THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

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Exploration Opportunities

Sweetness and light in Oman's Indian Ocean

Illuminating tight oil reservoirs in the Permian Basin

Cameroon: unlocking potential and reigniting exploration

From cuttings to clarity: AI unlocking the Norwegian Continental Shelf

UNCONVENTIONAL UNCONVENTIONAL GAS FROM THE DESERT

THE JAFURAH PROJECT IN SAUDI ARABIA

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Exploring synclines

RECENT EXPLORATION efforts and results are pointing to a shift away from drilling the good old anticlines and four-way dip closures. Of course, this is all bread and butter in the USA already, but the trend is going global.

Kuwait is one of those interesting examples. During the last few years, KOC has drilled a few offshore wells in an area that can be seen as the syncline between the two major structural uplifts along which most of Kuwait's oil and gas have thus far been found. And according to press releases, it seems like the absence of structural closures has not been detrimental to exploration success; two discoveries have now been announced in what might be very low-relief structures or in stratigraphic traps.

> "The trend of drilling synclines is going global"

Then there is the recent case of Uzbekistan, where a newly-erected state oil company has recently embarked on a very ambitious undertaking to drill up to 7.5 km into what can clearly be interpreted as a synclinal structure.

The motivation behind exploring these plays is probably of a different nature; Kuwait may be keen to use gas for domestic energy production, enabling the export of more oil. Uzbekistan seems to be energy hungry full stop; domestic gas production has seen a sharp drop in recent years.

Whatever the exact reasons are, it is clear that boundaries of petroleum systems are being pushed as we speak. The boundaries of the anticlines.

Henk Kombrink

BEHIND THE COVER

Saudi Arabia is another example where a syncline is currently being targeted. And on a grand scale as well. Just east of the biggest oil field in the world, Ghawar, Aramco has been quietly drilling away for the last decade or so, developing the Jafurah unconventional gas field. In fact, it is the source rock of the very Ghawar field that is now being developed for a project that competes with the Permian Basin in terms of scale. The front cover is a photo from the country where this is all happening. Rather than crushing waves in an offshore environment, in the case of Jafurah, it is the large dunes that form the occasional challenge to logistical operations.

PHOTOGRAPHY: NAJEEB ALAFAD VIA ADOBE STOCK

FIRSTS

"I went back to running oil and gas projects because there is no work in the energy transition"

Consulting geologist

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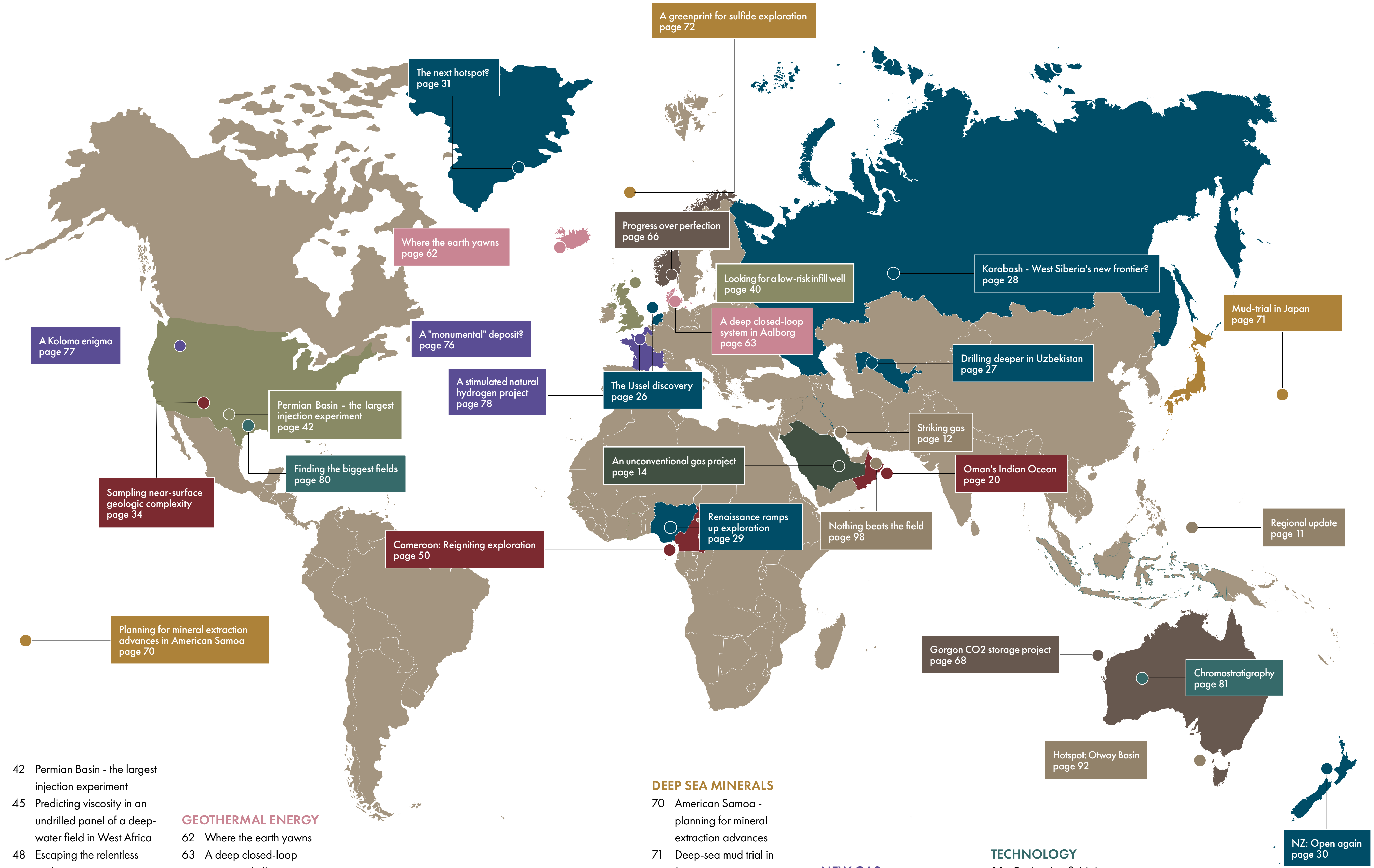
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The snippets of information shared here are based on conversations Editor in Chief, Henk Kombrink, has recently had. Sources are anonymous.

REDEVELOPING AN OIL FIELD WITHOUT DRILLING A NEW WELL

During a lunchtime talk in Aberdeen in October, Curtis Bracher from NEO Next presented on the Affleck field redevelopment in the UK North Sea. The room was full of people eager to know how this project was carried out; the field had produced oil for some years but had been shut in since 2016. Curtis nicely showed how oil production since start-up in January this year has been twice as high as the maximum production in the years before. The reason? Not because new wells were drilled, but simply because better gas-handling systems were put in place. In other words, re-opening the existing wells superimposed by infrastructure adjustments was sufficient to boost deliverability from this complex Chalk field reservoir.

"I WENT BACK TO OIL"

A seasoned geologist told me at a recent conference that he had taken on some work in oil and gas again, despite a pledge to himself a few years ago to only do energy transition projects. It shows the status of the energy transition; if a well-connected and very experienced geoscientist is unable to secure any work in the energy transition space, it does not bode well for the pace with which this transition is progressing.

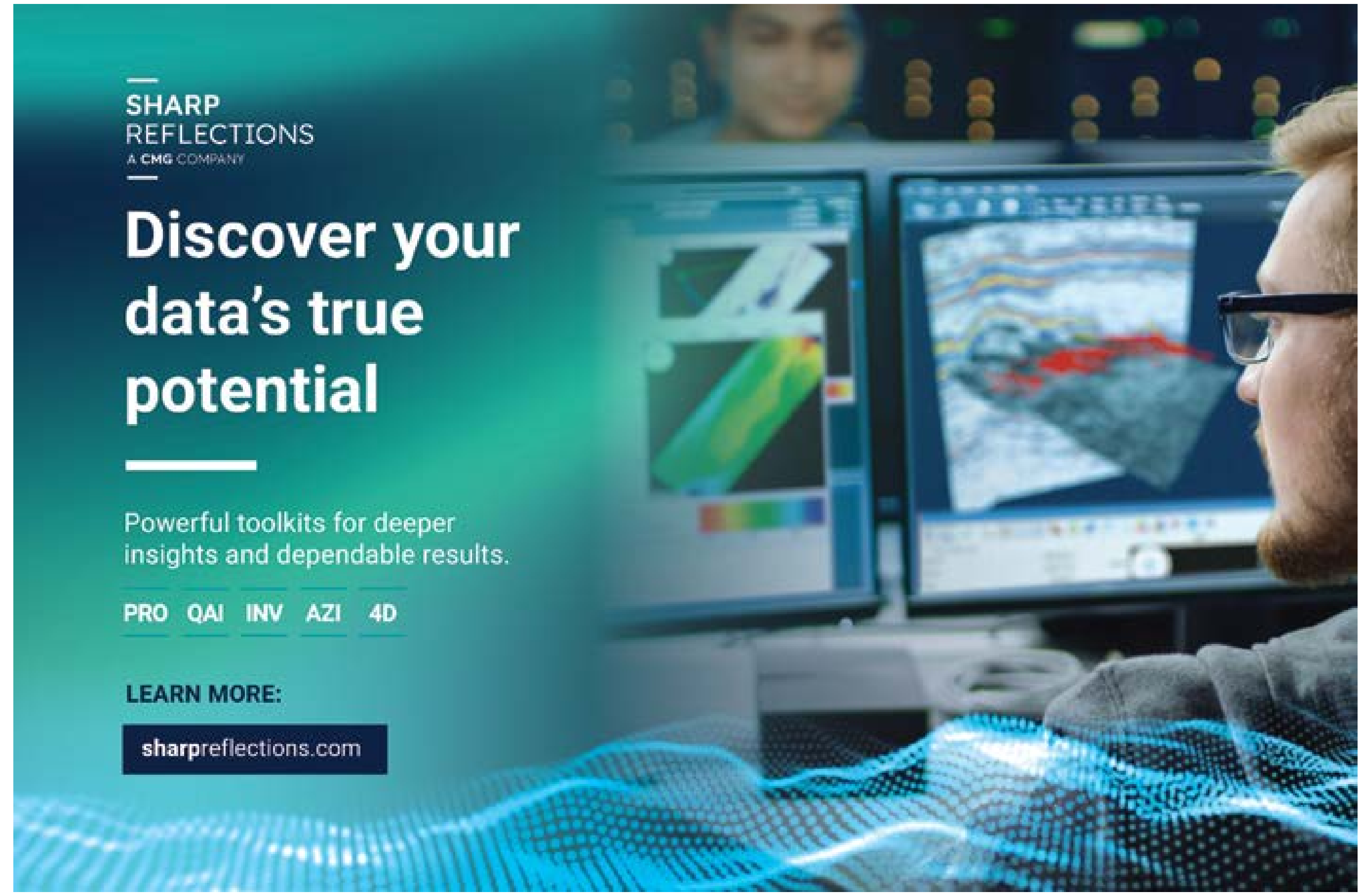
THE MONEY-SCRAPING EXERCISE THAT GEOTHERMAL DRILLING IS

"I have never seen this during my career in core analysis," said someone to me the other day. He was referring to a core cut in a geothermal well in a European capital city. "After the major expense of cutting a core from deep down, all the operator asked us to do was obtain a few plugs to run porosity and permeability tests on," he said. That was it. It shows how tight budgets are in the geothermal industry; there is no room to properly analyse data, even when that data was acquired at great cost. This is one of the problems of core analysis, too; it is always one of the last parts of the drilling budget, so only a bit of cost overrun will immediately result in subsequent work being scrutinised.

THE SAUDI JOB MARKET

Until recently, the risk of losing your job in Aramco was only something that the expats needed to worry about. For nationals, it used to be a place where you could spend your time until retirement. That has now changed, somebody told me the other day. Even Saudi nationals have to compete against each other and no longer have the guarantee of keeping their jobs for life. It is a sign of an increasingly competitive landscape in the oil business.

ILLUSTRATION: PCR.VECTOR / FREEPIK.COM



A loss of connection to our energy system

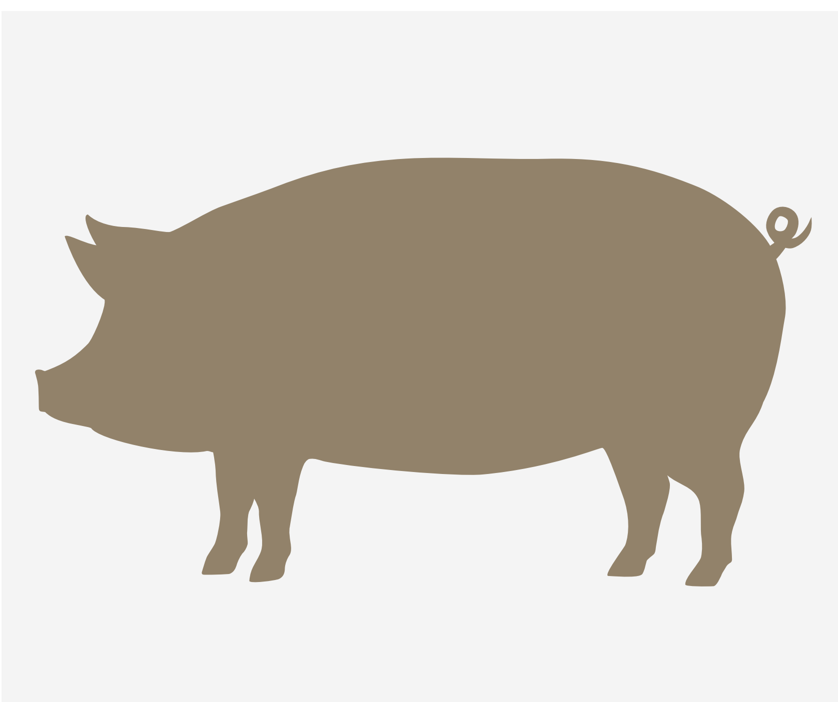
To understand our energy system is to also understand biology, as the biological world knows where their next meal is coming from

THREE ESSENTIAL pillars of modern society are food, energy and access to clean water. The World Resources Institute refers to insecurity in these resources as a "Triple Threat". The UN describes them as "a nexus at the heart of sustainable development".

It's often lamented that we have lost connection with the source of our food; occasionally, everyone gets a bit sad and donates money to a charity so that inner city kids can visit a zoo to see that ham does not grow in a packet. So, where is the same drive to reconnect with our energy system? Few people in the West cut their own firewood now, and centres of oil and gas extraction are generally far away.

As stated in one of my earlier columns, the problem stems from the fact we have forgotten what energy poverty means. Ask someone who experienced the recent Iberia blackout on the 28th of April what 24 hours of no energy means for a modern society. It grinds to a halt.

We should not treat our energy system as just another input to the economy - it **IS** the economy. The greatest single error of modern economics is the assumption that, if we understand money, we also understand the economy. This fallacy is reaching a climax now as the practice of diminishing returns of net energy comes into play from those 'easy to find' reserves and saving the difficult and costlier for a 'later' date.



This animal stands at the basis of your ham sandwich.

SOURCE: DENYS HOLOVATIUK VIA ADOBE STOCK

The 2025 world is in no imminent danger of running out of fossil fuels, but in the long run, they will have to be replaced regardless of their relationship to climate change. If we look at energy demand since we started using coal, it shows that our energy demand has gone up 10-fold, driven by industrialisation, population growth and expanding digital infrastructure.

So, what`s going to meet our energy needs for the next 100 years? If demand grows another 10x, we will need energy sources that are not just clean and reliable, but truly scalable. The uncomfortable truth is that this leaves only two serious contenders: fusion and fission. Fusion is a bit of a long-term bet, so that's why you can see the world's tech companies currently scrambling to underwrite the technological evolution of both forms of nuclear now.

As we stand on the brink of an energy future shaped by nuclear innovation and a deeper understanding of our biological roots, it's time to rekindle our connection - not just with the sources that power us, but with the very essence of how we sustain ourselves.

Only then can we forge a resilient, equitable, and truly sustainable energy system - one that remembers where it comes from and shares that knowledge with every generation to come. Because in reconnecting with our energy, we reconnect with our future. But to repudiate that connection is to return to our past, and all the danger, insecurity, discomfort and decivilisation that can be found there. ■

Rodney Garrard

Exploration in the vast marine expanse of Oceania

The smaller island nations of Oceania have seen various levels of oil and gas exploration, but soon, there will be another serious attempt to prove hydrocarbons in this part of the world

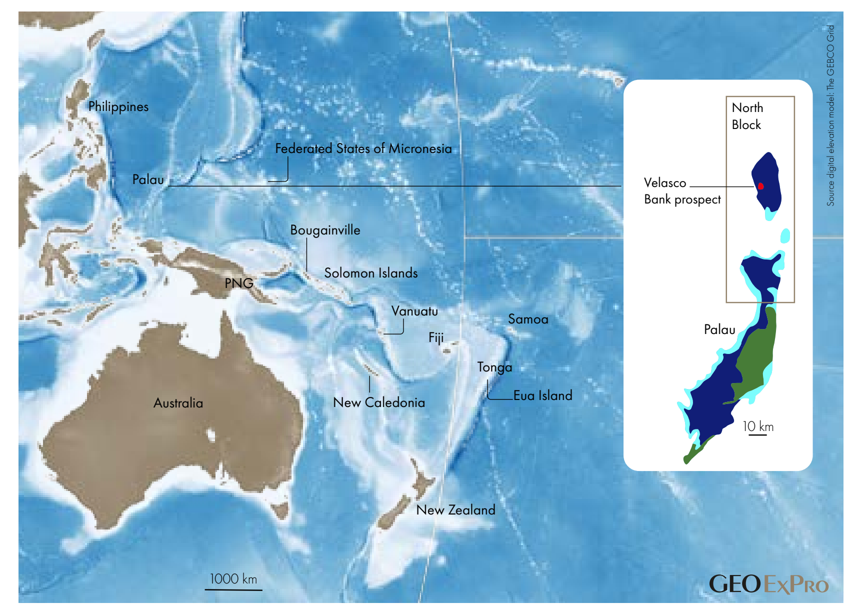
TEXAS-BASED Palau Pacific Energy (PPE) is the operator of the North Block Concession, off the northern part of the Republic of Palau, east of the Philippines, and is planning the first wildcat drilled in Oceania for a while. Palau saw its first exploration activity in 1977, when US company Yates Petroleum was awarded a licence and acquired seismic, and later TMBR/Sharp held a permit. The area was subsequently licensed to PPE. The target of PPE's wildcat is a large Miocene reef, designated the Velasco Bank Prospect, in 40 m of water; Pliocene gas sands are a secondary objective. The prospect is well-defined on 2D data and drill-ready. A 2022 resource report by Gaffney Cline & Associates (GCA) shows impressive volumes of over 700 million barrels of unrisked, prospective oil resources. Forward plans, after a successful test, may include the acquisition of 3D seismic.

Looking at the other remote islands in Oceania, Fiji saw a series of on- and offshore wells drilled in complex geology between 1980 and 1982. Operators included Chevron, a Worldwide Energy consortium led by Pacific Energy & Minerals, and Bennett Petroleum. After a lull in activity, Australian company Global Petroleum held blocks in the mid-2000s, and in 2009, Chinese-funded Southern Cross and Seu Tuinavatu Petroleum Mines & Minerals were awarded blocks that were subsequently revoked, following an apparent failure to fulfil work programmes. In 2019, there were reports that Fiji-based Akura, with some New Zealand backing, was negotiating for onshore acreage in Fiji, having previously held a position in the country between 2009 and 2014. A 1993 South Pacific Applied Geoscience Commission (SOPAC) publication highlights over 20 reefal leads of Late Miocene and Pliocene age.

The Solomon Islands have been the venue of a number of seismic surveys, including those undertaken by majors Shell and Mobil in the 1970s. No wells have, however, been drilled, although Shell's 1975 L'Etoile-1 wildcat, off the Papua New Guinea (PNG) island of Bougainville, is close to the Solomon marine border. Encouraged by the discovery of oil seeps on Eua Island, Tonga saw a flurry of activity in the early 1970s, when the Tonga Oil Exploration Consortium (TOEC) acquired seismic data and drilled two onshore wells. Later in the 1970s, a US company drilled three onshore wells. More recently, between 2014 and 2017, Baringer Oil & Gas held licences in Tonga, with a plan to drill wells, possibly targeting large Eocene reefs. However, the wells were not drilled, and the contracts expired.

New Caledonia saw some of the earliest exploration activities in the region, with the government-controlled Société de Recherche et d'Exploitation de Pétrole drilling onshore wells in the 1950s, on the Gouaro Anticline. In 1999, Victoria Petroleum drilled the Cadart-1 well on the same anticline, drilling deeper in the West Coast Basin, and discovering gas in a tight Cretaceous section. Despite the wells on the anticline having encouraging hydrocarbon shows, there have been no further drilling activities in New Caledonia. ■

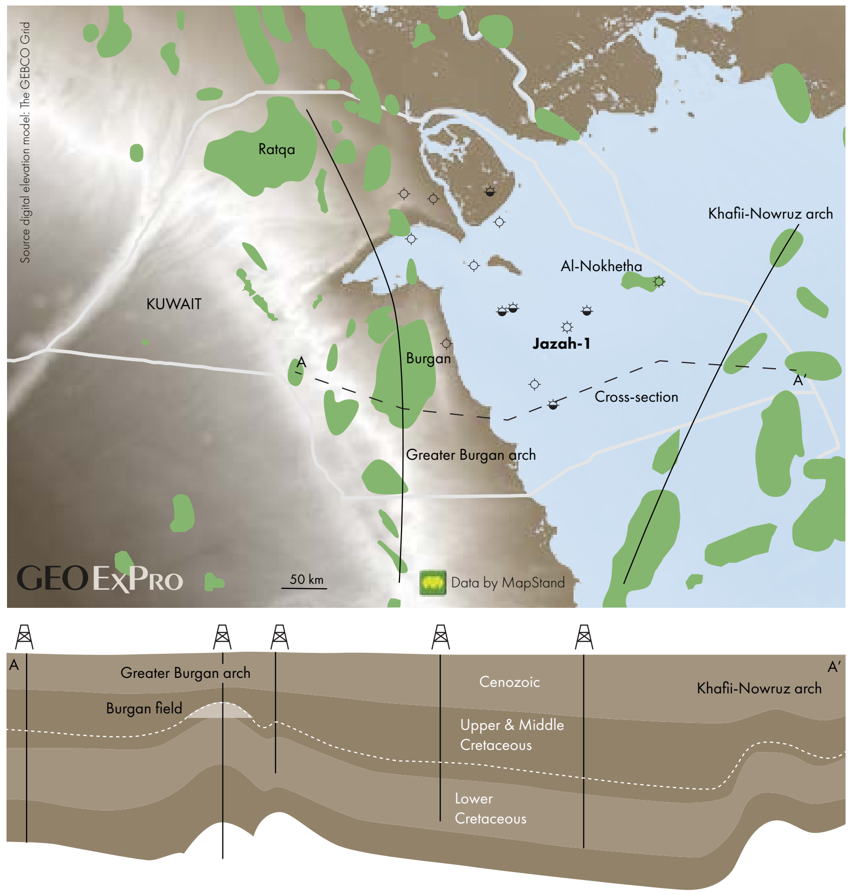
Ian Cross - Moyes & Co



KOC continues its exploration success in what could be described as a syncline

Oil and gas continue to be found in between the more prominent structural highs, where Kuwait's hydrocarbons are mainly from

A BIT MORE than a year ago, KOC announced the discovery of oil and gas in the Al-Nokhatha structure offshore Kuwait. Based on regional data and the location of the discovery, I concluded that a stratigraphic trapping element may be a key factor in the field, given that it was found in the large monoclinal structure between the so-called Burgan and Khaffji-Nowruz Arches. These arches represent the two uplifted and folded zones that still form the nucleus of where most of Kuwait's oil and gas have been found and produced, as the map illustrates.



This is not the first time exploration is taking place in the area of the monocline. In the 1960s, Shell drilled three wells at locations where very low-relief closures were mapped. As Abdul Aziz Al-Fares and co-authors explain in a paper they published in GeoArabia in 1998, the well that performed best fizzled out to 103 bopd after five days of testing. In the 1980s, KOC started another campaign offshore. One of those was to further test the area of the best-performing Shell well, but the results disappointed, with oil shows at best. The second well in the KOC campaign tested 420 bopd from the Minagish Formation. That is not a great amount, but still important in the light of what follows.

I am not entirely sure how much drilling followed after the 1980s KOC campaign, but it is unlikely that many wells were completed, given the information at hand. It may therefore be tentatively concluded that the current drilling operation KOC has embarked on in the area of the monocline is a third proper attempt to prove resources in this less "conventional" part of Kuwait's territory.

The drive to find additional resources may be more significant now. S&P published a study in 2022 concluding that Kuwait needs additional swing production capacity. In addition, similar to what Saudi Arabia is doing with the Jafurah project, Kuwait may also be interested in using gas for local electricity production whilst keeping more oil for export.

Regardless, the Jazah-1 discovery that was announced the other day is yet another exciting one, given the background information provided. Again, located in the heart of the monocline where structural closures are small or absent, it seems that KOC is now able to successfully target stratigraphically trapped resources that were missed in earlier attempts. The reported resource for Jazah-1 stands at about 1 Tcf or 29 Bcm, which is not major, but an encouraging result nonetheless. And similar to one of KOC's 1980s wells, the reservoir is reported to be the Lower Cretaceous Minagish Formation that produced 420 bbls / day on test 45 years ago. Are synclines the way to go? ■

Henk Kombrink

COVER STORY

"It would be a lot easier to build a pipeline to Qatar, but that is not an option"

Josef Shaoul – Fenix Consulting Delft

COVER STORY

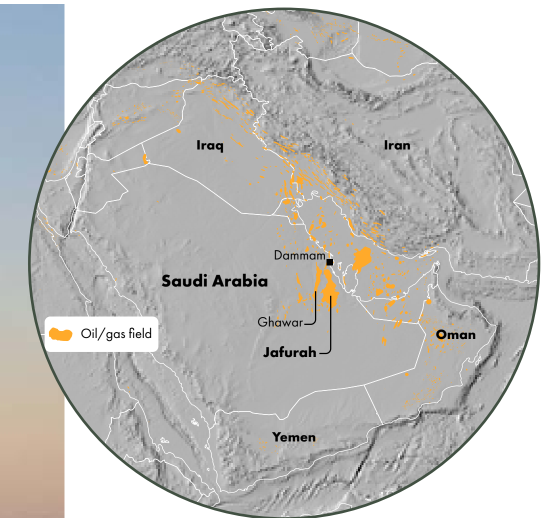
AN UNCONVENTIONAL UNCONVENTIONAL GAS PROJECT

As the Jafurah project in Saudi Arabia inches closer to first gas, the scale of the development becomes even more impressive. With about 10,000 wells to be drilled and fracced, Jafurah is comparable in size to what is happening in the Permian Basin, where around 5,000 wells are being drilled per year. However, there is one big difference, and that is the way first gas will be achieved in Saudi Arabia. Rather than incremental growth and hooking up new wells to production facilities one by one, as is the case in the USA, the Jafurah infrastructure has been built to open the taps at once, with many wells being drilled, fracced, tested and temporarily shut in over the years. The question, therefore, is how production will be once these wells are opened after sitting idle for years. Time for a closer look at what this project is all about.

HENK KOMBRINK

A typical desert landscape from Saudi Arabia.

PHOTOGRAPHY: ADOBE STOCK

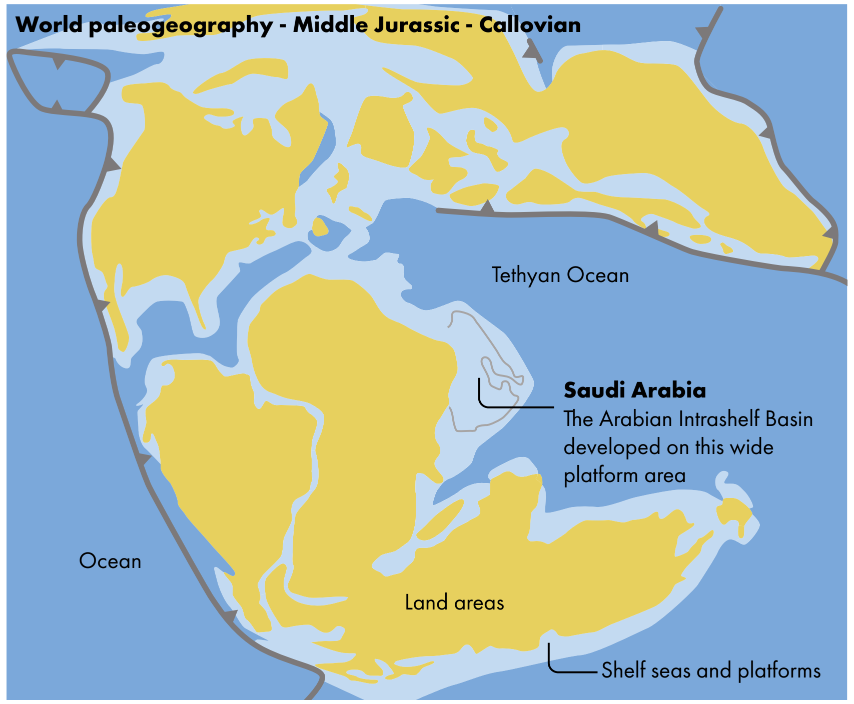


Location of the Jafurah field in Saudi Arabia.

When I visited the MEOS GEO Conference in Bahrain this year and spoke to some people about projects currently ongoing in the region, it slowly dawned on me that there was one project that had escaped my attention. One that is of such a scale that it is actually a miracle that it had never appeared on my radar before: The Jafurah unconventional gas project in Saudi Arabia. Even when I attended the IPTC Conference in Dammam in February 2024, browsing through my notes, I could not find a reference to this project that was happening not too far to the southeast of the city.

Two analysts from S&P Global woke me up; they raised the Jafurah project on several occasions whilst we were driving back to the hotel after a long day at the show. As happens often, it is those conversations with industry insiders that form the inspiration to write a story.

The scale of Jafurah is huge. The unconventional gas project entails drilling around 10,000 wells. And that is not the only thing that makes Jafurah special; it is even more special when one realises that these wells are sitting idle until they are being opened all at once, when the project will finally deliver first gas. That is a very different strategy compared to how unconventionals work in ▸



Global paleogeographic setting of Saudi Arabia, illustrating the wide shelf area the Arabian platform was part of in Callovian times. The Intrashelf Basin formed on this shelf.

REDRAFTED AFTER SCOTESE (2014)

the USA. There, wells are drilled, fracced and put on production straight away. The learnings of one well form the basis for drilling the next. It is the way to drain the sweet spots most efficiently.

However, with the Jafurah wells, this learning curve does not exist. Sure, wells are probably being subjected to a short-term production test after completion of the frac job, but are then closed in until the entire project is ready. As someone who has followed the project from nearby said: "It is an experiment on a large scale."

For this article, I draw on the input from several people I spoke to over a timespan of about a year. In a few cases, I was not even 100 % sure people were telling me something about Jafurah, but now, when pulling it all together, I became more convinced that they were. It shows the sensitivity around a project of this kind, which is understandable. To my knowledge, it is the first unconventional gas project on this scale that is being developed outside the USA and possibly Canada. And because it is being done in such a different way, i.e. through drilling the whole project first before putting it online in one go, it is worth being written about.

HARD BEDS AND DATA SCRUTINY

The first time I seem to have heard about the project was through someone I spoke to at yet another conference earlier this year. He was a driller and had spent six years in the desert working on Chinese rigs that were drilling "a huge gas field", as he described it. Now, thinking back, it might have been Jafurah. He also said that the rigs were primitive; the beds were just a simple wooden plank with a thin sheet to sleep on. So, in order to lie comfortably, he had to scramble as much linen as possible to make a slightly softer bed.

He also told me that there were six rigs in a row, drilling in a grid-like pattern and completing four wells per pad. It sounds very much like the approach taken at Jafurah, based on conversations I later had in Bahrain. One of the last things he said was that the wells were all drilled and completed before the surface infrastructure was put in place, adding that this was unheard of in the West.

This corresponds to what I heard through another conversation I had with someone who is probably directly involved with the wells that are being drilled. One of the things I remember him telling me is the scrutiny he and his team experienced when it came to using wireline logs to drill the wells. Let's put it this way: The suite of logs to be used to find the landing zone was always under review. Of course, this happens all the time, but with so many wells to be drilled, all in the same formation, it is not a surprise that there is pressure on saving money in any possible way.

And saving money is probably required, because unconventional gas developments are a very different kettle of fish compared to conventional projects.

CONVENTIONAL VERSUS UNCONVENTIONAL

As someone else with exposure to the unconventional business reiterated the other day, there is a big difference between unconventional and conventional projects. Margins tend to be much higher with conventional developments, simply because the geology is more favourable, with higher porosities and permeabilities. And there is a surprise in store sometimes, which means that production can also be much more favourable than anticipated. All thanks to the geology that ultimately remains hard to predict and model. Those sorts of presents are much harder to come by in the unconventional arena, because it is all about drilling wells. Many more than in the conventional domain. "And when it comes to engineering, there are no gifts," I was told.

The unconventional industry is much more like a real estate game, I learned as well. In the USA, the money you can make in shale is not through production, but through the acreage you can sell. It starts with a small company proving the potential through drilling a few wells, and once this has been demonstrated, the value of the acreage goes up and can be sold. In the Eagle Ford, the value of an acre went up from $25 in 2000 to around $50,000 for the same plot of land a few years later.

At the same time, booking reserves in shale can be done at a relatively low cost, as it is seen as a continuous basin that can be tapped into at any location. You are not required to prove commerciality with so many appraisal wells as is the case in the conventional business. This is probably one of the drivers for some companies to enter the sector and bump their reserve replacement numbers. The reality is different, of course, with Shell entering the US shale patch more than 15 years ago as an example. Peter Voser, a Swiss accountant who became Shell's CEO in 2009, decided to invest heavily in unconventionals in the USA, only to find out that production was not as rosy as they had expected. This subsequently led to the sale of their assets again, as well as the departure of Voser himself in 2013. Funnily enough, Shell is now back in shale.

Going back to Jafurah, we see another commercial dynamic. "Market conditions are very different in Saudi Arabia," says Josef Shaoul, who has been working in the frac business for decades with Fenix Consulting Delft. "The Jafurah gas production is all meant to save burning oil for power generation, so in that sense the cost of the project is directly tied to the money that Saudi Arabia can make by selling the oil on the international market rather than the gas price itself," Josef explains.

On top of that, Middle Eastern countries are adamant to develop their own gas resource rather than being dependent on supply from neighbours. "It would be a lot easier to build a pipeline to Qatar, but that is not an option," adds Josef. "In that sense, the pricing mechanism is not at all driven by the economic factors that determine the same industry elsewhere."

THE WELLS

In Texas, there is an army of engineers in the field that continuously check upon things and tweak wells whenever this is required, further supported by people in the office who keep an eye on pro- ►

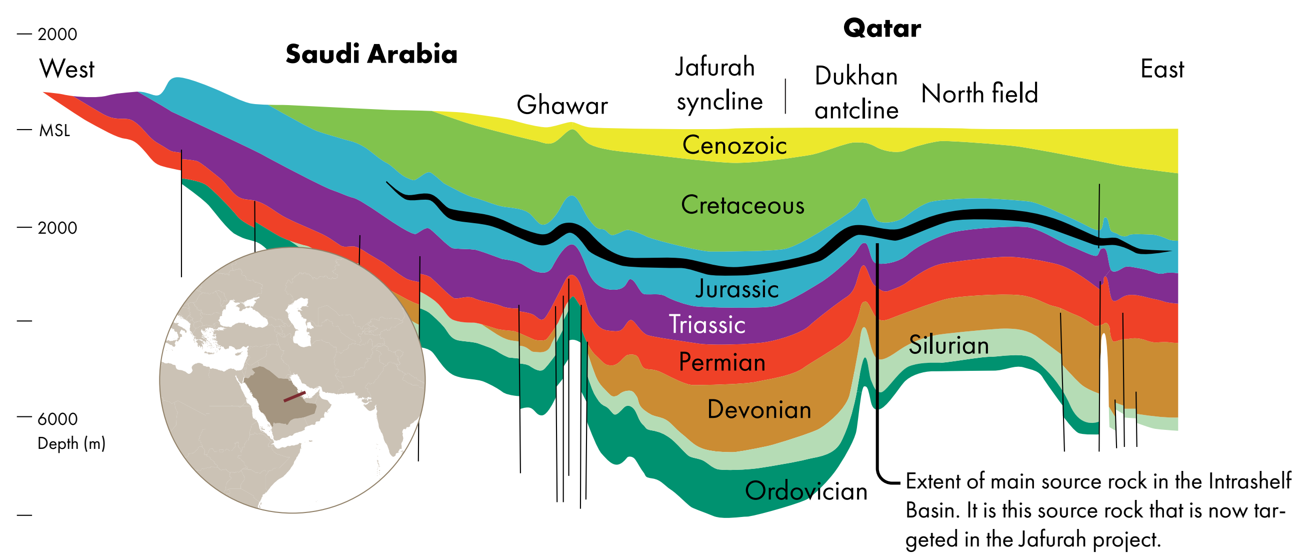
HOW NEW IS FRACCING TO THE MIDDLE EAST?

Hydraulic fraccing is not new to the Middle East. In fact, it has a long history. "Especially in Oman, a country that does not have all the same high permeability reservoirs as the other main producers in the region, fraccing has been applied to tight reservoirs for decades," says Josef Shaoul. "This was further aided through the PDO partnership with Shell and the international links established that way," he says. "In Algeria and Libya, fraccing has also been taking place since the 1970s."

"However, it is important to keep in mind that until recently, fraccing in the Middle East has focused on tight reservoirs and not on the shales that are being targeted in the US," says Josef. "For instance, in Oman, there are now projects ongoing that include fraccing of existing oil wells in an attempt to arrest the decline from mature fields. Some people in the Middle East might call it unconventional when a frac job is required, but it is important to realise that the reservoir quality in those cases is still a lot better than what the unconventional reservoirs in the US look like."

But regardless of the type of formation that is subjected to fraccing, the characteristic of a successful frac is that production is high initially, with a steep decline. "Some people don't get that and think that production should be sustained," explains Josef. "But that's not how a successful frac looks like. The frac job would not have been needed in the first place if production had been sustained for a long time after it. This is what we need to explain often."

"Fraccing is not the ultimate solution either," Josef adds. "If there are no hydrocarbons in the reservoir, a frac job will not result in more production. That is another aspect that seems to be forgotten about sometimes."



This cross-section illustrates the structural position of the Ghawar field in Saudi Arabia and the North field in Qatar, with the Jafurah syncline in between. The stratigraphic position of the Hanifa source rock, which is the interval that is now been targeted by the Jafurah wells, is shown in black. The lateral extent of the source rock also indicates the lateral extent of the Intrashelf Basin at the time of deposition. formed on this shelf.

ADAPTED FROM: ABDULKADER M. AFIFI, AAPG PRESENTATION, WITH MODIFICATION BY A. WILSON duction data all the time. And it is based on that type of work that the next frac job is planned. This system of working with experience being built up as the basin is further unlocked is missing in Jafurah, where it is a single development concept that does not allow for learnings to be implemented along the way.

So, the big question that must be in many people's minds is, how are the wells drilled on Jafurah going to produce, after having been shut in for about ten years in some cases?

Someone I spoke to, who has significant expertise in the engineering side of the unconventional business, is not so sure about the success of the operation. He fears that scaling and liquid loading will be issues that might require a re-frac for some of the older wells. Josef Shaloul is more optimistic about it. "When a short clean-up and production test is carried out immediately after the well has been fracced, there is a good chance the well will start producing as expected even after it has been sitting closed in for a while," he says. "I have seen this in Oman, where an LNG terminal was completed whilst the wells for the project had already been drilled. They were not closed in for ten years such as some wells at Jafurah, but still up to about a year. These wells seemed to start production just fine once the valves were opened."

NEW TECHNOLOGY

Josef is of the opinion that laser technology, which some sources say has been used to help stimulate the Jafurah wells, is not commonplace yet. He has not come across it as a way to replace currently applied fraccing technologies. "Aramco has a tendency to support R&D and test new technologies," he says, "but it is probably far off from being implemented widely. Even when people have wanted to work with lasers for a long time, I have yet to see it appear on the market as being truly disruptive. In unconventional applications, the key parameter for production is frac area. No other technology can compete with hydraulic fraccing in creating a fracture area for inflow of gas or oil."

THE GEOLOGY OF JAFURAH

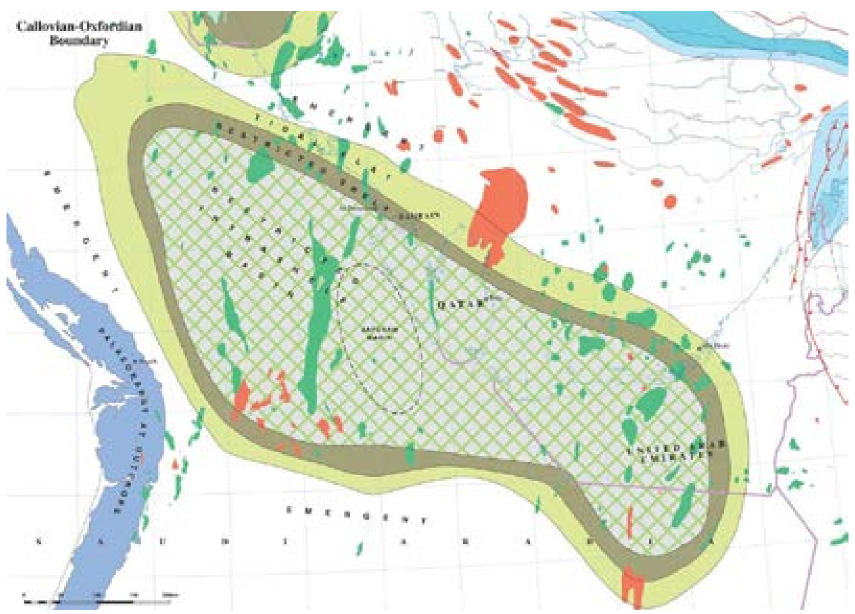
The Jafurah 'basin' play is within the broad synclinal trough between the Ghawar anticlinal trend and the Dhukan anticlinal trend, structures formed during the Tertiary when the Arabian Plate collided with the Eurasian Plate. The Jurassic interval of interest formed at the Middle and Late Jurassic boundary within the Arabian Intrashelf Basin. To find out more about the geology of the Jafurah basin, I travelled to London King's Cross to meet with Augustus (Gus) Wilson in a café not far from the station.

Gus worked for Saudi Aramco a long time ago, from 1973 to 1981, and later worked on other projects in the area, keeping alive his fascination for the geology of the Arabian Platform. Five years ago, he published a book on the regional geology of the area, Geological Society Memoir 53, which can be seen as a culmination of his studies in the region.

Gus remembers the years he worked at Aramco vividly. "One of the projects I worked on was to identify and map all the source rocks in the region," he says. "At the time, the understanding of what was actually the source rock of the Ghawar and other oil fields was still in its early stage," he says. "Some people claimed that the source rock was the same reservoir carbonate in which oil was found, but our analyses proved that the reservoir carbonates were unlikely to be the source rocks because they had very low TOC's. Instead, our analyses of the slightly older laminated black organic-rich carbonates clearly suggested that these were the prime suspects."

These early Late Jurassic (Oxfordian) source rocks of the Lower Hanifa Formation were deposited in what is described as the Arabian Intrashelf Basin. This basin formed on the eastern margin of the Arabian Platform, facing the Tethyan Ocean.

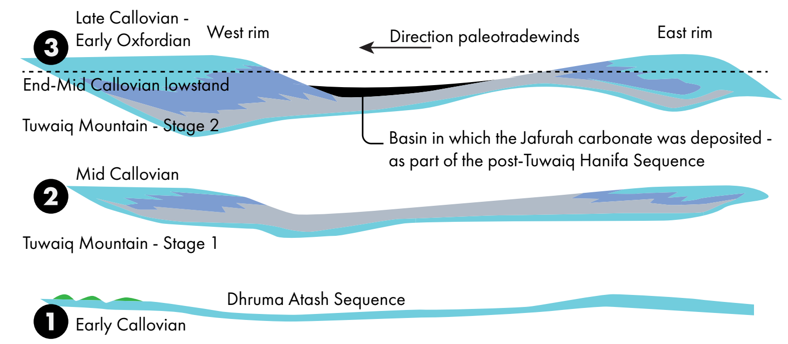
The Arabian Intrashelf Basin facies are underlain by regionally extensive and exceptionally uniform platform carbonates belonging to the Dhruma Atash Sequence, deposited across the Arabian Platform during Late Bathonian to Early Callovian times. As Gus describes in his book, it is hard to interpret the origin of such a flat, regionally extensive interval of similar facies.



Depositional environment map for the transition from Callovian to Oxfordian times when the deposition of the Lower Hanifa source rock took place in the Intrashelf Basin. Note the location of the current Jafurah project in the centre of the basin. This map is part of a series of depositional facies maps compiled by Cambridge Carbonates.

SOURCE: CAMBRIDGE CARBONATES

The transition to the subsequent Tuwaiq Mountain sequence, which is described as the time when the depositional geometry of the Arabian Intrashelf Basin really took shape, starts with the development of a huge body of water across a wide area, surrounded by a rim of shallow water carbonates. The shallow water carbonates forming the rim prograded basinwards over time, but projecting the position of the Jafurah development onto this map, the Jafurah region maintained a more distal position in the basin, away from the shallow carbonate rims.



Evolution of the Intrashelf Basin in Callovian times from the deposition of the homogeneous Dhruma Atash Sequence to the rimmed margins of the Tuwaiq Mountain. The Lower Hanifa source rock was deposited in the basin between the exposed rimmed shelves at the time of a sea-level lowstand. Adapted after figure 5.11 in Wilson (2000) – The Middle and Late Jurassic Intrashelf Basin of the Eastern Arabian Peninsula.

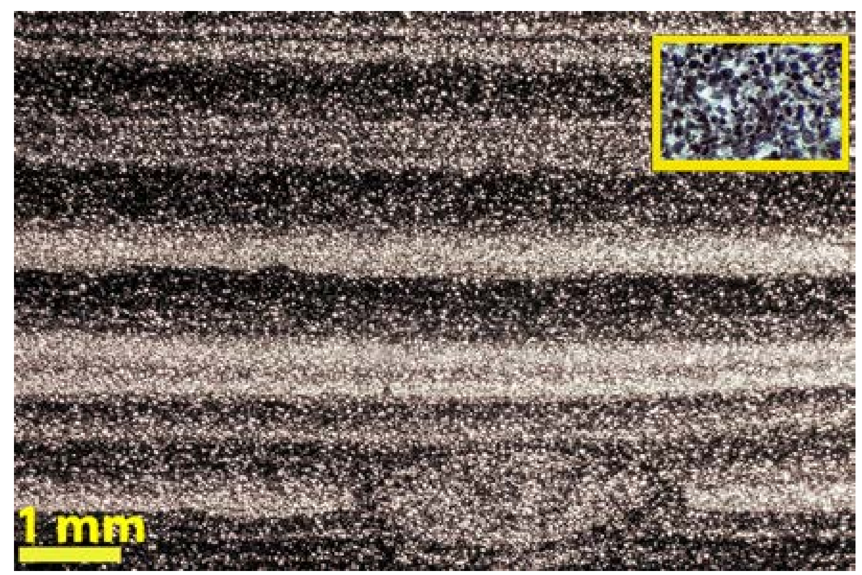
The Tuwaiq Mountain sequence of shelf progradation was probably terminated due to a global lowstand at the end of the Callovian. It is during that lowstand system in which the source rock that is now targeted by the Jafurah wells was deposited.

The base of the high-TOC interval is a very sharp boundary, indicating a sudden change in depositional environment. This has been observed by Gus in many wells across the region. But what are the further characteristics of the succession?

In contrast to what some people think, the source rock is not a shale, but a carbonate. To be more precise, it is a very organic-rich laminite, characterised by the alternation of light-coloured laminae of micropeloidal micrograinstone and dark organic-rich carbonate laminae. The light-coloured laminae show what can be interpreted as small-scale scouring, which may indicate reworking of the peloids by bottom currents. Gus adds that he has never seen a similar facies during his 50-year career working with carbonates of very different ages, although he does write that others have found such facies elsewhere.

Then there is the thickness of the source rock, which increases going from the east of the Intrashelf Basin to the west. Gus attributes this to the prevailing wind direction at the time of deposition, mostly blowing from the east. This meant that the western rim of the basin had a much higher wave energy than the eastern margin, which led to higher rates of deposition in the west, and hence a thicker source rock. There was also more accommodation space developed in the west.

The total thickness of the source rock is not very easy to reconstruct because of a lack of published well data, but the estimations vary from 10 m to a bit more than 40 m in the Jafurah area. A source rock maturity map compiled from published data in the book Gus published shows that the area of the Jafurah project is currently in the gas-generating window.



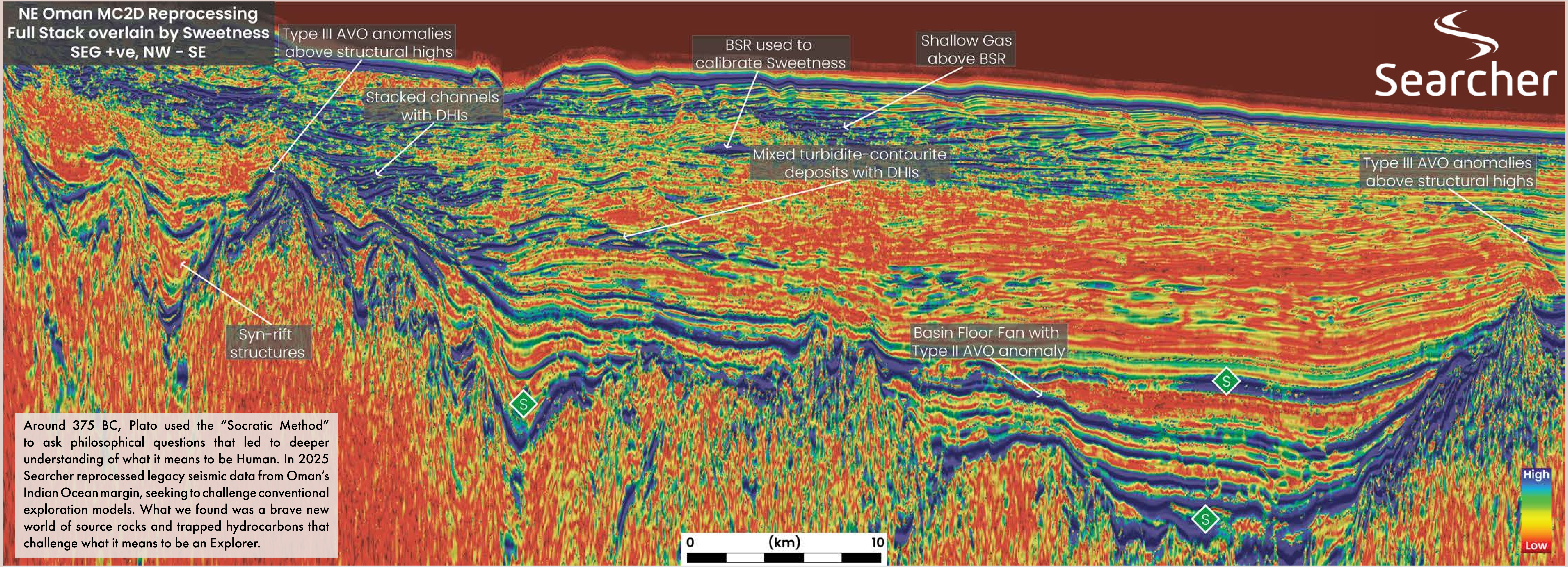
A thin section photo showing the composition of the Lower Hanifa source rock, a very organic-rich laminite, characterised by the alternation of light-coloured laminae of peloidal micrograinstone and dark organic-rich carbonate laminae

SOURCE: A. WILSON

FINAL THOUGHTS

Even though lots of aspects of the Jafurah development remain unknown because of data confidentiality, it is clear that the development is of a massive scale and because the estimated number of 10,000 wells will be hooked up after having been closed-in for up to ten years in some cases, it is very much the question of how these will behave during the first phase of production. However, as we have seen from the geological observations, the Lower Hanifa source rock in which the wells are being completed probably has a very strong lateral continuity, which is probably an advantage for Aramco, as they lack the opportunity to find the sweetspots in a similar way as their American colleagues do in the Permian Basin. Whether it will be enough to guarantee a big success remains to be seen, but it is obvious that Jafurah is very much an unconventional unconventional project. ■

Sweetness and light in Oman's Indian Ocean



Around 375 BC, Plato used the "Socratic Method" to ask philosophical questions that led to deeper understanding of what it means to be Human. In 2025 Searcher reprocessed legacy seismic data from Oman's Indian Ocean margin, seeking to challenge conventional exploration models. What we found was a brave new world of source rocks and trapped hydrocarbons that challenge what it means to be an Explorer.

NW-SE final PSDM line in depth displayed with the sweetness attribute (instantaneous amplitude (reflection strength) / square root of the instantaneous frequency).

Bringing the light to Oman's India Ocean hydrocarbon-rich future

Karyna Rodriguez describes how improved data resolution facilitating new technological inquiry in Oman's Indian Ocean is turning "flickering shadows on the cave wall" into high-definition images of unexpected source and reservoir

KARYNA RODRIGUEZ, NEIL HODGSON AND LAUREN FOUND, SEARCHER

In Plato's Allegory of the Cave (Book VII of The Republic), prisoners (you and me) spend their lives chained in front of a wall in a cave where all they observe are shadows cast by people walking past the cave mouth in the light. Imperfect understanding ensues; a powerful allegory for the world where only partial interpretations can be made because all one can observe are imperfect, partial images.

Reprocessing legacy seismic data through a modern deghosted PSDM sequence not only brings the prisoners out into the bright light of clear vision, but it also supplies them with a smartphone. In 2021 our understanding of the Tethyan petroleum systems of the Oman Sea off Oman's North Western coast was revolutionized by the imaging of Searchers' Reprocessing that underpinned the 2024 License Round. Now in 2025, Searcher has finalized reprocessing phase 2; 5,000 km of 2D in the Indian Ocean, and the results on Block 21 are truly surprising. As we are released from the "poor imaging cave", we can see stratigraphy in the syn-rift, a new stratigraphy and unexpectedly source rocks amongst clastic AVO responses that shine a light on directly indicated hydrocarbons.

The sweetness attribute (see the Foldout) has played a major role in the identification of unsuspected working petroleum systems, and this is especially powerful when combined with angle stack data (particularly the ultra-far angle stack). Sweetness is calculated as instantaneous amplitude (reflection strength) divided by the square root of the instantaneous frequency, and discriminates for low-frequency, hydrocarbon or organic-rich rock responses.

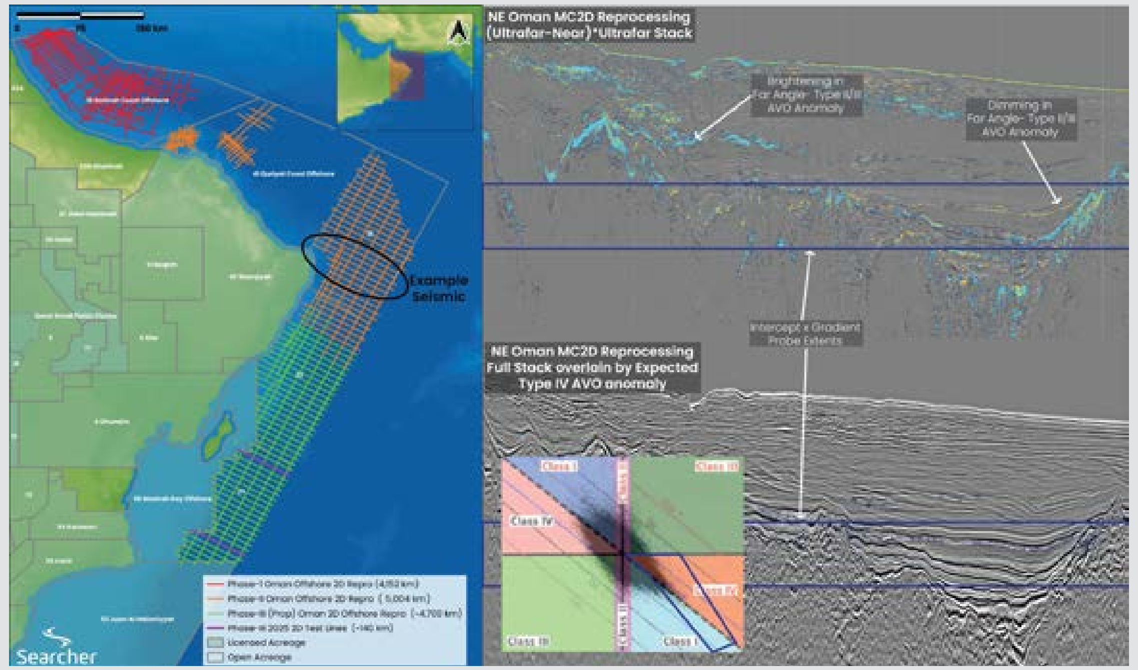


Figure 1: Location map showing reprocessed seismic data offshore Oman. The dark blue polygon in the seismic is the probe extent for the crossplot and in the crossplot is where we expect an AVO Type IV response. The top seismic section shows the (Ultrafar-Near)*Ultrafar angle display, where blue represents an increase in amplitude in the ultrafar angle (AVO Type II and Type III) and yellow indicates dimming the ultrafar angle (AVO Type IV). The candidate source rock indicated by the sweetness attribute is also associated with an AVO Type IV response.

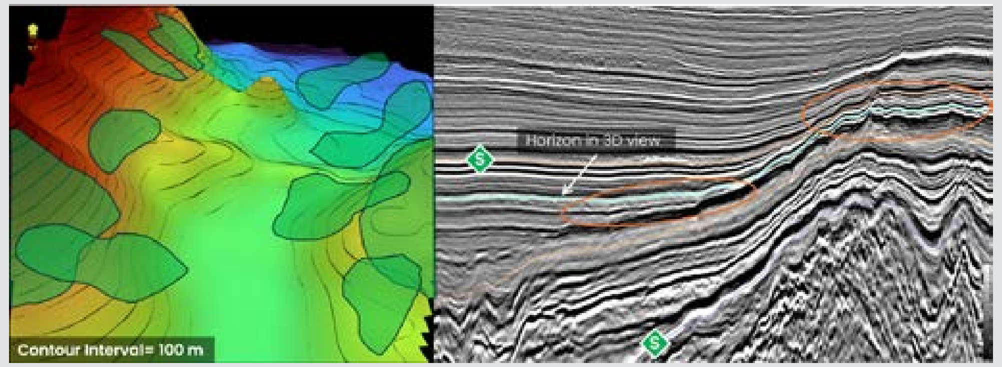


Figure 2: Map on the left is the structural map of the green event in the seismic section on the right. The purple and brown events are two of the source rocks identified. The green event has several clear and large, AVO Type II anomalies, outlined by the green polygons in the structural map and these are all structurally confined.

All observations are further calibrated with an extensive BSR (Bottom Simulating Reflector), interpreted to be the base of a methane hydrate zone, which overlies high-amplitude soft kicks of the free gas zone.

THE CAVE – A REGIONAL EVOLUTION MODEL AND LIMITED DATA

The Indian Ocean margin of Oman was a relatively abrupt Gondwanan passive margin on the southern Tethys, lying north of what would become the Indian subcontinent until some 200 Ma when Gondwana began to fragment. Syn-rift sediments of Triassic and Jurassic age were deposited as India initially separated from Africa, moving south, and then began its celebrated northern migration to scythe past Oman along the amazing Owen's transform. This strike-slip motion has created extraordinary, transpressional inversion folds to the south of Block 21, and even scraped an ophiolite slice across the syn-rift in the location of the Yumnah oil field south and west of Block 21.

On this incredible transform margin, India slid past Oman and the closing Tethyan ocean, docking with Asia in the Late Cretaceous, and consuming most evidence of the Oman conjugate margin beneath the western Himalayas. During the collision, though, it temporarily and partially closed the Sea of Oman in the Early Tertiary, allowing a restricted marine source rock to be deposited. During the Later Tertiary, the SW Oman margin opened onto the Indian Ocean and connected to the global ocean. Clastics being deposited in the closing Oman Sea were continually washed eastward to be deposited on the slopes of Oman's Eastern margin into counter regional dip traps (Figure 2) or down to and across the abyssal Owen transform. Whilst it had been thought that sediments coming off the eroding Oman Mountains (the Tethyan Ophiolite) might be basalt rich, the wadis flowing off the mountains rapidly cut through the ophiolite to erode granites generating quartz rich clastic deposits (Andy Racey, 2023). It is these sands that offer the high quality reservoirs of both stacked slope channel and basin floor sediments that we will chase using the newly reprocessed 2D.

THE SWEET ESCAPE – SOURCE ROCKS COME TO LIGHT

It has become common practice to use the sweetness attribute as a first pass in hydrocarbon prospectivity evaluation. This is greatly illustrated by the Orange Basin, where it was used to successfully identify the prolific Aptian source rock as well as the Mopane-3x (Galp discovery) and the Capricornus and Volans (Rhino discoveries).

Offshore Oman, the unexpected surprise was to see up to three candidate source rocks standing out with this attribute. Only one could have been suspected with the tectonostratigraphic evolution models. These events are extensive, with a decrease in acoustic impedance at the top and further corroborated with angle stack evaluation showing a clear AVO Type IV response where the high amplitude is seen dimming in the ultra-far angle stack (Figure 1).

Two more source rocks were identified using this methodology. And as can be seen in Figure 1, several AVO Type II and III anomalies were also confirmed. The AVO Type III response of the free gas associated with the BSR can be used to calibrate similar anomalies seen deeper in the section. Thrillingly, as seismic reprocessing allows the generation of ultra-far-angle stacks (36-48° for this dataset), AVO Type II anomalies are being identified and drilled successfully in deep water settings. Here, very large anomalies have been identified for the first time ever and mapped using this dataset. Some are clearly associated with structural highs (Figure 2).

THE RETURN TO THE CAVE

Staggering back into the cave to share the knowledge from the reprocessed data, we bring with us three blazing torches for illumination. First, the sweetness and AVO studies reveal at least three source rocks. Secondly, AVO Type III anomalies can be calibrated with the free gas below the BSR and the shallow gas anomalies and are found in the stacked basin floor sands below these. And lastly, most intriguingly, AVO Type II anomalies have been revealed on the ultra-far angle stacks, a trend observed in recent discoveries in the Orange Basin, where they indicate the presence of light oil.

In our global search for hydrocarbons to power the future world through its energy transition, we have escaped the bonds of incomplete illumination to find new truths that will set us all free.

When perforating below the Free Water level makes sense

How the IJssel discovery in the Dutch offshore became a success

"IT MAY BE the last oil field development in the Dutch sector," upstream analyst Bert Manders told me the other day. The IJssel field development in the northern part of the Dutch offshore, operated by ONE Dyas and partnered with Dana Petroleum, could indeed be the last oil discovery that will make it to first oil in the Netherlands. Only for that reason, it is worth writing an article about it. But there is another aspect that makes IJssel quite particular too, and that is the type of reservoir and the surprises it had in store.

IJssel is mostly reservoired in Upper Jurassic glauconitic sands of the Scruff Greensand Formation, deposited in a shallow marine environment. The difficulty with glauconite is that it has the physical characteristics of a sandstone but the chemical composition of a clay. Besides being a clay mineral, the glauconite grains themselves have a porous internal structure, adding up to a large portion of the total pore volume. Unfortunately, these grain-internal pores are micro-pores that hold capillary-bound water only, leaving no place for hydrocarbons. This is why water is more attracted to it than to "normal" sands, with the result that the derived water saturation log "reads" relatively high water saturations in glauconitic sands. In turn, that led to an initial placement of the projected Free Water level (FWL) at too high a level in the exploration well.

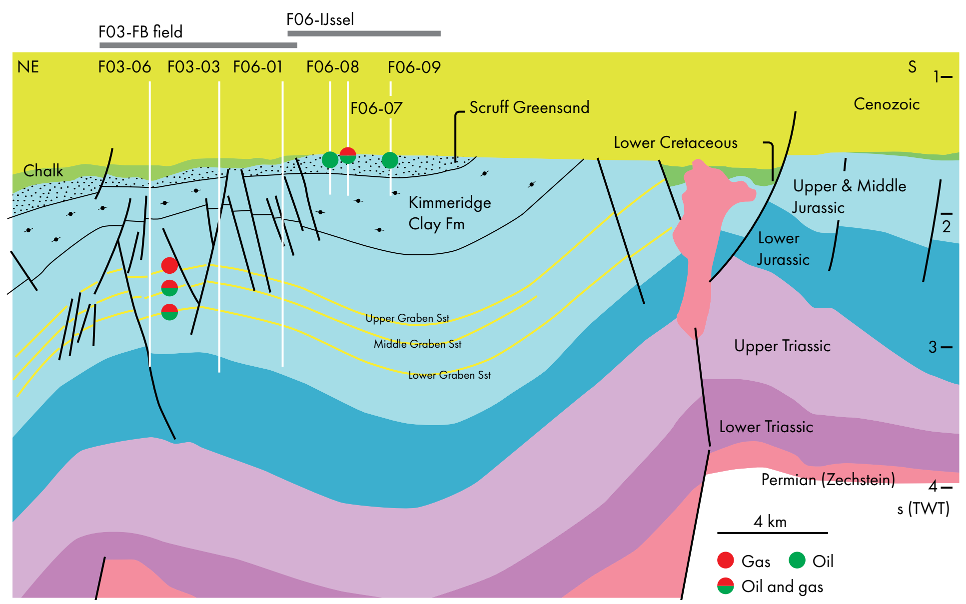
The tool that came to the rescue was the NMR tool, which is capable of differentiating between bound water and free water. The results from the NMR tool suggested that most of the water was bound, leaving room for another fluid to be in the macro-pores: Oil.

Then, it was also observed that oil shows had been made below the initially defined FWL, adding to the idea that there must be oil deeper down as well. This formed the basis to also test the formation below the FWL, with a very nice surprise as a result. As Rob Lengkeek presented at the Energy Geoscience Conference in Aberdeen in 2023, dry oil flowed at a stable rate from this newly and deeper perforated level.

This must have added the reserves to IJssel that made it worth pursuing with the development; ONE Dyas expects to produce almost 20 million barrels of oil from the field, as well as an additional 3.2 MMboe in gas over the course of 20 years, using four production wells and one water injector.

The last interesting thing about the IJssel discovery is that it is located very close to the F03B field, which has been producing oil and gas since 1994 from slightly older and deeper Upper Jurassic sands. The cross-section nicely shows how the F03B wells almost clipped the northern edge of the IJssel closure. It is not unlikely that the slightly "unconventional" behaviour of the glauconite-bearing reservoir forms one of the reasons why its potential was not realised until later on. But still in time for the field to be developed. ■

Henk Kombrink



N-S cross-section through the F03-FB field and the IJssel discovery in the northern Dutch offshore. The cross-section has been entirely redrawn on the basis of a seismic section published by Bouroullec et al. (2018). The stratigraphic position of the F03-FB reservoir units is schematic and does not represent reservoir thickness. The well locations are projected, and the white lines are not indicative of terminal depth.

Drilling deeper for new resources in Uzbekistan

Uzbekistan is seeing a 7.5 km well drilled to explore for gas in a stratigraphic trap setting

DOMESTIC GAS production has rapidly declined in Uzbekistan over the last few years, to the point where the country became a net importer since 2023 to meet demand. This has sparked the country's leadership to take action and form a new state-supported explorer under the name of Yangi Kon. This new organisation, whose role is to find petroleum resources in areas previously overlooked, has now embarked on a drilling project in the Ustyurt region in the west of the country that will hopefully prove potential in strata that have never been properly explored.

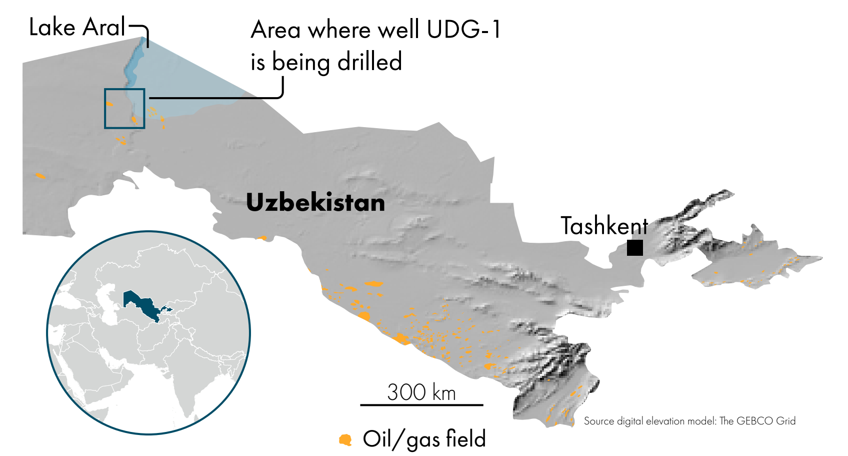
Thus far, the country has focused on exploring Upper and Middle Jurassic reservoirs. With UDG-1 well being drilled now, the focus is on Lower Jurassic strata, looking beyond the traditional plays. Another important factor to bear in mind is that, based on information available from a shared investor pack, the well is testing a series of stratigraphic traps, in contrast to the more traditional four-way closures. If the sandstones in the graben structure show good gas saturations, there is the potential for a major gas development. But at the same time, the depth of burial – around 6.5 km – means that there is a risk of finding fairly cemented rocks that don't flow that easily.

Another interesting aspect of UDG-1 is that the same Lower Jurassic strata were recently de-risked by another borehole (ZSK-1P), completed nearby. Instead of a stratigraphic trap, ZSK-1P targeted a structural closure, a bit shallower than UDG-1's planned TD. ZSK-1 did prove gas, though, which is a positive sign, and in fact de-risked the UDG-1 well.

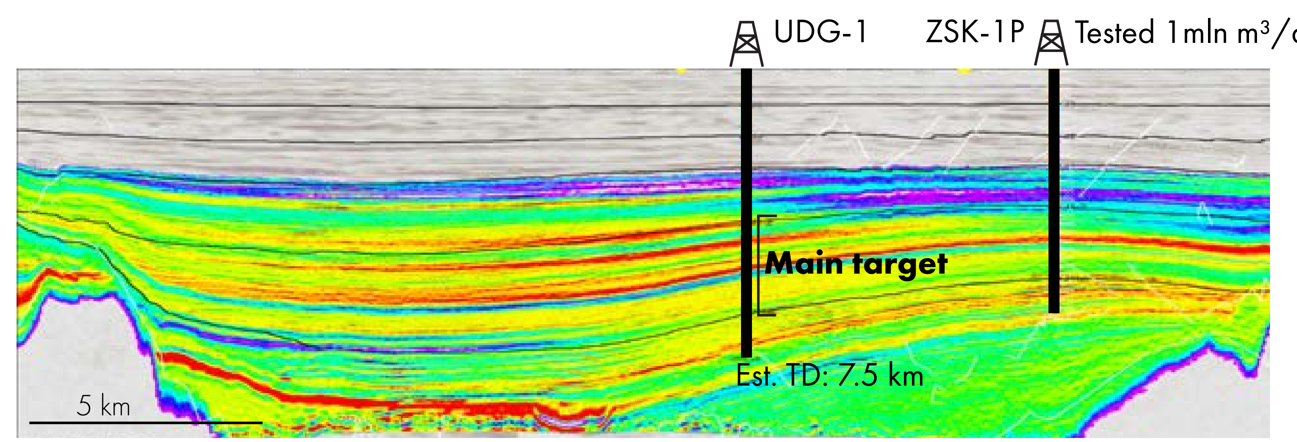
The location of the well spud is also quite special because only a few decades ago, this area used to be Lake Aral. The boats that can still be seen dotted around form a stark reminder of the size of this once great lake.

All in all, the drilling of UDG-1 is an example of how countries respond to declining domestic energy resources. With the establishment of a new company, there is no doubt the desire to put in place a new organisation that looks at opportunities with fresh eyes, whilst from a subsurface perspective, there is not only a push to explore deeper intervals, but also drill trapping styles that might previously have been ignored. A fascinating undertaking all in all. ■

Henk Kombrink



SOURCE: USTYURT DEEP GAS INVESTORS SLIDE PACK



The target zone of well UDG-1 is characterised by multiple layers of what is interpreted as high-porosity (red) zones on seismic inversion results. It can also be seen that these are pinching out to the right of the well (updip), thereby forming a potential stratigraphic trap.

Karabash – West Siberia's new frontier?

Results of newly drilled well points to shale oil as well as tight reservoir potential

DOMINIC LEWENZ, WELLIGENCE

The region of Karabash sits in the southern part of Khanty-Mansiysk and Tyumen. Historically, oil and gas developments have been more limited in this part of West Siberia, as the region is underlain by a series of grabens which have compromised the large four-way closures that form the supergiant fields to the north and west.

A more recent focus on regional exploration saw the 2021 drilling of a new well called Zaozernaya #1. Initial results were disappointing, with the conventional Jurassic reservoirs of the Bazhenov Formation being either tight or lacking trap integrity. This heterogeneity and atypical properties led to the interval being termed the "anomalous Bazhenov".

The disappointing early tests prompted a plan for an enhanced stimulation for the Bazhenov zone as the next step, given that core analysis indicated the reservoir was oil-bearing.

FRACCING THE BAZHENOV

The frac job of the Bazhenov Formation achieved a fracture length of about 570 m, a vertical height of 30–35 m and averaging 2.2 mm in width. Zaozernaya #1 subsequently saw a sustained oil flow, alongside small amounts of associated gas from the horizon – the first time Bazhenov has seen sustained flow locally. The presence of gas also indicates that hydrocarbons are lighter and more thermally mature than previously anticipated.

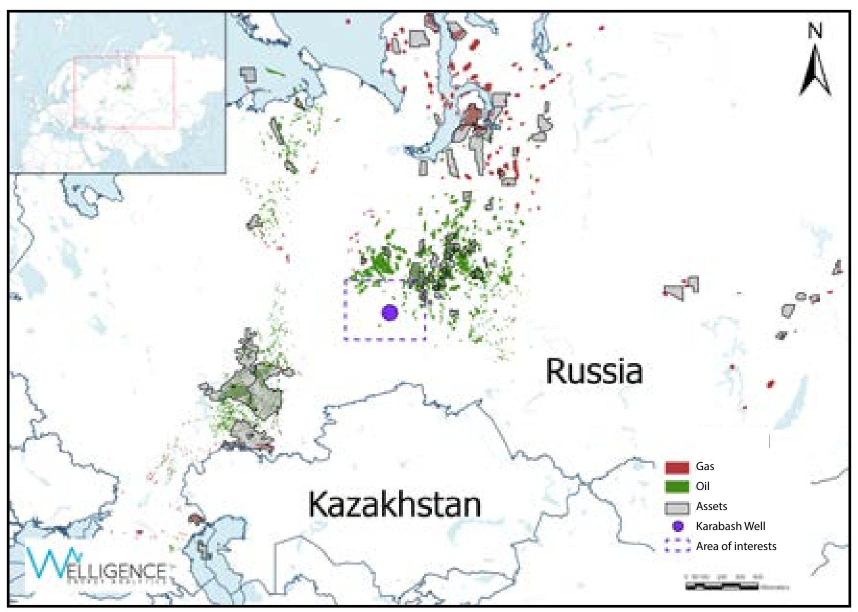
Core analysis found localised reservoir-quality features, such as natural fractures and porosity streaks, which can hold movable oil. Such reservoir pockets are low in permeability and discontinuous, which explains why standard tests historically yielded little flow. The reinterpretation is that the Bazhenov is not uniformly "tight" – it includes patchy high-TOC, low-resistivity reservoirs that were previously misidentified or underestimated. In other words, the Bazhenov Formation in Karabash may behave as a shale-oil play, requiring stimulation but holding significant oil in place.

The data from the Zaozernaya #1 well indicate that the resource potential can now be quantified with more confidence, confirming the existence of a working petroleum system. It suggests that untapped "shale oil" resources underlie broad areas of Karabash, not just conventional structural traps. Moreover, the well data are being used to understand if the "anomalous" Bazhenov was deposited in a different facies or underwent anomalous diagenetic conditions.

PLAYERS AND CONCLUSIONS

In addition to the possibility of a large unconventional play that could substantially add to Russia's resources, Zaozernaya 1's results are likely to aid better targeting of conventional reservoirs within the region. The discovery of the 176 MMbbl C1C2 conventional Ervye / Ouryinskoye oil field in 2013 proves that substantial conventional potential still exists. On the back of that, exploration interest and activity in the Karabash zone have risen over the last few years, with 34 license blocks issued to various companies as of mid-2025.

Significant development of the Karabash zone, especially its Bazhenov shale, still presents challenges, including those related to technology, tax reform, cost-optimisation and infrastructure. The level of recent operator interest, however, suggests that it remains an area to watch over the coming decade. ■



SOURCE: WELLIGENCE

Renaissance ramps up exploration activity in Nigeria

The Nigerian company that took on Shell's former onshore and shallow-water assets, Renaissance, is ready to embark on an extensive five-year seismic acquisition and drilling campaign to better map and drill prospects in the Niger Delta

"To meet the economic demands of the Nation and mandates given by the Federal Government, we need to increase production," says Johnbosco Uche, "that is one of our main targets for the years ahead." Johnbosco is the exploration and geosolutions manager at Renaissance Africa Energy Company Limited (Renaissance), the new Nigerian oil and gas producer which, in March this year, acquired Shell's onshore and shallow-water assets in the Niger Delta, becoming operator of Nigeria's largest oil and gas exploration and production joint venture – the NNPCL / Renaissance / TotalEnergies / Agip Energy and Natural Resources Joint Venture.

In his position, Johnbosco oversees activities across 18 Oil Mining Licences (OMLs) that have all seen various levels of development over several decades.

Johnbosco knows the assets well; he was formerly employed by Shell, as many of his Renaissance colleagues were. But with the transition to the new company came more of a focus on the Nigerian assets. "That is only a good thing," says Johnbosco, "because now, we have more of an incentive to critically look at these licences and evaluate their full potential, whilst, before, it was easier for Shell to redirect investment to other international parts of their portfolio."

"Given the advancements in technology, the quality of the seismic data we have is now dated," Johnbosco continues, "except from some more recent data that we acquired in shallow waters in 2019." For that reason, there is a strong belief amongst the leaders in the company that new data is required for many of the licences to identify and de-risk new drilling opportunities, all geared towards increasing production."

"We are looking ten years ahead," says Johnbosco, "with a concrete plan in place for the first five years to come." Expectedly, the second part of the ten-year plan will then be driven by the successes of the first phase. The company has kicked off the process for commissioning seismic surveys to acquire over five licences for now, using longer offsets than previously applied. "We are looking at 9 km offset seismic data, whilst before this was in the region of 3 to 4 km," Johnbosco explains. "This should enable us to image and map our deeper prospects with more confidence than we did before."

In the shallow water licences, Renaissance will work with OBN acquisition. This was also done for the 2019 survey, which has resulted in additional infill drilling opportunities. "As the new seismic data will come in for processing and interpretation, we will also ramp up our drilling activity on the back of that," continues Johnbosco. "We plan to drill two to three exploration wells per year post seismic acquisition, processing, and interpretation."

For Johnbosco's colleague and Chief Technical Officer at Renaissance, AbdulRahman Mijinyawa, Renaissance and Nigeria have a great opportunity to extend the life of the Niger Delta basin towards realizing Renaissance's vision of becoming the African energy leader, enabling energy security and industrialisation in a sustainable manner. ■

Henk Kombrink

PHOTOGRAPHY: NASA VIA WIKIPEDIA

View of the Niger Delta from space.

Open for business, again

New Zealand is hoping to attract explorers back to the country following the lifting of a drilling ban introduced in 2018

"WE HAVE to inject life back into the economy and avoid de-industrialisation," said Shane Jones during a webinar yesterday, hosted by Ross Compton from the EnerGeo Alliance. Mr Jones is not a random member of the public interviewed and asked for his opinion. Mr Jones is the Minister of Resources in the recently elected New Zealand government.

But it won't be easy to attract new companies. "We're effectively starting again, as there is zero frontier acreage under permit at the present day," said John Carnegie, CEO of Energy Resources Aotearoa, the organisation that forms a link between industry and government. That is the challenge: Bringing back the companies that are willing to take the frontier acreage and drill new plays in areas where infrastructure may not be in place yet.

It has certainly been made easier to apply for licences, as both Shane Jones and John Carnegie underline. The country now offers an open-door policy, and the government has also set aside a budget of 200 million dollars over the next four years to become a co-investor in new gas exploration projects. Reduction of red tape is another priority, with a mindset "that projects can go ahead unless there is a valid reason to block it," said Shane Jones. Finally, John Carnegie added that the government more recently decided to introduce a sovereign risk mechanism in the form of an investment underwrite.

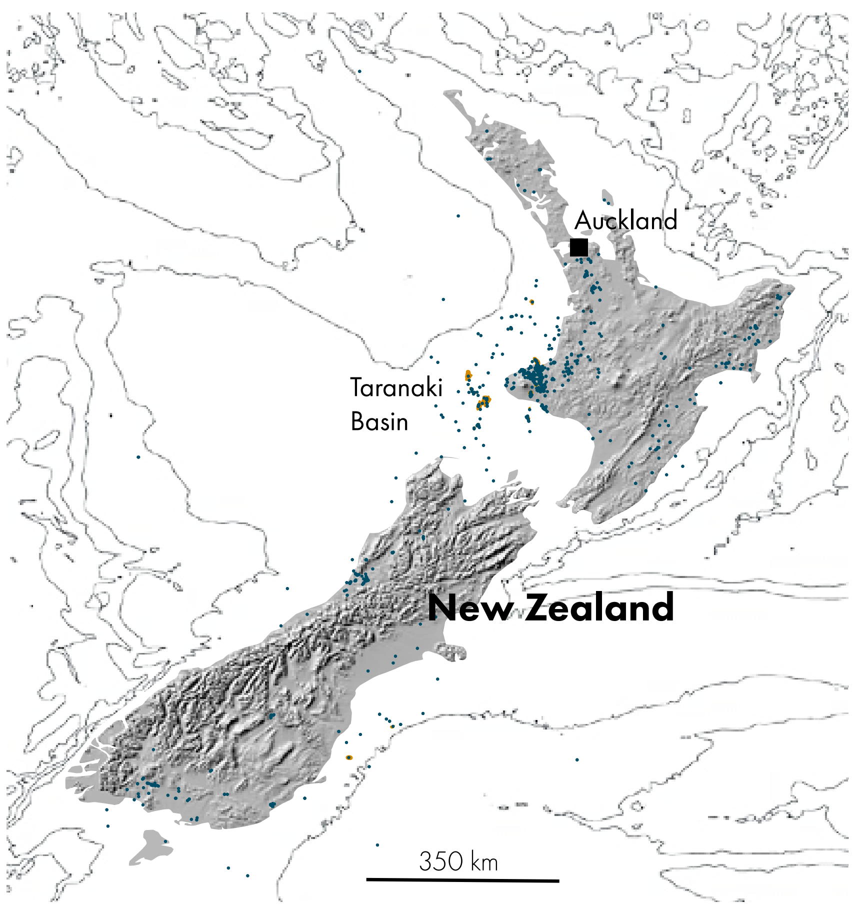
And it's not only about oil and gas. The minister also highlighted that additional funding will be made available for geothermal exploration, with a new site already selected on the North Island, in addition to a new hydrogen policy being announced later this year.

There is certainly potential in the country, especially offshore. John Carnegie reiterated that the area where oil and gas production is currently centred – the Taranaki Basin – is only one of a total of 18 mapped basins with petroleum prospectivity. "A total of 400 wells have been drilled in New Zealand so far," said Anne Forbes from WoodMac, "with only a handful wells in deeper waters – the last one drilled by Anadarko in 2014." In addition, there are seismic data available for initial screening, as both TGS and SLB illustrated during the webinar as well.

But at the end of the day, the key question remains whether this new policy will be reversed again once a newly elected government is in place in a couple of years. "This is unrealistic given the scenarios we now run," said John Carnegie, as he reiterated that, based on current polls, a future government will rely on a coalition in which the New Zealand First Party – which is the driver behind the ban reversal – will most likely form part of.

"We are politically a low-risk country," concluded John Carnegie. The question, of course, is, does the industry share this view? The proof of that will be seen in the next few years. ■

Henk Kombrink



SOURCE: DIGITAL ELEVATION MODEL - THE GEBCO GRID

Will Greenland be the next oil hotspot?

According to Robert Price, there is a good chance. And he and his team are going to test it with the drill bit next year

THESE DAYS, it is quite common to hear that frontier exploration is a thing of the past. But what is about to happen in Greenland next year should cast some doubt on that notion. If things go to plan, in July 2026, the first of a two-well campaign will be drilled by the Greenland Energy Company on Jameson Land, situated along the rugged east coast of the vast white island.

But didn't Greenland introduce a ban on oil and gas exploration a few years ago? Yes, that is true, and I was initially a bit sceptical when I was passed the drilling plans. However, there is a valid reason as to why drilling can start next year; the licences already existed when the ban was introduced, and the government acknowledged that drilling is allowed to take place.

And it will take place, as the project is 100 % financed through a merger between Pelican Acquisition Corporation, Greenland Exploration, and March GL Company. Only for that reason, it is worth writing about this, as so many companies claim that drilling is imminent, whilst in reality, they still need a farm-in partner to stump up the cash. I met up with Robert Price on Teams, who is calling in from Denver, Colorado, to hear more about the project.

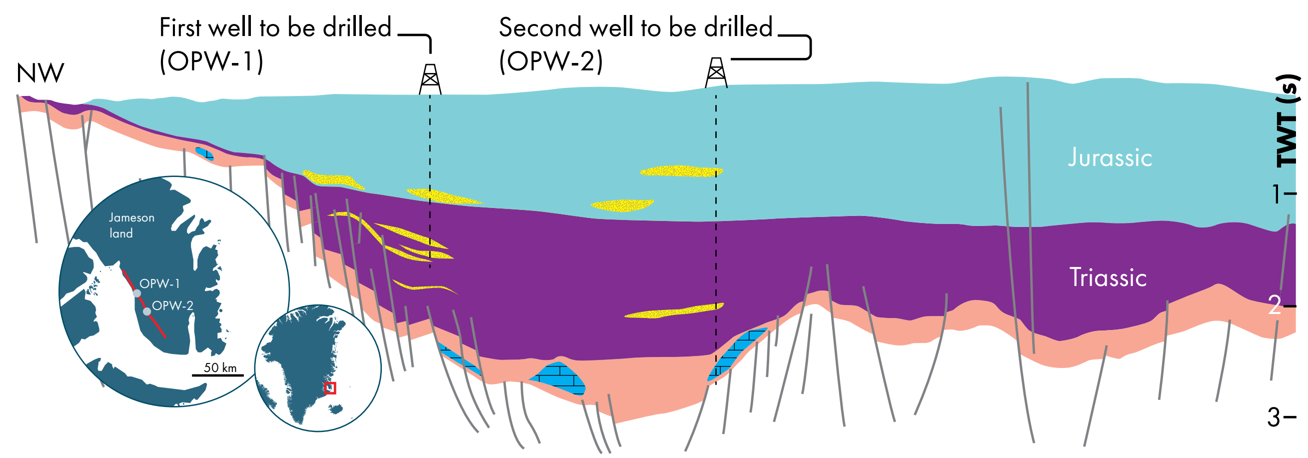
THE FOOTSTEPS OF ARCO

"We are walking in the footsteps of the ARCO New Ventures team here," he says. This company, which is behind the discovery of Prudhoe Bay and more global giants, had identified Jameson Land on the Greenland east coast as holding major promise in the 1970s and 80s. Before the North Atlantic break-up, the area neighboured what is now mid-Norway's Haltenbanken, where plenty of oil and gas have been found. The Arco team recognised that with the same source rocks and reservoirs present, there should be potential to discover something major. The company even built an airstrip on Jameson land that is now being used again.

But the first spud from Arco never came, driven by external factors, and the area was forgotten for many years. Until recently. "We have already secured an onshore drilling rig from Canada, transport is arranged to Greenland, and a road is currently being built," said Robert. He and a team of consultants and service company representatives had already visited the drill site, where they found oil slicks in little puddles.

But even though the area shares the presence of Jurassic source rocks with the Norwegian margin, a difference is that it experienced a more extensive phase of uplift during Cenozoic times than the Mid-Norway. One of the main questions, therefore, centres around how uplift affected the petroleum system. There is only one way to find out, and that is now going to happen. ■

Henk Kombrink



REDRAWN AFTER A CROSS-SECTION BY GREENLAND ENERGY COMPANY

Schematic cross-section showing the position of the two wells that will be drilled on the west coast of Jameson Land next year. The first well (OPW-1) will test Triassic reservoirs mainly, whilst the target of the second well (OPW-2) also includes what is generally seen as the most promising interval in the area; Permian carbonates.

Understanding the "Minimum Economic Field Size" concept and aggregating targets

There are a few things geologists need to understand when deciding where to focus their limited resources

Applying a "Minimum Economic Field Size" (MEFS) to your prospect assessment is a key process in quantifying the probability of finding hydrocarbon accumulations of a volume large enough to develop economically. However, the way this is handled in companies often leads to confusion, especially when there are multiple fluid phases or multiple prospects involved.

But even the case of a single prospect in which only oil is expected, the simplest example that we can look at, is something worth getting your head around first. As shown in the illustration, it is particularly important to be aware that applying a volume cut-off will always lead to the mean unrisked volume to increase in comparison to the non-truncated case. The reason for this is simple: As one discards the Monte Carlo scenarios where the volume is less than the cut-off, the remaining scenarios will return a higher mean volume.

At the same time, the chance of "commercial" success (Pc) comes down with respect to the non-cutoff case, because there are fewer scenarios in which you will find the field size (or greater) that you hoped for. These two opposing changes do not "balance out", and the risked mean value will change, typically as shown as a decrease with increasing cut-off volume along the line shown in the plot below.

The real world is often more complicated than single phase prospects. For instance, many prospects have both material oil and gas volumes. That means two cutoffs need to be applied concurrently to get a true insight into the probability of a commercial outcome: One for the oil and one for the gas, because gas is typically worth less than oil. In this case, you need software that can input these two values in one evaluation to get the overall commercial result. A similar real-world challenge is when there are material condensate volumes with the gas, and the user wants to apply a liquids cut-off (oil plus condensate) threshold. So, in summary, cut-offs can be tricky in many situations, and in many cases, two separate inputs are required. And in all cases, the output risked mean values will change.

Frequently, explorers rank their prospects by risked mean rankings. If this is the method you use to highgrade your portfolio, then evaluating the dependency between the two targets does not change the risked mean value at all, whereas applying a cut-off does. So, spending time on dependency evaluations is frequently a waste of valuable evaluation resources. ■

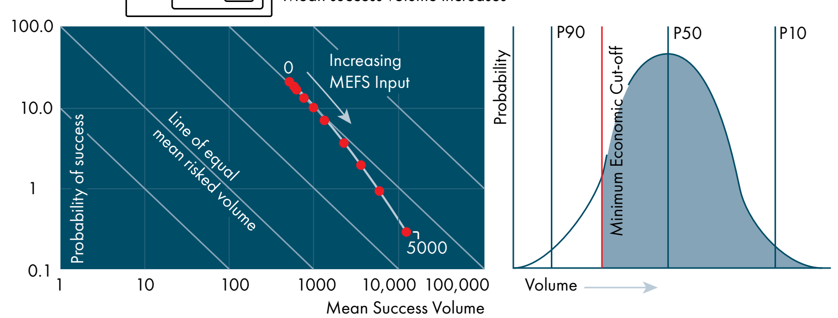
Henk Kombrink

GIS PAX PLAYER

This is the fifth 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.

MEFS	Mean	Pg	Risked Mean
0	498	20.0	100
10	553	18.0	99
20	609	16.3	99
50	754	13.0	98
100	959	10.0	96
200	1309	7.0	92
500	2189	3.7	81
1000	3454	2.0	69
2000	5702	1.0	54
5000	11649	0.3	34

Risk Mean success decreases
Probability decreases
Mean success volume increases



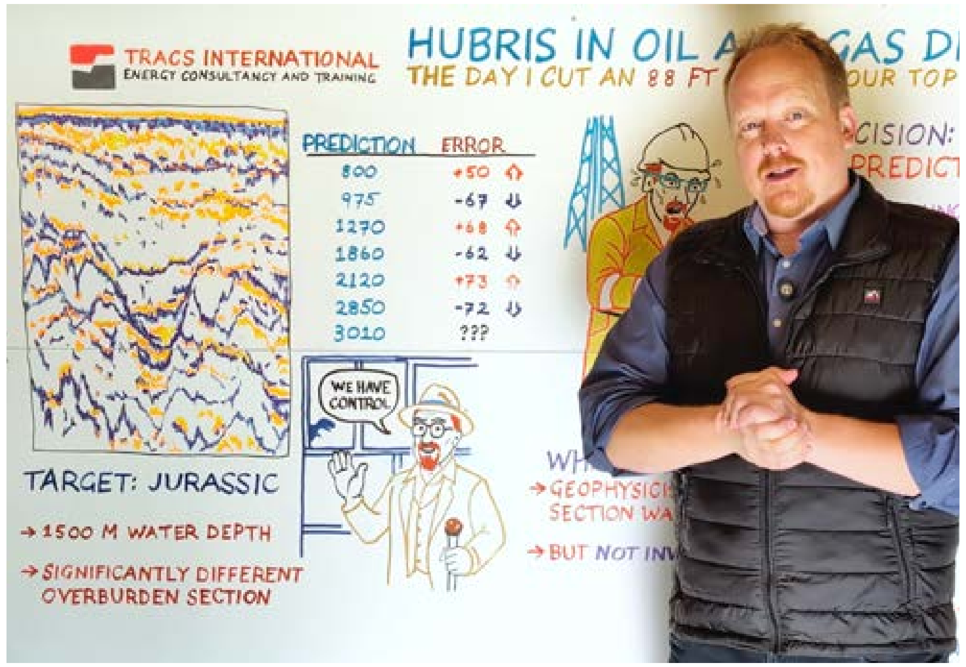
A single experiment using a 20 % oil prospect with an untruncated mean of ~500 MMb oil. As the cutoff increases, the unrisked mean increases, the geological chance of success decreases and in this case and most cases, the risked mean decreases with increasing cut-off volume.

More detail on this approach can be seen in the accompanying video of the GIS-pax LinkedIn Site:

"The day I cut an 88 ft core of top seal"

How communication between disciplines is key to arrive at the best possible drilling result

"LinkedIn seems to be the place to brag about your career successes," says Luke Johnson from TRACS International - but sometimes, it's the things that go wrong that teach us the most. That certainly applies to the lesson Luke learned when he helped drill a well as a wellsite geologist and called coring point too early.



Luke Johnson, TRACS International.

We are in deep-water offshore north-western shelf in Australia. The target of the well is an Upper Jurassic lowstand sandstone unit, slightly uncommon in an area where Triassic sands traditionally dominate as the main reservoir.

Even more uncommon is the prospect's overburden, as can be seen in the image below in the top left. "As the geophysicist in our team explained," Luke says, "the canyon-style feature carried a great deal of uncertainty regarding interval velocities and hence pre-drill depth estimates, because its infill differs greatly from the rest of the overburden."

"Because of this uncertainty," Luke says, "the tops did not come in as expected. Even more so, there was no consistency in the error, with some tops coming in shallow and some deep. As such, the geological team started to lose their faith in the pre-drill predictions."

Yet, the tops were very important, because the plan was to cut a 90 ft core from the thin reservoir unit, so drilling had to be stopped at exactly the right depth in order to capture the entire sandstone in one coring run.

"We, as a geological team, were still confident at that stage, though, unaware of the dinosaurs lurking in the background. It's because we thought we were supported by the tools we had at our disposal to overcome the uncertainties related to the pre-drill predictions," continues Luke. These tools included an uncalibrated resistivity-at-bit tool, which detects gas slightly ahead of the bit, and a backup from gas readings through mud circulation.

"So, when we called coring point, and I opened the core barrels on deck two days later, it was an unpleasant surprise to see that we had cut 88 ft of top seal and only 2 ft of the target reservoir sand at the bottom of the barrel", says Luke.

"Looking back," he says, "we had to admit that the geophysicist had warned us of the uncertainties in the velocity model and hence the time-depth conversion, because of the canyon fill. That's why he said that we should recalibrate the estimated depth of the top reservoir after hitting the last formation top before reaching target and just use the interval velocity to go forward from there."

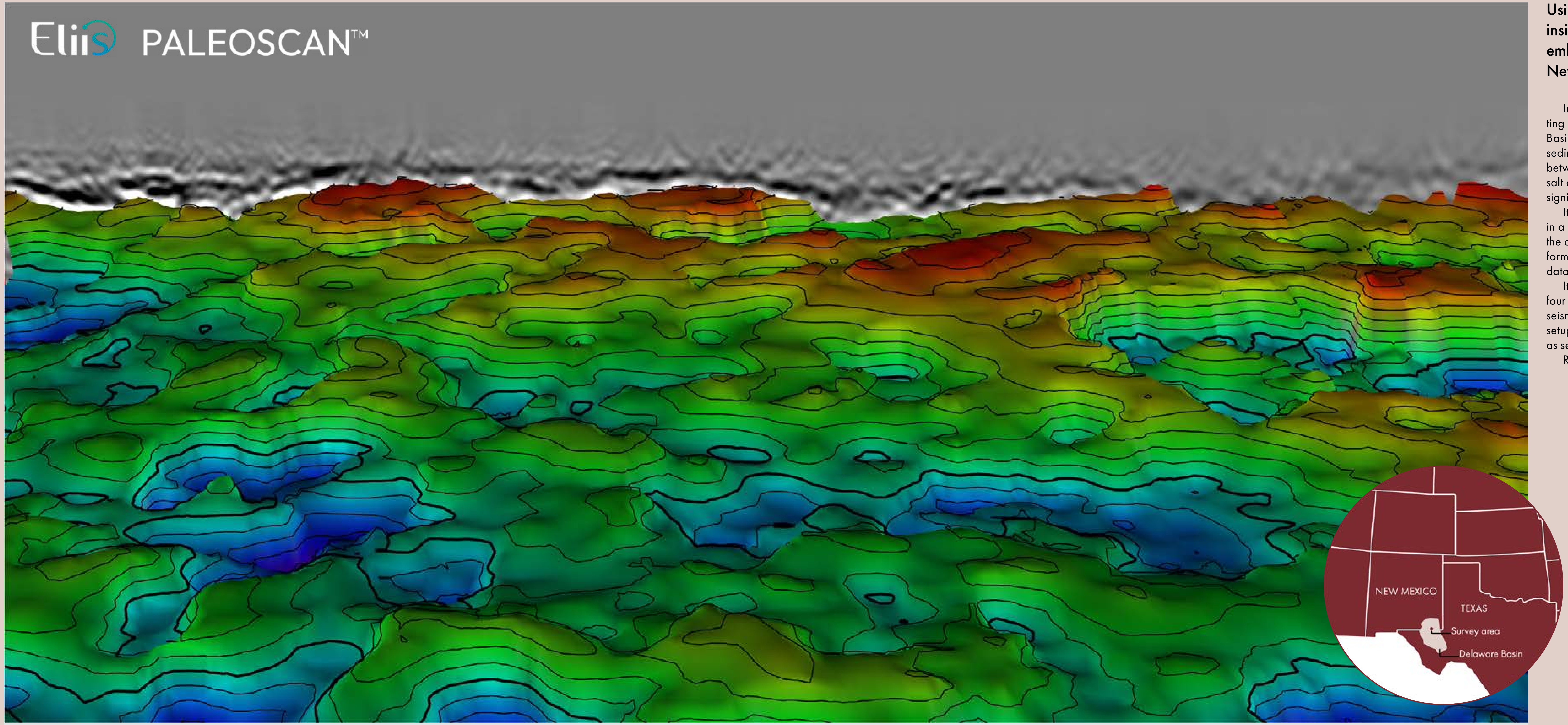
The mistake was that the geophysicist was not part of the operational team running the well. Instead, it was done by the geologists only, who were confident in the tools they had.

"If we had recalibrated our tops using the interval velocity, we would have hit the target at the correct predicted depth. But instead, we called coring point because we detected gas in a thin sand stringer that was irrelevant to our original target," Luke admits.

A very valuable lesson to learn. ■

Henk Kombrink

Proper sampling of near-surface geologic complexity illuminates tight oil reservoirs in the Permian Basin



This mapped surface is unique because it represents the first time the top of the Rustler Formation has been properly mapped in the Delaware Basin, including all the karst collapse features that hindered interpretation thus far. The interpretation was carried out in Paleoscan provided by Eliis.

Using an array of more than 41,000 seismic receivers inside four square miles, Fairfield Geotechnologies embarked on a unique project in the Delaware Basin of New Mexico to better map unconventional reservoirs

Imaging deep reservoirs in a complicated shallow overburden setting can be challenging. That's what some operators in the Delaware Basin concluded in areas where the reservoirs lie beneath the Cenozoic sedimentary fill zone. The reasons are numerous. Wavefield scattering between the different formations creates artefacts in the seismic data, and salt dissolution and subsequent collapse of the overlying rocks caused a significant vertical offset in the sedimentary strata.

It is that combination of factors that resulted in the seismic resolution in a large part of the Delaware Basin being insufficient to properly map the deeper unconventional reservoirs of the Bone Spring and Wolfcamp formations. This caused companies to give up on the idea of using seismic data to play a role in development plans.

It is against that backdrop that Fairfield Geotechnologies, supported by four operating companies in the Delaware Basin, ran a high-trace-density seismic acquisition campaign to prove that, with the right trace-density setup, imaging the shallow structural complexity of the Rustler formation, as seen in the foldout, improves the resolution of the reservoir beneath.

Read more about how this was achieved in the article.

fairfield GEOTECHNOLOGIES

STRYDE

Understanding sampling densities required to map the geology

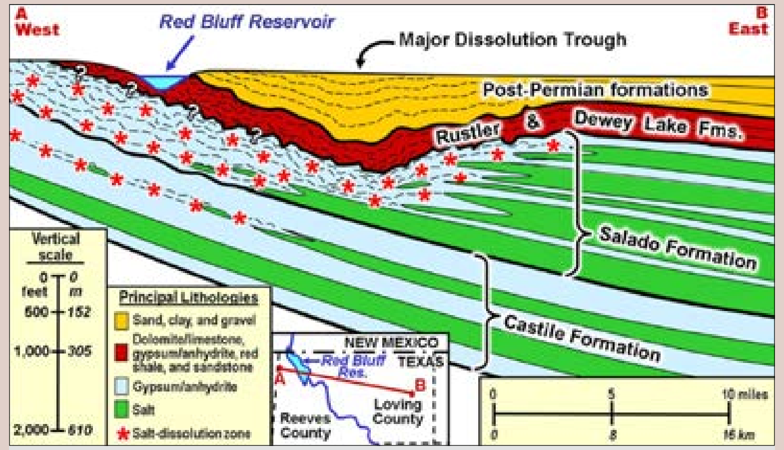
Why high-trace-density seismic surveys will be required to accurately image reservoirs in the world's major hydrocarbon-producing provinces. A case study

AN INTERVIEW WITH ANDREW LEWIS AND BRUCE KARR FROM FAIRFIELD GEOTECHNOLOGIES, BY HENK KOMBRINK

In some of the world's most important hydrocarbon-producing basins, the shallow overburden is causing seismic data quality to rapidly deteriorate with depth. For example, in the Middle East, from Egypt to Saudi Arabia and Oman, shallow karst has historically caused the rapid deterioration of seismic signals. This is why the Middle East is being carpeted with high-trace-density seismic – both onshore and shallow offshore – to achieve this goal.

This trend has now also made its way to the USA, where similar challenges exist.

A consortium of companies operating in the Delaware Basin commissioned Fairfield Geotechnologies with the acquisition of an ultra-high-density survey in an area that has traditionally been challenging to image due to a complex overburden that includes salt dissolution features and associated collapse structures.



The shallow subsurface complexities in the Delaware Basin. Source: Johnson et al. (2021) – Geological Survey Circular.

Here, Bruce Karr, Principal Technical Advisor and Andrew Lewis, VP of Geoscience, both from Fairfield, describe how the survey was optimised to overcome the shallow overburden challenges, how the project formed an opportunity to compare different nodes and how this concept may be required in other areas to tap into remaining resources effectively.

> "Without adequate sampling of the very near-surface geologic complexity, you will not be able to gain resolution in the deeper reservoir sections either" – Andrew Lewis

SALT DISSOLUTION

The Delaware Basin is located in West Texas and New Mexico. It is a basin with significant production of unconventional resources, which increasingly depends on more detailed seismic mapping; the Tier 1 acreage is increasingly being drilled out, and operators have to figure out how to economically produce Tier 2 and Tier 3 acreage that, while more marginal, still offers significant potential.

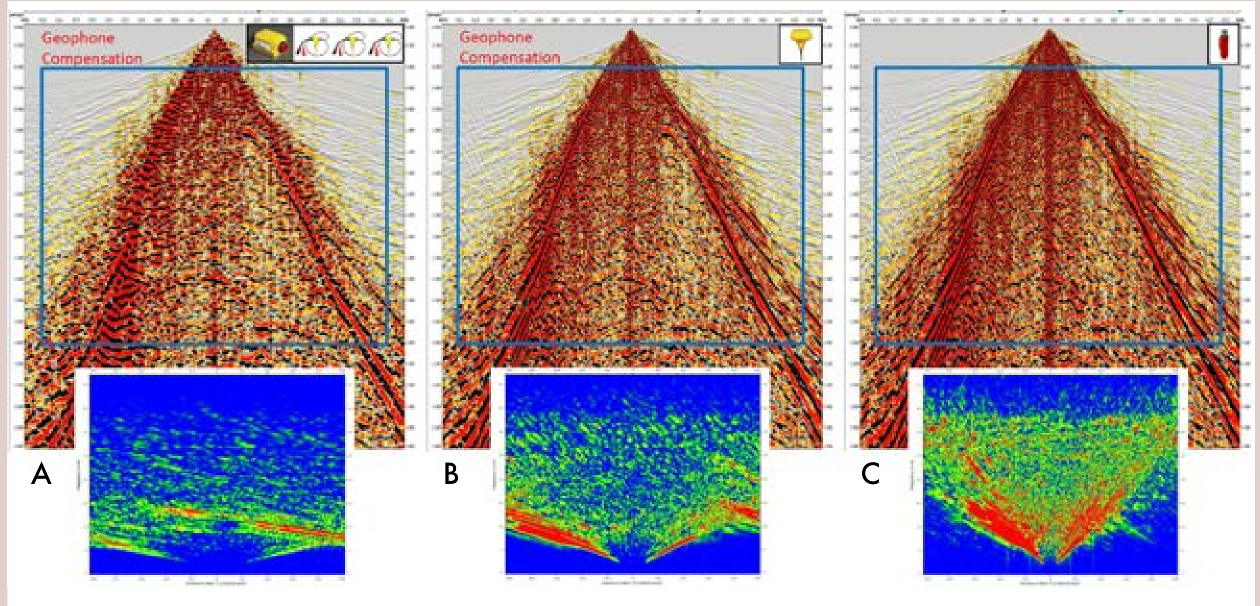
However, a challenge in the Delaware Basin has been over a regional area commonly referred to as "the Fill", which varies in thickness, but can be over 1,000 ft thick in the shallow subsurface. This succession, which is a combination of Permian, Triassic, Tertiary and Quaternary strata, has experienced collapse due to salt dissolution in the Permian Salado Formation, which consists of intermixed halite and anhydrite layers in this area.

Especially the Permian-aged Rustler Formation, which directly overlies the Salado, experienced collapse into the Salado, resulting in a heavily fragmented overburden stratigraphy and strong lateral structural changes and associated lateral velocity variation.

"Every geophysicist has their own explanation as to why they couldn't see the deeper reservoirs, but a combination of scattering, dispersion, absorption and insufficient source energy is probably a good summary," says Bruce. "That's why," adds Andrew, "when developing the unconventional resources beneath the Fill, seismic data has so far not played a major role simply because the resolution was not there." Until recently.

LIMITED BY EQUIPMENT

"We had already done some projects using high-trace density surveys in the Midland Basin," says Bruce, "and the results were promising. That led our partners / Permian Basin operators to also think about similar applications in the neighbouring Delaware Basin. So, it was great to find a consortium of four operators willing to test this with us last year."



Raw shots FK plots for (A) GSR 10 HZ geophones with low frequency geophone correction at 82.5′ station spacing, (B) Quantum 5 Hz nodes with low frequency geophone corrections at 41.25′ station spacing and (C) STRYDE nodes in velocity at 20.625′ station spacing.

But finding the desired sampling density required some conversations. "What if it is not even dense enough for what you are trying to achieve?" was a question Bruce had to reply to on multiple occasions.

Initially, the number of receiver lines and stations, laid out with 2,816 Geospace 10 Hz cabled geophones, was doubled from a 495 ft x 82.5 ft spacing to a 247 ft x 41.25 ft spacing using 11,008 INOVA Quantum 5 Hz nodal receivers. But, to convince the fourth operator to participate, Bruce was asked to reduce the station spacing even more, to a value below 30 ft. "This is where the STRYDE nodes came in," he explains. This configuration added another 22,016 autonomous nodal receivers at a 247 ft line spacing with 20.625 ft station spacing, at the same cost as the other 13,824 nodes deployed.

TOOL COMPARISON

"We did not plan to use nodes from multiple vendors, and it was not a request from the operators at all, but the number of receivers we required was so large, we had to source material from all corners of the area," says Bruce. "The benefit was that we could also compare the nodes with each other, which was a nice spin-off from the project. Andrew presented this work at the EAGE Land Seismic conference in Calgary earlier this year.

"The conclusion was," says Bruce, "that all three nodes were capable of capturing the low-frequency domain (4-5 Hz) equally well. Some people in the industry claim that the STRYDE nodes, which register acceleration rather than velocity, are less well-suited for lower frequency domains, but following integration of the STRYDE node data into the velocity domain, we saw that all three performed well." The signal-to-noise ratio was also similar between the sensors, with the Quantum and STRYDE ones appearing slightly superior to the GSR ones.

SCALING UP

"The operators who supported the seismic acquisition project have seen enough to be confident about the added value of what we are doing," says Bruce, when we continue about how to scale up this survey design.

However, repeating the exact same survey density is not without its challenges. Let's look at some numbers. "The Delaware Basin has got about 2,000 mi^2 of "Fill zone" to shoot," Bruce explains, "where this survey only measured 4 mi^2."

"That's why we are currently at the intersection of what is economically possible and still technically sound," adds Andrew.

"We are currently acquiring our third high-trace-density production survey in the Delaware Basin that doesn't have the same level of density as we used in the "Fill" project, but still changes the game when it comes to how seismic can now be used in this basin," he adds. "We have to be creative and match the problem to the available equipment and budget."

Ultimately, it boils down to feasibility and ROI. "We need to be thinking critically about where to go for higher trace density and where we won't," concludes Bruce. "But the fact remains, high-trace density acquisition will become a more and more important aspect of our continued search for remaining oil and gas resources - and it's the receiver technology that will ultimately determine how achievable this is."

This is where innovation in receiver system design becomes a game-changer. The choice of receiver technology fundamentally shapes crew composition and overall seismic camp costs. By utilising miniature, ultra-lightweight receivers and high-capacity node handling infrastructure like STRYDE's, operations can be leaner, faster, and more cost-effective, including in traditionally high-cost environments like the USA.

FEATURES

"In the background, while you are learning and delivering at a breakneck pace, the next re-org is there, buzzing in the back of your mind like a beehive. It makes for a very distracting work environment"

Samuel Price – former Shell employee

Looking for a low-risk infill well? You might want to consider areas of weak 4D response

With 4D seismic guiding 8 out of 9 infill wells to success on the Golden Eagle field, UK North Sea, there is no doubt that the value of repeat surveys cannot be overstated. But there is no easy answer to all anomalies

When porosities and fluid contrasts are modest, the acoustic impedance (AI) changes associated with water sweeping oil can be small, even at relatively shallow depths. That is the case in the Golden Eagle field in the UK North Sea, where the change in AI from baseline to repeat survey is only 3 % at best. In order to detect any 4D signal in an oil field with such a subtle response, the quality of the seismic data must be exceptional.

As Andrew Wilson from operator CNOOC International presented at the Seismic Conference in Aberdeen in May 2025, the high-density retrievable OBN surveys acquired over Golden Eagle have met these high-quality criteria. With a ratio of 3D signal to time-lapse noise of 25, it is one of the best in class, delivering quality as good as many permanently-installed ocean bottom seismic systems, but at much lower cost.

Making sense of the 4D seismic signal from Golden Eagle came with some interesting insights.

First of all, let's look at an example of varying sweep efficiency in the Burns reservoir and how this is revealed by the 4D survey. Figure 1 shows the 4D seismic signal calculated between the 2015 (baseline) and 2018 (monitor) surveys. A few things stand out. There is a strong hardening effect between water injector B and producers A and C, which is indicative of water replacing oil (increase in AI). However, it can also be observed that the 4D signal is much weaker to the south of well C, leading to the interpretation that this part of the reservoir was not as efficiently swept. At the same time, the presence of a weak 4D signal indicates the reservoir is not completely tight; otherwise, no signal would have been observed at all. A subsequent infill well drilled between well C and D showed that this interpretation was correct, and it became the best producer in the field.

> The Golden Eagle field was discovered in 2006, with first oil achieved in late 2014. The field has two main reservoir units, the Lower Cretaceous Punt and the Upper Jurassic Burns sandstone. The Punt is a relatively narrow and long submarine channel fill, whilst the Burns sands have a more widespread distribution with good aquifer support. Both fields have a combined stratigraphic, structural and fault trapping configuration. The recoverable volume of oil from Golden Eagle is expected to be 140 MMboe.

Another interesting observation from this seismic line comes from the injector well (B). In the vicinity of the well, at reservoir level, it can be observed that the 4D signal is dimmed, where one might expect a similar response to what can be seen a little further away. As Andrew clearly explained in his talk, the AI change is not only a result of an increase in AI due to water replacing oil, but also a decrease in AI due to a pressure increase in the local area to the injector. These components cancel each other out, resulting in a dim 4D response.

So, in one location, a dim 4D response indicated inefficient sweep and a good infill location, but in another area, a dim response results from efficient sweep plus pressure increase. Andrew asked: How can we tell the difference between these two scenarios, since only one of them would result in a good infill well? The answer was to look at not just 4D amplitude maps, but also 4D time shift maps and 4D character on seismic sections.

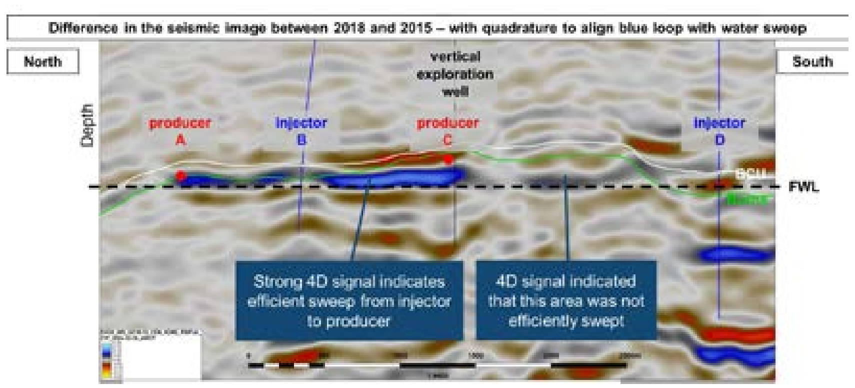


Figure 1: An infill well drilled into the dim 4D response between wells C and D showed that the 4D interpretation was correct, and it became the best producer in the field

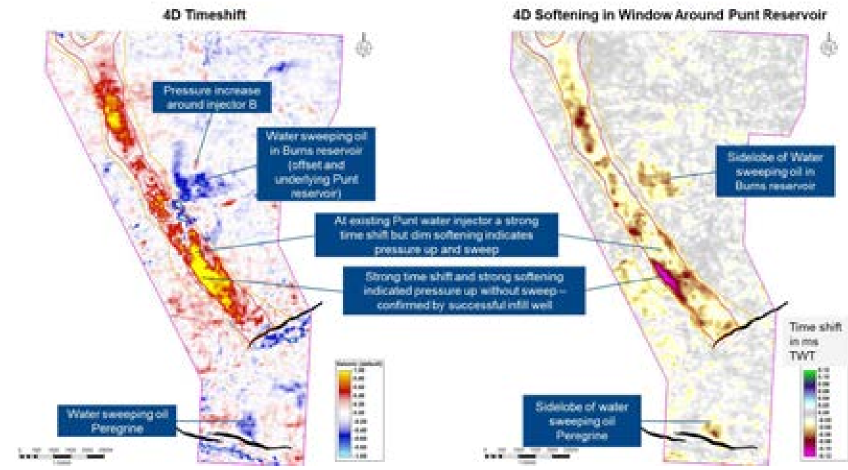


Figure 2: 4D time shift map responds to pressure changes in Punt but also to Burns sweep and to 3D seismic character – we can interpret Punt 4D using a combination of the Punt softening and time shift maps. A strong time shift and a strong softening indicated pressure support but without sweep, which was confirmed by a successful infill well.

In the Burns reservoir, the sands are widespread and well connected, voidage replacement has been good, and pressure changes are small except very close to water injection wells. However, the Punt reservoir has a much longer and narrower geometry and has experienced large and widespread pressure changes.

Andrew presented a case in the Punt reservoir, whereby the question was asked: How can we recognise unswept areas that have experienced a pressure-up? A strong downward timeshift signal was observed in an area of the Punt, which indicates an increase in pressure resulting from water injection. The 4D amplitude change map is dim at the water injectors, but one part of this area of strong time shift also had a strong 4D softening signal. Together, this strong time shift and strong softening indicate pressure increase but an absence of water replacing oil, i.e. a region which is well supported by water injection but poorly swept. This area was subsequently targeted by another infill well, which confirmed the 4D seismic interpretation.

Andrew then continued to show another example illustrating a slightly more complex pattern of differential depletion and sweep in the Punt reservoir. As illustrated by the seismic line below, the observed 4D response on either side of the producing well is different. North of the producer, there is a broad red signal, whilst south of it, there is a blue-over-red signal.

In order to better understand the setting that could be responsible for these different patterns, the team created so-called "4D response panels", which show the synthetic seismic 4D response for a variety range of sweep efficiency scenarios and pressure changes. This resulted in the observation that the broad red 4D signal corresponds to a poor sweep between 0 and 10 %, whilst the blue-over-red response is consistent with a 30-40 % sweep.

The examples shown here demonstrate that acoustic impedance changes can be caused by multiple factors, and that these all need to be assessed, together with the geology and field history, to make correct inferences on what a 4D signal really means. A dim area around a water injector could be well explained by a local pressure increase and a subsequent decrease in AI, balancing the increase in AI through water replacing oil. Taking these things correctly into account, the value of high-quality 4D cannot be easily overstated when it comes to planning infill wells in a mature field. One of the most important lessons is that a weak 4D signal may actually be a good sign for remaining oil; it shows that a connection does likely exist, but it may need another infill well to be exploited efficiently. A complete lack of 4D signal could be more risky, because it does not rule out the possibility that the lack of 4D signal results from a lack of reservoir at that location, not a lack of sweep. Both of those scenarios could be consistent with observing no 4D response.

Although all of the Golden Eagle infill well results were consistent with the observed 4D seismic, Andrew concluded that "4D seismic does not lie, but sometimes it does keep secrets". ■

Henk Kombrink

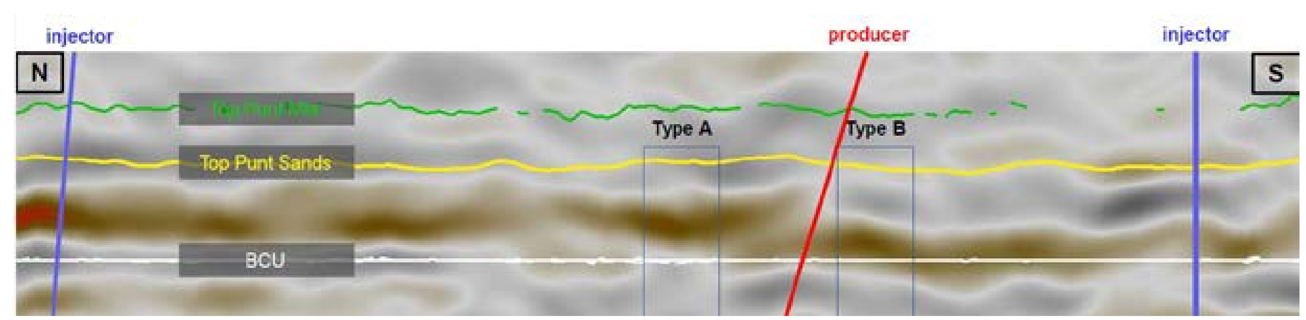


Figure 3: The difference in 4D seismic character on the northern and southern sides of the producer results from more efficient sweep from the injector to the south (Type B response) and less efficient sweep from the injector on the northern side of the producer (Type A response).

US Permian Basin – the largest injection experiment

A conversation with Katie Smye from the University of Texas at Austin on how to safely inject millions of barrels of waste water a day

If you look at the volume of water versus hydrocarbons produced from the Permian Basin per day, the basin would surely qualify as being predominantly a water production exercise: 20 MMbb of water versus 6 MMbb of oil. Every 24 hours.

Of that 20 MMbb, 16 million is currently being re-injected in the subsurface – there is currently no other place for the water, or better, brine, to go. The most economical solution is to dispose of it by drilling injection wells that put it deep underground.

But even though re-injection is the most economical solution, it is not without its drawbacks. Induced seismic events are one of those, in addition to issues related to compromised legacy wells from conventional oil and gas production, that allow re-injected brines or formation waters to flow back to surface and contaminate agricultural land.

And that is where Katie Smye from The University of Texas at Austin comes in. As principal investigator of the Center for Injection and Seismicity Research, she coordinates a major project that is looking at the regional plumbing system in the Permian Basin with the dual aims of understanding how problems related to water injection arise as well as better predicting how long safe injection can go on for.

"There has been a lot of interest in recent years in legacy wells, especially orphaned and abandoned ones," Katie says. "Most institutions working on those wells are focused on the surface expressions, such as methane or brine leaks, or using technology to find these abandoned wells in the first place. We have always been interested in the subsurface hazard posed by oilfield waste water injection," she says, "and because injection has become such a large-scale operation in the USA with the advance of unconventional drilling and associated produced water, the urgency to better understand how fluids behave in the subsurface has increased."

Let's get some of the definitions out of the way first.

Basically, there are two levels at which water is being reinjected in the Permian Basin: Either stratigraphically above the unconventional reservoirs or beneath them. "These two levels of injection are defined not by depth, but by stratigraphy, as the shales themselves can be found at different depths depending on the location in and structure of the basin," explains Katie, "but deep injection in this context means beneath the shales, whilst shallow indicates above the shales. Shallow in most cases is still around 6,000 ft deep, well below the aquifers used for drinking water production."

The history of water injection in the Permian Basin is diverse, and both shallow and deep reservoirs have been used from the start. However, what can be said in very general terms is that deep injection has given way to shallow water injection in recent years, mostly driven by induced seismic activity that has made headlines in a few cases. Most of the seismicity is caused by deep injection, close to more competent basement rocks that are faulted. Another drive towards shallow injection is the lower costs of drilling the injection wells.

Katie Smye.

LEGACY WELLS

As pointed out by Texans like Sarah Stogner, shallow injection has its drawbacks too, and they relate to a large extent to legacy wells.

"The problem we have inherited in the Permian Basin," says Katie, "is a vast pool of old wells that were drilled, operated, plugged and abandoned at times of less stringent regulations. The casings of these wells may have degraded over time and are now exposed to increased pressures due to injection.

And where is the waste water being injected? In the high-quality reservoirs from which we first produced conventional oil and gas through all these wells."

For that reason, many of the reservoirs in which injection now takes place have been artificially connected with the surface through thousands of rusty wells. "It sometimes keeps me awake at night," says Katie.

"Our data clearly show that for about 90 % of the leaking legacy wells in the Delaware Basin, we see uplift of the ground surface as indicated by satellite data," explains Katie. "That tells us a lot about what is happening in the subsurface, with pressure ramping up in reservoirs where waste water is being injected to such an extent that it has a measurable effect at surface level. And obviously, it is the increase in pressure that also affects some legacy wells in that brine is finding the path of least resistance through these anthropogenic pathways."

"What we do as a group in the Center for Injection and Seismicity Research is to better understand the subsurface risk factors that come with waste water injection and suggest ways to mitigate against any unwanted issues," says Katie.

And that research is badly needed. "When I speak at public events, I often have a number of ranchers lined up afterwards to talk to me about the issues that they are facing on their tracts of land. Operators tend to be concerned about their own acreage, but we try to build a supra-regional model combining all the observations we make and hear about, informed by data provided by those operators."

HOW MUCH CAN BE INJECTED?

The big thing that Katie and her research consortium are now pushing is the compilation of reservoir injection exceedance maps in order to arrive at a better estimation of what the several reservoir candidates for water disposal can safely host. That is less straightforward than you might think, because it is not only the reservoir properties that have to be taken into account, but also the observations already made when it comes to earthquakes or leakage to surface.

That subsequently opens the question of how to find all the wells that are leaking. "We use all methodologies that are at our disposal," says Katie. "We monitor the news, we look at temporary flight restrictions, and we also use the public list of high-priority wells that have been identified for state-funded plugging. In addition, we get information from the operators and other stakeholders in West Texas about the issues that they have been dealing with."

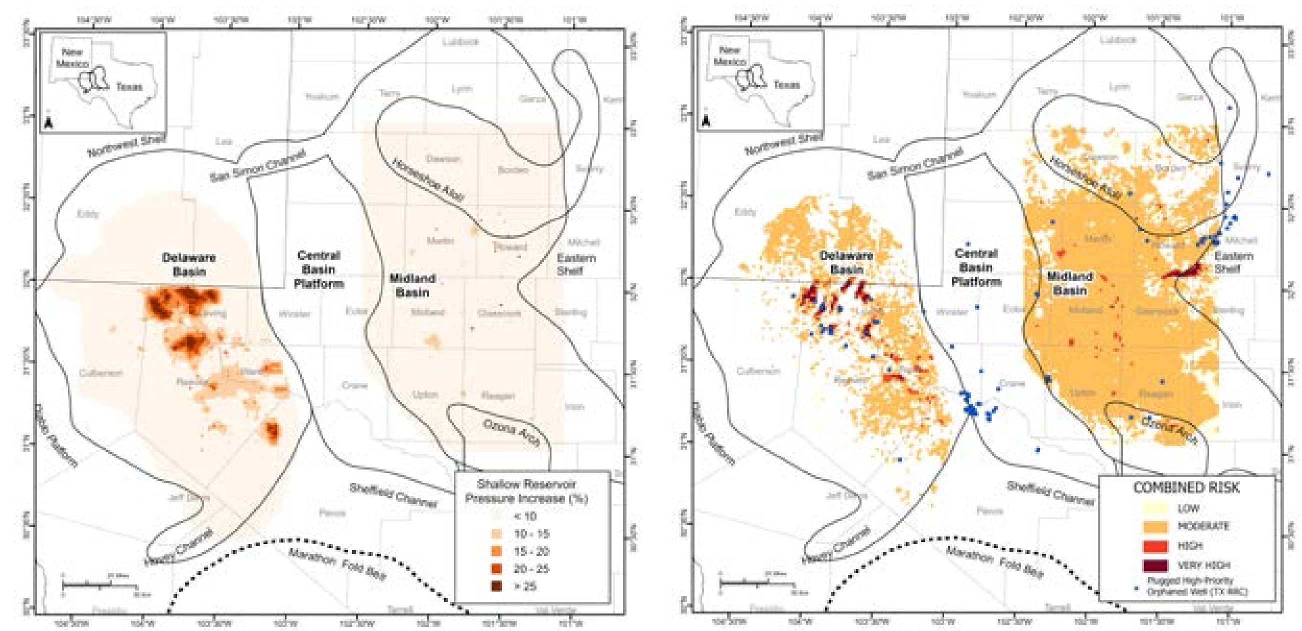
But that is only really the top of the iceberg. "I'm sure that for every well we see leaking at surface, there are a dozen where there is no surface expression. At the same time, these wells still present a risk to subsurface cross-flow," says Katie. It illustrates the uncertainty that comes with producing the maps, knowing that things like reservoir compressibility, porosity and permeability also play a role.

But no matter the uncertainties involved, Katie and her group have now produced the first series of basinwide injection capacity exceedance maps, providing more context on how much injection capacity remains in reservoirs across the Permian Basin. ▸

TRUCKING WATER ACROSS THE BORDER

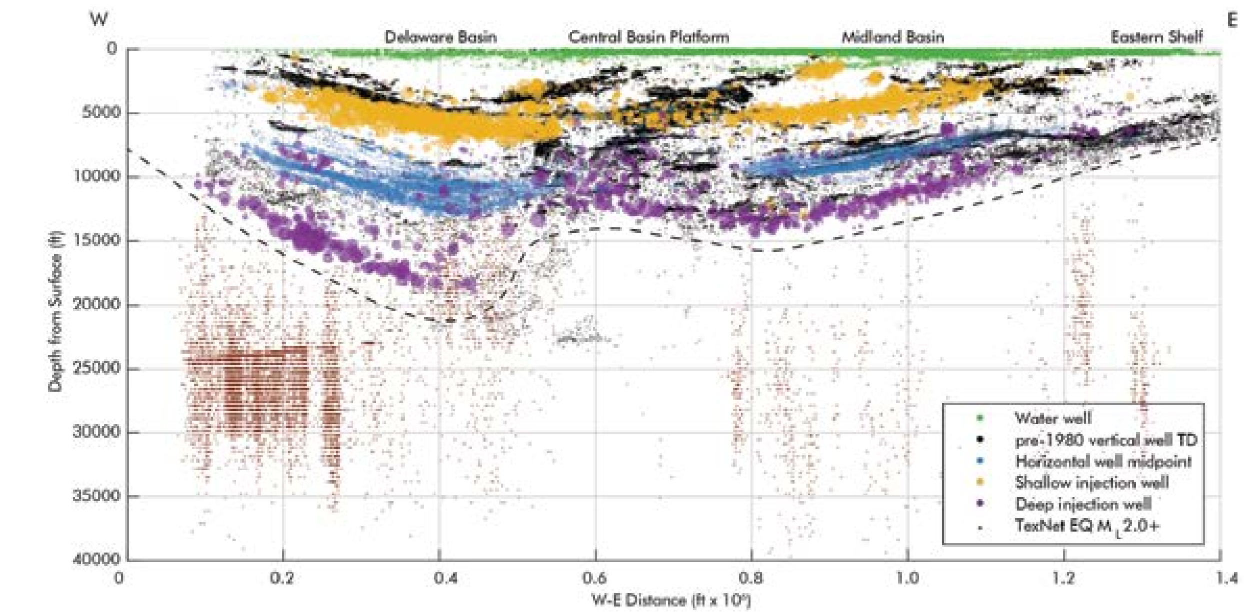
Each state has different regulatory frameworks when it comes to water injection. In the New Mexico part of the Delaware Basin of West Texas, which is one of the two major subbasins of the Permian Basin, shallow injection is not frequently permitted as it is thought to harm reservoirs that could be used for mineral extraction. As a result of this ban and the limited capacity of deeper reservoirs in New Mexico, 3 MMbb of water are currently transported across the border to Texas every day, where shallow water injection is allowed.

"The interesting aspect about this situation," says Katie, "is that sometimes New Mexico's shallow reservoirs still see the effects of shallow injection across the state line in Texas, whilst earthquakes still occur in the Texas Delaware Basin where deep water injection has stopped since the closure of 20 deep injection wells. It goes to show that geology, fluids and pressure fronts do not follow state boundaries."



SOURCE: KATIE SMYE

Shallow injection reservoir pressure increase as percent of original reservoir pressure (left); the hazard posed by shallow injection combined with the hazard posed by legacy well density and age shown with orphaned wells that were leaking at the time of plugging (right), indicating that the capacity of the reservoir to safely receive fluids has been exceeded. Central Basin Platform pressure increase has not yet been modeled.



Cross section of the Permian Basin subsurface showing the 50,000 horizontal producing wells (blue dots), deep wastewater injection wells (purple) and associated earthquakes (maroon), and shallow injection wells (yellow) in the same strata as many legacy vertical wellbores (black dots), which put the injection strata into potential hydrologic connectivity with water wells (green) and the ground surface). Most modern unconventional production is concentrated in the Delaware and Midland Basins, while legacy conventional production occurred on platforms and shelves.

It's very much an iterative process that needs constant maintenance. "For instance," Katie explains, "if there is a blowout in an area where the maps did not predict exceedance given the current injection and pressure data and models, we need to bring that injection capacity down."

"But all in all, I think this work is essential because we look at a basinal scale, combining observations and data from across the entire Permian Basin. And in addition to the outcomes being relevant to the oil and gas producers, this is also relevant to basin-scale carbon storage projects that may face similar issues."

COMMUNICATING SCIENCE

The analysis has also exposed Katie to the limitations and challenges of communicating science to the public. "If someone picks a square mile on our injection capacity map and sees that his/her tract of land is close to capacity exceedance, it becomes important that we have communicated the uncertainties behind our calculations and the range of possible scenarios. That uncertainty is not always easy to get across," she says.

Communication is also a very important factor when it comes to working with the industry partners in Katie's project. "For instance," she says, "the public often wants a reply from the Center for Injection and Seismicity Research when an earthquake happens. And not next year in a peer-reviewed publication, but today, explained in simple words. That is sometimes a challenge, because we may not always have the right data to draw robust conclusions in a timely manner."

"For example, we used to rely on injection data that was, in some cases, up to 18 months out of date. Under those circumstances, without knowing recent trends in injection rates and pressures, it was challenging to be certain about the causal agent of an earthquake. That situation has now improved with more stringent data reporting requirements, but the flipside is that we now end up in situations where we receive requests for public comment whilst our industry partners and regulatory agencies may benefit from publication of our work in peer-reviewed scientific journals rather than short-term commentary where uncertainties are difficult to communicate and messaging is out of our control."

"The best way around this is," Katie says, "to flag these things and discuss them with our advisory committee of company representatives. Whilst we have autonomy over our methods of communication, it is certainly a new field for us to provide commentary without peer-reviewed scientific backing, and we are much more confident in that effort if we have a broad consensus across our stakeholder group."

NO DENIAL

Regardless of these hurdles that must be jumped at times, Katie sees that many companies are taking a constructive approach towards the problems that arise. "We don't live in the days of denial of adverse impacts of injection anymore," she says. "All of our industry partners agree that earthquakes, surface flows, and other injection impacts are unwanted, and that facing the issue is the best way to mitigate them. Sure, companies differ in their approaches to mitigation and speed of response, but overall I'd say there is a willingness to work collectively to solve these challenges such that injection, and therefore production, can be sustained." ■

Henk Kombrink

SOURCE: KATIE SMYE

Predicting viscosity in an undrilled panel of a deep-water field in West Africa

Traditional models predicting fluid properties often consider only biodegradation for shallow reservoirs. This has proven inadequate in certain geological contexts. Here, we introduce a new model that considers the intricate geological history of an offshore field in West Africa, where multiple charge episodes and the competing processes of biodegradation and gas stripping are required to explain the observed trends in oil quality. This subsequently de-risked an undrilled fault panel of the field

THIERRY RIVES, YULIA KEDZIERSKI AND HONGGANG ZHOU, TOTALENERGIES

In 2023, the rapid oil production decline from the Bombadil Field (fictitious name), deep-water West Africa, triggered the necessity to develop additional resources. This is the moment prospect E appears on the radar, which is likely to host hydrocarbons in the same mid-Miocene turbiditic reservoirs as the remainder of the field. A clear DHI event suggested an OWC in the fault block as well. However, before drilling a well into prospect E could be justified, the observed viscosities in the producing field needed to be better understood.

The Bombadil field reservoirs are relatively shallow, with temperatures around 60-70° C, which means that biodegradation is a risk. However, in contrast to what would be expected in such a scenario, the development wells D1, D2, D3, A-1 and A-2, drilled in 2015, indicate that this model did not work as expected. Namely, fluids with the highest viscosity were observed at the crest of the structure, far away from the OWC where biodegradation should be most prevalent. What is going on?

First of all, oil family interpretation demonstrated that the Bombadil Field has multiple mature source rocks, ranging in age from Upper Cretaceous to Eocene, giving rise to fluid mixing and multiple phases of oil generation. As such, the presence of multiple episodes of charge, paleo-biodegradation, followed by recharge from the same or another younger source rock is therefore a plausible scenario. In turn, this provides a good mechanism for improving oil quality over time and works well in panel A where low-viscosity oil is produced from well A-1.

Another explanation as to why viscosities in the deeper parts of the field are lower than at the crestal regions is the particular depth range it finds itself in. A plot of fluid density and fluid viscosity versus burial indicates a break around 1,160 m burial between "good oils" with no or limited biodegradation and "medium to poor oils" showing high to severe biodegradation. This burial limit is also marked in associated gas that is clearly biodegraded above this burial depth. The fluid temperature indicates that the limit for biodegradation is about 65° C, and it just so happens that the 65° C runs through the field at the present day.

There is yet another explanation as to why the viscosity trends in the Bombadil Field, especially in Panel D, are opposite to what can be generally observed. It could also be explained by a spectacular gas chimney observed right above the panel D crest, and the gas stripping it may cause. Seismic reflection and 4D seismic interpretation indeed suggest ▸

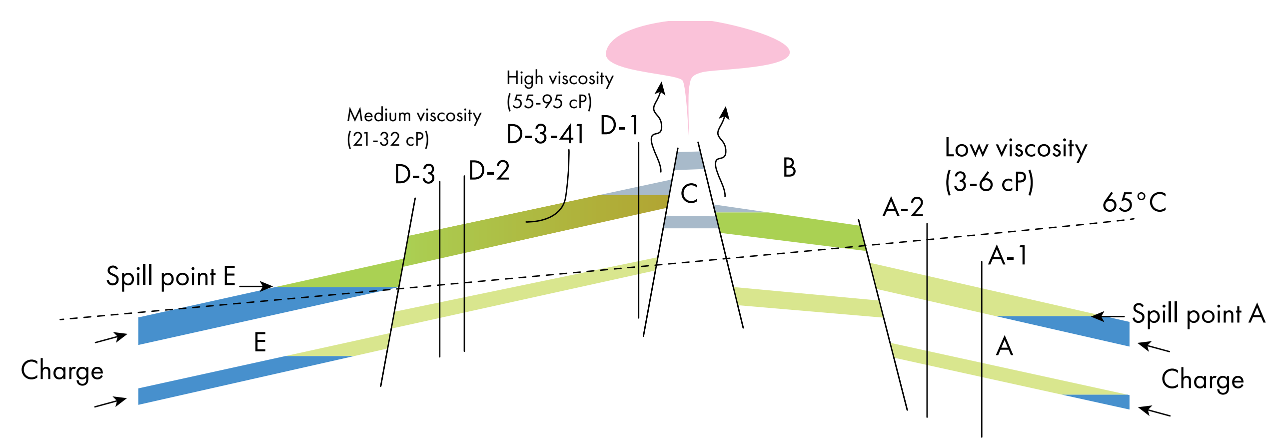


Figure 1: Proposed charge model for the Bombadil Field.

active gas production and repeated gas leaking out of the D panel.

A gas stripping effect has been modelled for a typical fluid – composed of three oil families – from the A panel. It suggests progressive depletion in light molecular compounds and the alteration of heavier components with increased gas stripping. However, the real component profiles of these three families do not fit a pure gas stripping distribution, suggesting a more complex, mixed origin. However, the observed profiles can be mimicked by mixing gas stripped oils with various amounts of "fresh" and slightly biodegraded oil.

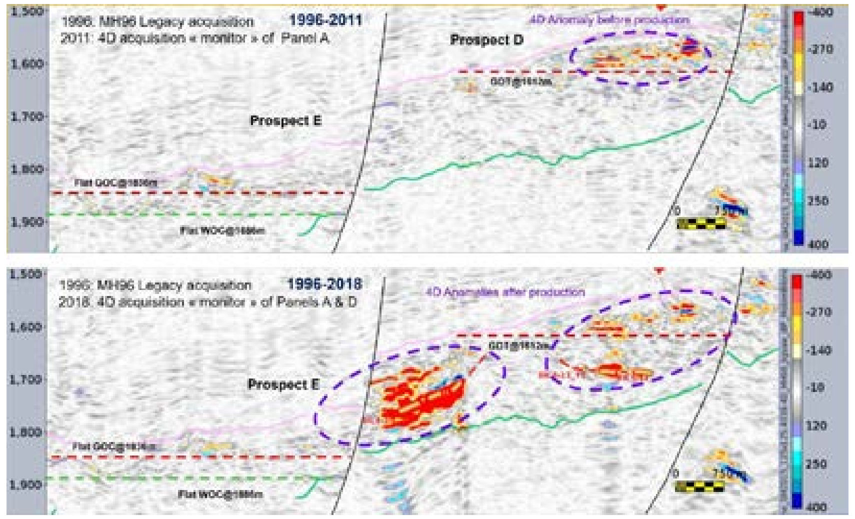


Figure 2: Seismic reflection and 4D seismic interpretation suggest recent and repeated gas leaks along Panel D.

CURRENT GEOLOGICAL MODEL FOR VISCOSITY PREDICTION

We conclude that the fluid properties of the Bombadil Field are controlled by the complex multi-charge history and competing biodegradation and gas stripping processes. Applying a model that includes a mixture of biodegraded oil and fresh recharged oil in various quantities, the following charge history could be proposed.

In Late Miocene times, reservoir charge is taking place from early mature Cenomanian source rocks, and oil is trapped as soon as the top seal is deposited. Because of the shallow depth of burial at the time, oil alteration starts immediately with bacterial activity (20-50° C), causing biodegradation. Also, the methane that is being generated in the process leaks away through the poorly developed top seal, further enhancing biodegradation through gas stripping.

The second phase, which takes place during Pliocene and Pleistocene times, is the period when the individual fault panels of the current field come into existence. Hydrocarbons continue to charge the reservoirs with late mature Cenomanian and early mature Upper Cretaceous – Paleocene / Eocene source rocks, which reduces the viscosity of the accumulation. However, active biodegradation continues at the same time, with continuous gas leakage and gas stripping.

At the present day, as burial continues over time, the field is now in a particular depth range. Biodegradation is still active in the shallower reservoir, but progressively stops in the lower reservoir below the 65° C isotherm. Strong oil alteration by intense gas stripping in response to gas leakage localised at the crest of the D panel is continuing until today, resulting in the huge gas chimney.

Based on this proposed model, it looks likely that the fluid properties at Prospect E would be similar to panel D2&3 with medium viscosity. An alternative scenario, with a better oil quality like panel A with low viscosity, is also possible. A DHI, including a flat spot, observed in Prospect E further indicates that the closure is compatible with a fill to spill scenario. This implies that the residue of the biodegraded oil from the first charge close to the OWC will be continuously swept out from the reservoir, leaving only freshly re-charged oil with slight biodegradation, similar to panel A. ■

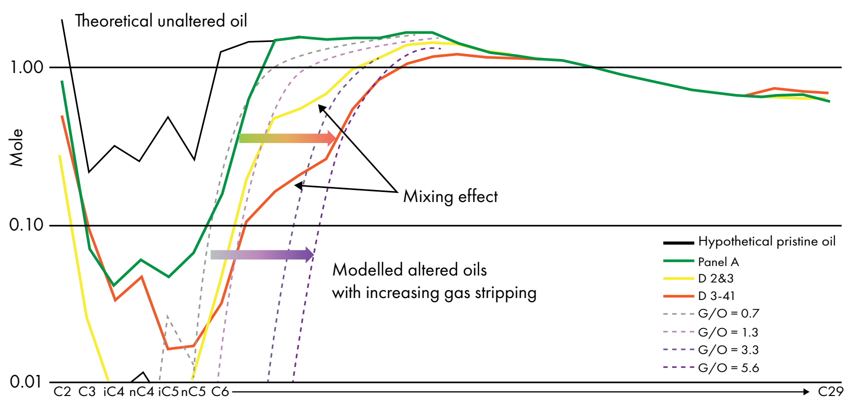


Figure 3: Gas stripping effect modelled for a typical fluid from Panel A. A significant volume of methane is required to strip the heavy components. The solid violet line represents the remaining part of the composition after stripping one mass of "Panel A" oil by 5.6 masses of methane. The oils from D-2&3 represented by a mixture of 35 % of "Panel A" oil and 65 % of the stripped oil, while the oil from D-1 represented by a mixture of 12 % of "Panel A" oil and 88 % of the stripped oil.

ACKNOWLEDGEMENT
We would like to express our sincere gratitude to TotalEnergies for allowing us to publish this article.

Escaping the relentless cycle of re-orgs

Samuel Price reflects on his time with Shell and how he transitioned to a new job outside the oil and gas industry

"THE REACTIONS were overwhelming," Samuel says at the start of our conversation in October. He alludes to the LinkedIn post he made when he left his role at Shell in Houston before embarking on another position in data analytics.

In the post, he wrote about the continuous reorganisations and the toll this took on him and his colleagues. Hundreds of thousands of people read the message, which is extraordinary because Samuel normally doesn't post on social media. "It struck a chord with more people than I could have imagined," he says.

I was intrigued to hear a bit more about Samuel's experiences and motivation to leave his role and embark on a new career. Here, he shares his story.

"The basis for my decision," Samuel says, "is that by the time we had a new organisation go live, rumours were already circulating about the next one. I know that as an industry we go through cycles, but what is happening now is an order of magnitude more frequent. And surviving a re-org is its own curse. The size of the workforce becomes smaller and smaller, but the amount of work remains the same."

Granted, Samuel joined Shell at a special time, a month before the Covid outbreak. The Shell Graduate Program, a three-year on-the-job training program, did not go as planned, with many out-of-office activities shelved or cut entirely. "Online courses were not a replacement for face-to-face learning", he says. "I felt behind in many respects, and I was isolated from mentors who should have played an integral role in my development."

But apart from the uncertainty the pandemic caused, Samuel had joined a company that created a lot of internal uncertainty for itself.

Samuel Price.

UNRECOGNISABLE

For the first year and a half, Samuel worked as an asset geophysicist for the Vaca Muerta play in Argentina. Even though there was a re-org happening in unconventionals at the time, as a graduate, he was ring-fenced against these changes.

Then, Samuel was transferred to the Permian Basin, one week before the asset was sold to ConocoPhillips. The promise of a protected role was broken. "When a cash buyer like ConocoPhillips turns up and wants to interview all personnel in the asset, they're not going to make an exemption for a handful of graduates." He had to apply for a new role with Shell after the takeover.

But the stars aligned.

"I secured an opportunity in seismic processing, the very discipline I fell in love with during grad school," Samuel continues. But within a year of starting in the processing department, another company-wide restructuring was announced.

"In the background, while you are learning and delivering at a breakneck pace, the next re-org is there, buzzing in the back of your mind like a beehive. It makes for a very distracting work environment."

Speaking to his more senior colleagues about this ongoing uncertainty, Samuel was told that the company had changed significantly over the years, to the point where it was almost unrecognisable. "In the end, I had to apply for my own role three times during the five and a half years I was with Shell," Samuel says.

"The technology we use in processing is extraordinary – on one project in the Gulf of Mexico, we worked with ultra-low frequencies down to 0.6 Hz and even interpreted the Moho – but this came against a background of deliver, deliver, deliver. There was little time to delve into the technology, to appreciate the intricacies of processing and learn its nuances, as was so common in the past. I felt like I was only scratching the surface."

"THE MOMENT I DECIDED TO LEAVE"

"It was only four months after the most recent re-org went live that we were being told our group was facing another phase of staffing cuts," says Samuel. But was this a surprise? No, it would have been naïve to think so, and that's why he had already decided to take his future into his own hands.

"I received an incredible offer the very same day that leadership began using the euphemistic language indicating another lay-off," says Samuel. "Our department lead wanted us to know, with tears in her eyes, that we were 'reprioritizing our differentiating technologies.' The decision to leave was practically made for me."

That doesn't mean it was easy to find a position. "Whilst searching for other roles, the biggest lesson I learned was how to translate your experience into a language that resonates with the people outside of the oil and gas industry. It didn't go well in the beginning, which led to several rejections coming through," Samuel explains.

But when it did happen, and after he had overcome the initial worry about not being able to fit in because of the jargon, Samuel quickly found out how transferable his skills are. "I can still apply many of the geoscience skills I learned in my previous roles, such as data interpretation and data processing. In fact, I think geoscientists have a leg up on candidates in other industries. The problems we face are some of the most technically challenging and most difficult to quantify in terms of risk. Finding any solution, even if it's a simple model, requires problem-solving skills other industries desperately need."

"I couldn't believe the sheer number of people in my new office when I walked in the first time," Samuel explains when we continue to speak about his new role. "Where we would have one person at Shell doing different jobs and wearing multiple hats, we have a group of six to ten at my new company. Moving to this position really made it clear to me how understaffed oil companies are. It's one of the main reasons why I chose to leave," concludes Samuel. "I have a much better work-life balance, and I get to spend a lot more quality time with my family. It's hard to put a price on that." ■

Henk Kombrink

PHOTOGRAPHY: SAMUEL PRICE PRIVATE ATCHIVE

GETTING USED TO BEING TOLD NO

Samuel did not enter the Shell graduate programme in the most conventional way. He graduated with a degree in international relations and Russian language before working in offshore logistics on an exploration drillship. Only then did he discover a passion for geophysics and decided to embark on a master's programme. That was quite a challenge, though, and he had to apply many times to get admitted. "I was determined," he says. "I wanted it. I wasn't going to fail without giving it my all." And it did pay off.

"I finished the master's programme with top marks. So, you can imagine when I was offered the role at Shell, it felt like I had finally made it. Then, to find out that you entered an organisation marred by unrest, combined with a ten-year lag in geophysics, I felt behind in terms of professional growth and benefits compared to my peers who had joined straight from university. It was not the environment I had expected to join."

THE MILLION-DOLLAR QUESTION

Why is there such a focus on reducing headcount while staffing costs are dwarfed by the costs of drilling a well or building a new platform? "It's the question everybody has," Samuel says, "but I think it's partly due to the rapid cost increases we have seen for almost everything during the pandemic. Against that backdrop, staffing costs are one of the few items left that can be easily reduced. But this is a short-term solution with a significant long-term impact. I also fear that companies are becoming increasingly nervous about their ability to find new resources, so it's no surprise that change is occurring. But the people who do the real work are the ones paying the price for uncertainty. That doesn't sit well with me."

Cameroon:
Unlocking potential and reigniting exploration

Cameroon's Douala/Kribi-Campo (DKC) and Rio del Rey (RDR) Basins offer significant exploration opportunities, underpinned by advanced seismic reimaging, integrated geological evaluation and modern interpretation techniques. In the RDR Basin, focus is shifting from the mature shallow Miocene-Pliocene plays to deeper Cenozoic turbidites and the Cretaceous succession, where improved imaging and regional analogues point to significant untapped resources. Meanwhile, reimaged 3D data in the DKC Basin illuminates stratigraphic, structural, and combination trap opportunities, adjacent to the Kribi-Campo High, and improves understanding of complex channel systems and salt-related plays. Together, these insights demonstrate how modern imaging and integrated geological analysis can unlock prospectivity across both basins. With the 2025 Licensing Round now open, Cameroon presents a fresh opportunity for discoveries and renewed exploration success.

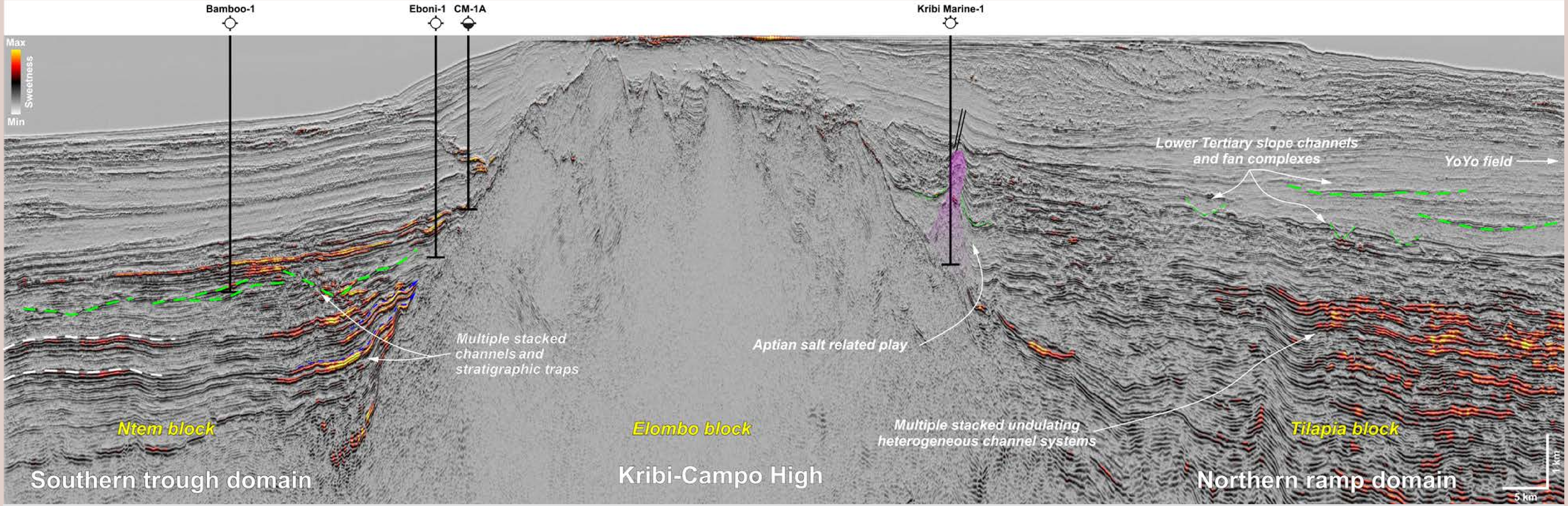


Figure 1: Arbitrary seismic line (pseudo-relief and sweetness co-blend) from the DKC Basin, spanning across the Ntem, Elombo and Tilapia Blocks, showcasing play diversity across different domains and DKC license blocks available in the 2025 Licensing Round.

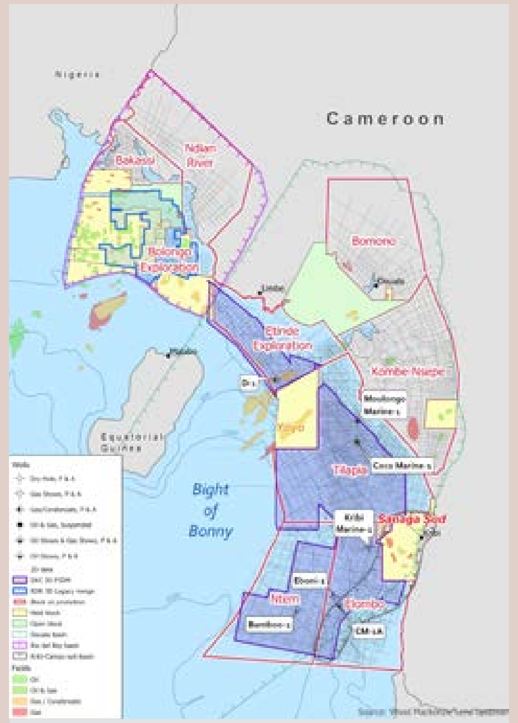


Figure 2: Location map showing 2025 Licensing Round blocks, Viridien's seismic coverage, selected wells, hydrocarbon fields and license blocks in the DKC and RDR basins.

Play diversity and untapped promise – A new licensing round opens fresh horizons in Cameroon

MISHA ISAKOV AND GRAHAM COOKE, VIRIDIEN

OPENING THE DOOR TO DISCOVERY

Cameroon's 2025 Licensing Round, launched by the Société Nationale des Hydrocarbures (SNH), offers nine highly prospective blocks covering nearly 20,000 km² across onshore and offshore areas of the Douala/Kribi-Campo (DKC) and Rio del Rey (RDR) Basins. Open for bidding until 30 March 2026, the round presents a compelling opportunity to explore a region with proven petroleum systems, established infrastructure, and proximity to key markets.

Situated at the eastern edge of the Niger Delta, the RDR Basin continues to deliver from established fields supported by robust infrastructure. To the south, the underexplored offshore DKC Basin presents significant untapped potential, with proven petroleum systems and a range of Cretaceous and Tertiary plays. Discoveries such as Sanaga Sud, Ebome, Mvia, and YoYo have confirmed both oil and gas potential across shallow and deepwater settings.

As the exclusive data provider, Viridien is supporting the licensing round with a comprehensive exploration data package: 6,800 km² of reimaged 3D PSDM seismic, ~9,000 km² of enhanced 3D coverage, 37,500 km of processed 2D seismic, and interpretative data from over 150 wells.

Viridien's 2021 regional 3D PSDM reimaging project, integrating ten legacy surveys across the DKC Basin, was undertaken using state-of-the-art technologies. Analysis of this dataset, coupled with recent integrated geological evaluation by Viridien and SNH, has provided a fresh perspective on the region, revealing insights on a regional scale. With modern imaging technologies and large regional 3D datasets, the subsurface picture is now greatly enhanced, with significant uplift in trap definition and structural imaging compared to legacy datasets. These advancements have highlighted areas of renewed exploration potential and further de-risked prospectivity.

REIMAGING THE PAST TO REFINE THE FUTURE

The 3D PSDM reimaging has delivered a step-change in data quality, with wave-equation deconvolution for multiple attenuation and joint source-receiver 3D de-ghosting technologies applied. Reflector continuity, signal-to-noise ratio, and bandwidth are markedly improved, particularly in deeper intervals. Depth positioning was refined through Full-Waveform Inversion (FWI) and multiple tomography passes, resolving ambiguities caused by complex velocity variations (Isakov et al, 2023). Compared to legacy time-domain data, the PSDM data offers clearer structural definition of prospective features.

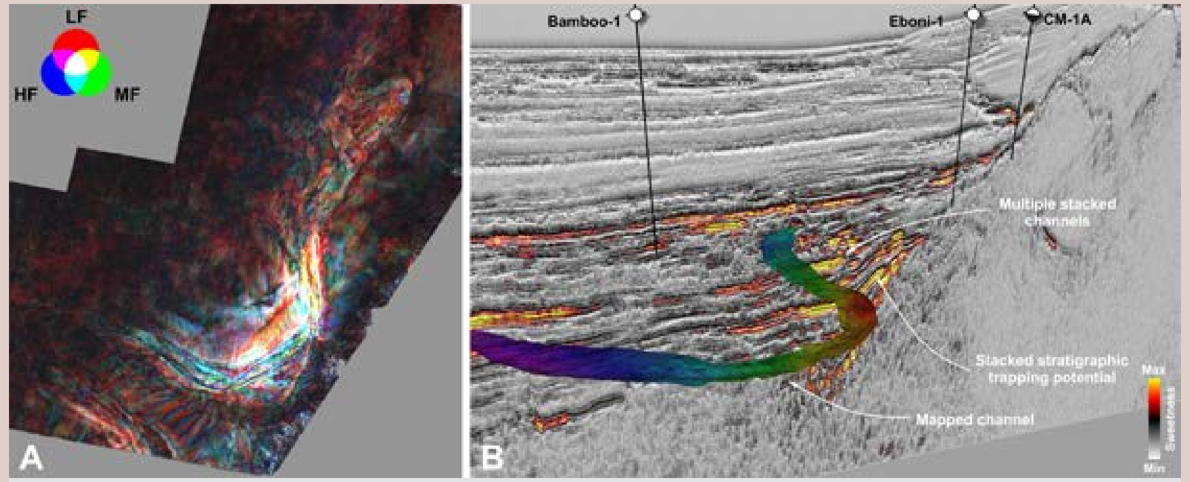


Figure 3. A – stratal slice at Albian to Campanian level with spectral decomposition results highlighting prominent channel systems; B – Seismic section overlaid with the seismic attribute sweetness, demonstrating deeper potential within stacked channel systems (projected well locations).

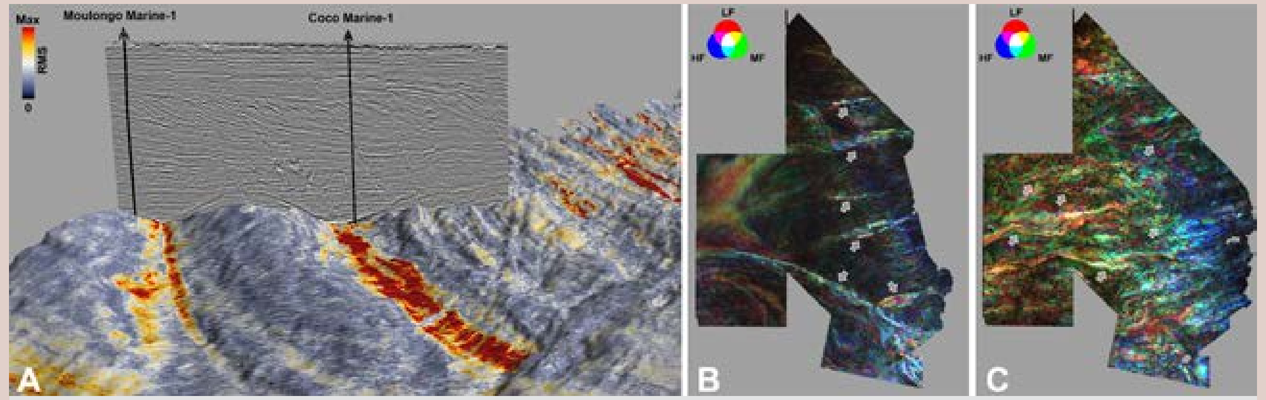


Figure 4. A – Stratal slice and seismic line within the Palaeocene demonstrating the position of Moulongo Marine-1X on the edge of the target channel; B – Stratal slice at ~Miocene level with spectral decomposition results highlighting several channels; C – Stratal slice at ~Cretaceous level with channel systems identified.

WHERE PLAY DIVERSITY DRIVES EXPLORATION

In the offshore DKC Basin, diverse plays span post-rift Upper Cretaceous to Tertiary slope and basin-floor fans, hosted in structural, stratigraphic, and combination traps, potentially charged by multiple Cretaceous and Tertiary source rocks.

The new interpretation of the reimaged 3D data has highlighted significant prospect potential within Cretaceous and Tertiary plays. In the Ntem and Elombo blocks, refined PSDM imaging and attribute analysis reveal deeper, potentially sand-rich targets that have previously gone untested in earlier campaigns. Multiple large-scale stacked Upper Cretaceous channel systems and associated stratigraphic traps are now clearly defined (Figure 1). Spectral decomposition and high-resolution seismic attributes (Figure 3A) reveal large compound channels with strong amplitude contrasts and depositional geometries that indicate potential for sand-rich fills and promising trapping configurations (Figure 3B).

Within the Elombo block adjacent to the Kribi-Campo high, structural and stratigraphic plays linked to salt diapirs offer additional promise. An Aptian salt body was penetrated by Kribi Marine-1 (Figure 1), highlighting potential for salt-related traps. The Lower Cretaceous Mundeck Formation likely serves as the source rock, with Mundeck sands forming suitable reservoirs. These salt-related plays, though confined to the rift, offer intriguing analogues to productive systems farther south along the Atlantic margin.

Across the Tilapia block, the Moulongo Marine-1X well, guided by 2D data, targeted an Upper Cretaceous submarine fan complex and missed the main basin-slope channel, while the nearby Coco Marine-1 well successfully encountered thick hydrocarbon-bearing channel sands that are clearly visible in Viridien's 3D dataset (Figure 4A). Attribute extractions at the Palaeocene stratal slice reveal clear channel systems extending towards the south-west and demonstrate how Moulongo Marine-1X is located at the edge of the target channel. The latest reimaged 3D PSDM data refines structural and stratigraphic interpretation and boosts confidence for identifying and optimising viable drilling targets.

Tertiary stratigraphic traps dominate exploration in the north DKC area, as proven by the Coco Marine, YoYo, and Sapele discoveries. Targets include Miocene turbiditic and channelised sandstones (Figure 4B), with additional potential in Eocene and Palaeocene intervals. Further prospectivity has been identified in Upper Cretaceous plays, where channel systems have been revealed (Figure 4C) and hydrocarbon shows encountered. In the Etinde Exploration block, petrophysical analysis indicated missed pay in several wells (Jean-Pierre Loule et al, 2018).

In the RDR Basin, exploration has historically focused on prolific shallow Upper Miocene–Pliocene plays, many of which are now nearing depletion. Emerging Cenozoic turbidite plays such as Isongo, Oongue, and Nguti, once considered high-risk, are now seen as promising following analysis of enhanced seismic data.

An even greater opportunity may lie within the untested Cretaceous play, long overlooked due to thick Tertiary overburden. Outcrops of Campanian-Maastrichtian and Albian-Cenomanian shales, together with discoveries in equivalent intervals along the West African margin, indicate strong geological correlation and a viable petroleum system.

Together, the RDR and DKC Basins showcase a remarkable range of plays, from deep Cenozoic and untested Cretaceous prospects in RDR to stratigraphic and structural opportunities in DKC.

NEW DATA, NEW HORIZONS

Recent imaging advances and renewed geological insight are reshaping the understanding of Cameroon's subsurface. Continued application of modern technologies promises to unlock overlooked potential and refine interpretation across both basins. With the 2025 Licensing Round now underway, these developments set the stage for a new wave of exploration success.

PORTRAITS

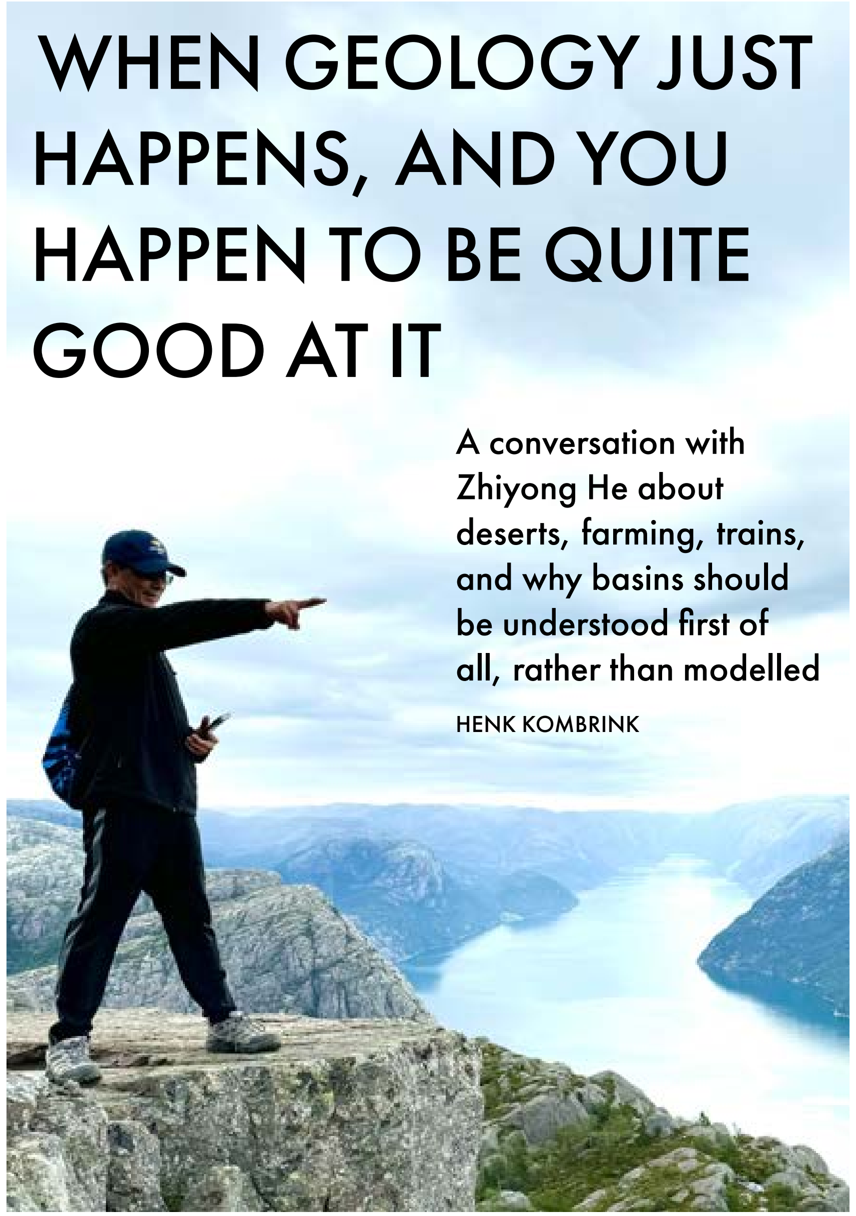
"The software is not a crystal ball to get an answer from, but a set of tools to help prospect evaluation and test different scenarios"

Zhiyong He – Zetaware

WHEN GEOLOGY JUST HAPPENS, AND YOU HAPPEN TO BE QUITE GOOD AT IT

A conversation with Zhiyong He about deserts, farming, trains, and why basins should be understood first of all, rather than modelled

HENK KOMBRINK



Zhiyong He in the Norwegian fjords – sculpted by ice.

PHOTOGRAPHY: ZHIYONG HE PRIVATE ARCHIVE

GEOLOGY? Going to university? It was not on his mind at all when he finished high school. Yet, he has become a world-renowned expert in petroleum systems and basin modelling, Zhiyong He. For this interview, I spoke for more than two hours with the founder of ZetaWare, the company Zhiyong started after he left ARCO in 1999. Ever since, a "pragmatic" approach has been his mantra, as he does not believe that more advanced 3D modelling software does a better job. Instead, he keeps on emphasising during the conversation how important it is to "model" a basin in your mind instead. But before we get to that, let's take a look at his earlier years.

"I was born and raised in a small town in the Gobi Desert near the Mongolia border in western China," says Zhiyong at the start of our conversation. "Life as a kid was very simple; we played outside until bedtime, no matter the high temperatures during summer or the cold in wintertime. School was not hard at all either; we had everything we needed."

DOUBLE STICK SHIFTS

Then, after high school, I assumed that Zhiyong went to university straight away, like most people I interviewed for this series. But that did not apply to him. "Colleges were suspended during the Cultural Revolution, so after high school we were sent to rural villages to be re-educated", Zhiyong says.

So, he moved to the countryside about 30 km away from his home, to a small village with seventeen farming families. "We cleared large tracks of land to grow wheat, and we even had tractors and combines. It was a great time," he says. "You always learn so many things you don't learn at school. For instance, how to drive a tractor with a double stick shift and a double clutch. I can still do it today."

After two years working on the farm, Zhiyong moved further away from the area he grew up in; in fact, it was a 10-hour bus ride away, and closer to industrial activity. He joined a steel factory where he worked on trains. "We had five locomotives to shift things around; bring coal and ore in, and ship the finished steel out," Zhiyong explains. "I worked as a switchman, hooking / unhooking cars, and hanging on the side of the leading car to signal to the engineer when the trains needed to be backed into loading docks. I often had to hop on and off while the train was moving. It was a dangerous job, but a great way to learn about trains and the railroads."

GEOLOGY, WHAT IS THAT?

After four years, universities opened up again, and Zhiyong took his chance to embark on an academic career. However, with many kids wanting to go, competition was immense. He wasn't selected the first time he tried, but a year later, in 1978, he was offered a place to study geology. "My preference was engineering," Zhiyong says, "but it is likely that the geology departments did not have that much interest, and so I was offered a place there, at one of the top-tier universities. As competition was so rife, it would have been foolish to say no, so I went, without really knowing what I was about to get myself into!"

Zhiyong went to the "Northwestern University" in the city of Xi'an. "I was surprised to see so many trees about," he says, "and it was a lot more humid as well." His class of thirty students consisted of a wide range of people, as universities had been practically closed for so long. Some came straight out of high school, others had worked as Zhiyong, or spent time in the military. Some people had kids already.

After a four-year undergraduate programme in petroleum geology in Xi'an, Zhiyong applied to graduate school in Beijing at the urging of his English teacher in college. Following the master's program that focused on basin modelling, he stayed at the university for two more years as an assistant professor. And there he made a difference, during a workshop.

WHY NOT?

The workshop was presented by Ian Lerche from the University of South Carolina, a genius astrophysicist from the UK who had made his way into geology. "The theme of the workshop was about basin modelling, and involved biomarker kinetics," Zhiyong says. "It was an odd topic, so most of the audience either tuned out or had no idea what he was talking about."

To make matters worse, the translator had difficulties with many of the specialised terminologies. Zhiyong, one of the few who understood the narrative, helped with the translation. It made an impression, which led Ian to invite Zhiyong to do a PhD with him in the US. "Why not?" Zhiyong responded.

At the University of South Carolina, Ian came up with the equations to model vitrinite reflectance, apatite fission tracks, and biomarkers. Zhiyong, together with other students, helped translate that into a software application. "This all happened as part of a big joint industry project in which multiple oil companies participated," Zhiyong explains.

During the second year of his PhD, Zhiyong landed a summer job at ARCO, basically doing the same he was doing at the university: Writing code to perform basin modelling with. And as if it was all destined to happen, he was subsequently offered a position at ARCO once he had defended his thesis. But not as a normal employee, but as a postdoc instead. "I was in the USA on a student visa," says Zhiyong, "and in order to stay in the country, it was easier to extend that. So I became a 'student' in ARCO, starting in their research department in 1989."

PUTTING A FOOT ON THE BREAK

The basin modelling landscape at the time of Zhiyong joining ARCO was still in a fairly early stage. "Most of the majors were developing their own modelling software," he explains, "and were also licensing the commercially available systems just to see how these were functioning and to learn from them."

As part of ARCO's research team, Zhiyong continued working on developing code himself as well, moving from 1D to 2D modelling over time. But when 3D came around in the mid 1990s, Zhiyong put his foot on the brake.

"I didn't believe it was practical at the time because we did not have the data necessary to calibrate a 3D model," he says. "In fact, I am still of the same opinion today. The physical principles involved are fine, but there are just too many uncertainties involved, especially when it comes to the presence and distribution of carrier beds and source rocks, and their quantity and quality."

ARCO management did not challenge Zhiyong in his belief that it was a waste of time to go the 3D route. Instead, he started working on a 2D map-based tool, the precursor to Trinity, which was much more in line with what geologists were doing in the new ventures departments. "You have to think about the practicalities of how geologists worked at the time," Zhiyong says. "They often only had paper maps and had to draw prospects, kitchens, and migration pathways with pencils. They commonly had ZMAP surfaces, and we built the software to use those surfaces to create maturity maps, migration pathways and fill and spill scenarios, to help evaluate prospects."

"As such, there was a real synergy between what the geologists were producing and what we could deliver on top of that," Zhiyong continues. "By visually presenting prospects and kitchens, and interactively drawing migration pathways and fill and spill patterns, explorationists had a new tool to sell their prospects to management."

THE WRONG QUESTION

Zhiyong worked at ARCO for eleven years, so I am intrigued by how often the software he developed proved critical in the decision to drill a well, or not. It turns out to be the wrong question. "The software is not a crystal ball to get an answer from," emphasises Zhiyong, "but a set of tools to help prospect evaluation and test different scenarios. It is highly experienced explorationists with the right focus and workflow who found Jubilee, Mangala, Johan Sverdrup, Liza, and Venus," he adds.

That's not to say that people always take the best approach.

> "The software is not a crystal ball to get an answer from, but a set of tools to help prospect evaluation and test different scenarios"

"I KNEW IT WAS GOING TO BE A DRY WELL"

"Once upon a time, I had lunch with a very well-known petroleum systems expert in a big oil company," says Zhiyong. "This person told me that his company just drilled a dry hole, even when he had written an internal report condemning the prospect two years before spud."

Zhiyong did not tell him what he thought of this kind of "I was right" boasting. "First of all," he says, "it is not possible to predict the outcome of an exploration well deterministically. If you predict an exploration well to be a dry hole, you would ►

PORTRAITS

be right most of the time, especially in a more frontier domain. It is nothing to brag about. Secondly, if you are THE expert of petroleum systems, and your company ignored your advice, it wouldn't be something I would be proud of either. I would rather the company listen to my advice even if I was wrong in the end."

"I believe our job as petroleum systems experts is to integrate all the relevant information, test all scenarios of outcomes with our models, and provide a probabilistic chance of success to the decision maker, not a deterministic answer. This requires the software to be able to model the key aspects very quickly. We cannot afford to take several weeks to build a model, and then several days to run and get a single scenario that's most likely wrong."

Another interesting observation about this story is that the well was drilled regardless of the negative advice from the expert. "Exploration managers probably have seen enough dry holes to know how to deal with uncertainties, while experts tend to be overly confident about what they know," says Zhiyong, "and therefore I understand that managers don't always listen to their own experts, especially when their judgment is very black or white."

Then there is the observation that experts do not always agree, and the Jubilee field offshore Ghana is a good example of that. "In the farm out discussions, one company claimed that the Cretaceous source rock could not be mature because the kitchen is sitting on oceanic crust," explains Zhiyong, "whilst another company's model predicted that it was overmature instead, also because the kitchen is sitting on oceanic crust!" At the same time, both ignored the fact that there was already an oil discovery updip of the Jubilee stratigraphic trap, clearly suggesting that there was a working petroleum system regardless. People put too much emphasis on modelling sometimes, and do not pay much attention to observations," Zhiyong says. "All models are wrong, and some are useful".

WHY ARE WE STILL DRILLING DRY HOLES IN ESTABLISHED BASINS?

Zhiyong prefers to make observations, which are powerful clues to how hydrocarbons migrate in sedimentary basins. One of these observations is that dry holes are still being drilled in basins where a mature source rock is proven. "I think there are two things to consider when it comes to explaining that," says Zhiyong.

"First, there are carrier beds," he continues. "These intervals are often obscure and hard to map, but they are the ones that cause lateral migration. If carrier beds exist above a source rock, the shallow prospect sitting directly above them may not have access to charge, as the hydrocarbons follow the carrier beds laterally. Observations in many basins confirm this principle, and therefore, shallower prospects further up above the carrier beds often have a low chance of success."

"Success rates are much higher if the reservoirs are adjacent to (directly above or below) the source rock," Zhiyong continues. "Vertical migration requires that the deeper carrier bed leak at structure locations, and that typically means the structure relief needs to be high enough allow buoyancy to work against the seals above the deeper carrier beds. That gives us some criteria to high-grade shallow prospects above such high relief structures."

"I worked with a small company that explored the Miocene reservoirs in the GOM," says Zhiyong. "Their criteria in farming in a prospect is whether the Cretaceous below had significant structural relief. This company had a very high success rate! In the North Sea, the same principle can be seen at work. Big fields like Montrose, Forties or Ekofisk sit on large basement highs, and that made it more likely for hydrocarbons to migrate into Cretaceous or Tertiary reservoirs. Yet in general, younger targets are much higher risk than the middle Jurassic reservoirs that sit directly below the Kimmeridge Clay source rock."

Secondly, the source rock may be mature, but is it generating enough to fill the deeper carrier beds and have enough left to migrate to updip structures, or leak up to shallow prospects? "The further away you get from the source rock, laterally or vertically," explains Zhiyong, "the more important that question becomes.

In the northwest Java basin of Indonesia, the Eocene source rock is mature, but has not generated large volumes due to limited potential. As a result of that, and mainly driven by migration models predicting a higher extent of lateral migration than what was actually the case, many dry holes were drilled into surrounding reefal structures. Only when drilling started next to or inside the kitchen area, discoveries were made," says Zhiyong.

"Being aware of these concepts," concludes Zhiyong, "and being aware of the large uncertainties, makes a strong case for not using a deterministic model in exploration. Instead, basin models should account for a probabilistic outcome, taking into consideration main controls such as presence and extent of carrier beds and source rocks, the seal quality above them, and the source rock potential and maturity."

TIMING DOES NOT MATTER

We continue our conversation about the intricacies of hydrocarbon generation. "People have spent a lot of time on modelling the paleo heat flow and kinetics of source rock maturation," Zhiyong says, "and describing the source rock in minute details. All with the aim to predict the timing of hydrocarbon generation and the type of hydrocarbon they will find in the trap. At some point in time, there were five industry consortia working on kinetic models. But does it all matter at the end of the day? Is it very much required for a trap to be ready once a source rock enters the kitchen? "No. it rarely does," Zhiyong says firmly.

"We have multiple examples of discoveries where the oil was generated tens of millions of years before the reservoir was even deposited," he explains. "And this concept is not new; the idea of hotelling the oil was already proposed in the 1970s. The difference between what people thought back then and what I, together with some of my peers, think these days is that this concept is much more common than we ever anticipated. In fact, I think it is the norm. The source rock itself is a large hotel, and so are the carrier beds."

Let's go and dive a little bit deeper into this and use the Gulf of Mexico as an example. "When the Tithonian source rock started expelling during the Oligocene," Zhiyong says, "the Middle Miocene to Pleistocene reservoirs had not even been deposited yet. But the oil made its way into carrier beds and stayed there. Then, five more kilometres of sediments were dumped on top of this, with the result that the source rock and the deeper carrier beds enter the gas window."

Timing-wise, this was actually a good thing," Zhiyong continues. "Cracking oil to gas expands volume quickly and pushes the oil at the front into the shallower Miocene reservoirs. So, even after the source rock has expelled all its hydrocarbons, oil continues to migrate into new reservoirs simply due to increasing burial.

And that immediately exposes another phenomenon that is often misunderstood. "Many people think that a good reservoir with Darcy permeability is all we need to make sure that hydrocarbons migrate into a trap. But that is neglecting a critical factor," says Zhiyong. "If you just generate one barrel, do you think that this single barrel will move all the way up to a closure? Of course not. What we need is the generation of a volume of hydrocarbons that is big enough for all the small traps along the carrier beds to be filled along the way to the trap that we ultimately want to drill. It's that volume that is key, and not so much the timing of generation."

"Seismic and our models don't capture the fine granularity of the storage and carrier system that exists in a kitchen area and therefore fill the big traps further away much more easily than reality suggests," stresses Zhiyong. "If the source rock generates less than that volume, there is no oil in our prospect. And that volume is unknown but often many times larger than the trap can hold. This unknown volume is one of the most important parameters to account for probabilistically."

PHOTOGRAPHY: ZHIYONG HE PRIVATE ARCHIVE

Utah National Parks – a geologist's heaven.

THE VALUE OF 3D AND DRILLING CLOSE TO THE KITCHEN

Although 3D seismic may not have high enough resolution to map those carrier beds and the subtle traps, it is very useful in better delineating structures and, hence, drilling targets. "A great example is the Western Desert in Egypt," says Zhiyong, "where Apache was the only company shooting 3D over the horst blocks separating the grabens."

"It paid off to do that," he says. "Through this approach, the company was able to demonstrate that an individual horst structure consists of multiple sub-blocks. In turn, this allowed them to pinpoint the fault blocks closest to the kitchen, and voila, success followed. The Jurassic source rock in the Western Desert is not as productive as the North Sea, so it is key to drill as close to the kitchen as possible."

FUNNY MODELS

We already know that Zhiyong is not a great fan of 3D models. Yet, we get to talk about them a bit more. "The sizes of grid cells are often totally unfit for ▸

purpose," Zhiyong says. "When a whole reservoir unit is captured by the thickness of one grid cell, it is impossible to have pressure gradients in there that drive how the hydrocarbons will move throughout the volume of rock. This alone is a reason not to rely on these models too much."

"Rather than building a complicated 3D model in a piece of software, people should build a 3D model in their heads instead, and be aware of the uncertainty"

"Another thing I observed frequently, and actually still observe today at times," he says, "is that models often predict accumulations where there is no trap at all, in a completely flat area. It is an artefact, because these models only rely on buoyancy for upward migration, rather than a combination with saturation-induced capillary pressure that pushes oil to lower saturations, which can also be downwards."

"All in all, there are so many details in a volume of rock that we cannot see and map. Rather than building a complicated 3D model in a piece of software, people should build a 3D model in their heads instead, and be aware of the uncertainty," Zhiyong concludes.

LUCK, PURE LUCK

We have been talking about technical insights for quite some time now, even when Zhiyong says that he is happy to continue talking for two more weeks. However, it is time to return to where we left his career timeline, when he was still at ARCO. At some point during the interview, Zhiyong tells me that he actually got much more exposure to the exploration game once he left ARCO after eleven years. It was the time he became independent and set up his own software and consultancy business. I am intrigued as to how this went and how he managed to grow from that point onwards.

"I was very lucky," he emphasises firmly.

Usually, companies don't allow departing employees to take software they have developed with them; it is seen as corporate IP. However, as bp did not have the tradition of developing software in-house, the situation was a bit different in this case. Because they were still interested in Zhiyong's approach and wanted to test the software for a few things, they decided to offer him the code, under the premise that he would support the company for six months.

"It meant I had something to market straight away," says Zhiyong. "And even better, my former ARCO colleagues who found positions elsewhere at other oil companies happened to be keen users, so I immediately had some customers as well."

And rather unexpectedly, bp came back after a few months, asking Zhiyong if they could join the consortium of companies that he had already pulled together, to the point where they wanted to have the most influence in deciding which direction the software should be developed. "I was in a great position to have generated an income straight away," Zhiyong says. "Can you now see how lucky I was?"

"I have always been a very practical guy," Zhiyong continues at the end of our conversation. "I understand the physics behind modelling, and have spent a lot of time on integrating things in code, but at the end of the day, when we see that it is the unobserved subsurface details that make any model too much of a generalisation for migration modelling, I think we have to admit that a 3D model is something we need to build in our minds. Only in this way is it possible to match your observations."

Someone who works with Zhiyong frequently calls him a legend. I'm sure that he will not use that word himself, modest as I think he is, but the conversation I had with him did confirm that I was talking to a man with vision and an infectious curiosity. What a delight to pen this article down. ■

GEOTHERMAL ENERGY

"99.9 % of homes in the Reykjavik area are heated with geothermal heat"

Susan Fellows

Where the earth yawns

Susan Fellows reports on a recent visit to a geothermal powerhouse

I first visited Iceland a decade ago. Recently, I returned, courtesy of a European Geothermal Research project, hosted by Reykjavik Energy. We learned about heating and electricity production in Iceland, and visited both low-temperature and high-temperature installations, including the Hellishöfði Geothermal Power Plant, famous for the Carbfix project.

At Hellishöfði, electricity is produced using 300° C steam, which powers seven turbine units, each connected to a generator, producing over 2,300 GWh of electricity per annum. Extracted gases from the geothermal liquids and CO_2 from a co-located Climeworks DAC installation are dissolved in the disposal water of the geothermal plant and re-injected into the underlying basaltic bedrock at a depth of 750 m. Over the next two years, the CO_2 is transformed into calcite, and the hydrogen sulphide into pyrite.

High-temperature geothermal water cannot be used directly for house heating, but instead, is used to heat cold water to 80° C. Hot water production amounts to 14 Mt/yr. A 25 km long pipeline connects Hellishöfði to Reykjavik, with the average heat loss on the way to Reykjavik being less than 2° C. Adjacent to Reykjavik, low-temperature area pumping stations deliver hot water to the district heating system directly from the ground. 99.9 % of homes in the Reykjavik area are heated with geothermal heat. Central heating is the predominant element in Icelandic energy requirements, with the length of the district heating system in the capital area itself being more than 3,000 km, equivalent to the distance from Reykjavik to Milan.

A memory from my first visit: The 'Bridge between the Continents', not marked, but unmistakable: Where the great mid-Atlantic Ridge strides ashore. The earth blatantly ruptured and split. Sudden nerves. The rift is not a hole down which I can fall to the centre of the earth. Yet, feet sinking in unexpected sediment, I am acutely aware that at this very place the earth is rather less than solid; the knowledge that here, beneath my feet, the earth yawns. ■

Susan Fellows, Heriot Watt IGE

SETTLING DISPUTES

The Icelandic Parliament, the Althing, was established at Þingvellir in 930 AD. Þingvellir sits directly on the mid-Atlantic Ridge, being a rift valley where the boundaries of the continents are visibly expressed as a dramatic network of fault lines and gorges. The Althing is widely considered one of the oldest formal political assemblies in the world, and one assumes that the Icelanders of the time simply viewed the impressive setting as a worthy location to create laws and settle disputes, though presumably interrupted on occasion by seismic events of a different nature and scale. In the 19th Century, the Icelandic Parliament relocated to Reykjavik, a more stable location geologically, if not perhaps politically.

Hellishöfði Geothermal Power Plant.

PHOTO: SUSAN FELLOWS

Denmark to embark on an innovative geothermal drilling project

A deep closed-loop system will be completed in Aalborg, with initial output expected in 2027

LOUISE BROEN LARSEN, MADS SYLVEST EEGHOLM, NIKOLAJ HOLMER NISSEN, CAMILLE HANNA AND KIM GUNN MAVER, GREEN THERMA

Green Therma, in collaboration with Aalborg Forsyning (the local utility company), is currently preparing to drill a single well to deliver geothermal heat directly to Aalborg's district heating network. While Denmark is recognized for its advanced district heating systems and strong renewable energy profile, geothermal has yet to play a major role in the national mix. The well will extend about 7 km in total: 4-5 km vertically, followed by a 2-3 km horizontal section. The concept draws on proven technology from the oil and gas industry, where long horizontal well sections are standard.

In the Aalborg area, subsurface temperatures increase by roughly 30° C/km. At depths of 4-5 km, rock temperatures are thereby expected to reach 120-150° C, providing a stable, long-term heat source suitable for direct use in district heating.

A CLOSED AND INSULATED SYSTEM

Unlike conventional doublet geothermal systems, which require at least two separate wells, the Heat4Ever™ system operates with a single well closed circuit. Inside the well runs a double pipe with vacuum insulation (DualVac™) between the inner and outer tubes. Water circulates continuously within this sealed system. It is pumped down in the annulus between the well casing and the outer pipe. Once it reaches the horizontal section, the water will then absorb heat from the surrounding rock and return, now heated, to the surface through the inner insulated pipe.

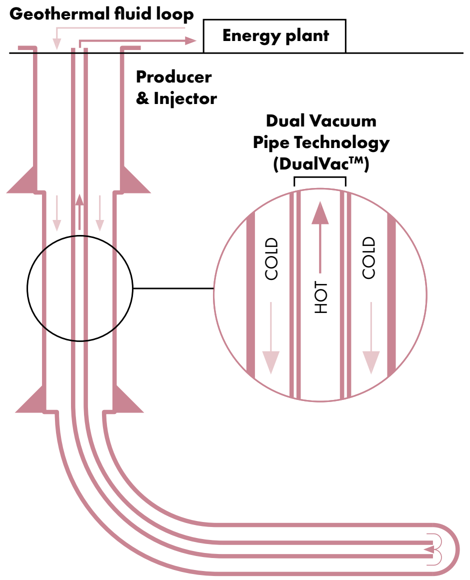
The system minimizes thermal losses to just a few % and eliminates the need to extract formation water from the reservoir. The closed system also prevents mineral scaling and corrosion issues often encountered in open-loop hydrothermal systems. At the surface, the heat is transferred through a heat exchanger directly to Aalborg Forsyning's district heating system.

Because of the depth and efficient insulation, the system is expected to deliver water at temperatures of around 85-90° C to the surface for more than 50 years, while the return temperature after heat exchange will be around 40° C. These temperatures allow the heat to be used directly in the district heating network without the need for a heat pump to boost the temperature, offering far higher overall efficiency when compared to conventional hydrothermal systems. The only energy demand in the Heat4Ever™ solution is a 45 kW circulation pump for a 1.5-2 MW well.

FROM DEMONSTRATION TO SCALABLE DEPLOYMENT

The plant will supply up to 2 MW of geothermal heat to Aalborg's district heating grid. Aalborg Forsyning has agreed to purchase heat from the facility for 30 years, providing a long-term framework for operational experience and data collection.

Green Therma views this project as a stepping stone toward broader deployment. While the operations in Aalborg involve a single well, the plan for future projects is to take a "multi-well" approach across global sites, drilling a sequence of 5-10 wells from a single surface location, each with horizontal sections extending in different directions. ■



Conceptual illustration of the Heat4Ever™ well, showcasing how water circulates in a closed-loop system. The water is pumped down in the annulus between the well casing and the outer pipe, heated by the surrounding rock in the horizontal section, transported to the surface in the inner pipe, completed with the DualVac™ system, and connected directly to Aalborg Forsyning's energy supply plant through a heat exchanger for district heating.

SOURCE: REDRAWN AFTER GREEN THERMA

Layer cake geology and a lack of grid access

The subsurface may be easier to predict than one may think, but that doesn't apply to above-ground conditions

A FEW YEARS ago, I asked a seasoned wellsite geologist about the biggest subsurface surprise she had ever seen over her long career working on rigs. Rather than coming up with a list of fascinating observations, she said she couldn't remember something very spectacular. I often think about that occasion, just because it was so different from what I expected to hear. I do believe what she said, though, and it shows that the subsurface is more of a layer cake than I wanted to admit.

At the recent GET Conference in Rotterdam, the Netherlands, I asked that question again. This time, it was a geologist working on the SCAN project, which is about drilling a series of geothermal exploration wells in the Netherlands in search for reservoirs that lend themselves to heating projects. When I asked the question, seven wells had been completed in areas that had never seen a major oil and gas exploration drive, which was the justification to drill these wells in the first place.

So, after I asked the question, there was a short silence. And then came the response that I could have foreseen, given my experience from before; nothing too obvious came to mind. However, in this case, it was not the end of the conversation. Maybe because in this case, it was an in-person conversation and not a Teams call, the geologists had another thought and concluded that there was, in fact, something that was worth noting.

In one of the more recent wells, Ede-01, the Rotliegend target, a Permian eolian sandstone unit, was not only found to be a good reservoir, but the hydraulic head of the brine turned out to be above surface level. In other words, the well would flow naturally if opened. That was a bit of a surprise. In most cases, due to the higher density of deeper brines, the hydraulic head of deeper aquifers remains at several tens of meters below surface, which is why a submersible pump is often required for geothermal projects.

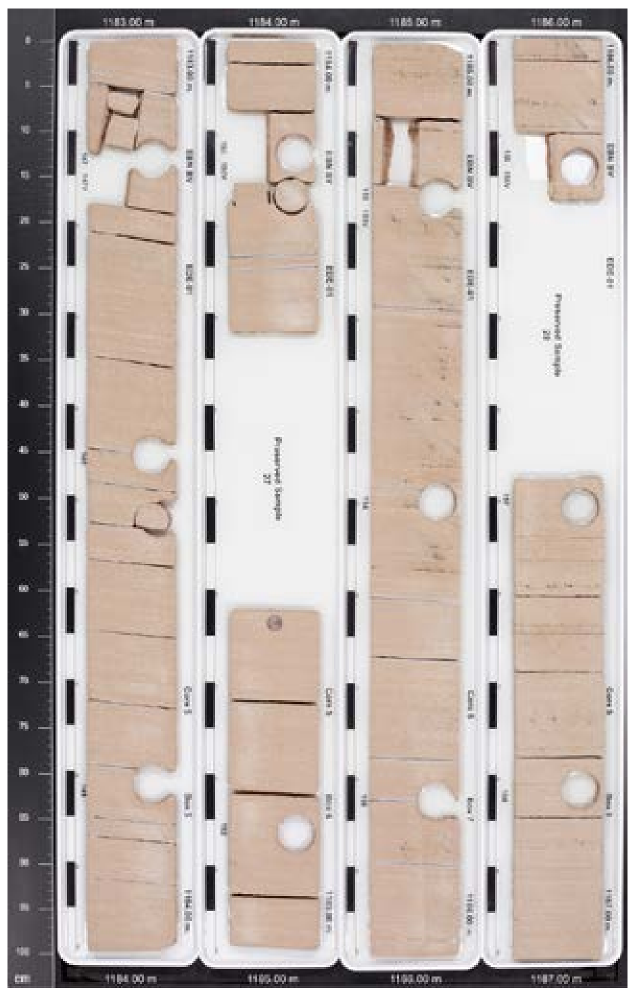
And that was not the only surprise this well had in store. In addition to the Rotliegend showing higher reservoir pressure than expected, the overlying Zechstein carbonate also showed good reservoir properties. That does not happen often, as this limestone unit is one of the Zechstein cycles that is not particularly known for its favourable reservoir properties.

Then, I asked when this area would see its first geothermal production well drilled; the positive outcomes would suggest that there should be an appetite for it. But then came yet another unexpected response; there will be no geothermal development drilling in the foreseeable future. The reason? Lack of access to the grid, or net congestion, as it is called in the Netherlands.

Even when drilling starts tomorrow, the site will not have access to the grid and will therefore need to wait until it can be connected. How long will that take? I think nobody knows, but it was definitely an unexpected response to what seemed to me a very straightforward question.

As it happens, subsurface conditions seem to be easier to predict than above-ground conditions. ■

Henk Kombrink



SOURCE: WWW.NLOG.NL

Core section from the Rotliegend Formation encountered in the Ede-01 geothermal exploration well, the Netherlands.

SUBSURFACE STORAGE

"When we start a project to monitor CO_2 injection, and there is a need to measure microseismicity, we don't always need to install a brand-new set of geophones"

May Zhang – Carbon Guardian

Progress over perfection

Equinor's renewables chief calls for pragmatism and collaboration to make CCS economically viable and store up to 50 million tonnes of CO_2 annually by 2035

The Norwegian continental shelf offers a wealth of opportunities for new industries alongside and after oil, and carbon capture and storage (CCS) has gained a solid foothold. Northern Lights has started commercial storage, and interest in new CCS licenses is high.

Equinor aims to store 30 – 50 Mt of CO_2 annually by 2035, roughly equivalent to Norway's emissions (45 Mt of CO_2 equivalent in 2024).

The company is involved in projects such as Northern Lights and Endurance in the North Sea, Bayou Bend in the USA and Kalundborg in Denmark, as well as a planned pipeline from the European mainland to the North Sea.

At the World CCUS Conference in Bergen in September, Andreas Jagtøyen, SVP of Renewable and Low Carbon Technology at Equinor, highlighted that CCS is the most cost-effective way to decarbonise industries where cutting emissions is challenging.

Equinor has been re-injecting CO_2 at Sleipner since 1996 and at Snøhvit since 2008. Andreas pointed out that the company has so far stored more than 27 Mt of CO_2 in the framework of these projects.

"It is promising and impressive," he said at the conference, "but it took us 30 years. We need to increase the pace significantly to solve the challenges of the future."

Andreas also stressed that CCS must become economically sustainable if we are to reach the zero emissions targets, and that high costs are a barrier.

"The EU ETS price (EU climate quota price) is currently just under 70 €/t, lower than the actual capture costs. 50 – 70 % of CCS costs are related to capture."

Capture accounts for more than half of the costs in a CCS value chain. Here from the capture plant at Heidelberg Materials' cement factory in Brevik, which opened in June 2025.

He called for collaboration between academia and operators to reduce costs, but also pointed out that on the transport and storage side, citing Northern Lights as an example, costs (about 75 €/t) must be reduced.

To accelerate the development of new projects, the low-carbon manager called for pragmatism: "We must talk about what is good enough and accelerate progress over perfection," he said, referring, among other things, to strict requirements for CO_2 purity and high capture rates that increase costs significantly.

On the transport side, he proposed flexible solutions, such as direct injection from ships into reservoirs to avoid expensive terminals such as the Øygarden facility (Northern Lights).

In conclusion, Jagtøyen called for collaboration across the value chain and to find solutions that are "good enough." He emphasised the need for new business models, strategic alliances and ideas for radical cost reductions.

He mentioned, among other things, CO_2 utilisation, such as synthetic fuels and building materials, and Equinor's investment in mineralisation technology to bind CO_2 in stable carbonates in the subsurface. ■

Ronny Setså

PHOTOGRAPHY: HEIDELBERG MATERIALS

SUBSURFACE STORAGE

Being smart with data

May Zhang from Carbon Guardian explains how the start-up leverages publicly available seismic and geoscience data to monitor CO2 injection sites and deep geothermal projects more efficiently

On the fringe of the EAGE GET Conference in Rotterdam, I meet with May Zhang, who is representing Carbon Guardian in the start-up zone. We previously met at the Annual Conference in Toulouse, France, so we picked up where we finished our conversation in early summer.

Carbon Guardian is a new start-up initiative founded by Martin Brudy, who has a rich background in well engineering and reservoir geomechanics. May, a geophysicist with more than 20 years of experience, is helping him launch C44™ – an integrated monitoring platform for geothermal and CCS applications. This time, we delve a bit deeper into what the company is building, as May walks me through a demo on her laptop.

NO NEED TO INSTALL NEW GEOPHONES

One of the features May highlights is the microseismic module. And it shows some interesting things that many operators may not be aware of. "When we start a project to monitor CO_2 injection, and there is a need to measure microseismicity, we don't always need to install a brand-new set of geophones," May explains. "Look at this area in the Permian Basin in the USA," she says, pointing at the screen, "there is already a network of public geophones in place, and the data they acquire can be downloaded from TexNet and analysed by anyone."

"That does not mean there is no need to go into the field and install dedicated instruments," she continues. "For detailed monitoring of a CO_2 injection site, you typically want additional sensors close to the well. But it is always wise to check what is already available before planning additional deployment," she says. "Our approach is to avoid over-engineering. We use free public data first, which helps keep costs down, which is only a good thing, both for us as well as for our clients."

MULTIPLE DATA SOURCES

The team has developed a cloud-native architecture that allows operators to efficiently ingest data from multiple sources – in real time – to monitor seismic activity. It integrates both publicly available datasets and project-specific data from private stations. "Besides being a cost-effective way of working", May adds, "combining private stations with public seismic data provides broader frequency and spatial coverage. Together with AI-assisted velocity model selection, this significantly improves the accuracy of event location."

As geothermal and CCS projects expand, reliable monitoring becomes essential for effective risk management and regulatory compliance. C44 helps bridge that gap, giving operators the clarity needed to advance the energy transition safely and responsibly. ■

Henk Kombrink

PHOTOGRAPHY: HENK KOMBRINK

May Zhang at the Carbon Guardian stand at the EAGE GET Conference in Rotterdam, October 2025.

Are the problems around the Gorgon CO_2 storage project proof that CCS does not work?

A lengthy discussion on social media exposes widely different points of view

"THE WORLD'S largest CCS project, the one that underpins CCS as a climate solution, as advocated by the oil and gas companies. But as the graph shows from the data Chevron provided, its performance is getting worse by the year," wrote Kevin Morrison in a LinkedIn post near the end of November 2025.

It sparked an outcry of reactions, varying from people who agree that CCS is a waste of time and money, given the tiny percentage of the emissions that are prevented this way and the potential that solar and wind have these days. On the other hand, others were quick to argue that the issues Gorgon is dealing with are unique, and that other projects such as Moomba in South Australia and Quest in Canada work well.

The issues that Gorgon faced, from a subsurface point of view, were multiple. First of all, corrosion of the pipes took place because of a high water content in the gas stream – something that should never have been allowed, according to some. Then there is the issue of sand production in the wells that were drilled to produce water from the reservoir to limit pressure from rising too much.

Despite the numerous comments on the post, it takes scrolling through to the last remark that provides a hint to the ultimate question that should be asked: "Given the pressure issues and all the related problems, why did Chevron and partners choose the Jurassic Dupuy Formation as the injection reservoir? Did they expect pressure issues from the start?

The answer is yes, they did. A paper from 2009 describes how a pressure handling system was designed to pump water from the Dupuy reservoir into the overlying Barrow Group from day one. In that sense, it is likely that the sanding issues in the water production wells were the unforeseen factor rather than the pressure limitations of the overall container itself.

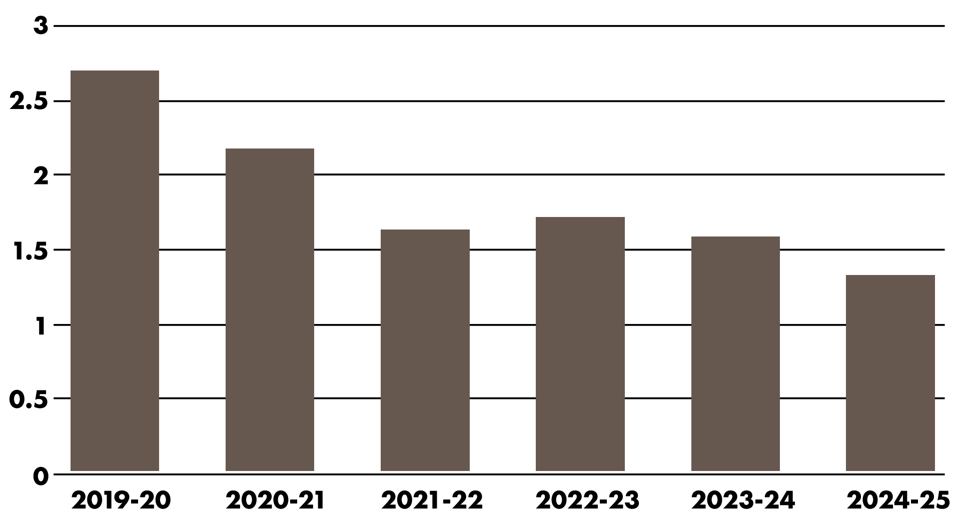
This leads to the next question: Was there no other reservoir candidate with a bigger volume that could be considered for injection? Given the work that seemingly went into the selection process, I doubt there was. That then leads to the question of why Chevron is so slow in acting on these issues through drilling more and better water production wells?

Again, opinions differ, with some blaming a slow governmental legislative process, whilst others say it is down to corporate inertia.

But at the end of the day, I do agree with what CCS proponent Margriet Kuipers concludes in her comments; the penalty Chevron now pays due to underdelivering is too small and allows the company to carry on producing gas and vent the CO_2. Money talks, and shareholders ultimately look at numbers.

So is Gorgon an example of a CCS project that doesn't work? I think it can work, even at Gorgon, but with the right stick. ■

Henk Kombrink



Gorgon volume of CO_2 injected (Mt).

SOURCE: CHEVRON VIA LINKEDIN

SEABED MINERALS

"..the accumulative volume of SMS deposits is larger at slow-spreading ridges"

Bramley Murton – Professor of Marine Geology at the National Oceanography Centre in Southampton, UK

American Samoa offshore minerals planning advances

BOEM has identified 134,000 km² offshore American Samoa for potential critical mineral leasing – the first major step in US seabed mineral planning, with multiple companies expressing interest in exploring the region

The US Bureau of Ocean Energy Management (BOEM) has completed Area Identification offshore American Samoa, marking the first time US waters have reached this stage in the federal seabed minerals process.

The move is part of BOEM's effort to evaluate leasing opportunities for critical minerals on the Pacific Outer Continental Shelf, following an executive order signed in April 2025. The order directs federal agencies to streamline permits for seabed mineral exploration under the Outer Continental Shelf Lands Act (OCSLA) and aims to secure minerals like nickel, cobalt, and manganese to reduce US reliance on foreign suppliers.

The newly identified area covers about 134,000 km² of seabed at depths of 1,400 to 6,000 m, near the eastern edge of the American Samoa Exclusive Economic Zone (EEZ), bordering the Cook Islands.

It lies within the Samoa Basin, which contains widespread polymetallic nodules across most of the area, while ferromanganese crusts are concentrated in the southern part of the identified area, as well as in the central parts of the American Samoa EEZ. These deposits are enriched in nickel, cobalt, copper, manganese, and rare earth elements.

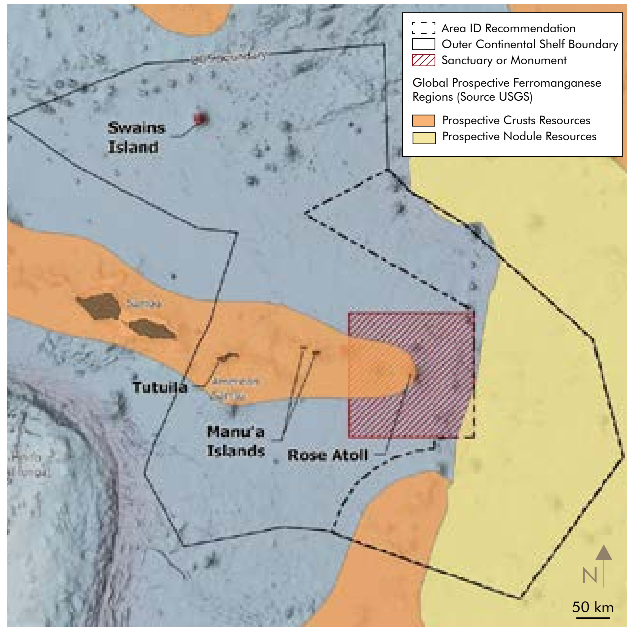
According to BOEM, the decision defines which tracts will now undergo environmental review to assess potential economic benefits and environmental impacts of future leasing.

"We are in the first step in the process of understanding the potential economic benefits and environmental impacts a lease sale would have for American Samoa. If done right, this could produce great economic return for our fellow Americans in the territory," said Principal Deputy Assistant Secretary for Insular and International Affairs William Hague.

The process was triggered by an unsolicited lease request from Impossible Metals, a US-based deep-sea mining company developing robotic systems to harvest nodules selectively from the seafloor.

Impossible Metals is the first company to request a lease of critical minerals, but it is not the only interested party. During a public consultation in mid-2025, BOEM received multiple indications of industry interest in the region. Feedback supported expanding the original area of interest by roughly 60,700 km² to the southwest.

In total, BOEM received over 76,000 public comment submissions in response to the Request for Information, including both support and opposition to commercial leasing. Local leaders, including the Governor and Congresswoman of American Samoa, raised concerns about environmental impacts, effects on fisheries and tuna industries, cultural heritage, and Indigenous rights.



The American Samoa EEZ with the identified Area ID in the western sector. Colours show regions prospective for nodules and crusts.

ILLUSTRATION: BOEM, BASED ON USGS MAP

Industry commenters provided input on leasing terms, royalty rates, and exploration strategies. BOEM considered all of these perspectives when formulating the Area Identification recommendation.

BOEM stresses that the Area Identification is not a decision to lease or mine, but the start of a detailed environmental assessment under the National Environmental Policy Act (NEPA). Any future lease sale would require additional public notice and further review.

While American Samoa now moves into environmental analysis, BOEM is also opening a Request for Information and Interest for the Commonwealth of the Northern Mariana Islands (CNMI) between November 12 and December 12, 2025, beginning the same process there.

Together, the two initiatives mark the first coordinated US push to evaluate seabed mineral resources across its Pacific territories and a significant step toward securing domestic supplies of critical minerals for clean energy and defence. ■

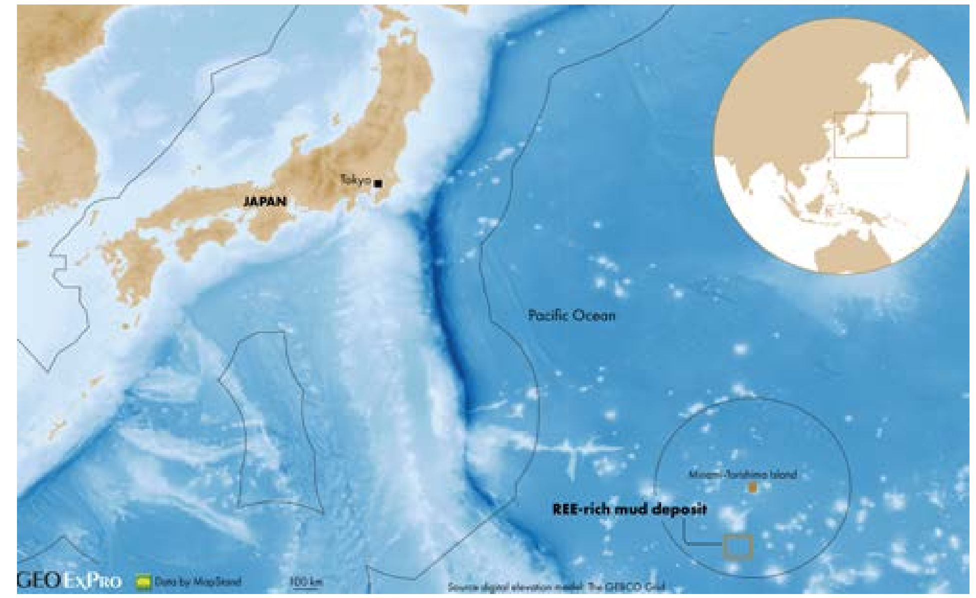
Ronny Setså

Deep-sea mud trial extraction to begin in 2026

Japan will start test mining of REE-rich muds from the seabed in January of next year. Pending a successful outcome, this may lead to a ramp-up to 350 t/day starting in 2027

Japan is set to launch test mining of a unique deposit of rare earth element (REE)-rich deposits in an area off the Minami-Torishima Island (Marcus Island) in the Pacific Ocean, some 1,900 km southeast of Tokyo.

First identified by the Japan Agency for Marine-Earth Science and Technology (JAMSTEC) in 2013, this deposit could provide Japan with a stable, long-term supply of REEs to meet its industrial demands.



According to Reuters, the test mining will commence in January 2026. Pipes from a JAMSTEC deep-sea exploration vessel will extract the mud, which will be transported to the mainland for analysis to assess its metal content.

"The goal is to secure a domestic supply to enhance national security, rather than to enable private companies to profit from selling rare earths. This would mark the world's first attempt to extract mud from the deep seabed for the separation and refining of rare earth elements", said Shoichi Ishii, program director of the Cabinet Office's national platform for innovative ocean developments, in an interview with the news agency earlier this year.

If the analysis yields positive results, the project aims to initiate trial operations in January 2027, using a system capable of extracting 350 t of mud per day.

While the concept is straightforward, the deposit lies at depths of 5,000-6,000 m, posing significant challenges for the pumps and pipes required for extraction.

Located within Japan's exclusive economic zone (EEZ), the deposit's potential justifies the effort.

A 2018 Nature Scientific Reports article reported core samples with REE and yttrium grades of up to 5,000 ppm (0.5 %), comparable to many global deposits.

Separation and selective processing could enhance the resource's economic value by increasing the grade in the lifted mud. Constituting the coarser domain in the grain-size distribution, the authors of the 2018 paper report that using a hydrocyclone separator, they were able to selectively recover the biogenic calcium phosphate grains, which have high rare earth elements and yttrium content of up to 22,000 ppm.

The most promising area (102 km²) and the uppermost 10 m of the mud could yield 1.2 Mt of REE oxide, potentially meeting global demand for yttrium, europium, terbium, and dysprosium for decades. Across the entire study area, the supply could last centuries.

A 1990 research article noted that REE-rich muds in the Pacific, like those near Minami-Torishima, contain fish-bone debris composed of biogenic calcium phosphate, which accumulates REEs from seawater. Low sedimentation rates and high biological productivity have contributed to the formation of these deposits, making them a lesser-known fourth type of deep-sea mineral resource, alongside nodules, massive sulfides, and polymetallic crusts. ■

Ronny Setså

A greenprint for Norwegian sulphide exploration

Norway's slow-spreading oceanic ridges could host large sulphide deposits. Lessons from the Semenov hydrothermal fields in the central Atlantic Ocean can enhance understanding and exploration strategies

THE SEMENOV hydrothermal fields along the Mid-Atlantic Ridge at 13° N, the same latitude as Senegal and Nicaragua, boast the world's largest known Seafloor Massive Sulphide (SMS) deposits, with a volume well over 100 million tonnes (Mt). Globally, over 600 SMS fields are known; Norway claims about 15, including recent discoveries such as Grøntua and Gygra. According to estimates by the Norwegian Offshore Directorate (NOD), Mohn's Treasure on the Mohn's Ridge could hold just over 2 Mt. However, SMS exploration in Norwegian waters is still at an early stage, with plenty of potential for larger discoveries to be made.

SEABED ORE FACTORIES

Hydrothermal SMS deposits are formed by seawater circulating through the hot rocks beneath mid-ocean ridges. They strip out various elements, particularly metals, which are then deposited at the seabed as the fluids emerge and cool at hot water vent systems. This process builds chimneys and mounds highly enriched in a wide range of metals, including copper, zinc, cobalt, gold and silver.

SLOW COOKING

The project ULTRA team has been mapping and collecting data from the Semenov fields. "It's a bit of a paradox", notes Bramley Murton, project leader and professor of Marine Geology at the National Oceanography Centre. Fast-spreading ridges host more hydrothermal vents due to higher heat budgets, while slow-spreading ridges like the Mid-Atlantic or Mohn's have fewer. "However, the accumulative volume of SMS deposits is larger at slow-spreading ridges."

At the slow spreading, amagmatic ridges, detachment faults can be active for hundreds of thousands of years. They maintain high temperatures, fluid pathways and continuous hydrothermal circulation. Slow-spreading ridges are like slow cookers – they do their job over a long period of time, allowing more minerals to accumulate.

GREEN EXPLORATION FLAGS

ULTRA also investigates how SMS deposits evolve. Christian Bishop, a postgraduate researcher at the University of Southampton, shares his insights on weathering.

As the deposits age and interact with seawater, their composition changes. A weathered deposit forms a rusty crust of Fe-oxyhydroxide, sometimes laced with bright green atacamite veins. Bishop's team found that atacamite flags copper-rich zones below and within the crust, while Fe-oxyhydroxide does not reliably signal the presence of deeper metals.

Atacamite has been observed along the Mohn's Ridge at the Grøntua, Fåvne and Gnitahei fields. The NOD announced that the green mineral is also spotted at the Gygra deposit along the Knipovich Ridge.

The relevance of project ULTRA to Norway's deep-sea mineral exploration is evident. The geological features found at Semenov are similar to the Norwegian ridges, including slow spreading rates, limited volcanic activity, and secondary atacamite mineralisation.

There is huge potential to discover extensive sulphide deposits in the Norwegian Exclusive Economic Zone. Although Norway's first licensing round hit a delay, ongoing scientific work is crucial in advancing knowledge and preparing for future operations. ■

Ronny Setså

Bramley Murton.

CREDIT: GEOPUBLISHING

A licence to operate

The transition of seabed mining from an "obscure" academic exercise to a potential commercial industry was on full display at the Underwater Minerals Conference in Florida

THE 53RD Underwater Minerals Conference (UMC) took place in St. Pete's Beach in Florida in November 2025 and gathered over 300 delegates – a significant increase from previous years. Historically a very academic conference, UMC has in recent years seen increased interest from commercial actors, reaching a new high as a result of the Executive Order (EO) on seabed mining, issued on 24th of April 2025 by the US government.

The EO lays out a plan to "rapidly develop domestic capabilities for the exploration, characterisation, collection, and processing of seabed mineral resources", and aims to open areas in the US exclusive economic zone and international waters.

Thus far, the process of facilitating an opening for mineral exploration in international waters has been spearheaded by the International Seabed Authority (ISA), an organisation established under the United Nations Convention on the Law of the Sea (UNCLOS). But the process has been slow, prompting companies like The Metals Company to lobby the US government for an alternative pathway.

But a parallel process to the ISA-process led by the US opens a potential minefield for this nascent industry – one that might not be favourable in the long run. In addition to the legal questions the EO opens up, many fear a "free-for-all" in international waters – where the world's largest economies again emerge as the winners, and smaller countries, whose interests have been attended to by the ISA, lose out again. Equally so, voices in the industry express a worry about a less rigorous approach to environmental regulations in a rush to exploitation, and hence the industry's "licence to operate".

The concern about the licence to operate is not merely theoretical. The mining industry has learned hard lessons from decades of terrestrial extraction: Communities and consumers increasingly reject projects perceived as environmentally reckless, regardless of their economic benefits. From blocked pipeline projects to divested mining operations, the pattern is clear – without social acceptance grounded in robust environmental protection, even legally permitted projects can become commercially unviable. For seabed mining, an industry without any operational track record, public trust must be earned before the first nodule is brought to surface, not after environmental impacts has occurred.

In a world where climate discussions have become polarised, there is a disconnect between the actual demand for fossil fuels and mineral resources needed for the energy transition. This paradox places seabed mining in a precarious position: It is simultaneously seen as essential for green technology supply chains, but it is viewed with deep suspicion by environmental advocates. The industry cannot afford to be caught in the middle of this contradiction by appearing to prioritise speed over sustainability. ■

Ingvild Ryggen Carstens

A calm sunset over Florida, contrasting the intense global discussions on seabed mining's future.

PHOTOGRAPHY: INGVILD RYGGEN CARSTENS

NEW GAS

"From an outsider's perspective, this wildcat well appears very risky, but Koloma's AI model evidently holds a different view"

Mariël Reitsma – HRH Geology

A "monumental deposit" or an attempt to revive coal-seam gas exploitation?

A closer look at the Lorraine hydrogen discovery

ARNOUT JW EVERTS, AEGEO

A discovery of hydrogen in Lorraine, France, made headlines in 2023. More recently, the appraisal drilling campaign announced by operator La Française de l'Energie (FDE) led to renewed interest. It's time to take a closer look.

The Carboniferous Lorraine coal basin was mined for coal from the mid-19th century to 2004 and, from the 1990s, explored for coal-bed methane (CBM). Folschviller-1ST/1A, a test well drilled in 2006 as part of EU-sponsored CBM research, is where FDE reported a discovery of hydrogen.

From the study results, we know that gas was detected in a succession of Westphalian coal seams, intercalated with sandstone and shale interbeds. Coal permeabilities from core are between 0.5 and 4 mD and declining with depth, as is usual in CBM assets. Gas content, also measured from core, varies between 7 and 10 m^3 /t of coal. Detected gas is predominantly methane, but hydrogen content increases with depth from 6 % hydrogen at 760 m to 20 % at 1,250 m.

NATURE OF HYDROGEN GAS SHOWS

FDE claims the detected hydrogen is dissolved gas and believes it may be derived from aquifer sands. However, Folschviller well data indicates the Carboniferous interbed sandstones are tight. In fact, the Carboniferous interbeds must be tight for a CBM exploitation to be viable; if some were porous aquifers of significance, effective depressurization of the coals by pumping off water becomes near-impossible.

A more plausible explanation is that the detected hydrogen-methane mixtures are derived from adsorbed gas in the coal seams. Indeed, the depths of reported hydrogen occurrences coincide with the position of prominent coal seams.

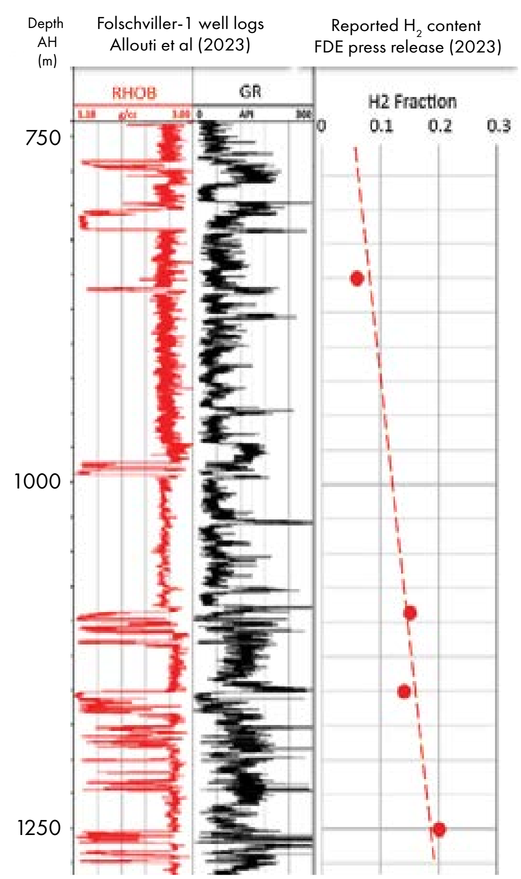
Coals have a documented capacity to adsorb large quantities of gas, including hydrogen, albeit they preferentially adsorb methane and CO_2. Higher hydrogen content with depth may indicate a closer proximity to the hydrogen source, but it could also be due to a limited methane charge, leaving more space for other gases as the adsorption capacity in the coals increases with depth.

RESOURCE ESTIMATES

Media coverage of the Lorraine discovery speculated about a "monumental size deposit" of possibly 46 Mt of hydrogen, quoting CRNS researchers but without detailing how these estimates were arrived at. Meanwhile, available gas-resource estimates for the permit, combined with an average 13 % hydrogen content, imply a much more modest H_2 resource of between 0.026 and 0.17 Mt only.

Development of Lorraine gas resources would inevitably face the same hurdles that hamper CBM developments elsewhere in the world: Low well productivity, high surface footprint and high co-production of water. The deeper coals with higher hydrogen content would be tighter and even more challenging to produce.

Another issue is the separation of hydrogen from methane. Effective separation, especially at low pressure and with modest hydrogen content, is technically challenging, energy-intensive and costly. If viable, a development of Lorraine gas, at least initially, would be merely a coal-bed methane project. ■



Density (left) and Gamma-Ray (centre) logs of Folschviller-1 well. Coal seams are clearly visible from the Density log (RHOB). Interburden beds are mostly tight sandstones (low Gamma Ray, high Density). To the right is hydrogen gas content from probe analysis, increasing with depth. Note that gas is typically sampled near or just above the top of a coal seam.

SOURCE: SCIENCEDIRECT.COM

The Koloma enigma

As one of the major players in the natural hydrogen sector, Koloma maintains a high level of confidentiality regarding its operations

The company describes itself as a technology-enabled exploration firm that leverages industry expertise, proprietary data, specialised exploration tools, and advanced data analytics to facilitate large-scale natural hydrogen production.

Backed by over $400 million in investments from organisations such as Bill Gates' Breakthrough Energy Ventures and Amazon's Climate Pledge Fund, Koloma has some serious cash to play with. In recent years, operating divisions of Koloma have drilled wells in Kansas and Iowa, but little information has been released. Now, Koloma has been granted a drilling permit for Canyon County, Idaho.

In Idaho, Koloma operates under the name 'Cascade Exploration'. They have received a permit to drill the vertical Twin Peaks 1W stratigraphic test well, located 50 km northwest of Boise. The drilling rig has been secured, and exploration efforts are set to start November 2025. The permit application emphasises that "the well will be drilled for stratigraphic and geological information purposes only and will not be completed as a producing well." The primary goal is to gather data that will inform decisions on where and how to drill future production wells and whether further exploration is justified.

The well is targeting a thick succession of Miocene volcanic rocks and interbedded sedimentary formations, including the Colombia River Flood Basalts, and is projected to reach a total depth of 3,658 m, in Lower Miocene intrusive and extrusive mafic deposits. The nearest known hydrogen occurrence is located 470 km away, on the other side of Idaho.

So why has Cascade Exploration selected this location?

The USGS hydrogen prospectivity map indicates a medium chance of success for the Twin Peaks well location. They predict a strong likelihood of finding high-quality reservoir rocks, presumably sandstones in the Poison Creek and Payette formations, as well as good potential for encountering rocks with sealing properties, likely mudstones within the aforementioned formations or the intercalated volcanic rocks from the flood basalt province. However, the existence of a hydrogen source is more questionable. The mafic, as opposed to ultramafic, nature of the igneous rocks makes significant hydrogen formation through serpentinisation reactions unlikely.

Hydrogen generation through radiolysis is more plausible given that the geology is favourable for elevated concentrations of uranium. Nonetheless, the chances of generating economic quantities of hydrogen are low. According to the USGS, the most likely scenario is that hydrogen would originate from a deep source. High heat flow has been reported in the area, which is often associated with geothermal fluid circulation, potentially facilitating hydrogen migration from deeper down.

From an outsider's perspective, this wildcat well appears very risky, but Koloma's AI model evidently holds a different view. Meanwhile, Shelley Brock from Citizens Allied for Integrity and Accountability has raised concerns that Cascade Exploration might be prospecting for hydrocarbons under the guise of natural hydrogen. Natural gas and liquid condensate are currently produced in Payette County, adjacent to Canyon County. ■

Mariël Reitsma, HRH Geology

Columbia River Flood Basalts outcropping in Palouse Falls State Park, Washington.

PHOTOGRAPHY: ZACK FRANK VIA ADOBE STOCK

France's first stimulated natural hydrogen project

Vedra Hydrogen aims to prove its technology of generating and producing clean hydrogen subsurface from a mature oil reservoir near Paris

PATRICK TARGET, STUART LAKE AND ETHAN LISH, VEDRA HYDROGEN

Clean hydrogen production from electrolysis remains expensive and difficult to scale, leaving industry without the reliable, affordable supply needed for substantial decarbonisation. Vedra Hydrogen has embarked on a complementary approach: Converting mature oil reservoirs into underground reactors that generate clean (carbon-neutral) hydrogen while permanently storing CO_2.

The Vedra method injects air into reservoirs containing residual crude oil and brine, stimulating low-temperature oxidation that produces hydrogen-rich syngas. Imperial College, other laboratories and Vedra have proven in lab tests on the reservoir fluids that this method works and can be scaled, whilst Vedra's IP is protected.

Oxygen entering a mature reservoir reacts with residual oil and formation brine through oxidation and gasification, converting long-chain hydrocarbons into syngas: Primarily hydrogen, carbon monoxide, and CO_2. Compositional reservoir models show that hydrogen migrates to production wells preferentially to CO_2, augmenting the natural separation due to buoyancy as hydrogen is 22 times lighter than CO_2. Simulations indicate that hydrogen rises to the production perforations, while CO_2 sinks and is permanently stored in the original container over a one-hundred-year run period.

The success of the project depends on careful reservoir selection. Residual oil in ideal candidates is 25 – 60 % of original oil in place. Other properties such as brine saturation, pressure, temperature, porosity and permeability are important. A robust seal is required, as well as existing infrastructure with integrity. Selected mature oilfields meet these criteria after decades of production and millions of years of safe containment.

The process sweep efficiency depends on the reservoir volume contacted by injected oxidants, which in turn determines the hydrogen yield. Careful well selection and optimised injection strategies, informed by downhole monitoring, maximise reaction residence time. Clean hydrogen can be produced for decades per development plans, with additional well clusters scaling and extending project life.

A demonstration project 40 km from Paris – near a cluster of major industrial demand – is in its final regulatory approval stage. Following the successful pilot, the method will be scaled commercially across multiple well clusters, then replicated across Europe and beyond. France banned oil exploration permits in 2017 and set a legislative phase-out of domestic production by 2040. If the remaining producing fields can be repurposed to clean hydrogen production, instead of oil, the benefits to energy security, employment, deferred abandonment, and domestic hydrogen supply are game-changing.

The hydrogen economy requires a portfolio of solutions, including stimulated natural hydrogen generation. It brings impact; transforming yesterday's oilfields into tomorrow's clean energy assets, complementing electrolysis, and delivering the affordable, scalable clean hydrogen supply that heavy industry urgently needs. The Vedra method is estimated to deliver clean hydrogen at one-third of the cost of flagship electrolyser projects like Shell Rheinland/REFHYN II, which reportedly is targeting 3 €/kg. The Vedra method can deliver a near-term, large, affordable clean hydrogen supply, building early demand with high impact to meet supply goals. ■

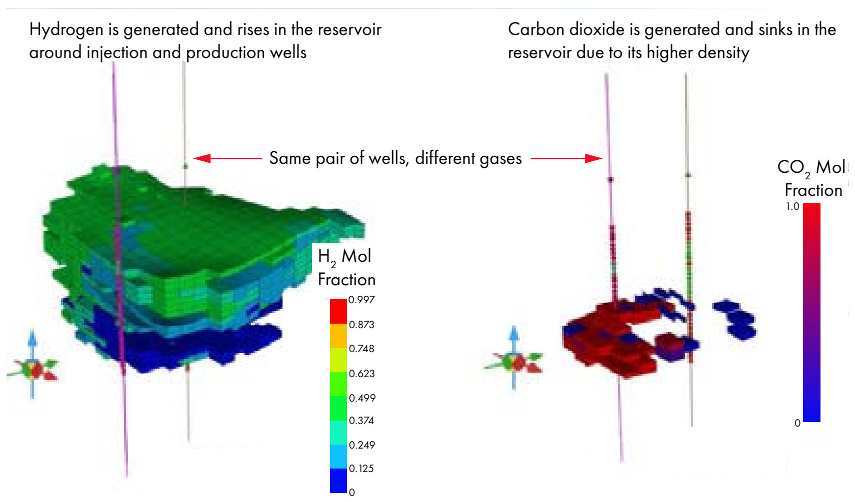


Illustration of hydrogen and CO_2 migration in reservoir.

SOURCE: VEDRA HYDROGEN 2025

TECHNOLOGY

"Subtle colour differences can reveal a lot about changes in depositional environment or changes in sediment input"

Simon Molyneux – Molyneux Advisors

Finding big fields by detecting the smallest element

The technology involved in helium surveying has made big leaps in recent years, moving closer to realising the first deep-water projects soon

"WE ARE CHANGING the world of exploration," says Denis Krysanov from Heologic. "I'm now planning on expanding Heologic's operations in the United States," he says. He currently lives in Argentina, but he's been in the Middle East and Asia for work before.

Helium anomalies in the subsurface are first and foremost an indicator of the presence of hydrocarbons. "And the good thing about helium is that it moves through the subsurface vertically – it is so small that it is not deviated by subsurface irregularities. So, when we see a helium anomaly, we can be sure that the hydrocarbon reservoir is straight down there," Denis explains.

However, until recently, the technology used to measure helium anomalies was not really able to "map" subsurface helium anomalies properly. "You can't go into the field, take samples, and analyse them in the lab for helium. It is simply too light; as soon as you sample it, it will mix with ambient air, and you will not measure the real concentrations," says Denis. "On top of that, helium fluxes change during the day, as well as with the lunar cycle. For all those reasons, helium surveys were, until a few years ago, only capable of detecting major fault zones, as it is in those places where helium concentrations are big enough for these systems to detect an anomaly."

"Based on these limitations of the "old" technology, we decided to take the lab into the field and take the measurements in situ. The devices we use are ultra-sensitive and collect data for about 15 minutes at each sample location, before the system allows the crew to move on; in other words, the software comes with a built-in quality control system that checks the validity of the acquired data on the spot."

The level of accuracy of these systems is far better than previous generations, to the point where Denis and his team can even detect channel systems in the subsurface, once they start integrating their data with subsurface information. "In addition, the magnitude of the helium anomaly allows us to distinguish between different fluid types, and even the depth of burial of the hydrocarbon reservoir. We are now even working on projects whereby we aim to disentangle an oil versus gas signal in the same place."

And mapping helium anomalies can not only be used for highlighting new drilling targets, it can also be used for identifying opportunities in mature fields, says Denis. We carried out a project in Southeast Asia, where we surveyed a field with 30 wells already drilled on it, that had ceased production. However, our data suggested that a large anomaly still existed in one corner of the accumulation, lending support to an infill opportunity.

The next frontier for Denis is going offshore, which also explains his move to Houston. "We have already done campaigns in shallow waters, ranging from a few meters to about 300 m, and also in these circumstances the signals we acquire are reliable," he says. "That's why we are now looking for investors, to help grow the company to such an extent that deep water surveying becomes a possibility as well." ■

Henk Kombrink

Digital helium survey in Colombian tropical farmland, integrating high-precision sensing with real-time data analytics for subsurface exploration.

PHOTOGRAPHY: HEOLOGIC GROUP

It's time to introduce chromostratigraphy

Using an AI-powered solution, Molyneux Advisors has developed a methodology to gain an order of magnitude more insight from cuttings than what was possible before

"OFF-WHITE, grey, quartz-rich, some occluded quartz and kaolinite." Simon Molyneux cites the description of a cutting sample from a composite well log, which is thought to represent an interval of around 200 m in a well. "It is these subjective descriptions that won't take us very far when we want to have a better understanding of colour changes along the wellbore," he says.

"Subtle colour differences can reveal a lot about changes in depositional environment or changes in sediment input. It's one of the reasons why we have developed our Grain-e technology," Simon adds.

The material required to analyse all cutting samples for an entire well fits in one shoebox. Once selected, project partner RockWash do the processing and imaging in high resolution. Then, the Grain-e AI-powered scanning software comes in, which is not only capable of capturing colour, but will also analyse each particle at the same time, offering lots of additional opportunities. One of the most important ones is grain size and its derivatives, such as roundness and length.

"There are several fields where this type of information is key," says Simon. "For instance, we already ran a project with a client to design the mesh size for their completions, based on the grain size measurements obtained through our technology. It is a good complement to particle size analysis that is usually done on cores only."

Some people argue that there are contaminants in the cutting samples, such as lumps of rock consisting of cemented grains or cavings. "Our technology enables filtering these out, and only retains moveable grains for further analysis," says Simon. "In this case, movable grains mean the grains that could move into the wellbore during production."

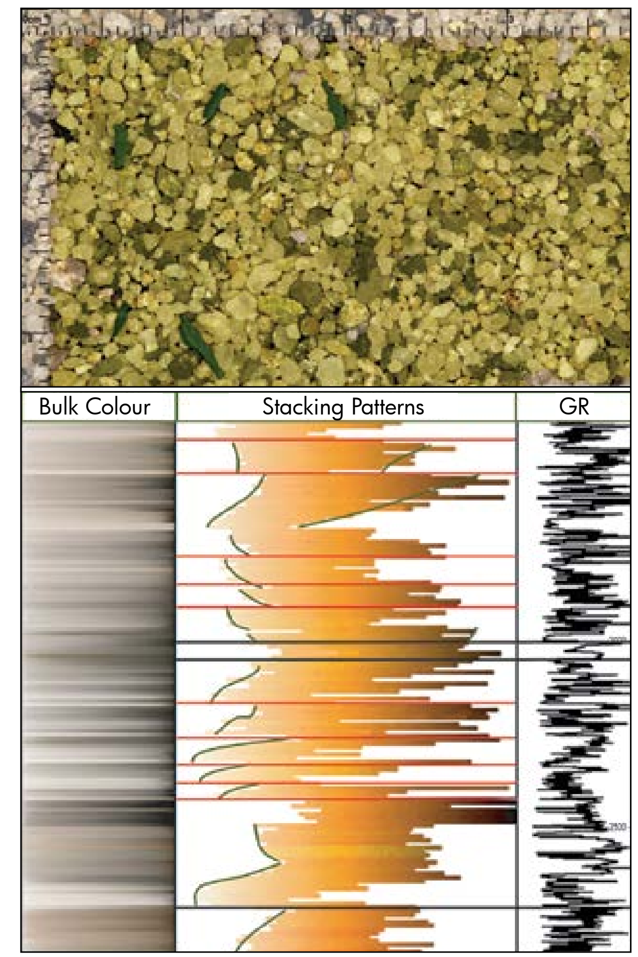
The identification of cavings in the images is another aspect that can help reconstruct of overpressured zones. "Admittedly, this is not something we will do real-time, but what it allows us to do is to identify zones where overpressure went undetected. Also, because we assess the colour of these cavings, we can even reconstruct the depth from which they come based on colour matching," Simon says.

"Well log correlation and identification of sequence stratigraphic boundaries forms yet another application of the way colours can be used now," concludes Simon. He points to a Gamma-ray log showing what looks like a fairly homogeneous succession, until the colours are plotted alongside, showing a clear trend at a certain position in the well that now turns out to be a maximum flooding surface. "It adds another useful tool to apply sequence stratigraphy and better predict facies changes away from the well."

In other words, Grain-e enables the identification of features in the well that were previously undetected or were not quantified, helping completion design, stratigraphic analysis, and more. And that for only one shoebox of samples per well. It's time for some more chromostratigraphy. ■

Henk Kombrink

SOURCE: GRAIN-E AND ROCKWASH



Top: A cuttings image of a sandstone sample with an overlying mask. Grain-e has highlighted the splintery cavings (green) and excluded all other grains (yellow).

Bottom: Log view showing selected Grain-e and legacy wireline data, including individual cutting grain colours, colour-driven stacking patterns, and a gamma ray curve across the same interval.

TECHNOLOGY

From scattered campfires to integrated cities: The future of energy software

Companies are not just buying tools; they are acquiring the essentials needed to construct the operating systems of the future

DAN AUSTIN, SEKAL

For the last decade, the technology landscape of the energy industry has resembled a wilderness at night – vast, dark and punctuated by innovative points of light. Over time, these points of light evolved into new software tools and became more like campfires – offering the industry new ways of working with raw data at a greater pace and scale but still unable to illuminate the whole map.

Recent consolidation, mergers and acquisitions mark the next phase in this evolution as the competitive focus shifts toward constructing robust platforms capable of interlinking these innovations into something greater than the sum of its parts. Much like how modern cities connect historic landmarks with modern infrastructure.

Companies such as Computer Modelling Group (CMG) and IMDEX exemplify this approach, actively pursuing acquisitions to expand their offerings and provide end-to-end solutions – from data management to asset modelling. In CMG's case, this is an entirely new seismic solutions business built on the acquisition of Sharp Reflections, Bluware and most recently Seisware. In contrast, IMDEX's purchase of Earth Science Analytics enhances its portfolio beyond its traditional strengths, and laying the technical foundation for their Digital Earth Knowledge business.

> **"There is always a risk that consolidation will lead to platform lock-in and function "freeze out" based on who you go with, but it seems that dominance of open source and demand for customisation should keep the doors open for now"**

Well-established companies with a strong client base and core IP are also an attractive proposition – over the last few years, Carina Software have acquired a few familiar names in the industry: Ikon, Geoactive and Geosoftware to name a few, while Ellis and Geoteric both have new owners in place.

Both the latter companies have launched new products and services since their change in owners – particularly in AI-powered services and grown rapidly since new investment. These investors are not necessarily seeking to integrate the target company into a larger operational entity in the same industry but rather see substantial standalone growth potential.

Of course, these changes will have an impact on the end user beyond updated desktop icons and contracts. Personally, I am optimistic that better integration will lead to faster innovation and in turn provide the right tools for decision-making and supporting the future of the industry. There is always a risk that consolidation will lead to platform lock-in and function "freeze out" based on who you go with, but it seems that dominance of open source and demand for customisation should keep the doors open for now. ■

SOURCE: GEMINI GENERATED BY DAN AUSTIN

From cuttings to clarity: AI unlocking the Norwegian Continental Shelf

EARTH SCIENCE ANALYTICS AND ROCKWASH GEODATA

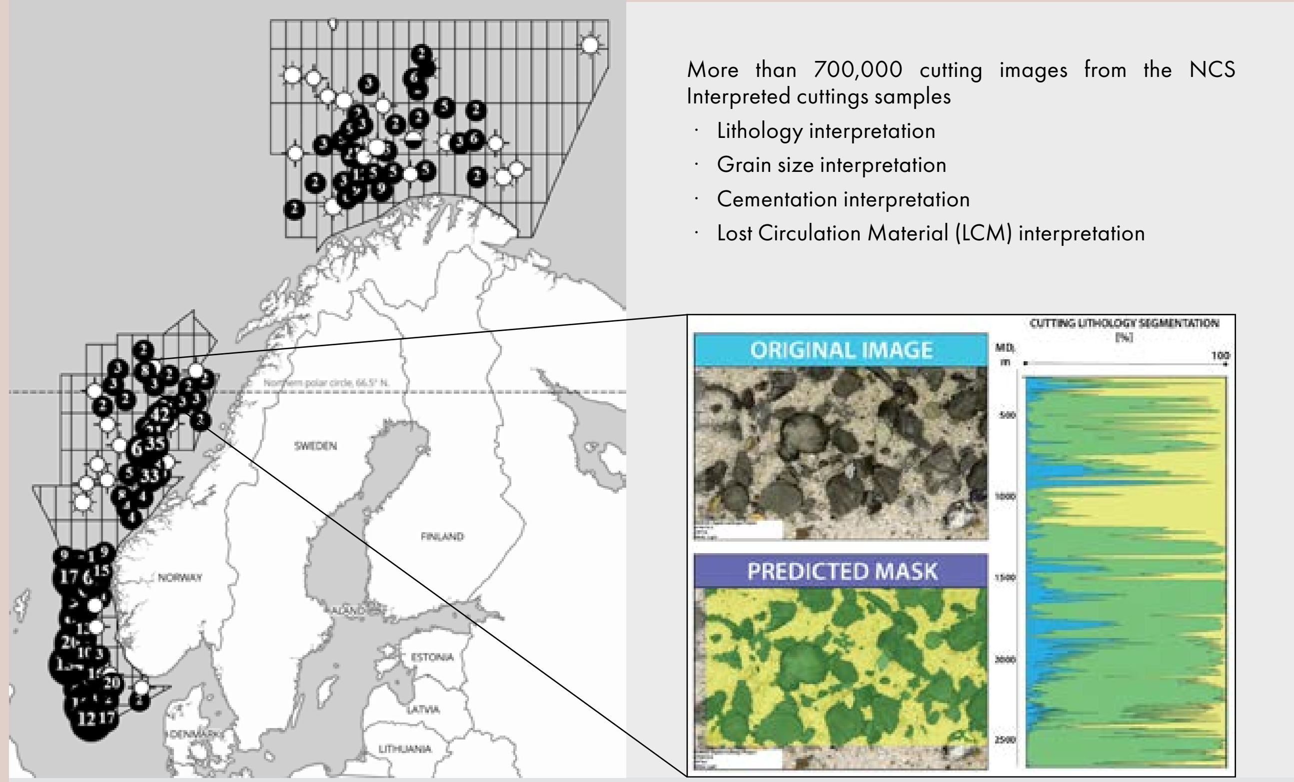


Figure 1: Map showing released wells contributing cuttings data to the NCS interpreted dataset.

This project enables geoscientists to gain access to a groundbreaking digital dataset - the Analytics-Ready Cuttings Dataset, available through EarthNET AI Images under a commercial software license. Developed by Rockwash Geodata (RW) and Earth Science Analytics (ESA), this collaboration transforms decades of geological cuttings from the Norwegian Continental Shelf (NCS) into an intelligent, machine-interpreted data product designed for exploration, CCS, and renewable-energy applications.

TURNING ARCHIVES INTO INSIGHT

The goal is simple: Make geological cuttings not just visible, but actionable (Figure 1). Traditionally stored in boxes and rarely re-examined, these samples record the geological history of every drilled well. Now, through AI-enabled digitisation, 718,663 cutting samples from the Released Wells Initiative (RWI) operated by NOROG have been standardised and interpreted for lithology, grain size, cementation, and lost-circulation material (LCM).

MACHINE LEARNING IN ACTION

Multiple machine-learning models work together to extract complementary insights from each cutting sample (Figure 2). Image-classification models analyse sample photographs to identify lithologies such as sandstone, shale, limestone, and mud additives such as LCM.

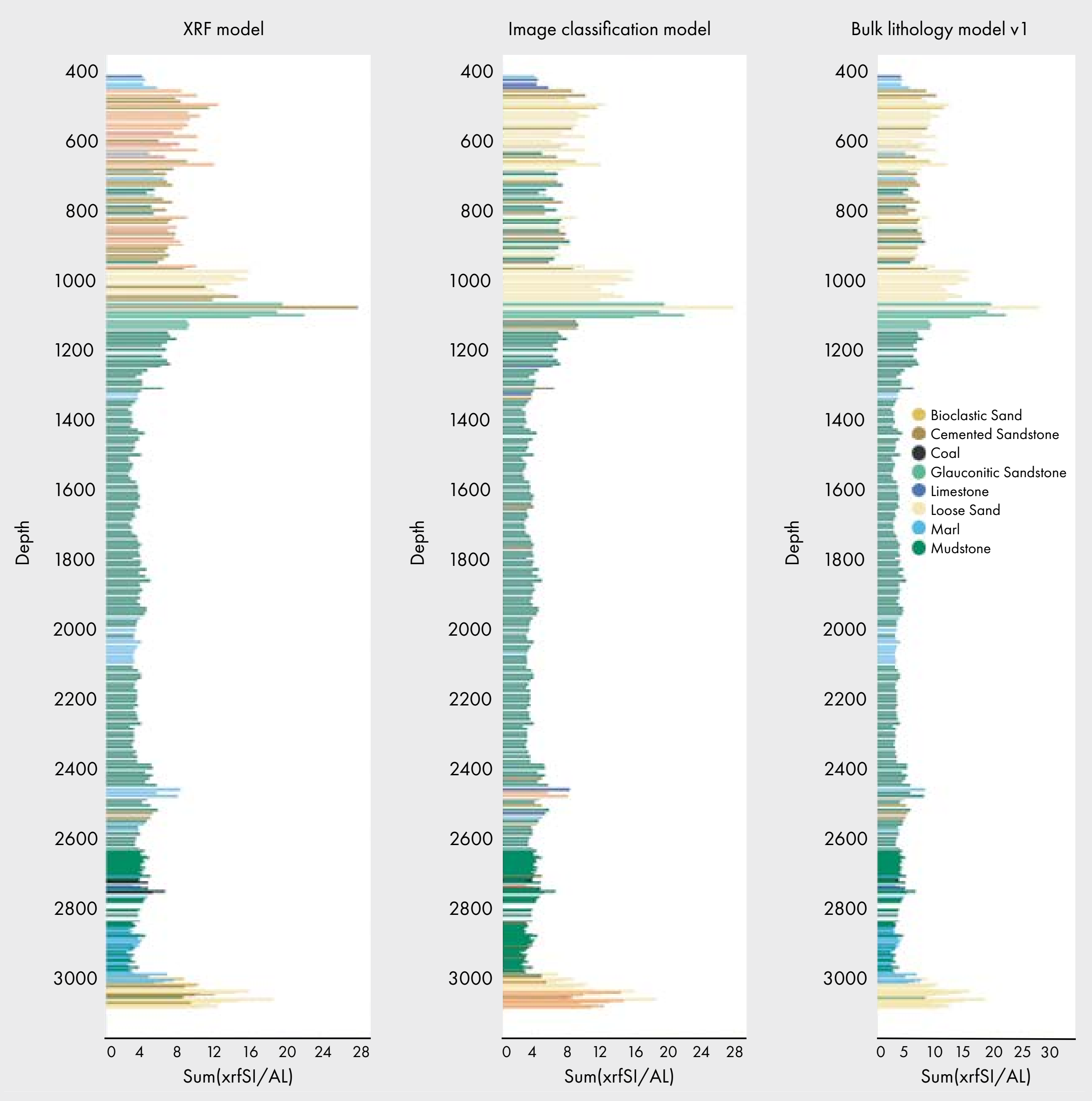


Figure 2: Plot for 33/9-13 S showing XRF model results (LGboost), image classification results and a combined plot based on ruleset.

Trained on thousands of annotated examples, they deliver consistent results, while bulk-annotation tools in EarthNET AI Images accelerate labelling and retraining.

Outputs from both models are merged through a rules-based workflow that combines image and chemical probabilities to select the most likely lithology, significantly reducing misclassification and improving consistency across.

SEEING INSIDE EACH SAMPLE

Beyond classification, semantic segmentation maps each pixel by lithology, quantifying mixed samples and revealing how multiple materials coexist within a single image (Figure 3).

Object-detection models further identify grains, cavings, and specific minerals, allowing grain-size estimation and depositional interpretation at the sub-millimetre scale.

The lithological classification and LCM identification model have demonstrated strong performance with rapid turnaround, enabling the automated classification of 16 distinct lithologies and LCM types (Figure 4). Validation through a confusion matrix shows that the majority of samples are correctly predicted when compared to training and test data. As expected, visually similar classes — such as marl and mudstone — display a higher degree of overlap, reflecting natural variability in sample appearance rather than model error. These results confirm that the workflow provides both accuracy and efficiency for large-scale geological interpretation.

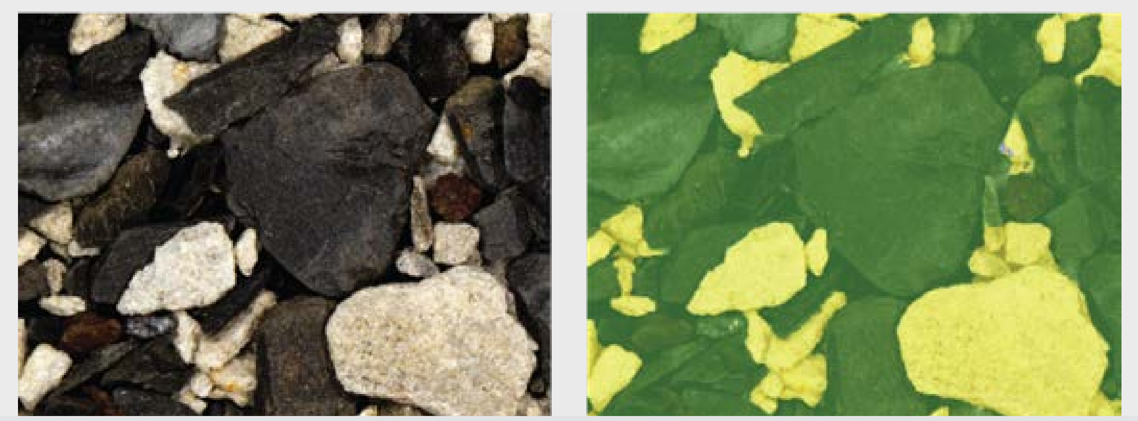


Figure 3: Semantic Segmented image showing pixel-level lithology mapping in a cuttings sample.

Figure 4: Example of classification ontology and results based on filters for XRF and other ML model results.

ROCKWASH GEODATA

EARTH SCIENCE ANALYTICS
Leading Brand of IMDEX

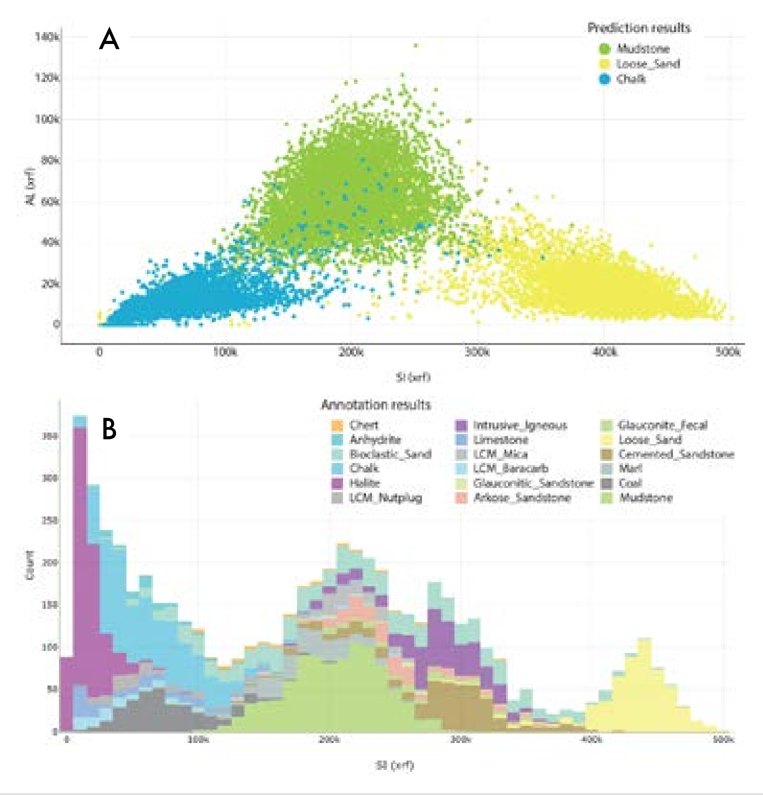


Figure 5: (A) Cross plot of XRF data showing silica vs. aluminium with colours corresponding to lithology classification and (B) histogram showing the distribution of annotated data, sorted by Silica abundance and colored by class.

OBJECT DETECTION

Object detection models for cutting images locate discrete entities (Figure 6) (cuttings, grains, minerals, cavings) within images. Although larger features are successfully detected, smaller particles (<0.5 mm) and multiclass imbalances remain areas for improvement.

XRF / CHEMICAL CLASSIFICATION

Parallel ML models classify samples based on chemical composition (XRF), providing a complementary view to imagery. These models excel at chemically distinct lithologies (e.g., halite, loose sand) and are less influenced by sample quality or surface texture. See Figure 5 for examples of lithology distribution with respect to XRF data.

As with the image classification, mixed samples may negatively affect the prediction results, i.e. a mixed limestone/mudstone sample may be predicted as a marl.

Sample types with similar chemistries may affect prediction quality, i.e. limestone/LCM Baracarb, coal/LCM Nutplug, loose sand/chert

Unlike image classification, sample quality appears to be less significant for prediction quality.

Multiple models have been tested, including LGboost, XGboost and random forest, with LGboost and XGboost showing the best results.

THE PRODUCT BEHIND THE RESEARCH

Data are delivered through EarthNET and as a ZIP package containing LAS and CSV files. Delivery via EarthNET enables seamless ingestion into the OSDU™ Data Platform, while also providing access to ESA's suite of visualisation and insight tools.

With EarthNET, users can visualise, query, filter and review the interpreted dataset to reveal patterns and correlations relevant to their projects (Figure 7). For clients seeking deeper analytical capabilities and integration with well logs and seismic data, a separate subscription to the full EarthNET platform includes advanced AI applications for automated data interpretation.

Now available for licensing through the EarthNET AI Images platform and module.

KEY FEATURES

Scope: 718,663 cutting samples from the Released Wells Initiative (RWI) operated by NOROG.
Interpretations: Lithology (semantic segmentation), grain size, cementation, and LCM.
Metadata: Well ID, depth, log values, stratigraphy, and geographic coordinates.

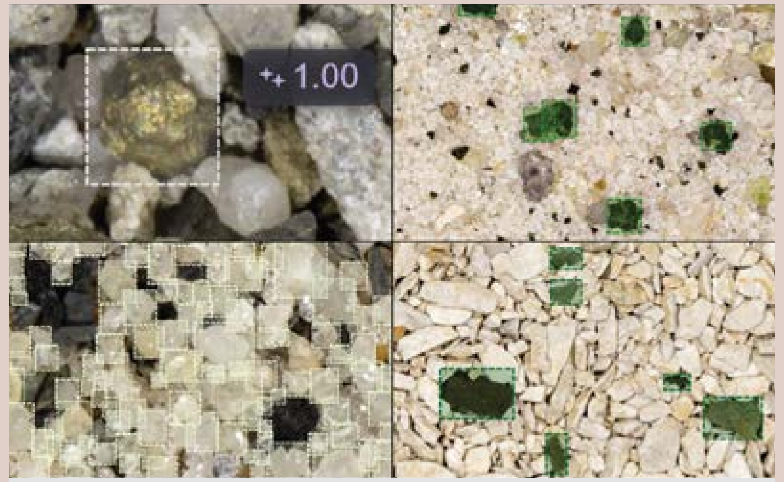


Figure 6: Object detection in cuttings images: Bounding boxes colour-coded by class.

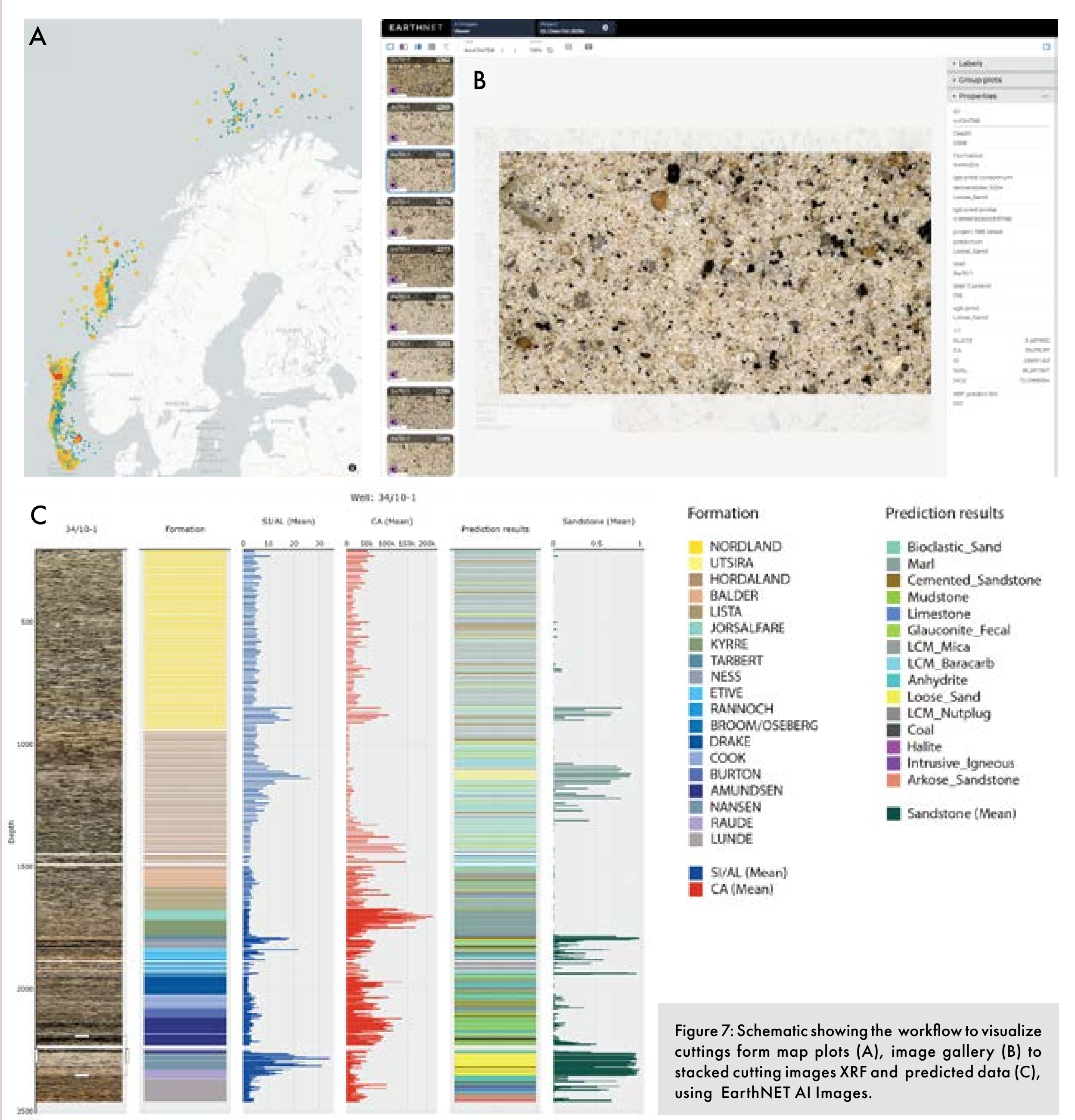


Figure 7: Schematic showing the workflow to visualize cuttings form map plots (A), image gallery (B) to stacked cutting images XRF and predicted data (C), using EarthNET AI Images.

Formats: Delivered via EarthNET Data Lake and ZIP (LAS + CSV); OSDU™ compatible.
Applications: Exploration, field development and CCS projects

LOOKING AHEAD

From dusty boxes of rock cuttings to digital intelligence in the cloud, the collaboration between RockWash Geodata and Earth Science Analytics marks a step-change in how the subsurface is understood.

With the launch of the Analytics-Ready Cuttings Dataset through EarthNET AI Images (Figure 7), the Norwegian Continental Shelf becomes one of the world's first basins where millions of rock fragments can be searched, visualised and analysed with AI precision.

What once required months of manual study can now be achieved in minutes - empowering explorers and developers from oil and gas to CCS to make faster, data-driven decisions. As machine learning continues to refine its geological vision, the NCS stands as proof that when AI meets geology, clarity follows.

If you're interested in learning how your cuttings can provide deeper geological insights - from porosity to lithology - into your assets, or would like to gain access to this project, please contact us at contact@earthanalytics.no.

INSIGHTS

"That old core taught me a simple but powerful lesson: Innovation often begins by re-examining what we think we already know"

István Nagy-Korodi – Consulting Geologist

The absurdity of security… or… comfortable being uncomfortable

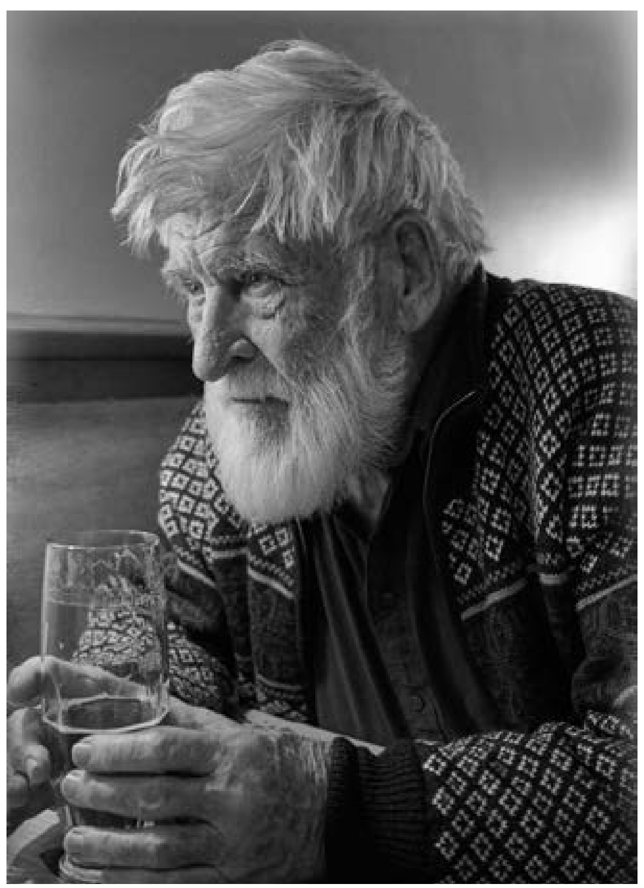
The precariousness that is most immediate to us oil and gas professionals is the precariousness of our industry

JUAN COTTIER, MMBBLS SUBSURFACE CONSULTING

MY FATHER, 90, is a product of the random precariousness of this world. His mother's first husband died at sea, washed overboard in a storm, whilst his father's first wife and infant twins died of tuberculosis. Two tragedies not uncommon for that time. A widow and a widower picked themselves up and tried again – hence my father.

Why is this relevant to our oil and gas industry?

Well, I am an unashamed advocate for the oil industry. I have no qualms about what we do. In just one hundred years, hydrocarbons have made the world warmer, safer, and more reliable. I sit comfortably with Alex Epstein and his moral case for fossil fuels being the foundation of – and vital to – a modern, flourishing civilisation; and with the Czech Vaclav Smil whose more nuanced and empirical view holds that hydrocarbons are an essential resource to be valued, not wasted. We are now so much better at staying alive. Hydrocarbons have reduced the precariousness of this world.



The contemplation of a precarious oil career.

But our industry is, by design, precarious. Oil and gas professionals know that better than anyone. There are current concerns about geopolitical instability, and how perceived weak or indecisive governments are killing the oil industry. That narrative seems to overlook two things: That business always blames government, and that the oil business has always been desperately unstable. Capitalism insists that the market is self-correcting and that only the weak are culled. But oil-price fluctuations kill companies; oil-price crashes kill communities.

Even when things are going well, there is uncertainty – lost careers and family sadness. Exciting new company mergers create redundancies, a euphemism for "discarded". Twice in my career, I worked for companies that chose to relocate from London to Aberdeen. All very positive – unless you were a Londoner with kids at school and the grandparents around the corner. I wasn't and didn't, so I headed north – twice – but 90 % of the staff were not free and so were forced to choose: Unemployed or leave your life.

A consulting colleague recently said, *"The difference between consultants and staff is that consultants know their tenure can end tomorrow"*. Eventually, for some, it's enough. I know plenty of people who have left the industry: Geologists to the civil service, a driller to defence, sports, to boatbuilding, to art, to e-gaming, to jewellery, to musical-instrument renovation, to market-gardening – on and on. All more stable. All happier.

My father-in-law was a pro-democracy agitator in communist Czechoslovakia. He would joke that Norway was *"the last remaining communist country"*. If that were true, then it is ironic and absurd that Norway has provided the most stable environment for oil-industry capitalism.

Václav Havel – Czech playwright and President – described hope as *"not the conviction that something will turn out well, but the certainty that it makes sense, regardless of how it turns out"*. In our oil industry, I doubt we have ever been able to expect either. ■

PHOTOGRAPHY: VALENTYNA PUGACHOVA, PICARTO.NET

Producing more by producing less

Why reservoir simulations need to be carried out in combination with surface constraints to really know how to manage a field best

"THE PRESSURE in the separation unit, where the produced oil is separated from gas, is the ultimate driver for your entire field development approach," says Alexey Danilko, production engineer at Rock Flow Dynamics, when we meet on a cold morning in Aberdeen, Scotland.

Alexey Danilko and an example of the screens he looks at during his working day.

No, this is not something that many geoscientists will have sleepless nights about, but it is a very important factor indeed. "It is quite straightforward to understand," says Alexey. "Because we need a wellhead pressure that exceeds the pressure of the separation unit – fluids need to flow into it – and the pressure of the separation unit is fixed, we can't allow the pressure in the wellhead to come down too much either. In turn, this has a knock-on effect on the bottom-hole pressure too."

Knowing this, it is easy to understand that running a reservoir simulation model without these surface constraints can result in a very different production profile than in a situation where you include these boundary conditions.

"For example," says Alexey, "we worked on a field development study for a client in which the four projected development wells were all dead after a year of production if we had opened the taps to their maximum extent. The reason for that is the gas that is also in the reservoir and is co-produced with the oil, is also leading to a rapid pressure loss in the reservoir. This causes the wells needing artificial lift and additional investment to continue production."

"To overcome issues like this," continues Alexey, "we model both the reservoir dynamic side of the operation as well as the well completion and surface constraints to arrive at a scenario where we continue the natural depletion of the field as long as possible and thereby maximising the economic recovery. Sometimes, that means we have to choke the well head a bit."

"Thanks to our software, we can now quickly find an optimal production scenario that comes up with the most efficient way of producing the hydrocarbons," says Alexey. "Python scripts and AI form a key factor in that," he says. "You don't need to be a professional programmer anymore to be able to tell the software that under a certain scenario, a valve needs to be closed for a while. AI can write the code for us." "That doesn't mean we are redundant," he says," our expertise is still required to make sense of the final results. But now, we are able to test many scenarios and truly perform an integrated asset management approach." ■

Henk Kombrink

VALUABLE EXPERIENCE

Before he completed a master's degree in petroleum engineering, Alexey spent five years with an operating company where he worked on the optimisation of wells and production facilities for an asset that was characterised by an oil rim overlain by a large gas cap. "Tweaking the wells to an extent that the surface facilities could both handle the gas as well as prevent water breakthrough or gas coning was very insightful for me; I still use what I learned there today."

PHOTOGRAPHY: HENK KOMBRINK

Offshore Otway Basin drilling campaign

New wells and strategic implications for Victoria's gas supply

NVENTURES

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JONATHAN CRAIG, NVENTURES

The Otway Basin, offshore Victoria and Tasmania, is undergoing a significant drilling campaign, using the Transocean Equinox semi-submersible rig, aimed at bolstering Australia's domestic gas supply. This initiative seeks to address the anticipated gas shortfall on the East Coast by 2029. An initial seven exploration wells are planned by Beach Energy, ConocoPhillips and Amplitude Energy, with a contingency for at least an additional four wells.

GEOLOGICAL CONTEXT AND RESERVOIR TARGETS

The Otway Basin's gas reserves are primarily found in the Cretaceous-aged Waarre and Pretty Hill sandstones. These reservoirs, part of major fluvial and alluvial depositionary systems in the Cenomanian and Valanginian, are characterised by their high porosity and permeability, making them ideal targets for gas exploration.

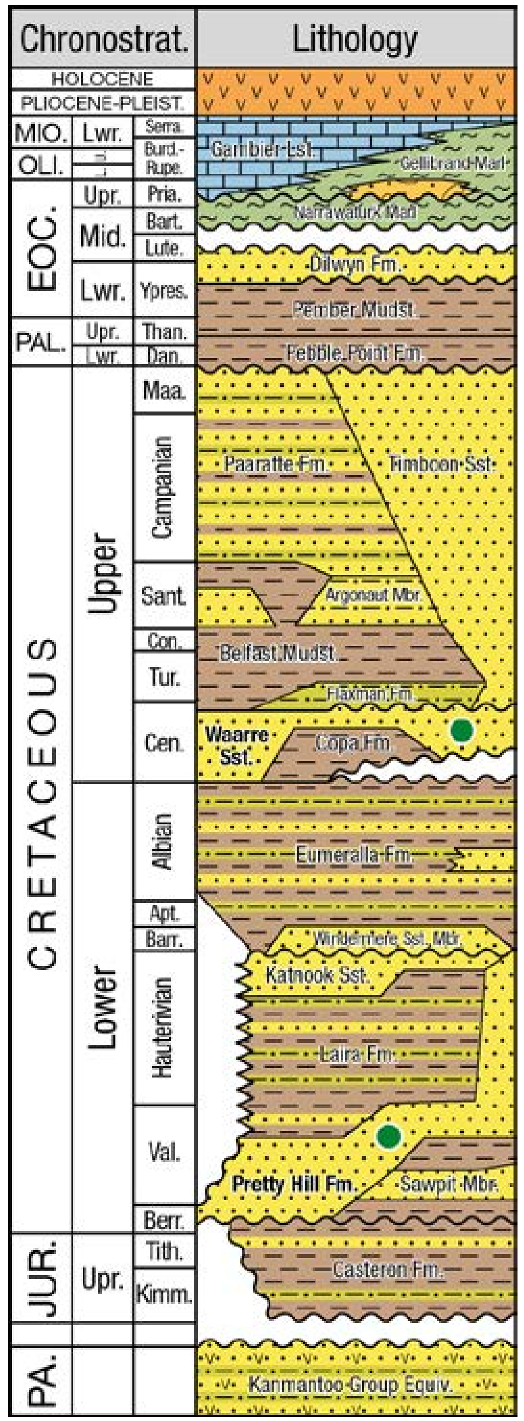
HERCULES-1 FAILS TO DO THE HEAVY LIFTING

Beach Energy kicked off the drilling campaign with the Hercules-1 exploration well in September-October 2025. Situated approximately 5 km south of the Artisan gas discovery in the VIC/P43 permit, Hercules-1 targeted a three-way fault-bound structure in the Waarre C reservoir. The prospect was considered to be medium to high risk and was ultimately proven to be, with the well plugged and abandoned dry at 2,350 m.

CONOCOPHILLIPS: ESSINGTON-1 SUCCESS WITH CHARLEMONT-1 TO FOLLOW

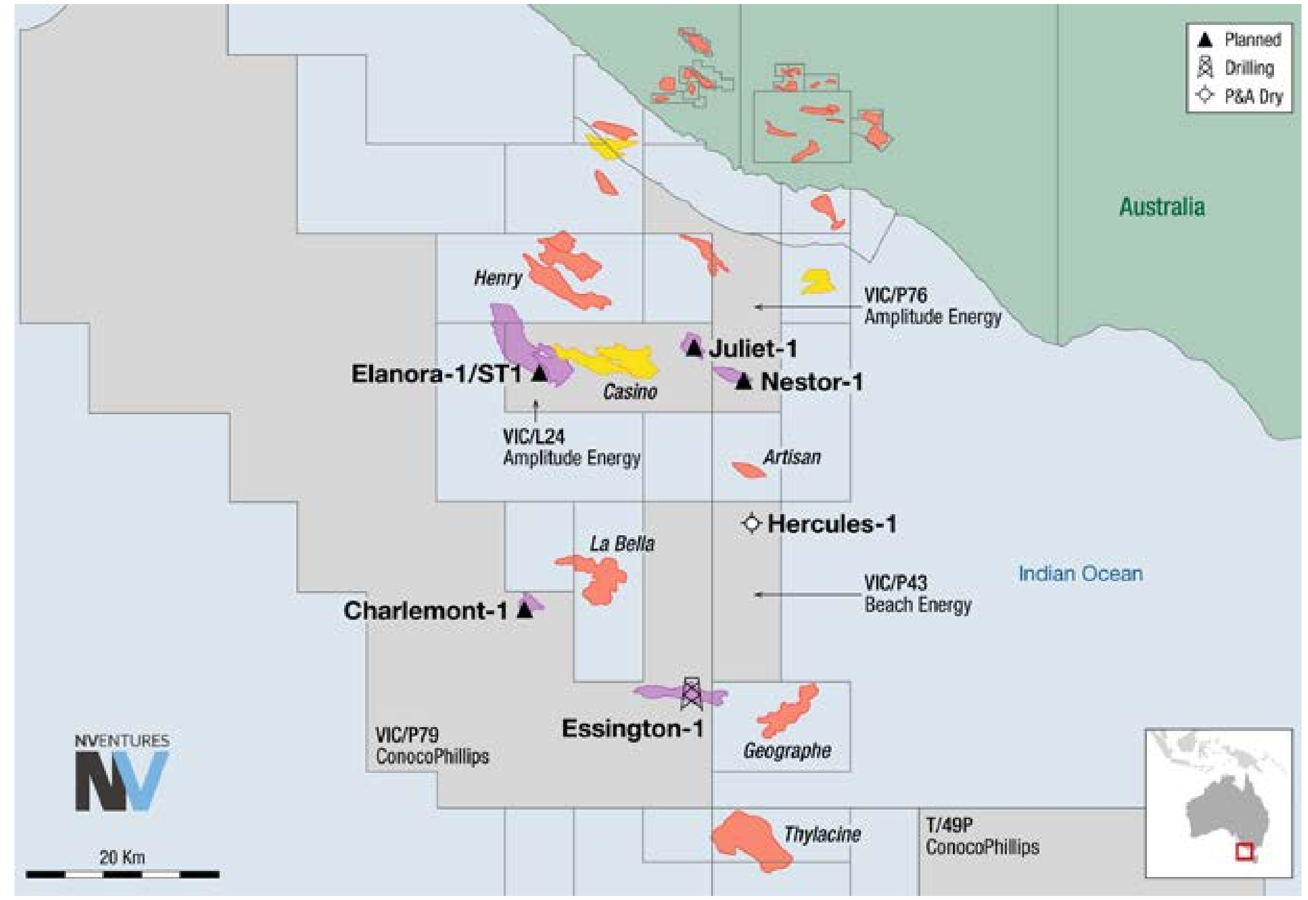
ConocoPhillips, in partnership with 3D Energi and Korea National Oil Corporation (KNOC), will drill two exploration wells in VIC/P79. The wells will aim to explore the potential of the Waarre A and C reservoirs, which have historically been prolific gas producers in the basin. Essington-1 started the campaign as a success, discovering gas in mid-November from both reservoirs. Wireline logs interpreted 58.5 m of net gas pay in the primary Waarre A reservoir at 2,515 m measured depth (MD) and 31.5 m of net gas pay in the secondary Waarre C reservoir, at 2,265 mMD.

Reservoir quality is reported to be consistent with pre-drill predictions. Essington-1 was targeting a combined 262 Bcf gross mean prospective resource from two stacked reservoirs. The Waarre C reservoir has a potential resource of 76 Bcf. The Waarre A reservoir has a potential resource of 186 Bcf. While results are encouraging, flow rates, recoverability, and commercial significance will be assessed using SLB's Ora wireline formation testing platform.



Stratigraphic column of the Otway Basin, Australia.

SOURCE: NVENTURES



Otway Basin Drilling Programme.

Charlemont-1 will target the Charlemont B prospect (previously known as Rosetta), located within the La Bella Complex – a series of tilted fault blocks that progressively step down into the basin, extending from the nearby 1993 La Bella gas discovery. Prospective resource at Charlemont-1 is 93 Bcf. Should these wells prove to be successful, a further four optional exploration wells could be drilled within ConocoPhillips-operated VIC/P79 and T/49P permits in 2026-28, which are adjacent to existing natural gas developments in the Otway Basin, such as the Casino and Thylacine fields.

AMPLITUDE ENERGY: TUNING THE BASIN

Amplitude Energy, in collaboration with O.G. Energy, plans to drill an initial three wells in Licence VIC/L24 in 2026: Elanora-1, Elanora-1 ST1 (sidetrack targeting the neighbouring Isabella prospect), and Juliet-1. However, the low-risk Nestor-1, in the neighbouring VIC/P76, could be added to the roster in Q1 2026 with a view to drilling in late 2026 or early 2027 to utilise the Transocean Equinox. These wells, part of Amplitude's East Coast Supply Project, are located approximately 25-40 km offshore from Peterborough, in water depths ranging from 65-74 m. The Elanora-1 well is targeting up to 161 Bcf of gas, while the sidetrack is targeting 149 Bcf from the Isabella prospect. Juliet-1 and Nestor-1 aim to tap into an additional 49 Bcf and 64 Bcf of gas, respectively. Amplitude's campaign benefits from its proximity to existing infrastructure in the Otway Basin and ability to utilise available gas processing ullage at the Athena Gas Plant near Port Campbell.

STRATEGIC IMPLICATIONS FOR GAS SUPPLY

Victoria's gas supply is under pressure due to declining output from legacy fields, high winter demand, and political resistance to new gas developments. The Otway Basin drilling campaign is a strategic response to these challenges, aiming to secure a reliable and affordable gas supply for the region. A successful outcome could reduce dependence on potentially costly LNG imports and support the state's energy security.

In summary, the Otway Basin drilling campaign represents a concerted effort by key industry players to address the looming gas supply challenges in southeastern Australia. With encouraging signs from Essington-1, promising geological targets and strategic partnerships, the campaign holds the potential to significantly impact the region's energy landscape. ■

When your oil reservoir turns out to be a lithium deposit

An old and neglected core from an oil and gas exploration well can still be very useful for the energy transition

ISTVÁN NAGY-KORODI, CONSULTING GEOLOGIST

As the global energy transition accelerates, the demand for critical raw materials (CRMs) is rising at an unprecedented pace. The list of elements essential for modern technologies – from lithium and strontium to boron and rare earths – continues to expand. Yet, in the race to secure new sources, one unconventional domain remains surprisingly overlooked: Oil and gas wells.

It is increasingly clear that subsurface fluids long known for their hydrocarbon potential may also host valuable concentrations of dissolved CRMs. Elements such as lithium, strontium, boron, and bromine frequently occur in reservoir waters, sometimes in economical concentrations. With modern geochemical techniques, these brines can be re-evaluated not just as waste by-products, but as potential new revenue streams.

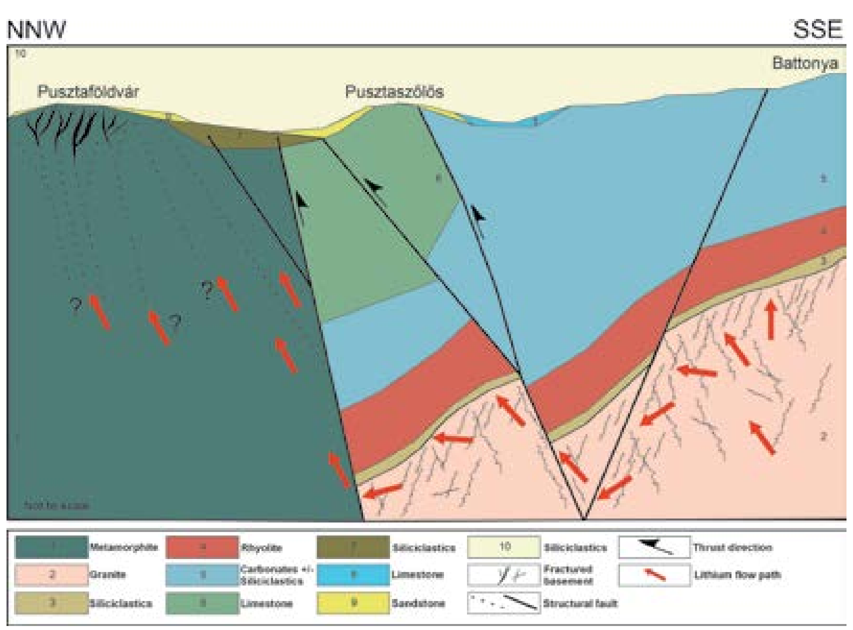
As both a geochemist and energy specialist, I have spent nearly a decade working at the intersection of petroleum geology and resource innovation. Among many experiences, one discovery stands out – a reminder that sometimes the past holds the key to the future.

During a project revisiting historic oilfield data, I examined core samples from a 60-year-old development well in an overmature oil and gas field in southeastern Hungary. The well, the 80th drilled in the field, had long been forgotten – its data filed away after production began decades ago. The original core descriptions were brief and routine, noting fine-grained sandstones typical of the reservoir. Nothing appeared unusual.

That changed when we re-analyzed the core with modern mineralogical methods. To our surprise, nearly half of the rock's mineral content was not quartz (SiO_2), but a lithium-bearing secondary mineral called cookeite. Cookeite is a Li-Al phyllosilicate, typically found in hydrothermally altered pegmatites and granitic systems – not in conventional oil reservoirs. Its presence indicated that lithium-rich hydrothermal fluids had circulated through this formation long after the reservoir formed. In other words, this "ordinary" oil well had intersected an unrecognized lithium-bearing system, hidden within the sedimentary sequence. Since then, more and similar features were observed in several other wells.

This finding was more than a mineralogical curiosity. It illustrated how legacy oilfield infrastructure can provide invaluable insights into the subsurface distribution of critical elements. With thousands of archived cores, water samples, and well logs available globally, the potential for discovering CRM anomalies within existing data is immense. By applying modern geochemical screening and isotopic analysis, old oilfield datasets could be transformed into CRM exploration tools, helping operators repurpose their geological knowledge for the low-carbon economy.

That old core taught me a simple but powerful lesson: Innovation often begins by re-examining what we think we already know. In the era of the energy transition, the boundary between hydrocarbon geology and critical mineral exploration is becoming increasingly blurred. Sometimes, the path to tomorrow's resources begins with a second look at yesterday's wells. ■



Seismic cross section of Pusztaföldvár-Battonya Ridge.

REFERENCE: NAGY-KORODI ET AL., IN PRESS. LITHIUM ANOMALIES IN HUNGARY (GSL, ED. TARI G.)

How structural setting and hydrocarbon phase are closely related

A case study from the Papuan Basin, Papua New Guinea

LUKASZ KRAWCZYNSKI AND MARTIN NEUMAIER

The Papuan Basin is located across a tectonically active area and is dominated by a gas-prone Jurassic petroleum system with a whole-of-system Gas-Liquid Ratio of 30,000 scf/bbl. The complex geology, coupled with a steep and karstified surface terrain, results in poor data coverage with even poorer quality, making attempts at standard bottom-up basin modelling to predict hydrocarbon distributions and phases almost futile.

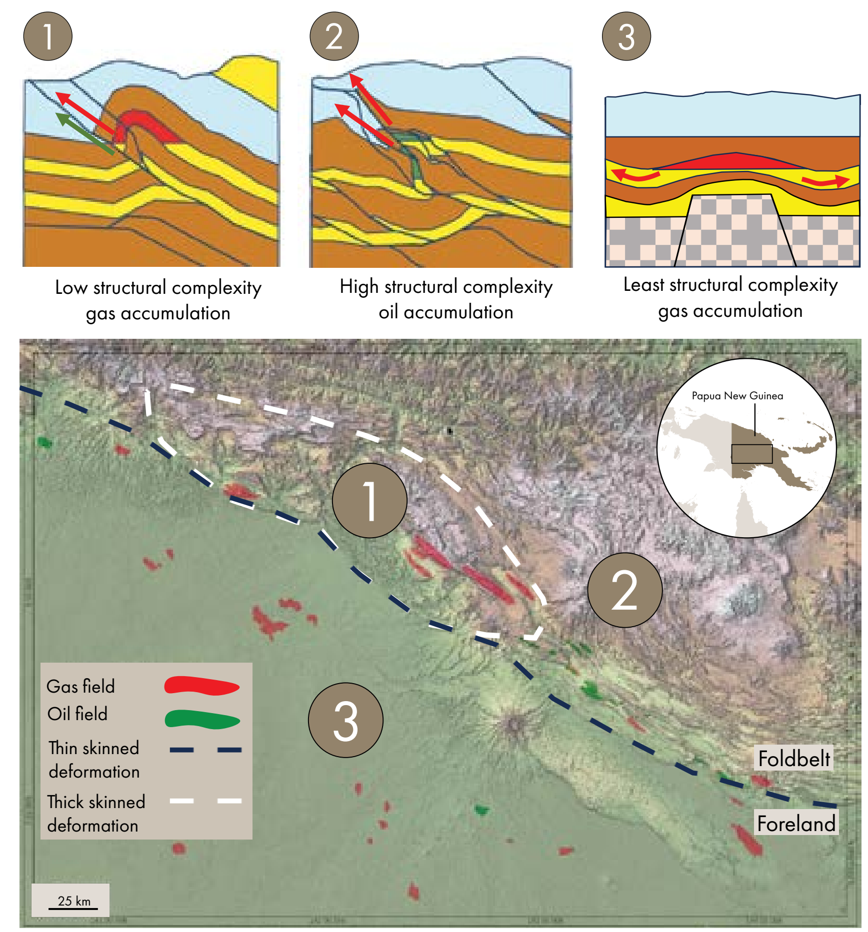
Therefore, the understanding of the petroleum system is driven by a top-down analysis integrating the existing accumulation trends and hydrocarbon bulk properties into the context of their structural setting.

Hydrocarbon column heights distribution analysis across the Papuan Basin shows that larger column heights are associated with gas-only accumulations, whereas none of the traps containing either an oil-only or a mixed phase are filled to spill.

Based on the existing PVT and geochemistry data, all the sampled Papuan Basin hydrocarbons are saturated and have the same origin. As the originally undersaturated condensates are expelled from the Middle Jurassic deltaic coals at greater depths, liquids drop out once they reach the dew point pressure on the upwards migration pathway. The preservation of the liquids in the traps is dependent on the structural setting and indirectly related to seal integrity. The greater the degree of structural complexity, the greater the likelihood of vertical gas leakage leaving behind oil accumulations.

Therefore, areas of lesser complexity, such as the thick-skinned deformed part of the Papuan Basin foldbelt (1), tend to be prone to gas-only accumulations with the oil having been displaced. The more structurally complex thin-skinned deformed part of the foldbelt (2) tends to also host oil accumulations, as some or all of the gas leaks through the faults, creating space for the oil. The foreland part of the basin (3), which is the least structurally complex setting, contains only gas accumulations of relatively low column heights that do not favour the accumulation of oil.

Despite the lack of data and the incomplete knowledge of the subsurface, the accumulation trends and related fluid properties can be used for a solid probabilistic prediction of prospect phase and column height. This requires prospect assessment workflows to include quantitative assumptions for PVT, charge and seal, so that oil and gas fluids are put in competition for pore and pressure space, obeying the mechanism as described above. ■



Distribution and structural controls on the hydrocarbon phase in the Papuan foldbelt.

SOURCE: KRAWCZYNSKI, L.; 2019 AAPG HEDBERG "THE JURASSIC PETROLEUM SYSTEM OF THE PAPUAN FOLDBELT"

What do air hockey and induced seismicity have in common?

It's all about reducing friction

MOLLY TURKO, DEVON ENERGY

AT FIRST GLANCE, air hockey – a fast-paced arcade game – and induced seismicity – earthquakes triggered by human activity – seem unrelated. Yet, both share a fascinating connection through the physics of reduced friction. The key lies in how airflow under an air hockey puck mirrors the increase in pore pressure along fault planes, facilitating an easier ability to move in unexpected ways.

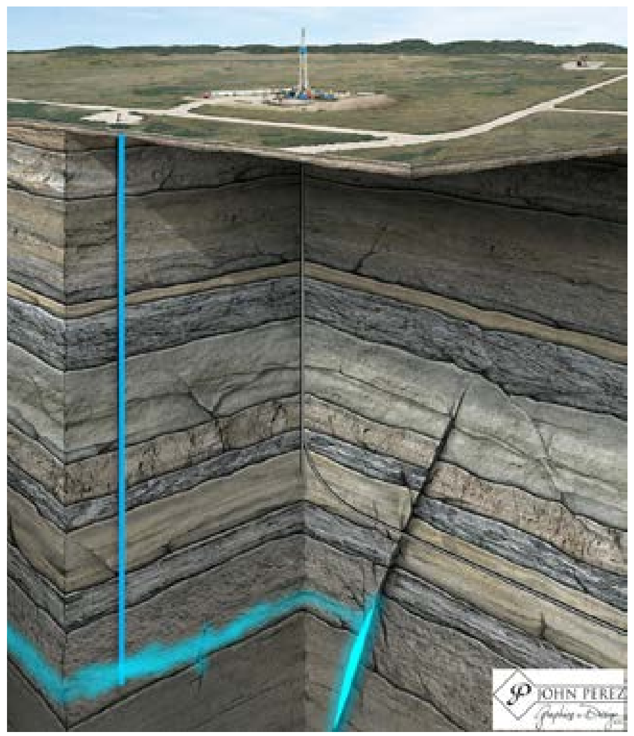
In air hockey, the table's surface is perforated with tiny holes that release a thin cushion of air, lifting the puck and reducing friction. This allows the puck to glide effortlessly, enabling quick, smooth plays. The airflow effectively counteracts the table's resistance, much like how increased pore pressure – fluid forced into rock pores – can potentially destabilise faults in the Earth's crust.

In induced seismicity, activities like hydraulic fracturing or wastewater injection can potentially elevate pore pressure along pre-existing fault planes, lowering the effective normal stress that may otherwise keep dormant faults locked.

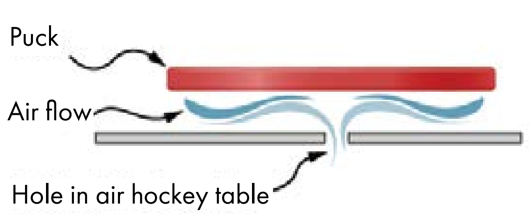
Although pore pressure plays a critical role in induced seismicity, fault orientation relative to the regional stress field and the coefficient of friction are also crucial. Faults critically oriented to the regional stress field are more prone to slip when subject to an increase in pore pressure from fluid injection, which reduces the effective normal stress clamping the fault.

The coefficient of friction, which governs fault stability, determines how easily a fault slips under these conditions. When pore pressure sufficiently lowers the frictional resistance on a critically stressed fault, it can trigger seismic events, ranging from microearthquakes to larger tremors, depending on the fault's characteristics and stress state.

This analogy simplifies induced seismicity for non-experts, dispelling exaggerated notions of "man-made" earthquakes. It clarifies that the process involves more than just "lubricating" fault planes, as often assumed with saltwater disposal (SWD). The analogy provides practical insights for the energy sector. Like air hockey players adjusting tactics to control puck momentum, geoscientists can reduce seismic risks by optimizing injection rates and selecting low-risk zones, preferably away from faults. ■



Water Displosal well triggering seismicity along a fault plane.



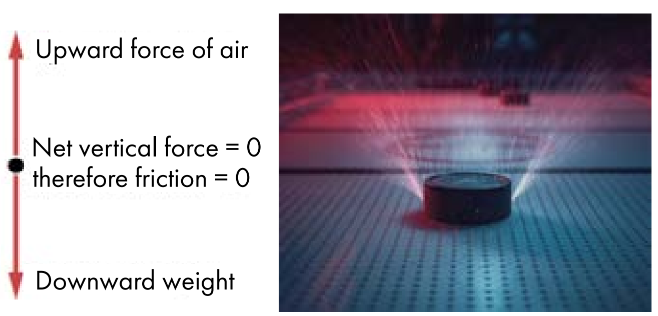


Illustration of air hockey dynamics.

DIAGRAM: JOHN PEREZ GRAPHICS & DESIGN, LLC GEOART.COM, ILLUSTRATION: MOLLY TURKO

The Grand Canyon of the Middle East

This photo shows what is commonly known as the Grand Canyon of the Middle East: Wadi Ghul and Wadi Nakr in the Jebel Shams Massif in northern Oman. From base to top, the rock record tells the Mesozoic story of drowning of the Arabian platform in Jurassic times, shallowing during the Cretaceous with various phases of carbonate platform build-out, and final drowning again towards the end of the Cretaceous when the source rocks of the Natih Formation were deposited before the region was uplifted due to the collision of the Arabian and Eurasian plates, starting in the Late Eocene, to form the mountain range and canyon we see today.

Photo and text: Joe Versfelt, V-Global Exploration Consulting

FEATURE YOUR OUTCROP

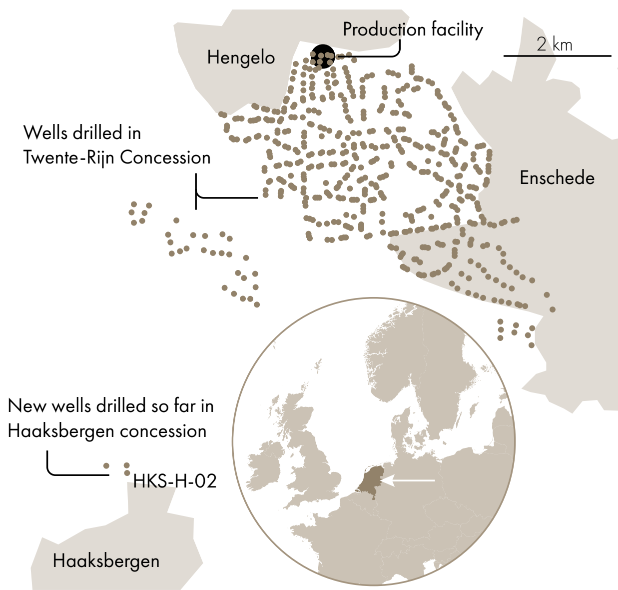
In this series, we show a range of outcrops to give more context to what core interpretation typically allows. Do you have a suggestion for an outcrop feature? Get in touch with Henk Kombrink – henk.kombrink@geoexpro.com.

Going deeper for salt mining

In the east of the Netherlands, Nobian is developing a new salt mining project to replace decreasing production from a long-standing neighbouring site

THE DUTCH subsurface is well known for its gas resources, hosting the world-famous Groningen field. What is less well known is that there is plenty of salt, too. These evaporites not only form a very effective seal for the Groningen gas; they also form a target in their own right.

The main geological strata hosting evaporites in the Netherlands are the Upper Permian Zechstein and the Triassic Röt Salt. In terms of thickness and volume, the Zechstein wins, but it is the Röt that formed the source for a large-scale salt solution mining operation in the east of the Netherlands for many decades, based on the Buurse and Twente-Rijn concessions. Here, the evaporites occur at a relatively shallow depth of around 400 m.



Zechstein halites from well HKS-H-02.

SOURCE: NOBIAN

With room for expansion being limited, operator Nobian decided a few years ago to shift operations to the deeper Zechstein evaporites that are also found in the area where the processing facility is currently located. The depth of the Zechstein salts in this area (the Isidorushoeve concession) is around 900 m.

As such, the company has embarked on a project to drill and core a total of eight wells, targeting the so-called Z1 Werra Formation evaporite. The first well was drilled in July this year, with the final one planned for mid-2026. Similar to the Twente-Rijn project, the Isidorushoeve concession will rely on solution mining, with the brine being transported by pipeline to the processing facility in Hengelo. All the required infrastructure is being put in place at the same time as drilling the wells, such that production can start shortly after the wells have been completed.

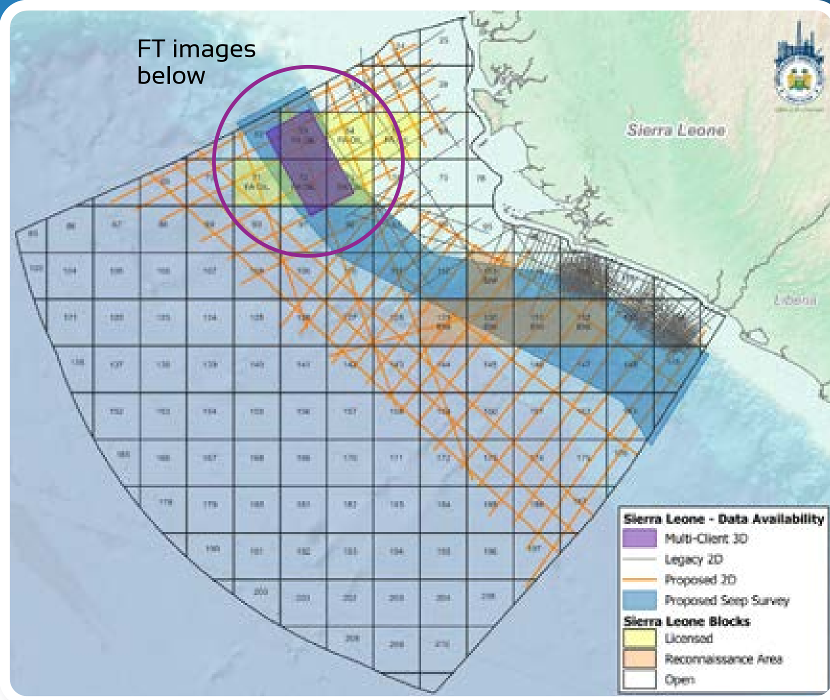
Geologist Martijn ter Braack from Nobian, who has been planning the wells and also closely follows the operational side of the project, shared a photo with us that beautifully captures the Zechstein halites in one of the cores they cut from the Zechstein salt target. Rather than illuminating the core from above and taking photos that way, in this case, the light source is placed below the transparent evaporite core, resulting in an almost artistic image. The darker zones in the cores represent a more anhydritic facies. ■

Henk Kombrink

Multi-Client Seismic Africa • Sierra Leone

Offshore Sierra Leone

Geophysical Data



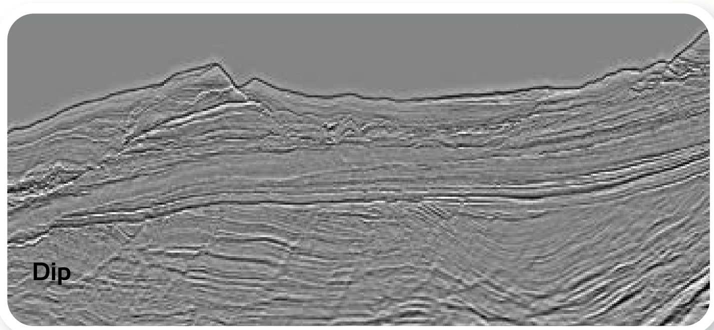
GeoPartners

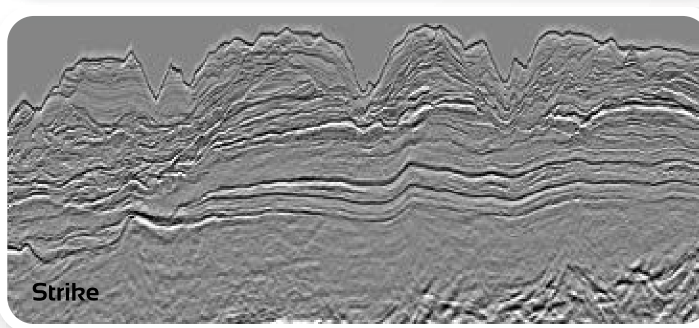
PETROLEUM DIRECTORATE SIERRA LEONE

Office of the President

GeoPartners is proud to work in partnership with **the Petroleum Directorate of Sierra Leone (PDSL)** to promote the hydrocarbon prospectivity the country's offshore has to offer. Our surveys will comprise full coverage of the offshore area from shallow to ultradeep water, providing ties to all existing wells and allowing a complete evaluation of the available acreage. The existing and proposed data volumes comprise:

- A new 3D seismic survey of 2,916 sq. km targeting the prospects derived from regional interpretation in the northern offshore area. The survey completed acquisition in August 2025 and is currently being processed to provide high-resolution broadband imaging in both the time and depth domains. Inline and Cross Line examples from the Fast-Track processing are shown to the right.
- The brokerage of over 8000 km of legacy 2D data, covering the full extent of the offshore area and with particular emphasis on the prospective inshore areas in the south. These data are currently being prepared for reprocessing early in 2026.
- A new 2D seismic campaign of over 7000 km targeting the deeper water shelf edge plays. Survey parameters will include using a single ultra-long cable, with a full suite of deliverables including PreSTM and PreSDM processed volumes.
- A new Seep Finding survey covering water depths between 750 and 3500m. This proposed survey of over 22,000 sq. km covers the entire deepwater area offshore and will involve the acquisition of Multi-Beam Echo Sounder data, selected piston cores and heat-flow measurements.





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