THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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THE SURINAME-GUYANA BASIN HOTSPOT

Geological controls on its size

EXPLORATION OPPORTUNITIES

Salar Basin, Canada
South Atlantic Conjugate Margins,
Trinidad & Tobago,
Liberia

GEO ExPro

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It can't only be the geology

WHY IS shale gas and oil such a success in the US and not so much in other places? It is a question that I asked myself when doing the dishes the other day. There are two things that sprung to mind.

> **"I begin to see how it really is a combination of factors that has caused the American shale boom."**

First, it is unlikely that the geological setting of the main shale basins in the US is unique to this country. An interview with a geologist in Russia reminded me of that. When I spoke to him on WhatsApp, he told me that Russia has extensive areas that would lend themselves well to shale oil and gas exploration. However, the bottleneck there, as he said, was the remoteness and difficulty of the terrain in Siberia. Imagine creating a dense road network in these remote areas. Everything is possible, but at what cost? The plains of Texas are an easy ride in comparison.

Second, there is the American way of working. Our interviewee for this issue, Hayet Serradji from Premier Corex, clearly illustrates how the mindset of the American workforce seems to be well aligned with the innovation the development of shale gas and oil requires. In the interview, Hayet talks about how she and her colleagues were specifically told to think outside the box and come up with crazy ideas. How often has your manager told you that?

Thinking of it again, I begin to see how it really is a combination of factors that has caused the American shale boom. And that geology is only one of the factors involved. Because of that, and increasing environmental concerns, it will probably be more challenging to repeat this elsewhere.

Henk Kombrink

BEHIND THE COVER

Lucia Perez-Diaz is a geoscientist who runs her own freelance illustration business. Her style is defined by a minimalistic approach and the use of bold colours. We asked her to use her creativity to design a front cover resembling the Suriname-Guyana area and its geology, which is also the topic of our cover story. Get your eye in and discover not only some characteristics of the geology, but also the culture and animal life of this spectacular place. If you are intrigued by Lucia's work, please check out her website at *luciaperezdiaz.com.*

COVER ILLUSTRATION: LUCIA PEREZ-DIAZ

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SHEARWATER

Eratosthenes Seamount still in the game

Surrounded by recent giant gas discoveries such as Tamar, Leviathan, Zohr and Calypso, the Eratosthenes Seamount (ESM) remains virgin of any hydrocarbon success and the whole region still awaits liquid hydrocarbons

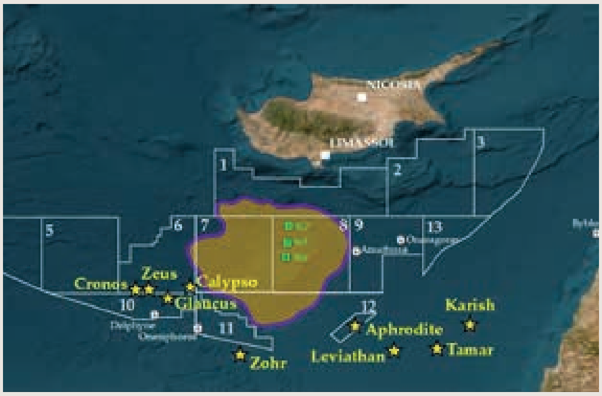
HOWEVER, WHEN it comes to SAR oil seep repeats, ESM is certainly more fertile. Despite prolific activity in its vicinity, ESM has yet to be really tested, with almost no drilling within Cyprus blocks 1, 7 & 8. ODP sites 965-966-967 have encountered carbonates in the Santonian, Maastrichtian and Eocene, but the main question mark relies on the absence of Messinian salt.

Some "killjoys" would welcome these oil seeps as a blatant signal of defective seal section. However, some other more optimistic explorers would arguably recognise some of the footprints of oil migrating from the nearby Levantine Basin. This unlikely but likable scenario would allow the potential combination of the Lower-Triassic shale source-rock, a Middle Triassic dolomite reservoir and the Upper Triassic evaporite caprock.

A game-changer for the existence of an oil-prone working HC system at the conjunction of ESM and Levantine Basin. Satellite oil seeps, just like oil and gas exploration, is not a binary science, and indeed must be seen as a crossroad rather than a one-way traffic, where the certainties of yesterday are jeopardised by the uncertainties of tomorrow.

Currently, 2023-2024 drilling activity plans favour Cyprus blocks 3 (Cuttlefish prospect), 5 and 10 while we are stubbornly keeping faith in blocks 1, 7 and 8. Let's be bold enough to eventually drill this giant four-way dip closure.

Clément Blaizot - SAR Satellite Oil Seeps



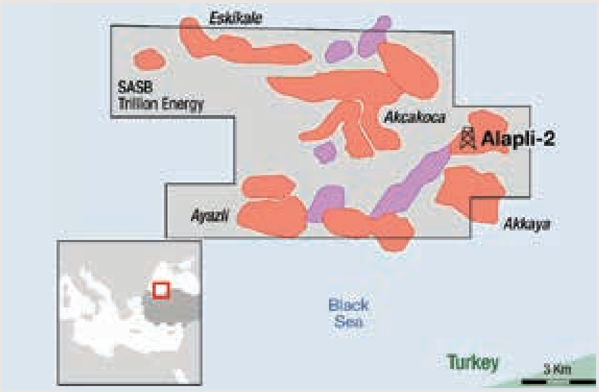
Gas discoveries (yellow stars), Cyprus blocks, unsuccessful wells (white), ODP's (green), Eratosthenes Seamount contours (orange).

Timely success for re-energised gas cluster offshore northwest Turkiye

CANADIAN FIRM Trillion Energy International have reported success at their SASB gas field cluster offshore northwest Turkiye. Alapli 2 reached 3,258m TD on 16 July 2023. Mud logging results suggest over 40m of potential natural gas pay within 6 separate sands in the Akcakoca Member (SASB production zone). Trillion and operator TPAO (51%) are evaluating LWD log data, after which they will run the production casing ahead of perforating for production.

The Alapli 2 well is the sixth well for Trillion in the SASB gas field cluster. The offset Alapli-1 well drilled several years ago (but was never produced) tested 7.1 mmcfgd from a combined three zones with a measured thickness of 15 metres. Most recently the group drilled Bayhanli 2 well nearby, recording 11.9 mmcfgd on test from 8 intervals in the same Akcakoca Member. The SASB cluster is expected to contain 323 BCF GIIP, with 93 BCF net recoverable gas to Trillion. This is expected to increase as the firm drills out the remaining 10 development wells, followed by 10 prospective resource exploration wells within the same cluster. Further upside may be delivered with new stratigraphic targets in the SASB area and targets in new acreage being negotiated by the firm in northwest Turkiye. The drilling adds to a string of interesting results for this burgeoning gas play, with major discoveries to the north in the Black Sea at Sakarya, and along the coast of Bulgaria and Romania.

Peter Elliott - NVentures



Map showing the location of the Alapli-2 well.

Oil potential in Somalia to be further de-risked this year

Coastline Exploration is planning a 3D seismic survey offshore Somalia

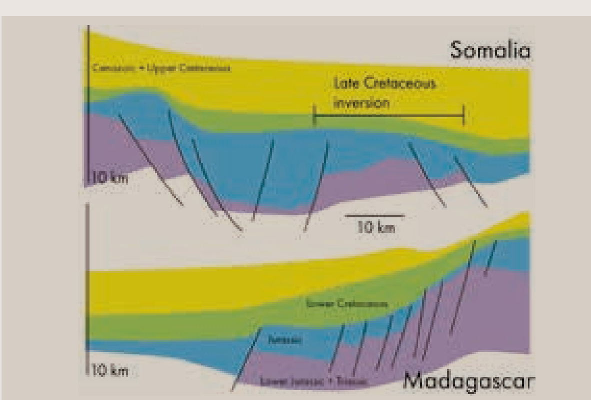
DURING THE BEOS conference in London in April, we caught up with the team from Coastline Exploration. The company has got significant acreage offshore Somalia in areas that have hardly been tested by the drill bit. Recently acquired 2D lines suggest the presence of valid closures, which has now made the company decide to acquire 3D seismic data this year.

The conjugate margin of Somalia is Madagascar, where oil seeps have already proven the presence of a working petroleum system. These seeps have not been observed in Somalia, which begs the question of why that is the case. Kevin Schofield, chief geoscientist of Coastline, explains the lack of surface expressions of hydrocarbons by the fact that subsurface trapping has occurred more effectively in Somalia than in Madagascar, which has prevented migration to surface.

“Somalia has experienced an inversion phase following rifting off Madagascar, which has created the structures required for trapping of migrating hydrocarbons”, said Schofield. The company identified both a carbonate as well as a siliciclastic play and will de-risk both during the upcoming 3D seismic acquisition campaign.

According to Erik Anderson from Coastline, the political situation in Somalia has become a lot more stable over the past few years and the company expects any future operations to run smoothly thanks to the relationships the company established in the country.

Further information at coastlineexploration.com



Two cross-sections illustrate the Madagascar and Somalia conjugate margins. In the latter, there is more scope for hydrocarbon trapping due to inversion.

Protecting the El Gordo Diapir

A call for the Conservation of an exceptional outcrop analog

THE EL GORDO DIAPIR is a geological marvel, comprising a mass of salt, sedimentary and igneous rocks, providing a rare window into Earth's history. With its arid climate and complex crust folding, the site offers continuous exposures of salt masses and deformed sedimentary units. This wealth of information helps us understand critical processes as well as finding solutions to tackle climate change.

The sad fate of a neighboring site, the Papalote Diapir, serves as a cautionary tale. Open-pit mining has devastated the Papalote Diapir, leaving geologists with insufficient time to study its unique features and mechanisms. The damage done there highlights the urgency to protect El Gordo Diapir before it faces a similar fate.

Mining companies are on the verge of obtaining government permission to operate in the El Gordo Diapir, putting this geological treasure in imminent danger. We firmly believe that preserving the El Gordo Diapir is of utmost importance, providing an opportunity for current and future scientists to deepen our understanding of salt movements within the Earth.

We appeal to all concerned parties to prioritize conservation over mining in the case of the El Gordo Diapir. To support our cause, please get in touch with us and stay updated in our social media publications on the matter. Together, let us work towards persuading the Mexican government to protect this exceptional site, ensuring that the invaluable knowledge it holds can benefit humanity for generations to come.

Ramón López, r.lopez.jimenez00@aberdeen.ac.uk

Should we let all the knowledge written in the rocks?

PHOTOGRAPHY: RAMÓN LÓPEZ

Unlocking African energy to power the future

Flagship Africa Conference to be hosted in London again for the first time in four years

IT MAY NOT SEEM like it, but the last in-person GESGB/HGS Africa Conference was back in 2019. But the good news is that for 2023 we are back! The latest incarnation will remain true to the conference's traditional strength with two days of top-quality technical talks focussed on all aspects of African geology.

The location for this year's event, taking place 20 & 21 September, is The Kia Oval cricket ground in London where the technical program will encompass our unifying theme of "Unlocking African Energy to Power the Future". This theme will focus the discussion on how the vast potential of Africa's subsurface can reduce energy poverty and help drive growth across the continent.

Exploration remains a strong theme of the conference with presentations covering all four corners of the continent. Presenters will also touch on recent well results, upcoming wells, insights into exploration hotspots and suggesting where to go next. Other sessions will focus on tectonics, sedimentary systems, new energy and how to unlock value. In addition, poster displays and trade exhibitor stands will provide the backdrop for the all-important networking opportunities.

Gavin Elliott – Africa Conference 2023 Technical Chair
More information at: africa.ges-gb.org.uk

The GESGB/HGS Africa Conference will be back in London after four years.

inApril successfully completes first project of the North Sea season

The first kit of ocean bottom seismic nodes (OBN) manufactured by Norwegian company inApril is being deployed by leading marine seismic contractors in the North Sea this summer

THE INITIAL NODES from the company's rental pool have already seen successful service on one North Sea project and are now being deployed on a second for a different OBN operator.

"This is the era of seabed seismic", says Anne Camerer, inApril's CEO. "We look forward to making an increasing contribution to the industry's demand for state-of the art ocean bottom nodes in keeping with the need for cost-effective and sustainable survey operations."

This summer, inApril´s total rental inventory 3,000 nodes will be available to the market. The kits feature the company's flexible A3000 nodes suitable for both node-on-a-rope and deeper water ROV applications with extended battery life of 150 days and a depth rating to 3,600 m. The 20 ft (6 m) automated charging and staging container offers parallel loading and unloading of nodes to ensure operational efficiency plus redundancy.

The company has also started the process of adding 8,000 next-generation A4000 nodes to its rental pool with expected availability next year.

More information at: inApril.com

"This is the era of seabed seismic" - Anne Camerer, inApril's CEO.

CREDIT: GESGB; PHOTOGRAPHY: INAPRIL

The Competency Alliance bridges the learning gap between petroleum and the energy transition

PetroSkills now offers training courses in the Clean Energy Space, building on the success of its oil and gas learning and development modules

THE ENERGY INDUSTRY is facing major challenges, such as the need for clean energy, new business models, emerging technologies, and the reallocation of oil and gas professionals to low-carbon or renewable energy. These challenges are driving the requirement for new skills and competencies. To better serve the industry and its customers, The Competency Alliance is building on the blueprint that PetroSkills used to become the Oil & Gas industry's leading competency assessment, management and development alliance and expanding it to the Net Zero and Renewable sectors.

The Competency Alliance is grouped to cover the three major energy sectors. As it has done for over 50 years, PetroSkills covers Upstream, Midstream, and Downstream oil and gas. NetZeroSkills includes Greenhouse Gas Management, Carbon Capture/Sequestration, and Hydrogen. RenewableSkills currently focuses on the Wind and Geothermal sectors.

Sectors are formed by energy companies coming together to collaborate and build performance-ready professionals. "The Alliance methodology is already proven effective for over 20 years in oil and gas. So, it's logical to use the same competency-based Alliance approach as we transition to new energy sectors," says Tony Sperduti, Senior Vice President of Renewables and Net-Zero Energy for The Competency Alliance. *More information at: thecompetencyalliance.com*

The Competency Alliance is building on the blueprint that PetroSkills used to become the Oil & Gas industry's leading training provider.

A new hydrogen play

Clay minerals trapping H2 produced by radiolysis of pore water are the main ingredients

EXPLORATION FOR GEOLOGICALLY occurring hydrogen is taking off. Last month, FDE announced a chance discovery of hydrogen whilst drilling for coalbed methane in France. In the USA, Hyterra Ltd drilled the world's first wildcat well targeting H2. Other locations of interest are in Australia and Mali. What all these localities have in common is that hydrogen occurs as a free gas, similar to a hydrocarbon reservoir. The H2 is thought to result from water-rock interactions such as serpentinization of iron-rich rocks.

However, a completely different hydrogen play has now been discovered in Saskatchewan, Canada, in association with a uranium deposit. The orebody is situated at the boundary between basement rocks and overlying sandstones, where hydrogen formed via radiolysis of pore water. Uranium decay emits radiation that breaks water molecules apart, resulting in H2 as one of the end members.

The H2 subsequently became trapped in the hydrothermal alteration halo that is present around the orebody. The alteration zone is made up of a mixture of clay minerals, extending up to 30 m away from the ore surface.

Research shows that H2 is preferentially adsorbed to chlorite and concentrated in both the ore zone itself as well as the clay halo below the orebody. Chlorite adsorption is an efficient H2 trapping mechanism; an estimated 476 tons of H2 is believed to be trapped. The hydrogen can be released from the clay surfaces via thermal desorption, starting at temperatures of 80°C. However, for now, the sole focus in Saskatchewan remains uranium mining.

Mariël Reitsma, HRH Geology

A typical land- and skyscape in Saskatchewan, Canada.

SOURCE: PETROSKILLS. PHOTOGRAPHY: JOSHUA REDDEKOPP VIA UNSPLASH

THE CORE

COVER STORY

NORTH WEST EUROPE

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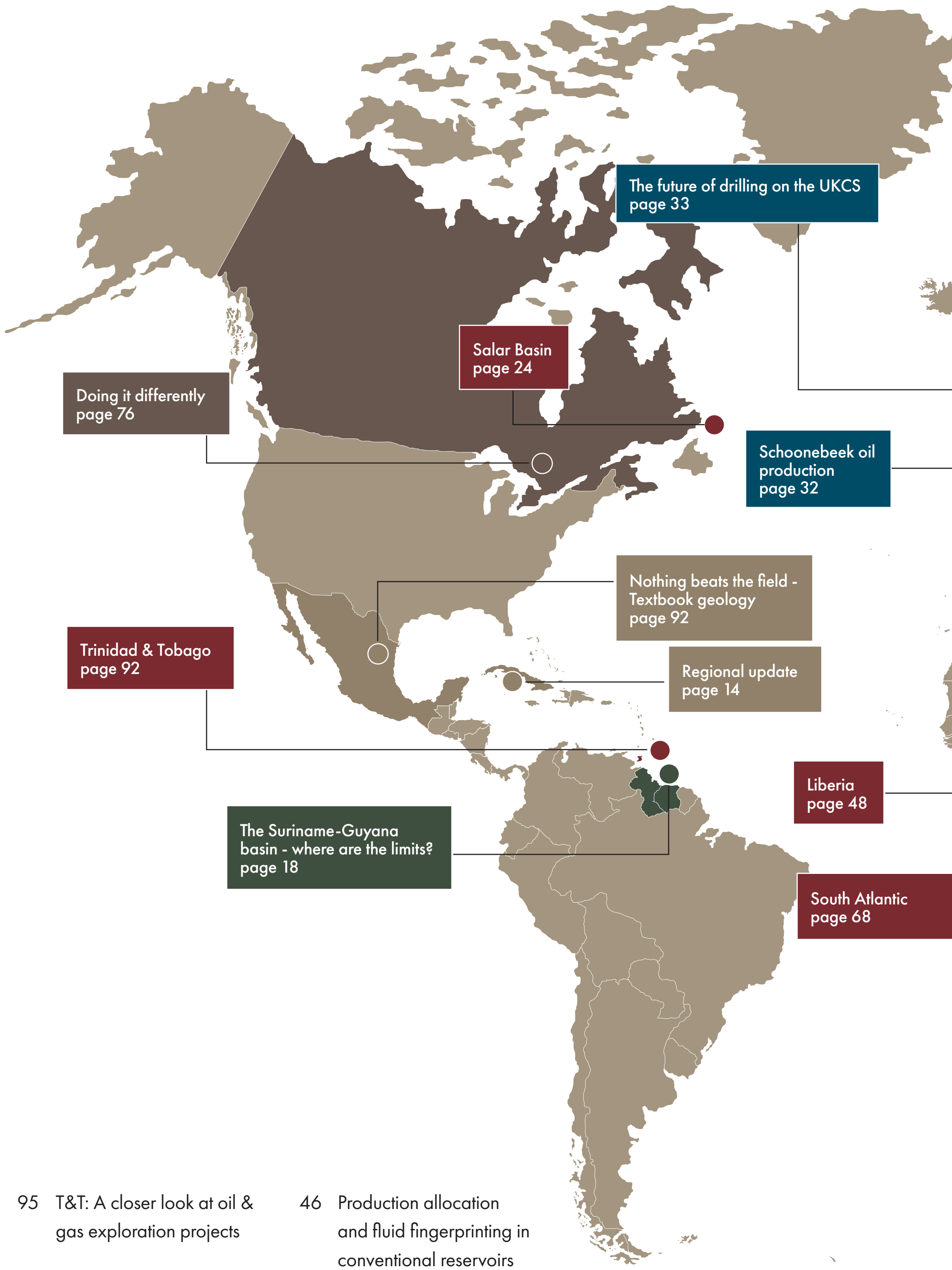


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Keeping an eye on Cuba

Hydrocarbon activity in Cuba has been a stop-start process, due to lack of investment associated with the US Embargo. However, with so much oil around in the system, coupled with more modern exploration and production techniques being introduced, the future looks exciting. The activities and plans of a number of companies operating in Cuba are testament to that

THE ISLAND of Cuba has a rich history of oil and gas exploration, dating back as far as the 1860s when commercial discoveries of heavy oil were found. The first significant discovery in Cuba was light oil in the Motembo oil field in 1881. The 1950s saw a boom following the discovery of the Jatibonico field in the Central Basin by a group of local businessmen under the company name of Grupo Jarueca, and other operators onshore at the time included Atlantic Refining, Gulf Oil, Shell, Standard Oil and Union Oil.

The state oil company Unión Cuba Petróleo (CUPET) was established in 1959. There was a further rush for acreage in the 1990s and those signing blocks included Alturas, British Borneo, Geopetrol, Premier and Sherritt. More recently, offshore blocks were awarded to CNPC, Petronas, PetroVietnam, PDVSA, ONGC, Repsol, Sonangol and Zarubezhneft. Interesting to note is the number of state oil companies that signed offshore blocks.

Calgary-based Sherritt International has the longest history of foreign companies in Cuba having been active in the country for over 30 years. During this period, Sherritt produced over 230 million barrels. It currently holds three exploration blocks. Sherritt has plans to drill exploration wells in Block 6A, aiming at extending the north coast oil trend, and Block 10, a prospect offsetting the Varadero Field.

BIG PLANS

ASX-Listed Melbana Energy prequalified as an operator in Cuba in 2013 and identified Block 9 on the north coast as a preferred opportunity due to its location along the same structural trend as the massive Varadero Field. Melbana were subsequently awarded the Block 9 PSC in 2015, and Angolan-state oil company, Sonangol, farmed in to a two-well drilling campaign in 2020.

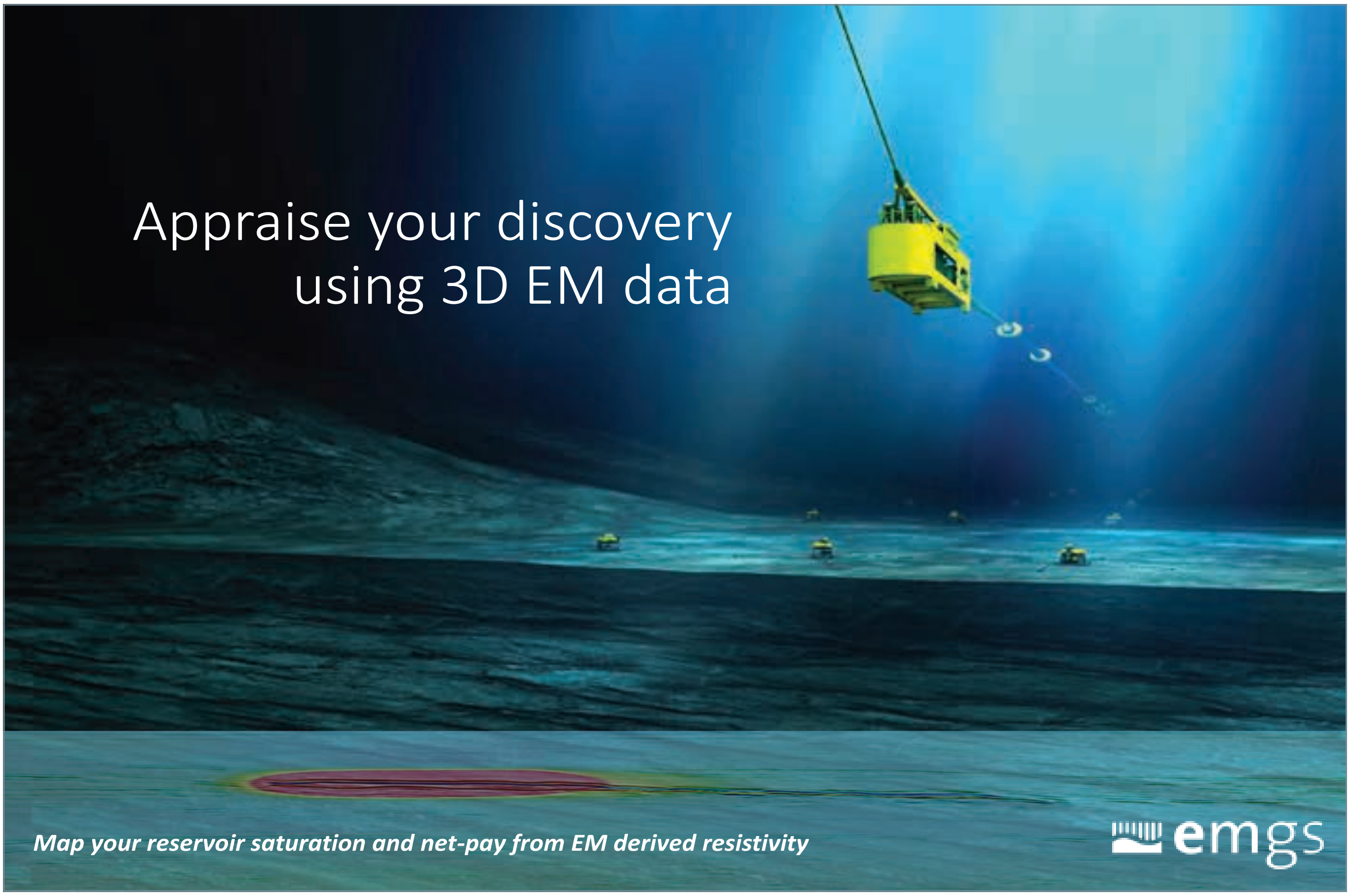
In 2021 and 2022, Melbana drilled two wells, designated Alameda-1 and Zapato-1. Alameda-1 is reported to have intersected three separate reservoirs that have been independently assessed to contain an impressive 5 billion barrels of oil in place, significantly exceeding initial expectations. Zapato-1 was reported to have encountered a thicker than expected volcanic sequence and with slow drilling the wildcat was suspended with the possibility of re-entering in the future.

Melbana started an appraisal programme on Alameda in June 2023 aimed at testing all three units of the Amistad Formation, targeting 88 million barrels of gross and unrisked prospective resources. A second well, targeting the deeper Alameda and Marti formations, will be drilled following the first well and is targeting 179 million barrels of gross prospective resources. Melbana hope that successful flow tests will allow the booking of reserves and the movement towards a development plan and production of oil.

Another Australian-based company, Petro Australis Energy Limited (PAE) has big plans in Cuba. PAE holds three onshore PSCs, two awarded in 2018 and the third in 2020. Its main activity is focused on Block 21A-IOR (Incremental Oil Recovery), which contains the Pina oil field, and the underlying and surrounding exploration Block 21A-P. Pina was discovered by Cupet in 1989 and only half the field is considered as exploited with no new wells drilled since 2001. PAE is planning a series of production wells with a target of an initial ramp-up to 5,000 BOPD. Meanwhile, Block 21A-P contains the carbonate Pina Deep Prospect, which is analogous to the 11 billion oil in place Varadero shallow water field in Cuba. Block 14-13NE is an exploration block on the north coast with a low commitment of reprocessing 2D seismic data.

In summary, the activities of Sherritt, Melbana and PAE are worth being closely watched, introducing a return of interest and exploration to the underexplored Cuban sector of the Gulf of Mexico. ■

Ian Cross - Moyes & Co



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using 3D EM data
Map your reservoir saturation and net-pay from EM derived resistivity
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Coastline Exploration has a 100% working interest in seven PSAs, signed in October 2022. We seek co-venturers with deepwater operating experience to partner with us to evaluate and explore these blocks. They total 35,000 square kilometres in what we believe to be one of the world's last unexplored basins with multi-billion-barrel discovery potential.
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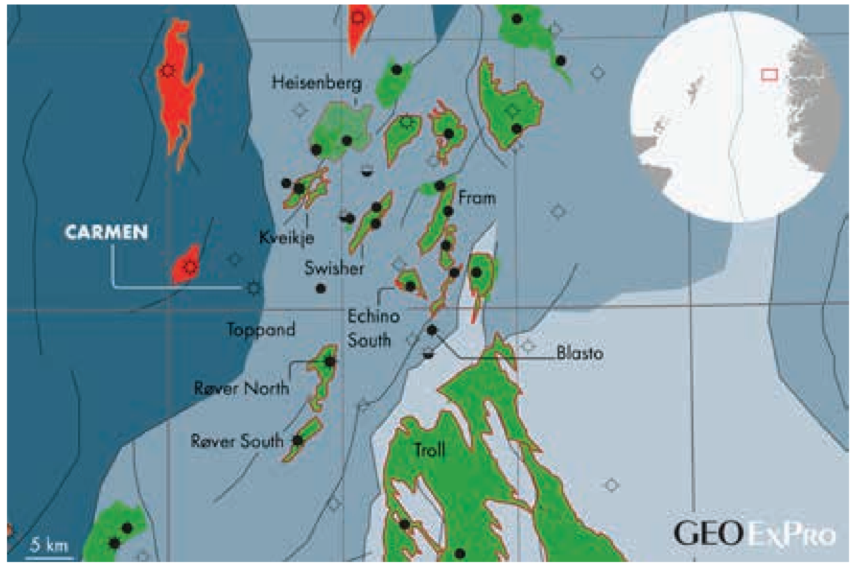
coastlineexploration.com

A significant gas discovery at the right time

Operator Wellesley strikes gas and condensate in what may turn out to be the biggest find in Norway in the last decade

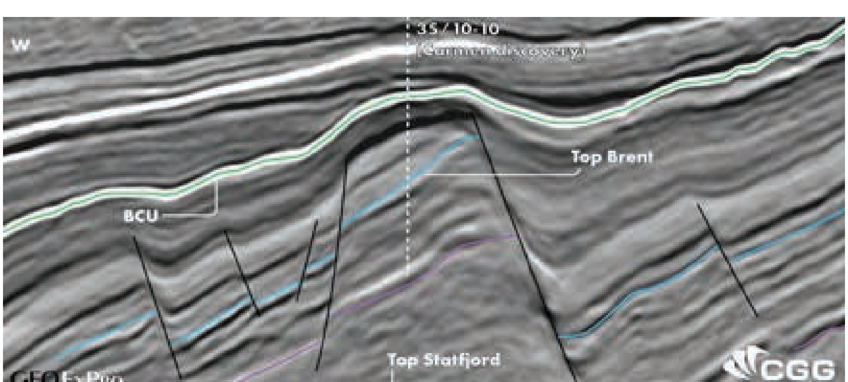
NORWAY IS THE GIFT that keeps on giving," said DNO's Executive Chairman Bijan Mossavar-Rahmani in a recent press release, when the discovery of gas and condensate in well 35/10-10A was announced by the Oslo-based company. According to DNO, which owns a 30% interest in licence PL1148, the gross recoverable resource of the Carmen discovery ranges between 120 and 230 MMboe. With a P50 of 175 MMboe, the discovery ranks as the largest in the previous ten years. The Wisting discovery from 2013 stands at around 427 MMboe.



This map of the north of Troll area shows the recent discoveries made. It is clear that Carmen is situated in a different structural setting compared to the other finds; it is on the eastern edge of the Viking Graben, which does explain the HPHT nature of the well.

NORTH OF TROLL

If it is Norway that keeps on giving, it is especially the area north of Troll. The 35/10-10A well is just the next success in a string of recent discoveries in the area, from the "early" Blasto and Echino South discoveries in 2019 and 2020 to Kveikje, Heisenberg and Røver South more recently.It would therefore be a logical step to include Carmen in the FANTA development plan, as the area is known. FANTA stands for Fram and North of Troll area and aims to connect the recent North of Troll discoveries into one development strategy.Equinor is obviously the biggest player in the region, and is also the operator of most exploration wells. With Carmen operated by Wellesley (50%) and Equinor only having a 10% stake, it seems likely for Equinor to acquire Wellesley's stake in the licence if Carmen is to be included in the FANTA development. In March this year, Equinor already acquired (most of) Wellesley's stakes in the Røver North, Røver South and Toppand discoveries.



W-E seismic line through the Carmen discovery, clearly illustrating the fault block that was targeted by the well. The location of the well is not exactly known with respect to the seismic line; hence the dashed line.

TOWARDS THE GRABEN EDGE

With 35/10-10A being located quite far to the west, towards the margin of the Viking Graben, the Middle to Lower Jurassic reservoirs are likely to be fairly deeply buried.

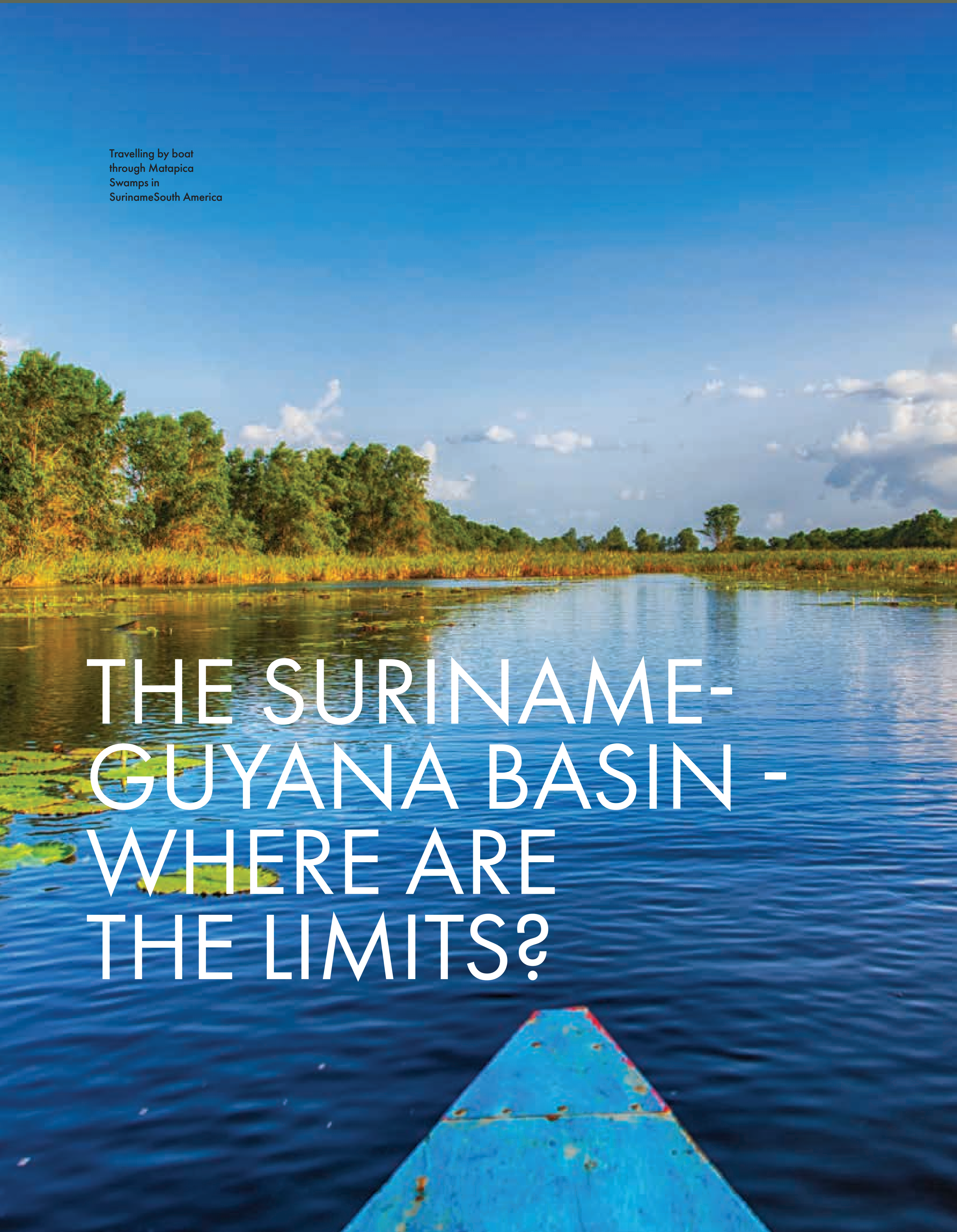
This also explains why Wellesley classified Carmen as an HP/HT prospect.The main reservoirs are probably the Brent sandstones, including the Oseberg Formation, with a possible contribution from the Cook Fm as well. Given that DNO announced a deeper contact than initially anticipated, it is even more likely that the Cook is hydrocarbon-bearing.

Based on this, Carmen could be the deepest find in the North of Troll area thus far. The hydrocarbon type differs from the other discoveries in the area, with oil being the dominant fluid in previous finds whilst gas and condensate is the reported result in Carmen. This might therefore put a challenge to the integration of Carmen into the FANTA development plan. ■

COVER STORY

"Extending the current extent of proven
plays in the Guyana-Suriname Basin is dependent
upon understanding the distribution
of Cretaceous source and reservoir rocks."

Jamie Vinnels – Petroleum Geologist



Travelling by boat through Matapica Swamps in SurinameSouth America

THE SURINAME-GUYANA BASIN - WHERE ARE THE LIMITS?

JAMIE VINNELS
AND HENK KOMBRINK

HYDROCARBONS were first noted in the Guyana-Suriname region by Dutch explorers in the 1750's.

Onshore discoveries of biodegraded heavy oil in Suriname supported the presence of a working petroleum system. In 2000, the United States Geological Survey (USGS) identified the Guyana-Suriname Basin as having an estimated mean recoverable oil reserves of over 13.6 billion barrels of oil, and gas reserves of 32 trillion cubic feet. After numerous unsuccessful wells, some with shows, the Liza-1 discovery was announced in May 2015 by ExxonMobil, and was the first significant oil find offshore Guyana. The well encountered more than 295 feet (90 metres) of high-quality oil-bearing sandstone Upper Cretaceous turbidite sandstone reservoirs. The gross recoverable resources from the Stabroek Block are now estimated to be nearly 11 billion oil equivalent barrels, with over 30 discoveries to date. The Stabroek Upper Creteacous discovery trend has now been extended by Apache and Total into Block 58 in Suriname, and into the Guyana Corentyne Block by CGX and Frontera. Drilling on the Demerara Rise to date has yet to yield a commercial discovery. Here, we examine the key controls on broader play and prospect trends within the region. ▶

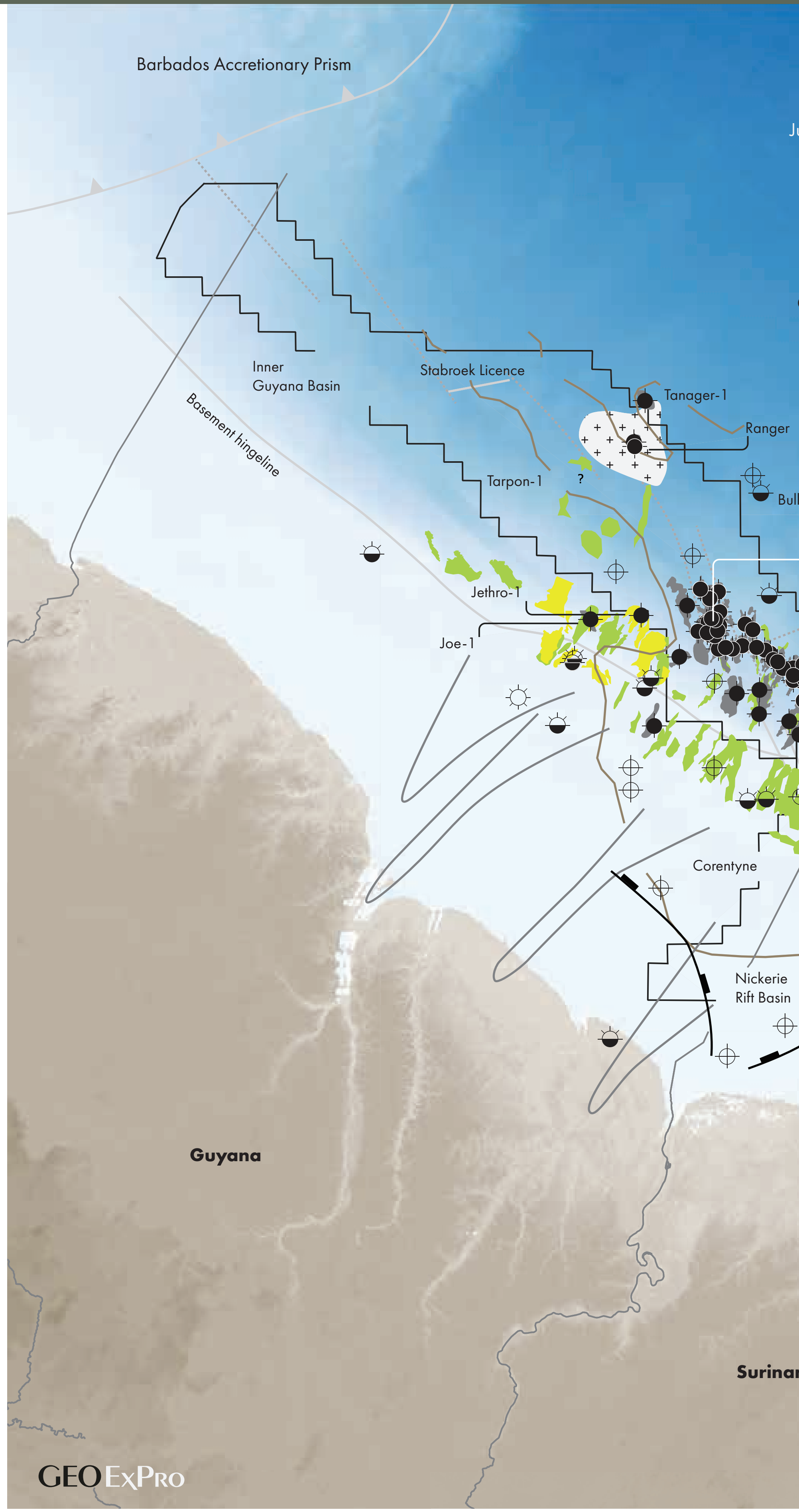
The centre of activity in the Guyana-Suriname Basin is in the southeastern part of the Stabroek Licence and Block 58 in Suriname. The key question now is, after more than 30 discoveries announced so far, how will the play further develop? ExxonMobil, the most important operator in the region, recently announced drilling of another 35 exploration and appraisal wells, so there surely is additional potential. Here, we take a look at the geological opportunities and risks for the area, radiating out from the centre of activity.

NW The northwestern continuation of the Guyana hotspot was tested by the Tarpon-1 well, which likely drilled the Jurassic syn-rift succession or a carbonate build-up. The results have yet to be announced. In terms of the typical Stabroek play, it is worth noting that canyon cuts have been mapped as far west as the ones shown here. These areas may have acted as conduits for reservoirs of a similar nature as the ones discovered to date.

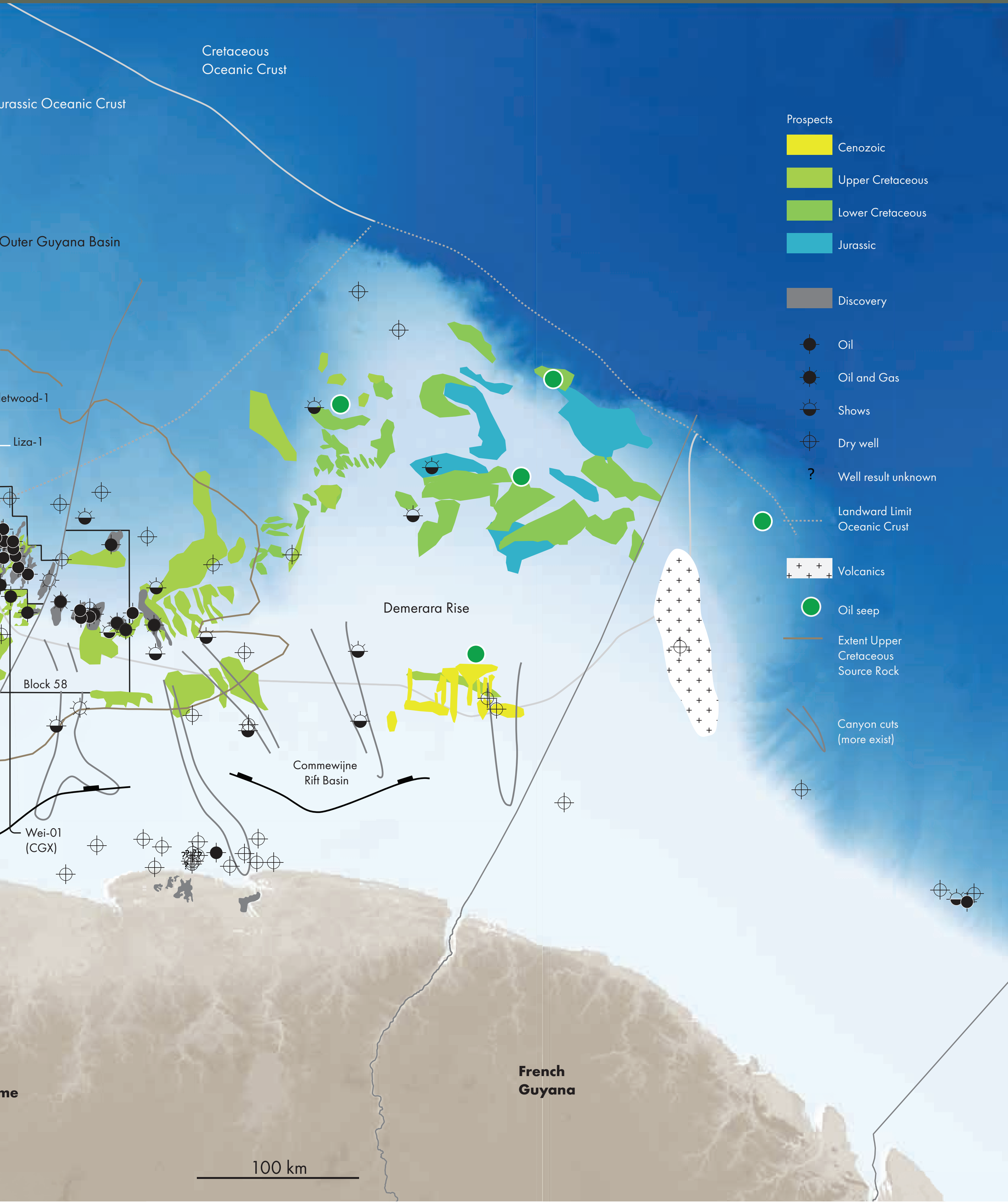
N The northward continuation of the Upper Cretaceous Stabroek play was proven by wells Tanager-1 and Bulletwood-1, but commercial quantities have not been found to date. Thinning of reservoir units in a northerly direction demands the presence of stacked reservoirs. Another play that was tested in this area is a carbonate play that is present on top of volcanic centres. The Ranger well targeted this play.

S The main risk exploring the area to the south of the current string of discoveries is the distance from the source kitchen in the north, i.e. heavy oil and biodegradation, and the potential lack of seal and traps because of the more updip nature of the turbidite reservoir sections.

E The Guyana Basin makes way for the Demerara Rise in the east. This area was the first to be explored and drilled in the 1970's, but has not resulted in commercial finds to date. The source rock in this area is probably an older Jurassic source rock, deposited in failed rift graben systems intersecting the area. As such, prospectivity also includes older reservoirs such as Jurassic sandstones. Oil slicks mapped in the area provide hints to an active petroleum system. ▶



DATA DERIVED FROM PUBLIC DOMAIN SOURCES. COMPILATION: JAMIE VINNELS; MAP: HENK KOMBRINK; SOURCE DIGITAL ELEVATION MODEL: THE GEBCO GRID


Cretaceous
Oceanic Crust
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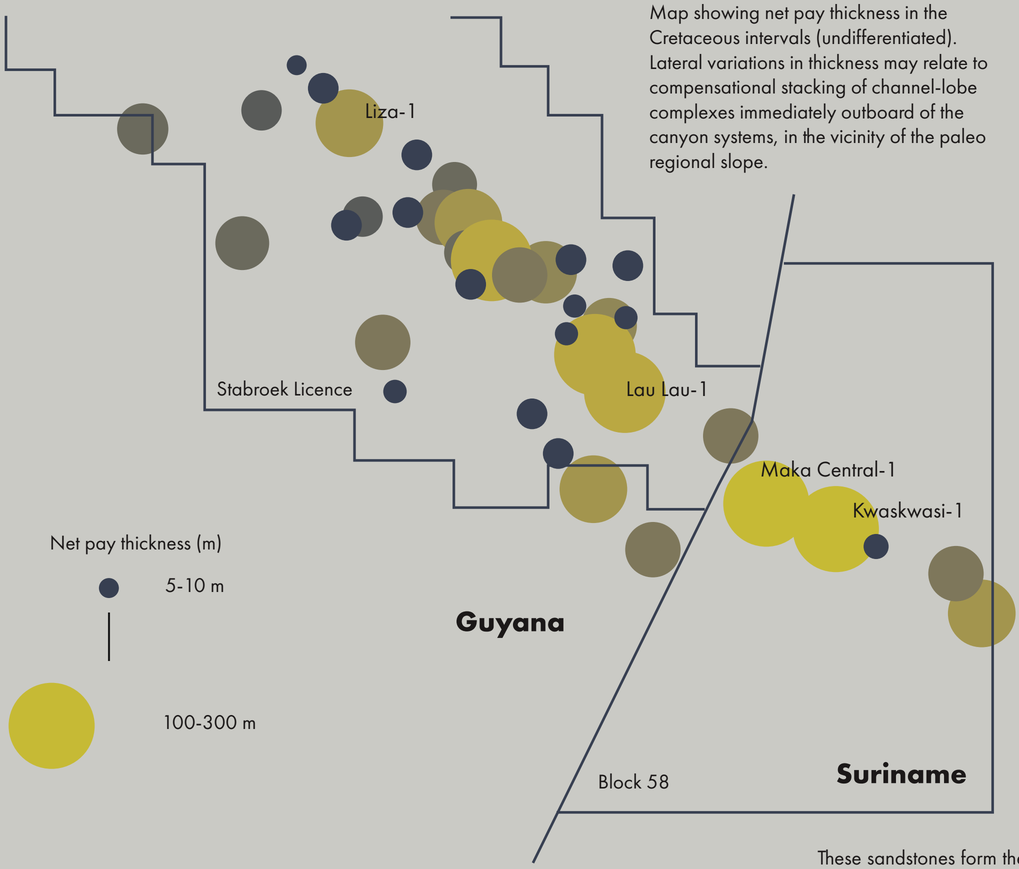
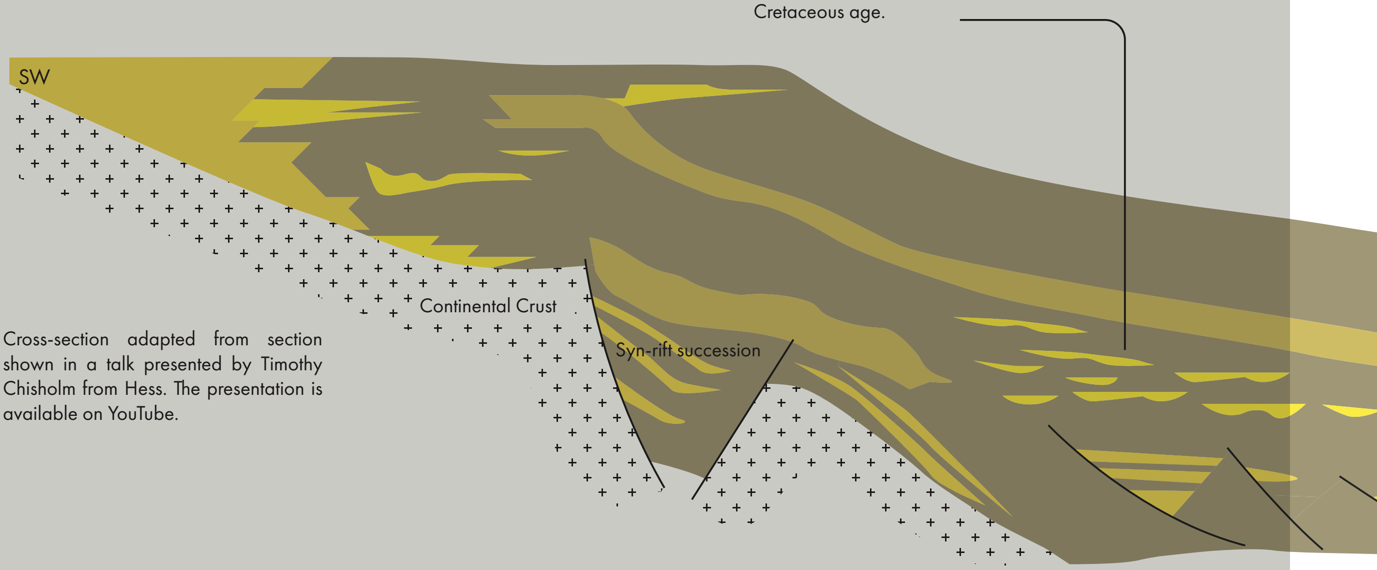
Outer Guyana Basin
letwood-1
Liza-1
Block 58
Wei-01
(CGX)
Demerara Rise
Commewijne
Rift Basin
French
Guyana
me
100 km
Prospects
Cenozoic
Upper Cretaceous
Lower Cretaceous
Jurassic
Discovery
Oil
Oil and Gas
Shows
Dry well
?
Well result unknown
Landward Limit
Oceanic Crust
Volcanics
Oil seep
Extent Upper
Cretaceous
Source Rock
Canyon cuts
(more exist)

Map showing net pay thickness in the Cretaceous intervals (undifferentiated). Lateral variations in thickness may relate to compensational stacking of channel-lobe complexes immediately outboard of the canyon systems, in the vicinity of the paleo regional slope.



These sandstones form the typical target in the Suriname-Guyana Basin - Deep-water turbidites of mainly Upper Cretaceous age.



Cross-section adapted from section shown in a talk presented by Timothy Chisholm from Hess. The presentation is available on YouTube.

STRUCTURAL TEMPLATE

The Mesozoic tectonostratigraphic development of the Guyana-Suriname region, associated with the opening of the Equatorial and Central Atlantic Oceans, exhibits periods of extension, transpression and compression. The development of the Demerara/Guinea Transform Margin Plateau and adjacent regions through the Jurassic and into the Early Cretaceous provided a structural template, which in turn influenced the development of post-rift depositional systems. These are thought to have a first order control upon the hydrocarbon prospectivity of the margin, particularly the deposition and thickness distribution of ~4% Total Organic Carbon (TOC) Albian to Coniacian source rocks and the prolific Upper Cretaceous turbidite sandstones in the basin.

ADDITIONAL SOURCE ROCK

Besides the prolific Cretaceous source rocks, numerous hydrocarbon seeps are evident above the Demerara Rise. This could be an indication of an additional Jurassic-aged source, particularly in the Nickerie and Commewijne Grabens on the present day shelf, along with 2.5% TOC sediments proven in the Takutu graben onshore. These grabens are interpreted to be part of a failed rift systems related to the earliest phase of Atlantic opening, and serve to influence the position of long-lived deposition systems, fed recycled Precambrian sediments from the Guyana Shield, into terrestrial and marine systems from the Cretaceous onwards.

CANYON-FED RESERVOIRS

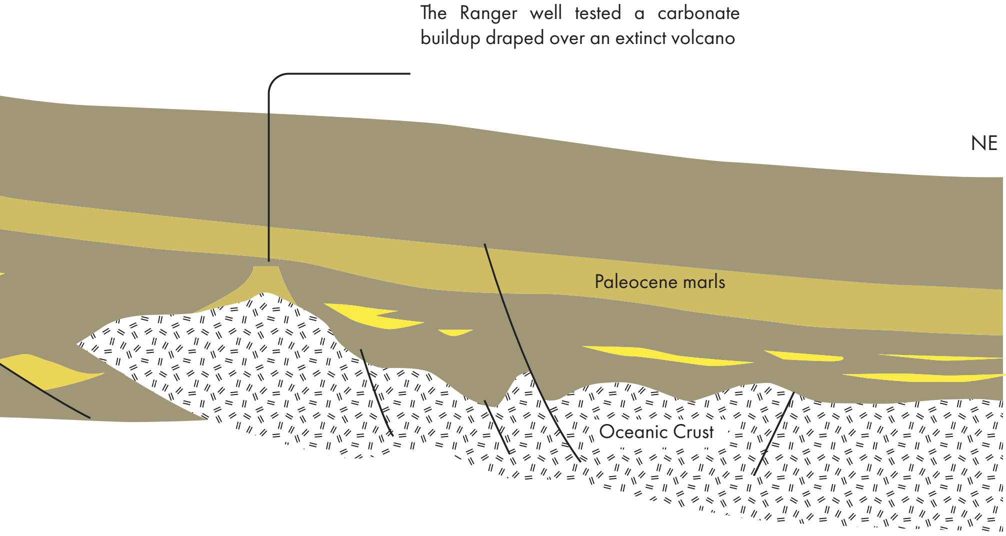
Passive burial through the Late Cretaceous continued with deposition of substantial thicknesses of turbidite sandstones and pelagic shales.These sediments fed directly through the shelf and slope via a series of deep-water canyons from the quartz rich Guyana Shield. Seismic facies indicate the presence of channel-lobe complexes, with high porosity and permeability reservoirs occurring across the play. Quantitative interpretation of reservoir units often proves challenging to differentiate between wet and pay sands. It may be just as important to understand the 3D nature of the sealing lithologies, along with sandstone pinchout and internal heterogeneity relationships in fully determining the stratigraphic trapping potential of these units.

MONOCLINE

Subtle topography may have been present at the time of deposition, with a monocline persisting through the Cretaceous and Cenozoic lying directly above older lineaments. The location of this monocline, which was identified by Trude et al. (2022), approximately lines up with the Basement Hingeline as shown on the map on the previous page. On that basis, prospectivity south of the hinge line is thought to be more limited than to the north. Regional scale inversion and drainage reorganisation during the Cenozoic led to the emplacement of mass transport complexes fed from shelf-slope, which led to the generation of petroleum at the present day.

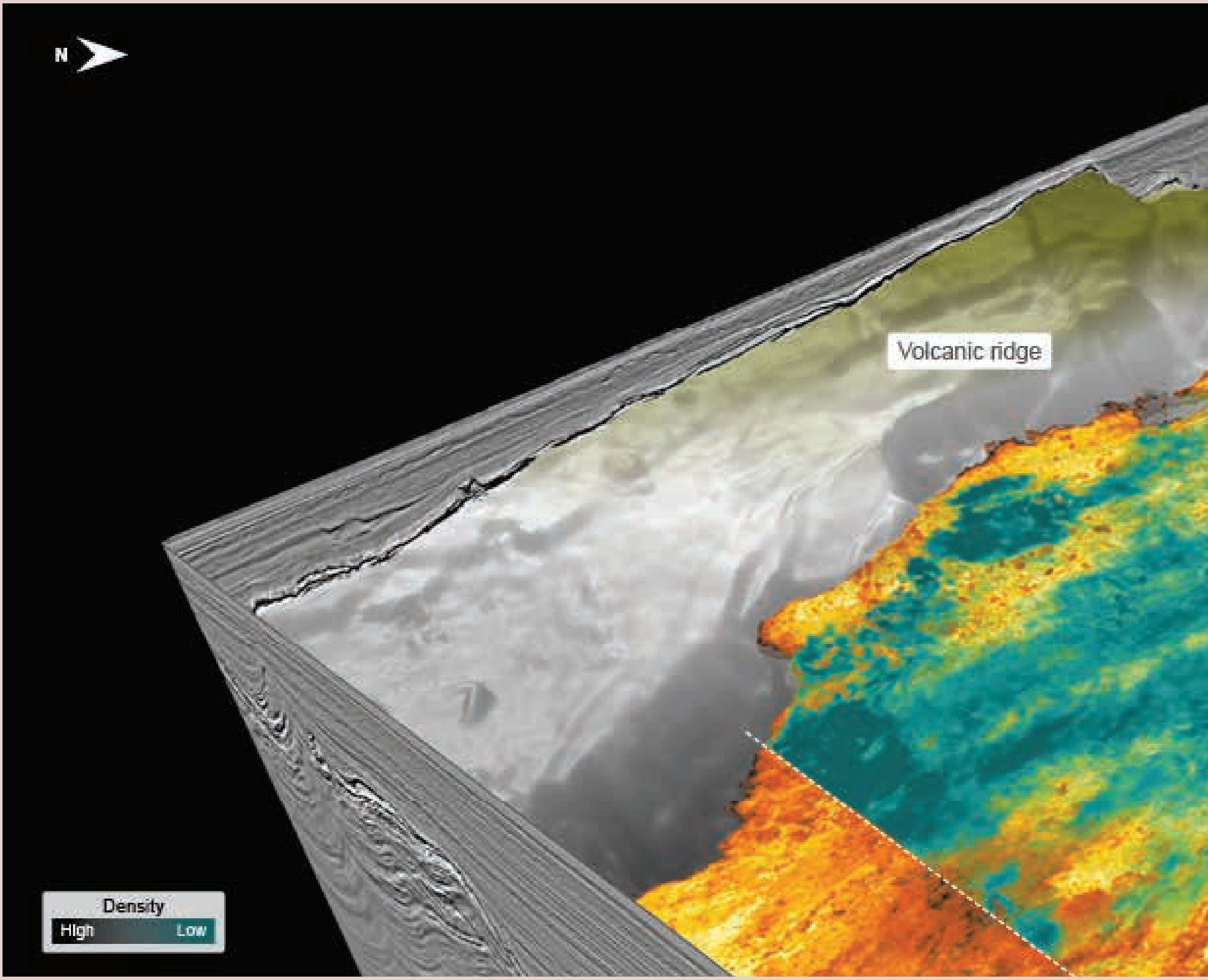
MORE THAN CRETACEOUS TURBIDITES

Aside from the prolific Upper Cretaceous turbidite sandstone discoveries, the Ranger-1 discovery in the NE portion of the Stabroek licence proved the presence of hydrocarbons in Lower Cretaceous carbonates, deposited on a relic volcano, which is dated as Aptian by Casson et al. (2021). Other volcanic features are noted upon the Demerara Rise. The Joe-1 and Jethro-1 wells drilled by Tullow on the Guyana slope proved the presence of pay in the Paleogene section, but are thought to be sub-commercial. Extending the current extent of proven plays across the margin is dependent upon understanding the distribution of Cretaceous source and reservoir rocks. These are determined by inherited structural features, leading to either preferentially thick deposition, or controlling sediment distribution across the depositional system. In turn, rapid burial is required to lead to generation of hydrocarbons. The Jurassic potential may depend more upon further 3D seismic investigations, which may form part of the work programs in recent auctions. ■



References provided online.

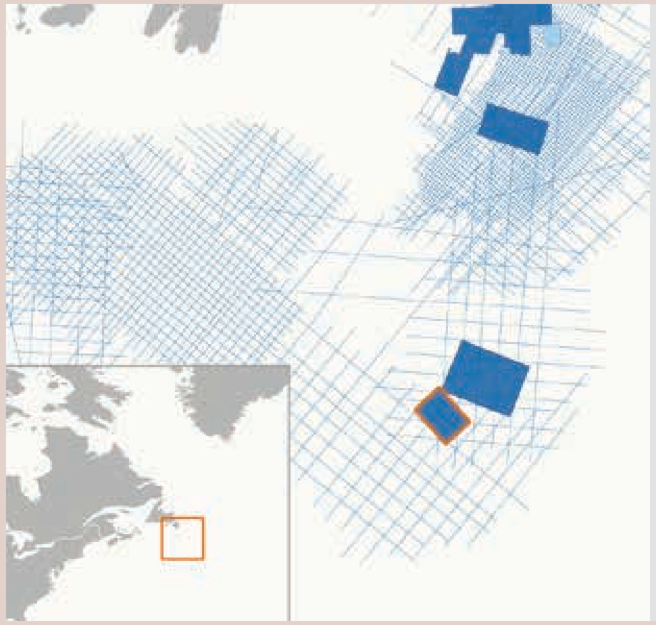
Revealing a promising new play concept in the Salar Basin, offshore Canada



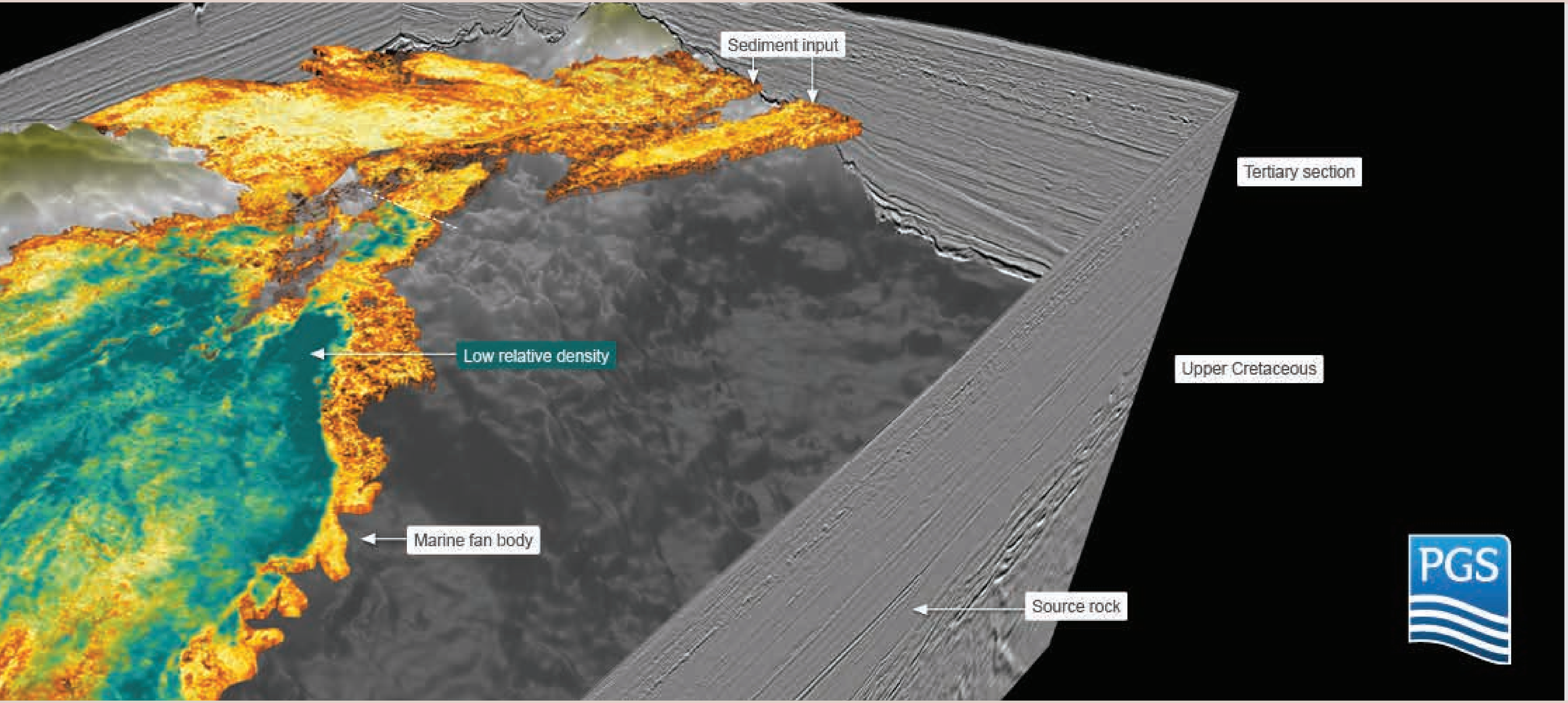
PGS, in partnership with TGS, have been acquiring modern 3D GeoStreamer data offshore Canada since 2015. The South Bank 3D survey was acquired in 2020 over an area of 2,635 km^2 using multi-sensor towed streamer technology with 16 streamers (8 km in length) in the Province of Newfoundland and Labrador.

The survey is located across the eastern slope of Grand Banks in the Salar Basin and enables further investigation of the petroleum system elements which legacy 2D data had already indicated were present and suggested there is a significant exploration potential in the area. A promising new play concept was identified in the Upper Cretaceous to Paleogene slope settings.

The new 3D data was acquired over an extensive clastic fan system and proved that sand reservoirs are present at large scale throughout the Upper Cretaceous to Paleogene sequence. Using a simultaneous inversion of velocity and reflectivity (PGS Ultima) on AVO-compliant GeoStreamer data provides a high-resolution velocity model, with relative impedance and relative density estimates to aid litho-facies classification. In combination, these attributes helped identify the petroleum system elements and support exploration across the area.



Joint PGS/TGS MultiClient data library. The study area is located in the Salar Basin. The South Bank 3D survey is shown in orange.



This 3D display shows a geo-body extraction from the upper marine fan (lobe 3) and its corresponding PGS Ultima relative density response. A pre-existing volcanic ridge controls the sediment input and deposition in this area. The source rock is expected to be present in the deeper part (Upper Cretaceous section). The fan lobe itself is well-developed. PGS Ultima elastic properties (relative impedance and density) help to assess its internal heterogeneity and estimate exploration risk. In this example, low relative density may signal good reservoir quality and possible hydrocarbon presence.

Estimating reliable earth properties using PGS Ultima

De-risking potential prospectivity in frontier areas of Canada's petroleum basins

YERMEK BALABEKOV, SUSANA TIERRABLANCA , SRIRAM ARASANIPALAI AND NIZAR CHEMINGUI, PGS

SEISMIC ATTRIBUTES are widely used in hydrocarbon exploration and play a key role in prospect identification. Pre-stack seismic inversion has typically been the solution to derive earth properties, particularly velocity ratio and reflectivity derivatives, which are then used to calculate various attributes. Traditionally, a sequential workflow using Full Waveform Inversion (FWI) followed by Least-Squares Reverse Time Migration (LS-RTM) has been employed to invert for subsurface velocity and reflectivity models. Recently, PGS introduced a new seismic inversion scheme that combines both inversions into a single process, PGS Ultima. A key aspect of the novel approach is the separation of the low- and high-wavenumber components of the earth model, enabling the simultaneous update of the velocity and reflectivity with minimum crosstalk. The approach is equivalent to performing FWI and LS-RTM simultaneously, where both velocity and reflectivity are continuously updated at each iteration.

The iterative inversion compensates for incomplete acquisitions and varying illumination in the subsurface to provide true-amplitude earth reflectivity.

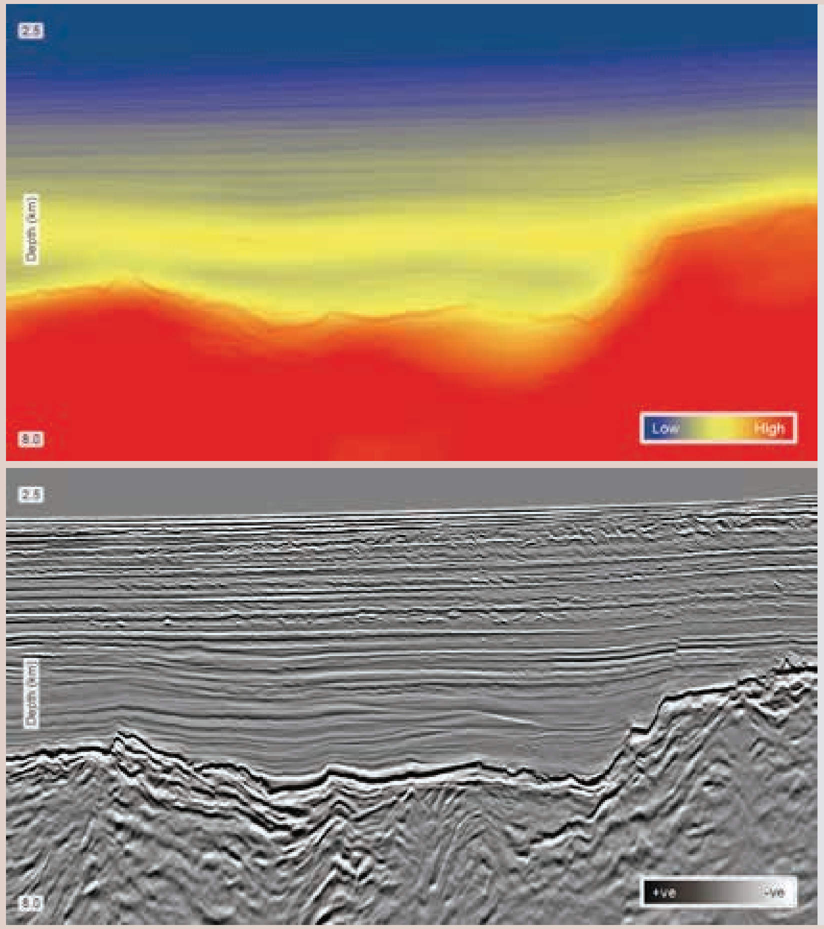


Figure 1: Velocity (left) and Reflectivity section (right) from angle gather output from PGS Ultima. The sections show improved resolution of the velocity in the Tertiary interval (2.5-6 km) and overall good signal-to-noise ratio as well as detail and clear definition of various stratigraphic units in the reflectivity image.

EXTRACTING RELIABLE EARTH PROPERTIES

Using a wave equation parameterised in terms of velocity and reflectivity removes the need for a density assumption in the PGS Ultima multi-parameter inversion process. Velocity and reflectivity outputs from the inversion can in fact be used to extract additional properties, such as relative impedance and relative density, for prospectivity assessment in a reliable and data-driven approach.

INVERSION FOR PRESTACK REFLECTIVITY

The simultaneous inversion workflow has recently been extended to the pre-stack angle gather domain, which is crucial for improving our understanding of subsurface elastic properties. A key aspect of this approach is the extraction of angle information using elements obtained from the solution of the reflectivity-based wave equation.

The inverted velocity and reflectivity models along with the derived relative impedance and density, and inverted pre-stack angle gathers, provide reliable information for subsequent amplitude versus angle (AVA) analysis and quantitative interpretation (QI).

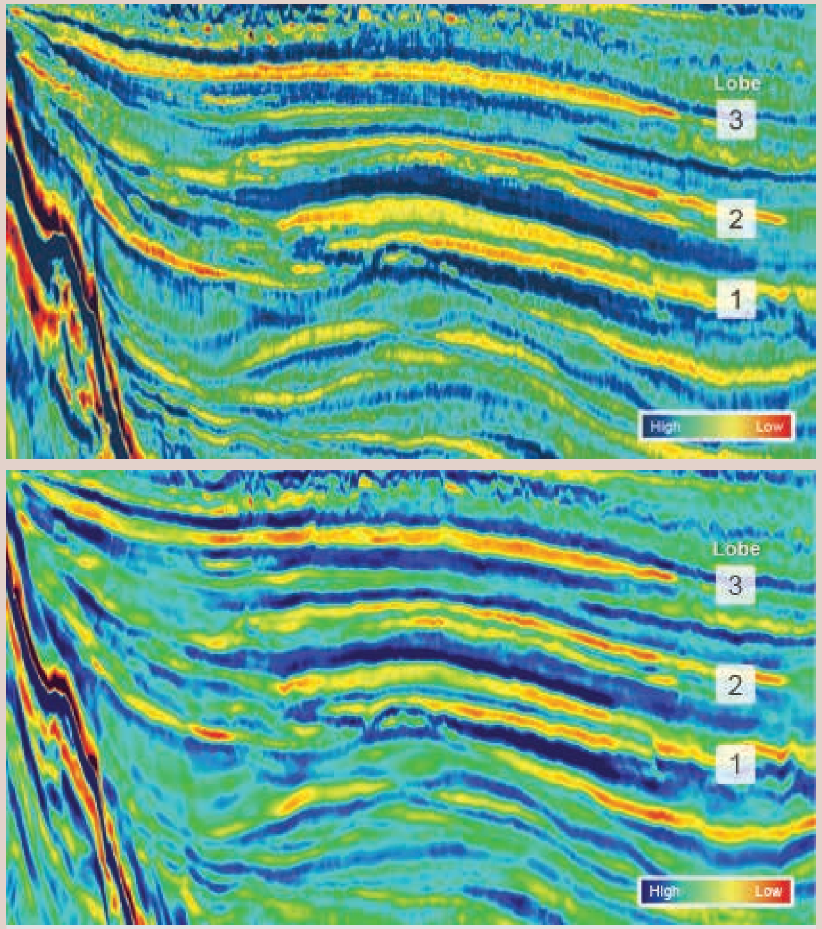


Figure 2: Comparison of relative Vp/Vs from Kirchhoff migration (top) and PGS Ultima (bottom). Note the improved signal-to-noise ratio in the PGS Ultima result. The response of the stacked reservoir units can be seen in both the Kirchhoff migration and the PGS Ultima QI results.

APPLICATION IN A FRONTIER EXPLORATION AREA

PGS' South Bank 3D seismic survey is located in the Salar Basin, which is an Early Cretaceous, isolated rift basin with passive margin fill from Late Cretaceous period and onward. Many fan systems have been identified along the margin using existing seismic data. They are interpreted as Oligocene in age, and the main prospectivity is believed to lie in these fans originating from the shelf and shelf-edge deltas. Class II and Ip anomalies are observed in the reservoir interval, along with class IV responses in the deeper section analogous to a modeled source rock in the region.

Figure 1 shows the PGS Ultima velocity model and stacked reflectivity from angle gather output from the simultaneous inversion. The resolution in the velocity model allows accurate spatial positioning of seismic events, while the reflectivity output aids improved stratigraphic and quantitative interpretation.

The following two figures (Figure 2) represent estimation of relative Vp/Vs ratio over a key prospect, which has three vertically stacked levels. The difference between the images is that the section on the top was produced in a conventional flow using the final and fully processed Kirchhoff migration data, whereas the bottom section is using PGS Ultima angle-dependent reflectivity. Note that the input to PGS Ultima was limited spatially. Yet, the PGS Ultima Vp/Vs response has an improved signal-to-noise ratio and good top and base definition of the layers compared to the Kirchhoff migration output.

A RELIABLE SOLUTION

The simultaneous inversion products, i.e., velocity, angle-dependent reflectivity, and the derived relative impedance and density, improve individual lead evaluation and provide better property constraints for QI analysis and anomaly interpretation. The high-resolution velocity model constrains lithologic relationships in the subsurface, resulting in higher confidence quantitative analysis. As such, PGS Ultima assists in de-risking potential prospectivity in frontier areas of Canada's petroleum basins.

NORTHWEST EUROPE

"There is only one talk on exploration at this UK conference and that is one about the global scene. It is a sign of the times."

Ross Cameron – Serica Energy

Schoonebeek oil production is on hold in the Netherlands - again

Due to water injection issues, NAM is currently unable to continue oil production from the Dutch part of the Schoonebeek field, but the company is working towards a new solution

When looking at a map of the Schoonebeek field, the biggest onshore oil field in NW Europe, one would almost think that the Germans and the Dutch agreed on the national border after the discovery of the field to ensure that both countries would have a slice of this attractive pie. However, that is not the case; when Schoonebeek was discovered in 1943, the boundary between the countries had already been in place for a long time.

Fast forward to today, the field has been independently developed both from the German and Dutch side of the border, using different production strategies. Whilst nodding donkeys have characterized the operational landscape in the German part of the field ever since production started, NAM abandoned this way of production in 1996, only to re-start production from Schoonebeek in 2011 using a system of long horizontal producers and steam injection at the same time.

As Schoonebeek oil comes with a high water-cut of around 90% or higher, the separated water was re-injected in three abandoned gas fields in the Twente area south of Schoonebeek, using an existing 70 km long pipeline to transport the fluids. However, this led to microbially-induced corrosion and the risk of leakage. This was subsequently remediated through the fitting of flexible pipes into the existing pipelines, ensuring minimal disruption and allowing quick resumption of operations.

However, a downhole rupture in the outer casing wall of one of the Twente injection wells was also found. Even though it did not lead to the leakage of fluids, NAM was accused of not picking this up in a timely manner. This helped trigger an outcry of public anger in the Twente area, which ultimately led NAM to stop water injection in August 2021. This also meant that the production of oil from the Dutch part of this major oil field came to a stop. With the Twente area looking increasingly difficult when it comes to re-starting production, NAM is currently looking at re-injecting produced water much closer to the field. The company now aims to drill four new injection wells into Zechstein carbonates below the Schoonebeek Cretaceous oil reservoir. Gas was previously produced from these Zechstein carbonates, so the pressure has depleted significantly, allowing for the injection of water.

The reason why the Schoonebeek field could be developed by two different companies without the risk of interference is the fact that the oil is quite heavy - 25° API. Also, because of the low temperature at a depth of around 700 m where the 20-30 m thick reservoir is situated, any well drilled into the reservoir will not "see" far into the formation and the risk of seizing the neighbour's oil is therefore small.

The Schoonebeek oil field in the Netherlands and Germany.

New pipelines of the NAM Schoonebeek redevelopment in the Netherlands against a backdrop of a typical landscape that is characterised by farmland and wind turbines.

As is so often the case with subsurface activities, the discussion centres around risks. What is the chance that leakage will occur, and what is the probability of induced seismicity? It is no surprise NAM cannot guarantee nothing will happen, but as Manuel Sintubin from Leuven University in Belgium said in a recent interview with Dutch broadcaster KRO-NCRV, when he addressed the risk of induced seismicity being minimal as long as the injection pressure does not exceed the fracture pressure: "This should give people some comfort."

Ultimately, it will be down to the Dutch authorities to approve NAM's plans, but it is clear that even in a village where the oil industry has been a strong partner in the local community, the licence to operate is not a given anymore. ■

PHOTOGRAPHY: HENK KOMBRINK

Sir Keir Starmer's stance is not really that much of a deal for the climate

No matter what happens to the future of drilling in the UKCS, the volumes that potentially can be added through exploration are not significant

TWENTY YEARS AGO, the first edition of Devex took place in Aberdeen. At the time, the conference revolved around extending the life of oil and gas fields. "Not much has changed in that regard", concluded Graham Davis during the opening session in June.

What has changed though is the gradual decline of talks on exploration. As Ross Cameron from Serica noted: "There is only one talk on exploration at this conference and that is one about the global scene. It is a sign of the times." And a takeaway message for Sir Keir.

"There is only one talk on exploration at this conference and that is one about the global scene. It is a sign of the times", said Ross Cameron from Serica during Devex 2023 in Aberdeen.

PHOTOGRAPHY: DEVEX

UNEXPLORED PARTS OF OLD FIELDS

When it comes to extending field lives, there were a couple of good examples presented during the conference. For instance, Rachael Crowe from Apache showed that a reprocessed survey from PGS across the greater Buckland field de-risked a fault panel along the western side of the field. Combined with a dynamic modelling exercise that suggested this panel was probably undrained, a new development well was drilled last year. The well came in to prognosis and has delivered a healthy boost to Buckland's daily production.

Based on this presentation and more of the same kind, Sir Keir could have concluded that drilling activity in the North Sea is really focused on squeezing those last barrels out of mature assets. By doing so, he would not have been too far off the mark at all.

CO_2 FOOTPRINT

David Moseley from Welligence put another perspective on maturing assets in the North Sea. As a result of the rapidly declining production from these fields, the CO_2 footprint per produced barrel across the North Sea will only rise further – from around 50 kg CO_2/barrel to around 100 in the late 2030's. At the same time, new developments such as Cambo or Rosebank are projected to produce around 10 kg CO_2/barrel. In other words, it is the old assets with the big old platforms that form the low-hanging fruit when it comes to reducing emissions related to oil and gas production on the UKCS.

A MORE ROBUST STRATEGY

Based on these observations, it is worth asking the question how much oil and gas is being left in the ground due to a potential ban on future oil and gas licensing. There are regional differences across the UKCS, but the claim that a ban would leave many fields undiscovered is unlikely. It's also what the industry is aware of, given the focus on drilling in core areas in recent years, even decades.

The proposed ban is therefore too late to make a material impact on producing more hydrocarbons from the UKCS. The industry is aware of that, despite all the noise.

Instead, it would be much more effective if Labour had a plan to incentivise cessation of production of the oldest assets whilst keeping the door open potentially find a new field or develop an existing discovery that can be produced at a much more efficient footprint, acknowledging that the UK still needs oil and gas for the foreseeable future. There are recent signs that Keir Starmer is indeed reassessing his initially strong stance on ending oil and gas production from the UKCS. ■

Ampfing's flirt with the subsurface is not over yet

A long history of oil production may now lead to a new chapter of geothermal heat supply for the Bavarian village

There are probably not too many climate activists in the small village of Ampfing in Southern Germany, as the information plaques and monuments dedicated to the local history of oil production look unspoiled. Can you even imagine living on Mobil Oil Strasse – Mobil Oil Street? It is possible in Ampfing.

The village appeared on the exploration radar in the 1950's, when the results of a seismic survey suggested the presence of a valid closure at Eocene level – at a depth of around 2,000 m. Subsequent drilling of the Ampfing-1 well in 1953 proved the presence of oil shows, but it was the second well that brought the success that was hoped for. To mark the discovery, the sandstone in which the oil was found was named the Ampfing Sandstone, which is still known as a stratigraphic name today.

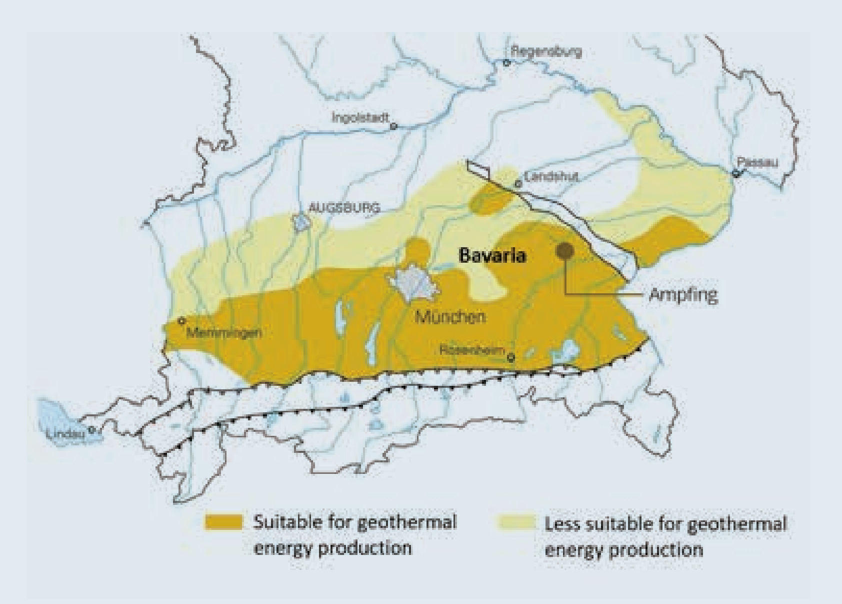
Many more wells were drilled, and as gas was also found, and in surrounding areas, a nationwide gas distribution system was built. This meant that Bavaria could say goodbye to gas generated from coal, which can in some ways be seen as the first step in the energy transition. Over the years, around 26 million barrels of oil and 13.9 billion cubic meters of gas were produced from the Bavarian oil and gas fields together.

Production from most fields started to become marginal in the 1980's and 1990's. Ampfing ceased production in 1987, and most followed in the decade after. That was not the end for Ampfing though, as a new attempt to revive production was made in 2016 when RDG – a spin-off from RAG Austria – drilled a new well into the field. A 3D seismic survey and more wells followed, but the production test in 2020 ultimately put a stop to further development as it was regarded uneconomic in the end.

Yet again, it was not the end of Ampfing's link to the deep subsurface. ONEO – formerly RDG – now aims to produce geothermal energy from the Upper Jurassic Malm that can be found beneath the Ampfing sandstone. To that end, the company aims to deepen one of the wells recently drilled into the field, and the completing of a new one.

A feasibility study has shown that between 19 and 24 MWth could be produced from the doublet, which is certainly a good amount. This is partly thanks to the relatively high geothermal gradient of around 40°C per km and the fact that the Malm carbonates tend to have good porosities and permeabilities in Bavaria. ■

Would you like a house on Mobil Oil Street?



Map showing the southern part of Germany, the village of Ampfing and the areas where geothermal energy production is looking feasible.

SOURCE: ONEO; PHOTOGRAPHY: HENK KOMBRINK

The 19 sanctioned oil and gas projects in Norway

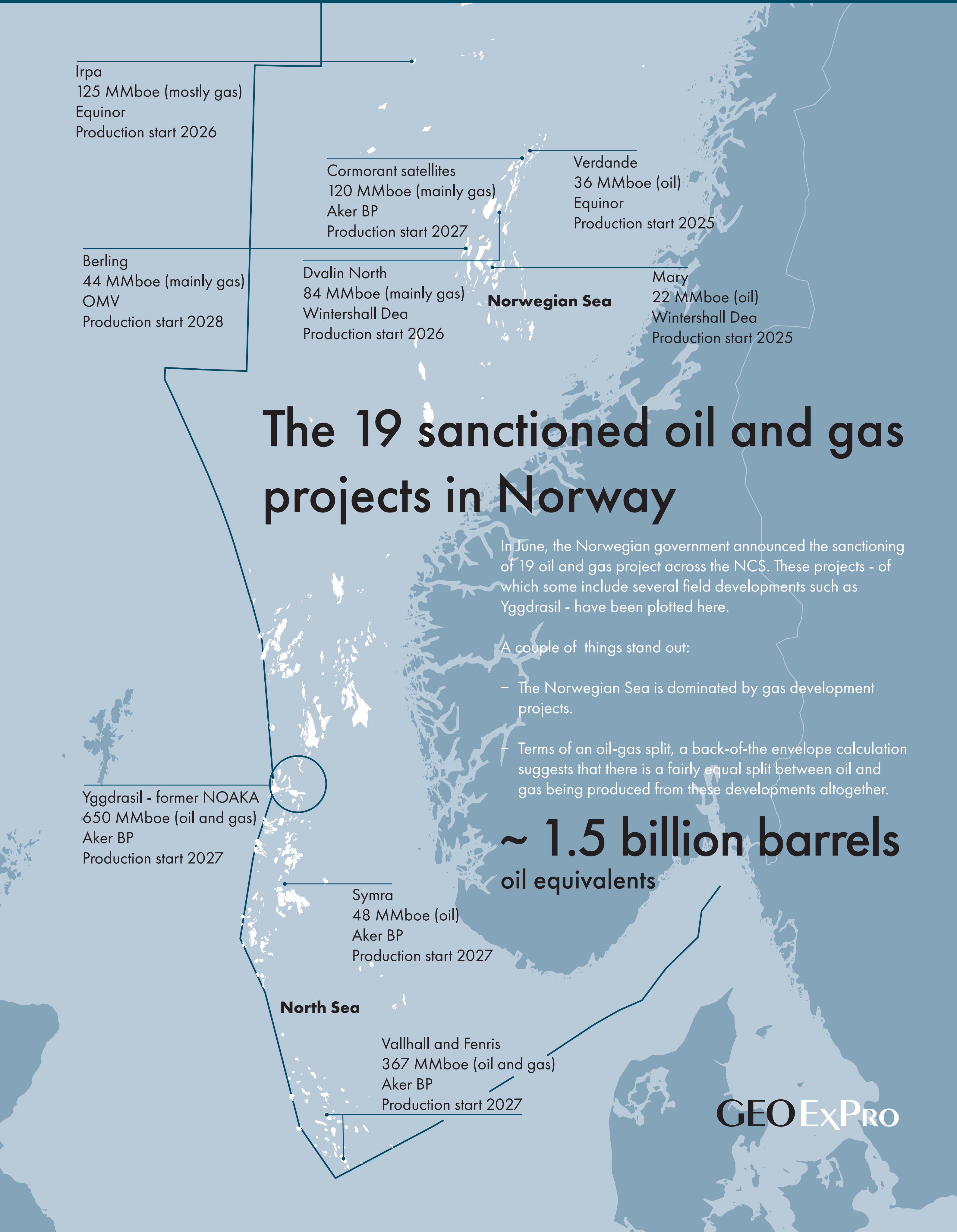
In June, the Norwegian government announced the sanctioning of 19 oil and gas project across the NCS. These projects - of which some include several field developments such as Yggdrasil - have been plotted here.

A couple of things stand out:

- The Norwegian Sea is dominated by gas development projects.
- Terms of an oil-gas split, a back-of-the envelope calculation suggests that there is a fairly equal split between oil and gas being produced from these developments altogether.

~ 1.5 billion barrels

oil equivalents



FEATURES

"Ignoring the fact that the same stratigraphic unit at two different locations can have a very different seismic amplitude response can lead to inaccurate, misleading, and sometimes wrong conclusions."

Åsmund Drotting – DIG Science

DE-RISKING GAS SATURATION

A case study from Julimar field offshore Australia illustrates the benefits of using advanced geophysical methods to differentiate between low and high-saturation gas

SAID AMIRI BESHELI, KUFPEC, AND PANOS DOULGERIS, DELFT INVERSION

Conventional workflows such as near versus far amplitudes or linear inversions often fail to differentiate between low and high-saturation gas reservoirs, mainly due to the relative lack of sensitivity to saturation. Often, this is complicated further by the presence of multiple scattering that tends to take its toll on the quality of far-offset data.

This issue has been a particular problem on the NW Shelf of Australia, where a number of wells were drilled in the Julimar field in an attempt to further prove commercial gas volumes at different levels of the productive interval. The results of some of these wells indicated only residual gas at a particular reservoir unit where commercial gas saturations were anticipated.

In order to better differentiate between low- and high-saturation gas accumulations and prevent drilling low-saturation gas reservoirs, KUFPEC who is a partner in the Julimar field contracted Delft Inversion to deploy its innovative methodology called WEB-AVO – Wave Equation Based AVO Inversion.

WEB-AVO METHOD

WEB-AVO inversion is a unique approach, not only because it includes interbed multiples, mode conversions and transmission effects, but also because it derives compressibility from seismic data directly. Compressibility is the reciprocal of bulk modulus and it proves to be notably more sensitive to saturation changes within the reservoir when compared to properties derived by conventional inversion (e.g. acoustic impedance, lambda-rho, etc.).

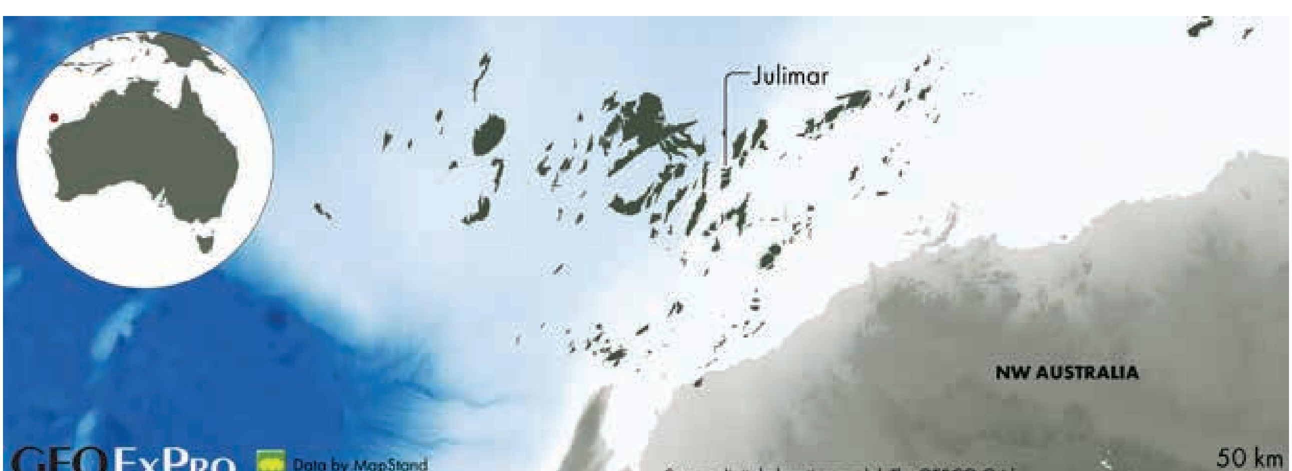
The WEB-AVO inversion technique belongs to the class of elastic Full Waveform Inversion (eFWI) methods. Simplified to 1.5D, assuming a locally stratified earth model with migrated seismic gathers as input, this allows a very non-linear inverse problem to be solved efficiently with modest modern computational resources.

The elastic wave-equation is solved iteratively with each iteration of adding an order of scattering, until convergence between the synthetic model and the input seismic is reached. In this way, multiple scattering, mode conversions and transmission effects over the target interval are properly accounted for while mitigating well-known challenges, e.g. cycle skipping and local minima, of global FWI schemes.

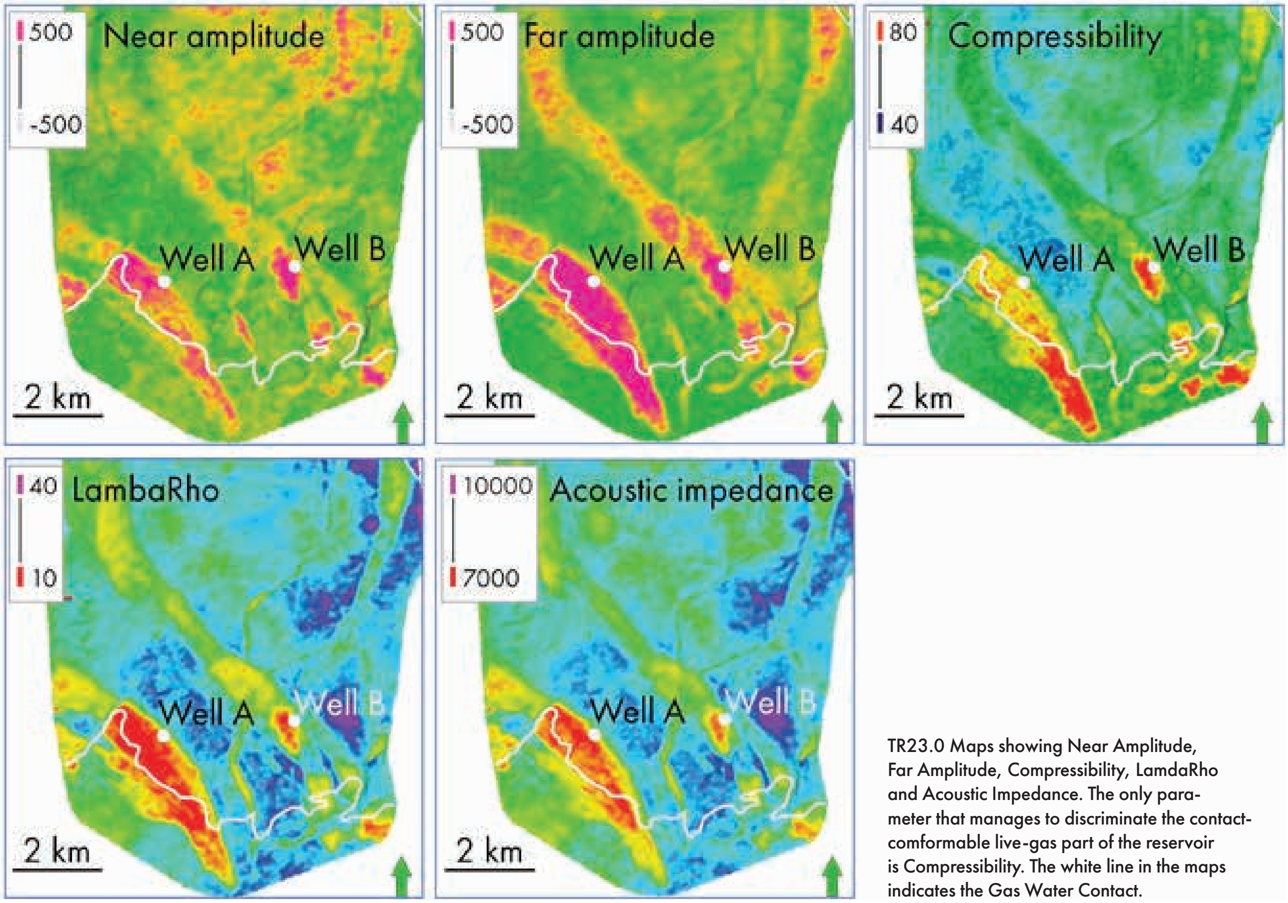
One of the unique features of the methodology is that it solves directly for the reciprocals of bulk and shear moduli, compressibility (k) and shear compliance (M), instead of conventional parameter sets like acoustic and shear impedance. k is the compressional product of WEB-AVO inversion and it is constrained by the near-mid offsets and the travel times of seismic events. It is also very sensitive to saturation changes, making this the ideal combination for attacking the residual gas challenge.

THE JULIMAR FIELD

Julimar was discovered in 2007 by Apache and was developed jointly with



Location map of the Julimar Field off Northwest Australia.



TR23.0 Maps showing Near Amplitude, Far Amplitude, Compressibility, LamdaRho and Acoustic Impedance. The only parameter that manages to discriminate the contact-comformable live-gas part of the reservoir is Compressibility. The white line in the maps indicates the Gas Water Contact.

the Brunello field a little further to the northeast. Both fields are situated in the Carnarvon Basin on the prolific Northwest Shelf of Australia.

The reservoirs of Julimar are of Upper Triassic age and belong to the Mungaroo Formation. The sandstones were deposited in a low-relief alluvial plain, where individual sandstone units can be interpreted as amalgamated channel bodies. Seismic data allows the interpretation of individual units and shows the southeast-to-northwest trend of the larger individual sandstones and a north-south trend of smaller fluvial sandstones.

The sandstones are separated by mudstones, which has resulted in a complex and compartmentalized setting of gas-filled, water-wet and sandstones characterized by residual gas, all sharing a similar AVO signature. Here, we take a closer look at one of the reservoir levels in Julimar, which is identified as TR23.0 and is one of the approximately 13 reservoir units that is being recognized in the field.

DRILLING WELLS

Well A and Well B were drilled to test the multiple fluvial stacked reservoirs including the sands in the TR23.0 interval. As can be seen on the Near and especially the Far Amplitude maps, the channel system in TR23 can be interpreted quite easily; the red to orange colours on both maps indicate sandy facies. However, are the Near and Far Amplitude maps or the elastic properties produced by linear inversions a good indication of gas being present in these channel sands? The results of the wells suggests not so, as only residual gas was found in the TR23.0 sands in both wells.

Instead, the Compressibility feature is able to distinguish between high- and low-saturation gas much better, as indicated below. The red tones in the map are areas of high compressibility, which corresponds to areas above the Gas Water Contact (GWC) that was subsequently mapped for this TR23.0 unit. The GWC is indicated by the white line in the Compressibility map.

On that basis, it can be concluded that Well A was drilled too far to the north; it would likely have found a high-saturation gas column when positioned a little further to the southeast. Well B can be seen skimming a small high-saturation gas pool, which even when it was hit would not have been economic to produce.

In conclusion, WEB-AVO Inversion forms a new generation of elastic seismic inversion techniques which based on the advanced physics used, presents the ability to improve the dynamic range of the saturation signature as well as the proper handling of multiples and non-linear wave propagation elements which help discriminate low from high-saturation sands and therefore assist in de-risking future drilling targets. ■

DID YOU KNOW THAT ROCKS HAVE MEMORY?

If you don't account for this, how can you trust the AVO results when de-risking and maturing leads and prospects?

ÅSMUND DROTTNING, PER AVSETH AND TORE NORDTØMME HANSEN, DIG SCIENCE

THE SEISMIC SIGNATURE of a sedimentary rock is strongly influenced by the geological history of the rock, e.g., the depositional environment, whether it has experienced tectonic burial and uplift, etc. These processes have direct impact on mineralogy, degree of sorting, amount of compaction, amount of cementation, degree of chemical alterations, forming of fractures, etc., and is what we term the "memory of the rock". This means that the same stratigraphic unit at two different locations can have a very different seismic amplitude response if the burial history changes between these two locations. Ignoring this fact can lead to inaccurate, misleading, and sometimes wrong conclusions from the seismic amplitude data analysis. Here we outline a workflow for consistent integration of the burial and diagenetic history of a sedimentary rock into quantitative seismic data analysis through consistent use of rock physics models.

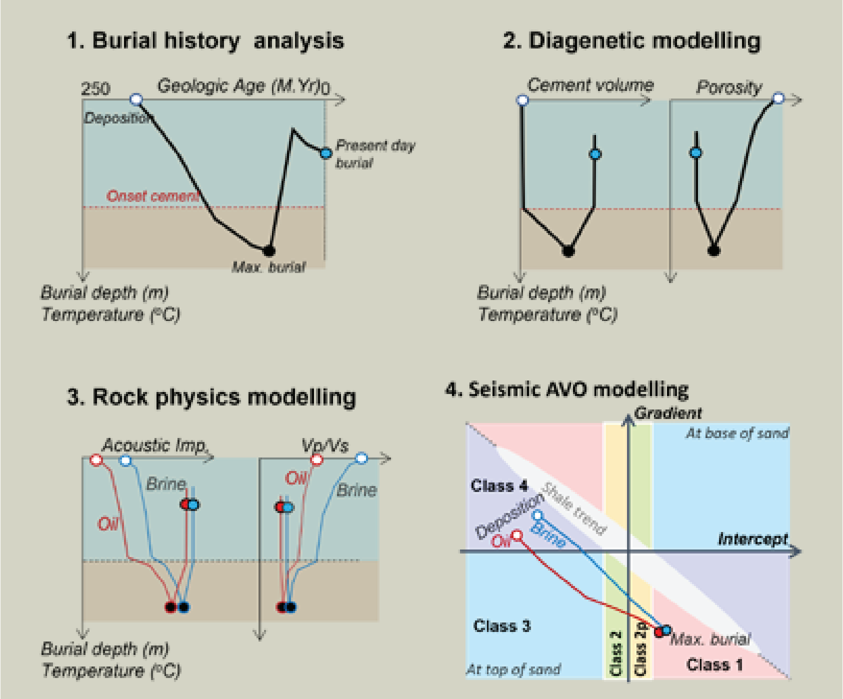


Figure 1. Schematic view of the AVO feasibility workflow. Figure modified from Avseth and Lehocki (2016).

BURIAL HISTORY OF A CLASTIC SEDIMENTARY ROCK

We can divide the burial history of a sedimentary rock into the following domains:

1. Deposition / near surface domain
2. Mechanic compaction domain
3. Chemical compaction domain
4. Deeply buried and subsequently uplifted domain

A seismic response is not caused by contrasts in the geological properties, but by the contrasts in the seismic properties associated with the geological properties, e.g., contrasts in P- and S-wave velocities and density. Therefore, the workflow needs to describe the impact each of these domains will have on the seismic properties of the rock.

Different lithologies, such as sandstones and shales, have different responses to the different domains. Subsidence of a sandstones will cause a gradual stiffening of the rock texture primarily due to sorting, packing, and crushing of the mineral grains. This will reduce the porosity and gradually increase the seismic velocities and density.

A more dramatic change in elastic properties occurs when the quartz-rich sandstone enters the chemical compaction domain around 70°C, i.e., it is heated enough for quartz cementation to start. Even a small amount of cement at grain contacts is known to drastically stiffen the rock, and consequently increase the seismic velocities. The amount of cement is a function of the time spent in the chemical compaction domain; both during burial and uplift.

Finally, subsequent tectonic uplift with possibility for erosion and stress release may cause fractures and cracks in the cemented sandstone creating increased variability in rock texture and pore shapes.

On the other hand, shales are typically deposited as randomly oriented clay platelets with high porosity. This is an unstable structure that quickly collapses during mechanical compaction, with drastically reduced poros- ▸

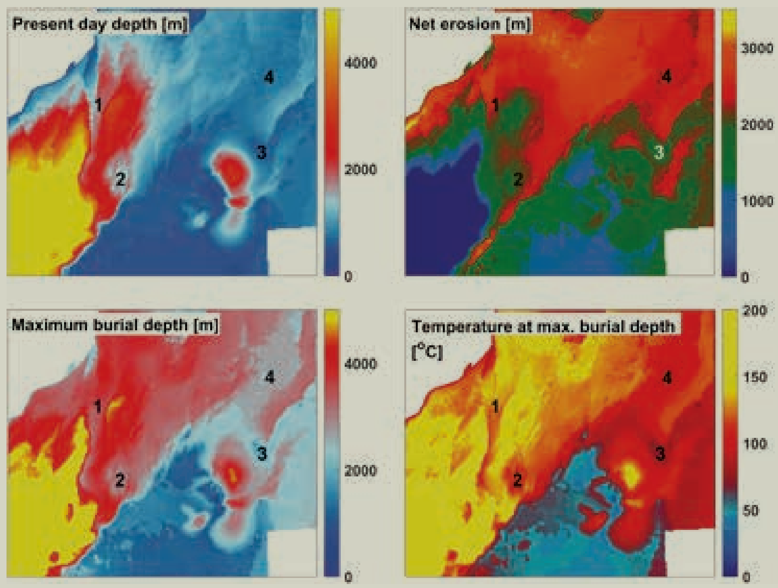


Figure 2. Property maps generated by the burial history analysis and diagenetic modelling. These will be used as input to the rock physics and seismic AVO modelling. Figure adapted from Avseth et al. (2020).

ity and increased seismic velocities and density as consequences. Alignment of the platelets will also make the seismic velocities dependent on the angle of the seismic wave relative to the alignment of the platelets, i.e., anisotropic velocities.

Chemical compactions for shales occur at higher temperatures than for sandstones, typically in the interval 80-140°C, and are characterized by mineralogical transformations. One example is how smectite is altered to illite causing an increase in the seismic velocities.

THE ROCK PHYSICS LINK BETWEEN BURIAL HISTORY AND SEISMIC PROPERTIES

The physical link between burial history and seismic response is described by a rock physics model. For a rock physics model to be credible, it needs to capture not only the present-day geological characteristics of the rock, but also needs to be consistent with the "memory of the rock". In addition, the rock physics model must remain consistent with the underlying physics of seismic wave propagation in complex heterogeneous media. This means that there is not a single rock physics model to be used throughout the burial history of a sedimentary rock, but rather a group of models to be used in each domain of the burial history.

An integrated modelling workflow has been developed to mimic how rock properties and associated seismic signatures change with the burial history. It can be used to investigate the feasibility to distinguish between different lithologies and pore fluids using seismic amplitude data. The main steps of the workflow are outlined in Figure 1.

The workflow starts with burial history analysis at the key wells, constrained by basin modelling, seismic interval velocity data, and petrophysical and geochemical data. Uplift and associated net erosion are estimated from seismic interval velocities calibrated to well log observations. This enables us to predict porosity and cement volume as a function of geological age. These parameters are subsequently put into the appropriate rock physics model to predict the seismic property curves that correspond to the burial history curve. Finally, the seismic AVO signature is predicted by seismic modelling and can be displayed as intercept-gradient data. Seismic signatures are often shown as AVO classes defined from the intercept-gradient cross-plot, being an efficient way of scanning for seismic anomalies of geological interest. ▸

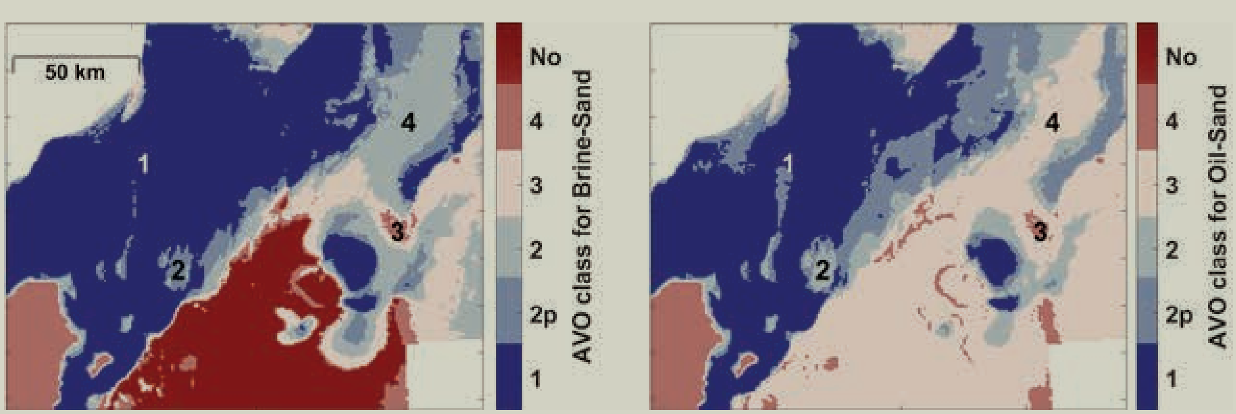


Figure 3. The results of the seismic AVO modelling can be displayed as maps over expected AVO class for the different pore fluids at the target surface. Figure adapted from Avseth et al. (2020).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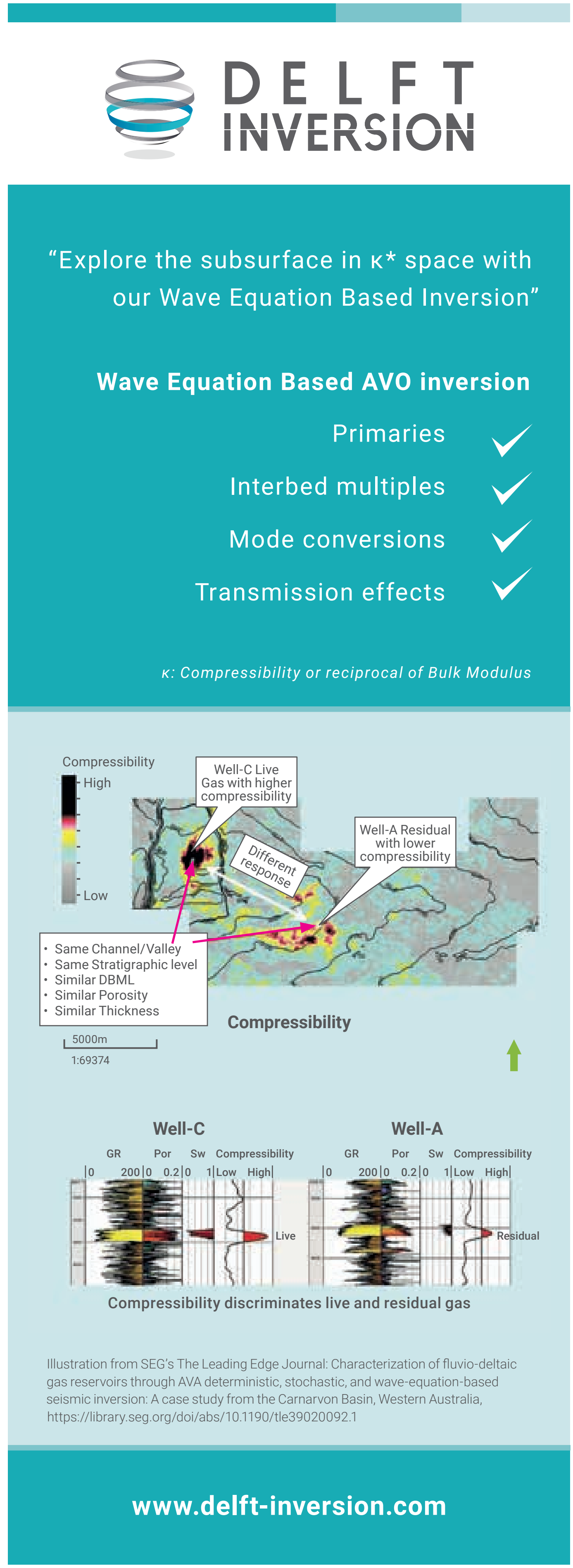
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Compressibility
High
Low
Well-C Live Gas with higher compressibility
Different response
Well-A Residual with lower compressibility
• Same Channel/Valley
• Same Stratigraphic level
• Similar DBML
• Similar Porosity
• Similar Thickness
Compressibility
5000m
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Well-C
GR Por Sw Compressibility
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Live
Well-A
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Residual
Compressibility discriminates live and residual gas
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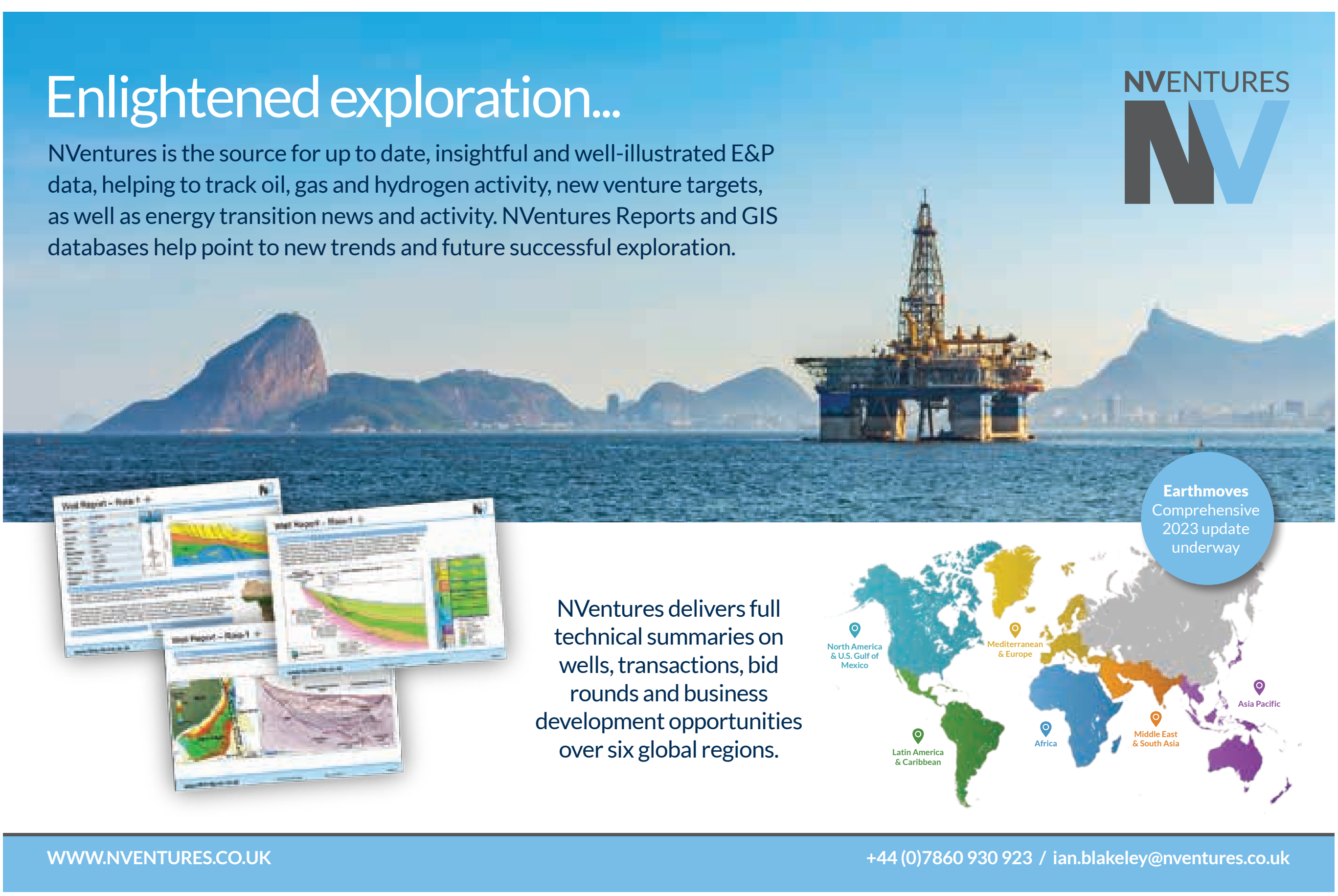
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An interactive tool has been developed specifically to calibrate the workflow parameters at well locations, and to validate the predicted burial history curve and associated seismic parameters and signatures. This also allows us to vary the burial history and automatically see the response in the diagenesis, the elastic rock properties, and the seismic signature. Performing sensitivity tests are important for evaluating the uncertainties of the workflow.

Having validated the input parameters, the workflow can be run in the whole area of interest. The results from are here presented as maps for a target surface (Figure 2). Note how the temperatures at maximum burial depth vary, implying that the degree of chemical compaction and quartz cementation will vary accordingly. In some areas, the target surface has not reached temperatures high enough to set off chemical compaction, and we should then expect unconsolidated sands.

The final step of the workflow is to predict the seismic signatures for the target formation assuming different pore fluids to be present (Figure 3). In prospect 1 we find AVO class 1 for both oil and brine saturated sandstones. It will therefore not be possible to discriminate between the pore fluids at this location, probably due to the overlap in the elastic properties of the stiff cemented sandstone. However, in prospect 3 the seismic signature can still be quite different between brine and oil even though they belong to the same AVO class. In prospects 2 and 4, the seismic signature falls in different AVO classes depending on the pore fluid, indicating that there is high likelihood of separating between a brine- and an oil-filled sandstone at these locations using seismic amplitude data.

The AVO feasibility workflow can easily be run with many scenarios to evaluate the stability and the sensitivity of the predicted properties to uncertainties in the burial history analysis and the geological features being used in the analysis.

DRAWING MORE ACCURATE CONCLUSIONS

Future subsurface exploration and maturation will likely need to focus on increasingly more subtle traps with subtle seismic signatures, e.g., located down-flank or up-dip from drilled/explored structures. Knowing which seismic amplitude signature that are associated with the different lithologies and fluids is essential for doing reliable geological interpretation of seismic amplitude data.

We have described a workflow that reduces the risk of drawing inaccurate or erroneous conclusions from seismic amplitude data, by considering the burial history of the formations of interest and integrating it with diagenetic, rock physics and seismic modelling. ■

PRODUCTION ALLOCATION AND FLUID FINGERPRINTING IN CONVENTIONAL RESERVOIRS

Production allocation via geochemical fingerprinting, in conventional reservoirs, relies solely upon collection and analysis of fluid samples. Deployable across most fields, and at a fraction of the cost compared to mechanical meter-based methodologies, it is surprising how underutilised this methodology is

CRAIG D. BARRIE AND ERIC MICHAEL, APT

Geochemical fingerprinting for production allocation of oil, gas or water is a well-established workflow in conventional reservoirs for both subsurface and topside facilities applications that have been in existence for more than 30 years. During this time various analytical methods, data pre-processing and treatment approaches have been applied. Geochemical methods utilise the 'natural' tracers, e.g. fingerprints, preserved within fluid samples as opposed to requiring the introduction of 'artificial' tracers into the wells, although in many projects the two methods are complementary.

Deployment of fluid fingerprinting workflows is underutilised in major plays globally. The reasons for such limited deployment are variable but often stem from a lack of knowledge around geochemical approaches and a general misunderstanding of geochemistry as exclusively an 'exploration/appraisal' workflow.

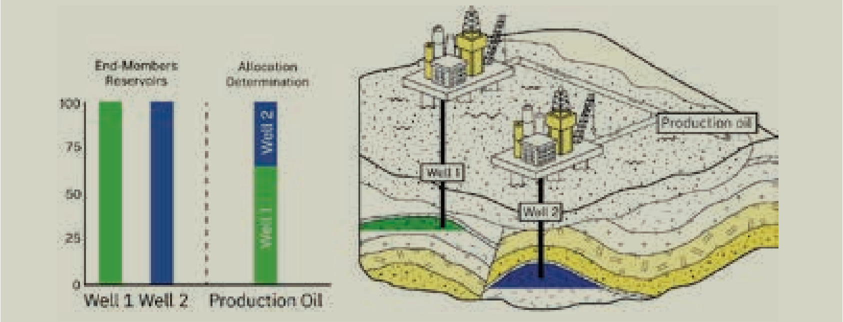


Figure 1: Schematic example of allocation determination from two 'discrete' reservoirs producing to a single pipeline in a conventional field.

The benefits of geochemical fingerprinting-based methods are low cost and the fact that no intervention is required to the production of hydrocarbons from a well. In addition, the methodology is applicable to a wide range of fields, irrespective of pressure, temperature, reservoir quality and reservoir fluid type.

Geochemical fingerprinting approaches require a minimum level of sample availability or data to proceed: Representative end-member samples from individual wells or reservoirs taken prior to commingling, and end-member fingerprints that are sufficiently discrete to ensure unmixing is feasible and valid.

Therefore, by far the biggest challenge to the success of production allocation projects is access to representative end-members from which allocation work can be undertaken. Where geochemical approaches are considered early, during initial development, end-members are much more readily accessible. However, when this approach is an afterthought, then end-member availability becomes much more challenging. Hence, the earlier this approach is considered the better the chance of its successful deployment.

OTHER WAYS TO ROME

Other avenues for accessing end-member samples exist, including public or proprietary databases as well as operators who may have sampled, and stored, the same or equivalent reservoirs. These

WHAT IS PRODUCTION ALLOCATION?

Production allocation is generally defined as the quantitative determination of the amount, or portion, of a commingled fluid that can be assigned to two or more individual fluid sources, also referred to as 'end-members'. In conventional reservoirs, allocation is commonly utilised for assigning contributions into a pipeline from multiple wells, reservoirs and/or fields (Figure 1). Allocation contributions are representative of the time at which commingled wells are sampled, they are a snapshot in time, whereas evaluation of changes in contributions through time is generally referred to as time-lapse geochemistry (TLG) or production monitoring.

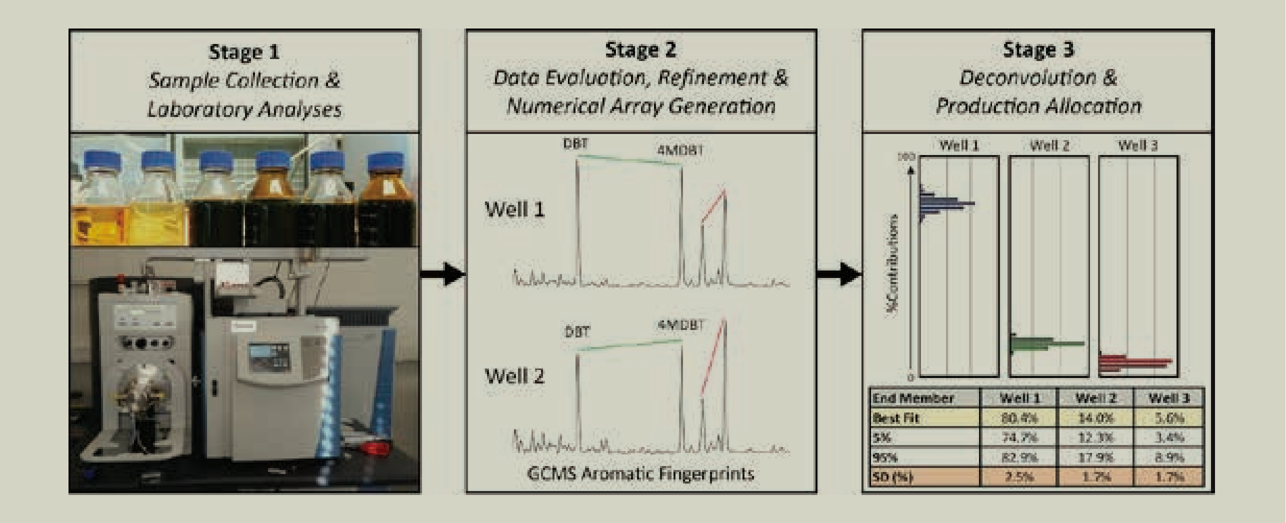


Figure 2. Standard Workflow for Production Allocation Studies. (1) Design, collection & analyses of samples; (2) Data review, evaluation & reduction to the 'best' features; (3) Contribution determination & uncertainty estimation.

avenues offer additional potential routes to ensure all end-members are analysed while also offering opportunities to evaluate any variability within end-member reservoirs themselves.

Care must be taken during sample collection, both for end-members and commingled production, to ensure good sample handling procedures and minimal contamination with oil-based drilling fluids (OBM). Both of these factors can potentially restrict the analytical approaches available and, in some cases, invalidate the use of crucial, if not irreplaceable, samples.

A successful production allocation study, once samples have been collected, consists of three stages:

- Determination of differences in the chemical composition of the end-member samples – and subsequent commingled samples – through identification of the appropriate analytical approach by using, for example, Gas Chromatography (GC) or Mass Spectrometry (MS);
- Data selection, pre-processing (e.g. selection of ratios & concentrations of components) and statistical treatment to build and refine the numerical array for deconvolution;
- Determination of end-member contributions by solving equations (e.g. least squares best fit) and uncertainty estimation

NO "ONE SIZE FITS ALL" APPROACH

The primary output from this workflow is end-member contributions (e.g. %A, %B, etc), along with an uncertainty estimate (+/- 5%). The level of uncertainty that should be expected in conventional projects varies – due to a wide array of project-specific factors – but with good separation of valid and discrete end members, less than 5% should be possible.

In conventional projects, uncertainty is primarily tied to the inherent variability associated with the analytical approach utilised, which in itself is selected to maximise end-member definition. There is no 'one size fits all' analytical approach; different analyses are more appropriate for certain basins or fluid types (e.g. gas, condensate, black oil, biodegraded oils) than others, a point noted consistently across the literature on geochemical allocation workflows.

By far, the most common analytical approach for conventional allocation projects is whole oil and gas chromatography (GC). This is the most cost-effective analytical approach and generally requires no sample preparation, meaning data can be collected and evaluated rapidly. Deconvolution utilising GC fingerprints is possible and has been extremely successful in many projects.

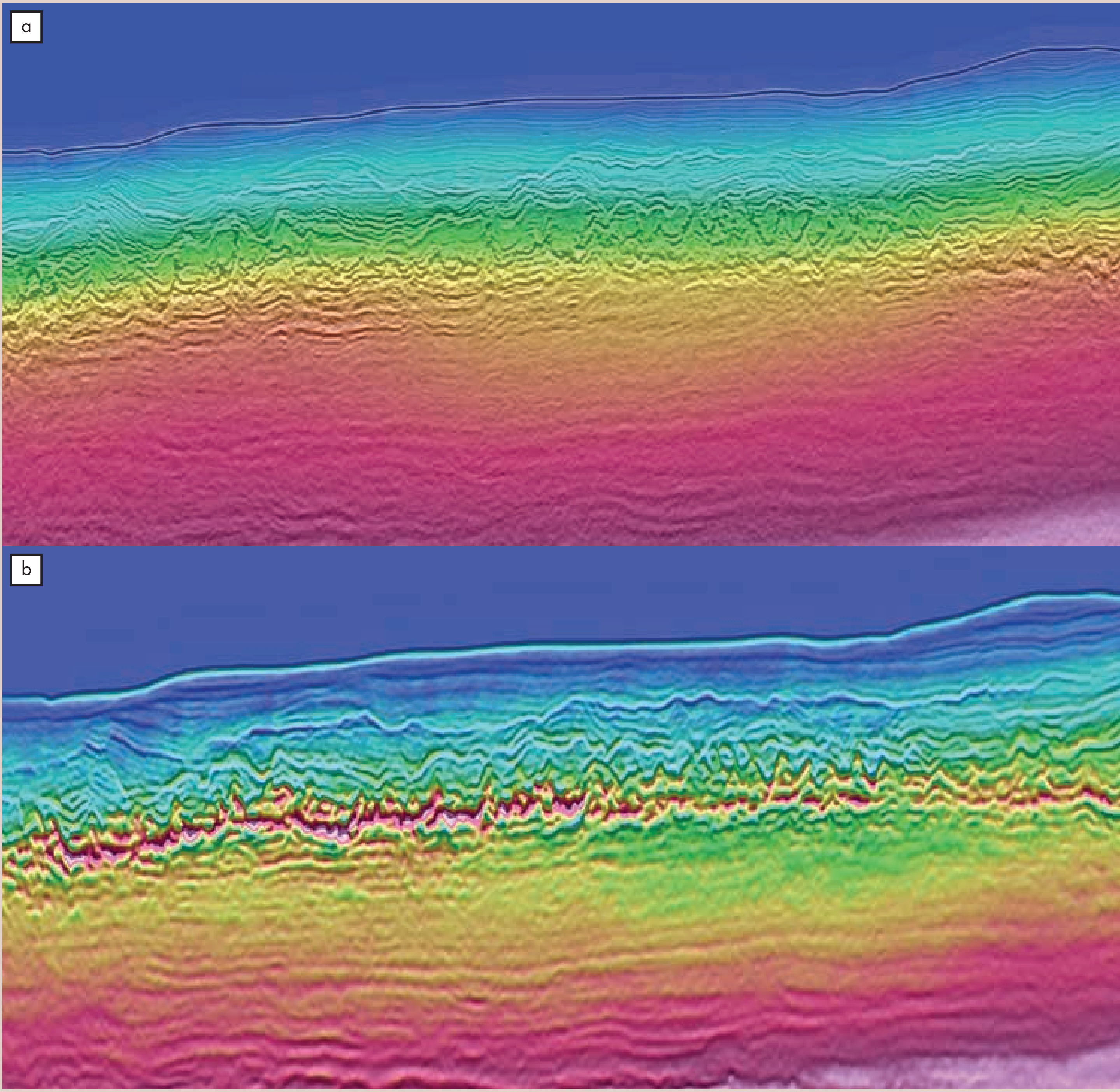
In some cases, this analytical approach may prove insufficient in definitively separating 'end-member' fingerprints to the extent needed for allocation. Other possible challenges are that this method is readily impacted by the presence of drilling fluid contamination, sample handling procedures, and biodegradation, potentially restricting the range of compounds available for fingerprinting and subsequent allocation.

HEAVIER COMPOUNDS

Where GC approaches alone are insufficient, gas chromatography mass spectrometry (GCMS) methods are generally the next logical analytical approach. These analytical methods are less impacted by contamination and sample handling processes as they are focused on the heavier, C15+ compounds. The specific MS approach adopted is guided by a range of project, basin and formation specific factors including information on thermal maturity and organofacies.

Although challenges exist, primarily around viable end-member acquisition as discussed previously, production allocation via geochemical fingerprinting is a cost-effective approach, relying solely on the collection of fluid samples. These workflows are deployable across most fields, can be adapted to meet most project challenges, and are comparable to mechanical meter-based methodologies at a fraction of the cost. ■

FWI Imaging under complex geological anomalies



Full Wave Inversion (FWI) delivers added value and detailed velocities enabling direct extraction of seismic images for improved interpretability and decision-making. In this example from offshore Liberia, FWI Imaging was used to address the the shallow turbiditic setting that generates signal absorption and scattering, diminishing the image resolution and amplitude continuity of traditional seismic imaging.

We would like to thank TGS management and NOCAL, National Oil Company of Liberia, for permission to show the seismic data used here.

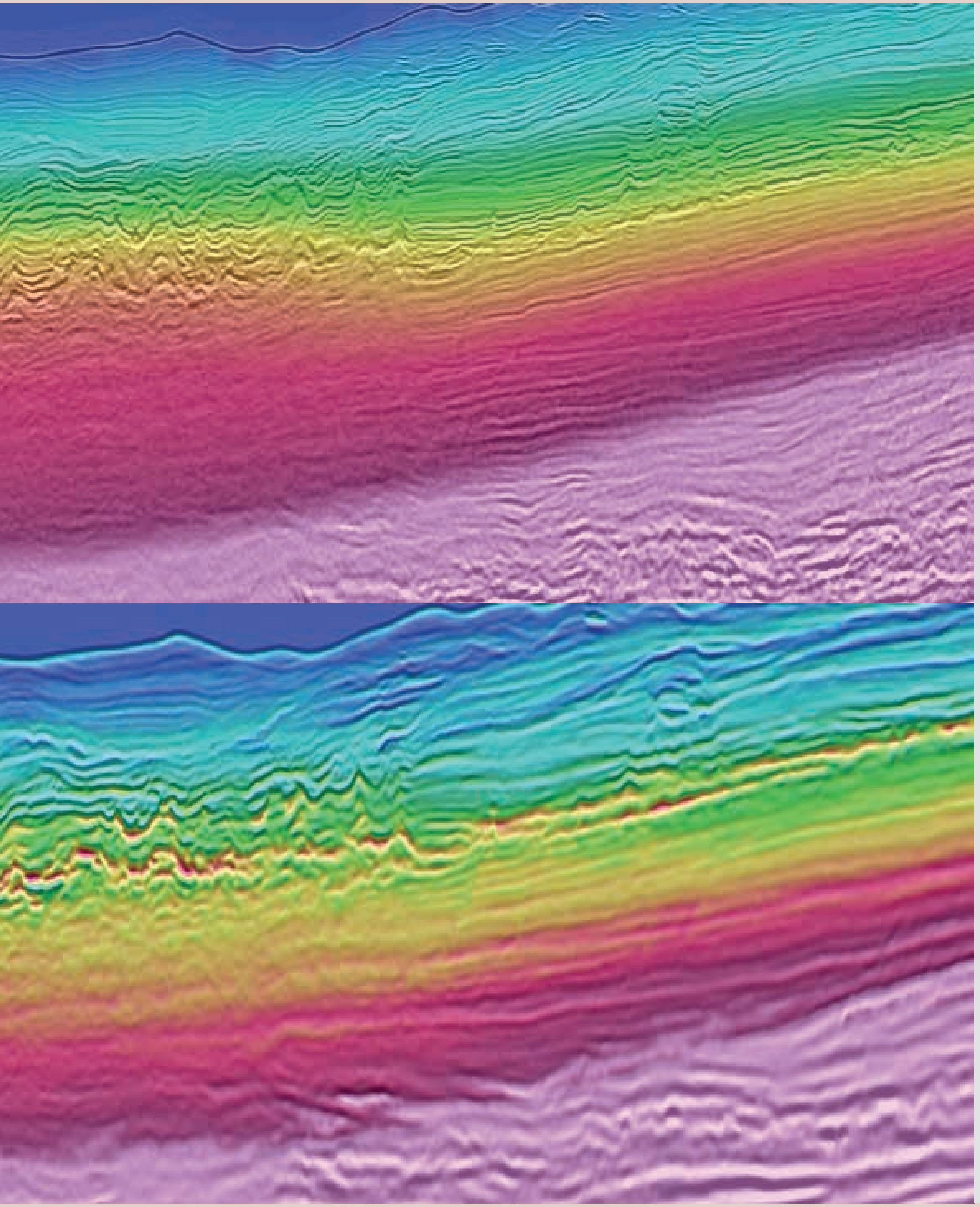
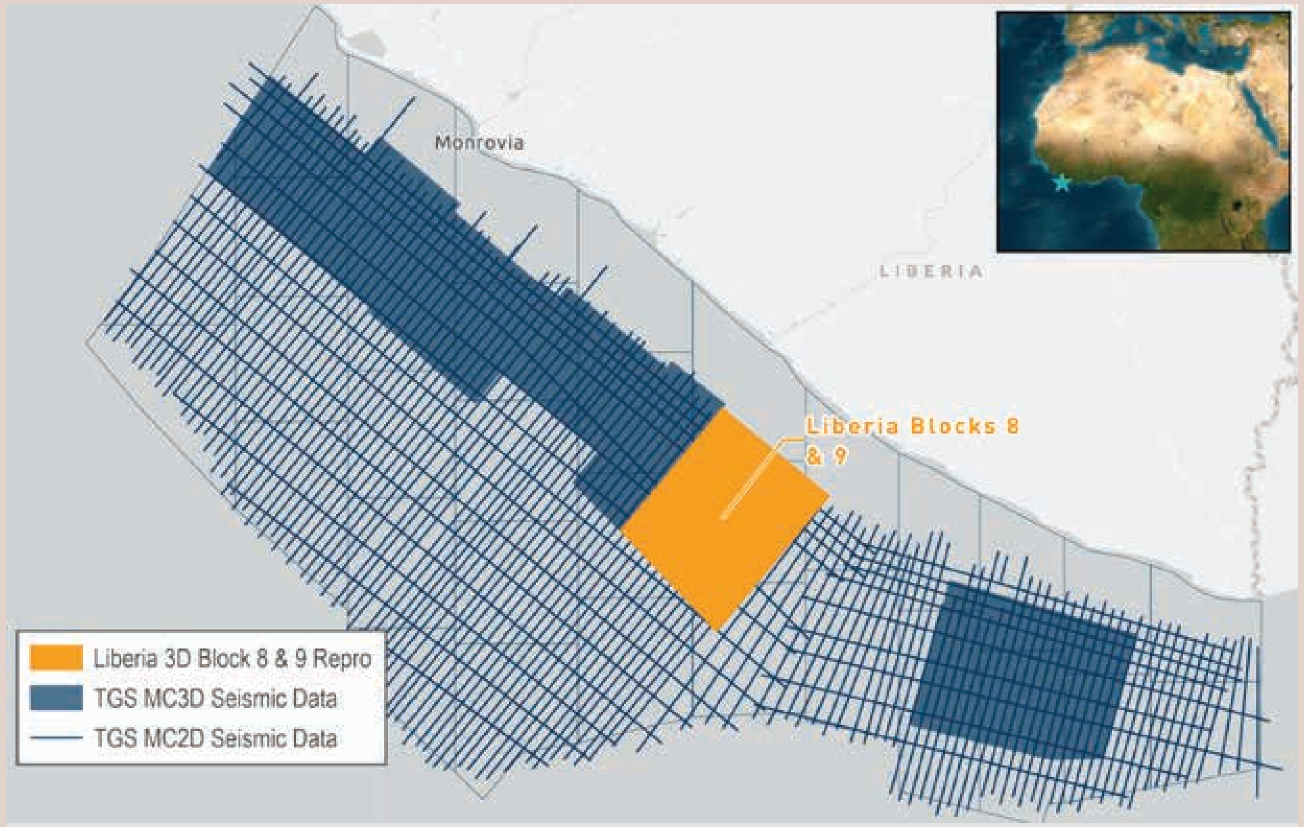


Figure 1:) Original Kirchhoff PSDM line (no deghosting applied) from 2010 verlaid with the tomography-based velocity model from 2010 (the mass transit complexes in the shallow section generate signal absorption and scattering); b) Latest 2023 hi-res DM FWI(40Hz) derived velocity model and associated FWI Image (enhanced image resolution with increased S/N, better illumination, and improved amplitude consistency).



Map of Offshore Liberia with project location in orange

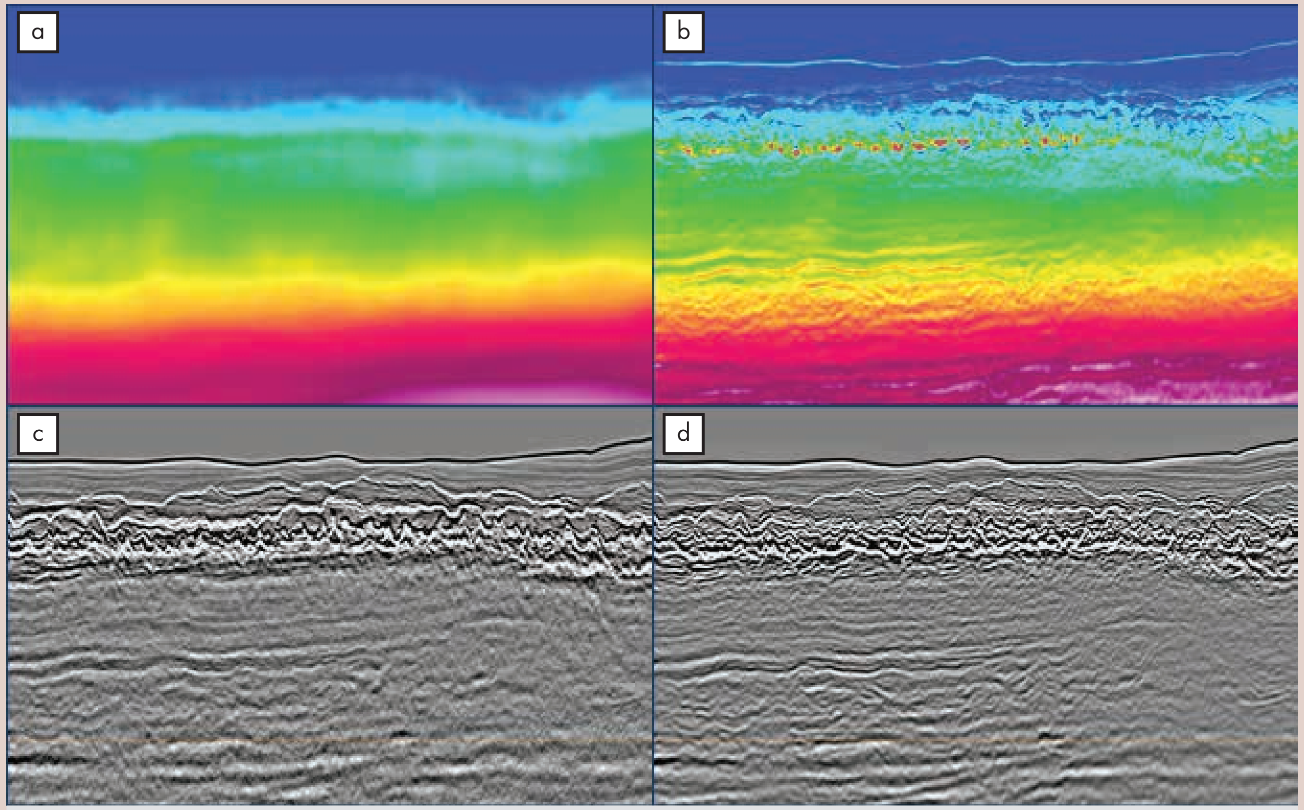


Figure 2: a) Tomography and 15Hz DM FWI (refraction) velocity model; b) Additional higher frequency DM FWI run up to 40Hz (reflections and refractions) build a more detail and geologically consistent model; c) 3D Kirchhoff migration using the model in (a); d) FWI image using model in (b).

The evolution of FWI Imaging technology

ADRIANA CITLALI RAMIREZ, SIMON BALDOCK AND STUART FAIRHEAD, TGS

FWI IS A SOPHISTICATED model-building technique.This method has traversed a remarkable journey, from its nascent stages in the 1980s to its near failure around 2000, battling with limited computational capabilities. With the exponential growth in computational power over the years, FWI has experienced significant advancement and a place as a vital model-building technology in current workflows.

About 15 years ago, work on FWI increased dramatically. Development efforts were focused on employing acoustic FWI as a complementary velocity model building (VMB) tool. Over time, it has aided in generating better-focused images of subsurface features by utilizing more waveform information recorded by seismic receivers (phase, amplitude, and different types of waves) than traditional methods such as tomography. Recently FWI's capabilities have expanded even further, transforming it into a technique capable of generating interpretable models that could start to be cross-validated with data from well measurements. In addition, the acoustic approximation is being changed to elastic FWI with a better theoretical agreement with the nature of field seismic data. All this is bringing new levels of confidence to FWI-derived models.

Today, we are creating derivative products of FWI to allow direct extraction of seismic images. These images, FWI-derived reflectivity, are providing complementary views of the subsurface to the standard images produced with seismic migration, as in the example from offshore Liberia (Figures 1 and 2). Here, an extensive series of shallow collapsed mass transport complexes (MTCs) with a highly variable velocity structure cause significant scattering and degradation of the seismic signal. To compensate for this and accurately image the target, capturing as much velocity detail as possible in the model is essential. Tomography cannot achieve this, but DM FWI, especially using higher frequencies, can produce models with greater detail and resolution. This allows more accurate imaging of the seismic data and enables the generation of an FWI Image. The added interpretability and geologically-consistent velocity provided by the 40Hz DM FWI, better resolves the MTC complexity and delineates more coherent, deep events on the FWI Image.

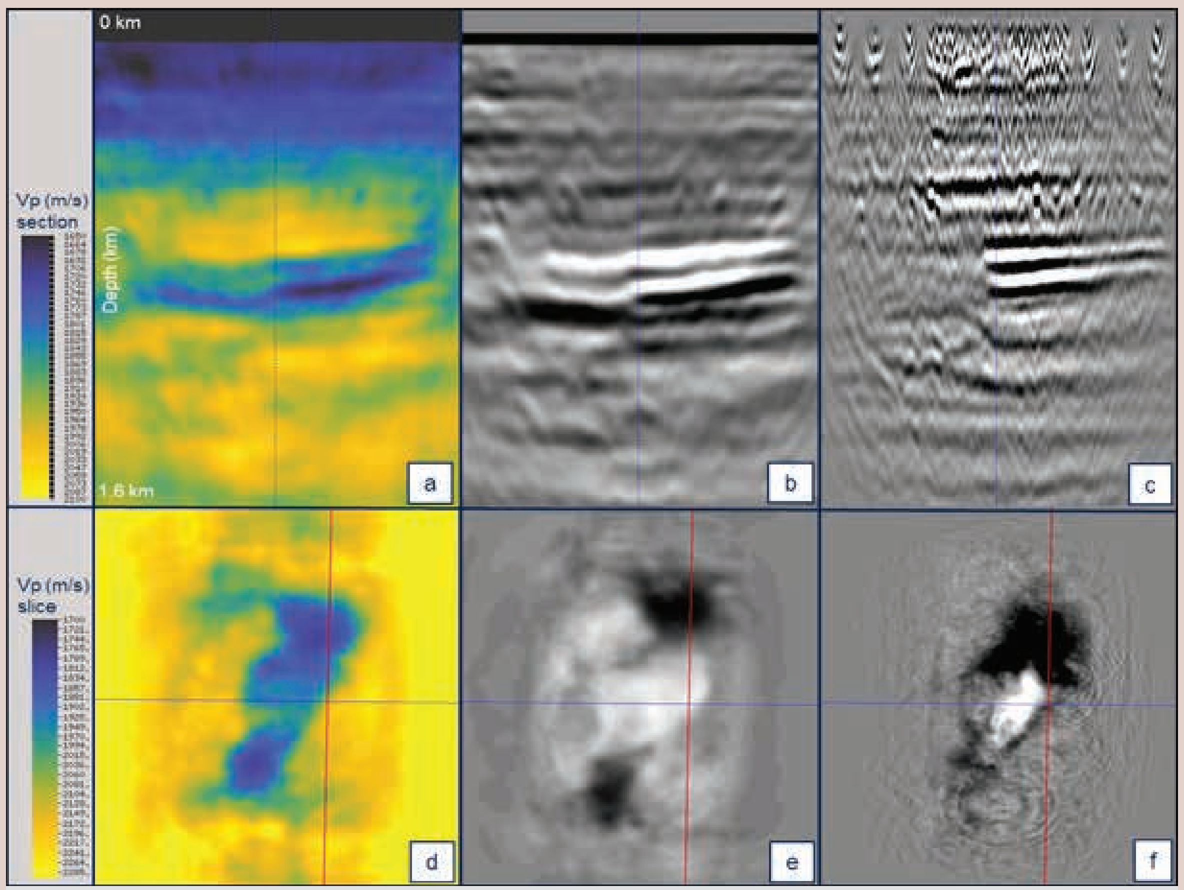


Figure 3: Sleipner OBN for CCS (Carbon Capture and Storage) monitoring. a) Inline through the velocity model from the 15 Hz FWI; b) Inline from the FWI Image; c) Inline through the 15 Hz RTM volume; d) depth slice through velocity model at 900 m; e) depth slice through the FWI image at 900 m; f) depth sliced through the RTM volume at 900 m.

The beauty of FWI Imaging lies in its ability to adapt to various geophysical survey scenarios and handle complex subsurface conditions. As a model-matching technique minimizing differences between observed and modeled seismic waveforms, it can reproduce more of the true model's features that are not always well illuminated by traditional seismic imaging given a survey design, illumination gaps, noise, residual multiples, etc. FWI iteratively builds these features into the model to better match the different types of measured waves. The future that we are starting to see accelerate is the realization of full wavefield scattering analysis of the data, generating models, structural maps, and imaged attributes such as gathers and angle stacks through FWI-based technology without needing or attempting to explicitly follow a traditional processing, model building, and imaging workflow.

Figure 3 is a realization of the latter. It shows early results from a pilot study in which XHR (eXtended High Resolution) short streamer and sparse OBN data were combined in a hybrid approach to image the CO_2 plume at the Sleipner CO_2 storage facility offshore Norway. A sparse grid of free-fall nodes was deployed on a 500 m x 525 m grid at an average bathymetry of 80m. The purpose of the node data is to update the current velocity model, while the XHR data is for high-resolution imaging. Here we focus on the value extracted purely from the node data.

Figure 3a shows the velocity model from the 15 Hz DM FWI, which can already identify changes in velocity associated with the CO_2 plume, in the Utsira formation (~800 m) and is easily identified as a reduction in p-wave velocity. The spatial distribution of the CO_2 can be seen in the depth slices at 900 m. The FWI Image in Figs 3b and 3e shows the plume and improved the shallow illumination. The RTM of the raw hydrophone in Figs 3c and 3f clearly shows the imprint of the node spacing.

Figure 4 from NOAKA OBN (Ocean Bottom Node) survey also explores FWI Imaging bypassing the traditional linear processing, model building, and imaging workflow. The data shown here is on the west of the Yggdrasil development in the NCS. The project is ongoing. However, sufficient detail has been achieved to produce with 15 Hz DM FWI an FWI image of the deeper Jurassic and older sections without fully processing the input data and running traditional migrations. This FWI Image shows clearer faulting and more interpretable deep events when compared to the equivalent filtered Kirchhoff image. These structures are difficult to image traditionally due to seismic attenuation and complex overburden effects. The production of FWI images at this interim stage in the model-building flow has allowed the interpretation of these deeper events to aid in an early understanding of the geology, also helping to improve the model-building process in terms of quality and turnaround.

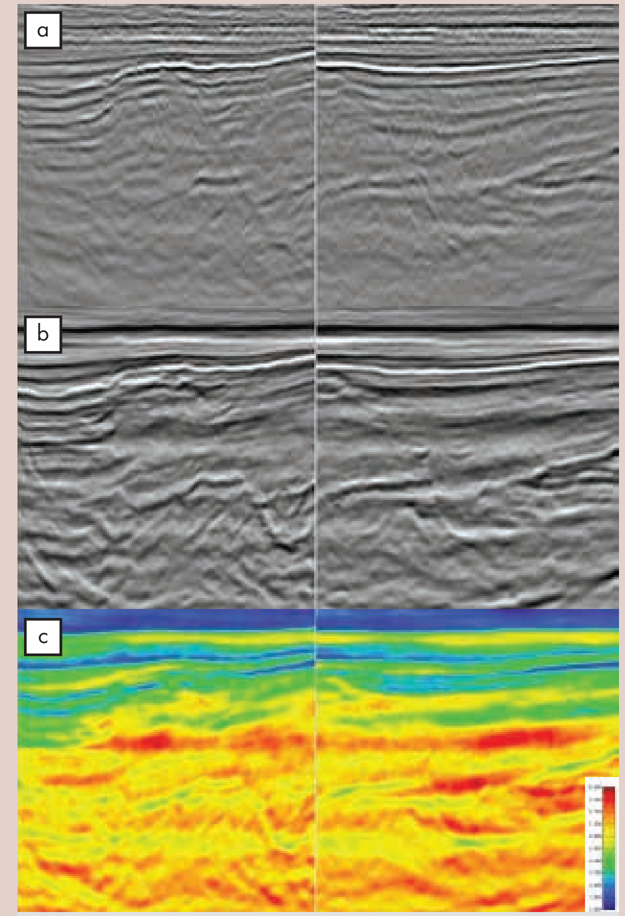


Figure 4: NOAKA OBN: a) Inline and crossline Kirchhoff migration sections with 15Hz high cut filter to match the FWI Image section, b) 15Hz FWI Image sections, c) 15Hz DM FWI velocity model.

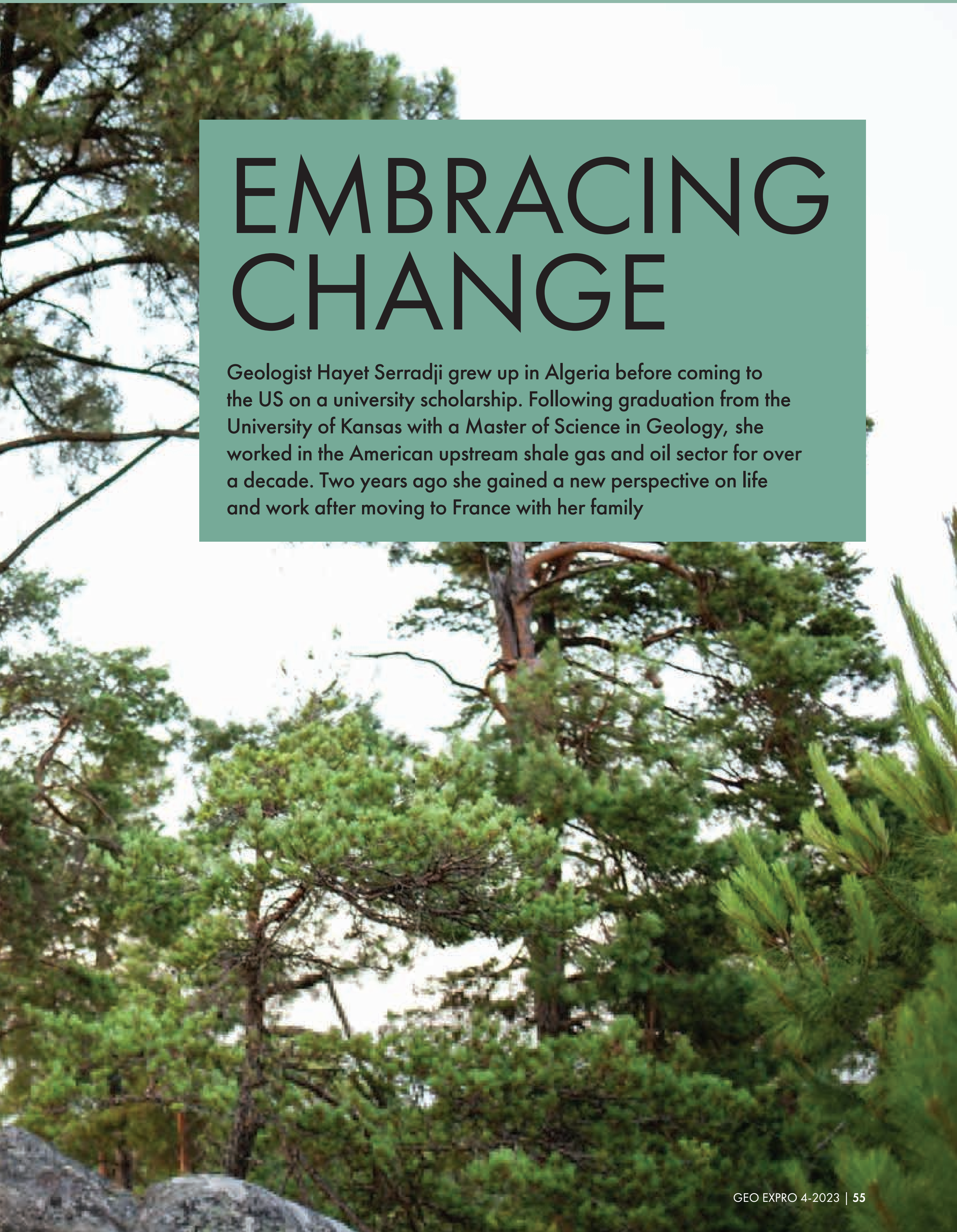
The advancements in FWI technology have been remarkable; yet, FWI still faces unrealized opportunities, and it is a thriving area of research and development. Despite these challenges, the future for FWI and FWI Imaging is exciting and full of promise. As demonstrated here, FWI Imaging can accelerate timelines, provide early interpretable products with better penetration and illumination of deeper or complex targets, and final high-detailed images that complement traditional images and have the potential to replace them in the future. This technology has proven especially useful when there are overburden complexities, illumination gaps, and shadow or attenuated zones precluding the effectiveness of traditional seismic migration products. FWI Imaging will continue to improve and deliver added value for derisking of prospects, subsurface understanding and decision-making in an accelerated turnaround.

PORTRAITS AND INTERVIEWS

"People in other countries tend to call us workaholics. I simply loved the speed and how much learning comes with that."

Hayet Serradji – Premier Corex

Hayet Serradji was born and raised in Algeria, then studied and worked in the US, and recently moved to France. She currently lives near Paris and manages a team spread out all over the world.



EMBRACING CHANGE

Geologist Hayet Serradji grew up in Algeria before coming to the US on a university scholarship. Following graduation from the University of Kansas with a Master of Science in Geology, she worked in the American upstream shale gas and oil sector for over a decade. Two years ago she gained a new perspective on life and work after moving to France with her family

"My parents approached my upbringing in different ways", says Hayet when we met up on Teams. "My father, an accountant, is curious and likes to look beyond what is thought to be the norm. My mum, a French teacher, comes from a more traditional background. That's why my upbringing is characterised as a collision between traditional and progressive views. Despite these differences, both of my parents pushed me to make the most of what life has to offer, by helping me to discover my passion while embracing the inevitable change happening all around us."

And that is really obvious when learning about Hayet's career.

"At first, I wanted to become an artist, but my parents really played the game well to get me into something that had some better career prospects. When I was due to be assessed for going to art school, the people asked for my portfolio of artwork. But I didn't have any, nobody had made me aware of that!" she laughs.

"My parents then told me to choose another university course and work on my artwork portfolio in the meantime, but as expected, that second part of the story never happened!" Hayet continues. "Parenting is the most difficult job out there, and thinking back, my parents were very smart in the way they guided me, indirectly, to a field that I am so passionate about. I hope to have that same wisdom when encountering similar challenges with my children."

That second choice was indeed, as you can guess, geology. "I loved drawing and fossils, and decided to combine the two", explains Hayet. Another aspect she appreciated a lot about geology are the opportunities to come up with creative, yet scientifically reasonable, solutions based on what we have learned from the past and apply them to the present, as well as the uncertainty that came with so many subjects. Towards the end of her studies in the Algerian Petroleum Institute (IAP), Hayet became aware that an American oil company (Burlington Resources) with operations in Algeria offered one scholarship per year for students to complete another master's degree at the University of Kansas, USA.

"I came in second during my first attempt, and was told that I needed to improve my English to beat the competition", Hayet says. "So, I took a year of English classes, again with full support of my parents, and received the scholarship on my second attempt! Only then I looked up Kansas on a map; I did not have any idea!", she laughs.

WOMEN IN GEOSCIENCE

"When I went to university in Algeria, it was not very common to see fathers pushing their daughters to embark on a study such as geology, including the many field trips it entailed", Hayet says, "but my parents were always there to support me in having made the right choice." A lot has changed since then in terms of women embarking on geoscience degrees, but there are still many instances where women feel that they are not offered the same opportunities. Hayet joined a workshop at the EAGE Conference in Vienna in May of this year about women in geoscience, which was attended by women from several different countries. "It struck me how many of them shared stories of gender discrimination, either at a university or in the workplace", she says. "I feel fortunate to have never experienced that. Whether at the university or at work, I believe that I was given the same opportunities as everyone else; it was much more about performance."

"People in other countries tend to call us workaholics. I simply loved the speed and how much learning comes with that."

BEING HIRED

The way Hayet was subsequently recruited into her first job after university in the US was another life-changing experience, an experience that still resonates with her today in the way she approaches her career as a manager and recruiting new talent.

"I was in the US on a student visa and gave little thought about pursuing a career there. Most companies required a work permit to even apply for a position", Hayet starts. "The lack of a work permit didn't stop me from helping others in their job search though."

So, during one of the recruitment events at the University of Kansas, Hayet volunteered and guided students through their recruitment and interview process without the intention of participating. "I just wanted to help students navigate the rooms and assist the recruiters where needed", she recalls.

However, near the end of the day, Hayet was invited by Chesapeake Energy to sit down for an interview. Why? "Because recruiters watched how I interacted with everyone else around me, and concluded that I was the type of candidate they needed: Someone who could work with others, someone who knew when to stop and listen, and then give feedback when needed", she says.

"The official interview was short. They went through my resume, talked about my thesis and invited me to visit the Chesapeake's Oklahoma City Campus a couple weeks later.

PHOTOGRAPHY: JEAN-BERNARD ANTOINE

"Failure made me work even harder."

After that, everything was arranged to make sure I could start.

"This was an unplanned change that offered me a great opportunity, so I embraced it! I moved to a new city, where I knew no one, but it became the home where my husband and I first lived together and where our children were born."

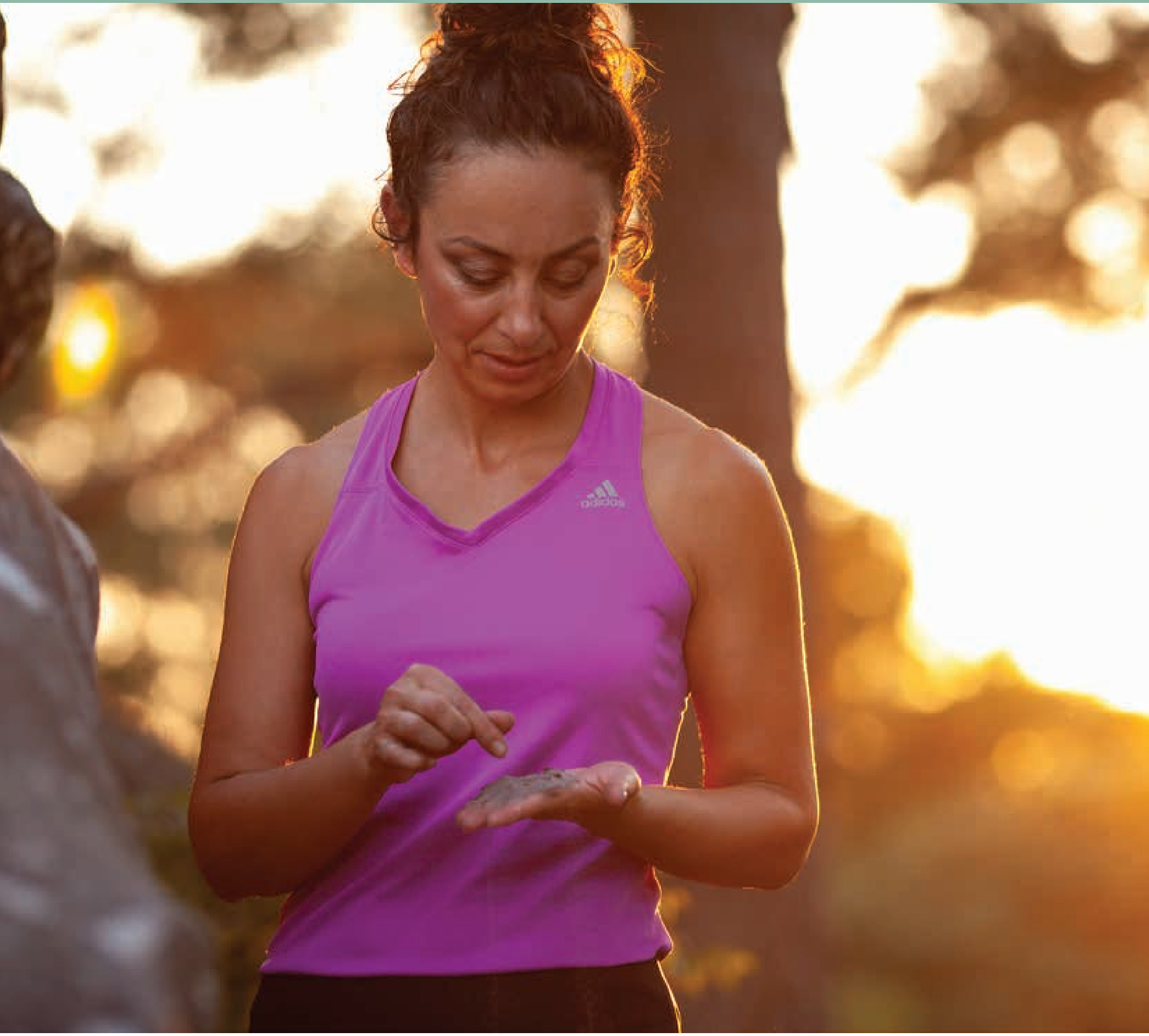
"How I was recruited to work in the US may seem unorthodox, but I recommend companies to embrace the human approach to recruitment", says Hayet. "It's not only about your CV and the university you went to; it is more about your attitude and your willingness to work with others and learn. That's what the recruiters recognised in me, and I will forever be grateful for that", she adds.

"Much more than in the US, recruitment is too much of a box-ticking exercise in other countries, without much flexibility to get to know people's personality and drive, a very important aspect to consider before bringing a new person to the team", she emphasises.

"People can perform very well at school, but subsequently lose momentum when entering their first job. The other way round is not uncommon either, so you never really know", Hayet concludes. "Therefore, I really think that recruitment should not be too protocolized."

CHESAPEAKE

Hayet stayed with Chesapeake for 13 years. "Let's not sugarcoat it", she says, "work and career in the US form a bigger part of one's life than what most people in Europe and other parts of the world may find comfortable. People are on call all the time." Yet, she never felt she was forced to work hard. "The can-do mentality and the ability to make things happen formed such a motivation for me", she says. "The mandate was: Think outside ►



The Oligocene Fontainebleau Sandstone provides the landscape south of Paris with a series of interesting outcrops, ready to be sampled by local geologists.

the box, look for innovative solutions. I liked that."

"In return for their commitment and dedication, Chesapeake was known to offer many perks to its employees, such as the latest technology at work and amazing field trips. Inside the campus, as they called it, Chesapeake provided healthy restaurants, a 5-floor gym, a daycare, and a medical center. Even IVF treatments and adoption services were sponsored by the company", Hayet adds.

"The downside of working in corporate America is the fact that your job can be axed at any time", continues Hayet. "In that sense, it is a challenge to build up a stable life. Every year there were redundancy rounds, and after surviving many, it was my turn after 13 years", she continues. "It was hard. Fear of the future and not knowing what to do next were real emotions."

"In that regard, some Europeans have no idea how comfortable their lives are when it comes to having a social safety net", Hayet continues. "In the US, there is nothing to fall back to when you're made redundant. Imagine such a situation in France, where I now live. The contrast is truly staggering." Yet, even though the American way of working is not ideal, Hayet continues to look back at her US years with satisfaction: "Work hard, play hard, it just suited me!"

"The benefit of Covid was that it taught us how to function as a team whilst still being in different places and time zones."

THE OIL PATCH

During her time at Chesapeake, Hayet saw the shale boom unfolding in front of her eyes. "The first thing that springs to mind is how close the link is between the shale industry and commodity prices", she says. "One day we were mainly drilling for oil, only to sell the acreage a little later to focus on gas."

Technological developments also played an important role in further reducing costs and increasing drilling rates. "At the beginning of my career, we drilled our horizontal wells using Microsoft Excel", Hayet explains with a smile. "Soon after, companies started to develop software for that, but we really only had the basics at the start. Drilling rates, length of the laterals, and the number of wells being completed from one pad; everything was developing so fast", she says.

"The sweet spots in shale gas and oil have now been drilled", Hayet continues. At the same time, that does not always mean that working in the more marginal areas is necessarily less valuable. "We found that by drilling the slightly less organic-rich intervals around the sweet spots, where the formations are more brittle, drilling was easier and faster, resulting in costs per well coming down."

APPLYING EXPERIENCE

Since Hayet moved to France in 2021, she has been working for Premier Corex, a relatively new company that originated in Houston and acquired the core analysis firm Corex in 2016. The company offers core services worldwide and helps clients optimise their production strategies. "I use my experience in the oil and gas industry to provide technical solutions to operators, based in the US and Europe. I am also learning about renewable energies and adjusting my skills to this new market. This is a new challenge for many geologists in Europe", Hayet says.

It is a sign of the times that the service Hayet provides with Premier Corex is more in demand, as the shale plays get more challenging to produce from. "For example, the combination of a long production history and multiple prospective zones in the US Permian Basin requires a careful well-planning approach when it comes to drainage, fracture heights, spacing between the wells and completion strategy. Therefore, now more than ever teams have to work in an integrated fashion", Hayet concludes.In contrast to her days in Oklahoma, there is no office for Hayet to go to anymore. "My team is literally spread out over the world", she says. But it does not stop people from working efficiently. "Even though I will always try to meet someone face to face when possible, I must say that Teams can do an amazing job in building a report with people", she says. "Yes, I sometimes need to ask someone to switch on the camera, but once I can see their expressions it is certainly possible to get to know someone even on the other side of the world", she says.

"Looking back at my career thus far, there is one thing that really forms a common thread", Hayet concludes as we approach the end of our conversation. "Only by embracing the changes imposed to us, changes that sometimes happen regardless if you want it or not, it is possible to see the opportunities that arise as a result. I can't predict the future, but I'm ready!" ■

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GEOTHERMAL ENERGY

"Given the high productivity of pumped wells, modular efficiency of heat exchangers, and proven technology, these projects have shown to be very profitable, especially in the western US."

Elliot N. Yearsley – Reservoir Engineer

Groundwater flow – a potential cost-saver for shallow geothermal loops

A regional study in Japan shows how thermal conductivity caused by the transfer of heat through moving groundwater can help optimise the depth of shallow geothermal systems

THE ENERGY transition is all about pipes. Where a single gas well was sufficient to deliver energy to power an entire city until recently, closed-loop geothermal boreholes are now increasingly drilled for individual houses, requiring many kilometers of pipe.

Groundwater flow has a positive influence on the performance of shallow closed-loop systems through the redistribution of energy in the subsurface.

In order to massively roll out the installation of these shallow geothermal loops in the most cost-efficient way, it is very much worth investigating the depth at which to terminate drilling, provided that sufficient energy can be withdrawn. In turn, that requires a level of understanding of the subsurface and its temperature gradients. But there is more, as a study recently published in the journal Geothermics (Shrestha et al., 2023) has shown.

Carried out by a team from Japan, the researchers show that besides different lithologies and associated thermal conductivities, groundwater flow is an important factor at play in the realm of the first couple of hundred meters. As they state in the introduction of the article: “Groundwater flowing in the shallow subsurface layers can induce advection, which has a significant impact on subsurface temperature distribution.”

In short, groundwater flow has a positive influence on the performance of shallow closed-loop systems through the redistribution of energy in the subsurface and as a result, areas with higher groundwater flow will require shallower closed-loop boreholes than ones in areas where groundwater flow is not as high.

In order to further quantify this, the authors looked at the Echigo plain in Japan, which is characterised by a thick succession of Quaternary sands, gravels and fines that extend from the mountains in the east to the coastal plain in the west.

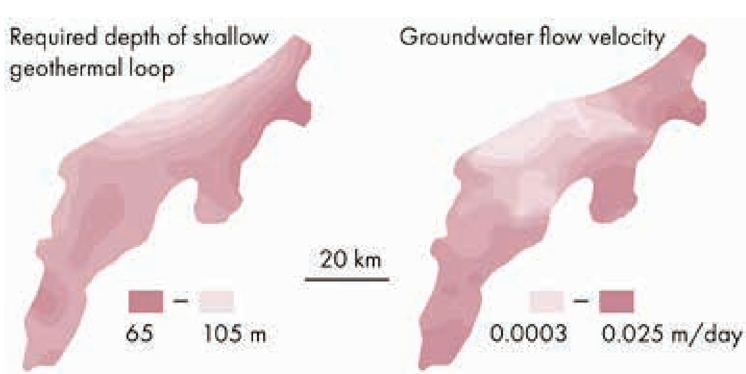
In areas where the Darcy velocity of the groundwater is low, the required lengths of the geothermal loop are longer than in areas where a higher velocity is observed, with lengths varying from 65 to 105 m.

For an individual loop, the cost gain of not having to drill to 100 m but to 70-85 m instead may not be huge, but when this technology is implemented on a large scale there is surely a benefit of having a better idea on what the minimum length is and savings will then add up.

The study also demonstrates the genuine benefit of performing regional studies covering entire basins in order to map out how groundwater flow is distributed across wider areas. Only a regional approach will shed more light on this. ■

HOW TO EXPLAIN THE REGIONAL DIFFERENCE IN GROUNDWATER FLOW VELOCITY?

The authors of the article explain the lower groundwater velocity areas near the coastline by the increased clay content of the Quaternary sediments when moving from the mountains in the east towards the coastal plain. In addition, there may also be a topographical element in the mix, with groundwater tables showing more of a gradient in the hills and mountains in the east compared to the coastal plain in the west.



SOURCE: SHRESTHA ET AL. (2023)

Coring the seal of a geothermal reservoir

A better understanding of the sealing unit can ultimately lead to safely extracting more energy from the geothermal reservoir

IN THE LITTLE village of Monster, which ironically translates to "sample" in Dutch, operator HVC recently completed a new geothermal well. The well targeted the Lower Cretaceous Delft Sandstone, from which brine is to be produced to heat a complex of greenhouses in the immediate surrounding area.

HVC subsequently put out a press release, announcing that a 60 m core was retrieved from the Rodenrijs Claystone Member, which happens to directly overlie the Delft Sandstone Member and is considered the sealing unit of the fluvial reservoir below. As the website explains, the core will shed more insight into the properties of the mudstone.

At first instance, it would be tempting to ask the question why the sealing unit was cored rather than the reservoir itself. Core data on the Delft Sandstone is relatively scarce and a section covering the reservoir would have been a welcome addition.

However, following conversations with several people involved in the matter, it has become clear that the primary target of the operation was to acquire a core of the Rodenrijs Claystone, even though a section from the Delft Sandstone itself would also have been a welcome addition too.

WHY WOULD A GEOTHERMAL OPERATOR BE INTERESTED TO CORE THE OVERBURDEN OF A GEOTHERMAL RESERVOIR?

The main reason to better characterise the Rodenrijs Claystone is to gain a better understanding of the geomechanical properties of the seal. It is well-known that injecting cooled brines can induce fracture formation in the reservoir, potentially including the overlying seal. The potential for fracture propagation depends on the in-situ stress, the physical rock parameters such as permeability, Young's modulus and Poisson's ratio and the exploitation parameters such as the flow rate, injection pressure and temperature.

A report by PanTerra Geoconsultants from 2021 describes such a study of the Maasdijk geothermal project, also operated by HVC and only about 10 km away from the Monster well. For this report, the Rodenrijs Claystone was subjected to a fracture propagation study. The authors indeed describe that there is a chance for the lower part of the Rodenrijs Claystone to be fractured – the so-called Rodenrijs waste zone in which a higher silt percentage occurs – but there was no concern for these fractures to migrate through the entire sealing unit provided that the rate of injection is kept below a certain limit.

To prevent unnecessary and conservative limitations when it comes to the geothermal exploitation parameters, HVC now has the ability to test Rodenrijs Claystone for its geomechanical properties, right at the location from where brine extraction will take place. Although much historical data is available in the area, data of the Rodenrijs Claystone has thus far been very limited partly because no hydrocarbons have been found in the Delft Sandstone.

If the Rodenrijs Claystone displays favourable geomechanical properties, a slight increase in injected volume or a slightly larger temperature drawdown means that more energy can be retrieved from the produced brine. ■

Core from the Rodenrijs Claystone in the Monster geothermal well. The fine-grained character of the rock is obvious, and it is interesting to see that some paleontology can also be done!

SOURCE: PIETER DE JONG (IOT GROUP) VIA HVCGROUP.NL

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The essentials of pump hydraulics and energy conversion for geothermal power projects

This is the second article in a series on Geothermal pumped-well power projects. The first article included a global overview of operating projects and subsurface characteristics (GEO ExPro 2023, Issue 3). This article focuses on pump hydraulics and energy conversion, and the third will cover economics and emerging technology

ELLIOT N. YEARSLEY (enyearsley@gmail.com)

PUMPED-WELL geothermal projects utilise "binary" power plant technology which consists of Organic Rankine Cycle (ORC) heat exchangers. The geothermal fluid is pumped from the wells as a single-phase liquid throughout the process of pumping, heat exchange and re-injection.

PUMP HYDRAULICS

There are several types of pumps available, including line shaft pumps (LSPs) which have the electric motor at surface and the pump impellor downhole with a rotating shaft connecting the two, and electric submersible pumps (ESPs) with both its motor and impellor located downhole. LSPs are by far the most commonly used in pumped-well power projects, although ESPs are required where the depth of the impellor precludes the use of a line shaft.

The essential purpose of the pump is to boost the pressure at the impellor intake sufficiently to maintain the fluid in single phase and provide the pressure and flow rate required at the plant inlet. There are often additional booster pumps either in the plant or prior to re-injection.

The impellor intake must be set deep enough below the static water level such that the water level above the pump while pumping, defined here as the *dynamic head,* provides sufficient pressure to prevent cavitation in the pump - i.e. prevent boiling or gas bubbles forming in the liquid phase (Figure 1).

This depth is primarily controlled by the fluid temperature and productivity index (PI). PI is defined as the volume flow rate per unit pressure, which determines the drawdown. To keep the fluid in single phase, the allowable drawdown cannot be exceeded and the pressure in the fluid cannot fall below the vapour pressure of water - the pressure at which the fluid will begin to boil.

The temperature determines the vapour pressure of the fluid, which is a primary factor controlling allowable drawdown, as the hotter the fluid the higher the vapour pressure and lower the allowable drawdown (Figure 1).

Figure 1 illustrates that the required flow rate for any given power output - in this case 5 Mwe - decreases with temperature, but the limit for allowable drawdown is reached about 190°C. This relationship is also dependent on the static water level and PI. However, the vapour pressure of water increases non-linearly, such that 190°C is usually the practical limit for pumped-well projects.

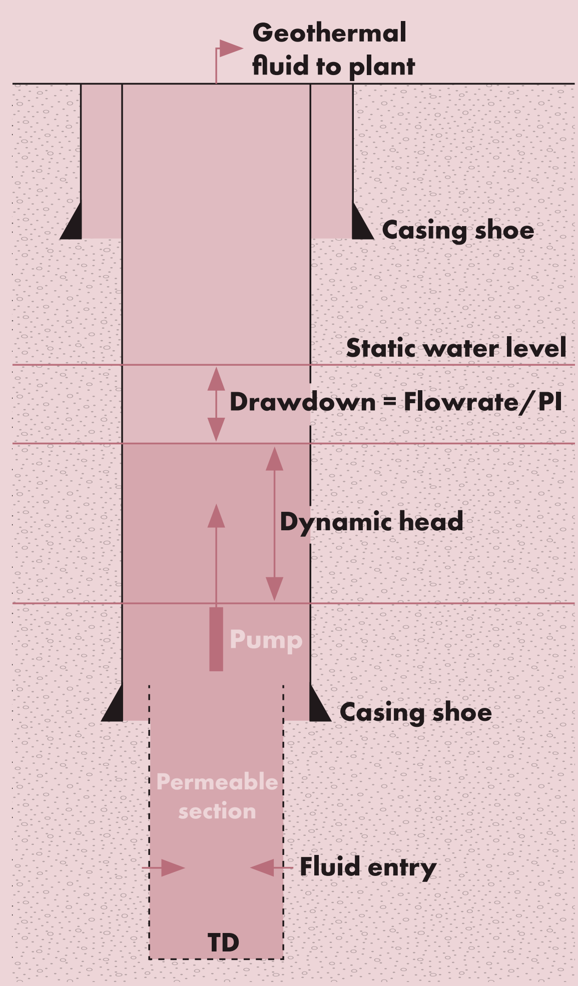


Figure 1: Pumped-well schematic.

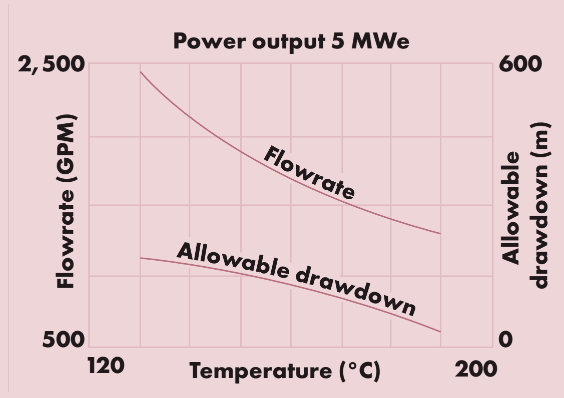


Figure 2: Flowrate and allowable drawdown.

The schematic shown in Figure 1 illustrates the key hydraulic parameters for a pumped well; namely:

- Static water level (water level without pumping)
- Dynamic head (water level above the pump while pumping)
- Drawdown (difference between static and pumping)

The pump impellor stages are set inside casing above the casing shoe and fluid entry is from the perforated liner below the shoe. Pumped wells in the western U.S. are completed comparatively shallow with permeable zones usually between 500-1,500 meters and pump set depths between 300-500 meters. Pumped wells in Europe tend to have deeper reservoirs and in some cases, the pump must also be set deeper.

ENERGY CONVERSION

The energy contained in a geothermal fluid is defined by its enthalpy, generally given in kilojoules per kilogram (kJ/kg). For a liquid, the enthalpy is primarily determined by its temperature. The electrical energy that can be derived from the geothermal fluid is a function of its mass rate, entry and exit temperatures into and out of the ORC heat exchanger, and the efficiency of the heat exchanger.

For example, a fluid temperature of 180°C contains an enthalpy of 763 kJ/kg. A mass rate of 80 kg/s (equivalent to 90 Liters per second) with an exit temperature of 80°C results in an available energy rate of 32,600 kJ per second (a Watt is defined as 1 Joule per second). This is sometimes referred to as the thermal rate and this example equates to 32.6 Megawatts thermal (MWt).

Temperature of fluid (C)	Fluid Enthalpy (kJ/kg)	Mass rate (kg/s)	Exit temperature (C)	Exit enthalpy
180	763	80	80	335

Table 1: Fluid entry and exit conditions

This energy rate is converted to electricity at some efficiency, depending primarily on the properties of the ORC heat exchanger and ambient conditions. This efficiency generally ranges between 10-16% for the types of ORC units used in geothermal pumped-well projects. Shown in this example is a process with 15.2% efficiency which results in 5 MWe (gross) power output for 80 kg/s mass flow rate.

Delta Enthalpy (kJ/kg)	Thermal energy rate (kJ/s)	Thermal Efficiency	MWe (gross)
407	32,600	15.2%	5

Table 2: Conversion to electrical energy

The example given above is a simplified approximation, but provides a useful overview of the energy conversion process. The enthalpies quoted are approximate for pure water and can vary depending on the total dissolved solids and non-condensable gases contained in the fluid.

PUMP POWER

A portion of the gross power generated by the ORC units is required to operate the pumps. This load is primarily determined by the flow rate and lift head, which is defined as the vertical height from the first stage pump impellor to surface, plus friction losses and required pressure at the wellhead. In its simplest form, pump power can be estimated by the following:

BHP = [(Q * H * rho) / 247,000]/E

Where BHP is the brake horsepower (multiply by 0.75 to convert to kW), Q is the volumetric flowrate in GPM, H is the lift head in feet, rho is the fluid density in pounds per cubic foot (lbs/cf), 247,000 is a constant to reconcile units, and E is the overall pump efficiency (%).

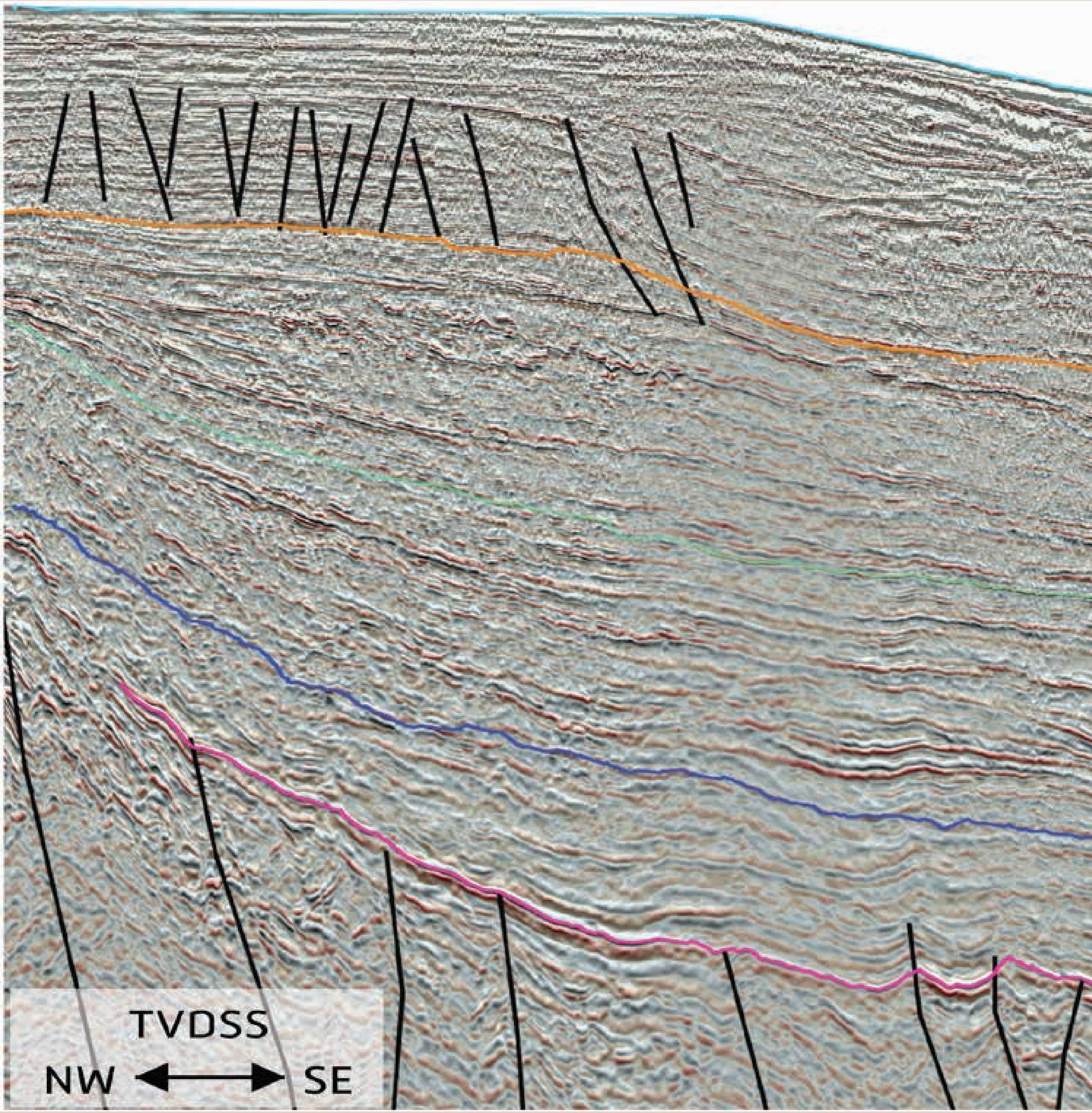
For the example given above, a rough approximation of pump power for a pump rate of 80 kg/s (equivalent to 1,427 GPM) of 180°C water (density 56 lbs/cf) with a total lift head of 2,000 feet and overall pump efficiency of 68% would be about 950 BHP (713 kW). Therefore, in the above example for a power output of 5 MWe (gross), roughly 0.7 MW of this power is used to run the pump.

NET VS GROSS POWER

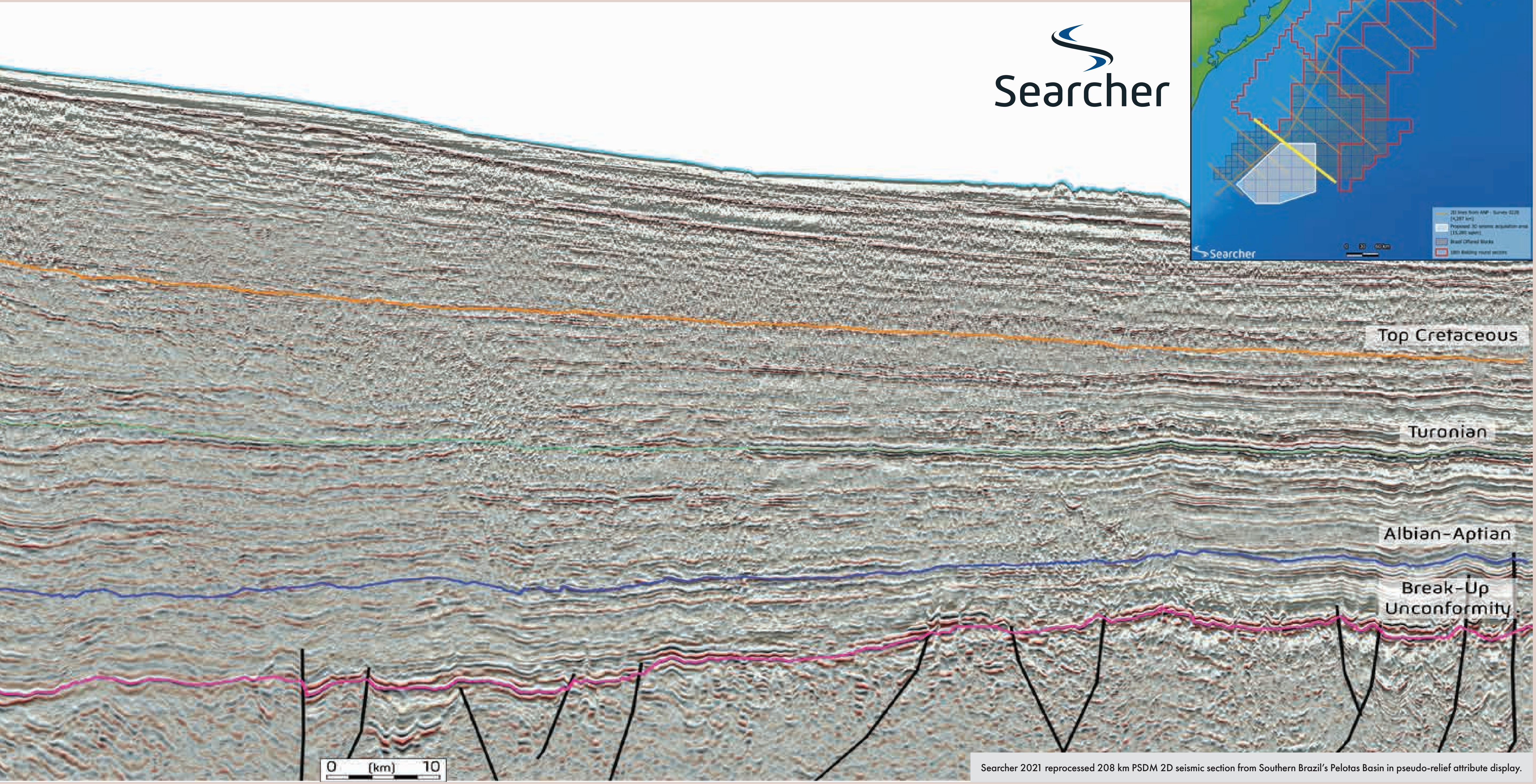
In addition to pumps, geothermal pumped-well power projects have other internal power requirements, including re-injection pumps and house load, which take between 5-10% of the gross generated power. As an approximation, pumped-well projects generally consume between 20-25% of the gross generation for own use.

Given the high productivity of pumped wells, modular efficiency of ORC heat exchangers, and proven technology, these type of projects have shown to be very profitable, especially in the western U.S. However, the economics of these projects has several important variables, which are explored in our next installment of geothermal pumped-well power projects. ■

"Cryptic Seismic Clues: Hunting for another Source Rock in the South Atlantic"



"The time for a conjugate leap from the significant discoveries of Namibia's Orange Basin to the unexplored Pelotas Basin of Southern Brazil and Uruguay is upon us. Enthusiasm for deep water exploration has never been greater and the multiple discoveries of Namibia are re-igniting both the explorers and indeed the entire oil and gas industry. And if you are going to cross the Atlantic, why just bring one source rock when you can bring two?"



Searcher 2021 reprocessed 208 km PSDM 2D seismic section from Southern Brazil's Pelotas Basin in pseudo-relief attribute display.

Two for the price of one: Source rocks aplenty fuel South America's next exploration frenzy

NEIL HODGSON, LAUREN FOUND AND KARYNA RODRIGUEZ, SEARCHER

EXPLORATION IS COOL AGAIN

Across the globe explorers are waking from a disturbing dream where the oil and gas industry was vilified into a new dawn where 'accessible', 'available' and most importantly 'affordable' hydrocarbons still have a role to play in propelling humanity towards a sustainable, better world. In the recently explorable deepwater space the prospects are bigger than ever, keen geoscience is making success huge and repeatable, and explorationists are the cool cats again.

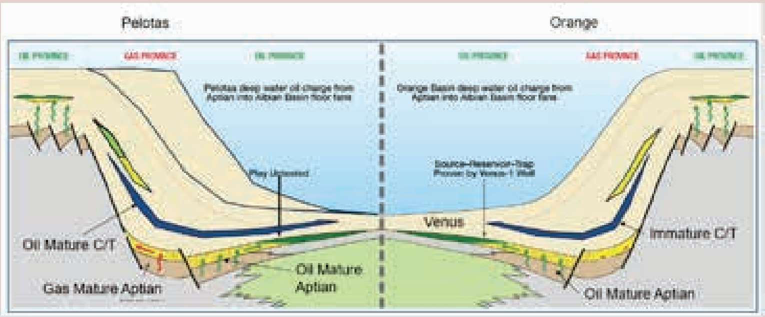


Figure 1: Conjugate margin prospectivity sketch. Thicker Sediment in Pelotas than Orange Basin.

CHASING SOURCE ROCKS

As oil and gas explorers, we need to locate oil and gas generative horizons and understand how the ravages of time may have led to them expelling hydrocarbons. We could short-cut this issue by looking for direct evidence of generation and migration; slicks or direct hydrocarbon phenomena on seismic. The huge mountain prospects offshore Sudan would be an example where the source story is obviated by multiple repeating natural oil slicks. The questions of source risk then reduces to "what else could have created these observations?," relieving the need to understand the issue at all.

Alternatively, we can use well data, outcrop geology and interpretation to jump information on source rocks from the explored shelf into the unexplored deep basin. The sources are then "basin-modelled" theoretically to see if, and when, they might have been hot enough to be mature, and if migration from the source at some point may have filled our reservoirs and traps. There are lots of places for cup and lip to misconnect on shelf to basin jumps, as we have to make a raft of best guesses in this "string of small miracles" approach. Sometimes this works brilliantly and other times, not so much - especially in new basins as best guesses with few constraints can let us down abruptly.

CONJUGATE MARGIN SOURCE ROCKS: YOU KNOW IT MAKES SENSE

So, where you cannot jump off the shelf, then sometimes you must jump continents. From the geology of one margin into similar geology on another – its conjugate (Figure 1). Gestated together like twins they drift apart with plate tectonics, but they share characteristics of their genesis in their DNA. In this way the Aptian source rock of Namibia can be correlated to its twin in the Pelotas Basin of Southern Brazil and Uruguay. The Aptian source rock is clearly identifiable in the seismic of the Orange Basin in Namibia as a soft topped unit with lower internal frequency, little internal structure, standing out in AVO space as a classic strong type IV anomaly. AVO has historically been used as a tool to look for oil or gas in clastic reservoirs i.e., a DHI tool yet in our process (and multiple other examples since the technique was promoted by Løseth et. al. in 2011), we turn this on its head and use AVO to characterise and identify source rock.

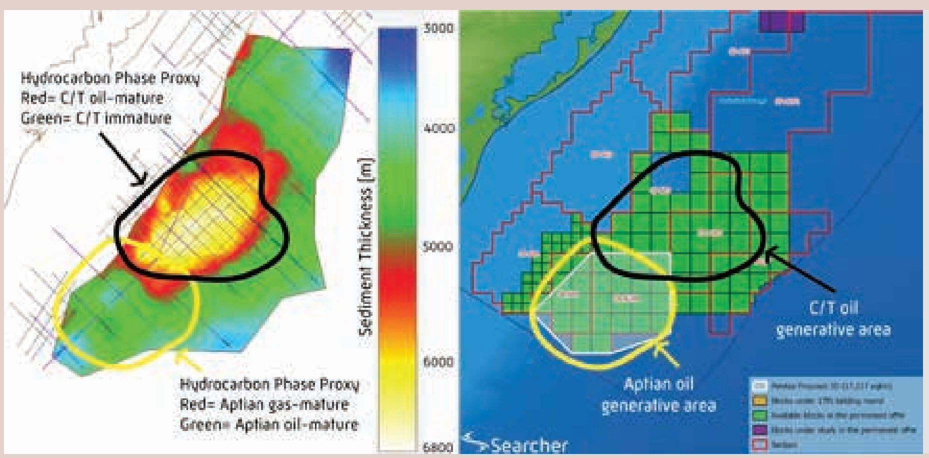


Figure 2: Pelotas Delta, Brazil. LHS: Isopach to top Aptian (thermal maturity modelling from BSR-derived geothermal gradient), RHS Aptian Oil generative polygon (yellow) and C/T oil generative (black polygon).

The Aptian source has proved so effective in Namibia with TotalEnergies' Venus-1 discovery and Shell's four up-slope discoveries, all charged from the Aptian Source rock, potentially offering tens of billions of barrels of recoverable light oil. It is no surprise at all that this source rock can also be identified from its seismic character in the Pelotas Basin of Brazil and Uruguay where it presents the same as Orange Basin but thicker and has a similar Type IV AVO response. The only surprise is that the Aptian sourced plays in this basin remain untested on this margin.

Like human un-conjoined twins though, the Pelotas Basin's lifestyle choices have varied somewhat from its Orange Basin twin. The continual dynamic topography induced instability of the Namibia margin and a lower sediment supply via the Orange River has led to a comparatively thin sedimentary section than is observed in Pelotas. Pelotas sedimentary section however is demonstrably stable, where no dynamic topographic inversion and shelf collapse has occurred and sediment supply via the proto-Platte River has been prodigious, generating a rather more generously proportioned sedimentary deposit than its West African twin (Figure 1). Therefore, only at the edges of the Pelotas Delta is the Aptian source rock buried just deep enough to generate Oil (Figure 2). In such places the Aptian is prodigious and is no-doubt charging some of the worlds' biggest prospects in the Cretaceous counter regional play. It is here that Searcher is acquiring 3D seismic in 2023/4 season. Elsewhere, the Aptian may indeed be buried too deeply, generating gas (Figure 2) and frustrating explorers too slow to access acreage at the edge of the Pelotas delta, yet who remain eager to try the conjugate leap from Namibian success to Brazil and Uruguay.

In such overburden-rich places then the slope channel plays of the Upper Cretaceous appear shipwrecked by the sediment load, and all looks lost. To progress we need to find a shallower source rock, with less overburden. And so, we embark on a new hunt for cryptic clues using the remote sensing tools we have, integrating with the geological stories we have learned on our journeys.

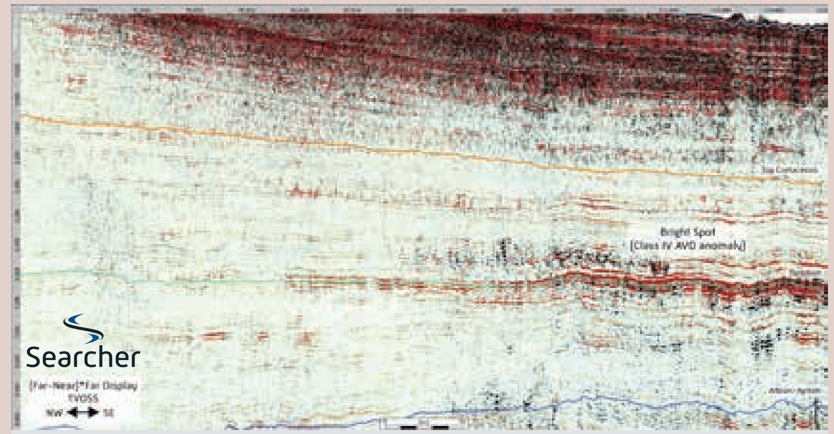


Figure 3: Far-Near*Far Display showing the AVO Type IV anomaly at Cenomanian/Turonian level.

CLUE HUNTING

Within the world of Enigmatology, Cruciverbalists (crossword solvers) have their own lexicon. You can 'Parse' an answer (work out the cryptic clue) or 'Biff' it (when the word fits but you do not know why). There are 'anagrams', 'charades', 'containers' or 'hidden' clues to name a few styles in the cryptic milieu. Our favourite though are the 'Ikea' clues – where the clue comes in parts that you then have to self-assemble to find the answer.

The first part of the "Ikean" thick-Pelotas clue, has actually been with us in the Orange Basin for 30 years, where work by many authors identifies the Cenomanian/Turonian (C/T) Source rock in the basin. The Cenomanian/Turonian black organic rich shale is identified as OAE II, a globally important source rock associated with global Ocean Anoxia Event leading to deposition and preservation of thick, high TOC (carbon rich) mudstone sequences around the world. The C/T source rock has been modelled countless times in the Orange Basin but a lack of sedimentary cover thickness there indicates immaturity for hydrocarbon generation. The lack of success drilling plays charged from the C/T source would tend to support this assertion.

Like an amnesiac conjurer, we have forgotten that a trick played once, can be performed again. Proven in Orange Basin the C/T source rock (formed in a global anoxic event) it is likely we will find this source in the conjugate Pelotas Basin where it is buried under a thicker overburden. Indeed, in the thickest parts of the Pelotas the C/T is buried with a depth of cover similar to that of the Aptian source at the edge of the delta. In Pelotas the C/T is identifiable as a soft topped unit with lower internal frequency, little internal structure, and stands out in AVO space as a classic, strong type IV anomaly (Figure 3).

This is then a repeat of the proven Aptian Conjugate source rock sleight of hand – but this time applied to the global Milankovitch cycle related OAE II event in the Orange Basin of Namibia. Taking the characteristics from the numerous penetrations of the C/T source in Namibia and applying that to the depositional sequence from the thicker Pelotas delta we find not only that the sequence would be generative, but generative for Oil.

In Uruguay, the same phenomena have been identified recently by a team led by Ancap and Searcher, collaborating with EMGS and an additional form of remote sensing data - CSEM (Controlled Source Electro Magnetism). Normally, CSEM is used to spot resistive oil-bearing sands in a clastic sequence. However, like AVO, it is just as able to be used to hunt for source rock. The results of a collaboration between Seismic and CSEM to hunt the C/T source rock in Uruguay is due to be revealed at the First EAGE Conference on South Atlantic Offshore Energy Resources to be held in Uruguay in September 2023.

Leaping from the proven Cretaceous sources of the Orange Basin to the unexplored Pelotas Basin of Southern Brazil and Uruguay requires no great stretch of the imagination. This will be a small step for an oil company but a giant leap for mankind as the future of affordable, accessible, and available hydrocarbons is secured for the remainder of our energy transition within the simple, big prospects with multiple source rocks that lie there. If you are going to do a conjugate-leap though, why just bring one source rock with you when you can bring two?

References provided online

SUBSURFACE STORAGE

"It is true that these projects experienced what I call 'geological surprises' along the way. However, as a whole, the Sleipner and Snøhvit CCS projects have had excellent regularity with only minor stoppages for well workovers."

Philip Ringrose – NTNU

A star to enable safer CO_2 storage

At Løten in Norway, research institute NORSAR buried several kilometers of fiber optic cables in shallow trenches. This infrastructure contributes to the development of better monitoring of future CO_2 reservoirs

IT FORMS a wonderful pattern, NORSAR's new array NORFOX, which is buried deep in the forest on Løten. However, it is not particularly visible. Some long tracks and a small hut with technical equipment are all.

NORSAR's new research facility for testing fiber optic sensor technology consists of many kilometers of fiber optic cables, laid in a star pattern with five arms, each 1.7 kilometers long.

"The NORFOX array is part of the Norwegian contribution to European consortium ECCSEL ERIC, which aims to offer world-leading research infrastructure in the field of capture, transport and storage of CO_2", says Volker Oye, seismologist and head of department at NORSAR.

According to Volker, NORFOX will contribute to the development of cost-effective solutions for monitoring CO_2 reservoirs. To understand how the buried cables on Løten will do this, we must first understand how fiber optic cables work.

REGISTERING TINY CHANGES

"At NORFOX, we measure laser pulses that are sent from one end of the cable to the other, and back. If the cable is compressed a little, or stretched, the travel time changes and we are able to register this. It is quite amazing", Volker says.

However, the facility would be of little value without an essential technology known as distributed acoustic measurement (DAS). DAS ensures that the researchers know where the deformation has taken place.

Briefly explained, the concept is that a small proportion of the laser pulses sent through the cable are continuously reflected back where they came from. It is the reflections that can reveal where the deformation took place.

NORSAR can thus record changes every five meters along the entire length of the cable. The technology turns one cable into hundreds of "measuring stations".

In combination with the fact that approximately 1,000 laser pulses are sent out per second, this provides large amounts of data and a good overview of deformations affecting the cable.

The data gives the NORSAR researchers insight into tremors in the ground at Løten. There could be explosions at the local quarry, someone trampling hard near the cables, or there could be an earthquake with an epicenter far beyond Norway's borders.

"The array was completely ready in April, and we have, among other things, recorded the earthquakes in Turkey this year", adds Volker.

The NORFOX array projected on an aerial photograph.

SOURCE: NORSAR

FIBER OPTICS FOR CO_2

Detection of tremors in the ground is also relevant for monitoring CO_2 reservoirs. If future CO_2 storage sites on the Norwegian continental shelf are equipped with fiber optic cables on the seabed, it can contribute to better control of what goes on in the depths.

"Monitoring of CO_2 reservoirs using fiber optic cables can be done in at least two ways. First, we can shoot seismic in the area and let the cables pick up the waves that have been reflected in the depths. If we carry out the process repeatedly over time, we can also see any changes in the reservoir", explains the seismologist.

But the cables can also passively listen to the smallest movements that take place in and around the reservoir, without the use of an active seismic source. Small seismic events create micro-vibrations and give an indication of pressure changes and where the injected CO_2 is migrating to.

"If we were to see an acceleration of microseismic activity in one particular place in the reservoir, it could be an early warning that measures must be taken to prevent leaks", concludes Volker. ■

Are Sleipner and Snøhvit calling into question the long-term viability of CCS?

Study claims that due to subsurface surprises at Norway's flagship CCS projects, the pair "cannot be used as models for the future of CCS"

IT APPEARS that the Institute for Energy Economics and Financial Analysis (IEEFA), headquartered in Ohio, US, is overly critical towards the future of Carbon Capture and Storage projects.

The Institute recently published a study that stated: "Unexpected challenges at Norway's flagship projects, Sleipner and Snøhvit, show CCS planners and regulators face underground unknowns that may spur financial and environmental risks." On that basis, the author claims that the "Norwegian projects cannot be used as definitive models for the future of CCS", also because the injection rates at these sites are less than what is planned with upcoming projects.

How to interpret these statements? The Norwegian projects are amongst the few long-term CO_2 storage projects in the world. Would it really be wrong to use these as examples of future CCS initiatives?

The IEEFA study explains that CO_2 migrated into previously unknown reservoirs at Sleipner, which are "challenging to model". At Snøhvit, the initial injection into the Tubåen Fm was stopped after three years due to pressure issues in the injection well.

"It is true that these projects experienced what I call 'geological surprises' along the way. However, as a whole, the Sleipner and Snøhvit CCS projects have had excellent regularity with only minor stoppages for well workovers."

Philip Ringrose

It cannot be denied that the two Norwegian CO_2 storage projects resulted in a few surprises and, especially in the case of Snøhvit, additional project costs to start injecting CO_2 into another reservoir.

However, as Philip Ringrose, Adjunct Professor in CO_2 Storage at the Norwegian University of Science and Technology (NTNU), stated in an email to us: "It is true that these projects experienced what I call 'geological surprises' along the way – something Equinor has regularly reported in the peer-reviewed literature. However, as a whole, the Sleipner and Snøhvit CCS projects have had excellent regularity with only minor stoppages for well workovers."

Carbon Capture and Storage; more than just pipes.

SOURCE: THE BLOWUP VIA UNSPLASH

REGULATORY FRAMEWORK

On that basis, whilst it is certainly desirable to ensure that subsurface risks are included in the economic models of a CCS project, the Norwegian projects should not be used as examples to demonstrate that "CCS projects create potentially indefinite contingent liabilities."

As the author of the IEEFA concludes himself, it is the way CO_2 storage projects are made to happen that creates the right environment or not. In Norway, companies pay US$41/t$CO_2$ emitted, which is way more than the storage costs of about US$17/t$CO_2$. This forms a good incentive for companies to embark on CCS projects. It also prevents a situation where unexpected project costs are being carried by the taxpayer. That is also what the EU carbon tax is about.

Yes, the injection rates of the Norwegian projects may be lower than the ones currently planned at various places around the world, but if the regulatory framework is right, subsurface risks for a project should just be part of the economic model and form a drive towards selecting the best site.

It should not be a reason to not go ahead with CCS at all and scare policymakers into lifelong bills at the expense of the taxpayer. That is ultimately down to creating the right regulatory framework. After all, more than anything else, the Norwegian projects have demonstrated that CCS works over longer timescales. ■

Doing it differently

As opposed to the US, Canada has applied a bottom-up approach to selecting sites for geological storage of nuclear waste. The two candidates are very close to the US border though

Approved in 2002, the Yucca Mountain Nuclear Waste Repository in Nevada, US, looked to become the country's final destination for high-level radioactive waste for quite a few years. Until 2011, when funding for the project was stopped under the Obama administration. Throughout its entire planning phase, the Yucca Mountain Repository was heavily contested by the public and politicians alike. Now, in 2023, the US is still without a long-term solution for its nuclear waste and the beginning of the end is not even in sight.

The Canadians must have seen events unfold in the US. And they must have concluded that another approach was required to build their own geological repository. One that has the support of the greater community and the buy-in from locals. I spoke to a representative of the Canadian government at the EAGE Annual in Vienna in May. He explained how his government has indeed taken a radically different approach to the US, where the selection of the site was much more a top-down approach.

"Today, Canada is in the unique position of both being a leader in our field and being able to lean on international best practices. We are not the first to implement a repository project, but we are among those at the front of the pack."

NWMO

INVITATIONS ONLY

The Canadian government invited local communities to volunteer hosting a nuclear waste disposal site in their areas. Not only one offer was received, but 22 communities expressed interest in hosting the site. This all took place between 2010 and 2012. Now, more than ten years later and after a careful process of narrowing down the list, two areas remain - the Wabigoon Lake Ojibway Nation -Ignace area and the Saugeen Ojibway Nation - South Bruce area, both in Ontario, southern Canada.

CONTRASTING GEOLOGY

In order to better study the geology of the two sites in Ontario, the Nuclear Waste Management Organization (NWMO) completed a deep borehole drilling programme last year that retrieved around 8 kilometers of core from the subsurface. Many reports on the results of the drilling campaigns can be found on the NWMO website, along with a whole raft of other technical documents dating back to 2007.

The two remaining areas have very different geological settings; the Ignace area is part of the Canadian Shield and is characterised by the 2.7 billion years old Revell Batholith whilst the South Bruce area is a sedimentary basin with a long history of oil and gas exploration. It seems logical that the NWMO deliberately chose two areas with very different geology in order to keep options open when it comes to suitability.

CLOSE TO BORDERS

Looking at the locations of the two sites in Canada, it is somewhat striking to see that they are both situated close to the border with the US. A similar thing is apparent in Switzerland, where NAGRA is progressing with their Nördlich Lägern site to build a geological repository in the north of the country. It is also very close to a border, with Germany in this case. Is there a pattern here? Especially in a vast country such as Canada, surely it should have been possible to select an area a little further away from the US border? Or is the geology always just better near the edge? ■

A world's first?

Whether the Abu Dhabi carbon storage project in a saline carbonate reservoir is the world's first or not, modelling and lab experiments suggest that it looks safe to inject CO_2 into a limestone reservoir

ENERGYVOICE RECENTLY announced the completion of drilling "the world's first carbonate saline aquifer CCS well" by Adnoc in Abu Dhabi. According to the site, the well will be monitored and assessed from Adnoc's Thamama Centre.

The article leaves the impression that CO_2 injection into carbonate reservoirs has never taken place yet, but that is not entirely the case. A quick search finds that it is Spain where a test facility was constructed that includes injection of CO_2 into a Lower Jurassic carbonate reservoir at 1,500 m depth. In addition, as a report written by the Global CCS Institute explains, the Weyburn oil field in Canada has also been the site of CO_2 injection into its carbonate reservoir. In this case, however, injection took place to enhance oil recovery.

Regardless of where the first CO_2 injection into a carbonate saline aquifer took place first, one of the main questions that always get asked when it comes to CO_2 and carbonate reservoirs is the risk of dissolution and the related integrity of the host rock. In that regard, it is important to know if the carbonates in Abu Dhabi are dominated by fracture of matrix permeability, as the way CO_2 will migrate through the reservoir is highly dependent on how the pore space is distributed. According to a person with working experience in the Thamama reservoir section, matrix porosity is probably the most important contributor to flow.

But what are the risks of karst dissolution features developing when injection of CO_2 starts in Abu Dhabi? As reported by the CCS Institute, simulation of large-scale injection tests into carbonate rocks, supplemented by small-scale laboratory testing, suggest that the risk of extensive cavities developing is limited. Buffering effects are thought to form the most important factor in reducing the rate at which dissolution occurs. ■

DEEP SEA MINERALS

"We currently have limited knowledge of the areas in the deep sea where the resources are found. I strongly believe that if the industry demonstrates resources they believe they can extract profitably, it will be possible to produce these resources sustainably and responsibly."

Terje Aasland - Oil and Energy Minister Norway

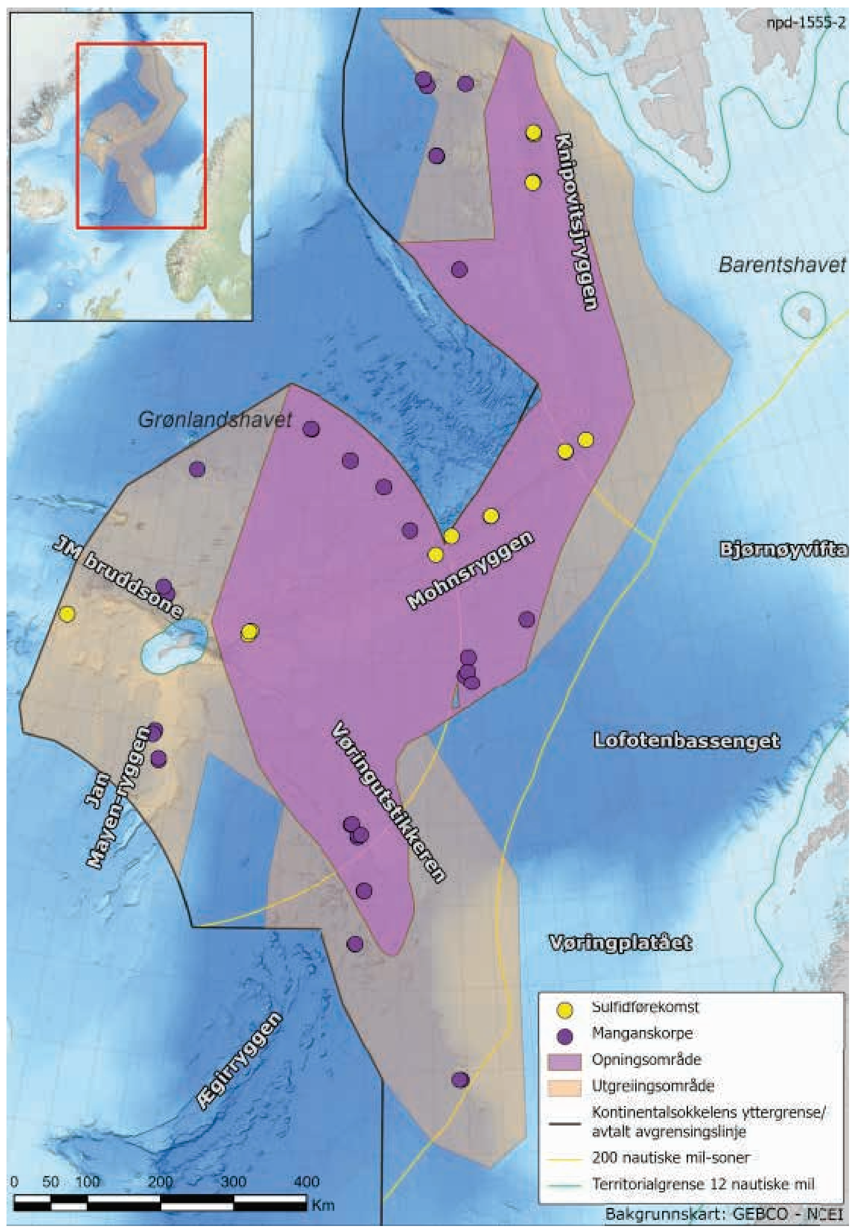
Norway inches closer to opening up for deep-sea mining

A report submitted for approval by parliament outlines next stepsto firm up resources through more detailed exploration campaigns

WE NEED MINERALS to succeed with the energy transition. Today, resources are controlled by a few countries, which makes us vulnerable. Seabed minerals can become a source of access to important metals, and Norway has a sound basis for being able to lead the way and show what it means to manage such resources in a sustainable and responsible manner", said Oil and Energy Minister Terje Aasland.

On Tuesday 20 June, the Ministry of Oil and Energy (OED) presented the long-awaited report to the Norwegian Parliament – Storting. The plan, which is yet to be approved, is to open up mineral operations within an area of 281,200 km^2 in the Norwegian and Greenland seas.

In this area, which includes the Atlantic spreading ridges, mineral resources in the form of massive sulphide deposits and cobalt-rich crusts have been found. However, Aasland was adamant that more knowledge is needed before extraction can take place, something that also emerged from several other studies.



The government's proposed opening area comprises 281,000 km^2 in the Norwegian and Greenland Seas (purple area). This is 53% smaller than the area that was part of the impact assessment (brown area).

SOURCE: UNIVERSITY OF BERGEN AND THE NORWEGIAN PETROLEUM DIRECTORATE

ONLY WITH DATA

"We currently have limited knowledge of the areas in the deep sea where the resources are found. I strongly believe that if the industry demonstrates resources they believe they can extract profitably, it will be possible to produce these resources sustainably and responsibly", Aasland added.

Not everybody believes that the resources mapped on the Norwegian Continental Shelf so far are worth chasing.

In a popular Tweet posted on Twitter, Joanna Ponicka from Equivest, showed data from the Loki Castle site to illustrate that the copper grades of seabed sampling campaigns are not too impressive – with very few samples having more than 1% Cu. Also, she noted that sampling was not performed randomly, with the "best sites" visited preferentially.When it comes to Rare Earth Elements, Li, Ni and Co, Joanna was not very upbeat either: "Well, the truth is there is very little of other metals in the collected samples. Nothing else has any economic grade", she wrote. "So, basically this is 0.5-1% Cu grades on average. Mined grades will likely be lower due to selective sampling."

Joanna continued her thread arguing that deposits of similar grade onshore need tens of them being situated close to each other to make an economic case. Given the more challenging conditions at which the Loki Castle deposits are found, she added: "Struggling to find the basis for a scientific or economic decision here…. Open to change my mind – but only with data :)"

Ronny Setsså, editor of the Geo365 and geoforskning websites and who is closely following developments in deep-sea mining, was quick to respond."In fact, Loki Castle is not the most attractive target", Ronny wrote in a message. "Yes, grade is key, and we need to see more consistently high-grade samples on the NCS, but Loki Castle is an active vent and it is an axial deposit, which tend to have lower grades than flank deposits. For instance, the Fåvne flank deposit has got copper percentages more than 3 times as high as Loki Castle."

A UNIQUE POSITION

Norway is in a unique position to be able to develop a new industry on the Norwegian continental shelf.

- The Norwegian Petroleum Directorate confirmed earlier this year that there are large mineral resources on the Norwegian continental shelf. Several of the metals in question play a key role in the energy transition and the electrification of society.
- It is is a world leader in offshore oil and gas technology and expertise, and much of this is transferable to the emerging seabed mineral industry.
- The country also has a world-leading processing industry, which can potentially contribute to the refining and the use of deep-sea minerals as an input factor on land (for example, battery factories).
- There is significant infrastructure on land and at sea that is relevant to the research and development of a deep-sea mineral industry. It includes several research vessels, Hugin AUV, Ægir ROV, Ocean Laboratory (SINTEF and NTNU), NTNU's recovery laboratory, ReSiTec's metallurgical laboratory and an observatory at Mohnsryggen (UiB).
- A seabed mineral law has been in place for several years. Given that parliament agrees with the government's proposal, there may soon be a licence round where companies can apply for areas for exploration.

STEP BY STEP

"By making it possible for commercial actors to search, you will get more data collection and more comprehensive knowledge acquisition", says the report that was sent to parliament.

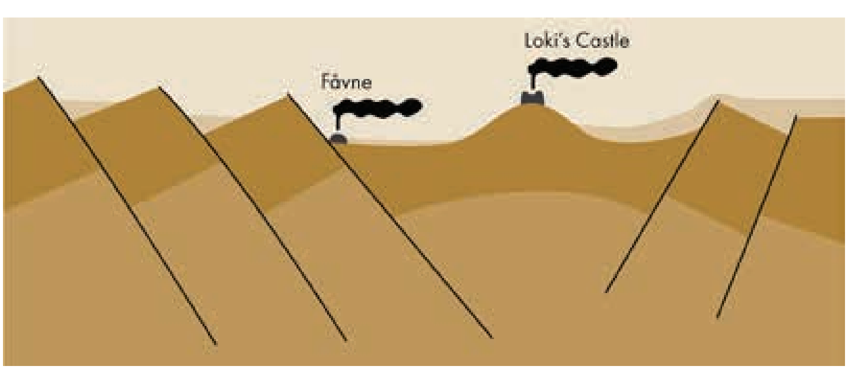
The process of opening up and allowing exploration to begin will not be a fast one though. Following a decision on opening, the ministry will initiate a process to award exploration permits. In this process, the exploration companies can provide input on which areas they wish to search in. The announcement of areas for exploration will take place in stages, i.e. only smaller areas will be announced at a time.

The ministry also points out that an opening does not automatically lead to recovery. Extraction will only be possible if the governing authorities receive applications that satisfy the requirements that have been set and extraction permits are granted.

An extraction permit can only be approved if the exploration companies prove that the extraction can take place in such a way that the environment, safety and possibly other industries are taken into account.

More concretely, the exploration companies must carry out an impact assessment as part of a plan for recovery. The government points out that these processes will provide a great deal of knowledge acquisition about local conditions.In addition, it will not be possible to obtain an extraction permit for active hydrothermal sources, and these will be protected so that they cannot be damaged by activities in adjacent areas.

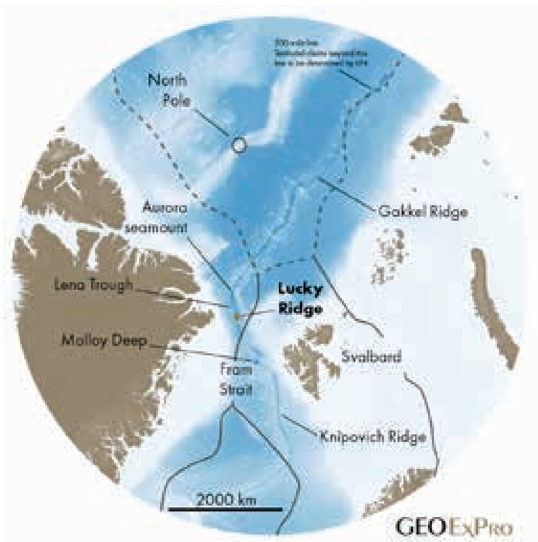
The Norwegian Petroleum Directorate's assessment of deep-sea mineral resources is only one part of a more time- and resource-consuming exploration and mapping process. As of today, the number of sulphide and crustal deposits is yet unknown. Those that are and will be detected still need to be studied and sampled more closely before the tonnage and grades can be determined with high precision, which is necessary to be able to determine economically drive value. ■



Schematic cross-section of the northern Mohns Ridge showing the distinct settings of the Fåvne and Loki's Castle. Depth not to scale. Adapted from Sahlström et al. (2023) – Ore Geology Reviews

An exciting discovery in the far north

Shortly before they had to return home, the researchers onboard RV Kronprins Haakon found what they were looking for – a new, unknown black smoker in the deep sea northwest of Svalbard



PLAN B became as successful as anyone could have hoped, as a new hydrothermal vent was discovered by a Norwegian team of researchers. This summer, the GoNorth expedition was originally aiming to go further north and east to the Gakkel Ridge in the Arctic Ocean to do groundbreaking research.

However, due to challenging ice conditions, the research vessel Kronprins Haakon was instead forced to stay in more navigable waters west and northwest of Svalbard.

The month-long expedition has collected a wide range of data in the water column and on the seabed at several localities along the Knipovich Ridge, including the Molloy Deep area - Norway's deepest point - and the Aurora seamount.

Late in July, the vessel made its way to the Lena Through, which connects the Knipovich and the Gakkel Ridge in the Fram Strait. In the area around the Lucky Ridge seamount, the remotely operated vehicle (ROV) was sent down to the seabed in several dives, and the researchers quickly found signs of hydrothermal activity, including heat signals in the water column, mineral crusts, and specific faunas that are dependent on hot, nutrient-rich waters emanating from the Earth's interior.

However, it was not until the last proper expedition day, on August 4th, that the discovery was made. Late in the evening, during what was supposed to be the last dive, the ROV's camera spotted a silhouette in the distance. They had just discovered a new, previously unknown, black smoker - an active hydrothermal vent with chimneys spewing out boiling, particle-rich water that resembles black smoke.

The expedition participants were ecstatic. Finding a new black smoker is rare. In Norwegian waters, we have so far documented ten of them. This discovery, presently unnamed, is number eleven. Samples were collected and will be analysed in the coming months.

This year's expedition was part of a three-year project that launched its operations in 2022. The project aims to considerably increase knowledge of the Norwegian part of the Arctic Ocean and has been planned since 2010.

In 2024, GoNorth plans to venture out to the conjugated Morris Jesup Rise and the Yermak Plateau, located on the Greenlandic and Norwegian sides of the spreading ridge, respectively. ■

ISA: No quick decisions despite deadline breach

Although some were hopeful, the International Seabed Authority did not complete and adopt the necessary mining regulations to start accepting and processing deep-sea mining applications from companies during its meeting in July. Instead, it has set its sight on finishing the work by 2025

THE METALS COMPANY (TMC) is eager to begin production. They might be the first company in the world to start deep sea mining in the Clarion-Clipperton Zone (CCZ), located in the Pacific Ocean between Mexico and Hawaii. A handful of other companies are following TMC suit.

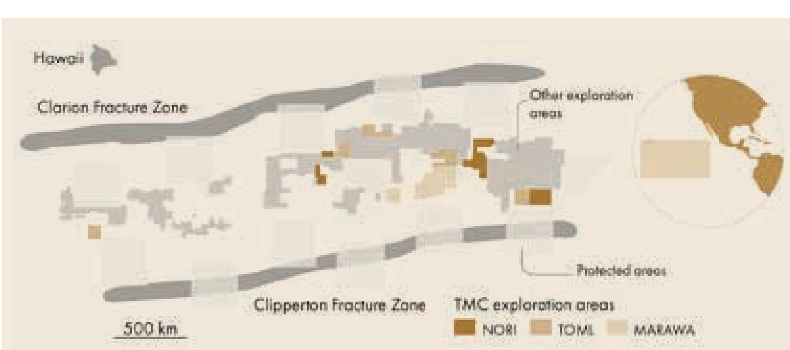
However, the International Seabed Authority (ISA), which manages maritime areas beyond the limits of national jurisdictions, including the CCZ, recently decided to pull the breaks.

The executive board of ISA, The Council, closed its meeting late in July. The main item on its agenda was whether it should conclude its work on regulations and the overall framework for the exploitation of mineral resources. The draft regulations for full-scale mining have been in the works since 2011.

The 36 members comprising the Council said they made significant progress concerning the regulations and announced that they intend to continue the work with a view to adopting them during their 30th session in 2025 (likely late in the year). A roadmap for continued work until their session in 2024 has been adopted.

> ".. by July 2023, ISA had by no means finished the job of issuing the necessary rules and regulations for mining permits."

The Council's decision means that the mining companies will need to exercise patience, especially those that had hoped for a quick resolution - TMC had its eyes on first ore mining late 2024. But, by July 2023, ISA had by no means finished the job of issuing the necessary rules and regulations for mining permits. ▸



SOURCE: MODIFIED AFTER THE METALS COMPANY

The Clarion-Clipperton Zone, indicating protected areas and exploration licences.

This collector was a key piece of the pilot nodule collection system trial carried out by The Metals Company and Allseas in the CCZ in September last year.

SOURCE: THE METALS COMPANY

TIME RUNNING OUT

Time was seemingly running out though. Two years earlier, the Republic of Nauru invoked a rule, requiring the ISA to adopt regulations for exploitation in the deep sea by July 9th, 2023, or accept applications under the current regulations that exist by that date.

Norway was among the countries that asked ISA to fulfil the Authority's mandate to finalise the regulatory framework by July. However, other ISA member countries as well as external stakeholders such as environmental organisations, argued that more time was required to better understand the impact of mining on the ecosystems.

Even though the green light for deep sea mining is yet to be given in the ISA area, the "two-year rule" still technically holds, meaning the Authority will have to accept a "plan of work" by companies that are eager to move forward.

ISA stated that they adopted a decision relating to such applications, should they appear before the exploitation regulations are completed. In short, if they do receive a "plan of work", they will decide how to take action during their next meeting in November 2023.

The Head of the Spanish delegation, Diego Bermejo Romero de Terreros, Ambassador of Spain and Permanent Representative of Spain to ISA, welcomed the agreement on the way forward as a key outcome of the meetings. "It will allow us to fulfill our mandate to complete the regulations while ensuring the effective protection of the marine environment," he claimed.

The CEO and Chairman of The Metals Company, Gerard Barron, said in a statement that the company is disappointed that ISA had failed to adopt regulations by July 9th, but that he believed the finish line is within sight.

Sponsored by member states, companies such as TMC are currently allowed to do mapping, exploration, and technology development and testing in the CCZ. ISA adopted regulations for exploration more than ten years ago, and they have currently granted more than 30 exploration contracts.

The Council will issue a consolidated negotiating text of the draft regulations following their meeting in November 2023. ■

The mineral resources in the CCZ are found in polymetallic nodules, potato-sized concretions on the seafloor that are rich in metals. TMC has for good reason branded them "battery rocks". Chemical analyses have shown that the nodules contain several metals such as nickel, cobalt, copper, and manganese that will likely be in high demand going forward due to their increasing use in battery manufacturing and other green technologies.

The grades surpass most onshore mines, and the CCZ is considered the largest nodule field in the world. Nodules are deemed advantageous in terms of extraction compared to other on- and offshore deposits. There is no need for blasting or quarrying to retrieve the nodules. Their size makes them easy to handle and harvest, and the high metal content results in smaller tailings. TMC even believes they can make use of all mineral components, leaving no residue at all.

Two Norwegian companies are involved in the CCZ: Loke currently holds two licences after they acquired UK Seabed Resources, while Green Minerals earlier this year announced that they signed a Memorandum of Understanding to partner in on a licence.

TECHNOLOGY

"In-situ tests show that even in the face of earthquake shocks the new technique produces flow-path seals that are durable and potentially have a wide range of subsurface applications."

Hidekazu Yoshida – Nagoya University

Half full or half empty

Poll shows almost 50-50 split when it comes to the question if oil output can double as a result of new fracking technology

"OIL MAJOR ExxonMobil bets that through technological advances, shale producers can manage to double crude output from their existing wells." That was one of the headlines from an article published by the website oilprice.com in June this year.

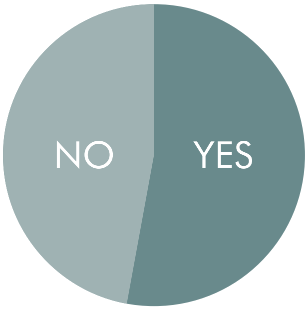
In order to find out what our followers on LinkedIn think about this claim, we decided to run a poll. It appears that out of a group of 48 voters, 52% are of the opinion that it is possible to achieve this, whilst the remaining 48% see it as a fairy tale. An almost 50-50 split. So, all eyes are now on ExxonMobil to see if they can make this happen and cause another wave of production from the shale patch.

As reported by Bloomberg News, ExxonMobil Chief Executive Officer Darren Woods said at the Bernstein Strategic Decisions conference this spring: "There's just a lot of oil being left in the ground. Fracking has been around for a really long time, but the science is not well understood."

According to Bloomberg, Exxon's plans include a more precise way of fracking along the wellbore, targeting previously undrained intervals. In addition, the major is also looking at ways to keep fractures open for longer.

Refracking wells is a technique that has already been adopted by several players in the US shale business, the oilprice.com article continues. In some cases, as a study performed by Robert Barba suggests, refracking of an older well can result in a significant uplift in recovery rates, because fractures resulting from a refrac operation will propagate into another direction compared to the initial fracking job. This is caused by the drop in pressure in the reservoir as a consequence of production and the associated change in stress regime.

Yet, refracking remains a niche market in the oil patch, the oilprice.com article further informs using data presented by Rystad. Out of the 8,900 total stimulations from January to September, only a little more than 2% were refracked wells. ■



VOTES: 48 (25 Y - 23 N)
Is it possible to double crude output from existing shale wells through refracking smartly?

FEEDBACK

We tried to get some feedback from individual voters on the motivation for their choice, but this was harder than expected. It seems that people are reluctant to share their insights, which could indicate that some just vote to see the result of the poll. For that reason, we will introduce an option to subsequent polls that includes "Here for the results".

Fracking operation in the Permian.

PRODUCING THE PERMIAN OCEAN

Ted Cross from Novi Labs recently posted on LinkedIn how the rise of oil production in the Permian Basin also meant a steep rise in water production. Someone rightfully commented on the post by stating that it is the fossil water from the Permian Ocean that is currently being produced. Interestingly though, Water-to-Oil Ratios have started to come down a little in the Permian. This could be explained by a gradual move towards lower permeability reservoirs where there is less free water available.

PHOTOGRAPHY: GETTY IMAGES

Rapid and long-lasting sealing of bedrock using concretion-forming resin

The induced formation of calcium carbonate concretions may form better barriers to flow than conventional sealing methods, also because of self-healing effects

HIDEKAZU YOSHIDA, NAGOYA UNIVERSITY

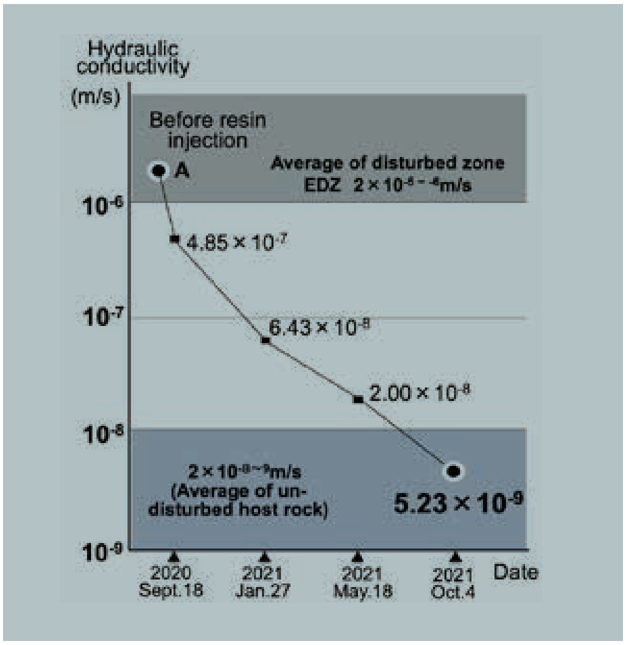
Wells and underground excavations typically require effective permanent sealing when they have fulfilled their intended functions. Abandonment of hydrocarbon production or CO_2 injection wells or sealing of underground waste repositories are key examples of this.

Seals must render potential bedrock flow paths impermeable. Examples of possible flow-paths are fractures, fracture zones and fault crushed zones that are intersected by wells or underground excavations, and damaged rock around boreholes or excavations.

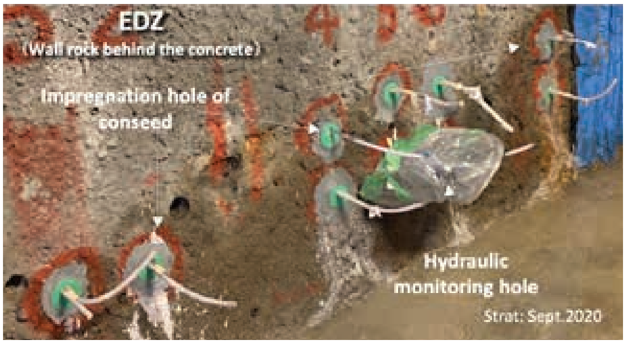
However, commonly used cement sealing materials may be insufficiently durable to achieve permanent sealing due to long-term leaching of key constituents, for example $Ca(OH)_2$ by formation waters. In addition, physical perturbations of seals, such as those caused by earthquakes, must also be taken into account for any kind of long-term usage of the underground environment.

Through the study of the natural formation process of spherical calcium carbonate concretions, a team of researchers from Japan and the UK have successfully developed a technology for rapidly producing long-lasting seals. This technology stimulates calcite ($CaCO_3$) precipitation along flow-paths by using a concretion-forming resin. The aim is to reproduce the process by which spherical calcite concretions form naturally.

The sealing capability of resin has been tested by in-situ experiments on bedrock flow paths next to a tunnel in an underground research laboratory (URL) at 350 meters depth at Horonobe, Hokkaido, Japan. The results of all experiments showed a decrease in permeability to as low as 1/100 to 1/1,000 of the initial permeability over a period of one year.



Hydraulic conductivity has decreased more than two orders of magnitude during one year to almost the same level as undamaged bedrock by verification in-situ test in URL. Such a continuous effect has not been seen using existing conventional sealing methods.



Test site showing injection of concretion-forming resin conseed.

EARTHQUAKES

During the experiment, earthquakes with focal points at 2 to 7 km and a maximum magnitude of M5.4 occurred below the test site and disturbed the seals. However, the flow-paths sealed initially by the concretion-forming resin were resealed rapidly, and within a few months had recovered to the same hydraulic conductivities as those occurring before the earthquakes.

All data provided by in-situ hydraulic tests, core observations after monitoring, and detailed mineralogical and geochemical analysis show that the fracture network developed in the excavation damaged zone (EDZ) around the tunnel was rapidly sealed by synthetically formed calcite.

This calcite formed due to super-saturation caused by synthetic 'concretion-seeds' reacting with groundwater constituents. The results of the in-situ test show that even in the face of earthquake shocks the new technique produces flow-path seals that are durable and potentially have a wide range of subsurface applications. ■

A leap into energy

Seequent's Leapfrog software applies technology first used in healthcare to speed up the process of geological subsurface modelling

JEREMY O'BRIEN, SEEQUENT

THE APPLICATION of geoscience and digital techniques to meet challenging carbon reduction goals in pursuit of cleaner energy forms has never been more critical in enabling growth and delivering energy projects more efficiently. Technological innovation is the key to quicker, more efficient and connected workflows.

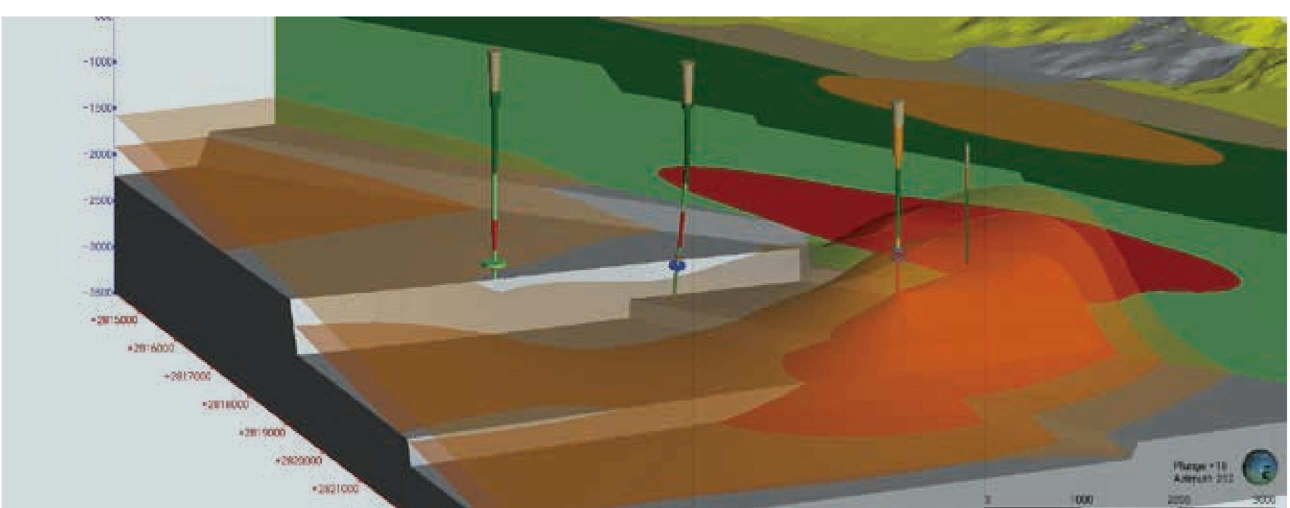
Seequent's recently launched Leapfrog Energy's ability to produce a comprehensive 3D model, using implicit modelling to reduce interpretation bias, is uniquely supporting work across different energy transition applications such as geothermal, wind, CCUS and oil and gas.

One of the key challenges in 3D subsurface characterization is the availability of often very limited sets of "hard" data, usually in the form of well or core samples, combined with a requirement to make inferences on the geology of the areas not tested by the drill bit. Consequently, multiple scenarios often need to be run in subsurface modelling software in order to capture the different geological scenarios that could exist. In turn, this demands powerful computing capabilities such that model run times are kept to workable lengths. One of the ways to speed up the process of faster subsurface modelling is the way interpolation is carried between these points of hard data.

This challenge of accelerating the way interpolation is performed is not unique to subsurface modelling software. It is not a recent thing either. Already in 1995, ARANZ developed the FASTRBFTM algorithm, which stands for Radial Basis Function, to speed up the process traditionally undertaken by dual kriging. One of the first sectors to use this way of interpolation was healthcare, which meant that prosthetics could be designed in a much more efficient way.

In 2004, Seequent adapted the FASTRBFTM algorithm to develop the Leapfrog Mining software, which introduced implicit modelling to subsurface modelling rather than using traditional wireframing or explicit interpretation techniques and digitizing. This increased the speed of geological model-

"Subsurface specialists need flexible and fast tools like Leapfrog Energy to understand subsurface conditions and share their knowledge in a way that resonates with technical and non-technical stakeholders. Leapfrog Energy can help companies make critical decisions in days rather than months due to its modern, workflow-based implicit modelling."



An example 3D model of a Synthetic Geothermal System created in Leapfrog Geothermal to show the geology, temperature, wells with casing designs and feed zones.

PICTURE: SEEQUENT

ling significantly, and models were also automatically updated as new data was added.

The company also started to explore ways to expand beyond the mining sector and find other industries active in the subsurface space that could benefit from the advanced 3D modelling capability. Along with the civil and environmental sectors, the geothermal industry quickly appeared on the radar. Geothermal had been the poor cousin of the mining and oil and gas industries. 3D modelling was not a core part of the industry, and it did not have a tailor-made solution.

Seequent teamed up with New Zealand geothermal experts utilising the core capabilities of Leapfrog Mining and added industry-specific capabilities such as well planning, pre and post processing for reservoir simulation and geophysical data integration, providing a robust tool for geothermal. In 2012, Leapfrog Geothermal was born and now supports over 50% of the installed geothermal power capacity globally.

The workflow-based modelling approach embedded in Leapfrog today allows users to build gridless geological and properties models that dynamically change when input data related to any part of the model is changed or new information is added.

With a strong foothold in the geothermal sector, the opportunity to again move to other subsurface sectors formed a logical next step. As such, Leapfrog Energy was launched earlier this year, highlighting that Seequent's geological modelling solutions and its geostatistical capabilities are now being used in offshore wind, carbon capture and storage and oil and gas. Examples of Leapfrog being utilised in Offshore Wind, sedimentary environments and geothermal are included in the figures. ■

IMPLICIT MODELLING: Rather than stitching together multiple 2D interpretations and being constrained by grids, implicit modelling utilizes a global solver to generate geometric surfaces and volumes. Boolean logic is used to represent geological concepts (e.g., depositional surfaces, erosional surfaces, intrusions/channels and veins) and these can be augmented with multiple other data sets (interpreted seismic horizons, faults, petrophysical data etc.) to rapidly understand subsurface geometries. Probabilistic and Objective: a data-driven approach that learns relationships between variables to discover complex and non-linear relationships that a geoscientist may not.

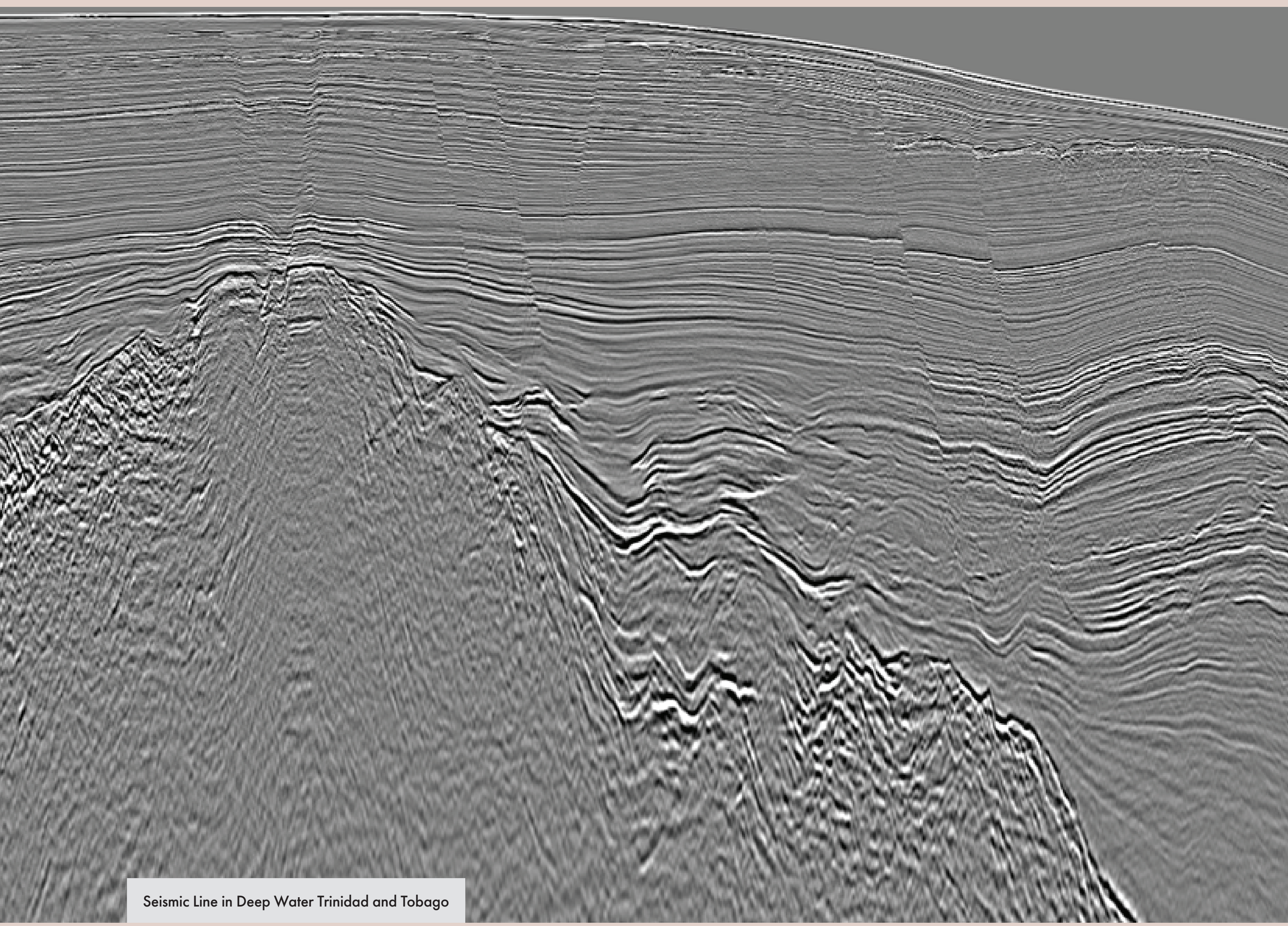
FLEXIBLE: Can handle sparse and varied data from a plethora of sources. Helpful when data is difficult to obtain and incomplete.

TIME-EFFICIENT: Can generate complex shapes and multi-z surfaces allowing geoscientists to spend more time analyzing geology.

DYNAMIC AND AUTOMATED: Rapidly update when new data becomes available and iterate alternate hypothetical models with dynamic scaling, reducing geological risk and increasing precision.

SIMPLE AND STABLE: Account for uncertainty and variability of the data and provides a measure of confidence in the predictions.

Trinidad and Tobago's advantage: Underexplored frontier amongst discoveries



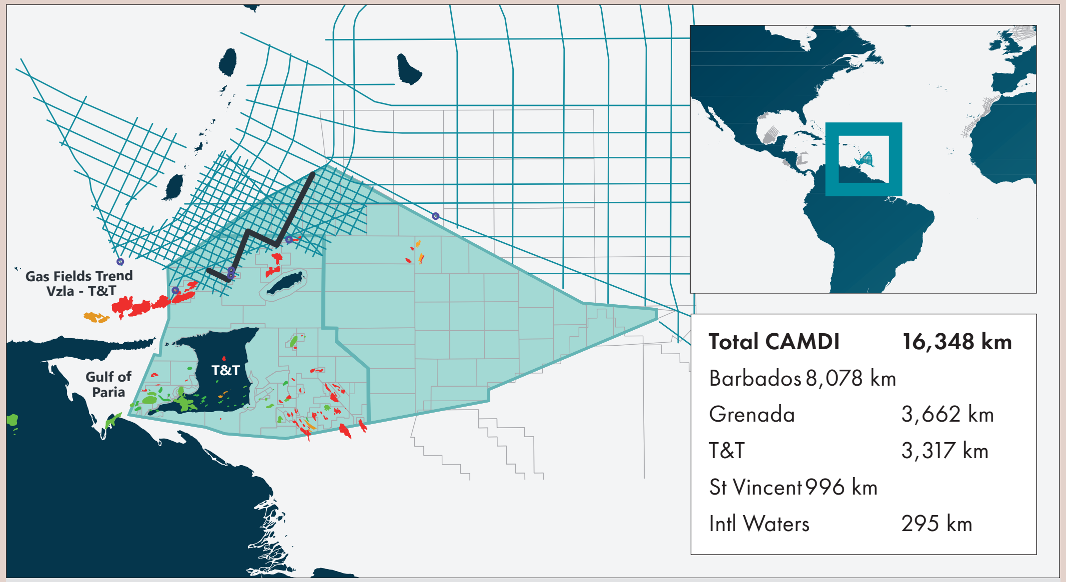
Seismic Line in Deep Water Trinidad and Tobago

The Tobago Trough is an underexplored area that has excellent exploration potential, evidenced by surrounding discoveries. However, only a few exploration wells have been drilled in this vast frontier area. To unlock this potential, Geoex MCG acquired 16,348 km of long-offset high resolution 2D seismic data in the region.

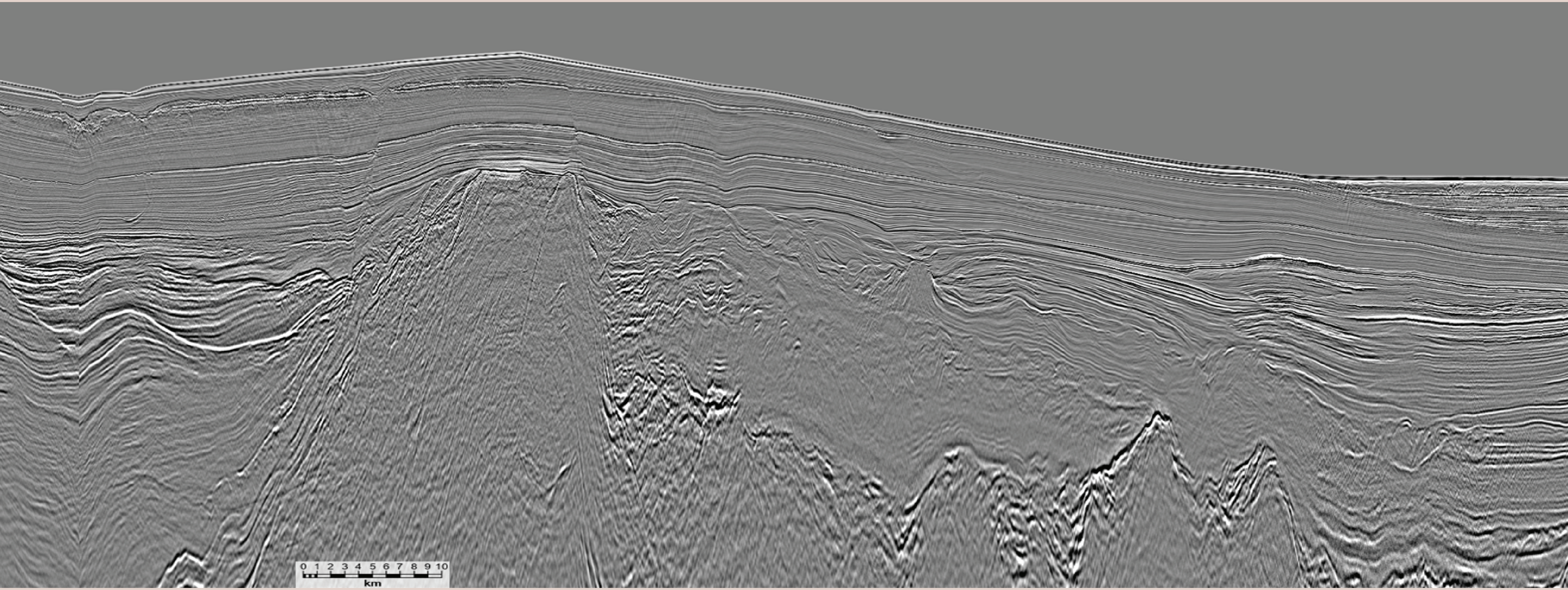
The survey is designed to improve understanding of the regional tectonic framework of the various basins along the Southeastern Caribbean. Additional seismic was acquired in a detailed grid, spanning T&T and Grenada, which ties producing areas to the deeper part of the Tobago Trough, and covers parts of T&T's shallow and deep-water blocks. This seismic remains an indispensable dataset, supporting upcoming licensing rounds with high quality PSTM, PSDM, gravity and magnetic data.

The Ministry of Energy and Energy Industries (MEEI) of Trinidad and Tobago has published the expected blocks on offer for Competitive Bidding in late 2023.

Geoex MCG



Map: CAMDI Seismic Lines over T&T Bid Round Blocks



T&T: A closer look at oil and gas exploration prospects

The Caribbean Atlantic Margin Deep Imaging seismic survey (CAMDI) spans 16,348 km, with long offsets (12 km) and a deep record length (18 seconds). This transnational survey covers acreage across the maritime borders of Barbados, Trinidad & Tobago (T&T), Grenada, and St. Vincent

JENIFFER MASI AND MIKE POWNEY, GEOEX MCG

THE SURVEY WAS ORIGINALLY DESIGNED in two grids. The regional grid provides a better understanding of the tectonic framework of the different basins along the Southeastern Caribbean and Western Atlantic Margin of Northeast South America. The detailed grid, offshore Trinidad & Tobago, and Grenada is designed to provide more localized detail, and to outline potential prospects. Seismic within the detailed grid ties the producing areas of T&T to the underexplored deeper part of the Tobago Trough. Approximately 3315 km of the CAMDI survey are located offshore Trinidad & Tobago, covering shallow and deep-water blocks.

GEOLOGICAL PROXIMITY TO PRODUCING FIELDS

The CAMDI MC2D survey is situated in close proximity to the producing areas of the Orinoco Delta and Northern T&T. The tectonic history of the region has afforded a preferential setting for hydrocarbon accumulations.

Tectonics offshore T&T were significantly influenced by the North/South American tectonic plates and their interaction with the Caribbean plate. During the Late Jurassic to Early Cretaceous, significant rifting occurred between North and South America. Following this rifting, the Caribbean plate migrated eastward from the Late Cretaceous onwards, relative to the North and South American plates to its present-day position.

During this migration and throughout the Cenozoic, the Caribbean plate converged obliquely with the North and South American plates in a diachronous manner. The points of collision shifted from westernmost Colombia during the Santonian era to western and central Venezuela in the Paleogene & eastern Venezuela in the Neogene. Present day convergence is believed to be between the Paria Peninsula of Venezuela and the Northern Trinidad Range. The Atlantic lithosphere has been subducting beneath the Lesser Antilles throughout these epochs and into the present day. The collision between these plate boundaries created a range of geodynamic processes including subduction, transpression and transtension, creating a large accretionary ridge which contributes to the regional geology.

The Tobago Trough is a curved-shaped forearc basin with a sedimentary fill of approximately 11-14 km of Oligo-Miocene to Pleistocene sediment. It is bounded by the Lesser Antilles arc to the west, the Barbados accretionary prism to the east, and the St Lucia Ridge to the north. To the east the Tobago Trough transitions to the Carupano basin offshore eastern Venezuela. The origin and age of the Tobago Trough basement is unknown. However, radiometric and paleontological ages from outcrops found in Tobago seem to indicate a Late Cretaceous forearc origin. This is supported by basement ages from Oil & Gas exploration wells in the Carupano basin.

The complex structural setting, geometries and subsidence mechanisms of the basins located in this area are controlled by several fault systems, that were the result of major tectonic events in the southeastern Caribbean.

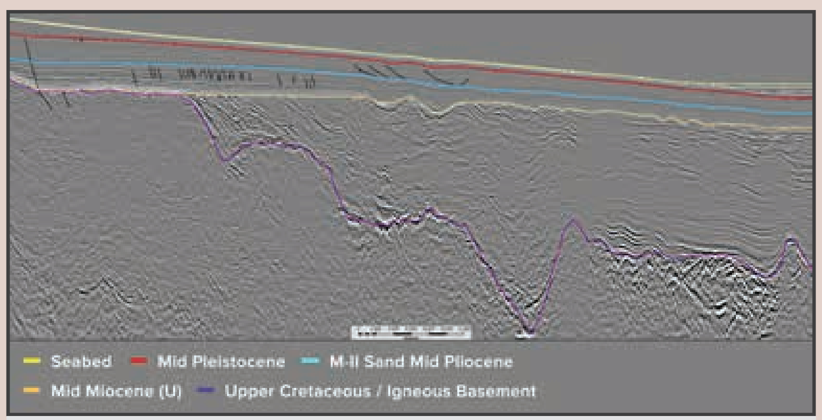


Figure 1: Seismic Section SSW-NNE across T&T showing the interpreted horizons.

DIRECT CONNECTION TO WORLD CLASS SOURCE ROCK (EQUIVALENT TO LA LUNA)

Distal DSDP and ODP wells offshore Venezuela and Barbados have shown evidence of a regional Upper Cretaceous source rock equivalent to the La Luna Formation of Venezuela. Maturation is predicted to have started during the Miocene in the Eastern Venezuelan Basin and during the late Miocene-Recent offshore Trinidad. Onshore Barbados, the Woodbourne oilfield produces oil and gas from the Eocene Scotland Group, sourced from a La Luna age equivalent source rock. This oil play remains unproven as there are no well penetrations in the Tobago trough. However, the CAMDI MC2D survey reveals a distinctive regional high amplitude horizon that could represent the Top Cretaceous Mejillones Complex (Figure 1).

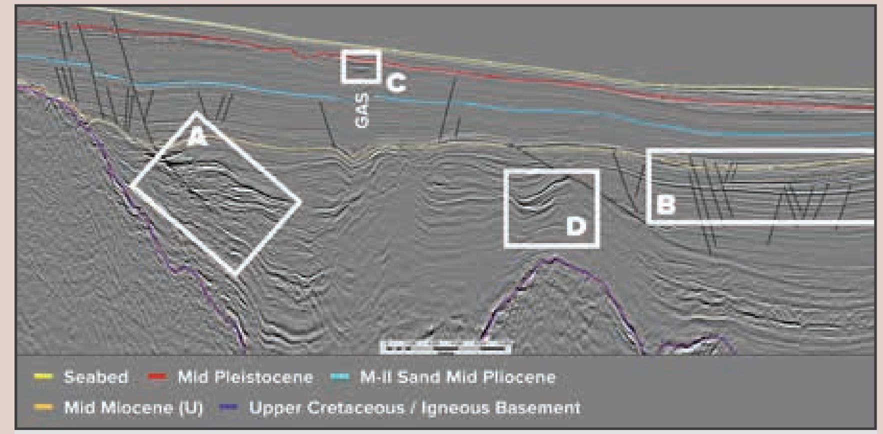


Figure 2: Lead Example. A. Turbidite Deposit. B. Mid Miocene Channels Exhibiting DHIs. C. Traditional Pliocene Play. D. Three Way Closure Against Fault with DHI's.

STRUCTURAL TRAPPING PLAYS A MAJOR ROLE

The area covered by the CAMDI survey is significantly underexplored. However, several biogenic gas fields (Hibiscus, Sancoche, Orchid, etc.) have been discovered in close proximity. The producing intervals are Miocene and Pliocene aged turbiditic and deltaic sands, which were deposited during the progressive easterly progradation of the Orinoco Delta.

Structural trapping plays a major role within the study area as reservoirs are often trapped against faulted structures and turbidites. While most target intervals and discoveries are situated in Pliocene intervals, Mid Miocene and Eocene sands are also possible reservoirs. Sands in the basin are predominantly turbiditic and channelized features. Above these sands, there is a highly contrasting interval representing a good seal for the system. Example leads include (Figures 2 and 3):

- Mid Miocene and older Turbidite Deposits
- Mid Miocene Channels exhibiting DHI's (Amplitude anomalies)
- Four-way closures exhibiting DHI's
- Three-way closures against a fault exhibiting DHI's
- Truncational play against the Ridge

All the necessary hydrocarbon elements for a working petroleum system are present in the region. Gas production from nearby fields offshore T&T, along with the onshore Barbados Woodbourne oil field production provide evidence for commercial hydrocarbon potential in the region.

The CAMDI MC2D survey shows a regional distribution of multiple, structural traps and potentially high-quality sheet turbidite reservoirs. Overlying hemipelagic marine clays would form the sealing facies with migration into the reservoirs (Miocene – Eocene) occurring along a combination of thrust and transtension strike slip faults associated with the deformation front. The presence of a La Luna age equivalent source rock suggests a potential oil play within the Tobago Trough, with further reservoir-seal pairs provided by the Plio–Pleistocene deep marine pelagic sediments.

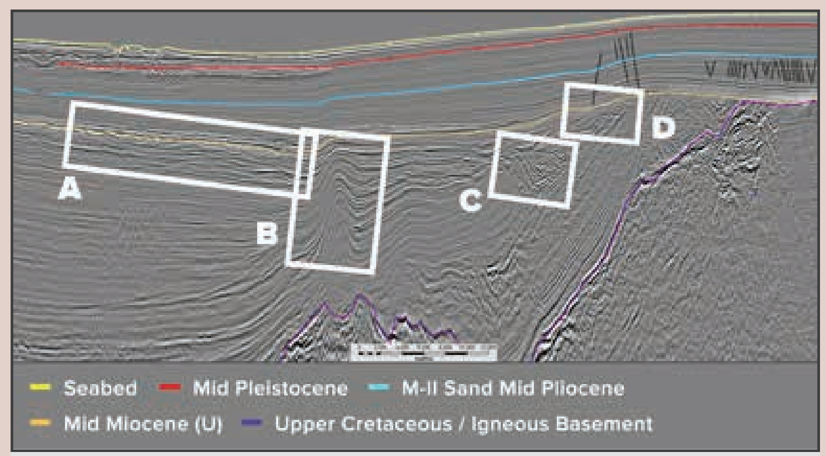


Figure 3: Lead Example. A. Mid Miocene Channels with DHI's. B. Four Way Closure with DHI's. C. Turbidite Deposit. D. Truncational Play Against Ridge.

A UNIQUE FRONTIER OPPORTUNITY

The Tobago Trough is an underexplored area flanked by oil and gas production in Barbados, T&T and a new gas discovery offshore Grenada. Seismic interpretation shows a thick sedimentary succession with high hydrocarbon potential. A Cretaceous, La Luna age equivalent, oil prone source rock is believed to have been identified, charging prospects in the area. The CAMDI survey offers the most modern PSTM, PSDM, gravity and magnetic data in the region, ideally positioned to support the upcoming license bid rounds in Trinidad & Tobago.

References provided online

NVENTURES

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Australia faces a future of contrasting policies for oil and gas in a rapidly evolving energy landscape

Australia's hydrocarbon sector appears to be having an identity crisis, with significant hydrocarbon state revenues contrasting with waning government support for new exploration for oil

GEOFF FREER, NVENTURES

STATE BUDGETS are in surplus for those with active producing sectors. For instance, Queensland announced A$2.33 billion in petroleum royalties for 2023, helping underpin a record A$12 billion surplus and a projected A$7 billion over the next five years.

Similarly, Western Australia announced a A$4.2 billion surplus for 2023 with the WA LNG industry comprising $66 billion or 23% of state gross production. Changes to the Petroleum Resource Rent Tax system will also result in an additional $2.4 billion over four years by capping deductions at 90% of annual income of large-scale projects.

Overall, the gas industry alone will contribute A$16.2 billion in state and federal revenue in 2023 alone.

However, the 2023 Federal Licence Round, for which nominations closed on 1st September is yet to progress with no consultation on included areas yet commenced. Only 10 areas were released in the 2022 Federal License Round with anectodical evidence suggesting over 40 areas were nominated by industry.

In contrast, over 63,000 km^2 of the offshore was offered in the 2021 Greenhouse Gas (GHG) Acreage release. Firm spend on the GHG bid rounds exceeds spend on Petroleum exploration bid rounds by a factor of four. Australia's permit awards, area under title and exploration spend have been in decline since 2013.

Australia is clearly taking its net zero by 2050 target seriously, but also understands the role of gas in the transition and the fact that manufacturers rely on gas for 42% of their final energy consumption, including many of the miners providing the various materials for making electrification possible around the globe.

Indeed, exported LNG is preventing many countries, including Japan, Germany and Korea, from expanding coal-fired generation further. However, the Federal Minister for Resouces, Madeleine King, took her Keynote speech at the recent APPEA conference to express her desire to build a "world class decommissioning industry" in Australia, which may signal more of her intentions.

Australia has also introduced the "Safeguard Mechanism", which effectively legislates that all future oil & gas developments should be net zero. This is a pragmatic solution to a problem where the use of hydrocarbons can never be avoided totally, but its impact on emissions is reduced.

Whilst gas production is healthy and exports are rising, domestic gas markets are tight. The Federal government have attempted to install a price cap of $12/GJ on wholesale prices on the East Coast, which quickly resulted in explorers and producers signalling drastic reductions in future activity. The mechanism is still being modified to provide certainty to the industry.

WEST COAST

Even West Coast gas prices are approaching $10/GJ despite many years of exploration success for onshore gas. Beach Energy historically has taken a front-row seat with several producing fields after its first entry into the Perth Basin in 2008. Beach and operator Mitsui first identified the potential of the Kingia Sandstone during the drilling of Senecio 3.

However, the company did not really capitalise on that knowledge and allowed Strike and others to license prospective areas. To further Beach's woes, reserve write-downs and cost blow-outs at its Mitsui-operated Waitsia Stage 2 project have delayed first gas and reduced its chances of exporting gas via Karratha as the export exemption it received only lasts 5 years. Coupled with recent poor exploration results at its Trigg-1 well, the running room for Beach in the Perth Basin seems limited. This fact may have been behind Beach Energy's bid for Perth Basin explorer Warrego in November 2022. Beach's bid galvanised two other Perth Basin contenders, Hancock Energy and Mineral Resources, with Hancock Energy the victor.

Yet, the onshore Perth Basin remains an exploration hotspot with up to 11 wells scheduled to be drilled in 2023 by Beach, Strike and Mineral Resources.

"Firm spend on the GHG bid rounds exceeds spend on Petroleum exploration bid rounds by a factor of four."

EXPLORATION MUTED

Exploration elsewhere is muted, not surprisingly with no refresh of portfolios via bid rounds seemingly available. Chevron and Woodside are due to drill Wheatstone Deep-1 and Gemtree-1, respectively, as exploration tie-backs to Wheatstone LNG. Central Petroleum and Santos plan to progress exploration in the Amadeus Basin in the Northern Territory with two sub-salt plays to test not only gas, but helium and hydrogen potential.

The approval of a gas pipeline to connect to the East Coast gas market could re-ignite the embers of Australia's central basins. Following this theme, the Beetaloo and MacArthur Basins offer immense gas potential after the fracking moratorium was lifted in the Northern Territory in April 2018. Empire Energy have drilled multiple wells at the Carpentaria site, proving up around 1.7 TCF contingent resource although flow rates will need to be increased for a commercial development. Current flow is sub 6 mmscfd from 2 km long lateral wells.

Santos, Origin and several other smaller players have exploration and appraisal plans as well. At the same time, Tamboran Resources has taken a long-term view by securing land in the Port of Darwin, adjacent to Inpex and Santos LNG terminals, on the back of the expectation that the Beetaloo basin will export 6.6 MTPA by 2030 to meet domestic shortfalls.

LOOKING OVERSEAS FOR GROWTH

What does this all mean for exploration in Australia? Gas and oil tell different tales, with gas production healthy and efforts to bring new (albeit tight) onshore gas to market, along with some backfill exploration offshore. Gas exploration and production is healthy with the exception of Australia's South East which is where most demand lies and most regulatory restrictions are present.

Oil exploration, on the other hand, is being left to wither to 40-year lows whilst Australia imports 190,000 bopd of crude and over 800,000 bpd of refined products and demand is not set to fall below currents levels before 2040.Larger operators are looking overseas for growth, evidenced by Santos' acquisition of Oil Search and growing its portfolio in Papua New Guinea and North America over developing its previously much heralded Dorado discovery on the North-west shelf. Santos was forced to redesign the development to reduce emissions from gas re-injection. Woodside has expanded its international portfolio with recent entries into Egypt, Congo and Namibia, along with imminent new oil production offshore Senegal.

Australia has excellent exploration potential both onshore and offshore, even for oil. Unless it wants to forgo energy security, importing crude rather than producing its own, the government could encourage many very willing companies to get back to exploration. Otherwise, it will be using high-emission barrels from international exporters to run its trucks for many years to come. ■

MAP: NVENTURES

A passion for the product

Kirsti Karlsson has been a key player in the GEO EXPRO team for decades

"MY BEST TIP for salespeople new to the job is to establish long-term relationships with clients. Let them know you will go the extra mile and show them a passion for your product and services and do not stop explaining how it is relevant to their business", says Kirsti Karlsson.

Since the start of the GEO EXPRO magazine twenty years ago, Kirsti has been the sales manager. She is the face of the magazine at the many conferences she attends, and lots of marketing people will know Kirsti through her emails and phone calls as well.

"I am a teacher by background and have no formal education in sales or marketing", Kirsti says. "However, I do believe that my teaching education and experience have been very valuable in my sales and marketing role, as it is all about communication and understanding people!"

GEO EXPRO continues to appear in print, we wonder: Is it harder these days to find advertisers for printed media? Kirsti responds: "I have seen a decline in print advertising, but surprisingly not as much as I thought it was going to be a few years back when many companies started focusing more on online campaigns. I see that some are back to also doing print advertising, probably because people also realise that print magazines still play an important role in this industry."

Kirsti has visited many, many conferences over the past decades. "The conferences are following the cycles of the industry. There is still a focus on oil and gas, but renewables are becoming more and more important. After a decline in the number of booths on the exhibition floor after Covid, they are now coming back, and I've also seen new companies exhibiting. However, I have not seen many of the huge two storey booths as in back the hay days", she laughs.

After decades of hard work, often literally around the clock, Kirsti is now approaching a well-deserved retirement. "I have recently moved from London to a small coastal town in Sweden, so I need to explore more the opportunities this country offers, but my main goal is to spend more time with family in Norway and Germany, and allocate more time to my friends. Our house in Provence in France has been a "havre de paix" for almost thirty years, so I hope to stay there for several months a year and maybe grow back my kitchen garden."

"It is twenty years since we started preparing the magazine and it has been a great journey with lots of fun. What I thought was going to be a part-time job ended up being three times more, but I have never regretted it. I want to thank all the great people I have worked with and all the people I have gotten to know as clients, readers, partners and suppliers!" ■

NORWEGIAN WITH A FOREIGN TOUCH

Kirsti is Norwegian and grew up in Norway. She studied English and French, followed by completing a teaching degree. Having been an expat for almost 30 years, she has lived in different countries around the world. However, she always got involved with community projects, ranging from sitting on school boards, to running the SLB Spouse Association in London and teaching Norwegian to expat wives in Stavanger and Norwegian children while living in the USA.

A familiar sight: Kirsti Karlsson handing out magazines at one of the many conferences she has attended over the last 20 years.

> ".. it has been a great journey with lots of fun. What I thought was going to be a part-time job ended up being three times more, but I have never regretted it."
>
> *Kirsti Karlsson*

Natural fracture networks are not created equal

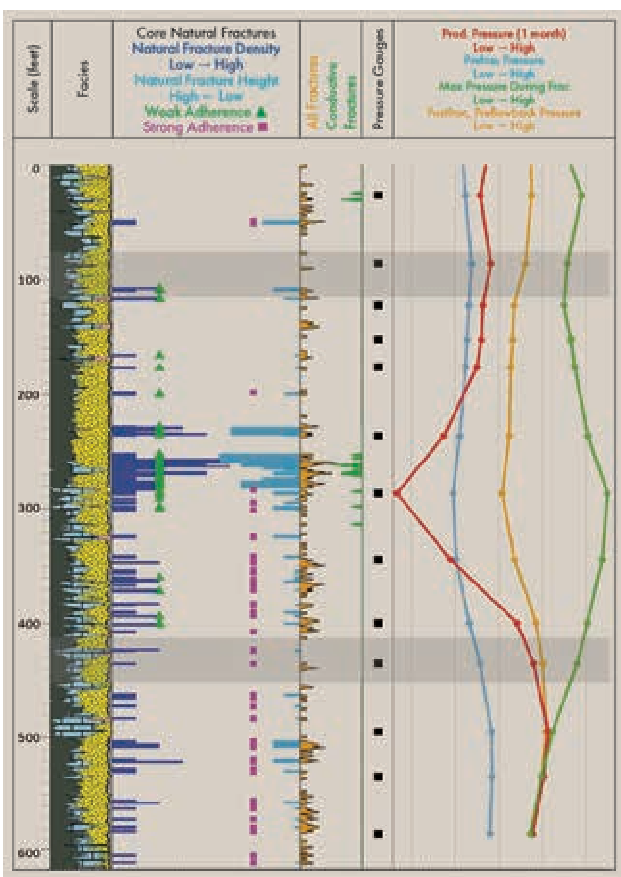
A Delaware Basin case study demonstrating the impact of fracture networks on reservoir pressure

MOLLY TURKO, DEVON ENERGY

Dr. Molly Turko,
TurkoTectonics@gmail.com

IN A TIGHT RESERVOIR, fractures may enhance the permeability and give production an upside. In a porous reservoir, a natural fracture network may connect to water, in which faults and fracture zones may want to be avoided. In some reservoirs, the fractures may be insignificant to operations and production. But how can we know which of these scenarios might ring true for your reservoir?

A recent analysis of a vertical data well in the Delaware Basin allowed us to understand the impact of an open natural fracture zone on an interval we were appraising. Data from this well include 600 feet of continuous core, petrophysical, image, and geomechanical logs, along with 13 in situ pressure gauges spanning 2 horizontal target zones.



Log showing petrophysical facies, natural fracture density, image log fracture density of all fractures in orange and conductive fractures in green, location of pressure gauges, and four pressure curves from various times. Target zones are highlighted in gray.

PRESSURES SAY IT ALL

The biggest takeaway comes from analyzing the 13 pressure gauges within the cored interval while nearby wells were being hydraulically fractured and produced. Column 6 in the figure shows pre-frac pressure (blue curve), post-frac pressure pre-flowback (orange curve), maximum pressure during frac (green curve), and reservoir pressure after one month of production (red curve) from nearby wells.

A highly fractured zone exists near the center of the core. The pressure gauges adjacent to the highly fractured zone show anomalously low pre-frac pressure (blue curve) but the highest pressure increases during the frac (green curve). We attribute this to the fracture network being depleted by nearby parent wells, then rapidly repressurized at the start of child-well fracs.

However, once the child wells were brought online, we see the highest drawdown through this zone after one month of production (red curve). We have concluded that the highly fractured zone has a high order of control on the vertical drainage profile through this portion of the stratigraphic section. In contrast, the lower three pressure gauges between 500-600 and where fracture adherence is strong, show that the producing pressure lacks any significant drawing down indicating that we are not seeing a contribution from this zone.

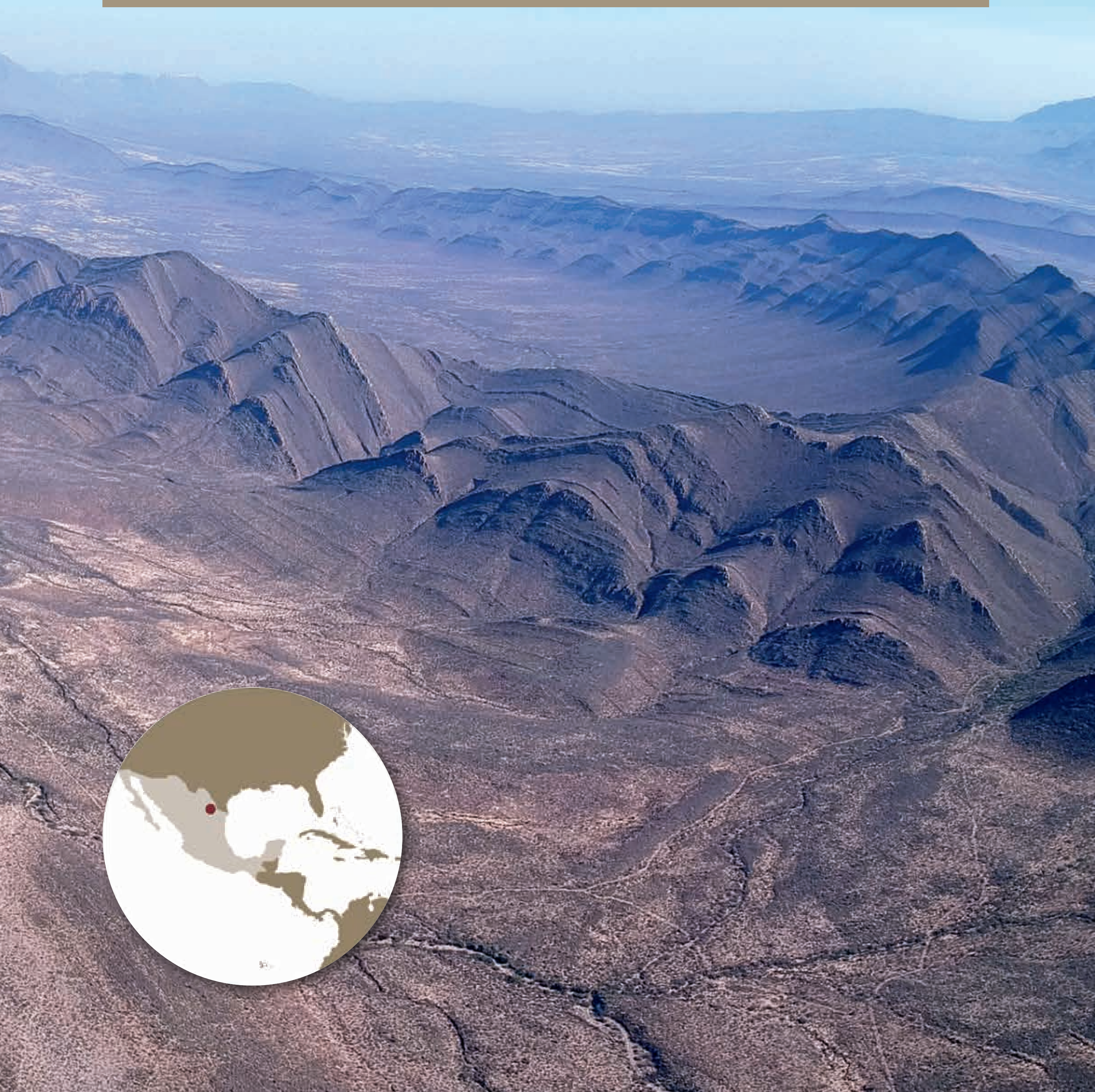
Between the accelerated production from the fracture zone, and lack of contribution in the deeper zone, we conclude that understanding and quantifying the performance impact of the fracture zone is helping inform optimal targeting and development strategies for the asset going forward along with helping to reduce any depletion risks related to open fracture networks. The results from this vertical well are a great example of how valuable it is to collect and integrate multidisciplinary data and expertise to help asset teams optimize operations and production for years to come! ■

Co-authored by Brendan Elliott, Sloan Anderson, Jarrett Borell, Jon Roberts, Zak Ward - Devon Energy.

Textbook geology

THE PANORAMIC PHOTO shows the El Gordo Anticline plunging in the subsurface towards the right of the image where, unseen, the El Gordo Diapir crops out. The El Gordo Anticline is part of the Coahuila fold and thrust belt, which is thought to have started to develop during the Late Cretaceous in an ancient foredeep basin (La Popa Basin). Most of the hinge of this anticline has been eroded, producing the current triangular facet-bearing scarps on both subvertical limbs of the fold. These facets have been produced in reddish sandstone packages interpreted as part of a deltaic system (the Cretaceous Muerto Formation). The El Gordo Anticline is about 60 km to the northwest of Monterrey City, in the state of Nuevo Leon, Mexico.

Photography and text: Ramón López Jimenez



FEATURE YOUR OUTCROP

In this series, we show a range of outcrops to give more context to what core interpretation typically allows. Do you have a suggestion for an outcrop feature? Get in touch with Henk Kombrink – henk.kombrink@geoexpro.com.

The northern Perth Basin in a nutshell

Using core photos, this is part one of two articles describing the Permian and Triassic infill of one of Australia's onshore exploration hot spots

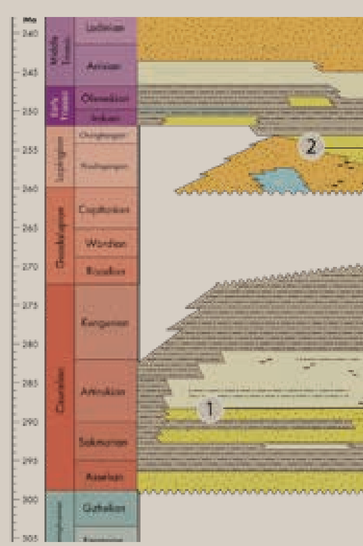
AMELY ALLGÖWER, MGPALAEO

THE NORTHERN Perth Basin is currently one of the most active areas of petroleum exploration in Australia, holding most hydrocarbon accumulations discovered in the Perth Basin thus far, including all the presently operational oil and gas fields. The basin is also piquing interest in Carbon Capture and Storage projects.Comprising a series of horsts and grabens, the basin was shaped through a long history of rifting episodes that commenced prior to the Early Permian and culminated in the separation of Greater India and Australia during the Early Cretaceous. Silurian to Cretaceous sediments exceed depths of up to 15,000 m in the deepest part of the basin, the Dandaragan Trough. Most of the hydrocarbon discoveries are within the Lower Permian to Lower Triassic reservoirs.

UPS AND DOWNS

The Asselian Nangetty Formation comprises glaciomarine deposits, whilst the overlying Holmwood Shale consists of marine mud- and siltstones with some glacial influence and occasional shallow marine coarsening-upwards sequences. The High Cliff Sandstone (Sakmarian), the lowermost reservoir target in the basin, interpreted as a shallow marine progradational shoreline succession, is terminated by the rapid transgression of the marine "Bit Basher Shale".

Subsequent marine regression resulted in the deposition of the shallow marine reservoirs of the Kingia Formation, which conformably grades into the tidally-influenced fluvio-deltaic Irwin River Coal Measures. The transition of the two formations, marked by an extensive network of Ophiomorpha, is captured in core number 1 from well Waitsia 3 shown here. Towards the end of the Artinskian, shallow marine mudstones of the Carynginia Formation rapidly began to prograde over the Irwin River delta, before a regional rifting event occurred during the Guadalupian that resulted in the widely recognized Late Permian Unconformity. The Upper Permian Beekeeper Formation, Wagina Sandstone and Dongara Sandstone were deposited as the first post-rift sediments in shallow marine environments. The Wagina Sandstone reservoir is overlain, in parts erosively, by the coarser-grained Dongara Sandstone reservoir, as captured in core number 2 from well Senecio 3. ■



Northern Perth Basin stratigraphic chart, showing the Permian and Lower/Middle Triassic sedimentary succession.

Contact between the Upper Permian Wagina and overlying Dongara sandstone reservoirs in well Senecio 3, 2657 m.

Contact between the Kingia Fm and the overlying Irwin River Coal Measures, marked by an extensive network of *Ophiomorpha*. Well Waitsia 3, 3239 m.

SOURCE: MGPALAEO