THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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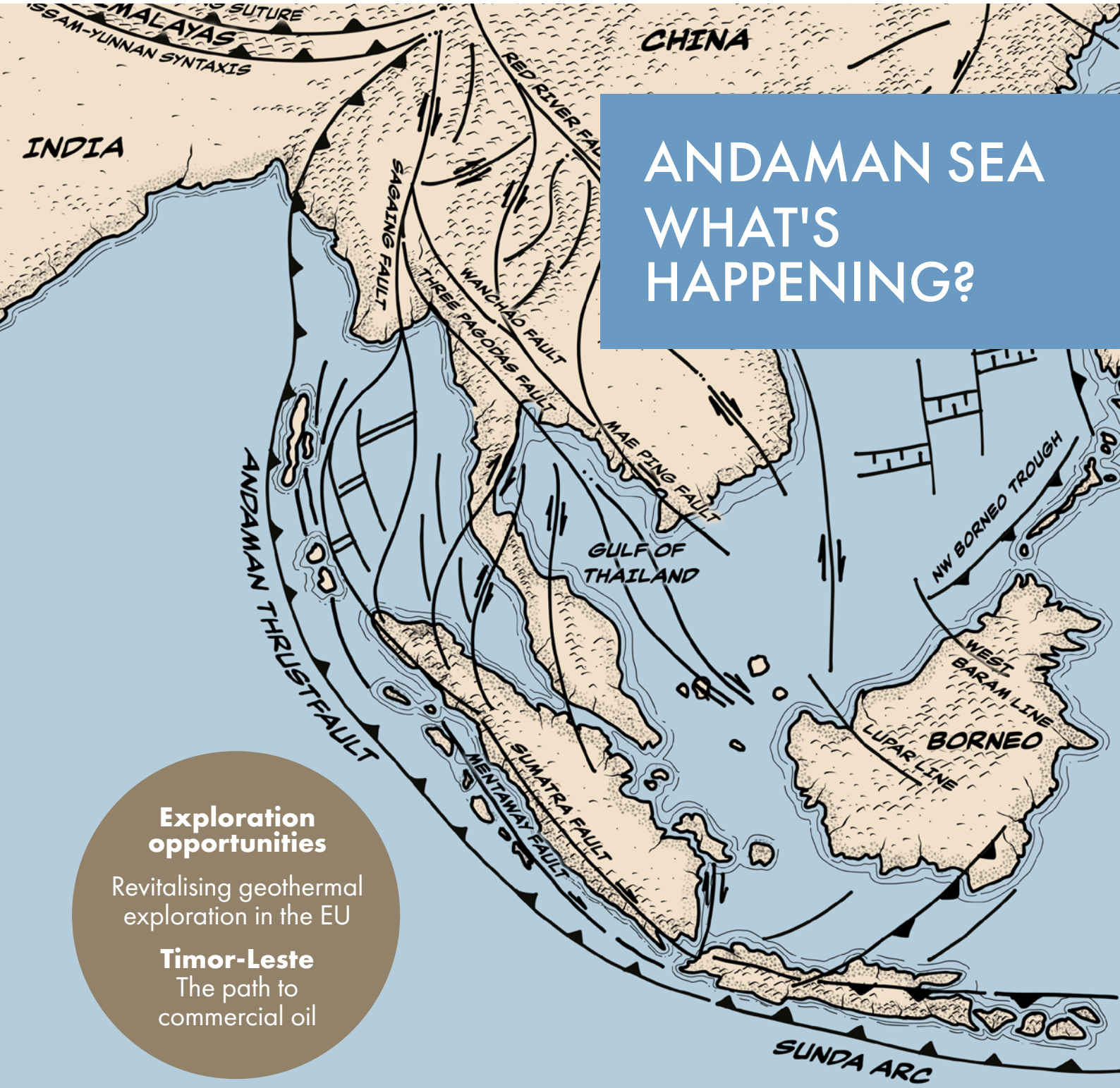

ANDAMAN SEA WHAT'S HAPPENING?

Exploration opportunities

Revitalising geothermal exploration in the EU

Timor-Leste

The path to commercial oil

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Be aware of pirates

WELCOME to the first issue of the year. Let's talk about pirates. Not a topic you probably had imagined, but on two recent and unrelated occasions, pirates came past my desk. Here is how.

First of all, when working on a story about exploration in a certain part of the world, the person I spoke to mentioned that back in the day, drilling was not conducted here because of the threat of pirates. It is one of those things you don't often think about - at least that applies to me.

Then, on the second occasion, it was a virtual pirate I came across. In this case, it was because I found that an article I had written for our website had been copied and pasted into another magazine without any credit given, as if I had written it for that particular outlet on invitation. It is a sad state of affairs to see these things happen, and one wonders how it must feel to steal content from other places this way.

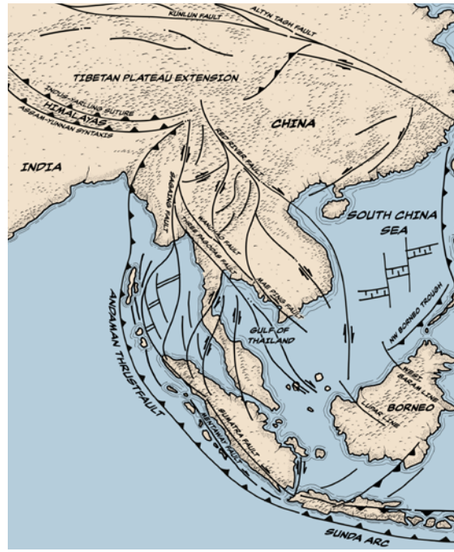
"..all our content is new, un-recycled, and there is always an effort behind it"

At the same time, as a reader, you can rest assured, we are no pirates. All our content is new, un-recycled, and there is always an effort behind it. The number of people I spoke to for this issue is large. We take pride in getting content to you that has been carefully selected and curated to bring you the latest subsurface news from the energy sector.

Henk Kombrink

BEHIND THE COVER

South-East Asia is our editorial focus this time, and for that reason we highlight recent developments in the Andaman Sea. Many will recall the Timpan discovery a couple of years ago, but maybe less known is that more exploration success has been achieved. It is an interesting thing to see unfold in an area that was previously explored for its carbonates. Now, it is the turbidite sands that matter. Many thanks to Marcos Asensio for setting the scene with yet another fascinating illustration.



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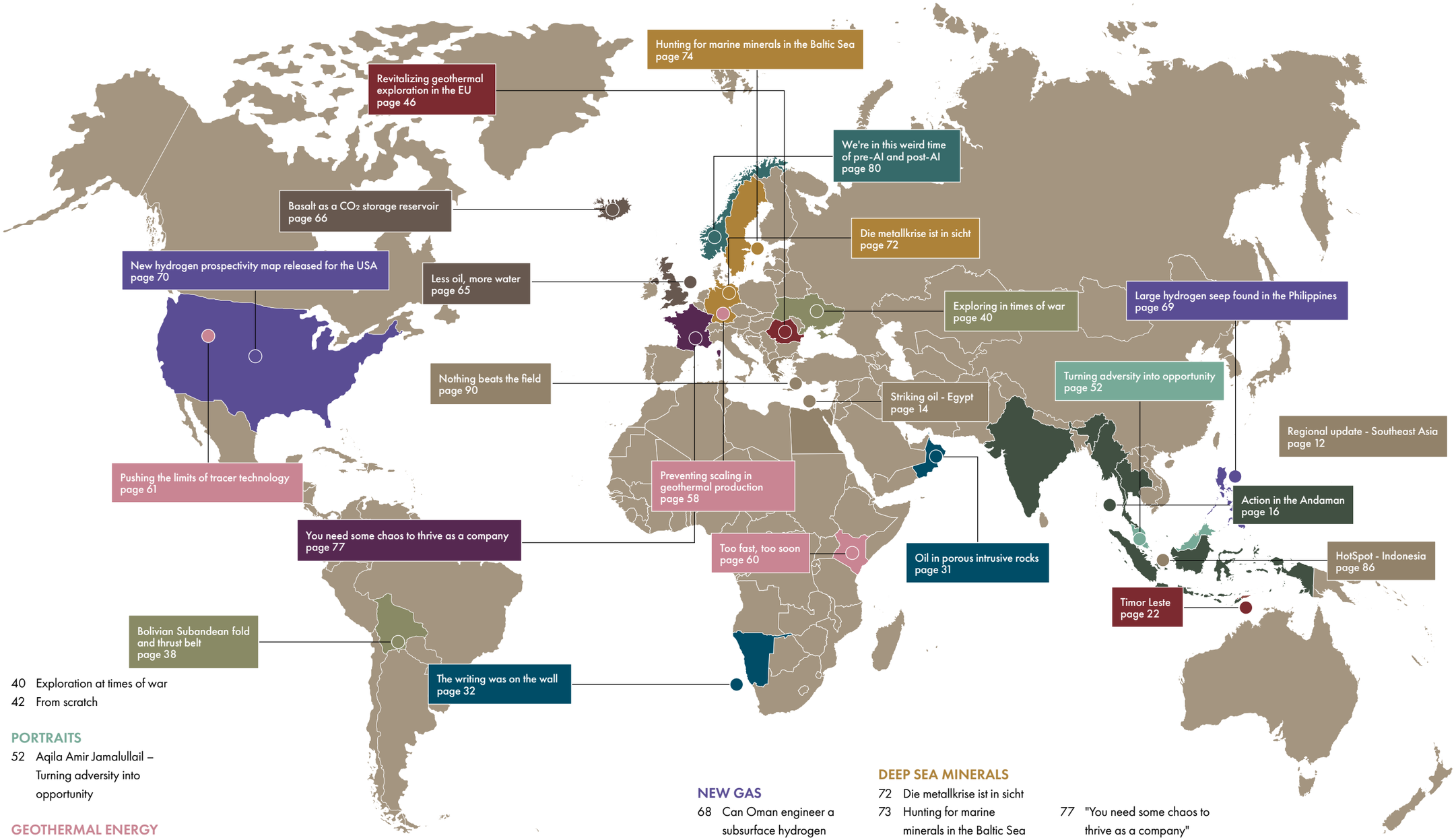
FIRSTS

"I discovered that most people think that energy is simple and that their own preferred solutions are all we need; we're all victims of our own confirmation biases, after all. But as a community, we should be leading a more robust discussion"

Rodney Garrard – Geologist

CONTENT



HOW TO KEEP PEOPLE ON YOUR PAYROLL WHEN YOUR ASSETS HAVE ALL CEASED PRODUCTION?

That's the question one particular operator faces in the North Sea. And they have found a great solution to this. I heard the company allows all employees to spend £5,000 a year on training in order to prepare for the next step in their careers as soon as the decommissioning process has been completed. And it seemingly helps; people have embarked on courses, and one person allegedly said: "People switch jobs all the time; I don't see a reason why I would not want to work for a company even when I know it will cease operating in 6 years, especially when the conditions are good."

IF THE PAYBACK TIME OF NEW TECHNOLOGY IS TOO LONG, YOU'VE GOT A PROBLEM

During a recent evening lecture, someone presented a new technology to decrease the water cut of produced oil. He showed graphs from a real project to back up the technology, clearly illustrating its potential. However, the person next to me was adamant when he said: "It will be hard to find an operator willing to trial this." Why? Because it is too expensive, and there is too much time between implementation and achieving results. It is a stark reminder of ALL aspects that need to be considered when marketing something new.

A LOWER SUCCESS RATE THAN DRILLING FOR OIL

At first glance, based on the notion that water is much more ubiquitous in the subsurface than hydrocarbons, you would say that drilling a geothermal well has a higher success rate than drilling for oil. That is not the case, however. Someone knowledgeable told me that the success rate for geothermal wells in Kenya used to be even lower than for hydrocarbon exploration wells. Why? Because of the fracture networks that are required to sustain flow. And these fracture networks are often below seismic resolution, which explains why it is so challenging to drill a successful well.

LACK OF RIGOR

"Some companies portray themselves as frontrunners in the Carbon Storage space", said Nick Richardson from the North Sea Transition Authority during last year's CCS4G Conference in London, "but when we as the regulator read through their applications for CO_2 storage licences, we do not see the technical rigor that is required to convince us of taking this seriously". It shows the discrepancy between shouting from the rooftop and the nitty gritty that only some people get to see.

The snippets of information shared here are based on conversations Editor in Chief, Henk Kombrink, has recently had. Sources are anonymous.

ILLUSTRATION: PCR.VECTOR / FREEPIK.COM

Energy sobriety – a moment of clarity in a "dry January"

Not only have we entered a new quarter century; we have also left behind the naive era of 1989…

AS WE ENTER a new year it's always important to ponder what we have learned from the previous year. I discovered that most people think that energy is simple and that their own preferred solutions are all we need; we're all victims of our own confirmation biases after all. But as a community, we should be leading a more robust discussion.

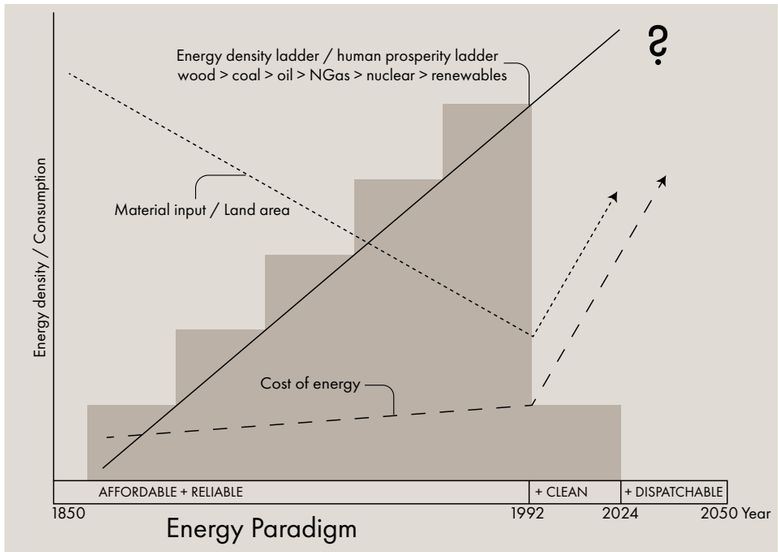
Supplying 8+ billion people with energy security while minimizing harm to the environment is a big and complex problem and that is why energy density matters. Ultimately, the best solutions depend on your geography - your 'geological endowment'. Folks in Iceland can rely on geothermal, Norwegians rely on hydro for their electricity, but most people around the globe burn coal and natural gas for their energy needs. And of course, industrial processes, transportation, and home heating – those are largely oil and gas almost everywhere.

It's very convenient to be a reductionist when living in the wealthiest European countries because the reductionist position is the only one compatible with fewer hydrocarbons and nuclear energy. But here's the kicker: What about the couple of billion people on this planet stranded without access to energy, or the billions of people that are just a recession away from energy poverty? I believe 2025 is a year in which we need to get back to the fundamentals of consuming more high net energy, as that equates to human prosperity.

Governments around the world prioritize energy security – up until very recently it had to be affordable and reliable. Then ushered in the Kyoto Protocol in 1992 and energy had to be 'clean' too. We are now entering a 4th energy paradigm, whereby energy must also be dispatchable. The type of transition ongoing now is a huge experiment with no data from similar trends in earlier historical transitions with increasing energy density over time. What it also shows is that global demand for energy will continue. Load growth is conveniently downplayed.

2025 marks not only the end of the first quarter of the 21st century, but is also the end of the era that began with the fall of the Berlin wall, Francis Fukuyama's "end of history" and the Kyoto Protocol. Hydrocarbons are transitioning away from us now, and it is partly because of this that the future looks a lot more serious than the past we leave behind. We find ourselves in the middle of this turmoil, and we will probably have to take more pragmatic and realistic decisions than what our parents did. In the long run, maybe that will be for the better though. ■

Rodney Garrard



The home of the world's first deep-water gas development

The Philippines industry has had a chequered history, but through offering some of the world's most attractive terms, it is now looking to attract more E&P investment

FOLLOWING World War II, a number of US-companies drilled onshore but never found anything commercial despite the presence of surface seeps. Fortunes changed in the 1970s with Cities Service making a number of small oil discoveries around Matinloc, and Amoco at Cadlao.

In 1989, Occidental ("Oxy"), who had taken over Cities as part of a global deal, made the Camago-1 gas and light oil discovery in 736 m of water. However, like other US-companies at the time, Oxy was a little cold on Asian gas and farmed out 50 % to Shell who were more positive about gas. Shell then drilled a successful well on a separate reef to the north of Camago designated Malampaya and further drilling proved this to be part of the same structure. What collectively became known as the Malampaya field had proven reserves of 2.7 tcfg and 85 million barrels of condensate. Production from what is considered to be the world's first deepwater gas development started in 2002.

Prime Energy now operates the field where plans include drilling the Camago and Malampaya East production wells, along with the drilling of the Bagong Pagasa-1 exploration well. A 60 m oil rim in Camago-Malampaya was never developed and is now part of a separate contract with reserves estimated at 30 million barrels.

Despite a flurry of discoveries made in the early 1990s, nothing matched the size of Camago-Malampaya. One should expect more discoveries to be recorded in the 50 to 200 million barrels of oil equivalent range. Where are they?

West of Palwan, on the Reed Bank in the West Philippine Sea, the Sampaguita gas discovery deserves attention. Sampaguita-1 was drilled in 1976 by Salen Oil and encountered gas in Late Paleocene sandstones. Sampaguita, in some 80 m of water, is now operated by PXP Energy subsidiary Forum Energy. PGS had previously estimated gas in place to be approximately 2.7 tcfg and additional prospects and a deeper Cretaceous play offer running room. However, the licence has been under force majeure since 2014 due to the maritime dispute.

In the recent joint 1st Bangsamoro Autonomous Region in Muslim Mindanao (BARMM) Conventional Energy Bid Round and the 2024 Philippine Bid Round the Department of Energy (DOE) announced that they received applications for PDA-BP-1 (Cotabato Basin), PDA-BP-2 and PDA-BP-3 (both in the Sulu Sea Basin). Triangle Energy teamed up with PXP Energy, Sunda Energy and Philodrill for the two applications. The acreage was previously drilled by ExxonMobil and three deep-water gas discoveries were made in Late Miocene turbidites. Significant upside remains in the play, which is analogous to the Kutei Basin to the south in Indonesia and the NW Sabah Basin in Malaysia. ■

Ian Cross - Moyes & Co

Source digital elevation model: The GEBCO Grid

A welcome gas find

In a country that struggles to maintain its domestic gas production, ExxonMobil's offshore gas discovery in a poorly explored part of Egypt's western offshore is surely welcome news. But is it a new play, as some outlets wrote, or rather a play extension?

WHEN LOOKING at the oil and gas fields in the Western Desert of Egypt, and then read the article from Simon Baer and colleagues at PGS (GEO EXPRO Vol. 13, Issue 1, 2016), which describes how the narrow shelf in this part of western Egypt can potentially be linked to the onshore discovery trend, it is in a way a surprise to see that only now companies have started to firm this up.

As Zohr has probably started to decline, as well as many other mature gas fields onshore and in the Nile Delta, the timing was probably right for international companies to explore for gas in the country now, as the market is there and gas is badly needed.

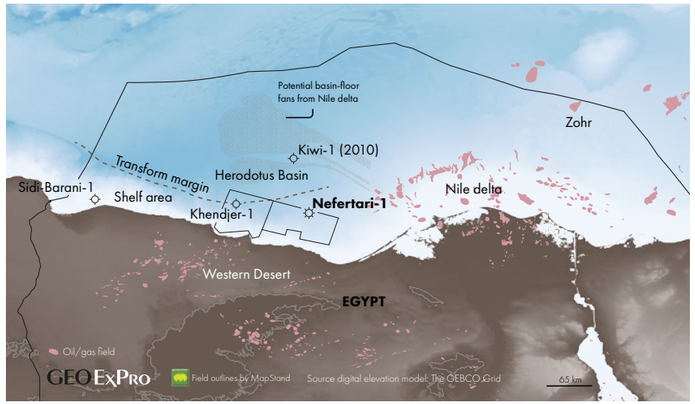
Alas, well Sidi-Barani-1 was drilled in the shelf area in 1976 already, but it is surely not on trend with the Western Desert finds. And Kiwi-1, drilled in 2010, targeted a different play altogether – Miocene sands – in the Herodotus basin, probably much younger than the reservoirs ExxonMobil now found to be prospective in the Nefertari-1 well.

As Simon Baer further describes in the 2016 article, the most common reservoirs onshore are in Lower Cretaceous Alam El Bueib and the Jurassic Khatatba formations. The seismic line shown here, which is from the shelf area shows these formations as well as a potential closure against a northwest-southeast trending fault that represents the general structural trend in the area.

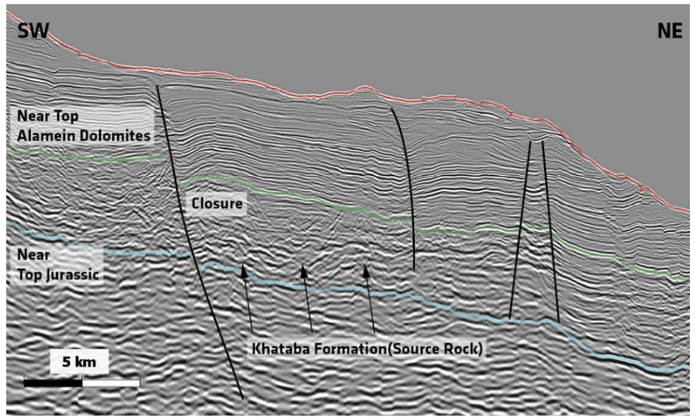
Will Nefertari-1 be the starting shot for more exploration in the area? Possibly, but it must be added that at the same time as ExxonMobil brought the good news, Chevron announced disappointing results at the Khendjer-1 well a little further to the west. Maybe stick to the Western Desert WSW-ENE trend a bit more?

And finally, is the well opening up a new play, as some media reported? Based on the literature we consulted, there could just as well be a chance that this well taps into the main play elements of the onshore Western Desert fields. If that is the case, there may be a long swath still to be explored. On the other hand, it would be equally interesting to know what the new play entails if it is indeed a new one. Time will tell. ■

Henk Kombrink



Map showing the location of the Nefertari discovery announced by ExxonMobil, and the dry well completed by Chevron (Khendjer-1), in the context of previously drilled wells in the offshore and other geological information. Please note that especially the Nefertari well was drilled in what some authors interpret to be the shelf area and not the Herodotus Basin. Sources: Fields - Mapstand, Geology - Baer et al. (2016), Licences - Mees.



Legacy seismic data example from the shelf area, an extension of the onshore Western Desert Basin with a proven petroleum system.

SOURCE: TGS

COVER STORY

"The addition of the three large recent discoveries, plus two with gas shows, markedly improves the exploration success rate and the estimated ultimately recoverable resources for the basin"

Andy Racey

COVER STORY

ACTION IN ANDAMAN

ANDY RACEY AND ANDY TAYLOR, WITH CONTRIBUTIONS FROM IAN CROSS, MOYES & CO, JAMIE HIGTON, WESTWOOD GLOBAL ENERGY, MIKE WHIBLEY, NAGA API RESOURCES AND ROB CHAMBERS, HOLT ENERGY ADVISORS

Recent exploration success in the southern part of the Andaman Sea has not only caused a stir in Indonesia but has also awakened renewed interest from its neighbours

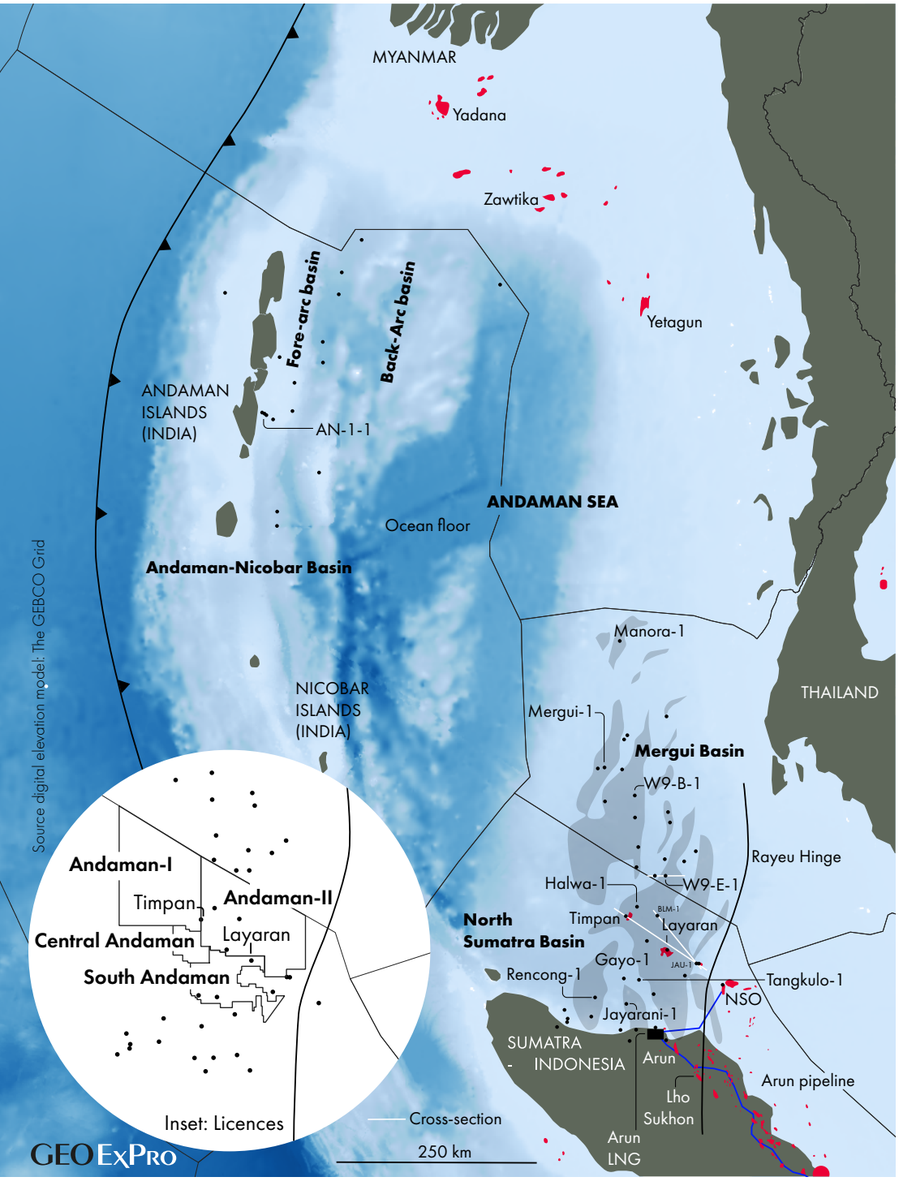
Outcrops of the Oligocene Andaman flysch. The keen observer could even distinguish some Bouma sequences.

BEFORE taking a dive into the past, recent and future exploration activity in the Andaman Sea, it is good to take note of an important above-ground advantage of the area. There are no country boundary conflicts. This is not because the entire Andaman Sea territory is claimed by a single country; there are four: Myanmar in the north, the Indian Andamans Islands towards the west, Thailand in the center and Indonesia in the south. This saves the area from major issues that other parts of SE Asia face, for instance, the nearby Thai-Cambodia Overlapping Claim Area.

The basin has a rich history of petroleum exploration, with Myanmar and Indonesia being more successful and Thailand and the Indian Andaman sector yet to celebrate their first commercial discovery. Despite the lack of commercial success in the latter two areas, the region is currently undergoing a renewed phase of interest following the announcement of the Tcf-sized Timpan discovery in the deep-water area of the North Sumatra Basin in early 2023, followed by the more recent Layaran-1 and Tangkulo-1 gas and associated condensate discoveries in the same area and play. This may encourage India to drill new wells near the Andaman Islands, with one of them currently operating, even though the geological setting is very different. It may also generate renewed enthusiasm in the Thai part of the geologically similar Mergui Basin.

What follows below is a brief overview of the Andaman Sea's petroleum geology, exploration history and future drilling plans. Most of the input is from Andy Racey and Andy Taylor, who have recently finished an extensive non-proprietary report on the petroleum geology of the southern Andaman Sea. This is supplemented with thoughts provided by Ian Cross and Mike Whibley. Finally, Rob Chambers provides some thoughts on how the recent discoveries around Timpan could be developed. ▸

COVER STORY



Since the recent exploration successes are solely in the south of the Andaman Sea, the focus of this article lies in the Indonesian and Thai parts of the basin.

GEOLOGICAL SETTING

The North Sumatra-Mergui Basin, which forms the southern Andaman Basin, is often referred to as a back-arc basin but is really developed in a dynamic transtensional tectonic setting. The onset of rifting started in the Late Eocene with associated volcanics and was followed by the deposition of a Lower Oligocene continental early syn-rift sequence. A major transgression in the Late Oligocene established the widespread late syn-rift deep marine clastic sequence. The Early Miocene subsequently marked the onset of inversion and regression with the deposition of shallow and deep marine carbonates. The Middle Miocene starts with renewed transgression and deposition of mixed shallow and deep marine clastic sequences. Subsequently, the uplift of the Barisan Mountains to the south in onshore Sumatra initiated the rapid deposition of a thick sequence of Upper Miocene to Pliocene aged marine clastic sediments.

DRILLING HISTORY

Drilling in the Andaman Sea area has been most prevalent in Myanmar and Indonesia. However, the first reports of oil and gas exploration in the Andaman Sea were in the late 1950s, when the Indian national oil company, ONGC, undertook surveying and mapping.

Approximately 112 wells were drilled offshore Myanmar, resulting in three producing gas fields in three different plays; Yadana, Zawtika and Yetagun.

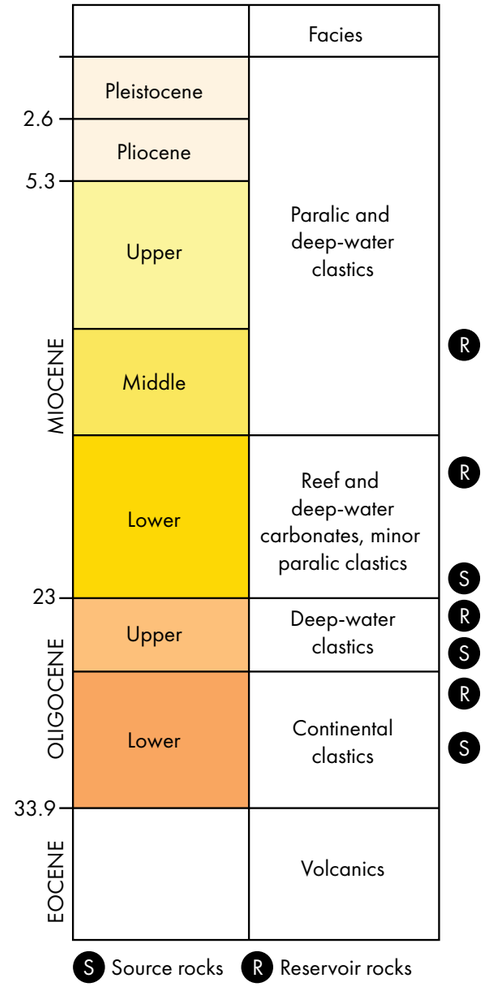
In both the Indian and Thai sectors, nineteen wells have been drilled in each so far. India's first exploration well, AN-I-I, was drilled in 1980 and was a small gas discovery, with another four wells reporting gas shows. In the Thai Mergui Basin, two untested gas discoveries were made with gas shows reported in a further five wells.

Drilling in the North Sumatra Basin resulted in the discovery of the giant Arun gas field onshore with around 14 % CO_2 and the Lho Sukhon and North Sumatra Offshore (NSO) fields, all within Lower Miocene carbonate reservoirs.

PHOTOGRAPHY PREVIOUS PAGE: MIKE SEARLE

In the northern part of the North Sumatra Basin, most of the large tested traps are stratigraphic and include Lower Miocene reefs on structural highs such as the Arun and Lho Sukon fields. Sandstone pinch-outs and drapes over structural highs and roll-over structures associated with growth faults and shale diapirs have also been tested. It has previously been assumed that vertical migration is required, and therefore, many of the structures drilled to date have been located on highs close to large faults, which are assumed to tap into the inferred deeper source kitchens.

Prior to the recent phase of exploration activity, around 20 wells had been drilled in the offshore North Sumatra Basin, west of the Rayeu Hinge, resulting in four minor gas discoveries, one small oil and condensate discovery and four wells with gas shows in an area of around 60,000 km^2. The addition of the three large recent discoveries, plus two with gas shows, markedly improves the exploration success rate and the estimated ultimately recoverable resources for the basin.



Simplified stratigraphy and facies diagram for the North Sumatra and Mergui Basins, Southern Andaman Sea. Redrawn after Racey & Taylor.

NORTH SUMATRA BASIN RECENT EXPLORATION

Where legacy exploration in the North Sumatra Basin previously mainly focused on Miocene reefs, more recent exploration efforts have targeted the Upper Oligocene Bampo Formation turbidite sandstones with a reported gross potential of 12 Tcf gas and 400 MMbbls condensate. This did not come out of the blue; flat spots had been observed in 2D seismic lines across the area for a long time, but the deep-water nature and the risk of elevated CO_2 levels, such as observed onshore Sumatra, delayed their drilling.

Timpan-1 was ultimately drilled in July 2022, and because of the associated flat spot it was considered by Harbour to be an "appraisal well" with a 70 % chance of success. Indeed, the well encountered a 119 m gas column and flowed at 27 MMscfgd and 1884 bpd of condensate and represents a 1.4 Tcf discovery. The reservoir comprises high net / gross fine-grained sandstones.

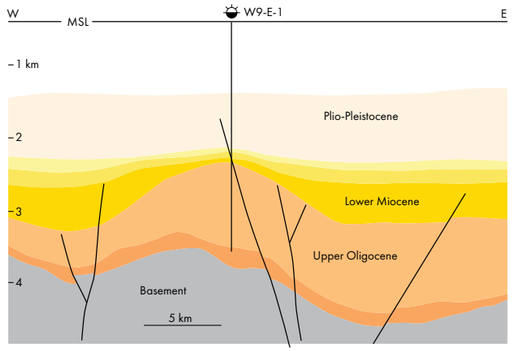
The much-awaited Rencong-1X wildcat was spudded just before Timpan-1 in the Andaman Block III PSC. The main play in this PSC, originally awarded to Talisman in 2009, was considered to be Upper Eocene to Oligocene carbonate build-ups. However, the well came in dry, which caused Repsol and PETRONAS to exit the North Sumatra Basin in August 2023.

The second well on the same clastic turbidite play as Timpan was Layaran-1, which encountered a 230 m gas column in the same sandstones that flowed gas at 30 MMscfd and is estimated to have a GIIP of 6 Tcf.

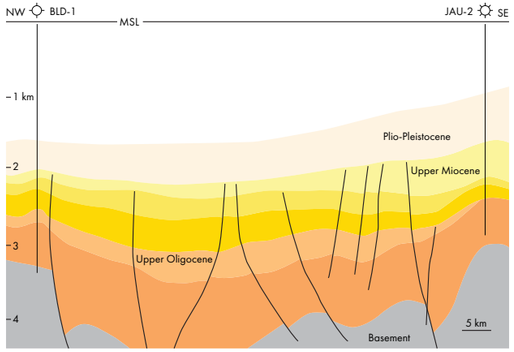
The third well, Gayo-1, identified a good gas column at the same level but of poorer reservoir quality. Subsequently, Halwa-1 encountered only gas shows but had good reservoir quality. At the Halwa-1 location, a fault runs from the target reservoir almost to seabed, where a bright spot can be seen in the seismic. The main risk was, therefore, around the presence of commercial quantities of gas deeper down, which now seems was not the case with trap breaching being the main potential issue. The most recent well, Tangkulo-1 drilled in the Andaman South licence, flowed 47 MMscfgd and 1,300 bcpd.

These recent exploration results indicate that the concerns about CO_2 were unfounded, but reservoir quality, especially permeability and chlorite cementation, remains an area of concern. Based on trends in reservoir quality, it now appears ▸

COVER STORY



Geoseismic section for the Mergui Basin and the W9-E-1 well that had minor hydrocarbon shows.



Geoseismic section for the North Sumatra Basin, showing the BLD-1 dry well and the JAU-2 undeveloped gas discovery.

that reservoir quality could get better in a westerly direction.

Further wells are planned over the next few years.

MERGUI BASIN EXPLORATION

Adjoining and contiguous with the North Sumatra basin to the north is the offshore Mergui Basin in Thai waters, which has an areal extent of around 50,000 km^2.

Exploration activities in the Mergui Basin is broadly divisible into two phases. From 1974 to 1979 Esso and Unocal acquired 2D seismic data and drilled 10 wells, resulting in two untested gas discoveries (W9-B-1 and Mergui-1). Esso drilled five wells in 1975 - 1976, while Unocal drilled a similar number around the same time.

From 1983 to 2000, additional seismic data were acquired and nine further wells were drilled, three by Placid Oil in 1987, five slimhole (mostly shallow) wells by Unocal in 1997 and one well by Kerr McGee in 2000 (Manora-1), which was the last one to be drilled in the Thai sector of the Andaman Sea. The Manora-1 well was a commitment well, and because Kerr McGee was keen on exiting the basin, rumour has it that the Manora prospect was selected quite haphazardly.

The main play tested to date in the Mergui Basin is similar to that seen in the North Sumatra Basin and assumes the presence of Oligocene Ranong Formation source rock in the grabens charging Miocene carbonates and clastics on basement highs sealed by younger mudstones. None of the wells drilled in the Thai sector reported any CO_2 associated with the gas.

Remaining hydrocarbon potential is likely to be limited to deeper water (>1 km) areas closer to the main thermally mature depocentres, with gas the most likely hydrocarbon type and source potential and charge effectiveness being the principal risks. The recent discoveries on the Indonesian side of the border suggests that the current geological model needs revising in terms of reservoir type and distribution.

The Mergui Basin is currently unlicensed with no exploration activity since 2000. Speculative non-proprietary seismic surveys are not allowed in Thailand, which limits the chances for the acquisition of new multiclient data. However, it is understood that PTTEP shot some newer proprietary 2D lines recently in the East Andaman Basin.

MYANMAR AND INDIA

Further north, in Myanmar, three main proven plays exist. In the Yadana field, thermogenic gas is produced from Lower Miocene shallow marine carbonates; biogenic gas is produced from Plio-Pleistocene shallow marine deltaic sandstones in the Zawtika Field - related to Ayeyarwaddy delta coming from the north - and thermogenic gas with condensate is produced from shallow marine sandstones shed from the peninsula to the east of the Yetagun Field. To the west of the Andamans, along the Rakhine coast, biogenic gas is produced from Pliocene sandstones in the Shwe / Mya complex of fields. Western companies have mainly pulled out of Myanmar because of the political situation.

The Indian sector of the Andaman Sea is characterised by a very different geological setting compared to Indonesia and Myanmar, as it sits mainly in the forearc basin of the Indian plate accretionary system and is impacted by distal sediment input from the Ganges-Brahamputra and Ayerawaddy deltas to the north.

As mentioned above, 19 wells have already been drilled in the past, but Oil India recently announced that it will spud three more, with one already drilling as we go to print Mid-February. There is limited further detail available, but the team at Westwood anticipates that the most likely prospects are Paleocene to Oligocene deep marine sands deposited in the accretionary wedge. Miocene carbonates on the highs could be another target.

In addition, Westwood also anticipates one deep-water well for ONGC in the Andaman Back-Arc basin, just south of Myanmar territorial waters, that will likely target plays similar to the syn-rift Lower-Middle Miocene clastics of the Yetagun Field, or the post-rift Upper Miocene-Pliocene deep marine clastics of the Zawtika field.

DEVELOPMENT SCENARIOS FOR THE RECENT GAS DISCOVERIES AROUND TIMPAN

The Andaman Sea has long been discussed as a frontier area with potential, and there will be companies looking at the recent success and asking, “Why weren’t we part of this?” and "Can we be part of this now?".

Mubadala and Harbour are the main incumbents, holding the majority of the current Andaman acreage. We saw both companies further cement their presence by signing a PSC last year with the Indonesian government for the Central Andaman work area. This work area covers acreage previously relinquished from the South Andaman PSC. bp is the other company currently involved, with a 30 % stake in the Andaman-II PSC that they acquired from KrisEnergy in 2019.

One potential way for a company to enter the area is through M&A. Either of, or both, Mubadala and Harbour could look to dilute their interests, especially if the new partners bring deepwater and LNG experience. For bp, they could look to be central to any development, or they may look to exit for a nice profit.

Another option for entry would be the acreage previously covered by the Andaman-III PSC. This was relinquished by Repsol and PETRONAS in August 2023 following the drilling of the Rencong-1 exploration well that came up dry. For this option, we will need to see how SKK Migas offers this acreage.

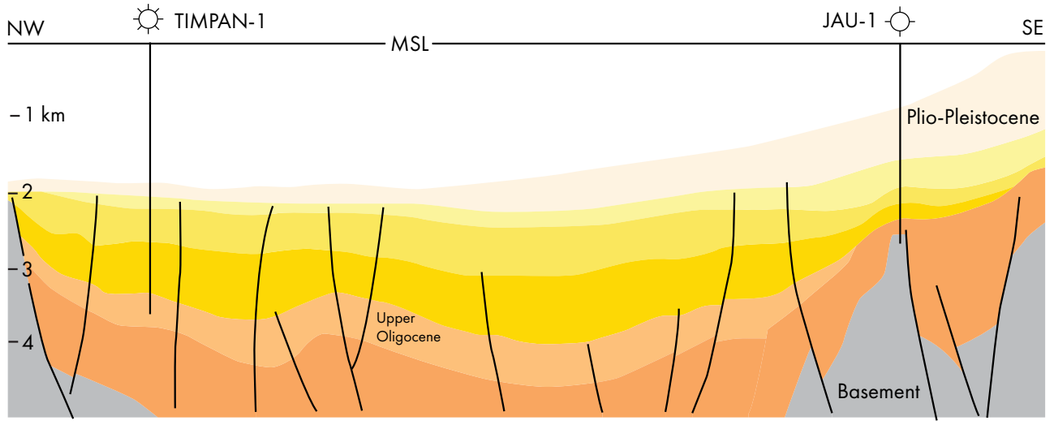
Given the potential scale of the development, there will inevitably be political interest, with one of the remaining issues being the end market(s) for the gas. Indonesia would like as much of the gas as possible for the domestic market, but the current infrastructure is limited. The Arun pipeline that could carry the gas south into Central Sumatra is understood to have a current capacity of about 300 MMscf per day. Other options for pipe gas include Singapore or Malaysia, with both countries likely to show an interest given rising domestic demand and high LNG prices.

Another option would be LNG, which may offer access to better prices. There is existing LNG infrastructure at Arun in North Sumatra. However, the plant has been mothballed for a number of years and is unlikely to be easy (or cheap) to reactivate. Other LNG options could include a new onshore LNG plant or and offshore LNG vessel (FLNG) could also be considered.

As hinted at above, domestic gas pricing is another challenge for the development, with Indonesia wanting to cap gas prices for industrial use at $ 6 to 6.5 per MMbtu. This means that Harbour and Mubadala are likely to be keen to export as much of the gas as possible given the higher price point that could be achieved.

We may see an eventual development based on a compromise, with both domestic gas commitments through the existing Arun pipeline and LNG exports. Whilst this works on paper, the details will need to be ironed out and, as we have seen elsewhere in Indonesia, this is not always a simple or quick process.

If FID was taken today, we could see first gas as early as 2028 / 2029. However, as we have seen, there are plenty of issues that need to be resolved before FID. In addition, Mubadala and Harbour may look to further appraise the discoveries or drill further nearby prospects. Given all of these factors, a more realistic target for first gas would be 2030 - 2032. ■

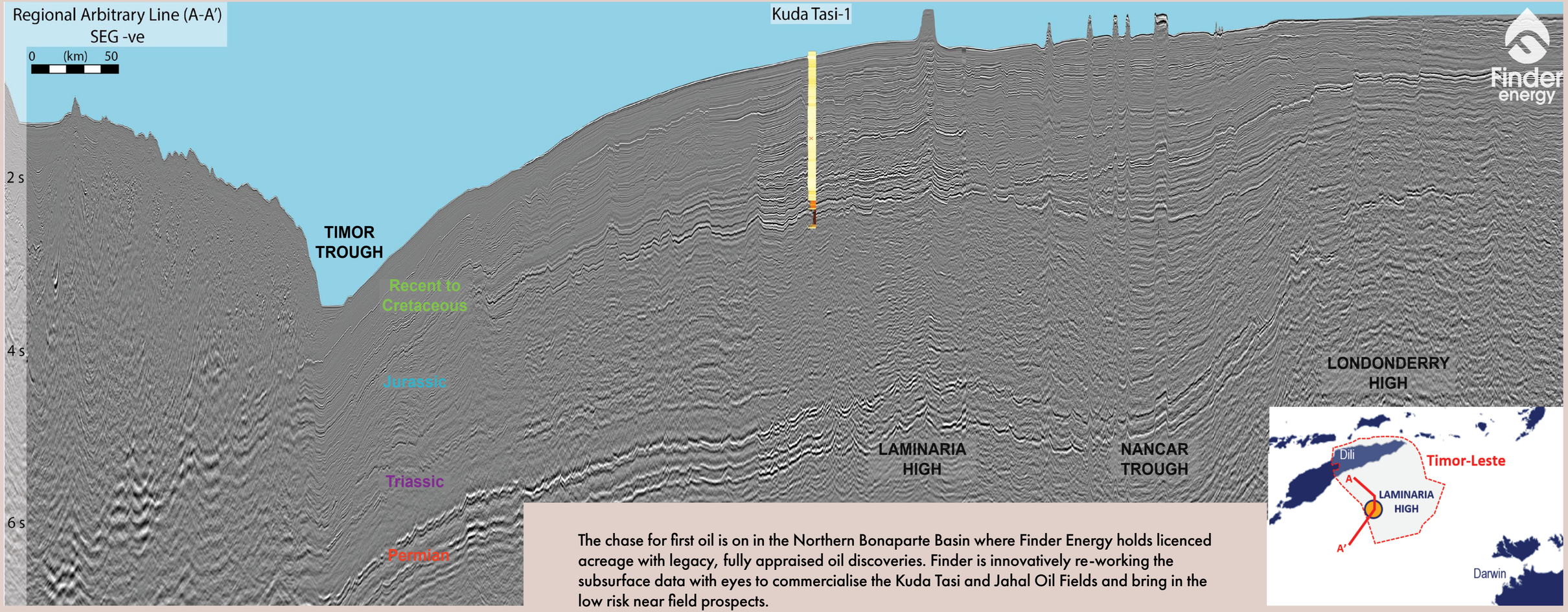


ILLUSTRATIONS: REDRAWN AFTER RACEY & TAYLOR

Geoseismic section for the North Sumatra Basin, showing the Timpan gas discovery.

The path to commercial oil:

Developing the Kuda Tasi and Jahal discoveries offshore Timor-Leste



The chase for first oil is on in the Northern Bonaparte Basin where Finder Energy holds licenced acreage with legacy, fully appraised oil discoveries. Finder is innovatively re-working the subsurface data with eyes to commercialise the Kuda Tasi and Jahal Oil Fields and bring in the low risk near field prospects.

Continuing the exploration and development success of the Laminaria High

In 2024, Finder Energy underwent a transformational change, acquiring the rights to develop several oil discoveries on the Laminaria High in the northernmost Bonaparte Basin, Timor-Leste. Previously, the successful global explorer focussed on finding oil and gas by leveraging its innovative exploration skills and experience. These skills, along with smarter seismic imaging will allow Finder to reduce subsurface uncertainties and combine the discovered oil pools into the new Kuda Tasi-Jahal development hub, targeting first oil within three years

AARON BOND AND SHANE WESTLAKE, FINDER ENERGY WITH ACKNOWLEDGEMENTS TO NEIL HODGSON AND LAUREN FOUND, SEARCHER, FOR THEIR INPUT

THESE DISCOVERIES were made in the late 1990's and early 2000's, and the availability of technology, both in imaging and in development concepts, has changed so much since then. Finder's transition from explorer to a highly profitable producer requires the energy, commitment and experience that Finder have in spades working together with the very supportive and knowledgeable Timor-Leste regulator, ANP and joint venture partner TIMOR GAP.

LAMINARIA HIGH – A PROLIFIC OIL PROVINCE

PSC TL-SO-T 19-11 (PSC 19-11) is located within the prolific oil province of the Laminaria High in the Bonaparte Basin. The Laminaria High is a major intra-basinal high flanked by lows; the Sahul Syncline and Nancar Trough to the southwest and south and the Flamingo Syncline to the east. Historically, The Laminaria High area has had an excellent exploration success rate, with 17 oil discoveries from 35 exploration wells. This has led to over 290 MMbbls of oil being produced from the six oil fields on the high (Figure 1), yet a lot more discovered oil remains undeveloped. Sub-sea technology improvements and cost optimization, in conjunction with a strong and steady oil price and good fiscal terms, will allow these stranded reserves to now be developed commercially.

The whole area under Finder's PSC 19-11 is covered by the legacy Ikan 3D survey. The seismic data is structurally very clear and shows "piano key" horst and graben structures, bounded by linear fault systems (Figure 2).

The primary hydrocarbon play for the area is the excellent quality Middle Jurassic Laminaria and Plover shallow marine fluvio-deltaic reservoir sandstones sealed by Upper Jurassic marine shales of the Frigate and Flamingo Formations (Figure 2). Hydrocarbon charge is from the Early-Middle Jurassic Plover Formation carbonaceous shales and coals.

The regionally extensive Laminaria/Plover sandstone provides a strong aquifer drive for the oil fields in the region. This, together with the excellent high API gravity and under-saturated oil, leads to favourable water flood mobility and good sweep, leading to high recovery factors with up to 65 % proven at the Laminaria Field.

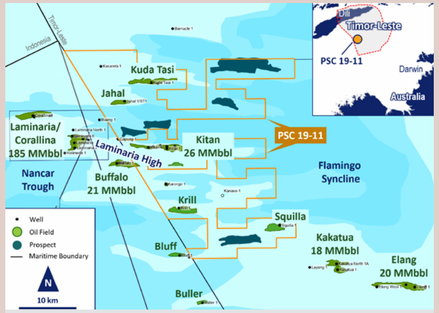


Figure 1. Location map showing producing and undeveloped oil fields and prospects.

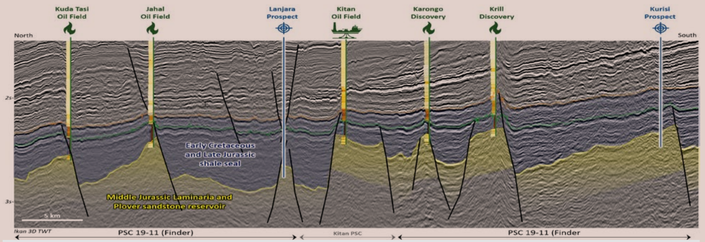


Figure 2. The existing Ikan 3D time data is of good quality for structural interpretation and field definition. Reprocessing will enhance the data in the southern extent and unlock the appraisal and prospective upside.

PSC 19-11 – DEVELOPMENT READY

Historical drilling with PSC 19-11 has seen seven exploration wells drilled with five discovering light, low GOR 55° API oil within the Laminaria Formation sandstones. The Jahal-1 (1996) and Kuda Tasi-1 (2001) discoveries in the north of the PSC have also undergone further appraisal with a total of five well intersections within the reservoir, proving up 22 MMbbl of 2C Contingent Resources.

Jahal-1 discovered a 10 m gross oil column within an east-west orientated tilted fault block structure. The following updip sidetrack well intersected a 33 m gross oil column which later flowed 1,350 BOPD on test. Kuda Tasi-1, located 6 km to the northeast intersected a 17 m gross oil column within an E-W trending normal fault and dip closure to the west, east and north. The up-dip Kuda Tasi-2 appraisal well intersected a 39 m gross oil column which flowed 55° API oil at a maximum rate of 5,200 bopd which was equipment constrained.

The comprehensive well datasets, along with the 2005 Ikan 3D seismic survey, which provides full coverage over the entire PSC, enables Finder to rapidly progress the development planning and production of the 22 MMbbl of Gross Contingent Resources. The fields, which are located in 400 m of water will be developed via sub-sea wells tied to a central FPSO.

A number of re-deployable FPSO's have already been identified by Finder which will allow quick development timeframes. High flow tests on Kuda Tasi-2 demonstrate superior reservoir performance due to excellent Laminaria Formation reservoir parameters such as porosity (11-13 %) and permeability (100s -1,000 mD). The regionally connected aquifer also provides high pressure support which leads to high recovery factors. Reservoir models show initial production rates in the range of 25,000 - 40,000 bopd, depending on FPSO facility constraints. Excellent production rates have been proven at the adjacent analogue Laminaria/Corallina, Kitan and Buffalo oil fields, all which produced from the same reservoir.

UPSIDE

In addition to the initial Kuda Tasi-Jahal development, there is significant upside potential within the PSC, with both Squilla-1 (1991) and Krill-1 (1994) finding a further combined 23 MMbbls 2C Contingent Resource. There are four other low-risk, near-field prospects with a combined 116 MMbbl Mean Prospective Resource identified on the Ikan 3D. These all provide opportunity to either tie-back to the FPSO, or alternatively once the Kuda Tasi and Jahal project is depleted, move the facilities, extending the life of the project and growing the value with low-risk exposure.

Finder is rapidly progressing through the Project Concept Select phase workstreams with key studies, including engineering, well design and subsurface technical and engineering modelling. Part of the technical workstream is reprocessing the Ikan 3D, which hasn't been processed in its entirety in nearly 20 years. Finder, along with its reprocessing project partners Searcher and Eif GeoSolutions, are all highly experienced in high-end modern PSDM reprocessing technologies. These include broadband de-ghosting and full waveform inversion to enhance subsurface imaging.

The original seismic data acquisition is of good quality yet does degrade slightly in the southern area where water depth decreases to 100 m and sea floor shoals are also present. The main objectives of the reprocessing project will be to enhance mapping of Kuda Tasi and Jahal to optimise placement of development wells to maximise production and recovery, and to derisk the appraisal potential of the Krill and Squilla discoveries and exploration prospects.

The future is bright for the undeveloped fields on the Laminaria High, and that will bring revenue and business growth to the people of Timor-Leste. For Finder Energy, this will demonstrate a transition from explorer to oil producer, providing the commitment and experience that will bring the long-awaited commercial success to all the partners involved. Finder is seeking a partner to join the company in developing the Kuda Tasi and Jahal oil fields.

OIL & GAS

"Too often, companies apply a uniform risking model between the P90 and P10 contours. However, this approach does not represent the changing geological risks at all, and it is, therefore, mixing segments that each have a different risk profile"

Iain Longley – GIS-Pax

Fault-valve behaviour of petroleum traps

Along-fault fluid flow at a critical segment of a fault can eloquently explain the initial reservoir pressure and hydrocarbon column height in a fault-bound trap. Episodic fluid expulsion at this fault-valve therefore provides a dynamic addition to a traditional view that fault-bound traps are only controlled by across-fault fluid flow

ARJAN BREM, STRUCTURAL GEOLOGY CONSULTANT

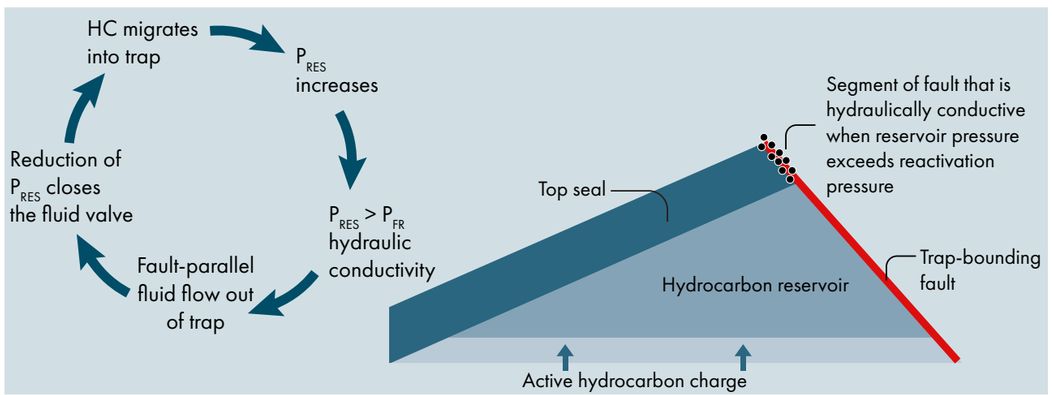
When evaluating fault-bound traps, it is common practice to map around-the-fault pathways through diligent seismic interpretation, juxtaposition diagrams, and 3D structural framework construction. It is also common practice to address across-fault sealing and evaluate hydrocarbon column heights by using industry-standard clay-smear algorithm correlations. Yet, quantifying along-fault hydraulic conductivity through fault-reactivation pressure is rare in trap evaluation, despite faults being considered as migratory pathways.

Fault reactivation pressures are calculated using the critically stressed fault concept related to shear failure. This geomechanical concept was applied in a study on an underfilled fault-bound oil field off the coast of Sabah, offshore Malaysia. The primary fault extends near the seabed, and the quality of seismic imaging above the crest of the trap is diminished. This reduction in image quality is interpreted as indicative of a gas cloud. The study identified a connection between the initial reservoir pressure, the hydrocarbon column height, and the fault reactivation pressure on a critical segment of the fault near the crest of the trap. Furthermore, the fault reactivation pressure is lower than the minimum horizontal stress.

It is hypothesized that an increase in reservoir pressure at the critical fault segment can trigger fluid flow along the fault and out of the trap. The cyclical nature of this dynamic behaviour is referred to as fault-valve after Sibson's original model published in 1990. In an active petroleum system, it forms a credible way to explain fluid release from a trap in addition to the other pathways mentioned above.

Recognizing that along-fault fluid flow can control the hydrocarbon column in a trap is not new. However, applying the critically stressed fault concept to evaluate fault-bound traps is rarely done. Reasons for this may be that the concept is not appreciated by all geoscientists. Also, many integrated subsurface software packages do not carry a fault reactivation module in their fault interpretation or structural framework section. Lastly, there is significant uncertainty associated with fault strength parameters, which may be considered too wide to yield meaningful results.

The critically stressed fault concept and its related fault-valve model are considered viable trapping mechanisms, impacting existing exploration, appraisal and production projects. This is particularly relevant when recognizing that preferentially oriented faults have the potential to leak at fluid pressures below the minimum horizontal stress. ■



Mixing models madness

Applying a uniform risk model does not work for most hydrocarbon traps because often there are multiple sealing mechanisms at play

With most prospects, multiple trapping elements contribute to the potential size of the discovery. For instance, a prospect can be a four-way at the top of the closure, but may be dependent on fault sealing deeper down. This change in geological control needs to be properly addressed when risking volumes pre-drill.

Let's take a look at an example that is loosely based on the Jubilee field in Ghana, where the trap is a combination of a small four-way, fault-seal, reservoir pinch-out and dip closure. How do companies tend to risk the volumes in a prospect of this kind?

Too often, companies apply a uniform risking model between the P90 and P10 contours. However, this approach does not represent the changing geological risks at all, and it is, therefore, mixing segments that each have a different risk profile.

SEGMENTS

Rather than using a uniform approach from P10 to P90, it is much better to create segments that are characterized by a single geological variable. That way, each segment can be risked differently, which is sensible because the geological factors are changing from one to the other.

In the example shown here, area A is just dependent on a four-way closure; segment B includes the fault, segment C adds the pinch-out on the east side of the prospect, and finally, segment D includes the pinch-out to the west. As such, the risk profile changes moving from segment to segment.

Obtaining a risked mean volume in this way reduces the volume of this particular prospect by 37 %, from 329.9 to 207.9 MMbo. Maybe that is not what explorers prefer, but this is much better in line with the geological risks nonetheless.

TOP SEAL INTEGRITY

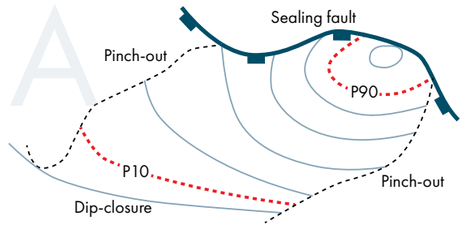
Finally, there is another element that needs to be introduced here, and that is the top seal risk. In this example, some of the more positive outcomes imply a column height of 750 m, which is fine when talking about a salt seal, but with clastic seals, there is probably a seal limitation capacity, which also needs to be evaluated.

This needs to be built in, especially when we are dealing with a non-marine seal that is typically unable to contain large columns. In that case, the mean risked volume is even completely dominated by the seal capacity, and reduces to 104.7 MMbo. ■

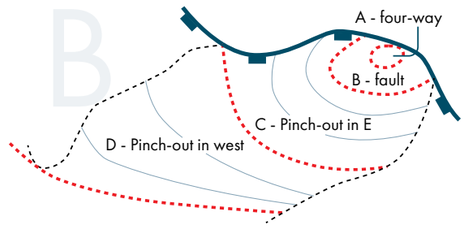
Henk Kombrink

GIS PAX PLAYER

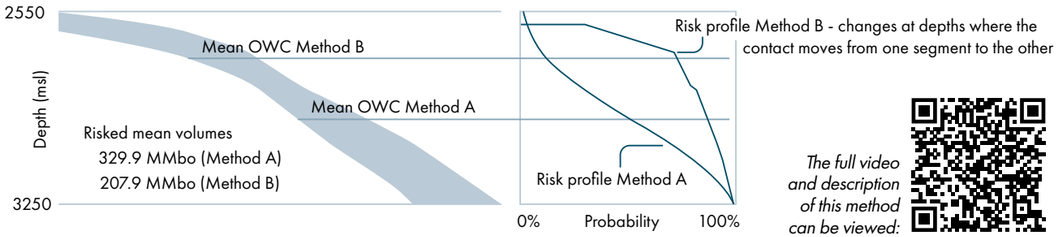
This is the first of a series of articles based on work and experience from the GIS-Pax team in Australia, as presented by Ian Longley in a series of videos on LinkedIn.



The P90-P10 method assumes one uniform model to risk volumes, regardless of the changes in geology with deepening the contact



Each segment has a different risk profile as the contact deepens, honouring the geology



The full video and description of this method can be viewed:

Oil in porous intrusive rocks

In contrast to the relatively common occurrence of hydrocarbons in fractured basement, a well drilled in Oman has found oil-bearing intrusives that rely on matrix porosity

BASEMENT plays are found in quite a few areas globally and have been well studied and reported on. Norway, Yemen, Vietnam and China are amongst those places where oil is being produced from granites buried beneath source and overburden rocks. In all these cases, it is either fractures or a granite wash resulting from extensive subaerial weathering that is behind the formation of reservoir potential.

It is less common to find hydrocarbons in crystalline rocks that lack a phase of fracturing or subaerial exposure and weathering. Yet, an example has now been found.

In a well drilled in Block 56 in southern Oman, a series of Late Neoproterozoic alkaline intrusives was found in the Huqf Supergroup. In addition, it was shown that these rocks contain hydrocarbons.

The igneous bodies were found to occur as both discrete and composite, decameter-scale sills separated by intervals of Huqf host rocks. Compositionally, they form a cogenetic suite of monzonites and syenites that can be related by fractional crystallization to a gabbro-diorite parental magma. Enrichment in alkalis and other large ion lithophile elements points to either an enriched mantle source or magma-crust interaction as the magma rose.

The geochemical profile of the intrusives closely matches similarly-aged Neoproterozoic alkaline eruptives, which are now found as exotic volcanic blocks entrained in the salt diapirs of the Ghaba Salt Basin. It is, therefore, thought that the Block 56 intrusives and the contemporaneous extrusives are derived from the same magma source.

Porosities in excess of 10 % have been recorded in the intrusives. Rather than fracturing or subaerial exposure, in this case, the pore space was probably formed by dissolution as the primary ferromagnesian minerals were converted to biotite and ferroan dolomite. A short-lived, fault-controlled Cretaceous hydrothermal event contemporaneous with uplift and alkaline volcanic activity in the Masirah Ophiolite further north in the country is interpreted to be the driver for this.

The main question regarding the potential of the intrusives to act as a producing reservoir is the permeability of the rocks. As no permeability measurements were obtained, this still needs further work. However, with oil being proven in succession, some form of permeability likely exists, as migration into the rocks must have occurred at some point. It is, therefore, worth considering these intrusive rocks as a candidate for unconventional production. Not only in Oman but possibly elsewhere, too. ■

Henk Kombrink

PHOTOGRAPHY: CORLAFFRA VIA ADOBE STOCK

Mobile drilling rig in the Omani desert.

The intrusives contain a Huqf-sourced oil with a light to medium viscosity appearance. Charging is believed to be coming from the cooler and shallower parts of the South Oman Salt Basin to the north and from beneath thick Tertiary cover in the basin to the south.

The writing was on the wall

It seemed like a matter of time until Shell came out with the news about writing down an oil discovery in Namibia

On January 8, 2025, Reuters broke the news that Shell has written off a $400 million exploration investment over "an oil discovery" in PEL39 in Namibia's deep-water area. Even though a field name was not mentioned, it likely relates to the Graff discovery.

Is it a surprise this has happened? No. The writing was on the wall for a while, as Wael Sawan already hinted at subsurface challenges.

Ultimately, it is the geology that determines whether or not a discovery can be economically developed, and it is the geology that has proven to be too complicated to make it happen in the end. At least, for now.

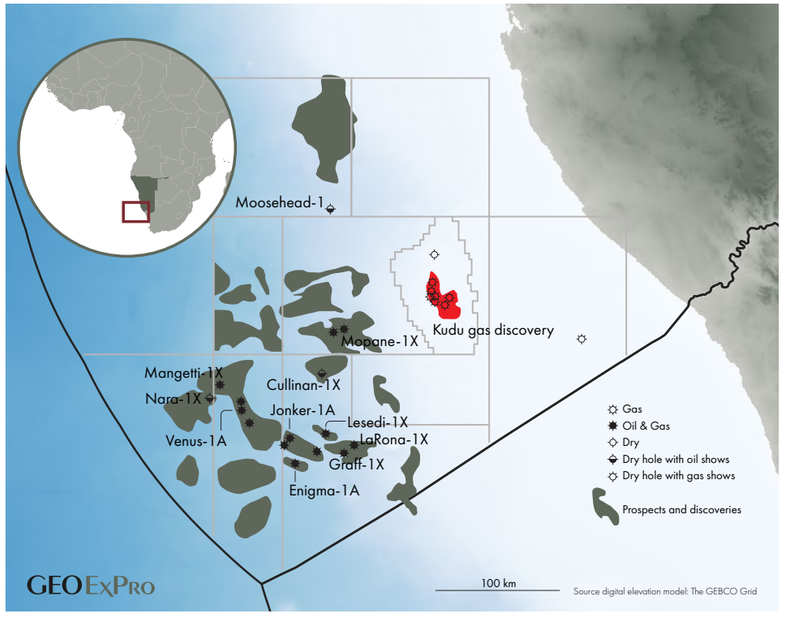
SUBSURFACE CHALLENGES IN NAMIBIAN DEEP-WATER DISCOVERIES

There are two major aspects to the subsurface challenges that the Namibian deep-water discoveries are facing. The first is the presence of chlorite, which can be detrimental in terms of clogging up the pore space, and therefore reducing the permeability of the reservoir. I spoke to Richard Worden from Liverpool University about this last year (GEO EXPRO Vol. 21, Issue 5, 2024). It is probably the presence of volcanic detrital material within the reservoir that has facilitated the anomalous growth of chlorite in the Namibian reservoirs. Marcio Mello, speaking at the IMAGE Conference last year, hinted that the reservoir quality was improving further to the north, so maybe the Mopane reservoir does not suffer from chlorite cementation to the same extent. The question, of course, is how bad it is at Venus, which lies west of Graff, and could have had the same sediment influx.

Then, there is the gas. As some people have said, the oil in some of the Namibian discoveries is close to bubble point, which means that the gas will come out of solution straight away once production starts, and the pressure in the reservoir starts to drop. Dealing with this right from the start is a big difference from a situation where gas becomes an issue later down the line. For instance, in Guyana, oil could be produced first before a gas solution was required, and that is now being worked on. The same holds for Baleine in Côte d'Ivoire, where the GOR is supposedly low, enabling the operator to first focus on oil production. This may be one of the reasons, in addition to the chlorite problem, that has thus far prevented companies from giving the go-ahead, because the engineering solution is more costly, especially given that this is deep water.

All in all, this is quite a blow for Shell, but even more so for Namibia, not the least because of the hype that the initial exploration results generated. This then poses the question: What about the other discoveries in the area? I don't think these are plain sailing either, even though TotalEnergies seems to move forward, working on a development concept for Venus, as well as exploring the wider area through drilling of the Tamboti-1X close to Venus at the moment. I'm holding my breath on this one, as well as on Mopane. ■

Henk Kombrink



FEATURES

"The times of gurus telling younger staff how to plough through a seismic volume and what to interpret is over"

Herman van Nieuwoudt – Bluware

How AI helps democratize seismic interpretation

If one thing transpired from a conversation with Herman van Nieuwoudt and Morten Ofstad from Bluware, it is that AI helps break down barriers between the younger and older generations

"THE TIMES of gurus telling younger staff how to plough through a seismic volume and what to interpret is over," says Herman van Nieuwoudt from Bluware. Herman started as the company's President in November last year, after a long career mainly with Baker Hughes in which he spent time in numerous countries across the world. "With the current advance of how specialists can interact with interpretation software, such as the InteractivAI tool we have been developing, everybody can do the job quickly. It generates a whole new working environment which fosters collaboration more than anything else," Herman adds.

Morten Ofstad, who has been with Bluware for more than 20 years in various software development roles and is currently their Chief Software Architect, corroborates this: "As we have such a fast way of performing an interpretation, it is now very straightforward to have the same survey analysed by a couple of people, after which the results can be compared. This not only generates fruitful discussions amongst geologists in the company, but also has the potential to lead to an even better final interpretation that is agreed on by everyone."

Herman van Nieuwoudt

Morten Ofstad

"The times of gurus telling younger staff how to plough through a seismic volume and what to interpret is over"

IT'S ALL ABOUT EMPOWERING GEOSCIENTISTS

"It's all about empowering the geoscientist," says Morten when we get to talk about how the software – that has now been patented - works. "We start with a clean slate machine learning model and then begin adding labels to the seismic indicating what you are looking for. For instance, you interpret a fault, which is the labelling aspect, and subsequently tell the machine that it needs to find similar features throughout the seismic cube. You then have two options – either to reject what the machine came up with, or to accept what it did."

This iterative approach allows the algorithm to learn from the interpreter in real-time. This process is much faster than interpreting the entire dataset by hand, but it also means that there is no fixed way in which the machine populates the seismic – it is still driven by what the geoscientist sees as the best way to interpret features observed.

Herman further strengthens this point. "Observations made by the geoscientist are still at the basis of our approach. Only in that way," he says, "we ensure that people will be able to tell a convincing story when they talk to management about their findings. The only difference is that once a training model exists, the computer will be able to interpret large areas fast. Data is the base-rock of what we do, not models."

"Because we start with a clean slate and tell the model what to recognize, we are not limited to interpreting faults – we can tell the machine to recognize any feature in the seismic dataset and it will return similarly shaped features throughout," Morten continues. "I have even seen people using the software for things that we did not really anticipate. We don't even have a complete picture of all the capabilities of the tool. But that is only a positive thing."

"What I do know is that the software is being used for velocity model building. The advantage of that is that when you have a newly migrated volume, you can apply the same model without redoing the interpretation. Sure, you might want to update in places, but the framework is already there," Morten says.

And it is not only the computationally fastest machines being able to do this. "In order to overcome computational issues when working with large volumes of data, the software creates smaller and random sections from the volume to perform its computations," says Morten. "This technology enables people to work with surveys of any size, because it is the random smaller subsets that the algorithm uses in each time step, limiting the computational power needed."

HOW DOES THE MARKET LOOK?

"It is very important to realize how seismic data is being looked at in different parts of the world," says Herman. "For people in the Middle East, touching their seismic data is like touching their sovereign wealth. In contrast, for people in the US, seismic is just a way to make more money, faster. It is these two very different mindsets that we have to navigate in, and all the other possibilities in between," he adds. "It requires a different way of marketing the product wherever you go."

Herman is open about where the centre of gravity lies when it comes to where his company finds its customers. "Oil and gas remains the backbone of the market. At the same time, Bluware is also moving into the CCS and geothermal spaces. Not missing a fault whilst de-risking a carbon store is critical, and running our software means that interpreters can be more confident that they haven't done this," says Herman.

"For us, our growth areas are those where there is ample exploration and development ongoing," continues Herman. "In that sense, it is not a surprise to see that we are focusing on the Middle East and South American regions, obviously without losing sight of other areas."

Bluware has been part of the CMG Group since 2023. And late last year, Sharp Reflections joined too. "This has created lots of opportunities," says Herman, "with the ultimate goal to create an entire seamless seismic to economics workflow. With improved data from Sharp Reflections, it enables our customers to do even better and more accelerated interpretations. Applying multi-volume training to different 4D outputs would further add value to production departments."

SURPRISES

"We are positively surprised to see customers using the tools in ways we had not foreseen, which is only a good thing of course," concludes Morten. "That's all down to the fact that you don't have any pre-training; it enables geologists and geophysicists to play with the seismic in so many ways. And it is not limited to seismic alone," he says; "we have seen people use the algorithms on CT scans of cores to see how much of a certain rock type occurs in a conglomerate."

"Our main focus right now," concludes Herman, "as we have proven the concept of the technology, is to make sure that it fits into people's workflows with other software they use. Also, you don't always start with a blank slate, as people may have some interpretation already which they want to use. It's important to keep that in mind, too. But across the board, it is justified to say that thanks to the pace with which the work can now be done, the way of working has changed. For the better." ■

Henk Kombrink

DE-RISKING DRILLING OPERATIONS

"Thanks to InteractivAI's ability to help interpreters identify subtle or hidden features of interest, we can help de-risk our customer's drilling operations," says Herman. "A telling example in that regard is that InteractivAI was used prior to one of our clients drilling a well and a fault was detected in the seismic that had not been seen during the manual interpretation process. The well trajectory was therefore altered, potentially saving the operator hundreds of millions of dollars."

How do recent geoscience graduates experience the job market?

We asked a small group of people from around the world to share their views

DURING PANEL debates, where industry-stalwarts share their visions on how the energy sector is evolving, it is often said that the job market for geoscientists in the energy sector will only get better. But is that a true reflection of what recent graduates experience once they enter the job market?

At the AAPG ICE Conference in Madrid in November 2023, PhD student Damian Pasiecznik stood up after a panel discussion on this very topic, and said that he and his PhD peers in academia did not see all the opportunities some of the panelists talked about. For me, it was a wake-up call, and it made me want to talk to more students to hear their views on how they experience the state of the job market for geoscientists in the energy space.

For this article, I asked people in Indonesia, Colombia, Spain and the UK about their views. Intan Pratiwi from Indonesia works as a geoscientist in the nickel mining and geotechnical industry. She graduated from the University of Lampung two years ago. Damian Pasiecznik, who currently works as a Geophysics AI Specialist, finished his PhD from the Montan university Leoben in Austria last year. Rodrigo Olivella from Colombia, who graduated with a bachelor in 2019, embarked on a masters degree in 2023 after having gained some years of working experience. And last but not least, Tom Langrish from the UK, who graduated from Royal Holloway in London late last year.

In what follows in this piece, all of these recent graduates share their insights through answering questions about the job market, the energy transition and its associated jobs, and whether they would be keen to work in oil and gas.

Damian Pasiecznik

Intan Pratiwi

How is the job market in your country?

The overall impression from the input received is that the job market in the countries the respondents are from is challenging. "I tried to find a job in my home country of Argentina and in Spain," writes Damian, "but the job market for geoscientists is basically non-existent in both countries. Just by searching in LinkedIn is enough to understand how bad it is."

Rodrigo's impression about the situation in Colombia is similar. He writes: "The most accurate answer to the question of whether a geologist can easily choose a job is probably a no. Although our education equips us to work in a wide range of roles, the reality of the job market is quite different. It is often limited and primarily focused on fieldwork, significantly narrowing our options. As a result, many professionals are forced to accept positions that do not necessarily align with their interests, personal values, or professional aspirations."

Intan is a bit more upbeat and tells us that there are quite a few opportunities for recent graduates in Indonesia. However, she did add that some geoscientists still struggle to find jobs.

Tom provided a quite detailed account of the UK job market situation. He mentions that there are not many entry-level positions available in the UK, even though he admits that he does not have the full overview of how this was in the past. He writes: "There is definitely a frustration felt amongst recent graduates at repeatedly being told about the impending crisis within the industry at the skills gap which is forming due to a workforce nearing retirement age, and a huge drop in students studying geology at universities. However, the job opportunities for graduates are still few and far between. If this skills gap is to be plugged, then we need to not only encourage more students to study geology, but also have the roles available for students when they graduate, as this is not due to a lack of trying on the students' part. Perhaps an increase in availability of entry level roles would help attract greater numbers of students, especially if they can see an accessible and fruitful career waiting for them when they graduate."

Do you think that the energy transition is creating many new job roles for young geoscientists?

Both Intan and Rodrigo are quite positive about the possibilities the energy transition offers to young geoscientists in Indonesia and Colombia respectively. "I believe the energy transition is creating exciting new roles and opportunities for geoscientists and geologists," Rodrigo writes.

However, there are some doubts too. "At this point in time, I believe that the energy transition is failing to create more opportunities for the young generation," says Damian. "I have heard companies repeating that the percentage of geoscientists graduating each year is falling short of what is needed to fulfill the future job demand. However, as I have seen, this is not reflected in the job market. This does not help increase the number of students in geoscience."

Rodrigo also adds that "significant challenges remain, particularly within the marketplace. Many large corporations are still reluctant to fully commit to the energy transition, and their internal teams dedicated to this effort have seen little growth in recent years. For the energy transition to succeed, it is imperative that industries not only recognize its importance but also actively invest in the development of new technologies, the expansion of specialized roles, and the cultivation of interdisciplinary talent."

Tom adds another interesting perspective by saying that "most of the energy transition roles seem to be filled by existing employees from within the industry, as sectors such as geothermal and CCS require similar skillsets to those required for oil and gas sector." Yet, he does believe that a positive turnaround is around the corner. "There are definitely more roles opening in renewables though, especially in offshore wind development, and I have a lot of hope for this industry in the near future," he concludes.

Rodrigo Olivella

Tom Langrish

Would you want to work in oil and gas?

Some may argue that the people I asked to contribute to this article do not form a representative sample of the overall geoscience community, but it is interesting to see that all four I spoke to are open to work in oil and gas, despite the narrative that is often presented about the next generation of geoscientists.

"I am currently working in the nickel mining sector, but would very much like to return to the oil and gas sector," writes Intan. "However, I haven't had the opportunity yet."

"Oil and gas is part of our lives and we need it for absolutely everything," reiterates Damian. "And because oil and gas companies are mixing their output with renewable alternatives, working for this industry today does not necessarily mean that you will be only focused on fossil fuels."

"Personally, I would be open to continuing my work in the oil and gas sector," writes Rodrigo. "However, I would only do so if the work aligns with the broader context of what is happening both globally and locally. For the oil and gas sector to remain relevant and contribute meaningfully, it must embrace a holistic perspective and actively participate in creating solutions that benefit society as a whole."

Tom is not dismissive of working in oil and gas either, and similar to Damian he stresses the continued requirement for hydrocarbon production during the energy transition. "I think that this aspect of the industry needs to be communicated effectively to the general public to allow for a successful transition to renewables," he writes.

Based on the input received from these four graduates, I feel a picture emerges of hope for good job perspectives as a geoscientist, fueled by what some may hear from the more senior people in the business, but a reality that is not as rosy.

Even though the responses are different, I do think there is one common theme centering around the observation that a real job bonanza, especially in the "new" energy sectors such as geothermal and CCS, has yet to materialize. I feel that students are clinging on to it, for very good reasons, but the reality surely seems more complicated than what the panelists at conferences seem to convey.

On that basis, it is important to not only complain about the falling student numbers for geoscience degrees, but also ask ourselves the question if there would be relevant jobs around in case numbers rise dramatically. The answer is probably clear, and it is something that panelists at conferences should take into consideration. ■

Henk Kombrink

FEATURES

Exploring the deepest parts of the Bolivian Subandean fold and thrust belt

Recent drilling reached near-record depths, but the results leave room for discussion

FERNANDO ALEGRÌA, YPFB CHACO

THE SOUTHERN Subandean fold and thrust range in Bolivia hosts multi-TCF gas fields, where production mainly comes from naturally fractured sandstones of the Lower to Middle Devonian Huamampampa Formation. But even though satellite images and surface geological maps have always facilitated prospect identification, it does not mean drilling is easy, nor has it been easy to predict the stratigraphy to be drilled.

DEEP GAS EXPLORATION

About ten years ago, the Caipipendi consortium (Repsol 37.5 % WI, operator; Shell 37.5 % and PAE 25 %) decided to explore to the south of the prolific Margarita-Huacaya gas field, looking for a deep gas accumulation in the overthrusted Huamampampa reservoir. The Boyuy prospect was regarded as an exploration opportunity for new gas resources in the Huamampampa reservoir in both the hanging wall and footwall blocks of the Mandiyuti fault. The targets in the hanging wall were the Huamampampa HA and Huamampampa HB reservoirs, which correspond to the proven hydrocarbon play in the Margarita-Huacaya field, while the Huamampampa HF was the target in the footwall of the Mandiyuti fault.

The well was spud in July 2017 and reached TD at 7,963 m MD in January 2019. Along the way, a few interesting observations were made. First of all, the Huamampampa HA and HB targets in the hanging wall appeared to be missed, due to a more complex structural configuration in the hanging wall block of the prospect. Then, once the well reached 6,500 m MD and did not find the footwall target either, rather than giving up, the Caipipendi consortium decided to deepen the well until 8,000 m MD.

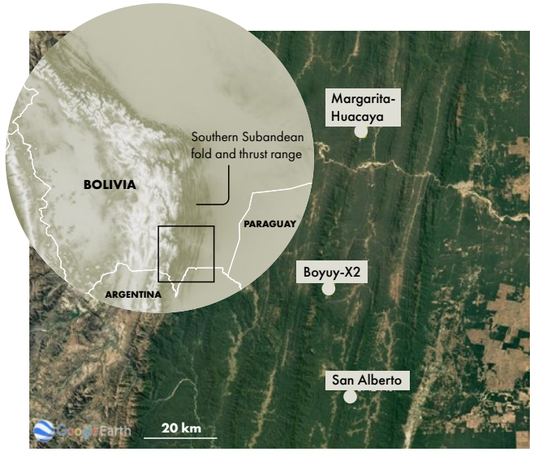
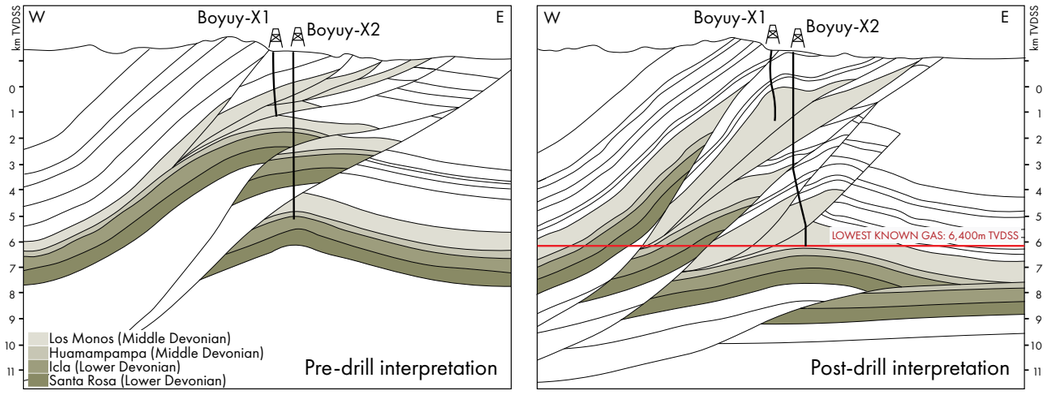
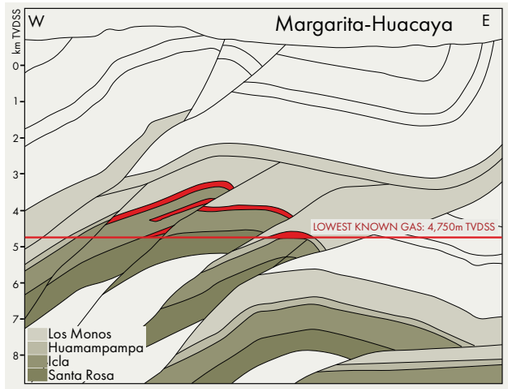


Figure 1: Map of Subandean fold and thrust belt, showing the wells and fields discussed.

The well finally tagged the top of the Huamampampa Formation at 7,640 m MD, at 6,211 m TVDSS, 1,365 m deeper than expected originally. Drilling into the reservoir continued until 7,963 m MD, where mechanical problems prevented going further and logging operations were initiated. By reaching this depth, the Boyuy-X2 became the first ultra-deep onshore exploration well in this basin and the wider region.

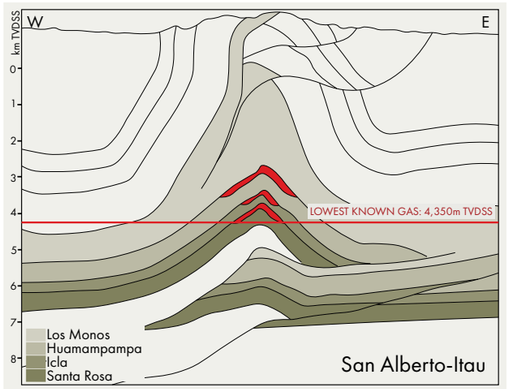




THE MARGARITA-HUACAYA FIELD – AN OVERPRESSURED RESERVOIR AND SEAL

To the west of the double plunging anticlines of the San Alberto field, surface structures show more tectonic complexity, with the anticlines affected by local or regional thrust faults. The exploration and production wells drilled in these structures encountered several tectonic repetitions of the Icla, Huamamapampa and Los Monos formations. Due to the thrust faults, the Devonian reservoirs, mainly Huamampampa, have been encountered in different structural compartments, some of them fully saturated with hydrocarbons, while in other cases the reservoirs are 100 % water wet. The Margarita-Huacaya gas field falls in this category.

The difference with the adjacent structural trend, San Alberto, is that in the Margarita-Huacaya field, both the Los Monos and Huamampampa formations are overpressured. This means that the effective stress at the trap crest is almost negligible, but the gas column is up to approximately 1,100 m. Each of these compartments has its own gas water contact or deepest known gas-down-to. The deepest gas production in the Margarita-Huacaya field comes from 4,700 m TVDSS. The deepest known gas-down-to was established at 4,750 m TVDSS.



THE SAN ALBERTO FIELD – AN OVERPRESSURED SEAL AND A HYDROSTATIC RESERVOIR

An example of a double plunging anticline is the San Alberto field, which is at the core of the anticline showing a hydrocarbon trap where the Huamampampa, Icla and Santa Rosa naturally fractured reservoirs contain large gas-condensate accumulations. The Los Monos Formation at the core of the anticline shows an increased thickness, sometimes up to 2,800 m, due to ductile flow of the incompetent layers in this formation. Also, the shales are overpressured and act as hydrodynamic top seal for the Huamampampa gas reservoir. It is important to mention that the pore pressure in the Huamampampa, Icla and Santa Rosa reservoirs are close to hydrostatic, therefore there is a large pressure differential between the seal and reservoir pair (Los Monos / Huamampampa). The measured effective stress at the crest of these structures (e.g., San Alberto) is around 3,600 psi. Due to this differential pressure between Los Monos and Huamampampa, the observed gas column in the Huamampampa reservoir is approximately 1,500 m. The deepest gas water contact (GWC) was established at 4,350 m TVDSS.

SOURCE: REDRAFED AFTER FERNANDO ALEGRÌA

The Gas Down To (GDT) depth determined by the Boyuy-X2 well is 6,533 m TVDSS, which is now considered the deepest proven gas accumulation in the basin and 1,800 m deeper than the deepest proven gas production in Margarita-Huacaya field and 2,300 m deeper than the established GWC in the adjacent San Alberto-Itau field.

Post-well structural interpretation shows the presence of a footwall structural closure for Huamampampa. The Boyuy-X2 well is located in the axis of the northern plunge, close to a potential spill point and gas-water contact.

Even though the Boyuy-X2 well discovered significant in-place gas resources in the Lower Devonian Huamampampa reservoir, the production test showed sub-commercial gas rates attributed to a poorly developed fracture system. But still, this gas discovery opens the possibility of new exploration wells targeting this ultra-deep Devonian play in similar footwall structures and deeper reservoirs than the currently known ones.

DRILLING CHALLENGES

As the well drilled by the Caipipendi consortium demonstrated, working in the Subanean requires persistence, imagination and resilience due to geological complexity. This mainly originates from an often poor seismic image quality of the cores of the anticlines, making it challenging to perform an accurate pre-drill scenario. Having drilling contingencies in place is therefore critical, because the tectonic complexity at the cores of anticlines usually ends up in changes of the stratigraphy and the related operational difficulties because of excessive drilling tool wear.

Logistical issues are also common. Because it is preferable to drill vertical exploration wells, such that a side track can still be drilled in case the target is missed, the well pads are usually located at the summit of the surface anticline. This often means that new roads have to be constructed to build the drilling pads. ■

Exploration at times of war

Maxim Vityk shares how his company Ukrgazvydobuvannya Naftogaz has positively transformed its exploration strategy during the most challenging times one could imagine

IN THE FACE of unprecedented challenges posed by Russia's attack on Ukraine, Ukrgasvydobuvannya (UGV) JSC, a subsidiary of Naftogaz of Ukraine NJSC and Ukraine's largest national gas producer, has demonstrated excellent resilience and outstanding economic performance. "We have been able to quadruple our gas production from exploration and development wells drilled in 2023 (a record-breaking result since 1998), a year after the full-scale invasion of Russia into our country and for a great part from the same area as where this unfolded.

And if you think that was because we were lucky, let's share that we matched this in 2024," Maxim Vityk (Max) says when we meet on Teams during the first week of January.

"The war has brought us together and has given us a larger purpose. A new resilience culture started to shape out. For me, it is when you become a part of something bigger than your personal life, both at the level of personal relationships, the level of the team, community, or a whole nation" explains Max, who is the director of Exploration and Development at UGV. "We now have a much clearer common goal of maximizing our domestic production at times when this is so badly needed."

And maximizing production is surely what the company achieved. "We have 42 operational rigs at the moment," Max explains. "Ukraine is, therefore, the busiest European country when it comes to onshore oil and gas exploration and production." When you think about it a bit more, it is an odd statistic. The main factor that contributed to the ability to increase production is a change in exploration and development strategy. "Let's face it, if we would have relied on our mature fields only, it would have been very difficult to ramp up production," Max says.

Max in front of one his works of art. The title of the painting is "Black Oil" and the photo was taken in 2024 at the Museum of Kyiv History in Kyiv.

SOURCE: MAXIM VITYK PERSONAL ARCHIVE

"...it is when you become a part of something bigger than your personal life, both at the level of personal relationships, the level of the team, community, or a whole nation"

Initially, when he had just started his job in 2020, the company had already decided to diversify its exploration strategy in three different ways. High-quality 3D seismic surveys were carried out in the Black Sea, unconventional gas became a serious target, and large onshore 3D seismic surveys were planned. However, due to the Russian occupation, both the Black Sea activities and the unconventional gas drilling had to be reduced, the latter because of the significant costs of deep horizontal drilling in Ukraine and its proximity to the war zone.

The focus remained on the onshore 3D seismic surveys as a way to prove up additional resources and quickly increase production. Both new seismic data and reprocessing of legacy surveys led a rapid identification of new prospects, both as near-field and in new plays. "The majority of our recent drilling targets were DHI-driven," says Max, "and most of the discovered resources could be put into production straight away."

"...it is remarkable to realise that whilst the city is under attack almost every day, life does go on..."

Apart from having new data to interpret, another thing that the company undertook was to train and form an entirely new and dedicated team of in-house seismic interpreters and geoscientists to make sense of all the new data. "It has really helped to rank the many opportunities we identified and generate high-quality drilling locations," Max explains.

When asked, Max says that the location of the new discoveries could not be shared. This time, it is not only because of the competition but also to prevent potential warfare intelligence from being shared too easily. It is a stark reminder of the unprecedented nature of the situation.

But seismic acquisition, and of course drilling wells, is not without danger in an area so close to the front line. "Land mines, drones and rockets are a serious risk in the areas that are in close approximation to the front line," says Max, "as well as being exposed to combat. For those reasons, it has been a challenge for our company to convince international players to bid for work in the area. Our domestic service providers are good, but we do recognize the importance of a diverse mix of companies and the need to bring in new technology as well."

And how is it to live in Kiev just now? "In some ways," Max says, "it is remarkable to realise that whilst the city is under attack almost every day, life does go on. Repairs are done swiftly, and as a result, almost everything functions as normal." Max and his colleagues go to their office every day, as if there is nothing of major importance happening so close by. But if there is one lesson that can be learned from this conversation, it is that stressed conditions can also bring a positive turnaround; in this case a major increase in gas production on the back of a professional and coordinated effort.

The record-breaking results of drilling by Naftogaz throughout the war show that, with the right modern technology, methods, and skilled work force, Ukraine still has a lot of potential for increasing its gas production. The company's accomplishments also represent the sustainability and sovereignty of the country. People in Ukraine are starting to realise that their country has enough natural gas to cover the nation's needs and replace a large portion of what Europe gets from Russia. This new insight evokes a natural sense of pride and patriotism, and this aspiration becomes real and worthy of implementation. ■

Henk Kombrink

Maxim Vityk, who is a Ukrainian-born US citizen, joined Naftogaz in 2020 after years of working for Shell and ExxonMobil. Especially during his time with Shell, he worked in Ukraine already from 2005 to 2012, as Shell acquired acreage in the eastern part of the country. He moved to Kyiv again in 2020 to join Naftogaz and has been there since. Max is also a well-known professional artist. He explores the cross-over between geology and art in his work, which mostly consists of heavily textured paintings that resemble geological rock formations. "For me, art is a way to express myself", Max says, "as well as a medium to find a balance in my life."

FEATURES

From scratch

How a group of young and academic engineers created a global core analysis company

"NO DATA, no problems," laughs Tanguy Lomme from Epslog when he reminisces on his years at Shell when he worked as a reservoir engineer. As soon as he joined founder and CEO Christophe Germay to become part of the Epslog team in 2013, his perspective on that mantra changed quite dramatically.

All of a sudden, Tanguy turned into an advocate of bringing high quality core data into the reservoir modelling workflow. But it wasn't too difficult for him: "I knew very well what company I had joined," he says.

Tanguy and Christophe had known each other for quite a few years already, going back to the mid 1990's when they both spent some time at the University of Minnesota, under the wings of Professor Emmanuel Detournay.

And with Emmanuel the story of how Epslog evolved starts, as his work stands at the very basis of what the guys from Liège in Belgium are doing now with their Core DNA product: Offering a wide range of continuous core analyses through scratching and scanning the rocks. But at the time, in the 1990's, it wasn't a core analysis device that Emmanuel had in mind. For him, it had a totally different purpose.

BETTER UNDERSTANDING BITS

What can be called the first core scratch test device was not a machine that was developed to test core: It was a device that was to test a single cutter of a PDC drill bit using a material that was as close to a formation as possible. Core seemed a logical candidate for that.

"What Emmanuel did is to use the outcomes of the tests to see how he could better understand PDC drill bits to ultimately overcome unwanted behaviour such as stick-slip vibrations and bit bouncing," Christophe says. "We all came from an engineering background, and it was the tools rather than the geology that interested us." Christophe studied engineering in physics specialized in space technics.

But as the scratch test device was further developed at the University of Minnesota, Emmanuel realized that the data they produced were also of use to geomechanical specialists, as one of the outputs was the uni-axial compressive strength. This resulted in him receiving sponsorship money, and some companies acquired a machine too.

"The advantage of the scratch test is that it is much less destructive than crushing a core plug, which is another way to determine the uni-axial compressive strength," explains Christophe, "and it measured the parameter across the entire length of the core rather than at a single point."

"NEXT TIME IT'S WHITE POWDER"

The first step in the students' business venture was to get a scratch test device from the US to Europe. "Emmanuel sent us to the Netherlands to deliver, install, and train people to use the first machine in Shell," recounts Tanguy. It was the very same machine that he himself had been using for his master's research project.

It became trip to remember.

"Me and a fellow student, Thomas Richard (another founder of Epslog), arrived at customs in Amsterdam with the machine in our hand luggage, and were ready to walk through the "Nothing to Declare" lane, until we got asked to undergo an inspection," says Tanguy. "Now you're travelling with this," the customs agent said, "but next time it will be with white powder."

"It got us into a bit of trouble and in the end someone from Shell had to come over to Schiphol and make a payment in cash," Tanguy laughs. "It beautifully illustrates how oblivious we were about the world beyond our lab and of very basic things such as customs."

And whilst Tanguy and Thomas were waiting in the customs clearing room, Thomas was still finishing the coding of the software that came with the device. "It was a surreal experience to have our first contact with the industry this way. But despite the trouble that the first shipment brought, it was the start of a collaboration that lasts until today. There was the tension of us not really fitting in, but yet delivering to satisfaction," concludes Tanguy.

The product was subsequently patented, but a US-based company acquired the rights and started marketing the service without further involving the university. At that point, it might just as well have been the end of the game for the young French and Belgian guys working with Emmanuel in the USA.

But it wasn't.

DOWN UNDER

It was in Australia in the early 2000's, when Christophe was carrying out his PhD on drill bit mechanics with Emmanuel Detournay, who was part time conducting research in CSIRO, that he overheard a conversation between Thomas and Emmanuel saying that they were keen to establish a new company based on the scratch test principle. This time it would be for the market outside the US, where a patent prevented them from competing.

PHOTOGRAPHY: EPSLOG ARCHIVE

Team photo with clients from Petrobras during commissioning of their newly acquired CoreDNA system.
Front: Christophe Germay. Back from left: Julien Monseur, Thomas Mazur, Bastien Pinchard, Geoffrey Trine, Luc Perneder, Anselmo Machado Borba (Petrobras), Rodrigo Davila da Silva (Petrobras). Bottom left: Tanguy Lhomme and Samuel Cheniaux.

It became Epslog. "The only ones we could convince investing in us were some former students from the University of Minnesota," says Christophe, "but it brought us € 90 k, enough to get going and pay for the development of the first equipment."

But just after all the paperwork was signed in November 2005, Thomas decided to pursue a career at CSIRO in Australia and leave the industry. It left Christophe, who was still working on his PhD, on his own in Liège.

After six months of developing everything from software to hardware, the company won its first contract with an Australian operator, even though the machine was not fully functional yet. But what do you do? Turn it down? Of course you don't. The result was working overnight again, helped by Thomas who spent the last nights and days coding the software.

THERE IS NO ONE PATTING YOU ON THE BACK TO SAY "KEEP GOING"

"This is a good moment to emphasize how important industry champions are," say both Christophe and Tanguy. People who understand that things go wrong sometimes, but who don't turn their back on you straight away.

"Dirk Mooren from RWE, Fons Marcelis from Shell, Edmond Poyol from TotalEnergies and Lutz Rieppe from PETRONAS were instrumental in that sense," says Christophe. "It really helped us build our portfolio after the initial contract in Australia. The industry as a whole was difficult to convince, but it is individuals who become early adopters that can make the difference for a small company."

But it remained challenging to win a lot more business, with the 2008 financial crisis on the horizon. "The geomechanical experts always challenged us, with some people claiming that the data we produced was just noise, or too good to be true," adds Christophe.

In some way, however, this challenge was a good thing, because he started looking at ways to prove that the data produced were not noise, and merely a result of different lithologies they scratched. So, he bought a camera with which he started recording the core at the same time as performing the scratch test. ▸

"It was just a low-resolution webcam at first," he laughs, "nothing to be too excited about. But it enabled us to plot the scratch test data onto the images to prove that the data had a relationship to the core material. On top of that, we started to automate a lot of things. And it worked, people started believing the data, now that we added a data track in the form of images to back up the scratch test results."

BREAKING INTO OTHER DISCIPLINES

"Yet, we needed something else to break into other disciplines of the upstream oil and gas sector if we were to ever scale up significantly," says Tanguy. "The geomechanics discipline is small and often unable to make key decisions."

That became the focus during the years around 2013, when Tanguy came to Epslog from Shell. More sensors were added to the machine, further aided by university collaborations and the guidance of seasoned professionals such as Lutz Rieppe, who as custodian petrophysics for PETRONAS, had a lot to say about how to tune Epslog deliverables to real world business objectives.

Then, the big slump in oil price came in 2014. "Our project portfolio was hit, for sure, but we also turned this into an opportunity," says Christophe, "and started investing into making our analysis much more efficient through automating workflows and making processing faster. All with the aim to reduce our prices and stay competitive."

MORE DATA SOONER

In 2017 the US patent on the scratch test expired, opening a path to the US market. The first steps in this new environment coincided with the strong recovery phase in the unconventional hydrocarbons sector following the 2014–2016 oil price crash. Here again, key individuals such as Robert Patterson were quick to recognize the potential of Epslog technology to transform core analysis for the better. Focus was on bringing "more data sooner", being first to the core and optimizing operational speed while controlling the test footprint to leave the core intact for further analysis.

This philosophy led to important wins with the major players like Ovintiv and EOG in the field of unconventional hydrocarbons.

DON'T BREAK MY CORES

"There was another reason why we needed to branch out to other disciplines beyond geomechanics," adds Christophe. "Geologists initially hated us because we left a groove in the rock whilst scanning the core solely for geomechanical applications. By broadening our measurement portfolio, and positioning ourselves as the company that can do the scratch test before slabbing and plugging, we provided geologists with a great dataset with which they could subsequently determine a much better thought-through plugging campaign. As this unfolded, we suddenly became the geologists' best friends!"

In 2019, the CoreDNA concept was ready to be deployed. From then on, the company could also provide useful data for petrophysical and sedimentological studies, such as automated grain size measurements, elemental analyses and ultra-high resolution images.

FAR AWAY

But being best friends doesn't automatically bring in new business. Being located in Belgium, not really an oil and gas centre, and without a dedicated sales team, how do you enthuse new customers?

"And again, trust played a vital part," says Christophe. "Jan Meltveit from Stratum Reservoir in Stavanger believed in our methodology and convinced companies of doing analyses with our kit – the results of which were then wired to Belgium for further analysis. It was a great recipe, a model that continues to this day."

"The collaboration with Jenny Omma and John Cummings, both at Stratum Reservoir, is a great example of how a sound technical message is the best basis to establish long lasting trust, which in turns creates an excellent synergy with their combined expertise on detailed mineralogy analysis and sedimentology."

"I must say the Norwegians are also very keen on quality data, and embracing innovation," says Christophe. "Where the industry may seem weary for new technology in other places, this is absolutely the contrary for Norway."

THE STARS ALIGNED

And this model of having machines on site without having someone physically there arrived just in time, as the pandemic unfolded soon after the working relationship with Stratum got underway. "If we had not had this in place, our situation would have looked very differently now," says Tanguy.

"Having that capacity to send data directly to the cloud for people to download it anywhere really arrived at the right time, when companies became much more open to this concept because of the restrictions we all experienced. It is a model that we continue to fine-tune to this day, further supported by our team who help develop all sorts of AI tools to further broaden our data analysis offering."

"I studied space technology, but little did I know that I would work a few kilometers under ground, "Christophe concludes at the end of our conversation. As if it was written in the stars. Is that where Christophe got the inspiration to hire top talents? Today, Epslog can count on a cracking team of star engineers and exceptional scientists, all sharing the idea that CoreDNA is there to make a difference on how core data is preserved. ■

Henk Kombrink

Revitalising geothermal exploration

GEO ALLIANCE
Driving Sustainable Urban Futures

A path toward efficiency and sustainability

FLORINA ȚULUCA, DUMITRU IOANE, LUCIAN PETRESCU, IULIAN POPA, LONELIA PANEA, IOAN MUNTEANU, NICOLAE CRUCERU, MIHAELA ROCA, MIHAELA SCRADEANU, ANDREI VODA, LOREDANA-SANDA BOTOS, GEORGIANA, RADULESCU AND ANDREEA CARSTEA, UNIVERSITY OF BUCHAREST

JURI MUZI, VITA KALASHNIKOVA, ALEKSNADRU SCHLETT, ALENA FINOGENOVA, RUNE ØVERÅS, VIKTOR GOMULSKY, NATALIA KUKLINA, ROY MACKINNON, ANDREI VORONIN, MARIAN BORDEIANU (TRANSGEX) AND ALESSANDRO BROVELLI (ISAMGEO ITALIA S.R.L.), PRE STACK SOLUTIONS-GEO (PSS-GEO)

IN OCTOBER 2024, Innovation Norway granted funding for a collaborative project between the University of Bucharest - Faculty of Geology and Geophysics and PSS-GEO entitled "Driving Sustainable Urban Futures: A Romanian — Norwegian Innovation Geophysical Alliance for Green Transition and SMART City Development." The initiative, carried out under the framework of the Geophysical Alliance for Green Transition and Smart City Development, aimed to address key challenges in the green transition, with a special focus on the geothermal energy sector and enhance efficiency in exploration methodologies as well as integrating geophysics in SMART city management.

160 YEARS
UNIVERSITY OF BUCHAREST
330 YEARS OF ACADEMIC TRADITION

PSS-Geo

Iceland Liechtenstein Norway grants
Norway grants

Innovation Norway

Geothermal energy offers immense promise as a sustainable resource, yet the European Union's geothermal industry faces recurring obstacles. One of the primary issues is its reliance on constant subsidies, which highlights the need to reevaluate exploration and appraisal practices to improve cost efficiency and reduce risks. The prevailing reliance on low-budget methodologies and assumptions often results in suboptimal exploration outcomes, jeopardising the feasibility of many projects.

GeoAlliance, formed by the University of Bucharest, Romania, renowned for its cutting-edge research in geophysics - particularly in environmental geophysics and natural resource exploration - and recognised for its geophysical expertise and fostering global collaborations through state-of-the-art facilities, along with Pre Stack Solutions-GEO (PSS-GEO), a Norwegian company with extensive worldwide hands-on experience in geoexploration and broad expertise in seismic and geophysical methods for lithology and fluid characterisation, developed a comprehensive plan to advance geothermal exploration.

The team investigated the available literature on geothermal knowledge in the EU, conducted studies focusing on the Romanian region, systematised modern methods used in geothermal energy exploration, proposed their application, and identified ways to improve efficiency. The resulting materials were compiled into study guides and handbooks, featuring both modelled and real examples to address challenges in geothermal exploration effectively.

It must be noted that several EU-funded grants have already been executed in the field of geothermal energy, including in Romania. During the research, many interesting and much-needed projects were identified. However, due to various challenges, some projects struggle with implementation in the industry.

This article provides an overview of the work carried out. The results obtained in the frame of the project were presented at workshops and technical knowledge transfer sessions organized with local stakeholders, authorities, and students. Additionally, educational materials were developed to further enhance knowledge dissemination and capacity building in geothermal exploration.

MAIN CHALLENGE GEOTHERMAL EXPLORATION IN THE EU

Geothermal resources are broadly categorised into low-enthalpy and high-enthalpy systems. Low-enthalpy reservoirs are characterised by limited temperature ranges, while high-enthalpy systems feature high flow-rates and high temperatures. In most cases within continental Europe, low-enthalpy reservoirs are common. These are economically efficient for district heating, making them a sustainable option for local energy needs. However, using low-enthalpy resources for electricity generation is more challenging. It often requires organic fluids with lower boiling points to produce power, but achieving efficiency on a wide scale remains problematic.

The primary challenge in geothermal exploration within the EU lies in the high financial risk and uncertainty associated with subsurface resource identification. Due to the lack of precise subsurface models, many geothermal projects face inefficiencies, such as drilling wells that fail to produce the expected flow rates or temperatures. Additional problems arise when extraction boreholes are placed too close, influencing each others productivity, or when injection borehole position is not well considered.

These challenges are exacerbated by the reliance on limited data, budget constraints, and the underutilisation of advanced geophysical methods, such as seismic surveys and deep-electromagnetic soundings. Additionally, administrative and regulatory hurdles, as well as insufficient data sharing across borders, hinder the development and scalability of geothermal energy projects.

For example, drilling a geothermal well to a depth of 2 km, at the cost of approximately €2 million, without a comprehensive understanding of subsurface geology frequently yields disappointing results - producing as little as 2 l per second of hot water instead of the desired 65 l. This reality underscors the need for precise subsurface modelling to mitigate financial risks and ensure better project outcomes.

The difficulties are further compounded by challenges in data acquisition within urban areas. These include the complex geometry of surveys, interference from urban noise, and the bureaucratic hurdles associated with obtaining permits for measurements, all of which create significant obstacles to effective geothermal exploration.

WHAT ABOUT OLD DATA?

Romania is an established oil and gas producer with a wealth of drilled and abandoned wells, as well as extensive archives of old 2D seismic data. These resources present a significant opportunity to be revitalised and repurposed for geothermal energy exploration. The practice of using old data has been widely adopted in other regions, such as the USA, where the National Geothermal Data System (NGDS) leverages historical data - originally gathered for oil and gas exploration - to assist in identifying geothermal resources. A recent study in the Gulf of Suez (Shawky et al., 2024) also demonstrates the utilisation of abandoned well logs and old seismic data to model deep geothermal resources, highlighting the cost-effective potential of reinterpreting legacy data for sustainable energy development.

While some countries serve as good examples of subsoil data accessibility, in other EU nations, publicly available data - such as thematic maps - are often outdated, scarce, or difficult to obtain. This lack of accessibility can significantly delay investment, sometimes extending the process by several years.

SOLUTIONS

The project addressed key challenges by enhancing subsurface understanding. A feasibility study was conducted before applying real data, using well log data (Vp, Vp/Vs ratio, density, resistivity, and gamma) to estimate rock properties and identify geothermal reservoirs. Integrating these with seismic data improved depth accuracy and structure localization, while resistivity methods provided insights into fluid presence and reservoir volume.

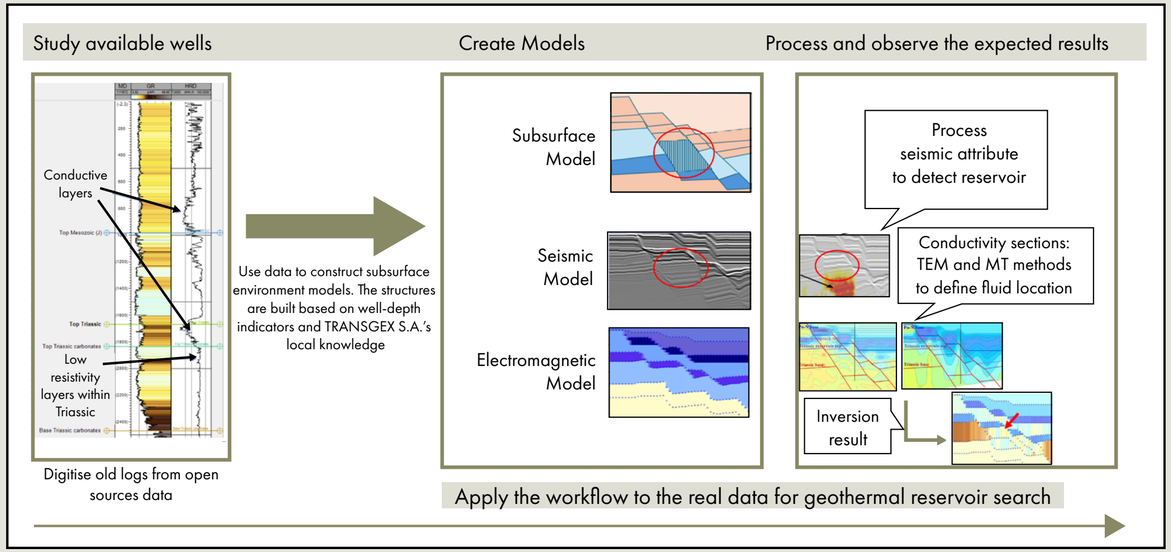
GeoAlliance first performed synthetic modeling on the Beiuș geothermal field, demonstrating seismic data's ability to pinpoint fluid-bearing subsurface structures. Electromagnetic (EM) studies further validated and de-risked findings. Seismic data played a critical role in identifying subsurface structures and fluid content. 2D seismic surveys (~€100,000, a small fraction of geothermal exploration costs) significantly improves subsurface model accuracy. Integrating seismic and well log data enhanced targeting accuracy, depth precision, and optimal drilling zone identification. Additional geophysical methods (electrical and EM surveys) refined imaging and reduced fluid accommodation uncertainties.

GeoAlliance also developed thematic maps using publicly available datasets, including national heat flux and temperature at 3,000 m, and consulted for SMART city solutions which could benefit from geophysical data. The project has gained strong interest within Romania's geoscientific community. Post-project, the University of Bucharest's Faculty of Geology and Geophysics, alongside professional associations, will continue updating the GeoAlliance dataset and develope new geothermal research. Results will be publicly shared in future publications.

ASSESSING THE WORTH

To evaluate the potential of seismic methods in resource prospecting, the likelihood of encountering economically viable reservoirs is typically assessed based on two factors. The first is the probability of identifying a reservoir at the target depth, and the second is the probability of achieving a flow rate sufficient for commercial viability. Successful prospects are generally located at depths between 1,500 and 3,500 m. Depths shallower than 1,500 m often fail to provide adequate temperatures, while depths beyond 3,500 m are constrained by high drilling costs and technical challenges. On average, for well-constrained initial geological models, our observations indicate a significant increase in probability, reflecting enhanced confidence in reservoir localisation and characterisation. These advancements directly lead to higher expected values for geothermal prospects and a considerable reduction in exploratory risks.

As part of the project, we have also explored the potential of reusing historical electrical resistivity data. In the past, such surveys were conducted down ▸



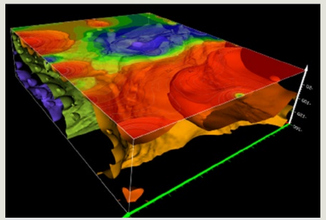


Figure 1. 3D electrical resistivity model from an area of Calimanesti City, Romania

Hafslund Oslo Celsio Waste-to-Energy plant, outskirts of Oslo. From left to right: Juri Muzi, Lecturer Florina Tuluca, Truls E. A. Jemtland, and Professor Dumitru Ioane.

GeoAlliance created learning materials for geothermal energy exploration that are available for students and professionals. The learning materials will be demonstrated at the Symposium "Green Energy Frontiers" on 27th February. To obtain materials and services for efficient geothermal exploration, you can contact juri@pss-geo.com.

to depths of 300-500 m, as they were primarily a cost-effective prospection method aimed at assessing the electrical signatures of thermal water upwellings in areas known for their geothermal potential.

By revisiting these legacy datasets, we have been able to refine the information and, starting from 1D data, we have successfully developed 3D models. Figure 1 is given as an example result based on a 1962 dataset (Papiu et al., 1962)

BUSINESS ASPECTS OF CASE STUDY PROJECTS

Geothermal projects are proving to be an efficient and sustainable option for district heating using low-enthalpy resources. Case studies in Romania show that geothermal heating is up to 3 times cheaper for end users compared to domestic gas, while emitting 50 % less CO_2 than gas-powered systems.

Local examples highlight its practicality. In Beiuș city, four geothermal wells supply ~80 % of seasonal heating and hot water for over 1,000 homes.

In Tășnad, a single well will heat the future Olympic-class swimming pool. In Oradea, 12 wells, in combination with an electrical gas plant, provide energy for over 145,000 people.

Romania has significant untapped potential for geothermal energy development, supported by geothermal wells drilled since 1960, convertible oil and gas wells, and existing central district heating systems in many cities. Because of that, geothermal designs can be tailored to different needs. For example, the Beiuș project showed the possibility of connecting a new district by drilling a new well and optimising the cost of the distribution system construction by connecting to the pre-existing infrastructure (only 1.7 km of the new pipeline was required). In contrast, the Tășnad development required a new heating distribution system.

Despite its advantages, geothermal energy faces challenges, including high upfront investments (€2.5–4.8 million per project) and exploration risks. Development timelines of 2–3 years can be a barrier for operators without sufficient incentives. Increased financial support from the state or investment funds (up to 70 %) is critical to attract developers and de-risk projects.

An additional way to improve geothermal efficiency is to decrease the risk during the exploration phase. The analysed wells can have various flow rates and some of them may not meet commercial targets, which clearly correlate with the income from each geothermal well.

ADDING ENERGY FROM WASTE

GeoAlliance integrates geothermal energy with urban energy systems, emphasizing sustainable solutions for low-enthalpy cases and waste energy utilization. The team visited Hafslund Oslo Celsio Waste-to-Energy plant, which heats 200,000 homes by repurposing excess energy - demonstrating how waste-to-energy can complement geothermal systems for efficient urban heating.

The project also explored managing gaseous emissions from municipal waste deposits as a potential biogas source in areas without waste incineration facilities. Instead of flaring methane, capturing it for electricity generation, supported by geophysical landfill monitoring, can enhance landfill gas management.

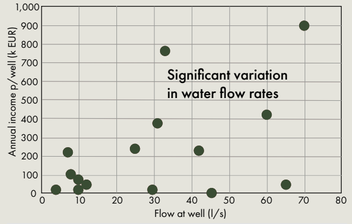
Green transition and geophysics for smart cities stakeholders workshop, 15 November 2024, Bucharest, Romania.

A SUSTAINABLE GEOTHERMAL FUTURE

By integrating revitalized geophysical data with advanced processing technology, the project introduced efficient, sustainable alternatives for geothermal exploration, reducing subsidy reliance and maximizing geothermal energy's role in the green transition.

PUBLIC COMMUNICATION ACTIONS

GeoAlliance hosted events to connect geoscience and engineering perspectives for renewable energy, emphasizing interdisciplinary approaches to the energy transition. As the world shifts to sustainable energy, integrating geological and geophysical expertise with energy professionals is crucial for unlocking renewable resources and achieving a low-carbon future.



Annual income p/well in 2023 vs well flow.

GeoAlliance events provided a platform for professionals, researchers, and policymakers to share insights, drive innovation, and foster collaboration. They also highlighted the role of geophysicists and geological engineers in supporting SMART cities, which face challenges in sustainability, public safety, infrastructure, and CO_2 reduction amid growing environmental concerns.

THE MAIN EVENTS HELD BY GEOALLIANCE

- Green transition and geophysics for smart cities stakeholders Workshop, 15 November 2024, Bucharest, Romania
- GEOEXPO Geophysical and remote sensing technology for Green Transition & SMART City Development (join action of GeoAlliance & National Institute of Earth Physics, Applied Geophysics, Prevention and Education Laboratory), 15 November 2024
- GeoAlliance & EarthresQue joint workshop, 3 December 2024, Lillestrøm, Norway
- EXPLORING GEOPHYSICS: Green Transition & Smart Cities, 19 December 2024, Buzau, Romania
- Symposium "Green Energy Frontiers. Bridging Geoscience with Energy Professionals" and "Geophysical and Geological Data for Smart City Solutions: Building Safer, More Resilient Communities", 27 - 28 February 2025, Bucharest, Romania

Driving Sustainable Urban Futures: A Romanian-Norwegian Innovation Geophysical Alliance for Green Transition and SMART City Development" is a grant from Iceland, Liechtenstein and Norway through the EEA Grants Romania 2014-2021, in the frame of the SME Growth Programme Romania. Grant number:2024/395080.

For the complete schedule of GeoAlliance activities, visit the project's webpage:

PORTRAITS

"I volunteered because I feel that when people feel safe and empowered, they are more effective in the workplace..."

Aqilah Amir Jamalullail – PETRONAS

TURNING ADVERSITY INTO OPPORTUNITY

Aqilah Amir Jamalullail knows how challenging life can be. Here, she tells the story of how she managed to shape her destiny through determination and the opportunity to study geosciences

HENK KOMBRINK

Aqilah Amir Jamalullail honored with the Most Impactful Person in ETRC award.

"I GREW UP in the state of Perak, north of Kuala Lumpur, in the town of Batu Gajah. Being the oldest of eight children, I felt the responsibility to take care of my younger siblings from an early age," says Aqilah when we start our conversation. "This became even more serious and even badly needed when my dad passed away due to a heart attack when I was only 11 years old," she continued.

From one day to the other, the family was without an income, with only a small pension contribution from her dad. "I think it changed me inside," says Aqilah, "all of a sudden, I needed to be stronger and help my mom."

The family had to do their utmost best to make ends meet. "For the annual Raya festival, we relied on clothes donations from the neighbourhood," says Aqilah. "We were given bundles of clothes to look through, and luckily often there was something that matched our sizes," she laughs.

"It is bittersweet now," she says, "when looking back at that time and knowing that our situation has changed in a positive way. But it was really tough, especially for my mom."

A bit of a turning point for the family came when one of their neighbours recommended moving to the state of Selangor immediately north of Kuala Lumpur, where support for those who needed it was well established by the Selangor Zakat Board, the Muslim body responsible for collecting and distributing charity in the Selangor state. So, the family did move and benefitted from the system that provided them with rice, flour and other basic food ingredients from time to time.

"We also had a good system in place to share responsibilities in the house," Aqilah says. "I took care of the youngest, my next sibling in line took care of the second youngest, and so on."

As well as being there for the family, Aqilah also felt the need to excel at school. She wanted to set an example and demonstrate that despite the difficult circumstances, it was still possible to perform well. For that reason, during the last year of primary school, not long after the unexpected loss of her dad, Aqilah was rewarded for being the best achiever in UPSR (the national exam for primary school) and for being a role model of the year.

Sharing training experience in Action Based Learning (ABL) Level 3 on Salt play exploration.

"Let's not sugarcoat it; it was not only a natural interest in geosciences that attracted me to it, but it was also the prospect of potentially higher financial reward."

Because of her good performance at school, Aqilah was offered a place at a science boarding school in Perak, back in the area where she grew up. "Even though my mom was reluctant to see me go, I made that decision for myself," Aqilah says. So, she left the house at the age of 13 and completed five years at boarding school. "I did not experience it as hard," she continues, "as I already had become a fairly independent person."

Aqilah continued to focus on her studies in boarding school, and again, it paid off. Based on her good results, she was recognized as the best student in PMR (Lower Secondary Exam) as well as in SPM (Upper Secondary Exam) at the very end of the curriculum. "In some ways," she reflects, "everything that had happened to us as a family gave me an enormous sense of purpose."

THE BEST STUDENTS NEED TO TAKE UP MEDICINE

As the end of her time at boarding school approached, Aqilah started thinking of what the next step would be. "Traditionally", she says, "the best-performing students were expected to study medicine. For that reason, the teachers showed some reservation when I decided to pursue the opportunity to study geology abroad under a scholarship provided by PETRONAS," she laughs.

"Let's not sugarcoat it, it was not only a natural interest in geosciences that attracted me to it," she continues, "it was also the prospect of a potentially higher financial reward." ▸

PHOTOGRAPHY: AQILAH AMIR JAMALULLAIL PERSONAL ARCHIVE

PORTRAITS

And given the circumstances Aqilah grew up in, that can be very well understood.

PETRONAS offered Aqilah a scholarship to embark on a geoscience degree in Melbourne, Australia. But there was one stumbling block: How to finance the journey to Australia and have a proper set of clothes to cope with the different climate? That was not easy for the family, as the finances were still tight.

Then something unexpected happened. A fund-raising event was organized by neighbours and friends from the village where her family lived, with the collected funds handed over during an emotional speech delivered by the committee head. "We have had a lot of help from people over the years," says Aqilah, "but this act of generosity was really more than I could have wished for, it was heartwarming."

GETTING USED TO A NEW WAY OF LEARNING - AUSTRALIA

When Aqilah arrived in Melbourne, it was the first time for her abroad. And even though she was helped by senior students, and locals were very welcoming, she had a difficult time. One of the key reasons for this was the totally different way the educational system worked in Australia compared to Malaysia. "Back home, studying was a very individual affair," Aqilah says. "I was good at it, and I was the master of my destiny. In Melbourne, we were often supposed to work in groups, which was totally new to me. I struggled with it, and at the same time, I wasn't really used to asking for help either. Reflecting on it now," she says, "I wasn't my best self."

WAITING FOR THE FIRST PAY SLIP

After completing her geology degree in Australia, Aqilah knew what the next step in her career would be - her first job at PETRONAS. Finding a place to live in Kuala Lumpur was not that easy, and she hardly had money to spare, so she moved back home for a while and became a commuter. It did not last long, though; after she got her very first pay slip, she soon managed to find a place to live in Malaysia's capital.

During the first year with the company, Aqilah worked on seismic processing techniques until it dawned on her that all this data crunching was done for a purpose. And it was that purpose that caught her attention: Exploration geology and seismic interpretation. So, she asked if she could be transferred to the exploration ventures department and received a positive response. It started a long and still ongoing career looking for new oil and gas accumulations. And in Aqilah's case, she got the third time lucky.

NUMBER 1 – SUPPORTED BY AN EXTENSION CABLE

"All I knew was that the prospect I was now being made responsible for was going to be drilled in less than 1.5 years," laughs Aqilah when we get to talk about her first months in the exploration team. It was a 100 % PETRONAS Carigali well she was now assigned to, in the Peninsular Malaysia area. But apart from having some experience with seismic data, she did not have any idea where to start.

It made her decide to seek technical support from specialists in the company. Support she also received, ranging from proper technical advice to someone buying her an extension cable to enable a second monitor to be plugged in. "I still use that extension cable to this day," she says, "because it was such a kind gesture from my technical advisor to buy one for me."

The well she planned was dry, but still, Aqilah had shown that she was able to work independently whilst also being able to ask for help when she needed it. "I was thrown in the deep end," she says, "but that is exactly what is sometimes needed to learn."

"WHAT HAVE WE DONE TO THIS JUNIOR?"

"One of the first things I had to do when I started the job in PETRONAS," says Aqilah, "was to sign up for a credit card. It was a totally new concept to her, having grown up in such a financially constrained environment.
The card had only just arrived when Aqilah was asked to make a hotel reservation for a team meeting in a few weeks. But then, the meeting had to be postponed, and her manager asked her to arrange this with the hotel. Being new to such a process, Aqilah panicked and said the booking had already been made. Seeing the worries in her eyes, her colleagues decided to go a bit further and said that the only option now remaining was to cancel the card. "And I did," she laughs, "as I thought I could not expense the money because I was told the meeting was postponed. My colleagues felt a bit guilty afterwards!"

NUMBER 2 – CARBONATES IN SARAWAK

The second well Aqilah worked on was in a totally new geological setting – whilst in the Peninsular Malaysia area, she had worked on fluvial and deltaic systems, now she became exposed to the well-known Central Luconia carbonates of Sarawak, in SK408. "And again, I drilled one well," she says. This time, it was a sub-commercial discovery, so it was a step up in comparison to the first one she had been involved in. "The overpressure in the field turned out to be quite high," she explains, "which had led to seal the breach and the probable leakage of gas. Because the structure itself was a pinnacle-like shape, the effects of a shifting column had had a detrimental effect on the remaining volume of gas."

LANG LEBAH – THIRD TIME LUCKY

After drilling the sub-commercial well in SK408, Aqilah was transferred to the nearby SK410B licence to drill the Lang Lebah prospect in 2019, with PTTEP as the operator. It turned out to be a key moment in her career.

At the Geology building of the University of Western Australia during a family trip to UWA.

"At first," she says, "the well did not carry too much weight for PETRONAS because it was a potentially high CO_2 and high H_2S gas prospect, and at the time, the company was mainly looking for oil. Moreover, PTTEP owned 85 % of the licence, so PETRONAS only had a small share. However, it was the potential of finding a sizeable volume that still caused Lang Lebah to be followed with interest.

The well that was to be drilled on the Lang Lebah structure was not the first one. Two previous attempts had been made, about 30 years ago, with the first well only drilling 1 m of reservoir before it being abandoned. The second well drilled 48 m of reservoir, yet the results were not convincing because of low porosity values obtained. On that basis, it was concluded at the time that the prospect had no further potential, which was still very much the narrative when Aqilah was asked to look at Lang Lebah again.

This also explains why her arguments about elevated gas readings and the presence of a deep-seated fault that provided good charge access were not taken too seriously at the start. She could also prove that the top seal had good characteristics, potentially being able to support a bigger column than people thought, with a P50 of around 250 m. "However, I was told it would be about 50 m tops," she says.

Still expecting a positive result, though, Aqilah recommended PTTEP to keep a DST on backup in case the drilling data warranted a test. And what happened? The results were encouraging, with the initial gas-down-to already surpassing the economic threshold. And the contact, which was ultimately drilled a year later, came in very close to the structural spill point. "Based on this success, the people who had initially been skeptical, were now advocating to drill all the Luconian carbonate closures in the area," Aqilah smiled.

AFRICA CALLING

When the Lang Lebah well was still in the plugging and abandoning stage, Aqilah was transferred once more and joined the Africa Ventures team in PETRONAS. Here, rather than having to work up and get one prospect drill-ready at a time, she was given a broader remit. For instance, she ensured that regional mapping projects were done in a consistent way, but she also worked on strategic studies to help steer the company's direction in Africa when it came to future licensing rounds. It also gave her a chance to better study deep-water clastics, which she had not worked on before.

"One of the biggest technical challenges during my time in the Africa team," she says, "was to convince a major operator who we partnered with in an exploration well to drill a deeper ▸

target than they had initially foreseen. It was quite daunting to have these conversations, also because the operator's team drew on so much experience. For that reason, we worked together with multiple teams from PETRONAS to define a strategy on how to pitch this to TotalEnergies, the operator in question. We also relied heavily on experience from nearby blocks where we are operating to leverage our position. But ultimately, the well was deepened, even though I cannot say too much about the outcome yet, as it happened quite recently."

THERE'S MORE THAN BEING TECHNICAL

Whilst in the Africa team, Aqilah also took more interest in management styles, as she got along very well with her supervisor. "I had the opportunity to hear more about different managerial styles and how it is to work with people from mixed backgrounds," she says.

Aqilah's desire to do something more for the company besides being a geoscientist did not come out of the blue. She had already served as the secretariat of the Exploration Management Committee during her time in the Sarawak JV team, which had provided her with experience working with higher management.

"I volunteered because I feel that when people feel safe and empowered, they are more effective in the workplace..."

So, when the opportunity arose to become the representative in Exploration to help analyse the results of the annual Organizational Culture Survey, she did not think long. "I volunteered because I feel that when people feel safe and empowered, they are more effective in the workplace," she says.

"Things that I have been able to address and discuss with management following the Culture Survey range from favouritism, lack of collaboration between groups, or more straight forward issues such as software not performing as it should," explains Aqilah.

"Another thing that we have been able to implement, were courses other than technical and leadership, such as Crucial Conversation Training where we learn about how to have an effective conversation with supervisors. We had a lot of positive feedback from those who attended these courses, because now they know much better how to speak up in both an honest and respectful way."

NEW ADVENTURES AWAIT

Aqilah is now embarking on a totally new adventure. By the time this article has been published, she and her family will have moved to Perth, Australia, to start a new chapter in their lives. "My husband is an entrepreneur," Aqilah says, "and he had an opportunity to go to Australia. I am taking a year of unpaid leave from PETRONAS, whilst orientating myself on what my next steps will be."

We are near the end of the conversation, and Aqilah says how much she has changed over the last ten years. From being a hard-working but very individual and determined student to someone who struggled to open up during group exercises in a totally new university environment, to then embarking on a career in a big organization, where she had to find her way and not only gain technical experience. Along the way, she got to know herself so much better, acknowledging that, in essence, she is an introvert, as she told me. But I think it is this realization that has, in fact, opened her up to so much more. ■

Preventing scaling in geothermal production wells

A new innovation has resulted in a significant reduction in project downtime in southern Germany

THE MUNICH area in Germany is lucky when it comes to its geothermal potential. There is a good Upper Jurassic carbonate reservoir at the right depth, and the water composition is also favourable when it comes to scaling and corrosion. "However, even though we don't have the same challenges with scaling as projects have elsewhere, we still face them," says Benedikt Broda from Stadtwerke München (SWM).

The utility energy company operates six deep geothermal projects in the city and Greater Munich Area, three of which suffered from calcium carbonate scaling in the production tubing.

"By not doing anything, we saw a growth of 2 to 3 mm per year in the tubing, especially at projects where the temperature of the produced water exceeds 100° C and where flow rates are higher than 100 l/s," Benedikt says.

In addition, scaling also adversely affects the operation of the ESP, the electronic submersible pump. And that device also happens to be the heart of the geothermal doublets. Replacing the ESP means the project is at a standstill for more than 10 days, including the mobilization of all the kit required to lift the pump out of the well. "We used to do this once or twice a year," Benedikt says, "whilst also doing cleanups of the well to remove the carbonate scale."

That's why SWM invested in an R&D project to investigate ways to prevent scaling from happening, in which Benedikt played a key role. "Starting in 2012, we have now found a good candidate, which consists of a biodegradable polymer that prevents precipitation of carbonates very efficiently. We need less than 1 l of it per hour," he explains, "against a total pumped volume of water of 400,000 l/hr."

SWM also developed an innovative way to inject the inhibitor into the production stream downhole. Rather than using another pump, which is prone to failure as well, they use the downhole versus surface plant pressure difference, which causes the fluid to be injected by itself.

"We tested the inhibitor in a bypass circuit first, before starting to inject it in the well below the ESP," Benedikt explains. "We subsequently reduced the dose to set the minimal dosage required to prevent scaling.

Photos of an electric submersible pump, which is placed deep in the geothermal production well, before the scaling inhibitor was used (top), and after its implementation (bottom).

PHOTOGRAPHY: STADTWERKE MÜNCHEN

And now, at one of the projects where we apply the inhibitor, the production well has been in operation for two years already without any problems. That is a big leap forward."

And the future is important, as SWM plans to drill 50 more deep geothermal wells in the years to come. Not all of these will require scaling inhibitors, but a handful will, "and having an adequate solution in place supports the economics of these projects significantly," Benedikt concludes. ■

Henk Kombrink

How interested is Eavor in sharing drilling results of the Geretsried project?

After a lot of emailing to key people involved in the project, we are none the wiser

IF I FAIL to hear back from companies when enquiring for information about a project, I mostly decide not to write about it at all. But in the case of Eavor, I think it is worth dedicating a page to it. An article in the Merkur newspaper in Germany namely suggested that changes has been made to the drilling program, but details were not disclosed

First of all, we asked the drilling company involved, KCA Deutag, if they could share some information about the project. I spoke to their German account manager, but it became clear that they cannot share any information as a contractor. That is not a surprise at all, of course, but it is also interesting to see how many activities that take place at the rig are outsourced again, which means that the drilling company has limited oversight of the project, even when it happens on their rig floor.

Then, I also approached someone at Eavor itself, via LinkedIn. My request was accepted after a few days, and I received an email address I could send my questions to. So I did, but only after reminding my contact twice I became aware that he had forwarded my questions to a colleague, who said that he was travelling and had limited time. In the meantime, a management assistant also got in touch, and she promised me a response as soon as possible. That was on January 29.

At the time of writing, it is one day before we go to print, and despite another two emails this week, I have not heard from either of my contacts again. That begs the question, is it something to be surprised about not hearing back from a company that is in the middle of such a landmark and no doubt stressful project?

If this were an operator drilling a well that was funded privately, I would not complain about not hearing back. But in this case, it is different. The Geretsried project is, for a significant part, funded by public money; €92 million through the EU Innovation Fund alone. In addition, in an article published late last year (merkur.de, Rekordhalter in der Branche: Geothermie-Kraftwerk ist fertig – Stromerzeugung verzögert sich), the authors write that "the company declined to say whether its cost estimates were on track to break even, with or without subsidies." I have reservations about this style of working; private companies spending public money should be made more welcoming to answering technical questions related to their projects. ■

Henk Kombrink

The Geretsried drill site.

PHOTOGRAPHY: EAVOR

The Geretsried project, a landmark closed-loop geothermal undertaking in the south of Germany, is Eavor's first large-scale drilling project whereby multiple loops are being drilled at depths of around 4.5 km. They tap into 160° C granitic basement rocks with the aim to circulate fluids and thereby extract the earth's heat.

Too fast, too soon

Thermal breakthrough in geothermal projects is like water breakthrough in oil – with loss of production and possibly entire wells as a result

IN GEOTHERMAL energy production, it is all about the temperature of the produced water, brine or steam. A drop in temperature has a direct effect on the amount of energy that can be extracted.

The timing of thermal breakthrough in a geothermal project depends on a few factors. The proximity of the injector well to the producer well plays an important role, as well as the properties of the rocks – are there any high-permeability zones – and / or the presence of natural recharge through which cooler waters can arrive at the production well? And last but not least, the rate at which geothermal fluids are produced also determines the timing of thermal breakthrough to a significant extent.

It is the latter that seems to have been an issue in Kenya at a couple of the countries' high-profile geothermal power projects.

Kenya is home to a well-established geothermal production province in the African Rift, where steam is being produced from moderate depths of around 2,000 m for electricity production. As such, Kenya occupies the eighth place in the world when it comes to geothermal energy production, with an estimated capacity near 900 MW.

The question now is whether the 900 MW capacity can be maintained through the existing projects alone. There are signs it will be a challenge. As we reported earlier (GEO EXPRO Vol. 20, Issue 6, 2023), the development of the Olkaria geothermal field has now reached a mature stage, and there is an increasing risk of well interference and drilling of unproductive wells.

And this may have already happened, with early thermal breakthroughs taking place at some key wells across various projects in Kenya.

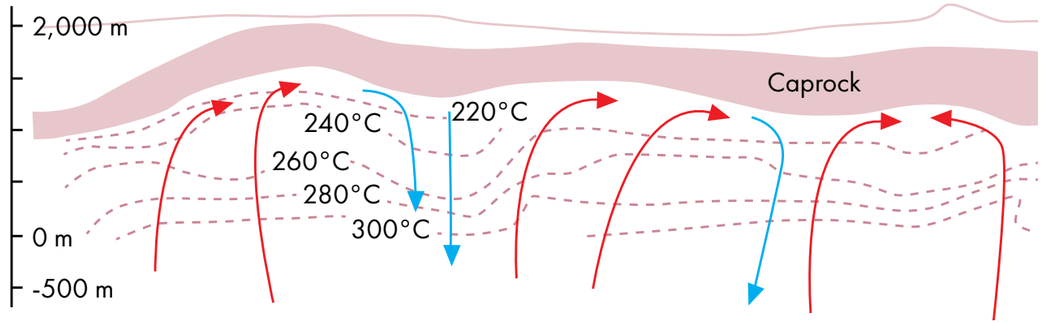
Reservoir complexities may be one of the reasons why this has happened. At Olkaria, the main reservoir consists of porous and permeable volcanic rocks such as rhyolites, trachytes and basalts. It can be easily envisaged that without mapping of individual flow units, it is hard to predict where "thief zones" are.

Nairobi, Kenya's capital, as viewed from Nairobi National Park.

It is possible to suspend production from that well and give it time to recover, but without understanding why the breakthrough happened in the first place, it probably will keep occurring.

All of this illustrates that geothermal energy production is not a simple exercise that entails drilling a production and injection well. It needs both geoscience to map out reservoir heterogeneities as well as a reservoir engineering approach to keep tabs on what is happening. This is not to say that these things were ignored in Kenya, but it rather reinforces continued vigilance and also illustrates the need to keep thinking about "replace reserves". ■

Henk Kombrink



PHOTOGRAPHY: HAMIDSLENS VIA ADOBE STOCK

Pushing the limits of tracer technology

As geothermal wells are drilled at increasingly higher temperatures, there is a growing need for tracer technology that can provide accurate reservoir understanding under these increasingly hostile circumstances

"THE CONVENTIONAL oil and gas industry has been familiar with tracer technology for a long time," says Roy Greig from RESMAN Energy Technology. "There, it is mostly used to determine which injector "talks" to which producer, calculate sweep area and direction, and more recently to calculate remaining oil saturation as fields mature."

The temperature ranges in conventional oil and gas operations are relatively moderate compared to the extreme conditions encountered in some geothermal projects, particularly in volcanic regions. "For that reason, tracers developed for oil and gas cannot simply be applied in geothermal projects," explains Roy. "This is especially true because we use organic compounds that tend to break down at higher temperatures."

Yet, there is a growing drive from the geothermal industry to develop more robust tracers as their projects benefit a lot from knowing when and where injected water breaks through. This is especially true given that the alternative to organic tracers - using deuterium - is increasingly being scrutinized in many places around the world.

"The solution we came up with is two-fold," says Roy. "First of all, we invested in lowering the detection limit of our machines that measure fluid samples returning from the field. While most tracer labs measure as low as parts per billion, we've pushed this down to parts per quadrillion. Because of this, we have been able to detect tracers in geothermal projects that were previously thought to be ineffective because they went undetected, leaving field operators confused and without data," says Roy. "So, the significant investment into R&D and even more sensitive methodologies has proven to be successful."

"But that still requires us to develop new tracers that can withstand temperatures above 300° C," continues Roy. "The main challenge was the limited number of variants at the industry's disposal, especially for more complex projects. A series of different unique tracers that can be injected at fixed time intervals are required to achieve multiple datasets across the reservoir. As long as each tracer has a slightly different composition, there is no need to wait for one to be completely flushed before injecting the next one. That's why raising the minimum number is essential," concludes Roy. "And that's also why we've invested in developing a broader range of tracers that can withstand the high temperatures used in some of our upcoming and current projects." ■

Henk Kombrink

Tracer technology in action at the Utah FORGE project in Utah.

PHOTOGRAPHY: RESMAN ENERGY TECHNOLOGY

UTAH FORGE

"The Utah Forge project has been a key project for us," says Roy. "Not so much because of the temperatures involved relative to some conventional geothermal plays, but because it's given us the opportunity to validate new tracers for EGS (Enhanced Geothermal Systems). By understanding how injected fluid flows from the injection well, through stimulated pathways, and 'hits' the producer well, we can start to quantify the success of multiple unique stages relative to each other. The limited number of previously qualified tracers did not meet the requirements to characterize all unique stages in larger projects."

SUBSURFACE STORAGE

"The problem is not the geology, the problem is the 1.1 million wells that have been drilled..."

Alexander Bump – University of Texas, Austin

Finding the right store for CO_2 can lead to very different outcomes

A clear divide in CO_2 storage approaches between the USA and Europe

IT HAPPENS quite regularly that people's surname seem to be closely linked to the profession they operate in. This certainly applies to Alexander Bump from the University of Texas in Austin. Even when he wasn't really advocating for storing CO_2 in bumps in the subsurface.

Alex' talk – the first of the GESGB's CCS4G Conference, which took place in London on the 17th of December 2024 – was also the most insightful one for me. The main reason for this was the sheer contrast in approach to finding the right CO_2 storage site in the onshore USA Gulf Coast compared to how it is being done in some places in Europe these days.

The CCS4G Conference was held at Alie Street in London, which is just around the corner from Leman Street - a very fitting name as it is the Leman Sandstone that is one of the key candidates for storage of CO_2 in the Southern North Sea and it it is the Leman field where a CO_2 injection test will soon be performed.

"The problem is not the geology", Alex said at the start of his talk. "The problem is the 1.1 million wells that have been drilled in this area." And with some of them completed in the early 1900's, when neither regulations nor cement existed, everybody understood where he came from.

Alex then zoomed in to a smaller sub-area of the Mississippi delta plain. Still a lot of wells all over the place. But the areas he subsequently selected as potential candidates for CO_2 injection were clearly the least drilled, all born out of the idea to minimize the risk of leakage.

Legacy wells are clearly the number one thing to avoid in the USA when it comes to CO_2 storage site selection. This is also underpinned by the well integrity issues, Sarah Stogner exposed over the past few years in the Permian Basin, where even much more recently drilled wells have proven to be leakage pathways for brines and oil.

But Alex went a bit further. He subsequently made a case for injecting CO_2 in reservoirs without a clear trap being available. His thinking? "We need to disperse the CO_2 as much as possible," he said, "and we won't get there when we inject in a 4-way closure and create a significant CO_2 column that is prone to breaching the seal.

"The secret", he said, "is to make sure that we inject into a reservoir where the CO_2 can migrate from, and subsequently go into solution and trapped by capillary force. As such, much of it will ultimately be contained this way." A play for migration loss, as he called it.

"In addition," he said, "we should ask ourselves how good a seal we really need for effective capture." In a video, he showed how the change from medium to fine sand caused CO_2 to migrate laterally, rather than straight into the fines. Do we need mudstones after all?

It all sounded quite interesting and refreshing in an environment where there is so much emphasis on containment and risk of leakage. However, what was lacking from Alex' talk was a concrete example of the presented concepts applied in reality. "When you would take someone from the regulator behind the bike shed," he said, "they would probably support the idea," he said. But how would that be when the same person would be in his office?

That's what we are up against.

But regardless, the contrast with Europe is huge. In the North Sea, a CO_2 injection test will soon commence into one of the oldest and mostly drilled fields, Leman. There are wells drilled in the 1960's, and it remains to be seen how good the cement of these wells still is. In the Netherlands, Porthos aims to inject CO_2 into a depleted Triassic field, and in Denmark this will happen in the relatively small Nini West field.

In conclusion, there seems no coherent recipe for what the best storage concept is. Avoiding legacy wells at all cost, finding an undrilled closure, or a depleted field that has proven to be a sound container. Maybe they will all work, maybe they will all fail. But let's get going. ■

Henk Kombrink

PHOTOGRAPHY: HENK KOMBRINK

Less oil, more water

As fields mature, the volume of water co-produced from reservoirs is usually on the rise. In the UK North Sea, this water is increasingly being re-injected into the subsurface

IT IS SOMETHING that I am not often exposed to, but that does not mean it is unimportant – produced water. The SPE Aberdeen section organized a panel discussion around the challenges of produced water in January, during which five experts shared their visions and experience on how to deal with increasing amounts of produced water as fields mature, how to cope with increasingly tight regulations and why it is better to re-inject rather than discharge overboard.

Here are two insights that are worth mentioning when it comes to the subsurface aspects of water production and injection.

LESS IS MORE

Myles Jordan from ChampionX said that rather than producing the water and then having to worry about it, it may be better not to produce it in the first place. A fair point. His company developed a polymer that is able to expand in thief zones that have contributed to early water break-through, thereby reducing the water-cut and allowing the less productive parts of the formation to drain the oil.

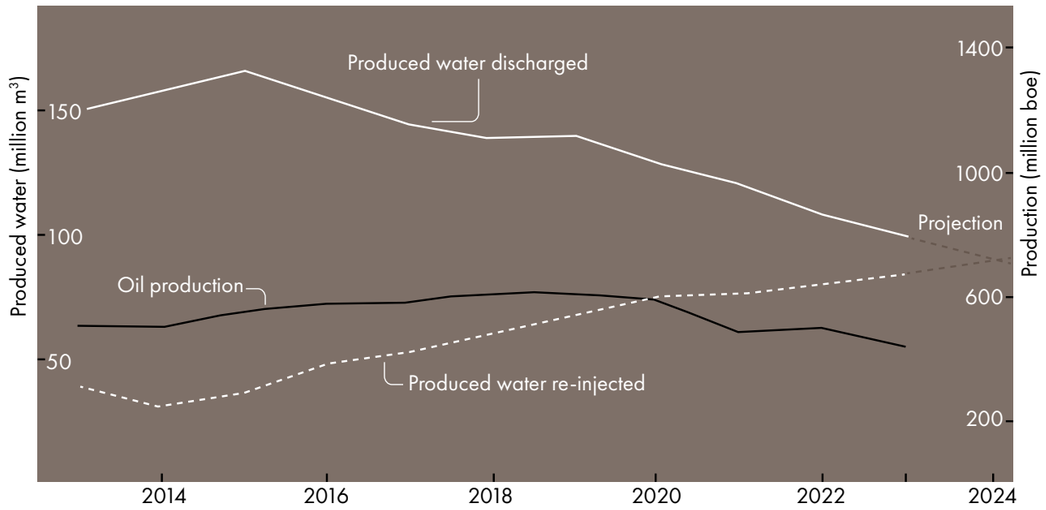
However, when asked about this technology during the Q&A, he admitted that the uptake has not been too high, partly because of the investment costs and the time it takes to see the effects. A person I talked to in the audience also added that these technologies typically require majors with deep pockets and long-term strategies to embark on these projects. The problem is that in a maturing basin as the North Sea, there are fewer and fewer of these majors left.

INJECTING MORE

Stephen Heath from Production Chemistry Training Ltd offered an interesting insight into the amounts of water that is actually being discharged into the UK North Sea on an annual basis. 99 million cubic meters of water was discharged in 2022, allowing around 1,600 t of oil to come with that. This sounds like quite a lot, but apparently, it has not caused issues so far.

At the same time, injected water, which is surely the preferred route for produced water to go, as the panellists all agreed, is projected to reach a similar volume to what is discharged at surface this year. This is quite an interesting observation; since 2014 the volume of produced water that has been re-injected into the reservoirs it was produced from has steadily increased in the UK North Sea, whilst discharged water has come down. Whether this is due to increasingly tight regulations or just a sign of more fields needing more pressure support, it is a positive sign for a very mature basin the North Sea is. ■

Henk Kombrink



SOURCE: OEUK/NSTA

Projecting the trends in produced water injection and discharge towards this year, it is likely that the volume of injected water will outpace what is being discharged. A positive development.

Basalt as a CO_2 storage reservoir

Rather than using sandstone reservoirs, basalts form a potential candidate for CO_2 storage too, with some additional benefits as well

LOIS GREENFIELD, ABERDEEN UNIVERSITY

Reykjanes Peninsula, Iceland (August 2023). Lava fields collide. The 3-week old basalt field from the 2023 Litli-Hrútur eruption meets the lava flows from the 2022 Fagradalsfjall eruption.

PHOTOGRAPHY: LOIS GREENFIELD

HARNESSING a natural process, mineralization of CO_2 is the process by which primary and secondary minerals such as Mg, Fe, and Ca present in basalts interact with CO_2-enriched fluids to convert it into solid carbonates.

The main benefit of employing basalts for CO_2 sequestration is the rapid timescales for CO_2 conversion into solid form, which is in the order of months to years as opposed to the thousands or millions of years, if at all, anticipated for most traditional sedimentary storage systems. By using basalts for CO_2 sequestration, the risks associated with unexpected plume migration and long-term seal integrity can, therefore, be avoided.

The conventional energy sector has rarely targeted basalts specifically, and our knowledge of these sequences as reservoirs is still in its infancy. But that may be set to change.

With pilot projects in the USA and Iceland, where CO_2 has successfully been injected into basalts to test the process of mineralization, these extrusive rocks have become more important in the discussion of permanently storing CO_2 in the subsurface, especially in areas where suitable sedimentary storage is not available.

Economically speaking, the best places to store CO_2 are close to high CO_2 emitters, which may not always be close to young, reactive volcanic sequences or safe sedimentary storage systems that are appropriate for conventional storage. For this reason, it is critical to understand whether CO_2 storage is feasible for the range of geology available to us. Furthermore, young and relatively fresh basalts are not ubiquitous, and the reservoir properties of older basalts with more complex or protracted burial histories is not well understood. To form a better understanding of the variability and heterogeneity of basaltic reservoirs, I am studying the reservoir properties of basalts of different ages from the UK and abroad in terms of porosity, permeability and mineralogy to investigate their suitability for CO_2 disposal.

It is estimated that the cost of CO_2 storage in basalt is currently between \$10-30/tCO_2. However, a number of variables, including the pH, temperature, and availability of reactive pore surfaces in the system, have a significant impact on the cost and rate of storage in a particular sequence. Therefore, to assess the suitability of a sequence for CO_2 storage from both geological and economic perspectives, I am looking to understand the local vertical and lateral variations in mineralogy and permeability distributions and understand their effect on reservoir quality.

Exploring the feasibility of applying basalt storage techniques in other regions of the world also requires an assessment of other selection criteria, such as proximity to CO_2 source, and the availability of transport infrastructure and water. For example, the Carbfix project in Iceland currently requires 22 tonnes of water to dissolve one tonne of CO_2. Therefore, implementing similar projects on other regions of the world requires consideration to the availability of water and the potential costs associated with transporting that water to the injection site. ■

Can Oman engineer a subsurface hydrogen kitchen?

Unlocking the potential of stimulated geological hydrogen production

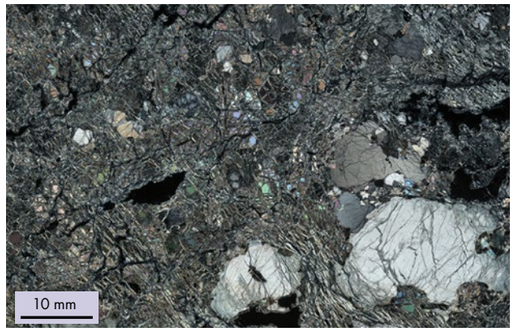
EXPLORATION for geological hydrogen has taken off over the past few years. However, nothing close to a major success case has been reported yet. Companies such as Gold Hydrogen in Australia have managed to flow hydrogen to surface, but questions around reservoir volume, pressure, and permeability remain. In other words, the large-scale economic viability of natural hydrogen production remains unproven. But what if we could give the hydrogen source rocks a helping hand by stimulating them to increase production rates?

One of the main mechanisms of hydrogen formation in the subsurface is via serpentinisation of iron-rich rocks. To speed up serpentinisation reactions, one could fracture basement rocks to increase the surface area of rock-water interaction and drill injection and production wells. The idea is simple but is the reality too?

A techno-economic analysis has shown that the natural rate of hydrogen formation must be increased at least 10,000 - fold to be profitable. This means the rate increase must pull from all available directories, i.e. chemical, mechanical, thermal, and biological enhancements. Catalysts can be added to the injected water to speed up reaction rates, as well as chemical components that prohibit microbial consumption of freshly generated hydrogen. If heating the formation is not feasible, wells can be drilled deeper to increase temperature and, hence, reaction rates. And finally, the aforementioned fracture density of the formation will have to be increased to expose more iron-rich minerals to circulating water.

THE SEMAIL OPHIOLITE: OMAN'S GEOLOGICAL TREASURE

The Semail Ophiolite in the Sultanate of Oman is the prime location to test stimulated geological hydrogen production. The iron-rich peridotite in the obducted oceanic lithosphere is easily accessible here, and gas bubbling up in natural springs consists of at least 60 % hydrogen, attesting that active serpentinisation is taking place. It also means a large part of the iron has already oxidised over geological time. However, estimates are that 1 – 2 kg of hydrogen can still be generated from each cubic meter of peridotite.



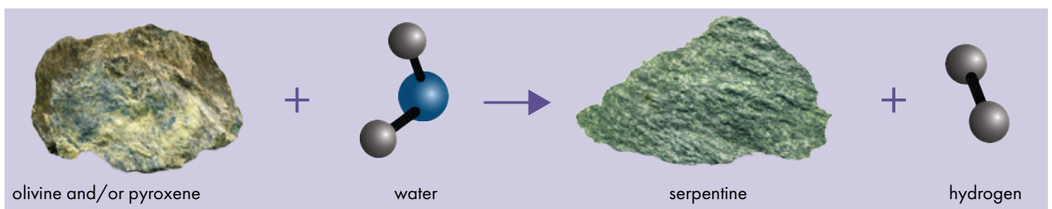
Thin section of serpentinised peridotite under cross-polarised light.

IMAGE SOURCE: VIRTUAL MICROSCOPE; THE PLANETARY SOCIETY

Geotechnical company Eden GeoPower has signed an agreement with Oman's Ministry of Energy and Minerals to test their Electrical Reservoir Stimulation technology to fracture the peridotite. The company claims this technology has a much lower carbon footprint than conventional hydraulic fracturing. It will be interesting to learn whether Eden can increase the fracture density by at least two orders of magnitude.

The government of Oman realises that all technical requirements to economically generate stimulated hydrogen are a tall order. Hence, they are not putting all their eggs in one basket and have opened the third tender round for green hydrogen projects. Oman aims to produce 1.4 million tonnes of green hydrogen per year by 2030. ■

Mariël Reitsma, HRH Geology



Simplified serpentinisation reaction.

Large hydrogen seep found in the Philippines

With more potential nearby, multiple exploration bids have been submitted to the authorities

THE NATURAL gas seeps at Mount Chimaera in Turkey have been known since antiquity. They are easily recognisable due to the constant burning of methane and hydrogen gas that seeps from the rocks. More recently, between 2006 and 2012, similar gas seeps were identified in the Philippines. Granted, they are not continually combusting and, therefore, difficult to spot. However, that doesn't mean less gas escapes from the subsurface; in fact, the opposite is true.

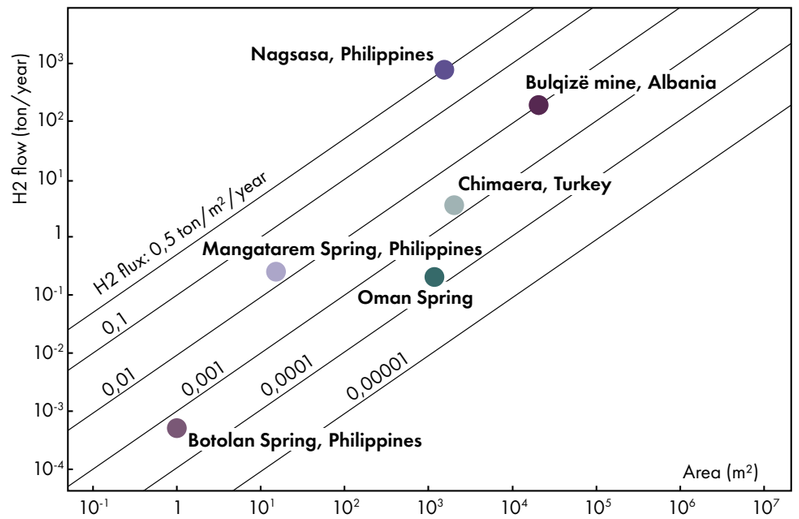
The Nagsasa field is a cluster of gas seeps concentrated in an area measuring 100 by 135 m. It is located on the west coast of Luzon Island, 100 km northwest of the capital Manila. Peridotite and gabbro from the Zambales ophiolite complex are exposed in this region, and the hydrogen gas is linked to serpentinisation of iron-rich minerals in these ultramafic rocks.

Researchers from the Philippine Nuclear Research Institute have quantified the natural hydrogen flux from the Nagsasa field. The gas composition consists of 58.5 % hydrogen and 38.7 % methane, venting from fractured rocks. The flow rate amounts to 808 t of hydrogen per year, making it one of the highest hydrogen flow rates and the largest natural hydrogen flux measured to date. For comparison, the Chimaera field is similar in size but has a flow rate of just 3.5 t of hydrogen per year.

The hydrogen seeping from the Nagsasa field could meet the energy demand of approximately 4,200 local households. This estimate assumes that the energy conversion is only 53 % efficient and does not account for the energy that could be generated from the methane simultaneously leaking from the field. Furthermore, the volume of the hydrogen seep points to the presence of a reservoir, because calculations demonstrate that the observed hydrogen flow cannot be sustained solely by present-day serpentinization. Therefore, it is likely that a fault or fracture zone accumulated hydrogen and methane over a prolonged period before its seal was broken.

The discovery of the large and active hydrogen seeps, along with the implications for subsurface reservoirs, has led to the inclusion of two areas for natural hydrogen exploration in the latest exploration licence round. Licence PDA-PH-1, covering the Zambales province and including the Nagsasa field, received three valid bids. Licence PDA-PH-2, covering the Pangasinan province - where the Zambales ophiolite is also exposed - received two valid bids. The Philippine Department of Energy is currently reviewing the bids and is expected to award the exploration contracts soon. ■

Mariël Reitsma, HRH Geology



SOURCE: MODIFIED AFTER AQUINO ET AL. (2025)

Total hydrogen flow rates per area for the major known hydrogen seeps associated with ophiolites.

New hydrogen prospectivity map released for the USA

But the first proper accumulation has yet to be found despite millions of wells drilled

"FOR DECADES, the conventional wisdom was that naturally occurring hydrogen did not accumulate in sufficient quantities to be used for energy purposes," says Sarah Ryker, United States Geological Survey (USGS) associate director for energy and minerals, on the website announcing the new hydrogen prospectivity map for the USA. "This map is tantalizing because it shows that several parts of the USA could have a subsurface hydrogen resource after all," she continues.

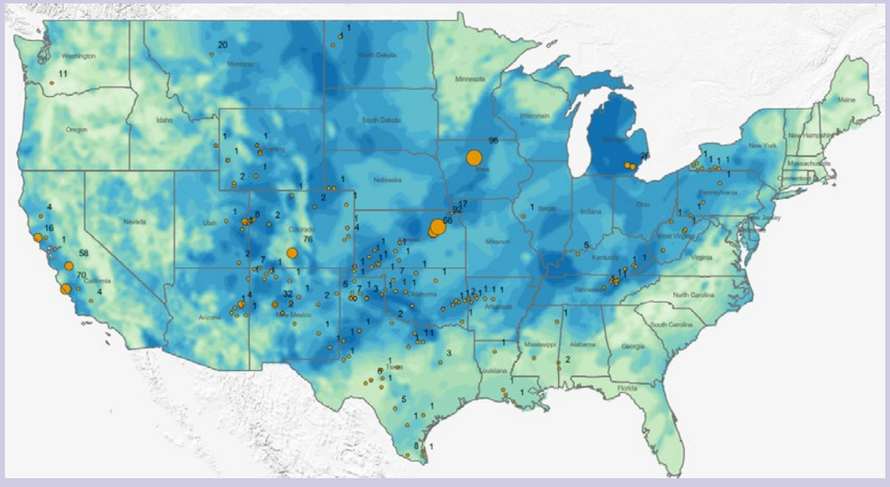
It was not only Sarah Ryker who was upbeat about the opportunities that lie ahead. "When it rains, it pours," wrote Jason Eleson on LinkedIn in response to the release of the data, which includes overviews of known occurrences of hydrogen, helium, and geothermal systems. In addition, the potential source types for hydrogen are presented and mapped separately, as are reservoirs and seals required to accumulate the small molecules in and under.

In the paper (USGS v.1.2, January 2025), that accompanies the online mapping tool, the authors write that recent hydrogen exploration in the US focused on the midcontinent rift in Kansas, Nebraska and Iowa. Their analysis suggests that the hydrogen is generated in the core of the rift, from where it migrates updip towards the areas where some wells proved elevated contents. This is also the area where the highest hydrogen content in the US of 96 Mol.% was found, in the Hoffmann #3 well in Iowa. Based on mapping, this well seems to be located in an area where migration routes of hydrogen are converging as they migrate further towards the northwest, away from the rift.

As a comment to Jason Eleson's post, petroleum engineer Greg Taft asks if anyone ever drilled a well in the US that contained more than a few percent hydrogen. Whilst that is certainly true, as demonstrated by the published data, Ramon Loosveld, who is often critical of people putting high hopes on the chances to find commercial quantities of hydrogen, writes in a reply: "Not one hydrogen gas accumulation. Anywhere. On earth. Despite millions of wells and hundreds of thousands of FDC-CNL logs and lab-based gas composition analyses."

It may be a bit disheartening to be reminded that nothing of commercial value has yet been found beyond being able to power a small village, as in Mali, or, as Mariël Reitsma writes on page 69, in the Philippines. But the real hydrogen accumulation, which can be produced in a similar way as a conventional gas field, has indeed yet to be found. Whether it is in the US or elsewhere, proving that concept will be the real game-changer the geologic hydrogen community is waiting for. Maybe it will happen this year in Spain, where Helios will be drilling the Monzon-2 appraisal well in the second half of this year, testing a closure that might prove that hydrogen accumulations exist. Next up, the USA! ■

Henk Kombrink



Hydrogen prospectivity map for the USA, with total prospectivity ranging from low (light blue) to high (dark blue), in addition to known hydrogen occurrences in Mol.%.

SOURCE: USGS

Die Metallkrise ist in sicht: A call for German deep-sea involvement

The Federation of German Industries is urging the country to participate more actively in deep-sea minerals activities

"JAPAN, Saudi-Arabia, Norway – more and more countries rely on raw materials from the deep sea. Germany can't escape this trend." The Federation of German Industries (BDI) published a report urging the German government to actively support the International Seabed Authority (ISA) in developing a mining code. This code will establish the regulations and framework for allowing companies to apply for exploitation licenses in areas managed by the ISA (i.e. international waters).

"Germany should help shape the mining code in line with its interests, instead of continuing to call for a precautionary pause. With innovative and environmentally friendly extraction systems, German industry can position itself as an important technology partner for marine raw materials projects," the authors write.

BDI emphasizes the increasing demand for critical raw materials and the effects of export restrictions driven by geopolitical motivations. Consequently, BDI asserts that deep-sea mining may be essential for German industry to secure and diversify its supply of raw materials. The report highlights Germany's significant reliance on the importation of metal-based raw materials.

The federation represents 39 industrial sector associations, including the German Association of the Automotive Industry.

The report focuses on manganese nodules, specifically referencing the world's largest nodule field, the Clarion Clipperton Zone (CCZ). This area is managed by the International Seabed Authority (ISA). The authors point out that the CCZ contains high concentrations of copper, nickel, and cobalt, making these nodules vital as a potential future resource.

Germany is already involved in marine minerals as a member of the ISA. Since 2006, the Federal Institute for Geosciences and Natural Resources (BGR) has been exploring a licensed area of the Clarion-Clipperton Zone (CCZ). Additionally, the BGR holds a license for sulfide exploration in the Indian Ocean.

However, once the ISA mining code is finalized, Germany may not proceed with extraction under its licenses. In 2022, the German government announced its support for a moratorium – a pause – on deep-sea mining.

"The goal must continue to be to make raw material extraction in the deep sea minimally invasive. To this end, it is important that Germany and the EU actively and quickly take every further step towards formulating and adopting the "Mining Code" and intensifying environmental research. Instead of a precautionary pause or a moratorium, pilot operations should, therefore, begin as soon as possible. This will enable important data on the impact on the deep-sea ecosystem to be collected and appropriate limits to be defined for responsible extraction of raw materials in the deep sea", the authors conclude. ■

Ronny Setså

The Reichstag in Berlin is home to the German parliament.

PHOTOGRAPHY: TEAMEISTER VIA FLICKR.COM

Hunting for marine minerals in the Baltic Sea

Swedish Scandinavian Ocean Minerals aims to extract metal-rich nodules from the Gulf of Bothnia, located between Sweden and Finland. The company recently received new exploration permits and has already conducted a sampling expedition

WHILE Norway is by far the most dominant player amongst the Nordic countries in terms of marine minerals, some activities are also being performed in Swedish waters.

The presence of iron and manganese-rich nodules in the Gulf of Bothnia has been recognized for decades. In recent years, the Swedish company Scandinavian Ocean Minerals (SOM) has begun to focus on these resources.

In September, the Geological Survey of Sweden (SGU) granted the company a permit to expand its exploration of mineral deposits in the Gulf of Bothnia. Last year, Scandinavian Ocean Minerals (SOM) received exploration permits for two areas in the Gulf, and this year's decision by SGU allows the company to explore two additional areas.

"This is a milestone that gives us the opportunity to collect the data necessary to advance our ambition to assist the industry with the green transition," said Peter Lindberg, CEO of Scandinavian Ocean Minerals.

Following the permits in September, the company spent two weeks in October conducting sampling in collaboration with Sweco. At the same time, researchers from Stockholm University carried out an independent research project to enhance understanding of the habitat in the Gulf of Bothnia.

Data collected during the expedition are being analyzed and will form the basis for an environmental impact assessment, which will be included in a permit application in 2025.

Iron and manganese nodules collected in the Gulf of Bothnia.

The company noted that 60 of the 80 surveyed square kilometers showed a "good presence" of manganese nodules, in line with previous estimates.

SOM has ambitions to start extracting the nodules, which they believe will help reduce Sweden's and the EU's dependence on importing critical minerals and metals. The company reports that the nodules contain manganese, iron, silica, phosphorus, and other elements useful in manufacturing electronic and medical products. It is estimated that the Gulf of Bothnia holds approximately 20 million t of these nodules.

"Our technology is developed to harvest nodules in an environmentally friendly way, which is essential for being able to extract the manganese nodules," noted Lindberg. He also points out that the relevant extraction areas, at depths of 60 to 120 meters, make the project more technologically feasible than nodule extraction in the deep sea, which may occur at depths of several thousand meters.

The Baltic Sea is facing issues related to nutrient over-fertilization and low oxygen content. SOM references a 2011 study suggesting that the nodules can dissolve over time due to seawater acidification, potentially releasing 240,000 t of phosphorus contained in the nodules. Currently, the Baltic Sea receives about 30,000 t of phosphorus from land. By extracting the phosphorus-containing nodules, they could potentially help to mitigate this issue. ■

Ronny Setså

PHOTOGRAPHY: SCANDINAVIAN OCEAN MINERALS

What happened to the Allseas vessel that brought the nodules to surface in 2022?

A recent documentary aired in the Netherlands shed light onto the matter

WHEN THE interviewer asks the CEO of Allseas, Pieter Heerema, how much money the company sunk into converting the former ultra deep-water drill ship Vitoria 10000 into getting the newly named Hidden Gem ready for the nodule harvesting trial that took place in the Clarion Clipperton Zone in 2022, there is a short silence before he says that 100's of millions were spent...

Early in the documentary, the CEO hints at what the challenges were; working at a depth even a global marine player such as Allseas was not familiar with. The riser that brought the nodules on board, developed by US oil and gas conglomerate Oil States, must have been one of the biggest expenses. And then there is, of course, the underwater vehicle that was lowered onto the seafloor; from the video footage I have seen, it looked quite small. But in the documentary when people are standing next to it, it appears much bigger. "It's getting a bit rusty in places," an Allseas engineer mentions in the documentary.

But where is it currently? "The best place we could find for the vessel was in South Korea," says Pieter Heerema, "where the costs of having it sitting idle is comparatively affordable."

The vessel has got a skeleton crew, though, and is eagerly anticipating changes in the regulatory regime around harvesting the polymetallic nodules so that operations can start immediately. The International Seabed Authority, the body that oversees the international waters, has, however, not decided on a way forward, even though there is pressure from countries that want to start operations, such as Norway.

At first sight, one would expect this vessel to drill a frontier deep-water well rather than carrying out a nodule harvesting trial, but that's what its new functionality is. Now it is waiting for the first job to start.

PHOTOGRAPHY: THE METALS COMPANY

"...maybe some countries may not wait until the ISA agrees on a regulatory framework"

LOSING PATIENCE

"However, maybe some countries may not wait until the ISA agrees on a regulatory framework," said Gerard Barron from The Metals Company. This is the company that carried out the nodule harvesting trial together with Allseas in 2022. At the end of that day, the organization has no power, according to Barron, and one powerful country is not even a member: The USA.

And with the recent change in government in the US, the wind may soon start to blow from another direction when it comes to the future of deep-sea mining, and the US government might well decide "to get on with it", as Gerard Barron said in the documentary.

All in all, this shows how big a bet Allseas has taken in the deep-sea mining sector. Near the end of the documentary, the interviewer asks Pieter Heerema who the biggest player in the field is. The answer is no surprise. This is also manifested in the share ownership of The Metals Company; Allseas itself has got around 20 % of the shares. The marine contractor even owns a licence in the Clarion Clipperton Zone called Blue Minerals, sponsored by Jamaica. ■

Henk Kombrink

Link to documentary:

DIGITALISATION

"If you want to remain an independent player whilst creating more impact, you will need to grow. It's a matter of life and death"

Benoît Matha – Eliis

Finding scribbles on the sides of composite well logs

Can machines detect and make sense of little hand-written notes such that overlooked pay zones could be more easily identified?

IT MUST have been in November 2018, as I chaired a session at the PETEX Conference in London, when Ronny Parr from bp gave a talk entitled "From Trash to Treasure – Sifting through old data with new tools and techniques to unlock the next generation of high-value discoveries in the UKCS". It was an inspiring presentation, not only because Ronny was an excellent speaker, but also because of the theme of the talk.

There are too many presentations about the value of digitalization without a real concrete example. But in this case, it was all about the examples, and they were good, too. Ronny discussed how a meticulous approach to scanning old data most people did not see the value of anymore could, in fact, contain the key to the next discovery.

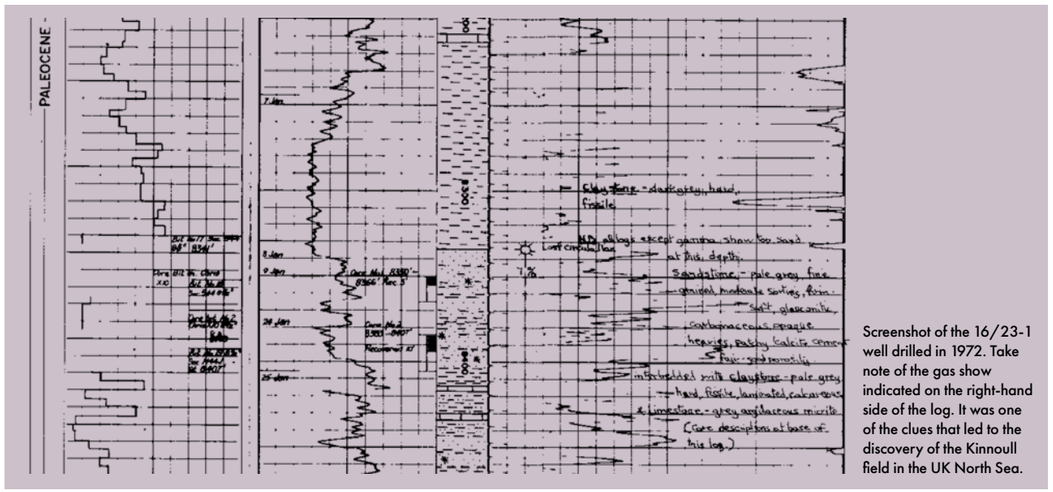
"In the 1970s and 1980s", Ronny said, "it was all about drilling the big bumps." The advance of 3D seismic made another generation of more subtle discoveries possible during the 1990s. Then, in the 2000s, with the integration of wells and seismic, in addition to better software becoming available, even more subtle plays could be explored.

In one example, Ronny showed a composite well log from 1972 in which the geologist had put a gas show sign on the right-hand side of the paper. In combination with the thin oil zones that could be demonstrated through log analysis, there were signs that a small hydrocarbon column had been found. However, it took two wells that failed to find a reservoir before the third was ultimately drilled in 2008 before the Kinnoull field was finally found. The key? Reservoir isochron mapping through the mapped closure at the level where the initial shows were noted. This clearly demonstrated that a band of sand crossed the closure from north to south, with the two unsuccessful wells drilled on either side. Only 36 years after drilling the first well, with the increased level of detail provided by seismic data, could this discovery be made. However, only through the initial observation of gas shows in the margin of the composite well log.

Ronny showed a few more examples of this kind, all demonstrating the value of digging through old files.

We are a few years further down the line now, and with the advent of AI and text recognition, the question is now: Is it possible to automate the search for hand-written notes in old well logs to increase the likelihood of finding overlooked pay? That is a question I recently asked a company specialised in scanning old borehole logs. They did not have an immediate solution available, but hopefully in the next issue, I may be able to report on this a bit more, as we will embark on a small research project. How many prospects are there still waiting to be uncovered? ■

Henk Kombrink



Screenshot of the 16/23-1 well drilled in 1972. Take note of the gas show indicated on the right-hand side of the log. It was one of the clues that led to the discovery of the Kinnoull field in the UK North Sea.

SOURCE: NDR

"You need some chaos to thrive as a company"

Benoît Matha from Eliis discusses his company's digital strategy and why a level of disorganization is required for growth

"LET'S GET this straight," Benoît Matha says at the start of our conversation on a Friday morning in February, "the subsurface upstream business is not a big data environment." It is one of the insights that comes with having worked in other sectors, as Benoît did before he joined Eliis five years ago. "In retail, huge amounts of data are being generated; seismic and well data are definitely not big data, also because of the secrecy that is so often associated with it," he says.

"And when it comes to AI, let's not claim that the subsurface energy sector was quick in embracing it. But now that it has, there are some very tangible effects," Benoît says. "First, it has accelerated the product lifecycle dramatically in all aspects of its development. It also leads to rapid commoditization of products, meaning that what we develop as cutting-edge software today is quickly overtaken in a world with multiple players in the same arena. It's therefore important to be very observant of what is happening in the tech industry and ride the wave of what is coming out there."

UPDATES

Our conversation clashes with the company releasing a new version of its software. But it is also a good example of how the company has adapted to changing times. "Releasing software updates once a year is a thing of the past," Benoît says. "The pace with which our customers expect software to be updated and the pace with which AI offers new ways to implement things have grown rapidly. It means that in order to keep up, software releases have to be done more often these days, even to the point where it becomes flexible and much less planned than it used to be before."

This new way of working also aligns with the way Benoît implemented a strategy of working in short project delivery intervals. "We organize our development in three-month slots to mature ideas into something that works in our software. And I see that people get much more productive with a shorter timespan like this compared to looking at a blank sheet of a year," he explains.

FROM EXPLO TO EXPRO

Eliis is well known for its PaleoScan software, which helps interpret seismic into stratigraphically consistent intervals. This software is mostly used in the exploration community, where geoscientists work with data to de-risk reservoir presence and distribution. ▸

Benoît Matha.

PHOTOGRAPHY: ELIIS ARCHIVE

"The upstream energy sector was a late-comer to embracing AI"

INTRODUCING BENOÎT MATHA

Benoît joined Eliis five years ago. Prior to that, he mainly worked as a strategy consultant in the health and insurance sector and acted as the COO of a software business. "I like to build things with a clear goal in sight," Benoît often says. Originally from Montpellier, Benoît is pleased to be back in his hometown after spells spent in other parts France.

"Looking at how the upstream business is evolving, Benoît continues, "We see that across the world, companies are now putting more of a focus towards squeezing the last drop out of existing assets than spending cash on frontier exploration. One can even say that exploration budgets are getting scrutinized more and more. For that reason, we have decided to venture into the reservoir modelling space in the coming years, and integrate that with our existing software expertise and offering."

And how to go about venturing into a new domain? "Obviously, we need a north star," says Benoît, "but at the same time, I think we need some chaos too. Chaos leaves room for launching ideas without lengthy procedures. That's why I think it is essential for people in this company to see me as an agent of chaos from time to time", he laughs.

"Likewise, it is my role to channel this chaos too, and make sure that once we decide to start something, we finish it as well. Because that remains one of our core competencies: To act faster than the bigger players in the market."

INTRODUCING ELIIS

Founded in 2007 and based in Montpellier, France, Eliis is particularly known across the industry for its PaleoScan software, which enables geologists and geophysicists to quickly interpret seismic data in a stratigraphically sound way. In doing so, reservoirs can be more confidently predicted and located.

GROWTH

Many people may have noticed that Eliis has grown significantly over the past few years. "Of course, growing for the sake of growing is not our goal," says Benoît, "but it is certainly our ambition to grow our footprint in the industry. And if you want to remain an independent player whilst creating more impact, you need to grow. It's a matter of life and death."

"And let's not overstate long-term strategies," Benoît concludes. "I think that the difference we can make as a company is to act fast and have a strong focus on making things happen. That's my most important mantra." It has certainly helped him transform Eliis from a company that marketed PaleoScan as a nice-to-have attribute, to a company that offers a platform in which business decisions are being made. ■

Henk Kombrink

PHOTOGRAPHY: ERIC VERNAZOBRES

TECHNOLOGY

"In order to construct any kind of geological model, you need to be able to recall some fieldwork reference points. Visualisation based on real things is an essential part of model construction"

David Scarlett – TotalEnergies

"We're in this weird time of pre-AI and post-AI"

And more insights from Dan Austin on how Norway is a breeding ground for new subsurface technology

A FEW MONTHS ago, I published some thoughts on how Norway has proven to be such a hotspot when it comes to new subsurface technology. Dan Austin, who has been in Norway for quite a few years, got in touch and offered to share some of his experience working in subsurface tech in Norway. Dan previously worked with Earth Science Analytics in the seismic and artificial intelligence space, and is now powering autonomous drilling with Sekal.

"What Norway got right from the geo and subsurface perspective was putting a big bet into getting all the data accessible, structured, clean and ready," says Dan. "No other country in the world has its subsurface data organized like Norway, and even though countries like Australia also offer a great deal, DISKOS has been a real boon to the industry. Especially for start-ups because the fees are affordable and the data presentation is standardized, giving companies a real head start."

It's also ok and accepted to try new things and fail in Norway," adds Dan. "There is an attitude towards entrepreneurship here, but there is also a safety net, to an extent that you don't really see in any other place in the world. On top of that, there is a stable political regime, a good licensing system, easy access to international markets and international money. That really creates the environment needed for investors to come in."

Skilled and smart people willing to work in the oil industry are also still around in Norway, with many having an interest in the technical sciences. "I think many people have the natural interest and technical skills to come up with new ideas," says Dan.

Dan Austin – Sekal.

PHOTOGRAPHY: TERJE SOLBAKK, GEOPUBLISHING

But where Norway has the right ingredients to launch ideas, it may not be the best place to find the talent to scale it into an international business. "I think sometimes the cultural norm in Norway is holding back companies from more success on a global scale. To find people with the mindset to challenge those expectations is like finding unicorns," laughs Dan.

At the same time, expecting to be the next tech Sillicon Valley unicorn in the subsurface tech world is maybe a bit too far-fetched even for companies that do well. "At the end of the day, it is good to realise that we are all oilfield service companies to some degree," says Dan. "There's always a risk that you lose sight of the bigger picture and there often comes a time where your technical competence will skew your commercial perspective. Sometimes this attachment to your product can be a barrier to growth."

What is the next big thing that will come out of Norway? "It is hard to see what comes next," says Dan, "as we seem to be in this zone between pre- and post-AI; where we are not fully automated yet and are still moving on from our legacy systems. However, I'm thinking along the lines of a secure solution to AI, making sure that the ethics of large language models is correctly implemented and respects the ownership and rights from companies. If there is one place this could come from, it is Norway," Dan concludes. ■

Henk Kombrink

How your WhatsApp call helps detect seismic activity

Leveraging subsea cables for subsurface imaging and monitoring purposes

J. ANDRES CHAVARRIA

OUR GLOBAL telecommunications infrastructure consists of millions of kilometers of fiber optic cables. These include terrestrial and subsea networks that ensure that information travels across the planet. With the increased use of subsea cables to connect different continents and countries, the need to accurately monitor these critical assets has become apparent. In recent months, subsea cable incidents have made more common appearances in the news cycle. This is due to the large impact that a cable failure can have on various telecommunication services.

Some of the failures can be due to geohazards like ground movement and landslides. Other ones can be due to human causes like anchors, dredging and potentially, intentional ones aimed at disrupting our infrastructure.

In addition to our telecom assets, there are offshore facilities like wind farms, pipelines and oil and gas platforms that are instrumented with cables that include fiber optics lines. All of this optical infrastructure, combined with the large telecom one, provides a unique opportunity for distributed fiber optic sensing (DFOS).

This technology effectively turns existing fiber optic cables into sensors that can detect tiny anomalies of vibration and acoustics (DAS), temperature (DTS) and strain (DSS) along their entire length with fine spatial resolution and density. The use of these tools provide real-time detection of third-party intrusions, power cable failures and precise cable fault localization, amongst others.

These same cables are also being used to image the subsurface. The use of DAS turns the cable into a permanent seismic sensor. Both natural and induced earthquakes, and active seismic sources are now being recorded with the technology. Recent work from the North Sea reveals that the seismic data from DAS provides images of PP and PS reflections.

Operators are using cables connecting the platform or umbilicals turning them into permanent receivers on the ocean floor. Using this antenna can complement existing sensing tools like ocean bottom nodes or PRM systems. Furthermore, they enable seismic imaging with high receiver density in areas where nodes are too expensive to deploy.

Fiber optic sensing technology gives the opportunity to use the same tools for various purposes, hence reducing overall operation costs. Leveraging it for our critical and expensive subsea assets not only allows us to monitor their integrity, but also allows us to illuminate the subsurface for exploration and geohazard mapping purposes. ■

"Using this antenna can complement existing sensing tools like ocean bottom nodes"

SOURCE: CO-PILOT (AI)

Subsea cables fitted with fiber optic technology can help detect (induced) seismicity.

Can technology replace fieldwork?

That's what we asked our followers on LinkedIn, and the answer is...

AT TIMES of better access to digital outcrop imagery, drone footage and satellite shots, is it still worth going into the field to have a look at the rocks in person? Universities offering geoscience degrees may have already concluded that it's not, given that students spend less time in the field than a few decades ago. But is this a good call? Would it not be better to beat the elements, struggle with scale, and being forced to think 3D whilst comparing scarce outcrops?

Yes, is the answer.

The poll we ran via our LinkedIn page did not leave too much room for doubt; the majority of respondents voted that there is indeed a lack of field experience with the younger generation of geoscientists, and that this is indeed a problem. David Scarlett, operations geologist at TotalEnergies commented: "In order to construct any kind of geological model, you need to be able to recall some fieldwork reference points. Visualisation based on real things is an essential part of model construction."

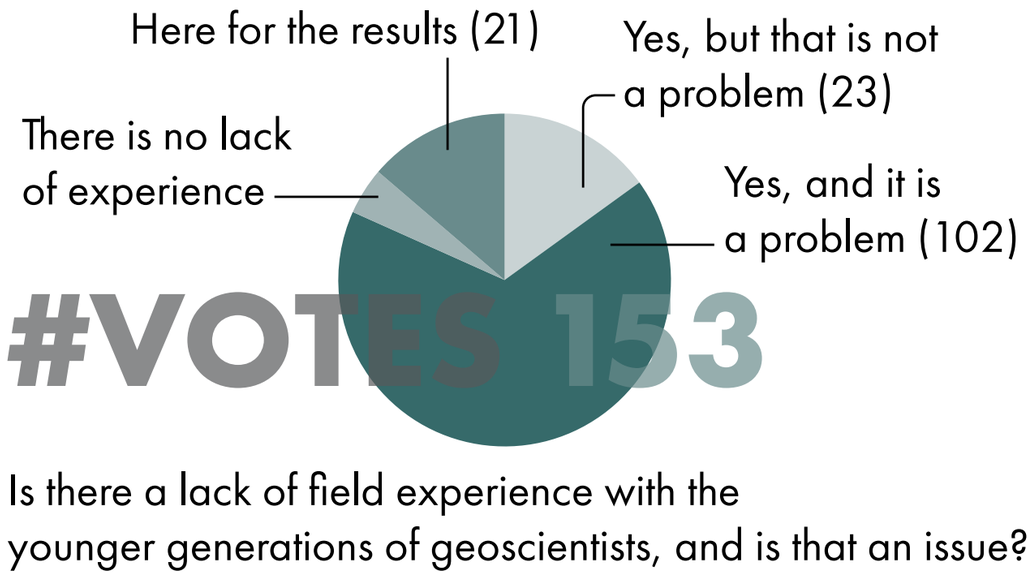
Michael Power, who runs Mercator Geological Services, is even more adamant about the need for fieldwork in these days of AI: "If anything, and especially with the rise of AI-assisted exploration solutions, fieldwork is more important now than in the past to ground truth and/or refine targets. AI only works with good data inputs, including good historical data and quality field data that includes good geologists collecting these data and often, refining and changing targets on the fly."

Bastian Koehrer from Harbour Energy further adds that digital outcrop models are great, but only as an addition. "You only develop a feeling for dimensions, both laterally and vertically, whilst looking at outcrops. And you best discuss your own observations with an interdisciplinary team in the field. I had my most formative "Aha" moments doing outcrop work, and not in front of a workstation."

Not everybody is on the same page, though. A reasonable group of people acknowledges that younger geoscientists lack field experience, but do not think this is a major issue. It may well be that in quite a few jobs geoscientists end up in, the need for having a broad spectrum of field experience is not required on a day-to-day basis. It is also worth asking the question of how much fieldwork is enough to be a good geoscientist. Again, that is very much driven by the diversity of projects people will be involved with.

And finally, a minority group is of the opinion there is no problem at all when it comes to field experience, whilst yet another reasonable group could not wait until the publication of this article to see the results of the poll. ■

Henk Kombrink



INSIGHTS

"The story shows just how important it is to have original and overlapping data, to share data among companies and not to rush through the model building. Take your time, invest a little bit and you'll be rewarded"

David Rajmon – Geosophix

The geology of Bronze Age epics

The deification of the fluvial processes and seismicity of Troy

JUAN COTTIER, MMBBLS SUBSURFACE CONSULTING

A NEW Year brings new challenges, and for me, that means writing for GEO EXPRO. I am writing after the Xmas break which is traditionally eating, drinking and watching old films. This year those films included Troy (2004), and what a lot of geology that story has. Based on Homer's epic poem The Iliad, the Kingdom of Troy is named after King Tros, whilst the city of Ilium is named after Tros's son, Ilus. Greek myths get very complicated, very quickly, so I hope you're securely strapped-in to your mythological seats.

Ilus's mother, and Tros's wife, was Callirhoe, daughter of the river god Scamander, who is geologically essential to the story. The city is located on a small hill overlooking the Plains of Ilium, which are the meander plain of the river Scamander where the battles between the Archaeans and Trojans took place.

We all know the death of Achilles, but less well-known is that he nearly died earlier in the story. Scamander was enraged by Achilles's rampage of death and the tossing of the Trojan dead into his river, considering it a desecration. In retaliation, he rose up in a furious flood to overwhelm the Greek hero.

This is plausible: A meandering, anastomosing river becoming clogged and reworked by the actions of thousands of bronze-clad warriors. Rerouted and overbanked, once dry areas flooded and well-worn pathways lost, so catching some unfortunate by surprise.

Achilles survived because Hephastus, blacksmith and god of earthly-fires, dried up the river and saved the day, or rather saved the deity. Hephastus was the god of volcanoes, and metals and ores, and thus our geological patron.

Troy, latterly famed for its Trojan Horse, but previously a renowned horse culture, was a client kingdom of Poseidon, the God of the oceans, rivers and lakes, and, yes, horses. Yet Poseidon was more than that; he was also the god of earthquakes, known also as Ennosigeios, the "earth-shaker".

Ennosigeios contains the Greek word σείω (seíō) "to shake" which is where we get the word seismic. Poseidon used his knowledge of earthquakes to build incomparably robust new defences for the city, whilst his companion Apollo played his lyre to inspire and beautify the construction. I think we've all worked with an "Apollo" at one time.

I have visited the archaeological site of Troy and seen those walls. They are meticulously constructed, with intricately interlocking stone blocks, supposedly earthquake proof. Troy is located in northwest Turkey at the boundary of the Eurasian Plate and Anatolian Microplate, with the devastatingly active North Anatolian Fault Zone running directly through the kingdom. If anyone was best qualified to build the walls of Illium it would be Poseidon, Ennosigeios, Lord of Earthquakes. ■

Amphitheater, the ruins of the ancient Greek city of Troy, near Çanakkale province in Western Turkey.

PHOTOGRAPHY: BULENT VIA ADOBE STOCK

HOT SPOT

Indonesia bid round push continues

Expanding exploration opportunities in Southeast Asia

JONATHAN CRAIG, NVENTURES

In Asia Pacific, Malaysia has been arguably the most successful country in promoting its exploration and development opportunities over the past few years, with the vast majority of its acreage now licensed. However, Indonesia has been a determined neighbour and is showing no signs of letting up when it comes to promoting exploration blocks, with the latest second phase of the 2024 bid round announced in December 2024. Figure 1 shows the location of the current bid round blocks: Air Komering, Serpang, Kojo, Binaiya, Gaea and Gaea II.

Indonesia has been holding regular bid rounds under improved terms since 2021. They include flexible Production Sharing Contracts (PSCs), which now offer companies the choice between cost recovery and gross split schemes, providing flexibility to select the model that best suits their investment strategies. In addition, efforts have been made to create a more attractive environment for investors in the upstream oil and gas sector. Improvements have been made to fiscal and incentive structures, which help ensure contract certainty, efficiency, and the adoption of advanced technologies. Similar to Malaysia, Indonesia has a membership scheme whereby companies can have full access to non-confidential data, either paid or free, for participants that have already accessed the bid document.

RECENT AWARDS AND KEY PLAYERS

Prior to the launching of the latest bid round, three block awards from the Phase 1 bid round were announced in September 2024, with the most notable award being the Central Andaman PSC to Harbour Energy and Mubadala, where both companies have had success in neighbouring blocks in recent years with an estimated 12 Tcf of gas in-place resources discovered. The other two blocks were awarded to Medco Energi (Amanah, onshore South Sumatra) and a consortium of Pertamina, Sinopec and KUFPEC for the Melati block in onshore southeast Sulawesi.

The bid rounds have had mixed success. Since 2021, less than 50 % of the blocks offered have been awarded, with 22 awards made from a possible 47 on offer. Nevertheless, a variety of companies have made successful bids with awards to majors such as BP and Eni and international NOCs such as Petronas and POSCO. Other awards have included large/medium-sized companies such as Cenovus (Husky Energy) and indigenous EMP (Energi Mega Persada), along with smaller IOCs like Conrad Asia Energy and other small local independents.

STRATEGIC INITIATIVES FOR EXPLORATION SUCCESS

Meanwhile, work continues at pace in the background for the next phases of bid rounds. The Ministry of Energy and Mineral Resources (ESDM) has plans to offer up to 75 potential onshore and offshore blocks through 2028 (Figure 2), with half offered between 2024-26 mainly in western Indonesia. These blocks also include 14 open areas.

To help the Indonesian government better understand its subsurface resources and in turn de-risk and identify areas that are more attractive for exploration and development investment, work is carried out in Joint Study Areas (JSAs) between the ESDM and private companies or consortiums. These studies are conducted to evaluate areas that have not been extensively explored or developed. A further enhancement to the bidding process has been that when these JSA areas are offered, they are under a direct bidding mechanism. Benefits can include terms tailored to the specific potential of the block, reducing administrative delays associated with public tenders, and companies face less competition compared to an open tender, increasing their chances of securing the block.

By late December 2024, there were 23 JSAs under study, with a further seven proposed for study. Most of the areas are offshore. These include areas near more established areas such as the Makassar Straits, east of Kalimantan and the Andaman Sea, north of Sumatra. Several JSAs are in frontier or underexplored areas such as West Papua in the Aru Trough, around southern Sulawesi in the Sengkang (Bone) and Buton basins, and north of the giant Abadi gas-condensate field, south of the Yamdena Island in the northern reaches of Bonaparte Basin. The Natuna D-Alpha block is currently under study in the East Natuna Basin, where activity has stagnated but still has significant potential. The block was last offered during the second phase of the 2023 bid round and is likely to resurface in a future bid round. KUFPEC is reportedly interested in the area, currently holding a stake in the Natuna Sea Block A PSC in the West Natuna Basin.

FUTURE DRILLING AND POTENTIAL IMPACT

In some of the relatively underexplored blocks awarded since 2021, planned wells are expected to start drilling in 2026 and beyond. Should any of these wells prove successful the future bid round push can only improve and help unlock undiscovered resources in a country that, according to ESDM, has 27 basins with proven hydrocarbon resources but not yet in production and 68 basins with limited geological data and exploration activities, such as Papua, Maluku, and deepwater areas. ■

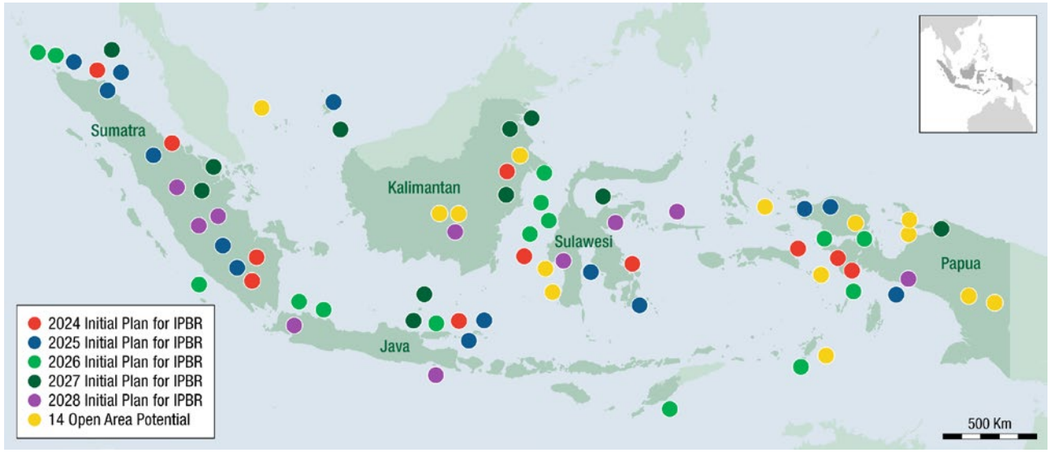


Figure 2. Planned bid rounds by Indonesia's Ministry of Energy and Mineral Resources.

Figure 1. Location of the current bid round blocks.

SOURCE: NVENTURES

Panorama of Jakarta, the capital of Indonesia.

SOURCE: NVENTURES; LEO LINTANG VIA ADOBE STOCK

How data analysis and 1D models help understand messy vitrinite data

And the importance of having original and overlapping data and taking your time to investigate

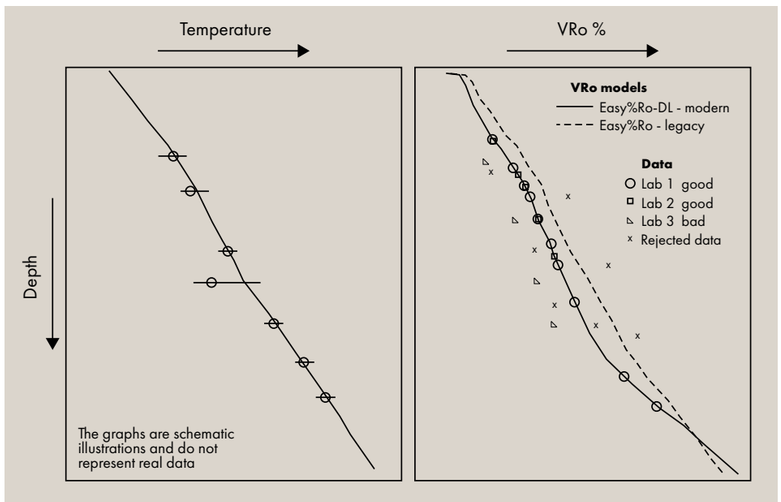
DAVID RAJMON, GEOSOPHIX

In my last column, I hinted at a case study, where I was able to interpret likely fluid migration based on temperature and vitrinite data in a single well. This study was a highlight of my career, in which our team could work with pretty much all of the data available in the basin.

At first, the vitrinite data were all over the place. A colleague from one operator company told me he just could not make any sense of those data in their license block and had to ignore them. We had the benefit of a much wider dataset and a wider context.

It turned out, we had reports for some wells that included original reflectance measurements with statistics and photographs for a number of wells. We had kerogen organoparticle analyses. We even had overlapping VRo data from two and even three different labs. Even though the data volume seemed overwhelming and messy I had a feeling we had a chance to make something out of it. So I decided to ignore the reported interpretations and dived into the files. I started organizing and typing all data in spreadsheets and began cross checking all the different pieces against each other. An incredibly tedious and time consuming effort. But it paid off.

Gradually, I started seeing patterns and relationships. Some measurements reported as VRo started to show up as clearly measured on different particle types. I could see which data were more reliable. I found that two of the labs consistently reported reliable or at least reasonable data while the third lab consistently reported incorrect data. So in the wells where I did not have underlying measurements, I could flag the reported data based on the lab of origin.



I also did similar detailed analysis on temperature and RockEval data. Gradually trimming the noise and high-grading the dataset.

Then I proceeded to build 1D thermal models. I defined fairly detailed lithology columns from the well logs. After I calibrated the first model, I continued building others with similar heatflow settings. The results just made my eyes pop! One model after another came out with an excellent fit to temperatures and VRo that I never saw again.

The models did not only serve as a temperature history estimate for maturity calculations, they were important tests of the data integrity and overall geological model validity. It also confirmed my previous experience that the more modern EasyRo%-DL model is the best one to calculate VRo in a basin model.

The story shows just how important it is to have original and overlapping data, to share data among companies and not to rush through the model building. Take your time, invest a little bit and you'll be rewarded! ■

Is it a true conjugate fracture set?

How to tell and why it matters?

MOLLY TURKO, DEVON ENERGY

Conjugate faults or fractures are a set of shear fractures that formed simultaneously under the same stress conditions. According to Andersonian Fault Theory, this could involve a series of left-lateral and right-lateral strike-slip faults separated by a 60-degree angle. For normal faulting, it could include synthetic and antithetic faults.

While a conjugate geometry is a key characteristic, not all fault or fracture sets with this arrangement are true conjugates. They might represent two distinct fracture sets formed at different times. Understanding whether a fault set is truly conjugate has significant implications for fracture connectivity, the degree to which fractures are interconnected, and the ability of fractures to transmit fluids. In that light, knowing that a set is not a conjugate pair also reveals important information about the paleo stress history and the past stress conditions that shaped the rocks.

Determining if a fault set is truly conjugate requires careful observation and analysis. Some key clues to look for include cross-cutting relationships, mineralization or alteration, and kinematic or slip sense analyses.

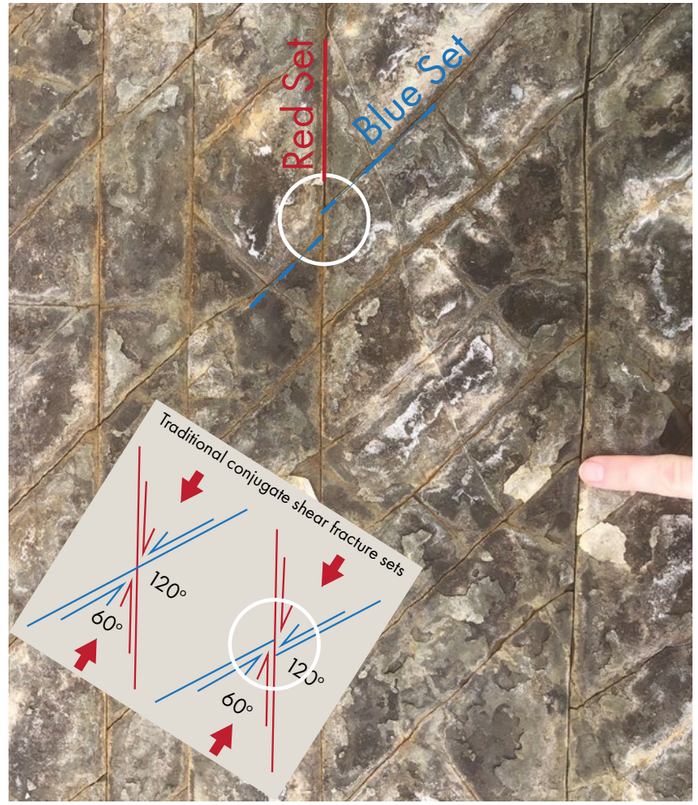
The fractures in the figure exhibit a conjugate-like geometry, but closer inspection reveals several clues suggesting they represent two distinct sets.

First, the cross-cutting relationships. The blue set appears to interact with the more through-going red set, suggesting the red set was pre-existing. For example, the finger points to a location where a blue fracture "curves" nearly perpendicularly to the red fracture, indicating an interaction that would only occur if the red set was already present.

Second, kinematic inconsistency. The red set appears to offset the blue set with a left-lateral sense of slip (white circle). This is inconsistent with Andersonian Fault Theory, which would predict a right-lateral offset for true conjugate faults, further supporting the idea of two separate fracture sets.

Third, differential alteration. Nearby, the red fracture set has undergone bleaching, while the blue set remains unaltered. This differential alteration provides strong evidence that these are not true conjugate fractures, as they likely formed under different conditions or at different times. Due to its more through-going nature, the red set is also more likely to be more conductive under ideal stress conditions than the blue set.

By carefully considering these clues, geologists can gain a more accurate understanding of the origin, evolution, and behavior of fault and fracture systems, which has significant implications on hydrocarbon exploration, groundwater flow, and injection and production of fluids and gasses. ■



Tectonically-influenced carbonate platform, Greece

A Pliocene carbonate platform (Rhodos Formation) is exposed in the NE part of the isle of Rhodes, Greece. Sedimentation was largely controlled by faulting relating to a late Pliocene or early Pleistocene tilting of the island, whereby unconsolidated sediment was re-deposited. The minimum thickness of the platform is ca. 25 m, and the platform extends some hundred meters out into the basin. In the transverse section (NE - SW), the platform can be followed by approximately 1.5 km.
The sequence is composed of moderately to well-sorted lime grainstones and rudstones, which were deposited along the margin of a narrow platform, mostly bordering a metamorphic basement or the underlying terrigenous Vasfi Formation. The deposits are characterized by bottomset units and giant-scaled, steeply dipping, cross-bedded foreset units. Topset units are locally present, but are commonly eroded. A variety of slope instability features are also present, both within the foreset and bottomset units. Stacked beds with backsets, i.e. cross-sets dipping in the upslope direction, are commonly associated with the foreset beds and are probably formed by accretion of sediment by successive retrogressive flow slides (illustrated in the bottom-left overlay photo). Plastically deformed sediments in the form of slumps occur within the lower platform slope. A giant channel composed of coarse-grained carbonate clasts (up to 1 to 2 m in diameter) cuts through the platform sequence (illustrated in the bottom-right overlay photo). Foresets and bottomsets are locally burrowed, mainly by sea urchins and Thalassionides burrows.

Photography and text: Arve Lønøy, Lonoy Geoconsulting

Topset

Backsets within foresets

Foresets

FEATURE YOUR OUTCROP

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

A legacy of hyperpycnal flows

Reinterpreting the U and T Sandstones in the Oriente Basin of Ecuador

MARCOS ASENSIO

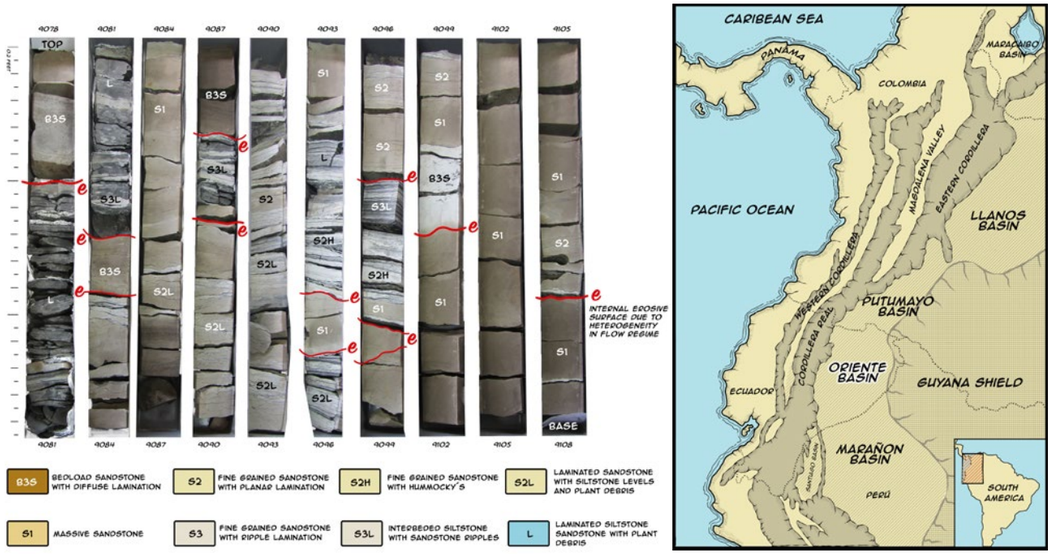
THE CRETACEOUS U and T sandstones, key petroleum reservoirs in the Oriente Basin of Ecuador, have been the focus of a groundbreaking reinterpretation. Recent studies of subaqueous systems and high-resolution genetic facies analysis have led to a new perspective on these formations. Traditional theories that describe them as fluvial, estuarine, or deltaic deposits reveal inconsistencies, primarily due to the vast dimensions of these systems, which would have extended from Colombia to Peru.

New research suggests that these formations are the result of hyperpycnal flows - dense subaqueous currents generated during exceptional fluvial floods loaded with sediments that meet cleaner water bodies. Due to their higher density, these currents plunge beneath the water surface, transporting large volumes of sediment and organic matter over hundreds of kilometers.

The sedimentological characteristics of the U and T sandstones provide strong evidence of a hyperpycnal origin. Basal load structures (facies B) include massive sandstones with rip-up clast levels, indicating transportation by drag at the base of the flow. Massive and laminated sandstones (facies S) exhibit parallel lamination and ripples, reflecting the gradual settling of suspended loads. The presence of plant debris and coal fragments suggests a direct continental origin. Lofting rhythmites (facies L) show intercalations of siltstones and very fine sandstones with plant remains, and are diagnostic features of hyperpycnal flows in marine environments where interstitial freshwater separates lighter materials from denser sediments. Finally, internal erosive surfaces are associated with the dynamic behavior of the flow.

This new interpretation provides a better explanation of the sedimentary dynamics of the Oriente Basin. Sustained hyperpycnal flows account for the wide distribution and lateral continuity of these units, even in low-gradient settings. The simultaneous presence of extra-basinal components (plant remains, coal) and intra-basinal ones (displaced microfossils) aligns with the erosion and reworking of the seabed caused by these dense flows.

The reinterpretation of the U and T sandstones as products of extraordinary hyperpycnal flow events establishes a direct link between the continent and the depths of the Oriente Basin. This new understanding not only enhances the comprehension of regional sedimentary evolution, but also opens new opportunities for resource exploration in similar systems. ■



Cores from the Cretaceous U and T formations in Ecuador, showing the facies characteristics of hyperpycnal flows.

ILLUSTRATION: MARCOS ASENSIO

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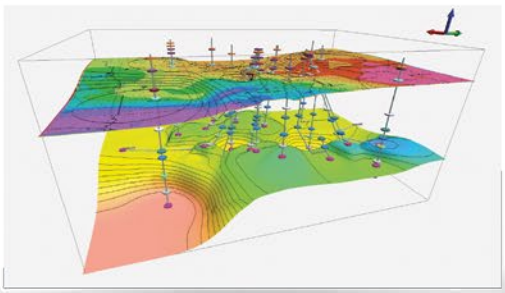

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