa.

Exploration started in Mozambique in the 1920s and there has been continual activity since then over the whole margin, both onshore and offshore. Offshore, 50+ exploration wells have been drilled to test play concepts and refine exploration models. The **Instituto Nacional de Petróleo (INP)** has been very progressive in making legacy data accessible to interested parties and hosting well supported License Rounds. With the changing global investment climate in oil and gas exploration, Mozambique, with its comprehensive technical database, known natural resources, established infrastructure and skilled labour force, must be one of the standout countries that will gain attention, even when the exploration industry as a whole is seeing year-on-year declines in activity.

Sedimentary basins along the Mozambiquan margin formed during extension and breakup of eastern Gondwanaland. Three, approximately north-south trending, transfer zones separate the margin into four main basin systems: the **Rovuma Basin**, the **Angoche Basin**, the **Zambezi Basin** and **Beira High**, and the **Limpopo Basin** and **Mozambique Plain**.

Mozambique has proven reserves of more than **125 Tcf** of natural gas, ranking the country at number four in the global list of reserves, and with Rovuma Basin production coming online soon, it will also become the world's fourth largest gas exporter. Future discoveries are waiting, with the Angoche Basin completely bereft of wells and with drilling limited in the Zambezi / Beira High area to a few wells on **Tertiary delta plays**.

Regulatory development over the last two decades, from the initial **Cabo Delgado** discoveries in **2007**, has progressed rapidly, such that legislation is now in place that has enabled the investment of over **$55bn** so far, together with approved future investments totaling a further **$65bn** to bring the discoveries onstream. Mozambique's institutions have demonstrated a transparency and competency inside the country that has enabled these funds to be invested, coupled with the development of an exploitation commercial sector providing high value skills and resources, as well as access to a domestic and international supply market.

Prior to any announcements of the 6th License Round schedule, companies can gain early access to the available legacy seismic data by visiting the GeoPartners website. ■

BP Invests in AI Business

Integrated energy company BP has acquired digital energy business Open Energi to strengthen its capabilities in optimizing the energy use of different assets over time. This digital platform uses real-time data to generate savings for customers by connecting to power markets and providing flexibility at times of low renewable generation and during price peaks.

Open Energi's products and services are used to optimize the performance of a network of energy assets with a total capacity of over 80 MW. The share of the primary energy from renewables is projected to increase from around 5% in 2018 to 60% by 2050 in the Net Zero scenario set out in BP's Energy Outlook (2020 edition). However, because generation from these sources depends on variable weather conditions, the growth will also bring increased market and price volatility. Digital platform technologies, such as Open Energi's, can be vital to maintaining the stability of global electricity energy grids. In efficiently connecting assets with the power grid, they help to flexibly balance supply and demand, and maximize the performance of low carbon energy resources. ■

Asian Cryptocurrency Mining Emissions Explode

China alone mined over **60%** of the world's total bitcoin using electricity that was predominantly coal-fired in **2020**. This equates to at least 40% of the bitcoin mined globally being powered by burning coal in China. Mining **cryptocurrencies** consumes huge amounts of energy and increasing scrutiny over the environmental impact of this activity has now led to the Chinese government ordering a crackdown on projects around the country. A **Rystad Energy** analysis shows that until recently, China's **bitcoin** production used to emit as much CO_2 as Portugal, an incredible 57 million tonnes annually.


Unsplash

Almost 8,000 terawatt-hours (TWh) of electricity was produced in China last year. In addition to coal, hydropower plants supply about 17% and the remaining 20% comes from a mix of other sources including wind, nuclear, gas and solar. Bitcoin mining in China is estimated to require 86 TWh of electricity per year, or just over 1% of China's total electricity demand.

The estimated carbon emissions from China's total power production were around 5,200 Mt last year, most of which was emitted by coal power plants. Applying this to the share of electricity used by bitcoin production, Rystad estimates that the total carbon emissions from this activity would be around 57 Mt – a level equivalent to the total emissions of countries like **Portuga**l or **Peru.**

It makes sense for the Chinese government to curb production of cryptocurrency given the energy intensity of this activity is very high. With its pledge of becoming carbon neutral by **2060** and reaching peak emissions by **2030**, this is an area China cannot ignore.

Other activities, such as the buying and selling of non-fungible tokens (NFTs), have brought other systems under the carbon emission spotlight. According to **Digiconomist, Ethereum**, the blockchain used by the majority of NFTs, consumes almost 30 TWh per year. That makes the network's consumption on a par with a small country like **Bahrain**.

Ethereum, now the world's second biggest cryptocurrency, is under growing scrutiny with respect to its environmental impact. Earlier this year **Tesla's Elon Musk** said his business was abandoning plans to accept bitcoin as payment, citing environmental concerns. In response Ethereum developers claim they are working on a software upgrade that will drastically reduce its carbon footprint.

Even if other cryptocurrencies do not follow Ethereum's lead with respect to software and system changes, there may be another solution to the system's energy usage: bitcoin's price has tumbled recently and has been 40% off its all-time high after powerful players signalled their dissatisfaction with the currency's emissions. ■

Secure Geological Disposal of Radioactive Waste

What skills can oil and gas geoscientists contribute to the UK's delivery of a long term solution to nuclear waste?

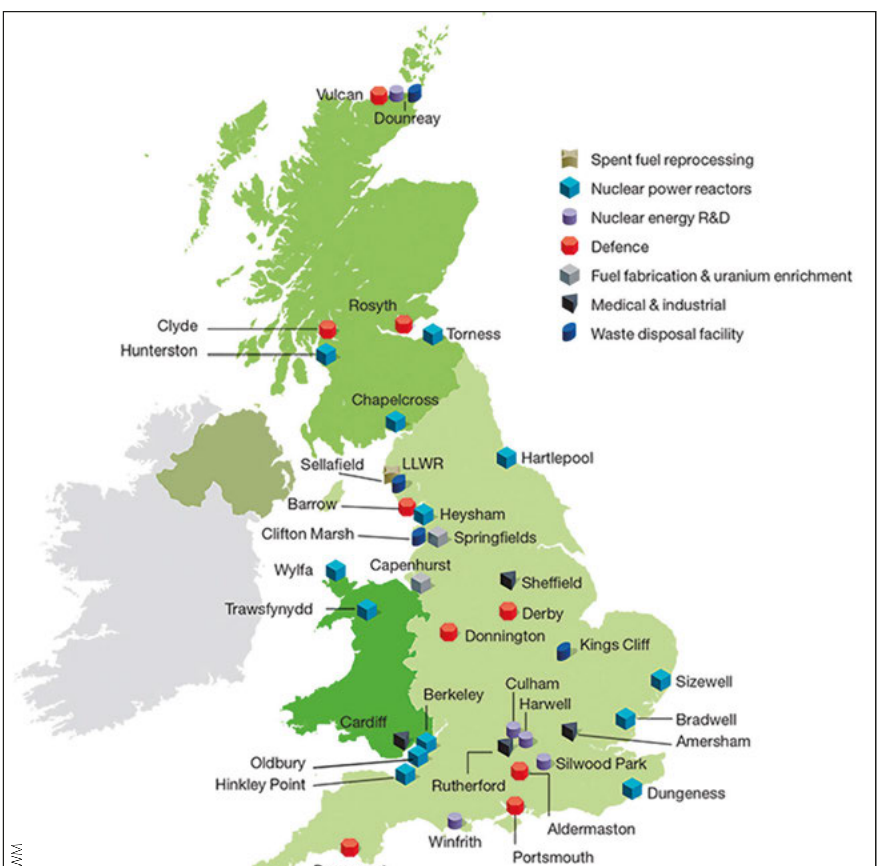
KIRSTY SIMPSON; RWM Ltd

Nuclear power generation has been part of the United Kingdom's energy mix for over 60 years since the first electricity generating plant opened in 1956 at Calder Hall and comprises approximately one fifth of its daily supply today. Nuclear technology also plays a critical role in the National Health Service, industry and defence. There are many strongly held opinions on the future of nuclear in the UK, however one thing is clear: there is a legacy of nuclear waste, which presents an environmental issue that must be dealt with.

Most of the UK's waste inventory (almost 95% by volume) is what is known as low-level waste and is safely packaged and disposed of primarily at the LLWR facility in Cumbria in the north-west of England. The rest of the higher activity waste, which includes the relatively small volumes of heat-generating 'High Level Waste' from reprocessing of spent nuclear fuel, various intermediate-level wastes and a small amount of low-level waste that is unsuitable for disposal at the LLWR, is currently held in interim storage, pending the availability of a final disposal route. All of these wastes are being packaged as solid materials ready for disposal. The UK also holds stocks of other nuclear materials, which are not currently classified as waste but could become so in the future, such as unreprocessed spent nuclear fuel. Individual components of this inventory have different half-lives; however, some of this waste will remain active for hundreds of thousands of years and any permanent disposal system must provide protection over these timescales.

Currently this higher level waste is safely stored in specially engineered containers and buildings at over 20 surface nuclear sites around the country (Figure 1); this is a temporary solution and requires regular intervention to maintain safely. As Professor Neil Hyatt, professor of Nuclear Materials Chemistry at the University of Sheffield, has put it: "Technically it is feasible to repackage the waste every few decades and build new stores. However, this is effectively kicking the waste can down a never-ending road; it would be leaving the cost, risk and responsibility of managing and safely disposing of the waste to future generations who did not benefit from the energy generation."

Figure 1: Current locations of radioactive waste facilities.



UK government policy is clear that maintaining waste in these interim stores for the many thousands of years into the future required for its radioactivity to return to safe levels places too high a cost and risk to people and the environment, and it needs to deliver a permanent solution for its higher activity waste.

Successive UK governments have agreed that the safest permanent solution for its higher activity waste is deep geological disposal, in keeping with international consensus and independent scientific opinion. Other countries including Canada, the USA, Sweden, Switzerland, France, Finland and Germany are all progressing plans for geological disposal. A Geological Disposal Facility (GDF) (Figure 2) will allow the waste packages to be isolated hundreds of meters below the ground surface away from economic, political, security or future environmental changes at the surface, without the need for human intervention for the hundreds of thousands of years required for the radioactivity to decay naturally.

What is Geological Disposal?

Geological disposal is a process by which radioactive waste is isolated deep inside a suitable volume of rock within a highly engineered multibarrier system with the host rock as the final barrier. Done correctly, this ensures that no harmful quantities of radioactivity ever reach the surface environment.

The specific multibarrier system components used will depend on the waste type and the host rock but are a combination of several factors including the form of the radioactive waste itself – for example, high-level waste that arises initially as a liquid is converted into a durable, stable, solid glass form before storage and disposal; packaging of the waste; engineered barriers (buffers) that protect the waste packages and limit the movement of radionuclides if they are released from the waste packages in the far future; engineered features of the facility that the waste packages are placed in and stable geological setting (rock) in which the facility is sited (Figure 3).

A GDF will comprise a surface site for receiving the waste packages from the transport network and transferring them to the underground facilities, which are expected to have two distinct areas: a system of vaults for the disposal of intermediate-level waste and an array of tunnels for the disposal of high-level waste. The separation is required due to the heat generated by the high-level waste and, potentially, spent fuel if any of this is designated as waste in future. The surface and underground facilities will be linked by a series of shafts or drifts (Figure 2).

The underground facilities will be 200–1,000m below ground level; a minimum 200m is required to be beyond the reach of surface processes such as glaciations over the lifespan of the GDF, and 1,000m is generally considered the maximum depth due to the increase in temperature and pressure with increased overburden thickness. The underground facilities will be completed gradually, over the approximately 100-year operational span of the GDF, as new vaults and tunnels are built, filled and eventually sealed, as required. The design of a GDF, like the multibarrier system, will be dependent on the geological setting; however, it could have a subsurface footprint of 10–20[2 superscript] km. It is possible in some locations that lateral separation might be preferable between the surface and subsurface facilities; as such it is possible that the underground facilities could be beneath the inshore whilst the surface facilities are located a few kilometers away onshore.

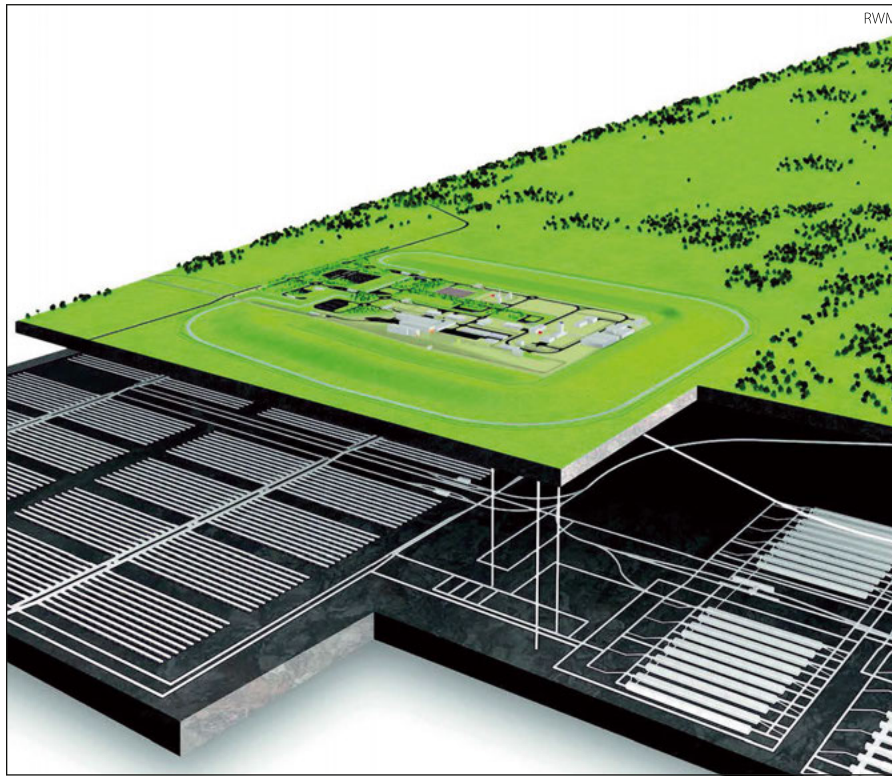


Figure 2: Artist's impression of what a GDF may look like showing the surface facilities and two separate subsurface storage areas for intermediate and high-level waste.

In the UK potentially suitable host rocks have been divided into three broad types: higher strength rocks (HSR) – igneous, metamorphic or in certain cases older sedimentary rocks which have very low matrix porosity and permeability, where the dominant method for groundwater flow is through fractures within the rock; lower strength sedimentary rocks (LSSR) – fine-grained sedimentary rocks with low permeability due to high clay mineral content and mechanically weak such that fractures are 'self-healing'; and finally, evaporite rocks – predominantly halite-dominated evaporites which provide a dry environment and are mechanically weak, undergoing creep where again fractures cannot be sustained.

A National Geological Screening exercise (NGS) was carried out by RWM, with the BGS, based on guidance developed collaboratively using experience from the geoscience community, our sister organizations overseas and wider interested parties, and reviewed by an independent review panel established by the Geological Society of London. The geological attributes assessed are critical for establishing the longterm safety of a GDF: rock type (as defined above), rock structure (in this case major faults defined as having throws greater than 200m and highly folded zones), groundwater, natural processes (glaciations, earthquakes etc.), and resources (both historical extraction and potential for future exploitation). A series of reports and maps for the 13 BGS-defined regions of England, Wales and Northern Ireland was published in 2018 as a resource for any interested parties or communities in starting communications about the GDF siting process (Figure 4).

UK and Welsh government policies are clear that site selection for a GDF will be based on community consent and support.* This means that the local community will have to expressly consent to hosting a GDF before RWM

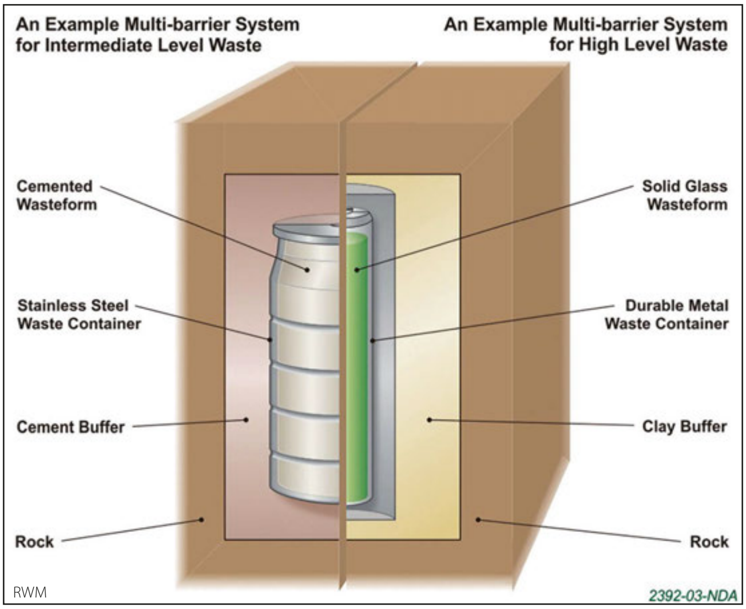


Figure 3: Example of potential multi-barrier systems.

can seek the necessary permissions to build and operate it. A GDF can also not be built unless RWM can demonstrate that it meets the high standards of safety, security and environmental protection required by the independent regulators, including the Environment Agency and Office for Nuclear Regulation (Figure 5).

Site Characterization for a GDF

The GDF program is a unique proposition in major infrastructure projects. Unlike HS2, Crossrail and the Thames Tideway Tunnel, it encompasses not just the surface and shallow subsurface (<100m), but requires the identification and characterization of a volume of rock hundreds of meters below the surface, an accessway of several km, and a much wider detailed understanding of the geology, hydrogeology, structure and future evolution of a significant region around the site to account for longterm safety post-closure. This is where the addition of the skills, knowledge and experience of subsurface professionals from outside the ground investigation and construction engineering industries can be hugely valuable.

The first stage of Site Characterization is similar to a New Ventures investigation. Building upon the information in the National Geological Screening (rather like a CGG 'Robertson New Ventures Study'), a detailed knowledge base must be built from publicly available data for any area being considered. This legacy data requires QA/QC, interpretation and further analysis including reprocessing of any seismic, building an initial high-level understanding of the potential host rocks, their geometries, overlying and underlying strata, facies and possible characteristics. At this point the Site Characterization team can provide initial models and variables (with large uncertainty ranges) that the hydrogeologists, geotechnical engineers, engineers, and safety case team can use to begin their models, designs, requirements, and feasibility assessments.

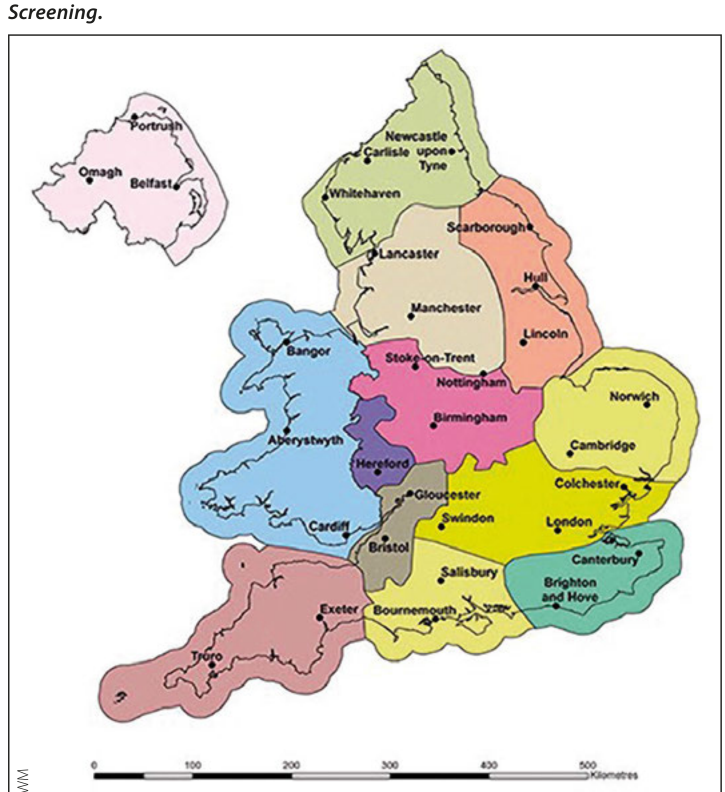
The analysis of this legacy data will also create a foundation for the investigative stages of the site characterization; in many cases seismic surveys will be the best source of non-intrusive data gathering. This is one area where experience from the oil and gas industry can be invaluable. Not only is seismic survey design and acquisition (including all the permitting and safety surrounding acquisition) the bread and butter of petroleum geophysicists, but as development of sophisticated acquisition and processing techniques has largely been driven by the requirements of oil and gas exploration and production, the specific requirements of imaging for a GDF site investigation will be an exciting challenge for any subsurface professional.

Importance of Seismic

RWM hopes to be able to begin acquiring our first seismic surveys in 2022, and it will provide many technical challenges to gain high-resolution imaging down to approximately 1.5km, especially in the shallowest sections, without compromising deeper imaging. It is highly likely that at least one community will wish RWM to investigate the inshore area, adding the acquisition challenge of working in very shallow water, transition zones or areas with large tidal ranges. The processing and interpretation of these surveys to gain as detailed an understanding as possible using offset wells will require the specialist expertise of many subsurface disciplines.

At this stage RWM will construct 3D geological models, which will give us an understanding of where within any areas being considered there is likely to be an appropriate volume of

Figure 4: The thirteen geological regions covered by the National Geological Screening.



potential host rock. Expanding upon this, using many of the techniques developed by the oil industry such as rock physics and seismic inversion, RWM will be able to start populating these models with more constrained parameters, which will allow our colleagues to perform sophisticated modeling and feasibility testing.

RWM anticipates that after the non-intrusive investigation stage there may be a number of prospective sites which will show greater potential than others for hosting a GDF that will meet and exceed the required safety standards; this subset of potential sites might continue in the process.

Carrying on the analogy between a GDF and oil and gas exploration, we might consider this stage to be equivalent to moving from exploration to appraisal of a discovery.

RWM's drilling campaigns will be targeted slightly differently from classic oil and gas drilling. The mechanics of our borehole planning and data acquisition will be very familiar to petroleum geoscientists. Key differences will be that the full length of several of our boreholes will be cored and logged, and drilling locations will be selected on different requirements, e.g., understanding the hydrogeological properties of what in oil and gas would be considered caprocks, or defining the damage zones around major fault systems; long-term measurements downhole lasting a number of years are likely.

The analysis of the initial borehole drilling will result in the updating of all models and the addition of new models, particularly hydrogeological and geochemical modeling, and a decision on further rounds of drilling investigation.

Our investigative boreholes cannot just be plugged and abandoned. If they potentially impact upon a GDF location then they must be sealed in such a way that they will not adversely affect the post-closure safety case of that GDF. Thus borehole sealing is an extensive area of study and planning at RWM, which needs to be included in any drilling campaign. This is because a borehole near a potential GDF site could affect groundwater circulation and provide an accelerated route back to surface for radionuclides if improperly sealed.

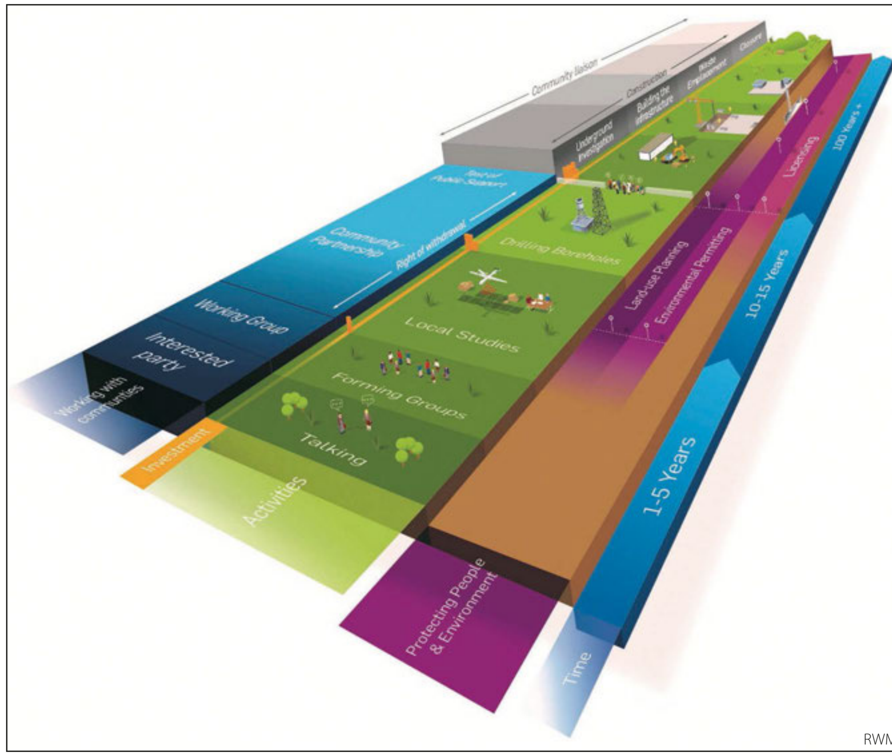


Figure 5: Process for implementing a GDF, this process is initiated by an Interested Party, who may be a landowner, local authority, member of the public, local organisation or company.

New Careers for Petroleum Geoscientists

The process of site characterization for a GDF is a fascinating blend of almost all the specialisms of geoscience, and myself and several of my colleagues have been lucky enough to move from oil and gas directly into this pursuit. Our daily work includes collaboration with people who are experts in their fields in many diverse areas, such as nuclear waste packaging specialists, civil engineers, ground investigation specialists, tunneling and boring specialists, and many more, constantly being challenged and learning whilst sharing our specialist expertise.

RWM feels very passionately that a GDF is the right solution for nuclear waste in the UK and works with an experienced supply chain that encompasses experience of major infrastructure projects, nuclear projects, renewable energy and oil and gas projects. As we progress down our path towards investigating and identifying sites and delivering geological disposal capacity for the UK, we will need increasing support from experienced geologists, geophysicists, drilling engineers, geotechnical engineers, geomechanics specialists, and many others. These experts will come from mining, oil and gas, civil engineering, nuclear, and many other industries, and what makes this a challenging and exciting project to work on is how much we all have to contribute and learn from each other.

Note

* Radioactive waste management is a devolved issue in the United Kingdom and the UK government in Westminster has responsibility for the policy only in England. The Welsh government has published its own policy on working with communities, and there are no plans to site a GDF in Northern Ireland. The screening report is purely a technical exercise. Any future policy decision on geological disposal in Northern Ireland would be a matter for the Executive.

References

Department for Business, Energy & Industrial Strategy (BEIS), Implementing Geological Disposal – Working With Communities, December 2018.

RWM, National Geological Screening, 2018. (http://www.gov.uk/guidance/about-national-geological-screening-ngs) ■

Countdown to CCS

Between 2020 and 2030, several large-scale CCS facilities will become operational in north-west Europe. While not the first, that honour already taken by the Sleipner CO_2 storage site, they represent a significant step forward in that CO_2 will be sourced from onshore industry and power generation, transported offshore and stored in the subsurface.

In this contribution, we share a summary overview of those sites focusing on Northern Lights, Northern Endurance and Acorn.

Operator	Expected First Injection	Age	Crest	Reservoir	Seal	Storage Capacity (MT)	CO_2 Injection (MT/pa)
Northern Endurance Partnership	2026	Triassic	1,040m	Bunter Sandstone	Triassic Halite and Shale	450	4 up to 10 by 2030
Northern Lights JV DA Aurora	2024	Jurassic	2,100m (post migration)	Johansen and Cook/ Dunklin Gp.	Lower Jurassic Drake Shale	minimum 100	1.5
Pale Blue Dot Acorn / Goldeneye	2024	Cretaceous	2,500m	Carrack Fm. Captain Sandstone	Lower Jurassic Rødby Paleocene Lista	152 (at Goldeneye) 500 (East Mey)	5 by 2030
INEOS Oil and Gas Denmark Project Greensand (Nini)	2025	Eocene/ Paleocene	1,700m	Siri Fairway	Eocene Claystones	4.5	0.5 (2025) 3.5–4 (2030)
Porthos JV P18-2, P18-4, P18-6	2024	Triassic	3,000–3,500m	Bunter Sandstone	Triassic and Jurassic Shale	38 expansion potential	c. 2.5

Table 1: Data gathered from company websites, TGS data and interpretive products (full references and additional data available Geo ExPro online).

TGS

NW EUROPE OFFSHORE CARBON STORAGE SITES

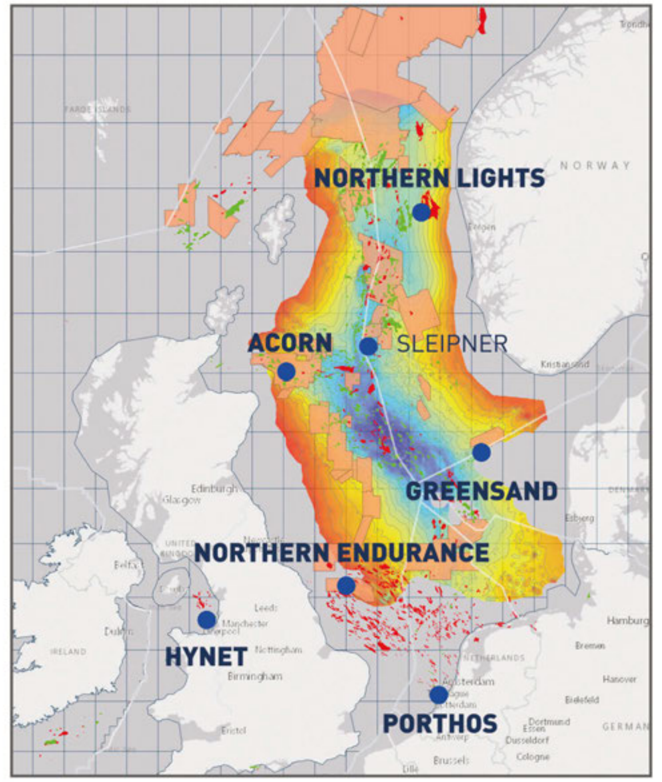
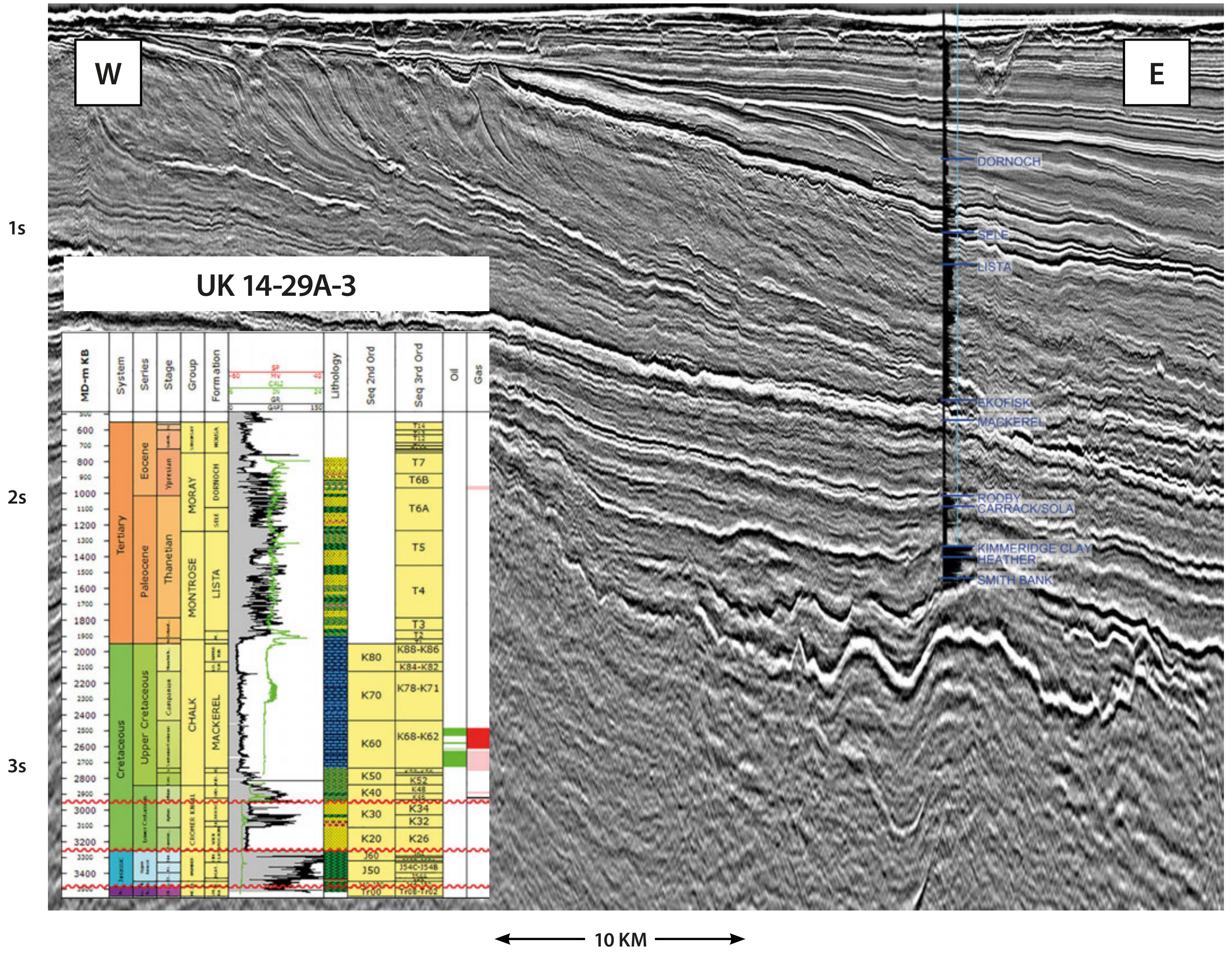


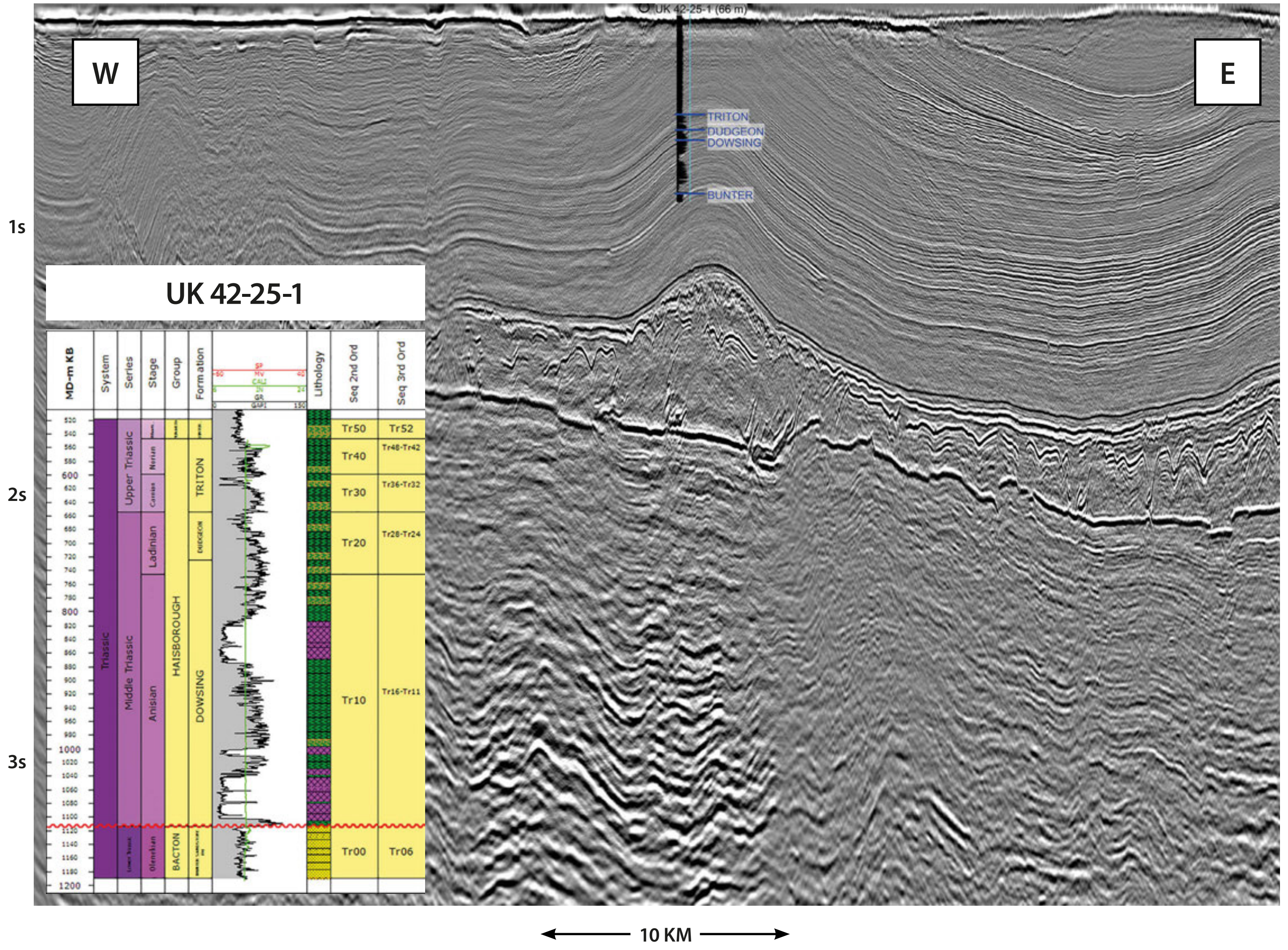
Figure 2: Map showing the location of the more advanced offshore carbon storage developments in the North Sea. Northern Endurance, Acorn and Northern Lights are expected to be the larger storage sites with Hynet, Porthos (plus other Dutch CCS sites) and Greensand representing either smaller storage potential or earlier phase development.

Figure 1: Foldout shows three seismic sections through TGS's 3D data over the Acorn CCS site, the Northern Endurance CCS site and a 2D line from TGS's CFI-NSR dataset over the Northern Lights CCS site. Inset well images are taken from TGS's Facies Map Browser.

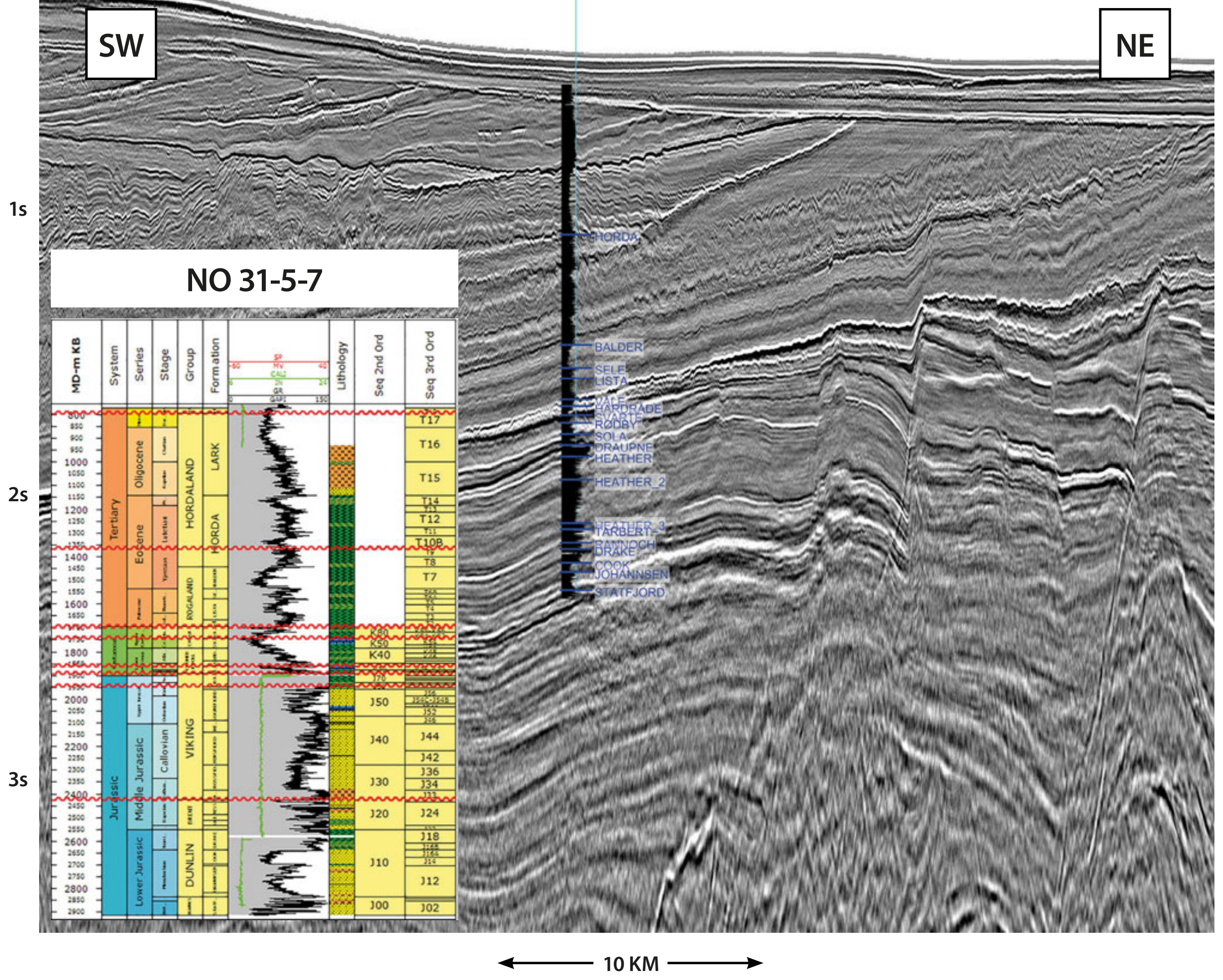
ACORN



NORTHERN ENDURANCE



NORTHERN LIGHTS



Large Commercial Scale CCS Projects Less Than Five Years Away in Europe

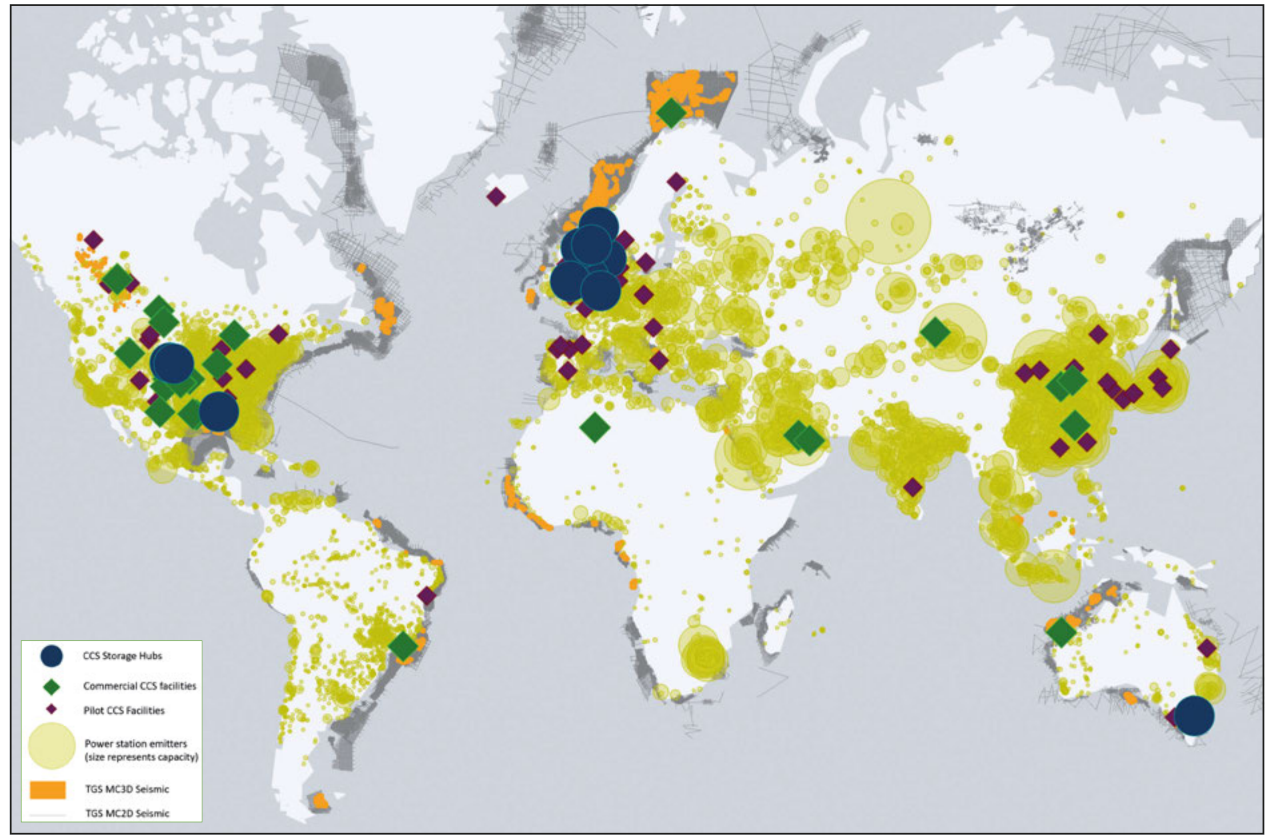
WILL BRADBURY, ALEX KUROBASA and BENT KJØLHAMAR; TGS

Europe is leading the way in the energy transition with growth in renewable energy sources being part of a wider story with many elements needed to deliver a sustainably developing and economically viable energy transition. The International Energy Association (IEA) estimates that the emissions generated by industrial processes from energy production to product creation constitute a quarter of the world's carbon emissions. Figure 1 shows a map of global CO_2 emissions from power generation highlighting optimal areas for Carbon Capture and Storage (CCS) project development. Carbon capture and storage are required to deliver the integrated energy system that facilitates efficiencies and transition while global energy demand continues to grow. The IEA includes the need for CCS in its roadmap to net zero by 2050, stating that reducing the role of carbon capture (as well as nuclear) will make achieving the net zero goal more costly and less likely (IEA, 2021).

The CCS Sites

The Global CCS Institute reports that the worldwide 2020 carbon capture capacity is about 40 megatons and needs to increase to more than 5 gigatons by 2050 for a two-degree trajectory. The current biggest European marine CCS hubs typically aim to store up to 5 megatons per year by 2030 albeit with expansion potential indicating undercapacity in storage relative to emitted CO_2, with the link between capture rates and injection rates expected to evolve over the coming years.

Figure 1: TGS worldwide CCS Pathfinder showing emissions, subsurface data availability and CCS sites in testing, currently operational and large-scale planned facilities.



Stakeholder engagement and support for CCS technologies will be needed alongside a commercial model that can take carbon storage beyond reliance on government subsidy. Evolving regulatory processes, carbon pricing or taxes are expected to support a global market; however, these are yet to drive wider scale nonsubsidized commercial developments. Focusing on the specific sites currently under development in the North Sea region we see that they represent a diverse range of solutions employing different subsurface, transportation and sourcing strategies. While a review of the risks and risk mitigation measures associated with one form of transport or site over another is beyond this contribution's scope, a summary of currently planned solutions is provided.

The primary European CCS sites such as Phase 1 of the Acorn project, will target the depleted Goldeneye field whereas the Northern Endurance project has targeted the Bunter Sandstone saline aquifer. Several different transport mechanisms are also planned, e.g., Northern Endurance and Porthos will primarily use pipelines from capture sites associated with industry, port facilities and power generation. Northern Lights will pipe CO_2 from a port facility onshore Norway. The onshore port will receive its CO_2 via shipping routes initially from emissions captured in the Oslo area; however, longer distance shipping and growth in supply routes is expected to drive expansion of operating storage hubs.

Table 1 on the main foldout summarizes some of the key elements of the existing storage sites. All are sandstone reservoirs possessing good porosities and thick, regionally extensive and often proven shale caprocks. Typically, the saline aquifers offer larger overall storage capacity compared to depleted fields, and all structural crests are deeper than 1,000m to accommodate CO_2 in an optimum state for storage. These sites will leverage the vast experience of the oil and gas industry in these play types. Further into the future more exotic solutions may be developed as alternatives; for example, storage within basalts offering a different solution to long-term fixing of CO_2 (Kjølhamar et al., 2021) that is currently being tested onshore at sites in Iceland and the US.

Leveraging Decades of Exploration

Decades of oil and gas exploration has led to the acquisition of vast volumes of subsurface seismic and well data across the North Sea. In more recent times, attention has begun to shift into leveraging this information and the wider geological understanding of the subsurface to evaluate saline aquifers for new potential CCS sites. Regional assessments and containment analysis of various stratigraphic intervals across the North Sea have also seen recent growth in fields of research and wider discussion within the energy industry (e.g., Heinemann et al., 2012; Norwegian Petroleum Directorate, 2014; Lloyd et al., 2021).

A detailed understanding of historical wells and their place in the basin's broader geological context is crucial to assess a potential candidate site. Reconciliation of all available well data integrated with high-resolution seismic data can build a robust and detailed geological model to accurately predict the presence and properties of potential injection intervals. Existing datasets, such as the TGS Facies Map Browser, are suitable for reconnaissance and identification of CCS sites.

A recent example of new data for CCS is the well NO 31/5–7 (see foldout), completed by Equinor in March 2020 close to the Troll field as part of the Northern Lights Project. This was the first dedicated CCS well to be drilled within the North Sea with the objective of assessing the CO_2 injection and storage potential.

There is a trade-off to be made when it comes to current subsurface understanding and risking. Depleted fields commonly have the largest amount of available data with which to understand the subsurface and feasibility of injecting CO_2. Conversely, older depleted fields will have multiple penetrations from older wells resulting in a different set of risks to consider. Saline aquifers typically don't have the volume of high quality data from seismic or wells; however, the storage capacity potential can be greater. This data gap between a saline aquifer target with limited data-derived subsurface constraint and an injectable CO_2 reservoir must be bridged. If this can be achieved with a cost-effective data acquisition program in the form of a well (as in the case of Aurora site for Northern Lights) or new/reprocessed seismic data, then less structurally complex saline aquifers may offer lower cost, lower risk carbon storage opportunities.

Monitoring

Site selection has implications for the monitoring solutions. 4D monitoring programs to screen ongoing reservoir conditions need to be fit-for-purpose, cost-effective and supportive of positive margins.

Thus, from a monitoring data perspective an element of the ongoing success of a CCS project is meeting the economic challenge of monitoring the integrity of the store. Fortunately in a basin as mature as the North Sea a vast array of geophysical technologies have been developed, tested and put into wide scale use with increasingly innovative solutions since the oil price started to rise at the end of the 1990s and early 2000s. Industry can draw from this experience to deploy smaller scale, more efficient, higher resolution solutions such as P-Cable-type streamer acquisition together with in well solutions such as optical fiber recording to deliver the data needed to demonstrate conformance and containment of the CO_2 stored.

Over the next 10 years Europe will see between three and six major CCS sites come online and likely a clear intent to expand these existing hubs as well as develop new sites. Continued and new support from stakeholders such as regulators, industrial partners, and the public will need to be in place for CCS to be an accepted technology with a key role to play in a sustainable, economically viable and integrated energy system for Europe.

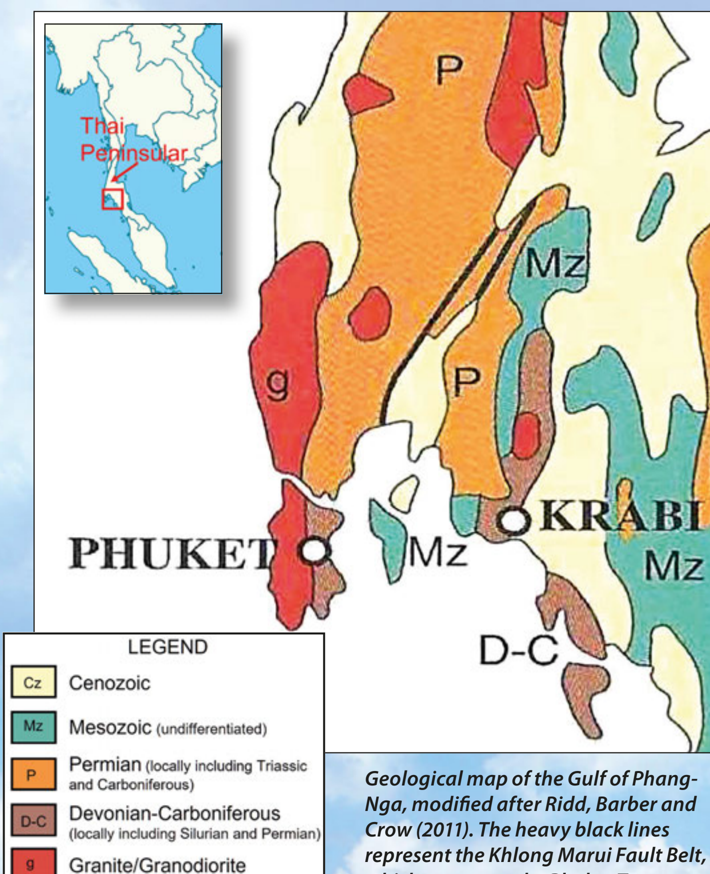
References available online. ■

Cliffs, Kayaks and Krabi

A popular tourist destination, the Thai Peninsular has plenty to tempt the geotourist.

JANE WHALEY

For many, Thailand is the epitome of the perfect holiday destination: sparkling blue seas, tropical islands; long, golden beaches; wonderful mountain scenery; and delightful, friendly people. As in many places, much of what is enjoyable here is a direct result of the underlying geology.



Geological map of the Gulf of Phang-Nga, modified after Ridd, Barber and Crow (2011). The heavy black lines represent the Khlong Marui Fault Belt, which separates the Phuket Terrane from the Lower Peninsular.

Stretching over 1,600 km from north to south and 780 km at its widest point, Thailand is too geologically varied for a single article, so while the mountains and plains north and east of Bangkok make up most of the country's land area, here we will concentrate on the Thai Peninsular, which extends nearly 1,000 km from Bangkok to the Malay border and in places is barely 12 km wide. In particular, we will look at the west-central part of the peninsular, centered on the horseshoe-shaped Gulf of Phang Nga, where some of the country's most popular tourist destinations, including Phuket and Krabi, are located.

Two Plates Meet

The Thai Peninsular runs roughly north to south – the Upper Peninsular – before bending halfway down to trend north-west–south-east at a point marked by the Khlong Marui Fault south of which is the Lower Peninsular.

Jane Whaley

Vegetation tumbles down towering karst cliffs that shelter hidden beaches near Krabi.

Two tectonic blocks have been involved in the creation of Thailand: the Indochina Block in the east, and Sibumasu, once part of the larger Gondwana mass, to the west. These drifted together in the Mesozoic, ultimately fusing to form one block, Sundaland. The dividing line between them suggests all of the Thai Peninsular was part of Sibumasu, except in the south, close to the Malaysian border.

A full succession of Paleozoic and Mesozoic rocks is represented in the Lower Peninsular, while Early Paleozoic is absent in the northern area. The oldest rocks comprise Cambrian sandstones and siltstones laid down in a warm shallow sea, while the Ordovician is represented by marine limestone, also with a rich fossil fauna. Silurian black shales were followed by limestones in the Devonian, probably deposited in deep water on the eastern edge side of the Sibumasu Block. Siliclastics followed up to the mid-Permian and these dominate in the Upper Peninsular, although they are much thinner further south.

Marine shelf sedimentation and the widespread deposition of limestones prevailed in Peninsular Thailand in the Late Permian, gradually becoming deeper as Paleotethys was subducted eastwards, which also resulted in the emplacement of submarine granitic and acidic volcanic rocks. By the Early Jurassic, the two plates had merged and Thailand was a single geological entity, with alternating marine and non-marine environments found in the Jurassic in the peninsular area. By the Cretaceous, continental deposition dominated, including claystones, siltstones, sandstones and conglomerates, probably deposited by meandering rivers and alluvial fans.

The Tertiary has been studied extensively in Thailand because of its importance in hydrocarbon and minerals exploration, and more than 70 intermontane and rift basins have been identified, including many offshore. However, only a few small Tertiary basins have been recognized in the peninsular, including one in Krabi Province.

Mangrove swamps and wooden jetties backed by karst limestone mountains in north-east Phang Nga Bay.

Picturesque Phuket

The island of Phuket was one of the first places in the country to be discovered by holidaymakers and is now quite built-up and busy, with an international airport, although it still retains some quieter areas. Separated from the mainland by a narrow 500m creek, it forms the western side of Phang Nga Gulf and lies at the inflection point of the Thai peninsular. Geologically, it is significant for giving its name to the Phuket Terrane, which dominates the Upper Peninsular and is sandwiched between two major fault belts: the north-east to south-west Three Pagodas Fault in the Upper Peninsula and the south-south-west – north-north-east trending Khlong Marui Fault to the south.

The Phuket Terrane mostly comprises rocks of the Late Carboniferous to Early Permian Kaeng Krachen Group, which is predominantly a thick, poorly-sorted pebbly mudstone (diamictite) containing some cobble or boulder-sized clasts, with limestone and shale layers. It is thought that the Phuket Terrane material was deposited in a glacio-marine environment in a rift formed as Sibumasu split from Gondwana. Similar rocks are found in a narrow band stretching from Sumatra to south-west China. The Khlong Maru Fault, which passes just to the east of Phuket, appears to have been the eastern edge of the rift, as similar-aged rocks are thinner in the Lower Peninsula, with less diamictite. On Phuket the Kaeng Krachen Group outcrops mostly along the eastern side of the island, forming headlands in the south-east at Cape Panwa and Ko Sire.

Much of Phuket itself is composed of medium-grained granite and granodiorite intruded into the sediments of the Kaeng Krachen Group as Sibumasu was subducted beneath the Indochina plate. These granites are part of the Cretaceous Western Granite complex running from Phuket northwards into Myanmar in a belt of small batholiths and isolated plutons. They form the mountains, up to 400m high, that dominate the landscape in Phuket. Many tours take visitors to admire the stunning viewpoints, such as Karon in the south of the island, Laem Singh in the west and Promthep Cape, a popular sunset viewing point at the southernmost tip of the island. From the Big Buddha site in the center of the south-west mountains one can have a 360° view covering much of Phuket – but you may have to share it with quite a few other visitors. The mountains also offer the traveler excitements such as mountain biking and jungle trekking.

James Bond Was Here!

Many visitors to Phuket take a boat trip to northern Phang Nga Bay to visit what is commonly known as James Bond's Island, which featured prominently in the 1974 movie *The Man with the*

Golden Gun. The bay is studded with picturesque islets formed by vegetation-clad, sheer-sided limestone pillars, many eroded around their base, creating a stunning seascape where the rocks seem to float on the sea. They are composed of Ratburi Limestone, which was deposited on the Kaeng Krachen Group from the Early Permian, as a large carbonate platform rapidly covered much of Sibumasu as it moved into more temperate and eventually sub-tropical waters in the Late Permian. Older sections of the Ratburi Limestone tend to be a dark gray well-bedded muddy limestone with chert nodules, while the upper member is lighter and more massive.

After uplift the wind, waves, water currents and tides gradually eroded the platform until, aided by tectonic movements, its remnants can now be seen throughout the area as dramatic isolated small islands, which can be tens of meters in height and just a few meters across at their base. Boats trips from either Phuket or Krabi take in a number of the islands, stopping for snorkeling or visiting the 'sea gypsy' village of Koh Panyee. It is also possible to explore them by sea kayak and to discover caves and hidden lagoons – all amazing experiences.

The islands are part of Ao Phang Nga National Park which also includes the largest area of native mangrove forest remaining in Thailand, with rare birds and animals; well worth a visit by kayak or raft.

Looking east across the karst scenery of Krabi Province from Dragon's Crest viewpoint, an outcrop of Mesozoic sandstone a few kilometers north-west of Ao Nang.

Cliffs and Caves

Traveling further east and then south round Phang Nga Bay we pass through a less touristed area dominated by Quaternary sediments, although there are still ample opportunities to explore the mangroves and limestone cliffs of the coastline, as well as to admire the karst hills rising steeply several hundred meters out of the flat inland scenery, before reaching the Krabi area. In recent years this has become a mecca for backpackers, attracted by the laid-back atmosphere and the plentiful opportunities for adventure sports such as climbing, hiking and sea kayaking. The abundance of these activities is again mostly due to the Ratburi Formation karst limestone cliffs and islands, particularly around Railay Beach, which, due to the surrounding sheer cliffs, is only accessible by boat from either

Part of the 'fossil beach' at Laem Pho. The pan shape is the result of compaction and drape over the irregular underlying Ratburi Limestone. Inset: Close-up of the gastropod bed.

Krabi town or the tourist center of Ao Nang. The limestone here is made more dramatic by alteration and staining of the white and gray rocks with yellow streaks and by dramatic stalagmites hanging from them. Also worth a visit are the pools surrounded by towering forested cliffs, created when coastal caves collapsed to form a lagoon, and often only possible to enter by swimming or kayaking through the cave entrance.

The small Tertiary-aged Krabi Basin, centered on the town of the same name, has been well studied as it contains three open pit coal mines. Although now considered an over-simplification, for some time all Tertiary rocks in Thailand were described as being part of the 'Krabi series'. The Paleogene sequence here passes from non-marine silts and clays to gradually coarser sediments laid down in a brackish or fluviomarine environment. There are abundant fossils in these beds and a major tourist attraction is the so-called 'Fossil Beach', situated at Laem Pho between Krabi and Railay, where pavements of an argillaceous fossiliferous limestone of Oligocene-Miocene age can be explored in the intertidal zone. The site has information notices that suggest that the fossils, predominantly gastropods, were living in freshwater lakes in which plant remains were also deposited, forming thin lignite bands.

Phi Phi Problems

Lying a 40-km ferry ride south-west of Krabi is Koh Phi Phi – actually several small islands, the two largest being linked by a narrow isthmus of Quaternary sediments. The archipelago is predominantly composed of Ratburi Limestone, with its classic steep-sided cliffs dropping into the sea, although on Phi Phi Don, the largest island and the only one where tourists can stay, the underlying Kaeng Klang group is exposed in the south and east. It contains less diamictite than on the Phuket Terrane and comprises black shales and poorly sorted sandstones, with some evidence of its glaciomarine origin in the form of dropstones.

Relatively untouched in 2000, the making of the Leonardo di Caprio film *The Beach* on the smaller of the two linked islands introduced Phi Phi to the world and it is now a popular destination, particularly for younger travelers, who enjoy its beauties by day and party by night. Diving or snorkeling on the coral reefs in the crystal waters around the smaller islands has become a great draw but unfortunately tourism has been detrimental to the ecosystem; at one point Maya Bay, where the filming took place, received thousands of visitors each day. The Thai authorities have attempted to rectify the problem by temporarily closing the beach and other areas and this, coupled with lack of tourists due to Covid-19, appears to be having some impact.

Peaceful Koh Lanta

Continuing our journey down the eastern side of the Phang Nga Gulf we travel through relatively flat Quaternary and Tertiary sediments, with a distant view of inland Mesozoic hills, before hopping onto a ferry for a short crossing to Koh Lanta Yai; a quieter destination, with less dramatic scenery than further north as the island is dominated by Upper Paleozoic siliclastics. There is little documentation on the actual rocks making up the island, but it is thought that they are primarily siliclastics of the Upper Carboniferous Kaeng Krachen Group, unconformably underlain by Lower Carboniferous siliclastics and possibly Devonian shales.

It is a delightful place to visit, with long sandy beaches, small coves, a hilly rainforest interior complete with hikes to a 'Tiger Cave', and the picturesque Lanta Old Town, which hosts century-old wooden houses built on stilts jutting into the sea, surrounded by mangrove forests. This is a great jumping-off point for snorkeling, diving and kayaking trips out to surrounding islands, where the karst once again predominates.

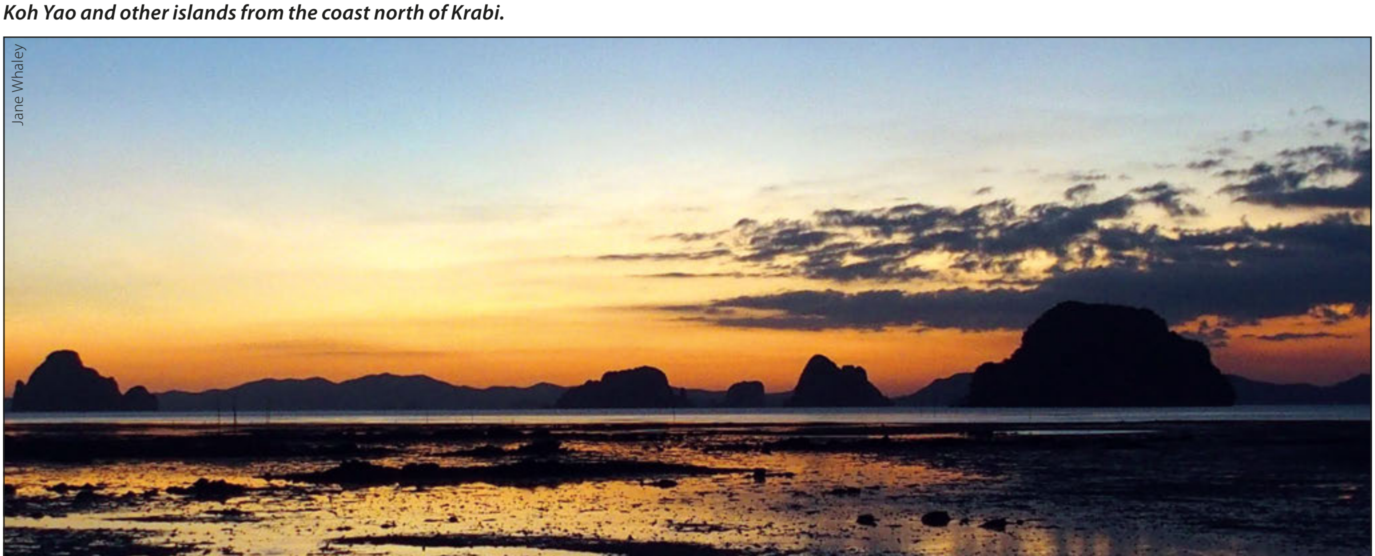
So, at the end of our tour, find a nice viewpoint, sit back and enjoy the ambiance as the sun slowly sinks into the sea in yet another spectacular sunset. Beautiful!

Reference

Ridd, M.F., Barber, A.J., and Crow, M.J. (Eds), 2011. *The Geology of Thailand*. Geological Society, Londoon

For further references and photos see online. ■

Koh Yao and other islands from the coast north of Krabi.



Jane Whaley

The Power of Data

Effective use of digital tools is vital for an affordable net zero future.

JANE WHALEY

In the energy transition conversation, discussions tend to center on where the energy of the future will be sourced and on how to deal with future emissions – but data is vital to any progress in these areas and therefore machine learning (ML) and artificial intelligence (AI) are key elements of the energy transition. According to the International Energy Authority, reaching net zero by 2050: "requires nothing short of a total transformation of the energy systems that underpin our economies" and effective use of data will play a crucial role in this transformation.

We know, for example, that the new energy world will be much more flexible than it is at present, with demand being fed from a wide variety of sources. The ability to switch between these sources quickly and efficiently will require the intelligent use of large quantities of digitized information, varying from weather reports to mechanical data, in order to maximize yields from wind and solar farms and balance generation and consumption locally.

As many oil and gas companies have realized, digital technologies will be key to achieving their net zero targets. These range from using predictive analysis to ensure the efficiency of their operations, to developing more accurate subsurface models to make maximum use of resources and to facilitate emission-reducing strategies like carbon capture and storage. As an example of progress already made, one supermajor recently described how an algorithm introduced to reduce emissions has resulted in improved production data, justifying the investment in AI.

Digitalization and Standardization

At the forefront of the movement towards the more efficient use of data is the need to transfer as much of it as possible into digitalized formats that will be accessible to and readable by a range of users. The oil and gas industry has always generated large quantities of data, but often in formats attached to specific applications and organizations. The pressure for standardization is therefore increasing, with companies and organizations collaborating globally to create common data standards. The Open Subsurface Data Universe Forum is a case in point. It comprises over 200 organizations from all over the world, ranging from supermajor oil companies and giant consultancies like Accenture and Ernst & Young to established subsurface service organizations and smaller cross-industry tech businesses, as well as data specialists. Its aim is to deliver an "open source, standards based, technology-agnostic data platform for the energy industry that stimulates innovation, industrializes data management and reduces time to market for new solutions."

It is important that the oil and gas industry makes full use of its existing data as well as gathers information from new sectors, as ML and AI need access to good quality digitized data, historical as well as current – but this can create huge data storage issues. Governmental and regulatory organizations like the UK's Oil and Gas Authority (OGA) are increasingly becoming involved by collecting data and making it available so companies no longer need to store it. Teams and partners can thus all access the same data without having to download and make multiple copies. Collaborative data can also be used to look at the wider energy sector to understand how energy assets can be more integrated, by, for example, using nearby wind farms to power offshore installations and thus reduce that installation's carbon footprint.

Digital twins: one of the many ways in which digital tools are helping the oil and gas industry achieve net zero.

Trust and Openness: the New Normal

As this demonstrates, a key factor in this new digitized energy world is the need for collaboration across a diverse range of companies and organizations. The energy industry cannot fully embrace digitalization alone and nor can individual companies; even a company as big as Shell admits it can afford neither the cost nor the time of 'going it alone' in this complex field, so new ways of working both between companies and across industries are paramount. At the same time, collaborating is not always easy; systems have to protect both business and financial interests, whilst ensuring that important data that could, for example, have safety implications, is accessible to all who need it.

Sourcing data and applications through the Cloud encourages collaboration and has proved to be cost efficient for the oil industry, as companies can access computer resources as they need them, rather than purchase heavy duty software without knowing their future requirements. Accessing data in this manner usually proves more efficient, as the geoscientists need to spend less time organizing and managing data and more time analyzing it.

Using the Right Data

With all this data-gathering and sharing, it will be important to know that we are collecting both the right data and the right amount of data for our decision-making. There is always a possibility that using digital technology simply generates yet more data, without it necessarily being useful, but AI can be used to extract patterns and help show which data is best at finding the most efficient methods, not just operationally but also in digitalization, helping organizations make better decisions. With limited time to make the changes needed to achieve net zero, it is important that we focus on identifying and working on those areas that can make the most impact in the energy transition.

Hywind Tampen is an 88 MW floating wind power project intended to provide electricity for the Snorre and Gullfaks offshore field operations in the Norwegian North Sea. It will be the world's first floating wind farm to power offshore oil and gas platforms.

One of the areas in which AI can significantly help O&G companies to reach their net zero targets is emissions information. Traditionally, this data has been collected at the end point in facilities, but it is better to gather data throughout the process, which will require installing additional sensors to look at a wider range of information. In this way, instead of just concentrating on production data when considering emissions, we would be able to interrogate the whole process and include additional data such as maintenance, downtime and access to spare parts. Manipulating that data will not only give us a clearer picture of the emissions involved; it will also point to ways in which those emissions can be quantified and controlled throughout the process. The resultant data needs to be standardized, so it can be read across a variety of applications and comparisons can be more easily made.

Oil companies with ambitious net zero targets are using AI and ML to look beyond just production as they gather huge amounts of data in a wide range of areas to analyze emissions across the range of their activities. For example, they will need to include improving emission levels from ships carrying their products across the globe; or if they decide on an EV fleet of road tankers, how will the electricity to power them be sourced and used and what is the carbon footprint of the construction of the vehicles?

Challenges Ahead

Major technological changes in any industry are never easy and using AI and ML in the energy transition is no different. Many questions are being asked, particularly around the speed, complexity and cost of the process. A much greater range of data than has been traditionally used will be generated in vast quantities – and even with AI, much more time will be spent in analyzing the data.

One of the most important issues is the huge amount of energy that will be needed just to power the giant computers needed for digitalization and AI; could we actually be making the problem worse? Certainly, training complex AI models consumes a lot of energy, but the savings generated from optimizing processes should outweigh the consumption. The process of creating a digital twin of a facility, for example, will obviously result in higher emissions, but the evidence so far suggests that aggregate emissions for the project will be lower.

To make any change effective, we need to have the right people with the best training available and also to ensure that everyone is involved in the process and understands the importance of what is happening and how to use the new technologies to make better decisions. Skills are a key part of the success of this transformation; not only ensuring that new people come into the O&G industry with the relevant expertise and a different mindset, but also helping existing employees gather the skills they will require for the future.

One area for concern is that increased collaboration and remote access heightens the potential for cyberattacks and data leaks, requiring increased security, which must be taken into account when considering the cost of digitalization.

The Way Forward

The need for digitalization, ML and AI in the petroleum industry has developed a new urgency as operators and the services sector strive to meet their ambitious net zero targets. However, one unexpected advantage of the Covid-19 pandemic is that it has accelerated the speed and lowered the cost of digitalization and AI throughout the world. It has also proved the veracity of the old adage 'necessity is the mother of invention'; technological innovations have made great strides and many of these will be applicable to helping the oil and gas industry move through the energy transition. ■

Suriname's Demerara

An exploration hotspot for the coming years?

CLÉMENT BLAIZOT

Guyana, close to Western Suriname's offshore boundaries, has steadily made headlines since 2015, delivering massive oil discoveries such as Payara, Liza, Tilapia, Haimara and even more recently Uaru. The gross recoverable resource for the Stabroek Block is now estimated to be more than eight billion oil equivalent barrels. If there seems to be no end to Guyana's offshore success, the story so far for Suriname is pretty much just beginning. Although Suriname has some old onshore fields (Tambaredjo and Calcutta) from the 1960's, the deep offshore part remains virtually unexplored. It was only a matter of time before Guyana's oily 'Golden Lane' eventually spread Eastwards and reached Suriname with Total's and Apache's Block 58 Maka, Sapakara and Kwaskwasi discoveries in 2020.

Chasing Guyana's Success

Lying between Guyana and French Guiana, the prominent Demerara spur (Figure 1) also hosts some exciting oil and gas prospects, despite some recent disappointment from Tullow's Block 47, Goliathberg-Voltzberg North prospect. In oil and gas exploration, as in many other aspects of life, success often follows early setbacks. This study focuses on the relatively abandoned deep offshore eastern part of Suriname where it is believed the recurrent oil seeps spotted on sea-surface from the old 1977–1978 wells, Demerara A2-1 westwards to the French Guiana 2-1 well eastwards, could predict future potential for the plateau. It highlights oil seeps detected on high coverage synthetic aperture radar (SAR) data, with more than 150 SAR images acquired at different dates within a 20-year timeframe. This time window offers a mean coverage of about 50 different images on every X and Y in the area of interest, which can be considered as a 'comfortable' coverage. Oil seeps have long been utilized in the exploration for oil and gas since the 'visual detection' of the Cantarell giant offshore oil field by Mexican fishermen in the 1970's. They can be quite elusive, very much depending on the interpreter and their methodology and experience in discriminating natural oil seeps from pollution or lookalikes. Furthermore, the conclusions one may draw from seeps can sound controversial; finding numerous seeps does not identify where to drill – it 'only' suggests that there is a working local petroleum system – while finding no seeps does not mean the area is devoid of potential. When possible, an essential step to strengthen the seep interpretation, is correlation with seismic data so that the hints from 'upstairs' can be confirmed 'downstairs'. Nevertheless, satellite seeps studies remain a formidable tool when used appropriately in conjunction with the retrieval of numerous SAR scenes at different dates. Very high data coverage, time recurrence (seeps persisting on different dates) coupled with spatial proximity (seeps concentrated in the same location) will help reduce uncertainty.

Figure 1: Study setting with discoveries and Demerara Plateau. Bathymetry from Ryan et al (2009).

Geological Setting

The passive margins of the Guiana Shield are located at the junction of the Central and Equatorial Atlantic rifting at a peculiar triple point between three continents: Africa, North America, and South America. Therefore, the region exhibits several different geological settings.

Located at the center of the study area, the Demerara Plateau is composed of an enduring series from Precambrian to Miocene. Following the development of thick Jurassic basaltic flows (as seen in the French Guinana 2-1 well and present in Florida and Guinea), a thick Lower Cretaceous carbonate platform developed in the western part of the Demerara Plateau (Demerara A2-1 well) whereas sedimentation remained very lean eastwards.

The western Demerara platform limit seems to be controlled by a SW-NE trending fault swarm (Figure 2) on its

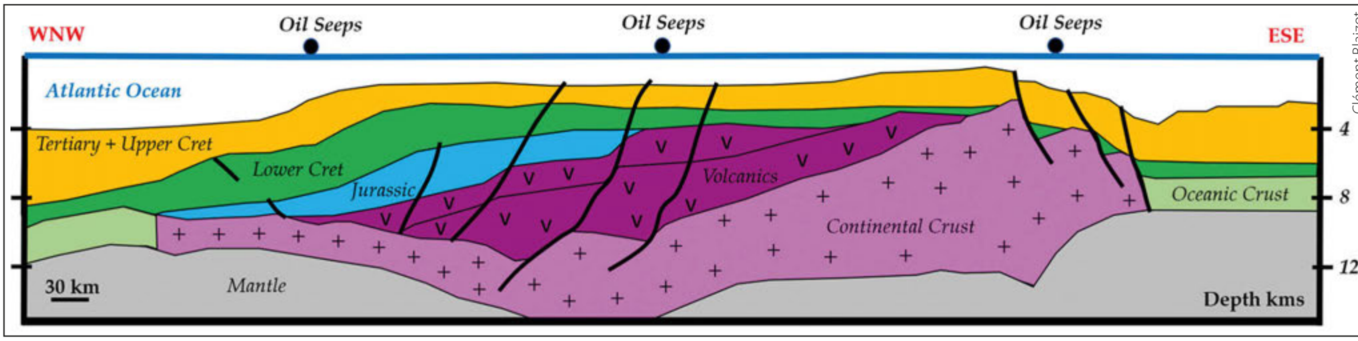


Figure 2: Cross-section sketch modified from Graindorge et al (2020) and Casson et al (2021).

eastern edge and is then covered by thin Upper Cretaceous to Miocene sediments emphasizing the high topography of the plateau relative to its neighboring basins to the west, north and east.

To the west the Guyana/Suriname Basin resulted from the Central Atlantic SW-NE rifting in Lower-Middle Jurassic times. Because of the incipient rifting conditions, Jurassic deposits could therefore correspond to lacustrine and/or restricted marine source-rocks followed by massive turbiditic sandstones in the Cretaceous. These turbidites interfinger with potential open marine source-rocks of Albo -Cenomano-Turonian age called the Canje Formation. These turbiditic clastic sediments were deposited through the steep canyons at the mouth of the Berbice and Maroni paleo-rivers, eroding the Guiana Shield.

To the East lies the Foz de Amazonas Basin, a result of the north-west to south-east Equatorial Atlantic rifting and its separation from Africa in Albo-Aptian times. The first syn-rift deposits in this basin are linked to the erosion of the adjacent shields and comprise mainly large fan sands and shales at the toe of the abrupt normal faults. Here also, the Cenomano-Turonian could correspond to rich sources rocks as found in Deep Sea Drilling Project site 144 and Ocean Drilling Program site 1258C.

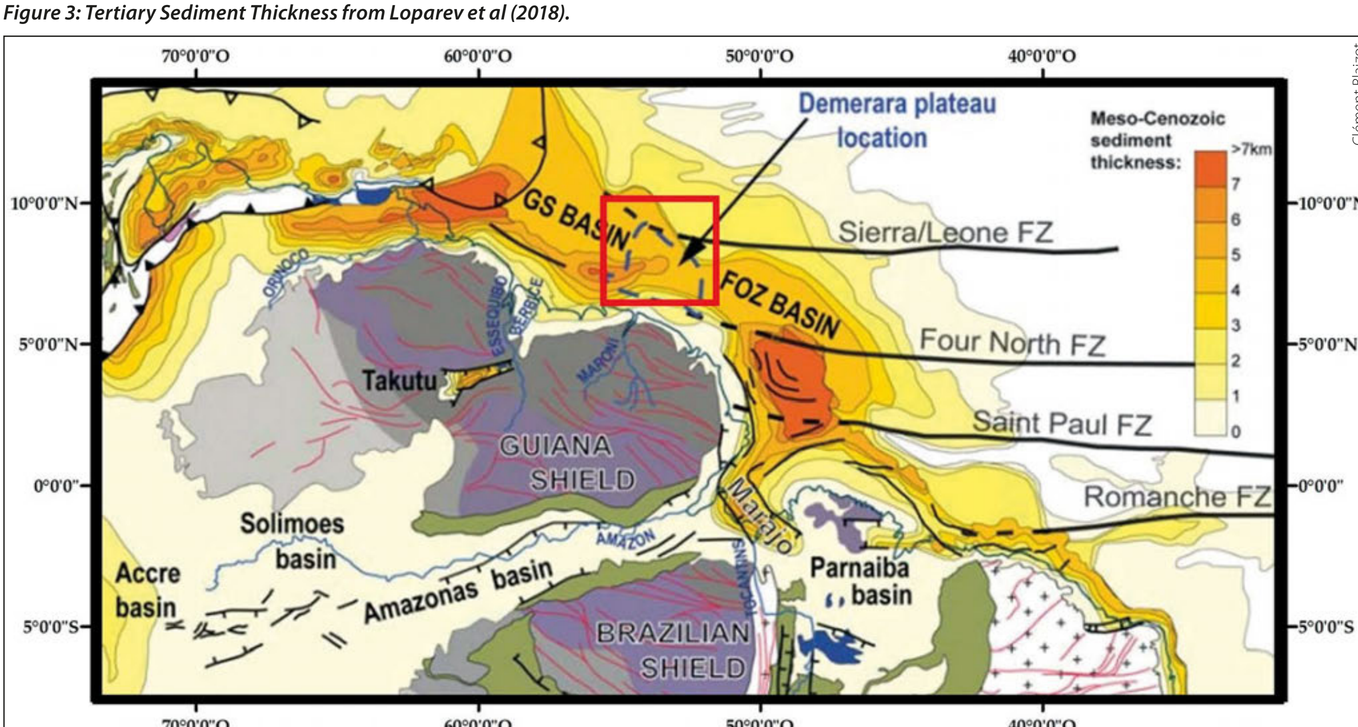
During the Tertiary, two major deltas expanded and two huge, associated deep-sea fans developed associated with the Orinoco to the west in the Guyana/Surinam Basin and the Amazon in the Foz de Amazonas Basin (Figure 3).

These major sediment loadings are a key element for generating hydrocarbons from the rich Cretaceous Albian and Cenomanian source-rocks. Within and around the Demerara Plateau, the recurrent oil seeps observed by satellite seem to be linked to two major trends. Firstly, the internal south-west to north-east faults crossing the Demerara Plateau which limit the thick Lower to Upper Cretaceous depocenter to the west. Secondly, the outer north-west south-east major faults separating the Demerara Plateau from the Central Atlantic basins.

Recurrence is Key

There are least three very promising repetitive seep anomalies (purple circles shown in Figure 4) extending from well A2-1 eastwards towards the flank of Demerara that could correspond to the termination of the oil migration conduits

Figure 3: Tertiary Sediment Thickness from Loparev et al (2018).



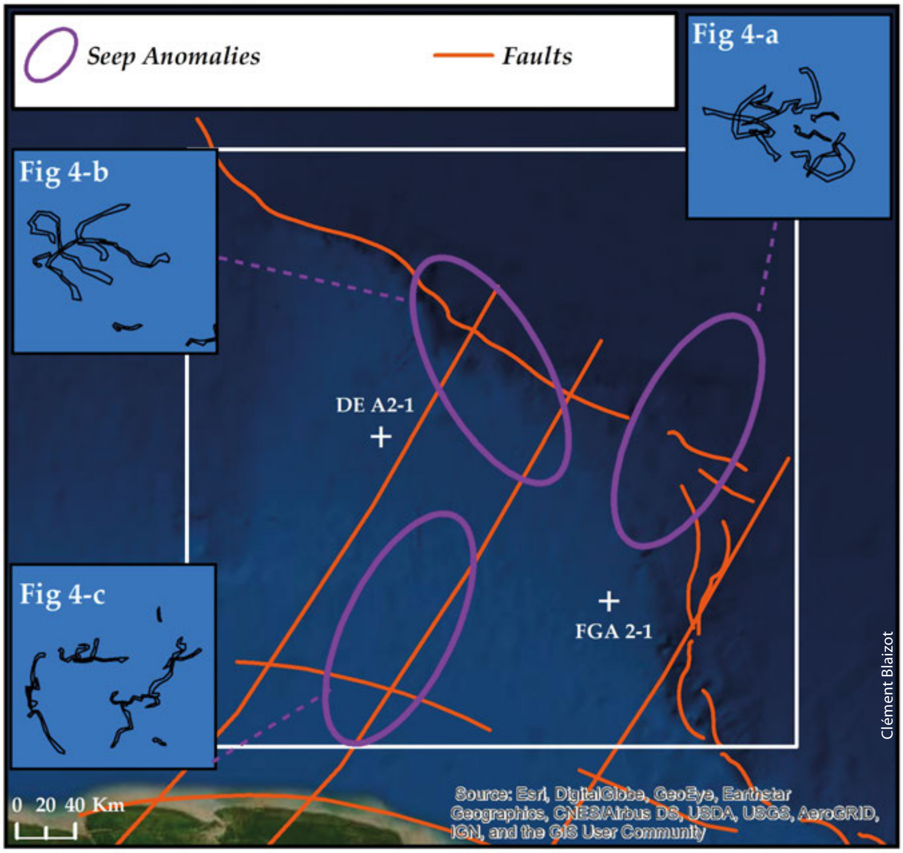


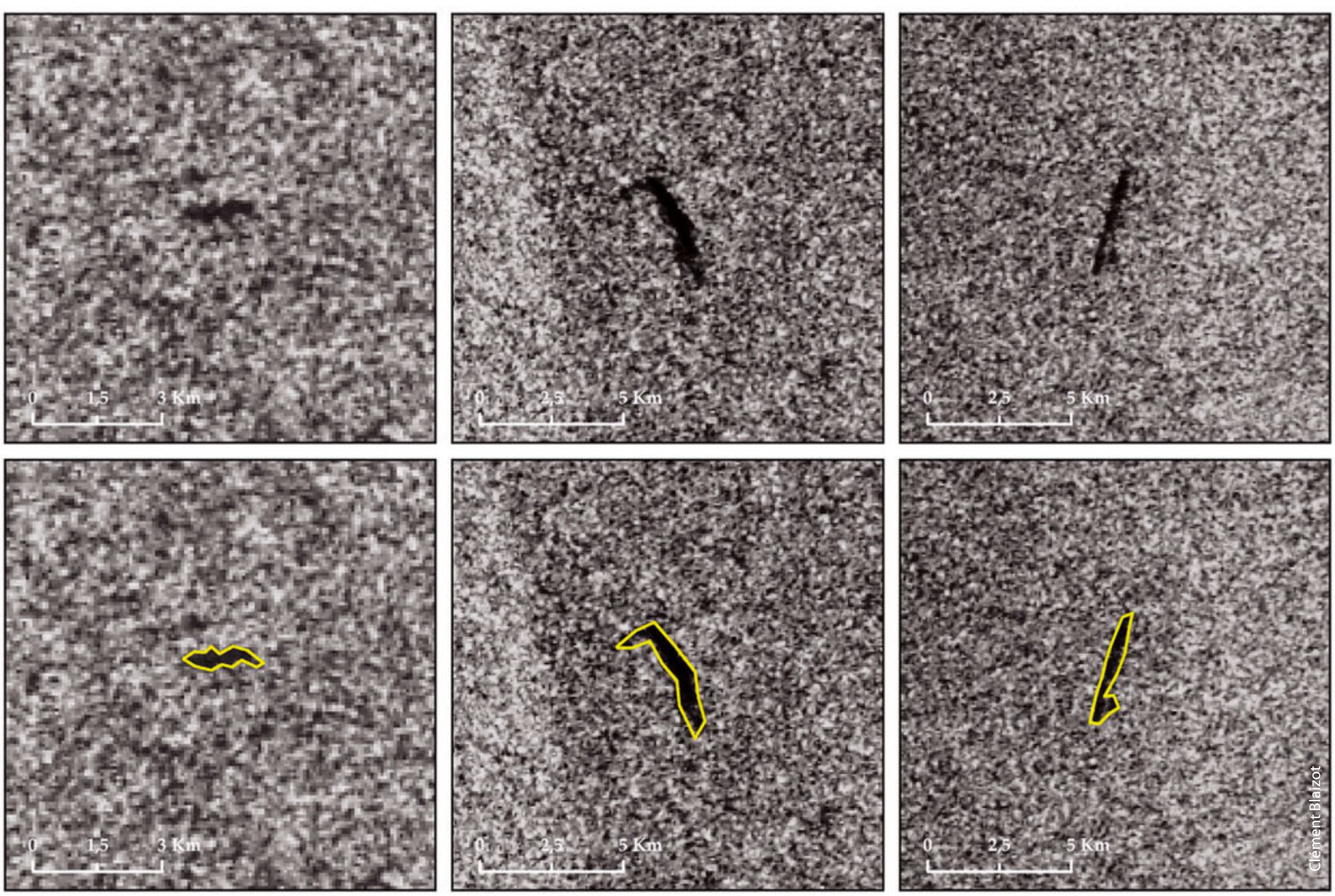
Figure 4: Oil Seeps anomalies in and around study zone. Faults modified from Casson et al.

– the main sandy Cretaceous fairways connecting oil kitchens of Albo-Cenomano-Turonian age towards the edges of the basins (Figure 2).

Seep anomalies on Figure 4-a, 4-b and 4-c respectively display 9, 6 and 11 seepages spotted at different dates. Seeps here are both concentrated, superimposed and for some of them almost shaping an emission point, the so called 'flower' or 'star' structure that seep specialists are always eager to find.

Whilst seeps near mature fields can be used to seek field extensions, seeps are even better suited to exploration in frontier areas such as Demerara, where little other geological and geophysical data is available. Seep occurrences based on good SAR data coverage are often labelled 'over-optimistic', but it is simply arithmetic: the more satellite scenes you analyze, the more seeps you tend to find. However, it is important to note that the methodology used here aims at highlighting locations, not quantities. Seeps are often the initial evidence in the long exploration enquiry chain and are the first to be detected on the 'geological crime scene'.

Figure 5: SAR illustrations of spotted potential oil seeps and vectorized in yellow.



Notwithstanding, it should always be remembered that we are dwelling on clues, not evidences. We remain investigators, not coroners.

The principal complexity in seep interpretation is the discrimination between 'natural oil seeps' rising from the seafloor versus sea surface pollution (spills/ship discharges). Within and around Demerara, more than 100 potential natural seeps have been observed. Confidence in them is high, regarding both their characteristic morphologies and signatures (Figure 5). As sea surface oil pollution and spills are relatively low in this area, the very significant number of seeps around Demerara adds weight to the conclusion that these are natural in origin.

Venturing in the Unknown

The iconic novel by Alan Sillitoe, *'The Loneliness of the Long-Distance Runner'* perfectly mirrors the challenges ahead for future oil and gas exploration. As a frontier explorationist, you might feel the loneliness of chasing evasive, long-term, 'against all odds' rewards rather than the more plentiful short-term targets. Undoubtedly, as time passes, fewer unexplored basins remain. At these uncertain crossroads, the lengthy and hazardous frontier path might possibly lead you into either a dead-end or into a lively beginning. Oil seeps provide a genuine helping-hand and Demerara has proved once again the usefulness of SAR seeps studies by mingling several key elements: a large dataset, high data coverage, spatial proximity, seep recurrence along with manual interpretation and 'blind' interpretation (do not chase the seeps exactly where the geology would tell you to look for or where you might want to find them).

As SAR satellite data becomes more widely accessible, accurate, real-time, and retrievable at any time, there is little doubt about its future role in the exploration cycle. More than ever, oil seeps stand as a 'fair way' to unveil the fairways.

References

Casson, M., Jeremiah, J., Calvès, G., De Ville de Goyet, F., Reuber, K., *et al.* 2021. Evaluating the segmented post-rift stratigraphic architecture of the Guyanas continental margin. *Petroleum Geoscience, Geological Society.*

Graindorge, D., Basile, C., Heuret, A., Klingelhoefer, F., Loncke, L., Roest, W.R., Sapin, F., 2020. Le plateau de Démérara et ses marges au large des Guyanes. *Géologues numéro 206.*

Loparev A., Rouby, D., Chardon, D., Ye, J., Bajolet, F., *et al.* 2018. Sediment routing systems of cratonic domains to their margins from accumulation histories and continental paleogeography at geological timescales: the Equatorial Atlantic margins of the West African and Guyana Shields. *European Geosciences Union General Assembly 2018, Apr. 2018, Vienne, Austria. Geophysical Research Abstracts.*

Ryan, W.B.F., S.M. Carbotte, J. Coplan, S. O'Hara, A. Melkonian, R. Arko, R.A. Weissel, V. Ferrini, A. Goodwillie, F. Nitsche, J. Bonczkowski, and R. Zemsky. 2009. Global Multi-Resolution Topography (GMRT) synthesis data set, *Geochem. Geophys. Geosyst.* ■

NVENTURES

Progress in Pakistan

Success in the hinterland of Pakistan's major fold and thrust belts.

PETER ELLIOTT and MADELEINE SLATFORD; NVentures Ltd

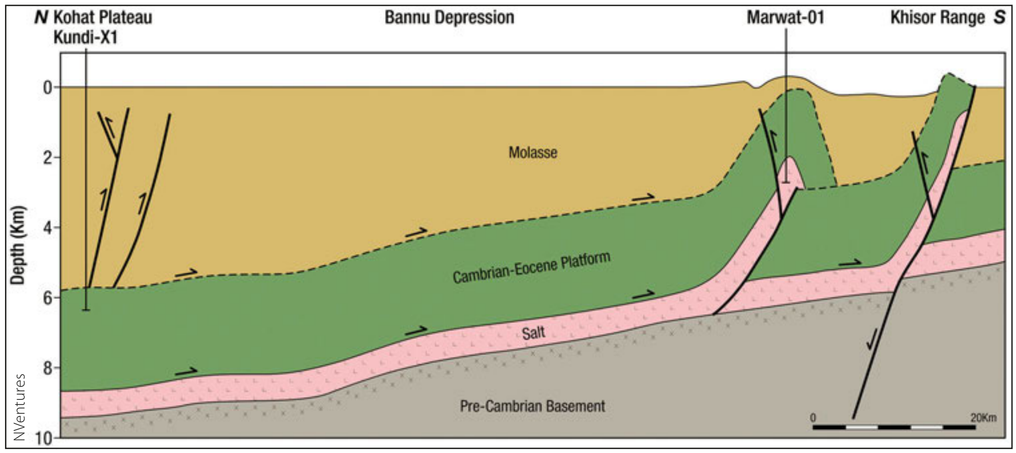
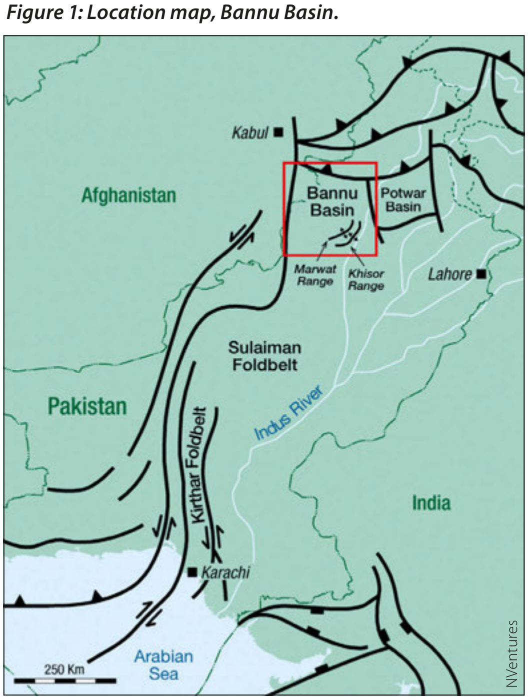


Figure 2: Cross-section, Bannu Depression.

Pakistan is an important gas-producing country with growing demand for energy. Like other mature petroleum provinces with strong state influence and good industry management by the national regulator, drilling and development activity levels have remained relatively strong since the last oil crash and through the pandemic. According to the Energy Information Administration (EIA) the country has been producing a steady 1.3 Tcf gas per year for the last few years, and consuming 1.6 Tcf a year, increasing at about 100 Bcf a year (no data is available since 2018).

Oil production is a modest 92 mbopd, with consumption running to 625 mbopd (EIA). Whilst foreign investment in the upstream sector remains low, in line with global exploration sentiment, domestic exploration focus is moving to early–mature and new basins in the west and north of the country, away from the established producing basins of the Sindh and Punjab regions.

Figure 1: Location map, Bannu Basin.



The Bannu Trough Basin of the Khyber Pakhtunkhwa (KPK) province is one such basin at the vanguard of new exploration efforts by the likes of Mari Petroleum, OGDCL, Zaver Petroleum and Pakistan Petroleum Limited (PPL). Although only 150 km west of Islamabad, the acreage being explored around Wali, Bannu West and Zindan is close to the 'red zone' of security issues with Afghanistan.

In July 2021 OGDCL announced a gas discovery at Wali-1 on the Wali Block. This is the first good test of gas and condensate in the Bannu Basin, with 11.8 MMcfgd and 945 bcpd from the Late Cretaceous Kawagarh Formation at a TD of 4,727m. Further tests of the Hangu and Lockhart Formations are expected soon. The basin is set within the Trans-Indus Salt Range of the Sulaiman fold and thrust belt. The Bannu and nearby Kohat Potwar Basins are foreland depressions hosting Proterozoic to Mesozoic and Paleocene petroleum systems with mild structuration from the Marwat and Khisor ranges to the east (Figure 1).

These mountainous thrust belts, along with the Surghar Range of the linked Kohat Potwar Basin to the north, are created by major thrust events over the Neoproterozoic salt detachment (Figure 2).

Nearby on the Bannu West Block, Mari Petroleum (with OGDCL and Zaver) acquired a difficult 2D and 3D seismic campaign in 2020, and subsequently spud the Bannu West-1 wildcat about 50 km north of Wali-1 in June 2021. This is a HPHT well with stacked targets in the Paleocene, Cretaceous and Jurassic, with a prognosed TD of 5,970m. Zaver Petroleum (ZPCL, a division of the Hashoo group), is a relatively new private Pakistan E&P firm and has partnered with OGDCL and Mari Petroleum to open up the KPK province. OGDCL and ZPCL discovered oil and gas in the Shakardara Block recently. Mari Petroleum was awarded the Wali West Block in 2018, and will watch with interest further testing results at Wali-1 as it drills ahead at Bannu West-1. To the north-east, MOL are drilling a wildcat Surghar X-1 in the Kohat Potwar Basin adjacent to Bannu, with similar geological style.

The major players in Pakistan such as OGDCL, Mari, PPL, PEL etc. continue to push the exploration envelope into early-mature and new frontier provinces, with high-risk profiles to be managed above and below ground, but geological success appears to be following these pioneering steps. ■

How Machine Learning is Helping Seismic Structural Interpreters in The Age of Big Data

ÇAĞIL KARAKAŞ, Schlumberger; JAMES KIELY, OMV Norge

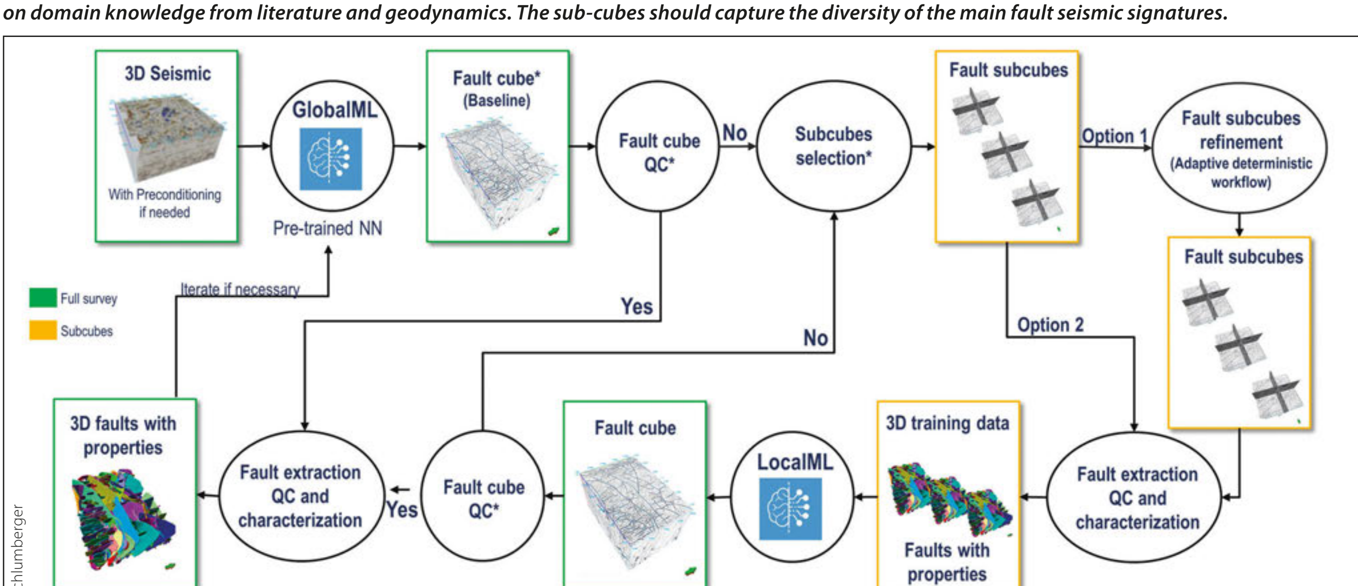
The availability of large 3D seismic surveys (i.e., greater than 10,000 km^2) offers unprecedented and challenging opportunities for multi-scale seismic characterization as they are likely to sample a representative amount of various tectono-stratigraphic features from different tectonic events. While manual and semi-automated structural interpretation of large seismic datasets is a very time-consuming task, often leading to a simplified fault model, a geology-driven, machine-learning workflow can significantly improve the turnaround time and accuracy of seismic fault mapping and characterization. We successfully applied this novel workflow on a 20,000 km^2 seismic survey with depths up to 10 km, capturing a variety of fault signatures, seismic signal-to-noise ratios, and frequencies (data courtesy of CGG and OMV Norge). Our approach enables the 3D fault interpretation process to be performed in a matter of hours compared to days while being geologically and mechanically realistic (Figure 1).

Generating a Fault Baseline Map with a Convolutional Neural Network

Machine learning (ML) is the study of computer algorithms that improve automatically through experience and using data and is considered a part of artificial intelligence. ML algorithms build a model based on sample data, known as 'training data', to make predictions or decisions without being explicitly programmed to do so. The proposed approach combines two training strategies of a 3D convolutional neural network (CNN): a 'global' scheme based on the generation of thousands of synthetic seismic volumes with labeled faults and a 'local' scheme trained using fit-for-basin, high-resolution 3D fault labels generated using automated deterministic solutions. The full workflow covers data audit; prediction of a first fault framework (baseline) by applying a 3D CNN trained on synthetic data; baseline quality assessment and identification of missing structures; baseline refinement by retraining locally the 3D CNN; structural analysis of the predicted faulting pattern; and fault network classification based on relative timing of faulting.

First, we collect and integrate geological knowledge to allow for the assessment of the seismic data quality in the area of interest, in this case the North Sea. The North Sea rift system is characterized by a variety of faulting patterns in terms of geometry and size cutting through the thinned crust. The rift system is interpreted to have migrated northward since its initiation in the Late Permian – Early Triassic period (Phillips et al., 2019). In this study, the area of interest captures three main tectonic events with a given stress regime for each one. Firstly, a rifting phase one in Late Permian – Early Triassic with N–S striking faults and reactivation of Devonian shear zones. Secondly, a rifting phase two in Late Jurassic – Early Cretaceous with NE–SW striking faults and lastly a Late – syn to post rifting phase with N–S striking faults.

Figure 1: Tectonic framework workflow associated with ML (global and local) assisted structural interpretation. Note: Quality control and selection based on domain knowledge from literature and geodynamics. The sub-cubes should capture the diversity of the main fault seismic signatures.



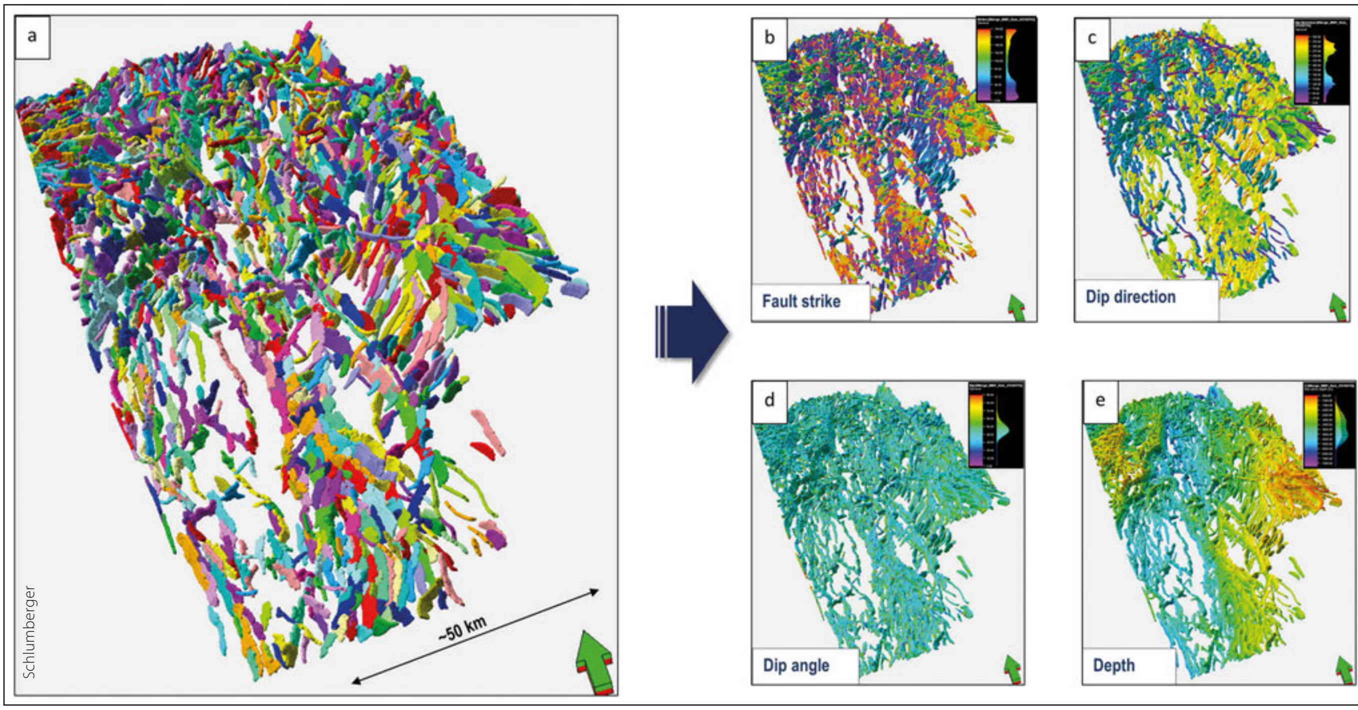


Figure 2: Object-based structural analysis applied on the full survey. (a) Extracted fault point sets, (b), (c), (d) and (e) are fault strike (in degrees), dip direction (in degrees), dip angle (in degrees) and depth (in meters) properties, respectively, mapped on the extracted fault point sets.

To address the 3D multi-scale faulting patterns and to optimize the dataflow pipeline for machine learning, we use a laterally equally sampled (50 × 50 meters) seismic volume with a vertical sampling of 20 meters. Then, we deploy a 'global' 3D CNN over the full survey (Wu et al., 2019, Sarajærvi et al., 2020) to obtain a baseline map of the fault network. The training is based on a collection of 6,000 synthetic seismic volumes (128 × 128 × 128 samples) with various resolutions and signal-to-noise ratios that contain labeled faults. We evaluate the baseline and validate the consistency and completeness of the predicted fault traces in 3D over the full survey focusing on fault termination, connectivity, and continuity. This way, structures not completely detected or missing in 3D are identified to be further improved in the next steps of the workflow. Then, we adopt a fit-for-basin approach aiming for a local enhancement of the fault network map. The enhancement is performed using deterministic solutions in selected sub-areas capturing the region's main fault signatures, from which, and when needed, 3D labeled training data are generated to retrain the 3D CNN (Figure 1).

Quality Assessment of the Global Machine Learning Baseline

The primary goal of the proposed iterative ML approach is to honor the geological context and principles, while capturing the local tectonic variability with a high level of detail and in 3D. To achieve this level of accuracy and to ensure that geological rules are respected, we consider key structural mapping concepts where the domain expert has a major role to steer and validate in the sub-areas. These include the type and location of the detected seismic discontinuities, the seismic horizons displacement along the discontinuities, the relationship between the detected discontinuities, and the 3D consistency of the fault geometry.

In the sub-areas, we optionally combine the baseline map with a set of advanced seismic attributes (Figure 1, option 1). For example, first, an amplitude-based approach with edge detection attributes can improve the continuity and connectivity of the fault network (Etchebes et al., 2019). And second, the *strata indicator* that can highlight stratified from unstratified chaotic areas. Defining contrasts may be used to identify structural discontinuities such as low-angle fault planes (Bounaim et al., 2019). If the baseline map does not require local improvement, then we proceed with option 2 (Figure 1).

Improving the Fault Map by Retraining the 3D CNN Locally

At this stage of the workflow, we proceed with a structural analysis that consists of a detailed study of the seismic signature across the mapped discontinuities. From our fault sub-cubes, structural properties such as fault azimuth, dip angle and planarity indicator are computed in a set of property volumes (Figure 1). These properties are used to assist the geoscientist in the structural interpretation as well as to condition the input fault volume for the subsequent fault extraction. Faults are extracted as point sets at the seismic resolution (Bounaim et al., 2013; Etchebes et al., 2019). Thereafter, the extracted and verified faults are transferred into triangulated meshes to obtain closed planes. These fault planes are then populated into labeled fault cubes and used as training data in the local 3D CNN (Figure 1). Subsequently, we run the trained network over the full survey. Finally, we validate the predicted faulting pattern by combining the refined set of structural properties with

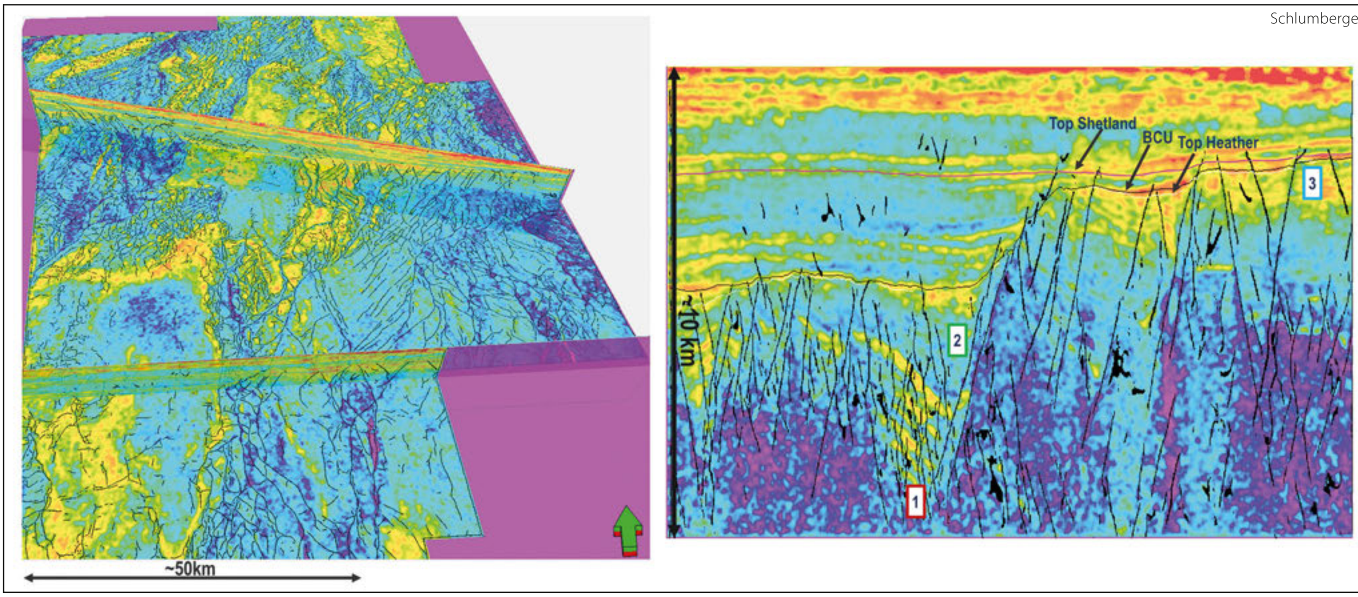


Figure 3: Fault map and strata indicator vector attribute combined for a relative timing of faulting analysis (on the left side) and cross-section (on the right) where relative timing of faulting is established based on their structural relation (1-oldest, 2 and 3-youngest) and the use of typical horizons (BCU, top Heather and top Shetland).

the *strata indicator* vector attribute map over the full survey (Figures 2 and 3).

The fault network map resulting from our workflow can be then used as an input for various applications. One of them is the paleo and present-day stress analysis which consists of combining the fault network analysis with stratigraphy sequence boundary analysis, enabling the classification of faults following their relative timing (Figure 3). The latter provides an indication of the evolution of the stress regime through time. The understanding of the paleo-stress regime and the present-day maximum horizontal stress (S_{Hmax}) direction can help to assess the potential conductivity of faults under a particular $S_{Hmax,}$ as the strike azimuth of conductive faults should coincide with the direction of S_{Hmax}.

In summary, the combination of ML, deterministic methods and domain knowledge applied to seismic structural interpretation increased the confidence in detecting geologically sound faulting patterns from seismic. Structural interpretation of large surveys by selecting key smaller areas of interest, and ideally capturing the main regional faulting patterns, is an appropriate starting point to ensure that the 3D CNN training is as representative as possible. Our approach of validating the consistency of the detected faulting patterns through analysis of automatically extracted structural properties (azimuth, dip, planarity, depth) and selected seismic tectono-stratigraphic attributes is unique and allows the application of a time-efficient fit-for-purpose approach on a very large-scale survey.

Acknowledgments
This study was part of a joint-research collaboration between Schlumberger and OMV Norge. A number of colleagues from both organizations contributed to this study. Details are available on-line at GEO ExPro.com. The authors would like to thank both companies for the permission to publish the results of this collaborative work. The authors also thank OMV Norge and CGG for the permission to use the data to create the figures.

References

Bounaim, A., Bø, T.H., Athmer, W., Sonneland, L. and Knoth, O. 2013. Large Fault Extraction Using Point Cloud Approach to a Seismic Enhanced Discontinuity Cube. *Extended Abstracts, 75th EAGE Conference and Exhibition, London, UK.*

Bounaim, A., Etchebes, M., Haukas, J., Borgos, H., Fotland, B.H. and Sonneland, L. 2019, September 25. Vector attributes: A family of advanced seismic attributes to assist in geological interpretation. *Society of Exploration Geophysicists Technical Program Expanded Abstracts*, pp.1813–1817.

Etchebes, M., Bounaim, A., Brenna, T. and Steckhan, D. 2019. Fault Characterization Using Advanced Seismic Interpretation Techniques–Quantitative Input for Optimal Well Placement in Structurally *Complex Reservoirs. Conference Proceedings, 81st EAGE Conference and Exhibition 2019, London, UK.*

Phillips, T., Fazlikhani, H., Gawthorpe, R., Fossen, H., Jackson, C., Bell, R., Faleide, J.I. and Rotevatn, A. 2019. The Influence of Structural Inheritance and Multiphase Extension on Rift Development, the Northern North Sea. *Tectonics*, 38(12), 4099–4126, doi:10.1029/2019TC005756.

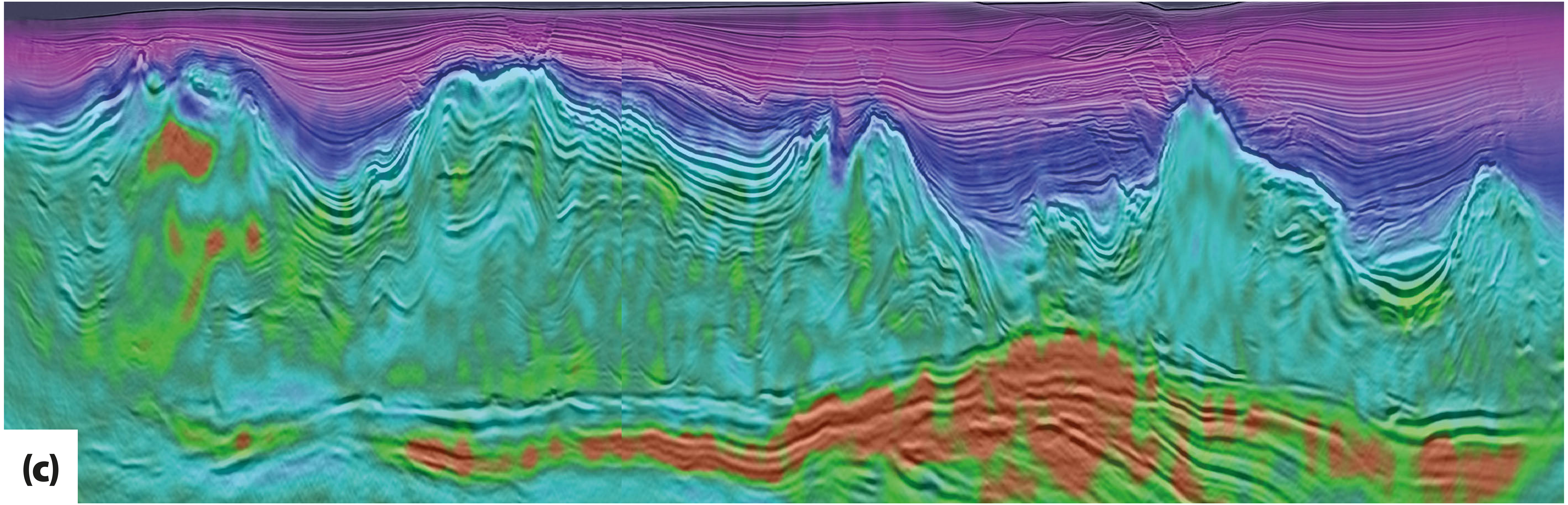
Sarajærvi, M., Hellem Bø, T., Goledowski, B. and Nickel, M. 2020. Robust Evaluation of Fault Prediction Results: Machine Learning Using Synthetic Seismic. *First EAGE Digitalization Conference and Exhibition*.

Wu, X., Liang, L., Shi, Y. and Fomel, S. 2019. FaultSeg3D: Using synthetic data sets to train an end-to-end convolutional neural network for 3D seismic fault segmentation. *Geophysics*, 84, IM35–IM45. ■

Can Sparse OBN Equal Savings and Data Quality?

YANNICK COBO, RODRIGO FELICIO, CARLOS CALDERON and PAUL FARMER; ION

Depressed demand for oil and gas due to the pandemic, as well as commitments to honor the goals of the Paris Climate Accord, continue to place pressure on oil and gas companies to decrease costs and capital expense in order to deliver value to shareholders. In exploration, drastic budget cuts took place, limiting exploration to nearfield and lower cost development opportunities. However, to exploit these nearfield opportunities efficiently, high-quality seismic data is necessary. Typically, higher quality seismic is associated with tighter acquisition geometries or acquisition types such as ocean-bottom nodes, in order to capture broader frequency spectra, longer offsets and richer azimuthal coverage. However, these qualities usually come with a higher price. One way to decrease the cost and time of seismic data acquisition is to design sparser surveys by decimating the number of shots and receivers used. To understand the tradeoffs of such decimations, we used ocean-bottom node data from a complex geological setting in a pre-salt play of the Santos Basin, offshore Brazil to compare how different geometries might impact the ability to build accurate velocity models.



(c)

Geology

The study area is in ultradeep waters (2 km) of the Santos Basin and the geology is comprised of a 2–4 kilometer-thick sequence of mostly clastic sedimentary rocks overlaying evaporite layers and thick salt comprised mostly of halite, with secondary intervals of anhydrite, gypsum, tachyhydrite and carnalite. These salt layers have a complex structural history and may form massive heterogeneous bodies up to 3 kilometers thick, displaying a complex array of folds, faulting, overhangs and mini-basins. Below these units, the pre-salt is comprised of syn-rift sequences of clastic sediments, basalts, carbonates and evaporites, which include reservoir rocks (Carlotto et al., 2017).

Method

The ocean-bottom node dataset used has approximately 3,000 nodes deployed on a 500m by 500m regular spacing grid, and shots on a 50m by 50m carpet grid. This design yielded rich azimuth data coverage with offsets as long as 27 km, and thus provided an excellent dataset to conduct our analysis.

For this analysis, we tested three scenarios, each representing a different shot and receiver decimation from the original survey, to understand the effects of such decimations for velocity model building with a fully automated workflow. The workflow solely uses full-waveform inversion (FWI) for the estimation of velocities, with the exact same inversion parameters for each scenario. Thus, each scenario utilizes the same initial velocity model which is a smooth model with no information related to the position of geobodies, and the same data-derived source wavelet.

The velocity estimation workflow is comprised of two different full-waveform inversion methods that use a cost function that emphasizes travel time differences between field and synthetic data to help prevent cycle skipping (Wang et al., 2019). For the initial iterations, only first-arrival events were modeled and matched to the real data, an approach akin to that described in the work by Sheng et al. (2006). Once the first arrival or FAFWI converged to a solution for relatively low frequencies, first arrivals and wide-angle reflections were also targeted using travel-time FWI (TTFWI). In TT FWI, a cross-correlation of local time windows was used to estimate the difference in time between the two datasets. Both FAFWI and TTFWI use a hierarchical scheme in frequency, starting from the lowest possible frequencies (<3 Hz) and progressing to a high frequency limit (5.5 Hz), at intervals of 0.5 Hz, designed to gradually build the velocity model from low to high wavenumbers (e.g., Virieux and Operto, 2009). We note that the velocity model building workflow did not include interpretation of high-contrast interfaces such as the top and base of salt bodies, in an attempt to use a data driven approach to model building, based on the high quality, long offset data.

Continued from page 66

In the first test, we used the original geometry of the OBN survey, nodes distributed on 500m by 500m grid and shots in a 50m by 50m carpet geometry; in the second, nodes were decimated to a 1 km by 1 km grid, while the shots were in a 100m by 300m carpet; in the third, nodes were further decimated to a 2 km by 2 km grid, whereas shots were kept in the same 100m by 300m configuration.

Scenario	Shot Spacing	Receiver Spacing
1	50m x 50m	500m x 500m
2	100m x 300m	1,000m x 1,000m
3	100m x 300m	2,000m x 2,000m

Results

We illustrate the quality of the models obtained for each of the three scenarios above in two ways. First, we compare the models against a higher-grade velocity model (labeled as 'Final model'). The final model is an accurate and matured velocity model, derived mostly from FWI from diving waves and wide angle reflections in the data, tomography iterations interleaved with subsequent iterations of FWI, and model refinement that used a top of salt horizon and well constraints. This model is not used for estimation of the velocity for the three described scenarios. We compare the migrated stacks obtained from prestack-depth migration of a legacy streamer dataset from the same area for the final model and each of the tested scenarios.

Figure 1 shows vertical sections of the velocity models obtained from the three scenarios compared to the final model. All four scenarios reached similar solutions that converge towards the final model, i.e., all inversions are able to predict the bulk of the salt geometry from the initial smooth sediment-only velocity model. Note also that model resolution decreases as a function of node density. For example, as the node spacing is increased, the cascaded FWI flow recovers a relatively smooth velocity gradient above the top of salt, while introducing undesirable velocity oscillations in both the salt and pre-salt sections, more evident in the case of 2 km receiver spacing. Thus, decreasing the number of nodes by an order of magnitude or more leads to 'noisier' solutions that require a more aggressive model regularization.

These observations are further corroborated by inspection of depth slices presented in Figure 2. Delineation of salt bodies (velocities of about 4500 m/s, i.e., reddish to white colors in the figure) and mini-basins are comparable to those observed from the final model (Figure 2a), but with model degradation as the nodes become sparser. The model derived from the 1 km node spacing provides a good compromise relative to the 500m result and the oscillatory nature of the 2 km node result.

Vertical sections of migrated images with a maximum frequency of 45 Hz for the models are shown in Figure 3. These migrations use a narrow-azimuth streamer dataset acquired over the same area as input, to evaluate the quality of the inverted models. In these comparisons, we observe the progressive loss of resolution of salt bodies and mini-basin delineation with sparser geometries resulting in a gradual pushdown of the top of salt events. We also note in the Figure a decrease in focusing and continuity of events marking the base of salt and pre-salt section, particularly beneath the mini-basin on the right side of the sections. Despite this decrease in resolution of the model, the result for the 1 km node spacing is very comparable to the model image derived from the 500m by 500m node spacing.

Velocity Model Building Conclusions

The velocity estimation results presented show that sparse node surveys in general produce poorer velocity models than relatively denser ones when deriving the model from FWI with primarily diving wave energy. However, a relatively coarse source-receiver distribution is still able to produce a high quality velocity model. In our particular case (OBN survey in ultradeep water), we find that receiver sampling of 1 km by 1 km and a shot geometry of 100m by 300m spacing is a viable alternative to denser node surveys with four times more nodes and six times more shots when estimating the velocity model from large offsets and low frequencies.

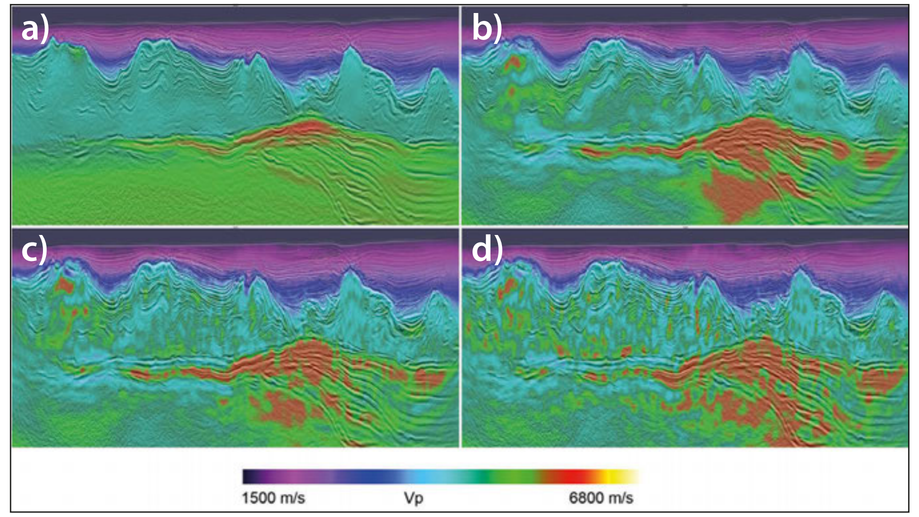


Figure 1: (a) Final 'reference' velocity model (b) FWI model for 50 x 50m shot spacing and 500 x 500m receiver spacing; (c) FWI model for 100m x 300m shot spacing and 1 km x 1 km receiver spacing; and (d) FWI model for 100m x 300m shot spacing with 2 km x 2 km receiver spacing. The stack image corresponds to a stack obtained with the final model derived with the dense geometry.

Practical Conclusions

Pre-salt exploration within the Santos Basin presents unique challenges because of the complex geological settings with deep targets, massive heterogenous salt bodies, and a complex array of structural features. Several recent ocean-bottom seismic (OBS) surveys have been acquired over fields within the Santos and Campos Basins with the aim of providing superior images for reservoir characterization and development. The reasons for superior imaging achieved by OBS data compared to towed streamer data are well understood and include extended bandwidth – particularly at lower frequencies, improved signal-to-noise, longer offsets, and full azimuth.

The application of full waveform inversion (FWI) to OBS datasets has proven highly successful for improving the velocity model – leading to superior imaging results. However, the survey effort required for a conventional OBS survey is still significant in terms of both its cost and duration. Consequently, OBS surveys are commonly limited to specific field appraisal and development objectives.

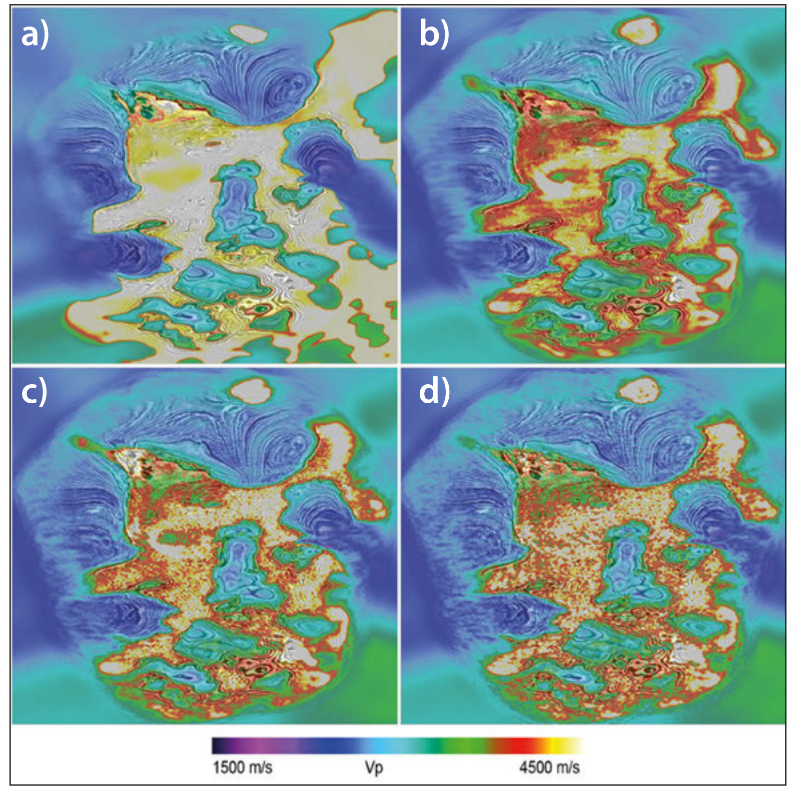


Figure 2. Depth slices below top of salt of velocity models for (a) Final model; (b) 50 x 50m shot spacing and 500 x 500m receiver spacing; (c) 100m x 300m shot spacing and 1 km x 1 km receiver spacing; and (d) 100m x 300m shot spacing with 2 km x 2 km receiver spacing. The stack image corresponds to a stack obtained with the final model derived with the dense geometry.

The decimation exercise described demonstrates that an improved and reliable velocity model can be derived from a 'sparse' OBS survey configuration. Deploying fewer receiver nodes at increased intervals and increasing the source sail-line separation can deliver significant efficiencies and allow an OBS deployment to be adapted for larger exploration-style surveys. Sparse OBS configurations do limit the imaging quality because of spatial aliasing and reduced signal-to-noise when compared to a conventional OBS dense survey; however, integration with legacy narrow-azimuth (NAZ) towed-streamer seismic data can provide significant uplift in imaging for the exploration process. NAZ streamer-data provides the well-sampled input data for imaging, particularly in a shallow-to-intermediate depth range, while the 'sparse' OBS data provides more reliable velocity updates that are crucial for improved deep imaging and potentially an improved pre-salt image.

Utilizing the traditional approach of NAZ streamer data, but refreshing the earth model with the use of high quality, *but sparse*, OBS data, will allow improvements in the overall quality of the final image at a fraction of the time, effort, and cost. Therefore, not only can early OBS-adoption during the exploration cycle provide a viable alternative in complex geologies, such as the pre-salt plays in Brazil, but in the longer term or further down the oilfield lifecycle, these 'sparse' surveys may also provide a baseline for future high-density infill for reservoir development as well as 4D-monitoring surveys. ■

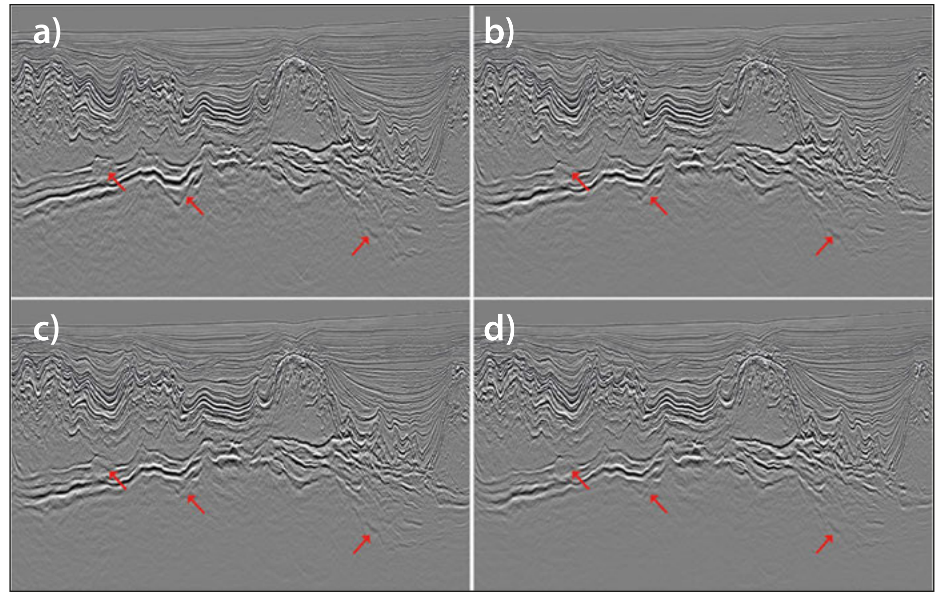


Figure 3: Kirchhoff PSDM stacks of streamer legacy data for (a) production model and the FWI-derived models with node grids of (b) 500 x 500m, (c) 1 km x 1 km, and (d) 2 km x 2 km.

New Life for Old Wells

Evolving the Oil Patch with Hydrocarbon-to-Geothermal Well Conversion.

JOSEPH BATIR, ALAN J COHEN and HAMED SOROUSH; Petrolern, LLC

Geothermal energy currently plays a small role in meeting the world's energy demand. Recent research focuses on high temperature Enhanced Geothermal Systems (EGS) and Advanced Geothermal Systems (AGS); however, there is a renewed interest in sedimentary basin hosted geothermal systems, as this may be an easy adaptation pathway for oilfield companies. There are recent and ongoing projects in sedimentary basin settings; yet there is still no commercial geothermal electricity generation from a sedimentary basin hosted geothermal system in North America. Here, we review recent geothermal projects in North American sedimentary basins and make observations to answer the question: with so much potential, why is there still no sedimentary geothermal power production?

Geothermal, in the Oil Patch?

Geothermal energy is the heat within the Earth, slowly cooling like the coffee in your insulated thermos. If you ask a Geologist where you would find geothermal energy, the simple answer is volcanic settings – Iceland, Hawaii, Yellowstone. While this is true, it is not a complete answer. Geothermal energy is everywhere, and we can produce geothermal electricity anywhere with sufficient heat and sufficient fluid to move that heat. The real question is where can we produce geothermal electricity at competitive prices? For the United States, this is currently limited to the western half of the country, in the Basin and Range tectonic province and volcanic centers along the North American – Pacific Plate boundary (Figure 1); however, there are similar geothermal (heat flow) signatures into the central and even eastern United States (Blackwell et al., 2011b; Roberts, 2014; EIA, 2016).

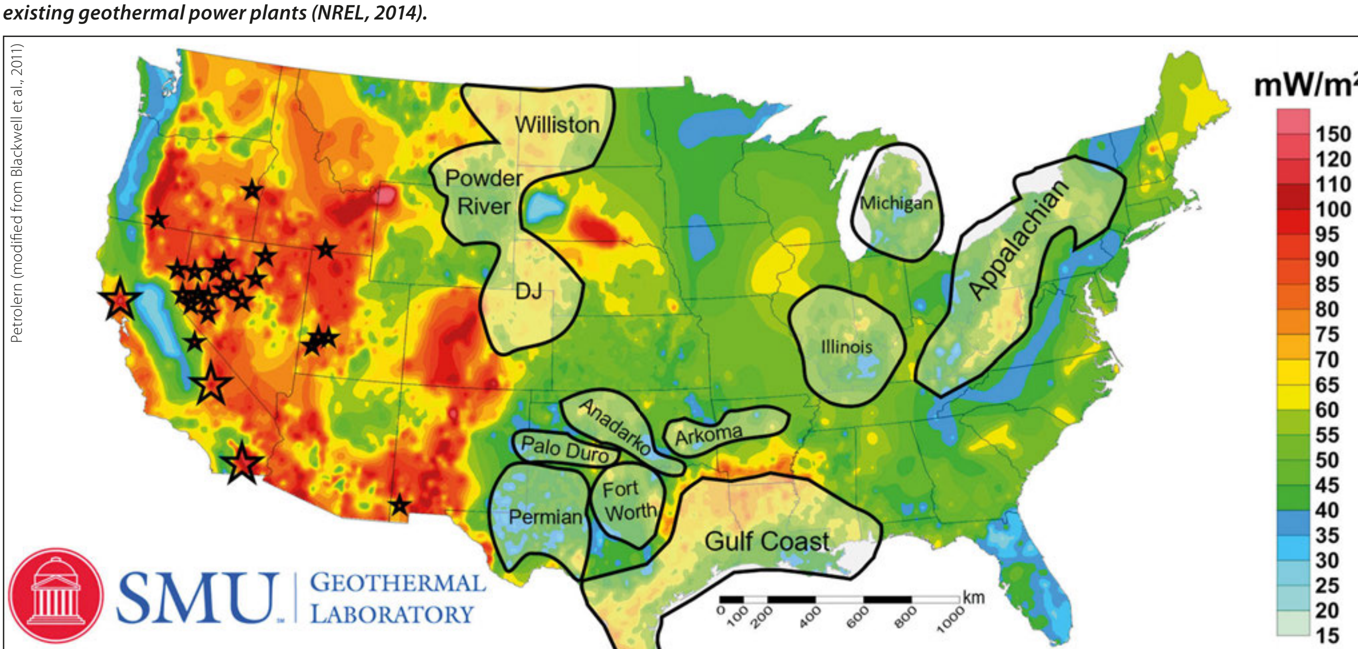
Through recent play fairway analyses, we have found promising geothermal targets within the Gulf Coast Basin with co-located high thermal potential and high porosity, high permeability lithologic sections (Figure 2); still, there is no present-day geothermal electricity production from a sedimentary basin within North America (Petrolern, 2020).

Sedimentary basin hosted geothermal systems have been actively studied for decades; yet, to our knowledge, there are no existing power plants in sedimentary basins in North America. Recent projects can be split into two categories: repurposing hydrocarbon wells for energy co-production or drilling new geothermal focused wells.

Existing Well Co-production

Co-production is production of hydrocarbons while simultaneously extracting heat from the produced water for utilization. An early project demonstrating the technical feasibility of co-production was the Rocky Mountain Oilfield Testing Center (RMOTC) demonstration project that ran intermittently from September 2008 through November 2010. RMOTC produced an average net 170 to 185 kW and showed a technically possible estimated levelized cost of electricity (LCOE) of $0.06/kWh (Williams et al., 2012). More recently a co-production demonstration was performed in the Williston

Figure 1: Major sedimentary basins overlaid on the heat flow map of the United States (Blackwell et al., 2011b). Black stars indicate general locations of existing geothermal power plants (NREL, 2014).



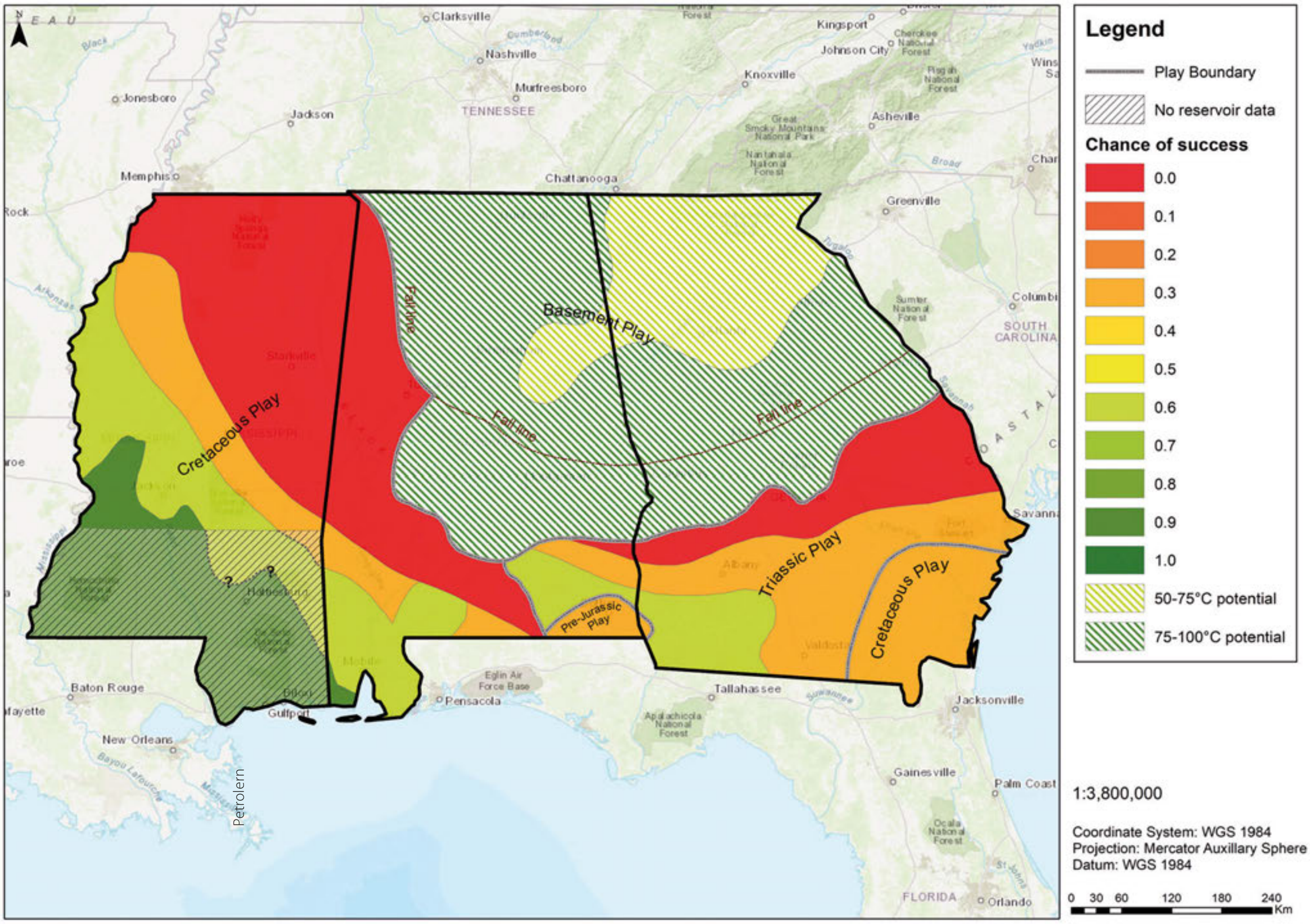


Figure 2: Recent play fairway mapping of Alabama, Mississippi, and Georgia showing several prospective areas highlighted for geothermal exploration, particularly in the southwestern portion of Mississippi.

Basin as a partnership between University of North Dakota, Continental Resources, and others. This project proved technical viability of net 124 kW electricity production. The demonstration had engineering issues and did not perform an extended operation phase. Still, LCOE was estimated at \$0.0725/kWh based on the limited production data (Gosnold et al., 2017). Both demonstrations presented technical feasibility and competitive electricity cost estimates based on respective location. New technology developments could further optimize power production and further decrease LCOE. Both projects were discontinued because of unforeseen circumstances, which is realistically a risk in any commercial project.

New Drilling

Another opportunity to produce geothermal energy from sedimentary basins is through drilling geothermal wells utilizing new technology. Deep Earth Energy Production (DEEP) successfully drilled and tested a geothermal well in the Williston Basin (DEEP, 2021a) in Canada. DEEP reported that the well was the first horizontally drilled and stimulated geothermal well in the world, as well as the deepest horizontal well in Saskatchewan. The temperature of the production test fluids was ~125°C. In addition to the DEEP project in Saskatchewan, Terrapin has a new drill prospect, the Alberta No. 1, which logged 118°C at 4 km depth in an adjacent well (Terrapin, 2021). No new drilling prospects have published LCOE estimates at this time, but we can estimate based on installed capacity costs.

Investment Size Comparison

There is a significant difference in total capital investment for the different sedimentary basin geothermal energy projects, which requires different investor strategies and different economic metrics. There are two projects in the Williston Basin, one co-production and one a new drilling project. The University of North Dakota-Continental Resources (UND-CLR) co-production system had a net production cost of ~\$900,000 for an installed 250 kW (Gosnold et al., 2017), or approximately \$3,600/kW. Comparatively, DEEP announced their first power plant will be 32 MW installed capacity and cost approximately Can\$8 million (~\$5.4 million US\$) (DEEP, 2021b) per MW, or approximately \$5,400/kW. If we use a direct correlation between installed cost to LCOE, the first DEEP power plant would have an approximate LCOE of \$0.105/kWh, or 1.5 times the price of the UND-CLR system. DEEP expects this cost to drop as additional experience produces more efficiency. The difference in installed cost and total investment is ultimately drilling and completion cost. For both projects, there are additional economic considerations including tax credits, additional hydrocarbon production, carbon emissions reduction, and stakeholder considerations that are not fully incorporated here.

US Gulf Coast Case Study

We recently scoped a geothermal electricity co-production project for an onshore US Gulf Coast petroleum producer. The proposed well had a flow rate of about 7,500 barrels of water per day (BWPD) and wellhead temperature of ~270°F. For this well, a 100 kW net modular power system was selected with an estimated cost of $3,000–3,500/kW. Initial estimates of power production cost including CAPEX and O&M were $0.033/kWh. Comparatively, the client estimated their current electric utility rate to be around $0.09/kWh. We estimated an unofficial internal rate of return range using simple average taxes and straight-line depreciation. If electricity was sold to a third party, internal rate of return (IRR) is approximately 7% for a 20-year system or 10% for a 30-year lifetime. The cost savings to the oil company relative to their current utility charges, and the profit from the hydrocarbon co-production, were not included; but, when accounted for, the overall IRRs would be significantly above the values listed here. While this is only one, more recent example, previous studies examined the Gulf Coast Basin for geothermal energy potential (Figure 3) and found prospective regions all along the Texas and Louisiana Gulf Coast, in addition to the recent geothermal potential zones found in Mississippi (John et al., 1998; Petrolern, 2020). It is clear that co-production and conversion projects are available in multiple areas throughout the world, but petroleum producers are unaware of the geothermal energy they are actively producing and how to utilize it in a profitable and effective way.

What are the Challenges?

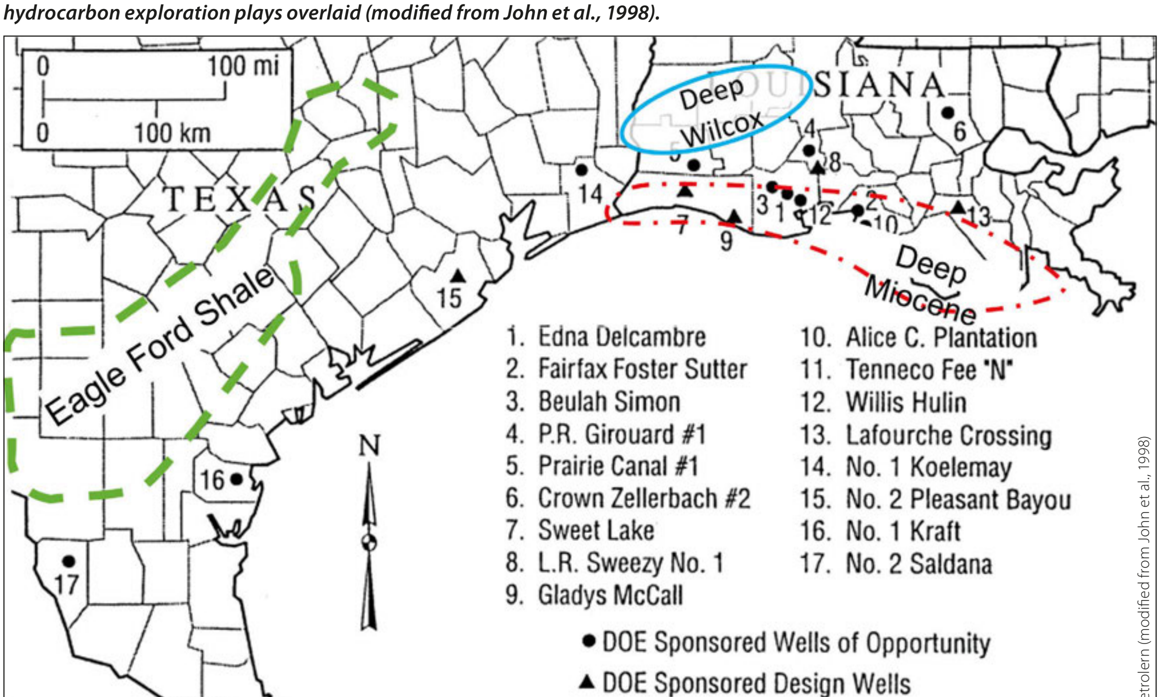
With the multiple previous projects and high geothermal potential, why is there not a commercial geothermal power plant in a sedimentary basin? Our experience suggests oil and gas companies do not have or want to allocate the personnel to produce a geothermal resource evaluation, design and optimize a geothermal power plant, and then evaluate electricity markets to determine the most profitable use of the produced electricity. These required skill sets are almost exclusively found in the largest, vertically integrated oil and gas companies, yet they are the minority in the US oil and gas industry. IHS Global Insight (2011) reported that smaller, independent operators accounted for oil and natural gas production of 45 and 65%, respectively, which was trending upward based on 2011 and prior data. The Independent Petroleum Association of America (IPAA) states that current oil and natural gas production by independent operators is 83 and 90%, respectively (IPAA, 2021). Based on these production shares, most oil and gas operators will not have the expertise to fully evaluate a geothermal resource co-located with their existing oil and gas operations.

In addition to the lack of expertise, the ideal well for geothermal energy production would be one with high water production. High water production is often a trait of lower hydrocarbon production, indicative of an end-of-life, marginally economic well. These end-of-life wells become an economic liability, where any additional capital investment is at risk of generating a net loss. With the end-of-life wells, geothermal energy production is a possible additional revenue stream that could extend the producing lifetime of the well; yet, even examining a well for geothermal energy is an additional expense that companies may not want to invest in an already marginally economic well. It is important to highlight, oil companies ultimately must plug and abandon end-of-life wells and might consider a solution that defers such costs and liabilities – i.e., geothermal conversion – if they realized that option was available.

Geothermal Growth Through Screening

Existing oil and gas wells provide an important, profitable opportunity for geothermal energy expansion, as shown by the examples above, because of the reduced drilling costs; however, wells are often not examined due to the high perceived risk in geothermal energy production from the petroleum industry. Similarly, hiring geothermal experts for evaluation or well workover costs for recompletion is an additional expense that may result in a net loss and is often not approved. A

Figure 3: Wells selected as part of the Geopressured Wells of Opportunity funding in the 1980s and 1990s with recent hydrocarbon exploration plays overlaid (modified from John et al., 1998).



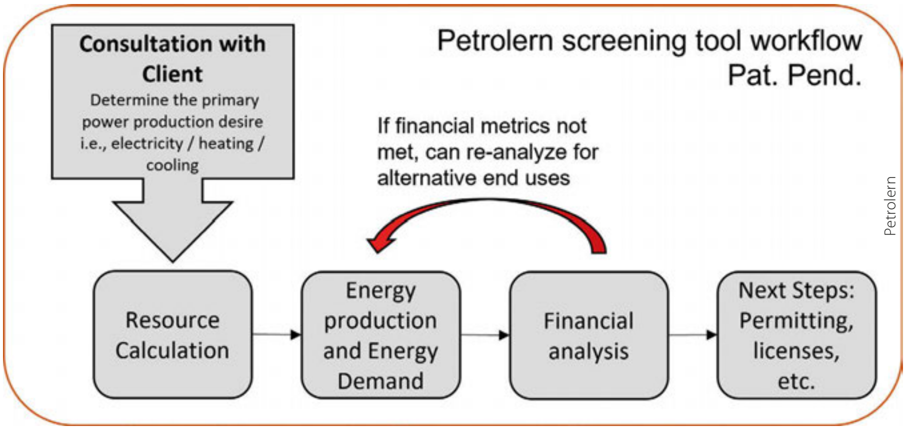


Figure 4: General step-by-step well screening methodology (Petrolern, 2021). A streamlined tool that performs all these tasks increased screening efficiency, saving time and money to find ideal well conversion candidates. Performing a similar task prior to well abandonment will facilitate geothermal energy adoption in the oil patch by highlighting the best candidate wells for conversion.

streamlined well screening should be performed in a step-by-step process (Figure 4) as part of the end-of-life assessment to find ideal well conversion opportunities. A streamlined process eliminates low potential wells early, thereby saving time and expenses for detailed evaluation of the most prospective wells, which may prove profitable to a company's bottom line. The Boak et al. (2021) CSEG Recorder article describes in more detail the benefits of proper screening following the flow outlined in Figure 4.

Screening should follow a similar workflow that provides assessments oriented to the stakeholders' project objectives, while also providing thermal results if the end user wants to consider additional use options. This means sites are quickly disqualified where wells fail to meet the desired geothermal resource output, or where there is insufficient data to make a direct assessment. If more hydrocarbon wells are screened prior to final abandonment, we expect significant growth in geothermal energy production associated with hydrocarbon-to-geothermal well conversion projects.

Teaching an Old Well New Tricks

There are significant geothermal resources within sedimentary basins, collocated with active oil and gas production, but not all basins will have economic geothermal resources. Some geothermal resources are already being produced by oil and gas operators, yet the geothermal water is discarded. This article focuses on the United States, but end-of-life hydrocarbon wells occur elsewhere in the world and offer an opportunity for geothermal energy production (Boak et al., 2021). Our projections, using real-world water production data and a conceptual conversion, indicate repurposing some oil and gas wells to geothermal heat and power production is profitable with IRRs of 7 to 27%. Sample costs of produced electricity are US$0.03–0.05/kWh. These potential values warrant evaluation of all wells prior to permanent plugging and abandonment. The primary issues hindering geothermal energy production in sedimentary basin settings seem to be the perceived high risk and high cost of geothermal projects and the necessary expertise to perform a full valuation of existing resources in a cost and time effective manner. A screening tool streamlines well evaluation for the oil and gas industry, to facilitate hydrocarbon-to-geothermal conversion. By providing cost effective and efficient evaluation of existing oil and gas wells, we expect more hydrocarbon-to-geothermal conversion and co-production projects within existing oil and gas producing basins, thereby growing the geothermal industry globally and lowering emissions within the oil patch. Conversion of end-of-life wells to geothermal utilization provides additional monetary value while also providing a pathway to decarbonize existing operations.

References available online. ■

Adventures in Middle Eastern Oil

Wendell Phillips: archaeologist, oilman and explorer.

M. QUENTIN MORTON

The 20th century American explorer Dr Wendell Phillips is best known for his colorful exploits in archaeology, which included surveys in Africa and Arabia, and for his work with the American Foundation for the Study of Man, which he formed in 1949. He was also an independent oilman who broke into the Middle East at a time when it was dominated by the major international oil companies. His subsequent career in the oil business was filled with tangled interests and mixed fortunes, but it was also remarkable for the fact that the impecunious archaeologist ended up as an oil magnate in his own right.

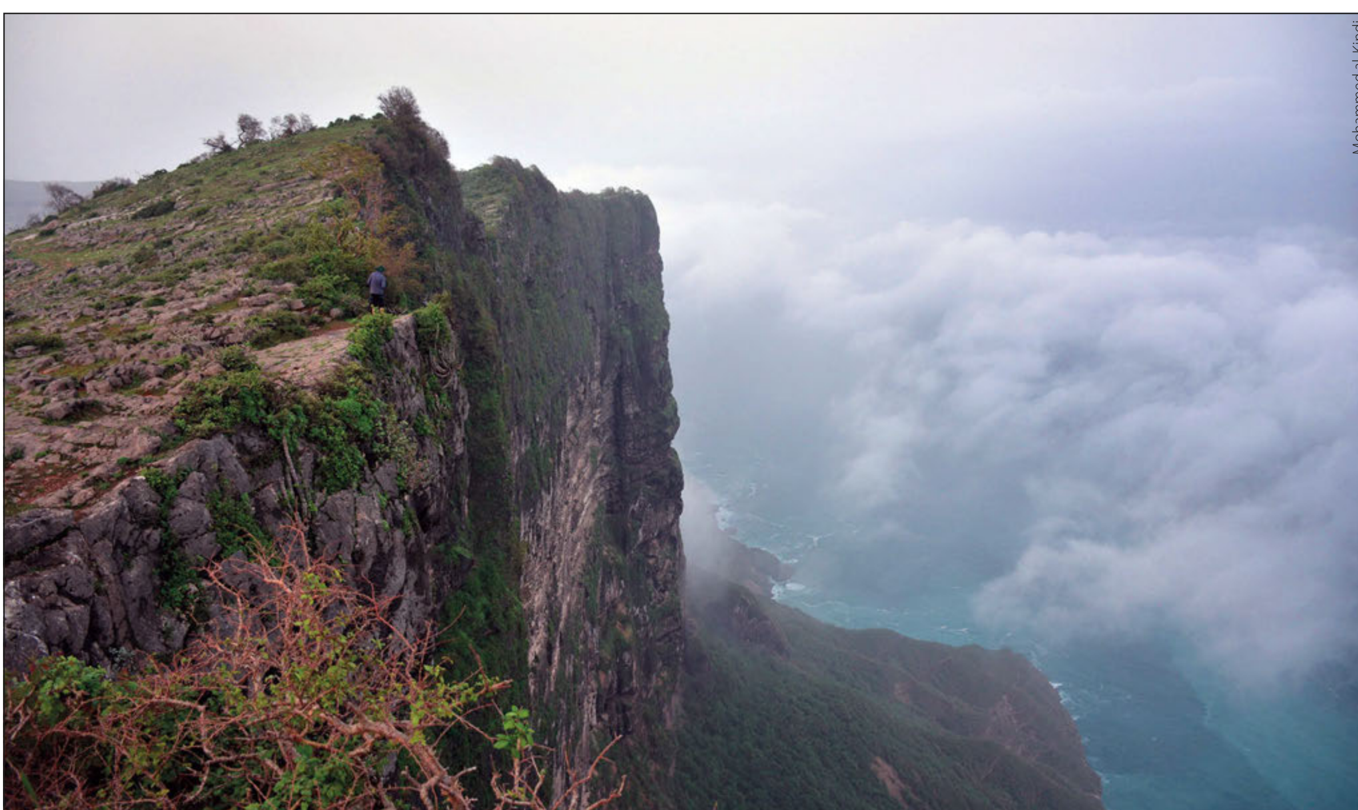
A Lucky Break

Even though Wendell Phillips was a lean man of medium height, he seemed to tower above the desert ruins in his Arab headdress with two pearl-handled pistols strapped to his waist. Among his many talents, he was an oilman, though his entry into that field was a lucky break. In 1952, he fled from Yemen after a disagreement with the authorities over an archaeological site at Marib, reputedly the palace of the legendary Queen of Sheba. He found refuge in the neighboring province of Dhofar, ruled by the sultan of Oman, Said bin Taimur. After befriending the sultan, Phillips began exploring the country for antiquities. But then, quite unexpectedly, he found himself the proud owner of an oil concession the size of Indiana.

He was an unlikely figure for this kind of adventure. Born to a poor family in Oakland, California in 1921, his mother was a gold prospector and wall-of-death rider, and he worked in various jobs as a youth, as well as suffering from polio, which he eventually recovered from. He attended the University of California at Berkeley, although his studies were interrupted by wartime duties in the Merchant Marine before he returned to college to obtain a Bachelor of Arts in paleontology. He joined in fossil-hunting expeditions to Arizona, Oregon, and Utah, but it was

Wendell Phillips in Arab headdress in 1966 – he was also an honorary sheikh of the Bal-Harith tribe of Yemen.

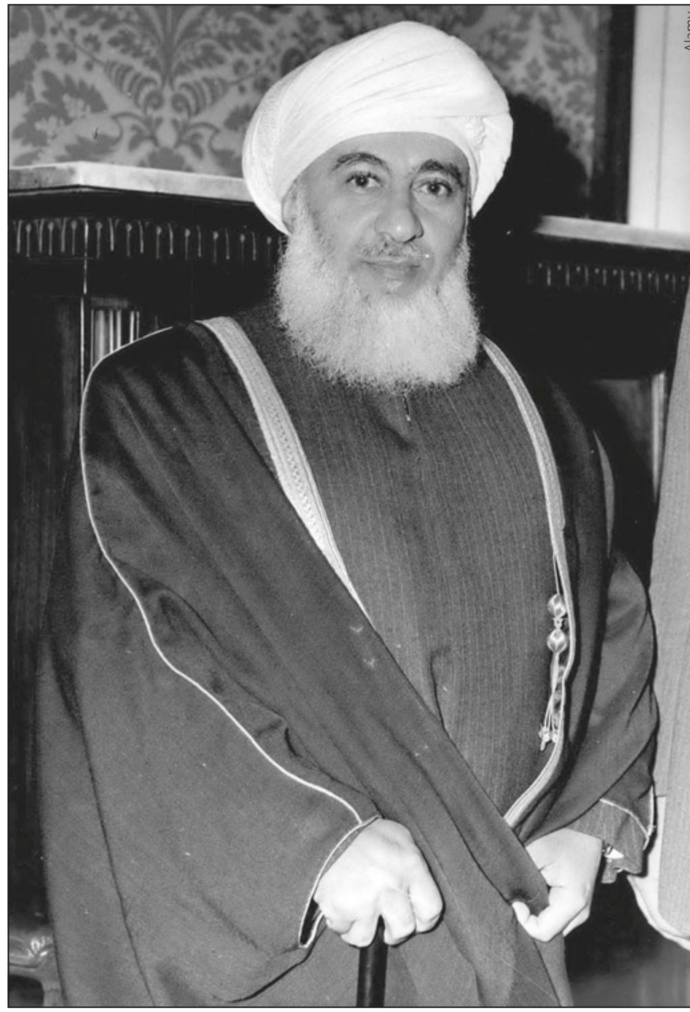
An escarpment in south Dhofar overlooking the Indian Ocean.



his powers of persuasion that won the funding for his first archaeological expedition to Africa.

The Dhofar oil concession came as a complete surprise. Phillips had no experience of the oil business and his main interest was archaeology. But perhaps the sultan saw something in this enthusiastic young man that suited him to the task, an ability to get things done. Over the next few days, Phillips hammered out an oil-concession agreement and then set about arranging finance, though the obstacles were formidable. Dhofar was 'remote from American thinking', and there were no port facilities, so that all equipment would have to be flown or floated in. Undaunted, he pressed on with his plans. In January 1953, the concession was assigned to a newly-formed company, Dhofar-Cities Service Petroleum. Phillips, taking a leaf out of the oil magnate Gulbenkian's book, retained a two-and-a-half percent royalty share.

In his early 30s at this time, Phillips was set for a stellar but often controversial career in the oil business. "To businessmen, he was a scholar, to scholars he was a showman," wrote Herbert Solow in *Fortune* magazine. Others were more flattering – Lowell Thomas, the American writer, made the comparison with Lawrence of Arabia. The oil companies looked on begrudgingly when he pulled off his latest business coup. This would be a recurring theme in his career: the maverick against the establishment. Not that Phillips was fazed – he never claimed to be an oilman, preferring to be called an explorer. "With me, oil is a hobby that happens to pay," he once said.


Alamy

Sultan Said bin Taimur on a visit to London in 1961.


D.M. Morton

Unloading oil drums on the shore at Raisut, 1960.

Marmul well number 125 in 1983 – after Petroleum Development (Oman) Ltd had taken over operations and developed the field.

A Pyrrhic Victory

The sultan's enthusiasm for a loner in the petroleum world is partly explained by the fact that, until then, oil exploration had been controlled by the British-led Iraq Petroleum Company, a consortium of major international oil companies, which had just surrendered its concession for Dhofar. The British authorities, who exercised considerable influence in Oman, were nevertheless concerned by Phillips' involvement because he represented American interests in an area where British interests held sway; and his activities also threatened to aggravate Oman's border problem with Saudi Arabia. Phillips' answer was to accompany the wali of Dhofar on an expedition to a disputed area of the desert to plant a territorial marker there, then to add his own name to it.

Dhofar-Cities Service set up their headquarters in a palm grove near a beach at Raisut to the west of Salalah, and a number of aerial surveys were flown over the territory. Dhofar had a three-month monsoon season known as the *khareef* which started in late spring and covered the coast in a thick fog, causing aircraft to fly out to sea and then descend to wave-top level before turning back towards the RAF airstrip. The sultan built a 50-kilometer road from Salalah into the Qara Mountains for huge Kenilworth trucks to transport collapsible derricks into the desert interior. Exploration camps sprang up overnight, and millions of dollars were spent.

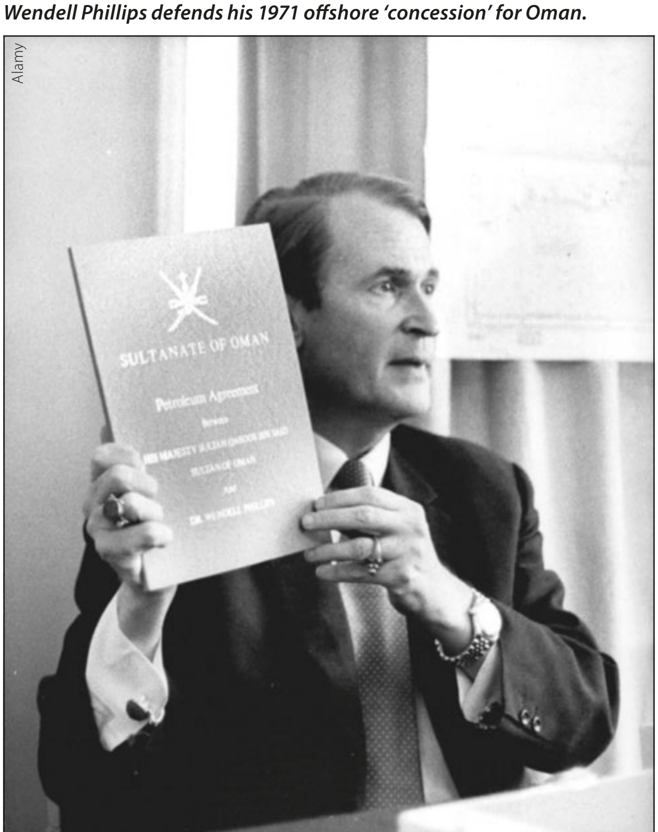
On April 15, 1955, Dhofar-Cities Service spudded-in their first test-well at Dauka, followed by two wells at Marmul in 1957 and 1958. The oilmen were expecting to strike oil, and did so at Marmul. However, their hopes were soon dashed when the oil flow declined on testing; it was a time of oil glut and low prices which made the heavy oil (22° API and 40–200 cP viscosity) at Marmul unprofitable. In 1962, the company assigned its interest to John Mecom and Pure Oil. In 1967, after more changes, with \$40 to \$50 million spent and 29 wells sunk, the Americans withdrew. They had found oil but at great cost and with no commercial advantage. When all was said and done, it was a pyrrhic victory, although Phillips had already sold part of his share for \$1 million by then.

The World Beckons

In April 1955, Phillips established contact with the Libyan government and ruling family, and obtained an exploration permit for the Cyrenaica area. But there was a problem – he needed the authority of the elderly and infirm King Idris to proceed, and the king would not see Phillips alone, but only as a member of a delegation. Undeterred, Phillips visited the king's palace at Tobruk on the coattails of an American delegation led by Harold E. Talbott, the secretary of the US Air Force. Forced to wait outside the royal chamber while the delegation went inside, Phillips slipped in as soon as the meeting was over. He talked to the king about archaeology, which was enough to secure a second interview to talk about oil.

The prospect of having an independent oil company operating in Libya appealed to the king, much as it had to the sultan of Oman. Repeating the tactics he used in Dhofar, Phillips turned over his exploration permit for Cyrenaica to a US oil company,

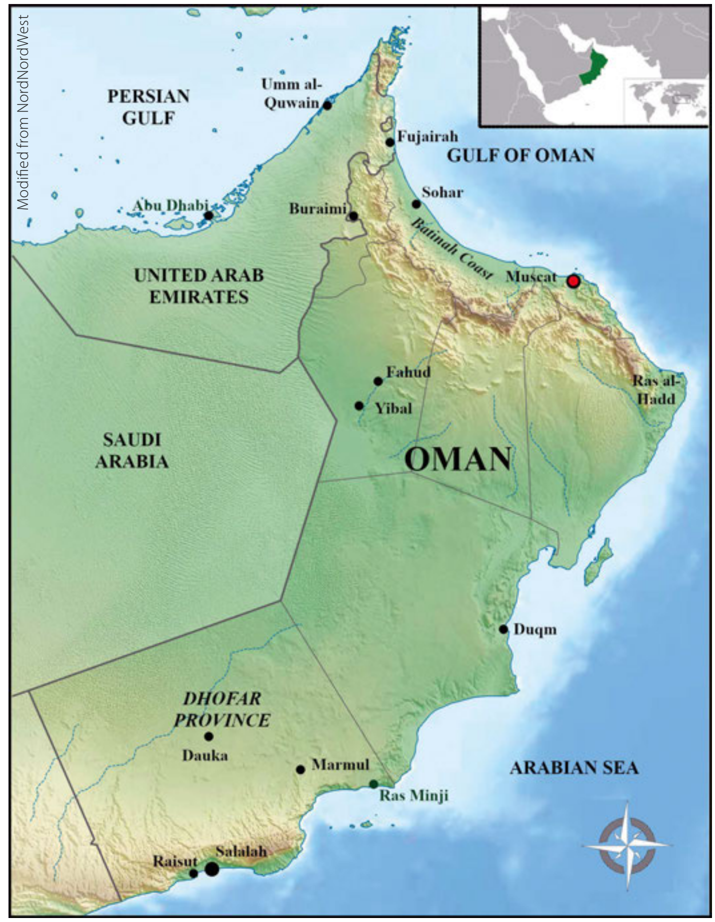
Wendell Phillips defends his 1971 offshore 'concession' for Oman.



the newly-formed Libyan American Oil Company, and retained a three percent royalty on future production. There followed an awkward period in which allegations were made against Talbott and Phillips – the gist being that they were 'thick in Libya' – but the Petroleum Commission decided in the company's favor, operations proceeded and Phillips' royalty share was intact.

He was never one to rest on his laurels. Oil ventures were calling from the rain forests of Venezuela, and from Africa and South East Asia. There were persistent reports that he was dabbling in the Trucial States (today's United Arab Emirates): in 1966 he made an offer to the sheikh of Fujairah for an offshore concession, and in 1969 he assembled a group of business interests to apply to the sheikh of Umm al-Quwain for an offshore concession in the Persian Gulf. And there was Australia: in 1968, it was reported that he had turned his attention to the Land Down Under. All these activities were coordinated from his home in Honolulu.

A bachelor till the age of 47, he married an 18-year-old local girl, but the marriage did not last. "She just could not adjust to my way of life," he told the press, alluding to his globe-trotting activities. By then he had 18 honorary degrees from universities around the world. "I am first and foremost an explorer and archaeologist. My second objective is to publish my findings. I'm getting close to that goal despite all the money that's come along," he told the *New York Times*.



A map of Oman showing the locations mentioned in the text.

A Comedy of Errors

His first love remained Oman. He wrote two books about the country and remained on good terms with the sultan, describing himself as his 'economic adviser'. In the 1950s, there was talk of an oil concession for the sultan's territory of Gwadar (now part of Pakistan). In December 1965, it was reported that the sultan had granted his company, Wendell Phillips Oil, an offshore concession stretching from the Batinah Coast to Ras al-Hadd, which he had assigned to a German firm, Wintershall Aktiengesellschaft. But in July 1970, his old friend Sultan Said bin Taimur was replaced in a bloodless palace coup by his son, Qaboos. This was followed in March 1971 with news that the new sultan had awarded his company a new offshore concession for the southern coast of Oman, stretching 450 miles from Ras al-Hadd to Ras Minji near the border of Dhofar province. In true style, a breathless Phillips announced the news to a press conference in London and waved a signed agreement in the air – it was a document handsomely bound in red leather with gold lettering. What could possibly go wrong?

At this point, the story takes a curious turn. Following the coup, the decision about Phillips' concession rested with Sultan Qaboos. There was confusion about what exactly had been granted: was it a concession, option, contract, commission to study, or something else? The sultan couldn't remember the details and in August 1971, Phillips' representative arrived in Muscat to make a down payment on the agreement only for his check to be written off as a 'dud'. In September it was announced that the concession had been cancelled because Phillips had not arrived in Oman to sign the documents. "No visa was sent to allow me to come to Muscat," he protested. To cap the whole comedy, word was received that his visa had been cancelled – even though he had never had one in the first place. Phillips lost the concession and was left to lick his wounds.

Wendell of Arabia

Wendell Phillips passed away in 1975 after a heart attack at the relatively young age of 54. He was a very rich man, reputedly with a fortune of over $130 million when he died, and some 40 producing oil wells and oil rights to 100,000 square miles of ocean to his name. The impression remains of a flamboyant showman and opportunist who achieved many remarkable things. In the oil business, he ruffled feathers as he went, although his singular skill in bringing together business interests in pursuit of his oil ventures shone through. "When opportunity came, I was not the odd man out," he once said. His start in the oil business was a lucky break, but it was all his own efforts after that. And, if we imagine the pistol-strapped explorer emerging from the desert in Arab dress, for a moment we might think a comparison with Lawrence of Arabia was not so fanciful after all. But then, the irrepressible Phillips would have added: "I'm better than Lawrence."

Thanks to Peter Morton and Alan Heward for their kind assistance. ■

A Journey of a Thousand Miles

Lebanon's Hydrocarbon Marathon Begins.

WISSAM CHBAT, WAEL KHATIB and JAD ABI KHALIL; Lebanese Petroleum Administration

First Step to Success

Drilling of the first ever exploration well in the Lebanese offshore began on March 3, 2020 and was completed on May 8, 2020 using Vantage Drilling's Tungsten Explorer drillship.

Total E&P Liban Sal, the operator of the international joint venture (JV) (Total 40%, ENI 40%, Novatek 20%) drilled Well 16/1 in Block 4, located 30 km offshore Beirut to a total depth of 4,076 meters from sea level, in water depths of approximately 1,500 meters.

The well penetrated the entire Oligo-Miocene section, which is the main target of this exploration well, and provided valuable data that will be used to further evaluate the hydrocarbon potential offshore Lebanon. Unlike the recent discoveries in the Eastern Mediterranean (1999–2015) that encountered sands as the main reservoir, well 16/1 encountered predominately carbonate lithologies consisting of marls, calcareous claystones, limestones and clayey limestones similar in lithology to some of the discoveries in the Eastern Mediterranean after 2015.

The first exploration activity that took place in a frontier, deepwater and previously underexplored north Levant Basin was safely concluded with no operational accidents but did not encounter the anticipated 'Tamar' Formation sands, though it did record traces of gas.

A Working Hydrocarbon System

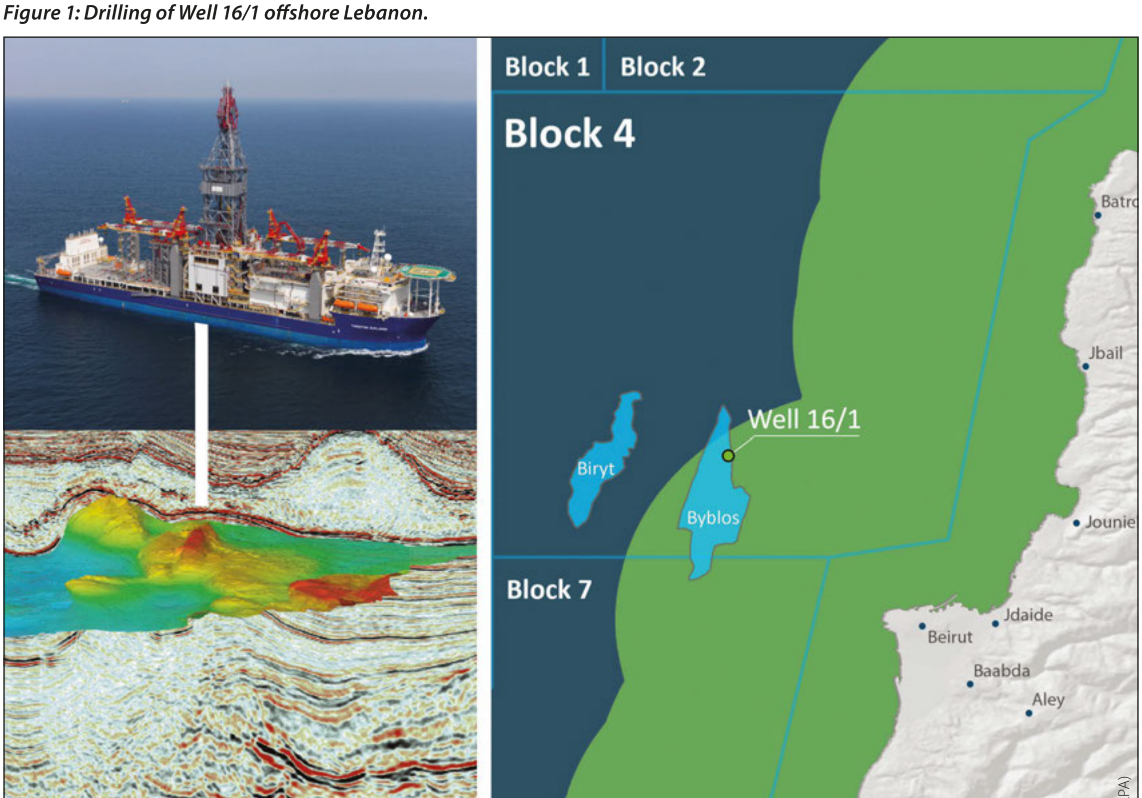
A study published by the University of Oxford in 2018 (Cartwright et al.) used available seismic data to identify multi-episode fluid expulsion in the Lebanese offshore. The study identified a suite of linearly distributed trails of fluid escape pipes with pockmarks at their upper terminus. The pipe trails are oriented orthogonal to the strike of the pre-salt folds, with a synchronous initial expulsion episode in each trail dated at ~1.7 Ma. The reservoir pressure is reported to have charged the structure-to-fracture gradient 21 times. A total trail of 21 pipes and pockmarks are identified overlaying a pre-salt anticlinal structure which highlights the continued generation of hydrocarbons below the North Levant Basin.

Well 16/1, drilled offshore Lebanon reinforces this concept. As reported by the operator, the well contained traces of gas confirming the presence of a hydrocarbon system, but it did not encounter any Tamar Formation reservoirs, which were the main target of the exploration well.

The Lebanese Petroleum Administration (LPA) performed a parallel study that resulted in the following findings: (i) the hydrocarbon system was proved to be functional; (ii) formation tops, breaks in deposition and ages were identified from biostratigraphy and mineralogical analysis; (iii) carbonate units are predominant in the zone around the well; and (iv) different types of source rocks were identified, including the potential for having both oil and gas offshore Lebanon.

Further studies are being conducted to adapt the previously used siliciclastic model to the actual carbonate

Figure 1: Drilling of Well 16/1 offshore Lebanon.



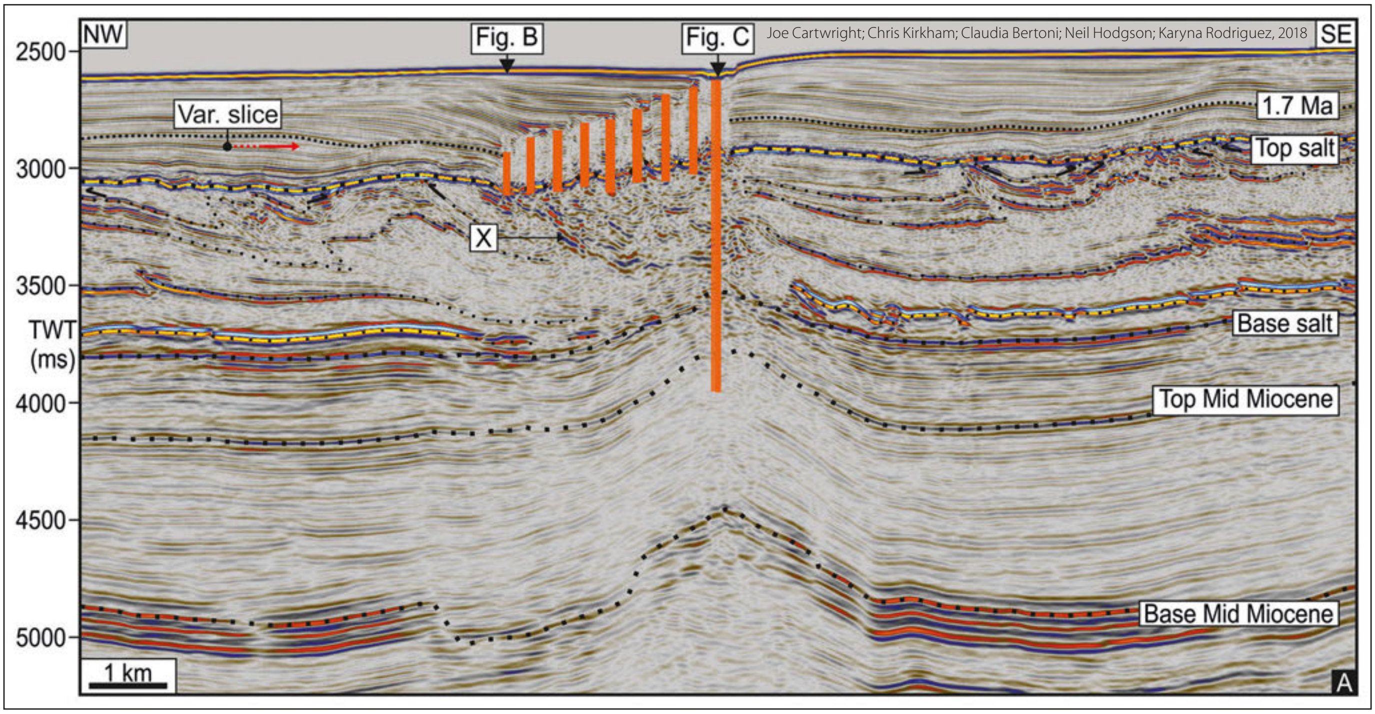


Figure 2: Multi-episode fluid expulsion identified offshore Lebanon.

environment discovered. These converged with the findings reported by the operator, based on geological and petrophysical analysis. However, further work is being conducted to understand the geological environment in which a potential reservoir could be located, by performing seismic interpretation and developing an elaborate sequence stratigraphy model.

As part of a second Exploration and Production Agreement signed in 2019 by Total E&P Liban Sal, the operator of the international JV, a second well is expected to be drilled in Block 9 in the upcoming year that is more proximal to proven discoveries in the south, such as Tamar, Leviathan, Karish and Aphrodite. Recent appraisal activities in Karish – ~2 km south of the Lebanese border – indicate porosity reaching up to 20% in the targeted sand formations with the presence of both gas as well as light oil and condensate, significantly enhancing the prospectivity of offshore southern Lebanon.

Geological Zones Offshore Lebanon

Lebanon's offshore has been separated into three main geological domains: (i) the deep basin; (ii) Latakia Ridge; and the (iii) Levant Margin. Each of these domains is marked by a general structural style, and various stratigraphic architectures, resulting in different source-reservoir-trap configurations. This subdivision into domains can impact exploration as it highlights specific geographic areas having distinct petroleum systems that can each be considered areas of interest in their own right. The deep basin is ~14 km thick and comprises sediments from the Jurassic to the Pliocene age deposited in a deepwater environment and is composed of hemipelagic shale and intercalated but discrete layers of sandstones which are the potential reservoirs. These sediments pinch-out eastward along the Lebanese continental margin. The Latakia Ridge domain is located in the north-west part of the Lebanese exclusive economic zone and is characterized by large SW–NE-oriented compressional structures with reverse faults and deep thrusts that are still active at the present time. The Levant Margin is comprised of the Mesozoic platform, which is characterized by thick shallow-water platform carbonates of Triassic to Middle Cretaceous age and the Neogene continental platform which is superimposed on the Mesozoic platform, and is comprised of Late Miocene and Plio-Quaternary sediments.

Lebanon is surrounded by proven hydrocarbon discoveries to the west and south, including the offshore fields Tamar, Leviathan, Aphrodite, Zohr and Calypso, as well as the many other discoveries onshore to the east in the Palmyrides. The Lebanese Basin is ideally situated for hydrocarbon exploration, lying as it does in an area proven to have favorable trap, reservoir and source rock combinations with the potential for mixed biogenic and thermogenic systems offshore Lebanon.

Wealth of Data Available

Hydrocarbon exploration in Lebanon is expected to move at a fast pace due to the accessibility of extensive geophysical data, which was made available before the closure of the first offshore licensing. This remarkable and possibly unique situation means that this wealth of information will allow stakeholders to learn a lot about the offshore hydrocarbon potential of the area, right up to prospect level, ahead of the important, decision-making processes inherent in the industry.

Specifically, more than 14,000 km and more than 15,000 km^2 of high quality 2D and 3D seismic data is available for licensing in Lebanon. Coupled with this extensive geophysical

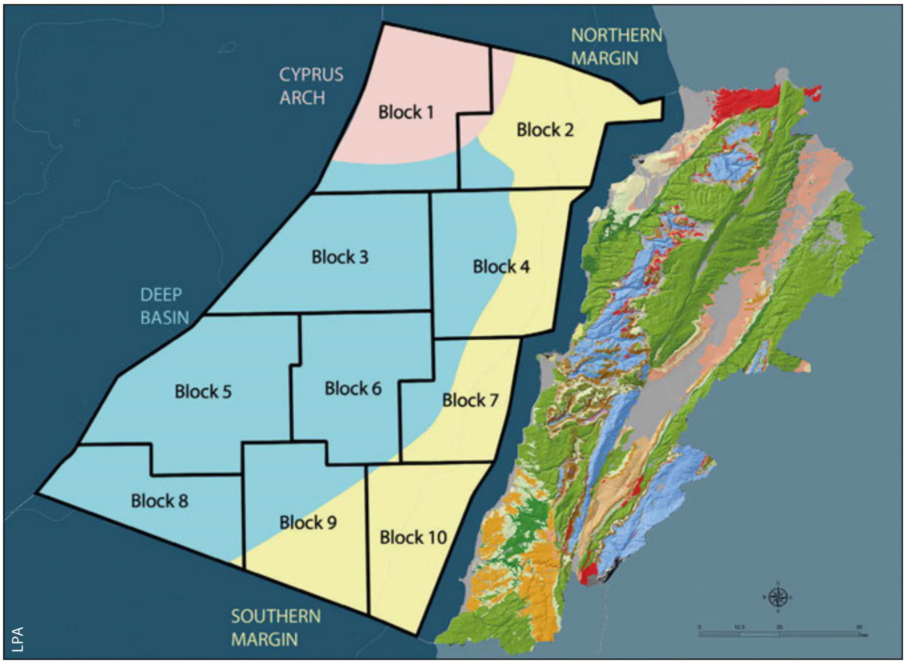


Figure 3: Geological domains of offshore Lebanon.

coverage, the data derived from the well provides invaluable information for stakeholder analysis.

What Next?

It is generally known in the industry that the Probability of Success (POS) of hitting a discovery from the first exploration well is less than 30%. Given this context, the exploration well marked a significant milestone that reiterates Lebanon's commitment to develop its prospective offshore petroleum sector for the benefit of current and future generations, keeping in mind that the oil and gas sector is inherently associated with risks and uncertainties. Persistent efforts will continue to achieve the long-term vision of the sector.

In addition to the scheduled second well to be drilled in Block 9, the Lebanese government approved the launch of the Second Offshore Licensing Round. The Ministry of Energy and Water and the Lebanese Petroleum Administration are working on the marketing of this round and are communicating with companies that expressed interest in taking part in it, including answering questions and providing clarifications about the procedure with which to submit applications. A recently approved draft decree allows companies to securely submit online applications for the Second Offshore Licensing Round.

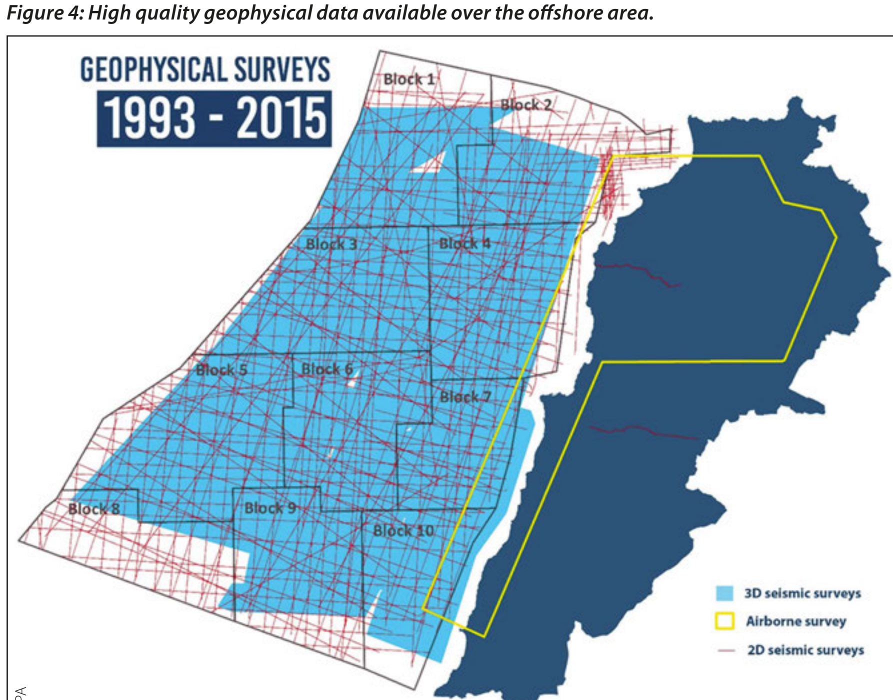
As the pandemic continued to spread around the world, it had a devastating effect on the petroleum sector from low demand for oil and gas products to a sharp decline in hydrocarbon prices. While the Covid-19 pandemic affected the financial and logistical capacities of petroleum-exploring companies, the decline in oil and gas prices led companies to lower their investments and to hold off exploration activities. Many countries have either postponed or put on hold their licensing rounds, which they had launched before the pandemic. As the conditions described above took their course, it was necessary to momentarily postpone the deadline for the submission of applications to participate in the Second Offshore Licensing Round to a later date which will be determined by a decision that the Minister of Energy and Water will make based on the recommendation of the Lebanese Petroleum Administration. The objective is to engage with the industry to find a suitable closure date for the Second Offshore Licensing Round.

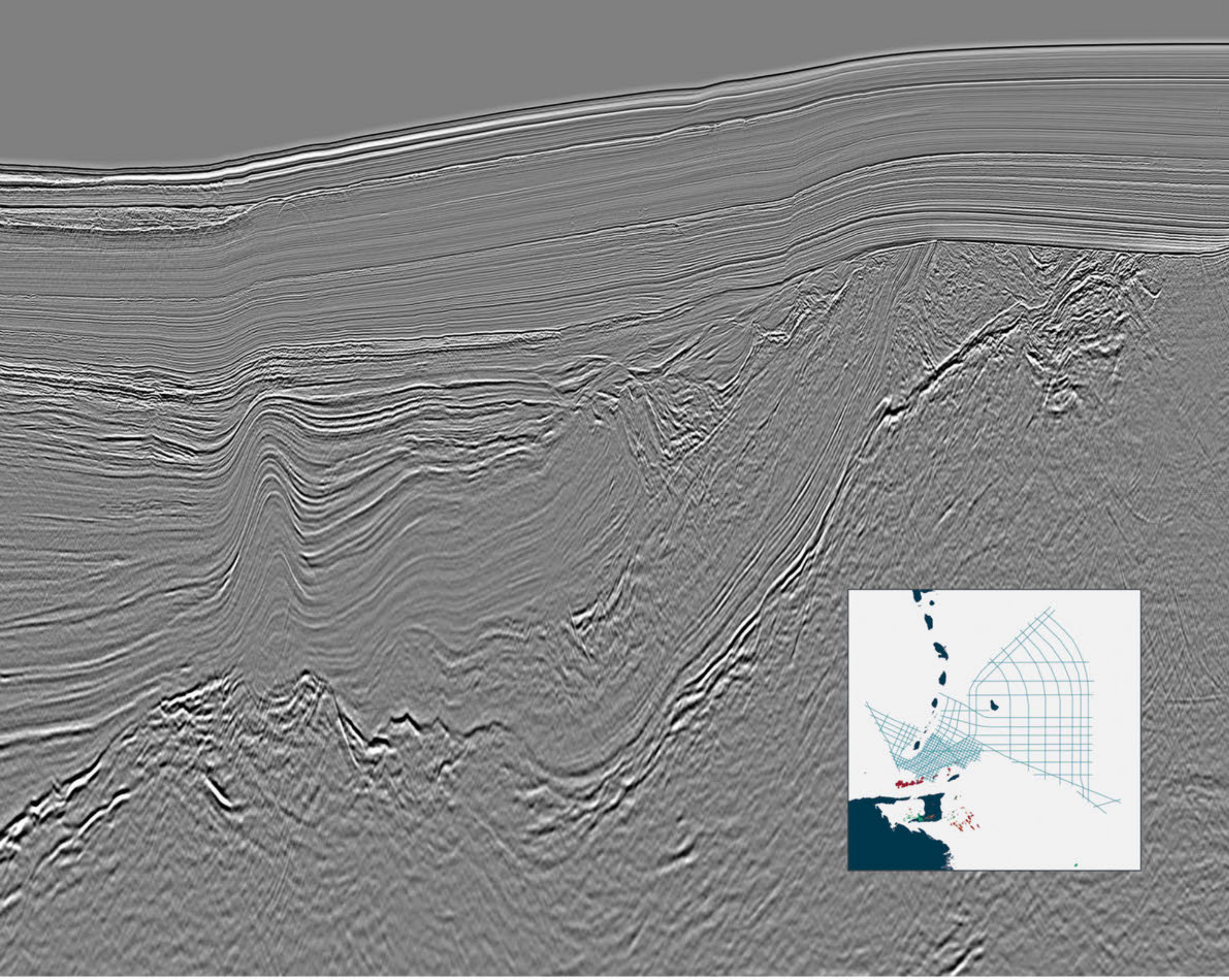
Meanwhile, in light of these changes the level of companies' interest will be evaluated through direct communication, and the Second Offshore Licensing Round's general framework will be studied while considering the inclusion of any amendments deemed necessary for the rules of participation in this round in order to keep pace with the new global situation.

References

Cartwright, J., Kirkham, C., Bertoni, C., Hodgson, N. and Rodriguez, K. 2018. Direct calibration of salt sheet kinematics during gravity-driven deformation. *Geology*, 46(7), pp.623–626, https://doi.org/10.1130/G40219.1. ■

Figure 4: High quality geophysical data available over the offshore area.





AI: a Game Changer in Seismic Acquisition and Processing

Leveraging artificial intelligence to improve efficiency, predictability and performance.

MATT DEIGHTON and
SVERRE OLSEN; PGS

A recent Gartner seminar made the bold prediction that "in the near-term AI will not replace humans, but humans that use AI will replace those that do not". What the presenter was trying to convey is that the targeted use of artificial intelligence and machine learning can result in significant operational improvements that in turn will result in tangible competitive advantages. This is especially true in areas where AI is used for predictive analytics to improve the quality of decision-making.

The process of safely acquiring and imaging marine seismic datasets is a major enterprise and requires a significant amount of human capital to operate seismic vessels and to image and characterize the many terabytes of seismic data collected each day. Many of the processes involved are implicitly repetitive and the use of AI has the potential to improve the efficiency of such processes.

Having recognized the potential of using AI, PGS has embarked on several digitalization transformation projects across its different product lines and we are happy to share some of our initial learnings and observations in this article.

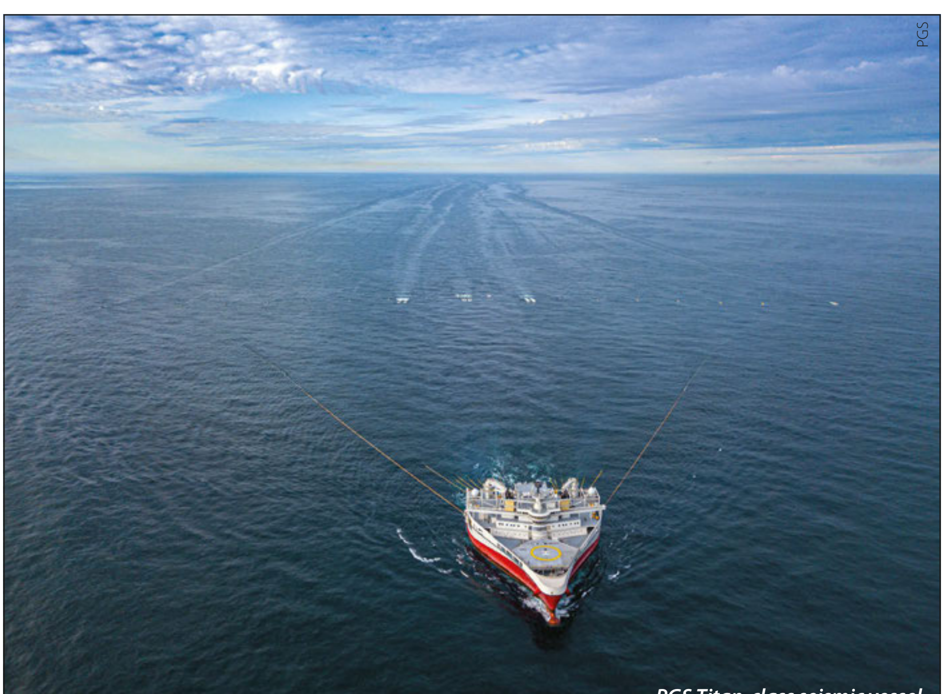
The application of machine learning within the context of fully integrated acquisition and imaging operations has allowed us to assess the impact of AI processes along the entire seismic life cycle, from the point of data collection to the delivery of seismic products to end users.

A decision was made early on to focus any AI development and application on repetitive processes that were seen to have the biggest impact on project execution and turnaround time, and on minimizing delivery risk and costs. One focus area was the optimization of vessel speed without compromising overall data quality. Specific focus was also given to the early identification of hardware failures before these could result in survey downtime, and the augmentation of human decision-making in somewhat predictable processes; reducing human exposure to unnecessary operational risk. Finally, some of the AI development work focused on simplifying workflow structures and reducing manual processes such as the QC of repetitive parameterization of seismic processing algorithms.

Improving Project Performance Through Smarter Vessel Operations

There are many factors that affect the speed at which a marine seismic vessel operates during a survey and most of them are routinely measured. To understand which of these factors are most critical at a given time, PGS teamed up with Cognite to use their Cognite Data Fusion™ analytics capabilities to analyze the available data. When designing the project, PGS saw an opportunity to combine the many factors that influence a vessel's optimal operating speed into a single, easily accessible and understandable tool that could be used by the operations management team.

Reports combining vessel sensor and operational data have provided new insight into the details of vessel production performance, and dashboards are used in onshore project planning and execution. Figure 1 is the near-real-time view of the vessel speed management dashboard showing machine learning predictions of the factors that are currently restricting the vessel speed. These include, among others, recorded noise levels, forces



PGS

PGS Titan-class seismic vessel.

experienced by the equipment, and time between shot points.

The systematic analysis of the speed metrics and better understanding of the recorded operational data has also enabled other beneficial avenues to be explored. The monitoring and modeling of performance shows promise for optimizing maintenance schedules, while processing text from safety reports has already identified trends allowing changes to be implemented that we hope will improve the HSEQ performance of the offshore crews. Informed preventative maintenance to avoid costly port calls is now a realistic target and will save millions of dollars each year.

Data Processing with Deep Learning is Real Automation

There are many repetitive processes in seismic processing that present opportunities for AI to enhance productivity. Parameter testing phases involve the geophysicist drawing upon their experience to evaluate the success of many tens of processes that almost always employ data visualization. Convolutional neural networks (CNNs) are one example of AI that can be trained to perform similar analysis but in an accelerated timeframe. Removing noise from seismic data is an important processing step and requires testing and QC. Farmani and Pedersen (2020) developed an automated noise removal workflow, incorporating machine learning into a framework with conventional methods, saving significant time and effort whilst delivering better results.

The neural network can high-grade the denoise performance of the processing step as shown in Figure 2. Panel B shows a manually parameterized, single pass denoise result which is fed into the AI framework. The results shown in Panel C demonstrate the high grading of the result following classification and automatic reparameterization and rerunning (where required); the difference of which is shown in Panel D, indicating that the machine learning approach has worked very well.

In another machine learning application, we focused on migrated images that are often contaminated by migration swings; a noise resulting from uneven subsurface illumination and propagation through complex media. As the noise has similar characteristics to the underlying seismic data, it is difficult to create filters that remove the noise without damaging the seismic data.

In the neural network-based approach developed by Klochikhina et al. (2020), training data is created using noisy images as an input to the network and clean images as an output. Figure 3 shows the results of an application of the trained network, for a deepwater data example from offshore Brazil. Yellow arrows in the upper left panel highlight the unwanted noise, whilst blue arrows in the bottom panel show how the CNN removes the noise that is still present when a conventional approach is used (turquoise arrows in the upper right panel). Orange arrows in the upper right panel also indicate locations that have lost detail because of the conventional approach.

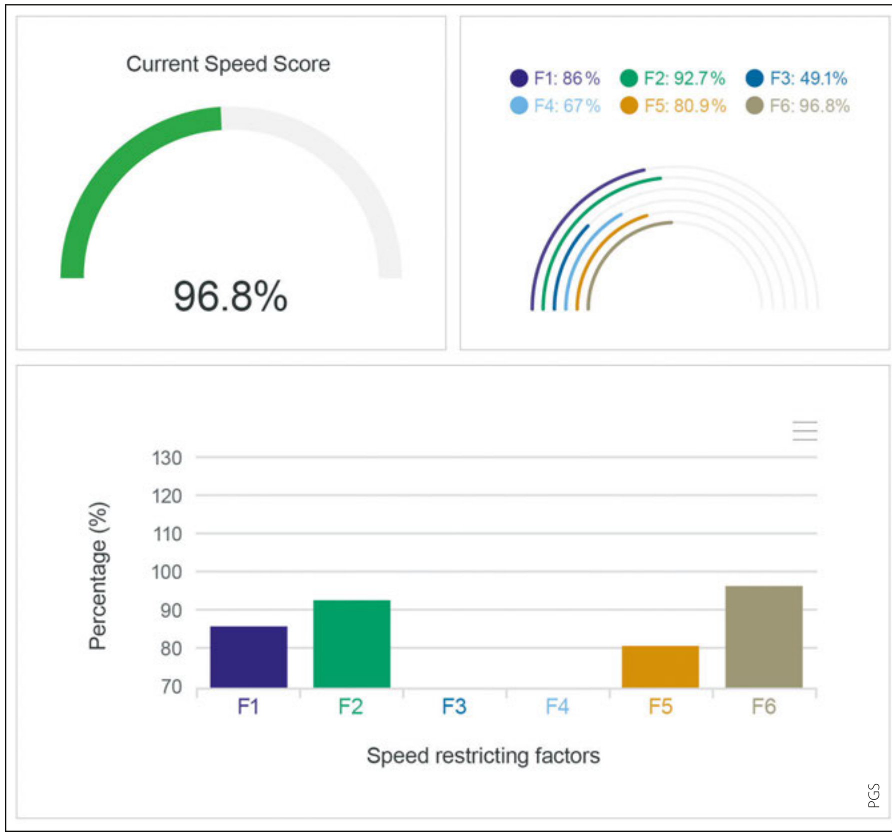


Figure 1: Vessel speed dashboard example showing how close the vessel speed is to the optimal level (i.e., 100%). The bar chart indicates how the different factors influence the current vessel speed. In this example factor 2 (green) and factor 6 (gray) are those that restrict the speed most. The dashboard is dynamically updated during the vessel operation allowing the crew to always optimize the vessel speed.

AI Beyond Vessels and Seismic Data

There are a wide range of opportunities in other parts of the seismic business where the use of AI holds great promise. Two such opportunities are well log prediction and fraud detection.

Well logs are physical measurements collected from boreholes that can provide an accurate view of the subsurface. As robust as they are, once this raw data is collected, it must be processed by specialists (a petrophysicist, and/or a rock physicist) to derive a set of conditioned logs. This is a lengthy process. Ruiz et al. (2021) show that machine learning with a rock physics library (PGS rockAVO) can rapidly predict conditioned properties such as porosity from measured logs; significantly reducing turnaround to the order of an hour for training and prediction.

When it comes to fraud in commercial transactions it is estimated that around 5% of global revenues are lost each year to fraud schemes with duplicitous invoicing being a

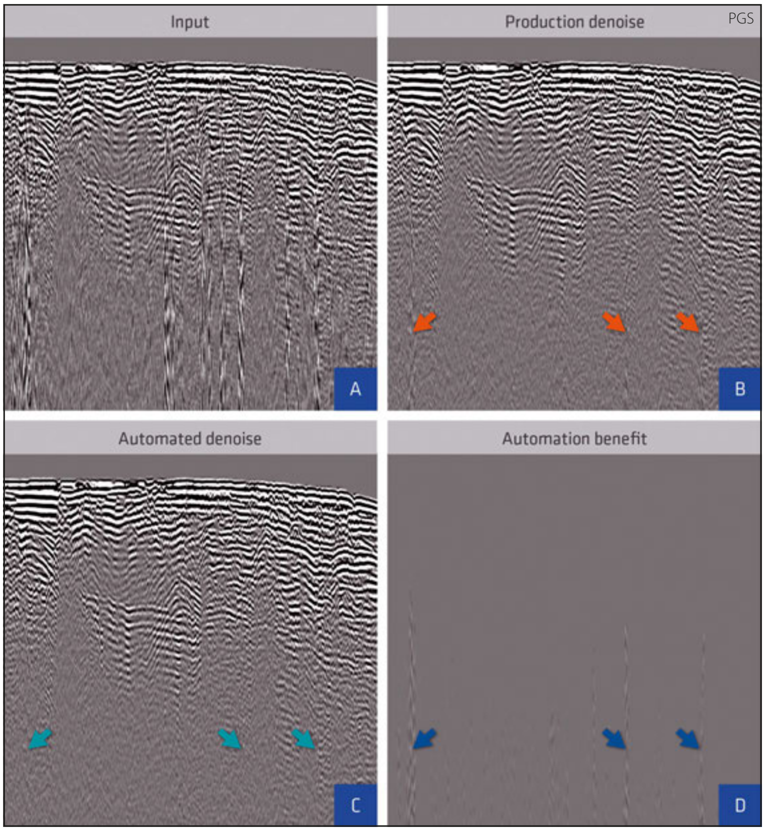


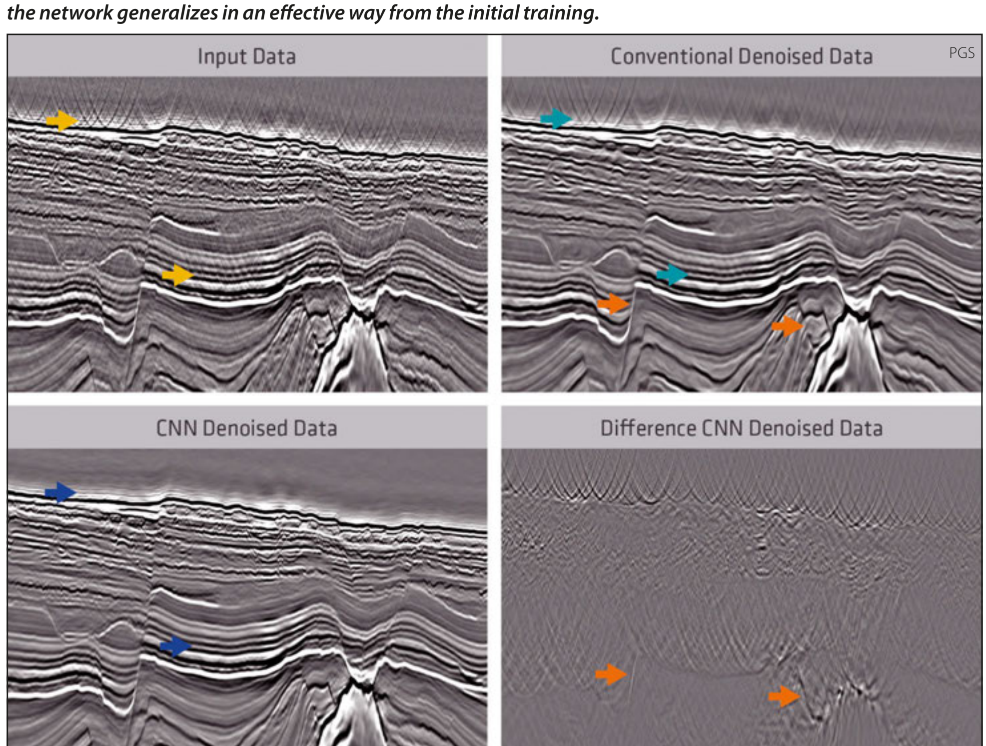
Figure 2: A) Input raw data showing strong vertical noise trains. B) Result of traditional workflow. C) Machine learning result. D) Difference between production workflow and AI result showing that more of the noise (blue arrows) has been removed using the machine learning approach.

commonly used tactic. The problem for auditing financial transactions for the purpose of fraud detection is that the number of legitimate invoices received by a company can be vast. Manual inspections rely on a small sample for analysis, which reduces the chances of discovering fraud. A successful AI application in our company now uses attributes from invoices and suppliers, building a set of models using clustering techniques, similarity measures, and statistical analysis. These are combined with expert rules to identify invoices that warrant further inspection by an Audit Team.

Early Learnings

As described in this article, machine learning as part of AI solutions can be successfully used in a variety of applications in the seismic industry, but success is not just based on the quality of the algorithms alone.

Figure 3: Example from offshore Brazil using the trained Convolutional Neural Network (CNN) to remove coherent image domain noise. Noise indicated by yellow arrows in the top left panel is better attenuated by the CNN application (blue arrows bottom left panel) than by using a conventional approach. The result shows that the network generalizes in an effective way from the initial training.



When it comes to making machine learning and AI applications a success, the following should be considered. Ensure resources are available, so prioritize developments with a good business case, build cross-functional teams including domain experts and data scientists, for continual progress, work in iterations and the ease of commercialization may vary depending on platform; legacy environments can be more challenging when it comes to deploying new AI solutions.

It is still early days, but as we gain more experience, we expect to increase the use of AI as part of the continuing trend for more automation in all parts of our industry.

References

Farmani, B. and Pedersen, M. 2020. Application of a convolutional neural network to classification of swell noise attenuation. *90th SEG Annual Meeting, Extended Abstracts*, pp.2868–2871.

Klochikhina, E., Crawley, S., Frolov, S., Chemingui, N. and Martin, T. 2020. Leveraging deep learning for seismic image denoising. *First Break*, 38(7), pp.41–48.

Ruiz, R., Roubickova, A., Reiser, C. and Banglawala, N. 2021. Data mining and machine learning for porosity, saturation, and shear velocity prediction: recent experience and results. *First Break,* 39(7), pp.71–76. ■

AI Seismic Interpretation for a Better, More Sustainable Tomorrow

AI is a game-changer in the understanding of the subsurface. These state-of-the-art tools are being utilized to establish the suitability of storage sites for use in carbon sequestration projects. Understanding storage capacity, the risk to containment, and the seal capacity are all critical elements affected by the presence of faulting that can be most clearly understood using Artificial Intelligence (AI).

Carbon Capture Utilization and Storage (CCUS) is thought to be an option to reduce net carbon emissions globally. Capturing carbon dioxide (CO_2) from large power plants or heavy industries, combined with safe subsurface storage, can help achieve the goal of net-zero emission. The Southern North Sea (SNS) Triassic Bunter Sandstone has been considered by many as an ideal aquifer for CCUS. Several potential storage sites (Bunter mounds) have been identified; however, some of these may be affected by faulting.

geoteric

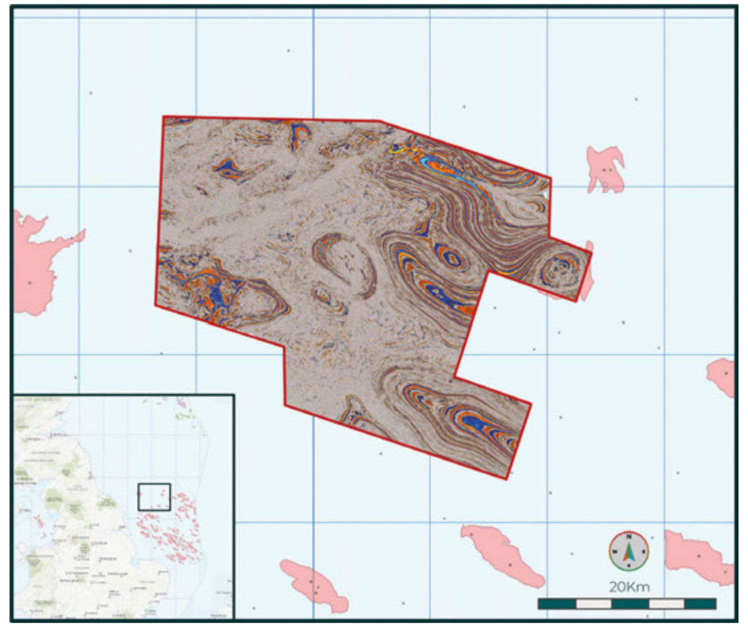


Figure 2: Base map showing the location of the Southern North Sea study area used throughout this project.

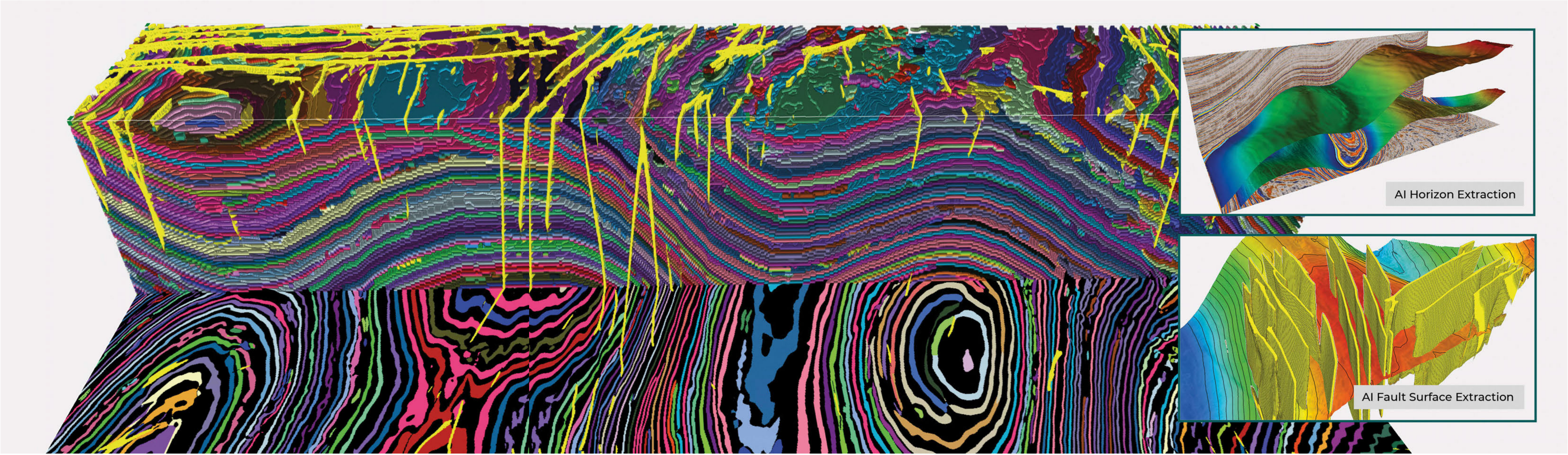


Figure 1: AI Seismic Interpretation from the UK Southern North Sea, identifying geological features for appropriate storing of CO_2. 3D imaging of the horizons reveals a series of mounded structures in the Bunter aquifer, one of which is heavily faulted whilst a second is free of structural complexity at the aquifer level. A significant unconformity, characterized by a series of underlying Triassic offlaps, can be clearly identified.

A Catalyst of Change for Net-Zero

RYAN WILLIAMS, CHRIS HAN, PETER SZAFIAN, MARK BROWNLESS and JAMES LOWELL; Geoteric

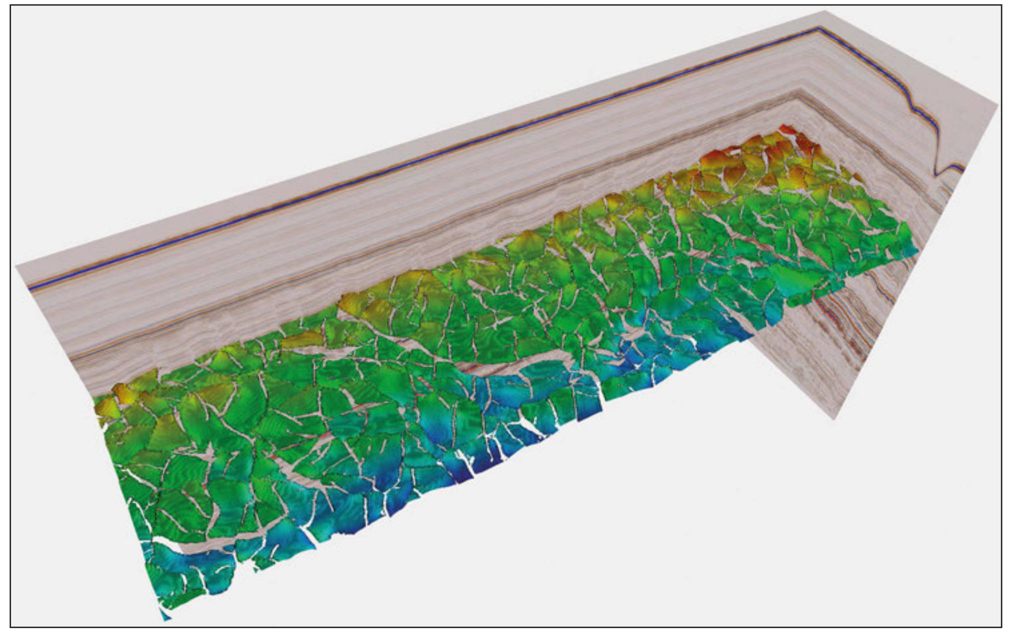
Artificial intelligence (AI) is making big waves in the subsurface world. In recent times, advanced neural networks have demonstrated their ability to surpass traditional attribute analysis in identifying, delineating, and extracting faults from seismic data. This isn't the first appearance of AI within the realm of seismic interpretation: neural networks have been used for years to improve the extraction of geobodies. So, it is only natural that horizon interpretation receives its long overdue upgrade.

AI Seismic Interpretation: The Implications for Subsurface Analysis

Seismic interpretation can broadly be separated into three components: faults, horizons and geobodies. While these elements are vitally important to define traps and accurately estimate the storage potential of a structure, their interpretation is very time-consuming. This is where AI, supported by modern day computing power, can drastically reduce the time required to undertake a detailed seismic interpretation, without sacrificing accuracy.

The ability to undertake quick and reliable subsurface analysis is crucial for any project involving seismic data, especially with data sizes increasing at an exponential rate. In most projects, the likelihood of several end products of the interpretation are often measured using a P10, P50 and P90 threshold. However, the initial interpretation is rarely treated this way. As the different elements – faults, horizons and geobodies are reviewed by peers and subsequently accepted as the absolute truth, this inevitably introduces interpreter bias. AI can be effectively deployed to reduce underlying bias. Extracting faults, horizons and geobodies in this manner will create a more 'neutral' response, which can be influenced using interpreter-guided fine-tuning. Furthermore, these results are generated far quicker than manual interpretation, without any drop-off in quality.

Figure 3: AI horizon extraction can interpret complex horizons, even those which are heavily faulted. Often these horizons may be overlooked for manual interpretation due to such levels of complexity.



Why is CCUS Essential in the Transition to Net-Zero?

AI seismic interpretation can be implemented for Carbon Capture, Utilization and Storage (CCUS) projects where subsurface investigation and interpretation is vital for success. The primary aim of CCUS is to capture and successfully store CO_2 within the subsurface to prevent net carbon emissions from large-scale industries entering the atmosphere. To successfully deliver CCUS projects, a detailed interpretation of the subsurface is required across two distinct areas. Firstly, site location and assessment, where a subsurface structure is identified for CCUS purpose. Secondly, containment and monitoring; the ability to track the fill and storage of CO_2 in the subsurface for an extended period of time after injection.

Assessing Potential CCUS Site Locations

A suitable CCUS target is a necessary first step in any project. Identification of a structure of sufficient size and storage capacity is driven by the seismic interpretation, with faults and horizons playing a lead role. Horizons and faults will constrain the extent of a structure. Faults may also dramatically affect the sealing capacity and directly impact the ability of a structure to fill with CO_2 by compartmentalizing the aquifer and subsequently controlling fluid-flow pathways through it.

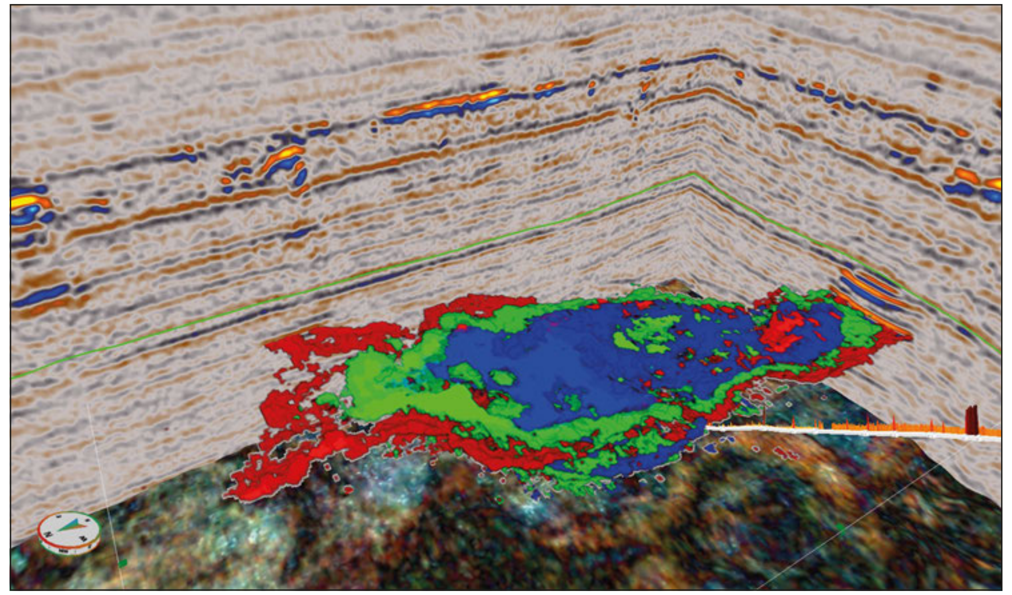


Figure 4: Geobodies illustrating CO_2 infill over time. After the initial fill period the blue geobody was generated to map and track the filling of the structure. As CO_2 injection continued, accompanying new volumes were used to track the filling process, shown with the green and red geobodies for two separate phases.

The manual interpretation of faults can be extremely time-consuming, and the interpreter's decision-making process may vary throughout. A further pressure is introduced by the need to simultaneously interpret horizons. Time constraints and inconsistencies in fault detection and interpretation may lead to mistakes which can be costly or even critical to a positive outcome with regards to CO_2 storage. Therefore, the ability to extract faults with a high level of consistency and limited interpreter bias and variability is crucial. As illustrated in the lower inset image to Figure 1 (main foldout), AI fault detection networks can be used to reveal the lateral and vertical extents of the faults. Furthermore, the ability to fine-tune a fault detection network enables an interpreter to guide the algorithm to better identify and delineate faults within a specific seismic volume.

It is generally accepted that with increasing structural complexity, stratigraphic horizons will take longer to interpret (Figure 3). Therefore, having the ability to automatically identify and extract faults and horizons in a seismic volume will free up a significant portion of an interpreter's time to concentrate on areas of complexity. As shown in Figure 1, the volumetric extraction of horizons in this seismic volume revealed two mounded structures. One of them is a potential site for CCUS, while the other has a greater risk of seal breach, due to the larger number of faults present over the crest of the structure. A regional unconformity is clearly identified along with all the underlying offlaps. This can further assist in understanding the lateral extent of both aquifer and seal units. AI can enable interpreters to speed up their work without any loss of accuracy.

Efficient Containment and Monitoring

Once CO_2 storage commences, the injected gas should be tracked and mapped within the aquifer. This is vitally important as it may identify compartmentalization, unforeseen leaks, and spill points, as well as high and low fluid-flow pathways. The ability to track the fluid fill can be achieved with geobodies.

Machine learning-based algorithms can analyze the seismic data to identify and capture the detailed and accurate extents of the CO_2 plume as a geobody. The procedure can be repeated, using the same parameters, over seismic volumes of varying vintages and/or offsets. As shown in Figure 4, a series of geobodies have been generated based on seismic data acquired before and at various times after the commencement of CO_2 injection. The gas plume identified in the first repeat survey is the blue geobody, while the green and red geobodies represent the changes in its extents as the structure fills. Based on the volume of the geobodies and the reservoir properties, the amount of CO_2 stored in the plume can be calculated and then compared to that of the injected CO_2. If there is significant difference between these two numbers, there may be a leak-off point in the aquifer/reservoir impacting the fill/storage potential of the structure.

Quick, Accurate and Reliable Results

The examples shared illustrate how AI can be used to further assist in subsurface examination of the Earth. In CCUS projects the automated horizon extraction and the identification of any intercepting faults help us meet the requirements for quick, reliable, consistent and repeatable interpretation. With the ability to fine-tune a network to a seismic volume's specific style of faulting, the interpreter is enabled to guide the AI solution to create even greater results. Involving the interpreter is crucial throughout, as they have the necessary experience, knowledge and skills. AI is only helping them along the way to complete the work, saving time and improving the quality of results.

Acknowledgments
We would like to thank the National Data Repository (UK), Geoscience Australia and Sleipner Group for access to the seismic volumes and well data used throughout this study. ■

What Drives Continents Apart?

Rather than convection currents within the mantle – could the forces at play be related to the Earth's velocity?

ROBERT MAURER

During a visit to Bolivia in 2001, the sight of marine sedimentary strata high in the Andes led to the consideration of the magnitude and direction of the tremendous forces involved. They are considered to have caused several major events such as the unrelenting unidirectional movement of the South American plate away from Pangea, formation of the Cordilleras by compression and the lifting of the oceanic crust and sediments from below sea level to five kilometers above it.

From an engineering perspective, however, the driving forces associated with heated convection currents as per the accepted model of Hess (1962) at convergent plate margins appeared to be neither large enough nor sustainable over geological time spans of say 150 Ma to cause this level of orogenic activity. This article offers an alternative analysis based on the forces associated with the rotational speed of the Earth to explain tectonic plate movements and orogenic processes.

Current thinking is that the movement of a continental plate (CP) is the result of the 'pulling action' applied to it by the subduction of the higher density oceanic lithosphere (OL) as it descends below the CP. The direction of the heated convection currents considered to cause subduction must vary over time and distance. Thus, it is difficult to reconcile unidirectional tectonic plate movements breaking up a supercontinent such as Pangea with omnidirectional changing forces due to convection currents.

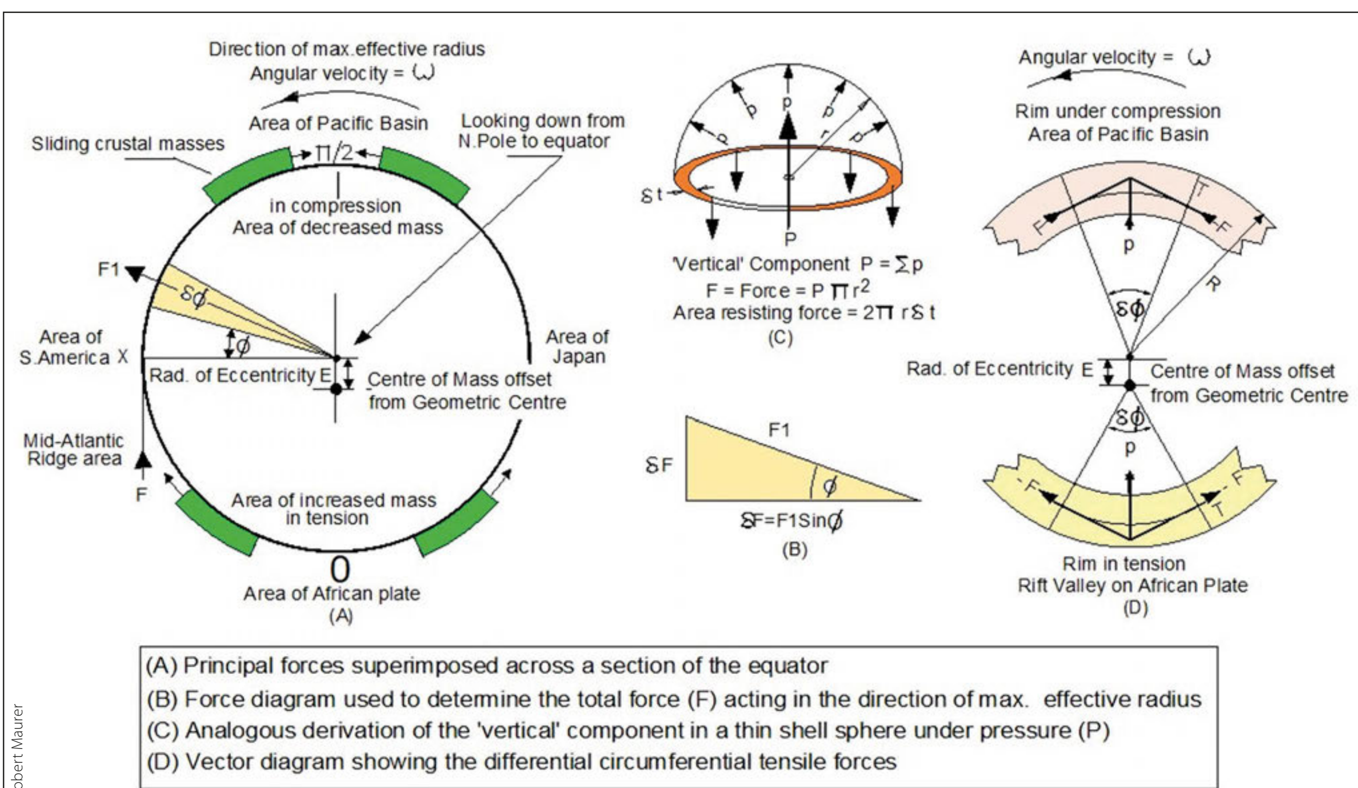
Analysis of the forces generated by the rotational velocity of the Earth (Maurer, 2020) suggests a quite different mechanism to explain the currently accepted 500-million-year cyclical break-up and reassembly of supercontinents.

Earth's Center of Mass Offset

It was noted that the 'wobbling' Earth, with its change in the orientation of the inclined spin axis, the associated Milankovitch Cycles, the nutation (nodding motion) as well as the variable and cyclical 'Chandler Wobble', closely mimics that of an unbalanced rotating shaft whose Center of Mass (COM) is offset from its spin axis. An everyday example is the vibration of an unbalanced wheel on a motor vehicle.

Illustrations of the break-up and dispersal of Pangea since the Jurassic period show that the South American plate moved west while the Australian plate moved east relative to the essentially central position of the African plate. The Indian plate also moved east before turning north-east.

Figure 1: Principal forces and vectors.



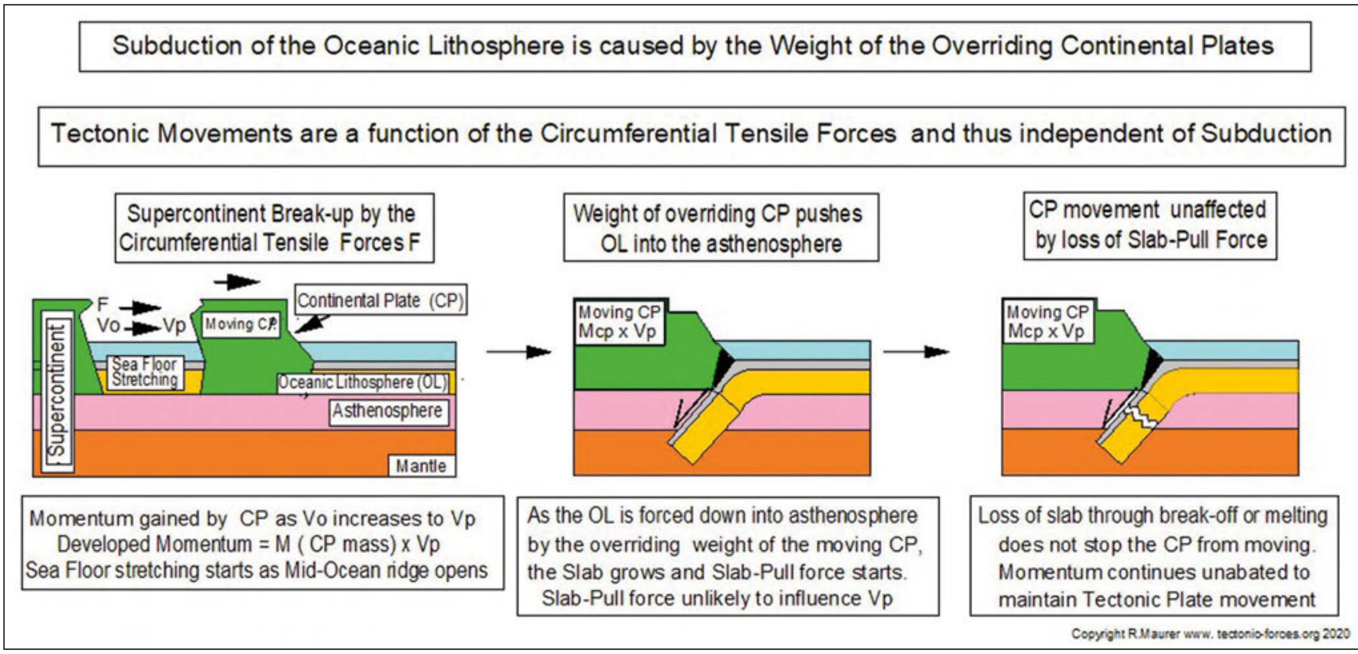


Figure 2: Separation of tectonic movements from subduction.

At the same time, the Laurasian plate moved north, later splitting into the Eurasian and North American plates with the opening of the North Atlantic. These movements suggest that the major plates were being redistributed from the heavier side of the Earth, occupied by Pangea, to the lighter side, occupied by the proto-Pacific. This premise was reinforced by an 8 km difference in mean elevation between the surface of the African plate and the floor of the Pacific Basin. Using a simple algebraic equation, based on isostatic equilibrium to estimate the COM or fulcrum point, and taking the elevation difference into account, the calculation showed that the COM was 2.09 km off-center in the African hemisphere.

However, the simple introduction of a displaced or offset COM will only describe the rotating Earth as an unbalanced rotating flywheel. As such it does not describe the circumferential forces (linked to tectonic movements) which allow the Earth's rigid lithosphere to move relative to the mantle.

To quantify the forces associated with the offset COM, it was necessary to mathematically model the Earth as a rotating unbalanced body. Kepler's Laws of Planetary Motion (published between 1609 and 1619) relating to the elliptical orbit of the Earth around the Sun showed that the Earth's orbital velocity increased as it approached perihelion (the point in the orbit at which a planet is closest to the Sun) and decreased by the same amount on its way toward aphelion (furthest from the Sun). In this respect the planets can be seen as rotating about their axes in a stable controlled position. As such the mathematical model is given a high degree of validity.

Circumferential Tensile Forces

By approaching the problem in terms of a thin shell moving relative to the mantle, it is possible to consider which increments of the tensile force are responsible for putting the Pacific Basin under compression and the African plate under tension. The African Rift Valley is today a case in point.

In calculating the effects of the circumferential tensile forces (Fcir) at the Earth's surface due to the COM being offset from the spin axis or geometric center, the term 'Radius of Eccentricity' (E) is introduced to denote the magnitude of the offset. Figure 1 shows this approach as a vector diagram in which the differential circumferential stresses are annotated. To simplify discussion and further calculations, E was placed at 1 km offset from the spin axis. Seen in context, this equates to (1/6400) × 100 or 0.016% of the Earth's mean radius of 6,400 km. The magnitude of the derived differential circumferential stress (Fcir) will thus be dependent on E. In a limiting case, if E=0, the differential stress will be zero, as the Earth will be balanced. The derived equation $Fcir = MR\omega^2E\pi/4$ relates Fcir to E, where R is the mean radius of the Earth, ω its angular velocity and M is the mass of a segment of the crust 1,000m × 1m × 1m. Using averaged published data for M, R and ω, sourced from USGS and National Geographic Society publications, the stress value is calculated to be 0.074 Newtons/mm^2 (10.8 lb/in^2). To understand a stress value of 0.074 N/mm^2, this figure equates to 118 people each weighing 81.8 kg (180 lb) pushing a braked motor vehicle with a rear surface area of 1.3 m^2.

Splitting Supercontinents Apart

In trying to establish that the differential circumferential forces (Fcir) are sufficient to split supercontinents apart, it should be borne in mind that the tensile strength of the oceanic lithosphere (OL) varies considerably with age and depth. The older OL (>10 Ma) is mechanically able to withstand lithospheric forces such as tectonic interactions, whilst the younger OL is considerably thinner and whose mechanical strength is substantially reduced by heat interactions (Cadio and Korenga, 2016). As such, rifting and ridge formation are more likely to occur in the younger OL (Lynch and

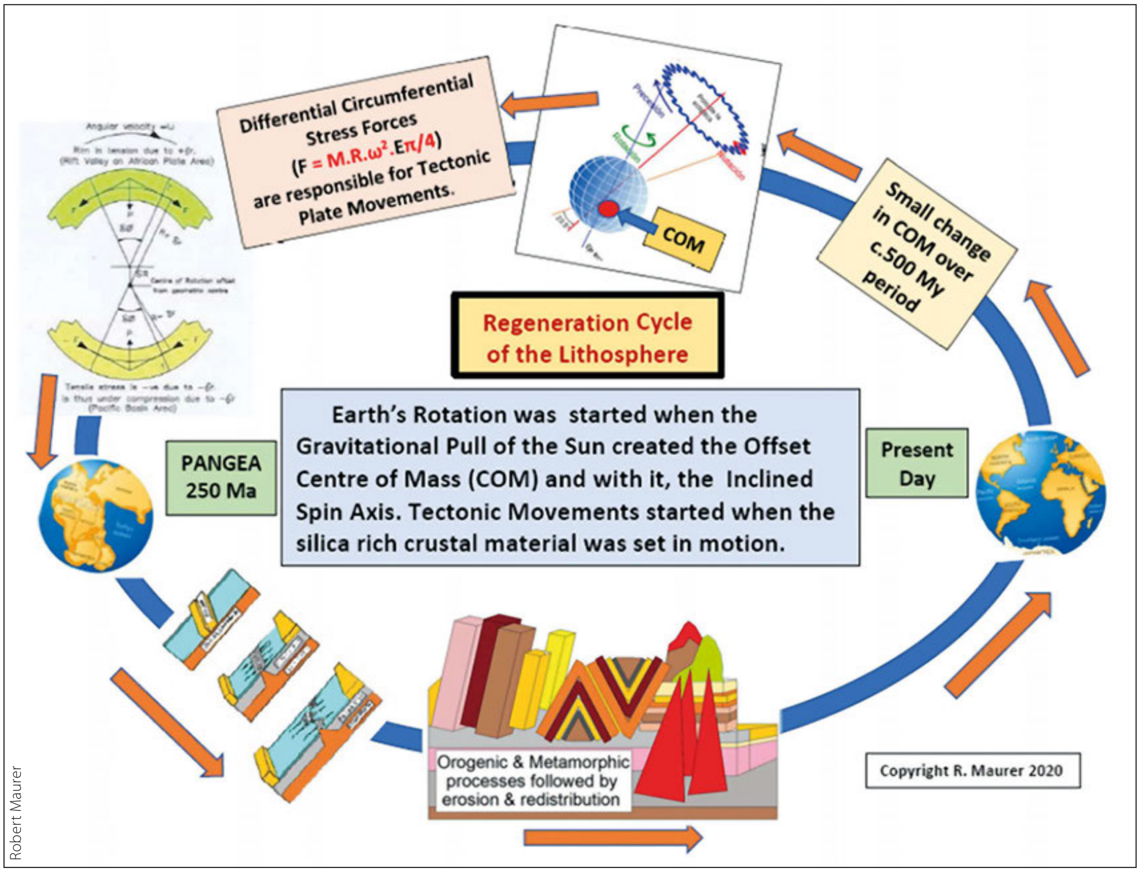


Figure 3: Earth's continuous regeneration cycle. The break-up of Pangea is given as an example.

Morgan, 1987). Based on this premise the rift that opens within a supercontinent will be along the weakest lines that allow separation to occur and magma to readily extrude onto the sea floor. The lack of distortion of the paleomagnetic lines demonstrates the lack of any viable compressive forces involved. On this basis the rift that opens within a supercontinent will be continuously pulled apart to allow the extrusion of magma onto the sea floor. The widening of the new ocean will be by sea floor stretching as opposed to sea-floor spreading. Thus, a ridge-push force exerted by rising magma can be zero so far as tectonic plate movement is concerned.

Consideration of Momentum and the Subduction Cycle

Perhaps the most important aspect in the breaking up of the supercontinent Pangea is that the plates will accelerate from almost zero velocity (Vo) to the present-day velocity (Vcp) of about 11 mm/year. In doing so the CP has momentum imparted to it as per Newton's Second Law of Motion, which is *Momentum = Mass × Velocity*, as V increases from Zero to Vcp, the equation will be:

Mcp (Mass of CP) * Velocity (Vcp-Vo) = Mcp*Vcp.

Whilst the velocity is low, the continental mass is extremely large. The overall momentum will make the slow but relentless movement of the CP unstoppable until it meets another CP. India crashing into the Eurasian plate creating the Himalayas is a case in point.

As the CP is forced away from the supercontinent (SC) by the circumferential forces, the weight of the CP will push the oceanic lithosphere under it into the asthenosphere (i.e., the ductile upper mantle) and finally into the lower mantle (Figure 2). Seismic observations have shown that a 'knee bend' forms in the oceanic lithosphere (OL) as it bends downwards as a 'slab' into the asthenosphere. The force associated with the weight of the slab is currently credited as being the major force aiding subduction and tectonic plate movements. The resistive forces associated with slab-pull are essentially friction and viscosity.

Examination of the major forces presently considered responsible for subduction can be summarized as follows:

Owing to the density difference,

Subduction Force = Net Slab-Pull Force + (gravitational force due the weight of the CP (FMcp) above the OL) + circumferential forces acting on the CP – Bending stress of the OL (FBol) + the upward buoyancy force (Fby).

The upward buoyancy force may be considered as the force needed to sustain isostatic equilibrium. The ridge-push force has already been shown to be negligible.

Separation of Subduction from Tectonic Plate Movement

The introduction of momentum and circumferential forces is new to the study of subduction. This innovative introduction has thrown up some interesting and far-reaching conclusions. The inevitable loss of the slab and thus the slab-pull force, either by detachment or by partial melting in the asthenosphere, has not hindered the movement of the CP. The equations for subduction are now,

Subduction Force= Resultant (FMcp + Fcir) > FBol + Fby

The momentum of the continental masses will keep them in motion.

The logical and unexpected conclusion is that continental plate movement is independent of slab-pull and subduction. The separation of subduction from tectonic plate movements is a major change in the study of plate tectonics. Subduction is now seen as being a *consequence* of tectonic plate movements rather than the driving force. This has brought with it the observation that slab-pull is applicable to the tensile stressing of the OL and possibly the ridge-push forces that may now be considered as *'ridge-pull'* ones. The origin of these forces associated with rifting and ocean ridges is still seriously debated.

Birth of Tectonic Plate Movements

It is interesting to note that all the planets (except Venus – considered as being upside down) rotate on their axes with the same anticlockwise motion as the Sun. The terrestrial planets have an almost identical polar/equatorial diameter ratio, but the gaseous planets are more oblate. Apart from Mercury and Venus, the planets' rotational periods are within the range 10 to 24 hours, and have the same bottom-left to top-right inclined spin axis (except for Venus and Uranus). The uniformity of planet behavior is puzzling as the gravitational pull of the Sun alone does not yield a satisfactory explanation regarding the rotation of the planets. Current wisdom favors the concept that the angular momentum of the low angular velocity swirling gas cloud during the formation of our galaxy, is now being shared between the Sun and the planets rotating at higher angular velocities.

As it is impossible to rotate a body about its dimensionless center line, it is likely that the COM offset was created when the Sun pulled on the embryonic partially cooled planets, towards the end of their accretionary stage, to cause them to rotate in the same direction as the Sun. The angular momentum imparted to the larger accretionary masses would ensure their permanent rotational mode. This approach also gives a plausible explanation regarding the creation of the tilted N–S spin axis of a planet.

Furthermore, the lower density silica-rich 'slag' or 'dross' floating on the surface would have been swirled about at this stage and plate tectonics on the Earth as we know it today was set in motion.

Regeneration of the Lithosphere

From the arguments put forward it is also possible to construct the regeneration cycle of the Earth's lithosphere as shown in Figure 3. The vibrational patterns associated with the Radius of Eccentricity/offset COM, will create the circumferential stresses that will cause the crustal masses to move to the lighter side or hemisphere. These tectonic plate movements with their associated orogenic, volcanic and erosion processes will shape the upper lithosphere. Over an extended time span the Radius of Eccentricity need only be varied by a small value to restart the cycle of moving crustal masses to a new configuration.

References provided online. ■

Hot Enough in the South-East Adriatic?

Some evidence for working petroleum systems offshore Montenegro.

TIAGO CUNHA, LAURA MILNE; Integrated Geochemical Interpretation (IGI, Ltd.) and LEONIDAS GOULIOTIS, GEORGE PANAGOPOULOS, PANAGIOTIS KONSTANTOPOULOS, DENNIS ANESTOUDIS; Energean

The Dalmatian platform offshore Montenegro has the potential to have equivalent carbonate plays conjugate to the Apulian platform. New geochemical information also reveals the presence of an oil-prone Late Jurassic–Early Cretaceous source rock, in addition to the well-established Late Triassic Burano Formation. The Dalmatian foreland basin also indicates optimal conditions for the development of a biogenic gas play, proven by the discoveries in the North Adriatic. Energean operates in two blocks, offshore Montenegro, recognizing the potential that is reinvigorating interest in the region.

From Rift to Foreland

The offshore Montenegro is located in the Adriatic foreland, that contains Triassic to Quaternary sedimentary rocks bordered by the SW-vergent Dinaride orogenic system to the east (Schmid et al., 2020; Figure 1a). The Dinarides are characterized by eastward subduction that began in the Mesozoic and largely ended in the Early Miocene in the northern and central segment, while within the southern portion (close to the Albanides and the Hellenides) subduction continues to the present (Moretti and Royden, 1998).

Regional structural and stratigraphic correlations from the eastern Adriatic suggest that during the Late Triassic, the paleogeographic domains of offshore Montenegro were part of a wider platform known as the Southern Tethyan Megaplatform (STM; Vlahović et al., 2005). During the middle Early Jurassic the break-up of the STM was accompanied by extension of the entire area, resulting in the formation of several intra-platform basins. In the Dalmatian part of the Adriatic carbonate platform, shallow water sedimentation lasted throughout the Jurassic and Cretaceous with extended periods of shallow-marine deposition interrupted by emergences of variable duration. The long-lasting carbonate sedimentation was interrupted abruptly during the Middle Eocene and the

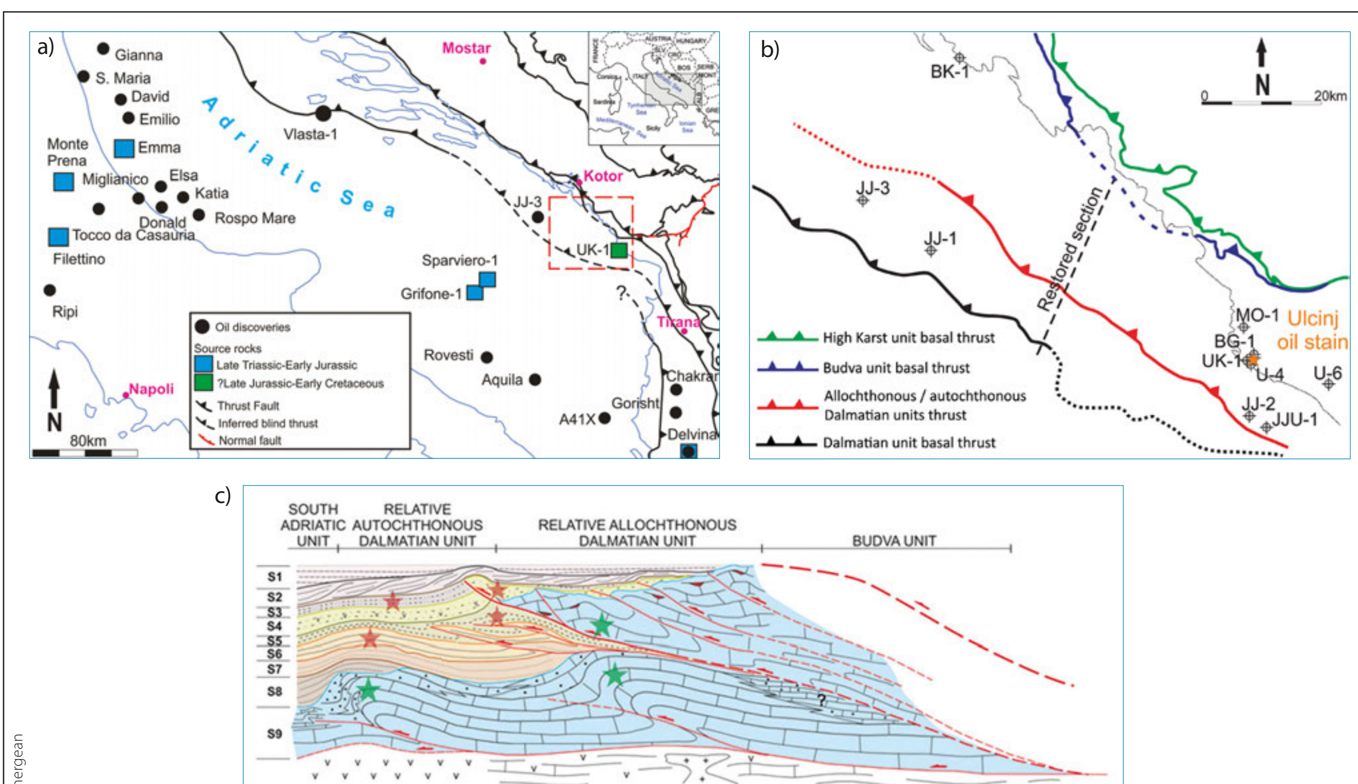


Figure 1: a) General geotectonic map of the Dinarides with the location of the main structural lineaments (modified from Schmid et al., 2020) and location of the oil discoveries and main source rock sites in the central-southern Adriatic (after Cazzini et al., 2015). The dashed red rectangle delimits the study area, where the tectonic map is shown. 1b) Simplified tectonic map of offshore and coastal Montenegro, with the key structural features, borehole locations and the Ulcinj oil stain (orange star). 1c) Geological interpretation of the restored seismic line (see Figure 4a) with identified seismic units: S1 (Seabed/Intra-Pleistocene), S2 (Intra-Pleistocene/Intra-Pliocene), S3 (Intra-Pliocene Base Pliocene), S4 (Base Pliocene/Burdigalian unconformity), S5 (Burdigalian unconformity/Intra-Chattian), S6 (Intra-Chattian/Intra-Rupelian), S7 (Intra-Rupelian/Late Eocene), S8 (Late Eocene/Top Carbonate) and S9 (Top Carbonate/Base Carbonate). The green and red stars highlight the potential oil and biogenic gas plays targeted in the area.

platform was covered by the clastic sediments of the foreland.

During the (?Late Oligocene–) Early Miocene, convergent deformation affected the Dalmatian unit. Thrusting propagated at considerable distance through the foreland and a series of growth anticlines were formed above blind thrust faults (Figure 1c). It is suggested that the tectonic structures offshore Montenegro (Figure 1b–c) exhibit several changes in their development that are gradual but can be tentatively grouped into two stages of convergent deformation. The first stage is associated with in-sequence (foreland-progressing) thrusting during the Early Miocene, followed by out-of-sequence (hinterland-propagating) thrusting from mid-Miocene to present (Figure 4a).

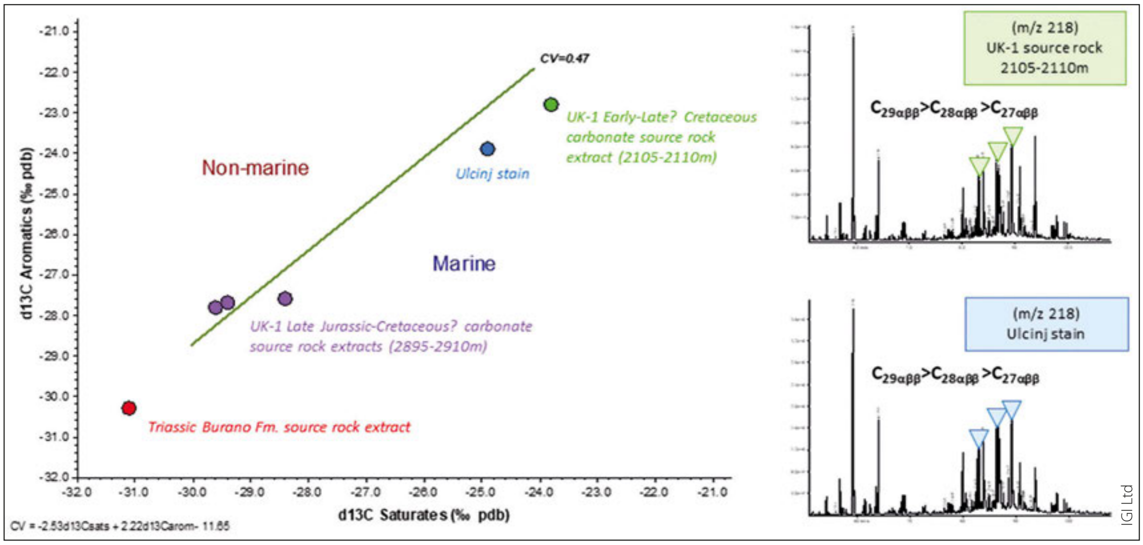


Figure 2: Left: Stable carbon isotope (δ13C) distribution for saturates and aromatics of the UK-1 well samples (see Figure 1 for location), and comparison with the Ulcinj stain and a source extract from the Burano Formation (Italy). Right: GC-MS chromatograms for m/z 218 from the shallow UK-1 Cretaceous source sample and the Ulcinj stain.

Exploration in the Central-Southern Adriatic

Relevant discoveries in the central-southern Adriatic and surrounding Italian-Dinaric-Albanian margins include the oils sourced by Mesozoic carbonate source rocks and trapped in carbonate reservoirs, and the biogenic gas in thick Pliocene to Pleistocene sequences.

The carbonate source rocks are Triassic to Late Cretaceous, deposited in dysoxic to anoxic environments, which typically generate high sulfur, low API oils (5° to 22° API). The exceptions are the Aquila (37° API) and Rovesti (25–30° API) fields in the southern Adriatic Apulian platform, conjugate to the southern Montenegro–Albania margin (Figure 1a; see Cazzini et al., 2015 for a detailed description of the oils). The biogenic gas accumulations are expected to occur in both stratigraphic and structural traps, similar to that found offshore Italy and Croatia, and the Durres Basin of Albania (Bega, 2015; and references therein). The SE Adriatic Montenegro carbonate platform and adjacent foreland basin are thus promising exploration environments being targeted by Energean.

Carbonate targets have been drilled in the past in various locations along the SE Adriatic platform with the discoveries in Vlasta-1 and JJ-3 (Figure 1). The closest discovery to the targeted area is JJ-3, which found a 20m live oil column within the Cretaceous carbonates. The majority of the wells in Montenegro have drilled the shallow hanging wall carbonate unit and were either dry or had oil shows.

A New Insight into Source-Fluid Correlations

The most prolific source rocks in the region are usually interpreted as Late Triassic to Early Jurassic sulfur-rich carbonates within thick carbonate-evaporitic sequences (e.g. Mattavelli and Novelli, 1990). Of particular relevance for the area are the thick Early Jurassic source intervals drilled in the Apulian carbonate platform, conjugate to the southern Montenegro–Albania margin. At well Sparviero-1, shown on Figure 1a, for example, quantitative source rock data presented in Cazzini et al. (2015) show a 90m-thick, dolomitized micritic limestone with an average TOC of 1.7% and HI values of up to 700–800 mg/gTOC, overlain by an around 35m layer of leaner (1% TOC), slightly less oil-prone (HI up to 600–700 mg/gTOC) Toarcian source rock. The oils from the Aquila and Rovesti fields have been correlated to the Late Triassic Burano Formation, based on biomarker and isotopic data and a source rock sample from a well (Trevi-1) in the central Apennines (Cazzini et al., 2015 and references therein), but may arguably be sourced from Early Jurassic horizons.

Highly oil-prone source rock horizons have also been identified in southern Montenegro, for example in the Ulcinj Kopno-1 (UK-1) coastal well, previously interpreted as Late Cretaceous. These samples have been re-analyzed and show variations in their molecular and isotopic compositions. As depicted in Figure 2, the shallower samples (2105–2110m) have saturate and aromatic stable carbon isotope signatures up to 5% heavier than the deeper source extracts (2895–2900m), and correlate well with the Ulcinj oil stain (see Figure 1b for location). A strong correlation is also apparent in the molecular composition of the shallower source extract and the oil stain, with sterane carbon number distributions of C29αββ>C28αββ>C27αββ, and C29αβ hopanes > C30αβ hopanes. On the other hand, the lighter isotopic composition of the deeper extracts resembles that of the Triassic Burano Formation. The samples' stratigraphy has also been

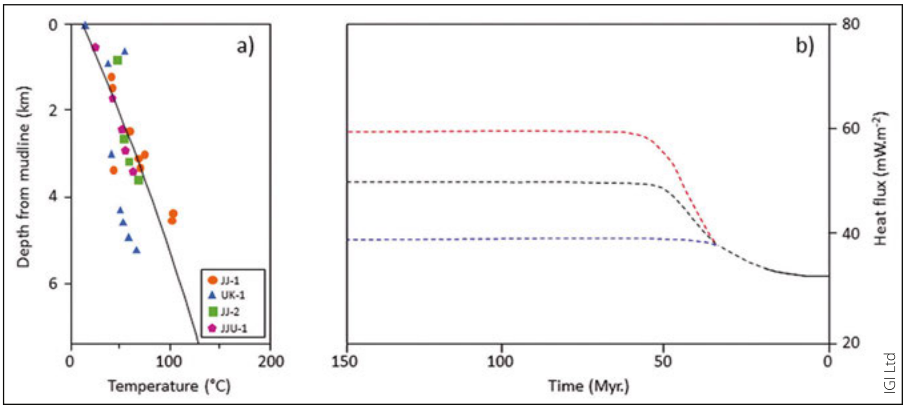


Figure 3: a) Calibration of the present-day geothermal gradient (black line) to the available borehole data (symbols: see Figure 1b for borehole location). Lateral variations are included via gradient scalers. b) Reference (black), cold (blue) and hot (red lines) base sediment heat flux models assumed to simulate the thermal evolution of the basin. The dashed lines represent the tentative higher geothermal gradients prior to the Dinaric subduction.

revised, suggesting a Late Jurassic to earliest Cretaceous age for the deeper samples, which could explain the observed variations in the isotopic and molecular compositions, associated with variations in the depositional environments.

Is the SE Adriatic Hot/Deep Enough?

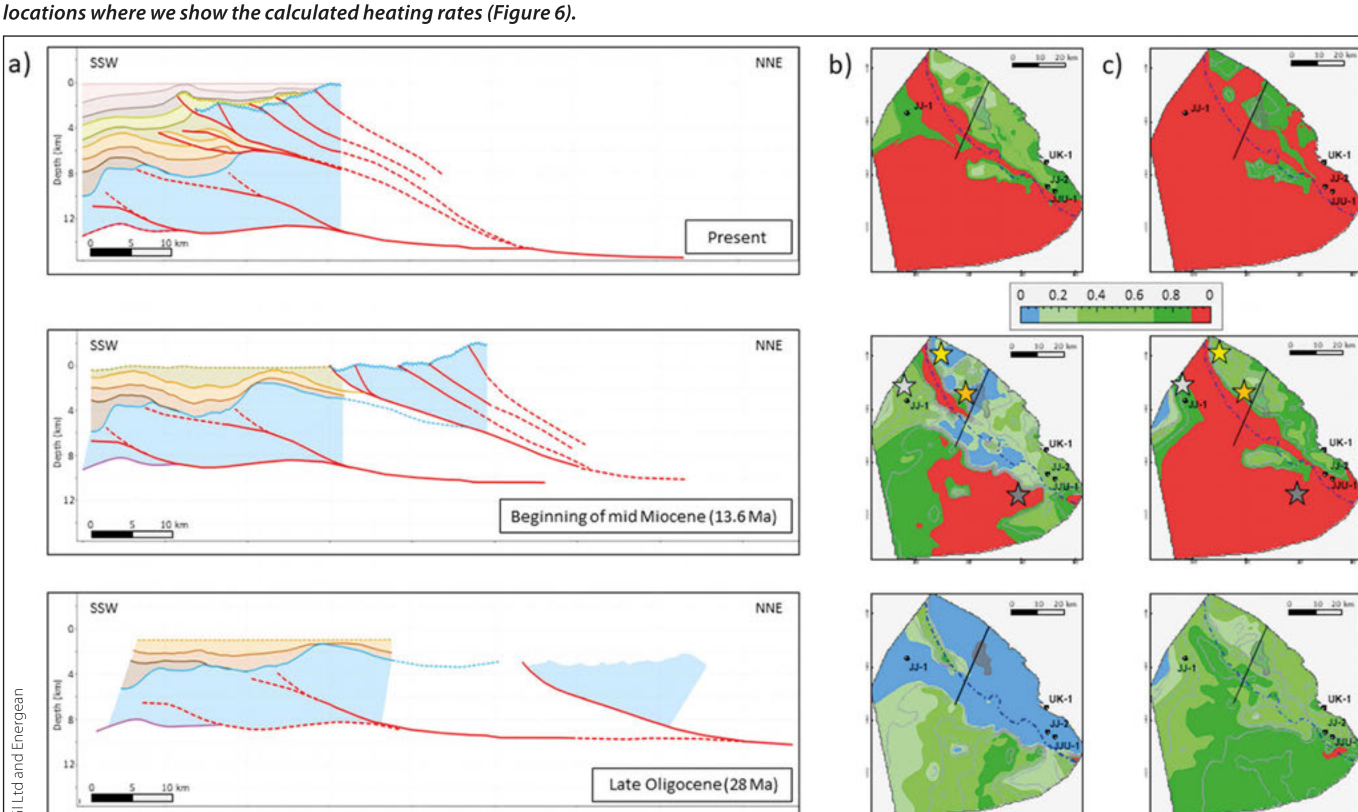
The SE Adriatic foreland basin and adjacent fold and thrust belt are traditionally regarded as a 'cold' place, overlying the Dinaric subduction. The emplacement of the thrust nappes from the Eocene-onwards has thickened the overburden along the Montenegro shelf by up to 7.5 km, and the Dalmatian foreland basin is up to 14 km thick (up to 5.5 km in the Plio-Pleistocene).

For this study, we built a 3D (map-based) thermal-burial model for the offshore Montenegro area based on recently processed and interpreted 2D and 3D seismic data and analogies with the Apulian conjugate margin, and calibrated it at borehole locations in the foreland basin and the fold and thrust belt (Figure 3a). The models suggest a decrease in the basement heat flux from 30–35 mW.m^{-2} in the foreland basin to 20–25 mW.m^{-2} in the platform, likely controlled by the geometry of the subduction zone, and account for a greater average heat flux pre-Eocene, in a post-rift margin setting (Figure 3b).

For the emplacement of the thrust nappes and the progressive thickening of the sub-thrust platform, we used the detailed structural reconstructions provided by Energean (Figure 4a). The reconstructions suggest that ~50% of the vertical load due to thrusting was emplaced between the mid-Oligocene and mid-Miocene, ~15% between the mid-Miocene and the early Pliocene, and ~35% from the early Pliocene onwards.

The carbonate source rock horizons parameterized in the sub-thrust carbonate platform include the Early–Late Cretaceous identified in well UK-1,

Figure 4: a) Palinspastic reconstruction of a seismic transect across the Montenegro platform (see Figure 1 for location). b–c) Maturity maps for the Cretaceous and Late Triassic–Jurassic SR horizons at 28 Ma, 13.6 Ma and 0 Ma. The solid black line is the reconstructed transect, the blue dashed-dotted line the thrust front, the gray shaded polygon the prospect where we test the charge/volumes history (Figure 5), and the stars in the middle plots the locations where we show the calculated heating rates (Figure 6).



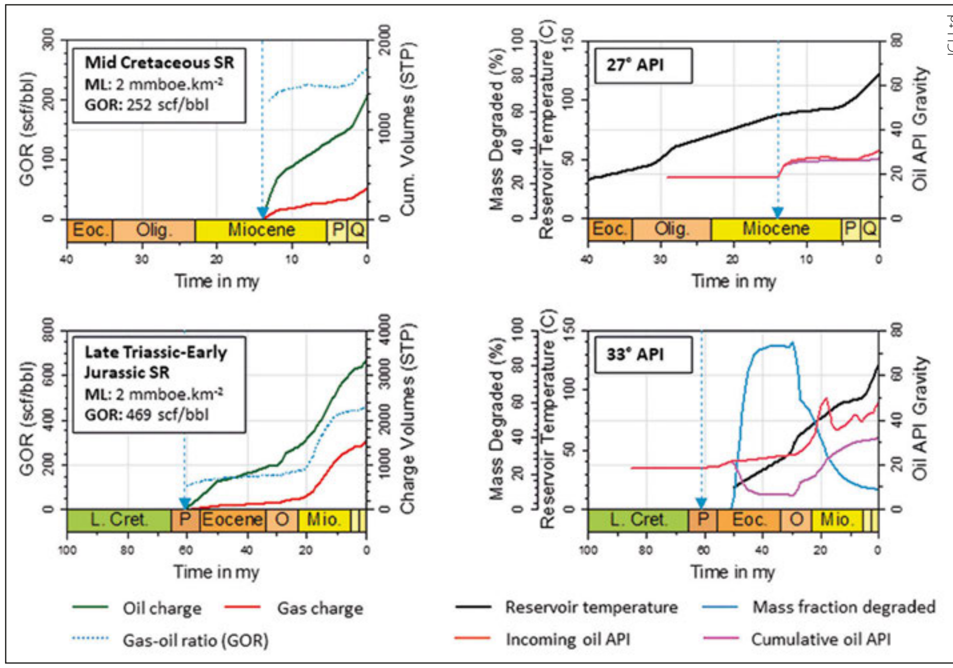


Figure 5: Predicted oil and gas charge volumes and GOR (left), and in-place API values (right), for a sub-thrust prospect in the Montenegro carbonate platform, assuming a mid-Cretaceous (top) and a Late Triassic–Early Jurassic (bottom) source rock horizon.

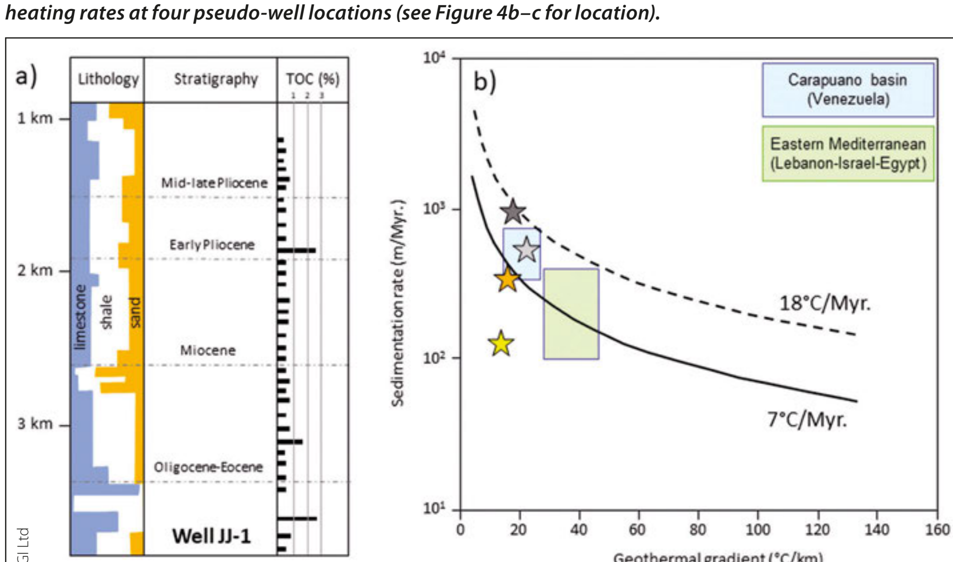
and the prolific Late Triassic–Early Jurassic documented in the conjugate Apulian platform. The modelling results indicate that: (1) an Early–Late Cretaceous horizon reaches oil and gas maturity over large parts of the foreland basin during Miocene-to-Recent burial, and mid- to late-oil maturity along the continental shelf-slope from the mid-Miocene onwards (Figure 4b); (2) a Late Triassic–Early Jurassic horizon reaches mid- to late-oil maturity over most of the area in pre-orogenic times, becoming gas mature in the foreland basin during the Miocene, and along the shelf from the mid-Miocene onwards (Figure 4c). The predicted maturity-generation timing in the sub-thrust carbonate platform is thus contemporaneous, or subsequent to the development of compressional structures along the continental shelf and slope.

Figure 5 shows the predicted charge history in a sub-thrust prospect (gray polygon in Figure 4b–c), for both the Cretaceous and Triassic–Jurassic source horizons. The models assume a 100m-thick source horizon, with a total organic carbon (TOC) content of 2% (wt%), HI of 600 mg/gTOC, and 2 mmboe.km $^{-2}$ migration losses, but the volumes shown here are merely illustrative. For both source horizons, the models predict a low gas–oil ratio (GOR) charge and black-oil API values trapped in-place, with significant biodegradation limited to the pre-Miocene charge, in the case of a Triassic–Jurassic source. Sensitivity tests varying the geothermal gradients or the source depths within reasonable uncertainty show similar maturity-generation-expulsion histories.

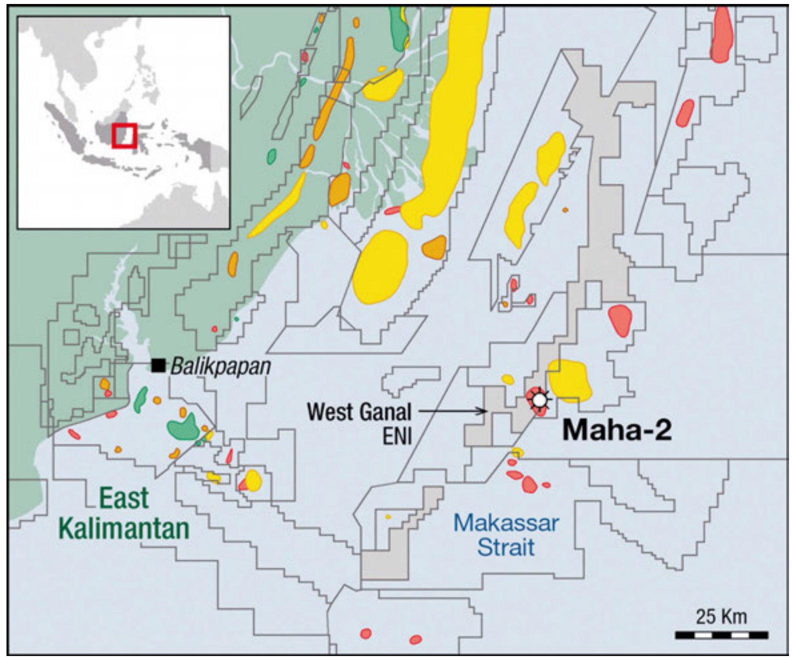
Another potential play in the area is the biogenic gas generated in organic-rich layers and accumulated in sand lenses within the Plio-Pleistocene (or older) turbiditic sequences. The geochemical logs in well JJ-1 (see Figure 1b for location) show intervals of significant organic richness within the Pliocene and Eocene–Oligocene detritical sequences, up to 2.8 %wt TOC (Figure 6a). Although the hydrolyzable (labile) fraction of the kerogen, that can be involved in the biochemical reaction, is probably limited to 30–40% of the TOC (Schneider et al., 2016 and references therein), a TOC of 0.7–1.1 %wt is sufficient to charge large structures, depending on the continuity of the organic-rich levels and the connectivity of the sand lenses. The heating rates (sedimentation rates x thermal gradients) in the area can be regarded as intermediate (platform-slope) to optimal (foreland basin) for the development of biogenic gas systems, and within the range of well-known fields (Figure 6b).

References provided on line. ■

Figure 6: a) Simplified lithology, stratigraphy and TOC logs for well JJ-1, in the foreland basin. b) Graphic modified from Clayton (1992) showing the ideal conditions for the development of biogenic gas plays (in Schneider et al., 2016). The heating rate curves of 7°C/Ma and 18°C/Ma delimit the optimal conditions for the development of biogenic gas plays. The shaded areas are tentatively defined for the Carapuano Basin (Venezuela; Schneider et al., 2012) and the Eastern Mediterranean, offshore Lebanon-Israel-Egypt (Schneider et al., 2016), where there are proven biogenic gas plays. The stars show the Pliocene to Present heating rates at four pseudo-well locations (see Figure 4b–c for location).



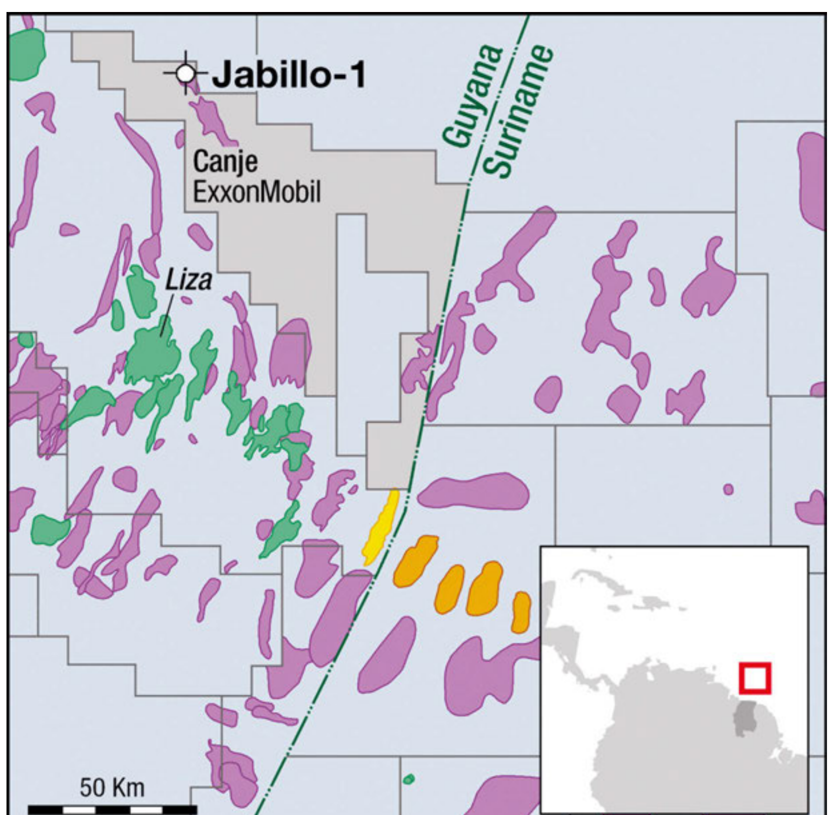
Maha-2 – Major Step-Out Success for Eni in the Mahakam Delta



Eni has drilled a successful appraisal to the **Maha gas field** in the mature **Mahakam Delta** within the **Kutei Basin, offshore Indonesia**, 20 years after the discovery well. Eni drilled the well with partners **Pertamina** and **Neptune Energy** on the **West Ganal Block**. **Maha-2** was drilled in April and May 2021 in 1,115m of water, to a depth of 2,970m and recovered gas from deltaic clastics. The well tested **34 MMcfgd** from 43m of net reservoir in Pliocene sands, and the development plan may utilize a subsea tie-back to the nearby Jangkrik FPU.

Neptune Energy, backed by private equity global players **Carlyle Group, CVC and CIC**, entered this basin in 2019 as part of a multi-asset deal with **Eni**. Eni have been exploring and developing gas in the basin for decades, and the opportunity to revisit some of the early discoveries in the **Ganal region** has proven successful so far, with Maha expected to hold up to **600 Bcf** gas. This West Canal Block was awarded to **Eni, Neptune and Pertamina** as part of the 2019 Indonesia bid round and includes a commitment to a further 3 wells. ■

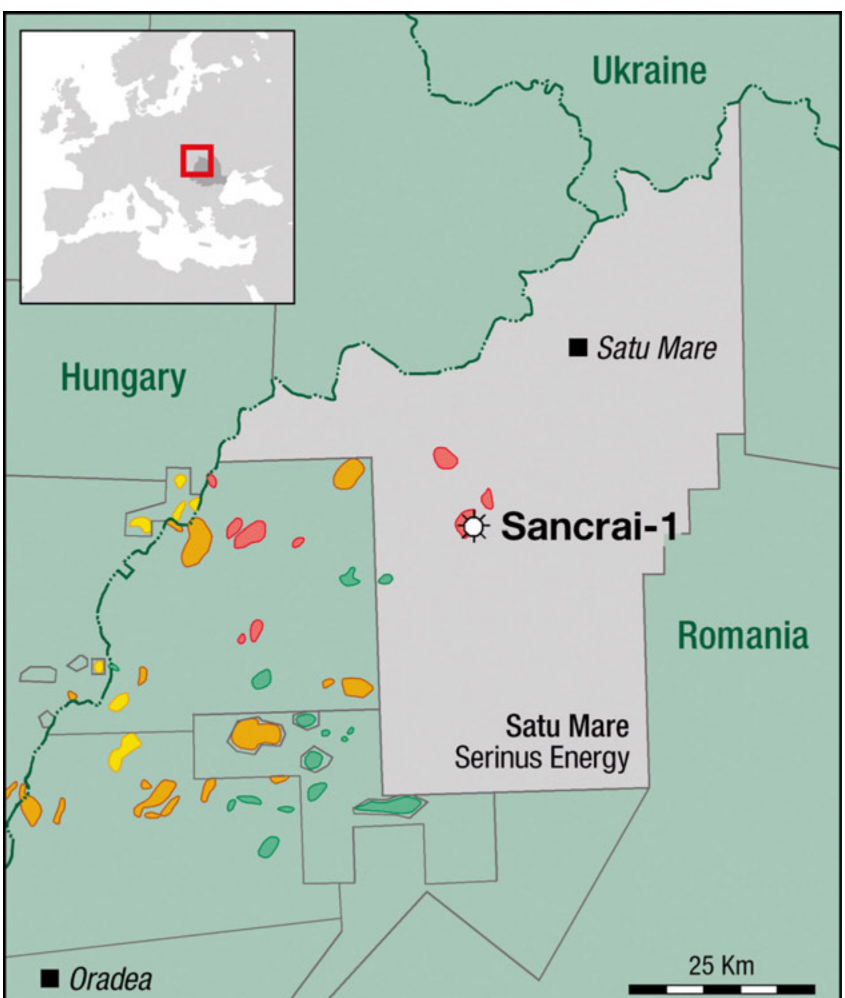
Jabillo – Prolific Liza Trend out of Reach on Canje Block, Guyana



ExxonMobil, with partners **TotalEnergies, JHI** and **Mid Atlantic**, have come up dry again on the **Canje Block**, downdip and apparently too far removed from the prolific **Liza cluster of giant fields**. **Bulletwood**, a similar prospect immediately to the south on this block, had oil shows in February 2021. **Jabillo** was targeting a **1 Bbo** Campanian age prospect in 2,903m water, in the distal turbidite fan complex of the Guyana Basin, reaching a TD of 6,475m. Press reports suggest no commercial hydrocarbons were encountered, but there is also no mention of shows. JHI is carried through the drilling campaign, along with investors **Westmount** and **Eco**, but all parties will be disappointed with the current run of form over the Canje Block. **Eco Atlantic** recently bought into the campaign, taking 6.4% equity in JHI at $2 a share. The operating group are already planning their next target here, a large, independent stacked target, **Sapote**, which is due to spud in **August 2021**. Meanwhile success continues in the greater Liza area, with **Whiptail-1** and **2** coming in for **Exxon/Hess/CNOOC**. The next major spud offshore Guyana will be the **Kawa-1** well on the **Corentyne Block (CGX and Frontera)**, very much on trend with **Stabroek** (Liza) and **Block 58 (Maka Central)**. ■

Serinus Falters in North-East Pannonian

Serinus Energy, the small exploration firm with producing assets in Romania and Tunisia, listed on AIM and Warsaw, have reported a gas discovery at **Sancrai-1** on the **EIV-5 Satu Mare Block in Romania**. Sancrai is a structural trap with strong seismic amplitude support, to the south of their producing field **Moftinu**. Gas shows were recorded over 20m of gross pay over four sand intervals from 855m to 875m. The latest development is that testing at Sancrai-1 was unsuccessful in August 2021, and further studies are underway to evaluate the options available, given the high total gas readings during drilling. Serinus has been exploring the Satu Mare Block since 2017. The play is a shallow biogenic gas play charging Miocene Pannonian drift sands with strong amplitudes. Further north at Moftinu the firm drilled 4 production wells with tests of up to 6.3 MMcfgd (Moftinu 1003), and Sancrai 1 was the second well in the current work programme commitment. Serinus have plans to test three other exploration 'clusters' at **Berveni**, **Nusfulau** (an oil play) and **Babesti**. SandHill operate the block to the west, **EX-1 Voizozi**, where they are planning a 3D as restrictions are eased. **Satu Mare**, at the north-eastern end of the **Carei Basin** trend, has a long history of gas exploration and production in this north-eastern part of the **Pannonian Basin**. Several wells in this western margin of Romania were committed in recent bid rounds, but few companies have been able to mobilize full campaigns. The most recent well, further south in the Pannonian of Romania was the dry **Iecea Mica** well in the **Ex-10 Parta block** by **ADX** and **Reabold Resources** in late 2019. ■



Representing Geoscience for Over 200 Years

Will the oldest Geological Society in the world continue its mission and if so, where will its home be?

The Geological Society was inaugurated in 1807 at a dinner at the Freemasons Tavern, which formerly stood at the site of the modern Connaught Rooms, in Covent Garden, London.

A Long History

The Society started its existence as a dining club but also accumulated a library and a collection of minerals, rocks and fossils. By 1810 the first Trustees were appointed, and the first meeting of the Council took place. The following year, the first volume of the transactions of the Geological Society was published, and in 1812 the first permanent officer was appointed to maintain the library and collections as well as acting as draughtsman and secretary to the Council and Committees.

A royal charter was granted in 1825 by King George IV to the Rev William Buckland, Arthur Aikin, John Bostock MD, George Bellas Greenough and Henry Warburton, who were nominated as the first Fellows of the Society. Shortly after this a further 367 members were elected as Fellows. Following several moves the Society relocated to its current home at Burlington House, Piccadilly, in 1874.

Today

Today the Geological Society of London is the UK's national society for geoscience, providing support to over 12,000 members in the UK and overseas. It has extensive library services, and a huge online resource in the Lyell Collection, which represents one of the largest integrated collections of Earth Science literature. The Society also provides lecture and meeting room facilities and publishes both journals and books. Fellows also benefit from access to Chartered Scientist (CSci) and Chartered Geologist (CGeol) schemes which allow members to access further qualifications and to become a competent person for the purpose of reserves certification.

Existential Crisis?

After over 145 years at New Burlington House, the Society faces being priced out of its long-term home because of unaffordable and rapidly rising rents. Following a 2014 change in Government policy, Burlington House began to be treated as an investment property. Prices in London's West End soared and, as a result, rents have increased more than 3,000% since 2012. As a charity, the Society cannot afford this.

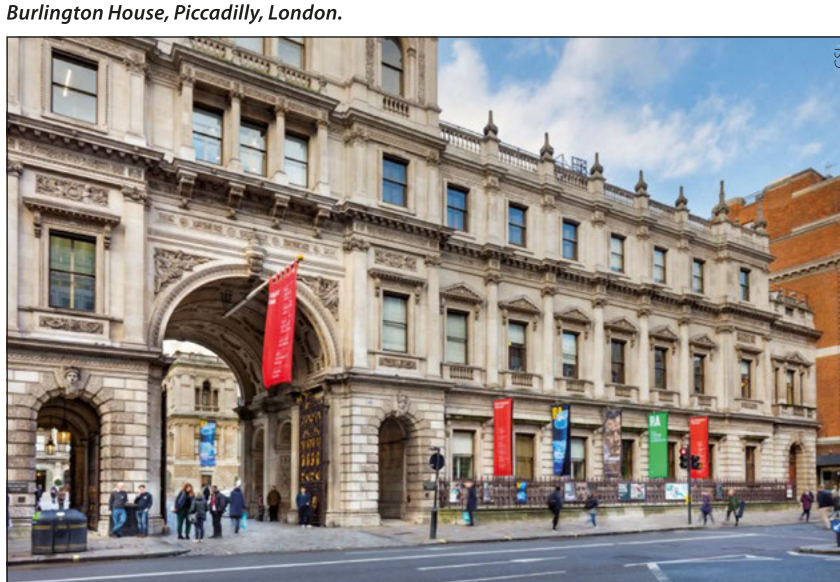
The Society launched a public campaign in a final attempt to find an affordable solution in collaboration with the other learned societies at Burlington House. A relocation could cost millions of pounds and is creating significant uncertainty when the UK should be investing more strongly in science, education, policy and outreach work to the benefit of society.

What will Happen with no Agreement?

Unless affordable and sustainable terms can be agreed with the landlord in the very near future, the Society will have no alternative but to relocate in 3–5 years' time. According to an analysis by international accountants PwC, the UK Government is set to lose up to a third of the *c.* £26.7 million in economic benefits to the UK economy each year from the Geological Society's work, greatly exceeding what it receives from rent. This is in addition to the risk to the UK's recognized position on the international stage.

There has been a huge public lobbying effort to resolve this situation which Sir David Attenborough has backed by writing to UK Prime Minister, Boris Johnson, to urge his intervention. Whether this will evoke a positive reaction remains to be seen but given the Government's mantra of 'being guided by the science', perhaps it is time for the authorities to step up and to maintain the scientific and cultural institutions at Burlington House, which as well as the Geological Society, include the Royal Astronomical Society, The Linnean Society of London, and the Society of Antiquaries of London. ■

Burlington House, Piccadilly, London.



2,000 GEO ExPro Articles and Counting

Kirsti Karlsson, Sales and Marketing Director of *GEO ExPro*, talks about her career with the magazine and how it is adapting to the new world order.

GEO ExPro was founded in 2004 and is now a well-established Geoscience publication.

Why did you get involved with* GEO ExPro*?
I had been a spouse in this industry for many years and had been quite involved in expat spouse communities. For example, when I lived in Stavanger, being a teacher by training, I started teaching Schlumberger spouses Norwegian on my own initiative and I was also the president for the Schlumberger spouses' association in London for a couple of years. We had just moved back to London and our founding editor approached my husband about starting an international magazine for geoscientists and engineers. He was not sure he would have time to do this but thought it might be a good opportunity for me. I took on the challenge and since I am not a geoscientist and had never worked in publishing before it was a steep learning curve and not at all the part-time job I had envisioned.

What were the founding principles of the magazine?
Geoscience and technology explained is the subtitle of *GEO ExPro* and we wanted to create an educational magazine for geoscientists and engineers focusing on the subsurface in the upstream oil and gas industry. A magazine with articles that were informative but not written in a too technical way. Informative for experts in one discipline about topics in another. In addition to the written text, pictures and illustrations play an important role and we wanted to include other topics in addition to technical articles like 'Geotourism', history of oil, country profiles etc.

GEO ExPro tells stories and has found a niche in the market between the academic, peer reviewed, highly technical journals and publications focusing on current news.

We believe we have succeeded in the goal we set for the magazine as we are now reaching a wide range of people with an interest in this industry. For example, it is fun to learn that spouses are reading it too. People tell me they love the magazine and that we tell complex stories in simple words.

Conference attendance has always been a key part of* GEO ExPro*'s interaction with the energy industry. How has the Covid-19 pandemic impacted the ability of the publication to do business and interact with colleagues and clients?
We decided to launch the magazine at the EAGE conference in Paris in 2004 as we thought this was a good way to make the magazine known. We had not originally planned to attend so many conferences each year but we saw this worked very well because we got to meet the readers in person, the advertisers saw their clients carrying copies of *GEO ExPro* and last but not least, conferences provide good opportunities to pick up ideas for current stories and help to keep on top of what is happening in the industry. We have media partnership deals with most of the important associations and organizations hosting conferences, which is beneficial for both parties.

An advantage for *GEO ExPro* during the pandemic has been that we already had a solid online presence but obviously it has made it more challenging to do business. On the other hand, we have attended many virtual conferences and delegates have been able to download the pdf copy of the magazine. As for most other businesses, Zoom/Teams meetings have been the main way to keep in touch with colleagues and the rest of the community but I really do miss meeting people in person and the informal networking possibilities that are difficult to create virtually. I think hybrid conferences are the likely format from now on.

GEO ExPro is a content focused magazine with strength in the upstream oil and gas industry. How have you coped with the changes wrought by the energy transition and what do you think the future of the oil and gas industry might look like?
GEO ExPro is a magazine for geoscientists and engineers focusing on the subsurface and we are of course adapting to the changing landscape by publishing articles of interest to this community including articles on energy transition topics relevant for this group. Our clients are themselves

changing and we have to reflect that. I believe easy-to-read cross-discipline information is even more important now when people need to learn about new disciplines where geoscientists and engineers will play an important role, for example in geothermal carbon storage, minerals etc. We are evolving from an oil and gas magazine to an energy magazine but I believe oil and gas will play a very important role in this mix for many years to come.

What are your best and worst memories of your 17 years at* GEO ExPro*?

The worst memory must be when the shipment with magazines for the EAGE conference in Paris where we were launching *GEO ExPro* was stuck in customs. Luckily, we had hand-carried a few copies with us so people did not notice. When we did not have any more magazines left, we told people we were sold out and the whole team went and had a very long lunch. To our great relief the shipment arrived on the last day and we were quite proud that we managed to hand out 1,000 copies that day. Since then, we only use companies that are specialists in conference shipments!

There are so many good memories, so it is difficult to pick one. I have visited many beautiful cities, for example the AAPG International Conference in Cartagena was one of the highlights. Celebrating our 10th and 15th anniversaries at the EAGE conferences in Amsterdam and London are also good memories because of the warmth and the support we felt from so many of our readers, contributors and advertisers attending the events.

This is a great industry to be part of and what I have enjoyed most is working in great teams, traveling and meeting all the very interesting and professional people with a passion for their disciplines. This is why I am still here.

What do you feel are the biggest challenges of producing a specialist print and online publication and what gives you most satisfaction in your role?

We are working on tight schedules since we cannot miss printing slots as magazines are shipped to conferences. The biggest challenge is to receive all the material by the deadlines and cope with last minute changes. What gives me most satisfaction, in addition to working in a great team and the industry people we meet, is to close ad sales especially with clients I have been trying to get onboard for a long time.

Can you tell us about any new initiatives at* GEO ExPro *that we can expect to see over the rest of this year and 2022?

We will endeavor to continue to create a high quality magazine both online and in print and make necessary changes before our readers start thinking we need to renew ourselves. We launched our webinar series 'GEOTalks' this year and have so far completed two, one on flaring and another on the geology of the planet Mars. Both got excellent reviews.

I also think we are sitting on a gold mine of an archive with 2,000 excellent and still very topical articles that everybody should know about and therefore we want to find new ways to promote this. ■

No Transition Without Offsets

If you are a big emitter of carbon, then reaching net zero means investing in carbon offsets – in the short term at least. By carrying on emitting in one place, runs the thinking, you have to show that you are invested in helping to remove or reduce carbon in another. Think rainforests and renewable energy and you begin to get a picture of why offsets have become so important along the road to low carbon transition.

It's perhaps no surprise that oil and gas companies around the world have become big players in the offset market. They have the buying power to invest – more so in recent weeks as the oil price recovers – and they have the clout – the sheer market muscle – to ensure that offsets deliver additional carbon reduction or avoidance.

And there lies the rub as governments and market sectors feel their way towards credible net zero projects. Is a burgeoning voluntary carbon market able to deliver enough legitimate offset projects? "The ability to remove and store carbon from the atmosphere is limited by the amount of land and energy available to do it, both of which are resources already under severe pressure," says Jim Elliott of the Green Alliance, a UK-based lobby group. While support for nature-based solutions like additional tree planting and forestry protection are welcome, he says, they should not be seen as a short-term fix in place of more costly engineered carbon removals. In other words, clean up your own backyard before looking to save the world elsewhere.

Oil and gas majors would argue that there is scope for doing both. BP Target Neutral, for example, claims that by the end of 2018 it had helped customers offset nearly 4 million tonnes of emissions. Projects in India, Mexico and China will be supported by BP Target Neutral this year, all of which have been independently verified as bringing about additional carbon reduction and removal, says the company.

Another objection put forward by Jim Elliott and others is that early movers like BP are locking up the cheapest forms of carbon removal for years to come. Thus, as offset demand booms, so the price of investing in an Indian solar energy project grows. As renewable energy projects become more viable and offer better returns, so investors pile in – regardless of the carbon credits on offer. No wonder former Bank of England Governor Mark Carney has called for new carbon offset markets while also urging companies to use offset as a complement to carbon reduction in the core business. BP for one would surely agree. ■

Nick Cottam

Shutterstock

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.

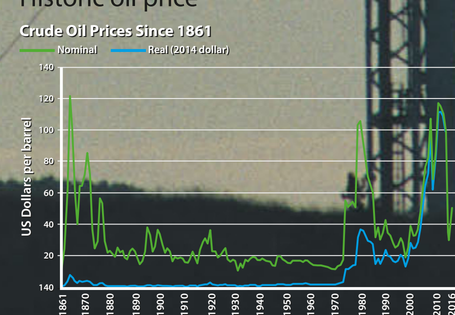
Numbers
Million = 1 x 10^6
Billion = 1 x 10^9
Trillion = 1 x 10^{12}

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

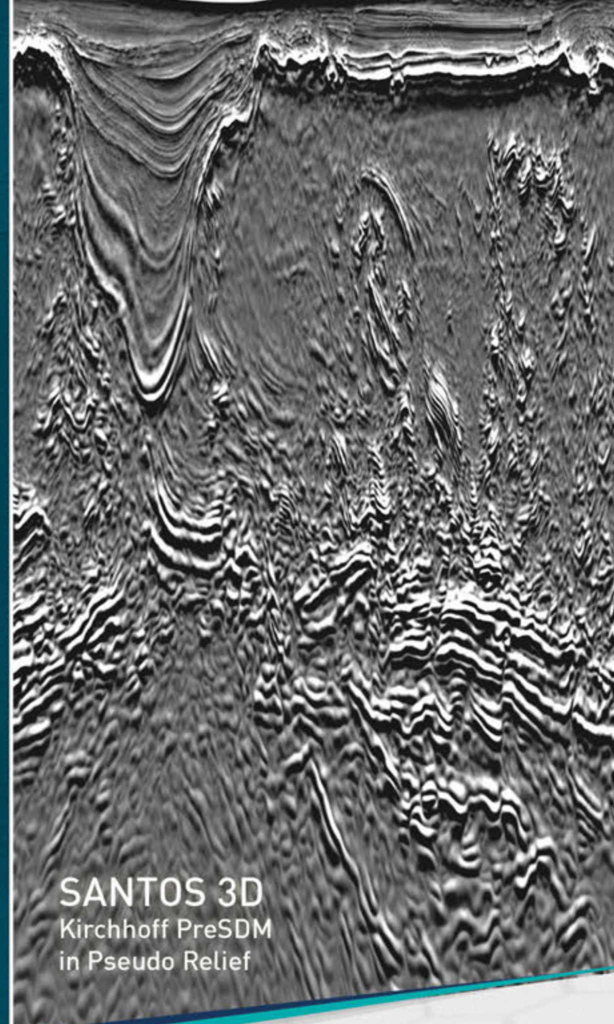
Giant field
Recoverable reserves > 500 million barrels (80 million Sm^3) of oil equivalents

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

Historic oil price




Foz do Amazonas
Pará-Maranhão
Ceará
Potiguar
Sergpipe
Alagoas
Campos
Santos
Pelotas


SANTOS 3D
Kirchhoff PreSDM
in Pseudo Relief