THE GLOBAL ENERGY SECTOR FROM A SUBSURFACE PERSPECTIVE

VOL. 23

GEO ExPro 3 2026

FRONTIER EXPLORATION – ARE WE SEEING A REVIVAL?

Exploration Opportunities

From image to insight: Why seismic data quality matters for CO_2 storage

A Cenomanian-Turonian source rock adventure in the Pelotas Basin

AI-Driven integration for deeper subsurface insights

Halo oils, tight-rock saturation and production allocation: The North American playbook for unconventional basins

GEO ExPro

geoexpro.com

Managing Director
Ingvild Ryggen Carstens
+47 974 69 090
ingvild.carstens@geoexpro.com

Editor in Chief
Henk Kombrink

Associate Editor
Mariël Reitsma
mariel.reitsma@geoexpro.com

Editorial Assistant
Marzena Pyteraf
marzena.pyteraf@geoexpro.com

Editorial enquiries
+44 7788 992374
henk.kombrink@geoexpro.com

Subscriptions
subscribe@geoexpro.com
GXP PUBLISHING AS
Trollkleiva 23
1389 Heggedal
Norway

Creative Direction
Ariane Busch

Layout and Design
XRB Media Limited, London, UK

Print
United Press, Latvia

GxP PUBLISHING

A niche species

"ARE YOU a geologist?" asked the engineer I was having coffee with the other day. "Yes," I said. "That's very much a niche job," he replied.

It got me thinking. In my bubble, there are a lot of geologists. Are we really that much of a minority species?

But yes, it is probably true. The number of engineers involved in actually making oil and gas flow from the fields to the ultimate consumer is much higher. Sometimes, it is a good thing to be made aware of that again. Looking outside your little bubble.

> "… to call this a true resurgence is still early days…"

If the number of geologists is already quite small in comparison to other disciplines, I feel that the job pool has been reduced even more over the last decade or so, on the back of multiple oil price crashes and the associated reduction in exploration spend.

But are we on the cusp of a renaissance? That's the question I've asked myself when pulling together the material for the cover story. It's a question that did not come out of the blue; there is a bit of a buzz around the return of frontier exploration activity.

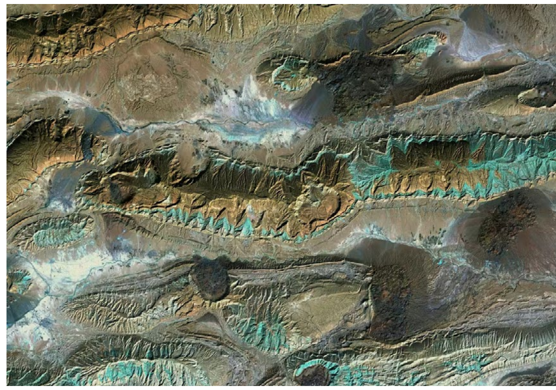
My preliminary conclusion? I think that whilst we are seeing more talk, more licensing activity – a land grab as someone I spoke to called it – and possibly some more wells being drilled, to call this a true resurgence is still early days.

For me, the ultimate proof will be an upturn in the job market. The return of hiring, the return of the recruiters pestering you. I feel that has not happened yet, and I see too many skilled people out there who are on the lookout for a reasonable job.

Let's see if the year to come will demonstrate that the pool of those "niche geologists" can actually grow again.

Henk Kombrink

BEHIND THE COVER



PHOTOGRAPHY: NASA

Frontier exploration usually dictates headlines. ENI's latest well in Libya, Shell's second attempt to prove up economic volumes in Namibia, and not to forget, news related to licensing rounds and new seismic surveys. But at the end of the day, the big engine that supports current levels of oil production is drilling in existing fields, and near existing fields. It is for a reason that last year's biggest discovery took place in an existing field in East Baghdad, Iraq. A new compartment containing around 2 billion barrels of oil was proven in what was already a giant field. It shows that continued activity in the old exploration heartlands pays off. And that is what is behind the front cover photo selection. It is in these landscapes, where surface anticlines and synclines could be easily mapped, such as here in the Zagros Mountains, where the early discoveries were made. And will continue to be made.

FIRSTS

"Until recently, there was a monitor in our office showing how much we were producing from the asset; it's been switched off. Apparently, the whole field now delivers less than what a single well used to do"

Anonymous – working in the North Sea Basin

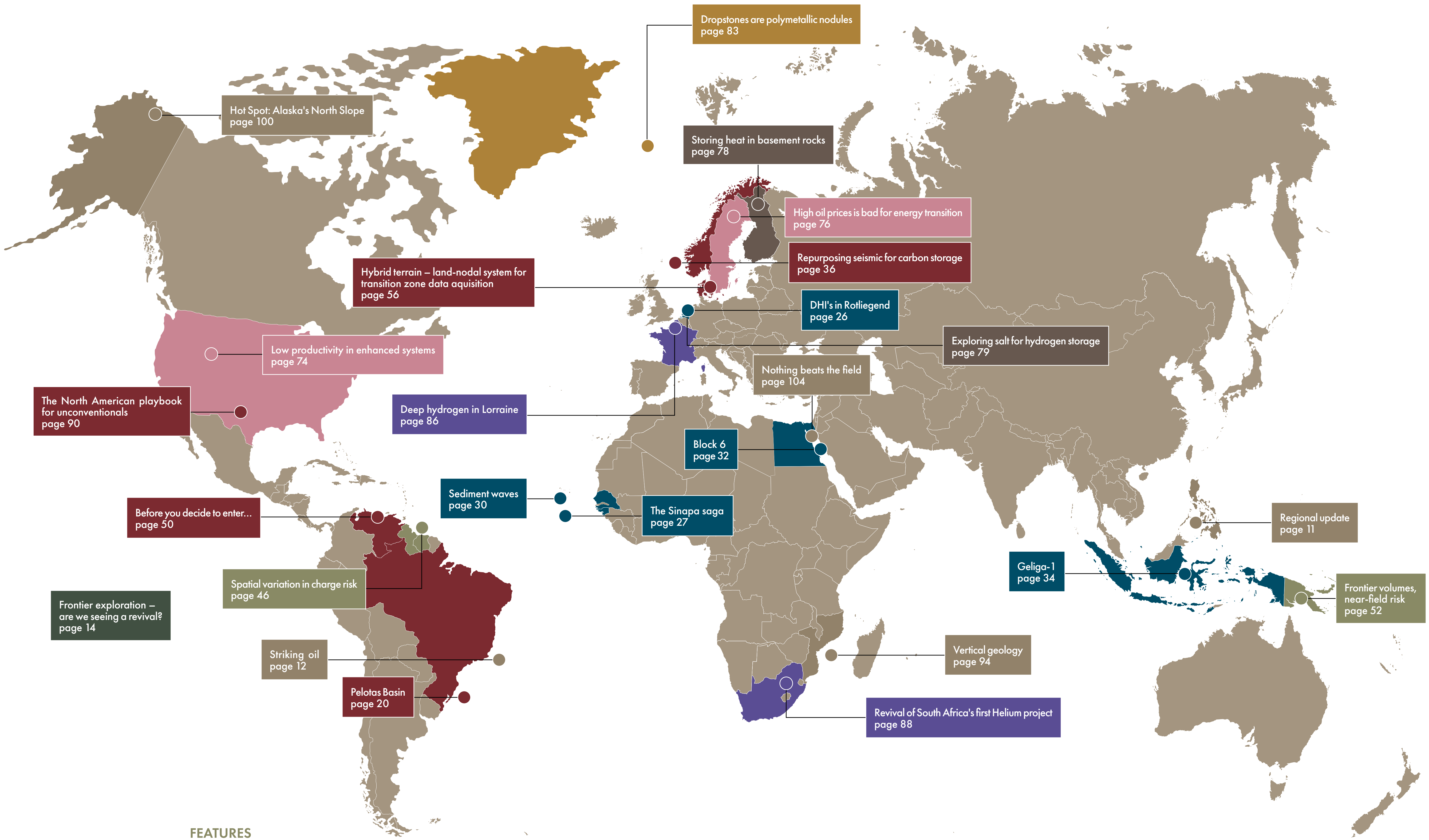
CONTENT

THE CORE

COVER STORY

OIL & GAS

CONTENT MARKETING



FEATURES

PORTRAITS

GEOTHERMAL ENERGY

SUBSURFACE STORAGE

DEEP SEA MINERALS

NEW GAS

THE REALITY BEHIND PRESS RELEASES

Talking to people is still the best way to find out what really happened when a well has been completed. "We drilled hundreds of meters of shale," an exploration geologist recently told me about an attempt to firm up a new play in one of the world's hotspots. "There was absolutely no resource. Yet, the press release still made note of a sub-commercial discovery, simply because one tiny sand stringer was found." It just shows how press releases have to be taken with a pinch of salt.

SWITCHING OFF THE MONITORS

I recently spoke to someone who works on the decommissioning project for a major oil field in the North Sea. "Until recently," he said, "there was a monitor in our office showing how much we were still producing from the asset, but it's been switched off. Apparently, the whole field now delivers less than what a single well used to do when it was taken into production a few decades ago. Too much to be confronted with that every day."

THE BENEFIT OF BEING AROUND FOR A WHILE

Being in the industry for a while often brings the ability to reflect on longer-term developments. In that regard, I found it interesting to hear at the recent NAPE Conference in Houston how unconventionals have changed the risk appetite for those who have only worked in this space. "These folks are not used to the high risk that comes with drilling a conventional well," said someone who has been in the business for a long time. On a similar note, I spoke to a seasoned driller who told me that the new generation in his field only knows PDC bits. "Sometimes," he said, "it is just as easy to opt for a roller cone bit, even when that may be looked upon as old-fashioned."

TAXI, SIR?

You can never tell what people are after when they pop past your small conference stand. I was in Cairo, promoting the magazine at the EGYPES Conference, and the first few hours of the exhibition had just passed by. Quite a few people were after gifts. At those occasions, I tell them that a free copy of the magazine is my gift. Often, that's not the gift they had in mind, unfortunately. Then there is the pompous guy who walked past a few times. He cast an eye on the magazine, leaving the impression that he took an interest in our work, and I asked him if he was interested in having a copy. But then the words come out: "Taxi to your hotel, sir?"

"THE FLARE LOOKS LIKE SO AND SO MUCH A DAY"

When developing an old discovery, operators have to deal with more uncertainty than what an initial data inventory may suggest. The availability of a Drill Stem Test (DST) is usually a great way to assess the deliverability of a reservoir, but in the case of the Victory field on the UK Continental Shelf, the DST was performed without any metering in place. The DST report says that the "flare looks like so many millions of cubic feet a day". Not a great calibration point when planning the field development so many years later.

ILLUSTRATION: PCR.VECTOR / FREEPIK.COM

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

Ideas over barrels

In 1974, France turned a crisis into a playbook. In 2026, Europe needs to steal the same page – only this time, the opponent isn't scarcity alone. It's physics, finance, and political whiplash

When France launched the slogan «On n'a pas de pétrole, mais on a des idées» during the oil shock, it wasn't clever copy – it was national reframing. Lacking domestic crude became a spark for ingenuity: Efficiency drives, speed limits, insulation campaigns, and a bet on nuclear that still anchors one of the world's lowest-carbon grids.

Crucially, France didn't just build reactors – it built a fuel cycle: Reprocessing at La Hague, MOX fabrication at Marcoule, and a recycling architecture that treated spent fuel as material flow, not wishful waste. That's geology-level thinking: Resources are finite, materials are stratified, and residues demand stewardship across time.

Half a century later, Europe faces a different kind of shock. We're not short of ideas; we're short of projects with clear physics and math: Offshore wind, geothermal, hydrogen, grids, storage, CCS – every pillar now meets hard constraints: Energy density, intermittency, seasonal balancing, geotechnical realities, and the price of money. If projects can't be financed, permitted, and dispatched at a predictable cost, they won't be built – no matter how beautifully we reorganise the org chart.

Meanwhile, the next chapter is quietly breaking ground. While much of Europe debates frameworks, France, the UK, and parts of Eastern Europe are doing something refreshingly old-fashioned: Moving dirt. From EDF's NUWARD program to early works at sites in Romania, small modular reactor efforts are progressing through soil investigations for foundation pads and early civil works. Geologists know the difference between a model and a pit: Progress is real when you start to measure disturbed earth, groundwater behaviour, and bearing capacity.

Golfech nuclear power plant in the Garonne plain seen from the hills above Auvillar.

PHOTOGRAPHY: LDGFR PHOTOS VIA ADOBE STOCK

WHAT 1974 GOT RIGHT – AND WE KEEP FORGETTING

First, respect physics and geology. Hydrocarbons are dense; electrons are fickle; molecules are hard to store. Batteries shine for short durations but stumble at seasonal scales. Hydrogen may be essential for steel and chemicals, but unless conversion losses and real-world storage constraints make economic and technical sense from the very start, the model doesn't hold. In 1974, France didn't argue with thermodynamics; it worked with it – pairing efficiency with firm, lowcarbon capacity and a materials pathway to manage fuel over decades.

Second, make scarcity a design constraint, not a moral crusade. The 1970s response didn't scold consumers; it invited them to coauthor resilience. Today, pragmatism means retrofit programs that move meters, demand-side signals that reward timing, and permitting standards that measure impacts in months, not years – with site characterisation, including seismicity, hydrology and slope stability, integrated early, so projects survive due diligence and the courts.

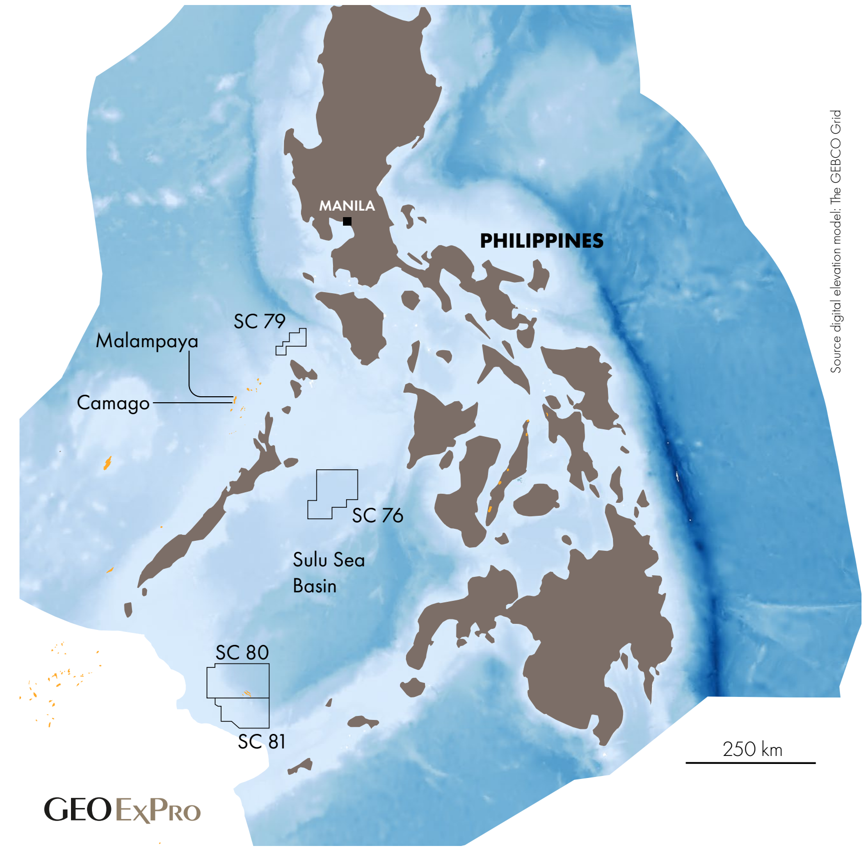
Europe's 2026 energy transition needs the same architecture. Ideas that ignore physics fail; ideas that ignore finance won't fund; ideas that ignore people won't last. The fuel-cycle story adds a fourth rule: Ideas that ignore materials and time won't close. If we want electrons we can count on, we must build like geologists think – start with the ground, respect the physics, price the time – and then turn that discipline into steel, concrete, and kilowatt-hours. ■

Rodney Garrard

The jewel in the crown

And other exciting upstream updates from the Southeast Asia region

The Philippines' upstream sector is seeing a resurgence, bolstered by Prime Energy's successful wells at Malampaya East-1 and Camago-3 just ahead of the recent SEAPEX Conference and Exhibition in Manila. Together with a string of recent concession awards, this has broken a long-standing lull in activity. With an attractive fiscal regime and a proactive Department of Energy (DOE), the country is now ripe for investment.



A number of standout underexplored areas were highlighted by speakers at the conference. In the Sulu Sea Basin, Triangle Energy is targeting Miocene turbidites and deeper carbonates across SC 80 and SC 81, whilst in East Palawan, Ratio Petroleum has identified a large Miocene frontal splay complex in SC 76. PNOC is pursuing multiple play types in SC 79.

Searcher also shared critical insights on the structural connections between the West Palawan, Southern Sulu Sea, and East Palawan basins. Several speakers highlighted the potential of the Philippine Arc. This area contains numerous oil seeps and was targeted for early onshore exploration, which resulted in only minor discoveries. A re-evaluation utilising modern geochemical analysis to refine concepts could stimulate new exploration ideas.

Malaysia remains the regional "jewel in the crown," with its vast potential and regulatory body Petronas serving as a global benchmark for the industry. The Malaysian Bid Round 2026 (MBR 2026), launched in February, offers a mix of exploration blocks and Discovered Resource Opportunities (DROs). TGS presented significant deepwater prospectivity off Sabah, using new MC3D datasets to showcase recent oil discoveries, such as Megah-1, in the Oligo-Miocene carbonate play, and their implications for the Layang-Layang Basin. Technical discussions also identified new play types, including pre-Tertiary carbonate targets.

Elsewhere in the region, Timor-Leste's National Petroleum Authority (ANP) is undertaking broad fiscal reforms, with revised terms expected ahead of the 2027 licensing round. High priorities include the Greater Sunrise project, with operator Woodside looking to expedite development, and the appraisal of Kelp Deep – a multi-TCF fractured Permian limestone feature. Looking ahead, Finder Energy and Sunda Energy are expected to coordinate joint offshore drilling campaigns in 2027. The vast "running room" of the Island of Papua was showcased through deeper plays in Indonesia's Bird's Head and numerous opportunities across Papua New Guinea. Cambodia is also drawing eyes; operator EnerCam plans to drill the country's first-ever onshore well (Kirirom-1) later in 2026, with reported oil seeps in Block VIII seemingly demonstrating a working petroleum system.

The sense of regional optimism was cemented by news of Eni's giant deepwater gas discovery at the Geliga-1 exploration well in Indonesia's deepwater Kutei Basin, off East Kalimantan. Preliminary estimates indicate in-place resources of approximately 5 Tcf of gas and 300 MMbbl of condensate – a fittingly high-note conclusion to the conference. ■

Ian Cross - Moyes & Co

Decommissioning and discovering at the same time

The post-salt Marlim field is one of Brazil's first deepwater developments. The giant field is currently being decommissioned, but that does not mean it's at the end of its life. Because with the old platforms going, two new FPSOs have recently arrived. And at the same time, exploration drilling doesn't stop either, with an additional pre-salt discovery recently announced

THE MARLIM field was discovered in 1985, on the back of the first proper exploration drive to test the potential of Brazil's deepwater Campos basin. Oil was found in Oligocene post-salt sands, mostly thanks to a pronounced seismic anomaly. The initial discovery had more than 6 Bbbl in place, with an estimated recoverable volume of 2.5 Bbbl. Production from Marlim started in the 1990's, overcoming many technical challenges related to deepwater production.

Now, many years later, with the post-salt reservoir being mature, and bearing in mind that the original plan was to cease production in 2025, the time has come for a reassessment. But instead of just decommissioning the infrastructure, operator Petrobras (100 %) decided to give the field another lease of life. The company estimated that the revitalisation project could add an additional 860 MMbbl of oil equivalent. Two new FPSO's – installed in 2023 – are part of that story, whilst the original nine platforms are now being dismantled. By February this year, three of these platforms had actually been removed, with six more to go. With the FPSOs in place, the field is now expected to produce up to 2048.

Part of the continued potential in Marlim is the additional opportunities offered by the deeper pre-salt play, probably in Lower Cretaceous carbonates. A paper presented at the Offshore Technology Conference in Houston in May 2024 states that, as part of the revitalisation project, a total of 72 post-salt wells and three pre-salt wells will ultimately be producing from the Marlim field. In other words, deeper reservoirs are already part of the mix. But that's not where the story ends.

Very recently, operator Petrobras (100 %) announced another discovery in the southern part of the Marlim field, in pre-salt reservoirs. In other words, with the production that is already coming from previous pre-salt finds in the area, Marlim is a perfect example of how giant fields continue to attract new drilling opportunities as well... ■

Henk Kombrink

BEHIND THE SCENES

We always try to speak to people about the topics we write about. Sometimes that is easy, sometimes it is not. In the case of Marlim South, it was not easy. Four individuals were approached on LinkedIn through an invite including a personal message. It resulted in just a single profile view. None of the invites was accepted. One contact in Brazil promised to ask her network. No response. Another direct contact never replied, and finally, an email address taken from a recently published paper got nowhere either. In other words, we try our best, but sometimes it just proves to be impossible.

COVER STORY

"Whilst there is a lot of talk of an exploration revival, it has not translated into more spending or more wells being drilled. What we are seeing currently is more like a land-grab"

Graeme Bagley – Westwood Global Energy

FRONTIER EXPLORATION – ARE WE SEEING A REVIVAL?

Ridges and valleys of the Zagros Mountains in southern Iran.

On the back of numerous announcements, press releases and social media posts, there seems to be momentum behind a return of frontier exploration. More acreage is being awarded, and companies are more vocal about their exploration portfolio again. But at the same time, it is good to be aware that if the tide indeed turns, the inflection point is still positioned at a genuine low in the overall market. The number of exploration wells has been very depressed over the past few years. A look at how the seismic acquisition sector has fared also demonstrates the impact that this lull in activity has had on the service sector as a whole. In this article, I will try to grasp this exploration revival a little more through conversations with experts on the matter, combined with some personal observations. But before we get to the main topic of the article, let's take a look at a very recent announcement in the exploration arena that has rocked the boat

HENK KOMBRINK

As I started writing this story, a contact in Iraq messaged me about a new well recently completed in the west of the country, near the border with Saudi Arabia. It is a well that was drilled by Zhenhua Oil, a state-owned Chinese company, under the local subsidiary name Qurnain Petroleum. This well, which was mistakenly named Shams-11 instead of Shams-1, made a discovery of around 8 Bbbl of oil.

Of course, it is early days, and as Jonathan Brown voiced as a response to our LinkedIn post dedicated to the discovery, it is too early to make such a detailed estimate of the field's size after drilling just one well. That is a valid remark indeed. But still, even if this discovery turns out to be smaller, it is still something to take note of.

Why is that?

It is because of the location of the discovery in the western part of Iraq. When looking at the map, ▸

the location of the licence where the discovery was made is far away from the classic fold and thrust belt and foreland petroleum plays that characterise the northern and eastern parts of the country.

Instead, the Qurnain discovery lies in the area that is interpreted as the "Stable Platform", or the Tethys passive margin. Hardly any oil fields have so far been found in this structural domain in Iraq. That's why this find can be regarded as a play opener. At least for the country of Iraq, because in neighbouring Saudi Arabia, the play is well known.

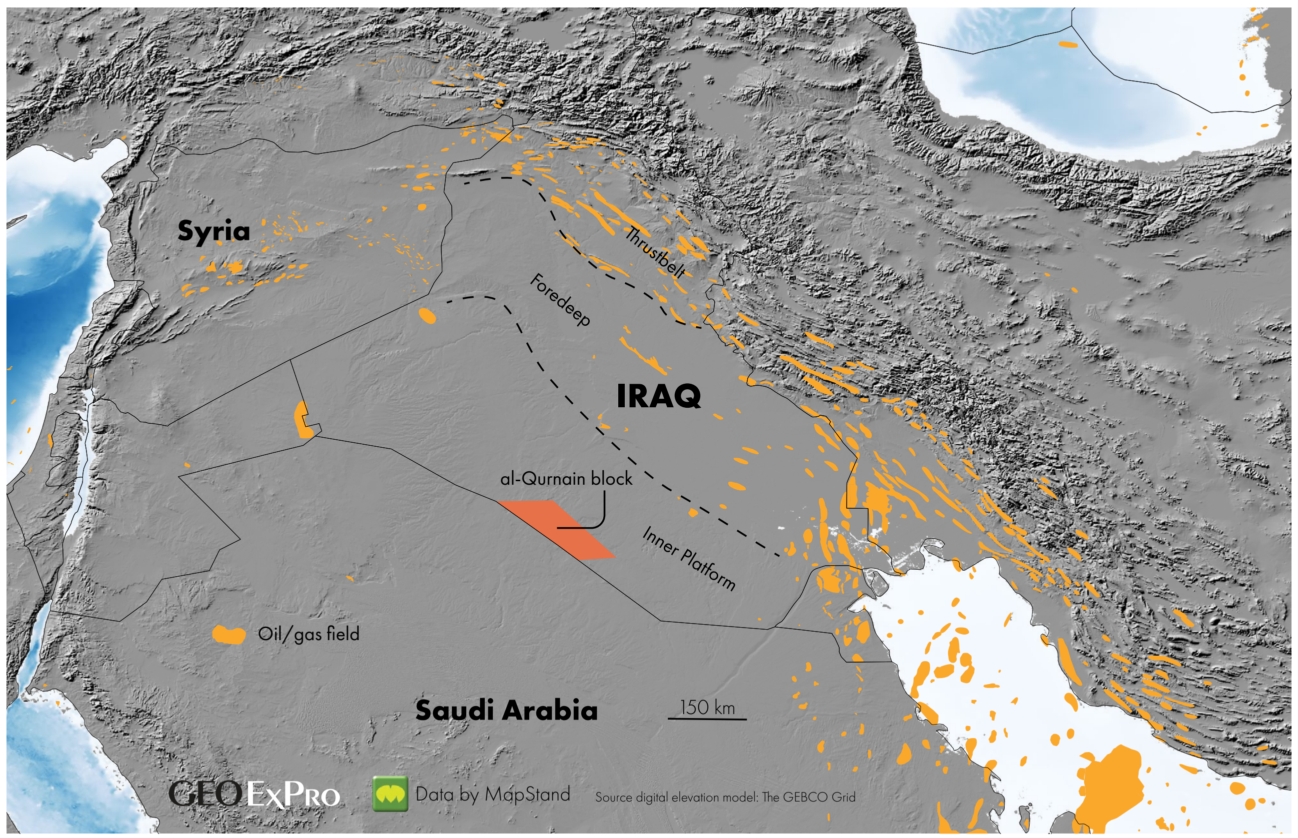
Mohammed Al-Mahmoud commented on LinkedIn: "Basin-wise, the discovery location is similar to the Jurassic oil fields in Saudi Arabia. It is on the western flank of the Mesopotamian basin. The Saudi major oil fields are on the western flank of the Arabian basin. On a more regional perspective, the Mesopotamian and Arabian basins are, geologically, not segregated from each other. Likewise, their western flanks are geologically connected. Hydrogeological studies in both Saudi Arabia and Iraq indicate hydraulic continuity of the rock units, which means that western Iraq and northern Saudi Arabia are likely one regional hydrocarbon play."

Have the Chinese unlocked a major new oil province? This is clearly something that we need to keep a close eye on. And I'm sure that all the international majors do too. Especially when you realise that the largest discovery of 2025 was made in Iraq, in the East Baghdad field – a supposedly 2 Bbbl find – also made by Zhenhua Oil.

All this is worth mentioning because it seems to be the Chinese who prove the volumes that the Western IOCs are craving for. And where one can argue that the East Baghdad find is very near-field, the Qurnain discovery is surely in a new play, at least for Iraq. The Chinese have therefore shown that more frontier exploration is also part of their playbook. That then begs the question: when do we see the IOC's make discoveries of the same nature again?

IS THE WORLD ON THE CUSP OF AN EXPLORATION REVIVAL?

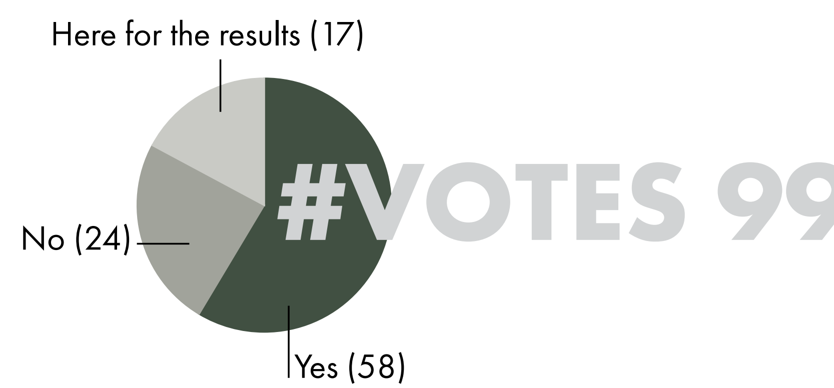
Let's dive into this question a little more. First, we asked our followers via a LinkedIn poll. As can be seen in the graphic here, most of those who cast a vote do indeed believe that something is happening in the exploration space. As ever, there is a good number of folk who are just keen to see the statistics without revealing what they think. However, the poll still serves its purpose.



The recent discovery in the al-Qurnain block in Western Iraq could be a game-changer in multiple ways. First, it shows that this part of the country is highly prospective. Second, it demonstrates that the Chinese are on to something that many Western IOC's are currently trying to do as well: Finding oil. Last year, Zhenhua chalked up the biggest discovery of the year, and in 2026, they may do the same if the 8 billion barrel find in the western part of Iraq is indeed true.

PHOTOGRAPHY PREVIOUS PAGE: NASA

Do you think the world is on the cusp of an oil and gas exploration revival?



I also asked a number of people from different parts of the world this question personally, in an attempt to gain a more nuanced understanding of what is happening in frontier exploration.

Simon Molyneux, who runs an E&P consultancy company in Perth, Australia, writes: "We've seen signs over the last 12 months or more that exploration is returning. We feel the driving force behind this is a realisation amongst corporates and private capital that new sources of oil and gas are needed over the long term to meet societies' growth in energy demand and replace declining legacy sources of oil and gas."

Graeme Bagley from Westwood Global Energy in London adds that over the last five years globally the industry has only found ~11 % of what has been produced by conventional high impact exploration, whilst demand for hydrocarbons continues to grow – currently. Whilst several of the large IOCs have only found less than 25 % of what they have produced.

From Houston, Luis Carlos Carvajal Arenas writes: "I have had the chance to be involved with global exploration for six years now, and I can say that I see an upturn in exploration at multiple levels. The world changed after COVID by accelerating the Energy Transition. Many companies decided to defund traditional energy and move towards New Energy projects. However, many energy transition pioneers are now stepping back because they faced the crude reality; many of the new energy projects delivered low ROIs or the projects were negative."

But apart from the observation that there is a desire to ramp up exploration activity, are there concrete examples of this really happening?

Graeme does not fully align with the narrative. "Whilst there is a lot of talk of an exploration revival, it has not translated into more spending or more wells being drilled. What we are seeing currently is more like a land-grab," he says. "Lots of new licences are being taken up, but generally at low commitment levels." Luis Carlos agrees with that. The new frontier licences picked up are what is called "technical evaluation agreements" or "recognition agreements", which can be shifted into exploration agreements if the company finds something encouraging to test," he writes.

Andrew Latham from Wood Mackenzie describes it in this way: "There's a lot more noise around exploration, but it's not yet much more than that. The majors and other big explorers are several years into a high-impact acreage reload, but much of this new acreage represents relatively low-cost options, with minimal signature bonuses and few firm drilling commitments. Most has yet to be drilled and is still held with high operator working interests that may need to be farmed down first. That said, we are seeing a bit of a trend of more big exploration wells being drilled at 100 % equity or something close."

The lack of genuine commitment to wells is also reflected in the number of high-impact exploration wells drilled. 2025 saw the fewest high-impact wells completed since 2015, with no clear upturn in sight. "Maybe we will see that in two or three years," Graeme says.

Simon adds: "There is no wild exploration spirit yet. Exploration spend is still very small compared to the heady times of the late 2000's and early 2010's. Opportunities have to be compellingly large and de-risked, with substantial acreage positions that can be executed at scale and pace, ideally with follow-up. But much of the world is not like Guyana. Available positions are fragmented, permitting is challenging and modern data is not readily available. Innovative players will navigate around these challenges."

> "There's a lot more noise around exploration, but it's not yet much more than that"
> – Andrew Latham

Graeme still sees companies prioritising on shareholder returns and debt reduction over investment in exploration, resulting in capital discipline that does not necessarily align with a more bullish exploration strategy. The opportunities for exploration success at scale are becoming more limited, and companies are also looking to develop discoveries that have sat on the shelf for a long time," he says. bp's Tiber and Kaskida developments in the Gulf of Mexico are good examples of this.

Joe Versfelt from Houston, says that many small to medium-sized ▸

American companies have significant debt to service versus cash flow and shareholder dividend expectations to meet. "I think ILX will still dominate, combined with a robust portfolio optimisation – especially in the Lower 48 US unconventional space."

Another example of ways to ramp up production for which no exploration drilling is required is the decision by ConocoPhillips and partners to reopen three formerly abandoned gas fields in the Ekofisk area in the Norwegian Southern North Sea, as demand for gas in Germany and the UK remains strong. Luis Carlos adds that Egypt is also focusing on ILX projects in the Nile Basin as the Egyptian market requires new reserves for internal consumption quickly.

"Winners from a resurgence in exploration will move with pace and scale, looking to fail fast, manage optionality and invest to maximise returns on success" – Simon Molyneux

In other words, based on these conversations, there is surely a first movement into the exploration space, but there is equally a cautious approach without too many commitments.

RIG MARKET

The rig market is also a good indicator of the state of play in the exploration domain, and how this market has consolidated just as much as the operator landscape. An informative post on LinkedIn from Dan Fortser makes a few good points. "The offshore drilling sector consolidated more in 18 months than it did in the previous decade," he wrote.

Transocean is acquiring Valaris, Noble has absorbed Diamond Offshore, and ADES has aquired Shelf Drilling. "This leads to a situation where the top three floater contractors now control roughly half the global fleet, and all these deals were struck when oil was $60 – 70."

With oil being back above $100 with no near-term end in sight, Dan sees a rig market that is getting "very hot". At the same time, he describes cost-cutting targets across these mergers mean headcount cuts to shore-based teams who manage procurement, maintenance programmes, and vendor qualification. "When the operational surge hits, and it will, the people who support them won't be there."

"It's not just a supply problem anymore," he concludes. "It's a concentration problem. Fewer entities control the assets, the workforce, and the pace of reactivation. The bottleneck isn't just rigs and people anymore. It's who owns the rigs and employs the people."

THE SORRY STATE OF THE SERVICE SECTOR SUPPORTING THE EXPLORATION BUSINESS

Due to the lack of drilling activity, especially in drilling exploration wells, I see a lot of people who are very skilled but are waiting for the job market to pick up again. Likewise, there are companies that are just hanging in there, with some people indicating that it won't be long until they falter. I met someone just the other day, representing a small outfit that helps operators drill their wells safely. The geologist attended a conference for the first time in his life, clearly because so far, there had never been a need to do so; the work came to them through their network. Now that the direct route seems to have dried up, he decided to venture to the conference arena. Another indication that the entire service sector in this space is contracting is the decline number of exhibitors at conferences. Over the past few years, this downward trend has become increasingly apparent.

WHO'S INVESTING IN PROJECTS THAT ONLY START GENERATING CASH IN 20 YEARS?

One reason why the industry may be slow or indecisive when it comes to drilling frontier wells is the prospect of a long lead time between discovery and first oil. Earlier this year, I was in Houston before the conference I was attending kicked off. An ideal moment to meet with some industry veterans. I met one of them for a beer to catch up on what he saw happening in the exploration realm. One of the main points he made was that the industry is no longer interested in projects that have a twenty-year gap between identifying a prospect and the start of production. "My father had to process a couple of 2D lines for Conoco in the 1980s," he said, "and it turned out to contain a whopping prospect." But it took a sale to another operator and more than twenty years before the first oil was achieved. "The industry can't do anything with lead times like that."

This is something I have heard before. In light of the discussion about peak oil as well as pressure to move away from hydrocarbons, it is not a surprise that in boardroom conversations, there is less of an appetite to move into projects that have decades-long timelines.

That's also why the discussion around speeding up the time from discovery to first oil is an ongoing conversation. In Norway, where lead times are still very high, state-player Equinor is becoming more serious about cutting down the time it takes to move from stage gate to stage gate.

But whatever an operator does to minimise delays, increasing red tape can still put the brakes on projects. I spoke to an American onshore wildcatter who said that due to all sorts of legislation and regulation, it takes significantly longer these days to get the bit in the ground onshore in the USA. In other words, companies can talk about how they will accelerate developments, but we also need changes on the regulatory side to reduce time to first oil. That is the other side of the coin.

WESTERN COUNTRIES HAVE BECOME MORE UNRELIABLE

An important aspect that has changed the overall global exploration outlook is how Western countries have positioned themselves towards continued drilling activities. Where in the 1970s, majors moved into the North Sea to find a very attractive basin with major potential, this cycle has started to come to an end. That's not only because of the maturity of the basin; it is also because many Western nations have shown themselves to be critical of continued oil and gas exploration. Denmark, Spain, New Zealand and the UK have all been vocal about either banning exploration altogether, or putting on the regulatory brakes.

The recent news about bp now openly contemplating a UK North Sea exit is surely partly driven by the lack of government support.

This does is to create less clarity for companies to invest, as we see in the UK sector, where Apache may be the best example of the response in corporate decisions to these measures. They stopped drilling development wells on the Forties and Beryl assets overnight when the government imposed a tax hike, and is now in the process of decommissioning these major North Sea fields.

Meanwhile, New Zealand has already returned to welcoming explorers again following a ban imposed by the previous government, but even though the energy agency has already received two new applications on the back of the reopening, the question everybody asks is how long this welcoming regime will last, given that there will be a round of elections at sometime in the near future.

Political uncertainty remains the big ticket item that many Western countries don't have a solid response to, because it will always go against the foundations of what these democracies stand on. Even in Norway, which is a country many see as a symbol of stability in regard to continued support for oil and gas exploration across party lines, an exploration manager I interviewed a while ago admitted that state player Equinor put the brakes on drilling for a few years on the back of more scrutiny from parliament. Even Norway is not immune.

In conclusion, many western countries — most notably the UK North Sea — have reached a mature stage of exploration, leaving limited scope for further investment. Political shifts and associated policies towards E&P companies have further curtailed the scope for continued exploration spend.

PUTTING THE MONEY WHERE YOUR MOUTH IS

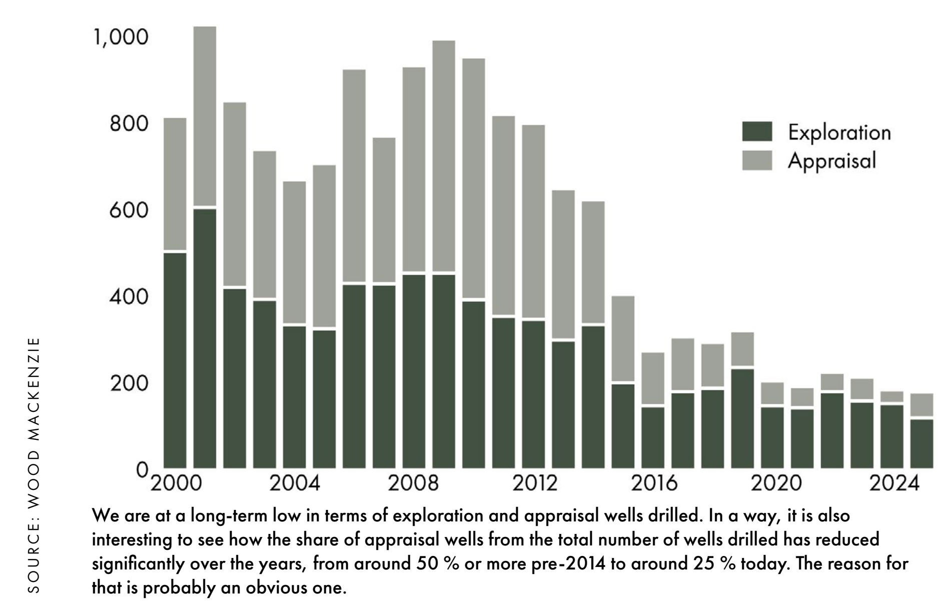
At times of unlimited access to short and bite-sized news and post feeds, it is easy to be convinced of the arrival of a new wave of exploration drilling. And whilst there is indeed a real increase in acreage uptake, and countries opening up (again), it is still early days to conclude that we have entered a new phase of increased activity. The limited commitments that come with the award of new licences are a testament to that, and there is no indication that we are on the verge of a hiring spree.

These observations show that even when we are at the start of a new exploration cycle, the overall setting has changed. Western countries, especially the European ones, have shown themselves to be unreliable when it comes to political support for oil and gas exploration, whilst their own resources are depleting.

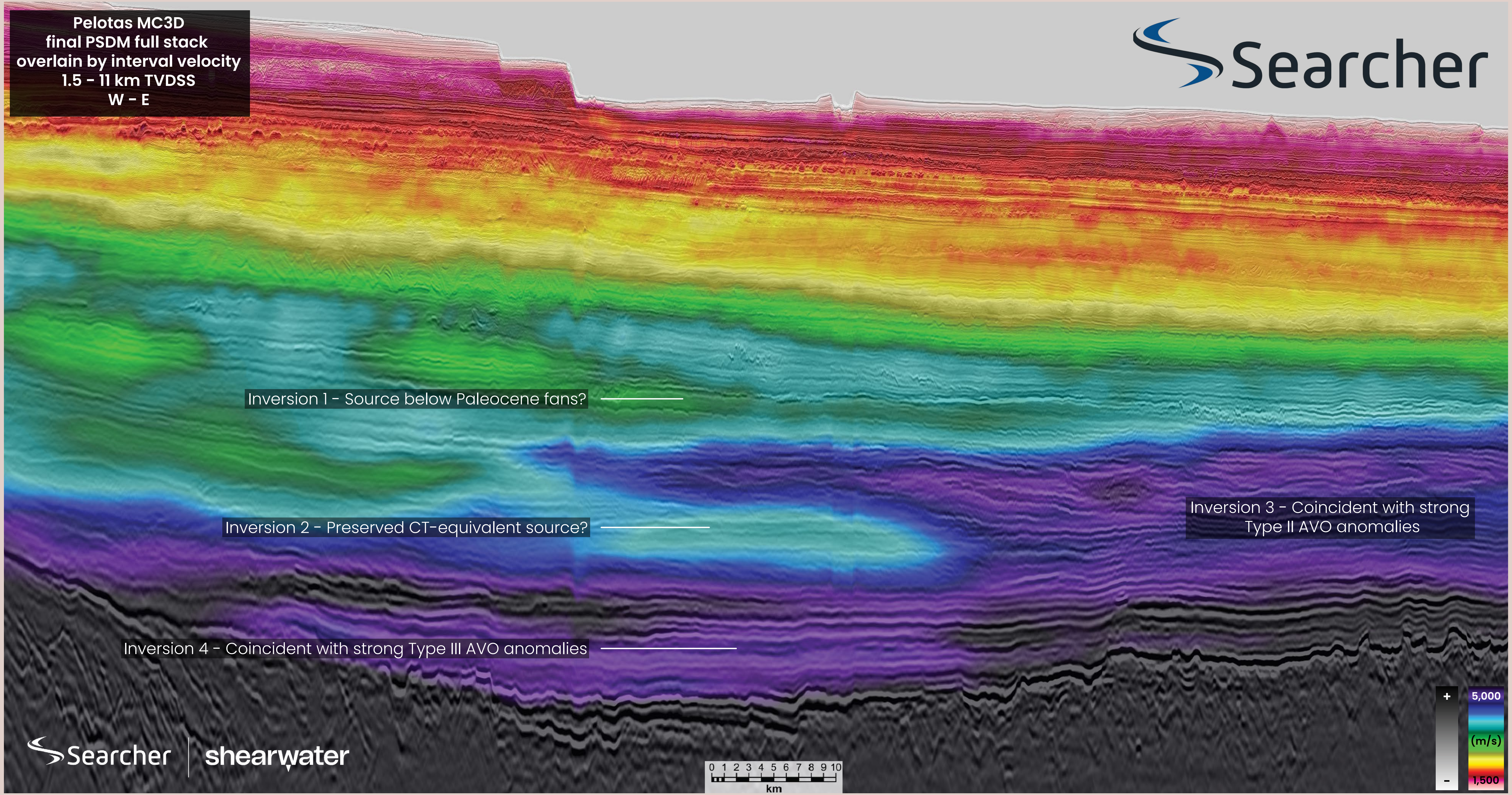
Meanwhile, China seems to be more successful in finding oil. Quietly picking up acreage in Iraq, it has not only discovered the largest oil field last year; if the recently announced find in their Qarnain licence in Western Iraq is indeed true, they have a good chance of yet again claiming the price in 2026.

We are now waiting for the IOC's to make discoveries they badly need to bump up their reserve replacement ratio. And that doesn't come with picking up licences alone. ■

Numbers of wells completed (count)

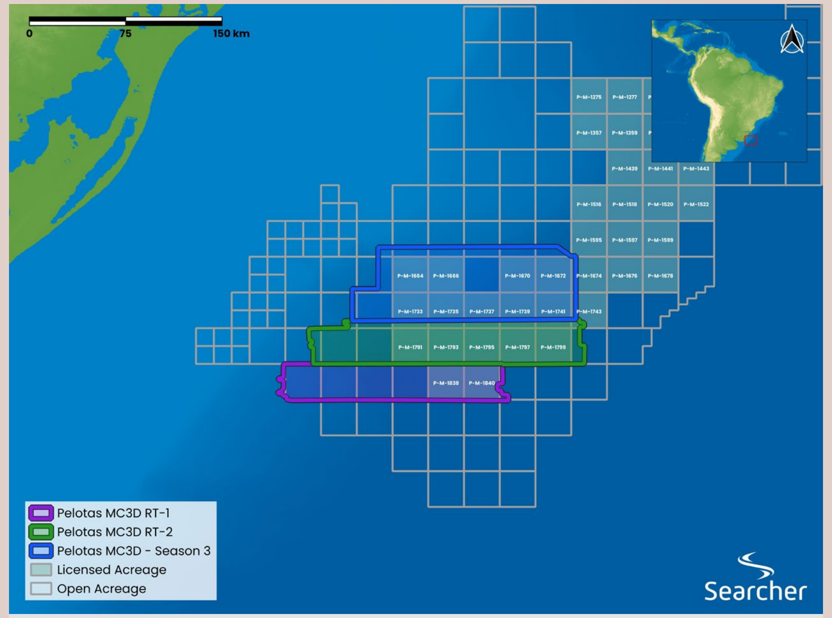


We are at a long-term low in terms of exploration and appraisal wells drilled. In a way, it is also interesting to see how the share of appraisal wells from the total number of wells drilled has reduced significantly over the years, from around 50 % or more pre-2014 to around 25 % today. The reason for that is probably an obvious one.



A Cenomanian-Turonian source rock adventure in the Pelotas Basin

After the Aptian source lying on top of the early-drift oceanic crust, the second most important source rock in the South Atlantic is the Cenomanian-Turonian (CT) sequence, a pelagic organic-rich mud ubiquitously deposited in a global anoxic event. Seismic velocity inversion of 3D seismic data in the Pelotas Basin reveals a nuance to the CT-driven play, interpreted to be partly reworked by contourites. The hunt for tools to chase this phenomenon is on...



Searcher and Shearwater's 16,500 km^2 3D in the Pelotas Basin, southern Brazil.

Hunting for Cenomanian-Turonian source rocks in the South Atlantic

KARYNA RODRIGUEZ, NEIL HODGSON AND LAUREN FOUND, SEARCHER

Like pieces of a jigsaw puzzle, key risk elements to any play (source, reservoir and trap) need to be located and joined together. On seismic, some source rocks stand out, impossible to ignore and in the South Atlantic, the omnipresent Cenomanian-Turonian (CT) interval deposited during a global anoxic event – Oceanic Anoxic Event (OAE2) belongs firmly in this category, at least, most of the time.

Globally, the CT OAE2 has generated world-class marine source rocks; from Venezuela's La Luna Formation to the organic-rich Canje Formation offshore Guyana, this interval has powered some of the most prolific petroleum systems on the planet. Across the South Atlantic, evidence of CT source rocks is widespread: From the MSGBC Basin to Brazil's Pelotas Basin, and into the conjugate Walvis and Orange Basins, where TOCs can reach double digits. Although the CT interval has often been dismissed as not being buried deeply enough to be mature for hydrocarbon generation, when present, it still tends to announce itself with a signature seismic swagger – a strong low-frequency amplitude event, dimming at far angles, the unmistakable fingerprint of an AVO Type IV anomaly. Thick, organic-rich, and often hydrocarbon-charged, these intervals light up seismic sections and sweetness attributes that boost high amplitude, and low frequency amplifying this signal.

So naturally, when the first 3D seismic dataset arrived in the Pelotas Basin, the expectation was clear: Use the seismic to define the source rock distribution in the basin.

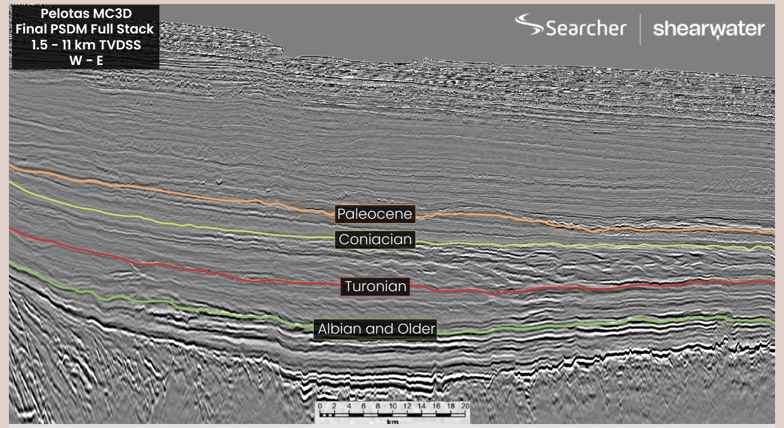


Figure 1: 3D PSDM seismic section showing the top of the CT sequence (red horizon) at the base of the reworked Coniacian channel sequence (light green horizon).

Whilst this worked perfectly for the Early Cretaceous Aptian Source Rock (as it had in the conjugate margin associated with the of Venus in Namibia), the Late Cretaceous CT interval was not playing ball and displayed a very different set of characters.

SOURCE HUNTING WITH 3D SEISMIC IN THE PELOTAS BASIN

Searcher's and partner Shearwater's newly acquired 3D seismic (2023-2026) revealed a well-defined Aptian source rock package emerging clearly from the data, correlating confidently with the proven system in the Orange Basin across the Atlantic. So far, so good, demonstrating this basin is incredibly prospective.

When the top of the CT sequence was tied using calibration from wells on the shelf, a distinct sequence boundary appears beneath a Coniacian channel system (Figure 1). This channel complex, heavily reworked by contourite currents, forms a striking geomorphological feature in the central portion of the seismic line in Figure 1. Up-section, in the CT sequence, the contourite bedforms pass into more parallel, lower-amplitude reflections. And yet the expected Cenomanian-Turonian AVO Type IV source rock indicator anomaly? Well, this is nowhere to be seen.

WHEN THE SIGNAL GOES MISSING

One explanation for the missing seismic signature lies in the contourite system itself. Persistent bottom currents may have reworked the CT interval so extensively that only fragmented remnants remain – thin, discontinuous slivers of what was once a regionally extensive source rock. RMS amplitude maps within this sequence reinforce this interpretation. The dominance of contourite bedforms, coupled with subdued amplitudes, suggests lower-energy currents reworking fine-grained sediments (Figure 2). In such an environment, the original seismic expression of a thick, organic-rich interval could easily be erased – or at least obscured.

CT SOURCE ROCK SEISMIC BUSTER

A less celebrated – but equally powerful – diagnostic of generative source can be fluid pressure disequilibrium revealed from seismic velocity inversions (decrease in velocity with increasing depth). Within the parallel seismic package overlying the contourite bedforms, a clear velocity inversion emerges. Subtle at first glance, but persistent and regionally coherent (Foldout Figure).

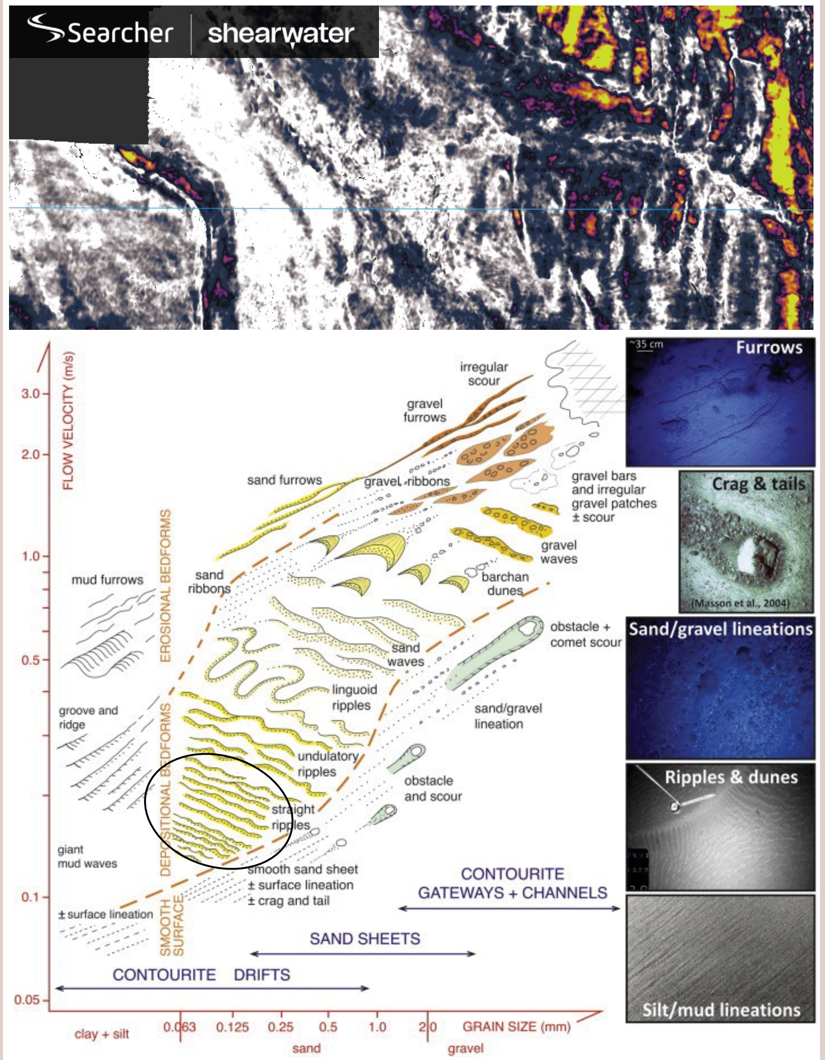
This is no ordinary anomaly. Organic-rich source rocks are known to exhibit reduced P-wave velocities. High kerogen content lowers density, softens the rock frame, and reduces elastic stiffness. As maturity increases, kerogen transforms into hydrocarbons – fluids that are more compressible than water – further decreasing velocity. Add overpressure into the mix – common in under-compacted, fine-grained systems and velocities drop even more dramatically. Elevated pore pressure weakens grain contacts, reducing stiffness and amplifying the velocity anomaly. In short, low velocity can mean high potential.

The observed inversion in the Pelotas Basin can be related to:

- organic richness (high TOC);
- hydrocarbon generation;
- overpressure;
- elevated porosity relative to depth.

Furthermore, this interval correlates with a proven Turonian source rock in well 2-BPS-0006A, where TOCs reach up to 4 %. And in addition, a thermal maturity model, constrained by a BSR-derived geothermal gradient, places the interval firmly within the oil window – approximately 100 to 115° C.

Given the highly favourable current location of the inferred CT source rock, generated fluids can move both vertically and laterally into adjacent clastic reservoirs, so the mapped AVO Type II and III anomalies outboard and laterally connected to the CT source suddenly take on new significance (Foldout Figure).



SOURCE: HERNANDEZ-MOLINA ET. AL. 2011

Figure 2: Top of figure is RMS amplitude map of the Top Turonian event. Bedforms revealed on that can be found on "current velocity vs grain size" for contourites.

THE VELOCITY OF ADAPTATION: RETHINKING SOURCE ROCK DETECTION

For years, seismic source rock characterization has leaned heavily on the identification of AVO Type IV anomalies. When present, they are powerful indicators – clear, confident, and easy to map. The Aptian system in the Pelotas Basin fits this model perfectly.

But the CT interval in the Pelotas Basin tells a different story. Here, the absence of a classic seismic response nearly led to a missed opportunity. It took a shift in perspective – from amplitude to velocity – to reveal what had been hiding in plain sight.

Not all source rocks shout – some whisper through velocity fields, subtle inversions, and secondary attributes. They require a different kind of listening.

FINAL CALL

So, is the CT source rock working in the Pelotas Basin of the southern South Atlantic?

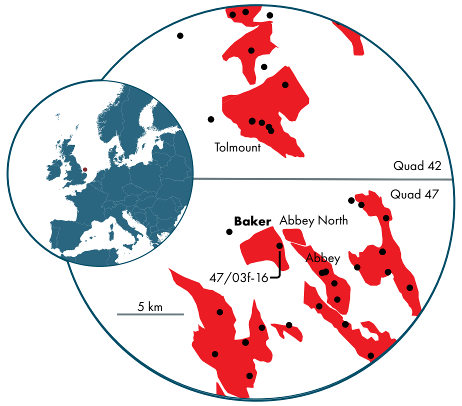
The evidence is mounting. If confirmed by future drilling, it could reshape our understanding of the region's petroleum systems – bringing it closer in line with the prolific basins further north. Because sometimes, when the amplitudes go quiet and the character you are looking for disappears, you don't abandon the hunt; you just pick up another tool.

OIL & GAS

"Deepwater production can offer some of the lowest-carbon barrels in an operator's portfolio; however, commercial viability remains a challenge"

Gordon Hardie – Welligence Energy Analytics

The increasing importance of DHI's in the Rotliegend play of the Southern North Sea



Better seismic data and more subtle targets have created an environment in which the presence of DHI's should be investigated even when they did not play a role in exploration in the past, and even when they are not always there

That's exactly what the team at Petrogas did before they successfully drilled the Baker exploration well (47/03f-16) in the UK Southern North Sea. And Baker had what looked like a Direct Hydrocarbon Indicator: A bright spot conformable to the interpreted trap, matching the Gas Water Contact, and also in agreement with synthetic data.

Still, there was some scepticism. Why did Baker have a DHI, but the nearby Abbey Field did not? And neither did the Tolmount gas field, just a stone's throw away. Following a closer look at the geology of the wider area, the team came up with an explanation as to why some prospects have a DHI, and some don't.

The key is in the overburden, and the reservoir characteristics themselves. The Baker reservoir is characterised by a very good quality reservoir, with up to 22 % porosity, permeabilities of 0,5 Darcy and a high net to gross of 91 %. In addition, Baker's overburden is quite benign; no major faults, nor strong thickness variations or dolomite rafts in the overlying Zechstein sequence.

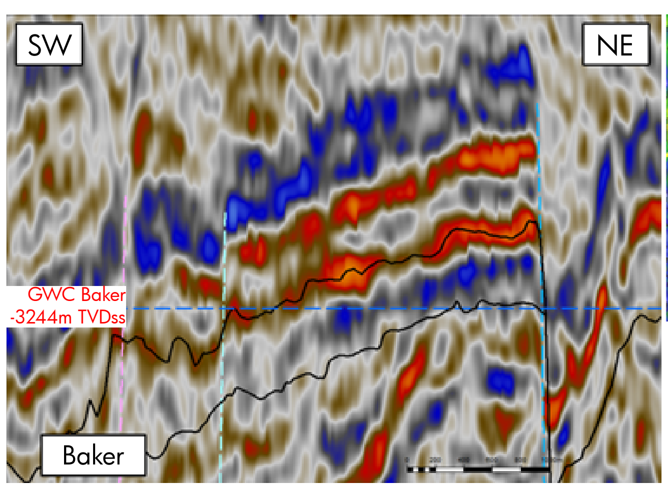
In contrast, the Tolmount gas field has a much more complex overburden, including a series of major faults in the Jurassic interval, in addition to more lithological variation in the Zechstein succession, including a series of dolomite rafts. Additionally, the reservoir at Tolmount is not fully resolved, with a thick intermediate shale layer that complicates the geophysical interfaces. These three elements have been proposed as causing too much of a downgrade in seismic signal for a DHI to be preserved.

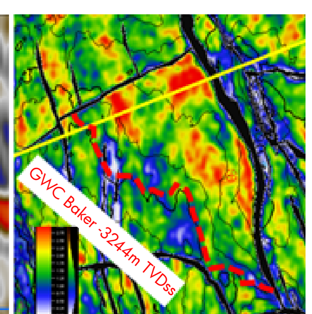
Abbey is another case. Here, the reservoir quality is of a tight nature, with significant illite in the pore throats, bracing and stiffening the framework. This means the impedance contrast with the overlying Silverpit shale seal is insufficient to cause a DHI.

These outcomes once more prove that seismic data are non-unique, and that the overburden geology and specific reservoir and geophysical nuances of each field need to be taken into account when hunting for a DHI. But the general rule of thumb that DHI's don't exist in the Rotliegend of the Southern North Sea should be retired. Instead, if the conditions are right, it can be of great help in de-risking remaining targets.

So, what does this mean for the future? Around the Baker discovery, there is a broad "sweet spot" where seismic quality and reservoir porosity are sufficient to display DHI's. This materially increases confidence in additional prospects in the area, including opportunities with considerable upside where fault seal appears effective, supported by DHI's that extend beyond the mapped three-way dip closures. ■

Henk Kombrink





SW-NE dip line across the Baker field (left). Max Amplitude extraction at Top Leman (Main Rotliegend reservoir).

SOURCE: PETROGAS

The Sinapa saga

The battle to escape the salt diapir

NEIL HODGSON

As with any exploration story, this story begins with a map that hides a secret. Salt, tall as a mountain, buried clear white veils of fluid rock, and a target that dares to wrap itself against its throat. We are in Guinea-Bissau, and it is the year 2004. A rig hums, hoses hiss, and the team faces a wall that isn't on the map. The Sinapa-1 well aims to drill down the slender side of the diapir, as it was mapped using 2D seismic and fancy PSTM processing. In the pre-drill scenario, the well would be a straight shot to the Albian sand reservoir. But the salt had plans of its own.

As soon as the well was at the depth where the diapir crest was expected, the story tightened. Rather than continuing into the sediments in which the diapir intruded, the bit slams into the very salt. So shallow, is this a wing? A canopy?

Stubbornly, the team carries on, but the salt doesn't go away. We circle the wagons, eyes bright with resolve, proposing a sidetrack to escape the diapir. Mud motors steer away, pressing on towards the diapir edge. But the edge is nowhere to be found. The seismic is just laughing at us.

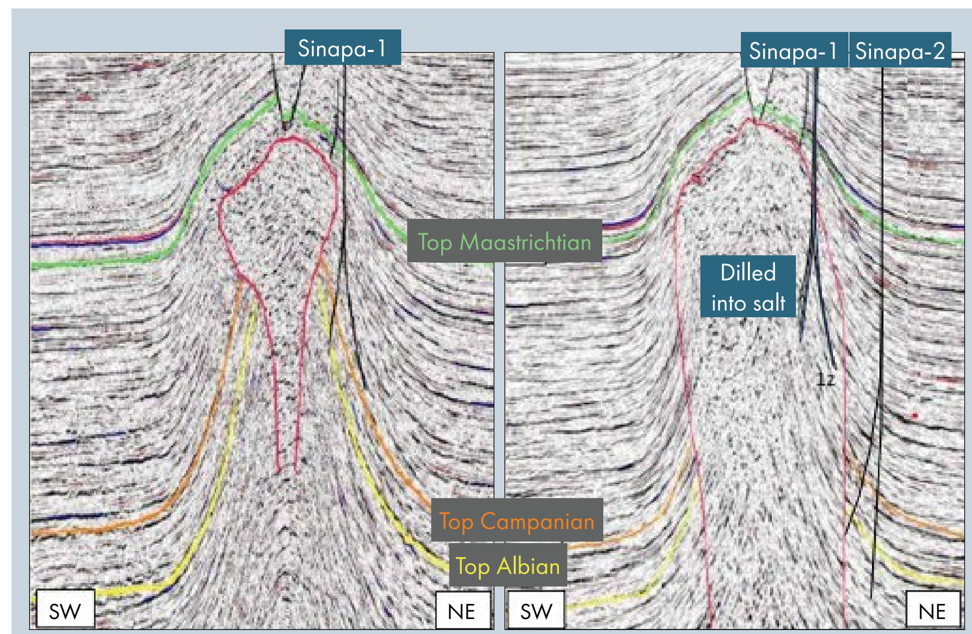
On toward the promised sands, and using mudmotor after mudmotor, we finally drill from salt into a mudstone. But it is not the type of mudstone we expected. These are Triassic red beds, huge blocks of sub-halofer strata sucked off the floor of the diapir and plastered up the diapir flank. And then, as the last mud motor goes in, we go back into salt. Then, mud motor sputters and fails. It's the end of the sidetrack.

A little later, the PSDM 3D seismic arrives like a new compass that sings with possibility. The map is rewritten, the edges of the salt move out and the diapir's boundary is sketched with new bravado. The team dares to redraw the epic and plans a second well with a safer margin.

Sinapa-2 enters the saga with the wind of renewal in its sails. This time, the crew refuses to flirt with the salt wall and starts way further out, only deviating towards the salt once the well is deeper down. But the gods of exploration are chuckling at this new plan. Albian sands come in and are full of black oil. Yet, they are tight.

However, a slightly deeper sand does demonstrate the presence of hundreds of meters of clean and good quality sand, albeit in the water leg. So what else to do than to pull back and sidetrack further up, to catch the good sands in the oil leg? But again, no luck, as we drill the same sequence again.

The story will no doubt continue. On the opposite side of the diapir, the reservoir is now mapped further up structure – one day the adventure will be taken on again, and perhaps there will be a good result from the epic battle to escape the diapir. When reconstructing the well paths, we were so close with the first well. Perhaps 100 m laterally from the TD of Sinapa-2 sidetrack. So near but so far. ■



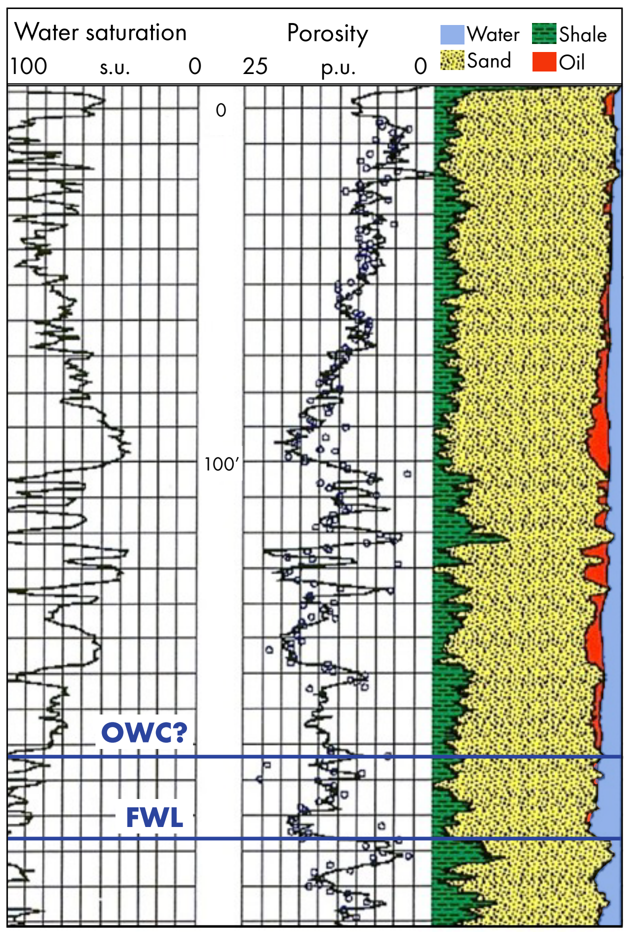
Left: Pre-drill seismic interpretation of the salt diapir and associated strata. Note that the well trajectory was planned not to hit the salt. The Sinapa-1 sidetrack subsequently attempted to get out of the salt, without luck. The post-drill seismic interpretation is shown on the right, with the Sinapa-2 well taking a safe distance from the salt. The subsequent sidetrack to the left is getting close to the edge of the diapir again.

SOURCE: NVENTURES

Oil-water contacts don't exist

The oil industry prides itself on being data-driven, yet one of its most widely used concepts, the oil-water contact, cannot be numerically quantified. Aberdeen-based petrophysicist Steve Cuddy argues that the industry should favour the only measurable contact, the free water level

Steve's argument goes back to a challenge set by the London Petrophysical Society. They invited petrophysicists to derive a function describing how water saturation varies with depth. Most responses followed the traditional route, searching for increasingly complex saturation vs. height relationships. Steve took a different approach; he focused on bulk volume of water (BVW), a quantity tied directly to measurement. His solution matched the data, and he therefore won the competition.



The log from the LPS challenge. It demonstrates how the interpretation of water saturation places the OWC higher than the pressure-derived FWL. The OWC is placed at the depth where water saturation shifts to roughly 100%. However, between the OWC and FWL the formation is tight and neither mobile oil nor water are present. The FWL is the true depth where the mobile fluid phase shifts from oil to water, which is determined by taking pressure points and deriving pressure gradients.

Logging tools and core analysis measure volumes; they quantify pore space and how much of that space contains water. Water saturation is calculated afterwards by dividing water volume by porosity. It is a ratio of two measurements, a percentage of a percentage, and therefore an interpretation rather than a direct observation, according to Steve. Resistivity tools respond primarily to the amount and connectivity of conductive water, they effectively indicate BVW rather than saturation.

Steve's theory centres on the free water level (FWL), the depth at which the oil and water pressure gradients intersect. It is a physically meaningful boundary, corresponding to zero capillary pressure, identifiable from pressure data, and often visible as a flattening of resistivity in the water leg. Above this level, oil is the mobile phase while water is held in the rock by capillary forces. The amount of water decreases continuously with height as buoyancy pressure increases.

The oil-water contact (OWC) is often defined as the depth at which oil first visibly enters the pore system. It is an interpretation of the log data, not defined by pressure data. Intervals above the contact can still show 100 % water saturation if the rock is too tight to hold any oil. Nothing physically happens at the depth of the OWC; it is better described as an "oil down to" depth, an interpretation rather than a measurable feature. If fluids are allowed to equilibrate in an open hole, oil sits on water at the FWL, not at the OWC.

From this perspective, reservoir modelling becomes much simpler. Instead of relying on the false concepts of transition zones or irreducible water, fluid distribution can be described using BVW as a function of height above the FWL. Once that relationship is defined, BVW can be estimated throughout the reservoir, and oil in place follows directly as porosity minus BVW.

Steve's idea is controversial because it challenges long-standing industry practice. But the question it raises is straightforward: Should reservoir models be built on evidence, or on what has long been assumed? ■

Mariël Reitsma

Deepwater's playbook for delivering growth

There are various ways to achieve the long-term attractiveness of deepwater projects

GORDON HARDIE, WELLIGENCE ENERGY ANALYTICS

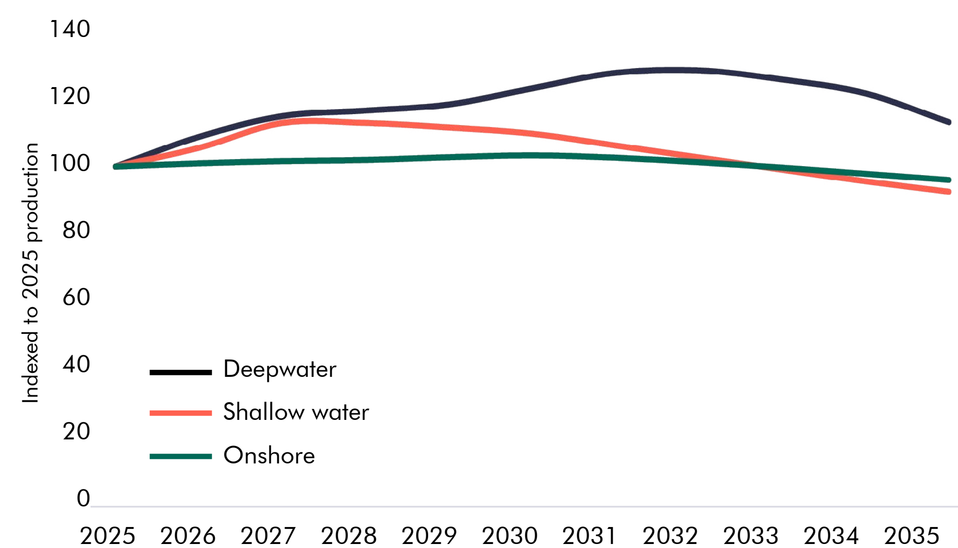
Deepwater production remains a core part of the long-term energy supply mix. While production from conventional onshore and shallow-water assets is expected to remain broadly flat under our base case, Welligence estimates that global deepwater oil production will grow from its current level of around 8 MMbbl/d to close to 10 MMbbl/d by the early 2030s.

However, post-2035, deepwater production is set to enter decline unless the hopper of pre-FID deepwater projects is replenished in the medium to long-term. But achieving this medium-term deepwater growth trajectory will require a tangible step up in investment. With IOCs maintaining a strong focus on capital discipline and applying strict criteria to new investment, only the most resilient and commercially attractive deepwater projects are progressing to FID.

As IOCs look to both existing and frontier opportunities, new developments are being assessed through a carbon lens as part of project screening, with emission reductions built in, not just bolted on. However, while deepwater production can offer some of the lowest-carbon barrels in an operator's portfolio, commercial viability remains a challenge.

With FPSO topside costs estimated at between $50,000 and $60,000 per tonne, the incremental capital required can be in the hundreds of millions of dollars. One emerging technology that could ultimately reduce the operational footprint on FPSO topsides involves moving processing equipment subsea. This solution could lead to an overall reduction in emissions while also cutting the topside weight requirement for the FPSO. But the potential costs and system reliability will be critical to adoption.

There is, however, a growing comfort with new technology, especially digitisation and artificial intelligence (AI), where adoption of technologies like digital twins can be leveraged for real-time monitoring to enable early risk identification. With predictive analytics, operators can pre-emptively intervene rather than reactively fix. This new approach reduces process downtime by up to 30 % in some deployments. AI can also streamline and eliminate waste. Logistics, spares management, optimised maintenance and inspection routines, and reduced specialist interventions can significantly reduce opex. Savings of between 10 and 20 % have been projected. With early adoption by operators including bp and Shell in GoM, the industry will be watching closely.



SOURCE: WELLIGENCE ENERGY ANALYTICS

Indexed global production outlook by sector (2025 – 2035).

As companies push the deepwater envelope and projects become increasingly more challenging, designing systems for remote operations not only reduces safety risk but can materially reduce the cost of crewed interventions over field life. While high initial costs have muted early implementation, with continual improvement in data processing and AI, tangible savings are likely and with that, a new addition to the deepwater playbook. ■

The sediment waves of Sangomar

How two conversations in a short period of time provided insight into the importance of sediment waves for this West African oil field

I ALWAYS try to pen down the most important topics discussed during conversations. Because I know that when I don't, the information that was shared with me will soon be forgotten. Of course, when you actually force yourself to do it briefly after meeting someone, there's always the thought that it's unnecessary because you think you won't forget, but surely you do.

And so it happened that I wrote down a few snippets following a conversation with a geologist in February in London. She told me that the sediment waves in the Sangomar field were connected to each other, implying that since the start of production, the volume of oil in place has turned out to be higher than foreseen. At the time, beyond this being an interesting observation, I did not study it much further.

That is until I met with someone else in a completely different setting. It was someone who I had never met before, but soon after we got talking, I realised that he had worked on Sangomar as well. In this case, however, it was in a much earlier phase of the field development. It was at a time when the field had just been found, and appraisal or development wells were being drilled.

During that stage of development of the reservoir, which consists of Lower Cretaceous prodelta sands, the locations of the wells were planned in such a way that they targeted the ridges that were mapped at the top of the reservoir. In plain view, these ridges could be interpreted as sediment waves, caused by bottom currents reworking the sands deposited by turbidites.

ONE PUBLISHED RECORD

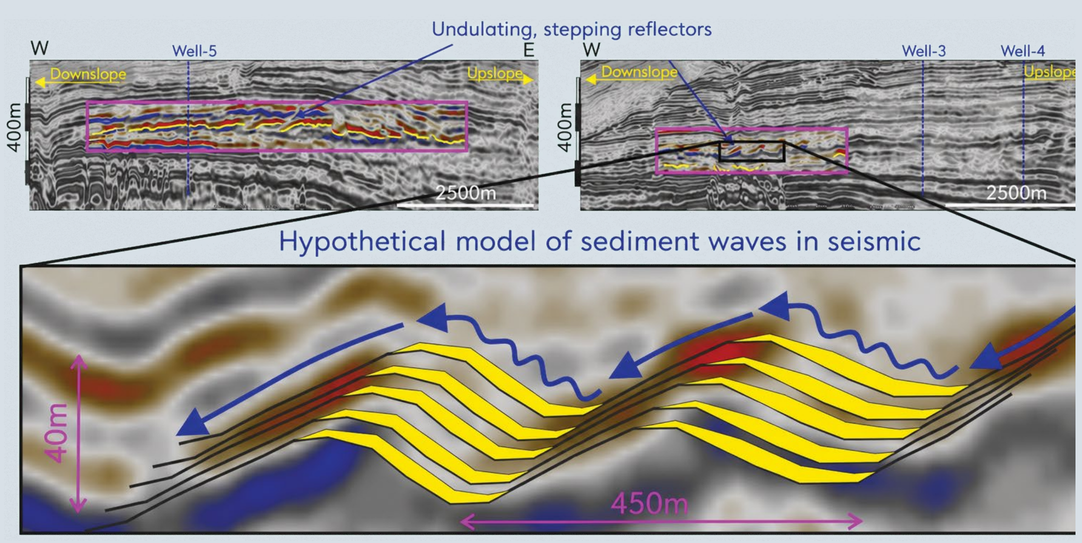
There is one published record of the sediment waves interpreted in the Sangomar field, and that is a poster available through ResearchGate, authored by Amanda Cunningham-Gray and colleagues. Published in 2018, it is interesting to see that Amanda writes that at the time, there were no published examples in the literature of deepwater sediment waves in petroleum reservoirs. Her work should therefore be seen as one of the first cases of the documentation of sediment waves constituting an oil reservoir.

Since then, hybrid systems where sediment waves or contourite deposits interact or modify turbidite deposits have been demonstrated in many areas, with the Rovuma Basin discoveries in Mozambique being a great example.

"The big question at the time," said the geologist, "was whether the crests of these sediment waves were connected, or whether the troughs were filled with much finer material such that the reservoir would be seriously compartmentalised."

That was the moment I remembered the conversation I had earlier this year in London. That was also the moment I could tell the person what had happened since he moved on from working on Sangomar; indeed the sediment waves had turned out to be connected. It was a very interesting turn in the conversation. ■

Henk Kombrink



How the sediment waves are expressed in seismic data across the Sangomar field.

SOURCE: CUNNINGHAM-GRAY (2018)

Seismic reflections – lithological boundaries or timelines?

Professor Heather Bedle explains why it can be both

This is the first in a series of articles dedicated to course content available on the SAGA Wisdom Platform

IN BASIC terms, acoustic impedance is a measure of how resistant a material is to sound waves passing through it. When that resistance changes across a lithological boundary, some of the seismic energy bounces back, creating a reflection. Because different rock types and sediments have different densities and velocities, it makes sense to assume that seismic reflections will highlight the boundaries between different rock types.

However, as this may be the case in some subsurface settings, for example, when we observe a mudstone draping a carbonate platform, it certainly does not always apply. As Professor Heather Bedle explains in her Seismic Fundamental Course that is available through the SAGA Wisdom Platform, "in deltaic settings we tend to see reflections that actually cross-cut large-scale lithological boundaries."

In most delta systems, as you move from the proximal to the distal domain, you often see a change from a relatively high net-to-gross ratio to a low net-to-gross ratio. You would expect seismic reflections to roughly follow this boundary, since the rock types on either side are quite different. These boundaries can be seen as more or less horizontal lines in Figure 1A.

However, the seismic reflections are basically cross-cutting these regional lithological boundaries, seemingly unaffected by this change in lithological composition (Figure 1B). How do we explain this?

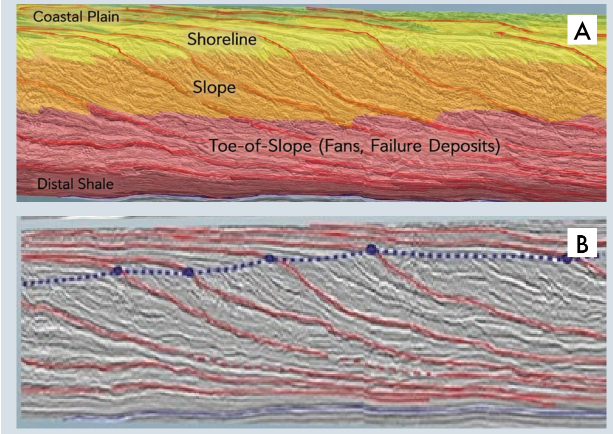


Figure 1A: Seismic reflections cross-cut facies and associated lithological boundaries. B: Red lines follow the most important reflections that clearly show the progradational character of the deltaic system.

"What we are in fact looking at in the seismic are timelines," says Heather. "One of the things we have to think about is that deposition of these sediments is happening over long periods of time, with periods of non-deposition in between. In turn, these periods of non-deposition allow for a degree of compaction. It is this compaction effect that forms the basis for the strong acoustic impedance response that can be seen across the entire seismic line."

"If we look carefully, we can still get some hints in our seismic data of changes in lithology," continues Heather during her course. "This is shown in Figure 2, where the amplitude of the reflection changes as you move from sand on sand (low), to shale on sand (high), to shale on shale (low). But even when it is the same lithology on top of the other, there is still an amplitude to be seen, due to the process described above."

So, always remember that in subsurface environments, a strong seismic reflection does not automatically mean you are looking at a boundary between two different rock types. You may instead be looking at a time surface... ■

Henk Kombrink

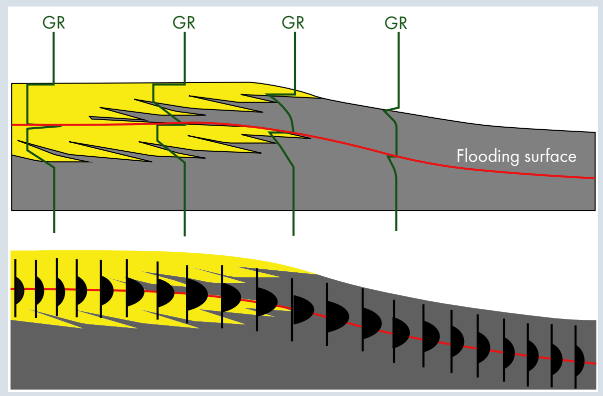


Figure 2: Even when a sand is overlain by a sand (left) or a shale is overlain by a shale (right), a seismic reflection can still be observed because of the density contrast that resulted from the time of non-deposition between the two intervals

SOURCE: FIGURE ADAPTED FROM HART (2011), AN INTRODUCTION TO SEISMIC INTERPRETATION, AAPG

The boon of Block 6

What could be the attraction of bp's recent award in the Egyptian Red Sea?

LET'S START with a quiz. What is the basin with the highest resource density in the world? The answer is the Gulf of Suez. Not many people will have guessed that. The Gulf of Suez is a small failed rift basin, yet with all the required elements for a world-class petroleum system.

The exploration success in the Gulf of Suez drove companies to project its riches into the Red Sea rift, with a notable exploration drilling campaign in the Egyptian Red Sea in the 1970s by Esso and Phillips. But, in sharp contrast to its smaller sister, the Red Sea has so far disappointed when it comes to juicy finds.

IT'S A SOURCE ROCK MATTER

Part of the answer to the question of why the Red Sea has so far disappointed lies in source rock presence. The rich source rock in the Gulf of Suez is a succession of transgressive Upper Cretaceous through Paleogene marine mudstones, associated with the post-rift succession of the Neo-Tethyan margin.

However, this source has so far been absent in well penetrations further south into the Red Sea due to a combination of the margin onlapping the Arabian promontory that pre-existed the Red Sea rift, and the fact that much of the Red Sea domain contains the Tortonian-aged evaporitic succession directly overlying a variety of basement rocks.

This is illustrated by the Quesir-B well, drilled by Phillips in 1977, which drilled over three kilometres of evaporites before calling TD in enigmatic "basement" rocks.

Yet, bp is going to have another stab at the offshore outboard region of the Egyptian Red Sea, as was announced in early April during the EGYPES Exhibition in Cairo. The company signed an agreement with GANOPE for the award of Block 6. This leads to the obvious question: What is bp looking for?

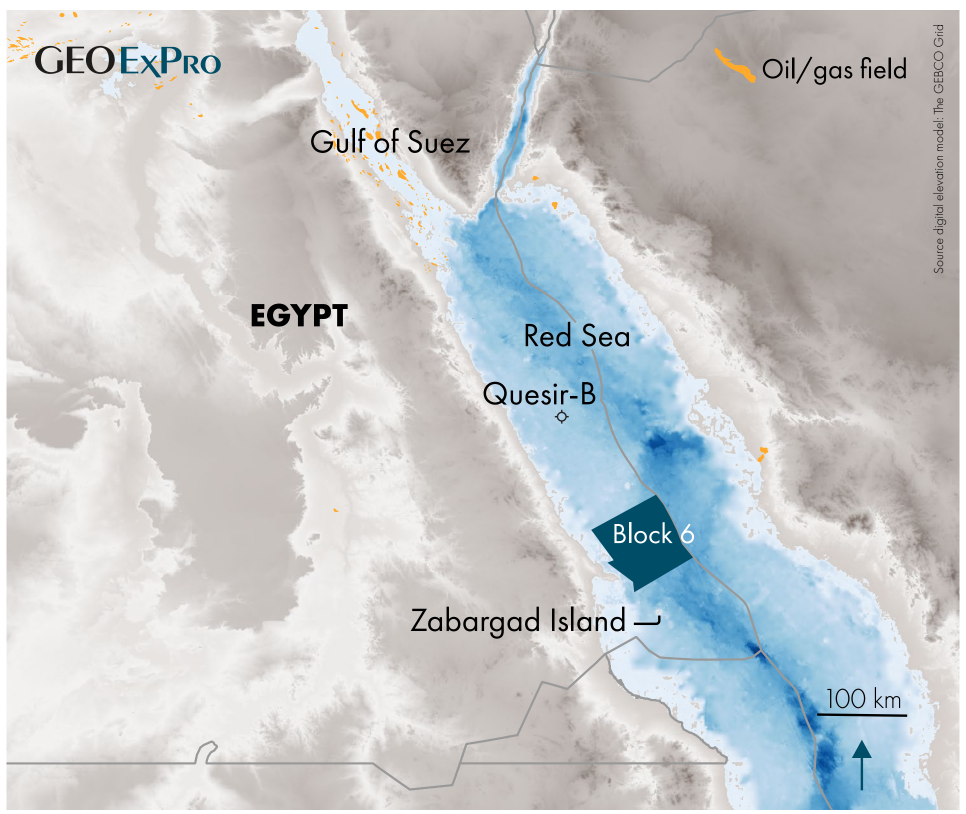
Block 6 holds a large base-of-salt structure. Given nearby well results, this could be yet another case of evaporites overlying a "basement" high. However, if the high represents a remnant continental crustal horst block, there could be tantalising pre-salt Miocene marine deposits present, including the possibility of Miocene shallow water carbonate build-ups. That might be a suitable reservoir candidate below a super-seal.

But the question remains: Where is the source rock, how do you mature it, and what is the maturation timing? This will be the main element for bp to attempt to de-risk before they decide to drill a well. Or perhaps it can only be derisked by drilling a well. ■

Rene Jonk and Henk Kombrink

UPLIFTED LITHOSPHERE

In the southern part of the Egyptian Red Sea, the Zabargad Island is interpreted to be an uplifted fragment of sub-Red Sea lithosphere, famously named "Topazos" in ancient Greek times for the presence of gemstones associated with peridotites.



The contrast between the presence of numerous fields in the Gulf of Suez and the scarcity of finds in the Red Sea is stark.

Why amplitude-supported prospects are not the silver bullet we are led to believe

And why this silver bullet doesn't work when it comes to the future of exploration in mature basins

"WHEN YOU don't see a scale bar at a seismic section that shows a nice bright spot, you should be scared", says Ian Longley from GIS-Pax in his recent video in which he shares his experience with amplitude-supported prospect mapping. "We have seen cases where the bright spot is only a kilometre across, but the fact that it is a bright spot too often makes up for the actual lack of prospective volume. Because people get overexcited when they see a Direct Hydrocarbon Indicator (DHI's)."

And that's for a reason, because some big discoveries have been made and continue to be made using DHI's, and they can significantly increase the probability of success. However, there is some nuance to be made, too.

"One of the reasons why people continue to be so excited about DHI's," says Ian, "is that the failures are not published. In turn, this means that calibration databases are commonly skewed to the successes. This leads the uninformed observer to think that amplitude-supported exploration is more successful than it is in reality."

Ian mentions three recent wells drilled in the Asia Pacific region that had amplitude support, but all failed for a variety of reasons. One of them had a bright channel feature that was an anomalous lithology, and another had a fit-to-structure that was probably a phase transition instead of hydrocarbons. In other words, it is very important to keep in mind that amplitude-supported prospects are not the silver bullet, whilst the reasons for failure are very diverse. "But don't talk to a quantitative geophysicist about this, as they often talk rubbish. It's best to avoid them," adds Ian.

Where do amplitude-supported prospects work best? "That is in frontier plays," explains Ian, "especially in relatively young strata up to Cretaceous age and in gassy systems. In deeper plays, the technology is certainly less reliable because of the smaller impedance contrasts."

However, keep in mind that it is only a proper de-risking tool if the following elements are present: a flat spot, a fit-to-structure and an AVO anomaly. "If you only have one 2D line showing a good flat spot, without any other indication, you'd better tear it apart," says Ian, "as our lookback suggests that you can't increase the probability only on that basis."

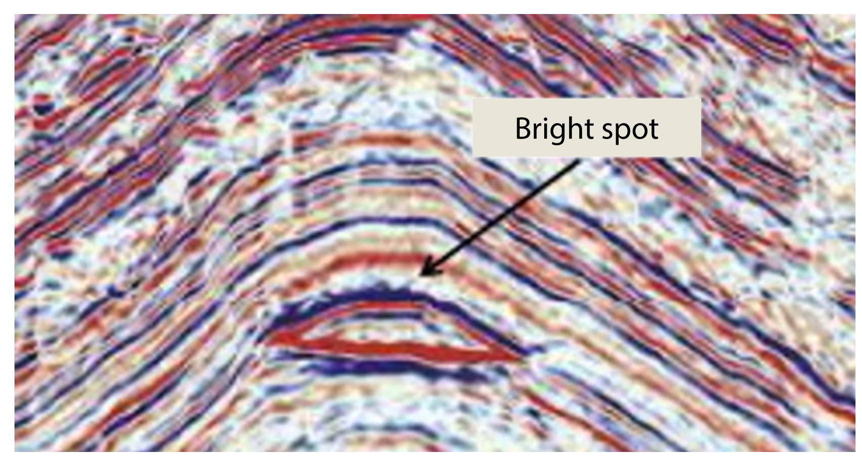
But where amplitude-supported prospects have been key to unlock new basins, such as Tamar in the Levant, the Rovuma Basin in northern Mozambique and Liza in Guyana, the number of amplitude-supported big finds in mature basins is much more scarce. The only known "recent" example is Zama in Mexico, which is a special case because it was likely observed by Pemex but ignored.

Why are amplitude-driven discoveries so much scarcer in these basins? "It is because following a success, everything that looks like a seismic anomaly gets drilled, so the only opportunities left in the more mature exploration phase are the non-amplitude supported (stratigraphic) traps," explains Ian. So we'd better start mapping our stratigraphic pinch-outs again and not wait for our quantitative geophysicist friends to come up with yet another DHI-supported feature that is just 1 km wide. ■

Henk Kombrink

GIS PAX PLAYER

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



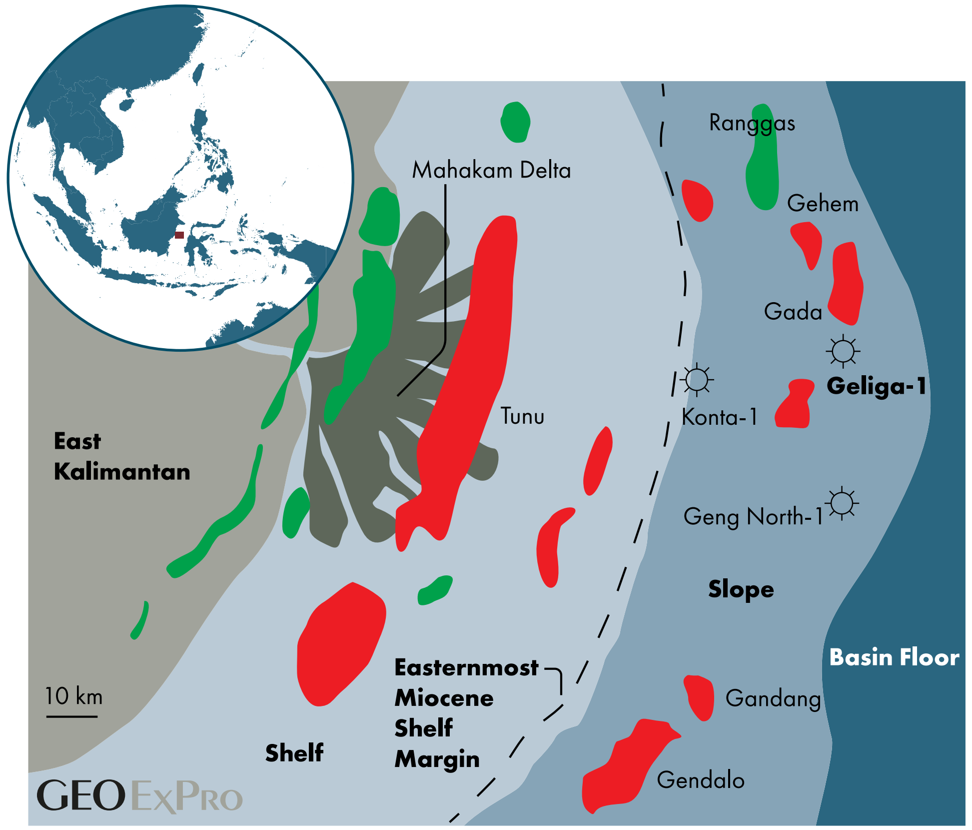
SOURCE: PGS

A blooming bright spot. But what is the scale? An example of why it is important to stay cautious.

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

Geliga-1 – the gas discovery sourced by sandstones

In contrast to what is often thought, the likely source for the gas and condensate found at ENI's Geliga-1 discovery, offshore East Kalimantan, is the sandstones in which the hydrocarbons were found, proving yet again that all petroleum systems have their unique signature



OPERATOR ENI and partner SINOPEC (18 %) reported a new giant gas and condensate discovery in the Kutei Basin, offshore East Kalimantan in Indonesia. According to ENI, the new find may host up to 5 Tcf of gas and 300 MMbbl of condensate.

When plotting the location of the well onto a map, it is apparent that this was not a frontier exploration attempt, with the Gada and Gula discoveries being situated close by, as well as the Geng North discovery announced in 2023, and Konta-1 reported last year. But even when this might be classified as near-field exploration rather than frontier, it must be concluded that the Kutei Basin still has a lot more running room than the North Sea, where near-field exploration tends to result in much smaller finds.

Another interesting aspect about this discovery is the observation that the source rock of the oil and gas found in the Mahakam Delta is supposedly coming from organic matter intercalated in the pro-delta sands rather than from the mudstones.

This is based on work published by Art Saller and co-authors in the AAPG Bulletin in 2006, in which they state that the turbidite sandstones tend to have higher TOC contents than their fine-grained counterparts. TOC values of 4.99 % were recorded from the sandstones, with much lower values for the mudstones. In addition, and in contrast to many other marine basins, no significant marine kerogens were found in the fine-grained sediments either. Well-oxygenated conditions, resulting in rapid decomposition of the algal material, and strong bottom currents are seen as two important factors as to why the shales are not considered the main source rock.

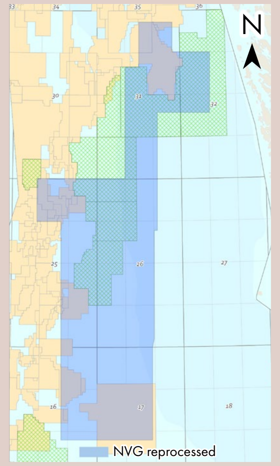
In contrast, the organic matter in the sandstones is supposed to be deposited rapidly as part of turbidity currents, facilitating the preservation of the material. The authors highlight that laminar coal fragments are the dominant type of organic matter found in the Miocene sands, of which the origin is thought to be leaf fragments, carried offshore by paleo-Mahakam fluvial systems.

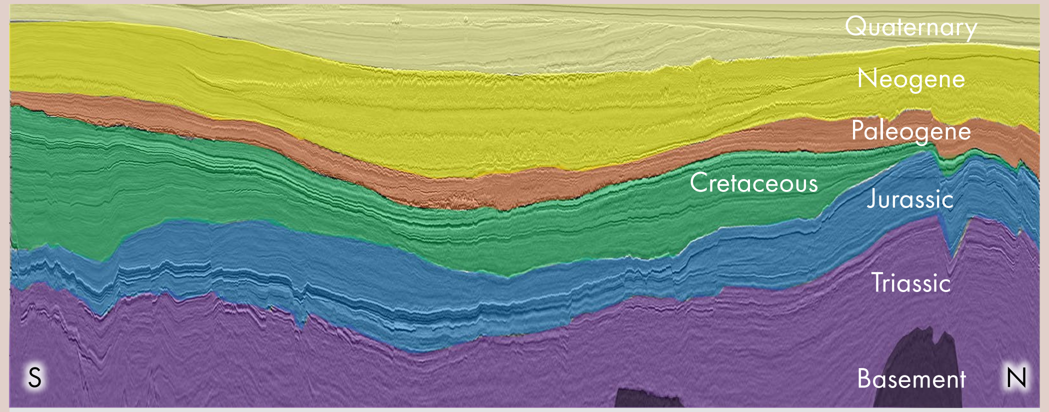
Sallar and co-authors also describe that the top of the oil window in the area sits at around 3,000 m below the mud line, which means that the top of the Miocene reservoir might just be in the oil window, given that the well was drilled to 5,100 m in 2,000 m water depth. ■

Henk Kombrink

From image to insight: Why seismic data quality matters for CO_2 storage

High-quality subsurface imaging, especially of the shallow stratigraphic section, is critical to the success of CO_2 storage projects. In 2014-2018, Viridien began acquiring a regional broadband 3D seismic survey in the Northern Viking Graben (NVG). This regional dataset covers the Horda Platform in the north and Stord basin in the south, as seen in Figure 1 below. This dataset has been reimaged with Viridien's latest proprietary technologies through continuous development, as industry demand for higher-quality data has grown. The newly reimaged NVG data (see map) reveals potential opportunities in semi-open aquifers with substantial storage capacity in the Stord Basin, where suitable reservoirs and seals may enable efficient injection and trapping of CO_2.





Coloured interpretation of the seismic line.

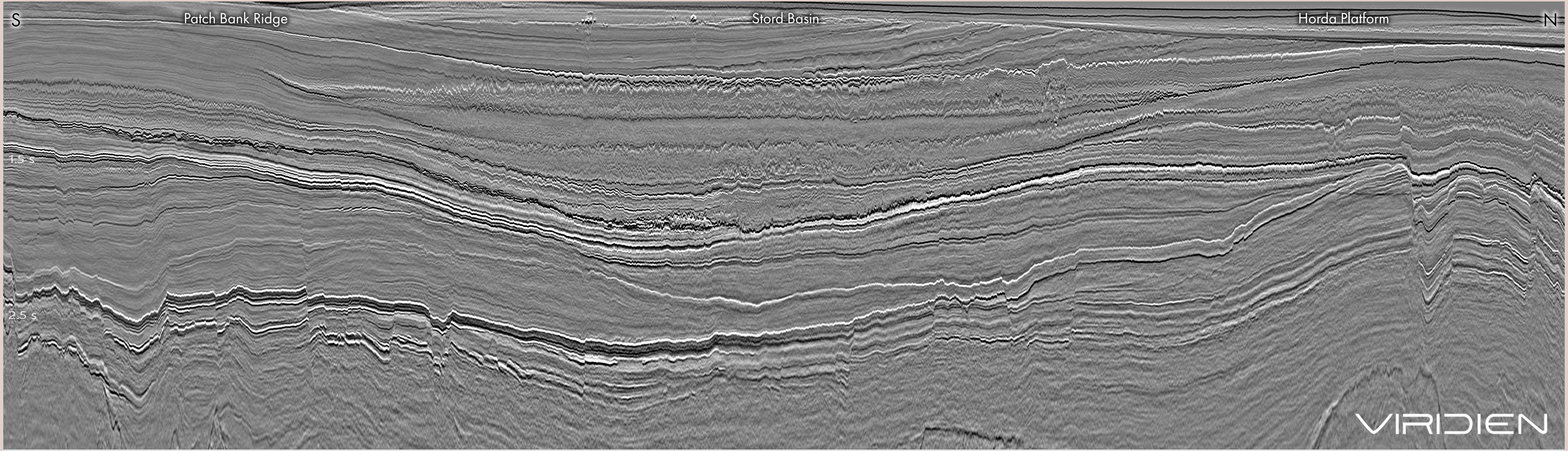


Figure 1: North-south trending seismic section across reprocessed NVG time data.

Repurposing seismic data for carbon storage activities

Carbon storage licensing on the Norwegian Continental Shelf has gained momentum, highlighting its role in the energy transition. Legacy seismic data, originally acquired for oil and gas exploration, is a valuable asset for assessing carbon storage reservoir potential. Maximising the value of this data plays a critical role in de-risking the carbon storage workflow, including site selection, design, and monitoring

IRINA PENE AND IDAR KJØRLAUG, VIRIDIEN

Carbon capture and storage has emerged as a critical technology to achieve the goals of the UN Climate Change Conference (COP21) Paris Agreement. Storage in saline aquifers on the Norwegian Continental Shelf (NCS) has proven to be an attractive solution.

The first CO_2 storage license, EL001 (Northern Lights), was awarded in 2021. Since then, several CO_2 exploration licenses have been granted across the Horda Platform and Stord Basin.

The limiting factor regarding CO_2 storage in most geological formations is not the capacity of the reservoir itself, but the volume of CO_2 that can be injected over a given period (Duval et al. 2024 and Valluri et al. 2021) and the geomechanical properties of the reservoir and seal to ensure containment. Detailed mapping of potential reservoir and seal units to identify the best location for CO_2 injection is therefore crucial for a successful storage project.

DATA QUALITY REQUIREMENTS

To address these needs, Viridien has reprocessed the 2014-2018 north–south acquired Northern Viking Graben (NVG) streamer legacy data, targeting key challenges specific to CO_2 storage. Applying advanced proprietary imaging workflows and technologies, such as debubbling and full-waveform inversion (FWI), has produced a higher-resolution volume with sharper fault delineation and an improved velocity model, thereby enhancing identification of both reservoir and seal units for CO_2 storage.

The updated velocity model with time-lag FWI (TLFWI) frequencies up to 15 Hz (Figure 2) provides a more accurate basis for seismic depth conversion, essential for CO_2 storage, where all major decisions rely on correctly resolving the true depth and geometry of subsurface structures. These improvements support a more robust quantitative and qualitative interpretation, as demonstrated across multiple key storage systems. In addition, high-resolution and well-calibrated velocities are a critical input to pore pressure prediction workflows.

GEOLOGICAL STORAGE FORMATIONS OF INTEREST

The Paleogene sand successions that host the Hermod, Heimdal and Ty reservoirs rank among the most prolific hydrocarbon-bearing intervals in the North Sea, offshore Norway. In the Stord Basin, well data, as seen in wells 25/6-3, 25/6-4 S, confirmed the presence of high-quality reservoir sands within both the Hermod and Ty Formations. These Paleogene sands have been identified by the Norwegian Offshore Directorate (NOD) as promising candidates for saline aquifer CO_2 storage.

The Hermod Formation is composed of sand-rich submarine fan deposits, overlain by the mudstone-dominated Sele Formation, which acts as the main regional seal. The RGB color blend (Figure 3A) highlights a complex network of channels and channelized lobes, with sediments sourced from the west. These channels and lobes contain good-quality sands, as demonstrated by well 26/4-2 (Figure 3B); understanding their spatial distribution is therefore critical for assessing reservoir connectivity and compartmentalization. This interpretation is further supported by seismic data, which shows channel-fill sands forming mounded geometries that are laterally confined by shale wedge terminations (Figure 3B).

Similarly, the Ty Formation was deposited as deep-marine fan systems, consisting of clean, high-quality sands, locally interbedded with thin clay layers (Figure 3C). The Ty Formation is overlain by the shales of the Lista Formation, which provide the primary seal, and underlain by the Våle Formation, dominated by marl, claystone, and limestone. Together, the Ty and Våle Formations exhibit a bright amplitude response on the seismic data, making it quite challenging to map them individually. However, the improved seismic data allows for a more accurate delineation of the Ty sands distribution (Figure 3C).

Other saline aquifers identified by the NOD are the Lower to Middle Jurassic Brent-Sleipner section and the Upper to Middle Jurassic Sognefjord delta.

Lower Jurassic plateaus and valleys were identified east of the Troll Field (Würtzen et al., 2023) and better highlighted on the reprocessed seismic data. The main valley is characterized by numerous sinuous streams and associated incised valleys (bright amplitudes in seismic sections, Figure 4C). Another major north–south trending river adjoins the valley farther west (Figure 4A). Fluvial sands encountered in well 32/4-1 are of good quality, indicating a potential new reservoir for CO_2 injection.

KEY OUTCOMES FOR CARBON STORAGE PROJECTS

Successful CO_2 injection depends on identifying high-capacity reservoir units and effective seals, which necessarily requires high-quality seismic data. Viridien's newly reprocessed NVG seismic data significantly enhances the identification and characterization of both reservoir and seal units, providing a more reliable basis for selecting and de-risking CO_2 storage sites on the NCS.

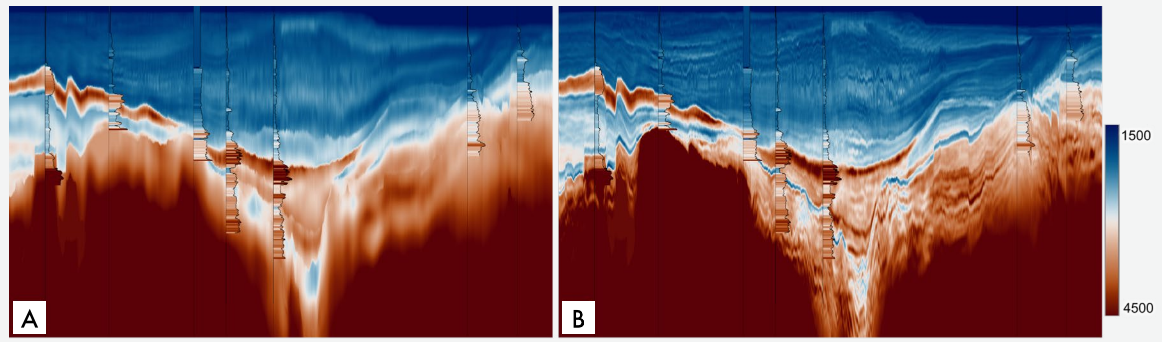


Figure 2: Vp velocities, (A) NVG legacy and (B) NVG reprocessed.

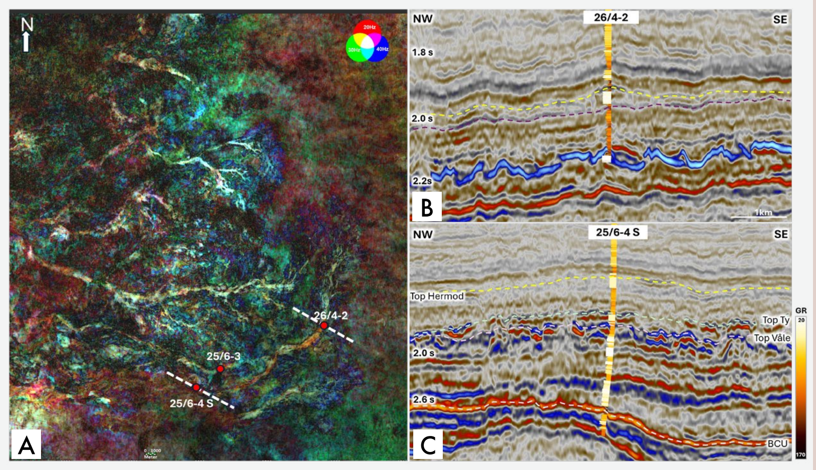


Figure 3: (A) RGB frequency colour blend slice through the Hermod Formation; (B) seismic section intersecting one of the channels penetrated by well 26/4-2; yellow and purple dashed lines represent top and base Hermod, respectively; (C) seismic section highlighting the variability of the amplitude response due to the complex lithology of the Ty and Våle Formations.

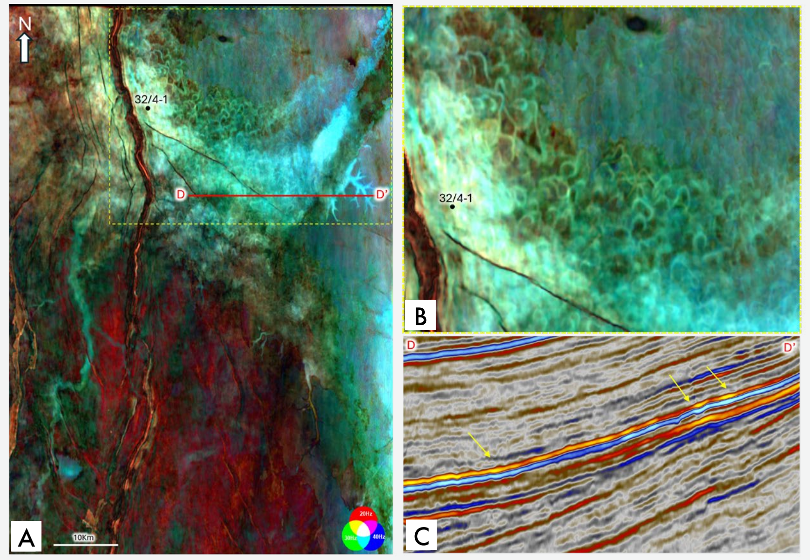


Figure 4: RGB frequency colour blend showing Lower to Middle Jurassic river valley (A); zoomed image of the main valley with oxbow lakes and sinuous streams (B); seismic section highlighting bright anomalies corresponding to the sinuous streams and oxbow lakes identified (C).

FEATURES

"The industry is ready to embark on a big push to develop near-field resources faster"

Lone Margrethe Olstad – AGR

The basement tapes

A conversation with Phil Henley and Tim Debacker on SEEBASE and the origin of Geognostics

"YOU'RE THE ONLY company that tells us where their model could be wrong." It is an observation that Phil and Tim have had from clients when presenting the latest version of their Global SEEBASE® basement model.

"We are open about the uncertainties inherent in our work," says Phil, Managing Director of Geognostics. "As we continue to integrate new research, literature, and the variety of data used in the interpretation, it can be a bit like detective work, but new data or insights are always opportunities to improve the interpretation."

Tim Debacker, Jon Teasdale, and Phil Henley in the Pyrenees in 2024.

THE FUNDAMENTALS

Geognostics is a small team, distributed around the globe, and focused on exploration through a bottom-up approach that starts with characterising basement. They do this for the industry through detailed plate reconstructions in the Geognostics Earth Model (GEM), the high-resolution Global SEEBASE® basement model, and tailored proprietary studies. SEEBASE also provides fundamental regional datasets used by governments, such as the long-running OZ SEEBASE project and the Central Europe SEEBASE funded by OMV.

"Basement is not this homogenous grey zone at the bottom of a seismic section," says Tim. Tim is Geognostics' principal geoscientist and brings more than 20 yrs of experience working as a structural geologist. "It is highly heterogeneous in terms of composition and rheology, and it is the response of this heterogeneous basement to tectonic activity that controls sedimentation, erosion, basin formation and preservation."

Geognostics specialise in understanding regional tectonics, interpreting basement architecture, and determining its influence on basin formation and heat flow. It requires piecing together clues from the integration of structural geology, potential field data interpretation, seismic interpretation, and an array of other datasets.

The geological interpretation of potential field data in the form of gravity and magnetics is key to a regional characterisation of basement, as it allows the interpreter to move away from geological observation points such as outcrop, well and seismic data. But this requires a thorough understanding of the geological history and processes in any given area.

For instance, the team is currently working on an update for the South Atlantic, where seaward-dipping reflectors (SDRs) frequently occur. "However, SDR interpretations are not always consistent," Tim says. "Interpretation of SDRs in literature can vary considerably, but, with our regional bottom-up approach, in which we have to map top basement in the presence of SDRs, we can see when, for example, SDRs have been mislabelled as volcanic basement or have been misidentified within basement rocks when they are in fact post-rift lava flows."

Later in 2026, Geognostics will move on to SE Asia where they will have to tackle a complex plate-tectonic puzzle and map heterogenous basement that contains a large number of intrusive bodies, within an area rich in carbonates. "Think of solving a plate tectonic puzzle, but first having to define the puzzle pieces, which in SE Asia can be difficult because of the strong influence of carbonates and magmatic bodies on the potential field data," says Tim.

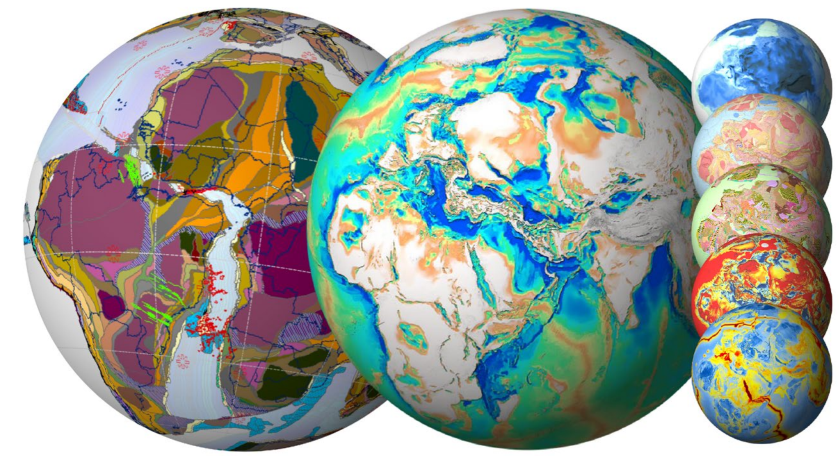
These ongoing updates build on nearly two decades of work on SEEBASE by the company Frogtech, before Geognostics came into play. What is the story behind that?

GOING BACK IN TIME

"SEEBASE has been continually developed over many years, by many great people, but I would really like to mention Henri Tykoezinski at this point," Phil says.

We need to go back a while to understand why. In 2004, Frogtech formed an Australia-based company that pioneered SEEBASE and brought together the team that is now Geognostics. That group of people originally included Jon Teasdale, who then moved to Shell for a decade, working as a global geological consultant.

PHOTOGRAPHY: GEOGNOSTICS



GEM, the Geognostics Earth Model and Global SEEBASE®, provide a comprehensive understanding of basement and basin evolution.

Jon and Henri had been close friends since working together for Shell in Aberdeen. In 2017, Jon left Shell to form Geognostics with Henri and develop GEM, the Geognostics Earth Model. A couple of years later, in a London pub, Jon mentioned to Henri that Frogtech had entered Administration and the IP had been put up for sale. "It was totally out of the blue for us, but Henri decided to purchase the IP, and that is how all that work, by so many people, lived on. It would have been a huge shame for such a unique body of work to disappear," says Phil.

Phil had met Henri only very briefly during the PETEX Conference in 2018. "It was one of those critical conversations you only realise the value of when looking back," he says. "Unfortunately, Henri is no longer with us, but everyone still working with SEEBASE owes him a debt of gratitude - particularly us."

THERE IS MORE TO BASEMENT

The Geognostics team has steadily expanded the product beyond the initial release focused on SEEBASE depth to basement; something initially made possible by the long hours of COVID. The product now includes interpretation of depth to Moho, basement terranes, and the dominant composition of the basement.

Last year, a predictive basement-focused heat flow grid was introduced, SEEBASE Geothermal, which leverages the SEEBASE model to predict heat flow where data is sparse. "It is a heat flow model utilising our crustal model – and a product that only we could do on the back of SEEBASE," explains Tim. "But instead of starting with the heat flow data, we have developed a bottom-up conductive model, generated entirely from our geological SEEBASE model, and used the heat flow data to assess the outputs. This process either validates the results or pushes us to question our model and improve our understanding of the geological setting."

Again, finding a discrepancy between the data and the model results is seen as an opportunity rather than a problem. "Obviously, as it is a conductive model, zones of convection will stand out. But also, areas with very thick salt deposits or areas with radiogenic shales can be recognised from the mismatches. This is actually good news," says Tim, "as that tells you something the heat flow data on their own could never do. Once we understand the reasons, we can correct for them, and the model continues to improve."

With future development supported by a client base including both conventional and emerging energy sectors, and increasing interest from governments looking to replicate the Australian success of OZ SEEBASE, the Geognostics team is excited to see SEEBASE is becoming a default basemap for exploration and natural resource management. ■

Henk Kombrink

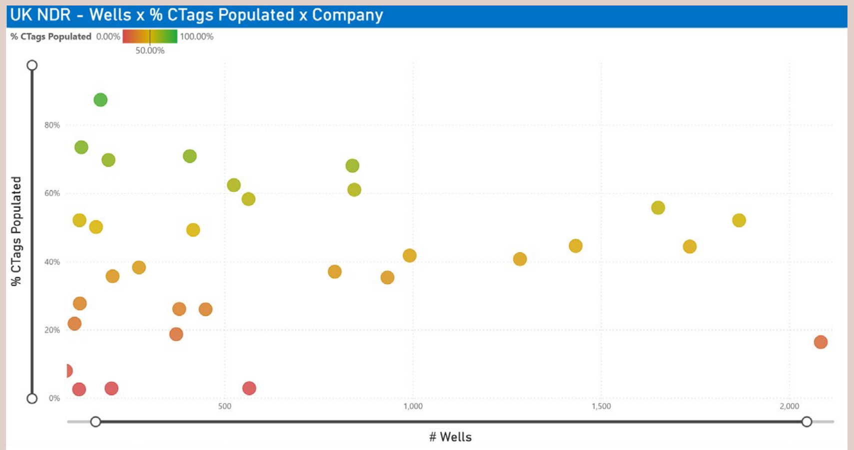
Is your data NDR compliant?

How Katalyst Data Management is solving the UK's subsurface data obligation issue

MARTYN BUDD, PRINCIPAL CONSULTANT AT KATALYST DATA MANAGEMENT

Good subsurface data has never been more valuable. From oil and gas exploration to carbon storage and offshore wind positioning, geological characterisation is essential, yet new data acquisition is becoming increasingly expensive. The case for reusing legacy datasets is clear.

In 2021, the UK's North Sea Transition Authority (NSTA) launched a cloud-based National Data Repository (NDR) to centralise subsurface data. When the NSTA urged operators to upload their holdings, many turned to Katalyst Data Management to mine, transform and submit data on their behalf. Well data and seismic submissions carry distinct regulatory requirements, and legacy holdings vary enormously.



Each circle represents a North Sea operator; many with major holdings are only 40 – 60 % CTAG (category tag) compliant. For seismic, most operators have tagged fewer than 20 % of their legacy projects.

SCALING THE DATA MOUNTAIN

Katalyst deploys experienced professionals with the latest tools to navigate decades-old archives across two domains, seismic data and well data, each with its own specialist workflow.

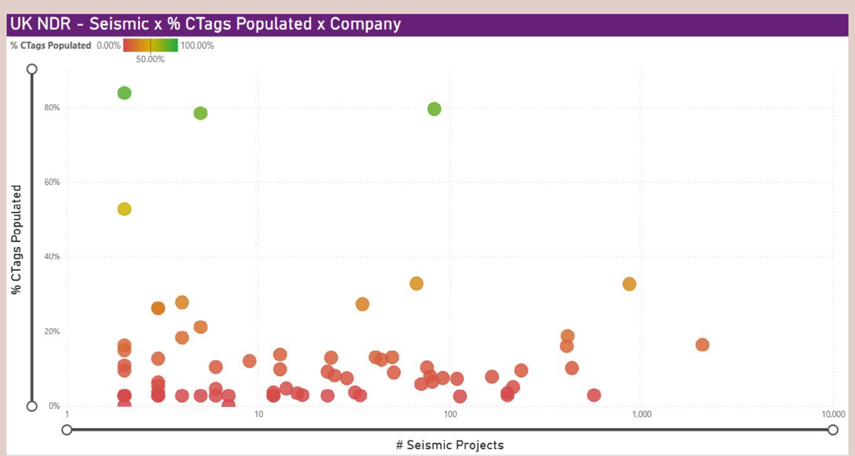
DATA SUBMISSION EXPERTISE

Seismic Data

A recognised leader in digital transformation and legacy-media handling, Katalyst offers a dedicated NDR seismic submission service, guiding operators' data from legacy media through format conversion, QC and metadata enrichment to a compliant upload.

Well Data

Well data compliance spans wireline logs, completion reports, geological assessments and production records, often scattered across fragmented systems. Katalyst's answer is CTAGer, a purpose-built tool that, alongside experienced professionals, cuts through this complexity and follows a rigorous QA/QC prior to upload.



If you would like to know where your company ranks, please get in touch at katalystdm.com.

KATALYST CTAGER: SIMPLIFYING REGULATORY REQUIREMENTS AND DRIVING DISCOVERY

CTAGer combines automation, intelligent workflows and discovery tools with a 'human in the loop' for efficient, trustworthy compliance.

Key capabilities include:

Information discovery at scale – AI search and contextual tagging provide rapid access across fragmented datasets.

User-validated compliance workflows – AI-suggested CTAGs are easily confirmed against document views and summaries.

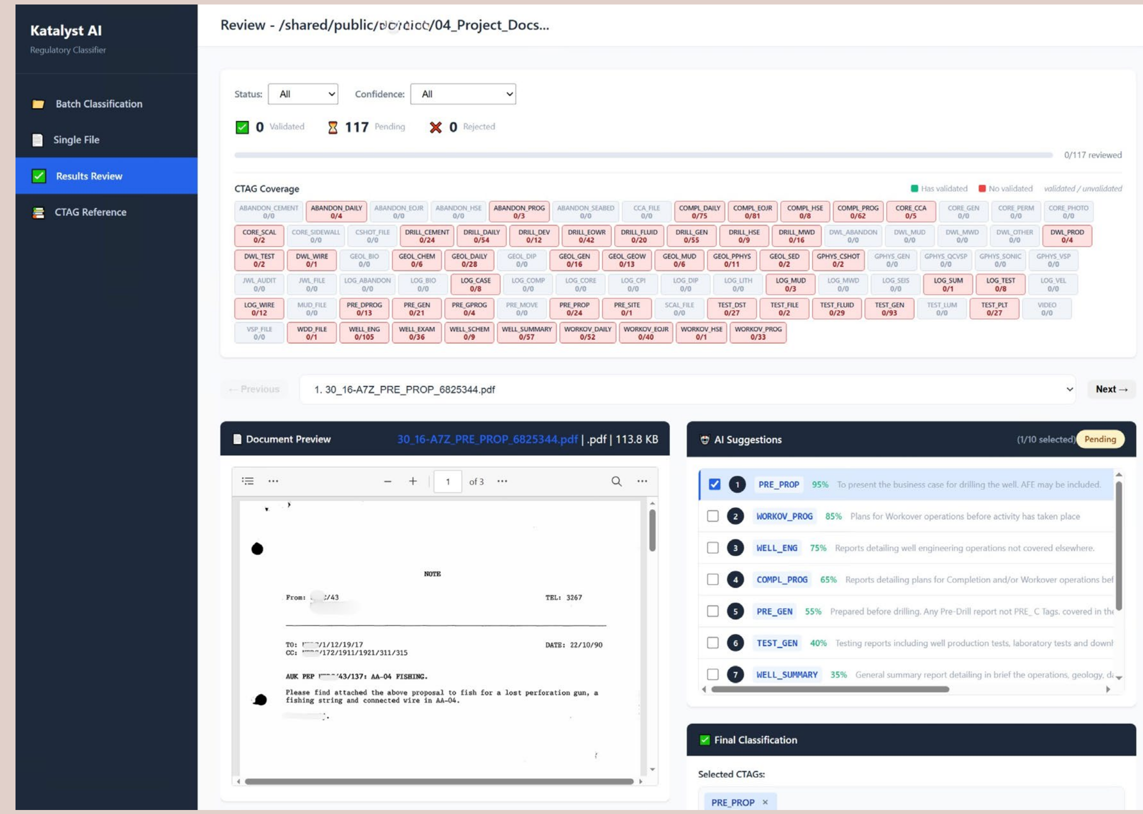
'At-a-glance' CTAG coverage – documents and data are ranked against NSTA requirements, letting users flag gaps before submission.

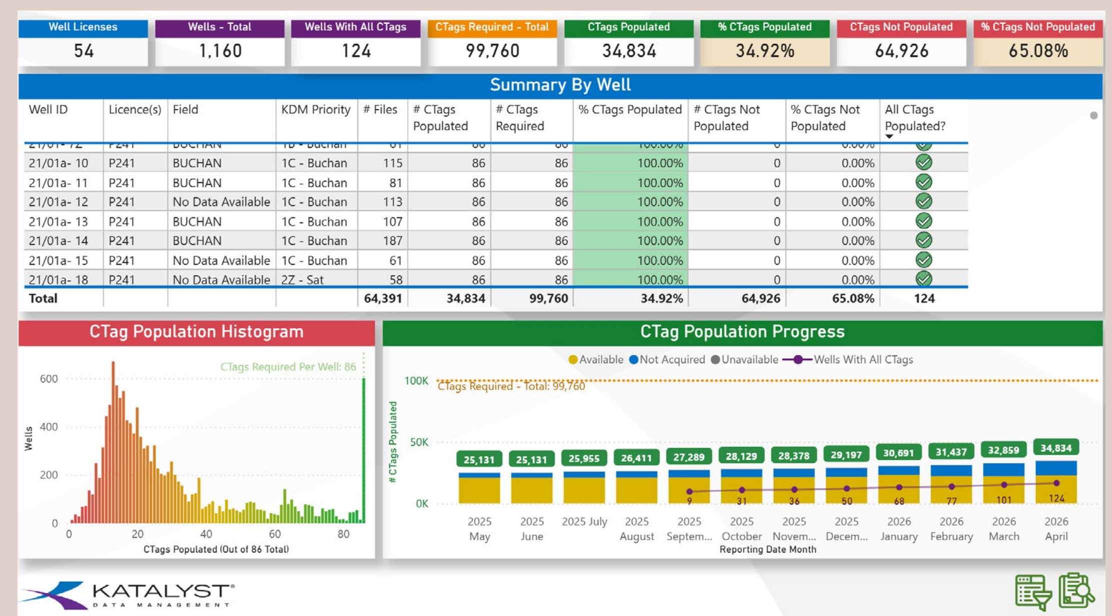
Dynamic dashboards and project reporting – real-time visibility into reporting status shows which have achieved 100 % compliance and how many still have outstanding obligations.

KATALYST'S BROADER VISION

NDR compliance is part of a broader ambition. Katalyst is driving digital transformation across the energy sector, building an automated ecosystem where compliance and discovery go hand in hand, unlocking data untouched for decades.

As the energy transition accelerates, operators who access and deploy legacy data fastest will hold a competitive advantage. With experienced well and seismic domain knowledge together with CTAGer and iGlass, Katalyst is positioning itself and its clients to do exactly that.





The Katalyst CTAGer NDR compliance tool and dashboard.

Spatial variation in charge risk along the Guyana-Suriname margin

Results of a new basin modelling study

KENNETH SHIPPER, PAUL MANN, CBTH PROJECT, UNIVERSITY OF HOUSTON
AND ANDREW PEPPER, THIS IS PETROLEUM SYSTEMS

THE GUYANA-SURINAME Basin is a Mesozoic rifted-passive margin along the northeastern coast of South America that has emerged as one of the most prolific deepwater petroleum provinces of the past decade. Since the Liza-1 discovery in 2015, the central play fairway, or "Golden Lane", has been established by more than 54 discoveries. Production from the Golden Lane has increased to 900,000 bbl/d and is sourced from stacked Upper Albian through Coniacian – and locally younger – marine source rock acmes. A source rock acme is a specific, geologic time interval commonly lasting millions of years that marks the preferential deposition and preservation of marine organic matter. Despite the remarkable discovery of the Golden Lane in Guyana, the eastward extension of the play fairway 300 km into offshore Suriname remains uncertain, as recent Suriname wells have failed to encounter commercial petroleum.

SOURCE ROCK POTENTIAL OF THE DEMERARA PLATEAU

In the first step of charge risk evaluation, we compiled published Rock-Eval pyrolysis data from exploration wells on the present shelf and upper slope, including data from five deepwater Demerara Plateau sites drilled in 2003 during Leg 207 of the Ocean Drilling Project. We augmented this with combined Cenomanian-Turonian Acme Ultimate Expellable Potential (UEP) values from the Staatsolie Atlas of Suriname (2025).

Multiple source rock acmes in both the Aptian-Lower Albian ('Aptian') and Upper Albian, Cenomanian, and Turonian (A3CT) contain Organofacies B kerogen in marine clay-rich mudstones containing up to 15.8 % organic carbon and with a Hydrogen Index (HI) up to 730 mg HC/g TOC. This translates locally into a truly world-class UEP of up to 126 mmboe/km² for the combined A3CT.

THERMAL MODELLING OF THE GUYANA-SURINAME MARGIN

The Guyana-Suriname margin is characterized by along-strike crustal variability with the Golden Lane of Guyana underlain by the 23-km-thick, non-volcanic, obliquely-rifted margin and the adjacent margin of Suriname underlain by the 25-km-thick and seaward-protruding, Demerara volcanic plateau. This crustal transition straddles the maritime boundary between Guyana and Suriname and is expressed by differences in lithospheric thickness, Moho topography, and radiogenic heat production, that combine to produce along-strike variations in source rock thermal stress.

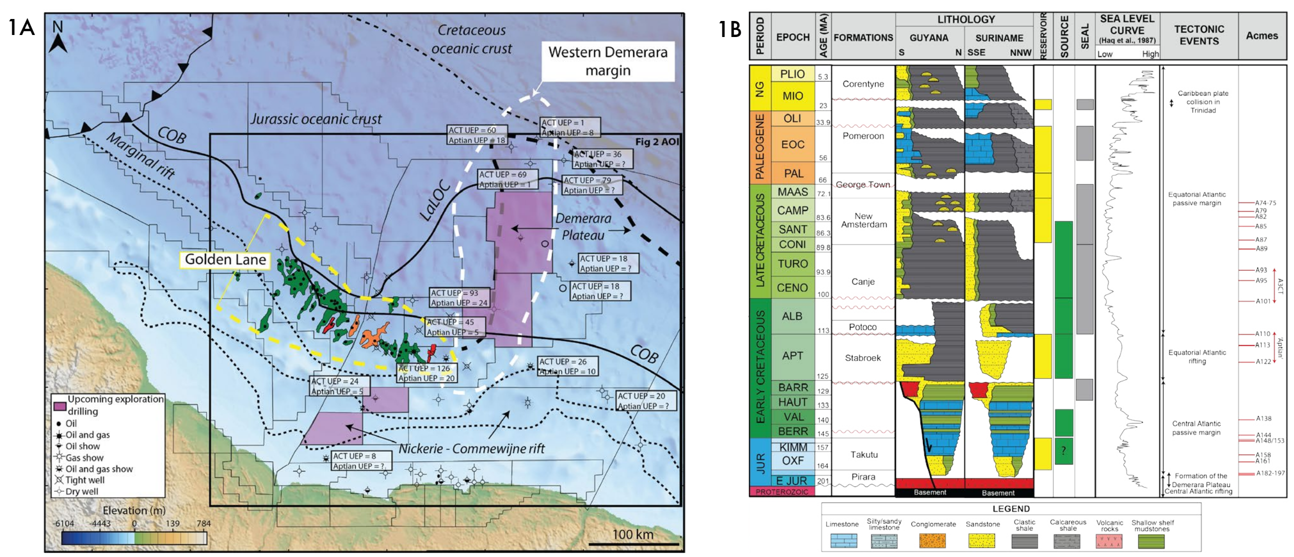


Figure 1A: Detailed map of the study area showing exploration and production blocks, distribution of oil and gas fields overlying the Jurassic margin rift shown by the dotted outline. The ultimate expellable potential (UEP) with values in mmboe/km² for both the A3CT and Aptian intervals are shown for key wells from offshore Suriname. Higher UEP follows the Cretaceous paleo-shelf-slope trend highlighted in white. 1B: Stratigraphic column showing the petroleum system elements of the Guyana and Suriname deepwater margin.

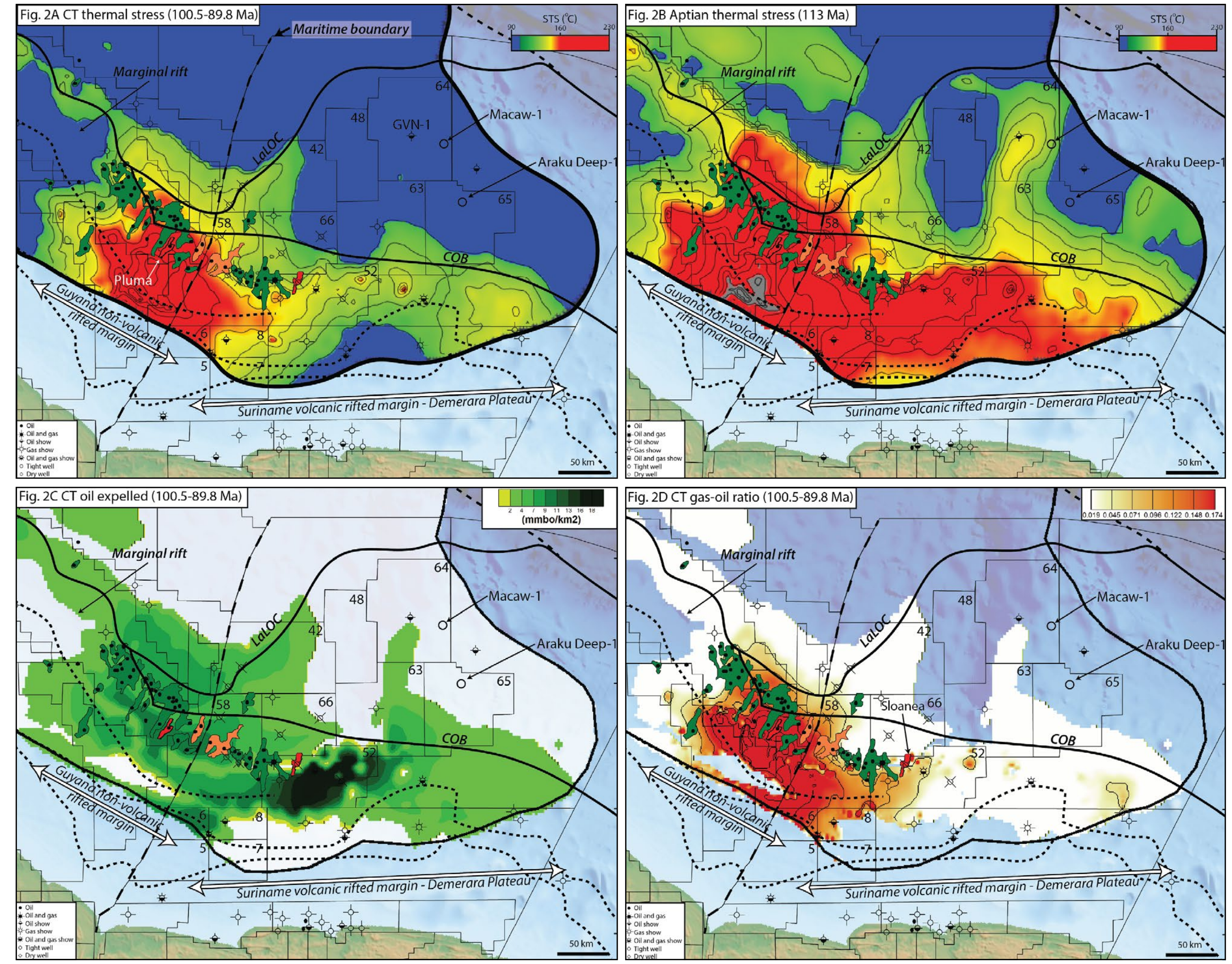


Figure 2A: STS of the A3CT source rock interval. Blue indicates immaturity, green indicates the oil expulsion window up to the typical ~ 3,000 scf/bbl liquid-vapor transition in yellow, and red indicates the dry gas window. 2B: STS of the Aptian source rock interval. GVN, Araku, and Sloanea are unlikely to be sourced by the A3CT based on our modeling; GVN oil shows are known to be Aptian-sourced. 2C: Oil expelled for A3CT source rocks showing a maximum 24 mmbo/km² below the present outer shelf near block 52 that decreases to northwestern Stabroek near Liza at 6 – 8 mmbo/km². 2D: Cumulative gas-oil ratio for A3CT source rocks showing a maximum 0.35 (GOR~4,000 scf/bbl) local to the Pluma gas field near the Guyana-Suriname maritime boundary. Note that the decrease in GOR offshore Suriname can be attributed to decreased thermal stress shown in Figure 2A.

Our full-lithosphere 3D basin model is calibrated using temperature data from seven, widely-spaced exploration wells and therefore provides an example of the value of 3D basin modeling in areas of limited data. Our basin model predicts the spatial distribution of Standard Thermal Stress (STS), resulting from variable burial histories and lateral changes in crust-lithosphere heat flow.

STS, VOLUMES AND CHARGE FAIRWAY

Modeled STS maps for the two source intervals (Figure 2A, Figure 2B) show the oil expulsion window in green is characterized by temperatures >110° C for Organofacies B sources and extends across Blocks 52 and 58 of the western, offshore Suriname area, but does not extend northward of Block 66 in the northwestern area of the seaward-protruding, Demerara volcanic plateau. The blue area indicates an area of no expulsion. The outboard limit of the source rock kitchen only extends 40 km north of the Golden Lane for the A3CT interval. Due to deeper burial, the oil expulsion window at the Aptian level extends 120 km east and north into Blocks 63 and 64 (Figure 2B). Increasing overburden and thermal stress levels result in a gas-condensate window (yellow) and dry gas window (red) in this shallower water area, especially near the Guyana-Suriname maritime boundary.

Expelled volumes of petroleum are a function of initial source rock UEP and the level of thermal stress attained. Figure 2C and 2D show expelled oil volume and Gas-Oil Ratio (GOR). In the Golden Lane area, our prediction matches the observed patterns of low GOR oil fields northwest of Stabroek (e.g. Liza), which become increasingly high GOR with vapor phase accumulations near the maritime boundary, and then become more oil-prone again along the southeastern Suriname trend (e.g. Grand Margu in Block 58). This variation in GOR is driven by variations in thermal stress that reflect the combined effects of an ▸

FEATURES

increase in burial depth and the higher radiogenic heat production from underlying, more granitic crust.

Note that in parts of Guyana, the model predicts a gassy charge where there are oil accumulations. This is common in many petroleum systems, and concerns the role that the trap plays in determining the GOR. Traps near gas kitchens that accumulate the whole charge history are 'cumulative', collecting all the charge over time, whereas a leaky or late-filled trap will behave in a more 'instantaneous' way, preferentially collecting the latest fluid expelled from the kitchen. This is likely a major source of the imperfect match (as well as the limited temperature calibration dataset). Mismatches where gas accumulations occur above oil kitchens, however, such as at Slonea and Araku, must be explained differently: These accumulations require a deeper source rock as predicted by the Aptian STS map (Figure 2B).

In terms of expelled petroleum volumes, the sweetspot shown by the darkest green area of Figure 2C occurs beneath the present outer shelf in Block 52 rather than in the present-day deepwater. This remarkably rich, shelfal sweetspot has fed updip migration across the hydrostatic shelf and charging of ~1 Bbbl of oil in the coastal, heavy oil fields of Suriname.

IMPLICATIONS FOR CHARGE AND MIGRATION RISK IN OFFSHORE SURINAME

The highly productive Golden Lane of central and southeastern Guyana is associated with underlying ACT source beds with STS exceeding 120° C (Figure 2A). Our model shows that the edge of the charge fairway in northwestern Guyana may reflect the decrease in expulsion volumes from the distal offshore area, preventing the charge front from reaching shallower Cretaceous submarine fan reservoirs. This charge risk element is related to reduction in overburden thickness and/or decreasing RHP on the Jurassic oceanic crust of the deepwater area.

Ongoing and planned drilling of the projected Golden Lane into offshore Suriname includes the Macaw-1 and Araku Deep-1 wells, along with three upcoming wells in Block 52: They will be susceptible to this vertical migration risk. Success in these wells would support our proposed extension of the petroleum system onto the western flank of the Demerara Plateau and / or the presence of Aptian source rocks in a more expansive expulsion kitchen (Figure 2B).

SIGNIFICANCE FOR EXPLORATION ALONG THE GUYANA–SURINAME MARGIN

Our model delineates the kitchen limits at the Aptian and A3CT source rock intervals over a strike distance of 245 km in offshore Guyana-Suriname. While the A3CT charge fairway terminates within Blocks 52 and 58, we propose a northeastern extension of the Golden Lane kitchen onto the western flank of the Demerara volcanic plateau that is sourced by Lower Albian-Aptian source rocks. Exploration success beyond the Golden Lane of Guyana-Suriname will depend on a combination of sufficient UEP and thermal stress sufficient to overcome vertical migration losses to younger Cretaceous reservoirs. ■

Before you decide to enter Venezuela...

The importance of correct and contextualised decision-making

KEVIN SCHOFIELD, KATYA CASEY, MAREL SANCHEZ AND JUAN FRANCISCO ARMINIO, U3EXPLORE

In recent months, several articles emphasising the historical, technical, and human aspects of the evolving "apertura" in Venezuela have been published in the AAPG Explorer and GEO EXPRO. In the former, Brown provided geopolitical and historical perspectives and an indication of "the size of the prize". Smith Llinas, also in the Explorer, pursued more personal stories from the perspectives of professionals who have worked in Venezuela, and summarised the geological reasons why Venezuela has such a rich petroleum legacy. The tone of these articles is one of restrained optimism..." there is a lot of oil, but". It is the "but" and the steps that have been taken to mitigate it that are the thrust of this article.

The "but" is encapsulated by a cautionary tale from the early 1990s. In an article in Issue 1 of this year's magazine, Kombrink spoke to former bp staffers who shared, with remarkable candour, the story of bp's redevelopment of the Pedernales field in the Orinoco delta. The project failed fundamentally because bp failed to understand the complexity of the field. As a result, they misinterpreted the results of a pilot production programme, brought expensive rigs into the field before interpreting new seismic data, drilled new wells without understanding what they were finding and plowed ahead regardless, as the wells failed to deliver. Within this disastrous lack of integrated project management, there are important lessons for investors entering Venezuela after twenty years of isolation.

HELP AVOID MISTAKES

To steepen the learning curve for those investors, and to help avoid repetition of prior mistakes, U3Explore, over the past seven years, has developed an integrated understanding of the petroleum habitat in the major Venezuelan petroleum provinces of the Eastern Venezuelan Basin, Maracaibo Basin, Falcón Basin, Barinas-Apure region, and the Caribbean and Atlantic Margins. This work will mitigate what we believe would be two of the most likely root causes of failure in the revitalization of the Venezuelan oil industry.

Firstly, it is necessary to appreciate how assets and resources in Venezuela have been accounted for historically, which will critically impact the assessment of their current worth and future value. Standard practice in most IOCs and NOCs is to delineate assets and their associated reserve and resource volumes based on geological criteria of reservoir intervals or fairways across mapped accumulations with structurally and / or stratigraphically-defined bounds. In contrast, in Venezuela, resource volumes were historically accounted based on individual producing units in geographically delineated licenses delivering fluids to specific gathering sites with little or no reference to the subsurface structural or stratigraphic constraints. For an investing entity, acquiring such an "asset", the uncertainties associated with the definition of remaining proven reserves, additional in-field resources, and exploration upside are significant, and the uncertainty in return on investment will be high without the ability to build a comprehensive and consistent ranking of opportunities.

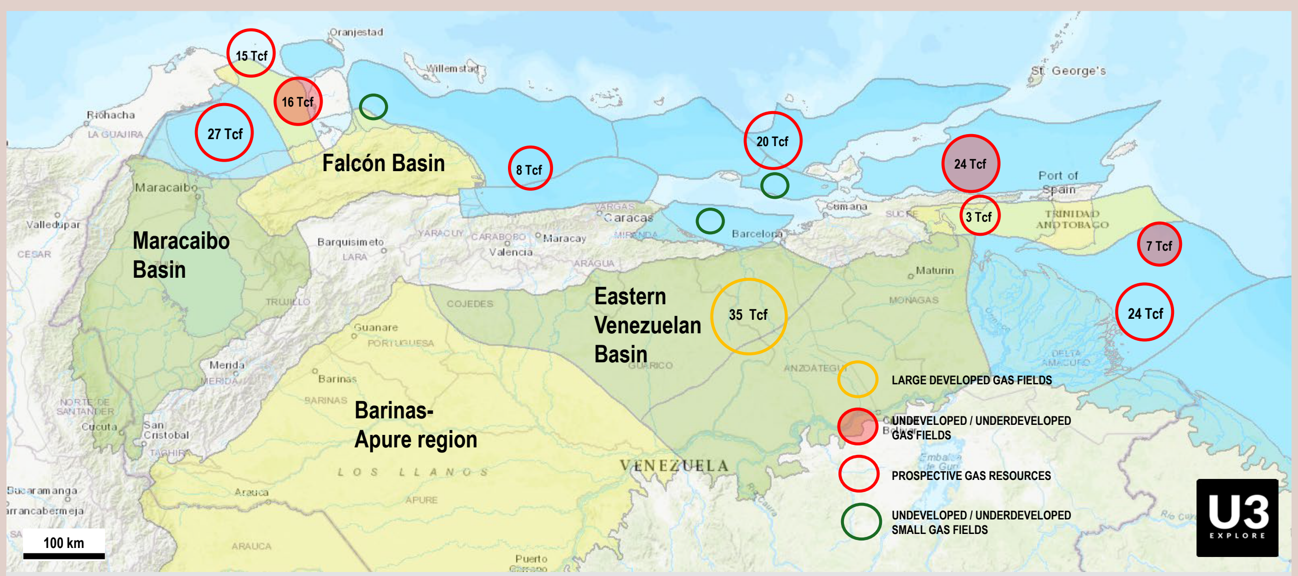


Figure 1: Undeveloped / underdeveloped and prospective gas resources in Venezuelan offshore basins. Giant petroleum provinces in green, commercial basins in yellow and prospective basins in blue.

SOURCE: BASINS MAP MODIFIED FROM ARMINIO ET AL. (2025), PROSPECTIVE RESOURCES FROM PDVSA (2016)

U3Explore's Venezuela project mitigates this risk by delivering the geological context of significant numbers of accumulations. It is underpinned by the integrated analysis of 21,000 flow-units in 306 fields in the East Venezuelan Basin, and over 2,600 in 64 fields in the Maracaibo Basin. These have been tied together in the context of their basinal setting, stratigraphic age / reservoir fairway and fluid content. The associated reservoir, field and fluid data and volumetrics have been documented in georeferenced datasets (GIS), and a proprietary database "U3D".

The analytical data points support back-calculation of the volumes available in actual fields, rather than geographical areas (Figure 2), and permit critical project analysis at flow unit and field scales.

These newly validated and contextualised data can then be input to economic models for making informed investment decisions (Figure 3).

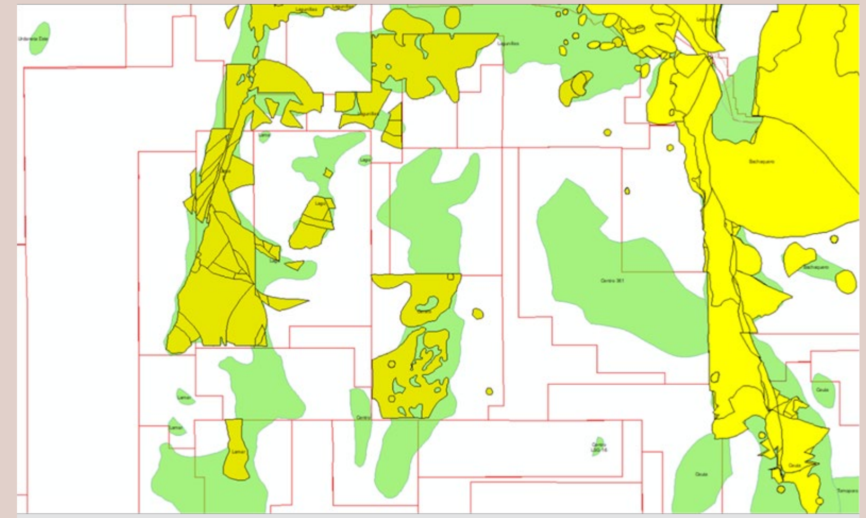


Figure 2: Field areas (green) with associated reservoir play fairways (bright and dark yellow) contrasted with producing unit areas (red).

COHERENT PLAY FAIRWAY MODELS

The U3 project was undertaken by ex-PDVSA professionals with decades of experience, parsing publicly available conference proceedings, theses, literature publications and PDVSA and Ministry of Energy reports and translating geographically defined resource volumes into geologically coherent play fairway-based models. This comprehensive piece of work mitigates another serious risk overshadowing projects in Venezuela; that of human capital.

Both Smith Llinas in the Explorer and Kombrink in GEO EXPRO draw attention to the fact that tens of thousands of highly experienced and skilled oil industry professionals left Venezuela as a result of purges in PDVSA and the later humanitarian crises in the country. With that diaspora, centuries of accumulated knowledge were fragmented, and have seldom been reconstructed outside of the U3 Venezuela Project. Outside Venezuela, but of no lesser importance, is the loss of human capital and data attrition within the IOCs. Most staff who worked on their Venezuelan projects have departed, and our experience suggests that many of their databases and reports will have been lost to the literal dumpsters of history. The U3 project will, to some degree, fill the gap, facilitating guided entry into projects, avoiding erroneous assumptions and unrecognised risks, reducing uncertainty and delivering on the promise of large returns.

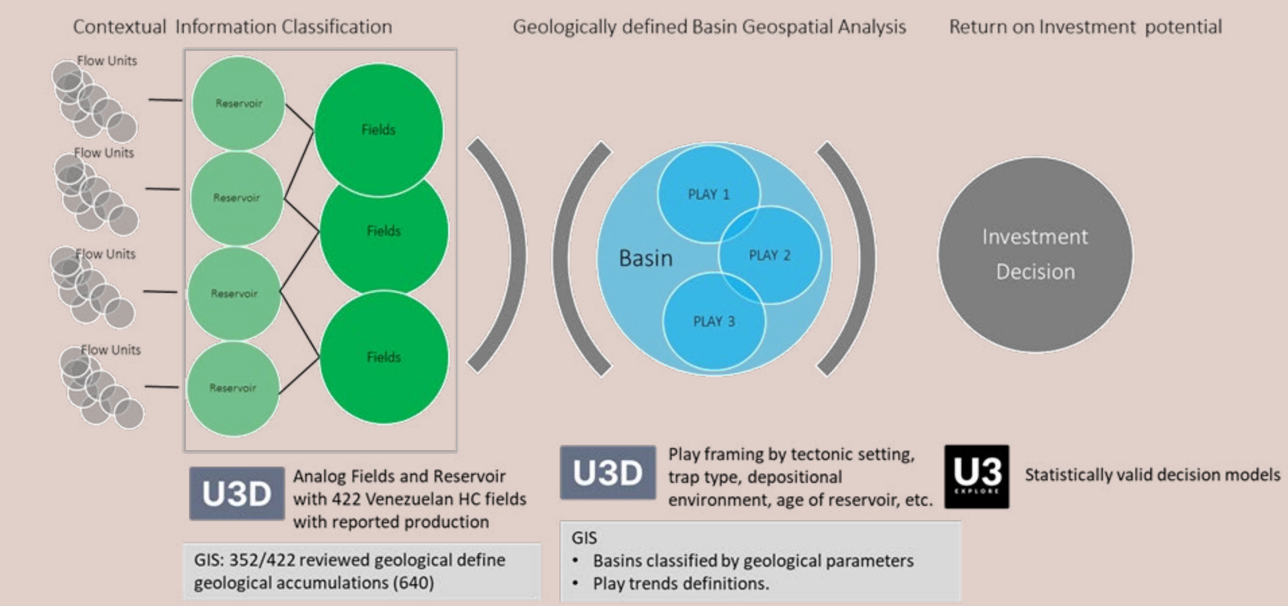


Figure 3: Upscaling from flow units to basin context to facilitate investment decisions based on confidently characterised volumetrics.

FEATURES

Frontier volumes, near-field risk

Papua New Guinea's Western Province has the ingredients to become another hub. And in that hub lie two prospectve licences owned by Heritage Oil

Papua new Guinea (PNG) rarely features in the E&P headlines, but in fact, the country has a lot to offer when it comes to the exploration scene. TotalEnergies and partner Petronas are likely to be drilling PNG's first deepwater well, Mailu-1, later this year, targeting a carbonate reef, which has the potential to be a play-opener. Meanwhile, Australia-based Larus Energy operates two partly onshore / offshore licences close to the capital Port Moresby that include at least one drill-ready and potentially stand-alone oil prospect.

Then there is PNG LNG, producing since 2014 and operated by ExxonMobil, which is a testament to the country's ability to support large-scale infrastructure projects, despite the often remote and difficult terrain. In addition, TotalEnergies and its partners are expected to take FID on the Papua LNG project, which will develop the Elk and Antelope onshore discoveries. Further, the P'Nyang project, which will tie into PNG LNG, is expected to start construction in 2028, adding a further 4.3 Tcf.

As such, there is more activity in PNG than one might think at first glance. A quick look at the country's creaming curve also suggests that there are a few big finds still to be proven. In a way, it might be about time for the next discovery to be made. And that potential is not limited to the offshore. In fact, the data suggest that success is more likely onshore. That's where Heritage's acreage in the Western Province comes in.

THE HISTORY OF HERITAGE OIL IN PAPUA NEW GUINEA

Heritage entered Papua New Guinea in 2013. The company initially had interests in four licences, in various plays in the country. Two wells were drilled in the North New Guinea basin, in the north of PNG, in 2015, which were dry. The company has also acquired 600 km of 2D seismic in PNG over the years, across three licence areas.

Heritage's primary focus is now on the proven foreland and fold belt plays. The company operates and has 100 % interest in the PPL437 and PPL676 licences in the Western Province and identified ~14 Tcf wet gas in place across 10 leads and prospects in multiple plays and targets.

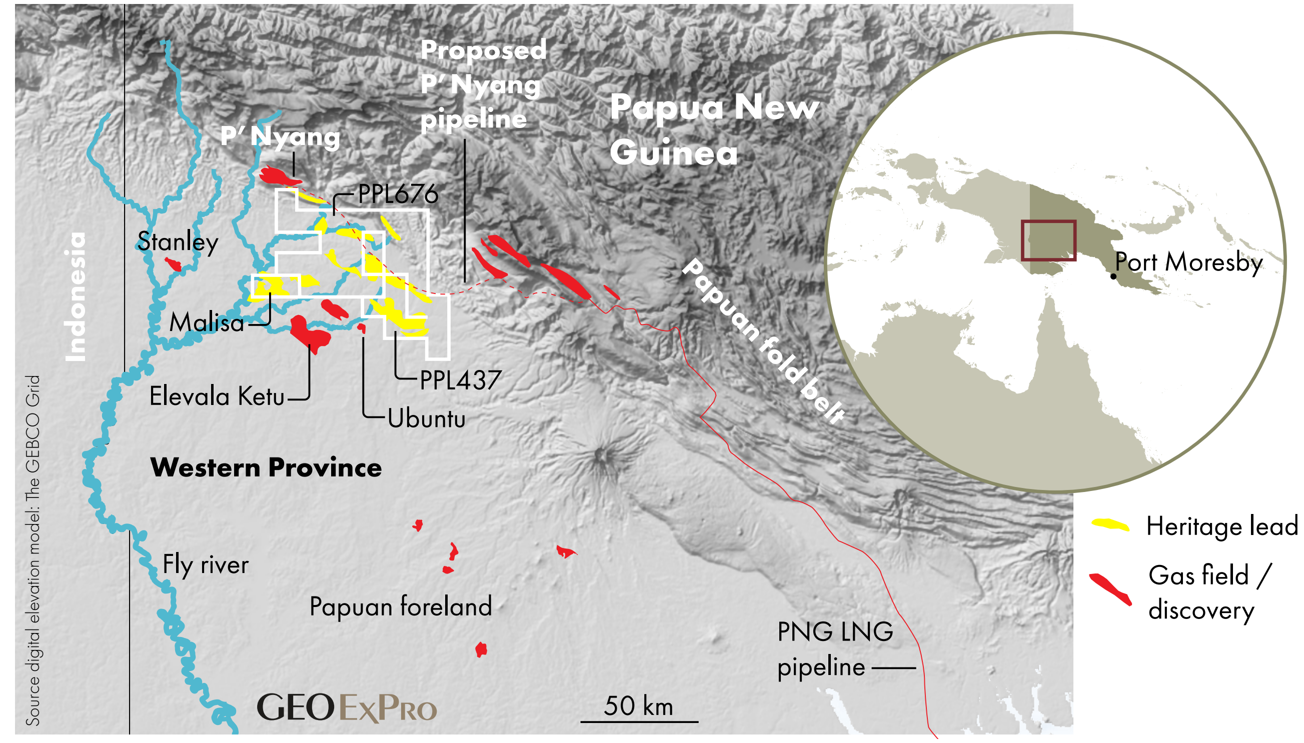
THE WESTERN PROVINCE'S PROMISE

In an early GEO EXPRO article (GEO EXPRO, Vol. 4, Issue 2, 2007), Jane Whaley wrote: "Outside the Central Highlands and Papuan fold belt, PNG is virtually unexplored. The Papuan Foreland and Fly Platform, for example, with its simple, flat-lying geology, has 12 as-yet-undeveloped discoveries, found from very few discovery wells." This yields a success rate of greater than 50 %, far higher than many of the global basins. This is exactly the area where Heritage's two licences are situated.

We are looking at the region that is situated close to the fields that are already feeding the PNG LNG project. There is already a cluster of finds awaiting further development, totalling a discovered volume of around 7 Tcf. And in the middle of that cluster of stranded discoveries is an area that has been part of Heritage Oil's PNG portfolio since 2014; PPL437 and PPL676, measuring a combined area of slightly more than 3,000 km².

PHOTOGRAPHY: RACHAEL HASLAR

The western Papua foreland in the area of Heritage's licences.



Location of Heritage's licences in PNG's Western Province.

TWO PLAYS

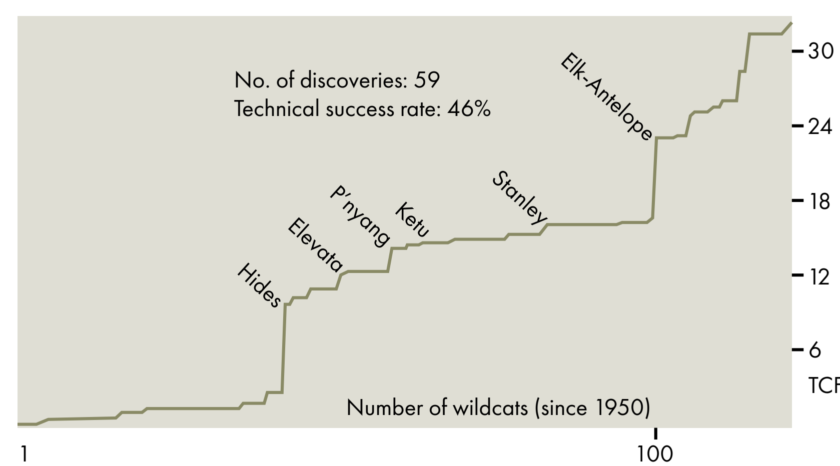
The two Heritage licences straddle an important geological transition; to the southwest is the flatlying foreland, whilst in the northeast the Papuan fold belt determines the structural grain. As such, there are two different play types associated with these zones: The basement drape play and the frontal fold play, respectively, both requiring a different approach when it comes to de-risking drilling targets.

The fold belt has seen the most extensive exploration activities so far in PNG. The reason for that is simple; there is no extensive seismic mapping required to find potential drilling targets; old-fashioned geological mapping and aerial inspection have proven to be successful in the past. In fact, some fields were found without any seismic lines acquired at all. In general, the area is so rich in hydrocarbons that if there is an anticline, it is likely gas-filled. It is often cheaper to drill than to shoot seismic.

In the adjacent foreland, the picture is very different, as the terrain is flat; surface mapping is therefore more challenging. It is in this region that Heritage acquired a significant amount of 2D data to better delineate its prospects in PPL437, specifically the Malisa prospect.

Heritage's main prospect is Malisa, which is situated in the foreland and classed as drill-ready, with a mean estimated GIIP of over 2 Tcf and condensate potential. The target reservoirs in Malisa are the Lower Cretaceous Elevala and Toro sandstones and the Jurassic Kimu sandstone, which are shallow marine sands shed from the Australian Craton to the southwest and proven in adjacent discoveries.

Due to the low relief nature of the prospect, multiple depth conversion methodologies were applied by the team, all of which confirmed a valid closure at reservoir level. In addition, the surrounding discoveries made in the foreland, such as Stanley, ►



SOURCE: CHAMBERS & MAXWELL, EAGE 2020

Creaming curve showing that the basin – especially when it comes to gas – is not creamed yet.

Elevala, Ketu and Ubuntu, are all similar in terms of reservoir and trap style, proving that the play works.

Again, based on offset wells, Heritage expects reservoir porosity to be in the order of 18 – 20 %, with an average permeability of around 50 mD. The overall chance of success is estimated at 44 %, which is comparable to the regional exploration performance that shows the Western Province to have a one in two success rate, despite the scarcity of data.

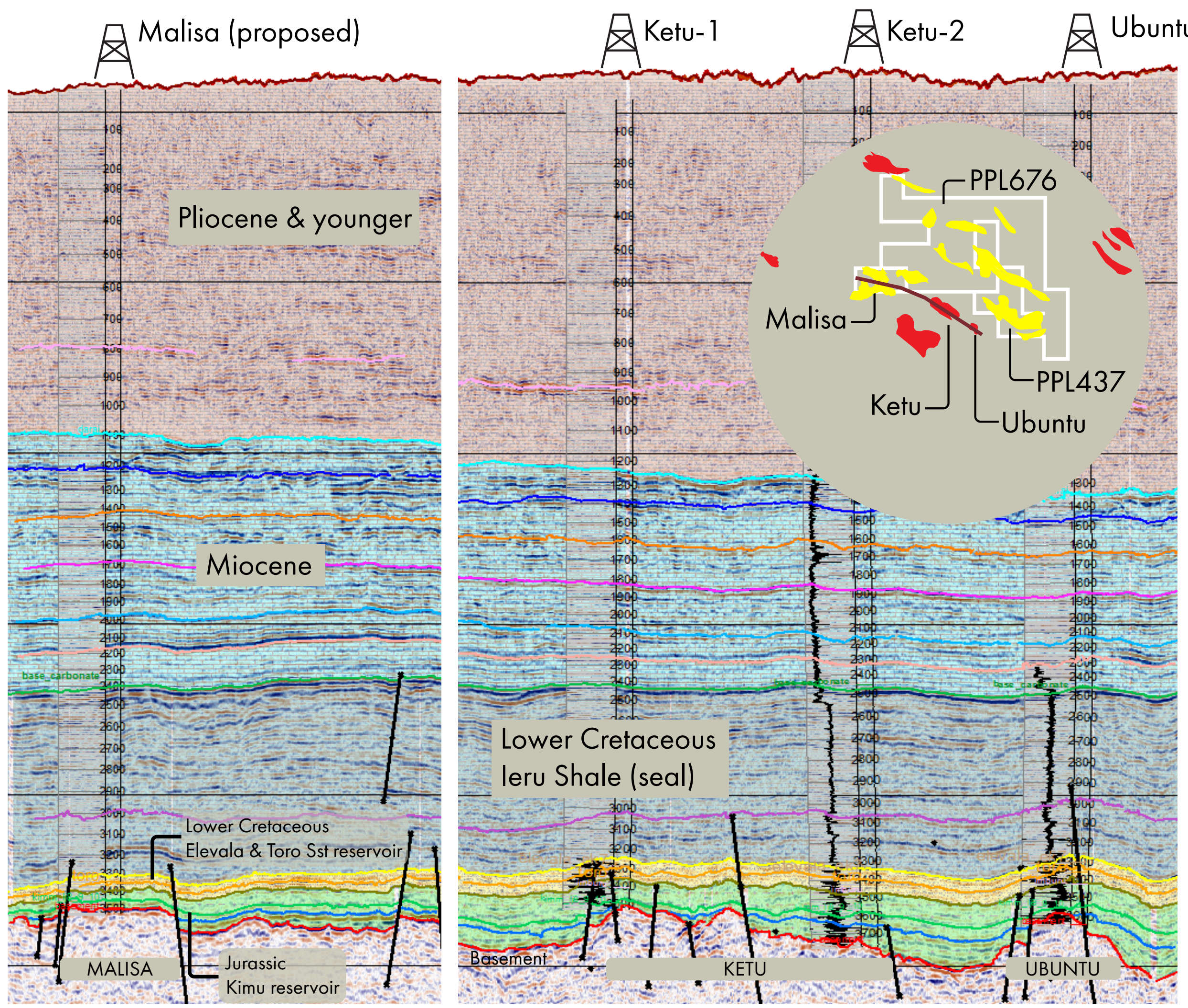
In total, Heritage has mapped 10 prospects and leads across the two licences, with seven of them being the foreland basin-drape type and three located in the fold belt play.

One of the main drivers of the exploration success in the region is the prolific Upper Jurassic source rock. The relatively thick Ieru Formation of Lower Cretaceous age also provides an efficient seal. Timing is still a key element, though; a dry well analysis of wells drilled to the west of Heritage's licences showed that these basement drape prospects were paleo-lows during the migration phase in Oligocene times.

UNLOCKING THE RESOURCE

The significant undeveloped discovered gas volumes in the area around the Heritage licences, combined with the prognosed volumes that are waiting to be unlocked through exploration drilling, would provide the scale and opportunity for a coordinated approach to the development of an additional LNG infrastructure system in the Western Province. Discussions have already taken place along these lines. But before that large-scale LNG development was to occur, there is also the opportunity for an early phased development of gas and associated condensate resource through local consumption and small-scale export. That is what the operator of the nearby Stanley field will now embark on through the planned construction of a data centre in the area. Other options include exporting the condensate – the existing discoveries tend to have a Condensate-Gas ratio of around 40 – via barge down the Fly River. The river is navigable and is already used for transport, demonstrating that this is a viable option too. ■

Henk Kombrink



Seismic line across Malisa prospect, showing the nearby gas discoveries in the same basement drape play.

SOURCE: HERITAGE OIL

Hybrid terrain, unified technology – GT's land-nodal system for high-quality transition zone seismic data acquisition

Geofizyka Toruń has redefined the process of seismic acquisition in the land-to-sea transition zone by adapting the latest generation of land nodes for marine deployment on their own high-stability buoys. This methodology has proven successful across several high-impact projects as it eliminates traditional survey "seams" by utilising a homogeneous nodal spread

PIOTR POTEPA, GEOFIZYKA TORUŃ

For sixty years, Geofizyka Toruń (GT) has built its reputation by pushing technological boundaries and exploring the most challenging environments in the field of global seismic acquisition. Since its earliest years, GT has consistently faced and managed operational challenges in deserts, cities, mountains, and areas where land meets the sea.

This openness has naturally led GT to become an innovator in highly complex transition zone (TZ) projects, where marine and terrestrial conditions overlap, and traditional seismic methods often fail. Tidal flats, marshlands, lakes, beaches, and shallow coastal shelves are among the least seismically explored areas due to operational complexity, cost, and the incompatibility of traditional land and marine systems.

Traditional cable-based marine equipment poses numerous operational difficulties, including heavy, specialised cables; high power demands; complex deployment procedures; and long acquisition downtime whenever failures occur. Additionally, Ocean Bottom Node (OBN) technology, though capable of delivering excellent data quality, is extremely costly and generally impractical in very shallow waters. In these areas, vessel access is restricted, and the size and weight of OBN units prevent efficient deployment.

Yet, GT has consistently accepted these challenges, developing intermediate solutions that bridge the gap between onshore and offshore environments. Over time, GT has not only adopted new methods but also actively shaped modern industry practices by reimagining how seismic data can be acquired across hybrid land-to-water terrains.

Figure 1: The evolution of Geofizyka Toruń's Transition Zone acquisition technology: from early foam platforms and solar-integrated systems to the current nodal buoys designed for marine conditions.

The technological evolution of our operations has shifted from heavy, cable-dependent infrastructure to agile, autonomous nodal systems (Figure 1). Initially, TZ surveys relied on specialised marine cables that presented significant operational challenges, including power supply issues, high failure risks, and complex retrieval processes that often resulted in costly downtime.

The first step toward a more flexible approach was the introduction of foam-based floating platforms equipped with early wireless recording units. While these units were effective in calm waters and lakes, their heavy battery requirements dominated the platform's mass, limiting their use. However, frequent battery swaps remained a logistical bottleneck until GT integrated solar panels into the design, enabling uninterrupted, long-term operations in remote marine environments. This system was first deployed internationally in the 2020 UAE Block 5 project, where nearly 1,000 platforms were deployed up to 8 km offshore.

The arrival of the latest generation of land nodes marked a definitive turning point in GT's engineering strategy. Originally designed for land use, these lightweight, high-endurance nodes were seamlessly adapted for marine conditions by housing them within custom-engineered, streamlined buoys. Unlike earlier platforms, these second-generation buoys are specifically designed for unsteady, wave-affected waters. Each buoy features a surface-mounted node powered by internal batteries, a counterweight ballast for stability and GNSS receiver for precise timing and positioning. The node is linked to a hydrophone resting on the seabed, enabling independent data storage and high-fidelity recording. GT utilises Low Power Wide Area Network (LPWAN) technology to ensure data integrity, enabling near real-time remote health monitoring of the spread.

Figure 2: Seismic transition zone surveying includes vibrator operations, onshore data recording by nodes, and offshore data recording by nodes mounted on buoys and surveyors working along the beach.

These technological advances have resulted in a series of successful large-scale projects, each of which demonstrates the effectiveness, reliability, and cost-efficiency of GT's land-nodal maritime solutions. The robustness of this approach was first validated through thorough implementation tests in the Baltic Sea during the harsh winter of 2023. Despite sea states reaching 9 – 10 on the Beaufort scale, the buoys maintained exceptional positional stability, with coordinate deviations of only a few meters. This reliability paved the way for international commercial success.

In the UAE Block 6 project (2023), GT successfully navigated a highly complex 615 km^2 area, with the offshore marine acquisition zone covering over 47 km^2. GT's system scalability was further demonstrated in the Baltic Sea during the Białokury 3D and Biesiekierz 3D surveys for ORLEN S.A. In the Białokury project, which covered 338 km^2, of which 79 km^2 were offshore, GT integrated nearly 1,000 marine hydrophone buoys and over 25,000 land geophones into a single, seamless acquisition grid extending up to 6 km from the coast (Figure 3).

The Kalundborg 3D project (2025) for Equinor, Ørsted, and Nordsøfonden in Denmark marked a new milestone for this methodology. The survey covered a total area of approximately 182 km^2, including a 47 km^2 offshore zone across Nekselø Bay. Designed to evaluate the suitability of the subsurface for carbon capture and storage (CCS), this offshore segment utilized 1,842 buoy-mounted nodes. Near real-time node status control was maintained via LPWAN technology, and GNSS-based positioning ensured precise receiver coordinates despite variable bathymetry and strict environmental regulations. Despite complex vessel logistics and changing sea conditions, the system proved exceptionally robust, with only four buoys lost throughout the entire offshore campaign.

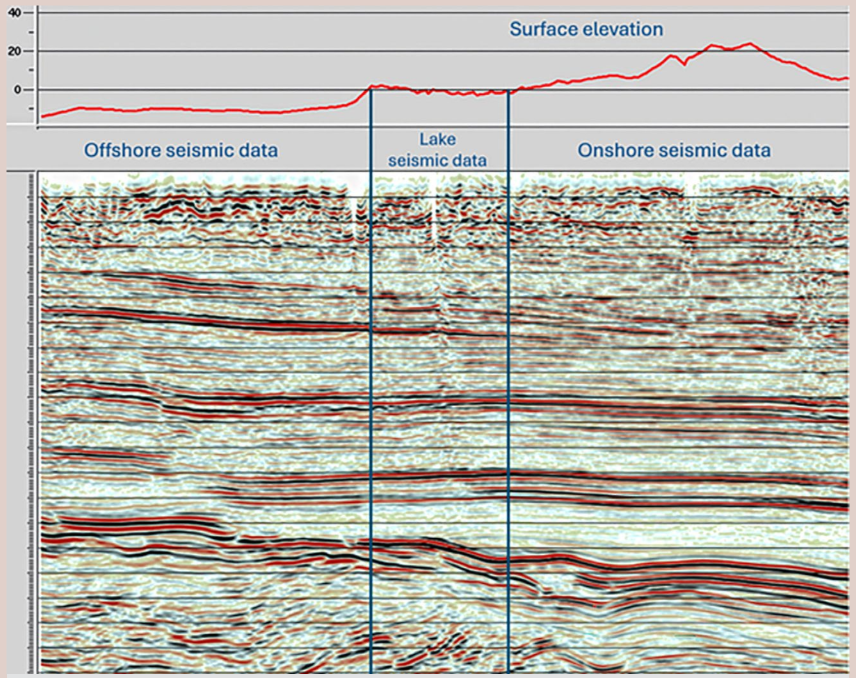


Figure 3: 2D seismic section extracted from the Białokury 3D survey volume. The profile demonstrates seamless continuity across diverse acquisition environments: From the offshore marine zone (left), through the lake segment (center), to the onshore area (right).

The ultimate validation of GT's nodal-buoy strategy can be seen in the final seismic product. GT has eliminated the discrepancies and "seams" typical of multi-environment surveys by using a homogeneous nodal system across land, lake, and marine environments. The data quality from buoy-mounted land nodes is comparable to standard onshore acquisition, providing seismic sections that remain uniform across environmental boundaries. After applying proprietary drift-correction algorithms and elevation statics, reflector continuity becomes seamless with no visible transition artifacts. This consistency, along with substantially lower operational costs compared to conventional OBN or cable-based systems, highlights that GT's solution is not only technically top-notch but also economically appealing. GT has refined its method for acquiring high-quality seismic data in previously inaccessible areas over the years, providing unmatched continuity across all segments of the Transition Zone.

"Reservoir engineering was too boring for me"

A conversation with Lone Margrethe Olstad on how she leverages her experience to grow her subsurface team at AGR

"OUR INDUSTRY is back in business," says Lone Margrethe Olstad enthusiastically when we meet on Teams. And so is AGR, the company she joined four months ago, as it has the ambition to grow the subsurface consultancy, evaluations and reserves and resources due diligence advisory. Not only in Norway, where they have broad experience and have worked on almost every single field, but also abroad.

Lone is determined to make it a success. She not only relies on the expertise of her Reservoir Management and Subsurface advisory team, which consists of almost 100 specialists from all the main G&G disciplines, but she also relies on her own skills and experience to make this happen.

"I'm from a small village in Norway, and possibly because of that, I am quite down to earth and tend to call a spade a spade," Lone says. "When I joined the industry, I really had to learn how people communicate in the oil business, where it is a bit more formal at times."

THE BUZZ OF OPERATIONAL CHALLENGES

If there is one thing that characterises Lone, it is that she has always jumped on opportunities. "I'm bored quite easily," she admits with a smile. She started her career as a reservoir engineer at ExxonMobil. "But being a reservoir engineer was too slow for me," she laughs. "It is a little too passive, as you tend to just turn the wheels on your simulation software and wait for a result, without too many surprises happening."

> "I like to jump on challenges and get things moving"

What attracted Lone much more is the production engineering side of the business. "You get involved with managing production by adjusting the wells," she says. "It's very hands-on. And then there are the operational challenges that happen all the time, for instance, when a well shuts down all of a sudden. It creates a buzz that I thrive on."

When she had the opportunity to become the first petroleum engineer at newcomer Marathon Oil in Norway, she didn't hesitate to apply and was offered the job. "I loved it," she says, "I was thrown in at the deep end. It also proved that I was made for the engineering side of things."

Lone Margrethe Olstad.

PHOTOGRAPHY: AGR

But her ambition stretched further than operating the nuts and bolts of the oil field. She had always aspired to become a leader. It didn't last long before she got the opportunity.

A NEW WAY OF WORKING

"With Aker BP, she explains, "I stood at the base of an entirely new way of working with contractors on development projects. We called it alliances, which replaced the old way of working with contracts in a top-down fashion. In the alliance model, we acted as a team with common goals, and thereby shared the responsibility with the contractor of arriving at the same product as before, but in a more efficient and cost-effective way.

> "A lot of magic tends to happen in one-to-one conversations"

"And this model is still alive today," Lone tells me, "whilst I've been away for quite a few years now. Something must work all right there."

"What was the secret to implementing this new way of working?" I ask. "Lots of one-to-one conversations," Lone says. "I think you need to have a feel for the internal dynamics in the team, and get those who enjoy the most respect in the team with you. That takes time, but I felt like I succeeded in doing so."

DELIVERING ADDED VALUE

Before starting at AGR earlier this year, Lone spent almost five years with Cognite, a company in the E&P software business. "It was a very different environment from what I had seen thus far," she says. "Fast-paced, young, dynamic, and round the clock. Plus, a lot of focus on creating added value for clients, while managing people and budgets. That's ultimately what that type of business is about, which is very different from an oil and gas operator, where the largest investments ultimately are tied up in tangible hardware. In that sense, the experience I gained as an independent subject matter expert is something I now bring into a consultancy like AGR, which operates in many of the same ways – delivering added value."

> "We talk oil and gas again"

But it was the big projects, the redevelopments, the wells, the technical engineering, that drew Lone back into the consultancy world. "I feel we have a good export product," she says. "True, Norway has something to learn when it comes to the speed with which some projects are being carried out, but the technical expertise is world-class."

FASTER AND WITH LESS RESOURCES TO FIRST PRODUCTION

There is now an increased awareness in the industry that near-field developments can't simply take ten years to develop. It has to be brought down to no more than three. Lone's work with Aker BP also comes in handy here. "I already showed that working in an alliance framework has the genuine potential to speed up projects, which is exactly what we are trying to do now with our clients at AGR. That's why we are already talking to some clients to implement that model of establishing a more integrated team, covering reservoir, wells, facilities, marine, and digital solutions," Lone explains.

Her first few months has consisted of a lot of talking and a lot of listening. But the conclusion is simple: "The industry is ready to embark on a big push to develop near-field resources faster," reiterates Lone. "We can help with that. We are ready to apply our experience across the Norwegian Continental Shelf, and abroad, as we identified a number of potential growth areas where we see tremendous potential."

With someone at the helm who likes to jump on a challenge, Lone is no doubt the right person for the job. ■

Henk Kombrink

CONTENT MARKETING

Moveout democratises data transformation

As the volume and diversity of seismic data continue to expand, many operators and data custodians face a persistent challenge: How to consolidate legacy datasets – often stored across multiple vintages and formats – into consistent, usable assets. Historically, this has required specialist service providers or significant internal resources

NEVIL HALL, MOVEOUT DATA

UK-based Moveout Data has spent more than a decade addressing this problem as a service provider. Now, the company is taking a different approach: Releasing its in-house data transformation platform, Metaseis, to the wider market.

The move reflects broader changes in how subsurface data is managed. With increasing emphasis on cloud-based workflows, regulatory reporting, and AI-driven interpretation, the need for structured, high-quality seismic data has become more pressing.

"We originally developed Metaseis to give ourselves a competitive edge in handling complex client data quickly and consistently," says managing director Darren McDonald. "Over time, it became clear that the same challenges we were solving internally were being faced across the industry."

FROM INTERNAL TOOL TO COMMERCIAL PLATFORM

Development of Metaseis began in 2014 as part of a strategy to improve turnaround times and adaptability. By building and refining its own software, Moveout was able to refine workflows through exposure to large volumes of real-world seismic data. The company now wants to extend access to the same proven technology that has supported its growth, enabling organisations to efficiently prepare, manage, and optimise their own seismic data at scale.

"From the outset, our strategic decision to develop our own software has certainly paid off," McDonald says. "Metaseis enables us to respond quickly to client needs, continuously evolving through processing petabytes of real-world data."

By now launching Metaseis to the global market, Moveout is offering access to the workflows that have underpinned its own success. The company sees Metaseis appealing to a broad user cohort, such as energy companies, national data repositories, multi-client libraries, transcription centres, field geophysicists and academia.

Whatever the media or format, Metaseis can overcome even the toughest data challenges.

PHOTOGRAPHY: MOVEOUT DATA

"Metaseis has been built by seismic data geophysicists, not a software house," McDonald continues. "It's shaped by real-world challenges and designed with usability in mind. Users can be productive quickly, benefiting from powerful, enterprise-grade functionality."

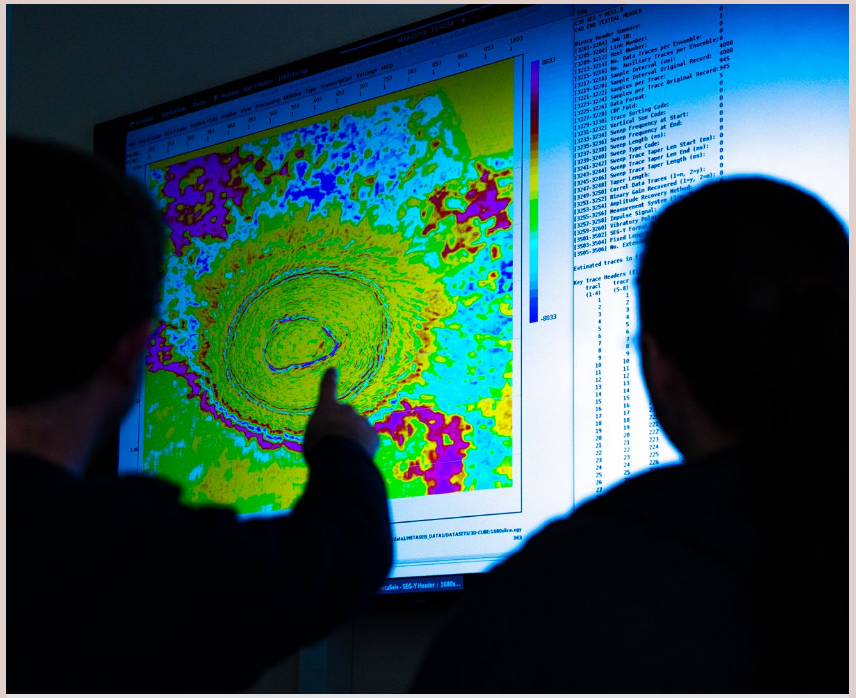
The platform now supports a range of functions, including metadata extraction, data organisation, quality control, validation, and transcription across formats such as SEG-B, SEG-D and SEG-Y, and can decipher TAP and SEG-RODE. These capabilities are particularly relevant for organisations managing legacy archives or preparing datasets for reprocessing and reinterpretation. Unlike many enterprise software solutions, Metaseis has been designed with a focus on usability. According to the company, users can begin working with the system quickly, without extensive training.

SUPPORTING NATIONAL DATA INITIATIVES

Metaseis has already been deployed in large-scale projects: notably, it underpins Moveout's role in supporting the UK's National Data Repository, where it has been used to streamline data ingestion and compliance processes since 2021.

Such initiatives highlight a wider industry shift towards improved accessibility and standardisation of subsurface data. As more countries develop national repositories, the ability to efficiently transform and validate incoming datasets is becoming increasingly important.

"As demand increases for cloud readiness and AI-driven workflows, Metaseis will enable organisations to standardise and prepare their seismic data," says Steve Callan, Moveout's sales director. "There's a clear trend towards the preparation of seismic data for advanced analytics and machine learning, which requires consistency and quality at the input stage."



Metaseis creates opportunities for visual collaboration and analysis.

ADDRESSING LEGACY CHALLENGES

A significant proportion of global seismic data still resides in older formats or on physical media. Converting and validating these datasets can be time-consuming and technically complex.

Moveout's experience includes hundreds of seismic navigation merge projects, as well as large-scale library rationalisation efforts. In one recent UK Continental Shelf project, the company supported the reporting and consolidation of dozens of wells and seismic surveys. "Twelve years of using the system gives us absolute confidence in its value to users, and our ability to support it," adds Callan.

This operational background has shaped the design of Metaseis. Features such as integrated QC visualisation and flexible transcription modules are intended to allow users to interrogate and verify data throughout the transformation process. The company says its team has a total of over 300 years' experience of acquiring seismic survey data, and knows what users need. This operational background has shaped the design of Metaseis, with features such as integrated QC visualisation and flexible transcription modules intended to allow users to interrogate and verify data throughout the transformation process.

A CHANGING DATA LANDSCAPE

The release of Metaseis comes at a time when the geoscience sector is re-evaluating how data is managed and utilised. As exploration strategies evolve and digital technologies mature, the ability to rapidly convert raw or legacy datasets into analysis-ready formats is becoming a key enabler of value.

By making its internal platform available externally, Moveout is positioning itself within this transition – not only as a service provider, but also as a technology supplier.

Whether this approach gains widespread adoption will depend on how organisations balance in-house capability with outsourced expertise. However, the direction of travel is clear: seismic data transformation is no longer a niche technical task, but a central component of modern subsurface workflows.

AI-driven integration for deeper subsurface insights

Artificial intelligence is transforming geoscience, enabling unprecedented improvements in seismic interpretation, reservoir characterization, and multi-disciplinary data integration. Traditional subsurface workflows – often slow, siloed, and constrained by manual interpretation – are being reshaped by foundation models, multi-modal learning, physics-informed neural networks, and agent-driven automation.

Recent breakthroughs in seismic foundation models (SFMs), multi-modal geoscience transformers, and generative AI have demonstrated substantial gains in speed, accuracy, and generalization across surveys. These advances mark the beginning of a new era in earth modelling: One that promises holistic, continuously updating digital twins of the subsurface.

EARTH SCIENCE ANALYTICS

THE STATE OF GEOSCIENCE TODAY: CHALLENGES & OPPORTUNITIES

THE RISE OF AI IN SUBSURFACE WORKFLOWS

Subsurface characterization has long relied on expert interpretation of subsurface rock samples, well logs, and seismic data. As datasets have become larger, and domain experts increasingly need deeper insight into complex geological heterogeneity, machine learning (ML), especially deep learning, has become essential for capturing nonlinear relationships and extracting meaningful insights at scale. ML is now central to image data interpretation, log interpretation, seismic interpretation, and reservoir property estimation from seismic (Figure 1).

WHY AI NOW?

Four converging factors enable the rapid adoption of AI in geoscience today:

- Massive growth in data volumes: Modern seismic surveys generate large-scale 3D subsurface volumes, enabling direct training of deep neural networks on volumetric data.
- Maturity of deep learning architectures: Transformers, diffusion models, and contrastive vision-language frameworks are now applied to seismic interpretation.
- Foundation models enabling cross-survey generalization: New models provide reusable seismic features across basins and data vintages, increasing robustness.
- Industrial demand: Operators seek faster, more accurate, and integrated workflows to improve well placement, reduce costs, and accelerate field development.

The energy industry generates vast amounts of subsurface data: Seismic surveys, well logs, core samples, rock data, and geological reports. Much of this information, however, is still underutilized. The main barriers are fragmented, discipline-specific workflows, heterogeneous data formats, limited cross-disciplinary interoperability, and slow, manual interpretation processes.

Advances in AI now address these challenges by integrating seismic data, text, geological maps, and numerical logs within unified analytical frameworks.

AI TRANSFORMATIONS ACROSS GEOSCIENCE DISCIPLINES

AI is delivering order-of-magnitude improvements across key subsurface workflows in the energy industry, fundamentally changing both the speed and quality of interpretation.

In seismic interpretation, modern AI-driven platforms such as EarthNET enable horizon and fault interpretation to be completed 20 – 200 times faster than traditional manual approaches. By automating pattern recognition and consistently applying learned geological features across large seismic volumes, these systems significantly reduce interpretation cycles while improving reproducibility and reducing interpreter bias.

AI is also accelerating reservoir characterization by enabling the rapid and coherent integration of diverse data types, including core and core-plug measurements, cuttings data, well logs, and seismic volumes. This integrated approach supports the construction of consistent, multi-scale earth models that capture both fine-scale rock properties and larger-scale structural trends, leading to faster insight generation and more robust subsurface understanding.

PROPERTY PREDICTION FROM WELL DATA

AI has now, for several years, been accelerating log editing and infill, as well as prediction of target properties based on available well logs. The ability to do this type of work efficiently and at scale has enabled basin-wide missed pay studies that have revealed overlooked exploration opportunities.

EarthNET can now integrate core photos (Figure 1B), cuttings photos (Figure1C), thin sections, logs (Figure1D), and geochemical data such as X-ray fluorescence (XRF) and X-ray diffraction (XRD) for more reliable classification of facies and prediction of target properties in wells.

This multi-modal approach enables petrologists and petrophysicists to characterize samples and interpret well logs faster, with higher consistency, while using all the available data.

The interpretation of geological timelines and age of samples is now possible using computer-vision-based fossil identification (Figure 1A) and biozone classification. Emerging, multi-modal models will soon merge fossil-derived timelines with well logs and seismic for chronological consistency, facilitating the creation of sequence-stratigraphic models based on all available data.

PROPERTY PREDICTION FROM SEISMIC

EarthNET users can leverage machine learning methods that integrate well data with seismic information, enabling more accurate and scalable prediction of key subsurface properties. By jointly analyzing logs and seismic partial stacks, these approaches can infer elastic properties, lithofacies distributions, porosity, fluid saturation (Figure 1E), and other critical reservoir parameters across large spatial domains. This integrated learning reduces uncertainty while extending well-based insights into areas with sparse direct measurements. More broadly, machine learning represents a significant advancement in the way seismic data is mapped to underlying rock and fluid properties.

Traditional empirical and physics-based workflows are increasingly complemented by, and combined with, data-driven models that can capture complex, nonlinear relationships in the subsurface.

STRUCTURAL SEISMIC INTERPRETATION

The efficient AI-assisted workflows for fault detection (Figure 1F), horizon tracking, geobody delineation, and seismic facies classification facilitate the construction of the structural and stratigraphic models that host the property volumes created from the combination of well and seismic data. As a result, ML-based techniques are improving subsurface characterization and prediction across a wide range of applications, including hydrocarbon exploration and production, CO_2 storage and monitoring, groundwater assessment, and geothermal resource development.

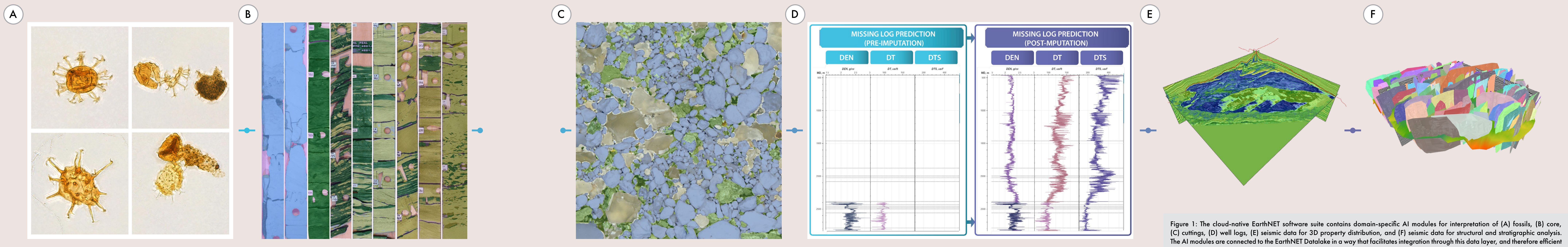


Figure 1: The cloud-native EarthNET software suite contains domain-specific AI modules for interpretation of (A) fossils, (B) core, (C) cuttings, (D) well logs, (E) seismic data for 3D property distribution, and (F) seismic data for structural and stratigraphic analysis. The AI modules are connected to the EarthNET Datalake in a way that facilitates integration through this data layer, and therefore efficient execution of multi-disciplinary workflows.

LEVERAGING FOUNDATION MODELS FOR SEISMIC INTERPRETATION

Foundation models are large, general purpose machine learning models trained on massive amounts of diverse data and designed to be adaptable to many downstream tasks (Figure 2). The emergence of such models reduced a significant bottleneck for the efficiency of AI-assisted seismic interpretation, i.e. the strong dependence of annotated data.

Self-supervised learning is the underlying training paradigm where labels are automatically derived from the data itself, rather than manually annotated by humans.

Seismic foundation models have demonstrated superior performance across seismic denoising and seismic interpretation tasks compared to traditional deep learning methods. Such models can generalize across surveys without retraining. With "human in the loop" workflows, these models can reduce interpretation cycle times (up to 200 times), for tasks such as fault, horizon and geobody interpretation.

PHYSICS-INFORMED NEURAL NETWORKS

Physics-informed neural networks (PINNs) incorporate governing physical laws directly into neural networks and can therefore leverage the knowledge accumulated by researchers and domain experts. We no longer have to choose between using a physics-based approach or a learning-based approach, but can now combine both using PINNs and get the best of both worlds. Recent work in Earth Science Analytics shows that by combining physics-based methods and learning-based methods in physics-informed foundation models we can achieve improved inversion robustness, better generalization across geologies and more physically consistent predictions.

Physics-informed AI bridges data driven ML with geophysical theory, transforming seismic inversion workflows.

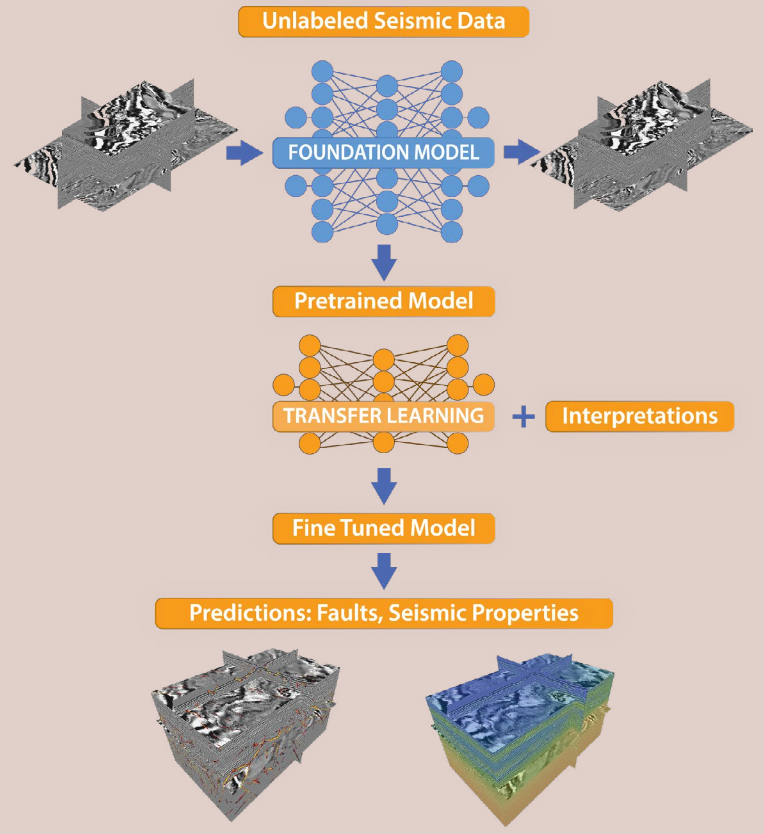


Figure 2: Foundation models leverage self-supervised learning, meaning that they can be trained at scale without the limitation of being dependent on human-annotated data. Through transfer learning, the models can be fine-tuned to perform a wide variety of tasks.

INTEGRATING DISCIPLINES IN THE ERA OF FOUNDATION MODELS AND PHYSICS-INFORMED NEURAL NETS

Within Earth Science Analytics, foundation models and physics-informed neural networks (PINNs) are already playing a central role in the integration of diverse subsurface data. These approaches are currently being applied to jointly analyze well-log measurements and seismic data, enabling the construction of coherent, high resolution three-dimensional volumes that describe elastic parameters and reservoir properties. By embedding physical constraints directly into the learning process, these models allow data driven insights to remain consistent with established geophysical and geological principles.

Looking ahead, our ambition is to move beyond pairwise data integration toward a deeper and more comprehensive unification of geoscience disciplines. This effort will focus on the development of multi-modal geoscience foundation models capable of ingesting, correlating, and reasoning across multiple heterogeneous datatypes simultaneously.

In addition to seismic volumes and well logs, these models will incorporate visual and petrophysical information derived from core images, cuttings images, and thin-section microscopy. Quantitative laboratory measurements, including core-plug data and X-ray fluorescence (XRF) analyses, will further enrich the learning process by providing direct constraints on rock properties and geochemical composition.

By enabling joint learning across these complementary data modalities, we aim to create integrated subsurface representations that capture structural, elastic, petrophysical, and compositional variability in a unified framework. This multi-modal approach is expected to reduce uncertainty, improve interpretability, and ultimately support more robust reservoir characterization and decision-making in complex geological settings.

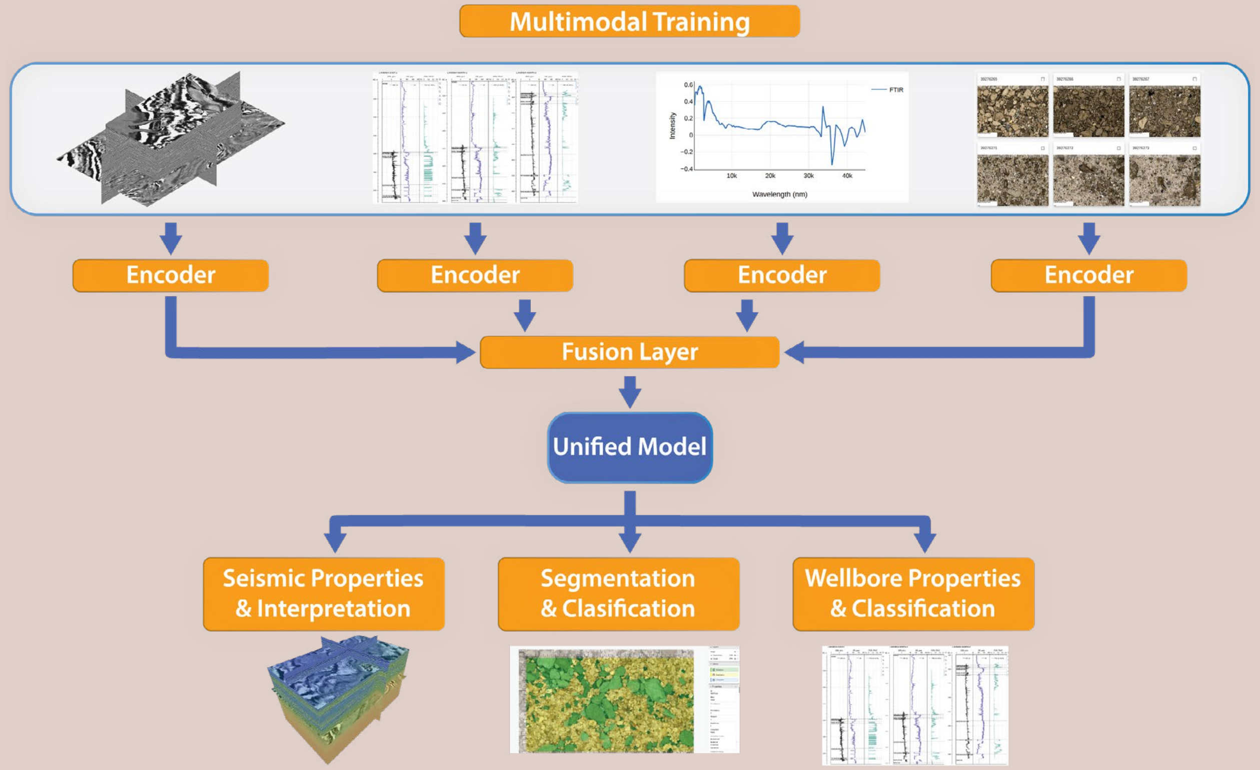


Figure 3: Multi-modal integration of geoscientific data can be facilitated by agentic AI capable of executing multi-step geoscientific workflows, creating self-improving solutions, better utilising all available geoscientific datatypes, and propagation of uncertainty through multi-disciplinary integrated workflows.

THE PATH TOWARD AUTONOMOUS WORKFLOWS

Agentic AI is a promising direction for pursuing our vision of multi-modal integration of geoscientific data (Figure 3). Agentic AI leverages autonomous LLM-driven systems capable of executing multistep geoscientific workflows and creating self-improving multi-modal AI models. We believe that this paradigm can open opportunities for better utilisation of all geoscientific datatypes, further automation of QC, and better propagation of uncertainty through multi-disciplinary integrated workflows.

We see a path to a future where agents can manage continuous model updates, run cross-disciplinary workflows, autonomously refine reservoir models, and support decision-makers with insights stemming from all available data. Advancements in artificial intelligence are transforming subsurface sciences, enabling the creation of high-fidelity digital twins that function as dynamic, continuously updated representations of the Earth. These living models integrate seismic, well, production, geological, and petrophysical data into a unified framework that evolves as new information becomes available. By combining multi-modal learning, seismic foundation models, physics-informed neural networks, and agentic AI, these systems support real-time scenario testing, uncertainty quantification, and automated decision-making. This convergence marks a fundamental shift away from fragmented, discipline-specific workflows toward holistic, autonomous subsurface modelling environments. As these technologies mature, they empower geoscientists to derive deeper insights, accelerate interpretation cycles, and achieve more accurate and integrated Earth models – ushering in a new era where AI is central to how we understand, predict, and manage the subsurface.

PORTRAITS

"When you try to pull together a complicated subsurface workflow, it is not always obvious that AI is a huge time saver because it still needs a lot of teaching, there is still a major role for experienced people"

Vasilii Shelkov – Rock Flow Dynamics

"RUNNING A COMPANY IS LIKE HAVING A LONG-TERM RELATIONSHIP – YOU HAVE TO GIVE AND TAKE, BUT ALWAYS CARRY ON"

A conversation with Vasilii Shelkov about how he established reservoir simulation software business RFD whilst coming from the academic world of physics and accelerators

HENK KOMBRINK

Surrounded by computers at the RFD Houston office.

PHOTOGRAPHY: RFD

"MOSCOW WAS a dark place near the end of the 1980s. Literally, dark. It was hard to find a bar to have a drink," remembers Vasilii Shelkov when we start our conversation about his early years as a physics student in Russia.

It wasn't a real surprise for Vasilii to go and study physics. "Both my parents were scientists," he says. As a family, they moved to Dubna, outside Moscow, which was known as a science city. It was constructed in the 1960s with the idea of becoming a rival to Berkeley Labs in the USA. Little did Vasilii know that he would later make a name for himself at this US rival.

"I saw my dad having so much fun," Vasilii continues. "They built all these new particle detectors, designed new experiments, and people were competing to reach another breakthrough. And we had access to computers much earlier than everyone else. I remember I was sending emails before I went to university, using mainframes that I I had access to through my parents' work."

"Times were a little crazy as I entered university during the last year of the Soviet empire in 1987," he says. "For years, all university students had been taught a compulsory course on the history of the communist party. Then, all of a sudden, it was scrapped, with no real replacement. That's why we ended up getting an overview of the world's religions instead," he laughs.

Russia changed fast as the country opened up in those years. "I took my future wife to Pizza Hut for our first date," says Vasilii. "It was a big thing for my generation to see the first Western chain restaurants established in Moscow. People were queuing to get in."

A MOVE TO TEXAS, BUT NOT FOR OIL

Thanks to the country's opening in the 1990s, Vasilii's opportunities broadened to an extent that previous generations had not enjoyed. "Immediately, students began applying for universities abroad, especially in the USA," he says. Including himself, as he found a PhD position at Southern Methodist University in Texas.

"Texas had become famous on the back of NASA," he says, "and people wanted to achieve something similar by constructing a big particle accelerator, even bigger than we currently know from CERN in Switzerland."

On the back of this promise, universities started to realise that they needed students to expand their research that could help build the accelerator. "I arrived during that time," says Vasilii, "when there was a real buzz around all this happening." And construction of the accelerator started, with two miles being completed before the Clinton administration pulled the plug in favour of more funding for the space agency.

"It all felt like landing on the moon," he says. "But we got into the swing of things very quickly, and it was in fact a great time, even though the work on the accelerator came to an abrupt halt." As a result, he quickly moved to Cornell University, where he and his colleagues had access to an accelerator they "could do some pretty cool things with."

When I ask if there was a big difference in the way universities worked between the US and Russia, Vasilii is adamant: "Let's not overegg it; of course, there are differences in PR and politics, but at the end of the day, we all tried to do science, and that was in fact quite similar. We all read the same books as well. It is the same language. Let's not forget that scientific collaboration continued between the Soviet Union, Europe and America, even when geopolitical tensions were high."

THE SILICON VALLEY YEARS

At the end of his PhD, Vasilii was not inclined to take a corporate job. On the back of making an exciting discovery during his PhD, he had built a bit of a name for himself. "It was kind of by accident that I found out more about the decay of Tau Lepton, which people hadn't observed before," he says. "I didn't break the Standard Model, but it was still regarded as quite unusual to discover something like that."

It got him a ticket to UC Berkeley, where he stayed for six years, doing two postdocs back-to-back. But whilst he was at Berkeley, his research was mostly centred around neighbouring Stanford, SLAC, where a new collider was being built. Vasilii primarily worked on the software side, both during the commissioning phase and during the first few operational years of the machine. "It got me into the very things that I'm still doing today," he says, "it was the time I learned about neural networks, data analysis and C++."

Living and working in Berkeley was instrumental. "As one of my supervisors always reiterated, it is good to spend some time in your career surrounded by the best people in the scientific community. Even when you don't know them personally, you can see how they perform," says Vasilii.

Berkeley was a place where that certainly applied, with so much money dedicated to hardware development from many different sources: the government, private sector and lets to forget, the military. "It's a giant soup," says Vasilii.

But after he turned 35, having witnessed the cycle of relentless work and subsequent software releases a few times, he decided it was time to do something else. "I applied to some companies in Silicon Valley," Vasilii continues, "but there was no match."

Ultimately, it led to a move to another lab, this time on the US East Coast; Brookhaven Lab on Long Island, New York. "But I didn't warm up to the work or the environment," Vasilii says. "The people were great, but I got tired of doing the same thing again. I also realised how small the community really was."

YUKOS CALLING

Then, unexpectedly, a very different opportunity came along in Russia. "Some friends told me that there was an open- ▸

ing at Yukos, one of the larger Russian operators at the time, to work in the software development team," Vasilii says. "To me, it felt like a good move to join a big company, and there seemed to be more momentum there – and in Moscow in general – than I had seen in New York over the past year."

Back in Moscow, Vasilii was soon introduced into the world of oil production monitoring. "The group next to me in my office was working on a first-generation simulator to monitor water floods," he remembers. It sparked his interest as he got to know them better.

But similar to his short spell in New York, his time at Yukos did not last long. Less than a year after joining the company, Yukos went under, and Vasilii and his colleagues were back on the job market.

"We stayed in touch as we all went out for interviews with service companies," he says, "but there was a feeling of mutual dislike; they didn't like us, and we didn't like them. In addition, I was obviously seen as an outsider, with only nine months working in the industry under my belt."

SCEPTICISM

Against this backdrop, Vasilii and some of his friends decided to go for it themselves. That's how Rock Flow Dynamics was born, with the right blend of software development skills and, obviously, the skill Vasilii brought from having seen how a place like Berkeley delivered its start-ups.

"We were met with a major degree of scepticism," says Vasilii. "Who are you going to compete with, these established providers?" is something he heard all the time. "Are you crazy? They hate you and will always claim to be better than you."

But Vasilii was convinced. "In fact," he says, "when you start a company, the first one you need to convince of your idea is yourself. Only then can you hit the road and convince everybody else. Otherwise, it is a road to hell."

On stage at the RFD Technology Summit 2026 in Kuala Lumpur.

PHOTOGRAPHY: RFD

> "Don't hire salespeople when your product doesn't sell. It's probably the product itself that needs to be improved first"

Early on, the company recorded only limited sales. At that point, Intel came along. "They wanted to work with start-ups and invited us to join," says Vasilii. "We were using their hardware and were expected to attend trade shows with Intel where we could tell the world what we were doing."

"Ultimately, it was a positive development, both in terms of motivation and as confirmation that a major industry player saw potential in our technology."

It also led to Intel investing $2 M in RFD because they saw the potential and were excited by what Vasilii and his colleagues were doing. "We had crossed that bridge of initial negativity," he says. "We were still alive."

"And whilst the company grew steadily," Vasilii continues, "whenever we had money, we always hired more software developers. That's what we have always done. Don't hire salespeople when your product doesn't sell. It's probably the product itself that needs to be improved first."

ONE WORLD

In those years, Vasilii frequently travelled between Moscow and the USA. "It was one world, much better than what we are seeing today," he says. "For example, I had my eyes on the first workstation that had eight CPU cores, the MacPro workstation. It turned out to be unavailable in Europe and in Russia. The first store that offered it was the 5th Avenue Apple Store in New York. So on a Tuesday, I flew to New York to join the queue on Thursday, and on Monday, we showed our Moscow clients how we ran our models on this eight-core device."

Vasilii moved back to the US in 2010. "Opening our Houston office was a great move," he says, "as I did all sorts of things that I had never done before." Within eight months, the team made their first sale to an exploration company in Dallas. From then on, things started to snowball, with the company opening offices in more and more countries. "I'm used to checking a new place for two essential things straight away," says Vasilii: "Is there a rack room for our computing cluster, and is the electricity supply sufficient?"

The move to the USA was an essential part of the company's journey. "You really have to move into new countries all the time," Vasilii says convincingly. "The market is too small for our type of software to limit ourselves to one country, even like the US or the Middle East. Sales cycles are long, and you need to have things going in multiple places to keep the momentum."

He also remembers the feeling of having no money in earlier phases of the company. "In those cases, we were saved by international clients coming in," he says. "It shows the philosophy of going international. You are forced to go beyond borders."

> "Once you have the momentum of opening offices across the world, all you need to do is not make too many mistakes"

"What happened with the Intel Capital involvement?" I ask at that point during the conversation. "We bought them out," says Vasilii. "At the end of the day, these companies want to cash in on their investments, but we did not want to be sold. That is why we initiated discussions directly with Intel, ultimately arriving at a solution in which we paid them to become independent," explains Vasilii. "But all in all, it was a true partnership and thanks to them we managed to grow the business in the early years."

A POND OF SLOW-MOVING ANIMALS

"How has the attitude from the major service companies towards RFD changed over the years?" I then ask. "The oil industry is a slow pond of animals," Vasilii says. "People don't move much, and that's why the penetration of the brand takes a long time. Any type of conservative industry is like that, so you have to present a story, you have to present a case."

"And even after so many years in business, we still come across companies that don't know us," Vasilii says. "A lot of people don't go to exhibitions at all; they tend to see their managers, and that's about it. So you can present at conferences all the time, but who is actually there? That's why you need to do other things as well to get your name out, in addition to having a lot of patience and persistence."

For Vasilii, these facts are enough to convince him that you need to cast your net widely. "We want to find those people who really want the technology, instead of fighting the gatekeepers who are only preparing for retirement."

"Yet, I don't want to complain," he says, "it's just the nature of the business.

At the same time, Vasilii has also recognised that the oil industry itself is not growing, which has made him and his team decide to expand into related sectors as well, such as mining, geothermal and lithium extraction. "Once again, you move away from your comfort zone," he says. "They send you to hell, and you have to build it all up yet again. But I tell my sales guys not to give up too easily. They do like our product, but they don't know about it yet!"

THE PANDEMIC BROUGHT POSITIVE CHANGE

Where you often hear how detrimental the pandemic was for businesses, Vasilii is convinced that overall, it was a net positive. "It allowed us to experiment with remote work to an extent we had never done before," he says. "And now, as a result, we are actually saving money because we don't need everyone in one place all the time. It also allows us to recruit in areas where we would not have recruited before. In terms of sales, the company was not too badly affected either. "Our revenue started to go in the wrong direction in the beginning," Vasilii says, "but went back to where it was before once people got accustomed to the new way of working. At the end of the day, what do you do when you sit at home? You run some models!

BEING REALISTIC ABOUT AI

"How does AI affect your business?" I ask. "You see the excitement of users all the time, especially when you show something really AI-driven," Vasilii says. "But when you try to pull together a complicated subsurface workflow, it is not always obvious that AI is a huge time saver because it still needs a lot of teaching. That's why I am not 100 % sold on AI, and I think there is still a major role for experienced people driving these things."

"In addition, there is also the concern that you become too dependent on data centres that you don't control," says Vasilii. "For us, it is a matter of how far you want to integrate with external AI companies."

Yet, Vasilii acknowledges that the pace with which the industry is moving is incredible, and agrees that AI has gained its place. "As an example, we use Claude Code to talk to our software, and it has become a systems administrator in that way. And it can do a lot."

"What is supercool as well," Vasilii adds, "is to anonymise a log file, take out all the field names, and let AI analyse it and provide a summary. That was a real wow moment, because it checks things that humas will never be able to do."

"Ten years ago," Vasilii continues, "it was the gaming industry that pushed the way performance computing innovated, with the shift from GPU to CPU. Nowadays, it is AI that is driving innovation, with much more focus on efficiency and electricity consumption. That's why platforms like ARM are now in focus in the industry, because they offer energy-saving technology. It is the same technology that enables your smartphone to be charged for a few days. It's a matter of time until this percolates to our business too." ▸

A SOFTWARE FACTORY

"If you promise people that you have all this shiny technology, you have to put something behind the words," says Vasilii when we start talking about software development. "The algorithm has to produce a result that makes sense, and that's why we shy away from becoming a visualisation-only tools company."

"We have a group of engineers that continuously tests newly developed code against existing lines," explains Vasilii. "We call it regression testing."

"It is our heartbeat," he continues, "our clients expect a swift fix, and we have to provide it. In the early days, you could fix things quickly on the go, but now, with more than 10 M lines of code, it has become much more protocolised just because of the size of the operation."

That's why the company recently opened a new data processing centre in Serbia. "Before we launched it," Vasilii continues, "it could take up to three days to test a new fix. Now we can do it in eleven hours."

"We still do four major releases per year, but in between there are around 10 minor releases," Vasilii explains. "It's a mockery of real technology not to continuously upgrade and update your software. It is a genuine factory now."

> "If you promise people that you have all this shiny technology, you have to do something behind the words"

COMPANIES AND RELATIONSHIPS

"I compare having and running a company with being in a long-term relationship," says Vasilii, as we come to the end of our conversation. "It's not always fun; there are always some issues that need to be resolved, but you have to keep going to survive. If you go ballistic at every conflict or misunderstanding, the whole thing will be over very quickly."

"What is important is to create a filter that allows you to red-flag the things that have to be resolved quickly," he continues. "In our case, that can be a bit of technology that we see our competitors use, but we haven't looked at yet. Then you need to push it through, even when your colleagues may not talk to you for a few days."

"What all this basically shows," concludes Vasilii, "is that things never stop. There will always be something new around the corner. In a way, it is similar to my early days as a scientist. There is always something new to be developed. It keeps you alive. And I feel energised to bring that to oil and gas." ■

GEOTHERMAL ENERGY

"A hard-earned lesson from the conventional geothermal industry is that low-permeability reservoirs tend to require a greater number of wells than anticipated, this may be true for Cape Station as well"

Elliot Yearsley

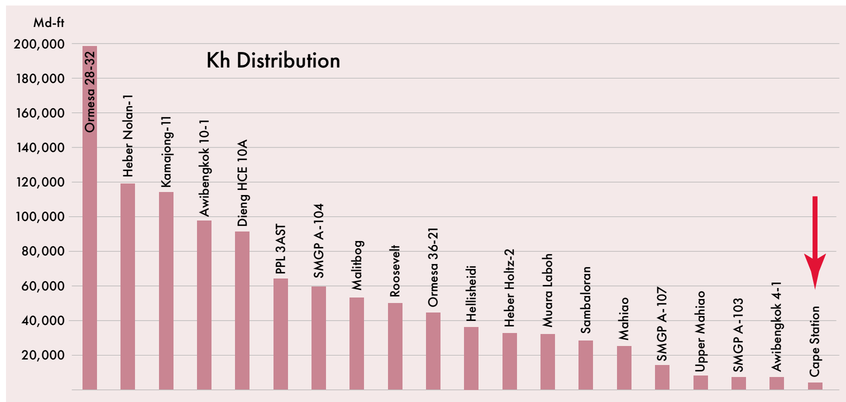
The low productivity of enhanced geothermal systems

Or, how Fervo's EGS project, created by fracking, is behaving like a low-permeability reservoir

ELLIOT YEARSLEY

FERVO ENERGY operate the world's most well-funded Enhanced Geothermal Systems (EGS) project at Cape Station, Utah, and has published well test results from which the Productivity Index can be estimated. This analysis for Cape Station shows that this key productivity metric is at the very low end compared to conventional geothermal wells, which suggests a level of reservoir risk that deserves more attention.

The Productivity Index (PI) of a well is essentially the pressure drop required to induce a given flow rate into the well. PI is one of the most useful indicators of well performance in geothermal reservoir engineering and can also be correlated to permeability-thickness (kh), a fundamental intrinsic property of the reservoir.



Examples of kh in conventional geothermal fields from well tests conducted by the author, reservoir modelling history matching, and public domain references.

PRODUCTIVITY INDEX FOR CAPE STATION WELL

The limited production test data published by Fervo for Cape Station is from the Frisco well pad. This pad is shown as consisting of five wells, two of which are designated as injectors and one as a production well. The injection and production wells are indicated by Fervo to be completed with 7" casing, assumed to be tied back to surface.

Fervo refer to this arrangement as a "triplet", and we assume that injection is evenly distributed between the two injectors. As shown in an earlier article (GEO EXPRO Vol. 23, Issue 2, 2026), the output at the end of the 24 hrs shown by Fervo is about 6.2 MW (net), and still declining. Despite reported successes in drilling and fracking, this is a relatively low result for three wells. The question is why, and what is this telling us about the reservoir?

Data provided by Fervo does not include downhole flowing pressures or injection rates, but an estimate of the PI can be made by making certain assumptions and tracing the pressure from the injection wells to the production wellhead (Table 2). For purposes of this exercise, a production flow rate of 93 kg/s is used. A total injection rate of 116 kg/s is used, assuming 20 % loss of injected water. Project Red data indicate a 30 % loss.

The two endpoints are the injection pressure of 2,150 psig (Table 2, Point 1) and production wellhead pressure of 320 psig (Table 2, Point 6). A simplified, analytical approach to tracing the pressure from the injection wells to the production wellhead is used and takes into account the weight of the water column in the wells, friction losses, and pressure losses in the formation. Vertical head calculations assume an average vertical depth of 8,500 ft and pressure gradients are based on a temperature of 176° F in the injection wells and a temperature of 383° F in the production well. This production temperature is given by Fervo, but the injection temperature is just a guess, based on data from Project Red in Nevada.

Field	PI (kg/s/bar)	PI (GPM/psi)	Type of well
Sorik Marapi	3.5		Hi temp. (2-phase feed)
Dieng	20.7		Hi temp. (liquid feed)
Patuha	4.7		Vapor dominated
Ormesa	7.7	9.2	Pumped well

Table 1: Representative PIs for conventional geothermal fields from well tests conducted by the author.

The friction loss is calculated for the entire wellbore to the end of the horizontal sections at 4,700 ft, so in reality, it may be less than this, as flow is said to be distributed. For the given end points, lower friction loss in the wellbore would mean more of the pressure drop is in the reservoir.

In this example with the assumptions stated above, the average pressure drop between each of the injection wells and the production well is estimated at about 1,400 psi (96 bar). The flow rate of 93 kg/s is divided by this pressure drop to derive a *combined* PI (for the triplet system) of about 1.0 kg/s/bar. In volumetric terms, the flow rate is 1,700 GPM or 58,000 Bbls/d, which translates to a volumetric PI of 1.2 GPM/psi or 41 Bbls/d/psi. A similar analysis was performed for Project Red, which indicated a PI of 0.4 GPM/psi, but this was for a "doublet" using one injection well.

Libbey and Murphy (2026) have published PIs for a number of conventional geothermal fields, which range from about 0.6 to 250 kg/s/bar. The PI of 1.0 kg/s/psi estimated in this article for Cape Station falls at the low end of this range. It should be noted that conventional geothermal fields with lower PIs tend to compensate with much higher enthalpies compared to Cape Station.

CORRELATION TO PERMEABILITY-THICKNESS

PI is related to permeability-thickness in millidarcy-feet (md-ft) by the diffusivity equation, which is more elaborately explained in the online version of this article. Based on this equation, for a flow rate of 58,000 Bbls/d, a PI of 41 Bbls/d/psi, and viscosity at reservoir conditions of 0.14 cp, the kh for the Cape Station Frisco well test can be estimated at 6,078 md-ft.

Although this is only a gross estimation based on the above assumptions, it is clear that permeability-thickness for this EGS reservoir falls at or near the very lowest end of the range compared to examples from conventional geothermal fields.

CAN THE TECHNICAL CHALLENGE BE RETIRED?

According to Fervo, the technical challenge of "successfully creating a high-conductivity hydraulic connection between injection and production wells has been retired". But the term *high-conductivity* is misleading when compared to conventional geothermal reservoirs, which have, on average, much higher PIs and, by correlation, permeability-thickness. From a geothermal reservoir engineering perspective, this is telling us that the EGS reservoir created by fracking is *behaving* like a low-permeability reservoir.

In effect, high injection pressures are required to overcome the pressure drop between injection and production wells. The triplet helps to distribute the pressure drop, but also means more wells would be required. Bigger casing could also help by reducing friction loss in the wells, which would result in slightly higher flow rates, but pressure drop in the reservoir is the more important factor.

IMPLICATIONS FOR WELL NUMBERS

A hard-earned lesson from the conventional geothermal industry is that low-permeability reservoirs tend to require a greater number of wells than anticipated, and this may be true for Cape Station as well. Fervo are no doubt aware of this issue as the capex estimate quoted in their recent S-1 filing is $7,000 per installed kW of generating capacity – some 50 % higher than most conventional geothermal projects – probably due in large part to the high well numbers. Fervo's warning in their S-1 filing that "we may be unable to deliver expected per-kilowatt cost reductions or step-ups in gross megawatt productivity per well" should be taken seriously until such time as they can prove this with well test data. ■

Point	Description	Pressure gain/loss (psi)	Pressure (psig)
1	Injection wellhead pressure		2,150
2	Vertical head in injection wells	3,571	5,721
3	Friction loss in injection wells	212	5,510
4	Pressure loss between injection and production wells	1,396	4,114
5	Vertical head in production well	3,188	926
6	Friction loss in production well	606	320

Table 2: Pressures for Cape Station well test – flow rate 93 kg/s.

Why high oil prices can also be a bad thing for the energy transition

An update from Sweden – a shallow geothermal hotspot

A LOT CAN happen in two years. That's how long it is since I spoke to Signhild Gehlin, CEO at the Swedish Geoenergy Centre. So, it was great to catch up with her to hear about what has changed in the world of ground source heating systems, or the shallow geothermal business, to describe it in that way. And why is that interesting? It is interesting because Sweden is a major player in this sector.

"2024 was a dramatic year in terms of ground source heat pump sales," says Signhild. "First of all, there was a general decline in the building industry, which led to a slump in installations. Secondly, an EU stimulus programme to boost heat pumps was delayed, which further dampened the market. Also, and that is not so visible in the statistics, we know that in 2024 and last year, about a third of the newly installed ground source heat pumps were replacement pumps. That means the borehole is in place already, with no additional work for the drillers. As Sweden embarked on ground source heat pumps already in the 1980s with a peak in the early 2000s, heat pumps are now increasingly getting towards the end of their lives."

"About a third of the newly installed ground source heat pumps were replacement pumps"

And there is another surprising development that one wouldn't guess straight away. Where you might think that a higher oil price is good for the geothermal business, in fact, it isn't. There are two reasons for that. First of all, the drilling rigs run on diesel, and secondly, the loops that are installed into the boreholes are made of plastic. "The price of plastic raw material for loops increased by 40 % since March, which obviously puts a damper on the economics of these systems," says Signhild.

Then there is the competition from district heating networks. Signhild has compiled countrywide data that enables her to map the differences in operating costs between ground source heating systems and district heating networks in different regions. "In some places in Sweden, the operational cost between ground source heating and district heating is quite small, but in other places ground source heating is much more favourable," she says. And that gap is widening even more, driven by the fact that access to biomass is getting more restricted. "Some people saw it coming," she says, "but it is becoming a reality now, and the problem is only increasing. One district heating company even sent a letter to its customers stating that prices won't increase more than 20 % this year."

Signhild Gehlin, CEO at the Swedish Geoenergy Centre.

PHOTOGRAPHY: SIGNHILD GEHLIN PRIVATE ARCHIVE

Finally, where two years ago there was not much discussion about deep geothermal potential in Sweden, the pendulum has now switched in its favour again. A couple of companies have floated ideas to drill very deep wells and produce electricity at depth. "I don't think these outfits have a very realistic idea as to how expensive drilling to these depths is compared to the potential for actual low-temperature power production in Swedish geology," Signhild says. "I remain sceptical, even when I'm always a supporter of looking into these things. My problem is that they seem to be so pervasive and manage to attract investors into something that seems very far-fetched in my honest opinion."

I'm already looking forward to catching up with Signhild in two years. ■

Henk Kombrink

SUBSURFACE STORAGE

"A large number of pilot projects depend on large amounts of subsidies without there being proof of the technology at scale"

Ruud Weijermars & Simone Pilia

Storing heat in basement rocks

Finland has no oil, but it has some good-quality rocks that can be used to store energy in. That's what a large thermal storage project that is currently under construction is all about

"HAVING A LOOK at our lineament map," says Jon Engström from the Geological Survey of Finland, "that is the first thing you need to do when you're planning a subsurface project in our country." Jon is a structural geologist who has extensive experience in mapping of structural deformation in Finland's subsurface, mostly gained through the site selection process for the nearly completed repository for nuclear waste.

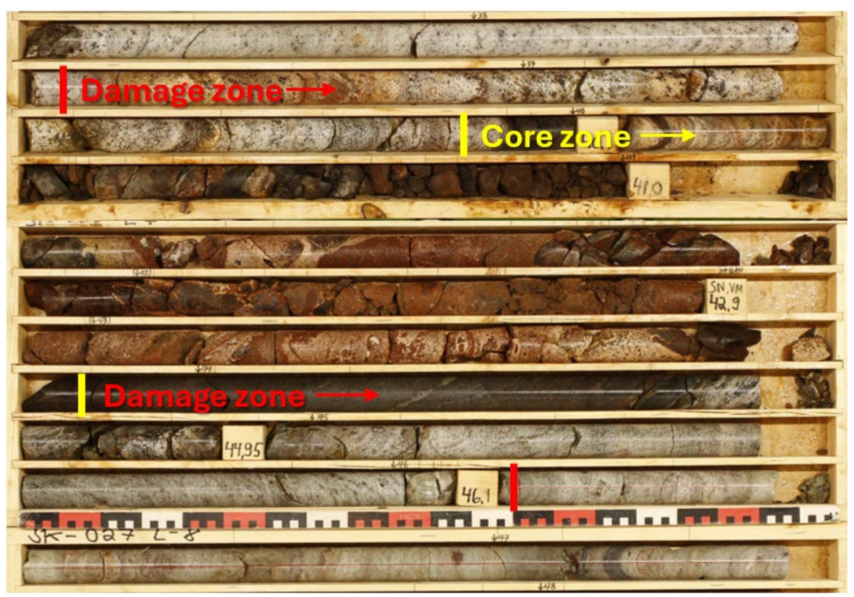
The lineament map provides a good indication of the bedrock blocks in southern Finland, which is primarily composed of granites that were subsequently metamorphosed and deformed to varying degrees. As such, the lineaments dissect the country into a patchwork of smaller blocks. In turn, it is these smaller blocks that form the basis for most subsurface projects because the degree of fracturing and faulting is usually less than in the lineaments themselves. This reduces the risk of geomechanical instability, reactivation or groundwater flow pathways.

It is groundwater flow within the bedrock that is especially critical to the Varanto project in the town of Vantaa, southern Finland, where the world's largest thermal energy storage project is currently under construction. It will be a seasonal storage facility that consists of a series of three huge man-made caverns that together will store 1,1 million m^3 of water at a temperature of around 140° C. In total, the energy stored this way amounts to 90 GWh, enough to heat a medium-sized town for as long as a year. The caverns will be 20 m wide, 300 m long, and 40 m high and are situated at around 100 m below the surface.

"We know that the rocks themselves are impermeable," says Jon, "but we also know that fracture zones are the most risky when it comes to potential fluid escape. That's why a rigorous mapping exercise is critical; not only through mapping the regional lineaments, but also by more detailed work carried out on site." That's where cores from boreholes come in, which were drilled at the project site. "You always need that type of data to gain a better understanding of the local geology," explains Jon, "also because the types of basement rocks vary and with that does the density of fractures."

"When you look at just granite, the fractures tend to be a set of two conjugates at a defined angle, but when the rocks are heavily metamorphosed, as is the case with the successions we are dealing with at the site, the fractures tend to follow the foliation and therefore it is more mixed up," Jon says. "That is the main reason as to why the cores are so critical to the overall assessment of deformation zones and fracture density." ■

Henk Kombrink



Drill cores from the Varanto project, where a deformation zone has been mapped with a fractured and deformed core zone with several faults. The core zone is surrounded by damage zones on both sides, with increased fracturing and alteration.

The database covering a nationwide overview of interpreted lineaments can be found through the website of the Geological Survey of Finland.:

PHOTOGRAPHY: JON ENGSTRÖM

Exploring salt for hydrogen storage

Dutch salt mining company Nobian has embarked on a drilling programme to gather geological information required to assess the feasibility of constructing storage caverns as part of a future hydrogen economy

ENERGYSTOCK, a wholly owned subsidiary of the Dutch state-owned company Gasunie, is working on a project called HyStock, which aims to facilitate underground hydrogen storage as a crucial element in the hydrogen economy. As part of this project, and prior to any potential cavern development, salt producer Nobian has started to drill three wells in an area where brine production already takes place from a Zechstein salt dome at Zuidwending in the northeast of the Netherlands.

The idea behind the project is, in due time, to construct three new caverns that will be suitable for storing hydrogen. These caverns will become smaller than conventional salt production caverns, having a diameter of around 75 m. But the biggest difference is that they will be significantly deeper than conventional caverns. "The top of the caverns will be around 900 m below the top of the salt," explains Allard, who is the lead geologist on the project. "This is intended to guarantee the cavern will always be able to withstand significant pressure and pressure changes; the geomechanics are an important element in this project."

Another difference is that the data acquisition has been more extensive than in other drilling projects. "We cored the entire 350 m interval within which the cavern will be planned," says Allard. "Of course, as a geologist, you'd like to see as much variation as possible in a core, but in this case, it was a good thing to mainly encounter clean halite. The more impurities in the form of magnesium or potassium-rich evaporites, the harder the brine processing will be."

With the drilling of the exploratory wells, an important first step has been taken to get more clarity about the subsurface conditions for the construction of new caverns. But that doesn't mean the caverns will be ready for hydrogen storage in the short term. "Starting the solution mining and the realisation of the above-ground facility adjustments are dependent on regulatory approvals that have yet to be obtained," says Allard.

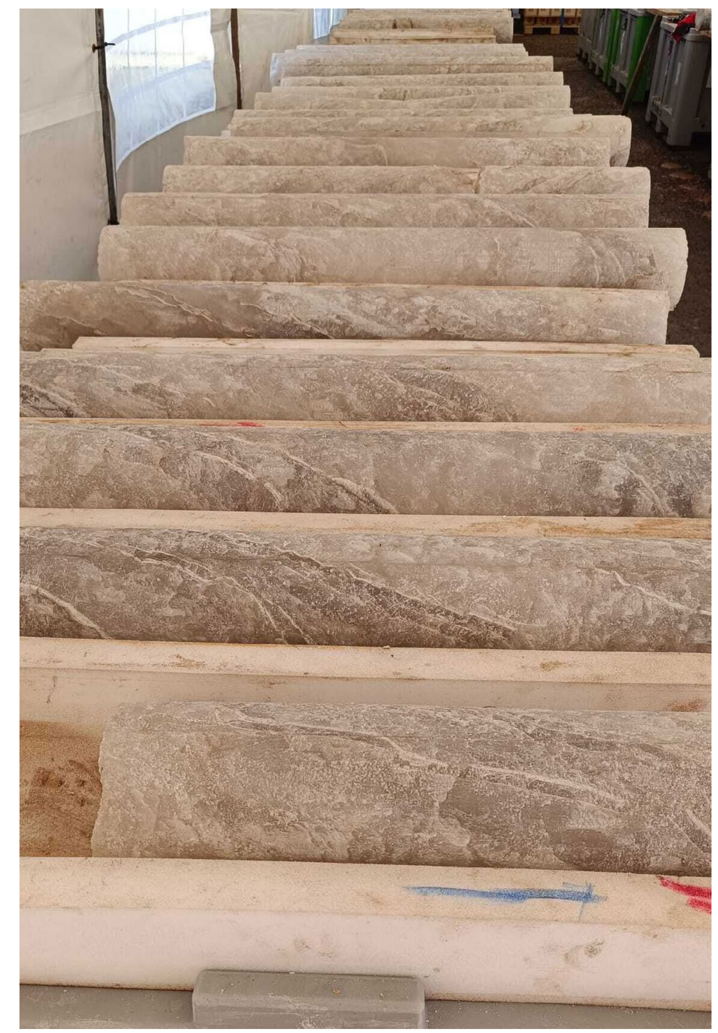
So far, the geology of the salt cores looks promising. According to the current schedule, exploratory drilling will be completed around the end of June. ■

Henk Kombrink

PHOTOGRAPHY: IOT HOLLAND

THREE NEW CAVERNS

The so-called HyStock project entails the potential construction of three new caverns, as well as the completion of an existing cavern for the storage of hydrogen. This year, Nobian will drill three wells, of which two are exploratory drills. The third one will be a so-called B-well into the existing cavern. Similar to the gas storage caverns already in operation in Zuidwending, the future hydrogen storage caverns will have two wells to ensure storage efficiency and continued operations in case of a workover on one of the wells.

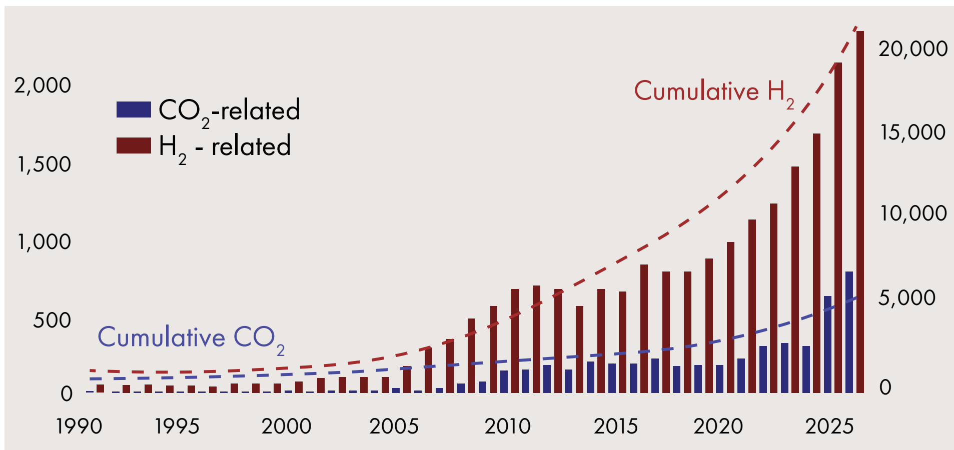


Halite cores from one of the exploration wells drilled to evaluate the Zuidwending salt dome for hydrogen storage readiness.

Many CCS projects will falter quietly without the promised benefits

That's the conclusion of a study recently published in First Break

In a recent special issue of EAGE's journal First Break, dedicated to underground storage, one finds the usual articles that one would expect for such a publication. But there happened to be one little outlier. Or maybe a slightly larger outlier. A paper published by Ruud Weijermars and Simone Pilia, both affiliated with the King Fahd University of Petroleum & Minerals in Saudi Arabia.



Number of publications per year (bars – left axis) and their cumulative totals (dashed curve – right axis) for research articles indexed in Scopus that match a selection of keywords related to CO_2 and H_2. The search was limited to content published by European research institutions.

SOURCE: MODIFIED AFTER WEIJERMARS & PILIA – 2026 - FIRST BREAK VOL 44, ISSUE 4

In the introduction, the authors already warn that their message will not resonate well with the current "research lobbies and bandwagon supporters" of both green hydrogen production (GHP) and geological carbon sequestration (GCS).

They argue that whilst these parties claim that the technologies to support these activities are mature, in fact they are not, despite the "ballooning" number of literature claiming the contrary.

This dynamic of high levels of literature output has created a system in which political decision makers have gained a level of confidence in these technologies that is, in fact, misplaced. And with politicians ultimately being responsible for handing out subsidies, against a backdrop of well-researched climate change acceleration and a sense of urgency, it is no surprise that we see what we see: A large number of pilot projects depending on large amounts of subsidies without there being proof of the technology at scale.

A HYPE

To back this up, the authors identify what they describe as a typical example of the Gartner-style hype: an initial trigger leading to a peak, followed by disillusionment and, subsequently, a "landing" in a phase of more modest, workable solutions.

Looking at the number of publications in the GHP and GCS spaces from European institutions, the authors observe a clear acceleration of publications during the last few years, which they now predict to decelerate or even start to fall in the next few years, as projects will progress at a slower rate than expected, or even just outright disappoint.

NO DOUBT

So, are we now in a phase where we see an increasing number of project failures? The authors leave little doubt. Looking at Gorgon in Australia, which keeps on being the only carbon storage project at scale, they observe continued injection challenges. They also argue that it is no surprise to see the Dutch CCS project Porthos experiencing cost overruns and project delays; the project was assigned to a government entity without operational experience that also lacks the contractor-handling leverage that large oil companies have.

Without denying that there is a climate problem that needs to be addressed, on the basis of their assessment, the authors cast doubt on whether CCS in the current form will ever be the way to achieve carbon neutrality.

This is an interesting conclusion, even when it is disconcerting at the same time. With all that public funding that has been and continues to be directed towards technologies that are lagging and costly, what are the alternatives? But still, maybe it is more important to have that very discussion more publicly than burying our heads in the sand. ■

Henk Kombrink

SEABED MINERALS

"Polymetallic nodules were not the focus of the original studies, and they were initially dismissed as dropstones"

Ebbe Hartz – Aker BP

Movement towards a mining moratorium

Whilst a lot of work is currently being done to formulate a mining code for the exploitation of deep-sea minerals in international waters, the call to ban metal extraction from the High Seas is just as loud. A multitude of governments and tech companies are in support of this

Mining in international waters is a hotly debated topic. One of the discussion points is environmental concerns about the effect of mining on the unique and poorly understood abyssal plain ecosystem. The Deep-Sea Conservation Coalition (DSCC) is passionate about protecting the marine environment. Their overarching goal is to substantially reduce the greatest threats to life in the deep sea and to safeguard the long-term integrity of the ecosystem. Threats include pollutants, plastic and climate change, but also proposed deep-sea mining activities.

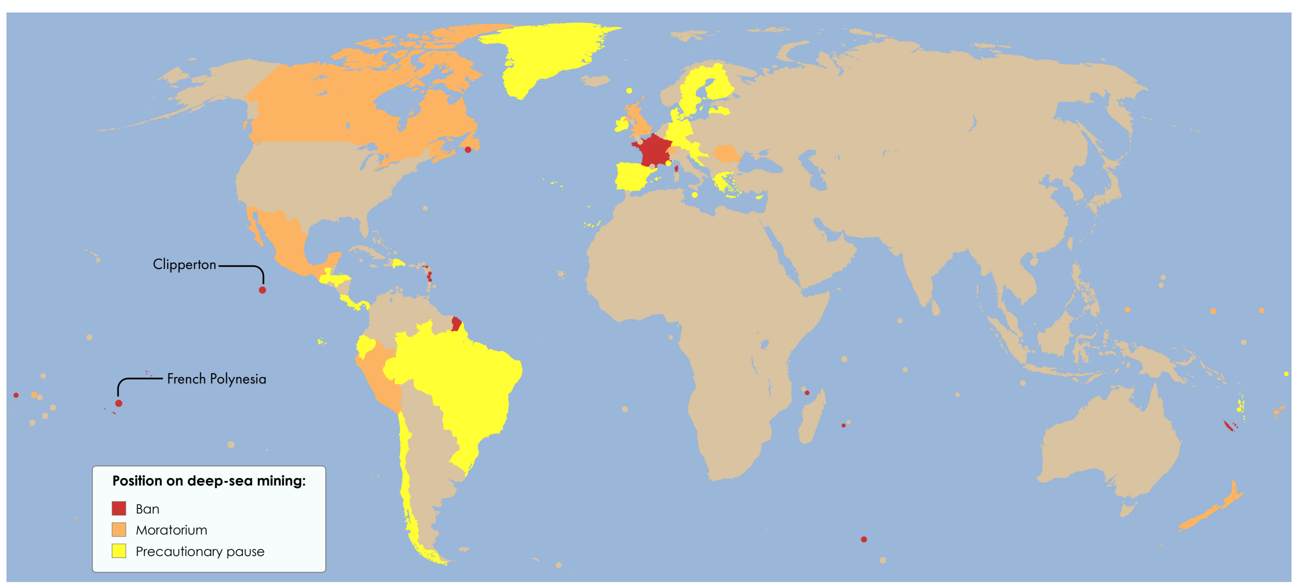
Although the International Seabed Authority (ISA) is still working on a mining code and has yet to give the green light for deep-sea mineral exploitation, the DSCC is already calling for a mining moratorium. So far, forty countries have taken a stance against mining in international waters. The majority of these countries are in favour of a precautionary pause to allow more time for further research and regulatory development, exactly what ISA is working on. A more select group calls for a formal agreement to temporarily prohibit deep-sea mining. France is the only country to call for a complete ban. That is surprising, since France has the largest exclusive economic zone (EEZ) out of all countries, thanks to its overseas territories dotted around four of the world's oceans. However, it applies the same rule in its own waters; it is not exploiting its marine metallic resources, even though much of France's EEZ is highly prospective.

On the seamounts surrounding French Polynesia, for example, iron-manganese crusts enriched in cobalt and platinum have formed. Regardless of the economic promise, the indigenous Polynesian population is in agreement with the ban; they have environmental concerns and regard the ocean as a sacred and spiritual place.

The 200 nautical mile radius around Clipperton Island is undoubtedly rich in polymetallic nodules, like the rest of the Clarion-Clipperton zone. France claimed the uninhabited atoll in 1858, being the only surface exposure of the much-explored Clipperton Fracture Zone, of which the majority resides in international waters.

But it is not only governments calling for a moratorium; 71 companies have signed a similar appeal by WWF. Among them are multiple car manufacturers and tech companies. This is interesting because these types of companies are often mentioned as beneficiaries of deep-sea minerals. The metals can be used to manufacture EV batteries, while rare earth elements are needed for technology to function at high standards. Clearly, Volkswagen, BMW, Apple, Philips and others are confident that terrestrial supply will be sufficient. ■

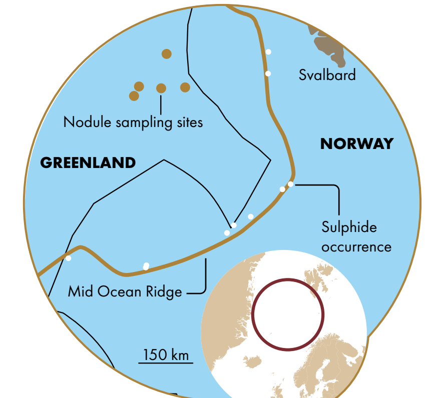
Mariël Reitsma



SOURCE: CREATED WITH MAPCHART.NET

Map of countries in support of the deep-sea mining moratorium proposed by the DSCC.

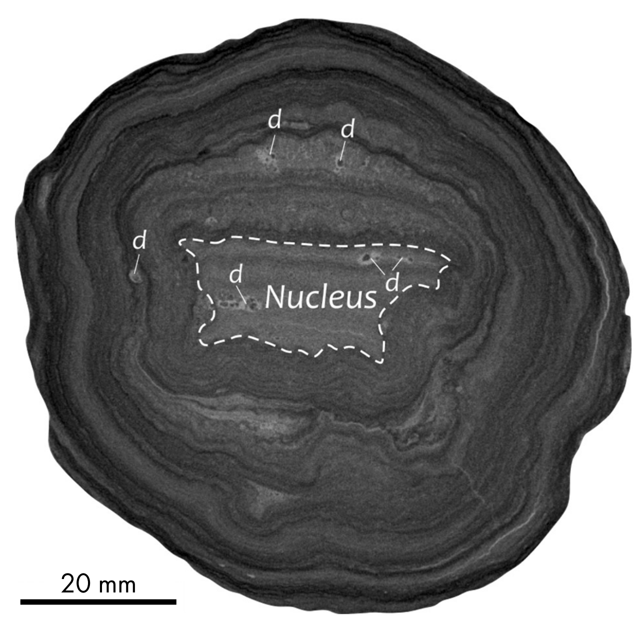
Mic drop: Dropstones are, in fact, polymetallic nodules



Two expeditions looking for hydrocarbons in the Greenland Sea didn't realise their find at hand and threw polymetallic nodules overboard. Scientific analysis on these nodules not only confirms their metal content, but also tells the story of the tectonic opening of the North Atlantic – Arctic gateway during the Miocene

In search of oil seeps and to understand regional stratigraphy, VBER and TGS conducted two seafloor sampling surveys on Greenland's north-eastern continental shelf over a decade ago. They retrieved samples through dredging and coring along the continental slope. Among the sample material were a multitude of 'dropstones', rocks carried out to sea by icebergs, or so was the interpretation at the time.

Dropstones were not the focus of the expedition, so about half of them were thrown back overboard, and the other half were filed away. Years later, Ebbe Hartz, a geologist at Aker BP, had a light bulb moment. Based on his understanding of the region's oceanography and mineral-forming processes, he believed that the dropstones might in fact be polymetallic nodules. When the archive was checked, there indeed turned out to be nodules present and a project was launched to study them in detail. Twenty-four nodules from three different locations were selected for analysis.



SOURCE: ZASTROZHNOV ET AL., 2026

Tomogram of a hydrogenetic nodule revealing a core consisting of an older nodule and small rock grain inclusions (d).

The research revealed two separate groups of nodules, each with its own distinct appearance, chemistry, origin and age. Both nodule types were found at each sample location. The first, and most prevalent group, displays well-developed, thin concentric banding around a nucleus. These nodules are interpreted to be of hydrogenetic origin: they formed over millions of years by precipitation of metals directly from seawater. Age dating indicates that growth began around 13 – 14 M yrs ago. This coincides with the opening and deepening of the Fram Strait between Greenland and Svalbard and the establishment of deepwater exchange between the Arctic and Atlantic Ocean.

The nodules thus point to a direct link between ocean circulation and metal supply to the Greenland shelf. Arctic water rich in dissolved metals began flowing south while oxygen-rich water from the North Atlantic flowed in the opposite direction. This favoured the necessary oxidising conditions and precipitation of dissolved iron and manganese on the seabed. Meltwater from the Greenland Ice Sheet may have provided additional metal input and influenced growth.

Nodules from the second group are fragments of larger, tabular nodules. They have an extremely high iron content, around 60 wt%, suggesting a hydrothermal origin. Age dating shows that they are much younger than the hydrogenetic nodules, around 0.3 – 0.4 M yrs, and have grown much faster. Although the origin of this nodule type is a bit of a mystery, mineralisation is thought to be the result of weak and diffuse hydrothermal circulation near the seabed.

There it is, the discovery of the first polymetallic nodules in the North Atlantic! An accidental find that almost went unnoticed. ■

Ronny Setså

Do we need seabed minerals?

In order to move away from fossil fuels, we need large numbers of magnets and batteries to capture and store renewable energy. To manufacture said equipment, substantial quantities of metals and Rare Earth Elements (REE) are required. The question is, where should these metals come from? Are terrestrial reserves sufficient, or is it time to add marine resources to the mix?

The debate on this topic is fierce. The Metals Company, which is gearing up to harvest polymetallic nodules from the abyssal plain, argues that even though terrestrial deposits can meet demand, the economics of extracting them are less favourable. Seabed minerals tend to have higher metal grades, meaning that smaller volumes of rock can be mined and processed with the same result.

Metals and REE are not mined evenly around the globe. For example, the USGS reports that 69 % of REE are extracted in China, 74 % of cobalt in Congo and 67 % of nickel in Indonesia. Seabed mining could be a way to diversify the market for many of the elements needed in the energy transition.

Although the International Seabed Authority has yet to give the green light for mineral exploitation in international waters, in the long run, this could open up reserves to countries that lack direct access to particular elements. That said, countries with a maritime border can already mine the Exclusive Economic Zone that extends 200 nautical miles from their shoreline.

Yet, mining within national waters has barely taken off. Is this a sign that exploration and extraction technology are not yet fully mature? Is it related to regulatory hurdles? Or can the costs of seabed mining not compete with traditional mining?

Allseas, the owner of the world's first deep-sea mining vessel, plans to charge around $150 per wet tonne of nodules extracted. In Indonesia, miners are paid $57 per wet tonne of 1.5 % grade ore through nickel laterite mining. Although the extraction of polymetallic nodules from great water depths is more expensive, the overall higher metal content could make up the difference. Nodules from the Clarion-Clipperton zone have a rough composition of 1 % nickel, 29 % manganese, 1 % copper and 0.2 % cobalt, whereas Indonesian laterite contains, apart from nickel, 0.02 to 0.1 % cobalt. It will depend on the exact ore composition and the fluctuating metal prices, which option is most lucrative.

Another potentially competitive option is urban mining, a fancy term to describe recycling of rare metals and REE from electronic devices and other anthropogenic waste. However, because the energy transition is only gearing up, a stock of critical minerals still needs to be built up to facilitate metal flows for recycling. For example, the first generation of EV batteries is expected to reach the end of their life after 2030, opening up the opportunity for larger-scale recycling at that point. The International Energy Agency (IEA) estimates that significantly scaling up recycling could reduce the need for newly mined minerals by 40 % for copper and nickel and 25 % for cobalt by 2050.

It remains to be seen how desperately we need seabed minerals and whether extracting them from kilometres below sea level is economically feasible at all. Maybe we are better off upping our game mining landfills? ■

Mariël Reitsma

Nickel laterite mine in Sulawesi, Indonesia.

PHOTOGRAPHY: ERBERTO ZANI VIA ADOBE STOCK

NEW GAS

"The hydrogen content at the base of the latest well in Lorraine could be as high as 90 %, but without data released by FDE, this remains mere speculation"

Arnout Everts – AEGEO

Deep hydrogen in Lorraine: An appraisal well or a science project?

Following the discovery of hydrogen in a coalbed methane test well in 2023, Lorraine's hydrogen potential made headlines again this year as La Française de l'Energie (FDE) has now drilled a dedicated and much deeper appraisal well. But is it really an appraisal well, or rather a scientific undertaking?

ARNOUT JW EVERTS, AEGEO

THAT'S THE question I am exploring in this article. Despite minimal information released by FDE beyond the statement that "natural hydrogen was confirmed at numerous intervals", a reasonably accurate picture can still be reconstructed based on well location and regional geology.

The Permo-Carboniferous Lorraine-Saar-Nahe Basin, where FDE is exploring for hydrogen, extends from SW Germany to NE France. The basin was extensively mined for coal and, from the 1990s, explored for coal-bed methane (CBM).

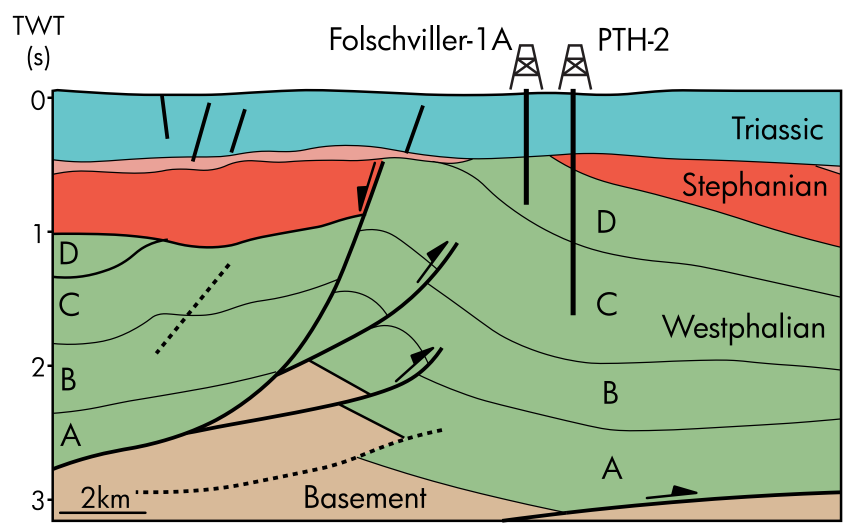
The drilling location of PTH-2 suggests that it must have penetrated the Westphalian-D succession, similar to the original CBM well Folschviller-1A, but at greater depth. The deeper section of PTH-2 will have penetrated the Westphalian-C and possibly tagged Westphalian-B.

In Folschviller-1A, sampling of wellbore fluids showed the dissolved hydrogen content increasing with depth from 1 % at 600 m to 18 % at 1,250 m. If this trend were to continue in PHT-2, hydrogen content near well TD could be as high as 90 %, but without data released by FDE, this remains mere speculation.

There is controversy over where the hydrogen actually resides in the Westphalian reservoirs. I have previously argued that hydrogen sampled in a CBM well is almost certainly derived from gas adsorbed to coal. Coals at this depth and temperature have a substantial gas storage capacity, and the seams in Folschviller are relatively thick (4 – 13 m) and permeable (0.5 – 4 mD). Resource density of coal-adsorbed hydrogen may be around 10,900 t/km^2, and dense development drilling could give a recovery efficiency of up to 50 %. Whilst the interbedded sandstones and conglomerates have too low a porosity (~5 %) to store meaningful quantities of dissolved gas, a mere 550 t/km^2 dissolved hydrogen-in-place, recovery of brine with dissolved gases would be near-impossible because of low permeability (<0.0001 to 2.9 mD). Yet, FDE insists that the sampled hydrogen is from dissolved gas in a sandstone aquifer.

As a gas development, this project would face the same hurdles that hamper CBM developments elsewhere in the world: low well productivity, high surface footprint and high co-production of water. Lorraine coals have yet to be flow-tested, but considering their modest permeability, many hundreds or even thousands of wells could be needed to achieve full-scale industrial offtake. The project may co-produce 10s of millions of barrels of water that need treatment and disposal. On top of that comes the technically challenging, energy-intensive, and costly separation of hydrogen from methane.

Whilst coals deeper than ca. 1,200 m, i.e. most of the succession in PTH-2, may have higher hydrogen content, they would be so tight that effective pressure depletion and drainage become near impossible. This renders the PTH-2 well merely a science project, not a useful test of exploitation potential of the play. ■



Geological setting and projected location of the Folschviller-1A and PTH-2 hydrogen wells.

SOURCE: MODIFIED AFTER HEMELSDAEL ET AL., 2023

Time to recycle party balloons

Iran's closure of the Strait of Hormuz not only affects global LNG supply but also helium. Soon, helium shortages will impact chip manufacturing, MRI scanners and, less urgently, party balloons. How to combat the shortfall?

A THIRD of the world's helium comes from Qatar, a lucrative by-product of natural gas production. Even though the North Field contains only 0.04 % helium, the vast volumes of hydrocarbon production result in Qatar being the second largest helium producer in the world, leaving only the USA ahead.

Due to the Iran war, helium production and supply have been halted. Closure of the Strait of Hormuz means tanker ships filled with helium cannot leave Qatar and even after reopening of the strait, helium supply will remain affected. Qatar Energy reported that missile strike damage to Ras Laffan Industrial City will take three to five years to repair and over that period Qatar's helium export will be down by 14 %.

Asia and Europe rely heavily on Qatari helium and are now questioning how to cover the shortfall and diversify their supply.

Over the past years, there has been a rising trend of helium exploration outside known hydrocarbon basins. Although most of this exploration and new production is concentrated in North America, there is also a promising project in the early stages of development in Tanzania. In South Africa, ASP Isotopes is progressing towards commercial co-production of helium and biogenic methane in Free State. The wells contain over 3 % helium, a whopping concentration when it comes to this noble gas.

The issue with helium is that the molecule is so small and light, that it eventually escapes to space. Hence, even though helium is not burned or altered, applications need to be constantly resupplied. MRI scanners, for example, use liquid helium to cool the magnets so they become superconductive. Traditional MRI systems need constant refilling with helium to counter evaporation, at a cost that easily exceeds £19,000/yr. However, the latest models are equipped with 'zero boil-off' technology and only need occasional refilling. Gradual upgrading of MRI machines will therefore reduce the helium demand of the healthcare industry.

Another still under-utilized option is the recycling of helium gas. Some large helium offtakers, like for example TSMC, one of the world's largest chip manufactures, have their own recycling system in place. Although they manage to reuse the majority of gas, losses amount quickly to significant volumes because of the large quantities of helium involved.

In response to smaller helium consumers that can't afford their own recycling technology, 45-8 Energy started a mobile recycling operation in Western Europe. Companies can sell their degraded helium to the Recycl'He program and 45-8 Energy will collect and repurify it.

In short, to achieve a more diversified helium supply, exploration should concentrate on politically stable regions and expand beyond the current list of eight producing countries. In addition, technological advances and increased helium recycling can reduce pressure on the market. Or we could all opt to have no helium balloons at our next party. ■

Mariël Reitsma

PHOTOGRAPHY: ANGEL VIA ADOBE STOCK

The Olympic cauldron at the Paris games in 2024. 45-8 Energy recuperated and recycled the helium from the balloon.

Revival of South Africa's first commercial Helium project

Boreholes drilled during gold exploration in the Witwatersrand Basin often emit gas, and not a little bit. Some of these so-called 'blowers' have reportedly flowed for decades without any noticeable drop in pressure, and frequently need to be plugged to avoid hazardous situations

These observations prompted Renergen to apply for a natural gas exploration permit across Welkom, Virginia and Theunissen in Free State, South Africa. They soon discovered that apart from methane, the gas also contained high concentrations of helium, an opportunity that could potentially double their income stream.

LNG production for the local market came online in 2022, yet output was well below target, and commercial helium production never materialised at all. In May 2025, ASP Isotopes stepped in and agreed to buy Renergen. Even before the acquisition was finalised, ASP launched a new exploration and drilling campaign. Within a year, this resulted in a 60 % increase in LNG production and 18 new wells drilled.

The Witwatersrand is not a conventional hydrocarbon basin, so the origin of the gas is intriguing. The Archean metasediments of the Dominion and Witwatersrand groups are not only enriched in gold but also in uranium and thorium. The slow radioactive decay of the latter elements has, over time, generated a large volume of helium, along with various solid decay products.

In addition, the Witwatersrand Group contains carbonaceous layers, possibly the remnants of stromatolite mats. Microbes are currently feeding on this fossil organic material and are producing methane as a result. Both the helium and biogenic methane migrate through basement faults, mixing in varying proportions. This means that the gas composition differs from well to well, with some wells having as much as 12 % helium.

Because the basement has virtually no porosity, the gas is trapped in faults as well as in sill and dyke contact zones. To increase the chance of hitting these structures, Renergen drilled deviated wells. ASP Isotopes continued with this strategy but drilled deeper and used improved subsurface modelling to optimise well placement. As a result, 15 out of the 18 new wells intersected gas. They also identified a previously unrecognised sandstone reservoir at shallow depth (<400 m), which contains additional gas.

With the drilling campaign completed, ASP is preparing to tie back the wells to the processing facility. The biogenic nature of the methane means that virtually no heavier hydrocarbons are present, simplifying LNG production. During liquefaction, the gas is cooled to -162° C and liquid methane is separated. The remaining helium-nitrogen mixture is then cooled further to -269° C to liquify the helium.

After tentatively being listed as the eighth helium-producing country in the world for several years running, 2026 might finally be the year that South Africa secures its place, albeit with a humble 58 MCF per day. ■

Mariël Reitsma

PHOTOGRAPHY: OSSEWA VIA WIKICOMMONS

Gold mine in Welkom, South Africa.

Halo oils, tight-rock saturation, and production allocation: What the North American playbook can and can't tell the next set of unconventional basins

GEOMARK

Eighteen years of source-rock, fluid and produced-water analysis across the US resource plays has produced a workable sequence of questions. Most of those questions can be asked of Vaca Muerta, the Beetaloo or the Dadas today – but only some of the answers translate

GRAHAM SPENCE, GEOMARK RESEARCH

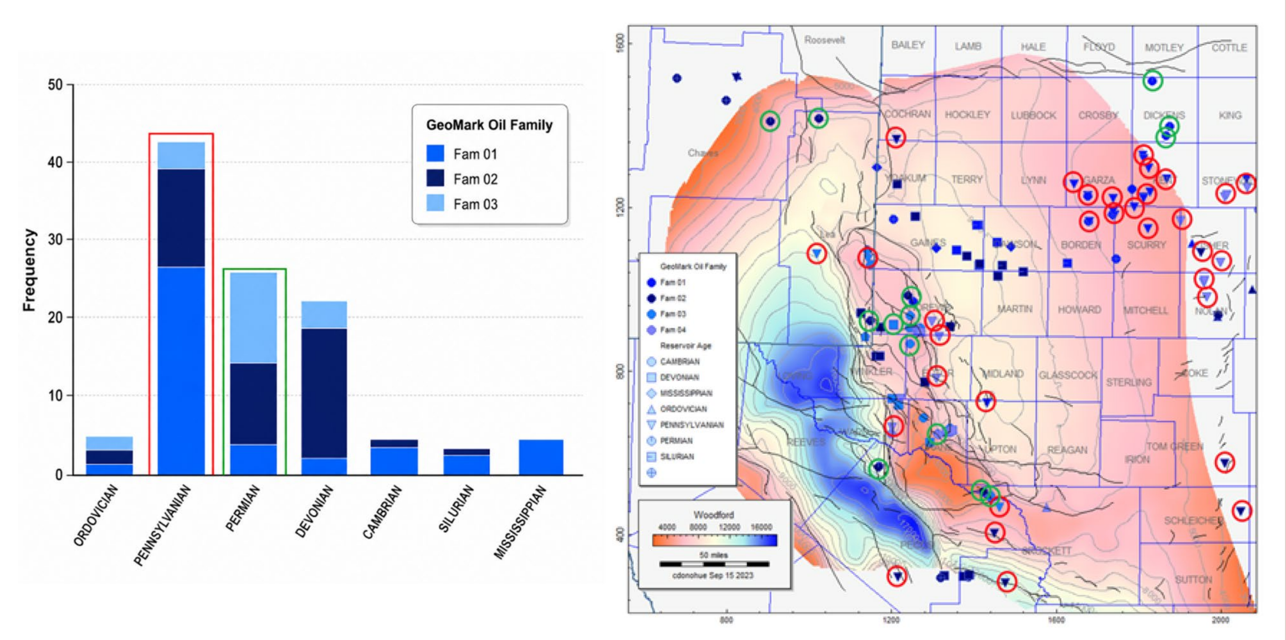


Figure 1: Distribution of migrated Woodford-sourced oils (Families 01, 02, and 03) and Barnett-sourced oils (Family 04) shown on a Woodford Formation depth map for reference across the Permian Basin, differentiated by the reservoir age in which the oils are currently trapped. These "halo" oils define basin-margin accumulations formed along migration pathways from the primary source intervals, with significant Pennsylvanian halo accumulations highlighted. The accompanying histogram illustrates the frequency at which these migrated oil families are observed within reservoirs of differing geological ages, demonstrating hydrocarbon charge into intervals beyond the primary source systems.

HALO OILS AND THE LIMITS OF THE SOURCE-ROCK MAP

The textbook example is the Permian Basin. The Woodford (Late Devonian) and the Barnett (Mississippian) are two of many principal sources, but the oils they generated do not always stay near the source. Mature Woodford- and Barnett-sourced oils are routinely identified in Pennsylvanian reservoirs along the basin margins, sometimes many miles vertically and laterally away from the kitchens that charged them (Figure 1). We refer to the outer envelope of these migrated, basin-margin fluids as the "halo", and the halo is not the edge of prospectivity – it is part of it.

What that implies for a basin where the maturity model is still being built is that the question to ask is not only "where is the source rock cooking?" but "where did the fluids it generated end up?" Vaca Muerta is the clearest near-term test case. The Tithonian-Berriasian Vaca Muerta Formation is itself the producing interval across most of the play, but in the southern and southwestern parts of the basin the formation grades into less mature areas, and migrated fluids in the overlying Quintuco and the younger Mulichinco- Agrio section are reasonably well documented in the literature. Figure 2 highlights the distribution of Vaca Muerta produced oils in younger reservoirs based on a previous GeoMark oil study of the Neuquén Basin. A halo framework imported from the Permian doesn't tell an operator where those secondary accumulations sit – basin geometry is too different – but it gives them a structured way to ask the question, and a comparable dataset of source-correlated oils to test against.

FREE, BOUND, AND WHAT MOVES

The single hardest lesson of the early North American shale boom was that volumes in place and volumes that come out of the well are not the same number. Laterals were producing ten barrels of water for every barrel of oil against petrophysical models that predicted nothing of the sort, and the industry's response, over roughly a decade, was a full rebuild of tight-rock petrophysics.

The piece that took longest to settle was the partitioning of pore fluid. In a conventional reservoir, total porosity and water saturation will get you most of the way to a usable inflow estimate. In tight rock, they will not, because a meaningful fraction of the fluid in the rock is bound – capillary-held in the smallest pores, or sorbed onto kerogen surfaces – and it does not move under production drawdown. The relevant quantity is the mobile fluid, not the fluid that is present.

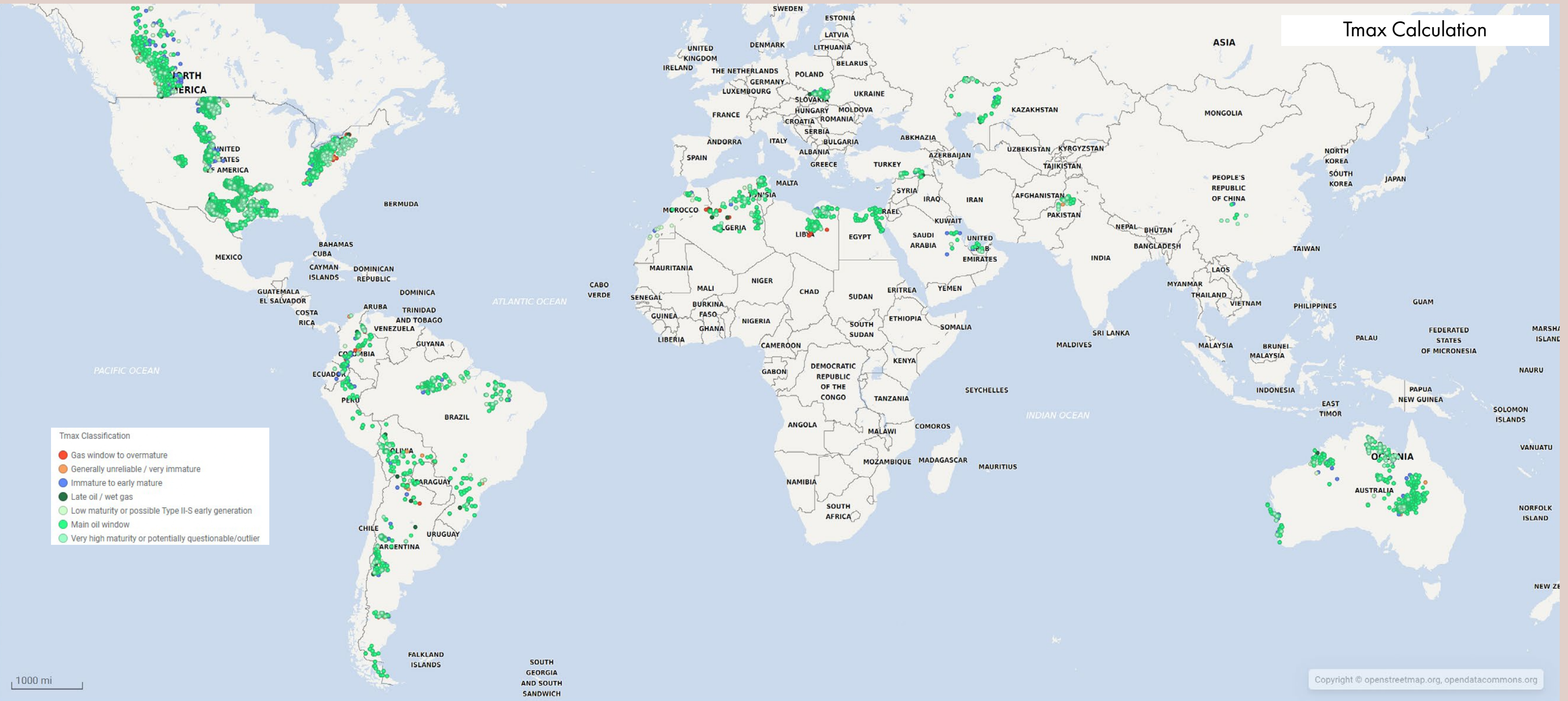
Our TruSat workflow was built specifically around this distinction. It quantifies bulk-volume fluid fractions of water and oil in tight rock and separates each into free and bound components, so a single sample delivers TOC, total porosity, water and oil saturation, programmed pyrolysis, and the geochemical characterization of the extracted fluids in one pass (Figure 3). The collection efficiency matters: In our lab, closed-retort collection routinely exceeds 98 %, against roughly 60 % that traditional conventional core-saturation methods return on the same kind of rock. That is not an incremental difference – it changes which fraction of the fluid you are characterizing.

What translates to a new basin is the question itself – how much of what is in the rock is actually mobile – because it is universal to tight reservoirs. What does not translate is the calibration. Vaca Muerta's carbonate-rich facies and the Beetaloo's Velkerri shales do not behave like the Wolfcamp at the level of bound-fluid response, and an operator in either basin still needs their own core program before mobility estimates can be defended in front of a development decision.

TIME-LAPSE ALLOCATION IN THE DEVELOPMENT PHASE

If exploration asks whether the hydrocarbon exists, and appraisal asks whether it is producible, development asks which barrel comes from where. Production allocation – geochemical fingerprinting of produced fluids and attribution to specific intervals or wells – is the tool we now use most heavily in North American

Global distribution of kerogen types across key unconventional and resource play basins, generated from a selection of source rock data contained within GeoMark's RFDbase™. The map highlights regional variations in kerogen type and corresponding depositional environments, providing insight into expected hydrocarbon generation behavior and the kinetics models most appropriate for petroleum systems evaluation and resource play characterization.



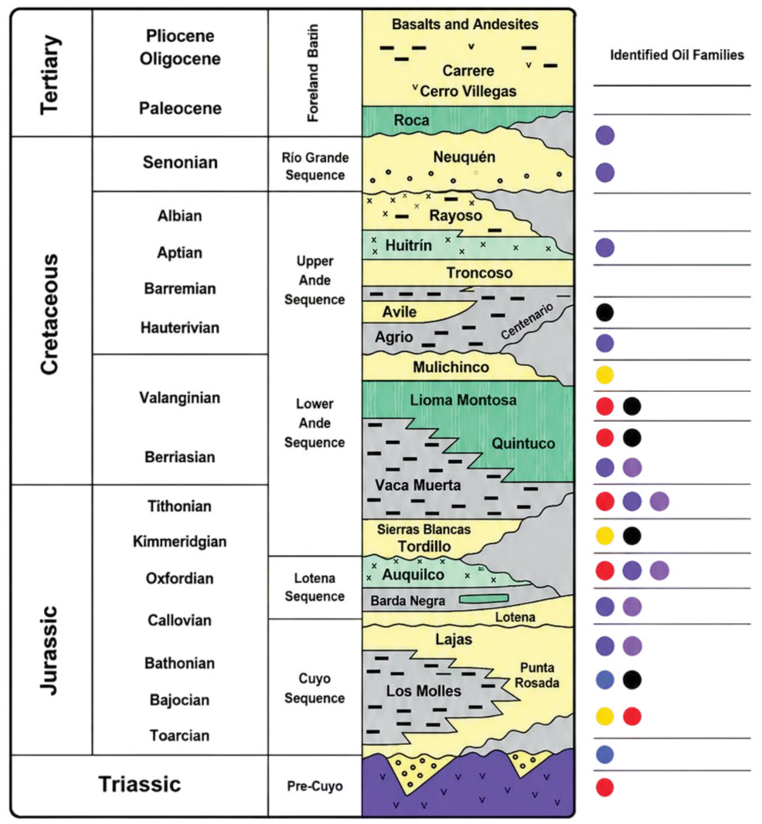
Global distribution of source rock Tmax values across key unconventional and resource play basins, generated from a selection of source rock data contained within GeoMark's RFDbase™. The map highlights regional variations in thermal maturity, providing insight into hydrocarbon generation stage, expected fluid phase distribution, and the relative positioning of source rocks within the oil and gas windows. These maturity trends help support basin screening, petroleum systems evaluation, and the identification of regions prospective for liquids-rich versus dry gas resource development.

development programs, and it is the part of the playbook that has the lowest barrier to transferring abroad.

The case we return to most often is from the Eagle Ford. An Eagle Ford operator, who held 130,000 net acres in the Karnes trough, was landing in the Lower Eagle Ford on the working assumption that stimulation would also reach the Upper Eagle Ford. The first two produced-fluid samples from a Lower Eagle Ford Lateral well confirmed both end-member signatures – Upper and Lower – and on that basis the assumption looked defensible. By the third sample, taken roughly sixty days later, the Upper Eagle Ford signature had disappeared from the produced fluid. The interval had been stimulated but was no longer in fluid communication with the wellbore. That is a quantitative basis on which to revisit completion design, landing depth, and the case for a dedicated Upper Eagle Ford development – none of which would have been visible from microseismic or pressure data alone.

Used at monthly cadence, allocation answers four operating questions: Which formation each barrel comes from; how finely targets can be differentiated in migrated systems; whether decline reflects Stimulated Rock Volume (SRV) drainage or another mechanical control; and whether stacked laterals share fluid or merely share pressure. In cube and staggered developments, that distinction routinely changes spacing decisions on the next pad.

For an operator in Vaca Muerta – where the Vaca Muerta itself and the overlying Cretaceous reservoirs may both contribute to a producing well – or in the Beetaloo, where Velkerri subunits sit in close stratigraphic proximity, the same workflow is directly usable, provided the baseline geochemical characterization has been done. That is the practical prerequisite. Without source-correlated end-member signatures for every interval in pressure communication with the wellbore, allocation has nothing to attribute against.



GeoMark's Neuquén Basin Oil Families	Interpreted Source	Age	Depositional Environment
N1	Los Molles Formation	Jurassic	Marine Shale
N2a	Vaca Muerta Formation	Upper Jurassic (Tithonian)	Clastic-rich, anoxic, restricted marine shale
N2b	Vaca Muerta Formation	Upper Jurassic (Tithonian)	Clastic-rich, anoxic, marine shale
N2c	Vaca Muerta Formation	Upper Jurassic (Tithonian)	Restricted marine shale
N3	Los Molles Formation	Jurassic	Highly anoxic, hypersaline, clastic marine shale
N4	Pre-Cuyo Sequence (possible Puesto Kaufmann Fm.)	Triassic (?)	Lacustrine Shale

Figure 2: Stratigraphic distribution of Neuquen Basin oil families.

SOURCE: MODIFIED FROM HOGG, 1993; URIEN AND ZAMBRANO, 1994; VERGANI ET AL. 1995

WHAT CARRIES OVER, AND WHAT DOESN'T

The North American playbook is, in the end, a sequence of questions and a set of measurements built to answer them. The questions – where the fluids went, how much of what's in the rock is producible, which interval is each barrel coming from – transfer cleanly. The measurements transfer too: The laboratory protocols, the geochemical end-member work, the closed retort fluid partitioning, the time-lapse sampling design. What does not transfer, and what we have been clear with operators about, is the answers. Vaca Muerta is not the Wolfcamp. The Dadas is not the Eagle Ford. The maturity windows, the migration pathways, the calibration constants for bound-fluid response, and the produced-fluid signatures are all basin-specific, and each one requires its own sample program before the workflow returns a number an operator can act on.

The honest version of what eighteen years in North America buys for the next set of basins is this: Not faster answers, but better-framed questions – and a measurement toolkit already debugged against the hardest cases.

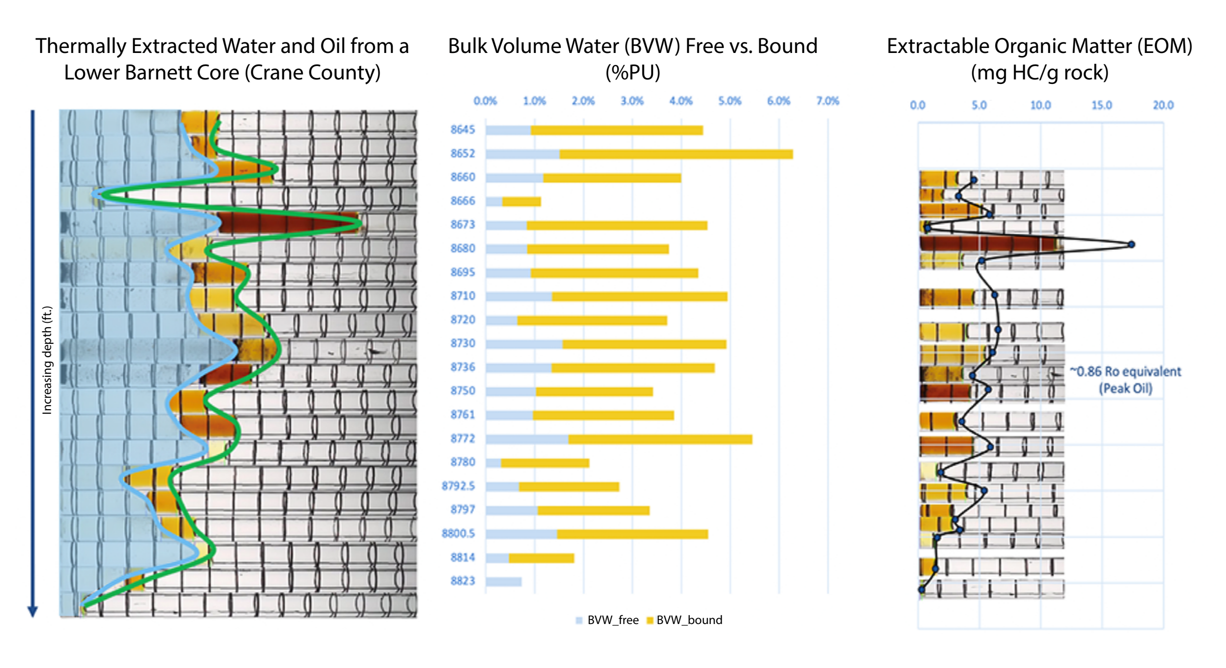


Figure 3: Thermally extracted water (blue shading) and oil volumes, bulk volume water (free versus bound), and Extractable Organic Matter (EOM) measured from a Lower Barnett core in Crane County, Permian Basin. The dataset was generated using GeoMark's TruSat™ workflow, which is increasingly being adopted by leading unconventional resource operators across North America to quantify in-place hydrocarbons, movable fluids, and reservoir saturation behavior in low-permeability systems.

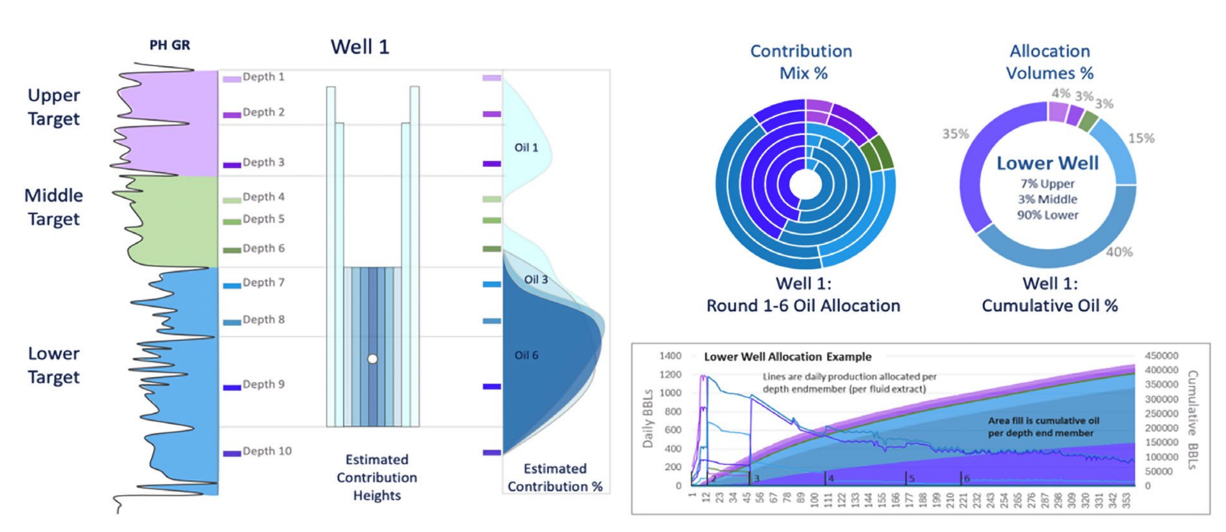


Figure 4: Time-lapse production allocation for a Lower Eagle Ford well, showing produced volumes, changing geochemical fluid contributions and the interpreted vertical extent of hydrocarbon access around the wellbore across the first six sampling events.

INSIGHTS

"National Data Repositories are more important than ever as data continues to be a fundamental bottleneck for the growing AI industry. Every digital twin, simulation, and predictive model relies on a pipeline of standardised, accurate data"

Dan Austin – Sekal

The class of '71

The closer you look, the madder it gets

JUAN COTTIER, MMBBLS SUBSURFACE CONSULTING

I AM WORKING on a Brent Province project at the moment. It's the appraisal of a significant discovery. The Brent is classic petroleum geology – and this project really does feel classic, it feels like heritage, it feels good.

The Brent Province, the Brent Group, the Brent Fields, the Brent Crude Assay, and the Brent Pricing Benchmark. It has underpinned the UK's lifetime of oil production. It's an honour to be on such a project.

The Brent field was discovered in 1971… same year as my birth, a significantly less significant event… by the Shell / Esso joint venture in the East Shetland Basin of the desperately inhospitable Northern North Sea.

Shell / Esso fields were evocatively named after seabirds. Alphabetically and not-quite-sequentially; Auk 1970, Brent 1971, Cormorant 1972, Dunlin 1973, Eider 1976, Fulmar 1975, Guillemot 1973, Gannet 1974, Kittiwake 1977 and so on. I had heard that the original plan was to be boringly alphabetical – A-UK being the first UK discovery, followed by B, C, D. Then someone with a drop of foresight pointed out that the yet-to-be-discovered sixth might prove tricky.

The Brent Group is Middle Jurassic – simplified regionally as shoreface and coastal delta deposition and rather tidily subdivided into five formations: Broom, Rannoch, Etive, Ness, Tarbert, referencing place names in Scotland. But neither simple nor tidy are common in geology, and the more the Brent was drilled, the less simple and less tidy it proved to be.

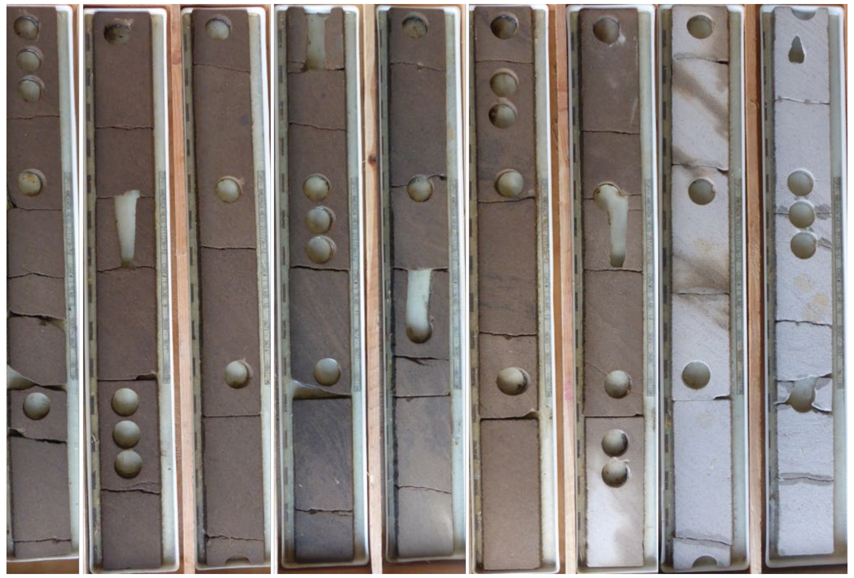
Initially, the stormy, wavy shoreface of the Jurassic sea, the mighty Brent Delta claws, consumes, and cannibalises across the coast. Advancing relentlessly. Inlets open, tides muscle in, the coast becomes complex and contested. The sea concedes in parts, the land dominates, a low delta plain emerges, waterlogged and panting. Saline becomes brackish becomes fresh. Wandering channels, stacked fluvial sheets, migrating mouth, and offshore bars, sands trapped in lagoons. And the infamous coals: Many as grand, extensive measures, many poor and ponded. The closer you look, the madder it gets. Modern seismic attributes help, but perhaps only to illuminate the madness.

Modern Delta analogues mostly disappoint: Danube too small and insufficiently coaly, Rhône way too small with not enough tidal or coal, Niger too rivery, Nile too arid. The best might be the Mahakam in Indonesia, but the picky can still poke holes.

For those who like etymology, Broom, Rannoch and Etive are specific Scottish locations, whilst Ness and Tarbet are more generic. Ness – Old Norse for a headland or promontory, literally "nose". Tarbert – Gaelic meaning a narrow isthmus which were used by Vikings as longship portages: Part convenience, part symbolic acts to claim land.

And talking of Vikings, Norway has its own Brent province – bigger, if anything. Delta-sans-frontières epitomised by the cross-border giant Statfjord, but also Gullfaks, Oseberg, Snorre and many more.

Our Brent project appraisal well is at this very moment turning-to-the-right. Every well we are involved with must involve a deep commitment; but a Brent well has the additional imposing weight of history. To quote the revered geophysicist Nigel Anstey, a pioneer of the modern seismic method: *"People are expecting great things from us. So, let's go. With care. Plain, simple, painstaking, conscientious care"*. ■



An oil-water contact in a Tarbert Formation sandstone, UK Northern North Sea, well 211/23b-12.

PHOTOGRAPHY: NORTH SEA CORE

The next step for National Data Repositories

Would it be possible to bypass interpretation software completely once National Data Repositories, AI, and OSDU work together seamlessly?

DAN AUSTIN, SEKAL

DISKOS recently turned 30, and it got me thinking about the role of National Data Repositories (NDRs) today, and how they can stay relevant as times change.

Historically, NDRs served as a custodian of posterity – a place where seismic records and well logs went to be archived, protected by regulatory mandates but often isolated from the pulse of active operations. However, as the industry grapples with the accelerating complexity of the energy transition, this archival model is proving insufficient.

Currently, NDRs are more important than ever as data continues to be a fundamental bottleneck for the growing AI industry. Every digital twin, simulation, and predictive model relies on a pipeline of standardised, accurate data; if that foundation is fractured, the entire analytical superstructure collapses.

The Norwegian Offshore Directorate has always been very forward-leaning when it comes to technology, and as such, it comes as no surprise that over 30 years, they have taken the NDRs from a simple national data repository for exploration and production-related data to a platform complete with AI-powered chatbots. Strategic investments in data capture, such as the Released Wells Initiative, AVATARA-P and Bypassed Pay studies, have enriched the existing data with modern insights, new datasets and strong foundations for AI and machine learning projects.

Operators and service companies have used each of the aforementioned projects to better understand the Norwegian Continental Shelf, produce new breakthroughs in interpretation such as automated biostratigraphy, seismic foundation models and more. One of the most interesting things to come out of the digitisation and standardisation process has been the relevance and ease of use of this information to support energy transition projects such as carbon storage.

To me, the next natural step on this journey would be for the NDR to curate open models, benchmarks and other important architectures for supporting AI projects. By having nationally realised and published benchmarks and guidelines, I believe it would be easier to build trust in the results and also accept generative input for decision support, automation and more. Perhaps there's even a place for NDR to provide the means to generate realistic synthetic data.

For regulators and national data managers, this means we could move away from intense pre-qualifications and licence rounds and toward smart recommender systems that match the right asset to the right partner in real time. Imagine a world where agentic AI performs the matchmaking, analysing a company's technical DNA and financial appetite against the specific geological risks of a block to suggest the most viable partnerships before a single bid is even cast.

Where does this end?

I think the logical endpoint is a radical simplification of the subsurface interface. If the NDRs solve the problem of data acting as a bottleneck, then we may soon see a world where the NDR merges with frameworks like OSDU to become a universal backend. From here, organisations and individuals could connect self-built applications, agents or even build toolkits on the fly – perhaps bypassing interpretation software entirely. ■

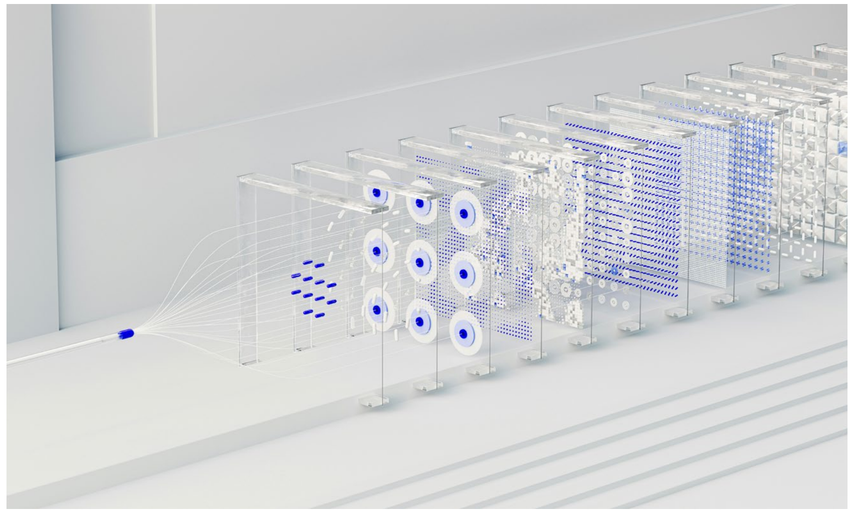


ILLUSTRATION: GOOGLE DEEPMIND

Your fault stability analysis might be lying to you

The number your geomechanical model spits out looks reassuringly precise. A tau-ratio of 0.76. A critical pore pressure of 55 MPa. A sliding friction coefficient of 0.6. Clean. Definitive. Often misleading

FERMIN FERNANDEZ-IBANEZ, SUBSURFACE ALLIANCE

THE MOHR SPACE represents stress states and, combined with fault strength criteria, is used to assess fault stability. It is simple, elegant, and widely accepted. It is also, when applied deterministically, rather misleading. Mohr circles are built on single best-estimate values for key geomechanical inputs, and they do not reflect the true variability and uncertainty of the subsurface. In other words, the number your model produces may look precise, but that doesn't make it right.

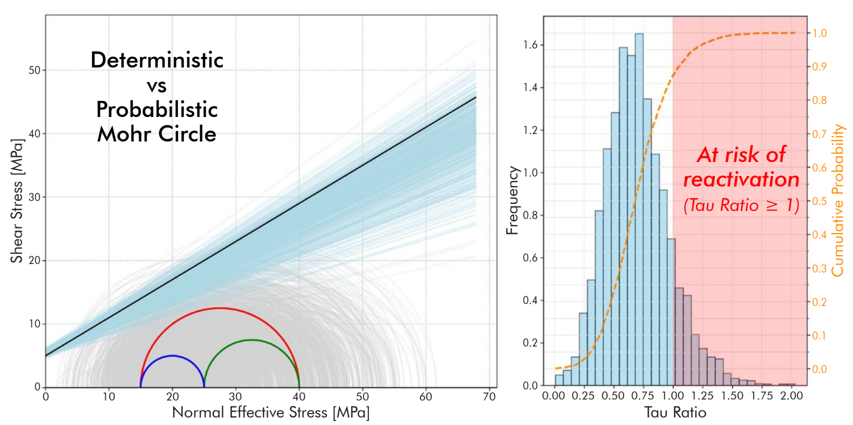
Your model is not wrong in a way that it would get flagged in a peer review. It is wrong because every single one of those inputs has an associated uncertainty. Your friction coefficient? Likely taken from literature and assumed to be representative of your fault. Your stress magnitudes? Inferred from leak-off tests and borehole breakouts at best from a sparse borehole dataset. Your fault geometry? Interpreted from limited resolution seismic data... The deterministic model takes all the uncertainties, collapses them into a single number, and hands you a verdict: Stick or slip.

The final verdict is just one plausible scenario, presented without acknowledging the many others. And the one place this matters most is fluid injection. In CO_2 storage, water flooding, wastewater disposal, or geothermal operations, pore pressure increases while reducing the effective stress with every pore volume injected, effectively moving the Mohr circle towards failure. The margin between stability and reactivation often lies within the uncertainty range that deterministic models refuse to acknowledge.

The solution is not a complicated fix, yet we often fail to go the extra mile. Instead of treating inputs as fixed values, treat them as distributions: Ranges that, when possible, are quantitatively defined from observed variation across wells in an area. This distinction matters. Field-calibrated uncertainty limits mean the model reflects actual spatial heterogeneity and measurement variability, not generic assumptions. From there, a Monte Carlo simulation runs thousands of realisations, propagating uncertainty in stress magnitudes, pore pressure, and fault properties through the stability calculation. What you get back is not a single number, but a chance of fault slip.

Probabilistic analysis should not be an advanced tool, but due diligence. Before committing to the cost and complexity of full 3D numerical models, a Monte Carlo assessment can help depict your risk landscape. If the probability of reactivation is truly zero across the entire input distribution, then results are defendable and it may be all you need. On the other hand, if a chance of fault slip exists, that is your signal to go beyond and commit time and resources to advanced 3D numerical simulations.

The threshold between stopping at the probabilistic assessment or continuing to numerical models is not set in stone; it depends on your risk tolerance, your regulatory context, and the consequences of getting it wrong. Probabilistic analysis does not make the call for you. It just ensures you are making it with a clear perspective. ■



Left: Mohr space showing in-situ stress state and failure envelope (thick solid lines) for a deterministic scenario, and uncertainty-driven plausible variations (thin grey / blue solid lines). Right: Probability of Tau Ratio ≥1.0 (which defines fault instability) for an optimally oriented fault (worst-case orientation for slip): 12 % chance of fault reactivation.

SOURCE: SUBSURFACE ALLIANCE

How decommissioning slowly becomes more of an integral part of the E&P cycle

Where abandonment has traditionally been regarded as an afterthought, awareness is growing in the industry that it makes sense to plan for the end of field life a little earlier

"FOR SOME, a career in decommissioning feels like a departure from traditional E&P geoscience roles," says petroleum engineer Susan Moloney from Elemental Energies when we meet in the Aberdeen office in April. "They prefer the thrill of drilling exploration and development wells."

Geologist Lynette Flockhart, who also joins the conversation, adds: "But despite that sentiment, we feel that the opportunities decommissioning brings, and the importance of doing it in the right way, are slowly dawning on people and companies."

Lynette Flockhart.

Susan Moloney.

PHOTOGRAPHY: SUSAN MOLONEY AND LYNETTE FLOCKHART PRIVATE ARCHIVE

"...there is a real detective element in our work" – Susan Moloney

That is for good reason, as decommissioning is going to be a more important industry in the years to come. Not only in the North Sea, but also in many other mature petroleum provinces across the world. The team at Elemental Energies, which covers a wide variety of disciplines serving the pipes all the way to the pores, sees that opportunity. "On the back of our experience we built up in the North Sea, our own backyard, we are now running projects abroad as well, such as one in the Black Sea at the moment," says Susan.

And whilst decommissioning is gaining momentum, there is also more of an understanding with the operators that being proactive in this space can save money in the long run. "We are working with a company that has a dedicated overburden team," says Lynette, "which would have been unheard of a while ago. The same operator is also open to running an extended leak-off test in one of their development wells. This has nothing to do with that particular well, but the measurement provides very useful information about the fracture gradient in the overburden that we can subsequently use as input for our project nearby."

"In addition, we also find that there are some forums here in Aberdeen that actively promote cross-operator conversations about how to share best practices. That is only of benefit to everyone," adds Susan.

Yet, challenges of course remain, especially when it comes to pulling together all the pieces of the subsurface puzzle. "Missing data is one of the biggest challenges," says Lynette, "as most wells historically have only had well logs acquired across the reservoir interval. Sure, the exploration and appraisal wells may have a more complete coverage, but the development wells, which may be in a different part of the field, sometimes lack any overburden data altogether."

Undocumented mechanical sidetracks are another thing to be wary of. "Historically, the reporting of mechanical sidetracks has been varied, particularly if significant data was not acquired and no hydrocarbons were identified," says Susan. "Yet, we have to include these sidetracks in our reporting to the regulator as part of mapping the entire plumbing system. So, you can imagine there is a real detective element in our work sometimes! ■

Henk Kombrink

North Slope leasing, exploration, and development

NVENTURES

Brought to you in association with NVentures www.nventures.co.uk

Interest in Alaska's North Slope has risen sharply over the past year, with strong lease sale results, expanding exploration programs, and major projects approaching production

KELLY BARKER, NVENTURES

In November 2025, the Alaska Division of Oil and Gas reported solid participation across its three North Slope regional lease areas. A total of 289 bids were received, including 273 bids in the core North Slope region, alongside more modest interest in the Beaufort Sea and North Slope Foothills. High bids totalled ~$17.5 M, with a mix of new entrants and established operators. Bids from Surprise Valley Resources, Lagniappe, and 88 Energy built on positions acquired in the 2024 sales, where they obtained a combined total of 56 leases in the North Slope area. Juneau, EE Partners, Lagniappe, and Savant took a combined 20 leases in the Beaufort Sea region, with high bids totalling around $10.9 M.

In March 2026, the Bureau of Land Management's lease sale in the National Petroleum Reserve–Alaska (NPR-A) attracted $163.7 M in bids from 11 companies, a dramatic increase compared to the roughly $11 M generated in the previous sale in 2019. Participation from major industry players, including ExxonMobil, ConocoPhillips, Repsol, and Shell, underscored growing interest in the region.

Activity shows exploration concentrating around a corridor from the NPR-A through the Colville River region and eastward into Prudhoe Bay. This area benefits from existing infrastructure, including pipelines and processing facilities, which significantly lowers development costs and timelines. Operators are increasingly targeting near-field prospects, close to existing fields.

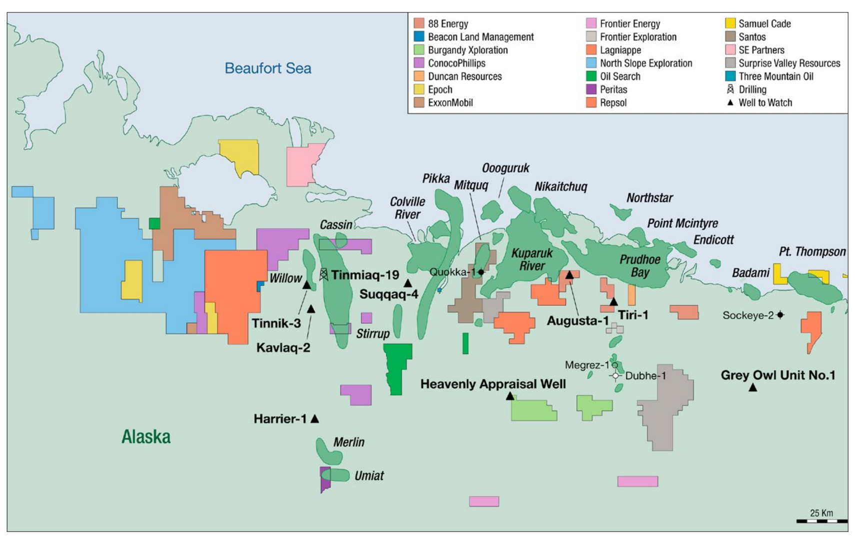
ConocoPhillips has begun a four-well drilling program for 2026 to the east of its Willow development, with the Tinmiaq-19 well underway, and Tinnik-3, Kavlaq-2, and Suqqaq-4 expected to follow. These wells are intended to extend known plays. Willow is expected to begin producing in 2029.

Similarly, Santos has reported encouraging results from its Quokka-1 well, which encountered high-quality oil in the Nanushuk Formation while appraising the Mitquq-1 discovery east of the Pikka development. Pikka is expected to deliver first oil later this year, one of the most significant new production start-ups in the region. Santos is currently evaluating the development potential for Quokka-1.

88 Energy is seeking partners to advance exploration at the Augusta and Tiri prospects in its South Prudhoe leases. In 2025, Lagniappe reported success at its Sockeye-2 well, and Pantheon announced a discovery at Dubhe-1, following disappointment at the nearby Megrez-1, where testing did not produce appreciable hydrocarbon flow.

A notable feature of the current North Slope landscape is the diversity of operators. While major companies continue to dominate core producing areas, a growing number of independents are playing an important role in exploration and early-stage development. Infrastructure is now a central factor shaping investment decisions, with companies prioritising opportunities that offer quicker paths to production, developing known resources and extending established plays.

A BLM sale in the Coastal Plain area of the Arctic National Wildlife Refuge is planned for June 5th 2026. Under the One Big Beautiful Bill Act, at least four more sales are expected over the next ten years in the area. ■



North Slope exploration and lease activity.

SOURCE: NVENTURES

What else is hiding in your reservoir brine?

Lithium may have started the conversation. Gold is how it continues

ISTVÁN NAGY-KORODI, CONSULTING GEOLOGIST

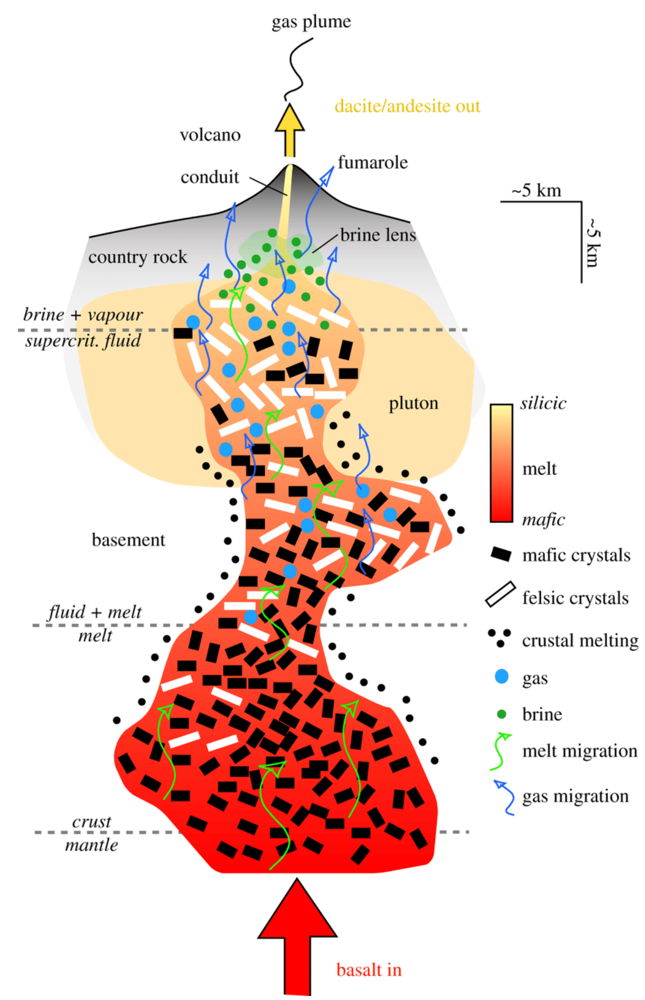
In oil and gas, water is usually treated as a liability – something to manage, re-inject, or dispose of. But from a geological perspective, produced water is not just a by-product. It is the most mobile part of the system, and often the most informative. Under the right conditions, it can carry metals, including gold. Not everywhere, and usually not at concentrations that immediately suggest economic value, but its presence in subsurface brines is real.

It must be emphasised that gold is not easily mobilised. That is exactly why it matters when it appears in fluids. In high-salinity systems, particularly where temperatures are elevated and fluid circulation is active, gold can be transported as chloride complexes. This is well established in geothermal and volcanic environments, where deep fluids interact with metal-bearing rocks and move elements through the system. The Ohaaki geothermal system in New Zealand is an example. The key controls are straightforward: Temperature, salinity, redox conditions, and open fluid pathways. Faults and fractures do the rest.

Most of what we know about metals in brines comes from geothermal systems. That is where the industry has looked. But the processes themselves are not limited to geothermal fields. Petroleum reservoirs – particularly those with deep basinal fluids, evaporites, or evidence of hydrothermal overprint – can host similar fluid chemistries. Produced water in these systems is rarely a single, uniform fluid. It is a mixture, shaped by long-term interaction with different rocks / minerals and temperature regimes. If those fluids have moved through metal-bearing zones, traces of gold can enter the system.

But are we looking for it? In most cases, we are not, because routine produced water analyses focus on scaling, corrosion, and compliance with calcium, barium, sulphate, strontium, CO_2 and H_2S being the main candidates for analysis. Gold is not part of that workflow. Even when trace elements are measured, detection limits and sampling protocols are rarely optimised for something like Au. So it goes unreported. But that does not mean it is absent. There are documented cases – mainly in geothermal and volcanic systems – where gold reaches measurable, even ppm-level concentrations in brines under specific conditions, for instance in Yellowstone, USA, and Hachimantai-Kusatsu in Japan. These are not typical reservoirs, but they show what is possible when temperature, salinity, and fluid flow align. The implication is simple: Fluids can carry gold in suspension or as colloids when the system allows it.

The industry has already started to rethink brines because of lithium. That shift was driven by economics, not geology. Gold pushes the discussion further. Not because it is immediately recoverable in most cases, but because it highlights how narrow our current lens still is. Produced water is not a deposit. It is an active, evolving system. Its value is unlikely to come from a single element, but from the combined presence of many, most of which we are not measuring at all. ■



Schematic of a typical transcrustal magmatic system showing ascent of melt as green arrows and fluids as blue arrows.

SOURCE: JON BLUNDY ET AL. (2021) - THE ECONOMIC POTENTIAL OF METALLIFEROUS SUB-VOLCANIC BRINES

Why dual-phase systems demand a new assessment approach

In mixed oil and gas traps, the hydrocarbon phase and recoverable volumes are controlled by a dynamic interplay between charge phase and volume, PVT conditions, trap geometry and size and seal capacity. Standard tools often overlook these factors, leading to unrealistic or misleading outcomes

LUKASZ KRAWCZYNSKI, TOP DOWN PETROLEUM SYSTEMS ANALYSIS AND MARTIN NEUMAIER, ARIANELOGIX

VARIOUS work-arounds attempt to compensate for these limitations, but each introduce their own artefacts. A common approach is to treat gas as a failure by assigning a "gas risk" and evaluating only oil scenarios. Another merges the risked and success case volumes from separate oil and gas cases, but eliminates the possibility of a dual-phase outcome. A third work-around subdivides the hydrocarbon column into a gas column and an oil column, often considered the most acceptable option, but it is rarely supported by justifiable parameter choices, and it fails to capture the controls on phase behaviour and column height.

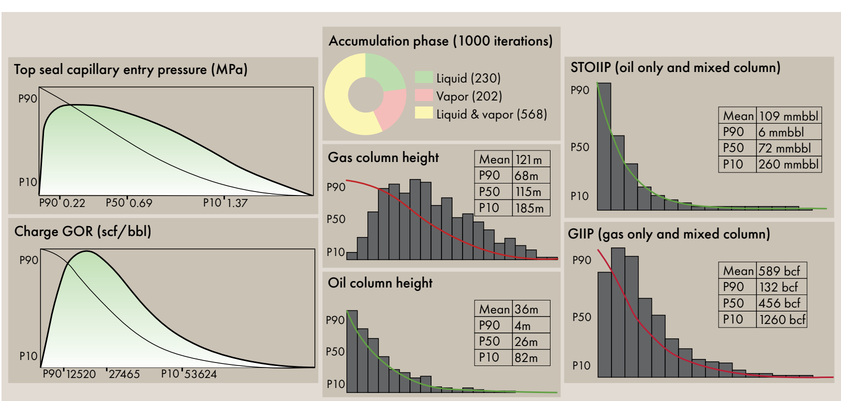
To overcome these limitations and to properly estimate prospect risk and volumes in systems where oil and gas phases compete for pore volume and seal capacity, the best workflow is a petroleum systems-based approach. This integrates charge volume and composition, PVT conditions and seal properties to derive the hydrocarbon phase risk associated with the expected range of oil and gas volumes.

This difference becomes clear when applied to a prospect assessment case study from the gas-dominated Vulcan Sub-basin, which illustrates how strongly resource estimates depend on the underlying fluid assumptions, even when pore volume is held constant.

An oil-only, filled-to-spill scenario yields an estimated mean STOIIP in excess of 1,000 MMbbl; however, as discussed in our previous article (GEO EXPRO Vol. 23, Issue 2, 2026), filled-to-spill oil-only accumulations cannot be physically explained in dual-phase charge systems. Constraining the oil column height based on nearby analogue field data reduces the mean STOIIP estimate to 477 MMbbl, but this approach is flawed because the analogue distribution is dominated by gas columns. Limiting the analysis to oil-only analogue columns lowers the mean STOIIP to 75 MMbbl, moving closer to a plausible range but still failing to account for mixed columns.

In contrast, the petroleum systems-based prospect assessment yields a mean STOIIP of 109 MMbbl and a mean GIIP of 589 Bcf, within a single probabilistic assessment where oil and gas are inherently associated. The results of this approach capture the natural continuity from gas-only (class 1), mixed (class 2) and oil-only (class 3) accumulations with a dual-phase scenario representing the most probable outcome (~60 %), and also the most prolific for oil. The increase in estimated STOIIP relative to the oil-only column case reflects the potential presence of a gas cap, which effectively displaces oil into structurally higher gross rock volume portions of the trap.

The case study demonstrates why petroleum system understanding and integration are essential to realistic prospect assessment. Standard methods often rely on assumptions that lead to unrealistic resource estimates, especially when evaluating an oil accumulation in a gas-dominated petroleum system. A petroleum systems-based approach inherently captures the inverse relationship between column height and oil phase in such settings, embedding phase behaviour within the methodology itself and eliminating the need for separate "oil versus gas" risking. ■



Petroleum systems-based approach for prospect assessment, with selected input uncertainty distributions for charge and seal calculations (left), resulting in probabilistic prediction of phase and column height (center) and final in-place volumes ranges for oil and gas (right).

The rebellious proto-Riedel shear zones

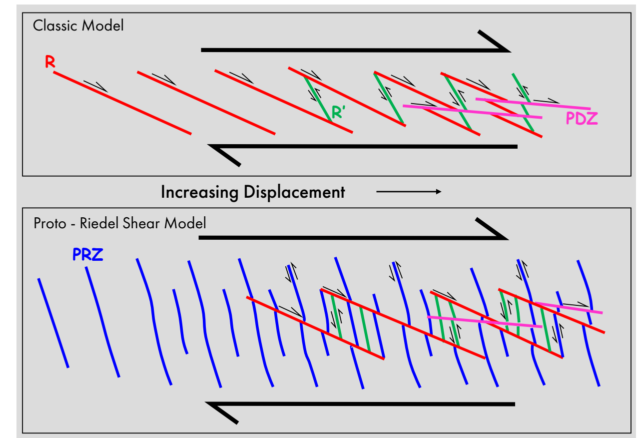
Fault nucleation order is not universally synthetic-driven but depends on lithology, fluid pressure, and boundary conditions

MOLLY TURKO, DEVON ENERGY

CLASSIC RIEDEL shears are the first subsidiary fractures that form prior to breakthrough of a master fault. They appear as low-angle (~15°) en echelon arrays oriented synthetically to the principal displacement zone (PDZ), sharing the same sense of slip. This synthetic-first sequence is widely assumed to control fault nucleation in brittle crust. Although best known in strike-slip settings, Riedel shears also occur on normal and reverse faults, where the low-angle synthetic set (R shears) and high-angle antithetic set (R′ shears) are often simply called synthetic or antithetic relative to the master fault.

Proto-Riedel shear zones (PRZs), defined by Ahlgren (2001) in the porous Jurassic Navajo Sandstone of southern Utah, are fundamentally different. They are the earliest tabular precursors to linked strike-slip faults and begin as spaced, en-échelon, high-angle (55° – 85°) deformation bands oriented antithetically to the overall zone. These bands nucleate under elevated fluid pressure via compactional cataclasis and granular flow. With increasing strain, the zone hardens, conjugate low-angle synthetic (R-equivalent) bands form, and the original high-angle bands are recycled as R′ shears. The result is a helicoidal, sigmoidal array that eventually localizes into a principal shear zone (PSZ). Similar PRZs occur in the age-equivalent Jurassic Aztec Sandstone at Valley of Fire State Park, Nevada – both eolian sandstones – where awkward spine-like fracture geometries (pictured here) fit Ahlgren's model.

Ahlgren's 2001 work is controversial because the nucleation sequence is antithetic-first, opposite to classic models. It challenges the universality of the synthetic-first paradigm and shows that lithology and pore-fluid pressure can control whether R or R′ shears dominate early growth.



Classic synthetic-first model of strike-slip evolution versus the PRZ antithetic-first model.

Post-2015 studies have broadened the discussion, though direct replication of antithetic precedence is still rare. Camanni et al. (2023) describe contractional relay zones on normal faults where multiple antithetic (R′-like) faults transfer throw between synthetic segments in Riedel-like geometry; later linkage of the synthetic faults bypasses the relay, preserving the antithetic array inside the fault zone – similar to PRZ recycling.

Thus, while Ahlgren's antithetic-first PRZs remain the clearest natural counter-example to lab models, recent work on normal-fault relays and numerical / induced-seismicity settings shows that early antithetic activity is more common than previously thought. The controversy continues: fault nucleation order is not universally synthetic-driven but depends on lithology, fluid pressure, and boundary conditions. ■

Right-lateral PRZ from the Valley of Fire, Andy Cube is ~5 cm from scale.

NOTHING BEATS THE FIELD

Wadi Nukhul – a glimpse of the Red Sea-Gulf of Suez rift system

During the Oligocene and Miocene, a 2,000 km long zone of extension developed that formed the Red Sea-Gulf of Suez rift system. In this outcrop photo, we are looking south in the Wadi Nukhul region on the east coast of the Gulf of Suez, and observe the pre-syn-rift unconformity (arrows) that developed as a result of the rifting event.

In this view, pre-rift Eocene limestones and marls of the Thebes and Darat Formations are unconformably overlain by fluvial and lacustrine red bed facies of the Rift Initiation Abu Zenima Formation, which fills major erosional valley systems cut into the pre-rift strata. The valley fill consists of a basal unit dominated by overbank heterolithics, mature paleosol / caliche horizons and local fluvial channel systems which pass upwards into a lacustrine to brackish mudstone interval (white units).

The buff to brown-colored units in the upper part of the cliff are tidal facies of the Rift Initiation Nukhul Formation, which include excellent high N/G estuarine tidal channel complex reservoirs and interbedded thin-bedded tidal flat heterolithics. The Nukhul Formation is overlain by offshore to shelfal mudstones and sandstones of the Lower Rudeis Rift Climax succession (topmost outcrops). Note the progressive decreasing dips up-section, related to syn-depositional growth on the Wadi Nukhul and Rift Bounding faults. The syn-rift cliff section is circa 150 m high.

In the offshore Gulf of Suez, circa 30 – 40 Bbbl (OOIP) have been discovered to date (10 – 12 Bbbl recoverable), split roughly 40 – 60 between pre-rift and syn-rift reservoirs / plays, charged by Cretaceous and Miocene source rocks and sealed by a super-regional seal of Mid to Late Miocene evaporites. Similar plays might be expected in the relatively unexplored inboard parts of the offshore northern Red Sea.

Text and photography: Ian Sharp, Equinor

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.

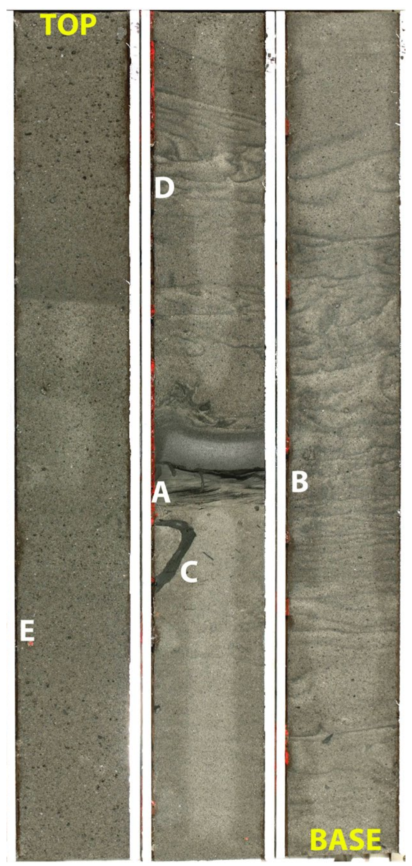
Beyond turbidites: Core insights from the Rovuma Basin

Few offshore basins have reshaped the global gas landscape as profoundly as the Rovuma Basin offshore northern Mozambique. Home to giant discoveries such as the Mamba or Coral fields, the basin offers a compelling opportunity to examine deepwater depositional systems and their influence on reservoir quality

CORNELIU COSOVANU, CORE LABORATORIES

THE ROVUMA basin evolved from Early Jurassic rifting into a passive margin by the Mid-Cretaceous, followed by significant clastic infill through the Cretaceous and Tertiary. Uplift associated with the early Paleogene East African Rift System drove substantial sediment supply, feeding deepwater channel systems and fan complexes.

Progressive sediment loading and gravity-driven deltaic tectonics led to collapse of the sediment wedge, forming a linked system of deformation characterised by numerous listric growth faults linked by a regional detachment layer downdip to compressional fold-and-thrust belts in deepwater area. Many major hydrocarbon discoveries are located near the toe of this thrust belt.



Core images from Paleogene reservoirs, deepwater Rovuma Basin.

CORE-CONTROLLED INSIGHTS

The insights presented here are derived from a regional core-based study undertaken in 2023 by Core Laboratories in collaboration with the Instituto Nacional de Petróleo (INP) in Mozambique. Core material from across the basin captures the full spectrum of the turbidite system – from proximal channel deposits through to channelised or amalgamated lobes and lobe-fringe facies. Several intervals display thick-bedded sandstones with very good to excellent reservoir quality, reinforcing the effectiveness of these systems as primary reservoir targets.

One important aspect in this area is the influence of bottom currents. Rather than acting independently, these currents interact with turbidity flows – either during deposition or through subsequent reworking, creating hybrid facies.

TURBIDITE – CONTOURITE INTERACTION

The evidence for contourites in the Rovuma Basin is mainly seen in the presence of unusually thick, stacked sandy turbidite beds, as the contourite currents strip out the finer-grained material and deposit them on the overbank margins of the channels as asymmetric drifts. In core, however, it is possible to observe some evidence of bottom current reworking within thin, finer-grained units locally preserved between the sandy, high-density turbidite (HDT) flows like the ones illustrated in the core photo (left).

Here we see that the HDT deposits, interpreted to form part of a channelled fanlobe, are separated by a thin finer-grained interval (A). The lower HDT (B) comprises coarse-grained, massive to fluidised sandstones with abundant dewatering structures (dish and pillar) and large deformed mudclasts (C), while overlying finer-grained intervals (A) display climbing ripples, clay drapes, and localized bioturbation. Deposition resumes upward with additional fluidized sands (D) and thicker granule-rich units (E), reflecting renewed high-density turbidity flow. In contrast, the thin finer bed (A) represents a low-density turbidity flow, possibly reworked by bottom-currents.

RESERVOIR IMPLICATIONS

Both HDTs exhibit high porosity, with permeability exceeding 1,000 mD in granule-rich intervals. However, the presence of finer-grained layers introduces subtle heterogeneities that can significantly influence reservoir connectivity and flow behaviour.

Although typically below seismic resolution, these features are identifiable in core and are critical for refining reservoir models in structurally complex deepwater settings. ■

PHOTOGRAPHY: INSTITUTO NACIONAL DE PETRÓLEO

OUR SPONSORS

GEOExPro

- envoi – delivering energy opportunities
- EPSLOG ENGINEERING
- AGR – An ABL Group Company
- moveout – BETTER DATA AT YOUR FINGERTIPS
- RESERVOIR GROUP
- NVENTURES
- WELLIGENCE – ENERGY ANALYTICS
- tNavigator – Rock Flow Dynamics
- GIS PAX PLAYER
- ROCKWASH GEODATA – A GEOTEK Company
- metatek
- MEADLANDS GEOCONSULTING
- top down – PETROLEUM SYSTEMS ANALYSIS
- Meren
- Qeye – beyond elastic
- ArianeLogiX
- SUBSURFACE ALLIANCE – DATA DRIVEN | SCIENCE BASED | FIT-FOR-PURPOSE
- GLEX