THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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Mozambique:
A Developing Gas Nation

Exploration opportunities:
Côte d'Ivoire
Brazil and Namibia
Barbados and T&T

GEONOVA

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Simple Questions

It is the simple questions that can ultimately lead to big discoveries. That is what I learned (again) when attending the BEOS Conference in London early September.

Phil Birch from Impact gave a talk on the long journey that ultimately led to the discovery of Venus in Namibian waters in April this year, and he illustrated how his search for prospective areas started by asking himself a simple question:

> With most hydrocarbon reservoirs in West Africa being in Cenozoic delta deposits, where do I find any Cretaceous reservoirs?

Sure, the Jubilee field is the exception to the rule as it is in Cretaceous sandstones, but no other examples sprung to mind. This simple question then led Birch and his team to investigate areas where Cretaceous deltaic deposits could be prospective, with the ultimate result being the discovery of Venus more than ten years later.

This is an overly simplistic version of the whole story, where many challenges had to be overcome, but the fact is that the role of exploration geologists is not so much answering questions, it is asking questions instead, in addition to challenging current beliefs.

This approach does not only apply to frontier areas such as Namibia, it also applies to mature areas such as the North Sea. Here, an example of challenging ideas by people from Hansa Hydrocarbons led to the discovery of N05-A in basal Rotliegend sandstones a few years ago. Before the discovery, most people would have argued that there was little chance to find any prospective sandstones as the model dictated that sandstones pinched out further south. Now, N05-A is being developed, which is good news for gas-hungry Europe.

Enjoy your read.

Henk Kombrink

BEHIND THE COVER

Source: Getty Images

The Mozambique coastline has a length of approximately 2,500 kilometres. Until around 2010, this line indicated the boundary where interest in the subsurface started or ended, depending on the direction one would look from. The offshore had little to offer in terms of prospective resources, was the overall idea. This radically changed when Anadarko discovered gas in Oligocene sandstones of the Rovuma Basin in the north of Mozambique's offshore. Today, the first shipment of LNG is about to set sail towards its buyer; a huge turnaround for the country.

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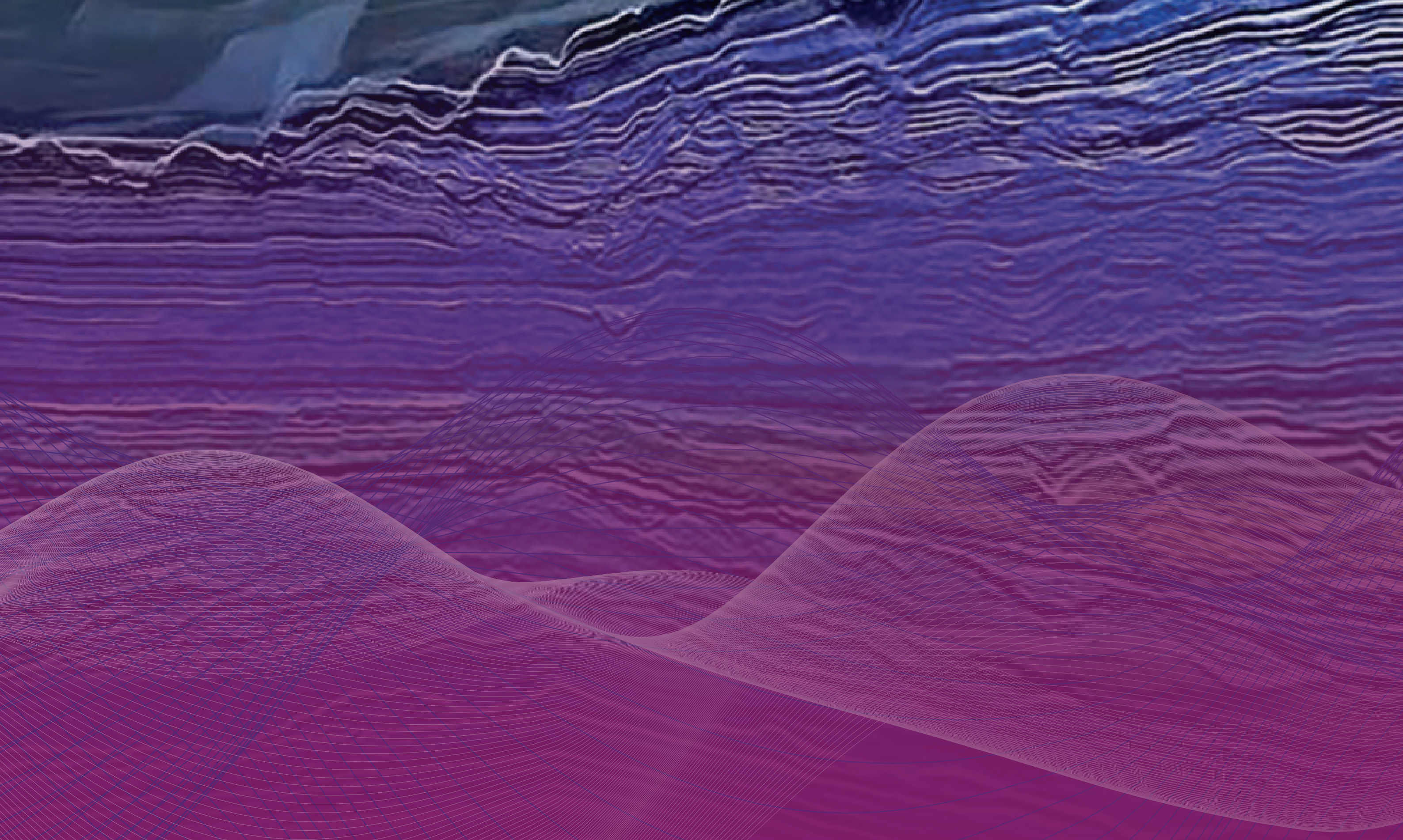
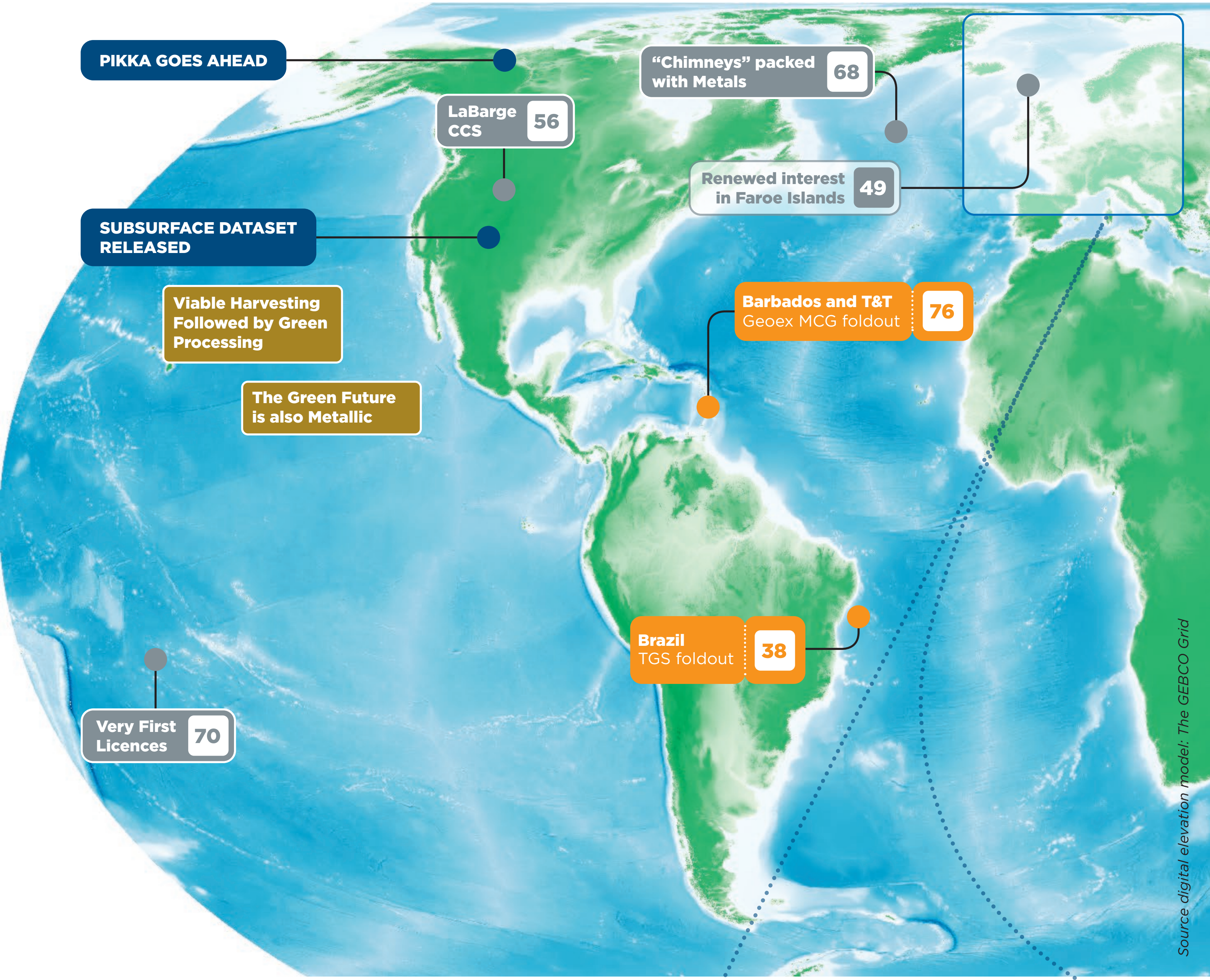




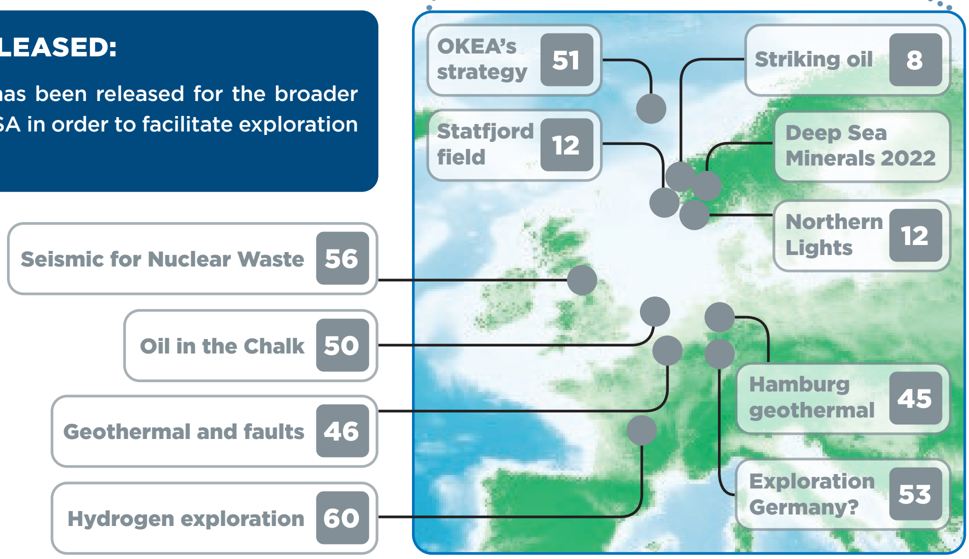
Source digital elevation model: The GEBCO Grid

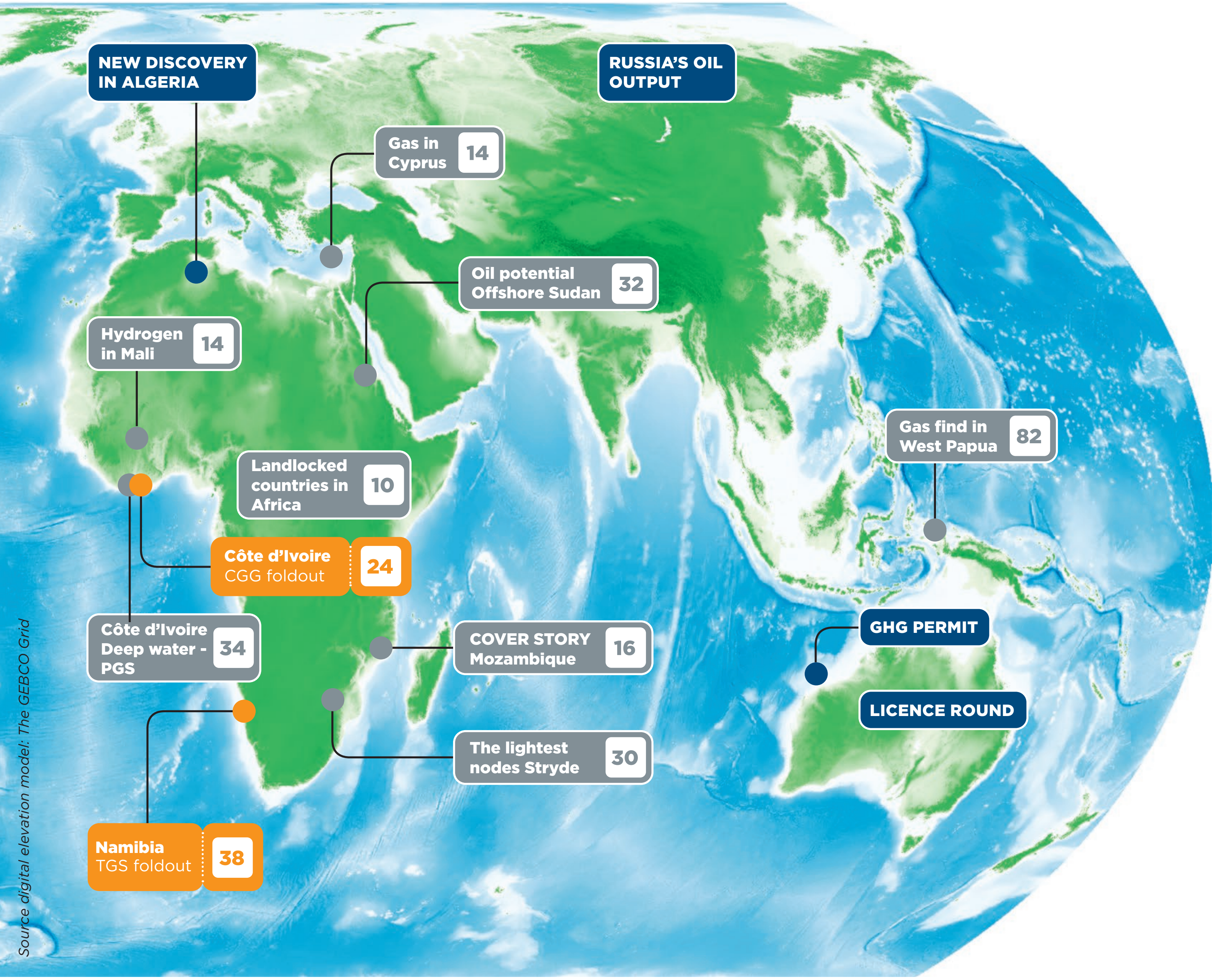
SUBSURFACE DATASET RELEASED:

A wide variety of geological data has been released for the broader Great Basin region of the western USA in order to facilitate exploration for geothermal systems.

PIKKA GOES AHEAD:

Australia-based Santos announced FID for the Pikka field situated on Alaska's North Slope. This shallow oil discovery in Cretaceous sandstones is expected to hold 397 MMboe and will produce 80,000 barrels/day at start-up in 2026.





NEW DISCOVERY IN ALGERIA:

State company Sonatrach announced an oil discovery with the Hassi Illatou well in the Adrar province. Initial estimated volumes are 151 MMboe.

RUSSIA'S OIL OUTPUT:

The Russian government expects oil output from Russia to fall between 9% and 17% this year, amounting to 1-2 million barrels.

LICENCE ROUND:

Companies have until 2nd of March 2023 to put their bids in for the 2022 Australian Offshore Acreage Release.

GHG PERMIT:

A joint venture led by Woodside Energy that includes BP, Shell, Chevron and Mitsibishi and Mitsui have been awarded a greenhouse gas permit offshore West Australia which should lead to a potential CCS project.

Searcher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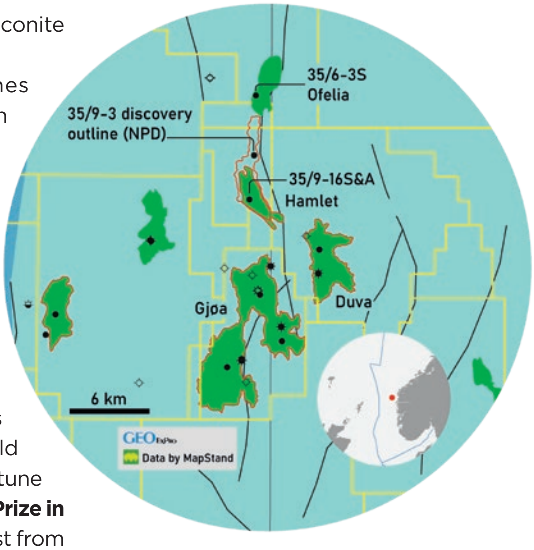
The Opening of a New Play in Norwegian Waters

With Neptune confirming oil in the Ofelia prospect recently, the company demonstrated the potential of the Lower Cretaceous Agat play.

In a strategically important area of the Norwegian North Sea for UK-headquartered **Neptune Energy**, the company struck oil and gas in Lower Cretaceous **Agat Formation** sandstones of the Hamlet prospect earlier in the year. Then, in August, the company also proved oil in the Ofelia prospect in the same Cretaceous play slightly further north. Let us take a closer look at these discoveries and the geology in this part of the Norwegian Northern North Sea.

During the Aptian and Albian, a little over 100 million years ago, Norwegian Quadrant 35 was situated in an area where turbidite sands sourced from the Norwegian mainland to the east were deposited through multiple NW-SE to E-W trending fairways. The individual sands are separated by mudstones, resulting in a complex reservoir architecture that requires detailed seismic mapping. The reservoir sandstones themselves are typical for the Lower Cretaceous: chlorite and glauconite are common constituents.

The Agat Formation sandstones drape a north-south trending high in the area of Hamlet and Ofelia, which can nicely be seen on the seismic line below kindly provided by CGG. The high already formed a topographical feature in Early Cretaceous times, given that the first generation of turbidite sands abut against it.

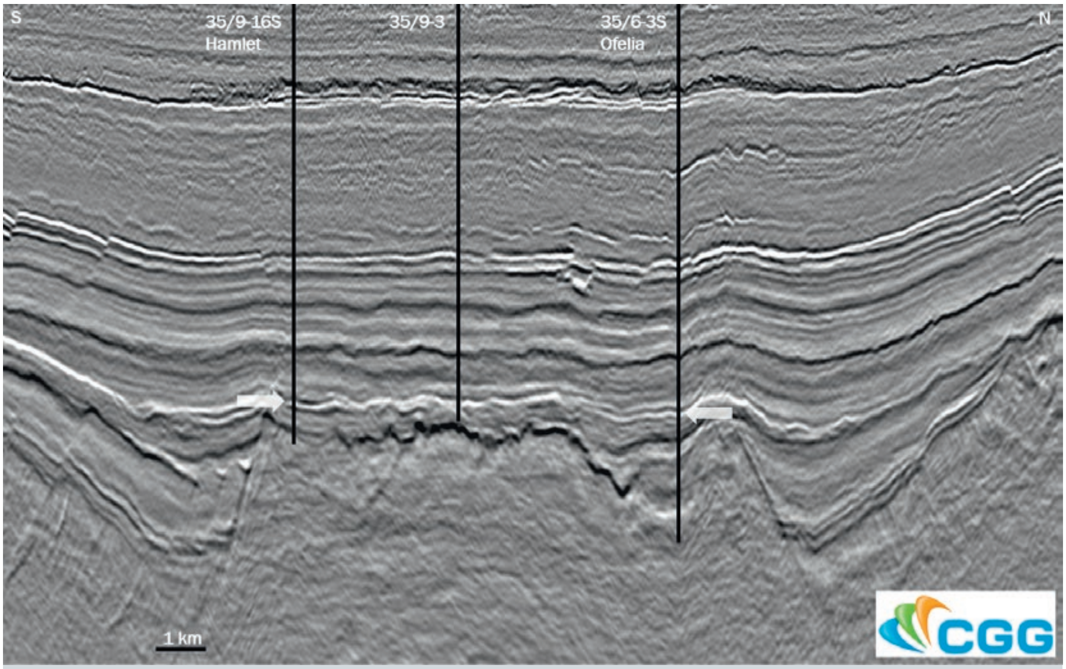


Neptune is not new to the Agat Formation; equivalent sandstones form the reservoir in the **Duva** field (discovered in 2016, for which Neptune received the **Exploration Innovation Prize in 2018**) slightly further to the southeast from Hamlet. The Duva discovery is an interesting story in its own right, given that the first well drilled on the prospect just clipped that oil leg and was therefore classified as dry.

Similar to the discovery of Duva, the exploration history of Hamlet is not a straightforward one either. Prior to completing the discovery well **35/9-16** earlier this year, well **35/9-3** was drilled in 1993 by Norsk Hydro on what the Norwegian Petroleum Directorate still carries as the outline of Hamlet (see map). This well did prove hydrocarbons, but after completing the Hamlet well Neptune confirmed that the 35/9-3 discovery indeed represents a smaller closure.

Neptune believes that between **8 to 24 MMboe** can be recovered from Hamlet. In combination with an estimated **16 to 39 MMboe** from Ofelia, the company is now considering development of the two discoveries as a tie-back to the Gjøa platform.

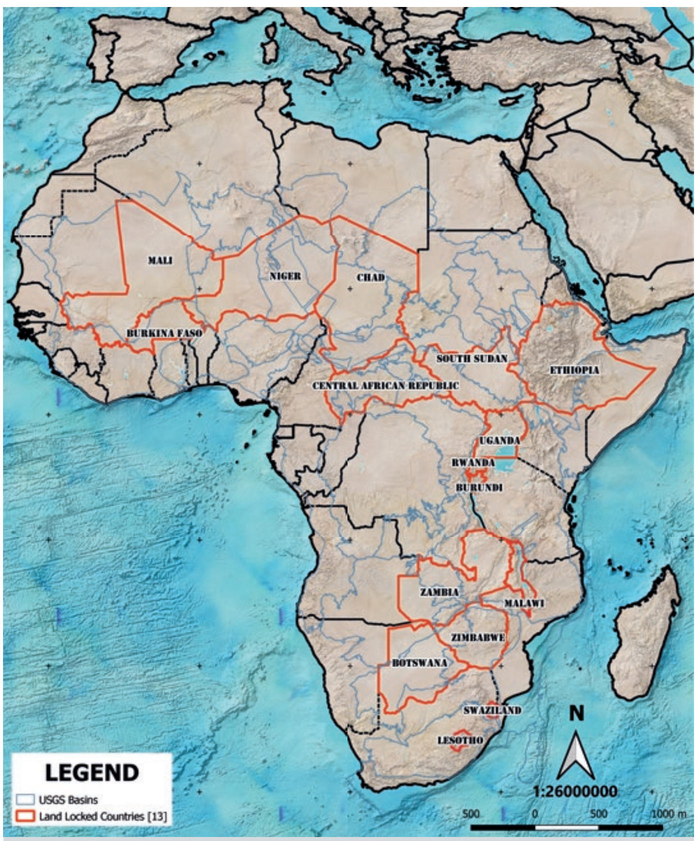
Henk Kombrink



Seismic line running from Hamlet in the south to Ofelia in the north. The Agat Formation sandstones interval is indicated by the white arrow in both the Ofelia and Hamlet wells. Seismic line kindly provide by CGG.

The often-forgotten potential of Africa's landlocked countries

While most of the focus is on the offshore of Africa, and in more recent years the deepwater, the landlocked countries of the vast continent are often ignored.



Land locked countries in Africa.

There are 16 landlocked countries in Africa: Botswana, Burkina Faso, Burundi, Central African Republic, Chad, Ethiopia, Eswatini (former Swaziland), Lesotho, Malawi, Mali, Niger, Rwanda, South Sudan, Uganda, Zambia and Zimbabwe. Being landlocked poses issues with the production and export of hydrocarbons but the E&P potential of several of these countries remains high. Most have a history of oil and gas exploration including Coal Bed Methane (CBM), and three are significant oil producers. Published production numbers understandably vary and should be treated with caution.

South Sudan is the biggest landlocked producer in Africa with an estimated production of 160,000 BOPD. However, the country earns lot less from this production due to high evacuation tariff and other fees as the oil passes through Sudan to the ports. **Chad**, the largest landlocked country in Africa, produces an estimated 65,000 BOPD with most exported through Cameroon to the coast. **Niger** is bumping along at around 10,000 BOPD with significant undeveloped discovered resources. Most of the oil is sold domestically and a small amount is exported to northern Nigeria.

Uganda boasts significant oil reserves but is yet to join the list of producers. The country's first oil discovery was made in 2006 in **Lake Albert**, but start-up of production has faced an unprecedented series of much publicised delays. However, oil production from the **Tilenga project** operated by TotalEnergies and the Kingfisher project operated by CNOOC is optimistically expected to start in 2025 and reach a combined 230,000 BOPD according to reports. One of challenges of the project has been how to build the 1,500 km electrically heated pipeline needed to export the crude via Tanzania. When completed it will be the world's longest heated pipeline.

Ethiopia has a series of gas discoveries in the **Ogaden Basin** at Calub, Hilala and El-Kuran. China's **Poly-GCL** is the operator of the multi-TCF Calub and Hilala fields and has been working on plans for an ambitious pipeline taking the gas across Ethiopia to Djibouti. Poly-GCL is understood to be planning to produce hydrogen in Djibouti from the gas.

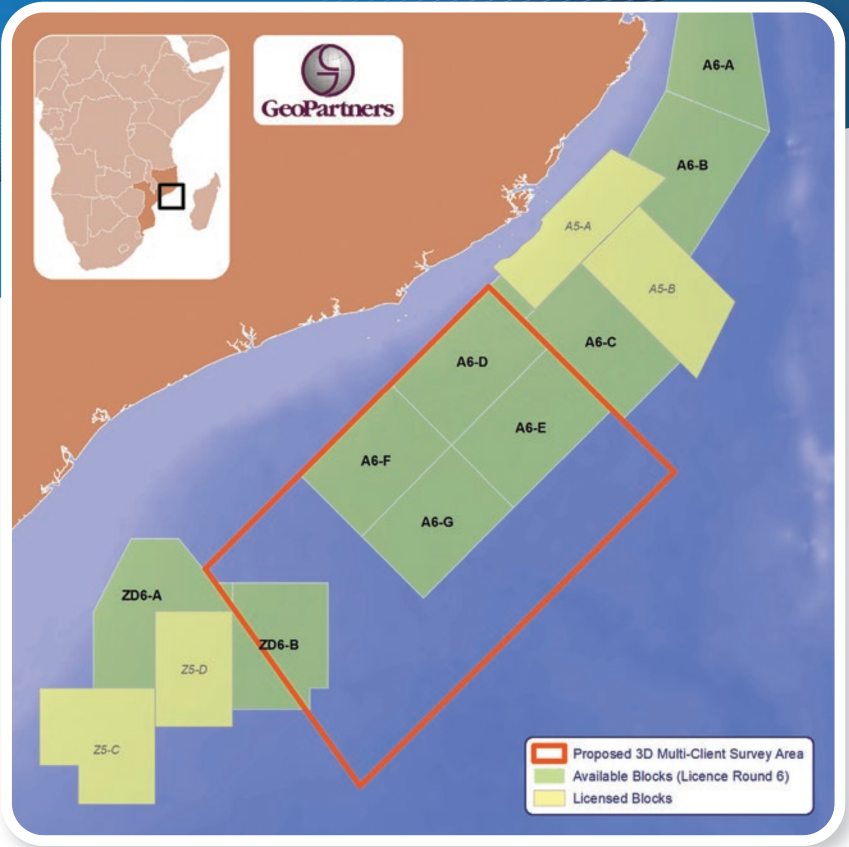
There is much anticipation in Zimbabwe with **Invictus Energy** planning to spud the **Mukuyu-1** wildcat in the Cabora Bassa Basin in the third quarter of 2022. It is touted as the largest known undrilled prospect onshore Africa with an independently estimated 20 Tcf and 845 million barrels according to Invictus. Mobil explored the country in the early 1990's, but Zimbabwe remains undrilled for oil and gas to date.

More recently, Canadian company **Reconnaissance Energy Africa** (or Recon Africa) announced that it has been granted a petroleum licence in northwestern Botswana contiguous with its **Namibia** licences. At the same time, in Zambia Geo Petroleum Ltd has secured rights to Block 31 and the transfer of Tullow Oil's equity to them.

Meanwhile, Burkina Faso, Burundi, Central African Republic, Eswatini (former Swaziland), Lesotho, Mali, Malawi and Rwanda have all seen varying levels of interest from the upstream industry. Some of it is stop-start as the smaller companies seek farm-in partners and funding to carry out exploration work. In Malawi RAK Gas had been planning seismic work over its acreage in the Lake Malawi Graben. ■

Ian Cross, Moyes & Co

EXTENSIVE NEW 3D SURVEY IN THE ANGOCHE BASIN, OFFSHORE MOZAMBIQUE



Available blocks in the Angoche Basin offshore Mozambique, with the location of the proposed 3D multi-client survey area

GEOPARTNERS LIMITED is pleased to announce the signing of an exclusive agreement with the **INSTITUTO NACIONAL DE PETROLEO ("INP")**, on behalf of the government of Mozambique, to conduct a major new multi-client 3D geophysical survey in the offshore Angoche Basin.

The project will comprise the acquisition of a minimum 12,000 square km of 3D multi-client data over blocks that will be awarded following the closure of the current 6th Licensing Round. Advanced new acquisition and imaging techniques will provide better illumination of complex structures to help reduce exploration risk and fast-track the region for potential production and development. Pre-acquisition permitting has started and it is anticipated that the 3D acquisition will commence in early 2023, with an expected duration of six months to complete and with early processed results available by end 2023.

Jim Gulland, Director of GeoPartners, announced, "We are honoured to have concluded this new agreement with INP to acquire this very large 3D seismic survey in the relatively underexplored but highly prospective Angoche Basin. The upcoming new multi-client 3D seismic acquisition program will help accelerate the identification of what will surely be the next wave of major discoveries in Mozambique."

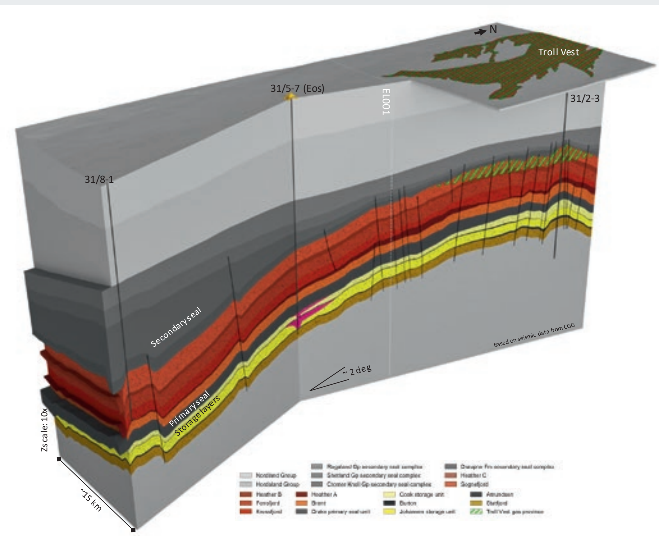
Angoche Potential

Although undrilled, existing 2D and 3D seismic indicates the development of large-scale slope-fan sandstones, particularly within the Cenomanian/Turonian and Paleogene, with potential stratigraphic traps and structural closures draped over syn-rift highs. Reservoir development at these levels is supported by seismic amplitude and AVO anomalies, with potential DHIs. Seismic response indicates potential source development in the Aptian, equivalent to the Lower Domo Shale and a potential gas/condensate and light oil source.

Open for Business in 2024

In August, the Northern Lights collaboration started the drilling of two CO_2 injection wells in Exploitation Licence 001 in the Norwegian sector of the North Sea.

The project will deliver carbon CO_2 storage as a service for clients throughout Europe. Starting in mid-2024, the wells (one primary and one contingent) will inject and permanently store 1.5 million tonnes of CO_2 per year as a part of the Norwegian state-financed **Longship CCS project**.



Schematic cross-section showing the subsurface setting of the Northern Lights project, going from south to north through the previously drilled 31/5-7 (Eos) well. The extent of the CO_2 plume after 37.5 Mt injection is illustrated in magenta. Source: Equinor

The transport and storage part of the project is carried out by the **Northern Lights** collaboration, consisting of **Equinor**, **Shell** and **TotalEnergies**.

Northern Lights will be the world's first **open-source** CO_2 transport and storage infrastructure. In other words, the project partners intend to deliver carbon storage as a service.

Studies have determined that the infrastructure, depending on market interest, can be scaled up 5 million tonnes per year (Phase 2).

The project has so far secured two clients for the upcoming storage business: the **Fortum waste-to-energy plant** in Oslo and the **Brevik cement factory** in Porsgrunn south of Oslo.

The CO_2 will be injected and stored in the Lower Jurassic Johansen Formation approximately 2,700 metres below sea level. It contains sandstones with good flow properties, which are overlain by the Drake Formation shales that provide a competent seal.

The Johansen and the connecting Cook Formation have a combined storage capacity of approximately **150 million tonnes CO_2**, meaning it could represent an important European storage site for many years to come.

More recently, Northern Lights also announced an MoU with the manganese smelter **Eramet** Norway for a partnership to test a CO_2 capture technology, followed by another deal with **Yara's** fertilizer plant in the Netherlands. Being the project's first cross-border deal, this formed a milestone for ongoing European decarbonisation efforts. ■

Ronny Setså

A 40 Years Life Extension

The operator and partners of the Statfjord field in the Norwegian North Sea receive the Norwegian Petroleum Directorate's prize for increased recovery.

One of the biggest fields in the Northern North Sea, Statfjord, started production in November 1979. It was expected to cease operations around 2003. However, with current plans from operator **Equinor** and partner **Vår Energi**, the field will produce until 2040, almost 40 years longer than initially foreseen.

Many different technologies have been, and continue to be, applied to boost recovery at Statfjord. Various water and gas injection methods, horizontal and multi-lateral wells, gas blowdown, improved seismic imaging of the subsurface, technology for improved sand control in wells, as well as technology for well plugging, just to mention a few.

Thanks to these efforts, the reserves of Statfjord have increased by an impressive 10% or around **380 MMboe**. The oil recovery factor for Statfjord is **68%**, the highest on the Norwegian continental shelf where the average recovery factor amounts to **46%** for oil fields. Statfjord has produced **3.6 billion barrels of oil** since the start of production.

To get the additional barrels out of the field, Equinor and Vår Energi have plans to drill more than 100 new wells. This is an impressive work programme, especially when compared to the situation in the UK Northern North Sea, where many Brent fields are currently in the process of being decommissioned. ■

Source: Equinor

Statfjord A platform.

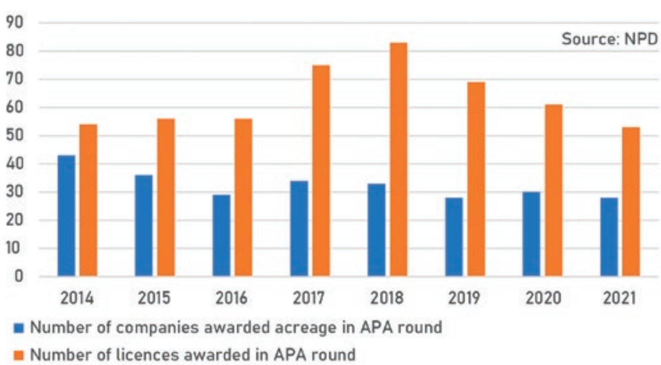
Where To Go Next

Number of applicants for APA 2022 hailed as a success, but much-needed operator diversity is on a downward trend.

The flock has been considerably reduced since the heydays. "Only" 26 companies applied in the latest licensing round offshore Norway. The Ministry of Petroleum and Energy is, however, not dissatisfied with the number of applications.

"The applications in APA 2022 show very good interest among the companies active on the Norwegian continental shelf in exploring new petroleum resources. This is very pleasant," says Minister of Petroleum and Energy, **Terje Aasland**.

Among the applicants we find **Shell**, **ConocoPhillips** and **TotalEnergies**. Other supermajors have withdrawn from Norway a long time ago. **Equinor**, **Aker BP** and **Vår Energi** are the major Norwegian companies on the list (Lundin has recently merged with Aker BP).



Awards in predefined areas (APA) is the annual licensing round for the best-known exploration areas on the Norwegian shelf. They comprise most of the available exploration areas. It is noteworthy that there is little interest amongst the same companies to do frontier exploration. And true enough, no significant discoveries have been made recently far away from producing fields. The latest one, **Wisting**, with **500 MMboe** discovered in 2013, is still not approved for development.

When looking at the number of companies having been awarded licences in the last eight years, 28 companies were awarded a licence earlier this year. 2014 saw the most diverse operator landscape with 43 companies welcoming an award, but this decreased towards the 30 mark in all the years that followed. In that sense, the 40+ number of companies seem to stem from a time when oil prices were north of $100 ***and*** from a time when acquisitions did not take place as frequently as today.

During the upcoming **NCS Exploration Strategy Conference** in Stavanger this fall (November 23-24), many of the important players will outline their exploration strategies and put these in light of the current and fast-changing world energy outlook. ■

"We Don't Want to be the Bad Guys"

New research paper describes how people working in the oil and gas industry respond to the tension between the business model of oil companies versus societal pressure to contribute to climate change mitigation.

It must be on many people's minds when talking to family and friends; how to justify my role in the hydrocarbon sector in the light of ongoing climate change and the pressure from peers to act in that spirit. "Do I leave my job at the expense of my income and uncertainties in my career prospects?"

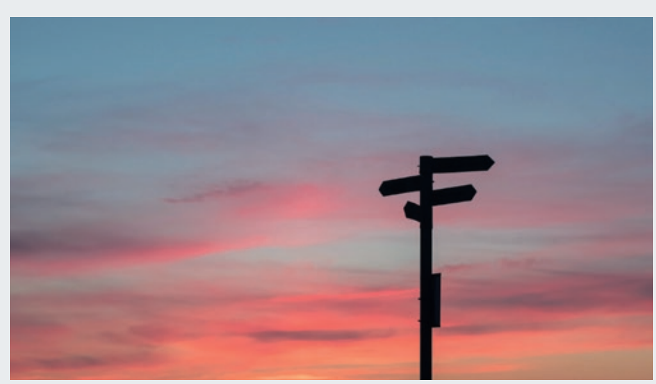
This is what lead researcher Krista Halttunen and co-workers from **Imperial College London** tried to get a better understanding of. They interviewed professionals from large international oil companies who work or have worked in climate-related roles. Based on the answers received, they mapped out the motivations and reasoning why people work in the sector.

The researchers grouped the responses into **strategic** and **defensive**. Amongst the strategic answers, the authors see that acceptance is the most at odds with the need to mitigate climate change. They claim that although some arguments are valid – access to energy being an important one – it also means that most people currently without access to energy now will be impacted most by climate change in the future.

It is interesting that the researchers find that especially amongst employees of European companies, there is more of a willingness to demonstrate more active engagement with the climate issue from within their organisations. Some of the respondents used strong language: *"There is no question about the need to change" and that "the oil industry will have to decarbonise by 2050 whether they like it or not."*

As part of the defensive responses, the authors note that one group of interviewees primarily calls on governments to take the lead in combatting climate change. Another way to defend the current status quo is to suggest ways to mitigate climate change through technical solutions such as CCS. In that regard, the discussion about unabated versus abated new fossil fuel developments fits into this category.

Paper published in Energy Research & Social Science 92, 2022. ■



Javier Allegue Barros - Unsplash

The World's First Commercial Hydrogen Field

Africa leads the way with the development of a natural hydrogen field in Mali.

The world's first commercially producing natural hydrogen field is coming online, in **Mali**. Operated by **Hydroma**, the company has been actively drilling in the area north of **Bamako**, in Block 25, since 2017.

The field was first discovered by chance in 1987 while drilling a water well. At the time, the wellhead ignited and the well was plugged and abandoned over safety concerns. In 2011, the well was reopened and a pilot unit was installed to generate electricity for the off-grid village of Bourakébougou.

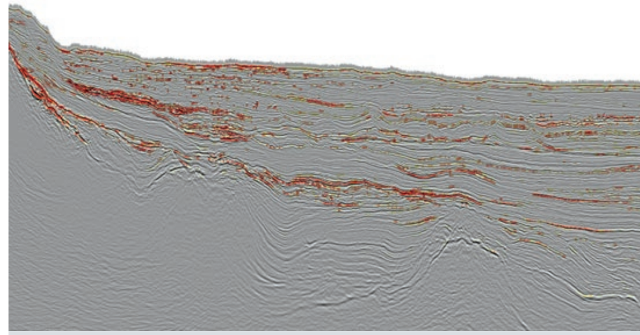
The successful pilot demonstrated that reservoir pressure did not drop over the trial period, pointing to sustainable hydrogen production in the subsurface. A 24-well exploration campaign in 2017/2018 discovered five stacked hydrogen reservoirs in **Proterozoic sedimentary rocks**, each sealed by a **Triassic dolerite sill**. The reservoirs range in depth from 100 m to about 1200 m and the estimated areal extent of the gas field is a minimum of 780 km^2.

Hydroma's 2022 drilling campaign is well underway and so far, all wells have yielded natural hydrogen gas with over 95% purity. The company's objective is clear; to transform this new source of energy into a large-scale industrial operation and to actively participate in the energy transition by promoting a decarbonized economy in Mali, Africa, and Europe. ■

Mariël Reitsma

Source: Hydroma

Cores cut from stratigraphic boreholes in Mali.



Source: TGS

3D PSTM Dip Line with highlighted AB+VO anomalies in the syn- and post-rift section.

Sierra Leone Licence Round Extension

Sierra Leone's Fifth Licensing Round bid submission deadline extended to 27th January 2023 due to a high level of interest.

The reason Sierra Leone is attracting so much interest is simple; the exciting, extensive hydrocarbon proceptivity and the stable and investable above-ground environment.

Sierra Leone has more than 400 km of Atlantic coastline that can be tectonically reconstructed back to fit with the Guyana Basin, a truly world-class oil-rich conjugate twin. The source rocks for the 15 Bbbls being produced in Guyana were deposited following the rift between the South American and the West African plates. Sierra Leone's **Venus**, **Mercury** and **Jupiter** fields are all being sourced from the rocks deposited in the same environment of the same Cretaceous age, the same as those sourcing neighboring commercial fields in Cote D'Ivoire and Ghana's **Jubilee** field.

Previous drilling offshore Sierra Leone has proven the working hydrocarbon system, with 7 of the 8 previous wells hitting hydrocarbons and providing near commercial success. These wells targeting **Upper Cretaceous fan systems** with class II/III AVO anomalies proved that all the petroleum system elements were in place and that the thermal regime was suited for oil generation and preservation. Oils recovered to surface were described as 'light sweet crude oil with a gravity of between 34° and 42° API' in multiple stacked reservoir sequences.

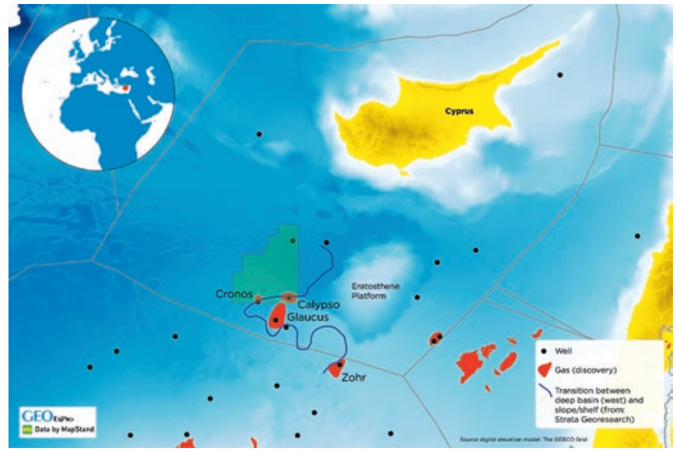
The existing high-quality seismic imaging (as shown in the figure above) provides extensive AVO anomalies, indicating huge untapped potential in the clastic reservoirs which were well sorted during deposition.

The above-ground terms and running room available make Sierra Leone a very attractive offshore investment opportunity, especially when combined with the flexibility and straightforward approach the **PDSL** has shown under the leadership of **Foday Mansaray**. The Licence Round deadline extension now provides additional time to review the seismic and well data before making an application. ■

Ben Sayers, GeoPartners;
Ahmed Tejan Bah, PDSL

The Eratosthene Platform Continues to Deliver

Cronos, another significant gas discovery in Cypriot waters was announced recently.



Operated by **ENI** and partnered by **TotalEnergies** (50%), the Cronos-1 well is reported to have found up to **2.5 Tcf** of gas in Block 6, which amounts to around **71 Bcm.** This is a significant find, for instance, if compared to the average North Sea gas find of around **7 Bcm** or less. ENI describes the reservoir as having fair to excellent quality with a pay zone of 260 m.

The discovery is made at a critical time, with TotalEnergies stating that it contributes to the energy security of Europe.

According to **Strata GeoResearch**, a company that specialises in the geology of the Mediterranean, the main reservoir is supposed to be a Cretaceous shallow marine limestone. These limestones were deposited on the margin of the Eratosthene platform to the south of the island of Cyprus, as shown by the blue line on the map.

Before the discovery of the Zohr field in reefal Miocene carbonates a little further to the southeast, also on the Eratosthene platform, little was known about the area. The leading model was that of a deep-sea basin north of the Nile delta, which did not include any shallow marine deposits. This model was proven wrong once Zohr was discovered in 2015, followed by **Calypso** and **Glaucus**.

The structural setting of the Eratosthene platform is one of a clear anticline, with an obvious expression on the sea floor. Carbonate deposition is thought to have taken place on the platform from the Cretaceous to the Neogene, as the area was intermittently uplifted because of the collision between Africa and Europe. ■

A Metal Detector for the Sea Floor

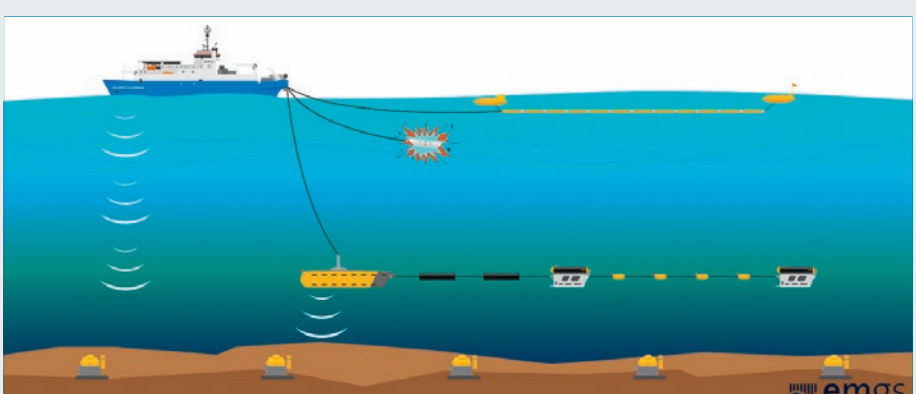
EMGS takes the lead in a research expedition to better map seabed minerals.

"Even though we now know that critical mineral deposits are present in places associated with the Mid Atlantic spreading ridge down at 3,000 metres in Norwegian waters, the accumulations found so far seem too small for commercial mining," says **Dag Helland-Hansen** from **EMGS**.

In combination with the need to find mineral deposits in non-active smokers, because ecosystems of active systems cannot be mined, the challenge is clear: **How to map non-active vents and how to best characterise their extent and mineral content once a system has been found?**

That is where the NTNU ATLAB consortium comes in. Supported by **NPD**, **Equinor**, **CGG** and **Aker** amongst others, the consortium recently deployed a vessel manned with a PGS and EMGS crew to undertake a ten-days expedition to the Mohn's Ridge. There, a whole suite of data was acquired in order to better characterise the sea floor and the shallow subsurface.

"We used a whole array of different methods," Helland-Hansen adds. "In addition to our own proprietary EM Systems, including a new high-frequency deep-towed EM streamer system, we acquired high-resolution multibeam data, **PGS** provided and operated the seismic streamer and airgun, **inApril** provided seabed seismic nodes and **Norce** provided sensors for environmental analysis. We are waiting for the data to be processed by the consortium members and looking forward to seeing the first results."



"Electromagnetic data form a potentially powerful tool to pin down these mineral deposits," said Helland-Hansen: "You can picture the technique as a kind of deep-sea metal detector."

"A next important step in the process to optimise data acquisition is real-time measurements, which will allow us to immediately change an exploration campaign to the data coming in," Helland-Hansen concludes: "It will be another hurdle taken towards finding economic volumes that may be applied for in a possible future Deep Sea Minerals licensing round." ■

Mozambique – a Gas Nation in Development

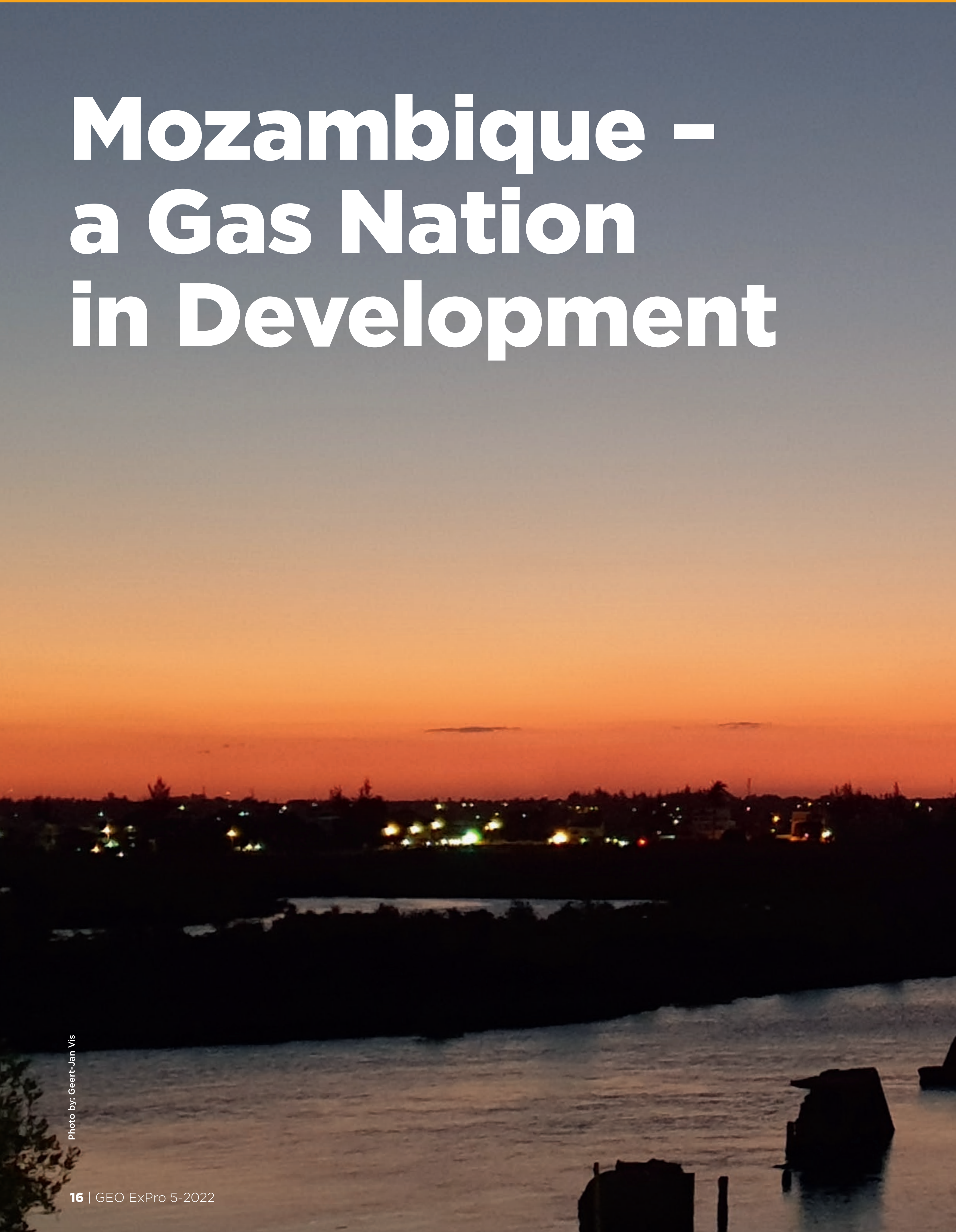
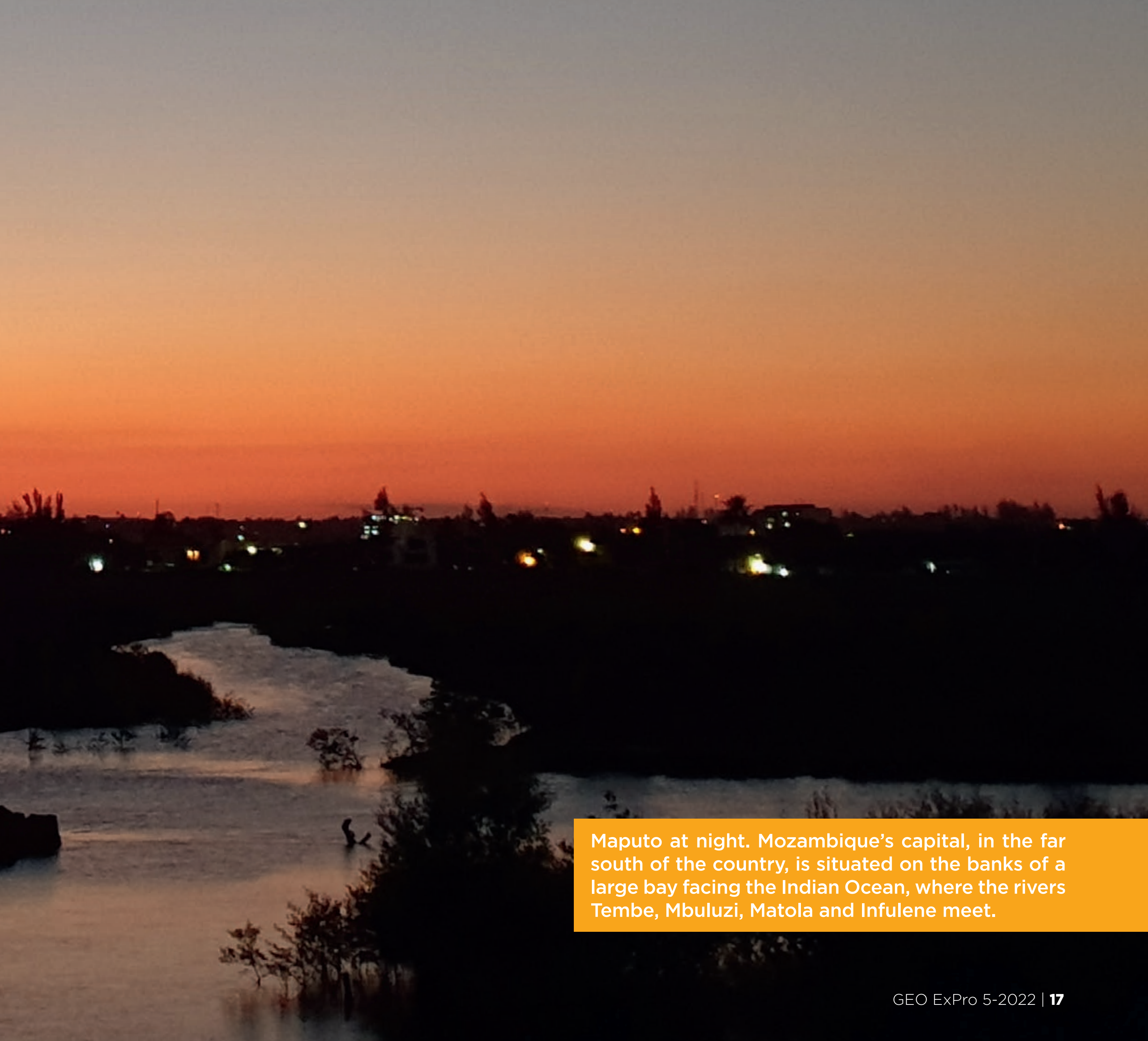
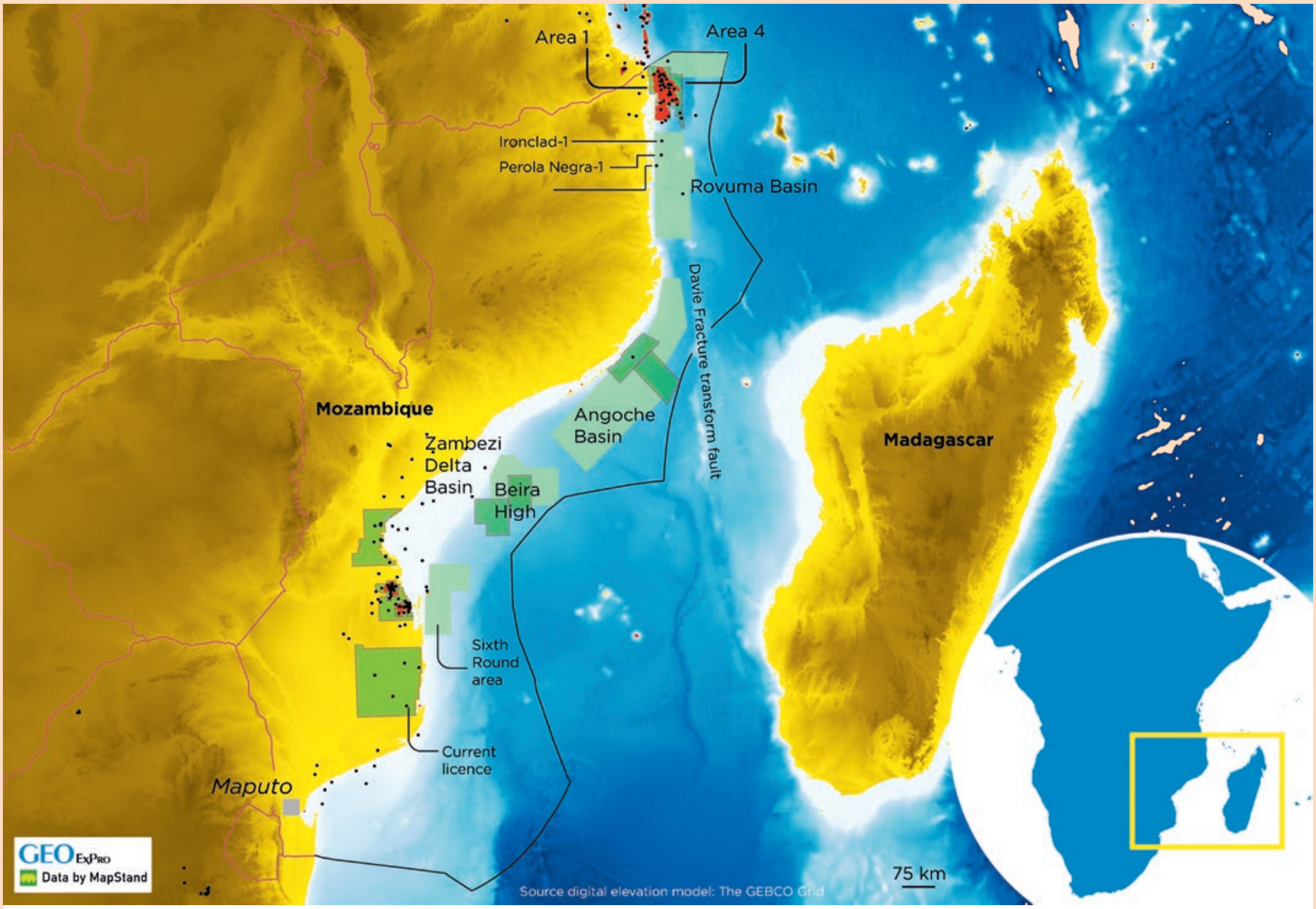


Photo by: Geert-Jan Vis

It took a long time until the first giant gas discovery was made in Mozambique in 2009. Since then, the Rovuma Basin in the north of the offshore sector has been a centre of activity with many wells drilled and discoveries made. However, the majority of Mozambique's offshore remains poorly explored. With the Sixth Licensing round coming to a close for bids in November, and blocks being on offer across major parts of the offshore sector, will there be an appetite to also explore the waters further south?



Maputo at night. Mozambique's capital, in the far south of the country, is situated on the banks of a large bay facing the Indian Ocean, where the rivers Tembe, Mbuluzi, Matola and Infulene meet.



Map showing existing licences across Mozambique as well the areas on offer in the current Sixth Licensing Round (pale green).

Text: Henk Kombrink

In August, Bloomberg reported that an LNG tanker was soon to arrive at Eni's new Floating Liquified Natural Gas Terminal Coral Sul (South), indicating that it will not be long before the first load of LNG will be on its way to its buyer. Combined with Eni's intention to build a second terminal in Mozambique that will be operational in less than 4 years, and TotalEnergy's plans to finalise the Rovuma onshore LNG plant, Mozambique will soon be an important player in the international gas market.

Although Mozambique has been a producer of onshore hydrocarbons for a while, the eyes of the global exploration community only turned to this east African country when **Anadarko** made a gas discovery in the Rovuma Basin in the north of the country in December 2009 when it completed the well **Windjammer-1** in Area 1. Before that, there had been little interest in the East African margin as most of the attention was focused on the western side of the continent.

The success in the Rovuma Basin followed on from the award of seven onshore and offshore blocks during the Second Licensing Round in 2006, resulting in the completion of **30 exploration and 32 appraisal wells** from 2010 to 2015.

Major gas resources have since been proven, with the **Instituto Nacional de Petróleo** (INP) estimating that the Rovuma basin holds **125 Tcf** in Areas 1 and 4 only. This amounts to around **3,500 Bcm** or almost **22 billion barrels of oil equivalent**.

Areas 1 and 4 are the only currently licensed areas in the Rovuma Basin, with **TotalEnergies** operating Area 1 in the west and a joint venture between **Eni**, **ExxonMobil** and **CPNC** operating Area 4 in the east.

With the Coral field in the south of Area 4 containing around **16 Tcf** of recoverable gas, it is easy to see that the first FLNG terminal is only just the beginning of a major phase of development for this northern area of Mozambique's offshore sector. TotalEnergies estimates that it has so far discovered **65 Tcf** of recoverable gas in Area 1, so almost four times as much as Coral.

But, even though around **50 offshore exploration wells** have now been completed in Mozambique in total, large parts of the offshore sector remain to be tested. Only one well was drilled to date in the Angoche Basin, and only a limited number of attempts were made in the Zambezi and Beira High areas. Legacy 2D and 3D seismic data sets demonstrate high potential in these areas though, which must be the driving force behind **Geoex MCG** recently announcing the acquisition of a total of 8,550 km^3 of broadband seismic mainly in the **Angoche Basin** in 2023.

The **Sixth Licensing Round**, which is still open for bids, also focuses on the Angoche Basin. In addition, several blocks are on offer to the north and south of Areas 1 and 4 in the Rovuma Basin as well. The closing date for submissions is the 11th of November this year.

MOZAMBIQUE'S OFFSHORE GEOLOGY

Focusing on the history of Mozambique's offshore sedimentary infill, we do not need to go back in time very far. During the **Middle Jurassic** (165 Ma), Africa, Madagascar, India and Antarctica still formed part of the Gondwana continent. Therefore, sediments dating back to the Middle Jurassic and older are relatively scarce and have a limited extent, even though the onset of a tensional regime and the formation of half grabens had already started as far back as the Triassic.

Around 160 million years ago, during the **Late Jurassic**, the first rifting episode took place, with initially the formation of the Somali Basin in the north and a little bit later the Mozambique Basin further south. Rifting had a strong dextral strike-slip component; the Mozambique and Somali basins were separated by the **Davie Fracture transform fault**.

The Rovuma Basin formed the southernmost part of the Somali Basin whilst the Angoche and Zambezi Delta basins form part of the Mozambique Basin.

Until the Late Cretaceous, the Somali Basin and the Mozambique basins formed separate basins. The sedimentary environments of both basins have been similar since.

The Cenozoic succession in both the Rovuma and Mozambique basins is characterised by a deltaic succession with proximal fluvio-deltaic facies in the west to deep water facies in the east. Two sedimentary cycles have been distinguished in the Cenozoic succession, separated by an unconformity; a Paleocene-Eocene and an Oligocene to Pliocene interval. The detachment plane of folds and thrusts that formed in the Oligocene and younger succession in the offshore Rovuma Basin are thought to be Paleocene or Eocene mudstones.

The seismic line shown here, which is from the Rovuma Basin, nicely shows a thrusted interval in the deltaic succession.

ROVUMA BASIN

In the Rovuma Basin, the Paleocene to Oligocene discoveries are characterised by stacked high-porosity deep-water channel and fan sandstones. The most commonly observed trapping mechanism is stratigraphic, but structural traps have also been found in the deep-water thrust belts of Palma and Mocimba.

In the Rovuma Basin, there is additional prospectivity in the areas flanking the main delta depocentre and the offshore extension of the Mozambique Plain further east, with proven high-quality reservoirs in the Cretaceous and throughout the Tertiary section. The Cretaceous is only penetrated by a limited number of wells, leaving this succession largely unexplored.

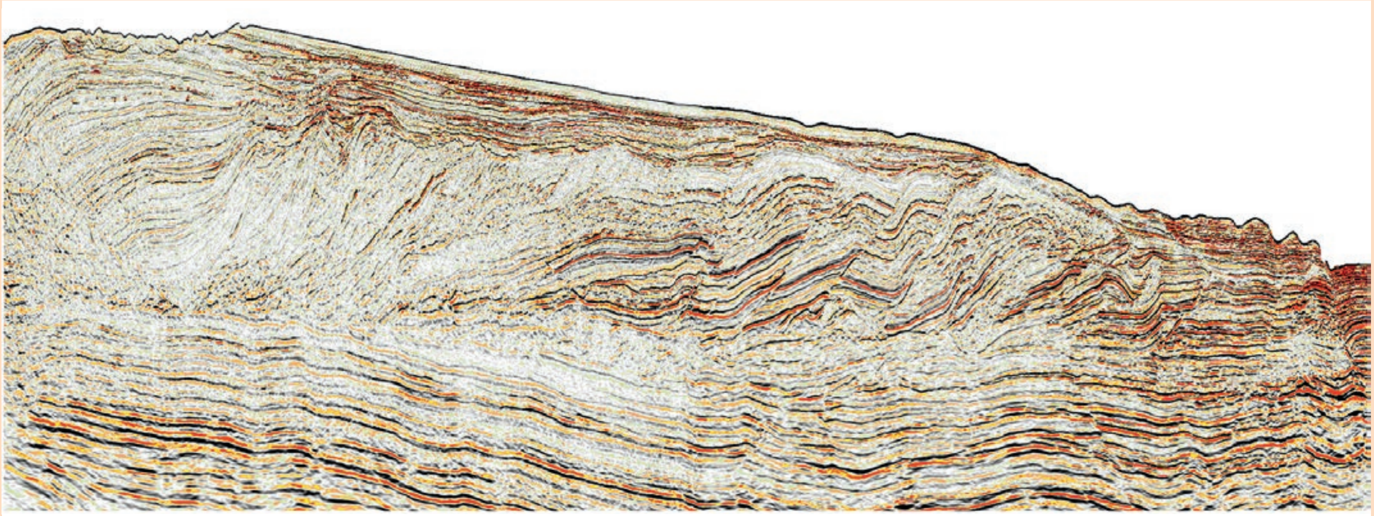
Rovuma gas is believed to be sourced from yet undrilled, gas-mature Lower Cretaceous marine shales. However, the presence of oil in Cretaceous sands in the Ironclad-1 well and coastal seeps in the southern Rovuma suggests that a potential oil-prone petroleum system also exists, with Lower Cretaceous, and Upper and Lower Jurassic successions as source rock candidates.

It is interesting to see that it is the Ironclad well that is the first well of a string of three wells south of Area 1. The two wells further to the south (Perola Negra-1 and Buzio-1) were both dry. The wells both fully tested the Cenozoic succession, thereby casting some doubt as to whether the trend of gas discoveries in Area 1 can be further extended towards the south.

ANGOCHE BASIN

In the Angoche Basin, where just one well has been drilled, the sedimentary succession of up to 7,000 m is a first indication that all requirements of a working petroleum system can be met. Similar to the Rovuma Basin, oil seeps have also been observed on the Angoche coast.

Source: Instituto Nacional de Petróleo (INP) - (https://www.inp-legacy-seismic-mz.com/data.html#rovuma)



East-West seismic line from the Rovuma Basin, nicely showing a thrusted succession in what is believed to be the Cenozoic delta succession.

Source: NASA.

The Zambezi delta.

Current seismic data also suggests the presence of large-scale slope fan sandstones, presumably within the Cenomanian/Turonian and Paleogene successions. Stratigraphic trapping is also thought to be the main trapping mechanism in this basin, with additional structural closures draped over syn-rift highs.

ZAMBEZI DELTA BASIN

The Zambezi Delta Basin is slightly different from the basins further north in the sense that below the 4 to 5 km of Upper Cretaceous to recent deltaic sediments of the delta, an up to 9 km thick succession of Upper Jurassic to Lower Cretaceous sediments can be found over a failed Middle Jurassic rift basin. In addition, the Beira High forms a prominent block of continental crust against which the onlap.

The Beira High has yet to be tested by the drill bit, whilst the Zambezi Basin wells drilled to date are believed to have been drilled off-structure or having missed the reservoir at the Upper Cretaceous target level. At the same time, in this area, seismic data also suggest the presence of deep-water channel and fan systems in the Upper Cretaceous succession. These may also drape the Beira High.

Potential source rocks in the Jurassic and Lower Cretaceous are thought to be in the oil window away from the Zambezi Delta Basin depocenter.

References provided online. ■

An important source of information for this article was the INP and GeoPartners Sixth Round Legacy Data website, which can be found under this address: https://www.inp-legacy-seismic-mz.com/index.html

Mapping Terra Incognita

Geological Survey of the Netherlands assists Mozambique in compiling a stratigraphic nomenclator for the offshore.

Photo: Geert-Jan Vis.

Studying core material from offshore wells in Mozambique.

Until the first gas discoveries were made in Mozambique waters a little more than 10 years ago, the offshore was very poorly mapped. "It's a situation we experienced in the Netherlands before exploration for gas took off in the 1960s," says Geert-Jan Vis, geologist at **TNO – Geological Survey of the Netherlands**.

"It's our experience in building up and archiving our evolving understanding of the subsurface that we now put to good use in helping build our colleagues at the **Instituto Nacional de Petróleo** (INP) in Mozambique a similar framework for their offshore," adds Vis. Mozambique's state oil company, **Empresa Nacional de Hidrocarbonetos** (ENH) is also involved in the project.

Through several workshops, the team achieved a good working relationship, further supported by geologists from companies currently exploring the area. Most of the work is carried out by the team in Mozambique, such as seismic interpretation, well data handling and subsurface model building.

ZAMBEZI DELTA

The team started their geological work on the offshore part of the Zambezi delta. It is a little further south of the area where most activity takes place, but it is on the radar of energy companies too. It seems that Eni has got plans to drill a well in the area in the near future. Also, there are a few wells in the shelf zone, which can be used as tie-in points to the regional 2D seismic lines that are already available.

The sedimentary succession deposited by the Zambezi delta offshore attains thicknesses up to 5-6 kilometres. Deposition started in the Early Cretaceous when Madagaskar started to drift away from Mozambique. Although the majority of sediments are thought to be hemipelagic fines, sandy turbidites and contourites have also been interpreted in the seismic data.

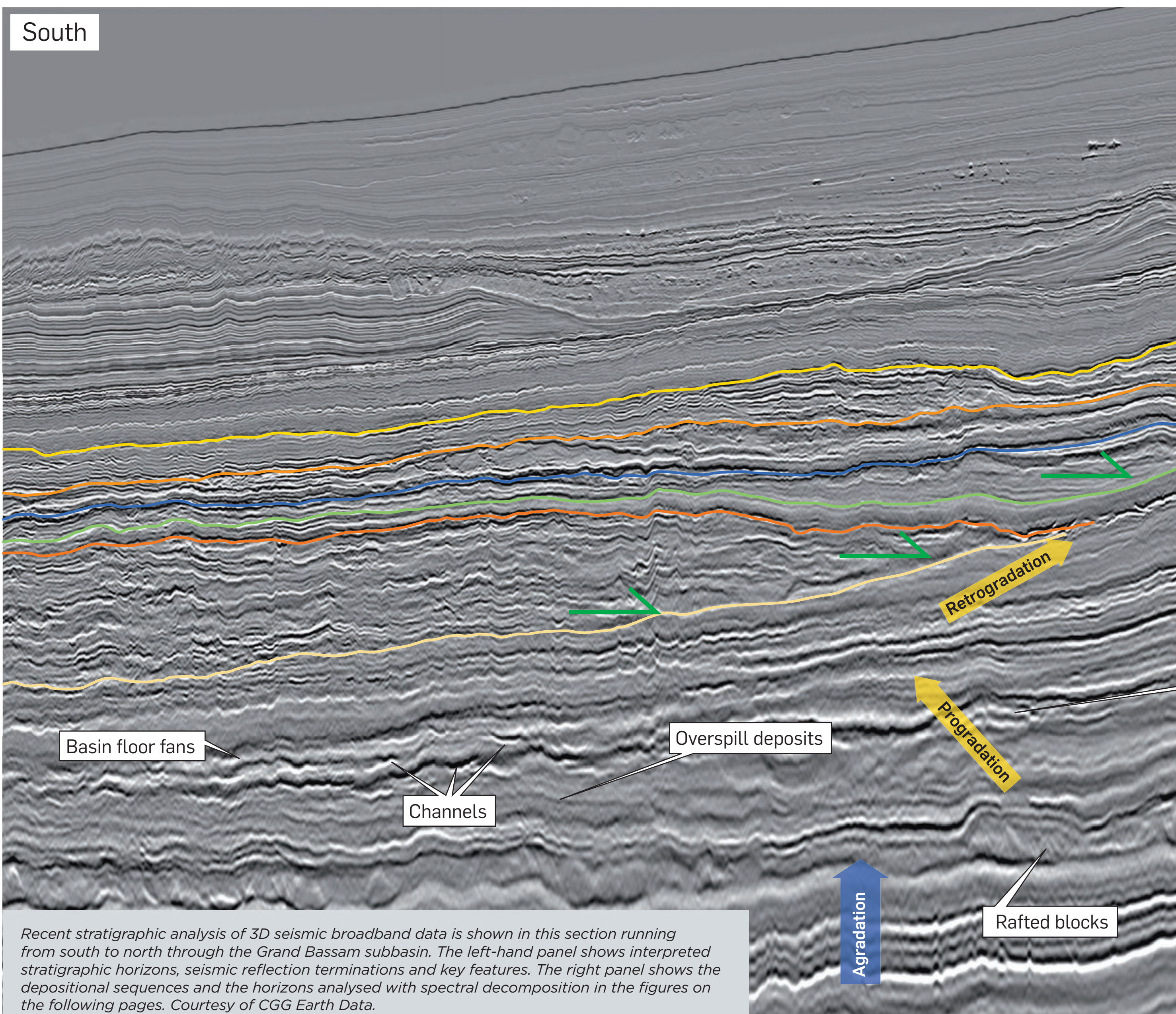
"We try to not only understand the distribution of the reservoirs but also put these into a wider geological framework of the Zambezi delta evolution. It is through the integration of legacy data and newly acquired data that we hope to help build a standard nomenclatore that is not only of value for the current activities unfolding in Mozambique but also for future generations should there be another purpose for further studying the fascinating offshore of Mozambique," Vis concludes. ■

WHAT IS A STRATIGRAPHIC NOMENCLATOR?

A nomenclator is a document (either in print or in digital format), which describes the various geological units present in a certain area. It is the foundation of any geological mapping exercise. Units are being defined in terms of lithology, age, depositional environment and boundaries to adjacent and underlying/overlying units. Often, key-wells are presented showing what the logs of a typical unit look like.

Baleine Discovery: Cote D'Ivoire's Exploration "Black Swan"

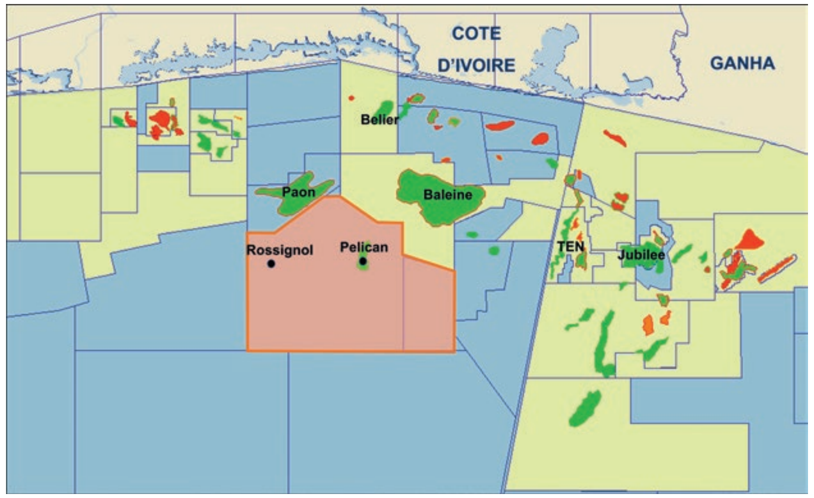
Broadband seismic data unlocks new play potential.

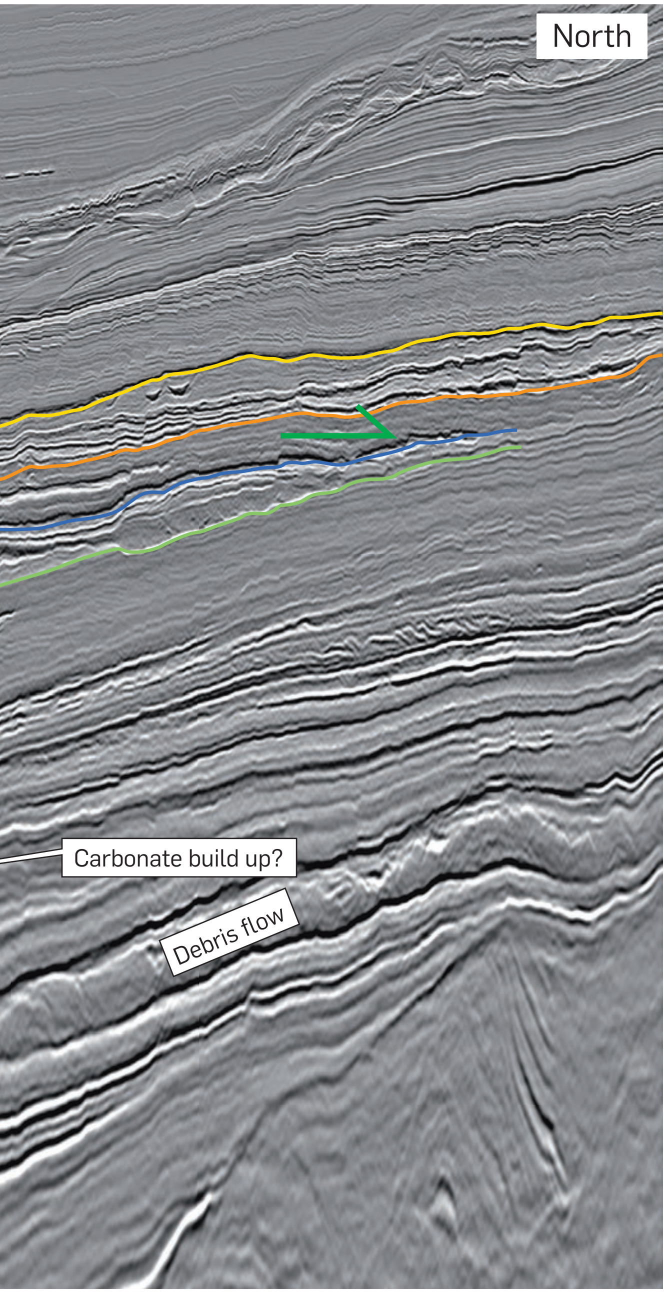


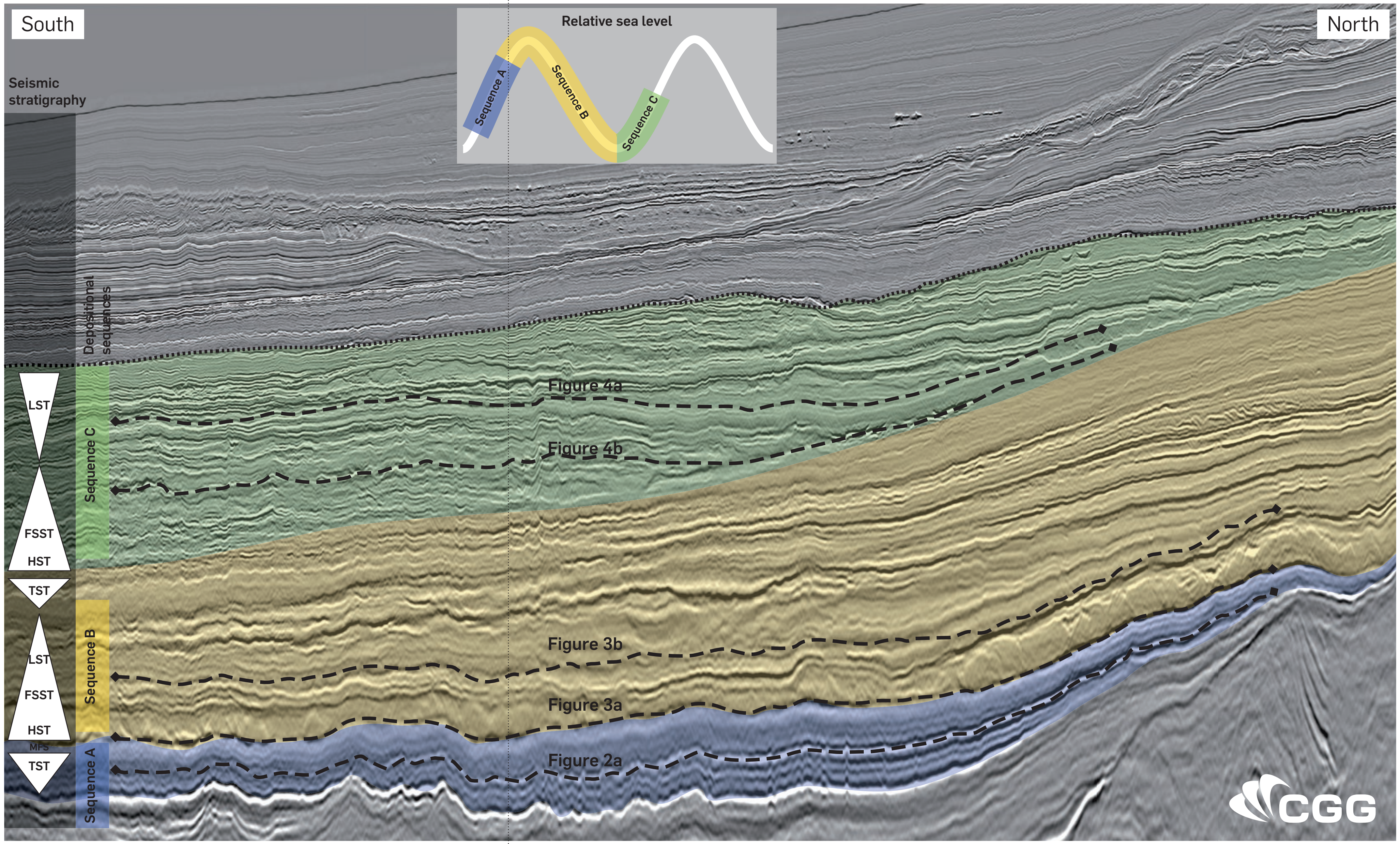
Recent stratigraphic analysis of 3D seismic broadband data is shown in this section running from south to north through the Grand Bassam subbasin. The left-hand panel shows interpreted stratigraphic horizons, seismic reflection terminations and key features. The right panel shows the depositional sequences and the horizons analysed with spectral decomposition in the figures on the following pages. Courtesy of CGG Earth Data.

The recent world-class **Baleine** discovery within the **Deep Tano Basin** has attracted renewed exploration interest for the offshore **Côte d'Ivoire**. Its structural complexity and depositional stratigraphy, resulting from multiphase rifting of this basin, require high-quality seismic data to develop detailed geological models. To achieve this, **CGG** recently conducted a seismic stratigraphic analysis using the **CDI-14 broadband multi-client 3D seismic dataset** over the **Grand Bassam** subbasin. The goal was to develop new insights into **Late Cretaceous** depositional mechanisms and key facies distribution to shed light on the potential prospectivity of this basin.

Location and coverage of the CGG broadband 3D seismic survey (4,400 km²) acquired in 2014 and the distribution of hydrocarbon fields across the Tano Basin.







The Tano Basin - Revealing Late Cretaceous Depositional Styles in a Frontier Basin

A recent seismic stratigraphic analysis demonstrates the presence of key petroleum system elements and the potential to develop new, high-impact prospects.

Text: Javier Martin, formerly CGG

Over the last few years, the industry's focus on hydrocarbon exploration has dramatically declined. Transforming resources into reserves has become a challenge for most African regions that have seen their production profiles shrinking substantially (Martin, 2022).

Despite this decline in exploration, there has been a high number of recent world-class discoveries in Africa. Among them, **Baleine** (Eni, 2021), offshore **Côte d'Ivoire**, is recognised as one of the biggest discoveries in recent history. A facies distribution model has been derived from seismic stratigraphic analysis, using CGG's multi-client 3D broadband seismic data from its **Earth Data Library** over the **Grand Bassam subbasin**, to help predict high-potential leads for further exploration.

CÔTE D'IVOIRE - CGG DATA COVERAGE

Over the last two decades, CGG has gained extensive insight into the acquisition, processing and interpretation of data sets in Côte d'Ivoire. Our first survey in 1999, comprising approximately 814 km^2 of 3D seismic data, was acquired to provide an understanding of basin structure and prospectivity and enable the mapping of clastic and carbonate systems within the **Tano Basin**.

In 2014, driven by in-house geological models and prospectivity predictions, CGG acquired a further 4,400 km^2 of 3D broadband seismic data (**CDI-14**) in the deep water offshore area of Côte d'Ivoire. The aim was to enhance imaging of **Late Cretaceous plays** that remained highly speculative and poorly understood at the time. Since the survey was acquired, the **Pelican** and **Rossignol** wells, drilled by Anadarko in 2016, confirmed CGG's predictive models, and Eni's **Baleine** discovery in 2021 put the Ivorian offshore basins at the forefront of exploration in West Africa.

MULTIPLE PROVEN HYDROCARBON PLAYS

With a total number of 137 exploration wells drilled since 1954 and 22 discoveries since 1974, the Côte d'Ivoire offshore territory has attained the status of a proven hydrocarbon province. Two main exploration phases have identified two major working petroleum systems (Martin et al., 2018):

1. The **Mid-to-Late Albian coastal syn-rift play**. Formed during the Late Albian continental break-up (Scarselli et al., 2017), when a series of syn-rift rotated fault blocks developed during a divergent tectonic cycle (Morrison et al., 2000).
2. The **Late Cretaceous deep marine post-rift play**. Well known along the Ghanaian side of the Tano basin, and identified more recently within the Grand Bassam sub-basin. This play is defined by the productive Cenomanian class II source rocks and the stratigraphic Turonian to Maastrichtian deep marine clastic reservoirs.

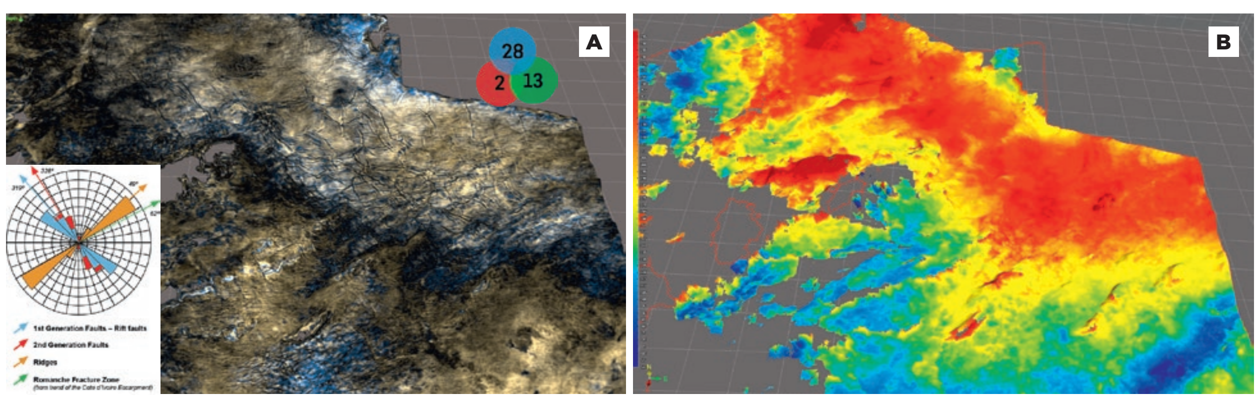


Figure 2. (A) Spectral decomposition attribute on a stratal slice from Sequence A (see seismic foldout). The complex basin architecture is formed by NW-SE normal faults related to divergence and transpressional ridges related to transform displacement. Colour key indicates spectral decomposition frequencies. (B) Isopach map of Cenomanian source rock showing the location of the depocenter in red colours. Images courtesy of CGG Earth Data. Rose diagram of fault orientation is taken from Scarselli et al., 2018.

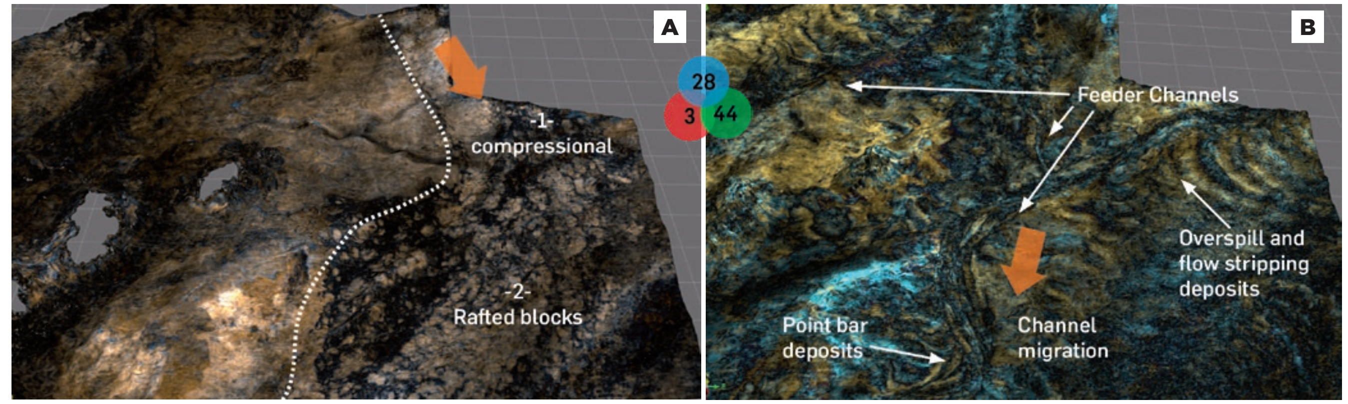


Figure 3. Spectral decomposition attribute over two different stratal slices from Sequence B (see seismic foldout). (A) Architecture and transport orientation of the MTC: 1 - Compressional domain and 2 - rafted blocks and debrites. (B) Feeder turbiditic channels with migration bars and flow stripping overbank deposits.

SEISMIC STRATIGRAPHY AND DEPOSITIONAL PATTERNS

From a geodynamic standpoint, the deep Ivorian basin has traditionally been described as a classic and well-known example of a divergent basin. The basin is bounded by transform faults that segment the African Equatorial margin into several transform margins (Mascle et al., 1995, Basile, 2015). Throughout its development, the basin has undergone multiphase rifting, tectonic reactivation, and volcanism, which have strong implications for sediment distribution and petroleum system development.

CGG's recent seismic stratigraphic analysis has provided new insights into the Late Cretaceous depositional mechanisms and facies distribution, through the identification and analysis of three main depositional sequences (seismic foldout).

SEQUENCE A

Overlies the Late Albian unconformity and is observed across the survey as a continuous, sub-horizontal and aggradational interval that displays a post-kinematic accommodation to the paleo-relief. Stacking patterns observed within this sequence suggest deposition occurred during a marine transgressive cycle sag phase, related to thermal relaxation after the continental breakup. The top of this sequence has been interpreted as a maximum flooding surface during maximum marine transgression.

This sequence is believed to host the prolific regional and class II Cenomanian oil-prone type II source rock, deposited in a depocenter identified within the north-eastern area of the survey (Figure 2). Considering its proximity to the recent Baleine discovery, the source rock within this area could have the potential to generate significant commercial quantities of oil.

SEQUENCE B

This unit, developed between sequence A and overlain by the Senonian erosive unconformity (seismic foldout), displays a distinctive progradational pattern in connection with a relative fall in sea level.

The onset of this sequence is likely to have occurred during a high stand system tract (HST) cycle and an early falling stage system tract (FSST) cycle. An extensive mass transport complex (MTC), in the form of a debris flow, has been observed towards the bottom of the sequence and mapped along the eastern half of the survey. This suggests slope instability and limited sediment transport between the extensional and compressional domains (Figure 3a).

The upper section of the sequence is characterised by a system of NE-SW moderately sinusoidal turbiditic channels and basin floor fans (Figure 3b). These were likely deposited during the FSST and early low stand system tract (LST) cycles. Onlap terminations towards the top of the sequence indicate retrogradation during the last stages of the LST, in connection with the relative onset of rising sea levels. Overbank deposits associated with the observed turbidite channels are characterised by sediment waves from overspills and flow stripping.

SEQUENCE C

This sequence is observed on the seismic as three major, vertically stacked turbiditic complexes displaying a retrogradational depositional relationship (Figure 4). The sequence hosts a system of lenticular unconfined slope fans, deposited during the LST and the onset of the transgressive system tract (TST) cycles. The internal architecture and geometries of the terminal feeder sections and inner distributary channels are related to the depositional dynamics of deep marine turbidite deposition.

The turbidite channels described in Sequences B and C form potentially highly prospective reservoirs. Our seismic stratigraphic and attribute analysis indicates that within most channels there is a series of recurring features which provide an understanding of the observed reservoir facies and heterogeneities. An understanding of the sinuosity of channels in Sequence B and the stacked nature of turbiditic channels observed in Sequence C, along with an understanding of facies distribution, sheds great light on the reservoir distribution and potential in the deep waters of the Tano Basin.

IMPLICATIONS FOR PETROLEUM SYSTEMS

The seismic stratigraphic analysis presented here has been fundamental in understanding the prospective potential of the deep-water region of Côte d'Ivoire. This has been achieved through the observation and interpretation of Late Cretaceous depositional features and mechanisms described within Sequences A, B and C.

Based on the interpretation, distribution of hydrocarbon fields, and data from nearby wells, we determine that the maximum vertical thickness of the Cenomanian class II source

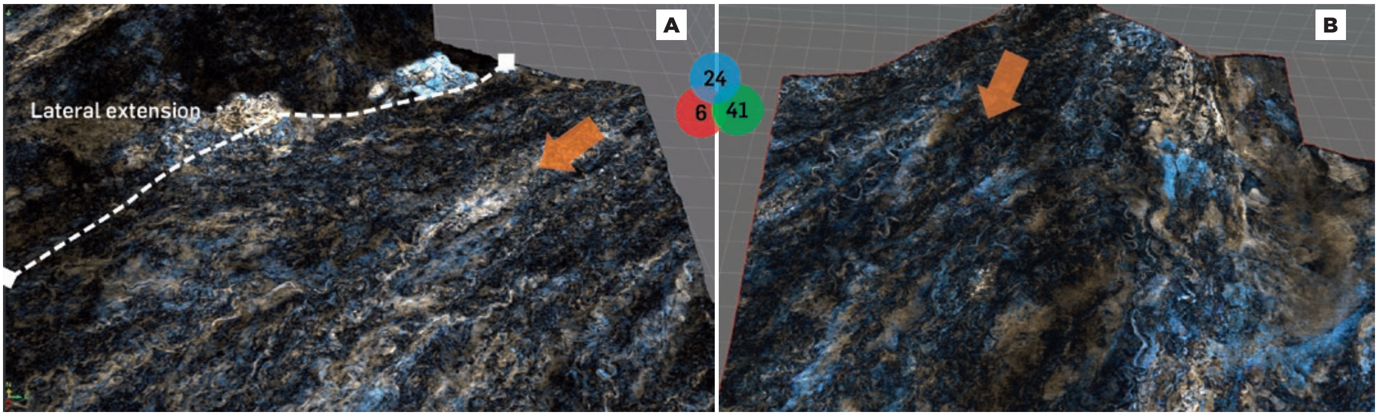


Figure 4. Spectral decomposition attribute over two different stratal slices within Sequence C (see seismic foldout) capturing the fan-like internal architectures. (A) Deepest fan complex with multiple terminal distributary channel segments active towards the eastern side of the area (B) Shallower fan active towards the central/western side of the area showing geometries typical from the inner fan system.

rock occurs primarily within the northeastern area of the CDI-14 survey. Reservoir facies and distribution have been inferred from analysis of the stacking patterns observed in Sequences B and C, in which a prolific system of NE-SW turbiditic channels and fan-like architectures have been identified. Channels in Sequence B show "feeder-type" morphologies typical of upper to middle continental slope environments. By contrast, Sequence C exhibits geometries and orientations typical of lower slope to basin floor fans.

Fault interconnectivity between source rock and reservoir facies is likely to be related to crustal readjustments, as evidenced by volcanic structures and faults identified throughout the area. The seismic stratigraphic analysis and conclusions discussed herein demonstrate the presence of key petroleum system elements and the potential to develop new, high-impact prospects.

All images courtesy of CGG Earth Data.

References provided online. ■

Acknowledgements: the author would like to thank Direction Générale des Hydrocarbures (DGH) Côte D'Ivoire and PetroCI for their great collaboration and for allowing us to publish this paper as well as my CGG colleagues for their support and reviews during this study.

Source: Stryde

How Stryde Enabled New African Opportunities to be Explored

While there is much discussion about the upsurgence and potential of renewable energy sources, there is still a great amount untapped resource lying beneath our feet – in particular in the unexplored basins of Northern Zimbabwe.

Last year, Australian gas and oil company, **Invictus Energy** began a multi-million-pound E&P project to tap the last untested large frontier rift basis in onshore Africa – the **Cabora Bassa Basin** in **Northern Zimbabwe**.

Welcomed by locals, the project has the potential to provide a solution to the country's energy crisis through offering Zimbabwe the chance to not only be energy independent but shift its position to that of an exporter into the region.

To explore the petroleum potential of the frontier basin, Invictus deployed a 2D seismic campaign that not only resulted in a more cost-efficient acquisition but promoted safer operations while reducing environmental impact in complex and remote terrain.

ENABLING SURVEY EXCELLENCE IN REMOTE LOCATIONS

Seismic, an exploration process of gathering subsurface vibrations using advanced technology to determine the existence of hydrocarbons, was implemented by Canadian seismic contractor, **Polaris Natural Resources**, who are on a mission to help end energy poverty in Africa by enabling operators to explore the petroleum potential beneath the flat savanna land.

Due to the remote survey location being deemed as an environmentally sensitive area, the team required an environmental impact assessment (EIA) to be completed prior to the survey being sanctioned, meaning it had to adhere to strict environmental footprint management conditions.

In addition to environmental concerns for the area, the complex terrain coupled with the survey being weather dependent also created logistical and time challenges.

The vast survey size traditionally would have required large volumes of seismic equipment to complete the survey effectively. However, as this was a frontier, unexplored basin, Invictus Energy required a solution that was low cost, without compromising the quality of the output dataset.

With a vision to make seismic data collection more cost-effective, agile, safe and sustainable, while delivering unparalleled subsurface imaging, **Stryde**'s state-of-the-art Nodal technology was selected to enable this crucial land seismic acquisition.

Launched to market in 2019, the disruptive technology offers pioneering, high-density seismic imaging systems, which play a key role in the exploration and production (E&P) stage of new discoveries, or of existing reservoir management.

Adaptable for land or marine, seismic data acquisition is the process of gathering information about the composition of the earth below the surface. This data is acquired using machine receivers, which create and listen for vibrations before processing the scans into raw data.

Stryde's **Nimble system™**, comprising of 9,540 Stryde Nodes™, a server and 4 Nests, navigator tablets, initiation devices, backpacks and the nodal operating software, as well as field support personnel, were delivered on-site in southern Africa within five days of the contract agreement to ensure the project started on time.

UNLOCKING HIGH-DENSITY SEISMIC, COST SAVINGS AND SAFER WORKING

Using 9,500 Stryde nodes, over 82,929 seismic receiver points were laid out, by foot during the survey, resulting in a total of 839.5 km of high-resolution 2D seismic data being acquired. 402 km was situated in Invictus' Special Grant 4571 license, and another 437 km of contiguous data in an existing application area.

As well as the vast seismic data acquisition, Stryde's system also unlocked significant cost savings, related to reductions in the number of people, equipment needed, logistics, vehicles, and project time when compared to competitor cable and nodal systems.

Utilizing **the world's smallest and lightest nodes**, the locally hired teams were able to carry 90 nodes per person by foot, resulting in being able to deploy and retrieve thousands of nodes per day. This minimized the need for line clearing and land disruption, shooting the survey in a more efficient manner, which reduced the project timeline considerably.

Continuously recording nodes allowed multiple receiver lines to be generated from a single shot line, resulting in the acquisition of high-resolution and increased density 2D lines and deep structure data that provided the insights required to make informed drilling decisions and to help plan future surveys.

In addition, the unique characteristics of the Nimble nodal system™ reduces the number of people and vehicles required to deploy and retrieve the nodes in the field and therefore reduce the acquisition contractor's exposure to risks on site.

As well as supporting the country becoming energy independent, the project also generated nearly 200 direct jobs during the campaign for the local Muzarabani and Mbire communities as well as the procurement of goods and services from local suppliers.

PROMISING PROSPECTS

Stryde's Nimble system™ is ideally suited to these kinds of remote 2D operations. The speed at which locally hired teams could learn how to operate the system allowed Polaris Natural Resources to deliver a very efficient project that delivered fantastic imaging results for Invictus Energy.

Around 1.6 gigabytes of high-density 2D seismic data was successfully harvested from Stryde Nodes, before being sent for processing and interpretation, enabling the company to identify and mature additional prospects and leads.

Drilling for the **Muzarabani-1 well** is underway, with the prospect considered to be the largest undrilled conventional oil and gas prospect onshore Africa. Invictus believes it could host prospective resources of about **9.25 trillion cubic feet of gas** and **294 million barrels of condensate**.

Source: Stryde

The Stryde Node™

Stryde's customers benefit from a substantially reduced environmental footprint, reduced HSE risk, faster surveys and significant operational and logistical efficiencies before, during and after acquisition.

To summarize, Stryde's products save customers money and time while enabling them to deliver the best quality seismic data.

ABOUT STRYDE

Stryde is helping organizations from around the globe to acquire an unparalleled understanding of the subsurface. As the creators of the World's smallest, lightest and most affordable seismic nodes, Stryde enables high-density seismic to be affordable to any industry.

To find out more about Stryde and the game changing Stryde Node™ please visit www.strydefurther.com or email us at sales@strydefurther.com. ■

Source: Stryde

Deployment of nodes in the field in Zimbabwe.

Photo: Damir Yanich

Sudan's Red Sea Oil

The Sudanese Red Sea is one of the world's most exciting underexplored passive margins. Here, we show how legacy 2D seismic reveals a stunning array of super-giant syn-rift plays in the pre-salt, capped by halite walls and canopies, in addition to mini-basins in a proven post-salt fairway.

Text: **Neil Hodgson, Karyna Rodriguez and Peter Hoiles, Searcher Geodata UK Ltd**

As explorers, we often find that the ground work of frontier hydrocarbon system evaluation is completed with heroic efforts on early basin wells, but that is then followed by an exploration pause.

The early 1960's wells **offshore Sudan** proved the existence of a working hydrocarbon system, proved numerous pre-salt and post salt source rocks, defined geothermal gradients and the stratigraphy, whilst proving the presence and effectiveness reservoirs.

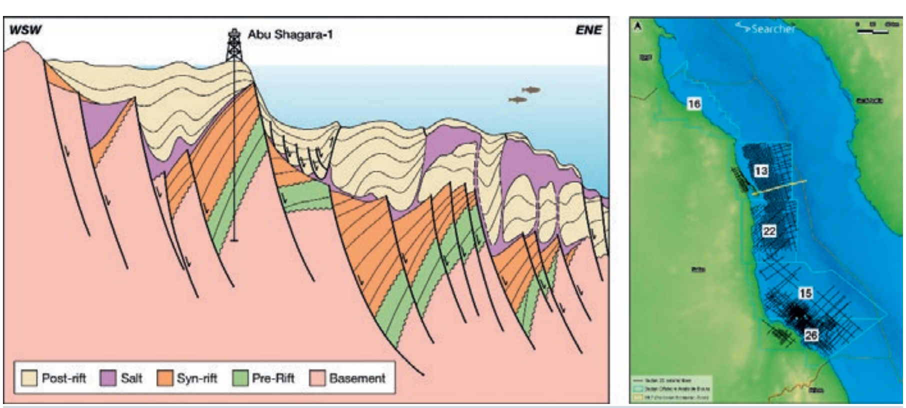
Ultimately, success came in the 1970's for **Chevron** with the gas and condensate discoveries of **Bashayer-1** and **Suakin-1.** However, these discoveries had unfortunate appraisals and exploration subsequently stalled.

RED SEA SOURCE AND SALT

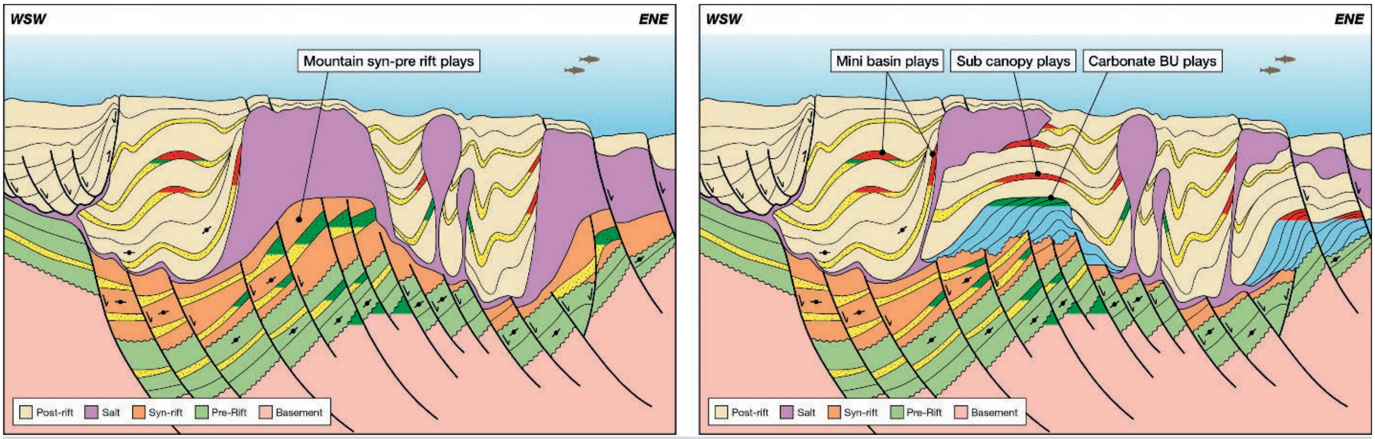
Source rocks proven in many of the wells drilled in Sudan's Red Sea province are found to have similarities to the prolific Gulf of Suez source rocks. The **Oligocene Hamamit Formation** (broadly equivalent to the **Thebes Brown Limestone** of the GOS) has 1.7-5% TOC, and the Middle and Early Miocene source rocks have TOC's up to 2%. Zeit Formation equivalent source rocks in the post salt are likely to have charged discoveries in the mini-basin play.

There were three major cycles of thick halite deposition in the Miocene, separated by evaporite and clastics in sequences not unlike the **South Gharib** and **Zeit** formations of the **Gulf of Suez** (GOS). Halokinesis of these thick salt bodies due to loading and extension commenced during the syn-rift, and as drift began and the post-salt mini-basins began to slide into the basin, this mobilized salt evacuation seawards into drift-space.

These Late Miocene-Pliocene mini-basins rapidly developed into welded sequences creating both turtleback traps in addition to the salt wall lick-up plays. The recent interpretations of the outboard salt suggest that the evaporitic succession was loaded so much in the Pliocene that salt was erupted onto the sea bed and submarine salt-glaciers flowed from these eruptive centres which now are represented as salt canopies in the section (see cross-sections).



Situated between Egyptian, Saudi Arabian and Eritrean waters on the western side of the Red Sea, the 57,000 square km of margin offshore Sudan is barely explored: just 14 wells were drilled, mostly pre-seismic. The cross-section shows AGIP's early 1963 Abu Shagara-1 well drilled on a prominent tilted fault block. It encountered gas shows in thick syn- and pre-rift sands and conglomerates below a thin salt interval. Figure drafted after Sudan's Ministry of Energy and Petroleum information pack on Block 13.



West-East dip sections across Sudan's northern offshore (Block 13). Pre-salt syn- and pre-rift targets either lie below thick salt walls (left) or below thinner salt canopies (right). Neither of these models have been tested in Sudan, although the intra-salt mini-basin play was successfully drilled in the ***Suakin-1*** *gas condensate discovery in the Miocene Zeit equivalent in the southern Sudanese Red Sea. Figure after Sudan Ministry information Block 13.*

RED SEA SEISMIC

Determining whether the salt is present as thick salt walls (such as the Amber structure drilled in Eritrea) or as thin salt canopies over super-thick syn-rift sections, is not unequivocal using legacy data.

To resolve this, **Searcher** plan to acquire 6,000 square km of 3D over this area in 2023. The salt thickness is key to understanding the maturity of the various source rocks as geothermal gradients measured in well penetrations vary from 35 to 47°C/km, yet none of these wells show the temperature below salt walls. The high thermal conductivity of salt will transmit heat from deep basins into the shallow section, both above the salt and adjacent to it.

Searcher has now rectified over 40,000 km of 2D seismic data into a **sAIsmic project** to help plan for the 2023 3D seismic campaign. These data are now available for industry Licensing.

Interpretation of this data set has revealed that a series of huge structures (known as the "mountain prospects") can be mapped out at Base salt or Top early syn-rift level (see cross-sections). These highs comprise pre-rift and early syn-rift clastics, with in excess of 1 km relief and hundreds of square km in areal closure.

There is potential (as yet speculative) for these "mountains" to include carbonate build-ups. Above these pre-salt mountains lies either thick salt (and perfect top seal) or thick evaporite and clastic sequences that are themselves capped by Gulf of Mexico style salt canopies. Situated in between the salt walls are drift mini-basins. These are similar to, though structurally less complex, than the **Suakin-1** condensate discovery.

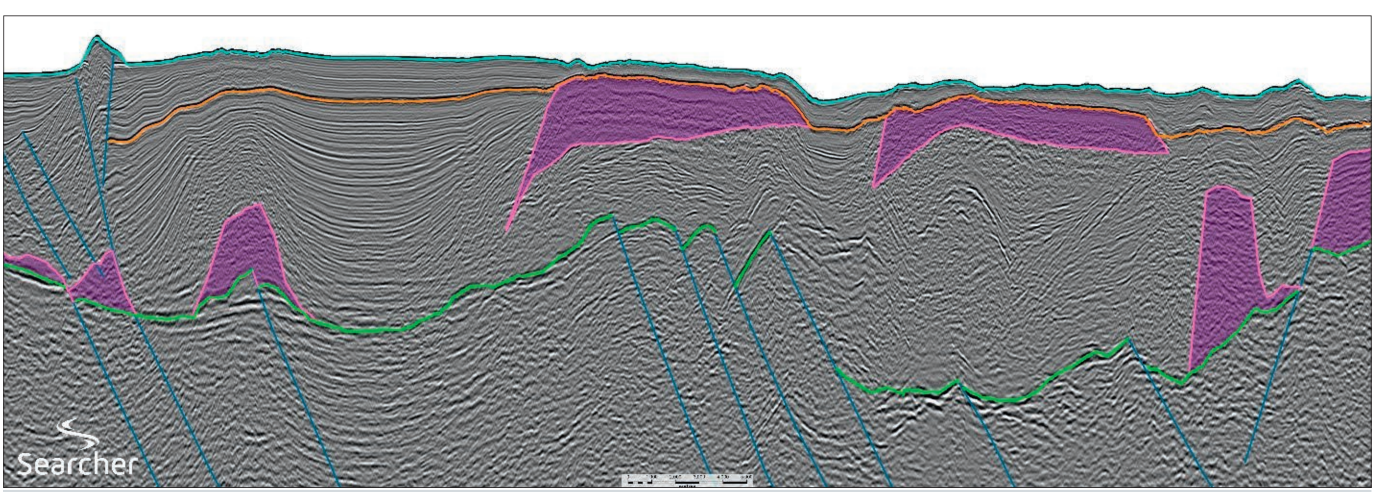
To the north, Egypt's Red Sea has become a focus of exploration efforts again with a successful licence round and award of licences where phenomenal repeating oil slicks have been captured in satellite image studies. These world-class oil slicks reappear over the mountain prospects of Block 13 in Sudans Red Sea (Clément Blaizot pers. com. 2021).

RED SEA RISING

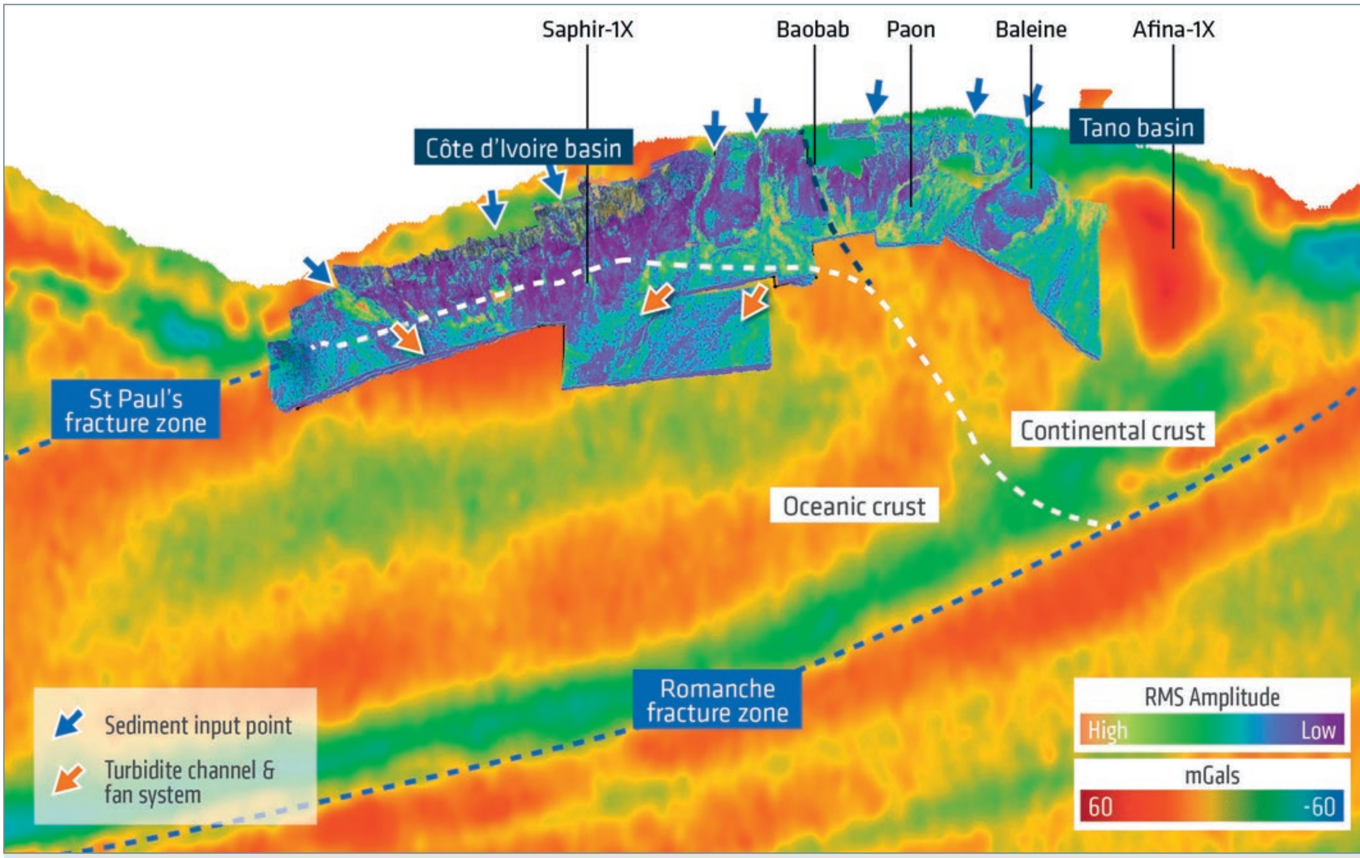
Multiple prospects are mapped on legacy seismic but new 3D is required to image salt and understand hydrocarbon system development. That is the next piece to the offshore Sudan oil puzzle to be provided with Searchers forthcoming 3D acquisition. These will be the final step on Sudan's Red Sea's journey to offshore exploration greatness as they prepare for drilling the vast pre-salt and mini-basins plays in this soon-to-be super basin.

Searcher would like to acknowledge sincerely the efforts and cooperation of the Sudan Ministry of Energy and Petroleum and in particular the Director General of Hydrocarbon Tarig Abdulrahman Abbas for their assistance in publishing this article.

References published online.



Example West-East legacy seismic line across Sudan's northern offshore (Block 13). Interpreted salt is "canopy" model (see cross-section). The highs at "green reflector" comprise the 'Mountains' prospects. Seismic data from Searcher.



RMS Amplitude extraction in the Upper Cretaceous overlain on a Bouguer Corrected Gravity (200 km high pass filter) map, offshore Côte d'Ivoire. The deep-water play is highlighted with potential turbidite channel and fan reservoirs charged by underlying Cenomanian/Turonian source rocks deposited over oceanic crust. RMS extraction derived from horizon interpretation of the full-stack PSTM Côte d'Ivoire MegaSurvey.

Go West: Deepwater Prospectivity in the Côte d'Ivoire Basin

Mapping of Upper Cretaceous reservoirs and source rocks across the deep-water area of Côte d'Ivoire suggests exciting exploration potential.

Text: **Avril Burrell and Elena Polyaeva, PGS, Sié Georges Kam and Samuel Essoh, PETROCI**

The **Tano Basin** has been the location of several high-profile discoveries made in recent years with the drilling of the **Afina-1X well** in **Ghana** and the discovery and subsequent expansion of the **Baleine** structure offshore **Côte d'Ivoire** (see map above).

These large accumulations have shown that there are significant volumes of hydrocarbons being found in Cretaceous-aged plays over continental crust in this well-explored basin. Using insights gained from extensive **PGS MultiClient** seismic data coverage, new play concepts from recent discoveries offshore Namibia can be applied directly to Côte d'Ivoire.

This enhanced regional scale understanding of petroleum systems highlights the remaining opportunities over oceanic crust in the western area of the Côte d'Ivoire offshore, allowing exploration potential to be extended from analogs and existing in-basin discoveries into underexplored areas.

TECTONIC HISTORY KEY TO PETROLEUM SYSTEM DEVELOPMENT

Offshore Côte d'Ivoire can be split into two main basins, the **Tano Basin** in the east and

Côte d'Ivoire Basin in the west. Both depocenters developed during the opening of the Atlantic, with transtensional rifting beginning in the Early Cretaceous and finishing at the end of the Albian with the formation of oceanic crust.

The Tano Basin developed in an area of relative tectonic quiescence between the Saint Paul's and Romanche Fracture Zones, resulting in pull-apart grabens with a thick clastic fill. This created a broad shelf to deep water profile with the basin underpinned by thick continental crust, gradually thinning towards the continental to oceanic crustal transition.

In comparison, the Cote d'Ivoire Basin has a narrow shelf to deep water profile, characterized by transtensional faulting and initial graben development orientated sub-parallel to the present-day coastline. The continental to oceanic crustal transition is also more abrupt here due to the underlying Saint Paul's Fracture Zone.

The stratigraphic section of both areas can be divided into the pre-, syn- and post-transform tectonic phases, each with a distinct depositional history and related petroleum systems. The pre-transform stage has not been penetrated by drilling in the Côte d'Ivoire Basin and so we will focus on the syn- and post-transform stages due to their contribution to proven petroleum systems.

The syn-transform phase of transtensional opening in the Gulf of Guinea began around the Berriasian and ceased at the end of the Albian. A thick section of continental to marginal marine clastics was deposited during this period, providing potential reservoir units in the form of fluvial to marginal marine sandstones. Source rocks transition from deeper Aptian lacustrine shales to shallower Mid-Albian marginal marine shales through the stratigraphic section as rifting progressed.

Extensional opening of the Transform Margin basins ceased at the end of the Albian and was followed by wide-spread deposition of Cenomanian-Turonian marine shales. The area formed a continuous anoxic seaway from the late Albian to Turonian, which resulted in a high total organic carbon content (TOC) oil-prone source rock in the region.

REGIONAL DATA COVERAGE FOR ENHANCED UNDERSTANDING OF PROSPECTIVITY

In partnership with **PetroCi** and **Direction Générale des Hydrocarbures**, **PGS** has a large footprint of MultiClient seismic data available offshore Côte d'Ivoire (see map below). The recently expanded **CDI MegaSurvey** offers almost complete west to east coverage of the Ivorian offshore with 33,861 sq. km of 3D and 31,743 line km of 2D.

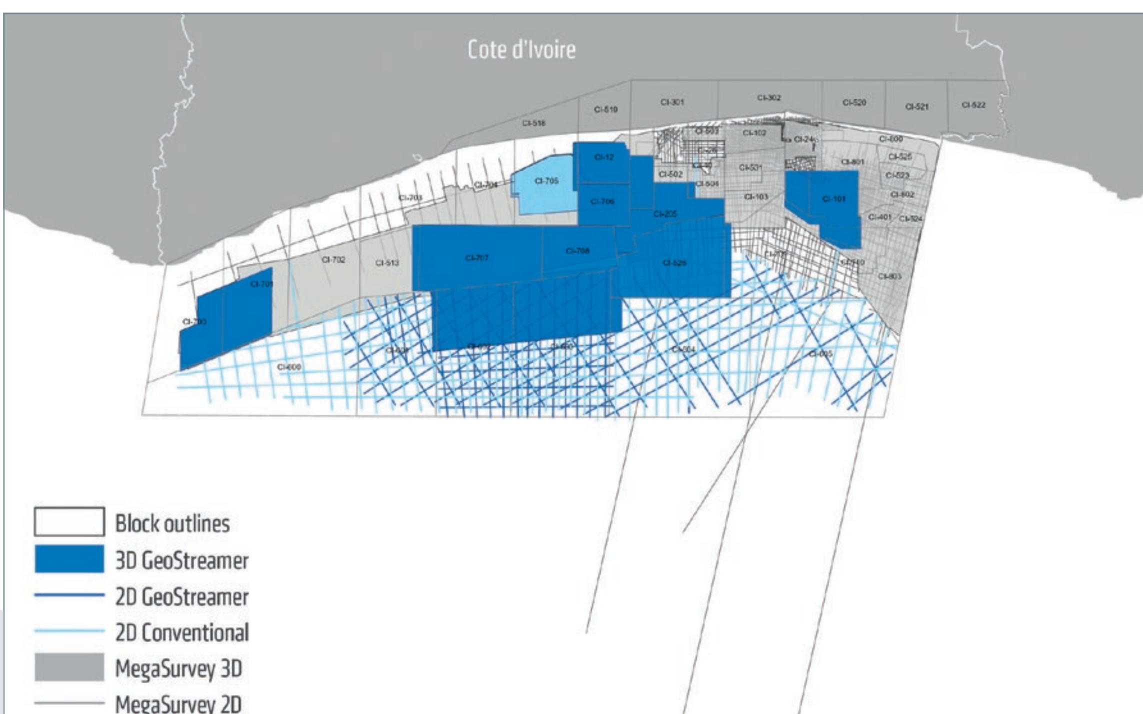
The various 3D input datasets have been matched, merged and re-binned onto a common grid resulting in a single, continuous volume of full-stack seismic data in the time domain, allowing for regional scale play analysis. Overlying the western portion of this dataset are several broadband **GeoStreamer** surveys where pre-stack data has been used to perform AVA analysis, enhancing the understanding of the prospectivity in the region (see next page).

EXPLORATION HISTORY OF THE TWO KEY PLAYS

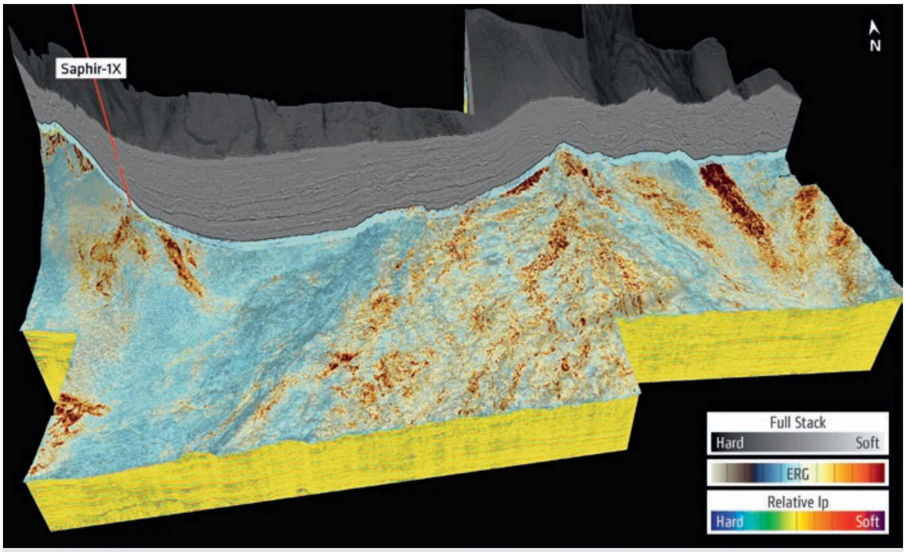
Two main plays have been the focus for exploration in the Ivorian offshore; the syn-transform Lower Cretaceous and the post-transform Upper Cretaceous. The Lower Cretaceous play dominates the area around the shelf edge in both the Tano and Côte d'Ivoire Basins. A contributing factor in this inboard dominance is the source rock maturation history.

Berriasian to Albian source rocks sit within the gas maturity window around the shelf due to a relatively thinner overburden, whereas they are likely to be over-mature in more distal syn-transform basins where depth of burial is greater. These source rocks are paired with Albian aged fluvial to shallow marine syn-transform sandstones, as proven in the Baobab Field.

The Upper Cretaceous system is most successful around and outboard of the present-day shelf edge due to the thick



The regionally extensive PGS MultiClient Data Library Offshore Côte d'Ivoire.

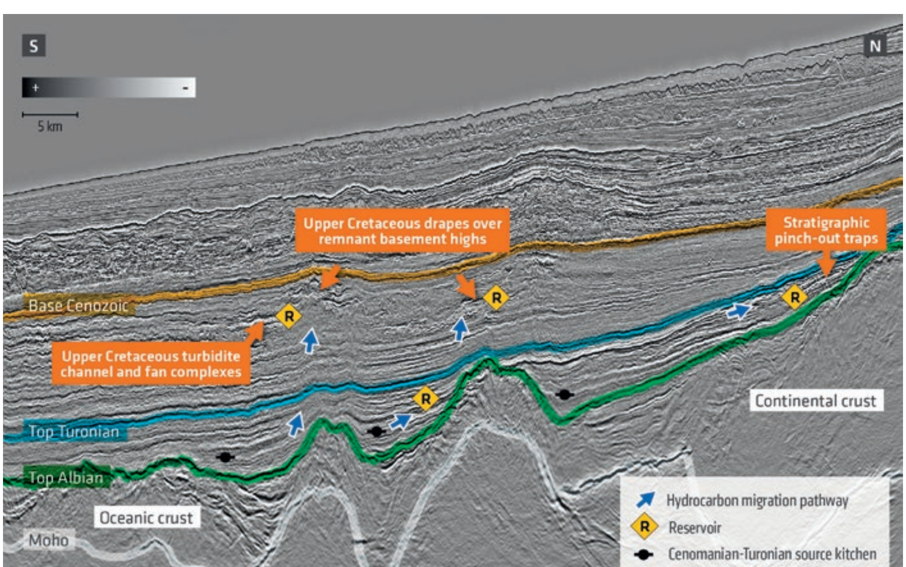


AVA anomalies across the deep-water offshore Côte d'Ivoire highlighted using an Enhanced Restricted Gradient (ERG) attribute from above the Base Senonian horizon. This has been draped over a relative acoustic impedance volume from various merged GeoStreamer MC3D surveys. Full Stack and Angle stacks were conditioned and matched cross-vintage to bring data into a common amplitude and bandwidth. AVA spectral balancing was also applied to match bandwidths of the near and far angle stacks to produce a consistent Enhanced Restricted Gradient (ERG) attribute. Relative Impedance attribute was also generated following a trace integration method.

clastic section allowing for sufficient burial of shallower Cenomanian-Turonian aged source rocks. These type II source rocks have mixed oil and gas potential. Complementing this widespread source kitchen are Albian to Santonian aged shallow to deep marine sandstone reservoirs.

The largest discovery in this play is contained within the **Baleine** shelf-edge structure which is reported by Eni to contain **2.5 billion barrels** of oil and **3.3 trillion cubic feet (TCF) of associated gas** over two main reservoir levels. This discovery has also expanded the Upper Cretaceous play to include carbonate shelf edge reservoirs.

The Paon discovery by Anadarko has proven that the Upper Cretaceous play extends into the deep water Tano Basin, with the Saphir-1X well drilled by Total illustrating that the play is present to the west in the Côte d'Ivoire Basin too.



Full-stack PSTM dip line from the Deepwater 2018 GeoStreamer MC3D survey, highlighting play concepts directly related to recent Namibian discoveries.

As shown by the RMS amplitude extraction from the Upper Cretaceous on the first image of this article, turbidite channel and fan complexes, annotated by the orange arrows, are widely deposited across the entire Ivorian offshore. Multiple sediment input points (blue arrows) are observed in both the Tano and Côte d'Ivoire Basins, highlighting the promising reservoir potential to the west of the Tano Basin. These features are also highlighted using pre-stack data (left), which indicate AVA anomalies in the deep-water area.

DEEP WATER PLAY CONCEPTS FROM NAMIBIA

Recent 2022 exploration success offshore **Namibia** with **TotalEnergies' Venus-1** and **Shell**'s **Graff-1** and **La Rona-1** discoveries have suggested that Cretaceous-aged source rocks deposited over transitional to oceanic crust are oil mature in outboard areas, expanding the Cretaceous play into the deep-water in the Orange Basin.

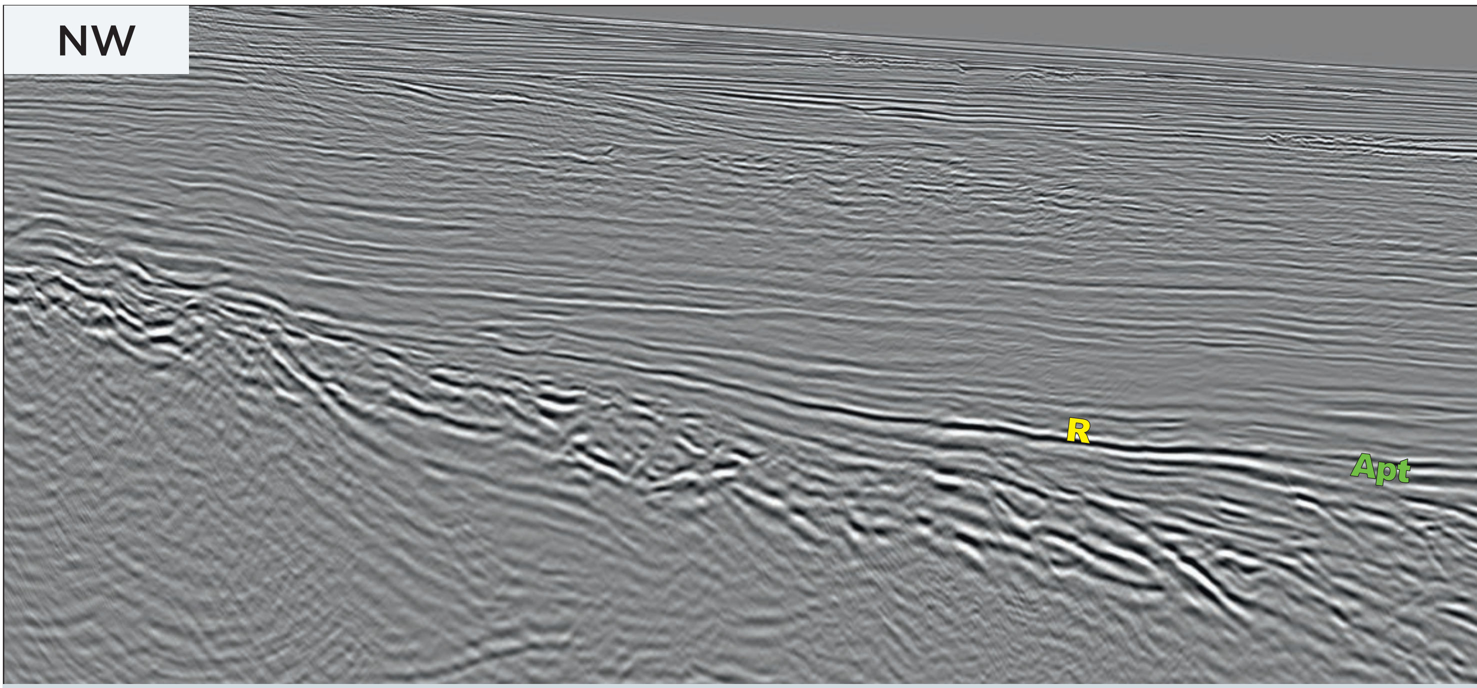
The concept for hydrocarbon generation and expulsion from source rocks subjected to increased heat flow due to a shallow aesthenosphere may also be applied to the deep water offshore of Côte d'Ivoire, expanding prospectivity beyond the area underpinned by continental crust in both the Tano and Côte d'Ivoire Basins.

Applying seismic facies analysis to the section shown here (bottom left), Cenomanian-Turonian-aged source rocks are hypothesized to have been deposited directly over transitional to oceanic crust. These deposits are characterized by their low amplitude, planar response typical of deep-water shale deposits. The Cenomanian-Turonian-aged shales are a proven source rock offshore Côte d'Ivoire, containing high TOCs.

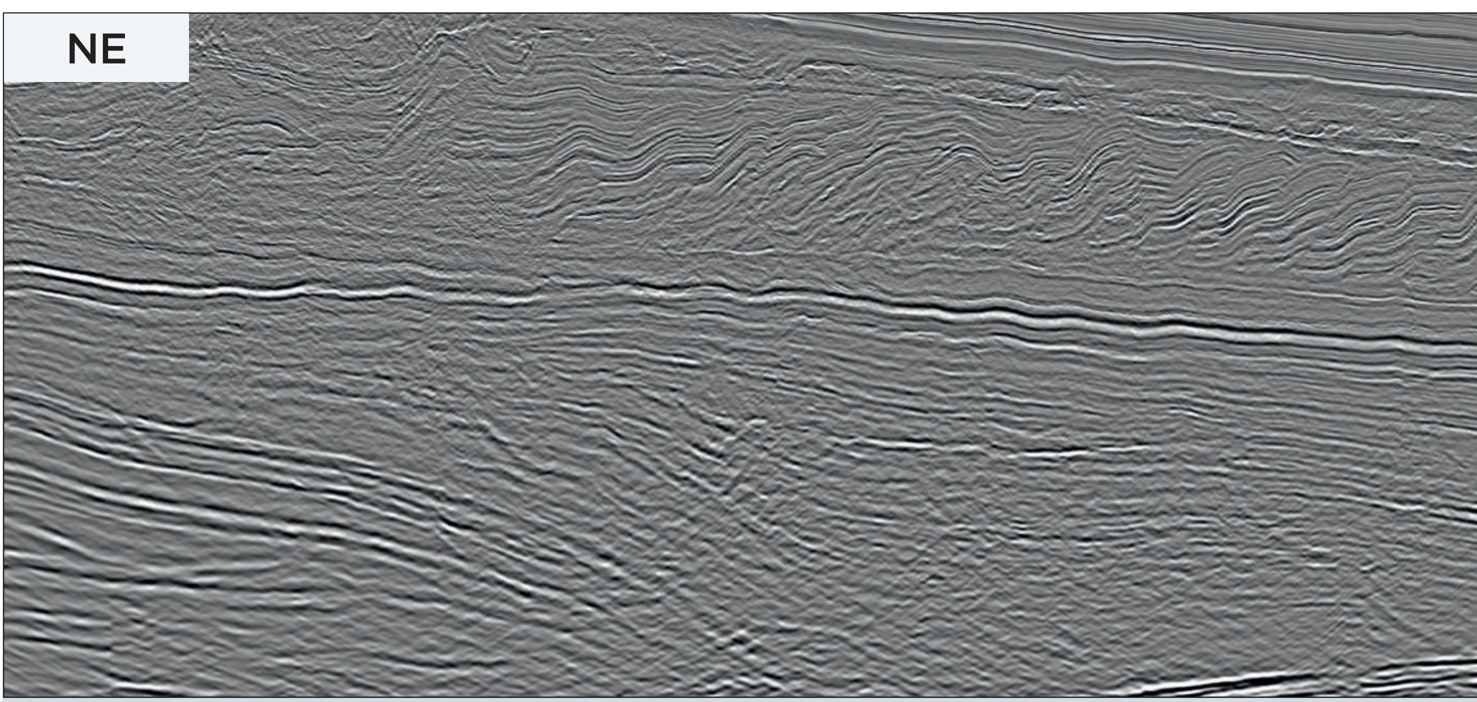
Similarities can be drawn between the location of the Namibian discoveries over transitional to oceanic crust and the extension of potential Upper Cretaceous reservoirs into the deep-water offshore of Côte d'Ivoire. Using Bouguer Corrected Gravity data and through mapping of the Moho on the seismic, these turbidite channel and fan complexes are observed to extend beyond the continental-oceanic crustal transition. These reservoirs, where draped over oceanic crustal highs and paired with underlying Cenomanian-Turonian potential source rocks, hint at exciting further exploration opportunities in the Côte d'Ivoire Basin (left). ■

Images courtesy of PGS

The Striking Similarities between Namibia and Brazil's Conjugate Margins



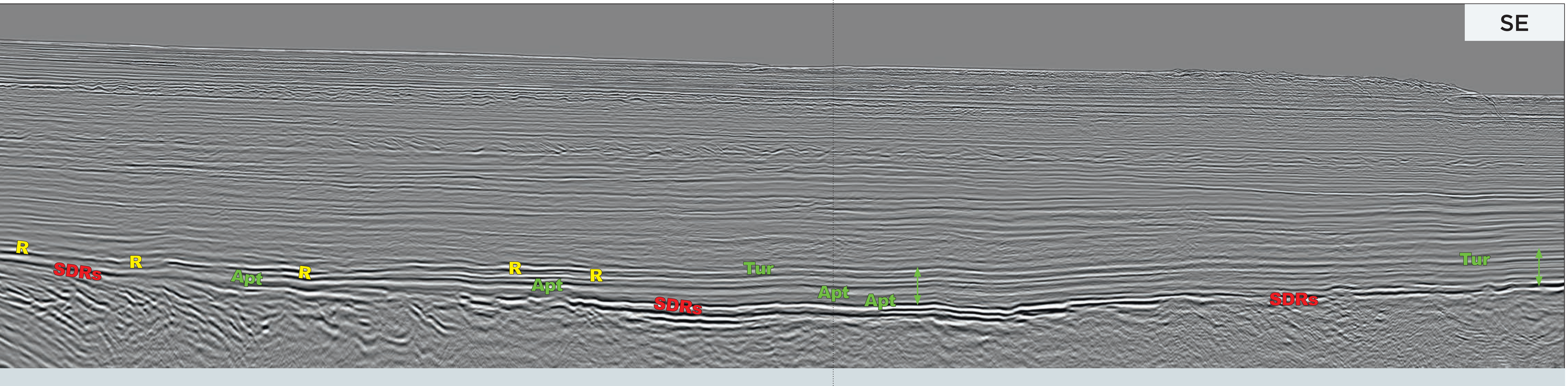
Pelotas 2D Kirchhoff PSDM Stack

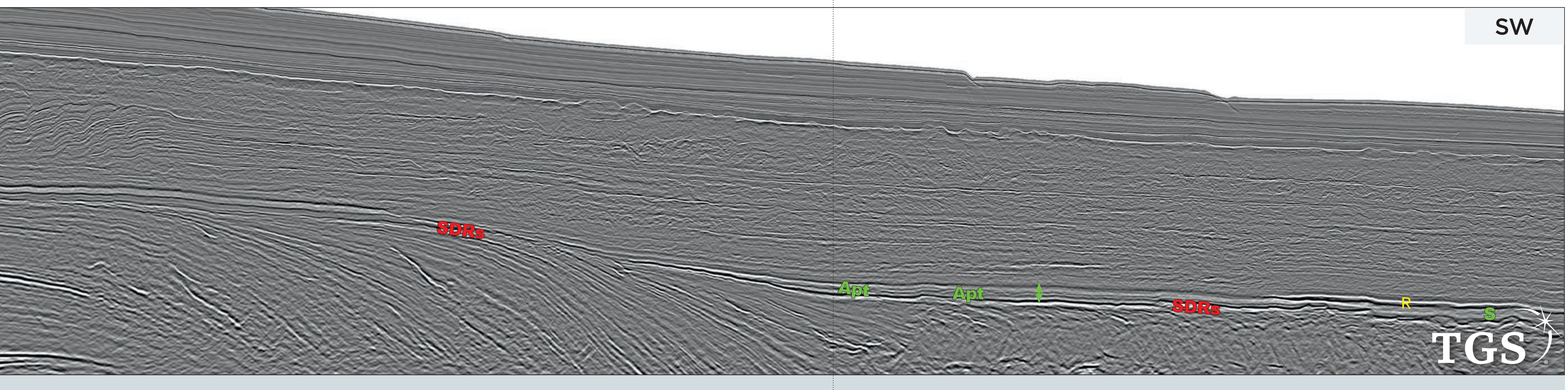


Namibia 2D Kirchhoff PSDM Stack

Regional seismic lines indicate that the Pelotas Basin in Brazil contains the same play ingredients as the Orange Basin in Namibia where the Venus discovery was recently made.

The similarity of geological and geophysical features between seismic lines from the conjugate Pelotas Basin in Brazil and Orange Basin in Namibia points to great chances of success for the replication of large discoveries in the former. From the source rocks at the base (in green) resting upon Seaward-Dipping Reflectors (in red), through the reservoirs (in yellow) interlayered with or resting upon the source rock interval to the great overburden of these rocks, nothing conspires against a successful spree of discoveries in the Pelotas Basin.

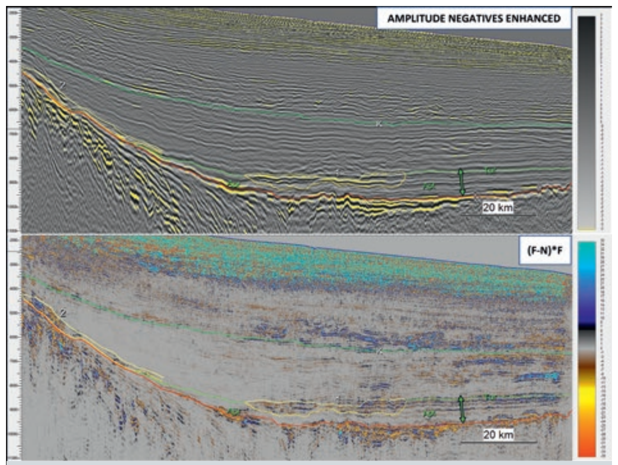




Pelotas Basin in Brazil – A Fantastic Analogue to the Orange Basin in Namibia

The astounding discoveries of gas condensate in South Africa (Brulpadda and Luiperd) and, more recently, of oil and gas in Namibia, drew the attention of the global petroleum industry. Therefore, major oil companies are now turning their sights to the other side of the South Atlantic Ocean, namely to the conjugate margins of southern Brazil, Uruguay, and northern Argentina.

Text: Pedro V. Zalan – ZAG Consulting, Rio de Janeiro • Randall Etherington, Milos Cvetkovic – TGS, Houston



Source rocks (in green) displaying DSIs (Type III/IV AVOs) and 2 prospects displaying DHIs (Type III/IV AVOs). Prospect 1 is turbidite channel incised into the source rock package. Prospect 2 is an updip pinching submarine fan resting upon the termination of the source rocks. K for top Cretaceous, Tur for Turonian, Apt for Aptian.

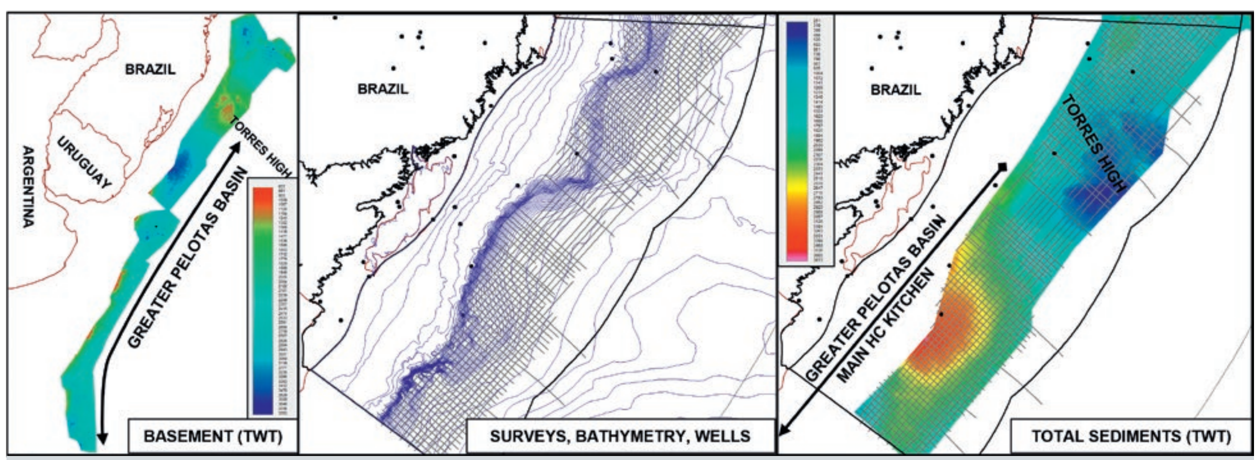
The **Greater Pelotas Basin** is comprised of a single, uninterrupted, enormous sag basin containing large thicknesses of Lower and Upper Cretaceous to Cenozoic Drift Sequences, resting upon volcanic substratum (either Seaward Dipping Reflectors (SDRs) or Oceanic Crust).

In this context, we are considering only the southern part of the Pelotas Basin, situated south of the **Torres High** (see map). Ten wells (9 in Brazil, 1 in Uruguay) have been drilled in this frontier area, and only three of them in deep/ultra-deep water.

These discoveries proved the capacity of the source rock system to generate commercial quantities of light oil and gas. The successful petroleum system is named the **Cretaceous Marine Anoxic Shales - Upper Cretaceous Turbidites**.

The source rocks are marine anoxic shales of Aptian-Turonian age of which the Aptian shale seems to be the richest and most effective contributor (see seismic lines). The reservoirs are Upper Cretaceous turbidites deposited in large basin floor submarine fans fed by channelized systems. With the reservoirs situated directly on top of the source rocks, the traps are mostly of stratigraphic nature.

In three of the four discoveries cited above, the reservoirs are of Aptian age and rest upon the Aptian shales. This system is ubiquitous in the continental margins of the South Atlantic Ocean. It has unveiled large reserves and production potential in Guyana and Suriname, Ghana and Ivory Coast, Sergipe-Alagoas, Equatorial Guinea, Espirito Santo, Campos, Santos, Angola, Namibia and South Africa. The only variation among these areas is the age of the main source rock; sometimes it is Aptian, sometimes it is Turonian.



Left: The Greater Pelotas Basin is defined as having a continuous, uninterrupted nature of the top of the economic basement; Center: The dense grid of 2D seismic data available in the Brazilian part of the Pelotas Basin; Right: The most important depocenter is situated in the southernmost part of Brazil.

The time has now come to prove the presence and effectiveness of these source rocks in the Greater Pelotas Basin, especially in southern Brazil. All the favourable indicators are present in this conjugate South American margin:

1. Seismic facies indicative of a basal package of source rocks.
2. Overburden in excess of 3,500 m to allow for the generation of hydrocarbons.
3. Direct Source Indicators (DSIs) as Type III/IV AVOs in sub-horizontal, tabular, parallel seismic facies indicative of low energies.
4. Seismic facies indicative of turbidite reservoirs in submarine fans, lobes and channels.
5. Direct Hydrocarbon Indicators (DHIs) such as bright spots with Sweetness anomalies and/or Type III/IV AVOs.
6. Direct Migration Indicators (DMIs) such as gas chimneys, flags along faults, buried mud volcanos, shallow pockets of gas.
7. Trapping geometries such as updip and lateral pinch outs, draping over buried basement structures and mixed traps.

STRIKING SIMILARITIES

The foldout displays the great similarity between 2D seismic lines in the Brazilian Pelotas Basin and in the Orange Basin in Namibia. The SDR economic basement is prevalent in both basins. The basal package of source rocks presents the same seismic facies of tabular, parallel, continuous alternating reflectors with moderately strong negative amplitudes.

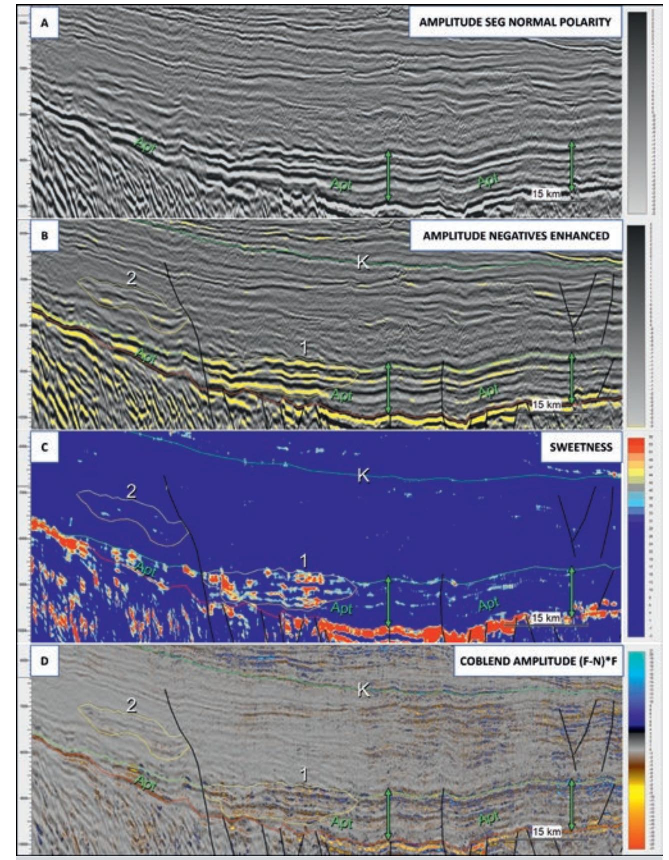
The source rock package in Pelotas seems to be thicker and more complete, possibly due to the presence of the Turonian. The total sediment thickness map (see map) shows that the main hydrocarbon kitchen in the Greater Pelotas Basin lies exactly beneath the Brazilian portion of the basin.

The reservoir is magnificently displayed as the Venus submarine fan resting on top of the Aptian source rock; highlighted by a strong bright spot in the far-right end of the Orange Basin line. In Pelotas, several indications of bright spots in channelized and pinch-out seismic facies resting upon and interlayered with the source rock package point to potential accumulations of hydrocarbons.

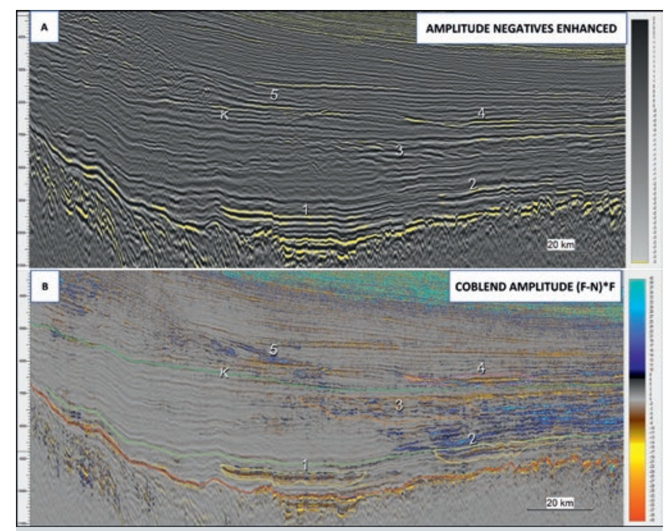
Regarding sealing in these source/reservoir sections, both basins are covered by identically thick seismic facies indicative of undisturbed low energy clastic sediments, the monotony of which is frequently broken by mass-transport deposits, channelized facies and wide, laterally pinching-out layers suggestive of stacked submarine lobes/fans.

TURBIDITE GEOMETRIES

The dense grid of 2D seismic data in the Pelotas Basin allowed the identification and mapping of several potential mostly Upper Cretaceous prospects. The most important ones are those interlayered with the source rocks, as demonstrated by the **Brulpadda**, **Luiperd** and **Venus** discoveries. All of them were first identified by their turbidite-like geometries with associated bright spots. The confirmation of the anomalously low-velocity character of the bright spots was subsequently highlighted by the Sweetness attribute and DHIs were obtained by the (F-N)*F attribute, separating Types III and IV AVOs.



Zoom view of a portion of the foldout highlighting the difference in the petroleum potential between a prospect interlayered with the source rocks and another situated outside them (outlined in thin yellow lines). Prospect 1 presents both Sweetness anomalies and DHI (Type III AVO). Prospect 2 has none of them. Source rocks present bright spots in the first two displays and DSIs in the last, indicating active generation of hydrocarbons.



Example of prospects displaying bright spots and DHIs in several stratigraphic positions. 1 and 2 – interlayered with source rocks; 3 - in the Upper Cretaceous, with lateral accretionary surfaces indicative of point bars in a meandering submarine channel; 4 and 5 – in the Lower Cenozoic, in channels.

Why Geothermal Projects Need to be Looked at Critically

During the IMAGE Conference in Houston in August, I participated in a panel discussion on the energy transition. Asked by the moderator to focus on geothermal energy, I decided to talk about several recent drilling projects in Northwest Europe where things have not entirely gone to plan.

Someone from the audience approached me after the session, raising the question of why I felt the need to focus on projects that did not come in as expected. The reason is simple.

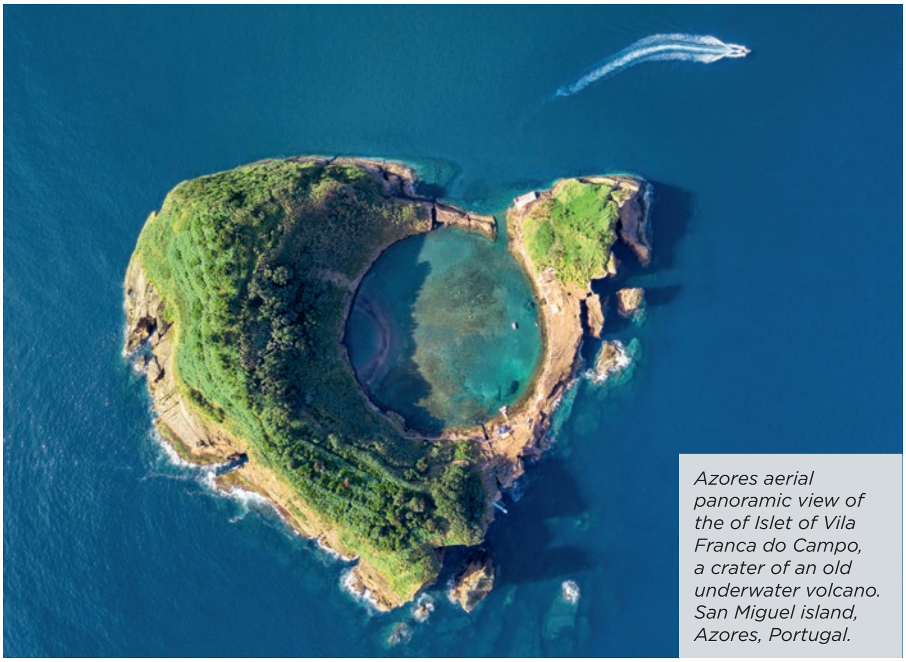
Geothermal energy is surely a valuable resource and it should be exploited to move forward with the energy transition. But, given the public money spent on many of these projects and the fact that there is a certain hype around anything related to the energy transition, a decent level of scrutiny should be justified.

As an example, two large geothermal projects are in different stages of completion in the southwest of England. Both projects will produce water from a fault zone in granitic basement at depths of more than 4 km. At both projects, low levels of seismicity were observed during the testing phase, even leading to the second project to temporarily halt.

This then sparks the question; would it not be better to first complete one project, ramp it up to full-scale production, and see how the subsurface reacts before embarking on another costly project?

I am not saying that these projects are guaranteed to fail, but given that induced seismicity is often associated with crystalline basement rocks, a more step-by-step approach may be worth considering. In my opinion, these questions are therefore worth being asked. Especially because there is public money involved in many of these geothermal projects.

Source: Getty images



Azores aerial panoramic view of the of Islet of Vila Franca do Campo, a crater of an old underwater volcano. San Miguel island, Azores, Portugal.

Drilling on a Continental Triple Junction

Unlike Iceland, the Azores do not have a long tradition of producing green energy. In the early 1990s, more than 90% of their electricity supply relied on fossil fuels. That is now changing for the better.

The islands of the **Azores** find themselves at the triple junction between the North American, Eurasian and African plates in the Atlantic Ocean. As such, it is a volcanically active area, with boiling temperature fumaroles, steaming ground and thermal springs as a result.

For that reason, it is no surprise to see that geothermal energy is being increasingly used for electricity generation on the islands. Currently, around 25% of the electricity demand is being supplied through geothermal energy, but the intention is to increase this even further.

Geothermal drilling company **Iceland Drilling** recently completed a multiple well campaign in the Azores, where wells were drilled to depths of around 1,500 to 2,500 metres according to Bruce Gatherer, geothermal drilling project manager at Iceland Drilling.

In a LinkedIn post, he explained that formation temperatures at these depths are north of 250°C. That is a lot higher than the temperatures observed in most parts of mainland Europe, where 70°C is a better estimate for depth ranges of this kind. That leaves little doubt as to the potential of geothermal energy production on these islands.

Hamburg Geothermal Well Should Have Been Drilled in Another Location

Based on a published conceptual geological model of the target reservoir, it may be no surprise that the well disappointed.

There is a lot of public and political pressure to make the energy transition a success. **Germany** is a country that faces this pressure too, further augmented by a strong reduction in gas supplies from Russia in recent months and the related need to urgently diversify the energy mix.

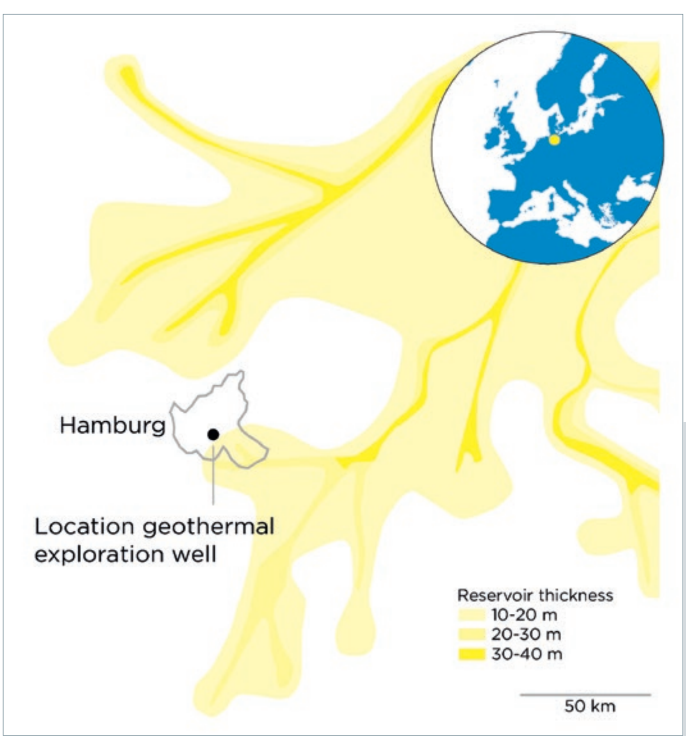
Against this backdrop, it is disappointing to see that a flagship geothermal exploration drilled in the north of Germany in the city of **Hamburg** has not delivered what many people had hoped for.

The Hamburg geothermal project aimed at a reservoir of Upper Triassic to Lower Jurassic age (Rhaetian sandstone) at a depth of more than 3 km. The target was reached - albeit 300 m shallower than foreseen - and core was cut. However, subsequent analysis revealed that the rock's flow properties were of insufficient quality to warrant drilling another well.

Targeting the Rhaetian sandstone in the area should not be regarded as an outright mistake though; the reservoir is known for its good quality in other parts of northern Germany.

However, when plotting the location of the well on a recently published map showing the sedimentary architecture of the Triassic reservoir in the area, it is clear that the well was not drilled in an optimal location. Constrained by several wells drilled in the area in the past, the conceptual model suggests that the deltaic sandstones are shaling out in the direction of where the well was drilled.

Even when one realises that this map remains a conceptual representation of the actual subsurface setting, and will always need revision with more wells being drilled, the fact that it was published before the well was spudded still sparks the question of why it was drilled at the chosen site.



Paleogeographic map showing a reconstruction of the Rhaetian deltaic system in the north of Germany. The Hamburg geothermal well is situated just outside the mapped sand fairway. Redrafted after Figure 11 in Franz et al. (2018).

GEOTHERMAL ENERGY

Low-temperature geotherminal energy. Temperatures under 30° at depths between 10 and 200 metres. Used to heat or cool single-family homes, apartment blocks or commercial buildings. Heat pumps are used to raise the temperatures for heating or lower them for cooling. Main use in shield areas.

Deep low-temperature geothermal energy. Temperatures between 30°C and 90°C collected at depths ranging from 200 to 2,500 metres. Connected to an aboveground heating system, this technique can be used to heat entire neighbourhoods or industrial parks. Main use in shield areas.

High-temperature geothermal energy. Working with temperatures over 150°C, either by using wells with steam far below the surface to produce electricity, or by injecting water into hot, dry rock deep underground, then recovering it back at the surface. Main use in areas of divergent and convergent plate boundaries.

Source: Erwan Hesry - Unsplash

Cold Water Injection May Cause Earthquakes

A newly published study points to injected water from geothermal projects as the main driver for induced seismic events

In the south of the Netherlands, two geothermal projects (A and B) realised in 2013 and 2017 targeted a **Lower Carboniferous limestone** succession. In order to maximise flow, the production wells for both projects were drilled into a major basin-bounding fault at 2 km depth, whilst the injection wells were situated slightly further away from the fault zone.

For some years, the wells successfully produced 75°C water at rates between 200 and 400 m3/hour to heat a complex of greenhouses. When a felt seismic event of ML = 1.7 took place in 2018, the plug was pulled from both projects.

In a recent paper published in the **Netherlands Journal of Geosciences**, Robert Vörös and Stefan Baisch attempt to answer the question of whether seismic hazard assessments performed during the lifetime of the geothermal projects correctly predicted these events.

In addition, through the analysis of production data, they were able to propose a mechanism explaining why induced seismicity took place and how it would be possible to mitigate against it should operations be allowed to start again.

RISK ASSESSMENT

From an early stage of the geothermal projects, a total of four seismic hazard assessments were carried out to investigate the risks of induced seismicity. Based on numerical simulations of stress changes due to water production and injection, the reports concluded that the so-called Tegelen fault is critically stressed. The mechanism that was identified as the most likely candidate to cause induced seismic events was inferred to be the injection of cold water and associated thermoelastic stresses.

Based on the analysis of seismic events that took place in the lead up to the 1.7 earthquake in 2018, the researchers concluded that it is the injected cooler fluids indeed that may have been the trigger to fault slip.

They found that most of the observed seismic activity occurred shortly after production had been temporarily stopped. The most likely explanation for this to happen is that as soon as the pressure drawdown resulting from water production does not counteract the effect of cooling as a result of water injection, the fault is much more likely to be activated. That also explains the timing of the earthquake; although injection had stopped already four months prior to the event, it was only when production was halted that the event took place.

QUESTIONS REMAINING

One might then ask the question; if the seismic hazard assessment identifies a probable cause for induced seismicity, as already flagged in the seismic hazard assessments, why was the project given the green light in the first place?

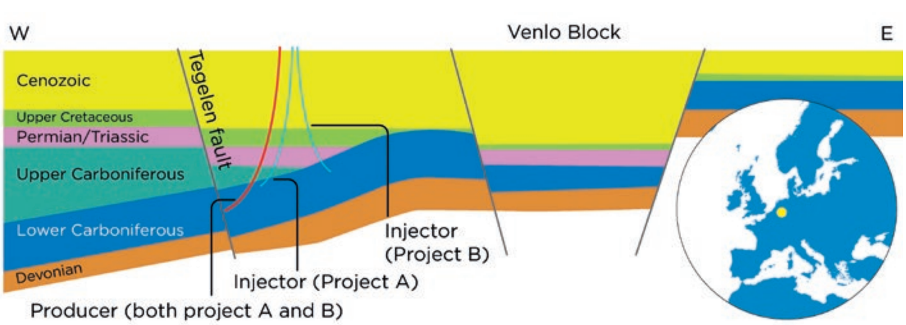
The answer probably lies in time. Only after the project was commissioned, the Dutch "framework for seismic hazard assessment in geothermal projects" was put in place. That would suggest that if this directive was in place prior to drilling, the projects as such might not have been given the green light at all.

INJECTION WELL TOO CLOSE TO FAULT

If it is the case that thermo-elastic stresses are responsible for earthquakes to happen, one of the ways to mitigate the risk is to drill a new injection well for geothermal project A. As the cross-section shows, the injection well of this geothermal project is situated relatively close to the fault. It is also this well that seems to line up with the depth where the seismic events occurred.

Geothermal project B, where the injection well is already situated further away from the Tegelen fault, is recommended for a re-start given that a further adjusted mitigation strategy to account for remaining uncertainties is put in place.

Redrafted after Vörös & Baisch (2022)



Schematic cross-section showing the subsurface setting of the two geothermal projects targeting the Lower Carboniferous limestones of the Venlo Block in the south of the Netherlands.

NAM Ready to Continue Production from Groningen

Up to 30 Bcm could be pumped from the field per year.

In a radio interview mid-September for Dutch radio station Business News Radio, **NAM** director **Johan Atema** confirmed that the **Groningen field** is able to produce up to **30 Bcm** per year, if the operator would get a mandate to do so.

He emphasised that it is ultimately up to the Dutch government to decide if there is a requirement for Groningen to open, but if that would be the case, the NAM will have the ability to open the taps. There is around **450 Bcm** left in the field at the moment.

If the winter will be colder than normal, or deliveries of LNG are not going to plan, having the backup of Groningen is not only essential for the Netherlands, but also for neighbouring countries Belgium, Germany, France and possibly even the UK.

There has been a lot of discussion whether to allow Groningen to re-open after the NAM was summoned to stop production this year following a series of induced earthquakes and the related damage to property. In combination with a huge drop in supply of gas from Russia, there is a serious threat for Europe to experience gas shortages this winter.

New LNG terminals are therefore hastily being built, especially in Germany, putting more pressure on the global gas market and the resulting increase in prices.

If Groningen is being re-opened, and the 30 Bcm would be produced, the risk of induced seismic events will increase again. That is the reason why the decision to resume production will only be taken if there is no other solution at hand.

Source: NLOG

Production from the Groningen field.

Image: Eszter Miller via Pixabay

A Faroese landscape, with cliffs consisting of volcanic strata in the background.

Renewed Interest in Faroese Offshore Sector

Whilst some European countries still seem reluctant to openly support oil and gas exploration, even in the situation the continent now finds itself in, the Faroe Islands are forthcoming when it comes to looking for hydrocarbon resources.

Representatives of the **Faroese Geological Survey – Jarðfeingi** – often attend industry events, such as the recent **BEOS Conference** in London to showcase the potential of the Faroese offshore area. They are not the only ones from the Faroe Islands to support activity; public support for oil and gas exploration is relatively high across the country.

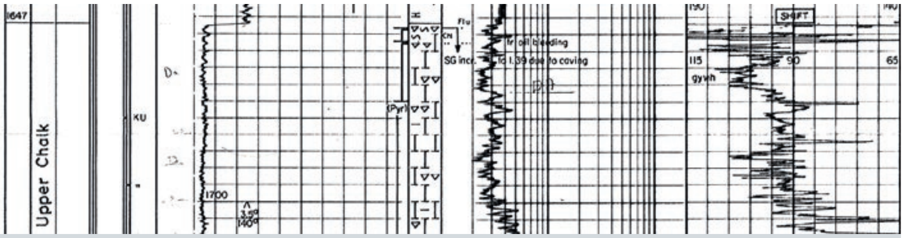
In a way, this is surprising given recent developments in **Greenland** where oil and gas exploration is now off the table, and **Denmark** where there has been a lot of attention to the government's decision to stop production of oil and gas beyond 2050.

However, the Faroe Islands are clearly on another path and would welcome companies willing to explore. There is strong anticipation that there are volumes to be proven and that there is renewed interest from the industry, even though there are no active licences in the area at the moment.

In a leaflet available at Jarðfeingi's booth at the BEOS Conference, **Niels Christian Nolsøe**, director of the Faroes Geological Survey, says: "In reality, energy companies are already looking for oil and gas in the Faroese sector. They are allocating manpower to this search and to studying the data." He even expresses the possibility that an energy company may apply for a licence through the **Open Door policy** as soon as this autumn. To put more gravity behind this, he added that "I also base this on the actual inquiries we are dealing with at the moment."

So far, after drilling of nine exploration wells across the Faroese offshore sector, one discovery has been made by the **Marjun 6004/16-1Z** well close to the UK median line. Although the well proved between **11 and 95 MMboe** in Paleocene sands, the size and low anticipated recovery factor prevented further development.

The most challenging aspect of exploration in the Faroese sector is thick layers of intrusives and extrusives emplaced in Paleocene and Eocene times.



Fragment of the composite well log from well F03-02 drilled in 1971, showing oil bleed at the top of the Chalk.

There is Still Life in the Chalk

Dana proves oil and gas just hundreds of metres away from a dry well drilled 50 years ago.

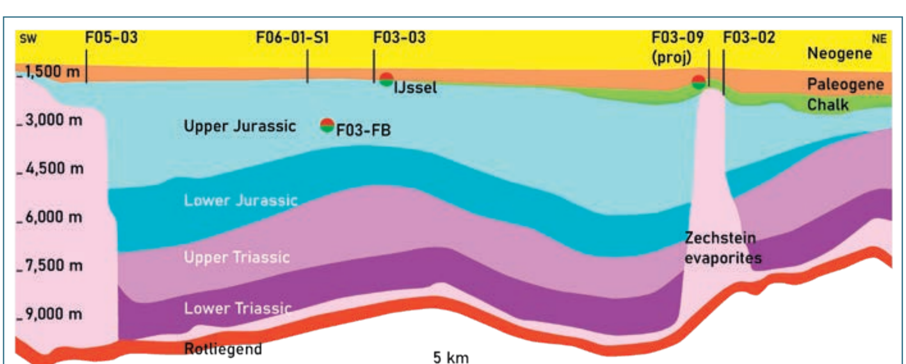
In 1971, NAM drilled a dry exploration well (F03-02) just 500 m away from where Dana has recently proven hydrocarbons in what was most likely to be the same target reservoir: the Chalk.

The main geological feature in the area is a Zechstein salt dome, with the Upper Cretaceous Chalk overlying it. F03-02 was drilled to 2,150 m, terminating in the Zechstein evaporites of the salt dome after drilling through almost 250 m of Chalk. Although the well was reported dry, the composite log does say that oil bleeding was observed at the top of the Chalk section.

When looking at the cross-section shown below, the F03-02 well was drilled slightly off the crest of the salt dome. Was the well drilled at this location deliberately? Let us assume it was, as it probably reflects the minimum volume required for a discovery to be commercial in those days. With lots more infrastructure in place now and a favourable oil price, the economic cut-off volumes are probably smaller these days.

With Dana having found oil in a more crestal position of the Chalk closure, there is once again proof that (small) volumes can still be found in the Dutch sector.

Besides the Chalk prospect, the second prospect named in various documents was Anteater. Although it is not entirely clear which interval this prospect has been defined in, it may be a shallow gas prospect in the overburden of Bokje. Since the well is also reported to have found gas, it may be that some prospective shallow gas has also been proven by Dana. ■



SW-NE trending cross-section through the Dutch Central Graben, showing the location of the F03-09 well. Also indicated are the recent IJssel discovery made by ONE-Dyas and the stratigraphic position of the F03-FB field. Cross-section drawn using data provided by TNO-Geological Survey of the Netherlands.

Small Changes Can Bring Significant Value

OKEA is working towards extending the economic life of mid- to late-life assets in a field with excellent reservoir properties. This requires a creative approach.

"If I tell people that it would be fantastic to increase the recovery factor of Draugen from 67% to 70%, most people do not really see why that should be so exciting," says **Andrew McCann**, Senior Vice President Subsurface from OKEA. "It just seems a small increment to most people," he adds. However, when he subsequently explains that it entails a doubling of the reserves left in the field, people get what his enthusiasm is about. It may equate to a greater volume than the average NCS present-day discovery of around 30 MMboe.

Draugen, is an undead creature from Norse mythology. The Old Norse meanings of the word are revenant, undead man and ghost. Draugen live in their graves, often guarding treasure buried with them in their burial mound.

BUT HOW EASY IS IT TO DOUBLE THE RESERVES OF A MATURE ASSET?

In 2019, one year after the acquisition of Draugen from Shell, OKEA immediately drilled two wells in order to prove up further potential. One exploration well was drilled east of the field. Unfortunately, well 6407/9-12 targeting the **Skumnisse** prospect came in dry. In addition, an observation well was drilled into the attic of the field to find out if there was any significant oil left to be produced. Even though oil was found, the thickness of the leg did not justify further development.

This subsequently prompted the team to look at infill opportunities within the producing zones.

"First of all, you have to understand the nature of the reservoir," McCann says. "In a way, the 'problem' with Draugen is that the reservoir is so good. Because of that, the entire field has been swept very efficiently. Oil remains, as it always does, but it is not necessarily sitting in undrained pockets. Instead, it is spread out all over the reservoir. "Even though we have identified potential infill opportunities," McCann explains, "these are just not making economic sense because the potential volume to be produced through these infill wells is too low."

So, with infill opportunities being difficult to justify and two wells drilled that did not result in tangible opportunities, OKEA had to look at other ways to up the recovery factor.

REDUCING WELLHEAD PRESSURE

"It can sound very boring," admits the explorationist, "but we have found another solution to increase the recovery factor." McCann alludes to the upgrade of subsea booster stations, which means that the pressure at the wellhead can be reduced by 4 to 6 bar. "As a consequence of this measure, we can accelerate production

Source: OKEA

Draugen Platform.

DRAUGEN AT A GLANCE

Draugen was discovered by Shell in 1984, PDO was approved in 1988 and production started in 1993. Original reserves were estimated at **955 MMb** of oil and **53 Bcm of gas and condensate.** Remaining reserves are estimated to 60 MMboe by norskpetroleum.no. The Draugen field produces oil from two formations. The main reservoir is in **Upper Jurassic sandstones** (Rogn Formation) while the western part of the field also produces from **Middle Jurassic sandstones** (the Garn Formation). The reservoirs lie at a depth of 1,600 metres, are of good quality (por/perm??) and relatively homogeneous across the field. Hydrocarbons are produced by pressure maintenance from water injection and by aquifer support.
The iconic Draugen platform was developed using a fixed concrete facility with an integrated topside. Production is from both platform and subsea wells. Stabilised oil is stored in tanks at the base of the facility. Two pipelines connect the facility to a floating loading-buoy.
At the moment, the production licence for Draugen runs until 2024, but OKEA has filed an application for it to be extended for sixteen more years, bringing it to 2040.

Source: NPD

It is easy to see that the Draugen reservoir is of good quality.

and continue producing wells for a longer period and therefore get more oil out of the reservoir."

Even though the ultimate recovery factor of Draugen may not end up as high as the desired 70%, the above illustrates that small changes can result in significant additional value creation.

OKEA'S STRATEGY

OKEA was founded in 2015 to work up stranded discoveries and marginal fields, of which the Yme redevelopment, operated by Repsol, is a prime example. With the arrival of Svein J. Liknes as new company CEO last year, the strategy was revised to be more in line with what the Draugen acquisition in 2018 already embodied – to successfully take over and manage mid- to late-life assets.

"We believe that prices will remain buoyant for some years to come," the McCann says, "and the Norwegian continental shelf presents good opportunities to capitalise on our strategy." With the acquisition of the Brage field from Wintershall Dea – which is subject to the customary authorities' approval – OKEA will be able to apply lessons learned from operating Draugen to another late-life asset.

ACCESSING GAS THROUGH HASSELMUS

The Hasselmus gas discovery is a good example of how OKEA's strategy differs from Shell's, the previous operator of Draugen. Even though the field was discovered already in 1999, it was never developed by Shell. Now, it presents a tangible opportunity for OKEA to get access to fuel gas to run the platform which will reduce cost and in addition earn revenues from gas and condensate export. At the moment, condensate produced from Draugen itself is being reinjected. A development well will be drilled this year, with first gas expected in late 2023.

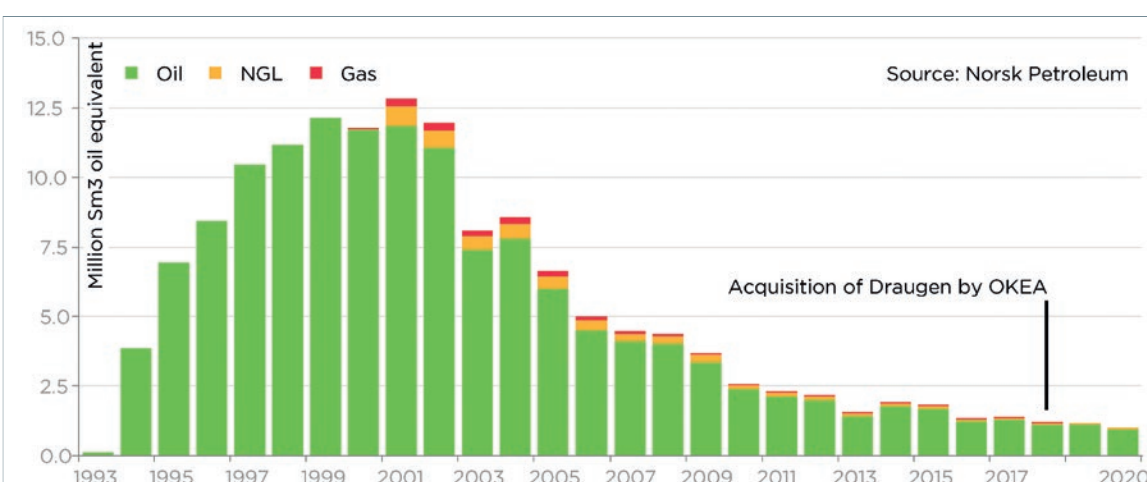
POWER FROM SHORE

In addition to Hasselmus coming onstream, OKEA is also expecting to sanction a project to electrify offshore operations through power from shore. This will be done in conjunction with the electrification of the Njord platform operated by Equinor a little further to the West.

"The electrification project is also a way to extend Draugen's field life," McCann says: "It not only cuts the amount of gas required for the platform's energy supply and thereby the related CO_2 emissions, it lowers the operating costs due to the reduction in CO_2 taxes".

FURTHER EXPLORATION OPPORTUNITIES

"We are very aware that a proactive attitude is required towards operating late-life assets," says Andrew McCann. That is why OKEA applied for and was awarded new licences around Draugen and that's why we are planning to drill further near-field exploration wells. "We prefer to see the glass as half full rather than half empty."



Production profile Draugen field.

Is there Room to Explore for Gas in Germany?

With gas imports from Russia being drastically reduced, could there be an uptick in activity in what once was an important petroleum province?

Oil and gas production in Germany goes back a long time. It was near Hannover, in a village called **Wietze**, where the first oil production from very shallow depths took place in 1859.

Following the discovery of oil and gas in **Zechstein carbonates** and subsequently the deeper **Rotliegend reservoirs** in the late 1950s and early 1960s, many fields were discovered in the northern part of Germany.

Now, about 70 years later, exploration has come to an end and most fields are at the tail end of their lives. It is no surprise that ExxonMobil has already put its assets on the market.

However, with Russian gas imports being drastically reduced and prices skyrocketing, there may be an incentive to start looking for additional domestic resources again. Is this going to happen?

PROBABLY NOT, AND THIS IS WHY

First, there seems to be a consensus that there is very little to explore for left onshore Germany. Many wells have been drilled and a wide variety of plays have been thoroughly tested.

As a person with knowledge of the matter said: "I don't think that onshore exploration will become a thing again in Germany. Technically, Germany is exploited."

"I don't think that onshore exploration will become a thing again in Germany. Technically, Germany is exploited."

There are some small undeveloped discoveries left, for instance in the area close to Berlin in the east of the country. However, the problem with these accumulations is that they are mostly filled with nitrogen, with only a small percentage of methane.

Infill drilling and field redevelopments form a more likely scenario to boost production from existing assets. Examples of this are **Neptune** developing the **Adorf gas field** close to the Dutch border and plans to carry out infill drilling in the **Römerberg oil field** in the south of the country in the Rhine Valley Graben.

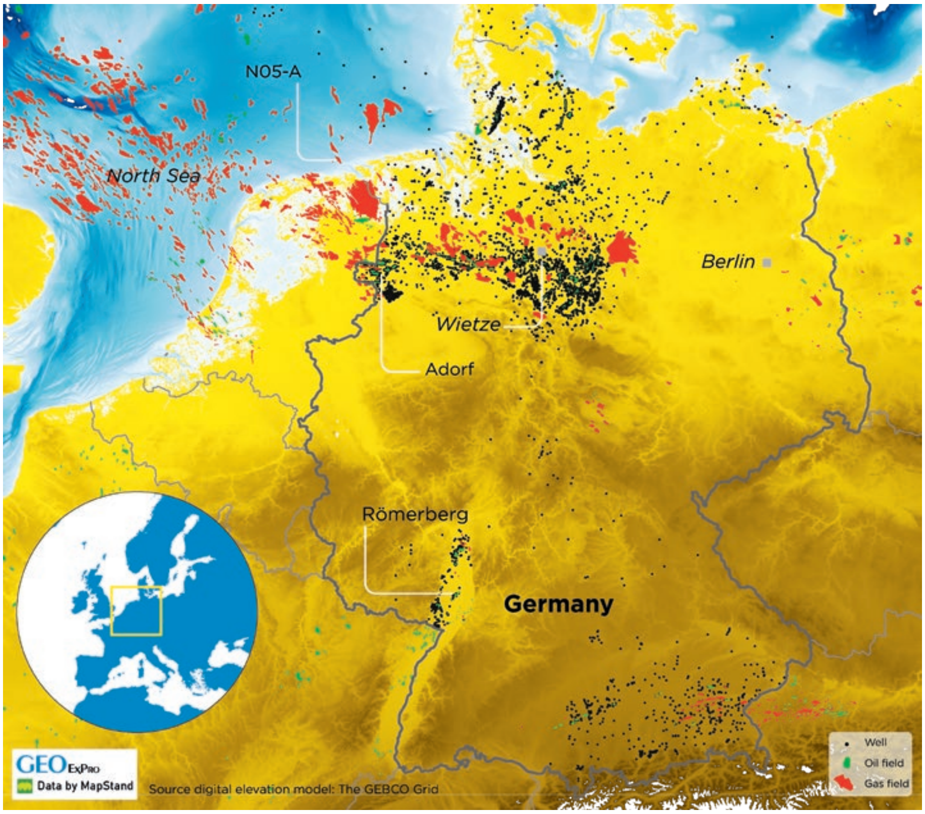
Another reason why any exploration drilling will be difficult in Germany is the opposition these activities were met with in the recent past. Even now that energy has become much more expensive, it is to be expected that local resistance will still be high should any plans unfold.

SOME MORE ROOM FOR THE NORTH SEA

This is a little less so for the offshore North Sea, where the German government has already approved the development of the **N05-A discovery** that straddles the Dutch-German median line. Although drilling will take place from the Dutch sector, wells are planned to deviate into German territory. Before the energy crisis started earlier this year, it seemed that even that activity was a no-go for Berlin.

In addition, the German North Sea sector is much less explored than its onshore counterpart, which is another reason why some activity could be seen offshore. The question then remains how long-lived the current gas price environment will be. Before any new find will come on stream, it can easily be 10 years later.

So, in hindsight, ONE-Dyas discovered N05-A at the right time. Whether any new discoveries will be made in Germany on the back of the current geopolitical situation is very much the question. ■



More CO_2 to be injected into LaBarge

Preparations have started to drill a third injection well into a deeper reservoir, increasing the project's capacity.

It is one of the world's longest ongoing Carbon Capture and Storage projects and the one that has stored the largest volume of CO_2: **LaBarge** in Wyoming, USA, operated by ExxonMobil.

During the IMAGE Conference in Houston in August, Patricia Montoya from ExxonMobil provided an update of the project that started injection of CO_2 in 2005.

Before 2005, CO_2 from LaBarge was mostly sold to operators across the USA in order to be used for Enhanced Oil Recovery, but as this market was not large enough to accommodate all the produced CO_2, ExxonMobil started looking into other options and initiated the injection scheme that is still operational until today.

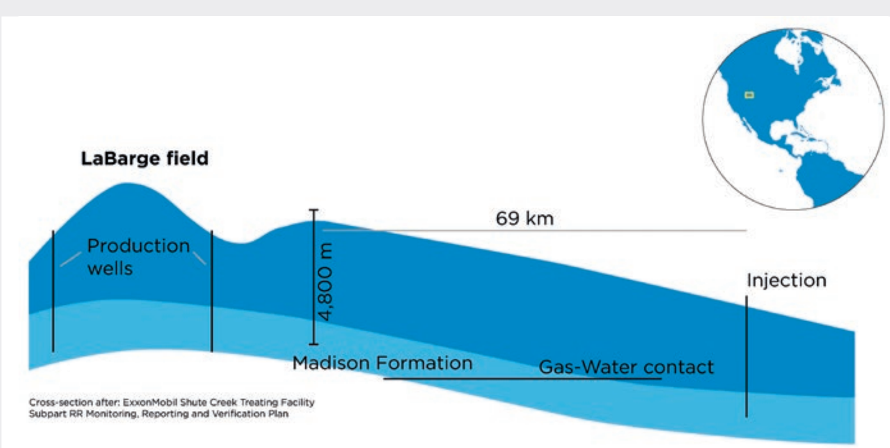
The LaBarge CCS project injects CO_2 that is produced from the LaBarge gas field itself, which had around **167 Tcf** or **4,731 Bcm** of gas in place originally. However, the gas consists of 66% carbon dioxide and only 21% methane, making the field essentially a carbon producer with associated CH_4. For that reason, it makes sense to capture the CO_2 and inject it back into the subsurface.

So far, two wells injection wells were drilled into the LaBarge structure to the south of the producing reservoir. Combined, these wells have ensured injection of between **6 and 7 million tonnes** a year recently. With the drilling of a third well, ExxonMobil estimates that a further **1.2 million tonnes** can be added to that.

The reservoir in which CO_2 has so far been injected is the Lower Carboniferous **Madison Formation**, which is an approximately 800 ft thick interval consisting of limestones and dolomites. Porosity mostly resides in dolomites, where values of up to 20% porosity are recorded.

Whilst injection of CO_2 takes place in the downdip intervals of the Madison Formation, production of gas takes place further updip, as the cross-section below shows.

The new and third well will be drilled into both the Madison Fm and the underlying Ordovician **Bighorn Formation**, which is a 300-400 ft thick succession of dolostones characterised by porosities ranging between 2 and 19%. In contrast to the Madison Fm, from which gas production takes place, no gas production has occurred from the Bighorn Fm. ■



Cross-section showing the producing Madison Formation updip (left) and the downdip section where CO_2 injection takes place.

Image: Shearwater

Seismic Acquisition for Geological Disposal

It does not happen very often that offshore deep seismic data is acquired for purposes other than oil and gas or CCS. But, in August this year, Shearwater completed a survey along the west coast of the UK in order to better map the subsurface for a potential Geological Disposal Facility (GDF).

Radioactive waste that will be disposed of in a GDF is currently being packaged in specially engineered containers and stored at over 20 nuclear sites around the UK. The stores are designed to withstand severe weather and earthquakes, but are generally considered not to be suitable as long-term storage.

The area that was investigated is off the coast of Copeland, Cumbria, in the northwest of England. It is part of the East Irish Sea Basin and is characterised both by evaporites as well as mudstones, deposited during the Permian and Triassic. It is likely that either the mudstones or the halites in this Permo-Triassic succession form the main candidates to construct the GDF in.

Research into finding a suitable location to permanently store nuclear waste has been ongoing for a long time in the UK, as it has been in the Netherlands and Germany too. However, regardless where a site will be selected, the construction will no doubt be hindered as much as possible by people not wanting such a thing in their back yard. This is probably one of the reasons why, despite decades of research, the UK still finds itself in the position to select the area to build the GDF in.

In that sense, building the site just offshore is probably a good idea. ■

Subsurface CO_2 storage – learning from past projects for better risk assessments

The crossover of oil and gas expertise to Carbon Capture and Storage is an important energy transition topic. A key aspect of this transferrable knowledge is subsurface volume and risk assessment for Subsurface CO_2 Storage (SCS).

Text: C. Jenkins, P. Pestman, P. Carragher, Rose and Associates; R.M. Constable, Constable Energy Consulting Ltd.

During oil and gas exploration programmes, companies accept there will be failures (such as dry holes or low-rate wells), and use the portfolio effect to ensure that overall, the value of discovered volumes exceed the program costs.

However, this is not acceptable in SCS projects. Failure to inject the contracted CO_2 volumes or contain CO_2 in the target reservoir could result in project shutdown. At the extreme, there is potential for environmental or material damage, or loss of life.

Therefore, a shift is required from focussing on geological success that is common practice in hydrocarbon exploration programmes, to a broader assessment of chance of failure (risk) throughout the life of a project.

LEARNING FROM PAST PROJECTS

To help ensure all potential risks are assessed, past projects should be carefully studied, particularly those that failed or experienced unexpected events. While subsurface carbon storage is relatively new, the process of storing injected fluids underground is not. Therefore, the history of these operations provides insights into the types and frequency of unexpected events.

Underground fluid storage projects have an impressive track record, but they also have a history of more than two hundred failure events worldwide (Evans, 2009, Schultz and Evans, 2020). Whilst most failures are associated with leakage up old wellbores or at surface facilities, geological factors are responsible for a small but significant fraction of injection project failures. These include 1) a lower-than-expected seal capacity of the overlying caprock, 2) the migration of injected fluids along fractures or across faults previously undetected or considered sealing, 3) an overestimate of the volume available for storage, 4) the migration of fluids away from the injector in an unanticipated direction, and 5) induced seismicity.

Incidents in the case of methane injection or water injection include:

- **Castor Project**, Spain: Gas injection into a depleted gas field caused failure along a previously undetected fault below the reservoir and induced seismicity within 3 days of commencing injection, leading to project shutdown (Vilarrasa et al., 2021)
- **Oklahoma**, US: Oilfield-produced water injected into deep wells has been causing seismicity along basement faults.
- **Long Beach**, California: Water injected into an oil field aquifer for pressure support moved downdip, pressuring-up wells in an adjacent oil field (Allen, 1977).

Despite a shorter history, examples exist of CO_2 injection projects that encountered unexpected events, which in some cases led to project shutdown, and demonstrate the relevance of a good monitoring program:

- **In Salah**, Algeria: CO_2 injected into the water leg of a gas field was expected to migrate towards the structural closure to the west, but instead migrated through fault zones to the north, causing the entry of CO_2 into a legacy borehole and fracturing of the seal (White et al., 2014).

Increasing Annual Event Rate

Increasing Time

Labels	Case 4	Case 3	Case 2	Case 1
Verbal Risk Description - Annual Chances	*Highly Improbable*	*Very Unlikely*	*Unlikely*	*Possible*
Chance of an Event Per Year	0.001%	0.010%	0.100%	1.000%
Chance of No Events Per Year	99.999%	99.990%	99.900%	99.000%
Chance of One or More Events				
in 5 Years	0.01%	0.05%	0.56%	4.86%
in 10 Years	0.02%	0.11%	1.04%	9.63%
in 25 Years	0.03%	0.26%	2.45%	22.19%
in 50 Years	0.06%	0.50%	4.77%	39.64%
in 100 Years	0.11%	1.02%	9.54%	63.61%
in 250 Years	0.25%	2.53%	22.18%	91.82%
in 500 Years	0.49%	4.94%	39.35%	99.32%
in 1000 Years	0.96%	9.56%	63.20%	100.00%
Verbal Risk Description, 1000 Year Outcomes	*Possible*	*Highly Probable*	*Almost Certain*	*Certain*

KEY: >10%; 1% - 5%; <1%

Monte Carlo simulation outcomes showing the chance that one or more events will occur given four different annual frequency rates (0.001% – 1.0%) over time frames of 5 to 1,000 years (models run for 100,000 iterations). Verbal Risk Description Scale from Watson (2014).

- **Snøhvit**, Norway: Storage capacity of the Tubåen reservoir fell short of expectations due to sub-seismic faults and reservoir heterogeneities which caused the reservoir pressure to quickly increase to the calculated fracture pressure (Hansen et al., 2013).
- **Gorgon**, Australia: Sand influx into water re-injection wells has resulted in a shortfall in injected volumes. In 2021, 2.26 Mt CO_2 was injected, compared to planned capacity of 4 Mt (Robertson and Mousavian, 2022).

An understanding of what caused these events provides important lessons that should be applied when planning for future geological carbon storage projects.

ADAPTING OIL & GAS RISK ASSESSMENTS TO CARBON STORAGE PROJECTS

Assessing the risk in an SCS project does require an assessment of geological success similar to that of evaluating a hydrocarbon prospect. However, there are several key differences and adaptations required for a thorough risk assessment:

1. Risk assessments must incorporate long timeframes.
2. The frequencies of events are likely to be very low, in the range of 1% per year and below, far lower than usual exploration chance assessments.
3. We cannot use expert judgement to differentiate the chance of an event occurring at such low frequencies, and therefore need a way to consistently assign risks to low frequency events.

To address these challenges, we recommend using frequency data from industry databases and published sources. Where historical frequency data is unavailable, a qualitative verbal risking scale, linked to an expanded log scale of probabilities appropriate to represent low frequency events can be applied.

An example of such a linked qualitative and quantitative risk scale was presented by Watson (2014) and is utilised in the table above. While imperfect in absolute terms, if such a scheme is applied consistently, the relative risk of events throughout the project life can be assessed.

THE IMPACT OF TIME ON RISK ASSESSMENTS

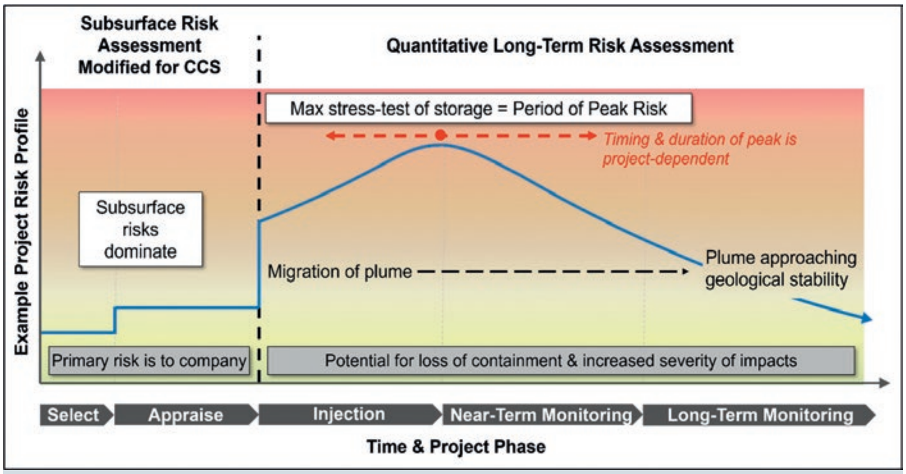
The cumulative impact of long timeframes on risk over the full lifecycle of a project is not generally appreciated. As a simple demonstration of this, the table shows four Monte Carlo scenarios run over timeframes of 5 to 1,000 years at different annual event frequency rates of between 0.001% and 1% per year. These results show that an event with an annual frequency of 0.1% is "unlikely" to occur on an annual basis, however over 1,000 years there is a 63% chance, or "almost certain" chance, of one or more events occurring.

In reality, the overall risk profile of an event will change over the life of the SCS project. During the injection phase all risks are stress tested. Project risk is then expected to decline gradually during the post-injection phase as the CO_2 plume stabilises. This general model leads to the concept of "Peak Risk" for a project when the storage container is put under maximum stress, a concept also referred to by Espie and Woods (2014) and demonstrated here.

LOW TOLERANCE

Any unexpected event occurring during the lifetime of an SCS project could have consequences beyond the companies directly involved in the project. The tolerance for failure in SCS projects from the public and regulators will likely be low. Companies must demonstrate a clear understanding of the risks of a project, the impacts that events can have, and how those risks will be mitigated to obtain and maintain their Social License to Operate. It is therefore important to use a robust and thorough quantitative risk assessment workflow which addresses the full lifecycle of a project.

References provided online. ■



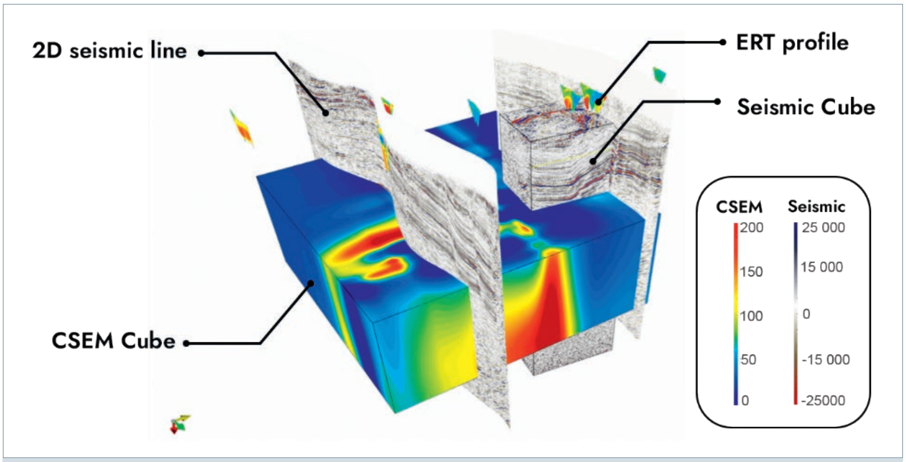
Conceptual change in project risk over time. Timing and duration of events will be specific to each project; therefore, the shape of the risk curve will vary.

Adapting Conventional E&P Workflows to Scale Up Hydrogen and Helium Exploration

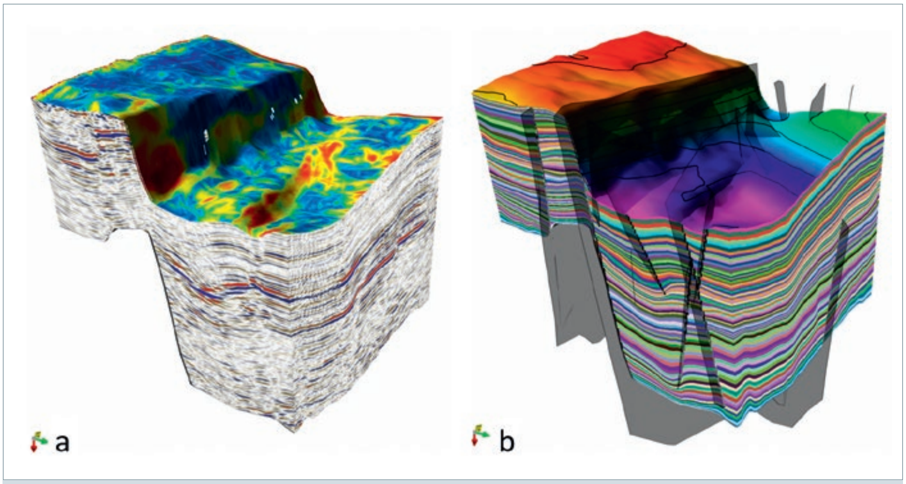
Natural hydrogen and helium exploration is booming worldwide. The combined production of hydrogen, helium and carbon dioxide in the Earth's subsurface provides alternative resources that could revolutionize the path to a low carbon future. Geophysical data could play a key role in finding a way to detect these accumulations.

Text: Marc-Antoine Dupont, Emmanuelle Baudia, Nicolas Daynac, Eliis

In the context of climate change and the search for new energies to reduce our carbon footprint, natural hydrogen and helium exploration has been underway for years. Accumulations of these gasses have been identified in many countries and new volumes are still being discovered around the world.



3D view of the data set used in the study: a seismic cube, two 2D seismic lines, a Controlled Source Electromagnetics (CSEM) cube and 6 Electrical Resistivity Tomography (ERT) profiles.



a) Input seismic cube draped with Fault Thinning attribute highlighting the probability of fracture occurrence on the top surface and b) output relative geological time mode with z-value on the top surface.

Decades of oil and gas exploration have significantly trimmed interests in other natural energy resources, hence leading to a limited amount of data and articles dedicated to hydrogen, helium and carbon dioxide exploration. More recently however, exploration of such resources has experienced renewed interest at an unprecedented level.

The **Fonts-Bouillants project** in **France** is one of these projects. It involved the acquisition of surface and geophysical data, which will hopefully lead to the detection of the hydrogen, helium and carbon dioxide accumulations. A better understanding of their distribution and volumes forms another major goal.

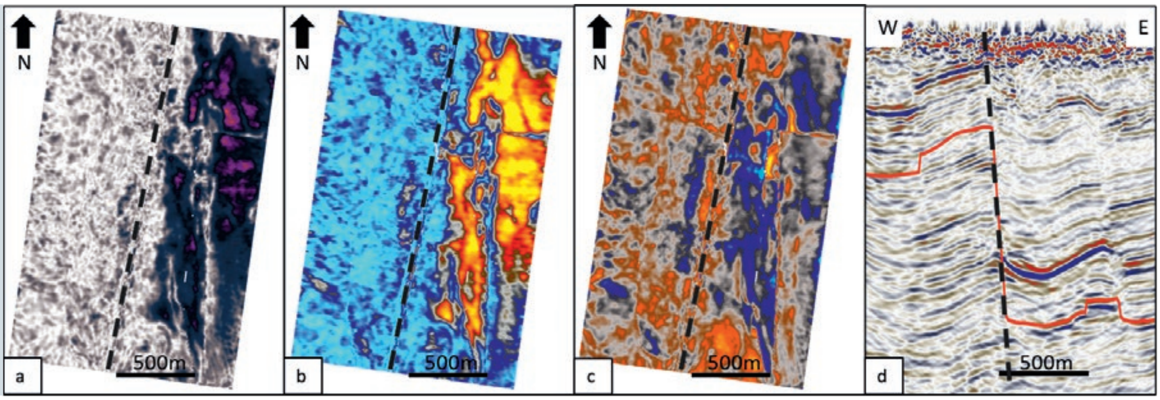
THE FONTS-BOUILLANTS PROJECT SCOPE

The Fonts-Bouillants area is located onshore in the **Paris Basin**, around 270 kilometres south of Paris. The area was a producer of sparkling water until the 1980s due to high gas concentrations in subsurface water reservoirs. Nowadays, Fonts-Bouillants is the very first project in France for helium, carbon dioxide and potentially natural hydrogen exploration.

The present study is mainly based on the Fonts-Bouillants 3D seismic cube, which was acquired in 2022, 2D seismic lines, a CSEM cube and ERT profiles. The seismic cube records Permian to Holocene formations and is centred around the major **Saint-Parize fault**, known to be the focal point of surface gas escape.

A detail structural framework is the critical factor to consistently assess gas accumulations in this area. With no deep wells available, the intensely studied Paris Basin geology is an asset to perform an approximation from freshly acquired surface data. With that approximation, the

a) RMS amplitude, b) Sweetness, c) Relative Acoustic Impedance maps highlighting a potential area of interest on the hanging wall of the fault (eastern tilted block), Figure d) seismic cross-section showing the intersection of horizon in a), b), c) with the seismic cube.



reservoir corresponds to the Triassic deltaic sandstones of the Buntsandstein formation.

STRUCTURAL AND STRATIGRAPHIC INTERPRETATION

The entire seismic volume is interpreted using a comprehensive approach combining structural and stratigraphic analysis. The fault network modelling relies on a hybrid process that allows to pinpoint the highest probability of the fracture occurrence in the seismic signal, avoiding noise detection common for fair to poor seismic data quality.

Advanced structural gradient attributes are generated from input multi-trace attributes to enhance the fracture images and ultimately extract 3D fault objects.

The early-built fault network is then used to structurally constrain the horizon interpretation. Seismic horizons (Peak, Trough, Zero Crossings, and eventually Inflection Points) are simultaneously auto-tracked across the full seismic volume, chronostratigraphically sorted and subsequently used as geometrical constraints to generate a signal-driven Relative Geological Time model (RGT model).

The RGT model has been refined to ensure consistency between the reflection events and auto-tracked horizons. Due to the importance of faults for migration pathways, attention has been paid to the termination of surfaces against them.

GEOLOGICAL INTERPRETATION AND RESULTS

The RGT model gives access to an unlimited number of isochronous surfaces enabling to strata slice the seismic cube at a sub-sample resolution. The whole batch of extracted isochrones is mapped with a series of attributes derived from seismic traces.

Three of those attributes are here computed to enhance physical property contrasts in different ways: Root Mean Square amplitude (windowed high amplitude maximum), Sweetness (energy signature changes driven by trace envelope and instantaneous frequency) and Relative Acoustic Impedance (estimation of apparent acoustic impedance variation).

Relative Acoustic Impedance values are interrogated from cross-correlated high values of RMS and Sweetness within a cross plot, both in vertical sections and stratal slices. This multi-attribute workflow emphasizes zones of higher probability of nonmetal (hydrogen), carbon dioxide and noble (helium) gases accumulation, lately correlated with high CSEM values.

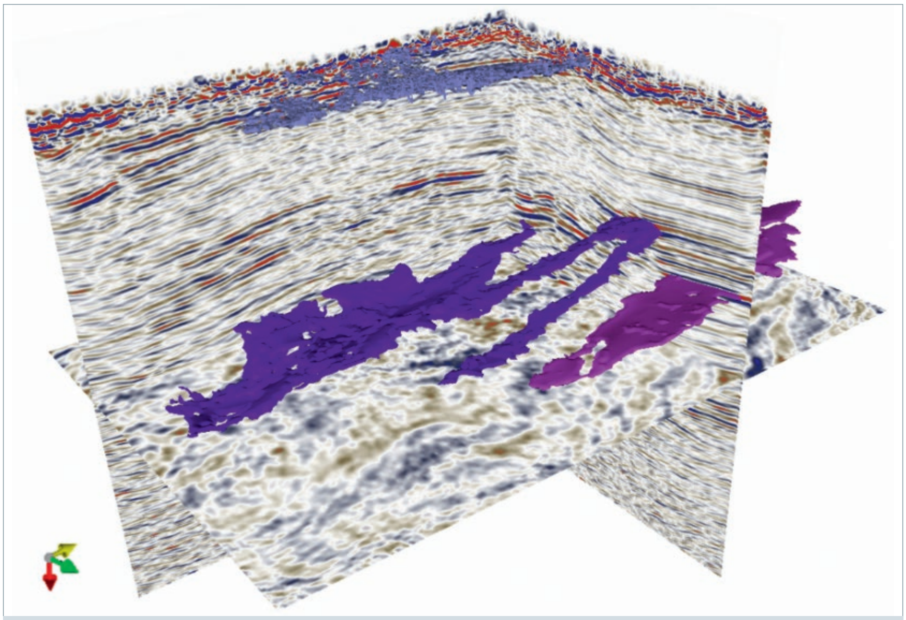
Multi-attribute seismic expressions are ultimately converted into three geobodies, eventually classified as shallow gas stock (light purple-colored) and deeper gas stock (dark purple and pink-colored). **The shallow stock has recently been drilled and therefore confirmed a helium-rich reserve.**

THE RIGHT APPROACH FOR DETECTING GASES

The comprehensive seismic interpretation approach based on automated processes (faults and horizons extraction) and driven by the exploitation of a signal-driven relative geological time (RGT) model unlocks new perspectives of nonmetal and noble gases detection from seismic expressions. The successful application on the Fonts-Bouillants project highlights a high potential for helium, hydrogen and carbon dioxide extraction, essential for further drilling campaigns and replication of the method on other projects.

ACKNOWLEDGMENTS

The presented workflow was obtained using PaleoScan™ software developed by Eliis. The authors would like to thank **45-8 Energy** for the dataset.



3D viewer showing the three areas of highest potential of gas in place.

Edited by: Halfdan Carstens

Getting Ready

Deep Sea Mining may not be imminent, but initiatives around the world make it more realistic.

The Cook Islands with – to say the least – a huge Exclusive Economic Zone did earlier this year issue three 5-year contracts for the exploration of **polymetallic nodules** in the abyssal plain surrounding this tiny country. While there is some resistance from environmental organizations, the prime minister is "a true believer" and is eager to promote the harvesting of potentially deep-sea riches to the benefit of his people.

Also in the Pacific, The Metals Company is continuing its heroic efforts to develop technology to collect **polymetallic nodules** in the ISA-regulated Clarion Clipperton Zone in an environmentally friendly manner. The International Seabed Authority (ISA) has recently recommended that the company subsidiary Nauru Ocean Resources Inc. (NORI), proceeds with independently monitored pilot collection system trials and is therefore poised to become the first deep-sea mining exploration company to take up commercial production.

On the other side of the Earth, Norway – with an Exclusive Economic Zone even larger than that of the Cook Islands – is preparing for a licensing round in search of **massive seafloor sulphides** and **ferromanganese crusts** within and around the Mid-Atlantic Ridge. An Impact Assessment study is on track, and it is up to the Norwegian government to make the necessary decisions in preparing the ground for deep sea mineral exploration.

These topics, and several more, will be dealt with at **Deep Sea Minerals 2022** in Bergen in October. ■

Green Light for NORI

Image by Allseas

The Allseas-designed nodule collector vehicle awaiting launch.

The Metals Company is underway to become the first deep-sea mining exploration company to take up commercial production. The small island of **Nauru** in the Pacific Ocean is at the centre stage.

The International Seabed Authority (ISA) has recently recommended that The Metals Company subsidiary **Nauru Ocean Resources Inc. (NORI)**, proceeds with independently monitored pilot collection system trials in the Clarion Clipperton Zone (CCZ) between Hawaii and Mexico.

With this green light, the team of engineers at **Allseas**, a Swiss-based offshore contractor specialising in – among other things – polymetallic nodule collection, will test a system consisting of a prototype nodule collector at the seafloor and a riser system to bring nodules to the surface production vessel. TMC and Allseas have previously completed successful trials of the nodule collector vehicle in deep water in the Atlantic Ocean.

The trials will be monitored by independent scientists from a dozen leading research institutions around the world who will analyse the environmental impacts of both the pilot nodule collector vehicle and the nodule riser system.

Approximately 3,600 tonnes of polymetallic nodules are expected to be collected during the trial beginning in September with an expected conclusion in the fourth quarter of 2022.

The data collected and many terabytes of existing baseline data collected by NORI throughout 16 offshore campaigns will form the basis of NORI's application to the International Seabed Authority for an exploitation contract. ■

NAURU

Natural resources may again bring wealth to a small and isolated nation. Situated only 42 kilometres south of the equator with Papua New Guinea to its southwest, the Republic of Nauru is a microstate in Oceania. With an area of only 21 km^2, Nauru is the third-smallest country in the world. Its population of about 10,000 is the world's second smallest. Nauru gained its independence in 1968. A coral reef surrounds the entire island which is dotted with pinnacles. Nauru is a phosphate-rock island with rich deposits near the surface. This allowed for strip mining for over a century. However, such practice leaves the earth largely barren, infertile, and unable to sustain plant life. Currently, about 90% of the island is covered in jagged and exposed heaps of petrified coral, which is unsuitable for both building and agriculture. Additionally, runoff from mining sites has left the water in and around Nauru severely contaminated (worldatlas.com). The Nauruan economy peaked in the mid-1970s when its GDP was estimated to have the highest per capita income rates in the world. A trust established to manage the island's accumulated mining wealth, set up for the day the reserves would be exhausted, has diminished in value through mismanagement (worldatlas.com). If The Metals Company is successful, a new and exciting chapter in the history of Nauru is to be written.

Image by Sasin Tipchai from Pixabay

The Green Future is also Metallic

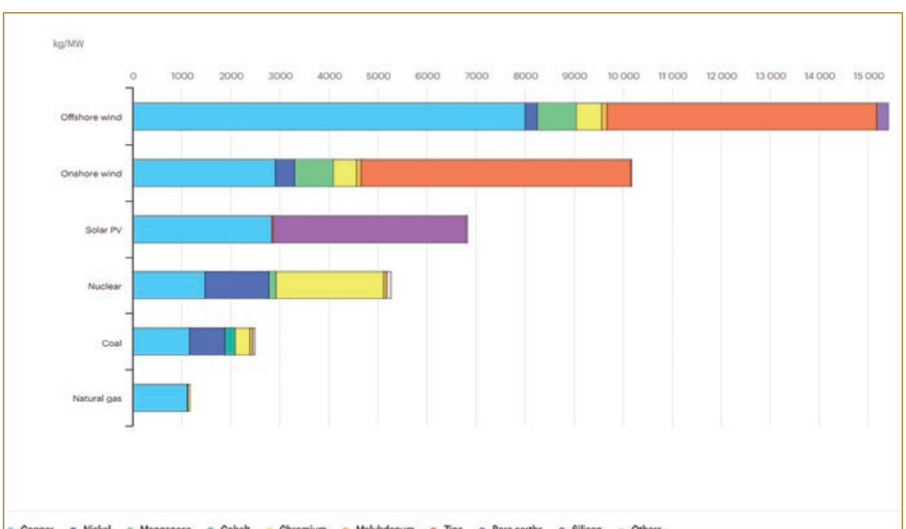
As opposed to many land-based mines, deep-sea mining will not threaten terrestrial environments and be a risk to vulnerable rainforests.

Huge resources of potato-sized nodules in the Pacific Ocean represent a viable alternative to onshore mining.

The consequence of building a green future, according to **Gerard Barron**, Chairman & CEO of **The Metals Company**, is that "our generation will need to mine more metal than we have mined in our entire history".

"Electric cars, wind and solar power, batteries – they all need metal, often several times more metal than is now used by gas-guzzling cars, coal, and natural gas-fired power plants," Barron says in the Canadian company's **Impact Report 2021**.

Image by IEA



Metals used in clean energy technologies compared to other power generation sources.

WITHOUT HARMING THE ENVIRONMENT

The overwhelming challenge is that metal extraction in land-based mines all over the world comes with its own set of human and environmental costs.

"How do we make sure the required metals are extracted without harming local communities and without exceeding planetary ecological boundaries? Barron rhetorically asks in his "Letter from the CEO".

The simple - albeit also intricate - answer is the mining of **polymetallic nodules** that have been deposited on the oceans' abyssal plains for millions of years.

"Instead of developing three different types of mines on land, we believe we have a way to obtain some of the critical metals – namely, **nickel, copper, cobalt** and **manganese** –

- without digging new mines,
- without cutting down rainforests and destroying natural carbon sinks,

A SINGLE ORE
"Polymetallic nodules, also called manganese nodules, contain four essential battery metals: **cobalt, nickel, copper**, and **manganese**, in a single ore. Formed over millions of years by absorbing metals from seawater, these nodules lie unattached to the abyssal seafloor and are almost entirely composed of usable materials. Unlike land ores, they do not contain toxic levels of heavy elements, and producing metals from nodules generates 99% less solid waste, with no toxic tailings."
The Metals Company

- without generating toxic waste, and
- without poisoning terrestrial habitats and human communities,"

Barron claims.

According to **GSR**, the composition and size of nodules vary slightly depending on where they are found. On average each is rich in nickel (1.3%), cobalt (0.2%), manganese (27%) and copper (1.2%).

SECURING MINERAL INDEPENDENCY

Moreover, most battery metals are mined in challenging jurisdictions and processed and refined in China, leaving the United States and the entire EU with a strong reliance on imported battery materials.

Strengthening the impression of the green industry's reliance on China comes from the fact China owns the vast majority of the world's solar panel supply chain, controlling at least 75-95% of every single key stage of solar photovoltaic panel manufacturing and processing, according to graphics from Visual Capitalist.

Developing a nodule resource can thus help secure mineral independence in several critical metals, according to the CEO who founded DeepGreen Metals (now The Metals Company) in 2011. His goal is to collect polymetallic nodules in international waters and transport them for processing and refining in plants next to the battery and EV manufacturers.

> It is estimated that there is more nickel, more cobalt, and more manganese [in polymetallic nodules at the seafloor] than on the rest of the planet.
>
> Kris Van Nijen
> Managing director of Global Sea Mineral Resources (GSR) to CBS NEWS.

Image by The Metals Company

Slow-growing deposits
Manganese nodules are formed as accretions at 4500 meters in the deep Pacific Ocean. They grow very slowly, about 1 cm per every million years, meaning that the potato-sized nodules may be as old as 10 million years. The habitat formed by manganese nodules is home to specific sessile and mobile fauna.

"Currently, we are piloting processing and refining technologies that will be used at these plants and assessing potential sites with a focus on having access to renewable power and exploring low-carbon alternatives to metallurgical coal," Barron states.

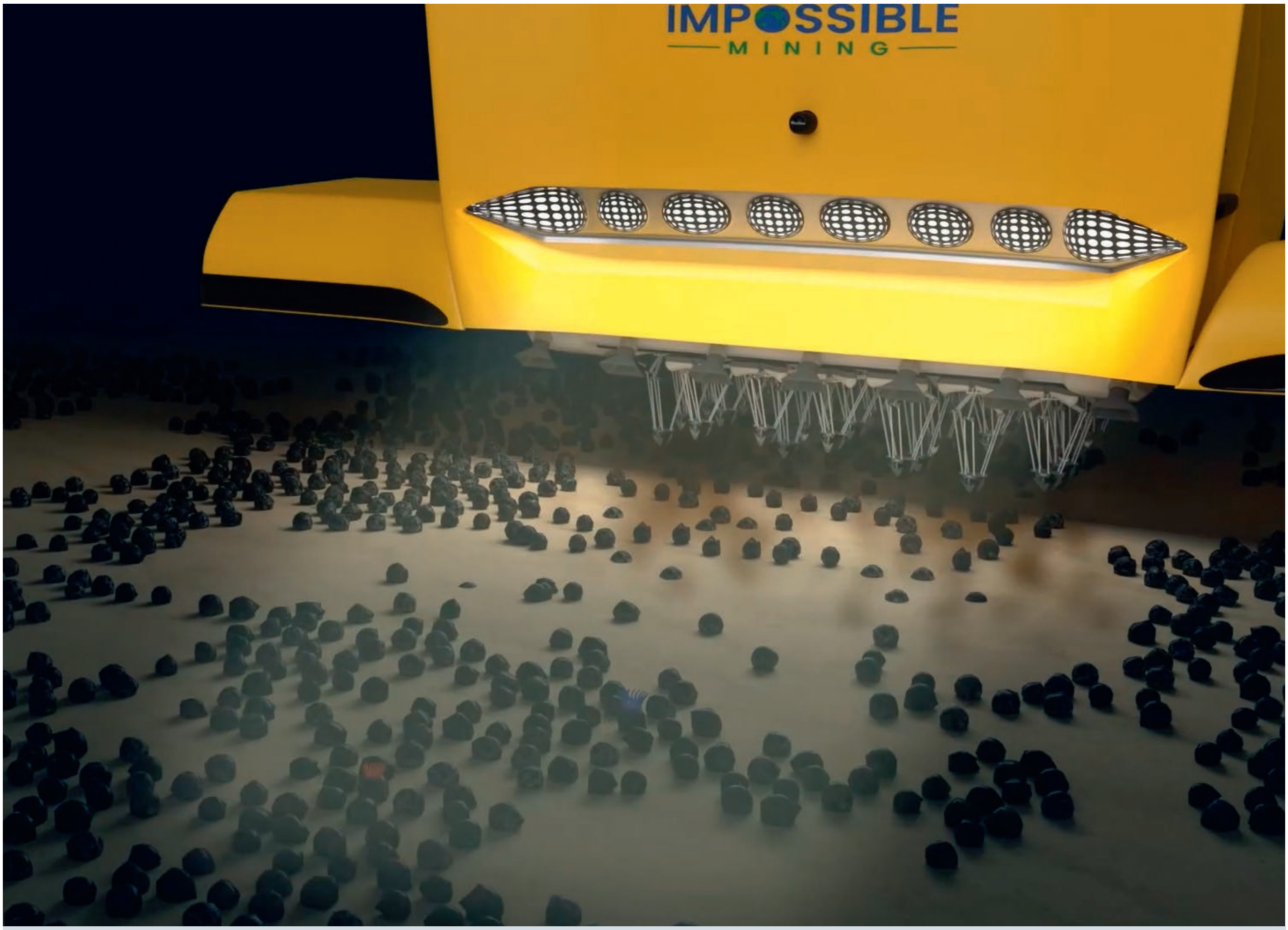
VALUE FOR ISLAND STATES

Values from The Metal Company's nodule projects will be shared with the Republic of **Nauru**, the Republic of **Kiribati** and the Kingdom of **Tonga**, developing countries that sponsor their work in the Area (the part of the world ocean which is under ISA (the International Seabed Authority) jurisdiction, beyond the limits of national jurisdiction, and which represents around 50 per cent of the total area of the world's oceans).

Sponsoring states will gain royalties, local employment, and educational and capacity-building opportunities according to ISA rules. The seabed mining industry, therefore, has the potential to provide a positive impact on the sponsoring states.

"These Pacific Island nations have done the least to cause climate change, yet they are first in line to suffer its impacts. They may be small in terms of land area and population size, but they are big in terms of their ocean area and spirit. Working with these island nations is an honour», CEO Gerard Barron says in his Letter. ■

COLOSSAL AMOUNTS
"It is predicted that by 2050 our planet will have a global population of 9.7 billion and 66 per cent of people will live in cities. With 90 per cent of this growth forecast in emerging economies, much of the necessary infrastructure does not yet exist and will require colossal amounts of metal to develop sustainably."
GSR



Screen dump from Impossible Mining's website.

Selective plucking of polymetallic nodules as envisaged by Impossible Mining.

Viable Harvesting Followed by Green Processing

Impossible Mining's mission is to accelerate the transition to sustainable energy by unlocking the potential of critical battery metals from the seabed, while at the same time preserving the deep ocean environment.

Impossible Mining, a battery-metal mining start-up only two years old, is now working on a Proof of Concept for both environmentally friendly nodule harvesting and bio-extraction technologies. No wonder the marine mining industry is curious.

AVOIDING THE PLUME

The most talked-about methodology to mine polymetallic nodules (PMN) is to vacuum them up. That sounds fascinating, but at the same time, biodiversity-rich sediments may follow suit and marine biologists argue that there is a lack of research on the undersea environment to fully understand the potential impact of using this methodology, such as the generation of a sediment plume.

Different from this, Impossible Mining's technology will hover above the sea bottom to literally pluck individual metal nodules from the seabed.

"We are building autonomous underwater robotic vehicles (AUVs) to collect battery metals from the seabed. Our fleet of AUVs will utilize remote sensing and camera imaging technology to identify polymetallic nodules, a series of robotic arms to pick the nodules up individually, and a dynamic buoyancy system to maintain neutral

LOW ENERGY PROCESSING
The bio-extraction methodology draws on knowledge gained from basic research on a group of bacteria that can rapidly dissolve various metal oxides, including insoluble iron (Fe) and manganese (Mn) oxides, under anaerobic conditions, thereby reducing the metal oxides to soluble metal salts. This technique will enable low-energy processing of minerals without traditional reagents like arsenic and cyanide, without generating toxic waste and without using fresh water. Furthermore, Impossible Mining will aim to achieve carbon neutrality, and eventually carbon negativity, by utilizing fossil fuel-independent carbon and energy sources for the microbes.

buoyancy above the seafloor, as the AUV harvests and reaches its payload limit," says **Oliver Gunasekara**, CEO & Co-Founder of the California-based company.

The remote sensing system will also enable the AUV to identify and avoid nodules that are hosting deep-sea fauna and to algorithmically program the AUV to leave behind a percentage of nodules as habitat corridors to ensure the ecosystem and habitat remains intact.

"Our technology is being developed in a manner that avoids the creation of a significant sediment plume that would impact nodules left behind, or the benthic ecosystem. The operation of the AUVs will avoid contact with the seafloor sediment, and the AUVs themselves are designed to ensure the buoyancy system, the harvesting system, and the overall fluid dynamics of the AUV minimize any production of sediment plume," says Gunasekara, a serial entrepreneur having founded and led 3 technology companies.

Conceptual economic modelling indicates that a fleet of 80 AUVs with two support vessels can achieve a 3Mt production rate with more favourable economic results than a dredge-like approach.

INNOVATIVE PROCESSING

"In addition, we are developing a novel, energy-efficient, microbial bio-extraction method for the processing of polymetallic nodules. Bio-extraction is different to traditional bio-leaching where the bacteria is used to generate acid to allow the leaching of metals. By comparison, bio-extraction occurs at neutral pH, in a process that is complete within hours," says Gunasekara.

Impossible Mining has already tested bio-extraction at the laboratory level on PMN and the technology has shown to be extremely effective, achieving recovery rates commensurate with existing mineral processing methodologies, and without the generation of a waste stream.

Concept economic modelling done by the mining company indicates that bio-extraction also has the potential to be extremely cost-effective when compared to any other form of mineral processing, for both CAPEX and OPEX, due to the low energy inputs, lack of reagent inputs and the lack of waste storage infrastructure required.

"When proven at scale, we believe this technology will completely disrupt current mineral processing methods, particularly the currently proposed mineral processing methods for polymetallic nodules, delivering a pathway to carbon-neutral, waste-free processing for the deep-sea mining industry," Oliver Gunasekara concludes.

Deep sea mineral mining may be closer than environmentalists would like to think. ■

DOING BETTER

"If we are the first company that shows those standards can be met, then the others have no choice but to follow. They will compete, they will innovate, and then the industry as a whole is doing better for the planet."

Renee Grogan, co-founder and chief sustainability officer of Impossible Mining, to TIME magazine.

At Deep Sea Minerals 2022 in Bergen, October 26-27, Oliver Gunasekara will present a status update on the two projects described above. The talk is entitled "Economically Viable Selective Harvesting & Green Processing of Polymetallic Nodules".

Three types of deposits

Seafloor massive sulphides (SMS, also known as polymetallic sulphides) form at hydrothermal vents when seawater penetrates the ocean's crust and becomes heated and chemically modified through interaction with crustal rocks and, sometimes, by input of magmatic fluids. The hot hydrothermal fluids then rise back toward the seafloor and precipitate minerals as they cool along flow paths and upon mixing with seawater. A wide variety of minerals form through hydrothermal activity, but seafloor massive sulphides are formed from reduced sulphur and may be enriched in **copper**, **zinc**, **iron**, **gold**, and **silver**.

Polymetallic nodules (manganese nodules) form a top sediment covering the abyssal plains of the global ocean. These nodules form by the accretion of iron and manganese oxides around a tiny nucleus, such as a large grain of sand, a shark tooth, or an older nodule fragment. Polymetallic nodules are usually potato size and grow very slowly. Nodules have high concentrations of battery metals in a single ore such as **manganese**, **nickel**, **copper**, **cobalt** and sometimes **lithium**. Unlike land ores, they do not contain toxic levels of heavy elements, and producing metals from nodules generates 99% less solid waste, with no toxic tailings.

Ferromanganese crusts (also called cobalt-rich crusts) grow very slowly, at several millimetres per million years, and precipitate onto exposed rock surfaces throughout the ocean. They do not form where sediment blankets the seafloor. In the oldest parts of the seafloor, some crusts have been forming for over 70 million years and can be over 20 centimetres thick. They are especially enriched in **cobalt**, **manganese**, rare metals such as **tellurium**, precious metals such as **platinum**, and **rare earth elements** (REE).

Source: USGS/The Metals Company

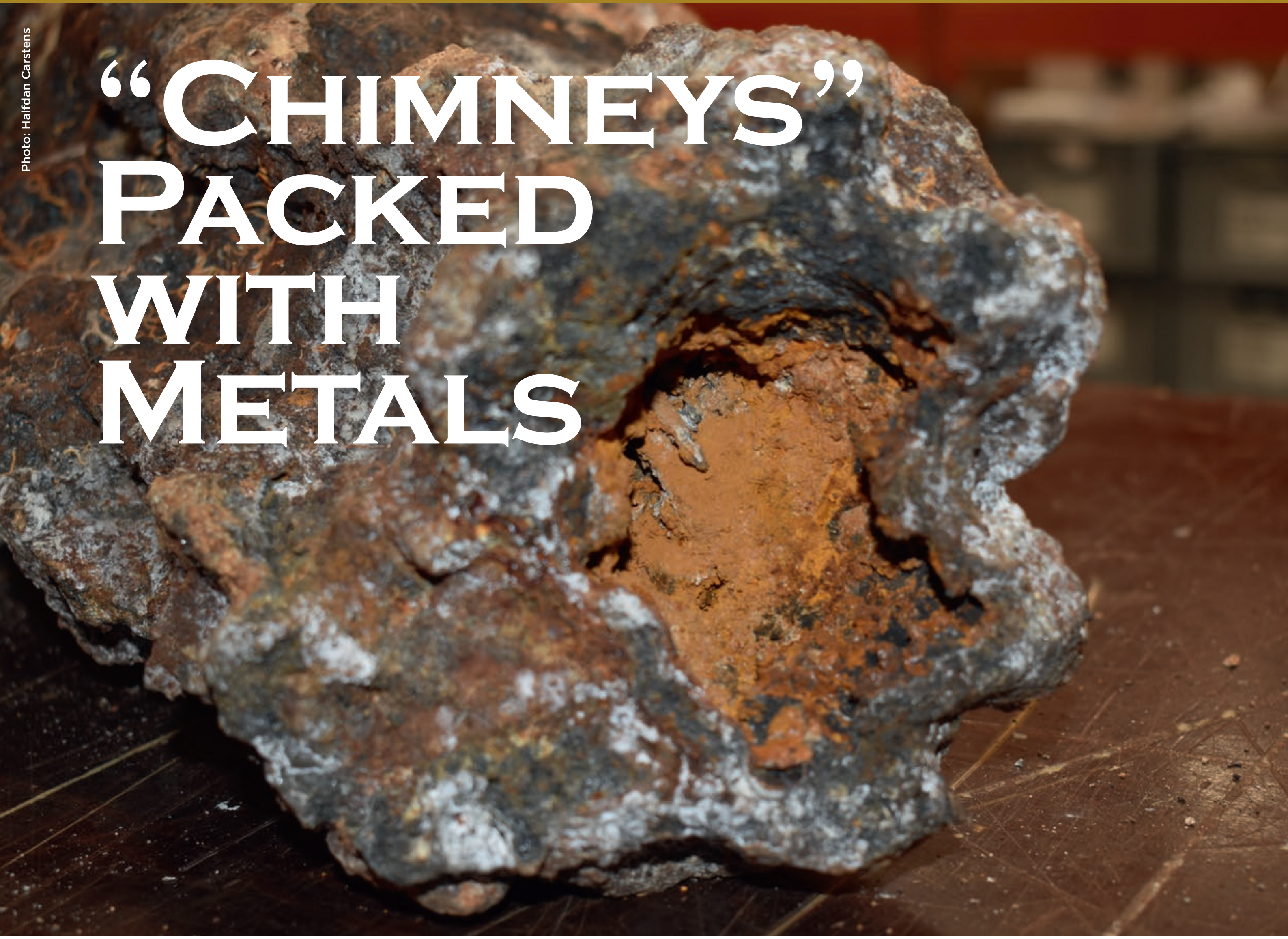


Photo: Halfdan Carstens

"Chimneys" Packed with Metals

This top part of an extinct black smoker ("chimney") is from the Mohns Ridge on the Mid-Atlantic Ridge between Norway and Greenland. It was collected by the Norwegian Petroleum Directorate during a cruise in 2020. The sulphides mostly contain iron, but they also have a high content of copper (up to 14 per cent in some samples), zinc (3 per cent) and cobalt (below 1 per cent). The sample is stored at NPD's core laboratory in Stavanger, Norway.

On April 21st,1979, deep sea explorers in the submersible HOV Alvin working on the East Pacific Rise took the first ever photo of a hydrothermal vent spewing dark grey hot water.

We now know that these **black-smokers**, as they are now called, form where tectonic plates diverge, such as mid-ocean ridges, volcanic arcs, and back-arc basins, and that they are particularly widespread around the Pacific Ring of Fire as well as the Central Indian Ridge, the East Pacific Rise, and the Mid-Atlantic Ridge.

This surely fascinating activity is intimately associated with the generation of metallic mineral deposits now known as **seafloor massive sulphides** (SMS for short, also referred to as polymetallic sulphides).

SMS originate where hydrothermal fluids (that originally seeped from the ocean into subterranean crust where they were heated by the molten rock (magma) and loaded with heavy metals) get in contact with cold seawater, causing the metals to precipitate out of solution, where they are deposited on the walls of a continuously growing "chimney".

Black smokers are active for periods from a few decades to a millennium before dying out and leaving sulphide mounds that can be mined.

Being topographically complex, SMS present technical challenges to deep-sea mining. However, the overall small areal footprint of individual deposits means significantly smaller operations than land-based metal mines. The lack of overburden, as opposed to terrestrial mines, minimizes the production of tailings.

In general, SMS are a significant source of copper, zinc, lead, gold and silver, with minor amounts of other trace metals, including cobalt, cadmium, indium, gallium, and germanium, of which several are important for the green shift. These deposits can range from several thousand to more than 100 million tonnes and are the modern equivalent of **volcanogenic massive sulphides** (VMS) mined all over the world.

The Norwegian government is presently finalizing an Impact Assessment programme in preparation for a future licensing round. At **Deep Sea Minerals 2022**, Cecilie Myklatun (Chief specialist at the Norwegian Ministry of Petroleum and Energy) will summarize the findings.

Photo: The Authority

On February 22, 2022, an exploration licence granting ceremony was held in Rarotonga.

The Very First Licences for Nodule Exploration

A separate session on the Cook Islands will be one of many highlights of the Deep Sea Minerals 2022 conference in Bergen, Norway, in October.

Altogether five talks are scheduled by government officials and license holders.

The Cook Islands' Prime Minister, **Honourable Mark Brown** will give the opening address entitled **"Our seabed minerals heritage in the Cook Islands"**. Get ready for a grand start.

The background is that as of February this year, three seabed mineral exploration licences were awarded in the Cook Islands Exclusive Economic Zone to the following companies: **Cobalt (CIC) Limited, Moana Minerals Limited and Cook Islands Investment Company (CIIC) Seabed Resources Limited**, the latter co-owned by the Cook Islands Government. Altogether the licenses encompass some 250,000 sq. km (the equivalent of roughly 40 North Sea quadrants). All licenses expire in 2027.

The licences allow the companies to find out if mining is a viable option which includes reviewing the environmental risks, and the companies have budgeted between USD 55.4 million to USD 71.7 million to conduct exploration over the next five years.

A CHALLENGING POSITION

"The conference in Bergen aims to address the challenges and opportunities that lie ahead as the need for critical minerals is expected to surpass supply from both the mining industry and recycling," says **John Parianos**, Technical Director of the Cook Islands Seabed Minerals Authority (Authority) in the Cook Islands, and a member of the programme committee for the conference.

John Parianos can look back at ten years in seabed minerals, much of it running the Tonga Offshore Mining Limited CCZ polymetallic program as well as seafloor massive sulphide exploration in Papua New Guinea and Tonga.

"I consider this conference an exciting opportunity for those who are

Photo: The Authority

Alex Herman is Commissioner of the Seabed Minerals Authority.

Photo: The Authority

Rima Browne is a senior technical officer of the Seabed Minerals Authority.

Photo: The Authority

John Parianos is technical director of the Seabed Minerals Authority.

interested in learning more about the latest developments in deep-sea mineral exploration," Parianos adds.

Commissioner of the Authority, **Alex Herman**, will give a talk on the Cook Islands seabed minerals regulatory framework, including the comprehensive 2020/2021 tender process and eventual granting of the abovementioned exploration licences.

Alex Herman has around ten years of experience in Cook Islands seabed minerals and regulatory work both in the Cook Islands and in the Area.

"It is exciting and more than a little challenging to be at the forefront of this industry," says Herman, "We are really happy to share our experience on the extensive preparation and implementation steps that have been necessary thus far."

DISCOVERIES TO BE EXPECTED

"Exploration of the Cook Islands seabed has been sporadic since the 1980s and with the recent issuance of exploration licences, a swath of new developments and discoveries is expected over the next five years," Parianos says.

Herman's talk will be followed by a presentation on scientific developments on seabed minerals in the Cook Islands presented by Parianos. **Rima Brown**, senior technical officer, will continue to present an updated mineral resource assessment for polymetallic nodules in the Cook Islands Economic Zone.

The session will round out with a talk from one of the licence holders (**Ocean Minerals**) on their proposed environmental and social work programmes. These are key requirements under the Cook Islands regulatory framework.

"The Cook Islands' session promises to be an informative case study on an emerging marine minerals industry within a country's national borders," Alex Herman concludes.

THE COOK ISLANDS

This small island large ocean state comprises 15 islands and atolls (including 3 uninhabited) in the South Pacific Ocean about halfway between Hawaii and New Zealand. The Exclusive Economic Zone (EEZ) covers 1,960,027 km^2 (a little larger than Alaska; Norway's EEZ is 2,385,178 km^2) and dwarfs the total land area of only 240 km^2.

The island nation is geologically situated on a relatively old portion of the Pacific Plate with abyssal plains and a massive underwater plateau dating back to the Middle Cretaceous. It is on the abyssal plains that large deposits of polymetallic nodules have formed, aided in part by slow-moving deep water oxygenated currents that are thought to originate from Antarctica (some 7,000 km to the south).

In the Tertiary period, this area crossed a series of mantle hotspots (the so-called Hot Spot Highway) leading to the formation of the islands. These have been subjected to various degrees of erosion, coral platform formation and in some cases subsequent uplift.

The Cook Islands have a resident population of 14,800 with 72% living on Rarotonga and 85.8% of the population identifying as Cook Islands Maori (2021 prelim census data). Most Cook Islanders are based overseas, with over 120,000 living in New Zealand and Australia.

The Cook Islands are thought to have first been settled around AD 900 by Polynesian people who probably migrated from various parts of Polynesia. Some 600 years later Spanish navigators were the first Europeans to spot the northern Cook Islands in 1595 followed by the first landing in 1606. The British navigator **Captain James Cook** arrived in 1773, and the islands were renamed after him in 1835 by Russian explorers.

The Cook Islands attained self-governance in 1965 and are a representative democracy with a parliamentary system in free association with New Zealand. The present Prime Minister, the Honourable Mark Brown, was re-elected in August this year. Alongside the elected government, the Cook Islands have traditional and religious leaders who together form the three pillars of power within Cook Islands society.

Photo: Halfdan Carstens

Biostratigraphers working on an offshore rig in the Northern North Sea. Micropalaeontology analysis like this allows important calibration during drilling operations to compare the pre-drill geoprognosis versus observed stratigraphic markers to safely reach the desired target and maximise reservoir contact. Palaeoenvironmental indicators can also improve understanding of the depositional system across the reservoir interval which can improve estimates of net to gross and other parameters that impact STOOIP calculations in exploration wells.

The Many Ways Fossils Help Decode the Subsurface

From determining how rocks correlate to reconstructing palaeoenvironments and palaeotemperatures, which is relevant to the petroleum geologist, fossils are of great significance to science and industry.

Dr James Etienne

Text: **Dr James Etienne, Halliburton**

While there are lots of different methods for dating rocks, fossils (through applied biostratigraphy) provide the ultimate foundation for the correlation of sedimentary rocks, leveraging zone fossils, bioevents and fossil assemblages in both outcrops and the subsurface (in wells) to determine the relative ages of rocks and their stratigraphic organisation.

Different groups of fossils are used for different periods of geological time, for example graptolites in the Silurian, conodonts in the Permian and ammonites in the Jurassic (see time scale). Obviously, zone fossils can only be used in the environments where they existed, which is why we have different ammonite zone fossils for the Boreal and Tethyan realms. Palynomorphs and other fossils are required to constrain time-equivalent non-marine stratigraphy.

In addition to biozones, we also use bioevents such as **First Appearance Datum** (FAD) and **Last Appearance Datum** (LAD), which are observations in any given succession of when a species first occurs

Left: The famous ‘Berlin’ specimen of Archaeopteryx lithographica. This is a photograph of the original fossil, a specimen that is displayed in the Museum für Naturkunde in Berlin. Source: H.Raab (User:Vesta) under licence CC BY-SA 3.0.
Right: Compsognathus. This is a cast of a fossil held at the Bavarian State Institute for Paleontology and Historical Geology acquired by Joseph Oberndorfer in Bavaria, Germany, in 1859. Source: Matthias Kabel under licence CC BY 2.5.
Comparative anatomical studies on fossils like these led Thomas Henry Huxley to propose that birds evolved from dinosaurs. Although Archaeopteryx is now not considered directly ancestral to birds, Huxleys interpretation of the link between birds and dinosaurs is of course now widely accepted.

or disappears. FADs and LADs are often shown on range charts and may bracket the entire biozone, or a shorter interval of time in that biozone depending on species radiation patterns and persistence of the right environmental conditions at that specific location. In addition to LADs, extinction events where whole clades of organisms became extinct are important stratigraphic markers.

WHEN THINGS GET COMPLICATED

Where diagnostic zone fossils are absent, fossil assemblages can be used to try and determine a more precise understanding of age for correlation than any individual genus or species may be able to designate alone.

Sounds simple? Think again – biostratigraphic interpretation can be very complex and subject to lots of important nuances. Nevertheless, the importance of fossils for understanding the age relationships of rocks remains fundamental to our ability to correlate and map rocks, from **William Smith’s** first geological map to present day sequence stratigraphic studies of the subsurface. Applied biostratigraphy enables time-equivalent successions to be correlated, highlighting sometimes non-obvious relationships compared with lithostratigraphic approaches. As a result of this, fossils are commonly used in subsurface drilling programmes leveraging a technique called ‘biosteering’.

Biosteering typically requires a pilot well to determine the occurrence, abundance and ratios of different microfossil species to be used. An experienced micropalaeontologist is then required at the rigsite of new wells to monitor the taxa encountered and ensure the target zone is reached, and any horizontal wellbores stay in-zone. This is particularly valuable in extended reach lateral drilling.

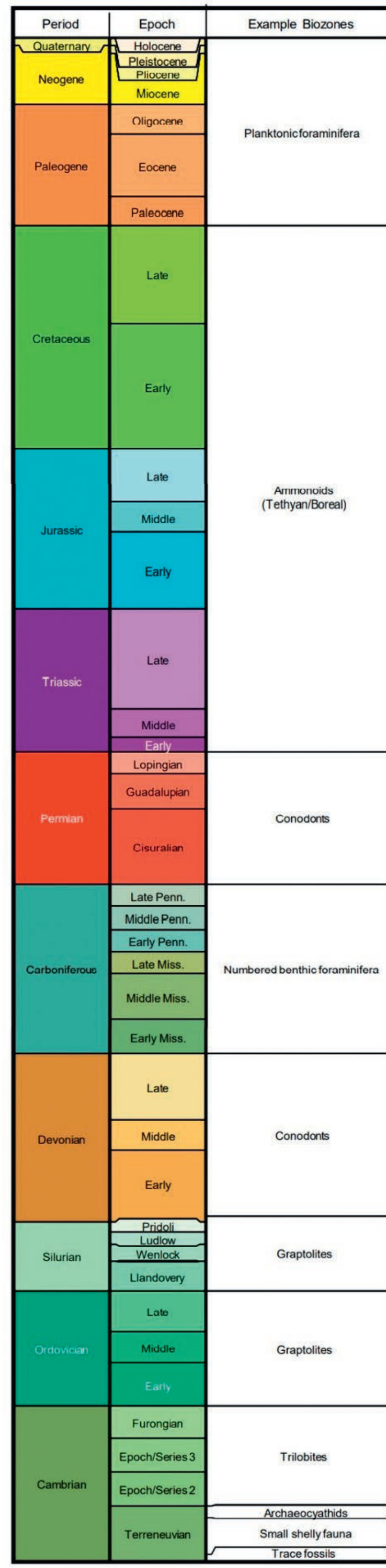
COMPLEX SOCIAL SYSTEMS

Assemblages of fossils can give us insights into **ecological systems** (through co-existence of different taxa) and we can glean a lot of information on the food chain and dietary habits through anatomical studies and observations from coprolites and preserved stomach contents in exceptional fossils.

Beyond basic ecological information, exceptional fossils allow **mode of life**, or behavioural traits to be observed (check out the excellent book ‘Locked In Time’ by Dean Lomax). Lomax highlights examples of fossils that demonstrate reproduction, evidence for parental care, social behaviour, sense of community, migratory patterns and much more.

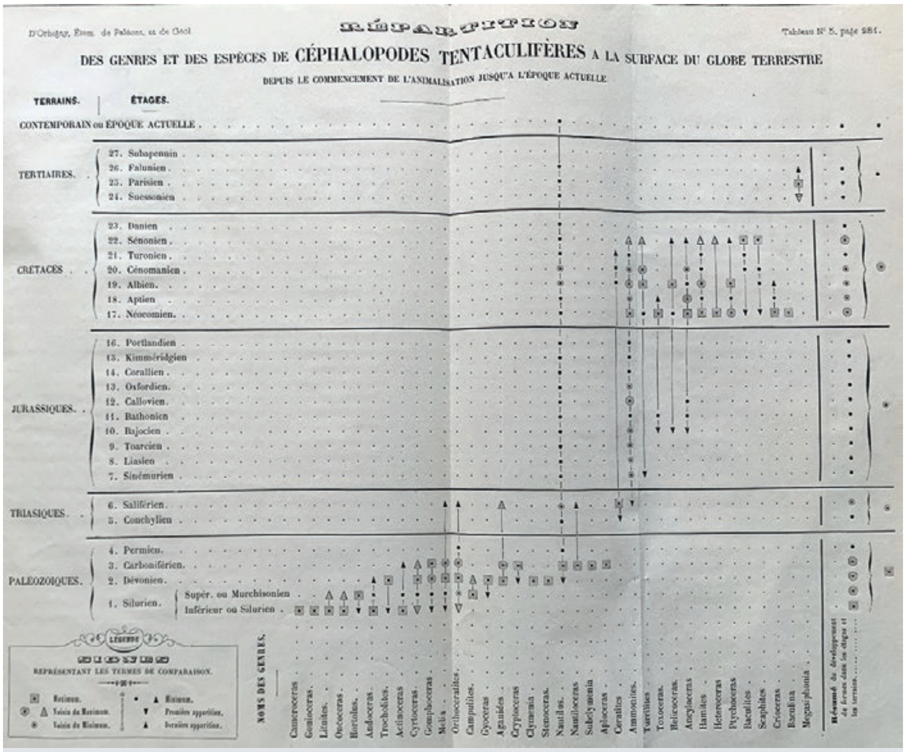
From such specimens we know for example that **complex social systems** existed in dinosaurs over 190 million years ago. For

Source: James Etienne.



Some example standard fossil groups that are commonly used for correlation in different geological periods. Thanks for Dr David Ray for support in preparing this image.

Source: James Etienne.



An example range chart for some terrestrial cephalopods. From the classic work 'Cours élémentaire de Paléontologie et de Géologie Stratigraphiques' by Alcide D'orbigny.

instance, an important fossil site in southern Patagonia shows convincing evidence for herd behaviour with age segregation in a population of the sauropodomorph *Mussaurus patagonicus.* Fossils of eggs and hatchlings, juveniles, and adults (individuals and pairs) were all grouped separately at the locality!

One example of life mode I particularly like is the evidence for K-selected viviparity of plesiosaurians. Plesiosaurians (like ichthyosaurs) are known to have given birth to live young, most likely to a single progeny of large size following a long gestation period. The young have been interpreted to stay close to the mother, probably for some considerable time after birth, with pod behaviour a bit like modern whales. Having had the good fortune to find two partial *Colymbosaurus megadeirus* skeletons for both a mature adult and juvenile in very close proximity to each other (just a few metres) this example really resonates for me (see photo). The key difference between these two specimens is that on the adult, the neural bones are fused to the vertebral centra, while on the juvenile they are not.

TESTING REGIONAL GEOLOGICAL MODELS

The radiative trends of species (proven by fossil distribution) provide lots of information on palaeogeography, including how, and when, landmasses were connected, and the presence of seaways and connections between marine basins. Indeed, the occurrence of both *Mesosaurus* and *Glossopteris* in both South Africa and South America led Alfred Wegener to propose the theory of continental drift. While continental drift was rightfully not accepted as the correct mechanism, the juxtaposition of these continents we now well understand through plate tectonics where geodynamic models can explain how identical fossils can be found on either side of the South Atlantic Ocean.

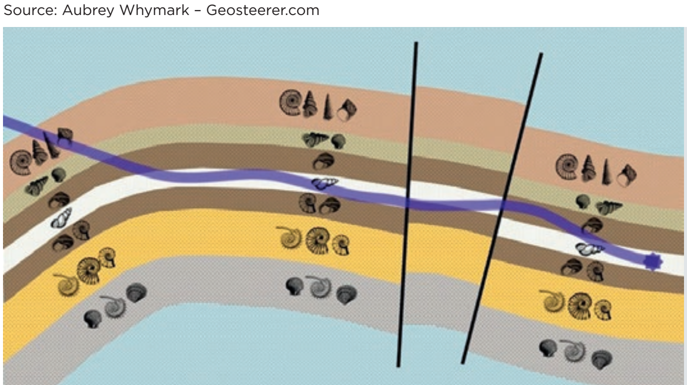
Since plate tectonics governs the organisation of continental and oceanic crust through time, fossils are thus incredibly useful tools in testing, validating or refuting different geodynamic models. The connection between marine basins (so-called 'oceanic gateways') is particularly important for understanding thermohaline circulation patterns and their impact on surface heat distribution on earth in the past.

During the Eocene, the Eurasian Basin (precursor to the modern Arctic Ocean) was a relatively isolated water body with a stratified column and a freshwater nepheloid lid. We know this because of the basin-wide occurrence of a fossilised freshwater fern called Azolla (See also Geo ExPro 2016/02). Surface drainage from the surrounding North American and Eurasian landmasses poured into the Eurasian Basin allowing Azolla to bloom, drawing down vast volumes of nitrogen and carbon dioxide from the atmosphere. In fact, this palaeoecological event is thought to have been a contributing factor to **global cooling** and the late Cenozoic ice ages.

RECONSTRUCTING PAST CLIMATES

Since most organisms occupy ecological niches where they have adapted to their environment, fossils and fossil assemblages can provide a lot of insights into **palaeoenvironmental** conditions. For example, the coiling direction of some foraminifera (clockwise versus counter-clockwise) can determine the likely range of water temperatures in which they lived. Some marine fauna (particularly fish) have strong preferences for the range of salinity they can tolerate (stenohaline organisms) which can be good indicators of palaeosalinity. Groups such as sponges, large bivalves (e.g. rudists), large benthic

Source: Aubrey Whymark – Geosteerer.com



If the fossil content of the layers above and below the target reservoir (white) is different, biostratigraphers can help geosteer a well back into the reservoir when crossing a fault with unknown throw.

foraminifera and green-blue algae are good tropical marine indicators, while others such as some species of brachiopods and crinoid-dominated bioherms can be indicators of cooler water conditions.

In the terrestrial environment, spore, pollen and plant macrofossils can provide information on likely air temperature, humidity and precipitation. Stomatal indices from fossil leaves can be used to imply atmospheric gas composition, and in vertebrate mammal populations, the degree of hypsodonty (teeth adapted for grassland) can even be used as an aridity indicator.

The observations above are known as proxy indicators for the environment, but fossils can also provide the raw material for **direct geochemical studies** such as stable carbon and oxygen isotope analysis on mollusc shells. Such analyses can provide information on seawater composition and palaeotemperature and are typically referenced to the Peedee belemnite. The Peedee belemnite (or PDB) is actually *Belemnitella americana* – a belemnite found in exposures of the Peedee Formation along the banks of the Peedee River in North and South Carolina. Since the original material is no longer available (the original study by H.C. Urey was published in 1951), you will see V-PDB (Vienna-PDB) a lot in the literature, which references another standard NBS-19 relative to PDB (although that is now also exhausted and has been replaced by IAEA-603 which is itself calibrated relative to V-PDB). A similar approach can be taken with tooth enamel of vertebrate fossils and has even been used to interpret changes in hominin diet over time.

Source: James Etienne.

Side by side – two partial plesiosaurian skeletons collected over a period of more than 2 years. On the left, an adult Colymbosaurus – the neural arches are fused to vertebral centra. On the right, the partial vertebral column of a juvenile found within a few metres of the other specimen, at the same stratigraphic level. Were they directly related? These specimens are currently on display in the Abingdon Museum.

BURIAL MODELLING AND THERMAL MATURITY ANALYSIS

In addition to all the insights mentioned above, some fossil material can even help provide proxy information on the burial history of the rocks in which they were deposited. This is really important in basin and **petroleum systems modelling**. With an understanding of how geothermal heatflow has evolved over time, it is possible to infer the likely burial depth of petroleum source rocks.

The kerogen type can provide an indication of the original source material and even a prediction of the likely hydrocarbon phase. Type I kerogen of lacustrine algal origin is typically oil prone, as is type II marine kerogen, although oil sourced from these kerogen types can be cracked to gas at sufficiently high temperatures. Type III kerogen, typically derived from land plants, tends to be gas prone, although there are some exceptions where tropical plants with thick waxy cuticles can produce liquid hydrocarbons.

THERMAL MATURITY

Vitrinite reflectance is a method used to determine coal rank, but is more generally used as a method to assess thermal maturity achieved during burial in basin and petroleum systems modelling. Determined under a microscope, vitrinite (a type of maceral or woody tissue typically derived from vascular plants) is subject to an incident light source and the amount of reflectance from the vitrinite surface is measured.

Since vitrinite reflectance increases with thermal maturity, it can be a good indicator of the likely depth of burial of sedimentary rocks. Sudden jumps in vitrinite reflectance profiles measured along well bores can also provide proxy evidence for cryptic unconformities. Of course, the interpretation requires care and attention, especially as vitrinite is durable and can be reworked into younger rocks that have not been subjected to as much burial.

ALTERATION INDICES

Developed in the 1970's by a group of researchers from the USGS, the **Conodont Alteration Index** (or CAI for short) is a colour-based scale for the thermal alteration of the apatite that composes conodont fossils. Applicable in rocks of Palaeozoic and Triassic age, the CAI is a visual microscope-based method for determining the approximate likely maximum temperature range the fossils were subjected to on burial. It has many uses – not only for evaluating burial modelling in hydrocarbon exploration, but also for metamorphic and structural geology studies. Thermal alteration indices have also been developed for other fossil groups including graptolites and acritarchs (organic-walled microfossils).

VERSATILITY

In this article, I have mentioned just a handful of examples of the ways in which fossils can be used to develop insights into the geological past. Whether used for their distinctive physical appearance to correlate rocks, in cladistics for determining evolutionary trends, as physical material for geochemical studies or for palaeobiological analysis, fossils allow a forensic analysis of sedimentary rocks and a window into the geological past.

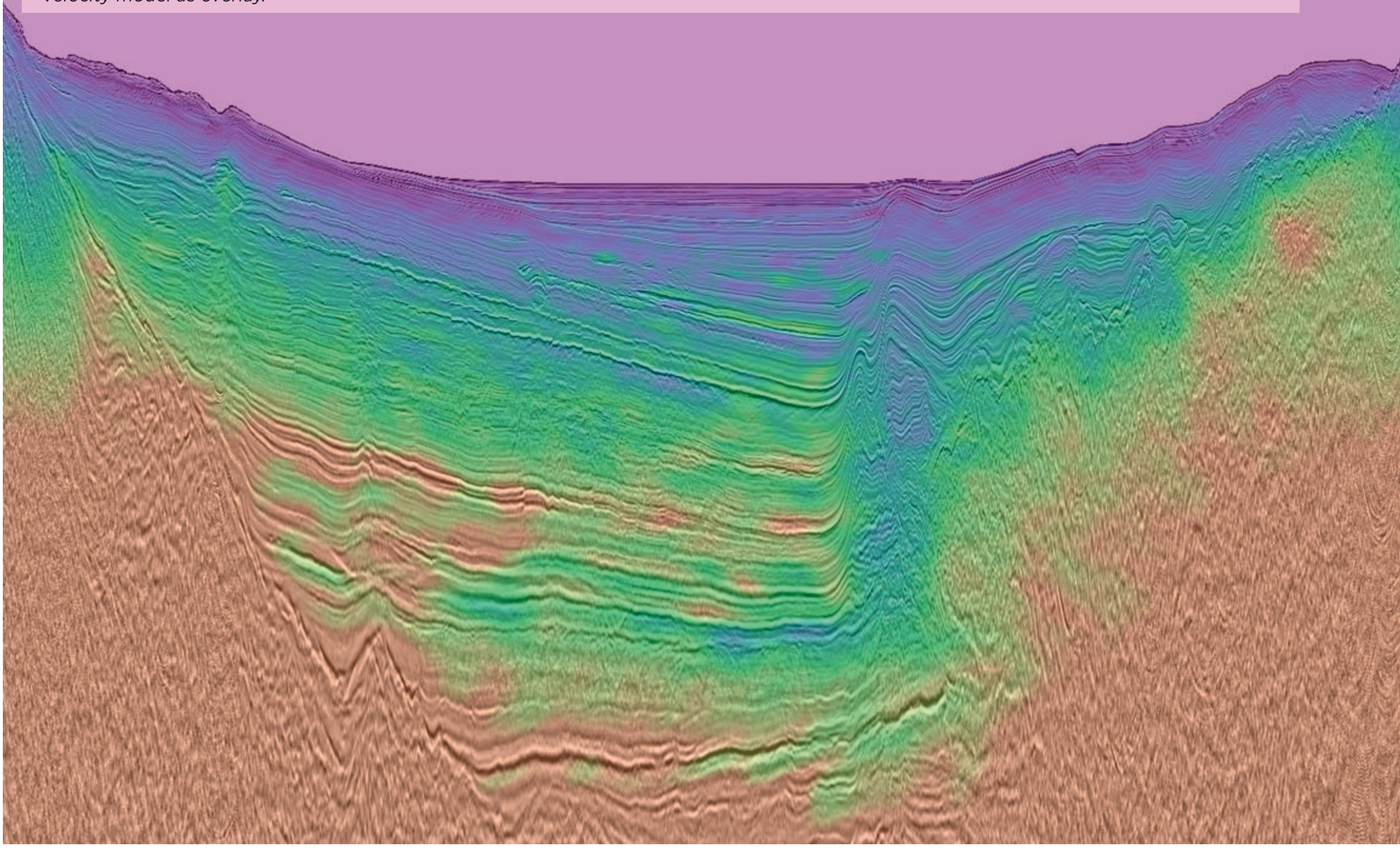
The Most Advanced Datasets Offshore Barbados and T&T

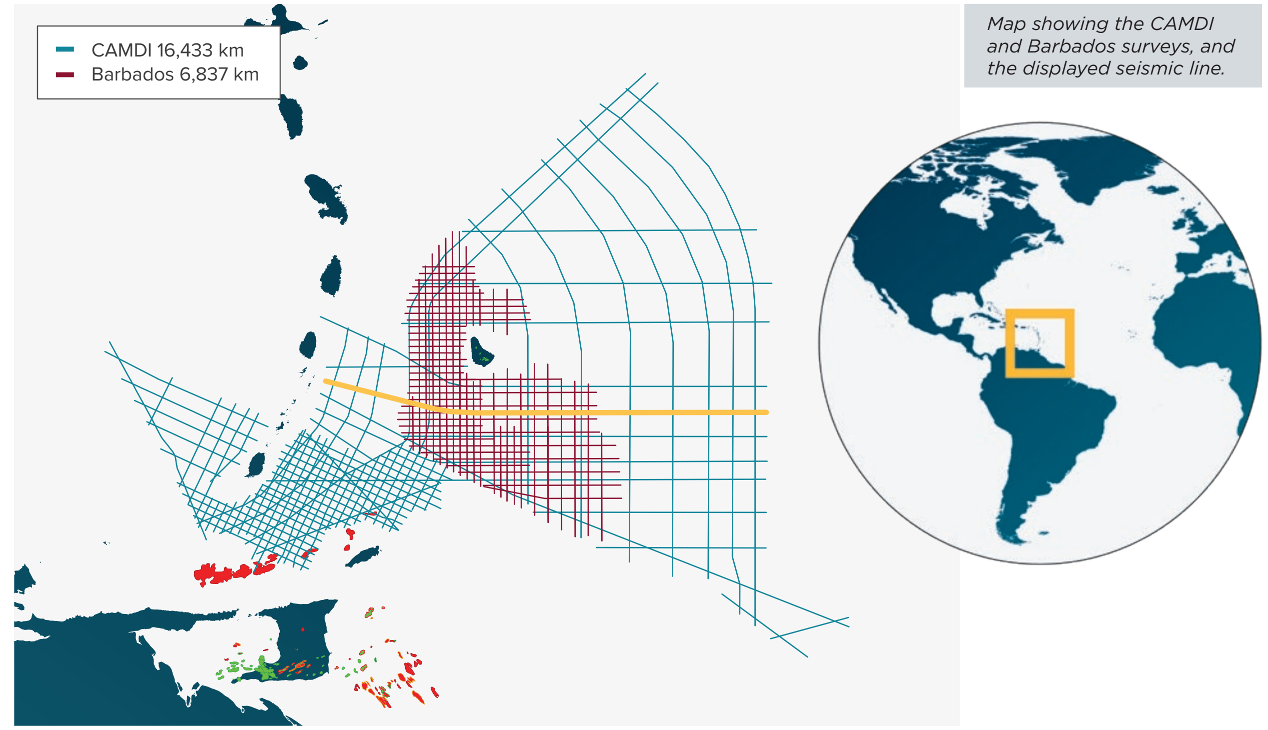
In March 2019, Geoex MCG completed the acquisition of 16,433 km of long-offset high resolution 2D seismic data in the Southeastern Caribbean. The survey area covers Barbados, Grenada, Trinidad & Tobago and St. Vincent, for the first time providing explorationists with a new view of regional structure and stratigraphy.

The survey is a deep, regional seismic acquisition that can be combined with the Barbados survey acquired by Geoex MCG in 2012/2013 with the objective to study the highly prospective, yet underexplored basins along the Southeastern Caribbean and Western Atlantic margin off Northeast South America. For that reason, the surveys are in a unique position to support the upcoming licence bid rounds in Barbados and Trinidad and Tobago.

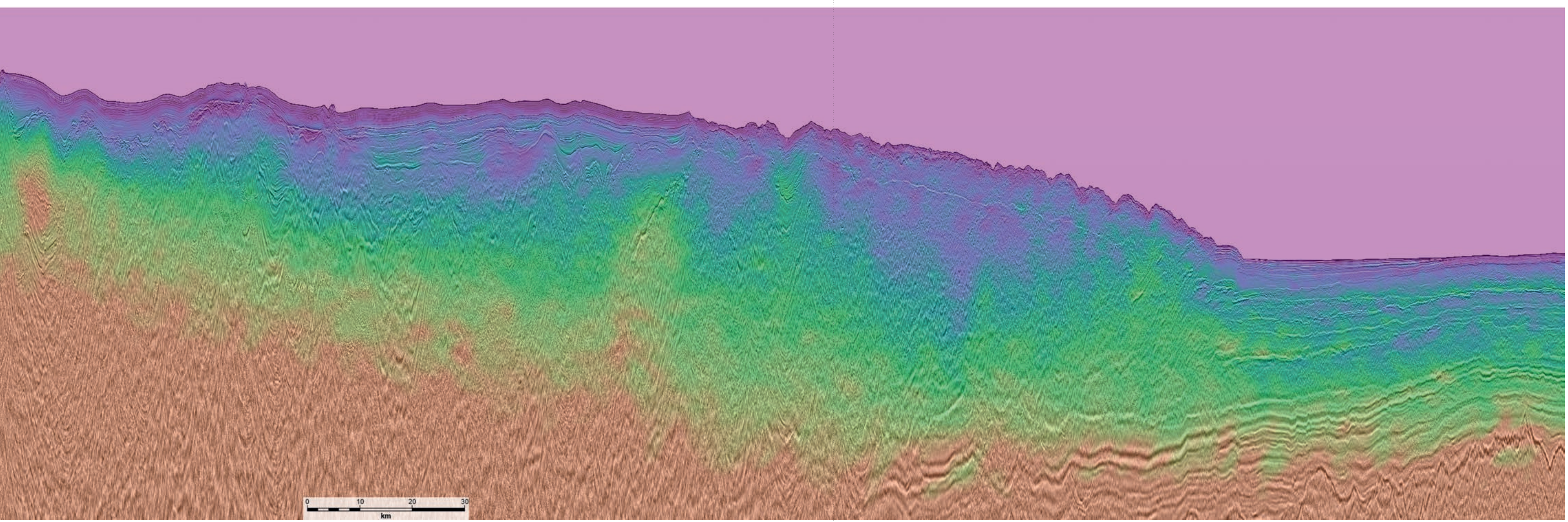
Beam tomography was used to allow for faster turnaround time and, at the same time, increase the accuracy of the velocity model by using wide-azimuth information that is typically unavailable in traditional tomography. In addition to beam tomography, high quality PSTM and PSDM data are available.

Seismic Line extending from the Tobago Though, though the Accretionary Prism and onto the Atlantic Abyssal Plain with Beam Tomography velocity model as overlay.





Map showing the CAMDI and Barbados surveys, and the displayed seismic line.



A New and Improved Velocity Model for the Southeastern Caribbean

Generate powerful insights for the 2022 Barbados and T&T Offshore Licensing Rounds with the CAMDI (2019) and Barbados (2013) data.

Text: Jeniffer Masi, Jeroen Hoogeveen, Geoex MCG Ltd. Nick Tanushev, John Walker, Alexander Mihai Popovici, Z-Terra Inc.

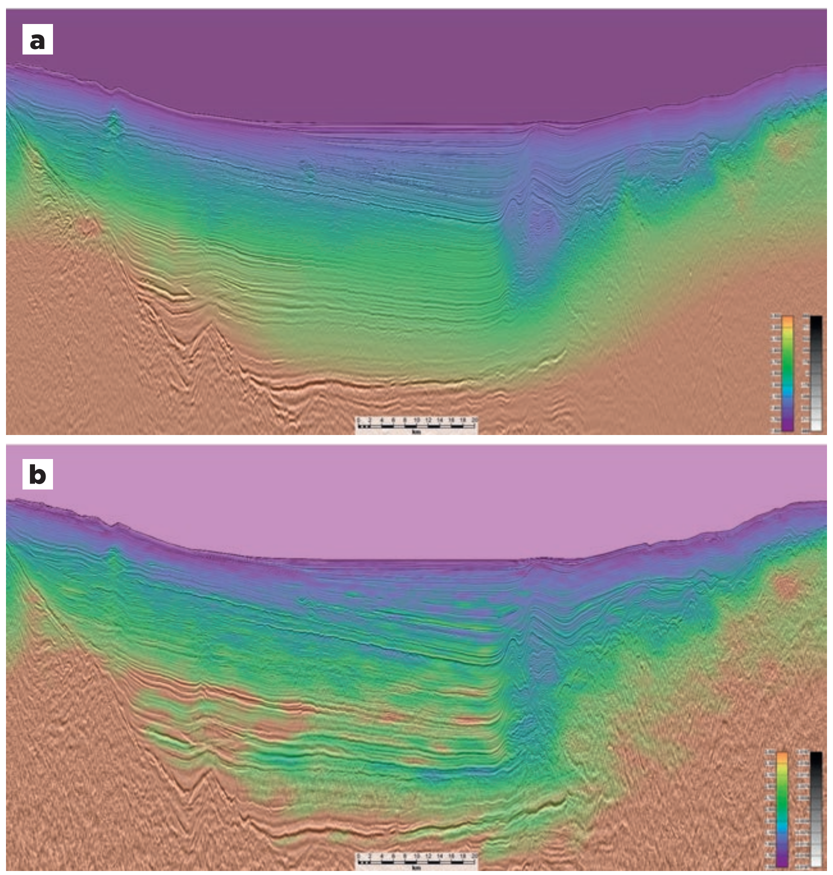
During 2018 and 2019, **Geoex MCG** acquired the **Caribbean Atlantic Margin Deep Imaging seismic survey (CAMDI).** This survey consists of 16,443 km MC2D long offset (12 km) and deep records (18 seconds) seismic data. This transnational survey continuously covers acreage across the maritime borders of **Barbados, Trinidad & Tobago, Grenada**, and **St. Vincent**.

The survey was originally designed in two grids. The **regional grid** is meant to provide a better understanding of the regional 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 detail, outline potential prospects and tying the producing areas in Trinidad & Tobago to the underexplored deeper part of the Tobago Trough.

The CAMDI survey can be combined with the Barbados Survey acquired in 2012/2013 by Geoex MCG to outline potential prospects in Barbados. The Barbados Survey is comprising 6,837 km of long-offset 2D seismic data over a 14 x 14 km and 7 x 7 km prospect grid, covering the **Barbados Trough**, the **Tobago Basin** and crosses the **Barbados Ridge**.

Both surveys provide clear imaging and broad coverage of all play elements in the region, including the oil prone La Luna source rock or its regional equivalent.



Velocity model: (a) Initial; (b) updated velocity obtained after 120 iterations of Beam Tomography.

INITIAL VELOCITY MODEL

The original processing sequence used a state-of-the-art broadband solution. A detailed velocity grid, that was estimated by global tomography was input into both the pre-stack time migration (PSTM) and the pre-stack depth migration (PSDM). This velocity model is structurally consistent, containing detailed shallow geological features such as mud volcanoes and potential gas anomalies (see left).

However, there is a lack of available well data in the area. In order to increase the accuracy of the velocity model, wide-azimuth beam tomography data was used that is typically unavailable in traditional tomography.

BEAM TOMOGRAPHY

Before beam tomography can update the velocity, the seismic data must be converted to beams, using a once-per-dataset, velocity-free procedure (Popovici et al., 2013 and Popovici et al., 2017).

The next step is to migrate the beams using the available velocity model. After the migration is completed, each of the resulting depth migrated beams contain the following information (among others):

- Seismic wavelet: The time signature of the event that is imaged;
- Beam correlation point: The (x, y, z) point in the subsurface locating the structure that the beam is imaging;
- Reflection angle: The angle at which the seismic waves reflected from the structure;
- Structural plane: These are the x and y dips of the subsurface structure. They are equivalent to the plane tangent to the structure at the reflection point.

We use this information to make groups of beams that are imaging the same structure. As with traditional tomography, the assumption is that beams that image the same structure should place it at the same point in the subsurface and any discrepancies are due to errors in the velocity.

For each group, we first align the beam seismic wavelet temporally. Then we calculate the spatial shift necessary to align the structure. We convert these space shifts to time shifts using the velocity to obtain a velocity correction along the ray trajectory. This correction is the residual for the tomographic equation and the tomographic matrix is obtained from the ray trajectories. The velocity update is obtained by solving the tomographic linear system of equations. Following the update, the procedure is restarted from the migration stage.

Since the above workflow does not require image gather or user input, beam tomography velocity updates can be done very rapidly so that the final model is the result of hundreds of iterations. Nonetheless, velocity model building is not a "black-box" procedure - image gather and other QC attributes can be generated at certain iteration numbers to allow monitoring and supervision of the algorithm.

UPDATED VELOCITY MODEL

After 120 iterations of Beam Tomography, an updated velocity model was obtained (figure left). This new velocity model produces flattens gathers and results in an improved signal strength (figure below). All iterations were conducted using Kirchhoff pre-stack depth migration (PSDM).

Additionally, Gaussian Beam migration (GBM) and reverse-time migration (RTM) were used in the imaging process. The new velocity model is highly resolved, and consistent with the geologic structures, containing detailed and subtle velocity changes within the sedimentary sequence and highlighting shallow geological features such as mud volcanoes and gas anomalies.

NEW PLAYS AND PROSPECTS

All the components for successful exploration are present offshore Southeastern Caribbean. The seismic line shown in the foldout is located south of Barbados, from the Tobago Trough, through the Accretionary Prism and into the Atlantic Abyssal Plain. Several trapping configurations can be identified: channels, rollover structures and anticlines.

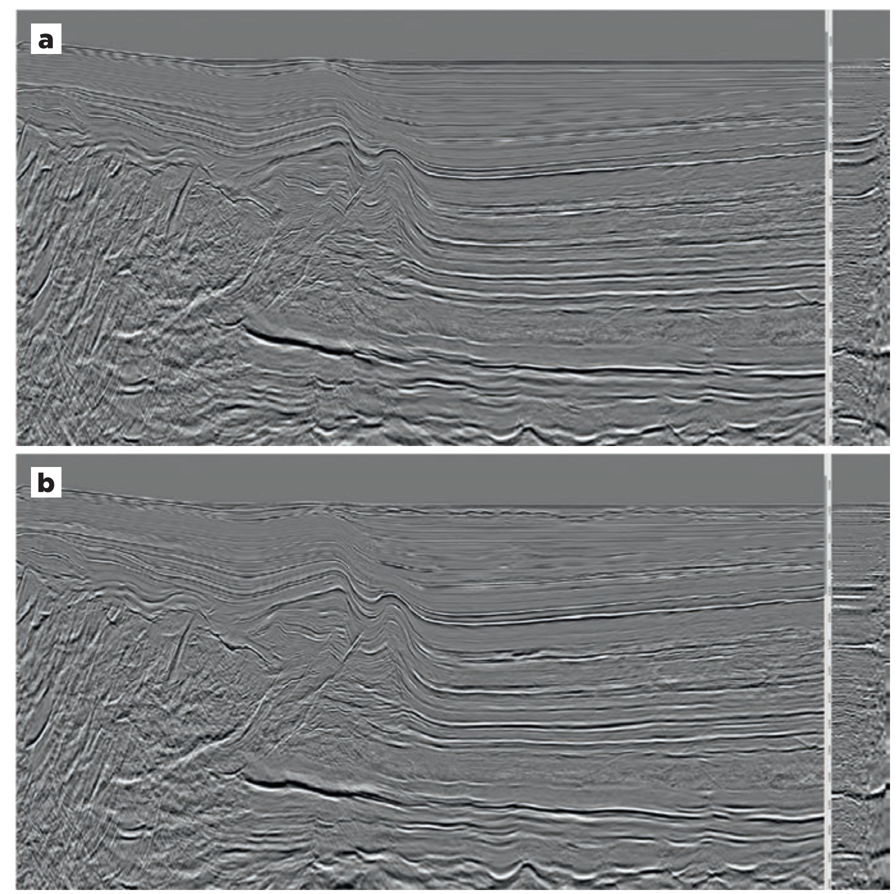
An integrated interpretation of both CAMDI and Barbados MC2D surveys have led to the identification of multiple prospects. These prospects are expected to be charged by the **La Luna formation** (or its regional equivalent). Structural and stratigraphic traps have been mapped out and **Direct Hydrocarbon Indicators (DHI's)** can be observed in connection with many of these traps.

The Southeastern Caribbean area is an excellent exploration opportunity, with only a few exploration wells are drilled in this vast untested area. Several world-class leads have been identified using both Geoex MCG surveys: CAMDI and Barbados.

Good quality offshore reservoirs appear in the data, optimizing the 'below-ground risk'. Meanwhile, regional Governments have created an exploration environment optimizing the 'above-ground risk'.

ONGOING LICENSING ROUNDS

The Government of Barbados recently announced the schedule for their Offshore Licensing round. In addition, the Government of Trinidad & Tobago has recently also published the expected blocks on offer for Competitive Bidding in Q4 2022.References provided online.



Kirchhoff Migration and common image gathers: (a) produced using the initial velocity model; (b) produced using the updated velocity model by Beam Tomography.

NVENTURES

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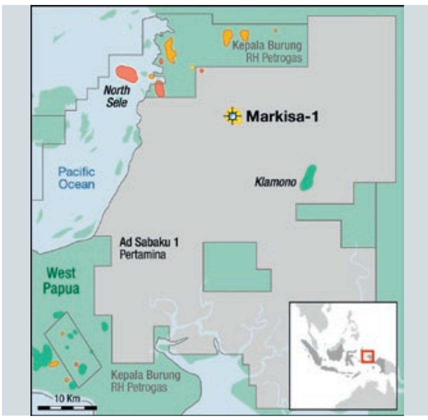
Edited by Ian Blakeley ian.blakeley@nventures.co.uk

Far East success with Markisa 1



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PT Petramina have reported a gas condensate discovery at **Markisa 1**, in the Ad Sabaku 1 Block onshore Indonesia. The well was drilled in August 2022 with the PDSI 28 rig in the Salawati Basin, targeting the Middle Miocene Kais formation. The drilling comes after a hiatus of 8 years of inactivity in the basin. On test the well flowed 9.7 mmcfgd and 219 bcpd from an 8m interval at 2012m, and testing was ongoing at the time of reporting.

The block is located on the westernmost region of West Papua in the Sorong Regency, difficult terrain for the current campaign of 1 development well and 3 exploration wells. The area is home to some of the oldest exploration activities in the region, with production from the nearby **Klamono Field** starting in the early 1940s.

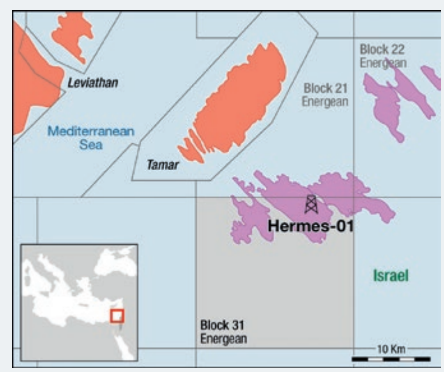
Hermes 1 – gas prospectivity rising in the Levant

Energean have started drilling the **Hermes 1** well offshore **Israel**. The well is targeting the Tamar D sands in the Miocene, in what is recognised as a prolific gas basin in the Levant Basin. The well is being drilled in Block 31 by the Stena IceMax in 1620 m water, and should reach TD in September.

The well is one of two option wells taken by Energean when they were awarded the acreage in 2017. Hermes is one of around 6 prospects in a cluster of Tamar structures similar to the T**amar Field** immediately to the northwest, which is already in production (Chevron and partners).

Leviathan and Tamar were the first major gas discoveries in the basin (2010) after which **Karish** and **Tanin** were discovered by Delek in 2011. Energean purchased the Karish and Tarin gas fields from **Delek** and Avner in 2016. The Karish Field remains on track for first gas in late 2022.

The Stena rig contract was extended this year after successful wells at KM4 (Karish) and the new field discovery **Athena 1** in Block 12. Should Hermes be successful, Energean will opt to drill the second well, Hercules 1, in what the operator is called the **Olympus Area**.



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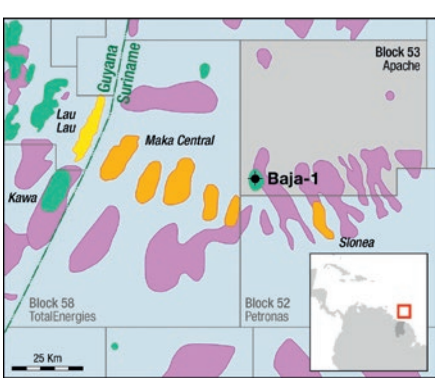
Hit and miss, but the Suriname trend stretches east

APA Corp and partners **Cepsa** and **Petronas** have announced a successful oil discovery at **Baja 1** in the south of Block 53 offshore **Suriname**. The well was drilled by the Noble Gerry de Souza drillship between July and August 2022 in 1140m water. TD was reached at 5,290 m, similar to the 5 to 6 km TD range for the wells in this basin, and over 34 m of oil pay was recorded in the Campanian.



NVentures

Baja is reported to be a down-dip lobe of the Krabdagu depositional system, which was successfully drilled to the west in Block 58 by APA and **TotalEnergies**. APA have been working on Block 53 a number of years, and drilled the **Popokai 1** well (oil shows) in 2015. In 2017, the current operating group drilled the **Kolibrie 1** well to the east of the block, again with only oil shows in the Upper Cretaceous.

Most recently, in April 2022, the operating group drilled the dry **Rasper** well in the north of the block in 2000 m water. With 34 m pay and a number of misses, APA and partners will need to decide if this is a commercial extension of the Suriname Campanian play, but for now the area remains part of a prolific petroleum basin.

Petronas and **ExxonMobil** are considering drilling options south of Baja in Block 52, with further opportunities to stretch the model. Block 58 remains the most successful block offshore Suriname, and Total Energies and APA will continue to evaluate the commerciality of five discoveries there. The group is currently taking an extension to the exploration phase on that block, where they also plan to appraise the **Sapakara field**. The Gerry de Souza rig will mobilise to Block 58 for the **Awari 1** well, located north of the original Maka Central discovery.

When the Tramlines are Missing

Sometimes it is hard to tell the orientation of a core based on sedimentary features alone. That is not the case for the Ness Formation from the Northern North Sea.

Photo: Henk Kombrink.

A slab of Ness Formation from well 211/23d-18 in the UK Northern North Sea.

In order to help geologists orientate cores correctly in terms of what is up and what is down, the outside of the core is often marked with a red and yellow line, the so-called tram line. Red is right, yellow is left.

In many cases, this is a great help, especially if you are not an expert in sedimentology. At the end of the day, only a small selection of cores shows clear sedimentological indications that indicate what the correct orientation of the core should be. Think of bottomset laminations or the way cross-bedded sandstones are truncated.

There is one sedimentary succession in the North Sea that very often does not need inspection of the tramlines in order to find out what the orientation of the core should be. That is the Ness Formation from the Northern North Sea.

The sediments of the Ness Formation were deposited during the Middle Jurassic and form part of the Brent delta succession that is characterised by a series of delta progradations and retrogradations.

Ness Formation strata are often characterised by beautifully laminated fine-grained sediments, as the image illustrates. It is the alternation between darker mudstones and whitish fine sands, in which very often wave ripples can be interpreted, that characterises many Ness Formation cores.

TOP OF THE DELTA

These sediments reflect a low-energy environment, where mud was deposited most of the time. However, a sediment source for coarser-grained siliciclastics must always have been close-by. Most people attribute the Ness sediments to a delta-top environment, where shallow lakes accommodated settling of fines, with intermittent input of coarser material from nearby distributary channels.

If the laminated fine sands cannot already be the clue towards putting a Ness core in the right orientation, then there are trace fossils that can do the job. What is generally thought of being the work of Diplocraterion, these bottom-feeders dug their way into the soft sediments of the Brent delta plain.

Photo: Henk Kombrink.

This core shows a good example of tramlines, with the red and yellow lines clearly marked on the outside. The red line should always be on the right.

Photo: Henk Kombrink.

Close-up of a Ness core showing burrows that clearly indicate what the orientation of the core needs to be.

Due to subsequent sediment compaction, the original mostly vertical burrows now often show up as a squiggly line, but that does not take way the possibility to discern the starting point from where the digging started.

Very often, it is a slightly sandier bit that formed the starting point of a new burrow, clearly enabling people to conclude what is up and what is down when looking at a bit of Ness. Even when the tramlines are missing. ■

Henk Kombrink

The cored section used for this article is held by North Sea Core CIC, the organisation that takes delivery of redundant core from the UK Oil and Gas Industry in order to save it from going to landfill and make it available for the wider geological community. Visit northseacore.co.uk for more information about this project.

NORTH SEA CORE

Discover a Clear Path to Your Success

Energy is everything. It's how we feed our people, move through the world, build, learn, and create. The future of energy is the future of us all.

And yet, this is a volatile industry. Shockingly disruptive events have rocked the energy market over the last few years. Pandemics, wars, wildly variable oil futures, rapidly-changing energy policies, inflation— these events are serious challenges.

But this volatility can also present incredible opportunities.

Change and Opportunity

The energy industry is evolving rapidly. Surging prices, energy shortages, inflation, regulation— to thrive in today's market, you have to be adaptable.

But the willingness to change isn't always enough. You need to know how to change, and when. And, you need this intelligence as quickly as possible.

Create More Value, Faster

An adaptable, decisive, fast-moving business can create value out of volatility. But to do this, your business needs:

- Clear, actionable intelligence of the entire energy ecosystem
- A single source of truth that brings all the data together
- Speed to be able to seize opportunities and mitigate risks

Intelligent Connections for the Energy Industry

Enverus is a single source platform for management, development, and acquisition, within the entire energy value chain. From early-stage investment to full-scale development, we provide the actionable intelligence, in-depth analysis and speed to support your changing energy strategy.

This is what we call Intelligent Connections: empowering your company to discover previously unseen insights and opportunities, act fast, and deliver extraordinary outcomes.

A Technology Partner for the Future

Enverus is the most trusted knowledge & analytics platform in the energy industry, with real-time access to analytics, insights, benchmark costs, revenue data and more.

Over 300 financial institutions and 5000+ energy companies rely on our analytics, intelligence, and technology to make capital investment decisions and increase investor ROI.

Our platform is built both by, and for, our industry. Our source is our own connections; with direct access to over 98% of US producers, and over 35,000 suppliers, we inform more efficient production and distribution, capital allocation, renewable energy development, investment, and sourcing.

Find out today how Enverus can help you remain agile, seize opportunities and focus on your core business in an ever-changing energy world.

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Barents Sea Geology Exposed

The islands of Svalbard form a great analogue for the subsurface geology of the Barents Sea, and that is why the area forms an important training ground for geologists.

Situated near the continental margin of Baltica, the western parts of the islands were uplifted in Paleogene times when oceanic spreading of the Mid-Atlantic ridge initiated a compressional regime along the flanks of the continent.

This has exposed – amongst a wide variety of other sedimentary strata – a succession of Triassic and Lower Jurassic sediments, as can be seen here.

The succession in the foreground shows the Upper Triassic Geerdalen Formation, which was deposited in a paralic environment. The sandstones were deposited by fluvial or tidal channels. These sediments form analogues for the Barents Sea Snadd Formation, which is a proven reservoir.

The hills in the background on the left of the image constitute of mudstones of the Upper Jurassic the Agardhfjellet Formation.

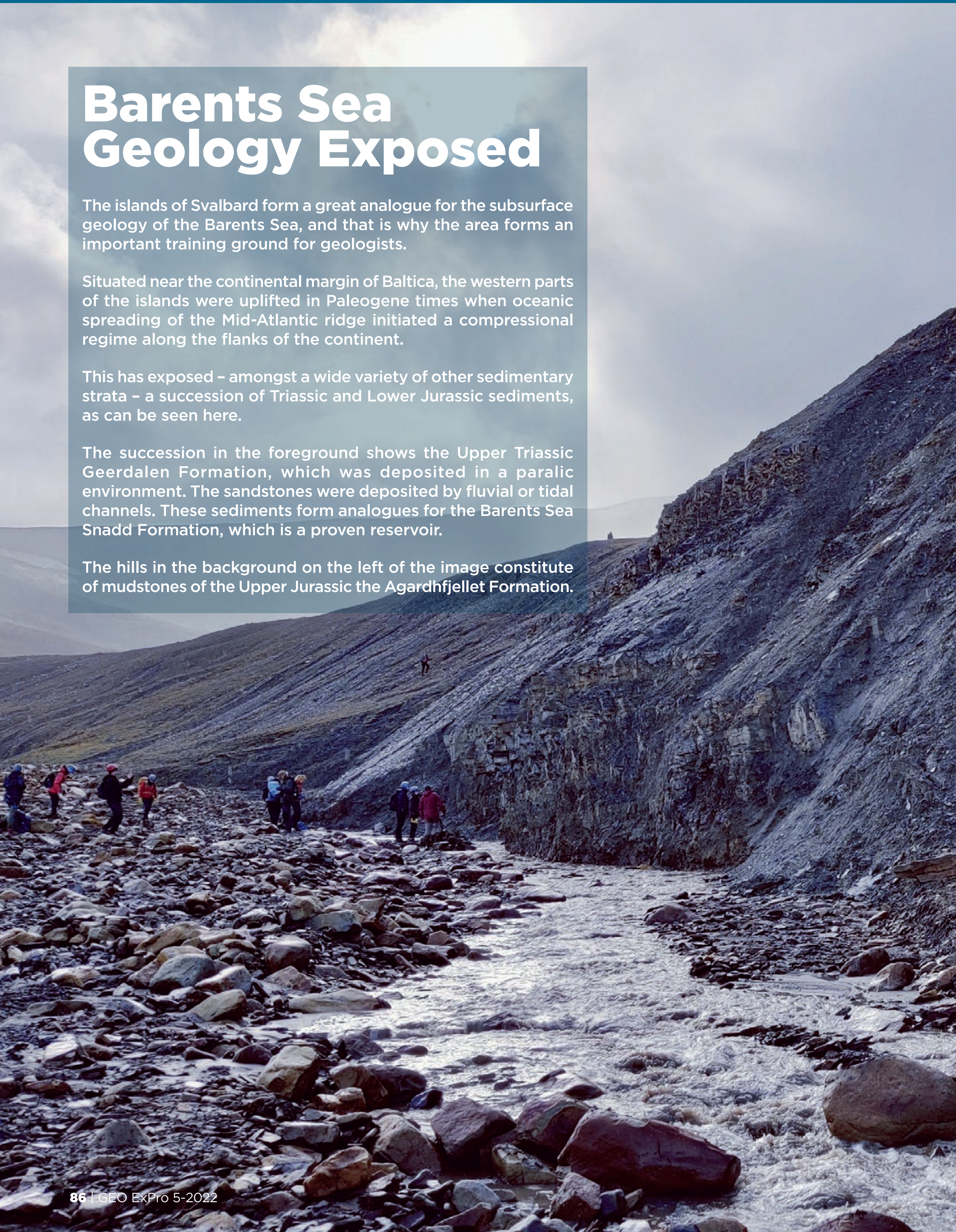


Photo: Roel Jan van Zonneveld, Utrecht University

Outcrops allow a much better inspection of sedimentary features than “1D” core data. In this series, we feature a range of outcrops to give more context to what core interpretation typically allows.

Do you have a suggestion for an outcrop feature? Please get in touch with us and email Henk Kombrink (henk.kombrink@geoexpro.com).

The New Gas Giants of Northwest Africa

Brought to you in association with NVentures www.nventures.com

A new cluster of gas giants is coalescing around the NW Africa region, amid the backdrop of surging global gas demand and energy prices.

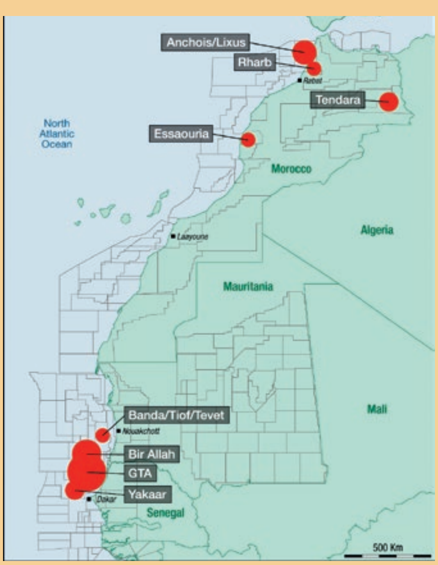
Whilst traditional oil and gas producers across North Africa have stepped up production and exports via pipelines from Algeria and LNG from Egypt, a new global energy landscape is expected to create sufficient demand to bring previous gas discoveries in **Senegal**, **Mauritania** and **Morocco** into rapid development.

After the first wave of discoveries in the region in the 1990s, **Woodside** and partners struggled with the **Chinguetti** oil development offshore Mauritania in the early 2000s, and left the gas-rich **Banda**, **Tiof** and **Tevet** fields stranded.

Between 2015 and 2019, **Kosmos Energy** took up the baton of high impact exploration, having had major success in West Africa. Drilling large AVO supported clastic fans and turbidites in the coastal basin offshore Senegal and Mauritania, the US firm notched up multi-TCF discoveries at **Bir Allah**, **Tortue/Ahmeyin** and **Yakaar**. Over 50 TCF of gas has been proven to date.

MAJORS JOIN IN

BP joined Kosmos soon after and the other supermajors **TotalEnergies**, **ExxonMobil** and **Shell** took up large frontier exploration positions nearby (ExxonMobil have since left).



The most advanced development, expected to start exporting valuable LNG as early as 2023, is the **Greater Tortue Ahmeyim** field (GTA) on the border of Mauritania and Senegal. This hybrid FLNG facility, with associated onshore facilities, is over 75% complete in Phase 1, and could hit the global market at a good time for gas and LNG prices.

Although both BP and Kosmos are rumoured to be seeking further investors or JV partners, or even an exit, the project is well funded and will be picked up by strategic partners, on a path to producing **2.5 MMtpa** LNG by end of 2023. This could double within two years, competing strongly with gas exports from the likes of Egypt and Angola.

BP and Kosmos are now in negotiations to re-start the Production Sharing Contracts with the government over the **Bir Allah** and **Yakaar** fields, a further **13 TCF** gas feedstock for Phase 2. To the north of Mauritania, US firm **New Fortress Energy** have signed an MOU for gas monetisation and onshore LNG projects with the government, and have been linked to the development of the Banda Field, a long-overlooked oil and gas asset near Chinguetti.

TRANSITIONAL GAS

Morocco has its own success story, with **Chariot** proving up good volumes of gas at **Anchois**, offshore the northern Atlantic coast. Anchois was first discovered in 2009 by Repsol. Chariot liked the amplitude driven clastic Miocene play, and drilled Anchois 2 in 2021, finding 150 m gas pay compared to 55 m in the first well. The result has been an uplift in resources to around **637 Bcf** (with a potential 4.5 TCF on the block) and a fast-track development.

Like GTA, this fast-track approach to gas monetisation reflects a change to new found respect for a once overlooked resource, playing straight into a hungry energy market immediately north in Europe, not to mention Morocco's own domestic energy needs. Chariot refer to the project as "transitional gas" and are running parallel projects in Mauritania and South Africa for **green hydrogen**.

Morocco provides huge potential for explorers, with many untested structures and modern seismic data to support exploration across multiple plays. Oil has already been recovered in the **Upper Jurassic** at **Sidi Moussa** (now Lagzira) and **Cap Juby**, and the potential for big gas offshore is a further incentive for exploration investment.

Onshore Morocco, gas has been produced in reasonably small quantities for a while in the coastal Rarb and Essaouira basins by the likes of **SDX**, while **Sound Energy** have great potential in their Tendrara Triassic play in the east of the country. Sound have a number of high impact exploration and appraisal targets ready to feed in to their micro-LNG and gas export strategy.

A SIGNIFICANT SWING

Covering multiple plays, jurisdictions and a large geographical area, the NW Africa margin represents a significant swing in upstream dynamics, promoting gas resources, monetisation, infrastructure and market development compared to a history of stranded and under-valued gas discoveries. European and regional markets look set to benefit, as demand continues to grow, outpaced it seems by supply problems. The growing hydrogen and "Power to X" industry will also benefit, as gas plays into this new value chain and the companies involved are heavily investing in the transition from producing oil and gas, to delivering energy. ■

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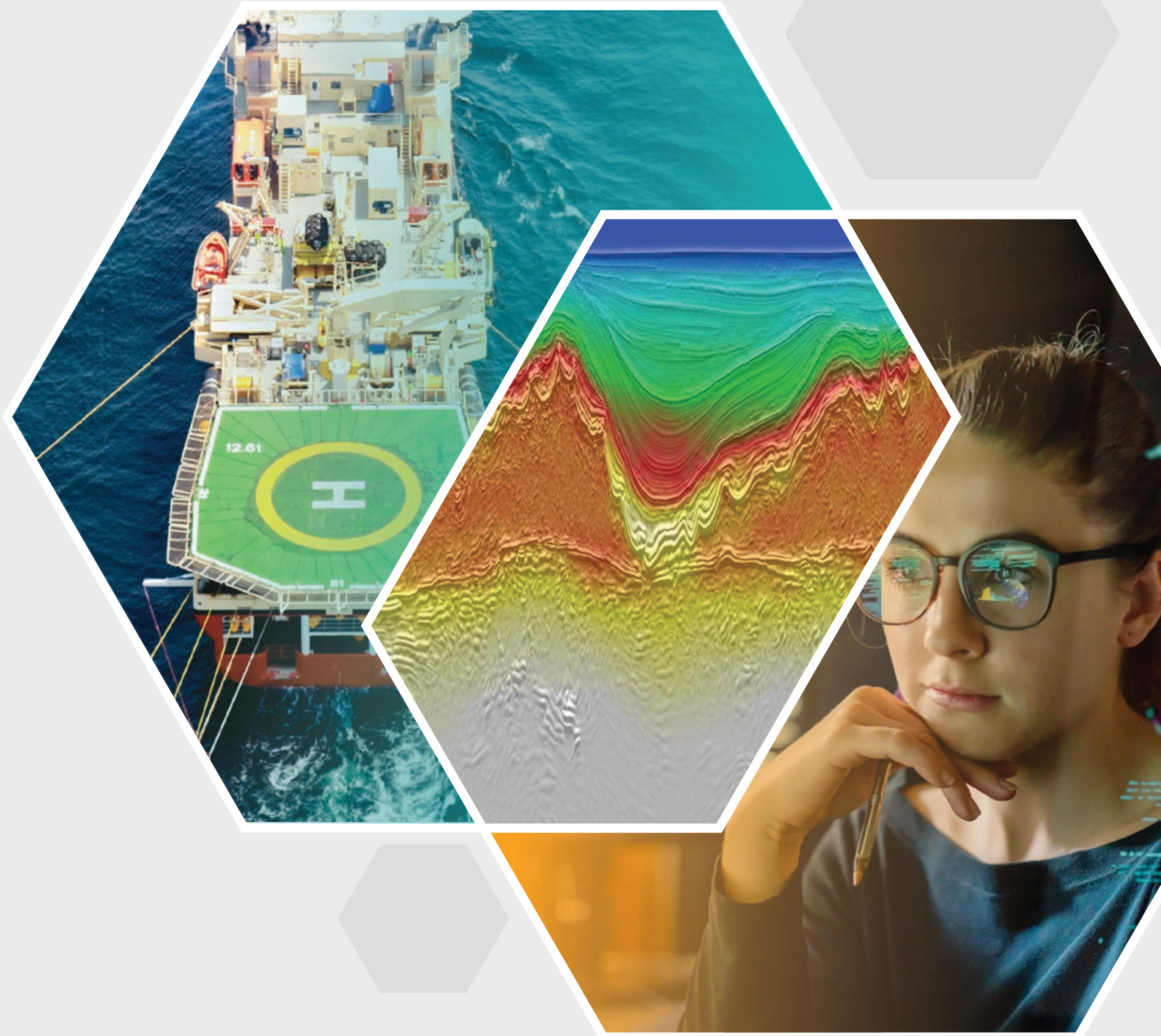
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