

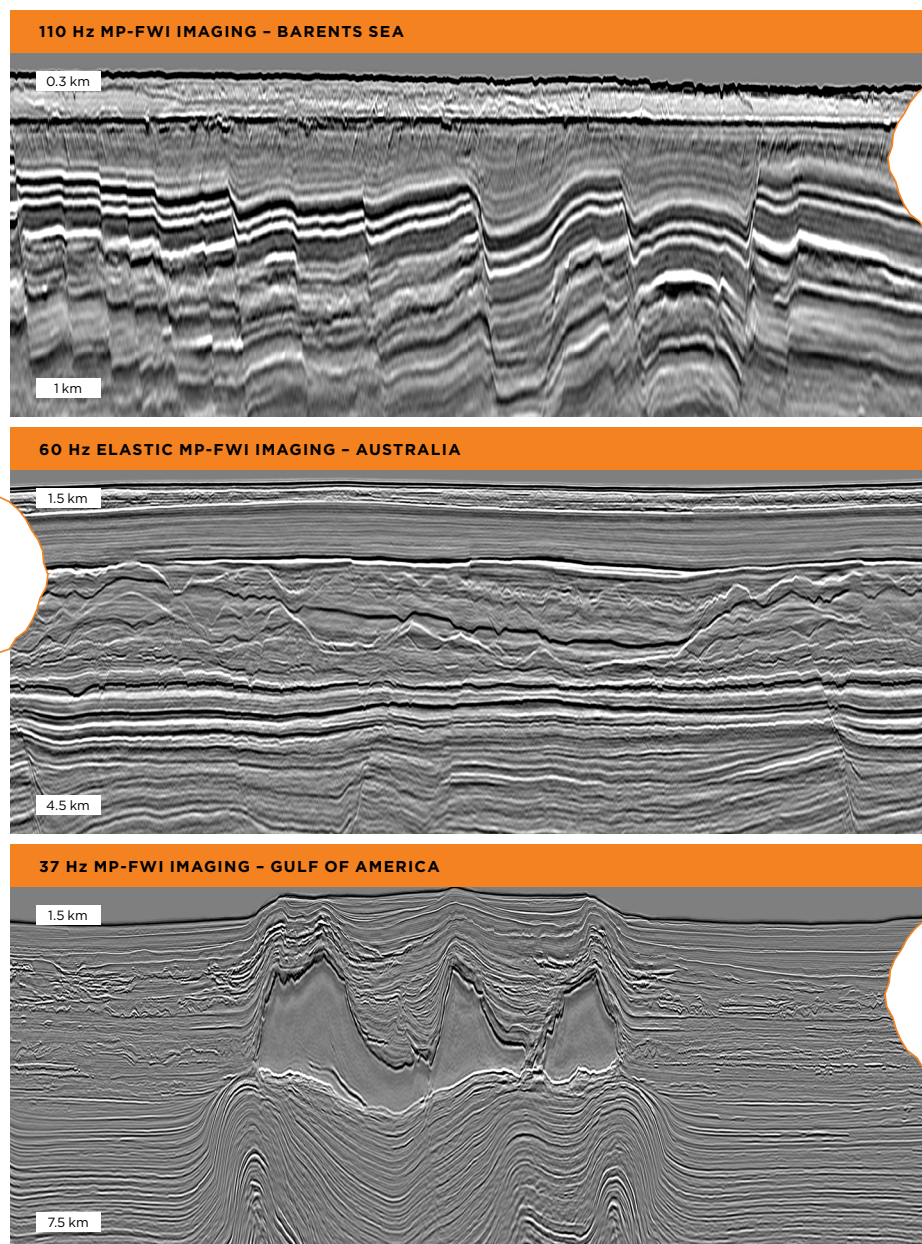
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PHOTOGRAPHY: HENK KOMBRINK

One foot in the Jurassic

"THERE IS NOT much that can compete with the power delivery of kerosine," an off-duty pilot once told me when we took off from Amsterdam Schiphol Airport. I had just asked him about his thoughts on the electrification of airplanes. Judging by his response, it seems like it's still a long way off.

Everybody talks about AI these days. And about the weather. As always. I grew up in a time when there were only three TV channels we could watch. Most of the time, there was nothing for kids to consume. So yes, we live in a world where some things have progressed a lot. For the worse or the better.

"But for now, our foot is still firmly stuck in the Jurassic. And because of that, this magazine exists"

But at the same time, when taking off from Amsterdam, there is the realisation that in a tank in the wings of this new and high-tech machine, there are the remains of what were once millions of algae floating in a warm Jurassic sea,



delivering the energy to accelerate and make it to the sky.

Despite our amazing technological progress, we still rely on tiny fossils to make our intercontinental and city-hopper journeys. Isn't that odd? I think about that often, and it makes me feel as if we are still stuck in the Stone Age. Or better, in the Jurassic.

Oil is an amazing product. It is a product of nature, too. Of course, it would be better if the wind was able to provide all the energy we need. But for now, our foot is still firmly stuck in the Jurassic. And because of that, this magazine exists. Where does the oil come from, and how do we produce it better? The 50 articles in the fourth issue of this year mostly revolve around that. Enjoy the read.

Henk Kombrink

BEHIND THE COVER

Core displays at conferences are always a pleasure to visit. And the one at GeoConvention in Calgary in May this year was no exception. That's where I met with Alisha Fridrich from Islander Oil. I had never heard about her company, nor had I met Alisha before. The cores she took with her were simply amazing; Lower Carboniferous mud mound carbonate facies from northern Alberta. What a delight to look at, with the individual crinoid parts contrasting with the oil-stained matrix. I took a photo, and Alisha and her team were happy for it to go on the front cover. There you go. And please read the accompanying article on page 32.



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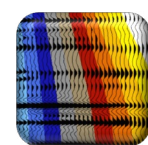
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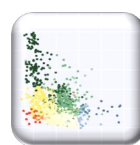
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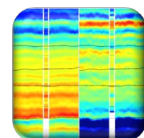
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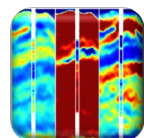
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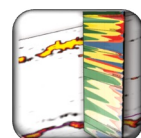
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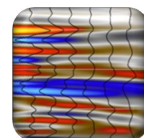
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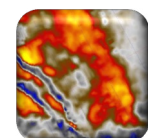
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"Geology sets the cadence"

Rodney Garrard

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

IT'S NOT ALWAYS A MATTER OF VISION

Sometimes it is worth flicking through the notebooks that I keep in my drawer. A few years ago, after interviewing someone about exploration drilling in Libya, I wrote down how the company Lasmo, after making the Elephant discovery in the Murzuk Basin in southern Libya, immediately became a takeover target. It was ENI that ultimately bought the company. With that takeover also came Lasmo's other assets, and one of those was acreage in the Kutei Basin in Indonesia, in which ENI recently made another sizeable discovery – Geliga. That is obviously all to be credited to ENI, but it is interesting to be reminded that getting the acreage in the first place was not a matter of deep study at all, as it was the Libyan asset that drove the purchase.

CONFIDENCE AND OIL

I was recently told the story of how Cairn discovered gas in Bangladesh initially, followed by the hugely successful campaign in India that resulted in the discovery of a large oil field in an area that had been given up by Shell not long before. As such, the owners of the company at the time became convinced that they could find commercial hydrocarbons anywhere. That is the backdrop against which the company embarked on the famous offshore Greenland drilling programme that took nine wells and cost a fortune. However, as may not be entirely unexpected, Cairn was not lucky the third time – a clear example of how confidence can turn into overconfidence.

RELATIONSHIPS AND AI

During a fireside chat at a recent conference in London, Katherine Roe, CEO of Pharos Energy, said that the oil business is a relationship-building business. I think I agree with that. In my experience, cold-calling is always much harder than being introduced by a common friend. It is ten times easier. It also makes me wonder how AI can play a role in facilitating this. So far, I have concluded that there is not too much of a role for AI here. At the end of the day, getting things done still involves human interaction. Let it stay that way. In the meantime, Pharos Energy has been acquired by the Israeli company Ratio Petroleum.

NO DRY WELLS ALLOWED

At a conference, I met a geologist who works for a mid-sized company. He told me that the owner of the explorer does not tolerate drilling dry wells. And this attitude causes a culture in which people can not criticise any plans because of the risk of going against the grain. The result is that exploration managers lose their jobs straight after a dry well has been completed. Wow.

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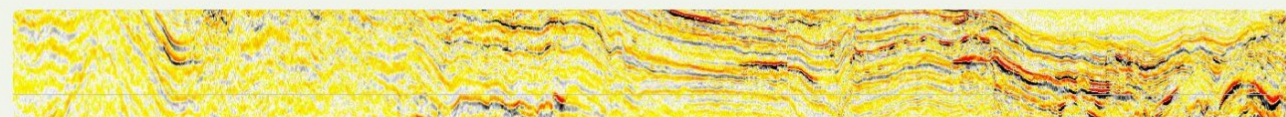
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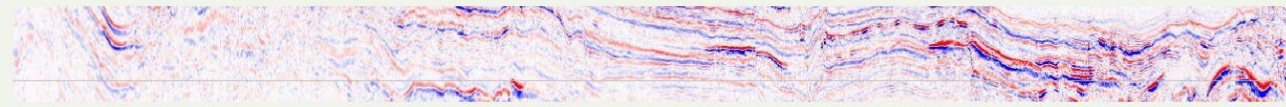
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Why geology still calls the plays in every energy system

We live in an era where big promises are easy to make. With enough funding, enough policy momentum, and enough glossy reports, almost anything can look inevitable. But there is one force that remains unimpressed by all of this: The ground beneath our feet



THE EARTH is not a suggestion box. It doesn't negotiate. It doesn't adjust to aspirations. Its rules were written long before we arrived, and they remain in force no matter how many times "crisis" is mentioned in the media. This is why geology – quiet, old, and stubborn – still determines what we can build, how fast, and at what cost.

A useful starting point for anyone thinking about energy is this: What exists is not the same as what we can use.

We often hear that certain countries are "rich" in minerals, or that the world has "plenty" of copper, lithium, uranium, or rare earths. But geology doesn't hand out neatly packaged inventories. It scatters minerals unevenly, locks them behind water constraints, tucks them under mountains, dilutes them with impurities, or places them in jurisdictions where permits take longer than a child's journey from kindergarten to university.

The gap between endowment (what the Earth holds), inventory (what we've identified), and production (what actually comes out of the ground) is where most energy debates come unstuck. People talk about resources as if they were Lego bricks; in reality, they behave more like weather systems – complex, variable, and stubbornly local.



Every energy system begins with geology.

EVEN "WEIGHTLESS" TECHNOLOGIES HAVE MASS

Take artificial intelligence and the cloud, now sold to the public as ethereal. A data centre is simply another kind of mine mouth. It devours copper for cables and transformers, electrical steel for machines, concrete and rebar for foundations and vast amounts of water for cooling.

There is nothing virtual about it. A server rack is an energy-hungry metal box that lives in the real world, connected to real geology and real constraints. If the aquifer is stressed, if the transmission line can't be built, if the copper isn't coming, your digital future will wait politely until the Earth allows it to proceed.

This is perhaps the hardest truth for energy planning: Geology sets the cadence.

You cannot accelerate an ore body. You cannot will a refinery into being faster than the materials, labour, permits, and water allow. You cannot mass-produce perfect wind sites or force transmission corridors through mountains without time, negotiation, and steel.

This is not pessimism; it is realism. Projects grounded in geological truth move more slowly in PowerPoints but faster in reality because they avoid the detours, redesigns, and overruns that come from ignoring the world's substrate. Geology is the literal and figurative foundation of anything we build; it sets the parameters of availability and stability, and we ignore it at our peril.

THE SCOREKEEPER THAT NEVER SLEEPS

In the end, geology is not pro-or anti-anything. It is simply the terrain on which all human plans must be built. It supplies the materials, constrains the options, and reports the final score when timelines slip or budgets swell.

Recognising that is not defeatist. It's the first step toward designing energy systems that actually work, because they respect the only approvals that matter: those granted by rock, water, and time.

Rodney Garrard

This article is adapted from the forthcoming book Rock Hard Truths: A Critique of the Consultancy Class in Energy Reality Discussions.

PHOTOGRAPHY: BRITANNICA.COM

Mediterranean eyes on Greece as deepwater drilling approaches

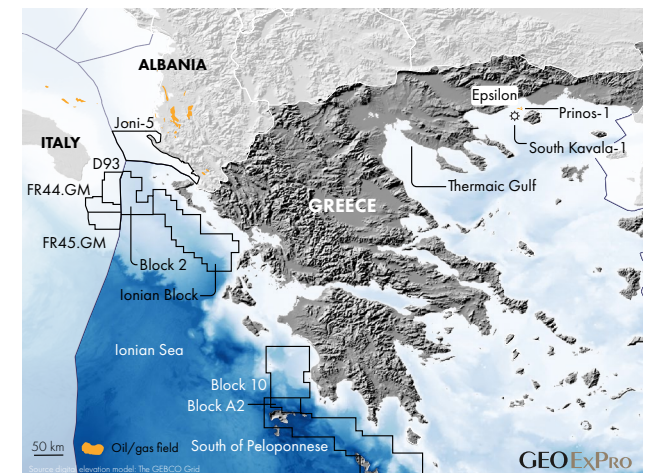
Testing a massive 10 Tcf Jurassic carbonate gas prospect, Energean will drill the Asopos-1 wildcat well in the northwestern Ionian Sea in early 2027, marking Greece's first offshore exploration well in 45 years



THE EXPLORATION hunt for hydrocarbons in Greece started in 1938 with the drilling of shallow wells. After a post-war lull, the passage of Greece's first comprehensive petroleum law in 1959 drew immediate international attention, prompting Esso to secure exploration permits. By 1960, companies flocked to the country, including bp and Hunt Oil. However, this early wave of excitement proved short-lived, and following a series of highly disappointing drilling campaigns, most of these original concessions were surrendered by 1965.

A second major wave of exploration kicked off in 1970 when Texaco entered Greece to take on an offshore concession located within the Thermaic Gulf. This era delivered Greece's first commercial success when Oceanic discovered gas at the South Kavala-1 well in 1973, which they quickly followed up in 1974 with a moderately heavy oil discovery within Miocene sands at the Prinos-1 well in the Gulf of Kavala. Today, the concession is held with a 100 % working interest by regional operator Energean, formerly known as Aegean Energy. The Prinos, Prinos North, and Epsilon fields within this area remain the only producing oil fields in Greece, although their operations have been stop-start.

In 1996, Greece opened its First International Licensing Round and alongside local company Hellenic Petroleum, Enterprise Oil and Triton were awarded acreage. Exploration campaigns on and offshore were disappointing, however, and exits followed. After a 15-year lull, Greece launched an Open-Door Round in 2012 and the Second International Licensing Round in 2014. While initial industry interest was mixed, the global energy sector took notice after massive deepwater carbonate discoveries were made in neighbouring Mediterranean waters across Egypt, Israel, and Cyprus. This regional success attracted supermajors Total and ExxonMobil to apply for Greek deepwater acreage, alongside Repsol and Edison. Strategic corporate realignments later caused TotalEnergies and Repsol to pull out of the country entirely, while Edison's exploration



arm was swallowed up by Energean, sparking a reshuffling of concession interests.

The current landscape features a high-stakes return of major US energy companies supporting the Greek government's push for domestic energy security. In November 2025, ExxonMobil increased its footprint and executed a farm-in agreement to take a 60 % stake in Block 2. Following this, Chevron expanded its Mediterranean growth strategy in 2026 by partnering with HELLENiQ ENERGY across five deepwater concessions, signing deals for South Crete 1, South Crete 2, Block A2, and the South of Peloponnese, followed by Block 10. In addition, Block 1 is the subject of a submitted bid.

This latest surge will reach an important milestone in 2027 with the drilling of the Asopos-1 wildcat well in Block 2. Approximately 40 % of the Asopos structure is understood to extend directly into Italian waters, and the prospect sits just south of Albania's open Block Joni-5. Energean had previously applied for the adjacent Italian 84FR-EL block (now designated as D93), and directly to the south in Italian waters, Global MED of Denver operate FR44.GM and FR45.GM contiguous with the Greek waters.

Ian Cross - Moyes & Co

A new discovery, but in what?

A recent scientific publication calls into question the established reservoir model for one of Libya's oldest plays. A play in which another discovery was recently announced

THE SIRT BASIN in Libya is the most prolific oil and gas province in the country. In 1967, Oxy found oil in Paleocene carbonates of the Intisar A field in the eastern part of the basin, testing at 43,000 bbls/d. This discovery helped cement Oxy's reputation as an oil finder and also as an adopter of new technology; the domal structures are located in a basinal area of the Sirt Basin and needed seismic lines to be delineated. A number of what were always thought to be pinnacle reefs have been discovered since – see map.

Libya's National Oil Company recently announced that the operators and partners of Concession 103, OMV and Zueitina, made another discovery in the Intisar cluster. The well (B1-106/4) targeting the Essar prospect was drilled only 6 km from the Intisar 103D field, positioning it between two existing accumulations. It tested 42 degrees API oil at 4,200 bbls/d from both the Paleocene

Upper and Lower Sabil formations, and is quoted as potentially containing 195 MMboe in reserves, which is quite sizeable.

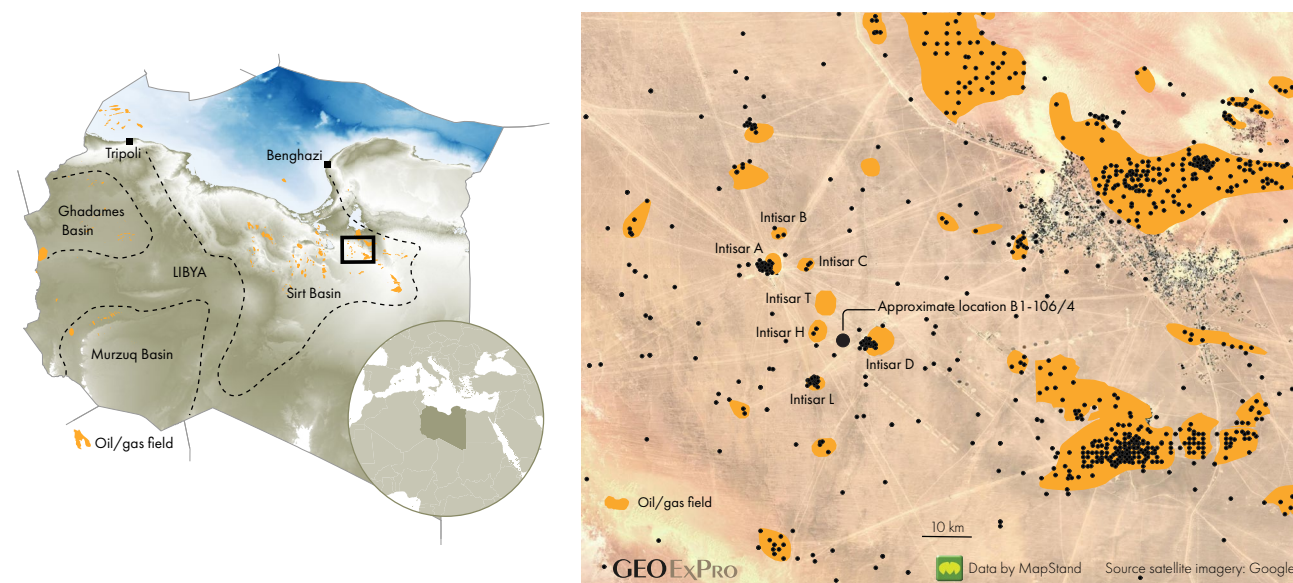
What is interesting about this discovery is the debate around what these Intisar domes of the Upper Sabil Formation actually represent. A paper published in 2021, based on a detailed facies analysis, deviates from the pinnacle reef interpretation. The authors conclude that the Intisar pinnacle reefs are, in fact, erosional remnants of a wider carbonate platform rather than isolated build-ups. It is mainly their facies analysis pointing in that direction, with the assemblages found being much more similar to ramp deposits as described elsewhere. The authors also argue that pinnacle reefs have never been found in local outcrops.

This is an interesting conclusion. If indeed the Intisar fields that we now see on the map are erosional remnants of a low-stand period, the ques-

tion is why they are so well-rounded. If they were eroded by fluvial activity, then one might expect a more incisive and valley-wise character of what remains. The paper does not present seismic data to further investigate this. It would be interesting to see a 3D horizon showing what the erosive landscape looked like at the time.

Regardless, the discovery is supposedly made in the same Upper Sabil formation from which the Intisar fields were produced, showing that even in such an old and established play, there is additional potential. It would be great to see a seismic line connecting the new discovery with the Intisar D field to the east and the Intisar H field to the west. Is it another bump that was previously ignored, or is it in another facies altogether? Anyway, plenty of questions remain, but yet again, this news is testament to the old statement that you need to seek oil where oil is.

Henk Kombrink



Location of the Essar discovery well (B1-106/4) in the Sirt Basin. The satellite image nicely shows how the tracks in the desert lead towards the centre of operations in the region, the Intisar A field.

COVER STORY

“What you can create with a continuous current in terms of sedimentary deposits is quite limited; ripples, dunes, sand waves, parallel lamination and anti-dunes, and that’s about it. It is very well possible to create the same structures in a gravity current. That’s where the challenge lies”

Wouter de Weger – Andalusian Earth Sciences Institute

STORIES FROM THE DEEP

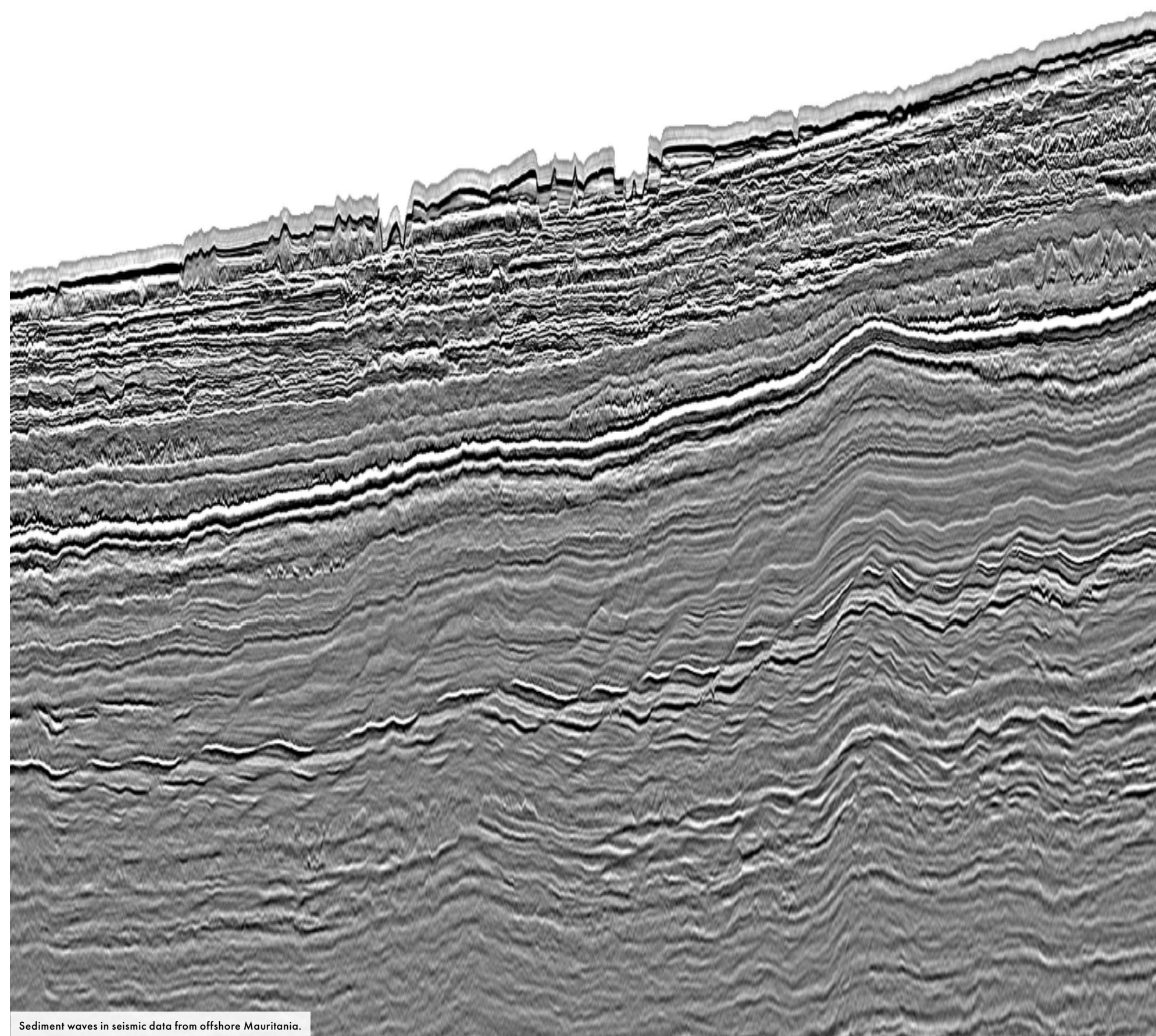
Deepwater sedimentation is a hot topic. As companies continue to explore deeper and deeper realms of the world's continental shelves, and even beyond, with it has come an increasing interest in the processes that shape the reservoirs that are being deposited in those places – going beyond the classic turbidites or gravity flow models. It is all about mixed systems nowadays, and better quantifying and understanding how turbidity flows interact with bottom currents.

HENK KOMBRINK

THE MAMBO and Coral fields offshore Mozambique form a key part of this story. In a 2024 paper, ENI authors show how the reservoir quality of the giant Paleogene gas discoveries improved because strong bottom currents redistributed fines from the channelised zones, leaving an even better-quality reservoir behind. But Mozambique is not the only example of the importance of understanding bottom current processes. The Jubilee field in Ghana, with its asymmetric levee systems, is another one. The more recently drilled Ephesus fan offshore Canada is also thought to be shaped by more than just a turbidite lobe: "I have never seen such

a thick and clean sand body in my life," a seasoned explorer told me when we spoke about it.

Associated with the interest in deepwater sedimentation comes a field of research into the matter, looking at examples in the geological record as well as studying processes acting on the present-day seafloors. For this story, I spoke to a number of researchers active in these domains, as well as some industry professionals. It will take us to Japan, Mozambique, Canada, Argentina, Spain, the Netherlands and Morocco, and we will see how the scientific work towards better understanding deepwater environments is still very much an evolving discipline, including some disagreements here and there. ►



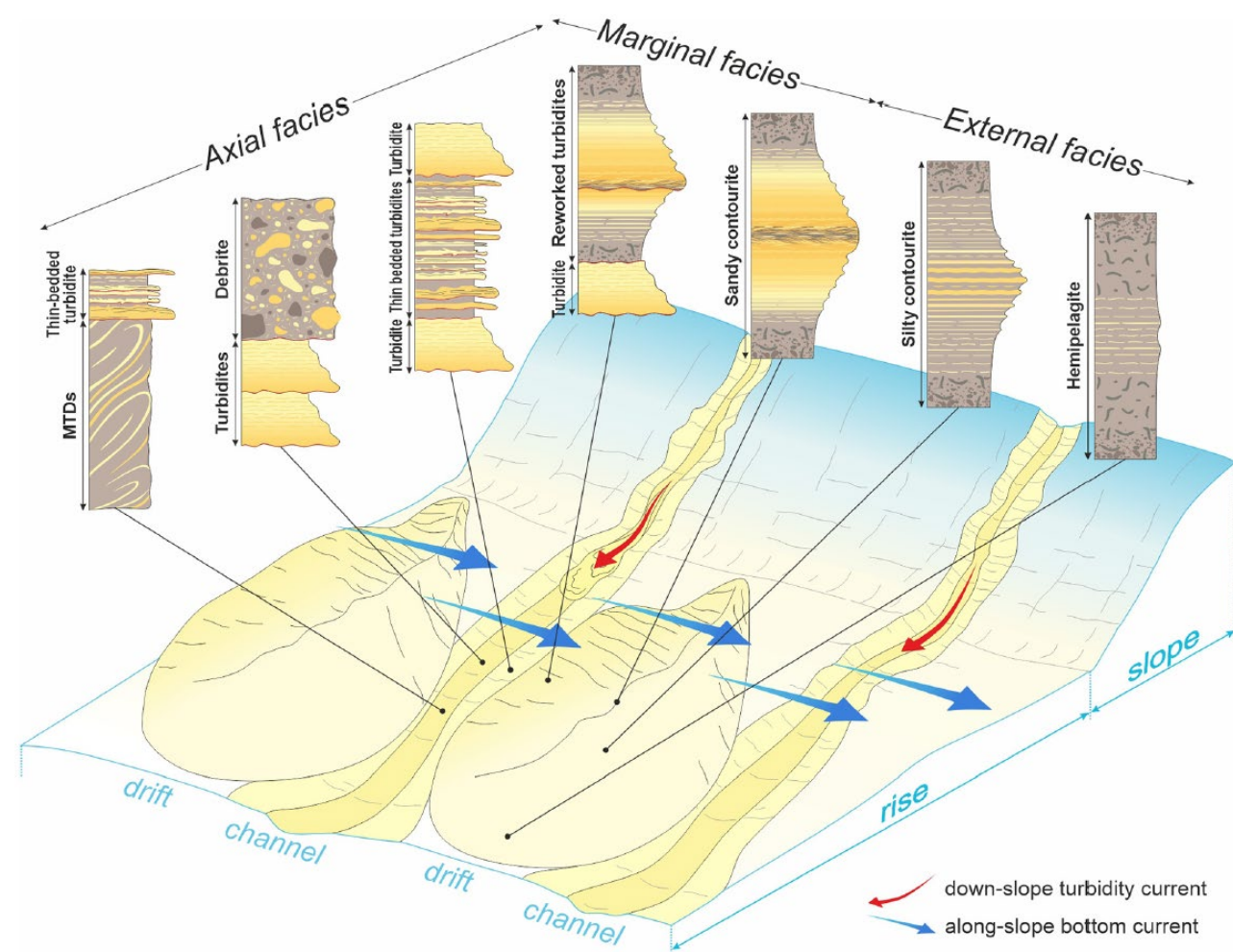
Sediment waves in seismic data from offshore Mauritania.

“Even in the chaos, there is an order,” says Sara Morgado Rodrigues when we have a call whilst she is working on a project in Buenos Aires, at one of YPF’s offices. Sara is a postdoctoral researcher at the Andalusian Earth Sciences Institute in Granada, Spain, and works in the group that is led by Javier Hernández-Molina. Sara and her co-authors published a paper in 2022 that proposes a new classification system for mixed depositional systems, following a PhD during which she studied these systems at three locations across the world. In the paper, she also nicely shows how the number of publications on mixed systems has exploded over the past 20 years, reflecting the growing interest from both industry and academia.

It is now well known that some deepwater oil or gas fields display

a clear bottom current component in the way the reservoirs formed, as mentioned above. “But there are probably more,” says Sara. “It’s just because the industry does not always share their insights straight away. For instance, I do know that Petrobras in Brazil is operating some oil fields in the Campos and Espírito Santo Basins where there is a system of deep-marine channels that was severely reworked by bottom currents, even creating barchan dunes and ridges amongst other structures. The Sirius discovery offshore Colombia is probably the most recent example of a reservoir that has been shaped by bottom currents,” Sara says. It is interesting that Sirius is also operated by Petrobras. Did they bring some of their mixed systems experience to Colombia?

“On the back of all these developments, I see that energy companies are hiring more people with knowledge about deepwater processes,” says Sara. “I guess that’s also why you are currently in Argentina?” I ask. “Sure,” she says, “even though for me, this is also a continuation of work I already did in Argentina before. But yes, there is a lot of interest here, as the offshore of northern Argentina leading to Uruguay is an area where we see a broad zone of mixed deepwater systems in the Cretaceous. And with more 3D data now becoming available, there is more of an opportunity to study these deposits. As another example, I was invited by ENI to give a talk at their office the other day, and they also showed us not only the Coral and Mambo cores, but also from a recent



Sedimentary facies identified in mixed depositional systems.

SOURCE: RODRIGUES ET AL. (2022) / SOURCE PREVIOUS PAGE: TGS



The sandstones in the top part of the El Adergha outcrop in northern Morocco are interpreted as being deposited by contourite channel and the associated more proximal gravitational systems, following work by Wouter de Weger and co-authors. That’s not to say that other interpretations exist. Daan Beelen and co-authors integrated the large foresets at the top of the photo in their framework of delta progradation. The grey and finer-grained middle part of the exposure is the outcrop feature on pages 108 and 109 of this magazine.

discovery in the far east. There is more willingness to share data.”

Two PhD students in Sara’s group are currently studying the time when bottom currents became active in the South Atlantic. “The earliest we see turbidite systems switching on is during the latest Aptian to early Albian, with bottom currents starting to rework these deposits slightly earlier in the south of Africa, followed by the same thing happening simultaneously in Namibia and Argentina,” she explains. “And then it continues all the way to the end of the Cretaceous, at which point the contourites take over during the Cenozoic. The reason for that is that turbidite systems became smaller, whilst at the same time, due to the continued opening of the Atlantic, bottom currents strengthened. So, it is really an evolution from only turbidites as the ocean opens, followed by a mixed system during the Late Cretaceous, juxtaposed by a contourite-dominated system during the Cenozoic.”

“But I’m not here to say that all turbidite systems show a bottom-current influence or reworking,” Sara reiterates. “For instance, the Bengal, Congo and Mississippi systems show very little bottom current reworking at

all, because of a combination of strong turbidity currents and a weak bottom current. And this is also something we can project into the past, even to a single location. For instance, we see in Brazil that one reservoir interval is strongly reworked by bottom currents, where the sands below and on top show a dominant gravity system signal.” Conditions can change all the time.

When it comes to recognising bottom-current activity in cores, Sara says that a big difference between turbidites and reworked sediments is the continuous presence of sedimentary features through the latter. “In turbidite systems, we often see an erosional base and structureless sands on top. That’s not what you tend to see in bottom current reworked intervals,” she says; “you see laminations throughout.”

Looking at the grain size variation, Sara explains that based on thin section work, it can be concluded that turbidite systems have a tendency to have a greater percentage of fines mixed with the sand, where in bottom-currents that is more limited because of their ability to remobilise the fines. Trace fossils are also very good indicators. “In turbidites, we tend to see a lack of trace fossils, especially at the base of the

deposits, where in bottom-current deposits we see trace fossils throughout.”

One of the questions the research community is focusing on now is to better define the moment when bottom currents start to rework sediments. “There are both numerical and flume tank experiments taking place to gain a better understanding of that,” Sara says, “with China being an epicentre of the numerical modelling side of things.” And there are the more regional studies too. “In that space, we are trying to understand if the process we are seeing whilst the Atlantic opened also apply to other oceans. There is still a lot to do.”

CONTOURITES OR DELTAS

As the research into mixed systems kicked off some twenty years ago, there was a desire to find outcrops that show sediments deposited through the action of bottom currents. But where the model of gravity flows has always been dominant, and to an extent still is, it is no surprise that only a few outcrops have been (re)interpreted in the light of bottom current reworking.

Then I learned about the work on Miocene outcrops in northern Mo- ▶

PHOTOGRAPHY: WOUTER DE WEGER

rocco published by Wouter de Weger, who is also a postdoctoral researcher at the Andalusian Earth Sciences Institute in Granada, Spain. Following work published by Walter Capella around ten years ago, he continued studying these outcrops, which, according to him and his co-workers, show deposits of contourite channels in what was then part of the narrow seaway connecting the Atlantic with the Mediterranean Sea.

But not everybody agrees with this interpretation, though. Following fieldwork in the same area, Daan Beelen, who is currently working as a lecturer at Utrecht University in the Netherlands but was a PhD student at the Colorado School of Mines at the time, drew the conclusion that the outcrops represent a complex of prograding and retrograding tidal deltas.

To find out a bit more about this, I spoke to both Wouter and Daan.

This is the situation. The outcrop shows an approximately 200 m thick succession, exposing an alternation of mudstones and sandier intervals. The issue lies in the way both researchers interpret this alternation. Wouter and co-workers have interpreted it as a succession of contourite channels and contourite drifts to explain the sandy and finer-grained intervals, respectively, whereas Daan and his colleagues, in his publication in the *Journal of Sedimentary Research*, interprets the succession as an alternation of deeper water fine-grained and more distal sedimentation versus tidal deltas prograding into the basin.

Both researchers agree that the fine-grained intervals host a deep-water fossil assemblage, whilst the sandier sections have a predominance of shallow marine microfossils and some macrofossils as well. The difference lies in how these assemblages are subsequently interpreted.

Wouter asked himself the question whether the “shallow marine fossils” are necessarily indicating a shallow marine depositional environment. “When you find a barnacle, is that proof for a

TURBIDITES OR CONTOURITES

“Despite the growth in research on mixed systems, the mainstream way of thinking is still very much focused on the gravity current idea,” Wouter de Weger says. “Because all our observations can generally be explained by gravity current activity, and a lot of research that is still being done today uses that gravity current model as the main driving force, which means that you run the risk of ignoring another mechanism that can equally explain the formation of sedimentary features as we observe them.”

“Taking that observation on board,” says Wouter, “it is not unlikely that in some areas where gravity flows have been invoked to explain certain sedimentary features may represent a bottom-current process. This is more likely because turbidity currents are driven by point sources, whilst bottom currents are much more widespread across the present-day oceans.”

“What I think is missing in geology is linking observations from oceanographic surveys to the geological record,” Wouter continues.

“One of those things is the interpretation of bidirectional flow and the idea that that is proof for tidal deposition. In other words, shallow marine. Now, oceanographic research clearly shows that tides can have an expression in the sedimentary record up to kilometers of depth. So, the question need to be asked; how good are the models we use to interpret observations with? And how reliable are these classic models?”

shallow marine environment, or can it be transported into a deeper setting?” he asks. “What really helped in this case is a cruise I participated in the Gulf of Cadiz, where we obtained cores from a water depth of around 800 m. If you don’t know that the cores are from a deep marine setting, you might not have guessed they are from that depth; we found all sorts of fossils and debris that came from a shallow marine source,” he says. “For me, finding a deep-marine fossil has therefore much more value when it comes to interpreting a depositional environment than finding a shallow marine assemblage; the latter can be quite easily transported deeper down.”

“That goes a bit against the current way of thinking in sedimentology where the identification of, let’s say, an oyster is seen as “evidence” that a deposit has a tidal origin,” Wouter continues. “I have my doubts about the value of these fossils as indicators for water depth, especially when they are found in relative isolation. Like I said, it is rather the deeper marine species that should be the leading indicator for water depths, and we found these in the Morocco outcrops as well.”

That is not the way Daan Beelen sees it. Instead, he and his co-workers argue that the micro- and macro-fossil content of the sands is indicative of what the environmental interpretation should be – shallow marine. “Ignoring the fossil evidence from the sands and subsequently interpreting it as a deep-marine deposit is not on in my view,” he says a couple of times during our conversation. Daan continues to say that he also carefully placed the outcrop in a sequence stratigraphic scheme, integrating the outcrops into a more regional framework.

In a way, the debate centres around two ways of interpreting fossil assemblages and how they should be seen in terms of translating those to a depositional environment. Just looking at the sedimentary features in the outcrops alone is probably not sufficient.

“It always remains a challenge to prove that an outcrop is actually representing a contourite deposit,” Wouter admits. “What you can create with a continuous current in terms of sedimentary deposits is quite limited; ripples, dunes, sand waves, parallel lamination and anti-dunes, and that’s about it. It is very well possible to create the

same structures in a gravity current. That’s where the challenge lies.”

SEDIMENT WAVES

Earlier in this article, Wouter de Weger argued that there should be a more direct link between research on present-day sedimentary systems and the work geologists are doing in terms of reconstructing the fossil record. Matthieu Cartigny, researcher at the University of Durham in the UK, is some-

one who is very involved with projects studying modern deepwater systems. He also has extensive experience running analogue modelling projects in which he studied the formation of bedforms in turbidite systems.

One thing Matthieu has observed in his research, is that submarine channels are often characterised by so-called trains of sediment waves. Extensive data acquisition campaigns in Bute Inlet in Canada and Monterrey Canyon

in California, the only places in the world that have seen such campaigns, have clearly demonstrated both the presence of sediment waves as well as their tendency to migrate upstream.

The last few years, Matthieu worked a lot on the Congo submarine canyon and the associated lobe. “We see sediment waves both in the confined channel as well as on the lobe, but they look very differently,” he says. “In the channel, the sediment waves have a crescentic shape and are separated by upstream-migrating scour holes. As soon as you hit the lobe, the bedforms become more linear and sinuous. It’s recent data and we don’t know very well what to make of it, but it’s clear that the lobe looks very different from what we thought it would; it’s not like a pancake with sediment waves superimposed on it.”

The levees of the confined channels are also characterised by the presence of sediment waves. However, their behaviour is still poorly known. “We don’t have any direct measurements from these levee systems,” Matthieu says. “The only thing we can say that in years when the turbidity current is active, we see the sediment waves move across the levees as well. But that is not to say that they are just idle when there is no turbidity current happening.”

An area that is currently very hot when it comes to the discussion around sediment waves and whether these were formed by contourites or turbidity currents, or both, is the South China Sea. “I just attended a conference in Kyoto, Japan,” says Matthieu, “and there was again a strong contingent of Chinese researchers debating the topic. The community is very much split up in groups who have quite opposing views,” he says. “So you can imagine that I’d really like to go out there and measure what’s happening there, as that is the only way to ultimately find out. Because so far, that has not happened yet.” And it’s not only of academic interest. “I’ve also held talks to oil companies that are very interested in the matter”, says Matthieu. ■

EPHESUS

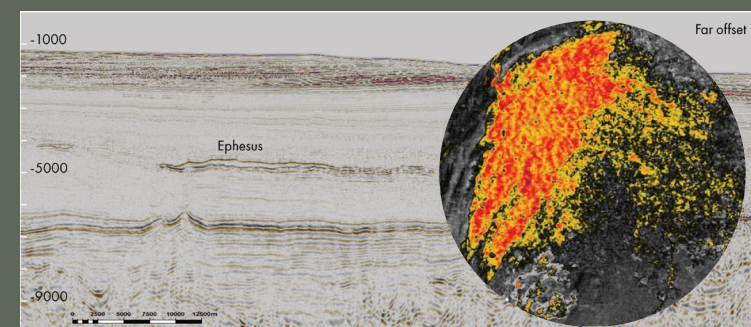
Let’s take a look at a recent exploration well that was drilled offshore Newfoundland, Canada; Ephesus. This was one of the exploration wells to watch in 2023, operated by bp, but it came in dry. Ephesus is another example of where there are different views on how the sands were deposited. Whilst there is agreement that the Oligocene succession is deep marine, people have different views on the exact mechanisms.

In 2024, Lindsey Henry and co-authors from bp published a paper on how they interpret the deposition and compartmentalisation of the giant Paleogene slope fan. They write that an initial mud slump created a flat topography in the area of the Ephesus fan. A second phase of mass transport deposits subsequently caused the formation of debrite ridges across the landslide, creating the fabric onto which the Ephesus sands were deposited as a series of elongate fans.

A rather different theory around the origin of the Ephesus fan is proposed by Richard Beaubouef and co-authors, all from Hess. Hess was a partner in the Ephesus well. “At first glance,” they write in an abstract, “the fan looks like a classic example of a basin floor fan, but closer examination reveals that it is rather an easterly oriented turbidite system that is reworked by a southerly contour current reworking the sediments.”

Deposited at the base of a contourite drift slope, the sands show both elements of turbidite currents with distributary channel networks and depositional lobes, but also reworking in the form of what appears to be sediment waves.

I had a conversation with one of the geologists who worked on Ephesus. When he saw the well results when they came in, he said that he was utterly surprised by the quality and thickness of the reservoir section, which in his eyes is another indication that there must have been some sort of reworking of the sands in order to arrive at such a clean and thick succession.



Seismic line through the Ephesus area, illustrating how the far offset brings out the prospect – which turned out to be dry – through its higher amplitudes. The round inset is a mean amplitude extraction on far stack seismic data across the Ephesus fan.

SOURCE SEISMIC LINE: OILCO / SOURCE INSET: HENRY ET AL. (2024)

Poised for passion: The race for riches in Equatorial Guinea’s deepwater

EQUATORIAL GUINEA has been one of the Gulf of Guinea's most successful hydrocarbon provinces for more than three decades. The giant Zafiro and Ceiba fields, together with the Alba gas complex and LNG exports from Punta Europa, have established the country as a major regional producer with proven petroleum systems, mature infrastructure and a stable operating environment.

While these assets continue to generate substantial value, many of the largest producing fields are now mature. The Ministry of Mines and Hydrocarbons (MMH) has recognised this and facilitated the development of numerous smaller discov-

eries through energy gathering networks, including cross-border discoveries from Cameroon. And now the MMH and key operators have collaborated to hunt for even greater potential.

In 2026, the MMH initiated a new phase of offshore licensing, as four large tranches of open acreage have been directly awarded to major international operators including ENI, Chevron, ConocoPhillips and Galp (Figure 1). These awards reflect growing confidence in the remaining exploration potential of Equatorial Guinea's offshore sector and recognise both the changing industry in-

terest in deepwater and the ability of modern seismic imaging to unlock previously underappreciated opportunities. The awards for several contiguous blocks allow and encourage operators to really invest and master the geology of a large area, representing a particularly welcome and ingenious licensing innovation.

Starting last year, Searcher has now reprocessed 10,550 km of legacy 2D data from all over EG’s prospective deepwater (see inset map for location). These multi-client data are available for licencing. The line shown here is EG98Repro, with PSDM displayed in depth.

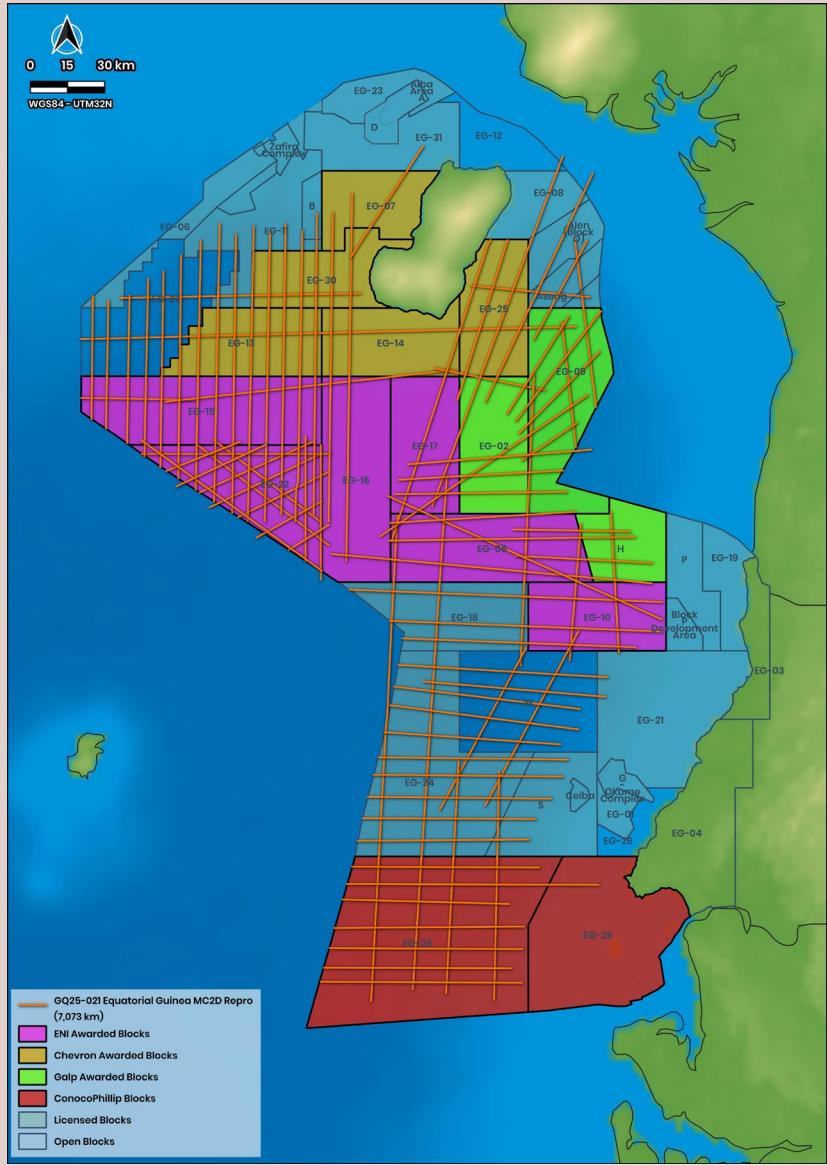
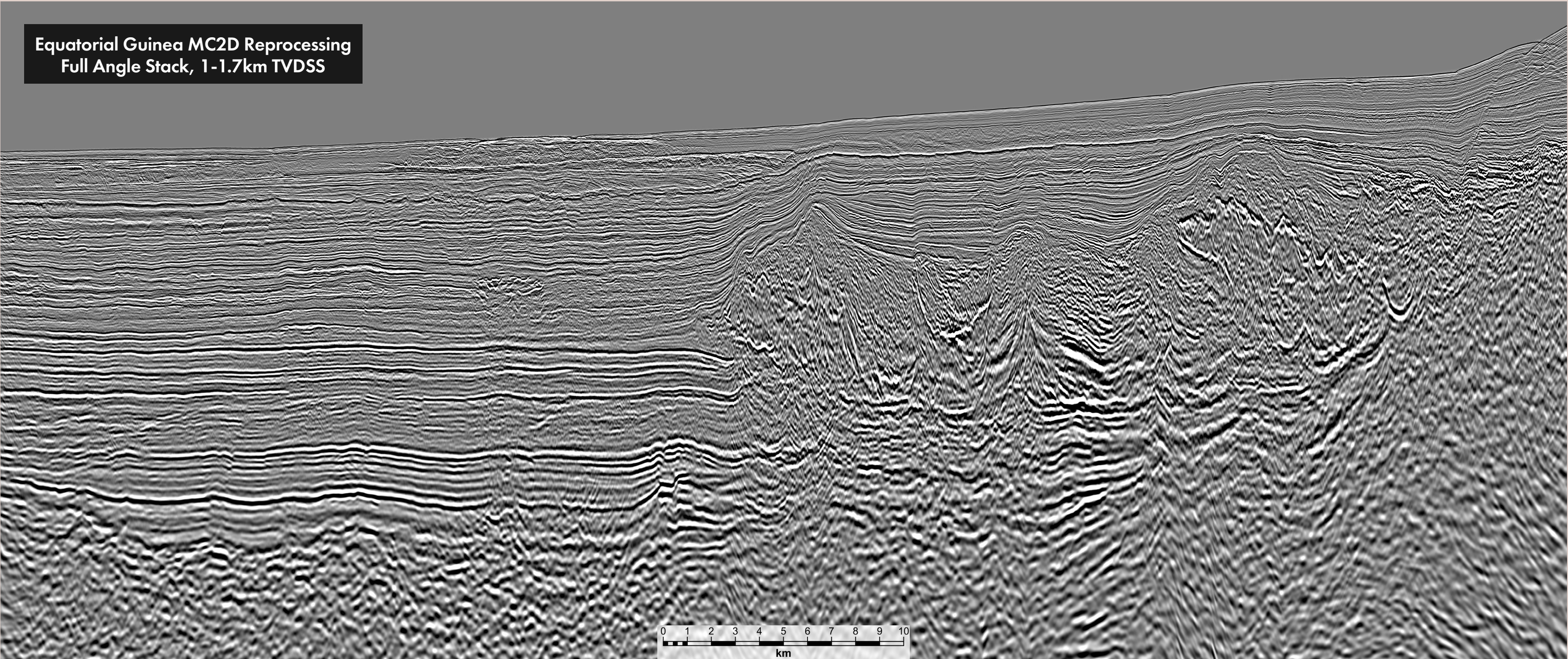


Figure 1: New license awards: ENI (purple), Galp (green), Chevron (orange) and ConocoPhillips (red).

Smart licensing in Equatorial Guinea

New awards necessitate the availability of a new regionally consistent depth-imaged seismic framework

NEIL HODGSON, KARYNA RODRIGUEZ AND LAUREN FOUND, SEARCHER

IN 2025, Searcher reprocessed approximately 10,500 km of 1998 legacy 2D seismic data using broadband pre-stack depth migration (PSDM) and full-waveform inversion (FWI) workflows, undertaken by EIF. The objective was to establish a regionally consistent depth-imaged framework capable of supporting basin-scale interpretation and modern exploration workflows. The resulting dataset provides the only coherent regional framework into which legacy 3D surveys can be integrated and sets the scene for a new strategically important understanding linking the proven hydrocarbon systems of Cameroon, Gabon and São Tomé and Príncipe to the deeper water areas of Equatorial Guinea. The reprocessed regional dataset, with flattened gathers yielding reliable angle stacks, now allows AVO character to be examined across the basin, improving understanding of both sediment routing systems and source rock distribution and subsequent hydrocarbon migration pathways.

The deepwater basin is underlain by oceanic crust and offers a diverse range of play types. In the Cretaceous, regionally extensive early drift source rocks were deposited in the Albian and Cenomanian-Turonian, when the deepest part of the basin (the basin floor nadir) was close to where the Cameroon Volcanic Line (CVL) sits today. Hence, all clastic turbidite systems cascading into the basin from the north, east and south all flowed from constrained slope channel systems onto the basin floor. Basin floor fans were deposited by the reduction in flow velocity at the base of slope, with the associated channel belts deflected or halted by topology on the pervasive set of transform faults running NE-SW across the basin. The CVL volcanism commenced towards the end of the Cretaceous, slowly lifting the central basin floor through the Tertiary from nadir to acme, building the CVL islands and creating counter-regional dip trapping configurations to stratigraphic traps.

PLAYS IN THE NORTH
In northern Equatorial Guinea, at the toe of the Niger Delta, exploration has previously focused on the structural traps in the east-west oriented Gravity Driven Fold and Thrust Belt (GDFTB), where the giant discoveries of Zafiro and Alba were made in the 1990s. In front of the GDFTB, within this play, are the large but shallow gas discoveries of Fortuna and Viscata, which we understand will be developed soon via the existing gas infrastructure associated with the Alba LNG development. However, industry attention is now turning towards the deepwater areas beyond and south of these established fields, where extensive Cretaceous basin floor depositional systems sourced from the Niger Delta downlapped or were ponded against fracture zones during deposition and have now been tilted into structural traps (Figure 2). Our PSDM imaging reveals systems that were only partially recognisable on legacy seismic, identifying prospectivity, includ-

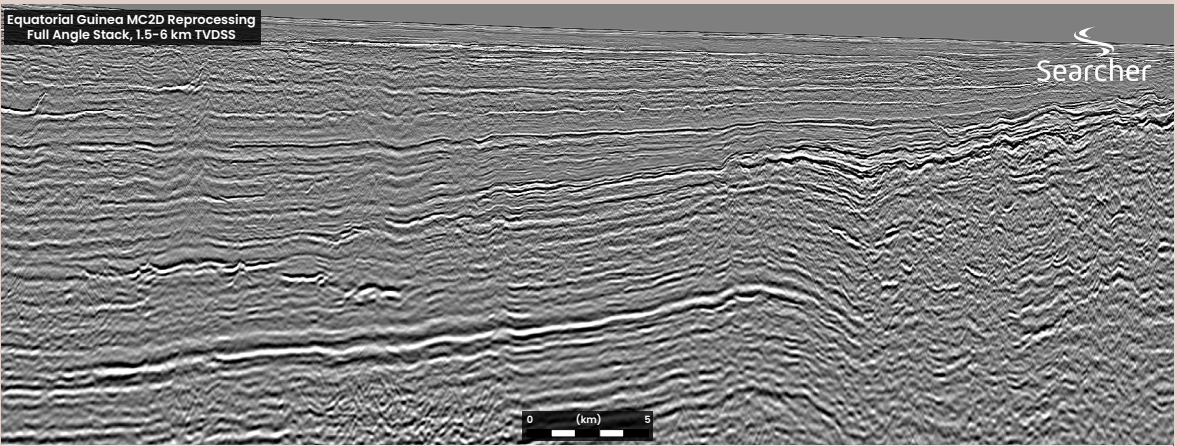


Figure 2: North-South Reprocessed EG98 line showing exquisite structure and stratigraphic downlap in the Cretaceous south of the Fortuna-Zafiro GDFTB.

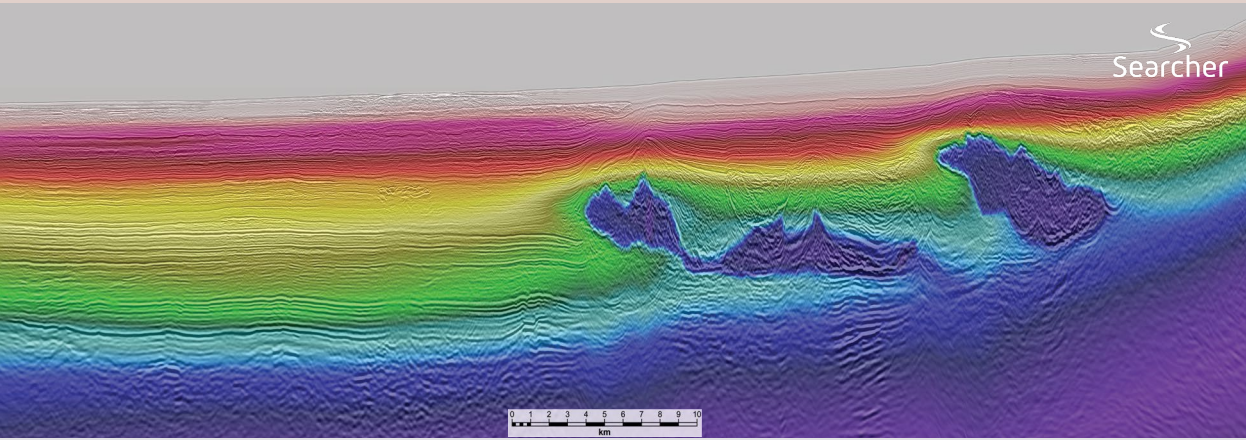


Figure 3: Velocity Overlay on the E-W Foldout line. Accurate velocity modelling reveals the sub-salt stratigraphy, in addition to allowing detailed AVO analysis of the soft bright reflectors out west of the salt canopy.

ing tilted fault blocks and extensive downlap stratigraphic traps that are now in counter-regional dip configuration. Importantly, the source rock intervals responsible for charging many of the established shelf discoveries are also present within the deeper basin and can be observed through frequency content and amplitude vs offset character (AVO). The combination of proven charge, improved reservoir prediction and more clearly imaged trap geometries significantly enhances the attractiveness of these northern deepwater play fairways. **DEEPWATER AND SUB-SALT PLAYS IN THE SOUTH**
The southern sector of Equatorial Guinea contains a distinctly different exploration character. Here, sediment transport systems that formed the Ceiba channel extend basinward into deepwater settings, delivering substantial volumes of clastic sediment into basin floor environments. Reprocessed seismic data reveal channel-levee complexes, basin floor fans and structurally influenced sediment fairways that can now be mapped with considerably greater confidence than was possible using earlier datasets. Just as it has north of the CVL, fracture-zone topography appears to have exerted an important influence on sediment routing and reservoir distribution throughout this region.

Sediments flowing north down slope from Ceiba hit transforms and either pond or get deflected to run west along the fracture zone topology. One of the most significant outcomes of the reprocessing programme has been the improved imaging beneath areas affected by the northern extension of the Gabon Salt Basin. Enhanced velocity modelling has transformed the understanding of the sub-salt section, allowing previously poorly resolved intervals to be interpreted with greater confidence (Figure 3). A key advantage of the reprocessed dataset is its ability to place Equatorial Guinea within a broader regional geological context. To the east, petroleum systems associated with the N'Tem Block of southern Cameroon extend across international boundaries into Equatorial Guinea's offshore acreage, particularly within Blocks 02, H and 09. To the west and southwest, sediment transport systems and structural trends continue towards São Tomé and Príncipe, where recent drilling activity has renewed interest in the region's exploration potential. The regional seismic framework demonstrates that many of the geological processes controlling reservoir distribution, hydrocarbon generation and migration operate across national boundaries. Understanding these regional relationships is therefore critical to evaluating

exploration risk and identifying the most prospective fairways. The exploration objective remains unchanged: the identification of large, high-quality reservoirs within robust trapping geometries supported by proven hydrocarbon charge. No part of offshore Equatorial Guinea is greater than 2,400 m of water, so even “deepwater” isn't that deep. What has changed and initiated this pursuit of acreage in Equatorial Guinea is the industry's understanding that the last truly significant hydrocarbon prospects lie where they haven't yet been hunted; in deeper waters in basins where the key risk elements of hydrocarbon systems have been proven, and prospects can be big, simple and permeable. Searcher is also driving forward with plans for new acquisition, both over the few remaining areas where legacy 3D does not exist but also where the aged legacy data was acquired with short streamer. The recent licensing awards demonstrate growing confidence in the basin's remaining potential. Supported by a modern regional seismic framework and an improved geological understanding of deepwater play systems, Equatorial Guinea is entering a new phase of exploration in which seismic can blaze the path for explorers with more confidence than at any previous point in the basin's history.

OIL & GAS

“I always think about the following infamous and inaccurate quote from Jad Babbín, former US Secretary of Defence: “Going to war without the French is like going deer hunting without an accordion. You just leave a lot of useless, noisy baggage behind”. I feel the same way about the role of basin modelling when it comes to predicting a Yet To Find estimate, because of the sheer amount of uncertainty in most of the inputs, especially hydrocarbon migration losses and the uncertainty it brings”

Ian Longley – GIS Pax

Listen to the drill bit

How a deep exploration well in Libya gave away essential geological information through drill bit performance

"OUR RUNS are getting shorter and shorter..." That's what Harrie and Nick from Aurora Drilling Optimisation Services were told by the Shell team that was drilling a deep on-shore exploration well in Libya about 15 years ago.

They helped design the bits and BHA programme for the 8,5 in and final section of the well, and were also involved with monitoring drilling progress. At the time, Shell was working on an extensive exploration programme across various countries, including Algeria and Saudi Arabia, in the search for deep and tight gas resources.

WHEN DRILLING PERFORMANCE BECAME A GEOLOGICAL INDICATOR

"In a frontier setting like this," Harrie says, "you need to be open to surprises, because offset wells are few and far between. And for that reason, you need to have bits available that might be required if drilling doesn't go to plan."

And that's exactly what happened in Libya.

Due to the bit runs getting shorter and shorter, calls were set up with the rig, office and technical team in Houston. The team in Houston recommended running the same PDC bit and sticking to the original plan.

"We did not agree with that approach," says Nick. "The ROPs told us that the geology was different from what was prognosed, and we felt that we needed to change the bit's cutting structure accordingly."

"The problem with such low ROPs is that you don't really get much useful geological material to surface," says Harrie, "because the formation is ground to powder. And that's a shame, especially because we were in a frontier setting. You need the geological information from the cuttings to determine in what interval you are."

At the same time, Harrie and Nick understand why there was resistance against changing the bit. "The alternative was to go for an impregnated turbine-driven bit, and these tools have the reputation of leaving even less visible traces of the geology. That was the main reason why we experienced pushback. We didn't fully

agree with that statement, though, also given the fact that drilling was so slow with the PDC bit that hardly any meaningful cuttings returns were seen anyway."

During that phase, as drilling very slowly progressed, the geologists went back to study the "cuttings" material again, and with what they could reconstruct, the conclusion was soon reached that they had indeed landed in an interval that was much older and harder than what they had prognosed – the Ordovician Gargaf Formation, in contrast to the Nubian sandstone of Cretaceous age, which was the target of the well.

"It meant that Nubian was missing at this location altogether," said Harrie. The team had to continue drilling, though, because of a well depth commitment. "We swapped to an Impregnated Turbine bit, which we had recommended as soon as runs started to decline, and reached TD quickly."

Looking back, the decline in ROP could have been sufficient to conclude that the geology was different from what was foreseen. ■

Henk Kombrink

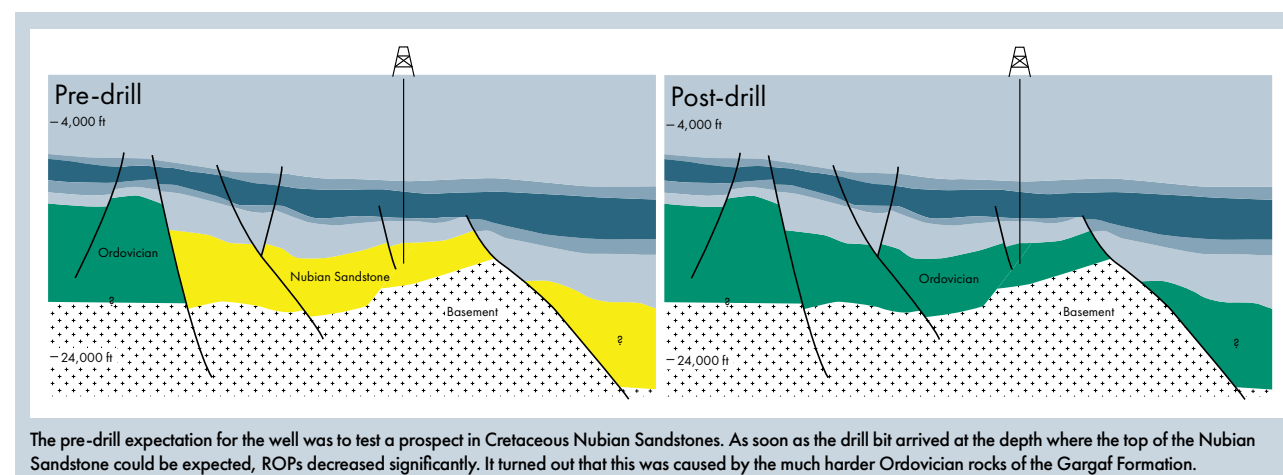


ILLUSTRATION: REDRAWN AFTER POST-Well REPORT - SHELL

Why there may be more non-reservoir in your slope channel complex than you think

And why that is good news, because it may be a seal for your prospect

"EVERY TIME I found a very obvious sandy deepwater channel base in outcrop," says professor Bryan Cronin from Deep Marine during his Deepwater Reservoirs in E&P course delivered through the SAGA Wisdom online platform, "it was always preceded by mud slumps. Sometimes they are gravelly or pebbly mudstones or just slumped facies, sometimes with shallow marine bioclastic debris. A poor reservoir for sure, but it was always underneath the base of the main channel complex."

So the question is, where do these fine-grained deposits come from? Are they coming down the slope channel complex? Are they part of the excavation? Or does their origin lie in slumps from the sides of the channel? "Whatever the origins, or maybe a mixture of origins, these mud slumps are certainly the first calling cards," adds Bryan.

Seismically, the deposits tend to be very chaotic or transparent. They often have very hard tops, which indicates

that they're very indurated. "I was on a cruise back in 1997," says Bryan, "off Western Corsica, where we cored into one of these mud slumps on the base of a modern active canyon. It took us a day and a half to get the gravity core back out because the mud slump was so indurated and dewatered."

In a gamma-ray log, you may be tempted to put the base of the deepwater channel system at the base of the sand. But the high gamma section below the coarser-grained reservoir section may in fact be part of the overall system too, as being the precursive mud slump. "So, the base is actually underneath the base as many people may instinctively draw it," explains Bryan.

He also shows how other authors have recently published about mud slumps at the base of deepwater channel complexes. "But as is often the case," he adds, "you only need to go back to the early 80s and you find that

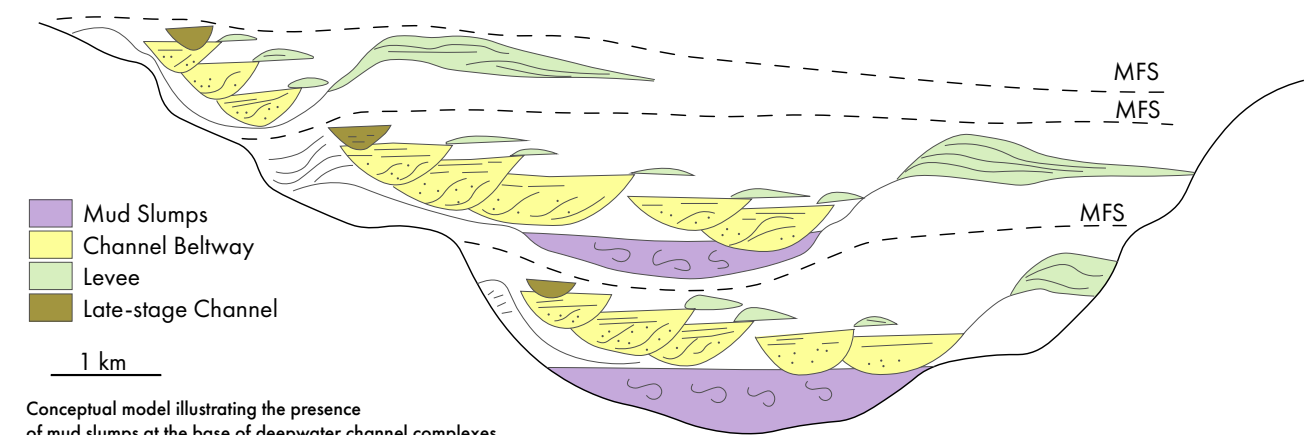
Professor Emiliano Mutti from Parma University has probably thought about it already. Some of his models from canyon complexes in the Eocene of the South Central Pyrenean Foreland Basin nicely describe these mud slumps at the base of the slope channels."

"In other words," concludes Bryan, "these mud slumps seem to be very common, and are a key part of almost every slope channel complex I've ever worked on."

And what are the implications? "As these features are quite extensive, they normally form a top seal to anything that's underneath it, forming a critical aspect of the risking process. If you have a canyon or a slope channel complex touching down onto a prospect, it doesn't necessarily need to be risked as being a position for leakage or a compromised top seal, given the lithologies often found. In fact, it may form a good seal." ■

Henk Kombrink

ILLUSTRATION: REDRAWN AFTER BRYAN CRONIN



Finding oil when everyone expects gas

When CEP drilled the Wolin East 1 exploration well in Polish shallow waters last year, the company was certain it would hit gas. Until the data were analysed

"IT TOOK US a while before we could accept that we found oil," says chairman Peter Putnam when we get to talk about the discovery his company Central European Petroleum (CEP) made in 2025. And there is a reason why the company, which only consisted of three full-time staff members at the time the well was drilled, thought it would be a gas discovery.

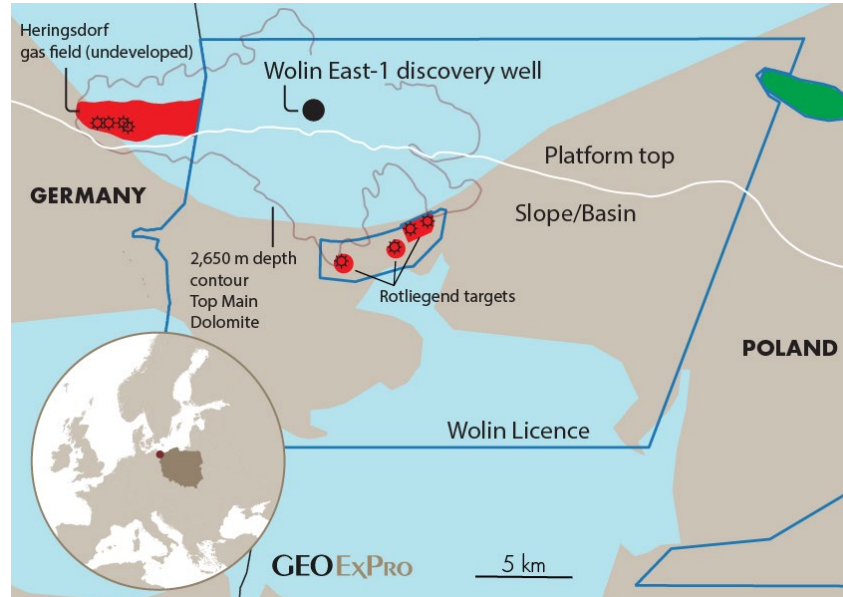
"It took us a while before we could accept that we found oil"

Just to the west, across the border in Germany, a few wells were drilled in the 1980s. These wells targeted the same Upper Permian Zechstein trend as the Wolin East 1 well did, and all of those found gas. "So it made a lot of sense to think that we would find gas too," says Peter.

But the mud logs, fluid and pressure data were surely conclusive. "We are dealing with oil, and potentially quite a lot of it," Peter explains. Estimates of recoverable hydrocarbons range between 200 and 400 MMboe. The gas field in the German part must therefore represent a separate compartment relative to the oil field," says Peter, "the pressures have shown that's the case." So how does this work?

A GEOLOGICAL EXPLANATION

"Older geological maps already show this," he says. "There is a set of north-south running faults that dissect the area. On seismic data, it is not very obvious if these faults make it into the Permian reservoir succession, so



we did not have clarity on that pre-drill. But now, post-drill, we can conclude that the faults are likely to have compartmentalised the field into at least the gas-bearing German part – which is known as the Heringsdorf field – and an oil compartment that we drilled."

PREPARING FOR APPRAISAL

The company is now preparing for an appraisal campaign to further test the discovery. Planned for spud in the fall this year, the well is located fairly close to where the 2025 hole was drilled. "The main aim is to perform a production test in the Zechstein oil column, investigating if there are more oil resources by drilling slightly more down into the structure, and assessing the potential of the underlying Rotliegend succession," says Peter. The discovery well

proved an oil column of 62 m without seeing any contacts.

"We are dealing with oil, and potentially quite a lot of it"

Rotliegend sandstones have already proven to be prospective in the area just south of the licence, including elevated helium readings.

All in all, the discovery of Wolin is a remarkable story in many ways. Remember that CEP drilled the well at 100%, which is very uncommon for a company of that size. Also, CEP is one of the very few small operators still active in Poland, where state-owned Orlen is by far the dominant player. We hope to report more extensively on this story later. ■

Henk Kombrink

Harmonising public data with ground truth

How satellite intelligence closes the information gap in US natural gas forecasting

HANA KABAZI, SYNMAX

PUBLIC production data is the backbone of natural gas market analysis, yet it arrives with a structural delay that few participants fully appreciate. Across 18 producing sub-regions, encompassing the Marcellus, Utica, Haynesville, Eagle Ford, and Permian basins, analysis reveals a median reporting lag of 15 mths between initial well production and its appearance in state regulatory filings. In Louisiana, home to the Haynesville Shale, that regulatory lag stretches to 36 mths. For the better part of three years, one of the nation's most prolific gas basins is effectively invisible to anyone relying heavily on public records.

INVERTING THE INFORMATION GAP

Satellite-derived surface intelligence offers a way to close that gap. By tracking rig mobilisations, frac crew deployments, and wellpad construction across the contiguous United States, Synmax matched 26,060 satellite-detected wellpads to their eventual state production records using geospatial and temporal alignment.

The result is a median satellite lead time of 5.9 mths, representing the interval between the first observable surface disturbance and the well's reported production start. In the Appalachian Marcellus, that lead time reaches 8.8 months. Rather than merely narrowing the in-

formation gap, the satellite signal inverts it entirely, providing forward visibility where public data offers only a rear-view mirror.

QUANTIFYING THE DUC LIFECYCLE

This visibility becomes especially valuable when applied to the Drilled but Uncompleted (DUC) lifecycle. The interval between spudding a well and bringing it online is not a fixed constant. Instead, it is a strategic variable shaped by operator economics, formation geology, and regulatory regimes.

Among 29,785 wells with complete timelines, operators working in the same formation show a 163-day spread in spud-

to-completion timing. This reveals sharply different capital deployment strategies that remain invisible in aggregated public data. These variations make real-time DUC tracking a powerful lens into completion scheduling and supply-side momentum, but only if the activity is observed as it happens, not reconstructed months later.

THE HAYNESVILLE HORIZON

Nowhere is the case more compelling than in the Haynesville. Put simply, what satellites see on the ground today dictates what production looks like seven months from now. The statistical correlation between current satellite activity and future output is $r = 0.875$, which is exceptionally strong by any empirical standard.

In a basin where public data arrives 26 months late, satellite intelligence provides a 7-month forward window. This shifts the analyst's vantage point by nearly three years relative to public filings alone. As the industry moves toward faster, more capital-disciplined development cycles, the ability to observe real-time ground activity is no longer a luxury. It is a competitive necessity. ■



SOURCE: SYNMAX

A depiction of high-resolution satellite imagery available through Synmax Intelligence.

The next test for US shale capital

Neuquén opens 15 Vaca Muerta block

FELIPE CALDERON AND ANDRES ARMIJOS,
WELLIGENCE ENERGY ANALYTICS

ON 4 MAY, Gas y Petróleo del Neuquén (GyP) and Governor Rolando Figueroa launched Round 1/2026 at the OTC in Houston, opening 15 hydrocarbon blocks to national and international bidders. The round was formally enacted on 29 May through its publication in the provincial Boletín Oficial, with awards expected before year-end and contract signature in Q1 2027.

The terms have been overhauled. Where prior GyP programs, PNH (2010 to 2017) and PEN (2018 to 2024), prioritised expanding granted surface and broadening the operator base, Round 1/2026 filters for technical and financial capacity.

A \$100,000 bid bond per offer, royalty bidding around a 15 % base (effective range 15–18 %), and

a coordinated three-bonus structure covering access, commerciality and cession signal a clear shift in how the province is looking to attract new investors. GyP participation is now a competitive variable at 10–20 % per block, effectively a modified carry-across exploration and exploitation. Offers are scored across sealed technical and economic envelopes, with the most competitive work and royalty proposals winning out.

WHAT IS ON OFFER?

The 15 blocks span three clusters, north, centre, and south, all sitting in the liquids window and selected for proximity to existing developments. Sizes range from roughly 50–240 km² (12,355–59,300 acres). Most carry access to existing infrastructure; some remain frontier acreage that will de-

mand patient appraisal before commercial commitment.

A wave of new pipeline and LNG infrastructure, advancing under RIGI, is easing Vaca Muerta's take-away risk. New Atlantic oil routes and pipeline expansions could double crude evacuation by 2027, while gas and LNG projects open outlets for production growth.

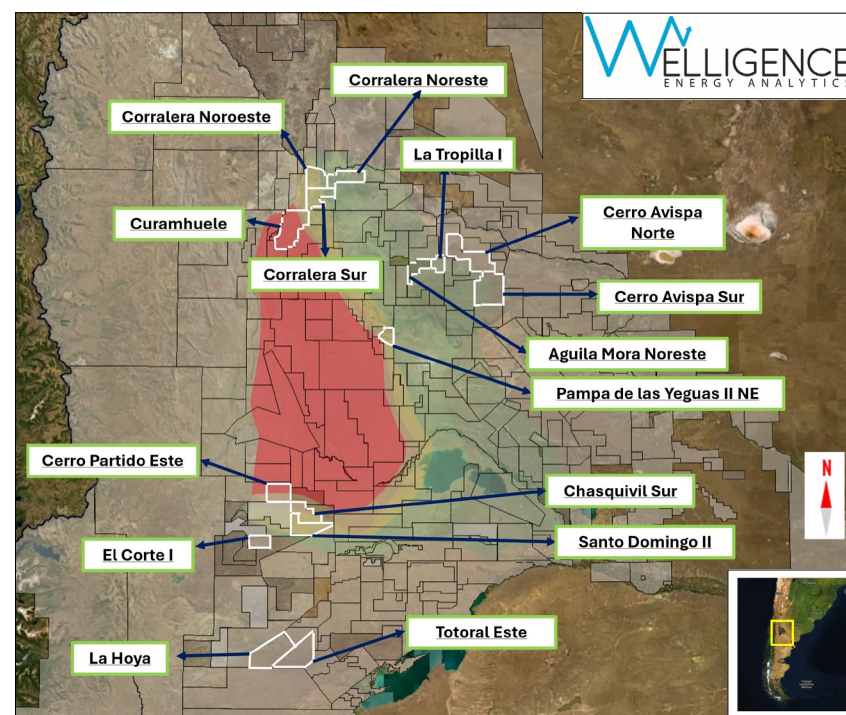
The timing reflects a deeper recalibration. The old framework was built to attract capital into unproven territory. Vaca Muerta is no longer that. With the play delivering commercial returns at scale, the province is reshaping its terms to match the basin's momentum and ensure awarded blocks translate into activity on the ground.

WHAT IS EXPECTED OF THIS ROUND?

Success will be judged on three metrics: How many of the 15 blocks attract offers, the diversity of bidders, and how aggressive the royalty proposals are. A round that brings Permian-focused independents to multiple areas would mark a turning point, confirmation that Vaca Muerta has decisively crossed into mainstream E&P investment. A thinner outcome, weighted toward local incumbents on adjacent acreage, would suggest the international investor base is still building.

RIGI eligibility (\$600 M onshore E&P minimum, 8 July 2027 deadline) is tight given Q4 awards, but not critical. Basin operators advanced projects for years before RIGI's February 2026 upstream extension, and further support mechanisms for exploration-phase projects are plausible. The consultation window closes on 10 August; bids open on 19 August.

SOURCE: WELLIGENCE ENERGY ANALYTICS



Areas offered.

An imperial testing facility

What used to be ExxonMobil's flagship heavy oil laboratory in Calgary is now available for any party to carry out research

"IT WAS a \$37 M donation from Imperial Oil, the largest to an educational institution in Alberta's history," says Gerald Desrochers when we meet for the lab tour he invited me to on a Thursday morning in May.

Just over ten years ago, ExxonMobil Canada – operating under the name Imperial Oil – built this world-class lab facility to perform cutting-edge research related to oil sands. But last year, the company decided that the facility was no longer needed. The Southern Alberta Institute of Technology, SAIT, a well-known educational institute in Calgary, has now taken ownership of it.

"We want to be in the middle between demands from operators and performing research that we can involve our students in," says Gregory Maidment, who heads up the facility. "More and more operators are closing their own labs, but we know there is still a demand for testing things such as new inhibitors and new fluids to help produce the heavy oil more efficiently. It also very much helps that the Canadian government has recently formalised enhanced oil recovery within the CCUS Investment Tax Credit. This will probably provide a boost to research in this realm, and our facility can form an important

vehicle to perform research in that space," Gregory says.

We start the tour at the Once-Through-Steam-Generator. Here, SAIT tests a variety of different scaling inhibitors that are added to the steam generated to be used for steam-assisted gravity drainage (SAGD). "It is a domain where we continue seeing development of new types of inhibitors," says Gerald, "and that needs to be tested first before being deployed in the field."

For Ehsan Aminfar, his job as Scientific Director at the SAIT facility was a bit like coming home. "I carried out physical modelling experiments for my PhD when I started in the field of researching heavy oil pro-

duction from sandstones." Now, Ehsan will be using the same setup of experiments again to continue this line of research. "The key in these experiments is that you need to speed up the reaction to create the steam chambers in a meaningful way," Ehsan tells me, "otherwise you'll be waiting forever."

SAIT is now expanding the facility with an even more advanced setup of combustion tubes from another donating company. "Using this setup, we can run fireflood experiments simulating combustion-assisted drainage of heavy oil. And we use genuine core samples from the field for this, which are able to mimic subsurface condi-

tions as closely as possible," explains Ehsan.

As we near the end of the tour and as a final example of the wide variety of research carried out at the facility, geologist and guide Jesse Wheaton then shows me a series of trays containing representative samples from mine tailings. "It doesn't look like a spectacular experiment," he admits, "but it's been running for eight years already. It allows us to measure how effective certain polymers are in separating water from solids and how soil remediation works on longer timescales. Because at the end of the day, we want the current oil mining sites to return to unspoilt nature."

Henk Kombrink



Gerald Desrochers showing a bottle of heavy crude.

PHOTOGRAPHY: HENK KOMBRINK

Chasing mud mounds

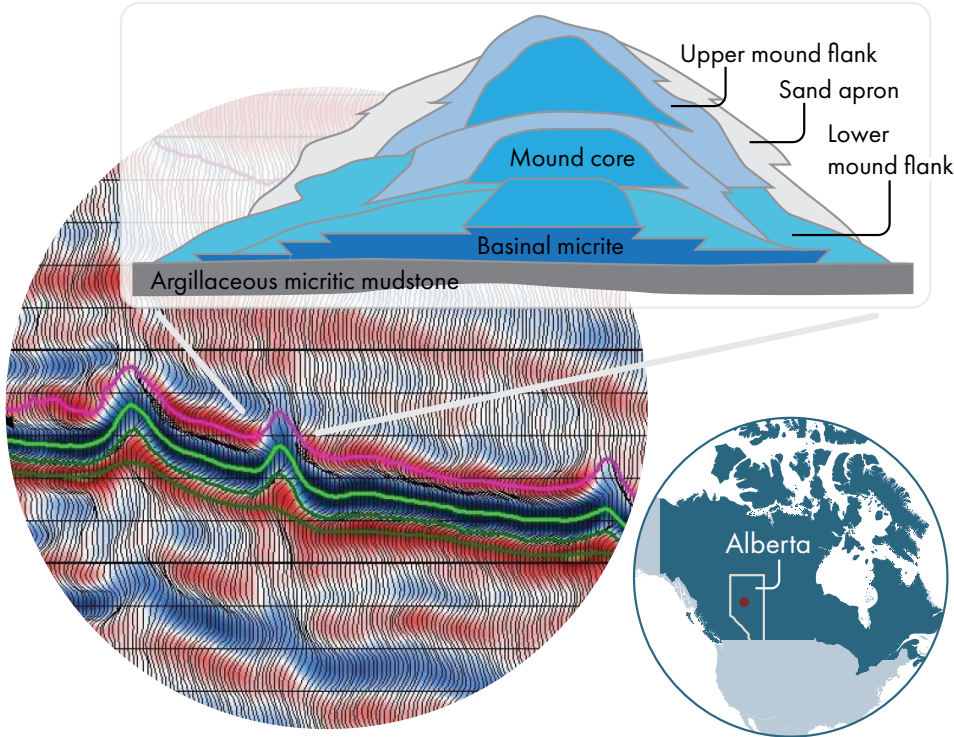
How a small oil company is successfully targeting a niche oil play in Alberta that the majors walked away from before

CORE DISPLAYS are one of my favourite features of geoscience conferences, and the one at the latest GeoConvention in Calgary in May again proved why. There, I met with Alisha Fridrich, who was already deeply engaged in a conversation about the beautiful Waulsortian (Lower Carboniferous) mud mound cores she had on display when I arrived. But fortunately, I could tag on.

The carbonate cores are not only a delight to look at; the story Alisha shared made them even more fascinating. That's because she is part of a small team – forming Islander Oil – that is successfully developing these complex, small mud mounds where others have previously failed. And in some ways, you can understand why developing these oil fields is challenging.

“The seismic data only allow mapping the top and base of the mud mound structures,” says Alisha. “And you surely need 3D. Not so much to map them internally, because we lack that resolution, but rather not to miss them in the first place.”

The mud mounds are often just a few hundred meters across and up to 3 km in length. The thickness of the carbonate build-ups is also less than 100 m. “It is a seis-



The Lower Carboniferous mud mounds chased by Islander Oil in Alberta are relatively small features and only express themselves as a small bump in the seismic. Yet, 3D seismic surveys are needed to map them.

mic play,” says Alisha. “The cost of acquiring the seismic data are significant, also because the terrain is not the easiest in Alberta, but the investment is essential.”

Previous drilling attempts tested these mounds through vertical wells, with Shell drilling quite a number of those not so long ago. “We thought, with the advance in horizontal drilling, it would be better to test them in that way,” says Alisha. And it worked. “Comparing how much we can produce from vertical versus horizontal wells, we are looking at around a three-fold increase for horizontal legs,” she explains,

“with a typical range of 120-435 bbl/d per well.”

“At the end of the day, it is quite simple,” she says, “because with the horizontal wells, we are accessing more reservoir.”

But uncertainty remains, Alisha admits, when we look at the cores again. Not all parts of the reservoir are oil-stained, clearly indicating that there are sweet spots. “That’s what we are up against,” explains Alisha, “together with the difficulty of mapping the structures in 3D, it means that it is hard to obtain a recovery factor for the individual fields we operate. We simply don’t have a good grip on the 3D

distribution of pay within the mud mounds.”

Despite that, it is really cool to see a small outfit being able to successfully develop this niche oil play within the Canadian oil patch. “There are other targets even at shallower levels that are also being developed,” says Alisha, “such as the Clearwater oil play. These reservoirs are easier to map and drill out, which is why most activity in the area is still focused on those horizons. But let’s not forget that there are small nuggets out there that are ready to be found and developed.”

Henk Kombrink

ILLUSTRATION: REDRAWN AFTER ISLANDER OIL COMPANY PRESENTATION

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Why USGS Yet-to-Find figures are an overestimation

A commercial decision to make a move into a basin is something you need Yet-to-Find (YTF) volumes for. But how do you arrive at a reasonable estimate of YTF?

ONE OF the most common ways to estimate YTF is the extrapolation of discovery rates, as can be calculated from a creaming curve. However, this methodology does not have any guidance on discovery size – is it just a single big one or lots of smaller pools? “Hence, we think it is not a very useful tool. Because what we really try to find are the large fields that are still out there, even in mature basins,” says Ian Longley from GIS-Pax in a recent video.

Then there is basin modelling. “However,” says Ian, “I always think about the following infamous and inaccurate quote from Jad Babbin, former US Secretary of Defence: “Going to war without the French is like going deer hunting without an accordion. You just leave a lot of useless, noisy baggage behind”. I feel the same way about the role of basin modelling when it comes to predicting a YTF estimate, because of the sheer amount of uncertainty in most of the inputs, especially

hydrocarbon migration losses and the uncertainty it brings.”

The most famous methodology is the one championed by ExxonMobil: Play maps with predicted prospects. Without going into much detail, it captures the main elements of each play in a map framework, which is followed by the integration of these elements into basin-wide maps. This can be quite an extensive process, and not all companies have the resources to do this. But there is a shortcut.

“Rather than looking at the entirety of a basin or a country, what we suggest is to only focus on the proven charge areas, where we know hydrocarbons have been generated and success rates can be calibrated,” explains Ian. “That way, we eliminate large areas where a detailed analysis would always be speculative at best. Within these proven charge areas, we only produce one risk map, which is calibrated by the local exploration results. When combining this with a prospect inventory, which we have access to through a collaboration with S&P Global, we can subsequently provide a global exploration



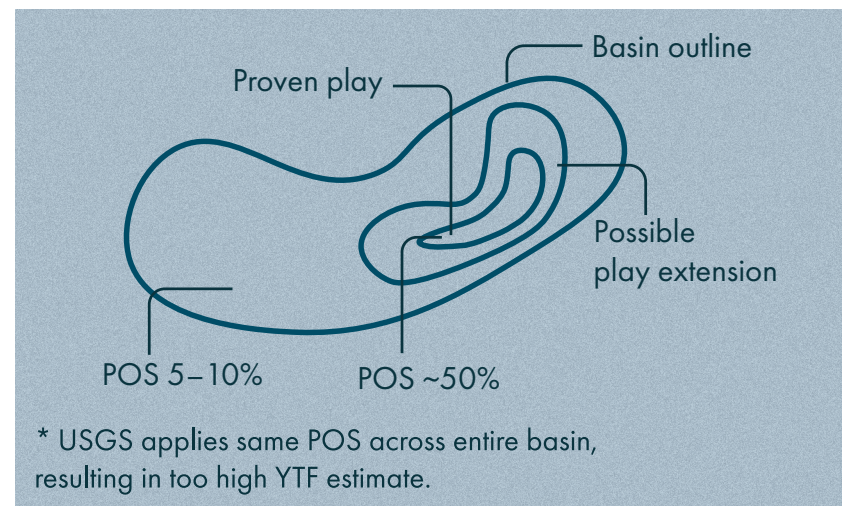
risk map that we then split up in 19 different stratigraphic intervals or plays.”

The best way to then find the Yet-to-Find estimates is to identify each mapped prospect and aggregate the mean risked volumes to arrive at a YTF estimate. “As a final step, we also introduce a methodology to estimate how many unknown prospects there still are out there, following the methodology outlined by Hood et. al. (2023).”

Why is this workflow better than the one applied by the USGS? “Because they apply the same exploration risk across entire area basin polygons and do not use real prospects, where we rely much more on sub-areas where the proven source areas are our main focus areas,” says Ian. “As a result, the USGS YTFs tend to be approximately three times as high as ours. In turn, this has a serious implication on how much oil there is still out there to be found. We won’t claim that our technique is without its assumptions, but we do believe that it is more accurate than the USGS’s estimate at least.”

Henk Kombrink

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



Up or down – in which direction did the sand go?

Jan Erik Rudjord and co-workers propose that freshly deposited sand can also sink, going against the more accepted idea of sand injection that implies upward movement

AT THE recent EAGE Annual in Aberdeen, I briefly met geologist Jan Erik Rudjord. He convinced me to see his talk on what he calls sinkites; sands that have apparently sunk into the underlying strata. It was a new topic for me, and I was intrigued. The reason is that it goes against the more commonly held idea that sand mobilisation takes place in an upward direction.

In several published papers, Jan Erik and co-authors describe what they call jack-up sand structures along the mid-Miocene unconformity in the Norwegian Northern North Sea that are hundreds of kilometres wide and up to 200 m in thickness. These structures are now found below the mudstones they were once deposited on. At least, that’s what Jan Erik thinks.

“We don’t have the silver bullet kind of evidence for Miocene sinkites yet,” he admits in a message. But amongst the many examples in the seismic 3D data he sees as supportive of his ideas, there is one that stands out: The Zulu East

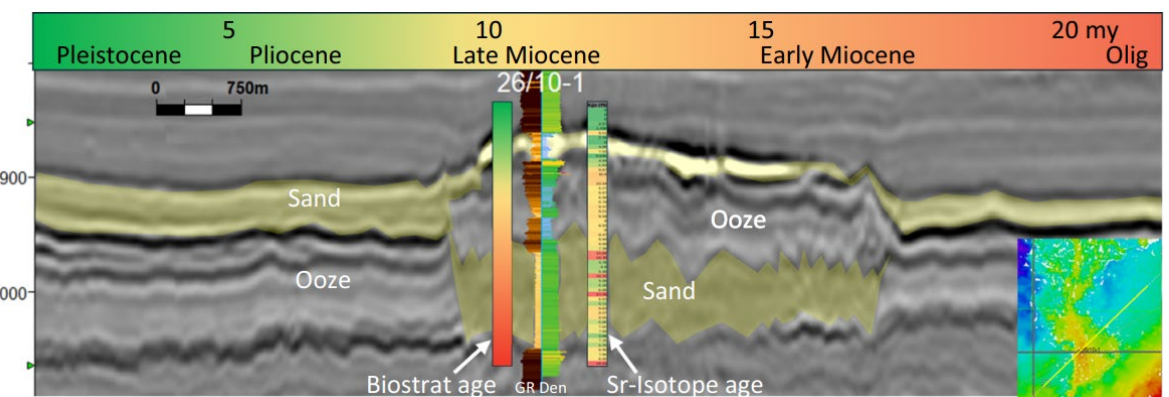
jack-up structure that was drilled by well 26/10-1. Here, as shown in the illustration below, we see a jagged sand body overlain by an interval of oozes, bounded on either side by an interval that shows the same succession in the opposite order. But can the sand drilled by 26/10-1 be correlated to the undisturbed sand higher up? Jan Erik looked at strontium isotope dates obtained from samples in the well, and saw that there are some that indicate a younger age than the host rock. That could indeed be a sign that there is an age reversal that would be expected in the case of sinkites. At the same time, he points out that previous research rejected the isotope ages because of caving, so there is an alternative hypothesis too.

Another line of support for sands moving downwards are density contrasts. All the mapped Miocene sinkites are constrained within one 200–500 m thick interval of fractured, early consolidated and low-density (1.7–1.8 g/cm³) bio-silicious ooze – consisting of fragments of diatoms and radiolaria mixed with 50–70 % clay. Assuming that the process took place at seabed, which is support-

ed by the observation that seismic horizons above and below the sinkites are undisturbed, a density of >2 g/cm³ can be assumed for the sands. This creates a density imbalance, which may have caused liquified sands to move down during earthquakes or due to upwards water expulsion, sinking via polygonal fractures and displacing rigid blocks of ooze upwards.

“The challenge extending this model to deeper Paleocene-Eocene structures is that the seismic imaging is of poorer quality and that the evidence of low-density ooze is masked by depth-dependent silica-diagenesis and compaction,” Jan Erik writes. However, he hopes that the availability of more well data may ultimately compensate for this. He is keen to further study Paleocene and Eocene sinkites, also because of the potential economic implications. At the end of the day, that’s where many fields, especially in the Norwegian North Sea, produce their oil from. That also makes the whole topic more controversial, of course. But that only peaks our interest.

Henk Kombrink



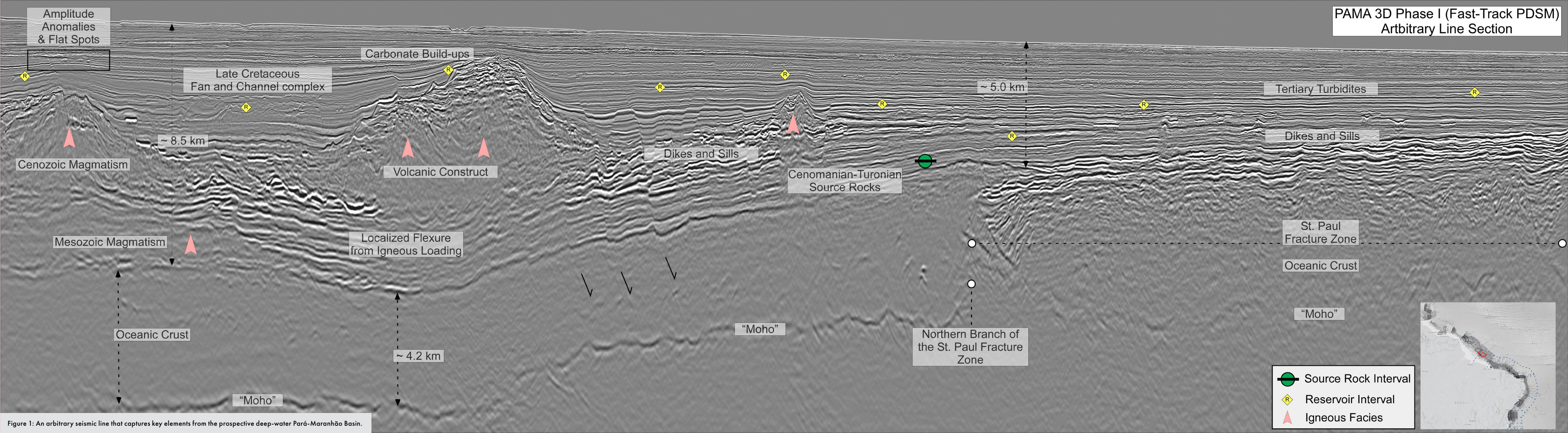
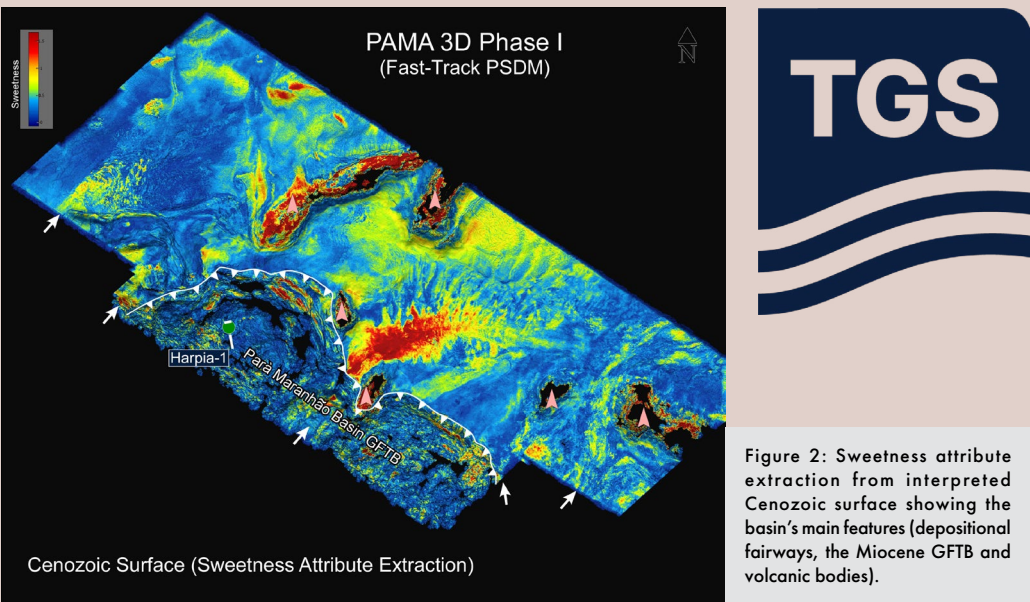
The Zulu East jack-up structure and associated sinkite sand in a Miocene succession. Note the age-colouring of the right track, showing green (younger) ages within the sinkite. This forms a key observation supporting the downward movement of the sand. Jan Erik Rudjord interprets the biostratigraphic ages (left track) as mostly representing the age of the host rock.

SOURCE: RUDJORD & HUUSE (2025) - COMMUNICATIONS EARTH & ENVIRONMENT - 6:490

Seeing the unseen: New 3D seismic insights from the deepwater Pará-Maranhão Basin

The Pará-Maranhão Basin on Brazil’s Equatorial Margin is an underexplored but promising deepwater frontier, where modern high-resolution 3D seismic data is critical for reducing exploration risk and imaging complex subsurface geology. Recent PAMA 3D surveys by TGS, covering over 30,000 km², provide unprecedented detail from basement to shallow stratigraphy, improving understanding of basin evolution and reservoir distribution. The basin, situated along the St. Paul Fracture Zone, contains complex structures, including gravitational

fold-and-thrust belts, magmatic intrusions and varied depositional systems. These new data have provided insights into influences on sediment pathways and trap formation, while seismic attributes reveal channels, fans and amplitude anomalies indicative of hydrocarbons. Recent discoveries in nearby basins and historical drilling confirm an active petroleum system in the region. Overall, integrated seismic interpretation highlights strong exploration potential and suggests that the deepwater basin may be nearing a transition from frontier to discovery phase.



Pará–Maranhão Basin: New insights from PAMA 3D seismic

New PAMA 3D seismic unlocks clearer imaging and reveals significant untapped hydrocarbon potential in Brazil’s Pará–Maranhão Basin

KYLE REUBER, DEREK UNGER, PEDRO ZALAN, HENRI HOULLEVIGUE, KENNETH SHIPPER, TGS

AS OIL AND GAS exploration heats up in the Equatorial Margin of Brazil, the need for modern, high-resolution 3D data continues to grow. The process of de-risking frontier deepwater plays requires the use of advanced processing algorithms to adequately image the subsurface. Clear visualisation is a critical tool for maximising discovery successes that are increasingly targeting subtle stratigraphic targets in complex geological settings, such as the Pará–Maranhão Basin of Brazil. This centrally-located basin is positioned between the Zaedyus discovery in French Guyana, the Morpho prospect in the Foz do Amazonas Basin, the recent Anhangá discovery in Potiguar Basin, and many other data points to support evidence of an active petroleum system in the region (Figure 2).

Historically, the lack of quality data in basins gives the perception of an area being high-risk or frontier. The recently acquired 3D surveys address this and have revealed new details of the basin opening, localised magmatism, tectonostratigraphic units and petroleum prospectivity.

Recently, TGS has acquired two phases of the PAMA 3D seismic program (Figure 3). The PAMA 3D Phase I survey spans over 19,000 km², covers the Harpia-1 well and more than 25 future exploration blocks in the prospective deepwater region of the central Pará–Maranhão Basin. Phase I is currently at the fast-track processing stage at the time of writing. The more recently acquired 11,500 km² PAMA 3D Phase II is positioned to the northwest of Phase I and is in the earliest stages of processing. This dataset provides unprecedented imaging of both crustal and sedimentary features, allowing for integrated interpretation from basement to shallow stratigraphy. This multi-client survey was acquired with a Ramform Titan-class vessel equipped with TGS GeoStreamer Technology and is currently being processed utilising proprietary TGS workflows.

The Pará–Maranhão Basin, spanning more than 150,000 km² along the Equatorial Atlantic margin of northern Brazil, represents a key frontier deepwater province with significant hydrocarbon exploration potential. The margin segment was formed during the Early Cretaceous rifting associated with the breakup of Gondwana, as part of the larger Equatorial Atlantic rift system. Structurally, it lies within a complex transform margin, shaped by significant

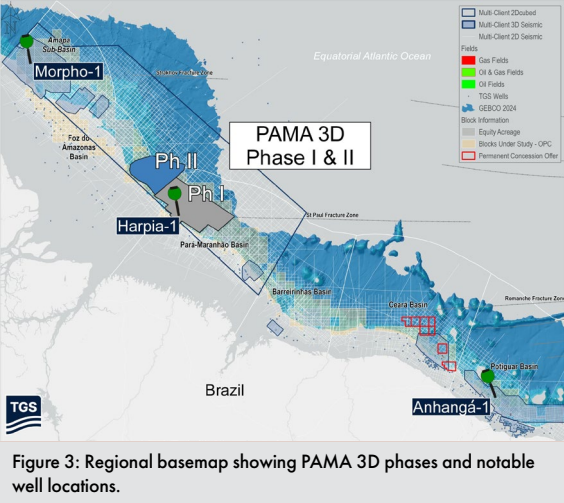


Figure 3: Regional basemap showing PAMA 3D phases and notable well locations.

lateral tectonic movements. A defining feature of this system is the St. Paul Fracture Zone, which bisects the basin and plays a fundamental role in crustal segmentation, structural compartmentalisation, and basin evolution. The basin exhibits a wide range of depositional environments, from shallow continental shelf areas to ultra-deepwater settings exceeding 4,000 m in water depth. Historically, regional 2D seismic data has been used to study the basin’s crustal architecture, tectono-stratigraphic evolution, and petroleum system elements. The new PAMA 3D has provided a more detailed understanding of those elements and furthered our understanding of the timing of key geologic events and how the geological processes governed reservoir development and distribution.

OCEANIC CRUST AND VOLCANIC INFLUENCE
A defining feature of the deepwater Pará–Maranhão Basin is its oceanic crust, particularly in relation to the St. Paul Fracture Zone. Observations in seismic data reveal that magmatic activity is significantly enhanced along fracture zones, where structural weakening facilitates magma ascent in the form of dikes and sills, whereas volcanic constructs are more prevalent away from the fracture zones (Figure 1). Volcanism is multi-phased, affecting both Mesozoic and Cenozoic intervals. Volcanic constructs seem to have developed in long-lasting sequential stages,

controlling the deposition of lateral growth strata. Igneous intrusions, flows and sills locally modify the sedimentary architecture, influencing depositional pathways and potentially creating structural and stratigraphic traps. In some areas, volcanic loading contributes to flexure of the oceanic crust, while regionally, sediment loading from the Amazon Cone further modifies basin geometry. Both types of loading created the optimal conditions for the development of a regional kitchen to the northwest and of local kitchens in the basin, respectively.

STRUCTURAL ARCHITECTURE: FOLD-AND-THRUST BELTS

One of the most striking structural elements in the basin is the presence of two major gravitational fold-and-thrust belts (GFTBs), developed during the Santonian and Miocene (Figure 4). These structural belts cover thousands of square kilometers within the survey and exhibit classic zonation from extensional to compressional domains, including listric faults, rollover structures, reverse and thrust faults, sitting atop detachment surfaces.

The formation of these GFTBs is likely linked to a combination of carbonate loading and reactivation of pre-existing syn-rift faults. The strong perennially active Saint Paul Oceanic Fracture Zone probably also imparted instability in the sediment deposits, triggering the gravitational failure of continental slopes. Importantly, the deformation had implications for reservoir connectivity and created potential structural traps, though their complexity necessitates careful seismic interpretation and risk assessment.

STRATIGRAPHY AND RESERVOIR SYSTEMS
Seismic attribute analysis from the PAMA 3D dataset reveals a diverse range of depositional features. Oligocene to Miocene intervals are characterised by sediment waves, polygonal faulting, and well-developed channel and fan systems in deepwater settings. Cretaceous sequences also host channel–fan complexes, indicating long-lived sediment delivery systems. Notably, volcanic features appear to influence depositional fairways, steering sediment pathways and controlling the distribution of reservoir facies. Amplitude anomalies observed in seismic data—such as brightening over structures and dimming beneath—may indicate hydrocarbon presence and support

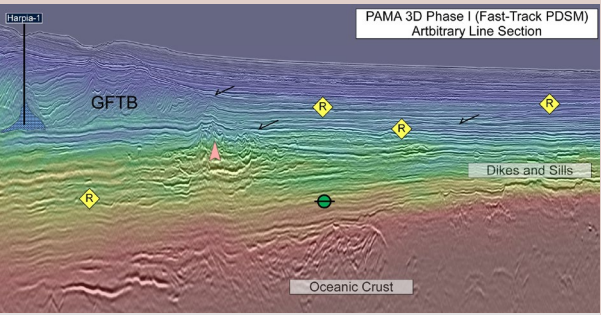


Figure 4: Arbitrary line through the Harpia-1 well, carbonate debris, Miocene gravitational fold and thrust belt (GFTB) and reservoir seismic facies.

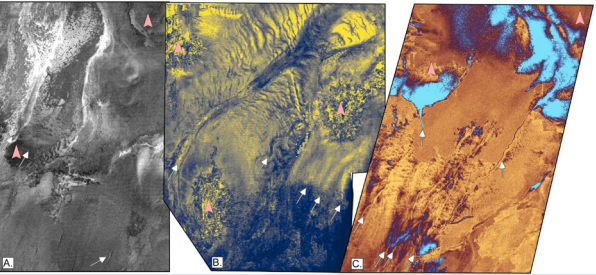


Figure 5: Seismic surface extractions of clastic depositional fairway systems. The image showcases PSDM Fast-Track Amplitude Extractions (A & C) and Trace Envelope Extraction (B).

the interpretation of an active petroleum system. Velocity anomalies and inversion results further enhance interpretation, suggesting contrasts consistent with lithologic variation and possible fluid effects.

EXPLORATION
The Harpia-1 well, drilled in 2011 in approximately 2,200 m water depth, provides a key calibration point (Figure 4). This well confirmed the presence of petroleum system elements, including migrated hydrocarbons and complex stratigraphy involving allochthonous carbonate debris. These results underscore both the promise and the challenges of exploration in the basin, where structural complexity and stratigraphic variability must be carefully integrated to reduce risk.

The integration of seismic, structural, and stratigraphic observations leads to several key insights (Figure 5 A-C). First, the mid-Cretaceous depocenter is better defined, improving regional understanding of source and reservoir distribution. Second, igneous activity plays a role in shaping depositional systems, requiring its explicit incorporation into exploration models. Third, the recognition of multiple phases of gravitational fold-and-thrust deformation provides new perspectives on trap formation and timing. Finally, consistent seismic amplitude anomalies with AVO responses suggest that a functioning petroleum system exists in the deepwater region of the Pará–Maranhão Basin, reinforcing its attractiveness as an exploration target.

FROM A BASIN OF 'SHOWS' INTO A BASIN OF DISCOVERIES
The Pará–Maranhão Basin represents a complex but highly prospective deepwater system shaped by the interplay of rifting, transform tectonics, volcanism and gravitational compressional deformation. The new PAMA 3D seismic data significantly enhances the understanding of the basin’s diverse reservoir systems and displays evidence of active charge. The evolving comprehension of the geological framework positions the basin as a compelling frontier for future exploration. With modern seismic tools, a refined understanding of the conjugate play model, and growing interest in Brazil’s equatorial margin, the Pará Maranhão Basin may finally be approaching the inflexion point that transforms a basin of ‘shows’ into a basin of discoveries.

FEATURES

“Let’s not use AI to find problems. We want to start with the problem and let AI solve it”

Paul Webber – S&P Global Energy CERA

Narrowing the gap between question and decision point

That’s what the role AI is playing when it comes to getting intelligence to the market quickly and trustworthily. Here, Paul Webber explains how his company is achieving that with CERA Titan, the company’s new platform for upstream market data and insights

“I RECENTLY put a photo of myself on LinkedIn when I was on a rig in the North Sea,” says Paul Webber, VP, Head of Global Upstream Product & Content, S&P Global Energy CERA, when we meet on Teams. Paul is leading the product management team in Upstream at S&P Global Energy CERA and in that role, he oversees developments on the CERA Titan Platform, which serves as the interface between customers and S&P Global Energy’s database and analytical capability.

“I took that photo in the year 1996,” he continues. “Four years later in my career, I consulted a spreadsheet of exploration and appraisal wells drilled across the North Sea as part of my new market intelligence job. Now, twenty-six years later, we still go back to the same data,

and the wells that have obviously been drilled since. The value of that data is still there, but the way we consult it has changed a lot.”

AI has recently formed a critical role in the way E&P data is being used in the intelligence space. “We are seeing AI as part of the core of our digital offering, and have therefore built our CERA Titan platform around that, rather than use it as a bolt-on to what we already had before AI came to the fore,” says Paul.

SOLVING PROBLEMS

“Our solution goes beyond a large language model that is just summarising large datasets into a summary,” Paul continues. “Let’s not use AI to find problems. We want to start with the problem and let AI solve it.”



Paul Webber.

“And what is that problem?” I ask. “The problem,” replies Paul, “is that individuals working at operators and any other companies interested in E&P data still spend too much time finding the right data that answers the questions

they have. That’s the problem that we want to solve with the AI-assisted way of querying our data. We want to narrow the gap between the question and the decision point.”

“We all know that once you make a call on where you’d like to focus your research on, let’s say a certain country, the next thing that usually happens is a search for data across different sources. We aim to take that away, and provide a service that finds the relevant data straight away, such that users can much more effectively focus on what they are really after and not go into the data rabbit holes that we all know exist along the way.”

And Paul is also adamant that his solution goes beyond a simple data query.

“The other thing we want to do is to provide a more proactive supporting mechanism of the search workflow,” he says. “For instance, if I’m looking at a certain area for legacy data, and there is a licensing round currently ongoing in that specific country, our software will suggest to the user if he or she wants to put the currently open blocks on a map. There is no need for the user to actively be aware that there is a licensing round happening at that time. That’s what AI is for.”

“The third item we strive towards,” Paul continues, “is the ability of the platform to summarise data into an executive summary. You know situations where you’re being asked to pull together one slide for an executive presentation within a few hours. These stressful occasions happen all the time in a fast-paced environment that comes with working in a competitive industry. Our platform has the ability to do exactly that. It’s not always a hefty report people are after, it may more often be an orderly summary that can be consumed quickly.”

FAST-PACED TECHNOLOGY AND TRUST

In contrast to what is sometimes said about the relatively slow pace with which the industry is adopting new technology, Paul sees that the E&P industry has been at the forefront of new technology for a long time.

“That’s not only through the recent advance in AI,” he says, “it’s across the spectrum. Look at what drilling technology has gone through with the evolution in bit technology and managed pressure drilling, in addition to how seismic acquisition and processing technology has evolved over the past twenty years.”

This touches on an important topic that is often overlooked in the discussion about fast-paced technology, and in this case, the advance of the use of AI in the workplace. And that is trust. “We want our customers to trust the data they will now have at their fingertips in a very short time,” says Paul. “The only way to build that trust is to have a stringent workflow of checks and a well-maintained structured database for AI to tap into. When that is in order, people will trust the analyses put out by an AI-assisted system.”

“In other words, we need the guardrails to be in place,” reiterates Paul, “especially when the deterministic responses that people require from us – i.e. how many discoveries were made in Brazil in 2024? – are returned within seconds.”

IT’S THE PEOPLE BEHIND IT

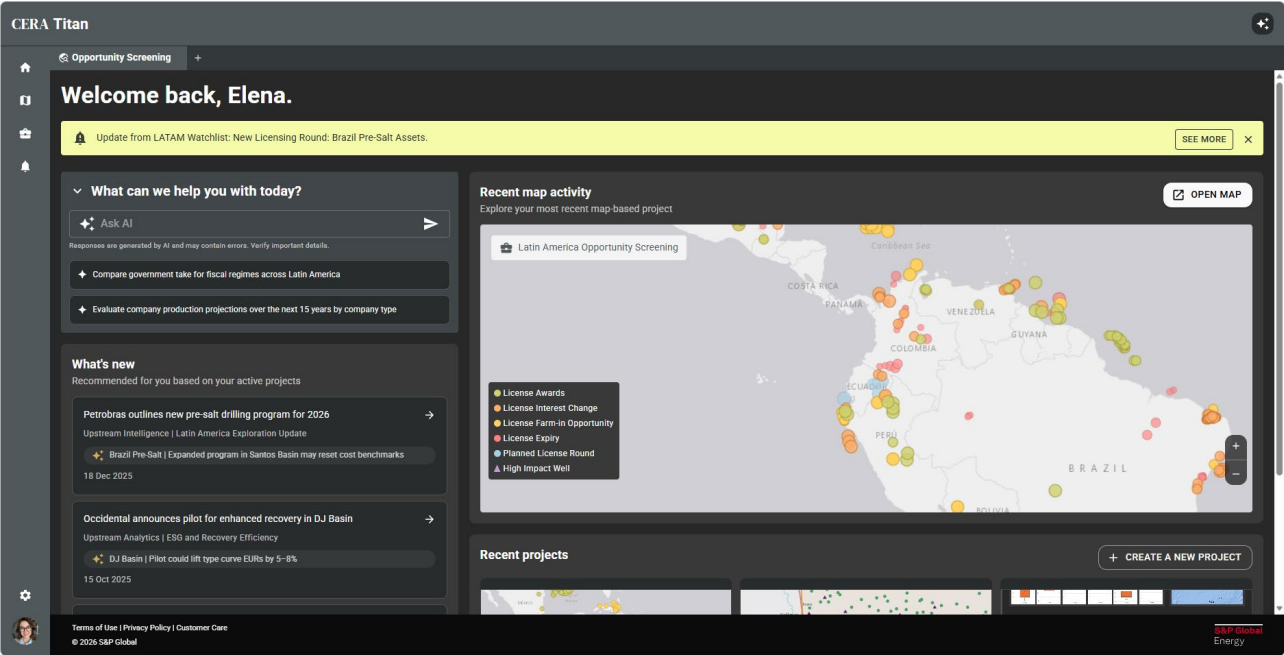
But having the prompt answers to a question presented in a format determined by the end-user is in fact only the result of what can represent decades of intelligence-gathering work. “At the very beginning are the analysts who do their day-to-day jobs across many parts of the world to build and maintain the database that we rely on for our data queries,” says Paul. “And it’s these analysts who are still the backbone of what CERA Titan is.”

“Because at the end of the day, especially when it comes to an analysis of newly obtained data – for instance the results of a newly drilled well – it is the context that our analysts provide that is still a key ingredient of our offering.”

“So yes,” Paul concludes, “AI narrows the gap between question and decision point, but equally, the work we do also still relies on having boots on the ground in all the areas we report on.”

Henk Kombrink

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"Oh, look! Oil everywhere..."

Field studies are crucial initial steps in hydrocarbon exploration, because the discovery of oil and gas seepages forms an important sign of a working petroleum system. However, whilst being optimistic about seepages is positive, caution needs to be exercised because not all seeps are the same

AYBERK UYANIK

WHAT SEEMS like an oil seep on a rock face, especially from a distance, can equally be the result of chemical weathering. When these types of rock coatings, which can be found across a wide range of settings, are misinterpreted as oil seeps, the implications can be serious. In exploration settings, such misinterpretations may influence geological assessments and investment decisions, particularly when observations are not supported by thorough geochemical or geological verification. This can ultimately result in significant financial losses and reputational consequences. To prevent these situations, understanding the existence and mechanisms of rock coatings becomes essential not only for field geologists but also for decision-makers.

MECHANISMS OF ROCK COATINGS

The most significant property of rock coatings is their colour on outcrops. The vast majority of rock coatings are

dark-coloured, usually black or brown, whilst forming flowing / cascading structures (Figure 1). They are also sometimes referred to as dark coatings in the literature.

Although the debate about the occurrence of rock coatings still continues, there are a couple of mechanisms proposed to explain the process. The most well-known ones are rock / manganese (Mn) varnish and iron film. Researchers such as Dorn (1998) and Lingappa et al. (2021) describe the Mn varnishing process whereby clay minerals and trace metals transported by wind, especially in arid climates such as deserts, adhere to the rock surfaces. With the help of dew, rainwater and bacterial activity, Mn is subsequently dissolved and oxidised, followed by the precipitation of oxidised Mn as birnessite. These minerals form a dark coloured, shiny coating on the surface of the rock. The simplified chemical formula for this process is:

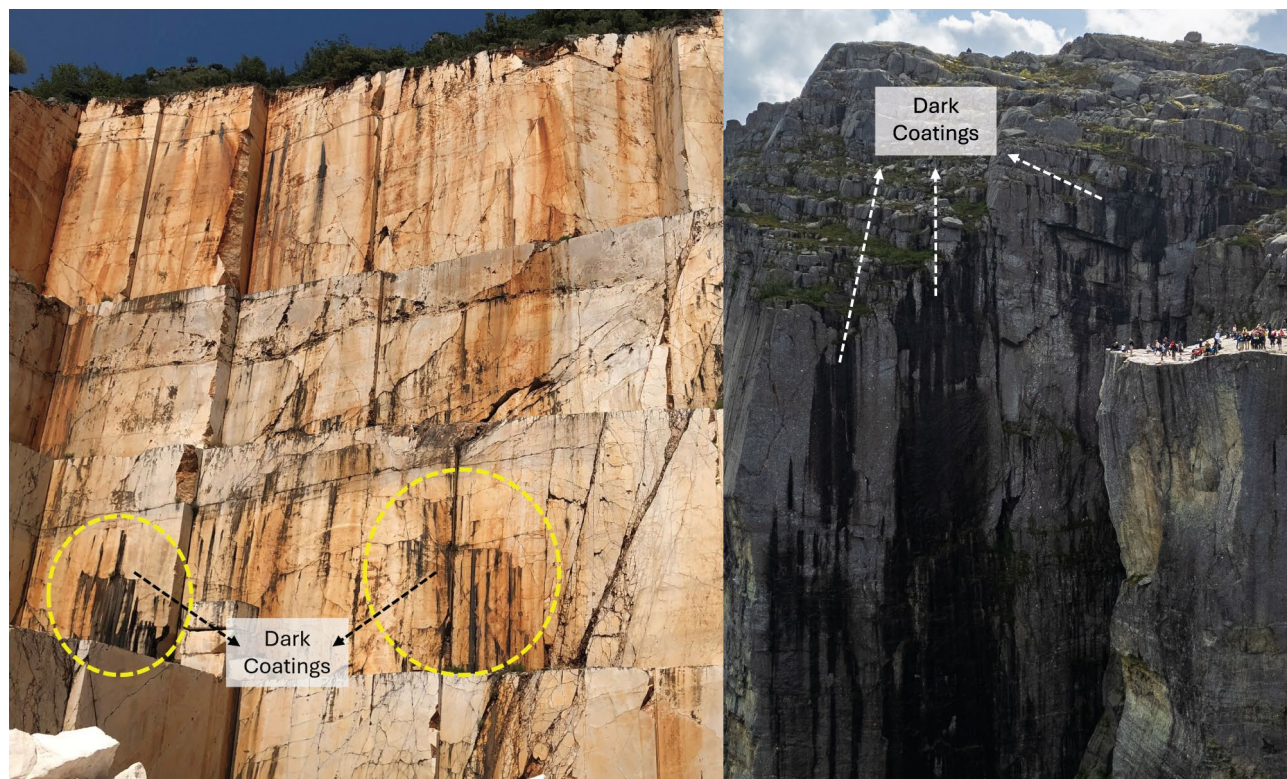
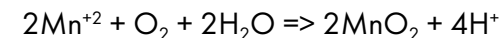


Figure 1: Rock coating examples from two different outcrops. Left: Eastern Mediterranean carbonates from SW Turkey. Right: Granites of Pulpit rock from Norway.

PHOTOGRAPHY: AYBERK UYANIK / ANDREA TABARO VIA ADOBE STOCK

Another widely accepted mechanism is the effect of groundwater. Mn/Fe-enriched groundwater seeps to the rock surface, and after evaporation and oxidation, precipitation occurs (Dorn, 1998). Seepage usually develops along fractures and creates a dark coating which directly resembles an oil seep (Figure 1). The Mn/Fe ratio determines the colour of the coating, with a high ratio indicating a black colour, while increasing Fe content causes a brown-orange colour, also named as iron film.

CASE STUDIES

I have come across significant misidentification by geologists during my field studies. The features shown in Figure 1 present a good example in which a suspected oil seep turned out to be rock coatings developed as a result of rain and groundwater seepage.

There are also some important studies in the literature. For instance, Price (1932) notes that iron films were mistaken for oil seeps in the Corpus Christi area of Texas, USA. Likewise, Arnold (1959) highlights the presence of iron films and manganese varnish and classifies them as pseudo-evidence of oil and gas based on his decades-long experience in the field. He also proposes a methodology that entails scratching the surface of the iron film with a pencil. If the film breaks into angular blocks, it is a direct indication of rock coating.

More recent studies demonstrate similar approaches as well. Blodgett and Clautice (2005) describe existing water pools with iron films that can be mistaken as oil seeps in the prospective Puale Bay-Becharof Lake-Wide Bay region on the northern Alaskan Peninsula. The study emphasises that resemblance can be developed not only on the outcrops but also on the water surfaces too. In a similar way, Tedesco (2012) warns that Mn/Fe oxides on outcrops can mimic hydrocarbon seepage signatures and might lead to false interpretations during surface geochemistry prospecting for oil.

DISTINGUISHING ROCK COATINGS FROM OIL SEEPS

So, the question emerges: If rock coatings are so common on outcrops, how can they be differentiated from oil seeps? Well, one of the most obvious indicators is the smell along the seeps. Oil seeps emit an odour of petroleum / bitumen, especially when they are scratched. Rock coatings have no odour. Physical properties such as hardness and texture differ as well. Rock coatings are hard to scratch with a fingernail due to their hardness level on Mohs (5–6). By contrast, oil seeps are much softer and may smear. In terms of texture, rock coatings are characterised as vitreous / matte edifices, while oil seeps are represented by a waxy texture.

One of the other most significant differences is how these two features react to UV light. Swanson (1981)

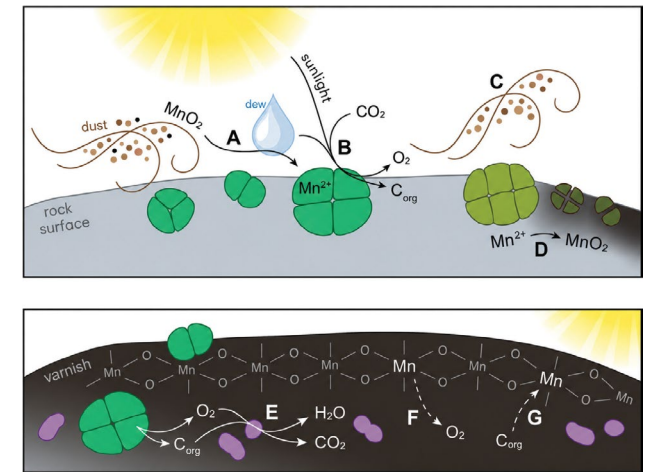


Figure 2: A sketch demonstrating the Mn varnishing mechanism.

has shown that hydrocarbons fluoresce under longwave UV light with a colour of either yellow, blue-white or green. Rock coatings have no ability to fluoresce as they remain dark under longwave UV. Therefore, with a simple portable UV torch, fluorescence behaviour can be tested in the field easily. Apart from that, a flame test might also indicate whether the edifice is an oil seep or a rock coating. When a lighter flame is applied to a rock coating, no reaction occurs, while oil seeps either melts, bubbles, or produces black-coloured smoke.

Another in-situ test includes a portable XRF analyser, which can identify the elements on a rock surface. It is usually recommended to have measurements both on the rock coating / suspected oil seep and bare rock surface to make a robust comparison. Detailed geochemical analysis in the lab would be the last step to reveal the nature of the rock samples coming from the outcrop.

KEY TAKEAWAYS

Rock coatings on outcrops might resemble oil seeps, occasionally looking almost identical. Therefore, to better understand the hydrocarbon potential of any sedimentary basin and to prevent poorly informed investment decisions, geoscientists working in the field should not forget that they are applying scientific principles and methods while examining outcrops. Thus, they should be cautious and sceptical until measurements clearly demonstrate the nature of the observed feature. Based on that understanding, they should follow field testing procedures, take samples, preserve them accordingly and conduct necessary geochemical analyses to verify the composition of the potential seepage. And finally, field geologists should communicate their findings objectively and transparently to managers and decision-makers, particularly those without a geoscience background, ensuring that their interpretations are supported by appropriate evidence and acknowledging any uncertainties that may remain.

Offshore Angola: Exploring frontiers and fringes with new and reprocessed seismic

Offshore Angola remains a highly prospective hydrocarbon province, with new seismic data and fiscal incentives driving renewed exploration. From mature deepwater basins to underexplored frontiers, TGS’s recent projects are revealing new opportunities to extend proven play fairways

MATTHEW PLUMMER, TGS

ANGOLA’S CONTINENTAL margin hosts rich petroleum systems that have charged prolific reservoirs, creating a province with over 30 Bbbl of recoverable oil. Production, mainly from the Lower Congo Basin, peaked in 2008 at around 2 MMbbl/d and has since declined to 1 MMbbl/d. The offering of negotiable, incentivised terms from ANPG is helping to offset that decline by encouraging near-field and frontier exploration. To assist exploration and better identify new targets across deep and ultra-deepwater settings of the Angolan margin, TGS is acquiring and processing new modern 2D and 3D seismic data, and reprocessing over 45,000 km² of legacy 3D coverage (Figure 1). Fast-Track (FT) products are available now for several projects, with final deliverables due over the coming months.

INVESTMENT GROUNDWORK AND IN-COUNTRY ACTIVITY

In 2018, Angola introduced legislative reforms to boost investor confidence and reverse declining oil production. The reforms simplified block bidding, added incentives for marginal discoveries and near-field exploration, and allowed gas monetisation. ANPG was established in 2019 as the national concessionaire, overseeing the hydrocarbon sector and helping attract further investment. Eight years later, company activity is widespread across all areas of offshore Angola as operators pursue opportunities created by these reforms. Companies active in the deepwater Lower Congo Basin have explored near-field, looking for deeper reservoir systems and proven fairways in alternative trapping geometries to maintain and expand oil production.

Gas exploration and development are fully in focus, with first production recently from the Quiluma-Maboqueiro fields, and success through the first dedicated gas exploration well in the country, Gajajeira-1 in Block 1/14 of the Lower Congo Basin. Further drilling for gas is currently ongoing at Katambi-2 in the Benguela Basin, appraising the 2014 discovery made when gas could not be commercialised.

ExxonMobil, TotalEnergies and Azule Energy have been exploring the frontier Namibe Basin, and Shell has returned to Angola after a two-decade absence, taking a significant acreage position in the ultra-deepwater frontier and underexplored northern Kwanza Basin. The changes in policy are working, with many wanting a piece of the Angolan prize.

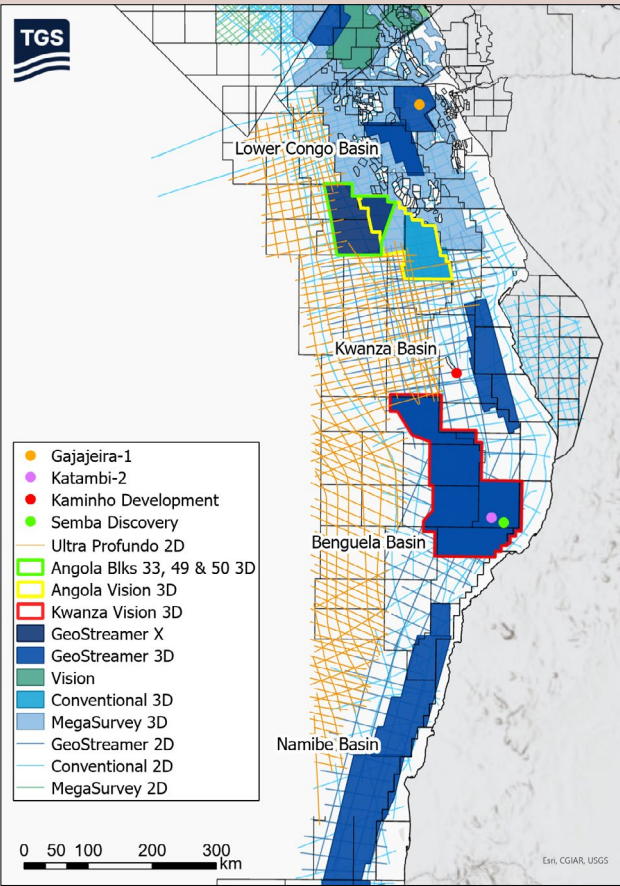


Figure 1: TGS data library with current projects highlighted: Ultra Profundo new 2D acquisition (orange), Angola Blocks 33/49/50 one-sided WAZ (green), Angola Vision block 33/34 reprocessing (yellow) and Kwanza Vision reprocessing (red).

EXPANDING PROVEN LOWER CONGO BASIN PLAY FAIRWAYS

3D seismic data was a game-changer for Angolan exploration in the 1990s, with huge success in blocks 15 and 17 of the Lower Congo Basin, derisked by amplitude-versus-offset techniques. Relatively simple trapping geometries were identified in the post-salt Oligo-Miocene section, where slope channel systems drape salt-induced pillows and turtle structures. As the easy-to-see prospects have been drilled out, legacy seismic data have become insufficient to identify and mature prospectivity in deeper

and more complex trapping geometries, often associated with the allochthonous salt bodies that are so prevalent in the deepwater part of the basin.

TGS currently has two recent / ongoing projects to help expand the proven fairways and identify new prospectivity in underexplored fringes and frontier regions of the Lower Congo Basin. In 2025, a multi-vessel one-sided Wide-Azimuth (WAZ) survey was acquired over blocks 33, 49 and 50 in the deep- and ultra-deepwater of the basin, and processing has just finished. The acquisition utilised deep tow multisensor GeoStreamer and six Gemini sources, providing an azimuth-rich dataset for improved subsurface illumination. Final deliverables include Kirchhoff Pre-Stack Depth Migration (KPSDM) and Reverse Time Migration (RTM) volumes, along with a Least-Squares RTM that has helped to resolve amplitude variations caused by acquisition and overburden complexities, in addition to improving vertical and spatial resolution.

Approaching completion is the Angola Vision product, a reprocessing of legacy seismic data over blocks 33 and 34 in an area where the salt is generally less complex but has been overlooked for exploration. Both projects have employed Elastic Dynamic Matching Full Waveform Inversion (E-DMFWI) technology, helping to more accurately image salt bodies and their geometries, carbonates and sediment features in both sub- and pre-salt settings.

REVISITING UNDEREXPLORED ACREAGE

The offshore Kwanza and Benguela basins are far more immature in terms of exploration than the Lower Congo, with only 109 wells drilled to date. The Kaminho project, which reached FID in 2024, is the first offshore development in the Kwanza Basin, with new fiscal terms for marginal fields and gas creating further production opportunities. These include both existing discoveries, e.g. Semba and Katambi on Block 24, and newly identified exploration targets. TGS is currently undertaking the Kwanza Vision project,

a modern depth reprocessing of 26,300 km² GeoStreamer data acquired in 2011–2012 and incorporating orthogonally acquired legacy data in the workflows to improve illumination and imaging. FT KPSDM, RTM and FWI-Derived Reflectivity data are available just four months after reprocessing commenced (Figure 2).

EXPLORING THE FRONTIER

Since the Venus discovery in the Orange Basin of Namibia in 2022, exploration activity in the distal parts of the West African continental margin has increased significantly, and numerous deals have been signed of late to evaluate their prospectivity. ANPG has recently delineated new acreage in their outboard EEZ, and to identify exploration opportunities, TGS has recently acquired the Ultra Profundo 2D survey, ~17,150-line km of long-offset data along the Angolan margin, from Lower Congo to Namibe basins. Acquired using Gemini sources and GeoStreamer, these data are already showing areas of interest. With data transmitted by Low Earth Orbit satellites for processing, Ultra Fast-Track PSTM images have been generated just two weeks after the last shot, enabling dynamic line position changes to ensure geological features of interest are surveyed and maximising exploration value. FT PSDM volumes are due for completion in July 2026, with final processed data due in 2027.

ANGOLA'S OFFSHORE RENAISSANCE

Angola’s offshore hydrocarbon sector has been an incredible success story since oil was first struck in the 1960s. The country’s legislative reforms have fuelled a reincarnation of its exploration landscape, and the showcased projects are enabling the continuation of that story. Legacy data, processed with modern techniques, continue to reveal new prospectivity insights in overlooked acreage, and newly acquired data are demonstrating significant potential for resources in new settings.

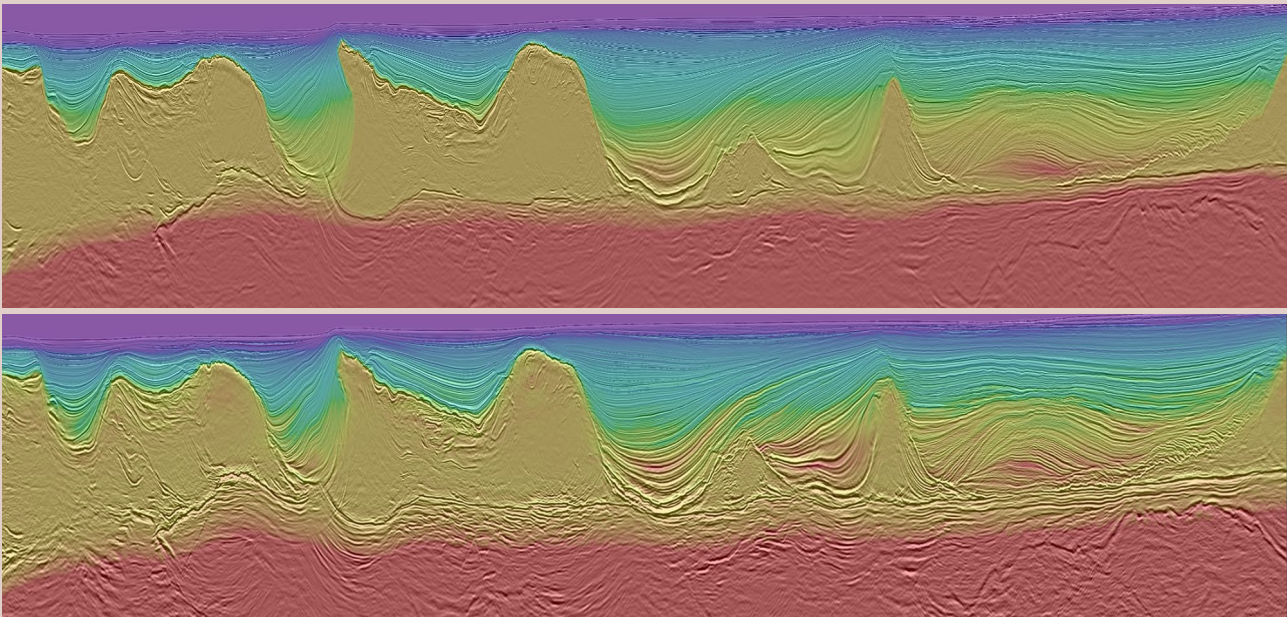


Figure 2: Comparison of legacy KPSDM stack / velocity model (top) and latest Kwanza Vision FT-KPSDM stack / E-DMFWI (12Hz) model.

The mood music of the E&P geoscience job market

How engineering, relocation, China, loose commitments, company consolidations, as well as AI and the energy transition, are all playing their part in explaining why the uptick in geoscience roles has not yet arrived, despite an increasing focus on security of supply

WHEN I was doing an internship at NAM (Shell / ExxonMobil joint venture) in the Netherlands in 2003, an experienced geologist took me aside and said, “Henk, be aware, China is coming, and you’d better be aware of that.”

It is now 22 years later, and I increasingly realise that the geologist was right, even when I wasn’t overly concerned at the time.

This article is based on some more recent conversations. And these conversations, or sometimes rather just some off-the-cuff remarks, tell a story. A story that contains an element of what I was told a couple of decades ago. A story that says that recruitment of geoscientists in the oil and gas sector is still at a low across some of the world’s oil and gas hotspots, which, in my eyes, and at first glance, feels odd given that the industry is moving back to oil and gas more openly.

So why is it that I still don’t see the pull for geoscientists? Is it all due to China? No, I don’t think so, and based on these recent conversations, I’ve landed on a number of factors that play a role. Here are some thoughts.

“Oil and gas production is becoming more of an engineering industry”

THE ENGINEERING OF OIL AND GAS PRODUCTION

Oil and gas production is becoming more of an engineering industry. Canada is a prime example of that, where

the production of heavy oil from shallow reservoirs does not require a great deal of geological input anymore. It is all about drilling horizontal wells after horizontal wells. And thanks to better technology, there is no wellsite geologist required anymore for every single one of them. It is not hard to see how this impacts the job opportunities for geologists. In fact, I believe it is one of the reasons why, despite the number of geoscience graduates having dropped dramatically over the past few years – a university professor from Canada told me that he now has eight students in his petroleum geology course where it used to be 25–30 a decade ago – those who do graduate still struggle to find a role.

“The times of the highly-paid expat who travels the world from one hotspot to another are over”

RELOCATING GEOSCIENCE

It is not often talked about, and the big IOC’s don’t tend to speak about it at all, but relocating geoscience roles to low-income countries is becoming quite a thing, with many of those roles supposedly going to India. In Calgary, I spoke to a geoscientist from Imperial Oil (ExxonMobil). The person told me that the company has decided to outsource the entire geoscience division to India, impacting tens of roles in the Canadian office. Imagine the knock-on effect this has on the opportunities for local graduates if such a number of experienced people end up on the lo-

cal job market? And ExxonMobil is not the only company embarking on this; I know Chevron has done the same, as well as Shell. The reason is obvious, and it shows that IOC’s are ruthless in their quest to save money. The times of the highly-paid expat who travels the world from one hotspot to another are over.

CHINA HAS ARRIVED

Then there is the increasingly important role China plays in the upstream oil and gas space. Wherever you go, you find Chinese companies taking up acreage. And the Chinese do what they are good at: Drilling wells, mostly onshore – they tend to be less forthcoming when it comes to offshore exploration, let alone frontier. To make all that onshore drilling happen, the Chinese ensure that there are people in China lined up to travel to far-flung places to stay in a compound for a few months until it’s someone else’s turn. This is the picture someone painted when having a conversation in Egypt, as we were talking about how China develops fields in Iraq. And this also includes most of the subcontractor work, which is primarily done by Chinese outfits.

LOOSE COMMITMENTS

There is another factor at play to explain the lack of geoscience roles advertised, and that is the observation that many of the IOC’s, despite them taking up exploration acreage, are not yet committing to actually drilling a lot of wells. We will report on that more extensively later, but it is fairly obvious that when you don’t plan to drill any new wells anytime soon in the acreage



you just acquired, there is a limited requirement for geoscience input apart from possibly some mapping of leads and prospects.

COMPANY CONSOLIDATIONS

There have been many company mergers and acquisitions over the past few years, with the Chevron takeover of Hess being one of the most prominent. But where news coverage of the deals is always there, the months after are usually followed by a quiet reorg affecting many G&G people. In the UK, a slightly different development has taken place. Here, many of the majors formed joint ventures in response to deteriorating tax conditions. Shell and Equinor forming Adura and TotalEnergies, Neo Next and Repsol under the Neo Next Plus umbrella are the most striking examples. Regardless of the shape all these company moves take, the result is a pool of experienced people now available for work.

AI HAS ARRIVED, TOO

Artificial Intelligence is no doubt another factor that reduces the need for human geoscience input. Whatever people say about people still being required to supervise the work, when a computer is able to interpret faults in a seismic cube in about 10 % of the time a seismic interpreter can do it, the conclusion is quite obvious. The same holds for the wellsite profession, where

it is thanks to AI that a geologist can process and monitor data from multiple wells now, where that certainly was not an option a few decades ago.

THE SUBSURFACE ROLE IN THE ENERGY TRANSITION IS LOSING MOMENTUM

And last but not least, I feel that many energy transition roles in geoscience are also under increased pressure. It was about ten years ago that we entered a cycle in which CO₂ storage was going to be the holy grail of mitigating climate change, with many companies pulling together teams of people to dedicate research to it, as well as drilling wells. It has kept many geoscientists in jobs for a long time, jobs that they could even boast about to their friends and family. But I feel that the time of opportunities in this space is narrowing, on the back of the increased focus on the security of supply and profit maximisation efforts. Short-term, for sure, but bp contemplating an exit from the North Sea as it just embarked on drilling a series of CCS wells on one of the major UK CO₂ storage projects tells me how serious the company is about the ranking of this very project in their global portfolio.

All in all, I fear that I will not be stalked by recruiters anytime soon. Instead, those who graduate in India or China may feel that opportunities have increased. ■

Henk Kombrink



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The deep-water architecture of northern Sierra Leone: A tale of two oceans

BEN SAYERS, GEOPARTNERS, PAUL BELLINGHAM, BGP INTERNATIONAL, AND IAN BULLEY, PVE CONSULTING



Long overshadowed by its shallower counterparts along the West African Transform Margin, the deep-water basin of northern Sierra Leone holds a remarkable geological secret. This unique margin preserves a polyphase tectonic history where Jurassic foundations from the Central Atlantic break-up, which formed the prolific Guyana-Suriname Basin, were later overprinted by the Lower Cre-

taceous South Atlantic transtensional opening. This complex structural inheritance did not just shape the seabed – it directly dictated the plumbing of ancient sediment pathways, carving out prolific opportunities for exploration. Now, armed with newly acquired, state-of-the-art 3D seismic data, we can peer deep into this multi-stage architecture for the very first time.

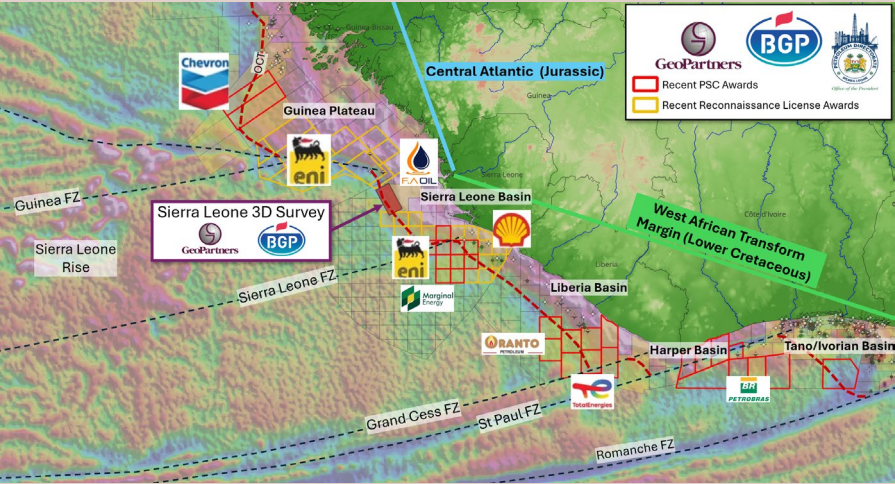
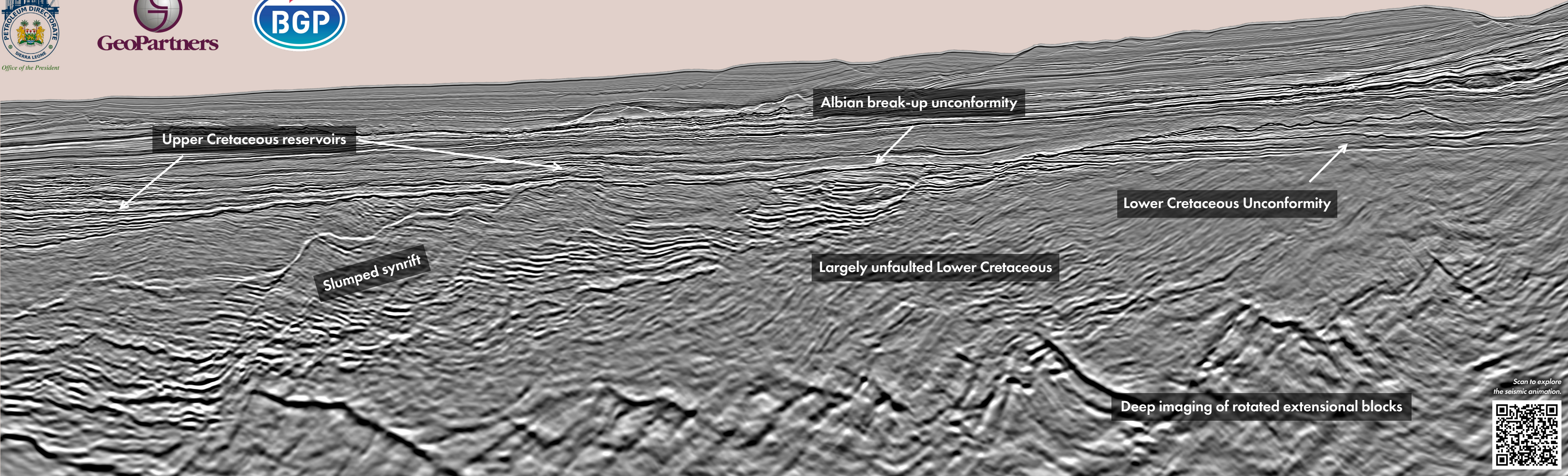


Figure 1: The new Northern Sierra Leone survey in the context of the western section of the WATM highlighting it's location in the transition between transform and extensional rift segments. New licensing activity from the last 12 months is also highlighted covering much of the open acreage.



A frontier margin revealed by new data

The deep waters of northern Sierra Leone represent one of the least explored parts of the West African Transform Margin (WATM), where exploration has historically focused on shelf and upper-slope environments. In 2025, GeoPartners, BGP and PSDL acquired nearly 3,000 km² of modern 3D multi-client seismic data in the area, providing a new perspective on the deeper-water basin architecture and associated petroleum potential. In May 2026, the final PSDM data became available, which has allowed us to refine our views of the margin development

TRADITIONALLY, the WATM has been considered to be a Lower Cretaceous aged mega-regional feature; these new data show how at the far western end of the WATM, the margin is shaped not by a single rifting event, but by the interaction of two distinct Atlantic opening phases. The first was the Jurassic Central Atlantic break-up, which established an inherited tectonic framework. This was later reactivated and overprinted during the Lower Cretaceous opening of the South Atlantic, producing the transform and extensional architecture that characterises the modern Sierra Leone margin.

Northern Sierra Leone occupies a particularly important position at the western end of the South Atlantic rift system. Unlike many parts of the WATM, the region retains a strong imprint from the earlier Jurassic Central Atlantic rifting phase. During the Lower to Middle Jurassic, the Central Atlantic break-up was accompanied by significant magmatism, with large volumes of volcanic material associated with the formation of the Guinea and Demerara Plateaus and the Bahamas Bank.

Although Northern Sierra Leone was not located directly above the main magmatic centre, it was po-

sitioned close enough to preserve elements of this earlier rift system. Seismic data indicate the presence of deep, high-amplitude rift-related packages and faulted structures interpreted as remnants of this Jurassic architecture. These inherited structures formed the foundation upon which later Cretaceous tectonic processes operated.

Following the Jurassic rift event, the region underwent a post-rift passive subsidence during which a progradational and aggradational succession was deposited over the area which now makes up the Northern Sierra Leone margin.

The second major phase occurred during the Lower Cretaceous, when the South Atlantic began to open. This event created the principal architecture of the present-day WATM, with segmented rift and transform zones developing as Africa separated from South America. Northern Sierra Leone sits at the end of one of these extensional segments (Figure 1). Break-up occurred around the Early Cretaceous, producing the margin geometry observed today.

The Early Cretaceous rifting is localised into the distal margin where the section shows small

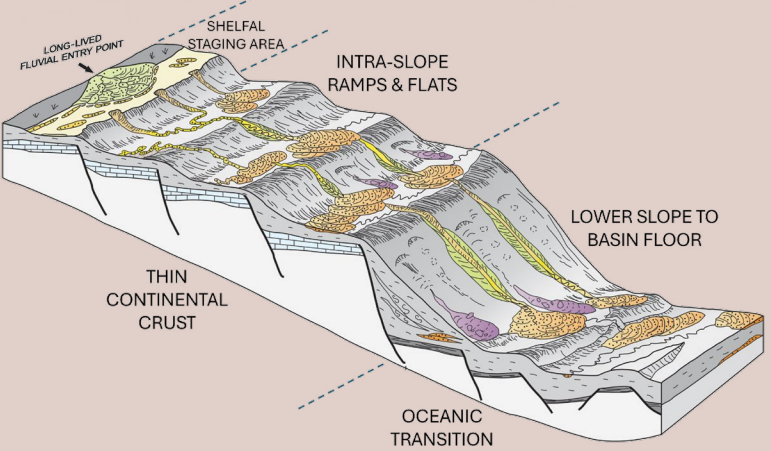


Figure 2: Depositional model for shelf to slope section in the transition between transform and extensional segments of a transform margin, demonstrating the opportunity for intra-slope ponding across intra-slope ramps and flats.

SOURCE: CRONIN ET AL. (2023); MINOR MODIFICATIONS BY THE AUTHORS

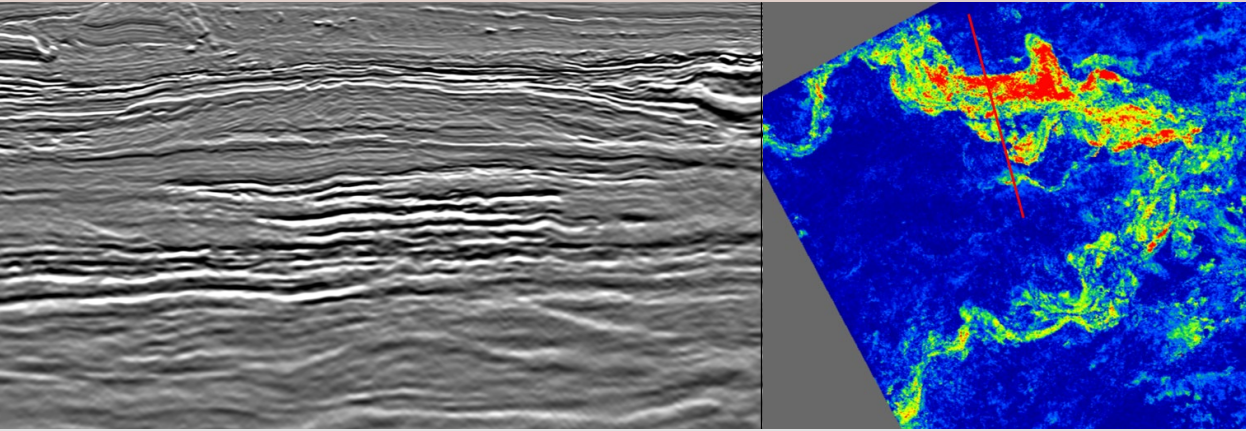


Figure 3: Example line and RMS amplitude through major Upper Cretaceous distributary system across a lower slope terrace.

scale slumped syn-rift faulting above a major detachment, the inner section being largely unfaulted (see Foldout). A prominent Albian unconformity separates the syn-rift system from the post-rift deposits which represent a deep-water slope environment. Here, in the transform / extensional transition zone we see a combination of structural complexity with gentler slope geometries, improved sediment retention and the opportunity for intra-slope ponding, all positive for potential hydrocarbon trapping (Figure 2).

UPPER CRETACEOUS PROSPECTIVITY: DEEP-WATER CHANNELS AND STRATIGRAPHIC TRAPS

The Upper Cretaceous section represents a major exploration opportunity, particularly in the mid- to lower-slope environment. This far west on the WATM, exploration has focused on Cenomanian–Turonian reservoirs in shelf and upper-slope settings, but the deeper slope domain remains comparatively underexplored. Sitting south of the Guinea Plateau promontory at the transition from Central to Southern Atlantic, previous exploration on the shallower parts of the plateau has confirmed a viable Cenomanian–Turonian petroleum system but its deeper water extension remains unexplored and has been missing quality data coverage.

The new seismic data reveal extensive Upper Cretaceous distributary systems developed above the Albian

unconformity. These systems appear to have been long-lived, with multiple phases of channel development producing stacked reservoir packages in consistent locations determined by the underlying slope architecture, itself defined by the multi-phase rift architecture.

To truly appreciate the evolution of these systems, one must watch them migrate and stack through the stratigraphy; scanning the QR code on the previous page opens a spectral decomposition animation ("Channel Surfing Through Time: A Spectral Spectacle") that slices down through the seismic volume, vividly bringing these ancient deep-water highways to life.

Particularly attractive are areas where slope gradients decrease, which promotes channel ponding and stacking. Channel complexes interacting with inherited bathymetric lows and subtle structural relief provide potential targets within the Upper Cretaceous succession.

LOWER CRETACEOUS PROSPECTIVITY: DEEP SYN-RIFT STRUCTURAL PLAYS

The deeper Lower Cretaceous section provides a different exploration opportunity. Here, prospectivity is linked directly to the syn-rift architecture created during the South Atlantic break-up.

Seismic imaging suggests that Early Cretaceous deformation, driven by down-slope detachment upon earlier

Lower Cretaceous deposits, created small-scale faulted structural domains, including segmented closures within larger regional closures. These structures are potentially charged by Lower Cretaceous source rocks.

A MARGIN DEFINED BY TECTONIC COMPLEXITY AND EXPLORATION OPPORTUNITY

Northern Sierra Leone demonstrates how tectonic inheritance can shape petroleum systems over geological time. The present-day basin architecture reflects the combination of Jurassic Central Atlantic rifting and Lower Cretaceous South Atlantic break-up, producing a margin where inherited structures, rift segmentation and transform processes interact.

This architecture provides the foundation for two complementary exploration play types. The Upper Cretaceous section offers extensive deep-water channel and distributary systems with stratigraphic and combination trapping potential, while the Lower Cretaceous section preserves deeper syn-rift structural targets.

As exploration moves into deeper and less mature areas of the WATM, understanding this multi-phase tectonic history will be essential. In Northern Sierra Leone, the relationship between ancient rift inheritance and later Cretaceous evolution is not simply a geological curiosity — it is the key to understanding where future discoveries may lie.

Oil fault traps in California's San Joaquin Basin

The role of active petroleum generation, heavy oil, and basin inversion

THOMAS L. DAVIS AND GEOFF GALLANT

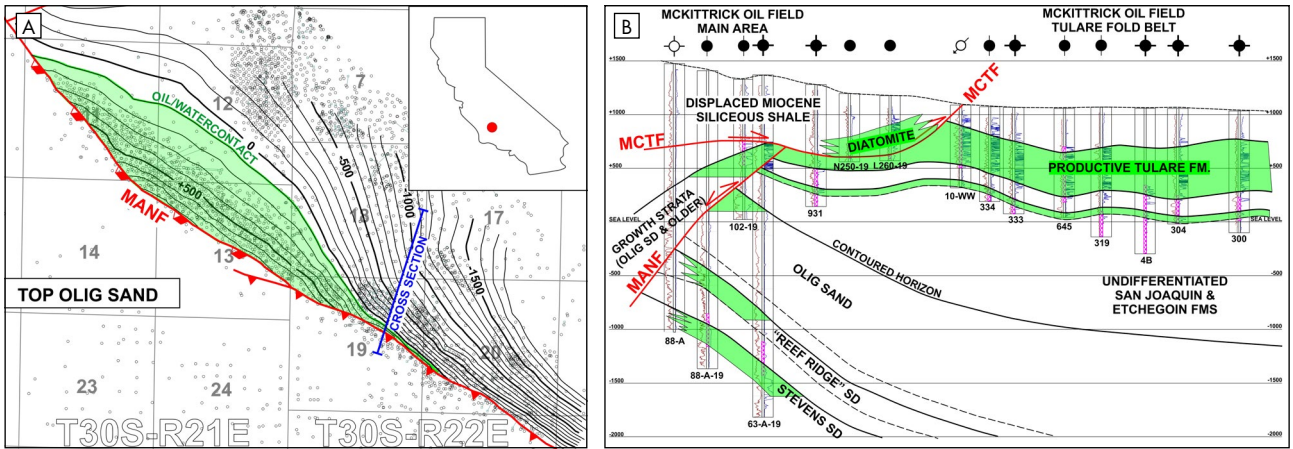
THE SAN Joaquin Basin (SJB) is one of the world's most prolific petroleum provinces and contains numerous oil accumulations that owe much of their trapping mechanism to faults. Unlike many light-oil and gas-prone basins where faults commonly degrade trap integrity, several characteristics of the SJB favour the development of fault traps that improve through geologic time. These include thick interbedded sandstone-shale successions, active petroleum generation dominated by Monterey Shale sourced heavy oil, and a tectonic setting that evolved from transtension to transpression adjacent to the San Andreas fault. Together, these factors allow faults to evolve from migration pathways into effective hydrocarbon barriers.

PRE-MIGRATION FAULT TRAPS
Due to the thick interbedded sandstone and shale sequences in the SJB, fault displacement often juxtaposes

reservoirs against seals, entrains shale into fault zones, and produces clay-rich fault gouge. Continued displacement extends shale-smear zones along fault surfaces while cataclasis of sandstone generates fine-grained fault rock that further reduces permeability. The most favorable traps are commonly associated with faults that formed before major hydrocarbon migration and have accumulated significant displacement. During Oligocene and Miocene extension, numerous normal and oblique-slip faults developed across the basin. Many were accompanied by deposition of fine-grained growth strata in their hanging walls, providing additional sealing capacity through reservoir-shale juxtaposition.

ACTIVE PETROLEUM GENERATION AND HEAVY OIL
A defining characteristic of the SJB is its active petroleum system, where oil and gas generation, migration, and entrapment have continued through-

out the basin's recent geologic history. Light oil and gas migrate farther and faster than heavy oil and are therefore the first hydrocarbons to encounter fault barriers. Where seals are imperfect, lighter hydrocarbons commonly leak through microfractures and partially connected damage zones. As leakage occurs, the hydrocarbon residue in the fault zones becomes progressively heavier, more viscous, and an impediment to flow through the zone. Heavy oil has a key role in enhancing fault-trap integrity. Lower buoyancy forces and reduced mobility make heavy oils less likely to overcome capillary entry pressures within shale smear and fault gouge. Heavy oil further reduces permeability by occupying pore throats, increasing residual oil saturation, and promoting precipitation of asphaltenes and resins within the fault zone. These processes create self-reinforcing seals that will improve through time. Many SJB and other California oil fields have heavy oil, limited gas caps, modest ►



Figures 1A and B: Structure map (left) and cross section (right) of the Main Area Pool, McKittrick Oil Field. The deeper Main Area Normal Fault (MANF) formed during late Miocene extension and provides the principal trap for deeper reservoirs. Subsequent basin inversion formed the shallower McKittrick Thrust Fault (MCTF), creating a second trap during active hydrocarbon migration. The field illustrates the evolution of fault systems from migration conduits to effective hydrocarbon barriers.

SOURCE: GEOFF GALLANT

oil columns, and exceptional longevity. Although high saline formation waters increase hydrocarbon buoyancy, this effect is commonly outweighed by the high-density and low-mobility of heavy oils. Burial depth further enhances seal capacity by reducing pore-throat size within shale smear and cataclastic fault gouge. Moderate burial depths of approximately 6,000–10,000 ft commonly provide optimal sealing conditions because effective stress is sufficient to compact fault-zone rock without promoting widespread reactivation.

BASIN INVERSION AND TRAP EVOLUTION

Many of the most effective fault traps in the SJB are formed through tectonic inversion. Late Oligocene and Miocene extension generated normal faults that accommodated basin subsidence and commonly served as migration pathways during early petroleum generation. During displacement, these faults accumulated shale smear and cataclastic fault gouge. Beginning in the late Miocene, re-

gional shortening associated with changes along the modern Pacific-North American plate boundary progressively increased horizontal compressive stress across the basin. Faults that once functioned as migration conduits became mechanically tightened. Increased normal stress reduced permeability, and enhanced fault-rock compaction. Many SJB fault traps represent inverted migration systems in which faults initially facilitated hydrocarbon movement and later evolved into effective trapping boundaries. The modern basin remains tectonically active. In strain-partitioned transpressional settings, strike-slip motion and shortening are localised onto separate fault sets. Older steeply dipping faults commonly experience increased compression normal to the fault surface, further enhancing shale-smear continuity and fault-gouge compaction.

MCKITTRICK OIL FIELD: TWO FAULT-TRAP STYLES

The McKittrick Oil Field provides an excellent example of fault-trap evolution. The shallow Main Area Pool is

trapped against the McKittrick Thrust Fault. The fault may have had recent prehistoric movement, yet its thick fault zone, cataclastic and clay-rich, is heavily oil-impregnated. Oil is trapped in footwall reservoirs beneath the thrust, while limited quantities of very heavy oil have leaked into the hanging wall to form a near-surface pod and an extensive surface breccia. The fault acts as a dynamic, partially sealing barrier. A second and deeper trap occurs along the Main Area Normal Fault (MANF), an older extensional structure beneath the thrust. Thick fine-grained growth strata deposited in the hanging wall provide an effective cross-fault seal, while juxtaposition of reservoir intervals against shale-rich strata further enhances trapping. The MANF represents a classic example of an extensional fault that evolved from a migration conduit into an effective hydrocarbon barrier.

IMPLICATIONS

Similar fault-controlled accumulations occur throughout the western SJB, including portions of the Cymric, South Belridge, Midway-Sunset, Lost Hills, and numerous smaller fields such as Pleito. The SJB demonstrates how interbedded sandstone-shale successions, active heavy-oil charge, and tectonic inversion combine to create long-lived hydrocarbon traps. Conditions are unique, but not uncommon worldwide, and provide trapping opportunities that would not be viable in many other oil provinces. In addition to the SJB and other California basins, these favourable conditions exist in Lake Maracaibo and Orinoco Heavy Oil Belt Venezuela, Trinidad, Llanos Foothills & Middle Magdalena Valley Colombia, Sureste Basins Mexico, Western Canadian Basins, Zagros Fold & Thrust Belt Iran, Sumatra & Java Basins Indonesia, Bohai Bay Basin China. Our observations are directly applicable to prospect evaluation and field development in active petroleum systems within active tectonic settings worldwide. ■

PHOTOGRAPHY: THOMAS DAVIS



Figure 2: Outcrop of the McKittrick Thrust Fault (MCTF) in the Main Area of McKittrick Oil Field. The exposure reveals a thick cataclastic fault zone that is locally oil-impregnated, illustrating how an active fault can function as a partially sealing hydrocarbon barrier.

PORTRAITS

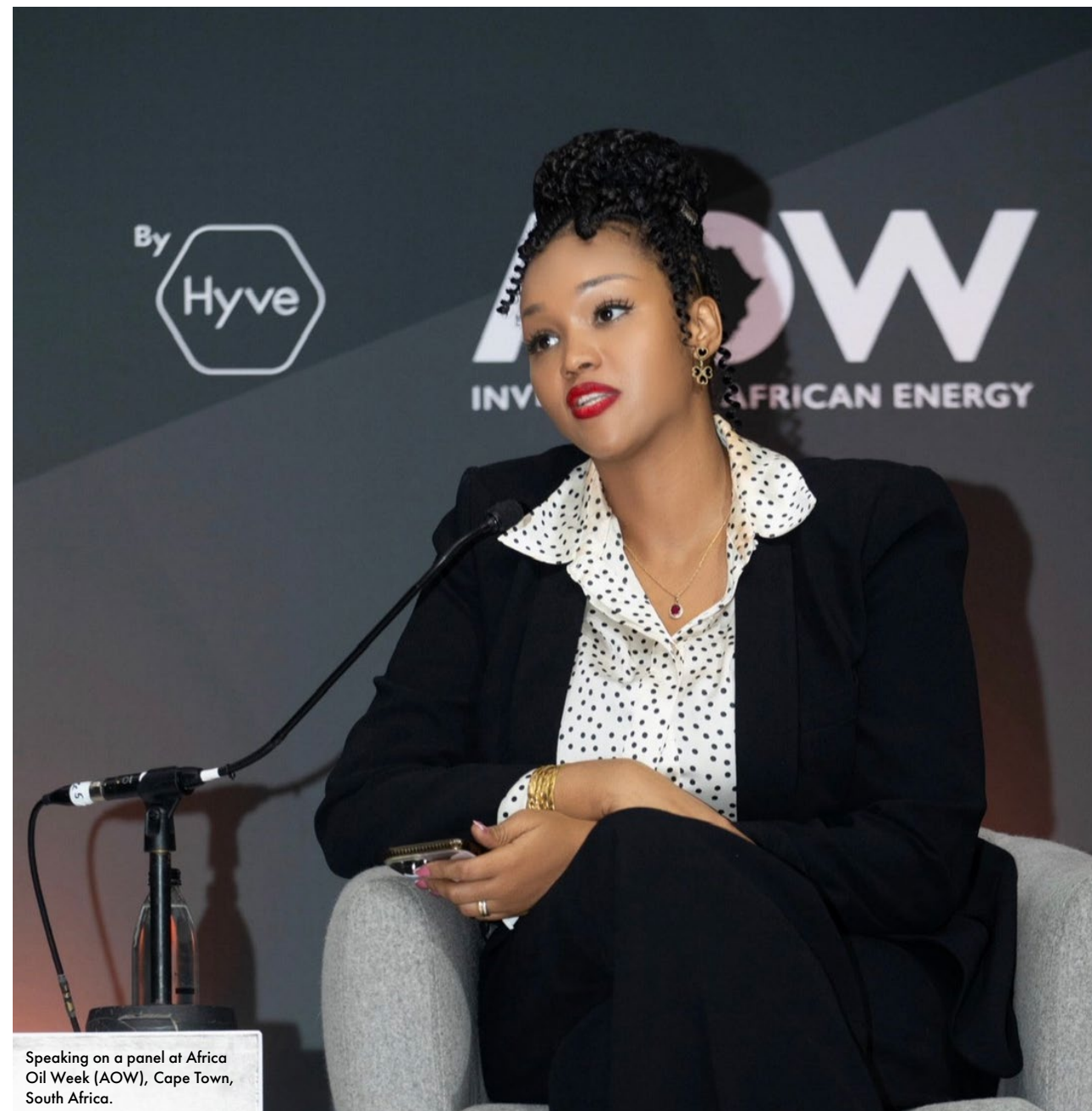
“I always loved the fact that I influenced the course of action, and the ability to take initiatives”

Cany Jobe – Petroleum Commission The Gambia

ALWAYS ON THE LOOKOUT FOR NEW FRONTIERS

A conversation with Cany Jobe, Director General of the Petroleum Commission in The Gambia, about how she got into oil, and how she is determined to make her country share in exploration success

HENK KOMBRINK



PHOTOGRAPHY: CANY JOBE PRIVATE ARCHIVE

Speaking on a panel at Africa Oil Week (AOW), Cape Town, South Africa.

"MY MOTHER was very patient with me," says Cany Jobe. "When I needed to make a big decision about which direction to take in high school, I gave her a hard time. I didn't want to choose between arts, science or commerce. I wanted to do them all."

But that's not how the system worked in The Gambia. So, Cany decided to talk to various people to seek advice. "The most intriguing recommendation I received was from a politician," she says. "He told me to choose the subject that wasn't where my heart was." "The thing you are most passionate about will endure anyway," he said. "Go for the science stream, it is a national priority."

"And that's what I did," says Cany. It says a lot about her sense of responsibility and her openness to opportunities. And that continues until today.

Cany excelled at school and was therefore selected to study abroad under a government-run scholarship scheme. The only caveat was that you couldn't pick your study yourself. "It was chosen for us depending on where the national priorities were," explains Cany.

"At some point, I was going to be sent to Malaysia to embark on a biochemistry course. But then there was a shift towards completing a medical degree in Moscow. This was followed by Cany finding herself on a shortlist to go to Houston for a petroleum course, as the president at the time had a meeting with a group of Canadians who suggested that there were good indications of a working petroleum system in The Gambia.

"Then," continues Cany, "there was a diplomatic interaction with the Taiwanese government, whereby they offered to pull together a dedicated petroleum programme."

That was the last switch of direction, and Cany flew to Taiwan together with a group of students. "I was never frustrated about this ping pong game," she says, "it was all just very exciting. We were the first

group ever from The Gambia to study in Taiwan; it was very special."

And it was a decent amount of time, four years, with internships at the Chinese Petroleum Corporation as well. Cany immersed herself in the new country. "It was a real cultural sensation," she recalls. "You won't believe it, but many locals had never seen a black person at that time, and we're talking between 2004 and 2008. People queued up to take photos with us all the time, and I was often called Serena Williams or some other African American star on TV who I looked nothing like."

Following her time in Taiwan, Cany got the opportunity to work in Venezuela. "Hugo Chavez and PDVSA had a good relationship with The Gambia, and they offered spaces for us to learn more about the profession," she says. "It was formative, and it really cemented my plan to be part of the oil industry."

Back in The Gambia, Cany won an Australian development award to do a master's course in Petroleum Engineering in Perth, Australia, where she also worked on the Browse FLNG project after completing her studies. "Again, I felt like going to the edge of the world, but spending three years there almost convinced me of wanting to stay forever."

A CALL FROM HOME

But home called. And in 2014, Cany moved back to The Gambia. She became the technical focal point with the National Oil Company of the Gambia (GNPC) straight away, forming the technical liaison between explorers and the government.

"I don't want to be just a cog in a wheel"

"In the job I had in Australia, I felt like quickly becoming a technical expert on a very specific thing, such as risers or subsea infrastructure," says Cany, "but at GNPC, rather than

remaining in a single technical discipline, I found myself involved in everything from technical work and negotiations to strategy, governance and stakeholder engagement. It felt more meaningful to negotiate directly with the companies exploring our offshore and contribute to the decisions shaping the sector. I also felt that working in a young national oil company allowed me to earn a seat at the decision-making table much earlier than I might have in a large IOC, where career paths are naturally more specialised and hierarchical."

"I also worked in administration, HR and procurement, but whatever role I was in, I always loved the fact that I influenced the course of action, and the ability to take initiatives. As an example, I was the driver behind introducing energy efficiency initiatives, including the solarisation of our head office and the petrol stations GNPC operates. I was also keen to identify and implement measures that aligned the public role of the company with national development priorities. At the end of the day, it is not only about turning a profit."

The experience she gained through all these different roles at the NOC put Cany in a great position to start a new role at the start of this year.

A NEW ROLE AT THE RIGHT TIME

Seven months ago, Cany became the Director General of The Gambia Petroleum Commission, the licensing regulator. With that change, she moved back to where she wants to be: In the exploration space. "The thing is," Cany says, "because we don't have an active upstream sector in the Gambia yet, the NOC is mainly dealing with the downstream side of the business – import of fuel, distribution, and trading. At the commission, we are mostly dealing with the upstream side of things."

She came in at a key moment in time. "We were having negotiations around offshore licences when ▶



Promoting investment opportunities in The Gambia's petroleum sector at the Africa Energies Summit, London, United Kingdom.

I started in January this year. Through my role in the NOC, I had already been part of that, but I suddenly moved from contributing to negotiations to now leading the Commission's role in bringing negotiations to a conclusion."

"At first glance," she explains, "signing an exploration licence seems relatively straightforward. You might assume that what the state wants is the same as what the investor wants, that is, to get the deal done. But every clause represents a balance between attracting investment and protecting the country's long-term interests. Reaching an agreement on a single provision can sometimes take hours or days of discussion."

Three offshore blocks have so far been awarded, one to Eni and two to Atlas Oranto. None has yet reached effective status though, with the Eni licence expected to become effective in the coming months.

"All our licences are broadly based on the Model PEPLA," explains Cany, "which includes firm drilling commitments during the Initial Exploration Period. So once an exploration licence

becomes effective, the agreed work programme takes effect." We have not issued Reconnaissance licences yet, which IOCs are increasingly gravitating towards when it comes to the recent flurry of exploration licences across West Africa."

Reconnaissance licences generally don't come with drilling commitments, which is sometimes a point of criticism towards the industry. "I see why that happens," says Cany, "but my take is that if a block has had a decent dataset acquired, with the associated studies that could have been done, there is not much point for companies to go for a Reconnaissance licence across those blocks."

"Are you open to issuing Reconnaissance Licences?" I ask. "Yes," she says, "but it depends on the work program, and it depends on the blocks these are applied for."

INCREASED INTEREST

Apart from the licences already issued, Cany observes a strong interest in what remains. "We do see that there is increased interest in the open blocks as well," she says, "including some blocks

that have never been licensed before. The A4 block, which is still open, is also progressing towards negotiation status. Overall, I see a massive potential for oil and gas across the entire West African margin."

When it comes to Sangomar, the field that is located just north of the maritime border with Senegal, Cany confirms that the wells drilled by FAR a few years ago do not see an extension of Sangomar into the Gambia. "However," she says, "we expect there is geological continuity. We can't speak with certainty as to whether Sangomar extends into the Gambia or not; there still needs to be more drilling to confirm that is the case. Bamboo wasn't entirely a failure either, as it had good shows. That's why I think further exploration is justified, because I believe it will take more effort to either confirm or rule out the presence of hydrocarbons in Gambian waters."

"At the end of the day, we only have five wells in total drilled across our on- and offshore acreage. Whilst in neighbouring Senegal, around 120+ wells were drilled before the discovery of Sangomar. Onshore, we had gas shows in the two wells that were drilled by bp in the 1960s. But at the time, gas wasn't regarded as a commercially viable product. We have never seen significant interest in these wells since, even though we are now also working on finding interested parties to have another look at those."

"Over the next few years," says Cany, as we are approaching the end of our conversation, "I want to be in the position to say that we have licensed all our blocks, and have shown moveable oil rather than an oil show."

"Look at Fahud in Oman," she says. "There, the reservoir was missed by the first exploration well, because normal faulting had cut out the productive part. In hindsight, it later turned out that the well only missed pay by a couple of hundred meters. You have to be an optimist, and I really am." Always looking for new frontiers. ■

PHOTOGRAPHY: CANY JOBE PRIVATE ARCHIVE

GEO THERMAL ENERGY

"...the missing reserves report, lack of review of the well testing, conflicting messages on thermal decline, and lack of public documentation to back up claims of sustainable flow rates indicate a level of subsurface risk at odds with Fervo's headlines"

Elliot Yearsley – Reservoir Engineer

Injecting methane in a geothermal well can double its net energy output

That is what a new published modelling study using the parameters of a Californian geothermal project suggests

INCREASING production from geothermal reservoirs is often done through the use of an electric submersible pump (ESP). Especially in regions where no significant overpressure exists, such as the German Molasse Basin, the use of an ESP is routine from day one. But as we have reported on before, ESPs are prone to scaling. High fluid flow, which is characteristic of geothermal projects, is not particularly good for these systems either, which causes ESPs to fail at unexpected moments. This requires costly workovers, with associated lost production time.

A new publication in the journal *Geothermal Energy* discusses a modelling study that addresses production enhancement from geothermal reservoirs in another way; namely, through gas injection. Personally, I was not aware that geothermal projects can also use gas injection as a means to lift production. Still, the authors – Orkhan Khankishiyev and Hamid Karami – describe several projects in the introduction of their paper. For instance, compressed air was used to initiate production from

geothermal wells in the Philippines in 1998, whereas nitrogen was injected in five geothermal wells in the Sibayak field in Indonesia from 1993 to 1995. However, the cost of the operation in Indonesia proved uncompetitive; the coiled tubing service as well as the gas were too expensive. It is interesting that the authors, a few paragraphs later, argue that gas lift in geothermal wells offers significant advantages because of its cost competitiveness.

The study reported on in this case looks at the effect of gas lift applied to the Brawley geothermal field in California, USA. After reproducing the well design and the reservoir and produced fluid parameters, the study simulates the change in production using different gas types – compressed air, methane, nitrogen and CO₂. The results show that an 80 % increase in fluid production can potentially be achieved, from 110 lbm/s to around 200 lbm/s at a gas injection rate of 1 MMSCFD. Taking into account the power demand required for the gas injection operation, this still means that net power output increases

HOW GAS LIFT WORKS

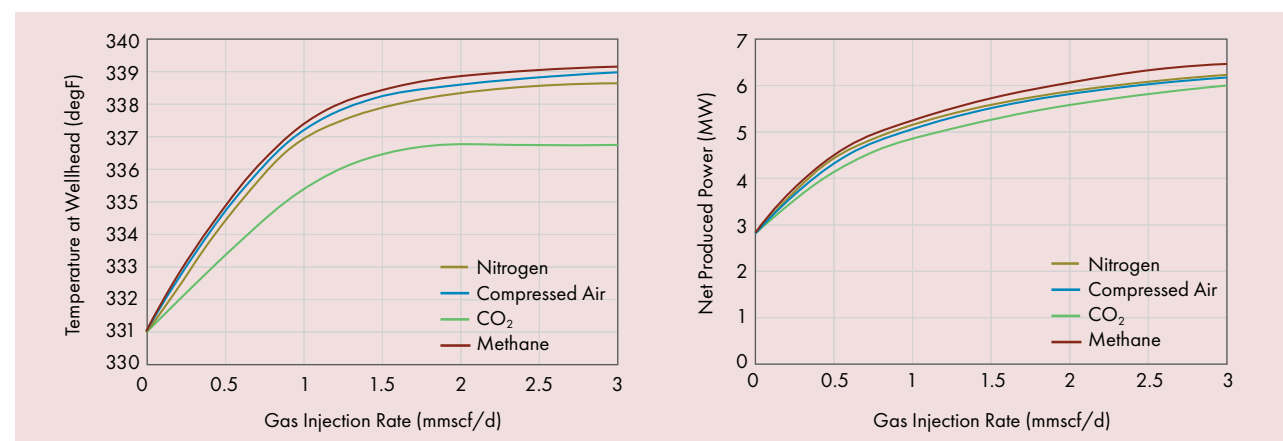
Gas injected in a well at reservoir depth mixes with the brine, which reduces the overall density of a fluid. In turn, this results in a reduction in hydrostatic pressure in the borehole, which means that the reservoir fluids will flow to the well more easily.

by 3.37 MWe, or 118 % of the initial power output.

It is also interesting to note that methane turns out to be the most effective in raising the output (128 %), where CO₂ is the least efficient (112 %). Yet, the authors note that there is no reported case of methane being used in a geothermal project to enhance production. Maybe it is about time for some associated gas from Californian production to be used in a geothermal project? Or is it still regarded as being too expensive after all, given the short-lived nature of the gas injection projects quoted in the introduction? ■

Henk Kombrink

SOURCE: REDRAWN FROM KHANKISHIYEV AND KARAMI (2026), *GEOTHERMAL ENERGY*



Temperature at the wellhead (left) and net produced power (right) with varying gas injection rates and types.

Cape Station and the case of the missing reserves report

In a press release dated June 10, 2025, Fervo Energy announced reserves report by DeGolyer & MacNaughton (D&M), which they say confirms that the Cape Station project can support over 5 Gigawatts of development. The next day, D&M issued their own press release, referring to this report as the "First Reserves Report on Enhanced Geothermal Systems", which was performed "in accordance with the principles of the Petroleum Resources Management System" (PRMS). We were sceptical, for good reason

ELLIOT YEARSLEY

THE S-1 filing related to Fervo's recently proposed Initial Public Offering refers to a Heat Initially in Place (HIIP) report by D&M, in which they make no mention of reserves or the PRMS.

The distinction between reserves and resources is important, with the latter being more speculative and potentially sub-commercial. In their S-1 filing, Fervo say that the geothermal resources for Cape Station "should not be viewed as a measure of reserves prepared under SEC guidelines or as a measure of estimated future production or generation capacity." These resources, say Fervo, are based on applying their "thermal recovery factor" to D&M's estimate of heat in place, which is akin to multiplying a theoretical number by a debatable factor.

Unlike in petroleum engineering, where recovery factors are considered reasonably well known, the geothermal recovery factor is poorly understood. Significant effort has been made to try to quantify geothermal recovery factors, and what has become clear is that the geothermal recovery factor is not a fixed constant but depends upon how reservoir volume is defined.

Recent work by Libbey and Murphy found that geothermal reservoirs with a low Productivity Index, such as indicated for Cape Station, tended to have recovery factors in the lower range of 5–15 %, whereas Fervo's estimate of the recovery factor for Cape Station is an oddly precise 30.5 %.

Fervo also state in the S-1 filing that their recovery factor is "estimated using a variety of methods, including computational reservoir simulation and decline curve analysis. But this generic statement is misleading. For one, decline curve analysis is generally performed on long-term production data, which for Enhanced Geothermal Systems (EGS) would be scarce to non-existent. The same can be said of relevant EGS case studies of field-scale reservoir analogues. Experience also tells us that even the impressive-sounding "computational reservoir simulation" is only as reliable as the history matching it is based on.

As Fervo's presumed geothermal resource expert, D&M do not attempt to address the geothermal recovery factor issue

in their Cape Station report. Instead, to calculate power from their heat in place numbers, they are provided "design specifications" for the ORC turbines by Fervo – and presto, out of this comes enormous amounts of power, with no field analogies or explanation of how this power is produced.

LEVEL OF SUBSURFACE RISK AT ODDS WITH THE HEADLINES

It is customary for geothermal power projects proposed for construction to have the well testing reviewed by a qualified third-party geothermal consultant. Key results from this type of review would be well productivity and the number of wells needed to meet the design flow rate required for the expected net power sales. No review of this nature appears to have been done.

From a reservoir engineering perspective, the absence of a review would be concerning, and this is especially true for a new production technology like EGS. Now we have also learned that the independent "reserves report" is actually just a heat-in-place report with no review of how that heat would be produced from wells.

Taken together, the missing reserves report, lack of review of the well testing, conflicting messages on thermal decline, and lack of public documentation to back up claims of sustainable flow rates indicate a level of subsurface risk at odds with Fervo's headlines. ■



Well testing – an essential element in quantifying the geothermal resource, or reserve. Test conducted at the Patuha geothermal site in Indonesia in 1997.

Eavor steps away from operator role in Geretsried

That's what Eavor's CEO Mark Fitzgerald said during an exclusive interview with us that addressed the company's recent project in Germany, as well as the new strategy it has now embarked on

FAIR PLAY. I have written about Eavor before (GEO EXPRO Vol. 23, Issue 1, 2026), and I've been critical not only of the level of secrecy surrounding the company and its operations, but also of the concept they have applied in the German town of Geretsried by drilling a series of deep closed geothermal loops. But in May, I was invited for an interview with Mark Fitzgerald, the new president and CEO of Eavor, in Calgary.

CHANGE OF STRATEGY

The first thing we talked about was the plan on how to proceed with completing the Geretsried project. At the end of the day, the original idea was to drill four injector-producer pairs with the associated loops. So far, the company has completed one injector-producer pair, with six horizontal loops connecting the two holes – instead of the planned twelve.

The most important shift is that the company has decided to step away from being the operator of the project. Even though there is no formal change in the ownership structure of the entire project, the implication of this decision is that Eavor is now having to find a company that can take on the role of operator. "We see ourselves as a technology provider," said Mark, "as we believe that other parties may be more capable of the operational side of things."

NET OR GROSS

Let's get back to the operational part of the Geretsried project. What was new to me was that out of the six

completed loops, only three to four are contributing to flow. Two loops experienced clogging by rock debris to such an extent that the cleaning operation could not alleviate the problem. The third loop is only contributing to a limited extent.

The current stated energy output hovers between 0,5 and 1 MWe. What I was keen to know is if this represents gross or net output, taking into account the operational power demand from the plant. "It is gross," confirmed Mark. With the power demand of the plant being around 0,5 MWe, the project does not deliver power to the grid most of the time.

"It must be said that in the current circumstance, with a limited number of loops contributing, the efficiency of the plant is very low, sitting at only 2 %," added Mark. "When more loops would become operational, the efficiency would ramp up to 14 %," he added.

FOLLOW-UP PROJECTS

"We are aware that we have to make money now, and we are actively looking for projects that have the potential to make that a reality," said Mark.

What the company is looking to do is go deeper than the 4,5 km-deep Geretsried wells in order to tap into hotter rocks, as well as completing at least twelve loops per injector / producer pair. "We see potential in multiple places in Germany," Mark said.

Whether this place is Hanover, the city in northern Germany that was originally going to be the next location where Eavor would land its



Mark Fitzgerald.

rigs, is not a certainty anymore. "The subsurface in the Hanover area is complex," said Mark.

All in all, Eavor's CEO remains upbeat about the potential of his company's closed-loop technology. "We believe that we have proven the concept. We now have to prove commerciality," he reiterated a few times during the conversation.

CAUTIOUS

I believe it is too early to call the Geretsried project a proof of concept. Granted, the team managed to cut drilling times for each consecutive loop. But given that this demonstration project has not delivered meaningful energy yet, has basically spent the budget that was initially available (€ 350 M) and is planning to go deeper than where it's ever been before for a potential follow-up project, it is enough reason for me to take a cautious approach. That said, the opportunity to talk to Mark Fitzgerald is much appreciated. ■

Henk Kombrink

PHOTOGRAPHY: EAVOR

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Gravitating towards discoveries in Angola's onshore Kwanza Basin

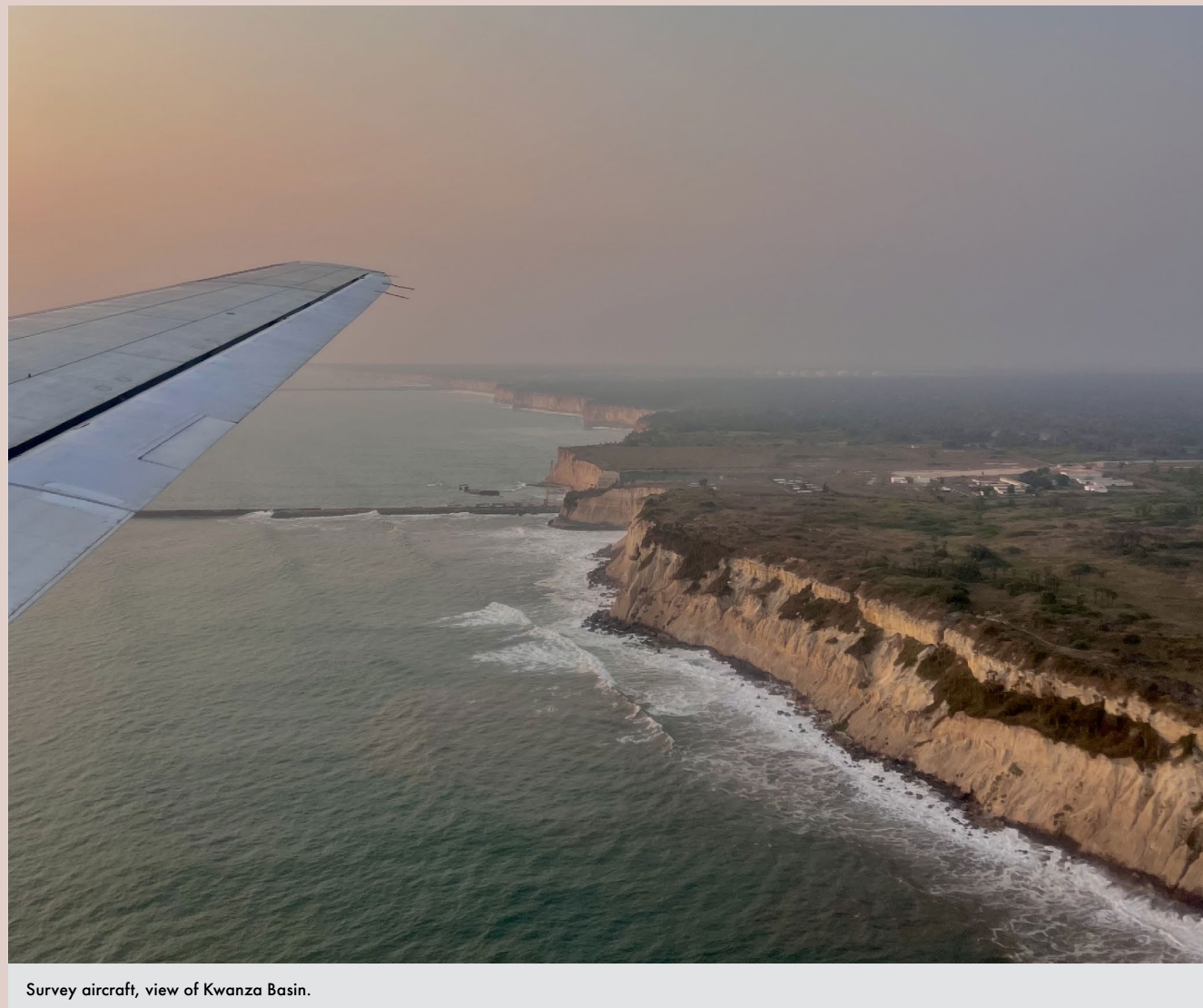


The onshore Kwanza Basin is a proven petroleum system, one of Angola's most compelling, yet underexplored hydrocarbon provinces. More than a century after exploration first began, a new generation of airborne geophysical technologies is transforming our understanding of the basin, revealing fresh opportunities and breathing new life into one of Africa's oldest petroleum frontiers.

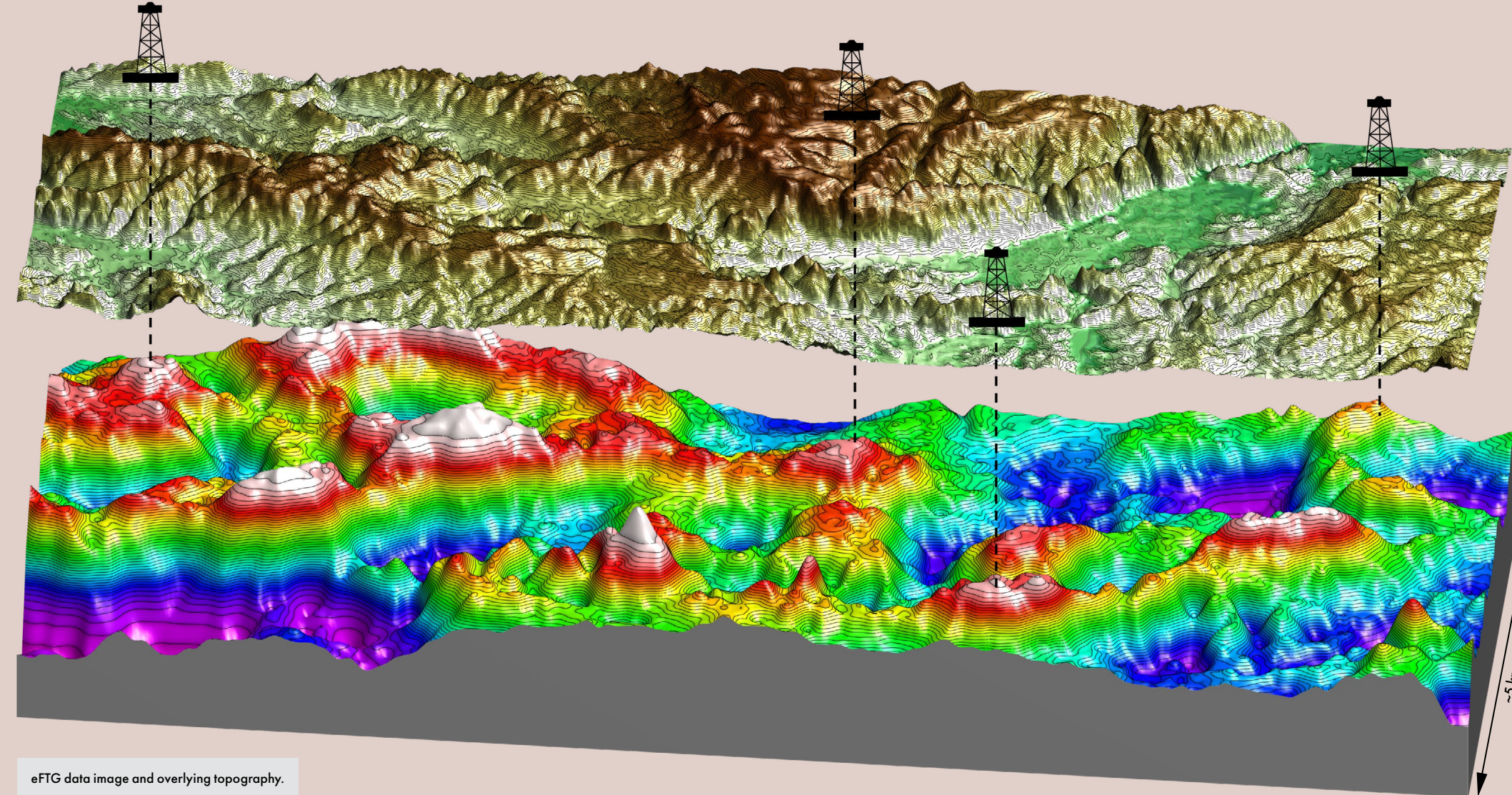
The Kwanza Basin has a long exploration history; however, much of its potential remains poorly understood due to sparse seismic coverage, limited well control, and imaging challenges associated with complex salt tectonics. Historically, exploration efforts have focused on post-salt objectives, leaving significant uncertainty surrounding the architecture and prospectivity of

deeper pre-salt plays. Recent changes in the Angolan exploration framework have enticed both local and international operators to take a fresh look at the basin's remaining potential.

In collaboration with the Agência Nacional de Petróleo, Gás e Biocombustíveis (ANPG) and local partner Striped Horse, Metatek has successfully completed a multiclient Enhanced Full Tensor Gravity Gradiometry (eFTG) survey over the onshore Kwanza Basin. The dataset provides clarity on the subsurface basin architecture, overcoming long-standing challenges posed by limited data and the intricate nature of salt-related structural complexity. The following article explores how airborne eFTG can contribute to a more integrated understanding of the basin and its remaining exploration potential.



Survey aircraft, view of Kwanza Basin.



eFTG data image and overlying topography.



Top: Angola location map, Bottom: Onshore Kwanza Basin licence area map.

Unlocking pre-salt potential through integrated airborne geophysics

NITHUL UDAYAN, CHRISTIAN RICHARDS AND JONATHAN WATSON, METATEK GROUP
CHARLES THOMAS, STRIPED HORSE

OIL PRODUCTION in Angola began in the onshore Kwanza Basin, where early discoveries such as Benfica, Tobias and Quenguela North were made on seismic datasets acquired during the 1960s to 1980s. These fields produced mainly from Lower Cretaceous post-salt Binga carbonates and Miocene sandstones. However, the legacy data offered little ability to image deeper pre-salt potential. Basin production peaked at around 18,000 bbl/d in the mid-1980s before declining due to natural depletion, civil unrest and the diversion of exploration attention toward larger offshore Lower Congo Basin opportunities. Historically, the onshore Kwanza Basin has produced around 90 MMboe, and now leaves a legacy of partially developed fields, bypassed oil, and of most interest, a deeper pre salt play potential that modern geophysical technology is helping explorers reassess.

In 2019–2020, ANPG implemented and executed presidential decree 52/19 for new concession licensing rounds and decree 282/20 outlining the 2020–2025 exploration strategy. These initiatives were designed to stimulate exploration and increase production in the Kwanza Basin through the adoption of new and innovative advanced survey technologies. This policy is particularly important since the basin remains data-limited, with sparse seismic coverage and persistent imaging challenges beneath thick, mobile salt bodies. As a result, understanding of the basin architecture has historically been constrained, limiting the identification of opportunities and prospects.

CUTTING-EDGE TECHNOLOGY BRINGS KWANZA IMAGING UPLIFT

Metatek's Enhanced Full Tensor Gravity Gradiometry (eFTG) represents a step-change in airborne geophysical acquisition and is the most advanced, highest-resolution airborne gravity gradiometry technology currently available. By accurately measuring the gradient of the Earth's gravitational field across all directional components of the gravity tensor, eFTG delivers exceptional geological insight from near-surface to deep basement. This enables accurate mapping of fault systems and basin architecture, improved imaging of salt distribution and tectonics, and

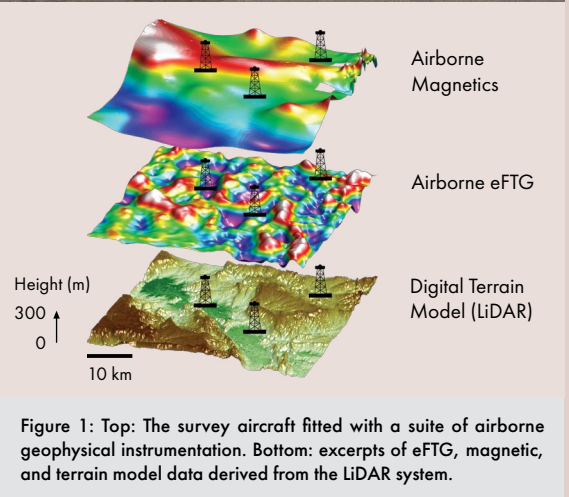


Figure 1: Top: The survey aircraft fitted with a suite of airborne geophysical instrumentation. Bottom: excerpts of eFTG, magnetic, and terrain model data derived from the LiDAR system.

critical understanding of pre-salt geological context. The technology provides consistent, high-resolution coverage across large areas, including regions where seismic imaging is limited or unavailable. By defining key structural trends, depocenters and potential play fairways ahead of seismic acquisition, eFTG helps operators optimise survey design, focus acquisition on the most prospective areas and reduce exploration risk before committing to higher-cost seismic programmes.

These benefits are particularly relevant in the onshore Kwanza Basin, where legacy 2D seismic datasets acquired between the 1960s and 1980s are generally of poor quality and offer limited opportunity for improvement through modern reprocessing. Furthermore, new onshore seismic acquisition has limited coverage with less than 900 line-km acquired since

2012 across an area of approximately 30,000 km². To address these challenges and support planned 2027 seismic acquisition commitments, a cost-effective multiclient airborne geophysical eFTG survey was commissioned across the onshore licence areas KON1–KON23.

Over a split period of seven weeks, data were acquired using a bespoke survey design. A 2 km × 5 km acquisition grid was flown across all licence areas, establishing the highest-resolution basin-wide airborne geophysical dataset currently available over the onshore Kwanza Basin. This regional framework was then supplemented by targeted infill acquisition requested by prefunding block operators, providing prospect-scale data at tighter line spacings, with the densest coverage reaching 250 m × 2.5 km.

The resulting dataset significantly enhances both regional and prospect-scale geological understanding, improving interpretation of basin architecture, structural trends and hydrocarbon prospectivity, while providing a robust framework for future exploration and seismic programs.

THE KWANZA BASIN AT A GLANCE

The onshore Kwanza Basin formed during the Early Cretaceous breakup of Gondwana and is an interior salt basin with pre-rift, syn-rift and post-rift successions affected by extensive halokinesis and structural deformation.

Its petroleum system includes Barremian-Aptian lacustrine source rocks, fluvio-lacustrine and shallow-marine sandstone reservoirs, locally fractured carbonates, and shale or evaporite seals. Trap styles include syn-rift fault-related structures, inversion features and stratigraphic pinchouts.

Whilst drilling has mainly targeted post-salt intervals, the deeper pre-salt section remains underexplored, but offers significant upside, with analogues to proven South Atlantic margin plays.

GEOLOGICAL INSIGHTS

The eFTG dataset provides a substantial improvement in basin-wide subsurface imaging compared to legacy data, enabling clearer definition of geological structures at both regional and prospect scales.

Key insights include enhanced mapping of basement highs and lows, salt structures, and carbonate units, together with the identification of structural lineaments and improved delineation of Cenozoic basin evolution. Sub-salt imaging has been significantly improved, providing a deeper understanding of pre-salt geometry and structural complexity.

Integration with seismic and well data support the development of more robust geological models, helping to reduce uncertainty and improve confidence in prospectivity. These results are consistent with global applications of airborne gravity gradiometry in frontier exploration.

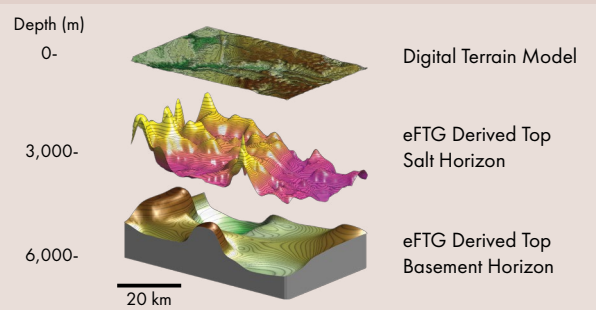


Figure 2: Example outputs from the integrated survey deliverables, including LiDAR-derived topographic imagery and derived top salt and top basement horizons.

WHAT'S NEXT FOR THE KWANZA BASIN?

Following the successful integration of the eFTG data with legacy seismic and well data, the onshore Kwanza Basin now has a stronger technical framework for future exploration. The next phase will focus on acquiring targeted, modern seismic data over the most prospective areas identified from the integrated eFTG / seismic interpretation. Redefined trap geometries, fault relationships, salt influence and reservoir distribution can be established. In parallel, selected exploration and / or stratigraphic wells will provide critical calibration for the geophysical interpretation. This understanding will move the basin towards focused prospect evaluation and production.

NEW INSIGHTS, NEW OPPORTUNITIES IN THE KWANZA BASIN

The onshore Kwanza Basin remains one of West Africa's most underexplored areas, it has a proven active petroleum system and has significant pre-salt potential. While early discoveries established the basin's credentials, exploration remains limited due to sparse seismic coverage, well control and the complexity of salt-related deformation. In response, ANPG's renewed licensing and exploration strategy has created fresh momentum for reassessing the basin using modern geophysical technologies.

Metatek's basin-wide airborne eFTG multi-disciplinary survey, provides a major uplift in subsurface understanding. The integrated eFTG results deliver a clearer definition of basement architecture, structural trends and salt distribution: This improved geological framework helps reduce uncertainty, guide future seismic acquisition and focus exploration activity on the most prospective areas.

Overall, the survey demonstrates how advanced airborne geophysics can accelerate exploration in data-limited and structurally complex basins. For Metatek and its partners, the project highlights the value of eFTG as a practical, high-resolution imaging tool with applications not only in hydrocarbon exploration, but also across wider natural resource sectors including mining, geothermal, environmental studies, agriculture and renewable energy.

SUBSURFACE STORAGE

“If you place a small reactor at a depth of around 2 km underground, the walls are in place already, and the footprint at surface can be a lot smaller too”

Liz Muller – Deep Fission

Spindletop spin-off: Helium storage

Due to the ongoing issues in the Persian Gulf, many countries and companies realise they should have built up helium reserves to counter the shortfall and price hikes

QATAR, generally responsible for a third of global helium supply, has had to halt production because the Iran war prohibits export. Storing liquified helium gas at surface is not cost-effective; highly specialised, insulated tanks are needed, and even then, the gas will still slowly evaporate. Hence, helium and natural gas are best left in the North Field reservoir until the Strait of Hormuz reopens.

The same is true when building a long-term helium stockpile; the gas is preferably stored in the subsurface. The US government realised this early on and has been incredibly successful at storing crude helium in the depleted Cliffside gas field in Amarillo, Texas. Starting in 1945, they stocked market excess helium for future military use and retrieved the majority during the Korean War and Space Race with Russia. Thanks to the very high recovery factor, the federal government decided to turn Cliffside into the official

National Helium Reserve in 1963. The facility was eventually sold in 2024.

The Cliffside field is a dolomite reservoir on top of a salt dome. With anhydrite capping the reservoir, a perfect trap was created. On the other side of the state, near Houston, salt tectonics are prevalent too. This is the area of the famous Spindletop gusher, the huge blowout that occurred when oil was struck in 1901. Here, a helium storage site has also been created, but this time not in a depleted reservoir but in the salt of the dome itself.

The top of the salt diapir is relatively shallow, sitting at around 365 m depth. It has a diameter of approximately 1.5 km and extends 3 km down. Caliche has solution-mined two caverns for helium storage in the Jurassic Louann Salt. One of the caverns is in use by Air Products, while the other, newer one, came online a year ago and was commissioned by Linde. The companies store helium that is recovered from the waste gas of

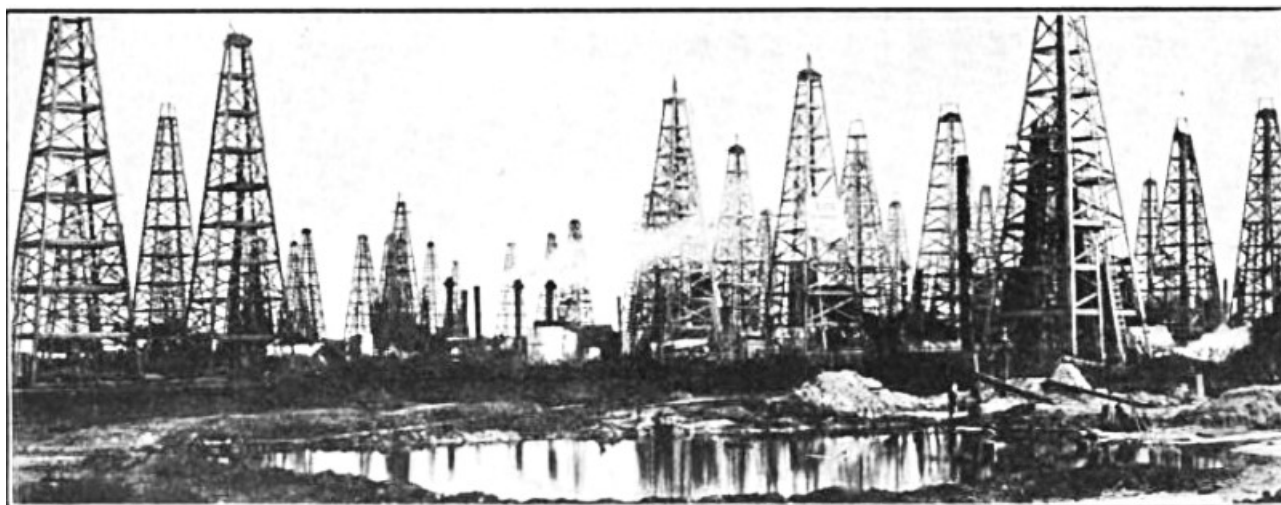
locally produced LNG; when methane is liquified, residual gas rich in nitrogen and helium remains.

Gasworld reports that Air Products has already tapped into its stored helium reserves due to the crisis in the Middle East. This comes at an additional cost because the helium has to be re-liquified before it can be supplied back to the market.

Apart from helium, the salt domes in the Spindletop field also contain caverns for hydrocarbon storage. The Big Hill diapir houses 14 caverns with a total storage capacity of 170 million barrels. These caverns make up about a quarter of the Strategic Petroleum Reserve of the US government. The Trump administration is currently selling stored hydrocarbons to oil companies to combat the price hike related to the Iran war.

More than a century after the Texas Oil Boom, Spindletop continues to influence the market. ■

Mariël Reitsma



A view of the Spindletop oil field, Texas, March 1903.

PHOTOGRAPHY: WIKIMEDIA COMMONS

Drilling a well to produce nuclear energy

How a US company brings together technology from the oil and gas and nuclear sectors to build small nuclear reactors one mile below the ground

THE FIRST time I heard about the company Deep Fission was through a conversation with an operations geologist. He had been working on the first well dedicated to the company's project in Kansas, USA. It all sounded a bit odd to me, putting a small nuclear reactor in a borehole, but when you listen to a few of Deep Fission's videos and read through the website, it may actually make sense.

One of the main issues the company, which was founded by a father and daughter – Richard and Liz Muller –

tries to tackle is the time it takes for “conventional” nuclear reactors to be built these days. It can easily take ten years, with one of the key factors being the extensive safety measures that need to be taken into account when building a reactor. If you place a small reactor at a depth of around 2 km underground, the walls are in place already, and the footprint at surface can be a lot smaller too. That is the main reason why Liz Muller, who is the CEO, is confident that they can achieve commercial production within the timeframe of two to three years instead.

As mentioned before, Deep Fission has recently drilled a test well in Kansas at the so-called Parson site to a depth of around 1,8 km. The main difference with an oil and gas well is the diameter of the well at depth; looking at images of the canister that will hold the reactor, the hole could have a diameter of around 50 cm or more. The lithology the company is probably targeting is granite, as suggested by a core photo from the website.

The idea is for the small pressurised water reactor to be placed in a canister, lowered down the hole, which is subsequently filled with water. One reactor is supposed to generate around 15 MWe, which is not that much, and compares to what a prolific geothermal well can produce. But in this case, there is no scaling nor a temperature decline.

Deep Fission went public on the 18th of June this year, raising around \$40 M. However, the share price dropped straight away from around \$15 to \$10. It has been hovering around that latter price for the past few weeks.

The company has now started to drill the second well in their campaign, and also announced that they already have signed Letters of Intent with various data centres and other industrial entities for the delivery of a total of 18.5 Gw of generation capacity. That would require more than 1,000 wells, meaning that the technology needs to upscale fast. Since the company aims to use known technology, with the only difference being the new setting, the teething issues may hopefully be limited. ■

Henk Kombrink



The Kansas drill site where the first test well was recently completed into granites.

PHOTOGRAPHY: DEEP FISSION

Is pressure space the nail in the coffin for large-scale CO₂ injection in saline aquifers?

A study in the US Illinois Basin suggests that if pressure perturbations are included in the permitting process of CCS projects, very large regions beyond the injection site have to be considered. But how workable is that going to be?

IT IS FOR a reason that companies, when presenting their CO₂ injection plans, don't put the actual pressures on the vertical axis of their pressure-versus-time plots. At least, that is what I observed a few times at separate events. Pressure seems to be one of the most critical aspects of CO₂ injection into saline aquifers. One of the reasons, as a recent publication from Jens Birkholzer and Quanlin Zhou from the Lawrence Berkeley National Laboratory shows, could be that the pressure front resulting from injection will travel much further away from the injection site than the CO₂ itself.

The team created a model representing the US Illinois Basin, in which they included twenty injection sites, all injecting 5 Mt of CO₂ per year for 50 years. As expected, the model clearly shows how the pressure front travels much further than the CO₂ itself, to a point where pressures in the periph-

ery continue to rise even after injection at the site has ceased – up to 250 km away. And this is not unimportant, not so much because of the risk of CO₂ leaking into the overburden, but rather the risk of saline waters making their way up into fresh water aquifers in the overburden. You only need one location where the sealing units are possibly more sandy than at the injection site, a fault that is unable to withstand the pressure rise, or, which is not unlikely in some parts of the world, a legacy well that doesn't have the right plugs, and a problem may arise.

Because of this pressure effect, the authors argue that the actual storage capacity of CO₂ in saline aquifers is likely to be lower than what many have so far assumed. The reason is that most assessments rely on a fraction of the reservoir pore volume, which is referred to as the storage efficiency factor. This methodology does not take pressure build-up into

account, leaving the assumption that pressure is not a limiting factor. But that's unlikely to be the case. The numbers the researchers came up with are shown in the diagram, where the upper and lower limits of storage space capacity without pressure being a factor are compared against the same scenario where pressure was taken into account.

From a regulatory perspective, if the area that needs to be assessed for a storage project is all of a sudden getting much bigger than initially foreseen, potentially more than 100 km away from the injection site, how feasible will it be to assess the fluid migration risk for such a large area? Especially for onshore injection projects, I see lots of challenges in that regard, especially when it comes to the geological screening that would be required to properly assess the risk of any leakage happening. ■

Henk Kombrink

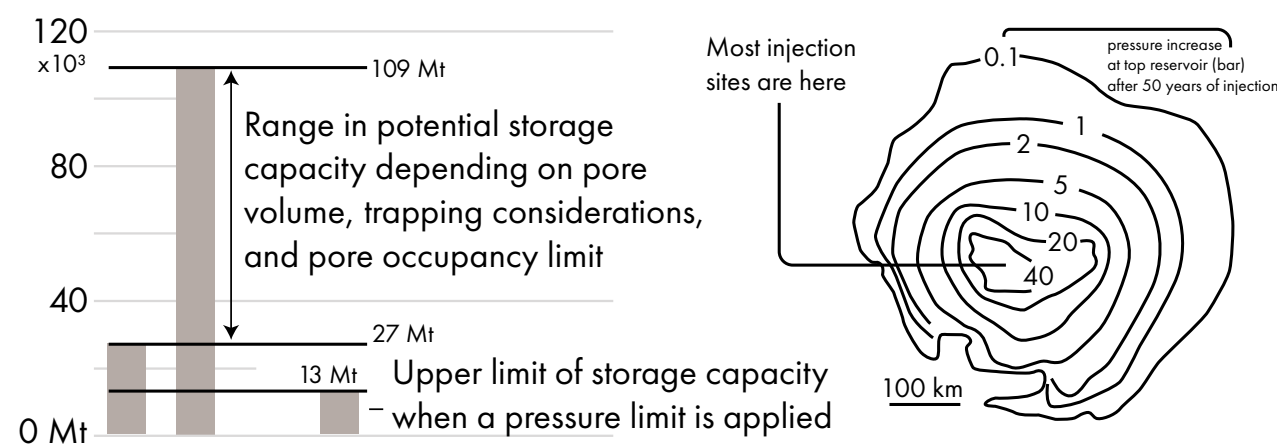


ILLUSTRATION: REDRAWN AFTER BIRKHOEHLER & ZHOU



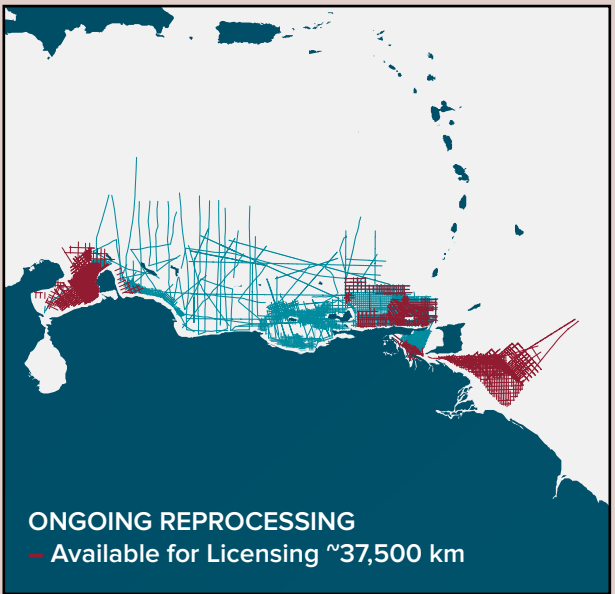
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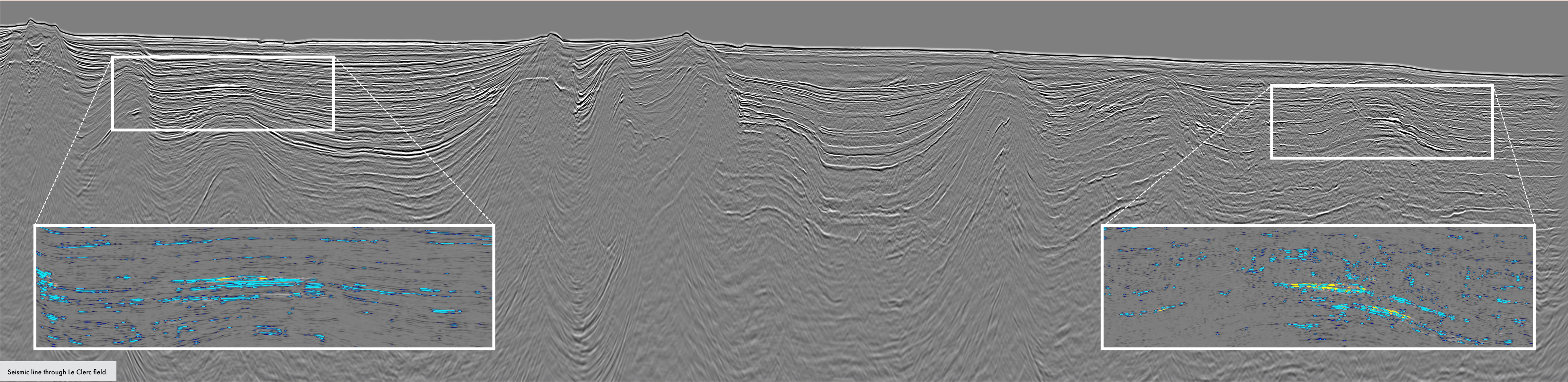
Exclusive access to Venezuela’s next offshore play

For decades, deltaic environments have been a globally prolific source of hydrocarbons. The Niger, Nile and most recently the Mahakam Delta provides evidence of the significant potential of these depositional environments. Large deltaic deposits in frontier settings are becoming more challenging to find, particularly those with relatively proximal discoveries and good existing infrastructure.

One such opportunity where this exists is offshore Eastern Venezuela. Here, a significant deltaic deposit is present and would be categorised as frontier in terms of drilling density; however, significant discoveries have also been made offshore Trinidad & Tobago within the Columbus Basin. Due to this unique setting, DHI’s can be seen on both sides of the border that help to de-risk this frontier area. Geoex MCG, in partnership with DUG Technology, have completed the reprocessing of Delta Amacuro 80B with reprocessing of the Delta Amacuro 69B survey underway (Figure 2). Both surveys provide a complete imaging coverage of the deltaic setting. Within the data there are hydrocarbon indications that have been identified in multiple areas with tieback potential to Trinidad’s LNG plant. This untapped potential is sure to attract significant industry interest.



Venezuela Offshore Multi-Phase Exploration Program, via exclusive multi-client agreement with the Ministry of Hydrocarbons (MINHID).



Venezuela offshore: A basin re-entering the global stage

Proven discoveries, established infrastructure and newly reprocessed seismic data are providing a clearer understanding of Plataforma Deltana, helping de-risk exploration and accelerate investment decisions across this underexplored basin.

MIKE POWNEY, JENIFFER MASI AND GEORGE BABA, GEOEX MCG
JULIAN SHERRIFF AND STEPHEN DOYLE, DUG TECHNOLOGY

SOURCING THE DELTA

This particular area offshore Venezuela has had a complicated tectonic history that resulted in proven reserves of hydrocarbons. Initially a rifting phase developed in the Jurassic between the North and South America plates which subsequently led to passive margin development within the Cretaceous, providing the predominant setting of the AOI.

The AOI was then subsequently disrupted, significantly, by the oblique collision of the Caribbean plate with the Northern boundary of South America. As a consequence, a foreland stage in the offshore of the Eastern Venezuela Basin (EVB) developed during the late Oligocene. From this period to the Early Miocene, south to north flowing fluvial systems and associated deltas, prograded northward from the Guyana shield to the EVB. Subsequently, following a Late Miocene regression event, and the lowering of the eustatic sea level along the passive margin, a major unconformity is visible across the margin, which

resulted in the development of submarine canyons that allowed the Orinoco Delta to prograde eastwards from the proximal EVB into the deeper water Atlantic area in the earliest Pliocene. From this epoch onward, progradation has taken place from the Orinoco Delta into the Atlantic Ocean.

The sediment supply has had a convoluted history. Prior to the uplift, the Orinoco delta was being deposited onshore in proximal areas from Northern South America to the current Andes. During the uplift of the Andes to the west, river systems migrated eastward before depositing in the Delta Amacuro region. The tectonic and depositional history can be summarized as follows:

- Stage 1** – Cretaceous to Early Paleogene passive margin stage and underfilled Paleogene foreland stage
- Stage 2** – Miocene underfilled to filled-foreland stage in the distal eastern area of the EVB
- Stage 3** – Plio-Pleistocene overfilled-foreland basin stage in the distal eastern area of the EVB

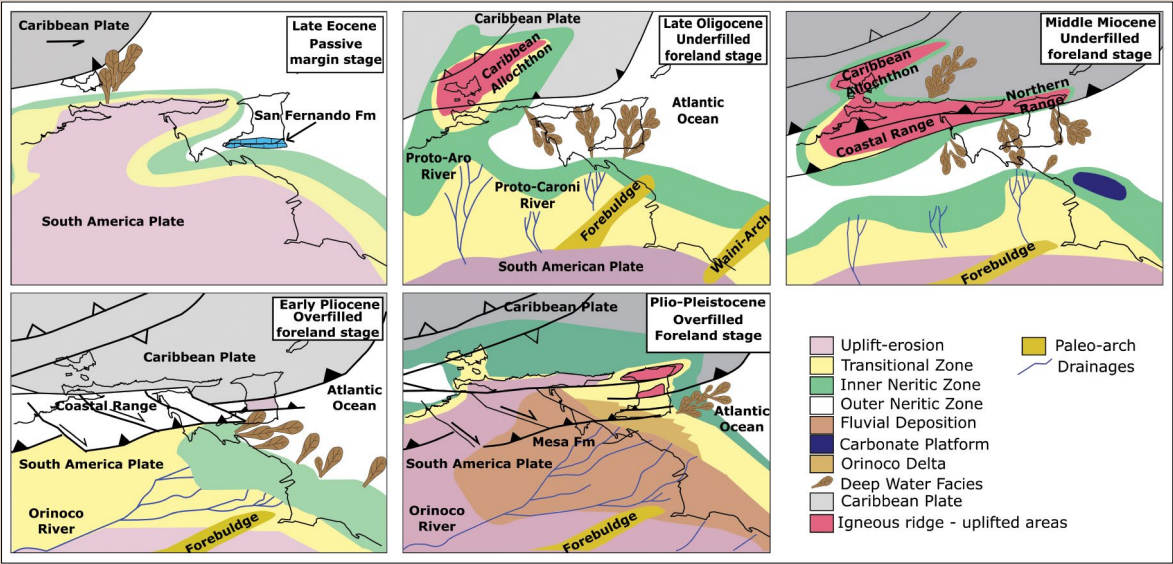


Figure 1: Gross Depositional Environment outlining the tectonic and depositional environment of the distal Eastern Venezuela Basin.

The synthesis of these depositional and tectonic systems is best summarized in Castillo & Mann (2021). Figure 1 demonstrates the complex interplay between tectonic and depositional systems (adapted from Castillo & Mann, 2021).

DE-RISKED BY DISCOVERIES WITH AVAILABLE INFRASTRUCTURE

The Delta Amacuro, or Plataforma Deltana, petroleum system is therefore characterized by a significant deposition of sands within listric faulting on a decollement layer. This has generated significant high porosity / high permeability intervals in shallow water, sealed by juxtaposed listric faults. The Querecual Formation is the main source rock providing hydrocarbons for these intervals, while others are postulated within the Paleogene.

This petroleum system has proved successful, as discoveries have been identified in several fields including Tajali, Loran and Cocuina. A Final Investment Decision (FID) has recently been made by bp to produce the Cocuina-Manakin field and provide the associated gas to the LNG pipeline in Trinidad.

It is therefore reasonable to deduce that if these types of plays with similar DHI's can be identified on seismic, these frontier areas can be de-risked, leading to fast-track production and monetization, and reduce the overall CAPEX associated with producing such areas.

LEGACY COVERAGE TO MODERN UNDERSTANDING

Geoex MCG and DUG Technology, have already completed the reprocessing of the Delta Amacuro 80B survey (Figure 2). This dataset crosses the border with Trinidad and Tobago, providing useful ties from producing areas to the underexplored southern region. An example of this line is shown in the Foldout.

Although only one of these features has been drilled and is subsequently producing, similar DHI's are observed on both sides of the profile. Geoex MCG can therefore use this data to compare self-similar DHI's and structures to produce an inventory of leads and prospects of key areas. In order to have a better coverage of the Plataforma Deltana region, Geoex MCG have begun to reprocess a second dataset Delta Amacuro 69B to provide a better understanding of the entire area (Figure 2).

The workflow associated with the reprocessing utilises modern algorithms and significantly improves the legacy data. Despite the limited offset associated with the acquisition parameters, the reprocessing workflow significantly increases the bandwidth of the data, de-ghosts the data and eliminates existing multiples, enhancing the signal.

The additional dataset provides the extended coverage required. This will be matched to the 80B survey to provide continuity and a seamless full coverage of this region in both time and depth. Due to the differences of vintage,

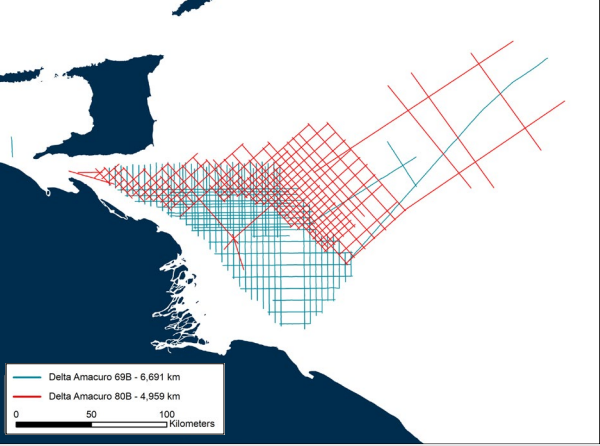


Figure 2: Geoex MCG's 2D coverage of the Delta Amacuro region with Delta Amacuro 80B (red) already reprocessed and available for licensing and Delta Amacuro 69B (blue) currently undergoing reprocessing.

Geoex MCG and DUG Technology will ensure that the lines are consistent in terms of amplitude, velocities and profile balancing.

By integrating both datasets, the interpreter will have entire coverage of the offshore Plataforma Deltana allowing for significantly better geological understanding of the locations and their associated risks whereby large discoveries could be made. Subsequent insight would then be used to provide a more focused view on where 3D acquisition should be acquired.

WHY THE TIME IS NOW

Geoex MCG and DUG Technology have already reprocessed seismic data offshore in the Orinoco Delta. These datasets provide insights from existing and producing fields in a frontier area. Limited drilling has yet to commence in highly prospective areas away from existing discoveries. This is in part due to the lack of modern data covering the full extent of the area, however, newly reprocessed volumes providing this coverage will soon be available.

This will provide the insight required to make investment decisions. There are few regions globally that can provide this unique opportunity. Now is the time to seize it.

EXCLUSIVITY AND SCALE

Geoex MCG operates under a multi-client agreement with Venezuela's Ministry of Hydrocarbons (MINHID) and is currently the only seismic data provider authorized to deliver new offshore multi-client seismic data in the country. This agreement positions the company as the exclusive commercial gateway for the Ministry's offshore seismic programme.

The programme covers Venezuela's full offshore domain, from the Gulf of Venezuela to the Plataforma Deltana. It combines new basin-scale seismic acquisition with reprocessing of legacy datasets to establish a consistent regional framework across both proven and frontier offshore areas. Licensing and prefunding options are available.

NEW GAS

"It's shaping up to be an extraordinary summer in Saskatchewan with comprehensive testing at Bracken and commercial validation drilling at Lawson"

Steve Halabura – MAX Power

Is helium the bonus or the business?

Multiple natural hydrogen explorers are planning to produce co-occurring helium as an upside. But is helium not the more lucrative gas? Why aren't these companies exploring for helium and then using any potential hydrogen to power their operations?

GOLD HYDROGEN started exploration on the Yorke Peninsula in South Australia on the back of a legacy hydrocarbon well. They had a clear lead on hydrogen but they also found exceptionally high helium concentrations. An independent commercial assessment now indicates that helium production at the Ramsay Project might be commercially viable. The results of the imminent flow test will determine whether Gold Hydrogen fast-tracks helium-focused production while pushing natural hydrogen opportunities to the medium- or long-term.

At the same time, MAX Power has also started with hydrogen exploration, but in an area that is known for its helium. That begs the question: Why? Their Grasslands license, on the Canadian side of the Saskatchewan-Montana border, is flanked on

three sides by production wells from North American Helium and situated within a known helium fairway that stretches into the USA. Yet, the recent Bracken well was first and foremost a hydrogen exploration well. Steve Halabura, Chief Geoscientist at MAX Power, said in an email to us: "At this point, our focus is clean energy."

The prompt to explore for hydrogen came from an accidental and initially overlooked hydrogen discovery made four years ago during helium drilling. The current Bracken well is located about 10 km to the south-east and is the first dedicated hydrogen (or helium) well on the Grasslands acreage. Bracken was drilled earlier this year to a depth of 2,600 m, reaching the Precambrian basement. The encountered basement rocks are favourable for hydrogen formation via serpentinisation and / or radiolysis, and gas anomalies during drilling included hydrogen signatures well above background level.

The overlying Basal Cambrian Deadwood sandstone is one of the formations North American Helium produces from. At Bracken, hydrogen and helium shows were observed during drilling, although testing will need to determine the reservoir quality. Devonian carbonates are another proven helium-bearing reservoir in the region. The Devonian will be a primary focus during the upcoming well testing program.

With little technical details supplied by MAX Power, it is hard to determine whether this is a hydrogen prospect with helium upside or the other way around. However, the company is already banking on producing both gases. Max Power's model shows the theoretical impact of value-added helium to the natural hydrogen find. Halabura: "We are about to test Bracken and determine the nature of what we believe to be a natural hydrogen and helium system. The anticipated gas stream will consist of economic amounts of each."

However, a commercially viable natural hydrogen reservoir needs a much larger volume of free gas than a helium reservoir. MAX Power's first well, Lawson, albeit 325 km to the north-east, found an aqueous reservoir. The much-anticipated well testing at Bracken should bring clarity as to which gas or gases can be economically produced here. But for now, MAX Power can hold out hope of becoming a clean energy provider. Or it may also evolve into a helium business as their Australian colleagues have already shown, demonstrating that helium is a bit more than a bonus.

Mariël Reitsma

PHOTOGRAPHY: MAX POWER



Drill rig at Bracken.

Poland is the only serious helium supplier in the EU, but not because its subsurface is so special

Europe's Critical Raw Materials Act stipulates that by 2030, 10 % of the EU's helium consumption should be extracted by the member states themselves. An ambitious goal, given that the European Commission acknowledges that its proven reserves are only 0.2 % of the global proven volume

THE EUROPEAN UNION has marked 34 substances as 'critical raw materials'. Helium is among them due to its significant industrial importance and the high chances of supply chain disruption. Those supply vulnerabilities are currently more acute than ever; 40 % of EU helium is imported from Qatar, but shipments can't be delivered due to the conflict in the Middle East. In addition, Russian helium is banned under sanctions related to the war in Ukraine. The majority of Europe's helium is thus imported from the United States and Algeria.

Poland is the EU's only significant helium producer. My estimate is that it covers around 7–8 % of EU consumption. That's not bad, given that Poland's natural gas fields generally contain less than 0.4 % helium.

Poland achieves its high helium output because the country has made it mandatory for operators to evaluate the helium resources of a field if the concentration exceeds 0.2 vol.%. This has resulted in the assessment of 17 gas fields, giving a combined contingent helium volume of 24 Mm³.

However, 76 % of Polish helium is actually produced from fields containing less than 0.2 % helium. The reason is that the Polish national oil and gas company (Orlen) needs to denitrify the natural gas to raise the energy density, and having this process in place means that it is relative-

ly straightforward to simultaneously capture helium.

All helium is produced from the Wielkopolska petroleum province in the west of the country. A study assessing a further 30 natural gas fields in the province has established 35 Mm³ in prospective helium resources.

Plenty of additional helium exploration opportunities in the rest of the country remain, with four prospective areas for helium exploration identified based on correlating basement geology with the existing petroleum provinces. Hard data are scarce, unfortunately, with helium concentrations lacking for most legacy wells in these areas. At the same time, it is well-known that a few aquifers in Paleozoic strata in the east of the country demonstrated up to 10 % helium.

Not all of Europe's hope is focused on Poland. 45-8 Energy is actively exploring the Baltic coast in Germany, where a series of dry wells proved to have elevated nitrogen and helium contents. The company is also drilling for helium at two locations in France. A recent exploration well at the site of a natural spring discovered 0.33 % helium, an 8-fold increase from the concentration naturally bubbling up to surface.

And finally, something could also be done on the demand side. For example, Poland's current production is enough to fill all EU party balloons that are produced annually, consuming around a third of the helium needed by the medical industry. Not a trivial amount.

Mariël Reitsma



Gas compressor station, Odolanów, Poland.

Exploring deep-seated hydrogen fluxes in Nova Scotia

Canadian company Québec Innovative Materials Corp. (QIMC) has drilled hydrogen exploration wells into a major fault zone. But how much hydrogen could potentially be produced from such a play?

ARNOUT JW EVERTS, AEGEO

QIMC'S EXPLORATION campaign focuses on the Cobequid-Chedabucto fault system in Nova Scotia, a crustal-scale fault zone that separates the Avalon Terrane to the north and the Meguma Terrane to the south. The zone is a series of sub-vertical strike-slip faults that locally branch into thrust-fault and flower structures. QIMC holds three hydrogen exploration licenses in Nova Scotia, two of which are on the fault zone itself. Although the complex geology could potentially create traps, their principal target appears to be migration pathways along the deep-seated faults themselves.

QIMC started with a soil-gas sampling campaign and noted anomalously high hydrogen readings in all licences. This led the company to interpret "four prospective hydrogen corridors" which, in their opinion, "confirmed the Cobequid Fault as a first-order hydrogen system".

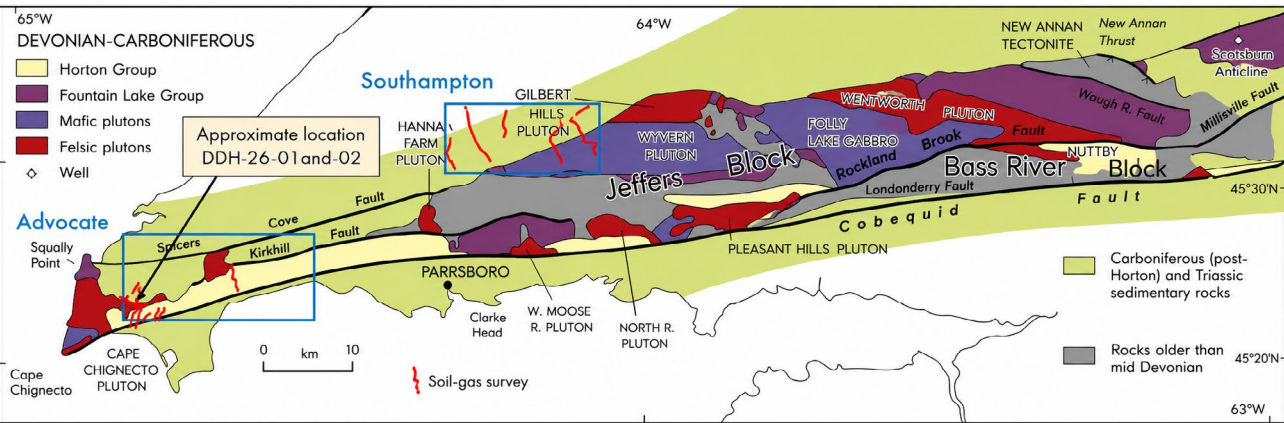
QIMC then commenced exploration drilling in the Advocate licence. The two wells are relatively shallow and deviated, presumably delineating some of the highest hydrogen anomalies noted at surface. Based on the detailed geological descriptions released by the company, hydrogen anomalies in the wells appear associated with faults. High hydrogen readings in the lower part of DDH-26-01 and the toe of DDH-26-02 could reflect a tentative SWS-ENE trending hydrogen "vent" along a 60–70 m wide fault zone. Drilling of another three wells is ongoing.

How much of the seeping hydrogen can be captured by producer wells? Migration pathways along deep-seat-

ed faults have hydrogen-saturated brine in the pores with a few percent of migrating hydrogen gas. A well drilled into a migration path will only capture migrating gas bubbles that coincidentally intersect the well trajectory; applying a pressure drawdown would merely pull in additional water. However, continuous lifting of water with dissolved hydrogen may eventually deplete pressure enough to release significant amounts of additional hydrogen from solution. How much of this hydrogen would then flow into the well, rather than escaping towards the surface, remains a further uncertainty.

Estimates of static, in-place, hydrogen volume in a fault zone in combination with pressure depletion assumptions can give an indication of the quantities of recoverable hydrogen. Assuming a fault zone of 2 km long, 1 km high and 70 m wide, with a hydrogen-rich migrating gas (80 % purity) hosted in rather tight rock (5 % porosity), the zone's indicative in-place hydrogen potential may be around 900 t. If continued fluid lifting could deplete pressure in the fault zone by 1,000 psi, around 100 t hydrogen may be recoverable (11 % recovery factor).

These are theoretical figures that require validation with real data. What is needed next are quantified reservoir properties from wireline logs and core, measured fluxes along the fault and an attempt at fluid lifting to demonstrate actual hydrogen recovery. Whilst QIMC's drilling programme remains scientifically intriguing, its commercial significance awaits further validation. ■



Geological map of Nova Scotia showing the location of QIMC's Advocate and Southampton hydrogen exploration licenses and the soil gas survey transects.

ILLUSTRATION: MODIFIED AFTER MURPHY ET AL. 2011

TECHNOLOGY

"We realised that no single node could solve all these challenges simultaneously"

Tom O'Toole – Stryde

Why shouldn't all nodes be the same?

STRYDE has launched a family of three nodes for land seismic practitioners who need more than one-size-fits-all recording

"THE NODES we produced until this point were tailored to fully autonomous recording," says Tom O'Toole from STRYDE when we meet up for a conversation. "You put them on the ground, leave them to record and retrieve them when the survey is done."

This concept has worked for many projects, which explains why STRYDE has been able to quickly conquer the onshore node market since its launch in 2019.

"But we did experience questions from our clients at the same time," says Tom, who has been working in technology development for STRYDE for over five years. "Three themes kept coming up. First, wireless node health QC is still seen as essential in some quarters. Second, GNSS is essential for time-synchronised seismic data, but reception can be challenging in certain onshore environments. Could we find a way to ensure timing accuracy in case GNSS signal gets lost? Third, seismic contractors are taking on an increasingly diverse range of survey types. Could we develop a more broadband sensor to better serve these varying needs?"

"Hearing this feedback, we realised that no single node could solve all these challenges simultaneously without being financially prohibitive. Instead, we chose to develop a family of three nodes that work together to address these combined challenges. The orange node continues STRYDE's heritage of fully-autonomous recording, with no radio comms and minimum cost. The white node includes wireless connectivity for node health QC. The blue node adds dual-clock technology to improve timing accuracy. All three are built on an evolved piezoelectric sensor and electronics platform that delivers broader sensing bandwidth from 0.5 to 200 Hz – it used to be 1 to 125 Hz – and lower noise and higher sensitivity," explains Tom.

"By simply walking or driving past the white node, you can check in on the device and perform a quick QC using a simple app running on your phone. We are already using drones for this type of work as well, which is especially useful in terrain where driving or walking are not easy options."



Tom O'Toole.

The blue node is the most technologically advanced, and focuses on the time synchronisation challenge. "Accurate time recording is fundamental to seismic acquisition," says Tom, "and without it you cannot reliably synchronise recordings between individual nodes. That's the reason why, to this day, cables are still used in some onshore environments."

"Our new blue node addresses this issue with its dual clock technology, typically allowing up to 7 days recording without GNSS. This facilitates operations in areas like marshes and dense forest that are characterised by difficult GNSS conditions, and even makes it possible to shoot nodal seismic in places like tunnels."

"With this family, we can match the node mix to the job: Orange where autonomous recording is sufficient and unit cost is the priority, white where real-time QC is needed, and blue where timing accuracy is critical. That flexibility means we can continue to make seismic acquisition accessible to industries where it is needed but has previously been out of reach," concludes Tom. "Not all nodes need to be the same."

Henk Kombrink

PHOTOGRAPHY: STRYDE



STRYDE's Halo node family offers tailored solutions for autonomous recording, wireless QC, and enhanced timing accuracy.

Chasing more subtle changes

A catch-up with Raúl Cova – geophysics manager at Qeye – about the changing quantitative interpretation market

"RESERVOIRS are getting tighter and dirtier, and on the back of that, the role of quantitative interpretation (QI) is evolving too," says Raúl Cova when we meet on Teams. "In other words, the signals are becoming more subtle, and a more advanced toolbox is required to identify the best opportunities. Where AVO used to be sufficient to identify and de-risk a prospect 20 years ago, today there are not so many of those opportunities left across the world."

One response to that is the advance of FWI, which has been and continues to be mainly used to get a better handle on velocity changes in the subsurface. "We use the results of FWI in our QI workflows," says Raúl. "More recently, we have also incorporated elastic FWI, which means that, in addition to P-wave velocities, the output now includes S-wave velocities and density data."

Raúl also identifies the incorporation of anisotropy, especially when it comes to amplitudes. "In AVO, amplitude anisotropy has never been used that much," he says, "because there was a line of thinking that the anisotropic difference was so small compared to the difference in amplitude versus offset. And to an extent, that is probably correct when you look at the 'good and relatively easy' prospects, but those days are over and we now see that anisotropic differences are at the same order of magnitude as the AVO signal. It makes more sense now to apply it," he says.

Another thing Raúl sees changing in the years to come is for the QI and (e)FWI disciplines to merge into one integrated service. "Somehow, they are still two separate worlds," he says, "but I think these will become one workflow in the next few years on the back of FWI processing costs coming down."

Henk Kombrink

PHOTOGRAPHY: QEYE

Raúl started his career with PDVSA in Venezuela where he worked in processing geophysics. He was then selected to participate in a one-year training programme that was facilitated by IFP in France to become a more rounded G&G professional. "This really taught me to include as many instruments as possible to better understand the subsurface," he says. Raúl moved to Calgary in 2012 to embark on a PhD in geophysics. He joined Qeye in 2019, also in the Canadian oil capital.

"Since the start of the company in 2012, we have always done the QI work in-house," says Raúl when we get to talk about the current business model. "But that is about to change," he adds, "because we have now entered a partnership with GeoSoftware to build a new QI platform (QeyeStudio) to produce a toolbox for our existing and possibly new clients to embark on themselves. We have had many requests over the years for such a product," he continues. "Now, we can say that this will be a reality!"



Raúl Cova (left) and Qeye co-founder Henrik Juhl Hansen (right) casually talking about the future of quantitative interpretation methods at the Qeye Calgary office in March 2026.

Finding hidden faults

How AI delves deeper into the structural geology of the Tern Field, UK North Sea

FOUND IN 1975 with the drilling of well 210/25-1, the Tern Field was one of the major Brent discoveries in the UK Northern North Sea. Over the decades, a total of 77 wells were drilled in the field – four exploration, four appraisal, and an impressive 69 development wells. Development well 210/25a-A49, and its sidetrack, A49Z, were completed in 2013 and 2014. The sidetrack was required after wellbore instability compromised the original well during hole-cleaning operations. Post-well analysis linked the instability to an unrecognised fault, one that had not been interpreted in the structural model and therefore had not been risked during planning. The operator’s end-of-well report, available through the UK National Data Repository, highlighted the need for more detailed seismic evaluation of the overburden in future

drilling campaigns. Although the sidetrack successfully navigated several interpreted faults and landed in the intended target, the incident underlined a broader issue: Traditional seismic interpretation can miss subtle structural features that nonetheless pose significant drilling hazards. As the operator wrote in the document, “When faulting is known, wellbore stability issues should always be planned for to avoid or reduce potential problems.” The seismic dataset used in this study, acquired in 1995, reflects the technological limitations of the time. Optimised for imaging Middle Jurassic Brent deltaic sands, the data lacked the resolution expected from modern acquisition. However, after running a series of Geoteric data conditioning tools and subsequently AI Foundation Network, the resulting AI Fault Confidence volume revealed a far more intricate fault network

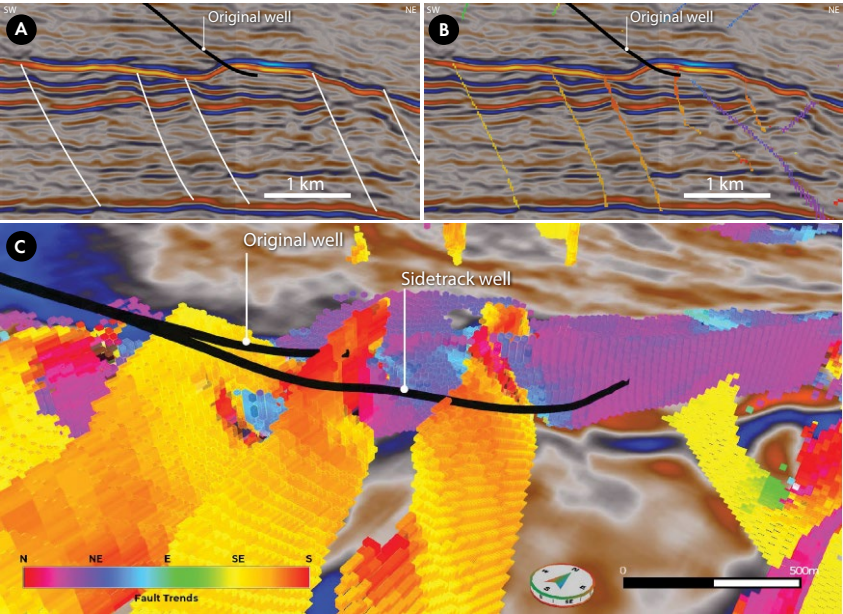
This article is the first in a series of articles with Geoteric in which the benefits of AI-assisted fault detection are demonstrated through real case studies.

than previously recognised. Distinct structural panels emerged, each defined by delicate fault linkages and subtle lineaments that traditional interpretation had overlooked. The AI Fault Confidence volume provided an unbiased detection of faults regardless of size, illuminating features that interpreters might have dismissed as insignificant. To test the effectiveness of the AI-derived interpretation, the original development well was subsequently imported into the project. The previously uninterpreted fault responsible for the wellbore collapse was clearly visible in the AI volume.

Further analysis showed why the fault had been missed. When coloured by orientation, two faults displayed contrasting trends: One parallel to the section, shallow and difficult to detect; the other perpendicular but near its tip, exhibiting minimal offset. Visualising these relationships in 3D revealed that the original well trajectory would have intersected an additional fault linkage point – another potential hazard. Ultimately, the AI Fault Confidence volume demonstrates how advanced interpretation workflows can improve drilling safety and reduce unplanned downtime. In the Tern Field case, nine days were lost between the collapsed well and the sidetrack. With clearer structural insight, such costly interruptions are far less likely, making the case for an AI-assisted fault detection exercise. ■

Henk Kombrink

SOURCE: GEOTERIC



A: Original fault interpretation. B: AI-assisted fault interpretation. C: 3D representation of AI-interpreted faults, showing that the original well intersected a linkage area where two faults meet that were both challenging to identify due to trend and minimal offset.

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MAKING ENERGY POSITIVE HISTORY BY 2030

The Keta Basin: Ghana's deepwater frontier edges back into focus

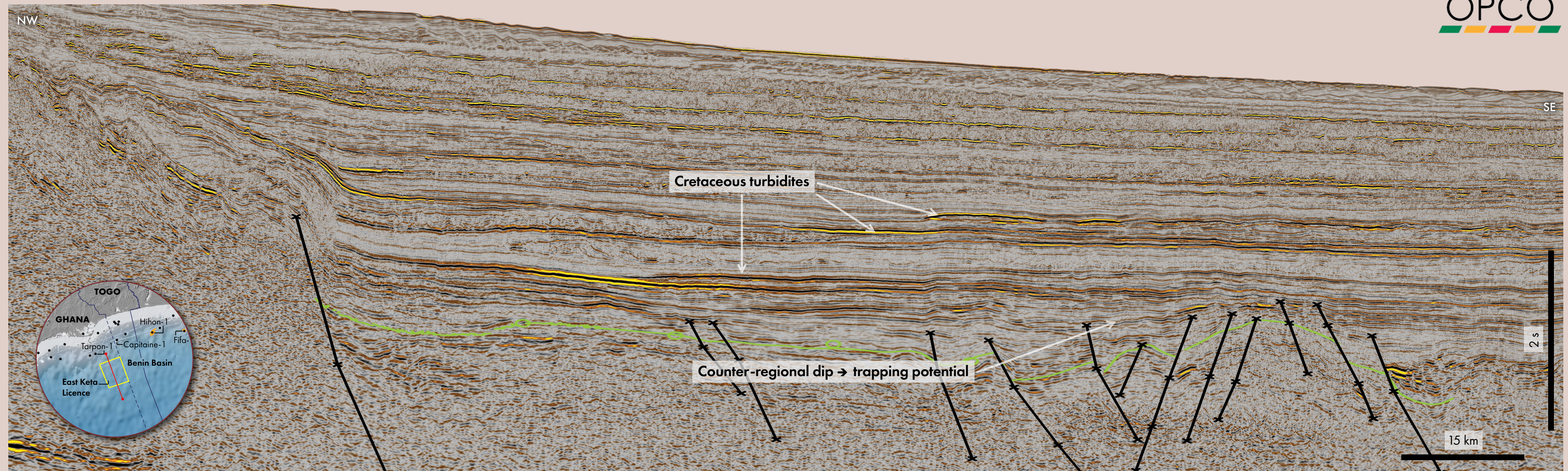
DAVE MCGURK, HERITAGE OIL EXPLORATION & PRODUCTION, GHANA

The underexplored Keta-Benin Basin is beginning to attract renewed interest as explorers reassess the hydrocarbon potential of one of West Africa's least drilled deepwater provinces. Whilst the region has historically sat in the shadow of Ghana's prolific Tano Basin, a growing body of geological evidence suggests the Accra-Keta section of the basin in particular may share many of the same elements that transformed

the Jubilee trend into a world-class petroleum province and brought the Transform Margin turbidite play to the fore.

Multiple encouraging indicators such as mature source rocks, stacked turbidites, high-quality reservoirs, and evidence of active hydrocarbon generation converge in the area as exploration trends towards ever deeper water.

Heritage Oil, through the "OPCO" joint venture, operates East Keta, the only licensed acreage in the Accra-Keta portion of the basin. With a "Frontier Potential with Frontier Risk" profile, the area presents a prime opportunity for a major to take a leading position. This article further describes why.



The Keta Basin – a basin with familiar geological DNA

THE EAST KETA acreage lies in the central portion of the Accra-Keta-Benin basin, formed during the Middle Cretaceous opening of the South Atlantic. Geologically, the basin shares some similarities with the Tano and conjugate Barreirinhas basins, but with its own subtle differences in maturation history and sediment supply due to its slightly earlier opening.

Sediment provenance is linked to the Volta River and associated deltaic systems, as outlined in the article from GeoPartners and Trois (GEO EXPRO Vol. 22, Issue 4, 2025), indicating that Keta reservoirs may be related to the high-quality reservoirs found in the Tano Basin.

The basin architecture comprises a progression of depositional environments, beginning with Lower Cretaceous syn-transform fluvio-deltaic and lacustrine sediments, overlain by Upper Cretaceous shallow-marine sands and shales, transitioning basinwards into deepwater slope-channel turbidite complexes. Together, these systems create multiple stacked reservoir intervals spanning from the Albian through the Tertiary.

THE PETROLEUM SYSTEM: INCREASINGLY DIFFICULT TO IGNORE

Lessons from historical wells provide evidence of the key elements of the petroleum system. At least two mature Cretaceous source intervals are expected across the basin, namely a Lower Cretaceous lacustrine shale sequence and overlying Turonian – Coniacian marine shales.

TOC values are encouraging, reaching up to 5 % in some intervals, and kerogen types are predominantly

oil-prone Type II and mixed Type II/III. In addition, thermal modelling indicates that much of the Upper Cretaceous section sits within the oil maturation window, while deeper Lower Cretaceous intervals may have entered the gas window.

Timing also appears favourable. Structural inversion is interpreted to have ceased during the Campanian, suggesting hydrocarbon generation post-dated major trap formation, critical for effective charge retention.

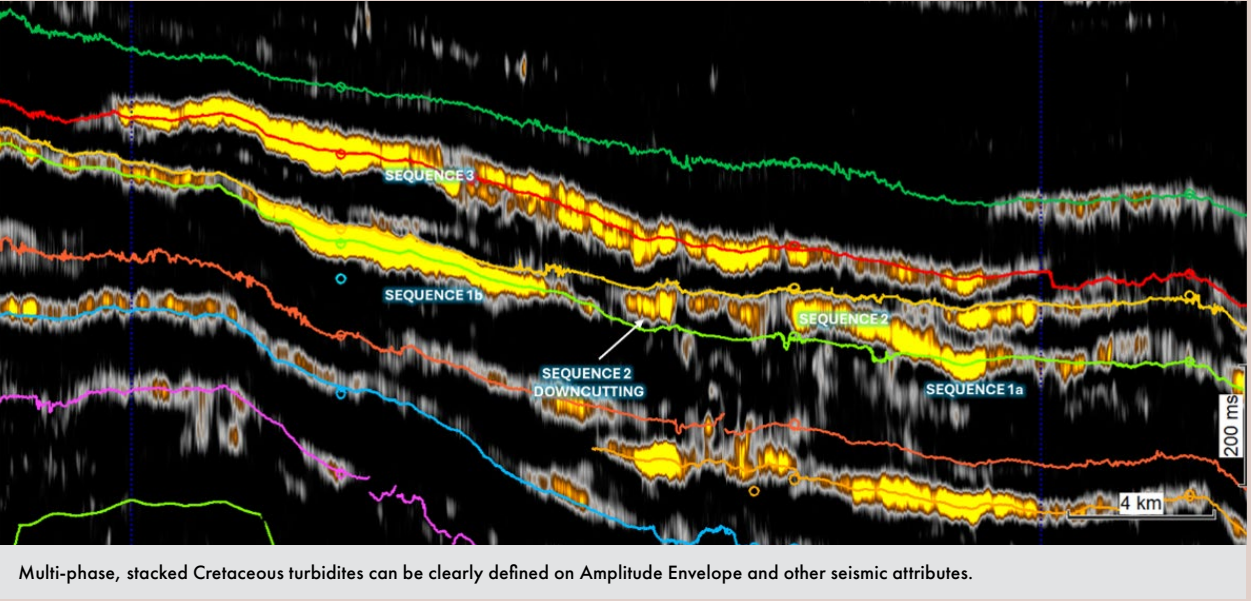
RESERVOIR QUALITY

Despite limited drilling, reservoir presence has repeatedly been confirmed in the Keta Basin. Deepwater wells encountered an array of Albian shallow marine sands, Upper Cretaceous turbiditic sandstone intervals and Miocene fan systems, with porosities ranging from 19–30 % and permeabilities locally exceeding 500 mD. These reservoir parameters compare favourably with successful Atlantic Margin plays elsewhere in West Africa and South America.

A HISTORY OF NEAR MISSES

The basin contains multiple sealing horizons, particularly within Cretaceous and Tertiary shale packages. Both structural and stratigraphic trapping styles are interpreted, though stratigraphic pinch-outs and combination traps are expected to dominate in the post-rift section.

The Keta Basin’s exploration history is best described as a series of near misses. Historical drilling has repeatedly confirmed key elements of a working petroleum system, providing evidence of mature source rocks, excellent



quality reservoirs and hydrocarbon shows, but without a commercial breakthrough to show for it.

Tarpon-1 encountered high-quality Miocene sands with porosities approaching 30 %, although the interval proved water-bearing and the deeper Cretaceous objectives remained untested. Capitaine-1 and Fifa-1 both confirmed good-quality Albian and Cretaceous reservoirs alongside mature source rocks, reinforcing the view that trap integrity and migration pathways remain the principal exploration risks. Most significantly, Hihon-1 recovered oil and condensate samples from Lower Cretaceous sands, including waxy 32° API crude, confirming an active Cretaceous petroleum system within the basin.

WHY INTEREST IS RETURNING

Exploration momentum in frontier basins often returns when technology catches up with geology. That may now be happening in East Keta on the back of a seismic reinterpretation exercise that has identified the presence of large slope-channel systems within the Campanian succession. The presence of combination structural-stratigraphic traps, similar to those observed across the margin, will likely be the key factor in determining the future drilling success of these turbidite fairways.

THE EAST KETA LICENCE: THE SCALE REQUIRED TO MOVE THE NEEDLE

With water depths ranging between 2,500 and 3,500 m, the East Keta licence lies firmly within the modern ultra-deepwater exploration arena. Analogous developments elsewhere in the Atlantic Margin demonstrate that such settings can be commercially viable when scale and charge align.

Fortunately for Heritage and the OPCO JV, the East Keta licence hosts prospectivity of the scale required to make such a frontier area attractive. Seismic interpretation

indicates two main prospective sequences in the Miocene and Upper Cretaceous, with the latter showing the familiar multi-phase slope channel turbidite complexes with direct access to source rocks within the oil window. Additional prospectivity lies in the deeper Cretaceous in counter-regional combination traps.

The scale of the turbidite complexes is difficult to ascertain on the available wide-spaced 2D data, yet mapping within the Upper Cretaceous shows three parasequences covering a significant portion of the licence with multi-billion barrel potential on their own.

Despite the growing optimism however, East Keta remains a frontier exploration province. The basin as a whole remains lightly drilled, with no modern deepwater well having fully tested the lower slope play concepts.

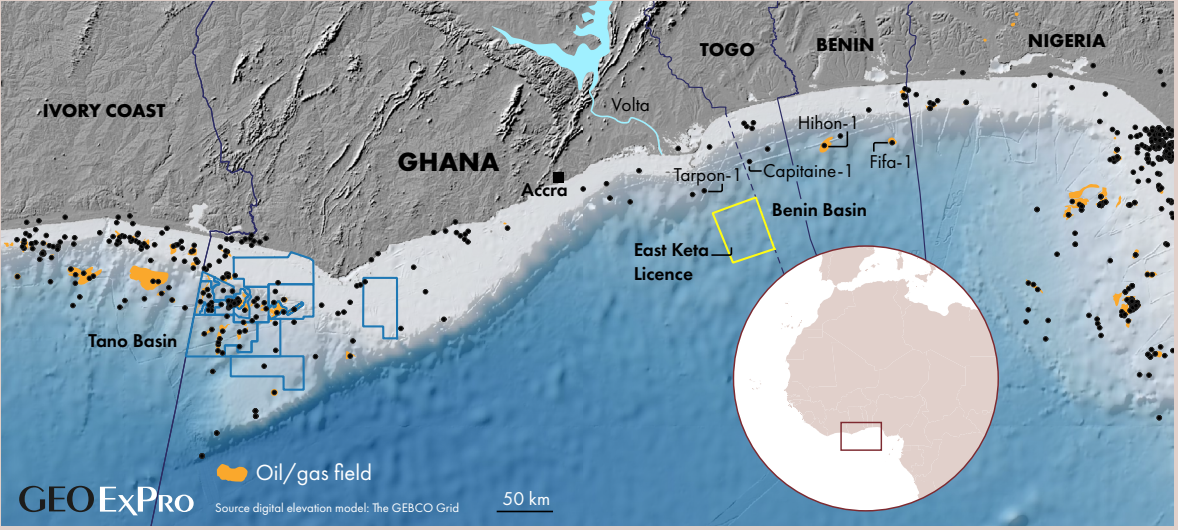
Many of these challenges would be addressed with modern, high-resolution 3D seismic data. While Heritage currently has access to a sparse 2D grid, the scale of the identified prospectivity is very encouraging.

A FRONTIER WORTH WATCHING

For the industry, the Keta Basin represents the kind of opportunity that periodically reshapes regional exploration narratives: a basin long overlooked, technically challenged, but increasingly difficult to dismiss.

The ingredients of a working petroleum system are present; reservoirs are proven and source rocks are mature. Oil has been recovered. What remains unanswered is whether the basin contains the scale, trap integrity, and migration efficiency necessary for commercial success.

In an era where the big explorers are revisiting overlooked Atlantic Margin acreage, such as TotalEnergies in Liberia’s Harper Basin, with fresh seismic tools and renewed appetite for frontier potential, the Accra-Keta basin may yet emerge as one of West Africa’s more exciting deepwater frontiers.



INSIGHTS

“Combining a field-based exercise with hands-on digital model building is rarely attempted in the industry”

Lilly Walker – Rock Flow Dynamics



Subsurface Evangelising – Preaching to the Choir

Sin, Saviour and Salvation

JUAN COTTIER, MMBBLS SUBSURFACE CONSULTING

I WAS a board member of a small oil company, and we were sent on public relations training. My assessment included the following: “Under no circumstance should Juan be allowed to talk with either the Press or the Public”. It continued: “He has an inability to hide his contempt for those who do not share his enthusiasm for geology or the oil industry”.

The readers of GEO EXPRO are neither the press nor the public, so we’re good.

We work amidst mind-boggling contrasts. Short timeframes, slashed budgets, skeleton teams - and then we’re asked to locate a half-billion-dollar semi-sub, drill a 5 km hole, deploy hundreds of people across dozens of companies, at a cost of a hundred million dollars. Given a fair wind and sun on our backs, that choice of ours could generate five, or fifty billion dollars of profit and tens of thousands of jobs.

THE SIN: We risk becoming less our authentic innovative selves and more part of a process. A worn and habituated cog in a pressurised machine. We protect ourselves against overbearing expectations with repetition, routine, formula, and pre-defined workflows. Companies protect themselves with “best practice” and individually we settle for groupthink and playing it safe.

Each field, licence or asset has a unique set of subsurface characteristics demanding unique viewpoints. We are not pattern-finding monkeys – we are unique, creative, passionate geoscientists.

If the Sin is BEWARE, then what is our Saviour?

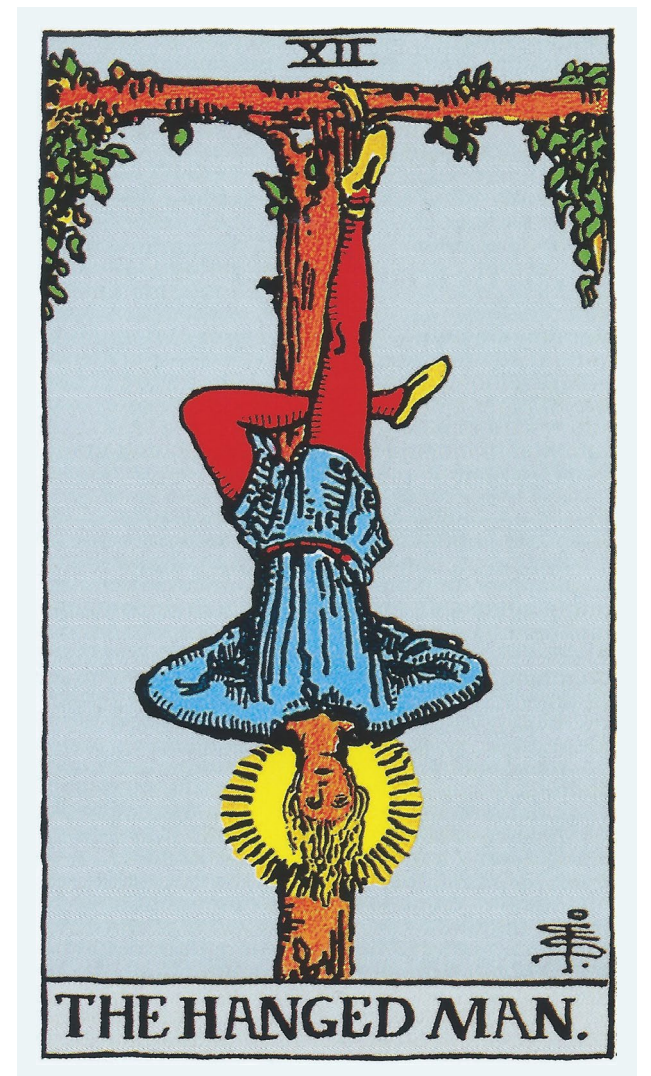
THE SAVIOUR: Easy! It’s us! Our curiosity and individuality. Curious enough to look at a problem differently.

The twelfth card of the Tarot is the Hanged Man, suspended from a tree – not in torture, but calm and composed, haloed in enlightenment. The imposed new perspective gives new insight. Easy to say, harder to do. The Hanged Man isn’t tortured, but he is uncomfortable. Being different, doing things differently, is uncomfortable. So, we need to be “comfortable being uncomfortable”. We need to be bold.

Be curious. See differently. Have ideas. Be bold. Remember: In the land of the bland, the one-idea’d man is King.

But it’s not a free-for-all, to quote Tommy Norris in the brilliantly bonkers TV show LANDMAN: “You have to know the rules of the game to bend them. And you really gotta know ‘em to break ‘em”.

THE SALVATION: We have thought differently, tried differently, acted differently. Results are unique. Probably bet-



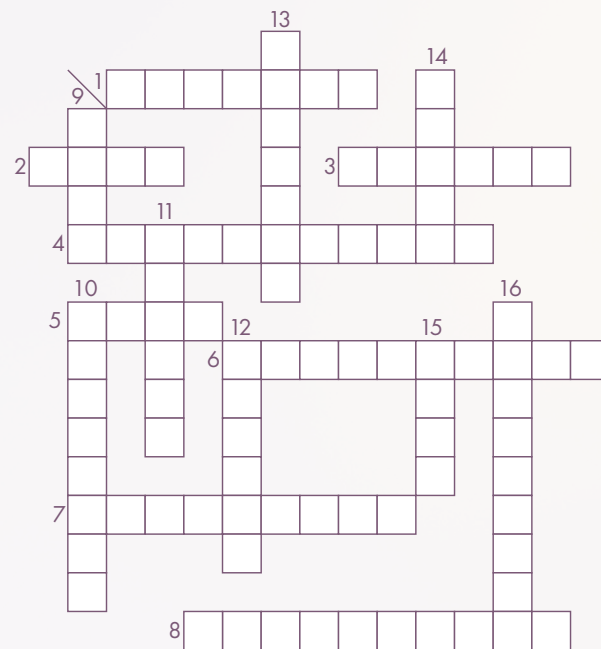
The Hanged Man card from the Tarot's Major Arcana.

ter. We have tested ourselves, challenged our team, shifted perspectives, and introduced innovation. And we know we have, and that feels great. Evolutionary improvement of the machine, one tiny act of individual creativity at a time, from that same multitude of unique, creative, passionate geoscientists.

Be aware. Be bold. Be better. ■

This article is a print version of a 2026 EAGE Annual Conference Presentation

CROSSWORD



GEOExPro

Across

1. Which Canadian province hosts Islander Oil's Waulsortian mud mound play?
2. What Libyan basin hosts the prolific Intisar oil fields?
3. In which sea will Greece's first offshore well in 45 years be drilled?
4. Which geothermal project in Nevada is at the centre of a debated reserves report?
5. In what rock type are the storage caverns constructed for the Spindletop helium facility?
6. What German geothermal project uses deep closed-loop subsurface wells?
7. What rock coating mineral forms a dark varnish sometimes mistaken for oil seeps?
8. What type of fault-related folding develops above a weak décollement?

Down

9. What Canadian company is drilling hydrogen wells along the Cobequid fault?
10. Which MSGBC field lies just north of The Gambia's maritime border?
11. Which country is the only significant helium producer in the EU?
12. Which formation unexpectedly appeared in Shell's deep Libyan well instead of the Nubian Sandstone?
13. What rock type is targeted for Deep Fission's borehole reactor emplacement?
14. Which Angolan basin contains prolific post-salt Oligo-Miocene channel systems?
15. Which Canadian Institute now operates Imperial Oil's former heavy-oil research lab?
16. Which Permian lithostratigraphic unit hosts the unexpected Wolin oil discovery?

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Why physical collaboration matters in a digital subsurface

Building advanced systems is meaningless if you ignore the human architecture required to run them

DAN AUSTIN, SEKAL



WILL BE HONEST: I was sceptical about bringing EAGE to P&J Live in Aberdeen, Scotland, this year. Historically, out-of-town campus venues risk fracturing a conference. You fight the traffic, you miss the organic energy of a city centre, and you worry the layout will split the audience into isolated silos. But setting out for the Granite City, still the operational base of the UK North Sea operator landscape, that scepticism evaporated the moment I hit the Icebreaker. The air was immediately thick with familiar faces, carrying an energy that felt less like "business as usual" and more like a collective statement of intent.

In an era dominated by peak uncertainty, remote workflows, and digital connections, 6,000 people still chose to make the journey. We stood shoulder to shoulder on an exhibition floor where service companies brought their

absolute best: Impeccably turned-out booths, tight technical programs, and genuine platforms for collaboration.

The true buzz of the week wasn't basic machine learning or large language models; it was agents – autonomous workflows capable of executing complex, multi-step reasoning. Based on what I witnessed on the floor and in the technical sessions, we have officially moved past the naive phase of "what can AI do?" and entered a highly pragmatic era focused squarely on what we should do and how we should execute it.

Yet, as we rush toward this agentic future, a critical truth emerged from the peer-to-peer sessions – building advanced systems is meaningless if you ignore the human architecture required to run them.

This is exactly why physical conferences and meetings still matter in an increasingly digital world. They provide

the definitive space for true human interaction and high-stakes debate about what we are doing and why – an environment that touches on the full spectrum of operational, economic, and ethical issues. While the comprehensive list of takeaways is exhaustive, three main themes stand out as the pillars defining our industry's path forward.

First of all, there is empathy in design. We have to build AI agents that respect and elevate the hard-won intuition of senior geoscientists, rather than treating human expertise as a data bottleneck to be bypassed. Secondly, we need pragmatic guardrails that ensure the transition to autonomous workflows is handled in a transparent, human-verifiable way that actively safeguards operational and geological integrity. And finally, collaborative problem-solving is essential by recognising that the ultimate goal of an AI agent is to free up human capital, allowing professionals to focus on the highest-value, most complex challenges facing global energy security.

This brand of pragmatism highlights that geoscientists are not waiting around for massive software conglomerates to hand them polished, one-size-fits-all tools. We understand the limitations of top-down software deployment in a domain built on ambiguity and specialised interpretation.

Instead, by developing and maintaining a highly engaged, collaborative subsurface community, geoscientists are actively building their own agentic future from the ground up. We are proving that the future of subsurface intelligence will not be dictated to us – it will be co-authored by us. ■

PHOTOGRAPHY: GEO EXPRO

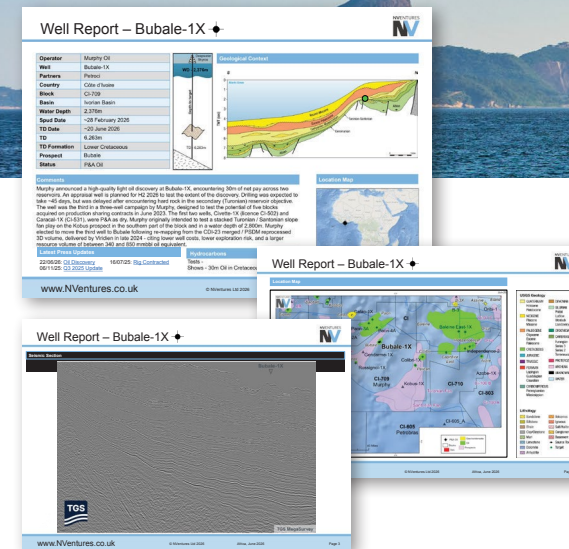


Delegates arrive at P&J Live, Aberdeen.

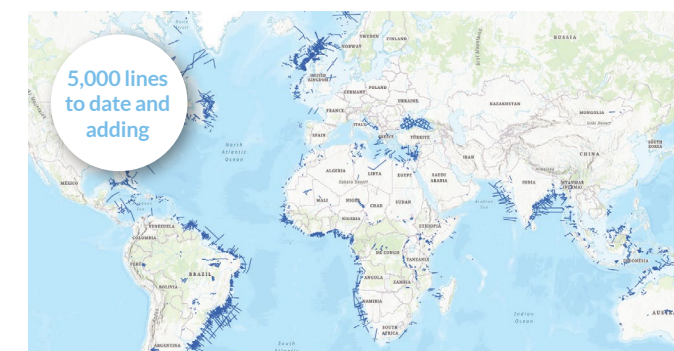
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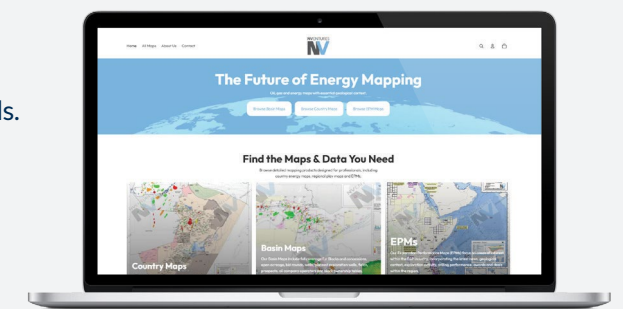
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Field trips and software don't mix very well – or do they?

With a solid preparatory effort, a team of passionate geoscientists managed to provide an outdoor exercise that included a digital model-building element at the same time, allowing participants to implement and check the impact of their field observations directly

"IT WAS a new thing to us," says Lilly Walker from RFD when we meet on what is her Wednesday afternoon in Perth, Australia. Lilly is a geologist and joined RFD's Australia team a little more than a year ago. "Combining a field-based exercise with hands-on digital model building is rarely attempted in the industry."

"You have to lug laptops along, need data to start with, and you need software that does the job quickly, such that people are not sitting around waiting," she says. "Given the mix of backgrounds

amongst the participants, there was another reason why we needed short run times and some pre-loaded relevant data; we didn't want reservoir engineers waiting till the end of the week for their dynamic model. We worked hard to get that right."

"But we made it happen," continues Lilly. Mark Bentley from Langdale23, who led the field exercise that was pulled together by Mark Riley from Precipice Consulting, split up the group of participants – a diverse group of geophysicists, petrophysicists, geolo-

gists and reservoir engineers from Santos – into different fluids – one dedicated to oil, one to gas, and a heavy oil one. "That made us all look at the outcrops in different ways," says Lilly.

Mark Bentley always says that if you can sketch it, you can model and simulate it. "And that is exactly what we tried to do," says Lilly. And that all with the help of props such as a shower curtain for petrophysical log responses, and seismic goggles to think about scale. In a way, the modelling exercises in the evenings made the group

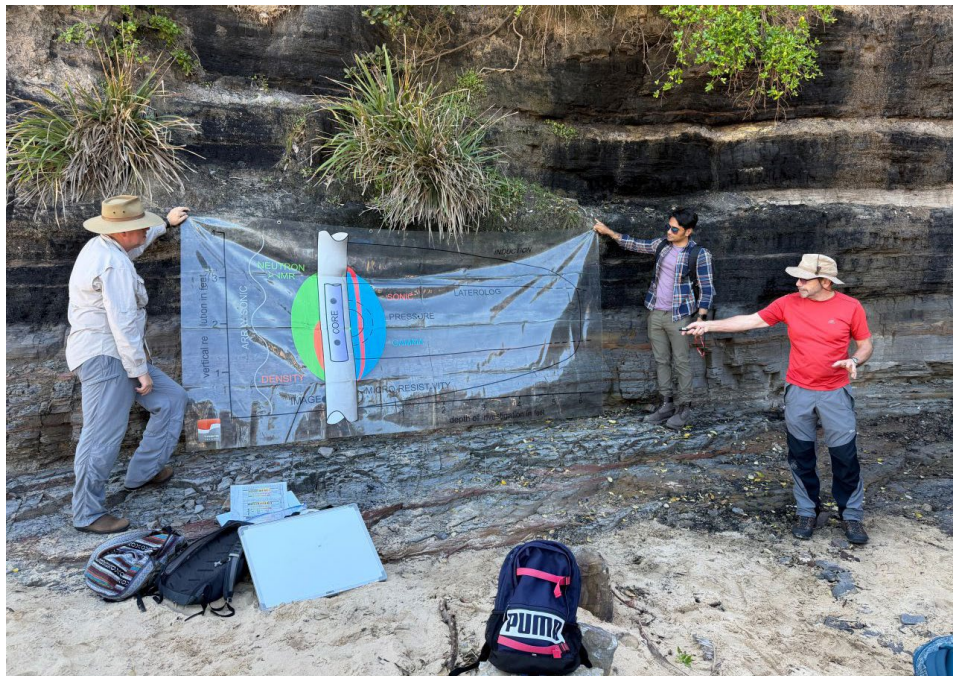
come together more: "Leaning into their instincts, geologists went full steam ahead in the field with classifying a multitude of lithologies at the outcrop, whereas the engineers were thinking more about flow units. The best discussions began when we got into our groups to challenge that behaviour and start thinking like the fluid."

"Immediately seeing the effects of the observations made in the field being reflected in how a reservoir model is built, how the sands are connected, and how the fluids are being produced from those was instrumental to better understand the impact of the decisions we make in our daily routines," adds Lilly.

"Spending time away from the office in a field setting really helped to encourage these discussions, and the software element builds the bridge to our 'normal' jobs at the same time, making it all the more relevant. It also made people from one discipline use the software tools that they normally don't use, which further stimulated understanding of each other's expertise." Maybe field trips and software exercises are a good mix after all. ■

Henk Kombrink

PHOTOGRAPHY: LILLY WALKER



How a shower curtain can be quite handy in the field explaining the vertical resolution of logs, seismic and core.

Can cement integrity be predicted before it becomes a containment risk?

A team of scientists at Elemental Energies is tackling this question through a novel dynamic modelling approach

ONCE a depleted oil or gas field is selected as a candidate for a possible CO₂ storage project, a first-pass well integrity study is often carried out to assess and rank wells according to the containment risks they may pose to the project. This can quickly identify the most problematic wells, for instance, where a required cement barrier is missing or known to be inadequate.

"No amount of modelling can redeem these obviously problematic wells," says James Hanson, a researcher at Elemental Energies with a background in physics and computational chemistry. "Instead, we focus on wells whose barriers have passed the standard decommissioning assessment but require further evaluation of the pressure and temperature conditions expected throughout the CO₂ storage project," James explains, "as well as the potential chemical effects of contact with the CO₂ plume. They may look unassuming at first glance, but they might be harbouring a risk. That is where our modelling work can make a real difference."

FIRST PRINCIPLES

James teamed up with Maria Chavez and Juan Chavez to build an entirely new modelling approach based on first principles. Together, they form a team that provides critical expertise from three different key disciplines.

"CO₂ injection changes reservoir conditions, causing the cement behind casing and the surrounding annular system that prevents the upward migration of CO₂ to evolve both mechanically and chemically," says Juan,

a geomechanics expert at Elemental Energies. "That is the process we want to model: a dynamic mechanism in which chemistry, geomechanics and fluid flow evolve together."

"Our drive is to innovate," says numerical modelling expert Maria, "and we felt that there is a need to do this in the CCS space. What we often come across in the literature is the assumption that leakage through cement is modelled by arbitrarily assuming a fixed leakage pathway. That approach is not sufficient to accurately map what happens in the subsurface, because the formation of a leakage pathway is a dynamic process. That is why we are integrating all these aspects, chemical and mechanical, into one tool."

LONG TERM

"This will also allow us to model and predict a set of scenarios when it comes to how a well will behave once injection has stopped," says Maria. "And not only for legacy wells, but maybe even more importantly, for the injection wells themselves. At the end of the day, it is the injection well that will experience the biggest change in reservoir conditions."

"We have already seen regulatory requirements moving towards the need to better predict leakage risks over hundreds of years of time, following the cessation of injection. Our approach is tailored to addressing that," James adds. The team is now working hard to finalise the software and plans to bring this numerical modelling work to market as a specialist service. ■

Henk Kombrink



Maria Chavez.



James Hanson.



Juan Chavez.

The inconvenient truth about pore pressure prediction in unconventional plays

Some reasons why traditional normal compaction trendline workflows undermine pore pressure prediction in shale plays, and why basin-specific, physics-based adaptations are essential for reliable pressure prediction

EWERTON ARAUJO, SUBSURFACE ALLIANCE

PORE PRESSURE prediction has always been central to safe drilling and well planning. But in the last two decades, during which thousands of wells have been drilled across US unconventional basins, the industry has learned a hard truth: Unconventional basins often carry complex burial histories, gas effects, thermal anomalies, and late-stage erosion. These factors distort the assumptions behind log-derived normal compaction trendlines (NCTLs), the backbone of most pore pressure workflows. Classic NCTL-based techniques rely on identifying deviations from a “normal” porosity – depth relationship to detect the onset and magnitude of overpressure. This works well in basins like the Gulf of Mexico, where compaction is dominated by progressive burial and undercompaction.

But onshore unconventional plays frequently violate these assumptions. Gas-charged mudrocks, uplifted sequences, and eroded basins introduce

non-unique porosity-stress relationships, making trendline-based predictions unreliable without modification. Here are three examples from three different basins demonstrating that unconventional pore pressure prediction is not a plug-and-play exercise.

HAYNESVILLE SHALE

The Haynesville is a deep, hot, gas-bearing system with pore pressures reaching 18 ppg and temperatures near 350° F. Gas effects distort acoustic velocities, making uncorrected acoustic-based methods misleading. To overcome these challenges, Zhang & Wieseneck (2011) suggest building basin-specific correlations for density and overburden, correcting compressional velocity using shear velocity (Castagna’s mudrock line), and honoring first-principles compaction behavior. This workflow resulted in a simple, reproducible workflow that respects physics and performs reliably across the play.

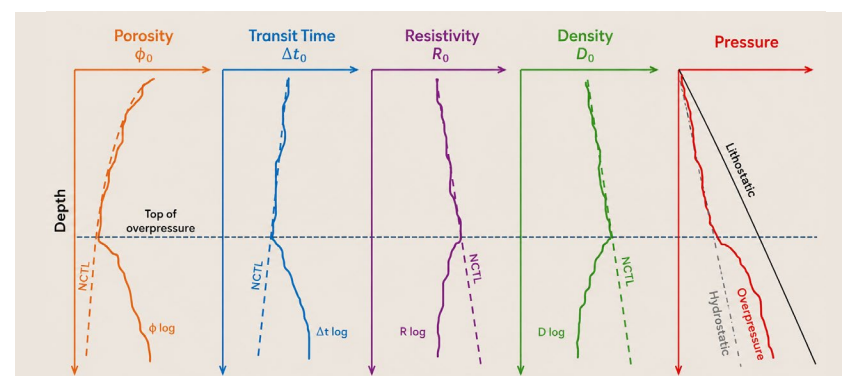
DELAWARE BASIN

Late-stage erosion in the Delaware Basin produces unloading, meaning porosity no longer maps uniquely to effective stress. Conventional NCTLs fail because the rocks “remember” deeper burial. To overcome these difficulties Lockhart et al. (2023) proposed a modified approach through applying Bowers-style unloading relationships, incorporating eroded thickness into effective-stress reconstruction, and modelling drained vs. undrained responses using poroelasticity (Wang, 2000). Their method not only matched well data, but also explained sub-hydrostatic pressures at the top of drained zones, an outcome physically consistent with the basin’s history.

NIOBRARA SHALE

A recently proposed model for the Niobrara (Orozco & Aguilera, 2021) claims to estimate pore pressure using “in-situ” Biot coefficients. However, the method yields Biot values greater than 1, which is a clear violation of poroelasticity theory (Wang, 2000) and contradicts both laboratory and numerical evidence. In contrast, Yale et al. (2018) offer a first-principles-based workflow that honors the geological basin history by using corrected velocities according to lithology and porosity using rock physics, applying a Biot coefficient within physical limits, and integrating thermal maturity with pore-pressure trends. Although the approach is robust, it still requires careful petrophysical calibration.

SOURCE: SUBSURFACE ALLIANCE



Normal Compaction Trendlines techniques applied to well logs to identify and quantify overpressure zones.

What else is hiding in your reservoir brine?

Gold continued the discussion.

Germanium shows how little we still know

ISTVÁN NAGY-KORODI, CONSULTING GEOLOGIST



LITHIUM changed the way many people look at produced water. It forced us to admit that reservoir brines are not simply waste streams. They are geological fluids that have spent millions of years interacting with rocks. Once that idea is accepted, another question naturally follows.

What else is dissolved in those fluids? One element that rarely enters the discussion is germanium. Unlike lithium, germanium is not associated with batteries. Most people never think about it at all. Yet, modern society depends on it. It is used in fibre-optic communication, infrared optics, satellites, semiconductor devices and high-efficiency solar cells. Without germanium, many technologies we consider ordinary simply would not function.

The interesting part is that germanium not only occurs in ores. It can also be transported by fluids. Geologists have known this for decades. Under elevated temperatures and suitable chemical conditions, germanium becomes mobile in hydrothermal systems. It commonly follows silica-rich fluids and is often associated with zinc-bearing deposits, volcanic environments and

deep basinal fluids. Salinity, temperature and fluid-rock interaction all influence its behaviour. None of these conditions is unusual in sedimentary basins.

Most petroleum reservoirs have experienced long and complex fluid histories. Formation waters rarely remain unchanged after burial. They dissolve minerals, mix with other fluids and migrate along faults and fractures. Every stage leaves a chemical fingerprint in the produced water. Germanium may simply be another part of that fingerprint. The problem is that we rarely analyse for it. Routine produced-water programmes focus on scaling, corrosion and production chemistry.

Calcium, barium, strontium, sulphate and iron receive attention because they affect operations. Germanium does not. In many cases, it is not included in the analytical package at all. If nobody looks for it, nobody reports it. That does not necessarily mean it is absent.

Whether germanium could ever become an economic product from produced water is a different question. In most reservoirs, the answer will probably be no. Concentrations are likely to be low, and extraction would rarely make sense on its own. But geology is not always about a single element. Since germanium sells for orders of magnitude more per kilogram

than lithium, even concentrations of 50–100 µg/L may contribute meaningfully to project economics if recovered alongside lithium, gallium, boron, rubidium, or caesium.

The petroleum industry has spent decades treating produced water as something to separate and dispose of. That made sense when hydrocarbons were the only resource we were looking for. Perhaps the next important discovery in produced water will not come from finding more lithium. Perhaps it will come from realising that we have only been measuring a very small fraction of what these geological fluids actually contain.



SOURCE: FAWWAZMEDIA VIA ADOBE STOCK

The supermajors are scaling up, are you?

Driven by advances in seismic acquisition, processing and interpretation, and the strategic need to tie up an entire play fairway before the spoils can be divided, the supermajors are picking up large tracts of acreage. West Africa, in particular, is centre stage for this new strategy, where the biggest oil companies are seeking basin-scale dominance

PETER ELLIOTT, NVENTURES



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IN THE NOUGHTIES and 10s, wildcat exploration, the fierce frontline of the E&P sector, was characterised by small, ambitious pioneers, testing new plays in large basins, with the large caps and majors usually playing the role of “fast followers”. These outfits took up hugely ambitious positions, funded early-stage exploration, and traded their reputation and shareholders' dollars on a prospect's chance of success.

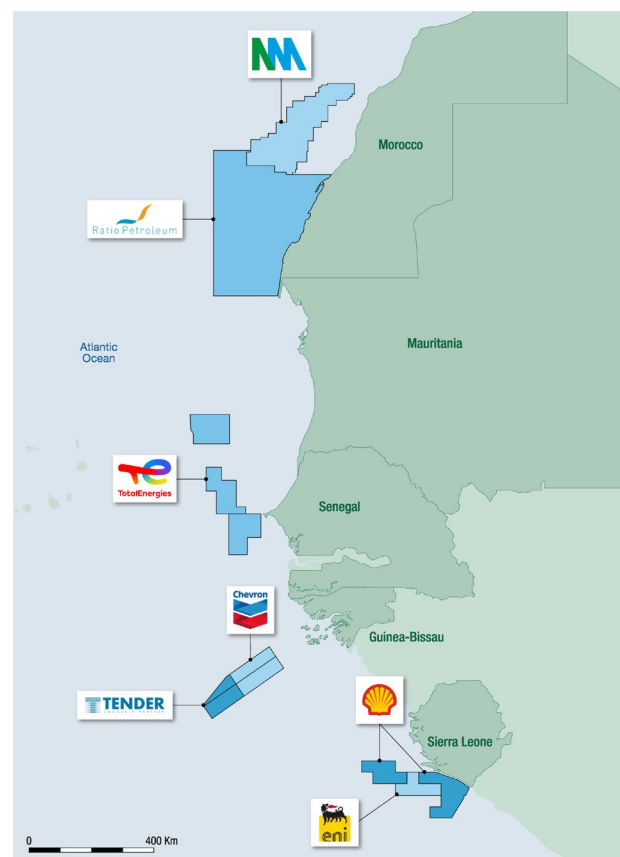
Whilst the industry waits with bated breath to welcome back this latent cohort of plucky pioneers, the majors and supermajors have taken matters into their own hands. The “supers” have taken large multi-block reconnaissance and PSC positions in frontier basins to establish basin-scale footprints where they plan to invest. This strategy allows well-resourced companies to screen whole basins before committing, or not, to intense exploration campaigns.

ESTABLISHING THE NEW ORDER

Early signs of this new approach were flagged in the MSGBC in 2016. NewMed took a large position at Boujdour in 2016, followed by compatriot Ratio in 2018 with a large PSC at Dakhla Atlantique, both offshore southern Morocco. In 2018, TotalEnergies chose to push the envelope on the Sangomar / FAN trend, with a large PSC over rufisque deep and ultra deep offshore, an early sign that the supers wanted to explore basins, not blocks.

Fast forward through an oil price crash, poor investor sentiment on the back of climate change fears, a global pandemic, and the prize is back in focus in the 2020s. The biggest oil companies are revving up new ambitions with basin-scale access once again. What appears to connect this new exploration theme is competition, scale, and capturing the top of the creaming curve early with the largest prospects. This represents a pragmatic shift to affordable work programme commitments through reconnaissance geology and geophysics, before major drilling commitments.

In 2024, Petrobras were reported to be evaluating around 50,000 km² offshore Côte d'Ivoire, covering at least



eight deepwater blocks. An award has yet to materialise, while Murphy did take a major 5-block position with full PSC terms and a three-well commitment between the Baleine and Baobab trends. The industry awaits the results of their third wildcat there, Bubale -1X.

This signalled the start of a major renaissance across the transform margin, sparked in part by ENI's billion-barrel blockbuster at Baleine and the availability of country-wide exploration acreage. Eni itself took a large 7-block position to protect the wider Calao trend soon after Baleine was discovered.

SOURCE: NVENTURES

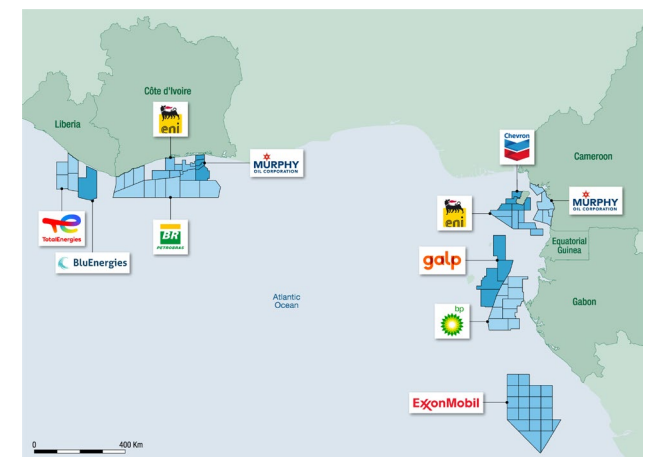
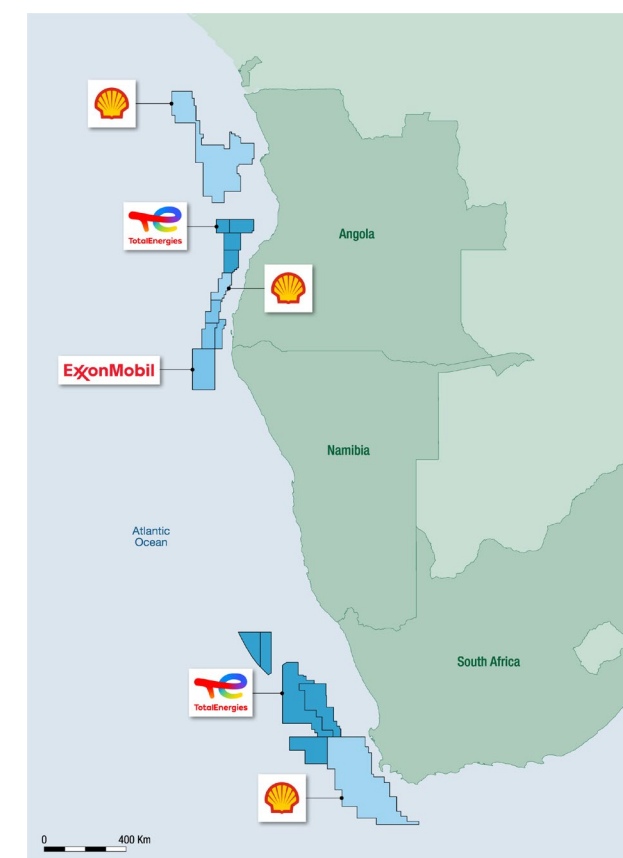
Liberia took the lead next, with exploration junior Blu Energies working on a new plan to build a large exploration position that would fit the super's new strategies, with low capital exposure, utilising reconnaissance-style commitments. TotalEnergies saw the model, saw the data, and, perhaps galvanised by success in ultra-deepwater Namibia at the Venus Basin floor fan play, concurrently signed up a further four blocks to seal a major PSC to the west of the Harper Basin.

The work programmes on these reconnaissance-style multi-block areas and joint application deals appear to hinge mainly on reprocessing seismic, applying modern QI techniques, and taking time to develop a new petroleum play fairway model for these high-risk offshore basins.

Sierra Leone, with a similar recent history to Liberia for intense but short-lived exploration campaigns in the 2010 to 2015 era, saw an opportunity to build on this renewed appetite for frontier acreage. After assigning a large PSC to FA Oil, the promotional data room efforts of PDSL attracted ENI to take a 5-block spread over the heart of the offshore basin, under Reconnaissance Licence terms.

PROTECTION ACREAGE

Whilst ENI, Chevron and Galp are taking up large swaths of acreage in Equatorial Guinea, Murphy continues its resurgence in West Africa with four contiguous blocks awarded with full PSC status offshore Cameroon.



Offshore Gabon, bp has taken a reconnaissance-style agreement over ten blocks in the North Gabon Basin, extending exploration efforts back up to the borders with São Tomé and Equatorial Guinea. In the South Gabon deepwater basin, ExxonMobil has signed an MOU to evaluate twenty contiguous blocks, with preferential rights to negotiate PSC terms should their mapping reveal significant potential.

The upstream regulator in Angola has made great efforts in recent years to help the country attract further investment for frontier exploration. After the halcyon days of super-production with the supermajors, ANPG see a clear opportunity to encourage new exploration efforts with large exploration tracts, large contiguous modern datasets and improved fiscal terms for high-risk exploration.

THE PRICE OF DOMINANCE

There are clearly pros and cons to this burgeoning tradition of large-scale basin-wide exploration. For the supers, these licences provide an opportunity to screen entire basins whilst keeping a competitive advantage. Work commitments can be relatively lenient, moving drilling commitments into the future and allowing for detailed G&G work. Both the government and oil companies can take advantage of existing good quality multiclient 2D and 3D, which otherwise would be gathering dust.

Conversely, governments, regulators and NOCs, whilst encouraging new investment, have to acknowledge that major tracts of acreage are effectively locked up. Whilst reconnaissance-style agreements can be non-exclusive, the door may appear tightly shut to smaller, low-budget players looking to pick up on new plays.

Will the scaled-up blocks lead to scaled-down wildcat drilling over time? The reality is that large tracts of frontier acreage are now waiting for expensive exploration campaigns from a shrinking community of large oil and gas exploration firms. But one thing is for sure: As the world comes to terms with its reliance on the natural resources of the subsurface, demand is set to remain.

Top-Down and Bottom-Up

An integrated petroleum systems modelling workflow for exploration

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

AS EXPLORATION challenges become increasingly complex, two complementary workflows have emerged as the foundation of effective petroleum systems studies: bottom-up basin modelling and top-down fluid systems analysis.

The traditional bottom-up approach reconstructs the geological evolution of a sedimentary basin through time. The principal strength of bottom-up modelling lies in its ability to quantify geological processes and predict source rock maturity, hydrocarbon generation timing and regional migration trends, especially in frontier settings.

However, predictive confidence decreases significantly when modelling secondary migration, trap filling and hydrocarbon distribution because these processes depend on complex subsurface heterogeneity and fluid flow

behaviour that remain difficult to characterise accurately.

Consequently, where bottom-up models often provide robust regional trends, they are less reliable in predicting fluid properties and prospect-specific charge behaviour.

The top-down approach begins from the opposite direction. Rather than predicting hydrocarbon distributions from geological history, it starts with observed fluid properties. These observations are then used to infer source rock characteristics, migration pathways, fluid mixing, thermal maturity and post-charge alteration. As such, it allows reconstruction of the geological processes responsible for their present-day distribution.

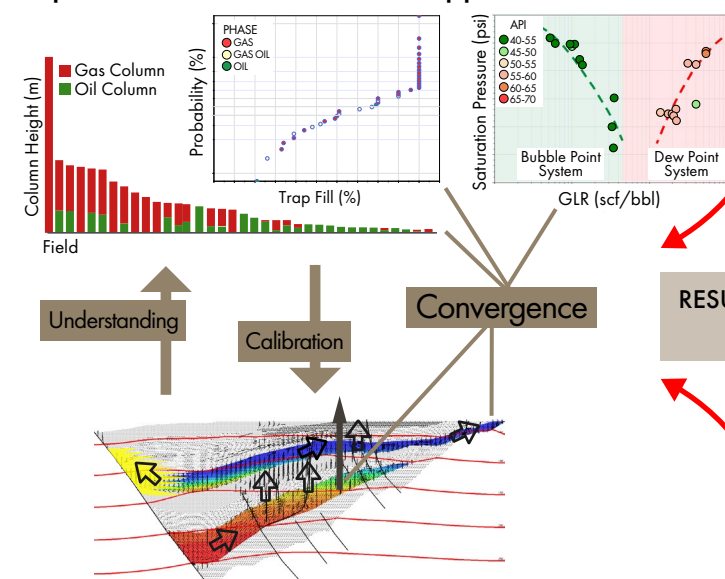
Top-down workflows are particularly valuable in mature exploration provinces where abundant fluid data exist, and regional basin architecture is already well understood. Be-

cause the analysis relies on measurable fluid properties, it can provide robust predictions.

Although both methodologies have distinct strengths, neither alone provides a complete understanding of the petroleum system. Bottom-up models establish the geological processes that generate and transport hydrocarbons, whereas top-down analysis validates these predictions using observed fluid evidence. Where both workflows converge, confidence in exploration predictions increases substantially. Conversely, discrepancies between model predictions and fluid observations highlight uncertainties that require further investigation.

As such, the most robust exploration decisions arise when geological models developed through bottom-up basin modelling are continuously tested against observations derived from top-down fluid analysis. ■

Top-down observation-driven approach



OBSERVE: Spatial and stratigraphic locations of hydrocarbon occurrences (shows and fluids), system GLR
OBSERVE: Phase state and saturation pressures vs. reservoir pressures
OBSERVE: Fluid GOR vs. saturation pressures, gas wetness and liquid molecular weight (or API), molecular and isotopic signatures
INTERPRET: Number and type of distinct fluid populations and families (geochemical inversion)
INTERPRET: Fluid maturity and mixing signals — number and direction of kitchens
INTERPRET: In-reservoir alteration: reservoir temperature vs. charge history etc.

RESULT: A prediction of the location, type and economic properties of undrilled hydrocarbon pools

CALIBRATE: Known HC occurrences and column heights
SIMULATE: Generation / Expulsion, lateral versus vertical migrations, kitchen yield vs. migration losses, phase separation, retention, leakage, in-reservoir alteration
INPUT: Source properties (thickness, kerogen type, TOC, HI), seal properties (capillary entry pressures, faults)
CALIBRATE: Pressure, temperature, thermal maturity
SIMULATE: Rock properties, heat flow, burial and thermal history
INPUT: Basin type, tectonics, age, sequence stratigraphy, paleoenvironment, paleoclimate, etc.

Bottom-down simulation-driven approach

Top-down meets bottom-up workflow summary (personal communication, Murray, 2026).

Know your faulted folds

Stratigraphic controls on contractional architecture

MOLLY TURKO, DEVON ENERGY



THE CONCEPT of "mechanical stratigraphy" is a staple in structural geology, yet we often confine our focus to the small scale, analyzing how individual beds or fractures respond to stress. By scaling up this perspective, we can leverage stratigraphy as a predictive tool to determine the specific styles of faulting and folding likely to emerge during an orogenic event. In thin-skinned deformation where the basement remains uninvolved, structural styles are heavily dictated by the macro-scale stratigraphic framework — whether the section is dominated by thinly bedded clastics, massive carbonates, or significant volumes of salt or shale.

Three primary styles of fault-related folding illustrate this relationship: fault-bend folds, fault-propagation folds, and faulted detachment folds. A fault-bend fold occurs as rock layers translate along a fault that changes dip, forcing the strata to conform to the ramp-and-flat geometry while largely preserving bed thickness. In contrast, a fault-propaga-

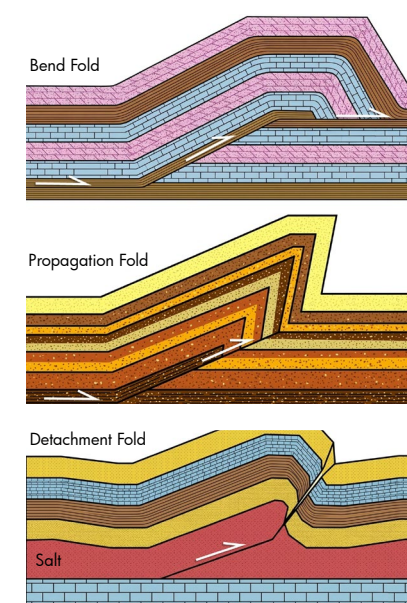


Figure 1: Fold styles related to various stratigraphy

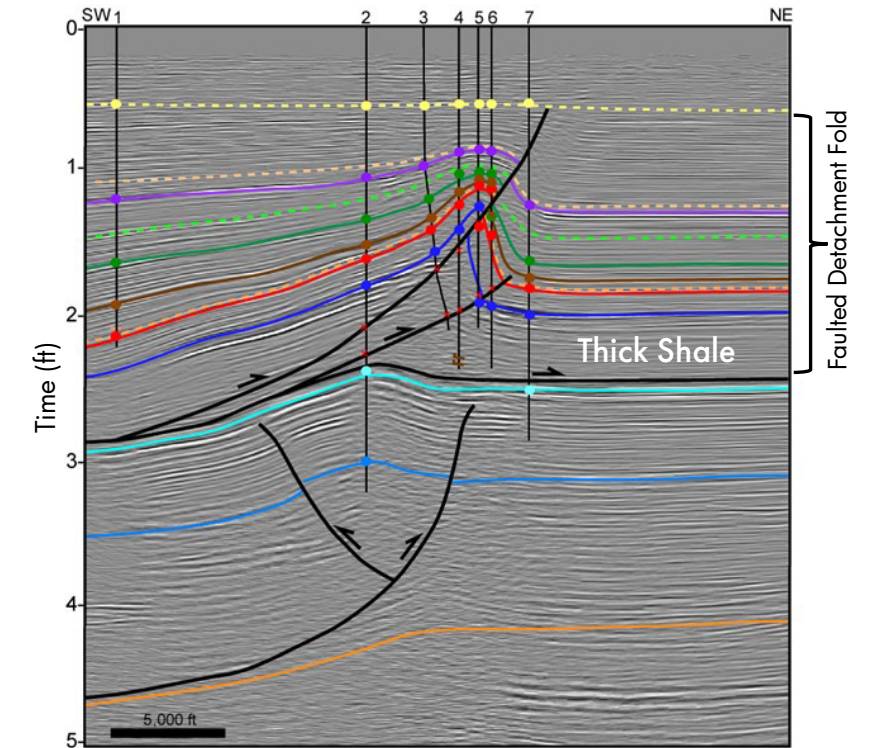


Figure 2: Carter-Knox anticline modified from Turko & Mitra, 2021, "Macroscopic structural styles in the southeastern Anadarko Basin, southern Oklahoma". *Marine and Petroleum Geology* 125.

tion fold develops at the leading edge of a growing fault tip where slip has yet to break through to the surface, accommodating shortening through the development of asymmetric anticlines. Finally, a faulted detachment fold begins as a fold above a weak, low-angle décollement and is subsequently modified by faulting as deformation progresses.

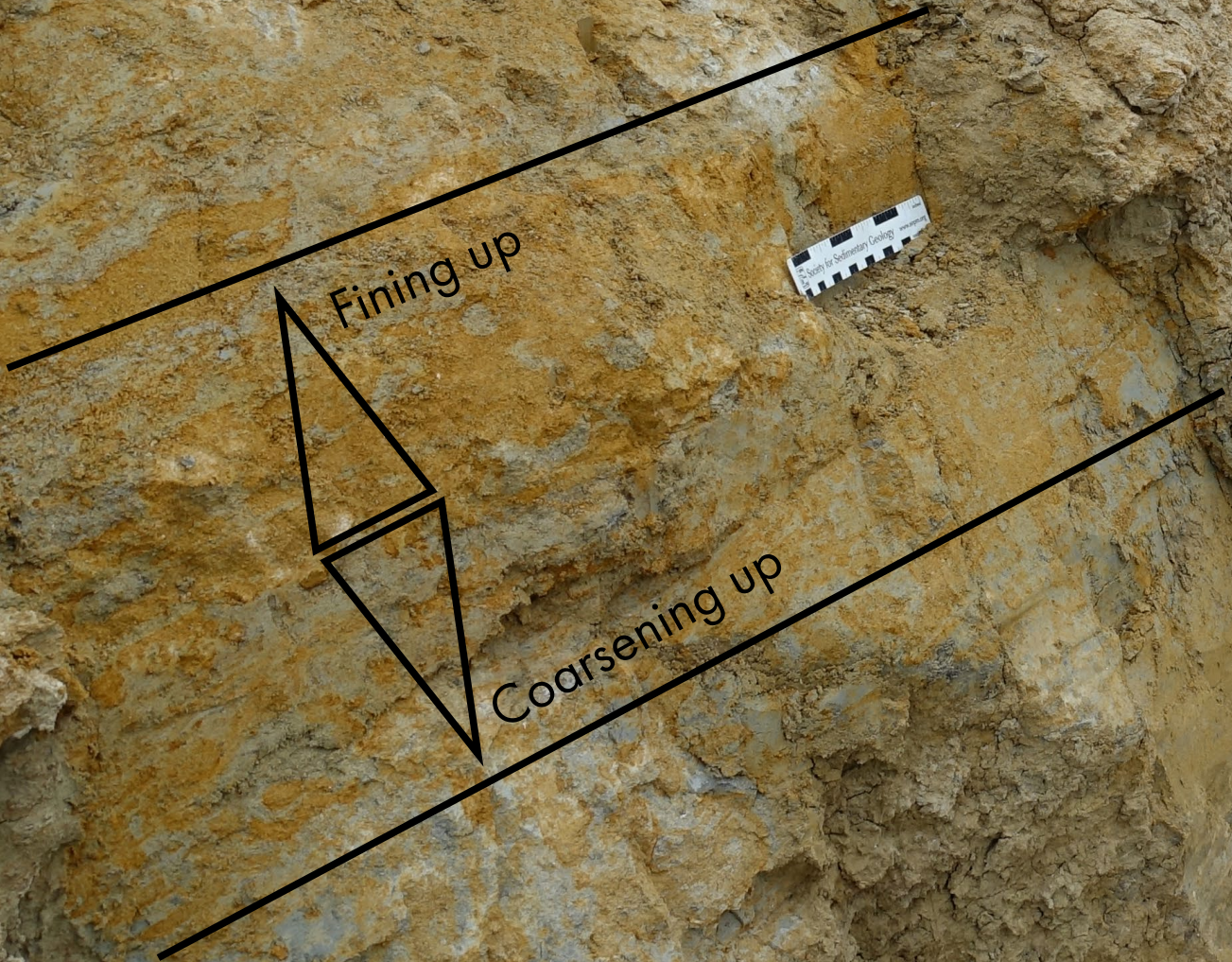
The development of these styles is closely linked to the mechanical properties of the rock column. Fault-bend folds typically occur in stratigraphy characterised by massive, competent units — such as thick carbonates — separated by thin, incompetent shale layers that facilitate slip before ramping upward. Fault-propagation folds tend to favour more homogeneous, thinly bedded mechanical stratigraphy, such as mixed sand-and-shale sequences. Faulted detachment folds are most prevalent in sections containing

substantial thicknesses of salt or over-pressured shale, where the weak décollement allows for significant ductile folding prior to any fault breakthrough.

These relationships are clearly visible in the subsurface of southern Oklahoma. Seismic data from the southeastern Anadarko Basin reveal two distinct levels of structuring: an upper faulted detachment fold situated above a thick shale, and a lower fault-related fold within thick, competent carbonates. While the lower structure is currently classified as a fault-related fold, continued deformation would likely have driven it toward a fault-bend fold geometry due to the competent nature of the units involved. Although nature often produces complex hybrids, these simplified models serve as a vital reminder that the mechanical stratigraphy is a fundamental blueprint for the structural styles we observe. ■



Where: El Adergha, Morocco
When: Miocene
Photography: Wouter de Weger
Text: Henk Kombrink



The 1-meter sand that made the decisive call

“Multiple depositional systems can be responsible for creating the same sedimentary facies,” explains deepwater sedimentologist Wouter de Weger from the Earth Science Institute in Granada, Spain. “For that reason, when looking at an outcrop with a group of specialists, who all bring a different background to the table, it is not surprising to see that there is no immediate consensus on what a certain depositional facies an outcrop represents.”

Wouter recalls a field trip to the northern part of Morocco with a group of sedimentologists. It was the area he spent a lot of time in during multiple field campaigns. “The aim of the trip was to see if the group would be able to agree on our interpretation of contourites being responsible for what we saw,” Wouter explains.

“There was no agreement amongst the members of the group,” Wouter said, “until we visited the last site on the final day of the field trip. There, in what is not a particularly large outcrop, we found a 1 m bed that clearly showed a bi-gradational succession. In other words, from the base of the unit one can observe a progressive increase in flow rate and associated increase in grain size, followed by a decrease or fining up. That is commonly regarded as diagnostic for contourite deposits, following seminal work published by Gonthier in 1984. When we inspected this outcrop together, everybody in the group agreed that we are dealing with the deposits of a contourite system.”

Once the group had reached consensus, observations of traction structures made during the previous days of field work also fell into place; these fit well into the model of bottom currents.

Argentina's pioneers and the secret of Cacheuta

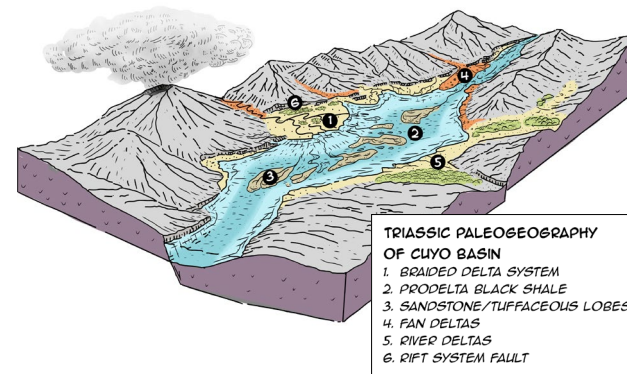
A world-class rift legacy

MARCOS ASENSIO, GEOLOGIST

IN APRIL 1886, Carlos Fader and the *Compañía Mendocina de Petróleo* chose a remote spot in Cacheuta, near Aconcagua, the highest mountain in the whole of the Andes, to drill Argentina's first commercial oil well. Armed with rudimentary machinery, they drilled down to 300 m, guided by natural oil seeps, and achieved a promising initial output of 250 Bbbl/d. This daring venture marked the birth of Argentina's hydrocarbon industry.

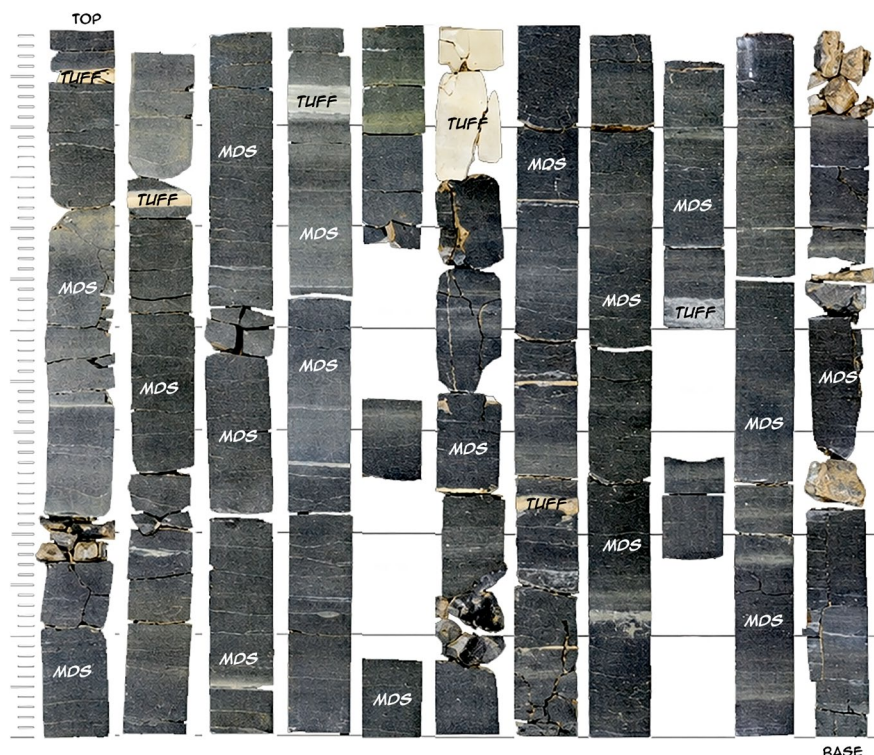
Yet, those pioneers could never have imagined the true scale of what lay beneath their boots. Today, we know that the Cuyo Basin is an ancient, asymmetric Triassic rift basin. Its unique structural architecture, formed by extensional tectonic forces, created deep, restricted troughs that were ideal for trapping thick organic-rich sediments.

It was within this specific rift environment that the magnificent Cacheuta Formation was born, with geochemical analyses revealing it as one of the world's most prolific lacustrine source rocks with typical TOC values of 3–10 % (peaking at 17 %) and high-quality Type I ker-

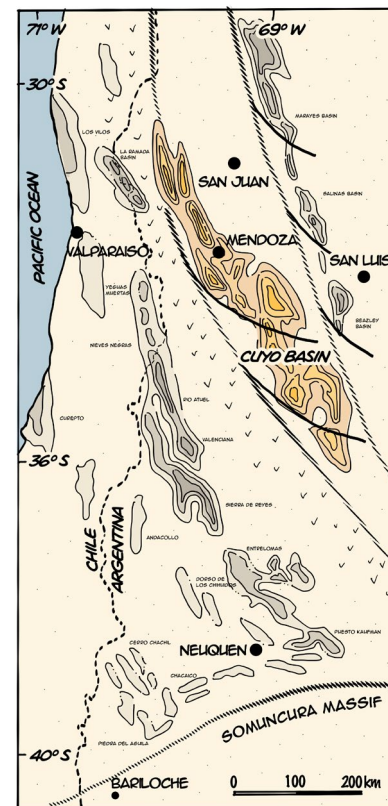


ogen. Its hydrogen index averages 600 mg HC/g TOC, putting it on par with the richest global lacustrine shales.

Though this high-performing rift system generated an estimated 40.1×10^9 barrels of oil equivalent over geological time, only a modest 1.3×10^9 barrels have been recovered so far. Today, as the province of Mendoza evaluates its massive unconventional *shale play* potential, the spirit of Fader lives on. The Cuyo Basin remains an extraordinary frontier where history meets world-class geology. ■



Cacheuta Formation: Triassic lacustrine source rock, the main of the Cuyo Basin and the richest in organic matter in Argentina. Mds: mudstone.



ILLUSTRATIONS: MARCOS ASENSIO / MAP MODIFIED FROM MPDOZIS Y RAMOS, 2008

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